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World Energy Outlook 2016

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The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- 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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In the Foreword to *World Energy Outlook-2015*, I challenged the negotiators at COP21 in Paris to take sober stock of the way that the energy sector was shaping up. Pointing to the unsustainable trends in our central scenario, Paris presented the opportunity to put forward a different vision of our energy future – a world in which energy needs are fully met without dangerously overheating the planet and in a secure and affordable way.

The negotiators had huge challenges to face. But they have done us proud. And sufficient ratifications now mean that the Paris Agreement has come into effect.

A new sense of direction pervades the international climate and energy community, not least the IEA, which is now reinforcing a role as the global "clean energy hub". The particular commitments made in Paris are national, but the determination to realise change is shared. The outlook for global energy changes in consequence.

Our new projections reflect this. The Nationally Determined Contributions, the climate pledges tabled in Paris, are now at the heart of our New Policies Scenario. The prospective changes to the global energy scene are not yet enough to deliver the necessary containment of CO_2 emissions. But we are making progress. No one believes that COP21 was the end of the story. But it is, perhaps, the "end of the beginning", the moment when the world put in place a suitable framework for concerted, collective endeavour.

Renewable energy plays an ever-increasing role in energy supply, both today and in the future. In 2015, renewables, for the first time, accounted for more than half of all new generating electricity capacity globally and we spell out the future prospects in this new edition of the *WEO*. To contribute to the realisation of the fuller role of renewables, we devote three chapters to this subject this year, probing, as part of this, their actual and prospective competitiveness against other forms of energy supply. We also evaluate the constraints on the share of electricity demand that renewables can supply and how they can be tackled.

Some colleagues and friends in the renewables industry have at times criticised the projections of future renewables energy supply in our main scenario as too conservative. They may indeed turn out to be too conservative; I sincerely hope that they do. But they rest squarely on the foundation of officially declared policy intentions. More can and should be done, as we demonstrate clearly in our other scenarios that require a more rapid pace of decarbonisation; but the underlying policies will have to change to make it happen. A clear-headed, rigorous assessment of what today's policy intentions can deliver, in my view, is the best way to encourage the necessary changes.

The global energy transition is gaining momentum, but traditional energy security concerns have not slipped off the agenda. Fossil fuels have had a turbulent year. Lower oil prices persist. Gas output is buoyant, but prices are low. Swathes of the coal industry have sought bankruptcy protection. We see a solid place for oil and gas in energy supply for many years to come and some recovery of fortunes by the next decade. But risks abound. A shortfall of new projects – following two years of declines in upstream spending – would lead to a period of market volatility. There is also the possibility that a surfeit of investment – in the event of a strengthened commitment to climate policies – could lead to some projects and assets becoming stranded. We examine the prospects in both of these cases.

Future constraints do not all lie within the energy industry. Energy production needs water; and water supply needs energy. We examine the interactions and risks.

As usual, the WEO team, led now by Laura Cozzi and Tim Gould, has done an excellent job of assembling data, interpreting it, building projections and drawing lessons from them. I thank them and the many friends around the world who have contributed so much to this latest *World Energy Outlook*.

Dr. Fatih Birol
Executive Director
International Energy Agency

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1. *Mexico Energy Outlook: World Energy Outlook Special Report* was launched in Mexico City on 26 October 2016. It is available to download at: *www.worldenergyoutlook.org/mexico*.

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- Renewables Workshop, Paris, 29 April 2016.

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

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More information about the *World Energy Outlook* is available at *www.worldenergyoutlook.org.*

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Part A: GLOBAL ENERGY TRENDS

Part B: SPECIAL FOCUS ON RENEWABLE ENERGY

The Paris Agreement on climate change, which entered into force in November 2016, is at its heart an agreement about energy. Transformative change in the energy sector, the source of at least two-thirds of greenhouse-gas emissions, is essential to reach the objectives of the Agreement. The changes already underway in the energy sector, demonstrating the promise and potential of low-carbon energy, in turn lend credibility to meaningful action on climate change. Growth in energy-related CO_2 emissions stalled completely in 2015. This was mainly due to a 1.8% improvement in the energy intensity of the global economy, a trend bolstered by gains in energy efficiency, as well as the expanded use of cleaner energy sources worldwide, mostly renewables. An increasing slice of the roughly $1.8 trillion of investment each year in the energy sector has been attracted to clean energy, at a time when investment in upstream oil and gas has fallen sharply. The value of fossil-fuel consumption subsidies dropped in 2015 to $325 billion, from almost $500 billion the previous year, reflecting lower fossil-fuel prices but also a subsidy reform process that has gathered momentum in several countries.

The renewables-led transformation of the power sector has given focus to a new debate over power market design and electricity security, while traditional energy security concerns have not gone away. Adding in issues of energy access, affordability, climate change and energy-related air pollution, as well as problems with public acceptance for different types of energy projects, there are many trade-offs, co-benefits and competing priorities that need to be untangled across the energy sector. This is the task that the *World Energy Outlook (WEO)* takes up in different scenarios and case studies, with the additional opportunity in 2016 to provide the first comprehensive examination of the new era opened up by the Paris Agreement. All the Paris climate pledges, covering some 190 countries, have been examined in detail and incorporated into our main scenario. More stringent decarbonisation options examined in *WEO-2016* include not only the 450 Scenario (consistent with a 50% chance of limiting global warming to 2 °C) but also a first examination of pathways that could limit warming further.

The world's energy needs continue to grow, but many millions are left behind

In our main scenario, a 30% rise in global energy demand to 2040 means an increase in consumption for all modern fuels, but the global aggregates mask a multitude of diverse trends and significant switching between fuels. Moreover, hundreds of millions of people are still left in 2040 without basic energy services. Globally, renewable energy – the subject of an in-depth focus in *WEO-2016* – sees by far the fastest growth. Natural gas fares best among the fossil fuels, with consumption rising by 50%. Growth in oil demand slows over the projection period, but tops 103 million barrels per day (mb/d) by 2040. Coal use is hit hard by environmental concerns and, after the rapid expansion of recent years, growth essentially grinds to a halt. The increase in nuclear output is spurred mainly by deployment in China. With total demand in OECD countries on a declining path, the geography of global energy consumption continues to shift towards industrialising, urbanising India, Southeast Asia and China, as well as parts of Africa, Latin America and the Middle East. China and India see the largest expansion of solar photovoltaics (PV); while by the mid-2030s developing countries in Asia consume more oil than the entire OECD. Yet, despite intensified efforts in many countries, large swathes of the global population are set to remain without modern energy. More than half a billion people, increasingly concentrated in rural areas of sub-Saharan Africa, are still without access to electricity in 2040 (down from 1.2 billion today). Around 1.8 billion remain reliant on solid biomass as a cooking fuel (down by a third on today's 2.7 billion); this means continued exposure to the smoky indoor environments that are currently linked to 3.5 million premature deaths each year.

A new division of capital

A cumulative \$44 trillion in investment is needed in global energy supply in our main scenario, 60% of which goes to oil, gas and coal extraction and supply, including power plants using these fuels, and nearly 20% to renewable energies. An extra \$23 trillion is required for improvements in energy efficiency. Compared with the period 2000-2015, when close to 70% of total supply investment went to fossil fuels, this represents a significant reallocation of capital, especially given the expectation of continued cost declines for key renewable energy technologies. The main stimulus for upstream oil and gas investment is the decline in production from existing fields. In the case of oil, these are equivalent to losing the current output of Iraq from the global balance every two years. In the power sector, the relationship between electricity supply and generating capacity is changing. A large share of future investment is in renewables-based capacity that tends to run at relatively low utilisation rates, so every additional unit of electricity generated is set to necessitate the provision of 40% more capacity than during the period 1990-2010. The increased share of spending on capital-intensive technologies is balanced in most cases by minimal operational expenditures, e.g. zero fuel costs for wind and solar power.

Climate pledges and climate goals

Countries are generally on track to achieve, and even exceed in some instances, many of the targets set in their Paris Agreement pledges; this is sufficient to slow the projected rise in global energy-related CO_2 emissions, but not nearly enough to limit warming to less than 2 °C. China's transition to an economic model oriented towards domestic consumption and services plays a critical role in shaping global trends. The build-up of China's infrastructure in recent decades relied heavily on energy-intensive industrial sectors, notably steel and cement. However, energy demand from these sectors is now past its high point, with the projected decline to 2040 bringing down China's industrial coal use in its wake. Almost all the growth in China's power generation comes from sources other than coal, whose share in the power mix falls from almost three-quarters today to less than 45% in 2040. China's energy-related CO_2 emissions plateau, only slightly above current levels. In India, coal's share in the power mix drops from 75% to 55% over the period to 2040, a major shift in a country that sees electricity demand more than triple (compared with a "mere" 85% rise in China). Among the main developed economies, the United States, the European Union and Japan look to be broadly on track to meet their climate pledges, although delivering on further improvements in energy efficiency will be vital. With a continued focus on full and timely implementation, the pledges are sufficient in aggregate to limit the increase in global CO_2 emissions to an annual average of 160 million tonnes. This is a marked reduction compared with the average annual rise of 650 million tonnes seen since 2000. But continued growth in energy-related CO_2 emissions, to 36 gigatonnes in 2040, self-evidently means that these pledges do not deliver the Paris Agreement's goal to reach a peak in emissions as soon as possible.

Efficiency is the motor of change

A step-change in the pace of decarbonisation and efficiency improvement is required in the 450 Scenario, underlining the importance of the five-year review mechanism, built into the Paris Agreement, for countries to increase the ambition of their climate pledges. The frontlines for additional emissions reductions are in the power sector, via accelerated deployment of renewables, nuclear power (where politically acceptable) and carbon capture and storage; a strong push for greater electrification and efficiency across all end-uses; and a robust and concerted clean energy research and development effort by governments and companies. With regard to efficiency, we highlight in *WEO-2016* the potential for further improvement in the performance of electric motor systems, which account for more than half of today's electricity consumption in a range of end-use applications (e.g. fans, compressors, pumps, vehicles, refrigerators). In the industrial sector alone, additional cumulative investment of around $300 billion in the 450 Scenario reduces 2040 global electricity demand by about 5% and avoids $450 billion in investment in power generation. Capturing these energy savings requires a system-wide approach that encompasses not only strict regulation of motors and motor-driven devices, but also larger uptake of variable speed drives and the implementation by operators of other measures to enhance the efficiency of the system as a whole, such as predictive maintenance.

Electric vehicles ready to move

Electricity takes an ever-larger share of the growth in final energy consumption: from just over one-quarter over the last 25 years, electricity accounts for almost 40% of additional consumption to 2040 in our main scenario and for two-thirds in the 450 Scenario. Non-OECD countries account for more than 85% of the increase in electricity use in both scenarios, but this is also one of the few energy carriers that gains ground within the OECD. Although a small factor in total power demand, the projected rise of electricity consumption in road transport is emblematic of the broader trend, as electric cars gain consumer appeal, more models appear on the market and the cost gap with conventional vehicles continues to narrow. The worldwide stock of electric cars reached 1.3 million in 2015, a near-doubling on 2014 levels. In our main scenario, this figure rises to more than 30 million by 2025 and exceeds 150 million in 2040, reducing 2040 oil demand by around 1.3 mb/d. Although battery costs continue to fall, supportive policies – which are far from universal for the moment – are still critical to encourage more consumers to choose electric over conventional vehicles. If these policies, including tighter fuel-economy and emissions regulations as well as financial incentives, become stronger and more widespread, as they do in the 450 Scenario, the effect is to have some 715 million electric cars on the road by 2040, displacing 6 mb/d of oil demand.

Renewables break free

The electricity sector is the focus of many Paris pledges: nearly 60% of all new power generation capacity to 2040 in our main scenario comes from renewables and, by 2040, the majority of renewables-based generation is competitive without any subsidies. Rapid deployment brings lower costs: solar PV is expected to see its average cost cut by a further 40-70% by 2040 and onshore wind by an additional 10-25%. Subsidies per unit of new solar PV in China drop by three-quarters by 2025 and solar projects in India are competitive without any support well before 2030. Subsidies to renewables are around $150 billion today, some 80% of which are directed to the power sector, 18% to transport and around 1% to heat. With declining costs and an anticipated rise in end-user electricity prices, by the 2030s global subsidies to renewables are on a declining trend from a peak of $240 billion. Renewables also gain ground in providing heat, the largest component of global energy service demand, meeting half of the growth to 2040. This is mainly in the form of bioenergy for industrial heat in emerging economies in Asia; and solar thermal applications for water heating, already an established choice in many countries, including China, South Africa, Israel and Turkey.

In the 450 Scenario, nearly 60% of the power generated in 2040 is projected to come from renewables, almost half of this from wind and solar PV. The power sector is largely decarbonised in this scenario: the average emissions intensity of electricity generation drops to 80 grammes of CO_2 per kWh in 2040, compared with 335 g CO_2/kWh in our main scenario, and 515 g CO_2/kWh today. In the four largest power markets (China, the United States, the European Union and India), variable renewables become the largest source of generation, around 2030 in Europe and around 2035 in the other three countries. A 40% increase in generation from renewables, compared with our main scenario, comes with only a 15% increase in cumulative subsidies and at little extra cost to consumers: household electricity bills in the 450 Scenario are virtually unchanged from those in our main scenario, thanks also to more efficient energy use.

The policy focus shifts to integration

Cost reductions for renewables, on their own, will not be enough to secure an efficient decarbonisation of electricity supply. Structural changes to the design and operation of the power system are needed to ensure adequate incentives for investment and to integrate high shares of variable wind and solar power. The rapid deployment of technologies with low short-run costs, such as most renewables, increases the likelihood of sustained periods of very low wholesale electricity prices. A careful review of market rules and structures is required 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. Strengthening the grid, incentivising system-friendly deployment of wind and solar, and ensuring the availability of power plants ready to dispatch at short notice can efficiently accommodate the variability of wind and solar output, up until they reach a share of around one-quarter in the power mix. After this point, demand response and energy storage become essential to avoid wind and solar installations having their operations curtailed in times of abundant generation. In the absence of these additional measures, by the end of the *Outlook* period in the 450 Scenario curtailment could occur for up to one-third of the time in Europe and around 20% in the United States and India, potentially idling the equivalent of up to 30% of the investment in new wind and solar plants. The timely deployment in this scenario of cost-effective demand-side and storage measures, as part of a suite of system integration tools, limits curtailment to below 2.5% of annual wind and solar output and paves the way for deep decarbonisation of the power sector.

The 2 °C pathway is very tough: the road to 1.5 °C goes through uncharted territory

The challenges to achieve the 450 Scenario are immense, requiring a major reallocation of investment capital going to the energy sector. The division of the $40 trillion in cumulative energy supply investment in the 450 Scenario (some $4 trillion less than in our main scenario) moves away from fossil fuels and towards renewables and other low-carbon investments in nuclear and carbon capture and storage. By 2040, the share going to fossil fuels drops towards one-third. In addition, $35 trillion is needed for improvements in energy efficiency (an extra $12 trillion, compared with our main scenario). The 450 Scenario puts the energy sector on course to reach a point, before the end of this century, when all residual emissions from fuel combustion are either captured and stored, or offset by technologies that remove carbon from the atmosphere. The more ambitious the target for limiting global warming, the earlier this point of net-zero emissions has to be reached. The transformation required for a reasonable chance of remaining within the temperature goal of 1.5 °C is stark. It would require net-zero emissions at some point between 2040 and 2060 (even if negative emissions technologies can be deployed at scale), thus requiring radical near-term reductions in energy sector CO_2 emissions, employing every known technological, societal and regulatory decarbonisation option.

Fossil fuels and the risks from the low-carbon transition

For the moment, the collective signal sent by governments in their climate pledges (and therefore reflected in our main scenario) is that fossil fuels, in particular natural gas and oil, will continue to be a bedrock of the global energy system for many decades to come, but the fossil-fuel industry cannot afford to ignore the risks that might arise from a sharper transition. While all fossil fuels see continued growth in our main scenario, by 2040 oil demand returns to the levels of the late 1990s in the 450 Scenario, at under 75 mb/d; coal use falls back to levels last seen in the mid-1980s, at under 3 000 million tonnes of coal equivalent per year; only gas sees an increase relative to today's consumption level. A fully fledged policy drive to decarbonise the energy system will have important consequences for future revenues of fossil-fuel companies and exporting countries, but the exposure to risk varies across fuels and across different parts of the value chain. For example, the capital at risk in the coal sector is concentrated in coal-fired power stations (for which carbon capture and storage becomes an important asset protection strategy); the key risk in the mining sector, which is much less capital-intensive, is to employment. Exporting countries can take steps to reduce vulnerabilities by limiting their dependence on fossil-fuel revenue, as Saudi Arabia is doing with its sweeping "Vision 2030" reform programme. In the case of oil, we find no reason to assume widespread stranding of upstream oil assets in the 450 Scenario, as long as governments give clear signals of their intent and pursue consistent policies to that end. Investment in developing new upstream projects is an important component of a least-cost transition, as the decline in output from existing fields is much larger than the anticipated fall in demand. But the risks would increase sharply in the event of sudden policy shifts, stop-and-go policy cycles or other circumstances that lead companies to invest for demand that does not materialise.

Oil markets could be in for another bumpy ride

A near-term risk to oil markets could arise from the opposite direction – a shortfall of new projects – if the cuts in upstream spending in 2015-2016 are prolonged for another year. In 2015, the volume of conventional crude oil resources that received development approval fell to its lowest level since the 1950s and the data available for 2016 show no sign of a rebound. A lot of attention is focussed on the remarkable resilience of US tight oil output through the current downturn and its potential ability, because of a short investment cycle, to respond in a matter of months to movements in price. But there is a threat on the horizon to the "baseload" of oil output, the conventional projects that operate on a different rhythm, with lead times of three to six years from investment decision to first oil. We estimate that, if new project approvals remain low for a third year in a row in 2017, then it becomes increasingly unlikely that demand (as projected in our main scenario) and supply can be matched in the early 2020s without the start of a new boom/bust cycle for the industry.

Over the longer term, oil demand in our main scenario concentrates in freight, aviation and petrochemicals, areas where alternatives are scarce, while oil supply – despite a strong outlook for US tight oil – increasingly concentrates in the Middle East. There are few substitutes for oil products as a fuel for trucks and planes and as a feedstock for the chemicals industry; these three sectors account for all of the growth in global oil consumption. Total demand from OECD countries falls by almost 12 mb/d to 2040, but this reduction is more than offset by increases elsewhere. India, the largest source of future demand growth, sees oil consumption rise by 6 mb/d. On the supply side, projected US tight oil output has been revised upwards, remaining higher for longer than in last year's *Outlook*, although non-OPEC production as a whole still goes into retreat from the early 2020s. OPEC is presumed to return to a policy of active market management, but nonetheless sees its share of global production rising towards 50% by 2040. The world becomes increasingly reliant on expansion in Iran (which reaches 6 mb/d in 2040) and Iraq (7 mb/d in 2040) to balance the market. The focus for oil trade shifts decisively to Asia: the United States all but eliminates net imports of oil by 2040.

A truly global gas market is coming into view

A 1.5% annual rate of growth in natural gas demand to 2040 is healthy compared with the other fossil fuels, but markets, business models and pricing arrangements are all in flux. A more flexible global market, linked by a doubling of trade in liquefied natural gas (LNG), supports an expanded role for gas in the global mix. Gas consumption increases almost everywhere, with the main exception of Japan where it falls back as nuclear power is reintroduced. China (where consumption grows by more than 400 billion cubic metres) and the Middle East are the largest sources of growth. But questions abound about how quickly a market currently awash with gas can rebalance, especially with another 130 bcm of liquefaction capacity under construction, primarily in the United States and Australia. Our *Outlook* assumes a marked change from the previous system of strong, fixed-term relationships between suppliers and a defined group of customers, in favour of more competitive and flexible arrangements, including greater reliance on prices set by gas-to-gas competition. This shift is catalysed by the increasing availability of footloose US LNG cargoes and the arrival in the 2020s of other new exporters, notably in East Africa, as well as the diversity brought to global supply by the continued, if uneven, spread of the unconventional gas revolution. Floating storage and regasification units help to unlock new and smaller markets for LNG, whose overall share in long-distance gas trade grows from 42% in 2014 to 53% in 2040. But uncertainty over the direction of this commercial transition could delay decisions on new upstream and transportation projects, posing the risk of a hard landing for markets once the current oversupply is absorbed. Export-oriented producers have to work hard to control costs in the face of strong competition from other fuels, especially in the power sector. In the mid-2020s, in gas-importing countries in Asia, new gas plants would be a cheaper option than new coal plants for baseload generation only if coal prices were $150/tonne (double the anticipated 2025 price). The space for gas-fired generation is also squeezed by the rising deployment and falling costs of renewables.

Coal: a rock in a hard place

With no global upturn in demand in sight for coal, the search for market equilibrium depends on cuts to supply capacity, mainly in China and the United States. There are stark regional contrasts in the coal demand outlook. Some higher income economies, often with flat or declining overall energy needs, make large strides in displacing coal with lower-carbon alternatives. Coal demand in the European Union and the United States (which together account for around one-sixth of today's global coal use) falls by over 60% and 40%, respectively, over the period to 2040. Meanwhile, lower income economies, notably India and countries in Southeast Asia, need to mobilise multiple sources of energy to meet fast growth in consumption; as such they cannot afford, for the moment, to neglect a low-cost source of energy even as they pursue others in parallel. China is in the process of moving from the latter group of countries to the former, resulting in a decline of almost 15% in its coal demand over the *Outlook* period. China is also instrumental to the way that the coal market finds a new equilibrium, after the abrupt end to the coal boom of the 2000s. China is administering a number of measures to cut mining capacity, a move that has already pushed coal prices higher in 2016 (after four straight years of decline). If, however, the social costs of this transition prove too high, China could ease the pace of supply cuts, raising the possibility of China becoming a coal exporter in order to get rid of surplus output: this would prolong the slump in the international market. Alongside measures to increase coal-plant efficiency and reduce pollutant emissions, the long-term future of coal is increasingly tied to the commercial availability of carbon capture and storage, as only abated coal use is compatible with deep decarbonisation.

Energy and water: one doesn't flow without the other

The inter-dependencies between energy and water are set to intensify in the coming years, as the water needs of the energy sector – and the energy needs of the water sector – both rise. Water is essential for all phases of energy production: the energy sector is responsible for 10% of global water withdrawals, mainly for power plant operation as well as for production of fossil fuels and biofuels. These requirements grow over the period to 2040, especially for water that is consumed (i.e. that is withdrawn but not returned to a source). In the power sector there is a switch to advanced cooling technologies that withdraw less water, but consume more. A rise in biofuels demand pushes up water use and greater deployment of nuclear power increases both withdrawal and consumption levels. On the other side of the energy-water equation, the *WEO* analysis provides a first systematic global estimate of the amount of energy used to supply water to consumers. In 2014, some 4% of global electricity consumption was used to extract, distribute and treat water and wastewater, along with 50 million tonnes of oil equivalent of thermal energy, mostly diesel used for irrigation pumps and gas in desalination plants. Over the period to 2040, the amount of energy used in the water sector is projected to more than double. Desalination capacity rises sharply in the Middle East and North Africa and demand for wastewater treatment (and higher levels of treatment) grows, especially in emerging economies. By 2040, 16% of electricity consumption in the Middle East is related to water supply.

Managing energy-water linkages is pivotal to the prospects for successful realisation of a range of development and climate goals. There are several connections between the new United Nations Sustainable Development Goals (SDG) on clean water and sanitation (SDG 6) and affordable and clean energy (SDG 7) that, if managed well, can help with the attainment of both sets of goals. There are also many economically viable opportunities for energy and water savings that can relieve pressures on both systems, if considered in an integrated manner. Efforts to tackle climate change can exacerbate water stress in some cases, or be limited by water availability. Some low-carbon technologies, such as wind and solar PV, require very little water; but the more a decarbonisation pathway relies on biofuels, concentrating solar power, carbon capture or nuclear power, the more water it consumes. As a result, despite lower energy demand, water consumption in 2040 in the 450 Scenario is slightly higher than in our main scenario.

PART A
GLOBAL ENERGY TRENDS

PREFACE

Part A of this *WEO* (Chapters 1-9) 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 – the central scenario in *WEO-2016*. The main alternative scenario is the 450 Scenario (consistent with a 50% chance of limiting global warming to 2 °C), which is accompanied by a first examination of pathways that could limit warming further.

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 and investment choices might have on future energy trends and risks.

Chapter 3 analyses the outlook for oil and what the recent price downturn, lowered investment and the decisions made at COP21 might mean for tomorrow's market balances.

Chapter 4 focuses on the outlook for natural gas and asks whether or not a truly global gas market is emerging.

Chapter 5 analyses the future of coal, including the impact that the ongoing structural shift in China's economy and policies to combat local air pollution and climate change have on major producing and consuming countries.

Chapter 6 looks at the future prospects for the power sector and how the interactions between low-carbon sources of electricity and power generated by fossil fuels affect investment, generation and prices.

Chapter 7 examines recent trends and future prospects for energy efficiency, with an in-depth focus on electric motor systems.

Chapter 8 evaluates what the climate pledges made in Paris mean for long-term energy and emission trends. In addition it explores the challenges associated with reaching temperature targets beyond a 2 °C trajectory.

Chapter 9 assesses current and future freshwater requirements for the energy sector, and, for the first time, provides a systematic global estimate of the amount of energy used in the water sector.

Introduction and scope

Mapping a changing energy landscape

Highlights

- In a momentous period for global energy, the entry into force of the Paris Agreement in November 2016 was a milestone in the international effort to tackle climate change, deployment of wind and solar technologies reached record levels and governments reaffirmed their intention to ensure universal energy access by 2030. An overhang of supply maintained downward pressure on fossil-fuel prices, even as lower hydrocarbon revenues curbed investment in new oil and gas projects. Among the major consumers, India's energy needs continued to grow rapidly, while China's transition to a less energy-intensive economy gathered speed.

- Our main scenario in *WEO-2016*, the New Policies Scenario, incorporates existing energy policies as well as an assessment of the results likely to stem from the implementation of announced intentions, notably those in the climate pledges submitted for COP21. The Current Policies Scenario includes only those policies firmly enacted as of mid-2016; this default setting for the energy system is a benchmark against which the impact of "new" policies can be measured. The 450 Scenario demonstrates a pathway to limit long-term global warming to 2 °C above pre-industrial levels: we also provide a first assessment of what it would take to reach even more ambitious goals, including a 1.5 °C target.

- Alongside energy policies, which differ between scenarios, the rates at which GDP and population are assumed to grow are the principal determinants of energy demand growth. In *WEO-2016*, global GDP is assumed to grow at a compound average rate of 3.4% per year, slightly below the level assumed in last year's *Outlook*. The world population rises from 7.3 billion in 2015 to 9.2 billion in 2040, with India overtaking China in the early 2020s as the most populous country.

- Energy prices and technology costs vary by scenario, responding to different market dynamics and policies. In the New Policies Scenario, balancing supply and demand requires an oil price approaching $80/barrel in 2020 and further gradual increases thereafter. As the natural gas market globalises, so the various regional prices start to move in tandem, with the US market – where the price rises above $6/MBtu by the late 2030s – increasingly serving as a global reference point. The rebound in coal prices is the slowest, with steam coal imports rising towards $90/tonne by 2040. The projections are very sensitive to the way in which technology learning affects supply costs, including the cost of investing in energy efficiency. Today's progress with deployment of low-carbon technologies is reflected in higher penetration of solar and wind in our projections, compared with *WEO-2015*; but fewer power plants are equipped with carbon capture and storage.

1.1 Defining the scenarios

This 2016 edition of the *World Energy Outlook (WEO)* looks out across an energy landscape in flux. The Paris Agreement on climate change, which entered into force in November 2016, brings together countries representing almost all of the world's greenhouse-gas emissions and energy use: it represents a strong signal of the determination of governments around the world to reduce emissions by accelerating the transition to a cleaner and more efficient energy system. The goals set out in Paris, and the measures that governments have announced to achieve them, significantly influence the projections in this year's *WEO*. Evidence of the momentum behind the energy transition goes beyond the signatures on the Paris Agreement: the latest energy data – on which this *WEO* is based – show how investment in low-carbon and more efficient technologies is having a tangible influence on energy trends. 2015 saw additions of renewable power generation capacity exceed those of fossil fuels. The number of electric cars on the road passed one million. Most significantly, the data for 2014 and 2015 suggested that what was once a very predictable relationship between rising economic activity, growth in energy demand and energy-related carbon-dioxide (CO_2) emissions is starting to weaken.

While the energy transition is unmistakeably gathering momentum, it also has a long way to go. In the power sector, which has the least complicated path to decarbonisation, average investment costs in solar power have fallen between 40% and 80% since 2010, yet solar power still accounts for barely 1% of electricity generation worldwide. In the end-use sectors, alternative fuels and technologies have been even slower to gain ground: 1.3 million electric vehicles is an impressive milestone, but it is only around 0.1% of the global car fleet. Oil, coal and natural gas still account for more than 80% of primary energy demand - a share that has barely moved over the last 25 years. Fossil fuels are abundant (particularly coal, the most carbon-intensive of the three main fossil fuels) and – for the moment at least – relatively cheap. The effects of the tight oil and shale gas revolutions in the United States continue to reverberate across global markets, providing a reminder that innovation and cost reduction are not solely the preserve of renewable energy technologies.

Decarbonisation of the energy system is one of a number of energy-related policy priorities being pursued by governments around the world. In September 2015, countries marked the 70th anniversary of the creation of the United Nations with agreement on new Sustainable Development Goals (SDGs), including the commitment in SDG 7 to "ensure access to affordable, reliable, sustainable and modern energy for all" by 2030. As the *WEO* has emphasised over many years, the absence of universal energy access is a lamentable failure of the world's energy system, with around one-in-six people in the world lacking access to electricity and two-in-five risking their health in the smoky environments caused by cooking over open fires using solid biomass as fuel.

Those without access to energy experience the most profound example of energy insecurity, but concerns about the security and reliability of energy provision extend much more widely. Hundreds of millions of people face daily interruptions to electricity supply, compromising their ability to light and cool their homes and interrupting the activity of their firms or farms. Two consecutive years of declining upstream oil and gas investment in 2015 and 2016 similarly raise concerns about the adequacy of future supply – as do political tensions and instability in major resource-rich countries such as Iraq, Libya, Nigeria and Venezuela.

This is still far from an exhaustive list of the different pressures on energy markets and decision-makers. Consumers prize reliable, affordable energy, so governments typically place a high priority on minimising the costs of energy provision, especially in uncertain economic times. In many countries, the immediate energy-related environmental concern is air pollution – the subject of a special report in the *WEO-2016* series (IEA, 2016a). Even well-laid plans for the future are liable to be disrupted by changes in key energy technologies, particularly as governments and industry step up their efforts to promote clean energy innovation. Public acceptance is a major constraint on policy adoption and implementation: fossil fuels are most subject to criticism, but they are not alone in facing an uncertain and difficult future.

With so many uncertainties and (occasionally competing) priorities, no path of development of the global energy system can be confidently drawn to 2040. That is why as in previous years, this edition of the *World Energy Outlook* presents several scenarios. The structure of the main scenarios is retained from previous *Outlooks*, in order to provide continuity and comparability with previous analysis, but the underlying assumptions have been reviewed carefully to reflect the post-Paris expectations for international co-operation on climate change. The three main global scenarios – Current Policies Scenario, New Policies Scenario and 450 Scenario – are supplemented by a first discussion of pathways that could limit global warming to well below 2 °C and 1.5 °C. 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. In addition to the core scenarios, *WEO-2016* also includes multiple case studies and sensitivity analyses, introduced in the individual chapters, to shed light on specific topics.

New Policies Scenario

Based on a detailed review of policy announcements and plans, the **New Policies Scenario** reflects the way that governments, individually or collectively, see their energy sectors developing over the coming decades. Its starting point is the policies and measures that are already in place, but it also takes into account, in full or in part, the aims, targets and intentions that have been announced, even if these have yet to be enshrined in legislation or the means for their implementation are still taking shape.

The climate pledges, known as Nationally Determined Contributions (NDCs)[1], that are the building blocks of the Paris Agreement provide a rich and authoritative source of guidance for this scenario. They have been carefully and individually assessed for this edition of the *WEO*. Where policies exist to support them and the implementing measures are clearly defined, the

1. Formally, the Intended Nationally Determined Contributions (INDCs) submitted for the Paris Agreement will become Nationally Determined Contributions (NDCs) when each Party ratifies the Agreement. This *Outlook* uses the term NDC to refer to both cases (INDCs and NDCs).

effects are reflected in the New Policies Scenario. Where considerable uncertainties persist, how far and how fast the policy commitments are met depends upon our assessment of the political, regulatory, market, infrastructure and financing constraints; in such cases, the announced targets may, in our *Outlook*, be met later than proclaimed or not at all. On the other hand, there are also cases in which energy demand, macroeconomic circumstances and/or cost trends lead countries to go further and faster than their stated ambitions.

The projections in the New Policies Scenario signal to policy-makers and other stakeholders the direction in which today's policy ambitions are likely to take the energy sector. This does not, however, make this scenario a forecast – a point that needs constantly to be kept in mind. Alongside other uncertainties, like the pace of economic growth and technology change, adjustments will be made to policies affecting energy consumption and the evolution of the power sector in the future, beyond those already announced, responding to new circumstances or priorities. We do not attempt to anticipate such future shifts in policy[2] or to predict major technological change; indeed, to do so would be to undermine the value and purpose of this scenario. The New Policies Scenario is not a normative scenario: it does not depict a future that the International Energy Agency (IEA) deems desirable or one that policy-makers or other stakeholders should try to bring into being. It provides a well-founded basis for expectations about the future and thereby also serves as an invitation for improvement: if the outcomes described are sub-optimal or, even, unacceptable, then policies and other conditions and factors need to change. Our intention in the *World Energy Outlook* is to stimulate those changes through evidence-based analysis.

Current Policies Scenario

The accomplishment of announced, new policy targets cannot be taken for granted. The **Current Policies Scenario** depicts a path for the global energy system shorn of the implementation of any new policies or measures beyond those already supported by specific implementing measures in place as of mid-2016. No allowance is then made for additional implementing measures or changes in policy beyond this point, except that – as with the New Policies Scenario – when current measures are specifically time-bound and expire, they are not normally assumed to lapse on expiry, but are continued at a similar level of intensity through to 2040.

Where policies taken into account in the Current Policies Scenario leave scope for a range of possible outcomes, this scenario assumes that only the lower level of ambition is attained. That is, this scenario not only describes a world in which there are no new policies, but also one in which the implementation of some existing commitments is sluggish. It depicts, for example, a world without the implementation of many of the policy changes promised at the United Nations Framework Convention in Climate Change (UNFCCC) Conference of

2. A partial exception relates to fossil-fuel supply, where there is a generic assumption, in all scenarios, that governments make efforts to stimulate domestic production where resources and market conditions offer opportunities to do so. Such efforts are subject to policy and political constraints, including public acceptance, that are taken into account, but the outcome may involve assuming the development of resources that are not currently foreseen for exploitation.

the Parties in Paris (COP21). This is likewise not a prediction but, rather, a "default setting" for the global energy system, with little or no change to settled, established positions. In this way, the Current Policies Scenario provides a benchmark against which the impact of "new" policies can be measured.

Decarbonisation scenarios

The decarbonisation scenarios examined in this *Outlook* are quite different in approach from those discussed above. The New Policies Scenario and Current Policies Scenario start with certain assumptions on policy and then see where they take the energy sector. The decarbonisation scenarios start from a certain vision of where the energy sector needs to end up and then work back to the present. The decarbonisation scenario described in detail in *WEO-2016* is the **450 Scenario**, which has the objective of limiting the average global temperature increase in 2100 to 2 degrees Celsius above pre-industrial levels.[3] A 2 °C target was mentioned explicitly in the Cancun Agreements in 2010 (the first time that it appeared in a document agreed under the UNFCCC framework[4]) and it has also been used as a yardstick in reports from the Intergovernmental Panel on Climate Change. As such, it has become a widely recognised benchmark for government policies and company strategies on climate change.

With this in mind, and to provide continuity with previous *WEOs*, the 450 Scenario retains a prominent position in this *Outlook*. We have, though, revisited important features of this 450 Scenario in the light of progress with the deployment of key low-carbon technologies. As described in more detail in Chapter 8 and Chapters 10-12, the 450 Scenario in *WEO-2016* relies more heavily on renewables, in particular wind and solar, to achieve the necessary reduction in energy-related CO_2 emissions. It relies less than in the past on the deployment of carbon capture and storage (CCS), given the slow pace at which this technology is being tested and deployed in practice, and the constraint that this implies on the pace of its future growth. The results of the 450 Scenario are a point of reference throughout this report, as well in the detailed tables in Annex A.

In addition to the 450 Scenario, *WEO-2016* includes a first appraisal (but not yet in the detail required for a full scenario) of two more ambitious emissions reduction pathways, derived from the Paris Agreement (Box 1.1). These would aim to limit warming to "well below 2 °C" and to 1.5 °C, respectively.[5] While the goal of the latter is well defined, to

3. The 450 Scenario was first introduced in *WEO-2008* at a time when climate targets were typically expressed in terms of the concentration of greenhouse gases in the atmosphere. This set out an energy pathway aiming to limit the concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2 equivalent. To reflect changes in the public and academic discourse surrounding climate change mitigation, the 450 Scenario is now expressed as realising a 50% chance of limiting warming to a 2 °C temperature rise in 2100. This is consistent with the previous concentration-based objective.

4. Article 2 of the 1992 UN Framework Convention on Climate Change committed the Parties to "stabilisation of greenhouse-gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system", without specifying what such a concentration might be.

5. Chapter 8 presents some initial findings in these areas. However, further research is required, in close collaboration with other relevant stakeholders, in order to understand in more detail the ways that such pathways could be achieved. This work is in hand.

date there is no commonly agreed definition of what would constitute a "well below 2 °C" outcome: this discussion is expected to gather momentum in political and scientific circles over the coming months and years. Pending the outcome of this debate, *WEO-2016* explores a trajectory with a 66% probability of limiting the global temperature rise in 2100 to below 2 °C, rather than the 50% chance offered by the 450 Scenario: that is, a trajectory with a higher likelihood of over achievement or, in other words, a higher prospect of a temperature rise less than 2 °C.

Box 1.1 ▷ Key provisions of the Paris climate change agreement

The accord reached in December 2015 at the Paris UNFCCC conference (COP21) was the culmination of a long and complicated negotiating process. The agreement, referred to as the "Paris Agreement", was already ratified by a sufficient number of Parties (the threshold of 55 Parties accounting for at least 55% of total global greenhouse-gas emissions) to allow it to enter into force on 4 November 2016, just before the start of the COP22 in Marrakech, Morocco.

The Paris Agreement sets out the common goal to limit global warming and identifies ways in which this might be achieved. It aims to strengthen the global response to the threat of climate change, by:

> *"Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels."*

Countries are committed to reach this goal via "global peaking of greenhouse-gas emissions as soon as possible", recognising that this will take longer for developing countries, and then by reducing emissions rapidly to a point – sometime in the second-half of this century – when the world achieves a balance between anthropogenic emissions and their removal by sinks, by means of measures such as afforestation or carbon capture and storage.

How is this goal to be achieved? The main mechanism is via Nationally Determined Contributions (NDCs), the pledges made in advance of Paris that outlined climate ambitions and which, implicitly or explicitly, include commitments relating to the energy sector. The first round of NDCs for the period from 2020 are formalised when countries ratify or accede to the Agreement; subsequent NDCs will be communicated every five years, with the next round set by 2020.

To facilitate implementation of the NDCs, particularly in developing countries, the Paris Agreement established various complementary obligations and mechanisms related to finance (the commitment to mobilise $100 billion per year in climate-related finance by 2020 was extended to 2025), capacity-building and technology development and transfer. Outside the formal Agreement framework, 20 countries and the European Union also agreed to double their clean energy research and development spending over the next five years as part of Mission Innovation, supported by commitments by companies – like those in the Breakthrough Energy Coalition – to invest capital in early-stage technology development.

The Paris Agreement includes provisions on adaptation to climate change, market-based emissions reduction mechanisms (establishing a successor to the Clean Development Mechanism), the roles of non-state actors and the need to achieve universal access to sustainable energy. There is also a unified system to track progress, with all countries reporting regularly on their emissions, progress with implementation of NDCs and adaptation actions.

1.2 Developing the scenarios

The World Energy Model (WEM) generates the energy projections used in this report.[6] The WEM is a large-scale simulation tool, developed in-house at the IEA over a period of more than 20 years, designed to replicate how energy markets function. It covers the whole energy system in detail, allowing the analysis to focus not only on global or regional aggregates but also to zoom in on a multitude of indicators, such as the roles of distinct technologies and end-uses, the evolution of power sector and end-user prices, and the implications of different pathways for investment, trade and greenhouse-gas emissions. 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. In addition to the main modules covering energy demand, fossil fuel and bioenergy supply, and energy transformation, there are supplementary tools to amplify the analytical capacity. The model is updated and enhanced each year in order to reflect ever more closely how energy markets operate and how they might evolve. The major changes introduced for the *WEO-2016* include:

- A new, more granular model of the power market, developed for the special focus on renewable energy, to assess the scope for the integration of variable renewables and the related costs (see Chapters 10-12). This allows for a more detailed understanding of the implications of seasonal, daily and hourly variations in the output of certain renewable energy technologies, notably wind and solar, in different markets and the flexibility that is required of other power system components.
- A detailed stock model for industrial electric motor-driven systems, enabling explicit modelling of the impact of policies on elements including the motor, the driven equipment, the use of a variable speed drive and system-wide improvements.
- A new sub-module for international shipping, developed in collaboration with the IEA's Mobility Model (MoMo).
- More detailed representation of renewable energy heat applications in various end-uses.

6. For details on the WEM methodology, see the "WEO Model" section of the *World Energy Outlook website: www.worldenergyoutlook.org.*

- More definition on finding and development costs for different types of conventional oil and gas, as well as a revised representation of associated gas production.
- New play-by-play models for tight oil and shale gas in the United States.
- An overhaul of the way that trade in natural gas is represented, incorporating the best available information on supply contracts and infrastructure plans, disaggregation by country in North America and more detail on gas imports by the European Union.

The WEM is very data-intensive, containing detailed and up-to-date data on energy demand, supply and transformation, as well as time series for a range of energy prices and costs. These data are drawn primarily from IEA databases, which are maintained by the IEA Energy Data Centre on the basis of submissions from IEA member and non-member countries, supplemented by additional research and other sources: historical cost data for wind and solar, for example, are drawn from the International Renewable Energy Agency. The base year for all of the scenarios is 2014, as comprehensive market data for all countries were available only up to the end of 2014 at the time the modelling work was completed. However, where preliminary data for 2015 were available (which was often the case), they have been incorporated. The outputs from the WEM are coupled with quantitative models from other organisations to generate additional findings and insights. Such collaboration in 2016 contributed importantly to two *WEO Special Reports*: *Energy and Air Pollution* (IEA, 2016a) with the International Institute of Applied Systems Analysis; and with the Organisation of Economic Co-operation and Development (OECD) computable general equilibrium model, ENV-Linkages, on the economic impacts of energy policies for the *Mexico Energy Outlook* (IEA, 2016b).

1.2.1 Inputs to the modelling

Energy policies

The policies that are assumed to be pursued by governments around the world vary by scenario: indeed, different policy assumptions are instrumental in producing the divergent outcomes that we see between the Current Policies Scenario, the New Policies Scenario and the decarbonisation scenarios. A good example of such policy differentiation between scenarios arises in relation to the Clean Power Plan in the United States, which aims to cut emissions of carbon dioxide and other pollutants from the US power sector. The Plan was first proposed by the US Environmental Protection Agency in June 2014 and a final version followed in August 2015. Once it was announced in 2014, it was incorporated into the New Policies Scenario. Once the final rules had been put in place, the Plan would normally have become part of the Current Policies Scenario as well. However, in February 2016, the US Supreme Court suspended implementation of the Clean Power Plan, pending judicial review. Even though some US states are moving ahead with implementation, the Clean Power Plan is therefore currently included only in the New Policies Scenario and not in the Current Policies Scenario.

The guidance that countries provided on future energy policies in their NDC's, submitted to the UNFCCC in the run-up to the Paris COP21, is an important input to the *WEO-2016*. The impact of the energy-related component of these climate pledges was analysed in the

WEO-2015 cycle, notably in *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015a), published in advance of COP21 and in a *WEO* Special Briefing for COP21.[7] However, more complete information on all the NDCs, as well as proposed implementing measures, is now available and has been considered in detail in the preparation of this *Outlook*. A detailed list of the policies assumed to be implemented in the various scenarios is included in Annex B. They include programmes to support renewable energy and improve energy efficiency, to promote alternative fuels and vehicles, and to change the way that energy is priced, for example, by reforming subsidised consumer prices for oil, gas and electricity.

On the latter point, during the recent period of lower oil prices many countries have signalled intent to remove fossil-fuel subsidies. But their removal is not assumed in the Current Policies Scenario unless a formal programme is already in place. In the New Policies Scenario, all net-importing countries and regions phase out fossil-fuel subsidies completely within ten years. In the 450 Scenario, while all subsidies are similarly removed within ten years in net-importing regions, they are also removed in all net-exporting regions, except the Middle East, within 20 years.

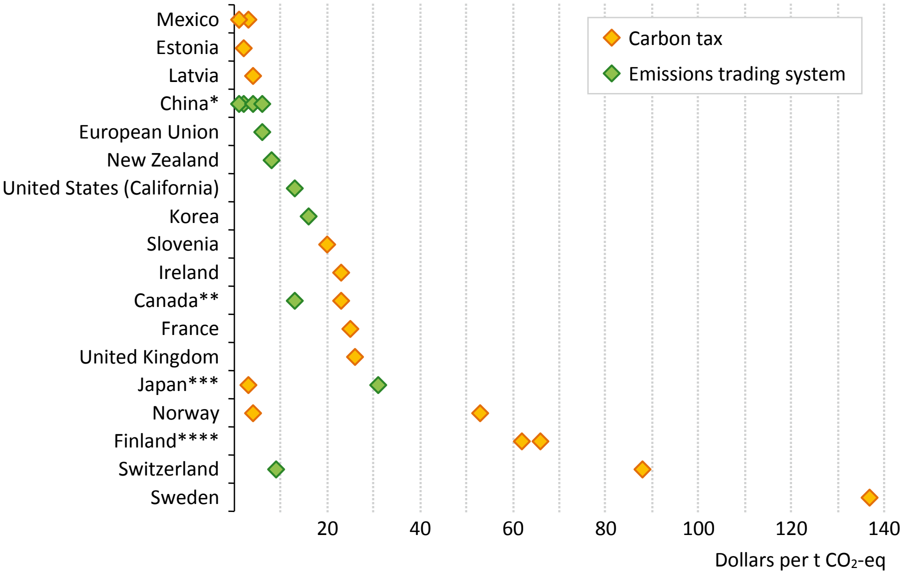
Another influential policy variation between the scenarios is the scope and level of carbon pricing, which has a major impact on the relative costs of using different fuels. As of mid-2016, 63 carbon pricing instruments were in place or scheduled for implementation, either cap-and-trade schemes or carbon taxes, with wide variations in coverage and price (Figure 1.1). In addition to schemes already in place, which are assumed to remain throughout our *Outlook* period, the New Policies Scenario includes the introduction of new carbon pricing instruments where these have been announced but not yet introduced. A notable example is China's carbon trading scheme, due to come into force by the end of 2017 for six large energy-consuming sectors: power, iron and steel, chemicals, building materials, paper and nonferrous metals. In the 450 Scenario, the use of carbon pricing instruments becomes much more widespread, especially within the OECD, and prices are significantly higher (Table 1.1).

Table 1.1 ▷ CO_2 price assumptions in selected regions by scenario

$2015 per tonne	Region	Sectors	2020	2030	2040
Current Policies Scenario	European Union	Power, industry, aviation	18	30	40
	Korea	Power, industry	18	30	40
New Policies Scenario	European Union	Power, industry, aviation	20	37	50
	Chile	Power	6	12	20
	Korea	Power, industry	20	37	50
	China	Power, industry	10	23	35
	South Africa	Power, industry	7	15	24
450 Scenario	United States, Canada, Japan, Korea, Australia, New Zealand	Power, industry	20	100	140
	European Union	Power, industry, aviation	20	100	140
	China, Russia, Brazil, South Africa	Power, industry	10	75	125

7. *www.iea.org/media/news/WEO_INDC_Paper_Final_WEB.PDF.*

Figure 1.1 ▷ Selected carbon pricing schemes in place as of mid-2016



Countries put a wide range of prices on carbon in different parts of the energy sector

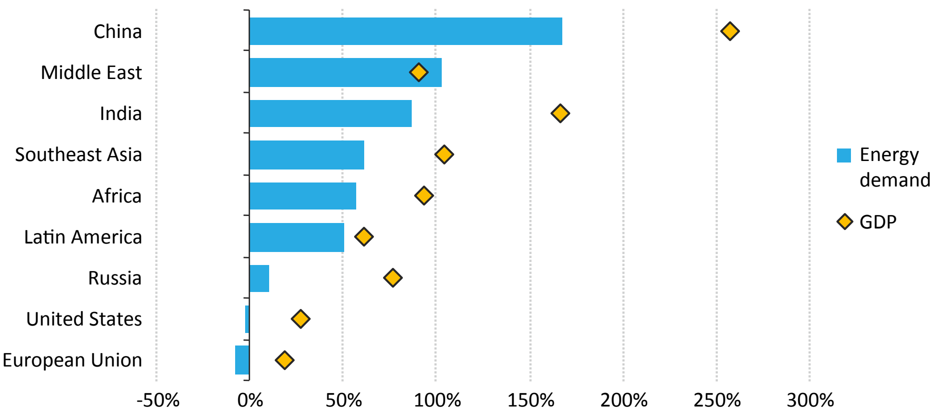
Notes: All prices as of 1 July 2016. \$/tCO_2-eq = US dollars per tonne of carbon-dioxide equivalent. The coverage of the various schemes varies widely, with many limited to specific sub-sectors and/or fuels. Values for Norway cover lower and upper values of carbon tax. * China includes pilot schemes introduced in Shanghai, Guangdong and Chongqing (\$1-2/tCO_2-eq), Hubei and Tianjin (\$4/tCO_2-eq), Beijing and Shenzhen (\$6/tCO_2-eq). ** Canada includes initiatives introduced by Québec (\$13/tCO_2-eq), Alberta (\$15/tCO_2-eq) and British Columbia (\$23/tCO_2-eq). *** Japan includes national carbon tax (\$3/tCO_2-eq) and Tokyo emissions trading (\$31/tCO_2-eq) **** Finland includes initiatives covering heating fuels (\$62/tCO_2-eq) and the transport sector (\$66/tCO_2-eq).

Sources: World Bank Group; Ecofys; Carbon Pricing Watch 2016.

Economic outlook

Economic prospects play a critically important role in determining the outlook for energy consumption, not only the headline rate of growth in gross domestic product (GDP), but also the way in which growth rates might vary across different sectors of the economy. For the world as a whole, GDP growth is pushing energy consumption higher. However, this relationship has diverged substantially across countries over recent years. Among the OECD group of economies, growth in GDP (expressed in real purchasing power parity [PPP] terms) was even associated with a slight decline in primary energy demand for the period 2000-2014. This is a noteworthy turn of events, but not necessarily a surprising one given that structural economic shifts, saturation effects and efficiency gains produced a peak in primary energy demand in Japan (in 2004) and the European Union (in 2006), since when demand in both has fallen by more than 10%; and demand in the United States is already 5% below the high point reached in 2007. Elsewhere, however, the links between economic growth and energy consumption remain strong (Figure 1.2). Overall, for every one percentage point rise in non-OECD economic growth over the period 2000-2014, energy demand increased by around 0.7%.

Figure 1.2 ▷ Changes in GDP and energy demand in selected countries and regions, 2000-2014



Comparing the pace of economic growth from 2000 to 2014 with energy demand growth over the same period shows wide country and regional variations

Note: GDP = gross domestic product.

In each of the scenarios included in this *Outlook*, the world economy is assumed to grow at a compound average annual rate of 3.4% over the period 2014 to 2040 (Table 1.2). This represents a slight reduction in anticipated growth compared with the 3.5% rate assumed in *WEO-2015*. The main differences occur over the period to 2020, where the new growth assumptions reflect the more subdued economic forecasts made by the International Monetary Fund (IMF), the primary source for our medium-term GDP outlook.[8] The downward revisions over this period have been sharpest for hydrocarbon exporters, particularly those in Latin America and Africa, where deteriorating fiscal and external balances have forced cuts to consumption and investment spending. Even for net hydrocarbon importers, the period of lower oil prices has proved to be less of an economic boost than many had expected. In many cases, the drop in fuel prices seen by consumers has been much less than the headline fall in the oil price: many countries have taken the opportunity of lower prices to cut domestic energy subsidies or raise fuel taxes. Exchange rate fluctuations and the strong US dollar have also had an impact (Box 1.2).

The way that future growth in economic activity translates into demand for energy is heavily dependent on policies (notably energy efficiency policies, the intensity of which

8. The medium-term outlook for GDP was adjusted slightly, in consultation with the IMF, to align with IEA expectations about energy market conditions.

varies by scenario) and structural changes in the economies.[9] Future GDP growth based on an expansion of industrial output, especially in energy-intensive sectors, such as iron and steel, cement or petrochemicals, has much stronger implications for energy demand than a similar expansion based on the services sector. For the global economy as a whole, services account for the largest share of current GDP, at 62%, and this share rises steadily to reach 64% by 2040. The rising role of the services sector in GDP is particularly striking in the case of China, whose economy is already rebalancing away from a reliance on manufacturing and exports towards a more domestic- and service-oriented economy, with a much less energy-intensive pattern of growth than in the past. The share of industry in China's GDP is projected to fall from 42% today to 34% in 2040.

Table 1.2 ▷ Real GDP growth assumptions by region

	Compound average annual growth rate				
	2000-14	2014-20	2020-30	2030-40	2014-40
OECD	**1.6%**	**2.0%**	**1.9%**	**1.7%**	**1.9%**
Americas	1.8%	2.3%	2.2%	2.1%	2.2%
United States	1.7%	2.3%	2.0%	2.0%	2.0%
Europe	1.4%	2.0%	1.7%	1.5%	1.7%
Asia Oceania	1.7%	1.4%	1.6%	1.3%	1.4%
Japan	0.7%	0.4%	0.8%	0.7%	0.7%
Non-OECD	**6.0%**	**4.6%**	**4.9%**	**3.8%**	**4.4%**
E. Europe/Eurasia	4.4%	1.1%	3.0%	2.7%	2.4%
Russia	4.1%	0.0%	2.6%	2.5%	2.0%
Asia	7.6%	6.1%	5.5%	3.9%	5.0%
China	9.6%	6.2%	5.2%	3.2%	4.6%
India	7.2%	7.5%	7.0%	5.3%	6.5%
Southeast Asia	5.3%	5.0%	4.9%	3.7%	4.5%
Middle East	4.6%	3.0%	3.8%	3.4%	3.4%
Africa	4.7%	4.0%	4.8%	4.3%	4.4%
South Africa	3.1%	1.7%	2.8%	2.9%	2.6%
Latin America	3.5%	0.8%	3.1%	3.1%	2.6%
Brazil	3.3%	-0.5%	2.9%	3.1%	2.2%
World	**3.7%**	**3.5%**	**3.7%**	**3.1%**	**3.4%**
European Union	1.3%	1.9%	1.6%	1.4%	1.6%

Note: Calculated based on GDP expressed in year-2015 dollars in PPP terms.

Sources: IMF (2016); World Bank databases; IEA databases and analysis.

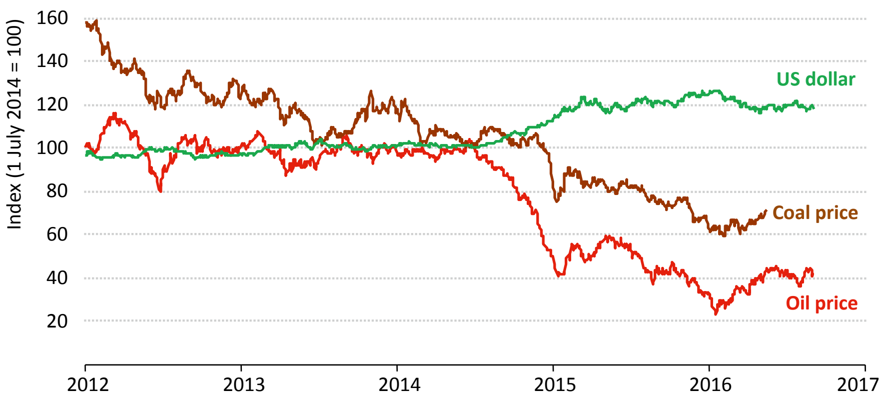
9. The shift in energy use in some developing countries away from the traditional use of solid biomass (particularly for cooking) towards modern fuels also has a large impact on measured energy use, as well as significant co-benefits in reducing exposure to air pollution.

Box 1.2 ▷ Impact of exchange rate fluctuations

All energy prices, investments and other costs are expressed in constant US dollars in our scenarios. This is an appropriate simplification for a modelling effort aimed at understanding the long-term dynamics of the energy sector and that seeks equilibrium only in this sector, rather than across entire economies. But, particularly in the short term, fluctuations in exchange rates can have important implications for energy trends, notably if the dollar – the currency in which much internationally traded energy is priced – gains or loses value against other currencies.

The steady strengthening of the dollar since mid-2014 is a good case in point (Figure 1.3). For economies whose currencies lost value against the dollar at a time when prices for oil, gas and coal were falling, the fall in prices for consumers was partly offset. Similarly, producers were shielded from some of the revenue loss. An oil price fall in US dollars of 50% can result in a price change of barely 25% in countries where currencies have suffered a fall against the dollar. It is not just energy prices that are affected, but also energy technologies. For countries looking to import solar photovoltaic (PV), for example, the striking decline in panel costs (expressed in US dollars) is much less impressive in local currencies that have lost value against the dollar. In Australia, for example, the costs of residential PV fell by half between 2012 and 2015, when expressed in US dollars, but in local currency terms – a much more relevant indicator for consumer uptake – they dropped by only a little more than a quarter. The energy implications for any individual country depend on the way that it sources energy products, services and technologies, whether locally or from the international market. We have taken this into account in *WEO-2016* when establishing the base year technology costs in markets that have seen large, recent currency swings.

Figure 1.3 ▷ Trends in oil and coal prices and US dollar value



A rise in the value of the US dollar has affected the way that falling fossil-fuel prices affect consumers in many countries

Note: The US dollar index is a measure of the value of the dollar against a basket of non-US currencies.

Demographic trends

Population and demographics are important underlying determinants of energy use. As in previous years, the *WEO-2016* adopts the medium variant of the latest United Nations' projections as the basis for population growth in all scenarios (UNPD, 2015). According to these projections, the world population is expected to grow by 0.9% per year on average, from 7.3 billion in 2014 to 9.2 billion in 2040 (Table 1.3). The increase in the global population is concentrated in Africa, India, Southeast Asia and the Middle East. Africa experiences the fastest rate of growth, its population nearly doubling to 2.1 billion people. India overtakes China to become the world's most populous country in the early 2020s, with its population exceeding 1.6 billion by the end of the period. A number of countries experience a decline in population over the period to 2040, including Japan (whose population in 2040 is projected to be almost 10% smaller than it is today), Russia and Germany. People increasingly concentrate in cities and towns, pushing the global urbanisation rate up from 53% in 2014 to 63% in 2040.

Table 1.3 ▷ Population assumptions by region

	Population growth*			Population (million)		Urbanisation	
	2000-14	2014-25	2014-40	2014	2040	2014	2040
OECD	**0.7%**	**0.5%**	**0.4%**	**1 272**	**1 394**	**80%**	**85%**
Americas	1.0%	0.8%	0.7%	496	592	81%	86%
United States	0.9%	0.7%	0.6%	323	377	82%	86%
Europe	0.6%	0.3%	0.2%	570	599	76%	82%
Asia Oceania	0.3%	0.1%	0.0%	206	203	90%	93%
Japan	0.0%	-0.3%	-0.4%	127	114	93%	97%
Non-OECD	**1.4%**	**1.2%**	**1.0%**	**5 983**	**7 758**	**48%**	**59%**
E. Europe/Eurasia	0.0%	0.1%	-0.1%	343	335	63%	68%
Russia	-0.1%	-0.1%	-0.3%	144	133	74%	79%
Asia	1.1%	0.8%	0.6%	3 779	4 459	43%	57%
China	0.6%	0.3%	0.1%	1 372	1 398	55%	73%
India	1.5%	1.1%	0.9%	1 295	1 634	32%	45%
Southeast Asia	1.3%	1.0%	0.8%	623	763	47%	60%
Middle East	2.4%	1.7%	1.4%	224	323	70%	75%
Africa	2.5%	2.4%	2.3%	1 156	2 062	40%	51%
South Africa	1.5%	0.7%	0.6%	54	63	64%	75%
Latin America	1.2%	0.9%	0.7%	481	578	79%	85%
Brazil	1.1%	0.7%	0.5%	206	236	85%	90%
World	**1.2%**	**1.0%**	**0.9%**	**7 255**	**9 152**	**53%**	**63%**
European Union	0.3%	0.1%	0.0%	510	511	75%	81%

* Compound average annual growth rate.

Sources: UN Population Division databases; IEA analysis.

1.2.2 International prices and technology costs

The variables discussed so far – assumptions on future energy policies, economic activity and demographic trends – are all introduced from outside the model (they are exogenous variables). Another set of variables, of considerable importance to the operation of the World Energy Model, is generated within the model itself. These are our price trajectories for each of the fossil fuels and the evolution of costs for different energy technologies. In the case of fossil-fuel prices, the need is to reach a level which brings the long-term projections for supply and demand into balance, and price trajectories are adjusted in iterative model runs until they satisfy this criterion (Table 1.4). The price trajectories are smooth trend lines, and do not attempt to anticipate the cycles and short-term fluctuations that characterise all commodity markets in practice.

Table 1.4 ▷ Fossil-fuel import prices by scenario

		New Policies Scenario			Current Policies Scenario			450 Scenario		
Real terms ($2015)	**2015**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
IEA crude oil ($/barrel)	51	79	111	124	82	127	146	73	85	78
Natural gas ($/MBtu)										
United States	2.6	4.1	5.4	6.9	4.3	5.9	7.9	3.9	4.8	5.4
European Union	7.0	7.1	10.3	11.5	7.3	11.1	13.0	6.9	9.4	9.9
China	9.7	9.2	11.6	12.1	9.5	12.5	13.9	8.6	10.4	10.5
Japan	10.3	9.6	11.9	12.4	9.9	13.0	14.4	9.0	10.8	10.9
Steam coal ($/tonne)										
OECD average	64	72	83	87	74	91	100	66	64	57
United States	51	55	58	60	56	61	64	53	52	49
European Union	57	63	74	77	65	80	88	58	57	51
Coastal China	72	78	86	89	79	92	98	73	72	67
Japan	59	66	77	80	68	84	92	61	59	53

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market. The China and European Union gas import prices reflect a balance of LNG and pipeline imports, while the Japan import price is solely LNG.

In the case of technology costs, the WEM incorporates a process of learning that brings down costs with the cumulative deployment of a given technology: the more a given technology is used, the quicker costs come down – so again it varies by scenario. Learning applies, in different ways, to all technologies across the entire energy system – from upstream oil and gas to renewables and energy efficiency, but the downward pressure on costs of greater scale of deployment is offset, in some cases, by other considerations, such as the effects of depleting a finite resource (most obviously, in the case of oil and gas) or other limits (such as the availability of prime onshore sites for wind power).

Oil

Moving into the last quarter of 2016, there are signs that the market rebalancing anticipated in last year's WEO (and in the IEA's short- and medium-term analysis) is underway; but the process is a slow one. With Saudi Arabia and other key Organization of Petroleum Exporting Countries (OPEC) producers raising output in 2016 to historic highs, the adjustment in the market has depended on the interaction between two other variables: the stimulus that a lower price gives to oil demand and the check that it provides on supply from more expensive sources, much of which is non-OPEC. Oil demand growth has indeed been relatively strong, and is anticipated to reach 1.2 million barrels per day (mb/d) for 2016 as a whole. Investment cuts are also starting to take their toll on non-OPEC output, which is expected to decline by around 0.9 mb/d in 2016. But output from the main low-cost Middle East producers has been rising steadily and – with no clear global surplus of demand over supply – global inventories remain at record levels.

As argued in last year's *Outlook*, the process of market rebalancing is rarely a smooth one and the oil market could well enter a new period of price volatility as it seeks a new equilibrium. A key consideration is the long lead times associated with most upstream projects, which mean that – in the majority of cases – the large cuts in upstream spending seen in many non-OPEC countries have yet to work their way through into lower supply. *WEO-2016* does not attempt to model short-run price fluctuations, but indicates that, in the New Policies Scenario, a price of around $80/barrel would be sufficient and necessary to balance the market in 2020.

The possibility that the oil market could settle at a lower price level cannot be ruled out: indeed, the market expectations expressed in the forward curve for Brent crude oil (as of October 2016) suggest prices around $60/barrel in 2020. Arguments in favour of such a price level as the "new normal" rest on the perception of a strong structural component in the recent decline in upstream costs, particularly in the case of US tight oil, implying resilience among key non-OPEC sources to a lower price environment. In addition, such arguments rely on the assumption that the main resource-holders, led by Saudi Arabia, are less able (or less willing) to exert meaningful influence on the market by restraining output than they have been in the past. A scenario in which ample supply keeps oil prices in the $50-60/barrel range until the early 2020s, before rising very gradually to $85/barrel in 2040, was examined in *WEO-2015* (Box 1.3) and the results of that Low Oil Price Scenario remain a point of reference and comparison in this *Outlook*.

Box 1.3 ▷ Are we in a Low Oil Price Scenario?

With the oil price only rarely breaking above $50/barrel in the first three-quarters of 2016, the idea that oil prices could stay "lower for longer" has gained a firm foothold in discussions on the oil market outlook. But how much longer could a period of lower prices plausibly last? In *WEO-2015*, we tested the long-term durability of this idea in a Low Oil Price Scenario, in which we examined a set of conditions that would allow lower oil prices to persist all the way through to 2040.

The main assumptions that differentiated this scenario from the New Policies Scenario were lower near-term economic growth and a more rapid phase out of fossil-fuel consumption subsidies (both restraining growth in oil consumption); greater resilience among some non-OPEC sources of supply to a lower price environment, notably tight oil in the United States; a lasting commitment by OPEC countries to give priority to market share and to a price that limits substitution away from oil; and favourable assumptions about the ability of the main oil-producing regions to weather the storm of lower hydrocarbon revenues.

One year on, some of these assumptions are holding. Economic prospects have indeed dimmed and many countries – including not just oil importers but also oil exporters – have announced their intention to reform energy prices, dampening prospects for strong demand growth. Production in some key non-OPEC countries, notably the United States and Russia, has held up well under testing conditions, although the shift towards greater reliance on lower cost producers in the Middle East, another feature of the Low Oil Price Scenario, is already visible, with the share of the Middle East in global output rising to 35%, a level not seen since the late 1970s.

However, other assumptions are looking shakier. Some other anticipated sources of future non-OPEC supply are showing the strain. In Brazil, Petrobras' annual investment plans have been slashed, as lower revenues, high debt and the repercussions of a corruption scandal take their toll on spending. In Canada, drilling activity in 2016 is set to be lower than at any point in the country's 40-year recorded drilling activity history.

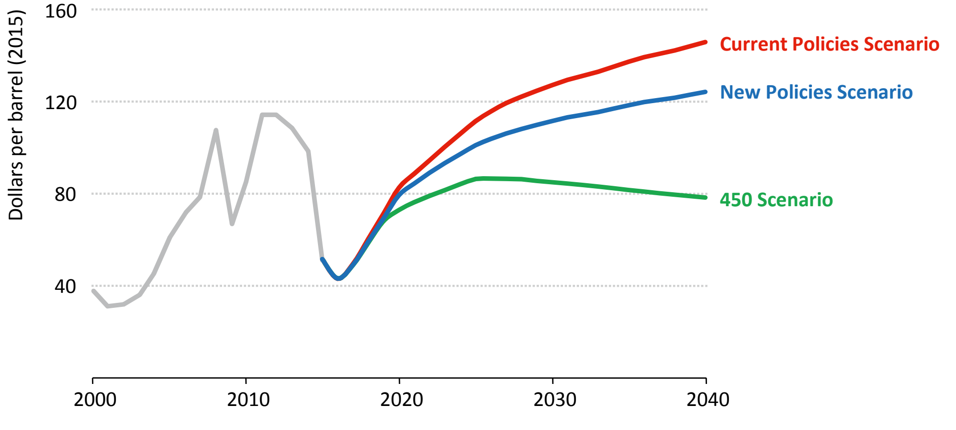
Moreover, after a long period in which consensus proved difficult to reach, OPEC countries announced a plan to return to active market management at a meeting in Algiers in September 2016, agreeing to cap crude oil output at a level between 32.5 mb/d and 33 mb/d (the group's first deal to cut production since 2008). The details of the agreement and the potential effect on market balances remain to be seen, but the announcement was indicative of the testing conditions that lower oil prices have created for many OPEC producers, especially those that faced the downturn with limited accumulated financial reserves. The budgetary cuts necessary to adjust to the reduced levels of revenue have been deeply destabilising in countries like Venezuela, Iraq, Nigeria and Libya, especially when considered alongside existing political and security challenges.

In practice, this tallies with a finding of *WEO-2015*: the Low Oil Price Scenario offers the potential for lower cost producers to expand their output (because of the stimulus to demand and because higher cost producers are squeezed out of the supply mix); but they also stand to lose more from the lower price than they gain from higher production. The pressure that a lower price trajectory puts on the fiscal balances of these key producers ultimately makes such a scenario look increasingly unlikely, the further it is extended out into the future.

In the New Policies Scenario, the oil price trend continues to edge gradually higher post-2020, with three main considerations underpinning this rise (Figure 1.4). The first relates to the amount of new production that is required to keep pace with demand. This might appear modest at first glance, since oil use rises only by 13 mb/d over a 25-year period; but most of the investment required in all scenarios is to replace declining production from existing fields (a point discussed in Chapter 3). Second, in almost all cases, oil is more costly to produce in 2040 than today. There have been strong cost reductions in many upstream activities in recent years, but, in our estimation, there is a cyclical component to these reductions that is set to reverse as upstream activity picks up and the supply and services markets tighten (see Chapter 3). We incorporate continued improvements in technology and efficiency into our *Outlook*, but their impact on upstream costs is more than counterbalanced, for most resource types, by the effects of depletion: as "easy oil" is depleted, so producers are forced to move to more challenging and complex reservoirs, that are more expensive to develop. This is the case also for tight oil in the United States, as operators eventually deplete the main "sweet spots", the most productive areas in the various plays, and are forced to move into areas of lower resource quality.

As well, logistical and other constraints on the rate at which oil can be developed (in both OPEC and non-OPEC countries) can easily keep the oil price trajectory above the marginal cost of the barrel required to meet demand. These include geopolitical risks, that might constrain investment and output of the world's lowest cost oil, and our assumption that the main low-cost resource-holders in OPEC follow through with efforts (following the recent meeting in Algiers) to defend a global price level above that implied by the global supply-cost curve.

Figure 1.4 ▷ Average IEA crude oil import price by scenario



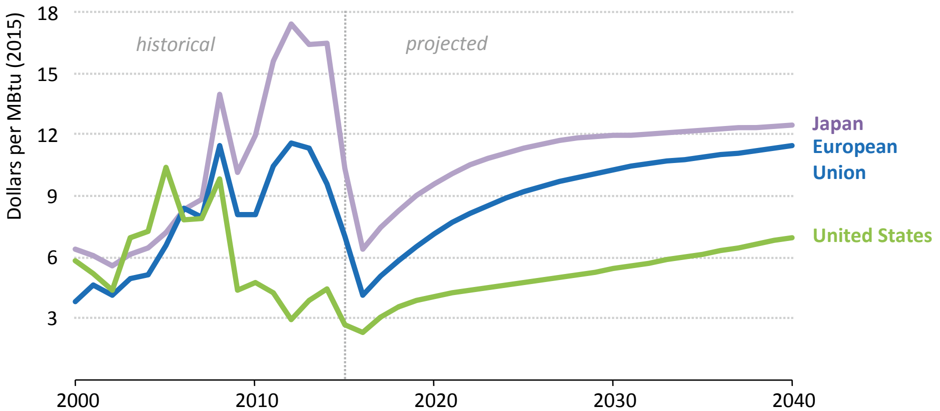
Oil prices vary widely by scenario, depending on the level of demand

Oil prices in the other main scenarios are similarly determined by the need for investment to meet projected demand. Higher demand in the Current Policies Scenario means a higher call on oil from costly fields in non-OPEC countries. Conversely, in the 450 Scenario, more aggressive policy action to curb demand means that a market equilibrium can be found at a lower price.

Natural gas

There is, for the moment, no single global price for natural gas. Instead, a set of regionally determined prices, loosely connected, reflect the distinct market dynamics and pricing mechanisms of different regional markets (Figure 1.5). In this *Outlook*, we focus on three regional prices: North America, Asia and Europe. In North America, 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 price of gas paid by North American consumers is calculated on the basis of a series of differentials from Henry Hub, reflecting the costs of transmission and distribution, and other fees and charges. The price of gas exported from North America as liquefied natural gas (LNG) reflects the additional costs of liquefaction, shipping in LNG tankers and regasification at the importing terminal.

Figure 1.5 ▷ Natural gas prices by region in the New Policies Scenario



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

Notes: US price is a wholesale price; other prices are average import prices.

Projected Henry Hub prices vary by scenario (Table 1.4). As of September 2016, Henry Hub prices are around $3/MBtu; our view is that this price will need to rise, in all scenarios, in order to balance the market – although the extent of this increase is highly contingent on the trajectory for composite demand (local and for export) and also on the size of US shale gas resources (as discussed in the sensitivity analysis in Chapter 4). Perhaps counter-intuitively, our US gas price trajectory in the New Policies Scenario remains relatively low over the medium-term as a result of the anticipated rebound in the global oil price: by increasing the value of the liquids produced along with the gas, and by encouraging tight oil production and its associated gas volumes, gas output remains buoyant at prices around $4/MBtu until well into the 2020s. However, looking further ahead, the need for the United States and Canada to produce more than 1 trillion cubic metres (tcm) of gas each year starts to tell. The twin cost pressures of relying more on dry gas production and depleting the most productive areas of the various shale gas plays has the effect of pushing the price gradually higher and by 2040 it is closing in on $7/MBtu. A similar narrative on the supply side, but accompanied by significantly different prospects for demand, explains the higher price trajectory in the Current Policies Scenario and, conversely, the lower path in the 450 Scenario.

The other regional gas price markers that are pivotal to the *Outlook* are the European and Asian import prices. The prices in Table 1.4 are the average prices paid in each case by importers: they reflect the different pricing arrangements prevailing in the various markets. In the case of Europe, this currently means an increasing share of imported gas priced off trading hubs, particularly in north-western Europe, but with a sizeable residual volume with prices indexed in full or in part to oil product prices (concentrated in southern and south-eastern Europe). In Asia, oil-indexation 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 (such as the US Henry Hub). Throughout the world, the trend is towards greater flexibility of contract terms, shorter contract duration and a greater share of gas available on a spot basis. However, there are still multiple contractual, regulatory and infrastructure barriers that prevent the gas market from operating like a standard commodity market.

A key strategic question for gas markets is the speed at which a truly global gas market might emerge, in which internationally traded gas is no longer tied to specific consumers or defined geographical areas but is free to move in response to price signals that are determined by the dynamics of gas-to-gas competition. This is indeed the direction in which gas markets are assumed to move, such that, by the latter part of the projection period, the price differentials between the various regional markets in *WEO-2016* settle into a range that essentially reflects the costs of moving gas between them.

The current period of over supply in gas markets, alongside the low level of oil prices, has brought down prices in all the major markets. In the New Policies Scenario (as examined in more detail in Chapter 4), the global LNG market does not rebalance until the mid-2020s, a consideration that curbs profitable export opportunities in the meantime. But the increased competition, combined with the arrival of the United States as a major LNG exporter, creates a propitious backdrop for movement towards more flexible pricing and trading arrangements. Large US resources and production flexibility, combined with an LNG export industry actively seeking arbitrage opportunities, means that Henry Hub is projected to become not only a regional but also a global reference point, shaping investment and marketing strategies in other exporting countries and regions. As a result, over the longer term, the European import price settles at around $4-5/MBtu above the US price (in all scenarios), a differential that reflects the cost of delivering gas to exporting terminals, its liquefaction, shipping and then regasification in the importing country. The Asian import price rises more quickly, due to the continued importance of oil-linked pricing in this region, but as this link weakens the "Asian premium" disappears and the differentials from the US price fall to around $5-6/MBtu (the additional sum, compared with Europe, reflecting the extra shipping distance to Asian markets).[10]

Coal

The global coal market consists of various regional sub-markets that interact with each other through imports, exports and arbitrage opportunities. Although less than one-fifth of the global coal production is traded between countries, the international coal market plays a pivotal role in connecting the different sub-markets and in determining overall price trends. Coal prices vary significantly between the regional markets – the differences are primarily due to transportation cost, infrastructure constraints and coal quality – but they typically move in lockstep with international coal prices.

All major coal prices had been in steep decline for four consecutive years before bottoming out in early 2016 (Figure 1.6). The average price of imported steam coal in Europe fell to $57/tonne in Europe and $59/tonne in Japan in 2015. Such price levels were last seen in the early 2000s, just before the big price hike started in the mid-2000s. While much of the price increase between 2007 and 2011 had to do with strong global coal demand growth, China's emergence as a major importer, supply capacity shortages, overheated supply chains and the relative weakness of the US dollar; much of the price decline over the last four years has to do with a reversal of these fundamentals. Global coal demand growth has stalled, Chinese imports are declining, supply capacity is amply available, the US dollar has appreciated against all major currencies and supply chains (shipping and infrastructure but also machinery and consumables supply) have slackened.

It is not unusual for coal markets to follow business cycles, but the key question for this *Outlook* is whether the coal market will find a way out of the current downturn and achieve an economically viable price trajectory. Our coal price trajectories rest on four pillars:

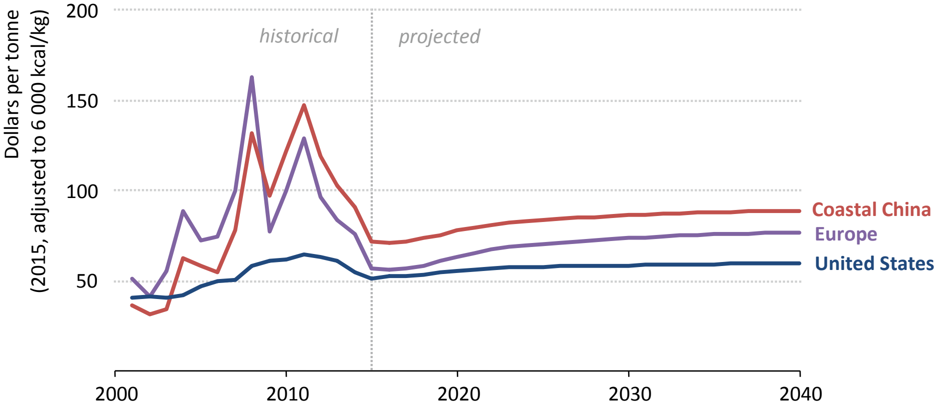
- Policies and market forces underpin the closure of mines that are unable to recoup their costs, which leads to a reduction of excess capacity and supports a balancing of supply and demand by the early 2020s, with the profitability of the industry by-and-large restored.

10. Moving LNG between markets is expected to become slightly less expensive over the period to 2040, as a result of efficiency and technology improvements that bring down liquefaction costs (and, to a more limited extent, shipping and regasification costs). See Chapter 5 in *WEO-2015* (IEA, 2015b).

- Global coal demand growth of 0.2% per year, in combination with gradual depletion of existing mines, partially absorbs overcapacity and requires investments in coal supply of $45 billion per year over the *Outlook* period in the New Policies Scenario.
- Geological conditions are worsening, new mines are deeper or further away from markets and coal quality is deteriorating; all of these factors put modest upward pressure on costs that cannot be fully offset by productivity gains.
- Current exchange rates remain unchanged, while cyclically low input prices for steel, tyres and fuel trend upwards in the long term.

Spurred by the implementation of a first set of capacity cuts in China, coal prices started rising in the second-quarter of 2016. The New Policies Scenario sees this process continuing slowly, with European and Japanese import prices reaching $70/tonne and $73/tonne respectively in 2025 and thereafter increasing gradually to $77/tonne and $80/tonne in 2040. China's coast line provides the link between the international market and the vast Chinese domestic coal market and remains of the utmost importance for international coal pricing, although a similar arbitrage point is projected to arise on India's west coast (see *India Energy Outlook 2015: World Energy Outlook Special Report*). Chinese coastal steam coal prices increase to almost $90/tonne in 2040 (assuming no change in taxation). Over the long term, average prices in the United States increase at a more moderate rate than international coal prices. This comes as production gradually shifts to the west, where prices are lower. Both the Powder River Basin and the Illinois Basin capture market share at the expense of the Appalachian basins, albeit in a rapidly declining market.

Figure 1.6 ▷ Steam coal prices by region in the New Policies Scenario



Steam coal prices recover from current lows but the long-term trend remains markedly below previous highs

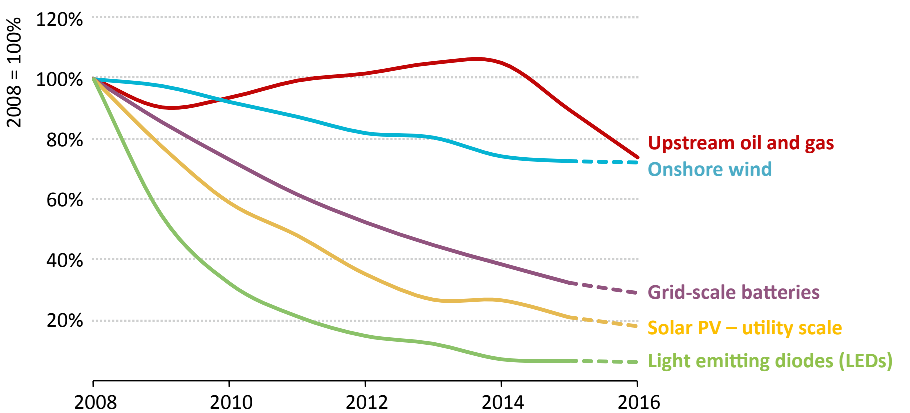
Notes: kcal/kg = kilocalorie per kilogramme. Coastal China represents imports and domestic sales (including domestic taxes). The European price is for imports. The US price is an average delivered price (primarily composed of mine-mouth prices in the sub-markets of the Powder River Basin, Illinois Basin, Northern Appalachia, Central Appalachia etc., plus transport and handling cost).

Technology innovation and costs

Many parts of the global economy have seen rapid, sometimes transformational technology change in recent years, most clearly in areas such as information technologies and communications. The energy sector is not yet one of these areas. The share of fossil fuels in primary energy demand remains almost exactly where it was 25 years ago, with the fastest growth among the fossil fuels over the last quarter-century registered by coal. Centralised power systems reliant on fossil fuels remain by far the dominant model in the electricity sector. Liquid petroleum-based fuels, feeding internal combustion engines, account for well over 90% of transport energy demand.

Yet efforts to overturn this apparently stable picture are gathering momentum and some contours of an alternative vision for the energy sector are taking shape: the rise of high-efficiency, variable renewable energy technologies led by wind and solar; a greatly reduced role for fuel combustion (with the possible exception of bioenergy), allied with control technologies to capture pollutants and greenhouse gases before they are released to the atmosphere; a major increase in the role of electricity across all the end-use sectors, combined with a surge in distributed generation and storage technologies that alter the traditional model of power delivery. All this would be tied together through efficient, integrated system management via smart metering and grids.

Figure 1.7 ▹ Recent cost trends for selected technologies



Cost deflation has affected diverse technologies across the energy spectrum

Source: IEA World Energy Investment 2016 (IEA, 2016c).

There are different views on whether and how quickly such a transformation might take place. Costs for many of the emerging energy supply technologies have fallen rapidly in recent years (as have costs for upstream oil and gas since 2014) (Figure 1.7). Yet they still remain, in most cases, above those of the competing conventional technologies, and so require some measure of government support to gain market share. In addition, major parts of the world's existing capital stock (today's power plants, buildings, factories, vehicles and energy supply infrastructure) have long lifetimes, typically being renewed or replaced only slowly. This creates substantial inertia in the system, even if the rate of change can be accelerated by policies that encourage building retrofits, efficiency upgrades or early retirement of some assets.

The projections in this *Outlook* are very sensitive to the way that technological changes affect the cost of different fuels and technologies, including the cost of investing in energy efficiency. The process of learning and cost reduction is fully incorporated into the WEM, both on the demand and supply sides, and applies not only to technologies in use today, but also to those approaching commercialisation. The extent of learning and cost reduction is linked to the level at which a given technology is deployed, which affects not just the costs of the technology itself, e.g. the batteries for electric vehicles or panels for solar PV, but also related costs for design, installation, inspection and maintenance. As a result, cost reductions for key renewable energy technologies are significantly greater in the 450 Scenario than in the New Policies Scenario.

Although technology learning is an integral part of the *WEO* approach, the *Outlook* does not attempt to predict technology breakthroughs, i.e. an advance that produces a step-change in technologies and costs. These are inherently unpredictable. Typically, they also take many years to proceed from the research laboratory to large-scale commercialisation. They cannot, of course, be ruled out for the period to 2040 and it is at least arguable that the pace of technological change and clean energy innovation will rise in the coming years. That is the express objective of a growing number of international initiatives, including Mission Innovation and the Breakthrough Energy Coalition (both launched at the Paris climate conference in 2015), as well as of established bodies, like the Clean Energy Ministerial.[11] The 20 countries, plus the European Union, participating in Mission Innovation are committed to double investment in clean energy research and development over the five years to 2021. The link to private sector investment in new energy technologies comes via the Breakthrough Energy Coalition, a group of private companies. Their success or failure can only be seen as a risk factor qualifying the numbers produced by our scenarios.

Electricity generation and storage is a focus for much of the work on technology innovation and improvement. On the generation side, the costs of solar PV and onshore wind have fallen dramatically in recent years: from 2010 to 2015, indicative global average onshore wind generation costs for new plants fell by an estimated 20% on average, while costs for

11. The Clean Energy Ministerial (CEM) is a high-level global forum to promote policies and programmes that advance clean energy technology, bringing together 24 countries and the European Commission that are estimated to represent around 75% of global greenhouse-gas emissions and 90% of global clean energy investment. Following a selection process in 2016, the secretariat supporting the work of the CEM will be housed at the IEA. The IEA also has close working ties with Mission Innovation, the Breakthrough Energy Coalition and other energy technology initiatives, as well as its own network of Technology Collaboration Programmes (*www.iea.org/tcp/*).

new utility-scale solar PV declined by two-thirds and further cost reductions are anticipated, albeit at a slower pace, in our projections for solar PV. Onshore wind projects also benefit from lower costs, although the effect of technology learning is offset, in some countries, by the need to move to less favourable sites for wind generation, as the most favourable sites are fully developed. Chapter 11 reviews in detail the impact of envisaged cost reductions on the competitiveness of various renewable energy technologies.

Storage technologies are expected to play a growing role in improving the flexibility of power systems and in the market penetration of electric vehicles, heating and cooling systems, and small- or medium-size off-grid installations. Although pumped storage hydropower continues to dominate the provision of large-scale energy storage, developments in battery storage have won the headlines, as costs have come down, performance has improved and new models of electric vehicles and residential-scale power storage have entered the market. The role of electricity storage in integrating large shares of renewable energy, alongside other sources of power system flexibility, is considered in detail in Chapter 12.

Some technologies and investment projects are not (yet) experiencing cost declines and could see lower deployment as a result. Policy and financial support for CCS in recent years has been lower than anticipated, meaning that deployment has also stalled: only one new CCS project came on line in 2015, at a Canadian oil upgrader. Such technologies risk falling further behind. The uptake of CCS in both the New Policies Scenario and the 450 Scenario has been revised downward in *WEO-2016* compared with last year's *Outlook*.

Overview

Take-aways from the *WEO-2016*

Highlights

- Consumption of all modern fuels continues to grow in the period to 2040 in the New Policies Scenario, although growth in coal is cut to 0.2% per year on average. Oil demand rises steadily to 103.5 mb/d in 2040; gas consumption rises by nearly 50%, overtaking coal. But renewable energy is the major growth story of the *Outlook:* in the power sector, 60% of all capacity additions to 2040 are from renewables.

- The relationship between global economic growth, energy demand and related CO_2 emissions is steadily weakening. The climate pledges made at COP21 lock in a continuation of this trend, but do not yet deliver the early peak in emissions that would be needed for a 2 °C emissions trajectory.

- An early peak and then a fall in emissions consistent with the 450 Scenario would require a step-change in the decarbonisation of the power sector, including measures to integrate variable renewables, and profound changes to the efficiency and carbon intensity of end-uses. The overall energy sector carbon budget for even more ambitious “well below 2 °C” or “1.5 °C” pathways would likely require emissions to fall to zero sometime between 2040 and 2060, even with carbon removal technologies.

- Subsidies to renewables were almost $150 billion in 2015, mostly in the power sector, but cost reductions mean ever greater deployment per dollar spent. By the 2030s, renewables subsidies are projected to be in decline, from a peak of $240 billion, and most renewables generation is competitive without subsidies by 2040. Today’s lower fossil-fuel prices have given additional impetus to pricing reforms in some countries and fossil-fuel consumption subsidies fell to $325 billion in 2015.

- In various parts of the energy system, there are questions whether policies, price signals or market designs are adequate to ensure investment is made when and where it is needed. In the case of oil, an increase in new upstream project approvals, compared with the very low levels seen in 2015 (and so far in 2016) is needed. Oil remains pivotal for energy security, but natural gas and electricity security are also being pushed to the fore by changes in global energy use, alongside issues such as the linkages between energy and water use.

- Acute deprivation persists in the global energy sector, with 1.2 billion people without electricity and 2.7 billion reliant on the traditional use of solid biomass for cooking. Achieving universal access to affordable, reliable and modern energy services by 2030 is now one of the UN Sustainable Development Goals, but our projections show today’s efforts falling short of reaching this goal.

Ten questions on the future of energy

There are many questions that could be asked about the future of energy. The intention of this chapter is to focus on a few of these, drawing on the analysis in this *World Energy Outlook (WEO)* and other reports in the *WEO-2016* series. No single vision of the future should be exclusively relied upon, so the responses often refer to multiple scenarios and outcomes. Taken together, they provide a coherent framework for assessing the impact of different policy and investment choices on future energy trends and risks and, in this way, they can help to inform the energy decisions that need to be taken today. The ten questions addressed here are:

- Has the world broken the link between rising economic activity, energy demand and energy-related CO_2 emissions?
- Which fuels and technologies are poised to do well in the post-Paris Agreement energy order?
- Are there limits to growth for renewable energy?
- Staying below the 2 degrees Celsius climate change limit: what would be required?
- What can the energy sector do to reduce air pollution?
- Energy investment – is capital heading where it is needed?
- How might the main risks to energy security evolve over the coming decades?
- Are we on the path to achieving universal access to energy?
- Changing places: is global spending on energy subsidies shifting away from fossil fuels and in favour of renewable energy?
- Does energy reform point a new way forward for Mexico?

2.1 Has the world broken the link between rising economic activity, energy demand and energy-related CO_2 emissions?

Recent data show a significant slowdown in the growth of energy-related carbon-dioxide (CO_2) emissions in 2014 and 2015, and the projections in the New Policies Scenario suggest that implementation of Nationally Determined Contributions (NDCs) would lock in this trend. In the New Policies Scenario to 2040, on an average annual basis, CO_2 emissions grow at 0.5% per year, while energy demand grows at 1% and the global economy expands at an average rate of 3.4%. But the peak in emissions needed to limit the temperature rise to below 2 degrees Celsius (°C) is not in sight in this scenario.

IEA data suggest that what has been a fairly inexorable rise in global energy-related CO_2 emissions slowed sharply in 2015, for the second year in a row. Before 2015, there have been only four periods in the past 40 years in which emissions stood still or fell compared with the previous year: three of those – the early 1980s, 1992 and 2009 – were associated with global economic weakness. In contrast, the most recent stall in emissions growth comes during a period of economic expansion. This represents a clear hint that the previously close relationship between global economic growth, energy demand and related CO_2 emissions is weakening. But is it too soon to conclude that the link is broken?

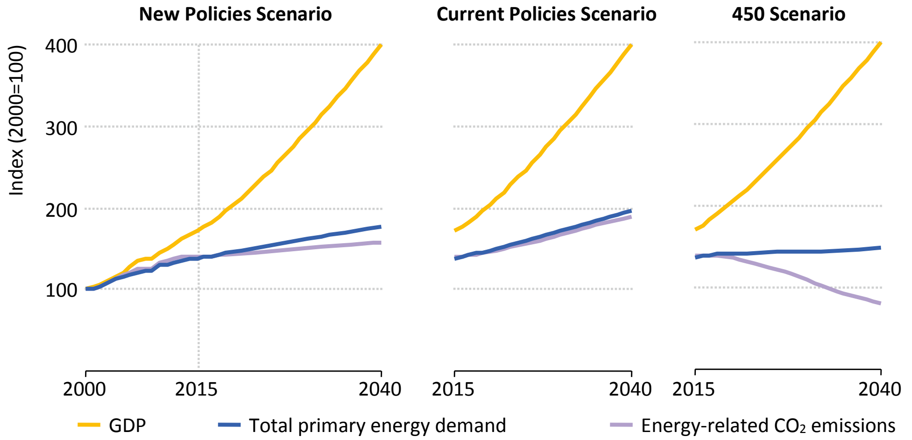
Energy intensity is a measure of the link between global economic activity and energy demand; preliminary estimates suggest that global energy intensity decreased by 1.8% in 2015, almost twice the average level of improvement over the last decade. Part of the reduction in energy intensity was due to changes in the global economy: for example, production of steel and cement fell by 2-3% in 2015, mainly because of developments in China. The increasing rigour of global energy efficiency policies also played a role. In turn, the link between energy demand and energy-related CO_2 emissions is determined by the mix of fuels and technologies used to meet the world's energy needs. Moving away from the most carbon-intensive fuels (for the first time, the United States generated as much power from natural gas as from coal in 2015) or introducing more renewables into the system (additional power generated from renewables was equal to more than 90% of the growth in global electricity generation in 2015) are the main ways to drive a wedge between energy and emissions trends. Overall, we estimate that around two-thirds of the contribution to the flattening in emissions in 2014 and 2015 came from reductions in energy intensity; the rest from an expansion of cleaner energy sources in global energy use.

The *WEO* projections offer an opportunity to trace trajectories for gross domestic product (GDP), energy demand and energy-related CO_2 emissions beyond 2015 and see how they respond to the application of different assumptions about future policies. The GDP trajectory (which is common to all three *WEO* scenarios[1]), anticipates annual average growth in the global economy of 3.4% for the period to 2040, meaning that the economy as a whole is well over twice as large in 2040 than today. But the energy required – and the emissions associated with this energy use – vary substantially across the three scenarios. Primary energy demand increases by 43% between now and 2040 in the Current Policies Scenario, by 31% in the New Policies Scenario and by a mere 9% in the 450 Scenario. The CO_2 emissions associated with this energy use rise by 36% in the Current Policies Scenario, 13% in the New Policies Scenario, but fall by 43% in the 450 Scenario (Figure 2.1).

An implication of this analysis is some of the factors that have caused the slowdown in global emissions growth in 2014 and 2015 are cyclical and might not be prolonged – the most pronounced slowdown in economic activity over this period occurred in some of the most energy and carbon-intensive parts of the global system, e.g. Russia, the Middle East and other hydrocarbon exporting countries and regions. A further implication is that, if indeed the trends seen in 2014 and 2015 are to be a turning point, then stronger policies than those in place or envisaged today would be needed to boost improvements in efficiency and the deployment of low-carbon energy.

1. The scenarios are defined in Chapter 1.

Figure 2.1 ▷ **Global GDP, energy demand and energy-related CO_2 emissions trajectories by scenario**



The decoupling between growth in GDP, energy demand and emissions is limited in the New Policies Scenario, strong in the 450 Scenario

The projections in the New Policies Scenario illustrate some of the reasons why it is challenging to turn the flattening of energy-related CO_2 emissions in 2014 and 2015 into a sustained fall (Table 2.1). In our projections, the annual average increase in GDP is assumed to pick up, from 3% in 2015 to an average of 3.7% over the ten years to 2025, meaning that improvements in energy intensity and deployment of lower carbon technologies have to clear a higher bar in order to deliver a net reduction in emissions. Global energy intensity continues to fall at a rate of 1.8% per year to 2040, a significant achievement given that GDP growth is concentrated in emerging economies, where economic activity is still relatively energy intensive. But the net result is still a stubborn upward trend in global demand for energy (Figure 2.2).

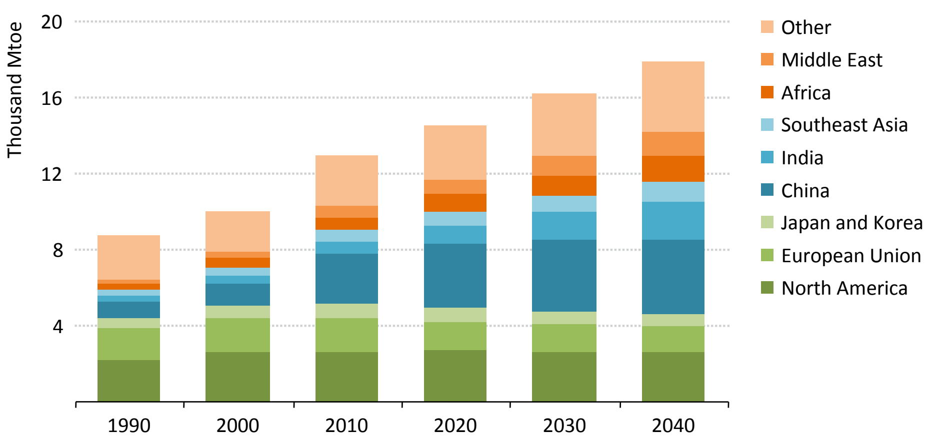
Primary energy demand in most advanced economies is set to fall over the coming decades: despite pockets of growth (as in Mexico, the subject of a special country focus in the *WEO-2016* series), the net trend for OECD countries as a whole is that they consume less energy in 2040 than they do today. But this is more than offset by increases elsewhere, with rising incomes, industrialisation and urbanisation – and rising levels of energy access – proving to be powerful spurs for consumption. China has had a huge influence on global energy trends since 2000 and continues to be the largest single source of global demand growth until the mid-2020s in our projections, when it is overtaken by India. But even as energy demand growth slows in China (Box 2.1), other countries in South and Southeast Asia, alongside parts of Africa, the Middle East and South America where energy demand per capita is low today, take on a more prominent role in pushing global energy demand higher.

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

	2000	2014	2020	2025	2030	2035	2040	CAAGR* 2014-2040
OECD	**5 299**	**5 276**	**5 293**	**5 215**	**5 140**	**5 093**	**5 077**	**-0.1%**
Americas	2 702	2 722	2 734	2 708	2 680	2 674	2 696	-0.0%
United States	2 270	2 212	2 211	2 176	2 130	2 101	2 094	-0.2%
Europe	1 766	1 697	1 690	1 641	1 601	1 568	1 540	-0.4%
Asia Oceania	831	857	870	866	859	851	842	-0.1%
Japan	518	442	424	411	399	389	381	-0.6%
Non-OECD	**4 469**	**8 046**	**8 866**	**9 664**	**10 535**	**11 406**	**12 178**	**1.6%**
E. Europe/Eurasia	1 004	1 101	1 120	1 152	1 189	1 232	1 271	0.6%
Russia	620	686	683	696	714	737	758	0.4%
Asia	2 189	4 809	5 398	5 930	6 488	7 010	7 437	1.7%
China	1 149	3 070	3 328	3 544	3 728	3 855	3 892	0.9%
India	441	824	1 033	1 225	1 457	1 700	1 938	3.3%
Southeast Asia	385	621	714	800	893	990	1 084	2.2%
Middle East	353	715	819	912	1 026	1 142	1 244	2.2%
Africa	498	781	884	979	1 085	1 207	1 336	2.1%
South Africa	111	147	148	152	158	165	173	0.6%
Latin America	424	639	646	691	747	815	890	1.3%
Brazil	184	300	296	317	344	376	408	1.2%
World**	**10 042**	**13 684**	**14 576**	**15 340**	**16 185**	**17 057**	**17 866**	**1.0%**
European Union	1 692	1 563	1 547	1 492	1 441	1 398	1 360	-0.5%

* Compound average annual growth rate. ** Includes international marine and aviation bunkers (not included in regional totals).

Figure 2.2 ▷ Energy demand by region in the New Policies Scenario



The geography of global energy demand continues to shift

Continuing to hold today's energy-related CO_2 emissions flat against the backdrop of steadily rising energy demand projected in the New Policies Scenario would require an acceleration of efforts to reduce the carbon footprint of energy use. The growth in energy-related CO_2 emissions slows from 2.4% per year since 2000 to a much more modest 0.5% per year over the period to 2040 in this scenario. But, despite all the policies in place to deploy low-carbon sources of energy and the commitments made to strengthen deployment in many countries included in the NDCs in the Paris Agreement (which are incorporated into the projections in the New Policies Scenario), there is still a residual increase in energy-related CO_2 emissions that averages around 160 million tonnes (Mt) per year. For a global energy system that generates 32 000 Mt of CO_2 each year, finding additional abatement of 160 Mt to stabilise emissions at current levels is not a large change (albeit not nearly enough to avoid severe impacts of climate change), but it is still the equivalent of decarbonising a country with today's emissions level of the Netherlands each year; or replacing 40 large coal-fired power plants with zero-carbon electricity; or replacing more than 50 million cars each year with electric vehicles, charged with zero-carbon electricity.

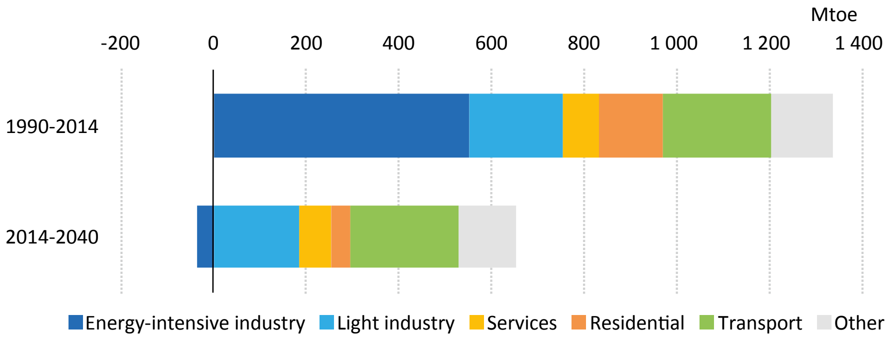
Box 2.1 ▷ China's economic transition gathers pace

The re-orientation of China's economy, away from investment in heavy industrial sectors and towards domestic consumption and services, has profound implications for our energy outlook for China and for global trends. Since 1990, energy-intensive industrial activity has been the single most important source of growth in final energy consumption in China (Figure 2.3). But in 2015, output fell in some energy-intensive sectors, notably steel and cement. Although growth in the chemicals sector is expected to remain strong to 2040, and aluminium also sees an increase, China's steel and cement production are expected to continue their decline, by around 30% and 40% respectively. There are multiple uncertainties for the outlook for China, but the net result in our projections in the New Policies Scenario is that aggregate energy demand from China's energy-intensive industries is lower in 2040 than it is today.[2]

Coal feels the sharpest impact of this transition: rising industrial activity has until now always been positive for coal consumption. This is no longer the case in the New Policies Scenario*:* China's industrial activity switches to lighter, higher technology, higher value-added products, for which the predominant energy inputs are electricity and natural gas. Industrial value added continues to rise, by an average of 4% per year. But industrial coal use falls by more than one-third to 2040 – a drop equivalent to almost one-and-a-half times Russia's entire coal output today. This is a key reason for the flattening in China's projected energy-related CO_2 emissions (which rise only to 9.3 gigatonnes [Gt] in the late 2020s, before falling back to 8.8 Gt by 2040 – below today's level of 9.1 Gt).

2. The *World Energy Outlook-2017* will include a major country focus on China.

Figure 2.3 ▷ Change in total final consumption in China in the New Policies Scenario



In the New Policies Scenario, energy-intensive industries are no longer the spur for growth in China's energy consumption

Note: Mtoe = million tonnes of oil equivalent.

2.2 Which fuels and technologies are poised to do well in the new energy order?

The stronger the policy focus on mitigating the environmental impacts of energy use, the more the energy mix shifts over the decades in favour of renewable energy sources, nuclear power (where it is politically acceptable) and, up to a point, natural gas, the least polluting of the fossil fuels. Yet coal (in power) and oil (in transport and petrochemicals) have very strong footholds in the energy system that are not easily dislodged.

The global energy mix does not change easily. Although government policies, relative prices, changing costs and consumer needs all create incentives to switch fuels or to introduce a new technology in order to obtain a better energy service, in practice the energy system has a great deal of inertia. Light bulbs and office equipment might be replaced every few years, but the lifetimes of vehicles, factories, power plants and buildings are much longer, and each bit of infrastructure locks in certain patterns of energy use. So, in the absence of a concerted policy push or a dramatic change in relative prices, the positions of the different fuels and technologies in worldwide energy use tends to be fairly stable. The Current Policies Scenario provides a useful example of the durability of the status quo: from a share of 81% today, the role of fossil fuels in global energy is essentially unchanged at 79% in 2040 in this scenario (Table 2.2). Oil and coal retain their primacy as the most-used fuels.

By contrast, the 450 Scenario represents a clean break with the past, as policies re-cast the energy system to comply with the imperative to limit greenhouse-gas (GHG) emissions. The main policies that underpin this transformation include a much stronger drive for renewables deployment in the power sector, broader adoption and stronger application of energy efficiency policies and low-carbon forms of transport, more widespread carbon pricing and use of carbon capture and storage (CCS) (in power and industry), and more rapid reform of fossil-fuel subsidies. In this scenario, a wholesale shift in the way that capital flows into the energy sector sees demand for the most carbon-intensive fuels plummet (coal demand in 2040 is 40% of the level in the Current Policies Scenario), with a commensurately sharp increase in renewables and other low-carbon technologies, particularly in the power sector.

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

			New Policies		Current Policies		450 Scenario	
	2000	2014	2025	2040	2025	2040	2025	2040
Coal	2 316	3 926	3 955	4 140	4 361	5 327	3 175	2 000
Oil	3 669	4 266	4 577	4 775	4 751	5 402	4 169	3 326
Gas	2 071	2 893	3 390	4 313	3 508	4 718	3 292	3 301
Nuclear	676	662	888	1 181	865	1 032	960	1 590
Hydro	225	335	420	536	414	515	429	593
Bioenergy*	1 026	1 421	1 633	1 883	1 619	1 834	1 733	2 310
Other renewables	60	181	478	1 037	420	809	596	1 759
Total	**10 042**	**13 684**	**15 340**	**17 866**	**15 937**	**19 636**	**14 355**	**14 878**
Fossil-fuel share	*80%*	*81%*	*78%*	*74%*	*79%*	*79%*	*74%*	*58%*
CO_2 emissions (Gt)	**23.0**	**32.2**	**33.6**	**36.3**	**36.0**	**43.7**	**28.9**	**18.4**

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

In the New Policies Scenario, pressure for change is bolstered by the commitments made in the Paris Agreement and there is a tangible shift in momentum and direction compared with the past – even if the transformation in global consumption is less profound and far-reaching than in the 450 Scenario (Table 2.3). The fuel most visibly affected is coal, whose surge in consumption in the early 2000s has slowed abruptly in recent years and went into reverse in 2015 when global coal demand fell for the first time since the 1990s. According to our projections in the New Policies Scenario, coal is not yet in terminal decline but growth is anaemic at only 0.2% per year to 2040, providing scant relief for the 80% of Chinese coal companies that were reportedly losing money in 2015 or the firms accounting for 50% of US coal production that were under bankruptcy protection in mid-2016.

The reason that coal demand continues to rise at all is due to robust demand growth in India and Southeast Asia – where readily available coal is difficult to ignore as an affordable solution to fast-growing energy needs. This offsets rapid declines in coal use in North America and the European Union. More so than for any other fuel, it is China – still by far the largest coal producer and consumer – that holds the keys to the global coal balance. The structural economic shift towards non energy-intensive industry and services sectors hits coal use hard and means that, barring an unexpected dry year for hydro, China's coal use is likely to have peaked in 2013. On the production side, China intends to close more than 1 billion tonnes of mining capacity in order to rebalance the market. Even if this restructuring proceeds according to plan, China's import needs are set to plummet by around 85% to 2040. If it is delayed, it is conceivable that China could even become a net exporter of coal again, a development that would prolong the current slump in international coal markets.

2

Table 2.3 ▷ World primary energy demand by fuel in the New Policies Scenario (Mtoe)

	2000	2014	2020	2025	2030	2035	2040	CAAGR* 2014-2040
Coal	2 316	3 926	3 906	3 955	4 039	4 101	4 140	0.2%
Oil	3 669	4 266	4 474	4 577	4 630	4 708	4 775	0.4%
Gas	2 071	2 893	3 141	3 390	3 686	4 011	4 313	1.5%
Nuclear	676	662	796	888	1 003	1 096	1 181	2.3%
Hydro	225	335	377	420	463	502	536	1.8%
Bioenergy**	1 026	1 421	1 543	1 633	1 721	1 804	1 883	1.1%
Other renewables	60	181	339	478	643	835	1 037	6.9%
Total	**10 042**	**13 684**	**14 576**	**15 340**	**16 185**	**17 057**	**17 866**	**1.0%**

*Compound average annual growth rate. ** Includes the traditional use of solid biomass and modern use of bioenergy.

Oil demand also slows noticeably over the projection period, resulting in a compound average growth rate of 0.5% for the period as a whole. There is a stark difference in consumption trends between advanced economies, where vehicle ownership levels are already high and efficiency improvements bring demand down over time, and emerging economies, where vehicle ownership is much lower and demand for petrochemical products and road freight services is growing much more rapidly. Oil consumption in OECD countries falls by some 12 million barrels per day (mb/d) between today and 2040, while non-OECD growth is closer to 19 mb/d, the net increase of 7 mb/d, alongside growth of 4 mb/d in international shipping and aviation, accounting for the overall rise in demand to 103.5 mb/d in 2040 in the New Policies Scenario. Efficiency and technology improvements, pricing reforms (as countries phase out fossil-fuel subsidies, see section 2.9) and steadily higher prices all serve to take the edge off oil demand growth. Although their impact is more muted in the New Policies Scenario, the potential for electric vehicles to make a sizeable dent in oil consumption comes through strongly in the 450 Scenario (Box 2.2).

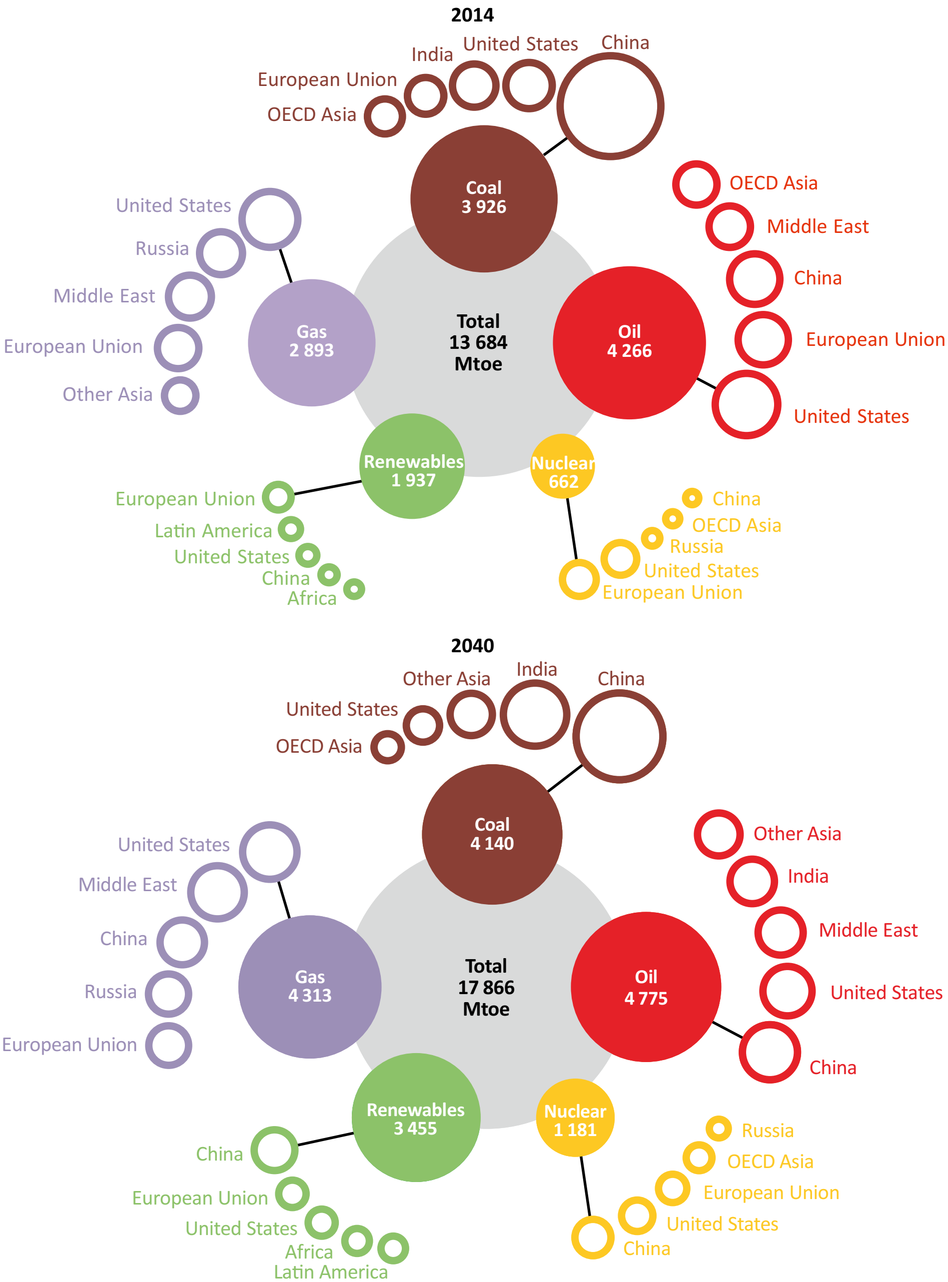
On the supply side, there are signs that the market is rebalancing following the dramatic drop in oil prices that began in 2014. But the impact of the severe downturn in upstream investment in 2015 and 2016 will play out over a longer period: whether this can be easily absorbed in future years, or whether the market will enter a period of price volatility as it searches for a new equilibrium, is a key question (examined in detail in Chapter 3 and summarised in section 2.6 below). The slowdown in the flow of new projects results in a reduced period of production growth in the 2020s in some major non-OPEC producers, notably Brazil and Canada. The destabilising effect of today's shortfalls in hydrocarbon revenue is reflected also in lower projected supply growth (compared with *WEO-2015*) from some major OPEC countries, chief among them Venezuela, Iraq, Nigeria and Libya. These downward revisions are offset by higher production in other areas: factoring in the recent decline in upstream costs and a higher estimate in *WEO-2016* of the tight oil resource base, US oil production reaches a higher plateau than in last year's *Outlook,* above 14 mb/d for much of the 2020s, and then tails off more slowly thereafter. In combination with steady reductions in US demand, as fuel efficiency measures start to bite, this means that US net imports of oil fall below 1 mb/d by 2040, down from more than 5 mb/d today.

Natural gas demand grows by nearly 50% in the New Policies Scenario over the period to 2040. The 1.5% annual rate of growth to 2040 is healthy compared with the other fossil fuels, although considerably less than the 2.3% seen over the last 25 years. Natural gas consumption increases almost everywhere, with the main exception of Japan, where it falls back from today's levels as nuclear power is reintroduced: China and the Middle East are the largest sources of growth. But, in the face of strong competition and saturation effects in some mature markets, the natural gas industry has to work hard to secure new outlets for its product. Gas prices rise steadily in all regions as the current supply overhang is absorbed. By 2025, in gas-importing countries in Asia (in the absence of carbon pricing) new gas plants would be a cheaper option than new coal plants for baseload generation only if coal prices were $150/tonne. The space for gas-fired generation is also squeezed in many markets by the rising share and falling costs of renewables. Gas demand for industry increases more quickly (at 2.1% per year) than for power (1.3%); the fastest growth (3.4%), albeit from a low base, comes from natural gas use in transport, including liquefied natural gas (LNG) for heavy goods vehicles and for shipping.

Gas production growth is dominated over the period to 2020 by Australia and the United States, but thereafter the increase in supply comes from a larger range of countries. East Africa emerges as a new gas province thanks to large offshore developments in Mozambique and Tanzania. Egypt makes a comeback with the start of production from the major Zohr field, as does Argentina with the development of its promising shale gas resource in the Vaca Muerta region. After remaining relatively flat into the early 2020s, Russia's output rises again as a new pipeline route opens up to bring gas to China, but a larger share of the increase in international trade is taken by LNG. New projects in North America, Australia, Africa, the Middle East and Russia help to boost the share of LNG in inter-regional gas trade from 42% today to 53% in 2040. The gradual removal of contractual restrictions, such as destination clauses, also eases the emergence of a globalised gas market in which prices are increasingly determined by the interplay of gas supply and demand.

The largest expansion in the primary energy mix comes from renewables (examined in section 2.3 and in detail in Part B of this *Outlook).* The expansion shown in Figure 2.4 actually underplays the rise in modern renewable technologies, as it includes also the use of solid biomass as a fuel for cooking in developing countries, which is a mark of energy poverty rather than a positive contribution to low-carbon development. In the case of nuclear, even though one-sixth of the global nuclear fleet is retired in the next decade (80% of this in OECD countries), overall prospects are buoyed by large new build programmes in a select group of countries led by China, Russia and India.

Figure 2.4 ▷ **Global primary energy mix in the New Policies Scenario** (Mtoe)



Renewables, followed by natural gas, are the main winners to 2040

Notes: The ranking of top-five demand regions for renewables excludes the traditional use of solid biomass as it is not a sustainable renewable energy source. However, in order to account for total primary energy demand in full, this is included in the aggregate number for renewables. OECD Asia = Japan, Korea, Australia and New Zealand. Other Asia = non-OECD countries in Asia, excluding China and India.

Box 2.2 ▷ Are electric vehicles about to make their move?

The global stock of electric cars passed the one million mark in 2015 and momentum looks to have been maintained in key markets in the first-half of 2016 – electric vehicle registrations in China rose by 130% year-on-year (helped by the fact that this avoids the lottery by which conventional vehicle registrations are assigned in major Chinese cities). Growth has been underpinned by policy support, the development of new models with clear consumer appeal and continuous improvement in the energy density of batteries; average battery costs in 2015 were less than $270 per kilowatt-hour (kWh) for plug-in electric hybrids and an estimated $210/kWh for battery electric cars (BEVs).

In the New Policies Scenario, ownership of electric cars picks up quickly to 10 million in 2020, exceeds 30 million by 2025 and 150 million in 2040. By 2040, one-in-nine passenger vehicles in China is electric and growth is also strong in parts of Europe and North America. But the overall share in the global passenger vehicle stock remains relatively small, at 8% in 2040, and oil demand is lowered by only 0.3 mb/d in 2025 and 1.3 mb/d in 2040. One reason is that, even though battery costs for BEVs decline to $125/kWh by 2025 and $100/kWh by 2040, this is not enough to achieve full cost-parity with conventional cars and policies in place or envisaged today are not sufficiently widespread or strong to bridge the gap.

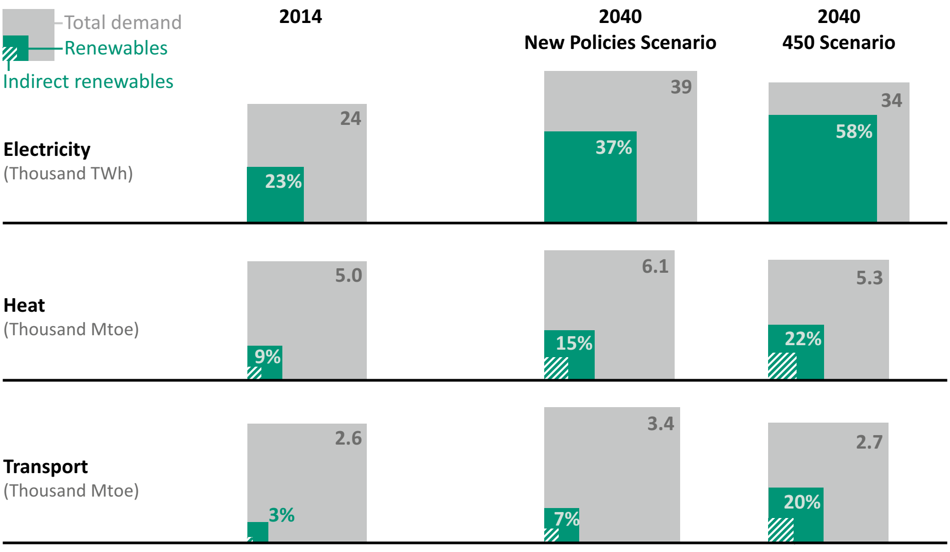
The outlook changes in the 450 Scenario. Policies that include more stringent regulations on fuel economy and tailpipe emissions, and greater support to the build-up of recharging infrastructure, provide a large boost to sales. The global stock of electric passenger cars rises to more than 700 million by 2040, displacing more than 6 mb/d of oil demand. With the parallel decarbonisation of the power sector in this scenario, the combination of smart grids and the storage provided by vehicle batteries also provides the co-benefit of supporting the integration of renewable power.

2.3 Are there limits to growth for renewable energy?

The contribution from renewable energy grows faster than that from any other source, in all scenarios, in large part due to the expansion of wind and solar PV in the power sector. Increasing deployment of variable renewables brings a continuing decline in their cost. But there is also the risk, if the power system is not well designed to integrate a rising share of wind and solar, that the energy transition could become less efficient and more expensive as a result. Solutions are to hand, but have to be applied. There is large untapped potential for renewable energy in heat production and transport, but policy attention and technology improvement in these areas have lagged behind.

Renewable energy is the major growth story in all the scenarios in *WEO-2016*. Even in the Current Policies Scenario, policies already in place are sufficient to make renewables the fastest-growing of all the sources of primary energy. But current policies barely scratch the surface of renewables' potential, either as a source of power, heat or mobility. In the New Policies Scenario, the additional impact of new policy announcements and declared intentions – many of which were made in connection with the Paris Agreement – leads to a further acceleration in deployment (Figure 2.5). More ambitious policies and targets have been facilitated by the large cost reductions seen in recent years: solar photovoltaics (PV) have led the way with both utility- and small-scale projects seeing declines of 35-80% in leading markets since 2010. Over the period to 2040, renewables account for almost 60% of all new power generation capacity additions in the New Policies Scenario. By 2040, wind and solar combined have more installed capacity than any other source of generation.

Figure 2.5 ▷ Shares of global demand met by renewable energy in selected sectors in the New Policies and 450 Scenarios



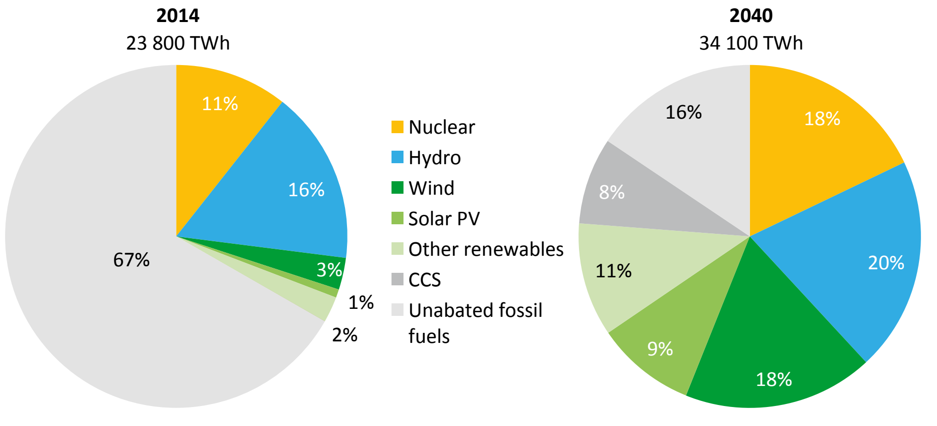
Three steps forward for renewables in the New Policies Scenario: a step-change in the 450 Scenario

Note: Indirect renewables refers to renewables-based electricity or combined heat and power that is then used for heat or transport fuels.

The attention to renewables is typically focussed on their place in the power sector, but renewable resources are also used in end-use sectors to meet heat demand and as a transport fuel. Use for heat can either be direct (from bioenergy or solar thermal, for example) or indirect (via renewables-based electricity or heat from combined heat and power plants). Use in the transport sector is as biofuels, mainly for road transport. In the New Policies Scenario (excluding the traditional use of solid biomass as a cooking fuel), the use of renewables-based heat in industry and in buildings both rise, but their share in total heat demand does not exceed 15%. In the case of biofuels, subsidies and advances in technology support a near tripling in consumption to 4.2 mboe/d in 2040 (65% ethanol), representing some 6% of transport fuel demand.

The 450 Scenario pushes the deployment of renewables significantly beyond the levels implied by today's measures and policy intentions. The power sector is largely decarbonised by 2040, with the share of renewables in generation rising to almost 60% (Figure 2.6). The share of renewables in the provision of heat rises to more than one-fifth. Higher blending mandates and other support measures increase biofuels consumption to almost 9 mboe/d by 2040, with biofuels making in-roads into shipping and aviation in this scenario. There is no shortage in aggregate of potential renewables supply to meet our projections over this timeframe, even if, as in other scenarios, there is a shortage in some countries of viable sites for new hydropower projects. Intensive wind deployment and the large demand for biofuels in a 450 Scenario do, though, result in a deterioration in the quality of the available resource as operators move to second- or third-tier sites for wind parks, or biofuels cultivation moves to more marginal land.

Figure 2.6 ▷ Evolution of the power generation mix in the 450 Scenario



The power sector is transformed and almost decarbonised by 2040 in the 450 Scenario

Notes: CCS = carbon capture and storage; TWh = terawatt-hours.

To the extent that renewables in the power sector test the limits of growth they do so for two reasons. First, particularly in countries with low rates of growth in electricity demand and very strong decarbonisation goals, the desired pace of change may exceed the natural rate at which existing capacity is retired. There is no technical barrier to early retirement of existing assets, but the political challenges can be a different matter and early retirement comes with a cost – an increase in the amount of overall investment or, in some instances, a claim for compensation for lost income. Second is the impact of variable renewables on the operation and reliability of the power system as a whole. At low shares of penetration in the power mix, wind and solar PV are unlikely to pose significant challenges. Yet, the deployment of such technologies to levels consistent with the 450 Scenario (as well as within some regions in the New Policies Scenario) requires a significant upgrade in technical, institutional, policy and market design, collectively known as system integration measures. In the absence of these measures to increase the flexibility of the system, there is a risk that wind or solar capacity would face significant curtailment during times of abundant generation, which could undermine the economics of projects, deter investment and make these technologies less effective as emissions abatement options. As shown in Chapter 12, any power system in which wind and solar PV installations face a regular risk of having their production curtailed is taking an expensive and inefficient route towards decarbonisation.

Flexibility, in power system terms, is traditionally associated with generators that can change their output very quickly (typically reservoir hydropower or gas-fired plants). But there are multiple potential sources of flexibility that can be exploited to shift the timing of the demand or of the delivery of supply in order to accommodate large shares of renewables. Markets can be designed in a way that incentivise investment in locations and technologies that offer the best value to the system as a whole, i.e. capable of delivering power at times of day and in places when it is particularly needed. Strengthening the network or integrating with neighbouring systems make it possible to aggregate output over a larger area, helping to smooth fluctuations that might occur in individual locations. Although its use has been limited so far (with the partial exception of pumped storage hydro), utility-scale storage offers promise – especially once costs come down – to accommodate supply and demand mismatches.

Another approach is to induce flexibility on the demand side, either by moving consumption in time without affecting the total electricity demand (e.g. shifting the use of a washing machine or the charge of an electric vehicle to a different time period), or by interrupting demand at short notice (e.g. stopping industrial production for a given amount of time) or adjusting the intensity of demand for a certain amount of time (e.g. reducing the thermostat temperature of space heaters or air conditioners to lower electricity demand at that time). As examined in detail in Chapter 12, a judicious mix of these solutions in the 450 Scenario can allow for very high shares of variable renewables in power systems, while reducing curtailment to negligible levels below 2.5% of their annual output in 2040. System integration measures provide the essential enabling mechanism for high growth of renewable power.

In the end-use sectors, there is a mixture of barriers that impede rapid growth in renewables. Technological progress has been much less rapid than in the case of wind or solar PV power, not least because policies that can help renewable heat technologies achieve full commerciality are much less widespread than those supporting renewables-based electricity. Not all sources of renewables for heat offer the range of heating temperatures demanded, especially in industry; but there is still ample scope for further penetration of solar thermal heating for use in the residential or services sectors or in low-temperature applications, such as textiles and food processing. Bioenergy offers a wider range of heating temperatures, although logistics and supply chain problems could emerge as a constraint on large-volume consumption. Research and development is still essential to bring down costs and to open up new areas for growth, for example solar thermal heating for medium-temperature industrial applications, or renewables-based cooling systems for buildings and industry.

The largest constraint in the end-use sectors applies to the expansion of biofuels supply. Reaching the level of biofuels projected in the 450 Scenario implies a significant increase in the volume of the biomass feedstocks that would be required to fuel the production facilities. This could be achieved through the use of under-utilised or derelict land and by increasing agricultural productivity (although measures to improve productivity, notably irrigation and fertilisers, also have a heavy energy footprint); the increased use of advanced biofuels in the 450 Scenario also helps to minimise the impacts. Nonetheless, the potential for tension remains: with other land and water users; with other policy priorities, e.g. food security; as well as with emissions reductions goals, if direct or indirect land use changes due to biofuels cultivation cause additional GHG gas emissions.

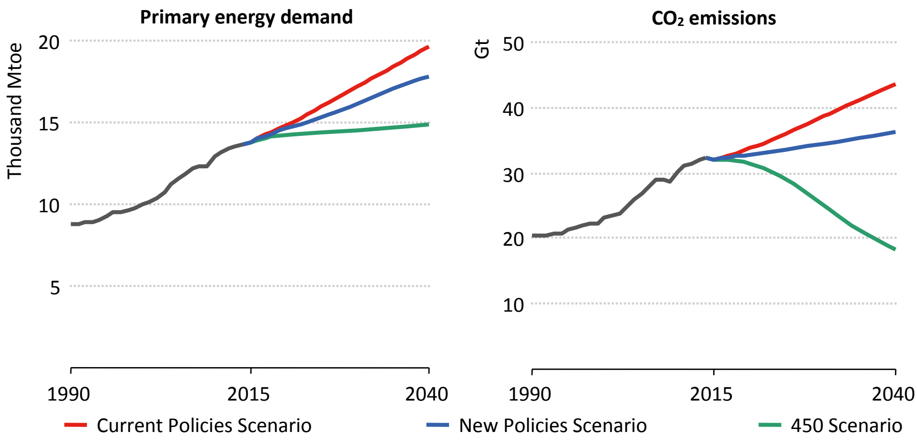
2.4 Staying below the 2 °C climate change limit: what would be required?

An emissions trajectory consistent with the 450 Scenario would require a step-change in policy action in the direction of much more efficiency and higher reliance across different end-uses on low or zero-carbon electricity. As the power sector moves closer to full decarbonisation – as in the 450 Scenario, and even more so in any well below 2 °C pathway – so the battleground for further GHG emissions reductions moves to areas that are difficult to electrify, such as freight, air and maritime transport and various heavy industrial processes, and to potential technologies to remove CO_2 from the atmosphere.

Energy production and use account for the majority of global GHG emissions today; pledges relating to the energy sector were also at the heart of many countries' NDCs, the building blocks of the Paris Agreement. Yet, as discussed above, the New Policies Scenario that incorporates these pledges sees a continued, albeit gradual, rise in energy-related CO_2 emissions to 2040 (Figure 2.7). Self-evidently, this fails to satisfy the aim embedded in the Paris Agreement to reach a "global peaking of greenhouse-gas emissions as soon as possible".

The scope to mitigate emissions further stretches across the entire energy sector. Despite the impressive growth of renewables in the power sector in recent years, two-thirds of power generation today continues to rely on fossil fuels, with the result that the power sector contributes more than 40% of current energy-related CO_2 emissions. The transport sector (with 23%) is the next largest contributor to GHG emissions; long-standing policy efforts promoting fuel efficiency and alternative fuels have paid dividends, but well over 90% of the world's road transport fleet continues to run on oil products. Industry (20% of energy-related CO_2 emissions) sources nearly three-quarters of its energy directly from fossil fuels; the comparable figure for buildings (with 9% of emissions) is closer to one-third, but the buildings sector is the largest consumer of electricity, and so is a major source of the demand that leads to emissions from power generation.

Figure 2.7 ▷ Global primary energy demand and related CO_2 emissions by scenario



While energy sector CO_2 emissions rise by 4 Gt in the New Policies Scenario, they fall by 14 Gt in the 450 Scenario

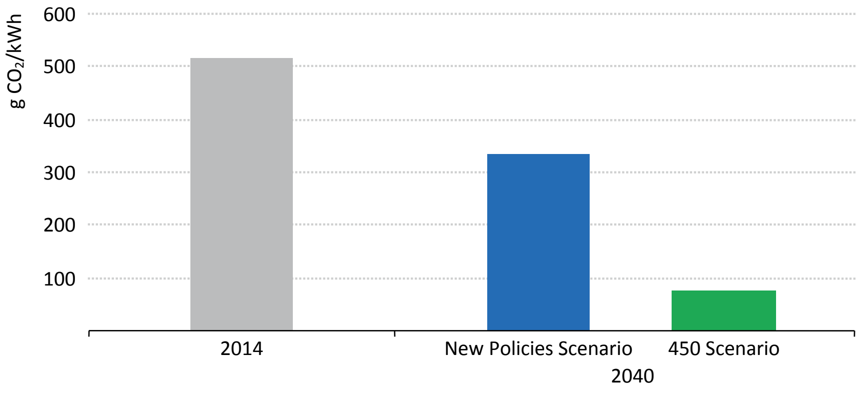
Note: Gt = gigatonnes.

The 450 Scenario depicts a low-carbon transition compatible with limiting the average global temperature increase in 2100 to 2 degrees Celsius above pre-industrial levels. It requires that emissions peak before 2020 and then drop steadily to around 18 Gt by 2040. Moving to this trajectory is the dominant focus for the analysis of the energy transition in *WEO-2016*. In addition, this *Outlook* includes a first assessment of even more ambitious emissions reduction pathways that, in the words of the Paris Agreement, can keep the rise in the global mean temperature to "well below 2 °C", and pursue "efforts to limit the temperature increase to 1.5 °C" (Box 2.3).

In the New Policies Scenario, the growth of low-carbon sources of power generation is sufficient to achieve the first stage in the decoupling of electricity generation from power sector emissions: electricity generation rises by two-thirds over the period to 2040, but power-related CO_2 emissions stagnate, rising only modestly above today's level. As a result, the emissions intensity of power generation falls from around 515 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) today to around 335 g CO_2/kWh in 2040 (Figure 2.8), a rate of improvement faster than that of any other sector.

But, to align with the 450 Scenario, the emissions intensity of power generation needs to fall much further and faster, to around 80 g CO_2/kWh. The additional reduction is facilitated by higher CO_2 prices and extended policy support to low-carbon generation, with the largest increases – as we have seen – in wind and solar generation. Nuclear generation also rises, with an absolute increase comparable to that of all solar technologies combined. Carbon capture and storage becomes an important protection strategy for fossil-fuel assets that have recently been built and have not recovered their investment costs: by 2040, some 430 GW of fossil-fuel plants are equipped with CCS in the 450 Scenario, of which more than half is in China, the country with the largest coal fleet today (at almost 50% of the global total).

Figure 2.8 ▷ Emissions intensity of global electricity generation in the New Policies and 450 Scenarios



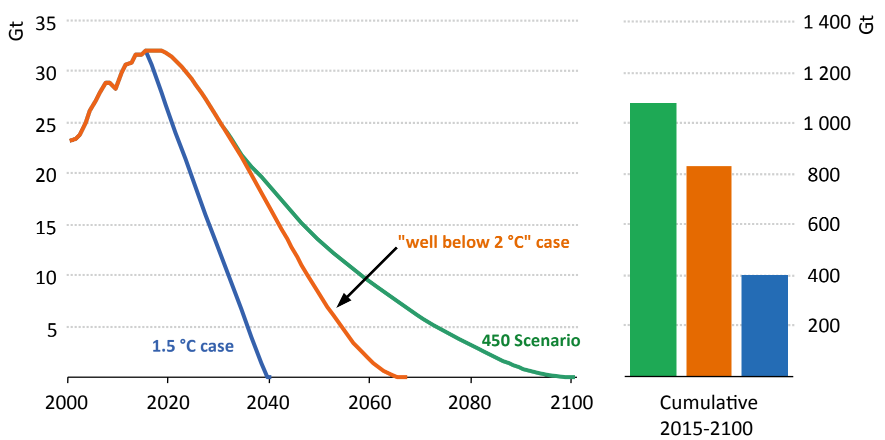
CO_2 emissions intensity of global electricity generation falls significantly in the New Policies Scenario, but drops substantially more in the 450 Scenario

The effort is not only required on the supply side: reductions in electricity demand in a 450 Scenario also contribute almost one-quarter of the required power-sector emissions savings. Much of these (as illustrated in detail in Chapter 7) come from electric motor systems, which – in different appliances and equipment across the end-use sectors – consume more than one-in-two kilowatt-hours consumed worldwide. By 2040, increased industrial activity – much of which is in China and India – would imply a doubling of global electricity use for motors in industrial motor systems. The energy efficiency policies applied in the New Policies Scenario contain this growth to 80%. These policies tend to focus just on efficiency of the motor and are already quite widespread – almost 90% of the industrial electric motors sold worldwide today are already covered by mandatory energy efficiency standards. However, capturing the larger savings available in the motor system as a whole requires a shift in attention from standards for single components to a system-wide energy efficiency approach. This encompasses not just stricter and wider regulation of motors and other equipment (e.g. pumps), but also the uptake of variable speed drives and a suite of other measures to do with system maintenance (such as fixing leaks or reducing pressure losses), predictive maintenance and a better match of the size of equipment to demand needs. The additional cumulative investment of around $300 billion for efficiency improvements in industrial electric motor systems in the 450 Scenario is far outweighed by avoided investment in power generation, of $450 billion.

Box 2.3 ▷ **Exploring the implications of a "well below 2 °C" or a 1.5 °C emissions pathway**

The Paris Agreement does not include a precise definition of what holding the temperature rise to "well below 2 °C", while also pursuing efforts to limit global warming to 1.5 °C, means as a target for climate action. One interpretation of the goals is as a range spanning a scenario that provides a reasonable chance of staying below 1.5 °C at the lower end, to a scenario that provides a reasonable chance of staying below 2 °C at the upper end. The 450 Scenario, for example, has a 50% chance of limiting the temperature rise to 2 °C and therefore lies at the top of this range. But within this putative range, we can select an illustrative case to explore some of the potential implications for the energy sector of aiming to go beyond the mitigation levels in the 450 Scenario. One such case, for which the "CO_2 budgets" have been examined in detail by the Intergovernmental Panel on Climate Change (IPCC), has a 66% chance of staying below 2 °C. It would imply a 50% chance of a 1.84 °C temperature rise in 2100.

Figure 2.9 ▷ **Indicative global energy sector emissions budgets and trajectories for different decarbonisation pathways**



Without net-negative emissions, energy sector CO_2 emissions fall to zero by 2040 for a 50% chance of 1.5 °C and around 2060 for a 66% chance of 2 °C

The remaining energy sector CO_2 budget between 2015 and 2100 in this illustrative "well below 2 °C" case is 830 Gt, some 250 Gt, or 25%, less than the 450 Scenario energy sector CO_2 budget (Figure 2.9). Multiple emissions trajectories are consistent with this CO_2 budget, but one that avoids relying on global emissions turning net-negative requires energy-related CO_2 emissions to be at net-zero by around 2060. Energy-related CO_2 emissions in 2040 would need to be around 16 Gt, just over 2 Gt lower than emissions in the 450 Scenario. While this might not appear to be an enormous escalation of ambition, it is important to place it in context of the changes already implemented in the 450 Scenario: by 2040, residual emissions occur only in those sectors that are particularly challenging to decarbonise.

The transformation beyond the 450 Scenario and towards "well below 2 °C" presents a formidable challenge: marginal emissions reductions require non-marginal changes to the energy system. For example, three-quarters of the global passenger light-duty vehicle fleet would need to be electric by 2040, up from one-third in the 450 Scenario. To satisfy the consequent increase in electricity demand, 180 GW of additional power capacity would be required above the level in the 450 Scenario, while the share of low-carbon capacity in the power mix would need to rise to almost 80% (from more than 70% in the 450 Scenario). Additional effort is also required in the buildings sector. Oil demand would fall to 63 mb/d in 2040, around 11 mb/d below the 450 Scenario, while gas and coal demand would be 370 bcm and 110 Mtce lower respectively.

Pursuing efforts to stay below a temperature rise of 1.5 °C present an even more challenging goal. The IPCC indicated that to have a 50% chance of keeping global warming to 1.5 °C, the remaining CO_2 budget from 2015 ranges between 400 and 450 Gt CO_2. But more recent reports have suggested it could be as low as 50 Gt CO_2. Even if the CO_2 budget is at the upper end of this range, at around 400 Gt CO_2, energy sector emissions would need to fall to net-zero by around 2040, if global energy-related CO_2 emissions cannot turn net-negative at any point. This would require, within the next two-and-a-half decades, all passenger and light-commercial vehicles to be electric, practically all residential and commercial buildings to be at zero emissions and, in the industry sector, a drastic acceleration of energy and material efficiency alongside increased use of low-carbon fuels. Electricity demand would be boosted to about twice the level of today, 90% of which would be provided by renewables and nuclear. Fossil-fuel use in 2040 would largely be confined to oil and natural gas, with gas demand one-third below today's level and oil demand falling to less than 40 mb/d. Any residual emissions would need to be compensated by biomass use with CCS (BECCS), for example in the power sector. Given the depth of decarbonisation by 2040 required to limiting warming to 1.5 °C, it is highly likely that CO_2 emissions would need to turn net-negative at some point in time. But the longer the date of net-zero emissions is delayed, the larger the level of BECCS that is subsequently required. In any event, energy sector CO_2 emissions would need to fall to zero at some point between 2040 and 2060. The unavoidable conclusion is that there is an urgent need for immediate radical reductions in energy sector CO_2 emissions if there is to be any chance of achieving the 1.5 °C goal.

Compared with the power sector, rapid decarbonisation of end-uses – notably transport and industry – presents an even tougher proposition. In the transport sector, demand for mobility and freight is growing fast; but options to reduce the dependency of the sector on oil are not yet available at scale, even if fuel-economy standards (for cars, if not yet for trucks in many countries) do moderate the rate at which oil demand grows. Electric vehicles can loosen oil's grip, but overcoming the deployment hurdles that are linked to high battery costs will require more dedicated efforts to achieve large-scale market commercialisation (see Box 2.2 and Chapter 3). Natural gas offers a lower carbon alternative to oil, well suited to road freight and international shipping in the form of LNG, but not a route to zero emissions. Advanced biofuels can play a critical role in decarbonising the aviation and maritime sectors, (where other options are limited), as well as road freight, but have not yet achieved commercialisation at scale. As in the transport sector, energy efficiency offers the main route to lower carbon intensity in the industry sector, alongside further efforts (including research) to develop renewable options for industrial heat production and to ensure that CCS becomes commercially available. The emissions intensity of buildings is much lower than other end-use sectors. The sector is the largest consumer of electricity and is a close second (after industry) for heat, and substantial emissions reduction in the buildings sector depends on reducing demand for both, via higher standards for appliances, lighting, air conditioners and other equipment and improving building insulation to reduce heating and cooling needs. As the power sector moves closer to full decarbonisation (as it does in the 450 Scenario, and even more so in a well below 2 °C pathway), so the battleground for further emissions reductions is set to move ever more firmly towards these end-use sectors.

2.5 What can the energy sector do to reduce air pollution?[3]

Fuel combustion in the energy sector is the main origin of the air pollutants that are a major public health hazard. Technologies to tackle this issue are well known, but – despite growing attention to this issue – the problem is far from being solved. Reconciling the world's energy requirement with its need for cleaner air is possible; and a strategy based on cleaner energy, clean cooking facilities and advanced pollution controls can go hand-in-hand with progress towards other environmental and development goals.

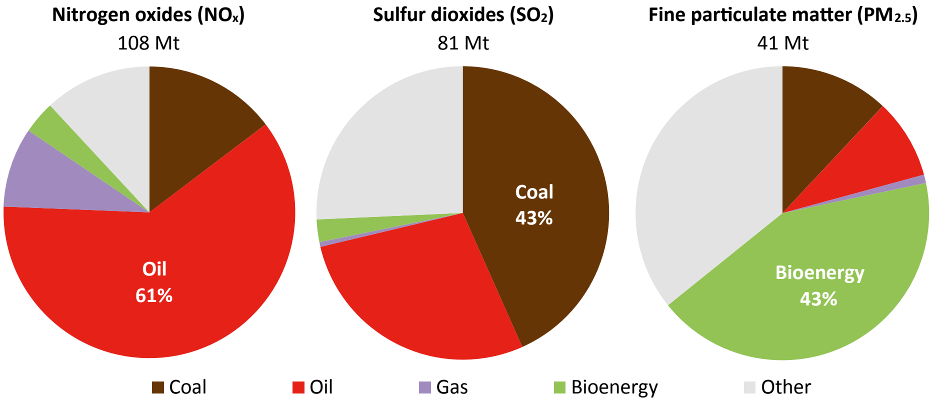
Around 6.5 million premature deaths worldwide are attributed each year to poor air quality, making this the world's fourth-largest threat to human health after high blood pressure, dietary risks and smoking. This is an energy sector problem, as energy production and use, mostly from unregulated, poorly regulated or inefficient fuel combustion, are the single most important man-made sources of air pollutant emissions: 85% of particulate matter and almost all of the sulfur oxides and nitrogen oxides (Figure 2.10). 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.

Each of the main pollutants is linked with a main fuel and source. In the case of fine particulate matter, this is the wood and other solid biomass that some 2.7 billion people use for cooking and kerosene used for lighting (and in some countries also for cooking),

3. This analysis is drawn from *Energy and Air Pollution-World Energy Outlook Special Report*, released in June 2016 (IEA, 2016a). Available at *www.worldenergyoutlook.org/airpollution*.

which creates smoky environments that are associated with around 3.5 million premature deaths each year. These effects of energy poverty are felt mostly in developing countries in Asia and sub-Saharan Africa. Finer particles, whether inhaled indoors or outdoors, are particularly harmful to health as they can penetrate deep into the lungs.

Figure 2.10 ▷ Estimated anthropogenic emissions of the main air pollutants by source, 2015



Combustion of oil, coal and biomass was responsible for most of the man-made emissions of the main air pollutants in 2015

The main fuel associated with sulfur dioxide emissions is coal (although high-sulfur oil products, such as those still permitted for use in maritime transport, are also a major contributor): sulfur dioxide emissions are a cause of respiratory illnesses and a precursor of acid rain. Fuels used for transport, first and foremost diesel, generate more than half the nitrogen oxides emitted globally, which can trigger respiratory problems and the formation of other hazardous particles and pollutants, including ozone. These emissions are linked with industrialisation and urbanisation, and coal and oil are the main sources (natural gas emits far less air pollution than other fossil fuels, or biomass). The unabated combustion of coal and oil in power plants, industrial facilities and vehicles is the main cause of the outdoor pollution linked to around 3 million premature deaths each year.

In the New Policies Scenario, the toll from air pollution on human life is set to rise (Box 2.4). So what more can the energy sector do to tackle this public health crisis? A Special Report in the *WEO-2016* series proposes a cost-effective strategy, based on existing technologies and proven policies, to cut 2040 pollutant emissions by more than half compared with our main scenario. This Clean Air Scenario relies on government action in three key areas, adapted in tailored combinations to reflect different national and regional settings:

- An ambitious long-term air quality goal, to which all stakeholders can subscribe and against which the various pollution mitigation options can be assessed.

- A package of clean air policies for the energy sector. This includes an accelerated energy transition, with a greater emphasis on efficiency, urban planning and on providing energy services in a way that avoids fuel combustion; it incorporates stringent emissions limits on combustion plants and vehicles, fuel switching to less-polluting fuels and strict regulation of fuel quality; and it embraces effective action to achieve full, universal access to cleaner cooking fuels and to electricity.
- Effective monitoring, enforcement, evaluation and communication to keep the strategy on track.

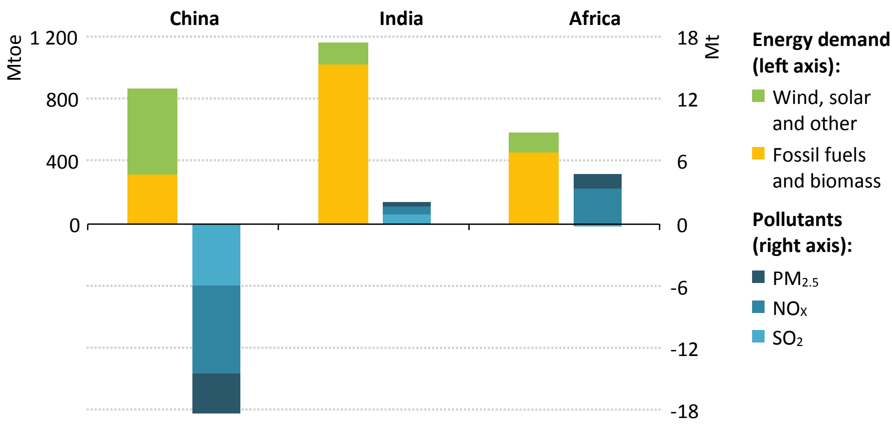
The Clean Air Scenario builds on the success already achieved in different parts of the world in improving air quality, by municipal and regional governments (which have often played a pioneering role in developing a policy response to air pollution) and through national and international efforts. It is also mindful of some pitfalls: for example, the large gap between test data and the higher real-world pollutant emissions from diesel vehicles, which underlines the essential nature of adequate enforcement and compliance.

Box 2.4 ▷ Solutions to air pollution are well known, but in the New Policies Scenario the problem remains far from solved

In the New Policies Scenario, growing attention to air pollution, together with an accelerating energy transition post-COP21, puts aggregate global emissions of the main pollutants on a slowly declining trend to 2040. Although no country has solved the problem entirely, emissions of most major pollutants are already falling in many OECD countries. A de-coupling of energy demand from pollutant emissions also comes into view in other emerging economies (Figure 2.11). In China, a strong policy focus on air quality bears fruit as energy consumption growth slows, the energy mix diversifies away from coal and strict pollution controls are enforced. In India, energy demand rises by 135% over the period to 2040, although tighter standards in the power and transport sectors, the replacement of traditional cooking fuels with liquefied petroleum gas (LPG) and ambitious targets for wind and solar, all help to limit the growth in pollutant emissions to around 10%. However, in the absence of stronger regulation, economic growth in sub-Saharan Africa (excluding South Africa) is set to be accompanied by a steady deterioration in air quality.

Despite the intensified policy efforts, regional demographic trends and rising energy use and urbanisation, especially in developing Asia, mean that the number of premature deaths attributable to outdoor air pollution grows from 3 million today to 4.5 million in 2040. Asia accounts for almost 90% of this rise as poor air quality affects a larger share of an increasingly urban population. In China, an ageing population becomes more vulnerable to the effects of air pollution, even though aggregate pollutant emissions fall. The worldwide health impacts from household air pollution improve somewhat, due to access to improved cookstoves and alternatives to solid biomass for cooking, but almost 3 million premature deaths are still attributable to household pollution in 2040.

Figure 2.11 ▷ Change in energy demand and energy-related air pollutants in selected regions in the New Policies Scenario, today to 2040

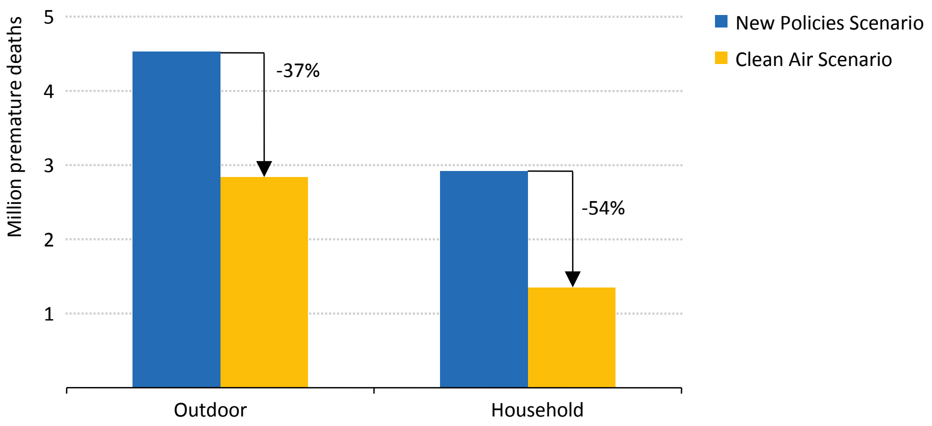


The link between pollutant emissions and energy demand weakens in the New Policies Scenario, but the extent of decoupling varies significantly by country and regions

With only a 7% increase in total energy investment over the period to 2040, compared with the New Policies Scenario, this Clean Air Scenario produces a sharp improvement in health outcomes: premature deaths from outdoor air pollution are 1.7 million lower in 2040 and, from household pollution, 1.6 million lower (Figure 2.12). Investment in the Clean Air Scenario includes an extra $2.3 trillion in advanced pollution control technologies (two-thirds of this to comply with higher vehicle emissions standards) and $2.5 trillion in a more rapid transformation of the energy sector. The resultant benefits are many times more valuable. The share of India's population exposed to air with a high concentration of fine particles (higher than the least stringent of the World Health Organisation's interim targets) falls to less than 20% in 2040 from more than 60% today; in China, this figure shrinks below one-quarter (from well over half), and in Indonesia and South Africa it falls almost to zero. Access to clean cooking for all is instrumental in securing life-saving reductions in particulate emissions. The extra impetus to the energy transition means that global energy demand is nearly 15% lower in 2040 than in the New Policies Scenario, thanks to improvements in energy efficiency, while the use of renewables (except biomass) increases more quickly. Of the energy that is combusted, three-quarters is subject to advanced pollution controls by 2040, compared with around 45% today.

Air pollution policy cannot be viewed in isolation: it is closely linked not only to policies for energy, but also to those dealing with climate, transport, trade, agriculture, biodiversity and other issues. Well-designed air quality strategies have major co-benefits for other policy goals. Improving air quality, via greater efficiency and increased deployment of renewables, goes hand-in-hand with the broader energy sector transformation agreed at COP21 – the Clean Air Scenario provides for an early peak in carbon-dioxide emissions, a central objective of the Paris Agreement. Reducing pollutant emissions improves water and soil quality, crop yields and, in turn, food security. Tackling household air pollution, via the provision of modern energy for cooking and lighting, promotes sustainable development goals dealing with poverty, education and gender equality. But policy-makers also need to be wary of some potential trade-offs. Measures to address climate change could, for example, lead in some instances to more air pollution: an isolated focus on reducing CO_2 emissions by encouraging the use of wood stoves, diesel cars or biofuels, could increase human exposure to fine particles. Similarly, an exclusive focus on direct emissions controls, rather than the package of measures proposed in the Clean Air Scenario, could result in increased commitments to high-carbon energy infrastructure, such as coal-fired power plants. Integrated policy approaches, in this area as in many others, are essential.

Figure 2.12 ▷ Premature deaths attributable to global air pollution in the New Policies and Clean Air Scenarios, 2040



With a 7% increase in investment, premature deaths attributable to air pollution are down sharply in a Clean Air Scenario

2.6 Energy investment – is capital heading where it is needed?

Energy investment activity in 2015 was characterised by a fall in spending on oil and gas, compared with the previous year, while investment in renewables for power generation remained buoyant. A major reallocation of capital, away from fossil fuels and towards renewables and efficiency, would need to be sustained and deepened in a 450 Scenario. But continued weakness in upstream activity would create the risk of price spikes and volatility, if the demand anticipated in the New Policies Scenario is to be met.

In 2015, around $1.8 trillion was invested in the global energy sector (IEA, 2016b), a total that includes fossil-fuel exploration and production, power generation across different technologies, networks and other energy infrastructure, and demand-side measures to improve energy efficiency. Of the $1.8 trillion, around $1.6 trillion was in energy supply, with fossil-fuel supply representing the largest share (some $900 billion) and the power sector accounting for most of the remaining $700 billion. Investments in energy efficiency were around $220 billion. Fossil-fuel investment was almost 20% lower than in 2014, pulled down by lower prices and lower upstream costs, and 2016 is set to be a second consecutive year of falling upstream oil and gas investment – the first time this has happened since the mid-1980s. Conversely, capital spending in the power sector was up around 5% on 2014, including almost $300 billion of investment in renewable sources of electricity.

The starting point for this *Outlook* is, therefore, a depressed level of investment activity in oil and gas, compared with recent years, but a more positive picture for renewables-based electricity, amid evidence of cost deflation in all sectors. The question posed by the IEA *World Energy Investment 2016* report is what comes next: will there be a cyclical upswing towards a higher carbon path or is the current situation the first sign of a structural low-carbon upswing towards decarbonisation?

Table 2.4 ▷ Cumulative global energy supply investment by type and scenario, 2016-2040 ($2015 billion)

	2010-15*	New Policies		Current Policies		450 Scenario	
	Per year	Cumulative	Per year	Cumulative	Per year	Cumulative	Per year
Fossil fuels	1 112	26 626	1 065	32 849	1 314	17 263	691
Renewables	283	7 478	299	6 130	245	12 582	503
Electricity networks	229	8 059	322	8 860	354	7 204	288
Other low-carbon**	13	1 446	58	1 259	50	2 842	114
Total supply	**1 637**	**43 609**	**1 744**	**49 098**	**1 964**	**39 891**	**1 596**
Energy efficiency	**221**	**22 980**	**919**	**15 437**	**617**	**35 042**	**1 402**

* The methodology for energy efficiency investment derives from a baseline of efficiency levels in different end-use sectors in 2014, the annual figure for energy efficiency in this column is the figure only for 2015. ** Includes nuclear and CCS.

The answer, unsurprisingly, depends on the scenario. Comparisons based on the monetary value of investment cannot be conclusive, as they do not take account of changes in underlying costs that – as the last few years have shown – can vary sharply from year to year. But the overall investment figures for the various scenarios provide some useful orientation (Table 2.4). The Current Policies Scenario unambiguously requires a cyclical upswing in investment towards a higher carbon path. In this scenario, fossil-fuel extraction, transport and oil refining, along with power plants using coal or gas, require two-thirds of total investment in energy supply, and the annual average investment in oil and gas supply over the period to 2040, at $1.1 trillion, is well in excess of the $900 billion on average that went into these sectors over the last five years. Equally clear, the 450 Scenario would require a massive reallocation of capital: a sustained increase in the capital flows going to low-carbon energy and energy efficiency, alongside a significant reduction in the amount required to supply fossil fuels.

What happens in the New Policies Scenario? The answer to that question is taken up in the various chapters of this *Outlook* and varies by sector. In the case of oil, the analysis in Chapter 3 starts from the observation that the volume of new conventional crude oil resources granted a final investment decision in 2015 – at 6.5 billion barrels – was down to a level not seen since the 1950s. The indications for 2016 are that the new resources approved for development are still far below the average levels seen in recent years. Given the long lead times for conventional oil and gas projects (up to five years from final investment decision to first oil, and then another three to five years to ramp up to full output), a dearth of new barrels being developed risks leaving a shortfall in supply once the current overhang in production and inventories has been worked off.

Box 2.5 ▷ Could oil investment fall short even in a 450 Scenario?

Around one-third of the supply-demand "gap" in 2025 is caused by oil demand growth in the New Policies Scenario, rather than declines in existing production. In a world where demand in 2025 is lower, it follows that the level of approvals required would also be lower. In the 450 Scenario, oil demand peaks in 2018 and by 2025 is 2.5 mb/d lower than 2015 levels (and 8.5 mb/d lower in 2025 than in the New Policies Scenario). However, lower oil prices and gas demand in the 450 Scenario also mean that multiple sources of production (including tight oil and natural gas liquids) are also lower than in the New Policies Scenario, by nearly 3 mb/d. Taken together the supply "gap" in the 450 Scenario that needs to be filled by new conventional crude oil projects in 2025 is 10.5 mb/d, compared with 16 mb/d in the New Policies Scenario. Following a similar logic to the New Policies Scenario, we find it is possible to fill the 2025 "gap" in the 450 Scenario with an average annual approval rate of around 12.5 billion barrels per year, even with three years of suppressed investments. This is an average level similar to that seen in the late 1990s, far below the level required in the New Policies Scenario.

This highlights a few important issues. First, the transition to a low-carbon energy system can help reduce significantly the implications of supply shortfalls resulting from the reduced levels of upstream investment currently being witnessed. But second, even under a scenario in which prices are low and oil demand is falling, new project approvals and capital investment into post-peak fields are required. The decline in production from currently producing fields far exceeds the decline in demand in the 450 Scenario. Therefore, despite the need to begin transitioning away from a fossil-based energy system, failing to invest in any upstream assets could lead to major problems. Supply shortfalls, and any accompanying price instability, would undoubtedly complicate the transition towards a lower carbon, more sustainable, global energy system.

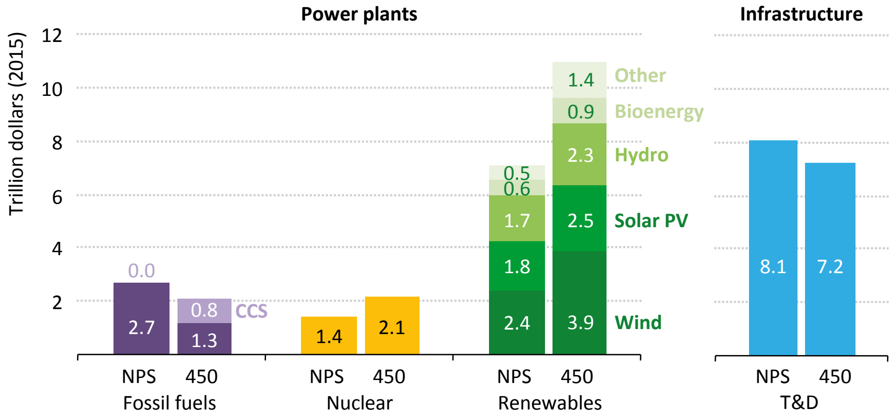
Based on detailed analysis of decline rates for different types of existing fields, accounting for projects that are already approved and are anticipated to start operation in the coming years, and building in a growth trajectory for tight oil in the United States (which has a much shorter investment cycle than conventional projects), there is a 16 mb/d gap opening up by 2025 that needs to be filled by new conventional project approvals in order to meet the oil demand projection in the New Policies Scenario. One year of low resources approved for development (i.e. 2015) can be compensated for with relative ease by rises in subsequent years. Two years with few new conventional project decisions (i.e. 2015 and 2016) creates a greater threat to future activity levels. But if a low level of final investment decisions on new conventional projects were to persist into 2017 as well, then approvals in future years would have to be consistently around historic highs – 21 billion barrels per year – in order to avoid a supply crunch in the 2020s. This would present a major risk of market volatility.

The downturn in natural gas markets means that they face many of the same issues as oil, although it takes longer for the gas market to work off the current supply overhang, as gas consumers – particularly in emerging economies – are less able to respond to a period of low oil prices because of a range of market and infrastructure barriers, which will take time to remove. A critical issue for a smooth adjustment to a new gas market equilibrium, discussed in detail in Chapter 4, is when the LNG market will tighten sufficiently to require new capacity to come online. As in the case of oil, decisions to proceed with investment in new LNG liquefaction capacity have all but dried up in the current price environment, although new projects in Australia and the United States – approved well before natural gas prices started falling – are expected to start operation in 2016 and 2017. In the New Policies Scenario, the point at which new capacity is needed to avoid a market tightening comes in the mid-2020s, in which case the flow of final investment decisions for new LNG projects would need to restart well before the end of the current decade.

In the power sector, the investment that went into renewable energy power technologies in 2015 – at almost $300 billion – is broadly consistent with the annual monetary investment that would be required in the New Policies Scenario (although, as technology costs come down, this level of investment capital would fund a steadily larger amount of capacity). Annual investment in power sector renewables capacity of $300 billion would even be sufficient to meet the annual requirements in the 450 Scenario until the early 2020s, after which point investment would need to pick up again in order to reach $530 billion per year by the late 2030s (and a cumulative $11 trillion by 2040) (Figure 2.13). Presently, these investment flows are responding to specific government incentives – whether feed-in tariffs or competitive tenders – that offer a degree of certainty for future revenues; for these investments, a key risk is policy volatility.

By contrast, investment into conventional fossil-fuel generation in 2015 – at $110 billion – lies between the annual average level required in the New Policies Scenario to 2025 ($115 billion) and the $85 billion required in the 450 Scenario. In competitive markets, these are investments that should be responding to market signals today, but maintaining the flow of new projects cannot be taken for granted, in part due to the large-scale addition of renewables. In most countries, renewables-based producers do not recover their investment cost from wholesale markets and, since their production depresses wholesale prices, they cut into the investment recovery of existing conventional plants and can deter investment in new capacity.

Figure 2.13 ▷ Cumulative global power sector investment in the New Policies and 450 Scenarios, 2016-2040



By the 2020s, the investment needs for the power sector in a 450 Scenario overtake those for fossil-fuel supply

Notes: NPS = New Policies Scenario; 450 = 450 Scenario; T&D = transmission and distribution; Other includes geothermal, concentrating solar power and marine.

The last major component of the investment picture is demand-side efficiency. In the New Policies Scenario, 70% of the cumulative $23 trillion required for energy efficiency is in the transport sector, responding to the increasing spread and stringency of fuel-economy standards, especially for passenger vehicles. Investment in more efficient buildings and the appliances, lighting, heating and cooling systems that they contain requires a further 25% of the total. In the 450 Scenario, tighter minimum energy performance standards for a range of energy-using equipment, higher fuel efficiency standards, the widespread implementation of net zero-energy buildings and other initiatives push up the cumulative spending on efficiency improvements to $35 trillion, more than 50% higher than in the New Policies Scenario. Measuring whether efficiency spending is on track for either of these scenarios is complicated by the way that efficiency spending is defined, but one proxy is the annual improvement achieved in global energy intensity. This reached 1.8% in 2015, in line with the average annual rate of improvement in the New Policies Scenario, but well below the 2.5% per year required in the 450 Scenario.

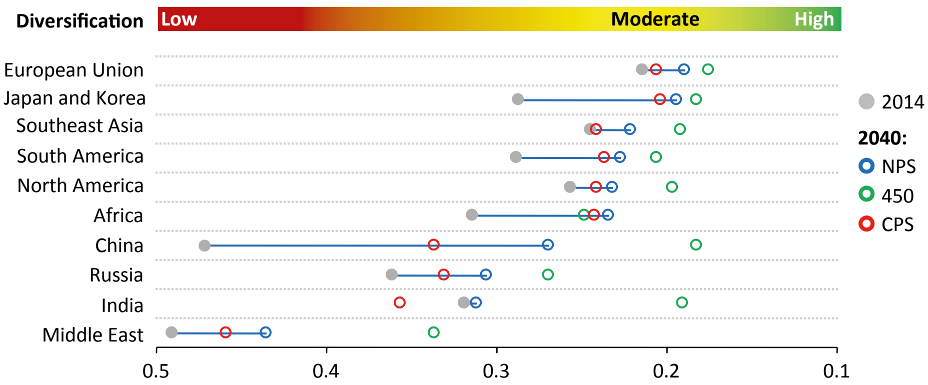
2.7 How might the main risks to energy security evolve over the coming decades?

The reliability of oil and gas supply is the traditional focus of assessment of energy security. Risks in this area remain, particularly for the Asian importers that provide the destination for a rising share of oil and gas trade. But the focus is shifting increasingly to electricity security, as electricity takes a higher share of final consumption. The rise of wind and solar power is central to this redefinition of energy security: it tempers import dependency yet creates new challenges for power system operation. Climate change is set to exacerbate vulnerabilities in the energy sector, not least via the impacts on water availability.

There are two main dimensions to the discussion of energy security. There is the short-term threat of unexpected disruption to the supply of a key energy source – and whether a given energy system has the flexibility to cope with such a shock. Then there are longer term questions over the evolution of the energy system and how investment patterns, security risks and vulnerabilities might change as a result. These two dimensions are linked: if investment falls short (as discussed in the section 2.6), or policies or regulation fail to keep pace with evolving risks, then there is a greater risk of sudden disruptions or shifts in the supply-demand balance. The projections in the *World Energy Outlook* shed light on some specific investment risks: they also provide some insights into the broader evolution of energy security vulnerabilities and how these change over time in the various scenarios. Understanding these risks is a vital first step towards the actions that are necessary to avoid them – where possible – or the measures that are required to mitigate or withstand them.

One measure that can be traced through our projections is the diversity of the primary energy mix among the different fuels: oil, gas, coal, nuclear, hydro, bioenergy and other renewables. Diversity of the primary energy mix is by no means a complete indicator of energy security: the various elements are often not substitutable and each brings a different set of attributes and problems. Nonetheless, obtaining energy from multiple sources can be seen as generally positive from an energy security perspective and high reliance on a single source as a weakness. From this perspective, the shifts illustrated in Figure 2.14 paint a generally reassuring picture. With the main exception of India in the Current Policies Scenario (in which India becomes more reliant on coal), the energy mix becomes more diverse between today and 2040, in all scenarios. The pace of change varies: China sees – by far – the largest shift in the direction of greater diversification, away from coal, underlining the scale and ambition of the transition that is underway. The Middle East is the other region that currently has a very concentrated structure, with oil and gas accounting for some 99% of primary consumption (their position entrenched by fossil-fuel consumption subsidies). The transition in this case is much less dramatic. Comparing across scenarios, the level of concentration in the energy mix in 2040 is highest in the Current Policies Scenario. The impression of higher energy security vulnerability in this scenario is reinforced by considering the additional investment required to meet higher demand. Conversely, in a 450 Scenario, not only is the system more diverse, but the overall demands on the system are much lower, because of the improvements in energy efficiency.

Figure 2.14 ▷ Diversity of the primary energy mix by scenario and selected region



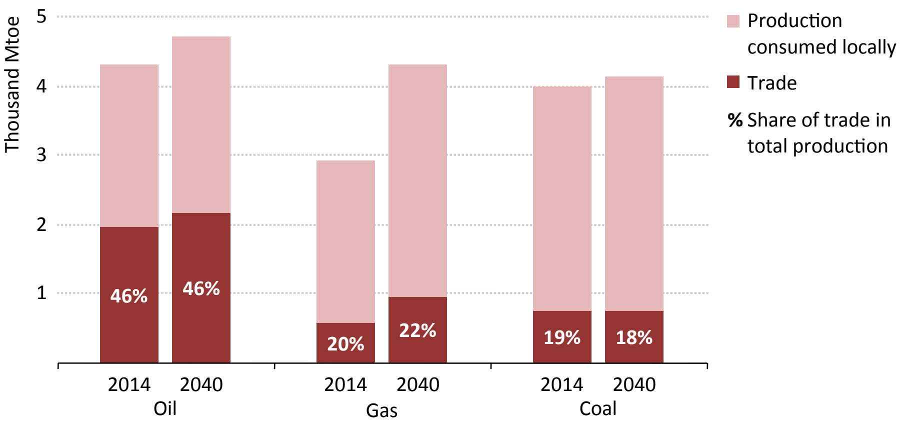
Energy systems almost everywhere shift to a more diverse mix of fuels and technologies in the coming years

Notes: NPS = New Policies Scenario; 450 = 450 Scenario; CPS = Current Policies Scenario. The indicator for diversity is calculated using a Herfindahl-Hirschmann Index, a commonly used tool to measure market concentration in different parts of the economy. The calculations use the share of each fuel in total primary energy demand in each scenario. Lower values indicate a higher degree of diversity in the energy mix.

An overall measure of diversity is useful, but an assessment of risks also needs to take into account the direction of the shifts among the fuels and technologies and the opportunities to switch between them. Here the situation becomes more nuanced. A common trend for many countries and regions in the coming decades – and a desirable one in view of climate objectives – is reduced reliance on coal. Yet, for all its environmental drawbacks, coal plays a positive role in many energy security strategies. Coal resources are widely distributed; once extracted, coal is relatively easy to transport and store; and the ability to switch to coal-fired generation can offer a useful backstop in case of a disruption in another part of the system. More limited recourse to this option can be an important consideration for countries that are also expanding their use of natural gas (as many are, at least in the New Policies Scenario), as it implies the need to build more safeguards and flexibility (and storage) directly into the gas supply chain.

Despite the rise in renewables, which tends to increase the share of energy produced domestically rather than bought or sold on the international market, global trade remains an important component of the energy system in all our scenarios. In the New Policies Scenario, 20% of the primary energy consumed in 2040 is traded between one of the *WEO* regions, compared with 22% in 2014: only in the 450 Scenario does this share fall more substantially, to 18%. Reliance on imported fuels – or export revenues – is not in itself an energy security hazard, but there are potential vulnerabilities. The New Policies Scenario shows a shift in aggregate away from coal trade (which falls slightly as a share of coal output) and towards oil and gas, commodities for which history shows a much greater incidence of interruptions to supply (Figure 2.15).

Figure 2.15 ▷ Global fossil-fuel trade in the New Policies Scenario



While coal stands still, the volume of traded oil and gas increases and the share of gas trade in total consumption moves higher

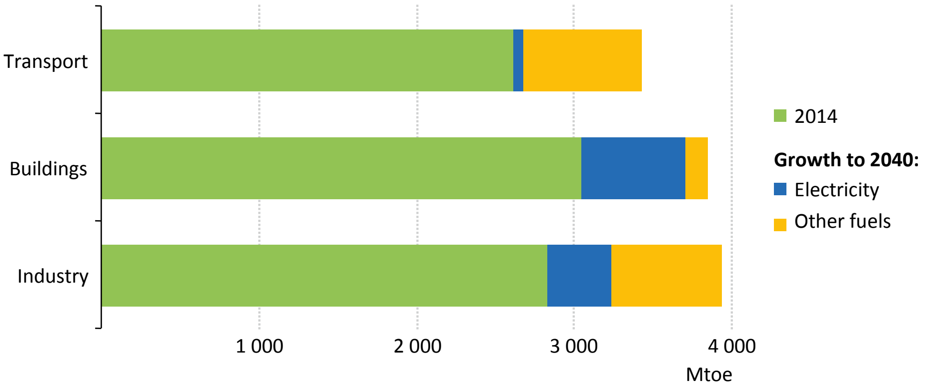
Note: Trade shows net trade between main *WEO* regions, not including trade within regions.

Trade patterns for oil and gas are transformed in our projections, compared with today, due to underlying changes in the geography of production and consumption. The rise of production in North America turns this region into a large net provider of oil and gas in the New Policies Scenario and rising demand means that an ever higher share of traded oil and gas is drawn towards Asia. Of the total volume of oil and gas traded today, 50% goes to a destination in Asia. In the New Policies Scenario in 2040, this share rises to 75%. With rising volumes and the anticipation of higher prices, import bills also grow significantly for many Asian importers in this scenario. China's import bill for oil and gas reaches $680 billion in 2040, up from an estimated $150 billion in 2015: India requires $460 billion to pay for imported oil and gas in 2040, compared with $65 billion in 2015; the net import bill for the ASEAN countries likewise rises sharply, from $60 billion in 2015 to $335 billion in 2040 (with oil accounting for more than 80% of the total in all cases). Beyond the financial considerations, it is also worth recalling Churchill's well known dictum, talking of oil, "safety and certainty … lie in variety and variety alone". On this point, the outlooks for oil and for gas start to diverge.

In all scenarios, the supply of gas becomes more diverse, as new LNG suppliers emerge and, to a lesser extent, as new pipeline routes are opened, e.g. from Russia to China. The share of LNG in global trade rises to 53% in the New Policies Scenario, from 42%, today and this is traded on an increasingly flexible basis, without the destination clauses and other restrictive arrangements that still characterise much of today's trade (see Chapter 4). The same trend is not visible in the case of oil, for which traded supply becomes more concentrated as the world becomes more reliant on exports from a single region, the Middle East. The degree of concentration is highest in the 450 Scenario, based on the fact that the Middle East is the largest source of low-cost oil, so in scenarios where demand and prices are lower, the Middle East takes a larger share of output and trade (while simultaneously being put under considerable pressure by the steady reduction in hydrocarbon revenue). The implication is that reducing reliance on oil, as in the 450 Scenario, may actually heighten oil security risks for the duration of the transition.

Another trend with strong implications for energy security is the increasing share of electricity in final energy consumption, which rises from 18% today to around a quarter of final consumption in 2040 in the New Policies Scenario. This rises further in deeper decarbonisation scenarios, as electricity also starts to take a larger share of transport demand (a shift that remains in its early stages in the New Policies Scenario) (Figure 2.16). Electricity represents more than 40% of total supply-side investment needs of the energy system in the New Policies Scenario (a cumulative $19 trillion out of total supply investment of $44 trillion), due to demand growth in non-OECD countries, ageing power generation and networks in OECD and the deployment of capital-intensive low-carbon sources almost everywhere.

Figure 2.16 ▷ Share of electricity in the growth in final energy consumption in selected end-use sectors in the New Policies Scenario



Electricity takes a major share of the growth in end-use consumption in buildings and industry, while also gaining a foothold in the transport sector

Electricity security is set to feature ever more strongly in the overall energy security debate. One of the risks highlighted by our projections is systematic under-investment in power plants and other infrastructure, due to regulatory problems or flaws in market design. The rapid growth of low marginal cost and variable renewables (wind and solar) production, while wholly desirable from a climate change point of view, creates additional challenges in this respect. As discussed in Chapter 12, high shares of wind and solar can be integrated successfully into power systems, but this does require a policy framework that incentivises investment to match the electricity demand profile, that allows for some of the variability in output to be absorbed by demand-side response and storage, and provides for a "smarter" network that operates with sufficient flexibility (a development that in turn raises the need for vigilance on cyber security). In most systems, the production and flexibility provided by conventional power plants also remains an essential component of electricity security; however (as discussed in the investment section above), committing capital to thermal generation requires a power market design that offers these plants adequate remuneration, which at present is not always the case.

A final element of change in the energy security discussion is the way that broader global problems, some related to energy use, intersect with and amplify challenges facing the energy sector. Chief among these broader challenges is climate change itself, which is often referred to as a "threat multiplier" because of the way that it widens existing fault lines in the global system. This can have indirect impacts on energy security, perhaps by giving an additional destabilising push to countries and regions that are already volatile, e.g. by worsening food security in some regions, due to changes in productivity of agricultural land. It can also have direct impacts in a variety of areas; the energy sector itself is not immune to the physical impacts of climate change. Energy system vulnerabilities include the sudden and destructive impact of extreme weather events that pose risks to power plants and grids, oil and gas installations, wind power installations and other infrastructure. Other impacts are more gradual, such as changes to heating and cooling demand, sea level rise on coastal infrastructure and the effect of shifting weather patterns on hydropower and water scarcity on power plants. As these last examples suggest, the intersection between energy and water security, covered in detail in Chapter 9, is of particular consequence for the future (Spotlight).

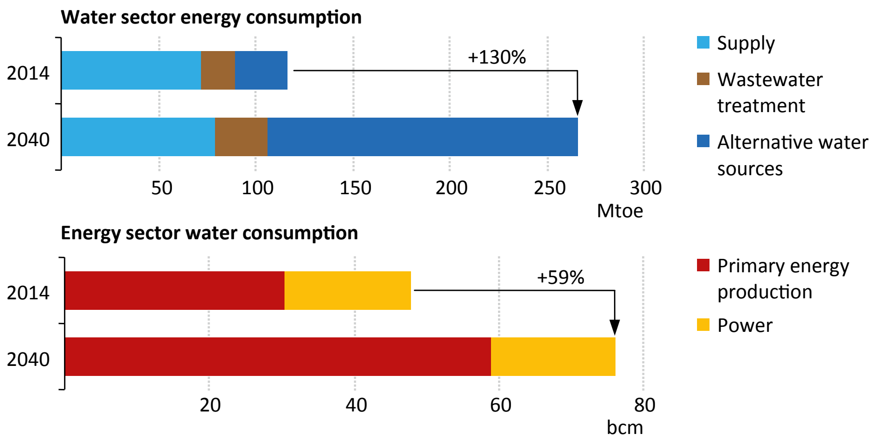
SPOTLIGHT

How does water fit into the energy mix?

In a ranking of potential global risks conducted by the World Economic Forum in 2016, three of the top-five concerned either energy (a failure of climate change mitigation and adaptation, or a severe energy price shock) or water (water crises). In practice, energy and water are closely interrelated. Water is essential for all phases of energy production, from fossil fuels to biofuels and power plants: energy is vital for a range of water processes, including water distribution, wastewater treatment and desalination. All of the weaknesses in the global energy system, whether related to energy access, energy security or the response to climate change, can be exacerbated by changes in water availability. All of the fault lines in global water supply can be widened by failures on the energy side.

Chapter 9 in *WEO-2016* shows how the interdependencies between energy and water are set to deepen in the coming decades. The analysis provides a first systematic global estimate for the amount of energy used to supply water to consumers, including the electricity used to extract, distribute and treat water and wastewater, and the thermal energy used for irrigation pumps and desalination plants. Over the period to 2040, the amount of energy used for these purposes is projected to more than double as desalination capacity rises sharply in the Middle East and North Africa and as demand for wastewater treatment (and higher levels of treatment) grows, especially in emerging economies. The energy sector also becomes thirstier over the period to 2040: there is a switch to advanced cooling technologies that withdraw less water, but consume more (i.e. water that is withdrawn but not returned to a source), while greater deployment of nuclear power increases both withdrawal and consumption levels, and an increase in biofuels demand pushes up water use from primary energy production. Some technologies, such as wind and solar PV, require very little water; but the more a decarbonisation pathway relies on biofuels production, the deployment of concentrating solar power, carbon capture or nuclear power, the more water it consumes. As a result, despite lower energy demand, water consumption in 2040 in a 450 Scenario is slightly higher than in the New Policies Scenario.

Figure 2.17 ▷ Global energy use in the water sector and water use in the energy sector in the New Policies Scenario



In the coming decades, the water consumed by the energy sector rises sharply, as does the energy consumed by the water sector

Notes: Supply includes extraction, water treatment, distribution and water transfer. Alternative water sources include desalination and re-use.

2.8 Are we on the path to achieving universal access to energy?

The target to achieve universal access to energy by 2030 is an ambitious one, with 1.2 billion people still without access to electricity today and 2.7 billion people without clean cooking facilities. Momentum is building behind national and international efforts in both these areas, but despite the anticipated progress (particularly with electrification), we project that some 780 million people remain without electricity in 2030 and that the number continuing to rely on the traditional use of solid biomass for cooking falls by less than 15%, to 2.3 billion.

Access to modern forms of energy is a critical enabler of human development; it occupies a priority place in national policymaking in countries where universal access has yet to be achieved and on the international development agenda. Efforts to promote access received a boost in 2015 with the adoption of the UN Sustainable Development Goals (SDGs), which include in Goal 7 (SDG 7), the aim to ensure universal access to affordable, reliable, sustainable and modern energy services, with a target date of 2030. The Addis Ababa Action Agenda, agreed earlier in 2015, covered the need to channel finance for the sustainable development agenda. The third crucial accord reached during the year was the Paris Agreement, which acknowledges the need to promote universal access to sustainable energy, particularly in Africa.[4]

Table 2.5 ▷ Population without access to modern energy services in the New Policies Scenario (million people)

	Without access to electricity			Without access to clean cooking facilities		
	2014	**2030**	**2040**	**2014**	**2030**	**2040**
Africa	634	619	489	793	823	708
Sub-Saharan Africa	633	619	489	792	823	708
Developing Asia	512	166	47	1 875	1 458	1 081
China	0	0	0	453	244	175
India	244	56	0	819	675	450
Latin America	22	0	0	65	56	52
Middle East	18	0	0	8	8	7
World	**1 186**	**784**	**536**	**2 742**	**2 345**	**1 849**

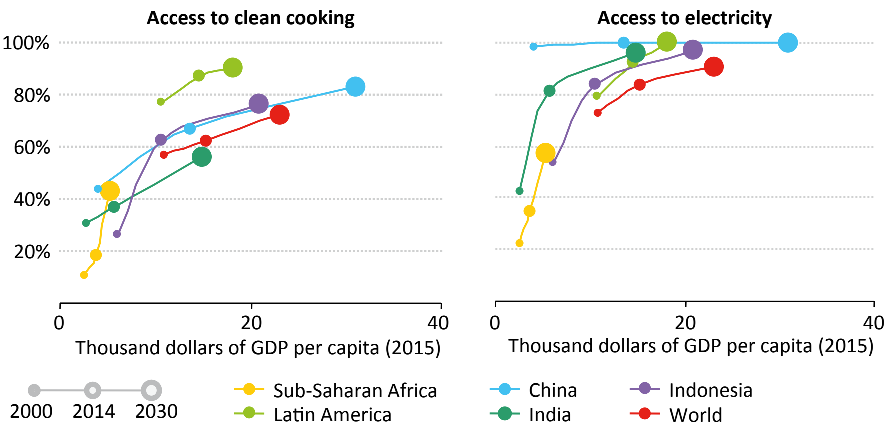
Sources: IEA and WHO (World Health Organisation) databases.

The size of the remaining task is huge (Table 2.5). Estimates show a huge deficit in access to energy for the world's poorest people. An estimated 1.2 billion people, or 16% of the world's population, still lacked access to electricity in 2014. However, this number represents a

4. Other initiatives launched over the last year include a G20 plan for enhancing energy access in Asia and the Pacific, building on the G20 Energy Access Action Plan for sub-Saharan Africa. The African Development Bank in September 2015 launched an initiative, "A New Deal on Energy for Africa", aiming to mobilise support and finance to achieve universal access to energy in Africa by 2025.

decrease of 15 million people compared with the previous year, despite an increase in the global population, showing the ambition and progress achieved in many countries.[5] Sub-Saharan Africa remains the region with the greatest concentration of energy poverty, with 65% of the population, 633 million people, lacking access to electricity (a reduction of less than 1% compared with the estimate for 2013) (Figure 2.18). In India, the electrification rate has reached 81%, an almost doubling of the 43% rate of electricity access in 2000, and access is a major political priority, with the current government pledging universal "24x7" power for all by 2022 (with ambitions for reaching this target before 2020). A major milestone in electricity access was reached at the end of 2015, with the announcement by the government that China had achieved universal electricity access, bringing an end to the largest national electrification programme in history. However, efforts to improve access should not stop with an electricity connection as it is no guarantee of reliable and affordable supply: curtailment caused by inadequate infrastructure and power supply is very common in many parts of the developing world, taking a large economic toll.

Figure 2.18 ▷ Evolution of access to clean cooking and to electricity by selected region in the New Policies Scenario



Projected progress in improving access to clean cooking lags behind access to electricity in the New Policies Scenario

Access to clean cooking receives far less attention than electrification and in many ways is more difficult to achieve. Progress has not been keeping pace with population growth: latest estimates show that 2.7 billion people, almost 40% of the global population, still rely on the traditional use of biomass for cooking, an increase from the previous estimate

5. Year-on-year progress in electricity access is difficult to measure due to changes in sources. However, progress is clear: had the rate of electricity access remained unchanged from the previous estimate for 2013, population growth would have implied that 27 million additional people would have been without electricity access in 2014.

in *WEO-2015* by around 20 million people.[6] Half of the global population that lacks clean cooking access lives in Asia, particularly India, where 63% of the population lack access to clean cooking (30% of the global total). The Indian government has pledged to give free LPG connections to 50 million identified poor rural households by 2019, which, if achieved, would reduce this access deficit significantly. The problem is also acute in sub-Saharan Africa, where more than 80% of the population cooks with biomass using traditional methods, yet there are far fewer initiatives for clean cooking than for electricity, even though interventions strongly benefit the poorest in society (EUEI PDF, 2016). The smoky environments caused by reliance on solid biomass in households are a major health hazard, particularly for the women and children that have the highest exposure (and in the case of younger children, also the highest vulnerability) to fine particulate matter in the air.

The outlook for access to electricity and clean cooking shows that the world is far from being on track to meeting the SDG 7 goal of achieving universal access to modern energy by 2030.[7] In the New Policies Scenario, more than 780 million people are projected to remain without access to electricity in 2030 and 540 million still in 2040. To an extent, these figures disguise the progress that is made: population growth means that around one billion people gain electricity access in both Africa and Asia in 2040 compared with today, with nearly three-quarters of this growth occurring in cities. An expanding centralised electricity grid provides nearly two-thirds of electricity generated for additional access in 2040, but decentralised solutions, particularly from renewables, are critical in providing access to remote rural areas of many countries (see Chapter 10, Spotlight). But progress is uneven and the remaining population without electricity access becomes more concentrated in sub-Saharan Africa (accounting for more than 90% of the global total without electricity access in 2040, up from just over half today). At present, per-capita electricity consumption in sub-Saharan Africa, excluding South Africa, is only 6% of the world's average and only grows to 14% in 2040 over the *Outlook*. The rural population is the most disadvantaged, with 95% of the population without access concentrated in rural areas in 2040, from around 80% today. Efforts are, however, gathering momentum in sub-Saharan Africa: Power Africa, a US government initiative, has this year published a roadmap to add 60 million new electricity connections by 2030 (USAID, 2016).

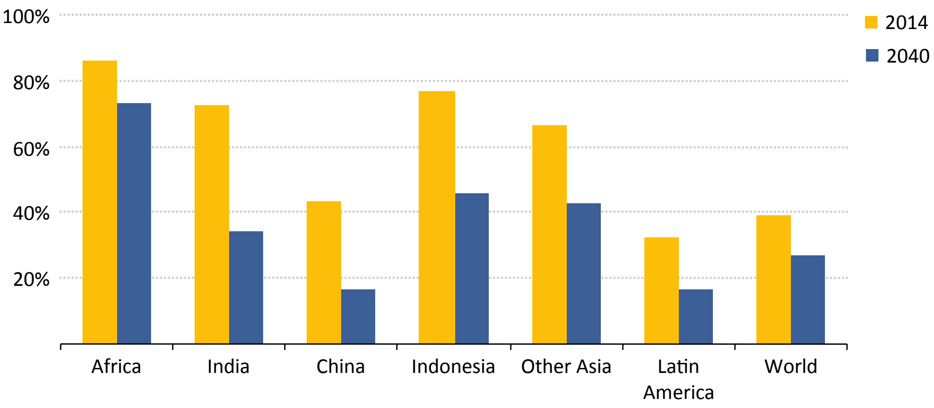
The projection for access to clean cooking facilities shows less progress than in the case of electrification: the number of people without access decreases by only 200 million by 2030, a reduction of 14%, as the adoption of clean cooking facilities struggles to keep pace with population growth in many of the countries concerned. Of those that gain access, three-quarters do so via LPG cookstoves, mainly in urban areas because of the relative ease of establishing fuel supply networks. In rural areas, the most common route to access is via

6. While "access to clean cooking" in this context refers to the use of fuels for cooking other than solid biomass used in a traditional manner, the SDG Indicator 7.1.2 refers to the "proportion of population with primary reliance on clean fuels and technology" for lighting and cooking, which excludes the use of unprocessed coal and kerosene. This indicator is monitored by the World Health Organization and amounted to about 3 billion in 2014.

7. A detailed description of the methodology underpinning the projections for energy access can be found at: *www.worldenergyoutlook.org/resources/energydevelopment/*.

improved biomass cookstoves: solid biomass remains a major fuel for residential use in our projections (Figure 2.19). Developing countries in Asia, despite reaching almost universal electrification, still have more than 1.5 billion people without clean cooking access in 2030, over one-third of the population at that time. Even in China, where universal electrification is already complete, around 450 million people still rely on the traditional use of biomass for cooking today and this number only falls to 250 million people in 2030. In sub-Saharan Africa, the switch is not rapid enough to keep up with the rise in population, and so the number of people without access increases by 2030, to over 800 million, before starting a gradual decline by 2040.

Figure 2.19 ▷ Share of solid biomass in residential energy use by selected region in the New Policies Scenario



The share of solid biomass in residential energy use declines in the New Policies Scenario, but remains widespread

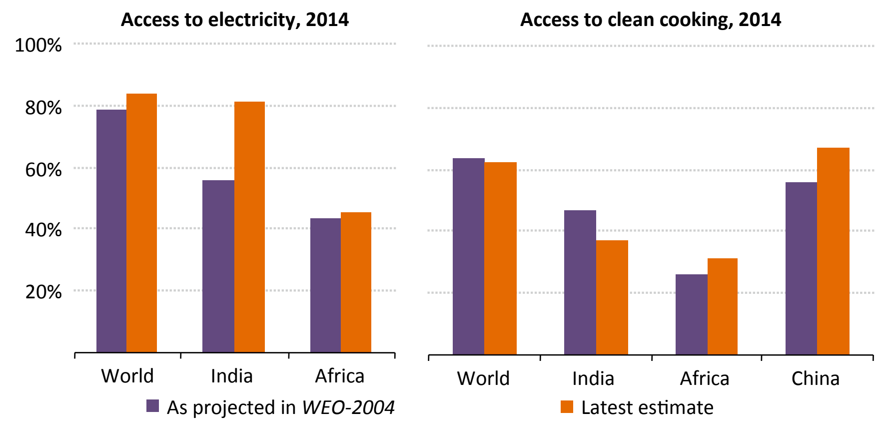
Dedicated policies to promote access are essential to break the vicious cycle of energy poverty, in which growth in incomes and living standards are severely hindered by a lack of modern energy services, while at the same time low incomes and poor investment are a fundamental barrier to increasing access. This is most evident in sub-Saharan Africa, where multiple developmental and environmental challenges are rooted in poverty and closely linked to a lack of access to modern energy services. The potential for policy to make a difference can be seen in multiple ways; it is even clear by looking at the way that concerted policy action in some countries has accelerated progress with access beyond the pace projected in the *World Energy Outlook* in 2004 (Box 2.6). Technology can also be a major enabler of effective policymaking and improvement on the ground: decentralised renewable energy is providing an increasingly viable and affordable way to close the access gap in rural areas, particularly for remote settlements far from the existing grid.

Box 2.6 ▷ Looking back at looking ahead: how did previous *Outlooks* see the access situation today?

The New Policies Scenario evolves each year with the changing policy landscape. Revisiting the access scenarios from *WEO-2004* (IEA, 2004) reinforces two messages made in this analysis (Figure 2.20). There is an imbalance in global action between electricity access, where there has been more rapid progress, and access to clean cooking. And countries can make a major difference with good policy choices and political will. From the base-year of 2002, when an estimated 73% of the global population had access to electricity, the expectation in *WEO-2004* – based on policies in place at the time – was that this percentage would rise to 78% by 2014. The latest estimate suggests that around 84% of the world's population had access to electricity in 2014, with improvement largely due to a successful push for electrification in India over the years. Projections in *WEO-2004* suggested that access to electricity in India might rise from 44% in 2002 towards 60% by 2014: in practice, the data show that more than 80% had electricity in 2014, testament to a strong policy drive by federal and state governments. However, in Africa, where enabling conditions did not change as starkly over the decade, the 2004 projections for access to electricity unfortunately reflect the current reality.

In general, improvements in access to clean cooking have proceeded in line with the somewhat pessimistic projection made twelve years ago. In contrast with the progress made in electricity access, India has achieved less in the intervening period with clean cooking than projected, although progress in Africa and in China has been slightly more rapid.

Figure 2.20 ▷ Comparison of *WEO-2004* projections for energy access with estimates for 2014



In the case of electricity, stronger policies have produced faster improvements than projected in WEO-2004; for clean cooking, the picture is more mixed

2.9 Changing places: is global spending on energy subsidies shifting from fossil fuels and in favour of renewable energy sources?

The fall in oil prices has provided an opportunity and incentive for energy pricing reform and brought the overall estimate for fossil-fuel subsidies down to $325 billion in 2015, from close to $500 billion in 2014. Subsidies to renewable energy rose in 2015 towards $150 billion, mostly in the power sector, and the effectiveness of the subsidies has also been increasing, with reductions in technology costs. Whether this shift continues depends on the resolve of governments to persist with pricing reform even once fossil-fuel prices start to rise; and on the speed at which renewable energy projects become economically competitive without any state support.

Fossil-fuel subsidies distort energy markets, promoting inefficient use of energy and increasing energy-related CO_2 emissions. They are a roadblock on the way to a cleaner and more efficient energy future. Their value, in terms of actual fiscal transfers to consumers and the opportunity cost of foregone revenue, has consistently dwarfed the amounts allocated by governments to subsidies for renewable energy: in 2014, for example, fossil-fuel consumption subsidies of almost $500 billion were more than three-times higher than renewables subsidies of some $140 billion (consisting of $114 billion for non-hydro renewables for power generation and $24 billion for other sectors, notably biofuels).[8]

A confluence of developments has opened up an opportunity to change this dynamic. On the renewables side, subsidies supporting the deployment of non-hydro renewables for power rose again to an estimated $120 billion in 2015, supplemented by nearly $30 billion supporting deployment of renewables in transport and other end-uses. As well as supporting existing projects in the power sector, these subsidies helped to facilitate capital investment of $230 billion and more than 120 GW of new non-hydro renewables capacity. Cost reductions mean that this spending on subsidies and new investment projects is progressively delivering more capacity per dollar spent. Subsidies increased by around 6% in 2015, but installed renewables capacity more quickly, by around 8%.

At the same time, the plunge in oil prices since 2014 has added to the impetus behind the reform of fossil-fuel subsidies – amplifying the political momentum created by commitments made in the G20, in the Asia-Pacific Economic Cooperation (APEC) and elsewhere (Table 2.6). Among net importers, pressure to phase out subsidies had built up during the period of high oil prices from 2011-2014 and the lower oil prices presented an opportunity to follow through as subsidy reform could be achieved without having a major upward impact on prices or inflation. Indonesia, for example, cut subsidies for both gasoline and diesel in 2015, with the complete removal of the latter under further consideration. The new dynamic in 2015-2016 was in the main oil and gas producing nations, where

8. The IEA uses a price-gap methodology to estimate fossil-fuel subsidies: the price gap is the amount by which the average final consumer price for a given fuel falls short of its reference price, which corresponds to the full cost of supply or, where appropriate, the international market price, adjusted for the costs of transportation and distribution, and value-added tax.

subsidies are concentrated in practice. Here the loss of hydrocarbon revenue has created huge pressure for fiscal consolidation, with cuts to wasteful fuel subsidies an obvious way to relieve the strain on budgets.

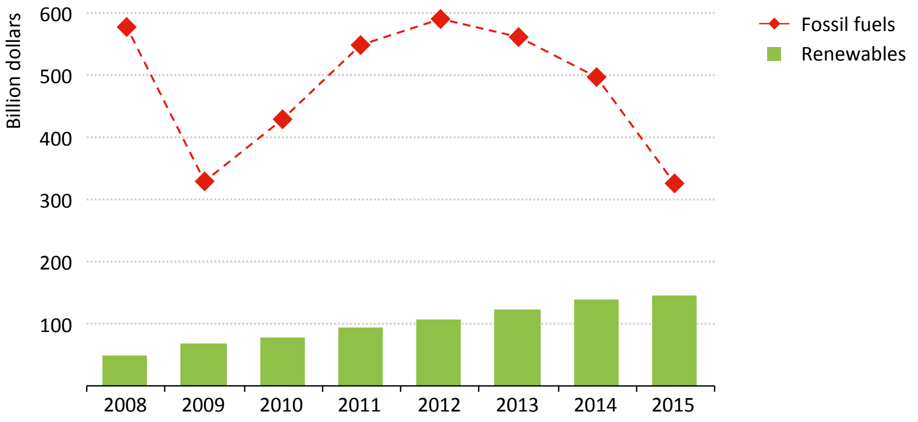
Table 2.6 ▷ Recent fossil-fuel subsidy reforms in selected countries

	Main fuels subsidised	Recent developments
Algeria	Gasoline, diesel, natural gas, electricity	In January 2016, increased prices of gasoline by 34% and diesel by 37%. Also increased prices of electricity and gas.
Angola	Kerosene, electricity	Ended subsidies for gasoline in April 2015 and for diesel in January 2016.
Argentina	Natural gas, electricity, LPG	In January, March and April 2016, increased prices of gasoline and diesel by 6% and in May 2016 by 10%. In April 2016, increased prices of natural gas for residential, industry, transport, and electricity by reducing subsidies.
Ecuador	Gasoline, diesel	In October 2015, announced elimination of subsidies for jet fuel, fuel oil, LPG and diesel for large industrial consumers.
India	Kerosene, LPG, natural gas, electricity	In April 2016, introduced direct cash transfer scheme for residential kerosene consumers and launched a programme to progressively raise kerosene prices, starting in July 2016.
Indonesia	Electricity, diesel	In January 2016, announced plans to reform electricity subsidies to be better targeted to poor and vulnerable households. In March 2016, announced a plan to remove subsidies for diesel.
Iran	Gasoline, diesel, kerosene, LPG, natural gas, electricity	In May 2016, cabinet approved the removal of gasoline quota for public and private passenger vehicles by September.
Nigeria	Gasoline, kerosene	In May 2016, increased a price cap for gasoline by 68% to NGN 145 per litre ($0.73).
Oman	Gasoline, diesel, natural gas, electricity	In January 2016, increased prices of premium gasoline (RON 95) by 33 % to OMR 0.160 ($0.42) per litre and regular gasoline (RON 90) by 23% to OMR 0.140 ($0.36) per litre. The price of diesel was also raised 9.6% to OMR 0.160 ($0.42) per litre.
Qatar	Gasoline, diesel, natural gas, electricity	In January 2016, increased prices of gasoline around one-third. In May 2016, started adjusting the prices of gasoline and diesel to global market prices.
Saudi Arabia	Gasoline, diesel, kerosene, natural gas, electricity	In December 2015, announced numerous price hikes, including gasoline, natural gas and electricity. Increased prices of premium gasoline (RON 95) by 50% to SAR 0.9 ($0.24) per litre and regular gasoline (RON 91) by two-thirds to SAR 0.75 ($0.20) per litre, and also increased prices of electricity.
Trinidad and Tobago	Gasoline, diesel, electricity	In September 2015, increased prices of gasoline and diesel. In April 2016, announced a budget that includes a decrease of subsidies for gasoline and diesel.
Tunisia	Gasoline, diesel, electricity, LPG, kerosene	In April 2016, announced to link fuel prices to market prices.
Thailand	LPG, natural gas, electricity	In January 2016, announced to deregulate prices for CNG starting in July.
Ukraine	Natural gas, electricity	In April 2016, introduced a market-based price for natural gas, together with targeted social support for residential consumers.
Venezuela	Gasoline, diesel, natural gas, electricity	In February 2016, increased prices of premium gasoline by 60-times to VEF 6.0 ($0.6) per litre, and regular gasoline by 14-times to VEF 1.0 ($0.1).

Notes: LPG = liquefied petroleum gas; CNG = compressed natural gas.

The value of global fossil-fuel consumption subsidies in 2015 is estimated at $325 billion, much lower than the estimate for 2014, which was close to $500 billion (Figure 2.21).[9] The decrease in the value largely reflects lower international energy prices of subsidised fuels since mid-2014, as the gap between international benchmark and end-user prices is closed by decreased international prices of energy, but it also incorporates the impact of pricing reform.[10] Of the total, oil subsidies accounted for 44% of the total ($145 billion, covering an estimated 11% of global oil consumption), followed by electricity subsidies estimated at just over $100 billion (covering 17% of global electricity use). Natural gas subsidies were also significant, amounting to nearly $80 billion (affecting the price paid for 25% of gas consumption). Coal subsides are relatively small, at $1 billion in 2015.

Figure 2.21 ▷ Estimates for global fossil-fuel consumption subsidies and subsidies for renewables



The drop in fossil-fuel prices and in the value of subsidies has raised prospects for reform; the fall in technology costs has boosted the effectiveness of subsidies for renewables

Although subsidies to fossil fuels remain well above those to renewables, the gap has narrowed substantially. In 2008, the ratio was more than 10:1, but in 2015 it was closer to 2:1. Some countries saw both a fall in fossil-fuel subsidies and an increase on the renewables side. India is a good example: the deregulation of diesel prices in late 2014, taking advantage of the fall in the oil price, meant that all oil-based transport fuels are now free of subsidy. As a result India's total subsidy bill fell by half from $38 billion in 2014 to around $19 billion in 2015. At the same time, India has been stepping up its support to renewables, its estimated subsidy in this area rising by nearly 40% to exceed 2 billion

9. The *WEO* estimate covers subsidies to fossil fuels consumed by end-users (households, industries and businesses) and subsidies to the consumption of electricity generated by fossil fuels.
10. See *www.worldenergyoutlook.org/resources/energysubsidies* for full details of the IEA's methodology for estimating subsidies.

in 2015 as it pushes to attain its target of 175 GW of renewables capacity (excluding large hydropower) by 2022 from a current level of less than 40 GW.

But, by and large, there is little overlap between the countries that provide the largest subsidies to renewables and those that subsidise fossil fuels. Among the former are the European Union, which accounts for just over half the estimated global subsidies to renewables for power (more than $60 billion), followed by the United States ($18 billion), China (almost $17 billion) and Japan ($10.5 billion). Meanwhile, the largest sources of subsidies to fossil fuels are Iran, with 16% of the total ($52 billion), Saudi Arabia ($49 billion), Russia ($30 billion) and Venezuela ($20 billion).

The outlook for subsidies, both for fossil fuels and renewables, depends on the way that fossil fuel prices, technology costs and government policies evolve. On the fossil-fuel side, pricing reform has gained momentum since 2014 – gains that are assumed to be maintained in the New Policies Scenario.[11] But there is always a risk – especially if "reformed" pricing mechanisms remain non-transparent – that governments come under pressure, as and when oil prices rise, to re-introduce price controls. The arguments are typically made on social grounds, to protect vulnerable consumers, even though subsidising end-user prices is a very inefficient way of pursuing social objectives: in practice, the lion's share of the benefits go to wealthier segments of the population that consume more of the subsidised product. A critical uncertainty is whether the impetus behind pricing reform in the Middle East is maintained, or whether it dissipates once fiscal pressures ease (Box 2.7).

In the case of subsidies to renewables (examined in detail in Chapter 11), these continue to be necessary to incentivise investment in renewables over fossil-fuel alternatives, for as long as markets fail to reflect the environmental and health costs associated with the emissions of CO_2 and other pollutants. But as technology costs come down and electricity and CO_2 prices increase in several markets, more and more new renewable energy projects become economically competitive without any state support: in India, solar PV is competitive without subsidies well before 2030; for the world as a whole, most new renewables-based generation in 2040 does not require subsidies. The value of the subsidies paid to all forms of renewable energy peaks at $240 billion in 2030 in the New Policies Scenario and then falls back to $200 billion by 2040, remaining well below the today's value for fossil-fuel consumption subsidies. The subsidy per unit of renewables-based electricity generation falls dramatically: subsidies to renewable-based generation rise by some 30% over the period to 2040, yet the electricity generated by non-hydro renewables increases by a factor of five over the same period. In a 450 Scenario, deployment of renewables is much higher, but more widespread pricing of carbon and other emissions and a faster pace of cost reductions (linked to higher deployment) means that the cumulative subsidy bill is only around 15% higher than in the New Policies Scenario.

11. In the New Policies Scenario, net-importing countries and regions phase out fossil-fuel subsidies completely within ten years, but pricing reform in net-exporting countries is assumed only where there is a specific commitment and timetable for a phase-out.

Box 2.7 ▹ Are energy price reforms in the Middle East here to stay?

Oil-reliant economies in the Middle East have been hit hard by the fall in the oil price since 2014. Oil export receipts fell by an estimated $330 billion in 2015 and the deterioration in fiscal balances forced countries to borrow or draw down financial reserves (where available), and to cut spending where possible. Our estimate of the value of fossil-fuel subsidies in the Middle East was around $130 billion in 2015, mostly foregone revenue from pricing fuels well below their international market value, and governments across the region have looked to recoup at least part of this value with pricing reforms. This was visible not only in countries such as Iran – where subsidy reduction has long been a stated priority – but also in the countries of the Gulf Cooperation Council such as the United Arab Emirates (UAE), Kuwait, Qatar and Saudi Arabia.[12]

Changes to pricing have been sharp, albeit from a low base. In August 2015, the UAE fully liberalised its gasoline and diesel prices, introducing a pricing mechanism where domestic prices are set on a monthly basis and are directly linked to international prices. In Saudi Arabia, prices for most fuels went up: premium gasoline by 50% (to $0.24/litre), diesel for industry by similar amount (to $14 per barrel); gas for power generation by 67% (to $1.25 per million British thermal units). Pricing reform has been the product of divergent circumstances across the region. To the extent that it is just a response to fiscal pressures, the reform is liable to be reversed once that pressure is relieved. But if it is part of a broad, long-term reform and diversification strategy (such as Saudi Arabia's Vision 2030, adopted in April 2016) and accompanied by other measures such as energy efficiency (to limit the impact on household and company budgets), then the chances of longevity rise sharply.

2.10 Does energy reform point a new way forward for Mexico?[13]

Mexico's reform seeks to revive an ailing energy sector by opening up the oil, gas and electricity sectors to new investment and technology, creating a new competitive environment for incumbents PEMEX and CFE. In our projections, it takes time for new projects to turn around the slide in oil output and to develop Mexico's large, untapped wind and solar resources; but the projected energy, economic and environmental outcomes suggest there can be a large positive return on a sustained reform effort.

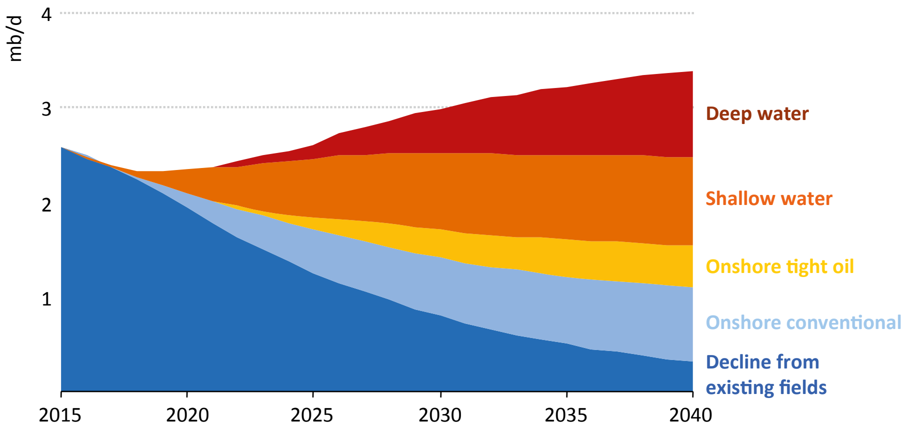
Mexico's 2013 announcement of wide-ranging economic reforms, including both in upstream oil and gas and in the power sector, is an historic attempt to revitalise the energy sector. Despite large oil resources, Mexico's production has been falling for more than a

12. Most of the reforms to GCC fuel and electricity end-user prices were implemented only in 2016 and so did not affect 2015 average end-use prices, upon which our latest subsidy calculations are based.
13. This analysis is drawn from *Mexico Energy Outlook: World Energy Outlook Special Report* (IEA, 2016c).

decade: bringing in new investment and technology, by breaking the upstream monopoly of *Petroleos Mexicanos* (PEMEX), was seen as the way to reverse this trend. Likewise, the introduction of new players into the power sector and restructuring the incumbent *Comisión Federal de Electricidad* (CFE) was seen as vital to ensure cost-efficient investment into both traditional and lower carbon sources of electricity and to bolster the overall economic outlook.

Total primary energy demand in Mexico has grown by a quarter and electricity consumption by half since 2000, but per-capita energy use is still less than 40% of the OECD average, leaving strong potential for further growth. The energy mix is dominated by fossil fuels, with oil accounting for around half of the total – a share higher than in the highly oil-dependent Middle East. Yet Mexico's long-standing position as one of the world's major oil producers and exporters has been weakened in recent years, with production declining by over 1 mb/d since 2004. This fall in output is linked to a shortfall in the funds available to PEMEX for capital expenditure to slow declines in mature fields or to develop new ones. Gas output has also been in decline (most of the production is associated with oil) and imports from the United States now meet around 40% of gas demand.

Figure 2.22 ▷ Oil production in Mexico in the New Policies Scenario

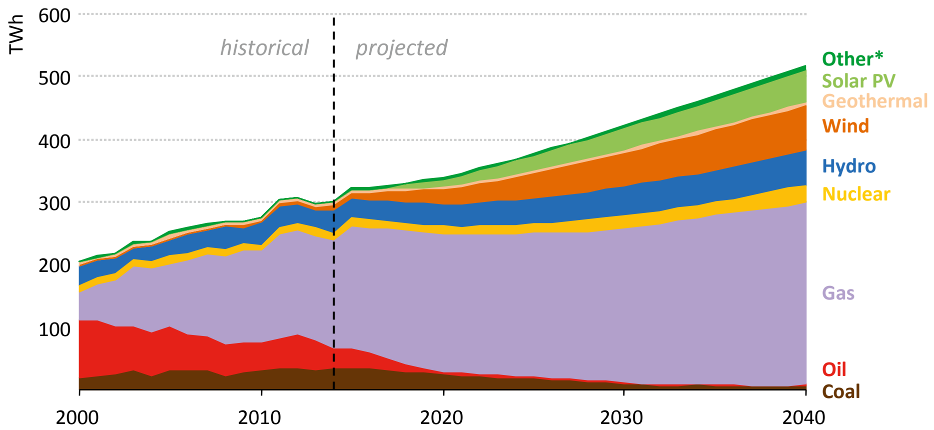


Mexico's oil output gets back on a rising path, but it takes time for new projects to offset declines in existing fields

A series of bid rounds that began in 2015 is opening the upstream oil and gas sectors to private investment and technology, leaving PEMEX to focus its resources and expertise on a narrower range of projects – either alone or in new joint ventures. Efforts to turn Mexico's oil fortunes around require tackling three distinct sets of challenges. The first relates to shallow water production in the Gulf of Mexico, the traditional mainstay of the country's output but one that requires renewed efforts to improve recovery and reduce field declines in mature areas, alongside investment to tie in new satellite fields to existing infrastructure. Deepwater production is the new frontier for Mexico and an area where PEMEX has less experience: international players are likely to take a lead. There are also some promising onshore resources, including significant tight oil potential and the huge, but technically difficult Chicontepec Basin. The upstream reforms were initially conceived when prices were high: lower oil prices have complicated, but not derailed, the process. It nonetheless takes some time for new investment projects to start operation, meaning that Mexico's oil production continues to fall back in the near term. Projected crude oil output bottoms out at under 2 mb/d towards 2020 and then starts to recover. By 2040, crude oil output returns to 2.4 mb/d, but adding in natural gas liquids and, by then, some tight oil takes total oil output in 2040 up to 3.4 mb/d (Figure 2.22).

In the electricity sector, there are likewise three vectors for change. One that is already well underway is fuel switching: oil has traditionally played a major role as a fuel for power generation, but is rapidly losing ground to natural gas whose cost advantage has been reinforced by the shale gas boom in the United States (Figure 2.23). The unbundling of CFE and a further opening of the power sector to private participation play a major role in mobilising the $10 billion per year that Mexico needs to upgrade the network and to keep pace with electricity demand that grows by 85% to 2040. Long-term auctions for energy, capacity and clean energy certificates provide an entry point for new players on a competitive basis and a cost-effective way to bring low-carbon generation into the mix: the first two auctions for new power supply, held in 2016, demonstrated strong readiness to invest in new solar and wind capacity. As well, investment in strengthening the grid and reducing Mexico's very high current losses in the transmission and distribution system, allied to efficiency gains on the retail side, all help to moderate the costs of electricity supply.

Figure 2.23 ▷ Power generation mix in Mexico in the New Policies Scenario



The power generation mix in Mexico becomes steadily more diverse and much less carbon-intensive

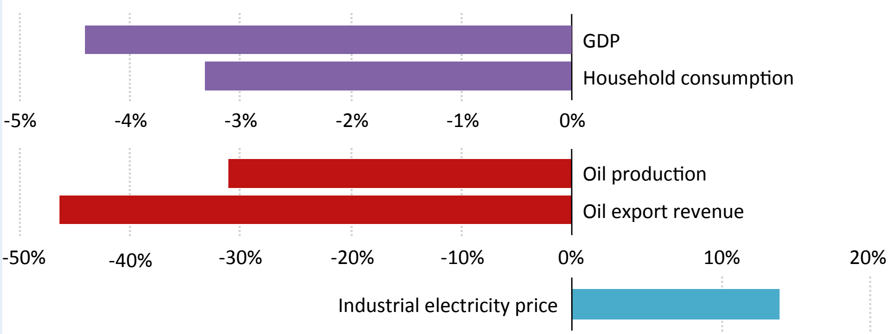
Note: Other include bioenergy and concentrating solar power.

Box 2.8 ▷ Assessing the value of change: No Reform Case

The pathway for Mexico projected in the New Policies Scenario is determined in large measure by the country's energy reforms. But what would the trajectory look like in their absence? To answer this question, a "No Reform Case" posits an outlook for Mexico in which none of the major reforms since 2013 are in place, so the state monopoly is maintained in oil and gas and there is no additional private participation or restructuring in the electricity sector.

Differences in the volume and type of investment going into the energy sector are the main reason for divergences between the New Policies Scenario and the No Reform Case (Figure 2.24). The historic relationship between oil revenue and PEMEX upstream spending was used to derive an outlook for upstream investment: in the context of today's continued declines in output, this severely limits Mexico's capacity to fund expansion and enhanced recovery projects in legacy fields, and delays the start of technically challenging deepwater and tight oil development projects. As a result, by 2040, oil production is some 1 mb/d lower than in the New Policies Scenario. In the power sector, without the same efficiency gains made in networks and other parts of the system in the New Policies Scenario, the costs of electricity supply are higher. Without specific policies to increase the role of clean energy, lower deployment of renewables leaves Mexico well short of its clean energy targets. The net impact in the No Reform Case is to leave Mexico's economy 4% smaller in 2040 than in the New Policies Scenario.[14]

Figure 2.24 ▷ Selected indicators for Mexico in the No Reform Case compared with the New Policies Scenario, 2040



In a No Reform Case, lower investment in upstream and power is felt in 2040 across the energy sector and the wider economy

14. This differential was calculated by coupling the results of the IEA's World Energy Model with the OECD's computable general equilibrium model, ENV-LINKAGES.

The result of these changes is a steady increase in generation capacity – more than half of which is renewables – and not just a halving in the CO_2 emissions intensity of power generation (from more than 450 g CO_2/kWh in 2014 to 220 g CO_2/kWh in 2040,) but also an absolute decline in power sector emissions over the *Outlook* period. A distinguishing feature of Mexico's power reform is that clean energy has been integrated into the reform package from the outset, helping to achieve the target (that is written into the Energy Transition Law) to have 35% of electricity generation sourced from clean energy by 2024. A steady increase in the price of natural gas exerts some upward pressure on average generation costs, but this is counter-balanced by efficiency gains and lower network losses: industrial electricity prices decrease in real terms over the period to 2040 – one of the many outcomes in the New Policies Scenario that would be difficult to anticipate in the absence of reform (Box 2.8).

An increasingly integrated North American energy market plays an important role in Mexico's energy outlook. Of the increase in primary energy demand, 70% comes from natural gas, much of it – at least in the first half of the projection period – sourced from the United States. The ample US refinery capacity along the Gulf Coast is well suited to Mexico's heavier crudes and provides a ready source of imported oil products. The current market environment, in which imported energy is readily and cheaply available, helps to offset the economic impact of lower hydrocarbon revenues (which remaining an important pillar of fiscal revenue, even if the government is taking steps to diminish this reliance). In the case of natural gas, it also lessens the incentive for PEMEX or other operators (most likely US based or international majors) to invest in Mexico's large shale gas resources in the near to medium term; in our projections, there is some initial activity in Mexico's north-eastern Burgos Basin, but larger scale shale development is postponed until the latter part of the 2020s, by which time rising gas prices in the United States have strengthened the economic case for natural gas projects in Mexico.

Oil market outlook

What's past is prologue

Highlights

- The pledges made as part of the Paris Agreement do not induce a peak in oil demand before 2040 in the New Policies Scenario. The difficulty of finding alternatives to oil in road freight, aviation and petrochemicals means that, up to 2040, the growth in these three sectors alone is greater than the growth in global oil demand. There are also marked changes in the geography of demand: India becomes the leading source of future growth, while China overtakes the United States to become the single largest consuming country in the early 2030s.

- The global stock of electric cars rises rapidly in the New Policies Scenario, from 1.3 million in 2015 to over 30 million by 2025 and more than 150 million by 2040, displacing 1.3 mb/d of oil. Battery costs decline to less than half today's level, but the time required to recoup the additional investment cost of electric cars, compared with conventional cars, constrains more rapid deployment. Additional policy support could, however, lead to higher deployment: in the 450 Scenario, the global stock exceeds 710 million in 2040, displacing more than 6 mb/d of oil demand.

- Tight oil production in the United States has been more resilient to the drop in oil prices than anticipated by many. The reaction to any price rebound will not be immediate. US tight oil production in the New Policies Scenario reaches a high point in the late-2020s at just over 6 mb/d. Helped by greater fuel efficiency and fuel switching, the United States all but eliminates net imports of oil by 2040.

- Declines in production from existing conventional crude oil fields are equivalent to losing the current oil output of Iraq from the global balance every two years, providing a powerful underlying stimulus for the current rebalancing of the oil market. Yet there is also the risk of an over-correction: the volume of conventional crude oil resources receiving development approval in 2015 fell to its lowest level since the 1950s and the data for 2016 show no sign of a rebound. There is scope to recover from one or two years of suppressed project approvals, but with the level of demand growth seen in the New Policies Scenario, prolonging this into 2017 or beyond could lead to more volatile oil prices and a new boom-and-bust cycle for the industry.

- There is no reason to assume widespread stranding of upstream assets for oil, even in a drive to decarbonise the energy sector, as in the 450 Scenario, provided governments pursue unambiguous policies to that end. Investment in oil and gas, albeit at reduced pace, remains an essential component of an orderly transition to a low-carbon future. But abrupt changes to climate policymaking or misjudgements of future oil demand by the oil industry could lead to more severe financial losses.

3.1 Recent market and policy developments

The fallout of the crash in oil prices, instability in many producing states and the re-entry of Iran to the international stage, have all contributed to a tumultuous time for oil markets since last year's *World Energy Outlook (WEO-2015).* Key events behind the fall in prices in 2014 were the extraordinary rise of tight oil production in the United States and the decision by key members of Organization of Petroleum Exporting Countries (OPEC) to refrain from constraining output to support oil prices. The growth of tight oil production has now stalled, but the full implications of recent developments will continue to ripple over markets over a long period. Investment in upstream oil and gas projects, which reached an historic high of $780 billion in 2014, fell by almost $200 billion in 2015 and is anticipated to fall by a further $140 billion in 2016. Projects already under development will come online over the next five years; but longer term prospects have been slashed. Whether these losses can be easily absorbed, or might lead to a period of heightened volatility, is a key question explored in this chapter. The fall in investment has been accompanied by a major reduction in the cost of producing oil and developing new fields. We examine whether this is a transitory phenomenon or whether it represents a structural break with past trends.

There are broad implications for producers. While most members of OPEC have so far weathered the impacts of low prices on their economies, the durability of the present strategy is uncertain. On the non-OPEC side, we now have a better understanding of how US tight oil reacts to a price fall, but how quickly activity and output can pick up if prices rise remains to be tested. Some countries, including Mexico and Saudi Arabia, have reacted to low prices by pressing ahead with a process of reform, but for others, particularly Venezuela and some parts of the Middle East, instability has been exacerbated. Either way, key producer countries are unlikely to emerge unchanged from the downturn, even if prices rebound.

The collapse in prices stimulated the largest annual boost in 2015 to global oil demand seen in the past five years and continuing robust growth is expected in 2016. But there are wider questions to consider looking forward. How far will the geography of demand shift? Will India take over from China as the main source of oil demand growth? How will oil demand change in oil exporting countries, as many are forced by fiscal strains to reform their subsidies to fossil fuels? How great a reduction in oil demand will stem from the Paris climate change agreement? Which segments of oil demand are most vulnerable? Where is substitution away from oil most practicable? More broadly, does the Paris Agreement mean that a peak in global oil demand is now in sight and could it lead to upstream assets becoming stranded? An historic milestone was passed in 2015 with the number of electric vehicles on the road exceeding one million. But does this signal a concerted assault on oil's dominance in transport or a long and tough battle for market share? These issues, alongside many others, are explored in this chapter.

3.2 Trends to 2040 by scenario

3.2.1 Medium-term dynamics

The surplus of oil supply over demand that caused the dramatic fall in the oil price from the end of 2014 reached a peak in mid-2015. Volumes held in storage soared and have continued to grow (despite the surplus dissipating) over the course of 2016. The large accumulation of stocks will act as a dampener on the pace at which future prices rise, but we continue to judge that a price of around $80 per barrel (bbl) in 2020 is necessary to ensure a matching of supply and demand.

Over the medium term (the next five years), the rate of global oil demand growth is expected to slow. There are signs of a gear-change in the Chinese economy, which has been the engine of global growth over the past ten years: the government is placing strong emphasis on less energy-intensive economic growth. In many other non-OECD countries, demand growth is set to be curtailed because of pricing reforms as governments reduce the subsidies ($150 billion for oil worldwide in 2015) that have become a large fiscal burden. In the New Policies Scenario, non-OECD oil demand growth proceeds at the slowest pace seen for more than 20 years; but this is still enough to offset a continued reduction in OECD countries' demand, which is constrained by policies aiming to improve vehicle fuel efficiency.

Understanding the differences in lead times between various types of project is essential when evaluating medium-term supply prospects. Tight oil will be one of the fastest sources to respond to any price increase (see section 3.3.2) and we expect tight oil to surpass its previous peak in production before 2020. Trends in other major producers are determined more by earlier investment decisions, such as those taken prior to the drop in oil prices in Brazil and Canada, whose fruits will be realised over the next five years.

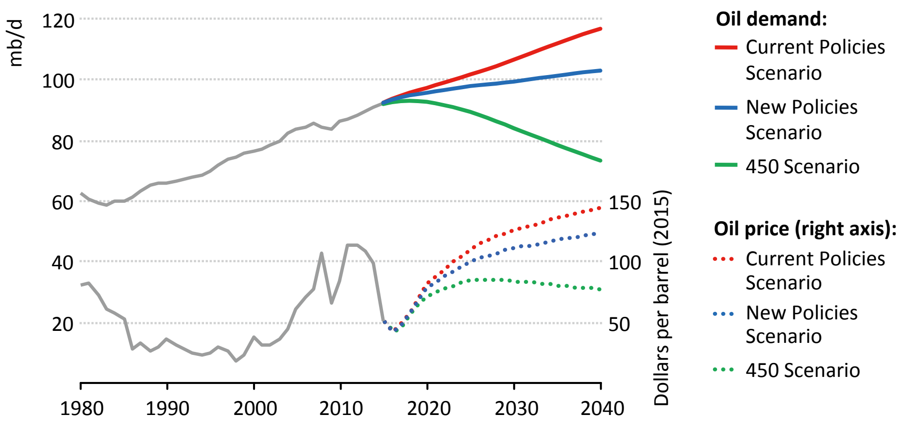
Among members of the Organization of Petroleum Exporting Countries (OPEC), production in Iran has risen by around 700 thousand barrels per day (kb/d) since the lifting of international sanctions at the start of 2016. Yet with multiple delays in specifying the terms for new upstream investments, the prospect that new projects will boost capacity towards the official target of 4.8 million barrels per day (mb/d) by 2021, compared with 3.6 mb/d in 2015, remains uncertain. Similarly, in Iraq, despite recording the biggest output gain of any OPEC member in 2015, declining oil revenues and ongoing security issues weigh heavily on future production prospects. Saudi Arabia, too, is facing a severe budgetary contraction and, in response, has advanced plans to diversify the economy away from reliance on oil revenues (its "Vision 2030" and National Transformation Program).

Questions therefore loom over both the core of future supply and the magnitude and geography of demand growth. The implications, of course, vary by scenario.

3.2.2 Long-term scenarios

In the Current Policies Scenario, oil demand grows at an annual average of just under 1 mb/d to 2040.[1] Policy ambitions that have yet to be implemented are disregarded in this scenario, so demand growth exhibits little slowdown over the next 25 years, requiring ever higher prices to bring the market into balance (Figure 3.1). Demand becomes increasingly concentrated in two sectors: transport and petrochemical feedstocks, which account for just under three-quarters of total oil consumption by 2040, up from two-thirds currently. This growth is met from a variety of sources: OPEC provides an increasing share, approaching 50% of global production by 2040 – a level not seen since the 1970s – while unconventional production more than doubles between 2015 and 2040.

Figure 3.1 ▷ World oil demand and price by scenario



World oil demand exceeds 103 mb/d in 2040 in the New Policies Scenario

There are significant differences in demand between the Current Policies Scenario and the New Policies Scenario, in which tighter fuel standards start to bite and fuel switching (to biofuels, electricity and natural gas) proceeds more quickly. These differences become manifest even over the next five years, with the largest regional differences occurring in China (280 kb/d lower in the New Policies Scenario in 2020), the European Union and the United States. After 2020, the structure of economic growth in key consumers changes, there are continued technological innovations and government policies are brought into effect that aim to reduce the environmental impact of energy provision. In these circumstances, global oil demand growth slows to an annual average of less than 400 kb/d to 2040. By 2040, demand is some 13.5 mb/d lower than in the Current Policies Scenario (Table 3.1), a gap greater than total current production in Saudi Arabia. However the policy

1. Oil demand here excludes any contribution from biofuels, which are only included when referring to "total liquids demand".

ambitions that are included in New Policies Scenario, which includes our assessment of the impact of the Nationally Determined Contributions made as part of the Paris Agreement, are insufficient to bring about a peak in oil demand prior to 2040.

On the supply side, by 2040 the main differences in the New Policies Scenario compared with the Current Policies Scenario are in North America, with production in Canada nearly 1.5 mb/d lower, and in the Middle East, particularly in Saudi Arabia and Iraq. China and the United States respectively import 2 mb/d and 1.5 mb/d less oil in 2040 than in the Current Policies Scenario and by 2040 the United States has all but eliminated net imports of oil.

Table 3.1 ▷ Oil and total liquids demand by scenario (mb/d)

			New Policies		Current Policies		450 Scenario	
	2000	2015	2025	2040	2025	2040	2025	2040
OECD	45.0	41.5	37.3	29.8	38.5	34.6	34.4	20.7
Non-OECD	26.3	43.6	52.2	62.5	53.9	69.9	48.4	46.4
Bunkers*	5.4	7.4	8.8	11.2	9.4	12.6	7.1	6.2
World oil	**76.7**	**92.5**	**98.2**	**103.5**	**101.9**	**117.0**	**89.9**	**73.2**
Share of non-OECD	*34%*	*47%*	*53%*	*60%*	*53%*	*60%*	*54%*	*63%*
World biofuels**	0.2	1.6	2.5	4.2	2.2	3.6	4.0	9.0
World total liquids	**76.9**	**94.1**	**100.8**	**107.7**	**104.1**	**120.6**	**93.9**	**82.2**

* Includes international marine and aviation fuels. ** Expressed in energy-equivalent volumes of gasoline and diesel.
Note: See *www.worldenergyoutlook.org/weomodel/* for more information on methodology and data issues.

Differences between the New Policies Scenario and the 450 Scenario highlight the extent to which the pledges made as part of the Paris Agreement fall short of the long-term ambition to limit global temperature rises to below 2 degrees Celsius (°C). In the 450 Scenario, global oil demand peaks by 2020, at just over 93 mb/d. The subsequent decline in demand accelerates year-on-year, so that by the late 2020s global demand is falling by over 1 mb/d every year. OECD countries register the largest change, relative to today's levels of consumption, their demand collectively declining by over 20 mb/d, led by a greater than 50% decline in the United States. There is more variation in the trajectory of demand in non-OECD countries. Declines are led by Latin America, in which consumption drops by 1.5 mb/d between 2015 and 2040 (half in Brazil). Demand in China peaks in the mid-2020s at around 12.5 mb/d, before falling by over 2 mb/d by 2040. In contrast, consumption in India nearly doubles from current levels by 2040 and consumption in sub-Saharan Africa grows by two-thirds. The rates of oil demand growth in India and sub-Saharan Africa are around one-quarter lower than in the New Policies Scenario; but aggregate non-OECD demand still reaches 2.8 mb/d above today's levels in 2040.

The majority of the 30 mb/d difference in global oil demand in 2040 between the New Policies Scenario and 450 Scenario is caused by reduced demand in the transport sector. Oil use in passenger vehicles in the 450 Scenario falls from just under 24 mb/d today to 15 mb/d in 2040, nearly 10 mb/d lower than the 2040 level in the New Policies Scenario. Oil use is replaced as a result of greater uptake of electric vehicles and biofuels (see section 3.3.1). The use of oil for freight transport is also curtailed, as natural gas and biofuels become more widely used: 2040 demand is over 7 mb/d lower than in the New Policies Scenario. Even so, despite substitution away from oil in the aviation and maritime sectors and a much more diversified portfolio of fuels in the transportation sector, oil still accounts for 65% of total transport demand in 2040 in the 450 Scenario (in energy-equivalent terms).

In contrast to the changes seen in the transport sector, consumption of oil for petrochemical feedstocks in the 450 Scenario is largely the same as in the New Policies Scenario. There are fewer substitution options away from oil available in the petrochemical industry (see section 3.3.1), so by 2040 it accounts for over 20% of total oil demand in the 450 Scenario, up from 12% today. Elsewhere, oil use in buildings is marginally lower than in the New Policies Scenario: the enhanced decarbonisation policies pursued in the 450 Scenario encourage the use of more efficient sources of heating and lighting, especially in developing countries as they switch away from the use of biomass. Heightened efforts are also made to substitute away from oil in power generation, with oil use in that application falling, on average, by over 5% every year to 2040.

On the supply side, it is assumed in the 450 Scenario, as in the New Policies Scenario, that OPEC maintains a strategy of controlling output in an attempt to support price levels, even though global demand is falling from the 2020s onwards (Box 3.1). Production from members of OPEC declines gradually between 2015 and 2040, finishing 10% below current levels. But this drop is much slower than the pace of decline in non-OPEC production, which falls by nearly a third over the same period. The largest change occurs in the United States, with production over 5 mb/d lower by 2040, compared with the New Policies Scenario, mainly as a result of lower tight oil and natural gas liquids (NGLs) production. OPEC's share of oil markets therefore grows steadily over the next 25 years and is consistently higher than in the New Policies Scenario.

Determined policy action in all countries, coupled with the ample availability of low-cost sources of oil supply, means that prices in the 450 Scenario peak during the mid-2020s at just over \$85/bbl and then decline slowly to under \$80/bbl by 2040. This is a marked change from the price trajectory in the New Policies Scenario and presents a profound challenge to the upstream industry. There is a risk that all existing proved fossil-fuel reserves will not be fully utilised, future investment into upstream oil assets will be curtailed and the returns of fossil-fuel companies will be severely affected. These issues are discussed in detail in section 3.4.2.

Box 3.1 ▷ Producer strategies and the oil outlook

The decision by members of OPEC in November 2014 to refrain from any attempt at active market management was a defining moment for the short-term oil market outlook, both in terms of the oil price fall that it hastened and the path towards rebalancing that it set in place, via the stimulus to demand and the squeeze on higher cost supply. Despite the resulting severe economic hardship in many large hydrocarbon producers from lower prices, it took the best part of two years, until the Algiers meeting in September 2016, for an indication that OPEC may be ready to resume its traditional role, with differing views on what this might mean in practice for the market.

In last year's *Outlook*, we assumed in the New Policies Scenario (but not in the Low Oil Price Scenario) that OPEC would eventually revert to a strategy of trying to manage oil supply. We retain this view in *WEO-2016*. In the *WEO-2015* Low Oil Price Scenario, all of the OPEC countries lost more from lower prices than they gained from higher volumes, compared with the New Policies Scenario. Maintaining a lower oil price environment for the long term therefore requires the active participation of countries that lose out as a result, a condition which, in our judgement, was unlikely to be met indefinitely. The oil price in the New Policies Scenario is therefore higher than it would otherwise be if OPEC members were to pursue a policy of prioritising market share.

The profile for oil demand under the 450 Scenario raises a further set of questions. Faced with falling demand, countries seeking to maximise the use of their resource endowments could ramp up production in an attempt to gain market share while there is still scope to do so. In this event, the combination of falling demand and increased availability of low-cost oil would undoubtedly lead to even lower prices. This would likely reduce geographic supply diversity, with associated energy security implications, increase the risk of "stranded assets" (see section 3.4.2) and, indeed, complicate the low-carbon transition itself. As discussed in *WEO-2015*, low prices can facilitate some positive policy shifts, such as easing the removal of fossil-fuel consumption subsidies or the introduction of an effective or actual price on CO_2 emissions. However, payback periods for many efficiency measures would increase and some renewable technology subsidy schemes may become more costly. Policy measures would need to be strengthened above and beyond what is already required in the 450 Scenario in order to counteract the effect of lower oil prices on transport and industrial demand.

There are multiple uncertainties over the oil price trajectory in the 450 Scenario, but we do not assume that this scenario sees a prolonged slump in prices. This would again rely on countries continuing to produce at ever greater volumes, even though they would receive less revenue as a result. One strategy to mitigate risks, from a producer perspective, is to redouble efforts to limit dependence on fossil fuel revenue, as Saudi Arabia is doing with its sweeping "Vision 2030" reform programme. Nevertheless, policy-makers need to make allowance for a range of possible reactions of the key producers under decarbonisation scenarios, to keep a low-carbon transition on track.

3.3 A closer look at the New Policies Scenario

3.3.1 Demand

Regional trends

The geography of oil demand has experienced a fundamental shift over the past 15 years. Consumption in OECD countries fell on average by nearly 250 kb/d every year during this period while year-on-year growth in non-OECD countries exceeded 1.1 mb/d. This non-OECD growth was underpinned by remarkable growth in China, whose demand grew on average by more than 400 kb/d every year, amounting to a near 150% increase over the 15-year period, and a near doubling of consumption in the Middle East. As a result, while in 2000 OECD countries consumed close to 60% of the world's oil, they now consume less than 45% (excluding international bunkers).

Even so, current per-capita annual oil consumption in China, at around 3 barrels per capita, remains well below that in the United States (20 barrels per capita) and the European Union (8 barrels per capita). There are signs of a slowdown, but we have not yet reached the end of the era of robust Chinese oil demand growth. Under the New Policies Scenario, demand in China grows by around 300 kb/d each year for the next ten years, but then slows to an average annual increase of 100 kb/d from 2025 onwards. China overtakes the United States in the early 2030s to become the world's largest oil consumer, but China's increase in consumption over the next 25 years (4.1 mb/d) is less than half what was added in the previous 25 years (8.6 mb/d).

A key question for oil markets is whether there is another source of demand that will offset this deceleration of growth in China, as well as the average annual 1.3% decline in demand seen in OECD countries out to 2040. Here the picture is quite mixed. Annual oil consumption in India is currently 1.1 barrels per capita, one-third of the level of China, and in the New Policies Scenario, India will be the largest single source of demand growth to 2040 (Table 3.2). However, despite the fact that India's gross domestic product (GDP) per capita in 2030 is around the same level as China's currently, Indian oil consumption in 2030 is below 1.7 barrels per capita. The projected pace of demand growth in India over the next 15 years is also considerably slower than that witnessed in China over the past 15 years. This is partly because the pace of GDP growth in India is projected to be lower, but also because car ownership per capita in 2030 in India is projected to be around 20% lower than in China currently, given higher reliance in India on the use of mass transport and two- or three-wheeled vehicles.

In the Middle East, a number of reforms to fossil-fuel subsidies have recently been announced that, if maintained, will slow future consumption growth. In April 2016, for example, Saudi Arabia unveiled an ambitious new strategy to build a more diversified economy and reduce its reliance on oil revenues, called "Vision 2030". Plans exist to privatise up to 5% of Saudi Aramco (the state oil company) and create the world's largest sovereign wealth fund with the remaining shares. There are also aims to restructure the extensive subsidies for energy which have been available to both industry and consumers. While prices are expected to remain well below international market averages, these reforms provide for an increase of over 200% in the price of diesel used in power generation (to $13/bbl) and an increase of up to 67% for gasoline (to between $0.2-0.24/litre). The decline in oil prices has also catalysed action in the United Arab Emirates, Qatar, Oman and Bahrain, which have similarly announced fuel pricing liberalisation or reductions in subsidy levels. In the New Policies Scenario, Middle East oil consumption grows at 1.3%/year between 2015 and 2040 and overtakes that of the European Union during the mid-2020s. However, this is a reduction in the rate of growth from *WEO-2015* and less than a third of the annual rate of growth seen over the past 15 years. By 2040, consumption has grown by over 2 mb/d in both the transport and petrochemical sectors, but this is partially offset by a 1.2 mb/d decline in use in power generation and industry.

Table 3.2 ▷ Oil demand by region in the New Policies Scenario (mb/d)

	2000	2015	2020	2025	2030	2035	2040	2015-2040	
								Change	CAAGR*
OECD	**45.0**	**41.5**	**39.8**	**37.3**	**34.4**	**31.9**	**29.8**	**-11.7**	**-1.3%**
Americas	23.1	22.6	22.4	21.4	19.9	18.6	17.5	-5.1	-1.0%
United States	18.9	18.0	17.9	16.9	15.5	14.2	13.1	-4.9	-1.3%
Europe	13.9	11.7	10.8	9.8	9.0	8.2	7.6	-4.2	-1.7%
Asia Oceania	8.0	7.2	6.6	6.0	5.5	5.1	4.8	-2.4	-1.6%
Japan	5.1	3.9	3.3	2.9	2.6	2.3	2.1	-1.8	-2.4%
Non-OECD	**26.3**	**43.6**	**48.0**	**52.2**	**55.7**	**59.4**	**62.5**	**18.9**	**1.5%**
E. Europe/Eurasia	4.1	4.7	4.9	5.0	5.1	5.0	5.0	0.3	0.2%
Russia	2.6	3.0	3.0	3.1	3.1	3.0	2.9	-0.0	-0.1%
Asia	11.4	21.6	24.7	27.4	29.7	32.1	34.1	12.5	1.8%
China	4.7	11.0	12.6	13.8	14.3	14.9	15.1	4.1	1.3%
India	2.3	3.9	5.0	5.9	7.1	8.5	9.9	6.0	3.8%
Southeast Asia	3.1	4.8	5.2	5.6	6.0	6.2	6.4	1.6	1.2%
Middle East	4.3	7.9	8.5	9.2	9.7	10.3	10.9	3.0	1.3%
Africa	2.2	3.6	4.2	4.6	5.1	5.7	6.2	2.6	2.2%
South Africa	0.4	0.6	0.6	0.7	0.7	0.8	0.9	0.3	1.6%
Latin America	4.2	5.8	5.8	5.9	6.1	6.3	6.4	0.6	0.4%
Brazil	1.9	2.6	2.5	2.6	2.7	2.9	3.0	0.4	0.5%
Bunkers**	5.4	7.4	8.1	8.8	9.6	10.4	11.2	3.8	1.7%
World oil	**76.7**	**92.5**	**95.9**	**98.2**	**99.8**	**101.7**	**103.5**	**11.0**	**0.5%**
European Union	13.1	10.8	9.9	9.0	8.1	7.3	6.6	-4.2	-1.9%
World biofuels***	0.2	1.6	2.0	2.5	3.0	3.6	4.2	2.6	4.0%
World total liquids	**76.9**	**94.1**	**97.9**	**100.8**	**102.8**	**105.3**	**107.7**	**13.6**	**0.5%**

* Compound average annual growth rate. ** Includes international marine and aviation fuels. *** Expressed in energy-equivalent volumes of gasoline and diesel.

Growth in demand in Africa is led by a doubling of consumption in sub-Saharan Africa. But there is a distinct slowdown in the pace of growth in many other non-OECD countries: annual growth to 2040 in Latin America drops to 0.4%, compared with 2.1% over the past 15 years, while growth in Eastern Europe/Eurasia all but grinds to a halt after 2020. Overall it appears that there is unlikely to be "another China" on the horizon to spur a substantial new wave of global oil demand growth, as long as governments enact the energy policies that they have announced. There are, however, marked changes in the geography of oil use: not least that demand in developing Asian countries constitutes over a third of global oil demand by 2040, having overtaken total OECD consumption in the mid-2030s.

Sectoral trends

Oil's share of total energy demand declines in all end-use sectors throughout the New Policies Scenario. Yet the ease of substitution away from oil varies widely between sectors. There are readily-available economic alternatives to the use of oil in power generation and industrial boilers. This is reflected, for example, in the projected near halving in its use for power generation by 2040 (Table 3.3). In the industrial sector, oil for steam and process heat generation has dropped by around 30% since its peak around 1980. Despite a slight volumetric increase by 2040 in the New Policies Scenario, its share of total final energy consumption for industrial heat generation drops from 11% in 2015 to 8% by 2040, given a much greater rate of increase in the use of gas and electricity.

These two sectors account for less than 15% of global oil demand in 2015 and, since substitution away from oil is more difficult in all other sectors, no peak is seen in total oil demand in the New Policies Scenario before 2040. For example, there are few direct replacements for aviation fuel (examined in detail in *WEO-2015*): biofuels offer some promise but, without strong policy support, these are unlikely to slow the growth to any major degree. Similarly, while the share of natural gas rises slightly in the petrochemical sector and there is a small uptake in the use of bio-derived feedstocks, this does little to erode a 50% increase in oil use in this sector between 2015 and 2040. In road freight, while three-quarters of global car sales are subject to efficiency standards, only four countries (United States, China, Japan and Canada) currently have such standards for trucks.[2] There are few ready substitutes for oil in freight vehicles and so the absolute growth in oil consumption for road freight in the New Policies Scenario is four-and-a-half-times that for passenger vehicles.

There are better prospects for replacing the use of oil in buildings, although the various products consumed exhibit quite different trends across different countries. For example, liquefied petroleum gas (LPG) is mainly used in OECD countries at present for heating and cooking, for which it is slowly displaced by natural gas and electricity.[3] However, this is

2. A public consultation on efficiency standards for trucks is currently underway in the European Union. The IEA will release a report on the impact of trucks on future oil demand and CO_2 emissions in early 2017.

3. LPG is included in the oil demand balance.

largely offset by an increase in the use of LPG as a cooking fuel in developing countries, given their switch away from the use of solid biomass, particularly in urban areas. There is also a small level of kerosene used in the residential sector, both for lighting and cooking. However, kerosene use in households is on a decreasing trend, given improved electricity access in developing countries and policies to replace kerosene as a cooking fuel, given its negative impacts on air quality and health. The net effect is a steady decrease in the use of oil in buildings through to 2040.

Oil use in the maritime sector has received increased interest lately, with regulatory changes aiming to reduce the sector's impact on local air pollution and its emissions of carbon dioxide (CO_2). International maritime transport is examined in more detail below. Various alternatives have also been put forward to reduce the dominance of oil in passenger vehicles. The use of biofuels and natural gas vehicles both grow at an annual average rate of around 4% to 2040 in the New Policies Scenario. However the alternative road vehicle that has received most recent attention is the electric car, whose prospects are also explored below.

Table 3.3 ▷ World oil demand by sector in the New Policies Scenario

	2000		2015		2040		2015-2040		Ease of substitution
	mb/d	%	mb/d	%	mb/d	%	Change	CAAGR*	
Transport	39.0	51%	51.7	56%	60.5	58%	8.8	0.6%	
Passenger vehicles	18.2	24%	23.9	26%	24.6	24%	0.8	0.1%	Medium
Maritime	3.7	5%	5.0	5%	6.2	6%	1.3	0.9%	Medium
Freight	11.9	16%	16.3	18%	19.7	19%	3.4	0.8%	Low
Aviation	4.6	6%	5.8	6%	9.3	9%	3.5	1.9%	Low
Industry	14.4	19%	17.0	18%	22.7	22%	5.7	1.2%	
Steam and process heat	6.1	8%	5.8	6%	6.5	6%	0.8	0.5%	High
Petrochemical feedstocks	8.1	11%	10.7	12%	15.7	15%	4.9	1.5%	Low
Buildings	7.7	10%	7.6	8%	6.0	6%	-1.6	-1.0%	Medium
Power generation	6.1	8%	5.4	6%	2.9	3%	-2.4	-2.4%	High
Other**	9.4	12%	10.8	12%	11.3	11%	0.5	0.2%	
Total	**76.7**	**100%**	**92.5**	**100%**	**103.5**	**100%**	**11.0**	**0.5%**	

* Compound average annual growth rate. ** Includes agriculture, transformation, other non-energy use (mainly bitumen and lubricants).

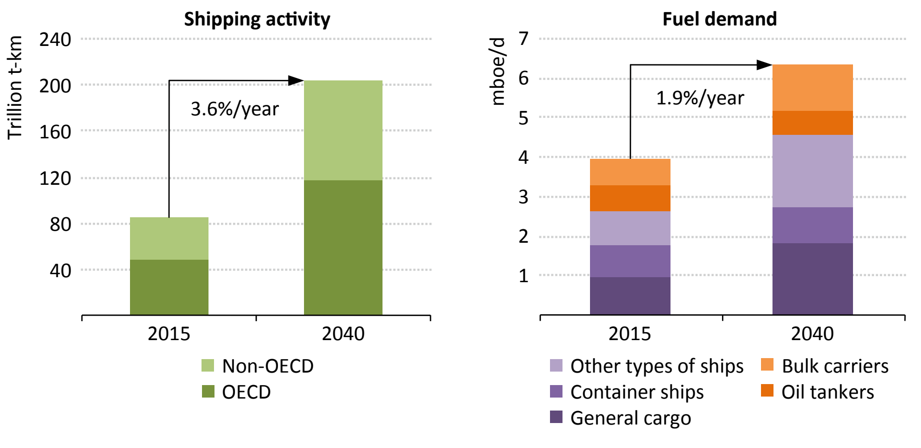
Focus: International maritime transport

The shipping sector is an important consumer of oil products, comprising around 5% of global oil demand (Table 3.3). Almost 80% of fuel use in the sector occurs in international shipping, commonly referred to as international marine bunkers, for which heavy fuel oil (3.2 mb/d) and diesel (0.6 mb/d) are the two key products. International shipping is also an important contributor to climate change: it is responsible for around 2% of global energy-related CO_2 emissions, as large as the emissions of Indonesia and Malaysia combined.

The main spur for international shipping is global trade: 90% of total international bunker fuel use is dedicated to maritime freight, with the remainder used for passenger services. International seaborne transport is the cheapest way to move long-distance freight and is responsible for around 80% of global physical trade in goods. International freight shipping activity is typically measured in tonne-kilometres (t-km) and amounts to over 80 trillion t-km today. Energy, in particular oil and oil products, is an important component of global shipping activity, comprising one-third of international seaborne trade; bulk goods (32%) and containerised products (15%) account for much of the remainder. The majority of the maritime transport activity takes place using tankers, dry bulk carriers (used for the transportation of agricultural products, coal, minerals and construction materials) and container ships.

The largest contributors to international shipping activity for freight transport are China and the United States, collectively accounting for around one-third of the global total (measured on the basis of exports). Growth of seaborne trade has historically been closely linked to economic growth and, in the New Policies Scenario, international freight shipping activity grows on average by 3.6% each year, in line with global economic growth, and exceeds 200 trillion t-km in 2040 (Figure 3.2). Trade activity from Africa, India and Southeast Asia also increases, which contributes to an increase in the length of each voyage by just over 0.3% per year on average.

Figure 3.2 ▷ Growth in international shipping activity and fuel consumption in the New Policies Scenario



Rate of growth in international shipping activity is double the growth in fuel consumption

Note: All fuel consumption in 2015 is oil, while in 2040 LNG accounts for around 13% in energy-equivalent terms (or 0.8 million barrels of oil equivalent per day).

Total fuel demand for international shipping grows at 1.9% per year to 2040, half the rate of growth in shipping activity. This is both because the energy efficiency of ships improves and because average ship sizes increase since larger ships are generally more efficient per t-km than smaller ones. There is also diversification in the fuels used by the sector. The average growth rate in oil consumption, at just over 1.2% per year, is one-third of the rate of increase in activity. In 2040, nearly 50 billion cubic metres (bcm) of gas is consumed by international shipping in the form of liquefied natural gas (LNG), around 13% of total fuel demand (in energy-equivalent terms).

Until recently the energy intensity of international shipping was unregulated and led by market considerations. Ship owners reacted to the period of high oil prices and the 2008 economic crisis by improving operational efficiency and introducing structural changes. An over-capacity of ships, as well the increased size of transoceanic cargo ships, meant that maximum speeds could be reduced, a practice, commonly referred to as slow steaming, that leads to fuel savings. Other operational measures included ensuring ship speeds were kept more homogeneous across routes, avoiding the need for high speed trips, and increasing the number of stops, to increase the utilisation of ships. But the absence of regulation limited the uptake of fuel-saving technologies.

Improving energy intensity was the intention of the Energy Efficiency Design Index (EEDI), introduced by the International Maritime Organisation (IMO), the UN standard-setting authority for international shipping. The EEDI entered into force in 2013 and is the first ever globally binding energy efficiency standard for the industry. It mandates a minimum 10% improvement in the energy efficiency per tonne-km of new ship designs from 2015, 20% from 2020 and 30% from 2025. These improvements are benchmarked against the average efficiency of ships built between 2000 and 2010 and are separately applied to different groups of ships, by type and size.

In the New Policies Scenario, the adoption of the EEDI helps dampen oil demand growth from international shipping. However, its effect is limited by the slow stock turnover in the sector: average ship lifetimes range between 25-40 years (Box 3.2). As a result, the average energy efficiency per ship-km of the international shipping fleet improves by only 15% between 2015 and 2030 (the current end of the EEDI implementation period). The increase in efficiency when measured in tonne-km, at 20%, is slightly larger, as there is also a projected rise in the load factors of ships (in line with recent historical trends). Improvements vary by ship type, depending on the growth of the stock of vessels over the projection period, size increases and the average lifetime of individual ship types. For example, container ships achieve the largest savings, with energy intensity per tonne-km falling by over 40% by 2030 in the New Policies Scenario, because of their relatively short lifetime and a stronger trend towards larger ship sizes. In contrast, the limited prospects for stock growth of tankers mean that the average tanker fleet registers less than an 8% drop in energy intensity by 2030.

Box 3.2 ▷ Beyond EEDI: how to contain oil demand and emissions growth in international shipping

Greenhouse-gas (GHG) emissions from international shipping were not directly included in the 2015 Paris Agreement. Nevertheless, several options exist for reducing the oil demand and CO_2 emissions growth of maritime vessels and ships below the levels achieved in the New Policies Scenario. Measures such as the optimisation of hull shapes through hydrodynamic design, improvements in the efficiency of engines (waste heat recovery or hybridisation), air lubrication and wind assistance (e.g. through kites), could all deliver reductions in fuel use. The fuel-saving potential in existing ships is lower, but the widespread use of retrofitting technologies, such as engine de-rating to match operational speed and engine size, wind assistance and improved maintenance, can deliver important GHG emission savings.

The use of alternative fuels, such as biofuels or LNG, can also reduce oil demand, with co-benefits for reducing air pollution. LNG use in the maritime sector, however, does not provide a full answer to the challenge of climate change, given its carbon content and the potential for fugitive methane emissions leakage through incomplete combustion of the gas in ship engines. Since around one-third of current shipping activity involves transporting fossil fuels, the decarbonisation of the wider energy system in the 450 Scenario, leads to a decline in global demand for fossil-fuel carriers. This leads to an 8% decline in overall shipping activity (in t-km) by 2040, relative to the New Policies Scenario. Together with increased energy efficiency measures, a significant increase in ship size and increasing use of LNG and biofuels (which could be encouraged, for example, by a sector-wide CO_2 levy or an emissions reduction target), oil demand from international shipping could be reduced to 3.5 mb/d by 2040, just below today's level.

Besides its importance for global oil demand growth, international shipping is also an important emitter of air pollutants, in particular sulfur dioxide (SO_2). In 2015, international shipping activity emitted 8.2 million tonnes (Mt) SO_2, 10% of global energy-related SO_2 emissions (IEA, 2016a). A significant proportion of these emissions occur hundreds of miles offshore, but coastal residents living near shipping lanes or ports are still adversely affected. In Hong Kong, for example, the contribution from maritime activities to sulfur emissions reached 44% before action was taken to tackle the problem. Airborne pollutants can travel several hundred kilometres in the atmosphere, contributing to air quality problems further inland.

The sulfur content of the heavy fuel oil used by most ships can be as high as 3.5%. This is significantly greater than the component of oil products used in road transport (which is as low as 10 ppm [0.001%]) and some regions have introduced regulations on the level of sulfur emissions allowed. These "Emission Control Areas", which encompass certain areas within Europe, North America and the Caribbean, ensure that the flue gas from ships operating within the designated areas must contain less than 0.1% sulfur. The IMO has plans to introduce a wider, global cap of 0.5% from 2020, although there is discussion of delay until 2025. There are also regional plans under discussion, in the European Union for example, to introduce a unilateral sulfur cap, also at 0.5%, regardless of the IMO's decision. The IMO regulation will not specify the type or quality of the fuel to be used, only the emissions content of the flue gas. Ship owners will therefore be free to decide whether to use 0.5% sulfur fuels (diesel or low-sulfur heavy fuel oil), switch to low-sulfur alternative fuels (such as LNG or biofuels), or install scrubbers to treat the engine effluents in order to remove the acid gases arising from the combustion of high sulfur fuels. All these solutions are likely to increase costs for ship operators. While this will have a knock-on effect on consumer prices, the impact is likely to be small, since maritime transport costs comprise only a fraction of the overall price of most consumer goods. In the New Policies Scenario, the global cap on maritime sulfur is cautiously assumed to take effect from 2025 (five years later than currently planned), bringing down SO_2 emissions from international shipping to 2.5 Mt in 2040. Earlier introduction would allow for earlier and quicker reductions (IEA, 2016a).

Focus: electric vehicles

Electric vehicles (EVs) are not new, having provided competition for the earliest gasoline-powered vehicles (in 1900, electric cars accounted for one-third of all vehicles on US roads) before they lost out to the internal combustion engine. After fading from view, they have made periodic and partial comebacks since the 1970s, before the latest – and strongest – surge since 2000. From a policy perspective, they have several advantages over conventional cars. They offer a way to reduce the oil dependency of road transport, diminish urban air pollution and combat climate change (if the electricity used is produced from low-carbon sources). Yet, they have never achieved a significant share of the global car market. Historically, prohibitively high costs and compromises on performance (such as range limitations) led to low consumer acceptance and a market that was supplied by only a few manufacturers.

In 2015, however, the global stock of EVs climbed to 1.3 million, a near doubling of the stock in 2014 (IEA, 2016b).[4] Although the share of electric cars in the global vehicle stock is still only 0.1%, this is a marked improvement from historic levels. Momentum has been broadly maintained over the first-half of 2016, as registrations in the European Union rose by around 20% and 130% in China, compared with the first-half of 2015 (EAFO, 2016; CAAM, 2016). China is now the largest market for EV sales, followed by the United States. The increase in sales has been accompanied by growth in the supply of EV support equipment. The number of publicly accessible chargers in 2015, for example, is estimated to be 190 000 globally, up from 110 000 in 2014.

4. Electric cars here include full battery electric and plug-in hybrid electric vehicles.

The recent rise of EVs has emerged both as a result of continuous technological improvements and because of mounting policy support (Table 3.4). Since 2008, research, development and deployment, as well as growing battery use in markets such as consumer electronics, have contributed to a four-fold increase in battery energy density. Costs have also fallen to less than $270 per kilowatt-hour (kWh) for batteries used in plug-in hybrid vehicles (PHEVs) and about $210/kWh for battery electric vehicles (BEVs).[5] Such improvements offer extended electric driving ranges at lower costs. Countries with the highest uptake of electric cars have typically made use of vehicle-purchase incentives, including subsidies and tax incentives, and invested in the deployment of recharging infrastructure to support deployment (IEA, 2016b; Tietge et al., 2016). Complementary measures often include exemptions from certain fees, such as parking or congestion charges, waivers on access restrictions, such as to urban centres or bus lanes, and exemptions from policies that limit the availability of new licence plates to combat urban air pollution.[6] Ambitions for the future deployment of EVs are high: Tesla Motors targets 0.5 million annual EV sales by 2018 (from 50 000 in 2015); Renault-Nissan aims for cumulative sales of 1.5 million EVs by 2020; Volvo aims to sell 1 million EVs by 2025; and Volkswagen recently announced a strategic shift to EVs and aims to launch 30 BEV models and achieve annual sales of 2-3 million by 2025.

In the New Policies Scenario, existing and planned policies and a wider availability of EV models continue to drive their deployment: their stock rises by around 50% per year to about 10 million by 2020 and 30 million by 2025. By 2040, the global stock of EVs exceeds 150 million, around two-thirds of which are plug-in hybrids (Figure 3.3).[7] However this represents only around 8% of the global passenger light-duty vehicle stock in 2040 and the impact on oil consumption is limited: 0.3 mb/d oil demand is displaced in 2025 and 1.3 mb/d in 2040. However the deployment of EVs becomes significant in individual markets where the policy environment is particularly conducive. In northern Europe (Denmark, Finland, Iceland, Norway and Sweden), for example, EVs reach 16% of the total car stock in 2040, with a sales share of more than 20% in that year. This is triggered by favourable overall regulatory frameworks (including strong commitments to reduce economy-wide CO_2 emissions), high fuel taxes, high taxes for the purchase of conventional cars (which improve the competitiveness of EVs and increase the effect of performance-based differentiated

5. BEVs have a lower power-to-energy ratio than plug-in hybrid electric vehicles. This leads to higher energy content per battery cell, and therefore lower cost per unit of energy stored in each cell.

6. For example, seven Chinese cities restrict the availability of licence plates, primarily through lotteries and/or auctions, and apply much looser restrictions to licences issued for electric cars (IEA, 2016b).

7. It is assumed that purchase subsidies remain in place until 2020 in countries where they currently exist, but they are reduced by half by 2025 and are then progressively phased out towards 2040. While important for the initial market uptake of EVs, financial incentives reduce government revenues from vehicle purchase taxes. For example, if the average selling price of a car is $20 000 and the tax on vehicle purchases is 20%, while EVs are subsidised by $5 000 and exempt from tax, then government revenues from vehicle taxation decline by 11% once the market share of EVs reaches 5%. The effect is compounded by loss of revenue from the taxation of petroleum products, which are most significant in countries with high levels of taxation, i.e. those with the highest shares of EVs in the New Policies Scenario.

vehicle taxation) and commitments to develop recharging infrastructure. The largest market for new EVs over the projection period is, by some margin, China, although its share of the global electric fleet shrinks from around 50% in 2025 to about 40% by 2040 as deployment in other countries increases. By 2040, one-out-of-nine cars in China is electric. The share of EVs in the total car stock is otherwise generally higher in countries with high taxes on oil products, such as Japan (16% in 2040). The United States is one of the leading global markets for EVs in the New Policies Scenario, in terms of overall volume, though deployment targets for 2020 are lower than in other OECD countries. Nevertheless, EVs constitute only 8% of the total US light-duty vehicle stock by 2040, with higher uptake held back by lower gasoline taxes, which limit the possible fuel cost savings from EVs, and vehicle sizes that are larger than in any other region.

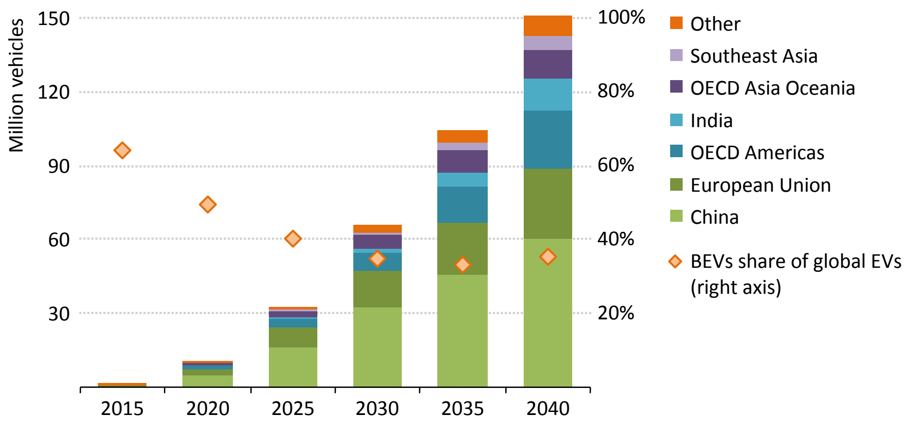
Table 3.4 ▷ Electric vehicle deployment targets and policy initiatives by country

	Electric car targets	Direct electric car policy initiatives
China	Stock target: 4.6 million (2020)	Purchase rebates and tax exemptions up to $9 000; road/bridge/tunnel tolls exemption in some places; waiver on lotteries/auctions for new licence plates.
France	Stock target: 2 million (2020)	Purchase rebates: $7 100 (BEVs), $1 100 (PHEVs); exemption from annual tax for company cars.
Germany	Stock target: 1 million (2020)	$3 300-4 400 purchase rebate; differentiated number plates enabling local circulation incentives.
India	Stock target: 200 000 - 400 000 (2020)	City of Delhi: 15% purchase rebate, VAT exemption and 50% discount on road taxes; additional incentives at state level.
Japan	Stock target: 1 million (2020); sales share target*: 50-70% (2030)	Purchase incentives up to $5 000; government grants <50% on charger installation cost; public-private partnerships for the installation of public charging infrastructure.
Nether-lands	Sales share target: 30% (BEVs) and 20% (PHEVs) (2025)	CO_2-based tax, road tax exemption and lower purchase tax for company cars (BEVs; PHEV incentives reduced since 2016); for companies, charging infrastructure investment deductible from tax in some cases.
Norway	Stock target: 50 000 (2018, already exceeded)	Purchase tax exemption equivalent to $12 000; VAT exemption for BEVs; free access to toll roads, bus lanes, municipal parking and public charging.
Sweden	No official target	$4 400 rebate on BEV purchase and $2 200 on PHEV; five years of road tax exemption and company car tax reduction.
United Kingdom	Sales share targets*: 16% (2020), 60% (2030), 100% (2040)	Maximum purchase rebate of $6 300 (BEV) and $3 500 (PHEV); government subsidy of $700 per each private charging installation.
United States	Stock target*: 3.3 million (2025) across eight states	$7 500 federal tax credit on BEVs and high range PHEVs; additional state-specific purchase incentives.

* Includes fuel-cell electric vehicles. BEVs = battery electric vehicles; PHEVs = plug-in hybrid vehicles; EV = electric vehicles.

Source: Update of data in IEA (2016b).

Figure 3.3 ▷ Electric vehicles in circulation in the New Policies Scenario



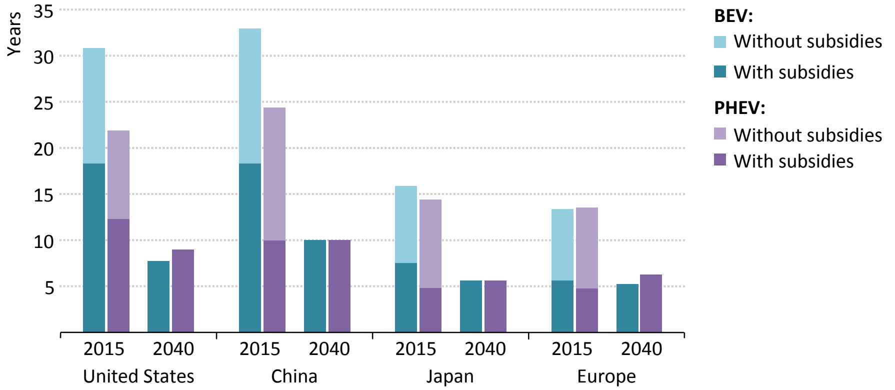
Electric vehicles grow from 1.3 million in 2015 to over 150 million by 2040

The market uptake of EVs in the New Policies Scenario comes with significant cost reductions. There is no certainty by how much battery costs can ultimately decline, but the rapid pace of deployment in the New Policies Scenario brings projected average battery costs for BEVs down to around $125/kWh by 2025 and just above $100/kWh by 2040.[8] While impressive, such cost reductions do not mean that EVs become competitive with conventional cars, even when taking into account the expected higher cost of more fuel-efficient conventional cars. At $125/kWh in 2025, for example, the additional costs of an average BEV and a home charger are around $6 500, compared with an equivalent average conventional European car (excluding potential subsidies) and around $8 500 for an equivalent average US car, which is larger and more powerful than in Europe. A faster decline in costs, to $100/kWh within the next ten years, as is expected by some car manufacturers, would reduce these additional costs to $5 000 for an average European car and $6 500 for an average US car. This is still a sizeable difference: diesel cars in Europe are on average around $2 000 more expensive than their gasoline-equivalents and have made major inroads only in markets where taxes on diesel fuels are low. Further, although EVs offer considerable fuel expenditure savings, the payback times associated with the additional capital costs are still well above the two-to-three-years that a consumer would typically tolerate (Figure 3.4). Nevertheless, with the projected cost reductions, the additional costs of electric cars are not a major impediment for their deployment. In all circumstances, payback periods are quicker for commercial cars with high annual mileages, such as taxis, company fleets or car-share vehicles, as the higher upfront investment can be offset by fuel cost savings more

8. The US Department of Energy estimates that battery costs for a 100 kWh battery pack could decline to $80/kWh, if all chemistry problems can be resolved, system engineering is favourable and batteries are manufactured in high volumes (US DOE, 2015a). The US DOE target for 2022 is $125/kWh (US DOE, 2015b).

quickly. For example, with an annual mileage of 60 000 kilometres (km) (several times more than the average), a BEV pays off in less than four years in the United States and just one year in Europe by 2025. Consumers may, also, increasingly decide to opt for the purchase of smaller EVs, rather than larger conventional ones, especially if the use of EVs is connected with additional benefits. This would reduce the required investment and payback time.

Figure 3.4 ▷ Average payback times for electric vehicles in the New Policies Scenario



Payback times for electric cars fall, but remain well beyond typical consumer expectations

Notes: BEVs = battery electric vehicles; PHEVs = plug-in hybrid vehicles. Payback times differ by market depending on the typical average car size, typical annual distance driven and the level of fuel taxation. For the cost comparison, BEVs are assumed to have a range of 200 km in 2015 and 350 km in 2040 and PHEVs to drive 30% of their annual distance in electric mode in 2015 and 40% in 2040. Subsidies in 2015 are \$5 000 for BEVs and \$3 300 for PHEVs in all regions; subsidies are assumed to be fully phased out by 2040.

The deployment of electric vehicles could, of course, be substantially higher than projected in the New Policies Scenario if there were additional policy interventions beyond those currently in prospect, or significant changes in consumer preferences. In the 450 Scenario, for example, the global stock of EVs rises to over 710 million by 2040, displacing more than 6 mb/d of oil demand. For the automotive industry, confidence in a long-term policy commitment to electric cars would encourage more investment in EV manufacturing, widening the range of models and providing more tailored options for consumers. But there is also a need to increase the attraction of EVs to consumers, given the long payback times. Specific policy measures could include:

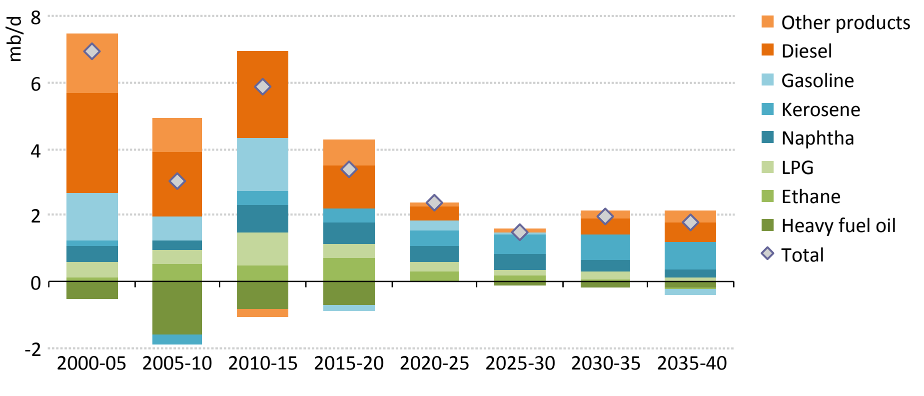
- Foreshadowing progressively tighter fuel-economy and emissions regulations (including for air pollutants) to indicate a long-term commitment to electric cars. Existing and planned standards, as reflected in the New Policies Scenario, can largely be met with conventional technologies without the need for EVs (even if EVs can enhance the ease of achieving the targets).

- Measures that favour access and parking for electric vehicles (such as differentiated parking prices and access to low emission zones) linked with vehicle performances.
- Support for the development of recharging infrastructure to help foster consumer confidence and reduce range concerns about the limited range of electric vehicles.
- Financial incentives such as differentiated vehicle taxation based on environmental performance. This would make the financial case for purchasing an EV more persuasive and lessen any consumer shift towards larger cars. Such financial incentives should be reviewed regularly and adapted to changes in market conditions, to mitigate the risk of placing an excessive burden on government budgets, but without casting doubt on the long-term commitment to support EVs.

Trends by oil product

Petrochemicals and road transport are the sectors which make the largest contributions to global oil demand growth (Table 3.3) and so the fastest growing oil product might be expected to be one of the key products in these two sectors. Yet it is kerosene use that grows fastest, because of its dominance in aviation, one of the few sectors with a positive growth trajectory in OECD countries, which also sees rapid growth in non-OECD economies. Indeed the use of kerosene is increasingly concentrated in aviation, as residential use for heating in OECD countries and for lighting and cooking in non-OECD countries is expected to decline, due to fuel substitution and increased access to clean energy sources.

Figure 3.5 ▷ Change in global oil product demand in the New Policies Scenario



Diesel and gasoline led recent increases in global demand but kerosene for aviation exhibits the greatest future growth

Product use for petrochemical feedstocks in non-OECD countries rises by nearly 6 mb/d between 2015 and 2040, but these increases are shared between naphtha, ethane and LPG. Diesel rises by close to 3 mb/d (Figure 3.5), given increases in shipping and road freight. The use of diesel in passenger vehicles grows until the early 2020s, but thereafter reductions in use among members of the European Union increasingly outweigh growth in non-OECD countries, and so by 2040 diesel use for passenger vehicles falls below 2015 levels.

Gasoline demand received a boost in 2015 as low prices encouraged a surge in driving in China and the United States. Over the longer term, such effects wane and demand grows more modestly, as fuel standards improve the efficiency of the vehicle stock. Gasoline consumption in non-OECD countries grows by over 5.5 mb/d, and global demand eventually reaches a high point in the early 2030s at just over 23 mb/d. This is not far in practice from today's level as growth in non-OECD countries is balanced by a commensurate reduction in gasoline for road transportation in OECD countries. The marginal changes in headline figures therefore mask an 11 mb/d swing in gasoline demand from OECD to non-OECD countries.

3.3.2 Production

Resources and reserves

The fall in the oil price has not had any major impact on estimates of remaining technically recoverable oil resources and reserves (Table 3.5). This is unsurprising for resource estimates since these are expressly defined to be independent of the prevailing oil price. But the oil price drop should have had a greater effect on the proved reserve estimates: these are defined as the volumes can be produced economically with reasonable certainty. Such changes have not materialised within the publicly available sources of reported proved reserves, such as those reported by BP Statistical Review or the Oil and Gas Journal. In the BP Statistical Review, for example, only two out of approximately 50 countries registered a downward revision of reserves when taking into account the production that occurred in 2015. Global reported proved reserves thus fell by less than 3 billion barrels in 2015, under 0.2% of reported remaining proved reserves. This highlights a key difficulty with such estimates and why we avoid using them directly in our modelling. We use, instead, a detailed field-by-field analysis and our database of global remaining technically recoverable resources.

Our estimates of remaining conventional oil resources are based upon combining, at a country-level, IEA estimates for remaining "known oil" and estimates from the United States Geological Survey (USGS) of undiscovered oil and "reserves growth". Previously the known oil estimates used by the USGS when generating its reserve growth estimates had not been released publicly. However, a recent report provides its assumptions, albeit aggregated at a global level (USGS, 2015). The USGS estimate of cumulative production and reserves outside the United States is 2 060 billion barrels, which is in close alignment with the IEA equivalent estimate of 2 050 billion barrels. Our resource estimates include large volumes of oil that are yet-to-be-found. However the volume of conventional oil discovered each year fell consistently between 2010 and 2014, despite huge levels of investment into exploration over this period. This situation has been exacerbated following the price decline, as exploration investment was one of the first areas to be cut (IEA, 2016c). The volume of discoveries in 2015 fell to a 70-year low.

The tight oil resource potential of the United States has been analysed in detail by many organisations: all agree that remaining technically recoverable resources are large, but there is still a high degree of uncertainty surrounding the total. The range of estimates for individual shale plays remains wide even when large numbers of wells have been drilled. For example, adding together the lowest and highest estimates for each play that is considered to hold potential (including from the US DOE/EIA [2015], Goldman Sachs [2016], USGS [2011, 2012c, 2013] and Rystad Energy) provides a range between 30-120 billion barrels for total US tight oil resources. To ensure that a consistent method is used across all plays, the 2015 data from the Energy Information Administration (EIA) forms the basis of our central tight oil resource estimate (used in the New Policies Scenario) of 80 billion barrels.[9] We do, though, consider the implications of different estimates in a sensitivity analysis (see non-OPEC production section).

Table 3.5 ▷ Remaining technically recoverable oil resources by type and region, end-2015 (billion barrels)

	Conventional		Unconventional			Total	
	Crude oil	NGLs	EHOB	Kerogen oil	Tight oil	Resources	Proven reserves
OECD	**319**	**144**	**808**	**1 016**	**135**	**2 422**	**254**
Americas	250	101	805	1 000	104	2 260	237
Europe	59	25	3	4	16	107	13
Asia Oceania	10	18	-	12	16	56	4
Non-OECD	**1 882**	**404**	**1 068**	**57**	**285**	**3 697**	**1 448**
E. Europe/Eurasia	260	65	552	20	88	984	142
Asia	125	50	3	4	56	239	46
Middle East	940	153	14	30	29	1 166	803
Africa	316	87	2	-	54	459	130
Latin America	242	50	497	3	57	849	326
World	**2 201**	**548**	**1 876**	**1 073**	**420**	**6 118**	**1 703**

Notes: EHOB = extra-heavy oil and bitumen. The IEA databases include NGLs from unconventional reservoirs (i.e. associated with shale gas) outside the United States, assuming similar gas wetness to that seen in the United States; these unconventional NGLs resources are included in conventional NGLs for simplicity.

Sources: IEA database; USGS (2012a, 2012b, 2015); OGJ (2015); BP (2016); BGR (2015); US DOE/EIA/ARI (2013, 2014).

9. The latest EIA tight oil resource estimate is 88 billion barrels, which includes both crude oil and lease condensate volumes. Lease condensate is a mixture of light hydrocarbons recovered as a liquid from gas fields and extracted before the gas is transported downstream, and is generally classified as NGLs. The EIA's tight oil production figures also contain some lease condensate. Our historical tight oil production figures for the United States generally follow those of the EIA, to aid comparability, and so some lease condensate is therefore also included. Our central tight oil resource estimate, which is 10% lower than the EIA's estimate, therefore does not aim to remove all condensates.

S P O T L I G H T

Will upstream capital costs bounce back?

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 have evolved over time (IEA, 2016c).[10] It measures changes in the cost of the construction materials and equipment (e.g. steel, cement), labour, drilling rigs and oilfield services required for these projects. The UICI more than doubled between 2000 and 2014, but has since fallen back dramatically; indeed, even in nominal terms, the cost of exploration and production is now broadly similar to what it was in 2005 (Figure 3.6) and in real terms it is much lower. A major factor underlying this decrease has been the efficiency gains achieved by operators when oil prices fell, especially in tight oil areas. Yet the UICI has traditionally always moved in tandem with oil prices: if prices increase, demand for services and equipment grows, the cost of oilfield services increases and so the UICI moves upwards. The converse is also true. But a key question facing the industry is whether the recent drop in costs will simply reverse when prices rise, as has been seen with previous cost declines, or whether the present downturn represents a more structural break with the historical relationship.

One element in common with previous cost declines is the overhang in the availability of oilfield labour and equipment. Historically this has gradually been worked off when prices rise, as companies restart upstream activity and new investments pick up. However, a key difference this time is the magnitude of the overhang in the service industry. Over the past decade, our analysis indicates that the growth in investment by the top three drilling and service contractors was 50% greater than the growth in capital spending by upstream companies. In other words, the service industry was investing heavily for a market that was derailed by the oil price drop: the over-supply may therefore take longer to work off than in past downturns.

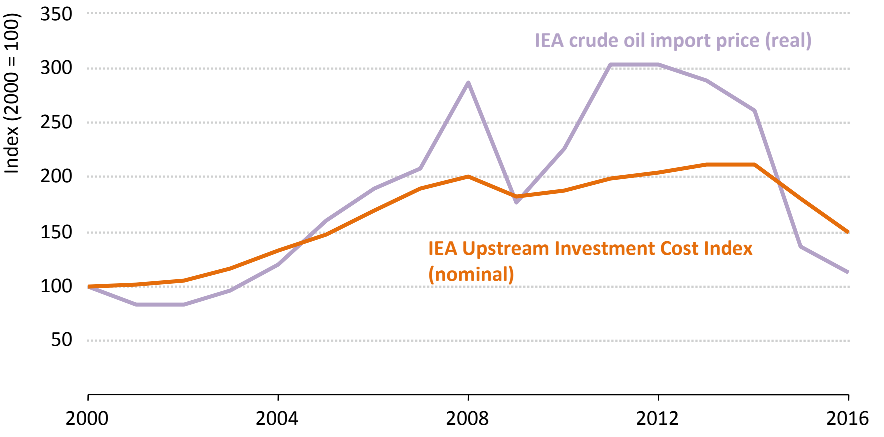
In addition, the severity of this downturn has meant that upstream companies made sizeable reductions in their workforces. A pick up in investments could be slow to emerge if this constrains their ability to react to any price increase. In any case, these companies are likely to exercise caution in committing to major new investments. The cost of raw materials, which fell by around a third between 2014 and 2016, is also likely to remain subdued, given the anticipated slower pace of economic growth globally.

On balance, we have taken the view that costs in the New Policies Scenario grow only marginally over the next three to four years, despite the rebound in oil prices seen in this scenario. There is variation across different regions, sectors and industry segments, and companies may be able to take advantage of lower costs over a prolonged period by locking-in contracts for certain services. However, the present downturn probably

10. The projects included within the UICI are fixed, i.e. the UICI does not account for changes in the complexity or geography of upstream projects that have been executed since 2000. A combination of these changes with changes in the UICI would be reflected in the global average cost of producing a barrel of oil.

does not represent a full structural break with past trends. Over the longer run, once the labour and equipment overhang is eliminated, we anticipate that costs globally will revert to the traditional pattern of moving broadly in line with prices. Of course, if prices do not rebound as projected in the New Policies Scenario, then costs are also likely to remain suppressed for a prolonged period.

Figure 3.6 ▻ IEA Upstream Investment Cost Index and oil price



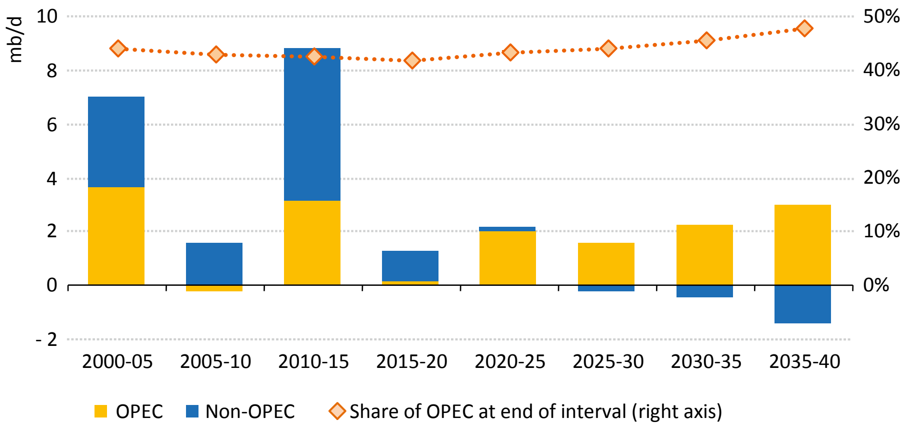
Upstream oil and gas costs have dropped 30% since 2014

Source: IEA (2016c).

Production prospects

Oil production surged between 2010 and 2015, registering its largest five-year increase since the late 1970s. This surge was built on the back of a prolonged period of oil prices, averaging above $90/bbl. In the New Policies Scenario, the fruits of prior investments are slowly reaped in terms of new production over the next five years. Prices recover to 2020, spurring new production from the more responsive sources of supply, much of which is required to replace underlying declines in currently-producing fields (see section 3.4.1). Non-OPEC production leads the way, exceeding relatively modest gains in OPEC over this period (Figure 3.7). Thereafter, the drop in investment that has occurred to date weighs heavily on future production. Growth in aggregate non-OPEC production grinds to halt, before exhibiting an accelerating decline between 2025 and 2040. Members of OPEC are therefore increasingly relied upon to meet demand growth and OPEC's share of production grows steadily from 2020 and 2040. But it is important to recognise that these New Policies Scenario trends assume that investment in new upstream projects recovers from today's levels when prices start to rise. A very different picture can emerge, looking forward, if the drop in prices presages a prolonged period of suppressed upstream investment. A future supply constraint becomes increasingly likely the longer investment stays low, a possibility explored in section 3.4.1.

Figure 3.7 ▷ Change in non-OPEC and OPEC oil production in the New Policies Scenario



Despite recent gains by non-OPEC, OPEC dominates future production growth after 2020

Oil production by type

Conventional crude oil currently comprises by far the largest share of oil production. While it maintains this position throughout the New Policies Scenario, underlying declines (discussed in detail below) mean that production from currently producing fields falls by over 45 mb/d by 2040, so a high degree of investment in new fields is required to ensure there is no precipitous drop (Table 3.10).

Other sources of production become increasingly important, including extra-heavy oil and bitumen (EHOB), tight oil and natural gas liquids. EHOB rises by 3 mb/d between 2015 and 2040, shared almost equally between Canada and Venezuela. The vast majority of tight oil production over the timeframe of the New Policies Scenario occurs in the United States. Canada currently has around 0.35 mb/d of tight oil production but this increases by less than 0.15 mb/d between 2015 and 2040 in the New Policies Scenario. Outside the United States, there is nearly 1.6 mb/d of tight oil production by 2040, similar to the levels foreseen in *WEO-2015,* with Mexico, Russia and Argentina the main sources of production growth.

NGLs play an important role in the economics of gas field development, providing an additional revenue stream, and their production tends to governed by the dynamics of gas markets. With the knowledge of tight oil and shale gas production continuing to evolve, we have revised NGL production in the base year of this year's *Outlook,* compared with *WEO-2015.* Given better data availability, some 900 kb/d of lease condensate in the United States, that we previously categorised as crude, has been reclassified as NGLs. In the New Policies Scenario, NGL production grows by over 5 mb/d, mirroring the increase in natural gas production and exceeds 20 mb/d by 2040.

Tight oil in the United States

The rapid emergence of tight oil as a major source of new production has undoubtedly been one of the largest shocks to oil markets in recent times. Tight oil production rose from less than 0.5 mb/d in 2010 to 4.3 mb/d in 2015.[11] Along with growth of 1.5 mb/d over the same timeframe in US NGL production, largely stemming from shale gas plays, this reversed the decline in US oil production that had been ongoing for nearly 40 years.

The abrupt drop in oil prices presented a disruptive challenge to the tight oil industry in the United States. It was estimated to have relatively high break-even costs before 2014, which meant that investment was expected to dry up quickly as prices fell, with production dropping soon after given the high decline rates of wells. But the resilience of tight oil production has been impressive. The number of tight oil rigs may have fallen from its peak by around 80%, but by mid-2016 production had dropped by less than 15%. A number of factors explain this.

First, while production from an individual tight oil well falls rapidly in the early years, it eventually reaches a level after which production declines slowly. Given that around 38 000 horizontal tight oil wells were completed between 2010 and 2014, these wells provide a cushion or base level of production that is quite insensitive to changes in the oil price.

Second, operators have managed to improve the average initial production and estimated ultimate recovery (EUR) of new wells. The average EUR per well across a number of the major tight oil plays (the Bakken shale, Eagle Ford shale and Permian basin) jumped by between 20-40% between 2014 and 2015. A key explanation for this has been the growing ability of operators to focus drilling within the best acreage owned, the so-called sweet spots, reducing the number of wells drilled in less productive areas. Operators have also continued to optimise the lateral length of horizontal wells and the amount of proppant used during hydraulic fracturing in order to improve the economics of production (as discussed in *WEO-2015*).

Third, operators have been able to fall back on their large inventory of drilled, but uncompleted, wells (DUCs) to maintain production levels. Although the number of DUCs is quite uncertain, prior to the drop in prices the DUC inventory is estimated to have grown to a peak of around 6 000. Because a large portion of the required capital for these wells had already been spent – drilling accounts for around 30% of the full cost of a tight oil well – operators have since been working through their inventories. Of the 9 000 horizontal tight oil wells completed in 2015, around 10% were previously DUCs.

Fourth, operators have been able to cut costs through higher drilling efficiencies. This has occurred because of operational improvements and the increased availability of higher quality drilling rigs (as older and less efficient rigs were retired), staffed by more

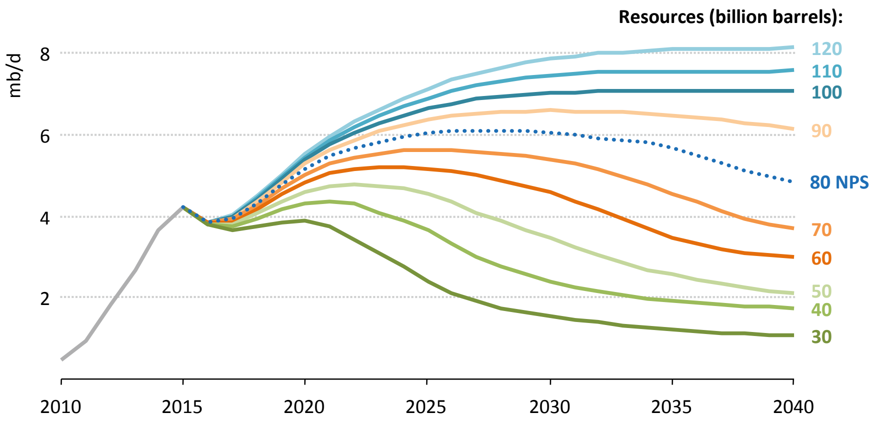
11. We do not classify as tight oil any production before 2006, so historical tight oil production figures are around 350 kb/d lower than those given by the EIA.

experienced staff (as less proficient crews were laid off). The average number of days taken to drill a horizontal well across the major tight oil plays has fallen by around 20% from the level in 2014. As a result of these improvements, as well as reductions in the costs of raw materials and services, the average cost of drilling a horizontal well in 2015 was 15% lower than in 2014 (Spotlight). Consequently the break-even costs of tight oil wells have fallen and allowed drilling to continue.

There are similarly good reasons to suspect a slow response to any price rebound. First, the tight oil boom was built on the back of debt: our analysis of a representative sample of 30 tight oil operators suggests that around 90% were cash-flow negative even when prices were high.[12] Since the price fall, capital budgets have been slashed, but the financial situation of a large number of operators remains extremely weak and many companies have been declared bankrupt. Companies will need time to repair their balance sheets (reduce their debt levels) in order to raise the finance necessary for a new wave of tight oil development.

Second, the length and depth of the price downturn means that it will take time to bring sufficient rigs, staffed by skilled personnel, back into operation. With the drop in oil prices, many rigs, along with other drilling and completion equipment, have been placed in storage or, in some cases, broken up for scrap. Taking into account the time to re-certify the rig and re-train operating personnel, we estimate that it will take at least six months to bring back into operation a rig that has been put into storage.

Figure 3.8 ▷ US tight oil production as a function of estimated resources



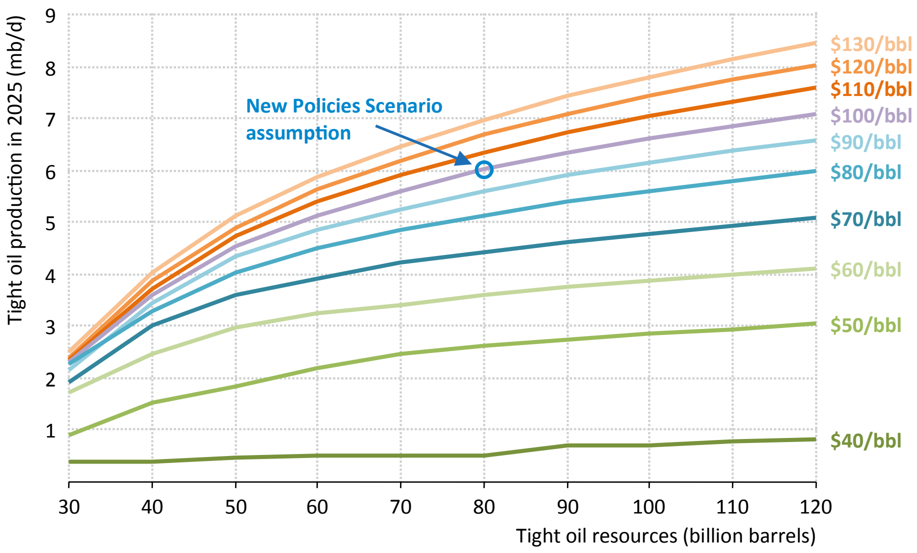
US tight oil production is extremely sensitive to assumed resource availability

Notes: NPS = New Policies Scenario. Oil prices in all pathways are from the New Policies Scenario.

12. A company is cash-flow negative when the revenue received from selling any oil and associated gas that is produced is not sufficient to cover the drilling of the next well once all costs and taxes have been paid.

Our detailed modelling at well level on a play-by-play basis takes all of the above factors into consideration. In the New Policies Scenario, with our updated assessment of resource availability (80 billion barrels), US tight oil production rebounds to 5.2 mb/d in 2020 and peaks at just over 6.1 mb/d in the late 2020s. However, this outlook is particularly sensitive to estimates of the remaining technically recoverable resources (Figure 3.8), which could range anywhere between 30 and 120 billion barrels (see resources and reserves section). Production in 2040 could exceed 8 mb/d if resources are high, or fall back to 1 mb/d at the opposite end of the spectrum. With our New Policies Scenario resource and price assumptions, production declines throughout the 2030s; but, by this time, net imports of oil to the United States are less than 1 mb/d. If remaining recoverable resources are closer to 100 billion barrels, rather than the 80 billion barrels we assume, it is possible that the United States could become a net exporter of oil by the early 2030s.

Figure 3.9 ▷ Sensitivity of US tight oil production in 2025 to oil prices and resource availability



A wide range of US tight oil production levels emerge as resources and oil prices are varied

Oil prices also clearly influence the number of rigs in operation and number of wells that can be drilled economically. When the uncertainty in resource availability and future oil prices is combined, the range of possible future trajectories for tight oil is widened further (Figure 3.9).[13] If prices remain low and are $40/bbl in 2025, production of US tight oil in 2025 is less than 1 mb/d, regardless of total resource availability. Similarly, if resources are

13. This analysis is carried out using the simplifying assumption that tight oil production volumes in the United States do not materially change the global oil price.

closer to the lower end of the estimates, then production falls to well below current levels, regardless of how high the price is in 2025. Conversely, if the price were to rise to above $130/bbl in 2025, or if the remaining resource potential were to be close to 120 billion barrels, then production could exceed the 6 mb/d reached in the New Policies Scenario by up to 1 mb/d.

Non-OPEC production

Non-OPEC production increased on average by over 700 kb/d each year over the past 15 years; but, in the New Policies Scenario, this rate of growth slows considerably and eventually reverses. Annual production grows by just over 200 kb/d from 2015 until reaching a peak of just under 55 mb/d in the early 2020s. After this, year-on-year declines are just under 100 kb/d until 2035, before accelerating to over 250 kb/d for the final five years of the 2030s (Table 3.6). The level of peak non-OPEC production is lower and occurs later than in *WEO-2015*. But with longer term production higher by around 1 mb/d, the rate of decline following this peak is more moderate. The different shape of projected output, compared with *WEO-2015*, is largely a function of changes to the outlook for tight oil production in the United States. Tight oil takes slightly longer to ramp up in the near term, but the larger resource base means a higher level of production in the longer term, with production in 2040, for example, some 1.5 mb/d higher than in *WEO-2015*.

Total oil production in Russia reached an historic high in 2015 of 11.1 mb/d as Russian companies were shielded to a large extent from the decline in oil prices. The rates of two of the key taxes levied, the mineral resource extraction (MET) tax and export duties, are functions of the prevailing world oil price. When prices fell, the rates of these taxes fell, so the government bore the majority of the loss of revenue. Russian companies were also aided by the fall in value of the rouble, which almost halved against the US dollar between July 2014 and July 2016. Oil prices, in rouble terms, therefore only fell by around 20% over this period. However, although Russian production costs remain among the lowest in the world, operators in Russia have not enjoyed cost reductions (largely in roubles) to the extent of the general reduction in costs seen elsewhere.

On balance, Russian producers have weathered the oil price drop better than international oil companies, and many managed to maintain, or even increase, capital spending in 2015 (in rouble terms). A key risk for producers is that fiscal terms will change in coming years, given the reduction in revenues that the government has experienced. Yet even if tax rates remain the same, it is important to recognise that, just as the Russian tax system shielded companies from the decrease in oil prices, they are unlikely to reap a large share of the benefit from any upturn in prices. With the boost in recent investment, production in the New Policies Scenario remains broadly flat over the next five years. But over the longer term, although new fields are developed in the mature conventional crude basins of West Siberia and the Volga-Urals, along with frontier projects, such as tight oil and in the Arctic, these are not sufficient to offset field declines and Russian production drops steadily, to under 8.5 mb/d by 2040.

Table 3.6 ▷ Non-OPEC oil production in the New Policies Scenario (mb/d)

	2000	2015	2020	2025	2030	2035	2040	2015-2040 Change	2015-2040 CAAGR*
OECD	**21.8**	**23.7**	**25.3**	**26.1**	**26.2**	**26.1**	**25.4**	**1.7**	**0.3%**
Americas	14.1	19.8	21.5	22.5	22.8	22.8	22.3	2.5	0.5%
Canada	2.7	4.4	5.1	5.1	5.3	5.6	6.1	1.7	1.3%
Mexico	3.5	2.6	2.4	2.6	3.0	3.2	3.4	0.8	1.1%
United States	7.9	12.8	14.1	14.7	14.5	14.0	12.8	0.0	0.0%
Europe	6.8	3.5	3.2	3.0	2.7	2.5	2.2	-1.2	-1.8%
Asia Oceania	0.9	0.5	0.6	0.6	0.7	0.8	0.9	0.4	2.4%
Non-OECD	**20.8**	**29.4**	**29.0**	**28.3**	**27.9**	**27.7**	**27.0**	**-2.5**	**-0.3%**
E. Europe/Eurasia	8.2	14.2	14.2	14.0	13.6	13.1	12.1	-2.1	-0.6%
Kazakhstan	0.7	1.7	2.1	2.4	2.6	2.6	2.6	0.9	1.7%
Russia	6.5	11.1	10.9	10.5	9.8	9.3	8.5	-2.6	-1.1%
Asia	5.6	7.2	6.6	6.3	6.0	5.8	5.6	-1.7	-1.0%
China	3.3	4.4	3.9	3.7	3.4	3.3	3.2	-1.2	-1.3%
India	0.8	0.9	0.8	0.9	0.9	0.9	0.9	-0.0	-0.1%
Middle East	2.2	1.3	1.2	1.2	1.2	1.2	1.0	-0.2	-0.8%
Africa	1.6	2.1	2.1	1.8	2.0	1.8	1.7	-0.4	-0.9%
Latin America	3.2	4.6	4.8	4.9	5.2	5.8	6.5	1.9	1.4%
Argentina	0.9	0.6	0.6	0.6	0.7	0.7	0.8	0.1	0.8%
Brazil	1.3	2.6	3.1	3.4	3.7	4.4	5.1	2.6	2.8%
Total non-OPEC	**42.5**	**53.2**	**54.3**	**54.4**	**54.2**	**53.8**	**52.4**	**-0.8**	**-0.1%**
Non-OPEC share	*57%*	*58%*	*58%*	*57%*	*56%*	*54%*	*52%*	*-5%*	*n.a.*
Conventional	**41.6**	**45.5**	**44.8**	**43.6**	**42.5**	**41.2**	**39.8**	**-5.6**	**-0.5%**
Crude oil	35.5	36.5	35.0	33.2	31.6	30.1	29.0	-7.5	-0.9%
Natural gas liquids	6.1	9.0	9.8	10.4	10.8	11.1	10.9	1.9	0.8%
Unconventional	**1.0**	**7.7**	**9.5**	**10.8**	**11.7**	**12.6**	**12.5**	**4.8**	**2.0%**
Tight oil	-	4.6	5.7	6.7	7.2	7.5	6.8	2.1	1.5%
Canada oil sands	0.6	2.4	3.1	3.2	3.3	3.5	3.8	1.4	1.9%
Coal-to-liquids	0.1	0.1	0.1	0.2	0.4	0.6	0.7	0.6	8.4%
Gas-to-liquids	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4	11.1%

* Compound average annual growth rate.

A trend exhibited by a number of major non-OPEC countries is growth in production to 2020, given the considerable levels of investment before the fall in oil prices, followed by a more moderate period of growth as the investment cuts in 2015 and 2016 begin to take effect. For example, there have been multiple postponements or cancellations of new upstream projects in Canada and in consequence, production in 2040 has been revised downwards by over 700 kb/d from *WEO-2015*. While production grows by nearly 700 kb/d over the next five years, over the following 15 years the increase is less than 500 kb/d.

Brazil also suffers from a significant downward revision compared with *WEO-2015*. Despite growth of over 500 kb/d between 2015 and 2020, increases over the longer term are much more subdued as a result of the investment delays implemented by Petrobras. Other companies are increasing investment, but Petrobras remains the dominant operator in Brazil's deepwater fields. It had spent aggressively to develop projects in the emerging pre-salt Santos basin, but this involved taking on more than $130 billion in debt (for comparison, ExxonMobil, the world's largest publicly traded oil company, has debt of around $40 billion). For the past two years Petrobras has been plagued by cost over-runs and, along with government officials and suppliers, enmeshed in a financial scandal. In parallel with the extended drop in oil prices, these issues have put at risk the ability of Petrobras to reduce its debt. As a result, after multiple revisions the company's latest five-year capital budget covering the period from 2017 to 2021 is $74 billion; a sharp reduction from the $235 billion that had been planned for the five-year period from 2012 to 2016. Foreign investment over the medium term, while potentially significant, is unlikely to fully compensate for these cuts. Our longer-term outlook for Brazil, though, is more upbeat: production exceeds 5 mb/d by 2040, a projection based on the high quality of Brazil's resource, crude prices sufficient to attract new investment and an anticipated easing of the policy and supply chain issues that have limited production growth in recent years.

Among other non-OPEC producers, aggregate production falls steadily to 2040. Declines in mature basins, especially the North Sea and China, are only partially offset by growth in Australia, which sees increases in NGL and unconventional oil production, and Mexico.[14]

OPEC production

Given the growth foreseen in non-OPEC production up to 2020, OPEC production in the New Policies Scenario initially increases at a much slower pace than that seen in recent years. Between 2000 and 2015, OPEC production grew on average by nearly 450 kb/d year-on-year. This falls to less than 50 kb/d between 2015 and 2020, although thereafter the pace of growth picks up as non-OPEC production stagnates and then enters decline. OPEC's share of global oil production approaches 50% by 2040.

OPEC members outside the Middle East endured a difficult 2015: ongoing economic and political turmoil in Venezuela, violence in Libya and falls in revenues for African producers weighed heavily on many of these countries. Only Angola registered any notable increase in production between 2014 and 2015 (up 100 kb/d), as a result of projects coming onstream that were approved before the oil price crash, while production in the other African members of OPEC collectively was down by over 170 kb/d. Indonesia and Gabon re-joined OPEC in 2016, adding just over 1 mb/d to total OPEC production in the base year.[15]

14. For further details, see *Mexico Energy Outlook: World Energy Outlook Special Report*, 2016. Available at: *www.worldenergyoutlook.org/mexico.*

15. We add production from Indonesia and Gabon to the whole historical record of OPEC for consistency over time.

The outlook for Libya and Venezuela remains particularly uncertain. Estimates of production in both countries have been revised down since *WEO-2015*. We do assume some stabilisation and recovery over the long term, but neither country manages to surpass previous peaks in production before 2040. Production in Angola falls to 1.5 mb/d in 2020, but then remains on a plateau around this level to 2040. Nigerian production eventually recovers from a similar dip over the next five years to grow by over 500 kb/d between 2020 and 2040, as the rise in oil prices eventually spurs a new wave of deepwater developments. Meanwhile, neither Indonesia nor Gabon has high untapped potential and their production falls to under 600 kb/d by 2040 (Table 3.7).

Table 3.7 ▷ OPEC oil production in the New Policies Scenario (mb/d)

								2015-2040	
	2000	2015	2020	2025	2030	2035	2040	Change	CAAGR*
Middle East	**21.3**	**28.7**	**30.4**	**32.3**	**33.4**	**35.0**	**36.9**	**8.2**	**1.0%**
Iran	3.8	3.6	4.8	5.1	5.3	5.6	5.9	2.3	2.0%
Iraq	2.6	4.1	4.5	5.2	5.7	6.3	7.1	3.0	2.2%
Kuwait	2.2	3.1	3.1	3.1	3.2	3.3	3.5	0.4	0.5%
Qatar	0.9	2.0	1.9	2.0	2.1	2.3	2.5	0.5	0.9%
Saudi Arabia	9.3	12.2	12.4	12.9	13.1	13.4	13.7	1.5	0.5%
United Arab Emirates	2.6	3.7	3.7	4.0	4.0	4.2	4.3	0.5	0.5%
Non-Middle East	**11.2**	**10.4**	**8.8**	**9.0**	**9.5**	**10.1**	**11.2**	**0.8**	**0.3%**
Algeria	1.4	1.6	1.4	1.4	1.4	1.4	1.5	-0.1	-0.3%
Angola	0.7	1.8	1.5	1.5	1.5	1.5	1.6	-0.3	-0.6%
Ecuador	0.4	0.5	0.5	0.4	0.3	0.3	0.3	-0.2	-2.3%
Gabon	0.3	0.2	0.2	0.1	0.1	0.1	0.1	-0.2	-4.7%
Indonesia	1.4	0.8	0.6	0.5	0.5	0.5	0.5	-0.3	-1.9%
Libya	1.5	0.4	0.4	0.6	1.0	1.3	1.6	1.1	5.2%
Nigeria	2.2	2.3	2.0	2.1	2.2	2.3	2.5	0.2	0.3%
Venezuela	3.2	2.6	2.3	2.3	2.5	2.7	3.2	0.6	0.8%
Total OPEC	**32.5**	**39.1**	**39.2**	**41.3**	**42.9**	**45.1**	**48.1**	**9.0**	**0.8%**
OPEC share	*43%*	*42%*	*42%*	*43%*	*44%*	*46%*	*48%*	*5%*	*n.a.*
Conventional	**32.2**	**38.3**	**38.2**	**40.0**	**41.2**	**43.0**	**45.3**	**6.9**	**0.7%**
Crude oil	29.3	31.8	31.4	32.4	32.8	33.9	35.6	3.7	0.4%
Natural gas liquids	3.0	6.5	6.8	7.6	8.4	9.1	9.7	3.2	1.6%
Unconventional	**0.3**	**0.8**	**1.0**	**1.3**	**1.7**	**2.2**	**2.8**	**2.1**	**5.4%**
Venezuela extra-heavy	0.2	0.4	0.7	0.9	1.2	1.5	2.0	1.6	6.3%
Gas-to-liquids	-	0.2	0.2	0.2	0.2	0.3	0.4	0.2	3.2%

* Compound average annual growth rate.

Note: Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

In contrast, members of OPEC in the Middle East have enjoyed a recent surge in production, led by Iraq (up 660 kb/d in 2015), Saudi Arabia (up 500 kb/d), the United Arab Emirates (up 160 kb/d) and Iran (up 150 kb/d, with large further increases in 2016). Given the differing circumstances of OPEC members, Middle Eastern countries are on the verge of providing three-quarters of OPEC production, the first time this will have occurred in the history of OPEC. The Middle East's share of OPEC production continues to rise in our projections, with most new capacity in the New Policies Scenario coming from Iraq, Iran and Saudi Arabia.

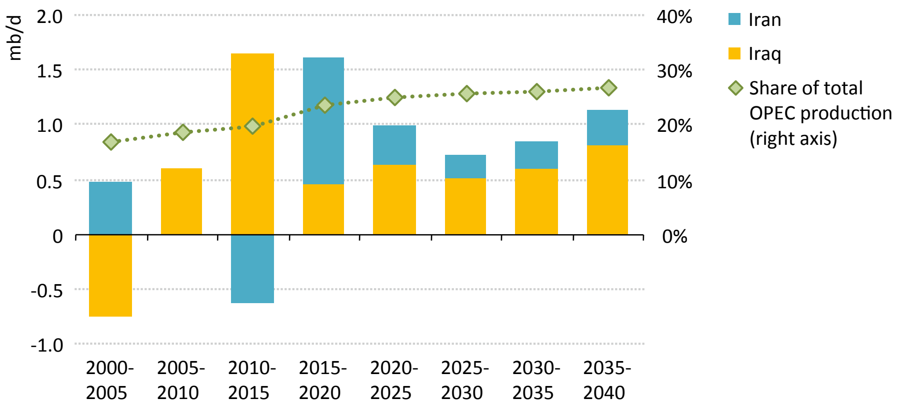
In Saudi Arabia, oil accounts for around three-quarters of both exports by value and revenue for the central government (IMF, 2016). Although the country has accumulated large financial reserves, the economy has still suffered from the drop in oil prices: the value of exports fell by $140 billion in 2015 while the budget deficit rose to 16% of GDP, a notable reversal from a 6% surplus in 2013. Saudi Arabia's remaining recoverable oil resources are vast, at just under 400 billion barrels, and could support greater growth than the 1.5 mb/d increase seen in the New Policies Scenario between 2015 and 2040 (broadly in line with the growth seen in *WEO-2015)*. But with the expected reversion to a strategy in which OPEC countries modulate output, large additional volumes are not required. Saudi Aramco, nonetheless, needs to spend significant sums each year maintaining production levels from existing fields and sustaining its estimated 1.5 to 2.0 mb/d of spare capacity. In our projections, Saudi Arabia maintains its pre-eminence among OPEC producers and its central role in global oil markets, even though Iran and Iraq enjoy a greater level of growth over the timeframe of the New Policies Scenario.

Iraq has remaining technically recoverable resources that stand at over 200 billion barrels and posted the biggest output gain in 2015 among OPEC members. But, given current security problems, institutional weaknesses and investment cuts, this paints a misleading picture of future growth potential. The growth in Iraqi production in 2015 was built upon capital investments made during the period of relative stability, between 2012 and 2014. This growth was split fairly evenly between fields controlled by the federal government, located in the south of the country and those controlled by the Kurdistan Regional Government in the north. The reduction in revenues accompanying the fall in oil prices has been almost entirely shouldered by the federal and regional governments. As a result, multiple payments to upstream operators in both areas have been missed. Given their failure to receive payment for past expenditure, particularly against the backdrop of the industry-wide fall in investment, companies are cutting back on future development plans. The effects of declining oil revenues on the Iraqi state and economy have been profoundly destabilising.

Because of its myriad problems, projected Iraqi production in the New Policies Scenario is moving closer to the low or "delayed" case, rather than to the central pathway, discussed in the special focus on Iraq in *WEO-2012*. If the security situation can be resolved and investment re-started, there is considerable upside potential to the outlook for Iraqi production. However, since the growth in the New Policies Scenario already relies upon significant growth in investment levels from those seen currently, and given the absence of any prolonged period of stability for oil markets in the country since the 1990s, it would appear prudent not to rely on major gains in Iraqi production above those in the New Policies Scenario. Production in 2040 reaches 7.1 mb/d, some 750 kb/d lower than in *WEO-2015*.

The agreement reached over its nuclear programme has meant that sanctions in Iran were lifted in January 2016. This provided a swift boost to Iranian supply of around 700 kb/d, bringing production back to levels similar to those before the 2012 sanctions were imposed. This bounce back was based upon restarting existing capacity and has been towards the upper level of expectations. The question now is whether the Iranian oil sector can fulfil the production potential implied by its vast resource base (estimated at over 200 billion barrels). The speed and level at which new investment can be mobilised to raise production capacity are critical, but on this point developments have been relatively slow.

Figure 3.10 ▷ Change in Iraq and Iran oil production in the New Policies Scenario



Iran's production growth slows after a post-sanction boost, while increases to Iraqi production emerge more steadily

The general terms of a new Iran Petroleum Contract (IPC) have been announced, but there have been repeated delays in issuing the specific details regarding remuneration and terms for operators. The IPC is expected to replace the buyback contracts and some of the largest Iranian oil fields are likely to be put up for offer (in partnership with selected Iranian companies). Nevertheless, in the current low price environment, Iran is competing with numerous other countries for a diminished level of private investment: Mexico and Brazil, not to mention the United States and Canada, have relatively attractive investment climates that could lure foreign capital away from Iran if the terms there are not sufficiently appealing. Under the New Policies Scenario, Iranian production exceeds 5 mb/d by 2025 and reaches 5.9 mb/d in 2040 (Figure 3.10). This is a 500 kb/d increase on the 2040 projection from *WEO-2015*, reflecting the brighter investment prospects now that sanctions have been removed. There is certainly further upside potential, but building confidence in political stability and a stable regulatory environment are essential to its realisation and are likely to take time.

3.3.3 Refining

While bad news for upstream operators, the collapse in oil prices brought some welcome relief to refiners. Margins reached multi-year highs as refiners benefited from cheaper feedstocks and managed to avoid reducing wholesale product prices to a commensurate extent. Even the European refining sector, on a structural decline trend for at least a decade, as decreased local demand and competition from export-oriented refiners weighed heavily on utilisation rates, enjoyed a sudden boom. Around a third of the near 2 mb/d global throughput increase in 2015 came from refineries in Europe.

However, these higher margins might have already sown the seeds of their own destruction. Refinery enthusiasm for higher throughput was not well-matched with demand and so, even though oil demand growth in 2015 was the fastest in a decade (excluding 2010's post-recession recovery), it still was insufficient to absorb all incremental product output. In addition, some of the increased demand in recent years for petrochemical feedstocks has been met by NGL products, such as ethane and LPG. These are products that largely bypass the refining sector. Refined product stocks increased throughout 2014 and 2015 and started putting pressure on the margins at the beginning of 2016. Refiners in Europe have, as a result, already been forced to start retreating from the high throughput rates seen in 2015.

Table 3.8 ▷ World liquids demand in the New Policies Scenario (mb/d)

	2015	2020	2025	2030	2035	2040
Total liquids	**94.1**	**97.9**	**100.8**	**102.8**	**105.3**	**107.7**
Biofuels*	1.6	2.0	2.5	3.0	3.6	4.2
Total oil	92.5	95.9	98.2	99.8	101.7	103.5
CTL, GTL and additives	0.9	1.0	1.2	1.6	2.0	2.5
Direct use of crude oil	1.1	0.8	0.6	0.5	0.4	0.3
Oil products	90.5	94.0	96.4	97.7	99.3	100.7
Fractionation products from NGLs	8.8	9.5	10.0	10.4	10.7	10.6
Refinery products	81.6	84.6	86.4	87.3	88.6	90.1
Refinery products share	*87%*	*86%*	*86%*	*85%*	*84%*	*84%*

* Expressed in energy-equivalent volumes of gasoline and diesel. CTL = coal-to-liquids; GTL = gas-to-liquids.

It is not just the European refining sector that experienced this cycle, and the tale of refining sector exuberance in 2015 and subsequent cool-down illustrates the perennial challenges facing refiners globally. Given the huge over capacity in the system, neither a supply-related slump in crude oil prices, nor a period of robust demand pushing up product prices, can provide elevated margins for refiners indefinitely. Looking forward, the headline oil demand growth rates also distort the picture for refiners, as NGL fractionation and other non-refined products claim increasingly higher market shares (Table 3.8).

Global refining capacity grows in the New Policies Scenario by over 16 mb/d by 2040 (Table 3.9). The refinery throughput of the Middle East doubles, as countries aim to satisfy both rapidly growing domestic refined product demand, which increases by 1.3% compared with 0.4% globally, and export markets. India and China are expected to become net refined product importers, despite throughput gains of 3 mb/d and 4 mb/d respectively.

Companies both from oil exporting regions, such as the Middle East and Russia, and from major refining centres, such as Japan and Korea, are expected to start looking abroad for downstream partnerships to expand their businesses. This search for growing markets eventually brings them to sub-Saharan Africa, where the extent of the deficit in transport fuels justifies new refining investments, albeit towards the later part of the projection period. At the same time, some refining capacity elsewhere will become redundant, due to lower demand and refinery runs. Almost 15 mb/d of capacity is at risk of closure by 2040, with Europe accounting for a third of the total.

Table 3.9 ▷ Refining capacity and runs by region in the New Policies Scenario (mb/d)

	Capacity	Net capacity change to	Refinery runs			Capacity at risk	
	2015	2040	2015	2025	2040	2025	2040
North America	21.3	-0.3	19.3	18.2	16.0	0.8	3.7
Europe	16.5	-1.2	13.7	11.8	10.0	2.7	4.8
Asia	31.7	10.3	27.3	30.0	35.2	2.1	2.9
OECD Asia Oceania	7.6	-0.9	6.8	5.8	4.8	0.5	1.6
China	12.8	4.9	10.8	12.6	14.8	1.2	0.9
India	4.4	3.4	4.6	5.3	7.6	-	-
Southeast Asia	5.0	2.6	4.0	4.8	6.6	0.1	0.1
Russia	6.2	0.1	5.5	4.9	4.6	0.7	1.0
Middle East	8.8	4.3	6.4	10.1	11.6	0.3	0.3
Africa	3.3	1.7	2.1	3.1	4.1	0.6	0.5
Brazil	2.1	0.8	2.0	2.3	2.7	-	-
Other	4.9	0.5	3.4	3.7	3.5	1.1	1.5
World	**94.8**	**16.1**	**79.7**	**84.1**	**87.6**	**8.3**	**14.7**
Atlantic Basin	53.8	1.5	45.5	43.6	40.4	5.9	11.5
East of Suez	41.0	14.6	34.2	40.6	47.2	2.5	3.2

Notes: "Capacity at risk" is defined for each region as the difference between refinery capacity, on the one hand, and refinery runs, on the other, with the latter including a 14% allowance for downtime. This is always smaller than the spare capacity, which is the difference between capacity and refinery runs. All the publicly announced future shutdown plans are already netted off the refining capacity total in the relevant years.

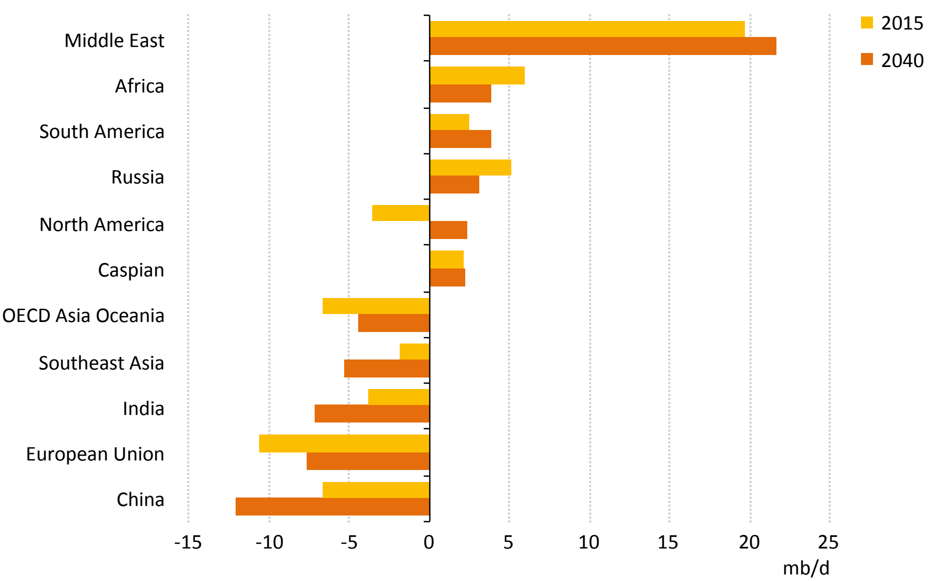
3.3.4 Trade

The Middle East is set to increase its market share in international crude oil exports, but the most notable changes occur among the ranks of importers (Figure 3.11). The largest of these is in North America, which not only disappears from the list of crude oil importers, but becomes an important exporter of crude oil (2.5 mb/d by 2040). This change arises both because of the rise in tight oil production in the United States, and because imports into the US Gulf Coast refining system are offset by projected exports of Mexican and Canadian crudes.

By 2040, China and India together import nearly half of internationally traded crude oil, up from just over 25% today. With 2040 crude oil imports projected at 12 mb/d, China alone is expected to import more crude oil than any country ever has in the past. These parallel developments put trade chokepoints into the spotlight again, as the substantially growing "call on Hormuz" is matched by an increase in traffic through the Malacca Straits on the way to China and other parts of Asia. If the current flows, of both crude oil and oil products, out of the Middle East or into Asia are not modified through land-based infrastructure or alternative sea routes, both of these straits could see 3-5 mb/d of incremental traffic volume. Geopolitical issues aside, this may result in operational safety issues due to congestion.

In oil products trade, non-refined products (ethane, LPG and naphtha) account for a third of some 3 mb/d growth in trade volumes, predominantly flowing from the United States and the Middle East to South America and Asia. Due to regional demand patterns and refinery configurations, west to east flows continue to be dominated by either light or heavy products, while it is the middle distillates that flow in the opposite direction.

Figure 3.11 ▷ Crude oil trade in major regions in the New Policies Scenario



By 2040, China and India import nearly half of all internationally traded crude oil, Middle East firms its market share, while North America becomes a net exporter

3.4 Investment trends and risks

The annual level of investment into upstream oil and gas projects that is necessary in the New Policies Scenario worldwide is $700 billion (Table 3.10).[16] This figure takes into account changes in the complexity and geography of the projects that are executed, how the Upstream Investment Cost Index will evolve over time (Spotlight) and the volumes of new oil and gas resources that are developed between 2016 and 2040. The investment figure is a reduction from the level in *WEO-2015* ($750 billion per year), because lower oil prices in early years pull down upstream costs, a lower proportion of supply comes from high cost areas (such as Brazil and Canada) and because a higher tight oil and shale gas resource base means the average cost of what is produced is lower. Of the $17 trillion cumulative upstream investment between 2016 and 2040, three-quarters occurs in non-OPEC countries, with spending growing gradually over time to 2040.

Table 3.10 ▷ Cumulative oil and gas supply investment by region in the New Policies Scenario, 2016-2040 ($2015 billion)

	Total oil and gas	Upstream oil and gas	Transport		Refining oil	Annual average upstream oil and gas
			Oil	Gas		
OECD	**8 195**	**6 469**	**147**	**1 209**	**369**	**259**
Americas	6 022	5 038	120	669	194	202
Canada	1 168	989	39	104	36	40
United States	4 100	3 404	54	508	134	136
Europe	1 514	1 066	14	317	118	43
Asia Oceania	659	364	13	223	58	15
Australia	504	345	11	141	5	14
Non-OECD	**14 202**	**11 020**	**572**	**1 695**	**914**	**441**
E. Europe/Eurasia	3 113	2 543	62	433	76	102
Caspian	1 089	972	26	77	14	39
Russia	1 841	1 470	32	287	53	59
Asia	3 357	2 120	88	588	561	85
China	1 580	1 152	30	270	129	46
India	533	217	27	98	191	9
Southeast Asia	934	609	23	127	174	24
Middle East	3 315	2 625	240	358	92	105
Africa	2 199	1 817	90	195	97	73
Latin America	2 219	1 915	93	122	88	77
Brazil	1 090	948	60	49	32	38
Shipping	440	n.a.	325	115	n.a.	-
World	**22 836**	**17 489**	**1 045**	**3 019**	**1 283**	**700**
Non-OPEC	n.a.	13 140	n.a.	n.a.	n.a.	526
OPEC	n.a.	4 349	n.a.	n.a.	n.a.	174

16. The upstream figure is combined here for oil and gas because of the crossover between investments for associated gas that takes place at oil fields and for NGLs at gas fields.

The New Policies Scenario carries the important assumption that oil markets reach a stable equilibrium. Prices reach the level required to stimulate sufficient investment into new sources of production to replace the ever present decline from currently producing projects and to satisfy demand growth. As a result of the drop in oil prices, however, upstream investment in 2015 fell to less than $600 billion and is set to fall to around $450 billion in 2016 (IEA, 2016c). While the drop in activity has been less dramatic (since costs have also declined) these investment levels are still well below what is required in the New Policies Scenario.

This highlights the possibility that oil markets could enter a prolonged period of suppressed upstream investments, which could lead to severe disruption. If insufficient new oil projects are developed to meet the rising demand levels in the New Policies Scenario, this would be likely to fuel a period of heightened price volatility. Alternatively, if vigorous climate policies were pursued so as to shift the trajectory of oil demand sharply downwards, a period of low upstream investment now could match supply to the lower market requirement, saving investors from the risk that some upstream investments might never pay off, becoming stranded assets. These two contrasting situations are explored in detail below, looking first at the levels of new project approvals necessary to meet the rising demand levels of the New Policies Scenario, and then examining the issue of possible stranded upstream assets in the 450 Scenario.

3.4.1 Upstream investment needs: mind the gap?

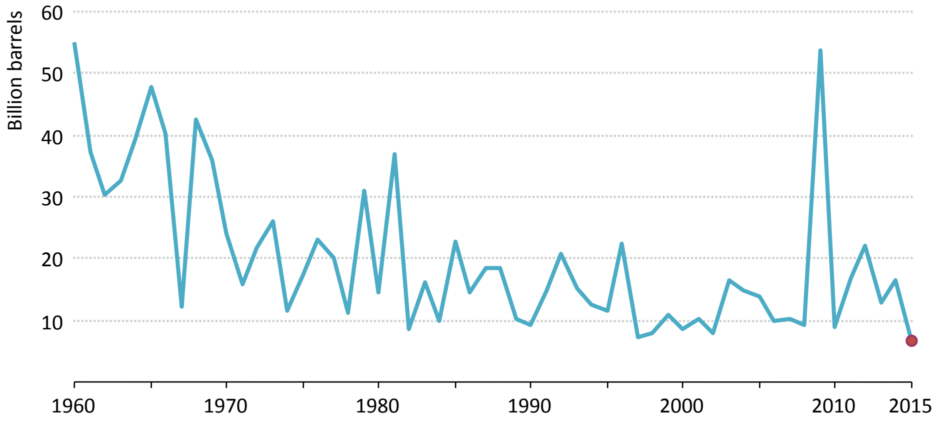
What impact has the drop in investment already experienced had on supply prospects? The level of oil reserves in projects in which production began in 2015 was just over 16 billion barrels (excluding tight oil). This was a drop on the level in 2014, but was not severely below the longer term average of around 20 billion barrels in the 2000-2015 period. This is not surprising. The complexity of upstream projects means that capital commitments are made and substantial sums spent well in advance of production beginning. Even if prices drop below the level necessary for full cost recovery – and are expected to stay low – as long as the revenue from anticipated production is expected to cover the remaining expenditure required, development will continue.

The same is not true for projects that have yet to be committed, meaning that they have yet to receive their final investment decision. Operators might well decide to delay or cancel expenditure on projects or activities into which little or no capital has yet been committed. For example, as mentioned in section 3.3.2, exploration expenditure fell by around 30% between 2014 and 2015, and discoveries dropped to a 70-year low (IEA, 2016c). What is more, the total level of resources in conventional crude oil fields that were given development approval in 2015 fell to the lowest amount sanctioned in a single year since the 1950s (Figure 3.12).[17] The volumes expected to be sanctioned over the course of 2016 are likely to remain at this suppressed level.

17. The spike in 2009 resulted from three of the super-giant fields in Iraq receiving re-development approval.

Against this background, we investigate below what levels of new approvals will be necessary to ensure that there is no mismatch between supply and demand in the New Policies Scenario. We start by examining the extent of decline in production from fields that are currently producing. We next add any new production issuing from new fields whose development is already committed and then compare this net total output with the level of demand growth seen in the New Policies Scenario. Any gap between these projections represents production that must come from new projects that have yet to receive approval, including fields that may yet be discovered, if demand is to be satisfied without substantial and sudden changes to the oil price.

Figure 3.12 ▷ Conventional crude oil resources receiving approval worldwide



Resources in conventional crude oil projects receiving approval fell to historic lows in 2015

Source: IEA analysis based on Rystad Energy.

Estimating the 2025 supply-demand gap

In order to build up the picture of future global supply prospects, it is first useful to distinguish between fields at different stages of their development and maturity. Here we differentiate, and assess separately, three distinct groups of conventional crude oil fields:

- Post-peak fields: fields that have passed their peak in production. These provided just over 50% of total oil production in 2015.
- Legacy fields: fields that have not yet exhibited any clear decline because they were subject to above-ground constraints or events that reduced their production in the past, and so might continue to produce at, or around, their peak level for some years to come. These constraints could be because of production limitations to meet previous OPEC quota requirements, or political or commercial events, such as the break-up of the Soviet Union. We define these fields as those in which first production occurred prior to 2000 but that had yet to display any clear decline in production by 2015. These fields cover 8% of total oil production.

- Ramp-up fields: fields that have been brought online since 2000 in which production has yet to peak (15% total oil production in 2015).

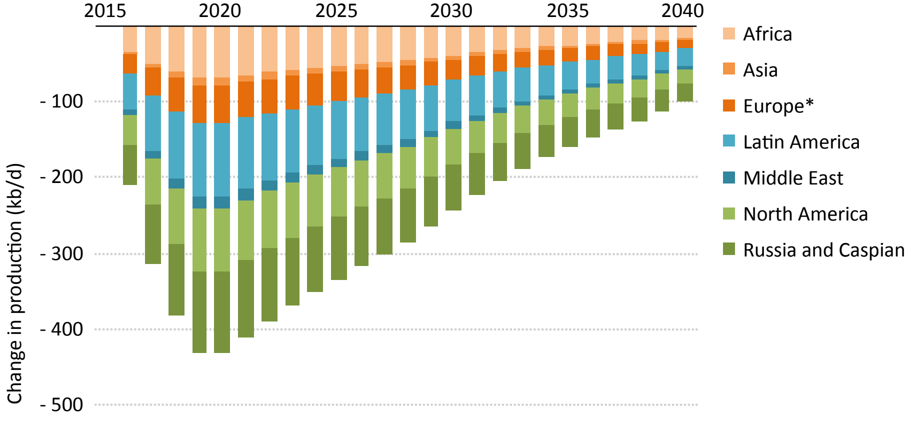
The remainder of global oil production in 2015 came from NGLs (17%) and unconventional oil (9%), including a minor contribution from coal-to-liquids, gas-to-liquids and additives (1%).

3

The rate at which production is expected to decline from the post-peak fields in the first category was examined in detail in *WEO-2013*. We revisit some of that analysis here. A decline rate refers to the percentage reduction in actual production from an individual field or a group of fields over time. It can vary widely from field to field, according to their size, maturity, location, geology and development strategy. When measuring the average decline rate for a group of fields, it is useful to distinguish between the *post-peak decline rate* which refers to the decline from a collection of fields that have passed their peak, and the *overall decline rate*, which refers to the decline in production from all currently producing fields, including those that have yet to peak. These *observed decline rates* are distinct from, and smaller than, *natural decline rates,* which are the rates at which production would decline in the absence of any additional capital investment.

Our updated detailed field-by-field decline rate analysis indicates that the current global average post-peak decline rate in 2015, weighted by each field's cumulative production, is around 6.2%. The global natural decline rate is much higher, at just under 9%,[18] highlighting the importance of ongoing investment into these conventional post-peak fields to avoid precipitous drops in production.

Figure 3.13 ▷ Loss of oil production from post-peak fields resulting from the drop in investment in 2015



Decline in investment in post-peak fields in 2015 results in nearly 450 kb/d production loss by 2020

*Contains OECD Europe and other Eastern Europe countries

18. These observed post-peak and natural decline rates are in close alignment with those from *WEO-2013.*

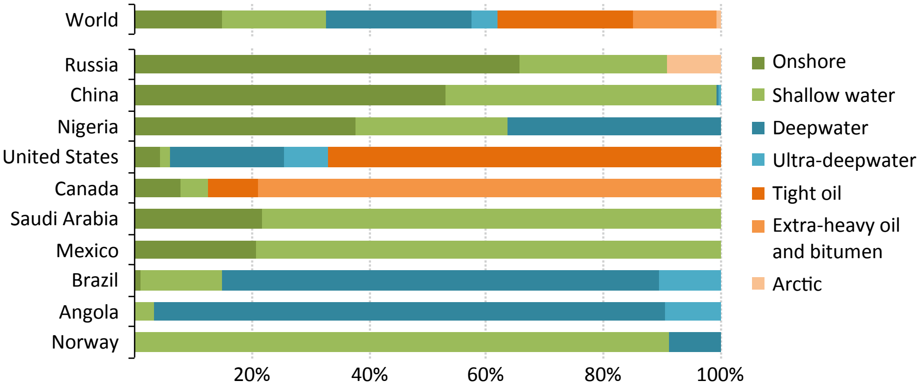
Investment in post-peak conventional crude oil fields in 2015, however, fell in nominal terms by around a quarter from the levels seen in 2013 and 2014. This is greater than the average 15% decline seen in capital costs (Figure 3.6), and so their observed decline rates have increased slightly towards the natural decline rate. This results in a loss in production of close to 450 kb/d by 2020 (Figure 3.13). If investment in these fields were to continue to remain suppressed, then the observed decline rates would trend further towards the natural decline rates and the impact on production would be greater. The New Policies Scenario assumes that investment rebounds, and, on that basis, we estimate that global production from post-peak fields will fall from just over 47 mb/d in 2015 to 29 mb/d by 2025.[19]

Legacy fields, those fields that came online before 2000 but that have yet to exhibit any clear decline, comprise only 3% of existing conventional crude oil fields. But they represent a disproportionately large amount of oil production globally, two-thirds of which occurs in states which are members of OPEC or in Russia. The above-ground constraints or events to which they were subject make it is hard to identify whether decline has yet commenced in these fields or when they might enter decline. The historic behaviour of approximately 5 000 post-peak fields, that had at least 10 million barrels of reserves and that are now clearly in decline, can help in this regard. This suggests that the ratio of cumulative production to initial reserves for fields (the *cumulative depletion rate*) is a useful metric for estimating when production will peak and pass through the subsequent stages of decline. A field is most likely to reach peak production once cumulative depletion reaches around 30%. It will drop below 85% of this peak (the end of the plateau phase) once around 50% is depleted; and the final stage of decline (50% below peak production) will occur once depletion reaches around 80%. As with the post-peak group of fields, the decline rates of the fields in this category also depend upon future investment rates. Based on the price and investment trends of the New Policies Scenario and assuming that fields in this category continue at current levels of production until they reach the above levels of depletion, we estimate that production from these fields will fall from 7.8 mb/d in 2015 to 5.1 mb/d by 2025.

Another type of field active in 2015 is those that commenced production recently and in which production is still growing. Obviously most investment in such fields occurred over the past few years, and between 2010 and 2015 such expenditure (in both conventional and unconventional projects) varied significantly from country to country, reflecting the nature and development stage of the resource base (Figure 3.14). For example, 70% of investment in the United States into new projects was for tight oil projects, over three-quarters of investment in Canada was for oil sands projects, while in Saudi Arabia and Mexico the majority of expenditure was for shallow offshore fields.

19. This drop in production cannot be calculated simply by multiplying the 2015 observed decline rate by current production. Decline rates are not stationary in time: as fields mature they enter later phases of decline, at different rates, while the contribution of different fields to the overall regional decline rate also changes over time.

Figure 3.14 ▷ Capital investment into oil project types starting between 2010 and 2015 by selected country



The new project types that received investment over the past five years vary widely

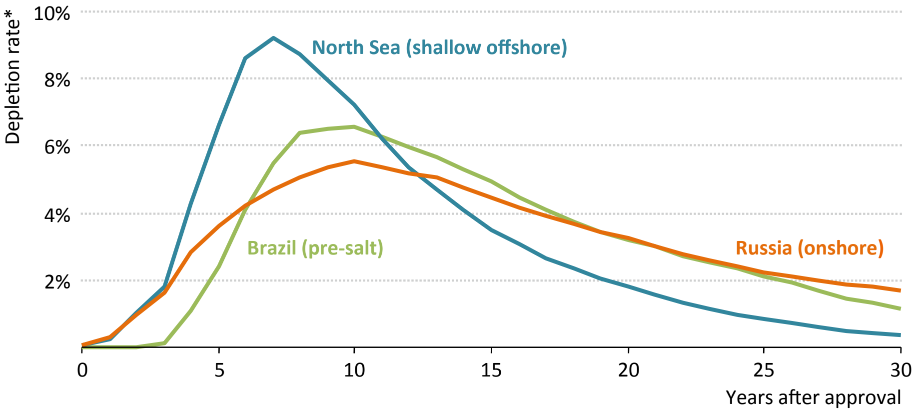
Notes: Shallow water fields have water depths less than 400 metres, deepwater fields between 400-2 000 metres and ultra-deepwater fields greater than 2 000 metres.

Source: IEA analysis based on Rystad Energy.

For these different types of projects, there is wide variation in the interval between when they are first approved, when they commence production, the rate at which they ramp up, their peak level of production and their subsequent decline. Some commence production very soon after approval if, for example, they are close to existing infrastructure, while others will be subject to multiple delays and have slow growth rates. For example, as discussed, the deepwater pre-salt projects in Brazil draw on a huge resource base but are extremely complex. We estimate that output from these pre-salt projects that recently commenced production, or are expected to do so soon, will reach its maximum level around ten years after first approval. In contrast, shallow offshore fields in the North Sea generally achieve maximum production fewer than seven years after approval. The profile of onshore fields in Russia is steadier than both of these, and is characterised by a slower ramp up and lower level of peak production but a less steep decline after peaking (Figure 3.15).

Production from conventional crude oil projects in their ramp-up phase is projected to grow from 13.4 mb/d to 15.7 mb/d between 2015 and 2018. However, these fields subsequently enter decline, and so, even with the ongoing capital investment that takes place in the New Policies Scenario, aggregate production falls by 2.9 mb/d from current levels by 2025. Summing together the contribution of the various groups of conventional crude oil fields, production falls by 23.7 mb/d over the ten-year period to 2025. The importance of this decline should not be overlooked: it is equivalent to losing the entire oil output of Iraq every two years.

Figure 3.15 ▷ **Rates of production after approval for various project types**



Following approval, production from Russian onshore projects grows more slowly than Brazilian pre-salt and North Sea projects

* The depletion rate is the ratio of annual production to a fixed estimate of its reserves, i.e. the percentage of initial reserves produced each year.

Resource and investment requirements

The necessary level of future conventional crude oil approvals needs to take into account both future demand growth and increases from other production sources. Between 2015 and 2025, unconventional sources of production, NGLs and processing gains together grow by just over 6.5 mb/d in the New Policies Scenario (Table 3.11). Further, in 2015 there is an excess of supply over demand, representing a build-up of stocks (estimated to be around 2 mb/d, although this figure is quite uncertain).[20] Subtracting these from the 23.7 mb/d drop in production from currently producing conventional crude oil fields results in a 15.2 mb/d gap that needs to be filled by new projects, just to keep supply in 2025 equal to current levels. To this must be added the 5.7 mb/d growth in demand in the New Policies Scenario over this period. This implies a gap of 20.9 mb/d in 2025.

The first contribution to filling this gap comes from those projects that have already been approved but that had not started production prior to 2016, since they were not yet included in the analysis. The IEA *Medium-Term Oil Market Outlook* (IEA, 2016d) provides detailed data on such projects and we estimate that by 2025 they will add around 5 mb/d, having collectively peaked in 2021 (Table 3.11). Subtracting this yields a gap of 15.9 mb/d in 2025 that must be filled by conventional crude oil projects that have yet to receive approval (Figure 3.16). If there is a continued shortfall in customary levels of investment in post-peak fields, production declines will accelerate and this gap will expand.

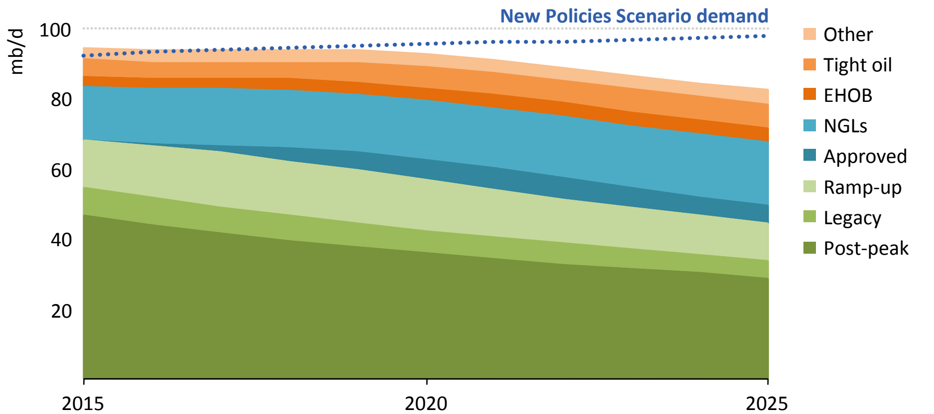
20. Some of the reported excess of supply over demand in the base year could also be a result of timing differences or misreporting of supply and demand figures, and unreported or misstated stock changes (IEA, 2016e).

Table 3.11 ▷ World oil supply by type in the New Policies Scenario (mb/d)

	2000	2015	2020	2025	2030	2035	2040	2015-2040 Change	2015-2040 CAAGR*
Conventional production	**73.8**	**83.8**	**83.0**	**83.6**	**83.7**	**84.1**	**85.1**	**1.3**	**0.1%**
Crude oil	64.8	68.3	66.4	65.5	64.5	64.0	64.5	-3.8	-0.2%
Existing fields	64.8	68.3	57.0	44.6	35.4	28.2	22.8	-45.5	-4.3%
Post-peak fields	*n.a.*	*47.1*	*36.1*	*29.0*	*23.6*	*19.3*	*16.2*	*-30.9*	*-4.2%*
Legacy fields	*n.a.*	*7.8*	*6.3*	*5.1*	*4.1*	*3.2*	*2.5*	*-5.3*	*-4.4%*
Fields in ramp-up	*-*	*13.4*	*14.6*	*10.5*	*7.8*	*5.7*	*4.0*	*-9.4*	*-4.7%*
Approved and not producing	-	-	5.8	5.0	3.2	2.2	1.4	1.4	n.a.
Yet-to-be-approved	-	-	3.5	15.9	25.8	33.6	40.3	40.3	n.a.
Yet-to-be-found	*-*	*-*	*-*	*2.9*	*6.6*	*10.5*	*14.5*	*14.5*	*n.a.*
Natural gas liquids	9.0	15.5	16.6	18.0	19.2	20.2	20.6	5.1	1.1%
Unconventional production	**1.2**	**8.4**	**10.5**	**12.1**	**13.4**	**14.7**	**15.3**	**6.9**	**2.4%**
Tight oil	-	4.6	5.7	6.7	7.2	7.6	6.8	2.2	1.6%
Extra-heavy oil and bitumen	0.8	2.8	3.8	4.2	4.5	5.1	5.9	3.1	3.0%
Total production	**75.1**	**92.3**	**93.5**	**95.7**	**97.1**	**98.9**	**100.5**	**8.2**	**0.3%**
Processing gains**	1.8	2.2	2.4	2.5	2.7	2.9	3.0	0.8	1.2%
Supply* **	**76.9**	**94.5**	**95.9**	**98.2**	**99.8**	**101.7**	**103.5**	**9.0**	**0.4%**

* Compound average annual growth rate. ** Volume increases in supply that occur during crude oil refining. *** Differences between historical supply and demand volumes are due to changes in stocks.

Figure 3.16 ▷ Global supply outlook from selected sources in the New Policies Scenario



A supply-demand gap emerges that must be filled by production from conventional crude oil projects yet-to-be-approved

Note: Other includes coal-to-liquids, gas-to-liquids, additives and processing gains.

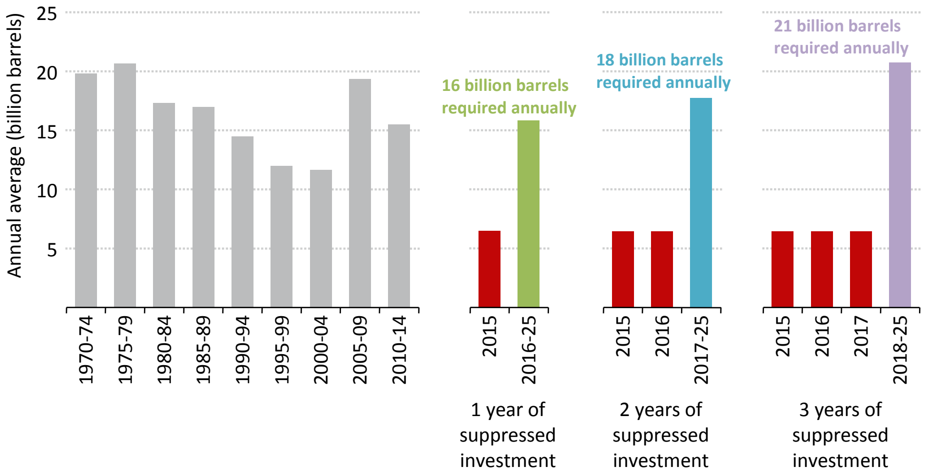
As discussed, production increases at different rates in various projects (Figure 3.15). We can use such profiles to explore what level of resources would need to be approved each year to fill the gap between supply and demand. For example, taking into account the reduction in investment and project approvals in 2015, on the assumption that an equal amount of resources are approved each year, then about 16 billion barrels need to be approved annually from 2016 to 2025 to fill the 2025 gap. This level of approvals remains below the average level that occurred from around the mid-2000s (Figure 3.17).

Extending the assumed period of low investment further in time heightens the subsequent necessary levels of approvals. During this extended period of suppressed investments, we assume that annual approval levels stay at 6.5 billion barrels (as was the case in 2015) and that there are further losses in production from the lack of investment in post-peak fields. Following the downturn, equal volumes are approved in each subsequent year. We find that with two years of suppressed investment, the annual amount that must then be approved between 2017 and 2025 rises to 18 billion barrels/year. Given the low level of approvals seen so far in 2016, this is likely the current state of play. If this is situation continues into 2017, i.e. with three consecutive years of suppressed investments, the amount that subsequently needs to be approved every year between 2018 and 2025 rises to just under 21 billion barrels/year. That exceeds any average level seen since the 1970s.

If such a level of conventional crude oil project approvals were not to materialise to 2025, then oil prices would need to rise to reduce demand and/or yield greater quantities of alternative production to replace the shortfall. The supply source that could potentially ramp up quickly is tight oil. In the New Policies Scenario global tight oil production is 6.7 mb/d in 2025, but if prices were higher, the volumes of tight oil produced in the United States would increase (Figure 3.9). However, despite the more flexible nature of tight oil production, this additional supply would take some time to materialise. For example, if prices in 2025 were suddenly to increase from $100/bbl (as in the New Policies Scenario) to $120/bbl, over the following three years around 600 kb/d of additional production might be expected to come online in the United States as a result. However, one year after the sudden price rise, the increase in production would be around 350 kb/d, only 60% of the total increase that would be ultimately realised. This is because, by 2025, the majority of the most economic sites across the different plays will already have been drilled and/or because the best remaining sites would be drilled even without the sudden increase in prices. Despite the higher number of rigs in operation and the greater number of wells that can be drilled economically, the additional wells drilled immediately after a price increase yield a relatively low level of incremental production. Tight oil could, therefore, play a role in ameliorating any sudden price rise, but it should not be relied upon to be able to satisfy within a year's time any major supply shortfalls that might arise.

In summary, the cuts in upstream oil investment have already re-shaped the outlook for oil markets. Some of the effects are manifest, such as the decline in tight oil production since its peak in early 2015; but, given the inherent lags in developing most sources of crude oil, many other impacts are likely to be most pronounced towards the end of the current decade and into the early 2020s. Our analysis suggests that there is scope to recover from one or two years of supressed investments; this is the current situation given the levels of investment seen in 2015 and so far in 2016. But, if this is prolonged into 2017 or beyond, it becomes increasingly unlikely that supply and demand can be matched without rapid price rises. If the level of project approvals in 2017 does not return to the average levels observed over the past ten years, this is likely to foreshadow the next boom-and-bust cycle for the industry and lead to a more volatile oil price environment.

Figure 3.17 ▷ Global conventional crude oil project approvals required to fill supply-demand gap in 2025



With three years of suppressed investments, future annual approvals must exceed 21 billion barrels, greater than any average level seen since the 1970s

Sources: IEA analysis; Rystad Energy for historical levels.

3.4.2 The impact of climate targets on upstream oil assets

While the previous section considered the possibility and consequences of under-investment, this section discusses the possibility that lower oil demand could result in surplus supply and stranded assets. Fossil-fuel producers are used to making long-term investment decisions, despite the myriad uncertainties that exist in markets. But firm pursuit of a 2 °C trajectory for GHG emissions represents a relatively new and pervasive risk, since it will have profound consequences for the role of fossil fuels in the global energy system.[21] Even with widespread deployment of carbon capture and storage, fossil-fuel consumption will need to fall to meet climate goals. Would these reductions in demand

21. The Paris Agreement aims to keep the global temperature rise "well below 2 °C" and to pursue efforts to limit the temperature rise to 1.5 °C (see Chapter 8.) This section focuses on the 450 Scenario, which has a 50% probability of a 2 °C temperature rise, recognising that mitigation in line with a more ambitious temperature objective would increase the risk of stranded upstream oil and gas assets.

put the upstream oil and gas industry at risk of severe losses, with upstream assets left stranded by falling demand? Or can the transition to a low-carbon economy be managed smoothly, with losses kept to a minimum? There are multiple strands to this issue, which are inter-related and often conflated. This section focuses on three questions:

- What happens to oil demand and existing oil production in the 450 Scenario?
- Do we need additional upstream investment in the 450 Scenario; if so, how much and what is the risk of leaving upstream assets stranded in this scenario?
- What would be the implications for the upstream if climate policies suddenly strengthen beyond the Nationally Determined Contributions made as part of the Paris Agreement, or the industry invests in anticipation of demand that does not materialise?

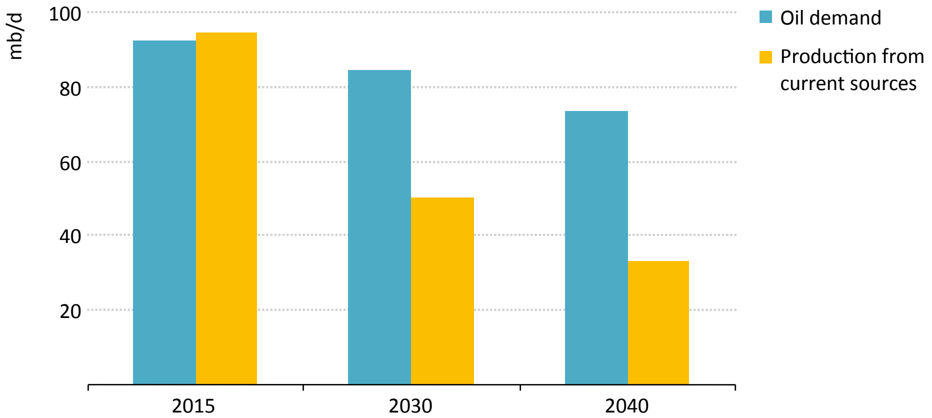
Capital investment into assets that is not recouped is said to be "stranded" and our analysis concentrates mainly on the upstream oil sector. In the 450 Scenario, coal is hit much harder than oil, in terms of lower demand, but coal extraction is much less capital-intensive than oil production and the value of extractive coal assets – and therefore of any potential stranded assets – is relatively small (although the implications for employment, in a labour-intensive sector, would be significant). As discussed in the *World Energy Investment Outlook* (IEA, 2014), the risk of stranded assets in the coal sector is concentrated further down the value chain, in coal-fired power stations. Conversely, in the case of natural gas, demand is higher than today in 2040 in the 450 Scenario. While there are potential risks for midstream gas infrastructure (including pipelines and LNG terminals), the issue of upstream stranded assets appears less pressing for gas than for oil in a 2 °C world.

Oil demand and existing production

In the 450 Scenario, global oil demand peaks by 2020 and then starts a steady decline, reaching 73.2 mb/d in 2040. By 2030, oil consumption is falling by an average of over 1 mb/d each year and is already 10% lower than the starting point in 2015. The maximum annual decline seen in any year is 1.5%. This is significant, but it is still well short of the amount by which production declines from oil fields each year (Figure 3.18). As discussed above, the observed decline rate for conventional fields that have passed their peak is around 6% per year, and if all investment were to cease entirely, this decline rate would accelerate to the natural decline rate, which is closer to 9% per year.

The way that production declines from existing oil and gas fields provides a critically important backdrop to the stranded assets debate. In order to keep oil production at the levels required in the 450 Scenario, these declines still have to be offset by developing new reserves in known fields and by discovering and developing new resources. In the New Policies Scenario, around 85% of oil and gas upstream investment to 2040 is required simply to compensate for declines at existing fields, rather than to meet increases in demand. In the 450 Scenario, offsetting decline becomes the sole driver for investment.

Figure 3.18 ▷ **Global oil demand and observed decline in current supply sources in the 450 Scenario**



The observed decline from today's producing fields is much greater than the anticipated decline in oil demand in the 450 Scenario

Upstream oil investment in the 450 Scenario

A significant tranche of oil production over the period to 2040 comes from the reserves in today's producing fields. These are the proven, developed reserves in existing fields that will be tapped by infrastructure that is already in place. These reserves are produced in all scenarios, without substantial additional capital expenditure. However, the contribution from these existing fields tails off over time and new fields need to be brought onstream. The volume of proven undeveloped reserves and new resources that will be exploited depends on the overall levels of demand, so it varies by scenario. In the New Policies Scenario, around 580 billion barrels of new resources and reserves need to be developed, compared with some 390 billion barrels in the 450 Scenario. Developing these reserves and resources requires capital expenditure: $11 trillion to develop the 580 billion barrels required in the New Policies Scenario and $6.8 trillion for the 390 billion barrels in the 450 Scenario.[22]

This 190 billion barrel differential between the two scenario projections provides some boundaries for the discussion about stranded assets, as it is investment in new fields that runs the most risk of becoming surplus to requirements. There are two aspects. First, some of these 190 billion barrels have already had money spent on their discovery and appraisal.

22. Note that these figures do not reflect the number of barrels actually produced in each scenario to 2040 (910 billion barrels are produced in the period 2016-2040 in the New Policies Scenario, 785 billion barrels in the 450 Scenario). Some of today's fields will continue to produce, in declining volumes, without significant investment, while additional capital investment made to 2040 continues to result in production post-2040. As a result, there is no direct equivalence between cumulative investment numbers and cumulative production numbers in our scenarios.

This investment is not recovered before 2040 in the 450 Scenario. Second, there is the possibility that companies decide to go ahead with new investment into projects involving these resources, but end up with production potential which is ultimately not needed – if, for example, companies plan for only a moderately carbon-constrained future, but end up in one aligned with the 2 °C goal. We consider each of these categories of investment in turn.

Of the 190 billion barrel differential between the two scenario projections, around 90 billion barrels consists of proven, but undeveloped, reserves. The capital already spent proving up these 90 billion barrels, i.e. the exploration costs, is not recouped in the 450 Scenario before 2040. Some of it might be recovered after 2040 but, for the purposes of this analysis, we shall assume that all of these exploration investments are stranded. It is not simple to assign them a value, particularly since the costs were, in some cases, incurred many years ago; but we estimate the expenditure incurred to be around $200 billion. The loss of revenue from failing to produce these reserves is a supplementary consideration, as discussed in Box 3.3.

Beyond these exploration costs, there is no reason why other upstream assets should become stranded in the transition, provided the process is one in which a consistent and credible course towards decarbonisation is pursued. If the path towards the 450 Scenario is clear and visible to investors, there would be little reason to develop new resources in the expectation of a much higher trajectory for demand and prices. The $6.8 trillion of upstream investment in the 450 Scenario brings about new projects that are just sufficient to balance supply and demand at prices that ensure that new projects generate an adequate return: markets are in equilibrium and adjust to the low-carbon transition. Although the valuation of the companies involved in the sector would be lower, in a well-ordered transition new upstream investments do not become stranded.

A smooth transition is obviously desirable, but this is not necessarily how markets function in practice or how policies evolve. Investments have to anticipate market and policy developments and can run behind, or ahead of, eventual demand. They could be made and not fully recuperated. This is most likely to occur if oil and gas companies and investors misread or misjudge future levels of energy and climate policy ambition, or there is a rapid, unanticipated switch in policy direction or intensity. Industry may re-invest current cash flows into developing new resources in anticipation of a steady increase in demand, but then find that these investments are operating in the much more constrained circumstances of the 450 Scenario. Given the long-term nature of upstream assets and the cyclical nature of the investment, policy-makers need to be aware of the disconnect between investments needs under the New Policies Scenario and the 450 Scenario when designing future decarbonisation targets.

Box 3.3 ▷ Putting a value on the shift in oil demand trajectory

Lower demand for oil in the 450 Scenario compared with the New Policies Scenario would be felt by upstream companies, as a reduction in revenue from both lower production and lower prices.[23] In countries where upstream activity is mainly conducted by private companies, the reduction in future income – to the extent that it is recognised by markets – would have implications for the company valuations. Moreover, if listed companies carry reserves on their books that they cannot produce in the 450 Scenario, this could also affect their valuations (although, as we have seen, large volumes of these reserves are produced, even in the 450 Scenario).

To give an indication of the potential size of these effects, we can compare the sum of the discounted future net income (total revenue net of costs and taxes) of private oil and gas companies in the New Policies Scenario and the 450 Scenario, using a field-by-field database that classifies asset ownership by type of company, and making assumptions about the ownership of future discoveries. This provides a rough indication of the difference in valuations between the two scenarios, based on the premise that the market value of listed oil and gas upstream companies should be roughly equivalent to the net present value of their future net income.

If one assumes that today's market capitalisation of listed oil and gas companies is based on an outlook similar to the New Policies Scenario, then the 450 Scenario results in an average fall in value of around 20% (although there will be variations depending, for example, on a company's relative focus on oil or gas and the costs of its project portfolio).[24] There are two factors that keep this difference in check and one major uncertainty affecting the calculation. The underlying declines in production from existing oil and gas fields means that most investment, in both scenarios, goes to offset decline, so the differences in demand between the two scenarios have a smaller effect on the overall picture than might be expected. And, even though there is a difference of some $50/bbl in the oil price between the New Policies Scenario and the 450 Scenario, discount rates mean that even large variations in net income late in the projection period have only a slight impact on the calculation of net present value. Not surprisingly, the major element of uncertainty is the movement of oil prices along the way. As we have seen in recent years, oil price swings can quickly produce short-term changes in valuation, greater than the long-term variability that our analysis attributes to climate policy. Such market volatility could be exacerbated by cycles of stronger and weaker policy action in relation to climate change, a possibility examined in the Disjointed Transition Case below.

23. This does not automatically imply lower net cash flow, as companies also incur lower investments and lower costs. As shown in the Spotlight above, costs in the oil industry are correlated to oil prices, with a feedback loop in which changes in costs affect prices, but price movements also have an impact on costs.

24. A 10% rate is used to discount future cash flows. The changes in valuation do not vary significantly if this is changed: the difference between scenarios is 23%, using a 5% discount rate, and 15%, using a 15% rate.

Forcing the issue: Disjointed Transition Case

One can imagine that, particularly in the early years of a shift in demand patterns, the industry might be overly optimistic in its reading of the future. Because timescales for investment decisions for oil production tend to be long (3-5 years or more), this may lead to investment in assets that become stranded due to lower demand. The actual volume of investment that might become stranded would depend on the character of individual investments. Larger-scale, higher cost projects would be most at risk. It would also depend on the way that over-supply affects markets: on one hand, over-investment can be compensated by reducing the investment needed later; on the other hand, it could also result in a period of lower prices that brings down project returns.

To quantify this question, we have created an illustrative "Disjointed Transition Case", in which demand follows the New Policies Scenario for a period (until 2030) and then drops abruptly to the level of the 450 Scenario over a relatively short period (in this case, over the five-year period to 2035). As a result, prior to 2030, operators invest on the assumption that prices and demand will continue to rise as in the New Policies Scenario, only to be faced with a sharp break in the trend (Figure 3.19). This is intentionally a profoundly disruptive case for oil markets. Less severe transitions – as the 450 Scenario itself shows – do not generate significant stranding. The Disjointed Transition Case could be taken to represent a trajectory in which national and international efforts are initially insufficient to deal adequately with the climate challenge but, by the mid-2020s, the perception of climate disruption is such that, whether through additional collective or individual efforts, it triggers a precipitous transition towards the 2 °C target.[25] It could also represent a case in which the impact of announced climate policies was not fully taken on board by industry until the moment when demand started to fall.

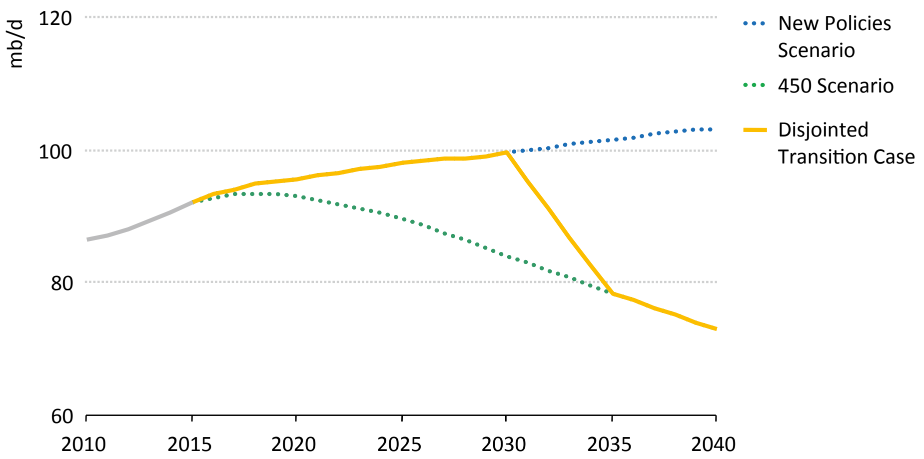
In terms of demand, this represents a massive shock – a decline of some 20 mb/d over a five-year period, which would lead in turn to a large overhang in supply (and a sharp drop in price). A significant part of this reduction in oil demand is absorbed by declining output from existing fields which, as investment in new fields dries up, serves to bring overall production down. Still, two types of stranded assets arise. Some projects developed between 2015 and 2030, with price expectations oriented to the New Policies Scenario outlook, fail to recover their invested capital. In addition, part of the demand shock is absorbed by shutting in fields that have already been developed. There is some overlap between these groups, since fields that are shut in would be those with higher operating costs and thus those less likely to recover the capital costs. In total, we estimate that balancing supply with reduced demand over this five-year period would strand an additional 30 billion barrels of oil and around $380 billion of additional above-ground investment. There are a number of moving parts to this calculation that might reduce the true amount at risk: government tax takes

25. It is important to recognise that such an emissions pathway would not be entirely consistent with a 50% probability of a 2 °C temperature rise (the objective of the 450 Scenario). This is because total GHG emissions to 2030 are higher than levels in the 450 Scenario. To have the same chance of avoiding dangerous climate change, efforts to reduce emissions after 2030 would need to be even stronger. The shock to demand and prices is, therefore, likely to be larger than modelled here.

could be reduced, for example, to ensure that the projects remain commercial (but with reduced income for governments and added burdens for taxpayers). On the other hand, the period of lower prices that would accompany a large supply overhang, and the fall in oil and gas revenues, could be deeply destabilising for companies and countries reliant on hydrocarbon income.

Moving this transition between scenarios forward so that the switch from the New Policies Scenario to the 450 Scenario takes place five years earlier (i.e. between 2025 and 2030), would lessen the impact. The demand shock remains severe – a decline of some 14 mb/d in a five-year period – but, in this case, we estimate that 22 billion barrels of oil would become stranded and just over $310 billion of above-ground investment would be stranded. The overall message is clear: the later the transition to a 2 °C trajectory is deferred, the more difficult and disruptive it promises to be for the upstream oil industry.

Figure 3.19 ▷ Global oil demand in a Disjointed Transition Case



Stranded upstream oil investments in the 450 Scenario are limited, but a disjointed transition would increase the risks sharply

Conclusion

Fossil-fuel producers (countries and companies) face a world full of uncertainties: economics, geopolitics, geology, technology, financing and policy. Some of these uncertainties present risks for fossil fuels, others opportunities. Making investments, despite these uncertainties, is familiar territory for the fossil-fuel industry, and resource-owners and licensees have always needed to develop risk strategies. Countries with fossil-fuel resources naturally look to maximise the national gains from their development, but also develop other sectors of their economy and build up financial reserves. Companies typically keep a portfolio of projects, with varying levels of exposure to risk.

Climate change is a profound challenge to a fossil-fuel dominated energy system, but one that is now well recognised. All fossil-fuel producers face the prospect that demand for fossil fuels will be affected, even with large-scale deployment of carbon capture and storage, as action to tackle climate change intensifies and policies encourage innovation and cost reductions in new technologies, rendering some fossil-fuel options less attractive or obsolete. Companies engaged solely in these businesses face the risk of losing out, particularly those engaged in capital-intensive projects that involve long cost recovery times. At a minimum, the industry needs to stress-test its strategies against the risks arising from climate change.

Yet a key message of this analysis is that significant investment in developing new oil and gas resources is needed, even in the 450 Scenario. Natural gas is least affected in this scenario, meaning that opportunities remain for countries rich in this resource (and companies focussing in full or in part on gas). But even if oil demand falls, as projected in the 450 Scenario, large new oil fields will still be required to meet global demand, because the decline in output from existing fields is much greater than the anticipated decline in demand.

If government policies can provide a clear and consistent route to decarbonisation – as in the 450 Scenario – there is little reason to assume upstream oil and gas assets will become stranded. Investment in oil and gas remains an essential component of a least-cost transition to a low-carbon future (albeit at a reduced pace compared with the levels required in the New Policies Scenario). But there is little room for the industry to be complacent about the future. Though government policies can smooth the transition, stop-and-go cycles of policy volatility can have the opposite effect. If the low-carbon transition is delayed or disjointed, or if the impact of announced policies is under-estimated, there is a risk that major losses will be incurred. Climate change represents a fundamental challenge to all those engaged in tackling the issue or its implications.

Natural gas market outlook

Every silver lining has a cloud

Highlights

- Global natural gas demand grows by nearly half over the *Outlook* period in the New Policies Scenario. The annual growth rate of 1.5% is lower than the 2.3% observed over the past 25 years, but gas is nonetheless the fastest growing among the fossil fuels and increases its share in global primary energy demand from 21% today to 24% in 2040. In contrast, in the 450 Scenario, gas use plateaus from the 2030s, but as a relatively clean and flexible fuel, gas still sees its share increasing slightly.
- The power sector accounts for 34% of the growth in global gas use, but gas faces stiff competition in some import-dependent markets (especially Asia) where it cannot, typically, beat coal on a commercial basis and vies with renewables for policy support. Even though assumed prices for imported gas are lower than in *WEO-2015*, in key Asian power systems new gas plants would be a lower cost option than new coal plants for baseload generation by 2025 (when gas prices reach $11/MBtu and coal prices approach $75/tonne), only if coal prices were $150/tonne.
- The United States and Australia contribute two-thirds to gas production growth until 2020, but from the early 2020s onwards the global gas balance increasingly relies on output growth from a much broader range of producers, with East Africa emerging as a new gas province and Argentina revived as an important gas producer, this time from shale. The Middle East, China and Russia respectively account for 24%, 13% and 8% of the incremental global gas production over the *Outlook* period.
- Inter-regional gas trade grows by some 70%, with 45% of the additional trade set to materialise over the coming ten years. The period to the mid-2020s sees a gas market in flux: LNG overcapacity is gradually absorbed; new players enter the stage; established market mechanisms and incumbents are challenged and gas prices rebound as the market rebalances. The concentration of import growth in Asia underpins a shift in trade flows towards the Asia-Pacific basin.
- Although, over the *Outlook* period, new pipeline connections are built and existing ones reinforced, complex pipeline projects generally find it harder to garner political and financial support in a market awash with LNG. Floating storage and regasification units help to unlock new and smaller markets for LNG. LNG captures around 70% of the additional gas trade and thus manages to increase its share in inter-regional gas trade from 42% in 2014 to 53% in 2040.
- Gas prices are increasingly determined by gas supply and demand fundamentals; new trading hubs and the gradual removal of trade restrictions, such as destination clauses, limiting the buyer's right to resell the gas, also ease the emergence of a globalised gas market. With the LNG overcapacity gone by the mid-2020s, timely investment in new gas supply projects is needed to pre-empt price volatility.

4.1 Recent market and policy developments

Growth in global consumption of natural gas has slowed markedly in recent years, from almost 3% per year in the first decade of this century, to around 1.4% per year on average since 2010. This slowdown has put some producers in a tight corner, as billions of dollars of investment had been poured into new gas fields, liquefaction facilities and shipping capacities in anticipation of stronger growth. Although there are some cyclical elements to the downturn and many regional variations, it has also raised some more fundamental questions about the longer term outlook for gas: while gas is set to perform much better than other fossil fuels over the coming decades, some of the pillars on which a bright future for gas have been constructed look a little less solid than they have in the past.

The power sector is a case in point. With gas use in industry continuing to grow robustly, the reasons for the slowdown in global gas demand growth can primarily be found in power systems around the world. In the European Union (EU), subdued economic growth and a rapid build-up of renewables generating capacity have created slack in the EU Emissions Trading System, reducing the carbon-dioxide (CO_2) price and so helping to tilt the economic calculation away from gas and towards coal; gas use in the EU power sector has fallen by nearly 12% per year, on average, between 2010 and 2014, a notable reversal. Even in countries experiencing strong electricity demand growth, as in much of Asia, gas has faced a struggle to gain ground against coal and renewables. In China, the double-digit growth rates in gas demand have faded: liquefied natural gas (LNG) imports to China hardly increased in 2015.

A combination of robust LNG supply, slowing demand growth, low oil prices and ample availability of shale gas in North America has pulled down regional gas prices around the world. In 2015, average import prices for gas stood at $7 per million British thermal units (MBtu) in Europe and $10.3/MBtu in Japan, both some 40% down from their respective peaks in 2012. Yet, for the moment, there are few signs that the drop in prices in Europe and Asia is triggering much additional demand, either because gas remains uncompetitive against other fuels or because gaps in markets and infrastructure prevent consumers from taking advantage. The situation though is quite different in North America, where prices well below $3/MBtu have prompted a new round of switching from coal to gas in the power sector, with as much power generated in the United States from gas in 2015 as from coal, for the first time.

On the production side, upstream capital spending declined markedly in 2015 and 2016, but a wave of previously sanctioned supply projects – notably LNG export projects in Australia and the United States – continues to collide into an already well-supplied market. This ramp-up of supply capacity amidst a general slowdown in demand growth is keeping the global market awash with gas. In turn, this is providing strong impetus to changes in the way that gas is priced and marketed, chipping away at the rigidities that have characterised LNG and pipeline supply arrangements in the past. Whether a combination of today's investment cuts and the advent of a more flexible and liquid market bodes well for the delivery of new long-term capital-intensive gas supply investments is a key uncertainty for our *Outlook*.

Another set of questions comes from the Paris Agreement on climate change. In advance of the 21st Conference of the Parties (COP21), more than 180 countries submitted pledges on how they intend to reduce their greenhouse-gas (GHG) emissions. The degree of ambition varies widely between countries and the role that gas will play in achieving the long-term target of the agreement is not evident. On the one hand, gas is too carbon intensive to take a long-term lead in the decarbonisation of the energy sector. Uncertainty over the extent of leakage of methane, a potent GHG, along the gas supply chain also cast a shadow over the fuel's environmental credentials. On the other hand, natural gas is the least carbon intensive of the fossil fuels and thus burning gas is a much more efficient way to use a limited carbon budget than combusting coal or oil. Gas is especially advantageous to the transition if it can help smooth the integration of renewables into power systems along the way.

Ultimately, the case for gas as a relatively clean and flexible source of energy remains very strong, especially for countries that have large resources within relatively easy reach. But, for countries relying on gas transported over longer distances, the commercial case for gas looks weaker: even at today's low prices, imported gas typically cannot beat coal on a cost basis, while vying with renewables that enjoy stronger policy support. Gas – LNG in particular – is amply available for the moment, but it will take time for new markets to develop and consumers to absorb the supply overhang, by which time the availability and price of imported gas might already be changing as markets tighten. Gas resources are large and widely distributed, but a dearth of new investment decisions in today's market – and the long-lead times of new supply projects – could mean a return to more volatile conditions in the future. As it seeks to promote new LNG projects, the industry will need to achieve significant cost reductions compared with the current wave of LNG investments. The emergence of Australia and the United States as key LNG exporters is reshuffling the international gas order, but it remains to be seen how the main incumbents, such as Russia and Qatar, will react to the more competitive international environment. As the analysis in this chapter shows, the potential for gas is large, but the pitfalls and uncertainties are many.

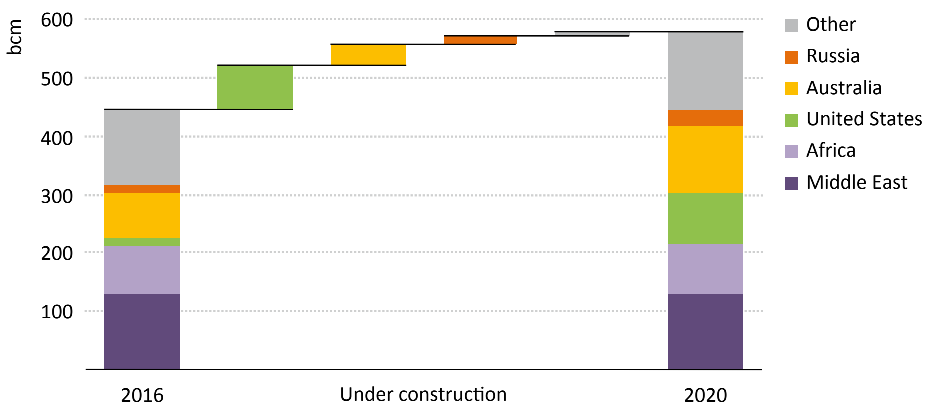
4.2 Trends to 2040 by scenario

4.2.1 Medium-term dynamics

The outlook for gas in the medium term (i.e. the period to the end of the current decade) is characterised by relatively low prices and subdued investment activity (IEA, 2016a). This is critically important to the long-term outlook. The markets for oil, coal and gas are currently all over supplied and the time it takes for the markets to swing back into equilibrium varies by fuel. We expect the global oil market to rebalance first, a process that has started, and the coal market to rebalance last. When the balance is achieved in the gas market is a question that depends on many moving parts. On the demand side, global gas consumption does not pick up quickly in our projections in response to lower prices: in the New Policies Scenario, it is projected to grow by an average of 1.4% per year for the rest of the decade, reaching 3 800 billion cubic metres (bcm) in 2020. Compared with oil, which grows at 0.9% per year, and coal, which declines at 0.1% per year over the same period, gas does well. But the average rate of growth does not exceed that seen in the past five years, as a more downbeat outlook on global economic growth restrains primary energy demand growth.

Markets therefore struggle to absorb the additional 130 bcm of liquefaction capacity currently under construction (85% of which is in Australia and the United States), which gradually comes online in the period to 2020 (Figure 4.1). Demand in Japan declines over the medium term while that in Korea stagnates – the two countries account for more than 60% of inter-regional LNG trade today. Additional LNG imports into Europe are limited by sluggish demand growth (due to subdued economic growth and efficiency improvements), low CO_2 and coal prices and competitive Russian supplies. Although Latin America and the Middle East offer pockets of growth, neither of these two regions is a natural home for large-scale LNG imports. Asia – with China at the forefront – holds the key to a well-balanced gas market: the region's potential for growth in LNG imports is huge, but unlocking it requires progress on market and environmental regulation and time for infrastructure development.

Figure 4.1 ▷ Liquefaction capacity by key region



Some 130 bcm of additional LNG capacity is under construction, 85% of which is in the United States and Australia

Sources: IEA analysis; Cedigaz (2016).

On the supply side, growth in production is concentrated in Australia and the United States, as investment elsewhere is subdued. But these two countries cannot be relied upon to sustain output growth over the period to 2040: the flow of new projects in Australia is drying up and the United States is unlikely, in our view, to maintain the precipitous growth in shale gas output that has been seen in recent years. With its major new upstream developments in the Yamal Peninsula underutilised, Russia has the largest available spare production and transport infrastructure capacity. The challenge for other producers is to pick up the baton, at a time of substantial changes in the contractual terms and pricing conditions on which new projects have traditionally relied: the anticipated shift over the medium term is unmistakeably in the direction of more LNG with shorter contract duration, full destination flexibility and weakened linkages to oil price movements.

4.2.2 Long-term scenarios

The New Policies Scenario, the central scenario in this *World Energy Outlook*, incorporates all policies and measures that are already in place today, while taking into account, in full or in part, the aims, targets and intentions that have been announced, even if the means by which they will be realised are not yet fully in force. Announced policies geared, for instance, towards improving energy efficiency, fighting air pollution, decarbonising the energy system or reducing methane emissions can be expected to have a marked impact on future gas market trends (Box 4.1). This scenario also reflects the climate pledges proposed at COP21.

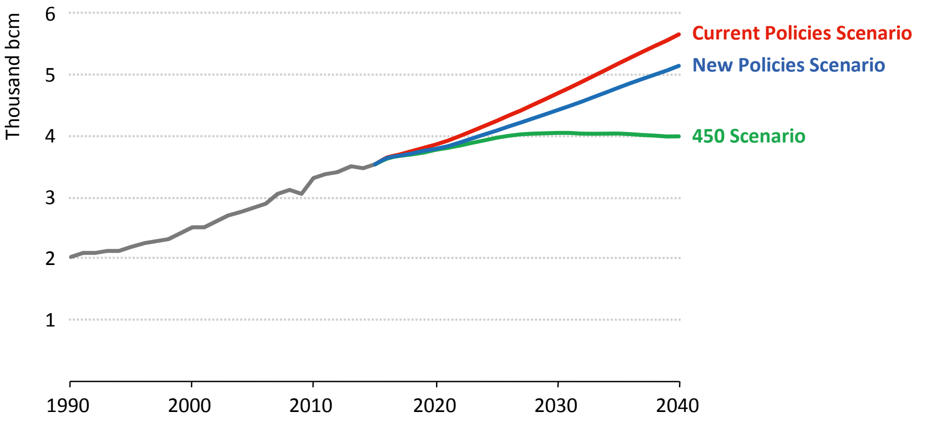
Box 4.1 ▹ Fugitive methane emissions: a rising concern

In 2016, the United States Environmental Protection Agency (EPA) published its annual greenhouse-gas inventory report, which contained a major revision of its estimates for the contribution of the oil and gas industry to methane emissions: the EPA increased its estimate of US oil and gas industry-related methane emissions by about 30% relative to the inventory from 2015.[1] The EPA states that the main reason for the upward revision in fugitive methane emissions is related to higher (and previously under-estimated) equipment counts, i.e. the number of wells, valves, pneumatic controls, compressors, pipelines, tanks and other potential sources of leaks. Several other stakeholders have maintained for some time that these EPA estimates are too low, while the industry points out that significant, voluntary progress in reducing emissions has been made over the last several years. Given the strong consequences that methane emissions have for near-term global warming, as well as their other harmful impacts (such as reduced agricultural crop yields), it is not surprising that this issue is rising up the energy agenda. Notable recent policy announcements include a commitment by the United States, Canada and Mexico to reduce their oil and gas-related methane emissions by 40-45% by 2025. Analysis of the level of methane emissions and the scope and costs to reduce them will be contained in a planned special report in the *WEO* series in 2017.

1. The 30% increase relates to the reporting year 2013, which is the most recent year reported in both the 2015 and 2016 US EPA greenhouse-gas inventories.

Similar to the growth rate projected over the medium term, global gas demand grows on average at 1.5% per year in the New Policies Scenario to 2040. This slowdown, compared with the annual growth of 2.3% observed over the past 25 years, reflects two important trends. First, there is the overall context of slower growth in primary energy demand, which is projected to rise at only half the rate seen between 1990 and 2014. Second, there is the impact of saturation in some mature markets, allied to a more competitive environment for gas. Yet gas does manage a steady expansion of its role in global energy, underpinned by demand in power and in industrial gas use. Growth in gas production will entail development of more complex projects, putting upward pressure on prices in all major regions (see Chapter 1). Gas prices in the United States, the European Union and Japan rebound in the first-half of the projection period, respectively reaching $4.7/MBtu, $9.2/MBtu and $11.3/MBtu in 2025. In the long term, prices gradually climb to around $7/MBtu in the United States, $11.5/MBtu in the European Union and $12.4/MBtu in Japan. These price trajectories facilitate investment of $9.4 trillion in gas supply over the *Outlook* period.

Figure 4.2 ▹ World natural gas demand by scenario



Global gas demand is projected to plateau from the late-2020s in the 450 Scenario

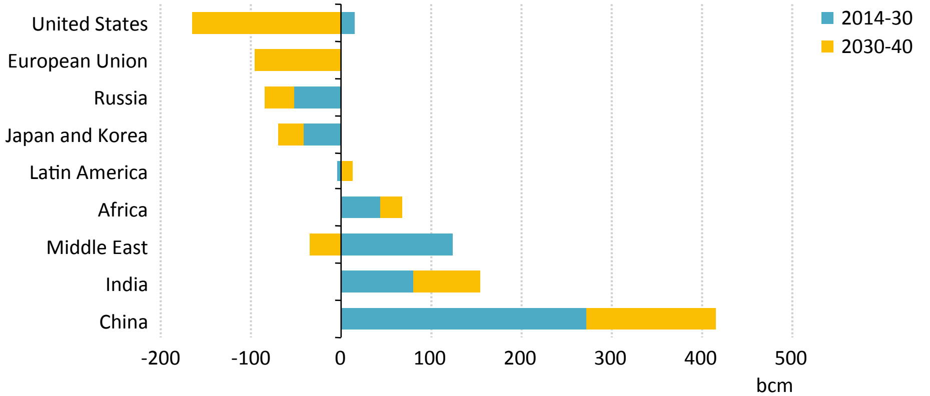
The Current Policies Scenario provides a trajectory for natural gas in an energy world shaped only by policies that were already firmly embedded in legislation as of mid-2016. Gas demand grows more quickly in this scenario – by 1.9% per year on average – but it makes less ground versus coal than in the New Policies Scenario, as coal faces substantially fewer policy headwinds. The share of gas in primary energy supply reaches 24% in 2040 (up from 21% in 2014) – well below oil and coal which stand at 28% and 27%, respectively, at the end of the *Outlook* period. Gas fares slightly better in the global power mix (24% in 2040, compared with 23% in the New Policies Scenario), the net result of two opposing trends. On the one hand, without the impetus of some of the policy changes in the New Policies Scenario, especially those spurred by COP21, coal often prevails in competition between coal and gas in the power sector. On the other hand, growth in renewables is lower, leaving more room for gas to satisfy higher power demand. In the Current Policies Scenario, in 2040, gas prices reach nearly $8/MBtu, $13/MBtu and $14.4/MBtu, respectively, in the United States, the European Union and Japan. Investment in gas supply amounts to $10.9 trillion, of which $7.5 trillion are dedicated to tapping into conventional and unconventional gas resources around the world, while $3.4 trillion are mobilised to expand pipeline and LNG infrastructure.

The 450 Scenario sets out an energy pathway consistent with a 50% chance of limiting the global increase in temperature to 2 °C. This scenario paints a strikingly different picture of future gas markets: gas demand keeps growing through the mid-2020s, but then starts levelling off, resulting in an overall growth rate of 0.5% per year over the projection period (Figure 4.2). Although gas fares markedly better than other fossil fuels – oil and coal decline by 1% and 2.6% per year respectively – this scenario brings out forcibly that even gas is too carbon intensive for long-term growth in a decarbonising energy system. Gas may be a supporting fuel for the transition to a low-carbon energy system but this should not be misunderstood as a sustainable growth opportunity in a 2 °C world. Gas still plays a critical role in power generation: in the first-half of the projection period, existing gas plants achieve significant CO_2 savings as they displace coal-fired generation. As the deployment of variable renewable energy sources grows over the *Outlook* period, flexible operation of gas-fired plants provides system services and aids the integration of these technologies. But the volumes actually consumed decline in the latter half of the projection period, as the sector approaches full decarbonisation. Gas demand plateaus in the buildings sector in the 2030s, while it continues to grow in industry and in transport (where gas use is higher than in the New Policies Scenario).

The role of gas in the 450 Scenario varies strongly by region (Figure 4.3). Through the late 2020s, growth in global gas demand is spurred by additional gas use in China, the Middle East and India, while consumption remains flat in the United States and the European Union in that time period. Gas burn in the power sector peaks in the United States and the European Union around 2025. The decline accelerates in the 2030s, as the fuel is too carbon intensive to deliver further decarbonisation gains in these systems and efficiency improvements reduce the demand for gas. With carbon capture and storage (CCS) picking up in the 2030s, China has another low-carbon option available that constrains the extent to which gas can gain market share in the power sector at the expense of coal. The momentum for gas demand growth therefore shifts to the transport sector, which accounts for a fifth of incremental Chinese gas demand between 2030 and 2040. CCS makes only limited inroads into the Indian power sector, thus leaving room for gas to decrease the carbon intensity of power generation by displacing unabated coal. In India the power sector, therefore, remains the primary driver of gas demand growth, even after 2030.

The 450 Scenario sees the lowest gas prices of all three scenarios in the long term. By 2040, US gas prices reach $5.4/MBtu while prices in the European Union and in Japan stand at nearly $10/MBtu and just under $11/MBtu respectively. Despite subdued production growth, the 450 Scenario still requires considerable investment in gas supply – amounting to $7 trillion over the *Outlook* period – not least to compensate for natural decline in the many fields that near depletion in the coming 25 years. More than a third of the investment is needed for transmission and export infrastructure. Some of the fields that have seen money spent on their discovery will not be needed in the 450 Scenario but, beyond the loss of these explorations costs, there are no inevitable reasons for further stranded assets to accumulate in this scenario (see Chapter 3).

Figure 4.3 ▷ Change in gas demand in selected regions in the 450 Scenario



Fuel switching plays a key role in the period to 2030 but efficiency gains and power sector decarbonisation reduce gas demand growth in the long term

4.3 A closer look at the New Policies Scenario

4.3.1 Demand

The New Policies Scenario sees global gas demand increase by nearly half from 3 500 bcm in 2014 to over 5 200 bcm in 2040 (Table 4.1). With an annual average growth rate of 1.5% over the *Outlook* period, growth in gas consumption is markedly stronger than in oil and coal, which grow at 0.5% and 0.2% respectively. In a post COP21 world, natural gas offers a lower carbon alternative to coal and oil and a way to tackle the ubiquitous air quality problems that harm the health of millions of people, especially in developing countries (IEA, 2016b). The outlook for gas is, however, clouded by uncertainties around the economics of gas *vis-à-vis* its competitors and the readiness of policy-makers to support growth in gas demand. In virtually all major gas-importing regions, gas is costlier than coal in energy terms. Without measures to tilt the calculation in favour of gas, the fuel is confined to markets where consumers have a convenience yield from gas use (e.g. in the buildings sector or in certain industries) or to mid- and peak-load power generation where the fuel cost disadvantage is offset by the lower capital costs of the stations providing such power. Fuel switching from coal – or in the Middle East from oil – to gas can quickly deliver significant reductions of CO_2 emissions from the existing power plant fleets, but in most markets this would not be delivered at scale unless there is a supportive policy framework, either in the form of carbon pricing or pollutant regulation, or – as in parts of China – restrictions on the construction of new coal-burning facilities or the forced closure of existing coal plants (for example, due to air quality concerns).

Table 4.1 ▷ Natural gas demand by region in New Policies Scenario (bcm)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
OECD	**1 418**	**1 624**	**1 697**	**1 732**	**1 764**	**1 807**	**1 835**	**211**	**0.5%**
Americas	806	941	994	1 015	1 038	1 074	1 113	173	0.7%
United States	669	756	796	807	812	824	840	83	0.4%
Europe	482	462	497	515	521	523	512	50	0.4%
Asia Oceania	130	221	206	201	206	210	210	- 11	-0.2%
Japan	82	129	103	94	95	97	96	- 34	-1.1%
Non-OECD	**1 099**	**1 878**	**2 097**	**2 357**	**2 675**	**3 013**	**3 335**	**1 456**	**2.2%**
E. Europe/Eurasia	594	657	655	665	678	704	725	68	0.4%
Caspian	82	116	129	141	149	163	176	60	1.6%
Russia	388	452	436	432	434	441	447	- 5	-0.0%
Asia	183	484	626	775	930	1 083	1 223	739	3.6%
China	28	188	297	386	475	547	605	416	4.6%
India	28	50	66	95	128	159	189	138	5.2%
Southeast Asia	88	167	176	192	211	237	267	99	1.8%
Middle East	174	441	509	570	660	741	804	363	2.3%
Africa	56	131	143	171	208	255	312	181	3.4%
South Africa	1	4	4	5	7	8	11	7	4.1%
Latin America	91	165	164	177	198	231	270	105	1.9%
Brazil	9	42	35	36	42	55	66	25	1.8%
Bunkers**	0	0	8	17	27	37	49	49	n.a.
World	**2 517**	**3 502**	**3 802**	**4 106**	**4 466**	**4 858**	**5 219**	**1 717**	**1.5%**
European Union	486	418	458	473	473	469	452	34	0.3%

* Compound average annual growth rate. ** LNG used as an international marine fuel.

The level of ambition laid out in the climate change pledges that countries prepared for COP21 does not depend critically on a major contribution from gas. Fewer than 30 out of over 160 submissions mention gas as an element of their strategy to meet the pledged emissions target. Gas-rich countries in the Middle East and North and East Africa constitute the majority of those making a positive mention of gas in their pledges. In developing Asia – where many gas exporters have pinned their hopes on a rapid increase in demand – only three countries (albeit among them China) specify a role for gas in achieving their climate goals.

Generally speaking, countries can achieve their proposed GHG emission reductions with different compositions of energy mix. While gas can certainly play a role, in countries like South Africa or India, which have large coal reserves, the emerging policy preference appears to be based on achieving emissions reductions by means of a combination of renewables and high-efficiency coal, rather than a combination of renewables and gas. In the light of amply available, relatively cheap coal and rapidly falling costs of renewables technologies, gas could gain ground in such cases only if it could demonstrate strong credentials as a secure, affordable and reliable energy source, with price levels and volatility kept within reasonable limits.

The gas demand trends of the New Policies Scenario reflect these challenges and trade-offs: gas demand grows in almost all major regions and expands in power generation, industry, buildings and transport. Yet, the fuel's share in global power generation stays flat over the *Outlook* period and the moderate increase in its share in global primary energy demand is mainly underpinned by robustly-growing gas consumption in industry. Demand is approaching saturation in many of the largest resource-rich regions, like the United States and Russia, although there remains scope for growth in the Middle East and in gas-rich parts of Africa and Latin America. The challenges for gas are toughest in net gas importing countries. In the European Union, for example, the share of gas in the region's power mix recovers somewhat as coal-fired capacity is retired, but much of the resulting gap in the mix is taken up by renewables. In coal-rich but gas-importing areas, like India or parts of Southeast Asia, gas use grows, but it faces an uphill battle to take market share from coal, while renewables deployment also grows rapidly. The gas industry becomes increasingly adept at developing niche markets and dealing with the variable seasonal needs of smaller off-takers, helped by technological advances, such as scalable floating storage and regasification units (FSRUs) that bypass, in part, the need for large-scale import infrastructure. But, in the face of strong competition, the gas industry has to work hard for growth.

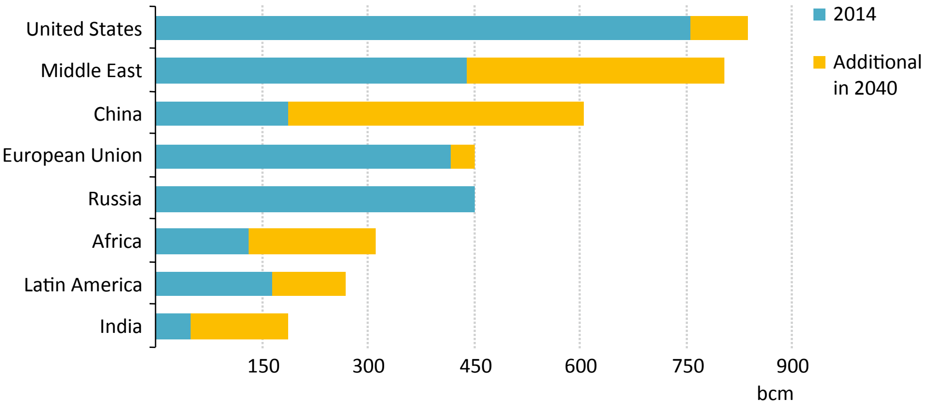
Regional trends in demand

In the New Policies Scenario natural gas demand expands almost everywhere over the period to 2040, with the fastest growth occurring in developing countries. Gas is an attractive fuel to meet their rapidly rising energy needs, particularly where a measure of this demand can be met by developing domestic resources. Nonetheless, a significant share of the rise in gas use is also met by a rise in imports: inter-regional gas trade grows slightly faster than the growth in global gas demand, eventually spelling good news for the export-oriented gas industry and its struggle with excess capacity.

China assumes the role of the engine of global gas demand growth. Over the *Outlook* period, China uses an additional 420 bcm of gas – an amount that is equivalent to today's entire gas consumption in the European Union – making it the third-largest gas consumer (up from fifth in 2014) after the United States and the Middle East (Figure 4.4). The Middle East is not far behind China in terms of gas demand growth in absolute terms: an incremental

360 bcm of gas are consumed in the various countries of the Middle East in the period to 2040. The Middle East thus becomes the second-largest gas consuming region, from third today. Gas demand is projected to expand rapidly also in India, Africa and Latin America, albeit from a low base. Each of these three regions grows – in absolute terms – by more than the United States, though the United States, despite saturating gas demand, remains the largest gas consumer over the period. Gas demand ends up higher than today at the end of the *Outlook* period in the European Union, but gas demand in 2040 does not exceed the level reached at the beginning of this decade.

Figure 4.4 ▷ Gas demand by selected regions in the New Policies Scenario



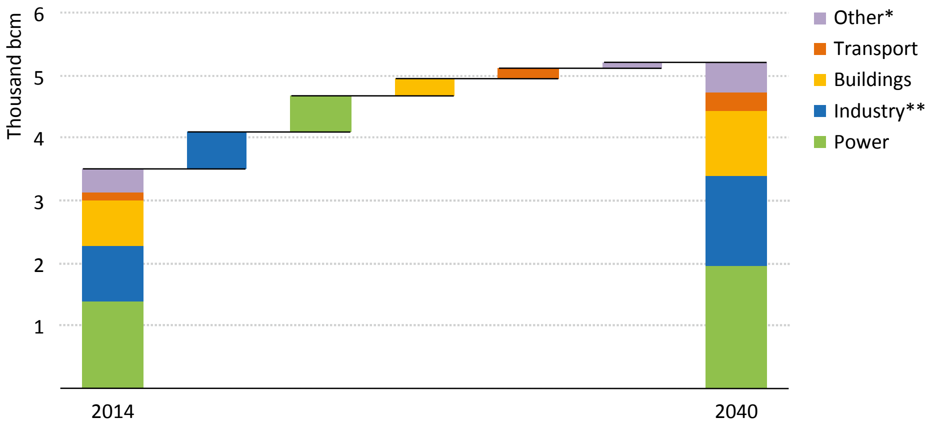
Developing countries lead the growth in global gas demand

Sectoral trends in demand

The power sector is the largest gas consuming sector, accounting for 40% of worldwide gas demand today (Figure 4.5). Power generation contributes 35% to global growth – as much as industry – but it is the sector of greatest uncertainty because of the number of competing fuels for power generation, ranging from coal to renewables. Competition from renewables increases as their costs come down and different technologies (for instance wind onshore) become competitive in various places over the projection period (see Chapter 11). Despite the strong growth in gas demand for power and heat plants, the sector's share in total gas consumption declines slightly over time, dipping to 38% in 2040.

Gas-fired technologies entail a far lower capital expenditure than coal or nuclear power plants: for instance in Europe, the overnight cost of a combined-cycle gas turbine (CCGT) amounts to $1 000 per kilowatt (kW), half the cost of a supercritical coal plant and nearly seven-times less than a nuclear plant. Depending on the relative fuel prices (and carbon prices where applicable), the investment cost advantage can offset the typically higher fuel cost of gas plants. The role of gas in regional power systems in practice varies strongly. In countries with large domestic gas reserves, such as the United States, Russia and parts of the Middle East, power generators benefit from low gas prices and gas-fired plants run at high utilisation rates, producing baseload electricity (often combined with district heating as in the case of Russia, or seawater desalination as in the Middle East). In gas-importing countries, like India, South Africa or China, the role of gas-fired plants is currently largely confined to meeting peak demand and providing balancing power, running at lower utilisation rates.

Figure 4.5 ▷ World gas demand growth by sector in the New Policies Scenario

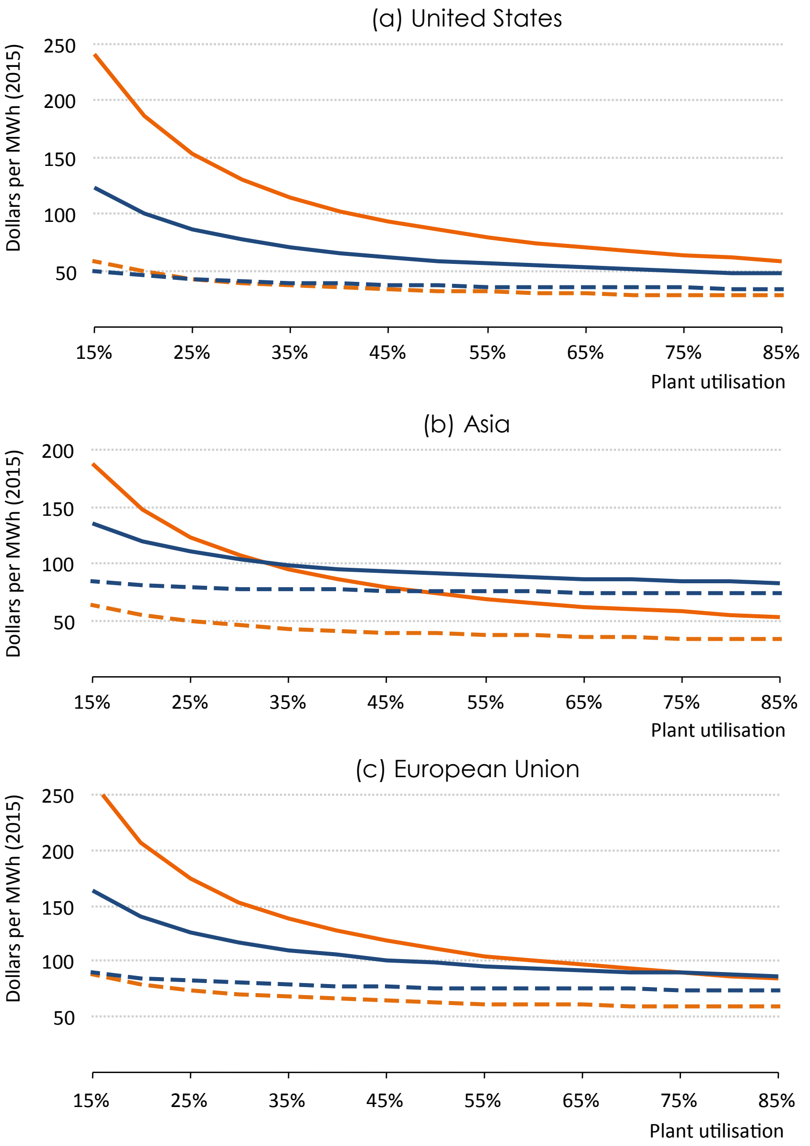


Power generation and industry hold the key to global gas demand growth

* Other includes agriculture and any other non-energy use. ** Industry includes gas used as petrochemical feedstocks, and energy consumption in coke ovens and blast furnaces.

Fuel switching, primarily between coal and gas, plays an important role in the power sector. Principally, there are two ways for fuel switching to happen: in the short term, existing plants compete for utilisation, based on relative fuel cost (and fixed operation and maintenance cost, if the question is whether or not to keep a given plant operational); and in the long term, fuel switching can be achieved as a result of investment that changes the composition of the power plant fleet. Fuel switching between existing plants is particularly relevant in systems with spare generating capacity and a narrow gap between coal and gas prices. In the United States, the fuel price evolution projected to 2025 keeps the economics of coal and gas plants close enough for existing power plants to compete in all three load segments (Figure 4.6), peak-load (plant utilisation of less than 40%), mid-load (utilisation between 40% and 70%) and baseload (utilisation larger than 70%). Taking investment costs into account suggests that CCGTs have a cost advantage over advanced coal-fired plants in all load segments. Despite an increase in the CO_2 price to $30/tonne in 2025, relative fuel prices in the European Union remain favourable to existing coal plants. However, similar to the United States, new CCGTs beat new coal plants in most utilisation categories. The prospects for new gas plants to be built in the European Union, however, are clouded by question marks around the design of electricity markets and power prices that currently do

Figure 4.6 ▷ Levelised cost of electricity generation for existing and new coal and gas plant by key region, 2025



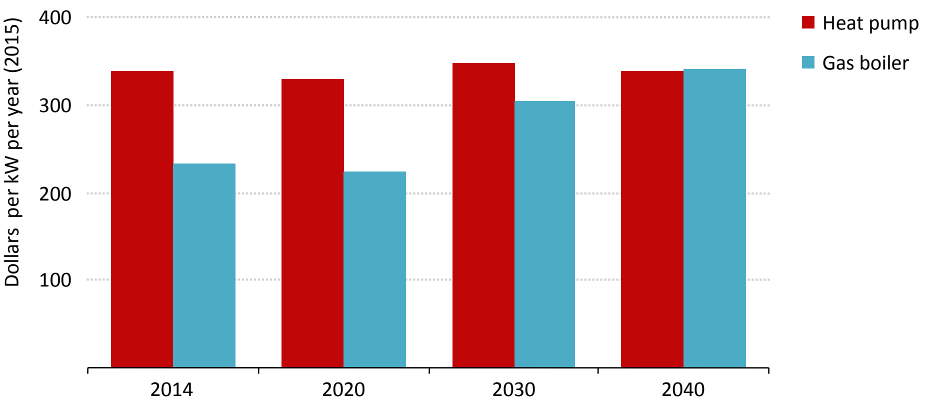
The commercial case for coal-to-gas switching in power generation is not self-evident in key markets outside the United States

Notes: MWh = megawatt-hour. Existing supercritical coal plant efficiency: 39%; existing CCGT efficiency: 58%. New ultra-supercritical coal efficiency: 43%; new CCGT efficiency: 58%. Coal price: $73/tonne in Asia, $70/tonne in the European Union and $58/tonne in the United States. Gas price: $11.3/MBtu in Asia, $9.2/MBtu in the European Union and $4.7/MBtu in the United States. A CO_2 price of $30/tonne is included in the European Union.

not reward investment in new plants. The situation is different in Asia, where (in the absence of a specific policy intervention favouring gas) coal plants have structurally lower generation cost than gas plants and new gas plant investment is profitable only in mid- and peak-load operation. Yet, the classic regulated utility model – often with state-ownership – which is prevalent in Asian power systems adds a political dimension to the economic calculation that tends to be the driving force behind investment in market-based systems.

Between today and 2040 gas consumption in industry grows by 625 bcm, accounting for just under 40% of global gas demand growth. The main factor underpinning this gas demand growth in industry is the rising demand for the process heat and steam generation needed to meet the requirements of economic growth. Dual-fuel firing is rare in industry, limiting the scope for fuel switching in the short term. In the long term, gas manages to displace coal, to a certain degree, in industrial applications with process heat or steam loads, mainly in China. The potential is highest in cities, or for smaller boilers, where pollution control devices are typically not cost-effective (IEA, 2016b). In the long term, heat pumps and solar thermal energy become key competitors for gas for the provision of low temperature heat in industries such as chemicals, food and paper. For instance, in the European Union, technological learning gradually brings down the investment cost of heat pumps and offsets increases in the electricity price over time, keeping the total costs of heat pumps flat, while rising fuel and CO_2 prices push up the cost of gas boilers. The cost gap between the two technologies closes by the end of the *Outlook* period (Figure 4.7).

Figure 4.7 ▷ Annual average running cost of a heat pump and a gas boiler in non energy-intensive industry in the European Union



In the European Union, the cost gap between a heat pump and a gas boiler is closing by the end of the Outlook period

Non energy-intensive industries, such as textiles, food and beverages or machinery, account for nearly half of the industry sector's gas consumption today. Gas demand in these branches surges by 360 bcm over the projection period, lifting the share of non energy-intensive industries in the industry sector's gas demand to over half in 2040. Accounting for a third of industrial gas consumption, the chemical industry is the second-largest user. Despite gas use in the chemical industry growing by over 200 bcm, the chemical industry's share in total industrial gas consumption remains at around a third in 2040. Today, a third of the gas used in the chemical industry is used as feedstock for the production of chemical products, mainly ammonia-based fertilisers and methanol, a precursor for several products, including resins, additives and polymers. The share of feedstock use in the chemical industry's gas consumption increases to 37% in 2040, as energy efficiency improvements reduce energy-related fuel consumption.

Natural gas use in buildings for space heating, water heating and cooking currently accounts for 22% of global gas demand, but this share drops to a fifth in 2040. Much of the seasonality in gas demand stems from gas use in the buildings sector and regional differences in seasonal heat demand. The buildings sector's gas consumption increases by 280 bcm over the *Outlook* period, 30% of that growth coming from China alone. With the envisaged expansion of China's gas distribution network, scope for gas to displace coal, oil and the traditional use of biomass is large in the Chinese buildings sector. In most other developing countries, ambient temperatures do not leave much room for heating demand growth, but displacing other fuels for water heating and cooking is still an important growth opportunity for gas. Lack of gas distribution infrastructure is, however, often a limiting factor that favours alternatives such as heat pumps, solar thermal or liquefied petroleum gas (which counts as oil demand). Growth opportunities for gas demand in the buildings sectors of developed countries are very limited: demand for heating is largely saturated, the average household size is already small, the energy efficiency of the building infrastructure is improving (e.g. better insulation of buildings), coal and oil have been widely displaced, and with solar thermal and heat pumps, new competitors are ready to gain market share – possibly even without policy support.

Gas demand in the transport sector grows globally by over 160 bcm, reaching some 280 bcm in 2040. Growth is primarily spurred by road transport which accounts for two-thirds of the additional gas demand in the transport sector. Most of the remainder is taken up by marine transport where the role of LNG as a bunker fuel rises rapidly. The United States leads the growth in gas use in road transport, accounting for nearly 30% of the incremental worldwide gas consumption to 2040 in road transport, followed by China (21%) and India (14%). Although the share of natural gas use in transport increases to 5% in 2040 (up from 3% in 2014), natural gas as a fuel for vehicles remains a niche application in most countries (some notable exceptions are Iran, Pakistan, Argentina and Brazil). The key uncertainty for the future role of gas in the transport sector remains the dilemma over infrastructure investment: natural gas-fuelled vehicles are unattractive without an adequate refuelling infrastructure in place, but without a critical mass of gas-fuelled vehicles, investment into new natural gas fuel pumps is risky.

4.3.2 Supply

Resources and reserves

Natural gas is a relatively abundant fuel with remaining technically recoverable resources close to 800 trillion cubic metres (tcm) at the end of 2015 (Table 4.2). This is sufficient to comfortably meet production growth to 2040 in all three scenarios of our *Outlook*. Unconventional resources currently comprise about 45% of the total gas resource but this figure is subject to large uncertainties. Outside the United States, our projections for unconventional gas production pale in comparison to the huge resource estimates, suggesting that resource availability is not a primary constraint and resource uncertainty consequently has a minor effect on our modelling in these regions. The situation is different in the United States, where variations in the estimates of the shale gas resource can have a marked impact on future gas markets (see Focus below). Total proven reserves of natural gas have not changed much since *WEO-2015*, approaching 220 tcm at the end of 2015 thus suggesting that the drop in gas prices over the last year has not led to a decline in reserves.

Table 4.2 ▷ Remaining technically recoverable natural gas resources by type and region, end-2015 (tcm)

	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
OECD	**78**	**24**	**81**	**16**	**121**	**199**	**22**
Americas	51	11	55	7	73	124	14
Europe	17	4	13	2	19	37	4
Asia Oceania	10	8	13	8	29	39	4
Non-OECD	**356**	**57**	**138**	**34**	**229**	**585**	**195**
E. Europe/Eurasia	138	11	15	20	46	184	74
Asia	35	13	40	13	66	101	16
Middle East	104	9	4	-	13	117	80
Africa	51	10	39	0	49	100	17
Latin America	28	15	40	-	55	83	8
World	**434**	**81**	**218**	**50**	**349**	**784**	**217**

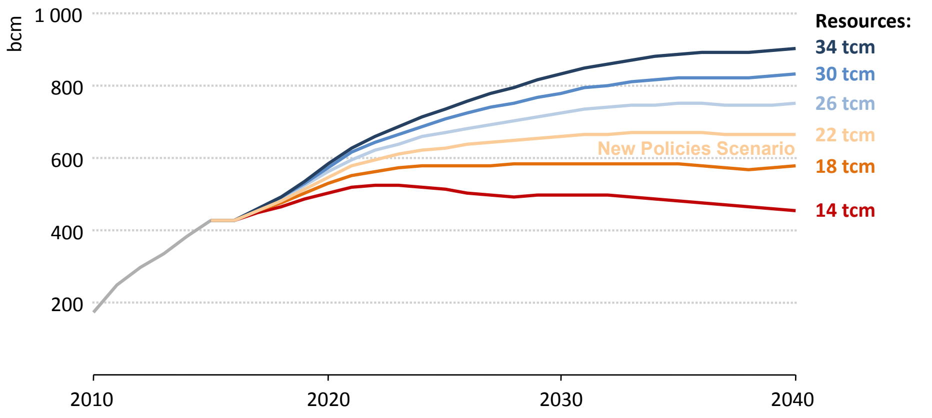
Sources: BGR (2015); BP (2016); Cedigaz (2016); OGJ (2015); US DOE/EIA/ARI (2013); US DOE/EIA (2015); USGS (2012a, 2012b); IEA databases and analysis.

Focus: How would higher US shale gas resources affect the Outlook?

As noted, resource numbers for US shale gas are subject to considerable uncertainties, as reflected in the large range of estimates from different official and private sources. While there are variations in the assessment of gas resources for all shale gas plays, the Marcellus (the biggest play) is at the heart of the uncertainty. Our analysis of the available estimates of US shale gas resources points to a conceivable range of 14 tcm to 34 tcm. The resource number that underpins the trends of the New Policies Scenario – 22 tcm as of end-2015 – falls just under midway across this bandwidth; this has been revised upwards compared with the 16 tcm used in last year's *Outlook*.

To demonstrate the marked impact of resource uncertainty on production trends, we have conducted an in-depth analysis of the production profiles of 27 shale gas plays, with varying estimates of their technically recoverable resources. Based on the price trajectory of the New Policies Scenario, the above-mentioned range of resource estimates translates into a range of production levels between 470 bcm and just over 900 bcm in 2040 (Figure 4.8). Productivity gains, in terms of wells drilled per rig and ultimate recovery per well, improve the well economics and thus enable more marginal portions of any given play to be produced but the main parameter affecting productivity and gas produced is the assumed quality of the resource (Box 4.2).[2] Because of the rapid decline rates of shale gas wells, producers must continuously scale up drilling activity in order to compensate for the drop in production from existing wells and expand output. Thus, even under the most optimistic resource estimate, production growth rates observed in recent years could hardly be sustained beyond the medium term. We project US shale gas production to reach a plateau in the latter half of the *Outlook* period, mainly due to the fact that development extends progressively into lower quality reservoirs, where initial flow rates are lower than in the past. A downbeat view on shale gas resources (14 tcm) still implies considerable growth over the medium term, but rapid decline rates would then lead to a peak in shale gas output in the early 2020s.

Figure 4.8 ▷ US shale gas production as a function of the resource estimate



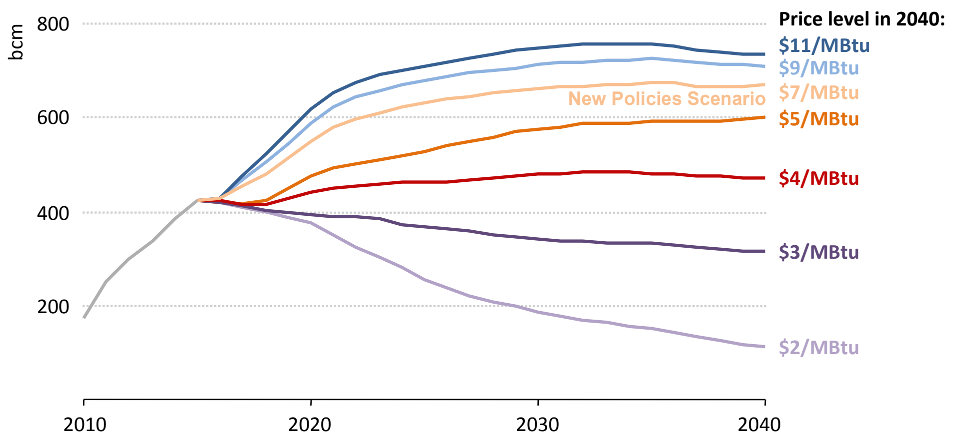
No matter how high the resource estimate is, recent production growth rates are not sustainable over the long term

While the shale gas resource estimate is a key parameter for the modelling of our production trends, variations in the long-term price trajectory can have a similarly striking effect on production. Based on resources of 22 tcm, the sensitivity of shale gas production

2. We assume a modest annual increase in the number of wells drilled per rig and an increase in expected ultimate recovery per well of 1.5% per year. Additionally, the natural gas liquids content is taken into account at the play level in determining the relative economics and development pace for all plays.

to price is at its largest if the price is between $2-4/MBtu in 2040, with production levels differing by over 400 bcm (Figure 4.9). For price trajectories above $4/MBtu in 2040, the price elasticity of shale gas production is markedly reduced, because many of the sweet spots in a given play have already been exploited at a price of $4/MBtu and the amount of additional gas that can be economically exploited declines sharply (in other words, the cost of supply curve for shale gas is flat for prices up to $4/MBtu and then becomes increasingly steep). Thus, production trajectories with a rapid ramp-up in the first-half of the *Outlook* period (such as might result from a price rise in the short term, which is sustained through to 2040) typically result in peak output reached before the end of the projection period, as compensating for the rapid decline rates of shale gas wells becomes increasingly more difficult (see also IEA, 2009). Even if the entire resource of a play becomes economic at a given price level, the requirement for rigs, skilled workforce and other supply chain components represents an additional constraint: increasing gas prices spur an expansion in drilling activity, which pushes up supply chain costs. Nevertheless, a near tripling of the price path from $4/MBtu in 2040 to $11/MBtu in 2040 would result in an additional 260 bcm of production per year at the end of the projection period. In short, while shale gas production growth cannot be sustained for long if prices remain significantly below $4/MBtu over the *Outlook* period, a steep increase in prices – from the current lows – does bolster a rapid ramp-up in output growth; but even at high prices production is likely to peak before 2040.

Figure 4.9 ▷ US shale gas production as a function of the price trajectory



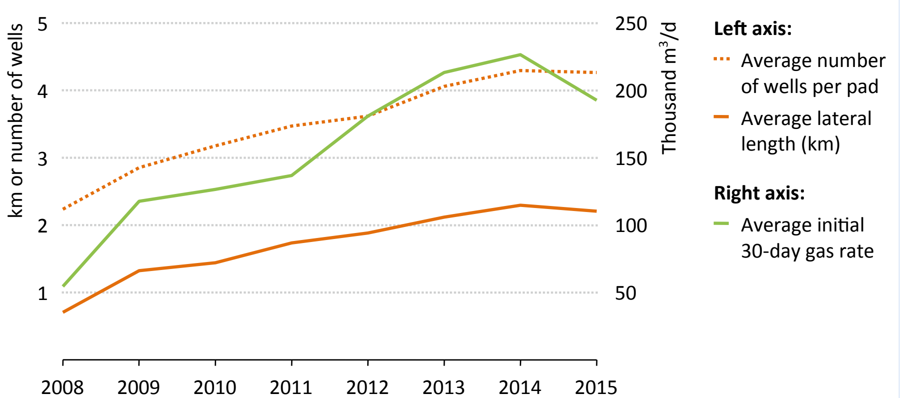
The price elasticity of US shale gas production is high between $2-4/MBtu, but very low for higher prices

Note: Natural gas prices are based on a smooth trajectory from current price levels to the levels assumed in 2040.

Box 4.2 ▷ Shale well productivity gains: endless rise or diminishing returns?

The productivity of a well is expressed in terms of the amount of gas that can be produced from it and the rate at which the gas flows to the surface. While the reservoir quality is the dominant factor in determining well productivity, the design of the well plays an important role too. In terms of design, the productivity of a horizontal hydraulically fractured well is mainly determined by the length and orientation of the horizontal section (or the lateral section) of the well, the number of fracturing stages and the fracture design (choice of pump pressures and volumes, fracturing fluids and proppant type). The lateral length and the number of fracturing stages are the main determinants of cost and there is a trade-off between the additional cost of longer and more extensively fractured wells and the associated productivity gain. For example, operators in the largest shale gas play, the Marcellus, have increased lateral lengths and wells per pad for several years, but more recently the increases are levelling off, suggesting that an economic optimum has been reached at current gas prices and well costs (Figure 4.10). The number of wells on a pad, a proxy for how tightly wells can be spaced in the reservoir, illustrates a trade-off that operators need to make. More wells on a pad increase the total recovery of the volume of gas in place and provide for economies of scale, but if the well spacing becomes too tight, the wells often interfere with and cannibalise each other, resulting in a drop in the flow rate.

Figure 4.10 ▷ Evolution of key well parameters in the Marcellus shale gas play



The average lateral length, number of wells per pad and well productivity in the Marcellus are all levelling off

Several shale gas plays other than the Marcellus show a similar evolution of key parameters, such as lateral lengths and wells per pad, but the effect on productivity is not uniform. This is probably the result of the overriding impact of the quality of the reservoir and the ability to consistently optimise the productivity trade-off. Operators and service companies continue to push the limits of what is technically possible to boost productivity, until the gains and associated costs result in diminishing returns.

Given the significant upside potential for US shale gas resources, how would a larger resource estimate than the one used in the New Policies Scenario affect the gas balance in North America and further afield, especially against the backdrop of a market that is currently awash with gas? Unsurprisingly, a larger resource base alone will not trigger a markedly higher production trend: output growth is set to stall sooner or later for want of gas demand, if market forces or policies do not unlock new opportunities for consumption growth. But suppose for a moment that US shale gas output was higher than in our New Policies Scenario. What would be the ripple effects? Moderately higher US shale gas production levels could be absorbed within North America. A larger resource base – with a higher number of sweet spots – would put downward pressure on US gas prices, encouraging further coal-to-gas switching in the power sector and strengthening the international competitiveness of the domestic industry. Similarly, low cost US shale gas would increasingly find its way across the borders to Mexico and Canada, displacing costlier shale gas development there (IEA, 2016c).

However, exceeding the production levels that could be consumed within North America would also require an expansion of LNG exports, beyond the shipments proposed by the New Policies Scenario. The competitive position of US gas exports is largely determined by the cost of the feed gas, i.e. the domestic natural gas price. Even with an optimistic estimate of resources, US natural gas prices cannot persistently stay at a level that would allow US LNG exporters to beat Russia or Qatar on a cost basis. Similarly, LNG exports from facilities whose capital expenditure is sunk could be offered at prices designed to deter large-scale exports from the United States. A price war could thus defer an expansion of the United States' export growth. Unless additional demand is being unlocked, US exporters may be confined to a strategy of curbing export growth from future LNG projects in Australia, Africa and Southeast Asia once the current oversupply is absorbed. Supplemental US gas exports entering international trade in the early 2020s could have the positive side-effect of reducing volatility at a time when the market is expected to tighten as current overcapacity is being absorbed. From an energy security perspective, a larger role for the United States is desirable, helping various importers to diversify their supply mix (although the importance attached to diversity might also prove a limitation on US exports at higher volumes). There are other non-technical elements that might add to resource uncertainty and might in practice constrain growth of shale gas production. Wide public acceptance is critical for successful expansion of shale gas production, but public opposition has won political backing and fracking bans have been put in place in various parts of the United States (e.g. in New York state), providing a further reason to be cautious about very bullish outlooks for US shale gas.

Production

In the New Policies Scenario, global gas production increases from 3 540 bcm in 2014 to around 5 220 bcm in 2040, an average annual growth rate of 1.5% (Table 4.3). The growth in gas production is dominated by unconventional gas, which ramps up at 3.5% per year, reaching some 1 700 bcm in 2040.

Table 4.3 ▷ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
OECD	**1 109**	**1 270**	**1 409**	**1 434**	**1 485**	**1 558**	**1 618**	**348**	**0.9%**
Americas	765	939	1 046	1 070	1 121	1 187	1 239	300	1.1%
Canada	182	164	156	151	155	184	223	59	1.2%
Mexico	37	45	40	41	42	50	60	15	1.1%
United States	544	729	850	878	923	952	954	226	1.0%
Europe	303	260	220	205	194	184	178	- 82	-1.4%
Norway	53	113	109	98	91	87	85	- 28	-1.1%
Asia Oceania	42	71	143	159	170	186	201	130	4.1%
Australia	33	63	134	152	164	181	197	134	4.5%
Non-OECD	**1 396**	**2 267**	**2 393**	**2 672**	**2 981**	**3 300**	**3 600**	**1 334**	**1.8%**
E. Europe/Eurasia	726	858	879	949	1 020	1 095	1 145	287	1.1%
Azerbaijan	6	19	25	35	43	51	55	36	4.1%
Russia	573	630	636	668	698	730	758	128	0.7%
Turkmenistan	47	80	97	119	142	166	181	101	3.2%
Asia	248	460	494	545	619	686	756	296	1.9%
China	27	130	172	211	255	298	341	211	3.8%
India	28	33	34	41	61	75	89	56	3.9%
Indonesia	70	75	73	84	102	117	130	55	2.1%
Middle East	198	559	613	706	784	865	955	396	2.1%
Iran	59	175	198	238	272	297	316	142	2.3%
Qatar	25	160	166	176	188	209	230	70	1.4%
Saudi Arabia	38	85	99	114	127	138	148	63	2.1%
Africa	124	214	230	282	341	395	447	234	2.9%
Algeria	82	83	84	93	105	111	112	29	1.2%
Mozambique	0	4	5	16	33	50	68	64	11.6%
Nigeria	12	42	42	45	51	62	75	33	2.2%
Latin America	100	176	178	190	218	258	297	121	2.0%
Argentina	41	39	42	51	70	90	106	67	3.9%
Brazil	7	23	27	31	41	61	80	58	5.0%
World	**2 506**	**3 536**	**3 802**	**4 106**	**4 466**	**4 858**	**5 219**	**1 682**	**1.5%**
European Union	264	153	112	102	96	90	84	- 69	-2.3%
Unconventional									
OECD	195	643	845	956	1 041	1 127	1 193	550	2.4%
Non-OECD	12	58	111	184	293	403	511	453	8.7%
World	207	701	956	1 140	1 334	1 530	1 704	1 003	3.5%

* Compound annual average growth rate.

Among the various unconventional gas types, shale gas accounts for two-thirds of the production growth, followed by coalbed methane (19%) and tight gas (11%). The United States, Canada and Australia continue to lead global unconventional gas development over the medium term, but during the 2020s production starts gaining momentum in other unconventional gas resource-rich countries, notably China and Argentina. Although various countries make progress in developing their unconventional resources, especially shale gas, replicating the North American experience is not an easy matter and our unconventional gas production outlook is subject to considerable uncertainty. Conventional gas production, while increasing at a much more moderate pace of 0.8% annually, still accounts for about two-thirds of global gas supply in 2040. As in previous editions of the *World Energy Outlook*, all major regions, except Europe, are projected to increase their gas production.

4.3.3 Regional demand and supply insights

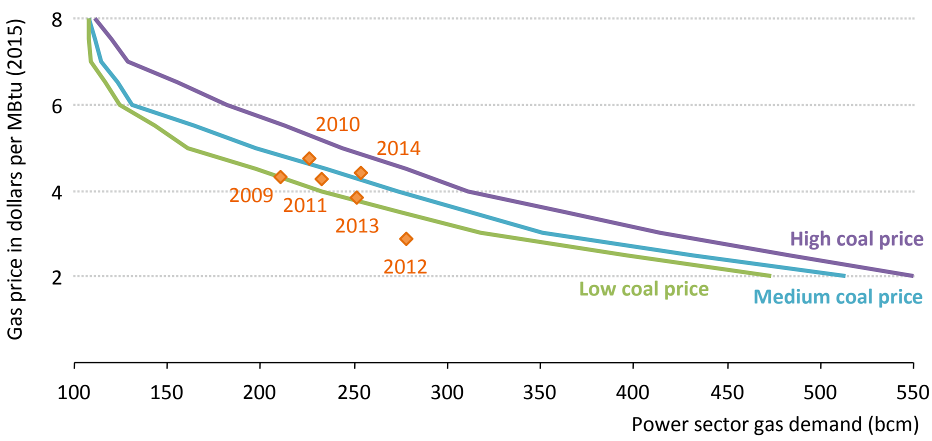
United States

Natural gas demand in the United States increases from just under 760 bcm in 2014 to some 840 bcm in 2040. The annual average growth rate of 0.4% is markedly lower than the global average. Currently one-third of the gas is consumed in the power sector, another third in buildings and over a fifth in industry. Gas consumption jumped in 2015, primarily underpinned by strong growth from the power sector where, for the first time, as much power was generated from gas as from coal. Gas-fired power generation faces headwinds over the medium term: the increase in gas prices to some $4/MBtu in 2020 slightly weakens the competitive position of gas *vis-à-vis* coal and the recent tax credit extensions for wind and solar are stimulating additional deployment of these technologies and thus effectively limiting the growth potential for gas over the medium term. In the long term, gas use in the power sector increases to nearly 290 bcm, up from 250 bcm in 2014 and output from gas power plants reaches 1 480 terawatt-hours (TWh), up 27% from 2014 levels (based on 2015 gas-fired generation estimates, growth to 2040 stands only at 7%).

Price is clearly not the only determining factor in gas-to-coal competition. The Clean Power Plan, which aims to reduce power sector CO_2 emissions by 32% in 2030 (compared with 2005 levels), helps the outlook for gas-fired power generation. However, uncertainties remain: assuming that overall emission reductions targets remain unchanged, faster deployment of renewables increases the CO_2 budget available for power generation from fossil fuels and thus reduces the need to displace coal in achieving targets (see Chapter 5). Although there is significant potential for fuel switching on a short-term basis, a persistent price-driven shift away from coal in power generation would require gas prices to remain below $3/MBtu for a sustained period of time (Figure 4.11). Yet, our analysis also suggests that such price levels are incompatible with continued growth in shale gas production. The coal and gas price trajectories of the New Policies Scenario make the United States one of the few regions where coal-to-gas switching is underpinned by economics. However, the rate at which gas grows in power generation remains sensitive to policy developments, both to back out coal and to support renewables.

The structurally lower natural gas prices in the United States lead to a change in the global landscape of gas-based chemicals production: underpinned by low feedstock prices, basic chemicals production in the United States increases strongly over the medium term (including the re-location of petrochemical industries from other parts of the world). In the coming five years, the US chemical industry accounts for over a quarter of the worldwide increase in feedstock use. The United States also sees one of the strongest increases in natural gas use in transport, with an additional 30 bcm consumed in road transport (mainly heavy-duty vehicles) over the *Outlook* period.

Figure 4.11 ▷ US power sector gas demand as a function of the coal price



The potential for fuel switching is large for prices below $3/MBtu, but this is also where shale gas production is very elastic

Notes: Orange diamonds represent historical price-demand combinations for the past six years. Low coal price corresponds to $50/tonne on average, medium coal price to $55/tonne and high coal price to $60/tonne.

The United States' gas output reaches more than 950 bcm in 2040, over 30% higher than in 2014. Our upward revision of the estimated shale gas resource to 22 tcm results in a more upbeat production trend (in 2040 US gas production is nearly 100 bcm higher than in *WEO-2015*). Shale gas production continues to increase rapidly over the coming years but then tapers off at some 660-670 bcm after 2030. The long-term plateau in shale gas production is largely compensated by increasing production of tight gas resulting in continued growth of the country's unconventional gas production throughout the projection period. Conventional gas production continues its decline through the mid-2025s but then stabilises between 90 bcm and 100 bcm for the rest of the projection period. The strong growth in unconventional gas production affects the country's trade position in two important ways: first, it underpins a rapid ramp-up in US exports of LNG over the medium term, the conditions for which (in terms of infrastructure investments) were established over the last few years. Second, the ample availability of relatively cheap US natural gas dampens the prospects of investment into shale gas production in Canada and Mexico, with the result that production growth in the two countries picks up only in the latter half of the projection period. The low gas prices seen over the past few years have spurred cross-border pipeline development to Mexico, which enable growing pipeline exports to

Mexico within the medium term. For Canada, the US shale gas boom implies a continued decline of its pipeline exports to the United States. The combination of these factors leads to the much anticipated switch in the net trade position of the United States, within the medium term, from a net importer of gas to a net exporter, with major implications for international gas trade. US net exports reach 70 bcm in the mid-2020s and then increase further to 110 bcm in 2040.

Russia

Russia should be well placed to take advantage of the world's rising needs for gas. The country has vast gas resources, low production costs and more than 100 bcm of spare production capacity since the new production facilities in the remote Yamal Peninsula came on stream; but, in practice, the problems facing the Russian gas industry are no less impressive than the size of its resources. Domestic consumption is plateauing; gas already accounts for more than half of Russian primary energy demand and even modest efficiency gains in the power sector, industry and buildings will be sufficient to keep future growth in check. In our projections, gas demand for power falls by some 20 bcm over the projection period, while total consumption stays flat at around 450 bcm.

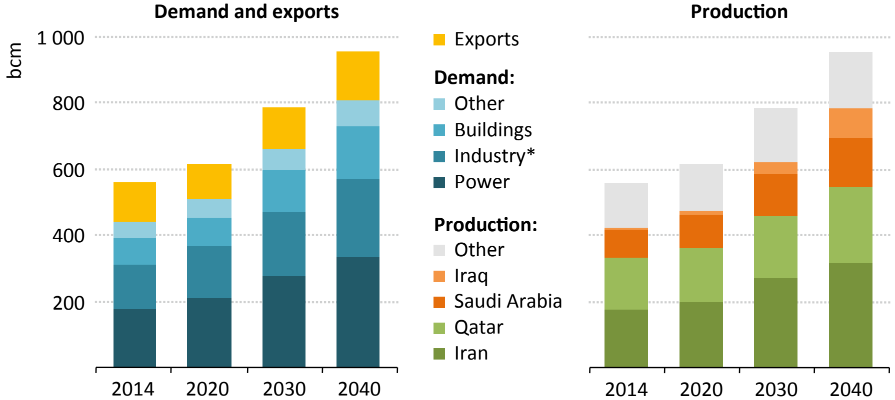
Pipeline infrastructure ties Russian export opportunities at present to the vagaries of gas demand in Europe, but the opportunities there have been constrained. Ukraine, hitherto one of the largest buyers of Russian gas (some 40 bcm as recently as 2011), has cut direct imports of Russian gas to a minimum (but receives a growing volume of Russian gas through the backdoor via its western neighbours). Falling European production has been outpaced by the drop in gas demand in the European Union, meaning that the region's import needs have not grown as Russia anticipated. At least for the medium term, Russia also faces strong competition in European markets from a well-supplied LNG market in which Europe is becoming the "buyer of last resort" for excess LNG volumes. We anticipate that, under these circumstances, Gazprom makes efforts to defend its market share in Europe and Russia's total exports rise back above 200 bcm by the end of the decade. While this would mark an increase over 2014 – a year that saw exports dropping to less than 180 bcm – it would not exceed the levels seen in other recent years.

The key longer term challenge for the Russian gas industry is to unlock new export markets through the development of gas fields and the provision of pipelines to Asian markets, as well as LNG terminals that can provide Russia with more options in its export strategy. These upstream and infrastructure projects, which require huge upfront investments, need to be developed against the backdrop of lower revenue from oil and gas exports (due to the drop in fuel prices), international sanctions and considerable uncertainty about demand growth, especially in Asia. In our projections, these new export arteries take time to develop but – starting with Novatek's Yamal LNG project and then the Power of Siberia pipeline to China – they begin to lift the infrastructure constraint from the early 2020s. As a result, Russia's net exports increase to over 300 bcm in 2040, with the contribution from LNG rising from 8% today (the Sakhalin LNG project) to over 20% in 2040.

Middle East

The Middle East region as a whole holds nearly 40% of global proven gas reserves. The region is diverse but its countries share a common challenge in our *Outlook*: policy-makers need to find ways to address above-ground risks (e.g. institutional and regulatory barriers) to ensure that a gas-rich region does not fall short of gas supply and cross-border pipeline projects advance. This is not an easy matter, as gas demand is projected to surge by some 360 bcm (only Chinese gas demand grows by more) in the period to 2040 (Figure 4.12). The power sector leads the demand growth, with an additional 150 bcm of gas burn. Power generation from gas plants grows two-and-a-half times and the share of gas in the region's power mix increases to nearly 70%, while the share of oil tumbles (from more than a third in 2014 to just over 10% in 2040). This trend is partially underpinned by the region's growing freshwater needs which lead to a surge in seawater desalination in gas-fired plants that combine power generation with freshwater production (see Chapter 9). Industrial gas use grows by over 100 bcm, with over 35% of this coming from the non energy-intensive industries where switching away from oil is (similar to the trends in power generation), a major driving force.

Figure 4.12 ▷ Natural gas demand by sector and supply by country in the Middle East in the New Policies Scenario



The region's role as a net exporter hinges on the ability of key producers to expand output

* Industry includes gas used as petrochemical feedstocks and energy consumption in blast furnaces.

Over the period to 2040, natural gas demand growth in the Middle East continues to be underpinned by the availability of gas at subsidised prices, despite some recent progress in phasing out subsidies in various countries. For instance, energy pricing reforms in Saudi Arabia, Oman and Bahrain have led to a jump in natural gas prices in these three countries (albeit from a very low level). Countries in the Middle East face a trade-off between politically unpopular gas price increases (the business model of a multitude of industrial consumers is built on low cost gas supply) and the lack of incentive to develop new upstream projects at low prices. Oman – the second-largest LNG exporter in the region – is a good example: the country has recently deferred LNG shipments to Asia and started cutting back on contracted volumes, as production cannot keep up with runaway domestic gas demand.

The Middle East has the resource potential to significantly increase its gas production, underpinning our projection that the region adds some 400 bcm per year to the global gas balance over the period to 2040 (the region's gas production is on a par with that of the United States at the end of the *Outlook* period). Whether the conditions above ground allow for such an expansion is an open question: security concerns and political considerations could continue to constrain investment, as could a shortage of investment capital so long as international hydrocarbon prices and domestic gas prices remain low.

In our projections, Iran contributes most to the region's growth in production, accounting for around one-third of the incremental output. The lifting of the main international sanctions earlier this year provided more of a boost to oil output than to gas (gas projects at Iran's huge South Pars field were slowed, but not halted, during the period of sanctions and have steadily lifted national gas output). Iranian production is projected to increase by some 25 bcm per year over the next five years and another 120 bcm thereafter, as investment in new projects gathers pace. Alongside domestic needs and some exports within the Middle East, Iran's pipeline connections outside the region are assumed to be reinforced with a new link to Pakistan and expanded export to Turkey. Iraq sees the second-largest increase in gas production in the region, with output reaching over 85 bcm in 2040, up from less than 10 bcm in 2014. Above-ground risks and barriers push the surge in the country's gas production back into the second-half of the *Outlook* period. Gas investment has recently gained momentum in Saudi Arabia with the Wasit project starting production this year and Saudi Aramco signing off on the $13 billion Fadhili gas project. Saudi Arabian gas production increases by nearly 65 bcm to some 150 bcm in 2040. However, Qatar remains the primary source of the region's exports: if not for Qatar the Middle East's trade surplus would dwindle. Based on the assumption that the moratorium on further expansion of the North Field is lifted by the mid-2020s, Qatar's gas production increases by 70 bcm over the period; the additional gas is almost entirely geared towards exports. Total net exports from the Middle East increase from just under 120 bcm in 2014 to around 145 bcm in 2040.

China

China becomes a central player in global natural gas markets in the New Policies Scenario, even though gas still constitutes only 12% of the country's primary energy mix by 2040. No other country's gas consumption or imports grow by more, in absolute terms, than that of China over the *Outloo*k period. Chinese gas consumption tops 600 bcm in 2040, some 415 bcm higher than today's levels. Demand in the power sector grows by a factor of five, reaching 170 bcm at the end of the projection period. Gas takes on various roles in the power system, as a source of peaking power and flexibility in an increasingly renewables-rich system, as well as a less polluting alternative to coal-burn in densely populated urban areas. Efforts to simplify and deregulate natural gas prices are underway and this helps to improve the fuel's competitive position over the medium term, particularly against oil products. But the share of gas in the country's power mix stays well below 10%, highlighting that imported gas appears, in the Chinese context, to be an expensive way to satisfy electricity demand.

With 225 bcm of natural gas use in 2040, up from 65 bcm today, the industry sector in China exhibits the largest absolute growth of all sectors and accounts for nearly 40% of the country's incremental gas use over the *Outlook* period. While economic growth is the principal determinant of gas demand growth in the industry sector, China is one of the few countries where significant scope remains for gas to displace coal in industrial use. Gas makes inroads especially in the non energy-intensive industry (textiles, machinery etc.) where coal use in smaller industrial boilers is still common today, contributing significantly to China's air quality problems. Nearly 80 bcm out of an additional 105 bcm of gas used in the non energy-intensive industries over the *Outlook* period can be attributed to fuel switching (mainly from coal, to a lesser degree from oil). Gas demand in buildings increases by over 85 bcm (around 20% of total demand growth) between 2014 and 2040. Expanding the distribution grid in the China's northern and north-eastern provinces is a policy priority that underpins the strong growth in gas-based heating in households. China's transportation sector sees demand growth of more than 25 bcm over the period, reaching nearly 45 bcm in 2040.

China's gas production increases by some 210 bcm, standing at 340 bcm in 2040. Conventional gas output is on a rising trend, but is set to reach a plateau in the early 2020s, at around 100 bcm. As discussed in detail in *WEO-2015*, the potential for unconventional gas production is large in China but comes with considerable uncertainty.[3] The New Policies Scenario sees an increase in unconventional gas output of 215 bcm in China over the projection period – growth that is only topped by the United States – but the number pales in comparison with the huge resource estimates. Shale gas is the main contributor to enhanced production with output expanding by 90 bcm, followed by coalbed methane at nearly 45 bcm, tight gas and coal-to-gas at around 40 bcm.

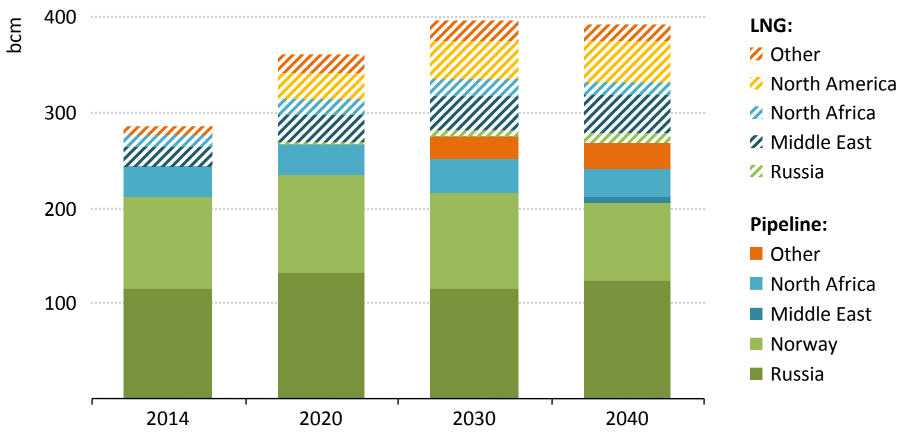
Gas exporters around the world place their hopes on a surge in Chinese imports to absorb the current overcapacity. We project Chinese net imports of gas to increase by some 210 bcm through 2040, with 120 bcm of import growth in the coming ten years alone. Over 70% of the import growth in the period to 2025 is supplied by pipeline, as imports from Turkmenistan and Myanmar are joined by Russian exports through the "Power of Siberia" connection. The long term sees a stronger contribution from LNG to Chinese gas import growth and, by 2040, the share of LNG imports in total net imports reaches a level of nearly 45%.

3. *World Energy Outlook-2017* will feature an in-depth and comprehensive assessment of China's energy prospects.

European Union

Natural gas consumption in the European Union recovers somewhat, to over 450 bcm in 2040 from 418 bcm in 2014, but consumption stays well below the historical demand peak reached in 2010. The bulk of the growth comes from the power sector: the EU targets a cut in greenhouse-gas emissions by 40% (compared with 1990 levels) in 2030, which creates room for gas use to expand as coal plants retire. Our projections indicate the need for more than 170 gigawatts (GW) of new gas-fired capacity in the European Union over the next 25 years. Whether the design of Europe's power market offers sufficient incentive for this capacity to be built is an important uncertainty. The rise in renewables has pushed current wholesale electricity prices down below the levels that would allow gas plants to run at adequately high load factors (various gas plants have been mothballed in recent years), let alone the levels that trigger new investment.

Figure 4.13 ▷ Natural gas imports in the European Union by exporter and transport mode in the New Policies Scenario



EU gas imports grow, but supplier diversity increases not least due to a boost in LNG trade

With domestic gas production in decline – we project a drop of 45% over the *Outlook* period – the region's net-gas imports grow to some 380 bcm in 2040. As the world's largest gas-importing region, security of supply has always been a key concern of European policy-makers. Dependency on Russian exports has been the main focus of the debate. The projections in the New Policies Scenario suggest that Russia is set to remain the largest single supplier of gas to the EU. However, despite growth in absolute terms in gas imports from Russia, the share of Russia in EU imports drops from 43% today to 35% in 2040. A decline in Norwegian volumes (due to depletion of large fields) is compensated for by imports from a wide range of other suppliers including LNG from Qatar, the United States, Canada and various African exporters (Figure 4.13). The boost in LNG imports is facilitated by a well-developed gas infrastructure (much existing regasification capacity is currently underutilised) and a well-functioning internal gas market. By 2040, the share of pipeline imports has dropped from nearly 90% in 2014 to two-thirds. With Middle Eastern and Caspian countries – most notably Azerbaijan – looking for ways to supply Europe along the southern corridor, supplier diversity in terms of pipeline imports is also on the rise.

Other countries/regions

4

The Caspian region holds large resources of relatively low cost gas, but bringing this to markets is not a straightforward task for these landlocked countries. Output growth over the period to 2040 is projected to remain constrained by infrastructure rather than by shortage of resources or economic considerations. The region nevertheless adds 150 bcm to the global gas balance by 2040. Turkmenistan accounts for two-thirds of the incremental production; this is largely due to further development of the super-giant Galkynysh field and expansion of the large-scale pipeline interconnections to China (these reach a combined capacity of 85 bcm once the fourth line, Line D, is assumed to start operation in the mid-2020s). Turkmenistan continues to seek other outlets for gas supply, especially now that exports to Russia – the country's traditional market – have dried up. But progress with other pipeline projects, to the south (Afghanistan-Pakistan-India) or to the west (feeding the southern corridor to Europe) faces significant political and commercial challenges. Of the various additional options for Turkmenistan, we cautiously expect some Turkmen gas to find its way to new markets: if new dedicated projects across Afghanistan or across the Caspian Sea prove impossible, then another approach would be to expand Turkmenistan's exports to Iran, thereby freeing up additional gas in Iran's balance for export to Turkey or Pakistan. To the west of the Caspian Sea, Azerbaijan seizes the opportunity to place growing volumes of gas on the European market via the corridor through Turkey and southeast Europe, underpinning a growth in the country's production by 35 bcm (most of it after 2020) to 55 bcm in 2040.

Natural gas demand in India increases nearly four-fold, reaching around 190 bcm in 2040. Around half of the growth in demand comes from power generation, where gas remains – despite the strong growth – a minor element in the mix, with only one-out-of-ten megawatt-hours generated by gas plants in 2040. The recently announced gas pricing reforms strengthen the incentives for upstream gas developments, yet much of India's conventional gas production comes from complex offshore projects and is projected to take time to develop (IEA, 2015). Similarly, unconventional gas production takes time to materialise. A boost to India's gas production is therefore not to be expected before the mid-2020s. In the long term, gas production in India rises to some 90 bcm. These volumes are insufficient to meet demand, requiring imports to rise to 100 bcm in 2040. The bulk of these imports are set to come in the form of LNG but we see potential for pipeline imports from the late 2020s, despite considerable political and commercial obstacles.

Gas production in Southeast Asia declines moderately through the early 2020s, but picks up in the latter half of the 2020s, when price levels justify the development of some complex fields, so that production reaches nearly 250 bcm in 2040 (up from just over 220 bcm in

2014). Malaysia – with 70 bcm of output, the second-largest producer in the region – sees its output steadily fall to around 50 bcm by 2040, as declines from existing fields are only partially offset by the development of new resources. In the long term, hopes for growth in the region's output rest on new fields in Indonesia to propel gas output upwards with the development of new fields. The biggest prospect is the East Natuna project (Asia's largest untapped gas field), but it is expensive and technically challenging, due to the high CO_2 content of the field. Key contributions to Indonesia's output growth also come from the "Indonesia Deepwater Development" project and development of the country's significant coalbed methane resources. More than offsetting declines in mature fields, the various new projects bring production to 130 bcm in Indonesia in 2040. Despite growing exports from Indonesia the region as a whole becomes a net importer of natural gas in the mid-2030s as Southeast Asian gas demand increases by 40%.

The emergence of new players shapes the natural gas production outlook for Africa. Tanzania and Mozambique, both exploiting East Africa's offshore resources, join the incumbent producers, Nigeria, Algeria, Angola and Egypt, to double the continent's gas output in the period to 2040. The production trend roughly follows two phases. A first phase of moderate growth extends into the early 2020s, primarily spurred by the ramp-up of the newly discovered Zohr field in Egypt. This is followed by a rapid growth phase that sees the take-off of various LNG projects off the coast in East Africa and the advent of unconventional gas production in Algeria. From the 2030s onward, Mozambique and Tanzania dominate production growth, together accounting for more than 35% of the continent's additional annual gas production of 235 bcm over the *Outlook* period. Africa is not short of outlets for its gas: the continent's own gas needs are growing rapidly and exports also increase to over 130 bcm, of which over three-quarters come in the form of LNG.

Australia has seen an unprecedented wave of LNG development in the past couple of years, which, when all plants are operational, will enable it to overtake Qatar as the largest global exporter of LNG around 2020. The industry has been suffering from a double whammy of huge cost-overruns and project completion right at a time of gas oversupply. With the drop in gas prices, Australian LNG development has lost steam (for instance, since 2014, Shell has cancelled its Arrow LNG project, Woodside has further postponed a final investment decision on Browse Floating-LNG and BHP Billiton has lowered the priority of its Scarborough project) and we expect the industry to take a cautious approach to new investments. Despite individual projects still coming to fruition over the projection period, the country does not experience another LNG boom over the *Outlook* period, with capital expenditure concentrated on brownfield expansion. This is reflected in the production trend: Australian gas production grows by 135 bcm in the coming 25 years (mostly export-oriented) but 55% of this growth occurs over the next five years.

Natural gas demand in Canada increases from around 105 bcm today to 165 bcm in 2040, a remarkable growth rate of 1.7% per year (the volumetric demand growth is only around 25 bcm less than that of the United States over the period). Nearly 30% of the additional demand comes from the power sector, backing out coal: gas more than doubles its share in the country's power generation mix to over 20%. With an additional 12 bcm, a significant amount of additional gas demand comes from the oil and gas industry itself: increasing amounts of gas are consumed in the steam-assisted gravity drainage process used for the extraction of oil from oil sands in western Canada. Gas production is relatively flat through the mid-2020s, when conventional production bottoms out and shale gas production becomes the main driver of the production trend. Production increases to almost 225 bcm in 2040. With declining pipeline exports to the United States, Canada's net exports decline until around 2030 (market conditions have taken a toll on export prospects from the west coast, e.g. recently Shell suspended its Canada LNG project indefinitely) when a wave of new LNG projects ramps up and propels net exports to some 60 bcm in 2040. In light of the LNG oversupply, the key challenge remains the development of the costly long-distance pipelines from producing areas to the coast, which includes finding a compromise with the First Nations about pipelines crossing their territories.

Focus: Is the Dead Cow going to bring Argentina's gas outlook to life? [4]

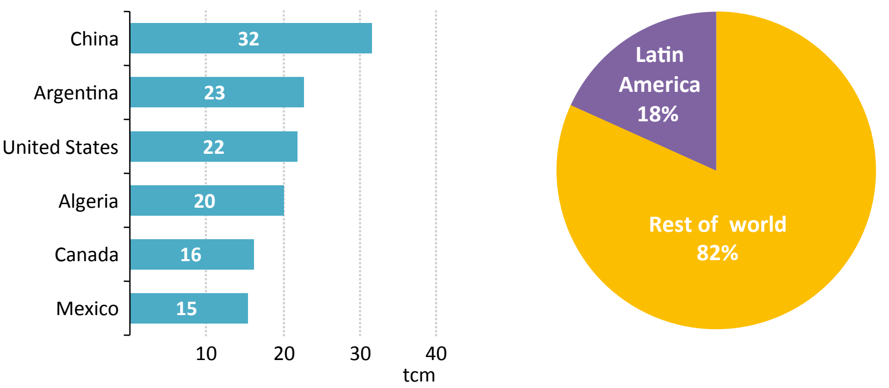
Latin America holds significant natural gas resources, estimated at some 83 tcm, of which two-thirds are unconventional resources. The largest resource-holder is Argentina: according to the US Energy Information Administration, Argentina is second only to China (and above the United States) in the size of its recoverable shale gas resource (Figure 4.14). Within Argentina, the most promising area is the Neuquén basin, and in particular the *Vaca Muerta* (Dead Cow) play, which has huge potential both as a source of tight oil and of shale gas. It is a relatively new play: the first shale gas well that was hydraulically fractured was completed in 2010, but activity did not really pick up until 2013, when YPF, Argentina's state-controlled oil and gas company, began a more intensive programme of appraisal and development. In total, around 600 wells have been drilled thus far, the majority of these by YPF, although several international majors (ExxonMobil, Chevron, Shell) and some smaller independent and Argentinian operators are also stepping up their presence. Most of the initial wells drilled were vertical, but larger scale drilling of horizontal wells with hydraulic fracturing began in late 2014 and, by the end of 2015, around 10% of the producing wells were horizontal – a sign that the engineers were becoming increasingly confident about their knowledge of the reservoir and the location of some of the more productive areas. Shale gas currently accounts for less than 1% of Argentina's 39 bcm of annual production, but some early signs of a shift in momentum are apparent.

Our long-term assessment of Argentina's shale gas production is relatively upbeat, but it will take time for unconventional gas production to take-off. The size and apparent quality of the resource base is a critical factor for our long-term view: much remains to be discovered about the unconventional potential of the Vaca Muerta, but the information available thus far suggests that it bears comparison with some of the best performing US plays,

4. This analysis is drawn in part from the proceedings of the 4th IEA Unconventional Gas Forum, held in Buenos Aires on 21 April 2016.

such as the Eagle Ford in south Texas.[5] The province is sparsely populated, limiting the risk of disruption to existing communities, yet not too remote. There is reasonable access to water from the Neuquén and Limay Rivers, as well as Lake Nahuel-Huapi. Moreover, the basin has a long pedigree in conventional oil and gas (now in decline), and so has pipeline and other infrastructure already in place, alongside a well-established upstream and services industry. In addition, there is a strong policy rationale and an increasingly favourable regulatory environment for Argentina to develop these resources. Gas accounts for half of Argentina's primary energy demand but, despite its resource wealth, the country became a net-gas importer in 2008 – by pipeline from Bolivia and via two regasification terminals for LNG – and policy is focussed on turning this trend around. The desire to bring in new investment has brought forward changes in the upstream, including a fixed \$7.5/MBtu wellhead price for domestic shale and tight gas, as well as broader shifts that have reduced the barriers to trade and financing.

Figure 4.14 ▷ Main shale gas resource-holders and Latin America's share in global shale gas resources, end-2015



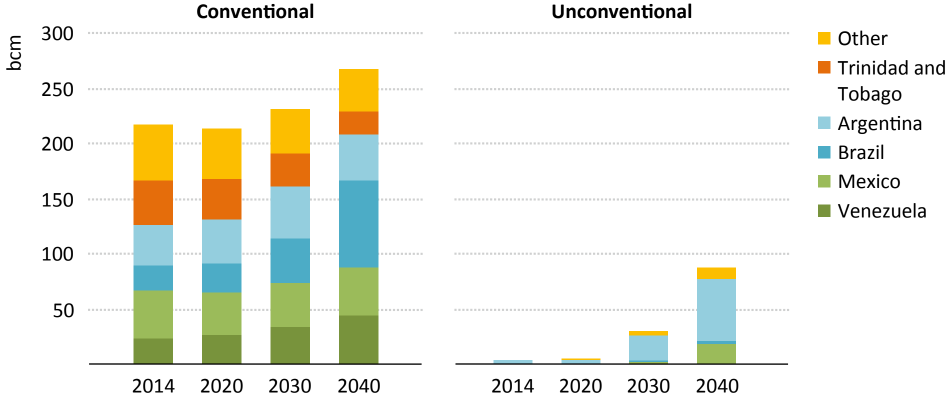
Argentina is estimated to have the second-largest shale gas resource in the world

On the other hand, current market conditions provide a ready alternative source of gas in the form of imported LNG, while the low price environment has taken a toll on capital availability for upstream spending by YPF and others. And there are other limitations and uncertainties. One immediate issue is the relatively weak supply chain for equipment, services and logistics; strengthening this chain will take time and a critical mass of upstream activity (the latter depending, in turn, on the availability of competitively priced services and supplies). For the moment, this still means the costs of production are relatively high: average costs are around \$11 million for a typical horizontal well, but drilling and

5. For example, well depths in the Vaca Muerta and the Eagle Ford are similar (2 000-3 000 metres); the strata containing economically producible hydrocarbons, the "net pay", is around 40-60 metres thick in the Eagle Ford, but 70-100 metres in the Vaca Muerta (which is why vertical wells can still be profitable in some areas); indicators such as total organic content, pressure and clay content are in comparable ranges.

completion costs are still well above those in the United States. More upstream players will be needed to spur the culture of innovation and learning-by-doing that has driven down costs and unlocked the potential of the US plays. Over the longer term, uncertainty over future policies and regulation also clouds the outlook for Argentina, given the country's history of government intervention in the oil and gas sectors. And, last but far from least, the prospect of rapid population growth in the resource-rich areas and the need to develop a tailored permitting and compliance regime raise questions about the social and environmental aspects of unconventional resource development and the administrative capacity to handle it. As we have argued elsewhere (IEA, 2012), public authorities need to anticipate future strains on infrastructure and regulatory capacity and take advance action to alleviate them, or they run the risk of losing public confidence when problems occur.

Figure 4.15 ▷ Natural gas production by country and gas type in South America and Mexico in the New Policies Scenario



Shale gas in Argentina provides a major boost to South America's gas production

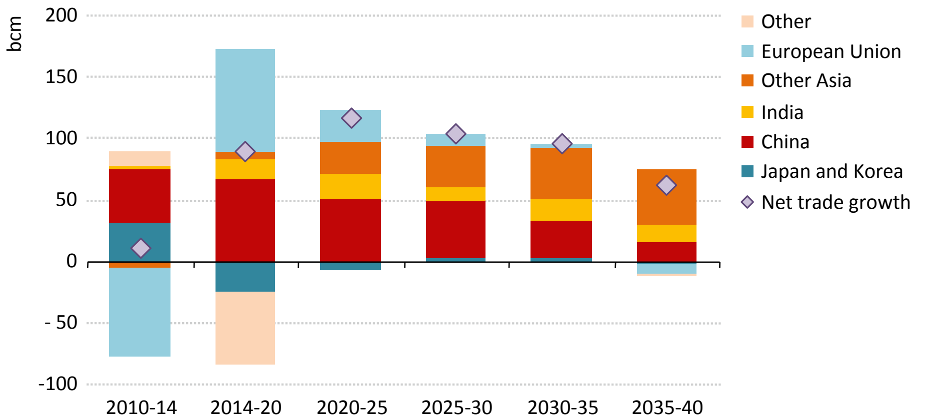
Despite the many hurdles to be overcome, Argentina is the only country in South America in our projections that succeeds in mobilising unconventional gas at scale, although Mexico also starts developing its large resources towards the end of the projection period. In Mexico's case, the proximity of a large and intensively developed resource in the United States and the construction of large new cross-border pipeline capacity postpones the time at which indigenous resource development becomes commercially attractive: shale gas output starts to pick up only around 2030 and reaches some 15 bcm in 2040.[6] The big ramp-up in Argentina's shale output is projected to start a little earlier, in the mid-2020s, and reaches over 40 bcm by 2040. It provides a major boost to overall South American gas output: between 2025 and 2040, unconventional gas is responsible for 60% of the rise in regional gas production (Figure 4.15).

6. A special country focus *Mexico Energy Outlook: World Energy Outlook Special Report* considers unconventional prospects in Mexico in more detail. Available at: *www.worldenergyoutlook.org/mexico*.

4.3.4 Trade[7]

Inter-regional gas trade has increased by 70% over the past 25 years and is projected to rise another 70% over the *Outlook* period. By 2040, over 1 100 bcm of gas are traded between regions – some 460 bcm more than in 2014; 45% of the additional trade is set to materialise over the next ten years, promising a very dynamic period for importers and exporters alike (Table 4.4). This time frame sees a gas market in flux: LNG over capacity is gradually absorbed, new players enter the stage, long-established market mechanisms are gradually overthrown and gas prices rebound as the market rebalances. At the same time the gas industry faces a major challenge as it needs to cushion the transition from structural oversupply to a market in balance. This implies that the industry – due to long-lead times – needs to mobilise fresh capital to develop new projects at a time when it just comes off a major bust phase.

Figure 4.16 ▷ Change in gas imports by region in the New Policies Scenario

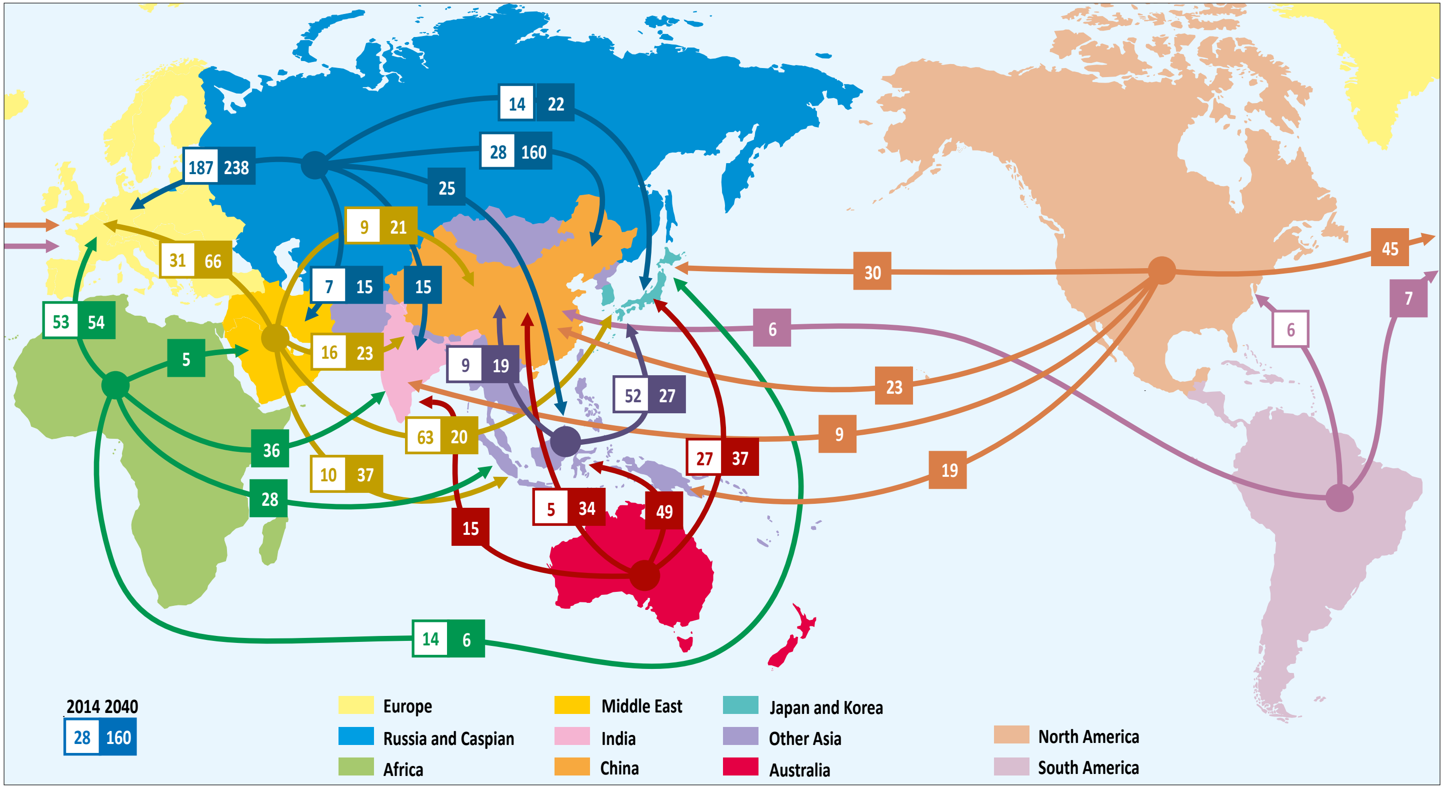


Asia is the engine for incremental gas imports with growth opportunities being limited elsewhere after the mid-2020s

Import growth in Asia – China, India, Pakistan and various other countries – provides not only a home for currently uncontracted LNG but also a pointer for the long-term evolution of trade (Figure 4.16). Over the medium term, the partial recovery of gas demand in the European Union leads to a temporary surge in the region's gas import growth, even though much of this upswing serves only to reverse the marked decline seen between 2010 and 2014. From the early 2020s, European import growth is robust and contributes – together with strong growth in Asian gas import demand – to exceptionally rapid trade growth in that period. Our projections suggest that, around 2025, the current surplus in LNG capacity has by-and-large disappeared.

7. 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.

Figure 4.17 ▷ Selected global gas trade flows in the New Policies Scenario (bcm)



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 strong import growth in Asia underpins a fundamental shift in trade flows away from the Atlantic basin to the Asia-Pacific region

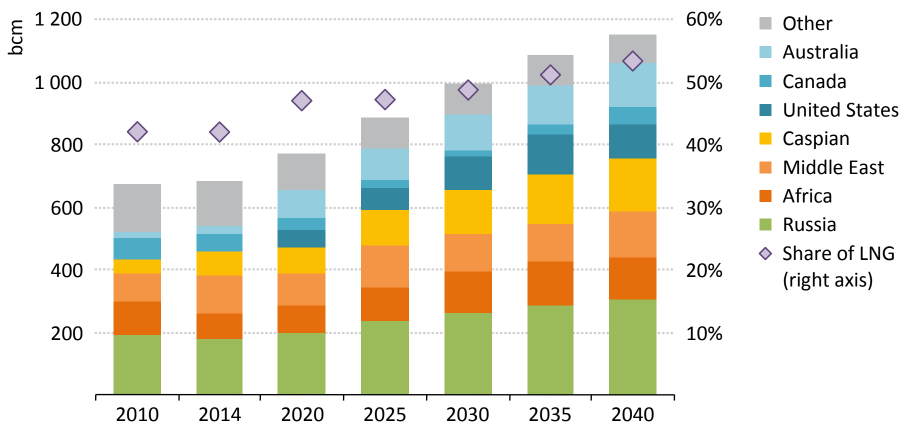
The concentration of import growth in Asia continues to redraw the inter-regional gas trade map, underpinning a fundamental shift in trade flows away from the Atlantic basin to the Asia-Pacific region (Figure 4.17). Large pipeline projects come online over the *Outlook* period in Asia, for instance the connections between Russia and China, the reinforcement of China's connection to Turkmenistan and lines linking South Asia with the gas fields in the Middle East and the Caspian region. However, in a market awash with LNG, capital-intensive and complex pipeline projects find it hard to garner support; this encompasses both the financial and political dimension. Various pipeline projects have recently seen their timeline reassessed, for instance the Eastern and Western Siberian pipelines connecting Russia and China. The former does not reach peak capacity before the mid-2020s and the latter is not expected to come into service before the mid-2030s in our projections. As a result, LNG manages to capture the bulk of import demand growth and sees its share in inter-regional gas trade increase from 42% in 2014 to 53% in 2040 (Figure 4.18). The growth in global LNG trade also benefits from increasing deployment of floating storage and regasification technology (FSRU), which helps to unlock smaller gas markets (Box 4.3). Bangladesh is a good example: the potential for gas demand growth is large, but it starts from a low base. A pipeline project would be economically prohibitive, as the volumes are too small to achieve the economies of scale needed to keep the costs in check. FSRU technology can help to create pockets of growth in countries that were not in the focus of LNG exporters until recently.

Table 4.4 ▷ Natural gas trade by region in the New Policies Scenario

Net importing regions in 2040	Net imports (bcm)			As a share of demand		
	2014	2025	2040	2014	2025	2040
European Union	-265	-374	-379	63%	79%	82%
China	-58	-176	-268	31%	45%	44%
Japan and Korea	-174	-144	-147	98%	98%	99%
India	-18	-54	-100	35%	57%	53%
Other Asia	-4	-29	-88	5%	28%	54%
Southeast Asia	56	24	-27	25%	11%	10%
Other Europe	8	0	-25	6%	0%	16%
Net exporting regions in 2040	**Net exports (bcm)**			**As a share of production**		
	2014	2025	2040	2014	2025	2040
Russia	178	235	307	28%	35%	40%
Caspian	79	108	168	40%	43%	49%
Middle East	117	134	145	21%	19%	15%
Australia	25	100	136	36%	64%	68%
North America	1	58	127	0%	5%	10%
Sub-Saharan Africa	29	47	79	49%	51%	38%
North Africa	53	64	54	35%	34%	23%
South America	8	7	18	5%	4%	6%

Notes: Positive numbers denote net exports and negative numbers denote net imports. Import and export totals should sum to zero; the difference in 2014 is due to stock changes.

Figure 4.18 ▷ Global gas trade by exporter in the New Policies Scenario



New exporters boost supplier diversity and underpin a gradual increase in the share of LNG in global gas trade

The boost in LNG trade is accompanied by a shift in pricing and trade mechanisms. In the United States, 75 bcm of LNG export capacity – more than half of the liquefaction capacity under construction globally as of mid-2016 – is set to gradually become operational over the medium term, bringing total US LNG export capacity to 90 bcm in 2020. Although LNG exports expand rapidly, reaching around 55 bcm in the early 2020s, the US export infrastructure clearly does not operate at full capacity. The market share of the United States in global LNG trade peaks at around 19% in the mid-2030s and then declines gradually as US unconventional gas production growth loses steam. The main contribution that US LNG exports make to the international gas trade is flexibility, rather than volume, as US LNG exports are free from destination clauses (a destination clause restricts the buyer's rights to resell an LNG cargo). Moreover, LNG exports extend the influence of the US gas market on the formation of regional gas prices. Towards the end of the *Outlook* period, the cost of liquefying additional gas from the United States and shipping it to Asia or Europe provides an effective price-ceiling in these regions. Consequently, by 2040, the differentials between the gas price in Europe or Asia and the price in the United States largely reflect the cost of bringing US gas to these markets. Gas trade flows also become increasingly responsive to cost and price differences, with exporters targeting the import markets with the best netbacks (i.e. the value of the gas in a potential market, less the cost of getting the gas there).

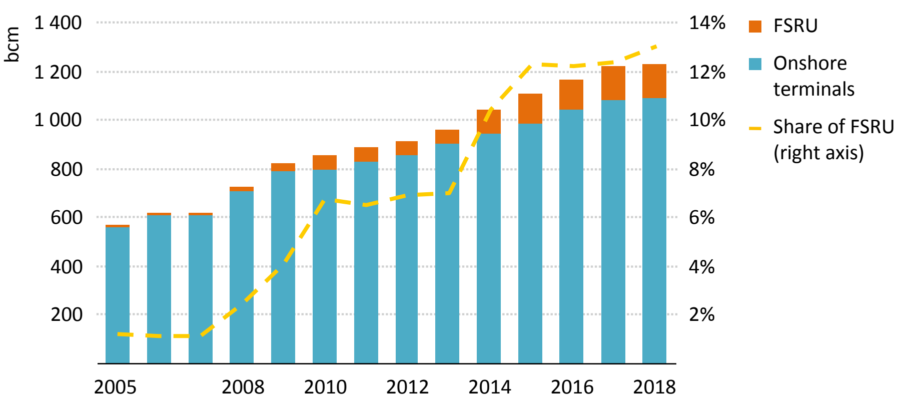
These developments on the supplier's side are complemented by initiatives from consumers to overturn some of the trade paradigms that were established when the LNG trade was a seller's market. The slump in gas prices and the growing volumes of uncontracted LNG have shifted bargaining power to the demand side. Large Asian LNG importers – Japanese stakeholders at the forefront – have started to seize this opportunity to revisit some of the contract terms that restrict the flexibility of the LNG trade. For instance, Japan's Ministry of Economy, Trade and Industry is pursuing a strategy to increase the flexibility of the LNG market and to establish an LNG trading hub in the country (others, most notably Singapore and China, are also pushing for gas trading hubs in their countries). Major elements of Japan's strategy are a reduction of oil-indexation in gas pricing, the removal of destination clauses, shorter contract duration and an increase in spot trading. Japan's Fair Trade Commission has reportedly launched a preliminary investigation as to whether destination clauses are anti-competitive. If this gains momentum, other importing countries could follow suit, giving a boost to the flexibility and liquidity of the LNG trade. Our gas trade trends and price trajectories allow for significant progress in increasing flexibility, but there remain numerous contractual, institutional and infrastructure barriers that prevent the gas market from functioning like any other commodity market (see Chapter 1).

New exporters reshape the global gas market in different phases, starting with Australia and the United States. These two countries are later joined by Turkmenistan and Canada ramping up their exports. The advent of Mozambique and Tanzania as major LNG exporters completes an increasingly diverse image of the global gas trade landscape. Well-established base suppliers like Russia and the Middle East complement this development by expanding into new markets. Russian producers unlock the huge Chinese market and make inroads into the LNG business, while producers in the Middle East substantially expand their stake in the European market and gain a foothold in South Asia. This rapid increase in the range of suppliers helps alleviate concerns about security of supply.

Box 4.3 ▷ How floating storage and regasification unlocks new markets

While floating LNG liquefaction units are only now coming of age, floating storage and regasification units (FSRUs) have been in operation for about ten years and their deployment continues to grow rapidly (Figure 4.19). The number of units operating and under construction currently exceeds 20 worldwide. These floating units are either purpose-built vessels or converted LNG carriers. They have a number of advantages over onshore terminals: FSRUs can be built faster and require a lower upfront capital expenditure than onshore terminals. Lengthy permitting processes and land acquisition, which can delay the commissioning of onshore terminals, are usually by-passed through the use of FSRUs. This technology therefore caters well to emerging gas markets in developing countries, where financing can be a serious constraint. The scalability of the units also allows the import infrastructure to grow in lockstep with the distribution network. The main disadvantage of FSRUs is their relatively small size (typically between 4-8 bcm), which makes them less suited for countries with a large and steady LNG demand. However, floating terminals are still an attractive technology for countries that want to increase flexibility (e.g. to meet seasonal demand swings) or diversify their gas import options. In 2015, Egypt, Jordan and Pakistan started importing LNG deploying FSRUs while Uruguay and Colombia will join the club of LNG importers soon by using FSRU. In our *Outlook,* FSRU technology is an important enabler for gas demand growth in various smaller LNG markets in Africa, Latin America and developing Asia. FSRUs become increasingly influential in the medium term: their relatively short construction times allow for a quick ramp-up of LNG imports in times of low gas prices, thus gradually increasing the price responsiveness of gas consumption.

Figure 4.19 ▷ Global regasification capacity by technology



Floating storage and regasification terminals grow in significance

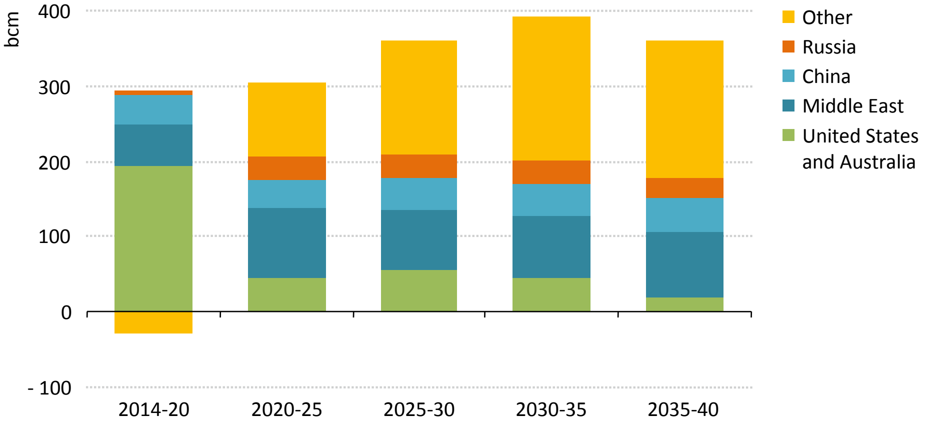
Sources: IEA analysis; Cedigaz (2016).

4.3.5 Investment

The United States and Australia dominate worldwide production growth over the medium term, but US shale gas production growth is likely to slow considerably and the slump in investment activity in Australia over the coming years results in subdued output growth in the period between 2020 and 2025. With the Middle East and China exhibiting relatively stable growth over the *Outlook* period, the draw on incremental production from a number of other suppliers is rising. From the early 2020s onwards, increasing volumes are needed from a set of countries that actually see their combined output decline over the medium term, such as Algeria, Indonesia, India, Mexico or Canada (Figure 4.20). In the 2020 to 2025 period, their contribution to incremental global production amounts to over 30%; a share that increases further to over 50% between 2035 and 2040. The global gas balance thus increasingly relies on producers and exporters that are either new or need to reverse their medium-term production trends, suggesting a formidable investment challenge.

Failure to invest and ramp-up production in these countries could arguably be compensated for by additional gas from Russia – the country holds significant spare production capacity – yet this would come at the expense of bolstering Russia's bargaining power over gas prices. Additional Russian gas exports, primarily to Europe, could free up LNG that would meet gas demand elsewhere. Such a shift in international gas trade, together with a higher supplier concentration, however, would be associated with upward pressure on global gas prices and uneasiness about Russian import dependency in Europe.

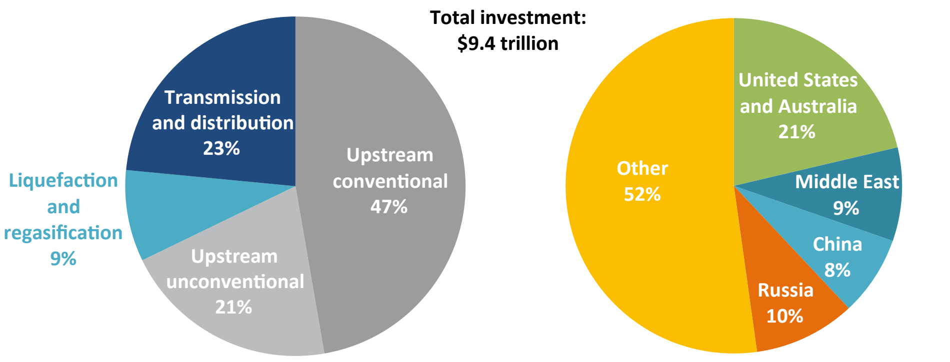
Figure 4.20 ▷ Change in gas production by selected region in the New Policies Scenario



Soon, a rising share of gas production growth will need to come from countries whose combined output falls in the medium term

The bulk of the projects that are needed to meet global gas demand in the long term are not economically feasible under current gas price levels. This is one of the factors that push prices higher in all regions as the gas market rebalances, but it is also a clear indicator that gas producers need to reduce their costs. With the long list of project slippage, shelving and postponements in mind, the key question is whether the transition from an over supplied market to a balanced market can be smooth. Timely investment in upstream projects and infrastructure is critical to this objective. The challenge also needs to be seen in the context of LNG over capacity gradually being absorbed over the next ten years – our modelling suggests that inter-regional gas trade has largely rebalanced by the mid-2020s. To achieve this, and provide for subsequent demand growth, investment decisions on upstream projects and LNG facilities will have to be taken much sooner. Some projects with long-lead times, such as greenfield developments may have to be sanctioned before 2020 while brownfield projects would need to go ahead at the beginning of the next decade. Moreover, these investment decisions would need to be taken at a time when the principles of international gas trade are undergoing considerable change: investors regularly claim that oil-indexation, long-term contracts and other trade rules (e.g. take-or-pay terms) provide the certainty required for financing capital-intensive upstream and infrastructure projects. Whether a gas market in flux can deliver timely investments is yet to be seen and constitutes one of the major uncertainties that accompany our *Outlook*. Failure to do so carries the risk that gas could come to be perceived as an unreliable and insecure source of energy, compromising its long-term interests.

Figure 4.21 ▷ Cumulative global gas investment by component and key region in the New Policies Scenario, 2016-2040 ($2015 billion)



Global gas supply investment over the Outlook period shows a high proportion of infrastructure investment

Note: Investment values for upstream natural gas require making assumptions about the capital cost of associated gas relative to non-associated gas, as well as how investments for natural gas liquids are shared between oil and natural gas.

Some $9.4 trillion of investment is needed in global gas supply over the *Outlook* period. The regional distribution of capital expenditure by-and-large reflects the trends in production growth, with more than half of the cumulative investment needed over the period in those countries that lead gas production growth after 2025 (Figure 4.21). The large upstream capital expenditure cuts that many oil and gas companies have implemented in 2015 and 2016 would need to be reversed, at least in part, in order to meet the supply requirements of the New Policies Scenario.

Coal market outlook

A rock in a hard place?

Highlights

- Global coal demand fell in 2015 for the first time since the late 1990s. In the New Policies Scenario the world's coal use grows by 0.2% per year in the period to 2040 – a stark contrast to the annual decline of 2.6% in the 450 Scenario, which outlines a deeper decarbonisation. Spurred by climate policies, high-income economies like the European Union or the United States slash coal demand by over 60% and 40% respectively in the New Policies Scenario. In India and Southeast Asia, excluding a low-cost fuel from their options to meet surging energy demand is a much less easy choice to make; these countries become the drivers of future coal demand growth.

- Measures to combat air pollution, to shift away from heavy industries and to diversify the power mix are re-shaping China's coal use. Our central scenario implies that coal demand in China, accounting for half the world's coal use, peaked in 2013 and is set to fall a further 13% to 2040. Coal's share in China's energy mix drops from two-thirds in 2014 to 45% in 2040. Industry leads the decline, with coal use dropping by nearly a quarter through 2040. Coal use in the Chinese power sector peaks around 2030 and ends up 5% lower than in 2014.

- The share of global steel produced in coal-intensive basic oxygen furnaces drops from 75% in 2014 to just over half in 2040, underpinning a 15% decline in coking coal use in that period. The global trend is mainly caused by a steep drop in China's coking coal demand and production as demand in other major steel producing countries continues to grow (e.g. India or Brazil). As these countries mainly rely on imports, coking coal trade grows by 0.4% per year, despite demand having peaked.

- Low prices – the result of over-capacity – have taken a toll on the profitability of the industry: companies producing nearly half of the US coal are currently under bankruptcy protection, while 80% of coal firms in China incurred losses in 2015. China successfully embarked on a 1 billion tonne capacity reduction, which has put upward pressure on coal prices in recent months. The New Policies Scenario sees the market rebalance by the early 2020s, accompanied by a continued rebound of coal prices. Australia remains the largest coal exporter, followed by Indonesia.

- Chinese imports are volatile over the medium term, but the long-term fundamentals point to a drop in imports of 85% over the *Outlook* period, resulting in a slump in global coal trade until the late 2020s. By then, robust import growth in India and Southeast Asia lifts trade volumes above current levels. However, Indian policy-makers are firm in expressing their intention to reduce coal imports and China's net trade position is sensitive to the vicissitudes of its domestic market, which could make China again a net exporter of coal. Either of these key uncertainties has the potential to leave the global coal market over-supplied for much longer.

5.1 Recent market and policy developments

The first decade of this century looked like the return of King Coal. Global coal demand growth – primarily underpinned by China and India – averaged 4.7% per year between 2000 and 2010 (in comparison, oil demand grew by 1.2% and natural gas demand by 2.8% over the same period). Coal's share in global primary energy use grew from 23% in 2000 to 28% in 2010 and stands at 29% today. Coal use in the power sector grew strongly and, with a 41% share of global electricity generation, coal is the backbone of many power systems around the world today. But the boom is over: global coal demand declined in 2015 for the first time since the late 1990s.

Coal demand in China stalled in 2014 and is estimated to have dropped by some 3% in 2015 as a result of China's transition: having established the largest heavy industry in the world, China now prioritises the expansion of its services sector. The transformation is well underway, with crude steel and cement production in China having peaked in 2014. In the United States, low natural gas prices have spurred a surge in gas-fired power generation at the expense of coal: for the first time in history, the United States generated as much power from gas as from coal in 2015.

After four consecutive years of falling prices, a rebalancing process is emerging with prices increasing since early 2016, mainly as a result of capacity cuts in China, but the prolonged price slump has left deep scars on the coal industry. Some 80% of China's coal producers incurred losses in 2015. The situation has not been much better in the United States where, over the last three years, nearly fifty coal firms – accounting for half of the country's coal output – have filed for bankruptcy protection. Though recent price increases hold promise of slightly better times, the profitability of the coal industry in various countries is yet to be re-established. Reducing excess capacity is still a key challenge for Chinese, American and some export-oriented coal producers.

Future prospects, though improving, are not rosy. The 21st Conference of the Parties (COP21) that took place in December 2015 concluded with an agreement that the increase in global temperatures should be limited to well below 2 °C in 2100. In preparation for COP21, more than 180 countries submitted pledges on how they intend to reduce or limit their greenhouse-gas emissions. While the degree of ambition varies between countries and implementation is yet to progress, only abated coal is compatible with the long-term commitment.

In light of recent market and policy developments it is unclear whether coal supply and demand will make a major comeback, level off or enter terminal long-term decline. From a demand-side perspective, the key uncertainty lies with the determination of governments to rigorously implement climate and environmental policies. In this context, coal's future in the global energy mix may be increasingly tied to the technical and economic feasibility of carbon capture and storage (CCS) as well as its public acceptance. From a supply-side perspective the key question is how and when supply and demand might be brought back into balance, establishing a price level that sustainably restores the profitability of the coal industry and one that is sufficient to stimulate the necessary investments in the long run.

5.2 Trends to 2040 by scenario

5.2.1 Medium-term dynamics

The coming five years see further capacity cuts – politically administered, market-driven or as a result of depletion – but in light of stagnating demand, these are expected to be inadequate to fully absorb the over-capacity in the market. The medium-term outlook (i.e. the period to the end of the decade) is thus characterised by a sustained disequilibrium between coal supply and demand. Nevertheless, the medium-term policy and market dynamics are setting the course for the long-term trends with mining capacity reduction continuing to show effects by the early 2020s, paralleled by a further increase in international coal prices by some 10-15% over the 2015 average prices.

By 2020, global coal demand is projected to have rebounded to 2014 levels. This is a result of growth in India and Southeast Asia, which more than offsets declining coal demand in the European Union, the United States and China. International steam coal trade declined in 2014 and 2015. With Chinese imports decreasing and Indian imports tapering off, the next few years see a further decline in the volume of internationally traded steam coal. Although global coking coal demand has peaked, according to our *Outlook*, coking coal trade exhibits robust growth. This comes as the decline in demand – primarily in China – hits domestic production of coking coal harder than trade. Moreover, other large steel producing countries, like India and Brazil, have growing import requirements.

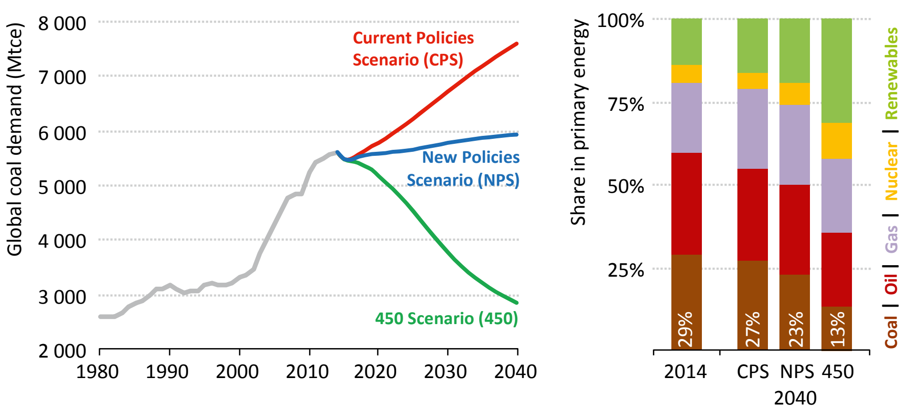
Investment activity remains sluggish over the next few years. The main exception is India where large new mines are being opened and substantial amounts of capital are being spent to expand coal-related infrastructure. Elsewhere, capital expenditure is likely to be concentrated on sustaining production in existing operations, with only a few, low unit cost expansion projects receiving a final investment decision. Outside India, new greenfield projects are unlikely to be initiated over the medium term, but considerable sums are spent on projects that are underway and too advanced to abandon.

5.2.2 Long-term scenarios

The New Policies Scenario, the central scenario in this *World Energy Outlook* (*WEO*), incorporates all policies and measures that are in place today, while taking into account, in full or in part, the aims, targets and intentions that have been announced, even if these are not fully implemented. Announced policy measures are diverse – they range from fostering energy efficiency, combatting air pollution, alleviating energy poverty, supporting low-carbon fuels to placing a price on carbon-dioxide (CO_2) emissions – and they all have wide-ranging implications for future coal markets.

In the New Policies Scenario, the policy, macroeconomic and demographic assumptions lead to coal consumption growth of 0.2% per year between 2014 and 2040, a stark deceleration compared to the annual growth rate of 2.4% observed over the past 25 years. This trend reflects, in particular, the falling cost of renewable energy resources and the climate pledges (Nationally Determined Contributions) that countries tabled at COP21. Our projections in this scenario suggest that the economic and policy headwinds facing coal are not strong enough, for the moment, to send global coal demand into actual decline, but the share of coal in global primary energy supply nevertheless falls markedly from 29% in 2014 to 23% in 2040 (Figure 5.1). Coal, currently only topped by oil in terms of its share in primary energy supply, falls to third after being overtaken by natural gas in the late 2030s. Growth in demand and depletion of coal deposits together mean capital expenditure of $1.1 trillion is needed in mines and supply infrastructure over the *Outlook* period.

Figure 5.1 ▹ Global coal demand and share of coal in world primary energy demand by scenario



Coal use and coal's share in primary energy is sensitive to the level of climate action

Notes: Mtce = million tonnes of coal equivalent.[1]

The Current Policies Scenario which assumes no new measures beyond those adopted today, sees coal demand expanding at a faster rate of 1.2% per year to 2040 (when coal demand is 30% higher than in the New Policies Scenario). This is a world without the impetus of many of the policy changes implied by the pledges made at COP21. Coal's share in primary energy demand drops only slightly, to 27% in 2040, with coal remaining the second-largest provider of primary energy after oil. Decarbonisation of the electricity system moves at a slower pace in this scenario, with coal retaining its leading position as fuel for power generation in 2040: 36% of the world's electricity is generated from coal in this scenario, well ahead of renewables (29%) or gas (24%). However, the Current Policies Scenario shares with the New Policies Scenario the feature that growth in coal use is concentrated in Asian developing countries. Decarbonisation efforts are already deeply engrained in many high-income countries' energy policies, leading to a fall in coal demand in all major OECD coal-consuming countries such as the European Union, the United States and Japan. Cumulative

1. A tonne of coal equivalent equals 7 million kilocalories (kcal) or 0.7 tonnes of oil equivalent. In practice, traded coal rarely reaches such high energy content, but typically falls into a range of 4.5 million kcal to 6.5 million kcal per tonne.

investments into coal supply in this scenario amount to $1.5 trillion, 30% higher than in the New Policies Scenario. Supported by relatively robust demand growth and OECD steam coal import prices (including handling fees at the import port and inland delivery cost) rising to $100/tonne in 2040, the Current Policies Scenario provides the conditions in which coal mining can profitably expand into untapped or under-developed deposits that require capital-intensive infrastructure.

Table 5.1 ▷ World coal demand, production and trade by scenario (Mtce)

			New Policies		Current Policies		450 Scenario	
	2000	2014	2025	2040	2025	2040	2025	2040
Demand	**3 308**	**5 609**	**5 650**	**5 915**	**6 229**	**7 610**	**4 535**	**2 858**
Power generation	2 236	3 440	3 373	3 527	3 871	4 964	2 411	986
Industrial use[2]	857	1 781	1 891	2 082	1 956	2 297	1 770	1 643
Other sectors	216	388	386	306	402	349	353	229
Power generation share	*68%*	*61%*	*60%*	*60%*	*62%*	*65%*	*53%*	*35%*
Production	**3 254**	**5 680**	**5 650**	**5 915**	**6 229**	**7 610**	**4 535**	**2 858**
Steam coal	2 504	4 374	4 392	4 812	4 905	6 356	3 440	2 100
Coking coal	449	1 016	979	861	1 006	929	901	639
Lignite*	301	290	279	242	318	325	195	119
Steam coal share	*77%*	*77%*	*78%*	*81%*	*79%*	*84%*	*76%*	*73%*
Trade**	**471**	**1 083**	**1 062**	**1 120**	**1 228**	**1 514**	**844**	**537**
Steam coal	310	801	767	824	917	1 190	580	320
Coking coal	175	284	306	311	323	340	275	229
Production which is traded	*14%*	*19%*	*19%*	*19%*	*20%*	*20%*	*19%*	*19%*

* 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.

The 450 Scenario sets out an energy pathway consistent with a 50% chance of limiting the global increase in temperature to 2 °C, an objective incompatible with unabated coal use. In this scenario, global coal demand drops sharply, at a rate of 2.6% per year. By 2040, world coal consumption is only half that in the New Policies Scenario and coal's share in primary energy supply has dropped to 13%. In power generation, coal's share drops to 7% in 2040, far behind renewables (58%), nuclear (18%) and gas (16%). By then, 70% of the electricity still generated from coal comes from power plants equipped with CCS (Box 5.1). The drop in steam coal use, primarily in power generation, is much larger than that in coking coal. This is because alternatives to coal use for power generation are widely available, unlike in the steel industry. Nonetheless, by the end of the *Outlook* period, coking coal consumption is a quarter lower than

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.

in the New Policies Scenario. This has important implications for trade: the volume of steam coal trade plummets to 40% of the current level while coking coal trade drops to 80% of the current trade volume. This means that exporters of high quality coking coal, such as Australia, Russia and Canada can sustain a considerable level of export-oriented mining activity, even in the 450 Scenario. The share of global steam coal production that is traded internationally drops, from 18% in 2014 to 15% in 2040. The main reason behind this trend is that by 2040 the majority of the coal used in the power sector is combusted in plants with CCS, which is often best suited to integrated operations that focus on the least-cost deposits near the power stations. The de-globalisation of the steam coal market hits exporters across the board, but those with low production costs and proximity to key importers in developing Asia, are slightly better off than exporters that have large market shares in the Atlantic basin. India, where CCS makes limited inroads in the 450 Scenario, also tends to focus on the exploitation of domestic deposits, meaning that steam coal imports peak around 2030; but the subsequent import decline is less steep than, for example, in China or Japan. In the 450 Scenario, cumulative investments are, unsurprisingly, the lowest in the three *WEO* scenarios. Nevertheless, cumulatively some $730 billion of investments still go into the global supply coal supply chain over the projection period to sustain production in existing mines and to compensate for depletion. Investment is focussed on small incremental projects in well-established mining regions, as the scenario leaves no scope for the development of large greenfield projects in remote basins.

Box 5.1 ▹ The role of CCS in the 450 Scenario

The 450 Scenario in *WEO-2016* relies considerably less than in the past on the deployment of carbon capture and storage, given the slow pace at which CCS projects are being demonstrated and tested. This should not be misinterpreted as a recommendation to reduce spending on CCS research and development. Indeed, the delays in CCS development highlight the need for intensification of the effort to establish the technology's marketability. This is also essential if biomass-based CCS is to be deployed as a means to achieve negative emissions in the latter half of this century in a "well below 2 degrees" scenario (see Chapter 8).

Despite the downward revision, CCS still has an important role to play in the 450 Scenario. In 2040, globally some 430 gigawatts (GW) of power plant are equipped with CCS in this scenario, 60% of which are coal-fired. By 2040, power plants equipped with CCS generate nearly 10% of the world's electricity. Around 75% of the coal-fired power plants using CCS are located in China. This highlights the key role that China is expected to take in advancing the technology in order to decarbonise its energy mix and to protect the value of its power generation assets and coal reserves. China is one of the ten countries that mentioned CCS in its Nationally Determined Contribution, stressing the need to strengthen research and development. The retrofitting of coal plants plays a critical role in China's CCS strategy, as more than 300 GW of Chinese coal plants meet a number of basic criteria for retrofit (IEA, 2016a). The key criterion is access to CO_2 storage, but efficiency, plant size and age are also important parameters for retrofit suitability.

How to effect the transition from over-supply and losses to a financially sound industry that is able to make the necessary new investments is not an easy matter and a common challenge in all our scenarios, whatever level of coal production is predicated. To bring supply and demand back into balance requires a combination of the following factors and conditions (which are all discussed in greater depth in relation to the New Policies Scenario, later in this chapter):

- Market forces stimulating industry consolidation, restructuring and shedding of unprofitable production capacity.
- State interventions to cut coal production capacity in countries with insufficient price responsiveness of supply.
- Supported by the first two factors, a rebound in coal prices in the first half of the projection period.

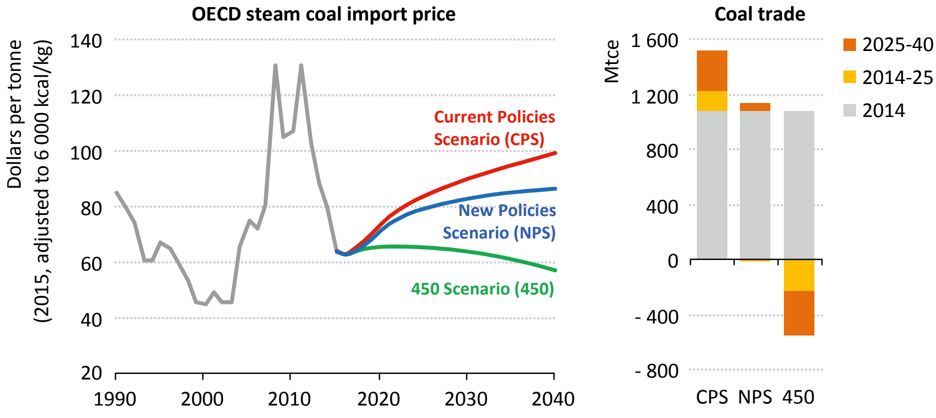
5

In all our scenarios, the coal market is projected to be broadly in balance by the early 2020s. Scenario-specific policy measures and energy demand fundamentals play an important role in determining how this might play out in practice: the 450 Scenario, which shows a sharp decline in demand, relies to a much larger degree on capacity reductions in order to balance the market – obviously, any rigidities that impede capacity from being cut have the potential to significantly prolong the current imbalance. Conversely, strong demand growth as suggested by the Current Policies Scenario reduces the reliance on timely capacity decommissioning as demand growth absorbs some of the over-capacity.

Coal prices face different fortunes in the three scenarios. Both production costs and consumption levels are scenario dependent and with higher consumption, more costly mines are needed to establish a balance between supply and demand, pushing coal prices up and vice versa. The three coal price trajectories broadly follow two phases, a continued rebound in the period to the early 2020s and a long-term evolution that reflects the fundamentals of the respective scenario (Figure 5.2). The rebound in prices is a result of the capacity adjustment process which restores profitability of some of the mines that are currently incurring losses. The price increase over the medium term is more modest in the 450 Scenario, compared to the other two scenarios, as the decline in demand requires an acceleration of mine closures, reducing the call on loss-making mines. The gradual increase in coal prices in the latter half of the period, in the New Policies Scenario and the Current Policies Scenario, reflects worsening geological conditions (primarily affecting mature mining regions), the need to tap remote deposits and increasing input costs (wages, fuel, steel and explosives), due in part to increasing oil prices. In the 450 Scenario, a concentration on the least-cost mines in combination with productivity gains which outweigh cost increases, results in a moderate long-term decline in coal prices. By 2040, the average OECD steam coal import price rises to $100/tonne in the Current Policies Scenario and about $90/tonne in the New Policies Scenario, but falls to under $60/tonne in the 450 Scenario.[3]

3. Unless otherwise stated, values in dollars per tonne are in real terms and adjusted to an energy content of 6 000 kcal/kg (net as received).

Figure 5.2 ▷ Average OECD steam coal import price and global coal trade by scenario



Coal prices rebound in the period to the early 2020s as the market rebalances

5.3 A closer look at the New Policies Scenario

5.3.1 Demand

Growth in global coal consumption is sluggish in the New Policies Scenario, demand reaching 5 915 million tonnes of coal equivalent (Mtce) in 2040, only some 300 Mtce higher than today (Table 5.2). Coal increasingly struggles in a post-COP21 era, with public opposition to coal-fired power plant developments (and mines) on the rise around the world. The average growth rate in demand of 0.2% per year over the period falls behind the rates of growth seen for oil and gas demand, which are 0.4% and 1.5% per year respectively.

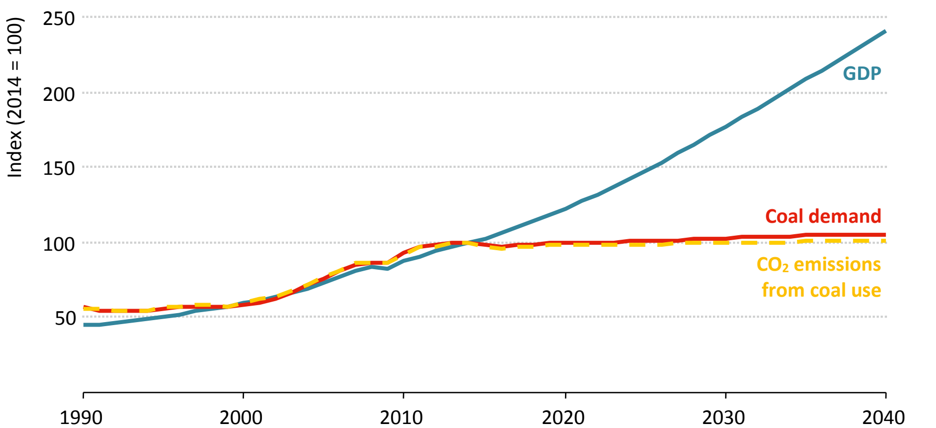
In the past 25 years, coal demand growth has been closely aligned with economic growth, a relationship that is set to be broken over the coming 25 years (Figure 5.3). The outlook for coal demand in high-income countries, such as in the European Union, the United States or Japan, is already almost completely detached from the overall economic outlook in these countries. By contrast, strong growth in incomes and energy needs in South Asia, Southeast Asia and sub-Saharan Africa continues to propel their coal demand higher (with a big contribution coming from steel and cement production, two heavily coal-reliant industries). China's position moves progressively to that of the higher income countries, exerting a strong influence on the global decoupling of coal demand from economic growth. China's economic rebalancing results in a decline of China's coal use over the projection period. With global coal demand growth levelling off, growth in CO_2 emissions from coal combustion stagnates over the *Outlook* period.

Table 5.2 ▷ Coal demand by region in the New Policies Scenario (Mtce)

	2000	2014	2020	2025	2030	2035	2040	2014-2040 Change	2014-2040 CAAGR*
OECD	**1 572**	**1 447**	**1 256**	**1 135**	**1 017**	**908**	**839**	**- 607**	**-2.1%**
Americas	822	672	556	506	463	422	396	- 276	-2.0%
United States	762	617	510	463	429	394	370	- 246	-1.9%
Europe	481	427	364	322	266	217	195	- 232	-3.0%
Asia Oceania	269	347	335	306	288	268	248	- 99	-1.3%
Japan	139	169	158	145	138	129	119	- 51	-1.4%
Non-OECD	**1 736**	**4 162**	**4 324**	**4 516**	**4 753**	**4 950**	**5 075**	**913**	**0.8%**
E. Europe/Eurasia	299	296	295	292	296	301	307	10	0.1%
Russia	171	148	150	152	158	161	162	14	0.3%
Asia	1 282	3 664	3 821	4 000	4 216	4 379	4 458	794	0.8%
China	955	2 896	2 831	2 807	2 786	2 698	2 521	- 374	-0.5%
India	208	540	686	820	985	1 162	1 338	798	3.6%
Southeast Asia	45	142	201	257	313	371	430	288	4.4%
Middle East	2	4	6	8	8	9	9	5	3.0%
Africa	128	160	162	174	186	210	245	84	1.6%
South Africa	117	146	137	134	127	121	117	- 28	-0.8%
Latin America	25	37	39	42	47	52	57	20	1.7%
Brazil	19	25	24	24	25	25	25	0	0.0%
World	**3 308**	**5 609**	**5 580**	**5 650**	**5 771**	**5 858**	**5 915**	**306**	**0.2%**
European Union	459	383	319	277	217	168	142	- 241	-3.7%

* Compound average annual growth rate.

Figure 5.3 ▷ Growth of global GDP, coal demand and CO_2 emissions from coal use in the New Policies Scenario



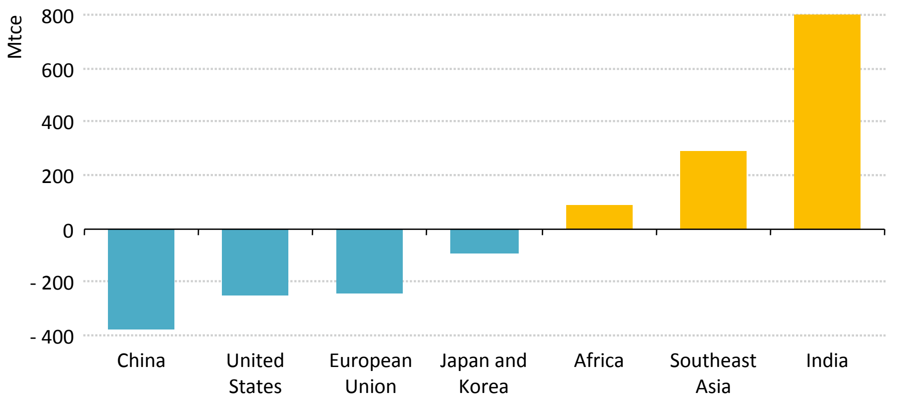
Global coal demand decouples from global GDP, largely due to changes in China

Note: The divergence in growth rates for coal demand and CO_2 emissions from coal use over the period stems from efficiency gains and the uptake of CCS.

Regional trends in demand

As noted, income and stage of economic development are critical determinants of the stance taken on coal in national energy and climate policies. Although competition from gas and renewables is an increasingly important consideration for coal markets, it is more than ever environmental policies that determine the evolution of regional coal demand. Higher income countries tend to have stagnant or slowly-growing coal demand, and can afford to back out coal use. Lower income countries, with fast growing consumption (and, often, large endowments of coal) need to mobilise all potential sources of energy and cannot, for now, afford to forego a relatively low-cost option – even as they pursue others in parallel. This results in a dichotomy of regional demand trends that is unmatched in oil and gas markets and shapes our *Outlook* for the future of coal markets, with far-reaching implications for coal trade.

Figure 5.4 ▷ Change in coal demand by key region in the New Policies Scenario



There are sharp regional contrasts in the way that coal demand changes to 2040

The climate pledges and energy policies brought forward by the European Union, the United States and China – together accounting for 70% of global coal demand – involve a significant reduction in greenhouse-gas (GHG) emissions and strong growth in the deployment of low-carbon technologies for power generation. This policy push fosters a drop in coal demand by 2040 of around 60% in the European Union, 40% in the United States and 15% in China (Figure 5.4). These declines, however, are more than offset by increasing coal demand in other parts of the world, particularly in South Asia, Southeast Asia and Africa. Coal demand in India grows by two-and-a-half times in the period to 2040 and that of Southeast Asia triples. Though many developing countries (including India) proposed at COP21 to increase the share of non-fossil fuels in their respective energy mixes, their coal demand, in absolute terms, grows. Overall, in the New Policies Scenario, coal remains a key pillar in the energy mix of many developing countries, and an integral part of their strategies for economic development and alleviation of energy poverty (1.2 billion people worldwide currently do not have access to electricity). Continued reliance on coal in these countries is often motivated by its abundance and relatively low cost. Other important considerations are the large diversity of coal exporters which minimises potential energy security concerns, and the value of jobs in the coal supply chain. Power generation from coal requires less infrastructure than gas, is technically less sophisticated than nuclear power or variable renewables and has shorter construction times and lower capital investment than, for instance, large hydro plants. Heavy industrial sectors – especially steel-making and cement production – which are robust drivers of coal demand, are typically dominant in the earlier stages of a country's economic development, as they underpin construction activity e.g. for housing and infrastructure.

Sectoral trends in demand

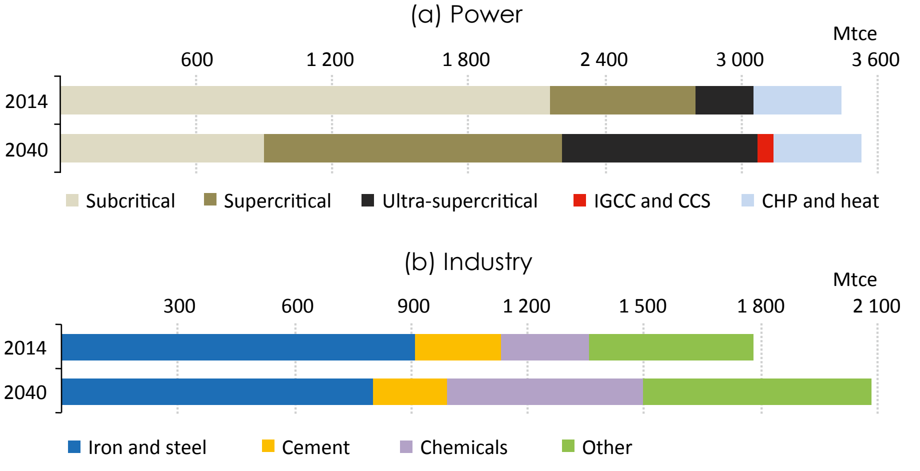
Two sectors, power and industry, are the main coal consumers and the primary sources of growth. Some 60% of the global coal demand comes from the power sector, to generate electricity and heat, a share that stays flat over the period to 2040. The power sector was the main engine for global coal demand growth over the past 25 years but going forward, coal demand growth in the power sector is more subdued than in the industry sector (as there is a wide range of decarbonisation technologies readily available in the power sector). Industrial coal demand constitutes one-third of total coal use today, which increases to 35% in 2040. Coal consumption in the buildings, agriculture and transport sectors diminishes over the period.

Coal demand for power generation increases by 90 Mtce in the period to 2040 and coal-fired generation reaches 10 785 terawatt-hours (TWh) in 2040, up from around 9 700 TWh in 2014; but the share of coal in power generation plummets from 41% in 2014 to 28% in 2040. Coal loses its rank as the number one fuel for power generation to renewables around 2030. Efficiency improvements in the global coal fleet also curb fuel-burn for power generation. The efficiency of the global coal fleet improves by over three percentage points over the period, reaching 44% in 2040. The efficiency gains are underpinned by a shift in boiler technology: today around 70% of the fleet use subcritical technology, a share that drops to 45% in 2040. The New Policies Scenario projects around 400 GW of new supercritical and 330 GW of new ultra-supercritical plant to be built over the next 25 years. As a consequence, the share of power sector coal demand coming from subcritical plants drops from around 70% today to 30% in 2040 (Figure 5.5).

Among the industrial sectors, the iron and steel industry is by far the largest coal consumer, accounting for half of industrial coal consumption in 2014. However, the weight of the iron and steel industry in industrial coal use declines over the *Outlook* period as its share drops to around 40% in 2040, even though global steel production expands by 20% over the same period, reaching nearly 2 000 million tonnes in 2040. The main reason is that the share of steel produced in basic oxygen furnaces (the production route that is preceded by coal-based blast furnaces) drops from three-quarters in 2014 to just over half in 2040, as steel production in electric arc furnaces – spurred by the growing availability of scrap –

ramps up quickly. This fall in steel production from basic oxygen furnaces, in combination with efficiency improvements, results in a decline of some 80 Mtce in coal use in the iron and steel industry over the period (Figure 5.5). This implies that global coking coal demand peaked in 2015 and declines by 15% over the period, falling to 860 Mtce in 2040. Increasing consumption of steam coal in steel production (used for instance as pulverised-coal-injection) also puts further downward pressure on coking coal use.

Figure 5.5 ▷ Global coal demand by key sector in the New Policies Scenario



Plant technology changes the power sector's demand structure, while chemicals are the primary growth engine for coal demand in industry

Notes: IGCC = integrated gasification combined-cycle; CCS = carbon capture and storage; CHP = combined heat and power.

Coal consumption in the chemical industry grows by two-and-a-half times over the *Outlook* period, reaching nearly 530 Mtce in 2040. Some 70% of the growth stems from coal-to-liquids and coal-to-gas transformation (mostly in China), both of which see strong growth rates as oil and natural gas prices increase faster than coal prices over the projection period. Yet, ammonia and urea production from coal also result in some growth in coal demand from the chemical industry. Much of the global growth in coal demand from non energy-intensive industries (e.g. textiles, food and beverage and machinery) arises in India where strong economic growth pushes up coal demand in all industrial sectors.

5.3.2 Supply

Reserves and resources

Coal deposits are abundant and geographically dispersed (Table 5.3). All major regions hold a significant share of the 985 billion tonnes of proven reserves (coal that is known to exist and thought to be economically exploitable with today's technology), a distribution that helps to explain the relative absence of energy security concerns about coal supply. This reserves number is up by 2% from the figure in *WEO-2015*, mainly as a result of slight upward revisions in Turkey, China, India and Indonesia (BGR, 2015). Reserves are often also a reflection of how advanced exploration is in a country or region; the United States, for instance, holds a quarter of the global proven coal reserves whereas Africa holds just over 1%. Significant reserves are also in Russia (16%), China (13%), Australia (11%), India (9%) and the European Union (7%). Resources, which include deposits that are not necessarily exploitable at current prices or with current technology, are more than 20-times larger than reserves.

Table 5.3 ▷ Remaining recoverable coal resources, end-2014 (billion tonnes)

	Coking coal	Steam coal	Lignite	Total resources*	Share of world	Proven reserves	Share of world	R/P ratio**
OECD	**1 676**	**7 303**	**2 317**	**11 297**	**49%**	**459**	**47%**	**227**
Americas	1 036	5 842	1 519	8 396	37%	262	27%	264
Europe	155	330	343	827	4%	83	8%	154
Asia Oceania	485	1 132	456	2 073	9%	115	12%	232
Non-OECD	**1 732**	**7 550**	**2 387**	**11 669**	**51%**	**525**	**53%**	**92**
E. Europe/Eurasia	757	2 254	1 441	4 452	19%	238	24%	390
Asia	920	4 984	920	6 824	30%	260	26%	55
Middle East	19	23	-	41	0%	1	0%	1 256
Africa	34	263	0	297	1%	13	1%	48
Latin America	3	27	25	55	0%	13	1%	131
World* **	**3 408**	**14 853**	**4 705**	**22 966**	**100%**	**985**	**100%**	**127**

* 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 proven reserves would last if production was to continue at current rates. *** Excludes Antarctica.

Sources: IEA analysis; BGR (2015).

Production

Global coal production grows from around 5 700 Mtce in 2014 to 5 915 Mtce in 2040, an annual average rate of 0.2% (Table 5.4). Currently, some 60% of the world's hard coal production comes from underground mines, with the remainder from surface mines. China is the largest coal producer in the world, a ranking that it keeps throughout the projection period. India, currently the fifth-largest producer in energy terms (India is third largest in terms of mass), overtakes the United States to become the second-largest producer in the early 2020s. Steam coal production amounts to 77% of the world's coal output today. This share increases to 81% in 2040, as coking coal production drops from 1 015 Mtce in 2014 to some 860 Mtce. Today, around 55% of global coking coal production occurs in China, but due to the rapid decline of coke-based steel production in China, its share in coking coal production drops to 40% in 2040. Australia is the second-largest coking coal producer, accounting for 17% of global production today and increasing its share to over a quarter in 2040. Lignite – primarily produced in the European Union, Russia, the United States and Australia – accounts for 5% of global coal production. Due to its high carbon intensity, demand for lignite and, hence, its production, declines over the period and accounts for 4% of global coal production in 2040. Following the pattern on the demand side, there are stark regional differences in coal production. By far the largest contribution to global coal production growth comes from India, followed by Indonesia and Australia. Coal production drops amply in the United States, China and the European Union.

Table 5.4 ▷ Coal production by region in the New Policies Scenario (Mtce)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
OECD	**1 381**	**1 395**	**1 205**	**1 116**	**1 055**	**986**	**959**	**- 436**	**-1.4%**
Americas	825	757	611	555	515	464	428	- 329	-2.2%
United States	767	693	561	506	469	425	389	- 303	-2.2%
Europe	311	225	168	132	95	71	62	- 164	-4.9%
Asia Oceania	245	412	427	429	445	450	469	57	0.5%
Australia	235	408	424	427	443	448	467	59	0.5%
Non-OECD	**1 873**	**4 286**	**4 374**	**4 535**	**4 715**	**4 872**	**4 956**	**670**	**0.6%**
E. Europe/Eurasia	319	423	416	422	430	431	431	7	0.1%
Russia	184	271	274	275	282	285	284	13	0.2%
Asia	1 318	3 549	3 647	3 797	3 954	4 097	4 149	600	0.6%
China	1 019	2 699	2 669	2 681	2 683	2 638	2 487	- 212	-0.3%
India	187	362	485	576	682	829	997	635	4.0%
Indonesia	65	389	395	437	480	517	551	162	1.4%
Middle East	1	1	1	1	1	1	1	0	1.0%
Africa	187	224	227	233	248	261	293	69	1.0%
South Africa	181	211	207	202	201	194	194	- 17	-0.3%
Latin America	48	88	84	82	82	82	82	- 6	-0.3%
Colombia	36	82	80	78	78	78	78	- 5	-0.2%
World	**3 254**	**5 680**	**5 580**	**5 650**	**5 771**	**5 858**	**5 915**	**234**	**0.2%**
European Union	307	214	156	120	81	57	47	- 167	-5.6%

* Compound average annual growth rate.

Note: Historical data for the world can differ from demand in Table 5.2, due to stock changes.

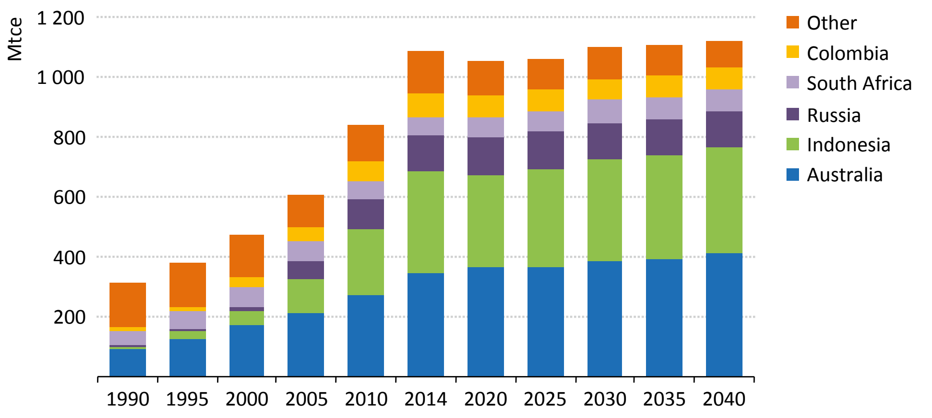
Trade[4]

In the New Policies Scenario coal trade remains in a trough over the medium term before rebounding in the early 2020s and then gradually rising to 1 120 Mtce in 2040, some 40 Mtce above the level in 2014 (Figure 5.6). The global trend is the result of declining demand for

4. 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.

imports in major importing regions – among them a 185 Mtce drop in Chinese imports – in the first-half of the projection period before strong import growth from India and various other developing countries becomes dominant in the latter half of the projection period. The share of international trade in global coal demand remains flat, at just under a fifth through 2040 (Table 5.5). Having become the largest coal importer in 2015, India maintains this position over the period, with shipments increasing by 90% to 340 Mtce in 2040. As imports in China are estimated to have dropped by a quarter in 2015, it falls slightly behind Japan as the third-largest coal importer. Imports in China are volatile over the next few years but continue their declining trend, dropping to around 35 Mtce in 2040. Nevertheless, China's southern coastal region remains pivotal for international coal pricing for a long time, as consumers in the region can arbitrage easily between domestic and international coal supply. With India's rise as a dominant force in international coal trade, India's west coast is set to emerge as a new arbitrage point and price marker similar to the role of China's coastline today.

Figure 5.6 ▷ Global coal trade by exporter in the New Policies Scenario



Global coal trade rebounds to 2014 levels only in the late 2020s, after a long slump

Steam coal dominates international coal trade, accounting for some three-quarters of the shipments, with the remainder taken up by coking coal. Steam coal and coking coal trade follow different patterns. Steam coal trade more closely follows the global demand trend, i.e. a decline over the medium term, with a rebound in the longer term. Two key steam coal importers – China and India – gradually decrease their import dependency over the projection period, resulting in an annual average growth rate of steam coal trade of 0.1%, considerably behind the rise of 0.4% per year observed in global steam coal demand. In contrast, coking coal trade expands by 0.4% per year despite global coking demand having peaked and declining by 0.6% annually. Much of the reason for coking coal trade growing while global coking coal demand falls relates to coking coal's relative scarcity, which favours trade. Outside China (which produces most of its coking coal needs domestically), coking coal demand increases by around 100 Mtce through to 2040. The bulk of the additional demand comes from countries that have limited endowments of coal suitable for steel production, such as India, Brazil, Southeast Asia and parts of Africa. This benefits exporters that hold large deposits of coking coal, like Australia, Russia, Canada and, increasingly, Mozambique. By 2040, 36% of the coking coal used worldwide in steel production is traded internationally, up from 29% in 2014.

Table 5.5 ▷ Coal trade by region in the New Policies Scenario

	2014		2025		2040		2014-2040
	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Change (Mtce)
OECD	**- 63**	**4%**	**- 19**	**2%**	**119**	**12%**	**182**
Americas	80	11%	49	9%	32	7%	- 48
United States	73	10%	43	9%	19	5%	- 54
Europe	- 208	49%	- 190	59%	- 133	68%	- 75
Asia Oceania	65	16%	123	29%	220	47%	155
Australia	347	85%	368	86%	410	88%	64
Japan	- 169	100%	- 145	100%	- 119	100%	- 51
Non-OECD	**91**	**2%**	**19**	**0%**	**- 119**	**2%**	**- 210**
E. Europe/Eurasia	122	29%	129	31%	124	29%	2
Russia	120	44%	123	45%	122	43%	2
Asia	- 140	4%	- 203	5%	- 309	7%	169
China	- 218	8%	- 127	5%	- 34	1%	- 184
India	- 181	33%	- 244	30%	- 341	25%	160
Indonesia	337	87%	327	75%	354	64%	17
Middle East	- 3	79%	- 7	86%	- 8	87%	5
Africa	60	27%	59	26%	49	17%	- 12
South Africa	65	31%	68	34%	76	39%	11
Latin America	52	59%	39	48%	25	30%	- 27
Colombia	77	93%	71	91%	67	87%	- 9
World**	**1 083**	**19%**	**1 062**	**19%**	**1 120**	**19%**	**37**
European Union	- 175	46%	- 157	57%	- 95	67%	- 80

* Production in net-exporting regions. ** Total net exports for all *WEO* regions, not including intra-regional trade.

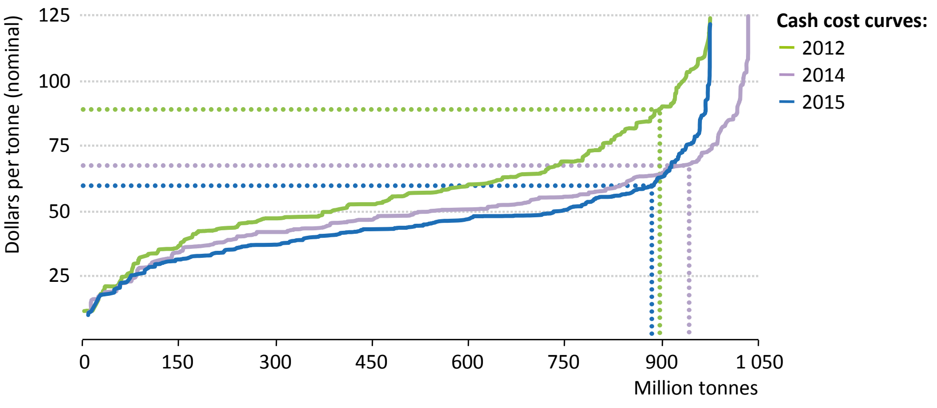
Notes: Positive numbers denote net exports and negative numbers denote net imports of coking and steam coal. OECD and non-OECD trade should sum to zero; the difference in 2014 is due to stock changes.

Costs and industry structure

The coal industry differs from the oil and gas industry to the extent that capital expenditure for exploration and development is modest and the bulk of the cost on the production side accrues in the form of operational expenses (often termed cash costs or variable costs). The variable cost of production (i.e. the cost of mining, upgrading, handling and transportation) – expenses which can be avoided by closing an operation – constitutes a price threshold below which an operation should cease production and shut down.[5] For older and fully amortised mines, generating a revenue that covers the variable costs is often sufficient to warrant continued operation, while mines that still need to recover their capital expenditure ideally require prices which exceed variable costs by a couple of dollars. No rule is without exceptions: large projects that target untapped deposits and require new infrastructure may need a substantial margin to breakeven, but such projects typically also benefit from lower mining costs.

The variable costs of the mines around the 90th percentile of the cash-cost curve are typically a reasonable indicator of the marginal costs of internationally traded coal (based on the principle that the variable cost of the last mine needed to satisfy demand determines the price). Marginal costs (excluding sea freight rates) dropped from $90/tonne in 2012 to just under $70/tonne in 2014 and then to $60/tonne in 2015 (Figure 5.7). In 2012, price setting mines had a margin of between $3-10/tonne (depending on which market they were targeting) to cover sea freight rates and fixed costs. This margin became negative by a few dollars in 2015, meaning that marginal exporters were unable to cover their costs.

Figure 5.7 ▷ FOB cash costs and market volume for global seaborne steam coal trade



Coal prices and FOB cash costs for internationally traded steam coal have decreased markedly between 2012 and 2015

Notes: Dotted lines represent seaborne steam coal trade volume and corresponding marginal FOB (free on board) cash costs. FOB cash costs include: mining costs; costs of coal washing and preparation; inland transport; mine overhead; and port charges. While standard definitions of cash costs often exclude royalties and taxes, they are included here. Seaborne shipping costs and capital cost are excluded.

Sources: IEA analysis; Wood Mackenzie databases.

5. Some variable costs can be avoided immediately by stopping production (e.g. fuel or explosives) while avoiding others, such as labour cost, may take longer. In most countries, transportation costs are a variable cost component, but where take-or-pay contracts are used, for instance in Australia, they effectively are a fixed cost component.

SPOTLIGHT

Could cutthroat competition prolong the coal industry crisis?

The global coal market is suffering from excess capacity and low prices. Although many mines have been idled or closed, the effect on markets has been more than offset by expanding production from lower cost producers which effectively impeded the market from finding its way back to balance. Prices bottomed out in early 2016 and have recovered since then but, given the dire financial situation of many coal companies in late 2015, the price recovery has only just started to lift producers out of the red. The majority of Chinese coal firms still remain unprofitable and the future of the fifty US coal companies that are under bankruptcy protection is uncertain. Producers targeting the international market are now largely covering their cash costs, but profit margins remain slim (with the exception of coking coal).

The answers as to why coal companies keep on churning out coal despite losing money are many. Much has to do with the cost structure of the industry in which the bulk of the costs are variable rather than fixed. As long as prices exceed the variable costs, operating assets contribute to service liabilities or take-or-pay obligations. Additional debt, unless lenders pull out, can keep companies going for a long time, despite increasing the companies' liabilities and thus worsening the situation. Another part of the answer lies with market expectations. Like other extractive industries, the coal industry is used to business cycles with extended boom-and-bust periods. Many company executives believe that current losses will be more than offset once the market tightens and that keeping assets operational will pay off in the future.

Competition in the coal industry leads to producers cutting prices in the hope that their rivals will have to exit the market. Economic theory suggests that this triggers an adjustment process in which excess capacity is shed and only the most efficient producers survive. However, collective over-optimism in the industry is capable of delaying this adjustment. This notion is not incompatible with a general expectation in the industry of decline; it simply means that the industry consistently acts as if it expects a better outcome than what turns out in the future.

The coal industry is often a major employer. High unemployment in a coal producing country could trigger a downward spiral in wages (or other employee benefits), as a low income is preferable to unemployment if chances of finding a new job are slim. This effect lowers the cost base and gives companies additional headroom to stay in business and further cut prices. As well, the costs of closing a mine or transferring it to care and maintenance may be significant; as long as the mine is just able to cover its variable costs, the company may want it to keep producing.

These potentially detrimental effects of too much competition are difficult to counteract; market-based mechanisms, such as price floors and scrappage bonuses are unlikely to have the desired effect. The Chinese are tackling the problem through direct intervention: in the period to 2020 up to 1 000 million tonnes per annum of coal mining capacity is to be shed. Successful implementation of these measures underpins our projections for China, while the outcome for many other regions rests on market forces restoring a broad market balance by the mid-2020s. Failure to reduce excess capacity or delays in the process, whether market led or administratively managed, could significantly prolong the current industry crisis and leave coal prices at rock bottom for much longer than is projected in the New Policies Scenario.

This analysis confirms that in recent years a growing number of mines continued to produce steam coal despite prices below their variable costs. We estimate that in 2015 over 15% of the mining capacity supplying the international market was not covering all of its variable costs. Despite the various factors described in the *Spotlight* that could leave coal markets unbalanced for a long time, our New Policies Scenario assumes that a combination of policy measures to cut capacity and market forces trigger a balancing process that re-establishes the paradigm of coal prices largely being set by the marginal cost of coal supply, with operating mines covering all their costs. This assumption also underpins our price trajectory in the period to the mid-2020s. As a result, the New Policies Scenario sees European and Japanese steam coal import prices rebound to $70/tonne and $73/tonne respectively in 2025, and thereafter increase gradually to $77/tonne and $80/tonne in 2040 while Chinese coastal steam coal prices increase to almost $90/tonne in 2040 (see Chapter 1.2.2).

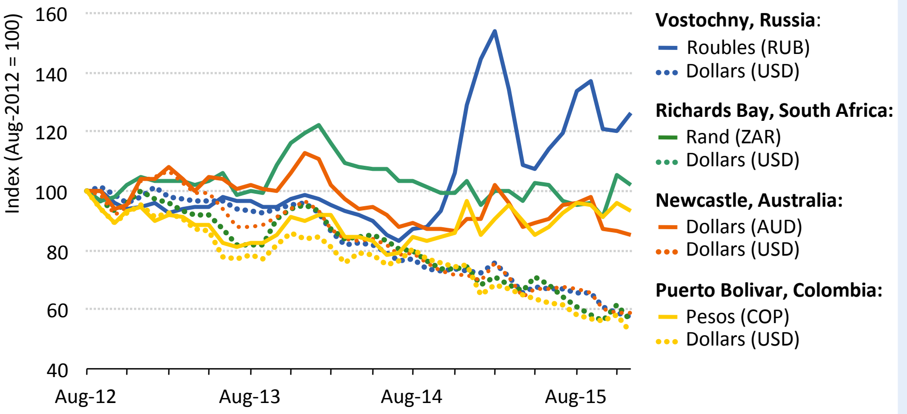
As seen, coal companies around the world have successfully managed to bring down the cost of production. Productivity gains, primarily achieved through workforce reductions and economies of scale to lower unit costs, together with the deferral of capital expenditure to sustain production and high-grading (selective mining of the least-cost deposits) have all helped to cut costs. External factors, such as a drop in the price of consumables like fuel, explosives, tyres and steel, together with foreign exchange rate effects, have also contributed to the drop in coal production costs (Box 5.2).

Box 5.2 ▻ The impact of exchange rates on coal prices

All major coal price indices show that coal prices, denominated in US dollars (USD) have been in decline for four consecutive years, suggesting that the supply side would react to this drop in prices by reducing output. Indeed, many coal mines have been closed around the world; but exports from key countries such as Australia, South Africa, Russia and Colombia have been either increasing or have stayed flat. The reason for this resilience in the face of decreasing prices lies partly in exchange rate effects (see Chapter 1.2.1). Since coal trade is mostly settled in US dollars, coal exporters generate revenues in dollars but pay for most of their costs in roubles (RUB), Colombian pesos (COP), rand (ZAR) or Australian dollars (AUD). The US dollar has gained strongly in value against other major currencies, especially since mid-2014. As a result, while coal prices expressed in US dollars have fallen since mid-2012, they stayed rather flat in key exporters' currencies

(Figure 5.8). Devaluation of the coal exporters' currencies allows them to accept lower US dollar denoted coal prices so long as their revenues, exchanged into domestic currency, still cover their costs.

Figure 5.8 ▷ Change in coal prices in local currencies and US dollars



Coal prices have hardly decreased in local currencies

Sources: IHS Energy (2016); IEA analysis.

Investment

Investment activity has varied around the world in recent years. In the export-oriented coal industry, capital spending for new projects has now largely dried up, in response to low coal prices. In China, coal mining and power generation projects have moved ahead despite the slowing outlook for demand, adding to the problem of over-capacity (IEA, 2016b). There is still money going into new projects in China, but the government has tightened its control over project approvals. In India, however, strong demand fundamentals justify continued capital spending, leaving investment activity unaffected by the prevalent excess capacity on the international market.

In the New Policies Scenario, cumulative investments of some $1.1 trillion are needed in the global coal supply chain over the next 25 years (Table 5.6). Three-quarters of the spending is for mining, with the remainder for infrastructure. While investment in an over-supplied market sounds like a paradox at first, a detailed look at the underlying drivers explains why considerable capital spending for coal supply is needed. To keep an existing mine operational, substantial capital needs to be spent over its lifetime (maintenance and replacement of machinery and equipment). This spending, termed "sustaining capital expenditure", accounts for nearly half of the mining investment over the projection period. The typical lifetime of a mine is around 25 years. This implies that many of the mines built during the coal bonanza in the first decade of this century start to near depletion from the mid-2020s.

Partial replacement of this capacity requires investment in brownfield expansion and new greenfield projects. Coal production growth rates differ by region and so does investment. India, along with some other countries, expands its coal production rapidly, increasing its mining investment. While a future supply gap, caused by a lack of investment, seems much less likely in coal than in oil and gas, it is clear that current price levels are insufficient to mobilise all the investment required in the New Policies Scenario. Divestment campaigns that try to hinder access to finance or increase the cost of financing coal projects have so far had only limited effects on mining investments. That said, the movement is growing and could eventually create considerable barriers for coal investments, especially in OECD countries.

Table 5.6 ▷ Cumulative coal supply investment by region in the New Policies Scenario, 2016-2040 ($2015 billion)

	Mining			Ports and rail	Total	Annual average
	Capacity additions	Maintenance	Total			
OECD	**82**	**87**	**169**	**37**	**206**	**8.2**
Americas	23	36	58	10	68	2.7
United States	17	29	45	8	54	2.1
Europe	4	5	9	12	21	0.8
Asia Oceania	56	46	102	15	117	4.7
Australia	56	46	102	2	104	4.2
Non-OECD	**351**	**330**	**681**	**183**	**864**	**34.5**
E. Europe/Eurasia	30	31	61	22	83	3.3
Russia	20	22	42	14	56	2.2
Asia	286	269	556	144	699	28.0
China	188	198	386	42	428	17.1
India	82	55	137	67	204	8.1
Indonesia	11	12	24	8	31	1.3
Middle East	0	0	0	1	1	0.0
Africa	23	22	45	13	58	2.3
South Africa	16	19	36	1	37	1.5
Latin America	11	8	19	3	22	0.9
Colombia	11	7	18	1	19	0.7
Shipping	n.a.	n.a.	n.a.	66	66	2.6
World	**433**	**417**	**850**	**286**	**1 135**	**45.4**
European Union	3	5	8	9	17	0.7

5.3.3 Regional insights

China

Coal fuelled China's rapid economic ascent in the first decade of this century, with demand growth rates averaging 10% per year between 2000 and 2010. Today, China is of paramount importance to developments in the global coal market, accounting for around half of the world's coal consumption and production. Even though India overtook China as the largest coal importer in 2015, China's coastline remains the main price arbitrage point indicating the state of the international coal trade. China has the largest coal-fired power plant fleet in the world and its equipment manufacturers, financiers and project developers have become increasingly active in coal plant investments around the world. No other country produces more steel or cement than China – two industries which are traditionally heavily coal-reliant. Yet, the abundantly available fuel has made inroads into less typical applications, such as drying processes in agriculture or providing feedstock for the chemical industry. A considerable amount of coal is also still burned in households for heating. As a result, only a little more than half of China's coal consumption is for power generation (the share is much higher in all other major coal-consuming countries).

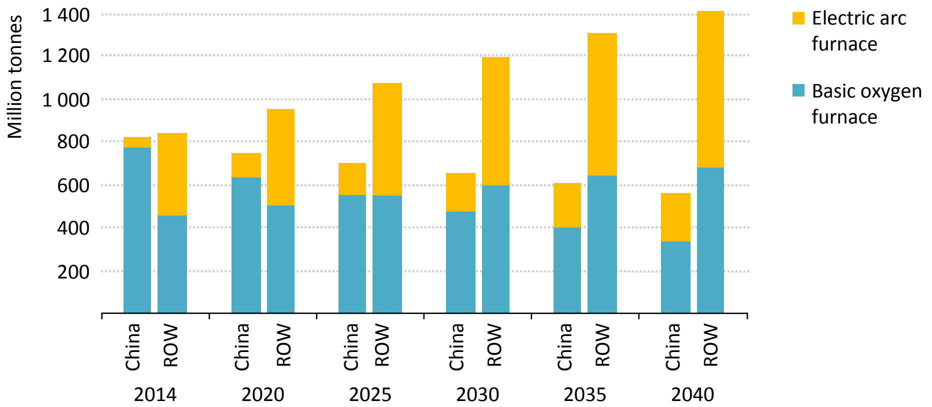
But China is changing: coal demand growth stalled in 2014 and 2015 saw its coal use decrease by an estimated 2.6%, marking 2013 as the peak year of coal demand in China, at 2 900 Mtce. It cannot be excluded that exceptionally strong electricity demand growth, coupled with poor hydropower availability (due to dry weather) and a surge in industrial production (e.g. due to a fiscal stimulus package) might, over the medium term, lead to a new, transient spike in coal demand that exceeds the historical peak. However, our analysis shows that all fundamentals point to Chinese coal demand having now entered a slow decline, dropping in the New Policies Scenario to 2 520 Mtce in 2040, down 13% from today's level.

The government's efforts to shift the economy from heavy industries towards a more services sector oriented growth model are bearing fruit: output from the steel and cement industries peaked in 2014, weighing on coal use in the industrial sector. Scrap availability increases rapidly over the projection period, spurring greater use of electric arc furnaces which gradually displace some of the traditional (coke-based) basic oxygen furnaces (Figure 5.9). Moreover, China's weight in the global steel market declines over time. Today, Chinese steel mills produce around half of the world's steel, but this share drops to 30% in 2040 as the country's economy transforms.

Coal use as feedstock for the petrochemical industry in China exhibits strong growth rates. Growth would be stronger if it were not for up to 25 million tonnes (Mt) of annual methanol imports that temper coal demand growth in the coal-to-olefins process by almost 40 Mtce per year. Nonetheless the growth of coal feedstock is insufficient to offset the declines in other industrial applications. By 2040, coal use in industry amounts to nearly 900 Mtce down from 1 170 Mtce in 2014.

The transformation of China's power sector is making significant progress, with an additional 63 gigawatts (GW) of renewable energy resources and 8.2 GW of nuclear added in 2015, compared with some 52 GW of new coal capacity (Box 5.3). Over the *Outlook* period, power generation from wind, nuclear and solar photovoltaic (PV) increases by 8%, 9% and 13% per year respectively. Although coal remains the backbone of the electricity system in China, its share in the power mix gradually drops from 73% in 2014 to 43% in 2040. Coal use in China's power sector has not peaked yet in the New Policies Scenario but rebounds slightly over the medium term as electricity demand growth picks up again (electricity consumption was flat in 2015), calling on coal-fired power generation. Power sector diversification and increasing generation efficiency lead to a peak in power sector coal use around 2030 at some 1 510 Mtce, only marginally up from 1 495 Mtce in 2014. Coal burn in power generation then drops to less than 1 430 Mtce in 2040.

Figure 5.9 ▷ Steel output by production route in China and the rest of the world in the New Policies Scenario



A declining share of basic oxygen furnaces in Chinese and global steel production weighs on coking coal demand

Note: ROW = rest of the world.

The recent slowdown in coal demand growth has hit the Chinese coal industry hard. Coal companies had made investments in the expectation of much stronger demand growth, resulting in an over-capacity in mining that some market observers estimate at between 1 000 and 1 500 million tonnes per annum (Mtpa) (more than the entire capacity of US mines). Coal prices in 2015 dropped to levels that allowed less than 20% of the country's coal companies to cover their costs. The government has started tackling the issue by ordering capacity cuts. This is embedded in a wider macroeconomic strategy to reduce reliance on the heavy industrial sectors and therefore extends also to other industries like steel, where over-capacity is similarly dire. Specifically, the government has started taking measures to speed up mine closures (especially mines that are considered unsafe) while also increasing the hurdles for new mine approvals and reducing the official working days in coal mines from 330 days per year to 276 days. Overall, the authorities aim to cut capacity of 1 000 Mtpa by 2020 (additionally, capacity cuts of 100-150 Mtpa are planned for the steel industry). The reduced working days schedule, implemented in the second-quarter of 2016, alone has led to a reduction in annual output by 500-600 Mt, suggesting that, in combination with the other measures, the official target may be exceeded. The measures implemented so far have proven effective: much of the coal price rally since the second-quarter of 2016 is due to a tighter supply and demand balance in the Chinese market which has also lifted imports above 2015 levels. As of September 2016, Chinese authorities were partly relaxing the capacity controls, for example allowing temporary exceptions from the working days rules for the most efficient producers in order to cushion price spikes and foster a smooth rebalancing of the coal market. The challenge for policy-makers in China is to strike a careful balance between the depth of the capacity cuts, job losses and price jumps (increases in coal prices eat into the margins of electricity generators or lead to higher regulated power tariffs).

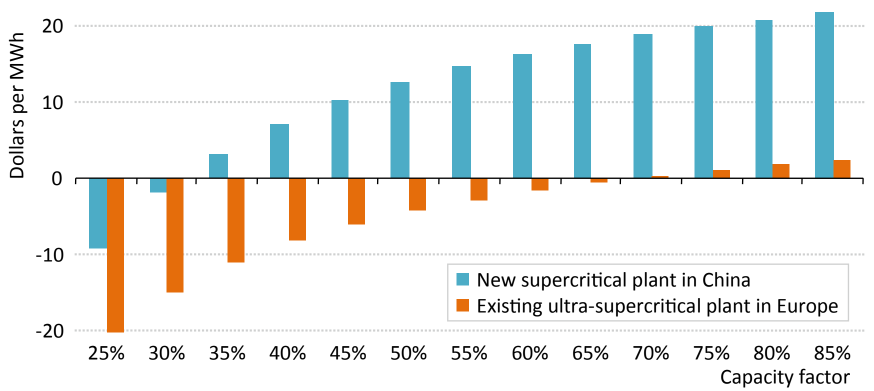
Whether the 1 000 Mtpa capacity reduction target in 2020 will be attained and be sufficient to bring the market back into balance, remains an open question. While coal demand is declining and capacity is being shed, there is still a substantial amount of new mining capacity in the investment pipeline that may come on stream over the next couple of years. Estimates on how much new capacity is ready to go ahead, if authorised, range between 700 and 900 Mtpa.

The New Policies Scenario sees coal production in China at 2 490 Mtce in 2040, down from 2 700 Mtce in 2014. Chinese net coal imports peaked at nearly 250 Mtce in 2013 before dropping by 12% in 2014 and by a further 26% in 2015. Our projections see a continued fall in net imports to around 35 Mtce in 2040. These coal production and trade trends are based on the assumption that sufficiently deep capacity cuts are implemented over the medium term, while investment activity is limited to productivity improvements, production-sustaining capital expenditure and advanced projects. Despite the efforts of policy-makers to smoothen the transition, there remains a risk that the volatility in coal production and pricing in China will increase over the coming years. The repercussions will be felt on the international market too. The result is stronger fluctuations in Chinese imports on a monthly basis – especially over the medium term – as imports increasingly take over a balancing role for small mismatches between demand and domestic supply. Year-to-date import data for 2016 suggest an increase in import volumes over the previous year. So, while the long-term import trend is set for decline, the road ahead may prove to be bumpy.

Box 5.3 ▷ China's coal plant conundrum

Utilisation rates of coal-fired power plants in China are falling rapidly, as new plants enter an electricity system in which renewables have expanded fast and demand has slowed markedly. Despite this, over 110 GW of plant is under construction and some investors are still proposing new plants (Platts, 2016). Why? The average capacity factor of thermal power plants in China dropped by nearly 10% in 2015, implying that the plants ran only during 4 360 hours of the year – a capacity factor of less than 50%. In most OECD countries, alarm bells ring with investors when coal plant utilisation drops below 70%. The capital cost of coal plants is normally high, up to $2 000 per kilowatt (kW) for a supercritical coal plant in Europe, requiring the plant to supply baseload electricity to earn sufficiently high revenues to recoup the upfront investment. The situation is different in China where overnight costs are substantially lower at $700/kW for a similar plant. Based on regulated power tariffs of around $50-60 per megawatt-hour (MWh) in 2015, an investor can expect a positive return as long as the plant runs for more than 2 800 hours per year, i.e. achieves a 32% capacity factor (Figure 5.10). Although Chinese investors may have planned for higher capacity factors (and would no doubt welcome them), the current market conditions with low coal prices, low capital costs, attractive financing and generous power tariffs leave sufficient room for a further decline in the average coal plant utilisation before the incentives to build new plants vanish – whether coal plants will be stranded is primarily dependent on the evolution of the regulated power tariffs. The situation is strikingly different in Europe, where current market conditions hardly allow existing coal plants to survive – even if they achieve high capacity factors – let alone provide the incentive to build new plants.

Figure 5.10 ▷ Profit margin of a new Chinese coal plant and an existing European coal plant, 2015

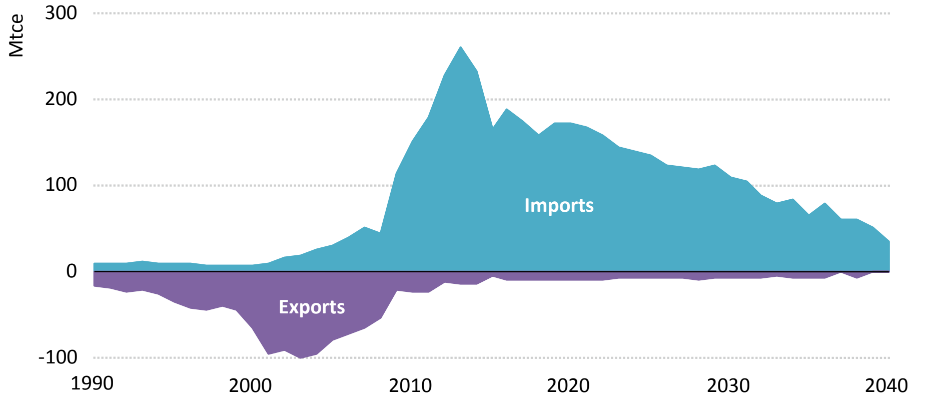


Profit margins of Chinese coal plants remain positive even at low capacity factors, underpinning continued investment in new plants

Focus: Could China become a net exporter of coal again?

China, a major coal exporter at the beginning of the first decade of this century, saw net exports peak at 87 Mtce in 2001 when it was the second-largest exporter after Australia. Only eight years later, China was a net importer of coal. Not only the shift, but also the magnitude of the subsequent import growth, took many coal companies and market observers by surprise. Similarly, the sudden and steep drop in coal imports in 2014 and 2015 came rather unexpectedly. Many are wondering whether Chinese imports could disappear as rapidly as they emerged, possibly even turning the country into a net exporter again.

Figure 5.11 ▷ **Chinese coal trade in the New Policies Scenario**



Although the fundamentals point to a long-term decline in imports, China remains a net importer of coal over the Outlook period

This question is not easy to answer. While China's net trade position is critical for coal exporters around the world, it remains a comparably small item in China's coal supply balance (currently less than 10% of demand) which is very sensitive to the vicissitudes of the domestic coal market. In the New Policies Scenario, China remains a net importer of coal throughout the projection period albeit on a declining trend, with net imports dropping from 220 Mtce in 2014 to around 35 Mtce in 2040 (Figure 5.11). Three inter-related assumptions underpin this view:

- State interventions to influence the trade balance or distort the economics of domestic coal *vis-à-vis* imported coal remain minimal.
- Chinese authorities successfully implement capacity cuts in the coal industry to re-establish a balanced coal market, while creating enough jobs in other sectors to avoid undue stress in the labour market.
- The bulk of domestic coal production remains costlier than imports along China's southern coast.

Our cost estimates suggest that, on average, imported coal currently has a cost advantage of around 10% over domestic coal in coastal regions (Figure 5.12). This narrows slightly over the projection period, as industry restructuring and mine consolidation in China brings some productivity gains (mainly due to economies of scale). It would narrow further if productivity gains end up higher than expected, although increasing labour costs and the need to tap deeper deposits might limit the effect of productivity improvements on costs. In addition, taxes play an important role in the coal market. In the past, taxation has been a good mirror image of China's role on the international market, with changes of tax rates that either encouraged or discouraged exports.[6] Tax rebates or even subsidies could flip the economics in favour of domestic coal.

Cutting more than 1 000 Mtpa of mining capacity between today and the early 2020s could result in the loss of some 0.9-1.3 million coal mining jobs. Bearing in mind that tackling over-capacity is not confined only to the coal industry, the government needs to create a significant number of jobs in other sectors and cushion social hardship for those who stay unemployed. Backing out imports reduces the pressure to slash capacity and buys additional time to strengthen other sectors of the economy. Even deliberately exporting coal at a loss may have an appeal if the avoided social costs (e.g. unemployment benefits) outweigh the losses from coal exports. In either case, the costs accrue primarily to China's state budget, due to the high level of state-ownership in the coal industry.

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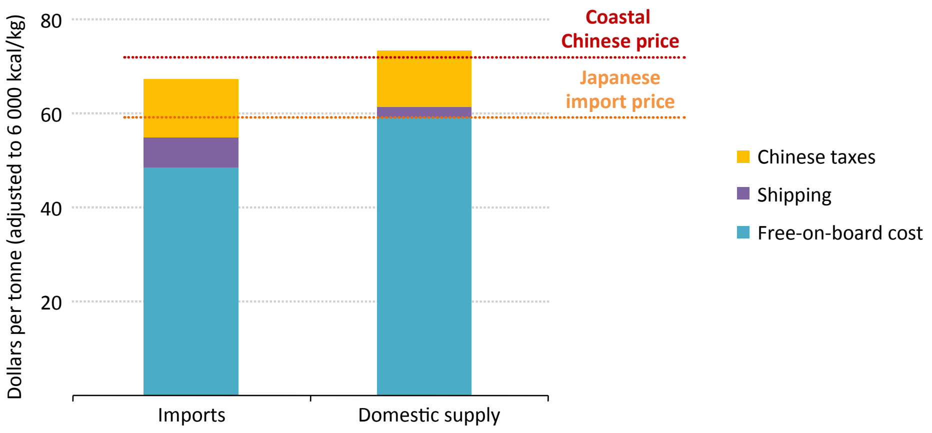
Figure 5.12 ▷ Average costs of steam coal delivered to southern coastal China by origin, 2015



Imported steam coal has a cost advantage over domestic coal in southern coastal China

A decline in the average cost of Chinese coal by 20% (delivered to the coast) – achieved either through productivity gains or state support – could enable net exports of up to 50 Mtce by the mid-2020s. Taking the displaced Chinese imports into account, the net effect on international trade would add up to some 180 Mtce. Primary markets for Chinese exports would be nearby importers (e.g. Korea, Japan, Viet Nam, Philippines) where competition with Indonesian, Australian and Russian exporters would be fierce. Such a shift in China's trade balance could sustain the imbalance on the international market, keeping

6. Chinese coal exports in the early 2000s were supported by a 13% export tax rebate which was removed in 2006. In the same year, the government introduced a 5% export tariff to discourage exports of increasingly scarce coking coal. Only two years later the export tax was lifted to 10% and expanded to include steam coal. In the context of the growing over-capacity the export tax level was reduced to 3% in 2015. Since 2009, a value-added-tax of 17% is levied on all coal sales.

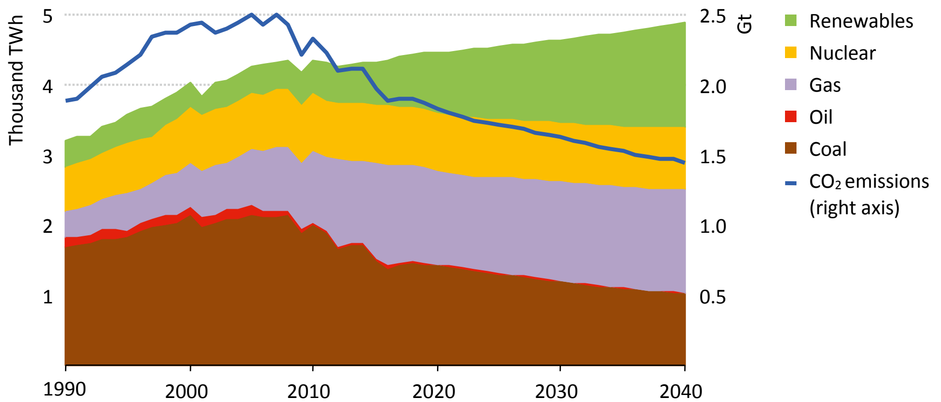
prices depressed for much longer. Even a price decline of \$5-8/tonne on the international market is unlikely to trigger much additional demand. In most countries that plan to expand their use of coal, coal is already markedly cheaper than gas or renewables, and a coal price drop does not flip the economics, while countries that have decided as an act of policy to reduce their reliance on coal are unlikely to revisit their decision due to a fall in coal prices.

United States

The United States is the second-largest coal producer accounting for 12% of world coal production. It is also the second-largest coal consumer (although preliminary data for 2015 suggest that India may have overtaken the United States). In 2014, US coal consumption amounted to nearly 620 Mtce, over 90% of which was used in the power sector. But coal has been on a declining trend for the last couple of years, as a result of strong competition from abundant and low-cost natural gas and policy measures to reduce air pollution from power generation mainly targeting sulfur dioxide (SO_2), mercury, particulate matter and nitrogen oxides (NO_x).

Over the medium term, the Mercury and Air Toxics Standard will continue to push coal plants into retirement. The cost of control technology retrofits can be significant (\$200-400/kW) and the US coal-fired fleet is among the world's oldest (half of the fleet is older than 40 years and 85% of the plants are older than 30 years) and least efficient, making companies think twice before investing additional money. Moreover, coal's role as a low-cost source of baseload power is increasingly challenged by gas, which traded at \$2.6 per million British thermal units (MBtu) on average in 2015. For the first time ever, power generation from gas was on a par with output from coal in 2015 reflecting a 14% drop in coal-fired output while gas-fired generation increased by 18%.

Figure 5.13 ▷ Electricity generation by source and power sector CO_2 emissions in the United States in the New Policies Scenario



Coal loses out to renewables and natural gas as the Clean Power Plan is realised

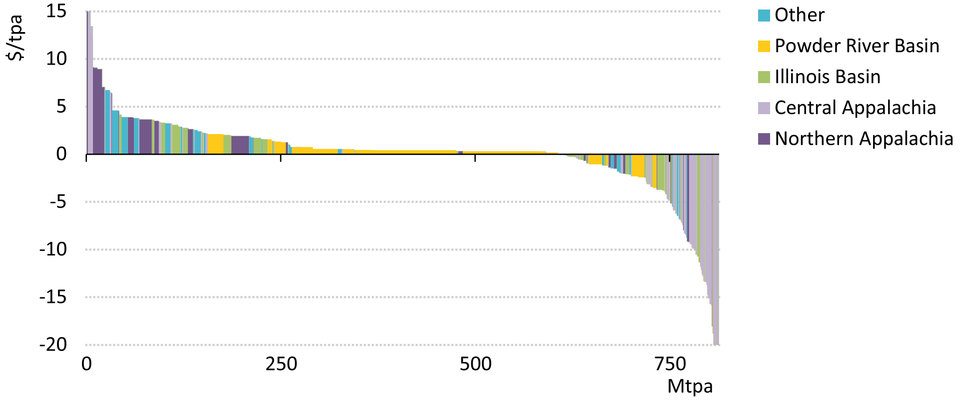
The Clean Power Plan which targets reductions of CO_2 emissions from the power sector of 32% by 2030 (compared with 2005 levels) and the Carbon Pollution Standard, which sets stringent CO_2 emission limits for new power plant, are important influences in the New Policies Scenario. In the longer term, these policies tighten the constraints on the role of coal in power generation while favouring gas-fired and renewable technologies (Figure 5.13). New coal plants can be built only if they meet a CO_2 limit of 1 400 pounds per MWh (approximately 635 grammes of CO_2 per kWh), effectively requiring some sort of CO_2 capture unit to be installed. As a result, coal use in the power sector is projected to decrease by 45% between 2014 and 2040. The multi-year extensions of tax credits for wind and solar PV, decided in December 2015, will support stronger deployment of renewables over the medium term. With CO_2 reduction targets unchanged, additional output from renewables reduces the need for coal-to-gas switching to meet the emissions targets, resulting in a slight upward revision of the long-term outlook for coal use in power, compared with last year's edition of the *WEO*.

5

The adverse market conditions for coal have taken their toll on the industry in the United States. In the first half of 2016, the country's two largest producers, Arch Coal and Peabody Energy both filed for bankruptcy protection, adding to the list of some fifty US coal companies that have done so since 2012. At the time of writing, nearly half of the country's coal production was under bankruptcy protection. Although industry consolidation and permanent mine closures are already underway – we estimate that since early 2015 some 40 Mtpa of capacity have been shut down (IEA, 2015a) – further capacity cuts are inevitable if the US coal market is to find its way to an economically sustainable balance. Even so, our price projections for all major coal basins in the United States, suggest that in the New Policies Scenario, barring productivity improvements, three-quarters of the currently installed mining capacity could be profitably operated for its remaining lifetime once the debt restructuring of the highly leveraged coal companies is accomplished (Figure 5.14).

Our *Outlook* for US coal production and prices assumes that the industry as a whole operates on a financially sound basis from the early 2020s although there is a possibility that this recovery will be delayed (Spotlight). US coal production drops from around 695 Mtce in 2014 to 390 Mtce in 2040 largely as a result of the demand-side constraints on coal-fired generation. Exports provide very limited relief: net coal shipments from the United States have been in steep decline for three consecutive years, falling to an estimated 53 Mtce in 2015, just over half the historical highs of around 100 Mtce. This declining trend is set to continue over the projection period, albeit at a slower pace, with coal exports from the United States at 20 Mtce in 2040. Opportunities to place coal on the international market are increasingly limited for US producers. If the projected decline in Chinese imports is realised (and bearing in mind the difficulties of building export infrastructure), the prospects of exporting larger quantities of coal from the US west coast are bleak while the ramp-up of coking coal exports from Mozambique will increase competition in Brazil and Europe – key export markets for US coking coal producers. In the shrinking European steam coal import market, Colombian producers have a clear cost advantage, not leaving much room for US steam coal exports either.

Figure 5.14 ▷ Average cash-margins of existing US coal mining capacities in the New Policies Scenario



The bulk of the US capacity can earn positive margins on operating costs, but debt restructuring is key to the financial viability of the industry

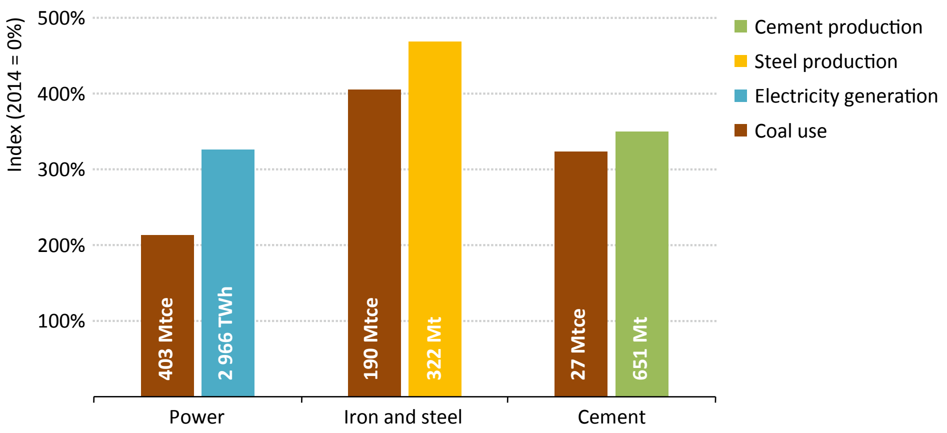
Notes: tpa = tonnes per annum. Net present value of cash-flows calculated for some 300 coal mines in the United States, based on 2015 costs, under the price trajectories for key US mining regions in the New Policies Scenario.

Sources: IEA analysis; WoodMackenzie databases.

India

Rapid economic development and strong population growth propel India's energy demand upwards. Coal is projected to remain a key element in India's energy economy, increasing its share in primary energy demand from 46% today to 48% in 2040. India's coal consumption then reaches 1 340 Mtce (up from 540 Mtce in 2014). Building infrastructure and housing requires a large expansion of heavy industries' output, such as steel and cement, the production of which relies primarily on coal (Figure 5.15). Industrial coal demand increases to 560 Mtce in 2040, three-and-a-half times more than today. Power generation expands by almost three-and-a-half times over the projection period and around half of this growth – an additional 1 400 TWh – comes from coal-fired stations. India's coal-fired power plant fleet grows by 260 GW, reaching 450 GW in 2040 (the second-largest coal fleet after China in a single country). In the past, new build plants chiefly relied on subcritical technology; resulting in a relatively low fleet efficiency of around 33% (high ash-levels of domestic coal and comparably high ambient temperatures also weigh on efficiency). Over the *Outlook* period, new coal plants are assumed mostly to use supercritical boiler technology, its share increasing to almost half in 2040 (from 15% in 2014). This raises the fleet efficiency by four percentage points to nearly 38%. The strong increase in coal-fired power generation over the period carries with it the risk of a further deterioration in India's already bad air quality, if it is not countered by stringent pollution regulations (Box 5.4).

Figure 5.15 ▷ Incremental coal demand to 2040 by key sector in India in the New Policies Scenario



Coal use is propelled by a surge in electricity generation, and steel and cement production

Coal production in India grew by some 7% in 2014, up from 1% in 2013 and 5% growth in 2012, and it is estimated to have grown at 6% in 2015. The growth in coal output came mainly on the back of Coal India Ltd (CIL, the country's main coal producer) achieving productivity gains in existing mines and rolling out improved technology. Periodic mismatches between production and demand in India are symptomatic of some unresolved issues with the structure and operation of both the coal and power markets. The precarious financial situation of the Discoms (electricity transmission and distribution companies), which often make losses on every kilowatt-hour of electricity they sell, in combination with unreliable power supply, constrains electricity demand growth. Moreover, domestic coal is primarily sold via supply contracts ("linkages") between CIL and individual buyers which require the coal to be used in a designated plant. Only limited quantities of domestic coal are sold to consumers without such a limitation and also at a significantly higher price (via "e-auctions"), plus many industrial consumers and independent power producers do not have a supply contract of any kind with CIL. This system prevents much of the additional output from being marketed, currently resulting in considerable stockpiling of coal at the mines. The government has started to tackle this by proposing a scheme that increases the flexibility in the use of coal purchased via supply contracts. The new scheme would allow domestic coal purchases to be re-distributed, but still only within the portfolio of a company's plants.

The New Policies Scenario assumes gradual electricity market reform and increasing use of market-based mechanisms to allocate domestic coal. The combination of these measures is a prerequisite for coal demand growth in India to pick up over the projection period and for domestic production to be distributed efficiently. There are important implications for global coal markets. While coal production in India expands from around 360 Mtce in

2014 to 1 000 Mtce in 2040, imports continue to increase, from 180 Mtce in 2014 to some 340 Mtce by the end of the period (although the import dependency declines notably from a third in 2014 to a quarter in 2040). However, we argue that the underlying logic of imports changes in the future. The bulk of the import growth seen over the past years was due to shortage of domestic coal or systemic constraints (either transport, quality or market constraints). For most consumers it would have been cheaper to procure domestic coal had it been available. More competition in the coal industry and the use of market-based mechanisms (user flexibility for domestic coal purchases, auctioning of supply contracts, competitive spot markets) gradually eliminate the cost gap between domestic production and imports, i.e. leading to a convergence of domestic and international coal prices (IEA, 2015b). This development has important implications: first, it allows for arbitrage opportunities and economic imports along India's coastlines and second, it supports the roll-out of modern mining technology to tap more complex coal deposits in India.

India, together with Southeast Asia and parts of Africa, is the only growth area in an otherwise depressed international coal market. Strong coal import growth in India has been anticipated and prepared for by the export-oriented coal industry around the world. However, there is considerable uncertainty around the achievement of the import trajectory presented in the New Policies Scenario: while there is a strong economic case for coal imports, they are politically unpopular in India and policy-makers have repeatedly stated their intention to reduce coal imports. Although the stagnation of coal imports in 2015, after years of strong growth, had more to do with sluggish demand growth amidst a jump in domestic output, a scenario in which India successfully and persistently reduces its imports cannot be discarded.

Box 5.4 ▷ Coal use and air quality

Combustion processes typically generate various pollutants, such as particulate matter (PM), sulfur dioxide (SO_2) and nitrogen oxides (NO_x) that, when released into the air, have adverse effects on human health and the environment. Coal-fired boilers in industry, power generation and other sectors account for nearly 60% of the global emissions of SO_2 and 15% of the worldwide emissions of NO_x and $PM_{2.5}$ (particulates with a size of 2.5 microns or less, which are particularly harmful to human health).

A suite of technologies is available to mitigate air pollution emissions from coal combustion: for instance, electrostatic precipitators or fabric filters can remove more than 99% of the PM from flue gas, while the most advanced scrubbers can achieve similar removal of SO_2. Selective non-catalytic reduction is an example of a technology that can achieve NO_x removal rates of up to 90% in commercial power plants. The cost of these technologies is far from being prohibitive, but their introduction requires regulatory action to ensure that investors plan their new power station projects with appropriately advanced control technology while also retrofitting the existing fleet. In the New Policies Scenario, coal-fired power generation grows more in India and

Southeast Asia than anywhere else in the world over the next 25 years. The rapid growth anticipated in this scenario implies that the bulk of the coal plants operational in 2040 are yet to be built in these systems (300 GW in India and 135 GW in Southeast Asia are built over the *Outlook* period), providing the opportunity to require them to be built to meet high standards of pollution control.

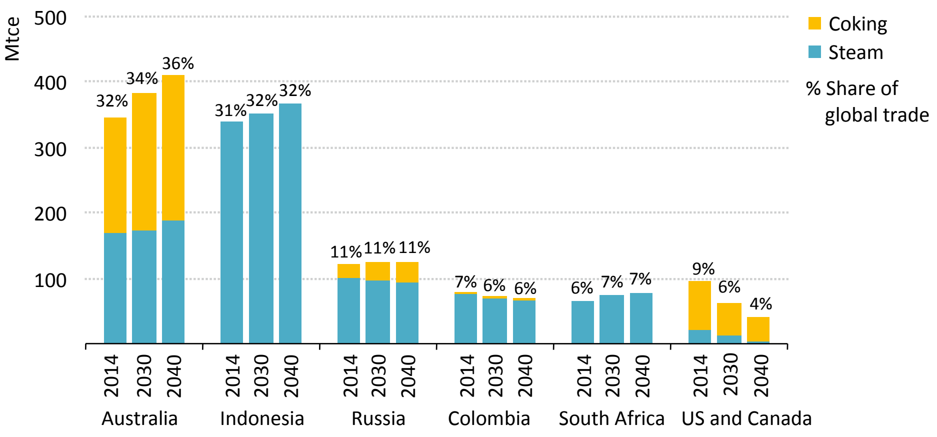
India tightened the limits for pollutant emissions substantially in December 2015 and if applied in concert with efficiency improvements, these measures can deliver a marked improvement in ambient air quality, despite strong growth in energy demand. The New Policies Scenario shows that enforcing compliance with these rules leads to a drop in the emissions of SO_2, $PM_{2.5}$ and NO_x from power generation by around 90%, 75% and 20%, respectively, through 2040 (IEA, 2016c). In Southeast Asia, there is considerable scope to increase the stringency of emission limits for power plants. In the absence of more ambitious standards, the strong growth in electricity demand of the New Policies Scenario suggests that emissions of SO_2 from power generation grow by some 85%, emissions of $PM_{2.5}$ double and emissions of NO_x increase two-and-a-half times over the *Outlook* period.

Major exporters

In 2014, Australia regained the rank of the largest coal exporter from Indonesia. Australia is critical to global coking coal supply: with relatively low supply costs and abundant reserves it provides over 60% of internationally traded coking coal. The coal industry in Australia is performing better in the current situation of over-capacity than many of its rivals. Strict cost-cutting, productivity improvements and a devaluation of the Australian dollar against the US dollar spurred a drop in the average cash-cost of exported coal by some 35% between 2012 and 2015. Australian exports are projected to increase to 410 Mtce in 2040, up from 350 Mtce in 2014, increasing Australia's share in international trade from 32% to 36% (Figure 5.16). In light of the declining import trend in China, the need to tap new deposits in Australia's Surat and the remote Galilee basins becomes increasingly tied to the trajectory foreseen for coal imports in India. A tapering of India's imports would make the economics of remote projects that require infrastructure development increasingly questionable.

Indonesia was hit hard by the coal glut in 2015, with exports dropping an estimated 10% from some 340 Mtce in 2014, (on top of a 4% decline observed in 2014). This is a huge turnaround from annual average export growth rates of over 15% between 2003 and 2013. Unlike other exporters, Indonesia incurs a relatively high share of its costs in US dollars and hence has not benefited from the appreciation of the dollar to the same extent as its rivals. Moreover, mining operations in Indonesia are often relatively small and thus lack the scope to gain economies of scale. It is estimated that up to 80 Mtpa of mining capacity has been closed over the last two years, but these are flexible truck-and-shovel operations, which could come back online quickly when prices rise. Indonesia has thus become a kind of swing supplier that adjusts its output rapidly to price movements. Declining import demand in China continues to affect the Indonesian coal industry over the projection period, while India has become the most important buyer of its coal and remains so in our *Outlook*. Indonesian exports do rebound, but at 355 Mtce in 2040 they only marginally exceed the level reached in 2014. Moreover, the level of exports is highly dependent on developments in India. Indonesian domestic demand increases four-fold, from 52 Mtce in 2014 to almost 200 Mtce in 2040 (for instance, the Indonesian utility PLN is pursuing a fast-track programme to expand coal-fired power generation). Yet, the absolute growth in domestic demand over the medium term is not strong enough to offset the decline in exports, resulting in a dip in the country's coal production in the next few years, before it rebounds in the early 2020s and increases to some 550 Mtce in 2040.

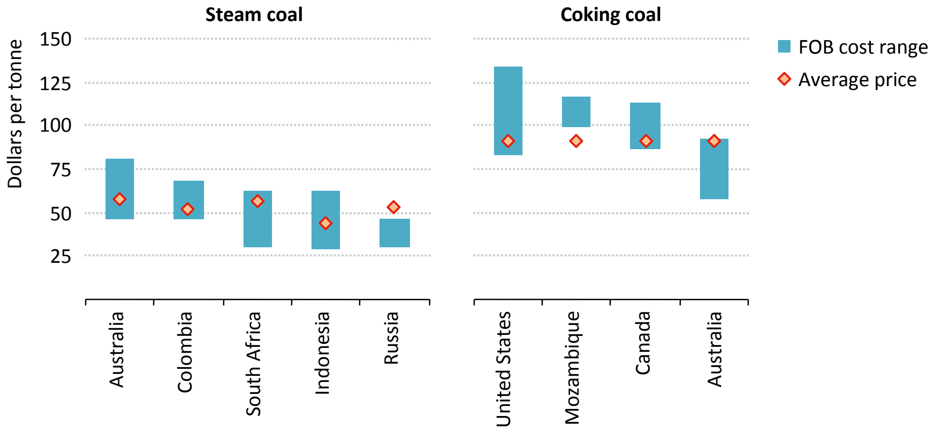
Figure 5.16 ▷ Major exporters of coal by type in the New Policies Scenario



Australia remains the largest coal exporter with strong exports of coking coal, but Indonesia keeps the top position in steam coal

Despite the grim situation on the international coal market, Russia managed to expand its exports by 15% in 2014 and, according to preliminary estimates, exports stayed flat in 2015. With net exports standing at 120 Mtce in 2014, Russia was the third-largest coal exporter. The country's export resilience amidst the low price environment has been underpinned by a marked depreciation of the rouble over the last two years which slashed Russian FOB cash costs (the majority of the costs are for labour and transportation). Between 2012 and 2015, the average cost of Russian coal exports is estimated to have dropped by 37%. Today, the bulk of the Russian exports are among the lowest-cost coal on the international market (Figure 5.17). However, Russia's competitiveness is somewhat impaired by the declining import trends in its key markets (Europe, China, Japan and Korea), while the growth centres in India and Southeast Asia are further away and involve an increase in shipping cost. Russian exports stay largely flat, at current levels, over the *Outlook* period.

Figure 5.17 ▷ Indicative FOB cash-cost range by key exporter and average coal price by type, 2015



Russia is now among the least-cost exporters of steam coal while Australia holds the top position for coking coal

Exports from Colombia increased by 4% in 2014 to 77 Mtce and are estimated to have further increased in 2015. Although Colombia's large mines benefit from low costs, the country's high exposure to the European market (currently around 70% of its coal is exported to Europe) limits its future growth opportunities. Over the next ten years there is some scope to displace South African and US coal from the European market, but in the longer term the decline in market volume cannot be offset by growth in market share. Colombian producers are increasingly forced to find ways to cut the transport cost to the Indian Ocean. Colombian exports are projected to gradually decline to around 65 Mtce in 2040. The production decline is partially offset by increasing domestic consumption.

Coal companies in South Africa benefit from a low-cost position and a geographical location that allows them to serve both the mature European market and the growing Asian market. Nonetheless, the South African coal industry faces a considerable challenge over the projection period: although domestic coal demand declines from 145 Mtce in 2014 to less than 120 Mtce in 2040 (as the country's coal-fired generation fleet becomes more efficient and renewable energy supply expands), depletion of the mature deposits in Mpumalanga Province proceeds faster, requiring an expansion of coal production in the remote Waterberg field in Limpopo Province. Our analysis suggests that South African coal exports can increase over the next 25 years, to reach around 75 Mtce in 2040; but the uncertainties to this trajectory are many: delays in further developing the Waterberg could constrain the availability of coal for export (albeit not without a marked increase in domestic prices) while high exposure to the Indian market makes export trends very sensitive to the evolution of Indian import demand.

Mozambique has made great strides towards becoming an important player in the international coking coal trade. First shipments of coal through the newly constructed 18 Mtpa Nacala corridor (a 900 km railway line linking the Moatize mine with the port of Nacala) were made during 2015. Mozambican exports in 2015 are estimated at 4 Mtce, similar to the level reached in 2014. Costs still exceed prices significantly, but they can be expected to come down markedly over the medium term, as the new infrastructure allows for economies of scale. Total coal exports are projected to exceed 25 Mtce in 2040. Further expansion of the mines also spurs domestic coal plant developments that use some of the steam coal by-product.

Virtually all of Canada's net exports are coking coal. Its total net exports of coal decreased by 15% in 2014, reaching 22 Mtce, and are estimated to have fallen further in 2015. In the long run Canadian exports are projected to rebound to 2014 levels, with investment primarily geared towards replacing depleted deposits, rather than gaining market share.

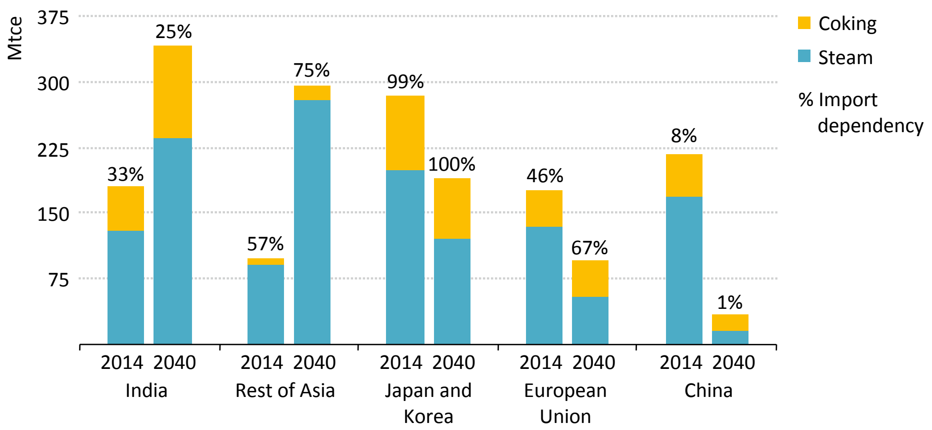
Major importers

No other major coal consuming country or region reduces its coal demand by more – in relative terms – than the European Union over the next 25 years. By 2030, the European Union intends to achieve a 40% cut in greenhouse-gas emission (compared with 1990 levels) and a 27% share of renewables total final energy consumption. Based on this, the region continues to back out coal from its energy mix, slashing total demand by some 240 Mtce to around 140 Mtce in 2040. The scope for coal-fired generation is squeezed relentlessly by renewables, particularly wind and solar PV, over the *Outlook* period such that the share of renewables in power generation increases from 29% to 53% in 2040. Domestic coal production declines from 215 Mtce to less than 50 Mtce in 2040. Meaningful quantities of hard coal are produced only in Poland, while lignite production continues in Germany and various countries in eastern and south-eastern Europe, albeit at much lower levels than today. Imports fall less steeply than domestic production, dropping from 175 Mtce in 2014 to below 100 Mtce in 2040 (Figure 5.18).

Japan's coal imports decreased by around 3% in 2014 and are estimated to have been flat in 2015, at just under 170 Mtce. Around 70% of Japanese imports are steam coal. Japanese imports are projected to decline by over 30% to around 120 Mtce in 2040. The key uncertainty for this trend is the restart of Japan's nuclear fleet: the New Policies Scenario assumes 17 GW will have restarted by 2020 and 27 GW by 2030, but there is significant downside potential to this assumption. Korea's imports are estimated to have increased 3% in 2015, up from around 115 Mtce in 2014, but are projected to decline in the long term, reaching some 70 Mtce in 2040, as alternative fuels increase their share in the power mix.

Total coal demand in the ten member countries of the Association of Southeast Asian Nations (ASEAN) is projected to triple over the *Outlook* period, reaching 430 Mtce in 2040. Only India experiences larger growth in absolute terms. Additional demand chiefly comes from the power sector, where coal overtakes gas as the leading fuel within the coming five years. Various countries in the region pursue coal plant projects (e.g. Thailand, Malaysia, Philippines), but the biggest contributions to growth are expected from Indonesia and Viet Nam, both of which also have significant domestic coal production. While Indonesia will unsurprisingly remain fully self-sufficient, Viet Nam – once a considerable exporter of anthracite to China – is now a net importer. Viet Nam's coal production increases only marginally over the projection period, implying increasing reliance on the international market to meet the country's coal needs. As a whole – exclusively due to Indonesia – Southeast Asia remains a net exporter, but the net surplus shrinks as imports to the rest of the region (an additional 130 Mtce over the projection period) grow much faster than Indonesian exports.

Figure 5.18 ▷ Major importers of coal by type in the New Policies Scenario



Despite Chinese imports plummeting, Asia dominates coal imports in 2040

Power sector outlook

A dispatch from the frontline of the energy transition

Highlights

- In the New Policies Scenario, electricity demand is projected to grow at 2% annually, increasing by two-thirds to 2040, compared with global economic growth of 3.4%, a marked change from the period 1990-2014 when they grew at almost the same pace. Energy efficiency measures but also macroeconomic and demographic factors slow electricity growth in several mature economies. Almost half of total global electricity demand growth is in China and India, mainly in buildings (23%) and industries (21%). All end-uses see their share of electricity increase, outside the OECD countries, from 12% in 2000 to 23% of final use by 2040.

- Electricity supply worldwide is set to diversify and decarbonise, with low-carbon generation overtaking coal before 2020. Coal-fired power's share of generation is projected to fall from above 40% now to 28% in 2040. By then, wind, solar and bioenergy-based renewables combined increase their market share from 6% to 20%. China generates almost all its incremental power from renewables, nuclear and natural gas. Globally, by 2040 producing a unit of electricity is projected to emit one-third less CO_2 than today; but emissions from the power sector still rise by 6%.

- The relationship between electricity demand and generating capacity is set to change: every new unit of generation is likely to necessitate the provision of 40% more capacity as over the period 1990-2010, as the renewables share of capacity soars. The reason is that the capacity factor of renewables such as solar and wind is lower than that of thermal power, the preferred plant choice of the earlier period. Accordingly, installed power capacity is projected to approach 11 200 GW in 2040. Renewables account for two-thirds of the increase.

- The expansion and maintenance of the power sector is projected to require $19.2 trillion investment through 2040, over 40% of it in transmission and distribution. Some 35% of the investment in power generation serves to replace plant retirements. Renewables account for 63% of the investment in new power plants, fossil-fuelled ones for almost a quarter and nuclear for the remainder.

- In the 450 Scenario, efficiency measures are projected to slow total electricity demand growth over the period to 2040 to 30% less than in the New Policies Scenario; the rise of electric vehicles does not offset lower demand in the buildings and industry sectors. Unabated fossil fuel-fired generation falls from two-thirds of the power mix to about 15% in 2040, the balance coming from low-carbon sources (renewables, nuclear, and coal and gas fitted with CCS). Power sector emissions of CO_2 drop to a quarter of today's levels. The power sector accounts for 60% of emissions saved, relative to the New Policies Scenario.

6.1 Recent policy and market developments

Electricity is an essential component of modern societies and a key input to economic growth. It constitutes just under one-fifth of global final energy consumption and its share is steadily growing across all sectors. As the share of the services sector in the global economy rises, the share of electricity demand in final energy use tends to rise too. Rising incomes in developing countries are likely to lead to greater demand for electricity-based energy services, such as cooling, refrigeration, lighting and digital services. Extending reliable power availability to all citizens is a high priority in many developing countries, as around 1.2 billion people still lack access to electricity.

Three observations capture the rising importance of the power sector in the broader energy outlook. First, while inputs into power generation account for almost 40% of primary energy requirements today, these inputs are projected to account for half the growth in primary energy use to 2040. Second, investment in power plants and transmission and distribution grids is projected to make up around 47% of the projected $15.3 trillion investment in energy supply over the next decade. In some countries, large shares of ageing generation assets are likely to need replacement, in others new power plants and transmission lines will need to be built to fuel economic growth and satisfy the needs of emerging middle classes. Third, the power sector (emissions from which currently account for 42% of energy-related carbon-dioxide [CO_2] emissions) is in the vanguard of efforts to decarbonise the energy system. Electricity provides the means to use non-fossil fuels, e.g. hydropower, nuclear and, increasingly, non-hydro renewables such as wind and solar, to produce low-carbon final energy and to contribute to the decarbonisation of final uses previously dependent on fossil fuels, for example by means of electric vehicles in transport and efficient heat pumps in industry. Over the last decade, the number of countries with targeted support for renewables (with a strong concentration in the power sector) grew from less than 20 to over 150. The successful conclusion of the Paris Agreement in 2015 is set to provide a further, powerful impetus to efforts to lower the carbon intensity of the power sector.

For the first time in 2015, additions of renewables-based generating capacity worldwide exceeded those from all other energy sources taken together, and total installed renewables capacity passed that of coal. (See Chapters 10-12 for more extensive discussions of renewables, including their integration into electricity markets and IEA, 2016a). Among the dispatchable[1] technologies of hydro, bioenergy and geothermal, some 85 gigawatts (GW) of new capacity has been added in the last two years. In these two years, the capacity of variable renewables, chiefly wind and solar photovoltaics (PV), has expanded by 200 GW, with a record 114 GW in 2015. Falling technology costs and policy support seem certain to maintain this momentum (IEA, 2016b).

1. Technologies whose power output can be readily controlled – increased up to the maximum rated capacity or decreased to zero – in order to match the supply of electricity with demand.

Between the start of 2015 and late 2016, 19 new nuclear reactors commenced operation, (two-thirds of them in China), and construction has started on nine new reactors in the same period. Currently, some 64 GW of new nuclear capacity is under construction, principally in China, (one-third), but also in Russia, the United Arab Emirates, the United States, Korea, the European Union and India. One-seventh of the global nuclear fleet is 40 years old or more, but moves are underway in some jurisdictions (e.g. the United States) to extend nuclear plant lifetimes to 60 or even 80 years.

Among fossil fuels, coal and natural gas are the key energy sources of the global power system. New coal-fired plants continue to be built; in 2014 and 2015, installed global capacity increased by 125 GW (a 7% rise over 2013 levels). A further 250 GW was under construction (and an additional 1 100 GW at various stages of planning). In the case of gas, global capacity rose by more than 110 GW in 2014 and 2015 (again around a 7% rise), while more than 140 GW is under construction, and a further 660 GW planned.

Growth in global electricity generation has shown a marked slowdown since 2013, rising at only 1.5% per year, (less than half the rate of gross domestic product [GDP] growth) with barely 1% in 2015. By contrast, in the period 1990-2012, demand for electricity grew at 3% per year, almost in step with GDP growth of 3.4%. The slowdown in demand growth, coupled with the expansion of renewable generating capacity, resulted in coal-fired electricity output flattening in 2014, and falling in 2015 by around 3.5%, (reversing the trend of strong continuous growth since the turn of the century). Gas-fired power grew nearly 9% from 2013 to 2015. Total renewables generated electricity grew even faster, overtaking gas-fired power in the global mix.

Of the increase in renewables-based electricity of nearly 500 terawatt-hours (TWh) between 2013 and 2015, three-fifths came from wind power and PV, a contribution to power generation equivalent to the total annual electricity production of Italy. These changes caused the CO_2 intensity of the global power sector to drop by 4% to 500 grammes of carbon dioxide per kilowatt-hour (g CO_2/kWh), and total emissions from the power sector fell by around 2%. Given that the power sector has seen almost unbroken growth in emissions over the last quarter century, (with the exception of a modest fall in the recession years of 2008-2009), this is a notable development (see Chapter 8.2).

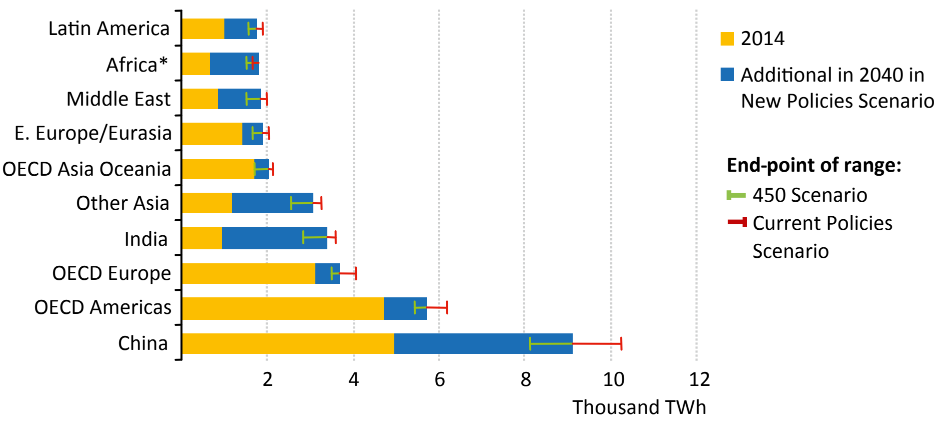
The interaction between low-carbon sources of electricity and power generated by fossil fuels is a major issue for the power sector outlook. Support policies for newer technologies, such as wind and solar, often include mandated shares of these generation sources. Many renewable sources of power also have very low short-run marginal costs, and so tend to be called upon ahead of coal and gas. As a result, even though today's lower prices for coal and gas increase their attractiveness, in many countries these two fuels only have access to a shrinking share of the market, for which they compete fiercely between themselves (IEA, 2016c). In addition, depressed wholesale prices that are being seen in some markets are creating considerable uncertainty over the business case for new investment in thermal generation capacity.

Recent years have seen major policy changes in a number of countries which are large power users, notably China and the United States. These changes, which will have important implications for the trajectory of their power sectors, are detailed in countries' Nationally Determined Contributions for COP 21, and are discussed in the regional insights section which concludes this chapter.

6.2 Trends to 2040 by scenario

This section examines and contrasts trends in our three main scenarios.[2] The evolution of the power sector varies markedly across the scenarios, reflecting different policy choices affecting demand and supply, including electricity prices. There is also a clear divergence in trends between more mature, developed economies of North America, Europe and Japan, and developing countries, notably China, India, Southeast Asia and the Middle East. The former tend to be characterised by lower rates of economic growth, declining shares of energy-intensive industry and clear signs of saturation in energy and electricity use. These countries already have high levels of appliance ownership and relatively little scope for further increases.

Figure 6.1 ▷ Electricity demand by region and scenario



Countries outside the OECD account for more than 80% of electricity demand growth to 2040 in all scenarios

* Electricity demand in Africa in the New Policies Scenario is higher than in the Current Policies Scenario as a result of new policies to provide greater access to electricity and more timely completion of new power plants. This increased demand is somewhat offset in the 450 Scenario, due to efficiency gains.

While developing countries are very diverse, they tend to exhibit faster economic growth, industrialisation and urbanisation (IEA, 2016d), sharply rising energy and electricity demand and, in a number of cases, a significant share of the population remaining without access

2. See Chapter 1 for a description of the scenarios.

to the modern energy services that electricity can provide. They may also have pressing air pollution problems (IEA, 2016e), frequently linked to energy resource extraction, production and use, and a heavy reliance on traditional use of solid biomass, again pointing to an expectation of growth in more modern energy services, including electricity. These trends have been clear over the last five years; OECD countries' electricity demand has been flat, while, outside the OECD, it rose at 5.5% per year, with most of the growth in developing Asia.[3] Electricity use in the countries outside the OECD overtook that of the OECD in 2012.

In the Current Policies Scenario, global electricity demand is projected to grow annually by 2.3% to 2040, less than the pace seen since 2000, but a still considerable 80% increase in absolute terms (Figure 6.1 and Table 6.1). Demand in developed economies grows by around 30% or around 2 850 TWh, a little faster than since 2000. The United States and Europe see annual growth of around 1%, below pre-recession levels, while Japan sees even lower growth. Electricity demand growth in countries outside the OECD slows to 3.1%, (half the rate seen since 2000), but still increases by over 13 600 TWh, to a level almost double that of the OECD countries. China, India and Southeast Asia are all projected to see strong growth: even though the rate of expansion in China slows to less than 3% per year, this still results in annual electricity use more than doubling between 2014 and 2040, to over 10 000 TWh. In India, electricity demand almost quadruples and, by 2040, approaches the current level of demand in the United States. Annual growth slows only modestly from recent levels of 7% towards 5% by 2040. Rapid urbanisation and electrification underpin a large increase in power use in India's buildings sector, to almost 1 800 TWh, with an important contribution coming from the 8% average annual increase in electricity demand for cooling in the residential sector. On a per-capita basis, India's electricity use triples from today's level; but at 2 200 kilowatt-hours (kWh) per person, it remains low by international standards. With power demand also rising fast across Southeast Asia, by 2040 developing countries in Asia account for 46% of worldwide power consumption.

In the New Policies Scenario, described in detail in section 6.3, global electricity demand is projected to rise by 13 700 TWh, 87% of this increase occurring in countries outside the OECD. The increase in Chinese electricity demand averages 2.4% per year, only a quarter of that seen in the last decade and just above half the rate of anticipated growth in GDP (an important factor in altering the global relationship between GDP and power demand). Nonetheless, China is still projected to be the source of 30% of global incremental demand to 2040, consuming double the electricity of the next largest user, the United States (and surpassing the per-capita use of Europe in the mid-2030s). Electricity demand in India is projected to more than triple as population and economic growth drive up demand growth at close to 5% annually, only marginally below the level in the Current Policies Scenario. Electricity demand in Africa increases at 4% annually, as the economy grows and wide ranging policies to increase access to reliable electricity bear some fruit, but annual per-capita use remains below 900 kWh, even in 2040.

3. Developing Asia includes all non-OECD Asian countries.

Table 6.1 ▷ Electricity demand by region and scenario (TWh)

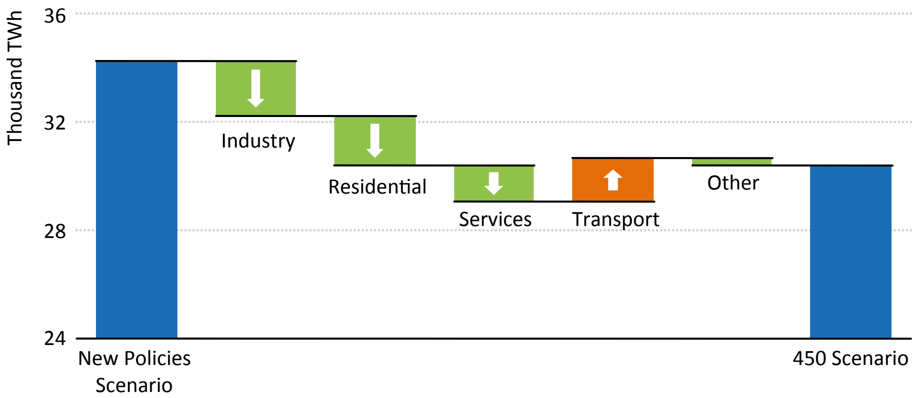
				New Policies Scenario						Current Policies		450 Scenario	
	2000	2014	CAAGR 2000-2014	2020	2025	2030	2035	2040	CAAGR 2014-2040	2040	CAAGR 2014-2040	2040	CAAGR 2014-2040
OECD	**8 600**	**9 561**	0.8%	**10 040**	**10 372**	**10 707**	**11 048**	**11 388**	**0.7%**	**12 412**	**1.0%**	**10 647**	**0.4%**
Americas	4 298	4 729	0.7%	4 948	5 100	5 279	5 471	5 697	0.7%	6 212	1.1%	5 421	0.5%
United States	3 590	3 880	0.6%	4 027	4 109	4 211	4 317	4 452	0.5%	4 907	0.9%	4 388	0.5%
Europe	2 819	3 113	0.7%	3 316	3 424	3 510	3 605	3 673	0.6%	4 069	1.0%	3 516	0.5%
Asia Oceania	1 482	1 720	1.1%	1 776	1 848	1 918	1 973	2 018	0.6%	2 131	0.8%	1 709	0.0%
Japan	1 005	955	-0.4%	929	944	965	982	999	0.2%	1 045	0.3%	805	-0.7%
Non-OECD	**4 599**	**10 996**	6.4%	**13 147**	**15 383**	**17 905**	**20 472**	**22 862**	**2.9%**	**24 625**	**3.1%**	**19 728**	**2.3%**
E. Europe/Eurasia	1 104	1 404	1.7%	1 474	1 571	1 684	1 801	1 912	1.2%	2 014	1.4%	1 648	0.6%
Russia	677	864	1.8%	882	935	999	1 060	1 116	1.0%	1 171	1.2%	972	0.5%
Asia	2 129	7 115	9.0%	8 834	10 500	12 291	14 036	15 563	3.1%	17 073	3.4%	13 490	2.5%
China	1 174	4 982	10.9%	5 999	6 925	7 832	8 604	9 116	2.4%	10 254	2.8%	8 108	1.9%
India	376	954	6.9%	1 336	1 759	2 265	2 820	3 383	5.0%	3 579	5.2%	2 823	4.3%
Southeast Asia	322	756	6.3%	996	1 206	1 453	1 724	2 014	3.8%	2 129	4.1%	1 694	3.2%
Middle East	359	828	6.1%	984	1 153	1 390	1 631	1 844	3.1%	1 972	3.4%	1 509	2.3%
Africa	385	643	3.7%	762	921	1 142	1 428	1 783	4.0%	1 670	3.7%	1 511	3.3%
Latin America	622	1 006	3.5%	1 094	1 238	1 398	1 575	1 758	2.2%	1 895	2.5%	1 571	1.7%
Brazil	327	516	3.3%	555	620	694	778	864	2.0%	936	2.3%	797	1.7%
World	**13 199**	**20 557**	3.2%	**23 186**	**25 755**	**28 612**	**31 521**	**34 250**	**2.0%**	**37 037**	**2.3%**	**30 374**	**1.5%**
European Union	2 605	2 774	0.5%	2 929	2 997	3 038	3 087	3 112	0.4%	3 461	0.9%	3 023	0.3%

Notes: CAAGR = compound average annual growth rate. 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.

In the 450 Scenario, electricity use rises at triple the pace of final energy consumption, electricity increasing its share in final consumption as a result. However, overall power demand growth of 48% between today and 2040 is almost 30% below the growth seen in the New Policies Scenario: a much stronger focus on more efficient electrical equipment, notably for electric motor systems (where savings due to energy efficiency exceed 1 600 TWh) and for major appliances and cooling systems (see Chapter 7), more than offsets increased electrification in the transport sector. In the 450 Scenario, all sectors see lower demand with the notable exception of transport, which expands by almost 1 600 TWh relative to the New Policies Scenario (Figure 6.2). The United States and China together account for more than 60% of the increase electricity use in road transport in 2040.

6

Figure 6.2 ▷ Change in global electricity demand in 2040 in the 450 Scenario relative to the New Policies Scenario



Transport is the only sector that sees higher global electricity demand in the 450 Scenario relative to the New Policies Scenario

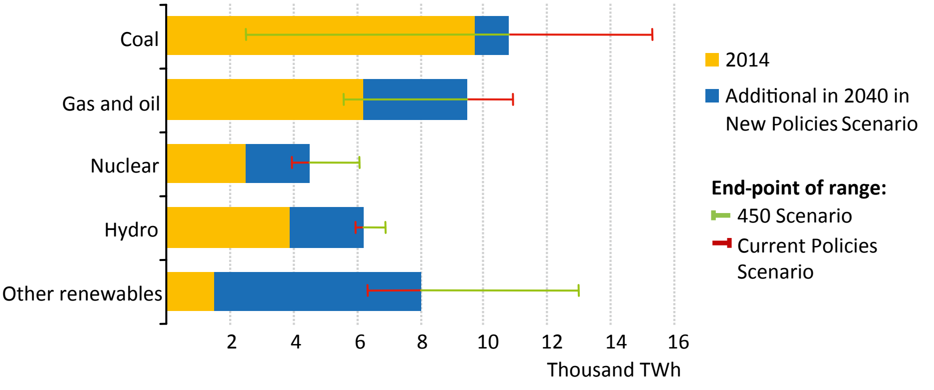
In the 450 Scenario, more stringent implementation and enforcement of building codes improves insulation and reduces the need for space heating in the buildings sector (mainly in OECD countries), compared with today, and moderates the growth in cooling demand (mainly outside the OECD countries). Even though more households use electricity for space and water heating, more efficient boilers and better insulated buildings keep electricity demand in the residential sector below that of the New Policies Scenario; this is true for all end-uses except cooking, where improved efficiency does not offset the growth due to higher reliance on electricity for this purpose.

There is a similar pattern in the industry sector, where increased electrification of heat demand with heat pumps is more than compensated (by almost a factor of five) by other efficiency gains related to electric motor systems in the 450 Scenario. As described in Chapter 7 (section 7.4.2), there are large savings available not only from the electric motors themselves but also from end-use devices (such as pumps, fans and air compressors), the introduction of variable speed drives in variable load systems and other system-wide measures. In addition, development of the electric process route in the steel sector – a way to reduce coal use – is limited in practice by the availability of scrap, so globally the level of steel produced through electric arc furnaces is similar in the two scenarios.

Overall, developing Asian economies account for almost two-thirds of the increase in power demand in the 450 Scenario. China, by dint of vigorous implementation of efficiency policies, contains annual electricity growth to less than 2%, with industrial power demand some 15% lower than in the New Policies Scenario thanks to tighter standards in a range of industries, notably steel and chemicals; residential and services sectors see even greater reductions of around 20% (more than 700 TWh) through stricter and more wide ranging efficiency standards. However, China's transport sector (especially road transport), sees major increases, rising to 830 TWh, well over double the level in the New Policies Scenario. In absolute terms, incremental power use in India, even in this scenario, is larger than current power use in OECD Asia Oceania, even as power use in most sectors is around 20% below that of the New Policies Scenario. Road transport sees an increase, by around 90 TWh. Electricity demand in Southeast Asia is some 16% below New Policies Scenario levels, but still more than doubles by 2040.

By contrast, in the OECD, demand growth is contained to less than 1 100 TWh in total (just over 10% over the *Outlook* period), with most regions showing low or even negative growth (Japan). OECD industrial and residential demand in 2040 are both below 2014 levels; only the services sector shows moderate growth, and all sectors are well below the New Policies Scenario levels. The exception is the transport sector (especially on-road) which grows rapidly, and by 2040 is almost four-times that projected in the New Policies Scenario (see Chapter 3.3.1).

Figure 6.3 ▷ Global electricity generation by fuel and scenario



Coal-fired generation sees the greatest variation across scenarios

Turning to the supply mix of electricity, the varied intensity of decarbonisation policies in the different scenarios leads to even more marked differences (Figure 6.3 and Table 6.2). The only common denominator is the outlook for oil in power: already a minor source, this fades to less than 1.5% of total generation in all scenarios. Gas-fired generation, which doubled between 2000 and 2015, doubles again in the Current Policies Scenario and increases by three-quarters in the New Policies Scenario. However, in the 450 Scenario, gas-fired generation peaks by the late 2020s, at a level around one-quarter higher than current levels and thereafter falls back towards current levels.

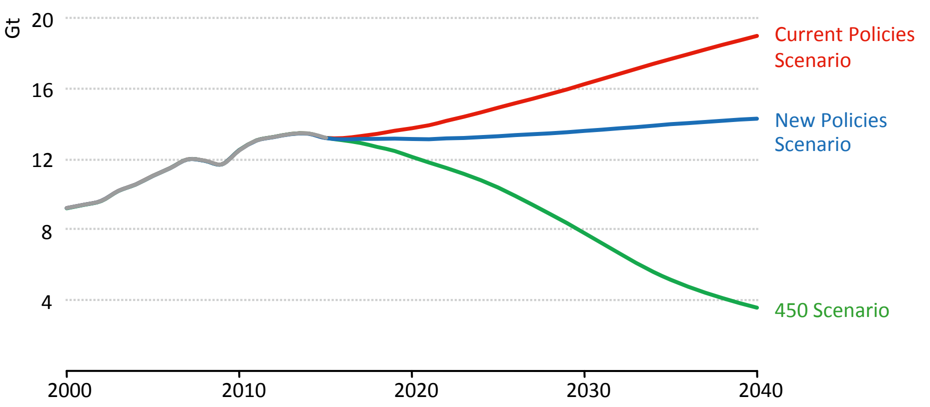
Table 6.2 ▷ World electricity generation by source and scenario (TWh)

			New Policies		Current Policies		450 Scenario	
	2000	2014	2025	2040	2025	2040	2025	2040
Total	**15 476**	**23 809**	**29 540**	**39 047**	**30 886**	**42 511**	**27 688**	**34 092**
Fossil fuels	10 017	15 890	17 175	20 243	19 183	26 246	14 113	8 108
Coal	6 005	9 707	9 934	10 787	11 479	15 305	7 062	2 518
Gas	2 753	5 148	6 514	8 910	6 957	10 361	6 466	5 389
Oil	1 259	1 035	727	547	746	580	585	200
Nuclear	2 591	2 535	3 405	4 532	3 319	3 960	3 685	6 101
Hydro	2 619	3 894	4 887	6 230	4 817	5 984	4 994	6 891
Other renewables	250	1 489	4 074	8 041	3 567	6 320	4 896	12 992
Fossil fuels	65%	67%	58%	52%	62%	62%	51%	24%
Coal	39%	41%	34%	28%	37%	36%	26%	7%
Gas	18%	22%	22%	23%	23%	24%	23%	16%
Oil	8%	4%	2%	1%	2%	1%	2%	1%
Nuclear	17%	11%	12%	12%	11%	9%	13%	18%
Hydro	17%	16%	17%	16%	16%	14%	18%	20%
Other renewables	2%	6%	14%	21%	12%	15%	18%	38%

Coal-fired generation (which doubled in the 20 years to 2014, to 41% of generation) is even more influenced by climate policies, given its higher carbon intensity. In the Current Policies Scenario, coal generation is projected to rise by nearly 60% by 2040, but the rise is only 11% in the New Policies Scenario. Across the three scenarios, the share of coal-fired power in the global power mix varies from a high of 36% in the Current Policies Scenario to a more modest 28% in the New Policies Scenario, and in the 450 Scenario to only 7% of global generation, in absolute terms, barely a quarter of 2014 generation. Given the importance of the power sector to steam coal demand, the implications for coal markets are significant (see Chapter 5, Figure 5.5). What is more, 70% of coal-fired generation in the 450 Scenario is dependent on plants equipped with carbon capture and storage (CCS), a technology yet to be developed and deployed at scale, and dependent on supportive policies or higher carbon prices. The share of fossil fuels in the generation mix, currently two-thirds, is projected to decline in the Current Policies Scenario to just above 60%. In the New Policies Scenario, the fall is faster, to just above half. However, in the 450 Scenario, the decline in market share is dramatic, to below a quarter, with gas-fired power twice as large as coal.

The projected decline in the share of generation from fossil-fuelled plants is matched by the rise of low-carbon power, especially renewables. Hydropower remains the most important contributor to low-carbon power, output increasing by more than half in all scenarios, with the biggest increase (3 000 TWh) and highest market share (20%) occurring in the 450 Scenario. Nuclear power output maintains a stable market share of around 11-12% in the New Policies Scenario, declines to 9% in the Current Policies, and grows to 18% in the 450 Scenario (almost two-and-a-half-times today's levels in absolute terms). The largest growth from any source comes from wind and solar, which are projected to grow rapidly in all scenarios, more than doubling output by 2020 in the 450 Scenario and showing major increases in the other scenarios. (The rise of renewable energy generation technologies is discussed more fully in Chapters 10-12.)

Figure 6.4 ▷ Global CO_2 emissions from fossil-fuel combustion in the power sector by scenario



The New Policies Scenario almost breaks the link between rising power demand and related CO_2 emissions, but the two are completely decoupled in the 450 Scenario

Global power sector CO_2 emissions increased by over 7% between 2010 and 2013, (almost 1 gigatonne [Gt] in total) before stabilising in 2014 and falling in 2015, mainly on the back of developments in China and the United States. In the Current Policies Scenario, emissions intensity is projected to improve from 516 g CO_2/kWh in 2014 to 415 g CO_2/kWh in 2040, but total CO_2 emissions in the power sector are still projected to grow steadily from 13.5 Gt to over 19 Gt by 2040. Cumulative emissions over the *Outlook* period total 410 Gt. In the New Policies Scenario, the carbon intensity of the global power mix falls to 335 g CO_2/kWh and total emissions are projected to slowly grow, so 2040 emissions are projected to be around 6% above those in 2014. Cumulative emissions total 354 Gt over the period 2015-2040, a relatively modest reduction of 14% from the Current Policies Scenario (Figure 6.4).

In the 450 Scenario, power sector emissions are projected to continue on their downward path through the *Outlook* period, falling at an annual average rate of 5% to 3.6 Gt in 2040, just over a quarter of 2014 emissions, or nearly 10 Gt below 2014 levels. This level of emissions has not been seen in the power sector since the 1970s, when power output at some 5 000 TWh, was well under one-sixth of that projected for 2040 in this scenario. Global emissions intensity in the sector falls to less than 80 g CO_2/kWh in 2040. Cumulative emissions over the *Outlook* period total 230 Gt, a dramatic reduction from the other scenarios. The power sector accounts for around 60% of the emissions avoided in this scenario, relative to the New Policies Scenario (see Chapter 8.4.1 and Chapter 10.5) and power sector emissions fall from more than 40% of energy-related CO_2 emissions today to less than 20% in 2040.

6.2.1 Accelerating the transition: power generation in the 450 Scenario

As noted, achieving the emissions trajectory required to meet the target of limiting the rise in average global temperatures to 2 °C requires effective efforts to reduce electricity demand, as well as large-scale deployment of all low-carbon power generation technologies, including renewables, nuclear (in countries in which it is acceptable) and fossil-fuel plants fitted with CCS, and reductions in output from unabated fossil-fuel power plants (Figure 6.5). The remainder of this section explores in greater depth the implications of the 450 Scenario for the power sector.

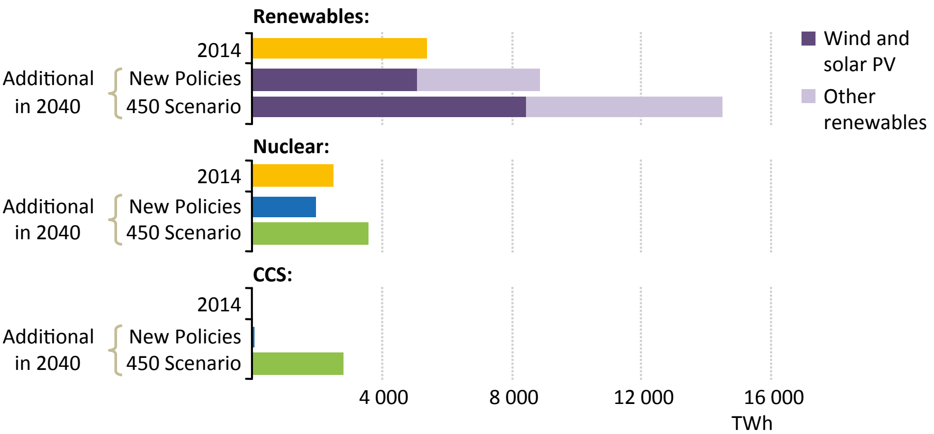
By 2040, 85% of global generation in the 450 Scenario is projected to come from low-carbon sources. Renewables expand to 58% of generation, compared with 37% in the New Policies Scenario and 23% today. Wind and solar expand to 10 500 TWh, almost a third of generation, from 4% today: wind power capacity is projected to increase from current levels by a factor of 5.5, to over 2 300 GW and solar PV to increase nine-times to 2 100 GW. Nuclear output more than doubles, based on a commensurate increase in capacity to 820 GW, with new builds in China, India, the United States, Southeast Asia, and the Middle East, plus lifetime extensions in many other countries (see Chapter 10.5.1 for regional breakdowns).

The contribution of coal shrinks to only 7% of the mix by 2040, of which 70% is generated by plants fitted with CCS, mostly in China and the United States (some 260 GW of coal-fired capacity is CCS-equipped, compared with 10 GW in the New Policies Scenario). Output from gas-fired power plants increases up until the late 2020s, but then falls to 16% of the mix by 2040, with capacity factors considerably lower than in the New Policies Scenario. By the end of the *Outlook* period, almost a fifth of gas-fired power comes from plants fitted with CCS, (mostly in the United States). More than a third of total output from plants fitted with CCS is from gas-fired plants, the balance from coal-fired units.

In the developed economies, by 2040 renewables-based capacity is projected to increase two-and-a-half times from 2015 levels (and is a third higher than the New Policies Scenario) to exceed 2 500 GW, with wind at over 920 GW and solar PV at 730 GW. Europe and the

United States are the major contributors; Europe with 380 GW of wind by 2040 and the United States with 325 GW of solar PV. Nuclear capacity increases by over one-fifth relative to the New Policies Scenario. By contrast, OECD coal capacity continues to fall to below 30% of its 2010 peak and CCS is fitted to a quarter of OECD coal generating plant: well over half is located in the United States. The impact on generation is marked: in the United States, fossil-fuel power output falls to 1 100 TWh by 2040, less than a quarter of total generation. Some 85% of this is gas-fired and unabated coal generation disappears. CCS-fitted plants (both coal and gas) account for less than 700 TWh. Wind and solar combined provide almost 40% of electricity, up from 5% now. In the European Union, fossil-fuelled power output falls to 10% of the total, with wind and solar rising to proportions similar to those in the United States. Combined absolute output from these sources increases almost four-fold from today's levels. Nuclear, hydro and bioenergy account for almost half of generation.

Figure 6.5 ▷ **Growth in generation to 2040 by low-carbon technology in the New Policies and 450 Scenarios**



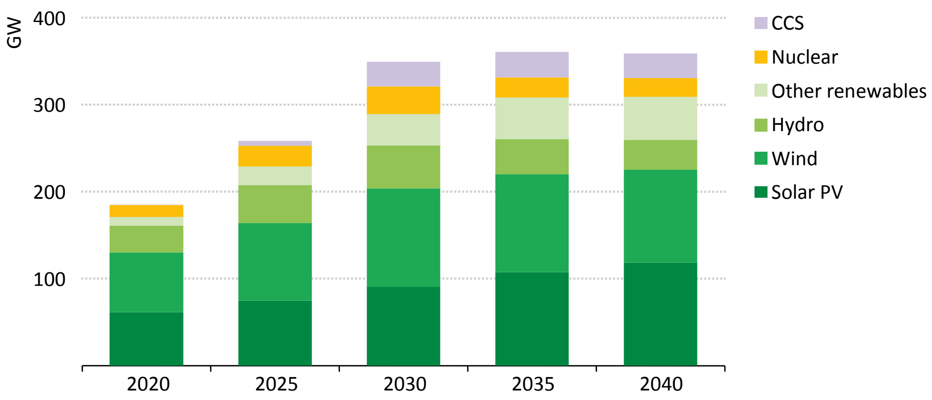
Generation from renewables more than triples in the 450 Scenario, compared with today; nuclear and CCS also support decarbonisation

In the countries outside the OECD, wind and solar PV capacities are each projected to increase to nearly 1 400 GW by 2040 (about half of the rise in each case being in China), more than 55% higher than the already impressive levels reached in the New Policies Scenario. Coal capacity in these economies continues to rise to 2020, surpassing 1 500 GW (two-thirds of which is in China), a 57% increase since 2010. But capacity additions then slow sharply, so that, by 2040, coal-fired capacity is at the level of 2010. China has 190 GW of CCS-fitted coal plant by 2040, compared with only 8 GW in the New Policies Scenario. China's gas-fired capacity triples in both the New Policies and 450 Scenarios, gas playing an important balancing role in the power system. Nuclear capacity in countries outside the OECD expands significantly, from 92 GW now to over 440 GW, (50% more than the New

Policies Scenario) with China responsible for more than half of the increase and India for one-sixth. Hydropower sees a relatively modest 14% boost over the level reached in the New Policies Scenario.

China's projected coal-fired power output falls from almost three-quarters of the total in 2014 to less than one-sixth by 2040, most of it coming from plants with CCS. Globally, three-quarters of power generated from CCS-equipped coal-fired power plants is in China (the United States and India contribute half of the balance). Even in the 450 Scenario, on the basis of plant recently installed and plant under construction, China is set by 2020 to have around 480 GW of high efficiency supercritical and ultra-supercritical plant, much located close to potential storage sites, and these plants are especially good candidates for CCS retrofit (IEA, 2016f). The relatively young age of China's coal fleet provides a strong incentive to develop and deploy CCS, especially over the next 20 years. Nevertheless, by the end of the *Outlook* period, wind, nuclear and hydro all have a share in generation in China bigger than coal, and wind becomes the single largest source of power. In addition, solar technologies generate 1 150 TWh in China, (more electricity than total output in Japan today). In India, the contrast in generation between the New Policies Scenario and the 450 Scenario is equally stark. In the New Policies Scenario, India becomes the second-largest producer of coal-fired power before 2025, on its way to more than doubling coal generation by 2040. In the 450 Scenario, coal generation peaks by 2020, and by 2040 gas, wind, hydro, and solar PV each contribute more than 500 TWh, all more than coal, which falls to 12% of the mix, compared to three-quarters today.

Figure 6.6 ▷ Global annual capacity additions of low-carbon technologies in the 450 Scenario



Annual capacity additions of low-carbon technologies need to exceed 350 GW per year by the 2030s

Note: Other renewables includes biomass, geothermal, concentrating solar power and marine.

With more than 350 GW in new low-carbon generation capacity required globally each year in the 450 Scenario from the 2030s onwards (Figure 6.6), it is no surprise that this dominates the investment requirement (see Chapter 2, Figure 2.13). By 2040, total annual power plant investment has risen by two-thirds to around $700 billion, of which almost three-quarters is for renewable technologies. The share devoted to fossil fuels falls from a third to less than 15%. Coal investment falls by almost 50% in dollar terms, but the share of this devoted to CCS rises from a very low share (in the New Policies Scenario) to around 80%: almost all investment in coal-fired plants in the United States and China is made in plants with CCS. Globally, about 40% of gas investment is also CCS based. Nuclear more than doubles to $80 billion per year by 2040.

Lower projected demand in the 450 Scenario reduces spending on transmission and distribution networks by a cumulative $850 billion (compared with over $8 trillion required in total in the New Policies Scenario). However, the annual average spending on networks in the 450 Scenario, having diverged for much of the *Outlook* period, gradually catches up with that of the New Policies Scenario because of the increased investment required to integrate greater shares of variable renewables into the power system (see Chapter 12).

6.3 A closer look at the New Policies Scenario

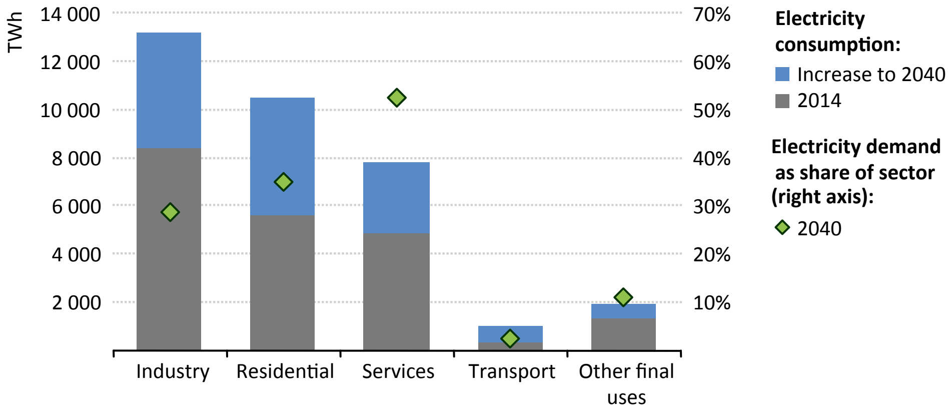
This section analyses developments in the electricity sector in the New Policies Scenario to 2040 in more detail. It covers projected electricity demand, capacity (including additions and retirements), generation, investment and greenhouse-gas (GHG) reductions and concludes with regional insights.

6.3.1 Electricity demand

Electricity demand[4] is strongly correlated to economic growth, although the extent of the linkage depends on a country's level of economic development, the structure of its economy and the extent of access to electricity. Over the last two decades, electricity demand globally has risen almost in tandem with GDP. But in the last few years, there are clear signs of this relationship changing. In the New Policies Scenario, the linkage between growth in global electricity demand and GDP continues to weaken, as efficiency improvements and the decline of energy-intensive industry in mature economies, plus the rise of the services sector everywhere, including in emerging economies, contribute to a decline in electricity intensity (electricity use per dollar of GDP). Globally, industry remains a major source of electricity demand growth (with the increase concentrated almost entirely outside the mature economies of the OECD), but residential and services sectors demand also rises rapidly (Figure 6.7).

4. 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.

Figure 6.7 ▷ **Growth in global electricity demand by sector and electricity's share of sector demand in the New Policies Scenario**

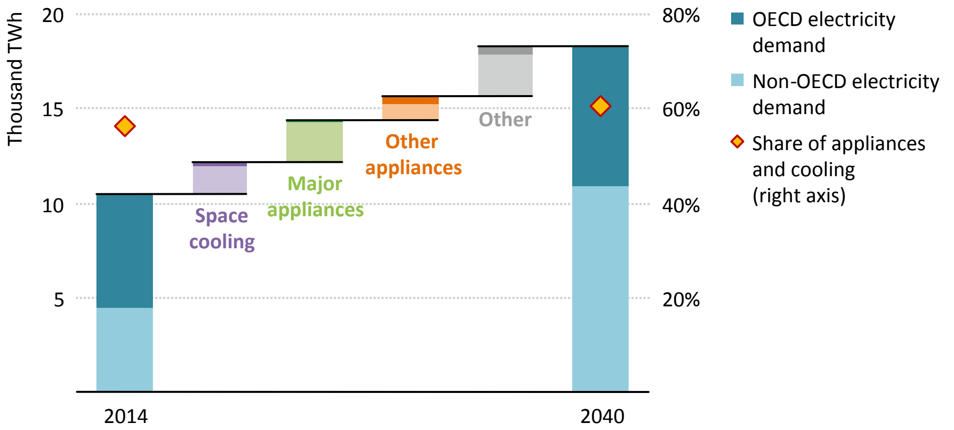


Globally all end-use sectors see robust growth in electricity demand

Today, electricity accounts for 30% of energy consumption in the buildings sector, but due to strong growth it rises to more than 40% in 2040. The growth take place mainly in countries outside the OECD, due to the rapid uptake of appliances and cooling systems from today's relatively low ownership rates: the fastest-growing non-OECD countries have significantly less need for space heating than in developed countries, but higher needs for space cooling (Figure 6.8). Total electricity consumption increases over time as rising living standards encourage people to buy larger appliances, e.g. refrigerators and televisions, and to switch from fans to air conditioners, which can consume up to ten-times more power. Smaller appliances, e.g. vacuum cleaners, hair dryers and network devices, represent up to half of the electricity consumption from appliances, but are not subject to energy efficiency standards in most countries. Consequently, these types of appliances contribute to driving up electricity demand in all major world regions, including OECD countries.

Within the mature economies of the United States, Europe and Japan, current electricity demand trends continue in the New Policies Scenario. These include generally slow growth, with industrial demand growth even slower, but relatively stronger growth in residential and especially services sectors' electricity demand. Since 2007, power demand in these economies has been flat or declined: industry use has fallen and only the services sector has seen modest growth. By 2010, services had emerged as the largest sector in power demand in the United States and Japan; two decades earlier it had accounted for barely a fifth of electricity use. In our *Outlook*, industry and residential demand recover slowly, but grow at less than 0.5% per year. Power use in the services sector grows at a higher rate, adding some 500 TWh in absolute terms, accounting for about half of total demand growth. Overall in OECD countries, GDP is assumed to grow at 1.9% per year, but electricity demand grows at only around one-third of that rate due to slowing population growth, saturation of electricity demand in some areas, a major push on energy efficiency and ongoing structural economic changes. Electricity use in transport, by contrast, triples to 330 TWh, accounting for around a third of the global increase in this sector. While the use of electricity for rail transport doubles, it is the road sector that sees the biggest increase, rising to around 140 TWh, as more electric vehicles enter service. Notwithstanding this rapid growth, electricity provides only 3% of the OECD transport sector's energy needs in 2040 (see Chapter 3.3.1).

Figure 6.8 ▷ Electricity demand in buildings by equipment and region in the New Policies Scenario



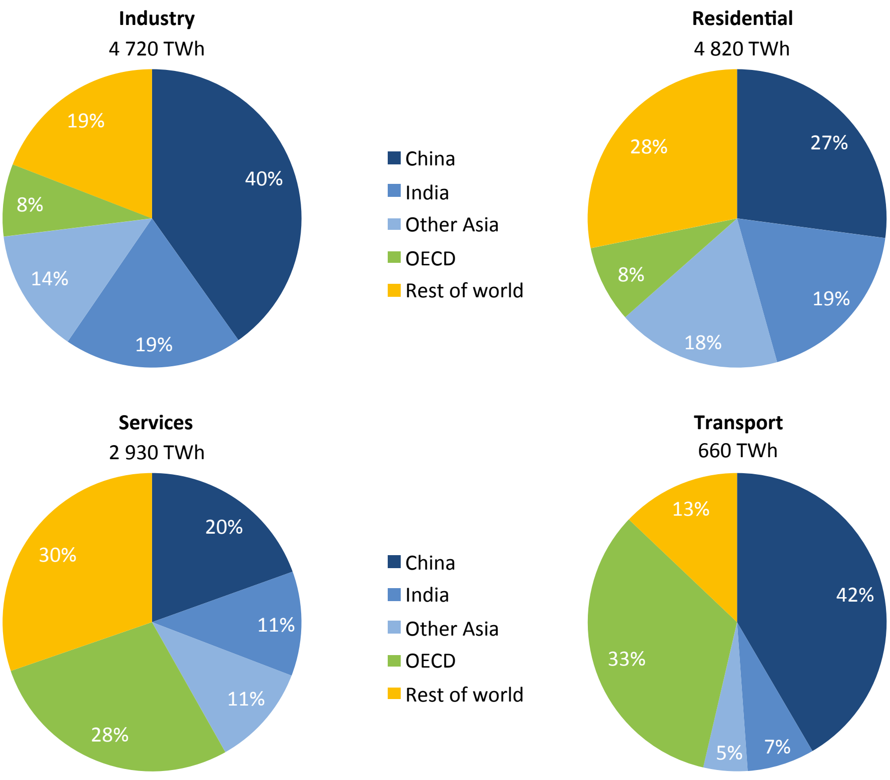
Countries outside the OECD account for the majority of electricity growth, due to the increased ownership of appliances and cooling systems

Notes: Major appliances include refrigerators and freezers, cleaning machines (washing, dryers and dish washers), televisions and computers. Other appliances cover appliances, such as vacuum cleaners, kettles and hair dryers. The other category includes other end-uses, such as lighting, space and water heating, and cooking.

The picture for countries outside the OECD is quite different, even though here too, there is a significant slowing in aggregate growth in electricity demand, compared with the past. Part of this is due to an expected slowdown in the expansion of GDP, from the 6% annually of recent years to an average of 4.4% per year. Population growth also slows, but it is structural economic shifts that mostly account for the reduced pace of growth in electricity demand from 6.4% (above GDP growth) to 2.9%, well below that of GDP. Nonetheless, the electrification of these economies continues apace; by 2040 electricity accounts for 23% of final energy consumption, almost double the share in 2000.

Developing Asia is the driver of global demand growth in all sectors (Figure 6.9). Industrial electricity demand growth in the countries outside the OECD slows from the 6.9% of recent years to 2.3%, but it still increases by more than 4 300 TWh. China remains the biggest contributor to industrial demand growth (some 1 900 TWh) while India increases by 900 TWh. Demand from the buildings sector in China and India combined grows by more than 3 100 TWh. Within this sector, China, India and other developing Asian countries account for almost two-thirds of global residential demand growth, underpinned by continued urbanisation (already today, two-thirds of final energy use in the buildings sector is consumed in urban areas). Electricity use for cooling in buildings in India and China grows to almost 1 200 TWh in 2040, nearly four-times today's level. Demand in the services sector also increases rapidly, with China and India accounting for more than 40% of the growth outside the OECD. Developing Asia also increases transport electricity use by 360 TWh, more than half of the global increase in this sector. Nonetheless, despite impressive increases in many regions, power demand in the transport sector makes up less than 3% of the world's power use in 2040.

Figure 6.9 ▷ Change in electricity demand by sector and region in the New Policies Scenario, 2014-2040



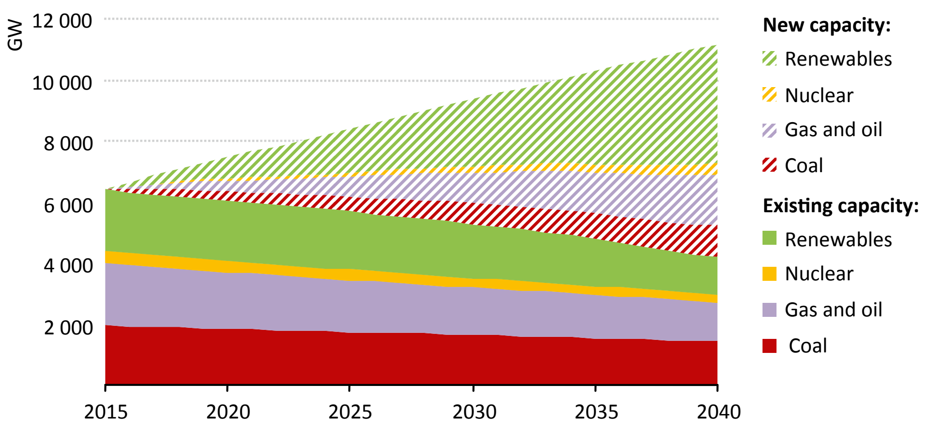
Developing Asia takes the lead in pushing demand higher in all sectors

6.3.2 Capacity and generation

In the New Policies Scenario, global installed generating capacity is projected to rise from 6 400 GW in 2015 to nearly 11 200 GW in 2040 GW.[5] Within this overall figure lies a complex regional pattern of capacity retirements, additions and shifts in the make-up of the generation capacity, varying over time (Figure 6.10). The technical life of generation technologies varies; the longest are hydro (70 years), coal (50 years) and nuclear plants (40-60 years). Subject to technical, economic and safety constraints, power plants can be refurbished, extending their lifetimes. Some nuclear plants are seeking authorisation beyond 60 years towards 80 years, notably in the United States. Renewable technologies, such as wind and solar PV, tend to have a shorter economic life, although turbines and panels can be replaced (see Chapter 10).

At global level, coal-fired capacity expands by a quarter, even though its market share is projected to fall from 31% to 22%. Developing countries, especially in Asia, account for four-fifths of this total, which increasingly consists of higher efficiency plant (more than half of the coal fleet is supercritical or ultra-supercritical by 2040). Gas, hydro and nuclear all experience modest falls in market shares. Other renewables, including wind, bioenergy and solar technologies, increase by 2040 from 12% to 30% of installed capacity, resulting in a major shift in generation over the *Outlook* period.

Figure 6.10 ▷ Global installed generation capacity in the New Policies Scenario



Renewables account for almost two-thirds of the overall growth in installed generation capacity to 2040

Over 2016-2040, some 2 400 GW of capacity is projected to be retired (Table 6.3). Again, there are important differences between mature economies, with many older plants (especially coal and nuclear) and emerging economies, where most capacity is more recent, in the timing and type of retirements. In the period to 2025, retirements occur predominantly

5. All capacities reported are gross generating capacity, where onsite power consumption is not subtracted.

in developed countries, which account for almost two-thirds of plant closures. Coal plants are the largest group to close, almost a third of the total. Reflecting the relative age of plants, plus the strong policy measures adopted in, for example the United States and the European Union, five-sixths of coal plant retirements occur in OECD countries and Eurasia/ Eastern Europe. A high proportion of United States coal plant retirements (some 60 GW) occur by 2025, in large part due to tightening emissions standards. Overall, a similar picture emerges for natural gas, although these retirements are split between OECD countries and Russia. Older, oil-fired plants, often running at low capacity factors, also figure prominently in plant retirements in developed countries.[6] Almost half of plant closures globally in the next ten years are fossil-fuel plants in mature economies. More than one unit in every six of the global nuclear fleet is projected to be retired by 2025, mostly in developed economies and Russia; 40% of the retirements are in Europe. The imminent retirement of large amounts of baseload generation plant poses major policy challenges for a number of mature economies.

In the remainder of the *Outlook* period (2026-2040), the share of retirements in developing countries is projected to rise. For example, the retirement of coal-fired plants in China and India make up an increasing share of total coal plant retirements. But the most notable feature of this period is the share of new renewable installations (wind and solar) that reach the end of their assumed operational lifetimes. Given that the developed economies tended to be early adopters of these technologies, these retirements are concentrated there, with about a third coming from Europe, followed by retirements in developing countries towards the end of the *Outlook* period. Between 2030 and 2040, annual renewables retirements worldwide accelerate from 40 GW to over 100 GW, wind and solar making up almost 90% of the latter figure. Nuclear plant closures total 150 GW over the next quarter century, out of a current fleet of just over 400 GW.

Installation of new generation capacity is a function of retirements, demand levels and policy shifts, and can provide an insight into how rapid and effective policies can be in changing the generation mix. Again, the differences between developed and emerging economies are pronounced (Table 6.4). Developing Asia dominates coal-fired capacity additions, with around three-quarters of the global total of over 1 000 GW: India takes over from China as the leading builder of coal plants later in the projection period. But the region also builds more than 2 000 GW of renewables capacity, two-thirds of it in China. Gas-fired plant is important in the Middle East and Eurasia, while China builds 36% of the world's nuclear capacity; but, later in the projection period, new nuclear capacity appears in the United States, Europe, Russia and India. In the latter part of the *Outlook* period, renewables constitute three-fifths of newly built capacity almost everywhere, with gas providing half of the remainder.

6. Annual capacity factor can be defined as the actual gross electricity production over the course of a year divided by the theoretical maximum production over the same period (capacity multiplied by hours per year [8 760]). For example, 1 GW of capacity that generates 4 380 gigawatt-hours (GWh) of electricity in one year has a capacity factor of 50%, producing exactly half of the maximum 8 760 GWh (4 380 GWh generated = 50% capacity factor × 1 GW capacity × 8 760 hours).

Table 6.3 ▷ Cumulative power plant capacity retirements by region and source in the New Policies Scenario, 2016-2040 (GW)

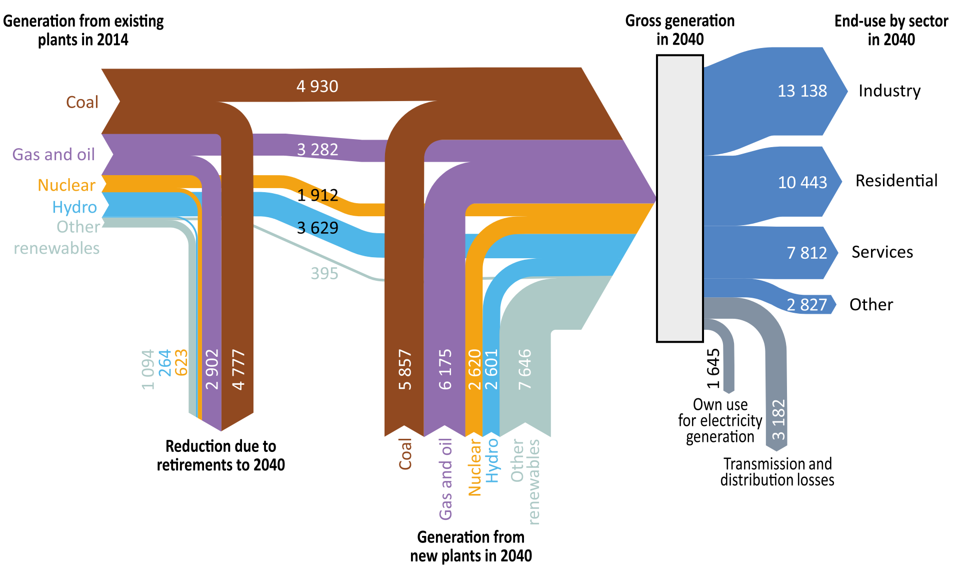
	2016-2025						2026-2040						2016-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
OECD	**124**	**87**	**117**	**52**	**74**	**455**	**156**	**163**	**49**	**52**	**511**	**931**	**1 385**
Americas	64	62	56	13	25	221	41	89	15	12	167	325	545
United States	62	55	45	10	19	191	33	85	7	12	137	275	466
Europe	47	4	28	27	42	148	86	44	19	35	276	459	607
Asia Oceania	13	22	32	12	7	86	29	30	15	5	68	147	233
Japan	7	18	29	11	5	71	10	22	12	5	49	98	169
Non-OECD	**91**	**90**	**53**	**14**	**17**	**266**	**165**	**136**	**97**	**29**	**327**	**754**	**1 020**
E. Europe/Eurasia	53	66	10	9	0	139	45	48	7	25	16	140	279
Russia	22	50	2	8	0	81	21	39	2	12	3	77	158
Asia	29	5	10	4	11	60	93	35	38	1	277	445	504
China	19	0	1	-	4	25	50	1	4	-	218	273	298
India	7	0	0	0	3	11	35	7	9	1	42	93	104
Southeast Asia	0	2	5	-	3	10	5	20	16	-	11	52	62
Middle East	0	11	12	-	0	24	0	30	30	-	1	62	86
Africa	8	3	11	-	2	24	25	15	11	2	9	61	85
Latin America	1	5	9	0	5	19	2	8	11	1	24	46	66
Brazil	0	1	1	-	3	6	1	0	1	1	17	19	24
World	**215**	**178**	**170**	**66**	**92**	**720**	**321**	**299**	**146**	**82**	**837**	**1 685**	**2 405**
European Union	49	6	29	26	37	147	86	42	19	34	268	450	597

Table 6.4 ▷ Cumulative gross power plant capacity additions by region and source in the New Policies Scenario, 2016-2040 (GW)

	2016-2025						2026-2040						2016-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
OECD	**41**	**216**	**13**	**31**	**521**	**823**	**37**	**356**	**7**	**68**	**973**	**1 441**	**2 264**
Americas	3	119	8	8	228	367	4	177	5	22	380	588	955
United States	2	86	7	8	175	279	3	123	4	20	294	444	723
Europe	21	57	1	6	219	303	14	140	2	32	457	645	948
Asia Oceania	17	40	5	18	73	153	19	39	0	14	136	208	361
Japan	4	29	5	3	45	85	3	21	0	3	80	107	193
Non-OECD	**450**	**383**	**45**	**99**	**899**	**1 876**	**494**	**617**	**62**	**152**	**1 720**	**3 044**	**4 920**
E. Europe/Eurasia	42	87	0	19	18	165	34	71	0	34	64	204	369
Russia	13	51	0	15	7	87	12	38	0	22	29	101	187
Asia	379	137	9	72	725	1 323	410	243	31	98	1 288	2 070	3 393
China	190	62	0	59	491	802	108	70	0	68	815	1 062	1 864
India	114	26	4	10	154	308	186	66	15	24	289	579	888
Southeast Asia	54	31	2	1	42	130	82	75	8	4	104	271	402
Middle East	2	82	19	6	21	130	1	131	10	9	100	251	381
Africa	24	53	12	-	56	145	45	109	18	7	140	318	463
Latin America	4	25	5	2	78	113	4	63	3	4	128	201	314
Brazil	1	7	0	1	47	56	-	10	1	3	70	83	139
World	**491**	**599**	**58**	**131**	**1 419**	**2 699**	**531**	**973**	**69**	**220**	**2 693**	**4 486**	**7 184**
European Union	16	52	1	4	187	259	9	121	1	31	429	592	851

By 2040, almost 25 000 TWh of electricity supply comes from new power plants, while 14 000 TWh (36% of total generation) comes from plant in existence today, highlighting the massive challenge in attracting this level of investment for new power plants, much of it relatively capital intensive (Figure 6.11). Overall, incremental electricity demand of some 13 700 TWh is projected to be met by new generating plant of all types, but with a sharp increase in the share of renewables and a fall in the share of coal, especially in OECD countries, where coal-fired generation falls from a third to a sixth of generation. By the end of the *Outlook* period, three-quarters of the world's coal-fired power is generated in developing Asia, but the share of coal-fired generation there falls from 67% to 45%, as renewables more than triple in the region, to 6 000 TWh, almost a third of the power mix. Countries in the OECD generally see a doubling in the market share of renewables. Europe leads the way (from 29% to 53%): the United States and Japan both see renewables attain a market share of 30%. Excluding hydro, other renewables achieve the biggest increase in market share, from 6% now to more than 20% in 2040. Globally, all forms of renewables overtake coal as the major generation source by around 2030.

Figure 6.11 ▷ Global generation by fuel and demand in the New Policies Scenario (TWh)



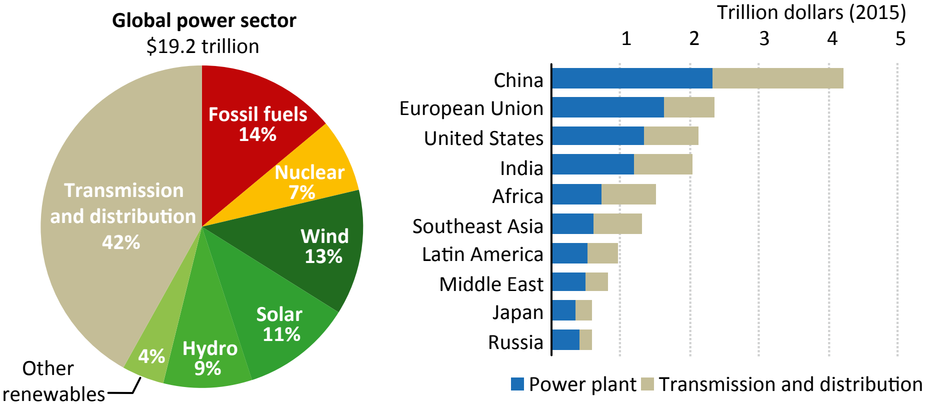
The global generation mix becomes more diverse to meet a power demand increase of 13 700 TWh by 2040

6.3.3 Investment

In the New Policies Scenario, cumulative global investment in the power sector is estimated to be \$19.2 trillion over the 2016-2040 period, averaging \$770 billion per year (Table 6.5 and Figure 6.12). Transmission and distribution investment accounts for 42%

of the total, spread relatively uniformly over the *Outlook* period. Well over half of this investment is required to meet increased demand, mostly in countries outside the OECD. By comparison, given low demand growth, developed economies account for only one-quarter of investment in this category. Additional investment in networks to accommodate higher shares of renewable energy makes up about 5% ($430 billion) of total transmission and distribution investment.

Figure 6.12 ▷ Cumulative power sector investment in the New Policies Scenario, 2016-2040



Two-and-a-half times as much is invested in renewable technologies than that of fossil-fuel plants

As we have seen, investment in new generation capacity is dominated by renewable energy technologies: these technologies account for around 60% of the total in the next decade, accelerating to two-thirds later in the *Outlook* period. In 2040, almost half of the power plant investment of $515 billion is projected to be made in wind and solar technologies, with a further 18% in hydro and bioenergy. The share of total investment for renewables is highest in the OECD countries, although, in absolute terms, developing countries typically spend about one-and-a-half times as much as developed economies on renewables-based generation investment. Together, China and India are projected to invest $2.3 trillion over the *Outlook* period in renewables, around a fifth of total global investment in power generation. Mobilising investments on this scale is a profound challenge, with a persistent risk that there will be under-investment in power plants and other infrastructure, with consequent risks to the security of electricity supply, if regulatory frameworks or market designs are flawed. This applies to renewable technologies but also to other generation investments, the incentives for which are often diminished by rapid growth in low marginal cost sources of power. The risks are widespread, and cover many developed markets, especially in Europe, as well as emerging economies (see Chapter 2.6).

Table 6.5 ▷ Cumulative investment in the power sector by region and type in the New Policies Scenario, 2016-2040 ($2015 billion)

	2016-2025						2026-2040						2016-2040
	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Total
OECD	**285**	**222**	**1 115**	**1 622**	**976**	**2 597**	**401**	**403**	**1 728**	**2 532**	**1 389**	**3 922**	**6 519**
Americas	115	91	468	674	410	1 084	191	153	661	1 005	619	1 624	2 709
United States	87	75	368	531	330	861	145	139	511	795	465	1 260	2 121
Europe	97	64	484	645	373	1 018	139	187	815	1 142	489	1 630	2 649
Asia Oceania	72	67	163	302	192	494	71	62	252	386	282	667	1 162
Japan	37	15	99	150	95	246	25	22	140	187	148	335	580
Non-OECD	**863**	**307**	**1 429**	**2 599**	**2 014**	**4 612**	**1 135**	**485**	**2 806**	**4 426**	**3 681**	**8 106**	**12 719**
E. Europe/Eurasia	173	76	39	287	171	458	154	136	149	439	266	705	1 164
Russia	82	61	16	159	65	223	76	84	78	237	111	348	571
Asia	500	202	1 068	1 769	1 387	3 157	659	273	1 850	2 783	2 310	5 093	8 250
China	200	159	666	1 025	797	1 822	130	182	997	1 309	1 078	2 388	4 209
India	149	29	225	403	291	694	268	67	445	779	566	1 345	2 040
Southeast Asia	103	2	90	196	221	417	179	16	222	416	482	898	1 314
Middle East	85	21	47	153	95	249	113	32	206	352	218	570	818
Africa	80	-	122	202	202	404	159	27	334	520	598	1 118	1 522
Latin America	25	9	154	187	158	345	50	16	266	332	288	620	965
Brazil	6	5	88	99	83	181	7	11	130	149	158	307	488
World	**1 148**	**529**	**2 544**	**4 220**	**2 989**	**7 210**	**1 536**	**888**	**4 534**	**6 958**	**5 070**	**12 028**	**19 238**
European Union	86	59	410	554	325	879	116	187	764	1 067	407	1 474	2 353

Note: T&D = transmission and distribution.

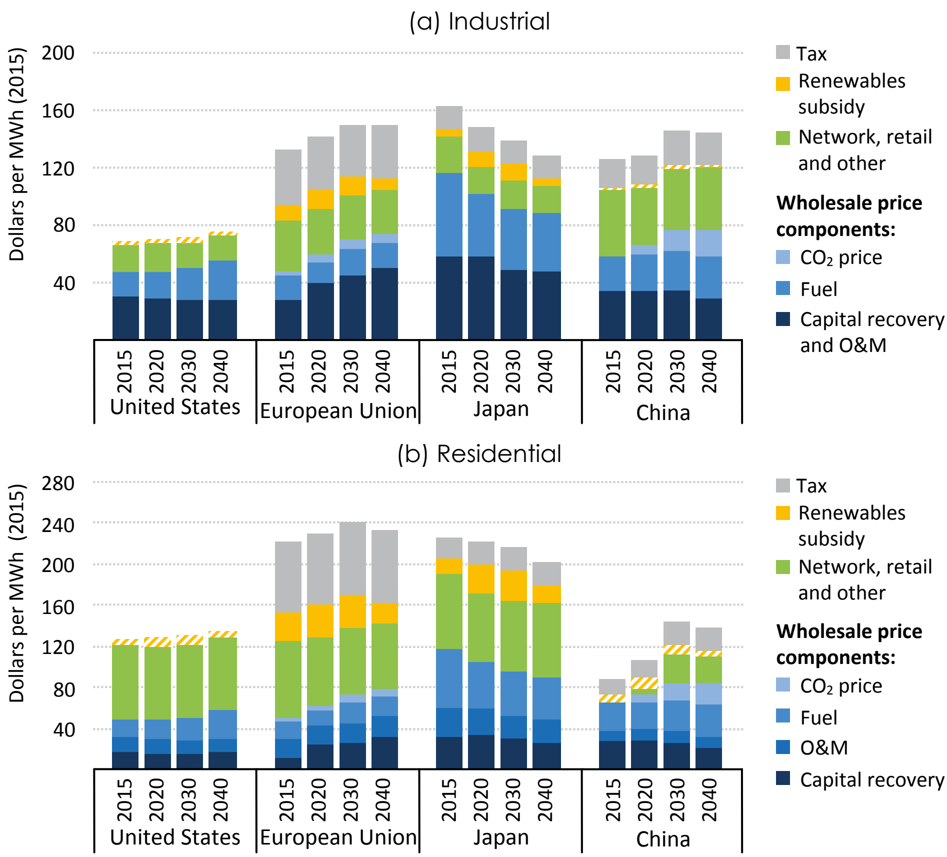
6.3.4 End-user electricity prices

Electricity prices to end-users are strongly influenced by wholesale generation costs, transmission and distribution costs, retail costs for commercial and residential consumers, and subsidies and taxes. How these cost factors are reflected in prices depends heavily on the way that the electricity market is set up and the type, degree and scope of regulation (most regions have both competitive and regulated portions of the power system). Wholesale electricity prices and costs have recently decoupled in some OECD power markets, particularly where the share of renewables with very low marginal costs is increasing. Wholesale prices have been driven down, and can reach levels that provide returns insufficient to attract investment in new or even existing power plants. In the longer term, wholesale prices need to fully cover generation costs (including sufficient returns on capital investment) if price signals are to trigger adequate and timely investment: the assumption that this will be the case is reflected in wholesale electricity prices beyond 2020 in the New Policies Scenario.

Wholesale power generation costs are the most important factor in power pricing, comprising capital, operating (including fuel costs) and CO_2 costs where applicable. The mix of available power generation technologies influences how wholesale costs evolve over time. For regions relying more heavily on highly capital-intensive technologies, such as nuclear and renewables, upfront investment is higher but fuel costs are negligible, or at least lower and more stable. Low-cost domestic fuel sources, such as coal or natural gas in the United States, can put strong downward pressure on costs, while high-cost imports (such as seen in Japan in recent years) have the opposite effect. With an economic lifetime extending over decades, the turnover of power plants is generally slow; decisions taken today will influence costs for decades into the future. Transmission and distribution losses are inevitable to some extent, but efforts to reduce them, as are being made in India and Mexico (IEA, 2016g), can significantly reduce their impact on end-user electricity prices.

In industry, electricity prices can be an important factor in overall competitiveness. Today average electricity tariffs for the industry sector in the United States are lower than in China and Japan, and well below those of the European Union, reflecting very low natural gas prices and low taxes in the United States (Figure 6.13a). While electricity prices rise almost everywhere to 2040 in the New Policies Scenario, the United States retains its competitive advantage, even as gas prices increase somewhat. Prices in China are projected to rise over the *Outlook* period as carbon prices become more widespread. Prices in the European Union, already high, increase further, as larger shares of capital-intensive technologies replace ageing fossil fuel-fired plant. The share of capital recovery in total costs in the European Union is projected to be one of the highest worldwide to 2040, putting considerable pressure on market design to encourage investor certainty. Today's wholesale prices in the European Union are around \$15-20 per megawatt-hour (MWh) below costs, a situation that undercuts the viability of investment unless the plant is subsidised (IEA, 2014). Japan's high industry prices reflect high wholesale generation costs, exacerbated in recent years by the need to import larger quantities of gas and oil. These pressures are projected to moderate over the *Outlook* period, so that Japan's industrial prices fall over time, even below those in the European Union and China.

Figure 6.13 ▷ End-user electricity prices in the New Policies Scenario



Regional price trends are driven by different underlying costs and regulatory frameworks

Notes: MWh = megawatt-hour. Hatched areas represent subsidies that are partly or fully borne by taxpayers rather than consumers. Prices for China do not include the potential removal of cross subsidies from other sectors.

Residential electricity tariffs tend to be higher than those to industry, (reflecting dispersed customer bases that require high-cost distribution lines and retail services) except where residential prices are controlled or subsidised. Prices within and between countries show a wide range, reflecting sub-regional differences, rate structures that favour low-income consumers, and include time-of-use and other features (Figure 6.13b). US prices for residential consumers reflect low wholesale costs, but high network and retail costs. China's residential users benefit from an important cross-subsidy from industrial users (which is partly removed by 2040). Over the *Outlook* period, residential electricity prices in all regions tend to converge, as subsidies such as those seen in the Middle East are assumed to be phased out and renewable power unit costs fall. Per-capita GDP growth outpaces electricity price increases in all major regions, meaning – in aggregate – a trend towards more affordable electricity.

6.3.5 Carbon-dioxide emissions from the power sector

In 2014, the world's power sector (including heat production) accounted for 13.5 Gt of CO_2 emissions, or 42% of global energy-related CO_2 emissions. Some three-quarters of power sector emissions are from coal-fired power plants, reflecting their current high share in total generation, their relatively low efficiency in many cases and high carbon intensity. Despite a projected 11% rise in coal-fired generation to 2040, increasing efficiency of coal-fired plant (plus a very modest start to CCS) means that emissions from this source are projected to increase barely to 2040 in the New Policies Scenario. By then, the emissions intensity of the global coal-fired fleet improves from 945 g CO_2/kWh to 855 g CO_2/kWh. Gas-fired power also improves from 450 g CO_2/kWh to 385 g CO_2/kWh. Alongside the rise in renewable power, this means that total power sector emissions increase by only 6% to 14.4 Gt, a notable flattening, given that power output increases by almost two-thirds over the period. Improvements in emissions intensity are visible in all regions (Figure 6.14).

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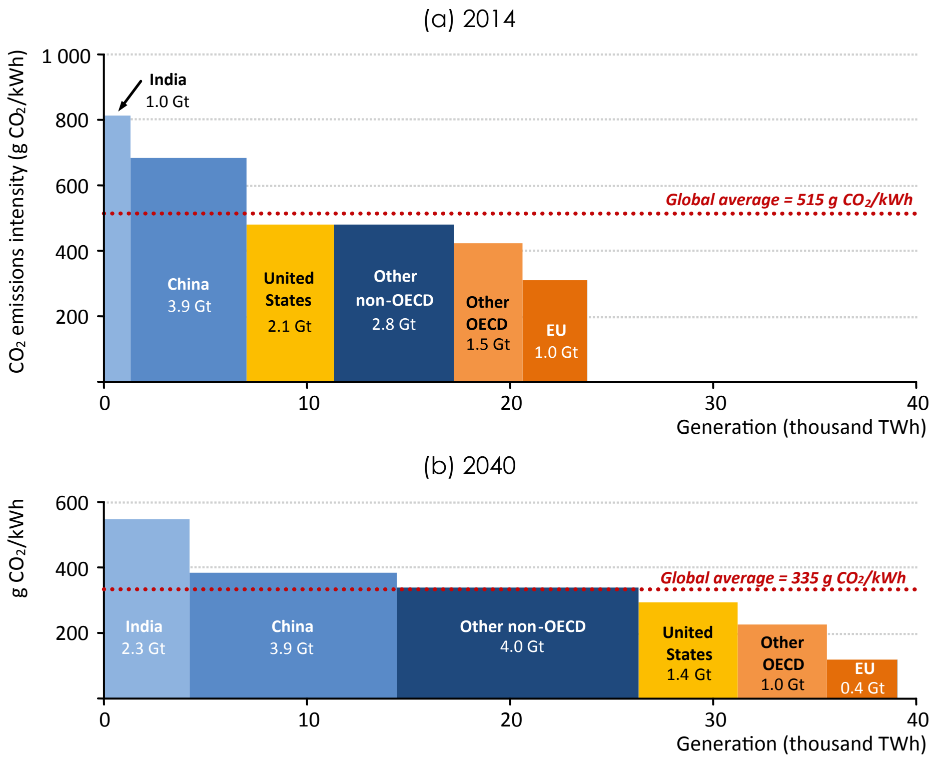
Figure 6.14 ▷ Carbon intensity of electricity generation by region in the New Policies Scenario



The carbon intensity of global power generation falls by one-third to 2040

Note: EU = European Union.

6.3.6 Regional insights[7]

United States

The United States, the world's second-largest power producer after China, has experienced slow growth in electricity demand over the last five years; a major shift away from coal to gas that was underpinned by the availability of low-cost shale gas, and a large increase in the deployment of renewables. In 2010, coal provided twice as much power as gas; but in the first-half of 2016, gas-fired generation had risen to exceed that of coal. Emissions from the power sector have fallen by almost one-sixth between 2010 and 2015. Major policies advanced by the United States federal and state governments seek to build on this momentum. In particular, the Clean Power Plan finalised in 2015, and the extension of tax credits for wind and solar power in late 2015, are poised to accelerate the decarbonisation of the power supply in the United States.[8]

Electricity demand growth to 2040 in the New Policies Scenario is projected to be around 0.5% per year, only a third of the rate seen over the last 25 years (Figure 6.15). The buildings sector, which accounts for around three-quarters of US power use, is set for slow growth, even as households increase in number and commercial floor space increases. Key federal efficiency standards in most major end-uses, covering lighting, refrigeration, space heating and cooling, are the main reason, as well as state and local building codes. Saturation effects are also clear, with air conditioning, for example, already available in a very high proportion of homes. However, demand from appliances, many small and not subject to efficiency standards, rises to 1 600 TWh, growing faster than all other types of demand in buildings. The industrial sector is projected to make a continued shift to less energy-intensive activity (with some notable regional exceptions such as chemicals), and more energy-efficient technologies.

The United States has put a number of policies in place to reduce carbon intensity in power generation, contributing to the overall aim of bringing emissions down by around a third by 2030, against a baseline of 2005. The Clean Power Plan plays an important role in our *Outlook*, via the incentives that it provides for states to promote end-use efficiency measures, gas-fired power, renewables, nuclear and coal plant with CCS (in different combinations, depending on state circumstances and priorities). In addition, in late 2015, the key Production Tax Credit (mainly supporting wind power) and the Investment Tax Credit (supporting solar PV) were extended to 2022. A tax credit for utility-scale PV is open-ended, providing an important continuing stimulus for deployment. The extension of these measures opens the prospect of strong renewable energy power deployment in the medium term. In 29 states plus Washington DC, the effect is reinforced by existing state-

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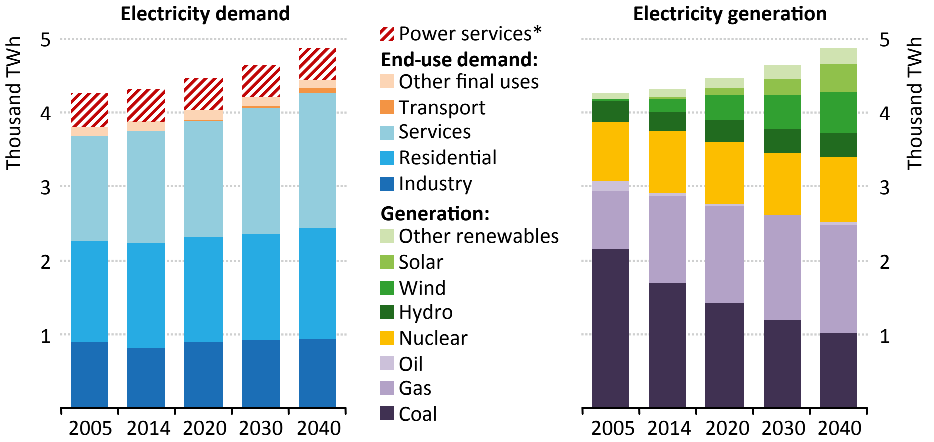
7. Case studies on the integration of variable renewables in the United States (see Chapter 12.3.1), European Union (see Chapter 12.3.2) and India (see Chapter 12.3.3) are included in Part B of this *Outlook*.

8. As mentioned in Chapter 1, in early 2016 the United States Supreme Court issued a stay on the implementation of the Clean Power Plan, pending further review, increasing uncertainty for this pivotal element in United States energy and environmental policy. As an announced policy, the implementation of the plan is nonetheless incorporated into the New Policies Scenario.

level renewable power mandates, which include notably aggressive long-term targets in Oregon, Vermont, Hawaii, and California, where for example, the aim is to source half of power supply from renewables by 2030. The Mercury and Air Toxics Standards are a driving force behind the accelerated retirement of coal-fired plants, the vast majority of which were installed between 1950 and 1990. In 2015, some 15 GW of capacity was retired and a further 45 GW is expected to be retired by the end of the decade: in 2020, coal-fired capacity totals around 245 GW, compared with 335 GW as recently as 2010. The US Environmental Protection Agency's Carbon Pollution Standards set emission standards that effectively prohibit new coal-fired plant construction without effective CO_2 abatement technology.

Figure 6.15 ▷ Electricity demand and generation in the United States in the New Policies Scenario



The US Clean Power Plan provides a major boost to renewables-based generation, while efficiency measures restrain demand growth

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

One impact of these policy interventions is rapid growth in wind and solar generation, which more than doubles by 2020 and more than quadruples by 2040, so that this group of technologies then provides over one-fifth of power production, up from 5% now. Hydropower and bioenergy combined see a modest rise in share to around 10%. Coal-fired output, which peaked in 2005, declines steadily from the 2014 level of 1 713 TWh to 1 015 TWh by 2040. Gas-fired power growth slows sharply from the 4.4% per year seen since 2000, remaining at around 2015 levels to 2025, before resuming modest growth. It remains the leading source of power generation throughout most of the projection period. Output from renewables of all types overtakes coal soon after 2030 to become the number two power source. Nuclear power retains a share of around 18%, while fossil-fuelled plants fitted with CCS start modestly around 2030 (covering less than 0.5% of US power generation by 2040). Power plant investment is dominated by renewables, especially wind and solar, which account for two-thirds of the total.

The impact of these shifts in power generation on the emissions performance over the projection period is significant. The United States has already seen emissions intensity drop since 2010 from 527 g CO_2/kWh to 450 g CO_2/kWh in 2015, on the back of the rapid increase in gas-fired power. Continuing falls are projected, so that intensity drops to around 295 g CO_2/kWh by 2040, as low-carbon power (including nuclear and hydro) increases its share in the mix to almost 50% from today's 32%. Thus, even as electricity demand grows by 15%, CO_2 emissions from the power sector are projected to fall by around one-third or almost 0.7 Gt, making an essential contribution to the overall decrease in total US energy-related CO_2 emissions of 1.3 Gt.

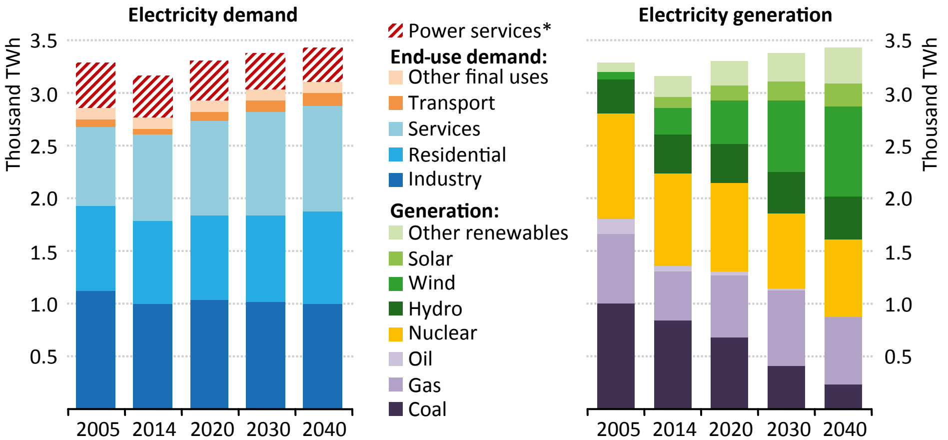
European Union

The European Union's (EU) energy strategy is geared towards the achievement of a series of policy goals for 2020, 2030 and 2050 relating to GHG emissions, renewable energy and energy efficiency. A range of regulatory measures is in place or under consideration. For power, some of the most important are the plans for a new renewables directive (for the period 2020-2030), improvements to Europe's power market design and measures to raise the effectiveness of the Emissions Trading System (which covers the power, industry and aviation sectors). Carbon prices have languished in the range of €4-7 per tonne of CO_2 in recent years. By adjusting the supply of allowances, the aim is to increase carbon prices sufficiently to incentivise large-scale fuel switching into low-carbon power sources, but it remains to be seen whether the current proposals will have this effect. The target for renewable energy as a whole implies that the share of renewables in the power sector should increase from 29% today to at least 45% by 2030. The rapid development of renewable energy already poses challenges for the EU electricity system, which needs to adapt to increasing capacities and volumes of decentralised and variable production from wind and solar (discussed further in Chapters 10-12).

Since the pre-recession electricity demand peak of almost 3 000 TWh in 2008, both the demand and supply picture in the European Union have changed rapidly, with economic, demographic and policy factors all instrumental. Total power demand fell around 6% between 2008 and 2014 before rebounding slightly in 2015: slow projected growth means that power consumption returns to the 2008 level only after 2020. The trajectory for industrial power use (which fell by 13% between 2007 and 2014) continues to dampen demand prospects in the *Outlook.* EU steel and cement production is anticipated to remain at around current levels. The chemical sector (one of the largest power users in industry) faces competition from new facilities in the United States, which have access to relatively cheap natural gas and ethane. Accordingly, ethylene and propylene production fall by around a quarter, and electricity use in the sector falls by a third.

Efficiency gains in many sectors also restrain demand and – even though electricity increases its share in industry energy demand to 35%, becoming the largest industrial energy source – industrial power use remains broadly flat, well below 2007 levels. Efficiency policies also hold back electricity demand growth in the buildings sector: the rise of 0.6% per year is only half that seen over the 2000-2014 period. Transport electricity use more than doubles, but only to 5% of total electricity demand (Figure 6.16).

Figure 6.16 ▷ Electricity demand and generation in the European Union in the New Policies Scenario



Wind becomes the largest single source of generation in the European Union soon after 2030

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

Between 2008 and 2014, the share of wind grew by 4% and that of bioenergy and solar by 3% of EU power output. Germany led the way, with wind, solar and bioenergy providing 22% of power output in 2014 (and an estimated 28% in 2015), triple the share of a decade earlier, even though coal, at 43%, remained the largest source of generation. Power supply in the EU is projected to continue to see profound changes over the coming decades, with the shift to renewables projected to continue. By 2040, a tripling in wind and solar production is projected, taking the share of these technologies to almost a third of EU power generation. Coal continues its structural decline: coal-fired power falls to less than one-third of current levels (or 7% of generation) and Europe's ageing coal fleet sees average annual capacity retirements of 5 GW. Natural gas produced 800 TWh of the EU's power requirement as recently as 2008 (almost a quarter of the total), but this fell to 450 TWh in 2014. In our projections, gas-fired power output climbs steadily over the period to 2030 (when it reaches 700 TWh, or one-fifth of the EU total), before falling slightly thereafter. The share of generation from nuclear power drops from 28% today to 21% in 2040, reflecting divergent approaches in various countries.

Against this backdrop, it is not surprising that the investment outlook is dominated by renewables, notably wind, but also solar, bioenergy and hydropower. Together, these technologies account for more than 70% of the average $65 billion spent annually. A large share of existing thermal plants is projected to retire in coming years and requires investment of around $15 billion per year (including plants already under construction) in order to extend the lifetime or replace this capacity in the New Policies Scenario (to the extent necessary). This will be challenging given the current wholesale prices and a market design that is failing to provide adequate returns for existing power plants. Our projections are predicated on this design issue being resolved. In addition, the EU needs to spend around $30 billion annually on transmission and distribution, including around 10-15% attributable to the need for increased investment required to integrate new renewables.

Carbon intensity in the EU power sector is already relatively low, at 313 g CO_2/kWh, due to the contribution of nuclear, hydro and bioenergy-based power (46% of output in 2014), supplemented by the rise of other renewables, led by wind and solar, that boost the total share of low-carbon generation to 57%. By 2040, this share is projected to rise to almost three-quarters, bringing the carbon intensity of EU power generation down to 116 g CO_2/kWh. Total EU power sector CO_2 emissions fall to 535 Mt from today's over 1.1 Gt, providing more than half the region's total energy-related emissions reductions of 1.15 Gt to 2040.

The speed and depth of the projected transition to new renewable energy sources in power generation in the EU makes it a living laboratory for other large economies seeking to ramp up variable renewable generation, including China and the United States. While rapid changes have been made to generation technologies in the past, the deployment of variable renewables poses new challenges, including how to ensure that adequate firm dispatchable capacity remains available to ensure secure supply, as the utilisation rates of conventional fossil-fuelled plant fall, potentially quite quickly, and ageing plants (especially coal) are retired.

Japan

Japan's high dependence on imported energy has engendered an understandable policy priority on energy security. In the power sector, this has meant creating a diverse generating mix, developed after the first oil price shock, with, until 2010, almost equal shares of nuclear, gas and coal, plus smaller shares of hydro and oil. (Japan is one of few developed economies where oil remains important in the power sector). This diversity of mix proved valuable when, in the wake of the Fukushima nuclear accident in 2011, all nuclear plants were shut, with a loss equivalent to 25% of the electricity generated in 2010. The shortfall was met through a combination of natural gas (up by a third 2010-2014, to 40% of power output), oil (initially doubling, but since falling), a modest increase in coal-fired power output, and by reduced demand and improved efficiency. Strong policy incentives for solar PV, including an attractive feed-in tariff, secured an increase in PV capacity of an estimated 30 GW between 2010 and 2015, adding 3% (30 TWh) to Japan's power supply. To maximise the deployment of renewables while keeping costs to the public under control, the feed-in tariff law was amended in May 2016. The increase in fossil-fuel imports and use over the period led to a large increase in Japan's energy import costs and the carbon intensity of the power sector rose from 428 g CO_2/kWh in 2010 to 567 g CO_2/kWh in 2013, causing a 10% increase in CO_2 emissions (2013 versus 2010) despite lower power output.

The demand outlook to 2040 is influenced by declining population (10% lower by 2040), and a mature and energy-efficient economy, with ongoing efficiency improvements. Annual power demand growth averages only 0.2% per year. The residential sector shows almost no growth and industrial power use declines with continued structural change, especially in the chemicals sector. Efficiency standards in appliances and motor systems are effective in slowing growth. The services sector shows an increase in demand of around 10% over 2014 levels by 2040, while transport more than doubles, to a still nominal 42 TWh. Even by 2040, power demand does not approach its pre-recession peak of 1 060 TWh (Figure 6.17).

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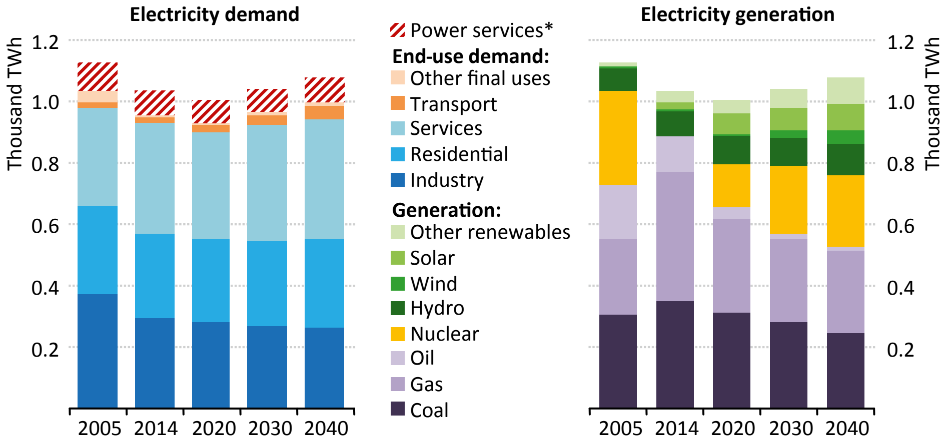
Figure 6.17 ▷ Electricity demand and generation in Japan in the New Policies Scenario



While demand barely grows, the return of nuclear and the expansion of renewables allow for rapid growth in low-carbon power

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

The rate at which nuclear plants return to the generating fleet is the key uncertainty for the future of the power supply in Japan. As of mid-September 2016, three reactors had restarted, with others approved in principle but delayed by local opposition or judicial proceedings. Our projections are based on a gradual return to service of a large proportion of the nuclear fleet, noting that some older reactors may be decommissioned in the face of high re-start costs. Thus, by 2020, nuclear output is projected to be around half its pre-Fukushima peak, with a gradual increase thereafter, so as to supply a little over one-fifth of power output by 2040. A strong policy drive related to renewables increases its share in the mix to 30%, (hydro 10%, solar PV 8%, with the balance from bioenergy, wind and geothermal). The increase in PV capacity from 34 GW to 77 GW is notable, of which two-thirds is distributed solar PV and the rest is utility-scale deployment.

These two developments bring about a marked reduction in fossil-fuel use in the power sector, with an accompanying improvement in the sector's carbon intensity. By 2040, gas is projected to decline to a quarter of the power mix. Coupled with a shift away from steam turbines and a rise in combined-cycle gas turbine (CCGT) generation to over 90% of gas-fired power, efficiency improves from an already high 47% to reach 57% and projected gas imports for power use fall by almost half. Similarly, coal-fired power generation falls to just under a quarter of power output by 2040 and high efficiency ultra-supercritical and integrated gasification combined-cycle (IGCC) units account for almost two-thirds of output. Hence, coal consumption in the power sector falls by a third. Oil-fired power, which rose to almost 20% of the power mix post Fukushima, falls to 4% as early as 2020, (saving some 30 Mtoe) and almost disappears by 2040. Thus, by the end of the *Outlook* period, fossil-fuel inputs into the power sector fall by nearly half. The carbon intensity of electricity production falls to below 300 g CO_2/kWh, just over half the peak level seen in 2013. Total power sector GHG emissions fall by 250 Mt.

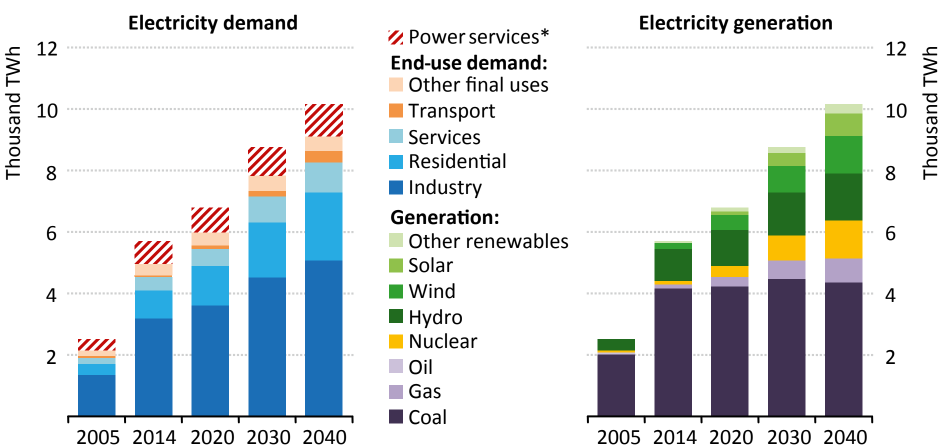
Renewables, led by solar PV, are projected to account for 70% of new power plant investment, their share of investment increasing to over 90% by 2040, or $15 billion annually by that time. In addition, around $10 billion annually is needed to replace ageing transmission and distribution infrastructure. While such investment levels will be challenging, Japan has faced and overcome major problems in its power sector over the last 50 years, responding, for example, by increasing nuclear power more than ten-fold over the 20 years to 1995. Major electricity policy changes in the wake of Fukushima, including deregulation of the retail sector and unbundling of generation, plus the co-ordination of regional transmission systems, should go some way to delivering the structural changes needed in Japan's power system and facilitating the necessary high levels of investment and the integration of larger shares of renewables (IEA, 2016h).

China

China, the world's largest power producer, illustrates well the rapid effect that a change in economic and policy direction can have on electricity production. Between 2000 and 2013, power output grew 11% annually, quadrupling over the period. However, from around mid-2014, a major structural change in China's economy has been underway: a shift in the economy has taken place towards less energy-intensive industries and overall economic growth has slowed. Electricity demand growth slowed sharply in 2014 to just below 5%, most of it occurring in the first-half of the year. In 2015, power output grew only by 0.5%. Over the same period, there has been a major expansion in hydro, wind, solar and nuclear power capacity, with the result that coal-fired electricity generation in 2015 declined. Given China's weight in the global energy system, these shifts were enough, on their own, to affect global trends. CO_2 emissions from China's power sector are estimated to have fallen in 2015 by more than 160 Mt, or 4%, making the most significant contribution to the observed global fall in CO_2 emissions from the power sector of around 250 Mt.

Policy positions are designed to support the achievement of peak emissions around 2030. Planned changes include increased efficiency in new coal-fired plant and realising a target of 300 GW of wind and solar capacity by 2020. New targets for 2020 are under active discussion and envisage even higher targets of as much as 250 GW for wind, and 150 GW for solar, although these have yet to be adopted. The implementation of a national carbon trading system is planned for late 2017, building on pilot schemes at regional level and applying to power plants and major industrial facilities. There are also measures planned which aim to tackle China's severe problems with local air pollution. On the broader economic front, the government is actively promoting a more services-oriented, consumption-focussed economy, while taking steps to deal with massive over-capacities in sectors such as steel and coal mining. The overall policy agenda has far-reaching implications for the evolution of the power sector to 2040.

Figure 6.18 ▷ Electricity demand and generation in China in the New Policies Scenario



Coal stands still while renewables, nuclear and gas meet China's rising power needs

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

In the New Policies Scenario, annual power consumption growth, which was nearly 11% between 2000 and 2014, falls to an average of only 2.4% over the *Outlook* period, around half the rate of GDP growth. Electricity plays an increasingly important role in energy supply to industry, increasing its share from a quarter today to two-fifths by 2040 (displacing coal as the number one energy source in industry around 2035). Non energy-intensive industrial consumers tend to favour electricity and efforts to encourage greater efficiency are also likely to encourage electricity use in applications such as secondary steelmaking and electric arc furnaces. Residential and services sectors are projected to see strong growth, their demand more than doubling to 3 230 TWh by 2040. In the residential sector, key electricity end-uses including appliances, refrigeration and cooling triple, so residential demand grows to more than 2 200 TWh. With transport use increasing to 330 TWh, overall electricity demand exceeds 9 100 TWh by 2040 (Figure 6.18).

China's power generation mix is in the early stages of a fundamental re-orientation towards lower carbon and less polluting sources of power. By 2020, wind and solar power output is projected to triple, to over 600 TWh, and, by 2040, to reach almost 2 000 TWh, (more than the total current power output of OECD Asia Oceania). This would make China the clear world leader in variable renewables. Hydropower remains an important resource, its output increasing by nearly half over the *Outlook* period. But hydro's contribution to total output is overtaken by other renewables around 2030 and its share in the power mix drops to 15%. Taken together, all renewable sources of power make up 38% of the generation mix by the end of the *Outlook* period. Nuclear power grows slightly faster than wind, producing nearly 1 200 TWh by 2040, a nine-fold increase over 2014, so that by the end of the projection period, half of national power supply is from low-carbon sources.

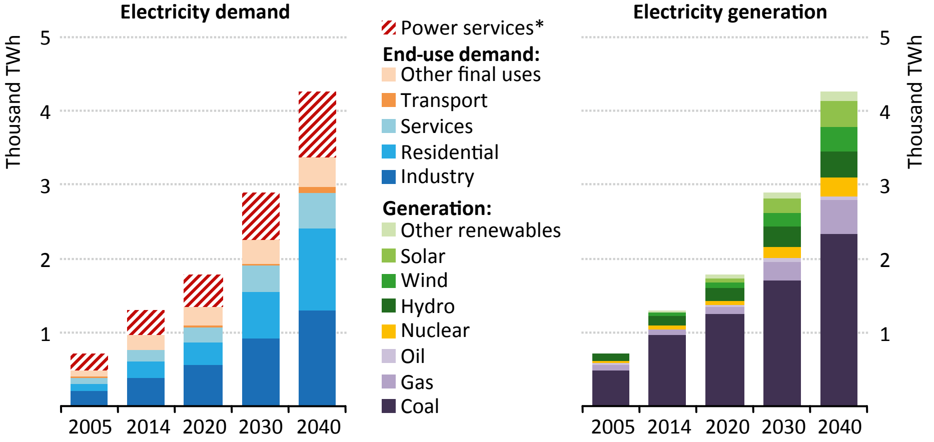
Even with these changes and a sharp decline in new coal-fired capacity, coal remains an important component of the power supply. Coal-fired generation grows slowly (much more slowly than overall demand) to just over 4 400 TWh in the late-2020s, before falling thereafter. By 2040, coal's share of generation is 43%, down from 73% in 2014. The ongoing rapid improvement in the efficiency of China's coal-fired fleet, from 32% in 2005 to 39% in 2015, continues, as more ultra-supercritical and supercritical capacity is installed, taking the fleet efficiency to 42% by 2040 (lower efficiency plants tend to run at much reduced capacity factors). Given that the power sector accounts for just over half of national coal use, the very weak (if any) projected growth in coal demand in the power sector, from its level in 2014, is a key factor in overall coal use likely peaking in 2013 (see Chapter 5). CCS-equipped plants provide only 0.5% of China's power by 2040. Gas grows steadily from 2% to 8% of the power mix.

Based on these developments, new power plant investment is projected to be dominated by renewables. More than 70% of the near $95 billion invested annually goes to renewable energy technologies. Massive investments in transmission and distribution (of around $80 billion per year) are needed early in the projection period to meet rising demand and integrate new power sources. Transmission bottlenecks already are leading to some curtailments in wind generated power and around 10% of total transmission and distribution investment is needed to address this issue (see Chapter 12). But investment in transmission and distribution drops to around $50 billion later in the *Outlook* period. The result of these investments is a spectacular improvement in China's power sector emissions intensity (a major determinant of global trends). Even as power output grows nearly 80% by 2040, a doubling in the share of low-carbon power (plus improved coal-fired plant efficiency) results in total projected power sector CO_2 emissions levelling out a little after 2030 at only around 5% above today's levels. The emissions intensity of the power sector drops from 680 g CO_2/kWh in 2014 (already having fallen to an estimated 650 g CO_2/kWh in 2015) to around 390 g CO_2/kWh by 2040. The sharp slowdown in the growth of power sector CO_2 emissions makes a critical contribution to the overall peaking of China's energy-related CO_2 emissions at 9.3 Gt before 2030.

India

India's 2014 power output of nearly 1 300 TWh made it the world's third-largest national power producer. India has made impressive strides in expanding power supply since 2000, with output growing at an average of 6% per year, despite serious structural issues in the power market (IEA, 2015a). These are most visible in the distribution sector, where utilities have been accumulating large financial debts. Alongside relatively high technical losses, non-technical losses (due to theft, non-billing and non-collection of payments) mean that total system losses are among the highest in the world, at around 20%. Despite the rise in supply, India still faces many challenges if the power sector is not to be a limiting factor on economic growth: not least, an estimated 240 million people, a fifth of India's population, still lack access to electricity and many more suffer from poor quality service (see Chapter 2.8).

Figure 6.19 ▷ Electricity demand and generation in India in the New Policies Scenario



India mobilises all sources of power to meet demand that grows at 5% per year

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

A fast-growing economy, a population that becomes the world's largest, rising incomes and progress with electrification mean that power demand in India more than triples over the period to 2040 (Figure 6.19). In the industry sector, the need for new infrastructure and the "Make in India" initiative underpin rising demand for steel, cement and other building materials. Industrial power demand reaches 1 300 TWh by 2040, up from around 390 TWh today. Demand in the services and agriculture sectors expand rapidly, the latter driven by high reliance on electric pumps for irrigation, although growth slows later in the *Outlook* period. Residential electricity consumption is projected to rise by a factor of five, to over 1 100 TWh as rising incomes spur increasing demand for appliances, rising to 460 TWh. Residential cooling demand is likewise set to increase rapidly, to a similar level: currently only around 2% of Indian households have air conditioning, but sales have been growing by 20% per year in recent years. Overall, a projected average 5% annual growth rate in India sees total power demand reach 3 400 TWh in 2040, larger than the total demand of OECD Europe today.

On the supply side, coal has been the dominant energy source in India's power sector. India is a large coal producer. While that is projected to remain so through to 2040, important changes can be expected, as government policies favour greater diversity in the power mix. Coal-fired power output is projected to more than double to 2040, but its share of the generation mix falls from three-quarters to 55%. Renewables, nuclear and natural gas all increase their shares. Hydropower output almost trebles to 2040, but its share in generation edges downwards below 10%. Solar PV is driven in the short term by ambitious medium-term targets, which aim to have 100 GW of installed capacity by 2022. Although this target is not achieved in full under the assumptions of the New Policies Scenario, policy support is instrumental in giving momentum to a spectacular expansion of solar PV from current very low levels to 350 TWh in 2040 (a level equivalent to the total power output of the United Kingdom today). Wind expands to similar levels, so that, by 2040, total renewables make up over a quarter of Indian power output, almost twice today's share. Gas-fired power also doubles its share to 11% and plays an increasingly important balancing role in the power system. Nuclear power expands almost eight-fold to 270 TWh. Over the period to 2040, the absolute growth in Indian electricity supply approaches 3 000 TWh, almost one-fifth of the global total. While transmission and other losses are addressed to some extent over the *Outlook* period, system losses are high and remain a major opportunity to improve power sector reliability, affordability and emissions. As the share of fossil fuels (predominantly coal) falls back from today's 80% to two-thirds of the power mix and coal plant efficiency improves, the carbon intensity of generation falls from 810 g CO_2/kWh to 550 g CO_2/kWh. Hence, even as Indian power output triples, the sector's CO_2 emissions only increase from just above 1.0 Gt to 2.3 Gt, an important factor in restraining India's CO_2 emissions growth.

To achieve these impressive structural changes in power supply, massive investments will be required (even though unit investment costs are lower than in many other countries). By 2020, annual investment needs in power generation are projected to approach $40 billion, increasing to over $55 billion by 2040. Almost 60% of this investment goes to renewables, with solar PV benefiting most. Transmission and distribution investment add a further $30-40 billion annually over the projection period, so annual power sector investment needs exceed $90 billion after 2030. Attracting this level of investment will be a formidable policy challenge, given the recent history of uncertainty of returns for generators, under-investment in infrastructure and low quality of service in some regions.

Regulatory and tariff reforms, enabling adequate returns on generation investment, robust permitting and approval systems, grid strengthening, and massive and diverse generation capacity expansions are all needed if the power sector is to make its essential contribution to economic and social progress in India.

Southeast Asia[9]

The last quarter century has seen a five-fold increase in power production in Southeast Asia, with an equally sharp transition away from oil, (which provided almost half of power in 1990) towards gas (reaching a share of 44% of generation in 2014) and coal (34%). Almost all this new generation was provided by subcritical technology in the case of coal, with relatively low efficiencies, and by gas CCGT plants with a higher efficiency.

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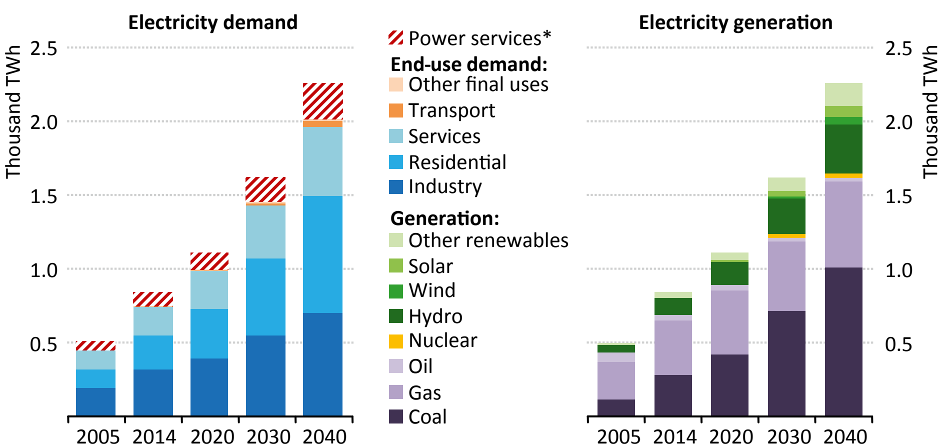
Figure 6.20 ▷ Electricity demand and generation in Southeast Asia in the New Policies Scenario



Coal and renewables make the largest gains as Southeast Asia expands its power sector rapidly

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

The ten countries of Southeast Asia are projected to experience population growth of more than 20%, to 760 million by 2040, and primary energy demand growth of almost three-quarters over that period. Electricity demand grows faster still, in keeping with global trends towards increased use of electricity. Growth approaches 4% per year, almost tripling to

9. Southeast Asia refers to Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam. For further information and discussion of the long-term energy outlook for Southeast Asia refer to *Southeast Asia Energy Outlook 2015, World Energy Outlook Special Report* (IEA, 2015b), available at: *www.worldenergyoutlook.org/southeastasiaenergyoutlook*.

2 000 TWh in total (Figure 6.20). Industrial power demand more than doubles, underpinned by a tripling of steel, aluminium and paper production. But the buildings sector (services and residential) sees the most rapid expansion in consumption. Demand reaches 1 260 TWh by 2040, with the largest share (some 790 TWh) from the residential sector, as rising living standards bring a rapid uptake of appliances and cooling equipment, together more than 550 TWh. Electricity grows to provide over half the energy needs in the buildings sector, from a quarter in 2014. Electricity increases its dominant hold on energy use in the services sector, meeting more than 80% of its energy needs in 2040, as power use more than doubles.

Coal and natural gas are projected to continue to dominate the generating mix over the next two decades, reversing their roles as the share of coal overtakes that of gas, but together still provide more than 70% of total power. By 2040, coal-fired plants generate output of 1 000 TWh, 45% of the region's electricity production, underpinned by the price advantage of coal over gas. Gas grows more slowly, but still reaches almost 600 TWh by the end of the *Outlook* period. Oil almost disappears from the mix. Renewables increase their share of generation to over a quarter in 2040, with hydropower playing the largest role (320 TWh), followed by solar PV, geothermal and wind (collectively contributing 190 TWh, up from 23 TWh today).

The efficiency of the coal fleet, the capacity of which is projected to more than triple to 190 GW by 2040, is a particular concern. While almost 50 GW of supercritical capacity and almost 40 GW of ultra-supercritical capacity are projected to be built, the capacity of low efficiency subcritical plant still almost doubles to 95 GW, with additions concentrated in the next decade. The efficiency of the total fleet improves from 35% to 39%, and coal use and coal plant CO_2 emissions more than treble to 2040. A larger proportion of generation from high-efficient gas-fired power plants helps improve the overall efficiency of the gas fleet from 43% to 50%. As a result, natural gas use increases by less than 40%, even as output rises by 60%.

Renewables, including hydro, bioenergy, solar and wind, are an attractive option for Southeast Asia, contributing to both security and environmental goals, and are projected to increase from 18% to 27% of the power mix by 2040. The region has substantial undeveloped hydro capacity (only 96 GW from an estimated 170 GW potential is projected to be developed even by 2040) and good solar and wind resources. However, additional policy measures will be needed for renewables to reach their potential. As things stand, only a modest fall in the carbon intensity of power generation in Southeast Asia is projected, to 510 g CO_2/kWh from today's level of 577 g CO_2/kWh. CO_2 emissions from the sector rise from 0.5 Gt to 1.2 Gt, making a major contribution to the region's doubling of energy-related CO_2 emissions to 2.3 Gt by 2040.

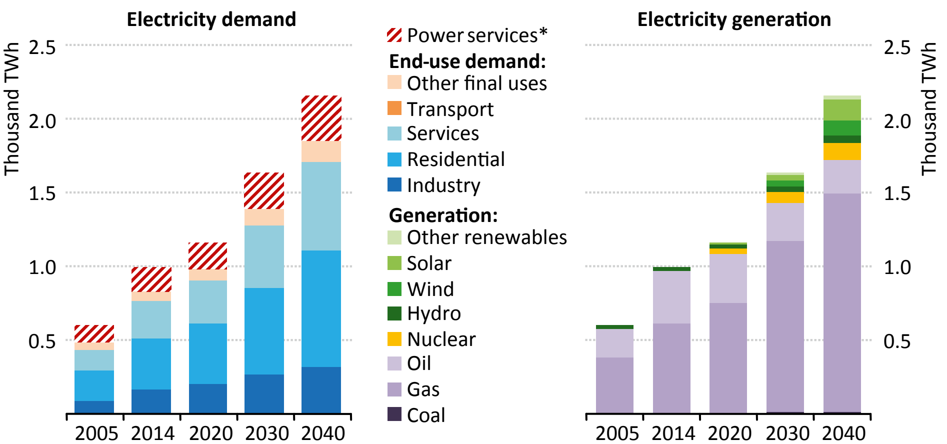
Middle East

Power demand in the Middle East has more than quadrupled since 1990, with subsidised power prices in many countries a contributing factor, along with a focus on expanding energy-intensive industrial output, as well as rising residential and services sector demand.

Generation has been dominated by gas and oil: the Middle East is one of the few regions where oil-fired power still has a major, albeit declining, role. The share of natural gas in the power mix rose steadily until the early 2000s, to above 60%, has since remained at similar levels.

For the *Outlook* period, a key variable is the extent of subsidy removal. This will affect the price of fuel used in the power sector, as well as end-user electricity prices. Falling world oil and gas prices have lowered government revenues substantially, putting increasing pressure on governments in the region to reduce fossil-fuel subsidies across the board. Some countries in the region are implementing important reforms including Iran, Kuwait, Qatar, Saudi Arabia and the United Arab Emirates (see Chapter 2.9). Subsidy reforms contribute to greater efficiency as well as to the economic case for the use of alternative generation technologies, such as renewables and nuclear power. In the New Policies Scenario, only a modest pace of progress with subsidy reductions in the power sector is assumed in the period to 2040.

Figure 6.21 ▷ Electricity demand and generation in the Middle East in the New Policies Scenario



Natural gas is gradually joined by renewables as the fuel of choice

*Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution.

By 2040, power demand growth in the Middle East region is projected to fall to half the 6.2% annual rate seen between 1990 and 2014, as population and GDP growth both slow. Nonetheless, final power demand in the region more than doubles, led by strong growth in the residential and, to a lesser extent, services sectors (Figure 6.21). By 2040, around one-quarter of total regional power demand, some 430 TWh, is projected to come from the use of appliances in the residential sector. Cooling demand in the residential sector triples to almost 200 TWh. Industrial demand sees a falling share of the total, although aluminium smelting expands rapidly, continuing to account for about half of demand in industry.

The Middle East region's power supply mix changes rapidly, as oil-fired power peaks quite soon and then loses share to fall to around 10% by 2040, compared with over a third today. Gas-fired power rises to meet almost 70% of total power generation. Generation from wind and solar technologies grow from close to zero today to almost 240 TWh, reading a larger share than oil. The share of nuclear power also increases (up to 5% by 2040). The capacity of high efficiency CCGTs increases by around 80 GW, while combined heat and power, mostly combined power and desalination units (see Chapter 9) increase by almost 50 GW. As a result, the overall efficiency of the gas-fired fleet increases to 46%, so that gas consumption rises by less than 90%, even though power output increases by 140%. The improvement in gas-fired plant efficiency and the increasing share of low-carbon power (20% by 2040, compared with 2.5% today) are important factors in the projected improvement in the carbon intensity of power supply by over 40% to 390 g CO_2/kWh. Average annual investments in new power plants over the next decade of around \$15 billion are dominated by gas, but in the decade leading up to 2040, investments in solar and wind account for almost 60% of the projected \$24 billion of annual investments.

Energy efficiency outlook

Will motors drive electricity savings?

Highlights

- In 2015, despite relatively low energy prices, global energy intensity improved by 1.8% (almost twice the rate seen over the last decade), making the largest contribution to halting the rise in energy-related CO_2 emissions in 2015. Increasing mandatory efficiency regulation, which now covers 30% of global final energy use, played a key role in moderating the effect of low prices on energy use. Yet, a prolonged period of low prices can put a brake on energy intensity improvements: energy efficiency across all end-uses is higher in regions with higher energy prices.
- In the New Policies Scenario, improved energy efficiency slows growth of total final energy consumption by almost 1 percentage point to 1.1% on average per year to 2040, mainly thanks to efficiency gains in industry. The average annual energy intensity improvement to 2030 reaches 1.9% in the New Policies Scenario, slightly short of the UN's SDG goal to double the rate of improvement in energy efficiency. Structural changes in the global economy – a relative move from heavy industry towards services – reduce the average annual growth in energy demand by 0.2 percentage points (supplementing gains from energy efficiency). Despite higher energy prices in the 450 Scenario, energy-related expenditure by households is not higher than in the New Policies Scenario, as energy efficiency dampers energy consumption.
- Today, more than half of the electricity consumed worldwide is used in electric motor systems and 30% (6 000 TWh) of global electricity consumption is used in industrial electric motor-driven systems. By 2040, increased industrial activity (almost half of which occurs in China and India) would double global electricity use for motors, were it not for the energy efficiency policies under consideration which constrain this growth to 80%. Almost nine-out-of-ten industrial electric motors sold globally are already covered by mandatory efficiency standards, albeit at various levels of stringency.
- The potential for energy savings in electric motor systems is only partly tapped in the New Policy Scenario, as existing policies mainly focus on the motor itself, while the largest savings potentials are in the wider system. Shifting policy attention to a system-wide energy efficiency approach, as assumed in the 450 Scenario, can reduce global electricity demand in electric motors by 8% in 2040. In the industry sector, motor systems can on average consume up to 40% less energy by pursuing a co-ordinated suite of policy measures, including stricter regulation of motors and motor-driven equipment, much larger uptake of variable speed drives and, importantly, other system-wide efficiency measures. Overall, additional cumulative investment in industry of around $300 billion is outweighed by avoided investment in power generation of $450 billion.

7.1 Introduction

Energy efficiency needs to be at the heart of any strategy to guarantee secure, sustainable and inclusive economic growth. It is one of the most cost-effective ways to enhance security of energy supply, to boost businesses' competitiveness and to reduce the environmental burden of the energy system. Almost nine out of ten of the Nationally Determined Contributions (NDCs) submitted to the 2015 climate summit in Paris mention energy efficiency. Not only can the growth of carbon-dioxide (CO_2) emissions be cut by the more efficient use of energy (and the link between economic and energy demand growth be weakened), but energy efficiency can also improve air quality around the world, helping to reduce the related millions of premature deaths each year (IEA, 2016a).

This chapter highlights recent trends in energy efficiency and includes recent changes in energy efficiency policies. It analyses the relationship of economic development and rate of energy efficiency improvement, including the affiliation between energy efficiency and energy prices. It provides an update on *WEO-2015* analysis of energy efficiency regulation and sets recent developments in an historic context. The chapter continues with an analysis of energy efficiency trends in the New Policies Scenario, our central scenario, to 2040, highlighting the role that energy efficiency plays to mitigate global energy demand growth. As around half of the electricity consumed worldwide is used in electric motor-driven systems, their efficiency is given a special focus. We quantify electricity demand trends in motor systems by end-use, assess the potential for energy savings and provide policy recommendations (an essential part of the toolkit for the 450 Scenario) to unlock these savings.

7.2 Current status of energy efficiency

7.2.1 Recent and historical trends

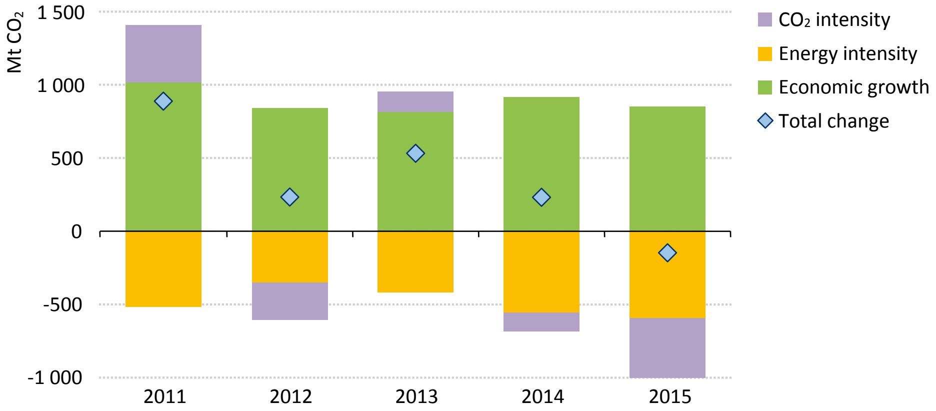
In the 2014 and 2015 period, parallel developments have decoupled the relationship between global economic output, energy use and energy-related carbon-dioxide (CO_2) emissions (Figure 7.1) (see Chapter 8). More productive use of energy (a reduction in the energy intensity of economic output[1]) has reduced the total volume of energy required for the same level of output. Together with these energy intensity improvements, increased use of clean energy sources (a reduction in the average CO_2 emission factor[2]) has put a brake on CO_2 emissions. Preliminary estimates show that energy intensity decreased by 1.8% in 2015 (almost twice the rate of improvement over the last decade), confirming for the second year in a row that low energy prices have not weakened the trend to lower energy intensity. Around two-thirds of the drivers dampening CO_2 emissions growth in 2014 and 2015 came from reductions in energy intensity and the remainder from the expansion of cleaner (mostly renewable) energy sources in global energy use. Part of the reduction in energy intensity is due to economic restructuring from heavy industry towards

1. Energy intensity is measured as total primary energy demand per unit of gross domestic product expressed in market exchange rate.

2. CO_2 emission factor is measured as energy-related CO_2 emissions per unit of total primary energy demand.

services and lighter industries: global production of both steel and cement declined by 2-3% in 2015, mainly driven by developments in China. While it is difficult to determine with precision how much energy efficiency contributed to the decline in energy intensity, alongside economic restructuring and weather-related effects, it is possible to say with confidence that a sustained decoupling of CO_2 emissions from economic growth will not happen without major gains in energy efficiency.

Figure 7.1 ▷ Change in global energy-related CO_2 emissions by driver



Improved energy intensity has significantly slowed growth in CO_2 emissions in recent years

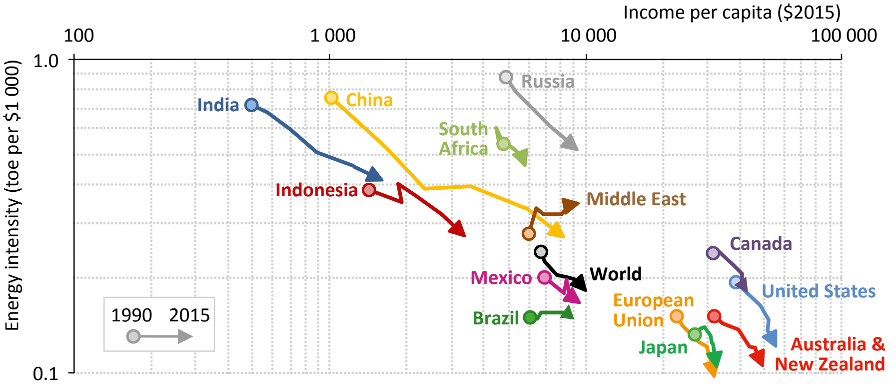
Note: Mt CO_2 = million tonnes of carbon dioxide.

Source: IEA analysis.

The above-average reduction in energy intensity in 2015 stemmed, in particular, from decreases in primary energy demand in the large energy consuming countries. Energy intensity declined by more than 6% in China and by more than 3% in the United States. Primary energy demand in China declined slightly in 2015, despite still strong (but slowing) economic growth, the first such decline in almost twenty years. Electricity demand grew by a mere 0.5% in 2015, which combined with an increase in the average efficiency of electricity generation led to a small decline in energy use for power generation. In addition, generation from low-carbon energy sources increased. Industry was the biggest contributor to the decline in energy intensity, but this was related only to a limited degree to energy efficiency, as China continued its change in the structure of its economic growth. Like China, the United States experienced an absolute fall in primary energy demand, as more efficient natural gas-fired power plants replaced some less efficient coal-fired power plants and a mild winter, compared with the previous year, reduced the need for space heating (winter 2015-16 was the warmest on record in the United States).

Since 1990, most countries have experienced a close relationship between energy intensity and income (measured in economic output per capita), with increasing income tending to improve energy intensity. Over that period, global gross domestic product (GDP) per capita has risen by almost two-thirds, while energy intensity has improved by almost a quarter. Interestingly, the relationship changes according to income levels: the richer the country, the larger the energy intensity improvement with increasing per-capita income (Figure 7.2). In developed countries, energy intensity has improved faster than in developing countries, in part because energy efficiency has had a higher policy priority, with the gradual broadening and deepening of energy efficiency regulation ensuring continued energy savings. Economic restructuring and saturation effects play a role, alongside energy efficiency, but correcting for changes in economic structure with a decomposition analysis does not change the picture significantly.

Figure 7.2 ▷ Income per capita and energy intensity by selected region, 1990-2015



The reduction in energy intensity accelerates with higher income levels

Notes: toe = tonnes of oil equivalent. Data are shown in five-year intervals from 1990 to 2015. The slopes indicate the elasticity of energy intensity with respect to income per capita. Income per capita is measured as GDP per capita in year-2015 dollars at market exchange rate and primary energy intensity is measured using GDP in year-2015 dollars at market exchange rate. For Russia, the first data point is 1995.

In the United States, energy intensity has declined by 37% since 1990, while per-capita income increased by 43%, meaning that the relationship between per-capita growth and energy intensity reduction is close to one.[3] Similar patterns are found in other high-income countries. In China, this relationship is around 0.1 (in India, about 0.2), indicating a far slower reduction in primary energy intensity compared with high-income countries. For some countries the presence of high subsidies is an obstacle to the adoption of energy efficiency measures as the subsidies decrease its economic attractiveness to the end-user (see Chapter 2). In Brazil, energy intensity has increased over the past 25 years, mostly due to reduced reliance on hydro power generation as thermal power generation has grown which require more primary energy for equivalent output.

3. Excluding economic restructuring (using decomposition analysis) shows that the elasticity drops from 0.9 to 0.8.

Energy efficiency policies expanded their coverage in 2015 and 2016 (Table 7.1). The 2015 climate summit provided a valuable push for energy efficiency, almost nine out of ten of the NDCs submitted in its run-up made reference to energy efficiency. In addition to the NDCs, several agreements have been reached at international level since mid-2015. One of the 169 specific targets in the United Nations' Sustainable Development Goals (SDG) is to double the rate of improvement in global energy intensity by 2030 compared with historical improvements. Under the auspices of the International Civil Aviation Organisation, the aviation sector (following the navigation sector) has put in place CO_2 limits for new aircraft from 2028; this will be achieved almost exclusively by means of more efficient engines. The Clean Energy Ministerial has launched several worldwide campaigns.[4] For instance, its Global Lighting Challenge aims to achieve cumulative sales of 10 billion high-efficiency lighting products, such as light-emitting diodes (LED). This initiative is supported both by governments and private sector stakeholders. The chances of achievement have been reinforced by significant price drops over the past few years for LED bulbs. In 2015, LEDs led to global electricity savings of 100 terawatt-hours (TWh) (IEA, 2016b).

China has continued its long-standing efforts to improve the efficient use of energy in its economy. As part of the 13th Five-Year Plan, China set the goal of achieving energy intensity improvements of 15% within five years from 2015, slightly below the target over the previous five years of 16%. Recognising the significant surplus capacity in several energy-intensive industries, China plans to close old and inefficient steel capacity of 100-150 million tonnes (9-13% of current capacity) of within the next five years. China explicitly mentioned efficiency gains in electricity generation and in buildings in its NDC, together with a more efficient industrial structure.

In the United States, regulations to strengthen and expand fuel-economy standards for medium- and heavy-duty vehicles were finalised in August 2016. In order to increase energy efficiency in buildings and industry, the US administration has introduced new energy performance standards for air conditioners, residential boilers and water pumps, among others. The European Union has published a strategy to enhance the energy efficiency of heating and cooling systems in industry and buildings. At the member country level, Germany has launched a large-scale push for energy efficiency, including competitive tenders for electricity savings projects, while Poland's parliament passed a new act that includes obligations relating to energy efficiency. In 2015 and 2016, energy efficiency policy developments in Japan focussed on buildings, with the introduction of minimum energy performance standards[5] (MEPS) for new non-residential buildings, the strengthening of standards for refrigerators and freezers and the extension of mandatory energy efficiency benchmarking for the services sector.

4. The IEA has been awarded the privilege of being the home for the new Clean Energy Ministerial secretariat.

5. A minimum energy performance standard is a policy instrument mandating a minimum level of energy performance for a specific energy-using device.

Table 7.1 ▷ Selected energy efficiency policies announced or introduced in 2015 to mid-2016

Region	Sector	New policy measure
China	General	Improve energy intensity by 15% by 2020 compared with 2015 (13th Five-Year Plan). Circular Economy Promotion Plan supporting industrial parks and waste recycling.
	Industry	Planned closure of 100-150 Mt of inefficient steel capacity within five years.
United States	Buildings	Energy conservation standards for air conditioners, heat pumps, walk-in coolers and freezers, residential boilers, battery chargers and dehumidifiers.
	Industry	Introduction of energy conservation standards for clean-water pumps.
European Union	General	Germany: Competitive tenders for electricity saving projects, support for efficient cross-cutting technologies and waste-heat recovery. Poland: New act on energy efficiency including obligatory energy audits and a modification of the efficiency certificates system.
	Buildings	Proposal to revise the EU Directive on energy labelling of consumer appliances.
India	Transport	Plans to implement a "green tax" of 1% on small petrol, LPG and CNG cars, 2.5% on certain diesel cars and 4% on larger cars and SUVs.
	Buildings	National Energy Efficient Fan Programme to distribute efficient ceiling fans.
Middle East	Buildings	United Arab Emirates (Dubai): Plan to introduce energy efficiency ranking of buildings and MEPS for retrofits.
Latin America	General	Mexico: Energy transition law to establish an efficiency goal and a roadmap. Brazil: Increased funding for the National Electricity Conservation Programme. Uruguay: Implementation of the National Plan for Energy Efficiency 2015-2024 with the goal of saving a cumulative 1.69 Mtoe.
	Buildings	Mexico: MEPS on split-type air conditioners. Brazil: Installation of LED street lights in Rio de Janeiro for the Olympic Games.
Southeast Asia	General	Philippines: Energy Efficiency and Conservation Action Plan 2016-2020 to reduce energy intensity by 40% by 2030 from 2005. Thailand: Drafting of the Energy Efficiency Development Plan 2015-2036 with a target to reduce energy intensity by 30% in 2036 compared with 2010.
	Buildings	Philippines: Approval of energy labelling and efficiency standards for refrigerators and air conditioners.
Japan	Buildings	Mandatory energy efficiency standards for new non-residential buildings from 2017 and a labelling system from 2016. Phase out incandescent light bulbs and fluorescent tubes by 2020. Top Runner Program requirements strengthened for refrigerators and freezers. Update of mandatory efficiency benchmarking to include the services sector, with the aim to cover 70% of energy demand in services and industry by 2018.
Canada	Buildings	Update and strengthen the national energy codes for buildings, including lighting and HVAC systems.
Australia	General	Release of the National Energy Productivity Plan aiming to improve energy productivity by 40% between 2015 and 2030.
International	Transport	Announcement of CO_2 limits for new aircraft from 2028 by the ICAO.
	General	Almost nine out of ten of all national submitted NDCs mention energy efficiency. One of the UN's SDGs is to double the global rate of improvement in energy efficiency.

Notes: LPG = liquefied petroleum gas; CNG = compressed natural gas; HVAC = heating, ventilating and air conditioning systems.

Energy efficiency policies are being implemented in an increasing number of developing and emerging economies. In India, the first cycle (2012-2015) of the innovative Perform, Achieve and Trade (PAT) scheme in industry has been completed with targets exceeded. The Indian administration has announced plans to introduce a green tax on transport and has implemented a programme to distribute more efficient ceiling fans. In Latin America, Mexico's energy transition law has come into force, setting an energy efficiency target for the next 30 years. Uruguay has implemented the National Plan for Energy Efficiency, which is designed to save a cumulative 1.7 million tonnes of oil equivalent (Mtoe) in the period 2015-2024 (around 3% of energy demand in the period). In the countries of the Association of Southeast Asian Nations (ASEAN), the Philippines has established an Energy Efficiency and Conservation Action Plan, aiming to reduce energy intensity by 40% by 2030. Thailand is in the process of drafting an Energy Efficiency Development Plan, targeting a 30% reduction by 2036.

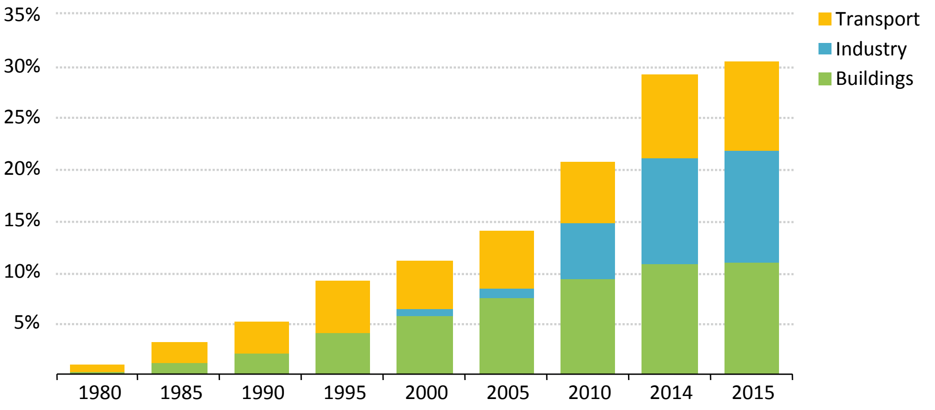
7.2.2 Energy efficiency regulation and prices

Regulating energy efficiency through the use of MEPS for end-use equipment has become widespread. By setting minimum efficiency levels, policy-makers help to overcome behavioural barriers to adopting more efficient technology and thus encourage consumers to save energy and money. *WEO-2015* assessed the amount of global final energy consumption covered by mandatory energy efficiency regulation. The analysis included a large number of efficiency regulations in all world regions and the end-use sectors buildings, industry and transport. The estimation of the proportion of energy consumption that can be attributed to equipment that is subject such regulation takes into account the point in time at which it was first introduced, energy consumption by equipment type and the average lifetime of the equipment. This analysis was updated and expanded to examine the stringency of the regulations in greater detail in the *Energy Efficiency Market Report 2016* (IEA, 2016b). It shows that efficiency-regulated energy use in 2015 covered 30% of global final energy consumption (Figure 7.3) and that the average stringency of regulation has increased by 23% since 2005.

The increase from 2014 to 2015 in the share of global final energy consumption covered by mandatory energy efficiency regulation was one percentage point. It arose partly from the continuing turnover of equipment and devices, but also from (among other things) new MEPS for space and water heating in the European Union, fully enforceable fuel-economy standards for heavy-duty vehicles in Japan, and MEPS for industrial electric motors in Turkey, Saudi Arabia and Taiwan. The one percentage point increase is lower than the average yearly improvement over the last decade of 1.6 percentage points, but this was, however, more than three-times higher than the average annual improvement in the period up to 2005.

Mandatory energy efficiency regulation is not the only instrument in a policy-maker's tool box. Adjusting the energy price level can be an efficient alternative or supplementary method to achieve energy savings, whether in the form of a gradual phase-out of consumer subsidies, raising energy taxes or putting in place a CO_2 price. Higher prices stimulate consumers to reconsider their energy consumption and make savings where this can be done most cheaply, whereas regulation through mandatory standards may not be the least-cost or most effective approach. For instance, a fuel-economy standard for a car will lower the energy consumption per driven mile, but not the number of miles driven.[6] On the other hand, a higher price for fuel will result in both more efficient vehicles and fewer miles being driven (other things being equal). The effect of energy prices should therefore not be ignored and an effective energy policy package will normally include both pricing and regulatory elements.

Figure 7.3 ▷ Share of global final energy consumption covered by mandatory energy efficiency regulation



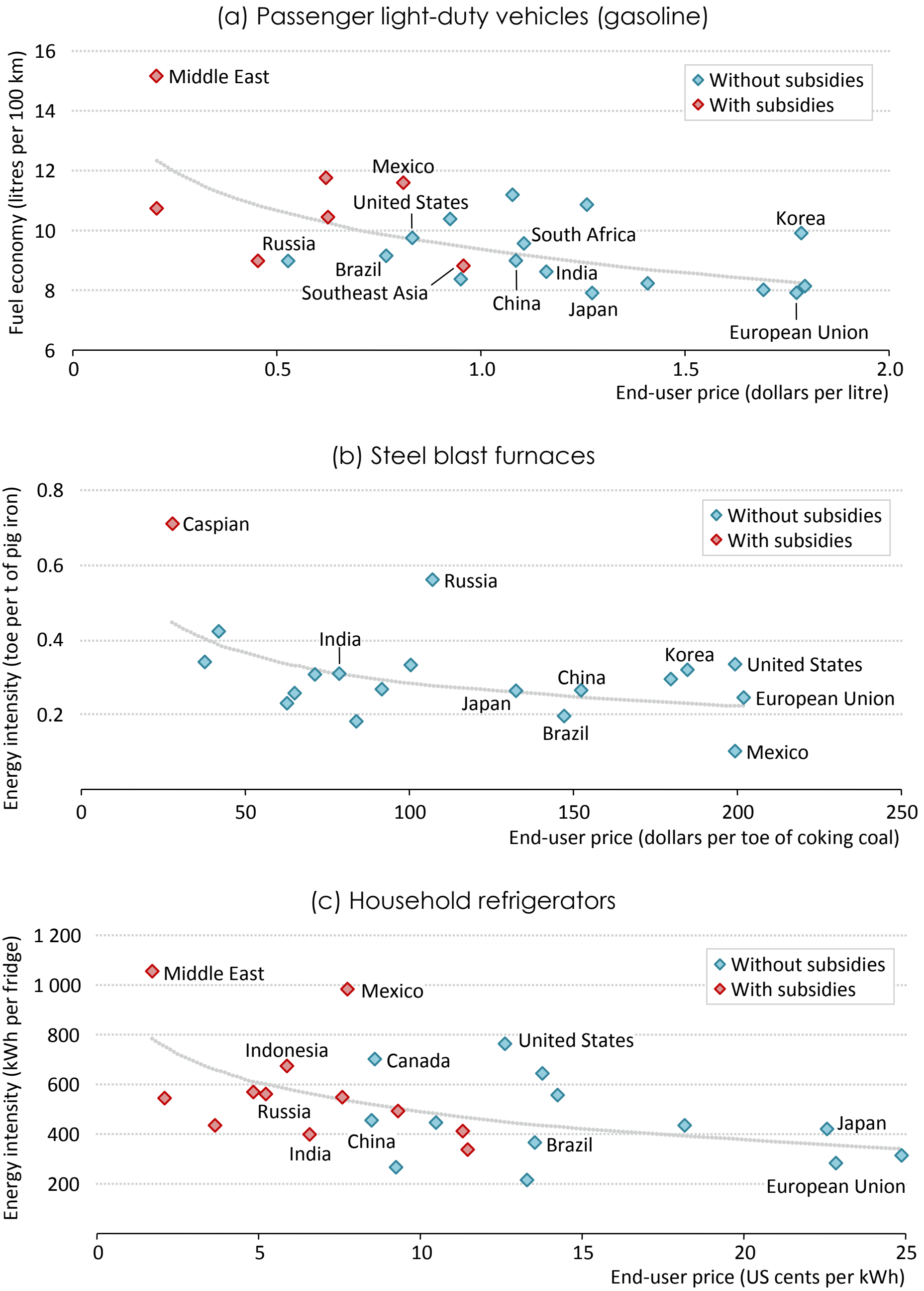
Global mandatory energy efficiency regulation more than doubled over the past decade

Sources: IEA analysis; IEA (2016b).

Recent low energy prices present a risk that efficiency will suffer despite the broader scope and reach of mandatory energy efficiency regulation. With lower energy prices, the economic attractiveness of saving energy and investing in energy efficiency decreases. This is not just a theoretical argument. Detailed country by country analysis focussing on three end-use equipments (cars, steel blast furnaces and refrigerators), shows clearly that end-user energy prices do influence consumers' choices across all end-use sectors (transport, industry and buildings). Even in wealthier countries, where the share of energy expenditures in overall income tends to be lower, prices continue to matter. Where end-user prices are low, energy efficiency tends to be poorer and vice versa (Figure 7.4).

6. It might actually increase the number of miles driven as the cost of an extra mile is lower in a more efficient vehicle, the so-called rebound effect.

Figure 7.4 ▷ Energy prices and energy efficiency levels by sector, 2014



Energy efficiency tends to be better in regions with higher energy prices

Notes: km = kilometre; toe/t = tonne of oil equivalent per tonne; kWh = kilowatt-hour.

Many governments already influence energy prices by taxes or subsidies, and when subsidies are employed it is often with conflicting underlying objectives. For example, subsidies that reduce the price of fossil fuels and electricity are often intended to act as a social benefit mechanism, targeting low income households, particularly in non-OECD countries. But in practice, they tend both to increase energy demand (see Chapter 2) and fail to meet their social objective, since energy consumption tends to increase with income levels and the greater part of these subsidies is typically captured disproportionally by higher income groups. For instance, in developing countries the richest 20% of households enjoy six times more in fuel subsidies than the poorest 20% households (Arze del Granado, et al., 2012).

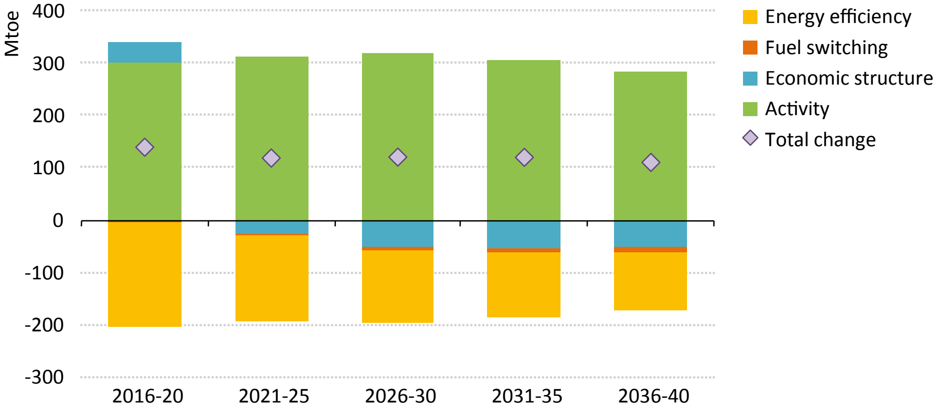
Though the relationship between prices and energy efficiency is complex, as also regional regulatory and structural differences play a key role, it is clear that when policy-makers influence end-user prices through subsidies, they assume heightened risks of lower energy security, increased local air pollution and higher energy-import bills (or lower exports in producing countries). Phasing out energy subsidies and instead taxing end-user prices can provide a revenue stream to public coffers that can be used to more directly benefit low income groups with carefully targeted mechanisms, as well as to deliver multiple benefits from the more efficiency use energy.

7.3 Outlook for energy efficiency

In the New Policies Scenario, global final energy consumption increases by 1.1% per year to 2040, significantly less than the projected average annual economic growth rate over the same period of 3.4%. It is also significantly below the 1.8% annual energy growth observed over the past two-and-a-half decades. Energy efficiency plays a vital role in the New Policies Scenario to mitigate the increase in energy consumption (Figure 7.5). Without the projected level of efficiency improvements, global final energy consumption would increase each year by more than 140 Mtoe (about today's energy consumption level in France) from today to 2040. In Organisation for Economic Co-operation and Development (OECD) countries, energy efficiency savings, expressed as a share of final energy consumption (27%), are generally higher in 2040 than in non-OECD countries (20%), as policies to control energy consumption affect a wider share of energy-using equipment and are generally more stringent. For instance, in the United States the reduction in energy consumption from efficiency measures entirely compensates for the higher demand for energy services in the New Policies Scenario.

Shifts in economic structure (those sectors where economic value is created) effects energy consumption because different sectors are dependent on energy to different extents. For instance, the industry sector on average is seven-times more energy intensive (on a value-added basis) than the services sector. In the short term, rapid capacity expansion in the US and Chinese chemical industries, (particularly in China's coal-based methanol-to-chemical industry) boosts the significance of energy-intensive industries even at the global economic level. In the long-run, however, there is a worldwide shift towards less energy-intensive sectors (particularly in non-OECD countries) as saturation effects soften demand growth for industrial products such as steel, paper and cement, and as economic growth gradually shifts towards the services sector, where value added is higher per unit of energy input. Over the period to 2040, economic restructuring lowers global final energy consumption by almost 30 Mtoe per year.

Figure 7.5 ▷ Average annual change in global final energy consumption by driver in the New Policies Scenario



Energy demand increase is slowed by energy efficiency gains and economic restructuring

Source: IEA analysis based on decomposition analysis.

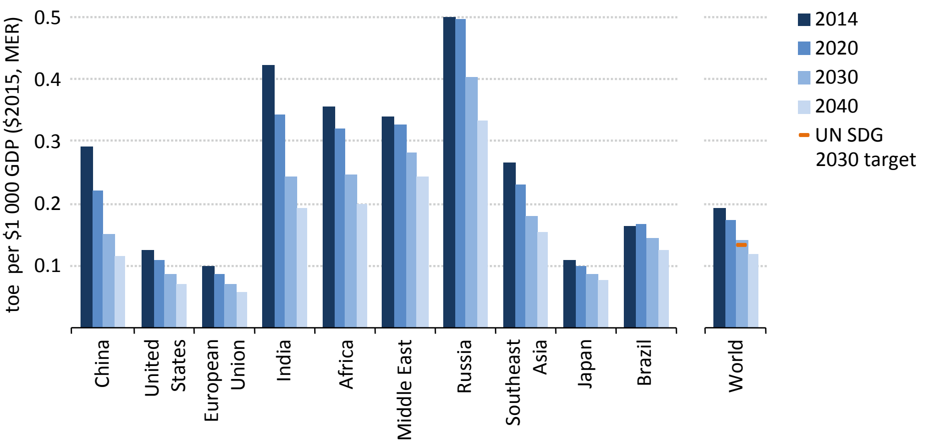
In the New Policies Scenario, all world regions see an improvement in the energy intensity of GDP in the long term (Figure 7.6). Most impressively, China is projected to improve energy intensity by 3.5% per year on average from 2014 to 2040, followed by India, with an average annual improvement of 3.0%. At the world level, energy intensity drops by more than 60% by 2040, compared with 2014, but will fall short of the UN SDG goal in 2030: the target is 2.1% average annual improvement in the period 2010-2030, while the New Policies Scenario estimates only 1.9% per year in the same period.[7] Although the difference is small, the extra effort needed to reach the UN SDG target is significant and will require stringent energy efficiency measures in all world regions.

In *WEO's* 450 Scenario, in line with the international goal to limit the rise in the average global temperature to 2 °C by 2100, global energy intensity improves at an average annual rate of 2.5% to 2040. This is more than one-third faster than in the New Policies Scenario, which sees an annual improvement of 1.8% to 2040. The higher rate of improvement in the 450 Scenario reflects implementation of ambitious policies. These include, CO_2

7. The UN SDG energy intensity target is officially set at 2.6% average annual improvement in energy intensity measured in purchase power parity terms. Converting the target to improvements in energy intensity at market exchange rate gives 2.1%.

pricing in all OECD countries and in several large non-OECD countries, international agreements on targets for iron and steel sector energy savings, support for alternative transport fuels, stringent energy building codes and enhanced efficiency standards (including fuel-economy standards) in all end-use sectors and all regions, among other policies (see Annex B).

Figure 7.6 ▷ Energy intensity in selected countries/regions in the New Policies Scenario



Energy intensity improvements fall slightly short of reaching the UN SDG target in 2030

Note: MER = market exchange rate.

7.3.1 Sectoral trends

Today, the industrial sector accounts for the highest share (38%) of final energy consumption.[8] Buildings account for 31% of final energy consumption, transport for 27% and agriculture, as well as non-feedstock related non-energy use each for 2%.[9] Over the projection period to 2040, the share of industry is projected to increase to 39%, while that of buildings decreases to 30%. This reflects a decline in the traditional use of biomass in households (today more than a third of household energy consumption worldwide) and steady growth in industry, in which about 15% of the sector's energy demand is feedstock for the petrochemical industry, an area in which further efficiency gains are difficult.

Energy demand in industry has increased by 2.0% per year since 1990, but this rate of growth is expected to slow to 1.2% per year over the period to 2040. While energy efficiency is projected to continue to improve over the next two-and-a-half decades,

8. In this chapter, energy demand in industry also includes blast furnaces, coke ovens and petrochemical feedstocks.

9. This includes mainly the use of lubricants in industry and transport vehicles, bitumen for roofing and road pavement, as well as the use of petroleum coke for anodes in the aluminium industry and paraffin waxes.

slower demand growth for most energy-intensive materials will be an important supporting factor in limiting energy demand growth. As an example, steel production has increased by 3.3% per year since 1990, but average growth over the period to 2040 slows to 0.6% per year. This is mainly a consequence of a restructuring of the Chinese economy, where steel production is projected to fall by more than 30% from 2014 to 2040. The wider application of energy efficiency measures across all industries over the period to 2040 leads to energy savings of 1 740 Mtoe in 2040. In other words, without energy efficiency, annual industrial energy demand growth would be 2.4% to 2040, instead of 1.2%, i.e. twice as high. Three-quarters of the energy efficiency savings arise in countries outside of OECD and half of worldwide savings due to energy efficiency come from only two countries: China and India. This is a consequence not only of the still relatively large potential for energy efficiency in both countries, but also of the policies that have been put in place.

In the buildings sector, almost three-quarters of energy is consumed in households, with the rest distributed across different uses in the services sector, including public buildings, offices, shops, restaurants and water treatment and pumping (see Chapter 9). Energy demand growth in services of 1.6% annually to 2040 is more than twice as high as in households, since economic growth (and therefore the need for energy) is fastest in the services sector while, on the other hand, population declines in some parts of the world in the later part of the projection period, including China, Russia and several OECD countries. The realisation of efficiency measures means that energy consumption in the New Policies Scenario in the buildings sector as a whole grows by only 0.9% instead of 1.5% in the absence of action on energy efficiency. In households, over 40% of the savings are realised in space and water heating, as buildings become better insulated and heating equipment becomes more and more efficient. More efficient lighting is responsible for a third of the savings in households, as most countries have already committed to phase out the use of the least efficient incandescent light bulbs and are promoting LEDs. In geographic terms, the United States, China, the European Union and India account for two-thirds of all energy efficiency savings in buildings.

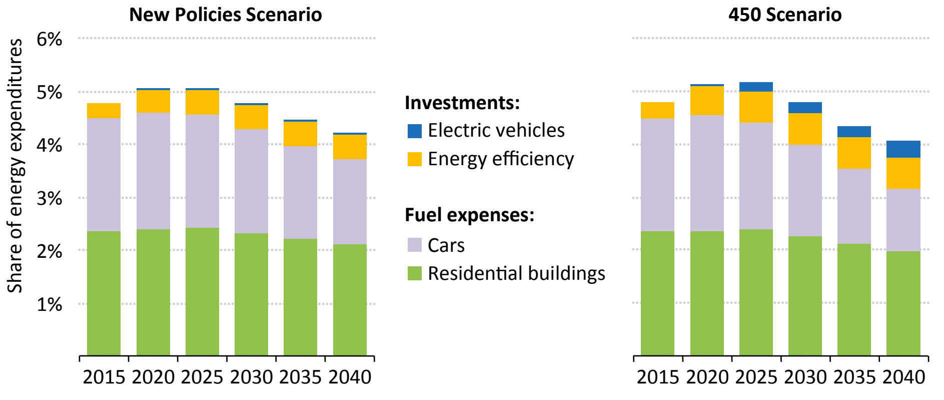
Today the transport sector accounts for slightly more than a quarter of final energy consumption, of which more than 90% is in the form of oil. Since 1990, energy consumption in transport has expanded at an annual rate of 2.2%. Without the further strengthening of fuel-economy standards assumed in the New Policies Scenario, energy demand growth in transport would be at a similar annual rate of 2.1%. However, more efficient vehicles, ships, aircraft and trains save more than 1 000 Mtoe in 2040 compared with today, or 30% of the transport-related energy consumption which would otherwise arise. Three-quarters of the efficiency savings to 2040 are achieved in road transport, of which 80% are realised in cars and trucks. Strengthening the Corporate Average Fuel Economy (CAFE) standards in the United States delivers roughly 30% of global efficiency-related savings for cars, while China's fuel-economy targets delivers 17% and the European Union's CO_2 emission standards account for 16%.

7.3.2 Multiple benefits

Household expenditures

Global energy expenditures absorbs just below 5% of household disposable income, a share which has increased during the last decade. The call of energy expenditure on household income is projected to fall slightly in the New Policies Scenario and in the 450 Scenario in the longer term (Figure 7.7). Household energy bills in this context are defined as the sum of fuel expenses (e.g. natural gas use for space heating and gasoline in vehicles), occasional investments in more expensive but more energy-efficient household appliances and cars, and the extra costs of electric vehicles. The latter is included to facilitate a better comparison between the New Policies Scenario and the 450 Scenario, in which the uptake of electric vehicles lowers expenditure on gasoline and diesel, but entails an additional cost for the vehicle.

Figure 7.7 ▷ Share of energy expenditures as a call on global household income



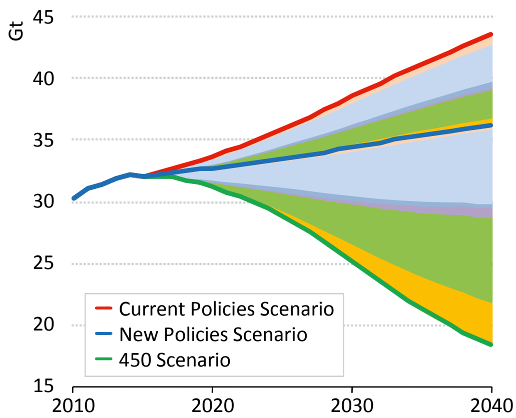
Due to energy efficiency, households do not see higher energy bills in the 450 Scenario

In real terms, household energy bills are expected to increase by more than 80% from today to 2040 in the New Policies Scenario, but as global income is expected to more than double, the share of energy in household expenditures is slightly lower in 2040 than today. In the period to 2025, the projected rebound of energy prices (see Chapter 1) temporarily pushes up the share of energy expenditure in total household expenditure in the New Policies Scenario. In the 450 Scenario, higher investments in energy-efficient devices and vehicles enable household energy consumption to stay flat during the projection, period bringing total energy expenditure slightly down at the end of the projection period, compared with the New Policies Scenario despite higher end-user prices: the additional cost associated with the purchase of more efficient equipment and vehicles is outweighed by the lower expenditure that result from the energy savings.

Avoided CO_2 emissions

As noted, energy efficiency and the deployment of renewable energy technologies play an important role in global energy-related CO_2 reduction in both the New Policies and the 450 Scenarios (Figure 7.8) (see Chapter 8). In the Current Policies Scenario, energy-related CO_2 emissions reach 43.7 gigatonnes (Gt) in 2040, up from 32.2 Gt today (an average annual growth of 1.2%). The New Policies Scenario saves a cumulative 88.0 Gt over the period compared to the Current Policies Scenario with emissions falling to 36.3 Gt in 2040. Almost half of the savings are a result of higher energy efficiency, with the efficiency gains in appliances and equipment in the buildings sector being an important element. However, the New Policies Scenario leaves a significant amount of the energy efficiency potential untapped.

Figure 7.8 ▹ World energy-related CO_2 emissions abatement by scenario



CO_2 abatement in 2040	CPS to NPS	NPS to 450
Activity effect	12%	2%
End-use efficiency	39%	33%
Supply efficiency	6%	2%
Fuel and technology switching	3%	4%
Renewables	32%	39%
Nuclear and CCS	9%	19%
Total (Gt CO_2)	**7.4**	**17.9**

Energy efficiency is a key abatement measure in the New Policies and the 450 Scenario

Notes: CPS = Current Policies Scenario; NPS = New Policies Scenario; CCS = carbon capture and storage.

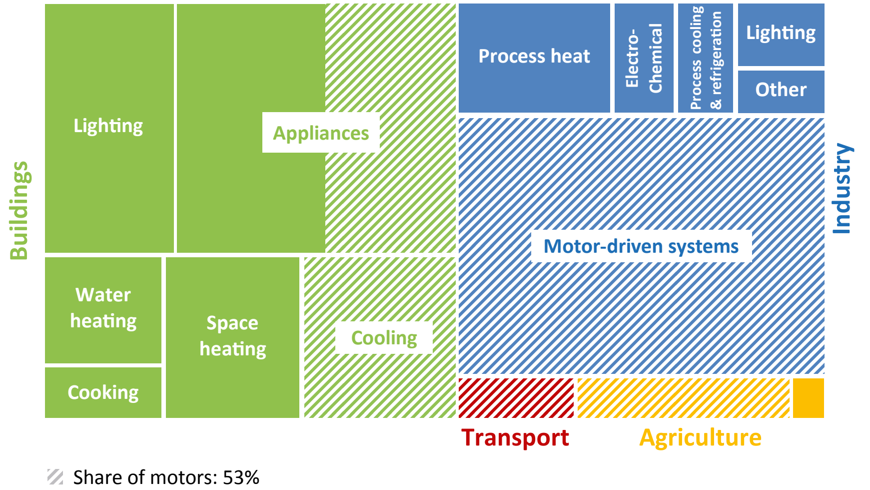
In the 450 Scenario, this potential is exploited, as more stringent policies and higher end-user prices incentivise energy efficiency investment. In particular, energy efficiency in small- and medium-size enterprises plays an important role. As a result, energy-related CO_2 emissions drop to 18.4 Gt in 2040, down almost 50% compared with the New Policies Scenario. Energy efficiency is the second largest source of emissions reduction in the 450 Scenario, following renewables, in particular for power generation.

7.4 Focus: Electric motor-driven systems

7.4.1 Introduction

Based on new analysis for this *Outlook*, it is estimated that more than half of the electricity consumed globally is used in electric motor systems in industry, buildings, agriculture and transport. In industry, electric motors are used extensively in various sub-sectors, including chemicals, paper, food, metal and textiles, and they account for just over 70% of industrial electricity consumption. Motors are used to drive pumps, fans, compressed air systems, material handling, processing systems and more. Their size ranges from very small (less than 0.1 kilowatt [kW]) to having a higher output than heavy-duty trucks (more than 1 000 kW). In the buildings sector, electric motors (mainly very small) are part of the many household appliances upon which people rely every day (e.g. refrigerators, washing machines, air conditioners, fans in computers). They account for about a third of electricity consumption in buildings. In the agriculture sector, electric motors are used to drive irrigation pumps; and in the transport sector, electric motors are used in electric vehicles, rail transport and pipeline compressors. Currently, the industry sector and the buildings sector together account for over 90% of electricity consumption by motors, with the rest consumed in agriculture and transport (Figure 7.9).

Figure 7.9 ▷ Global total final electricity consumption by end-uses, 2014



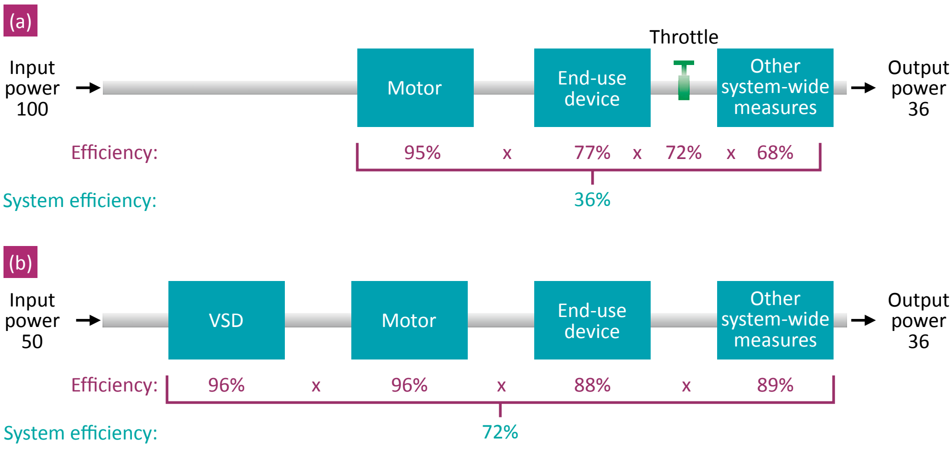
Motors account for more than half of today's electricity consumption

Source: IEA analysis.

Given the high share of motor systems in global electricity consumption, the rest of this chapter takes a close look at the outlook for electricity consumption in motors and the potential for energy savings. For this purpose a new motor model has been set up and integrated into the World Energy Model (WEM), estimating global electricity use in motors and projecting it to 2040 as part of our usual scenario framework (Box 7.1). The industry sector — where 30% of global electricity is consumed in electric motor systems — is the focal point of this analysis. Motors in the industry sector are usually a part of a larger system. So far, policy-makers have, in their efforts to control electricity consumption in industrial motors, focussed on putting in place MEPS on the motor itself. Consequently, the current analysis shows that almost nine-out-of-ten industrial electric motors sold worldwide today are covered by MEPS. But, as we explore below, attention needs to turn to the whole system of which the electric motor is but one part.

The majority of electricity savings in electric motor systems can often be found not in the motor itself but elsewhere in the system. Typically the electricity losses occurring in the electric motor are only a minor share of the total electricity losses in the entire system the motor is driving. To visualise a typical industrial motor system, one can think of a connected range of system components: the electric motor, the end-use device (e.g. a pump) and other system components (such as the coupling between the motor and the end-use device, the control system, pipes or valves) (Figure 7.10). The efficiency of each component is important to the efficiency of the entire system. Generally, electric motors are already fairly efficient, meaning that further improvements to the motor affect the efficiency of the system only marginally. On the other hand, the efficiency of the driven equipment often leaves much room for improvement.

Figure 7.10 ▷ Illustration of two industrial electric motor-driven systems: (a) normal and (b) efficient



All components of the motor system affect system efficiency

Note: VSD = variable speed drive.

Indeed, the largest potential savings in industrial electric motor-driven systems can often be found by looking not only beyond the motor but also beyond the end-use device. Industrial motor systems can be large and complex, and consist of a large number of flow paths and demand-side needs, large-scale control systems and different transmissions. Further, the operator's behaviour can enhance the efficiency of the system, for instance through an upgrade of system maintenance, carrying out predictive maintenance, avoiding the tendency to buy oversized motors and by carefully matching the motor system to the specific need at hand. Taken together these various system-wide considerations have the potential to significantly increase energy efficiency in electric motor-driven systems.

Box 7.1 ▷ Quantifying electricity consumption in motor systems

We project global electricity consumption in electric motor systems in industry, buildings, transport and agriculture to 2040 with the use of the WEM. For this analysis, we have carried out an extensive literature review and have been in contact with leading experts in this field. It continues the IEA's previous work on electric motors (IEA, 2011a; 2011b) and (IEA 4E, 2015) and is the subject of an energy technology network within the IEA: the 4E Electric Motor Systems Annex (EMSA).[10]

In order to investigate the potential energy savings in electric motor-driven systems in the industry sector, we have constructed a model for industrial motor systems which consists of two parts: a regionally disaggregated stock model for both electric motors and end-use devices, and a module for calculating the savings associated with variable speed drives (VSDs) and other system-wide measures.[11] The uptake of more efficient motors, VSDs, equipment and other system-wide measures is driven by current and planned policies and standard economic considerations for investment decisions (based on simple payback periods).[12] We distinguish between four types of end-use devices: pumps, fans, compressed air systems and mechanical movement. For the efficiency of motors, the International Electrotechnical Commission (IEC) classification definitions are used:

Efficiency class	Classification
IE1	Standard efficiency
IE2	High efficiency
IE3	Premium efficiency
IE4	Super premium efficiency

The "other system-wide measures" category consists of a wide range of various improvements in motor system components and management practice, all of which increase the efficiency of the system. These measures can be broadly categorised as the upgrade of system maintenance (such as fixing leaks, reducing pressure losses), predictive maintenance, eliminating unnecessary uses (such as the use of pressure systems), matching the equipment to demand needs (such as downsizing of equipment or changing the impeller), correcting system flow problems and the use of smart manufacturing. The latter describes the use of sensors and software that improve measurement, evaluation and validation, and thus provide data feedback to the control system.

10. See also *www.motorsystems.org/*.
11. A variable speed drive is a piece of equipment used to control the speed of machinery.
12. The methodology for this stock model follows previous work by the IEA (2011b).

To analyse the motor-related electricity consumption in buildings, transport and agriculture, we have made use of the existing detail of the WEM. This includes explicit modelling of electricity consumption in refrigerators, air conditioners, washing machines, electric heat pumps in buildings and electric vehicles in transport. For the agriculture sector, electricity consumption in motors for irrigation pumps has been estimated. The New Policies Scenario – our central scenario – provides for the effects of current energy policies and those that are under discussion, but does not exploit the full energy efficiency potential. In the 450 Scenario, policy measures are put in place that enable the full economic energy efficiency potential to be realised.

One of the most promising measures to save electricity is the installation of a VSD, a device to control the speed of the motor.[13] Many (but not all) industrial processes require the motor to operate at different speeds but, in most cases, this is not possible as the majority of motors today are fixed-speed motors. In a fan system, for example, the fixed-speed motor is chosen to meet the maximum air flow requirement and this flow is then regulated via a throttle: for most of the time, the airflow is invariably higher than it needs to be. Controlling the speed of the motor via a VSD can make the use of a throttle unnecessary and significantly reduce the required electricity input. A simplified illustration in transport would be to drive a car with the accelerator pedal fully depressed, adjusting the speed solely through the use of the brake pedal. Removing the throttle and installing a VSD can increase system efficiency by 15-35% in a standard motor system with variable load (EC, 2000).

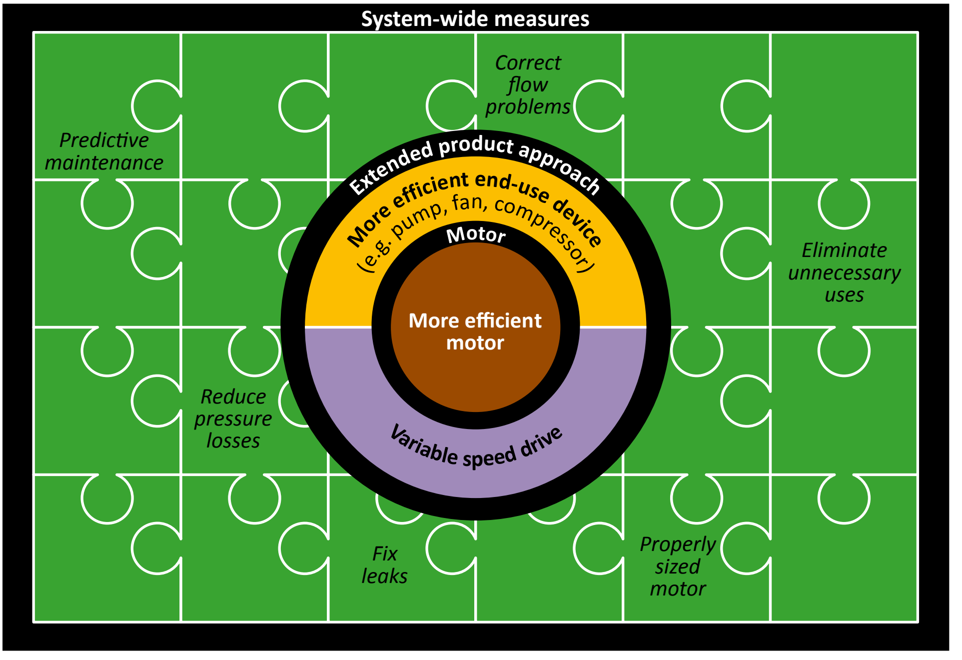
In this analysis, savings potentials are divided into four categories:

- More efficient motors;
- More efficient end-use devices;
- Installation of VSDs; and,
- Other system-wide saving measures.

As mentioned, most policy intervention concerning motor systems so far has focussed on the motor itself, but several countries are now targeting energy savings in the motor, end-use device and VSD (this grouping is also called the extended product). The main aim is to create standards for the extended product, which could unlock significant energy savings (more on this in the section on policy recommendations). The largest saving opportunities exist in further system-wide measures, but it is difficult to incentivise their uptake (Figure 7.11).

13. Other names for VSDs include variable-frequency drive, adjustable speed drive, frequency inverter or simply inverter.

Figure 7.11 ▷ **Illustration of energy-saving options in electric motor systems**



Electricity saving options exist in many parts of the electric motor system

Note: The puzzle pieces illustrate what is referred to in the text as "other system-wide measures".

7.4.2 Energy and emissions trends for electric motor systems

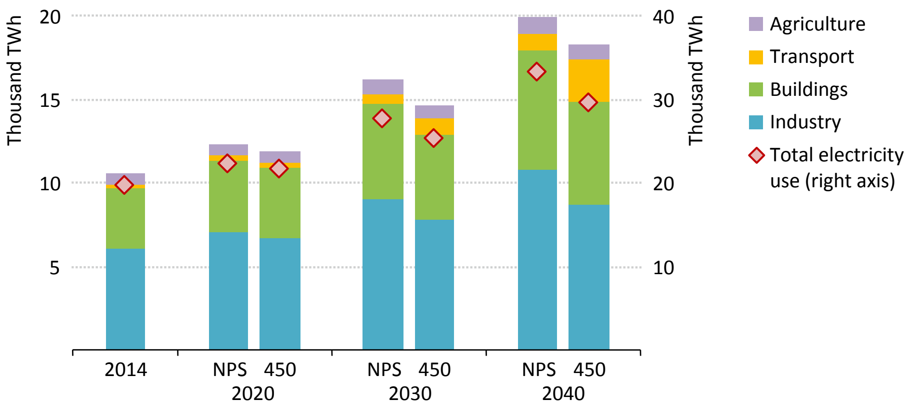
New Policies Scenario

In the New Policies Scenario, global electricity consumption in electric motors is projected to increase in all sectors. Starting from an estimated 10 500 TWh in 2014, the electricity consumption in motors almost doubles in 2040 in the New Policies Scenario (Figure 7.12). The industry sector accounts for half of the increase in electricity consumption in motors, as a consequence of strong industrial growth, particularly in developing Asia. As income levels rise in all countries and, in particular, in emerging countries, the demand for industrial products rises in tandem, pushing up the demand for the services provided by electric motors. Globally, total demand for energy services from industrial motors more than doubles by 2040, almost half of this increase is in China and India. This increased demand is only partly offset through improvements in industrial motor system efficiency in the New Policies Scenario, which improves by almost 20% on average.

China dominates the global picture, as over 40% of world electricity consumption in industrial motors occurs there, a share which is projected to increase slightly over the projection period in the New Policies Scenario (Figure 7.13). The increase in efficiency in electric motors occurs gradually over time, as new, more efficient motors replace old motors.

As many countries already have mandatory MEPS in place for electric motors, premium efficiency motors (IE3), whose share today is negligible, are projected to be the dominant efficiency class in 2040 (Figure 7.14). This trend is driven predominantly by developments in three world regions: China, the European Union and the United States. China introduced the first MEPS for electric motors in 2002, which eliminated sales of motors with an efficiency level below IE1. Changes in 2011 required motors to meet at least IE2 levels and new changes in 2015, IE3 levels. This move to IE3 level has been subsequently postponed, but in the New Policy Scenario it is assumed that it will eventually be implemented. The European Union set a minimum standard of IE2 in 2011, which was upgraded in 2015 to IE3, or IE2 if the motor is equipped with a VSD. The United States has had minimum requirements for electric motors since 1992. The stringency of the requirements for most motors from 2011 was increased to a level similar to IE2 from 2011, and, in 2016, to IE3. Despite the projected progressive transformation of the global motor stock, the average efficiency of motors (taken in isolation) increases by only 2% in 2040 compared with today, because of the already high degree of efficiency in motors.

Figure 7.12 ▹ Final electricity consumption in motor-driven systems in the New Policies Scenario and 450 Scenario

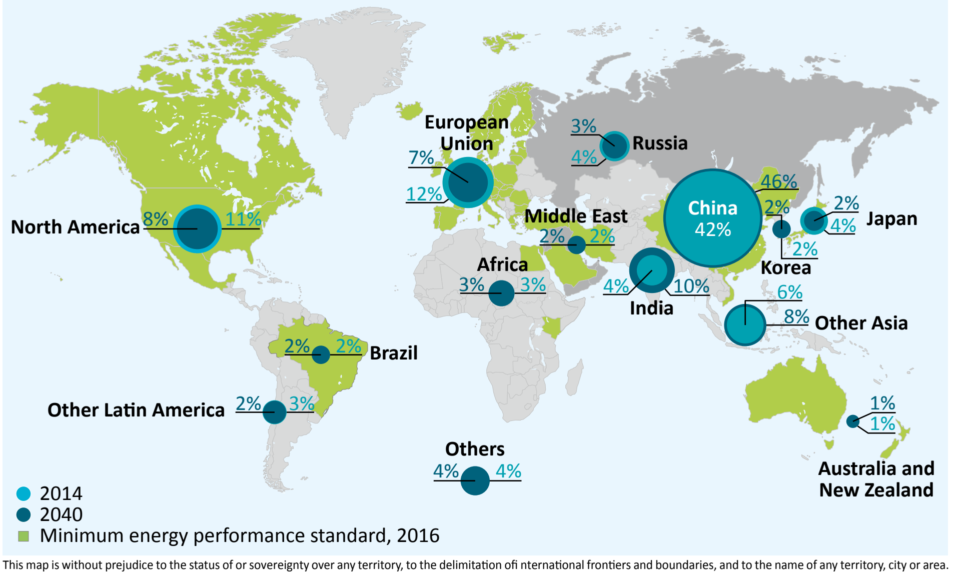


Electricity consumption almost doubles to 2040 in the NPS with significant savings untapped

Notes: NPS = New Policies Scenario; 450 = 450 Scenario.

The regulation of end-use devices (as opposed to the motors themselves) is still behind that of motors, but it is progressing in several key countries. China leads the field with standards in place for pumps, fans and air compressors. The European Union has standards for pumps and fans, and is in the process of developing regulation for compressors. In the United States, pumps are subject to MEPS and the US Department of Energy is currently engaged in rulemaking for fans and compressors. Outside these three regions, very few countries regulate energy use in industrial end-use devices. Since only a few countries having commitments to introduce regulation and those have limited scope, the efficiency of industrial end-use devices increases by only 1% in 2040, compared with today, as old devices are gradually replaced by new ones. The vast potential for future electricity savings in the New Policies Scenario in the industry comes from the adoption of system-wide savings measures.

Figure 7.13 ▷ Share of global industrial electricity use in motor systems in the New Policies Scenario

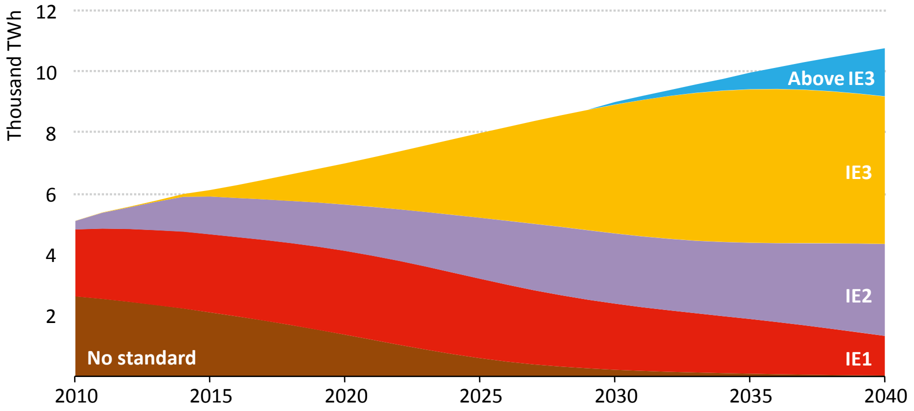


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation ofi nternational frontiers and boundaries, and to the name of any territory, city or area.

Global electricity consumption in industrial motor-driven systems remains dominated by China

As electricity prices increase, industries become more aware of the economic savings to be made from conducting predictive maintenance of the system, fixing leaks and incorporating so-called smart manufacturing strategies that optimise the system as a whole. Moreover, several countries have already taken steps to create incentives for the uptake of such other system-wide measures. China, India and Japan have set mandatory saving targets for larger, energy-intensive plants, while several European countries have voluntary agreements with industry in place. Furthermore, several countries require industrial consumers to undergo regular energy audits and to install energy management systems, which provide for the better use of data and policy development for the more efficient use of energy. These policies, taken together, incentivise the uptake of system-wide savings measures sufficiently to increase the energy efficiency of an average motor system by 9% in 2040, compared with today. The use of VSDs in motor systems is expected to increase as well, although only to a minor extent in the New Policies Scenario because of the current absence of policies to incentivise their uptake.

Figure 7.14 ▷ Global industrial electricity consumption by motor efficiency class in the New Policies Scenario



Motor electricity use almost doubles, but 60% of use in 2040 comes from IE3 motors or better

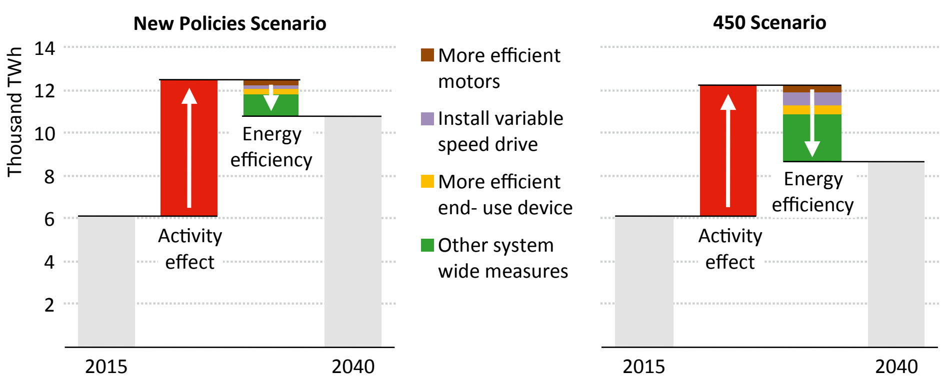
In the buildings sector, electricity consumption in electric motors doubles over the next 25 years as rising income levels create more demand, especially for household appliances and heating, ventilating and air conditioning (HVAC) systems. Demand for household appliances accounts for half the increase in electricity consumption by 2040 and the demand for cooling for 45%. The rest of the increase is due to higher demand for heat pumps, which is a result of households switching from fossil-fuel boilers or electric resistance heating. In the agriculture sector, electricity consumption in motors also increases in line with higher needs for irrigation, the main motor use in agriculture. In the transport sector, electricity demand in motors triples by 2040, as the sales of electric vehicles increase almost forty-fold (see Chapter 6). Higher electrification in buildings and in transport pushes up the share of electric motors in total electricity demand, to reach almost 60% by 2040.

450 Scenario

In the 450 Scenario, energy efficiency is a central strategy to achieve the necessary emissions reductions. Realising the potential energy savings from energy efficiency in electric motor systems is an essential part of the efforts to bring down energy use. Electricity consumption in electric motors in the 450 Scenario in 2040 is reduced by more than 1 600 TWh (8%), compared with the New Policies Scenario, which corresponds to the shutting down of around 250 large coal power plants in that year. This reduction includes the transport sector, where a large increase in electric vehicles more than doubles electricity consumption in motor vehicles in the 450 Scenario, compared with the New Policies Scenario. By exploiting the full economic energy efficiency potential, the electricity savings in the 450 Scenario reduce CO_2 emissions in 2040 by up to 700 Mt (or roughly Germany's current energy-related CO_2 emissions).

In order to reach these savings, electricity prices rise in the 450 Scenario above the New Policies Scenario, as CO_2 pricing is applied in many countries and investments in renewable energy technologies in the power generation sector increase significantly (see Chapter 6). This reduces the payback periods associated with energy efficiency investments and thus increases their economic attractiveness. In addition, in the 450 Scenario, a range of policy measures is adopted, including more stringent MEPS for electric motors (most OECD countries and China adopt the IE4 motor standard by 2025) and end-use devices, incentives for the introduction of VSDs in variable load systems, the introduction of energy management systems and the regular implementation of energy audits in the industry sector. The effect of the introduction of MEPS for appliances in buildings, as well as for irrigation pumps in agriculture and further increases in the stringency of fuel-economy standards in transport (which provide an incentive for the uptake of electric vehicles) are also provided for in the 450 Scenario.

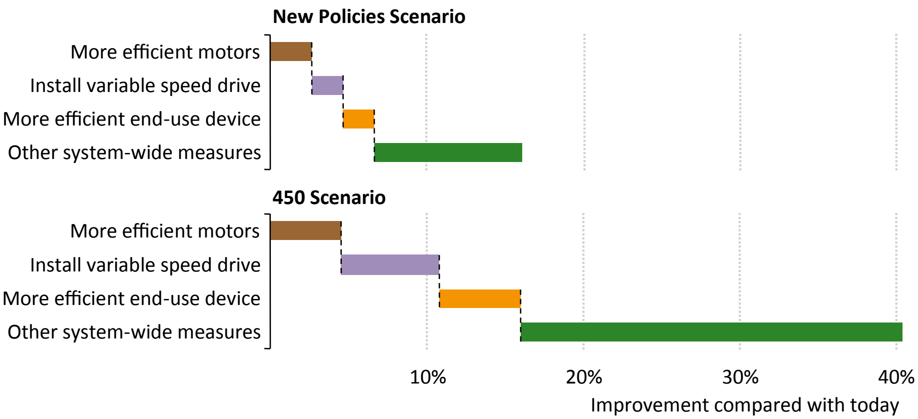
Figure 7.15 ▷ Change in global demand in industrial electric motor-driven systems



Energy efficiency gains are driven by other system-wide measures and installation of VSDs

In industry, the average global efficiency of electric motor-driven systems increases by 41% in 2040 in the 450 Scenario, compared with today, which is more than twice the level of improvement in the New Policies Scenario (Figure 7.15). Other system-wide measures make the largest contribution to the savings (Figure 7.16). Although these measures are only slowly implemented, particularly in developing countries, they play the largest role in increasing energy efficiency in industrial electric motor-driven systems because they hold a significant savings potential. In all regions, industrial motor efficiencies increase to IE3 in the medium term and eventually to IE4 at the end of the projection period, as higher end-user prices improve their cost-effectiveness. For countries without any efficiency standards for electric motors at present, such as India, this provides a large increase in the overall efficiency of its industry sector; but on a global scale, this does not unlock significant amounts of electricity savings, as average motor efficiency improves by only 4%, compared with today. With MEPS in place for end-use devices, their efficiency improves by 5% on average by 2040, compared with today. The adoption of VSDs contributes significantly to the savings in the 450 Scenario, due to the large untapped potential in the New Policies Scenario and the added incentive of shorter payback periods.

Figure 7.16 ▷ Efficiency improvements in global industrial electric motor-driven systems in 2040 compared with today



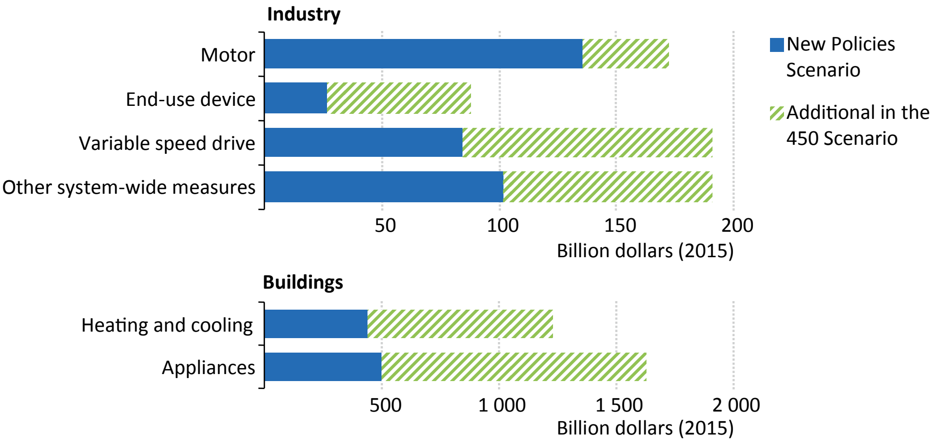
System-wide savings and the uptake of VSDs contribute the most to electricity savings

In the buildings sector, energy efficiency savings in the 450 Scenario are reached mainly through the introduction and strengthening of MEPS for appliances in households and commercial buildings, saving 12% in the 450 Scenario compared with the New Policies Scenario in 2040. However, opportunities exist to expand energy efficiency savings in buildings even further. One is to use the ability of VSDs to regulate motor output in a smart grid framework. Cooling and ventilation appliances in residential and commercial buildings could be used to store electricity when it is cheap and lower demand when it is scarce. In supermarkets, for instance, large commercial refrigerators can shift their electricity demand according to electricity prices in the short term, as temperatures in refrigerators change only slowly, so that food quality is not jeopardised. Consequently, VSDs could increase the flexibility of the electricity grid by creating opportunities for demand-response in buildings (and potentially industry), which could be an important way to integrate large amounts of variable renewable energy technologies into the electrical system (see Chapter 12).

7.4.3 Investments in energy efficiency in electric motor systems

The cost to conserve electricity is generally far lower than that associated with higher electricity generation (amplified by sometimes high transmission and distribution losses in developing countries), so that energy efficiency is an economically attractive option, albeit involving different groups of investors. Mobilising the cumulative sum of $1.3 trillion (or \$50 billion per year[14]) to finance the necessary motor-related investment in energy efficiency in the New Policies Scenario will require a suitable framework. About 70% of the investment is directed to improve the efficiency of appliances in buildings, particularly the efficiency of refrigerators and freezers, with the rest spent on industrial motors (Figure 7.17). Future efficiency progress in household appliances is less a consequence of more efficient motors (most appliances already adopt efficient permanent magnet motors), but rather of increased insulation. The total investment costs of motor-driven equipment in buildings are more than 2.5 times higher than the investment costs in industry as the equipment, such as air conditioners and refrigerators, has a shorter lifetime than industrial motors, and thus there is a higher rate of turnover while investment costs per unit of energy saved are higher. Despite the higher investment costs and consequently longer payback periods (which, in general, exceed five years, which is rarely the case for industrial equipment), households make the necessary investments in more efficient household appliances because of the burden of electricity prices to households.

Figure 7.17 ▷ Global cumulative investment in electric motor-driven systems in the New Policies and 450 Scenarios, 2016-2040



Investment is highest in buildings; in industry other system-wide measures and VSDs lead

In the New Policies Scenario, cumulative investment in industrial motor systems stands at \$350 billion or \$14 billion annually. The largest amount (almost 40%) is for more efficient motors, despite the fact that more efficient motors are only responsible for 16% of the electricity savings in the New Policies Scenario. To put it differently, more efficient motors lead to limited savings and are a comparatively expensive savings option. On the other hand, "other system-wide measures" account for only 29% of all investment but are responsible for almost 60% of the electricity savings. While the payback period associated

14. This compares with an estimated energy efficiency investment of \$8 billion in motor systems in 2015.

with more efficient motors ranges from two to six years, system-wide savings measures generally payback in far less than two years. Similarly, the average payback period for VSDs rarely exceeds three to four years, making such investment a cost-effective efficiency measure.[15]

Cumulative investment in energy-efficient motor systems in the 450 Scenario almost triples with respect to the New Policies Scenario to $3.5 trillion. The largest increase occurs in buildings with wider adoption of more efficient equipment and broader deployment of heat pumps. In industry, cumulative investments are roughly 80% higher in the 450 Scenario, with the largest increase in VSDs, followed by system-wide efficiency measures. The large increase in investment for VSDs recognises the significant efficiency potential which exists relative to the New Policies Scenario. The additional cumulative investment in industrial motor systems of around $300 billion is more than offset by avoided investment in electricity generation of $450 billion.

7.4.4 Policy recommendations for electric motor systems

The results of the New Policies Scenario show that it is unlikely that the full extent of the potential savings identified in motor-related electricity uses will be realised without the introduction of additional measures and incentives. Barriers to the uptake of energy efficiency include low awareness, a lack of information, the risk of disruptions to production and high initial capital cost, coupled with insufficient access to capital. The multiple benefits of energy savings, including the reduction of environmental harm and the stimulation of economic growth through more reliable and competitive production systems, can justify political intervention to mitigate the barriers.

As noted, the regulatory challenge in relation to industrial processes is more difficult than in buildings and transport. While the efficiency of a car or consumer appliance is relatively easy to regulate via fuel-economy standards or MEPS, regulating multiple, highly diverse industrial motor systems is by no means simple, since system components are often custom-built or are site specific. (Yet, policy-makers need to consider an increase in the stringency of fuel-economy standards and MEPS for consumer appliances [IEA, 2015a]). The remainder of this section focuses on the particular issues policy-makers face when regulating industrial electricity consumption.

Currently, a strong focus is put on the regulation of components at full load conditions, particularly motors and driven equipment. This gives rise to two problems: it does not target the large energy savings available in the rest of the motor system and it does not take real-world working conditions into account, i.e. that a significant amount of motor systems are operated at part-load for much of the time. Today, about 90% of the motors sold are covered by mandatory efficiency standards, but this is projected to lead to savings of only 2% in industrial motor systems by 2040. Similarly, existing standards for pumps and

15. Except for countries with low electricity prices, such as the United States, where average payback periods can be up to seven years.

fans are responsible for only 2% of electricity savings. Some administrations, notably China, European Union and United States, have examined ways to cover the extended product (motor, VSD, mechanical components and pump) for pump and fan applications. But, in general, insufficient attention has been given to the system-wide approach despite the big savings potential. Bearing this in mind, policy-makers should consider a full range of the available measures to improve savings in industrial motor systems as a whole. These include:

Motor and end-use devices

- **Minimum energy performance standards**: MEPS limit the maximum amount of energy that a device may consume and are a proven policy tool in many different applications. The advantage of MEPS is that they are mostly internationally harmonised for motors and that consumers are familiar with this kind of regulation. The vast majority of motors in the 0.75-375 kW range are subject to MEPS, while the regions with the largest electricity consumption (China, European Union and United States) have enacted or are developing regulation for pump, fan and compressor applications. While MEPS are very effective in raising the average efficiency, their limitation is that they target only one part of the motor system, with limited savings opportunities.

Extended product

- **Extended product approach**: The extended product approach expands the coverage of the regulation to the motor-driven unit, such as pump or compressor, to include the motor, end-use equipment, mechanical components and VSDs. This approach is usually based on an energy efficiency index similar to that used for consumer appliances. Its advantage is that it covers a far larger part of the motor system, allows the consumer to increase efficiency where it is cheapest to do so and considers a variable load profile. Agreed international standards to calculate and test motor system efficiency will ideally be needed. As motor systems are rarely sold as a package and are very diverse, enforcement of regulations in this area is a major challenge. Since testing and measurement of each system would put too large a burden on both industry and regulators, one solution could be to calculate the efficiency performance of the system based on part-load component data and standardised calculation models.

System-wide

- **Energy labelling**: A labelling scheme generally divides energy-using devices into different efficiency classes and thus helps consumers to choose more efficient products. Such an approach raises awareness and allows competition to drive innovation, allowing motor system integrators more readily to optimise the system. A labelling scheme can also be used for an extended product if system components are sold together. Again, system diversity can make implementation difficult. Compared to MEPS, a labelling scheme offers fewer guarantees of energy savings, but it can be used to complement MEPS.

- **Price signal**: In several countries, fossil-fuel subsidies and the inadequate embodiment of externalities in prices distort the true cost of electricity and thus can render desirable efficiency investment economically unviable in the eyes of the consumer. Phasing out subsidies, introducing or increasing a price on CO_2 emissions or increasing taxes on electricity can all provide an appropriate incentive to encourage the uptake of more efficient products and systems. The advantages of a clear price signal are the very low bureaucratic burden involved and the encouragement given to improvements in the entire system. Yet for companies where electricity cost are a very low share of production cost, a moderate price increase may be insufficient on its own to change behaviour or stimulate investment in efficient motor systems.
- **Competitive tenders**: Competitive tenders are common for renewable energy projects in many countries, but are still an exception for efficiency projects (though Switzerland has such a scheme and Germany has recently launched one). In such schemes, regulatory entities state willingness-to-pay for energy savings and invite companies to submit energy-saving projects with those having the lowest cost per saved unit of energy being adopted. An advantage of this approach is that it does not make any presumption about where the savings in the system can best take place. A disadvantage is the administrative cost.
- **Energy management systems** (EMS) **and energy audits**: Such systems are computer-based tools that provide a framework to optimise the energy performance of an entire industrial plant (e.g. ISO 50001).[16] These systems help to bring an organisational structure into energy planning, and identify and assess energy savings in the entire motor system. The introduction of an EMS can be made more effective through a requirement to carry out a regular energy audit, which should include a survey and analysis of energy consumption and targeting reduced energy use. Audits and EMS can prove an effective to tool to visualise data on energy use in order to improve awareness and identify energy savings in the entire system. Requirements to report energy-saving opportunities and justify actions taken can make the policy more powerful. In several countries, large energy-intensive industries are required to have EMS. In the past, financial incentives to carry out audits have been used mainly for small- and medium-size enterprises, where the installation of EMS would be too costly. No-cost energy assessments are carried out in the United States at the Industrial Assessment Centers.
- **Energy service companies** (ESCOs): ESCOs carry out energy efficiency projects for their customers (generally in the framework of an energy savings performance contract) and are paid from the energy savings achieved. The market for ESCOs can be stimulated through preferential tax treatment of such companies, targeted public procurement and standardisation requirements. ESCOs are in many regions (except China) mainly focussed on the buildings sector, but they could play a bigger role in identifying the available energy savings options in motor systems.

16. The Energy Management Working Group (EMWG) of the Clean Energy Ministerial seeks to accelerate the use of energy management systems based on the ISO 50001 best practices.

- **Industry-wide schemes:** Various industry-wide efficiency regulations exist across the world. Japan, China and India have mandatory energy efficiency targets for designated industries with obligations for annual energy reductions. In India, this is combined with a trading scheme for efficiency certificates. Several European countries make use of voluntary agreements, which exempt industries from paying some portion of energy taxes in return for a commitment to annual intensity reduction targets. Such schemes give industrial stakeholders the freedom to carry out efficiency improvements where they are most cost effective, but they do not target motor systems in particular.
- **Energy supplier obligation:** Utilities are given saving targets and can (among others) source the savings from investment in motor systems via energy efficiency programmes for customers. Such programmes can be coupled with a certificate trading scheme. Such obligations on utilities exist in several European Union member states, in Brazil and in 25 US states, where they are known as Energy Efficiency Resource Standards.
- **Awareness-raising measures:** Low awareness and a lack of information present a significant obstacle to the uptake of energy efficiency. Training initiatives (capacity building), technical advice and documentation or energy efficiency networks can provide effective measures to address this aspect.
- **Financial incentives:** Targeted financial incentives in the form of tax rebates, loan guarantees or subsidies for the installation of more efficient technologies can ease the burden of high initial capital expenditures involved in some energy efficiency investments.

Summarising, a range of policy measures is necessary to exploit the energy-saving potential of motor systems used in industry to the full extent possible. Policy-makers need to look beyond the current focus on component regulation to systems taken as a whole; and to pursue several approaches in parallel. Policy-makers should, in particular, consider widening the scope of motor and end-use device regulation beyond the current range and products, increasing the stringency of electric motor standards to the IE4 level in the medium term. Measures should be considered to increase the uptake of VSDs in systems with variable load, for example through the extended product approach, if market compliance can be ensured. At the same time, a clear price signal is one of the most straightforward ways to provide an incentive for efficiency increases in an entire system. Other measures that have proven successful include requirements for energy management systems or energy audits, provided these come with an obligation to publish results and justify actions taken, competitive tenders, energy supplier obligations and industry-wide agreements.

Energy and climate change

The Paris Agreement: is it the start of something new?

Highlights

- The Paris Agreement was a major milestone of climate negotiations and the pledges made provide impetus for a transition to a low-carbon energy future. Additional policy commitments and falling costs of renewable power generation mean that the power sector is set to decarbonise faster than ever before: electricity generation rises by two-thirds to 2040 in the New Policies Scenario, but emissions growth stagnates. The transition lags behind in other sectors and is slowest in transport although electric vehicles make inroads. Global energy-related CO_2 emissions continue to rise to 36 Gt in 2040, but at a much lower rate than historically.

- Emissions of all energy-related GHGs grow to less than 42 Gt in 2030 in the New Policies Scenario, slightly lower than what is required for meeting the energy sector contributions to the Paris pledges (the NDCs). The main reason is that important steps towards their implementation are already being taken: China is set to surpass its energy and emissions targets, and India to exceed its clean energy targets. Additional energy efficiency improvements are key to achieving the stated targets in the European Union and in the United States, where low oil prices currently challenge realising the target road vehicle fuel-economy standards.

- It is not clear yet what the "well below 2 °C" target of the Paris Agreement might mean in practice. One possible pathway would cut the cumulative CO_2 emissions budget of the energy sector by 2100 to 830 Gt, 250 Gt below the level of the 450 Scenario. Energy sector emissions would need to become net-zero by around 2060. This is a formidable challenge that would require a significantly higher ramp-up of low-carbon technologies than in the 450 Scenario. For example, it would require 1.5 billion electric passenger vehicles to be on the road by 2040, more than twice the level of the 450 Scenario. The power sector would need to decarbonise to an average of 65 g CO_2/kWh in 2040, with the share of low-carbon power capacity reaching almost 80%. Oil demand would fall to 63 mb/d in 2040, around 11 mb/d below the 450 Scenario. Gas and coal demand would be 370 bcm and 110 Mtce lower than in the 450 Scenario, respectively.

- The energy sector challenge associated with a temperature goal of 1.5 °C is stark: it could require reaching net-zero emissions as early as 2040. For this to happen, all end-use sectors would need to be electrified at unprecedented pace, and practically all power and heat production would need to be low-carbon. It would need rapid deployment of biomass with CCS to compensate residual emissions from fossil-fuel use in sectors where they are difficult to substitute. Regardless of future technology availability, it would require radical immediate reductions in CO_2 emissions, using every known technological, behavioural and regulatory decarbonisation option.

8.1 Introduction

The successful negotiation of the Paris Agreement on climate change, the result of the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties 21st (COP21) meeting in December 2015, marks a critical milestone for the energy sector. Under the Agreement, countries have set the objective of keeping the global average temperature rise "well below 2 degrees Celsius" (°C), and agreed to pursue efforts to limit this to 1.5 °C. This is an increase in ambition over previously adopted targets. The Paris Agreement has achieved near-universal support from developed and developing countries, with some 190 Parties having formally signed the Agreement.

The threshold for entry into force of the Agreement – which will occur when at least 55 Parties representing at least 55% of global emissions formally join (ratify or accede to) the Agreement – was not expected by negotiators at COP21 to be attained until around 2019. But momentum for early entry into force accelerated during 2016. Spurred by the decision of the United States and China to join the Agreement in early September, and with further ratifications of major emitters such as the European Union and India, the Agreement entered into force in early November 2016: a very positive signal from governments of their commitment to implementation.

Ahead of COP21, Parties had submitted their Intended Nationally Determined Contributions (INDCs), which described the actions they proposed to take to reduce emissions. Once a Party ratifies or accedes to the Paris Agreement, it must submit its Nationally Determined Contributions (NDC), with the default process being that the Party's existing INDC automatically becomes its NDC.[1] The NDC will be subject to the agreed procedures of the Paris Agreement, including a five-year cycle for the submission of NDCs, laying the groundwork for promoting progression over time, and a transparent process to track progress towards and achievement of the NDC. The expectation that commitments to more intensive action will be made over time is a critical element of the Paris Agreement, as the initial NDCs, submitted before Paris, fall short of what is needed. The *World Energy Outlook Special Briefing for COP21* found that they put the world on track towards a 2.7 °C temperature rise by 2100 (IEA, 2015a).[2] There will be a "facilitative dialogue" on progress in 2018. While Parties may increase the ambition of their NDCs at any time under the Paris Agreement, this facilitative dialogue is expected to focus collective attention on the shortfall between current pledges and what is needed to meet the collective global temperature goal.

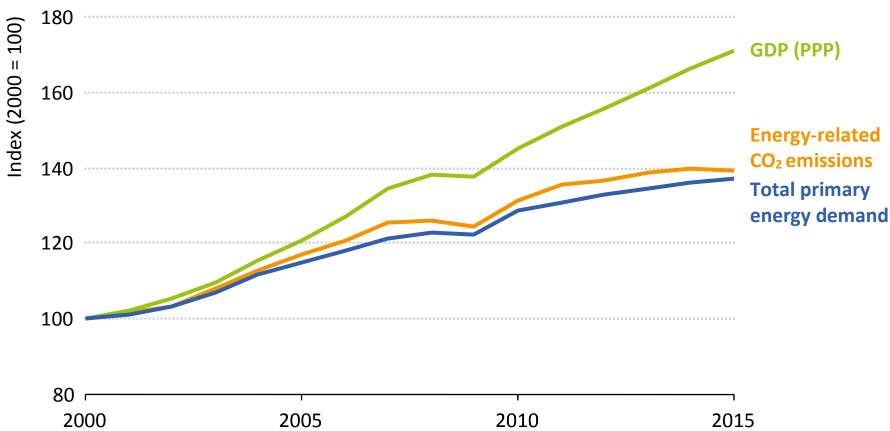
1. Formally, the Intended Nationally Determined Contributions submitted for the Paris Agreement will become Nationally Determined Contributions when each Party ratifies the Agreement. This *Outlook* uses the term NDC to refer to both cases (INDCs and NDCs).

2. To assess the impact on the global average temperature increase, the Model for the Assessment of Greenhouse-Gas Induced Climate Change (MAGICC) was used, with an emissions pathway in between the Representative Concentration Pathways (RCP) 4.5 and 6 from the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report. This was judged to be the long-term emissions trajectory most closely aligned with the INDC analysis.

8.2 Recent developments

Beyond the successful outcome of climate negotiations, a variety of key energy indicators signal that progress is being made towards the global objective. The IEA's preliminary estimate of global energy-related carbon-dioxide (CO_2) emissions in 2015 reveals that emissions stayed flat, a clear sign of a decoupling of the previously close relationship between global economic growth, energy demand and energy-related CO_2 emissions (Figure 8.1). There have been only four periods in the past 40 years in which CO_2 emission levels were flat or fell compared with the previous year, with three of those – the early 1980s, 1992 and 2009 – being associated with global economic weakness. By contrast, the recent halt in emissions growth comes in a period of economic growth.

Figure 8.1 ▷ Change in global economic output, energy demand and energy-related CO_2 emissions



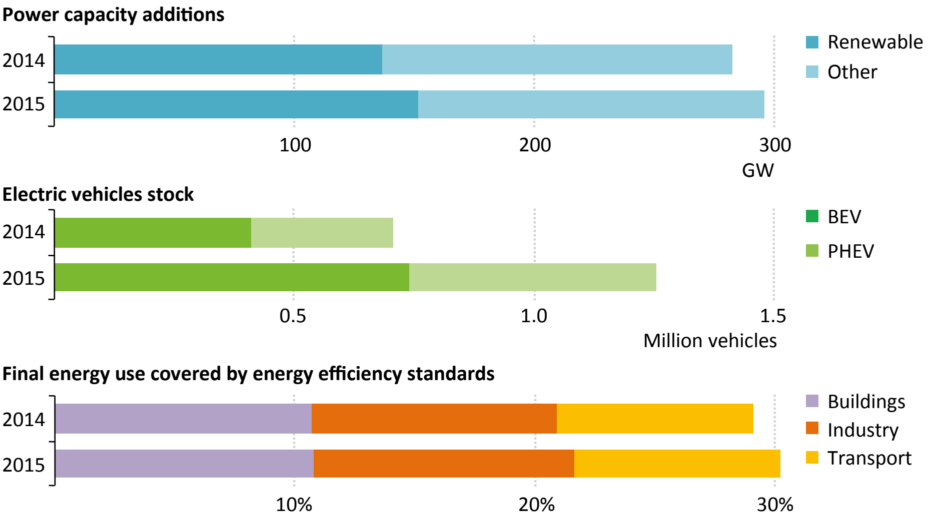
Global economic output, energy demand and energy-related CO_2 emissions are decoupling gradually

Note: GDP (PPP) = gross domestic product on purchasing power parity basis.

Sources: Historical data to 2014 from the IEA Data Centre; data for 2015 are preliminary and based on *World Energy Outlook* analysis.

The recent trends in energy-related CO_2 emissions confirm an ongoing energy sector transition in many countries (Figure 8.2). Increasing policy support to renewables over the past two decades has helped bring down the costs of wind and solar photovoltaics (PV) technologies in particular (see Chapter 11). In 2015, for the first time, renewables accounted for more than half of the new generating capacity installed in the power sector worldwide. Energy efficiency, too, has been given increasing policy support over the past decade, to the extent that mandatory energy efficiency regulation (such as minimum energy performance standards) in 2015 extended to 30% of final energy demand, up from only 14% one decade ago (see Chapter 7). Other critical, yet still nascent, technologies have gained momentum: in 2015, the global stock of electric vehicles for the first time passed the 1 million mark, to reach 1.3 million cars on the road by the end of the year (see Chapter 3). While this number still pales against a global stock of nearly 1 billion cars, it represents a near-doubling over the 2014 stock and is a marked sign of progress in a sector that is critical for the low-carbon transition. Even so, there is no room for complacency: as *World Energy Outlook (WEO)* analysis in the run-up to COP21 demonstrated, the climate pledges are not yet sufficient to meet the agreed climate goal (IEA, 2015a). And, despite progress in many areas, the pace of deployment of key technologies is not yet compatible even with the 2 °C target, let alone more stringent climate targets (IEA, 2016a).

Figure 8.2 ▷ Recent global decarbonisation trends in the energy sector



Deployment of low-carbon technologies grew in the power and transport sectors, and energy efficiency policy coverage now extends to 30% of final energy demand

Notes: GW = gigawatts; TFC = total final energy consumption; BEV = battery electric vehicle; PHEV = plug-in hybrid vehicle.

8.3 NDCs and the energy sector: emissions trends in the New Policies Scenario

8.3.1 What is in the Nationally Determined Contributions?

The Intended Nationally Determined Contributions (INDCs) are the core “bottom-up” element of the Paris Agreement. Once national governments ratify the Agreement, the INDCs become Nationally Determined Contributions (NDCs). Prior to COP21, they were generally expected to represent “a progression beyond the current undertaking of that Party” (UNFCCC, 2015). But there was no agreed specification for the structure or content of the NDCs: guidance did exist, but the actual scope – for example, whether they were to include e.g. mitigation, adaptation, finance, technology development and transfer, and capacity building components – was left open.

Most of the NDCs turned out to be greenhouse-gas (GHG) targets, brought forward in a variety of formats (Table 8.1). They include absolute GHG emissions targets, reductions from "business-as-usual" emissions trajectories, emissions intensity targets (i.e. GHG emissions per unit of economic output), or reductions or limitations in per-capita emissions. In some cases, they were statements regarding policies and measures to be implemented. In other cases, the GHG mitigation target (or its extent) was made conditional on other factors, in particular the availability of finance. But they all included coverage of energy sector emissions, often (but not always) accompanied by targets or actions to address them. The most common energy-related measures were those that target increased renewable energy deployment or improved efficiency in energy end-use. Some other energy sector measures that could help to cut energy-related GHG emissions in the short term, such as reducing the use of inefficient coal-fired power plants, lowering methane emissions from oil and gas production, fossil-fuel subsidy reform or carbon pricing, were reflected in the NDCs of just a few countries. Some technology or policy options for a long-term transformation of the energy sector, such as nuclear power, carbon capture and storage (CCS) and alternative vehicle fuels (e.g. advanced biofuels, electric vehicles), were rarely mentioned. In many cases, an overall GHG target was specified within an NDC, but without making clear its expected contribution to the energy sector: the contribution to GHG emissions expected from land-use, land-use change and forestry (LULUCF), can, in some countries, be very significant.

Table 8.1 ▷ Greenhouse-gas emissions reduction goals in selected NDCs

Country/region	Nationally Determined Contributions
United States	Economy-wide target of reducing GHG emissions by 26-28% below 2005 levels in 2025 and to make best efforts to reduce emissions by 28%.
Mexico	Economy-wide target to reduce GHG and short-lived climate pollutant emissions by 25% below business-as-usual by 2030 (unconditional target), or up to 40% subject to a range of issues including access to low cost financial resources and technology transfer (conditional target).
Japan	Economy-wide target of reducing GHG emissions by 26% below fiscal year 2013 levels by fiscal year 2030.
European Union	A minimum 40% domestic reduction in total GHG emissions by 2030 compared with 1990, to be fulfilled jointly.
China	Achieve peak CO_2 emissions around 2030 and make best efforts to peak earlier; lower CO_2 emissions per unit of GDP by 60-65% from the 2005 level; increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030.
India	Reduce emissions intensity of GDP by 33-35% below 2005 levels by 2030; achieve about 40% cumulative electric power installed capacity from non-fossil sources by 2030 with the help of technology transfer and low cost international finance.
Indonesia	Economy-wide target of reducing GHG emissions by 29% below a business-as-usual scenario by 2030 (unconditional target), or by up to 41% if subject to provision of support in technology, capacity building and finance (conditional target).
Brazil	Economy-wide target of reducing GHG emissions by 37% below 2005 levels by 2025.

Now the focus increasingly turns on implementation. The extent to which countries will eventually deliver on their pledges in the energy sector critically depends on two main factors: the policies that support the required longer term structural energy sector transition, and the short-term macroeconomic and energy market trends, which may accelerate – or impede – the transition towards a lower carbon energy future. The former is directly in the hands of governments. The latter too, can be addressed by government policy. For example, the impact of low international fossil-fuel prices on investment in energy efficiency is lower in countries with a high level of fossil-fuel taxation, and can be moderated further by reducing subsidies to fossil fuels in many countries (IEA, 2015b).

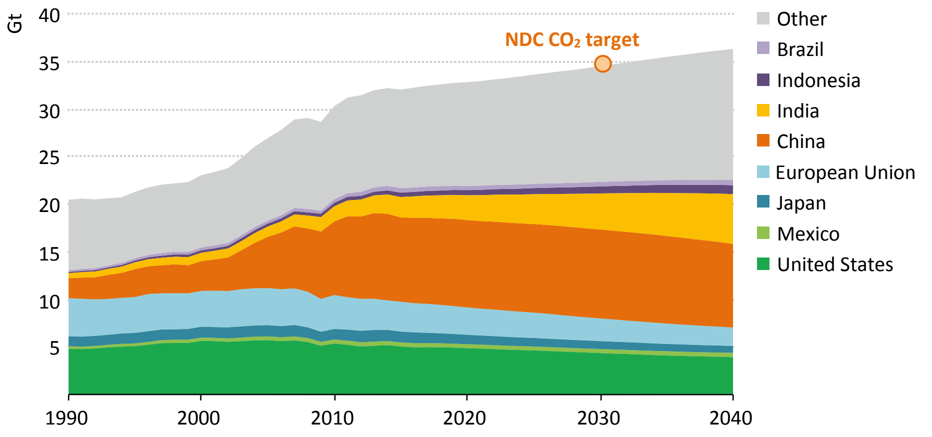
The extent that announced government commitments can successfully deliver the desired energy sector contribution can be analysed by reference to the New Policies Scenarios. This scenario assumes that countries act to fulfil their declared intentions, but does not take for granted the GHG emissions targets of the NDCs. Rather, it starts from the actual implementing measures that governments have brought forward and, beyond that, takes judicious account of all energy policies that are in place or have recently been announced as part of their energy sector strategies and steps towards their implementation. The objective of the next section is to assess whether the measures, be they directly part of the NDC submission or otherwise part of government policy, will be sufficient to meet the pledged GHG targets, taking account of the expected market-driven changes in the energy sector.

8.3.2 Emissions trends in the New Policies Scenario

Energy production and use are the major source of global GHG emissions today, the largest component being CO_2 emissions. The energy activities covered by the NDCs represent a large component of strategies to combat climate change by setting GHG targets. Consequently, climate change strategies are embedded within the energy policy objectives of individual countries such as enhancing energy security and guaranteeing an affordable energy supply, along with wider objectives such as reducing energy-related air pollution or increasing energy access. In fact, such deliberations were explicitly mentioned in many of the NDCs as key considerations for policy-makers when establishing the GHG mitigation targets.

Analysis within the context of the *World Energy Outlook* series has shown that full implementation of the unconditional targets expressed in the NDCs would contain growth in energy- and process-related GHG emissions to just below 42 gigatonnes of CO_2 equivalent (Gt CO_2-eq) in 2030, with around 35 Gt being CO_2 emissions from fossil-fuel combustion. Taking into account NDC targets and trends for non energy-related GHG emissions plus emissions from LULUCF, the unconditional climate pledges at COP21 are estimated to represent total GHG emissions of more than 50 Gt in 2030 and to put the world on track for an average global temperature increase of 2.7 °C by 2100 (IEA, 2015a; IEA, 2015c). Taking the energy component alone, the energy policy environment today appears generally conducive to reaching the pledged climate targets. In the New Policies Scenario, although global energy-related CO_2 emissions resume their historical upward trend, the growth rate is much lower and in 2030, the target year of most NDCs, energy-related CO_2 emissions reach 34.5 Gt (Figure 8.3). This is slightly lower than the anticipated contribution from the energy sector in the NDCs. An additional 2.4 Gt of CO_2 emissions arise from industrial processes in 2030, and 4.5 Gt from other energy-related emissions (including methane and nitrous oxide). According to our estimate, this would imply that non energy-related emissions could grow above today's level – or, in other words, if non energy-related NDC emissions targets were achieved, then the global GHG emissions from energy and non-energy sources combined would be lower than required to match the unconditional GHG emissions targets pledged at COP21. In the New Policies Scenario, energy-related CO_2 emissions would continue to grow modestly after 2030, to reach 36 Gt in 2040.

Figure 8.3 ▷ Energy-related CO_2 emissions by region in the New Policies Scenario



Energy-related CO_2 emissions growth resumes, but slowly, in the New Policies Scenario

Emissions trends by region

Achieving the emissions target of the *United States* critically depends on the energy sector, the main source of GHG emissions. Clean energy has been given strong policy support in recent years and low natural gas prices have stimulated a gradual shift away from coal towards gas in power generation. The US NDC rests on four main policy pillars for the energy sector: the Clean Power Plan, which is anticipated to reduce power sector carbon emissions by 32% in 2030, relative to 2005; fuel-economy standards for road passenger and heavy-duty vehicles, which aim to significantly reduce average fuel consumption for new vehicles; methane standards for the oil and gas sector, which aim to reduce methane emissions from oil and gas extraction and distribution by 40-45% in 2025, relative to 2012; and multiple measures to improve energy efficiency in the buildings sector, such as minimum energy performance standards for appliances. Recent policy developments further support the energy sector transition: the extension of tax credits for renewables for power generation is expected to be a major stimulus for further renewables deployment (see Chapter 10); new standards to reduce GHG emissions and improve fuel efficiency from medium- and heavy-duty vehicles through to 2027 were announced in August 2016 and are expected to trigger significant innovation in road freight transport (Table 8.2). In addition, the draft technical assessment report issued by the US authorities as part of the mid-term evaluation of fuel-economy standards for cars and light trucks has revealed that the pace of innovation in the automotive industry is sufficient to meet, and possibly exceed, the established 2025 standards at lower costs than originally anticipated. This assessment, established as part of the rulemaking for the vehicle standard, is an important vindication of the regulatory standard adopted in 2012. Depending on the final findings of this assessment in 2018, the standards could even be made more stringent.

Overall, the United States can achieve its climate pledge. But there are also factors that could compromise this achievement. Meeting the CO_2 emissions goals of the Clean Power Plan, for example, will require not only the uptake of low-carbon generation technologies, but also implementation of sufficient energy efficiency measures to curb the growth of electricity demand at the required rate, much of which depends critically on consumer behaviour. And persistence of the relatively low international oil prices could undermine the case for efficiency in the transport sector: while the average efficiency of cars and light trucks keeps rising, gasoline demand in 2016 is now expected to be higher than anticipated one year ago, supported by rising sales of sports-utility vehicles and increasing average mileage. This was confirmed in the mid-term evaluation of fuel-economy standards which warned that a marked shift of consumer choice towards heavier vehicles puts the 2025 target at risk.[3] As well, there remains uncertainty about the amount of methane that is currently emitted during oil and gas extraction. The most recent analysis by the US Environmental Protection Agency revised past data significantly upwards.

The NDC of *Mexico* rests on a set of national climate change policies, including the General Climate Change Law and the National Climate Change Strategy.[4] The latter includes explicit targets for the energy sector, in particular for the power sector. The Energy Transition Law (LTE), approved in December 2015, further reaffirms these targets and makes Mexico one of only a few countries in the world to codify its ambitions in law, with interim targets of 25% of electricity generation from clean energy sources[5] by 2018, 30% in 2021 and 35% in 2024.[6] To incentivise investment in renewables, the government has introduced clean energy certificates as part its power sector reform. In the New Policies Scenario, Mexico meets its interim targets and surpasses the 2035 target set by the Law for the Development of Renewable Energy and Energy Transition Financing. This is achieved primarily as a result

3. The US GHG and fuel-economy standard, CAFE, for passenger vehicles distinguishes two categories: passenger cars and light trucks. Whether the overall average standard of 54.5 miles per gallon is achieved by 2025 depends on the sales in these two segments, as each have individual standards.

4. For more details on energy sector trends, see *Mexico Energy Outlook: World Energy Outlook Special Report*, 2016. Available at: *www.worldenergyoutlook.org/mexico.*

5. While the majority of this is planned to come from renewable energy sources, the definition of clean energy in Mexico's policy is broader and includes efficient cogeneration and nuclear power.

6. During the North American Leader's Summit in June 2016, the three countries additionally agreed to set a target of 50% for clean power across North America by 2025 and to align fuel efficiency standards by 2025 and GHG emissions standards by 2027. Mexico has also adhered to an existing commitment to reduce methane emissions by 40-45% by 2025.

of the proliferation of solar PV and wind power projects, which expand strongly — these two together account for over two-thirds of the growth in clean energy to 2040.

Table 8.2 ▷ Emissions and policy trends in selected regions in the New Policies Scenario (CO_2-eq)

Country/region	Energy-related GHG emissions* in		Selected recent energy policy developments
	2014	NDC year	
United States	5.7 Gt	5.0 Gt (2025)	Extension of investment tax credit (solar PV) and production tax credit (wind power) by five years. Mid-term review of fuel-economy standard reinforces 2025 target for cars and light trucks. Finalised new GHG and fuel-economy standards for medium- and heavy-duty vehicles to 2027.
Mexico	0.5 Gt	0.5 Gt (2030)	New Energy Transition Law (power sector). New methane emissions target (oil and gas).
Japan	1.2 Gt	0.9 Gt (2030)	New Innovative Energy Strategy: energy efficiency policies (industry and buildings); subsidies for fuel-cell and electric vehicles and refuelling infrastructure (transport); carbon-intensity target and amendments to law on feed-in tariffs for renewables (power).
European Union	3.3 Gt	2.5 Gt (2030)	Proposed revision of the Emissions Trading System (ETS) for the period after 2020. Proposed "Effort Sharing Regulation" with binding annual GHG emissions targets for sectors outside the ETS. Release of European Strategy for Low-Emission Mobility. Planned release of an energy efficiency package and proposals for power market design for 2016.
China	9.8 Gt	10.1 Gt (2030)	Reduce carbon intensity by 18% in 2020 and energy intensity by 15%, relative to 2015, under the 13th Five-Year Plan. Upward revision of renewable energy targets. New air pollution emission standards for light-duty vehicles (China 6).
India	2.1 Gt	4.0 Gt (2030)	State-level targets towards the Renewable Purchase Obligation target of 17% by 2022. Environment Protection Amendment Rules to reduce pollution emissions from the power sector; new air pollution emissions standards for light- and heavy-duty vehicles for 2020 (Bharat VI).
Indonesia	0.5 Gt	0.8 Gt (2030)	In January 2016, announced plans to reform electricity subsidies to be better targeted to poor and vulnerable household. In March 2016, announced a plan to remove subsidies for diesel.
Brazil	0.5 Gt	0.5 Gt (2030)	Resolution No. 687: new framework to enable solar power generation, e.g. through expansion of net metering programme. Federal initiative to provide tax incentives for solar power.

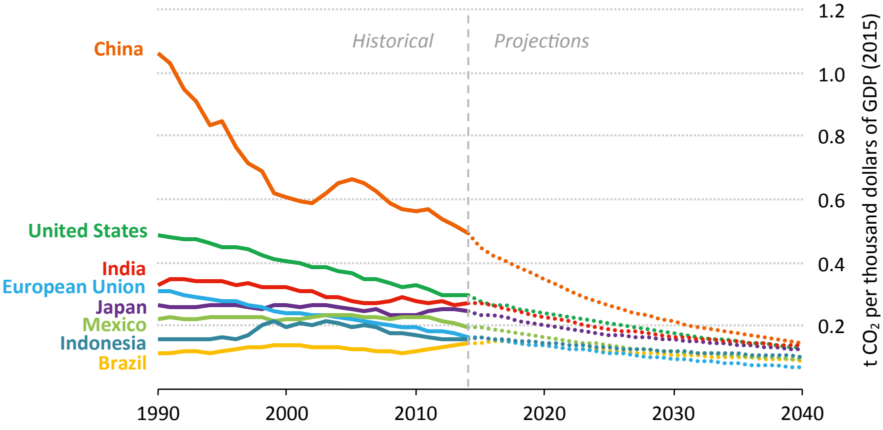
* Includes CO_2 emissions from fossil-fuel combustion, and energy-related emissions of methane and nitrous oxides. GHG emissions are presented in CO_2-eq terms based on the global warming potentials from the IPCC's Fifth Assessment Report, averaged over 100 years. The column that refers to the NDC year indicates the emissions in the target year expressed in the NDC (given in brackets).

Reaching Mexico's overall GHG mitigation target is, therefore, likely to depend on emissions trends outside the energy sector: the lower bound of the pledged target requires overall GHG emissions to be reduced to around 760 million tonnes (Mt) in 2030. In the New Policies Scenario, energy-related GHG emissions fall modestly, to around 460 Mt in 2030, meaning that emissions from other sectors (such as agriculture or waste) would need to stabilise roughly at the present level if the lower end of the GHG target is to be achieved. The higher end of the pledge would require GHG emissions to drop to around 620 Mt in 2030, an emissions budget that, without additional measures, is likely to be largely absorbed by the energy sector.

The NDC submission of *Japan* rests on very concrete targets for the energy sector, based on the expected level of final energy consumption in 2030, the required level of electricity generation and detailed shares by power generation technology for meeting demand. The targets for the power sector imply a re-start of nuclear generation and a significant increase in renewables generation. Generous feed-in tariffs have supported renewables and led to a fresh wave of approvals for solar PV projects, although recent amendments to the law put in doubt the implementation of significant parts of the programme (see Chapter 10). To ensure the NDC targets are met, the government of Japan formulated the Innovative Energy Strategy in April 2016, which encompasses, *inter alia,* policies to reduce energy consumption in the industry and buildings sectors, subsidies to support alternative fuel vehicles and its related infrastructure, and an overall emissions standard for power generation of 370 grammes of carbon dioxide per kilowatt-hour (g CO_2/kWh) by 2030. It also establishes a "nega-watt" market as part of the effort to encourage electricity demand response in order to facilitate the integration of variable renewables in the power sector. Implementation of these policies, along with existing measures, is reflected in the results of the New Policies Scenario, in particular in the power sector, where NDC target shares by technology are reached in 2030.

The COP21 pledge of the *European Union* is based on the 2030 framework for energy and climate policies, though it is not formally part of the NDC. Besides establishing the GHG mitigation target, it sets targets for 2030 for the energy sector, which include increasing the share of renewables to at least 27% of final energy consumption and boosting energy efficiency by at least 27% (relative to a projected reference level). While this pledge offers guidance on the way forward, the European Union and its member countries are still working towards establishing the implementing details. For example, current fuel-economy targets for passenger cars are only to 2020, but the recent European Strategy for Low-Emission Mobility confirms that an ongoing process is in hand towards establishing a 2030 target, a crucial signal for the automotive industry to adapt its strategies, such as for the deployment of electric vehicles (see Chapter 3). The strategy paper also acknowledges the need to establish standards for reducing CO_2 emissions from trucks, buses and coaches, which are currently absent (unlike in the United States or China). As well, in the buildings and industry sectors, efficiency measures in place to reach a 2020 target will continue to affect emissions levels, though more will need to be done to reap further efficiency gains post 2020. Important efforts are underway. In July 2015, the European Commission (EC) a legislative proposal to revise the EU Emissions Trading System (ETS) for the period after 2020; and in 2016, the EC presented a proposal for a regulation to limit post-2020 emissions of GHGs in sectors not covered by the ETS, including transport, buildings and agriculture, as a successor of the Effort Sharing Decision for the period 2013-2020. A further policy package related to energy efficiency and a proposal for electricity market design are expected in late 2016. Specific energy sector targets will be critical towards achieving the climate pledge.

Figure 8.4 ▷ Emissions intensity of economic growth in the New Policies Scenario



Emissions intensity of economic growth falls in all countries, although the pace varies

Note: t CO_2 = tonnes of carbon dioxide.

China's NDC focuses on CO_2, which accounts for the majority of its current GHG emissions. Its climate pledge is generally recognised to have been of crucial importance to the success of COP21, as China revealed its intentions early in a joint statement with the United States. China's NDC specifies a number of policies and measures to achieve its target, most of which were already in place (which led to some criticism about the actual degree of ambition of the pledge). In addition, just prior to COP21, China's National Bureau of Statistics revealed an upward revision of historical coal demand, with implications for past CO_2 emissions: according to the most recent IEA statistics, which incorporate these revisions, in China CO_2 emissions from fossil-fuel combustion over 2000 to 2013 were around 1.3 Gt higher than previously reported. Yet, China continues to take additional steps to improve the sustainability of its energy sector, with benefits for climate as well as for other environmental concerns such as air pollution and energy security. The recently adopted 13th Five-Year Plan sets a goal to reduce the carbon intensity of the energy sector by 18% in 2020, relative to 2015, and energy intensity by 15%. While details for the energy sector are yet to be confirmed, it is generally expected that these targets will be further supported by a significant upward revision of the targets for the deployment of low-carbon technologies in the power sector by 2020, including for renewables and nuclear (see

Chapter 6). The likelihood of achieving these targets appears high: the carbon intensity of total energy demand fell by 5.6% in 2014, one of the highest rates of the past 15 years; and energy intensity in 2014 dropped by an unprecedented 5.2%. Our preliminary estimates for 2015 show that coal demand fell by 2.6%, and while a temporary increase above the historic peak may be possible should there prove to be strong growth in electricity demand coupled with poor hydropower availability (due to dry weather) and increased growth in industrial production (e.g. due to a fiscal stimulus package), all the fundamentals point to a structural decline of coal demand in China over the medium-term. It is likely that 2013 marked the peak of Chinese coal demand (see Chapter 5). Putting these policy and market trends together, it is increasingly likely that China will exceed its climate pledge: in the New Policies Scenario, energy-related CO_2 emissions peak just before 2030, as emissions intensity drops by more than two-thirds, relative to 2005 and the share of non-fossil fuels in primary energy consumption rises to around 23%.[7]

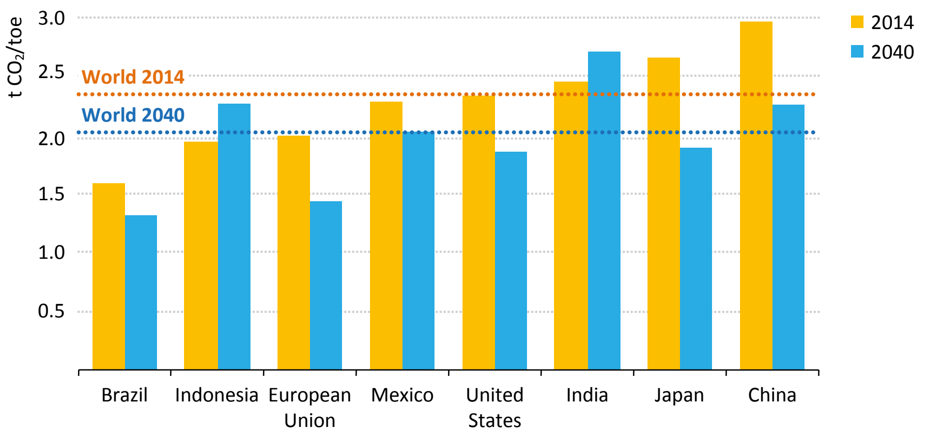
Achieving economic development is of paramount importance for *India*, where average GDP per capita is less than 40% of the global average. Energy plays a key role in this process and in lifting people out of poverty: around 245 million people still have no access to electricity in India today and around 820 million people rely on the traditional use of biomass for cooking. Achieving growth in a sustainable manner is a recognised challenge in India. Air pollution, for example, is already a significant issue in many of its cities, and recent policy efforts have focussed on bringing air pollution regulation from the power and transport sectors on a par with standards in Europe, with potential benefits for climate change mitigation (IEA, 2016b). India's NDC offers a range of energy-specific targets, including, in particular, the promotion of low-carbon technologies (such as renewables and nuclear) and clean coal technologies in the power sector, energy efficiency in the buildings and industry sectors, and improving urban transport systems. The stated targets draw to a large extent on existing domestic policy targets, such as those expressed under the National Solar Mission. Among the most recent policy moves are the establishment of state-level targets towards the country's Renewable Purchase Obligation target of 17% by 2022, alongside government efforts to accelerate the approval of large-scale solar PV projects. Even if uncertainties remain over the state-level implementation of national targets and financial constraints, India appears to be on track to achieve its energy-related NDC target. Although deployment targets for the mid-term are achieved only with significant delay in the New Policies Scenario, the installed power capacity from non-fossil sources comfortably exceeds the pledged 40% of total generation capacity in 2030. In the New Policies Scenario, the rate at which the carbon intensity of the energy sector in India increases through 2040 is almost four-times slower than over the past 25 years (Figure 8.4). Nonetheless, CO_2 emissions per unit of energy use still rise through 2040, as energy demand grows strongly and is satisfied by all energy carriers (Figure 8.5).

Indonesia's unconditional mitigation target in its NDC requires total GHG emissions broadly to stabilise at current levels in 2030. A significant part of the mitigation needs to come from emissions associated with LULUCF, its dominant source of GHG emissions. Indonesia's energy sector is responsible for around one-fifth of total GHG emissions. Energy sector emissions

7. Measured by the accounting methodology of Chinese energy balances. IEA methodology reveals a share of 19%.

mitigation is, nonetheless, likely to play a vital role towards achieving the target, as reducing LULUCF emissions is challenging, despite the significant potential, because deforestation, forest degradation and agricultural development have contributed to economic development. Reducing such emissions is possible, but requires comprehensive spatial planning and effective institutions, among other factors. While the energy sector's contribution towards the overall GHG target is not explicitly stated in the NDC, the government does specify a target to increase the share of "new and renewable energy" to 23% in 2025. This target covers renewables in the power and transport sectors, but could, in principle, also be met by "new" fossil-fuel technologies, such as coalbed methane, coal-to-liquids or coal-to-gas, with adverse impact on emissions. Recent policy efforts to reduce fossil-fuel subsidies will be helpful in achieving the energy target, but its level is a formidable challenge: today's share of all these technologies combined is estimated to be less than 10% of the total energy mix.[8] Achieving the target will require additional supporting measures.

Figure 8.5 ▷ Emissions intensity per unit of primary energy demand by region in the New Policies Scenario



World emissions intensity of energy demand falls but trends differ by region

Note: t CO_2/toe = tonne of CO_2 per tonne of oil equivalent.

The energy sector contribution to overall GHG emissions in *Brazil* is relatively small, in comparison to other countries, at only around 30%. Low-carbon sources already make a significant contribution to many sectors: three-quarters of power generation comes from low-carbon sources (including renewables and nuclear) and biofuels meet almost 20% of fuel demand in road transport (on an energy-equivalent basis). LULUCF emissions are an important source of GHG emissions in Brazil, despite progress in recent years to address

8. Based on the methodology of Indonesia for primary energy balances to enhance comparability with the targets expressed in the NDC. IEA methodology would suggest a share of around 16% today.

deforestation. Methane emissions from agriculture and waste are (in CO_2-equivalent terms) comparable to CO_2 emissions from the energy sector. Nevertheless, energy is an important part of the NDC, with renewables given a target share of 45% in total energy demand in 2030 (with a contribution of non-hydro renewables of 28-33%, mostly from the power sector). These targets are met in the New Policies Scenario, with the recent push towards wind power being the most important element in increasing the share of non-hydro renewables in power generation beyond one-fifth in 2030. The NDC also requires sustainable biofuels to have a share of 18% in the total energy mix, although the allocation by sector is not specified.

Box 8.1 ▷ Raising ambitions towards 2030 – an achievable set of policy goals towards the global stocktake of mitigation efforts

The bottom-up process for formulating the NDCs contributed to the success in reaching a global deal on climate at COP21. But their cumulative effect may also fall short of putting the world on a path to the agreed long-term temperature goal. This is where another key element of the Agreement comes into play: an ambition mechanism has been adopted, under which countries make successive pledges that represent a progression every five years, informed by a global stocktake of progress. The first global stocktake is due in 2023, but the first milestone of this process – a facilitative dialogue in 2018 – is fast approaching and could give important direction to the process of the second-round of NDCs before 2020.

The energy sector needs to be an effective partner in these climate negotiations given the implications for future energy investments. More stringent climate targets than those implied by current NDCs are not only conceivable, but are seen as an essential element of the next stage of the Paris Agreement's implementation. *WEO* analysis shows that policy-makers have the tools available now for realising higher ambitions (IEA, 2015c). The IEA's Bridge Strategy that relies on proven technologies and policies alone is tailored to national circumstances and could achieve a peak in global energy-related GHG emissions in the near-term, without harming economic growth in any region. This proposed strategy was embraced by the energy ministers of IEA member countries during their Ministerial meeting in Paris in November 2015.[9] It has five core elements:

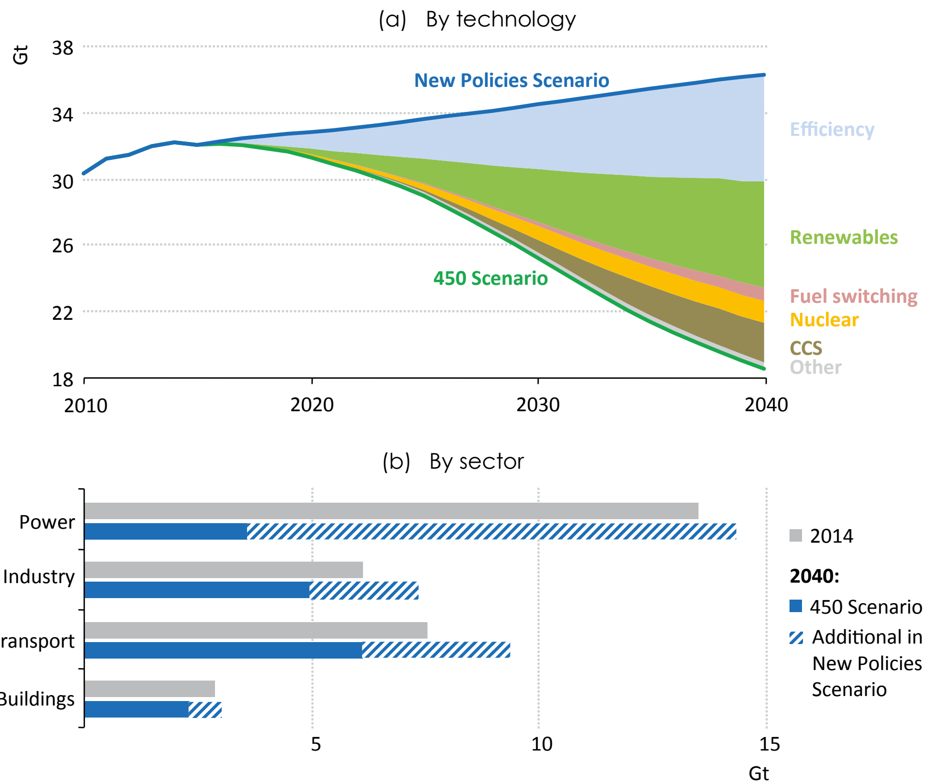
- Increasing energy efficiency in the industry, buildings and transport sectors.
- Progressively reducing the use of the least-efficient coal-fired power plants and banning their construction.
- Increasing investment in renewable energy technologies in the power sector to reach $400 billion in 2030.
- Gradually phasing out fossil-fuel subsidies to end-users by 2030.
- Reducing the methane emissions arising from oil and gas production.

9. *www.iea.org/media/news/2015/press/IEA_Ministerial_Statement_on_Energy_and_Climate_Change.pdf.*

8.4 From NDCs to 2 °C: steps in the 450 Scenario

Despite the impressive progress made in recent years, the transition of energy supply towards a low-carbon future compatible with the 2 °C target is not yet in prospect. Global energy-related CO_2 emissions continue to rise in the New Policies Scenario, which reflects the NDC pledges. On the other hand, in the 450 Scenario, which holds back the increase in the global mean temperature to 2 °C, energy-related CO_2 emissions peak before 2020 and drop to around 18 Gt by 2040 (Figure 8.6). Such a transition requires enhanced efforts across all parts of the energy sector, beyond the commitments of the NDCs and beyond the results of the New Policies Scenario, with energy efficiency and renewables being key elements in the transition. In the New Policies Scenario, by 2040, CO_2 emissions from all sectors are at least at the same level as today, even if the rate of emissions growth of most sectors is lower than it was over the past decades.

Figure 8.6 ▷ Global CO_2 emissions reductions in the New Policies and 450 Scenarios



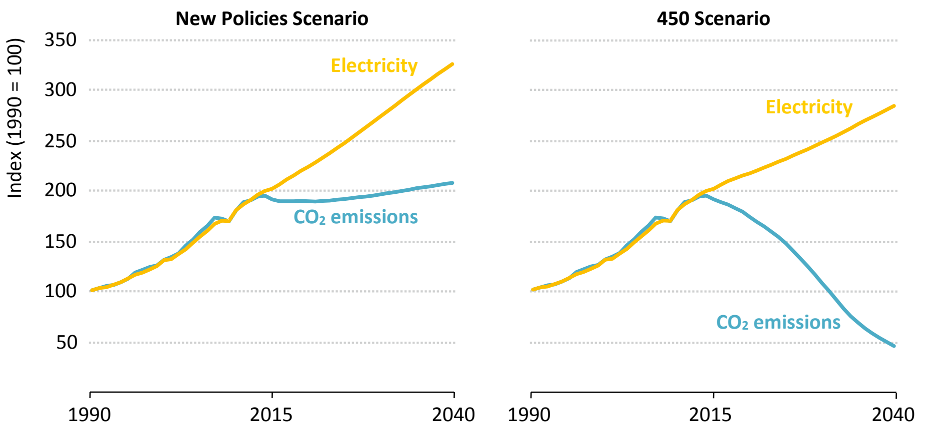
Energy efficiency and renewables are central to achieve climate targets; the required rate of decarbonisation in the 450 Scenario is highest in the power sector

This section identifies the progress being made in different sectors towards the more ambitious decarbonisation goals of the 450 Scenario, in order to identify those sectors that are moving fastest towards decarbonisation and those that are lagging.

8.4.1 Steps in the power sector

A transformation is underway in the power sector: the increasing policy focus on renewable energy sources has brought about rapid cost reductions in recent years, in particular for solar PV and wind. Today, 152 countries have policies in place to support the uptake of renewables for electricity generation and they are key mitigation pillars of many NDCs. These efforts, alongside those to promote other low-carbon fuels in the power sector and energy efficiency in end-uses, are now having a noticeable impact on global CO_2 emissions from the power sector, which stagnated in 2014 and are estimated to have fallen in 2015. In the New Policies Scenario, these first signs of a decoupling of electricity generation and CO_2 emissions growth become a long-term trend. Electricity generation rises by two-thirds in 2040, relative to today, to satisfy increasing demand (Figure 8.7). But CO_2 emissions stagnate and rise only modestly to 14.4 Gt in 2040 (from 13.5 Gt today) as low-carbon technologies expand their share in electricity generation from one-third today to 48% in 2040, led by increases in solar PV and wind power. This makes electricity generation the sector that decarbonises fastest in the New Policies Scenario: at 1.1% per year (measured in CO_2 emissions per unit of energy).

Figure 8.7 ▷ Growth in global electricity generation and related CO_2 emissions in the New Policies and 450 Scenarios



Electricity generation and CO_2 emissions decouple in the New Policies Scenario, but more is needed to achieve climate goals

While these improvements under existing and planned policies are impressive, they are not sufficient to put the power sector on track towards achieving a level of decarbonisation that is required for meeting climate goals. In the New Policies Scenario, the emissions intensity of power generation falls from around 515 g CO_2/kWh today to around 335 g CO_2/kWh in 2040. But, in the 450 Scenario, emissions intensity in the power sector falls further, to around 80 g CO_2/kWh. CO_2 emissions from the power sector fall to 3.6 Gt in 2040, delivering 60% of the required global CO_2 emissions reduction, relative to the New Policies Scenario, and reducing the emissions intensity of fuel use in power generation by 7% per year on average between 2014 and 2040. The additional reduction of emissions intensity in the 450 Scenario is facilitated through increasing CO_2 prices and extended policy support to low-carbon generation, which increases renewables generation by almost 40% in the 450 Scenario over the level that is achieved in the New Policies Scenario, with the largest increases made in wind and solar generation.[10] Nuclear generation rises by a similar amount in relative terms, although from a much smaller base. The use of CCS rises rapidly, both to reduce emissions and as an important protection strategy for fossil-fuel assets that have recently been built and have not recovered their investment costs. By 2040, some 430 GW of fossil-fuel plants are equipped with CCS in the 450 Scenario (including retrofits), of which more than half is in China, the country with the largest coal fleet today (at almost 50% of the global total). Nevertheless, around 675 GW of coal-fired power generation capacity is retired prior to the end of its lifetime in the 450 Scenario. But bringing overall power sector emissions down to the level of the 450 Scenario requires more than low-carbon power generation technologies alone: the reduction of electricity demand, relative to the New Policies Scenario, is almost as large as the increase in electricity generation from wind, solar PV and hydro combined, and yields almost one-quarter of the savings in global cumulative power sector CO_2 emissions (Figure 8.8).

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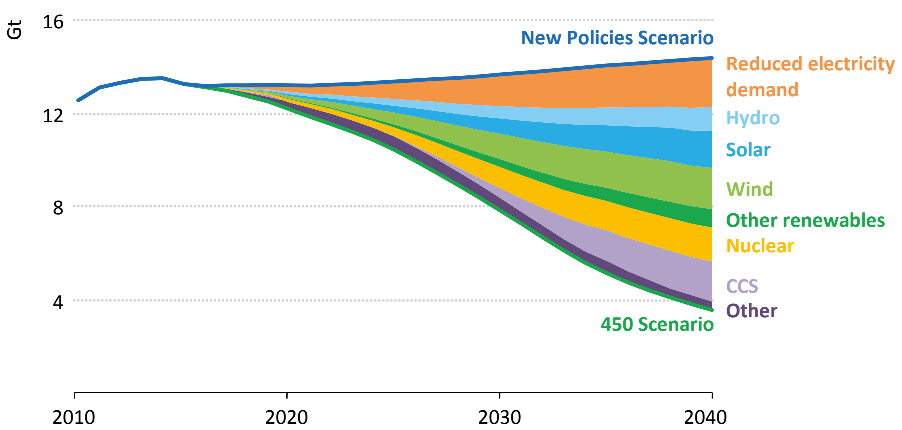
Figure 8.8 ▷ Global CO_2 emissions savings in the power sector in the 450 Scenario relative to the New Policies Scenario



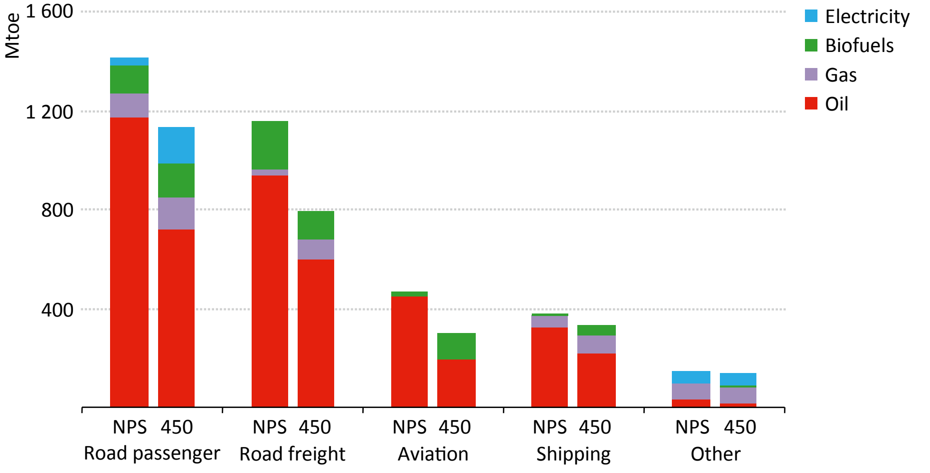
Reduced electricity demand contributes almost one-quarter of the cumulative power sector emissions savings in the 450 Scenario

10. See Chapter 12 for a discussion of implications for the integration of renewables in the electricity network.

8.4.2 Steps in the transport sector

As the second-largest contributor to global energy-related CO_2 emissions, the transport sector is critical to decarbonise. Yet, the rate of its decarbonisation is slow: at 0.2% per year on average, the emissions intensity of transport fuel use in the New Policies Scenario drops at a slower rate than that of any other energy-consuming sector. Transport sector emissions rise to 9.4 Gt in 2040 (from 7.5 Gt today) and the share of transport in global energy-related CO_2 emissions grows by two percentage points to 26% in 2040. There are many reasons: demand for mobility grows, in particular in developing countries, which boosts the total passenger vehicle stock by a factor of two to around 2 billion vehicles by 2040. Demand for road freight transport grows strongly (around one-third of net global oil demand growth to 2040 comes from trucks) and demand in other areas, such as aviation and international shipping also increases. The mounting policy focus on fuel-economy standards in road transport of recent years moderates some of the possible growth in oil demand to 2040. But current policy efforts (as reflected in the New Policies Scenario) appear insufficient to reduce the oil dependency of transport; for electric cars, for example, overcoming the deployment hurdle that is associated with high battery costs will require more dedicated efforts to achieve large-scale market commercialisation (see Chapter 3). In 2040, there are more than 150 million electric passenger vehicles on the road in the New Policies Scenario, around 8% of the total fleet of this type, five-times lower than the number of electric vehicles required in the 450 Scenario.

Figure 8.9 ▷ Global transport fuel demand in the New Policies and 450 Scenarios, 2040



Transport fuel demand is lower and more diversified in the 450 Scenario, but oil remains the mainstay

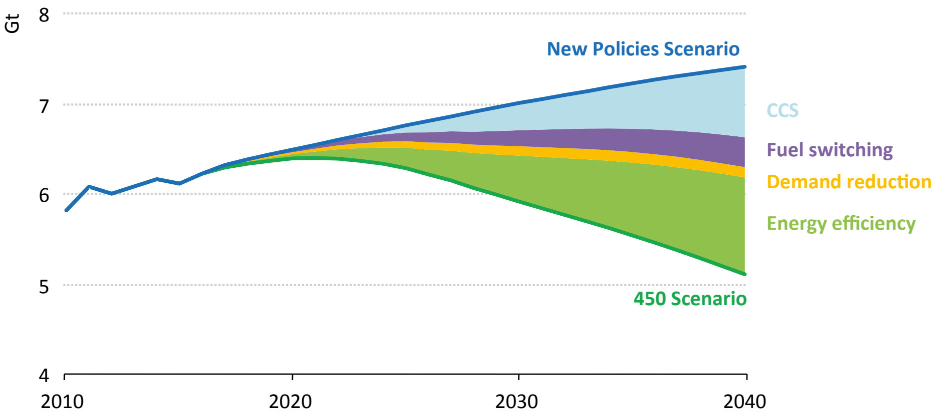
Notes: NPS = New Policies Scenario; 450 = 450 Scenario.

Advanced biofuels – a nascent technology that has not yet achieved commercialisation at scale – will be essential to decarbonise the aviation and maritime sectors in particular (where other options are limited). Advanced biofuels are also significant for road freight transport. Total biofuels use reaches 9 million barrels of oil equivalent per day (mboe/d) in 2040 in the 450 Scenario, twice the level achieved in the New Policies Scenario (Figure 8.9). For natural gas, consumption gets squeezed in many sectors in the 450 Scenario, as the competitiveness of low-carbon alternatives improve and energy efficiency policy reduces overall energy demand. This makes the transport sector appear an attractive outlet for the gas supply sector. In the 450 Scenario, natural gas use in transport rises to around 415 billion cubic metres (bcm), driven by road freight and, increasingly, by international shipping. Overall, in the 450 Scenario, transport-related CO_2 emissions fall to 6.1 Gt in 2040, 3.2 Gt below the level in the New Policies Scenario.

8.4.3 Steps in the industry sector

Regulatory efforts to reduce the carbon intensity in the industry sector typically focus on improving energy efficiency. The degree to which regulatory action is being pursued has been mounting in recent years, in particular in China where the industry sector is responsible for one-third of its total energy demand today and uses more energy than the industry sectors of all OECD countries combined. Such efforts are critically needed: worldwide, the emissions intensity of fuel demand in the industry sector has been on the rise over much of the past 15 years. In the New Policies Scenario, the emissions intensity of fuel demand in the industry sector falls by 0.6% per year on average through 2040 as policies help facilitate the more efficient use of coal, oil and gas, and rising fossil-fuel prices (alongside CO_2 prices in some regions) incentivise the uptake of low-carbon options. However, CO_2 emissions continue to increase in the New Policies Scenario to reach 7.4 Gt in 2040, up from 6.1 Gt today (Figure 8.10). An additional 5.0 Gt of indirect emissions occur from rising electricity and heat demand in 2040. A key reason for the further emissions increase is that in the New Policies Scenario, a significant part of the energy efficiency potential in industry remains untapped, given the hurdles to the deployment. Electric motors, for example, can achieve more efficiency gains if the energy savings potential for the integrated motor system is exploited and the motors are calibrated to real-world conditions, such as part-load operations (see Chapter 7). Beyond energy (and material) efficiency, there is a need for further research, development and deployment to increase the uptake of renewables-based options, for example to produce heat for use in industry, and to improve the commercialisation prospects for CCS. CCS is responsible for about 30% of the cumulative CO_2 emissions savings in the 450 Scenario, relative to the New Policies Scenario, bringing up the rate of decarbonisation in industry to 1.4% per year on average to 2040 and contributing to reducing CO_2 emissions from the industry sector to 5.0 Gt in 2040.

Figure 8.10 ▷ Global direct CO_2 emissions savings in the industry sector in the 450 Scenario relative to the New Policies Scenario



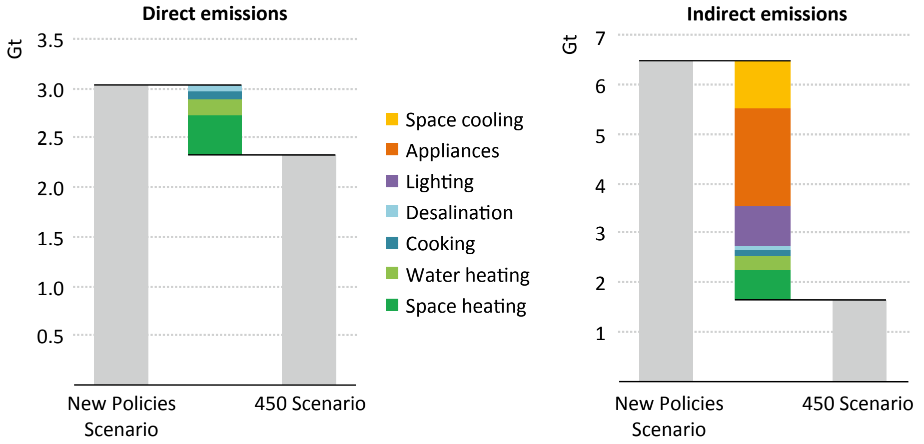
Energy efficiency and CCS are key contributors to additional direct CO_2 emissions savings in the industry sector

8.4.4 Steps in the buildings sector

The emissions intensity per unit of energy use in the buildings sector is two-to-three-times lower than that of other sectors. But the buildings sector is also the largest consumer of electricity and district heat, responsible for half of global electricity demand today. The associated indirect CO_2 emissions, at 5.6 Gt, are almost twice as large as the direct emissions in the buildings sector itself. In broad terms, decarbonising the buildings sector takes two principle angles: reducing energy demand or switching to low-carbon fuels for consumer goods such as appliances and lighting; and improving building insulation to reduce heating and cooling needs. Significant progress has been made in the consumer goods area with the adoption of minimum energy performance standards in many countries. This holds back energy demand growth to 2040 in the New Policies Scenario, which increases at only about 60% of the rate than over the last two-and-a-half decades and reduces emissions intensity of fuel demand further. As a result, direct CO_2 emissions from the buildings sector stabilise at about today's level and reach 3.0 Gt in 2040, although indirect emissions continue to rise to 6.4 Gt with rising electricity and heat demand (Figure 8.11).

The projections of the New Policies Scenario imply significant untapped potential to further reduce emissions from the buildings sector. Phasing out the least-efficient categories of appliances (e.g. refrigerators, freezers, washing machines and dryers) and all incandescent light bulbs (including halogens) by 2030 helps significantly to cut electricity demand growth in the 450 Scenario, which is reduced by more than one-third, relative to the New Policies Scenario. In some cases, such measures are already justified by the market, but consumers need an additional incentive: for example, although light-emitting diode (LED) lamps are already competitive, consumers continue to buy halogen lamps in many developed markets. Significant additional potential lies in improvements to the building envelope: building codes for new buildings are not yet mandatory in all countries, although more than half of the floor area worldwide in 2040 is yet to be built. Imposing such requirements helps to reduce energy demand for space heating and cooling in the 450 Scenario, which falls by around 20% in 2040 below the level of the New Policies Scenario. As a result, direct CO_2 emissions from the buildings sector fall to 2.3 Gt in 2040 in the 450 Scenario, while indirect emissions from an increasingly decarbonised power sector fall by two-thirds below today's level.

Figure 8.11 ▷ Global direct and indirect CO_2 emissions savings in the buildings sector in the 450 Scenario relative to the New Policies Scenario, 2040



Direct emissions from buildings are cut by one-quarter, while energy efficiency and power sector decarbonisation combined cut indirect emissions by a factor of four

8.5 Revisiting temperature thresholds after COP21

The 450 Scenario of the *World Energy Outlook* has for many years assessed what is needed from the energy sector up to 2040 if the world is to comply with the target of limiting the rise in the global mean temperature to below 2 °C – the target in the Cancun Agreement in 2010. As outlined, the Paris Agreement in 2015 adopted new language for the global temperature target: the target is now to limit the rise in the global mean temperature to "well below 2 °C" and to pursue efforts to limit warming to 1.5 °C. At this point, however, it is not clear what these temperature targets mean in practice. First and foremost, "well below 2 °C" does not set a precise temperature target, but rather a direction towards a range of possible outcomes. Second, there is a paucity of research investigating the feasibility of greenhouse-gas emissions pathways consistent with temperature limits of around 1.5 °C. And third, few previous studies have examined such a transformational change and the implications for the pace and extent of the required energy sector change is unknown.

The following section focuses on the possible implications of the temperature targets of the Paris Agreement, which we approach in three steps. First, we discuss what various temperature limits mean for the remaining global CO_2 budget to 2100. Second, we choose one illustrative CO_2 budget that could be compatible with the "well below 2 °C" target and discuss what such a budget could mean for the required pace of decarbonisation, and, in general terms, the implications for the energy sector transition, beyond what is called for in the 450 Scenario. Third, we sketch what an energy sector commensurate with decarbonising to the 1.5 °C limit might look like and highlight some of the steps likely to be necessary to achieve this.

The objective of this analysis is neither to be comprehensive, nor conclusive, as the implications of the Paris Agreement for the climate target will continue to be discussed in international fora and assessing the implications for the energy sector requires much further research about possible technology and policy routes. Rather, the objective is to identify some of the critical questions that will need to be answered in order to put the Paris Agreement into practice in the energy field.

8.5.1 Making the temperature goal tangible: implications for CO_2 budgets and emissions trajectories

Energy sector CO_2 budgets[11]

Relating GHG emissions from the energy sector to future temperature rises is a subject of a myriad of complexities. The process for doing so is generally undertaken in stages. Emissions of greenhouse gases are first related to changes in the atmospheric concentration of these gases, then to changes in the Earth's radiative forcing (the net change in the energy balance between the Earth and space because of differences between incoming solar radiation and outgoing terrestrial radiation), and then to a temperature change. There are multiple feedbacks within this process, whose magnitudes cannot be directly observed, and each is subject to a variety of uncertainties. Climate change can, therefore, be discussed only in terms of the probability of staying below a specific temperature rise. Our 450 Scenario, for example, is designed to have a 50% probability of achieving the 2 °C temperature goal in 2100: but there is a possibility that the outcome could be higher or lower than 2 °C.

Recent climate studies have indicated that the average global surface temperature rise is almost linearly proportional to cumulative emissions of CO_2. This useful relationship has resulted in the concept of a remaining global "CO_2 budget" (the cumulative amount of CO_2 emitted over a given timeframe) commensurate with a probability of remaining below a chosen temperature target (IPCC, 2014). Here, we establish first the "CO_2 budget" for all emissions of CO_2, from whatever source or sector, and then the energy sector CO_2 budget within that.

11. Details on the calculation of the CO_2 budgets for the energy sector in the 450 scenario and the "well below 2 °C" case are also included in a paper available in the World Energy Model section of the *WEO* website (*www.worldenergyoutlook.org*).

Box 8.2 ▷ Overshooting temperature thresholds

The temperature targets and probabilities discussed throughout *WEO-2016* refer to the temperature rise in 2100. This reflects practice in the UNFCCC in the 5th IPCC Assessment Report (IPCC, 2014), although it differs slightly from analysis presented in previous *WEO*s, which referred to stabilisation of temperatures in the long-term (usually occurring beyond 2200, depending on the scenario). It is, nevertheless, important not just to consider the temperature rise in a specific year but also the pathway over time to this level. For example, the average global surface temperature rise could temporarily exceed, or "overshoot", the 2 °C threshold, before returning to 2 °C in 2100. Indeed recent analysis has indicated that some scenarios can embody a rise of as much as 2.25 °C for a period of time and still revert back to 2 °C in 2100 (Bernie and Lowe, 2015).

The rates of non-CO_2 emissions are of particular importance when considering temperature overshoots, as they can have immediate and extreme effects. Control of non-CO_2 emissions, as long as CO_2 emissions are also falling, is therefore a key component of efforts to minimise any temperature overshoot above a stated goal. Another key consideration is that a larger or prolonged overshoot would necessitate the use of negative-emissions technologies (see below), or other geo-engineering technology, such as solar radiation management, in order to bring temperatures back to the target level.

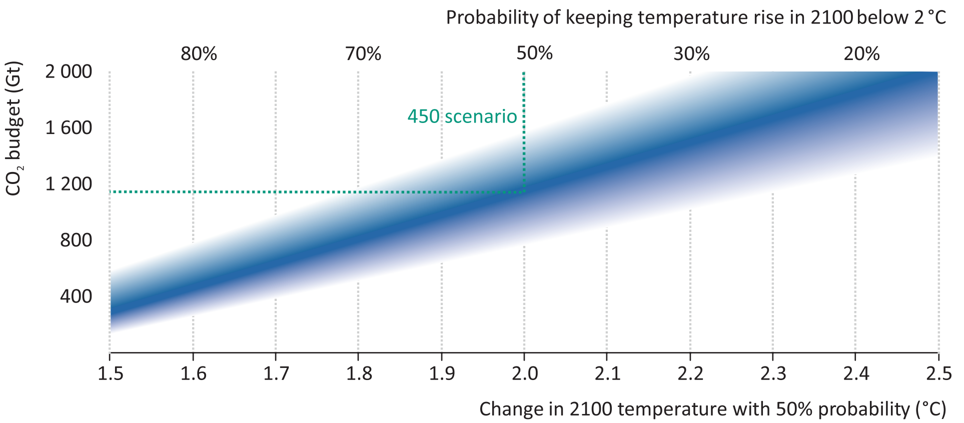
While it may, therefore, be technically possible at some point in the transition to overshoot a specific temperature rise and yet still stay below 2 °C in 2100, this would imply relying, at scale, on yet unproven technology. It would also exacerbate the likelihood of adverse physical impacts arising from climate change (which generally occur in a non-linear fashion at progressively higher temperature rises). In all of our scenarios, warming remains below the target level in 2100 (with at least a 50% probability) at all times.

8

It is important to remember that CO_2 is not the only agent to affect global mean temperature: non-CO_2 forcers mean that the CO_2 budget must be reduced in order to achieve the same probability of a given temperature rise. Non-CO_2 forcers include methane (CH_4), nitrous oxide (N_2O), aerosols and other more minor agents. Some, such as N_2O, are long-lived and are often considered a stock pollutant (i.e. one which endures in the atmosphere) in a similar way to CO_2. Most others have a shorter life span and do not accumulate in the atmosphere in the same way as CO_2, so their contribution to climate change is generally referred to in terms of flows (i.e. the annual emissions levels) rather than stocks (i.e. cumulative emissions levels). Different non-CO_2 forcers also have different contributions to the temperature rise, ranging from those that have a cooling effect (i.e. lower the temperature rise) to those that are many times more potent than CO_2 and have an extreme warming impact over a short period of time (Box 8.2). These differing characteristics mean that it is not possible to generate a "non-CO_2 budget" analogous with the CO_2 budget. However, non-CO_2 forcers can by no means be ignored: their levels are of crucial importance to the temperature rise likely to be realised.

Most non-CO_2 emissions originate from non-energy sectors (in particular from agriculture and waste) and variations in the projections from these sectors affect the necessary rates of transformation of the energy sector. To allow for this, publications such as the IPCC 5th Assessment Report associate a range of CO_2 budgets with a given probability of staying below a defined temperature rise: higher non-CO_2 emissions mean a lower CO_2 budget and vice versa. Projections of non-CO_2 emissions in our work are based upon the most appropriate scenarios produced by the longer term models assessed in the IPCC reports. All energy-related GHG emissions, both CO_2 and non-CO_2, are modelled in the World Energy Model. With projections of non-CO_2 out to 2100, it is possible to calculate residual CO_2-only budgets in the various scenarios. For this we rely on the climate model MAGICC (Model for the Assessment of Greenhouse-Gas Induced Climate Change) (Meinshausen, Raper and Wigley, 2011), which has been widely used in studies assessed in the IPCC reports. For the 450 Scenario, which has a 50% chance of staying below 2 °C, the total CO_2 budget from 2015 to 2100 is 1 140 Gt. This lies in the middle of the 990 – 1 240 Gt CO_2 range from a study discussing CO_2 budgets commensurate with a 50% chance of staying below 2 °C (Rogelj, et al., 2016).

Figure 8.12 ▷ Uncertainty in associating remaining CO_2 budgets to probabilities of temperature rises in 2100



Remaining CO_2 budgets are very sensitive to small changes in target temperature thresholds and probabilities

Note: Shaded area represents the band of uncertainty relating CO_2 budgets to the temperature rise in 2100.

Sources: IPCC (2014); IEA analysis using MAGICC.

Small changes in the probability of achieving a given temperature rise can have a large impact on the remaining CO_2 budget (Figure 8.12). For example, moving from a 50% chance of achieving 2 °C to a 66% chance reduces the total CO_2 budget by around 250 Gt. Moving

Moving to an 80% chance reduces the budget by around 650 Gt.[12] As the target probability of remaining below 2 °C increases, the majority of the additional mitigation necessary is assumed to come from reductions in CO_2 emissions, with only a slight decrease in non-CO_2 emissions. This is because the level of non-CO_2 mitigation that is possible, beyond the levels in the 450 Scenario, is far from clear. In the majority of the 2 °C scenarios included in the IPCC 5th Assessment Report, for example, the temperature contribution from non-CO_2 emissions in 2100 is only marginally lower than the assumptions in the 450 Scenario, suggesting that the scope to do more is limited. This has important implications when seeking to limit temperature rises to 1.5 °C. For example, the remaining CO_2 budget for a 50% chance of 1.5 °C is around 150 Gt – fewer than five years of CO_2 emissions at current rates – if non-CO_2 emissions remain at the same level as in the 450 Scenario.

The final step to arrive at an energy sector CO_2 budget is to subtract from the total CO_2 budget those CO_2 emissions not related to fossil-fuel combustion in the energy sector. These emissions predominantly arise from two sources: industrial processes (70% of which are from cement production) and LULUCF. Annual industrial process emissions are currently around 2 Gt, and in the 450 Scenario, these emissions rise marginally to the mid-2020s, before declining over the course of the century as the use of CCS becomes more widespread. Estimates of LULUCF emissions are much more uncertain. One estimate for 2013 indicated emissions were around 3.3 Gt, but could range from 5.1 Gt CO_2 to 1.5 Gt CO_2 (Le Quéré, et al., 2015), with some estimates from other sources even lower than this. The high degree of uncertainty arises from the differing methods that can be used to generate LULUCF estimates, the poor quality of land-use change data in some key regions and the difficulty in attributing emissions to human activities or to natural processes. Our projections of LULUCF emissions are based on data from the UN Food and Agriculture Organisation, national analyses and NDC pledges, many of which contain mitigation actions to reduce LULUCF emissions. As a result LULUCF emissions are close to zero by 2040 and turn negative thereafter, and so, over the course of the century, LULUCF emissions are assumed to be negative. The net effect of these two factors is to reduce the total CO_2 budget for the 450 Scenario for the period 2015 to 2100 from 1 140 Gt to an energy sector only budget of 1 080 Gt.

From temperature objectives to emissions trajectories

As discussed, the Paris Agreement makes reference to keeping temperature rises to "well below 2 °C" and pursuing efforts to limit the temperature increase to 1.5 °C. But it offers no clear guidance on what "well below 2 °C" means in practice, or what probabilities should attach to these goals. One way of interpreting these temperature goals is to take them together as spanning a range: from a scenario providing a reasonable chance of staying below 2 °C at the upper end to a scenario providing a reasonable chance of staying below 1.5 °C at the lower end. The upper end of this range is therefore broadly equivalent to the 450 Scenario, while the lower end could, for consistency, be set as a 50% chance of

12. The inter-quartile range, or spread, of the underlying probability density function over temperature rises in 2100 increases at higher median temperatures. These values and Figure 8.12 are therefore approximate.

limiting the temperature rise to 1.5 °C (discussed in section 8.5.3). Of course alternative probabilities could be chosen to establish these bounds: the definitions of scenarios consistent with the Paris Agreement temperature goals will develop over the coming years, as more analysis is undertaken.

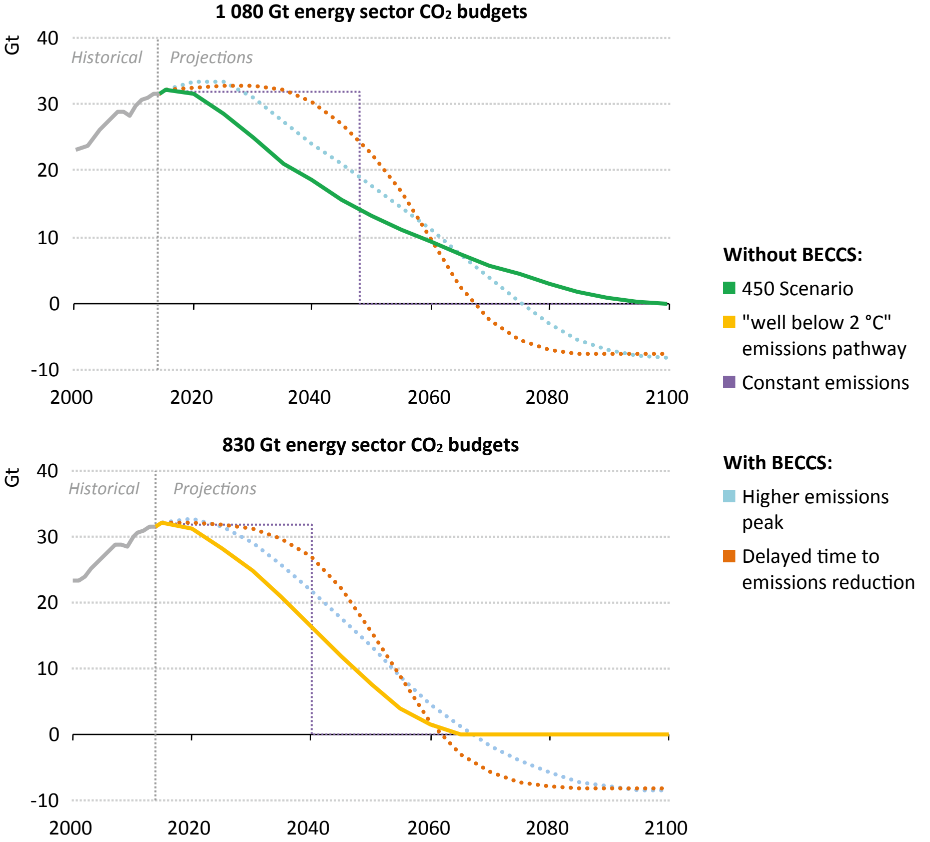
The potential additional implications for the energy sector of aiming to go beyond the mitigation levels in the 450 Scenario can be illustrated by selecting a scenario within this putative range. One such option is a scenario that has a 66% chance of staying below 2 °C, rather than the 50% chance in the 450 Scenario, and the emissions levels consistent with this have been examined in detail by the IPCC and others. Such a scenario provides a 50% chance of limiting the temperature rise to 1.84 °C in 2100 and has an energy sector CO_2 budget from 2015 to 2100 of 830 Gt (Figure 8.12), a reduction of 250 Gt, or around 25%, on the energy sector CO_2 budget in the 450 Scenario. For clarity and simplicity in the following discussion we refer to this as the "well below 2 °C" case, recognising that other scenarios, which have lower median temperature rises in 2100, could equally be considered consistent with the "well below 2 °C" objective. We explore in more detail what this change would imply for the energy sector (section 8.5.2).

If energy sector CO_2 emissions were to remain at 2015 levels (around 32 Gt), the energy sector CO_2 budgets for the 450 Scenario and this "well below 2 °C" case would be exhausted within around 35 and 25 years, respectively. Drastic reductions in emissions are evidently required: but how far and how fast? One key to addressing this is whether or not it might be possible for total energy sector CO_2 emissions to turn negative in the future. This is possible only if CO_2 removal technologies are available that are capable of removing CO_2 from the atmosphere; one such technology is bioenergy with carbon capture and storage ("BECCS"). Bioenergy can be used as feedstock for the production of synthetic fuels or electricity, as a substitute for petrochemicals or be combusted directly for heat. In some of these instances, it is possible to capture and store the CO_2 that is emitted when the bioenergy is consumed. As bioenergy is produced by photosynthesis and so CO_2 was removed from the atmosphere when it was growing, it is possible for the life-cycle emissions of BECCS to be negative.[13] The use of BECCS, or other negative-emissions technologies, could help offset emissions from difficult-to-decarbonise areas, such as the aviation or iron and steel sectors. Extending this further, if BECCS were deployed on a wide enough scale and accompanied by decarbonisation of all energy sub-sectors, it is theoretically possible for the entire energy sector to become net CO_2 negative.

Such a situation is vastly removed from the realities of the current energy system, and the prospect is remote from today's perspective. But, if net-negative emissions were to be realised, then CO_2 budgets could still be respected and emissions peak later or at a higher level, or decline more slowly, or approach net-zero later (Figure 8.13). Judgement about the availability or not of BECCS therefore has significant near-term implications.

13. For this to be the case, the amount of CO_2 that may have been emitted during cultivation of the bioenergy (for example from the use of fertiliser or during harvesting) and the amount of CO_2 that cannot be captured by CCS must be less than the amount that is captured and permanently stored.

Figure 8.13 ▷ **Pathways for energy-related CO_2 emissions under different CO_2 budgets, with and without BECCS**



Delaying emissions reductions requires reliance on negative-emissions technologies that are currently unproven at scale

However, BECCS is, as yet, an unproven technology at scale and there is a huge degree of uncertainty surrounding its viability. The uncertainties are not necessarily about the CCS technology itself. Another question is what level of bioenergy resources might be available to be used by the energy sector at large scale. For example, to achieve 8 Gt of net-negative CO_2 emissions (the approximate levels shown in Figure 8.13) and assuming that the rest of the global energy system is CO_2-neutral so that there is no need to offset any emissions, around 3.0 million square kilometres (km^2) of arable land would be required. This land area is broadly equivalent to the size of India. There are also critical questions surrounding whether or not bioenergy can be considered a CO_2-neutral fuel (Zanchi, Pena and Bird, 2012). In constructing emission pathways to 2040, we therefore assume that some level of BECCS can be deployed, which can help to offset emissions in difficult-to-decarbonise sectors, but that global energy-related CO_2 emissions cannot turn net-negative at any time.

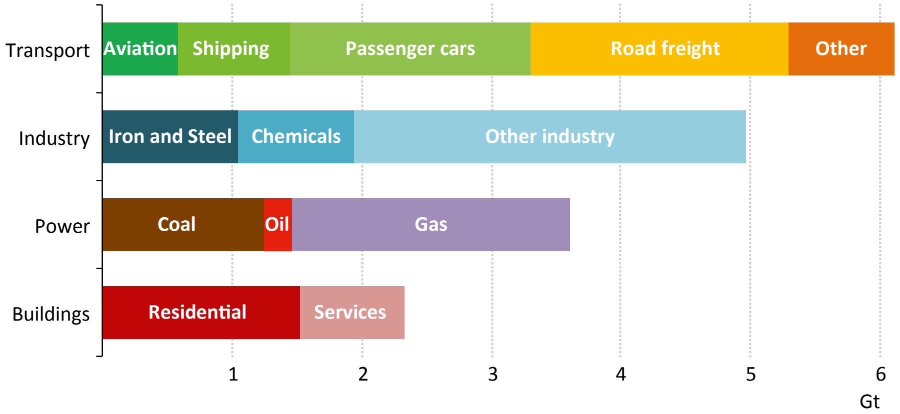
Our detailed modelling of the energy sector in the 450 Scenario is, therefore, calibrated to ensure that emissions between 2015 and 2040 and the rate of decarbonisation during this period are consistent with an energy sector CO_2 budget of 1 080 Gt CO_2 between 2015 to 2100 and a long-term emissions trajectory that does not rely on global emissions turning negative (Figure 8.13). For the CO_2 budget in our illustrative "well below 2 °C" case, one possible emissions trajectory would require energy-related CO_2 emissions to be net-zero by around 2060. The implications for the emissions trajectory to 2040 appear not to be enormous, compared with what is already required under the 450 Scenario: energy-related CO_2 emissions in 2040 would need to be around 16.3 Gt, around 2.1 Gt (or 11%) lower than the emissions in the 450 Scenario. The challenge appears larger after 2040: if one excludes the possibility that global emissions can turn negative later in the century, then emissions would need to drop to zero more than 30 years earlier than in the 450 Scenario.

8.5.2 The energy sector to 2040 in a "well below 2 °C" world

Saving the additional 2.1 Gt in 2040 identified above might not appear unduly challenging, given the level of reduction already achieved in the 450 Scenario, where CO_2 emissions from the energy sector drop by around 14 Gt below today's level through 2040. But the reality of the energy sector in the 450 Scenario is that many of the low-hanging fruit have already been harvested by 2040. More than 70% of global power generation capacity is low-carbon, including from renewables, nuclear and CCS. Much of the economically viable potential for energy efficiency is already tapped as, for example, the least-efficient energy appliances are banned from 2030 and the average fuel consumption of new passenger vehicles drops to half the level of today by 2040. In the industry sector, the efficiency of electric motor-driven systems has been raised by more than 40% on average, relative to today (see Chapter 7). Fuel switching towards low-carbon fuels has also occurred on a large scale across most end-use sectors, thus making further efforts challenging.

Nevertheless, there are still ways to achieve the target. Such routes may be technology-oriented, intensifying efforts along technology and policy pathways that are already known. No sector has been fully decarbonised in 2040 in the 450 Scenario (Figure 8.14). But reducing the remaining emissions is challenging, as they often arise from sectors in which the options for fuel switching are very limited (such as in road freight or aviation) or where stock turnover is slow (such as the buildings stock). Among the main remaining options are a further push to electrification in end-use sectors, in particular in transport; a further push for low-carbon technologies in the power sector; a further increase of the direct use of renewables for heat generation and as transport fuels; stepping up the renovation rate of the existing buildings stock, in particular in OECD countries where around two-thirds of the current residential floor area will still exist by 2040; and increasing the use of CCS in the industry sector. Tapping these remaining potentials is by no means impossible, as many of the required technologies exist or are at least known; but the technologies associated with their achievement are likely to come at costs well beyond those of the 450 Scenario.

Figure 8.14 ▷ Global energy-related CO_2 emissions by selected sector in the 450 Scenario, 2040



Emissions that remain in the 450 Scenario in 2040 are concentrated in areas that are increasingly challenging to decarbonise

8

There are other possible routes towards the "well below 2 °C" target than those reliant on technology alone. They would address the decarbonisation of the economy in a more holistic manner, acknowledging the relative proximity of 2060, the date of net-zero emissions and the required pace of emissions decline after 2040. They could, for example, strive to address transport sector emissions reduction in an even more transformative way by densifying urban areas through compact city planning (which would help reduce mobility needs) and promote a substantial shift of transport demand towards mass transport (such as railways) (IEA, 2016a). Increasing the efficiency of the use of materials in the industry sector would lower life-cycle GHG emissions from industrial products (IEA, 2015b). And there is a potentially vast untapped role for information technology (IT) in inducing transformational changes, such as by IT-based comprehensive controls of energy use in buildings, or by changing consumer behaviour through enhancing the role of the internet.

We do not attempt here to identify the optimal route towards a "well below 2 °C" pathway, nor to weigh costs and benefits or to prescribe a possible policy evolution towards achieving the target. The IEA will continue to undertake further research, in collaboration with other relevant stakeholders, in order to understand the opportunities and pitfalls that individual routes may offer.[14] But, in order to illustrate the extent of the challenge for the energy sector in a "well below 2 °C" emissions pathway, as described earlier, we set out a possible route that could bridge the emissions gap of 2.1 Gt in 2040 between the 450 Scenario and the illustrative "well below 2 °C" case. The focus is on further scaling up the efforts of the

14. The IEA held a first workshop on the energy sector implications of a "well below 2 °C" pathway in June 2016, see *www.iea.org/workshops/re-defining-climate-ambition-to-well-below-2c-.html*.

450 Scenario in the power, transport and buildings sectors, although we fully account for the impact of reduced fossil-fuel demand on other parts of energy transformation. There are three main pillars:

- **Road transport electrification:** further uptake of electric vehicles in the light-duty passenger vehicle segment.
- **Power sector decarbonisation:** further increase in the use of low-carbon technologies for power generation, in particular renewables and nuclear.
- **Buildings renovation:** further increase in the renovation rate of the stock of existing buildings to reduce heating and cooling demand per square metre of floor space in industrialised and transition economies.

The challenge is formidable. For example, we find that three-quarters of the global passenger light-duty vehicle fleet would need to be electric by 2040 (from one-third in the 450 Scenario). In the power sector, an additional 2 400 terawatt-hours (TWh) of low-carbon electricity generation would be required by 2040, almost 10% more than in the 450 Scenario, both to meet increasing demand from transport and to compensate for less generation from unabated fossil fuels (mainly coal). In the buildings sector, fossil-fuel use would fall by one-quarter, relative to the 450 Scenario, driven in particular by the residential sector where specific heating and cooling demand per square metre of floor space in industrialised and transition economies would drop by around one-third by 2040 (Table 8.3). There are, of course, other possibilities: full electrification of not only passenger, but also commercial light-duty vehicles, for example, could, of itself, be nearly enough to bridge the emissions gap between the 450 Scenario and a "well below 2 °C" pathway. But the required total electric vehicle stock would reach 2.2 billion cars in 2040, up from around 1.3 million cars today and three times more than in the 450 Scenario.

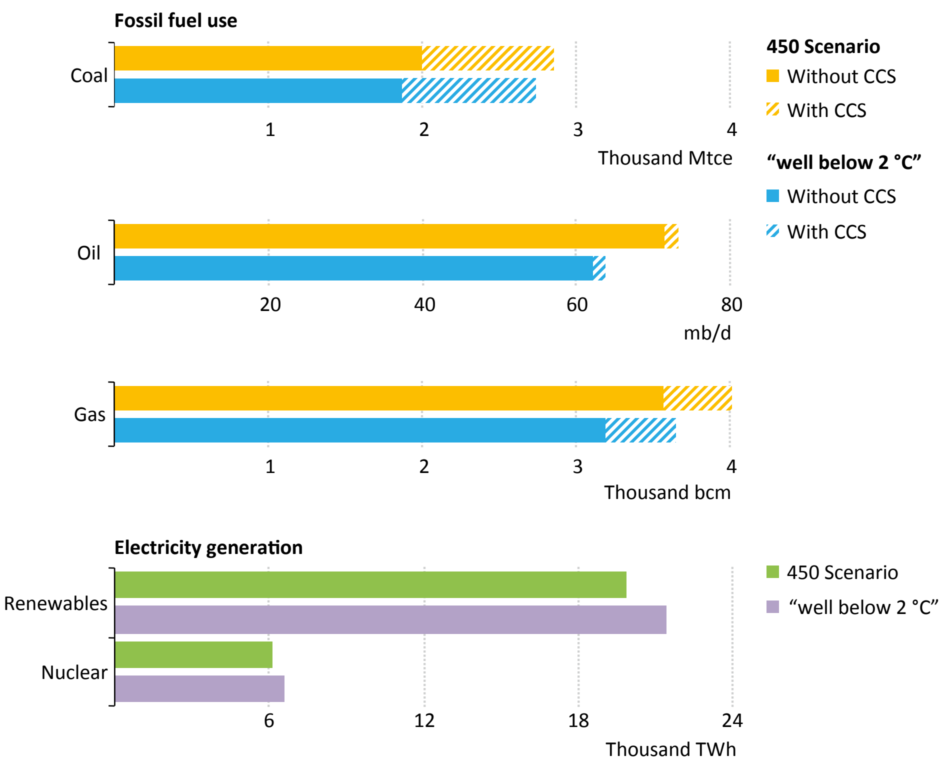
Table 8.3 ▷ Key elements in a "well below 2 °C" pathway, 2040

Sector	450 Scenario	"well below 2 °C" pathway
Road transport	710 million electric passenger cars (one-third of global car stock electric).	1.5 billion passenger electric cars (three-quarters of global car stock electric).
Power sector	CO_2 emissions intensity of electricity generation falls to 80 g CO_2/kWh.	CO_2 emissions intensity of electricity generation falls to 65 g CO_2/kWh.
Buildings sector	Residential buildings stock in industrialised and transition economies reaches average heating and cooling demand of around 80 kWh/m^2 per year.	Residential buildings stock in industrialised and transition economies reaches average heating and cooling demand of around 50 kWh/m^2 per year.

Note: kWh/m^2 = kilowatt hours per square metre.

Such a transformative change would have significant implications for the energy sector as a whole. In the example outlined in Table 8.3, further electrification of transport would require additional power capacity of 180 GW in 2040, relative to the 450 Scenario, and the share of low-carbon capacity in the power mix would rise to almost 80% (from more than 70% in the 450 Scenario). Oil demand would be further reduced, falling by another almost 11 mb/d below the level of the 450 Scenario to 63 mb/d in 2040, almost 30 mb/d below today's level (Figure 8.15). Demand for natural gas, which is the only fossil fuel with rising demand in the 450 Scenario, would peak and decline back to today's level, 370 bcm below the level reached in the 450 Scenario. Coal demand would shrink by around 110 million tonnes of coal equivalent (Mtce) in 2040, relative to the 450 Scenario, mainly in power generation.

Figure 8.15 ▷ Global fossil-fuel demand and low-carbon power generation in the 450 Scenario and a "well below 2 °C" case, 2040



A "well below 2 °C" pathway reduces fossil-fuel use below the level of the 450 Scenario and increases low-carbon electricity generation

Notes: Mtce = million tonnes of coal equivalent; mb/d = million barrels per day; tcm = trillion cubic metres; TWh = terawatt-hours. Dashed area denotes the share of fossil-fuel consumption that is used with CCS.

8.5.3 The energy sector in a 1.5 °C world

The inclusion in the Paris Agreement of the aim to pursue efforts to limit the increase in temperatures to 1.5 °C was relatively unexpected by the scientific community. There is, therefore, a paucity of research investigating the feasibility of GHG emissions pathways or

CO_2 budgets consistent with this level.[15] Further, as with the goal of keeping temperatures "well below 2 °C", the Agreement offers no guidance as to the probability level that should be attached to achieving this goal. Understanding the implications for the energy system of pursuing efforts to keep temperatures below 1.5 °C is therefore fraught with considerable uncertainty. The IPCC has indicated that to have a 50% chance of keeping global warming to 1.5 °C, the remaining CO_2 budget from 2015 lies between 400 – 450 Gt CO_2. But more recent reports have suggested that the remaining CO_2 budget, still with a 50% probability, could be as low as 50 – 250 Gt CO_2 (Rogelj, et al., 2015), even if temperatures are allowed temporarily to overshoot the targets. The level of the CO_2 budget is very sensitive to assumptions on non-CO_2 emissions (as discussed above).

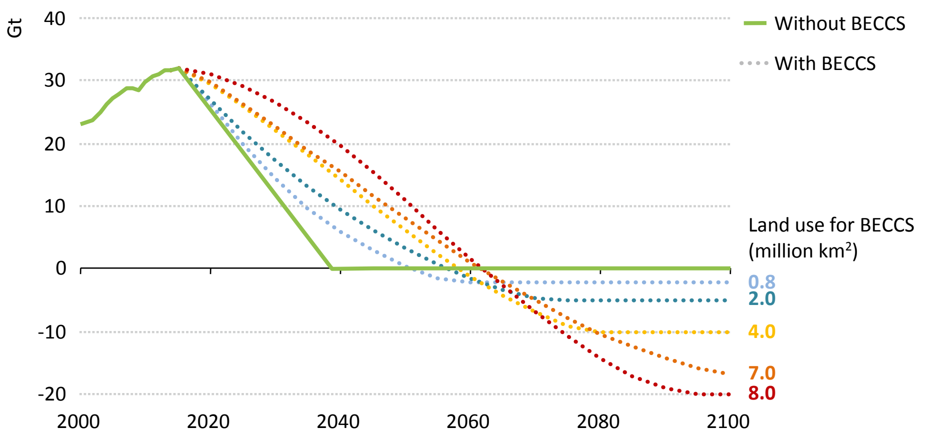
The changes to the energy system implied by such constrained CO_2 budgets are stark. To illustrate this, even if the CO_2 budget is at the upper end of this range, at around 400 Gt CO_2, energy sector emissions would need to fall to net-zero by the late-2030s if global energy-related CO_2 emissions cannot turn net-negative at any point (as is assumed in the 450 Scenario and the "well below 2 °C" case) (Figure 8.16). This would require an immediate ramp-up of all low-carbon options at a rate of deployment sustained over the next 25 years that can barely be imagined from today's perspective. By 2040, all passenger and light-commercial vehicles would need to be electric (around 2.2 billion cars and light trucks, unless significant efforts were undertaken to avoid traffic) and heavy-duty trucks and buses would increasingly be electrified, requiring those of the world's roads and highways to be equipped with overhead lines that carry freight activity. In the industry sector, material and energy efficiency would need to be maximised to reduce energy demand below today's level, the deployment of electricity, biomass and other renewables-based heating technologies significantly increased, and the uptake of low-carbon innovative process technologies drastically accelerated to enable further emissions reductions. Practically all residential and commercial buildings would need to be at zero emissions by 2040, with all remaining energy use satisfied exclusively by renewables and low-carbon electricity. As a result of increasing electrification of end-uses, electricity demand would be boosted to about twice the level of today, with around 90% of generation from renewables and nuclear. Natural gas generation with CCS would be responsible for the remainder, with the level of generation being about the same as in the 450 Scenario to ensure system flexibility (alongside greater amounts of storage and efforts to improve the flexibility of the newly electrified end-uses). Coal use for power generation would drop dramatically, as its combustion, even with CCS, would entail residual emissions that would be increasingly challenging to compensate elsewhere.

Fossil fuels would nevertheless still be used in the energy sector, comprising around 30% of the total energy mix (down from about 80% today). But fossil-fuel use would largely be confined to oil and natural gas. Gas demand, at around 2 300 bcm in 2040, would drop one-third below today's level and would mostly be for power generation; the remainder

15. The Paris Agreement contained a decision inviting the IPCC to explore the impacts of 1.5 °C global warming and emissions pathways consistent with this goal. The IPCC accepted this invitation and is due to provide a special report on the issue in 2018.

would be in the industry sector. Demand for oil would drop below 40 mb/d in 2040, almost 50% below the level in the 450 Scenario. Almost half of oil demand would be from sectors where substitution is most difficult, such as petrochemical feedstocks (where it is used to produce plastics). Much of the remainder would occur in transport, in particular in aviation and road freight where the limited availability of sustainable biomass would restrain the ability to switch to biofuels.

Figure 8.16 ▷ Energy sector CO_2 emission pathways consistent with a 1.5 °C temperature rise



CO_2 emissions need to fall to zero between 2040 and 2060 to stay below 1.5 °C

Note: BECCS = bioenergy with carbon capture and storage.

For the energy sector as a whole, the availability of sustainable biomass becomes a key constraint. If it was limited to around 100 exajoules per year (EJ/year) in 2040 as suggested in some parts of literature,[16] this would mean that 80% of all biomass use in power and heat generation, industry or for the production of biofuels would need to be equipped with CCS to compensate for residual emissions from the remaining use of fossil fuels. For the energy sector to be at net-zero emissions in 2040, it would require about 4 Gt of CO_2 to be captured each year from fossil-fuel use in the power and industry sectors, and an additional almost 4 Gt of CO_2 emissions being captured through BECCS. In the power sector alone, this would require some 500 GW of biomass generation to be equipped with CCS. The use of biomass with CCS would require around 1.5 million km^2 of arable land, equivalent to half of the land area of India.

There might be other ways to achieve the 1.5 °C target. In theory, geo-engineering technologies could be employed to reduce the rate of decarbonisation necessary in

16. See for example (Creutzig, et al., 2014).

the energy sector, reducing CO_2 emissions, for example through the direct capture of CO_2, or reducing the Earth's temperatures directly, such as by spraying aerosols into the stratosphere to reflect incoming solar radiation. However, if the energy sector is itself to decarbonise to an extent consistent with limiting warming in the long term to 1.5 °C, it is highly likely that it will be necessary to deploy bioenergy with CCS and that global CO_2 emissions turn net-negative.

It is important to bear in mind that CO_2 emissions could fall to zero and then turn net-negative at a later point in time than discussed above. But the longer the date of net-zero emissions is delayed, the larger the level of BECCS that is subsequently required. Nevertheless, given the need to offset the additional emissions that would occur, the latest point in time for achieving net-zero emissions appears to be around 2060, regardless of the level of BECCS that can be deployed. If net-zero emissions were not achieved until 2060, then global emissions would quickly need to fall to minus 20 Gt CO_2. This would require 8 million km^2 of land to be committed to bioenergy production, equivalent to the land area of Australia (assuming that there are also no sources of CO_2 emissions from other sectors that need to be offset). Regardless of assumptions about future technology availability, the conclusion is the urgent need for radical near-term reductions in energy sector CO_2 emissions, employing every known technological, behavioural and regulatory decarbonisation option, if there is to be any realistic chance of achieving the 1.5 °C goal.

Water-energy nexus

Stress points, savings and solutions

Highlights

- Energy needs water, water needs energy: the dependencies in both directions are set to intensify rapidly. The availability of water affects the viability of energy projects and must be considered when deciding on energy options. And the dependence of water services on the availability of energy will impact the ability to provide clean drinking water and sanitation services.
- In the New Policies Scenario, water withdrawals for primary energy production and power generation rise by less than 2% through 2040 to reach over 400 bcm, while the amount of water consumed in the energy sector increases by almost 60% to over 75 bcm. A shift towards higher efficiency power plants with advanced cooling systems lowers withdrawals (but tempers consumption), while a rise in nuclear power generation and in biofuels production increase both.
- Switching to a lower carbon pathway could, if not properly managed, exacerbate water stress or be limited by it. While withdrawals in the 450 Scenario are 12% lower in 2040 compared with the New Policies Scenario, consumption is 2% higher due to more biofuels production and the deployment of concentrating solar power, carbon capture and storage and nuclear power – each of which can be water intensive.
- Energy consumption of the water sector worldwide was 120 Mtoe in 2014; a majority of this was in the form of electricity, corresponding to 4% of total global electricity consumption. Of the electricity consumed for water, around 40% is used to extract water, 25% for wastewater treatment and 20% for water distribution. Roughly half of thermal energy used in the water sector is to pump groundwater for agricultural purposes, with the remainder for desalination.
- In the New Policies Scenario, global energy use in the water sector more than doubles by 2040. Electricity consumption rises by 80% by 2040, equivalent to twice the electricity consumption of the Middle East today. The largest increase comes from desalination, which grows over eight-fold, accounting for more than 20% of water-related electricity demand in 2040. There is significant potential for energy savings in the water sector. The pursuit of a co-ordinated suite of policy measures can reduce electricity consumption by 225 TWh and increase electricity generation from wastewater by 70 TWh relative to the New Policies Scenario.
- Over the next 25 years there is a general shift towards more water-intensive energy and energy-intensive water. But there are options available to avoid potential stress points by integrating energy and water policies and infrastructure, tapping the energy embedded in wastewater, improving the efficiency of the water and energy sector, and using alternative water sources in the energy sector.

9.1 Overview

Water for energy. Energy for water. Two sets of linkages with enormous significance for economic growth, life and wellbeing. Water is needed for all phases of energy production, for fossil-fuel extraction, transport and processing, power production and irrigation of feedstock for biofuels. Water can also be produced as a by-product of fossil-fuel production. Energy is required for a range of water-related processes, such as water transport, wastewater treatment and desalination; and, energy can be produced as a by-product from wastewater treatment. Both sides of this equation come with considerable risks. In its Global Risks Report, the World Economic Forum asks expert respondents to rank a series of potential global threats according to their likelihood and impact: in the 2016 edition, energy (a failure of climate change mitigation and adaptation, or a severe energy price shock) and water (water crises) are identified as three out of the top-five risks facing the world in the next decade (World Economic Forum, 2016). Moreover, the interdependency of these two resources has also emerged as a critical global issue, recognised by a host of fora and institutions as a potential source of vulnerability.[1] And water and energy are front and centre in the new UN Sustainable Development Goals (SDG 6 and 7). Most of the weaknesses in the global energy system examined in this *Outlook*, whether related to energy access, energy security or the environmental impacts of energy use, can be exacerbated by changes in water availability, variability and predictability. Most of the fault lines in global water supply can be widened by failures on the energy side. Managing these interdependencies has become the focus for a wide range of policy-makers, businesses and other stakeholders.

Recognising the importance of the nexus between these two resources, the *World Energy Outlook* in 2012 (W*EO-2012*) examined the water requirements of the energy sector and the issue has been taken up in subsequent years, most recently in *WEO-2015* with a study of the impact of water scarcity on the choice of cooling technology in coal-fired power plants in India and China. This, the second dedicated chapter to water and energy in the *WEO* series, updates and expands upon the previous analysis. In addition to new projections for future freshwater requirements[2] for energy production in various scenarios, this chapter assesses for the first time the energy used for a range of different processes in the water industry, such as wastewater treatment, distribution and desalination, highlighting opportunities for improved efficiency as well as the potential vulnerabilities and stress points.

9.1.1 The state of global water resources

Water in and of itself is an abundant resource; however, freshwater makes up only 2.5% of global water resources. Of that, less than 1% is available for human consumption, as

1. These links and potential trade-offs were the subject of the UN World Water Day and its World Water Development Report in 2014.

2. Unless otherwise noted, the term "water" in this chapter refers to accessible renewable freshwater.

nearly 70% of the world's freshwater is locked up in glaciers and ice, roughly 30% is deep underground and some is contaminated and not suitable for human consumption or use. The amount of renewable water resources that exist in each country varies widely and annual averages often mask considerable seasonal variability (see Box 9.1 for a list of terms used in this chapter). Many countries face some degree of water stress – more than a billion people live in areas of water stress, a figure expected to more than triple by 2025 (WWAP, 2014). By 2040, almost one out of every five countries is anticipated to have an extremely high ratio of withdrawals to supply, including countries in the Middle East, Central Asia and India (Luo, et al., 2015).

Global freshwater withdrawals from surface water and groundwater sources have increased by roughly 1% per year since the 1980s as demand in developing countries has surged (WWAP, 2016). Currently, groundwater provides roughly a third of supply. Groundwater supplies are being systematically diminished by a rate of extraction at 1-2% per year globally, outpacing recharge rates (WWAP, 2012). An estimated 21 of the world's 37 largest aquifers are severely over-exploited and since the greater part of the world's freshwater resources come from groundwater, better management of aquifers will be particularly important. Given the interconnectedness of the hydrological cycle, excessive withdrawals in one area can easily have knock-on effects in others, e.g. the removal of groundwater from an aquifer can reduce the discharge rate to rivers and wetlands or could result in seawater intrusion into an aquifer. Transboundary water basins represent a particular governance challenge – there are over 270 transboundary river basins in the world, covering approximately 60% of the globe's freshwater flow and roughly 40% of the population (Giordano, et al., 2013). Additionally, there are an estimated 600 aquifers that are shared by two or more nations (IGRAC). How a river or aquifer is managed or used in one location can drastically affect other locations further up or downstream.

Water availability can also be affected by water quality, as the cost of treatment may be prohibitive, creating physical water scarcity of economic water resources. While potable water is not needed for all purposes – such as in certain industries and agriculture – clean water is crucial for households. Toxic contamination, eutrophication, micro-pollutants (such as medicines, cleaning products) and acidification are harmful to human and ecosystem health. They also increase the cost and associated energy requirements involved in removing nutrients and pesticides to improve the quality of the water to meet drinking water standards (OECD, 2012). Similarly, thermal pollution, can impact the ecology of a waterbody in addition to diminishing its effectiveness as a medium for cooling thermal power plants.

There is increased uncertainty about future water availability and the impact that climate change will have on water resources. In some areas, it could be beneficial, while in others it could amplify or introduce scarcity. It is expected that climate change will alter the intensity, frequency, seasonality and amount of rainfall, aspects which impact both surface water flows and groundwater recharge, as well as the temperature of the resource

(IPCC, 2013).[3] These changes could manifest themselves in several ways, including reduced snowpack and the timing of snowmelt, a rise in sea level, higher rates of evaporation, more frequent and widespread droughts, downpours and heat waves. With continued population and economic growth and deteriorating water quality (both from physical and thermal pollution), a changing climate is set to place further constraints on a finite resource.

Box 9.1 ▷ Glossary of energy and water terms

Surface water: Natural water in lakes, rivers, streams or reservoirs.

Groundwater: Water that is below the land surface in pores or crevices of soil, sand and rock, contained in an aquifer.

Aquifer: Large body of permeable or porous material situated below the water table that contains or transmits groundwater.

Freshwater: Water with less than 1 000-2 000 parts per million (ppm) of dissolved salts.

Non-freshwater resources: Includes brackish or saltwater; urban or industrial wastewater (with or without treatment); and agricultural drainage water. Also referred to as alternative or non-conventional water resources.

Renewable water resources: Total amount of surface and groundwater resources generated via the hydrological cycle.

Non-renewable water resources: Deep aquifers that have minimal rate of recharge during an average human life-time.

Water stress: Defined as when renewable annual freshwater water supplies fall below 1 700 cubic metres (m^3) per person; *water scarcity* is below 1 000 m^3 per person; and *absolute scarcity* below 500 m^3 per person.

Water withdrawal: The volume of water removed from a source; by definition withdrawals are always greater than or equal to consumption.

Water consumption: The volume 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 treatment: Process of removing contaminants from water or wastewater in order to bring it up to water quality standards and for storage in freshwater reservoirs.

Desalination: Reducing the contents of total dissolved solids or salt and minerals in sea or brackish water.

3. For more analysis on the impact of rising temperatures on energy production, see *Redrawing the Energy-Climate Map 2013: World Energy Outlook Special Report*.

Water distribution: Delivery of treated water to the customers via distribution networks (pumping, pressurising, storing and distributing).

Wastewater treatment: Involves collection (pumping, transporting sewage), treatment (primary, secondary, tertiary) and discharge.

Re-used water treatment: Processes related to re-using or recycling the not discharged, treated wastewater effluent (conventional tertiary treatment, membrane treatment).

9.1.2 Water demand by sector[4]

The rate of demand growth for water has been double the rate of population growth over the last few decades. Over the next 25 years, water withdrawals are expected to increase by almost 10% from 2014 levels, while consumption rises by over 20% over the same period.[5] Regional patterns of withdrawals and consumption can vary widely, depending on how economies are structured. Irrigated agriculture accounts for more than 40% of the world's crop production (WWAP, 2012). Irrigated agriculture is already the world's largest water user, accounting for roughly 70% of total global freshwater withdrawals and up to 85% in some developing countries, although its share of withdrawals is projected to fall back slightly over the period to 2040 (Figure 9.1). Agriculture is also responsible for the bulk of water consumption, stemming from evaporation from land surfaces during irrigation and transpiration from plants.

Withdrawals to meet municipal water demand accounted for 13% of the total in 2014 and are projected to rise to 17% in 2040. Three-fifths of the increase comes from three regions: India, Africa and other developing countries in Asia (excluding China). The levels of consumption in the municipal end-sector are lower, accounting for 5% of total global consumption in 2014. Future trends will be shaped by growing urbanisation and rising standards of living, as changes in dietary preferences and more demand for goods require increasing quantities of water. Additionally, over 650 million people, primarily in sub-Saharan Africa, lack access to an improved source of drinking water and 2.4 billion do not have access to improved sanitation (United Nations Children's Fund/World Health Organization, 2015). One of the UN Sustainable Development Goals (SDG 6) is to ensure the availability and sustainable management of water and sanitation for all. The pursuit of this goal, to provide improved access to drinking water for the remaining 10% of the global population without adequate supply and improved sanitation for the one-third that lacks it, could increase domestic demand, and the energy and infrastructure necessary to provide such services.

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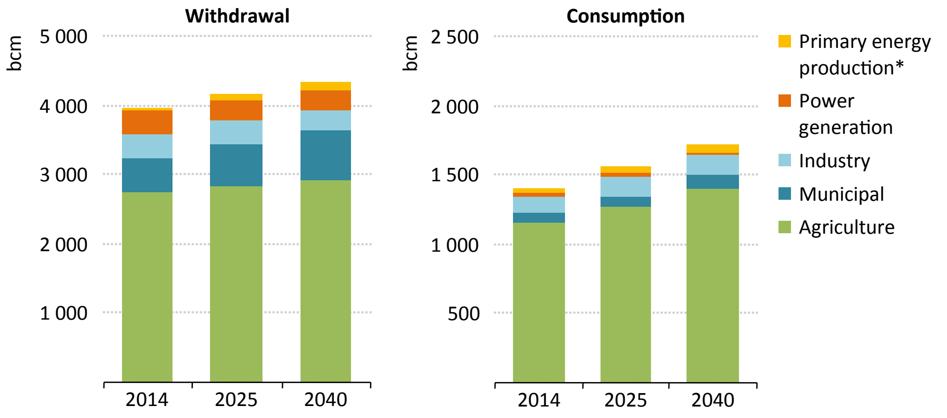
4. Analysis in this chapter focuses on freshwater use. While non-freshwater sources are already being used, either to replace or complement freshwater, in many places the use of alternative sources is at a nascent stage or is not yet economic, relative to freshwater.

5. See Box 9.2 for information on the methodology and source of our projections for water withdrawals and consumption.

Figure 9.1 ▷ Global water demand by sector to 2040



Agriculture remains the primary source of global water demand, but other sectors gain ground

* Primary energy production includes fossil fuels and biofuels.

Notes: bcm = billion cubic metres. Water withdrawals and consumption for crops grown as feedstock for biofuels is included in primary energy production, not in agriculture. See Box 9.2 for a detailed description of the methodology used to project water availability and demand.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Almost 10% of global water withdrawals in 2014 were for industry (excluding the energy sector). In advanced industrial nations, industry accounts for 12% of water withdrawals, whereas in many developing countries, industry accounts for less than 8%. Water is used in industry for processing, but also for fabricating and washing. Industry is the second-largest water consuming sector (after agriculture), its share projected to stay steady around 8% to 9% over the *Outlook* period. The energy sector, including power generation and primary energy production, is often included in the industry sector in analyses of water use. Energy is considered separately here (and in detail in the next section), an approach which shows that, in 2014, primary energy production and power generation accounted for roughly 10% of total worldwide water withdrawals and around 3% of total water consumption.

9.2 Water for energy

9.2.1 Overview

Water is an important input for nearly all forms of energy. Within the energy sector, the power sector is by far the largest source of water withdrawals, although in terms of consumption, primary energy production is larger (Table 9.1). Global aggregates, provided here, give invaluable overall guidance; but assessment of the impact of withdrawals and consumption, in terms of water stress or competition with other users, naturally needs to be very location specific (see section 9.4.1 for regional profiles). Even those parts of the energy sector with very low water needs in a global context can have major local implications, and vice versa.

Table 9.1 ▷ Energy-related water withdrawals and consumption, 2014

	Withdrawal (bcm)	Share of total energy water withdrawals	Consumption (bcm)	Share of total energy water consumption
Power	**350**	**88%**	**17**	**36%**
Fossil fuels	230	58%	13	28%
Nuclear	112	28%	4	8%
Renewables*	9	2%	1	1%
Primary energy production	**47**	**12%**	**30**	**64%**
Coal	11	3%	10	22%
Oil	8	2%	6	13%
Conventional	7	2%	6	12%
Unconventional	1	0%	1	1%
Natural gas	2	0%	2	3%
Conventional	1	0%	1	2%
Unconventional	1	0%	1	1%
Biofuels**	26	7%	12	25%
Total	**398**	**100%**	**48**	**100%**

* Renewables includes bioenergy, geothermal, concentrating solar power (CSP), solar photovoltaics (PV) and wind.
** Refers to irrigated crops grown as feedstock for biofuels.

Notes: Estimates of water requirements for energy production are based on the application of published water withdrawal and consumption factors. These factors are applied in each WEO region by fuel type and electricity generating (and cooling) technology. More information on the water factors used and key assumptions are at *www.worldenergyoutlook.org/resources/water-energynexus/*. Hydropower is not included in the estimates presented here (see power sector section below for further details).

Power sector

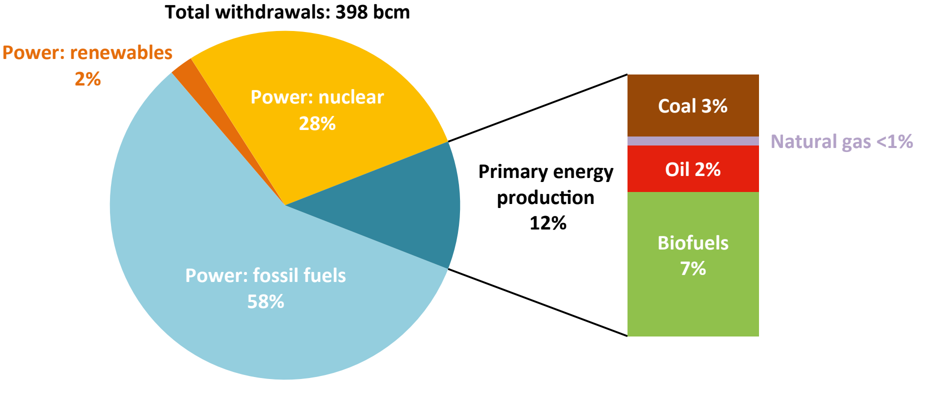
Thermal power plants[6] made up 70% of total installed capacity worldwide in 2014 and are the main source of water demand in the power sector (Figure 9.2). The power sector withdraws significant amounts of water – mostly from surface water sources – after which much of it is returned (often at a different temperature [thermal pollution]). While several factors, such as the fuel mix, the power plant's role in the electricity system (i.e. baseload or peaking), turbine design and weather influence the amount of water required, the type of cooling technology used is a key determinant of how much freshwater is withdrawn and ultimately consumed and the overall efficiency of thermal power plants (IEA, 2012a; IEA, 2015).

There are three main types of cooling technologies – once-through[7], wet-tower[8] and dry cooling. There are trade-offs associated with each in terms of water withdrawals versus

6. Includes coal, natural gas, oil, nuclear, geothermal and CSP.
7. Once-through is also referred to as open-loop cooling.
8. Wet-tower is also categorised as a closed-loop or wet re-circulating system. Cooling pond is another system in this category.

consumption, capital costs, energy penalties and impacts on water quality. In general, once-through technologies are the most efficient and have the lowest capital cost requirements, but have the highest withdrawal rate; wet-tower technologies withdraw less water, but consume more. Dry cooling on the other hand uses very little water, but is more expensive and has the lowest efficiency. For example, a 400 megawatt (MW) coal-fired dry cooled power plant, compared to once-through, has an energy penalty in the range 4-16% depending on the plant and conditions (Carney, 2011). Dry cooling and hybrid cooling (a mix of wet and dry cooling systems offering greater flexibility) may be more widely deployed in the future, spurred by regulation or competition for water. These systems, while proven technologies, often are not cost competitive when water is free and widely available (King, 2014).

Figure 9.2 ▷ **Water withdrawals in the energy sector, 2014**

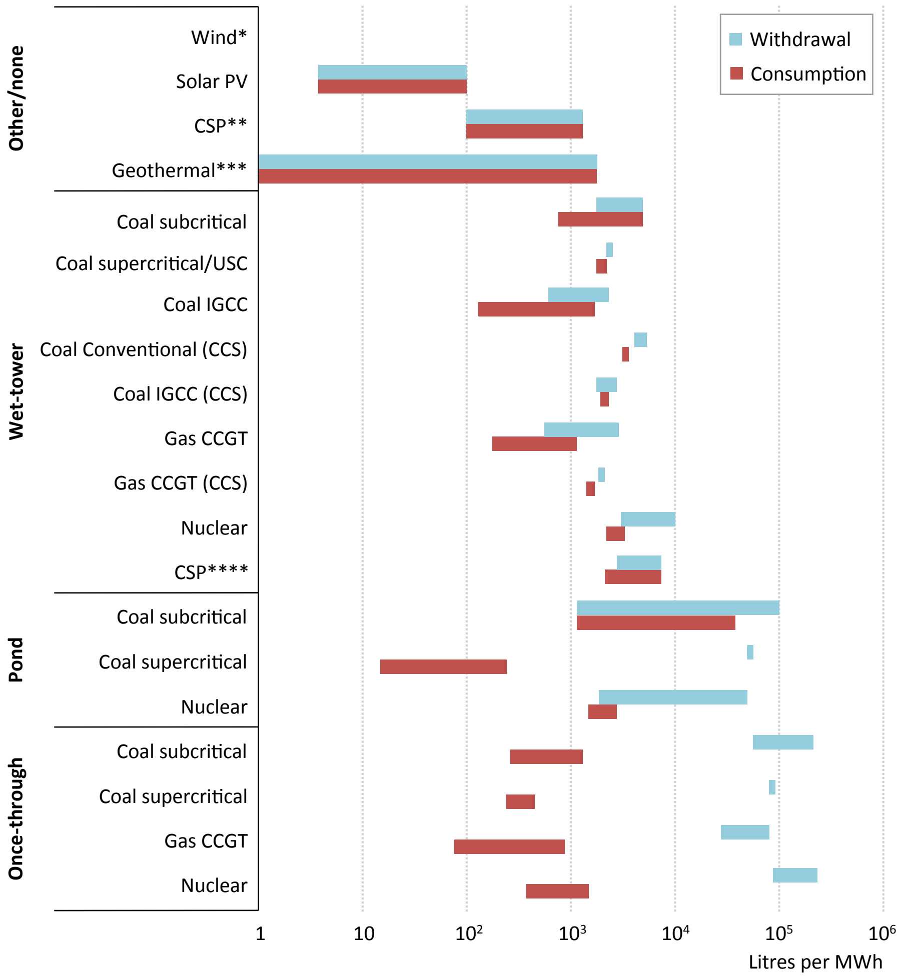


Power generation is by far the largest source of energy-related water withdrawals

Notes: Renewables includes solar PV, CSP, wind, geothermal and bioenergy. Water requirements are quantified for "source-to-carrier" primary energy production (oil, gas, coal), a definition which includes extraction, processing and transport. Water withdrawals and consumption for biofuels account for the irrigation of dedicated feedstock and water use for processing. For electricity generation, freshwater requirements are for the operational phase, including cleaning, cooling and other process related needs; water used for the production of input fuels is excluded. Hydropower is excluded.

When comparing the same cooling systems, nuclear power plants on average withdraw more water per unit of energy than coal or natural gas plants, in part because they have large cooling needs and cannot dismiss heat directly into the atmosphere. Combined-cycle gas turbines (CCGT) on the other hand, have some of the lowest rates of water withdrawals and consumption among thermal power plants, as they require less cooling and have a higher thermal efficiency, thereby generating less heat and needing less water (Figure 9.3).

Figure 9.3 ▷ Water use for electricity generation by cooling technology



The intensity of water use varies widely across the power sector

* The amount of water used during operation is minimal and does not register on this chart. ** Includes trough and tower technologies using dry and hybrid cooling systems. *** Includes binary, flash and enhanced geothermal system technologies using tower, dry and hybrid cooling. **** Includes trough, tower and Fresnel technologies.

Notes: Solar PV= solar photovoltaics; CSP = concentrating solar power; USC = ultra-supercritical; IGCC = integrated gasification combined-cycle; CCGT = combined-cycle gas turbine; CCS = carbon capture and storage. Ranges shown are for the operational phase of electricity generation, which includes cleaning, cooling and other process related needs; water used for the production of input fuels is excluded. Ranges are based on estimates summarised from the sources below. Ranges for supercritical coal are also used for ultra-supercritical coal technologies. This chart is a representative sample of technologies; see *www.worldenergyoutlook.org/resources/water-energynexus/* for a more detailed list including the numerical averages of each technology.

Sources: Meldrum (2013); Macknick (2011); Sprang (2014); NETL (2011); US DOE (2006); IEA analysis.

A common assumption is that switching to a lower carbon pathway would reduce water requirements. However, the use of clean energy technologies can increase or decrease water demand depending on the technology employed. For example, solar PV and wind do not require heat to make electricity and so consume little or no water during operation (some water is needed to clean solar panels). Renewable energy sources that use heat to drive a steam cycle, such as CSP and geothermal, often use water for cooling. Depending on the cooling technology, CSP's water withdrawals and consumption can be of the same order as conventional power plants. This can be problematic for CSP, as the best locations are often in arid areas with water supply constraints. Enhanced geothermal systems, depending on the location of the resource, can require water to be injected in order to power the steam cycle. While some of the water can be recaptured and reinjected to form a closed-loop system, geothermal systems can experience significant losses, resulting in elevated levels of consumption, compared with other thermal power plants. Carbon capture and storage (CCS) equipment, which carries high expectations as a way to extend the use of fossil fuel-based power plants, reduces carbon-dioxide (CO_2) emissions but can almost double a plant's water withdrawals and consumption, depending on the cooling technology used.

Hydropower relies on water passing through turbines to generate electricity, while also serving as a major source of global energy storage. A majority of the water withdrawn is returned to the river; however, hydropower's water consumption varies depending on a range of factors such as technology type (reservoir versus run-of-river), reservoir size, climate, engineering and amount of demand from end-users (such as agriculture and recreation). The amount consumed is highly site-specific and the measurement methodology is not agreed upon. Because of this, we do not present ranges for water withdrawals and consumption for hydropower.

Primary energy production

Water needs for energy production vary widely, depending on the fuel and the phase of the fuel cycle (extraction, processing and transport) (Figure 9.4). Water is a critical input for crops used for biofuels, which are the largest source of water withdrawals and consumption for primary energy production. The scale of water use for biofuels depends on whether or not crops are rain-fed or irrigated.[9] For irrigated crops, the total water use depends on the type of feedstock, regional climate and production technology used (Wu, et al., 2014). It is estimated that roughly 2% of total water for irrigation is used for producing biofuels (WWAP, 2009). However, there remain significant opportunities to improve efficiency and reduce water demand. For example, the provision of energy subsidies to farmers often has the unintended consequence of encouraging farmers to use water inefficiently and pump aquifers at an unsustainable rate (WWAP, 2012).[10] Advanced biofuels currently rely

9. In our analysis we only consider freshwater used for irrigation of biofuel feedstocks, often referred to as blue water, and do not include soil moisture from rainwater (green water).

10. See *India Energy Outlook 2015: World Energy Outlook Special Report* for a discussion of energy subsidies and agriculture in India.

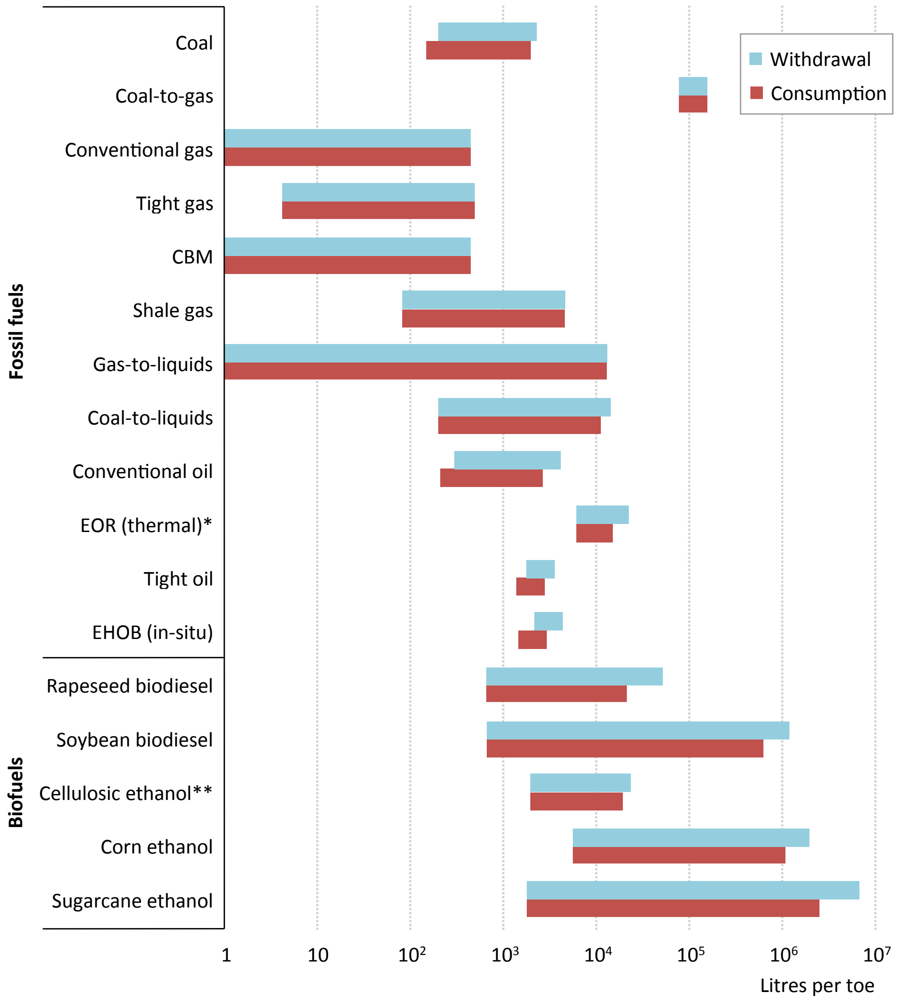
primarily on waste products (agricultural, food and municipal waste); and in this case the water use is attributed to the primary objective. However, should there be a shift towards dedicated crops for advanced biofuels, water use for energy could increase. In addition to concerns about water quantity, there are also concerns about the impact on quality, due to the potential run-off of effluent, which can contain high levels of fertilisers and pesticides, and soil erosion which can pollute waterways. Water is also required for the biofuel conversion process and refining. Compared with oil and gas, biofuel refineries need significant amounts of water, mostly in the form of steam for fermentation.

Water use for coal production comes primarily from activities associated with mining, with variance in quantity between surface and underground mines and according to the depth, geology, and width of the coal seam and the energy content of the coal. Some mines need to be de-watered before production can begin; if the water is re-used, it can supplement or reduce the amount of freshwater required, though it is often highly contaminated and requires treatment. Depending on the quality and the destination, coal may be washed to improve its quality and the efficiency of its transport and use. There are concerns about the impact of coal mining on water quality, the potential for run-off or drainage, spills from settling ponds, discharge of produced water and contamination of surface or groundwater sources by mine tailings.

Water needs for the production of conventional oil depends on the technology used, the geology of the field and the extent of secondary recovery. Water injection as a means to improve oil recovery, can require significant volumes of water, as much as ten-times more than primary recovery, depending on the technique. Production of extra-heavy oil, such as oil sands, is also water intensive, both for surface mining and steam-assisted gravity drainage (SAGD), where steam is used to make heavy oil flow (although SAGD is generally less water intensive than surface mining). The amount of water needed for extraction of conventional natural gas is minor compared to other fossil fuels.

Unconventional oil and gas production that requires hydraulic fracturing, such as tight oil and shale gas, are not necessarily more water intensive than their conventional counterparts per unit of energy produced. If water injection is being used to enhance recovery, then conventional oil can be in a comparable range to tight oil. The water requirements for shale gas are slightly higher than those of conventional gas, given the additional water required for fracturing. The water needs of an individual unconventional gas well depends on the extent of the reservoir, the depth and thickness of oil and gas-bearing layers, the productivity of the well, the number of fracturing stages and the quantity of flow-back recycled (Clark et al., 2013). While the water demand for each individual well is small, the cumulative requirements, depending on the scale of operations and the frequency of drilling, must be considered against other regional variables, such as water availability and the seasonality of flows, competing uses, the geology and population growth (IEA, 2012b).

Figure 9.4 ▷ Water use for primary energy production



Crops used for biofuels can have high water intensities

* See the *WEO*'s water-energy website for water use for EOR-CO_2, EOR-chemical and EOR-other gas, *www.worldenergyoutlook.org/*resources*/water-energynexus/*. ** Excludes water use for crop residues allocated to food production.

Notes: CBM = coalbed methane; EOR = enhanced oil recovery; EHOB = extra-heavy oil and bitumen. Ranges shown are for "source-to-carrier" primary energy production, which includes withdrawals and consumption for extraction, processing and transport. Water use for biofuels production varies considerably because of the differences in irrigation needs and methods among regions and crops; our analysis considers only the water used for irrigation and excludes rainwater. The minimum for each crop represents non-irrigated crops whose only water requirements are for processing into fuels. This chart is a representative sample of fuels; see *www.worldenergyoutlook.org/resources/water-energynexus/* for a full list, including the numerical averages of each fuel.

Sources: Schornagel (2012); Olsson (2015); US DOE (2006); IEA analysis.

Public concerns about water use for unconventional oil and gas have centred on the potential for increased competition for water in water-stressed areas and the risk of contamination of aquifers from fracturing operations or from gas and chemical interactions with shallower groundwater formations. They also include the treatment and disposal of wastewater, either from extracted formation water (as in coalbed methane extraction) or flow-back water and drilling/fracturing liquids.[11] Appropriate regulation and adherence to best practices for lifecycle management of water can reduce the quantities of freshwater required, reduce environmental risks and decrease disposal costs. There are alternatives to water for fracturing, as well as foams that can reduce water use by up to 90%. But for the moment, the non-water alternatives all have their own drawbacks: for example, propane has been used as a fracturing fluid, but is flammable and so requires extra safety precautions. Using foams can reduce water usage but involves higher volumes of chemicals and is less effective. Fracturing can also be done with non-fresh water resources, but accessing these resources involves additional cost and the industry has thus far generally preferred to focus on improved management of other sources of water, such as recycling and re-use.

Refining, which combines thermal and chemical processes, also requires water either as a direct input or for cooling to turn oil and natural gas into end-use products. The total use will depend on the complexity of the refinery, the type of cooling system and the extent of re-use and recycle.

9.2.2 Future water requirements for energy production

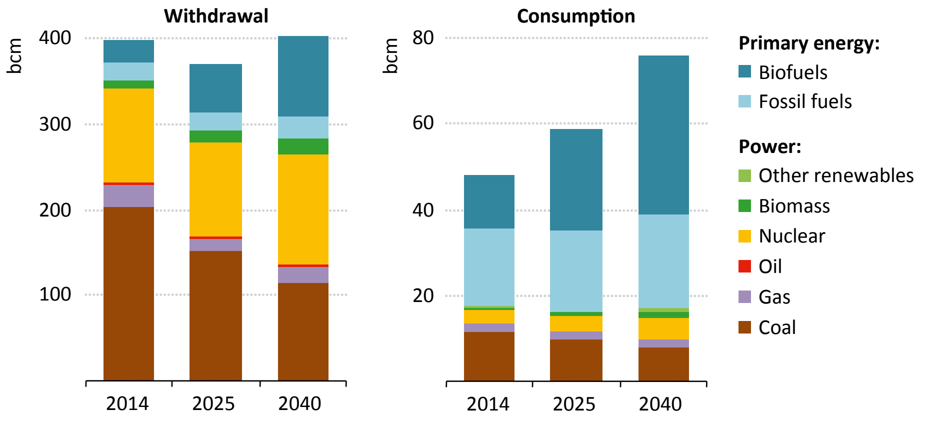
Water is a potential chokepoint for energy, but the risks are not shared evenly across the sector or across the world. In the New Policies Scenario, global freshwater withdrawals in the energy sector rise from 398 billion cubic metres (bcm) in 2014 – less than the mean annual discharge of the Mekong River (475 bcm) – to just over 400 bcm in 2040. Consumption increases from 48 bcm, roughly 12% of energy-related water withdrawals in 2014, to over 75 bcm (Figure 9.5). The power sector continues to account for the majority of water withdrawals in the energy sector, though its share declines with time. Primary energy production is responsible for almost two-thirds of energy sector water consumption today, a share that continues to rise to 2040.

Water withdrawals increase by roughly 1.5% by 2040, but the rise is not a steady one. In the first part of the *Outlook* period, water withdrawals decline temporarily, as the retirement of less efficient subcritical coal plants and the deployment of more supercritical and ultra-supercritical coal plants, pushes down withdrawals. These reductions are partly offset by increased withdrawals for nuclear power and biofuels production. After 2025, power sector withdrawals roughly stabilise, but demand for biofuels in the transport sector, which grows

11. Concerns include the potential for increased seismic activity associated with hydraulic fracturing and deep aquifer disposal of wastewater. See Chapter 6 in *World Energy Outlook-2015* for more on key public concerns associated with unconventional gas production.

on average by 3.5% per year in the period 2025-2040, pushes overall withdrawals higher. While the fuels and technologies that drive water withdrawals from the energy sector shift, overall growth is slow, rising on average less than 0.1% per year. By contrast, the average annual growth rate of water consumption over the projection period is 1.8% reflecting the shift in the power sector towards more consumption-intensive technologies, increased biofuels supply for transport and, to a lesser extent, increased fossil-fuel production.

Figure 9.5 ▷ Global water use by the energy sector by fuel and power generation type in the New Policies Scenario, 2014-2040



Energy-related water withdrawals rise by less than 2% to 2040, but consumption rises by almost 60%

Note: Other renewables includes wind, solar PV, CSP and geothermal.

Non-OECD countries account for most of the global increase in energy-related water withdrawals and consumption, mirroring the trends in global energy demand (Table 9.2). In the OECD countries, total water withdrawals fall by almost a quarter between 2014 and 2040, the average annual rate falling faster than energy demand. In non-OECD countries, however, water withdrawals rise by 35%. In terms of consumption, the increase in non-OECD countries is over 30-times greater than in OECD countries, where consumption stays relatively stagnant over the course of the projection period.

The United States, which accounts for 40% of OECD electricity generation, accounts for almost two-thirds of both water withdrawals and consumption in the energy sector in the OECD as coal and nuclear power are key power generators in the United States. The US' share of the OECD's withdrawal and consumption remains steady to 2040. In the non-OECD, Asia accounts for half of water withdrawals in 2014 and 60% of consumption. By 2040, Asia accounts for over 55% of withdrawals and almost 70% of consumption. Within Asia, India overtakes China to become the largest source of energy-related water demand, as its coal demand more than doubles and the production of biofuels for transport rises.

Table 9.2 ▷ Energy-related water withdrawals and consumption in the New Policies Scenario (bcm)

	Withdrawal				Consumption			
	2014	2025	2040	2014-2040*	2014	2025	2040	2014-2040*
OECD	**215**	**182**	**159**	**-1.1%**	**21**	**24**	**22**	**0.1%**
Americas	165	140	121	-1.2%	16	18	17	0.3%
United States	141	121	103	-1.2%	14	17	15	0.2%
Europe	46	38	35	-1.0%	5	4	4	-0.5%
Asia Oceania	4	4	4	-0.4%	1	1	1	0.4%
Non-OECD	**182**	**186**	**244**	**1.1%**	**26**	**35**	**54**	**2.8%**
E. Europe/Eurasia	68	61	60	-0.5%	4	4	4	0.3%
Asia	92	101	140	1.6%	15	23	37	3.4%
China	45	43	55	0.8%	11	11	15	1.3%
India	35	47	68	2.6%	3	9	20	7.3%
Middle East	3	4	5	1.8%	2	2	3	1.9%
Africa	6	5	11	2.5%	1	2	2	1.8%
Latin America	13	15	28	2.9%	4	4	7	2.5%
World	**398**	**369**	**403**	**0.1%**	**48**	**59**	**76**	**1.8%**
European Union	51	42	39	-1.0%	4	4	4	-0.6%

* Compound average annual growth rate.

Note: Table includes withdrawals and consumption for the power sector and primary energy production.

Power sector

Though the power sector remains the largest source of energy-related water withdrawals in the New Policies Scenario, at over 280 bcm in 2040, they are almost 20% lower than today. Water consumption, on the other hand, stays steady at 17 bcm; but the source of consumption shifts. There are several factors at work here, starting with the changes that take place in the power mix in different regions. A trend that affects water use is the lower share of coal-fired generation in the global mix, although the implications for water withdrawals and consumption depend on the particular fuels or technologies that take its place. In the United States, for example, coal-fired power generation declines by around 40%, and water withdrawals for the power sector decrease by over 30%. Although some of the fastest growing sources of generation in the United States are solar PV and wind, which are much less water intensive than coal, some coal-fired generation is replaced by geothermal and nuclear, which are also water dependent. Another feature is the increase in the use of non-fresh water sources for cooling, especially for coal-fired power plants in China and the United States. There is also an increase in the average level of efficiency of the global coal fleet, reflecting the retirement of less efficient plants and the increase in power generation from more efficient designs (see Chapter 5). For example, although China's coal-fired electricity generation increases by 4% from 2014 to 2040, water withdrawals for those plants decline by almost 40% (14 bcm). This is, in part, due to the increase in the average efficiency of China's coal-fired power plants (by four percentage points), which reflects the decline in the share of coal-fired generation from less efficient subcritical power plants from almost 60% to just over 10%.

The shift away from coal-fired generation using once-through cooling systems lowers water withdrawals; but the rising deployment of more efficient coal-fired power plants using wet-tower cooling systems tempers the rate of decline in water consumption; global water consumption by coal-fired power plants decreases at a much slower average annual rate than withdrawals (-1.5% versus -2.2%) and in 2040 still accounts for almost one-out-of-two units of water consumed by the power sector. As well, electricity generation from nuclear power plants almost doubles, with the majority of plants relying on once-through cooling systems. As a result, water withdrawals for nuclear plants increase by almost 20%, as growth in water withdrawals from nuclear generation in non-OECD countries offset the decline (-10%) in OECD countries.

Primary energy production

In the New Policies Scenario, water withdrawals for primary energy production also grow at a faster average annual rate than consumption. By 2040, water withdrawals are two-and-a-half times higher than in 2014, reaching 120 bcm, while consumption roughly doubles (to reach 60 bcm). Of the primary fuels, biofuels are by far the largest source of demand for both water withdrawals and consumption, accounting for 80% of water withdrawals for primary energy production and over 60% of water consumption in 2040. Whether to bolster energy security or as part of a decarbonisation strategy, policies that mandate an increase in the production of crops for biofuels, such as sugarcane, corn and soybean for ethanol and biodiesel, result in a steep rise in energy-related water demand. Even though India is projected to fall well short of its ambitious blending targets for biofuels, it helps propel the increase in water withdrawal and consumption for biofuels over the period to 2040, along with Brazil and China. Whereas China meets biofuel demand through a diverse set of feedstocks, India relies primarily on sugarcane for producing bioethanol, which requires significant amounts of water.

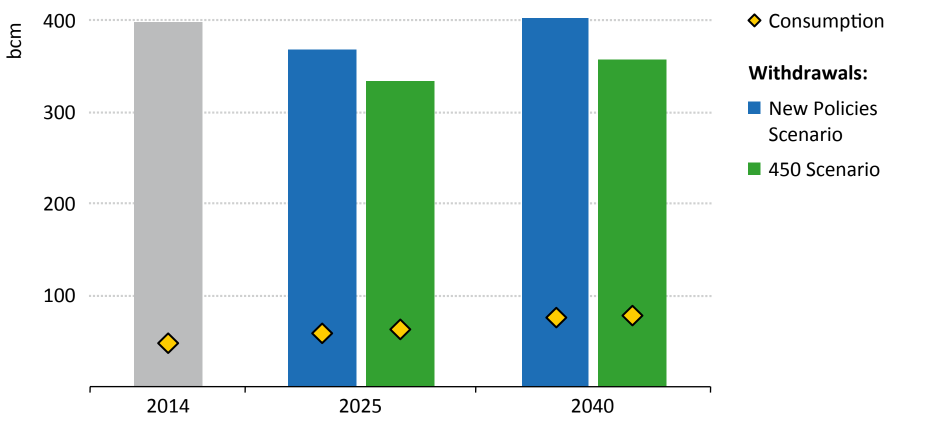
Among the fossil fuels, the production of coal requires the most water. Global coal production grows only modestly to 2040 in the New Policies Scenario, with China maintaining its role as the largest coal producer in the world, even though India's production rises substantially (see Chapter 5). Water withdrawals for coal increase by 4%, to reach 12 bcm in 2040, while consumption reaches 11 bcm. More rapid increases in oil and gas output mean rates of faster growth in their water use. Withdrawals for oil production reach 11 bcm by 2040, while consumption increases by 30%, with the strongest growth coming from EOR (tertiary recovery) and unconventional oil. Natural gas-related water withdrawals and consumption remain relatively low, reaching roughly 3 bcm each by 2040. While unconventional gas accounts for 75% of the increase in water demand for natural gas, overall it is responsible for just 1% of total water withdrawals and 2% of consumption for primary energy production (including biofuels) in 2040, its withdrawals are almost ten-times less than coal and more than 70-times less than biofuels in 2040.

450 Scenario

In the 450 Scenario, annual water withdrawals for the energy sector decline to almost 360 bcm in 2040, a decrease of 10% over 2014, while water consumption rises to almost 80 bcm, over 60% higher than 2014. Relative to the New Policies Scenario, water withdrawals are more than 45 bcm or 12% lower, but consumption increases by 2 bcm (2%) (Figure 9.6). The divergence reflects the different demand trajectories, various fuels and technologies used in the power sector (including more CCS and CSP) in the 450 Scenario and greater reliance on biofuels in transport and other forms of bioenergy for power.

While the 450 Scenario provides significant environmental benefits, the suite of technologies and fuels used to achieve this reduction can, if not properly managed, exacerbate or introduce water stress, depending on the location, the availability of water and the range of competing users. Similarly, in some instances, a lack of water could act as a constraint on the technology suite available to pursue low-carbon pathways. The power sector is a good example of the potential trade-offs. While water withdrawals in the power sector in the 450 Scenario are 18% lower than in the New Policies Scenario by 2040, water consumption is more than 45% higher. Further improvements in the efficiencies of fossil-fuel power plants, along with a decided shift away from coal and natural gas towards more renewables, help to reduce CO_2 emissions, local air pollutants and water withdrawals; but, the reduction in water use is offset by the deployment in the power sector of other carbon-friendly, yet water-intensive technologies, such as nuclear, CCS and CSP. Some climate-minded policies can exacerbate existing water stress and policy-makers therefore need to assess and evaluate chokepoints. The potential stress does not apply across the board, but it does imply that plans for power developments using more water-intensive technologies will have to take current and future water availability into consideration in the choice of sites and cooling technologies, as well as seek to use alternative water sources, where possible.

Figure 9.6 ▷ Global water use by the energy sector by scenario



The energy mix of the 450 Scenario means lower withdrawals but higher consumption, compared with the New Policies Scenario

On the production side in the 450 Scenario, lower demand for fossil fuels reduces water withdrawals for coal, oil and natural gas production by 10 bcm compared with the New Policies Scenario. However, this decline is more than offset by a rise in water use for biofuels production. Global demand for biofuels more than doubles relative to the New Policies Scenario; as a result, water withdrawals increase by almost 15 bcm by 2040. By the end of the *Outlook* period, water consumption for biofuels is more than one-and-a-half-times greater than water consumption by the entire power sector in the 450 Scenario. The increased demand for biofuels in the 450 Scenario pushes crop production onto more marginal lands, especially in India, Southeast Asia and Europe, which can have greater irrigation needs (depending on factors including the location and soil type). Given the diversity of land that is classified as marginal land and the limited analysis conducted regarding the changes in water needs on marginal land, we did not increase the water intensities for production that occurs on marginal land in our analysis. As a result it is feasible that water use could be much higher. We also do not account for potential improvements in irrigation technologies, which could lower water requirements.

9.2.3 Impact of climate variability on hydropower

Hydropower has not been included in this analysis of water use thus far[12], but it accounts for 16% of today's global electricity production and provides energy storage. It also provides a highly visible example of the impact that water insecurity – either from short or medium-term drought, fluctuations in seasonal water availability or longer term impacts, like climate change – can have on generation. Several areas already bear witness to the impacts of water variability on hydropower. In the United States, California, Oregon and Washington are responsible for over half of the country's hydro generation. These states are also highly vulnerable to climate change and its potential effect on the snowpack. In California, drought reduced hydropower's share of the electricity mix by five percentage points in 2013, compared with the thirty-year average (Garthwaite, 2014). In the Colorado River basin, a 1% decline in precipitation reduces streamflow by 2-3% and a 1% decline in streamflow results in a 3% decline in power generation (US National Oceanic and Atmospheric Administration, 2009). In Zambia, which depends on hydropower for 95% of its electricity, a severe drought in 2015-2016 caused regular blackouts: the Kariba Dam, which generates more than 40% of the nation's power, has been operating at less than a quarter capacity, and in January 2016, capacity went as low as 11% (Onishi, 2016). Low water levels at Venezuela's Guri dam, which provides almost half the country's hydroelectricity, have resulted in nationwide power cuts throughout 2016. Brazil and Chile have also suffered from ongoing drought.

There remains significant uncertainty regarding the precise magnitude and location of the impacts of climate change and what changes in rainfall patterns might occur as a result. One possible outcome is more frequent and intense droughts and floods, changing the

12. See section 9.2.1 for a detailed explanation of hydropower's exclusion.

patterns of water flow over the year, straining reservoir management and altering the viability of hydropower. At a global level, the output from hydropower is not anticipated to change drastically, with hydro's share of generation remaining steady at 16% over the *Outlook* period in the New Policies Scenario, but there are likely to be significant regional variations, with some regions experiencing increased generation potential, while others see a reduction.

Hydropower in Latin America

The International Energy Agency, in partnership with MINES ParisTech, has conducted a sensitivity analysis to consider the indicative impact that two different pathways for future climate change – a severe one and a moderate one – might have on water availability and hydropower production in Latin America at a country or regional level.[13,14] Latin America was chosen as the focus since hydropower plays a large role in power generation there, accounting for 56% of power output in 2014.

The results of this sensitivity analysis indicate that the impacts of climate change on water availability over the next 25 years could vary substantially by country across Latin America (Figure 9.7). Overall, the change in annual water availability between the two pathways is large enough to suggest a potential decline in hydropower potential in some areas in the more severe case, such as in the Chilean and Argentine basins. Other regions such as Venezuela, southeastern Brazil or Colombia might expect an increase in annual water availability. In addition to changes in annual availability, the variability of seasonal streamflow is likely to change, affecting the need for inter-seasonal water storage. These changes are due not only to a change in precipitation patterns, but also from the retreat of glaciers in the Andes mountains, accelerated by climate change: it is estimated that the Andes glaciers have already lost between 20-50% of their surface area in the second-half of the 20th century (Albert, et al., 2014). In a region where hydropower is expected to remain the predominant source of electricity production, the impacts of climate change, despite the high levels of uncertainty, need to be considered in long-term energy planning.

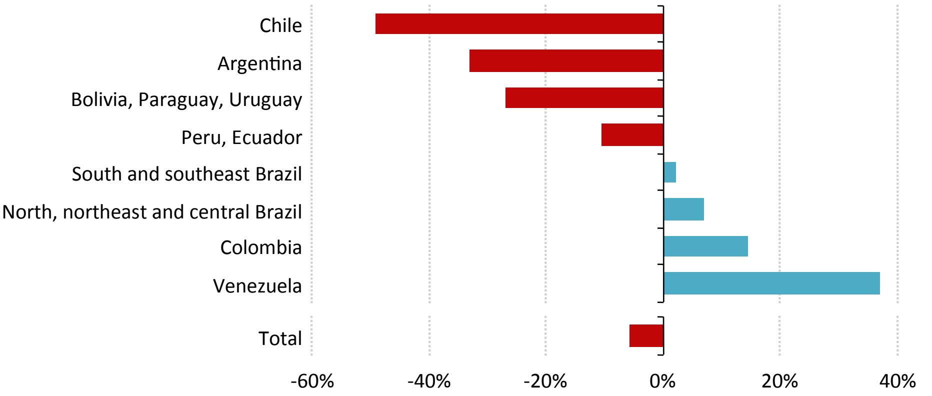
Given the level of the anticipated variability, both in terms of absolute annual supply and monthly hydrological patterns, and the uncertainties involved, how might the preference of decision-makers for different hydropower technologies (run-of-river versus reservoir) change in response to the potential risks posed by climate change? In this sensitivity

13. The hydrological scenarios used in this analysis rely on data provided by the World Resources Institute (WRI). Two climate pathways were derived from the standardised emission trajectories described by the Intergovernmental Panel on Climate Change (IPCC), Representative Concentration Pathways (RCP) 4.5 and RCP8.5. In the text, they are referred to as the moderate climate pathway (RCP4.5) and the severe climate pathway (RCP8.5). Compared with *WEO* scenarios, RCP4.5, which assumes a median temperature rise of 2.4 °C in 2100, is closest to our Intended Nationally Determined Contribution (INDC) Scenario contained in the *Energy and Climate Change 2015: World Energy Outlook Special Report*; RCP8.5, which assumes a temperature rise of 4.3 °C, is closest to our Current Policies Scenario. This sensitivity analysis is an additional case to the three core *WEO* scenarios.

14. At a watershed level, there is likely to be variability in conditions that are not captured here.

analysis, from now to 2020, run-of-river dams are the preferred technology choice in the region for several reasons. First, while these systems can be more expensive per megawatt-hour (MWh), they have shorter commissioning times than their reservoir counterparts, making them attractive to countries seeking to satisfy fast-growing electricity demand. Second, the development of large-scale reservoir dams is often subject to legal challenges on social and environmental grounds, making smaller run-of-river systems more politically and socially tenable (IEA, 2013). Run-of-river systems are most effective in areas of high annual levels of available water, with minimal variability in the monthly streamflow, as high levels of variability impact the reliability of these systems.

Figure 9.7 ▷ Difference in annual water availability between a severe and moderate climate pathway in Latin America in 2040



Annual water availability in Latin America could vary substantially between the two pathways

Notes: % change refers to the percent change in rainfall in a severe climate scenario, compared with a moderate climate scenario. Rainfall per region/country represents an average value for the area.

Source: Data provided by World Resources Institute.

Further into the future, the variability brought on by changes to the hydrologic cycle and the need for inter-seasonal regulation becomes an important reason to prefer reservoir systems, where possible, as they provide a way to adapt to changing conditions by storing water.[15] In this sensitivity analysis, most new reservoir dam investment occurs post 2025, due to the combination of high investment costs and long-lead times and a gradual improvement in the understanding of the risks posed by climate change and of the infrastructure that is best suited to deal with changes in the prospective climate conditions.

15. Environmental concerns and public opposition to large-scale reservoirs could continue, limiting future development. Another aspect in support of more reservoir systems is the contribution they can make to integrating variable renewable energy into power systems.

Both southeastern Brazil and Venezuela, under the severe climate pathway, see an increase in the total quantities of water available annually, but Venezuela also experiences an increase in variability. Given these anticipated changes, southeastern Brazil could see the installation of more run-of-river plants in a severe climate pathway than in a moderate one.[16] Whereas Venezuela, given the increased variability, might seek to build less run-of-river capacity, instead building more reservoir dams, if social and environmental constraints can be overcome, so that it can store water and counteract the variability. For countries that get drier under a severe climate pathway, such as Chile and Argentina, reservoir systems become less attractive, as they cannot ensure there will be enough water to generate electricity efficiently.

In either scenario, hydropower remains the primary source of electricity generation in the Latin America region and significant technical potential remains. The prospective changes to the region's hydrology suggest the potential for not only a shift in hydropower technology preferences to hedge against potential climate risks, which could be lesser or greater at a watershed level depending on the location, but also in technology choices across the power sector. Given the availability and potential of renewable resources in Latin America, other renewable energy resources could step in to compensate for any potential shortfall or impact from an increase in variability from hydropower generation. But the choice of renewable energy technology may be influenced by a shift in hydropower technology preferences; reservoir systems bring greater flexibility to the electricity sector, and so provide an easier avenue to integrate a larger share of variable renewables, e.g. wind and solar. Where there are readily available domestic resources, fossil fuels and nuclear could also play an increased role, especially given their reliability during dry months or seasons.

In addition to adapting hydropower technology and infrastructure, and diversifying the energy mix, other efforts can be undertaken to help shore up Latin America's ability to meet demand, despite potential changes to available energy supplies. The use of demand response mechanisms could help reduce overall electricity demand, temper demand at peak times and maintain grid stability, helping to offset some of the variability that changes to the hydrological cycle might bring. Additionally, greater network integration throughout the continent, while politically challenging, would allow countries to use resources elsewhere to help offset potential domestic disruptions, providing greater flexibility to accommodate increasing variability of hydropower output.

16. Given that a significant amount of existing hydropower potential in southeastern Brazil has been developed, the installation of additional capacity is constrained by remaining potential. However there is an increase in run-of-river installations in a severe scenario, relative to a moderate one, though it is small relative to the capacity already built.

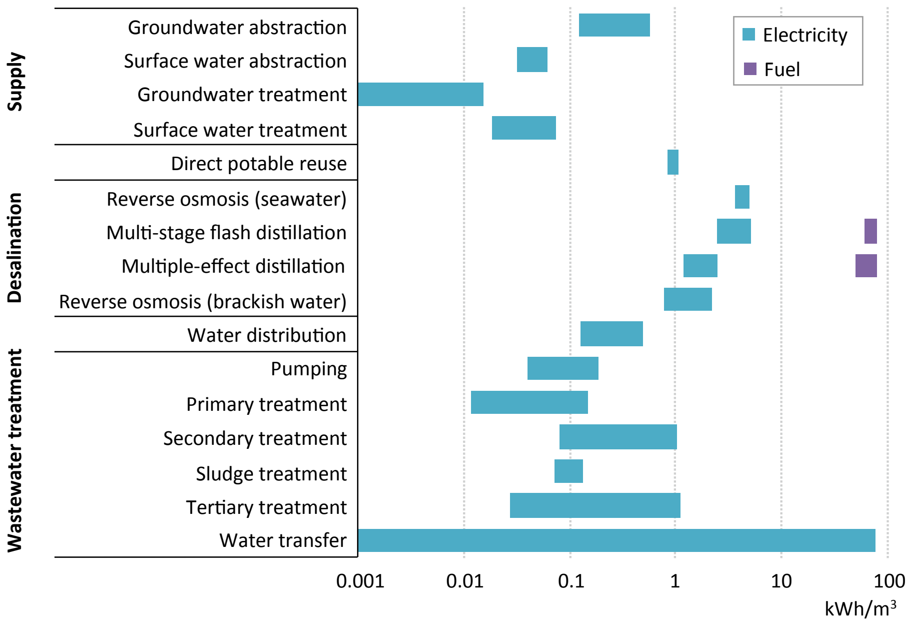
9.3 Energy for water

9.3.1 Overview

Not only does energy production need water, but water supply is also dependent on energy. The provision of freshwater from surface and groundwater sources or via desalination, its transport and distribution, and the collection and treatment of wastewater all require energy (Figure 9.8). The amount of energy required varies. It is influenced by a range of factors, such as topography, distance, water loss and inefficiencies, and the level of treatment necessary.

So far, there has been no systematic attempt to quantify the amount of energy consumed in the global water sector, or to examine how this might evolve in coming decades. To attempt such an assessment, we have combined estimates for water withdrawal and consumption with the energy intensities of each process in the water sector (Box 9.2).

Figure 9.8 ▷ Energy use for various processes in the water sector



Seawater desalination and wastewater treatment are the most energy-intensive processes in the water sector

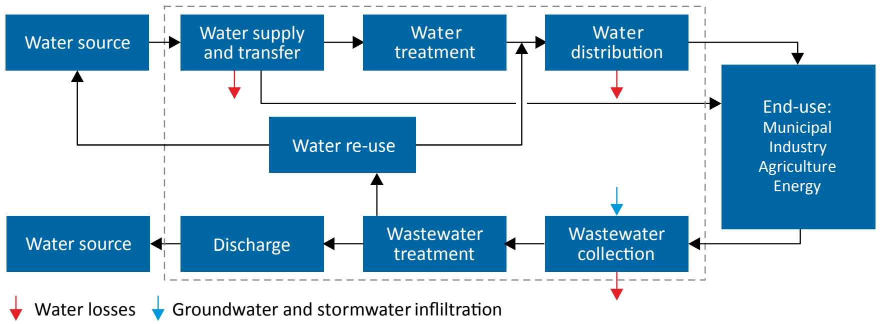
Notes: See Box 9.2 for more detail on methodology. See *www.worldenergyoutlook.org/resources/water-energynexus/* for the detailed list including the numerical averages for each process.

Sources: EPRI (2002); Pabi, et al. (2013); Jones and Sowby (2014); Plappally and Lienhard V (2012); Spooner (2014); Li, et al (2016); Japan Water Research Center (n.d.); (Choi, 2015); Miller, et al. (2013); Singh, et al. (2012); Noyola, et al. (2012); Liu (2012); DWA-Leistungsvergleich (n.d.); Caffoor (2008); World Bank Group, (2015); Fillmore, et al. (2011); Brandt, et al. (2010); IEA analysis.

Box 9.2 ▷ Quantifying the energy needs of the water sector

In order to estimate today's energy consumption in the water sector and project future developments, we have considered all the major processes in the water sector: water supply – including groundwater and surface water extraction; long-distance transport; water treatment; desalination; water distribution; wastewater collection; wastewater treatment and water re-use. Only energy consumption for processes whose main purpose is to treat/process or move water from or to the end-user has been included (Figure 9.9). For example, groundwater pumping to the farm gate is considered in our analysis, but energy consumption for irrigation systems in the field is excluded. Similarly energy used to heat water in households is excluded. The analysis has used the best available data and the results were calibrated against the available country studies; but significant data challenges remain, because of a lack of recorded, precise measurement of many of the processes involved. The result is a first comprehensive estimate of global energy consumption for water use, which is to be improved as more data becomes available.

Figure 9.9 ▷ Processes of the water sector



Energy is needed in each step of the water process

Notes: Water losses include leaks, theft, and water lost through legal usage for which no payment is made. The dashed line indicates the boundaries of our analysis.

Source: Adapted from Sanders and Webber (2012).

In the analysis, we have relied on water projections from the leading institutions in the field: projections for groundwater and surface water extraction, as well as water withdrawal and consumption for agriculture and by municipal sources and industry come from the World Resources Institute (Luck, Landis and Gassert, 2015), the University of Utrecht (Bijl, et al., 2016), the University of Kassel and the International Institute for Applied Systems Analysis (Wada, et al., 2016). For future levels of water withdrawals and consumption for power generation and primary energy production, we have used our own projections. In addition we have collected information on water losses, wastewater collection rates and treatment levels from various sources, including the OECD (2016), Eurostat (2016), GWI (2016) and the World Bank (2016).

To estimate the energy consumption of the water supply sector, we applied average energy intensities by region to each process. For this purpose, we undertook a review of the available literature and obtained feedback from leading researchers, as well as private companies active in this field.[17] For projections on desalination, we have relied on current capacity data from GWI (2016) and, for re-use, on FAO (2016). Current policies have been taken into account and the assumption made that countries of the Middle East and Africa will gradually reduce withdrawals from non-renewable sources towards the end of the projection period. In order to assess the energy-savings potential, we have carried out a review of relevant technology for all steps in water treatment and distribution, and wastewater facilities (including energy recovery).

Overall, we estimate that roughly 120 million tonnes of oil equivalent (Mtoe) of energy was used worldwide in the water sector in 2014, almost equivalent to the entire energy demand of Australia.[18] About 60% of that energy is consumed in the form of electricity, corresponding to a global demand of around 820 terawatt-hours (TWh) (or 4% of total electricity consumption), which is almost equivalent to today's electricity consumption in Russia (Figure 9.10). The rest is thermal energy, half of which is used in diesel pumps, mainly to pump groundwater for agricultural purposes. The remainder is used for desalination, mainly in the form of natural gas and almost exclusively in the Middle East and North Africa.

Of the electricity consumed, the largest amount is used for the extraction of groundwater and surface water (around 40%), followed by wastewater treatment (including collection) with 25%. In developed countries, the largest share of water-related electricity consumption (42%) is used for wastewater treatment. In developing and emerging countries, electricity use for wastewater treatment currently plays a lesser role, as a lower share of wastewater is collected and it is treated to a lesser degree, but this is expected to increase in the future. About 20% of electricity is used for water distribution to consumers. On a global level, desalination accounts for only 5% of the water sector's electricity use, but this share is far higher in the countries of North Africa and the Middle East. The remainder of electricity consumption is accounted for by large-scale inter-basin water transfers, freshwater treatment and water re-use.

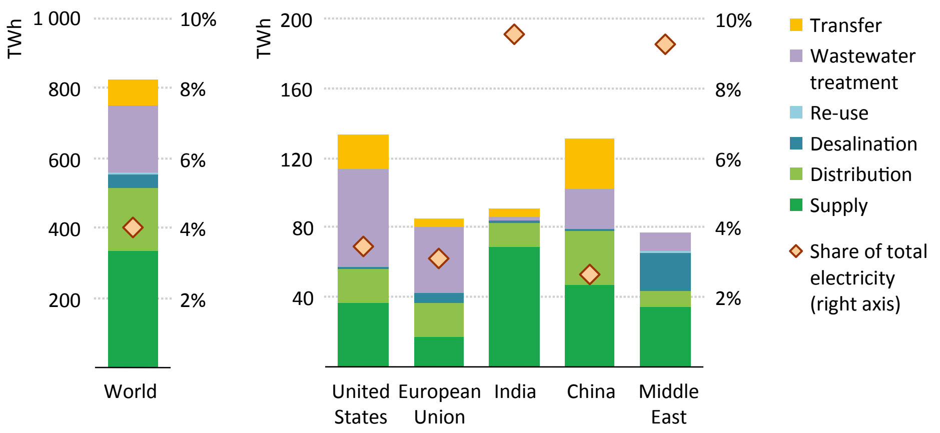
The United States consumes more electricity in the water sector than any other region or country, roughly 40% of electricity consumption in the water sector in the United States goes to wastewater treatment. China is a close second, accounting for over 15% of global

17. More information on the energy factors used and key assumptions can be obtained at www*.worldenergyoutlook.org/resources/water-energynexus/*.

18. This water-related energy demand is not additional energy demand, previously unaccounted for, but rather demand that is already included in various sector data and brought together for this analysis. For example, desalination in integrated water and power plants is accounted for under power generation, while stand-alone desalination plants are part of the services sector. Wastewater treatment is accounted for in the services sector or in industry if wastewater is treated in industrial facilities.

electricity needs in the water sector. The Middle East, where the water sector accounts for 9% of electricity consumption, is the only region where desalination accounts for more than a quarter of water-related energy consumption. Groundwater extraction in India accounts for almost 60% of the electricity consumed by the water sector as India is by far the largest user of groundwater, accounting for about 40% of global groundwater use.

Figure 9.10 ▷ Electricity consumption in the water sector by process and region, 2014



The water sector accounted for 4% of global electricity consumption in 2014

Notes: Supply includes water extraction from groundwater and surface water, as well as water treatment. Transfer refers to large-scale inter-basin transfer projects.

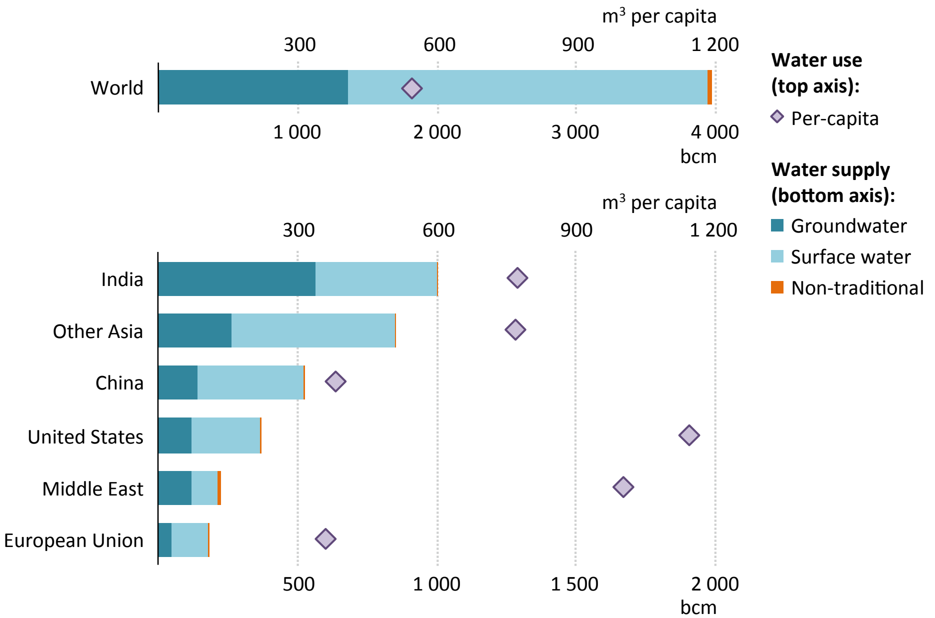
Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Water supply and transport

Energy is needed to extract water from lakes, rivers and oceans, and to lift groundwater from aquifers and pump it through pipes and canals to the treatment facility. The amount of energy required depends on the source (groundwater pumping is roughly seven-times more energy intensive than surface water extraction) and the distance and elevation that the water must travel before reaching the storage or treatment facility. Globally, surface water accounts for around two-thirds of all water withdrawals and groundwater for about a third (Figure 9.11). Non-traditional water sources (water re-use and desalination) currently satisfy less than 1% of all water needs.

Globally, water extraction is estimated to consume over 310 TWh of electricity per year and about 0.5 million barrels per day (mb/d) of diesel fuel. Almost half of global electricity for extraction is consumed in Asia, as this is the continent with the largest water use. India is the world's largest water user by far, partly due to inefficient irrigation in agriculture, and accounts for around a quarter of global water withdrawals, although per-capita use is well below that of the United States. Other developing Asian countries are also large water users, notably Pakistan, Indonesia, Thailand and Viet Nam. Some countries, such as India and Middle Eastern countries rely heavily on groundwater, which is reflected in their relatively high energy consumption. On the other hand, Europe, China and the United States meet their demand mainly from surface water.

Figure 9.11 ▷ Water supply by source by region, 2014



Two-thirds of global water withdrawals in 2014 were from surface water, with most of the remainder from groundwater

Notes: m³ = cubic metre. Non-traditional water includes water re-use and the desalination of seawater, as well as brackish water. Other Asia refers to other developing Asia.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

While in most countries water resources are sufficient at a country-wide level, the water is not always available where it is needed. Consequently, several countries have embarked on large-scale water transfer projects in order to make water available in water-stressed areas. We estimate that currently around 70 TWh of electricity are used for long-distance water transfer. The largest undertaking is China's South-North Water Transfer Project, with capacity projected to increase to 45 bcm per year by 2050. Another project is the State Water Project in California, which is 1 100 km long and serves roughly 25 million people a year. This is the single largest energy user in California, at 2-3 % of all electricity consumed in the state (Webber, 2016).

Water treatment

In a water treatment facility, energy is used primarily to pump and process water, and treat it to meet drinking water standards – the level of treatment depends mainly on the stringency of the standards required by the regulations in place. At the facility, contaminants, sediments and chemicals are removed using a process of mechanical screens and sedimentation. The water is then, typically, passed through a series of filters to a storage tank for disinfection (usually chlorination), before it is pressurised. It is estimated that globally, water treatment requires 65 TWh of electricity, of which pumping accounts for 80-85%. While the extraction of groundwater is much more energy intensive than that of surface water, the energy needs for its treatment are usually only a fraction of those for surface water, as it is typically less contaminated. In developing countries, surface water can be heavily polluted, requiring high levels of treatment and/or increasing reliance on groundwater resources.

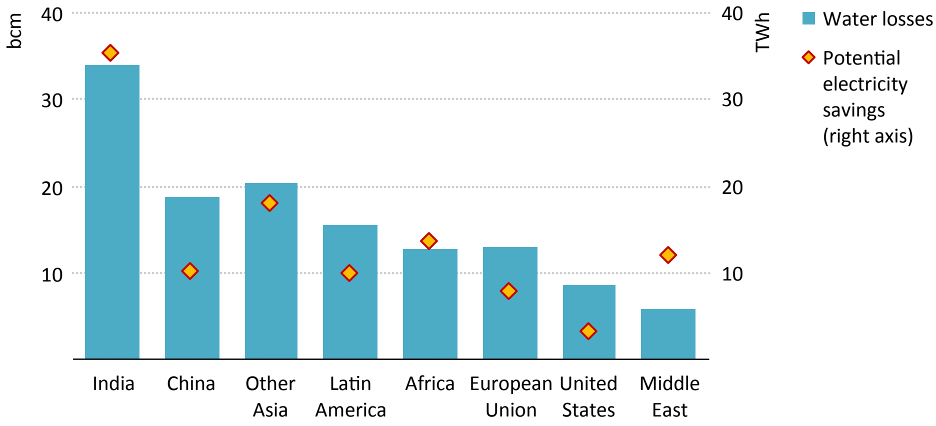
Water distribution

Pumping water from the treatment plant via a pressurised distribution system to the end-user consumes a large amount of energy. It is estimated that water distribution for public supply consumes globally about 180 TWh today, with its energy intensity varying enormously from one place to another, depending on elevation changes and pressure requirements.[19] Significant quantities of water are lost each day through pipe leaks, bursts and theft. Losses, theft and inaccurate metering plague developed and developing nations alike; water losses in public supply are estimated at 12% in the United States, 19% in China, 24% in the European Union and 48% in India. The highest volume of water is lost in developing countries in Asia, with India accounting for more than a fifth of worldwide losses in public water supply (Figure 9.12). Due to ageing pipes and insufficient levels of maintenance, volumetric losses are also high in the European Union, amounting to 13 bcm or almost equal to the entire water withdrawals of Korea.

Water losses entail a waste of energy that could be used for water extraction, treatment and distribution. Measures exist to reduce water losses, including pressure management, leakage control and replacement of infrastructure, but they are inadequately applied. If all countries reduced water losses to 6% (a level seen in the most advanced countries, including Denmark and Japan), 130 TWh, or the entire electricity needs of Poland, could be saved today (this includes avoided energy use in water extraction, treatment and distribution). The potential electricity savings are highest in India, where the electricity demand from the water sector could be cut by almost 40%. The gains in terms of electricity savings are particularly large where water production is energy intensive, as in the Middle East. Since diesel pumps are widely used for water extraction in developing nations, lower water losses would also reduce diesel consumption, by an estimated 0.12 mb/d.

19. In some countries, low water pressure in the public supply requires households to use booster pumps. The energy use for such pumps is not included in the analysis.

Figure 9.12 ▷ Water losses by region, 2014



Huge water losses in distribution networks represent both wasted water and wasted energy

Note: Other Asia refers to other developing Asia.

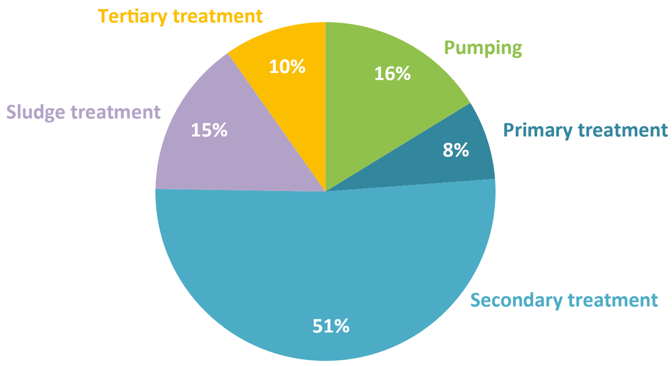
Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Wastewater treatment

After water is used by consumers, energy is required to collect, transport and treat it so that it can be safely discharged to minimise adverse environmental and human health impacts. Globally, wastewater treatment consumes about 200 TWh or 1% of total energy consumption. In developed countries, wastewater treatment is the largest energy consumer in the water sector. Similarly the energy needs for wastewater treatment can be very important at the local level. For some municipalities, the energy consumed by water and wastewater utilities can account for 30-50% of their energy bill (United States Government Accountability Office, 2011). Five factors influence the energy consumption for wastewater treatment: the share of wastewater collected and treated; the level of groundwater infiltration and rainfall into the sewage system; the treatment level; the contamination level; and the energy efficiency of the operations.

It is estimated that today over 35% of municipal wastewater is not collected, a figure that can be as high 60-95% in developing countries. In addition, wastewater might be collected but subsequently treated insufficiently. This represents not only a threat to human health and the environment but also means that there is significant upside potential in energy demand should more wastewater be collected and thoroughly treated. The intake at wastewater treatment facilities often does not consist only of wastewater but also of rainwater and storm water run-off (in addition to infiltrated groundwater due to pipeline leaks). In the case of Germany, wastewater, strictly defined, accounts for only 50% of the water treated in wastewater treatment plants (BDEW, 2014). Reducing the water inflow that does not need treatment is one way to significantly reduce energy consumption.

Figure 9.13 ▷ **Typical energy consumption in a wastewater treatment facility**



Biological processes as part of secondary treatment dominate electricity use in wastewater treatment and collection

Sources: Based on WRF and EPRI (2013); Plappally and Lienhard (2012); IEA analysis.

Wastewater can undergo three treatment stages (primary, secondary and tertiary) before the water is discharged or re-used:

- *Primary:* Removal of solids via filters, screens, sedimentation tanks and dissolved air flotation tanks.
- *Secondary:* Biological processes to remove dissolved organic matter through techniques such as an aeration tank, trickling filter and activated sludge process, followed by settling tanks.
- *Tertiary (advanced treatment):* Additional treatment to remove nutrients, such as nitrogen, phosphorous and suspended solids through technologies including sand filtration or membrane filtration. Disinfection is often the final step before discharge.

The treatment level varies enormously across the world: while primary treatment is the dominant process in some countries in Asia and Africa, secondary treatment is today standard in OECD countries, with many also using tertiary treatment. For example, the Urban Wastewater Directive of the European Union (EU) is one reason why almost 40% of wastewater in the EU is treated to tertiary level (in the United States the share is even higher at 60%). About half of the energy used in advanced wastewater treatment and collection is consumed in secondary treatment, notably to satisfy the requirement for aeration in the biological step (Figure 9.13). Other important energy uses include pumping for wastewater collection and throughout the plant, as well as sludge treatment, notably anaerobic digestion. The energy input in sludge treatment is in general far outweighed by energy recovery in the form of heat and/or electricity from biogas production. Energy recovery from sludge is increasingly being applied in larger facilities in developed countries in order to produce biogas, which can be turned into heat or electricity. It is estimated that current global electricity production from sewage sludge is around 6 TWh and thus covers around 4% of worldwide electricity needs in the municipal wastewater sector. Tertiary treatment is typically a less significant energy consumer, but increasingly stringent water quality standards in developed countries have already led to higher energy consumption for tertiary treatment.

Desalination and water re-use

Almost all of the world's water demand is met from groundwater and surface water, but varying levels of water stress in some parts of the world, particularly North Africa and the Middle East, have driven several countries to augment their natural water supplies through increased use of non-traditional water resources, including desalination and re-use. At its simplest, desalination is the process of separating saline water (seawater or brackish water) into freshwater and concentrated salt. The desalination of brackish water, given its lower salt concentration, consumes only about a tenth of the electricity needed in seawater desalination. Today there are two main types of desalination technologies:[20]

- *Thermal:* Water is boiled to separate out salts by evaporation, which requires a large amount of thermal energy, usually natural gas, but also some electricity. Multi-stage flash systems and multi-effect distillation are the most common technologies. Multi-effect distillation can be used with a combined-cycle power plant in an integrated water and power plant, in order to optimise the use of the heat of the combined cycle.
- *Electric (membrane-based):* A semi-permeable barrier is used to filter out the dissolved solids. Reverse osmosis is the primary technology, which uses electric pumps to push water through the membrane to remove the salt.

Today reverse osmosis is the most commonly installed technology, spurred on by technological improvement, its relatively low energy intensity and cost reductions. In 2015, over 65% of global installed desalination capacity was equipped with reverse osmosis membranes. As of 2015, there were roughly 19 000 desalination plants worldwide, with an available production capacity of roughly 15 bcm per year to provide water to both municipal and industrial users. The Middle East houses almost half of global installed desalination capacity, followed by the European Union with 13%, the United States with 9%, and North Africa with 8% (GWI, 2016). Globally, seawater is the most common feed water type, supplying about 60% of installed capacity, followed by brackish water at over 20%.

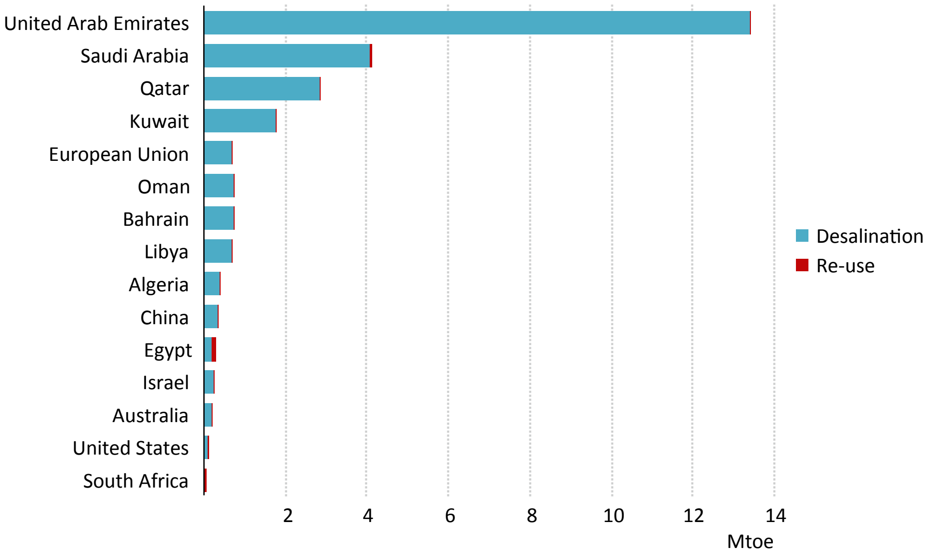
Water re-use describes the use of discharged wastewater as a source of freshwater. In general, a distinction is made between potable and non-potable re-use with non-potable re-use employed mainly for irrigation. As drinking water needs to meet higher quality standards, the process of re-using water for potable purposes requires more energy than non-potable purposes. Given the ready availability of wastewater and the lower energy

20. Generally two established technologies dominate the market today, though several new ones are emerging, such as high-recovery reverse osmosis, forward osmosis, membrane distillation and renewable desalination. The technologies aim to decrease the energy required and the costs, as well as the environmental impact.

intensity of advanced treatment for water re-use compared with seawater desalination, water re-use presents an increasingly attractive option to meet demand.

Although desalination and water re-use meet only 0.7% of global water needs today, these processes account for almost a quarter of total energy consumption by the water sector. Less than 15% of the energy is provided in the form of electricity, with natural gas being the preferred fuel for thermal desalination. Energy consumption for the desalination of brackish water and water re-use is fairly small in comparison to seawater desalination, as seawater desalination is much more common and requires higher levels of energy input. The United Arab Emirates (UAE) has the largest desalination capacity, followed by Saudi Arabia. The UAE accounts for about half of the global energy use in desalination as it relies mainly on seawater as an input and on the multi-stage flash systems technology, which is the most energy-intensive process (Figure 9.14). Currently, water re-use does not play an important role in terms of energy consumption, but it is becoming more important, notably in the United States and India.

Figure 9.14 ▷ Energy demand for desalination and re-use, 2014



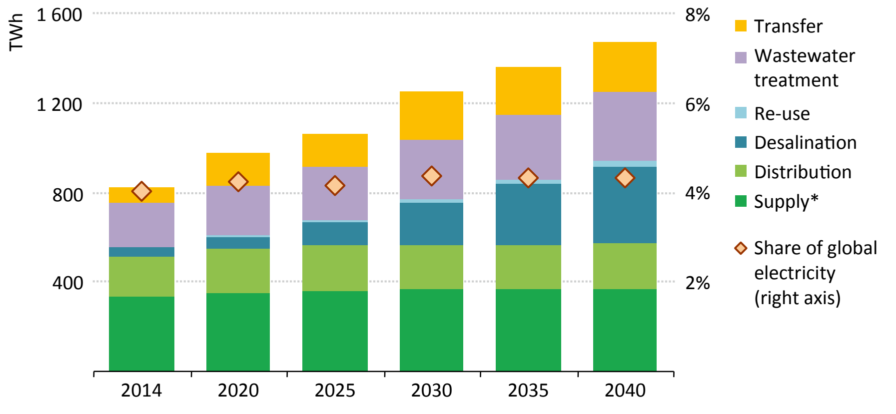
Around half of global energy consumption for desalination in 2014 was in the United Arab Emirates

Sources: GWI (2016); IEA analysis.

9.3.2 Energy requirements for water in the New Policies Scenario

Global energy use in the water sector is projected to more than double over the *Outlook* period to 2040, i.e. increasing more rapidly than water withdrawal, to reach a level of about 270 Mtoe. Though the water sector accounts for just 2% of global final energy consumption in 2040, the rate of increase between 2014 and 2040 is almost three times greater than that of final energy consumption over the same period. Thermal energy needs in the sector are projected to increase to 140 Mtoe, mainly driven by an increase in desalination capacity. The use of diesel fuel declines, however, by roughly 0.2 mb/d, as diesel pumps are gradually replaced by electric ones. Higher desalination needs in the future drive the almost five-fold increase in natural gas consumption in the sector, although this is less than the growth in desalination capacity, as membrane-based desalination and desalination using concentrating solar power gain in market share.

Figure 9.15 ▷ Electricity consumption in the water sector by process



Electricity consumption in the water sector increases by 80% over the next 25 years

* Supply includes groundwater and surface water treatment.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Electricity consumption in the water sector increases by 2.3% per year in the future to reach a total of 1 470 TWh in 2040, equivalent to almost twice the electricity consumption of the Middle East today (Figure 9.15). The largest increase is projected to come from desalination, as production from seawater desalination increases almost nine-fold and brackish water desalination increases five-fold. Accordingly, in 2040 desalination accounts for more than 20% of all electricity consumed by the water sector, up from only 5% today. Desalinated water gains a larger share of the water market in many countries around the world, but the largest increase is concentrated in countries of the Middle East and North Africa. As desalination becomes more important in the future so does water re-use, particularly in developed countries. Consumption of re-used water more than quadruples over the next 25 years, with the largest increase projected to occur in the United States, China, India, North Africa and the Middle East. Non-traditional water sources combined account for 4% of water supply in 2040, compared with only 0.7% today. The second-largest increase in electricity consumption in the water sector comes from large-scale water transfer projects, as China is expected to go ahead with the different routes of its South-North Water Transfer Project. By 2040, it is estimated that a total of 180 TWh will be used for water transfer projects in China, accounting for 2% of total Chinese electricity consumption in that year. This includes moving up to 45 bcm of water through the South-North Water Transfer infrastructure project.

Global electricity consumption for wastewater collection and treatment requires over 60% more electricity in 2040 than in 2014, as the amount of wastewater in need of treatment increases. Two trends concerning the energy intensity of wastewater treatment on a worldwide basis counterbalance each other: developing countries move towards treating wastewater to a higher level, increasing the global energy intensity, while efficiency improvements in treatment mitigate this growth. Wastewater treatment is projected to become 7-27% (depending on the region) more efficient by 2040, compared with today. This is achieved partly through more efficient wastewater pumping but also through efficiency gains in secondary treatment (see section 9.3.3). Increased water quality standards, especially in developed countries (e.g. standards requiring the removal of pharmaceutical substances) will increase energy consumption in the future, but only to a limited degree. Electricity needs for groundwater extraction increase by almost 30 TWh over the next 25 years, not only as a consequence of higher levels of groundwater extraction but also due to a gradual shift from diesel to more efficient electric pumps.

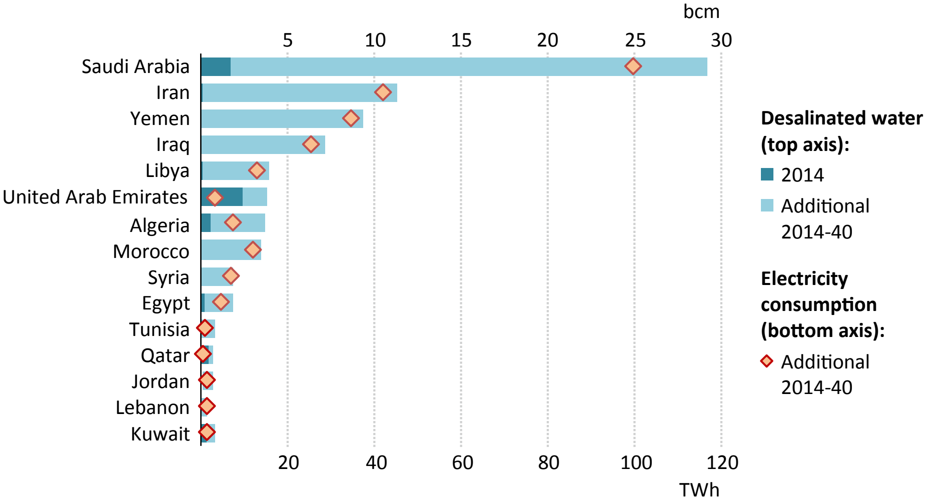
The water sector's share in global electricity consumption stays fairly constant at around 4%, but this hides strong regional divergences: in the United States and the European Union the share remains fairly constant at around 3%; the share decreases from around 10% to 4% in India (as other electricity uses increase much faster); the share increases from 9% to 16% in the Middle East (as desalination capacity increases quickly) and in China from 3% to 4% (as a consequence of the South-North Water Transfer Project).

Desalination in the Middle East and North Africa

Eight of the ten countries with the lowest renewable water resources on a per-capita basis are located in North Africa and the Middle East. One of the consequences of such low availability is dependence on withdrawals from non-renewable groundwater resources. In the late 1990s, it was estimated that the share of non-renewable groundwater resources used to satisfy water demand was as high as 95% in Libya, 89% in Oman, 85% in Saudi Arabia and 70% in the UAE (Foster and Loucks, 2006). During this same time period, the largest absolute non-renewable groundwater withdrawals occurred in Saudi Arabia (18 bcm), followed by Libya (3 bcm) and the UAE (2 bcm). As this way of satisfying water demand is not sustainable, countries in the region have sought alternative solutions. The United Arab Emirates, for example, have increased their desalination capacity by almost 1.7 bcm since the early 2000's, reducing non-renewable groundwater withdrawals; today its largest share of water comes from seawater desalination. However, in many countries the gap between renewable water resources and current withdrawals remains high.

It is estimated that in 2014 around 7 bcm of desalinated water was produced in North Africa and the Middle East. In order to reduce reliance on non-renewable groundwater, it is projected that the amount of desalination (seawater and brackish water) increases twelve-fold to 2040, with the largest increase being realised in Saudi Arabia, the country with the largest water deficit (Figure 9.16). Other countries with a significant increase in desalination capacity include Iran, Yemen, Iraq, Libya, Algeria and Morocco. Water re-use in general presents an economically viable alternative to desalination, given its lower energy intensity. Yet in many of these countries, agriculture is responsible for the majority of water withdrawals, meaning that the available wastewater is not sufficient to satisfy significant parts of water demand.

Figure 9.16 ▷ Additional desalination and increased electricity demand, 2014-2040



Saudi Arabia adds the most desalination capacity over the next 25 years

Sources: GWI (2016); IEA analysis.

The impact of these changes on future electricity demand is substantial. In total, additional electricity consumption of around 250 TWh is necessary to power desalination plants in 2040 (about ten-times current consumption) in the Middle East and North Africa. Similar to the Middle East, the water sector's share of total electricity consumption Northern African countries is projected to rise from 10% today to 14% in 2040. Higher needs for desalination are not the only driver behind quickly rising electricity demand. In addition, future desalination capacity is expected to shift to some degree from fossil fuel-based technology to membrane technologies and CSP-based desalination. That said, demand for fossil fuels for desalination in the Middle East and North Africa is still four-times higher in 2040 than in 2014, accounting for 8% of total primary fossil-fuel demand in the Middle East and North Africa in 2040.

9.3.3 Measures to save energy

The New Policies Scenario – our central scenario – captures the effect of evolving energy prices and the impact of current policies and those that are adopted but yet to be implemented. As such, it reflects an outlook that is far from exploiting the full potential for energy efficiency and energy recovery from wastewater. A range of barriers remain, including but not limited to:

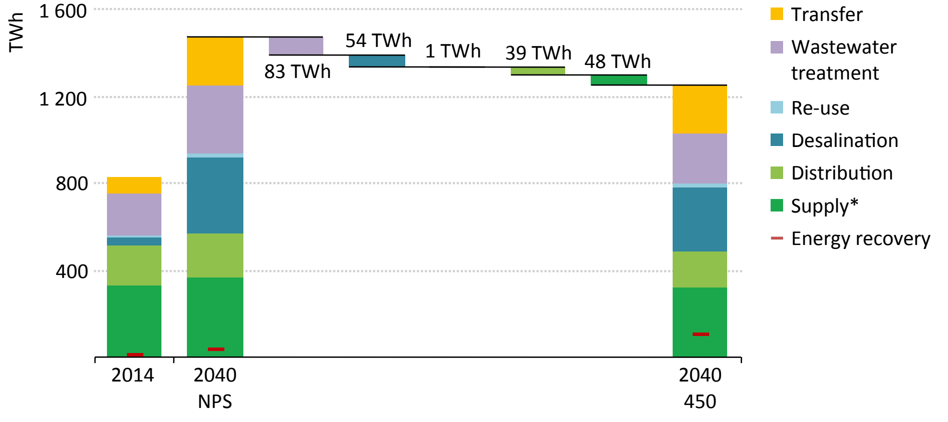
- The electricity consumption of different parts in the system is often not quantified, contributing to a general lack of awareness about the potential for efficiency improvements.
- Energy efficiency measures require upfront investment, which can deter action if financing is associated with an increase in water tariffs.
- Larger wastewater facilities are rarely considered as an integrated system to be optimised as a whole.
- Efficiency projects save electricity but their adoption can interrupt processes or increase maintenance requirements.
- Some energy-savings measures are not easily replicated from one facility to another, as the layout and water quality at each facility may differ.

9

This does not mean that energy efficiency improvements are excluded in the New Policies Scenario: in fact, electricity consumption in the water sector as a whole would have been more than 10% higher in 2040 without improved energy efficiency. In the 450 Scenario – where the rise in average global temperature is limited to 2 °C by 2100 – the economically viable energy efficiency potential is fully exploited. In the 450 Scenario, electricity consumption in the water sector grows annually by 1.6% to 2040, i.e. by 0.6 percentage points less than in the New Policies Scenario. This delivers electricity savings of almost 225 TWh by 2040 and additional electricity generation from sewage sludge of 70 TWh in the 450 Scenario (relative to the New Policies Scenario), which together are enough to replace the electricity generation of around 50 large-scale (800 MW) coal-fired power stations. The largest savings are achieved in wastewater treatment, desalination and water supply, followed by freshwater distribution (Figure 9.17). Almost 60% of the electricity savings occur in just four regions: the Middle East, China, the United States and India. In the Middle East, electricity consumption for the water sector is lower mainly as a result of a shift from membrane-based desalination towards thermal desalination using CSP, while in China and the United States savings from wastewater treatment dominate and in India savings come mainly from groundwater pumping.

Global electricity consumption in wastewater treatment in the 450 Scenario is about 230 TWh, roughly 25% lower than in the New Policies Scenario, as a result of a wide deployment of energy efficiency measures, operational improvements and a reduction of storm and groundwater infiltration into sewage systems. The biological process, which is the most energy intensive within secondary treatment, offers the largest savings potential. The wider deployment of variable speed drives, fine bubble aeration, better process control and more efficient compressors are among the most important efficiency measures (see Chapter 7.4), which together reduce energy consumption in the biological step by up to 50%. Further efficiency savings in the 450 Scenario are realised in sludge treatment, via improved methods for dewatering and in wastewater pumping through more efficient pumps, pipe maintenance and the deployment of variable speed drives. In addition, reducing run-off and groundwater infiltration by 20% through better infrastructure maintenance and gradually changing combined sewer systems to separate systems, decreases the water inflow and consequently the energy necessary for pumping.

Figure 9.17 ▷ Electricity savings in the water sector by process in the 450 Scenario relative to the New Policies Scenario



Exploiting the energy recovery potential and economic energy efficiency opportunities can enable municipalities to self-supply 20% of their electricity for water services

* Includes groundwater and surface water treatment.

Notes: NPS = New Policies Scenario; 450 = 450 Scenario. Energy recovery represents the amount of electricity generated from anaerobic digestion of the wastewater sludge.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Electricity needs worldwide for desalination are reduced by over 50 TWh in 2040 in the 450 Scenario, in comparison with the New Policies Scenario, 80% of which is realised in the Middle East and North Africa. The reduction in the 450 Scenario is mainly a consequence of a shift towards renewables-based thermal desalination technologies, but is also partially driven by continued efficiency gains in reverse osmosis technology, where the electricity intensity falls to around 3 kilowatt-hours per cubic metre (kWh/m^3) by 2040. Efficiency gains are not limited to wastewater treatment and desalination, as freshwater distribution and water extraction also have large savings potential. Using more efficient and correctly sized pumps, variable speed drives and predictive maintenance is projected to reduce electricity needs for water extraction and freshwater distribution by 15% in 2040 relative to the New Policies Scenario.

In addition to the opportunities to save energy in the water sector, there are also opportunities to produce energy from wastewater. On average, the energy content of wastewater is five-to-ten-times greater than the energy necessary to treat it. Anaerobic digestion can convert chemically bound energy into biogas (primarily methane). The biogas can then be used to produce heat (either to satisfy a plant's own needs or to feed into a district heating network), or electricity or serve as a fuel for trucks or buses, or for cooking/heating. Theoretically, up to 0.56 kWh/m³ of electricity can be produced from sewage sludge on average: however, in reality this number is significantly lower, due to inefficiencies in the digestion process and electricity conversion, and barriers limiting its uptake. In general, small plants (i.e. < 5 million litres per day [MLD]) cannot generate enough biogas to make energy recovery cost-effective, while plants larger than 5 MLD can generate electricity only if digesters are part of the plant. The makeup of wastewater is another factor. For example, in the United States, the more diluted nature of the wastewater (due to infiltration of storm and groundwater) makes it more difficult for a utility to recover energy. Another key factor is the location of the facility and whether or not there is an outlet for excess biogas, such as compressed natural gas for transport or applications that can use excess heat. Such infrastructure does not exist in many parts of the world. Moreover, in developing countries, the over-riding objective of a utility is to meet existing and future needs for wastewater treatment. As such, more significant steps towards capitalising on the embedded energy in the short term are unlikely.

Given these many obstacles, electricity production from sewage sludge is projected in the New Policies Scenario to increase from almost 6 TWh today to almost 30 TWh in 2040. Though this is a five-fold increase, it corresponds to just 0.06 kWh generated per unit of wastewater treated, less than half the level achieved in several European countries today. Under the right incentive schemes, such as those assumed in the 450 Scenario, it is, however, possible to increase electricity generation to about 100 TWh in 2040. This would satisfy over 55% of the electricity needs for municipal wastewater treatment (but only 8% of the needs of the entire water sector). It means that net municipal electricity needs (electricity requirements minus electricity produced from biogas) for water supply and wastewater treatment are cut by more than 30% in the 450 Scenario, compared with the New Policies Scenario. While some in developed countries have already achieved, or are on track to achieve, energy neutrality (a concept where energy needs are entirely satisfied with own-generation), at a global level, full energy neutrality is unlikely over the next 25 years (Box 9.3).

Box 9.3 ▹ Energy neutrality: an end to wasting energy on wastewater

There is significant potential for the wastewater industry and municipalities to utilise existing technologies to improve process efficiency and harness the embedded energy in wastewater. This could even produce excess energy for other uses. In our projections, by 2040 electricity produced from wastewater covers 12% of the electricity demand from municipal wastewater treatment in the New Policies Scenario and over 55% in the 450 Scenario. However, when looking at the total electricity needs of the water transport and treat water, own-generation from wastewater supplies just 2% of the total electricity needs in the water sector in the New Policies Scenario, a share that increases to 8% in the 450 Scenario.

Several municipalities in Europe and the United States though have made greater strides towards the concept of energy neutrality, serving as examples of how it can be achieved and the consequent benefits. The path to this self-sufficiency comes in two parts: first, is energy savings through efficiency gains and the second is electricity generation from biogas.

Europe, in particular, has made significant progress in the pursuit of energy neutrality in wastewater treatment. In Denmark, the Aarhus Marselisborg Wastewater Facility has both improved the efficiency of its operations (via process optimisation, better aeration, sludge liquor treatment to improve the efficiency of ammonium removal) and invested in energy recovery units for biogas use in high efficiency combined heat and power (CHP) units that feeds surplus heat into a district heating system and surplus electricity to the grid. It is now an energy positive facility — i.e. it produces more energy than it needs. In 2014 it generated almost 40% more electricity than it consumed and sold 2.5 gigawatt-hours (GWh) of heat to the district heating system. Combined, this equals almost 100% more energy produced than is consumed at the facility.

Several wastewater treatment facilities in the United States are also focussing on reducing the amount of energy they require from the grid and making better use of waste streams. The wastewater treatment plan in Gresham, Oregon was the first facility in the United States to become energy neutral by co-mingling outside organic waste streams from restaurants with its wastewater to produce biogas. DC Water in Washington DC has the world's largest thermal hydrolysis advanced anaerobic digestion facility and the biogas created at its wastewater treatment plant is used in its CHP plant. The Stickney Water Reclamation Plant in Chicago, the largest in the world, has announced plans to become energy neutral by 2023 by producing enough energy to replace three-quarters of its energy demand and satisfying the remainder via efficiency gains.

9.4 Stress points and solutions

This analysis of the energy and water sectors highlights areas of potential stress, as well as areas where action can bring co-benefits across the water-energy nexus. Limitations on water can restrict energy production and energy disruptions can limit water provision. Our analysis shows a general shift towards more water-intensive energy and energy-intensive water. The system is evolving and new stress points and chokepoints could arise at country, local and policy levels. That said, there are several opportunities for action to overcome such risks, using both technical and non-technical solutions.

9.4.1 Potential stress points

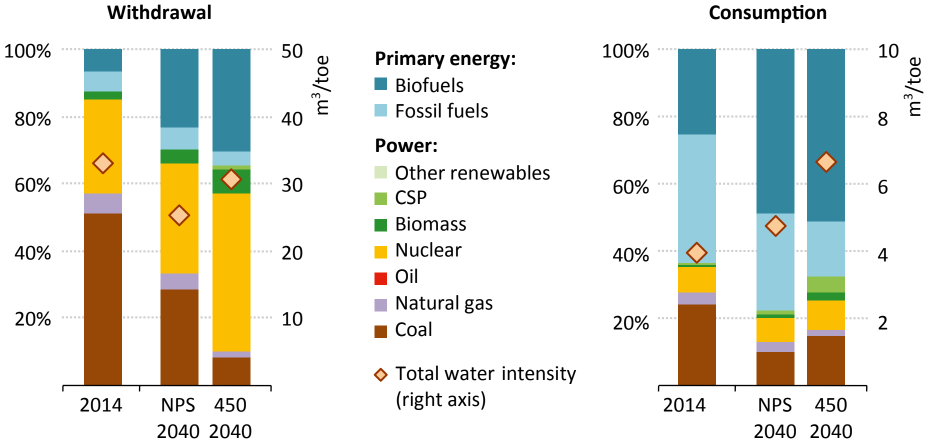
A more water-intensive energy sector

Globally, the water consumption-intensity of the energy sector – that is, total water consumed per unit of energy produced showing the relative consumption-intensity of the energy portfolio as a whole – increases in both scenarios in the future, by 20% in the New Policies Scenario and by almost 70% in the 450 Scenario relative to 2014. This happens over a period when water demand is growing from all sectors (see Figure 9.2) and when climate change is expected to change the patterns of water availability. This focus on consumption is not to understate the importance of water withdrawals by the energy sector. Although the water withdrawal-intensity is set to decline overall (almost 25% in the New Policies Scenario and less than 10% in the 450 Scenario compared to 2014) – and much of the water withdrawn is ultimately returned – the withdrawal of water at a given point in time can stress the water system, depending on the needs of other users, the seasonality of water availability and the state in which the water is returned. Water consumed on the other hand is, by definition, not returned and necessarily decreases the amount of water available to other users.

Overall the water consumption-intensity of the 450 Scenario is 40% higher in 2040 than the New Policies Scenario, while the water withdrawal-intensity is 20% higher (Figure 9.18). Therefore, despite the fact that total energy produced in the 450 Scenario is more than a quarter lower than in the New Policies Scenario in 2040, its water use per unit of energy is higher. This indicates that the technology and policy choices related to decarbonisation could introduce unintended stress points if not properly managed. Three components of a low-carbon portfolio, in particular, affect water intensity in the 450 Scenario. First, the power sector's share of consumption in the 450 Scenario is roughly ten percentage points higher than in the New Policies Scenario in 2040 due to the deployment of low-carbon technologies such as nuclear and CSP, with CSP accounting for 5% of the 450 Scenario's consumption (up from 1% in the New Policies Scenario) and nuclear accounting for 9% (compared to 7% in the New Policies Scenario). Nuclear also accounts for almost half of the 450 Scenario's withdrawals in 2040 (an increase of 15 percentage points compared with the New Policies Scenario). Second, the share of consumption from coal-fired power plants increases by over 40%, compared with the New Policies Scenario, due to the deployment of carbon capture and storage. Finally, an increased share of biofuels in total energy supply relative to the New Policies Scenario, increases its share of withdrawals and by 2040 biofuels account for almost a quarter of the 450 Scenario's withdrawal.

Just as not all low-carbon technologies or fuels affect water use in the energy sector, the impact varies on a country or regional level as well. Of course, the availability of total water resources varies drastically by country and even within countries. Countries that are not classified as water stressed at a national level, such as the United States, face areas of water scarcity that will intersect with different types of energy projects. Given the differences in the national energy portfolios and levels of water availability, the challenges are not uniform. A few of the potential stress points in the New Policies Scenario are set out below.

Figure 9.18 ▷ Share of withdrawal and consumption by fuel or technology and total water intensity by scenario, 2014 and 2040



The increased share of nuclear and CSP in the energy mix and the shift to more water-consumptive cooling technologies in coal-fired power plants in the 450 Scenario boosts its water intensity

Notes: CSP = concentrating solar power. Under primary energy, fossil fuels include coal, oil and natural gas. Under power, other renewables includes solar PV, wind and geothermal; coal and natural gas include both power plants that are fitted with CCS technology and those without. Total water intensity is calculated as total water withdrawal or water consumption by the energy sector divided by total energy produced.

India is already classified as "water stressed". Over the *Outlook* period India's total energy-related water withdrawals almost double, reaching almost 70 bcm while energy-related water consumption rises to almost 20 bcm. The increases reflect an increased role for nuclear as well as a continued reliance on coal-fired power plants, many of which are located in areas of water stress.[21] As a result, more power plants use either wet-tower cooling, which withdraw less water but increase consumption, or non-freshwater systems in coal-fired power generation by 2040. As discussed, India's reliance on water-intensive sugarcane to produce bioethanol also exacerbates existing water stress in some parts of the country, given rising demand from other users (municipalities in particular, where demand doubles), limited land availability and food security concerns.

In the New Policies Scenario, China's energy-related water withdrawals rise by over 20% from 2014 to 2040, to reach almost 55 bcm, while its consumption increases at a faster rate, rising by over 40%, to 15 bcm. Water constraints are expected to increase as agricultural water withdrawals are also projected to rise by 11% and municipal needs to rise by over 30% over the next 25 years. China is already experiencing water scarcity in several regions,

21. The IEA has analysed the impact of water scarcity on the location and cooling technology choices of coal-fired power generation in China and India. See *World Energy Outlook-2015*, Chapter 8 and Chapter 14 for the case studies. Excerpts can be found at: *www.worldenergyoutlook.org/resources/water-energynexus/*.

which is affecting coal production, power plant siting and the choice of technologies for new coal plants (IEA, 2015). As in India, in order to adapt, the power sector is installing more wet-tower cooling systems, though China has mandated that all new coal-fired power plants being built in arid regions use dry cooling. The expansion of China's nuclear power capacity, a portion of which is proposed to be built inland, is water intensive and, depending on where it is sited, this expansion could increase competition for scarce water resources.

Water scarcity is already a constraint on energy production in the Middle East. In the New Policies Scenario, while its total water withdrawals and consumption for energy are low relative to other countries, the energy sector in the Middle East consumes much of the water it withdraws. In the power sector, consumption's share of withdrawals increases from 16% to almost 40% between 2014 and 2040 and in primary energy production it rises from 80% to 83%. The Middle East has to come to terms with rising needs for water consumption alongside limited water availability and increasing reliance on more energy-intensive sources of water supply (see section on desalination in the Middle East and North Africa in section 9.3.2).

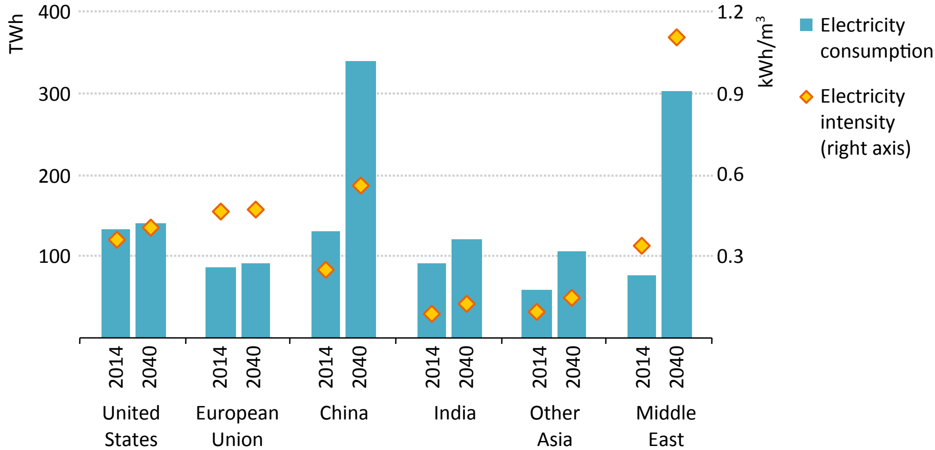
A more energy-intensive water sector

In parallel with the rising water intensity of the energy sector, operations in the water sector are set to become more energy intensive. In the New Policies Scenario, the global electricity intensity of the water sector increases from around 0.2 kWh/m^3 in 2014 to 0.3 kWh/m^3 in 2040, which is reflected in every major water-using region (Figure 9.19). The underlying reasons for this increase differ by country, but the most common are high growth in municipal and industrial water withdrawals, an increased reliance on non-traditional water resources and increased amounts of wastewater being treated to higher levels. The largest increase occurs in the Middle East, where, by 2040, the energy intensity of water withdrawals is about three-times higher than in the United States. In most Asian countries, including China and India, one of the largest increases in electricity consumption in the water sector stems from higher volumes of wastewater, treated to a higher level.

Cities will be a major source of energy demand for water. In 2014, over 50% of the world's population resided in urban areas. Over the projection period, the share of the population living in urban areas is expected to grow at 0.6% on average per year in the New Policies Scenario and by 2040, over 60% of the population is likely to be living in urban areas, an increase of 1.9 billion people. Most future urbanisation will occur in cities in developing countries, many of which are already facing challenges related to water and energy, especially in Africa, South Asia and China (WWAP, 2014). Almost one-out-of-four cities worldwide are in a water-stressed area (McDonald et al., 2014).[22] Water stress could increase with climate change, and rising water and energy demand from other users will further strain energy and water needs.

22. In the study conducted by McDonald, et al. 2014, water stress is defined as those cities that use at least 40% of the water they have available.

Figure 9.19 ▷ Electricity consumption and intensity in the water sector in the New Policies Scenario, 2014 and 2040



Water use is projected to become more electricity intensive

Notes: Electricity intensity is calculated as total electricity consumption in the water sector, divided by total water withdrawals from agriculture, industry, power generation and municipal uses. Other Asia refers to other developing Asia.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); IEA analysis.

Given that water provision and wastewater treatment already account for a large share of municipal energy bills (30-50%), increasing energy efficiency in wastewater treatment will be necessary to constrain the impact on public budgets. As discussed, more efficient equipment, including more efficient pumps and the use of variable speed drives can lead to significant energy and cost savings (see Chapter 7.4 for more on variable speed drives).

Points of intersection

There are wide disparities in the management and pricing of energy and water. Market forces tend to propel energy sector development, while improvements to water-related services are often determined by social priorities. Energy and water are often managed at different levels: energy top down and water bottom up, with varying levels of private sector involvement (drinking water and sanitation services are predominately the responsibility of the public sector, compared with a larger role of private companies in the power sector).

Unlike energy, there is no global water market and therefore no international price. What consumers pay for water often does not reflect relative scarcity. Some users pay for extraction, while others pay just for delivery (i.e. the cost of electricity to access the water, transport it, clean it and remove waste), and in some places this cost is heavily subsidised or free. In these circumstances, there is little incentive to conserve water and, unlike the market price signals for some forms of unsubsidised energy, the cost does not go up during times of scarcity. Moreover, some industrial and agricultural consumers secured long-term water contracts in times of low prices and do not have a price incentive to invest in water conservation measures and equipment.

Under-pricing of water and energy undercuts investment in more efficient energy and water infrastructure and can lead to unnecessarily high consumption levels. Agriculture is a case in point. Low electricity prices can lead to an excessive call on groundwater resources while low water prices can increase demand for electricity for pumping. India is one example where this dynamic is evident. Agriculture accounted for 85% of water withdrawals in India in 2014 and the system relies heavily on electric pumps with low efficiency rates (20-35%). Improving the efficiency of India's irrigation systems, if done in an integrated way, would help reduce electricity and water consumption in agriculture. However, as emphasised in *WEO-2015*[23], improving the efficiency of water pumps without changing the price of electricity or irrigation practices could have unintended consequences in the form of increased water consumption and further depletion of aquifers. Saudi Arabia is another example where low water and electricity prices in the agriculture sector combined with a policy of promoting domestic agriculture have contributed to unsustainable levels of water withdrawals (86% of water withdrawals in 2014 were for agriculture), including from non-renewable fossil aquifers (Napoli, et al., 2016).

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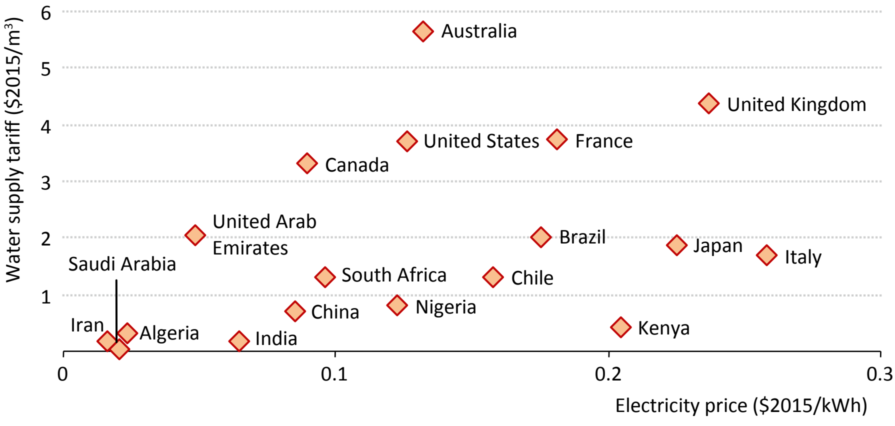
Figure 9.20 ▷ Water and electricity prices by selected country, 2015



There are wide country-by-country variations in relative water and electricity prices, but low water tariffs are widespread

Notes: The water tariff is comprised of the fixed charge, variable charge and relevant taxes for both water and wastewater. It represents an average of different water bills for a range of cities within each country, based on data provided by Global Water Intelligence. The benchmarking consumption level is 15 m^3/month/consumer. The energy price shown in the graph is the end-user electricity price.

Sources: GWI (2016); IEA analysis.

23. See *WEO-2015*, Chapter 12 for a discussion of energy demand in the agriculture sector.

Countries that are in the lower left corner of Figure 9.20, which shows water and electricity prices, in many cases, have some of the lowest renewable water resources per capita in the world but also some of the highest rates of water consumption. Water and electricity subsidies have been put in place for a myriad of political and social reasons; however, in most cases the low water tariff does not reflect the scarcity of the resource. The impact on state revenues of the recent prevailing low oil price has caused some countries, such as Saudi Arabia, to propose increasing the water tariff level. Even so, to bridge the gap between water demand and available renewable water resources, many of these countries – Saudi Arabia, Iran, UAE and Algeria – are turning to desalination as a means of increasing water supply, leading to an increase in the electricity consumption of the water sector (which, depending on the energy source used to power the desalination facility, could increase water needs in the power sector). Given the water constrained future faced by many countries in the Middle East and North Africa, the introduction of demand-side measures to improve the efficiency of water use and the removal or reduction of subsidies for water may become necessary to lower the water supply gap.

The economic, social, environmental and demand implications of inefficient energy subsidies have been the source of much debate, including at the international level (see Chapter 2.9). So what about the pricing of water? Recognition by the United Nations in 2010 that access to clean water and sanitation was a human right has made discussions of the question highly sensitive. Water is often thought of as a public good and, in this regard, there is concern that economic pricing of water would turn it into a luxury good, beyond the reach of the poor. Nonetheless, open debate should occur regarding the role of economic instruments. Just as the discussion on the rationale for and design of energy subsidies has emerged (leading to commitments to phase out distorting subsidies), so to there is room for a similar discussion about water subsidies and the waste and distortions that result from under-pricing. As is the case of energy pricing, distinct social measures, supplementing economic water pricing, might be the right answer.

Sustainable development is another area in which energy and water objectives interact. Two of the UN Sustainable Development Goals (SDG) are related to improving access to energy and water: SDG6 aims to provide available and sustainable management of water and sanitation for all, while SDG7 aims to provide affordable, secure, sustainable and modern energy for all. As of 2015, 91% of the world's population used an improved drinking water source, but over 650 million people are still without access to an improved water source. In terms of energy access, while 84% of the global population has access to electricity, almost 1.2 billion people are still without (see Chapter 2.8 for more detail). If properly co-ordinated, action towards realising these SDG goals can be complementary.

Africa and developing Asia are the regions with the highest number of people without access to electricity. Agriculture is an important sector in these regions and a key source of water demand. As highlighted, agriculture in India accounts for the bulk of its water withdrawals. Similarly, in sub-Saharan Africa, agriculture accounted for 80% of water withdrawals in 2014. As in India, subsidised electricity in many African countries has led to the inefficient use of water for irrigation. As countries in Africa and developing Asia gain increased access to electricity, it will be important to put in place policies that ensure that it does not result in inefficient water consumption, especially as some countries, notably India, are already facing water stress.

It also is important for all stakeholders to recognise that there is a feedback loop between the energy and water sector. A rise in energy demand in the water sector, depending on the technology and fuel mix used to meet it, impacts the water needs for power and primary energy production. Similarly, an increase in freshwater needs for the energy sector could tighten overall water supply to the point of requiring increased levels of treatment depending on how water used in primary energy is managed. While these impacts are highly localised and depend both on the energy portfolio and the level and type of energy demand in the local water sector, integrated planning is necessary to minimise unintended consequences and improve efficiency, as a reduction in the amount of energy or water needed in one sector will have trickle down effects for the other (Box 9.4).

Box 9.4 ▹ Is concentrating solar power the solution for the water sector in the Middle East and North Africa?

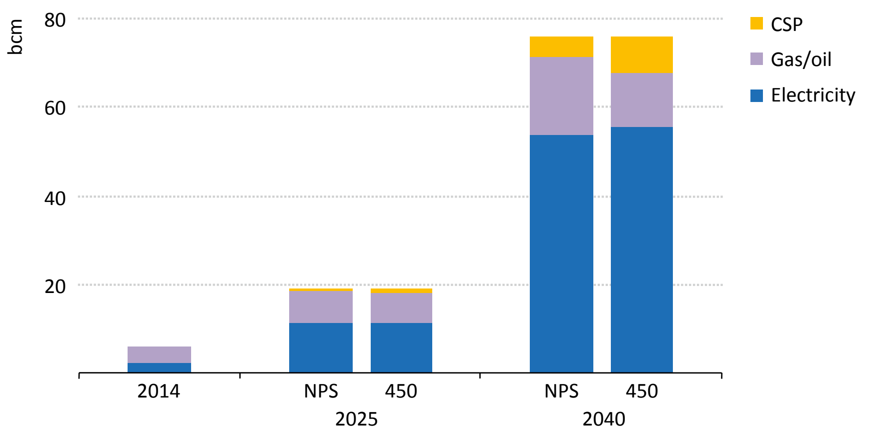
In order to reduce unsustainable water withdrawals from non-renewable groundwater resources while satisfying the increasing water demand, the production of desalinated seawater in the Middle East and North Africa is projected in the New Policies Scenario to be 13-times higher in 2040, compared with 2014 (see section 9.3.1 on desalination and water re-use). Traditionally, desalination in these regions is either thermal-based (oil or natural gas) or membrane-based, which needs significant quantities of electricity, again mainly derived from oil and natural gas.

In addition to being the world's most important exporters of hydrocarbons, these regions also have significant levels of direct solar radiation and large deserts close to urban centres. This provides the potential for countries in these regions to shift away from direct and indirect (via electricity) reliance on fossil fuels towards carbon-free energy sources, in this case concentrating solar power. Indeed, the world's largest CSP complex is currently under construction in the Ouarzazate province of Morocco, which could eventually provide the heat for a desalination plant. Making this transition across the region not only frees up resources for export, but also reduces CO_2 emissions and local air pollutants. Unlike some renewable energy sources, with available technologies CSP can be coupled with efficient storage systems and thus provide continuous energy supplies to produce desalinated water.

Globally, CSP is not economically competitive with conventional technologies today – the cost of desalinated water with CSP as the energy source is roughly three-times higher than natural gas-based multi-effect distillation or membrane-based reverse osmosis. Consequently, no large-scale CSP desalination plant is in operation. Support mechanisms for pilot plants will be needed if they are to be developed in the future.

Although electricity prices in the Middle East and North Africa increase to 2040 in the New Policies Scenario, future cost reductions for membrane-based technologies mean that electricity remains the preferred energy carrier for desalination. Despite reductions of almost 50% in the costs of thermal desalination using CSP technology from 2014 to 2040 in the New Policies Scenario, CSP remains roughly 60% more expensive than desalination using traditional technologies in that scenario. Accordingly, CSP accounts for only 6% of desalinated water production by 2040 (Figure 9.21).

Figure 9.21 ▷ Water production from seawater desalination in the Middle East and North Africa by input fuel and scenario



The share of CSP in global desalination capacity in the 450 Scenario is almost double the capacity in the New Policies Scenario in 2040

Notes: NPS = New Policies Scenario; 450 = 450 Scenario; CSP = concentrating solar power.

Sources: Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016); GWI (2016); IEA analysis.

The picture changes to some extent in the 450 Scenario where subsidies for fossil fuels and electricity are completely phased out and electricity prices increase as a consequence of the higher share of renewables. CSP desalination becomes cost competitive with natural gas-based desalination in the late 2020s, and in 2040 it is only 30% more expensive than electricity-based reverse osmosis. Accordingly, CSP in global desalination capacity almost doubles with respect to the New Policies Scenario and reaches 10% in 2040. However, CSP, depending on the cooling technology employed, can be water intensive. Given that there is already limited water availability in the Middle East and North Africa, some of the desalinated water output may be needed for cooling at CSP plants, reducing the net output of CSP-based thermal desalination and its efficiency compared to equivalent fossil fuel-based plants.

9.4.2 Policy solutions

Water does not have to be a limiting factor for the energy sector and a rise in water demand does not have to be accompanied by a similar increase in energy demand. Policies and technologies already exist that can help reduce water and energy demand, and ease potential chokepoints in the water-energy nexus. Successful policymaking will require a better understanding of where the chokepoints lie both now and in the future, further innovation, determination on the part of regulators and industry to deliver, and consumer willingness to adapt. Avenues to consider include:

- **Integrating energy and water policymaking.** Include the energy needs of water sources (existing and new) and the water requirements for different energy technologies and policies in planning to ensure not only the viability of energy or water projects but also that the development of one sector does not have unintended consequences for the other. A first step is to identify where data gaps exist and take steps to fill them. Reliable, updated and complete water (and energy) data are essential to be able to model, forecast and manage the resources and make informed decisions. Understanding how much water and energy are used in each sector is critical for establishing a baseline against which to measure the costs and benefits of potential changes.
- **Co-locate energy and water infrastructure.** Water utilities often assume they will have the energy they need, while energy utilities likewise assume they will have the water they need. One way to improve this situation is where possible, to co-locate energy and water utilities. Integrating utilities allows the waste stream of one to be utilised by the other, reducing by-products, minimising transportation costs and lowering energy and water requirements. Other potential benefits include using water treatment and storage as an energy storage mechanism and using the wastewater sector to support demand response in the energy sector.
- **Utilise the energy embedded in wastewater.** Wastewater contains significant amounts of embedded energy and capitalising on this resource has the potential to provide over 55% of the energy required for municipal wastewater treatment by 2040. The greater use of biogas can also help manage variable renewable energy resources in a network. While there is significant potential to recover embedded energy and to pair it with other waste via co-fermentation, increased use of waste-to-energy technologies will require both the right regulatory framework and at least initially, fiscal incentives. Including the energy generated from wastewater treatment plants in renewable energy programmes such as certificate schemes and tax credits could encourage its wider use.
- **Use alternative sources of water for energy.** Our analysis shows that the availability of freshwater will remain an important criterion for assessing the viability of energy projects. One way to minimise the impact of this demand on freshwater resources is increasingly to use alternative water sources. Produced water from oil and gas operations can be treated onsite and re-used in production operations or be used for

cooling at nearby power plants. In the power sector, the use of municipal wastewater, brackish or sea water or mine water can help protect against interruptions in service due to drought or short-term water seasonality. Adequate treatment of the water from such sources will be required to reduce corrosion, scaling and fouling of pipes and equipment. Additionally, commitment to the use of alternative sources must take into account the additional energy needed to treat the water to the levels required for each function, as well as the location of the alternative water sources (energy savings are negated if significant pumping is required).

- **Save water, save energy.** As seen in the 450 Scenario, improved energy efficiency in water processes can reduce the amount of energy required by 13%. There are several ways in which industry and policy-makers can help. First, tools such as auditing and benchmarking should be used to identify problem areas and track progress in energy and water efficiency. Second, policy-makers should alter the standards against which water and wastewater utilities are judged to include efficiency targets alongside health, environmental and water quality requirements. Where necessary, policy-makers can encourage the uptake of efficiency through incentives or regulation to overcome barriers and bring down payback periods.

  Extensive opportunities to improve efficiency also exist in the energy sector (see Chapter 7). Increasing the efficiency of the power plant fleet, the deployment of more advanced cooling systems, increasing water-less fracturing for unconventional hydrocarbon production, improving efficiency in irrigation practices to produce biofuels and developing advanced biofuels can all help reduce water use. The impact of greater efficiency is already evident in our scenarios: the shift away from subcritical coal-fired power generation in the New Policies Scenario results in reductions in water withdrawal of over 100 bcm from that technology, which helps lessen the impact of increased demand from other technologies.

PART B
SPECIAL FOCUS ON RENEWABLE ENERGY

PREFACE

Renewable energy is at the heart of the effort to transform the energy system to make it less carbon intensive, sustainable and compatible with the internationally adopted climate goals. The following three chapters focus on renewable energy, addressing many of the key questions. How fast is it expanding? Does it need to grow even faster? Are renewables competitive today? If not, when? What roles will policy-makers need to play? Can variable renewables be successfully integrated into the electricity system at the scale required?

Chapter 10 sets the scene by surveying the emerging policy landscape, key market developments and status of renewable energy in energy systems today. The outlook to 2040 is discussed for each of the main *WEO* scenarios, detailing the use of renewable energy to generate electricity, produce heat and make transport fuels. The gap between the deployment of renewable energy on the scale projected, based on governments' presently declared intentions, and the scale needed to achieve climate objectives clearly indicates the need for further government action.

Chapter 11 focuses on the competitiveness of renewable energy, evaluating the ability of renewable energy technologies in electricity, heat and transport to stand on their own financial merits without outside support. This enables the cost of necessary government intervention to be estimated, set against the wider benefits in terms of fighting climate change, improving air quality and strengthening energy security. All this can be achieved while maintaining energy affordability for consumers.

Chapter 12 provides a detailed look at the integration of variable renewable energy in power systems. It considers the scale of the challenge related to increasing shares of wind and solar PV in the power supply, stemming from their distinct characteristics, and examines the range of integration measures available to address the challenge. Case studies focus on the situation in the United States, European Union and India. The successful integration of significant shares of wind and solar power in the mix is shown to be both possible and necessary to make the best use of wind and solar PV output.

Renewable energy outlook

Surging ahead

Highlights

- Renewable energy technologies are now a major global industry. Wind and solar PV have led recent growth in renewables-based capacity, though hydropower and bioenergy remain by far the largest source of supply. Renewables have overtaken coal as the largest source of power generation capacity and are the second-largest source of electricity supply. Renewables make a modest contribution to heat and transport and while progress is slower they have huge potential in these sectors.

- The commitments made at COP21 are a positive step towards decarbonisation, but the New Policies Scenario shows that they are not enough to put the world on a 2 °C climate path. The 450 Scenario, a path that is consistent with a 2 °C target, sees energy sector investment shift its balance towards renewables and energy efficiency. Modern renewables account for 27% of the primary energy mix in 2040 (from 8% today), and energy-related CO_2 emissions peak by 2020 and then decline.

- Renewables provide nearly 60% of power capacity additions in the New Policies Scenario (and reach 5 170 GW in 2040) and become the largest source of electricity supply before 2030. Wind capacity additions are led by China and the European Union; solar PV by China, India and the United States; and hydro by China, Latin America and Africa. A higher outlook for renewables in *WEO-2016* is driven by key policy changes in the United States (tax credit extensions) and China (emerging revisions to 2020 targets). In the 450 Scenario, renewables are the leading source of supply by the early-2020s and nearly 60% of all supply in 2040.

- Demand for heat is and remains the largest of all energy services. But a lack of strong policies in the New Policies Scenario means that the share of renewable heat only grows from 9% today to 15% in 2040. In the 450 Scenario, renewable supply obligations (as part of stricter building codes) help ensure that 40% of households rely on renewables for water heating in 2040. In industry, efficiency efforts cut heat demand while better awareness/information, targeted financial incentives and carbon pricing help overcome barriers to adopting renewables for heat. By 2040, around 20% of industrial heat use is from renewables, led by biomass and electricity.

- In transport, the share of renewable energy grows from 3% today to 7% in 2040 in the New Policies Scenario. Blending mandates help biofuel use reach 4.2 mboe/d in 2040 and one-in-ten passenger vehicles sold globally is an electric vehicle (EV), with nearly 40% of the energy used by EVs being renewable. In the 450 Scenario, actions on efficiency, emissions standards and fuel switching all help cut the role of oil in transport (to 65% in 2040), and boost the combined share of biofuels and electricity (nearly one-quarter). By 2040, road transport uses 6.1 mboe/d of biofuels and aviation uses 2 mboe/d, and around half of all passenger vehicles sold are EVs.

10.1 Introduction

Any credible path to achieving the world's climate objectives must have renewable energy at its core. The global transition to a low-carbon future is one of the most fundamental and comprehensive challenges ever faced by the energy sector, with every part of the energy system affected. The necessary effort will last for decades and the picture is evolving every day. The last year has been characterised by strong deployment of renewable energy options (Box 10.1), growing employment in this area, falling costs and new policies. The political commitments made at COP21 have reinforced the position of renewables as the dominant energy growth story. The power sector is leading the change, with the renewable component regularly breaking its own records for investment and deployment. But, in a decarbonised world, renewables must also permeate other fields of energy use in industry, buildings and transport, where supportive policies are often fewer and adoption has been slower.

Renewables bring environmental, economic and energy security benefits. But the challenges that they face are large. While some renewables are already competitive in existing markets, others teeter on the line between needing support and being competitive, while others clearly cannot survive without financial support.[1] Technology breakthroughs, in the renewables field or outside it, foreseen or unforeseen, can bring abrupt change in an already fast-moving market. Complex power systems that value reliability above all else are being asked to integrate large- and small-scale variable renewables that rewrite the supplier-consumer relationship and how the market operates. Policy stability is much desired by investors but very difficult for policy-makers to deliver.

Change is certain and the implications need to be considered. How far and fast can renewables establish themselves across different parts of the energy sector? How quickly will cost reductions lead to renewables being competitive in well-functioning markets? Are there limits to the extent to which variable renewables can be integrated successfully into the power system? The *WEO-2016* special focus on renewable energy in this chapter and chapters 11 and 12 seeks to put the latest policy and market developments into perspective, and to explore the shape and implications of various futures for renewable energy, across sectors, technologies and countries/regions. Two key challenges are considered in-depth: the competitiveness of renewables (see Chapter 11) and the integration of variable renewables into the energy system (see Chapter 12).

1. In this *WEO-2016* special focus on renewable energy, the terms "competitive", "financially attractive" and "cost-effective" have specific definitions. Renewables that are competitive are those projects that are profitable for an investor without government support. Those that are financially attractive also include those projects that are profitable to investors with government support. Renewables that are cost-effective are those that are the most economically desirable option for achieving society's goals. See Chapter 11, Box 11.1 for more details.

Box 10.1 ▷ Renewable energy resources and technologies

Renewable energy encompasses a broad range of energy resources and technologies that have differing attributes and applications. Renewable resources include solar, wind, bioenergy, hydropower, geothermal and marine energy. They are abundant (the collective energy potential being very many times greater than world demand) and widely distributed; but they are not equally easy to harness. Some examples include hydro and wind resources for electricity generation, bioenergy resources for road transport fuels (liquid biofuels) and biomass, solar and geothermal resources to produce electricity and/or heat. While renewable energy may be harnessed to provide a range of energy services (powering appliances and motors, space/water heating and cooking in buildings, transport etc.), not all types are able or suited to provide all types of energy service. Some important distinctions when discussing renewable energy are:

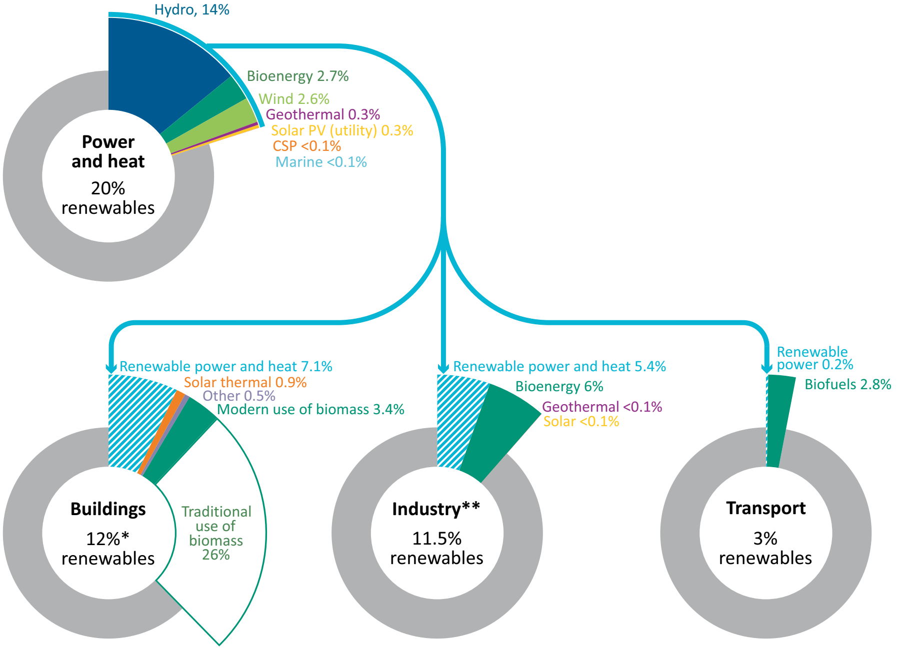
- **Variable or dispatchable renewables –** Due to the fluctuating nature of some resources (such as wind and solar), variable renewables cannot always be called upon when desired. Dispatchable renewables (e.g. hydropower or bioenergy) can be controlled to a greater extent and be called upon to help meet either fluctuating demand or to complement variable forms of supply. Energy storage can blur the line between variable and dispatchable renewables, enhancing the flexibility of variable renewables, but also increasing the capital cost.[2] Hydropower comes in different forms, all of which are dispatchable over the short-term (except in extreme drought); but those without reservoirs are more exposed to seasonal variations.[3]
- **Centralised or distributed generation –** Electricity may be supplied on a large scale by utilities through the grid or from smaller scale, distributed assets, such as rooftop solar on homes or businesses, which may or may not be connected to the main grid.
- **Direct or indirect renewable energy –** Renewable energy may be used in a relatively direct way to provide an energy service (such as solar thermal for heat) or indirectly from renewables-based electricity or renewables-based heat that is then used to provide an energy service (such as to run heat pumps or electric vehicles, or district heating).
- **Traditional or modern use of bioenergy –** The traditional use of solid bioenergy refers to the use of solid biomass for cooking or heating, using very basic technologies, such as a three-stone fire, often with no chimney or one that operates poorly. The modern use of bioenergy refers to biomass use in improved cookstoves or modern technologies using processed biomass, such as pellets, liquid biofuels or biogas.

2. For instance, this could be wind or solar PV linked to battery storage, concentrating solar power with thermal storage or hydropower with a large reservoir and/or pumped hydro storage.
3. Run-of-river hydropower, natural storage/reservoir hydropower and pumped hydro storage. Run-of-river hydropower projects avoid flooding extensive areas but as a result have limited amounts of water storage, meaning that their power output is subject to seasonal variations.

10.2 Recent developments

In 2014, the global supply of renewable energy increased by 2.7% over the previous year (in energy-equivalent terms), while overall primary energy demand rose 1.1% (and coal by around 1%). Collectively, all forms of renewable energy, including the traditional use of biomass, account for 14% of the global energy mix (8% if the traditional use of biomass is excluded). Wind and solar photovoltaics (PV) have led recent growth in renewables-based capacity, although hydropower (for electricity) and bioenergy (mainly biomass used for cooking and heating in the world's poorest communities) are by far the largest sources of renewables-based energy supply today (Box 10.2). Renewables are the world's second-largest source of electricity supply (after coal) and growing rapidly, while their role in heat and transport is at an earlier stage, but with huge growth potential (Figure 10.1). In many cases, government targets and supporting policies are a driving force behind renewable energy growth, signalling the intention to make renewables a very much bigger part of the energy system and the determination to overcome the obstacles. These policies often assume very different forms, such as support to technological innovation or pricing to account for emissions-related externalities of other fuels. Market developments are also critical, with the industry's capacity growing and evidence building of renewable energy attaining cost-competitiveness within the criteria of existing markets.

Figure 10.1 ▷ World share of renewable energy by sector and type, 2014



Power is leading the transition to renewable energy; other sectors lag behind

* Excludes the traditional use of biomass. ** Includes blast furnaces and coke ovens in industrial energy use.

Box 10.2 ▷ Bioenergy must be sustainable

In terms of sustainability, different forms of bioenergy are not alike. Bioenergy feedstocks represent a collection of different products and by-products from the agriculture, forestry and waste sectors (e.g. wood, charcoal, sugarcane, palm oil, wheat straw, animal waste) and many pathways exist for them to be used to produce energy (heat, electricity and fuels). Solid biomass remains the number one source of energy used by households (in energy-equivalent terms) and is often consumed in inefficient and polluting cookstoves, with no chimney or one that operates poorly (mainly in Africa and developing Asia[4]). The resulting household air pollution is estimated to be responsible for around 3.5 million premature deaths per year (IEA, 2016a). This so-called "traditional use" of solid biomass is neither sustainable nor desirable. The volumes concerned are treated separately throughout this text and are generally excluded when presenting shares of energy from renewable sources.

Solid biomass can also be used for cooking and heating in more advanced, efficient and less polluting stoves. It may also be used as fuel in combined heat and power (CHP) plants or transformed into processed solid biomass (pellets), liquid biofuels or biogas. However, there are a number of potential concerns regarding sustainability that have to be considered seriously when planning to use biomass, such as the over-intensive use of resources, deforestation, loss of biodiversity, life-cycle greenhouse-gas (GHG) emissions, including from land use changes and air pollution linked to combustion. This means that transparent and stringent sustainability criteria need to be designed, implemented and enforced. Advanced biofuels offer a route to address many of these concerns within the transport sector (e.g. those based on lignocellulosic biomass) but, despite some progress, commercialisation of these fuels has been slower than anticipated. In addition, the use of residues from existing forestry and agricultural activities, as well as biomass sourced from different waste streams, can satisfy sustainability considerations.

The sustainability of bioenergy continues to be hotly debated. The focus is on overall net carbon savings that can be achieved and the extent to which biomass use for energy purposes could impinge on food production. A number of national and supra-national initiatives exist, such as the Global Bioenergy Partnership, which has developed and is piloting a set of sustainability indicators across countries. Many assessments of the global potential of sustainable biomass have been conducted, but often with different assumptions about some of the less settled issues (such as crop yields on marginal lands). Bioenergy has the potential to contribute to decarbonisation of the power, heat and transport sectors, as well as bring wider benefits in terms of rural development and diversification of energy supply. However, it is important that these benefits are balanced against the sustainability considerations that are unique to each bioenergy supply chain application.

4. Developing Asia includes all non-OECD Asian countries.

10.2.1 Policy developments

Sustained government policies and support measures are a critical determinant of the pace at which renewable energy develops around the world and, over the last year, countries have made an exceptional number of related commitments. There is a virtuous cycle emerging between policy support (across research, development and deployment) and renewable energy technology costs that continues to improve the outlook: policy support leads to more deployment of renewables that drives down their costs, which enables policy-makers to support more renewable energy while respecting budgetary constraints and consumer affordability.

COP21 delivered a range of outcomes that were supportive of renewable energy, from the commitment to hold the increase in global temperatures to "well below 2 degrees Celsius (°C)" (and to make efforts to limit it to 1.5 °C) to the 162 Nationally Determined Contributions (NDCs) to tackle climate change (over 100 countries identified renewable energy as a priority area and over 70 tabled specific deployment targets, mainly relating to renewables-based power generation). Complementary initiatives included the International Solar Alliance, Global Geothermal Alliance, Global Alliance for Buildings and Construction (cleaner, more efficient buildings), Mission Innovation (double public investment in clean energy research) and the Breakthrough Energy Coalition (private sector energy innovation). The UN Sustainable Development Goals include a target to increase the share of renewables in the global energy mix substantially by 2030 and, under China's Presidency, the G20 adopted a Voluntary Action Plan on Renewable Energy. In June 2016, the Clean Energy Ministerial (CEM) (whose members account for around 90% of global clean energy investments and 75% of GHG emissions) announced new actions on renewables and energy efficiency, and entrusted its secretariat to the International Energy Agency (CEM, 2016).

Over 150 countries have adopted specific policies for renewables-based power, 75 have policies for renewables-based heat and 72 for renewables in transport (Figure 10.2). Power sector policies are evolving, as the status of renewables matures: initial policies were targeted at bridging a large cost gap, but recent initiatives have moved towards reducing the risks of capital-intensive investments. Feed-in tariffs have been pivotal in accelerating the deployment of renewables and remain the dominant form of policy support for renewables-based power generation; but 2015 was the first year since 2000 that no new schemes were launched (REN21, 2016). A positive indication of the maturity of the market is the increasing popularity of the use of auctions as the means by which to contract for renewables-based power: over 60 countries had some form of auction mechanism in place in 2015 (REN21, 2016). The shift towards auctions is widely viewed as an effective means of price discovery.

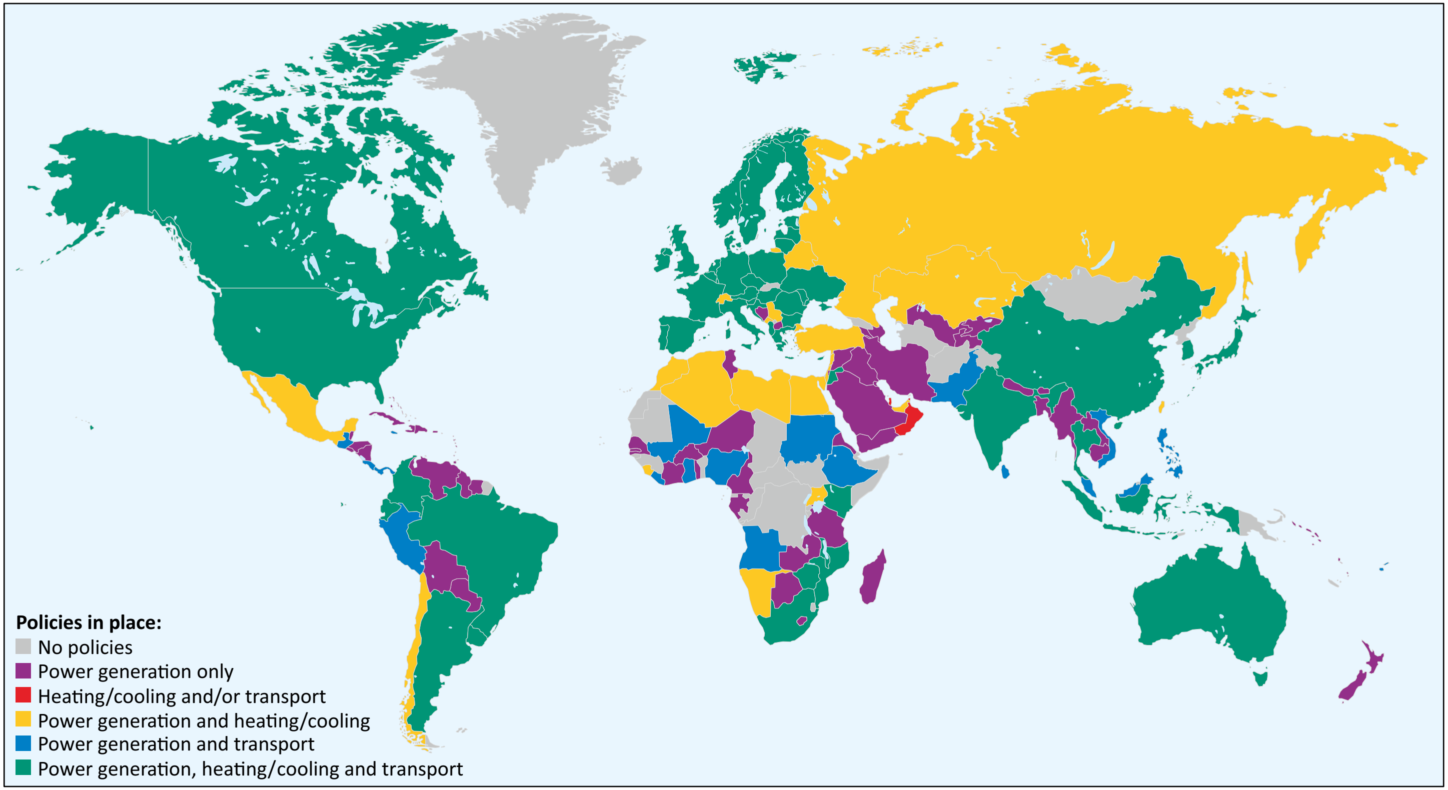
Policies to encourage renewables-based heat (often referred to here simply as "renewable heat") remain relatively scarce, although there are some examples in industry (the Heat Fund in France and the Renewable Market Incentive Programme in Germany) and in buildings (the Renewable Heat Incentive in the United Kingdom, Austrian support for small-scale biomass heat and France's Heat Fund). The preferred policy measure tends to be either fiscal incentives (primarily for households and often linked to building renovation, energy efficiency or, in some cases, fuel switching) or building standards (primarily those requiring new-builds to have a certain share of heat supplied from renewables, or a solar thermal system for water heating, e.g. in Israel, Spain, Brazil and Kenya). Renewables obligations as part of building standards can be particularly effective in emerging economies where the building stock is expanding quickly. For example, South Africa has specified that renewables or other non-resistance heating[5] should meet at least 50% of water heating requirements in new buildings. Those countries, like Denmark and Sweden, which have been particularly successful in achieving a high share of renewable heat have tended to set ambitious targets backed up by measures such as building standards, obligations to connect to district heating networks and carbon taxes.

Renewable energy policies in transport have also generally been slow to develop, with most being focussed on road transport and biofuels (mostly conventional biofuels; but growing support for advanced biofuels is evident), in particular options that do not require costly modifications to existing infrastructure and the vehicle fleet. Biofuels production continues to be underpinned by blending mandates (with some countries, such as Brazil and Indonesia, increasing their mandates in recent years), subsidies (such as in the United States, the largest biofuel market) or a combination of both. In the European Union, sustainability concerns are a significant influence on biofuel development, emphasis is now being placed on accelerating the transition to more advanced biofuels (European Commission, 2016). In 2015, the update of the fuel quality and renewable energy directives decreed a 7% cap on conventional biofuels in final transport consumption while maintaining the 10% target for renewable sources in all forms of transport by 2020 (a withdrawal of support for conventional biofuels by 2020 is also under discussion). As well as blending mandates, some administrations, such as in India and California, have used tax incentives to support the use of biofuels. Measures to increase the distribution infrastructure for renewable fuels have also been introduced in some regions, such as in the United States, where $100 million has been made available to expand pump infrastructure for E15 and E85 ethanol fuel blends (15% and 85% ethanol by volume).

In the United States, the duration of two key power sector support policies have been extended by five years, marking a major positive change in the policy outlook (Figure 10.3). They are the Business Energy Investment Tax Credit (ITC), which mainly supports solar PV, and the Renewable Energy Production Tax Credit (PTC), which mainly supports wind power. On the other hand, a pending Supreme Court decision on whether to uphold the Clean Power Plan has created uncertainty for the US power sector.[6]

5. Resistance heating refers to direct electricity transformation into heat.
6. To reflect the uncertainty around the implementation of the US Clean Power Plan and possible changes to China's 2020 renewables targets, the treatment differs across scenarios. The Current Policies Scenario does not assume the implementation of either of them, while the New Policies Scenario and the 450 Scenario do.

Figure 10.2 ▷ Renewable energy policy coverage by country and type

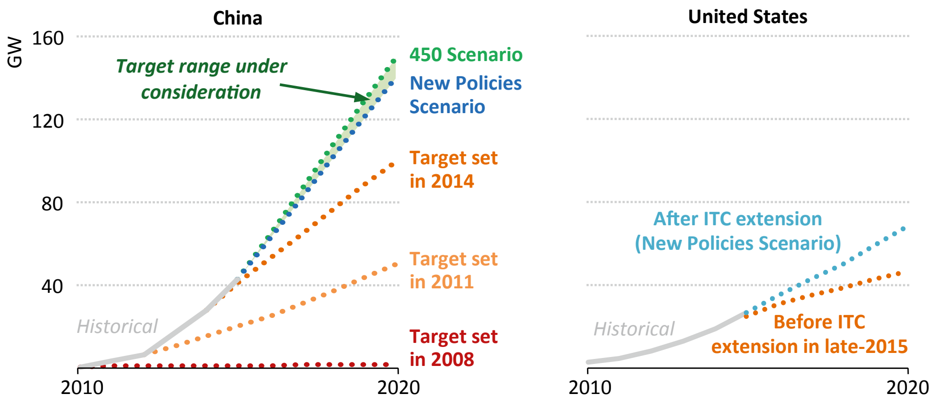


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Sources: IEA/IRENA Policies and Measures Database (2016); IEA SHC (2016); RES LEGAL Europe (2016); IEA analysis.

In the last few years, China has led the world in expanding its renewables-based power generation capacity and its ambition shows no sign of weakening. China's COP21 commitment indicated that wind capacity is to be expanded to 200 gigawatts (GW) by 2020 and solar power to 100 GW. *WEO-2015* highlighted the scope for China to push beyond these levels and there are clear signs that some higher targets for 2020 are being considered: a possible 30-50 GW increase for both wind and solar PV and a 10 GW increase for concentrating solar power (CSP), though cuts for hydro (55 GW) and biomass (15 GW) are also under consideration). The target revisions are material to the outlook both for China, reflecting an increase in pace and trajectory, and for the world at large.

Figure 10.3 ▷ Solar PV targets and deployment in China and the United States



Evolving policy targets have boosted the outlook for solar PV

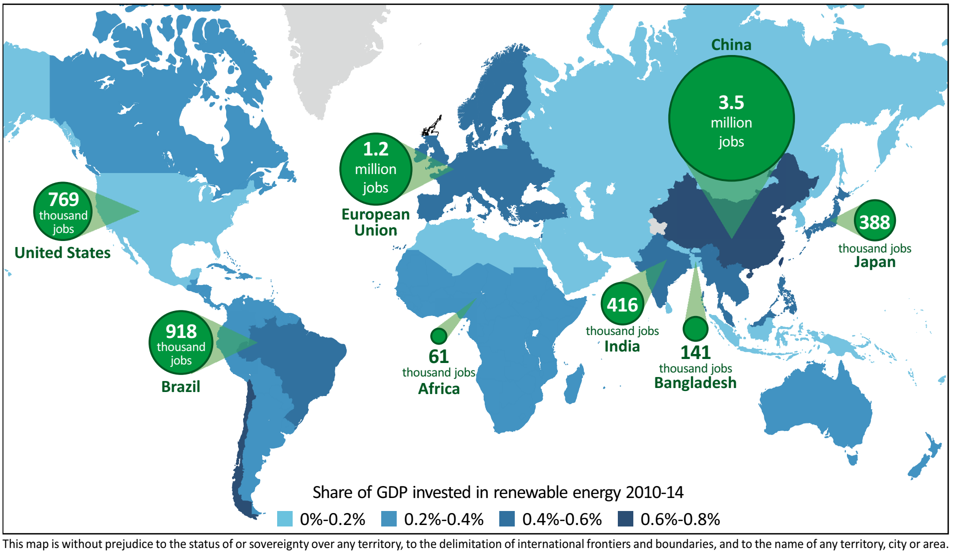
Notes: For the United States, solar PV capacity reaches 70 GW in 2020 in the 450 Scenario, slightly beyond the already significant expansion in the New Policies Scenario.

In May 2016, Japan amended the terms of its (generous) feed-in tariff to require authorised projects to have connection contracts with power companies by no later than end-March 2017 or they will be cancelled. Over 100 GW of solar PV projects have been approved to date, with around 30 GW having been installed by the end of 2015, so the remaining 70 GW are subject to the new deadline. In February 2016, India released state-specific targets consistent with its national aim of a 17% Renewable Purchase Obligation (RPO) level by 2022. The government has also accelerated the approval of large-scale solar PV projects through its Solar Park initiative, which aims to support the creation of the necessary infrastructure to enable the establishment of concentrated zones of development of solar power generation projects (around 20 GW of new capacity has been approved so far) (SECI, 2016). In the European Union, targets to provide "at least" 27% renewable energy and 45% renewables-based electricity by 2030 remain important in promoting and pacing progress. The feed-in tariff model that successfully expanded renewables-based capacity in Germany's power system has been replaced by a system of competitive auctions for large-scale solar power systems and adjustment mechanisms introduced for feed-in tariffs for small installations. The law bringing in the change specifies a target of 55-60% of renewables-based electricity by 2035 and at least 80% by 2050.

10.2.2 Market developments[7]

A major global industry for renewable energy has been established and continues to grow. At $288 billion in 2015, renewables accounted for 70% of total electricity generation investment, dwarfing investment in fossil-fuel based generation (IEA, 2016c). Though the level of investment in renewables for electricity generation has remained broadly stable since 2011, this investment now funds projects that generate one-third more electricity on an annualised basis, thanks to technological progress and cost reductions. Investment was led by wind power (37%), solar PV (34%) and hydropower (20%). China led global investment in renewables-based generation in 2015 ($90 billion, more than double its investment in fossil fuel-based generation), followed by the European Union ($56 billion, led by wind), the United States ($39 billion, led by solar PV and wind) and Japan ($30 billion, mainly solar PV).

Figure 10.4 ▷ Average renewables investment as a share of GDP (2010-2014) and renewable energy jobs in selected regions, 2015



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.

China leads renewables investment and jobs, followed by the European Union, Brazil and the United States

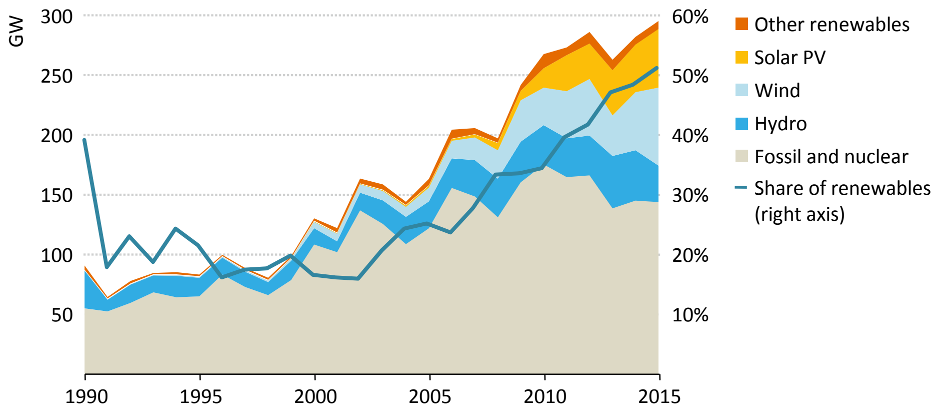
Note: Levels of investment in renewables are calculated based on *WEO* regions.

Sources: IEA (2016c); IRENA (2016a).

7. For more on short-term market developments for renewables see the IEA's Medium-Term Renewable Energy Market Report (2016b) at *www.iea.org*.

An estimated 8.1 million people are employed in the renewable energy sector worldwide (excluding hydropower), led by China, the European Union, Brazil, the United States, India and Japan (Figure 10.4) (IRENA, 2016a). Solar PV is the largest renewable energy employer, followed by biofuels and wind. The solar industry has seen the manufacturing capacity of PV modules expand by almost 20%, to reach 62 GW per year in 2015, with over half of the total capacity located in China (SPV Market Research, 2016). Annual wind turbine manufacturing capacity now stands at around 80 GW per year, Chinese companies accounting for around one-quarter of total supply, followed by the European Union and the United States (BNEF, 2016).

Figure 10.5 ▷ World renewables-based power capacity additions by type and share of total additions



Renewables-based power capacity additions set a new record in 2015 and exceeded those of all other fuels for the first time

Note: Other renewables include biomass, CSP, geothermal and marine.

The renewables industry passed a major milestone in 2015, with capacity additions exceeding those of fossil fuels and nuclear for the first time (Figure 10.5). In addition, the more than 150 GW of renewables-based capacity additions in 2015 was a new record, nearly quadruple the level achieved a decade earlier.[8] The world's renewables-based generation capacity at around 1 985 GW now exceeds that of coal (1 950 GW), albeit supplying around 40% less electricity than from coal. While the scale of capacity additions fluctuates from year to year, the trend of rapidly growing deployment of wind, solar PV and (to a lesser extent) hydro over the last decade is unmistakable and perhaps one of the clearest signs of an energy transition taking place.

8. Total power capacity additions were also at an all-time high and around three-times the average level of the 1990s (see Chapter 6).

Renewables-based power capacity additions in 2015 were led by wind, which were nearly 35% higher than the previous year and established another record high (65 GW). China (half of all additions), the European Union (led by Germany) and the United States together accounted for more than 80% of the global total for wind power capacity additions. At 49 GW, in 2015 solar PV outperformed its previous record year by around 25%. China added more than 15 GW of new capacity and overtook Germany as the country with the largest installed solar PV capacity.[9] The United States saw solar PV additions rise substantially (to 7.3 GW) which, for the first time, was more than total natural gas capacity additions, a notable achievement given the low natural gas prices and that gas has been a leader in US capacity additions. Japan's government target and subsidy scheme were key to the addition of 11 GW of solar PV capacity. The United Kingdom saw the highest level of solar PV capacity additions in Europe (3.7 GW), while Germany, which once set the global pace for solar PV expansion, saw a slowdown. World hydropower additions were 31 GW in 2015 and, while down over 30% on the previous year, mainly due to less activity in China, there were still notable increases in capacity in the Middle East, Turkey and India. Bioenergy additions have remained relatively stable, at around 7 GW per year, since 2010.

Renewables contributed 23% of global electricity supply in 2014 (the most recent year for which comprehensive statistics are available), of which more than 70% was from hydropower and 17% from variable renewables. China and the European Union are the leaders today in terms of total renewables-based electricity generation, while the likes of Iceland, Norway, Brazil, Canada, Austria and Sweden are in a league of their own when it comes to the share of electricity generated from renewable sources. The European Union (EU) has the highest share of variable renewables, meeting 11% of overall electricity demand from projects harnessing wind or solar resources, but there is considerable variation across individual EU member states.

Turning to renewable heat capacity, at the global level this has grown, though progress has been uneven. Worldwide, solar thermal capacity is estimated to have reached 435 gigawatt thermal (GW_{th}) in 2015 (IEA, 2016b). China's solar thermal capacity accounts for more than 70% of the world solar thermal market, exceeding the "400 million square meters of solar collectors" targeted under the 12th Five-Year Plan. Global geothermal capacity reached 22 GW_{th} in 2015, with output of 75 TWh (REN21, 2016).

Biofuels have enjoyed policy support (primarily blending mandates) for a number of years. Yet some factors have limited demand growth, including the slow and uneven economic recovery and advances in conventional vehicle fuel economy, which have resulted in weaker than expected demand for transport fuels. Several challenges remain, including the need to adapt fuel distribution infrastructure, low uptake of flex-fuel vehicles and sustainability concerns. Global conventional biofuels production increased by 1.2% in 2015

9. Solar PV developers in China rushed to complete projects by mid-2016 so as not to be affected by feed-in tariff reductions, resulting in a record-level of 22 GW being installed by July. At the time of writing, capacity additions were expected to slow in the second-half of 2016 to reach a total of 27 GW by the end of the year.

(to 1.3 million barrels of oil equivalent per day [mboe/d]), with blending mandates often proving effective in shielding biofuels from the low oil price environment (although price was a challenge in some markets). The largest markets for ethanol are in the United States, Brazil, China, Canada and Thailand, while the largest for biodiesel are in the United States, Brazil, Germany, Argentina and France. Two commercial advanced biofuels plants started operations in 2015, two others are scheduled to do so by the end of 2016 and nine other projects have been announced. Also, there has been further progress in the demonstration of biofuels use for aviation and shipping. Biojet fuels, with blends of up to 50% biofuel, have been used by more than 20 airlines in more than 2 500 commercial flights (IATA, 2016). In the maritime sector, a US-funded project has reported the completion of over 14 000 nautical miles using biodiesel (Scripps Institution of Oceanography, 2016).

Electricity can power clean transport when supplied by low-carbon sources: on average, 16% of the electricity used by the world's electric vehicles (EVs) in 2014 is estimated to have come from renewable sources. While electric power is long established in the rail sector, major efforts are underway to expand electric-powered road transport. World sales of EVs grew by 70% in 2015 and, for the first time, numbers on the road exceeded one million (reaching nearly 1.3 million) (IEA, 2016d).[10] The market share of EVs is now above 1% in seven countries: Norway (23%), the Netherlands (nearly 10%), Sweden, Denmark, France, China and the United Kingdom. China's was the main market for sales of EVs in 2015, ahead of the United States for the first time. Worldwide there are now more than 200 million electric two-wheelers on the road (with China, by far, having the strongest deployment) and around 170 000 buses. To date, purchase incentives have proven among the most effective ways of boosting EV sales. A broadening range of EV models becoming available (and the number of automakers offering them) is also expected to support higher sales. Some cities have seen electric light-duty commercial vehicles become an increasingly common sight, while some manufacturers have announced plans to introduce electric heavy-duty trucks within the next few years. Battery costs have been cut by a factor of four since 2008 and energy density has been boosted by a factor of five (IEA, 2016d), with further advances in technology holding the promise of further improvements.

Rapid cost reductions for some power technologies (together with supportive policies) have underpinned the major expansion of the market for renewables-based generation. Many electricity retailers or utilities are also becoming more positive towards distributed generation, notably rooftop PV. To date, markets such as Australia and Belgium have seen among the highest rates of rooftop solar PV adoption in homes.

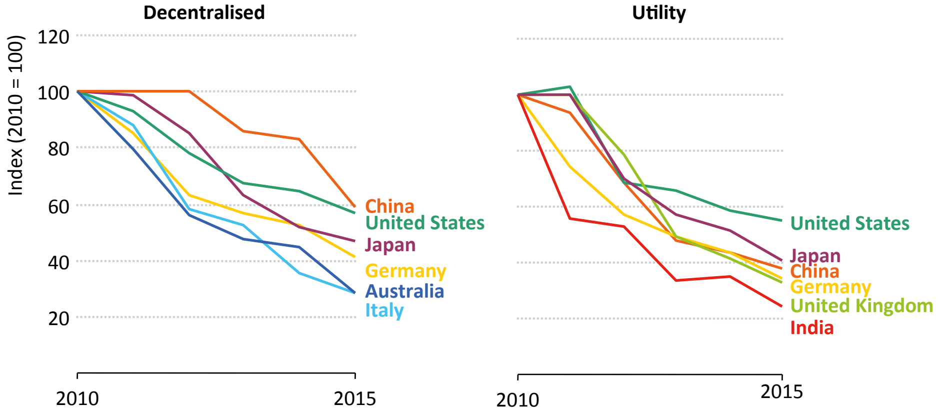
Solar PV has led the way on cost reductions for renewables with both utility- and decentralised-scale installations seeing cost declines of 40-75% in leading markets since 2010 (Figure 10.6). Europe was a leader in driving down solar PV costs, with low cost manufacturing in China also playing an important role as its costs have come down quickly since it began ramping up deployment. By contrast, the United States is a high cost region

10. Including battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

for solar PV (mainly due to higher "soft costs", e.g. various non-hardware costs, such as permitting/regulation, installation and maintenance); but costs are coming down.

Wind power has also enjoyed major cost reductions. Indicative global onshore wind generation costs for new installations having fallen by around one-third on average between 2008 and 2015. This has been achieved by increasing capacity factors more than by reducing unit investment costs. Specifically, new wind turbines, with higher towers and longer blades, which were first developed to suit lower wind speed areas, have also been erected in higher wind speed areas. In the United States, more recent wind turbine installations generally achieve higher capacity factors than older projects; in 2015, projects completed in 2014 averaged 41%, compared with around 31% for those installed from 2004-2011 (US DOE, 2016).

Figure 10.6 ▷ Index of solar PV unit investment costs in selected markets



Solar PV investment costs have fallen rapidly around the world

Notes: For buildings, no data are available for China in 2010 and 2011. For utility, no data are available for the United Kingdom and Japan for 2010.

Sources: For *WEO-2016*, the International Renewable Energy Agency (IRENA) has provided solar cost data by region up to 2015 (2016b); IEA analysis.

Auction bid prices for renewables-based electricity supply are closely monitored and reported as a means to try and gauge the extent to which renewables can compete with other forms of supply. This positive development is associated with the growing maturity of renewable energy markets, as reflected in lower capital, operations and maintenance costs, but also in improved performance (such as from higher capacity factors) and other factors. However, the reported bid prices should be interpreted with some caution. For instance, it may not be clear if offer prices are being reported before or after government support has been accounted for, or whether they take into account costs to connect projects to the grid. (See Chapter 11 Box 11.2 on Auction bid prices versus LCOEs.)

10.3 Overview of trends by scenario[11]

The technical potential for renewable energy is enormous and the resources available around the world could, in theory, meet all the energy needs projected in each *WEO* scenario with ease. Good quality wind and solar sites are still available in most countries, both for utility-scale and distributed generation and less favourable, but still viable, areas for wind and solar development have been expanding due to technological advances, such as low-speed wind turbines and more efficient solar cells. Worldwide technical potential for hydropower generation is estimated to be around 14 600 TWh per year, with a corresponding installed capacity of over 3 700 GW (IPCC, 2011), roughly three-times the current installed capacity (IHA, 2016). The potential is especially large in countries with great need for increasing electricity supply (the potential is highest in Africa, Asia and Latin America). While many developed economies have already largely exploited their hydropower potential, many developing economies have yet to do so and these are the countries expected to lead the growth in electricity demand. Biomass feedstocks, which include agricultural and forestry residues, energy crops and some waste resources, are widely available but clear governance measures are needed to achieve fuel sustainability. Geothermal is a mature renewable energy technology and can achieve low levelised costs, but high quality resources are less widespread.

WEO scenarios demonstrate the huge impact that government policies can have on the energy and emissions outlook and the policy environment for renewables is perhaps the most dynamic in the energy sector. The outlook for renewables is very bright in each of the three scenarios, but the pace of growth varies significantly: as policies to make the energy system more sustainable and secure are strengthened across the scenarios, they both slow the growth in overall energy demand and, at the same time, accelerate the uptake of renewable energy options (Table 10.1). The key difference between the Current Policies Scenario and the New Policies Scenario is that the latter allows for the implementation of the intentions announced in the COP21 climate pledges, the Clean Power Plan in the United States and the signalled revision to 2020 renewables targets in China. However, global energy-related carbon-dioxide (CO_2) emissions continue to rise through to 2040 even in the New Policies Scenario, showing that the COP21 commitments are not sufficient to put the world on a path that limits long-term global warming to no more than 2 °C above pre-industrial levels. The 450 Scenario, therefore, sets out one plausible energy path to achieve this goal, making due allowance for technology preferences and restrictions. It highlights the need for a further step-change in renewable energy as it, together with energy efficiency, represents the most promising emissions abatement option. (The energy sector implications of a "well below 2 °C" climate pathway, which portrays more rapid action to decarbonise than the 450 Scenario, is considered in Chapter 8.5.)

11. The Current Policies Scenario includes only policies firmly enacted as of mid-2016 and, as such, represents a baseline against which to assess greater action. The New Policies Scenario incorporates existing energy policies as well as an assessment of announced intentions but intentionally does not (and indeed cannot) project the results of policies that have yet to be defined and adopted. The 450 Scenario illustrates one plausible pathway to limit long-term global warming to 2 °C above pre-industrial levels (see Chapter 1).

Table 10.1 ▷ World renewables consumption by scenario

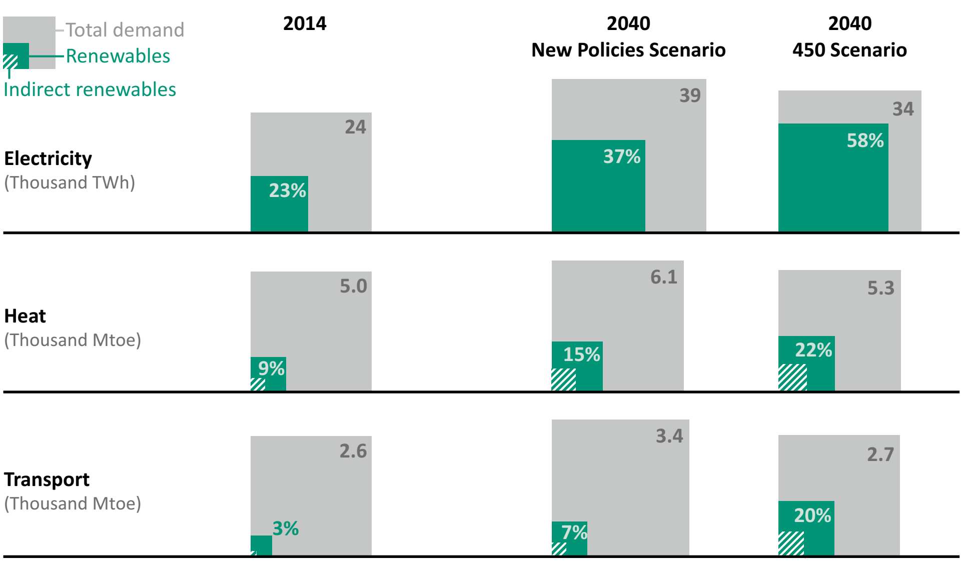
		New Policies		Current Policies		450 Scenario	
	2014	**2025**	**2040**	**2025**	**2040**	**2025**	**2040**
Primary demand (Mtoe)	**1 161**	**1 786**	**2 837**	**1 705**	**2 528**	**2 017**	**4 049**
Share of global TPED	*8%*	*12%*	*16%*	*11%*	*13%*	*14%*	*27%*
Traditional use of solid biomass (Mtoe)	**776**	**744**	**619**	**748**	**629**	**742**	**612**
Share of total bioenergy	*55%*	*46%*	*33%*	*46%*	*34%*	*43%*	*27%*
Electricity generation (TWh)	**5 383**	**8 960**	**14 271**	**8 384**	**12 305**	**9 890**	**19 883**
Bioenergy	495	785	1 353	754	1 151	843	1 899
Hydropower	3 894	4 887	6 230	4 817	5 984	4 994	6 891
Wind	717	2 118	3 881	1 859	3 132	2 575	6 127
Geothermal	77	150	361	141	299	181	548
Solar PV	190	953	2 137	761	1 539	1 153	3 209
Concentrating solar power	9	61	254	49	170	137	1 118
Marine	1	6	54	3	30	7	92
Share of total generation	*23%*	*30%*	*37%*	*27%*	*29%*	*36%*	*58%*
Final consumption (Mtoe)[1]	**819**	**1 260**	**1 979**	**1 193**	**1 762**	**1 439**	**2 816**
United States	128	188	268	178	250	232	413
European Union	165	228	300	217	269	240	356
China	120	250	440	224	360	292	598
Share of global TFC	*9%*	*12%*	*16%*	*11%*	*13%*	*14%*	*26%*
Heat consumption (Mtoe)[1,2]	**436**	**611**	**920**	**597**	**862**	**665**	**1 168**
Industry	221	296	434	296	432	316	527
Buildings and other[3]	215	315	485	300	430	349	641
Share of total heat demand	*9%*	*11%*	*15%*	*11%*	*13%*	*13%*	*22%*
Biofuels (mboe/d)[4]	**1.6**	**2.5**	**4.2**	**2.2**	**3.6**	**4.0**	**9.0**
Road transport	1.5	2.5	4.0	2.2	3.4	3.4	6.1
Aviation and maritime[5]	0.01	0.05	0.25	0.03	0.13	0.65	2.8
Share of total transport fuels	*3%*	*4%*	*6%*	*3%*	*4%*	*7%*	*18%*

[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.

Notes: Mtoe = million tonnes of oil equivalent; TFC = total final consumption; TPED = total primary energy demand; TWh = terawatt-hours; mboe/d = million barrels of oil equivalent per day.

The differing levels of policy ambition determine the share of renewables in the primary energy mix in the scenarios: from 8% today to 13% by 2040 in the Current Policies Scenario; 16% in the New Policies Scenario; and 27% in the 450 Scenario. In terms of final energy consumption, the share of renewables in the mix goes from 9% in 2014 to 13% in 2040 in the Current Policies Scenario; 16% in the New Policies Scenario and 26% in the 450 Scenario. In all scenarios, the long-term trend of increasing electrification continues, with the relative role of renewables-based electricity strengthening in line with energy-related climate policies and declining technology costs.[12] Generation from all renewable energy technologies grows (Figure 10.7), with solar PV and wind expanding most rapidly, but hydro remaining the largest renewables contributor to electricity supply in all scenarios. Electricity sees the strongest growth among final energy sources in the New Policies Scenario, raising its share in energy end-use from 18% to 23% by 2040, but it grows more slowly in the 450 Scenario, as stronger energy efficiency actions are taken (see Chapter 6).

Figure 10.7 ▷ Share of global demand met by renewables in selected sectors in The New Policies and 450 Scenarios



Renewables grow significantly across sectors, but must do so more quickly in a scenario consistent with limiting climate change

Note: Within each sector, the area of the boxes is scaled relative to 2014, but not across different sectors.

Over the *Outlook* period, the use of renewables for heat grows substantially in the Current Policies Scenario and more than doubles in the New Policies Scenario. In both cases, although industry and buildings see significant growth (but from a low base), the renewables share of total heat use (which also grows) remains relatively low. In transport, liquid biofuels use increases to 3.6 mboe/d in 2040 in the Current Policies Scenario (where supportive policies are fewer) and 9.0 mboe/d in the 450 Scenario. Advanced biofuels promise to provide a sustainable pathway to raising total biofuels production, but have to overcome major challenges to become available on the scale required in the 450 Scenario.

12. Electrification both in terms of more people gaining access to electricity (today, 1.2 billion people still do not have access to electricity) and in terms of electricity being used to underpin a broader range of energy services from appliances to transport.

The traditional use of biomass in households decreases in all scenarios, but remains widespread, not because of a weakness in renewables policies per se, but because, despite increasing awareness, policy action to provide modern forms of energy for cooking and heating has yet to reach the level of intensity required (see Chapter 2.8 on energy access).

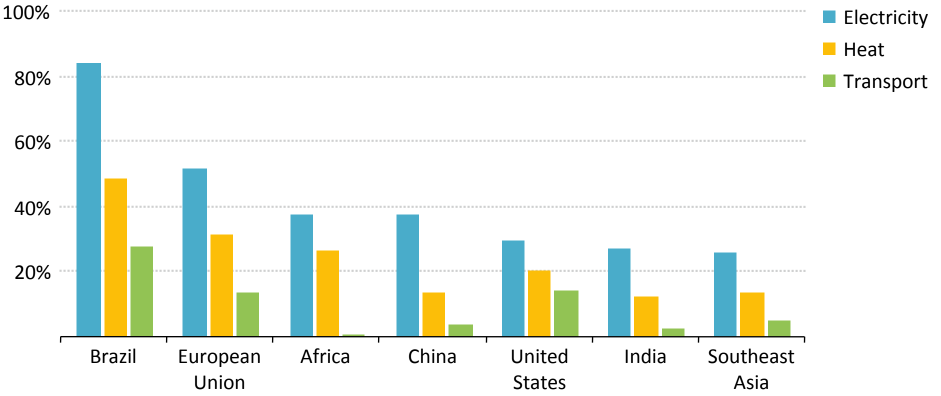
10.4 Outlook in the New Policies Scenario

Expectations for renewable energy continue to be raised as more ambitious targets and policies are announced, and cost reductions continue to be realised. In the New Policies Scenario, renewable energy used to meet primary energy demand increases by almost 150%, reaching nearly 2 840 Mtoe in 2040 (more than 3% higher than estimated in *WEO-2015*). While policies will continue to evolve, the commitments made at COP21 provide solid insight into national ambitions for renewable energy in the pre-2030 period. In the New Policies Scenario, the slight slowing of the growth in renewable energy post-2030 does not reflect a constraint on renewables potential, but is more a reflection of the fact that policy beyond 2030, or the measures to be adopted, has, in many cases, yet to be established (whereas the projections in the New Policies Scenario are based on known intentions).

Demand grows for all fuels (fossil and low-carbon alike) in the New Policies Scenario and energy-related carbon emissions continue to increase (albeit more slowly than in the past). The *Outlook* presented in the New Policies Scenario accordingly reflects a relative shift towards low-carbon supply, rather than a definitive energy transformation. Regions around the world see the share of renewables in their energy mix increase over the period, with the power sector generally leading the way (Figure 10.8). The transport sector lags behind. In the United States, renewables accounted for more than three-quarters of all power generation capacity additions in 2015 and by 2040 renewables make up almost 40% of all installed power generation capacity. The outlook for solar PV is noticeably higher than in *WEO-2015,* reflecting the new measures adopted in the last twelve months. The United States sees the share of renewables in the primary energy mix increase from 7% today to 16% in 2040, while the share of coal declines from almost 20% today to just 12%. China's energy development has entered a new phase, with the transition of the economy to a less energy-intensive form being accompanied by a move from the coal-led growth of the past to growth led by renewables and other forms of energy (such as gas and nuclear) and increased energy efficiency. China's renewables-based power capacity now exceeds that of the European Union and is more than double that of the United States. Renewable energy now accounts for 5% of China's primary energy mix and this increases to 14% in 2040 (the renewable share of electricity rises to 38%).

The European Union has been a long-time leader in the adoption of renewable energy and in action on climate change: 14% of its primary energy mix is renewables today (up from 6% in 2000) and this share increases to 28% in 2040 (over half of all electricity generation). In India, policy targets and competitive auctions are set to speed the expansion of renewables capacity in the power sector, especially solar PV. India achieves more than any other country (in absolute terms) in expanding electricity access over the *Outlook* period and is successful in providing electricity to its entire population by 2040. The grid remains the main conduit for electricity supply in India, though mini- and off-grid solutions play an important role in delivering electricity access in more remote areas.

Figure 10.8 ▷ Share of renewables by use in selected regions in the New Policies Scenario, 2040



All regions see the share of renewables grow, but they dominate in only selected regions and sectors by 2040

10

10.4.1 Electricity

Capacity additions[13]

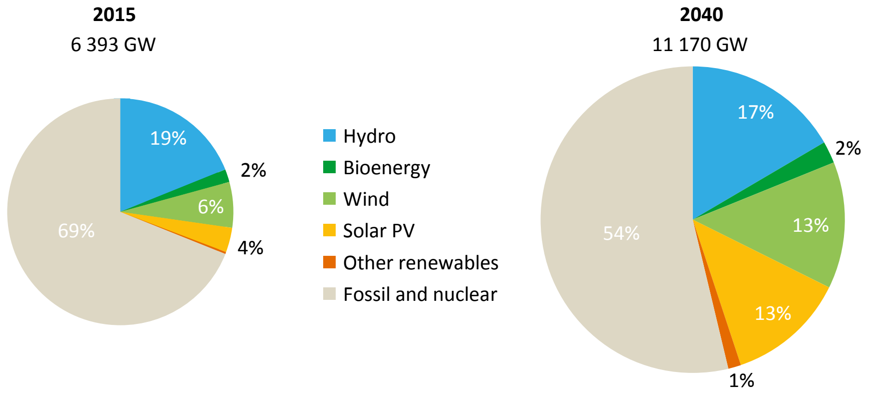
Renewables account for nearly 60% of all new power generation capacity additions in the world to 2040 in the New Policies Scenario. More than 4 000 GW are deployed from 2016 to 2040, four-times the level of coal-fired capacity additions. Of the renewables capacity additions to 2040, 37% are wind (led by China and the European Union), 35% solar PV (China, India and the United States) and around 20% hydro (China and Latin America). By 2040, renewables make up nearly half of total power generation capacity, up from less than one-third in 2015 (Figure 10.9). Combined, wind and solar PV capacity account for more than one-quarter of global installed capacity, higher than the figure for either coal or natural gas.

Variable renewables make up more than 40% of total generating capacity additions to 2040 and almost three-quarters of all renewables-based capacity additions. Wind power leads the way, mainly developed onshore in many countries around the world, while offshore installations make up 10% of total wind power capacity additions, mostly in China and the European Union. Solar PV capacity, including large- and small-scale installations, is close

13. Data are for gross capacity additions.

on the heels of wind, accounting for more than one-third of renewables-based capacity additions and one-fifth of total capacity additions for all fuels. Dispatchable renewable energy technologies (see Box 10.1), account for more than one-fifth of renewables-based capacity additions, led by hydropower. Dispatchable renewables can play an important role in helping to integrate variable renewables into the electricity system, as can the complementarity of some variable renewable resources with one another and other integration options (see Chapter 12.2).

Figure 10.9 ▷ World power generation capacity by type in the New Policies Scenario



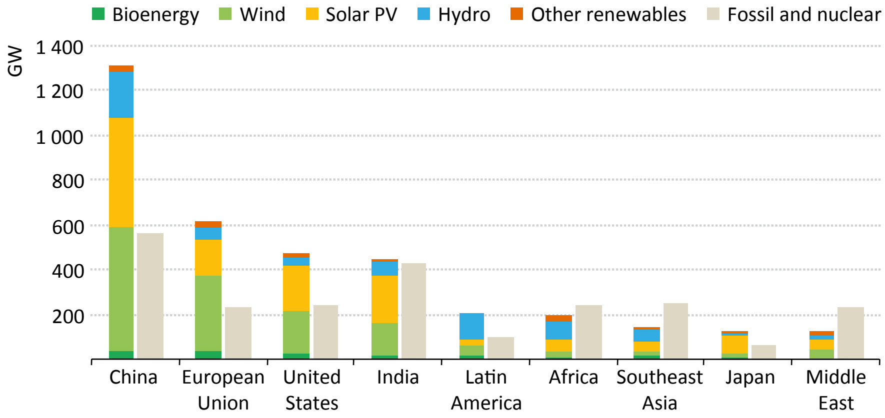
Renewables account for nearly half of total installed capacity by 2040, up from 31% today

Note: Other renewables include CSP, geothermal and marine.

Over the *Outlook* period, renewable capacity additions far outweigh all others in the European Union, China, Japan, across Latin America and in the United States (Figure 10.10). In India and Africa, renewable and non-renewable capacity additions are more evenly matched, while in the Middle East and Southeast Asia fossil fuels still lead the way. While it is now common for countries to have support policies in place for renewables in the power sector, the recent changes in two countries have particular importance in shaping the global trajectory of renewables. China, bolstered by the indicated change to its 2020 targets, by a wide margin, leads the expansion of renewables in the power sector in the New Policies Scenario, adding close to 1 300 GW by 2040, more than double its expansion of fossil fuel and nuclear capacity combined. In the United States, the extension of tax credits for solar and wind means that both technologies are set to grow faster to 2020 (when wind is 15 GW higher than in *WEO-2015*; solar PV around 20 GW higher). The ITC is phased out in 2022 for household-scale solar PV, while for utility-scale it is reduced to 10% at that time, thereafter providing a reduced but continuing incentive. By 2040, wind generation capacity in the United States exceeds 180 GW while solar PV capacity reaches

195 GW, making this the first time in the *WEO* series that the long-term prospects for solar capacity in the United States surpass those of wind (albeit not yet true of electricity output). In terms of electricity supply, renewables collectively are on a par with natural gas by 2040 (from only half the level of natural gas today).

Figure 10.10 ▷ Power capacity additions by region and type in the New Policies Scenario



China, European Union, United States and India together account for over two-thirds of the world's renewables-based power capacity additions to 2040

Note: Other renewables include CSP, geothermal and marine.

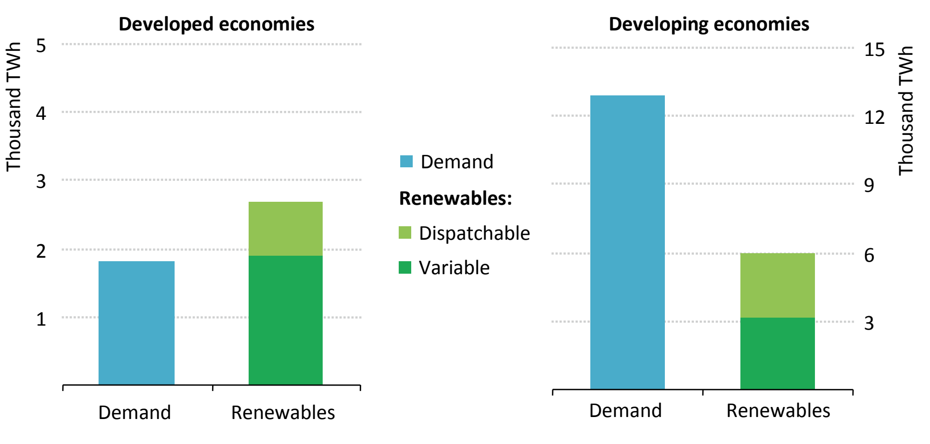
By 2040, the European Union has more than 740 GW of renewables capacity, of which almost 70% is variable. Wind power takes over as the largest source of electricity supply shortly after 2030 and the high share of variable renewables overall places the EU at the forefront of the challenge to tackle large-scale integration of variable renewables (see Chapter 12.3.2). India has set ambitious medium-term targets for renewables and solar PV in particular, in the National Solar Mission, as part of its commitment to reduce dependency on coal-fired power and address concerns relating to air pollution and carbon emissions. In the New Policies Scenario, renewable capacity additions in India match those of non-renewables, but renewables account for a much lower proportion of the additional electricity generation. Japan sees solar PV deployed rapidly in the near-term (reaching 60 GW in 2020), but the scale of annual additions then slows closer to that of wind. Thanks to its excellent solar resources, the solar PV capacity deployed in Africa achieves high capacity factors. However, the level of deployment does not match that of Japan to 2040, underlining the fact that more than just good sunshine is needed to make extensive solar PV capacity a reality.

Electricity generation

By 2030, more electricity is produced globally from renewables than from coal in the New Policies Scenario, led by a more than quadruple increase in output from wind and solar PV and continued growth from hydropower. By 2040, renewables account for 37% of global electricity supply, having left coal far behind (28%). Electricity generation from hydropower increases by 60% maintaining hydropower as the largest source of renewable supply, a critical (if less-discussed) part of the renewable energy mix. Wind and solar PV collectively come close to matching the level of supply from hydro by 2040, but with a growing challenge due to their greater short-term supply variability. By 2040, nearly half of the world's electricity supply is low-carbon. Of this, renewables account for around three-quarters, far beyond the share of nuclear and of fossil-fuel capacity fitted with carbon capture and storage (CCS).

Global electricity consumption increases by around 2% per year in the New Policies Scenario, with the expansion in renewables serving to meet more than half of the increase (see Chapter 6.3.1 for more on the outlook for overall electricity demand). Across the developed economies, renewables-based power generation increases more quickly than electricity demand, meaning that they displace output from fossil-fuelled power plants over time (Figure 10.11). Looking across developing economies, additional renewable electricity generation is not sufficient to meet the full increase in demand in the New Policies Scenario, meaning that electricity from renewable sources increases alongside growth in supply from other sources (rather than displacing them). Renewables also play a key role in providing access to electricity in developing countries (Spotlight).

Figure 10.11 ▷ Change in total electricity demand and renewables-based power generation in the New Policies Scenario, 2014-2040



Growth in renewables-based electricity generation outpaces total demand growth in developed economies but lags behind in developing economies

SPOTLIGHT

Bringing power to the people through distributed renewables

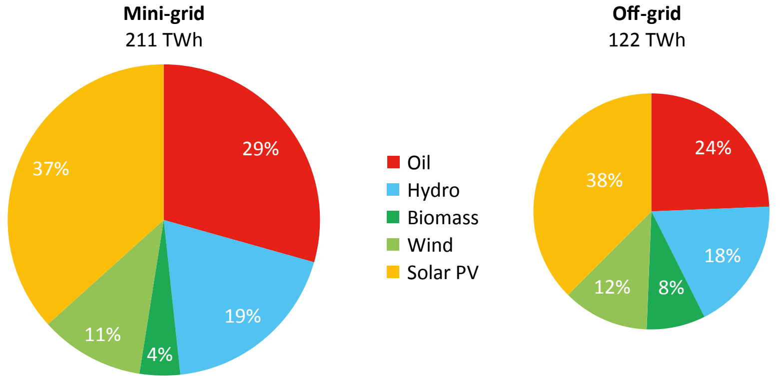
Over half a billion people are projected to remain without access to electricity in 2040 in the New Policies Scenario, with the majority being in sub-Saharan Africa. Renewable energy technologies could make a major contribution to universal access in a sustainable way. Many of those parts of the world which suffer high levels of energy poverty are blessed with abundant renewable energy potential. In Africa, for example, renewables account for half of the growth in electricity generation to 2040 in the New Policies Scenario. Grid-based solutions (including renewables-based supply, such as hydropower, wind and solar, and also geothermal where it is available) will play an important role in providing access to electricity in Africa and developing Asia (as they have done around the world), but many developing countries also have large, sparsely populated areas, far from existing grid infrastructure, which make grid electrification prohibitively expensive. Consequently, mini- and off-grid technologies must form a significant part of the solution to universal access. As technology costs come down, the economics of renewable systems, as part of such off-grid systems, become more attractive than those of the main alternative, diesel-fuelled generators, and are often already competitive.

In a scenario where universal access to modern energy is achieved by 2040,[14] 60% of the capacity additions to deliver electricity access are mini- and off-grid systems, all of which provides electricity to communities in rural areas. Two-thirds of the mini- and off-grid systems are powered by renewables, mainly solar PV, followed by small hydro and wind (Figure 10.12). The productive uses for decentralised renewable energy are many, with even low power services, like lighting and mobile phone charging, and more power-intensive services, such as refrigerators and water pumps, improving the quality of life and increasing productivity.

While the off-grid power market is still at an early phase of development, sales and investment figures suggest the necessary market transformation is beginning. In 2015, an estimated $276 million was raised by off-grid solar companies, 58% of which was raised by pay-as-you-go (PAYG) companies (REN21, 2016). The PAYG business model allows customers to pay a small upfront cost and (using mobile payments) lease the equipment over a number of years at a smaller cost than they would pay for kerosene lighting. By 2016, one company, M-KOPA, had sold more than 280 000 off-grid solar packages (which combine a small solar panel with several LED lightbulbs, a mobile phone charger and radio) for use in homes across several countries in East Africa using this model. The acceleration of sales in these solar packages results largely from their affordability, helped by the PAYG business model, falling costs of solar technology and the increased efficiency of the appliances that allows the solar panel to be smaller.

14. This scenario is drawn from *Energy and Air Pollution: World Energy Outlook Special Report* (IEA, 2016a). Available at: *www.worldenergyoutlook.org/airpollution.*

Figure 10.12 ▷ Mini- and off-grid electricity generation for electricity access in a universal access scenario, 2040



Renewables-based mini- and off-grid electricity solutions play an important role in providing access to electricity in remote rural areas

Small solar-powered systems, such as solar lamps, can greatly improve the current situation for many but are generally suited only to low powered appliances. Larger scale residential solar systems can power additional appliances, such as refrigerators. In Bangladesh, around 4 million solar home systems have been installed and the government plans to increase this number to 6 million by 2017 as a key part of its plans to bring electricity to every household in the country by 2021.

Mini-grids are a potential source of greater levels of electricity supply. They can be powered by renewable or oil-based sources, or a combination of both. A key initiative of the Indian government, which aims to electrify every home by 2022, is the Deen Dayal Upadhyaya Gram Jyoti Yojana, which includes a dedicated component for mini-grids, to complement expansion of the grid. The Asian Development Bank also has a mini-grid fund to address financing gaps and help to scale-up efforts, while the African Development Bank launched the first phase of its Green Mini-Grids Market Development Program in 2015. Obstacles to mini-grids include the lack of clarity about grid expansion plans, tariff structures and licensing mechanisms and the inability of many potential customers to afford appliances that consume enough power to make the projects economic. The design of policies to increase energy access through off- and mini- grid renewables can draw from previous experience. They need to take into account communities' present and future energy needs, use quality materials, develop a skills base for operating and maintaining the new systems, and, above all, ensure the systems are affordable, which often means providing financing support to help cover the high upfront costs.

10.4.2 Heat[15]

The demand for energy to supply heat is the source of 52% of global final energy consumption today (twice the level of transport). In the New Policies Scenario, global demand for heat increases by one-fifth over the *Outlook* period and accounts for almost half of final energy consumption in 2040. Heat has a range of uses, including space heating, water heating and cooking in buildings, desalination and process applications in industry. The nature and scale of heat demand varies significantly between countries because of differences in climate, the efficiency of the buildings stock and heating equipment, the level of economic development, the availability of fresh water and industrial structure.

In industry, heat demand grows in the New Policies Scenario in response to higher levels of production in industries that require process heat or space and water heating (such as the iron and steel, chemical/petrochemical, cement, food and tobacco, machinery, automotive or textile sectors). Such growth is concentrated in developing countries, with India alone accounting for half of the global increase in industrial heat demand from now to 2040, followed by Africa and the Middle East (around 10% each). In many developed economies, demand for industrial heat has stabilised or is in decline by 2040, reflecting a combination of production and efficiency trends.

In the buildings sector, space heating is the main application of heat, but the growth in demand is largely related to water heating as a factor of a growing population, combined with rising incomes and levels of access to modern energy in developing countries. In the case of space heating, demand grows more slowly over the *Outlook* period, mainly as a result of the increase in total floor area in regions with cold climates being offset (to an extent) by greater energy efficiency in new buildings (see Chapter 7.3.1). By contrast, heat demand for cooking is projected to decline to 2040, not because demand for the service itself drops (there are 1.9 billion more people in the world by 2040) but because there is a gradual shift away from highly inefficient forms of cooking using solid biomass towards more efficient alternatives (see Chapter 2.2).

While heat demand for desalination (which is reflected in heat demand in the services sector) is currently very low (less than 1% of total heat demand), this application sees significant growth to 2040. Most of the growth is in North Africa and the Middle East where water stress, the need to reduce reliance on non-renewable groundwater and population growth combine to raise energy demand for fresh water (see Chapter 9.3). Desalination using renewable energy is at the pilot phase but, by 2040, it is competitive in some cases and is responsible for almost one-fifth of the growth in heat demand in North Africa and the Middle East (see Chapter 9, Box 9.4).

The use of renewables to meet heat demand can be achieved in several ways. Heat can be derived directly from bioenergy or solar thermal (direct heat), for example, or indirectly from renewables-based electricity or renewables-based heat supplied from district heating systems (indirect heat) (Table 10.2). Excluding the traditional use of solid biomass,

15. This section refers only to demand for heat and does not include energy used to disperse heat i.e. cooling.

10

the direct use of renewables currently meets 7% of global heat demand. A further 2% is supplied indirectly using renewables. Demand for renewable heat more than doubles from today to 2040 in the New Policies Scenario, renewables (both direct and indirect renewable heat) meeting half of the growth in total heat demand. This marks a major shift, relative to the last 5 years when only 12% of heat demand growth was supplied by renewables. While such a shift is positive, the growth in renewable heat does not come close to tapping the overall potential and can be traced back in large part to the absence of policy initiatives to stimulate greater use of renewables for heat production and greater barriers to uptake, starting with high upfront costs.

Table 10.2 ▷ Renewable heat options in industry and buildings

Source	Buildings	Industry
Bioenergy	Boilers and wood stoves for space and water heating. Improved and advanced cookstoves for cooking using solid biomass, biogas or liquid fuel.	Boilers or CHP for all ranges of temperature needs.
	Small quantities of biogas through network distribution are also consumed in both the buildings and industry sectors.	
Solar thermal	Solar collectors for hot water and space heating. Solar cookers in rural areas (limited deployment).	Large-scale solar collectors for low-temperature heat production (up to 125 °C). CSP steam production for medium-high temperatures (up to 400 °C).
Geothermal	In-situ direct geothermal energy supply for low-temperature needs.	
		Higher temperature process heat and steam needs can be satisfied in locations with a high-temperature (up to 300 °C) resource (e.g. Indonesia, Philippines, United States).
Indirect renewable	Renewables-based electricity supply used to meet thermal needs (such as heat pumps or electric resistance heating).*	
	Heat supplied through renewables-based district heating (i.e. biomass-based CHP, geothermal or solar thermal). **	

* For heat pumps, which are treated as an energy efficiency measure in the *World Energy Outlook*, only the contribution of renewables to production of the electricity consumed by the heat pumps is counted (not the heat extracted from outdoor air or the ground).

** Use of waste or excess heat recovery for district heating is not treated as renewable source in this report.

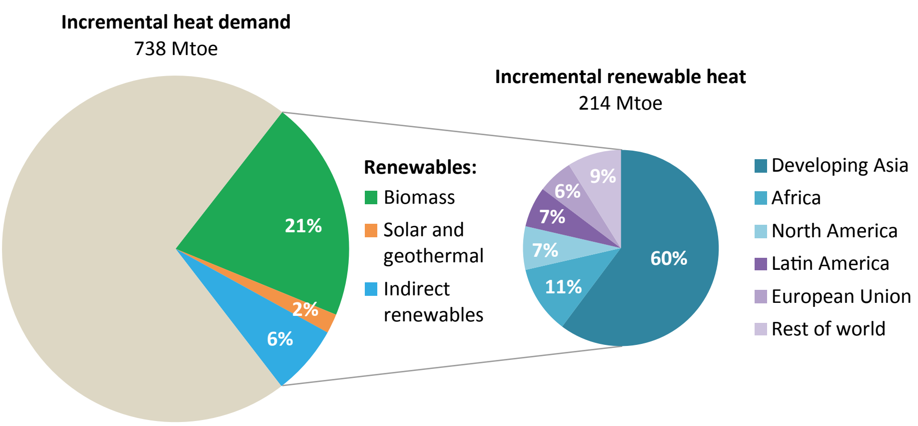
Renewable heat produced from electricity, such as by using heat pumps, grows rapidly from its low base, but it plays only a small part in meeting global demand for heat. The switch to efficient heat pumps for low-temperature heat needs reduces the growth of final energy demand, as efficient heat pumps replace inefficient fossil-fuel boilers and electric radiators.[16] Over the projection period, direct use of renewables for heat continues to greatly outweigh indirect use.

16. See Chapter 4.3 for analyses on the cost-competitiveness of heat pumps versus gas boilers in industry.

Renewable heat in industry

Given the absence of strong policy support in the assumptions underpinning the New Policies Scenario, the share of renewable heat in industry remains relatively low, going from 9% today to 13% in 2040.[17] While the share remains low, the level of activity is increasing and continues to do so; falling costs and improved competitiveness relative to other options increasingly make the case for renewable heat investments to be developed and approved. In absolute terms, the use of renewable heat in industry nearly doubles by 2040. More than 70% of the increase comes from bioenergy, followed by indirect renewables (through heat and power generation) and solar and geothermal (Figure 10.13). Most of the growth in renewable heat demand occurs in developing Asia (mainly China and India), followed by Africa, where significant demand growth is met, in many countries, by large biomass resources (though there are sustainability concerns).

Figure 10.13 ▷ Growth in industrial heat demand by fuel and region in the New Policies Scenario, 2014-2040



Growth in renewable heat in industry is led by bioenergy use in developing Asia and Africa

Bioenergy for heat can be competitive with other options in terms of price (see Chapter 11.3), can be used to meet virtually all types of heat needs through its combustion in steam boilers, furnaces or CHP and (in most cases) does not require major technical system changes to be used. Among the energy-intensive sectors, the pulp and paper industry is currently the largest consumer of bioenergy for heat purposes, but demand in this industry increases more slowly than in some other sectors, such as cement, where demand for this form of heat grows five-fold over the *Outlook* period. In this sector, co-firing with other fuels or wastes in cement kilns is often a simple and more profitable option for bioenergy

17. This includes direct and indirect renewable heat. Industry includes blast furnaces and coke ovens.

use. Today, most of the bioenergy is used in non energy-intensive industries, such as food, beverages and textiles. Consumption growth continues in those sectors, but mostly as a result of an expansion in industrial activity, rather than dedicated policies encouraging fuel switching. One-third of the global increase in use of bioenergy in the industry sector by 2040 comes from non energy-intensive industries in developing Asia. This represents a step towards mitigating climate change while contributing to the economic development of communities in many developing and least-developed countries, but it also poses the challenge of ensuring sustainable biomass supply.

The use of solar thermal and geothermal energy in industry is currently small and, while it grows strongly in the New Policies Scenario, it makes up only a limited part of the heat mix for industry through to 2040. Challenges holding back further growth include relatively high costs, lack of information and the difficulty of integrating solar and geothermal technologies into industrial processes. Today, most supportive policies are small-scale, with relatively few being at national level. They also tend to focus on hot water and rarely target process heat, where most of the potential lies. Much more intensive policy action would be required to overcome the barriers to solar and geothermal heat use in the industry sector.

Industrial use of solar heat increases more strongly than geothermal in the New Policies Scenario. It is used to meet low-temperature needs in, among others, the food and beverage, automotive, textile and chemical sectors (e.g. for pre-heating, bleaching/dyeing, washing and drying applications and for pasteurisation/sterilisation). Greater use of solar heat occurs, particularly in developing Asia, where low-temperature needs are high, especially in India and China, where the success of solar technology in buildings could be carried over to industry (solar thermal targets in the 13th Five-Year Plan[18] may require a contribution from industry). The European Union and the United States also see some positive development in the use of solar heat in the New Policies Scenario but, despite good resources, the Middle East and Africa do not develop solar heat to a significant scale, mostly due to a lack of government intervention and the availability of cheap alternatives i.e. low natural gas or bioenergy prices. The contribution of geothermal heat is limited, due to its lower potential and higher costs than solar heat (IRENA, 2015).

Electrification is an ongoing theme across a number of industrial sectors. In so far as electricity is generated increasingly from renewables (the global share increases from 23% today to 37% in 2040) and is used by industry to generate heat, it contributes to the drive to decarbonise heat use in industry.

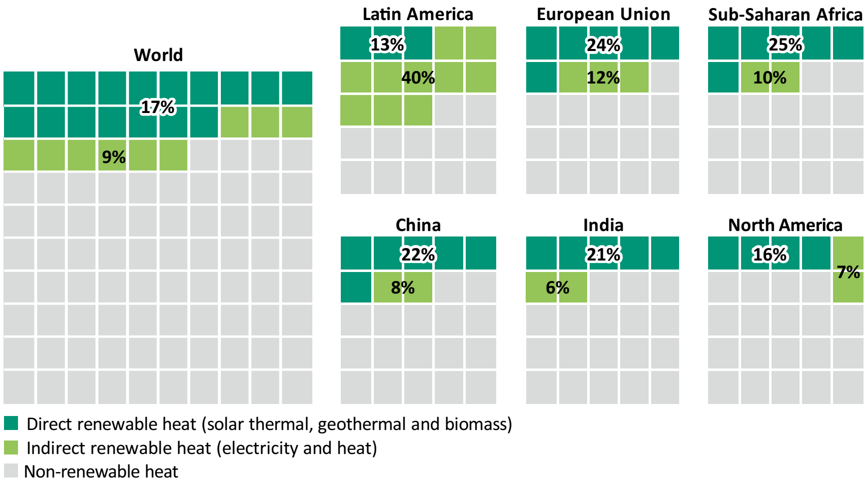
Renewable heat in buildings

The world's use of renewable heat in buildings grows in the New Policies Scenario, with differences in demand trends depending on the policy environment and the competitive landscape, meaning that market development is country specific. Costs play an important

18. The National Energy Administration's draft plan for solar applications targets a doubling of solar collectors to 800 million square metres by 2020.

role in the renewable heat outlook (with some solutions already being competitive), but cost alone is insufficient to determine choices. Even if an assessment of the value of total life-cycle costs and benefits from a renewable heat option is compelling, relatively high upfront capital costs can be a barrier to adoption, as these can weigh heavily on household investment decisions. Moreover, barriers such as split incentives between the owner and the tenant of a building, or simple consumer inertia, can result in sub-optimal investment decisions. Supportive policies are required to overcome these barriers.

Figure 10.14 ▷ Space and water heating demand in buildings by region in the New Policies Scenario, 2040



One-quarter of the world's space and water heating demand in buildings is met by renewable sources in 2040

The most important and established application for direct renewable heat in the buildings sector is for space and water heating, where its use doubles by 2040 in the New Policies Scenario. Yet, it continues to be dwarfed by heat supplied from non-renewable sources (Figure 10.14). Solar thermal is already an established choice for water heating in several countries (China, South Africa, Israel, Greece and Turkey) and is benefiting from policy support in others (Kenya, Brazil, Thailand), while making some small inroads into space heating. The use of solid biomass in conjunction with modern technologies is already a feature of space and water heating in some countries (such as in Europe and North America). Geothermal is a more site specific resource and is adopted in only a few countries, such as China, Turkey, New Zealand, Japan and Iceland. Looking beyond space and water heating, the direct use of modern renewables for cooking is currently small. However, such solutions can (and are) proving to be attractive in situations where policy support is in place. In particular, biogas digesters and solar cookers can be attractive in the context of delivering energy access in rural areas, where there may be significant logistical and financial obstacles to supplying alternatives. Overall, the share of renewables in cooking (both direct and indirect) grows from 1% today to less than 5% in 2040 – if the traditional use of solid biomass is excluded, the share of cooking using renewables grows from 5% today to over 10% in 2040.

Around 35% of European households rely on renewable sources (direct and indirect) for space heating in 2040 in the New Policies Scenario, but around 45% still rely on gas. The European Union heating and cooling strategy, the Renewable Energy Directive and decreasing unit investment costs all help to boost the market for renewables-based space and water heating, with renewables-based electricity and solar thermal becoming more common alongside the use of biomass. In North America, the United States sees the use of solar thermal, geothermal and the modern use of biomass all grow and collectively meet 14% of heat demand in buildings by 2040, while the absence of strong policy support in Canada means that the huge potential translates into only modest growth in renewable heat use in its buildings (albeit from a higher base).

Developing Asia remains a high growth market for solar thermal in the New Policies Scenario and accounts for more than one-fifth of water heating demand in buildings by 2040. The big push for solar thermal in China continues, albeit not at the very rapid pace of recent years. The Energy Conservation Buildings Code supports the adoption of solar thermal in non-residential buildings in those states in India where it is mandatory. Elsewhere in Asia, only a few economies, such as Chinese Taipei and Thailand, have implemented support-schemes for the use of renewable heat in buildings, holding back opportunities for greater growth. By 2040, around one-third of the households in Southeast Asia that have access to modern fuels rely on electricity to meet their space and water heating needs, indirectly boosting the share of renewables used to satisfy heat demand.

In Latin America, Brazil meets its target of having 20% of new buildings equipped with solar water heaters in the New Policies Scenario, but many other countries in the region have no targets in place. The high share of renewables in power generation means that indirect renewable heat is more significant than for many other regions. In sub-Saharan Africa, current levels of access to electricity and clean cooking are very low, but some countries, such as Kenya and Zimbabwe, have targets for new buildings to be built with solar water heaters. The high potential for renewables in Africa, and signs that renewable heat in buildings is becoming a policy priority, underpin an outlook that sees them account for one-third of space and water heating demand in buildings in 2040 (excluding the traditional use of solid biomass).

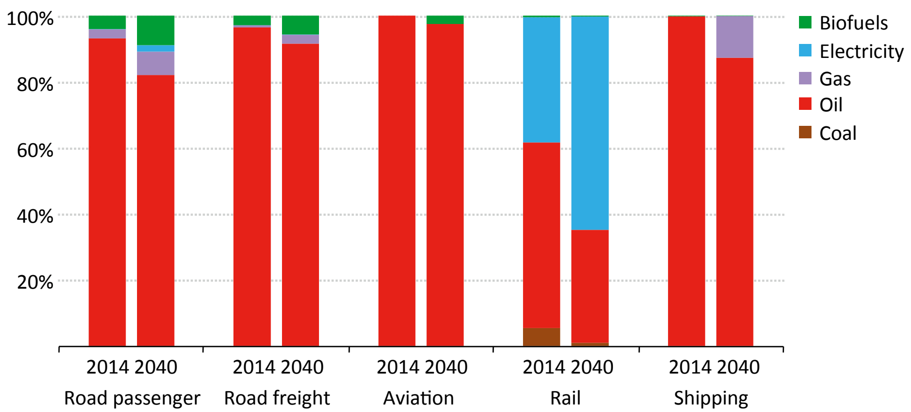
10.4.3 Transport

Of the end-use sectors, transport is the largest CO_2 emitter today and the most heavily reliant on fossil fuels. There is much discussion of the prospect of an energy revolution in the transport sector, in particular for road passenger vehicles, be it talk of changes in the fuel mix (biofuels, natural gas, electricity, hydrogen etc.), in technology (vehicle efficiency, self-driving cars etc.) or cultural change (car sharing, modal shift). The consumption of

1.6 mboe/d of biofuels in 2015 and the presence on the road of around 1.3 million electric vehicles are both impressive milestones, but they represent only 3% and 0.1% of the total market today, respectively. It is clear that there is still a long road ahead, but will there be acceleration in the rate of change?

Policy support for alternative-fuelled transport does not waiver or backtrack in the New Policies Scenario, but nor do present policies justify an assumption that it strengthens dramatically on a global scale. As just one example, all COP21 pledges cover transport sector emissions and yet few make specific reference to targets or policies to reduce them. Even so, continued support and advances in technology together do see biofuels consumption increase significantly in the New Policies Scenario, to 4.2 mboe/d in 2040 (nearly 65% ethanol, 30% biodiesel and the rest aviation biofuels). While biofuels continue to be used mainly for road transport, where they account for 8% of total energy use in 2040 (Figure 10.15), their role in aviation and shipping takes off only slowly (3% and less than 1% of the market in 2040, respectively). The United States, the European Union and Brazil remain the largest markets for biofuels, but see their collective share of global consumption drop from 86% in 2014 to 66% in 2040. Policy support (mainly blending mandates) and higher domestic production both help to boost markets in Asia: China becomes the third-largest market for ethanol, while the biofuels markets in India, Thailand, Indonesia and Malaysia all grow substantially.

Figure 10.15 ▷ Share of final energy use in transport by sub-sector and fuel in the New Policies Scenario, 2040



Progress fails to match potential, with transport policies proving insufficient to deliver a major change in fuel use by 2040

The United States is currently the largest global consumer of biofuels (0.7 mboe/d), which account for 6% of US road transport energy use. With growth driven largely by the Renewable Fuel Standard (RFS2), which requires minimum absolute volumes of renewable fuels to be blended with gasoline and diesel, and supported by an expanding supply infrastructure and take-up of flex-fuel vehicles, biofuel consumption exceeds 1 mboe/d by 2025 and reaches 1.4 mboe/d by 2040 (four-fifths ethanol, one-fifth biodiesel). By 2040, the share of biofuels in US road transport has increased to 16%. In the European Union, the Renewable Energy Directive target of 10% for renewable energy in transport by 2020 (currently around 5%) helps biofuels use grow to around 0.5 mboe/d in 2025 and 0.7 mboe/d in 2040, accounting for 15% of road transport energy demand. In Brazil, biofuels already account for almost 21% of road transport fuels, by far the highest share in the world, with flex-fuel vehicles making up about two-thirds of the light-duty vehicle fleet and more than 90% of new vehicle sales. Brazil's ethanol blending mandate has been increased to 27%. In the New Policies Scenario, Brazil continues to be a leading biofuels market, seeing consumption increase to levels similar to the EU in 2040, despite a much smaller vehicle fleet.

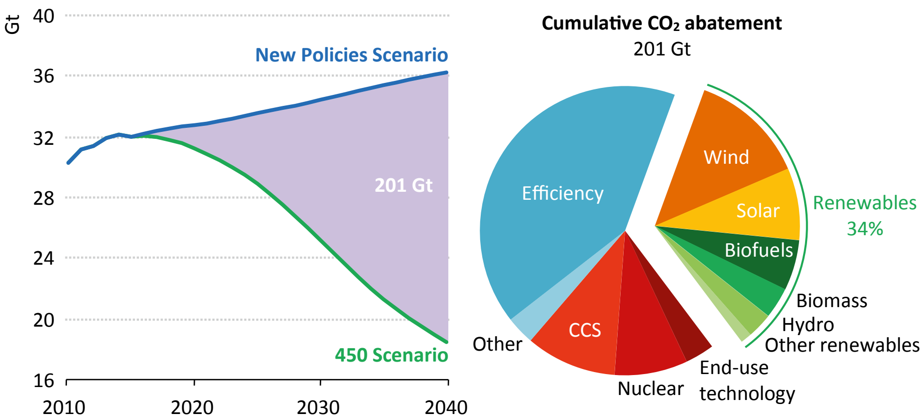
In 2015, India brought in new measures intended to strengthen ethanol demand and improve compliance with its 5% blending mandate. India has also expressed ambitions to increase its blending mandate, with reports varying from 10% to a possible 22.5% target. Should such ambitious targets be implemented, the transition from current levels to those desired may well take some time as ethanol production capacity and distribution infrastructure is built up; but they could make India the world's biggest ethanol growth market. In the absence of any new official target or measures to implement it, the projection in the New Policies Scenario is modest, with biofuels use reaching 0.2 mboe/d in 2040. In 2015, Indonesia introduced a range of policies, including an increase in its biofuel blending mandate (to 20%), to stimulate the transition from an export-driven biodiesel market towards higher domestic consumption. In the New Policies Scenario, Indonesia sees biofuels demand reach 0.1 mboe/d in 2040.

Sales of electric vehicles continue to grow in the New Policies Scenario and account for almost 10% of global sales in 2040, with the global stock of electric cars exceeding 150 million at that time. Growth is particularly strong in China, Europe and the United States, but the projected cost reductions and policy support measures are not sufficient in the New Policies Scenario to achieve parity with conventional vehicles. By 2040, electric vehicles are still only 8% of the global fleet. (See Chapter 3 for a focus on electric vehicles and Chapter 11 for more on the competitiveness of alternative transport fuels).

10.5 Outlook in the 450 Scenario

Although the New Policies Scenario sees the world on a path to an energy transition, progress is slow and energy-related CO_2 emissions continue to trend upward. The 450 Scenario, by setting out one possible path consistent with the 2 °C climate goal, provides a basis for understanding the type and scale of the additional actions required to keep global warming below 2 °C (which would, of course, have to be further intensified for a goal of "well below 2 °C" (see Chapter 8). The broad direction of the 450 Scenario is one in which the world invests to make its energy system increasingly efficient and reliant on low-carbon energy sources. More demanding policies are adopted in order to achieve the level of energy sector change required. For example, carbon pricing is applied more widely around the world and prices rise more quickly, while fossil-fuel subsidies are phased out in all countries, though the pace varies (see Chapter 1 for more on the definition of the 450 Scenario and Annex B for the additional policy actions taken).

Figure 10.16 ▷ Global energy-related CO_2 emissions by scenario and additional CO_2 abatement by measure in the 450 Scenario



Renewable energy ramps up faster in the 450 Scenario, abating an additional 69 Gt of CO_2 emissions (2015-2040) relative to the New Policies Scenario

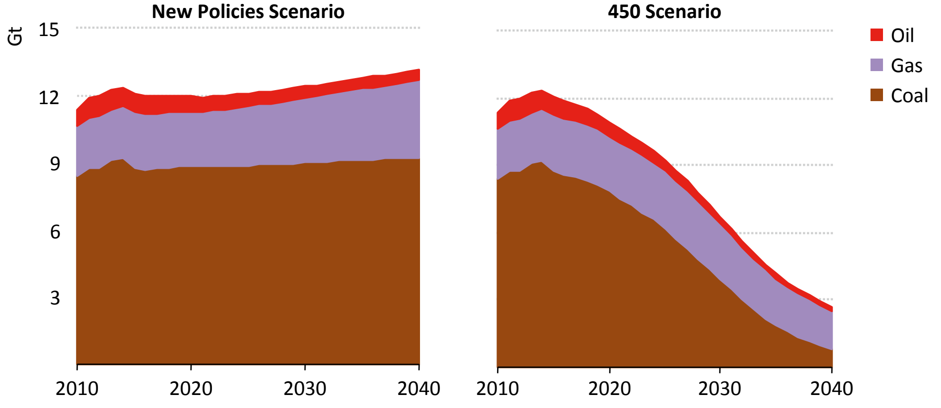
Note: Other renewables include geothermal and marine.

The 450 Scenario is not a "renewables-only" scenario, but one where they are the core of a range of actions that take proper account, also, of economic and energy security objectives (Figure 10.16). Global energy demand continues to grow in the 450 Scenario, but at less than one-third the rate of the New Policies Scenario. In contrast, energy-related CO_2 emissions decouple from demand and start to decline, a trend already established in some countries and one which takes hold quickly and irrevocably at a global level in the 450 Scenario. By 2040, global energy demand is less than 10% higher than today, but global energy-related CO_2 emissions are 43% lower (and nearly half the level of the New Policies Scenario). Renewables account for 31% of the primary energy mix in 2040, led by bioenergy (covering both traditional and modern uses), followed by hydro, wind and solar PV.

10.5.1 Electricity

Renewables are a favoured and highly effective means through which the power sector decarbonises electricity supply in the 450 Scenario. The largest source of CO_2 emissions in the world today, the power sector cuts them by almost three-quarters by 2040 (compared with a 6% increase in the New Policies Scenario) (Figure 10.17). In cumulative terms, this scenario avoids the release of 125 gigatonnes (Gt) of CO_2 emissions from the power sector and the carbon intensity of electricity generation drops to one-sixth of current levels. Of the huge cumulative emissions reductions achieved, renewables are responsible for 25% and, as part of the package of options adopted in the 450 Scenario, ensure the foundation is in place for further decarbonisation post-2040.

Figure 10.17 ▷ World power sector CO_2 emissions by scenario and fuel



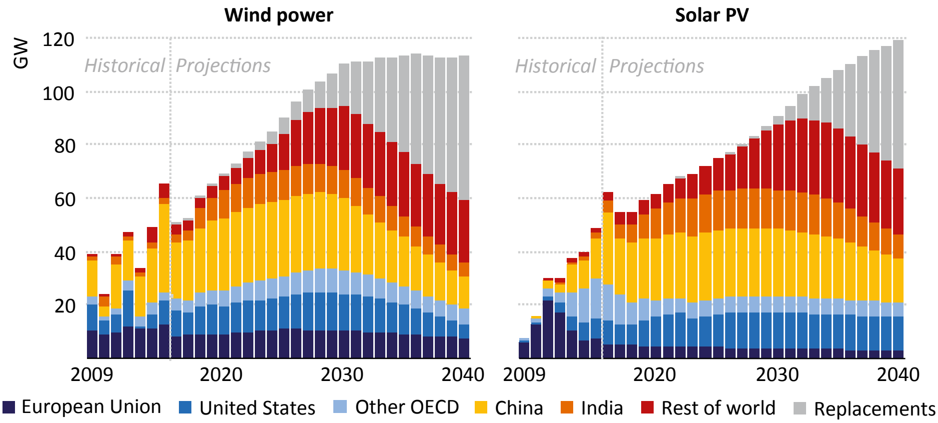
In the 450 Scenario, power sector CO_2 emissions are cut by 80% by 2040, with renewables accounting for nearly 60% of global electricity supply

Power generation capacity

Renewables account for over 60% of all power generation capacity in the world in 2040, having increased to three-and-a-half-times the level of today. Installed capacity of wind power, hydropower and solar PV all exceed 2 000 GW in 2040, with gas-fired capacity the only non-renewable source of supply in the same league. At 250 GW per year, renewables-based capacity additions grow at a rate 50% higher than in the New Policies Scenario, entailing significant expansion of the renewables industry. All renewables see substantial capacity growth in the 450 Scenario, but wind power and solar PV see the biggest scale-up, leveraging cost reductions and taking advantage of their widespread availability and relatively short construction times. Annual capacity additions of wind power, including a rapidly growing market for replacements, increase to over 100 GW per year by 2030 (Figure 10.18). The market for solar PV, including both at utility-scale and in buildings, surpasses 90 GW per year by 2030 and is over 110 GW by 2040. At that point, the global average capital costs for solar PV are less than half the level of today (see Chapter 11), with government support encouraging large-scale deployment and that deployment, in turn, pushing down costs and boosting the ability of the technology to compete without support.

Dispatchable renewables also experience a strong boost in the 450 Scenario, as their flexibility is valued for the stability it can help bring to a power system incorporating a growing share of variable renewables (see Chapter 12). While hydropower (already the icon of flexibility when projects include large reservoirs) registers capacity growth that is lower than that of wind and solar PV, increasing by around 70% over the *Outlook* period, it is certainly no less important. Bioenergy-based power plants provide a valuable dispatchable option, as does concentrating solar power, which sees rapid growth in some markets, mainly after 2030.

Figure 10.18 ▷ Annual power capacity additions for wind and solar PV by region in the 450 Scenario



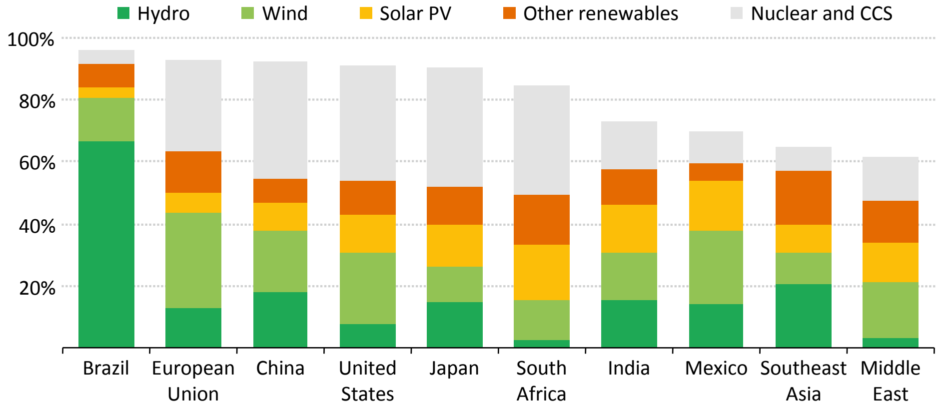
The global market size for wind and solar PV doubles in the 450 Scenario

Electricity demand and supply

In the 450 Scenario, electricity, almost 60% of which is derived from renewables, establishes itself as the largest form of energy supply in industry (overtaking coal), strengthens its role as number one in buildings and sees its share of energy use in transport increase eight-fold. At the same time, major investments to improve efficiency bear fruit and mean that, even despite increased electrification in end-use sectors, global electricity demand is 11% lower than in the New Policies Scenario in 2040 (but still nearly 50% higher than today).

Renewables help lift the low-carbon share of total generation to around 90% or more in many of the largest markets (Brazil, European Union, China, United States, Japan) (Figure 10.19). Energy efficiency measures mean that the increase of renewables-based supply can displace fossil fuels (and related emissions), rather than simply meeting demand growth. The largest share of renewables-based generation comes from hydropower, which sees major growth in China, India and Africa, though wind power is close behind as the second-largest renewable energy source, led by China, the United States and the European Union. Solar PV is the third-largest source of renewable electricity, with more than 16-times higher global annual output in 2040 than in 2014, led by installations in China, India and the United States.

Figure 10.19 ▷ Share of electricity supply from low-carbon sources in selected regions in the 450 Scenario, 2040



In the 450 Scenario, the share of low-carbon electricity supply exceeds 80% in many markets around the world, with renewables playing the largest role

Notes: CCS = carbon capture and storage. Other renewables include biomass, CSP, geothermal and marine.

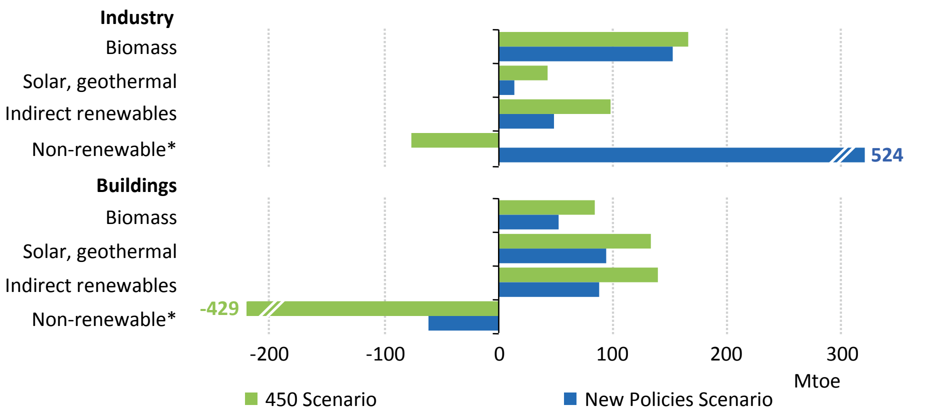
10.5.2 Heat

In the 450 Scenario, the world's demand for heat increases modestly, ending 5% higher than today by the end of the *Outlook* period. Across sectors, heat demand is restrained by energy efficiency efforts. Industry is responsible for the growth in heat demand, while heat demand in the buildings sector is 3% lower than today in 2040 (Figure 10.20). Use of renewables as a source of heat grows by 4% per year, on average, its share of total heat demand increasing from 9% today to 22% by 2040 (including direct and indirect renewables). While this indicates that much potential remains untapped over the *Outlook* period, it does represent an important and necessary acceleration of deployment that can be, and will need to be, continued beyond 2040, especially as opportunities to improve energy efficiency eventually diminish.

Renewable heat in industry

Renewables are by far the main contributor to the growth in heat use in industry from 2014 to 2040, thanks to carbon pricing policies which improve the competitive position of renewables (in developed countries, but also in China, South Africa, Brazil), and sectoral agreements to improve energy efficiency that help reduce fossil fuel use, in particular in energy-intensive sectors. Despite this, renewables meet only around 20% of total industrial heat demand in 2040 in the 450 Scenario, including both direct and indirect supply. Bioenergy continues to be the most widespread source of renewables-based heat in industry but it sees the lowest additional growth of all renewable options in the 450 Scenario, compared with the New Policies Scenario. This is partly because it is already a competitive option in many instances in the New Policies Scenario and partly because energy efficiency improvements in the 450 Scenario deliver further fuel savings. The global pulp and paper industry remains the dominant user of bioenergy for heat among energy-intensive sectors, while the majority of the growth in its use is centred on the cement and chemical sectors and some smaller, non-energy-intensive, industries.

Figure 10.20 ▷ Change in heat consumption by fuel in the New Policies and 450 Scenarios, 2014-2040



Renewables are the largest contributor to meeting the growth in heat demand in industry and buildings in the 450 Scenario

* Non-renewable includes fossil fuels and the traditional use of biomass.

All other forms of renewable-based heat see faster growth in the 450 Scenario than the New Policies Scenario, led by indirect supply via electricity, followed by solar heat and geothermal. In global terms, these other renewable technologies collectively see close to a six-fold increase from today, to equate, in total, with around one-quarter of China's industrial heat demand in 2040. But the potential remains far from exhausted, with the increased activity up to 2040, providing a foundation for more rapid change thereafter. Increases in the use of indirect renewables for heat are not driven by growth in demand (which stays relatively flat, due to efforts to improve efficiency), but by a combination of greater deployment of electric heating (mostly heat pumps addressing low-temperature needs), and the greater decarbonisation of electricity supply. By 2040, more than one-third of global demand for electricity-based heat comes from heat pumps in the industry sector (only marginal today). Despite there being additional potential to replace fossil fuel-based heat with electricity-based heat in the industry sector, in the 450 scenario not all of it is been tapped by 2040. The growth of solar heat in the 450 Scenario is led by China and India, with other regions registering some growth, either as a result of policy support or the presence of particularly good solar resources. Geothermal heat in industry is also led by China, which has relatively high technical potential, as well as a favourable price environment (i.e. high fuel and CO_2 prices in the industry sector). There are also some innovative deployments in other countries (Box 10.3).

Box 10.3 ▷ Geothermal and solar heat use in the food and beverages sector

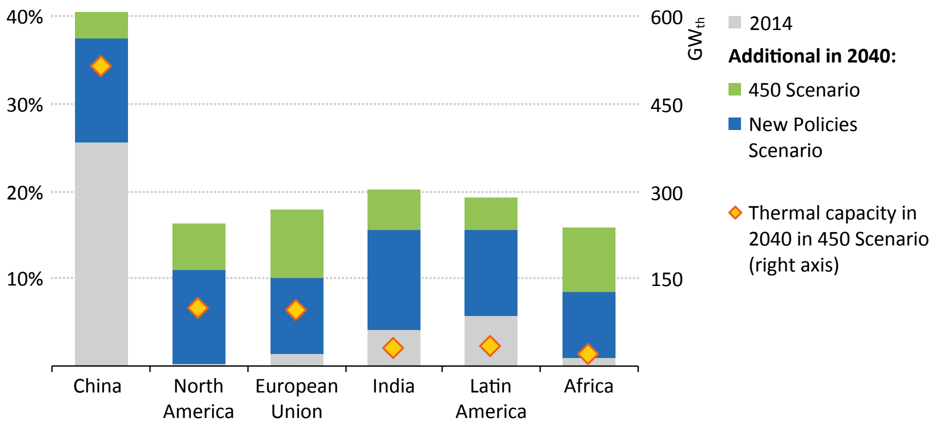
The food and beverage industry is a prominent user of low- and medium-temperature heat and examples of renewable heat use, especially bioenergy, are common. However, the direct use of geothermal energy also offers potential, as demonstrated by the newly commissioned Écogi plant in eastern France. Water is brought up from a depth of 2 500 metres at a temperature of 165 °C and transported over 15 kilometres through insulated pipes to supply heat to a starch manufacturing plant, where it is used to produce steam. Along with a fuelwood boiler and an installation for the production of biogas, it allows the site to meet 75% of its steam needs from renewable energy sources. About 45% of the €55 million project cost was provided from the French government's Fond Chaleur renewable heat support programme. In addition, solar systems have already demonstrated their ability to supply process heat to this sector and, in areas of good solar irradiation, have shown themselves to be competitive with diesel or liquefied petroleum gas boilers. For example, Nestlé's dairy factories in Lagos de Moreno and Chiapa de Corzo in Mexico use CSP installations to deliver hot water at about 90 °C for pasteurisation and the firm that built the installation is now proposing solutions for applications ranging from 50 to 250 °C. The possibility to supply heat at higher temperatures makes CSP devices technically able to serve many other industrial applications, for instance in chemical/petrochemical areas.

Renewable heat in buildings

Much stronger efforts to improve the efficiency of the building stock – such as insulation to reduce space heating demand – and of the energy-consuming equipment within them (e.g. boilers and stoves) sees total heat demand in buildings slowly flattening over time (see Chapter 7). This slowing growth for heat demand is led by developed countries, which partially offsets the growing demand (mainly for water heating) in developing regions, where the consumption of hot water by households increases thanks to higher income levels and better infrastructure. While all other fuels see demand decrease by 2040, the share of renewables in total heat demand increases to around 25% in the 450 Scenario (including direct and indirect renewable heat). The growth in direct renewable heat, underpinned by stronger policies, is led by solar thermal and modern biomass, while greater electrification through heat pumps (and the higher share of renewables in the power mix) also makes a significant contribution. Space heating demand is mostly influenced by investments in insulation and the higher penetration of heat pumps, while water heating sees fuel switching from fossil fuels to electricity or renewables. While they vary by region, higher fossil fuel end-user prices in the 450 Scenario generally help to make renewable options more competitive (see Chapter 11). No carbon price is assumed in the buildings sector in the 450 Scenario, but accelerated removal of fossil-fuel subsidies leads to this increase.

Use of solar thermal increases across world regions in the 450 Scenario (Figure 10.21), but continues to be led by those developing economies that have been quick to adopt dedicated policies, such as China and South Africa. By 2040, almost 35% of households that have access to modern fuels in developing countries are using direct renewable options for water heating, compared to around 25% across developed countries, where unit investment costs are higher and policies fewer. Today, modern biomass is mostly used in OECD regions, in wood stoves or boilers, but the growth in its use is spread equally between OECD and non-OECD over the *Outlook* period. Space heating demand in buildings decreases modestly, as the pace of efficiency retrofits of existing buildings, and the slow turnover of the existing building stock in many regions, is not enough to realise more rapid improvements in the overall levels of building efficiency. By 2040, around 30% of households that have access to modern fuels rely on renewable sources (directly or indirectly) for space heating. Building codes focus mainly on new buildings, but it is the existing stock that will drive most of the energy demand for space heating in buildings in 2040. Policies need to focus on these old buildings in order to take advantage of the overall sectoral potential for decarbonisation. Geothermal energy offers a solution only in countries that have, or could build, district heating systems and continues to play a relatively limited role, compared with biomass and solar thermal. In the 450 Scenario, the phase-out of fossil-fuel subsidies and carbon pricing helps to double the amount of renewables-based heat used for desalination.

Figure 10.21 ▷ Share of households using solar water heaters by country and scenario, 2014 and 2040



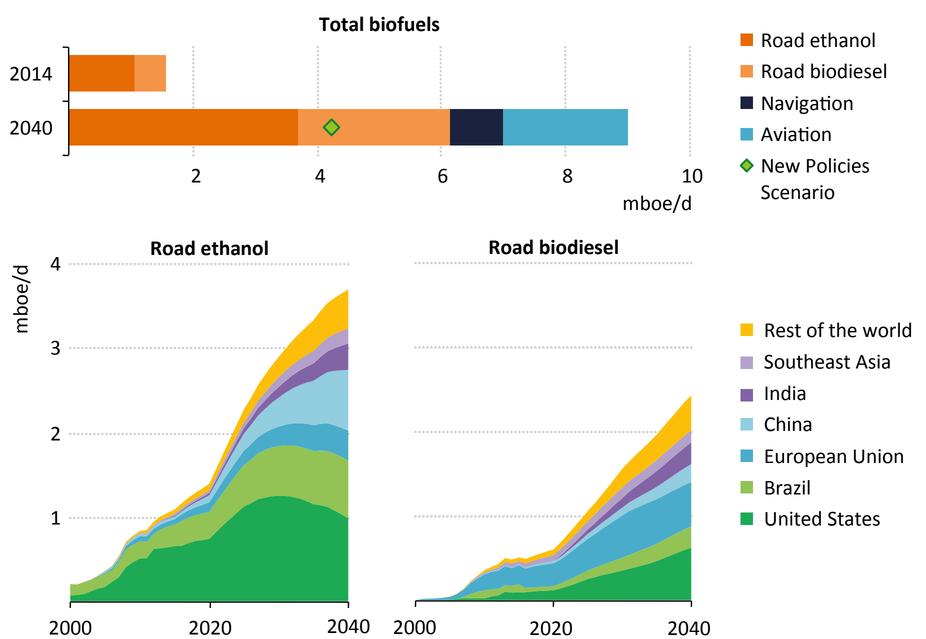
Use of solar water heaters expands across regions, but China remains the largest market in 2040

10.5.3 Transport

Renewables play an important role in an integrated approach to reducing transport emissions (Spotlight), with the 450 Scenario including strategies to boost energy efficiency and fuel switching, particularly to biofuels and electrification. An energy transition clearly takes hold in the 450 Scenario: oil's share of total transport demand drops from over 90% to under 65% in 2040, the combined share of biofuels and electricity increases to nearly one-quarter and passenger kilometres travelled are 10% lower than in the New Policies Scenario. As a result, CO_2 emissions from transport peak just before 2020 and then drop to 20% below the level of today in 2040.

Today, around 33 barrels of oil are consumed in the transport sector for every barrel oil equivalent of biofuels. By 2040, that ratio has dropped to around 4-to-1 in the 450 Scenario, with the global market for biofuels having increased to 9 mboe/d. Biofuels see particular success in road transport (6.1 mboe/d by 2040) and aviation (2 mboe/d). In the case of long-haul freight, the value of biofuels is emphasised by the restricted choice of viable low-carbon alternatives. In aviation, there is already significant market interest in biofuels, but supply chains need to develop and solutions be found to overcome the cost advantage of conventional jet fuels. In 2040, demand for ethanol is led by the United States, China and Brazil, while biodiesel demand is led by the United States and the European Union (Figure 10.22). Cumulative investments in biofuels are $1.1 trillion over the period 2016-2040, averaging around $67 billion per year towards the end of the *Outlook* period. In the 450 Scenario, carbon prices are applied in more regions and at higher levels, helping to boost the competitive position of biofuels, and a greater shift towards advanced biofuels helps mitigate the environmental impact of the increased demand, while achieving the desired reduction in transport-related CO_2 emissions.

Figure 10.22 ▷ Demand for ethanol and biodiesel by region in the 450 Scenario



Demand for biofuels grows rapidly across regions in the 450 Scenario, accounting for 20% of all liquid transport fuel use by 2040

Technological advances in biofuels broaden the range of potential feedstocks and production processes, as well as enhancing their ability to interchange with other fuels easily. However, as of today, technologies to deliver advanced biofuels are generally at a relatively early stage of development and commercialisation. These key issues for the future of biofuels are discussed further in Chapter 11.

By 2040, electric passenger light-duty vehicles (PLDVs) account for around 50% of global PLDV sales and more than one-third of the world's stock of PLDVs in the 450 Scenario. The global stock of electric vehicles grows to over 710 million, displacing 6 mb/d of oil demand. By far the largest market for EVs is China – in which 30 million vehicles a year are sold by 2040, compared with around 16 million in India, 9 million in the European Union and 7.5 million in the United States. The share of renewables-based electricity powering these vehicles also grows significantly in the 450 Scenario: the world average, which increases from 23% in 2014 to nearly 40% in the New Policies Scenario in 2040, approaches 60% in 2040 in the 450 Scenario. The EU and US markets achieve shares of over 55% in the 450 Scenario, while China and India also achieve major increases and see the carbon intensity of their transport sectors decline slightly as a result.

The scale of the increased EV fleet means that it can play an important role in integrating enhanced proportions of variable renewable electricity generation into electricity systems, by providing a source of flexible demand during times of high levels of generation from solar or wind. The transport sector may also stimulate additional investment in renewables generation specifically to service the EV market, for example, through dedicated urban charging stations supplied by solar or other renewable options, or through dedicated renewable supply designed to provide energy for rail or other transport systems. For example, Netherlands Railways are already powered to a level of 50% by renewables and this is expected to reach 100% by 2018. The metro in Santiago, Chile will soon be powered mostly by solar energy.

SPOTLIGHT

Policies to support a more rapid shift to renewables – the Nordic case

The Nordic countries underpin competitive, low-carbon economies with renewable energy.[19] Three insights are particularly relevant to policy-makers well beyond that region. First, it is clear that renewable energy can be consistent with economic growth. Second, successful renewable energy policy must be ambitious, stable and go beyond short-term subsidy schemes. Third, market integration and interdependency between countries can reduce costs and enhance energy efficiency and energy security.

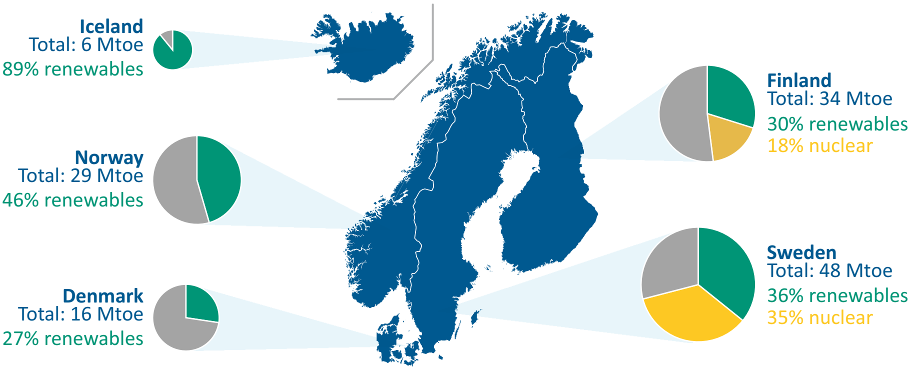
In 2014, 37% of Nordic total primary energy supply was from renewable sources (more than four-times the world average), up from 27% a decade earlier (Figure 10.23). Hydropower accounts for over half of Nordic electricity generation which, together with

19. Denmark, Finland, Iceland, Norway and Sweden, collectively the world's 12th largest economy.

wind, bioenergy and smaller shares of waste and geothermal, makes the power mix 69% renewable. Bioenergy is the main means of meeting the region's significant heating demand, which is 54% renewables, while transport fuels are 8% renewables. This rapid shift towards renewables has not come at a cost to competitiveness or energy security in Nordic countries.[20]

In fact, renewable energy has benefited the Nordic economies in terms of jobs, industrial competitiveness and technology export. Danish wind turbines and Finnish bioenergy technology are prominent examples. Actions to increase Nordic utilisation of renewables, including policies to encourage innovation, efficiency and an industrial focus on high-value products, can further bolster Nordic competitiveness globally.

Figure 10.23 ▷ Shares of renewable and nuclear energy in total primary energy supply in the Nordic countries, 2014



Renewable energy plays a significant role in each of the Nordic countries

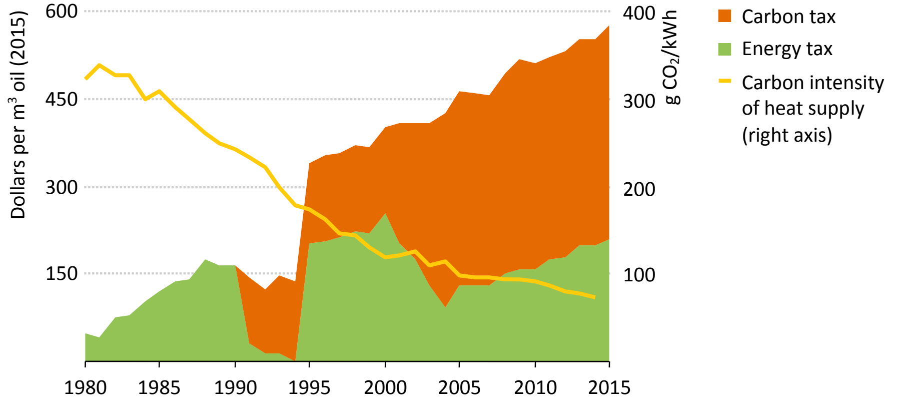
Decarbonising heat and power

The carbon intensity of Nordic heat and power dropped to 74 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) in 2014, a fifth of the OECD average. Regional integration of energy systems and ambitious, stable policy frameworks have driven the displacement of fossil fuels by wind and bioenergy. Four of the Nordic countries are joined by multiple interconnectors and share a common wholesale electricity market, helping to increase efficiency, reduce emissions and lower electricity generation costs. Danish wind power covered over 40% of domestic demand in 2015, a level made possible by interconnectors to dispatchable hydropower in Norway and Sweden, flexible thermal generation (coal, gas and bioenergy) and integration of power and heat.

20. Nordic countries occupy three of the top-ten positions in the 2015 Global Innovation Index and three of the top-five in the World Economic Forum 2016 Energy Architecture Performance Index.

Nordic energy policies are guided by long-term goals and a vision that has broad political support. Importantly, the policy framework goes well beyond the provision of renewable subsidies, encompassing CO_2 taxation, permitting procedures, grid access and research development and deployment (RD&D) support. Finland and Norway are the only OECD countries where public energy RD&D support has averaged over 0.1% of GDP during the last five years. Sweden's efforts to achieve zero net emissions of greenhouse gases by 2050 are a good example of long-term vision. Steadily increasing taxation of CO_2 (up to $137 per tonne for some sectors in 2016) has contributed to the near decarbonisation of district heating in Sweden (Figure 10.24). Policies such as tradable green certificates have helped to usher in low-carbon alternatives, such as bioenergy, waste incineration and electricity.

Figure 10.24 ▷ Decarbonisation of district heating through taxation in Sweden



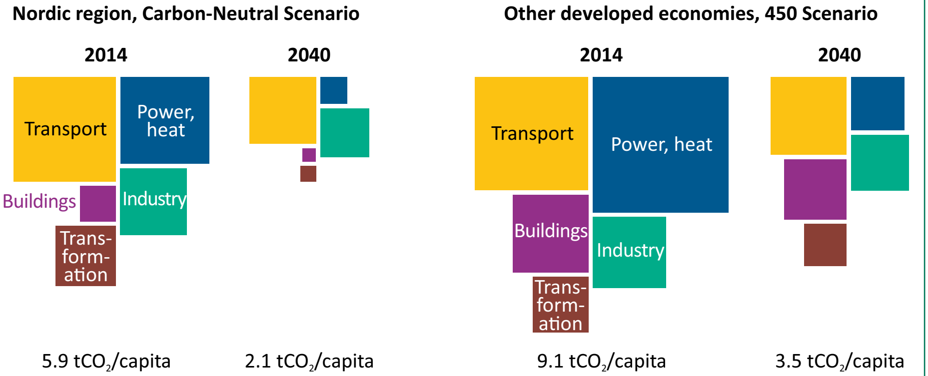
Rising taxes have driven down the carbon intensity of heat supply in Sweden

Powering decarbonisation in transport and industry

The Nordic case illustrates how a clean electricity supply can facilitate the decarbonisation of more challenging end-use sectors. In a Nordic regional scenario reflecting the national climate targets, Nordic CO_2 emissions drop by 67% from 1990 levels by 2040, broadly in line with the ambitions of the Paris Agreement.[21] Total primary energy supply is 62% renewables by 2040, with transport and industry accounting for the bulk of remaining CO_2 emissions (Figure 10.25). The virtually carbon-free power sector accelerates emission reductions in energy use in transport, buildings and industry through electrification. Other developed economies, by comparison, have significant emissions from power in 2040 in the 450 scenario, slowing decarbonisation in end-use sectors.

21. The Nordic Carbon-Neutral Scenario as outlined in *Nordic Energy Technology Perspectives* (IEA/NER, 2016).

Figure 10.25 ▷ Per-capita CO_2 emissions by sector in the Nordic region



Per-capita CO_2 emissions in the Nordic region fall by nearly two-thirds to 2040

Notes: tCO_2/capita = tonne of CO_2 per capita. Agriculture is excluded. Transformation includes the oil and gas industry. Other developed economies are non-Nordic OECD countries.

Source: IEA/NER (2016).

The Nordic Carbon-Neutral Scenario requires three key actions from policy-makers:

- A well-designed, interconnected and flexible electricity system should be incentivised. In this scenario, wind displaces coal and nuclear to reach 25% of total generation by 2040. Public acceptance has to be secured to further develop onshore wind installations and measures taken to integrate wind power into the system (grid strengthening and interconnectors, integration of power and heat, flexible thermal generation, demand response and greater utilisation of dispatchable hydropower). Energy efficiency efforts to free up surplus power would allow well over 10% of Nordic electricity generation to be exported to other European countries, while also providing flexibility to balance wind and solar in those countries. Electricity trade could benefit the Norwegian economy as oil and gas production declines. By 2040, the Nordic Carbon-Neutral Scenario sees revenues from electricity exports reaching \$3-4 billion, equivalent to 5-6% of Norway's oil and gas revenues in 2015 (IEA/NER, 2016).
- Technology development should be accelerated for long-distance transport and industry. Decarbonisation of shipping and aviation requires broad commercialisation of advanced biofuels, while CCS can play a role in decarbonising the steel, cement and chemical industries. Technology development and innovation must play a central role in ensuring that aggressive policy action in the industrial sector does not risk pushing industry to countries with more lax regulation.

- National policy should leverage positive actions in cities. The largest CO_2 emission reductions must be achieved in road transport and additional investments are required in this sector through to 2040. Nordic cities have already made progress in modal shifts, road pricing and transport electrification. Almost a quarter of new cars sold in Norway in 2015 were fully electric. Other Nordic countries would benefit from following Norway's lead.

These three strategic actions are, although focussed on the Nordic region, relevant to most countries and regions looking to realise a competitive and low-carbon economy.

Competitiveness of renewable energy

Green gold?

Highlights

- The competitiveness of renewable energy is rapidly evolving, with falling costs set against the backdrop of broader energy system developments. Understanding when renewables can stand purely on their own commercial merits, without targeted support, is of great interest to policy-makers and investors alike.
- In the power sector, hydropower and geothermal are largely competitive today, while solar PV and onshore wind power are increasingly so to 2040, with projected cost reductions of 40-70% and 10-25% respectively. By 2040, over 60% of total renewables-based generation does not require subsidy in the New Policies Scenario. However, at higher market shares, the declining value of variable renewables can make competitiveness elusive. In the New Policies Scenario, subsidies for renewables-based power increase from the estimated $120 billion in 2015 to a peak of $210 billion in 2030 before falling back to $170 billion in 2040. However, subsidies per unit drop dramatically for new projects over the next decade. In the 450 Scenario, robust CO_2 prices enable 40% more generation from renewables with little impact on total subsidies.
- Renewables used to produce heat are competitive in several instances today. This improves for some technologies, as costs fall and fossil-fuel prices rise. Solar water heaters are often competitive today on a levelised cost basis, but the upfront costs can be a major hurdle to wider adoption. Bioenergy is the most used renewable energy in industry and space heating, and it can be competitive with fossil fuels where cheap feedstocks are readily available, though this limits its market potential. Renewable heat received about 1% of the total support for all renewables in 2015, while accounting for about one-third of the total renewable energy supplied.
- In transport, conventional biofuels are generally not competitive with fossil fuels today. Apart from sugarcane-based ethanol in Brazil, they will struggle to become so in the future given the very high share of feedstock costs in overall production costs, which are not expected to decline. Advanced biofuels, produced from cellulosic materials, hold more promise but will still find it difficult to compete with fossil fuels in the absence of carbon pricing and technology breakthroughs. Biofuel use triples in the New Policies Scenario by 2040, while subsidies stay around $25 billion per year.
- Renewable energy provides a means to achieve many societal goals. In addition to fighting climate change, renewables help redefine energy security in many cases by raising the share of domestically sourced supply. They also reduce energy-related air pollution and the resulting health impacts (although bioenergy requires special attention). These benefits come at little cost to consumers, as total power system costs and household electricity bills in the 450 Scenario are virtually unchanged from those in the New Policies Scenario, thanks also to increased energy efficiency.

11.1 Introduction

The competitiveness of renewable energy technologies is a crucial factor in determining the extent to which they are developed and deployed purely on their own commercial merits, and therefore, the extent to which support may be required to enable society to meet many of its goals, such as mitigating climate change, reducing pollution and improving energy security. Announcements for recently contracted renewable energy projects suggest further cost reductions in the near future and deployment becoming less dependent on government intervention and support. In-depth analysis of the costs and value is necessary to assess when investment in each technology might go forward without support measures. To help policy-makers come to grips with these issues, this chapter aims to provide a picture of the competitiveness of renewable energy technologies from the vantage point of the investor, while bearing in mind that of society as a whole (Box 11.1). Consideration of the societal perspective can provide insights into the scale of the challenge the world faces to move successfully to a pathway consistent with international climate change goals.

For a long time, some forms of renewable energy have offered competitive and cost-effective means to generate electricity and heat, and to fuel transport. As a means of producing electricity, hydropower is foremost among competitive technologies. It has long been the largest source of renewable energy supply and currently provides about one-sixth of the world's power supply. Bioenergy-based and geothermal power plants have also been deployed on a commercial basis in several markets. When cheap feedstocks are available, bioenergy is also competitive in some industrial applications, such as cement or food and beverages, and in the production of biofuels. For example, in Brazil, sugarcane-based hydrous ethanol has been able to compete directly with conventional oil-based fuels over the past decade.

Box 11.1 ▷ Key concepts in evaluating renewable energy

The analysis presented in this chapter relies heavily on the following three, related but distinct concepts (Figure 11.1):

1. **Competitiveness** is used in this analysis to indicate when renewables are profitable for investors without targeted support from the government or other outside sources (even where support is currently available), but including the cost of emissions when they are priced. Projects are profitable only when the expected value (revenues or avoided costs) exceeds the expected costs over the economic lifetime of the project, both discounted at the appropriate rate. An investor can be one of a variety of actors, including project developers, financial institutions, households and commercial entities. Evaluating the profitability of renewables, or any investment, requires information about current market conditions and a clear view of future

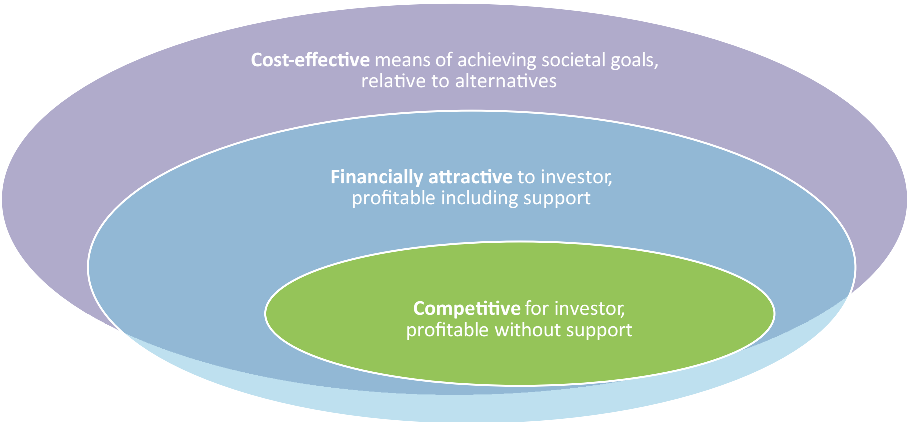
costs and value. While there can be no certainty about the future, the scenario-based projections in the *World Energy Outlook* provide the foundation for consistent assessment of competitiveness across regional energy markets. Competitiveness, assessed on this basis, indicates when renewables will be deployed without financial support, their installation relying solely on the profit-seeking motives of the private sector.

2. **Financial attractiveness** indicates when a project is profitable for an investor taking into account the impact of available support schemes, which may provide additional revenues or reduce costs. The inclusion of support is what distinguishes financial attractiveness from the concept of competitiveness. A project is financially attractive if it is competitive or when support measures are sufficient to ensure the profitability of the project, as measured in commercial terms alone.

3. **Cost effectiveness** is a familiar, well-defined concept. It refers to the assessment of the relative costs of meeting a set of defined objectives, whether, for example, a given form of renewables-based power generation is more or less costly than nuclear power or carbon capture and storage as a means of decarbonising power supply, enhancing energy security, improving air quality and contributing to economic growth; or how the cost of one renewable energy solution compares to another. Commercial investors will also discuss the cost effectiveness of different ways to earn a targeted financial return. But the concept of cost effectiveness, as used in this chapter, applies primarily to the evaluation of different ways to meet societal objectives, which go beyond earning a given financial return. The value of these objectives is for each government to assess.

11

Figure 11.1 ▷ Key terms for renewable energy projects



Renewable energy may present a cost-effective means of achieving societal goals, but investors need a strong financial case to make robust deployment a reality

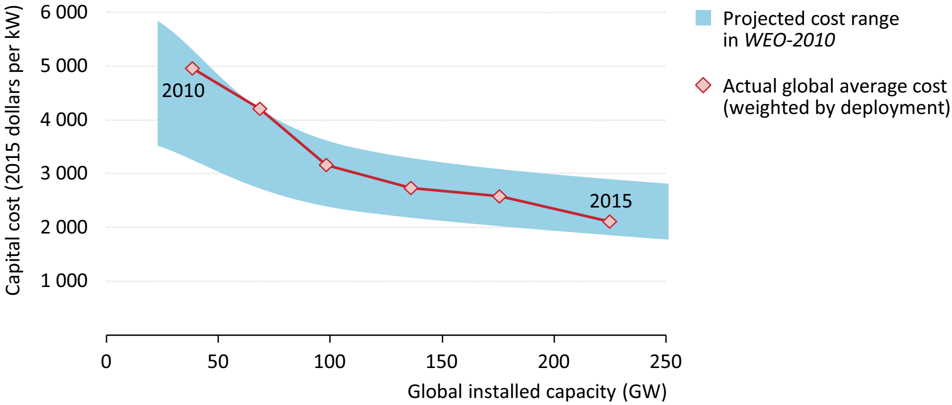
These three key concepts, as defined here, are inter-related. Competitive renewable energy projects are always part of the larger group of financially attractive projects, but they are not always the most cost-effective means of achieving societal goals. For example, in markets where multiple technologies are competitive, they may not all be equally well-suited to achieve broader societal goals. Financially attractive projects, receiving outside support, might be assumed to have been deemed cost effective in this wider sense by the government or other support provider. However, there is a risk that, due to a lack of information, technical experience or high quality analysis, the technologies receiving support may not always be the most cost-effective solutions. In this case, the cost of support required to achieve social goals may be excessive. Ideally, in the pursuit of societal goals, the set of projects made financially attractive should be least-cost solutions and so fall within our definition of cost-effective projects. The range of potentially cost-effective renewable energy projects may be much larger than those that are financially attractive, as current or proposed support policies may be insufficient to bridge the gap, as the full range of social benefits that renewables can deliver may not have been taken into account.

In recent years, a growing number of countries have intervened in markets in order to promote the development and deployment of renewable energy, particularly for wind and solar power technologies, and tap a wide array of perceived benefits, both immediate and long term. In 2015, we estimate that some $150 billion was spent to support renewable energy worldwide – with the United States, Germany, China, Italy, Japan, the United Kingdom and Spain leading the way (listed in order of magnitude). In addition to the immediate benefits, this support has been provided with an eye towards driving down the costs, so making renewable energy more affordable and expanding its place in future energy markets. In many cases, these early efforts have been well rewarded, with the costs of renewables falling and the prospects of competitiveness improving. The power sector has been the primary beneficiary to date, with a massive decline in the costs of solar photovoltaics (PV) and wind power, turning theoretical declining cost curves (related to each doubling of capacity) into reality (Figure 11.2). The pace of progress has been even more impressive; strengthening policy support in many countries since 2010 enabled solar PV to achieve in 5 years what was projected to take 15 years, given the state of the policy environment at the time. The cost of renewables-based heat production equipment has been falling too, though government support has been less widespread than for power. Processes to produce conventional biofuels are mature, on the back of recent cost improvements, while advanced biofuels are gaining a foothold, but have much farther to go.[1] The cost of electric vehicles has declined significantly, due to the falling cost of batteries. The evidence of progress across the renewables spectrum has induced more countries to get on board, raising the number of countries with support policies for renewables to 155 in 2015. Many have met their initial targets and then raised them for coming years, while respecting budget constraints.

1. See the definitions of conventional biofuels and advanced biofuels in Annex C.

Achieving competitiveness on a commercial basis is a crucial milestone for renewable energy technologies; but that may not be the most important test. The ability of renewable energy technologies to mitigate carbon-dioxide emissions (CO_2), enhance energy security, improve air quality and create jobs will be critical. These additional benefits must be weighed in the balance, particularly in the light of the long lifetime of many assets related to energy use, including power plants, the housing stock and personal vehicles. The variety of considerations and long technology lifetimes suggest that policy-makers will continue for many years to have an important role in supplementing market forces to pursue societal goals, using the available tools such as support policies and fiscal measures like pricing emissions.

Figure 11.2 ▷ Projected and actual global weighted average capital costs for solar PV, 2010-2015



Increasing policy support has accelerated the cost reductions of solar PV

Note: kW = kilowatt.

Sources: IEA (2010a); IRENA (2016a).[2]

This chapter provides an overview of the current and projected economic situation of renewable energy technologies that generate electricity, produce heat and meet the needs for transport services. Each section begins with an overview of renewable energy costs today and how those costs might evolve to 2040. Based on these projected costs, the future competitiveness of these technologies is assessed. This analysis is done, first, from a commercial investor's perspective, considering both costs and market value as they evolve over time and taking into account region-specific market conditions. In this manner, the analysis provides an indication of the role that markets can play. For those projects that fall short of attaining competitiveness and whose expansion therefore depends on

2. The historic capital costs were provided by IRENA for solar technologies by region (direct communication, May 2016). Starting from the base year data, projections of future costs are made in the World Energy Model, determined by projected capacity additions and technology learning rates.

continuing government support, the instruments available to policy-makers to change the situation are discussed and the total financial support is estimated. In closing, taking a societal perspective, we examine the broader implications of a transition to renewable energy, including some of the desirable co-benefits.

11.2 Electricity

11.2.1 Technology costs

The costs of renewables in the power sector are commonly expressed in two ways: per unit of installed capacity and per unit of electricity generated. Costs per unit of installed capacity are referred to as capital costs, also called "overnight costs", and are expressed in dollars per kilowatt ($/kW).[3] They are calculated by dividing the total investment of the installation by its total capacity. The levelised cost of electricity (LCOE) represents the cost per unit of electricity produced and is expressed in dollars per megawatt-hour ($/MWh). In addition to these two basic cost terms, several others should be kept in mind (Box 11.2). Knowing the LCOE permits cost comparisons between types of power plants; but it does not provide sufficient information to determine competitiveness. In order to estimate competitiveness (or profitability), the market value of a project also needs to be estimated (see section 11.2.3).

Box 11.2 ▷ Power plant cost terminology

The **levelised cost of electricity** (LCOE) is an indicator of the average cost per unit of electricity generated by a power plant. Under the standard formulation, LCOE is the minimum average price at which electricity must be sold for a project to "break-even", providing for the recovery of all related costs over the economic lifetime of the project. The LCOE accounts for all categories of expected power plant costs and includes:

- Capital costs or initial upfront expenses.
- Debt servicing and return on equity invested (represented by the weighted average cost of capital).
- Operation and maintenance costs.
- Fuel costs and associated costs for carbon-dioxide or other emissions (if priced in the market).
- Decommissioning costs (if applicable).

Annualised costs, adjusted for inflation and discounted at a specified interest rate (the weighted average cost of capital) to account for the time-value of money and the financing structure of the project, are then divided by the expected amount of electricity produced each year of the assumed economic lifetime of the project.

3. Costs expressed in US dollars are converted from local currencies based on 2015 average exchange rates.

Capital costs are one-time upfront expenses, including the cost of land, permitting, legal and insurance fees, equipment, construction and labour, and connection to the grid. In the *World Energy Outlook*, financing costs are not included in this category.

The **weighted average cost of capital** (WACC) reflects the financial structure of the project and is the rate of return on the total investment needed to meet financial obligations to creditors, shareholders and other providers of capital. The WACC reflects the relative contribution of debt and equity to financing the project, the cost to service debt and the rate of return on equity invested – corresponding to lenders' and shareholders' requirements. Risk is an important factor that affects the cost of both debt and equity: higher degrees of regulatory, credit, geopolitical, technological and other risks can raise the required rate of return significantly, compared with the risk-free rate of return (usually equal to the government bond rate). The WACC is critical to an LCOE calculation, particularly for capital-intensive technologies, which include many renewables, nuclear and, to a lesser degree, advanced fossil-fuel power plants. Reducing the WACC, which can be achieved through support measures, such as long-term purchase agreements, is an effective way to reduce the LCOE for a new project.

Capacity factor is a critical element in estimating the LCOE of a project and indicates the relationship between the generation of a project and its capacity. Annual capacity factors are calculated by dividing gross electricity production over the course of a year by the theoretical generation where output is equal to the maximum rated capacity throughout the year (that is, if the plant operated at full capacity in all hours of the year). The capacity factor can vary by technology.

Current costs[4]

Dispatchable renewables – including some forms of hydropower, bioenergy, geothermal and concentrating solar power (CSP) – represent about three-quarters of all renewables-based power generation today and supply about one-fifth of global electricity.[5] The capital costs of these technologies currently span a wide range, depending on many factors, including the quality of the renewable resources available in various regions. For recently completed projects, the global average capital costs for large hydropower and bioenergy-based power plants were around $2 000/kW, less than the average costs for geothermal ($2 600/kW) and CSP ($5 000/kW). The typical total capital cost for a new power plant today can range from millions of dollars for projects with capacities in the tens of megawatts (most

4. Where available, current costs refer to projects completed in 2015. With the exception of solar PV capital costs, provided by IRENA, capital costs and performance characteristics for all other renewable energy technologies were collected by the IEA through industry surveys and communications, complemented and verified by publicly available project-level information, as well as regional and technology-specific reports.

5. Dispatchable renewables refer to technologies whose output can be readily controlled – increased up to the maximum rated capacity or decreased to zero – to help match the supply of electricity with demand. Bioenergy-based power plants represent dedicated power plants that burn biomass. Other designs, including combined heat and power plants, may have varying costs per unit of electricity generation. Throughout this chapter, CSP is assumed to include thermal storage.

often bioenergy-based, small hydropower and geothermal) up to billions of dollars (for hydropower and CSP projects of several hundred megawatts). Taking account of the typical operating pattern of each technology (for example, geothermal projects tend to generate electricity in most hours of the year), the range of LCOEs for recent projects tends to be lowest for geothermal projects ($40-90/MWh) and hydropower ($50-140/MWh), followed by bioenergy-based power plants ($100-180/MWh, based on feedstock costs of $30-100 per tonne) and for CSP ($230-260/MWh). For comparison, the LCOEs of common fossil-fuel power plants are provided in Figure 11.3. These costs are most relevant for comparison with dispatchable renewables, for which the operating characteristics and revenue earning potential are similar.

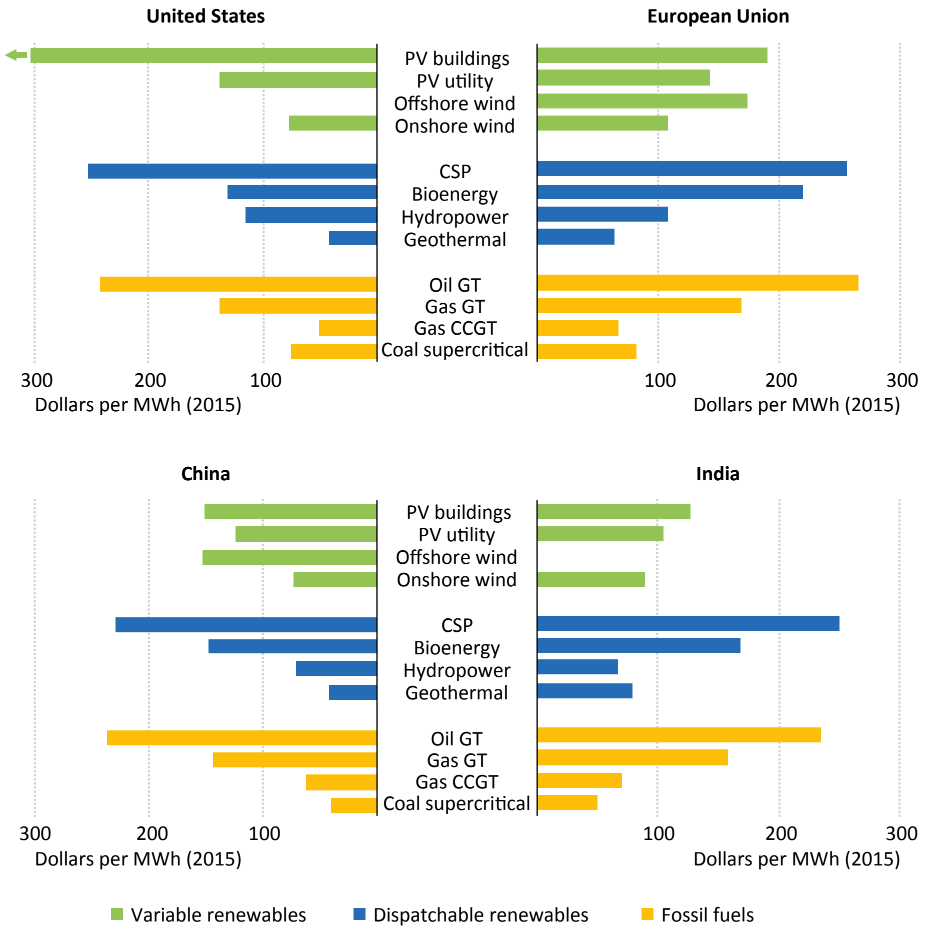
Variable renewables[6] – led by solar PV and wind power technologies – provide a small share of total electricity output today, but are rapidly gaining momentum. They are taking centre stage in large part due to the cost reductions already achieved and the potential for further reductions. For solar PV, the global average capital cost has fallen by almost 60% in the past five years (with the average potentially masking a broad range of costs experienced by individual projects). Global average capital costs for utility-scale solar PV projects completed in 2015 were about $1 700/kW,[7] with the lowest costs in Germany, China and India, at $1 200-1 450/kW, while the United States, South Africa and Japan were higher cost markets (each over $2 000/kW on average). The capital costs of solar PV in buildings were just above $2 400/kW on average worldwide in 2015, almost 50% higher globally than those of large-scale installations. This is due, in part, to the absence of economies of scale and site-specific requirements, which increase the time and cost of each installation. Of the total capital costs, the solar PV module itself, the heart of the system, currently makes up less than half for utility-scale projects in most markets and as little as one-quarter for rooftop applications (Bolinger, 2015; IRENA, 2015).

In terms of the LCOE, utility-scale solar PV achieved a global weighted average of about $135/MWh for projects completed in 2015, with the vast majority of projects around the world falling between $100-300/MWh (IRENA, 2016b). Very low reported prices from recent auctions, several well below $50/MWh, suggest that solar PV costs are about to take a major step down the cost curve; but these reported prices may not fully reflect the underlying costs (Box 11.3). Solar PV projects in buildings tend to be more expensive – the global average was $260/MWh in 2015 – though individual installations most often range from under $100/MWh to $400/MWh. In general, the difference between small- and large-scale solar PV projects reflects the gap in capital costs and the higher performance of utility-scale applications, made possible by wider use of tracking equipment and greater design flexibility (including optimal orientation).

6. Variable renewables refer to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources, such as wind or solar insolation.

7. All solar PV capital costs are presented in direct current (DC) terms, referring to the rated capacity of the solar panel array.

Figure 11.3 ▷ Average levelised costs of electricity by technology and region for projects completed in 2015



All but the cheapest renewable energy technologies have difficulty matching the LCOEs of baseload fossil-fuelled power plants, at current low fossil-fuel prices

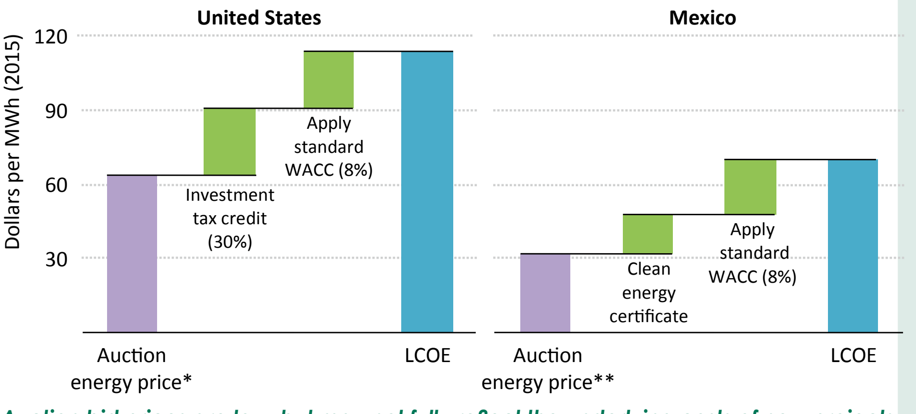
Notes: GT = gas turbine; CCGT = combined-cycle gas turbines. Values above $300/MWh are indicated by an arrow. Bioenergy represents dedicated power plants that burn biomass. All values reflect regional averages, representing a range of project-level costs. Values are not provided for renewable energy technologies in regions which, in 2015, had installed capacity of less than 1 gigawatt. Values for fossil fuels account for regional differences in capital costs and fuel prices, but share common assumed capacity factors (8% for oil and gas GTs, 40% for gas CCGTs and 70% for coal supercritical).

Box 11.3 ▷ Auction bid prices versus LCOEs in the *World Energy Outlook*

The use of auction systems to procure renewable energy has expanded in recent years, and has yielded record low prices, that have been widely reported, for projects that are still to be constructed, but will come online in the next few years. The lowest bids have mainly been for utility-scale solar PV, including in the United Arab Emirates ($24/MWh), Chile ($29/MWh), Dubai ($30/MWh), Mexico ($35/MWh), the United States ($37/MWh) and India ($65/MWh). Low bids have also been reported for wind power projects, including onshore projects in Morocco ($30/MWh), Chile ($39/MWh), Mexico ($43/MWh) and Brazil ($52/MWh), and offshore projects in Denmark ($72/MWh) and the Netherlands ($80/MWh).

Auction prices may not reflect the full underlying costs of the projects (IRENA, 2016b). These prices can be notably lower because they include the benefits of renewable energy support policies and measures (such as the US investment tax credit for solar, equal to 30% of the capital cost, or clean energy certificates in Mexico) and a below average cost of capital (available because of the lower risk reflected in long-term power purchase agreements often awarded in auctions). Auction prices also reflect companies' bidding strategies: they may accept unusually low returns on investment in order to gain a competitive advantage in the market. By contrast, the LCOEs presented in this analysis reflect the full underlying technology costs, based on a consistent set of assumptions designed to facilitate cost comparisons and support the evaluation of competitiveness (when combined with value estimates). For example, the same WACC is applied to all power generation technologies, in order to provide greater transparency; while direct financial support for technologies, renewables-based or otherwise, is not included. The impact of this methodology can be significant. For example, in the United States and Mexico, the auction price can be half the level of LCOE for the same project (Figure 11.4).

Figure 11.4 ▷ Auction energy price versus LCOE for the same solar project



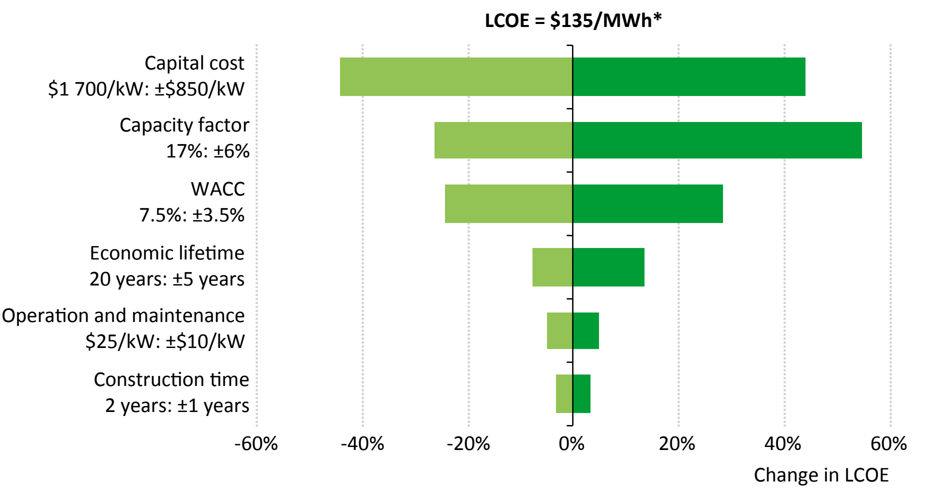
Auction bid prices are low, but may not fully reflect the underlying costs of new projects

* Based on capital costs of $1 700 /kW, 21% capacity factor (DC terms), 20-year lifetime and 5% WACC.
** Based on capital costs of $1 200/kW, 24% capacity factor (DC terms), 20-year lifetime and 3% WACC.

Wind power has also achieved cost reductions in recent years, though the major emphasis has been on improving performance, rather than reducing costs. Capital costs for onshore wind power stood at about $1 500/kW on average worldwide in 2015, more than 10% lower than in 2010, with most projects falling between $1 000-2 500/kW. Over the same period, the global average capacity factor for new onshore wind projects has increased by several percentage points, to over 27% in 2015, due to higher hub heights, longer blades and advanced turbine designs, including those that perform well in a low wind speed environment. With this gain, the global average LCOE of onshore wind was about $80/MWh in 2015, with project-level costs ranging from below $50/MWh in Brazil and the United States to over $100/MWh in lower quality wind regimes and less mature markets.

Offshore wind power facilities represent only a small share of the wind power market today, but will be an important renewables option going forward. Offshore wind projects have higher capital costs, on average, than their onshore counterparts – in excess of $4 500/kW for projects completed in 2015 – their much higher costs being associated with the costs of the foundations, installation and the transmission connections (IRENA, 2016b). Offshore projects tend to have longer turbine blades than is feasible on land, raising the maximum and average output over the year. Their enhanced performance partially offsets the additional investment required, bringing the average LCOE for completed projects in 2015 to around $170/MWh, more than double that of onshore wind, but there are indications that the next wave of projects will take a step down the cost curve.

Figure 11.5 ▷ Sensitivity of the LCOE of solar PV to varying parameters



The levelised cost of solar PV largely depends on capital costs, capacity factor and the weighted average cost of capital

*The starting LCOE reflects estimated global average parameters for utility-scale projects completed in 2015.

In order to demonstrate the impact of varying cost-related parameters on the overall LCOE of a project, consider utility-scale solar PV, starting from the global average LCOE for projects completed in 2015 ($135/MWh).[8] Halving the capital cost compared with the starting value reduces the LCOE by more than 40% (Figure 11.5). The capacity factor depends largely on the quality of the resource: world-class sites, with capacity factors above 20%, potentially reduce levelised costs by over 25%. A 3.5 percentage point increase or decrease in financing costs can change the levelised cost by 20% or more, emphasising the role that preferential financing can play to make renewable energy projects financially viable for developers. By combining the low end of the range for each cost element, the LCOE for utility-scale solar PV falls to around $35/MWh, which would put it among the lowest cost sources of electricity, renewable or otherwise. Though some elements may differ, the example also provides insight into the cost structure of smaller scale solar PV projects and wind power.

Projected costs

The costs of renewable energy technologies in the power sector are projected to continue to decline over the next 25 years. The extent of cost reductions to 2040 depends largely on further technology improvements and developers gaining from experience, both linked to scale of deployment. Based on assumed technology learning rates, greater deployment of renewables in the 450 Scenario, compared with the New Policies Scenario (particularly wind and solar PV), leads to greater capital cost reductions (Figure 11.6).[9] There are some offsetting factors that create upward pressure on the overall costs of new projects, such as rising labour costs, particularly in developing countries where gross domestic product (GDP) growth is higher, and the depletion of the sites with the most favourable resources.

Dispatchable renewables continue to be deployed over the period to 2040 in all scenarios, though the high degree of maturity of the leading technologies limits the potential for sustained cost reductions over time: the capital costs and LCOEs of hydropower, geothermal and bioenergy-based technologies stay relatively stable to 2040, on average, in both the New Policies Scenario and the 450 Scenario. The exception is CSP, for which global installed capacity increases dramatically, from less than 5 gigawatts (GW) in 2015 to 76 GW in 2040 in the New Policies Scenario, driving down global average capital costs and LCOEs by 30-50%, to about $3 500/kW and $150/MWh respectively.[10] In the 450 Scenario, installed capacity of CSP is more than four-times higher than the New Policies Scenario in 2040, reducing capital costs and the average LCOE by an additional 20% on average. The cost

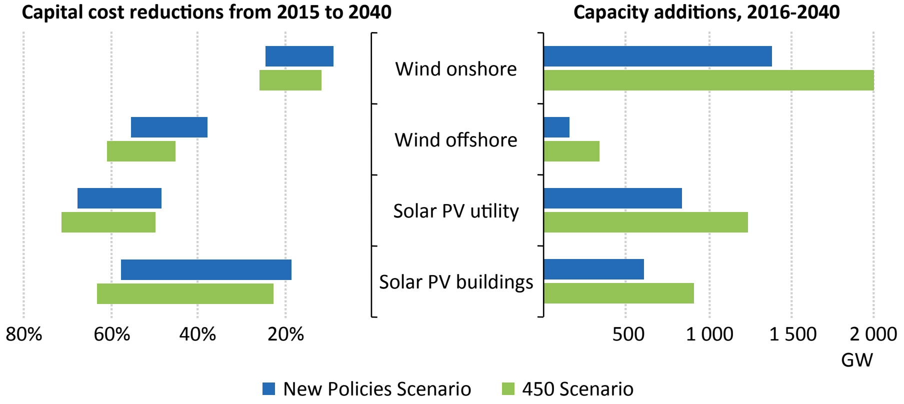
8. The starting LCOE reflects global average values for projects completed in 2015 for capital cost and expected capacity factor. Other parameters reflect the standard assumptions in the *World Energy Outlook*, including the cost of capital (WACC), which is 8% in OECD countries and 7% non-OECD countries.

9. In the World Energy Model, capital costs for renewables in each region are based on local and global annual capacity additions, applying technology-specific learning rates for each doubling of cumulative capacity additions (e.g. 20% for solar PV, 10% for CSP, 11% for offshore wind and 5% for onshore wind).

10. Projected reductions of the levelised costs of electricity can be and often are greater than the reduction of capital costs, due to projected performance gains.

reductions for CSP will make it an increasingly attractive source of flexibility as power systems evolve in order to integrate higher shares of generation from variable renewables in the overall power mix (see Chapter 12).

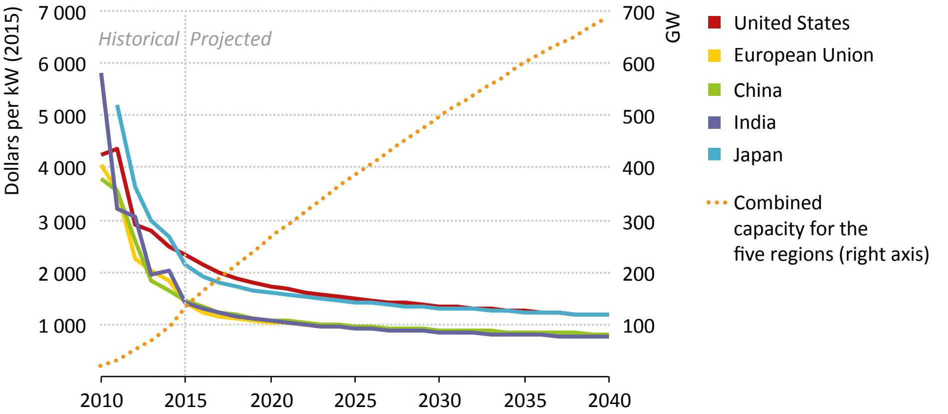
Figure 11.6 ▷ Global wind and solar PV capacity additions and capital cost reductions across regions by scenario to 2040



The cost to build wind projects is projected to fall by 10-60% by 2040, while solar PV capital costs decline by 20-70%

Variable renewables have demonstrated their ability to achieve cost reductions over time and this is projected to continue. Solar PV is projected to lead the way, the market expanding from a record high 49 GW in 2015 to almost 90 GW per year by 2040 in the New Policies Scenario, and cumulative capacity additions to 2040 amount to over 1 400 GW. This strong growth supports technology gains that reduce both the costs of solar modules and other costs, driving down the global average capital costs of utility-scale projects in some major markets to below $800/kW in 2040 (Figure 11.7). Regional variations diminish over time but remain, to some extent, largely due to local, non-module costs, which include other hardware (cabling, racking and mounting, and grid connection), installation (including inspection) and "soft costs" (largely financing, permitting and customer acquisition). The market structure in some countries emphasise the deployment of utility-scale solar PV, such as in Mexico, leading to greater reductions than for smaller scale applications. Technology innovation also strongly reduces the costs of solar PV in buildings. For example, increasing solar cell efficiencies decrease the size per unit of capacity, reducing costs related to both transportation and installation. Standardisation of the installation process is an active focus of interest and expected to contribute to future cost reductions. In the New Policies Scenario, the market for solar PV in buildings continues to grow; nearing 40 GW per year in 2040 (including replacements) and accounting for over 40% of the solar PV market at that point, with cumulative capacity additions of 600 GW from 2016 to 2040. This strong deployment drives the capital costs down by 40-50% in most regions, though cost reductions are less pronounced where markets remain limited.

Figure 11.7 ▷ **Historic and projected average capital costs for utility-scale solar PV in selected regions in the New Policies Scenario**



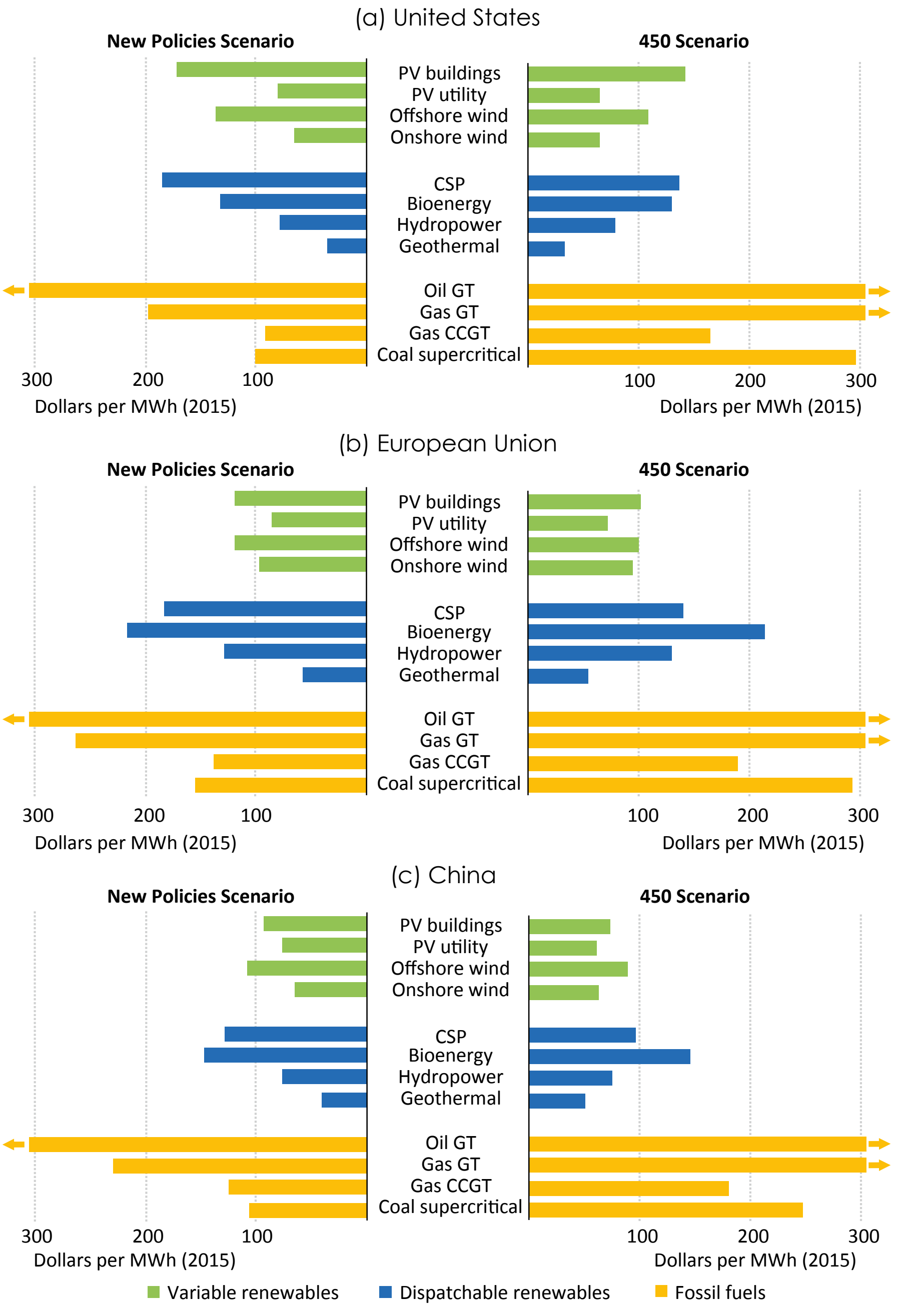
The overall costs of solar PV continue to fall over time, building on recent cost reductions

Note: Historic capital costs provided by IRENA (2016a).

The growth of wind power is second only to that of solar PV, with an increase in installed capacity of close to 1 100 GW to 2040 in the New Policies Scenario, driving down the global average capital costs of onshore wind towards $1 400/kW and offshore wind to about $2 900/kW in 2040. Offshore wind is mainly deployed in markets where installations already exist, led by the European Union, though deployment is more widespread in the 450 Scenario. Compared with the global average for wind power, several regions remain low cost throughout the period, including China and India, and individual projects in many regions are likely to be able to come in at lower overall cost. However, increasing labour costs put noticeable upward pressure on both onshore and offshore wind power costs, offsetting part of the cost gains that come from improvements in turbine and nacelle manufacturing and installation efficiency.

Over the next 25 years, the levelised costs of electricity from several renewable energy technologies are projected to rival the LCOEs of fossil-fuel power plants (Figure 11.8). On the one hand, the costs of renewables are on the way down, with the costs of wind and solar PV falling well below $100/MWh in most markets prior to 2040 (based on a WACC of 7-8%). On the other hand, the costs of fossil-fuel power plants are on the rise, increasing beyond $100/MWh in most cases, due to increasing fuel prices in most markets. In the 450 Scenario, both trends are accelerated: the cost of renewables falls further with greater deployment and, for fossil-fuel plants, broader application and higher levels of carbon-dioxide (CO_2) prices dramatically raise the LCOEs from plants that are not equipped with carbon capture and storage. While levelised costs are an important point of comparison, they do not, alone, demonstrate profitability and competitiveness. Considerations of revenues or avoided costs are also required to enable that determination.

Figure 11.8 ▷ Average levelised costs of electricity by region, technology and scenario, 2040



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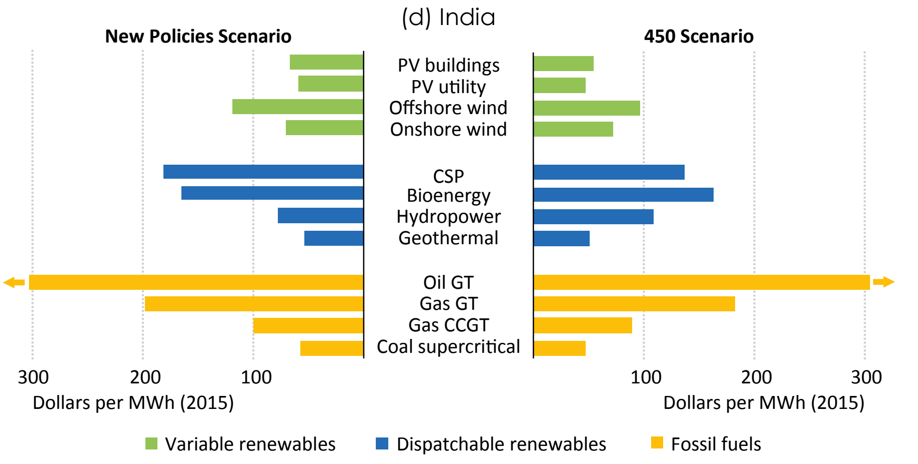


Many renewable energy technologies beat fossil fuels on costs alone in the coming years, but value needs to be considered to evaluate competitiveness

Notes: GT = gas turbine; CCGT = combined-cycle gas turbines. Values above $300/MWh are indicated by an arrow. Bioenergy represents dedicated power plants burning biomass. All values reflect regional averages, representing a range of project-level costs. Values for fossil fuels account for regional differences in capital costs and fuel prices, but share common assumed capacity factors (8% for oil and gas GTs, 40% for gas CCGTs and 70% for coal supercritical).

11.2.2 Value of renewables-based electricity

With the lifetime of a technology measured in decades, investment decisions in relation to renewables-based power plants must be based on the expected costs and value well into the future. In the face of the many uncertainties, the energy futures described in the main scenarios of the *World Energy Outlook* provide a coherent basis for assessing the value prospects for investments in renewable energy. The focus of attention of the investor in assessing the value of renewables depends on the purpose of the project: the value will come primarily from revenues from electricity sales for utility-scale projects and avoided costs in the case of distributed renewables.

For utility-scale projects supplying electricity to the grid, market-based revenues[11] for electricity sold to the grid represent the estimated market value in the analysis of competitiveness (direct financial support is not included).[12] The value of renewables varies

11. Simulated market-based revenues are based on the main source of revenue - energy provided to the grid. Revenues are calculated as the product of the quantity of electricity provided and the hourly price, which is set by the power plant dispatched to meet demand with the highest marginal cost. Each region is represented as a single balancing area, free of congestion points. Locational marginal pricing could lead to higher revenues in the presence of congestion points and greater use of peaking plants or lower revenues where regional fuel prices are below average or output from renewables is less well matched to demand. Revenues for participation in other markets (capacity or ancillary services) are not included.

12. The concept of declining value also applies to regions without competitive electricity markets, but may be less clearly identifiable.

noticeably by region, as market-based prices reflect the specific characteristics of each system.[13] The first of three key factors is the amount of variable renewables in the system, as higher shares tend to reduce the average market price of all electricity and they tend to operate at times when prices are lower than the average (Hirth, 2013; Mills and Wiser, 2012). At low shares, variable renewables may receive prices higher than the average, but as their maximum output is determined by the time of day or the weather conditions, they are price-takers, rather than price-setters (prices are set by the highest marginal cost power plants in operation). Dispatchable technologies are able to shift their output to periods with higher prices, but this is not true (without storage) for variable renewables. The second key factor is related to fossil-fuel prices, particularly the price of natural gas, which tends to be the price-setting fuel in wholesale electricity markets. The third key factor is the level of CO_2 prices applied, its price impact being related to the carbon intensity of the power mix.

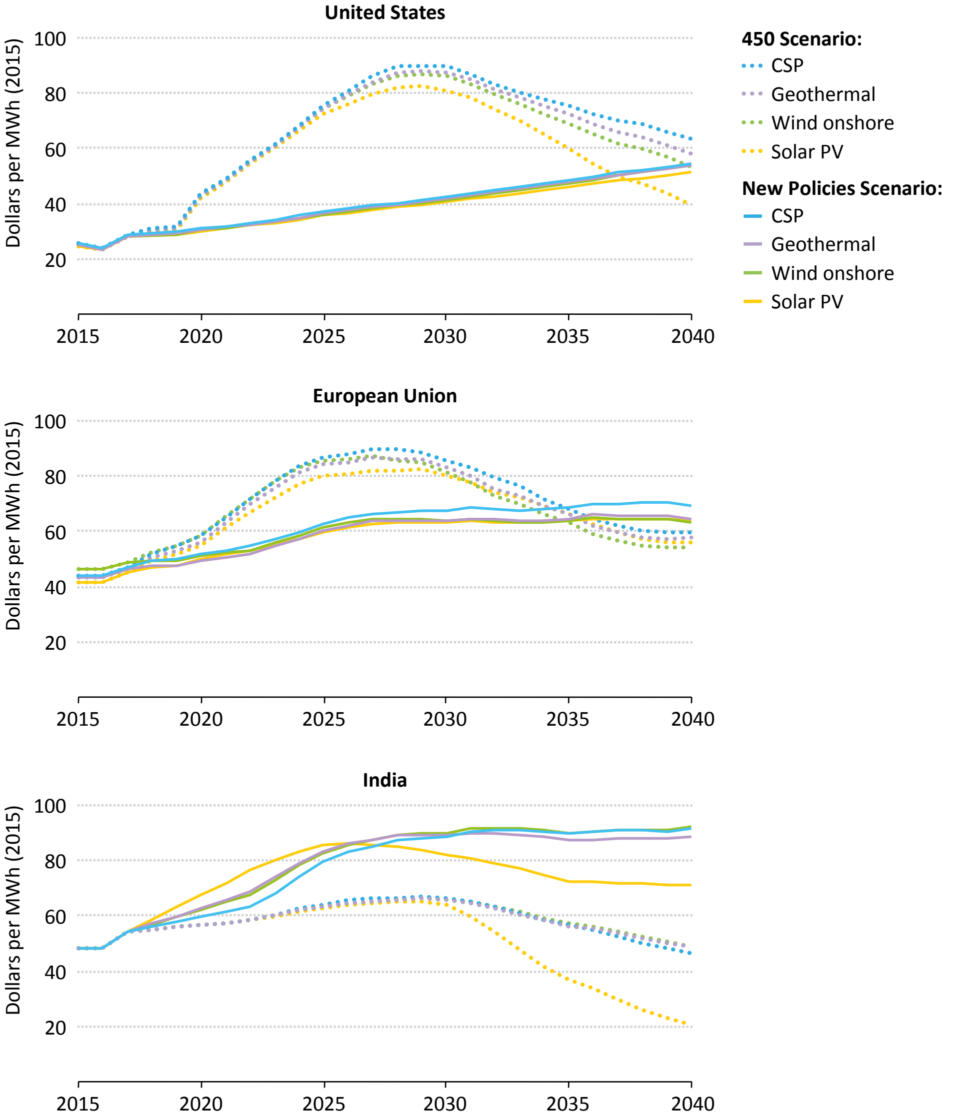
Over the period to 2040, we project how the value of variable renewables evolves in the United States, European Union and India, for which a new hourly model for power supply and demand was developed (see Chapter 12, Box 12.2). In the New Policies Scenario, the value of variable and dispatchable renewables remains broadly similar to 2040 in these three regions, close to the average wholesale electricity price (the value of geothermal power is particularly close to the average price as it operates in most hours of the year). Market-based revenues for all renewables steadily increase in the three regions, largely due to rising gas prices. Though the share of variable renewables in total generation rises in each region – higher in the European Union (31%) than in the United States (19%) or India (16%) – their average market revenue remains similar to the average wholesale price in most cases. Solar PV in India is the exception, as its market value departs notably from that for other technologies by 2030 and continues to 2040, due to strong emphasis placed on the deployment of solar PV relative to other renewables. Among the three regions, CO_2 pricing is only present in the European Union, reaching \$50 per tonne of carbon dioxide (\$/tCO_2) by 2040 (for which a fully functioning EU emissions trading scheme is essential).

The dynamics of the 450 Scenario (i.e. higher and more widespread CO_2 prices) raise the market value of renewables in most cases. In each region, variable renewables make up larger shares of overall power supply throughout, reaching 37% in the European Union, 35% in the United States and 31% in India. The increase is most significant in the United States, where it puts downward pressure on the value of solar PV and wind power after 2030. Greater emphasis on wind power in the European Union keeps its value in line with that of solar PV throughout the period to 2040. In India, solar PV is relied on heavily, greatly reducing its market value by 2040 compared with other technologies in both scenarios. In all three regions, fossil-fuel prices are lower in the 450 Scenario, due to lower regional and global demand (e.g. 30% lower for natural gas in the European Union in 2040, compared with the New Policies Scenario), adding to the downward pressure on prices. Robust CO_2 prices in the United States and European Union (reaching \$100/tCO_2 by 2030 in both regions) more than offset the downward forces, raising average market prices by as much

13. Alternatively, the value of renewable energy can be represented by the avoided cost in the power supply for a given project, as in the *Annual Energy Outlook 2016* (US EIA, 2016).

as 50% to 2030 (Figure 11.9). After 2030, even higher CO_2 prices (to $140/t$CO_2$ in 2040) have a diminishing impact on average market prices over time, as the power mix becomes almost completely decarbonised.

Figure 11.9 ▷ Average revenues received for utility-scale renewables by technology and scenario in selected regions, 2015-2040



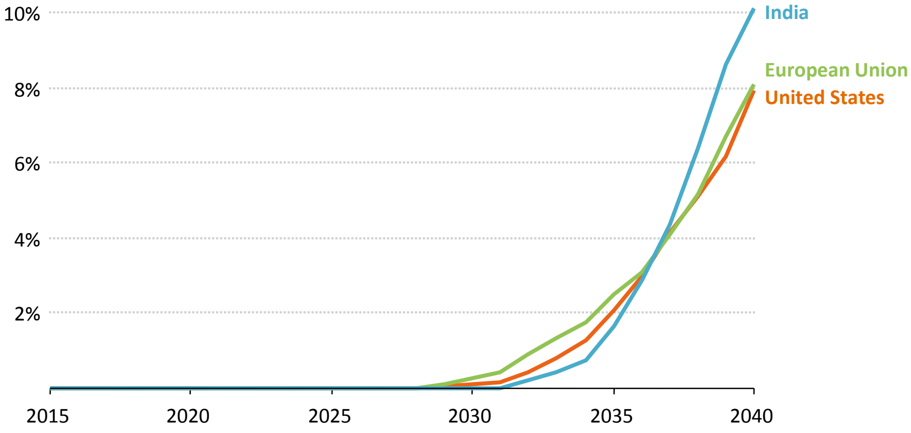
The market value of renewables-based electricity gets a boost from rising CO_2 prices in the United States and European Union in the 450 Scenario

Beyond the three regions modelled in detail, the value of renewables tends to be higher in regions relying on higher cost fossil fuels, such as in Japan, and lower in regions with access to inexpensive domestic fuels, such as China, Russia and many countries in Latin America and Africa. The implementation of CO_2 pricing and the level reached in the New Policies and 450 Scenarios strongly impact the value of renewables. The average value of renewables described by region applies to entire regions that have (or nearly have) a single electricity market, or to sub-regional balancing areas (over which electricity demand and supply are matched) that are characterised by fuel mixes and delivered fuel prices that are similar to the regional average. Congestion in the transmission system may also affect the value of renewables, as certain sub-regions may need to rely on higher cost fuels. The first renewable energy auctions in Mexico provide a clear example, as they assigned greater value to proposed projects in certain areas (e.g. in the Yucatan peninsula), due to congestion issues.

Preserving the financial health of the power system as a whole throughout the transition to a low-carbon pathway is one of the largest challenges facing planners and the detailed price simulations provide them with helpful insights. For several years before and after 2030, when average revenues peak in the United States and European Union in the 450 Scenario, the market price provides sufficient revenues over the course of the year to cover the annual costs of the entire power system – the minimum required for the system to be financially solvent. Within that window, total revenues exceed the overall power generation costs of power supply, including recovery of invested capital in fossil-fuelled and nuclear power plants. This has not been the case in recent years and, outside that window, market revenues are again insufficient to cover total power system costs. Additional sources of revenue, possibly including capacity payments, may be needed in those years to ensure the continued reliability of the power supply (IEA, 2016a).

Another indicator related to the value of renewables is the number of hours in which the market price falls to levels near zero, which occurs when the supply of very low short-run cost supply options, including variable renewables, meets or exceeds demand. To date, the instances of market prices near zero (or below zero), have been of short duration and have occurred in sub-regional markets in a limited number of countries, including Germany, the United Kingdom and the United States. In the 450 Scenario, hourly simulations reveal that these events become increasingly commonplace over time as the volume of generators with low short-run costs rises (as found in other studies of highly decarbonised power supplies [Mai, 2012; IEA, 2015a]). This occurs even though balancing areas have been greatly expanded. By 2040, near zero prices occur quite regularly, in 7-10% of the hours in the year in the 450 Scenario in the United States, European Union and India (Figure 11.10). In a case with the same level of renewables and other low-carbon sources as the 450 Scenario but without demand response and energy storage, energy-only market prices would be near zero much more often, about one-third of the time in the European Union and around 20% of the time in the United States and India. Failing to take action on demand response and energy storage would have other implications as well, as more curtailment of output from renewables would be compensated by increased consumption of fossil fuels and CO_2 emissions (see Chapter 12.3).

Figure 11.10 ▷ Percentage of hours in the year with simulated market prices near zero by selected regions in the 450 Scenario, 2015-2040

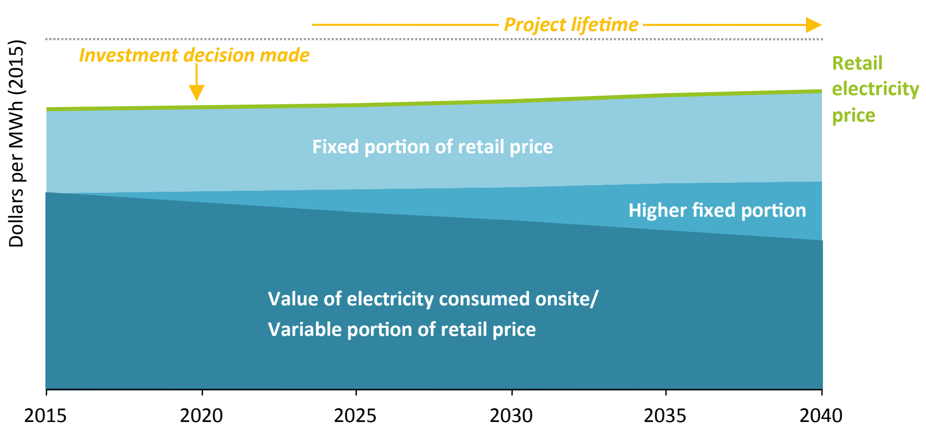


Hourly market prices near zero become increasingly common in the 450 Scenario, but would occur much more often without demand response and energy storage

The value of small-scale distributed projects to consumers already connected to the grid comes from two sources: the avoided costs of electricity that otherwise would have been purchased from the main electricity grid and revenues received for sales of electricity to the grid. Avoided costs for electricity have greater weight in the calculation when individuals are able to consume high shares of the renewable electricity produced onsite (i.e. own use), which is possible when electricity consumption can be matched to the profile of renewable electricity produced. Avoided costs may make up a larger portion of the value proposition for commercial entities, compared with households. For example, commercial consumers whose demand is concentrated during the day may be able to consume up to 90% of the electricity produced onsite from a solar PV system (without energy storage), while residential consumers typically consume less than one-third (European Commission, 2015). The value of renewable electricity consumed onsite is usually higher than the market value of electricity supplied to the grid, in part due to avoiding the energy taxes that apply, in most markets, to the electricity purchased from the grid.

For each unit of electricity produced and consumed onsite, the avoided cost is equal to that part of the retail electricity price that varies with consumption. The full retail electricity price cannot be avoided in most markets, as grid connected consumers have some charges related to the fixed costs of the power system. While the fixed portion represents only 30% or less of the retail electricity price in many markets, the fixed costs of the overall power system actually tend to be 50% or more of the total costs. Furthermore, the share of fixed costs tends to increase over time in the projections, particularly in the 450 Scenario, as renewables and nuclear power gain market share, reducing the value of electricity produced and consumed onsite. This inconsistency between the structure of the retail tariff and the underlying system costs can introduce a distortion, which becomes more pronounced as rooftop solar PV and other distributed technologies gain in popularity. This effect is reinforced when the tariff paid for sale of surplus electricity from distributed generation to the grid is higher than the market value of electricity at the time, as it is in many markets with net metering programmes. In both cases, those with solar PV fail to pay their fair share of fixed power system costs, indicating that appropriate value for determining competitiveness is lower than it may seem (IEA, 2013). Energy taxes are avoided as well, in most cases, and may be shifted to other consumers. The redistribution burden usually falls onto fellow consumers, rather than government, often shifting costs from high-income households to low-income ones. The phenomenon is already apparent in several markets where distributed generation has been deployed in significant amounts. The US states of California and Arizona have added to or considered raising the fixed charges. The debate is ongoing in Spain, where the fixed portion approaches 50% of the total. As a result of this effect, the variable portion of the retail tariff could decline over time, in turn reducing the value of electricity produced and consumed onsite (Figure 11.11). In the long run, the value of electricity produced and consumed onsite should equal the average variable costs of the power supply.

Figure 11.11 ▷ Indicative evolution of the value of distributed renewables-based electricity consumed onsite



The value of electricity produced by distributed renewables depends on the fixed portion of the retail electricity price

The value of electricity from distributed renewables sold to the grid also varies over time, largely in step with the market value of the larger scale version of each technology. For example, the value of electricity sold to the grid from solar PV in buildings follows the same trend as utility-scale solar PV. Therefore, the declining value of utility-scale variable renewables that occurs as their market share increases can also reduce the value of small-scale variable renewables, for the portion of electricity produced that is sold to the grid. Local grid conditions may increase or decrease the value of output from distributed renewables. Considering, instead, those not already connected to the grid, including the 2.9 billion people gaining access to electricity for the first time over the period to 2040, the value of renewable energy is extremely high, the alternative often being expensive electricity supplied by small generators burning oil products.

Adding energy storage is one way to increase the value (and, of course, the cost) of distributed renewables. Energy storage enables a higher share of renewable electricity produced to be consumed onsite, by reserving the final supply of electricity to times when it is needed. In most cases, those consumers whose distributed renewables include energy storage will remain connected to the grid in order to guarantee the same level of energy services, and so will continue to have to bear the fixed portion of the retail electricity price. The level of fixed charges will be affected only marginally by a relatively small number of distributed electricity installations with storage; but, where such installations become popular, there could be both upward and downward pressure on the fixed charges. The total fixed costs of the system may decline (due to lower requirements for investment in transmission), they may rise (due to potentially higher investment in distribution) or they may stay the same but become a bigger share of total electricity bills (as the consumption of electricity from the grid declines).

11.2.3 Competitiveness of renewables-based electricity[14]

Are renewable energy technologies competitive yet? Their falling costs, particularly wind and solar PV, have led many commentators to assert that they are, in fact, competitive today. Comparing the levelised costs and projected value of projects provides the foundation for the evaluation of their profitability and thereby their competitiveness (as defined in this analysis). Where the average LCOE is below the average unsubsidised revenue received (measured in $/MWh), a technology is considered profitable and can be deemed "competitive", able to stand on its own commercial merits. At that point, the discounted net revenues would be positive, the internal rate of return would exceed the specified WACC and the discounted payback period would be less than the economic lifetime of the project, all widely used metrics of the profitability of individual projects. Once profitable based on market revenue, renewables have the potential to deliver societal benefits without the intervention of governments or others. But the pace of deployment based on market forces, may still not be sufficient to achieve, for example, the rapid transition needed to a low-carbon pathway required to realise international climate goals.

Competitiveness of new wind and solar PV projects

The date when new wind power and solar PV projects become competitive depends on the region, as both the costs and market value vary. In the New Policies Scenario, India is one of the first regions where variable renewables become competitive; around 2020, both

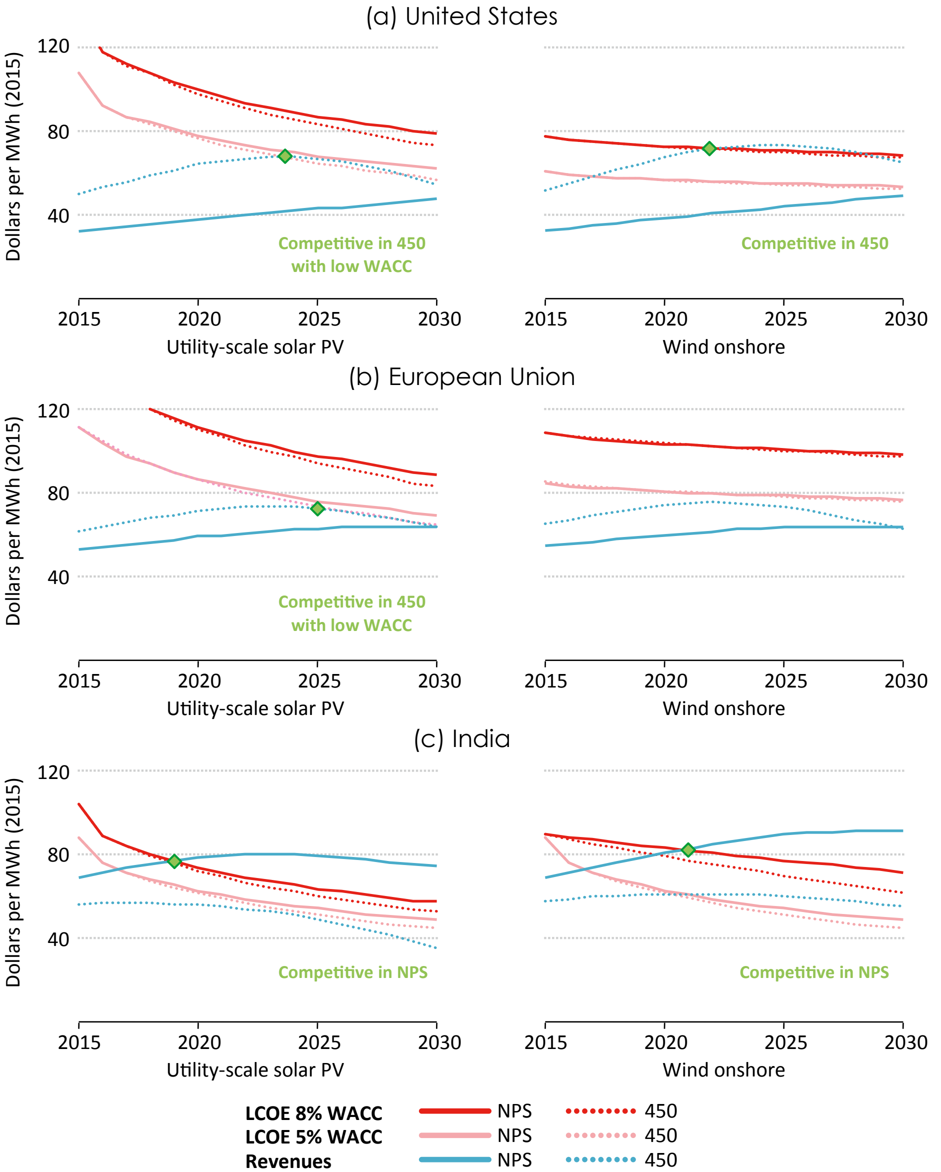
14. The profitability of renewables will also be measured against alternative investments, both within the power sector and beyond, but these evaluations are beyond the scope of this analysis.

the average utility-scale solar PV and onshore wind project are profitable based on market revenues alone, due to their relatively low costs and high market value (Figure 11.12). This is one of the earliest dates for a large region, though variable renewables can be competitive earlier in smaller markets that rely on high-cost imported fuels. Other regions where the prospects for the competitiveness of wind and solar PV are promising prior to 2030 in the New Policies Scenario include China, Mexico, Australia, South Africa, and countries in Southeast Asia and the Middle East. Where the market value is particularly low, the commercial case for wind and solar PV is much more difficult. For example, in the European Union, the average cost solar PV projects require a low WACC (5% or less) to be competitive prior to 2030. In the United States, the low average market value of variable renewables (estimated below $40/MWh until the mid-2020s), which is linked to very low natural gas prices, makes the financial case for investment in renewables difficult without additional support. There are several cases that improve the prospects for individual projects, including where they have below-average costs, where local grid conditions increase their value and where participation in ancillary service markets provides additional revenue.

In the 450 Scenario, the prospects for the competitiveness of renewables are better than in the New Policies Scenario in most regions due to lower renewable energy technology costs and higher value prospects in regions where CO_2 prices are either strengthened or introduced. For example, higher CO_2 prices in the European Union helps the average solar PV project with a low WACC to become competitive around 2025, five years earlier than in the New Policies Scenario. While this improves the prospects for wind power, only those projects with below-average costs and a low WACC are able to stand on their own financial merits by 2030. In the United States, the implementation of a CO_2 price in 2020 increases the market value of wind and solar PV projects by upwards of three-quarters (over their 20-year economic lifetimes), enabling average-cost projects to become profitable between 2020 and 2025. Other regions where the market value of renewables is significantly higher in the 450 Scenario (also due to phasing out fossil-fuel subsidies) include Australia, Korea, South Africa and countries in North Africa and the Middle East.

In regions without CO_2 prices, the competitiveness of variable renewables can suffer in the 450 Scenario. The effect is linked to lower fossil-fuel prices and, ultimately, lower wholesale electricity prices that result from less fossil-fuel consumption globally in the 450 Scenario. Without CO_2 prices to compensate for lower fuel prices, the market value of renewables (and other technologies) may be reduced substantially. For example, the commercial case for investment in onshore wind and solar PV projects in India is weaker in the 450 Scenario, as average revenues over their lifetimes are 15-50% lower for projects completed before 2030. A similar effect occurs in Southeast Asia, hurting the competitiveness of wind power, while solar PV is able to overcome the additional challenge through additional deployment and resulting cost reductions. This effect reinforces the importance of CO_2 pricing in the transition to a sustainable energy pathway, as they can unlock market forces to help pursue renewable energy and the many associated co-benefits to society.

Figure 11.12 ▷ Average LCOEs and revenues for wind and solar PV in selected regions in the New Policies and 450 Scenarios, 2015-2030



Declining costs and rising values improve the prospects of wind and solar PV, though low-cost financing may be necessary to achieve profitability in some markets

Notes: NPS = New Policies Scenario; 450 = 450 Scenario. WACC = weighted average cost of capital. Years indicate the completion date for new projects. Revenues equal the average revenue received over the 20-year economic lifetime of projects.

Source: WEM hourly model, IEA analysis.

When renewables-based power plants are competitive in the market, they move into the next phase of their development. They join the suite of centralised power generation technologies available on a commercial basis to meet electricity demand growth (over 13 600 terawatt-hours (TWh) from 2014 to 2040 in the New Policies Scenario) and to replace the output of retired power plants (2 400 GW of retirements in the New Policies Scenario from 2016 to 2040). On this basis alone, renewables deployment would be insufficient to deliver the level of decarbonisation needed to meet international climate goals. To do so, renewables or other low-carbon sources of electricity must pass additional milestones, requiring even deeper cost reductions, so that they can also displace a large portion of the output from existing fossil-fuelled units (IEA, 2015b).

The theoretical market potential for rooftop solar PV and other distributed renewables captures the imagination of many. Millions of households and many businesses around the world are potential investors. For consumers that remain connected to the grid, the financial attractiveness of investing in rooftop solar PV or other distributed renewables will be a moving target, as larger amounts of distributed generation will add to the pressure for retail tariff structures to reflect the underlying share of fixed costs in the power system. Where the fixed portion of consumers' bills are small and remain so, rooftop solar PV can be financially attractive in the near future, but could shift substantial costs on other consumers. In the case that should be applied in the determination of long-run competitiveness, where the fixed portion of electricity bills reflect the share of fixed costs in the system, solar PV in buildings will find it difficult to attract investment, particularly in regions that deploy utility-scale solar PV. When energy storage is added, both the cost and value increase. In certain circumstances, consumers that install distributed generation technologies could usher in a significant change in the way that electricity is produced and delivered, making obsolescent the centralised utility model that has been prevalent for more than a century and providing more control and responsibility to consumers. For this transformation to take hold, the cost of energy storage must decline substantially, alongside the costs of distributed renewables, as consumers will need to invest in large amounts of storage in order to disconnect from the grid without compromising on the quality of their energy services.

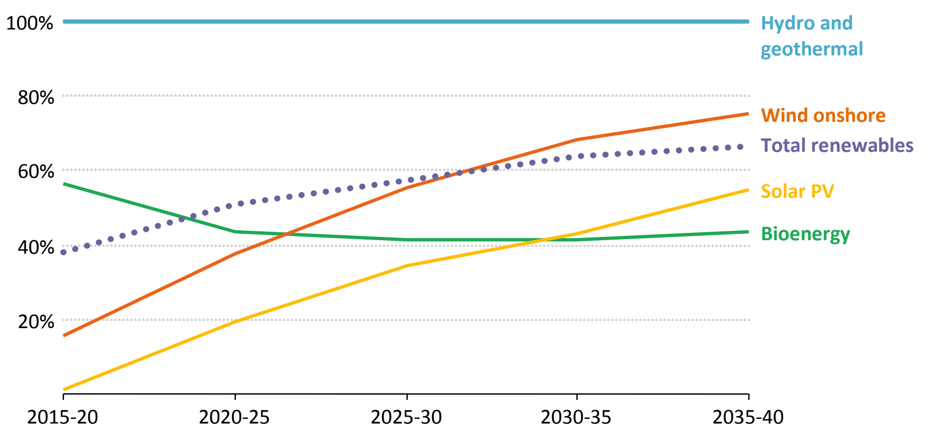
Uncertainties are always critical factors in evaluating an investment, particularly in an asset with an operational life measured in decades, as in the power sector. Revenue uncertainty is the key concern for renewables (and all power plants), stemming from risks to both price and quantity (the volume of electricity that can be sold). With a market-based revenue stream, the average price received in the New Policies Scenario and 450 Scenario diverge markedly. Much depends on confidence in the long-term commitment of the government of a region or country to a declared policy path, adding a degree of certainty to a financial case necessarily built on assumptions. The Paris Agreement on climate change influences the future of renewable energy technologies by establishing the clear intention of the international community to pursue a sustainable low-carbon pathway. "Quantity risk" relates to confidence in the amount of electricity that actually will be generated and sold and is relatively low in most cases. (Chapter 12 discusses the risks associated with the need to ensure that steps are taken to provide large-scale integration of variable electricity into power systems.)

Competitiveness of the overall supply of renewables-based electricity[15]

It is also possible to assess the collective competitiveness of the fleet of existing renewable energy projects, meaning the prospects of their covering their annual costs (including payments to recover capital invested). By 2040, over 60% of renewables-based power generation does not require external financial support, compared with about 5 000 TWh that require some level of support.

Of the dispatchable renewables, hydropower and geothermal are largely competitive today and additional generation to 2040 does not require subsidies, while the competitive share of bioenergy-based power plants fluctuates somewhat, depending on the technology type and where it is deployed (Figure 11.13). The competitive share of bioenergy rises as a result of wider use in countries with low-cost biomass resources, such as Brazil, but is depressed by additional projects relying on imported biomass, as many do in the European Union.

Figure 11.13 ▷ Share of generation from new renewable energy projects that do not require subsidies by technology in the New Policies Scenario

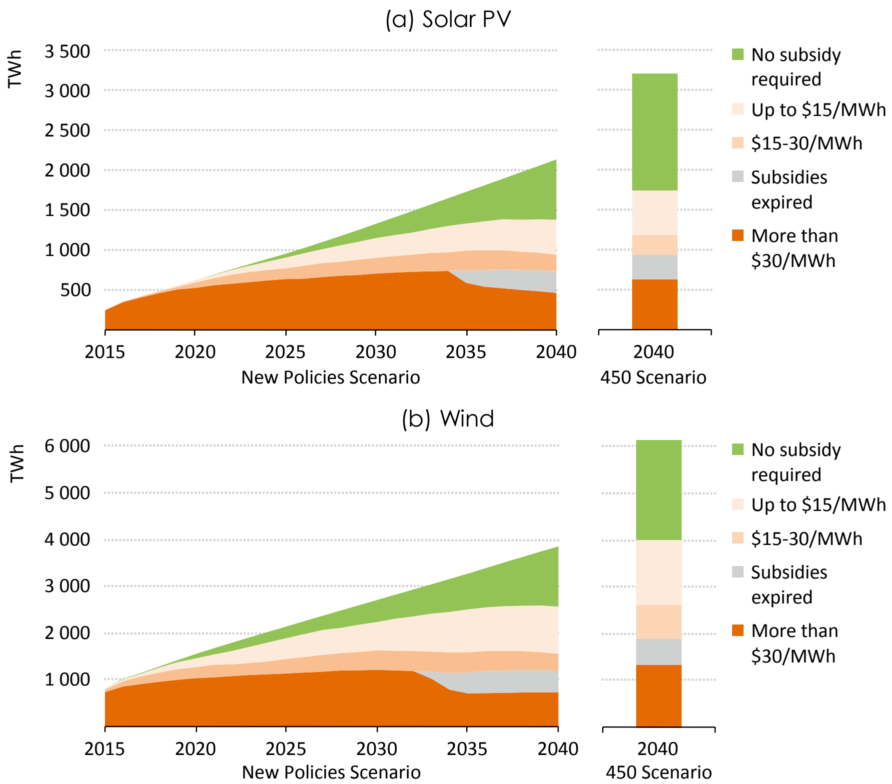


Increasing shares of new wind and solar PV projects become competitive over time

15. While LCOEs for renewable energy technologies are presented as regional averages, a range of LCOEs are represented in the World Energy Model, based on a range of capital costs and performance characteristics, and this range underpins the global assessment of competitiveness and renewable energy support. For regions other than the United States, European Union and India, the value of dispatchable technologies is equal to the projected wholesale electricity prices in the World Energy Model (aligned with average power generation costs). The value of variable renewables also takes into account the declining value as the share of variable renewables increases in each region, applied as a percentage reduction from wholesale electricity prices.

As we have seen, variable renewables make substantial gains in terms of competitiveness by 2040 in the New Policies Scenario, led by onshore wind, for which competitiveness becomes the new norm. Despite less robust capacity growth than onshore wind, offshore wind achieves greater cost reductions, making great strides towards competitiveness. Solar PV becomes steadily more competitive over time; by 2040, 30% of total generation from solar PV does not require subsidy. By the late 2030s, many existing solar PV facilities reach the end of their operational lifetime and are replaced, but at lower costs than an entirely new project (assuming a 20% discount). These facilities are largely competitive. Overall, the competitive share of generation from the entire fleet of utility-scale solar PV, including new capacity and replacements, exceeds 40% in 2040, an impressive accomplishment for a technology that was several times more expensive than fossil-fuel alternatives as recently as 2010. For rooftop solar PV, the competitive share steadily climbs in the New Policies Scenario, from a small share today to around 40% by 2040.

Figure 11.14 ▷ Generation from solar PV and wind power installations by subsidy level in the New Policies and 450 Scenarios



The majority of solar PV and wind power projects require no or very low government support in the New Policies Scenario in 2040

As for the projects that fail to stand completely on their own financially, their degree of competitiveness can be represented by calculating the level of support needed to fill the financial gap. In the New Policies Scenario, the share of new projects that require only very low levels of subsidy, below $15/MWh, starts to increase by 2020. For comparison, $15/MWh is between only 5-10% of the average electricity end-user price at global level. In 2040, solar PV generates more than 2 100 TWh of low-carbon electricity, more than one-third of which is competitive without subsidies, 13% are no longer receiving subsidies because they have expired (after fully recovering their capital costs) and a further 20% receive only low levels of subsidy (below $15/MWh) (Figure 11.14). Wind power generally requires even lower levels of subsidy. In 2040, out of 3 800 TWh of total wind generation, one-third is competitive and almost another quarter requires subsidies of $15/MWh or lower. In the 450 Scenario, about 75% more generation from variables renewables is fully competitive in 2040, with more than 1 000 TWh of solar PV and almost 2 000 TWh of wind power. By that point, variable renewables generation that requires $15/MWh or less of support in the 450 Scenario exceeds the total amount of variable renewables generation in the New Policies Scenario in the same year.

11.2.4 Support to make renewables-based electricity financially attractive

Government policies supporting the deployment of renewable energy technologies have been widely introduced, with policies currently in place in some 155 countries. The financial value of the support is calculated as the difference between the levelised cost of electricity and the wholesale electricity price in each region, which is then multiplied by the amount of generation for each renewable energy technology.[16] Based on a survey of established national level policies and on the known deployment of new renewable energy projects in 2015, we estimate that global subsidies provided to renewable-based electricity projects at $120 billion in 2015, $6.4 billion higher than in 2014. The appreciation of the US dollar over the period helped to keep down the level of support. For example, if exchange rates had remained stable at 2014 levels, the increase in subsidies expressed in dollars, would have been more than twice as large, at around $14 billion.

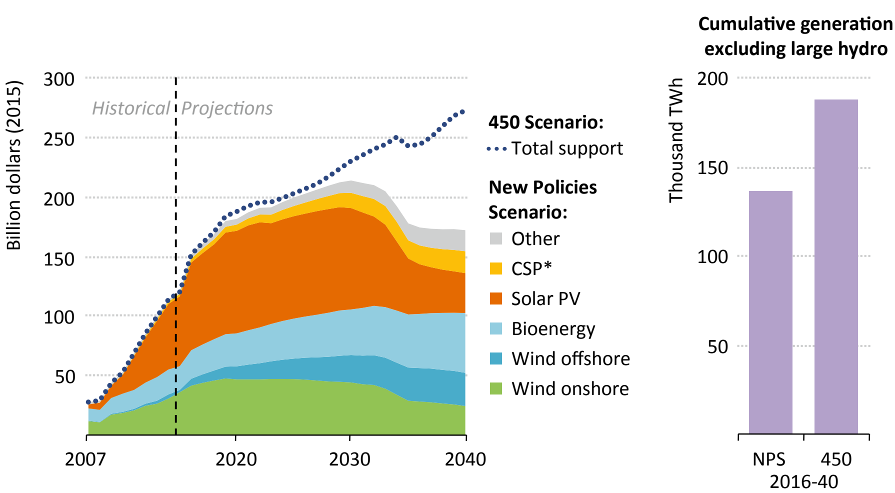
Wind power and solar PV led the increase in renewable subsidies for power generation, while those for bioenergy decreased by $1 billion (or 5%), as some subsidies expired in the European Union. In 2015, solar PV accounted for 50% of the subsidies, wind power for 30%, bioenergy for 17% and geothermal and CSP for 2% each. Japan, India, China and the United States are the countries in which subsidies increased most (a combined rise of $10 billion). Despite deployment of renewable energy technology in many regions, subsidy payments are concentrated in a few countries. In 2015, the top-five countries – Germany, the United States, China, Italy and Japan – accounted for two-thirds of the total and the top-ten countries – including the United Kingdom, Spain, France, India and Belgium – for almost 85%. The European Union continued to provide the largest amount of subsidies

16. See *www.worldenergyoutlook.org/weomodel/documentation* for more information on the methodology for estimating subsidies for renewables.

to renewables for power generation (52% of the total in 2015, down from 60% in 2014), despite a year-on-year decrease of 9% (due mainly to the weakness of the Euro against the US dollar).

In the New Policies Scenario, subsidies paid to renewable-based electricity generation peak just above $210 billion in 2030 and then decline to about $170 billion in 2040 (Figure 11.15). Of total cumulative subsidies over the period to 2040, about three-quarters goes to solar PV and wind power, around 20% to bioenergy and the remaining portion to other renewables-based power plants. By 2040, of total renewable electricity subsidies, the share going to solar PV and wind decreases to about half, from 80% in 2015, while the shares of bioenergy and CSP increase to 30% and 11% respectively.

Figure 11.15 ▷ Renewables-based electricity support and cumulative total generation in New Policies and 450 Scenarios



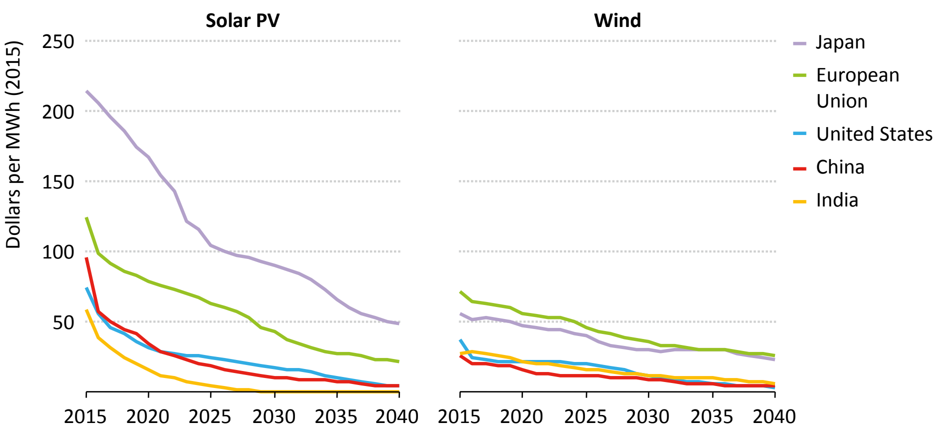
While support for renewable electricity will be needed for years to come, transitioning to a low-carbon pathway can be achieved for just 15% more support

*CSP = concentrating solar power.

In the New Policies Scenario, cumulative subsidies to renewables-based electricity generation worldwide total $4.7 trillion over 2016-2040 (equivalent to about 0.2% of the cumulative global GDP over the period), supporting a cumulative production of 136 000 TWh from renewables excluding large hydropower. In the 450 Scenario, these technologies lead the strong decarbonisation of power supply, with an additional 50 000 TWh of generation over the period to 2040. However, with additional cost improvements in the technologies, more widespread use of carbon pricing around the world and higher electricity prices, the additional subsidies are about $700 billion, 15% more, over the next 25 years.

While total subsidies to renewables-based electricity generation increase by about 40% from today to 2040 in the New Policies Scenario, the level of generation from renewables excluding large hydropower is close to five-times higher. Hence, the subsidy per unit of electricity generated, or "unit subsidy", decreases dramatically over time, particularly for solar PV and wind power, again as a result of technology cost reductions and rising electricity prices in most cases (Figure 11.16). The unit subsidy for new solar PV projects declines rapidly over the next decade, falling by two-thirds in the United States, about three-quarters in China and by half in Japan and the European Union, while solar PV in India does not require any subsidies for new projects built after 2030. The unit subsidy for wind power also decreases steadily over time in the largest global markets, as levelised costs continue to decline and electricity prices increase.

Figure 11.16 ▷ Estimated average subsidy rates for new solar PV and wind power plants in the New Policies Scenario

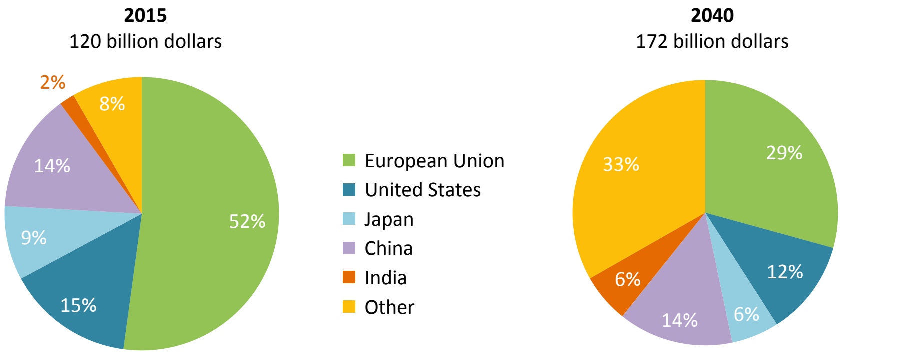


The rate of subsidy needed for new PV and wind power falls dramatically in the coming years

In the New Policies Scenario, the regional composition of support for renewables in power changes significantly (Figure 11.17). In 2040, in terms of the total amount of subsides provided, the European Union continues to lead (the share of wind power in its total subsidies increases to about 50%, from 28% in 2015, while solar PV is down to 12%, from 48% in 2015), followed by China, the United States, India and Japan. An increasing amount of support is provided to renewable energy projects in Southeast Asia, Africa, Latin America and the Middle East.

Support mechanisms for renewable energy come in a variety of forms and have varying levels of appeal from the perspective of the policy-maker or the investor. Characteristics of support schemes that are valued by policy-makers include: ease of implementation; the predictability of the budgetary impact; transparency of the level of support provided per unit of energy produced; harnessing competitive forces; and exposing supported projects to market signals. From an investor's perspective the financial viability of the project is the key criterion, for which predictability of revenue streams, clear and reliable rules, and low transaction costs are key parameters. In their simplest forms, support schemes are able to meet these criteria to varying degrees. For example, feed-in tariffs[17] can be very attractive to investors, providing a high degree of revenue certainty. However, without additional volume or cost limits, feed-in tariffs set at generous levels can lead to a boom in deployment and rapidly increase the total level of support needed, as occurred in several countries in the European Union. For most support schemes, careful designs with additional measures such as limits can successfully support the deployment of renewables while meeting essential criteria for policy-makers and investors.

Figure 11.17 ▷ Global subsidies to renewables-based electricity generation in the New Policies Scenario, 2015 and 2040



Support for renewables in power is more evenly spread across the world over time

Auction schemes[18] have been gaining momentum in recent years and were in use in over 60 countries as of 2015, given their broad appeal. From the policy-makers perspective, they are relatively easy to implement and the government has direct control over the volume of renewable energy contracted, ensuring fulfilment of renewable energy targets. Competition between participants enables auctions to identify the lowest cost projects, minimising the cost to government budgets. Recent auctions have received record low bids for solar PV and wind projects in several regions, including Mexico, Peru, Morocco, Egypt, Brazil, South Africa and India (IEA, 2016b).[19] Contracts awarded through auctions (as well as feed-in tariffs) provide fixed payments during the entire subsidisation period and are insensitive to

17. Feed-in tariffs are fixed payments per unit of renewables-based electricity fed into the grid, often technology-specific and committed for a specified amount of time, e.g. 20 years.

18. Auction schemes are quantity-based support mechanisms in which the government issues a call for tender for a certain amount of renewables-based power from approved technologies. Bidders compete mainly on costs. Winners are awarded long-term contracts for generation at bid prices.

19. Where no additional revenues are available, bids provide clear signals of actual technology costs. In fact, bid prices may be reduced by other support measures, such as tax credits or grants, preferential land prices or targeted low-cost loans.

market developments: there is no incentive to vary output according to the needs of the market. From the investor perspective, bidding schemes provide a guaranteed purchase price for a given quantity of generation over a determined number of years. This helps to reduce the financing costs of the project, provided the power purchase agreement is with a party with a high credit rating, such as a government, decreases the counterparty risk (risk of non-payment). However, auctions are not ideal from the investor's perspective. Bidders may be required to issue financial guarantees at an early stage of project development and incur high administrative costs in order to navigate complicated auction procedures.

11.3 Heat

11.3.1 Technology costs

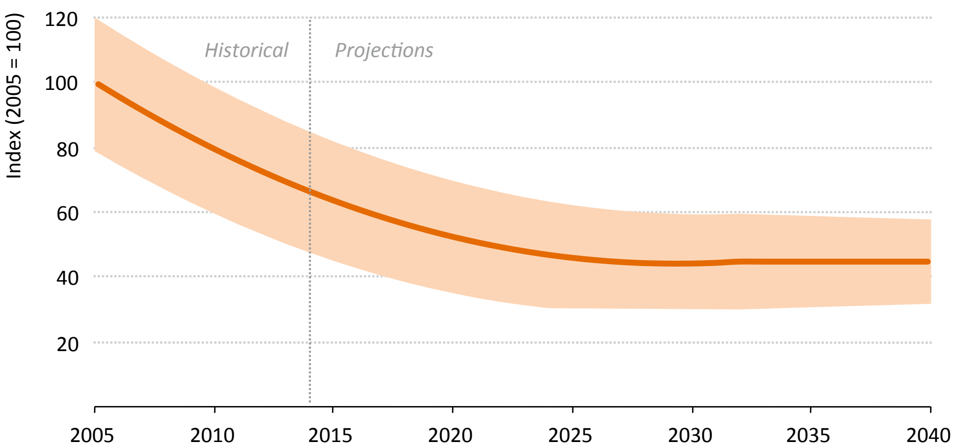
Direct modern use of bioenergy currently meets 6% of global demand for heating and represents 70% of the use of renewables to provide heat (including indirect contributions). In the New Policies Scenario, bioenergy meets 9% of demand for heating by 2040. Most of the bioenergy is converted into heat in boilers, a well-established technology, based on mass produced components. The scope for cost reduction of the boilers by process improvement is limited. There does remain scope for optimising costs by modifying the overall system design, but the extent of this varies widely between installations and countries. Investing in a biomass boiler costs two- to five-times more than a comparable natural gas boiler, mostly due to the engineering complexity of biomass systems and the lower economies of scale in production compared to natural gas. Biomass boilers also require storage space for the fuel. Depending on the density of the heat requirement in a given area, the use of bioenergy to provide heat to industry and (in most cases) buildings is done most efficiently through the use of district heating, supplied by combined heat and power plants using bioenergy. Over the *Outlook* period, we assume that, on average, the capital costs of such installations will decline by 10-20% depending on the location and market size.

Among other renewable energy technologies that provide heat, solar water heating (SWH) accounts for the highest proportion of demand growth in the New Policies Scenario.[20] SWH accounted for 6% of hot water production in the buildings sector worldwide in 2014, having increased by about 17% per year since 2000. SWH grows three-fold from the level in 2014 and accounts for almost 15% of water heating by 2040. The upfront cost of the technology has come down, as a result of concerted efforts by industry in research, development and manufacturing. Globally, the total cost of SWH systems ranges between \$200-3 000 per kilowatt thermal (kW_{th}). It can be as low as \$120 per square metre (m^2) for a simple thermosiphon system in the south of Turkey (where deployment is increasing

20. In this chapter, solar water heating and solar water heaters refer to the use of solar irradiation through a solar thermal collector to provide domestic and commercial hot water (excluding swimming pool heating and space heating applications).

without any government incentives) to as high as $1 950/m^2 for a more complex pumped system in the northern climate of Paris (IEA, 2016b). System costs include the cost of the equipment, installation cost and taxes. With taxes usually being a small share of overall cost, in many regions, the equipment makes up most of the system costs and typically has three major components – a solar heat collector (about half of the equipment cost), a water storage tank and, often, an auxiliary heater. The cost also varies by collector, according to the surface area and type of system. The largest regional variation is due to differences in technology types, installation costs and the cost of components required to balance the system (BOS).[21] In some countries of the European Union, installation costs can make up as much as 50% of the system costs, while they are around 10% in Brazil (Renewable Energy World, 2011). China's relatively low system costs are attributable to inexpensive labour and the technology type being deployed: 85% of the systems use thermosiphons that have less auxiliary equipment than more expensive pumped systems. Beyond system costs, the economics also depend on the performance of the technology, local climatic conditions and consumer behaviour.

Figure 11.18 ▷ Change in the cost of a solar water heater in the New Policies Scenario, 2005-2040



Solar water heater cost reductions slow, as rising labour costs offset technology learning

Source: IEA analysis based on ITW, University Stuttgart.

The potential for lower SWH costs lies mainly in the equipment, in particular the manufacturing costs, which can be improved by economies of scale (e.g. arising from their use in district heating), simpler designs, development of more manufacturing capacity and use of better techniques, including automation. While realising efficiencies in the

21. Quality of manufacturing varies across regions, leading, among other things, to different lifetimes of solar water heaters.

manufacturing process is a key source of potential cost reductions, past experience, such as for flat plate collectors, shows that the benefit of such savings may be reduced if other costs rise (such as raw material costs). While the average cost of SWH systems has almost halved since 2005 (Figure 11.18), reductions are expected to continue at a modest pace over the *Outlook* period and then to level off by 2040, as increases in labour cost offset technology learning.

11.3.2 Competitiveness of renewables-based heat

Industry

Bioenergy is the largest renewables contributor to heat supply in the industry sector and is set to remain so in all scenarios. However, the economics of bioenergy use in industrial boilers varies across regions and scenarios, mostly due to differences in regional market conditions (e.g. fossil-fuel supply costs or different subsidy and taxation schemes). Coal is often the lowest cost source of heat, but governments around the world are increasingly regulating coal use, mostly due to climate-related concerns and the local pollutant emissions associated with its use (IEA, 2016c). From 2020, for example, China is banning coal burning in industrial boilers in cities in the Beijing-Tianjin-Hebei cluster, the Pearl River Delta and the Yangtze River Delta.

Despite current low oil prices, biomass boilers are, on a levelised cost basis, providing cheaper heat than oil boilers in most countries (Figure 11.19). Notable exceptions are oil-producing countries in the Middle East, the Caspian region and some Latin American and African countries, where oil products are currently subsidised (e.g. in Algeria, Egypt, Gabon, Argentina, Bolivia and Venezuela). As oil prices are expected to increase more than biomass feedstock prices, the financial attractiveness of biomass boilers over oil boilers is expected to widen. Areas that are not connected to natural gas grids are expected to become key growth areas for bioenergy use in the industry sector.

Greater efficiency, lower investment costs and low fuel prices make natural gas boilers the most competitive option for the industry sector in most countries today (especially in those where gas is readily available), although this is not necessarily the case in areas where cheap local biomass resources (such as agricultural residues, or by-products of industries or wastes) can be supplied. In the New Policies Scenario, the competitiveness of bioenergy is on a par with natural gas in most importing countries by 2040, as gas prices increase and as some countries and regions, such as China and the European Union, implement or strengthen their CO_2 pricing policies.[22] Natural gas remains more financially attractive in regions where it remains particularly cheap or is subsidised, which is the case in many gas-exporting countries, and in regions where there is limited supply of low-cost biomass.

22. The CO_2 price reaches \$50 per tonne of CO_2 in the European Union and \$35 per tonne of CO_2 in China in 2040 in the New Policies Scenario.

Figure 11.19 ▷ Typical levelised cost of heat production in industrial boilers by fuel in selected regions

The competitiveness of bioenergy improves in most regions as fossil-fuel and CO_2 prices increase relative to today

Notes: NPS = New Policies Scenario; 450 = 450 Scenario; O&G = oil and gas. Ranges reflect various biomass sources: the low-end refers to sources such as biomass from agricultural residues and wastes, including animal manure; the high-end refers to more expensive processed biomass fuels, such as pellets or syngas.

Lack of CO_2 pricing in the New Policies Scenario prevents bioenergy from being cost competitive with gas in many cases. In the 450 Scenario, CO_2 pricing becomes a major element adding to the financial attractiveness of bioenergy relative to natural gas, especially in OECD exporting countries, such as the United States and Canada, where the natural gas price remains low. CO_2 pricing on its own, however, will not enable the most expensive forms of bioenergy to compete in all applications. Policies that phase out subsidies also play a role for bioenergy to compete more successfully in the 450 Scenario in some regions.

Beyond the cost of the fuel itself, other barriers to the deployment of bioenergy in industry remain. Where large-scale supply needs exist, storage requirements and seasonal factors affect the practicality of the biomass supply, as well as the efficiency of the organisation of the supply chain at the local or regional level. A technical barrier is the integration of biomass conversion in industrial processes (such as in the chemical and petrochemical sectors) where material and energy flows are intertwined. Even where, as in China and India, biomass residues can be found in large and cheap quantities, there are other important considerations, such as sustainability and the potential impacts on local air quality.[23] Upgrading the biomass used to better quality forms, such as pellets, and mandating emissions control technologies can ensure the sustainability of large-scale biomass use in these countries and in the rest of Southeast Asia.

In the New Policies Scenario, solar heat enjoys the second-largest growth in the direct use of renewables for heating purposes in the industry sector. Although the use of solar is already becoming increasingly cost competitive in some regions and for specific applications (washing, drying or space heating), it still involves higher upfront investment costs and lower full-load hours than other available options. Its future development is constrained by the temperature levels that can be delivered by conventional designs (up to 125 °C with direct solar air collectors or solar water systems), which fall short of the level required by many industrial processes. Even so, solar heat applications in industry present some advantages over those in buildings. These include greater economies of scale, relatively constant levels of demand throughout the year and lower installation costs (as a share of total investment). Nonetheless, in the period to 2040, additional incentives, such as preferential loans or grants, will be required if solar heat in the industry sector is to realise anything like its full potential. In the short term, technology deployment support, including further research, development and demonstration (RD&D) is needed to improve the business case for early industrial adopters and to gain from learning effects.

Buildings

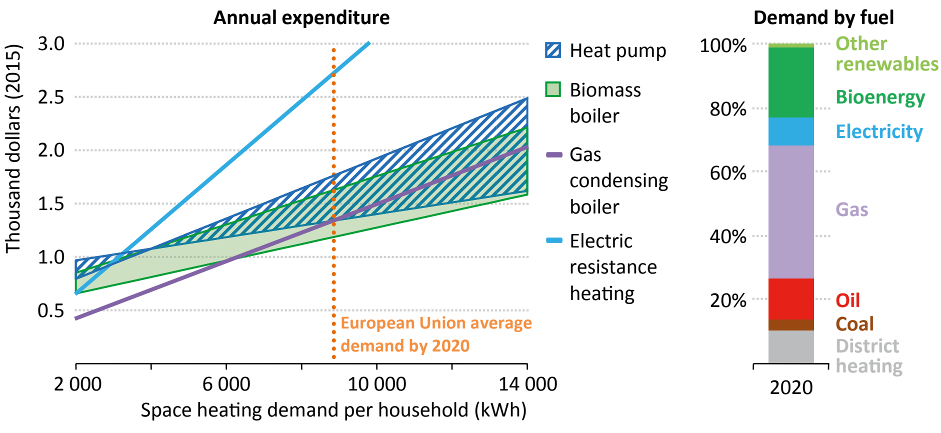
Today, almost 80% of energy demand in the buildings sector is for heat. In cold climates, it is used mostly for space heating and in temperate climates for water heating and cooking. Renewables satisfy 9% of heat demand in buildings, mostly in the form of modern bioenergy (more than 50%) usually used for space heating, solar heating for hot water (around 10%), with the remainder being mainly indirect renewables through the use of electricity or district heat supplied by renewable energy sources. While much of the growth in renewable heat in buildings relied on support policies, many technologies are now mature and can provide heat at a competitive price *vis-à-vis* fossil fuels in those markets that have relatively high fossil-fuel taxes. But concerns about local pollution from bioenergy use and high upfront costs are serious challenges to further deployment.

The cost competitiveness of renewable options *vis-à-vis* fossil-fuelled equipment to meet space heating demand varies by region and depends primarily on the capital cost of boilers,

23. For instance in the case of agricultural residues, a certain percentage should be retained in-situ to ensure nutrient depletion of the soil does not occur.

fuel prices and the level of overall space heating demand.[24] Most of the demand for space heating is concentrated in developed countries. While the European Union and North America represent only 10% of the global total floor area, they account for 54% of space heating needs today. This share decreases to 48% by 2040 in the New Policies Scenario, highlighting the importance of offering competitive renewable options in these regions. As discussed previously, biomass boilers are already well-established technologies, and, alongside indirect options (the use of electricity or district heating supplied from renewables), are often the most attractive renewable option to satisfy space heating needs. Despite higher upfront costs than gas condensing boilers and electric heaters, biomass boilers can be an attractive heating option where cheap biomass feedstocks are available, such as Canada and the United States. The levelised cost of heating also favours bioenergy when gas and electricity prices are high (e.g. as a result of energy taxation), as is the case in several European countries. Space heating with bioenergy, which currently provides over 15% of Europe's space heating demand in buildings (a similar share to coal and oil), becomes one of the lowest cost options in the region by 2020 where space heating needs exceed the European average (Figure 11.20). Nevertheless, fuel price differences are not the same across all regions, favouring less bioenergy outside the European Union. Large-scale development of biomass for heat in buildings is also limited by other considerations, as noted above in relation to industrial use.

Figure 11.20 ▷ Annual expenditure for space heating options and demand by fuel in the European Union in the New Policies Scenario, 2020



Even by 2020, biomass heat is competitive with fossil fuels in the European Union where space heating needs are high

Notes: Annual expenditure includes the average annualised investment cost and the average fuel cost until the end of the lifetime of equipment purchased in 2020 in the European Union relative to space heating needs and efficiencies of the different equipment.

Source: IEA analysis based on IRENA/IEA-ETSAP (2010-2013).

24. Space heating needs vary with heated floor area and building envelope, with lower heating needs for well insulated buildings.

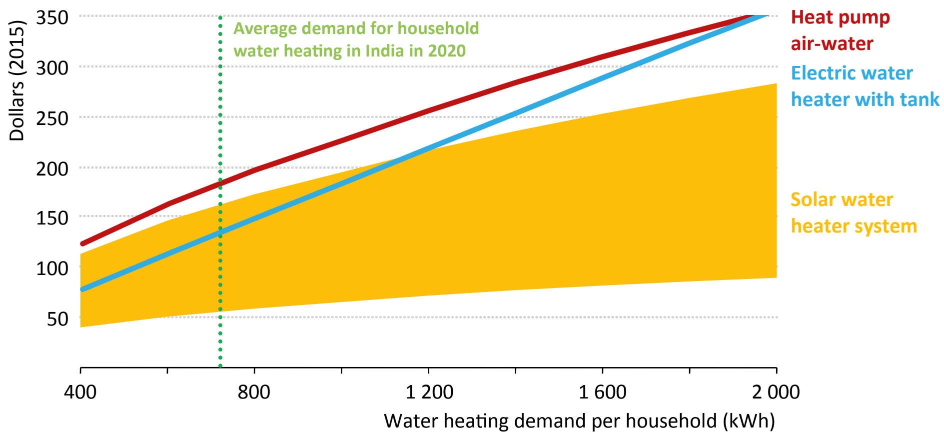
Even though bioenergy can be competitive, natural gas accounts for about 40% of demand for heat in the residential sector in the European Union and remains the preferred option to 2040 in the New Policies Scenario. It remains the cheapest source of heat at lower levels of consumption in households. The natural gas network infrastructure is widely established, enabling the heating and cooking needs of many urban households to be met. This represents a significant investment and technology lock-in. Bioenergy may have a better case for penetration in these areas through the use of biogas. The incorporation of biogas upgraded to bio-methane into the natural gas network is an option that does not carry additional investment cost for the consumer, and is showing some promise in Europe. For example, in France and the United Kingdom, bio-methane injection into the gas network has been authorised and subsidised since 2011.

In 2020, at higher levels of space heating demand, heat pumps (ground-source and air-source) also become a cost competitive option in the European Union, despite their higher upfront costs, since operating costs are relatively low. Heat pumps run on electricity so the power price can affect the economic attractiveness of the option. For instance, some electricity tariffs embed charges, such as support for renewables, that are not part of the cost structure of natural gas supply. On average, electricity prices for households in the New Policies Scenario in the European Union increase slightly to 2020, while gas prices decrease by 1.1%. Renewable solutions, especially ground-source heat pumps, are likely to be most suitable for new buildings, due to the extensive installation work needed. Even though electric resistance space heating apparently is not cost competitive in the European Union (Figure 11.20), it represents a good option in highly efficient buildings where the need for space heating is low.

While the total demand for water heating in developed countries is similar to the rest of the world, developing countries represent more than 90% of the global growth in water heating demand to 2040. Going forward, SWH contributes substantially to the water heating needs of developing countries, especially in areas with high levels of solar insolation and where electricity infrastructure is underdeveloped. In the New Policies Scenario, 70% of the increase of solar water heating comes from non-OECD countries (Box 11.4). Over the last few years, SWH has experienced significant cost reductions. While the initial cost is higher than gas or electric boilers, operating costs for SWH are much lower, even when electricity is used as a backup. The payback period is already short for consumers in developing countries, while it is still high in European Union and North America. This is due to the difference of equipment and higher installation costs, resulting in lower adoption rates and the roof area often being used to install solar PV (Box 11.4).

No financial incentives are needed to make SWH competitive today in China and India. In India, SWH systems can be cost competitive with electric water heaters, even when demand is relatively low (Figure 11.21). Nonetheless, some municipalities have started introducing SWH requirements into building codes (e.g. Shenzhen) to spur deployment. A justification is the high investment cost differential between SWH and electric heater systems, estimated to be around $600, equivalent to one-third of the annual income of an average Indian household. This has resulted in a relatively slow uptake of SWH and indicated the need for action to help with financing. In addition, SWH requires a backup system (which will be more important in certain seasons and weather conditions), which further erodes their cost advantage. In cities, where the available roof space per household is lower and hot water demand is higher (due to higher income levels), heat pumps can be a good alternative.

Figure 11.21 ▷ Annual expenditure for water heating equipment in India in the New Policies Scenario, 2020



In India, solar water heating systems are already competitive

Notes: A range of investment cost has been assumed for solar water heaters to represent the various types of equipment available on the market in India, with the purchase being made in 2020. The upper range for solar water heating systems includes an electric backup, with the related investment and fuel costs.

Sources: Indian Environment Portal, (2013); IEA SHC (2016); IEA analysis.

Box 11.4 ▷ Solar PV versus solar thermal – how is a roof best used?

There are two key options for meeting water heating demand through renewables – solar thermal systems or solar PV (either directly linked to electric water heaters or to a more efficient heat pump). Which solution is more attractive to consumers is dependent on location, level of demand and the availability of government incentives. The competition to meet water heating demand is important, as it accounts for 12% of buildings energy demand worldwide and will be a leading source of energy demand growth in developing countries to 2040. The use of renewable energy to meet all or part of this new demand, may help to avoid CO_2 emissions related to the electricity supply, as in many countries, electric water heaters are used.

Solar thermal has an advantage of requiring less space, due to its high thermodynamic efficiency. In hot, sunny climates, solar thermal for domestic water heating requires an area of only 2-4 m^2, whereas meeting the same level of demand with solar PV would require three-times the area. Solar thermal panels can also be placed on façades, as they work well at a higher tilt. By using less space to meet hot water demand means that more rooftop area is available for solar PV to provide other services, such as running appliances, charging electric cars or selling excess power to the grid.

The cost comparison between solar PV and solar thermal hinges on the technology costs and regional climate. Generally, in warm, sunny climates, solar thermal systems can produce most of a building's hot water needs at low cost while a solar PV-heat pump or electric water heater is likely to be more expensive and a more complex system. In regions where the investment cost of SWH is low, the levelised cost of heat (LCOH) favours its installation to provide hot water. In India, the LCOH of SWH today can be as low as $60/MWh while it is closer to $100/MWh for a combined solar PV and electric water heater. The same comparison can be made in other developing countries and the result can be quite clear in some cases, such as Brazil where the LCOH of solar PV is about double that of SWH, or somewhat closer, as in South Africa where the LCOH of both options are comparable. Over time, the falling costs of solar PV make the comparison more evenly matched. In higher latitudes, production of hot water through solar thermal comes at a higher cost today, due in particular to additional protections against freezing plus backup with a gas or electric water heating device, and this may skew the balance towards solar PV. In the European Union, the LCOH of SWH is some 15-20% higher than that of solar PV. The relative financial attractiveness would still depend on other factors, such as feed-in-tariffs or the local cost of electricity. Other considerations include the noise of heat pumps or in the case of solar thermal systems, maintenance and more complex installation requirements.

For buildings with swimming pools or high hot water demand, such as hotels or hospitals, solar thermal systems are almost certainly more financially attractive. Solar thermal is also more cost effective in large applications (e.g. district heating systems), due to lower losses and the more constant level of heat demand. In remote areas in the developing world, solar thermal can provide an inexpensive way to increase access to hot water, which is important for health and hygiene.

11.3.3 Support to make heat from renewables financially attractive

Overall, global support for heat from renewables is estimated to be about 1% of the total support provided to all renewables in 2015, on the order of $2 billion.[25] Relative to solar PV in power, solar thermal in heat received a very small amount of support in 2015 while capacity additions were about 80% as large (40 GW_{th}). Capacity additions of solar thermal have slowed in the last two years, mostly due to the lower growth rate in China since several incentive programmes terminated, such as the "Home Appliances Going to the Countryside" in 2013. A similar slowdown has been observed in markets such as Australia, Israel and Germany (REN21, 2016).

25. Tax rebates and preferential loans, as well as sub-national economic supports are not considered in this assessment, which is limited by the availability of information about policies and their related implications for public budgets.

Most of the current renewable heat policies have been developed in the last ten years, under the impetus to curb greenhouse-gas (GHG) emissions. Renewable heat policies are rarely expressed as specific objectives; targets usually embrace both renewable electricity and heat together. Where specific policies exist to promote renewables for heat, they are often focussed on particular equipment, such as solar water heaters or biomass boilers or stoves. Renewables support in the heat sector takes various forms. Technical and organisational forms of support, such as RD&D and capacity building programmes, help to meet the practical challenges that come with increased deployment. Economic instruments, such as feed-in tariffs and premiums, capital grants, subsidies, soft loans and tax incentives, help to fill the financial gap.

In the New Policies Scenario, building codes begin to incorporate renewable heat or SWH targets more systematically (mainly in emerging economies) and may be accompanied by further economic support.[26] Such codes tend to focus on new construction rather than the existing building stock, which is responsible for most heat demand through to 2040. As the New Policies Scenario is based on existing policies or declared intentions, few new policy developments in relation to heat demand in industry are projected and direct renewable heat use, such as solar thermal and geothermal, develops in line with its profitability.

Much more needs to be done to unlock the potential of renewable heat. In the 450 Scenario, additional economic policy instruments address the high upfront costs of renewable energy technologies for heat supply. Additional policies are implemented to address specific national and local circumstances and to overcome the many non-economic barriers. These measures in the 450 Scenario aim to:

- Address information barriers, so as to create awareness of the potential benefits of renewable heating in various applications.
- Develop the necessary technical frameworks (e.g. insurance methods and technical standards) to ensure quality control.
- Introduce training and education in renewable heating technologies (e.g. solar and geothermal) for relevant stakeholders.
- Support and facilitate the introduction of new business and financing models.
- Accelerate RD&D to reduce costs and to increase system efficiency (e.g. develop and standardise system integration for solar heat in industrial processes).

Although the direct use of renewables in the heating sector is not a one-size-fits-all solution, it should be included in the overall climate change strategy alongside both electrification and energy efficiency solutions. While energy efficiency can and does enable the dramatic decrease in space heating demand in the 450 Scenario, it can only reduce the level of water heating, cooking and industrial processes heat to a certain extent. Renewable heat and electrification are required to fully realise these targets.

26. These have been effective in countries such as Israel and Greece, where such policies have led to the adoption of solar water heaters by around 90% and 30% of households respectively.

11.4 Transport

The transport sector is overwhelmingly oil-dependent and is responsible for 57% of global oil demand. Renewable energy can fuel transportation demand directly with biofuels, which displace gasoline and diesel in internal combustion engines, or indirectly through the electrification of transport modes. Increasing the share of renewables in the transport sector to levels consistent with sustainability targets, however, would require a considerable step up in efforts, given that biofuels currently account for only 3% and electricity for 0.1% of total transport fuels.

The vast majority of biofuels produced today are conventional ethanol and biodiesel derived from well-established industrial processes. Conventional ethanol is produced by fermenting food-based organic matter, including sugar cane (the main source in Brazil), corn (widely used in the United States), wheat and sugar beets and subsequently blending the end product with gasoline. Conventional biodiesel is produced from vegetable oils, typically from rapeseed, soybean and palm. In recent years, continual decline in crude oil prices has weighed heavily on the prospects for biofuels, and the sustainability of bioenergy remains a pressing issue. Advanced (second- and third- generation) biofuels are produced from non-food matter (e.g. woody or grassy materials and waste), use relatively cheap feedstocks (e.g. straw, forest residues, sawmill by-products, waste cooking oil) and do not directly compete with food production or land-use, though are at an early stage of deployment.

Electrification can increase the diversity of the fuel mix used in transport. Deployed jointly by governments and industry, significant efforts over the past ten years have boosted the sales of electric vehicles. However, even in a context of rapidly decreasing battery costs, ramping up adoption of electric vehicles remains a major challenge.

11.4.1 Technology costs

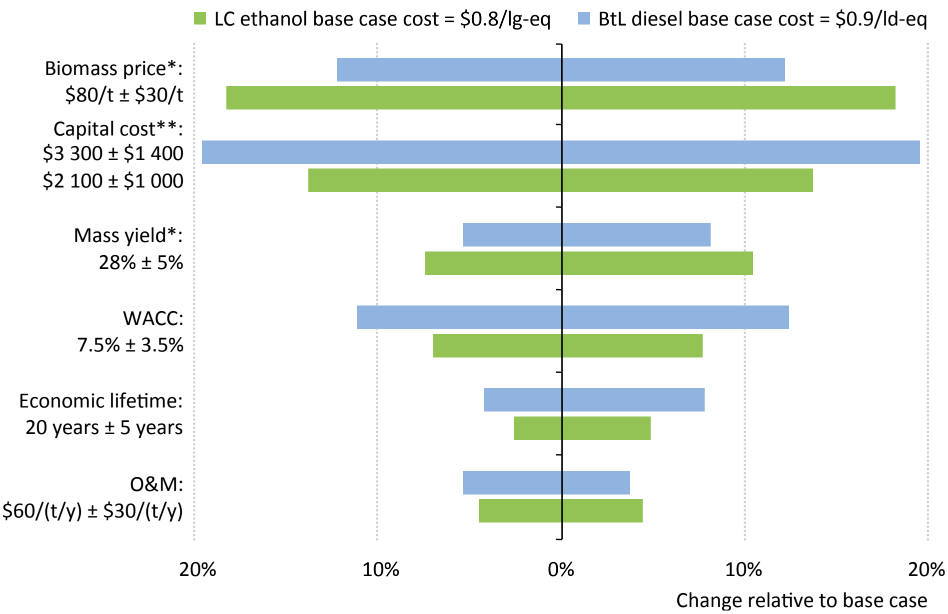
While biofuels can be used alone, in most cases they are blended with conventional fuels before being sold to consumers. To consumers, there are no additional costs for low level blends, which can be used in conventional engines. Using higher blends of biofuels requires modifications to the vehicle engine at a typical cost of $400-700.[27] To fuel suppliers the only additional cost, albeit small, is the infrastructure cost related to delivering the different fuels to consumers.

Current estimates of conventional ethanol cost ranges from $0.60-1.30 per litre of gasoline equivalent. In 2015, despite a good corn harvest in the United States that helped lower the production cost of corn-based ethanol, limited gains were made in closing the price gap with gasoline in a low oil price environment. The use of palm oil, often considered the cheapest vegetable oil, for biofuel production is a potential alternative as a low-cost

27. Higher blending levels means more than 10% volume for ethanol and 30% volume for methyl ester biodiesel in most of today's internal combustion engines.

biofuel, but continues to face issues concerning sustainability and its competition with food production. Currently, hydro-treated palm oil is particularly competitive in the United States, with a lower bound at $0.60 per litre of diesel equivalent, as lower gas prices have reduced the cost of producing hydrogen, which is used in the production process. Given that population growth and economic development are likely to put the market for agricultural commodities under pressure (OECD-FAO, 2016), the cost of conventional biofuels is not expected to decrease substantially over the *Outlook* period.

Figure 11.22 ▹ Sensitivity analysis of levelised cost of advanced biofuels production



The two main levers for cost reduction of advanced biofuel processes are supplying cheap biomass and decreasing capital costs

Notes: * On a dry matter basis. ** Capital cost is expressed in dollars per tonne per year of production capacity. LC = lignocellulosic; lg-eq = litres of gasoline equivalent; BtL = biomass-to-liquid; ld-eq = litres of diesel equivalent; WACC = weighted average cost of capital; O&M = operation and maintenance; t/y = tonnes per year.

About 65-90% of the levelised cost of conventional biofuels is dependent on the feedstock used, which presents significant price risks to biofuel producers. The capital cost element in the total cost of biofuel production can vary significantly, from around 5% (in the case of ethanol production from wheat and ester biodiesel in the European Union) to 20% (for sugar-derived fuels). Despite recent advances in technology, the costs of advanced biofuels remain high. Large amounts of biomass are required for production at an industrial scale: more than half a million tonnes of dry matter are required for a bio-refinery producing

150 000 tonnes of lignocellulosic ethanol a year. Such a scale requires a wide radius of domestic supply or imports, and creates upward pressure on feedstock costs and limit its use for other industries. Advanced biofuels are capital intensive, although co-processing of non-food biomass in existing plants, such as oil refineries or conventional ethanol plants, could help reduce the cost. Several recent projects have demonstrated the feasibility of advanced biofuels on a commercial scale. There are currently more than 60 pilot and demonstration scale projects and five commercial scale plants producing advanced biofuels in the United States (NREL, 2015). Despite this, extensive RD&D is still needed to make progress on the efficient conversion of lignocellulosic material, which is chemically complex, into liquid fuel.

In the long term, the prospects for advanced biofuels costs will largely depend on further technological progress. Economies through scaling-up the process and moving down the production learning curve are expected to occur more quickly in thermochemical processes that share common processes with the petrochemical industry; but the biochemical processes face more challenges, such as the handling of large amounts of living micro-organisms. In the long term, with cheap biomass costs and low capital costs, the LCOE of lignocellulosic ethanol and biomass-to-liquid diesel could be reduced to $0.4 per litre of gasoline equivalent and $0.5 per litre of diesel equivalent, respectively (Figure 11.22). For electric vehicles (see Chapter 10), the contribution of renewables-based electricity depends on the generation mix in a particular country (see Chapter 6).

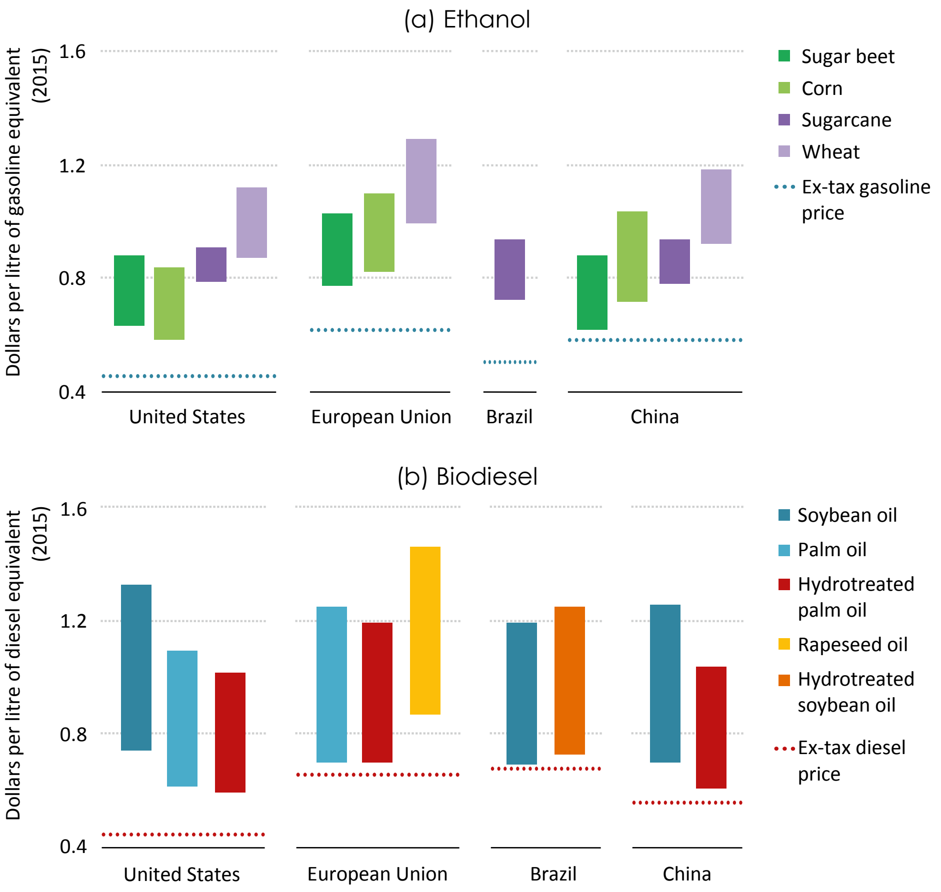
11.4.2 Competitiveness of renewables in transport

The oil price is a major factor for the cost competitiveness of biofuels. The low oil price environment since 2014 has had a detrimental effect on the competitiveness of biofuels (Figure 11.23). However, some are still financially attractive where they are shielded by mandates and supportive policies and a few, including some Brazilian ethanol, are fully competitive. Fluctuations and uncertainties about the price of oil have compounded uncertainties over future biofuel developments, especially for advanced biofuels technologies.

The nature of the market regulation of biofuels can be another limiting factor to their deployment, in cases where they reach competitiveness. For example, in the United States, the fuel quality regulations limit the ethanol content in standard gasoline sold at the pump (up to 15% ethanol in volume terms), which may need to be increased to meet the future total volume requirements defined in the Renewable Fuels Standard. Regulation is also in place in some regions to ensure biofuels production does not compete with food. This is the case in India, where imports are currently needed to fulfil its 5% ethanol blending target: expanding domestic production using alternative crops or promoting advanced biofuels can overcome these barriers.

Despite these challenges, conventional biofuels are cost competitive in individual regions and can be made so in others depending on the domestic cost of feedstocks and the prevailing oil price. More ethanol can be used in the gasoline mix through increased deployment of flex-fuel vehicles. Such vehicles are a mature technology already in use in many countries, especially in Brazil. Though, beyond a point, the environmental acceptability of biofuels fuels comes into question in many countries, so substantial growth depends on moving beyond conventional biofuels that rely on energy crops.

Figure 11.23 ▷ Levelised costs of biofuels production by feedstock and ex-tax price of fuel for selected regions



Conventional biofuels struggle to compete in a low oil price environment

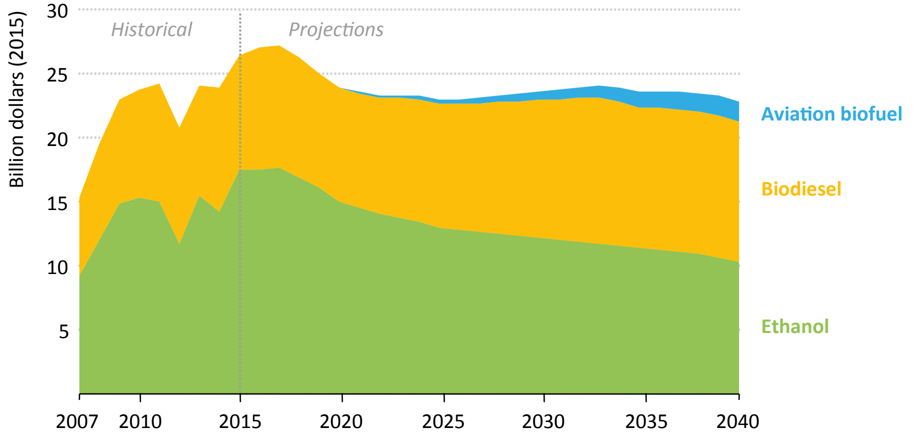
Given that biofuels in general fall short of being cost competitive with conventional fuels without government mandates and subsidies and that electric vehicles are still at an early stage of deployment, only limited growth in the use of renewables for transport is foreseen in the New Policies Scenario. From today, the share of liquid biofuels in total transport demand increases by about three percentage points to reach 6.7% in 2040, with renewables-based electricity meeting another 1%. However, determined decarbonisation efforts in the transport sector in the 450 Scenario see electricity from renewables and biofuels contribute around one-fifth of transport fuel demand by 2040.

11.4.3 Support to make renewables in transport financially attractive

In 2015, biofuels support reached $26 billion, $2.7 billion more than 2014 (Figure 11.24). This was due to higher global consumption, which was up 3% and increased support to close the widening price gap with fossil fuels in the United States, European Union and Brazil (see Chapter 10.2).

Future subsidies for biofuels in the transport sector are estimated by taking the difference between the projected biofuel price and the projected ex-tax price of the conventional fuel it replaces. In the near term, low oil prices in the New Policies Scenario will lead to an increase in biofuels support to narrow the price gap with conventional fuels. In the medium and long term, however, biofuels support will decline slightly as average biofuel prices diminish and fossil-fuel prices recover. The decline in total biofuels support is gradual, from $26 billion to $23 billion over the *Outlook* period, as incentives remain necessary to ease the transition to advanced biofuels, which are more expensive to produce. During this time, the subsidy per unit of biodiesel drops, from $0.30 to $0.16 per litre of diesel equivalent, while per unit ethanol support falls from $0.28 to $0.06 per litre of gasoline equivalent. The result is that the share of biodiesel in total support increases slightly. The support for renewables-based electricity for transport is linked to that provided for the overall supply of renewables-based electricity, discussed in section 11.2.4.

Figure 11.24 ▷ Evolution of subsidies for liquid biofuels in the New Policies Scenario



Biofuels use triples to 2040, while subsidies remain stable at about $25 billion per year

11.5 Cost effectiveness of renewables

The concept of cost effectiveness, as used in this chapter, applies to the ability of a technology to achieve societal objectives, quite distinct from competitiveness (Box 11.1). Mitigating climate change has been a prime motivator for many governments to increase support for renewables in the global energy system. The contribution that renewable energy can (and must) make to tackle climate change is amply demonstrated elsewhere in this analysis and in this *WEO* (see Chapter 8). But other societal considerations, such as curbing air pollution, improving energy security and concerns about energy affordability, also motivate policy-makers. While not attempting to be exhaustive, this section assesses some of the broader benefits (and occasional risks) that an energy sector pathway consistent with 2 °C might bring in relation to selected societal objectives. Of course, judging the relative value of various societal objectives is a core responsibility of government. Putting a value on such considerations is no easy matter, but this analysis attempts to do so in several informative respects and, importantly, highlights the need for such an evaluation to take place when policy-makers are assessing the level of intervention in markets that might be justified in pursuit of renewable energy promotion. There are also associated costs, such as possible adverse impacts on ecosystems (e.g. land-use change linked to conventional biofuels and stress of water resources) and visual intrusion. Evaluation is difficult and likely to be imperfect. That does not invalidate the effort.

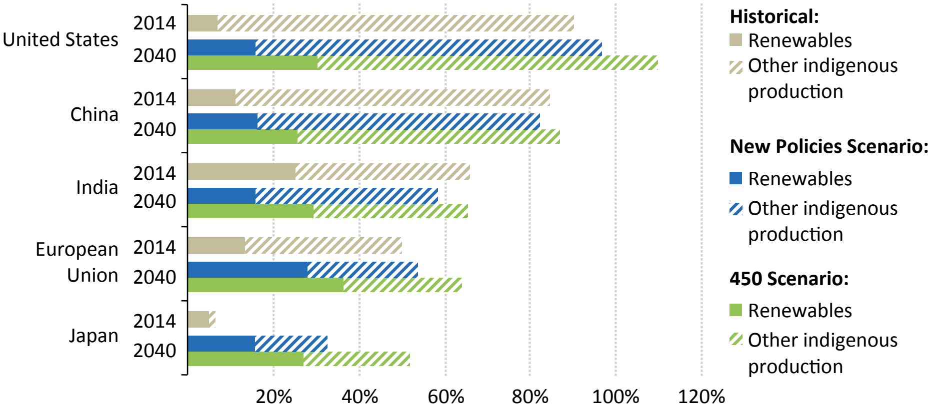
11.5.1 Energy security

Energy security, which may be defined as the uninterrupted availability of energy sources at an affordable price, has many dimensions. Long-term energy security mainly concerns timely investment to supply energy in line with economic developments and sustainable environmental needs, while short-term energy security focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance. Anxiety about the physical unavailability of supply is more prevalent in energy markets where supply and demand must be kept in constant balance, such as electricity, and, to some extent, natural gas, but, historically, much action to enhance short-term energy supply has related to oil – indeed, it was the moving force behind the creation of the International Energy Agency.

Renewables redefine energy security, as they shift the energy dependence of many countries away from finite, external sources of supply to renewable, domestic ones. For most countries, renewables provide an opportunity to diversify their domestic energy mix. While energy security can certainly not be measured solely by relative reliance on foreign or domestic sources of supply, tapping domestic renewable energy resources does help reduce risks, e.g. relating to movements by pipeline, tanker or other transport means. On the other hand, shifting to renewables may bring new risks, e.g. weather-related issues and the greater challenges to balance electricity supply and demand at all times.

In both the New Policies and the 450 Scenarios, the growth in renewables outpaces the growth in other forms of energy and is largely domestically sourced. The United States sees its net energy import dependence decline in the New Policies Scenario and it switches to being a net exporter in the 450 Scenario (Figure 11.25). The European Union also sees its reliance on domestically sourced energy supply increase from around 50% in 2014 to 55% in 2040 in the New Policies Scenario (although its reliance on natural gas imports remains high) and 65% in the 450 Scenario (where natural gas imports decline). Japan takes a major additional step in domestic energy production in the 450 Scenario, relative to the New Policies Scenario, as renewables increase and nuclear supply comes back online. By 2040, Japan has reduced its reliance on external sources of supply to almost 50% of its total energy mix. Major energy exporters can benefit too. Renewables can free-up energy resources for export that otherwise would be consumed within the country. In some instances, there may be a business case for investing to develop renewable resources for export, both on its financial merits and as a possible way to help with renewables integration.

Figure 11.25 ▷ Share of domestically sourced energy supply in selected regions by scenario, 2014 and 2040



The increased deployment of renewables in the 450 Scenario helps to reduce relative reliance on energy imports in many regions

11.5.2 Air pollution

Around 6.5 million premature deaths result from air pollution each year, with many of the causes and cures to be found in the energy sector.[28] Urban air pollution is a serious issue around the world: many major cities, even in the most developed countries, fail to meet the World Health Organization target for air quality and some fall well below the lowest

28. *Energy and Air Pollution: World Energy Outlook Special Report 2016*, available at: *www.worldenergyoutlook.org/airpollution.*

standard of acceptability. Fossil fuels (led by coal) and bioenergy are the main culprits, producing sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM) and other pollutants when combusted. Replacing electricity produced from coal by renewables-based electricity can mitigate these emissions. And since air pollutants and GHG emissions arise from many of the same sources in the energy sector, action to curb CO_2 emissions can often simultaneously eliminate other air pollutants. But it is not always simple. A key example is the combustion of bioenergy, which can reduce GHG emissions if it is substituting for fossil fuels, but burning bioenergy does emit harmful air pollutants that may require additional mitigation action.

In the New Policies Scenario, annual global emissions of key energy-related air pollutants change in the following ways: SO_2 emissions fall by 20% from 2014 to 2040, NO_X by 10% and PM by 7%. The broader use of renewables in the 450 Scenario brings additional air pollution benefits. For SO_2 emissions, renewables displacing coal in the power mix contributes around one-quarter of the additional 15 million tonnes (Mt) emissions reduction achieved in the 450 Scenario. For NO_X emissions, which are largely associated with the transport sector, the shift to renewables is directly accountable for 15% of the additional 20 Mt emissions reductions, with electric vehicles emitting no local air pollution from combustion (though there is still some from tyres, brake use, etc.) and, if fuelled by renewables-based electricity, no air pollution from combustion. However, the increased combustion of biomass in the 450 Scenario results in decreased CO_2 emissions but, at best, appears neutral and could, in some circumstances, lead to higher emissions of PM and associated negative health impacts. In this context, the IEA proposed a dedicated Clean Air Strategy that builds on proven and pragmatic energy and air quality policies and uses only existing technologies (IEA, 2016c). Implementation of the strategy, which includes the wider adoption of renewables in the power sector, serves to reduce air pollution-related premature deaths by tens of millions over the *Outlook* period. While placing a value on each life saved is a contentious process, when looking across a range of studies the so-called "value of a statistical life" (which reflects an individual's willingness to pay to reduce the risk of mortality) ranges from \$0.4-8.8 million.

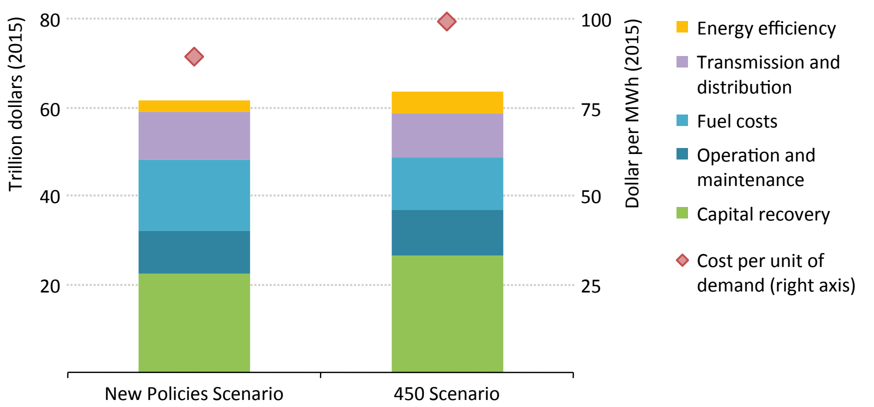
11.5.3 Affordability

There are frequently cited concerns that the investment required to decarbonise the energy sector will increase energy bills for consumers, especially household electricity bills. In the New Policies Scenario, renewable energy technologies in the power sector attract \$7.1 trillion in capital investment over the *Outlook* period, accounting for \$63 out of every \$100 invested in new power plants. Wind power accounts for the largest share of this investment (34%), followed by solar PV (26%) and hydropower (24%). In the 450 Scenario, cumulative investment in renewables-based power generation capacity increases to more than \$11 trillion of investment, more than 70% of total investment in generation capacity.

While investment in generation capacity is higher, cumulative costs for the global power system as a whole are virtually the same in both the New Policies Scenario and the

450 Scenario (Figure 11.26).[29] Investment in more capital-intensive renewable energy technologies increases total investment costs by nearly 20% to 2040; but this is directly offset by lower total fuel costs, through both lower consumption and the lower prices that result from lower demand. Transmission and distribution investment is largely unchanged, though a larger share is dedicated to connecting renewables in the 450 Scenario. Energy efficiency plays a major role in the 450 Scenario, lowering global final electricity demand. With fewer units of electricity demanded, the average system cost per unit of electricity demand increases by about 10% over the period. But, while this translates into higher prices per unit of electricity, consumers are more concerned with the overall effect of the transition, as a whole, on annual electricity bills.

Figure 11.26 ▷ Total costs of power supply in the New Policies and 450 Scenarios, 2016-2040



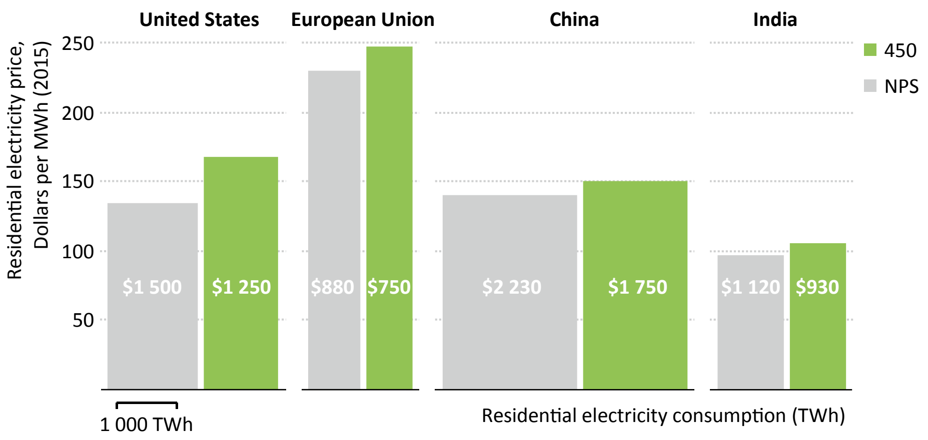
The transition to a low-carbon power system can be achieved at little additional cost

In 2040, household electricity bills are similar or lower in the 450 Scenario than in the New Policies Scenario (Figure 11.27). Again, energy efficiency plays a vital role in offsetting slightly higher electricity prices per unit by reducing the typical level of electricity consumption. For example, in the European Union, although electricity consumption in residential households is already relatively low in the New Policies Scenario in 2040, a larger shift in the 450 Scenario from electric radiators to efficient heat pumps, and improved insulation, reduces residential electricity consumption further and lowers electricity bills in 2040 by almost 10%. Similarly, in China, a shift to more efficient refrigerators and lighting helps to reduce electricity consumption in the 450 Scenario relative to the New Policies Scenario, and sees electricity bills cut by over 15% in 2040. A similar pattern is observed across other

29. Total system costs, including recovery of capital investment, operation and maintenance costs, fuel costs, investments in transmission and distribution as well as energy efficiency.

regions. In this way, the 450 Scenario achieves strong decarbonisation of the power sector while minimising the impact on total power system costs and electricity bills.

Figure 11.27 ▷ Total residential electricity bills in 2040 by region in the New Policies and 450 Scenarios



Despite higher prices, consumer electricity bills in 2040 are at similar or lower levels in the 450 Scenario, as a result of more efficient electricity use

Notes: 450 = 450 Scenario; NPS = New Policies Scenario. The area of each bar represents the aggregate size of residential electricity bills in a given region by scenario in 2040. The height reflects the average residential electricity price and the width represents the level of residential electricity consumption.

Integration of variable renewables in power systems

How far can you go?

Highlights

- In the 450 Scenario, nearly 30% of the world's electricity is supplied by wind and solar PV in 2040. As such, variable renewable energy (VRE) becomes the leading source of electricity supply around 2030 in the European Union and around 2035 in the United States, China and India. The efficient decarbonisation of electricity supply will need structural changes to the design and operation of the power system, both to incentivise investment and to integrate high shares of VRE into the power mix.

- Using a new hourly model, VRE integration needs in the 450 Scenario are studied in detail for the United States, the European Union and India. The results demonstrate the value of effective power system design and VRE integration measures, both for these diverse markets and more broadly. Across these markets, commonplace actions to ensure an effective power system (i.e. grid expansion and the adequate deployment of flexible forms of supply) are sufficient to fully integrate VRE up until their share of total electricity supply reaches around one-quarter. Beyond this threshold, a broader toolkit of integration measures is required, including energy storage and actions that shift electricity demand (demand-side response [DSR]).

- In the 450 Scenario, the adoption of energy storage and DSR in the United States, the European Union and India provides an effective means to ensure that VRE is utilised to the fullest extent: by 2040, the share of VRE supply that their power systems are not able to utilise (known as "curtailment") is limited to 2.5%. Each region deploys 20-30 GW of energy storage by 2040 and DSR measures enable up to 15-20% of total electricity demand to be shifted to times when VRE can be better utilised. In 2040, these measures help to avoid curtailing around 80 TWh of VRE supply in the United States, 65 TWh in the European Union and 60 TWh in India.

- If energy storage and DSR were not deployed in the 450 Scenario, the curtailment of VRE would start in the late-2020s in the European Union (spread relatively evenly across the year), in the early-2030s in the United States (focussed in the spring) and around 2035 in India (focussed in the winter, during daylight hours). After these dates, the level of curtailed VRE supply would increase rapidly (levels reaching up to 8% of total VRE supply in 2040) and curtailment would occur, to varying degrees, for up to one-third of the hours in the European Union in 2040, and around 20% of the time in the United States and India. During these periods, available electricity supply would go unused, electricity prices would fall to near-zero and, overall, revenues for all power producers would be lower, hampering their ability to invest. In this case, the curtailment across the three regions would result in wind and solar PV capacity worth $165 billion of investment being idled, an additional $58 billion in fuel costs being incurred and an additional 650 million tonnes of CO_2 being emitted.

12.1 Overview

12.1.1 Context

The long-term transition to an energy system consistent with climate change goals will require a significant increase in the use of low-carbon technologies, including renewable energy, in electricity, heat and transport. As we have seen in Chapters 10 and 11, the power sector – which is today responsible for 42% of energy-related carbon-dioxide CO_2 emissions – is set to undertake large-scale deployment of renewables as part of this transition.

Variable renewable energy (VRE) accounts for 27% of electricity generation in 2040 in the 450 Scenario – more than 50% higher than in the New Policies Scenario.[1] Wind power is expected to see the biggest growth (5 400 terawatt-hours [TWh]), followed by solar photovoltaics (PV) and hydropower (around 3 000 TWh each). At low shares of penetration in the power mix (usually a few percentage points), VRE is unlikely to pose a significant challenge to most power systems. However, the deployment of VRE technologies to the extent projected in the 450 Scenario (as well as within some regions – notably the European Union – at the lower levels of in the New Policies Scenario) will require significant enhancement of system integration measures. Such approaches encompass various technical, institutional, policy and market design aspects to enable the cost-effective uptake of large amounts of VRE in the power system. The suite of these measures is referred to as system integration measures.

Failing to put in place these measures could mean that, in some circumstances, not all the power available from variable renewables-based generation could be accommodated in the power system, a situation known as curtailment.[2] This can undermine VRE economics and make them less effective as decarbonisation options. Integration measures and their respective roles in supporting the accelerated deployment of renewables (in particular in the 450 Scenario) are the focus of this chapter.

12.1.2 Global trends of wind and solar PV in the New Policies Scenario and the 450 Scenario

In the New Policies Scenario, wind generation sees a five-fold and solar PV an eleven-fold increase in generation worldwide by 2040 relative to 2014 levels. Wind and solar PV together account for one-third of the global growth of power generation over the *World Energy*

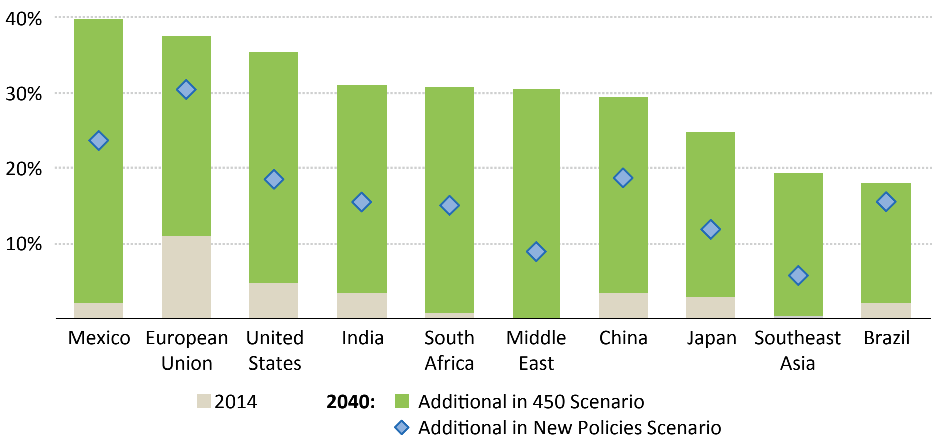
1. Variable renewables energy (VRE) includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave). This chapter focuses on wind and solar PV systems due to their significance in the *Outlook*.

2. Curtailment is the amount of VRE generation that is not used to meet demand and therefore is "lost". It occurs when the available output from variable renewables exceeds the ability of the grid to absorb it. Contributing factors include low demand, insufficient flexibility from other power plants, or transmission and operational constraints (see *WEO-2015*, Chapter 9, Box 9.3). Curtailment may also be based on economic grounds (when electricity prices are very low or negative) or to enable VRE plants to provide system or ancillary services.

Outlook (*WEO*) period, and provide 15% of power generation worldwide in 2040. The share of wind and solar PV generation in total electricity generation is highest in the European Union (over 30%), followed by Mexico and Australia (around one-quarter each) and China and the United States at less than 20% (Figure 12.1).

In the 450 Scenario, the growth of VRE is significantly stepped up: solar PV and wind power generation see a seventeen-fold and nine-fold increase, respectively by 2040. The share of wind and solar PV in total generation doubles in the United States, India, South Africa and Japan, while it more than triples in the Middle East and in Southeast Asia. Growth remains relatively limited in regions with already high shares of hydropower (such as Brazil and Canada) and nuclear power (such as Korea, Russia and Eastern Europe). By 2040, the combined share of wind and solar PV generation is higher than generation from any other single source in the biggest four regions (United States, the European Union, China and India).

Figure 12.1 ▷ Share of wind and solar PV in total electricity generation by region in the New Policies and the 450 Scenarios



More than one-quarter of global electricity is generated by wind and solar PV by 2040 in the 450 Scenario

12

12.1.3 Characteristics of variable renewables and the integration challenge

The physical nature of electricity requires demand and supply to be in balance at all times. Traditionally, electricity demand has been met by large-scale power plants, capable of adjusting their output to track changes in power demand. Generating power from variable renewable energy, such as wind and solar PV, differs from conventional power plants in a number of ways. First is that production depends on the availability of the wind and sun (Box 12.1). Hence, the rising share of VRE is leading to a more volatile supply, from installations that tend to be smaller in scale and more geographically dispersed.

Box 12.1 ▷ Characteristics of wind and solar PV

Wind and solar PV have five technical properties that make them distinct from more traditional forms of power generation. First, their maximum output fluctuates according to the real-time availability of wind and sunlight. Second, such fluctuations can be predicted accurately only a few hours to days in advance. Third, they use devices known as power converters in order to connect to the grid (this can be relevant in terms of how to ensure the stability of power systems). Fourth, they are more modular and can be deployed in a much more distributed fashion. Fifth, unlike fossil fuels, wind and sunlight cannot be transported, and while VRE resources are available in many areas, the best resources are frequently located at a distance from load centres (thus, in some cases, increasing connection costs). Although wind and solar PV share these general characteristics, there are, also, important differences (Table 12.1).

Table 12.1 ▷ Overview of differences between wind power and solar PV

	Wind power	Solar PV
Variability at plant level	Often random; subject to daily and seasonal weather patterns.	Change in the sun's position is the main source of variability, combined with weather patterns (e.g. cloud cover).
Variability when aggregated	When aggregated, the variability from a large number of systems is smoothed and changes occur much more slowly.	When aggregated, the random variability (e.g. cloud cover) from a large number of systems is smoothed and only the variability coming from the changes in the sun's position remains.
Uncertainty when aggregated	Shape and timing of generation unknown.	Shape known, but scaling factor unknown.
Ramps	Changes in wind generation on the power system level tend to occur more slowly, typically over the course of hours.	Steep ramps at sunset and sundown, also influenced by environmental factors such as fog and cloud cover.
Scale	Mainly community and above (standard turbines), some household and above (small-scale turbines).	Household and above.
Technology	Non-synchronous and mechanical power generation.	Non-synchronous and electronic power generation.
Typical capacity factors	Onshore 20%-45%, offshore 35%-55%.	10% to 25%.

Source: Adapted from IEA (2014).

The scale of the integration challenge is determined by the interaction of two components: the characteristics of VRE generation and the flexibility of the power system. The more flexible a system is, the easier it is to integrate variable renewables. Flexibility, in power system terms, is traditionally associated with generators that can change their output very quickly, such as hydropower plants with reservoirs (often the most flexible ones); but flexibility can also be achieved through grid interconnection to neighbouring power systems, storage (e.g. pumped storage, batteries or heat) and demand-side response measures.

In power systems that do not require significant amounts of new power plants (slow rate of demand growth and few plant retirements), making better use of existing power system flexibility and using more sophisticated system operations (e.g. VRE production forecasts) is often a least-cost option. Where power systems are expanding to meet growing demand or are retiring significant amounts of old power plants, flexibility should be carefully considered in system planning to minimise integration challenges.

The integration challenge is defined by three parameters:

- ***Scarcity***: When periods of low VRE output coincide with relatively high demand, other resources are needed to meet demand, such as dispatchable generation[3], imports from other systems, demand-side response or storage. The contribution, known as capacity credit[4], of VRE to system adequacy[5] is often low, becoming progressively lower as shares of VRE generation increase.
- ***Variability:*** The output of VRE sources can fluctuate substantially and rapidly over time, which may require dispatchable generators to start (or increase) quickly or to stop (or decrease) production. This characteristic is also referred as the plant's "ramping" capability. For example, a rapid increase in VRE generation can require other plants to ramp down to prevent the curtailment of VRE generation, normally a cheaper source of electricity in the merit order scale. The converse is also true: in cases of decreasing VRE generation or increasing electricity demand, conventional plants have to ramp up to ensure that electricity demand is satisfied.
- ***Abundancy:*** When periods of high VRE output coincide with relatively low demand, periods of excess generation can occur, in particular at high levels of penetration of VRE technologies in the power system. In order to achieve high shares of VRE generation in the power mix, large amounts of VRE capacity are needed due to their relatively low capacity factors. As a comparison, to produce the same amount of energy as 1 gigawatt (GW) of nuclear power, about 2-4 GW of wind or 4-8 GW of solar PV are typically needed.

There are several implications of these three challenges. Dispatchable power plants, that are needed to ensure the reliability of the power system due to the low capacity credit of VRE, achieve low utilisation factors because VRE generation is abundant and cheap in the

3. 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.

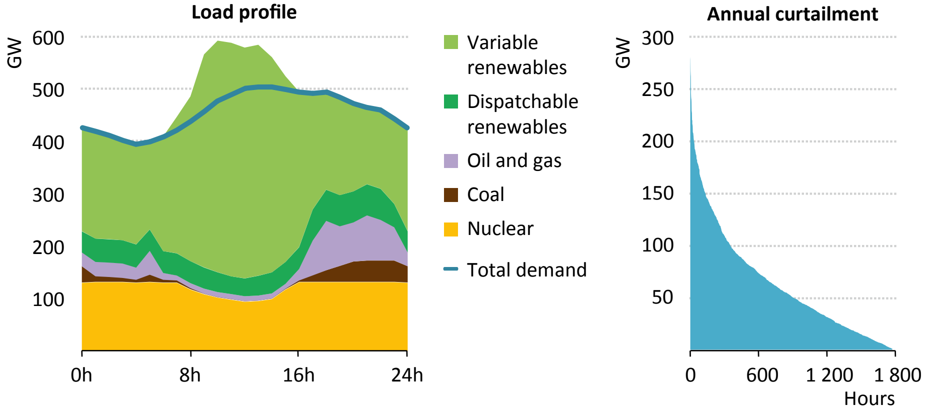
4. Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the network to which it is connected.

5. The capability of the power system to meet changes in aggregate power requirements in the present and future, using existing and new resources, and in the future with new resources, as required.

merit order (and therefore, preferred) when the circumstances are right. Frequent ramping of conventional generation plants that were not designed or retrofitted for such operations can result in faster wear-and-tear of plant parts, decreasing plant efficiency. These two factors can damage the economic attractiveness of such assets.

Periods of possible excess generation may occur, even when VRE generation does not exceed total power demand at a given moment. In order to maintain the reliability of the electricity supply, operators employ techniques known as ancillary services (or system services). Traditionally such services have been provided by varying the output of conventional generators. New ways of securing these services are needed in order to be able to power down conventional units during times of abundant VRE generation. Various approaches are being applied to meet system service needs. For example, the Danish, Irish, Spanish and some US system operators have recently begun using wind power to meet part of their ancillary needs, while Italy's power grid operator TERNA and the United Kingdom's National Grid have installed or called on battery storage devices for similar purposes.

Figure 12.2 ▷ Electricity load profile on a summer day and impact on hours and volume of annual curtailment in the absence of integration measures in the United States in the 450 Scenario, 2040



At high shares of wind and solar PV, integration measures are needed to avoid significant amounts of curtailment

Notes: As policies to support VRE deployment aim to reduce fossil-fuel generation and related emissions, production from dispatchable low-carbon technologies' (renewables and nuclear in this example) is dispatched throughout the year to the extent of the typical utilisation rate (e.g. nuclear) or storage capability, where relevant (e.g. concentrating solar power). Lower utilisation rates are technically feasible to avoid curtailing VRE production, but would then result in the replacement of one low-carbon technology with another.

In the absence of measures to increase the flexibility of the system, curtailment during times of abundant VRE generation can pose a significant challenge to the economic viability of VRE plants (Figure 12.2). Curtailment results in a loss in production volume, which in turn affects revenue streams and the recovery of project investments. Furthermore, during the hours of excess generation, electricity prices are often zero or even negative. As a significant portion of the production of VRE occurs during those hours, this further reduces the revenues of these projects.

Box 12.2 ▷ WEM hourly model: digging beyond the annual data

To quantify the scale of the challenge arising from the integration of high shares of VRE and to assess which measures could be used to minimise curtailment, a new hourly model has been developed for *WEO-2016*, to provide further insights into the operations of power systems. The model builds upon the annual projections generated in the World Energy Model (WEM)[6] and makes it possible to explore emerging issues in power systems, such as this, that arise as the share of VRE continues to rise. The model then feeds the main WEM with information about additional constraints on the operations of different power plants. The model is a classical hourly dispatch model, representing all hours in the year, setting the objective of meeting electricity demand in each hour of the day for each day of the year at the lowest possible cost, while respecting operational constraints.[7] All 106 power plant types recorded in the WEM and their installed capacities are represented in the hourly model, including existing and new fossil-fuelled power plants, nuclear plants and 16 different renewable energy technologies. The fleet of power plants that is available in each year is determined in WEM and differs by scenario, depending on the prevalent policy framework. These plants are then made available to the hourly model and are dispatched (or chosen to operate) on the basis of the short-run marginal operating costs of each plant (which are mainly determined by fuel costs as projected in WEM) to the extent required to meet demand. The dispatch operates under constraints: there are minimum generation levels to ensure the flexibility and stability of the power system and to meet other needs (such as combined heat and power); the variability of renewable resources (such as wind and solar) determines the availability of variable renewables and, hence, the maximum output at any point in time; and ramping constraints apply, derived from the level of output in the preceding hour and the characteristics of different types of power plants. The hourly dispatch model does not represent the transmission and distribution system, nor grid bottlenecks, cross-border flows or the flow of power through the grid. It therefore simulates systems that are able to achieve full integration across balancing areas in each WEM region (e.g. United States, European Union, China and India).

Key inputs to the model include detailed aggregate hourly production profiles for wind power and solar PV for each region, which were generated for the WEO by combining simulated production profiles for hundreds of individual wind parks and solar PV

6. For the full WEM methodology, see *www.worldenergyoutlook.org/weomodel/.*

7. The model works on an hourly granularity, and therefore all intra-hour values of different devices (e.g. of storage technologies) are not captured.

installations, distributed across the relevant region.[8] The individual sites were chosen to represent a broad distribution within a region, allowing the model to represent the smoothing effect achieved by expanding balancing areas. On the demand side, the model uses a detailed analysis, with hourly demand profiles for each specific end-use (such as for lighting or water heating in the residential sector), coupled with the annual evolution of electricity demand by specific end-use over the *Outlook* period from the main WEM (see Box 12.5).

The hourly model accounts for demand-side response and storage, flexible generation and system-friendly development of VRE, in three steps: first, it assesses the amount of curtailment of variable renewables that would occur without demand-side response and storage. Second, it deploys demand-side response measures, based on the available potential in each hour for each electricity end-use. And third, it uses existing and new storage facilities to determine the economic operations of storage based on the price differential across hours and charge/discharge periods. It thereby enables the integration needs arising from growing shares of renewables to be assessed.

Among the other important model outputs is the resulting hourly market price, which can drop to zero in the hours when generation from zero marginal cost generators (such as variable renewables) is sufficient to meet demand. By multiplying the market price by generation output in each hour, the model calculates the revenues received for the output in each hour by each type of plant, creating a basis for calculating the value of VRE. Naturally, the model also includes hourly operation information for each plant type, including fuel costs and associated greenhouse-gas and pollutant emissions.

12.2 Integration measures

Given the broad impacts that high VRE shares can have, a comprehensive and systemic approach is required to address the challenge of system integration of VRE. As identified by a large body of research, including previous IEA analysis, a co-ordinated approach can significantly reduce integration costs and ensure electricity security (EirGrid/SONI, 2010; NREL, 2012; NREL, 2013; DNV GL, 2014; IEA, 2014). Success depends upon the balanced use of different integration measures. Each of the five measures presented in this section forms a distinct ingredient from which to build an integration strategy. The relevance of each measure depends on the specific circumstance of a particular system. It is not possible to derive an optimal mix of integration measures that applies to all countries or power systems.

Sources outside the electricity sector can contribute to flexibility. In fact, the growing importance of flexibility may create stronger links to other energy sectors, such as heat and transport. In the heat sector, for instance, space and water heating, augmented by

8. Wind and solar PV data are from Renewables.ninja (*https://beta.renewables.ninja/*) and Ueckerdt, et al., 2016.

thermal storage systems and co-generation, can create opportunities to integrate VRE (Box 12.3). Electric vehicle (EV) fleets may provide a valuable opportunity to expand energy storage so as to make better use of VRE output that is surplus to need at the time it is produced. Making the best of existing flexible resources is often the most cost-effective way to integrate VRE. This requires upgrading the way the power system is operated and the design of markets.

Five main integration measures can be identified:

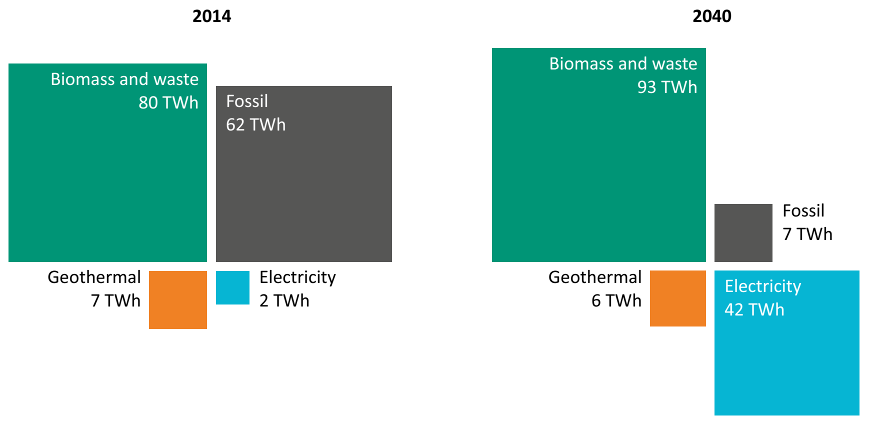
- VRE can contribute to its own integration by reducing the amount of flexibility that is needed in the system and by providing some flexibility itself.
- Flexible power plants (currently the largest source of flexibility).
- Demand-side measures.
- Electricity storage to provide a broad range of different system and ancillary services.
- Strong and smart transmission and distribution grids, which smooth VRE output and connect flexible resources together.

These are discussed below. Then we present three case studies that assess curtailment, demand-side response (including a quantification of potential by region) and storage in the United States, European Union and India in the 450 Scenario. This chapter concludes with a look at the implications for market and policy frameworks.

Box 12.3 ▷ District heating networks offer flexibility for VRE integration

District heating networks, unlike electricity grids, do not require that heat be consumed at the time it is produced. Significant amounts of energy can be stored in the heat network, a capability that can be enhanced through heat storage – large insulated water tanks, often installed near co-generation plants (Figure 12.3). Furthermore, heat networks can facilitate flexible generation by allowing co-generation plants to produce heat only when electricity prices are low (often at times of high VRE output). This avoids a complete shutdown of the co-generation plant, allowing it to produce power again quickly when electricity prices recover. Demand response is called upon last, enabled in the form of power-to-heat through utility-scale heat pumps and electric boilers. Compared to heat pumps, electric boilers are less efficient, cheaper and therefore best suited for less frequent utilisation, when electricity prices are very low or negative. In the Nordic region (where nearly half of heat demand is met through district heating networks), a scenario where wind accounts for 25% of generation in 2040 results in a ten-fold increase in utility-scale heat pump capacity (IEA/NER, 2016). Alongside interconnection and hydropower, heat networks are seen as one of the most important flexibility options for the Nordic region. Denmark already uses heat to balance its high share of wind, and other countries with both wind power and district heating networks (such as China) have significant potential for further utilisation of heat networks for flexibility.

Figure 12.3 ▷ Share of heat production by technology in Nordic district heating networks in the 450 Scenario, 2014 and 2040



Electrification of heat production is set to play a bigger role in facilitating flexible generation by 2040

Notes: Figure is based on the Nordic Carbon-Neutral Scenario, where wind accounts for 25% of Nordic generation in 2040, up from 7% in 2014. Nordic refers to Denmark, Finland, Iceland, Norway and Sweden.

Source: IEA/NER (2016).

12.2.1 System-friendly deployment of variable renewables

System integration is often perceived as making the system more "friendly to variable renewables". However, that is only half of the picture. It is equally important to make variable renewable more system-friendly and, indeed, there are a number of ways to achieve this. The essence of system-friendly deployment of VRE is to minimise the overall cost of the power system, not focussing "solely on the generation costs of VRE".

Location and technology mix of VRE

The best VRE resources are often located far away from load centres. This means that adequate capacity must be available on the transmission lines (whose role in VRE integration is discussed in section 12.2.5.). From a power system perspective, the combined cost of investment in generation and grid infrastructure must be minimised. This can mean that it is desirable to site power plants closer to load, even if the resource conditions there are less favourable. At present, the cost of VRE generation is going down more quickly than the cost of new grid investments, and this is expected to continue, which tends to favour deployment closer to load in situations where new lines are needed. Technical advances in wind turbine technology have made wind generation feasible even in lower wind speed locations, expanding choice for siting installations.

Combining the deployment of different VRE technologies (e.g. wind and solar power as well as run-of-river hydropower) can lead to a generation profile that is less variable and hence easier to integrate. The reason is that different types of VRE generation are often complementary (i.e. when there is no sun it is often windy and vice-versa) in many parts of the world. Deploying a mix of VRE technologies can minimise the overall cost of the power system, even if this means that the VRE technology with the lowest levelised costs of electricity (LCOE) is not predominately deployed.

VRE System service capabilities

Technological advances have improved the degree to which VRE output can be forecast and controlled in real time. This means that system operators have more accurate forecasts, several hours in advance, of how much wind and sun they can expect to generate and can adjust VRE output in real time to help balance supply and demand.[9] In addition, modern VRE power plants can provide a number of technical services needed for system operation (voltage and frequency control) that have in the past been available only from conventional generators. For example, Xcel Energy Colorado has equipped two-thirds of its wind turbines with frequency support capabilities (regulation as well as inertial response). The response time of such wind turbines has outperformed that of conventional plants. Similarly, a study by NREL, Hawaiian Electric Company (HECO) and SolarCity has demonstrated that advanced PV inverters are capable of actively stabilising voltage on the system (NREL, 2016). This has enabled HECO to raise the limit it imposes on distributed PV in the system from 120% of minimum daytime load to 250%. Such capabilities are often not used elsewhere because existing technical standards prevent VRE from providing system services or the procurement of system services has not been modified to take account of capabilities and presence in the system of large shares of VRE (see section 12.4).

Generation profile shifting plant design

VRE operation can also be optimised at plant level to facilitate integration. This is achieved by changing the output profile of the plant so that it better matches demand. For example, more solar panels can be installed per unit of inverter capacity, which will limit production during mid-day and add generation during the morning and evening – often a better match with demand. Similarly, in utility-scale solar PV systems, installing solar panels so that they are east-facing and/or west-facing, so that they actively track the sun, rather than facing the equator, can bring overall system benefits. Wind power turbines can be designed with blades longer than those normally associated with a given nameplate capacity, which leads to a more stable power output and thus higher value electricity (Hirth and Müller, 2016).

Overcoming integration challenges via system-friendly deployment means investments in other flexible resources can be deferred. However, beyond a certain share of VRE

9. VRE plants can run below their maximum output (partial curtailment) to provide upward reserves. This can be particularly relevant at times of high VRE availability, where few or no conventional plants are needed to meet demand.

generation, additional investments in system flexibility will be required if additional VRE deployment is undertaken. Our evaluation of the cost-effectiveness of VRE takes this factor into account.

12.2.2 Flexible power plants

Dispatchable power plants, whether renewables or fossil-fuelled, can adjust their output in line with system needs.[10] Today, dispatchable plants are the most important source of flexibility in virtually all power systems. Depending on their design (or later modifications), power plants differ widely in how flexibly they can be operated. A power plant is more flexible if it can: 1) start production at short notice; 2) operate at a wide range of generation levels, including very low output; and 3) quickly move between different generation levels. Within the limits of resource availability, VRE plants can also provide flexibility.

Rising shares of VRE gradually shift the role of flexible power plants. Increasingly, their output becomes subordinate (or complementary) to that of VRE, particularly because VRE has minimal marginal operating costs. Output from flexible generation is higher during times of low VRE production and needs to be ramped up at times of high demand when VRE covers only a small portion of demand. Comparing the installed capacity of VRE generation to the levels of power demand reveals that, depending on the region, wind and solar PV capacity combined in 2040 in the 450 Scenario is likely to exceed minimum and average power demand, in the absence of demand-side response measures, during certain periods (Figure 12.4).

In the 450 Scenario, the total installed capacity of all types exceeds maximum power demand by a large amount in a number of regions. This is due to requirements for system adequacy, but also to the fact that significant amounts of the non-VRE capacity available today remain in the system, even though their use has been largely displaced by low-carbon sources, so they operate at much lower capacity factors than currently. This benefits the deployment of VRE resources: during times of low wind and solar PV output, this existing reserve generation capacity can be used to ensure demand is reliably met.

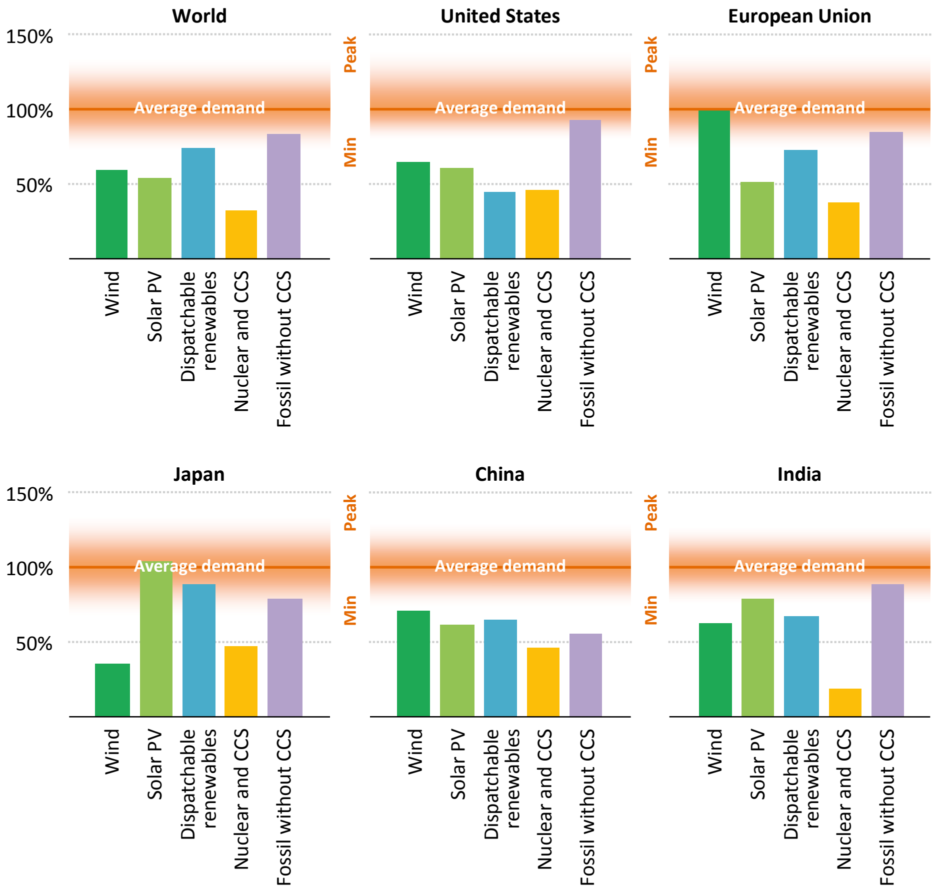
The flexibility available from existing dispatchable power plants, both thermal and renewables, can often exceed what is needed, even at fairly high shares of VRE generation. Systematic reviews of existing plants frequently reveal a potential for higher flexibility than initially assumed. In countries with rising shares of VRE generation, such as Denmark and Germany, thermal power stations – in particular hard coal plants – have been adapted[11] to allow for a more flexible operating pattern and, as coal is displaced in the generation mix, the displaced capacity is operated primarily to provide flexibility for VRE integration. The

10. This renewable category includes reservoir hydro and biomass power plants. CSP power plants equipped with thermal energy storage can also adjust their output flexibly. Depending on plant design, geothermal power plants can also vary electrical output to a certain degree.

11. There are many technical adaptations that can be made to improve thermal power plant flexibility, see NREL (2013) for further details.

cost for adapting existing power plants is highly plant specific. For example, enabling a 30% increase in ramping speed, along with a 50% reduction of both minimum generation level and start-up time in a large coal plant (500 MW) can involve costs in the range of $0.2-3 per megawatt-hour (MWh).

Figure 12.4 ▷ Installed capacity by technology as a share of average power demand for selected regions in the 450 Scenario, 2040



Wind and solar PV capacity combined account for around 120-150% of average power demand by 2040

Notes: Min = minimum; CCS = carbon capture and storage.

Operating power plants more flexibly generally increases wear-and-tear, can reduce fuel efficiency and increase emissions of local pollutants and CO_2 per unit of generated electricity. The exact impact of more flexible operation is highly plant specific. However, in a comprehensive modelling study of the effects of increasing plant cycling on power system costs, the US National Renewable Energy Laboratory found that the costs associated with operating fossil-fuelled plants more flexibly are very modest (NREL, 2013). For the US Western Interconnection (a wide area synchronous grid), the study found the costs per MWh due to starts and stops and ramping increase from $0.5/MWh under a no-VRE scenario to $1.3/MWh for a VRE penetration of 33% in annual generation.

12.2.3 Energy storage

Energy storage can complement a large-scale roll-out of renewables by providing a wide range of services across the energy system: large-scale storage in transmission grids can hold surplus electricity produced when wind and solar generation exceeds demand, and release it to the grid when renewable power resources are insufficient to satisfy consumption; network operators can rely on grid-scale storage technologies to provide valuable technical services to mitigate the impact of VRE on electricity grids; and small-scale storage ,coupled with rooftop PV, can increase the own use of generated power, and provide off-grid power solutions. In such applications, however, storage will compete with other integration measures (e.g. deploying flexible power plants, demand-side response and expanding balancing areas through flexible transmission links).

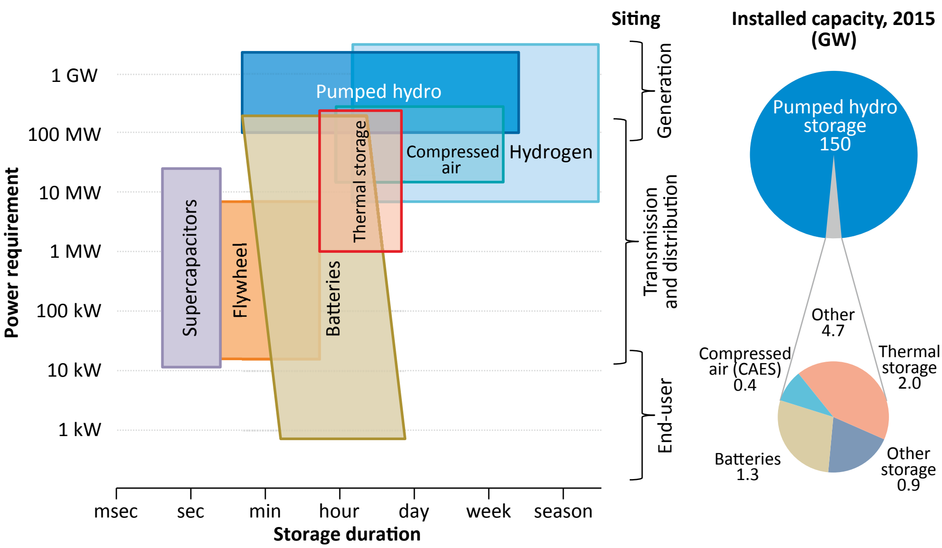
Current power storage capacity is just under 3% of global electricity generation capacity (or 150 GW) and is dominated by a single technology, pumped storage hydropower (PSH). Most of this capacity was built by utilities as a cost-saving measure to help manage peak demand and to allow for the continuous operation of inflexible baseload power generation plants. In recent years, PSH plants have also been deployed to help mitigate the challenges of integrating increasing volumes of VRE into power systems. They still comprise the majority of planned power storage deployments today: 27 GW of pumped storage plants are expected to come online in the next ten years, mainly in China, the United States and Europe. Other power storage technologies comprise just under 5 GW (Figure 12.5); but the global grid-scale battery fleet is rapidly growing and has doubled in less than three years, largely driven by lithium-ion batteries.[12]

Pumped storage hydro facilities, like compressed air energy plants, tend to be large scale and deployed upstream from end-users. While the technical potential is high, the rate of deployment is limited by the restricted availability of sites suitable for new developments or of existing hydro facilities that can be converted to pumped storage plants. Battery storage, on the other hand, can be deployed almost anywhere and at a small scale. In certain contexts, battery storage is already cost effective (e.g. in certain off-grid systems, where it competes with diesel generation). In the larger markets, for grid-related applications, it remains relatively expensive: with current investment costs at $350-750 per kilowatt-hour (kWh), the LCOE of a lithium-ion battery designed to smooth daily demand is currently two-to-four-times that of a PSH plant and around eight-times that of a comparable gas

12. Lithium-ion batteries are also the most popular type of rechargeable batteries for portable electronics and electric vehicles. Generally they have higher energy density and lower self-discharge than lead-acid batteries.

turbine providing the same service. However, grid-scale battery costs have declined by more than two-thirds in eight years and costs are expected to continue to fall at a rapid pace over the *Outlook* period, aided by battery deployment in the automotive and consumer electronics industries. The current annual manufacturing volume for lithium-ion batteries is approximately 30 gigawatt-hours (GWh), 80% of which is used in consumer electronics products; battery manufacturers plan to increase production capacity four-fold, to around 120 GWh by 2020. In the 450 Scenario, total storage deployment capacity is projected to more than double to almost 380 GW over the *Outlook* period. While growth in PSH plants is expected to continue at its historic pace, battery deployments accelerate, due to continual reductions in costs, aided by the proliferation of electric vehicles (EVs) and by uptake of small-scale storage systems for distributed generation in the residential and commercial sectors and off-grid applications. Four regions – the United States, India, China and the European Union – account for about three-quarters of all battery storage deployments.

Figure 12.5 ▷ Storage technology characteristics and global installed capacity in 2015



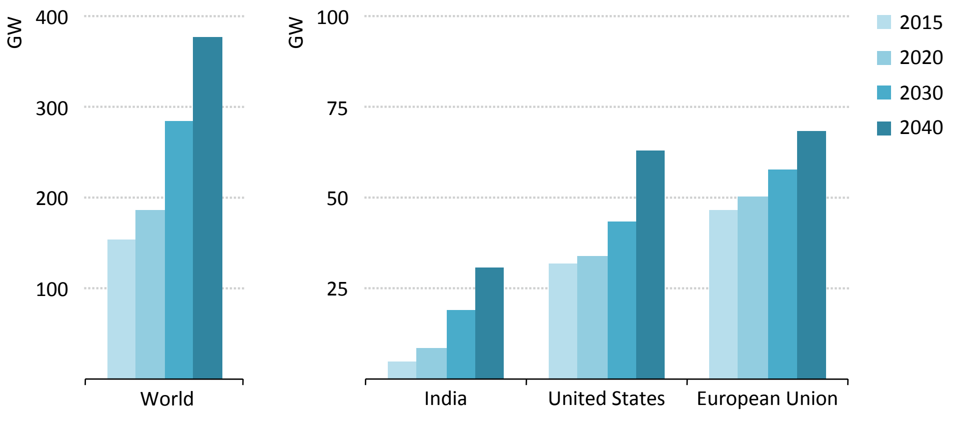
The maturity, economics and applications of electrical energy storage vary greatly by technology

Notes: msec = milliseconds; sec = seconds; min = minutes. Thermal storage refers to molten salt storage for CSP plants and other applications above 1 MW installed capacity.

The rate of decline of battery costs is highly uncertain, but at the current rate of deployment and technical progress lithium-ion grid-scale batteries, designed to deliver daily load shifting, would achieve parity with pumped storage hydro facilities before 2035 and with gas turbines, deployed to meet peak demand, by 2040. Costs for other storage technologies are also falling. Coupled with various generation technologies, this can improve the economic prospects of the overall system. For example, the combination of concentrating solar power (CSP) with thermal energy storage (TES) makes CSP plants more valuable from a system perspective and stimulates their deployment (Box 12.4).

While utility-scale deployments continue to dominate, in terms of total installed capacity, residential and commercial-scale storage deployments have, in recent years, become a defining energy trend. Interest in distributed generation has been growing, stimulated by supporting policies (such as feed-in tariffs, technology grants and a shift towards liberalised markets), rapid cost reductions in low-carbon technologies (such as solar PV and smart grid solutions) and alternative business models for electricity provision. This, in turn, has created new applications and demand for residential storage systems – the launch of the Tesla Powerwall (a 6.4-kWh lithium-ion storage solution) was received with much publicity in 2015. At a cost of around $470/kWh for the battery only (which can double when factoring in installation costs and necessary auxiliary equipment) such residential storage solutions are in the majority of cases not yet competitive. Small-scale storage is also making in-roads into off-grid applications; notable investments having been made over the last year to increase the access to energy of rural populations in Africa and South Asia (IRENA, 2015).

Figure 12.6 ▷ Installed capacity of energy storage systems in selected regions in the 450 Scenario



Storage systems in the United States, Europe and India are expected to almost double, with the biggest increase in India

To reach the levels of storage capacity projected in the 450 Scenario (Figure 12.6), current policy, technical and market frameworks will have to be modified to fully capture and monetise the value of the full range of services that storage can provide. The business case for deploying storage can be complex, and often not persuasive, under current market and regulatory conditions. With increasing deployment of VRE, the ability to respond very rapidly to mismatches between supply and demand becomes more important. Market design is expected to evolve to also reward the speed and frequency with which storage can respond to changing demand, compared to other forms of flexibility, and to fully capture and monetise the advantages associated with "benefits stacking", i.e. bundling several power (e.g. frequency response) and energy (e.g. peak demand management) applications together.

With the high levels of generation from VRE reached in some regions in the 450 Scenario, longer periods of excess or abundant generation will arise in the longer term, which will give rise to a need for technologies capable of storing large amounts of energy over several days. Such technologies are not mature today, but redox-flow batteries, a unique category of battery where the volume of energy stored can be scaled up at a lower cost than other battery technologies, hold promise of storing electricity over a large number of hours. Chemical energy storage, for example in the form of hydrogen, could also be an option for longer term storage in such applications: hydrogen is very energy dense and large volumes can be stored or converted to natural gas, at a cost, for use elsewhere in the energy system (referred to as "power-to-gas"). However, converting and storing hydrogen still has very high cost and faces safety issues.

Box 12.4 ▷ Thermal energy storage increases the value of CSP

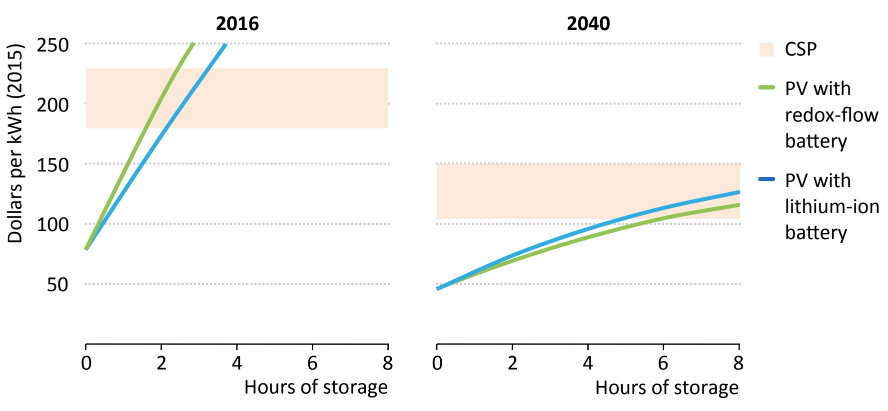
The deployment of concentrating solar power technologies has lagged behind that of PV: In 2014, PV installed capacity totalled 225 GW, while CSP deployments added to a mere 5 GW. Despite recent success stories, such as the completion in 2014 of three large CSP projects in the United States, totalling over 900 MW, and the start of operations of the first module of the Moroccan Noor Power Station (rated at 160 MW) in early 2016, several CSP projects have been delayed or cancelled, sometimes in favour of solar PV projects. Compared with solar PV projects, which are smaller scale, more modular and so can be deployed more quickly, CSP projects are larger, involve substantial capital and are often perceived as riskier by investors. As a result, CSP has had little opportunity to achieve cost reductions through learning-by-doing or economies of scale needed to keep pace with the significant cost reductions achieved for solar PV.

However, CSP has some important advantages compared to solar PV. In a CSP plant, vast fields of mirrors concentrate light from the sun to generate heat and drive a turbine. This produces alternating current electricity directly, similar to a conventional fossil fuel-fired plant, which offers technical benefits to the grid that PV cannot directly provide. Furthermore, it is possible to store the heat before it is converted into electricity by using thermal energy storage devices - most commonly, molten salts - which currently have capital costs per unit of energy stored which are 90% lower than those from batteries. Increased utilisation compensates for the high capital costs of CSP and boosts revenues as a result of the extension of generating hours. CSP plants may be called to generate mostly just before and after sunset, when demand (net of PV) peaks and electricity may have higher value.

Given the fundamentals of the technology, the rate of cost reduction of CSP is expected to be slower, relative to other renewable technologies. Currently CSP with TES is cost effective at any storage duration over two hours – i.e. when the heat storage facility is sized to store an amount of energy that allows the plant to operate at full power for over two hours. However, by 2040, cost reductions in battery storage technology are expected to make PV plus battery storage more cost effective for any storage duration under five hours, greatly undermining the advantage of CSP in serving evening peak demand (Figure 12.7).

The prospects for CSP, nonetheless, are expected to improve over the *Outlook* as a low-carbon source of flexibility to power systems with increasing shares of VRE. In the New Policies Scenario, CSP capacity grows to 76 GW and in the 450 Scenario it reaches 325 GW.

Figure 12.7 ▷ Comparison between the LCOEs of 50 MW CSP and PV plants with battery storage facilities, 2016 and 2040

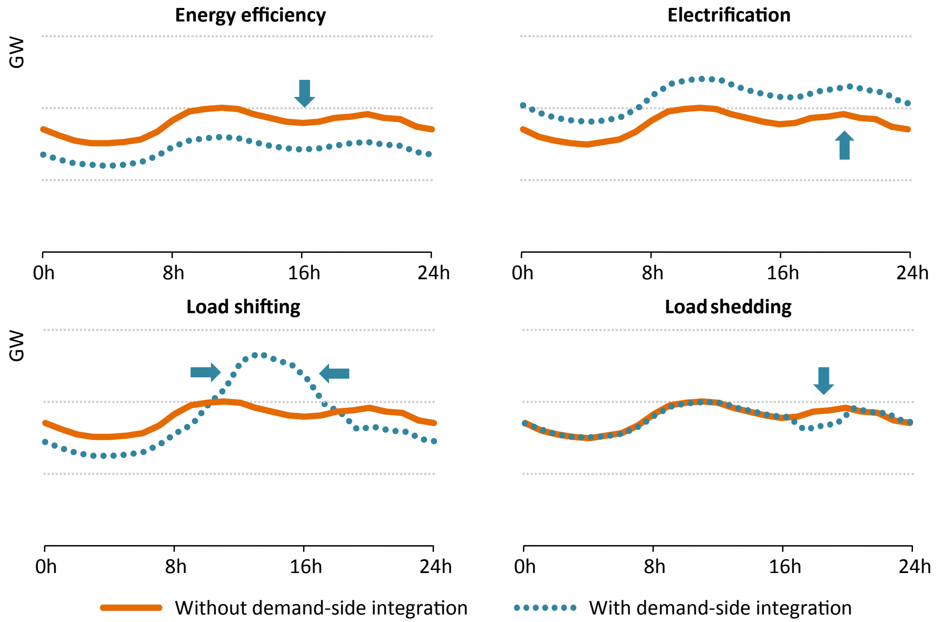


While thermal energy storage can increase the value of CSP projects, reductions in battery costs by 2040 will narrow the price gap between solar PV + battery systems and CSP + TES systems in long duration applications

12.2.4 Demand-side response

Because systematic control of electricity demand at short notice has historically not been a viable option, power systems have so far been designed to ensure electricity supply is instantaneously adjusted to match demand. However, the expansion of variable renewables is making supply more variable and less predictable, while the rise of modern information and communication technologies (ICT) is making it possible to monitor and control demand rapidly and at large scale. This is giving rise to a paradigm shift: looking at options to make demand flexible and to dynamically match supply. Demand-side integration consists of two types of measures to reshape demand load: actions that influence load – energy efficiency and electrification; and actions that manage load – demand-side response (Figure 12.8).

Figure 12.8 ▷ Illustrative demand-side integration measures



A paradigm shift: electricity load curve can be shaped to match supply

Electrification[13] and energy efficiency aim at scaling up or down the load by influencing the level of the electricity demand while keeping the same level of energy service.[14] Increased electrification within the energy system widens the opportunities for load shifting to accommodate variable renewables, provided the planning of, for example, the wider introduction of EVs embraces arrangements to shift their demand on the grid away from hours of very low VRE supply (or to hours of high VRE supply). Energy efficiency reduces demand thus help reshape the load. For example, the use of light-emitting diodes (LEDs)

13. Electrification refers to the increasing use of electricity in end-uses, such as powering transport and providing different forms of heat-related services. Heat has a range of uses, including space heating, water heating and cooking in buildings and for process applications in industry.

14. Electrification and energy efficiency are well established in comparison to demand-side response and correspond to long-term decisions. These DSI measures are already included in our scenarios (see Chapters 7 and 10).

reduce the evening peak, more efficient motors reduce the load during working hours and more efficient air conditioners reduce the load in summer, while more efficient refrigerators reduce the overall load.

Matching demand and supply dynamically is usually thought of in terms of instantaneous measures. In the past, for example, attention was focussed on top-down management of demand by the system operator, for example to shed load when supply threatened to fall short of demand. Top-down management remains important, but the load management concepts increasingly embrace consumer-driven action, stimulated by the appropriate information, e.g. price signals, which can be communicated instantly, using available technology. Demand-side response (DSR) describes actions which may be top-down or bottom-up and which can perform different functions:

- ***Load shifting:*** Re-shaping the load curve to transfer demand in time without affecting the total electricity demand (e.g. shifting the use of a washing machine or the charging of an EV to a different time period).
- ***Load shedding:***[15] Interrupting demand for short intervals (e.g. stopping industrial production for a given amount of time) or adjusting the intensity of demand for a certain amount of time (e.g. by adjusting the thermostat on space heaters and air conditioners to lower electricity demand at a particular time).

Shifting demand towards periods of high VRE supply is also a critical element of DSR. This is particularly true in a system with a high share of VRE, when curtailment might otherwise be required. DSR can be a very good complement to VRE for providing operating reserves during times of high VRE generation.

Policies and technologies to trigger demand-side response

Reaching the full potential of demand-side response requires co-ordinated policy measures and effective collaboration between utilities, government, grid operators and consumers. Depending on the maturity of the power sector, the status of energy reform already in place and the diffusion of relative technologies (e.g. smart meters), a large variety of measures is possible. Some are prerequisites for the successful implementation of DSR (Table 12.2). A clear regulatory framework is essential to lead technology diffusion, market development and, to some extent, to ensure the cybersecurity to the grid.[16] From a purely technical perspective, advanced smart meters ensure the capability of metering consumption with high accuracy and the installation of remote load control devices can guarantee controllability of end-user demand. From a market perspective, consumers should respond to time-dependent price signals and adjust their consumption accordingly.

15. In the case of load shedding, there can be a "lost load" as the result of an economic decision by a consumer; this is different from curtailment.

16. The use of ICT in power networks has increased enormously. The physical electric infrastructure is now connected to advanced equipment (smart meters, remote load control devices) via the telecommunication network. In this situation, the risk of intentional and unintentional threat to system infrastructure has to be assessed and managed, in order to maintain the stability and the reliability of the power system.

The diffusion of advanced metering systems is by no means uniform around the world. China is the world leader in smart grid investment, with more installed smart meters than the rest of the world combined: about 70% of households (Yang, 2015) are already connected and China is committed to a full coverage in the coming years. The share in other regions is lower, but it is increasing fast, with many governments having set a target of reaching full coverage within the next few years. In the European Union, the target date is 2022, but the average share remains low (around 15% today) – although Italy and Sweden have current adoption rates of over 90% (SEDC, 2014). Deploying smart grid technology is expensive and requires the grid operator to be capable of financing the installation, though the operation and maintenance costs are relatively low.

Table 12.2 ▷ Market and technology enablers of demand-side response

		China	India	European Union	United States	Japan
Smart meter share	Today	>70%	*n.a.**	>15%	>40%	>10%
	Full coverage (expected year)	*n.a.**	*n.a.**	2022	*n.a.**	2024
Time-based tariff		🔴	🟡	🟡	🟡	🟡
Regulatory framework		🔴	🔴	🟡	🟡	🔴
Wholesale market		🔴	🔴	🟢	🟡	🟡
Aggregator		🔴	🔴	🟡	🟡	🔴

🟢 Fully implemented

🟡 Partially implemented or implemented only in some states

🔴 Not implemented

* Data not available or no official policy target.

Sources: CapGemini (2008); METI (2016); US DOE/EIA (2016a).

Remote control of demand requires the installation of load control devices. In the past, they have been confined to large industrial consumers, allowing the grid operator to disconnect relatively large blocks of consumption in order to offset spikes in demand or supply outages. The upfront cost for enabling DSR is usually low: companies frequently already have the required equipment installed. However, the opportunity cost of the possible reduction of output of goods has to be considered. Similar control over the consumption of commercial consumers (refrigeration, air conditioning, water pumping) is relatively new, as is the application of such controls to household appliances such as air conditioners, water heaters, heat pumps, clothes dryers and refrigerators. While individually modest, the upfront cost for enabling remote control of these smaller installations is relatively higher than for industry. However, these costs can be expected to decrease once certain features are streamlined into the appliance production process, i.e. that smart appliances become the new standard. Monetising the flexibility of these devices may yield valuable savings for end-users on their electricity bill, to offset the disadvantages. A number of countries have successfully introduced these features: in the United States, several demand-side response programmes are in place for residential as well as industrial and commercial customers.

Tariff structures need to evolve to improve customer awareness and responsiveness. Prices should accurately and constantly reflect the cost of electricity, which can vary substantially across the same day and between seasons. This will increase the volatility of retail prices but enable the introduction of a dynamic time-based tariff. Two main tariff categories are emerging, even though time-based pricing is seldom in use:

- Time-of-use tariffs: Predefined blocks of hours (peak/off-peak) with different prices.
- Real-time pricing: The price of every single hour of the day varies, reflecting the wholesale price.

One way of realising a larger share of the maximum potential of DSR is for consumers to participate in the market through aggregate service providers. The aggregator, a new actor in the electricity market, gathers consumer demand of any type and the supply of distributed producers, such as renewables-based power plants, to provide balancing services to the grid by adjusting power demand and/or shifting loads at short notice. The "pool" of aggregated load is managed as a single flexible consumption unit – equivalent to a virtual power plant – and sold to the markets or to the grid operator. In 2015, California put in place a public demand-response auction mechanism to select aggregators able to provide flexibility to the grid.

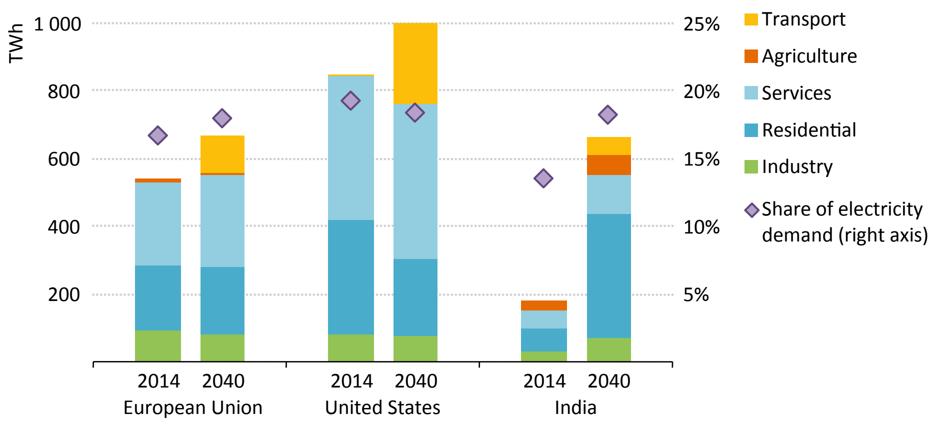
As with any innovative market development, ongoing collaborative research and knowledge-sharing across the industry is needed to shape this emerging model and bring it to maturity. The effort should include standardisation of the rules and procedures concerning smart grids, setting standards for communications between customers, suppliers and grid managers, and facilitating access to data and technologies. To make a massmarket DSR system successful, an initial drive to kick-start commercialisation and to give momentum to its adoption may well be needed within the context of a long-term strategy, and allowing time for the new system to evolve, mature and win acceptance. Initiatives by consumer authorities and utilities to educate the general public about the benefits of DSR are likely to be necessary.

Current and future potential of demand-side response

Currently, DSR programmes are directed mainly at the industry sector, often involving the use of back-up generators to shift load (usually with a higher carbon footprint) and payment for the cost and inconvenience. The scope of these arrangements is limited by relatively high costs for frequent use. The potential of DSR varies by region and sector but in all regions most of the current and future technical potential at lower overall cost (upfront and opportunity costs) lies in the buildings sector, especially in space and water heating and cooling. EVs are expected to become participants in DSR programmes over time, but their current low share in the global car fleet makes them a marginal component today.

Electricity demand for space heating and cooling can be shifted over a certain number of hours, the extent depending on the thermal inertia of the building – the better the insulation, the longer the period of shift in demand. As for water heating, most households in cold climates that use electricity to meet their hot water needs are equipped with a storage tank, so water can be warmed a few hours before it is used. Air conditioners can be similarly equipped with thermal energy storage, such as chilled brine tanks. Most of the remaining potential in buildings is related to electricity used for big appliances. Cleaning appliances (washing machines, dish washers and dryers) can be run at any time of the day (within the limits of maintaining service quality) and most machines sold in the market already have time programming functions. Refrigerators can be turned off for short periods, to take advantage of their thermal inertia.

Figure 12.9 ▷ Technical potential of demand-side response by region in the 450 Scenario



The technical potential for demand-side response is large, up to 20% of electricity demand, with electric vehicles set to play a larger role through 2040

12

The current potential of demand-side response is, therefore, high in regions where heating and cooling in the buildings sector represent a high share of the electricity demand. We estimate that currently DSR could be applied to almost 20% of the annual electricity demand in the European Union and the United States, shifting demand to different periods within the same day (Figure 12.9). In India, to the high number of people without access to electricity and the relatively low level of ownership of appliances, we estimate the current potential for DSR to be lower, at about 15% of current electricity demand.[17]

In the 450 Scenario, energy efficiency measures temper the growth in electricity demand for major appliances, and of heating and cooling demand, lowering the overall importance of DSR potential in the United States and slightly increasing it in the European Union. On

17. Currently, India faces a structural shortage of power and, when they can afford it, consumers rely on back-up generators to meet their electricity demand. These back-up generators are not taken into account in our DSR potential assessment. By 2040, in our scenarios, the anticipated increase in the reliability of power supply leads to progressively less reliance on back-up systems.

the other hand, increased penetration of EVs in the fleet pushes the overall potential of DSR higher, so maintaining DSR potential at around 20% of total annual demand in all the regions analysed (see section 12.3). The outlook for India is wholly different: total electricity demand almost triples by 2040, as higher incomes and increased electrification lead to higher ownership rates of cooling systems and appliances. The rapid growth in the share of buildings demand in overall electricity demand leads to higher potential demand-side response, increasing the share of electricity demand that can be shifted from 14% to 18%.

Box 12.5 ▻ Assessing the potential of demand-side integration

While energy efficiency and electrification for heat production are long-standing components of the World Energy Model, to assess demand-side response a new tool has been developed, since measurement of demand-side response requires a higher temporal resolution. To assess the potential amount of flexibility in end-use electricity demand that might be used to facilitate higher penetration of variable renewables, a three-step methodology was used. The first was to assess temporally the load profile for each sector and subsector or end-use (residential and services [e.g. space heating, water heating], industry [e.g. steel, chemicals industry], transport [e.g. road and rail] and agriculture) for every 24 hours of 36 typical days (weekday, Saturday and Sunday of each month). The aggregate electricity demand of each end-use or subsector temporally was matched to the total load profile of a given country.[18] An example of the load aggregation is displayed in Figure 12.10.

The second step was to assess the share of demand that is flexible in each end-use. This share is the product of three flexibility factors, sheddability, controllability and acceptability (Ookie Ma, 2013):

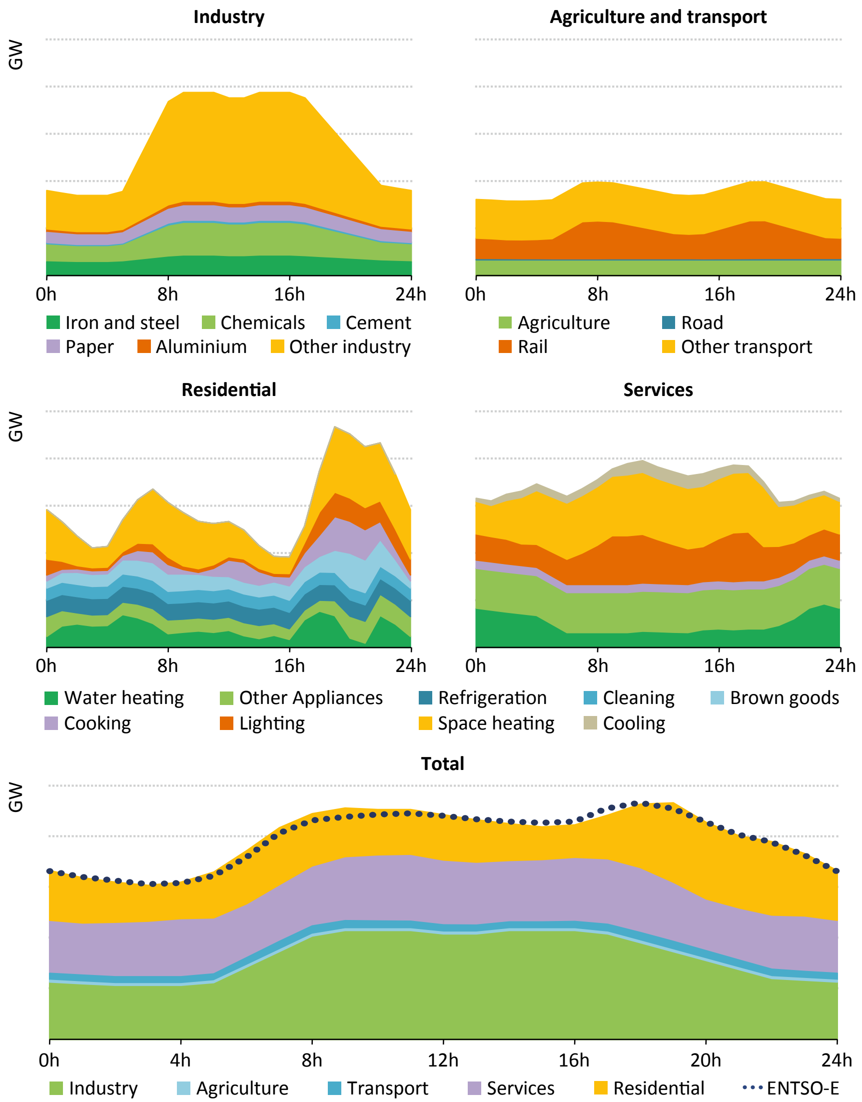
- **Sheddability**: Share of the load of each end-use that can be shed, shifted or increased by a typical DSR strategy.
- **Controllability**: Share of the load of each end-use which is associated with equipment that has the necessary communications and controls in place to trigger and achieve load sheds/shifts.
- **Acceptability***:* Share of the load for a given end-use which is associated with equipment or services where the user is willing to accept the reduced level of service in a demand-response event in exchange for financial incentives.

This framework enables scenarios to consider demand flexibility from various technologies and at varying levels of social acceptability.

The third step was to integrate the DSR profiles in the hourly model, which is described in Box 12.2, to determine the load that can be shifted, given market conditions in the region analysed.

18. Data from ENTSO-E, PJM, ERCOT, MISO, NEISO, NYISO were used to replicate respectively the overall load curves of European Union, United States and India.

Figure 12.10 ▷ Illustrative load curves by sector for a weekday in February in the European Union compared with the observed load curve by ENTSO-E in 2014



The load profile is an aggregation of the sectoral load profiles for typical days of the year

Note: ENTSO-E represents the aggregated load curve for the 28 European Union countries.

Sources: ENTSO-E (2016); IEA analysis.

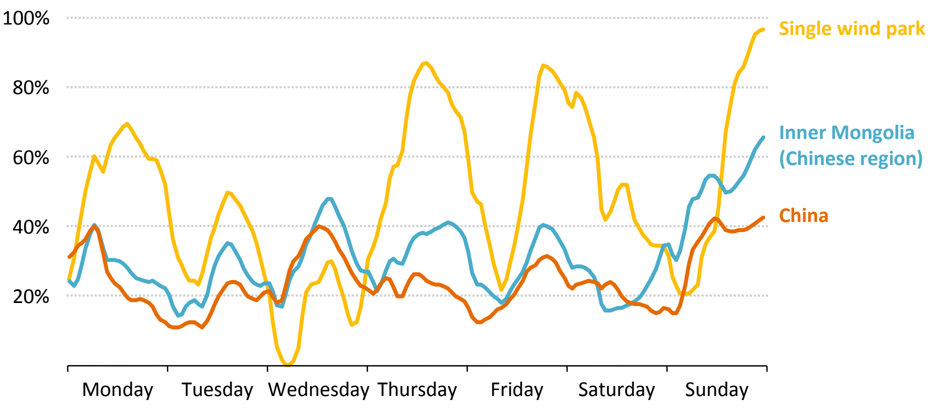
12.2.5 Transmission and distribution networks

The way transmission and distribution networks are planned, constructed and operated greatly influences the integration and competitiveness of variable renewables. Transmission grids comprise high-voltage lines that transport power over large distances from power plants to cities and large industrial facilities. Distribution grids deliver power to households and businesses at lower voltage levels, as well as accommodating power supplied by distributed resources.

Grids can expand the potential of variable renewables and increase their value

By providing links to renewable energy resources, the grid infrastructure expands the potential of wind, solar and other renewables (e.g. hydropower and geothermal), as the best resources are often in remote locations. Grids are a unique flexibility resource that can correct for the geographic mismatch between supply and demand and connect distant and distributed resources to load centres. Grid planning must take into account the trade-off between resource quality and the investment needs of the transmission infrastructure. Insufficient transmission capacity can lead to curtailment of renewables-based generation by the grid operator. For example, wind power in Texas, which experienced a curtailment rate of 17% in 2009, saw this figure drop to just 0.5% of total generation potential in 2014, after transmission capacity was improved (US DOE, 2014). Transmission can also connect geographically distant markets, crossing national borders or seas, for example, enabling price differences between markets to incentivise the development of otherwise uneconomic renewables, thereby expanding their potential (Box 12.6).

Figure 12.11 ▷ Hourly capacity factor of wind power in selected regions, 2014

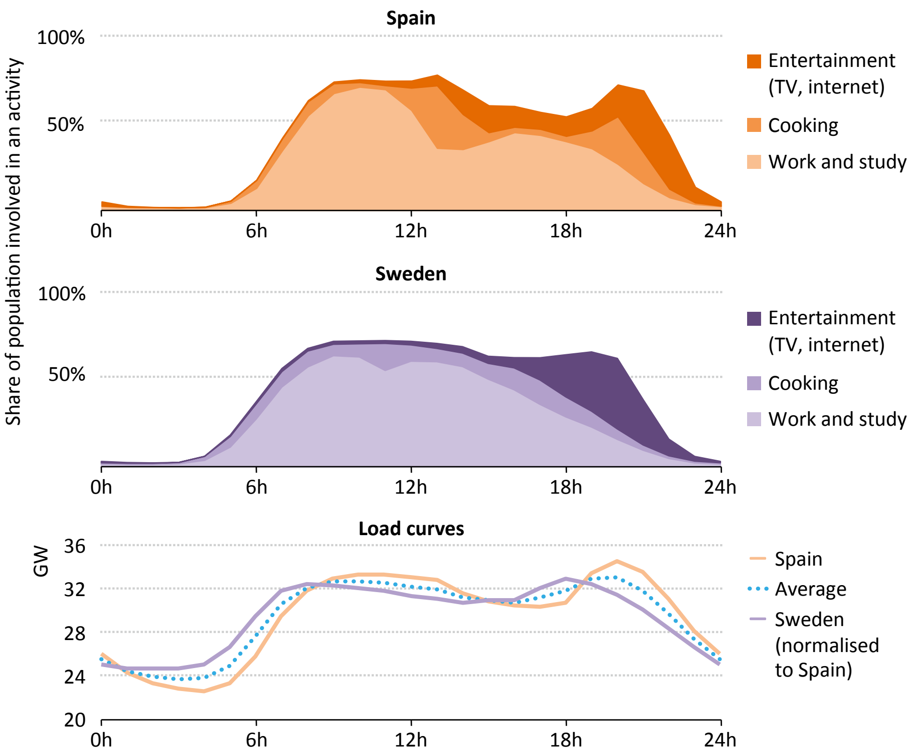


Increasing grid interconnection among different wind parks can significantly smooth the variability of wind power production

Note: Weighted wind power production profiles for the week 20-26 January 2014 for: a single wind park in Inner Mongolia; all wind parks in Inner Mongolia; and wind parks across China.

Grids increase the value of VRE (and in general of any electricity system) by making it possible to balance supply and demand over a larger area, thus, facilitating regional smoothing. This smoothing effect is relevant for both supply and demand. By connecting multiple wind or solar installations in different locations, grids aggregate the output, reducing the fluctuations evident at a single site, due to changes in wind speed or cloud cover (Figure 12.11). The effect of weather forecasting errors becomes less pronounced where there is a combination of sites rather than one single site. On the demand side, grids can connect markets which have differing demand profiles, due to cultural norms or location in different time zones. An aggregation of profiles of electricity demand and behavioural patterns illustrate this effect (Figure 12.12).

Figure 12.12 ▷ Extent of aggregation of electricity demand profiles and behavioural patterns on load curves in Spain and Sweden



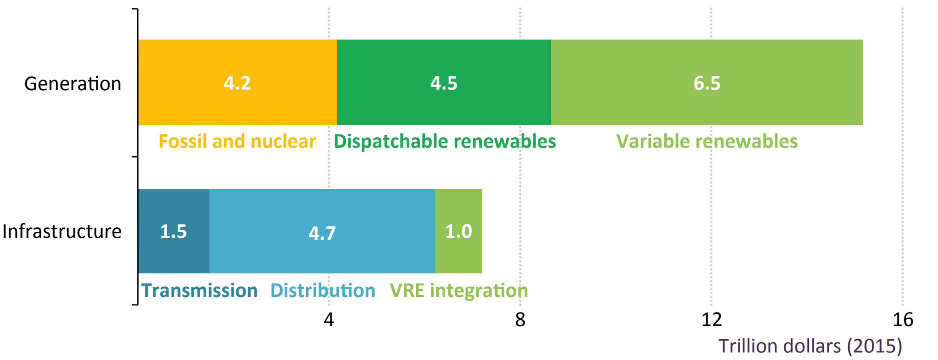
Differences in cultural norms create potential for electricity demand smoothing through transmission

Notes: Load curves for 3 March 2015. The Swedish load curve is normalised to the average Spanish load to facilitate comparison.

Sources: ENTSO-E (2016); Eurostat (2009) for the breakdown by end-uses.

In the 450 Scenario, global investment in transmission and distribution through 2040 amounts to around $7 trillion, equal to over 45% of investment in power plants (Figure 12.13). Strategic planning of these investments is crucial to ensure that grids provide adequate flexibility to maximise system value under high shares of VRE. Without sufficient grid flexibility, the value and environmental benefits of VRE could be lost through curtailment and volatile, or even negative, prices. Countries with fast growing electricity demand (such as India) require higher investment in new grid infrastructure and thus are well positioned to design transmission and distribution with VRE in mind.

Figure 12.13 ▷ Total global power generation and T&D investment in the 450 Scenario, 2016-2040



Investments in transmission and distribution grids for integrating VRE are a small portion of the total investments in the power sector

The time required to construct transmission lines frequently exceeds that of installing VRE capacity. A high-voltage interconnector may take decades from planning to operation while a wind park can be several years and a rooftop solar PV installation in just months. This is due not only to the scale of the transmission and distribution (T&D) investment, but also particularly to the challenge of gaining public acceptance of both the physical infrastructure and the implications for the price of supply. This is especially true of international interconnections, where the distribution of investment costs and the allocation of the bottleneck revenues that may result if there are price differentials between countries require detailed international co-operation. The development of grid infrastructure has typically been managed at the regional or national level, with grids thinning towards administrative boundaries. International interconnections also involves investment to strengthen grids within national or regional boundaries.

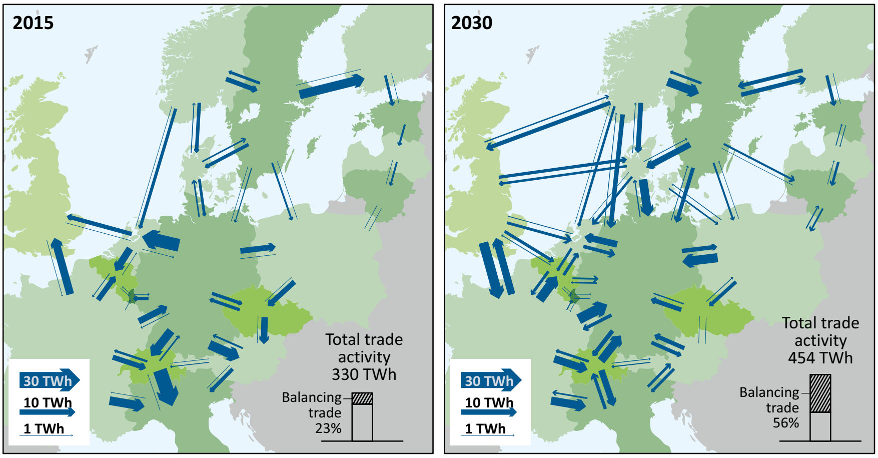
Smart grid technologies are increasingly allowing system owners and operators to circumvent some of these traditional obstacles faced when reinforcing or developing transmission infrastructure. ICT technologies allow transmission lines to be monitored and safely operate much closer to engineering limits, and collect real-time, location-specific measurements of the condition of the system. Such technologies significantly increase the efficiency of operating a high-voltage grid, mitigate network congestion and crucially may defer or avoid the need to invest in new transmission corridors.

Box 12.6 ▷ Transmission expands the potential of variable renewables in Northern Europe

In a detailed analysis of the VRE integration potential of Northern Europe, transmission capacity emerged as one of the most promising means of increasing flexibility (IEA/NER, 2016). The central scenario in the analysis (the Nordic Carbon-Neutral Scenario) sees the VRE share of generation in Northern Europe rise from 10% in 2014 to 34% in 2030.

This analysis demonstrates the potential for regional smoothing through interconnection, illustrating the changing role of transmission grids under high shares of VRE. The majority of electricity trade today is uni-directional, flowing from an exporting country to an importing country. Under high shares of VRE, greater bi-directional utilisation of interconnectors means most of the electricity traded is used for balancing, resulting in regional smoothing. Total trade activity increases by 38%, from 330 TWh to 454 TWh in 2030, while balancing trade (trade of equal size in both directions during the course of a year) increases dramatically from 23% to 56% of total trade activity (Figure 12.14).

Figure 12.14 ▷ Electricity trade in Northern Europe, 2015 and 2030



By 2030, greater two-way utilisation of interconnectors in Northern Europe increases electricity trade and helps accommodate a larger share of VRE

Note: Balancing trade is the trade of equal size in both directions for a given country pairing during the course of a year.

Source: IEA/NER (2016).

The analysis provides an example of how interconnections can expand the potential of VRE, bringing remote, high-quality resources to load centres. The scenario sees the Nordic region (Denmark, Finland, Iceland, Norway and Sweden) expand wind generation beyond collective domestic demand, in response to higher electricity prices on the continent. This allows the region to supply over 50 TWh of power (10% of total Nordic generation from its expanded and largely decarbonised power system) to other European countries by 2030, in addition to significantly increasing balancing trade in order to better utilise dispatchable hydropower in Norway and Sweden.

Distribution grids will take on a new role under higher VRE shares

Distribution (low- and medium-voltage) grids have historically been passive and uni-directional energy networks. Power was generated centrally, transported through high-voltage transmission networks and delivered through medium- and low-voltage networks to consumers in the residential, commercial and industrial sectors; and consumers in low-voltage networks have been largely unresponsive to changes in the broader electricity system. The rise of distributed generation (led by solar PV), the penetration of EVs, together with commercial- and residential-scale storage and demand response, is set to give distribution grids fundamentally new functions. Almost a quarter of all power sector investments in the 450 Scenario are directed towards replacing, upgrading and "smartening" the distribution network infrastructure which will accommodate these emerging distributed energy resources (DERs).

Over 40% of all PV in both the 450 and the New Policies Scenarios will be distributed. Being able to actively control, monitor and plan distribution grids with such volumes of DERs will require both technical innovation and major changes in regulatory roles and responsibilities. Network codes and other regulations need to be progressively adapted and monitored so that DERs interact with distribution grids with minimum impact (e.g. by introducing charging schedules for EVs that respond to local system needs or ensuring rooftop PV can support the network through system services). Network operators will have to make increasing use of ICT to gain visibility and control of DER deployment within their control areas. To facilitate the emergence of these new practices, institutional change would also be needed in the long run: local markets for exchanging power, local aggregators and business models based on smart metering and ICT, so as to fully capitalise on the much wider availability of data.

Upgrading, reinforcing and smartening transmission and distribution grids can reduce the need for other flexibility investments such as storage. Conversely, system-friendly VRE, smart placement of storage, demand-response measures and flexible generation can reduce the need for traditional T&D infrastructure. The expansion of grid infrastructure must be subject to a holistic economic assessment that considers other options for system integration. Such assessments will require distribution grid operators to acquire new capabilities, and much greater co-ordination between T&D operators, equipment manufacturers and utilities.

12.3 Country case studies: integrating VRE in the 450 Scenario

The following section aims to quantify when, how frequently and to what extent curtailment might occur as the share of VRE in the power mix rises. This analysis is conducted for three regions – the United States, the European Union and India – which have very different market frameworks, generation mixes and demand outlooks. The object is to understand how those factors affect the possible curtailment of VRE production and to identify solutions.

The analysis takes the projections of the 450 Scenario as a starting point. This scenario works back from the defined objective in 2040, defining a path by which it can be achieved. In doing so, it already assumes a number of actions are taken which limit curtailment. One example is that efforts are made to expand the grid, integrating power markets in each region, and facilitating the integration of the various balancing areas. Cross-border interconnections are improved. Time-of-day pricing becomes more sophisticated. Wind and solar PV systems are deployed in a system-friendly manner (geographical location, increased deployment of low-speed wind turbines and an increased DC/AC sizing factor for solar PV). Flexible power plants are available and used. The electricity demand profile is re-shaped by extensive energy efficiency measures and increased electrification of bulk heat production and transport. And demand-side response and storage measures are introduced to make it possible to match VRE output more closely to demand.

These measures are successful in the 450 Scenario. Curtailment is reduced to 1.5-2.5% of potential VRE output. This residual amount of curtailment remains in the system, as it is uneconomic to eliminate it by further integration measures.

What our analysis concentrates on is the particular contribution made by DSR and storage. So, in a sense, the analysis first unpicks the 450 Scenario to see what the situation would be without those DSR and storage measures. What level of curtailment would result? The answer is 7-8%, depending on the country. We then explain the DSR and storage measures which transform this situation – the solutions.

Unravelling the impact of the other factors listed above, such as lower levels of grid integration, of lower availability of flexible plants is beyond the scope of this analysis (it would, in some cases, require further enhancement of the model used). It would certainly increase the level of curtailment beyond the levels presented.

The results are based on the new hourly model and take into account minimum plant loads (e.g. nuclear or combined heat and power plants), the constraints on ramping up and down of dispatchable power plants, and the availability of resources (Box 12.2). While dispatchable renewables, nuclear and carbon capture and storage (CCS)-fitted plants can (and do) modulate their output over time, within the given individual constraints, the model does not allow new wind and solar PV systems to displace existing nuclear generation or dispatchable renewables (and only partially so, in the case of CCS plants), as this would deliver no net-benefit for CO_2 abatement, which is the determining goal in the 450 Scenario.

12.3.1 United States

Current status of flexibility

Today, the power system of the United States consists of several systems. There are more than 7 300 power plants, nearly 260 000 kilometres (km) of high-voltage power lines and millions of low-voltage power lines and distribution transformers, which connect 145 million customers (US DOE/EIA, 2016b). The flexibility of the US power system is currently mostly ensured by a large fleet of flexible power plants (40% of the fleet is composed of relatively modern and flexible gas-fired power plants, half of which are efficient combined-cycle gas turbines); but the grid is fragmented (including ten wholesale electricity markets, several markets regulated at the state level and 66 balancing authorities across the whole country).

The United States is one of the few regions today that have successfully demonstrated the use of demand-side response to manage energy demand, with around 40% adoption rate of smart meters (Federal Energy Regulatory Commission, 2015). However, even if the country is on track for a full-fledged scale-up in this respect, deployment of time-of-use retail tariffs remains limited (less than 5% of households have access to dynamic time-based tariffs). The introduction of capacity markets has encouraged investment in demand response.[19] For example, the PJM Interconnection consolidates more than 10 GW of flexible demand, coming from various segments, including manufacturing, office buildings, households, schools, retail service and hospitals (PJM, 2016).[20] One-fifth of customers in California participate in demand-side programmes, contributing 5% of total peak demand savings. However, the way in which demand-side actions should be valued in capacity markets has been a source of controversy in recent years, delaying their proliferation. A recent US Supreme Court ruling which allows demand-side response to be compensated, like generators, in wholesale energy markets (which cover about 60% of US power supply) is expected to result in faster business growth (US DOE/EIA, 2016c).

In addition, the United States is currently one of the global leaders in the deployment of energy storage technologies. On a federal level, the US Department of Energy has several research development and demonstration (RD&D) programmes, covering both traditional and emerging storage technologies, in both transportation and utility-scale generation applications. The United States has also been one of the first regions to introduce distinct market mechanisms for storage. Strong support momentum for the technology can also be

19. Capacity markets are regulatory instruments designed to create revenues for all capacity, in the form of generation, demand response or other technology. They typically involve system operators defining annual capacity requirements (in MW) and procuring this capacity through an auction, often three to four years in advance. Capacity mechanisms or capacity markets have been introduced in many power markets with the objective of ensuring resource/system adequacy. The main argument for the implementation of capacity markets is that energy prices (energy only markets) during periods of capacity shortage are not high enough to incentivise sufficient investment in capacity in order to meet reliability standards.

20. The PJM Interconnection co-ordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

seen at the state level, e.g. California adopted an energy storage mandate in 2013 requiring 1.3 GW of additional storage to be procured by 2020.

Curtailment in the absence of additional integration measures in the 450 Scenario

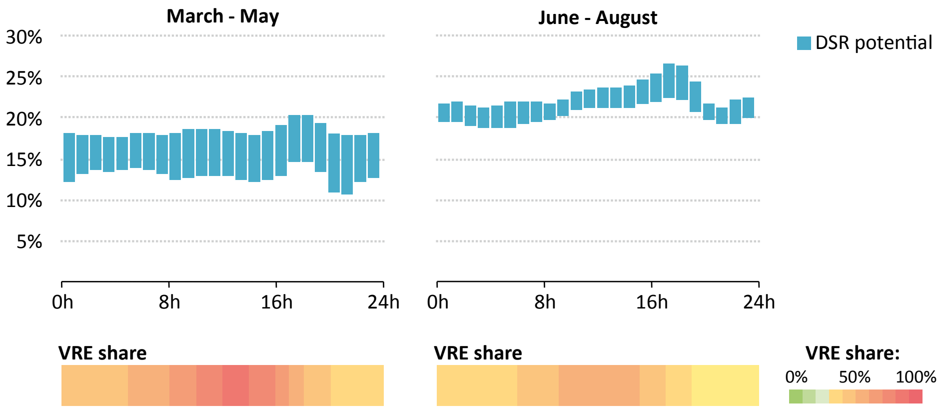
Electricity demand in the United States (including both demand met by utilities and own-use from distributed generators) is set to grow at a modest 0.5% per year, or around 500 TWh above 2014 levels by 2040 in the 450 Scenario. Energy efficiency measures in the industry and services sectors stabilise demand at current levels, while electricity demand in the residential sector declines, mainly thanks to the deployment of heat pumps and more efficient appliances, including air conditioning. Most of the growth of electricity demand comes from the strong uptake of electric vehicles in transport: they account for one-in-seven kWh consumed in the United States in 2040.

Within this level of total demand, several features are of particular significance to the discussion of the scope for demand-side measures to limit the need for VRE curtailment. The summer period offers the greatest scope for shifting demand to other time periods, due to the extensive use of cooling in US buildings. One-in-three cars in 2040 will be an EV and 40% of their electricity demand can be regarded as part of the demand-side response potential where measures could be implemented to influence load profiles. For example, if the vehicle charging is done after the business day, it would add to the evening peak load throughout the year and price signals or other approaches could be adopted to influence consumer behaviour. In total, the absolute technical potential for demand-side action increases from 2014 to 2040 in the 450 Scenario; but its share, as a proportion of the total load, decreases by one percentage point, to 18%, due to the growth in the use of small appliances that are difficult to integrate into DSR programmes. This total average potential is not constant throughout the day, however: 23% of the load during evenings in summer (July) could be shifted to other time periods, while only 16% of the total load could be shifted during mornings in spring (Figure 12.15).

As a contribution to meeting total electricity demand, renewables-based electricity generation more than quadruples by 2040, an increase of almost 2 000 TWh from 2014. Almost three-quarters of this growth come from wind and solar PV, whose combined share reaches 35% in 2040. This annual average conceals the major fluctuations in wind and solar PV over the course of the year: half of their annual generation is concentrated into one-third of the year (during which time they account for more than 50% of total generation); the other half is spread out over the remaining two-thirds of the year (when their contribution to total generation is only 26%).

In 2040, wind and solar PV capacity combined exceeds 675 GW, just short of the current installed capacity of coal and natural gas combined. Wind capacity reaches 350 GW and consists mainly of onshore installations, with offshore wind reaching 35 GW, or 10%, of total installed wind capacity in 2040. While utility-scale solar PV is set to grow in share of total PV capacity and reach 60% of overall PV capacity, solar PV in buildings sees an eleven-fold increase.

Figure 12.15 ▷ **Share of load that can be shifted for typical days in two seasonal periods in the United States in the 450 Scenario, 2040**



20-25% of the evening load in summer can be shifted to adjust the load profile, but only 15-20% in spring in the United States

Notes: The range represents the minimum and maximum hourly values of DSR potential within the typical days of the selected months. The colour scale represents the share of variable renewables electricity in the hourly demand ranging from green with the lowest share to red with the highest share of reliance on variable renewables and therefore the need to employ integration measures such as demand-side response.

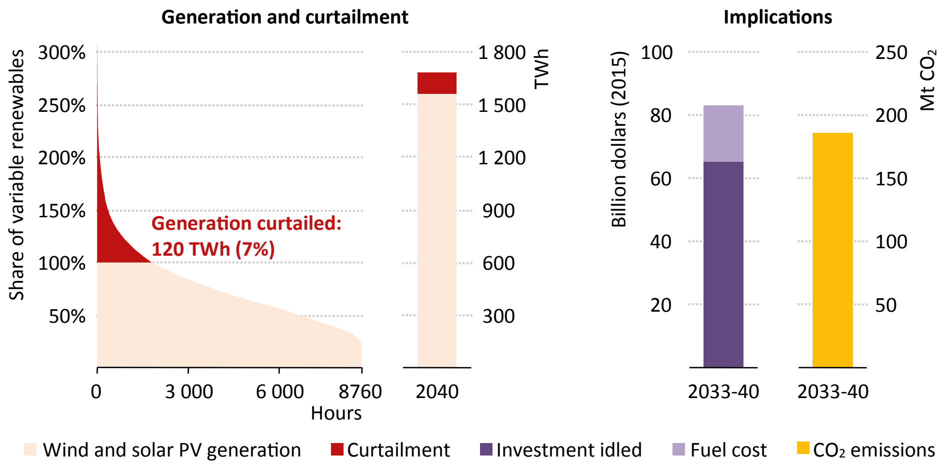
Source: IEA analysis.

In the 450 Scenario, dispatchable renewables, nuclear and CCS-fitted fossil-fuelled plants play a very important role in the adequacy of the system, adding to the flexibility of the existing gas fleet, much of which is relatively young and remains operational throughout the entire *Outlook*. The modest growth in electricity demand, due to the widespread use of energy-efficient technologies, reduces the need for new plants for adequacy and flexibility purposes.

By 2040, in the 450 Scenario, the grid is assumed to allow for balancing of VRE fluctuations throughout the whole of the United States, while VRE is deployed in a friendly manner (see section 12.2.1) throughout the country. Even under these conditions, and allowing for all of the flexibility in the system, excess generation from wind and solar PV, measured on an hourly basis, occurs for over 20% of the time (or the equivalent of two-and-a-half months in the year). This has the effect of setting power prices at near-zero or below, if no additional integration measures are put in place. Curtailment is quite small in summer, when there is relatively less wind and a good match between solar PV power generation and electricity demand. Conversely, it is highest in spring (when more than half of the curtailment occurs) as demand is relatively low, but there is quite high production of electricity from wind and solar PV. This is particularly so during periods of low demand such as early on a Sunday afternoon.

In the absence of DSR and storage measures, total curtailment in 2040 in the United States would reach around 120 TWh, or 7% of the overall combined generation of wind and solar PV. The maximum amount of curtailment, albeit only over a few hours, would reach about 300 GW, equivalent to around 40% of total installed variable renewables-based capacity. The curtailment becomes significant when VRE generation surpasses 28% of the electricity mix, which occurs as of 2033 in the 450 Scenario.[21] Curtailment of generation from the additional wind and solar PV capacity installed after this date (potentially generating around 470 TWh) would be as high as 25%, in the absence of additional integration measures.

Figure 12.16 ▷ Implications for fuel and investment costs, and CO_2 emissions from curtailing variable renewables generation without storage and DSR measures in the United States in the 450 Scenario, 2040



Without the additional DSR and storage measures deployed in the 450 Scenario, curtailment would waste \$65 billion of investment in wind and solar PV and incur an additional \$18 billion in fuel costs and 200 Mt of CO_2 emissions

Note: VRE output in each hour as a share of the supply needed (total demand less minimum operations from other power plants) for all hours of the year.

Source: WEM hourly model, IEA analysis.

In this case, the level of curtailment would be equivalent to total output from almost 20 GW of wind capacity and 30 GW of solar PV capacity, installed at a cost of \$65 billion, about one-quarter of the investment in new wind and solar PV capacity (excluding replacements) in the last eight years of the projection period. Moreover, curtailment of such low-carbon generation to this extent would have to be compensated by an equivalent amount of

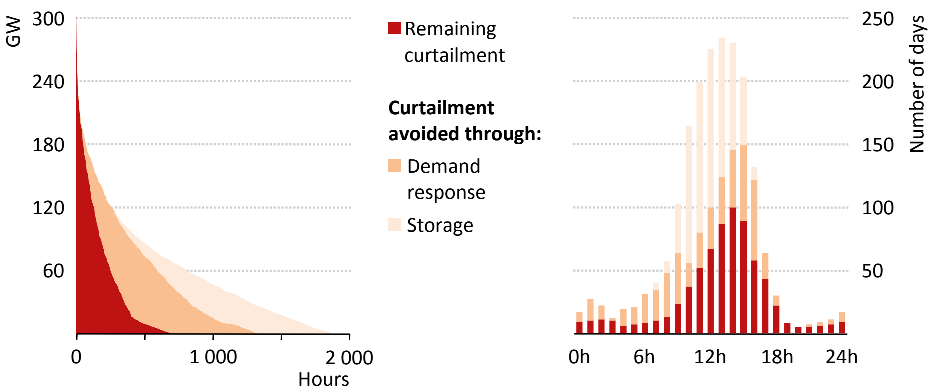
21. After 2033, new wind and solar PV additions see a curtailment of 10% or more of their generation.

generation from fossil fuels. In the United States, cumulatively over 2033-2040, almost 100 billion cubic metres (bcm) of gas, worth around $18 billion, would be burned, leading to almost 200 Mt of CO_2 emissions, or 7% of the cumulative emissions related to power generation in that period (Figure 12.16).

Implications of additional integration measures

Additional integration measures are very important to facilitate the projected deployment of VRE. Demand-side response options and storage play an important role. In the 450 Scenario, of the 120 TWh of VRE that otherwise would be curtailed, around two-thirds can provide power thanks to DSR measures (25%) and the use of storage (40%). Employing these measures reduce the curtailment level to 2.5% (Figure 12.17).

Figure 12.17 ▷ Change in curtailment levels with the use of DSR measures and storage in the United States in the 450 Scenario, 2040[22]



Demand-side response and storage technologies cut curtailment by around two-thirds in volume and number of hours

Source: WEM hourly model, IEA analysis.

In the 450 Scenario, demand-side response shows significant potential, at around 1 000 TWh in 2040. The amount available at a particular time varies according to the type of DSR measure: some can shift load for an hour or two while others can influence the load curve for longer; others may have seasonality. By employing additional DSR measures, about 30 TWh of curtailed output is eliminated by 2040. Most of them are the lowest cost measures, mainly affecting water and space heating in buildings. Yet, curtailment is pronounced in the spring when the scope for effective time shifting of load is not as flexible and many measures can shift load only for a few hours, while the curtailment during this season can persist over longer periods.

22. The sequence of implementation of flexibility options can influence the relative contribution to the reduction of curtailment.

Today more than 30 GW of storage capacity is installed in the United States, the vast majority of which is pumped hydro storage. Cost reductions in batteries, both large and small scale, bring a doubling of storage capacity, adding more than 30 GW of storage, including some small increases in pumped storage capacity. While cost reductions are essential to make batteries more cost-competitive, the establishment of the necessary technical, regulatory and market frameworks also needs to be carefully considered, to stimulate a wide array of solutions for a range of requirements. The economic viability of storage technologies hinges critically on price differentials between charging and discharging times. In a low-carbon system, low prices are probable at many times, with prices ranging between $0-30/MWh in 2040 in the United States in almost one-hour-out-of-four. The price differential sets the limit for economic deployment of storage to around 30 GW. By 2040, the use of storage technologies reduces the need for curtailment by almost 50 TWh, of which around 50% is related to existing storage capacity and the remainder to new storage capacity. The implementation of both DSR and storage measures reduces the amount of days with curtailment by around 60%, from 235 days in the year to around 100 days, reducing the total hours curtailed to less than 700 hours in the year.

12.3.2 European Union

Current status of flexibility

The adoption of integration measures is underway in many countries within the European Union. Power grid interconnections between countries have created a large synchronous frequency area, extending into the eastern parts of continental Europe. The capacity of these interconnections is equivalent to 11% of the installed generation capacity across the European Union (EU) countries (IEA, 2016). There is potential for further integration with neighbouring networks, such as those in the Baltic States and southeast Europe. Likewise, there is scope for the use of demand-side response to improve system management and boost flexibility of the grid.

Storage enhances flexibility and the European Union has pushed strongly for technical innovation through RD&D programmes, such as the Horizon 2020 Programme and the Strategic Energy Technology Plan (European Commission, 2016). Storage capacity is increasing, particularly in Germany. At utility level, large battery systems in Schwerin (5 MW) and Feldheim (10 MW) are already providing load-balancing services to the grid, while at consumer level, an estimated 27 000 small-scale energy storage units had been sold in Germany by the end of 2015, mostly together with rooftop solar PV for distributed generation (UNEP, 2016).

More can be done to tap the high potential of DSR in the European Union. For example, currently the implementation of time-of-use retail tariffs remains generally low and their form is diverse. They are often available only to industrial customers and not to households. In some countries, such as Italy and France, peak and off-peak tariffs are in place, but they are far from well-differentiated time-of-use pricing (with more than three different tariff periods) or real-time pricing. Nevertheless, there have been some significant developments in recent years. Given the success of using well-designed capacity markets and programmes to kick-start markets for demand response in the United States, some countries, such as the United Kingdom, France and Belgium, have begun to follow suit.

Curtailment in the 450 Scenario in the absence of additional integration measures

In the 450 Scenario, electricity demand in the European Union increases by less than 10% by 2040 from 2014 levels (around 250 TWh). Electricity demand from the industry sector decreases as increasing uptake of energy-efficient processes and technologies outweighs increased electrification in the sector. Demand in the buildings sector increases slightly, as electricity use in the services sector offsets a small decline in the residential sector. By the end of 2040, overall energy savings from energy efficiency measures are largely counterbalanced by the increased electrification of the road transport fleet: road transport electricity demand increases to 275 TWh from a very small level today.

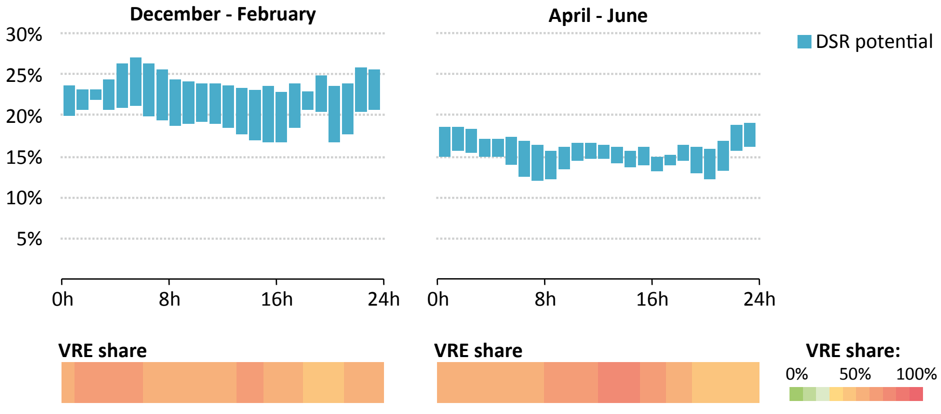
Energy efficiency through insulation and retrofits, and switching from electric resistance heating to heat pumps, play an important role in curbing electricity demand for heating. The share of electricity demand related to major appliances decreases, whereas the share of small appliances (e.g. computers, hair dryers), which are more difficult to include in DSR programmes, rises. With increasing electric vehicle sales and assuming a 40% of the fleet participation rate in demand-side response overall DSR potential in the European Union increases. The overall share of electricity demand that can be shifted in time remains, on average, around 20% of total annual demand.

The amount of load that can be shifted differs significantly according to the season and the time-of-day (Figure 12.18). Even with the high insulation levels reached in the 450 Scenario, the electrification of heat in buildings and industry represents a large potential, but it is concentrated in the winter months. In spring and fall, that are likely to have abundant VRE production (and possibly surplus), the need for heating and cooling is lower, limiting the potential of demand-side response.

To decarbonise the European power sector and to replace retiring fossil-fuel plants, by 2040 over 570 GW of wind and solar PV installations come online in the 450 Scenario. Renewables make up 63% of total electricity generation, reaching almost 2 100 TWh in 2040, more than twice the level of today. Among the suite of renewables for power generation, wind and solar PV account for about 60%, making the EU one of the regions with the largest combined share of wind and solar PV in total power generation.

By the end of the *Outlook* period, wind accounts for two-thirds of VRE capacity. Onshore wind capacity more than doubles from today. Offshore wind expands to more than 90 GW by 2040; the second-highest installed capacity after China. Strong growth in solar PV sees total installed capacity more than double by 2040 from today's levels. Although utility-scale capacity enjoys a faster rate of growth, solar PV capacity remains concentrated in the commercial and residential sectors, accounting for about 70% of total solar PV in Europe by 2040 – one of the highest shares in the world, alongside Japan and Australia.

Figure 12.18 ▷ **Share of load that can be shifted for typical days in two seasonal periods in the European Union in the 450 Scenario, 2040**



Up to a quarter of winter load can be shifted to adjust the load profile, but only 15% in spring in the European Union in 2040

Notes: The range represents the minimum and maximum hourly values of DSR potential within the typical days of the selected months. The colour scale represents the share of variable renewables electricity in the hourly demand ranging from green with the lowest share to red with the highest share of reliance on variable renewables and therefore the need to employ integration measures such as demand-side response.

Source: IEA analysis.

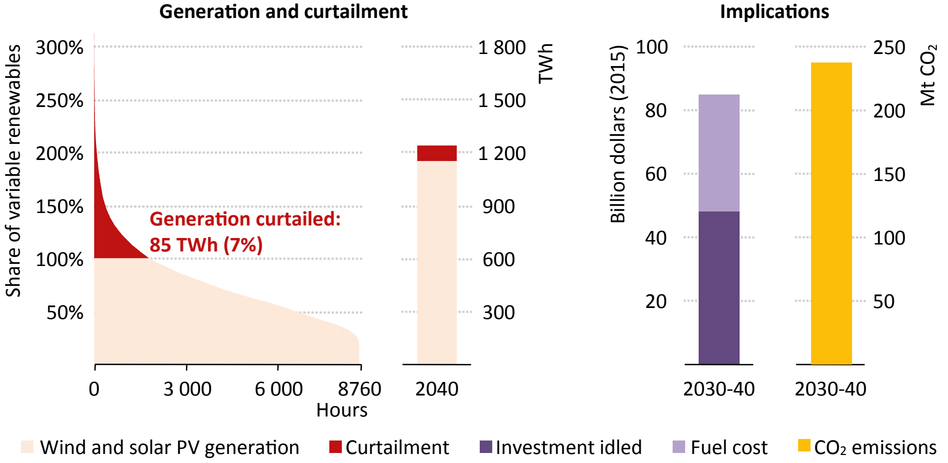
Improved interconnections within and between the balancing networks and deploying VRE in a friendly manner allows for a higher share of renewables to be integrated across the continent. In addition, about 50 GW of dispatchable renewables and 60 GW of flexible fossil-fuel plants (most of which are gas-fired) are expected to replace fossil-fuel plants that are retired after 2020 in order to maintain system adequacy. But, even under these conditions, with no further integration measures, wind and solar PV would be curtailed for almost 3 000 hours in 2040 – the equivalent of four consecutive months. Most of the curtailment occurs when the share of VRE production in total electricity generation increases beyond 27%, on average, across the continent. This level is already well surpassed today in Denmark (where interconnectors play a pivotal role) and comes close in other EU countries, such as Spain and Ireland.

The total curtailment in 2040, in the absence of additional integration measures, exceeds 85 TWh, which is equivalent to 6.9% of the combined generation from wind and solar PV. This share increases to almost 20% over the period 2030-2040.[23] The critical hours of curtailment are more widely distributed across the year than in the United States. Nonetheless, most of them occur on spring and summer weekends, at the end of the morning and during the afternoon.

23. Similar to the US case, the curtailment of the marginal unit beyond 2030 is above 10%.

This level of curtailment is equivalent to the total output of about 30 GW of wind and solar PV installations (70% wind and 30% solar PV), costing almost $50 billion, or over one-fifth of the investment in new wind and solar PV plants over the period 2030-2040 (excluding replacements of old units). This curtailed energy would mostly be replaced by natural gas-fired generation and would cumulatively require over 100 bcm of gas, costing about $35 billion over the period 2030-2040. An additional 240 Mt of CO_2 would be emitted, or 10% of the GHG emissions of all power generation in the same period (Figure 12.19).

Figure 12.19 ▷ Implications for fuel and investment costs, and CO_2 emissions from curtailing variable renewables generation without storage & DSR measures in the European Union in the 450 Scenario, 2040



Without the additional DSR and storage measures deployed in the 450 Scenario, curtailment would waste $50 billion of investment in wind and solar PV and incur an additional $35 billion in fuel costs and 240 Mt of CO_2 emissions

Note: VRE output in each hour as a share of the supply needed (total demand less minimum operations from other power plants) for all hours of the year.

Source: WEM hourly model, IEA analysis.

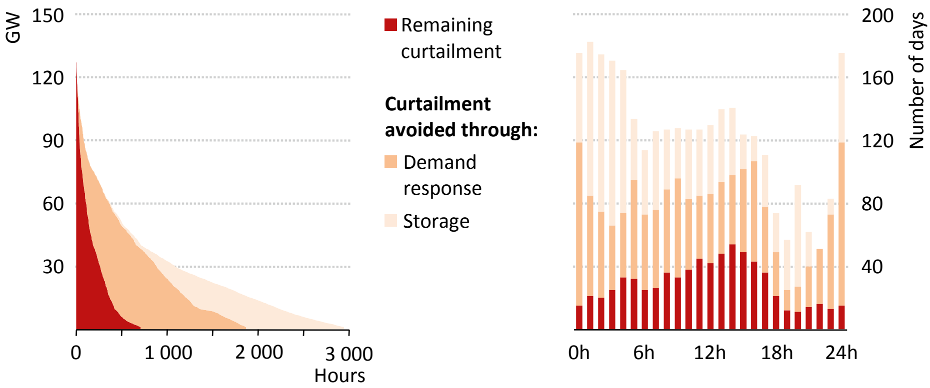
In the New Policies Scenario, the European Union also has a higher share of VRE (over 30% by 2040) in the power mix than any other country or region. Curtailment occurs in the New Policies Scenario too, but at a smaller scale, due to the lower scale of deployment of wind and solar PV and to the lower level of decarbonisation reached in the system. Overall curtailment reaches about 35 TWh in the absence of additional storage and DSR measures; however, it is almost entirely dealt with existing storage capacity – the cheapest DSR option – and deployment of batteries.

Implications of additional integration measures

The introduction of additional integration measures is therefore very important for wind and solar PV additional deployment. In the 450 Scenario, by 2040, storage technologies and

DSR measures can help to limit curtailment to 1.6% of total wind and solar PV generation (Figure 12.20). DSR plays an increasingly important role over time. In the 450 Scenario, the overall electricity demand of the European Union continues to peak in the evenings, with increased use of energy for household appliances, and EV charging. The increased adoption of smart grid technologies and the use of time-of-use pricing can help shift the use of electricity for household appliances to periods of lower demand or to periods that coincide with high generation from wind and solar PV plants. For example, smart washing machines could be programmed to start in the afternoon, when the share of solar PV output is much higher. Load control programmes that allow for the cycling of heating units, air conditioners and water heaters during periods of peak demand, coupled with an increased deployment of energy-efficient buildings technologies (e.g. better insulation) can achieve significant load shifts. By 2040, the implementation of these measures reduces the curtailment by some 22 TWh, or more than a quarter.

Figure 12.20 ▷ Change in curtailment levels with the use of DSR measures and storage in the European Union in the 450 Scenario, 2040



Demand-side response and storage technologies cut curtailment by around three-quarters in volume and number of hours

Source: WEM hourly model, IEA analysis.

A further 45 TWh can be saved through energy storage by 2040. Currently, about 45 GW of pumped hydro storage exists in the European Union, the second-highest capacity in percentage terms, relative to total capacity, after Japan. Benefiting from cost reductions from increased penetration of EVs, the growth of both large- and small-scale batteries will provide most of the increased storage, which reaches almost 70 GW by 2040 (including pumped hydro storage). As elsewhere, the price differential between charging and discharging times is a key element for the economic deployment of storage technologies. The very high carbon price seen by 2040 in the 450 Scenario and the large deployment of low-carbon technologies, bring prices to surpass \$100/MWh in several hours and to below \$30 per MWh for more than 40% of the year, thereby stimulating the implementation of new storage capacities due to the possibilities of price arbitrage. The implementation of DSR and storage reduces the occurrence of curtailment from 330 days to below 90 days, and to just above 700 hours in the year.

12.3.3 India

Current status of flexibility

Power demand in India is set to increase robustly over the *Outlook* period in all scenarios, propelled by gross domestic production (GDP) growing five-fold, population growth that makes India the world's most populous country by the mid-2020s and a rapid alleviation of energy poverty (currently some 245 million people lack access to electricity). The power system in India thus faces challenges that are distinctly different from those in the United States or the European Union. Strong electricity demand implies that most of the capacity operating in 2040 is yet to be built. This presents the formidable challenge of mobilising sufficient capital for a rapid expansion of generation capacity; but it also brings the advantage that shrewd and forward-looking policymaking can shape the power system to meet the full range of future needs. Relevant considerations include the strategic location of dispatchable plants to minimise network expansion and the importance of the flexibility of the new stations.

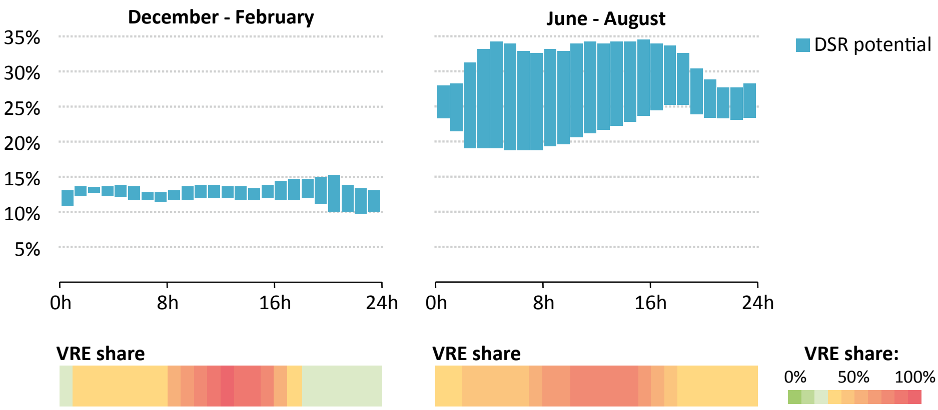
As a means of alleviating electricity shortages, India made a start in 2010 on regulations to facilitate demand response, defined as "a reduction in electricity usage by end customers in response to congestion charges for which such consumers could be given a financial incentive or lower tariff". In 2013, the Ministry of Power released the *Smart Grid Vision and Roadmap for India*. Its goal is to transform the entire Indian power system into a smart grid over the next decade. The roadmap set ambitious objectives, including improving the efficiency of the grid, electrifying 100% of households by 2022, mandating demand response for selected categories of consumers, developing 100 smart cities, implementing dynamic tariffs, encouraging customers to become producers, and developing and diffusing indigenously produced smart meters (see Chapter 2.8).

Curtailment in the 450 Scenario in the absence of additional integration measures

The outlook for India is dramatically different from that of the United States or the European Union, as total electricity demand almost triples by 2040 in the 450 Scenario, with over 70% of the growth coming from the residential and industry sectors (the two sectors contribute almost equally), while the transport sector sees the highest rate of growth. Today, the electricity load profile over the course of a typical day is relatively flat in India with load usually peaking in the evening hours as residential power consumption spikes. The shape of the daily load profile is projected to change over time, featuring more distinct load swings. However, the system in India is expected to remain an evening peaking system, as increasing incomes allow a growing number of households to benefit from the amenities of electric appliances and reliable power supply. Higher income levels and electrification lead, in particular, to higher ownership of cooling systems and appliances. The use of air conditioning in office buildings, shops and factories also becomes more widespread, which results in an upswing of load over the course of the morning and a downswing in the early evening before the later peak.

Even with the higher efficiency levels assumed in the 450 Scenario, electricity demand for appliances and for cooling more than quadruples. The higher share of the buildings and transport sectors in overall electricity demand gives rise to more potential for demand-side measures, increasing both the absolute potential and lifting its share, relative to overall electricity demand, from 14% to 18%. High temperatures from May to August increase the use of cooling systems (Figure 12.21). Based on recent guidelines for new residential buildings and the energy efficiency elements of building codes for public buildings, it is projected that a reasonable share of the cooling demand can be shifted in time during the summer season due to the higher thermal inertia of new buildings by 2040. In winter, due to relatively low space heating demand, the DSR potential is only between 10-15%. The increasing supply of solar PV does not occur during the peak load and consequently reduces the flexibility of the system during daytime. This is the period that DSR programmes should focus, such as EVs charging.

Figure 12.21 ▹ Share of load that can be shifted for typical days in two seasonal periods in India in the 450 Scenario, 2040



Almost a third of electricity demand in India could be shifted in summer, but only between 10-15% in winter

Notes: The range represents the minimum and maximum hourly values of DSR potential within the typical days of the selected months. The colour scale represents the share of variable renewables electricity in the hourly demand ranging from green with the lowest share to red with the highest share of reliance on variable renewables and therefore the need to employ integration measures such as demand-side response.

Source: IEA analysis.

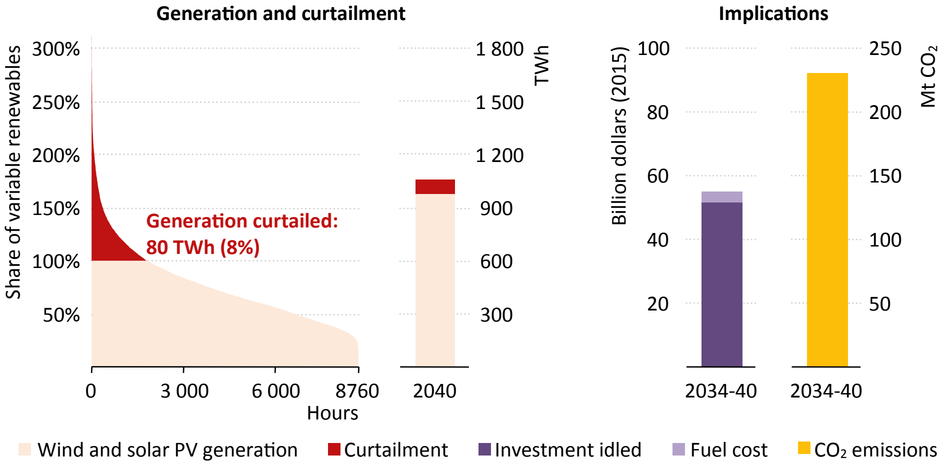
Variable renewable power generation capacity tops 555 GW in 2040, of which solar PV makes up nearly 310 GW. Underpinned by ambitious deployment targets, solar PV installations ramp up quickly and, by 2035, solar PV becomes the number one source of generating capacity, overtaking coal. The government has announced its intention to have 100 GW of solar PV installed by 2022. This target sets the trend in our 450 Scenario. So far, policy support has been geared primarily towards utility-scale PV facilities, for instance via the National Solar Mission that fosters the creation of large solar parks. Thus, rooftop PV capacity accounts for only around 10% of India's total PV capacity today; but this share is set to increase to more than 35% in 2040, with some 110 GW installed. As in most countries, wind power development is mainly land-based with less than 10% of India's wind capacity being offshore by 2040.

The transformation of the power system in India has profound implications for fossil-fuelled power plants. By the end of the *Outlook* period, the share of unabated coal-fired generation is projected to have dropped to below 10%, down from 75% in 2014. In the period to 2040, some 130 GW of fossil-fuelled capacity is retired (about half of which is decommissioned prematurely). However, 190 GW of fossil-fuelled capacity is added after 2020 to ensure system adequacy. About 55% of this capacity is natural gas-fired, such plants having the advantages of low capital cost and the ability to ramp up and down rapidly to provide system flexibility. The coal plants that remain follow a new operational pattern, unlike that of today, which is characterised by load-following and frequent start-ups.

The T&D grid is one of the weakest links in India's power system today. Reducing the huge technical and commercial losses currently experienced is a policy priority. Although India has recently made progress in interconnecting its five network zones in order to establish a nationwide grid, the transmission grid and the interconnections remain too weak to handle the large-scale build-up of variable renewables proposed in the 450 Scenario. This scenario therefore assumes that further action is taken to strengthen India's T&D network, while recognising that the boost to distributed generation can help reduce the strain on the transmission grid. Integrating variable renewables requires additional grid investment of almost $90 billion over the coming 25 years. At around 10%, this is only a fraction of the total network investment, which includes modernisation and replacement of lines, as well as reinforcing the interconnections needed over the *Outlook* period. Investors are taking advantage of India's geography when installing wind and solar PV parks: the combination of a well interconnected network and shrewd locational planning for new installations can help smooth the generation profile of variable renewables across the country. In this context, deployment of system-friendly renewables, e.g. low-speed wind turbines or planning the coupling of solar PV with air conditioning, makes an increasingly important contribution to the integration of these technologies.

By 2040, renewables account for 57% of power generation in India in the 450 Scenario. Large contributions come from wind and solar PV, each accounting for 15% of the country's electricity output in 2040. For the reasons discussed in the other regions studied, the output from wind and power plants will, at certain times of the day or days in the year, exceed the maximum demand on the system. In 2040, the 555 GW of combined wind and solar PV capacity exceed the country's average demand by 40%. Although, due to the size of the country – and hence the difference in regional weather conditions – it is extremely unlikely that all wind turbines and PV modules will generate electricity at full capacity at the same time, there are still about 1 800 hours per year (around two-and-a-half months) when generation from wind and solar will be curtailed, were it not for the additional DSR measures and the deployment of new storage facilities built into the 450 Scenario projections. All of the curtailment in India would take place during daylight, concentrated during winter days and parts of the spring, while the curtailment would be very limited during summer, when production from solar PV matches well the demand for air conditioning.

Figure 12.22 ▷ Implications for fuel and investment costs, and CO_2 emissions from curtailing variable renewables generation without storage and DSR measures in India in the 450 Scenario, 2040



Without the additional DSR and storage measures deployed in the 450 Scenario, curtailment would waste \$50 billion of investment in wind and solar PV and incur an additional \$3 billion in fuel costs and 230 Mt of CO_2 emissions

Note: VRE output in each hour as a share of the supply needed (total demand less minimum operations from other power plants), for all hours of the year.

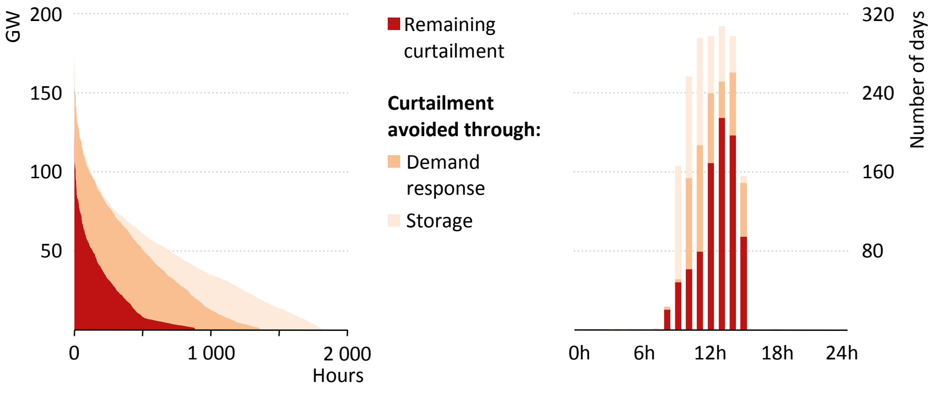
Source: WEM hourly model, IEA analysis.

In the 450 Scenario, significant curtailment of output from the new wind and solar PV projects actually occurs only during the last years of the projection period, when the share of VRE increases beyond 28%. From 2034 to the end of the projection period, over one-quarter of the generation from solar PV and wind plants added after 2034 is curtailed to an extent corresponding to the generation from about 10 GW of wind and 35 GW of solar PV. This represents an investment of more than \$50 billion, or almost one-third of the investment in all new wind and solar PV installations (excluding replacements) after 2034. Curtailing this generation and not using it to meet demand at other times of the year results in a need to burn fossil fuels (mainly coal) in its place, at a cost of $3 billion and adding 230 Mt of CO_2 emissions – 5% of the cumulative emissions from power generation over 2034-2040 (Figure 12.22).

Implications of additional integration measures

Strengthening power system interconnections across the sub-continent, deploying system-friendly VRE and taking advantage of flexible power plants (with hydropower playing an important role in the mix) all help India to reach the much higher shares of VRE in the 450 Scenario; but achieving those levels requires additional system integration measures. Demand-side response (e.g. shifting the timing of demand) and deployment of storage technologies both play a critical role in making productive use of surplus VRE power generation and together help to reduce curtailment by three-quarters (Figure 12.23). The scope for DSR measures is, however, somewhat constrained by the large share of solar PV in the system (India reaches one of the highest levels in the world by 2040): most load shifting potential is only for short periods (e.g. making use of the thermal inertia of buildings to interrupt or reduce cooling for a few hours).[24] But surplus generation in India often occurs over several consecutive hours during the day in winter and parts of spring, with relatively lower demand. Also, the potential to shift loads over longer periods (i.e. more than eight hours) is larger in the United States and in the European Union, due to their higher share of electric water heating (which can be used as a storage device).

Figure 12.23 ▷ Change in curtailment levels with the use of DSR measures and storage in India in the 450 Scenario, 2040



Demand-side response and storage technologies cut curtailment by around three-quarters in volume and the number of hours by half

Source: WEM hourly model, IEA analysis.

24. Additional potential could come from the use of thermal energy storage in air conditioning (AC) systems. For example, in periods of high VRE production, electricity could be used to produce ice and then re-injected in the AC system.

Successful demand-side response measures rely to a large degree on the penetration of smart meters. India's weak metering infrastructure can be turned into an opportunity to roll-out smart metering technology: efforts to bring down commercial losses in the power system will involve the installation of meters, while an additional 570 million electricity consumers will need to be equipped with meters, too.

About 5 GW of pumped hydro storage are currently operational in India's power system. Although this figure is projected to grow to around 20 GW in 2040, there remains in the 450 Scenario, a gap of 10 GW between pumped storage capacity and the total storage capacity needed. As in other regions, for storage to be profitable, a sufficiently large price differential between the charging and discharging times is needed (the price difference needs to cover the technical losses and investment cost of the storage). The expected evolution in India of the typical daily electricity price reflects the high share of solar PV in the system and broadly follows two phases: during daylight hours, in 2040 prices are low – typically below $30/MWh – as output from solar PV plants is high and few other plants are needed to serve demand. In the evening and during the night, prices surge, as output from PV plants dwindles to zero and fossil-fuelled generators ramp up. This price differential is reduced by the gradual introduction of storage technologies, setting a limit to their deployment. The implementation of both DSR measures and storage in India reduces the frequency of curtailment; the amount of hours in which curtailment occurs is halved to just below 900 hours and shift from almost a daily occurrence to instances in less than 270 days.

12.4 Policy and market framework

Policies, rules and regulations governing electricity markets are primarily set up with the aim of ensuring electricity security (including fuel security) and reliable system operations. They also aim to ensure the economic efficiency of the electricity supply and investment in new capacity (in order to meet demand at all times). Reaching environmental goals e.g. CO_2 and pollutant emissions reductions has become increasingly important and relevant for market designs.

These objectives hold true for vertically integrated monopolies, as for competitive markets, which are increasingly being used around the world as a tool to increase efficiency through the use of wholesale markets (Joskow, 2008; IEA, 2016). However, very few power systems or market frameworks have been designed with variable generation in mind. As variable renewable energy (VRE) is set to become an increasingly important part of the set of low-carbon power generation options in many countries, networks need to continue to evolve to ensure they are compatible with the deployment of VRE. While initial deployment of VRE capacities poses no significant challenges, as long as a few key principles are being followed, increasing shares of VRE, as projected in the 450 Scenario, require policy and market design change (IEA, 2014).

Means need to be found to secure investment in a range of assets, including flexible power plants (both renewables and thermal) but also, increasingly, in storage and demand response, as well as in T&D networks. With the development of distributed resources such as rooftop solar PV, small-scale batteries and more active customers, price signals are, often, the most efficient way to activate responses in the market. Providing efficient price signals, in markets which capture all aspects of system value, becomes a priority. Three steps towards this objective include:

- Unlock the flexibility in the existing power system.
- Prioritise VRE projects that are of high value to the power system (including integration aspects) as a means of minimising the scale of the integration challenge.
- Enable new investments needed to increase flexibility and ensure market participation.

12.4.1 Unlock the flexibility in the existing power system

Existing power systems already cope with volatile demand and with planned and unplanned outages. Current systems therefore already have considerable flexibility, which can often be increased in order to accommodate the variability associated with growing shares of wind and solar power. Competitive wholesale markets provide a good starting point for tapping the flexibility potential of existing systems, through changes in short-term electricity prices. Prices rise when electricity is scarce as a result of shortage of capacity or fall when electricity is abundant. In situations of capacity shortage, peak prices provide incentives to generators to make capacity available when electricity is most needed and allow them to recover the costs of capacity rarely used. Conversely, in situations of abundant generation, for example when there is a lot of VRE generation but relatively little demand, prices can be very low or even zero, providing signals to the market to shift consumption out of these hours or store electricity.

Market prices can also reward flexible power plants for their ability to vary their output rapidly. When electricity demand or VRE generation changes rapidly, capacity on the system can become constrained due to these fast variations. Market prices can reward flexible power plants for their ability to respond quickly to the system needs during these times. While some competitive wholesale markets have successfully introduced means to reward flexibility, several markets will need to develop these arrangements further. Cross-border trade is still not used optimally in this respect. Price signals are a no-regret option for any power system, but will be even more important with increasing shares of VRE.

One important step in this process is to use VRE generation forecasts effectively, in order to integrate VRE in an economically efficient manner. Forecasts are more accurate for a few hours ahead of operation than for several days in advance. Committing units at a market price close to the time of operation allows increasingly optimal contributions by all flexible sources (generation and demand). Another increasingly important dimension is to provide price signals with a high geographical resolution, to convey to generators where electricity is abundant, compared to demand and network capacity. In short, the market should seek to reflect the value of electricity by time and location in order to provide investment and operational signals.

12.4.2 Prioritise VRE projects that are of high value to the power system

With improved systems operations and a working market providing clear price signals, ensuring the future deployment of VRE is in line with market principles is the next priority. Deploying VRE only on a least unit cost basis, without taking into account their value in the system (e.g. without including locational benefits), can lead to increased integration costs. Putting in place an adequate carbon price can help determine the appropriate value across the various technologies. But introducing a sufficient carbon price often takes time and the energy transition is urgent. Given the generally low level of electricity market prices today and the consequent caution about financing new investments, support mechanisms (such as long-term arrangements backed by governments) often remain necessary to attract sufficient levels of low-carbon power generation, at least during the transition period. When a carbon price cannot be put in place at a sufficient level and in a short timeframe, the design of these support policies becomes essential and demands great care. If they too strongly insulate VRE investors from price signals, there can be potentially adverse effects for the functioning of the power market, such as VRE generation at negative electricity prices, instead of curtailment. If electricity prices are not factored in by investors, they might not consider the optimal location for VRE plants or the optimal technology to deploy.

There are many ways to ensure that generation investors are made fully subject to relevant market price signals. Introducing RE certificates or providing feed-in premiums are two possible examples, both creating an additional revenue stream for the VRE generator, on top of the market price. In both these examples, the price signal influences the investor, ultimately incentivising innovation in technology design, location of new projects and operation in a manner consistent with the value of electricity for the system, and ultimately reducing the need for additional flexibility. Projects developed to participate in such markets (as opposed to fixed contracts or other guaranteed revenue mechanisms, such as feed-in tariffs), expose investors to another variable income stream, involving greater market risk. There needs to be a trade-off between risk sharing and system-friendly deployment of VRE. Balancing the two objectives is possible, but may require more complex subsidy scheme structures (IEA, 2016).

12.4.3 Enable new investments needed to increase flexibility and ensure market participation

Market design will play an important role in facilitating investments in the efficient mix of resources needed to ensure adequate flexibility. For instance, the business case for energy storage is to buy electricity in hours at which it is cheap and sell it in hours at which it is expensive, providing ancillary services to balance demand and generation. Wholesale markets and system operators should encourage the providers of such services, where this is not yet the case. Similarly, demand response, which can be developed through the dynamic pricing of electricity, can also be facilitated if demand-response aggregators can participate explicitly in wholesale markets.

Investment in new dispatchable (often fossil-fuelled) power plants to ensure capacity adequacy will also be needed in many power systems. With increasing shares of VRE, these dispatchable plants can count on only a limited number of running hours, which can result in lower revenues and introduces additional uncertainty that the return on investment will be positive. Many markets are therefore using, or considering, targeted capacity mechanisms in one form or another as they create an additional revenue stream for investors. Such mechanisms, if adopted, have widespread impacts on the system and need to be well-designed to avoid adverse effects on the functioning of the power market.

As the share of VRE generation increases in the system, it also becomes important to allow VRE generators as well as energy storage providers and demand-response aggregators to participate in balancing and capacity markets and in so-called system service markets. System services include frequency response, reactive power supply and voltage support, and, if the requirements for power plants allowed to deliver such services are too stringent, they can be an obstacle to VRE market participation. As well, it is important to co-ordinate the planning of T&D networks developments with VRE deployment, as low-cost VRE generation areas (such as very windy areas) are valuable only if they can be connected to the grid at a reasonable cost. Where network investments and VRE deployment are inadequately co-ordinated, more congestion can be expected in the future. To avoid this, preferred development zones should be identified as part of integrated planning processes. This process will require co-operation between parties who may not be accustomed to working together.

Improving market operations, setting appropriate incentives to deploy VRE in a system-friendly manner and ensuring that investments in new flexibility-providing assets will be forthcoming, are all measures needed to facilitate the maximum effective integration of variable renewables. Despite the cost reductions being achieved in VRE, the role of government is far from being over if VRE is to be deployed at levels consistent with achieving an average global temperature of no more than 2 degrees Celsius.

ANNEXES

World Energy Outlook links

General information: ***www.worldenergyoutlook.org***

Model

Documentation and methodology
www.worldenergyoutlook.org/weomodel/documentation/

Investment costs
www.worldenergyoutlook.org/weomodel/investmentcosts/

Policy databases
www.worldenergyoutlook.org/weomodel/policydatabases/

Topics

Energy access
www.worldenergyoutlook.org/resources/energydevelopment/

Energy subsidies
www.worldenergyoutlook.org/resources/energysubsidies/

Unconventional gas forum
www.iea.org/ugforum/

Water-energy nexus
www.worldenergyoutlook.org/resources/water-energynexus/

Recent special reports

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www.worldenergyoutlook.org/airpollution/

Energy and Climate Change
www.worldenergyoutlook.org/energyclimate/

India Energy Outlook
www.worldenergyoutlook.org/india/

Mexico Energy Outlook
www.worldenergyoutlook.org/mexico/

Tables for Scenario Projections

1. General note to the tables

The tables detail projections for *fossil-fuel production, energy demand, gross electricity generation* and *electrical capacity*, and *carbon-dioxide* (*CO_2*) *emissions* from fossil-fuel combustion in the New Policies, Current Policies and 450 Scenarios. Please see the preceding page for download details of these tables. The following regions are covered: World, OECD, OECD Americas, the United States, OECD Europe, the European Union, OECD Asia Oceania, Japan, non-OECD, Eastern Europe/Eurasia, Russia, non-OECD Asia, China, India, the Middle East, Africa, South Africa, Latin America and Brazil. The definitions for regions, fuels and sectors can be found in Annex C. By convention, in the table headings CPS and 450 refers to the Current Policies and 450 Scenarios respectively.

Data for *fossil-fuel production, energy demand, gross electricity generation* and *CO_2 emissions* from fuel combustion up to 2014 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 2016 version) and the International Atomic Energy Agency PRIS database (*www.iaea.org/pris*).

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 "-".

2. Definitional note to the 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. Using the 2006 IPCC guidelines, instead of the older 1996 guidelines, has led to a change in the definition and absolute levels of CO_2 emissions from fossil-fuel combustion since *WEO-2015* compared with previous *WEO* editions. For more information please visit: *www.iea.org/statistics/topics/CO2emissions*.

New Policies Scenario

	Production							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Oil production and supply (mb/d)										
OECD	**18.9**	**22.8**	**25.3**	**26.1**	**26.2**	**26.1**	**25.4**	**25**	**25**	**0.4**
Americas	13.9	18.9	21.5	22.5	22.8	22.8	22.3	21	22	0.6
Europe	4.3	3.3	3.2	3.0	2.7	2.5	2.2	4	2	-1.5
Asia Oceania	0.7	0.5	0.6	0.6	0.7	0.8	0.9	1	1	1.9
Non-OECD	**46.5**	**66.8**	**68.2**	**69.6**	**70.8**	**72.8**	**75.1**	**75**	**75**	**0.4**
E. Europe/Eurasia	11.6	14.1	14.2	14.0	13.6	13.1	12.1	16	12	-0.6
Asia	6.1	7.9	7.2	6.8	6.5	6.3	6.1	9	6	-1.0
Middle East	17.7	28.6	31.6	33.5	34.6	36.2	38.0	32	38	1.1
Africa	6.7	8.6	7.5	7.6	8.2	8.4	8.8	10	9	0.1
Latin America	4.5	7.7	7.6	7.6	8.0	8.8	10.0	9	10	1.0
World oil production	**65.5**	**89.6**	**93.5**	**95.7**	**97.1**	**98.9**	**100.5**	**100**	**100**	**0.4**
Crude oil	58.5	67.2	66.4	65.5	64.5	64.0	64.5	73	62	-0.2
Natural gas liquids	6.6	14.8	16.6	18.0	19.2	20.2	20.6	16	20	1.3
Unconventional oil	0.3	7.6	10.5	12.1	13.4	14.7	15.3	8	15	2.8
Processing gains	1.3	2.2	2.4	2.5	2.7	2.9	3.0	2	3	1.2
World oil supply	**66.8**	**91.8**	**95.9**	**98.2**	**99.8**	**101.7**	**103.5**	**98**	**96**	**0.5**
World biofuels supply	0.1	1.6	2.0	2.5	3.0	3.6	4.2	2	4	3.9
World liquids supply	**66.9**	**93.4**	**97.9**	**100.8**	**102.8**	**105.3**	**107.7**	**100**	**100**	**0.6**
Natural gas production (bcm)										
OECD	**882**	**1 270**	**1 409**	**1 434**	**1 485**	**1 558**	**1 618**	**36**	**31**	**0.9**
Americas	643	939	1 046	1 070	1 121	1 187	1 239	27	24	1.1
Europe	211	260	220	205	194	184	178	7	3	-1.4
Asia Oceania	28	71	143	159	170	186	201	2	4	4.1
Non-OECD	**1 191**	**2 267**	**2 393**	**2 672**	**2 981**	**3 300**	**3 600**	**64**	**69**	**1.8**
E. Europe/Eurasia	831	858	879	949	1 020	1 095	1 145	24	22	1.1
Asia	132	460	494	545	619	686	756	13	14	1.9
Middle East	95	559	613	706	784	865	955	16	18	2.1
Africa	73	214	230	282	341	395	447	6	9	2.9
Latin America	60	176	178	190	218	258	297	5	6	2.0
World	**2 073**	**3 536**	**3 802**	**4 106**	**4 466**	**4 858**	**5 219**	**100**	**100**	**1.5**
Unconventional gas	*79*	*701*	*956*	*1 140*	*1 334*	*1 530*	*1 704*	*20*	*33*	*3.5*
Coal production (Mtce)										
OECD	**1 533**	**1 395**	**1 205**	**1 116**	**1 055**	**986**	**959**	**25**	**16**	**-1.4**
Americas	836	757	611	555	515	464	428	13	7	-2.2
Europe	526	225	168	132	95	71	62	4	1	-4.9
Asia Oceania	171	412	427	429	445	450	469	7	8	0.5
Non-OECD	**1 645**	**4 286**	**4 374**	**4 535**	**4 715**	**4 872**	**4 956**	**75**	**84**	**0.6**
E. Europe/Eurasia	533	423	416	422	430	431	431	7	7	0.1
Asia	936	3 549	3 647	3 797	3 954	4 097	4 149	62	70	0.6
Middle East	1	1	1	1	1	1	1	0	0	1.0
Africa	150	224	227	233	248	261	293	4	5	1.0
Latin America	25	88	84	82	82	82	82	2	1	-0.3
World	**3 178**	**5 680**	**5 580**	**5 650**	**5 771**	**5 858**	**5 915**	**100**	**100**	**0.2**
Steam coal	*2 216*	*4 374*	*4 285*	*4 392*	*4 560*	*4 704*	*4 812*	*77*	*81*	*0.4*
Coking coal	*567*	*1 016*	*997*	*979*	*950*	*905*	*861*	*18*	*15*	*-0.6*

Current Policies and 450 Scenarios

	Production						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Oil production and supply (mb/d)										
OECD	**25.8**	**28.0**	**28.3**	**24.6**	**22.1**	**16.2**	**25**	**23**	**0.8**	**-1.3**
Americas	22.0	24.3	24.8	20.9	19.1	14.0	22	20	1.0	-1.1
Europe	3.3	2.9	2.5	3.2	2.4	1.5	2	2	-1.1	-2.9
Asia Oceania	0.6	0.8	1.0	0.5	0.6	0.7	1	1	2.5	0.8
Non-OECD	**69.2**	**75.8**	**85.2**	**66.4**	**60.0**	**54.8**	**75**	**77**	**0.9**	**-0.8**
E. Europe/Eurasia	14.4	14.3	13.1	13.8	11.6	9.6	12	13	-0.3	-1.5
Asia	7.4	7.0	7.2	7.0	5.3	4.3	6	6	-0.4	-2.4
Middle East	31.9	36.6	42.4	30.8	30.4	29.0	37	41	1.5	0.1
Africa	7.7	9.1	10.5	7.3	6.5	5.8	9	8	0.8	-1.5
Latin America	7.7	8.8	12.1	7.4	6.3	6.2	11	9	1.7	-0.8
World oil production	**95.0**	**103.9**	**113.6**	**91.0**	**82.0**	**71.1**	**100**	**100**	**0.9**	**-0.9**
Crude oil	67.2	69.0	73.1	64.6	54.6	47.3	62	65	0.3	-1.3
Natural gas liquids	17.1	20.1	21.9	16.1	16.2	14.5	19	20	1.5	-0.1
Unconventional oil	10.7	14.8	18.6	10.3	11.2	9.2	16	13	3.5	0.8
Processing gains	2.4	2.9	3.4	2.3	2.3	2.2	3	3	1.7	-0.1
World oil supply	**97.4**	**106.8**	**117.0**	**93.3**	**84.3**	**73.2**	**97**	**90**	**0.9**	**-0.9**
World biofuels supply	1.9	2.5	3.6	2.1	5.7	9.0	3	11	3.2	7.0
World liquids supply	**99.3**	**109.3**	**120.6**	**95.4**	**90.0**	**82.2**	**100**	**100**	**1.0**	**-0.5**
Natural gas production (bcm)										
OECD	**1 440**	**1 581**	**1 760**	**1 412**	**1 360**	**1 160**	**31**	**29**	**1.3**	**-0.3**
Americas	1 069	1 201	1 341	1 044	1 011	827	23	21	1.4	-0.5
Europe	224	202	196	223	192	169	3	4	-1.1	-1.6
Asia Oceania	147	178	222	145	157	163	4	4	4.5	3.2
Non-OECD	**2 425**	**3 145**	**3 953**	**2 383**	**2 702**	**2 848**	**69**	**71**	**2.2**	**0.9**
E. Europe/Eurasia	905	1 108	1 321	877	957	952	23	24	1.7	0.4
Asia	493	632	802	493	616	742	14	19	2.2	1.9
Middle East	620	813	994	606	664	663	17	17	2.2	0.7
Africa	230	354	481	230	284	306	8	8	3.2	1.4
Latin America	178	237	355	178	181	185	6	5	2.7	0.2
World	**3 865**	**4 726**	**5 713**	**3 795**	**4 062**	**4 008**	**100**	**100**	**1.9**	**0.5**
Unconventional gas	*970*	*1 407*	*1 885*	*941*	*1 190*	*1 239*	*33*	*31*	*3.9*	*2.2*
Coal production (Mtce)										
OECD	**1 271**	**1 300**	**1 352**	**1 008**	**588**	**432**	**18**	**15**	**-0.1**	**-4.4**
Americas	630	590	570	462	195	124	7	4	-1.1	-6.7
Europe	179	132	115	154	58	24	2	1	-2.5	-8.2
Asia Oceania	462	578	666	392	335	284	9	10	1.9	-1.4
Non-OECD	**4 517**	**5 429**	**6 258**	**4 166**	**3 197**	**2 425**	**82**	**85**	**1.5**	**-2.2**
E. Europe/Eurasia	425	487	533	376	268	199	7	7	0.9	-2.9
Asia	3 763	4 536	5 234	3 503	2 678	2 015	69	70	1.5	-2.2
Middle East	1	1	1	1	1	1	0	0	1.2	-1.0
Africa	236	297	379	211	181	159	5	6	2.0	-1.3
Latin America	91	108	111	75	70	53	1	2	0.9	-2.0
World	**5 788**	**6 729**	**7 610**	**5 174**	**3 786**	**2 858**	**100**	**100**	**1.1**	**-2.6**
Steam coal	*4 474*	*5 418*	*6 356*	*3 940*	*2 822*	*2 100*	*84*	*73*	*1.4*	*-2.8*
Coking coal	*1 008*	*991*	*929*	*970*	*815*	*639*	*12*	*22*	*-0.3*	*-1.8*

World: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**8 774**	**13 684**	**14 576**	**15 340**	**16 185**	**17 057**	**17 866**	**100**	**100**	**1.0**
Coal	2 220	3 926	3 906	3 955	4 039	4 101	4 140	29	23	0.2
Oil	3 237	4 266	4 474	4 577	4 630	4 708	4 775	31	27	0.4
Gas	1 663	2 893	3 141	3 390	3 686	4 011	4 313	21	24	1.5
Nuclear	526	662	796	888	1 003	1 096	1 181	5	7	2.3
Hydro	184	335	377	420	463	502	536	2	3	1.8
Bioenergy	907	1 421	1 543	1 633	1 721	1 804	1 883	10	11	1.1
Other renewables	37	181	339	478	643	835	1 037	1	6	6.9
Power generation	**2 987**	**5 147**	**5 453**	**5 820**	**6 282**	**6 781**	**7 257**	**100**	**100**	**1.3**
Coal	1 217	2 408	2 344	2 361	2 404	2 441	2 469	47	34	0.1
Oil	385	277	230	203	175	161	152	5	2	-2.3
Gas	582	1 155	1 217	1 300	1 406	1 537	1 650	22	23	1.4
Nuclear	526	662	796	888	1 003	1 096	1 181	13	16	2.3
Hydro	184	335	377	420	463	502	536	7	7	1.8
Bioenergy	59	165	208	247	293	345	402	3	6	3.5
Other renewables	33	144	281	401	539	699	868	3	12	7.1
Other energy sector	**920**	**1 508**	**1 564**	**1 622**	**1 688**	**1 751**	**1 801**	**100**	**100**	**0.7**
Electricity	*185*	*343*	*364*	*388*	*422*	*457*	*491*	*23*	*27*	*1.4*
TFC	**6 161**	**9 410**	**10 204**	**10 794**	**11 392**	**11 989**	**12 538**	**100**	**100**	**1.1**
Coal	754	1 076	1 107	1 127	1 142	1 146	1 143	11	9	0.2
Oil	2 599	3 737	4 001	4 134	4 231	4 339	4 434	40	35	0.7
Gas	944	1 421	1 597	1 749	1 922	2 092	2 254	15	18	1.8
Electricity	836	1 709	1 933	2 152	2 397	2 645	2 879	18	23	2.0
Heat	230	274	296	303	308	312	313	3	2	0.5
Bioenergy	795	1 157	1 214	1 253	1 289	1 318	1 346	12	11	0.6
Other renewables	4	37	58	77	104	136	169	0	1	6.1
Industry	**1 805**	**2 836**	**3 113**	**3 335**	**3 547**	**3 756**	**3 941**	**100**	**100**	**1.3**
Coal	462	859	880	907	931	948	959	30	24	0.4
Oil	336	327	350	349	347	346	343	12	9	0.2
Gas	354	610	707	782	855	933	1 009	22	26	2.0
Electricity	388	724	815	901	982	1 061	1 130	26	29	1.7
Heat	153	123	141	145	147	146	143	4	4	0.6
Bioenergy	113	193	219	248	280	312	343	7	9	2.2
Other renewables	0	1	1	3	6	9	14	0	0	11.8
Transport	**1 573**	**2 622**	**2 828**	**2 981**	**3 119**	**3 274**	**3 435**	**100**	**100**	**1.0**
Oil	1 477	2 422	2 582	2 682	2 756	2 841	2 915	92	85	0.7
Of which: Bunkers	*202*	*363*	*409*	*447*	*486*	*524*	*564*	*14*	*16*	*1.7*
Electricity	21	26	33	42	54	67	83	1	2	4.6
Biofuels	6	74	95	119	142	167	199	3	6	3.9
Other fuels	69	101	118	138	167	197	237	4	7	3.3
Buildings	**2 141**	**3 044**	**3 210**	**3 343**	**3 521**	**3 697**	**3 852**	**100**	**100**	**0.9**
Coal	238	136	131	121	111	99	87	4	2	-1.7
Oil	319	315	304	282	261	246	239	10	6	-1.1
Gas	438	628	663	710	772	827	866	21	22	1.2
Electricity	397	904	1 019	1 135	1 279	1 428	1 570	30	41	2.1
Heat	75	148	152	155	158	163	166	5	4	0.5
Bioenergy	671	880	886	869	846	814	775	29	20	-0.5
Other renewables	3	34	54	71	95	122	149	1	4	5.8
Other	**642**	**907**	**1 054**	**1 135**	**1 205**	**1 263**	**1 310**	**100**	**100**	**1.4**

World: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**14 819**	**17 183**	**19 636**	**14 204**	**14 468**	**14 878**	**100**	**100**	**1.4**	**0.3**
Coal	4 051	4 710	5 327	3 622	2 650	2 000	27	13	1.2	-2.6
Oil	4 548	4 960	5 402	4 345	3 883	3 326	28	22	0.9	-1.0
Gas	3 194	3 898	4 718	3 136	3 349	3 301	24	22	1.9	0.5
Nuclear	793	936	1 032	815	1 234	1 590	5	11	1.7	3.4
Hydro	375	450	515	378	486	593	3	4	1.7	2.2
Bioenergy	1 540	1 695	1 834	1 550	1 928	2 310	9	16	1.0	1.9
Other renewables	319	535	809	359	939	1 759	4	12	5.9	9.1
Power generation	**5 592**	**6 796**	**8 098**	**5 239**	**5 445**	**6 038**	**100**	**100**	**1.8**	**0.6**
Coal	2 469	2 973	3 475	2 094	1 211	690	43	11	1.4	-4.7
Oil	234	182	160	221	116	65	2	1	-2.1	-5.4
Gas	1 251	1 534	1 889	1 228	1 259	1 062	23	18	1.9	-0.3
Nuclear	793	936	1 032	815	1 234	1 590	13	26	1.7	3.4
Hydro	375	450	515	378	486	593	6	10	1.7	2.2
Bioenergy	206	272	348	209	345	546	4	9	2.9	4.7
Other renewables	264	449	680	295	793	1 492	8	25	6.1	9.4
Other energy sector	**1 592**	**1 811**	**2 043**	**1 527**	**1 477**	**1 386**	**100**	**100**	**1.2**	**-0.3**
Electricity	*373*	*462*	*560*	*352*	*364*	*386*	*27*	*28*	*1.9*	*0.5*
TFC	**10 332**	**11 951**	**13 566**	**10 014**	**10 433**	**10 706**	**100**	**100**	**1.4**	**0.5**
Coal	1 124	1 212	1 257	1 086	998	881	9	8	0.6	-0.8
Oil	4 067	4 540	5 034	3 887	3 579	3 127	37	29	1.2	-0.7
Gas	1 607	1 978	2 355	1 584	1 791	1 975	17	18	2.0	1.3
Electricity	1 970	2 533	3 110	1 879	2 194	2 561	23	24	2.3	1.6
Heat	300	327	346	293	285	266	3	2	0.9	-0.1
Bioenergy	1 210	1 275	1 335	1 221	1 443	1 629	10	15	0.6	1.3
Other renewables	54	86	129	64	145	267	1	2	5.0	7.9
Industry	**3 151**	**3 708**	**4 224**	**3 070**	**3 221**	**3 316**	**100**	**100**	**1.5**	**0.6**
Coal	894	987	1 049	867	817	737	25	22	0.8	-0.6
Oil	355	364	367	346	316	294	9	9	0.5	-0.4
Gas	712	886	1 067	698	767	813	25	25	2.2	1.1
Electricity	826	1 022	1 209	796	880	955	29	29	2.0	1.1
Heat	142	157	163	140	134	117	4	4	1.1	-0.2
Bioenergy	221	289	361	219	287	356	9	11	2.4	2.4
Other renewables	1	3	8	2	20	43	0	1	9.3	16.7
Transport	**2 863**	**3 315**	**3 845**	**2 750**	**2 770**	**2 750**	**100**	**100**	**1.5**	**0.2**
Oil	2 631	3 007	3 418	2 485	2 196	1 753	89	64	1.3	-1.2
Of which: Bunkers	*422*	*529*	*634*	*359*	*349*	*312*	*16*	*11*	*2.2*	*-0.6*
Electricity	31	43	56	33	85	220	1	8	3.0	8.5
Biofuels	89	120	167	99	272	432	4	16	3.2	7.0
Other fuels	112	145	204	133	217	346	5	13	2.8	4.9
Buildings	**3 259**	**3 701**	**4 141**	**3 144**	**3 267**	**3 378**	**100**	**100**	**1.2**	**0.4**
Coal	133	120	102	124	88	56	2	2	-1.1	-3.3
Oil	313	290	287	293	222	185	7	5	-0.4	-2.0
Gas	674	818	940	644	682	677	23	20	1.6	0.3
Electricity	1 047	1 381	1 738	986	1 153	1 300	42	38	2.5	1.4
Heat	154	166	179	149	148	146	4	4	0.7	-0.0
Bioenergy	887	847	778	889	857	800	19	24	-0.5	-0.4
Other renewables	51	80	117	59	119	213	3	6	4.8	7.3
Other	**1 059**	**1 227**	**1 356**	**1 051**	**1 175**	**1 262**	**100**	**100**	**1.6**	**1.3**

World: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**11 863**	**23 809**	**26 698**	**29 540**	**32 732**	**35 989**	**39 045**	**100**	**100**	**1.9**
Coal	4 425	9 707	9 741	9 934	10 245	10 547	10 786	41	28	0.4
Oil	1 358	1 035	822	727	633	585	547	4	1	-2.4
Gas	1 753	5 148	5 804	6 513	7 305	8 155	8 909	22	23	2.1
Nuclear	2 013	2 535	3 053	3 405	3 847	4 205	4 532	11	12	2.3
Hydro	2 143	3 894	4 387	4 887	5 382	5 834	6 230	16	16	1.8
Bioenergy	131	495	642	785	954	1 147	1 353	2	3	3.9
Wind	4	717	1 508	2 118	2 706	3 296	3 881	3	10	6.7
Geothermal	36	77	111	150	207	283	361	0	1	6.1
Solar PV	0	190	599	953	1 329	1 731	2 137	1	5	9.8
CSP	1	9	30	61	109	175	254	0	1	13.7
Marine	1	1	3	6	15	30	54	0	0	16.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**6 117**	**7 479**	**8 371**	**9 349**	**10 299**	**11 168**	**100**	**100**	**2.3**
Coal	1 882	2 159	2 228	2 318	2 391	2 437	31	22	1.0
Oil	441	373	334	292	273	254	7	2	-2.1
Gas	1 563	1 844	2 029	2 262	2 487	2 703	26	24	2.1
Nuclear	398	438	468	520	565	606	7	5	1.6
Hydro	1 177	1 345	1 484	1 622	1 745	1 848	19	17	1.7
Bioenergy	113	140	166	195	226	259	2	2	3.3
Wind	351	670	903	1 119	1 319	1 504	6	13	5.8
Geothermal	12	17	23	31	42	55	0	0	5.9
Solar PV	176	481	715	949	1 183	1 405	3	13	8.3
CSP	5	10	20	34	53	76	0	1	11.5
Marine	1	1	2	6	12	21	0	0	15.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**20 448**	**32 175**	**32 795**	**33 596**	**34 485**	**35 452**	**36 290**	**100**	**100**	**0.5**
Coal	8 280	14 868	14 561	14 661	14 841	14 939	14 975	46	41	0.0
Oil	8 492	10 955	11 334	11 496	11 570	11 747	11 926	34	33	0.3
Gas	3 676	6 351	6 900	7 439	8 075	8 766	9 389	20	26	1.5
Power generation	**7 599**	**13 496**	**13 194**	**13 353**	**13 657**	**14 037**	**14 351**	**100**	**100**	**0.2**
Coal	4 995	9 899	9 598	9 648	9 792	9 911	9 992	73	70	0.0
Oil	1 237	868	730	643	556	512	481	6	3	-2.2
Gas	1 367	2 729	2 866	3 062	3 309	3 614	3 879	20	27	1.4
TFC	**11 879**	**16 997**	**17 901**	**18 525**	**19 104**	**19 674**	**20 182**	**100**	**100**	**0.7**
Coal	3 133	4 562	4 581	4 638	4 683	4 677	4 644	27	23	0.1
Oil	6 739	9 488	9 996	10 249	10 421	10 647	10 858	56	54	0.5
Transport	*4 423*	*7 306*	*7 781*	*8 085*	*8 314*	*8 576*	*8 802*	*43*	*44*	*0.7*
Of which: Bunkers	*630*	*1 130*	*1 273*	*1 391*	*1 511*	*1 628*	*1 749*	*7*	*9*	*1.7*
Gas	2 008	2 948	3 324	3 638	4 000	4 350	4 680	17	23	1.8

World: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**27 243**	**34 766**	**42 511**	**25 928**	**29 655**	**34 092**	**100**	**100**	**2.3**	**1.4**
Coal	10 275	12 770	15 305	8 702	4 966	2 518	36	7	1.8	-5.1
Oil	835	661	580	783	396	200	1	1	-2.2	-6.1
Gas	6 014	8 093	10 361	5 898	6 475	5 389	24	16	2.7	0.2
Nuclear	3 041	3 590	3 960	3 128	4 734	6 101	9	18	1.7	3.4
Hydro	4 363	5 232	5 984	4 392	5 655	6 891	14	20	1.7	2.2
Bioenergy	635	878	1 151	646	1 153	1 899	3	6	3.3	5.3
Wind	1 411	2 276	3 132	1 585	3 846	6 127	7	18	5.8	8.6
Geothermal	108	185	299	114	292	548	1	2	5.3	7.8
Solar PV	533	996	1 539	638	1 794	3 209	4	9	8.4	11.5
CSP	27	77	170	39	325	1 118	0	3	12.0	20.4
Marine	2	8	30	3	19	92	0	0	13.9	19.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**7 436**	**9 303**	**11 161**	**7 447**	**9 554**	**11 766**	**100**	**100**	**2.3**	**2.5**
Coal	2 201	2 617	3 030	2 094	1 687	1 194	27	10	1.8	-1.7
Oil	375	300	264	367	261	211	2	2	-2.0	-2.8
Gas	1 874	2 443	3 035	1 789	2 010	2 251	27	19	2.6	1.4
Nuclear	437	488	529	449	642	820	5	7	1.1	2.8
Hydro	1 338	1 571	1 770	1 348	1 718	2 057	16	17	1.6	2.2
Bioenergy	139	180	223	141	233	362	2	3	2.7	4.6
Wind	621	940	1 214	710	1 572	2 312	11	20	4.9	7.5
Geothermal	17	28	44	18	44	80	0	1	5.0	7.4
Solar PV	424	708	991	517	1 278	2 108	9	18	6.9	10.0
CSP	9	24	50	14	101	337	0	3	9.7	18.1
Marine	1	3	12	1	8	36	0	0	12.6	17.6

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**33 722**	**38 594**	**43 698**	**31 256**	**25 180**	**18 427**	**100**	**100**	**1.2**	**-2.1**
Coal	15 149	17 480	19 589	13 431	8 691	4 375	45	24	1.1	-4.6
Oil	11 553	12 562	13 824	10 945	9 322	7 484	32	41	0.9	-1.5
Gas	7 020	8 552	10 285	6 879	7 167	6 568	24	36	1.9	0.1
Power generation	**13 798**	**16 313**	**19 058**	**12 169**	**7 841**	**3 603**	**100**	**100**	**1.3**	**-5.0**
Coal	10 110	12 127	14 112	8 576	4 581	1 255	74	35	1.4	-7.6
Oil	740	576	505	700	370	206	3	6	-2.1	-5.4
Gas	2 947	3 610	4 441	2 894	2 890	2 143	23	59	1.9	-0.9
TFC	**18 195**	**20 436**	**22 642**	**17 436**	**15 966**	**13 745**	**100**	**100**	**1.1**	**-0.8**
Coal	4 652	4 968	5 102	4 485	3 814	2 896	23	21	0.4	-1.7
Oil	10 196	11 351	12 645	9 656	8 482	6 919	56	50	1.1	-1.2
Transport	*7 930*	*9 074*	*10 317*	*7 483*	*6 624*	*5 298*	*46*	*39*	*1.3*	*-1.2*
Of which: Bunkers	*1 315*	*1 648*	*1 969*	*1 120*	*1 090*	*976*	*9*	*7*	*2.2*	*-0.6*
Gas	3 347	4 118	4 895	3 295	3 670	3 929	22	29	2.0	1.1

OECD: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**4 526**	**5 276**	**5 293**	**5 215**	**5 140**	**5 093**	**5 077**	**100**	**100**	**-0.1**
Coal	1 081	1 013	879	794	712	635	588	19	12	-2.1
Oil	1 871	1 881	1 806	1 688	1 552	1 431	1 333	36	26	-1.3
Gas	843	1 344	1 405	1 436	1 464	1 502	1 527	25	30	0.5
Nuclear	451	517	555	557	575	589	603	10	12	0.6
Hydro	101	120	130	136	141	145	149	2	3	0.8
Bioenergy	149	303	348	379	411	439	468	6	9	1.7
Other renewables	29	98	170	225	285	350	410	2	8	5.7
Power generation	**1 727**	**2 167**	**2 144**	**2 139**	**2 154**	**2 179**	**2 212**	**100**	**100**	**0.1**
Coal	758	803	672	596	521	453	411	37	19	-2.5
Oil	162	63	30	22	17	14	11	3	1	-6.4
Gas	176	476	486	499	509	524	527	22	24	0.4
Nuclear	451	517	555	557	575	589	603	24	27	0.6
Hydro	101	120	130	136	141	145	149	6	7	0.8
Bioenergy	52	100	117	128	140	151	162	5	7	1.9
Other renewables	26	88	153	200	251	304	349	4	16	5.5
Other energy sector	**411**	**477**	**489**	**488**	**485**	**483**	**486**	**100**	**100**	**0.1**
Electricity	*107*	*126*	*125*	*124*	*125*	*126*	*127*	*26*	*26*	*0.0*
TFC	**3 099**	**3 631**	**3 699**	**3 656**	**3 598**	**3 557**	**3 536**	**100**	**100**	**-0.1**
Coal	232	113	111	105	98	91	85	3	2	-1.1
Oil	1 581	1 712	1 671	1 568	1 448	1 343	1 256	47	36	-1.2
Gas	589	736	771	780	789	800	811	20	23	0.4
Electricity	554	802	841	870	899	928	957	22	27	0.7
Heat	43	57	59	60	61	61	62	2	2	0.3
Bioenergy	97	201	229	249	269	286	303	6	9	1.6
Other renewables	4	10	17	25	34	47	61	0	2	7.1
Industry	**842**	**853**	**894**	**893**	**884**	**877**	**876**	**100**	**100**	**0.1**
Coal	159	91	91	87	82	76	71	11	8	-0.9
Oil	177	124	125	119	111	105	100	15	11	-0.8
Gas	226	282	302	302	299	297	296	33	34	0.2
Electricity	230	257	271	277	279	283	288	30	33	0.5
Heat	15	24	24	24	22	21	20	3	2	-0.8
Bioenergy	37	74	80	84	88	91	95	9	11	1.0
Other renewables	0	1	1	1	2	4	5	0	1	8.9
Transport	**937**	**1 215**	**1 190**	**1 137**	**1 075**	**1 025**	**994**	**100**	**100**	**-0.8**
Oil	910	1 127	1 080	1 009	926	855	796	93	80	-1.3
Electricity	8	9	12	15	18	23	28	1	3	4.5
Biofuels	0	51	64	74	84	92	101	4	10	2.7
Other fuels	19	29	34	39	46	55	69	2	7	3.5
Buildings	**976**	**1 198**	**1 221**	**1 235**	**1 257**	**1 281**	**1 302**	**100**	**100**	**0.3**
Coal	69	17	15	14	12	11	10	1	1	-2.1
Oil	202	138	123	103	83	65	52	12	4	-3.7
Gas	304	403	404	407	413	418	416	34	32	0.1
Electricity	311	525	548	568	591	612	630	44	48	0.7
Heat	27	32	35	37	39	40	42	3	3	1.0
Bioenergy	59	73	80	85	90	95	100	6	8	1.2
Other renewables	3	9	15	22	30	40	53	1	4	7.1
Other	**343**	**366**	**394**	**390**	**382**	**373**	**364**	**100**	**100**	**-0.0**

OECD: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**5 374**	**5 453**	**5 583**	**5 142**	**4 635**	**4 331**	**100**	**100**	**0.2**	**-0.8**
Coal	902	842	797	744	328	224	14	5	-0.9	-5.6
Oil	1 836	1 680	1 551	1 768	1 318	903	28	21	-0.7	-2.8
Gas	1 446	1 599	1 744	1 412	1 329	1 071	31	25	1.0	-0.9
Nuclear	555	549	548	563	650	735	10	17	0.2	1.4
Hydro	129	139	146	130	144	155	3	4	0.8	1.0
Bioenergy	343	396	456	348	491	603	8	14	1.6	2.7
Other renewables	164	249	340	176	375	640	6	15	4.9	7.5
Power generation	**2 188**	**2 304**	**2 435**	**2 059**	**1 927**	**2 008**	**100**	**100**	**0.5**	**-0.3**
Coal	694	645	605	544	159	86	25	4	-1.1	-8.2
Oil	33	18	12	29	11	6	1	0	-6.1	-8.9
Gas	512	594	664	519	483	289	27	14	1.3	-1.9
Nuclear	555	549	548	563	650	735	22	37	0.2	1.4
Hydro	129	139	146	130	144	155	6	8	0.8	1.0
Bioenergy	116	135	155	117	154	197	6	10	1.7	2.6
Other renewables	149	226	306	156	325	541	13	27	4.9	7.3
Other energy sector	**500**	**523**	**556**	**473**	**415**	**347**	**100**	**100**	**0.6**	**-1.2**
Electricity	*127*	*135*	*143*	*121*	*111*	*107*	*26*	*31*	*0.5*	*-0.6*
TFC	**3 744**	**3 788**	**3 858**	**3 622**	**3 315**	**3 045**	**100**	**100**	**0.2**	**-0.7**
Coal	112	101	90	108	88	70	2	2	-0.9	-1.8
Oil	1 696	1 568	1 464	1 637	1 235	856	38	28	-0.6	-2.6
Gas	781	822	860	750	707	663	22	22	0.6	-0.4
Electricity	856	951	1 042	820	844	900	27	30	1.0	0.4
Heat	60	65	68	58	57	54	2	2	0.7	-0.2
Bioenergy	224	258	299	229	334	403	8	13	1.5	2.7
Other renewables	15	23	35	20	50	99	1	3	4.8	9.2
Industry	**902**	**912**	**917**	**880**	**815**	**761**	**100**	**100**	**0.3**	**-0.4**
Coal	91	83	74	88	73	58	8	8	-0.8	-1.7
Oil	127	116	105	124	102	87	11	11	-0.6	-1.4
Gas	305	310	312	298	266	235	34	31	0.4	-0.7
Electricity	273	287	299	265	256	250	33	33	0.6	-0.1
Heat	25	23	21	24	20	17	2	2	-0.6	-1.4
Bioenergy	81	92	103	80	91	101	11	13	1.3	1.2
Other renewables	1	2	3	1	7	14	0	2	7.0	13.3
Transport	**1 202**	**1 153**	**1 144**	**1 161**	**972**	**807**	**100**	**100**	**-0.2**	**-1.6**
Oil	1 098	1 022	972	1 055	745	440	85	55	-0.6	-3.5
Electricity	10	14	17	11	36	107	1	13	2.4	10.0
Biofuels	60	75	98	62	138	174	9	22	2.6	4.8
Other fuels	33	42	56	34	53	86	5	11	2.6	4.4
Buildings	**1 244**	**1 338**	**1 428**	**1 188**	**1 154**	**1 124**	**100**	**100**	**0.7**	**-0.2**
Coal	16	14	12	15	11	8	1	1	-1.2	-3.0
Oil	128	100	73	118	69	33	5	3	-2.4	-5.3
Gas	412	439	461	388	358	313	32	28	0.5	-1.0
Electricity	561	639	714	533	543	534	50	48	1.2	0.1
Heat	35	42	47	34	36	37	3	3	1.5	0.5
Bioenergy	79	85	91	82	98	118	6	11	0.8	1.9
Other renewables	13	20	29	17	41	81	2	7	4.7	8.9
Other	**395**	**385**	**369**	**393**	**374**	**352**	**100**	**100**	**0.0**	**-0.1**

OECD: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**7 666**	**10 772**	**11 245**	**11 574**	**11 904**	**12 248**	**12 592**	**100**	**100**	**0.6**
Coal	3 094	3 478	2 962	2 647	2 339	2 063	1 902	32	15	-2.3
Oil	733	276	131	94	74	61	47	3	0	-6.6
Gas	774	2 614	2 826	2 972	3 075	3 184	3 215	24	26	0.8
Nuclear	1 729	1 981	2 130	2 136	2 205	2 260	2 315	18	18	0.6
Hydro	1 179	1 401	1 514	1 586	1 640	1 685	1 727	13	14	0.8
Bioenergy	123	330	393	439	485	529	569	3	5	2.1
Wind	4	488	868	1 130	1 369	1 589	1 782	5	14	5.1
Geothermal	29	48	67	85	112	143	165	0	1	4.8
Solar PV	0	147	336	455	557	655	751	1	6	6.5
CSP	1	8	16	24	36	51	68	0	1	8.5
Marine	1	1	3	6	14	28	51	0	0	16.4

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**2 920**	**3 192**	**3 352**	**3 531**	**3 702**	**3 862**	**100**	**100**	**1.1**
Coal	614	562	521	483	437	402	21	10	-1.6
Oil	198	123	94	72	62	53	7	1	-5.0
Gas	883	974	1 024	1 088	1 157	1 217	30	32	1.2
Nuclear	315	307	291	295	301	307	11	8	-0.1
Hydro	476	501	518	532	544	554	16	14	0.6
Bioenergy	71	82	90	98	105	111	2	3	1.7
Wind	215	350	437	515	580	635	7	16	4.3
Geothermal	8	10	13	16	21	25	0	1	4.7
Solar PV	137	277	353	416	470	518	5	13	5.2
CSP	4	5	7	11	15	20	0	1	6.3
Marine	1	1	2	6	11	20	0	1	15.1

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**10 952**	**11 748**	**11 009**	**10 388**	**9 732**	**9 163**	**8 746**	**100**	**100**	**-1.1**
Coal	4 240	3 950	3 393	3 047	2 703	2 379	2 172	34	25	-2.3
Oil	4 831	4 713	4 411	4 073	3 711	3 397	3 149	40	36	-1.5
Gas	1 881	3 084	3 205	3 268	3 318	3 386	3 426	26	39	0.4
Power generation	**4 065**	**4 664**	**4 032**	**3 714**	**3 411**	**3 148**	**2 969**	**100**	**100**	**-1.7**
Coal	3 132	3 339	2 787	2 467	2 156	1 870	1 694	72	57	-2.6
Oil	519	200	97	69	55	45	36	4	1	-6.4
Gas	413	1 124	1 148	1 177	1 200	1 233	1 239	24	42	0.4
TFC	**6 312**	**6 354**	**6 211**	**5 911**	**5 571**	**5 278**	**5 046**	**100**	**100**	**-0.9**
Coal	1 034	496	487	462	432	401	374	8	7	-1.1
Oil	3 979	4 204	4 009	3 714	3 383	3 097	2 865	66	57	-1.5
Transport	*2 699*	*3 361*	*3 222*	*3 009*	*2 762*	*2 551*	*2 375*	*53*	*47*	*-1.3*
Gas	1 299	1 653	1 715	1 735	1 756	1 780	1 807	26	36	0.3

OECD: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**11 447**	**12 629**	**13 763**	**10 945**	**11 084**	**11 669**	**100**	**100**	**0.9**	**0.3**
Coal	3 059	2 911	2 822	2 393	677	327	21	3	-0.8	-8.7
Oil	141	78	51	125	41	16	0	0	-6.3	-10.3
Gas	2 982	3 594	4 104	3 039	2 906	1 633	30	14	1.8	-1.8
Nuclear	2 128	2 105	2 102	2 161	2 495	2 819	15	24	0.2	1.4
Hydro	1 497	1 611	1 701	1 516	1 677	1 797	12	15	0.8	1.0
Bioenergy	389	464	533	395	548	723	4	6	1.9	3.1
Wind	841	1 222	1 542	887	1 813	2 683	11	23	4.5	6.8
Geothermal	65	103	149	68	133	219	1	2	4.4	6.0
Solar PV	327	504	677	343	695	1 084	5	9	6.0	8.0
CSP	15	29	54	16	80	286	0	2	7.5	14.7
Marine	2	8	27	3	17	83	0	1	13.6	18.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**3 197**	**3 576**	**3 971**	**3 145**	**3 602**	**4 179**	**100**	**100**	**1.2**	**1.4**
Coal	568	526	498	540	328	179	13	4	-0.8	-4.6
Oil	125	77	57	118	58	36	1	1	-4.7	-6.4
Gas	999	1 207	1 420	933	994	1 065	36	25	1.8	0.7
Nuclear	306	284	277	311	334	375	7	9	-0.5	0.7
Hydro	496	523	544	502	548	581	14	14	0.5	0.8
Bioenergy	81	93	104	82	110	142	3	3	1.5	2.7
Wind	338	463	556	359	668	923	14	22	3.7	5.8
Geothermal	10	15	21	10	19	31	1	1	4.0	5.6
Solar PV	268	377	466	283	509	729	12	17	4.8	6.6
CSP	5	9	15	5	25	83	0	2	5.2	12.3
Marine	1	3	11	1	7	33	0	1	12.3	17.2

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**11 286**	**10 951**	**10 735**	**10 365**	**7 007**	**4 404**	**100**	**100**	**-0.3**	**-3.7**
Coal	3 487	3 233	3 005	2 850	1 073	455	28	10	-1.0	-8.0
Oil	4 497	4 091	3 810	4 300	3 019	1 851	35	42	-0.8	-3.5
Gas	3 302	3 627	3 919	3 215	2 915	2 097	37	48	0.9	-1.5
Power generation	**4 191**	**4 129**	**4 106**	**3 582**	**1 731**	**618**	**100**	**100**	**-0.5**	**-7.5**
Coal	2 877	2 673	2 504	2 265	613	135	61	22	-1.1	-11.6
Oil	105	58	39	93	35	18	1	3	-6.1	-8.9
Gas	1 209	1 398	1 563	1 224	1 083	466	38	75	1.3	-3.3
TFC	**6 311**	**6 015**	**5 793**	**6 049**	**4 685**	**3 363**	**100**	**100**	**-0.4**	**-2.4**
Coal	490	445	396	471	365	251	7	7	-0.9	-2.6
Oil	4 081	3 738	3 478	3 912	2 767	1 687	60	50	-0.7	-3.5
Transport	*3 276*	*3 048*	*2 900*	*3 145*	*2 221*	*1 312*	*50*	*39*	*-0.6*	*-3.6*
Gas	1 739	1 833	1 919	1 666	1 553	1 425	33	42	0.6	-0.6

OECD Americas: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**2 264**	**2 722**	**2 734**	**2 708**	**2 680**	**2 674**	**2 696**	**100**	**100**	**-0.0**
Coal	491	471	390	354	324	296	277	17	10	-2.0
Oil	921	992	987	943	875	814	766	36	28	-1.0
Gas	517	777	821	839	859	889	923	29	34	0.7
Nuclear	180	247	244	239	246	252	260	9	10	0.2
Hydro	52	61	65	69	72	74	76	2	3	0.9
Bioenergy	85	139	155	169	183	198	213	5	8	1.7
Other renewables	19	36	71	95	121	151	180	1	7	6.4
Power generation	**852**	**1 069**	**1 041**	**1 034**	**1 044**	**1 061**	**1 086**	**100**	**100**	**0.1**
Coal	419	425	346	312	282	253	232	40	21	-2.3
Oil	47	21	8	6	6	5	3	2	0	-6.7
Gas	95	253	277	283	289	299	309	24	28	0.8
Nuclear	180	247	244	239	246	252	260	23	24	0.2
Hydro	52	61	65	69	72	74	76	6	7	0.9
Bioenergy	41	30	34	38	42	46	52	3	5	2.2
Other renewables	19	33	65	86	107	131	154	3	14	6.1
Other energy sector	**194**	**241**	**252**	**259**	**264**	**271**	**282**	**100**	**100**	**0.6**
Electricity	*56*	*66*	*65*	*65*	*65*	*66*	*67*	*27*	*24*	*0.1*
TFC	**1 550**	**1 883**	**1 930**	**1 916**	**1 889**	**1 875**	**1 881**	**100**	**100**	**-0.0**
Coal	61	28	28	27	25	24	23	2	1	-0.8
Oil	809	921	924	881	817	763	719	49	38	-0.9
Gas	361	420	431	436	443	453	467	22	25	0.4
Electricity	272	395	413	427	442	459	478	21	25	0.7
Heat	3	6	7	6	6	5	5	0	0	-1.1
Bioenergy	44	109	121	131	141	151	161	6	9	1.5
Other renewables	0	3	6	9	14	20	27	0	1	9.2
Industry	**365**	**372**	**397**	**401**	**402**	**405**	**412**	**100**	**100**	**0.4**
Coal	50	27	26	25	24	23	22	7	5	-0.7
Oil	65	38	39	38	36	36	35	10	9	-0.3
Gas	138	158	173	174	173	172	173	43	42	0.4
Electricity	94	102	110	114	116	120	124	27	30	0.8
Heat	1	5	6	5	5	4	4	1	1	-1.0
Bioenergy	17	41	43	45	47	49	52	11	13	0.9
Other renewables	0	0	0	0	1	1	1	0	0	19.8
Transport	**562**	**744**	**739**	**710**	**667**	**636**	**620**	**100**	**100**	**-0.7**
Oil	543	683	667	628	572	526	489	92	79	-1.3
Electricity	1	1	2	3	4	7	10	0	2	8.2
Biofuels	-	36	44	50	57	63	68	5	11	2.5
Other fuels	18	24	27	29	34	41	53	3	9	3.1
Buildings	**463**	**599**	**596**	**605**	**618**	**634**	**651**	**100**	**100**	**0.3**
Coal	10	1	1	1	0	0	0	0	0	-12.1
Oil	64	50	47	41	36	31	27	8	4	-2.3
Gas	184	227	213	215	217	220	221	38	34	-0.1
Electricity	176	288	297	306	317	328	340	48	52	0.6
Heat	2	1	1	1	1	1	1	0	0	-1.7
Bioenergy	26	30	31	32	34	36	38	5	6	0.9
Other renewables	0	3	6	9	13	18	24	0	4	8.8
Other	**159**	**168**	**198**	**201**	**201**	**199**	**198**	**100**	**100**	**0.6**

OECD Americas: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**2 773**	**2 844**	**2 971**	**2 634**	**2 370**	**2 236**	**100**	**100**	**0.3**	**-0.8**
Coal	398	373	364	294	95	70	12	3	-1.0	-7.1
Oil	1 000	947	904	964	731	508	30	23	-0.4	-2.5
Gas	845	928	1 014	837	790	648	34	29	1.0	-0.7
Nuclear	244	240	249	245	271	312	8	14	0.0	0.9
Hydro	66	72	76	65	72	77	3	3	0.9	0.9
Bioenergy	153	178	214	155	239	302	7	14	1.7	3.0
Other renewables	67	106	149	74	173	318	5	14	5.7	8.8
Power generation	**1 066**	**1 123**	**1 195**	**983**	**901**	**963**	**100**	**100**	**0.4**	**-0.4**
Coal	354	329	313	251	59	38	26	4	-1.2	-8.9
Oil	11	7	4	9	4	2	0	0	-6.1	-8.8
Gas	295	338	366	312	292	187	31	19	1.4	-1.2
Nuclear	244	240	249	245	271	312	21	32	0.0	0.9
Hydro	66	72	76	65	72	77	6	8	0.9	0.9
Bioenergy	34	40	50	35	49	69	4	7	2.0	3.3
Other renewables	63	98	136	67	154	277	11	29	5.6	8.5
Other energy sector	**259**	**289**	**327**	**243**	**221**	**191**	**100**	**100**	**1.2**	**-0.9**
Electricity	*66*	*71*	*75*	*62*	*57*	*56*	*23*	*29*	*0.5*	*-0.6*
TFC	**1 948**	**1 983**	**2 052**	**1 882**	**1 729**	**1 601**	**100**	**100**	**0.3**	**-0.6**
Coal	28	26	24	27	22	18	1	1	-0.6	-1.7
Oil	934	884	849	902	684	477	41	30	-0.3	-2.5
Gas	433	450	477	417	393	372	23	23	0.5	-0.5
Electricity	423	471	521	401	416	458	25	29	1.1	0.6
Heat	7	6	5	7	5	3	0	0	-1.1	-2.4
Bioenergy	119	138	164	121	189	232	8	15	1.6	3.0
Other renewables	4	8	13	7	19	40	1	3	6.1	10.9
Industry	**401**	**414**	**429**	**392**	**370**	**355**	**100**	**100**	**0.6**	**-0.2**
Coal	27	25	23	26	21	17	5	5	-0.6	-1.7
Oil	39	38	37	39	34	32	9	9	-0.1	-0.7
Gas	174	177	180	171	154	135	42	38	0.5	-0.6
Electricity	111	119	128	107	104	105	30	30	0.9	0.1
Heat	6	5	4	6	4	3	1	1	-1.0	-1.9
Bioenergy	44	50	56	43	50	57	13	16	1.2	1.2
Other renewables	0	1	1	0	2	6	0	2	19.3	26.9
Transport	**743**	**717**	**726**	**718**	**601**	**503**	**100**	**100**	**-0.1**	**-1.5**
Oil	673	629	607	648	451	266	84	53	-0.5	-3.6
Electricity	1	2	3	2	15	58	0	11	2.9	15.8
Biofuels	42	53	70	42	96	119	10	24	2.6	4.7
Other fuels	26	33	47	27	39	61	6	12	2.6	3.7
Buildings	**605**	**650**	**698**	**576**	**562**	**551**	**100**	**100**	**0.6**	**-0.3**
Coal	1	1	0	1	0	0	0	0	-4.1	-14.2
Oil	49	44	36	45	30	18	5	3	-1.3	-3.8
Gas	214	221	231	201	182	157	33	28	0.1	-1.4
Electricity	306	345	384	288	293	292	55	53	1.1	0.1
Heat	1	1	1	1	1	0	0	0	-1.5	-5.6
Bioenergy	31	32	35	33	39	52	5	9	0.6	2.2
Other renewables	4	7	11	7	16	33	2	6	5.6	10.0
Other	**198**	**201**	**199**	**197**	**196**	**191**	**100**	**100**	**0.7**	**0.5**

OECD Americas: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**3 819**	**5 344**	**5 562**	**5 714**	**5 897**	**6 095**	**6 333**	**100**	**100**	**0.7**
Coal	1 796	1 837	1 520	1 382	1 257	1 141	1 059	34	17	-2.1
Oil	211	85	38	30	26	22	15	2	0	-6.4
Gas	406	1 407	1 636	1 707	1 777	1 860	1 948	26	31	1.3
Nuclear	687	948	937	917	944	966	996	18	16	0.2
Hydro	602	706	761	802	833	860	884	13	14	0.9
Bioenergy	91	94	112	129	147	165	183	2	3	2.6
Wind	3	214	393	488	563	637	710	4	11	4.7
Geothermal	21	25	33	40	53	69	83	0	1	4.8
Solar PV	0	24	124	208	281	350	418	0	7	11.6
CSP	1	3	7	10	14	19	27	0	0	9.3
Marine	0	0	0	1	3	5	8	0	0	26.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**1 364**	**1 457**	**1 524**	**1 611**	**1 696**	**1 787**	**100**	**100**	**1.0**
Coal	321	263	245	237	227	208	24	12	-1.7
Oil	85	48	37	32	30	26	6	1	-4.4
Gas	510	563	574	594	618	662	37	37	1.0
Nuclear	120	119	115	119	121	125	9	7	0.2
Hydro	199	207	215	222	228	233	15	13	0.6
Bioenergy	22	26	29	33	36	39	2	2	2.1
Wind	78	141	170	193	214	234	6	13	4.3
Geothermal	4	5	6	8	10	12	0	1	4.0
Solar PV	21	81	128	168	204	238	2	13	9.8
CSP	2	2	3	4	6	7	0	0	5.8
Marine	0	0	0	1	2	3	0	0	20.4

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**5 488**	**6 215**	**5 875**	**5 627**	**5 337**	**5 104**	**4 951**	**100**	**100**	**-0.9**
Coal	1 958	1 845	1 518	1 378	1 251	1 130	1 042	30	21	-2.2
Oil	2 367	2 591	2 494	2 347	2 152	1 988	1 858	42	38	-1.3
Gas	1 163	1 779	1 863	1 901	1 934	1 987	2 051	29	41	0.5
Power generation	**2 050**	**2 372**	**2 063**	**1 935**	**1 824**	**1 728**	**1 662**	**100**	**100**	**-1.4**
Coal	1 676	1 709	1 384	1 248	1 126	1 010	926	72	56	-2.3
Oil	151	69	28	21	19	16	11	3	1	-6.7
Gas	223	595	651	665	679	702	724	25	44	0.8
TFC	**3 105**	**3 415**	**3 355**	**3 224**	**3 049**	**2 909**	**2 814**	**100**	**100**	**-0.7**
Coal	275	122	120	115	110	105	101	4	4	-0.7
Oil	2 030	2 350	2 284	2 148	1 963	1 807	1 683	69	60	-1.3
Transport	*1 601*	*2 024*	*1 975*	*1 859*	*1 695*	*1 558*	*1 449*	*59*	*51*	*-1.3*
Gas	801	944	950	961	976	997	1 030	28	37	0.3

OECD Americas: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**5 693**	**6 300**	**6 920**	**5 383**	**5 484**	**5 954**	**100**	**100**	**1.0**	**0.4**
Coal	1 556	1 468	1 434	1 104	262	166	21	3	-0.9	-8.8
Oil	47	30	18	39	19	8	0	0	-5.7	-8.5
Gas	1 746	2 076	2 331	1 856	1 781	1 118	34	19	2.0	-0.9
Nuclear	936	921	954	939	1 038	1 199	14	20	0.0	0.9
Hydro	763	833	889	761	840	898	13	15	0.9	0.9
Bioenergy	110	137	168	113	182	273	2	5	2.3	4.2
Wind	375	518	643	405	865	1 296	9	22	4.3	7.2
Geothermal	32	50	73	33	59	103	1	2	4.3	5.6
Solar PV	121	253	381	128	383	663	6	11	11.2	13.5
CSP	7	12	21	7	51	212	0	4	8.2	18.3
Marine	0	2	7	0	4	17	0	0	26.2	30.7

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 469**	**1 657**	**1 879**	**1 428**	**1 683**	**2 036**	**100**	**100**	**1.2**	**1.6**
Coal	265	249	242	251	139	72	13	4	-1.1	-5.6
Oil	50	36	30	47	24	15	2	1	-4.0	-6.5
Gas	582	662	772	539	573	623	41	31	1.6	0.8
Nuclear	119	116	120	119	131	153	6	8	-0.0	0.9
Hydro	208	222	233	207	225	238	12	12	0.6	0.7
Bioenergy	26	30	35	26	40	59	2	3	1.8	3.8
Wind	134	178	212	147	295	416	11	20	3.9	6.7
Geothermal	5	7	10	5	9	15	1	1	3.4	4.8
Solar PV	79	151	217	84	230	376	12	18	9.4	11.7
CSP	2	4	6	2	16	62	0	3	4.6	14.7
Marine	0	1	2	0	1	6	0	0	19.7	24.2

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**6 001**	**5 902**	**5 899**	**5 456**	**3 725**	**2 362**	**100**	**100**	**-0.2**	**-3.7**
Coal	1 551	1 441	1 371	1 132	302	96	23	4	-1.1	-10.8
Oil	2 531	2 368	2 275	2 425	1 722	1 068	39	45	-0.5	-3.3
Gas	1 919	2 093	2 253	1 898	1 701	1 198	38	51	0.9	-1.5
Power generation	**2 145**	**2 129**	**2 125**	**1 763**	**853**	**294**	**100**	**100**	**-0.4**	**-7.7**
Coal	1 416	1 314	1 252	1 002	204	31	59	10	-1.2	-14.3
Oil	36	22	13	29	13	6	1	2	-6.1	-8.8
Gas	693	793	860	733	636	257	40	87	1.4	-3.2
TFC	**3 387**	**3 265**	**3 222**	**3 254**	**2 510**	**1 805**	**100**	**100**	**-0.2**	**-2.4**
Coal	121	113	104	117	87	57	3	3	-0.6	-2.9
Oil	2 311	2 161	2 066	2 220	1 575	969	64	54	-0.5	-3.4
Transport	*1 993*	*1 864*	*1 798*	*1 918*	*1 337*	*787*	*56*	*44*	*-0.5*	*-3.6*
Gas	954	992	1 052	916	849	779	33	43	0.4	-0.7

United States: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**1 915**	**2 212**	**2 211**	**2 176**	**2 130**	**2 101**	**2 094**	**100**	**100**	**-0.2**
Coal	460	432	357	324	301	276	259	20	12	-1.9
Oil	757	782	782	740	674	616	570	35	27	-1.2
Gas	438	624	655	665	670	681	694	28	33	0.4
Nuclear	159	216	217	215	220	226	232	10	11	0.3
Hydro	23	22	25	26	27	28	29	1	1	1.0
Bioenergy	62	105	118	129	141	152	164	5	8	1.7
Other renewables	15	29	57	76	97	121	145	1	7	6.3
Power generation	**750**	**901**	**870**	**860**	**863**	**868**	**878**	**100**	**100**	**-0.1**
Coal	396	396	322	292	268	242	223	44	25	-2.2
Oil	27	9	5	4	4	3	2	1	0	-5.8
Gas	90	206	224	229	230	233	235	23	27	0.5
Nuclear	159	216	217	215	220	226	232	24	26	0.3
Hydro	23	22	25	26	27	28	29	2	3	1.0
Bioenergy	40	23	25	27	30	33	36	3	4	1.7
Other renewables	14	27	52	68	84	103	121	3	14	5.9
Other energy sector	**150**	**160**	**167**	**169**	**168**	**167**	**168**	**100**	**100**	**0.2**
Electricity	*49*	*50*	*49*	*49*	*49*	*49*	*49*	*32*	*30*	*-0.1*
TFC	**1 294**	**1 538**	**1 572**	**1 550**	**1 511**	**1 486**	**1 480**	**100**	**100**	**-0.1**
Coal	56	22	22	21	19	18	17	1	1	-1.0
Oil	683	744	747	706	644	592	550	48	37	-1.2
Gas	303	355	361	362	365	370	381	23	26	0.3
Electricity	226	326	338	345	354	363	375	21	25	0.5
Heat	2	6	6	5	5	4	4	0	0	-1.4
Bioenergy	23	82	93	102	111	120	128	5	9	1.7
Other renewables	0	2	5	8	12	18	24	0	2	9.2
Industry	**288**	**276**	**296**	**295**	**292**	**290**	**293**	**100**	**100**	**0.2**
Coal	46	21	21	20	19	18	17	8	6	-0.8
Oil	49	20	22	21	20	20	20	7	7	-0.1
Gas	110	129	140	139	136	134	133	47	46	0.1
Electricity	75	71	76	78	78	79	81	26	28	0.5
Heat	-	4	5	4	4	4	3	2	1	-1.2
Bioenergy	9	30	31	32	34	35	37	11	13	0.8
Other renewables	-	-	0	0	0	1	1	-	0	n.a.
Transport	**488**	**623**	**618**	**592**	**550**	**519**	**503**	**100**	**100**	**-0.8**
Oil	472	568	552	516	462	418	382	91	76	-1.5
Electricity	0	1	1	2	3	5	8	0	2	10.2
Biofuels	-	34	42	48	55	60	65	6	13	2.5
Other fuels	15	20	23	25	30	36	48	3	10	3.4
Buildings	**389**	**506**	**500**	**504**	**512**	**522**	**532**	**100**	**100**	**0.2**
Coal	10	1	1	1	0	0	0	0	0	-14.6
Oil	48	35	33	28	23	19	15	7	3	-3.2
Gas	164	198	184	184	185	186	186	39	35	-0.3
Electricity	152	252	258	263	271	277	284	50	53	0.5
Heat	2	1	1	1	1	1	1	0	0	-2.2
Bioenergy	14	16	18	19	20	22	23	3	4	1.4
Other renewables	0	2	5	8	12	17	23	0	4	8.9
Other	**129**	**132**	**158**	**160**	**157**	**154**	**151**	**100**	**100**	**0.5**

United States: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**2 243**	**2 262**	**2 310**	**2 121**	**1 872**	**1 743**	**100**	**100**	**0.2**	**-0.9**
Coal	364	345	339	262	79	61	15	3	-0.9	-7.3
Oil	789	731	680	760	554	368	29	21	-0.5	-2.9
Gas	678	725	755	679	636	501	33	29	0.7	-0.8
Nuclear	216	214	221	217	243	280	10	16	0.1	1.0
Hydro	25	27	29	25	28	31	1	2	1.0	1.2
Bioenergy	117	136	167	118	187	232	7	13	1.8	3.1
Other renewables	53	84	120	59	144	270	5	15	5.5	8.9
Power generation	**892**	**933**	**974**	**817**	**741**	**795**	**100**	**100**	**0.3**	**-0.5**
Coal	330	310	297	229	51	35	31	4	-1.1	-8.9
Oil	5	4	2	5	3	1	0	0	-5.5	-8.5
Gas	242	273	282	263	253	159	29	20	1.2	-1.0
Nuclear	216	214	221	217	243	280	23	35	0.1	1.0
Hydro	25	27	29	25	28	31	3	4	1.0	1.2
Bioenergy	25	28	34	25	36	52	4	7	1.6	3.2
Other renewables	49	77	109	53	127	236	11	30	5.5	8.7
Other energy sector	**172**	**183**	**189**	**160**	**140**	**114**	**100**	**100**	**0.6**	**-1.3**
Electricity	*51*	*53*	*56*	*47*	*43*	*42*	*29*	*37*	*0.4*	*-0.7*
TFC	**1 586**	**1 589**	**1 623**	**1 529**	**1 377**	**1 253**	**100**	**100**	**0.2**	**-0.8**
Coal	22	20	18	21	17	13	1	1	-0.8	-2.0
Oil	753	699	657	726	531	354	41	28	-0.5	-2.8
Gas	363	370	387	349	321	297	24	24	0.3	-0.7
Electricity	347	380	413	328	337	372	25	30	0.9	0.5
Heat	6	5	4	6	4	3	0	0	-1.4	-2.8
Bioenergy	91	108	132	93	151	179	8	14	1.8	3.1
Other renewables	4	7	11	6	17	34	1	3	6.0	10.6
Industry	**299**	**301**	**304**	**292**	**269**	**252**	**100**	**100**	**0.4**	**-0.3**
Coal	21	19	18	21	17	13	6	5	-0.7	-1.8
Oil	22	21	21	21	19	19	7	7	0.0	-0.4
Gas	142	140	138	139	121	103	45	41	0.2	-0.9
Electricity	77	80	84	74	71	70	27	28	0.7	-0.0
Heat	5	4	3	5	4	3	1	1	-1.2	-2.1
Bioenergy	31	36	41	31	36	41	13	16	1.2	1.2
Other renewables	0	0	1	0	2	4	0	2	n.a.	n.a.
Transport	**621**	**591**	**595**	**598**	**490**	**405**	**100**	**100**	**-0.2**	**-1.6**
Oil	556	510	483	534	358	201	81	50	-0.6	-3.9
Electricity	1	1	2	1	13	53	0	13	4.0	18.4
Biofuels	41	51	69	40	85	99	12	24	2.7	4.1
Other fuels	23	29	42	23	34	53	7	13	2.8	3.7
Buildings	**508**	**539**	**571**	**482**	**464**	**449**	**100**	**100**	**0.5**	**-0.5**
Coal	1	1	0	1	0	-	0	-	-4.2	-100
Oil	34	29	21	31	19	8	4	2	-2.0	-5.4
Gas	184	187	193	173	153	128	34	29	-0.1	-1.7
Electricity	266	297	326	250	251	248	57	55	1.0	-0.1
Heat	1	1	1	1	1	0	0	0	-1.9	-7.4
Bioenergy	17	19	20	20	26	35	4	8	0.9	3.0
Other renewables	4	7	10	6	15	29	2	6	5.6	9.9
Other	**159**	**157**	**152**	**157**	**154**	**146**	**100**	**100**	**0.5**	**0.4**

United States: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**3 203**	**4 315**	**4 458**	**4 538**	**4 639**	**4 745**	**4 882**	**100**	**100**	**0.5**
Coal	1 700	1 713	1 419	1 289	1 192	1 090	1 016	40	21	-2.0
Oil	131	40	22	18	17	14	9	1	0	-5.6
Gas	382	1 161	1 334	1 380	1 410	1 441	1 480	27	30	0.9
Nuclear	612	831	832	826	845	868	890	19	18	0.3
Hydro	273	261	290	302	313	328	342	6	7	1.0
Bioenergy	86	82	92	104	117	130	142	2	3	2.2
Wind	3	184	333	403	454	508	561	4	11	4.4
Geothermal	16	19	26	32	44	58	70	0	1	5.2
Solar PV	0	22	105	174	234	291	347	1	7	11.2
CSP	1	3	6	8	10	14	20	0	0	8.1
Marine	-	-	-	1	2	4	5	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**1 132**	**1 188**	**1 226**	**1 282**	**1 337**	**1 395**	**100**	**100**	**0.8**
Coal	302	244	226	222	214	196	27	14	-1.6
Oil	60	29	22	22	21	19	5	1	-4.4
Gas	458	495	494	497	504	531	40	38	0.6
Nuclear	104	104	103	105	108	110	9	8	0.2
Hydro	102	105	107	110	113	115	9	8	0.5
Bioenergy	17	20	22	25	27	29	2	2	2.1
Wind	65	118	138	153	168	182	6	13	4.0
Geothermal	4	4	5	7	9	10	0	1	4.1
Solar PV	19	68	106	138	168	195	2	14	9.4
CSP	2	2	3	3	4	6	0	0	4.7
Marine	-	-	0	1	1	2	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**4 783**	**5 155**	**4 839**	**4 600**	**4 319**	**4 068**	**3 888**	**100**	**100**	**-1.1**
Coal	1 837	1 699	1 396	1 266	1 165	1 057	977	33	25	-2.1
Oil	1 951	2 036	1 962	1 831	1 645	1 489	1 365	39	35	-1.5
Gas	995	1 420	1 481	1 503	1 509	1 523	1 546	28	40	0.3
Power generation	**1 881**	**2 108**	**1 832**	**1 715**	**1 621**	**1 522**	**1 446**	**100**	**100**	**-1.4**
Coal	1 582	1 592	1 291	1 165	1 069	967	890	76	62	-2.2
Oil	88	31	16	13	12	10	7	1	0	-5.8
Gas	211	485	526	537	540	545	550	23	38	0.5
TFC	**2 643**	**2 792**	**2 728**	**2 602**	**2 423**	**2 283**	**2 187**	**100**	**100**	**-0.9**
Coal	253	98	97	92	87	82	78	4	4	-0.8
Oil	1 711	1 894	1 833	1 711	1 532	1 384	1 267	68	58	-1.5
Transport	*1 391*	*1 681*	*1 633*	*1 529*	*1 368*	*1 237*	*1 132*	*60*	*52*	*-1.5*
Gas	679	800	798	799	805	817	841	29	38	0.2

United States: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**4 577**	**4 996**	**5 396**	**4 311**	**4 356**	**4 752**	**100**	**100**	**0.9**	**0.4**
Coal	1 451	1 382	1 358	1 008	227	153	25	3	-0.9	-8.9
Oil	22	18	10	21	12	4	0	0	-5.2	-8.3
Gas	1 445	1 678	1 809	1 583	1 546	959	34	20	1.7	-0.7
Nuclear	831	822	848	833	933	1 076	16	23	0.1	1.0
Hydro	290	311	338	290	321	355	6	7	1.0	1.2
Bioenergy	90	108	129	92	150	227	2	5	1.8	4.0
Wind	316	415	506	345	743	1 102	9	23	4.0	7.1
Geothermal	25	42	63	26	48	88	1	2	4.8	6.1
Solar PV	102	209	314	108	328	575	6	12	10.8	13.4
CSP	6	9	17	6	44	199	0	4	7.2	18.0
Marine	-	1	4	-	3	14	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 199**	**1 323**	**1 479**	**1 162**	**1 368**	**1 664**	**100**	**100**	**1.0**	**1.5**
Coal	245	231	225	231	124	61	15	4	-1.1	-6.0
Oil	29	23	21	28	14	8	1	0	-3.9	-7.5
Gas	515	561	632	475	501	541	43	32	1.3	0.6
Nuclear	104	102	105	104	116	137	7	8	0.0	1.0
Hydro	105	109	114	105	112	119	8	7	0.4	0.6
Bioenergy	19	23	26	20	31	48	2	3	1.6	4.0
Wind	110	140	163	123	250	351	11	21	3.6	6.7
Geothermal	4	6	9	4	7	13	1	1	3.7	5.0
Solar PV	65	124	177	70	196	326	12	20	9.0	11.6
CSP	2	3	4	2	14	58	0	4	3.8	14.7
Marine	-	1	1	-	1	5	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**4 943**	**4 788**	**4 660**	**4 451**	**2 901**	**1 711**	**100**	**100**	**-0.4**	**-4.2**
Coal	1 425	1 337	1 279	1 016	248	72	27	4	-1.1	-11.5
Oil	1 984	1 816	1 699	1 900	1 291	750	36	44	-0.7	-3.8
Gas	1 534	1 635	1 682	1 535	1 362	890	36	52	0.7	-1.8
Power generation	**1 903**	**1 892**	**1 858**	**1 548**	**727**	**221**	**100**	**100**	**-0.5**	**-8.3**
Coal	1 319	1 239	1 188	913	174	25	64	11	-1.1	-14.8
Oil	16	13	7	16	9	3	0	1	-5.4	-8.5
Gas	568	641	662	619	545	194	36	87	1.2	-3.5
TFC	**2 752**	**2 600**	**2 521**	**2 638**	**1 966**	**1 360**	**100**	**100**	**-0.4**	**-2.7**
Coal	98	89	82	94	68	42	3	3	-0.7	-3.2
Oil	1 853	1 695	1 586	1 775	1 204	696	63	51	-0.7	-3.8
Transport	*1 647*	*1 510*	*1 429*	*1 581*	*1 060*	*594*	*57*	*44*	*-0.6*	*-3.9*
Gas	801	815	854	768	694	621	34	46	0.3	-1.0

OECD Europe: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**1 631**	**1 697**	**1 690**	**1 641**	**1 601**	**1 568**	**1 540**	**100**	**100**	**-0.4**
Coal	452	299	255	226	186	152	136	18	9	-3.0
Oil	616	550	515	468	426	388	354	32	23	-1.7
Gas	260	380	410	426	431	435	426	22	28	0.4
Nuclear	205	229	218	190	189	190	187	14	12	-0.8
Hydro	38	49	53	55	57	58	59	3	4	0.7
Bioenergy	54	140	164	179	194	205	215	8	14	1.7
Other renewables	6	50	76	97	119	141	161	3	10	4.6
Power generation	**627**	**725**	**719**	**705**	**698**	**697**	**698**	**100**	**100**	**-0.1**
Coal	279	216	176	151	117	88	77	30	11	-3.9
Oil	51	15	11	8	6	5	4	2	1	-4.8
Gas	41	113	126	141	146	150	146	16	21	1.0
Nuclear	205	229	218	190	189	190	187	32	27	-0.8
Hydro	38	49	53	55	57	58	59	7	8	0.7
Bioenergy	9	59	68	74	80	85	89	8	13	1.6
Other renewables	4	44	66	84	103	120	136	6	19	4.5
Other energy sector	**152**	**146**	**140**	**133**	**126**	**120**	**114**	**100**	**100**	**-0.9**
Electricity	*39*	*44*	*43*	*42*	*42*	*42*	*42*	*30*	*37*	*-0.2*
TFC	**1 130**	**1 186**	**1 208**	**1 190**	**1 173**	**1 156**	**1 139**	**100**	**100**	**-0.2**
Coal	124	47	44	42	39	36	33	4	3	-1.3
Oil	525	499	471	432	396	362	333	42	29	-1.6
Gas	201	248	264	265	265	265	261	21	23	0.2
Electricity	193	261	279	288	296	304	310	22	27	0.7
Heat	40	45	47	49	50	51	52	4	5	0.5
Bioenergy	46	80	93	103	111	118	125	7	11	1.7
Other renewables	1	6	9	12	16	20	25	1	2	5.6
Industry	**325**	**295**	**300**	**298**	**292**	**285**	**281**	**100**	**100**	**-0.2**
Coal	71	29	28	27	26	24	22	10	8	-1.1
Oil	59	36	34	32	30	27	25	12	9	-1.4
Gas	77	91	93	91	89	86	84	31	30	-0.3
Electricity	88	99	102	103	103	103	103	33	37	0.2
Heat	14	16	16	16	15	14	14	6	5	-0.7
Bioenergy	14	23	26	28	29	30	31	8	11	1.1
Other renewables	0	0	0	1	1	2	2	0	1	7.4
Transport	**268**	**331**	**322**	**307**	**295**	**282**	**270**	**100**	**100**	**-0.8**
Oil	263	308	291	269	250	232	214	93	79	-1.4
Electricity	5	6	7	9	10	11	13	2	5	3.2
Biofuels	0	14	19	23	27	29	32	4	12	3.2
Other fuels	1	3	5	6	8	10	11	1	4	5.0
Buildings	**404**	**439**	**464**	**468**	**473**	**479**	**482**	**100**	**100**	**0.4**
Coal	49	15	13	12	11	10	9	3	2	-1.9
Oil	96	54	45	35	24	14	8	12	2	-6.9
Gas	105	143	157	157	159	160	157	33	33	0.4
Electricity	97	152	164	171	178	185	189	35	39	0.8
Heat	25	28	31	33	35	36	38	6	8	1.1
Bioenergy	30	41	46	49	53	56	59	9	12	1.4
Other renewables	1	5	8	11	14	18	22	1	5	5.7
Other	**134**	**122**	**122**	**118**	**113**	**109**	**105**	**100**	**100**	**-0.6**

OECD Europe: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 723**	**1 720**	**1 724**	**1 660**	**1 486**	**1 364**	**100**	**100**	**0.1**	**-0.8**
Coal	266	242	213	227	108	77	12	6	-1.3	-5.1
Oil	529	472	422	507	363	232	25	17	-1.0	-3.3
Gas	425	490	536	406	376	297	31	22	1.3	-0.9
Nuclear	218	177	164	226	227	237	9	17	-1.3	0.1
Hydro	52	55	57	53	58	61	3	4	0.6	0.8
Bioenergy	161	184	203	164	211	246	12	18	1.4	2.2
Other renewables	73	102	129	77	142	214	7	16	3.7	5.8
Power generation	**733**	**754**	**787**	**703**	**659**	**669**	**100**	**100**	**0.3**	**-0.3**
Coal	187	170	149	151	47	30	19	4	-1.4	-7.3
Oil	11	6	5	11	5	2	1	0	-4.5	-7.2
Gas	133	179	217	127	121	68	28	10	2.6	-1.9
Nuclear	218	177	164	226	227	237	21	35	-1.3	0.1
Hydro	52	55	57	53	58	61	7	9	0.6	0.8
Bioenergy	68	78	85	68	84	100	11	15	1.4	2.0
Other renewables	65	89	112	67	118	172	14	26	3.7	5.4
Other energy sector	**143**	**135**	**129**	**137**	**111**	**90**	**100**	**100**	**-0.5**	**-1.8**
Electricity	*44*	*46*	*48*	*42*	*38*	*37*	*37*	*41*	*0.3*	*-0.7*
TFC	**1 230**	**1 252**	**1 265**	**1 191**	**1 090**	**990**	**100**	**100**	**0.2**	**-0.7**
Coal	45	41	37	43	35	28	3	3	-0.9	-2.0
Oil	484	439	397	464	339	220	31	22	-0.9	-3.1
Gas	272	289	296	259	238	214	23	22	0.7	-0.6
Electricity	282	313	343	274	283	298	27	30	1.1	0.5
Heat	48	54	59	47	47	46	5	5	1.0	0.0
Bioenergy	91	104	116	93	125	144	9	15	1.5	2.3
Other renewables	9	13	17	10	24	42	1	4	4.1	7.7
Industry	**303**	**303**	**298**	**295**	**267**	**243**	**100**	**100**	**0.0**	**-0.7**
Coal	28	26	23	28	23	19	8	8	-0.9	-1.7
Oil	35	31	27	34	27	21	9	9	-1.1	-2.0
Gas	94	93	91	91	77	65	31	27	0.0	-1.3
Electricity	103	106	108	101	95	91	36	37	0.3	-0.3
Heat	16	16	15	16	14	12	5	5	-0.4	-1.3
Bioenergy	26	30	33	26	29	31	11	13	1.4	1.2
Other renewables	0	1	1	0	2	5	0	2	4.5	10.8
Transport	**328**	**318**	**307**	**316**	**264**	**212**	**100**	**100**	**-0.3**	**-1.7**
Oil	301	282	263	285	201	113	86	53	-0.6	-3.8
Electricity	7	9	11	7	16	38	3	18	2.5	7.7
Biofuels	17	22	27	19	38	46	9	22	2.6	4.7
Other fuels	4	6	6	5	8	15	2	7	2.9	6.2
Buildings	**476**	**516**	**551**	**458**	**449**	**435**	**100**	**100**	**0.9**	**-0.0**
Coal	14	12	11	13	10	7	2	2	-1.1	-2.8
Oil	47	32	20	44	21	6	4	1	-3.8	-8.1
Gas	164	180	190	153	144	126	34	29	1.1	-0.5
Electricity	167	194	219	161	167	165	40	38	1.4	0.3
Heat	32	38	44	30	33	34	8	8	1.6	0.7
Bioenergy	45	49	53	46	54	62	10	14	1.0	1.6
Other renewables	7	11	15	9	20	35	3	8	4.2	7.6
Other	**122**	**115**	**108**	**121**	**111**	**101**	**100**	**100**	**-0.5**	**-0.7**

OECD Europe: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**2 682**	**3 556**	**3 748**	**3 849**	**3 925**	**4 014**	**4 075**	**100**	**100**	**0.5**
Coal	1 040	906	743	639	491	371	331	25	8	-3.8
Oil	216	53	38	27	20	18	13	1	0	-5.1
Gas	168	595	695	798	826	845	800	17	20	1.1
Nuclear	787	876	835	730	723	728	718	25	18	-0.8
Hydro	446	568	618	645	663	676	687	16	17	0.7
Bioenergy	21	192	225	246	267	284	298	5	7	1.7
Wind	1	255	432	573	711	829	921	7	23	5.1
Geothermal	4	14	19	22	27	31	35	0	1	3.7
Solar PV	0	91	131	155	174	193	209	3	5	3.3
CSP	-	5	9	12	18	25	33	0	1	7.2
Marine	1	0	1	3	6	14	29	0	1	17.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**1 073**	**1 186**	**1 260**	**1 329**	**1 395**	**1 446**	**100**	**100**	**1.2**
Coal	184	183	163	133	102	91	17	6	-2.7
Oil	58	41	31	21	18	14	5	1	-5.2
Gas	235	254	290	327	366	386	22	27	1.9
Nuclear	129	121	106	104	105	102	12	7	-0.9
Hydro	207	222	230	235	239	243	19	17	0.6
Bioenergy	40	46	49	53	55	57	4	4	1.3
Wind	129	192	241	287	323	349	12	24	3.9
Geothermal	2	3	3	4	4	5	0	0	3.6
Solar PV	86	122	142	157	168	176	8	12	2.8
CSP	2	3	4	6	8	10	0	1	5.9
Marine	0	1	1	3	7	13	0	1	16.2

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**3 913**	**3 396**	**3 182**	**2 973**	**2 712**	**2 478**	**2 309**	**100**	**100**	**-1.5**
Coal	1 749	1 164	977	858	699	561	500	34	22	-3.2
Oil	1 605	1 368	1 271	1 145	1 033	931	843	40	37	-1.8
Gas	558	864	934	970	980	987	965	25	42	0.4
Power generation	**1 430**	**1 236**	**1 080**	**999**	**859**	**742**	**679**	**100**	**100**	**-2.3**
Coal	1 169	926	750	642	496	373	325	75	48	-4.0
Oil	165	45	34	24	19	16	13	4	2	-4.7
Gas	96	265	296	333	344	353	342	21	50	1.0
TFC	**2 311**	**1 993**	**1 943**	**1 826**	**1 715**	**1 609**	**1 511**	**100**	**100**	**-1.1**
Coal	540	202	192	180	167	154	143	10	9	-1.3
Oil	1 331	1 238	1 159	1 051	952	859	780	62	52	-1.8
Transport	*784*	*934*	*880*	*814*	*758*	*703*	*649*	*47*	*43*	*-1.4*
Gas	439	553	593	595	596	596	588	28	39	0.2

OECD Europe: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**3 800**	**4 175**	**4 530**	**3 681**	**3 731**	**3 877**	**100**	**100**	**0.9**	**0.3**
Coal	788	738	662	626	159	90	15	2	-1.2	-8.5
Oil	39	20	15	37	13	4	0	0	-4.8	-9.9
Gas	736	1 030	1 254	709	673	302	28	8	2.9	-2.6
Nuclear	835	678	628	866	872	911	14	23	-1.3	0.1
Hydro	599	636	663	619	671	705	15	18	0.6	0.8
Bioenergy	224	259	284	226	282	336	6	9	1.5	2.2
Wind	424	618	771	436	807	1 139	17	29	4.3	5.9
Geothermal	18	22	26	19	32	44	1	1	2.5	4.6
Solar PV	127	156	186	133	188	248	4	6	2.8	3.9
CSP	8	15	28	9	26	57	1	1	6.4	9.5
Marine	1	3	15	1	8	43	0	1	14.0	18.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 178**	**1 321**	**1 459**	**1 177**	**1 335**	**1 501**	**100**	**100**	**1.2**	**1.3**
Coal	186	154	133	176	107	58	9	4	-1.3	-4.4
Oil	41	22	15	39	20	13	1	1	-5.1	-5.7
Gas	258	366	459	246	282	317	31	21	2.6	1.2
Nuclear	121	98	89	125	124	128	6	9	-1.4	-0.0
Hydro	217	228	236	223	239	249	16	17	0.5	0.7
Bioenergy	46	51	55	46	55	64	4	4	1.2	1.8
Wind	188	253	300	194	322	424	21	28	3.3	4.7
Geothermal	2	3	4	3	4	6	0	0	2.5	4.5
Solar PV	117	141	155	123	169	206	11	14	2.3	3.4
CSP	3	5	8	3	8	17	1	1	5.1	8.0
Marine	0	2	7	1	4	19	0	1	13.4	18.1

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**3 304**	**3 219**	**3 084**	**3 035**	**2 056**	**1 307**	**100**	**100**	**-0.4**	**-3.6**
Coal	1 023	935	819	863	361	192	27	15	-1.3	-6.7
Oil	1 312	1 168	1 045	1 248	847	476	34	36	-1.0	-4.0
Gas	969	1 116	1 220	925	848	639	40	49	1.3	-1.2
Power generation	**1 140**	**1 164**	**1 151**	**975**	**486**	**227**	**100**	**100**	**-0.3**	**-6.3**
Coal	793	723	627	642	190	78	54	35	-1.5	-9.1
Oil	34	19	14	33	14	6	1	3	-4.4	-7.2
Gas	313	422	510	300	281	142	44	63	2.5	-2.4
TFC	**2 002**	**1 907**	**1 798**	**1 906**	**1 459**	**1 007**	**100**	**100**	**-0.4**	**-2.6**
Coal	194	176	158	186	143	94	9	9	-0.9	-2.9
Oil	1 198	1 080	971	1 139	784	441	54	44	-0.9	-3.9
Transport	*911*	*855*	*797*	*865*	*609*	*341*	*44*	*34*	*-0.6*	*-3.8*
Gas	611	651	669	581	533	473	37	47	0.7	-0.6

European Union: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**1 643**	**1 563**	**1 547**	**1 492**	**1 441**	**1 398**	**1 360**	**100**	**100**	**-0.5**
Coal	456	268	223	194	152	118	100	17	7	-3.7
Oil	607	509	469	425	384	346	314	33	23	-1.8
Gas	297	343	377	390	392	389	376	22	28	0.4
Nuclear	207	228	219	191	188	190	187	15	14	-0.8
Hydro	25	32	32	33	34	35	36	2	3	0.4
Bioenergy	47	142	165	180	194	204	213	9	16	1.6
Other renewables	3	40	61	79	98	117	135	3	10	4.8
Power generation	**646**	**667**	**659**	**638**	**622**	**613**	**606**	**100**	**100**	**-0.4**
Coal	287	202	161	136	99	70	57	30	9	-4.8
Oil	62	16	12	8	6	5	4	2	1	-5.2
Gas	55	92	111	125	129	128	121	14	20	1.1
Nuclear	207	228	219	191	188	190	187	34	31	-0.8
Hydro	25	32	32	33	34	35	36	5	6	0.4
Bioenergy	8	58	67	73	78	81	84	9	14	1.4
Other renewables	3	38	57	72	88	104	117	6	19	4.5
Other energy sector	**152**	**129**	**122**	**114**	**108**	**102**	**97**	**100**	**100**	**-1.1**
Electricity	*39*	*40*	*39*	*37*	*36*	*36*	*35*	*31*	*36*	*-0.5*
TFC	**1 132**	**1 095**	**1 108**	**1 086**	**1 061**	**1 037**	**1 013**	**100**	**100**	**-0.3**
Coal	122	37	34	31	28	25	23	3	2	-1.9
Oil	504	460	429	392	356	322	292	42	29	-1.7
Gas	226	235	251	250	248	246	241	21	24	0.1
Electricity	186	233	246	252	255	260	262	21	26	0.5
Heat	54	46	47	49	50	51	51	4	5	0.4
Bioenergy	39	82	96	106	114	121	127	8	13	1.7
Other renewables	1	2	4	7	10	13	18	0	2	7.9
Industry	**344**	**268**	**271**	**267**	**259**	**250**	**245**	**100**	**100**	**-0.3**
Coal	69	24	23	22	20	18	17	9	7	-1.3
Oil	59	33	32	29	27	24	22	12	9	-1.5
Gas	97	86	87	85	82	78	76	32	31	-0.5
Electricity	85	86	88	88	87	86	86	32	35	-0.0
Heat	19	15	15	14	14	13	12	6	5	-0.9
Bioenergy	14	23	26	28	29	30	30	9	12	1.0
Other renewables	-	0	0	0	1	1	2	0	1	19.1
Transport	**259**	**307**	**295**	**281**	**268**	**255**	**242**	**100**	**100**	**-0.9**
Oil	253	285	264	244	225	206	189	93	78	-1.6
Electricity	5	5	7	8	9	11	12	2	5	3.1
Biofuels	0	14	19	23	27	30	32	5	13	3.2
Other fuels	1	3	4	6	7	8	10	1	4	4.6
Buildings	**396**	**409**	**430**	**431**	**432**	**434**	**434**	**100**	**100**	**0.2**
Coal	49	10	8	7	6	4	4	2	1	-3.9
Oil	90	51	43	33	22	13	8	12	2	-6.9
Gas	108	135	148	148	149	149	146	33	34	0.3
Electricity	91	138	147	151	156	160	161	34	37	0.6
Heat	34	30	32	34	36	37	39	7	9	1.0
Bioenergy	24	43	48	52	55	58	61	10	14	1.4
Other renewables	1	2	4	7	9	12	16	1	4	7.8
Other	**134**	**112**	**111**	**107**	**102**	**97**	**92**	**100**	**100**	**-0.7**

European Union: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 577**	**1 549**	**1 525**	**1 520**	**1 348**	**1 222**	**100**	**100**	**-0.1**	**-0.9**
Coal	233	200	159	197	90	66	10	5	-2.0	-5.3
Oil	482	426	377	462	328	206	25	17	-1.1	-3.4
Gas	388	444	481	374	346	268	32	22	1.3	-0.9
Nuclear	219	176	165	227	224	230	11	19	-1.3	0.0
Hydro	32	34	35	32	35	37	2	3	0.4	0.5
Bioenergy	163	185	203	165	209	238	13	19	1.4	2.0
Other renewables	60	83	106	62	116	178	7	15	3.8	5.9
Power generation	**670**	**671**	**682**	**645**	**597**	**598**	**100**	**100**	**0.1**	**-0.4**
Coal	170	145	112	137	43	31	16	5	-2.2	-7.0
Oil	12	6	4	12	5	2	1	0	-4.9	-7.7
Gas	114	157	189	113	110	60	28	10	2.8	-1.6
Nuclear	219	176	165	227	224	230	24	38	-1.3	0.0
Hydro	32	34	35	32	35	37	5	6	0.4	0.5
Bioenergy	67	75	80	67	80	93	12	15	1.2	1.8
Other renewables	56	77	97	57	100	146	14	24	3.7	5.4
Other energy sector	**124**	**116**	**111**	**118**	**95**	**78**	**100**	**100**	**-0.6**	**-1.9**
Electricity	*39*	*39*	*41*	*38*	*33*	*32*	*37*	*41*	*0.0*	*-0.9*
TFC	**1 129**	**1 135**	**1 130**	**1 092**	**989**	**886**	**100**	**100**	**0.1**	**-0.8**
Coal	34	29	25	33	25	19	2	2	-1.5	-2.6
Oil	442	396	351	423	306	194	31	22	-1.0	-3.3
Gas	258	272	276	246	223	197	24	22	0.6	-0.7
Electricity	249	271	291	242	246	256	26	29	0.9	0.4
Heat	48	53	58	47	47	45	5	5	0.9	-0.0
Bioenergy	94	107	120	96	127	143	11	16	1.5	2.2
Other renewables	4	7	10	5	16	32	1	4	5.6	10.5
Industry	**274**	**269**	**260**	**267**	**237**	**211**	**100**	**100**	**-0.1**	**-0.9**
Coal	23	21	18	22	18	14	7	7	-1.1	-2.1
Oil	32	28	24	31	24	19	9	9	-1.3	-2.1
Gas	88	86	82	86	71	58	32	27	-0.2	-1.5
Electricity	89	90	90	87	81	76	35	36	0.2	-0.5
Heat	15	14	13	15	12	10	5	5	-0.6	-1.6
Bioenergy	26	30	33	26	29	31	13	15	1.3	1.1
Other renewables	0	0	1	0	2	4	0	2	14.8	23.1
Transport	**301**	**290**	**277**	**290**	**241**	**191**	**100**	**100**	**-0.4**	**-1.8**
Oil	274	255	234	260	182	100	84	52	-0.8	-3.9
Electricity	6	8	10	7	14	34	4	18	2.5	7.4
Biofuels	17	22	27	19	37	44	10	23	2.5	4.5
Other fuels	4	6	6	4	7	13	2	7	2.8	5.9
Buildings	**442**	**473**	**499**	**424**	**411**	**395**	**100**	**100**	**0.8**	**-0.1**
Coal	9	6	5	8	5	3	1	1	-2.9	-4.8
Oil	45	30	18	42	20	6	4	1	-3.8	-8.0
Gas	155	169	178	145	134	117	36	30	1.1	-0.6
Electricity	149	169	188	144	147	143	38	36	1.2	0.2
Heat	33	39	44	32	34	35	9	9	1.5	0.6
Bioenergy	48	53	57	49	57	64	11	16	1.1	1.6
Other renewables	4	6	9	5	14	28	2	7	5.5	10.2
Other	**112**	**103**	**94**	**111**	**99**	**88**	**100**	**100**	**-0.7**	**-0.9**

European Union: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**2 577**	**3 155**	**3 299**	**3 355**	**3 379**	**3 416**	**3 427**	**100**	**100**	**0.3**
Coal	1 050	841	673	569	409	284	229	27	7	-4.9
Oil	224	57	41	27	20	17	12	2	0	-5.7
Gas	193	457	590	688	708	702	642	14	19	1.3
Nuclear	795	876	839	731	720	727	719	28	21	-0.8
Hydro	290	375	373	386	398	407	415	12	12	0.4
Bioenergy	20	189	222	241	258	272	283	6	8	1.6
Wind	1	253	416	542	666	771	851	8	25	4.8
Geothermal	3	6	8	10	14	17	20	0	1	4.6
Solar PV	0	92	128	149	165	183	197	3	6	3.0
CSP	-	5	8	11	15	22	29	0	1	6.7
Marine	1	0	1	3	6	14	29	0	1	17.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**985**	**1 066**	**1 123**	**1 176**	**1 228**	**1 265**	**100**	**100**	**1.0**
Coal	177	169	147	114	83	70	18	6	-3.5
Oil	58	39	29	19	15	12	6	1	-5.9
Gas	212	226	259	292	324	338	22	27	1.8
Nuclear	129	121	105	103	104	102	13	8	-0.9
Hydro	151	157	161	166	169	171	15	14	0.5
Bioenergy	40	45	49	51	54	55	4	4	1.3
Wind	129	186	230	271	303	326	13	26	3.6
Geothermal	1	1	1	2	2	3	0	0	4.5
Solar PV	87	118	136	150	160	166	9	13	2.5
CSP	2	2	3	5	7	9	0	1	5.4
Marine	0	1	1	3	7	13	0	1	16.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**4 005**	**3 104**	**2 882**	**2 671**	**2 391**	**2 142**	**1 953**	**100**	**100**	**-1.8**
Coal	1 774	1 057	865	745	573	433	361	34	18	-4.1
Oil	1 590	1 277	1 168	1 046	935	833	747	41	38	-2.0
Gas	641	770	849	879	883	876	846	25	43	0.4
Power generation	**1 528**	**1 130**	**982**	**899**	**743**	**615**	**534**	**100**	**100**	**-2.8**
Coal	1 201	865	685	579	421	297	238	77	45	-4.8
Oil	199	49	36	25	19	16	12	4	2	-5.2
Gas	129	216	261	295	303	302	284	19	53	1.1
TFC	**2 308**	**1 827**	**1 765**	**1 650**	**1 535**	**1 424**	**1 324**	**100**	**100**	**-1.2**
Coal	535	162	150	139	126	112	102	9	8	-1.8
Oil	1 281	1 145	1 059	956	858	765	687	63	52	-1.9
Transport	*755*	*864*	*802*	*739*	*681*	*626*	*572*	*47*	*43*	*-1.6*
Gas	493	520	556	555	551	547	536	28	40	0.1

European Union: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**3 343**	**3 599**	**3 827**	**3 238**	**3 228**	**3 314**	**100**	**100**	**0.7**	**0.2**
Coal	712	622	488	562	140	92	13	3	-2.1	-8.2
Oil	41	20	14	40	12	3	0	0	-5.3	-10.8
Gas	606	876	1 068	607	591	240	28	7	3.3	-2.5
Nuclear	839	677	632	870	861	882	17	27	-1.3	0.0
Hydro	373	395	412	374	405	426	11	13	0.4	0.5
Bioenergy	221	251	271	222	269	310	7	9	1.4	1.9
Wind	410	582	716	417	723	1 009	19	30	4.1	5.5
Geothermal	8	11	14	8	18	28	0	1	3.2	5.9
Solar PV	124	148	174	130	178	232	5	7	2.5	3.6
CSP	8	14	25	8	22	49	1	1	6.0	8.8
Marine	1	3	15	1	8	43	0	1	14.0	18.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 064**	**1 171**	**1 275**	**1 060**	**1 181**	**1 312**	**100**	**100**	**1.0**	**1.1**
Coal	172	129	95	164	98	55	7	4	-2.4	-4.4
Oil	39	19	12	38	18	11	1	1	-5.7	-6.2
Gas	229	329	411	219	255	272	32	21	2.6	1.0
Nuclear	121	97	89	125	123	125	7	10	-1.4	-0.1
Hydro	157	165	170	157	169	176	13	13	0.5	0.6
Bioenergy	45	50	53	45	53	60	4	5	1.1	1.6
Wind	183	241	282	187	292	381	22	29	3.1	4.3
Geothermal	1	1	2	1	2	4	0	0	3.2	5.9
Solar PV	114	134	146	120	161	195	11	15	2.0	3.2
CSP	2	4	8	2	7	15	1	1	4.7	7.4
Marine	0	2	7	1	4	19	1	1	13.4	18.1

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**2 988**	**2 842**	**2 630**	**2 746**	**1 844**	**1 155**	**100**	**100**	**-0.6**	**-3.7**
Coal	904	775	607	756	302	162	23	14	-2.1	-7.0
Oil	1 207	1 061	934	1 147	770	422	36	37	-1.2	-4.2
Gas	876	1 005	1 090	843	772	570	41	49	1.3	-1.1
Power generation	**1 029**	**1 005**	**929**	**885**	**446**	**213**	**100**	**100**	**-0.8**	**-6.2**
Coal	724	618	473	583	175	82	51	39	-2.3	-8.6
Oil	37	19	13	36	15	6	1	3	-4.9	-7.6
Gas	269	368	443	267	256	124	48	58	2.8	-2.1
TFC	**1 821**	**1 715**	**1 591**	**1 731**	**1 308**	**883**	**100**	**100**	**-0.5**	**-2.8**
Coal	152	132	112	145	105	65	7	7	-1.4	-3.5
Oil	1 095	978	863	1 040	710	389	54	44	-1.1	-4.1
Transport	*831*	*773*	*709*	*788*	*552*	*303*	*45*	*34*	*-0.8*	*-3.9*
Gas	574	606	616	545	492	429	39	49	0.7	-0.7

OECD Asia Oceania: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**631**	**857**	**870**	**866**	**859**	**851**	**842**	**100**	**100**	**-0.1**
Coal	138	243	235	214	202	188	174	28	21	-1.3
Oil	335	339	304	277	252	229	212	40	25	-1.8
Gas	66	187	174	171	174	178	178	22	21	-0.2
Nuclear	66	41	93	128	140	147	156	5	19	5.3
Hydro	11	11	12	12	12	13	13	1	2	0.8
Bioenergy	10	24	29	31	34	37	39	3	5	1.9
Other renewables	5	12	23	33	45	59	68	1	8	6.8
Power generation	**248**	**372**	**384**	**400**	**412**	**422**	**429**	**100**	**100**	**0.5**
Coal	60	161	150	132	123	111	101	43	24	-1.8
Oil	64	27	11	7	5	4	4	7	1	-7.5
Gas	40	110	83	75	74	74	72	30	17	-1.6
Nuclear	66	41	93	128	140	147	156	11	36	5.3
Hydro	11	11	12	12	12	13	13	3	3	0.8
Bioenergy	3	11	14	16	18	20	22	3	5	2.6
Other renewables	3	11	21	30	40	52	60	3	14	6.7
Other energy sector	**65**	**90**	**96**	**95**	**95**	**92**	**90**	**100**	**100**	**-0.0**
Electricity	*12*	*16*	*17*	*18*	*18*	*18*	*18*	*18*	*21*	*0.5*
TFC	**418**	**561**	**561**	**549**	**537**	**526**	**516**	**100**	**100**	**-0.3**
Coal	47	38	38	36	34	31	29	7	6	-1.1
Oil	247	291	276	255	235	218	205	52	40	-1.3
Gas	26	69	76	79	81	82	83	12	16	0.7
Electricity	88	145	149	155	161	166	170	26	33	0.6
Heat	0	5	5	5	5	5	5	1	1	-0.1
Bioenergy	7	13	15	15	16	17	17	2	3	1.2
Other renewables	2	1	2	3	5	6	9	0	2	7.7
Industry	**152**	**186**	**197**	**195**	**191**	**187**	**183**	**100**	**100**	**-0.1**
Coal	37	35	36	34	32	29	27	19	15	-1.0
Oil	53	50	52	49	45	43	40	27	22	-0.8
Gas	11	33	37	38	38	38	39	18	21	0.7
Electricity	47	56	58	60	60	61	61	30	33	0.4
Heat	-	3	3	2	2	2	2	1	1	-0.9
Bioenergy	5	10	11	11	12	12	13	5	7	1.1
Other renewables	0	0	0	1	1	1	2	0	1	8.3
Transport	**107**	**140**	**129**	**120**	**112**	**107**	**104**	**100**	**100**	**-1.1**
Oil	105	136	123	113	104	97	93	97	90	-1.4
Electricity	2	2	2	3	4	4	5	2	5	3.6
Biofuels	-	1	1	1	1	1	1	0	1	0.9
Other fuels	0	2	3	4	4	4	5	1	4	4.2
Buildings	**109**	**160**	**161**	**163**	**166**	**168**	**169**	**100**	**100**	**0.2**
Coal	10	1	1	1	1	1	1	1	0	-1.9
Oil	42	34	31	27	23	20	16	22	10	-2.8
Gas	15	33	34	35	37	37	37	20	22	0.5
Electricity	38	85	87	91	95	99	101	53	60	0.7
Heat	0	3	3	3	3	3	3	2	2	0.6
Bioenergy	2	3	3	3	3	4	4	2	2	1.6
Other renewables	2	1	2	2	3	5	7	1	4	7.6
Other	**50**	**76**	**75**	**71**	**68**	**65**	**61**	**100**	**100**	**-0.8**

OECD Asia Oceania: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**878**	**889**	**889**	**849**	**780**	**732**	**100**	**100**	**0.1**	**-0.6**
Coal	238	227	221	223	125	77	25	10	-0.4	-4.3
Oil	307	262	225	298	224	162	25	22	-1.6	-2.8
Gas	177	181	194	169	163	126	22	17	0.1	-1.5
Nuclear	93	132	135	93	152	185	15	25	4.7	6.0
Hydro	12	12	13	12	14	17	1	2	0.6	1.6
Bioenergy	29	34	38	29	41	55	4	8	1.8	3.2
Other renewables	23	41	62	25	60	109	7	15	6.4	8.7
Power generation	**388**	**427**	**453**	**373**	**367**	**375**	**100**	**100**	**0.8**	**0.0**
Coal	153	146	143	143	53	18	32	5	-0.5	-8.1
Oil	11	5	4	10	2	2	1	0	-7.4	-10.4
Gas	84	76	80	80	71	34	18	9	-1.2	-4.4
Nuclear	93	132	135	93	152	185	30	49	4.7	6.0
Hydro	12	12	13	12	14	17	3	4	0.6	1.6
Bioenergy	14	17	20	14	21	28	5	7	2.3	3.5
Other renewables	21	38	58	22	53	92	13	25	6.5	8.5
Other energy sector	**98**	**99**	**99**	**93**	**83**	**66**	**100**	**100**	**0.4**	**-1.2**
Electricity	*17*	*19*	*20*	*16*	*15*	*14*	*20*	*21*	*0.8*	*-0.5*
TFC	**566**	**553**	**540**	**550**	**496**	**454**	**100**	**100**	**-0.1**	**-0.8**
Coal	38	34	29	37	31	24	5	5	-1.0	-1.7
Oil	278	245	218	271	212	159	40	35	-1.1	-2.3
Gas	77	84	87	74	76	77	16	17	0.9	0.5
Electricity	151	166	179	145	145	144	33	32	0.8	-0.0
Heat	5	5	5	5	5	5	1	1	-0.1	-0.4
Bioenergy	15	16	18	15	20	27	3	6	1.3	3.0
Other renewables	2	3	4	2	7	17	1	4	4.9	10.5
Industry	**198**	**195**	**190**	**193**	**178**	**163**	**100**	**100**	**0.1**	**-0.5**
Coal	36	32	28	35	29	23	15	14	-0.9	-1.7
Oil	53	47	42	51	41	34	22	21	-0.7	-1.5
Gas	37	39	41	36	36	34	21	21	0.8	0.2
Electricity	58	62	63	57	56	54	33	33	0.5	-0.1
Heat	3	2	2	3	2	2	1	1	-0.9	-1.1
Bioenergy	11	12	14	11	12	13	7	8	1.4	1.3
Other renewables	0	1	1	1	2	3	1	2	6.4	11.4
Transport	**131**	**118**	**110**	**127**	**107**	**92**	**100**	**100**	**-0.9**	**-1.6**
Oil	125	111	103	122	92	62	93	67	-1.1	-3.0
Electricity	2	3	3	2	5	10	3	11	1.9	6.3
Biofuels	1	1	1	1	4	9	1	10	0.3	10.9
Other fuels	3	4	3	3	6	11	3	12	2.7	7.8
Buildings	**163**	**172**	**179**	**155**	**144**	**138**	**100**	**100**	**0.4**	**-0.6**
Coal	1	1	1	1	1	1	0	0	-1.7	-3.4
Oil	32	25	18	29	17	9	10	7	-2.4	-4.9
Gas	35	38	41	33	32	30	23	22	0.9	-0.3
Electricity	88	100	110	84	83	78	61	56	1.0	-0.4
Heat	3	3	3	3	3	3	2	2	0.6	0.3
Bioenergy	3	3	3	3	4	5	2	3	0.7	2.2
Other renewables	1	2	3	2	5	13	2	9	4.4	10.5
Other	**75**	**68**	**61**	**75**	**67**	**60**	**100**	**100**	**-0.8**	**-0.9**

OECD Asia Oceania: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**1 164**	**1 872**	**1 935**	**2 011**	**2 082**	**2 139**	**2 185**	**100**	**100**	**0.6**
Coal	258	734	699	627	592	551	512	39	23	-1.4
Oil	306	137	55	38	27	21	18	7	1	-7.6
Gas	200	611	494	467	472	479	468	33	21	-1.0
Nuclear	255	156	357	489	538	566	600	8	27	5.3
Hydro	131	127	135	139	145	150	156	7	7	0.8
Bioenergy	11	45	55	63	71	80	88	2	4	2.6
Wind	-	19	43	68	95	123	152	1	7	8.4
Geothermal	4	10	15	23	32	43	46	1	2	6.1
Solar PV	0	32	81	92	102	112	124	2	6	5.3
CSP	-	0	0	1	4	6	7	0	0	33.5
Marine	-	0	1	3	5	8	15	0	1	13.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**483**	**549**	**568**	**591**	**611**	**629**	**100**	**100**	**1.0**
Coal	109	116	113	113	108	103	22	16	-0.2
Oil	54	34	26	19	14	12	11	2	-5.6
Gas	138	157	161	168	173	169	28	27	0.8
Nuclear	66	67	70	72	74	79	14	13	0.7
Hydro	69	71	73	74	76	78	14	12	0.4
Bioenergy	8	10	11	12	14	15	2	2	2.3
Wind	8	17	26	34	43	52	2	8	7.5
Geothermal	1	2	3	5	7	9	0	1	7.0
Solar PV	30	74	83	91	98	105	6	17	4.9
CSP	0	0	0	1	2	2	0	0	28.8
Marine	0	0	1	2	3	5	0	1	12.1

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**1 551**	**2 137**	**1 952**	**1 789**	**1 683**	**1 580**	**1 487**	**100**	**100**	**-1.4**
Coal	533	941	898	811	754	689	630	44	42	-1.5
Oil	858	754	646	581	526	479	448	35	30	-2.0
Gas	160	441	408	397	404	412	409	21	28	-0.3
Power generation	**585**	**1 056**	**889**	**780**	**728**	**678**	**628**	**100**	**100**	**-2.0**
Coal	287	705	654	577	534	486	443	67	71	-1.8
Oil	204	86	35	24	17	13	11	8	2	-7.5
Gas	94	265	200	179	177	178	173	25	28	-1.6
TFC	**895**	**945**	**913**	**860**	**808**	**760**	**721**	**100**	**100**	**-1.0**
Coal	219	173	175	166	155	143	131	18	18	-1.1
Oil	617	617	565	515	469	431	402	65	56	-1.6
Transport	*314*	*404*	*367*	*336*	*309*	*289*	*277*	*43*	*38*	*-1.4*
Gas	59	156	172	179	184	187	188	16	26	0.7

OECD Asia Oceania: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 954**	**2 154**	**2 313**	**1 881**	**1 869**	**1 838**	**100**	**100**	**0.8**	**-0.1**
Coal	715	706	726	663	255	71	31	4	-0.0	-8.6
Oil	55	28	18	49	9	4	1	0	-7.5	-12.4
Gas	500	487	519	474	452	213	22	12	-0.6	-4.0
Nuclear	357	507	519	357	585	709	22	39	4.7	6.0
Hydro	134	141	149	136	166	194	6	11	0.6	1.6
Bioenergy	56	69	81	56	84	113	3	6	2.3	3.7
Wind	42	86	129	47	141	248	6	14	7.7	10.5
Geothermal	16	31	50	16	42	72	2	4	6.4	7.9
Solar PV	80	95	110	83	124	173	5	9	4.9	6.7
CSP	0	2	5	0	4	16	0	1	31.9	37.7
Marine	1	2	6	1	6	23	0	1	10.1	16.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**551**	**598**	**632**	**540**	**583**	**642**	**100**	**100**	**1.0**	**1.1**
Coal	117	122	124	114	82	49	20	8	0.5	-3.0
Oil	35	19	13	32	15	8	2	1	-5.4	-7.1
Gas	160	179	190	148	139	125	30	19	1.2	-0.4
Nuclear	67	70	68	67	79	93	11	15	0.1	1.4
Hydro	71	73	75	72	85	95	12	15	0.3	1.2
Bioenergy	10	12	14	10	15	19	2	3	2.0	3.3
Wind	17	31	44	19	51	84	7	13	6.9	9.5
Geothermal	2	5	7	2	6	11	1	2	6.4	7.9
Solar PV	73	85	94	76	110	146	15	23	4.5	6.3
CSP	0	1	1	0	1	4	0	1	26.1	31.8
Marine	0	1	2	0	2	8	0	1	8.2	14.1

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 980**	**1 830**	**1 751**	**1 874**	**1 227**	**735**	**100**	**100**	**-0.8**	**-4.0**
Coal	913	857	815	855	409	167	47	23	-0.6	-6.4
Oil	654	555	490	628	450	307	28	42	-1.6	-3.4
Gas	414	418	446	392	367	261	25	36	0.0	-2.0
Power generation	**905**	**836**	**830**	**844**	**392**	**96**	**100**	**100**	**-0.9**	**-8.8**
Coal	668	636	625	621	219	25	75	26	-0.5	-12.0
Oil	35	17	12	31	7	5	1	5	-7.4	-10.4
Gas	202	183	193	192	166	66	23	68	-1.2	-5.2
TFC	**922**	**843**	**773**	**889**	**715**	**551**	**100**	**100**	**-0.8**	**-2.1**
Coal	175	157	134	167	135	101	17	18	-1.0	-2.1
Oil	572	496	441	553	409	277	57	50	-1.3	-3.0
Transport	*371*	*329*	*305*	*362*	*275*	*184*	*40*	*33*	*-1.1*	*-3.0*
Gas	174	190	198	169	171	173	26	31	0.9	0.4

Japan: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**439**	**442**	**424**	**411**	**399**	**389**	**381**	**100**	**100**	**-0.6**
Coal	76	118	111	102	97	90	83	27	22	-1.4
Oil	250	192	159	140	124	109	98	43	26	-2.6
Gas	44	108	86	79	79	81	80	24	21	-1.2
Nuclear	53	-	37	54	56	58	61	-	16	n.a.
Hydro	7	7	8	8	8	9	9	2	2	0.9
Bioenergy	5	11	13	14	15	16	17	3	4	1.6
Other renewables	3	5	11	14	20	27	34	1	9	7.4
Power generation	**181**	**188**	**184**	**189**	**193**	**198**	**203**	**100**	**100**	**0.3**
Coal	25	69	61	55	54	51	47	37	23	-1.5
Oil	59	22	7	5	3	2	2	12	1	-9.6
Gas	33	77	51	43	42	43	41	41	20	-2.4
Nuclear	53	-	37	54	56	58	61	-	30	n.a.
Hydro	7	7	8	8	8	9	9	4	4	0.9
Bioenergy	2	8	9	10	11	12	13	4	6	2.0
Other renewables	1	5	10	13	18	25	31	3	15	7.5
Other energy sector	**46**	**48**	**46**	**43**	**40**	**37**	**34**	**100**	**100**	**-1.3**
Electricity	*9*	*7*	*7*	*7*	*8*	*8*	*8*	*15*	*23*	*0.4*
TFC	**287**	**296**	**282**	**268**	**257**	**246**	**238**	**100**	**100**	**-0.8**
Coal	30	24	23	22	20	18	17	8	7	-1.4
Oil	171	156	140	126	113	101	92	53	39	-2.0
Gas	15	30	34	35	36	36	37	10	15	0.8
Electricity	66	82	80	81	82	84	85	28	36	0.1
Heat	0	1	1	1	1	1	1	0	0	1.0
Bioenergy	3	3	4	4	4	4	4	1	2	0.6
Other renewables	1	1	1	1	1	2	3	0	1	6.9
Industry	**110**	**90**	**89**	**85**	**81**	**77**	**74**	**100**	**100**	**-0.8**
Coal	29	23	22	21	19	17	16	25	21	-1.4
Oil	39	25	23	20	17	15	13	27	18	-2.3
Gas	4	14	16	17	17	17	17	16	24	0.8
Electricity	36	25	24	24	23	23	23	28	31	-0.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	3	3	4	4	4	4	4	4	5	0.6
Other renewables	-	-	0	0	0	0	0	-	1	n.a.
Transport	**68**	**72**	**63**	**57**	**52**	**48**	**44**	**100**	**100**	**-1.8**
Oil	67	70	61	55	49	44	40	98	91	-2.1
Electricity	1	2	2	2	3	3	4	2	8	3.4
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	0	0	0	0	0	0	0	0	1	6.8
Buildings	**73**	**99**	**96**	**96**	**95**	**95**	**95**	**100**	**100**	**-0.2**
Coal	1	1	1	1	0	0	0	1	0	-0.9
Oil	31	27	24	22	19	16	14	27	15	-2.5
Gas	11	16	17	17	18	19	19	16	20	0.7
Electricity	28	55	53	55	56	58	59	55	62	0.3
Heat	0	1	1	1	1	1	1	1	1	1.0
Bioenergy	0	0	0	0	0	0	0	0	0	-0.9
Other renewables	1	0	1	1	1	2	3	0	3	6.8
Other	**35**	**35**	**32**	**30**	**28**	**26**	**25**	**100**	**100**	**-1.3**

Japan: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**427**	**410**	**395**	**410**	**357**	**322**	**100**	**100**	**-0.4**	**-1.2**
Coal	112	110	102	105	62	34	26	11	-0.6	-4.7
Oil	160	128	104	154	109	76	26	24	-2.3	-3.5
Gas	87	81	86	81	67	47	22	15	-0.9	-3.2
Nuclear	37	48	46	37	64	78	12	24	n.a.	n.a.
Hydro	8	8	9	8	9	11	2	3	0.8	1.7
Bioenergy	13	15	17	13	18	22	4	7	1.6	2.7
Other renewables	11	20	31	11	26	54	8	17	7.1	9.4
Power generation	**186**	**199**	**210**	**178**	**168**	**169**	**100**	**100**	**0.4**	**-0.4**
Coal	62	66	65	59	24	5	31	3	-0.2	-9.9
Oil	7	3	2	6	1	0	1	0	-9.5	-16.0
Gas	52	42	46	48	34	14	22	8	-2.0	-6.3
Nuclear	37	48	46	37	64	78	22	46	n.a.	n.a.
Hydro	8	8	9	8	9	11	4	7	0.8	1.7
Bioenergy	9	11	12	9	12	15	6	9	1.9	2.7
Other renewables	10	20	30	11	24	46	14	27	7.3	9.1
Other energy sector	**46**	**41**	**35**	**43**	**36**	**27**	**100**	**100**	**-1.1**	**-2.2**
Electricity	*7*	*8*	*8*	*7*	*6*	*6*	*24*	*21*	*0.7*	*-0.9*
TFC	**284**	**263**	**248**	**274**	**231**	**201**	**100**	**100**	**-0.7**	**-1.5**
Coal	23	20	17	22	18	13	7	7	-1.3	-2.2
Oil	141	116	98	137	102	72	39	36	-1.8	-2.9
Gas	34	37	39	32	32	31	16	15	1.0	0.1
Electricity	80	84	89	77	72	68	36	34	0.3	-0.7
Heat	1	1	1	0	0	0	0	0	1.1	-0.7
Bioenergy	4	4	4	4	5	7	2	3	0.9	2.8
Other renewables	1	1	1	1	3	8	1	4	3.7	11.1
Industry	**90**	**83**	**76**	**87**	**75**	**65**	**100**	**100**	**-0.7**	**-1.3**
Coal	22	19	16	21	17	13	21	20	-1.3	-2.1
Oil	23	18	14	22	16	11	18	18	-2.2	-2.9
Gas	16	18	18	16	16	15	24	24	1.0	0.3
Electricity	24	24	23	24	22	20	31	31	-0.4	-0.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	4	4	4	4	4	6	6	0.9	0.7
Other renewables	0	0	0	0	1	1	0	2	n.a.	n.a.
Transport	**64**	**53**	**47**	**63**	**50**	**39**	**100**	**100**	**-1.6**	**-2.4**
Oil	62	51	45	61	45	30	94	77	-1.7	-3.3
Electricity	2	2	2	2	3	5	5	14	1.7	5.0
Biofuels	-	-	-	-	1	3	-	7	n.a.	n.a.
Other fuels	0	0	0	0	1	1	1	2	4.9	9.6
Buildings	**97**	**99**	**101**	**91**	**78**	**73**	**100**	**100**	**0.1**	**-1.2**
Coal	1	1	0	0	0	0	0	0	-0.6	-4.1
Oil	25	20	15	22	13	8	15	11	-2.2	-4.6
Gas	17	19	20	16	15	15	20	20	1.0	-0.3
Electricity	54	59	63	51	47	43	63	59	0.6	-0.9
Heat	1	1	1	0	0	0	1	1	1.1	-0.7
Bioenergy	0	0	0	0	0	0	0	0	-1.0	-1.0
Other renewables	0	1	1	1	2	7	1	10	3.6	11.1
Other	**32**	**28**	**25**	**32**	**28**	**24**	**100**	**100**	**-1.3**	**-1.3**

Japan: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**873**	**1 036**	**1 005**	**1 021**	**1 043**	**1 062**	**1 079**	**100**	**100**	**0.2**
Coal	118	349	312	286	279	264	247	34	23	-1.3
Oil	284	116	39	28	18	12	9	11	1	-9.5
Gas	171	421	303	270	275	279	270	41	25	-1.7
Nuclear	202	-	142	207	216	222	233	-	22	n.a.
Hydro	87	82	89	92	95	99	104	8	10	0.9
Bioenergy	10	36	42	46	50	53	57	3	5	1.8
Wind	-	5	10	17	25	33	43	0	4	8.6
Geothermal	2	3	4	7	11	17	22	0	2	8.6
Solar PV	0	25	63	69	74	79	87	2	8	5.0
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	1	2	8	-	1	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**305**	**332**	**330**	**333**	**336**	**339**	**85**	**100**	**0.4**
Coal	50	48	47	47	44	40	16	12	-0.8
Oil	45	27	21	14	11	9	15	3	-6.1
Gas	83	93	95	98	98	94	27	28	0.5
Nuclear	-	39	34	31	30	32	-	9	n.a.
Hydro	50	51	51	52	54	55	16	16	0.4
Bioenergy	7	7	8	9	9	10	2	3	1.6
Wind	3	5	8	10	13	16	1	5	7.0
Geothermal	1	1	1	2	3	4	0	1	8.1
Solar PV	23	60	65	69	74	77	8	23	4.7
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	1	3	-	1	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**1 041**	**1 178**	**991**	**891**	**834**	**777**	**722**	**100**	**100**	**-1.9**
Coal	298	464	426	391	372	348	321	39	44	-1.4
Oil	628	454	359	313	273	239	213	39	29	-2.9
Gas	115	260	206	187	188	191	188	22	26	-1.2
Power generation	**395**	**572**	**426**	**371**	**356**	**340**	**318**	**100**	**100**	**-2.2**
Coal	131	314	278	251	243	229	213	55	67	-1.5
Oil	186	71	23	16	11	7	5	12	2	-9.6
Gas	79	188	125	104	103	104	100	33	32	-2.4
TFC	**597**	**552**	**515**	**474**	**436**	**400**	**370**	**100**	**100**	**-1.5**
Coal	145	120	117	110	102	93	85	22	23	-1.3
Oil	417	362	320	284	251	223	199	66	54	-2.3
Transport	*200*	*208*	*183*	*163*	*146*	*131*	*120*	*38*	*32*	*-2.1*
Gas	35	70	78	81	83	85	86	13	23	0.8

Japan: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 016**	**1 073**	**1 130**	**971**	**908**	**864**	**100**	**100**	**0.3**	**-0.7**
Coal	318	344	345	301	127	21	31	2	-0.0	-10.3
Oil	39	18	9	32	4	1	1	0	-9.5	-16.1
Gas	308	275	300	283	219	92	27	11	-1.3	-5.7
Nuclear	142	185	176	142	247	299	16	35	n.a.	n.a.
Hydro	89	94	101	91	108	128	9	15	0.8	1.7
Bioenergy	42	49	55	42	56	69	5	8	1.7	2.6
Wind	10	24	41	11	47	99	4	12	8.4	12.2
Geothermal	5	13	23	5	14	31	2	4	8.7	10.0
Solar PV	62	70	79	63	85	113	7	13	4.6	6.0
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	1	-	1	11	0	1	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**333**	**338**	**340**	**321**	**323**	**349**	**100**	**100**	**0.4**	**0.5**
Coal	49	52	51	48	34	20	15	6	0.1	-3.4
Oil	27	15	9	24	11	5	3	1	-6.0	-8.4
Gas	95	103	101	84	72	58	30	17	0.8	-1.3
Nuclear	39	29	24	39	35	41	7	12	n.a.	n.a.
Hydro	51	52	53	51	59	66	16	19	0.3	1.1
Bioenergy	7	9	10	7	10	12	3	3	1.4	2.3
Wind	5	10	15	5	18	35	4	10	6.8	10.3
Geothermal	1	2	4	1	3	5	1	2	8.2	9.5
Solar PV	59	66	71	61	80	102	21	29	4.4	5.8
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	0	-	0	4	0	1	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 001**	**906**	**841**	**947**	**607**	**345**	**100**	**100**	**-1.3**	**-4.6**
Coal	432	431	406	407	218	90	48	26	-0.5	-6.1
Oil	362	283	231	345	232	150	27	44	-2.6	-4.2
Gas	208	191	204	195	158	104	24	30	-0.9	-3.4
Power generation	**433**	**414**	**413**	**404**	**187**	**34**	**100**	**100**	**-1.2**	**-10.3**
Coal	283	301	297	268	103	2	72	6	-0.2	-17.5
Oil	23	11	5	19	2	1	1	2	-9.5	-16.0
Gas	127	103	111	117	82	31	27	92	-2.0	-6.7
TFC	**519**	**450**	**393**	**497**	**384**	**285**	**100**	**100**	**-1.3**	**-2.5**
Coal	118	102	86	110	90	69	22	24	-1.3	-2.1
Oil	323	261	217	311	220	144	55	50	-1.9	-3.5
Transport	*184*	*152*	*133*	*181*	*135*	*88*	*34*	*31*	*-1.7*	*-3.3*
Gas	78	86	90	75	74	72	23	25	1.0	0.1

Non-OECD: New Policies Scenario

	Energy demand (Mtoe)							**Shares** (%)		**CAAGR** (%)
	1990	**2014**	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**	**2014-40**
TPED	**4 045**	**8 046**	**8 866**	**9 664**	**10 535**	**11 406**	**12 178**	**100**	**100**	**1.6**
Coal	1 139	2 914	3 027	3 161	3 327	3 465	3 553	36	29	0.8
Oil	1 164	2 022	2 259	2 442	2 592	2 753	2 879	25	24	1.4
Gas	819	1 549	1 729	1 940	2 199	2 478	2 745	19	23	2.2
Nuclear	74	145	241	331	428	507	578	2	5	5.5
Hydro	83	214	247	284	322	357	387	3	3	2.3
Bioenergy	758	1 118	1 195	1 252	1 308	1 362	1 410	14	12	0.9
Other renewables	8	83	169	253	358	485	626	1	5	8.1
Power generation	**1 260**	**2 981**	**3 309**	**3 681**	**4 128**	**4 601**	**5 044**	**100**	**100**	**2.0**
Coal	459	1 606	1 672	1 765	1 883	1 988	2 058	54	41	1.0
Oil	223	215	200	181	158	147	141	7	3	-1.6
Gas	406	679	730	801	897	1 013	1 123	23	22	2.0
Nuclear	74	145	241	331	428	507	578	5	11	5.5
Hydro	83	214	247	284	322	357	387	7	8	2.3
Bioenergy	7	65	91	119	153	194	240	2	5	5.2
Other renewables	8	57	128	201	289	395	518	2	10	8.9
Other energy sector	**509**	**1 032**	**1 075**	**1 134**	**1 202**	**1 267**	**1 315**	**100**	**100**	**0.9**
Electricity	*78*	*217*	*239*	*264*	*297*	*331*	*363*	*21*	*28*	*2.0*
TFC	**2 861**	**5 417**	**6 090**	**6 677**	**7 285**	**7 874**	**8 392**	**100**	**100**	**1.7**
Coal	521	963	996	1 022	1 044	1 055	1 058	18	13	0.4
Oil	816	1 663	1 921	2 119	2 297	2 472	2 614	31	31	1.8
Gas	355	684	819	955	1 111	1 261	1 401	13	17	2.8
Electricity	282	908	1 091	1 282	1 498	1 717	1 921	17	23	2.9
Heat	187	217	237	243	247	251	251	4	3	0.6
Bioenergy	699	955	985	1 003	1 018	1 029	1 037	18	12	0.3
Other renewables	0	26	40	52	70	89	108	0	1	5.6
Industry	**963**	**1 984**	**2 219**	**2 442**	**2 663**	**2 878**	**3 064**	**100**	**100**	**1.7**
Coal	303	767	790	820	850	872	888	39	29	0.6
Oil	159	203	224	231	236	240	243	10	8	0.7
Gas	128	328	404	479	556	636	712	17	23	3.0
Electricity	158	468	545	625	703	778	841	24	27	2.3
Heat	138	99	117	122	124	125	123	5	4	0.9
Bioenergy	76	119	139	164	192	221	248	6	8	2.9
Other renewables	0	0	0	1	3	6	9	0	0	15.1
Transport	**434**	**1 045**	**1 222**	**1 383**	**1 535**	**1 690**	**1 831**	**100**	**100**	**2.2**
Oil	365	932	1 093	1 226	1 344	1 462	1 555	89	85	2.0
Electricity	13	17	22	28	36	45	55	2	3	4.6
Biofuels	6	23	31	44	56	72	93	2	5	5.6
Other fuels	50	72	77	85	99	111	127	7	7	2.2
Buildings	**1 165**	**1 847**	**1 989**	**2 107**	**2 264**	**2 416**	**2 550**	**100**	**100**	**1.2**
Coal	169	119	116	108	98	88	77	6	3	-1.6
Oil	117	177	181	178	178	181	188	10	7	0.2
Gas	133	225	259	302	359	409	450	12	18	2.7
Electricity	86	378	471	567	688	816	940	20	37	3.6
Heat	48	115	117	118	120	122	125	6	5	0.3
Bioenergy	612	807	806	784	756	718	675	44	26	-0.7
Other renewables	0	26	39	50	65	81	96	1	4	5.2
Other	**299**	**541**	**660**	**745**	**823**	**890**	**947**	**100**	**100**	**2.2**

Non-OECD: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**9 018**	**11 187**	**13 388**	**8 676**	**9 403**	**10 083**	**100**	**100**	**2.0**	**0.9**
Coal	3 150	3 868	4 530	2 878	2 322	1 776	34	18	1.7	-1.9
Oil	2 290	2 751	3 217	2 217	2 216	2 111	24	21	1.8	0.2
Gas	1 742	2 285	2 943	1 701	1 981	2 173	22	22	2.5	1.3
Nuclear	238	387	485	252	584	855	4	8	4.7	7.1
Hydro	246	311	368	247	342	438	3	4	2.1	2.8
Bioenergy	1 196	1 299	1 377	1 198	1 395	1 611	10	16	0.8	1.4
Other renewables	155	286	468	183	563	1 118	3	11	6.9	10.5
Power generation	**3 405**	**4 492**	**5 662**	**3 180**	**3 518**	**4 030**	**100**	**100**	**2.5**	**1.2**
Coal	1 775	2 329	2 870	1 549	1 052	605	51	15	2.3	-3.7
Oil	201	163	147	192	105	59	3	1	-1.4	-4.8
Gas	739	940	1 225	709	775	774	22	19	2.3	0.5
Nuclear	238	387	485	252	584	855	9	21	4.7	7.1
Hydro	246	311	368	247	342	438	7	11	2.1	2.8
Bioenergy	90	137	193	92	191	348	3	9	4.3	6.7
Other renewables	116	223	374	139	468	951	7	24	7.5	11.5
Other energy sector	**1 092**	**1 288**	**1 487**	**1 055**	**1 062**	**1 039**	**100**	**100**	**1.4**	**0.0**
Electricity	*246*	*327*	*417*	*231*	*253*	*280*	*28*	*27*	*2.5*	*1.0*
TFC	**6 162**	**7 619**	**9 042**	**6 006**	**6 689**	**7 197**	**100**	**100**	**2.0**	**1.1**
Coal	1 012	1 111	1 167	978	910	811	13	11	0.7	-0.7
Oil	1 949	2 443	2 937	1 891	1 994	1 960	32	27	2.2	0.6
Gas	822	1 141	1 464	812	1 045	1 255	16	17	3.0	2.4
Electricity	1 114	1 582	2 068	1 059	1 350	1 661	23	23	3.2	2.4
Heat	240	262	277	234	228	212	3	3	0.9	-0.1
Bioenergy	986	1 017	1 035	988	1 067	1 130	11	16	0.3	0.6
Other renewables	39	63	94	44	95	168	1	2	5.0	7.4
Industry	**2 249**	**2 796**	**3 307**	**2 189**	**2 406**	**2 555**	**100**	**100**	**2.0**	**1.0**
Coal	803	904	975	779	744	679	29	27	0.9	-0.5
Oil	228	248	262	223	215	207	8	8	1.0	0.1
Gas	407	576	756	400	500	578	23	23	3.3	2.2
Electricity	553	735	910	531	625	706	28	28	2.6	1.6
Heat	118	134	142	116	114	101	4	4	1.4	0.1
Bioenergy	140	197	257	139	196	255	8	10	3.0	3.0
Other renewables	0	2	5	1	13	29	0	1	12.3	20.5
Transport	**1 234**	**1 618**	**2 036**	**1 203**	**1 368**	**1 478**	**100**	**100**	**2.6**	**1.3**
Oil	1 111	1 456	1 812	1 070	1 102	1 001	89	68	2.6	0.3
Electricity	21	30	40	22	49	113	2	8	3.3	7.5
Biofuels	29	44	68	32	92	162	3	11	4.3	7.8
Other fuels	74	89	117	78	125	202	6	14	1.9	4.0
Buildings	**2 015**	**2 363**	**2 712**	**1 956**	**2 113**	**2 254**	**100**	**100**	**1.5**	**0.8**
Coal	117	106	90	109	77	48	3	2	-1.1	-3.4
Oil	185	190	213	175	153	152	8	7	0.7	-0.6
Gas	262	379	479	255	324	364	18	16	2.9	1.9
Electricity	485	742	1 024	453	610	766	38	34	3.9	2.8
Heat	119	124	131	115	112	109	5	5	0.5	-0.2
Bioenergy	808	762	688	807	759	682	25	30	-0.6	-0.6
Other renewables	38	59	87	41	79	132	3	6	4.8	6.5
Other	**664**	**842**	**987**	**658**	**801**	**910**	**100**	**100**	**2.3**	**2.0**

Non-OECD: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**4 197**	**13 037**	**15 454**	**17 966**	**20 827**	**23 740**	**26 453**	**100**	**100**	**2.8**
Coal	1 331	6 229	6 779	7 287	7 906	8 485	8 884	48	34	1.4
Oil	625	759	691	633	559	524	500	6	2	-1.6
Gas	979	2 535	2 978	3 541	4 230	4 971	5 693	19	22	3.2
Nuclear	283	555	923	1 269	1 643	1 945	2 217	4	8	5.5
Hydro	963	2 493	2 873	3 301	3 742	4 149	4 503	19	17	2.3
Bioenergy	8	165	249	347	469	619	785	1	3	6.2
Wind	0	230	640	988	1 337	1 707	2 099	2	8	8.9
Geothermal	8	29	44	65	95	139	196	0	1	7.6
Solar PV	0	42	262	498	773	1 076	1 386	0	5	14.3
CSP	-	1	14	37	73	124	186	0	1	23.4
Marine	0	0	0	0	1	2	3	0	0	25.5

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**3 197**	**4 287**	**5 020**	**5 818**	**6 596**	**7 306**	**100**	**100**	**3.2**
Coal	1 268	1 596	1 706	1 835	1 954	2 035	40	28	1.8
Oil	244	250	239	220	212	201	8	3	-0.7
Gas	680	870	1 005	1 175	1 331	1 485	21	20	3.1
Nuclear	83	132	177	225	265	300	3	4	5.1
Hydro	701	844	966	1 090	1 202	1 294	22	18	2.4
Bioenergy	41	59	76	97	122	149	1	2	5.0
Wind	136	320	466	604	739	870	4	12	7.4
Geothermal	5	7	10	15	21	29	0	0	7.3
Solar PV	39	205	362	534	712	887	1	12	12.8
CSP	0	5	12	23	38	56	0	1	20.4
Marine	0	0	0	0	1	1	0	0	23.7

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**8 866**	**19 297**	**20 496**	**21 784**	**23 190**	**24 589**	**25 698**	**100**	**100**	**1.1**
Coal	4 040	10 918	11 167	11 613	12 138	12 560	12 803	57	50	0.6
Oil	3 030	5 111	5 650	6 032	6 348	6 721	7 028	26	27	1.2
Gas	1 795	3 267	3 679	4 138	4 705	5 308	5 867	17	23	2.3
Power generation	**3 535**	**8 832**	**9 162**	**9 639**	**10 246**	**10 889**	**11 382**	**100**	**100**	**1.0**
Coal	1 863	6 560	6 810	7 181	7 636	8 041	8 297	74	73	0.9
Oil	718	668	634	573	501	466	445	8	4	-1.5
Gas	953	1 605	1 718	1 884	2 109	2 381	2 640	18	23	1.9
TFC	**4 937**	**9 513**	**10 400**	**11 191**	**11 970**	**12 695**	**13 292**	**100**	**100**	**1.3**
Coal	2 099	4 065	4 094	4 176	4 251	4 276	4 270	43	32	0.2
Oil	2 130	4 153	4 714	5 144	5 527	5 922	6 244	44	47	1.6
Transport	*1 094*	*2 814*	*3 286*	*3 686*	*4 040*	*4 397*	*4 678*	*30*	*35*	*2.0*
Gas	708	1 295	1 592	1 871	2 192	2 497	2 778	14	21	3.0

Non-OECD: Current Policies and 450 Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total generation	**15 796**	**22 137**	**28 749**	**14 983**	**18 571**	**22 423**	**100**	**100**	**3.1**	**2.1**
Coal	7 216	9 859	12 483	6 309	4 289	2 192	43	10	2.7	-3.9
Oil	694	583	529	659	355	184	2	1	-1.4	-5.3
Gas	3 032	4 499	6 258	2 859	3 568	3 756	22	17	3.5	1.5
Nuclear	913	1 485	1 859	967	2 239	3 282	6	15	4.8	7.1
Hydro	2 866	3 621	4 283	2 877	3 978	5 094	15	23	2.1	2.8
Bioenergy	246	413	618	251	604	1 176	2	5	5.2	7.9
Wind	570	1 054	1 590	698	2 033	3 444	6	15	7.7	11.0
Geothermal	43	82	150	46	159	329	1	1	6.5	9.8
Solar PV	205	492	861	295	1 099	2 125	3	9	12.3	16.2
CSP	12	48	117	22	245	833	0	4	21.2	30.7
Marine	0	0	2	0	2	8	0	0	24.4	30.6

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total capacity	**4 239**	**5 727**	**7 190**	**4 302**	**5 953**	**7 587**	**100**	**100**	**3.2**	**3.4**
Coal	1 633	2 092	2 531	1 554	1 359	1 015	35	13	2.7	-0.9
Oil	250	224	207	249	203	175	3	2	-0.6	-1.3
Gas	874	1 236	1 615	855	1 015	1 186	22	16	3.4	2.2
Nuclear	131	204	251	138	308	444	3	6	4.4	6.7
Hydro	842	1 048	1 226	846	1 170	1 476	17	19	2.2	2.9
Bioenergy	58	87	119	59	123	220	2	3	4.1	6.6
Wind	283	478	659	352	905	1 388	9	18	6.2	9.3
Geothermal	7	13	22	7	25	49	0	1	6.2	9.4
Solar PV	156	331	525	234	768	1 378	7	18	10.6	14.7
CSP	4	16	34	9	76	254	0	3	18.2	27.6
Marine	0	0	1	0	1	3	0	0	22.7	29.0

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total CO_2	**21 110**	**25 962**	**30 922**	**19 720**	**16 992**	**12 915**	**100**	**100**	**1.8**	**-1.5**
Coal	11 663	14 247	16 583	10 581	7 618	3 920	54	30	1.6	-3.9
Oil	5 741	6 824	8 046	5 525	5 213	4 657	26	36	1.8	-0.4
Gas	3 707	4 891	6 293	3 613	4 161	4 337	20	34	2.6	1.1
Power generation	**9 607**	**12 185**	**14 952**	**8 587**	**6 111**	**2 985**	**100**	**100**	**2.0**	**-4.1**
Coal	7 233	9 455	11 608	6 311	3 969	1 120	78	38	2.2	-6.6
Oil	635	518	466	607	335	188	3	6	-1.4	-4.8
Gas	1 739	2 212	2 878	1 669	1 807	1 677	19	56	2.3	0.2
TFC	**10 558**	**12 739**	**14 809**	**10 216**	**10 100**	**9 273**	**100**	**100**	**1.7**	**-0.1**
Coal	4 162	4 523	4 706	4 014	3 449	2 645	32	29	0.6	-1.6
Oil	4 799	5 965	7 198	4 624	4 624	4 257	49	46	2.1	0.1
Transport	*3 339*	*4 377*	*5 449*	*3 218*	*3 313*	*3 010*	*37*	*32*	*2.6*	*0.3*
Gas	1 597	2 251	2 905	1 578	2 026	2 371	20	26	3.2	2.4

Eastern Europe/Eurasia: New Policies Scenario

	Energy demand (Mtoe)							**Shares** (%)		**CAAGR** (%)
	1990	**2014**	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**	**2014-40**
TPED	**1 539**	**1 101**	**1 120**	**1 152**	**1 189**	**1 232**	**1 271**	**100**	**100**	**0.6**
Coal	367	208	207	205	207	210	215	19	17	0.1
Oil	468	223	229	232	234	230	224	20	18	0.0
Gas	603	541	539	548	561	583	602	49	47	0.4
Nuclear	59	78	85	100	109	115	120	7	9	1.7
Hydro	23	26	28	29	31	33	35	2	3	1.2
Bioenergy	18	24	27	29	33	39	46	2	4	2.5
Other renewables	0	2	5	9	14	21	29	0	2	11.9
Power generation	**742**	**534**	**538**	**548**	**564**	**589**	**617**	**100**	**100**	**0.6**
Coal	197	126	125	120	121	122	124	24	20	-0.1
Oil	125	13	12	10	9	8	7	2	1	-2.4
Gas	333	282	275	271	270	276	283	53	46	0.0
Nuclear	59	78	85	100	109	115	120	15	19	1.7
Hydro	23	26	28	29	31	33	35	5	6	1.2
Bioenergy	4	7	8	9	11	15	20	1	3	4.3
Other renewables	0	1	4	8	13	20	28	0	4	12.3
Other energy sector	**199**	**191**	**185**	**188**	**191**	**196**	**201**	**100**	**100**	**0.2**
Electricity	*35*	*42*	*41*	*41*	*42*	*43*	*44*	*22*	*22*	*0.2*
TFC	**968**	**693**	**721**	**752**	**783**	**813**	**835**	**100**	**100**	**0.7**
Coal	114	36	36	37	39	40	41	5	5	0.5
Oil	280	181	190	197	201	201	197	26	24	0.3
Gas	261	214	222	229	239	249	258	31	31	0.7
Electricity	126	107	114	123	133	143	153	15	18	1.4
Heat	173	138	141	145	150	155	160	20	19	0.6
Bioenergy	14	16	18	20	21	23	25	2	3	1.7
Other renewables	-	0	0	1	1	1	2	0	0	8.9
Industry	**395**	**227**	**239**	**253**	**267**	**281**	**293**	**100**	**100**	**1.0**
Coal	56	27	27	29	30	32	33	12	11	0.9
Oil	51	27	28	28	28	27	26	12	9	-0.1
Gas	86	80	83	87	90	94	98	35	33	0.8
Electricity	75	46	49	54	58	62	66	20	22	1.4
Heat	127	45	50	53	57	60	63	20	22	1.3
Bioenergy	0	2	3	3	4	5	6	1	2	4.3
Other renewables	-	0	0	0	0	0	1	0	0	28.2
Transport	**173**	**144**	**146**	**152**	**156**	**158**	**157**	**100**	**100**	**0.3**
Oil	124	103	104	108	111	109	105	71	67	0.1
Electricity	12	9	10	10	11	13	14	6	9	1.6
Biofuels	0	0	1	1	1	1	2	0	1	4.8
Other fuels	37	32	32	32	33	34	36	22	23	0.4
Buildings	**286**	**266**	**270**	**275**	**283**	**293**	**301**	**100**	**100**	**0.5**
Coal	56	8	8	8	7	7	6	3	2	-1.1
Oil	35	19	19	18	17	16	15	7	5	-0.9
Gas	111	87	90	92	97	101	104	33	35	0.7
Electricity	26	48	50	53	57	60	64	18	21	1.1
Heat	45	90	89	89	90	92	93	34	31	0.2
Bioenergy	13	14	15	15	16	16	17	5	6	0.8
Other renewables	-	0	0	0	1	1	1	0	0	6.8
Other	**115**	**55**	**66**	**71**	**77**	**81**	**85**	**100**	**100**	**1.7**

Eastern Europe/Eurasia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
TPED	**1 131**	**1 232**	**1 345**	**1 104**	**1 101**	**1 107**	**100**	**100**	**0.8**	**0.0**
Coal	211	222	243	188	127	97	18	9	0.6	-2.9
Oil	231	240	237	227	219	194	18	18	0.2	-0.5
Gas	545	594	663	537	515	490	49	44	0.8	-0.4
Nuclear	86	103	107	93	140	153	8	14	1.2	2.6
Hydro	28	31	34	28	35	45	3	4	1.0	2.1
Bioenergy	27	32	40	27	42	70	3	6	2.0	4.2
Other renewables	4	12	21	5	24	59	2	5	10.5	14.9
Power generation	**543**	**583**	**643**	**530**	**525**	**549**	**100**	**100**	**0.7**	**0.1**
Coal	129	136	152	109	55	33	24	6	0.7	-5.1
Oil	12	9	7	12	9	7	1	1	-2.4	-2.4
Gas	277	283	308	275	247	220	48	40	0.3	-1.0
Nuclear	86	103	107	93	140	153	17	28	1.2	2.6
Hydro	28	31	34	28	35	45	5	8	1.0	2.1
Bioenergy	8	10	15	8	18	39	2	7	3.1	7.0
Other renewables	4	11	20	4	22	53	3	10	10.9	15.2
Other energy sector	**186**	**199**	**214**	**181**	**169**	**158**	**100**	**100**	**0.4**	**-0.7**
Electricity	*42*	*44*	*47*	*40*	*37*	*36*	*22*	*23*	*0.5*	*-0.6*
TFC	**729**	**814**	**890**	**713**	**728**	**726**	**100**	**100**	**1.0**	**0.2**
Coal	36	40	42	35	34	33	5	5	0.6	-0.4
Oil	192	208	212	188	187	166	24	23	0.6	-0.3
Gas	225	253	284	219	222	223	32	31	1.1	0.2
Electricity	116	138	160	112	122	132	18	18	1.5	0.8
Heat	143	154	167	139	138	137	19	19	0.7	-0.0
Bioenergy	18	21	24	18	23	30	3	4	1.5	2.3
Other renewables	0	1	1	0	2	5	0	1	6.3	13.3
Industry	**241**	**275**	**307**	**235**	**243**	**248**	**100**	**100**	**1.2**	**0.3**
Coal	27	30	33	26	27	26	11	11	0.8	-0.1
Oil	28	28	26	27	26	25	8	10	-0.1	-0.3
Gas	84	96	108	82	80	76	35	31	1.2	-0.2
Electricity	50	59	68	48	52	56	22	23	1.5	0.8
Heat	50	58	66	49	52	53	21	21	1.4	0.6
Bioenergy	3	4	6	3	5	8	2	3	4.6	5.8
Other renewables	0	0	0	0	1	3	0	1	24.4	36.2
Transport	**148**	**162**	**170**	**146**	**150**	**139**	**100**	**100**	**0.6**	**-0.2**
Oil	105	115	117	103	101	82	69	59	0.5	-0.9
Electricity	9	11	14	10	12	16	8	12	1.5	2.2
Biofuels	1	1	1	1	2	3	0	2	0.8	7.0
Other fuels	32	35	39	32	35	38	23	27	0.7	0.7
Buildings	**274**	**298**	**325**	**265**	**261**	**259**	**100**	**100**	**0.8**	**-0.1**
Coal	8	8	8	8	7	6	2	2	-0.2	-1.6
Oil	19	18	17	18	14	12	5	4	-0.4	-2.0
Gas	91	103	116	88	89	90	36	35	1.1	0.1
Electricity	51	60	68	49	51	51	21	20	1.4	0.3
Heat	90	93	97	87	84	82	30	32	0.3	-0.4
Bioenergy	15	16	17	15	16	17	5	7	0.7	0.9
Other renewables	0	0	1	0	1	2	0	1	4.1	9.3
Other	**66**	**78**	**87**	**66**	**75**	**81**	**100**	**100**	**1.8**	**1.5**

Eastern Europe/Eurasia: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2014**	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**	**2014-40**
Total generation	**1 894**	**1 741**	**1 815**	**1 908**	**2 022**	**2 143**	**2 260**	**100**	**100**	**1.0**
Coal	429	392	397	381	384	386	396	23	18	0.0
Oil	256	18	15	11	7	5	4	1	0	-5.8
Gas	715	706	721	749	780	821	841	41	37	0.7
Nuclear	226	299	327	381	418	440	460	17	20	1.7
Hydro	267	305	321	338	360	384	410	18	18	1.2
Bioenergy	0	6	10	14	22	36	55	0	2	9.2
Wind	-	11	16	21	30	44	57	1	3	6.7
Geothermal	0	0	3	7	12	18	25	0	1	16.7
Solar PV	-	4	5	6	7	9	11	0	0	4.3
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	0	0	0	-	0	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2014	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**	**2014-40**
Total capacity	**447**	**466**	**478**	**494**	**517**	**542**	**100**	**100**	**0.7**
Coal	111	107	101	93	92	91	25	17	-0.8
Oil	20	15	10	5	4	3	5	1	-7.0
Gas	164	180	187	196	202	210	37	39	1.0
Nuclear	44	48	54	60	62	63	10	12	1.4
Hydro	97	101	107	113	119	127	22	23	1.0
Bioenergy	2	3	4	6	8	12	0	2	7.2
Wind	5	7	9	13	18	23	1	4	5.9
Geothermal	0	0	1	2	3	4	0	1	15.5
Solar PV	3	4	5	6	8	10	1	2	4.6
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2014**	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**	**2014-40**
Total CO_2	**3 933**	**2 422**	**2 396**	**2 397**	**2 421**	**2 454**	**2 478**	**100**	**100**	**0.1**
Coal	1 369	711	701	689	697	705	717	29	29	0.0
Oil	1 190	548	540	539	535	520	500	23	20	-0.4
Gas	1 373	1 163	1 155	1 170	1 189	1 228	1 261	48	51	0.3
Power generation	**2 001**	**1 244**	**1 207**	**1 172**	**1 167**	**1 183**	**1 204**	**100**	**100**	**-0.1**
Coal	817	526	518	498	501	504	513	42	43	-0.1
Oil	402	46	39	34	30	26	23	4	2	-2.6
Gas	782	672	650	640	637	653	667	54	55	-0.0
TFC	**1 822**	**1 039**	**1 056**	**1 089**	**1 115**	**1 131**	**1 133**	**100**	**100**	**0.3**
Coal	541	178	175	183	188	193	197	17	17	0.4
Oil	725	450	452	460	462	452	434	43	38	-0.1
Transport	*370*	*306*	*310*	*322*	*329*	*324*	*313*	*29*	*28*	*0.1*
Gas	555	411	428	446	465	486	502	40	44	0.8

Eastern Europe/Eurasia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 839**	**2 103**	**2 380**	**1 779**	**1 850**	**1 938**	**100**	**100**	**1.2**	**0.4**
Coal	405	427	476	347	146	60	20	3	0.7	-7.0
Oil	15	7	4	15	6	3	0	0	-5.9	-6.7
Gas	737	862	989	704	605	415	42	21	1.3	-2.0
Nuclear	328	393	411	357	536	586	17	30	1.2	2.6
Hydro	320	355	395	321	410	519	17	27	1.0	2.1
Bioenergy	10	19	39	10	47	123	2	6	7.7	12.6
Wind	16	23	40	17	73	163	2	8	5.3	11.1
Geothermal	3	10	18	3	17	43	1	2	15.3	19.1
Solar PV	5	6	8	5	11	25	0	1	3.1	7.5
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	0	-	0	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**471**	**506**	**563**	**461**	**495**	**566**	**100**	**100**	**0.9**	**0.9**
Coal	110	104	106	101	57	35	19	6	-0.2	-4.4
Oil	15	5	3	15	5	3	1	1	-7.1	-7.1
Gas	182	208	241	176	175	170	43	30	1.5	0.1
Nuclear	48	56	56	52	74	83	10	15	1.0	2.5
Hydro	101	111	122	101	127	157	22	28	0.9	1.9
Bioenergy	3	5	9	3	11	26	2	5	5.7	10.4
Wind	7	10	16	8	32	61	3	11	4.6	10.0
Geothermal	0	1	3	0	3	6	0	1	14.0	17.8
Solar PV	4	5	7	4	10	24	1	4	3.3	8.2
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	0	-	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**2 430**	**2 575**	**2 769**	**2 313**	**1 949**	**1 643**	**100**	**100**	**0.5**	**-1.5**
Coal	718	763	837	629	384	262	30	16	0.6	-3.8
Oil	544	555	547	534	488	398	20	24	-0.0	-1.2
Gas	1 167	1 257	1 385	1 150	1 078	983	50	60	0.7	-0.6
Power generation	**1 227**	**1 261**	**1 378**	**1 140**	**827**	**655**	**100**	**100**	**0.4**	**-2.4**
Coal	534	563	627	451	221	127	45	19	0.7	-5.3
Oil	39	30	23	39	29	23	2	3	-2.6	-2.7
Gas	654	669	728	650	577	505	53	77	0.3	-1.1
TFC	**1 068**	**1 167**	**1 237**	**1 042**	**1 004**	**885**	**100**	**100**	**0.7**	**-0.6**
Coal	177	192	202	171	157	130	16	15	0.5	-1.2
Oil	456	481	480	447	419	341	39	39	0.2	-1.1
Transport	*312*	*342*	*350*	*307*	*300*	*243*	*28*	*27*	*0.5*	*-0.9*
Gas	435	494	555	424	428	413	45	47	1.2	0.0

Russia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**880**	**686**	**683**	**696**	**714**	**737**	**758**	**100**	**100**	**0.4**
Coal	191	104	105	106	111	113	113	15	15	0.3
Oil	264	143	142	142	142	138	132	21	17	-0.3
Gas	367	369	356	354	357	364	370	54	49	0.0
Nuclear	31	47	53	63	68	75	83	7	11	2.2
Hydro	14	15	16	17	18	20	21	2	3	1.3
Bioenergy	12	7	8	9	10	13	17	1	2	3.5
Other renewables	0	0	2	5	9	14	20	0	3	21.0
Power generation	**444**	**356**	**353**	**362**	**375**	**394**	**414**	**100**	**100**	**0.6**
Coal	105	59	61	61	64	65	66	17	16	0.4
Oil	62	10	10	9	8	7	6	3	2	-1.7
Gas	228	219	207	203	202	204	205	62	49	-0.3
Nuclear	31	47	53	63	68	75	83	13	20	2.2
Hydro	14	15	16	17	18	20	21	4	5	1.3
Bioenergy	4	4	5	5	6	9	13	1	3	4.2
Other renewables	0	0	2	5	9	14	20	0	5	21.0
Other energy sector	**127**	**121**	**116**	**115**	**115**	**117**	**119**	**100**	**100**	**-0.1**
Electricity	*21*	*27*	*26*	*26*	*26*	*27*	*27*	*23*	*23*	*-0.0*
TFC	**520**	**432**	**436**	**448**	**463**	**476**	**484**	**100**	**100**	**0.4**
Coal	55	11	11	12	12	13	13	3	3	0.7
Oil	145	112	112	114	116	114	109	26	23	-0.1
Gas	143	134	134	135	138	141	144	31	30	0.3
Electricity	71	63	66	70	76	82	86	15	18	1.2
Heat	98	109	111	114	118	122	126	25	26	0.6
Bioenergy	8	3	3	3	4	4	5	1	1	2.4
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Industry	**208**	**155**	**159**	**167**	**175**	**183**	**188**	**100**	**100**	**0.8**
Coal	15	8	9	10	10	11	12	5	6	1.3
Oil	24	21	21	21	21	20	20	13	10	-0.2
Gas	30	59	59	60	61	63	65	38	34	0.3
Electricity	41	29	29	31	34	36	37	19	20	1.0
Heat	98	38	40	44	47	50	53	24	28	1.3
Bioenergy	-	0	1	1	1	2	2	0	1	5.9
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**116**	**93**	**91**	**92**	**93**	**92**	**90**	**100**	**100**	**-0.2**
Oil	73	60	58	58	58	56	52	65	57	-0.6
Electricity	9	8	8	9	9	10	11	8	13	1.5
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	34	25	25	25	25	26	27	27	30	0.2
Buildings	**131**	**150**	**148**	**148**	**151**	**153**	**156**	**100**	**100**	**0.2**
Coal	40	3	2	2	2	1	1	2	1	-3.2
Oil	12	11	10	9	8	8	7	7	5	-1.5
Gas	57	40	40	40	41	41	41	27	26	0.1
Electricity	15	26	27	28	30	32	34	17	22	1.1
Heat	-	70	68	67	68	69	71	46	45	0.1
Bioenergy	7	2	2	2	2	2	2	1	1	0.5
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Other	**65**	**34**	**38**	**41**	**45**	**48**	**50**	**100**	**100**	**1.5**

Russia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**689**	**740**	**801**	**676**	**668**	**672**	**100**	**100**	**0.6**	**-0.1**
Coal	107	117	127	93	64	49	16	7	0.8	-2.8
Oil	143	145	138	140	134	118	17	18	-0.1	-0.8
Gas	360	378	414	355	328	303	52	45	0.4	-0.8
Nuclear	53	65	73	61	88	96	9	14	1.7	2.7
Hydro	16	18	21	16	21	27	3	4	1.2	2.2
Bioenergy	8	9	14	8	17	36	2	5	2.6	6.4
Other renewables	2	8	15	2	16	43	2	6	19.7	24.6
Power generation	**357**	**386**	**428**	**351**	**353**	**376**	**100**	**100**	**0.7**	**0.2**
Coal	63	71	81	51	28	19	19	5	1.2	-4.2
Oil	10	8	6	10	8	6	1	2	-1.8	-1.7
Gas	208	210	222	206	181	158	52	42	0.1	-1.2
Nuclear	53	65	73	61	88	96	17	25	1.7	2.7
Hydro	16	18	21	16	21	27	5	7	1.2	2.2
Bioenergy	5	6	9	5	12	29	2	8	2.9	7.5
Other renewables	2	8	15	2	15	41	3	11	19.6	24.4
Other energy sector	**117**	**119**	**125**	**113**	**101**	**91**	**100**	**100**	**0.1**	**-1.1**
Electricity	*27*	*28*	*29*	*26*	*24*	*22*	*23*	*25*	*0.3*	*-0.8*
TFC	**441**	**483**	**520**	**431**	**432**	**425**	**100**	**100**	**0.7**	**-0.1**
Coal	11	12	13	11	10	9	2	2	0.5	-0.6
Oil	113	118	116	111	108	94	22	22	0.1	-0.7
Gas	136	149	166	133	131	130	32	31	0.8	-0.1
Electricity	66	79	90	64	70	76	17	18	1.3	0.7
Heat	111	121	132	109	108	107	25	25	0.7	-0.1
Bioenergy	3	3	4	3	4	7	1	2	2.0	3.8
Other renewables	0	0	0	0	0	2	0	0	n.a.	n.a.
Industry	**160**	**181**	**200**	**156**	**159**	**160**	**100**	**100**	**1.0**	**0.1**
Coal	9	10	11	8	8	8	6	5	1.1	-0.3
Oil	21	21	19	21	20	19	10	12	-0.3	-0.4
Gas	60	66	74	58	55	52	37	32	0.8	-0.5
Electricity	29	34	38	29	31	34	19	21	1.1	0.6
Heat	41	48	55	40	43	43	28	27	1.5	0.6
Bioenergy	1	1	2	1	2	3	1	2	5.6	7.6
Other renewables	0	0	0	0	0	2	0	1	n.a.	n.a.
Transport	**92**	**97**	**99**	**91**	**92**	**84**	**100**	**100**	**0.2**	**-0.4**
Oil	58	60	57	57	54	41	58	49	-0.2	-1.5
Electricity	8	9	11	8	10	13	11	16	1.4	2.1
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	26	28	30	26	28	30	31	35	0.7	0.6
Buildings	**150**	**159**	**170**	**146**	**138**	**133**	**100**	**100**	**0.5**	**-0.5**
Coal	2	2	1	2	2	1	1	1	-3.0	-2.5
Oil	10	9	8	9	7	5	5	4	-1.0	-2.7
Gas	41	44	50	40	38	38	29	28	0.9	-0.2
Electricity	27	32	36	26	26	25	21	19	1.3	-0.1
Heat	69	70	73	67	63	61	43	46	0.2	-0.5
Bioenergy	2	2	2	2	2	2	1	2	0.1	1.0
Other renewables	0	0	0	0	0	0	0	0	n.a.	n.a.
Other	**38**	**46**	**51**	**38**	**44**	**48**	**100**	**100**	**1.6**	**1.3**

Russia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**1 082**	**1 055**	**1 078**	**1 128**	**1 192**	**1 256**	**1 315**	**100**	**100**	**0.9**
Coal	157	158	163	159	166	162	160	15	12	0.0
Oil	129	9	9	6	5	3	2	1	0	-4.7
Gas	512	528	507	510	521	527	513	50	39	-0.1
Nuclear	118	181	203	239	260	288	319	17	24	2.2
Hydro	166	175	187	198	213	229	247	17	19	1.3
Bioenergy	0	3	5	7	11	20	34	0	3	9.6
Wind	-	0	0	2	5	10	16	0	1	21.7
Geothermal	0	0	3	6	10	15	22	0	2	16.0
Solar PV	-	0	0	0	1	1	1	0	0	8.0
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**251**	**257**	**260**	**266**	**273**	**284**	**100**	**100**	**0.5**
Coal	49	46	41	35	33	31	20	11	-1.7
Oil	4	3	2	2	1	1	2	0	-4.7
Gas	120	121	122	125	121	121	48	42	0.0
Nuclear	26	30	34	37	41	44	10	16	2.0
Hydro	51	53	56	60	64	68	20	24	1.1
Bioenergy	1	2	2	3	5	8	1	3	6.8
Wind	0	0	1	2	4	6	0	2	16.9
Geothermal	0	0	1	1	2	3	0	1	15.0
Solar PV	0	0	0	1	1	1	0	0	20.2
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**2 163**	**1 442**	**1 393**	**1 383**	**1 393**	**1 396**	**1 385**	**100**	**100**	**-0.2**
Coal	707	317	321	324	340	349	352	22	25	0.4
Oil	619	336	316	308	300	284	265	23	19	-0.9
Gas	837	788	756	752	753	763	769	55	56	-0.1
Power generation	**1 177**	**809**	**773**	**760**	**768**	**776**	**778**	**100**	**100**	**-0.2**
Coal	443	250	253	253	266	272	274	31	35	0.4
Oil	199	36	32	29	26	23	21	4	3	-2.0
Gas	535	523	488	479	476	481	483	65	62	-0.3
TFC	**932**	**567**	**558**	**563**	**567**	**563**	**550**	**100**	**100**	**-0.1**
Coal	263	63	63	66	69	72	73	11	13	0.6
Oil	383	264	251	248	244	233	216	46	39	-0.8
Transport	*219*	*179*	*172*	*173*	*173*	*165*	*153*	*32*	*28*	*-0.6*
Gas	286	241	244	249	253	259	262	42	48	0.3

Russia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 091**	**1 237**	**1 378**	**1 055**	**1 093**	**1 139**	**100**	**100**	**1.0**	**0.3**
Coal	166	174	186	136	55	28	14	2	0.6	-6.4
Oil	9	5	2	9	5	2	0	0	-4.9	-4.8
Gas	517	577	621	481	367	188	45	17	0.6	-3.9
Nuclear	203	249	280	234	335	367	20	32	1.7	2.8
Hydro	187	211	239	187	247	312	17	27	1.2	2.2
Bioenergy	5	10	23	5	32	91	2	8	8.1	13.9
Wind	0	2	9	1	37	105	1	9	19.1	30.9
Geothermal	3	10	17	3	14	36	1	3	14.8	18.4
Solar PV	0	0	1	0	2	8	0	1	5.2	16.1
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**259**	**273**	**299**	**254**	**267**	**307**	**100**	**100**	**0.7**	**0.8**
Coal	48	40	39	43	20	9	13	3	-0.9	-6.5
Oil	3	2	1	3	2	1	0	0	-5.3	-5.0
Gas	122	131	142	117	101	89	48	29	0.7	-1.1
Nuclear	30	36	39	34	46	50	13	16	1.5	2.5
Hydro	53	59	66	53	69	86	22	28	1.0	2.0
Bioenergy	2	3	6	2	8	20	2	7	5.2	10.6
Wind	0	1	4	0	17	38	1	12	14.6	25.6
Geothermal	0	1	2	0	2	5	1	2	13.8	17.3
Solar PV	0	0	1	0	2	9	0	3	17.1	29.2
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 413**	**1 475**	**1 556**	**1 343**	**1 125**	**929**	**100**	**100**	**0.3**	**-1.7**
Coal	331	370	413	278	166	110	27	12	1.0	-4.0
Oil	318	309	286	312	277	218	18	23	-0.6	-1.7
Gas	764	796	857	753	683	602	55	65	0.3	-1.0
Power generation	**786**	**819**	**884**	**731**	**561**	**455**	**100**	**100**	**0.3**	**-2.2**
Coal	263	297	338	213	112	74	38	16	1.2	-4.6
Oil	32	26	21	32	26	21	2	5	-2.1	-2.1
Gas	490	496	525	486	422	361	59	79	0.0	-1.4
TFC	**565**	**596**	**612**	**551**	**513**	**429**	**100**	**100**	**0.3**	**-1.1**
Coal	63	68	69	60	50	34	11	8	0.4	-2.4
Oil	253	253	236	247	223	172	39	40	-0.4	-1.6
Transport	*173*	*178*	*169*	*169*	*159*	*120*	*28*	*28*	*-0.2*	*-1.5*
Gas	249	275	306	243	239	224	50	52	0.9	-0.3

Non-OECD Asia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**1 578**	**4 809**	**5 398**	**5 930**	**6 488**	**7 010**	**7 437**	**100**	**100**	**1.7**
Coal	683	2 565	2 675	2 800	2 951	3 065	3 120	53	42	0.8
Oil	320	1 004	1 188	1 310	1 412	1 520	1 604	21	22	1.8
Gas	69	394	510	627	750	872	988	8	13	3.6
Nuclear	10	56	133	205	281	345	400	1	5	7.8
Hydro	24	118	137	157	178	197	211	2	3	2.3
Bioenergy	466	601	616	629	647	669	696	12	9	0.6
Other renewables	7	72	140	202	269	341	418	1	6	7.0
Power generation	**323**	**1 846**	**2 129**	**2 429**	**2 762**	**3 083**	**3 354**	**100**	**100**	**2.3**
Coal	219	1 398	1 468	1 558	1 670	1 769	1 829	76	55	1.0
Oil	46	41	39	37	36	34	32	2	1	-1.0
Gas	16	144	185	230	273	322	367	8	11	3.7
Nuclear	10	56	133	205	281	345	400	3	12	7.8
Hydro	24	118	137	157	178	197	211	6	6	2.3
Bioenergy	0	43	65	86	111	139	170	2	5	5.5
Other renewables	7	46	103	157	214	276	344	3	10	8.0
Other energy sector	**180**	**560**	**581**	**603**	**638**	**667**	**683**	**100**	**100**	**0.8**
Electricity	*26*	*125*	*144*	*161*	*184*	*207*	*227*	*22*	*33*	*2.3*
TFC	**1 202**	**3 211**	**3 679**	**4 051**	**4 416**	**4 759**	**5 044**	**100**	**100**	**1.8**
Coal	382	892	922	943	961	965	958	28	19	0.3
Oil	240	878	1 064	1 190	1 296	1 406	1 497	27	30	2.1
Gas	31	203	286	368	454	532	604	6	12	4.3
Electricity	83	592	739	881	1 034	1 183	1 313	18	26	3.1
Heat	14	79	95	98	98	95	91	2	2	0.6
Bioenergy	451	542	534	526	519	511	506	17	10	-0.3
Other renewables	0	25	38	46	55	65	74	1	1	4.2
Industry	**392**	**1 388**	**1 565**	**1 731**	**1 891**	**2 032**	**2 139**	**100**	**100**	**1.7**
Coal	227	714	733	758	783	797	802	51	37	0.4
Oil	55	107	124	129	132	134	135	8	6	0.9
Gas	9	105	153	201	250	298	339	8	16	4.6
Electricity	51	351	415	481	543	601	647	25	30	2.4
Heat	11	53	67	68	68	65	60	4	3	0.5
Bioenergy	39	56	72	92	113	132	148	4	7	3.8
Other renewables	0	0	0	1	3	5	8	0	0	14.5
Transport	**104**	**508**	**647**	**753**	**850**	**956**	**1 055**	**100**	**100**	**2.8**
Oil	91	470	594	680	753	835	905	93	86	2.5
Electricity	1	7	11	16	23	30	37	1	4	6.7
Biofuels	-	5	10	16	23	32	45	1	4	8.5
Other fuels	12	25	31	40	51	59	68	5	6	3.9
Buildings	**587**	**984**	**1 062**	**1 108**	**1 169**	**1 226**	**1 278**	**100**	**100**	**1.0**
Coal	110	103	101	94	86	76	66	10	5	-1.7
Oil	34	96	100	96	92	90	91	10	7	-0.2
Gas	5	51	72	91	113	131	148	5	12	4.2
Electricity	22	203	274	339	418	498	571	21	45	4.1
Heat	3	26	28	29	30	31	31	3	2	0.7
Bioenergy	412	480	451	415	379	341	306	49	24	-1.7
Other renewables	0	24	36	44	52	59	65	2	5	3.8
Other	**120**	**332**	**406**	**459**	**506**	**544**	**572**	**100**	**100**	**2.1**

Non-OECD Asia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**5 523**	**7 001**	**8 347**	**5 268**	**5 750**	**6 119**	**100**	**100**	**2.1**	**0.9**
Coal	2 791	3 466	4 047	2 551	2 073	1 559	48	25	1.8	-1.9
Oil	1 211	1 519	1 800	1 168	1 229	1 195	22	20	2.3	0.7
Gas	511	758	1 024	504	716	931	12	15	3.7	3.4
Nuclear	130	252	334	136	396	606	4	10	7.1	9.6
Hydro	137	171	197	137	192	238	2	4	2.0	2.7
Bioenergy	614	627	643	619	713	848	8	14	0.3	1.3
Other renewables	127	208	301	153	431	742	4	12	5.7	9.4
Power generation	**2 212**	**3 079**	**3 907**	**2 035**	**2 326**	**2 657**	**100**	**100**	**2.9**	**1.4**
Coal	1 566	2 094	2 602	1 366	945	540	67	20	2.4	-3.6
Oil	39	37	33	39	31	22	1	1	-0.8	-2.4
Gas	186	272	371	180	264	366	10	14	3.7	3.7
Nuclear	130	252	334	136	396	606	9	23	7.1	9.6
Hydro	137	171	197	137	192	238	5	9	2.0	2.7
Bioenergy	63	97	132	65	140	247	3	9	4.4	7.0
Other renewables	91	157	236	112	358	638	6	24	6.5	10.6
Other energy sector	**593**	**695**	**788**	**568**	**559**	**538**	**100**	**100**	**1.3**	**-0.2**
Electricity	*149*	*209*	*272*	*139*	*155*	*171*	*34*	*32*	*3.0*	*1.2*
TFC	**3 735**	**4 661**	**5 488**	**3 629**	**4 052**	**4 318**	**100**	**100**	**2.1**	**1.1**
Coal	937	1 024	1 060	906	837	733	19	17	0.7	-0.8
Oil	1 086	1 397	1 685	1 047	1 129	1 120	31	26	2.5	0.9
Gas	286	464	636	286	436	564	12	13	4.5	4.0
Electricity	758	1 105	1 441	717	933	1 139	26	26	3.5	2.5
Heat	97	108	110	95	90	75	2	2	1.3	-0.2
Bioenergy	534	513	492	537	555	583	9	13	-0.4	0.3
Other renewables	37	51	65	40	74	104	1	2	3.7	5.6
Industry	**1 591**	**2 001**	**2 343**	**1 545**	**1 706**	**1 789**	**100**	**100**	**2.0**	**1.0**
Coal	746	836	886	723	685	613	38	34	0.8	-0.6
Oil	127	141	150	124	119	115	6	6	1.3	0.3
Gas	154	261	366	153	229	297	16	17	4.9	4.1
Electricity	422	573	711	404	484	543	30	30	2.8	1.7
Heat	68	76	76	67	61	48	3	3	1.4	-0.4
Bioenergy	73	113	150	72	115	153	6	9	3.8	3.9
Other renewables	0	1	4	1	11	21	0	1	11.5	18.9
Transport	**657**	**904**	**1 161**	**634**	**761**	**864**	**100**	**100**	**3.2**	**2.1**
Oil	609	831	1 047	581	622	584	90	68	3.1	0.8
Electricity	11	17	24	11	34	87	2	10	4.9	10.2
Biofuels	9	17	29	11	47	96	2	11	6.7	11.7
Other fuels	28	40	61	31	59	98	5	11	3.4	5.3
Buildings	**1 079**	**1 233**	**1 377**	**1 045**	**1 091**	**1 113**	**100**	**100**	**1.3**	**0.5**
Coal	102	92	75	95	66	39	5	4	-1.2	-3.6
Oil	103	98	102	97	77	70	7	6	0.2	-1.2
Gas	73	123	160	71	107	121	12	11	4.5	3.3
Electricity	285	462	641	263	367	458	47	41	4.5	3.2
Heat	29	32	34	28	28	28	2	2	1.1	0.3
Bioenergy	451	378	304	452	385	318	22	29	-1.7	-1.6
Other renewables	36	48	60	38	60	79	4	7	3.5	4.6
Other	**409**	**523**	**607**	**404**	**494**	**552**	**100**	**100**	**2.4**	**2.0**

Non-OECD Asia: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**1 274**	**8 314**	**10 246**	**12 111**	**14 139**	**16 112**	**17 835**	**100**	**100**	**3.0**
Coal	728	5 536	6 057	6 542	7 129	7 675	8 027	67	45	1.4
Oil	167	141	130	118	111	104	94	2	1	-1.5
Gas	59	701	975	1 266	1 552	1 862	2 184	8	12	4.5
Nuclear	39	216	510	786	1 077	1 325	1 535	3	9	7.8
Hydro	274	1 368	1 593	1 828	2 075	2 288	2 455	16	14	2.3
Bioenergy	1	99	167	241	331	435	547	1	3	6.8
Wind	0	196	539	833	1 115	1 405	1 701	2	10	8.7
Geothermal	7	20	29	38	50	66	86	0	0	5.7
Solar PV	0	37	235	435	656	889	1 119	0	6	14.0
CSP	-	0	11	24	41	61	84	0	0	21.9
Marine	0	0	0	0	1	2	3	0	0	25.3

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**2 000**	**2 862**	**3 437**	**4 034**	**4 587**	**5 060**	**100**	**100**	**3.6**
Coal	1 106	1 424	1 533	1 663	1 775	1 849	55	37	2.0
Oil	63	63	63	64	61	54	3	1	-0.6
Gas	203	282	349	417	487	557	10	11	4.0
Nuclear	32	71	108	145	178	205	2	4	7.4
Hydro	411	506	586	666	732	782	21	15	2.5
Bioenergy	25	36	48	63	79	96	1	2	5.4
Wind	122	285	413	529	636	734	6	15	7.1
Geothermal	3	5	6	8	10	13	0	0	5.4
Solar PV	34	186	323	467	610	745	2	15	12.6
CSP	0	4	8	12	18	24	0	0	19.0
Marine	0	0	0	0	1	1	0	0	23.5

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**3 318**	**12 882**	**13 876**	**14 837**	**15 834**	**16 746**	**17 385**	**100**	**100**	**1.2**
Coal	2 394	9 691	9 946	10 363	10 846	11 215	11 376	75	65	0.6
Oil	817	2 390	2 847	3 122	3 354	3 617	3 839	19	22	1.8
Gas	108	801	1 082	1 352	1 635	1 913	2 170	6	12	3.9
Power generation	**1 063**	**6 169**	**6 530**	**6 988**	**7 520**	**8 010**	**8 328**	**100**	**100**	**1.2**
Coal	876	5 699	5 970	6 330	6 763	7 145	7 363	92	88	1.0
Oil	150	132	126	118	115	109	101	2	1	-1.0
Gas	38	338	434	540	643	756	864	5	10	3.7
TFC	**2 099**	**6 220**	**6 890**	**7 401**	**7 870**	**8 293**	**8 623**	**100**	**100**	**1.3**
Coal	1 458	3 752	3 766	3 830	3 887	3 887	3 844	60	45	0.1
Oil	610	2 117	2 575	2 854	3 088	3 350	3 577	34	41	2.0
Transport	*273*	*1 417*	*1 790*	*2 052*	*2 272*	*2 518*	*2 728*	*23*	*32*	*2.6*
Gas	32	351	549	716	895	1 056	1 202	6	14	4.9

Non-OECD Asia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total generation	**10 538**	**15 243**	**19 821**	**9 925**	**12 585**	**15 110**	**100**	**100**	**3.4**	**2.3**
Coal	6 480	9 016	11 500	5 656	3 921	1 996	58	13	2.9	-3.8
Oil	131	115	99	130	99	62	1	0	-1.3	-3.1
Gas	983	1 555	2 194	949	1 505	2 198	11	15	4.5	4.5
Nuclear	501	967	1 283	520	1 518	2 326	6	15	7.1	9.6
Hydro	1 592	1 988	2 293	1 597	2 237	2 766	12	18	2.0	2.7
Bioenergy	164	281	409	169	434	827	2	5	5.6	8.5
Wind	472	853	1 264	593	1 667	2 625	6	17	7.4	10.5
Geothermal	28	41	60	30	103	184	0	1	4.2	8.8
Solar PV	180	407	682	266	927	1 644	3	11	11.9	15.7
CSP	7	20	33	16	173	478	0	3	17.6	30.4
Marine	0	0	2	0	2	5	0	0	24.2	28.3

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total capacity	**2 811**	**3 930**	**4 948**	**2 883**	**4 212**	**5 225**	**100**	**100**	**3.5**	**3.8**
Coal	1 458	1 907	2 324	1 390	1 242	930	47	18	2.9	-0.7
Oil	63	65	57	63	62	50	1	1	-0.4	-0.9
Gas	283	437	596	275	394	533	12	10	4.2	3.8
Nuclear	70	131	172	73	208	311	3	6	6.7	9.1
Hydro	506	633	725	508	725	885	15	17	2.2	3.0
Bioenergy	35	54	72	36	82	146	1	3	4.2	7.1
Wind	249	411	551	314	766	1 094	11	21	6.0	8.8
Geothermal	4	6	9	5	16	27	0	1	3.9	8.4
Solar PV	139	282	432	213	665	1 107	9	21	10.3	14.4
CSP	2	6	9	6	52	139	0	3	14.8	27.3
Marine	0	0	1	0	1	2	0	0	22.4	26.5

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total CO_2	**14 414**	**18 172**	**21 632**	**13 313**	**11 185**	**7 854**	**100**	**100**	**2.0**	**-1.9**
Coal	10 413	12 851	14 969	9 454	6 839	3 358	69	43	1.7	-4.0
Oil	2 917	3 665	4 409	2 791	2 808	2 603	20	33	2.4	0.3
Gas	1 085	1 656	2 255	1 068	1 538	1 893	10	24	4.1	3.4
Power generation	**6 931**	**9 248**	**11 491**	**6 102**	**4 258**	**1 714**	**100**	**100**	**2.4**	**-4.8**
Coal	6 368	8 491	10 511	5 555	3 546	895	91	52	2.4	-6.9
Oil	126	118	107	124	100	69	1	4	-0.8	-2.5
Gas	437	639	873	423	612	750	8	44	3.7	3.1
TFC	**7 018**	**8 442**	**9 638**	**6 768**	**6 581**	**5 877**	**100**	**100**	**1.7**	**-0.2**
Coal	3 830	4 146	4 256	3 694	3 144	2 363	44	40	0.5	-1.8
Oil	2 641	3 383	4 118	2 525	2 589	2 436	43	41	2.6	0.5
Transport	*1 835*	*2 505*	*3 159*	*1 751*	*1 874*	*1 761*	*33*	*30*	*3.1*	*0.8*
Gas	547	913	1 263	549	849	1 078	13	18	5.1	4.4

China: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**879**	**3 070**	**3 328**	**3 544**	**3 728**	**3 855**	**3 892**	**100**	**100**	**0.9**
Coal	533	2 027	1 982	1 965	1 950	1 889	1 765	66	45	-0.5
Oil	122	508	606	658	682	705	710	17	18	1.3
Gas	13	151	239	305	370	424	468	5	12	4.4
Nuclear	-	35	103	168	220	266	307	1	8	8.8
Hydro	11	90	100	110	119	127	132	3	3	1.5
Bioenergy	200	218	207	207	217	233	255	7	7	0.6
Other renewables	0	41	91	131	171	212	256	1	7	7.3
Power generation	**180**	**1 243**	**1 375**	**1 529**	**1 678**	**1 796**	**1 858**	**100**	**100**	**1.6**
Coal	153	1 046	1 019	1 033	1 053	1 050	998	84	54	-0.2
Oil	16	7	8	7	7	6	6	1	0	-1.1
Gas	1	27	58	80	103	123	140	2	8	6.5
Nuclear	-	35	103	168	220	266	307	3	17	8.8
Hydro	11	90	100	110	119	127	132	7	7	1.5
Bioenergy	-	21	32	43	56	70	85	2	5	5.4
Other renewables	0	16	55	88	120	154	191	1	10	10.0
Other energy sector	**110**	**411**	**413**	**412**	**415**	**408**	**394**	**100**	**100**	**-0.2**
Electricity	*15*	*81*	*88*	*94*	*102*	*109*	*113*	*20*	*29*	*1.3*
TFC	**660**	**1 997**	**2 230**	**2 381**	**2 498**	**2 584**	**2 615**	**100**	**100**	**1.0**
Coal	308	727	709	677	635	582	520	36	20	-1.3
Oil	87	454	553	609	636	663	673	23	26	1.5
Gas	9	107	167	217	268	307	336	5	13	4.5
Electricity	41	409	496	575	652	718	761	20	29	2.4
Heat	13	78	94	96	96	94	90	4	3	0.5
Bioenergy	200	196	175	164	160	163	170	10	6	-0.6
Other renewables	0	25	36	43	51	58	65	1	2	3.8
Industry	**237**	**992**	**1 065**	**1 115**	**1 149**	**1 160**	**1 142**	**100**	**100**	**0.5**
Coal	171	569	540	511	475	430	378	57	33	-1.6
Oil	22	54	63	60	57	53	47	5	4	-0.5
Gas	3	43	76	105	131	154	170	4	15	5.4
Electricity	30	272	312	353	388	418	435	27	38	1.8
Heat	11	53	67	68	67	65	60	5	5	0.5
Bioenergy	-	-	8	18	29	39	47	-	4	n.a.
Other renewables	-	0	0	1	1	3	5	0	0	13.1
Transport	**35**	**271**	**351**	**405**	**442**	**479**	**505**	**100**	**100**	**2.4**
Oil	25	246	316	358	378	402	413	91	82	2.0
Electricity	1	5	9	13	19	24	29	2	6	6.9
Biofuels	-	2	4	7	12	18	26	1	5	10.8
Other fuels	10	18	22	27	33	35	38	7	7	3.0
Buildings	**314**	**529**	**563**	**581**	**605**	**626**	**639**	**100**	**100**	**0.7**
Coal	95	85	82	76	68	60	52	16	8	-1.8
Oil	8	46	44	39	31	24	19	9	3	-3.3
Gas	2	38	55	70	86	99	110	7	17	4.1
Electricity	6	117	158	191	226	257	278	22	43	3.4
Heat	2	25	28	28	29	29	30	5	5	0.7
Bioenergy	200	194	162	136	116	101	90	37	14	-2.9
Other renewables	0	24	35	42	48	55	60	4	9	3.6
Other	**74**	**205**	**251**	**279**	**302**	**319**	**329**	**100**	**100**	**1.8**

China: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**3 419**	**4 085**	**4 512**	**3 241**	**3 272**	**3 236**	**100**	**100**	**1.5**	**0.2**
Coal	2 073	2 311	2 401	1 900	1 430	996	53	31	0.7	-2.7
Oil	619	746	822	591	562	488	18	15	1.9	-0.2
Gas	237	372	484	237	355	462	11	14	4.6	4.4
Nuclear	103	207	269	103	306	443	6	14	8.2	10.3
Hydro	100	116	128	100	122	136	3	4	1.3	1.6
Bioenergy	205	206	228	208	248	322	5	10	0.2	1.5
Other renewables	81	127	179	100	250	390	4	12	5.9	9.1
Power generation	**1 440**	**1 897**	**2 230**	**1 315**	**1 431**	**1 555**	**100**	**100**	**2.3**	**0.9**
Coal	1 094	1 336	1 503	954	645	404	67	26	1.4	-3.6
Oil	8	7	6	7	5	3	0	0	-1.0	-3.0
Gas	57	101	137	56	100	158	6	10	6.4	7.0
Nuclear	103	207	269	103	306	443	12	28	8.2	10.3
Hydro	100	116	128	100	122	136	6	9	1.3	1.6
Bioenergy	32	50	68	32	68	106	3	7	4.5	6.4
Other renewables	46	80	120	62	186	306	5	20	8.0	12.0
Other energy sector	**422**	**452**	**461**	**405**	**362**	**311**	**100**	**100**	**0.4**	**-1.1**
Electricity	*91*	*113*	*133*	*85*	*87*	*89*	*29*	*29*	*1.9*	*0.4*
TFC	**2 269**	**2 675**	**2 932**	**2 195**	**2 256**	**2 219**	**100**	**100**	**1.5**	**0.4**
Coal	722	689	608	697	546	377	21	17	-0.7	-2.5
Oil	566	698	781	540	525	464	27	21	2.1	0.1
Gas	165	273	359	167	261	326	12	15	4.8	4.4
Electricity	511	705	857	482	591	678	29	31	2.9	2.0
Heat	96	106	108	94	88	74	4	3	1.3	-0.2
Bioenergy	174	156	160	176	180	215	5	10	-0.8	0.3
Other renewables	35	47	59	39	65	84	2	4	3.4	4.8
Industry	**1 085**	**1 241**	**1 318**	**1 052**	**1 030**	**949**	**100**	**100**	**1.1**	**-0.2**
Coal	551	521	453	533	410	268	34	28	-0.9	-2.9
Oil	64	63	56	62	49	36	4	4	0.1	-1.6
Gas	76	139	192	76	123	162	15	17	5.9	5.2
Electricity	318	414	493	305	352	373	37	39	2.3	1.2
Heat	68	76	76	67	61	47	6	5	1.4	-0.4
Bioenergy	8	28	47	7	30	52	4	5	n.a.	n.a.
Other renewables	0	0	2	1	7	11	0	1	8.5	16.7
Transport	**355**	**470**	**556**	**340**	**383**	**420**	**100**	**100**	**2.8**	**1.7**
Oil	325	427	492	305	291	236	89	56	2.7	-0.2
Electricity	8	14	19	9	29	71	3	17	5.3	10.6
Biofuels	4	9	17	5	24	53	3	13	9.0	13.9
Other fuels	18	21	27	21	40	61	5	14	1.7	4.9
Buildings	**576**	**648**	**701**	**552**	**552**	**539**	**100**	**100**	**1.1**	**0.1**
Coal	82	71	57	77	51	30	8	6	-1.5	-3.9
Oil	45	32	24	42	22	12	3	2	-2.5	-5.2
Gas	56	95	120	55	81	85	17	16	4.5	3.1
Electricity	168	257	322	151	194	217	46	40	4.0	2.4
Heat	28	30	32	27	27	27	5	5	1.0	0.3
Bioenergy	162	116	89	163	120	97	13	18	-2.9	-2.6
Other renewables	35	46	56	37	56	70	8	13	3.4	4.3
Other	**253**	**315**	**358**	**250**	**291**	**312**	**100**	**100**	**2.2**	**1.6**

China: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**650**	**5 706**	**6 797**	**7 802**	**8 785**	**9 614**	**10 150**	**100**	**100**	**2.2**
Coal	470	4 146	4 199	4 313	4 462	4 513	4 324	73	43	0.2
Oil	51	10	8	7	7	6	4	0	0	-3.4
Gas	3	124	312	452	594	724	835	2	8	7.6
Nuclear	-	133	396	644	844	1 019	1 177	2	12	8.8
Hydro	127	1 051	1 165	1 276	1 384	1 471	1 536	18	15	1.5
Bioenergy	-	57	94	135	183	233	285	1	3	6.4
Wind	0	156	442	664	865	1 062	1 259	3	12	8.4
Geothermal	0	0	1	2	4	7	14	0	0	20.0
Solar PV	0	29	171	288	407	527	650	1	6	12.7
CSP	-	0	9	21	35	50	65	0	1	33.7
Marine	0	0	0	0	1	1	2	0	0	23.8

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**1 382**	**1 958**	**2 293**	**2 612**	**2 883**	**3 082**	**100**	**100**	**3.1**
Coal	855	1 040	1 079	1 123	1 149	1 137	62	37	1.1
Oil	10	9	9	9	7	5	1	0	-2.6
Gas	58	99	129	158	182	198	4	6	4.9
Nuclear	20	55	87	112	135	155	1	5	8.1
Hydro	304	365	407	447	478	500	22	16	1.9
Bioenergy	10	16	23	30	38	46	1	1	6.1
Wind	97	230	325	406	476	537	7	17	6.8
Geothermal	0	0	0	1	1	2	0	0	18.1
Solar PV	28	140	228	316	401	482	2	16	11.6
CSP	0	3	7	10	14	18	0	1	28.9
Marine	0	0	0	0	0	1	0	0	22.1

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**2 109**	**9 101**	**9 174**	**9 306**	**9 342**	**9 208**	**8 779**	**100**	**100**	**-0.1**
Coal	1 802	7 569	7 210	7 075	6 921	6 619	6 088	83	69	-0.8
Oil	287	1 196	1 434	1 536	1 559	1 591	1 584	13	18	1.1
Gas	21	336	530	695	862	998	1 107	4	13	4.7
Power generation	**664**	**4 382**	**4 336**	**4 444**	**4 562**	**4 581**	**4 388**	**100**	**100**	**0.0**
Coal	609	4 294	4 173	4 229	4 297	4 269	4 039	98	92	-0.2
Oil	53	25	25	25	24	22	19	1	0	-1.0
Gas	2	64	137	190	242	290	330	1	8	6.5
TFC	**1 359**	**4 355**	**4 502**	**4 535**	**4 463**	**4 323**	**4 105**	**100**	**100**	**-0.2**
Coal	1 141	3 050	2 842	2 662	2 451	2 191	1 907	70	46	-1.8
Oil	207	1 082	1 319	1 422	1 449	1 485	1 484	25	36	1.2
Transport	*73*	*742*	*953*	*1 079*	*1 140*	*1 212*	*1 243*	*17*	*30*	*2.0*
Gas	11	223	341	451	562	648	714	5	17	4.6

China: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**7 015**	**9 528**	**11 484**	**6 602**	**7 871**	**8 851**	**100**	**100**	**2.7**	**1.7**
Coal	4 531	5 767	6 680	3 950	2 606	1 381	58	16	1.9	-4.1
Oil	8	7	4	8	4	3	0	0	-3.1	-5.0
Gas	307	577	779	298	572	926	7	10	7.3	8.1
Nuclear	396	793	1 033	396	1 173	1 699	9	19	8.2	10.3
Hydro	1 165	1 345	1 489	1 165	1 416	1 576	13	18	1.3	1.6
Bioenergy	92	157	222	94	219	348	2	4	5.3	7.2
Wind	385	647	930	482	1 189	1 750	8	20	7.1	9.7
Geothermal	1	3	8	1	5	20	0	0	17.5	21.5
Solar PV	125	215	311	193	530	842	3	10	9.5	13.8
CSP	5	16	27	14	154	304	0	3	29.2	41.9
Marine	0	0	2	0	1	2	0	0	22.7	24.7

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 915**	**2 528**	**2 988**	**1 971**	**2 662**	**3 025**	**100**	**100**	**3.0**	**3.1**
Coal	1 069	1 309	1 472	1 015	861	607	49	20	2.1	-1.3
Oil	9	9	6	9	9	5	0	0	-2.1	-2.6
Gas	98	165	210	95	149	197	7	7	5.1	4.8
Nuclear	55	106	136	55	158	223	5	7	7.6	9.7
Hydro	365	430	483	365	459	514	16	17	1.8	2.0
Bioenergy	16	26	36	16	36	57	1	2	5.1	7.0
Wind	200	312	406	250	533	713	14	24	5.7	8.0
Geothermal	0	0	1	0	1	3	0	0	15.6	19.5
Solar PV	100	167	230	160	411	624	8	21	8.4	12.7
CSP	2	5	7	5	45	82	0	3	24.6	36.6
Marine	0	0	1	0	0	1	0	0	21.0	22.9

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**9 575**	**10 936**	**11 589**	**8 802**	**6 421**	**3 392**	**100**	**100**	**0.9**	**-3.7**
Coal	7 577	8 322	8 548	6 887	4 400	1 508	74	44	0.5	-6.0
Oil	1 473	1 744	1 891	1 390	1 207	926	16	27	1.8	-1.0
Gas	525	871	1 150	524	814	958	10	28	4.8	4.1
Power generation	**4 645**	**5 723**	**6 457**	**4 068**	**2 601**	**742**	**100**	**100**	**1.5**	**-6.6**
Coal	4 484	5 461	6 115	3 911	2 356	471	95	63	1.4	-8.2
Oil	25	24	19	24	17	11	0	2	-0.9	-3.0
Gas	135	238	322	133	227	260	5	35	6.4	5.6
TFC	**4 586**	**4 864**	**4 791**	**4 408**	**3 581**	**2 485**	**100**	**100**	**0.4**	**-2.1**
Coal	2 894	2 668	2 258	2 787	1 913	955	47	38	-1.2	-4.4
Oil	1 356	1 625	1 777	1 280	1 124	869	37	35	1.9	-0.8
Transport	*980*	*1 288*	*1 483*	*921*	*878*	*710*	*31*	*29*	*2.7*	*-0.2*
Gas	336	570	756	342	543	661	16	27	4.8	4.3

India: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**307**	**824**	**1 033**	**1 225**	**1 457**	**1 700**	**1 938**	**100**	**100**	**3.3**
Coal	93	378	480	574	690	814	936	46	48	3.6
Oil	63	185	241	283	337	401	465	22	24	3.6
Gas	11	43	57	81	109	136	161	5	8	5.2
Nuclear	2	9	17	28	43	57	71	1	4	8.1
Hydro	6	11	14	18	23	26	30	1	2	3.9
Bioenergy	133	194	210	216	217	212	205	23	11	0.2
Other renewables	0	4	13	25	39	54	69	1	4	11.3
Power generation	**65**	**309**	**394**	**477**	**584**	**701**	**821**	**100**	**100**	**3.8**
Coal	48	249	305	343	397	461	531	81	65	3.0
Oil	5	8	8	9	11	12	12	3	1	1.6
Gas	3	14	18	31	46	61	75	4	9	6.8
Nuclear	2	9	17	28	43	57	71	3	9	8.1
Hydro	6	11	14	18	23	26	30	4	4	3.9
Bioenergy	-	14	20	25	29	34	39	5	5	4.0
Other renewables	0	4	12	23	36	49	63	1	8	11.5
Other energy sector	**23**	**71**	**89**	**109**	**133**	**156**	**177**	**100**	**100**	**3.6**
Electricity	*7*	*30*	*39*	*46*	*57*	*68*	*80*	*42*	*45*	*3.9*
TFC	**245**	**556**	**702**	**836**	**991**	**1 152**	**1 309**	**100**	**100**	**3.4**
Coal	39	114	151	195	244	292	337	20	26	4.3
Oil	52	156	212	253	306	369	432	28	33	4.0
Gas	6	29	38	49	61	73	84	5	6	4.2
Electricity	18	81	114	150	194	241	290	15	22	5.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	130	175	185	187	183	172	161	31	12	-0.3
Other renewables	0	1	1	2	3	5	6	0	0	9.6
Industry	**69**	**200**	**269**	**345**	**429**	**513**	**590**	**100**	**100**	**4.3**
Coal	26	99	136	181	230	279	326	50	55	4.7
Oil	10	18	24	29	34	40	46	9	8	3.7
Gas	1	18	24	30	35	41	45	9	8	3.5
Electricity	9	33	48	63	79	96	112	17	19	4.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	23	31	37	43	49	55	59	15	10	2.5
Other renewables	0	0	0	0	1	2	2	0	0	17.8
Transport	**21**	**78**	**114**	**143**	**181**	**231**	**286**	**100**	**100**	**5.1**
Oil	18	75	108	133	167	211	258	95	90	4.9
Electricity	0	1	2	2	3	4	6	2	2	5.3
Biofuels	-	0	1	2	3	5	8	0	3	12.7
Other fuels	2	2	3	5	8	11	15	2	5	8.5
Buildings	**134**	**221**	**244**	**257**	**274**	**289**	**303**	**100**	**100**	**1.2**
Coal	10	15	15	15	14	13	11	7	3	-1.2
Oil	11	29	33	35	38	44	48	13	16	2.0
Gas	0	2	3	4	6	7	9	1	3	6.6
Electricity	5	32	44	61	83	109	137	14	45	5.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	108	144	147	142	131	113	94	65	31	-1.6
Other renewables	0	1	1	1	2	3	4	0	1	7.8
Other	**22**	**57**	**75**	**91**	**106**	**120**	**131**	**100**	**100**	**3.2**

India: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 054**	**1 561**	**2 123**	**1 009**	**1 272**	**1 518**	**100**	**100**	**3.7**	**2.4**
Coal	499	801	1 132	456	466	422	53	28	4.3	0.4
Oil	245	357	508	239	308	360	24	24	4.0	2.6
Gas	57	104	156	57	111	175	7	12	5.1	5.5
Nuclear	17	34	52	17	59	116	2	8	6.8	10.1
Hydro	14	22	28	14	29	45	1	3	3.5	5.4
Bioenergy	210	213	195	211	234	256	9	17	0.0	1.1
Other renewables	12	30	52	15	65	144	2	10	10.1	14.5
Power generation	**409**	**660**	**953**	**375**	**449**	**552**	**100**	**100**	**4.4**	**2.3**
Coal	321	497	711	283	204	90	75	16	4.1	-3.8
Oil	8	11	13	8	10	10	1	2	2.0	1.1
Gas	18	42	71	18	51	90	7	16	6.6	7.6
Nuclear	17	34	52	17	59	116	6	21	6.8	10.1
Hydro	14	22	28	14	29	45	3	8	3.5	5.4
Bioenergy	19	25	31	20	36	68	3	12	3.0	6.2
Other renewables	11	28	48	14	59	133	5	24	10.3	14.8
Other energy sector	**92**	**148**	**205**	**87**	**116**	**138**	**100**	**100**	**4.2**	**2.6**
Electricity	*41*	*69*	*101*	*37*	*47*	*57*	*49*	*41*	*4.8*	*2.5*
TFC	**710**	**1 027**	**1 372**	**695**	**928**	**1 126**	**100**	**100**	**3.5**	**2.8**
Coal	154	252	349	149	218	273	25	24	4.4	3.4
Oil	215	324	471	210	279	333	34	30	4.3	3.0
Gas	38	61	83	38	58	83	6	7	4.1	4.1
Electricity	116	204	306	111	174	242	22	21	5.2	4.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	186	183	158	186	194	183	12	16	-0.4	0.2
Other renewables	1	2	5	1	5	12	0	1	8.4	12.4
Industry	**272**	**439**	**603**	**266**	**393**	**499**	**100**	**100**	**4.3**	**3.6**
Coal	138	236	335	134	206	266	56	53	4.8	3.9
Oil	25	37	51	24	34	43	8	9	4.1	3.5
Gas	23	33	40	24	32	36	7	7	3.0	2.7
Electricity	49	81	114	46	68	89	19	18	4.8	3.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	38	51	61	37	50	59	10	12	2.7	2.5
Other renewables	0	1	2	0	3	6	0	1	17.1	22.0
Transport	**116**	**193**	**313**	**113**	**169**	**233**	**100**	**100**	**5.5**	**4.3**
Oil	110	180	288	107	145	172	92	74	5.3	3.3
Electricity	2	3	4	2	5	13	1	6	3.5	8.8
Biofuels	1	1	3	1	11	27	1	12	8.4	18.3
Other fuels	3	9	18	3	7	21	6	9	9.4	9.9
Buildings	**247**	**285**	**320**	**241**	**261**	**266**	**100**	**100**	**1.4**	**0.7**
Coal	16	17	15	15	12	8	5	3	0.0	-2.4
Oil	34	40	51	33	35	40	16	15	2.2	1.3
Gas	3	6	9	3	6	9	3	4	6.6	6.7
Electricity	45	90	149	43	73	107	47	40	6.2	4.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	147	131	94	147	132	96	29	36	-1.6	-1.5
Other renewables	1	2	2	1	2	5	1	2	6.1	9.2
Other	**76**	**109**	**136**	**75**	**105**	**129**	**100**	**100**	**3.4**	**3.2**

India: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**293**	**1 287**	**1 768**	**2 275**	**2 896**	**3 572**	**4 254**	**100**	**100**	**4.7**
Coal	192	967	1 242	1 435	1 694	2 003	2 334	75	55	3.4
Oil	13	23	25	29	33	37	38	2	1	2.0
Gas	10	63	92	174	272	372	466	5	11	8.0
Nuclear	6	36	66	106	165	219	271	3	6	8.1
Hydro	72	131	164	213	263	308	350	10	8	3.9
Bioenergy	-	25	42	57	72	90	109	2	3	5.8
Wind	0	37	85	141	198	257	313	3	7	8.5
Geothermal	-	-	0	1	1	2	2	-	0	n.a.
Solar PV	-	5	49	115	193	276	353	0	8	17.9
CSP	-	0	1	3	5	9	16	0	0	14.9
Marine	-	-	-	-	0	0	1	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**295**	**467**	**617**	**785**	**950**	**1 102**	**100**	**100**	**5.2**
Coal	176	260	300	351	403	451	60	41	3.7
Oil	8	9	11	13	15	16	3	1	2.7
Gas	27	37	54	74	94	113	9	10	5.6
Nuclear	6	10	16	24	31	39	2	3	7.6
Hydro	44	56	70	85	97	108	15	10	3.5
Bioenergy	7	10	13	16	19	22	2	2	4.3
Wind	23	50	77	102	125	146	8	13	7.3
Geothermal	-	0	0	0	0	0	-	0	n.a.
Solar PV	3	35	75	118	162	202	1	18	17.5
CSP	0	1	1	2	3	5	0	0	12.7
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**530**	**2 018**	**2 611**	**3 133**	**3 785**	**4 509**	**5 236**	**100**	**100**	**3.7**
Coal	366	1 493	1 892	2 249	2 689	3 167	3 648	74	70	3.5
Oil	151	468	614	727	878	1 065	1 258	23	24	3.9
Gas	13	57	105	158	218	277	330	3	6	7.0
Power generation	**216**	**1 045**	**1 280**	**1 465**	**1 719**	**2 015**	**2 324**	**100**	**100**	**3.1**
Coal	192	989	1 212	1 364	1 578	1 835	2 112	95	91	3.0
Oil	16	24	26	30	33	36	37	2	2	1.6
Gas	8	32	42	72	108	144	176	3	8	6.8
TFC	**298**	**937**	**1 291**	**1 623**	**2 016**	**2 439**	**2 849**	**100**	**100**	**4.4**
Coal	169	501	676	879	1 103	1 322	1 525	53	54	4.4
Oil	128	413	554	662	807	987	1 174	44	41	4.1
Transport	*56*	*228*	*329*	*404*	*509*	*643*	*786*	*24*	*28*	*4.9*
Gas	2	23	61	82	106	129	149	2	5	7.4

India: Current Policies and 450 Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total generation	**1 819**	**3 154**	**4 695**	**1 708**	**2 541**	**3 438**	**100**	**100**	**5.1**	**3.9**
Coal	1 310	2 104	3 062	1 161	902	411	65	12	4.5	-3.2
Oil	25	36	42	25	32	33	1	1	2.4	1.4
Gas	94	255	458	92	310	571	10	17	7.9	8.9
Nuclear	65	131	201	66	228	445	4	13	6.8	10.1
Hydro	165	257	320	165	334	520	7	15	3.5	5.4
Bioenergy	40	60	79	43	96	218	2	6	4.5	8.6
Wind	76	157	239	98	329	541	5	16	7.4	10.8
Geothermal	0	1	2	0	3	5	0	0	n.a.	n.a.
Solar PV	42	150	286	56	291	521	6	15	16.9	19.6
CSP	1	3	5	2	18	171	0	5	10.0	25.7
Marine	-	-	1	-	1	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total capacity	**461**	**774**	**1 093**	**476**	**877**	**1 244**	**100**	**100**	**5.2**	**5.7**
Coal	265	396	540	255	260	212	49	17	4.4	0.7
Oil	9	14	17	9	13	14	2	1	3.1	2.2
Gas	37	77	121	35	81	136	11	11	5.9	6.4
Nuclear	10	19	29	10	34	63	3	5	6.5	9.6
Hydro	56	82	96	56	111	166	9	13	3.0	5.2
Bioenergy	10	13	16	10	20	41	1	3	3.2	6.9
Wind	44	80	110	59	168	246	10	20	6.1	9.5
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	30	92	161	42	184	309	15	25	16.5	19.4
CSP	1	1	2	1	6	56	0	4	7.8	23.5
Marine	-	-	0	-	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total CO_2	**2 701**	**4 276**	**6 131**	**2 509**	**2 761**	**2 677**	**100**	**100**	**4.4**	**1.1**
Coal	1 968	3 126	4 416	1 795	1 754	1 395	72	52	4.3	-0.3
Oil	626	944	1 396	610	787	926	23	35	4.3	2.7
Gas	107	206	319	105	220	357	5	13	6.8	7.3
Power generation	**1 345**	**2 112**	**3 034**	**1 193**	**959**	**530**	**100**	**100**	**4.2**	**-2.6**
Coal	1 276	1 978	2 826	1 126	807	286	93	54	4.1	-4.7
Oil	26	35	40	26	32	32	1	6	2.0	1.1
Gas	42	98	168	41	120	213	6	40	6.6	7.6
TFC	**1 315**	**2 112**	**3 028**	**1 276**	**1 761**	**2 105**	**100**	**100**	**4.6**	**3.2**
Coal	687	1 140	1 579	664	941	1 102	52	52	4.5	3.1
Oil	566	868	1 303	551	724	863	43	41	4.5	2.9
Transport	*334*	*548*	*878*	*326*	*442*	*524*	*29*	*25*	*5.3*	*3.3*
Gas	62	104	146	61	96	140	5	7	7.3	7.1

Middle East: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**211**	**715**	**819**	**912**	**1 026**	**1 142**	**1 244**	**100**	**100**	**2.2**
Coal	1	3	4	5	6	6	6	0	1	3.0
Oil	137	341	376	408	427	452	474	48	38	1.3
Gas	72	366	423	473	548	616	668	51	54	2.3
Nuclear	-	1	10	13	18	23	30	0	2	13.3
Hydro	1	2	3	3	4	4	4	0	0	3.3
Bioenergy	0	1	2	3	6	9	13	0	1	11.0
Other renewables	0	0	2	6	17	32	48	0	4	22.0
Power generation	**62**	**254**	**288**	**307**	**338**	**375**	**410**	**100**	**100**	**1.9**
Coal	0	0	1	2	3	3	3	0	1	11.5
Oil	27	103	98	89	72	64	62	41	15	-1.9
Gas	34	148	175	195	230	260	275	58	67	2.4
Nuclear	-	1	10	13	18	23	30	0	7	13.3
Hydro	1	2	3	3	4	4	4	1	1	3.3
Bioenergy	-	0	1	1	3	5	8	0	2	27.4
Other renewables	-	0	1	3	8	17	27	0	6	24.0
Other energy sector	**18**	**73**	**82**	**90**	**100**	**109**	**117**	**100**	**100**	**1.8**
Electricity	*4*	*16*	*18*	*21*	*25*	*28*	*31*	*22*	*26*	*2.6*
TFC	**150**	**474**	**549**	**632**	**729**	**822**	**903**	**100**	**100**	**2.5**
Coal	0	3	3	2	2	2	2	1	0	-0.3
Oil	103	230	265	302	338	371	399	48	44	2.1
Gas	31	171	197	225	260	293	321	36	35	2.4
Electricity	16	69	82	96	116	137	155	15	17	3.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	2	3	4	5	0	1	7.5
Other renewables	0	0	1	3	9	15	22	0	2	20.4
Industry	**38**	**121**	**140**	**156**	**173**	**190**	**205**	**100**	**100**	**2.0**
Coal	0	2	2	2	2	2	2	2	1	-0.3
Oil	18	18	17	18	18	19	19	14	9	0.3
Gas	16	87	103	115	128	141	154	72	75	2.2
Electricity	3	14	18	21	23	26	27	12	13	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	-	-	0	1	2	2	3	-	1	n.a.
Other renewables	-	0	0	0	0	0	0	0	0	23.1
Transport	**48**	**137**	**154**	**179**	**203**	**224**	**239**	**100**	**100**	**2.2**
Oil	48	130	149	173	196	216	230	95	96	2.2
Electricity	-	0	0	0	0	0	0	0	0	10.7
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	-	6	5	5	6	7	8	5	3	1.0
Buildings	**41**	**135**	**150**	**176**	**217**	**258**	**293**	**100**	**100**	**3.0**
Coal	-	0	0	0	0	0	0	0	0	-1.6
Oil	19	18	17	16	15	15	15	13	5	-0.6
Gas	10	65	72	85	106	122	135	48	46	2.9
Electricity	12	51	60	70	87	104	120	38	41	3.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	1	1	2	2	1	1	3.9
Other renewables	0	0	1	3	8	15	21	0	7	20.1
Other	**24**	**81**	**104**	**121**	**136**	**151**	**167**	**100**	**100**	**2.8**

Middle East: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**820**	**1 058**	**1 343**	**799**	**877**	**961**	**100**	**100**	**2.5**	**1.1**
Coal	4	6	7	4	4	4	1	0	3.2	1.3
Oil	376	443	531	367	336	313	40	33	1.7	-0.3
Gas	425	572	738	411	470	440	55	46	2.7	0.7
Nuclear	10	13	18	10	25	49	1	5	11.0	15.5
Hydro	3	3	4	3	4	5	0	1	3.3	4.3
Bioenergy	2	5	12	2	7	21	1	2	10.6	13.1
Other renewables	2	13	33	2	31	127	2	13	20.3	26.6
Power generation	**290**	**351**	**442**	**276**	**275**	**284**	**100**	**100**	**2.2**	**0.4**
Coal	1	3	3	1	2	2	1	1	11.8	8.6
Oil	98	75	67	95	44	15	15	5	-1.6	-7.2
Gas	177	248	329	167	178	112	75	40	3.1	-1.0
Nuclear	10	13	18	10	25	49	4	17	11.0	15.5
Hydro	3	3	4	3	4	5	1	2	3.3	4.3
Bioenergy	1	2	7	1	4	14	2	5	26.5	30.3
Other renewables	1	6	14	1	18	86	3	30	20.9	29.7
Other energy sector	**82**	**105**	**131**	**80**	**81**	**73**	**100**	**100**	**2.3**	**0.0**
Electricity	*18*	*26*	*33*	*17*	*20*	*23*	*26*	*31*	*2.9*	*1.4*
TFC	**549**	**748**	**969**	**538**	**644**	**754**	**100**	**100**	**2.8**	**1.8**
Coal	3	2	2	2	2	2	0	0	-0.2	-1.8
Oil	264	350	448	260	280	291	46	39	2.6	0.9
Gas	197	265	329	194	244	286	34	38	2.5	2.0
Electricity	83	120	165	78	102	128	17	17	3.4	2.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	3	5	1	4	7	1	1	7.6	8.7
Other renewables	1	7	20	1	13	41	2	5	19.9	23.3
Industry	**141**	**176**	**211**	**138**	**157**	**166**	**100**	**100**	**2.2**	**1.2**
Coal	2	2	2	2	2	1	1	1	-0.2	-2.0
Oil	17	18	20	17	16	16	9	10	0.4	-0.3
Gas	103	130	158	101	114	117	75	70	2.3	1.2
Electricity	18	24	28	17	22	24	13	15	2.5	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	0	2	3	0	2	4	2	3	n.a.	n.a.
Other renewables	0	0	0	0	0	3	0	2	23.3	35.8
Transport	**153**	**213**	**283**	**150**	**164**	**178**	**100**	**100**	**2.8**	**1.0**
Oil	148	207	276	145	146	132	97	74	2.9	0.1
Electricity	0	0	0	0	0	3	0	2	0.4	19.7
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	5	6	7	6	19	42	3	24	0.5	7.6
Buildings	**151**	**224**	**309**	**145**	**191**	**250**	**100**	**100**	**3.2**	**2.4**
Coal	0	0	0	0	0	0	0	0	-1.6	-1.6
Oil	17	17	19	16	13	13	6	5	0.2	-1.3
Gas	72	108	140	70	91	104	45	41	3.0	1.8
Electricity	61	91	130	56	74	94	42	38	3.6	2.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	2	1	2	2	1	1	3.8	4.4
Other renewables	1	7	19	1	12	37	6	15	19.7	22.9
Other	**104**	**136**	**166**	**104**	**132**	**160**	**100**	**100**	**2.8**	**2.6**

Middle East: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**224**	**990**	**1 160**	**1 357**	**1 631**	**1 910**	**2 154**	**100**	**100**	**3.0**
Coal	0	1	4	11	13	14	14	0	1	13.5
Oil	98	351	327	310	262	236	231	35	11	-1.6
Gas	114	613	752	917	1 160	1 359	1 479	62	69	3.4
Nuclear	-	4	37	49	69	89	116	0	5	13.3
Hydro	12	20	30	36	41	45	47	2	2	3.3
Bioenergy	-	0	2	5	10	19	29	0	1	27.4
Wind	0	0	4	13	31	59	102	0	5	24.2
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	0	4	12	32	60	91	0	4	32.6
CSP	-	0	1	4	13	29	46	0	2	22.3
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**285**	**356**	**402**	**468**	**534**	**591**	**100**	**100**	**2.8**
Coal	0	1	2	3	3	3	0	0	8.8
Oil	83	91	90	77	71	69	29	12	-0.7
Gas	185	234	265	316	352	366	65	62	2.7
Nuclear	1	6	7	10	13	16	0	3	11.3
Hydro	15	20	23	26	27	28	5	5	2.4
Bioenergy	0	0	1	2	3	4	0	1	32.4
Wind	0	2	6	13	24	40	0	7	25.1
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	0	2	7	18	32	47	0	8	26.7
CSP	0	0	2	5	10	16	0	3	20.5
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**536**	**1 727**	**1 864**	**2 029**	**2 213**	**2 397**	**2 536**	**100**	**100**	**1.5**
Coal	1	13	15	20	21	22	22	1	1	2.2
Oil	381	929	937	988	1 006	1 043	1 081	54	43	0.6
Gas	153	785	912	1 021	1 186	1 332	1 433	45	56	2.3
Power generation	**166**	**672**	**723**	**748**	**778**	**822**	**855**	**100**	**100**	**0.9**
Coal	0	2	4	10	11	12	12	0	1	7.4
Oil	86	323	309	280	227	201	196	48	23	-1.9
Gas	79	347	411	458	540	610	647	52	76	2.4
TFC	**333**	**923**	**998**	**1 129**	**1 273**	**1 403**	**1 505**	**100**	**100**	**1.9**
Coal	1	9	9	9	9	9	9	1	1	-0.3
Oil	272	557	581	654	724	787	830	60	55	1.5
Transport	*144*	*391*	*446*	*520*	*588*	*647*	*688*	*42*	*46*	*2.2*
Gas	61	357	408	466	540	608	666	39	44	2.4

Middle East: Current Policies and 450 Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total generation	**1 171**	**1 692**	**2 306**	**1 108**	**1 415**	**1 742**	**100**	**100**	**3.3**	**2.2**
Coal	4	13	16	4	7	7	1	0	13.9	10.5
Oil	327	275	252	317	159	55	11	3	-1.3	-6.9
Gas	764	1 248	1 770	710	915	663	77	38	4.2	0.3
Nuclear	37	52	68	37	95	189	3	11	11.0	15.5
Hydro	30	40	46	30	47	59	2	3	3.3	4.3
Bioenergy	2	9	24	2	13	52	1	3	26.4	30.3
Wind	4	28	68	4	101	313	3	18	22.3	29.7
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	3	18	43	4	53	215	2	12	28.9	37.1
CSP	1	10	19	1	24	189	1	11	18.3	29.2
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total capacity	**356**	**469**	**579**	**356**	**445**	**686**	**100**	**100**	**2.8**	**3.4**
Coal	1	3	3	1	2	2	1	0	9.3	6.6
Oil	91	80	74	91	71	61	13	9	-0.4	-1.2
Gas	234	329	409	233	245	244	71	36	3.1	1.1
Nuclear	6	8	9	6	14	26	2	4	9.0	13.4
Hydro	20	25	28	20	29	35	5	5	2.4	3.2
Bioenergy	0	1	4	0	2	8	1	1	31.3	35.6
Wind	2	11	25	2	43	124	4	18	22.9	30.7
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	2	9	21	3	30	118	4	17	22.7	31.2
CSP	0	3	7	0	9	68	1	10	16.5	27.4
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2014-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total CO_2	**1 868**	**2 319**	**2 869**	**1 810**	**1 733**	**1 455**	**100**	**100**	**2.0**	**-0.7**
Coal	15	22	24	14	14	12	1	1	2.4	-0.2
Oil	936	1 057	1 258	910	733	584	44	40	1.2	-1.8
Gas	917	1 241	1 587	885	986	859	55	59	2.7	0.3
Power generation	**729**	**829**	**997**	**695**	**560**	**297**	**100**	**100**	**1.5**	**-3.1**
Coal	4	11	13	4	6	6	1	2	7.7	4.6
Oil	309	236	211	299	138	46	21	15	-1.6	-7.2
Gas	416	581	773	391	416	245	78	82	3.1	-1.3
TFC	**997**	**1 322**	**1 679**	**975**	**1 049**	**1 060**	**100**	**100**	**2.3**	**0.5**
Coal	9	9	9	9	7	5	1	0	-0.2	-2.4
Oil	580	763	985	565	554	506	59	48	2.2	-0.4
Transport	*443*	*619*	*826*	*433*	*436*	*396*	*49*	*37*	*2.9*	*0.1*
Gas	408	550	685	401	488	550	41	52	2.5	1.7

Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**390**	**781**	**884**	**979**	**1 085**	**1 207**	**1 336**	**100**	**100**	**2.1**
Coal	74	112	114	122	130	147	171	14	13	1.6
Oil	87	169	196	216	237	261	284	22	21	2.0
Gas	28	109	119	142	173	212	260	14	19	3.4
Nuclear	2	4	4	4	7	10	12	0	1	4.7
Hydro	5	11	14	19	25	32	38	1	3	5.1
Bioenergy	194	372	427	457	478	487	482	48	36	1.0
Other renewables	0	4	10	19	34	59	90	1	7	12.5
Power generation	**68**	**168**	**176**	**204**	**248**	**310**	**389**	**100**	**100**	**3.3**
Coal	39	71	68	74	78	82	88	42	23	0.8
Oil	11	23	24	23	23	25	25	14	6	0.3
Gas	11	55	54	62	76	97	129	33	33	3.3
Nuclear	2	4	4	4	7	10	12	2	3	4.7
Hydro	5	11	14	19	25	32	38	6	10	5.1
Bioenergy	0	1	2	4	7	10	14	1	4	10.4
Other renewables	0	4	10	18	32	54	83	2	21	12.3
Other energy sector	**57**	**119**	**145**	**166**	**180**	**195**	**205**	**100**	**100**	**2.1**
Electricity	*5*	*14*	*15*	*17*	*21*	*25*	*30*	*12*	*15*	*2.9*
TFC	**292**	**562**	**642**	**704**	**775**	**848**	**925**	**100**	**100**	**1.9**
Coal	20	22	23	24	27	31	40	4	4	2.4
Oil	71	144	169	188	209	231	253	26	27	2.2
Gas	9	34	43	54	68	83	98	6	11	4.1
Electricity	22	54	64	78	97	121	152	10	16	4.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	171	308	342	360	372	377	375	55	41	0.8
Other renewables	0	0	1	1	3	5	6	0	1	15.7
Industry	**55**	**90**	**106**	**120**	**137**	**161**	**191**	**100**	**100**	**3.0**
Coal	14	13	15	17	20	24	33	14	17	3.6
Oil	15	16	18	20	21	23	25	17	13	1.9
Gas	4	21	25	29	34	39	47	23	24	3.2
Electricity	12	22	25	29	33	39	46	24	24	2.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	10	19	22	25	29	34	40	21	21	3.0
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**38**	**92**	**110**	**122**	**136**	**148**	**160**	**100**	**100**	**2.2**
Oil	37	90	107	119	132	145	156	98	97	2.1
Electricity	0	0	1	1	1	1	1	1	1	3.3
Biofuels	-	0	1	1	1	1	1	0	1	24.3
Other fuels	0	1	1	1	1	1	2	1	1	1.6
Buildings	**185**	**356**	**398**	**431**	**466**	**500**	**529**	**100**	**100**	**1.5**
Coal	3	7	6	6	5	5	5	2	1	-1.4
Oil	11	24	26	29	34	39	46	7	9	2.6
Gas	2	9	12	18	27	36	42	3	8	6.0
Electricity	9	30	36	46	60	78	101	8	19	4.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	160	286	316	330	338	338	330	80	62	0.5
Other renewables	0	0	0	1	2	4	6	0	1	15.3
Other	**15**	**24**	**28**	**32**	**36**	**40**	**44**	**100**	**100**	**2.3**

Africa: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**891**	**1 122**	**1 404**	**869**	**1 004**	**1 168**	**100**	**100**	**2.3**	**1.6**
Coal	114	138	188	108	95	92	13	8	2.0	-0.8
Oil	199	252	320	190	202	213	23	18	2.5	0.9
Gas	120	179	263	116	145	166	19	14	3.4	1.6
Nuclear	4	7	11	4	10	28	1	2	4.5	8.2
Hydro	14	22	31	14	26	49	2	4	4.3	6.1
Bioenergy	431	494	514	426	478	485	37	42	1.3	1.0
Other renewables	10	31	77	11	49	135	6	12	11.8	14.2
Power generation	**176**	**249**	**373**	**168**	**207**	**313**	**100**	**100**	**3.1**	**2.4**
Coal	68	82	96	63	47	28	26	9	1.2	-3.5
Oil	25	23	23	22	13	13	6	4	0.1	-2.2
Gas	54	80	127	51	58	53	34	17	3.3	-0.1
Nuclear	4	7	11	4	10	28	3	9	4.5	8.2
Hydro	14	22	31	14	26	49	8	16	4.3	6.1
Bioenergy	2	7	12	2	8	18	3	6	10.0	11.5
Other renewables	10	29	72	11	45	124	19	40	11.7	14.0
Other energy sector	**147**	**192**	**232**	**144**	**171**	**183**	**100**	**100**	**2.6**	**1.7**
Electricity	*15*	*21*	*30*	*14*	*18*	*24*	*13*	*13*	*2.9*	*2.0*
TFC	**647**	**797**	**972**	**634**	**730**	**825**	**100**	**100**	**2.1**	**1.5**
Coal	24	29	44	23	23	30	5	4	2.8	1.2
Oil	172	224	291	165	185	196	30	24	2.7	1.2
Gas	43	68	96	42	61	84	10	10	4.1	3.6
Electricity	64	94	142	62	86	129	15	16	3.8	3.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	344	380	393	341	371	375	40	45	0.9	0.8
Other renewables	0	2	6	1	4	11	1	1	15.0	18.0
Industry	**107**	**142**	**199**	**104**	**125**	**162**	**100**	**100**	**3.1**	**2.3**
Coal	15	21	36	15	17	24	18	15	4.0	2.5
Oil	19	23	28	18	19	21	14	13	2.2	1.2
Gas	25	34	46	25	30	36	23	22	3.1	2.2
Electricity	25	34	47	24	28	37	24	23	3.0	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	22	31	43	23	30	43	22	26	3.2	3.2
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**111**	**144**	**185**	**107**	**120**	**126**	**100**	**100**	**2.7**	**1.2**
Oil	109	142	182	105	114	111	98	88	2.7	0.8
Electricity	1	1	1	1	1	1	0	1	2.4	4.4
Biofuels	1	1	1	1	3	6	0	4	21.8	30.8
Other fuels	1	1	1	1	3	8	1	7	-0.1	8.2
Buildings	**400**	**474**	**541**	**394**	**450**	**495**	**100**	**100**	**1.6**	**1.3**
Coal	7	6	6	6	4	3	1	1	-0.4	-2.8
Oil	27	37	54	25	31	40	10	8	3.2	2.0
Gas	12	27	42	12	22	33	8	7	6.0	5.0
Electricity	36	57	90	35	54	87	17	17	4.3	4.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	318	345	344	315	335	323	64	65	0.7	0.5
Other renewables	0	2	5	1	3	9	1	2	14.7	17.2
Other	**29**	**37**	**46**	**28**	**35**	**42**	**100**	**100**	**2.5**	**2.1**

Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**316**	**775**	**919**	**1 107**	**1 366**	**1 702**	**2 118**	**100**	**100**	**3.9**
Coal	165	258	276	307	329	354	387	33	18	1.6
Oil	41	87	95	92	93	100	100	11	5	0.5
Gas	45	282	322	378	468	593	792	36	37	4.0
Nuclear	8	14	14	14	26	39	46	2	2	4.7
Hydro	56	122	165	224	293	372	441	16	21	5.1
Bioenergy	0	1	6	14	25	37	50	0	2	15.3
Wind	-	5	19	31	45	60	77	1	4	10.8
Geothermal	0	4	8	13	24	42	66	1	3	11.3
Solar PV	-	1	12	26	48	76	112	0	5	18.2
CSP	-	-	3	8	16	29	48	-	2	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**186**	**260**	**317**	**390**	**476**	**574**	**100**	**100**	**4.4**
Coal	44	55	60	66	73	80	24	14	2.4
Oil	35	38	38	39	43	44	19	8	0.9
Gas	72	107	128	154	182	222	39	39	4.4
Nuclear	2	2	2	4	5	7	1	1	4.8
Hydro	28	39	53	70	89	104	15	18	5.2
Bioenergy	1	2	4	6	8	11	0	2	12.1
Wind	2	7	12	16	21	26	1	5	9.5
Geothermal	1	1	2	4	7	10	0	2	11.5
Solar PV	1	7	15	26	39	55	1	10	15.2
CSP	-	1	3	5	9	14	-	2	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**525**	**1 096**	**1 216**	**1 342**	**1 491**	**1 679**	**1 904**	**100**	**100**	**2.1**
Coal	228	402	399	428	452	488	549	37	29	1.2
Oil	238	470	574	627	687	757	820	43	43	2.2
Gas	59	224	243	286	352	434	535	20	28	3.4
Power generation	**216**	**469**	**474**	**511**	**558**	**629**	**728**	**100**	**100**	**1.7**
Coal	155	282	269	293	307	324	349	60	48	0.8
Oil	35	58	77	73	73	78	78	12	11	1.2
Gas	25	129	127	144	178	227	301	28	41	3.3
TFC	**279**	**538**	**640**	**715**	**808**	**912**	**1 027**	**100**	**100**	**2.5**
Coal	73	78	90	94	102	118	146	15	14	2.4
Oil	192	401	476	526	584	643	704	75	69	2.2
Transport	*110*	*284*	*323*	*358*	*398*	*434*	*469*	*53*	*46*	*2.0*
Gas	14	58	74	94	122	151	176	11	17	4.4

Africa: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**913**	**1 337**	**1 990**	**886**	**1 206**	**1 776**	**100**	**100**	**3.7**	**3.2**
Coal	275	341	417	258	197	119	21	7	1.9	-2.9
Oil	96	93	95	87	52	49	5	3	0.3	-2.1
Gas	324	488	765	309	380	337	38	19	3.9	0.7
Nuclear	14	26	43	14	37	106	2	6	4.5	8.2
Hydro	160	253	365	165	301	571	18	32	4.3	6.1
Bioenergy	6	23	44	7	29	64	2	4	14.8	16.4
Wind	17	38	66	20	68	140	3	8	10.1	13.4
Geothermal	8	22	54	8	27	76	3	4	10.4	11.9
Solar PV	9	36	85	13	72	163	4	9	16.9	19.9
CSP	4	17	58	5	43	151	3	9	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**256**	**373**	**530**	**260**	**382**	**583**	**100**	**100**	**4.1**	**4.5**
Coal	54	67	84	53	49	42	16	7	2.6	-0.2
Oil	39	39	42	38	31	31	8	5	0.7	-0.4
Gas	106	156	212	106	133	156	40	27	4.2	3.0
Nuclear	2	4	6	2	6	15	1	2	4.3	8.1
Hydro	37	60	86	39	73	139	16	24	4.4	6.4
Bioenergy	2	6	9	2	7	13	2	2	11.6	13.1
Wind	7	14	22	8	25	48	4	8	8.9	12.1
Geothermal	1	3	8	1	4	12	2	2	10.6	12.1
Solar PV	6	20	42	9	41	85	8	15	14.0	17.1
CSP	2	6	17	2	14	43	3	7	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 228**	**1 575**	**2 073**	**1 168**	**1 173**	**1 150**	**100**	**100**	**2.5**	**0.2**
Coal	402	477	600	378	305	226	29	20	1.5	-2.2
Oil	583	733	935	556	577	597	45	52	2.7	0.9
Gas	242	364	538	235	291	327	26	28	3.4	1.5
Power generation	**475**	**584**	**748**	**442**	**356**	**247**	**100**	**100**	**1.8**	**-2.4**
Coal	270	324	382	251	178	81	51	33	1.2	-4.7
Oil	78	72	73	71	41	41	10	16	0.9	-1.3
Gas	128	187	293	121	136	125	39	51	3.2	-0.1
TFC	**650**	**862**	**1 156**	**624**	**706**	**782**	**100**	**100**	**3.0**	**1.4**
Coal	92	111	164	87	86	98	14	12	2.9	0.8
Oil	485	629	818	465	512	532	71	68	2.8	1.1
Transport	*328*	*426*	*547*	*316*	*343*	*332*	*47*	*43*	*2.6*	*0.6*
Gas	74	122	174	72	108	152	15	19	4.3	3.8

South Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**90**	**147**	**148**	**152**	**158**	**165**	**173**	**100**	**100**	**0.6**
Coal	67	102	96	94	89	85	82	69	47	-0.8
Oil	11	22	26	28	31	34	36	15	21	1.9
Gas	-	3	4	4	5	7	9	2	5	4.1
Nuclear	2	4	4	4	7	10	12	2	7	4.7
Hydro	0	0	0	0	0	0	1	0	0	7.3
Bioenergy	10	16	17	19	20	22	24	11	14	1.6
Other renewables	-	0	1	3	5	7	10	0	6	14.4
Power generation	**39**	**68**	**62**	**63**	**66**	**69**	**74**	**100**	**100**	**0.3**
Coal	36	64	55	54	49	45	43	94	58	-1.5
Oil	-	0	0	0	0	0	0	0	0	7.4
Gas	-	-	0	1	2	3	5	-	6	n.a.
Nuclear	2	4	4	4	7	10	12	5	16	4.7
Hydro	0	0	0	0	0	0	1	0	1	7.3
Bioenergy	-	0	1	2	3	4	5	0	7	16.0
Other renewables	-	0	1	2	4	6	8	0	11	15.7
Other energy sector	**15**	**26**	**28**	**29**	**29**	**30**	**30**	**100**	**100**	**0.6**
Electricity	*2*	*4*	*4*	*5*	*5*	*5*	*5*	*16*	*18*	*1.0*
TFC	**51**	**75**	**81**	**85**	**91**	**97**	**104**	**100**	**100**	**1.3**
Coal	16	19	19	18	18	17	17	26	16	-0.5
Oil	15	25	29	32	35	38	40	33	39	1.8
Gas	-	2	2	2	2	2	3	2	3	1.7
Electricity	12	17	18	20	23	26	29	23	28	2.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	8	11	12	12	13	13	14	15	13	0.7
Other renewables	-	0	0	0	1	1	1	0	1	10.5
Industry	**22**	**27**	**27**	**28**	**29**	**30**	**31**	**100**	**100**	**0.6**
Coal	11	11	12	12	11	12	12	43	37	0.1
Oil	2	1	1	1	1	1	1	5	4	-0.1
Gas	-	2	2	2	2	2	2	6	8	1.4
Electricity	7	10	11	11	12	12	13	39	42	0.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	1	2	2	2	2	2	3	7	9	1.2
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**10**	**18**	**23**	**26**	**29**	**32**	**34**	**100**	**100**	**2.5**
Oil	10	18	22	25	28	30	32	98	94	2.4
Electricity	0	0	0	0	0	1	1	2	2	2.9
Biofuels	-	-	1	1	1	1	1	-	4	n.a.
Other fuels	0	0	0	0	0	0	0	0	0	2.9
Buildings	**14**	**23**	**24**	**24**	**26**	**28**	**31**	**100**	**100**	**1.1**
Coal	2	6	6	5	4	4	4	27	12	-1.9
Oil	1	2	1	1	1	2	2	7	6	0.4
Gas	-	0	0	0	0	0	0	0	1	21.3
Electricity	4	6	7	8	10	12	14	26	46	3.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	6	9	9	9	9	9	10	40	31	0.1
Other renewables	-	0	0	0	1	1	1	0	4	10.0
Other	**6**	**7**	**7**	**7**	**7**	**7**	**8**	**100**	**100**	**0.4**

South Africa: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**150**	**167**	**191**	**145**	**139**	**141**	**100**	**100**	**1.0**	**-0.2**
Coal	98	98	99	93	68	43	52	31	-0.1	-3.3
Oil	26	34	43	25	26	24	23	17	2.6	0.3
Gas	4	5	8	3	6	11	4	8	3.6	4.8
Nuclear	4	7	11	4	9	19	6	14	4.5	6.7
Hydro	0	0	0	0	0	1	0	0	6.9	8.5
Bioenergy	17	19	23	18	22	26	12	19	1.5	2.1
Other renewables	1	4	7	2	7	16	4	12	12.9	16.8
Power generation	**63**	**71**	**84**	**59**	**53**	**55**	**100**	**100**	**0.8**	**-0.8**
Coal	57	56	57	53	31	8	69	15	-0.4	-7.5
Oil	0	0	0	0	0	0	0	0	7.9	5.4
Gas	0	2	3	0	3	7	4	12	n.a.	n.a.
Nuclear	4	7	11	4	9	19	13	35	4.5	6.7
Hydro	0	0	0	0	0	1	1	1	6.9	8.5
Bioenergy	1	3	5	1	3	6	6	10	16.0	16.7
Other renewables	1	3	6	1	7	14	7	25	14.2	18.0
Other energy sector	**28**	**29**	**31**	**28**	**28**	**29**	**100**	**100**	**0.7**	**0.4**
Electricity	*4*	*5*	*6*	*4*	*4*	*4*	*19*	*13*	*1.4*	*-0.4*
TFC	**82**	**95**	**114**	**79**	**81**	**85**	**100**	**100**	**1.6**	**0.5**
Coal	20	20	20	19	15	13	17	15	0.1	-1.5
Oil	30	37	47	29	30	28	41	33	2.4	0.4
Gas	2	2	3	2	2	3	2	3	1.6	1.6
Electricity	18	24	31	18	20	24	27	28	2.3	1.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	12	12	13	12	13	15	12	18	0.6	1.1
Other renewables	0	0	1	0	1	3	1	3	8.6	13.2
Industry	**28**	**30**	**33**	**27**	**25**	**25**	**100**	**100**	**0.8**	**-0.2**
Coal	12	12	13	11	10	9	39	35	0.5	-1.0
Oil	1	1	1	1	1	1	4	4	0.2	-0.8
Gas	2	2	2	2	2	2	7	8	1.4	0.7
Electricity	11	12	14	10	10	10	41	40	1.0	-0.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	2	3	2	2	3	9	12	1.4	1.7
Other renewables	0	0	0	0	0	0	0	1	n.a.	n.a.
Transport	**23**	**31**	**40**	**23**	**25**	**25**	**100**	**100**	**3.1**	**1.3**
Oil	23	30	38	21	23	21	96	85	3.0	0.7
Electricity	0	0	1	0	0	1	1	4	2.1	4.8
Biofuels	0	1	1	1	2	2	2	10	n.a.	n.a.
Other fuels	0	0	0	0	0	0	0	1	1.8	13.9
Buildings	**24**	**27**	**33**	**23**	**24**	**27**	**100**	**100**	**1.4**	**0.6**
Coal	6	5	5	5	4	3	15	10	-0.8	-3.3
Oil	2	2	2	1	1	1	6	4	1.1	-1.2
Gas	0	0	0	0	0	0	0	1	19.0	20.9
Electricity	7	10	15	6	9	12	47	43	3.7	2.7
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	9	9	9	9	9	10	29	35	0.0	0.1
Other renewables	0	0	1	0	1	2	2	8	8.4	12.4
Other	**7**	**7**	**8**	**7**	**7**	**7**	**100**	**100**	**0.5**	**0.1**

South Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**165**	**249**	**265**	**284**	**310**	**344**	**378**	**100**	**100**	**1.6**
Coal	156	232	231	228	217	209	203	93	54	-0.5
Oil	-	0	0	0	1	1	1	0	0	6.8
Gas	-	-	2	7	13	21	31	-	8	n.a.
Nuclear	8	14	14	14	26	39	46	6	12	4.7
Hydro	1	1	4	5	5	5	6	0	2	7.3
Bioenergy	-	0	2	6	10	14	18	0	5	17.0
Wind	-	1	7	12	17	22	28	0	8	13.4
Geothermal	-	-	0	0	0	0	0	-	0	n.a.
Solar PV	-	1	5	9	15	22	29	0	8	13.3
CSP	-	-	1	3	6	10	15	-	4	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**48**	**63**	**71**	**81**	**93**	**105**	**99**	**100**	**3.1**
Coal	39	45	45	45	46	46	80	44	0.7
Oil	3	4	3	3	3	3	6	3	0.8
Gas	-	2	4	7	9	13	-	12	n.a.
Nuclear	2	2	2	4	5	7	4	6	4.8
Hydro	2	4	4	4	4	4	5	4	2.5
Bioenergy	0	1	2	3	3	4	0	4	11.6
Wind	1	3	4	6	7	9	1	8	11.0
Geothermal	-	0	0	0	0	0	-	0	n.a.
Solar PV	1	3	5	8	12	15	2	14	11.1
CSP	-	1	1	2	3	4	-	4	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**244**	**438**	**420**	**418**	**409**	**403**	**404**	**100**	**100**	**-0.3**
Coal	201	364	332	322	302	284	274	83	68	-1.1
Oil	43	70	83	90	98	106	113	16	28	1.9
Gas	-	4	5	7	9	13	17	1	4	5.8
Power generation	**143**	**252**	**221**	**215**	**200**	**188**	**182**	**100**	**100**	**-1.2**
Coal	143	252	220	212	195	180	171	100	94	-1.5
Oil	-	0	0	0	0	1	1	0	1	7.4
Gas	-	-	1	2	4	7	11	-	6	n.a.
TFC	**98**	**142**	**157**	**161**	**167**	**173**	**180**	**100**	**100**	**0.9**
Coal	57	71	72	69	66	64	63	50	35	-0.4
Oil	41	68	81	87	96	104	110	48	61	1.9
Transport	*29*	*53*	*66*	*73*	*83*	*90*	*97*	*37*	*54*	*2.4*
Gas	-	4	4	5	5	6	6	3	3	1.7

South Africa: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**268**	**323**	**402**	**257**	**264**	**299**	**100**	**100**	**1.9**	**0.7**
Coal	234	241	257	220	133	32	64	11	0.4	-7.4
Oil	0	1	1	0	0	1	0	0	7.2	4.6
Gas	1	10	23	1	18	46	6	15	n.a.	n.a.
Nuclear	14	26	43	14	36	74	11	25	4.5	6.7
Hydro	3	4	5	4	6	8	1	3	6.9	8.5
Bioenergy	2	10	17	3	12	21	4	7	16.9	17.8
Wind	6	14	23	8	21	38	6	13	12.6	14.8
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	5	12	22	6	27	53	5	18	12.1	16.0
CSP	1	4	9	1	10	25	2	8	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**63**	**81**	**104**	**64**	**82**	**110**	**100**	**100**	**3.0**	**3.2**
Coal	45	48	54	45	35	23	52	21	1.3	-2.0
Oil	4	3	3	4	3	3	3	3	0.8	0.7
Gas	2	6	12	2	5	16	11	15	n.a.	n.a.
Nuclear	2	4	6	2	5	10	6	9	4.3	6.6
Hydro	3	4	4	4	4	5	4	5	2.1	3.2
Bioenergy	1	3	4	1	3	5	4	4	11.5	12.3
Wind	2	5	7	3	7	12	7	11	10.1	12.2
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	3	7	11	4	15	28	11	25	10.0	13.8
CSP	1	1	3	1	4	7	3	7	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**429**	**452**	**488**	**405**	**304**	**180**	**100**	**100**	**0.4**	**-3.4**
Coal	338	337	341	320	210	83	70	46	-0.3	-5.5
Oil	85	106	133	81	83	76	27	42	2.5	0.3
Gas	5	9	14	5	11	21	3	12	5.0	6.6
Power generation	**225**	**227**	**236**	**210**	**122**	**19**	**100**	**100**	**-0.2**	**-9.4**
Coal	224	223	227	210	115	3	96	17	-0.4	-15.4
Oil	0	0	1	0	0	1	0	3	7.9	5.4
Gas	1	4	8	0	6	16	3	80	n.a.	n.a.
TFC	**161**	**182**	**210**	**153**	**141**	**120**	**100**	**100**	**1.5**	**-0.7**
Coal	74	73	74	70	55	40	35	33	0.2	-2.2
Oil	83	104	130	79	81	74	62	62	2.5	0.3
Transport	*68*	*89*	*114*	*64*	*70*	*64*	*54*	*53*	*3.0*	*0.7*
Gas	4	5	6	4	5	6	3	5	1.6	1.3

Latin America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**327**	**639**	**646**	**691**	**747**	**815**	**890**	**100**	**100**	**1.3**
Coal	15	26	27	30	33	37	40	4	5	1.7
Oil	151	285	270	276	282	290	293	45	33	0.1
Gas	48	139	138	150	167	195	228	22	26	1.9
Nuclear	2	6	9	10	13	14	16	1	2	4.1
Hydro	30	58	66	75	84	91	99	9	11	2.1
Bioenergy	80	120	124	134	144	158	174	19	20	1.4
Other renewables	1	5	12	17	24	32	40	1	5	8.0
Power generation	**65**	**178**	**179**	**195**	**217**	**244**	**275**	**100**	**100**	**1.7**
Coal	3	10	10	11	12	12	13	6	5	1.0
Oil	14	35	26	22	18	17	15	19	5	-3.2
Gas	12	51	41	43	48	58	68	28	25	1.2
Nuclear	2	6	9	10	13	14	16	3	6	4.1
Hydro	30	58	66	75	84	91	99	33	36	2.1
Bioenergy	2	14	16	18	21	24	27	8	10	2.5
Other renewables	1	5	10	15	21	29	37	3	13	8.1
Other energy sector	**55**	**89**	**82**	**86**	**93**	**100**	**110**	**100**	**100**	**0.8**
Electricity	*8*	*20*	*21*	*23*	*26*	*28*	*31*	*23*	*28*	*1.7*
TFC	**249**	**477**	**498**	**538**	**582**	**632**	**685**	**100**	**100**	**1.4**
Coal	6	11	13	14	15	16	18	2	3	1.7
Oil	122	230	232	243	252	262	268	48	39	0.6
Gas	23	62	71	79	90	104	121	13	18	2.6
Electricity	35	85	92	104	118	133	149	18	22	2.2
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	63	88	89	96	103	113	125	18	18	1.4
Other renewables	-	1	1	2	2	3	4	0	1	7.2
Industry	**84**	**158**	**168**	**182**	**196**	**215**	**236**	**100**	**100**	**1.6**
Coal	6	11	13	14	15	16	17	7	7	1.7
Oil	21	36	37	37	37	37	38	23	16	0.2
Gas	13	35	40	47	54	64	74	22	31	2.9
Electricity	17	35	37	41	45	50	56	22	24	1.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	27	41	41	42	44	47	51	26	21	0.8
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**72**	**163**	**165**	**177**	**190**	**205**	**221**	**100**	**100**	**1.2**
Oil	65	139	138	144	151	157	160	85	72	0.5
Electricity	0	0	0	0	1	1	2	0	1	6.5
Biofuels	6	17	19	25	30	37	45	10	21	3.8
Other fuels	0	8	7	7	8	10	14	5	6	2.3
Buildings	**67**	**106**	**109**	**118**	**128**	**138**	**149**	**100**	**100**	**1.3**
Coal	0	0	0	0	0	0	0	0	0	-1.6
Oil	17	19	19	19	20	20	20	18	14	0.2
Gas	6	13	14	16	17	19	21	12	14	1.8
Electricity	17	47	51	59	67	76	84	44	57	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	27	26	24	23	22	21	20	25	14	-0.9
Other renewables	-	1	1	2	2	3	4	1	2	6.9
Other	**26**	**50**	**55**	**62**	**68**	**74**	**79**	**100**	**100**	**1.8**

Latin America: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**653**	**774**	**949**	**637**	**671**	**728**	**100**	**100**	**1.5**	**0.5**
Coal	29	36	45	27	23	23	5	3	2.2	-0.4
Oil	273	297	329	264	230	196	35	27	0.6	-1.4
Gas	142	181	255	133	136	146	27	20	2.4	0.2
Nuclear	9	12	14	10	14	19	2	3	3.7	5.0
Hydro	66	85	102	66	85	101	11	14	2.2	2.2
Bioenergy	123	141	169	124	155	187	18	26	1.3	1.7
Other renewables	11	22	36	12	29	55	4	8	7.5	9.3
Power generation	**184**	**229**	**298**	**172**	**185**	**227**	**100**	**100**	**2.0**	**0.9**
Coal	12	14	16	10	4	2	5	1	1.7	-5.5
Oil	26	20	17	23	8	3	6	1	-2.8	-8.8
Gas	44	58	89	36	28	22	30	10	2.2	-3.1
Nuclear	9	12	14	10	14	19	5	9	3.7	5.0
Hydro	66	85	102	66	85	101	34	45	2.2	2.2
Bioenergy	16	21	27	16	21	30	9	13	2.5	2.9
Other renewables	10	20	33	11	26	49	11	22	7.6	9.4
Other energy sector	**83**	**97**	**123**	**82**	**82**	**87**	**100**	**100**	**1.2**	**-0.1**
Electricity	*22*	*27*	*34*	*21*	*23*	*27*	*28*	*30*	*2.0*	*1.0*
TFC	**502**	**599**	**723**	**493**	**534**	**574**	**100**	**100**	**1.6**	**0.7**
Coal	13	15	18	12	14	14	2	2	1.8	0.8
Oil	235	266	301	230	214	187	42	33	1.0	-0.8
Gas	71	92	120	70	83	98	17	17	2.6	1.8
Electricity	93	124	160	90	108	133	22	23	2.5	1.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	89	100	121	90	114	136	17	24	1.2	1.7
Other renewables	1	2	3	1	3	6	0	1	6.2	9.0
Industry	**170**	**202**	**246**	**166**	**176**	**190**	**100**	**100**	**1.7**	**0.7**
Coal	13	15	18	12	13	14	7	7	1.8	0.9
Oil	37	38	39	37	33	30	16	16	0.4	-0.7
Gas	41	56	77	40	47	52	31	28	3.1	1.6
Electricity	38	46	57	36	38	46	23	24	2.0	1.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	42	47	54	41	44	47	22	25	1.0	0.4
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**166**	**195**	**236**	**164**	**172**	**171**	**100**	**100**	**1.4**	**0.2**
Oil	140	161	189	137	120	92	80	54	1.2	-1.5
Electricity	0	1	1	0	2	5	0	3	3.5	10.6
Biofuels	18	26	38	20	41	58	16	34	3.1	4.9
Other fuels	7	7	9	8	10	16	4	9	0.5	2.9
Buildings	**110**	**134**	**160**	**107**	**121**	**137**	**100**	**100**	**1.6**	**1.0**
Coal	0	0	0	0	0	0	0	0	-1.6	-4.3
Oil	19	20	21	18	18	17	13	13	0.4	-0.4
Gas	14	18	22	14	16	18	13	13	2.0	1.2
Electricity	52	73	94	50	63	77	59	56	2.7	1.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	24	22	20	24	22	21	13	15	-0.9	-0.9
Other renewables	1	2	3	1	3	5	2	3	5.9	7.9
Other	**56**	**68**	**80**	**55**	**66**	**76**	**100**	**100**	**1.8**	**1.6**

Latin America: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**489**	**1 217**	**1 314**	**1 482**	**1 669**	**1 874**	**2 086**	**100**	**100**	**2.1**
Coal	9	43	44	46	51	55	61	4	3	1.3
Oil	64	162	124	102	86	80	72	13	3	-3.1
Gas	45	232	208	232	270	336	398	19	19	2.1
Nuclear	10	21	36	39	52	52	60	2	3	4.1
Hydro	354	678	764	875	972	1 060	1 149	56	55	2.1
Bioenergy	7	59	64	73	82	93	104	5	5	2.2
Wind	-	17	62	89	115	139	163	1	8	9.1
Geothermal	1	4	5	7	10	14	19	0	1	6.1
Solar PV	-	1	8	18	30	42	53	0	3	19.6
CSP	-	0	-	1	3	5	9	0	0	20.6
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**280**	**344**	**385**	**433**	**483**	**540**	**100**	**100**	**2.6**
Coal	7	9	10	11	11	12	2	2	2.2
Oil	42	43	39	34	33	31	15	6	-1.2
Gas	55	67	76	92	108	130	20	24	3.4
Nuclear	4	5	6	7	7	8	1	2	3.2
Hydro	150	178	196	215	233	253	54	47	2.0
Bioenergy	14	17	19	21	23	25	5	5	2.2
Wind	7	19	26	33	40	47	2	9	7.8
Geothermal	1	1	1	1	2	3	0	0	5.7
Solar PV	0	5	11	17	23	29	0	5	17.5
CSP	0	-	0	1	2	2	0	0	61.0
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**553**	**1 170**	**1 145**	**1 178**	**1 231**	**1 313**	**1 394**	**100**	**100**	**0.7**
Coal	47	101	107	114	122	130	139	9	10	1.2
Oil	404	774	752	756	766	784	787	66	56	0.1
Gas	103	294	287	308	343	399	468	25	34	1.8
Power generation	**89**	**279**	**229**	**220**	**223**	**245**	**268**	**100**	**100**	**-0.2**
Coal	16	51	50	50	54	57	60	18	23	0.7
Oil	44	109	83	68	57	53	47	39	18	-3.2
Gas	29	119	96	102	112	136	161	43	60	1.2
TFC	**404**	**793**	**816**	**858**	**904**	**956**	**1 003**	**100**	**100**	**0.9**
Coal	27	47	54	60	64	69	74	6	7	1.8
Oil	331	627	630	649	670	690	698	79	70	0.4
Transport	*196*	*417*	*416*	*434*	*454*	*473*	*480*	*53*	*48*	*0.5*
Gas	46	118	132	149	170	197	231	15	23	2.6

Latin America: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 336**	**1 763**	**2 252**	**1 284**	**1 514**	**1 856**	**100**	**100**	**2.4**	**1.6**
Coal	51	62	74	44	18	10	3	1	2.1	-5.3
Oil	124	93	79	110	38	14	4	1	-2.7	-8.9
Gas	224	346	539	187	162	144	24	8	3.3	-1.8
Nuclear	34	47	55	38	52	74	2	4	3.7	5.0
Hydro	764	986	1 184	764	983	1 179	53	63	2.2	2.2
Bioenergy	64	81	102	64	82	111	5	6	2.1	2.5
Wind	62	112	152	64	124	204	7	11	8.8	10.0
Geothermal	5	9	17	5	12	25	1	1	5.7	7.4
Solar PV	7	25	43	8	37	78	2	4	18.7	21.4
CSP	-	2	6	-	5	14	0	1	19.1	23.0
Marine	-	-	-	-	-	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**345**	**448**	**570**	**342**	**418**	**528**	**100**	**100**	**2.8**	**2.5**
Coal	9	12	14	9	9	7	2	1	2.7	-0.1
Oil	43	34	31	43	34	30	5	6	-1.2	-1.4
Gas	68	107	157	64	68	82	27	16	4.1	1.5
Nuclear	5	6	8	5	7	10	1	2	2.8	3.9
Hydro	178	220	266	178	217	260	47	49	2.2	2.1
Bioenergy	17	21	25	17	21	26	4	5	2.1	2.4
Wind	18	32	43	19	38	61	8	12	7.5	8.9
Geothermal	1	1	2	1	2	4	0	1	5.3	6.9
Solar PV	5	14	23	5	22	44	4	8	16.5	19.4
CSP	-	1	2	-	2	4	0	1	59.0	64.3
Marine	-	-	-	-	-	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 170**	**1 321**	**1 580**	**1 115**	**951**	**812**	**100**	**100**	**1.2**	**-1.4**
Coal	115	134	155	106	76	62	10	8	1.6	-1.9
Oil	760	814	897	734	606	475	57	58	0.6	-1.9
Gas	295	372	528	275	269	275	33	34	2.3	-0.3
Power generation	**245**	**263**	**337**	**208**	**109**	**72**	**100**	**100**	**0.7**	**-5.1**
Coal	58	66	75	50	18	10	22	14	1.5	-6.1
Oil	83	62	52	74	26	10	16	14	-2.8	-8.8
Gas	104	135	210	84	66	52	62	72	2.2	-3.1
TFC	**824**	**947**	**1 100**	**807**	**760**	**670**	**100**	**100**	**1.3**	**-0.6**
Coal	54	65	76	53	55	50	7	7	1.8	0.2
Oil	637	709	797	623	551	442	72	66	0.9	-1.3
Transport	*421*	*485*	*567*	*411*	*359*	*277*	*52*	*41*	*1.2*	*-1.6*
Gas	133	172	227	132	154	178	21	27	2.5	1.6

Brazil: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**138**	**300**	**296**	**317**	**344**	**376**	**408**	**100**	**100**	**1.2**
Coal	10	18	17	17	17	18	18	6	4	0.0
Oil	59	126	117	121	126	133	138	42	34	0.3
Gas	3	35	30	31	36	47	56	12	14	1.8
Nuclear	1	4	7	7	8	8	10	1	2	3.6
Hydro	18	32	36	41	45	48	51	11	13	1.8
Bioenergy	48	83	84	93	100	108	118	28	29	1.3
Other renewables	-	2	6	9	11	14	17	1	4	9.3
Power generation	**22**	**75**	**72**	**77**	**87**	**99**	**112**	**100**	**100**	**1.6**
Coal	2	6	5	4	4	4	3	8	3	-2.2
Oil	1	8	3	1	1	1	1	10	1	-7.0
Gas	0	16	7	6	7	13	17	21	15	0.2
Nuclear	1	4	7	7	8	8	10	5	9	3.6
Hydro	18	32	36	41	45	48	51	43	46	1.8
Bioenergy	1	8	9	11	12	14	15	11	14	2.3
Other renewables	-	1	5	7	10	12	14	1	13	10.5
Other energy sector	**26**	**47**	**44**	**47**	**50**	**54**	**58**	**100**	**100**	**0.8**
Electricity	*3*	*11*	*11*	*12*	*13*	*15*	*16*	*23*	*28*	*1.6*
TFC	**111**	**232**	**238**	**257**	**278**	**302**	**326**	**100**	**100**	**1.3**
Coal	4	8	8	9	9	10	10	3	3	0.9
Oil	53	110	109	114	120	127	131	47	40	0.7
Gas	2	13	15	17	20	23	27	5	8	2.9
Electricity	18	43	46	52	58	65	72	19	22	2.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	34	58	59	64	70	76	83	25	25	1.4
Other renewables	-	1	1	1	2	2	3	0	1	6.0
Industry	**40**	**80**	**85**	**91**	**98**	**106**	**115**	**100**	**100**	**1.4**
Coal	4	8	8	9	9	9	10	10	8	1.0
Oil	8	11	13	13	13	14	14	14	12	0.8
Gas	1	9	11	13	15	18	20	12	18	3.1
Electricity	10	18	19	21	23	25	28	22	24	1.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	17	34	34	35	37	40	43	42	37	0.9
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**33**	**86**	**85**	**91**	**97**	**105**	**112**	**100**	**100**	**1.0**
Oil	27	69	66	68	70	74	77	79	68	0.4
Electricity	0	0	0	0	0	1	1	0	1	6.1
Biofuels	6	15	16	22	25	28	32	18	29	2.9
Other fuels	0	2	2	1	1	2	2	3	2	-0.8
Buildings	**23**	**38**	**38**	**41**	**45**	**50**	**55**	**100**	**100**	**1.4**
Coal	-	-	-	-	-	-	-	-	-	n.a.
Oil	6	7	7	8	8	8	9	19	16	0.7
Gas	0	1	1	1	1	2	2	1	4	6.1
Electricity	8	23	25	28	32	36	40	60	73	2.2
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	9	7	4	3	2	1	1	18	2	-6.8
Other renewables	-	1	1	1	2	2	3	2	5	5.6
Other	**16**	**28**	**30**	**34**	**38**	**41**	**44**	**100**	**100**	**1.7**

Brazil: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**299**	**357**	**432**	**293**	**312**	**338**	**100**	**100**	**1.4**	**0.5**
Coal	17	18	19	17	12	11	4	3	0.4	-1.8
Oil	118	135	151	115	99	83	35	25	0.7	-1.6
Gas	31	42	65	28	28	35	15	10	2.4	-0.1
Nuclear	7	8	10	7	8	11	2	3	3.6	3.9
Hydro	36	46	56	36	44	52	13	15	2.1	1.8
Bioenergy	84	97	114	85	109	128	26	38	1.2	1.7
Other renewables	6	11	16	6	11	18	4	5	9.1	9.5
Power generation	**74**	**95**	**124**	**70**	**76**	**96**	**100**	**100**	**1.9**	**1.0**
Coal	6	5	5	5	-	-	4	-	-0.8	-100
Oil	3	3	3	2	1	1	2	1	-4.0	-9.1
Gas	9	11	22	6	3	5	18	5	1.2	-4.3
Nuclear	7	8	10	7	8	11	8	11	3.6	3.9
Hydro	36	46	56	36	44	52	45	54	2.1	1.8
Bioenergy	9	12	15	9	12	14	12	15	2.3	2.0
Other renewables	5	9	14	5	9	14	11	15	10.4	10.5
Other energy sector	**44**	**53**	**63**	**43**	**46**	**49**	**100**	**100**	**1.2**	**0.2**
Electricity	*11*	*14*	*18*	*11*	*12*	*14*	*28*	*29*	*2.0*	*1.1*
TFC	**239**	**285**	**340**	**236**	**255**	**273**	**100**	**100**	**1.5**	**0.6**
Coal	8	9	10	8	8	8	3	3	1.0	-0.1
Oil	110	126	142	108	95	80	42	29	1.0	-1.2
Gas	15	20	28	15	18	21	8	8	3.0	2.0
Electricity	47	61	78	46	54	67	23	25	2.3	1.7
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	58	67	80	59	79	94	24	34	1.2	1.8
Other renewables	1	1	2	1	2	4	1	1	4.9	7.2
Industry	**85**	**100**	**120**	**84**	**89**	**97**	**100**	**100**	**1.6**	**0.7**
Coal	8	9	10	8	8	7	8	8	1.0	-0.1
Oil	13	14	14	13	12	12	12	13	0.9	0.2
Gas	11	15	21	11	13	14	18	15	3.2	1.6
Electricity	19	23	29	19	20	23	24	24	1.9	1.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	34	39	46	34	36	39	38	40	1.2	0.5
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**85**	**98**	**115**	**84**	**86**	**83**	**100**	**100**	**1.1**	**-0.2**
Oil	67	76	86	65	48	30	75	36	0.9	-3.2
Electricity	0	0	1	0	2	4	1	4	3.7	11.0
Biofuels	16	20	26	17	35	46	23	56	2.2	4.4
Other fuels	2	1	2	2	2	3	2	4	-1.1	0.9
Buildings	**38**	**48**	**61**	**37**	**42**	**51**	**100**	**100**	**1.8**	**1.1**
Coal	-	-	-	-	-	-	-	-	n.a.	n.a.
Oil	7	8	9	7	7	7	15	14	0.9	-0.1
Gas	1	2	2	1	1	2	4	4	6.3	5.1
Electricity	25	35	46	24	30	37	76	74	2.7	1.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	2	1	4	2	1	2	2	-6.7	-6.7
Other renewables	1	1	2	1	2	3	3	6	4.6	6.4
Other	**31**	**38**	**44**	**31**	**37**	**43**	**100**	**100**	**1.8**	**1.7**

Brazil: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**223**	**590**	**624**	**699**	**785**	**883**	**983**	**100**	**100**	**2.0**
Coal	5	27	22	19	18	17	16	5	2	-2.1
Oil	5	35	14	5	5	5	5	6	1	-7.1
Gas	0	81	45	36	42	74	98	14	10	0.7
Nuclear	2	15	26	26	31	31	39	3	4	3.6
Hydro	207	373	415	477	523	559	599	63	61	1.8
Bioenergy	4	46	48	54	59	64	70	8	7	1.6
Wind	-	12	49	70	88	105	123	2	12	9.3
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	-	5	12	18	25	31	-	3	n.a.
CSP	-	-	-	-	1	2	3	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**132**	**170**	**189**	**208**	**227**	**253**	**100**	**100**	**2.5**
Coal	4	5	5	4	4	4	3	1	-0.6
Oil	8	8	7	7	7	7	6	3	-0.4
Gas	12	17	18	19	20	27	9	11	3.3
Nuclear	2	3	3	4	4	5	2	2	3.9
Hydro	89	106	115	123	131	140	67	55	1.8
Bioenergy	12	14	16	17	18	19	9	8	1.9
Wind	5	14	19	24	28	32	4	13	7.5
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	3	7	10	14	17	-	7	n.a.
CSP	-	-	-	0	1	1	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**184**	**476**	**440**	**444**	**468**	**508**	**538**	**100**	**100**	**0.5**
Coal	28	68	65	64	65	65	65	14	12	-0.2
Oil	151	330	312	316	329	345	354	69	66	0.3
Gas	6	78	63	64	75	98	119	16	22	1.7
Power generation	**13**	**95**	**55**	**41**	**42**	**54**	**62**	**100**	**100**	**-1.6**
Coal	8	34	28	24	23	21	19	35	31	-2.1
Oil	4	24	9	3	3	3	4	25	6	-7.1
Gas	0	37	18	14	17	30	39	39	63	0.2
TFC	**156**	**351**	**353**	**368**	**388**	**412**	**429**	**100**	**100**	**0.8**
Coal	16	32	34	37	39	40	42	9	10	1.1
Oil	136	291	287	296	308	322	331	83	77	0.5
Transport	*82*	*208*	*199*	*205*	*213*	*225*	*231*	*59*	*54*	*0.4*
Gas	4	28	32	36	42	49	57	8	13	2.7

Brazil: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**636**	**835**	**1 069**	**613**	**724**	**903**	**100**	**100**	**2.3**	**1.6**
Coal	24	22	22	21	-	-	2	-	-0.8	-100
Oil	14	12	12	11	3	3	1	0	-4.0	-9.1
Gas	55	64	126	38	19	32	12	3	1.7	-3.6
Nuclear	26	31	39	26	31	42	4	5	3.6	3.9
Hydro	415	540	648	415	513	600	61	66	2.1	1.8
Bioenergy	48	59	70	48	56	66	7	7	1.6	1.4
Wind	49	88	119	49	84	129	11	14	9.1	9.5
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	5	18	30	5	17	32	3	4	n.a.	n.a.
CSP	-	1	3	-	-	-	0	-	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**170**	**217**	**274**	**169**	**200**	**245**	**100**	**98**	**2.8**	**2.4**
Coal	5	5	4	5	-	-	2	-	0.0	-100
Oil	8	7	7	8	7	7	3	3	-0.3	-0.8
Gas	17	23	33	17	17	18	12	7	4.0	1.6
Nuclear	3	4	5	3	4	5	2	2	3.9	3.9
Hydro	106	128	156	106	120	141	57	58	2.2	1.8
Bioenergy	14	17	19	14	16	18	7	7	1.9	1.7
Wind	14	24	31	14	23	34	11	14	7.4	7.8
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	3	10	17	3	9	18	6	7	n.a.	n.a.
CSP	-	0	1	-	-	-	0	-	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**450**	**512**	**606**	**430**	**334**	**269**	**100**	**100**	**0.9**	**-2.2**
Coal	68	70	74	64	35	28	12	10	0.3	-3.4
Oil	315	354	394	306	243	176	65	65	0.7	-2.4
Gas	67	87	138	60	56	66	23	24	2.2	-0.6
Power generation	**62**	**62**	**87**	**49**	**9**	**14**	**100**	**100**	**-0.3**	**-7.1**
Coal	31	28	27	27	-	-	32	-	-0.8	-100
Oil	9	8	8	7	2	2	9	14	-4.0	-9.1
Gas	22	26	51	15	7	12	59	86	1.2	-4.3
TFC	**357**	**408**	**465**	**350**	**297**	**230**	**100**	**100**	**1.1**	**-1.6**
Coal	34	39	43	34	32	25	9	11	1.2	-0.9
Oil	291	327	364	284	228	164	78	71	0.9	-2.2
Transport	*201*	*230*	*261*	*197*	*145*	*90*	*56*	*39*	*0.9*	*-3.2*
Gas	32	43	59	32	37	41	13	18	2.9	1.4

Policies and measures by scenario

The *World Energy Outlook-2016* (*WEO-2016*) 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*. In addition to incorporating the policies and measures that affect energy markets and that had been adopted as of mid-2016, it also takes into account, in full or in part, the aims, targets and intentions that have been announced, even if these have yet to be legislated or fully implemented. This includes the greenhouse-gas (GHG) and energy-related targets of the Nationally Determined Contributions (NDCs) pledged under the Paris Agreement. We take a generally cautious view in the New Policies Scenario of the extent and timing of which policy proposals will be implemented. This is done in view of the many institutional, political and economic circumstances that could stand in the way.

The ***Current Policies Scenario*** (CPS) takes into consideration only those policies for which implementing measures had been formally adopted as of mid-2016. No allowance is made for additional implementing measures or changes in policy beyond this point. It depicts, for example, a world without the implementation of many of the policy changes promised under the Paris Agreement. In this way, the Current Policies Scenario provides a benchmark against which the impact of "new" policies can be measured.

The ***450 Scenario*** (450S) is the main decarbonisation scenario (see Chapter 1) in *WEO-2016*. It assumes a set of policies with the objective of limiting the average global temperature increase in 2100 to 2 degrees Celsius (2 °C) above pre-industrial levels.

The key policies that are assumed to be adopted in each of the main scenarios of *WEO-2016* are presented below by sector and region. The policies are cumulative: measures listed under the New Policies Scenario supplement those under the Current Policies Scenario and measures listed under the 450 Scenario supplement those under the New Policies Scenario. The following tables start with broad cross-cutting policy frameworks and are followed by more detailed policy assumptions, by sector, as adopted in this year's *Outlook*.

Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions

	Scenario	Assumptions
All regions	CPS	• Fossil-fuel subsidies are phased out in countries that already have policies in place to do so.
	NPS	• Fossil-fuel subsidies are phased out within the next ten years in all net-importing countries and in net-exporting countries where specific policies have already been announced.
	450S	• Staggered introduction of CO_2 prices in all industrialised countries. • $100 billion annual financing provided to developing countries for domestic mitigation by 2020. • Fossil-fuel subsidies are phased out by 2025 in all net-importers and by 2035 in all net-exporters.*
United States	CPS	• State-level renewable portfolio standards that include the option of using energy efficiency as a means of compliance. • Regional Greenhouse Gas Initiative: mandatory cap-and-trade scheme covering fossil-fuelled power plants in nine northeast states. • Economy-wide cap-and-trade scheme in California with binding commitments.
	NPS	• NDC GHG targets: economy-wide target of reducing GHG emissions by 26-28% below 2005 levels in 2025 and to make best efforts to reduce emissions by 28%.
	450S	• CO_2 pricing implemented from 2020.
Japan	NPS	• NDC targets: economy-wide target of reducing GHG emissions by 26% below fiscal year 2013 levels by fiscal year 2030; sector-specific energy targets.
	450S	• CO_2 pricing implemented from 2020.

European Union	CPS	• 2020 Climate and Energy Package:
		  o 20% cut in GHG emissions compared with 1990 levels.
		  o Renewables to reach a share of 20% by 2020.
		  o Partial implementation of 20% energy savings.
		• Emissions Trading System reducing GHG emissions in 2020 by 21% below the 2005 level.

	NPS	• NDC GHG targets/2030 Climate and Energy framework:
		  o 40% cut in GHG emissions compared with 1990 levels.
		  o Renewables to reach a share of at least 27% in 2030.
		  o Save at least 27% of energy use compared with a business-as-usual scenario.
		• Partial implementation of the Energy Efficiency Directive target to reduce primary energy consumption by 20% in 2020, but full implementation of sectoral provisions.
		• Emissions Trading System reducing GHG emissions in 2030 by 43% below the 2005 level.
		• Structural change in the Emissions Trading System by establishing a market stability reserve from 2019.
		• Revised Emissions Ceiling Directive as part of the Clean Air Policy Package.

	450S	• Emissions Trading System strengthened in line with the 2050 roadmap, covering power, industry and aviation sectors.
Russia	NPS	• NDC GHG targets: limiting GHG emissions to 70-75% of 1990 levels by 2030.
	450S	• CO_2 pricing from 2020. • More support for nuclear and renewables. • Partial implementation of the “Energy Savings and Increase of Energy Efficiency for the Period to 2020” programme.

Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions (continued)

	Scenario	Assumptions
China	CPS	• Increase the share of non-fossil fuels in primary energy consumption to around 15% by 2020. • Action Plan for Prevention and Control of Air Pollution.
	NPS	• NDC GHG targets: achieve peak CO_2 emissions around 2030 and make best efforts to peak early, and to lower CO_2 emissions by unit of GDP by 60-65% from 2005 levels by 2030. • NDC energy targets: increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030. • Efforts to restructure the economy and to shift emphasis away from investment and export-led growth towards the services sector and domestic consumption. • Emission trading scheme covering power and industry sectors from 2017. • Expand the use of natural gas. • Energy price reform, including more frequent adjustments in oil product prices and increase in natural gas price by 15% for non-residential consumers.
	450S	• Strengthening of emission trading scheme covering power and industry sectors.
India	CPS	• Pursuit of National Mission on Enhanced Energy Efficiency. • Creation of National Clean Energy Fund to promote clean energy technologies based on a levy of INR 100/tonne of coal. • Efforts to increase the share of manufacturing in the national economy via the "Make in India" campaign.
	NPS	• NDC GHG targets: reduce emissions intensity of GDP by 33-35% below 2005 levels by 2030. • NDC energy targets: achieve about 40% cumulative electric power installed capacity from non-fossil 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. • Increase in the National Clean Energy Fund. • Open the coal sector to private and foreign investors.
Brazil	NPS	• NDC GHG targets: reduction of GHG emissions by 37% below 2005 levels by 2025. • NDC energy targets: increase share of sustainable biofuels to around 18% of total primary energy demand (TPED) by 2030; increasing renewables to 45% of TPED by 2030, including increasing share of non-hydro renewables to around 28-30% of TPED and at least 23% of power supply by 2030. • Partial implementation of National Energy Efficiency Plan.
	450S	• CO_2 pricing from 2020.
Mexico	NPS	• NDC GHG target: reduction of GHG and short-lived climate pollutant emissions by 25% (unconditional target) and 40% (conditional target) below business-as-usual by 2030. • The National Program for Sustainable Use of Energy to promote optimal use of energy and reduce energy intensity in all sectors, formulated on the basis of the Energy Transition Law. • Excise (carbon) taxes for oil products, such as gasoline, diesel and fuel-oil. • Prices of gasoline, diesel and LPG are liberalised in 2017.

*Except the Middle East where subsidisation rates are assumed to decline to an average of 8% by 2035.

Notes: NDC = Nationally Determined Contributions; GHG = greenhouse gas; LPG = liquefied petroleum gas. Pricing of CO_2 emissions is by emissions trading schemes or taxes.

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions

	Scenario	Assumptions
United States	CPS	• Extension of Investment Tax Credit and Production Tax Credit. • State-level renewable portfolio standards and support for renewables prolonged over the projection period. • Mercury and Air Toxics Standards. • New Source Performance Standards. • Clean Air Interstate Rule regulating sulfur dioxide and nitrogen oxides. • Lifetimes of some US nuclear plants extended beyond 60 years. • Funding for CCS (demonstration-scale).
	NPS	• Implementation of Clean Power Plan: CO_2 emissions reduction from the power sector of 32% by 2030, compared with 2005 levels, including the following building blocks: o Improve efficiency of existing coal-fired power plants. o Substitute gas-fired generation for coal-fired generation. o Substitute renewables (e.g. wind and solar PV) for coal-fired generation. • Implementation of Carbon Pollution Standards, limiting CO_2 emissions intensity for new, modified and reconstructed fossil-fuelled power plants. • Extension and strengthening of support for renewables and nuclear.
	450S	• CO_2 pricing implemented from 2020. • Extended support to renewables, nuclear and CCS. • Efficiency and emission standards preventing refurbishment of old inefficient plants.
Japan	CPS	• Support for renewables-based generation. • Air Pollution Control Law.
	NPS	• Achievement of the target to increase renewables to 22-24% of power generation by 2030. Gradual restart of electricity generation from nuclear power plants, with the aim of reaching 20-22% of power generation in 2030. • Lifetime of nuclear plants typically to 40 years, possibility of extensions up to 60 years. • Implementation of the feed-in tariff amendment law. • 44% share of non-fossil fuel power generation by 2030, corresponding to the carbon intensity of 370 g CO_2/kWh. • Efficiency standard for new thermal power plants (coal: 42%, gas: 50.5%, oil: 39%).
	450S	• CO_2 pricing implemented from 2020. • Share of low-carbon generation to increase by 2020 and expand further by 2030. • Expansion of renewables support. • Introduction of CCS to coal-fired power generation.
European Union	CPS	• EU Emissions Trading System (EU ETS) in accordance with 2020 Climate and Energy Package. • Support for renewables in accordance with overall target. • Early retirement of all nuclear plants in Germany by the end-2022. • Removal of some barriers to combined heat and power (CHP) plants. • Industrial Emissions Directive.
	NPS	• EU ETS in accordance with 2030 Climate and Energy framework. • Revised Emissions Ceiling Directive as part of the Clean Air Policy Package. • Extended and strengthened support to renewables-based electricity 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.
	450S	• Reinforcement of government support in favour of renewables. • Expanded support measures for CCS.

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Competitive wholesale electricity market.
	NPS	• State support to hydro and nuclear power; strengthened and broadened existing support mechanisms for non-hydro renewables.
	450S	• CO_2 pricing implemented from 2020. • Stronger support for nuclear power and renewables.
China	CPS	• 365 GW of installed hydro, 200 GW of wind and 100 GW of solar capacity by 2020. • Air pollutant emission standard for thermal power plants.
	NPS	• Emissions trading system from 2017. • Lower coal consumption of electricity generation in newly built coal-fired power plants to around 300 g/kWh. • By 2020: 58 GW of nuclear, 365 GW of hydro capacity, including pumped storage, 230 GW of wind capacity, 140 GW of solar capacity and 15 GW of biomass capacity.
	450S	• Emissions trading system in accordance with overall target. • Enhanced support for renewables: 250 GW of wind and 150 GW of solar capacity by 2020. • Continued support to nuclear capacity additions post 2020. • Deployment of CCS from around 2025.
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 the transmission and distribution networks. • Environmental (Protection) Amendment Rules.
	NPS	• Strengthened support measures to increase the share of renewables, towards the national target of 175 GW of non-hydro renewable capacity by 2022 (100 GW solar, 75 GW non-solar), including competitive bidding. • Increased uptake of supercritical technology for coal-fired power plants. • Expand efforts to strengthen the national grid, upgrade the T&D network, progress towards original aim to reduce aggregate technical and commercial losses to 15%. • Increased efforts to establish the financial viability of all power market participants especially the network and distribution companies.
	450S	• Expanded support to renewables, nuclear and efficient coal. • Deployment of CCS from around 2030.
Brazil	CPS	• Power auctions for all fuel types. • Guidance on the fuel mix from the Ten-Year Plan for Energy Expansion.
	NPS	• Enhanced deployment of renewables technologies through power auctions.
	450S	• CO_2 pricing from 2020 and further increases of generation from renewable sources.
Mexico	NPS	• Development of wholesale power market and establishment of CFE as a modified state enterprise, unbundled into power generation, T&D, load-serving entities and retail sectors to promote efficiency and competition. • Development of generation capacities and T&D networks based on the Development Program of the National Electric System 2016-2030. • Clean energy share of 25% in generation by 2018, 30% by 2021 and 35% by 2024. • Clean Energy Certificates which will provide additional revenues from selling electricity, development of wholesale market auctions and other incentives for clean energy, such as tax relief, soft loans and net metering schemes.

Notes: CCS = carbon capture and storage; g/kWh = grammes per kilowatt-hour; GW = gigawatt; T&D = transmission and distribution.

Table B.3 ▷ **Transport sector policies and measures as modelled by scenario in selected regions**

	Scenario	Assumptions
All regions	NPS	• Realisation of ICAO goal to improve fuel efficiency of the aviation sector by 2% per year to 2020; aspire to carbon-neutral growth from 2020 onwards. • Emission offsetting mechanism for international aviation in line with the ICAO Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). • Fuel sulfur standards of 10-15 ppm for road fuels. • A global cap of 0.5% on sulfur dioxide emissions and tightened nitrogen oxides emission standards in emission control areas for maritime fuels by 2025.
	450S	• On-road stock emission intensity for PLDVs in 2040: 60 g CO_2/km in OECD countries, 85 g CO_2/km elsewhere. Enhanced support to alternative fuels. • Light-commercial vehicles: full technology spill-over from PLDVs. • Medium- and heavy-freight vehicles: 40% more efficient by 2040 than in NPS. • Aviation: reduce fuel intensity by 2.6% per year and scale-up biofuels use to reduce CO_2 emissions by 50% in 2050, relative to 2005. • Retail fuel prices kept at a level similar to NPS.
United States	CPS	• CAFE standards: 35.5 miles/gallon for PLDVs by 2016 and further strengthening after. • Renewables Fuel Standard. • Tier 3 emission standards for light-duty vehicles and fuel sulfur standards (EURO 6/VI equivalent); US 2010 emission standards for heavy-duty vehicles. • Truck standards for each model year from 2014 to 2018 to reduce average on-road fuel consumption by up to 18% in 2018.
	NPS	• CAFE standards: 54.5 miles/gallon for PLDVs by 2025. • Stock target for electric vehicles (EVs) of 3.3 million by 2025 across eight states, with federal and state-specific purchase incentives. • Truck standards to reduce average on-road fuel consumption by 20% in 2018, and 16% and 25% improvement for medium- and heavy- trucks respectively for 2021-2027. • Support for natural gas in road freight. • Moderate increase of ethanol blending mandates.
Japan	CPS	• Fuel-economy target for PLDVs: 20.3 kilometres per litre (km/l) by 2020. • Average fuel-economy target for road freight vehicles: 7.09 km/l by 2015. • Financial incentives for plug-in hybrid, electric and fuel-cell vehicles, including charging infrastructure. • Post-new long-term emission standards (PNLTES) for light-duty/heavy-duty vehicles and fuel sulfur standards (Euro 6/VI equivalent).
	NPS	• Adoption of target sales share of next-generation vehicles (clean diesel, hybrid, plug-in hybrid, electric and fuel-cell vehicles) of 50-70% by 2030. • Stock target of 1 million EVs by 2020, including purchase incentives and government support for public and home charging installation costs.
European Union	CPS	• Euro 6 emission standards for light-duty vehicles; Euro VI emissions standards for heavy-duty vehicles; EURO 6/VI fuel sulfur standards. • Subsidy support to biofuels blending. • EU Emissions Trading System covering domestic EU aviation sector.
	NPS	• Achieve target to reach 10% of transport energy demand by renewable fuels in 2020. • Fuel Quality Directive, reducing GHG intensity of road transport fuels by 6% in 2020. • More stringent emission targets for PLDVs (95 g CO_2/km by 2020) and light-commercial vehicles (147 g CO_2/km by 2020), further strengthening after 2020. • Enhanced support to alternative fuels and vehicle powertrains, including sales and stock share targets for EVs, but limited role for food-based biofuels. • EU Emissions Trading System in accordance with 2030 Climate and Energy framework, covering domestic EU aviation sector.

Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
China	CPS	• Subsidies for hybrid and electric vehicles and consolidation of vehicle charging standards. • Promotion of fuel-efficient cars. • Ethanol blending mandates of 10% in selected provinces. • Cap on PLDV sales in some cities to reduce air pollution and traffic jams. • Enhance infrastructure for electric vehicles in selected cities. • China 5 emission standards for light-duty vehicles; China IV emission standards for heavy-duty vehicles (gasoline); China V emissions standards for heavy-duty vehicles (diesel); fuel sulfur standards (EURO 6/VI equivalent).
	NPS	• Fuel-economy target for PLDVs: 5 l/100 km by 2020. • Stock target of 4.6 million electric vehicles by 2020, including purchase and use incentives. • Extended subsidies for purchase of alternative-fuel vehicles. • Complete fossil-fuel subsidy phase out within the next ten years. • Promote the share of public transport in motorised travel in large and medium cities. • Implementation of China 6 emissions standards from 2020.
India	CPS	• 5% blending mandate for ethanol. • Support for alternative-fuel vehicles. • Bharat IV emission standards for light-duty/heavy-duty vehicles; fuel sulfur standards (EURO 4/IV equivalent).
	NPS	• Continued efforts to increase blending mandates (also for biodiesel) subject to availability. • Extended support for alternative-fuel vehicles, including the National Electric Mobility Mission Plan 2020. • Fuel-economy standard for PLDVs: 5.5 l/100km of fuel on average by 2017/2018 and 4.8 l/100km by 2022/2023. • Increased support for natural gas use in road transport, particularly for urban public transport. Dedicated rail corridors to encourage shift away from road freight. • Implementation of Bharat VI emission standards by 2020.
Brazil	CPS	• Ethanol blending mandates in road transport between 18% and 25%. • Biodiesel blending mandate of 5%. • L-6 emission standards for light-duty vehicles; P-7 emissions standards for heavy-duty vehicles; fuel sulfur standards: EURO 4/IV equivalent for diesel ppm and EURO 2/II equivalent for gasoline ppm.
	NPS	• Inovar-Auto initiative targeting fuel efficiency improvement for PLDVs of at least 12% in 2017, compared with 2012/2013. • Increase of ethanol and biodiesel blending mandates. • Local renewable fuel targets for urban transport. • Long-term plan for freight transport (PNLT). • National urban mobility plan (PNMU).
Mexico	CPS	• Emission standards for light-duty vehicles (EURO 3/III equivalent); emission standards for heavy-duty vehicles (EURO 4/IV equivalent); fuel sulfur standards: EURO 2/II equivalent for diesel ppm and EURO 3/III equivalent for gasoline ppm.
	NPS	• National standard for fuel-economy and carbon emissions standards for light-weight vehicles.

Notes: ICAO = International Civil Aviation Organization; ppm = parts per million; CAFE = Corporate Average Fuel Economy; PLDVs = passenger light-duty vehicles; LCVs = light-commercial vehicles; g CO_2/km = grammes of carbon dioxide per kilometre.

Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	450S	• CO_2 pricing introduced from 2025 at the latest in OECD countries and as of 2020 in Russia and Brazil; strengthening of emissions trading system in China and South Africa. • International sectoral agreements with energy intensity targets for iron and steel, and cement industries. • Enhanced minimum energy performance standards, in particular for electric motors by 2025; incentives for the introduction of variable speed drives in variable load systems, and implementation of system-wide measures. • Mandatory energy management systems or energy audits. • Policies to support the introduction of CCS in industry. • Wider hosting of international offset projects.
United States	CPS	• Better Buildings, Better Plants Program and Energy Star Program for Industry. • Boiler maximum achievable control (MACT) technology rule to impose stricter emissions limits on industrial and commercial boilers and process heaters. • Superior Energy Performance certification programme that supports the introduction of energy management systems. • Industrial Assessment Centers providing no-cost energy assessments to small- and medium-enterprises. • Permitting program for GHG and other air pollutant emissions for large industrial installations.
	NPS	• Tax reduction and funding for efficient technologies, continuation of the Business Energy Investment Tax Credit and strengthened R&D in low-carbon technologies. • Further assistance for small- and medium-size manufacturers to adopt "smart manufacturing technologies" through technical assistance and grant programmes.
Japan	CPS	• Energy efficiency benchmarking. • Tax credit for investments in energy efficiency. • Financial measures to encourage small- and medium-sized businesses to invest in energy conservation equipment and facilities. • Free energy audits for small and medium-size companies. • Mandatory energy management for large business operators. • Top Runner Programme setting minimum energy standards for machinery and equipment for industrial use.
	NPS	• Maintenance and strengthening of top-end/low-carbon efficiency standards by: ○ Higher efficiency CHP systems. ○ Promotion of state-of-the-art technology and faster replacement of ageing equipment. ○ Continuation of the Japanese Voluntary Emission Trading Scheme.
European Union	CPS	• EU Emission Trading System 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, Ireland, Netherlands, Portugal, Luxembourg, Sweden and United Kingdom. • EcoDesign Directive (including minimum standards for electric motors, pumps, fans, compressors and insulation). • Industrial Emissions Directive.
	NPS	• EU Emission Trading System in accordance with 2030 climate and energy framework. • Implementation of Energy Efficiency Directive and extension to 2030: ○ Mandatory and regular energy audits for large enterprises. ○ Incentives for the use of energy management systems. ○ Encouragement for small and medium-size enterprises (SMEs) to undergo energy audits. ○ Technical assistance and targeted information for SMEs. • Implementation of Medium Combustion Plant Directive.

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	• Industrial gas prices reach equivalent of export prices (less taxes and transportation) in 2020. • Limited phase out of natural gas subsidy to domestic uses.
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 iron-making. • Mechanism to incentivise energy-efficient "leaders", i.e. manufacturers and brands that exceed specific energy efficiency benchmarks set by the China Energy Label.
	NPS	• Expansion of energy-intensive industries is contained and a circular economy developed, including a recycling-based industrial system. • Accelerated retrofit of older coal-fired industrial boilers. • Emissions trading system in accordance with overall target. • Continuation of industrial energy intensity reduction contributing to the overall 13th Five-Year Plan period target (2016-2020). • Full implementation of Industrial Energy Performance Standards. • Enhanced use of energy service companies and energy performance contracting.
India	CPS	• Energy Conservation Act: mandatory energy audits, appointment of an energy manager in seven energy-intensive industries. • National Mission on Enhanced Energy Efficiency (NMEEE): o Perform, Achieve and Trade (PAT) mechanism, targeting a 5% reduction in energy use by 2015 compared with 2010 through a trade system with plant-based efficiency levels. 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 and extension to include more sectors (railways, refineries and distribution companies). o Further strengthening of fiscal instruments to promote energy efficiency. • Strengthen existing policies to realise the energy efficiency potential in SMEs enterprises.
Brazil	CPS	• PROCEL (National Program for Energy Conservation). • PROESCO (Support for Energy Efficiency Projects).
	NPS	• Partial implementation of the National Energy Efficiency Plan: o Fiscal and tax incentives for industrial upgrading. o Invest in training efficiency. o Encourage the use of industrial waste. • Extension of PROESCO.
Mexico	NPS	• Continuation of the National Programme for Sustainable Energy Use (PRONASE) for industry (under the Sustainable Use of Energy Law). • Voluntary energy management systems in large industries and energy efficiency programmes for SMEs. • National standard for motor efficiency.

Notes: CCS = carbon capture and storage; R&D = research and development; CHP = combined heat and power; SMEs = small- and medium-size enterprises.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
United States	CPS	• AHAM-ACEEE Multi-Product Standards Agreement. • Energy Star: federal tax credits for energy efficiency; new appliance efficiency standards. • Energy Improvement and Extension Act of 2008. • Budget proposals 2011: institute programmes to make commercial buildings 20% more efficient by 2020; tax credit for renewable energy deployment. • Weatherisation programme: 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 to facilitate energy savings in commercial buildings. • Extensions to 2025 of tax credit for energy-efficient equipment (including furnaces, boilers, air conditioners, air and ground source heat pumps, water heaters and windows), and for solar PV and solar thermal water heaters. • Mandatory energy requirements in building codes in some states. • Tightening of efficiency standards for appliances.
	450S	• Mandatory energy requirements in building codes in all states by 2020. • Extension of energy efficiency grants to end of projection period. • Zero-energy buildings initiative.
Japan	CPS	• Top Runner Programme. • Energy reduction of 1%/year and annual reports to the governments by large operators. • Energy efficiency standards for new buildings and houses (300 m^2 or more). • Capital Grant Scheme for renewable energy technologies installed by local governments and private companies.
	NPS	• Energy efficiency benchmarking for commercial and service sectors. • Energy efficiency standards for new buildings and houses (set by 2020). Extension of the Top Runner Programme. • Voluntary buildings labelling; national voluntary equipment labelling programmes. • Net zero-energy buildings by 2030 for all new construction. • High efficiency lighting: 100% of sales by 2020; 100% of all lighting by 2030.
	450S	• Rigorous and mandatory building energy codes for all new and existing buildings. • Net zero-energy buildings by 2025 for all new construction. • Strengthening of high efficiency lighting for non-public buildings.
European Union	CPS	• Energy Performance of Buildings Directive. • EcoDesign and Energy Labelling Directive. • EU-US Energy Star Agreement: energy labelling of appliances. • Phase out of incandescent light bulbs. • Individual member state financial incentives for renewable heat in buildings.
	NPS	• Partial implementation of the Energy Efficiency Directive. • Building energy performance requirements for new buildings (zero-energy buildings by 2021) and for renovated existing buildings. 3% renovation rate of government buildings. • Mandatory energy labelling for sale or rental of all buildings and some appliances, lighting and equipment. • Further product groups in EcoDesign Directive. Enhanced renewables-based heat support in member states.
	450S	• Zero-carbon footprint in new buildings; enhanced energy efficiency in existing buildings. • Full implementation of the Energy Efficiency Directive. • Mandatory energy conservation standards and labelling requirements by 2020.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Implementation of the federal law on energy conservation and energy efficiency. • Voluntary labelling program for electrical products. • Restriction on sale of incandescent light bulbs.
	NPS	• Gradual above-inflation increase in residential electricity and natural gas prices. • New building codes, meter installations and refurbishment programmes. Information and awareness on energy efficiency classes for appliances. • Phase out of incandescent >100 Watt light bulbs. • Limited phase out of natural gas and electricity subsidies.
	450S	• Accelerated liberalisation of natural gas and electricity prices. • Extension and reinforcement of all measures included in the 2010 national energy efficiency programme; mandatory building codes by 2030 and phase out of inefficient equipment and appliances by 2030.
China	CPS	• Civil Construction Energy Conservation Design Standards. • Appliance standards and labelling programme.
	NPS	• Promote the share of green buildings in new buildings in cities and towns to reach 50% by 2020. • Civil Construction Energy Conservation Design Standard: heating energy consumption per unit area of existing buildings to be reduced by 65% in cold regions; 50% in hot-in-summer and cold-in-winter regions compared to 1980-1981 levels. New buildings: 65% improvement in all regions. • Building energy codes for all buildings to improve building envelope and HVAC system efficiencies in place (applies to cold climate zones); mandatory codes for all new large residential buildings in big cities. • Energy Price Policy (reform heating prices to be based on actual consumption, rather than on living area supplied). • Mandatory energy efficiency labels for appliances and equipment. • Labelling mandatory for new, large commercial and governmental buildings in big cities. • Introduction of energy standards for new buildings and refurbishment of existing dwellings. • Phase out of incandescent light bulbs production over the next ten years. • All fossil-fuel subsidies are phased out within the next ten years.
	450S	• More stringent implementation of Civil Construction Energy Conservation Design Standard. • Mandatory energy efficiency labels for all appliances and for building envelope. • Faster energy price policy reform to set stronger incentives for energy savings. • Partial Implementation of the Building Conservation Plan, which foresees that 95% of new buildings achieve savings of 55-65% in space heating from 1980 levels, depending on the climate zone.
India	CPS	• Measures under National Solar Mission. • Energy Conservation Building Code 2007, with voluntary requirements for commercial buildings. • Green Rating for Integrated Habitat Assessment – rating system for green buildings. • Rural electrification under the Deen Dayal Upadhyaya Gram Jyoti Yojana scheme. • Promotion of clean cooking access with liquefied petroleum gas LPG as a cooking fuel, including free connections to poor rural households through Pradhan Mantri Ujjwala Yojana. • Promotion and distribution of LEDs through the Efficient Lighting Programme (Energy Efficiency Services Limited).

Table B.5 ▷ **Buildings sector policies and measures as modelled by scenario in selected regions** (continued)

	Scenario	Assumptions
India	NPS	• Standards and Labelling Programme: Mandatory standards and labels for room air conditioners and refrigerators, voluntary for seven other products and LEDs. (More stringent minimum energy performance standards for air conditioners). • Phase out incandescent light bulbs by 2020. • Voluntary Star Ratings for the services sector. • National Action Plan on Climate Change: measures concerning the building sector in the National Mission on Enhanced Energy Efficiency. • Energy Conservation in Building Codes made mandatory in eight states and applies among others to 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. • All fossil-fuel subsidies are phased out within the next ten years.
	450S	• Mandatory energy conservation standards and labelling requirements for all equipment and appliances by 2025. • Increased penetration of energy-efficient lighting. • Implementation of the Super-Efficient Equipment Program.
Brazil	CPS	• Labelling programme for household goods, public buildings equipment.
	NPS	• Partial implementation of National Energy Efficiency Plan.
	450S	• Full implementation of National Energy Efficiency Plan.
Mexico	NPS	• Accelerated depreciation allowing companies and individuals to depreciate 100% of expenses on renewable energy equipment in one fiscal period. • National standards for energy efficiency for building envelope and building components, such as thermal insulation and appliances. • Development of an energy efficiency code for buildings to promote the adoption of relevant building codes by local governments. • Replacement programmes for inefficient lightings and appliances. • Soft loans for sustainable housing.

Notes: AHAM = Association of Home Appliance Manufacturers; ACEEE = American Council for an Energy-Efficient Economy; LED = light-emitting diode; HVAC = heating, ventilation and air conditioning.

Definitions

This annex provides general information on terminology used throughout *WEO-2016* 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
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)
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	barrel 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	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11 630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.40 boe per toe.

Currency conversions

Exchange rates *(2015 annual average)*	**1 US Dollar equals:**
British Pound	0.65
Chinese Yuan	6.23
Euro	0.90
Indian Rupee	65.20
Indonesian Rupiah	13 435.88
Japanese Yen	121.04
Russian Ruble	60.70
South African Rand	12.75

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% life-cycle 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- 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 and biogas. 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 source heat), 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 sugarcane 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 (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: 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 at disposal for 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: Includes natural gas, both associated and non-associated with petroleum deposits, but excludes natural gas liquids. (Also referred to as natural gas.)

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 reservoirs, capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport vehicles 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 sectors 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.

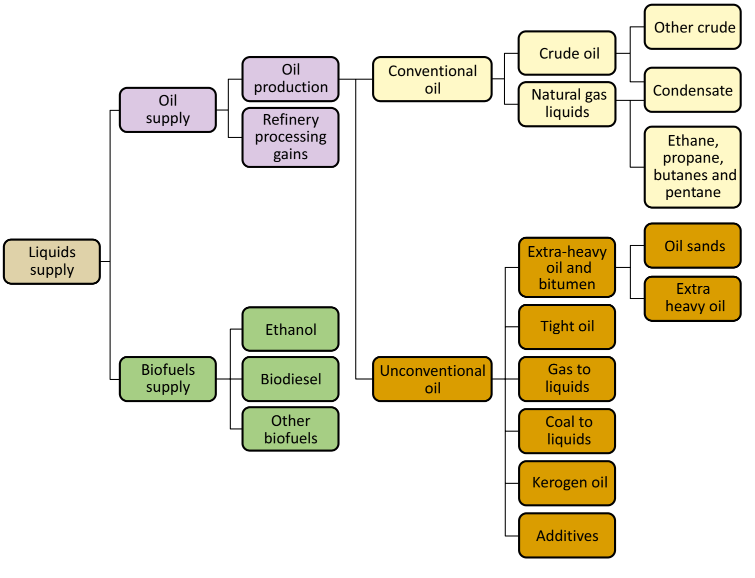
International marine bunkers: Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. 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-2015 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 the following figure. 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.

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. 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, 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): Variable renewable energy 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 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

Africa: Algeria, Angola, Benin, Botswana, Cameroon, the Republic of the Congo, Côte d'Ivoire, the Democratic Republic of the Congo, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, the United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[1]

1. 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.

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

China: Refers to the People's Republic of China, including Hong Kong.

Developing Asia: Includes all non-OECD Asian countries.

Developing countries: Non-OECD Asia, Middle East, Africa and Latin America regional groupings.

Eastern Europe/Eurasia: Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, the Former Yugoslav Republic of Macedonia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, the Republic of Moldova, Montenegro, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus[2,3], Gibraltar and Malta.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[2,3], 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.

G-20: Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Korea, Mexico, Russian Federation, Saudi Arabia, South Africa, Turkey, the United Kingdom, the United States and the European Union.

Latin America: Argentina, Bolivia, Brazil, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other non-OECD Americas countries and territories.[4]

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.

2. 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".

3. 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.

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, Suriname, Turks and Caicos Islands.

Non-OECD Asia: Bangladesh, Brunei Darussalam, Cambodia, China, Chinese Taipei, India, Indonesia, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.[5]

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

OECD: Includes OECD Americas, OECD Asia Oceania and OECD Europe regional groupings.

OECD Americas: Canada, Chile, Mexico and the United States.

OECD Asia Oceania: Australia, Japan, Korea and New Zealand.

OECD Europe: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom. For statistical reasons, this region also includes Israel.[6]

OPEC (Organization of Petroleum Exporting Countries): Algeria, Angola, Ecuador, Gabon, Indonesia, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, the Lao People's Democratic Republic, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Southern Africa: Angola, Botswana, Comoros, Lesotho, Madagascar, Malawi, Mauritius, Mozambique, Namibia, Seychelles, South Africa, Swaziland, the United Republic of Tanzania, Zambia and Zimbabwe.

Sub-Saharan Africa: Africa regional grouping excluding the North Africa regional grouping.

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

5. 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, Tonga and Vanuatu.

6. 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.

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
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
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)
NGL	natural gas liquids
NGV	natural gas vehicle
NPV	net present value
NOC	national oil company
NO_X	oxides of nitrogen
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 resources
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 Program
UNEP	United Nations Environment Program
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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