MARKET REPORT SERIES

International Energy Agency
Secure Sustainable Together

RENEWABLES 2017

Analysis and Forecasts to 2022

MARKET REPORT SERIES

International Energy Agency
Secure Sustainable Together

RENEWABLES 2017

Analysis and Forecasts to 2022

Explore data behind the Renewables 2017

The IEA is expanding the availability of data behind Renewables 2017. Please visit www.iea.org/publications/renewables2017 to find all related press materials of the Report including executive summary, launch presentation and key figures.

To download the electronic databook with country and technology forecast numbers behind the Report please visit the restricted website www.iea.org/publications/renewables2017/data. Your username is "IEA_Reuser" and password is "REforecast2017".

INTERNATIONAL ENERGY AGENCY

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.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

International Energy Agency
Secure
Sustainable
Together

International Energy Agency
Website: ***www.iea.org***

The European Commission also participates in the work of the IEA.

FOREWORD

For the sixth straight year, our market report shows new records for renewable energy, which accounted for two-thirds of all global net electricity capacity growth in 2016. This year's uncontested star is solar photovoltaics (PV), whose capacity for the first time grew faster than any other fuel.

We are delighted with such progress, unthinkable just a decade ago. Three main factors contributed to this impressive success story. First, strong government policy support, which initially began in Europe, creating a market that allowed the renewable industry to grow around the world. Second, industry delivered on its promise by continuously improving its technology and reducing costs. Third, the arrival of giant emerging economies – the People's Republic of China, in particular – spurred step change economies of scale.

Ten years ago, China had just 100 megawatts of installed solar PV capacity. By the end of 2016, that figure had increased almost 800 times to reach 77 gigawatts. China is now the undisputed leader in several renewables sectors, including hydropower, onshore wind, bioenergy for heat and electricity, and of course solar PV, where it plays a pivotal role. Chinese companies account for over 60% of global PV manufacturing, and its domestic market is equal to half of global demand. This means China effectively sets deployment volumes and prices for solar PV around the world.

Along with new policies that spur competition in several other countries, this Chinese dynamic has led to record-low announced prices of solar PV and onshore wind, which are now comparable or even lower than new-built fossil fuel alternatives. This is radically changing the narrative in other emerging economies, which are now looking at renewables as attractive options to sustain their development. This year's forecast finds that renewable electricity capacity growth in India will overtake the European Union for the first time. Soon – and, we hope, very soon – African countries may see the next wave of development supported by cheap renewable power.

While this is all undoubtedly good news, there is little room for complacency. For now, the success of renewables in the electricity sector remains limited to wind and solar, which together represent more than 80% of total capacity expansion for renewables in the next five years. This is why system integration of renewables is becoming so critical. In many countries, market design and policy frameworks will need to evolve to integrate growing shares of variable renewables while ensuring electricity security at all times. This will require increasing the flexibility of power systems through better grids and interconnections, more flexible power plants, affordable storage and demand-side response.

Much more also needs to be done beyond the power sector. Today, electricity accounts for just a fifth of total final energy demand. The next chapter in the rise of renewables will require multiplying their uses in the building, industry and transport sectors. For instance, new uses for renewables in industry are emerging that can open completely new markets and applications.

In this fast-changing renewable industry – as we do every year – our report reflects the latest and most up-to-date analysis on government policies and their impacts on market developments.

Dr. Fatih Birol

Executive Director

International Energy Agency

ACKNOWLEDGEMENTS

Renewables 2017 was prepared by the Renewable Energy Division of the International Energy Agency (IEA). The lead authors of the report were Heymi Bahar, who led and co-ordinated the analysis, Yasmina Abdelilah, Emanuele Bianco, Ute Collier, Karolina Daszkiewicz, Pharoah Le Feuvre, Megan Mercer and Yasuhiro Sakuma. Cédric Philibert also contributed to the drafting of this report.

Paolo Frankl, Head of the Renewable Energy Division, provided strategic guidance and valuable input to this work. Keisuke Sadamori, Director of Energy Markets and Security reviewed the report and provided expert advice. This report also benefited from the valuable administrative support provided by Michelle Adonis and Jane Berrington.

Other IEA colleagues who have made important contributions to this work include:

Carlos Alvarez Fernandez, Elie Bellevrat, David Bénazéraf, Stéphanie Bouckaert, Willem Braat, Amos Bromhead, Pierpaolo Cazzola, Laura Cozzi, Davide D'Ambrosio, Kate Dourian, Duarte Figueira, Marine Gorner, Paul Hugues, Joerg Husar, Timur Guel, Yemao Li, Kieran McNamara, Duncan Millard, Bruce Murphy, Matthew Parry, Uwe Remme, Jacob Teter, Laszlo Varro, Michael Waldron, Brent Warner, Matthew Wittenstein, Lei Yang, Aya Yoshida.

Timely data from the IEA Energy Data Centre were fundamental to the report, with particular assistance provided by Duncan Millard, Chief Statistician, and Emmanouil Christinakis, Loïc Coent, Laila El-Ashmawy, Markus Fager-Pintila, Vladimir Kubecek, Roberta Quadrelli, Rémi Gigoux, Dae Yong Kwon, Beatriz Martinez and Céline Rouquette.

This work benefited from extensive review and comments from the IEA Standing Group on Long-Term Co-operation, IEA Renewable Energy Working Party, members of the Renewable Industry Advisory Board (RIAB) and experts from IEA partner countries and other international institutions. The work also benefited from feedback by the IEA Committee on Energy Research and Technology, IEA Technology Collaboration Programmes (IEA TCPs)

Many experts from outside of the IEA provided valuable input, commented and reviewed this report. They include:

Countries

Australia (Department of the Environment and Energy, Department of Industry, Innovation and Science), Brazil (Empresa de Pesquita Energética, Ministry of Foreign Affairs and Ministry of Mines and Energy), Canada (Natural Resources Canada), China (China National Renewable Energy Centre, Energy Research Institute, National Development and Reform Commission), France (Ministry of the Environment, Energy and the Sea), Germany (Federal Ministry of Economic Affairs), Hungary (Ministry of National Development), India (Council on Energy, Environment and Water, The Energy and Resources Institute), Ireland (Sustainable energy Authority of Ireland), Italy (Gestore dei Servizi Energetici S.p.A), Japan (Ministry of Foreign Affairs, New Energy and Industrial Technology Development Organization, The Institute of Energy Economics, Japan), Kenya (Energy Regulatory Commission), Korea (Korea Energy Economics Institute, Korea Energy Agency), Mexico (Secretaría de Energía), New Zealand (Ministry of Economic Development), Norway (Research Council of Norway), Portugal (National Laboratory for Energy and Geology), Spain (Instituto para la Diversificación y ahorro de la Energia), Sweden (RISE Research Institutes of Sweden), Ukraine (Ukrainian Association of Renewable Energy), United Kingdom (Committee on Climate Change, UK Energy Research Partnership), United States (Department of Energy, Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory).

RIAB members

Électricité de France (EDF), Eneco, Enercon GmbH, Enel Green Power, European Solar Thermal Electricity Association (ESTELA), First Solar, Iberdrola, Siemens Gamesa, Global Wind Energy Council (GWEC), Innogy, International Energy Agency (IEA), J-POWER, Meyer Burger Technology AG, National Renewable Energy Laboratory (NREL), Nordex Acciona, Renewable Energy Policy Network for the 21st Century (REN21), SolarPower Europe, Total, Vestas Wind Systems, WindEurope.

Technology Collaboration Programmes (TCPs)

IEA Advanced Motor Fuels Technology Collaboration Programme (AMF TCP), IEA Bioenergy Technology Collaboration Programme (Bioenergy TCP), IEA Hydrogen Technology Collaboration Programme (Hydrogen TCP), IEA Hydropower Technology Collaboration Programme (Hydropower TCP), IEA Technology Collaboration Programme on Concentrated Solar Power (SolarPACES TCP), IEA Technology Collaboration Programme on Geothermal Energy (Geothermal TCP), IEA Technology Collaboration Programme on Ocean Energy Systems (OES TCP), IEA Technology Collaboration Programme on Photovoltaic Power Systems (PVPS TCP), IEA Technology Collaboration Programme on Renewable Energy Technology Deployment (RETD TCP), IEA Technology Collaboration Programme on Solar Heating and Cooling (SHC TCP), IEA Technology Collaboration Programme on Wind Energy (Wind TCP).

Other organisations

Association of the European Heating Industry (EHI), Australian Renewable Energy Agency (ARENA), Becquerel Institute, Brazilian Sugarcane Industry Association (UNICA), Bridge to India, Clean Energy Alliance, Dong Energy, E4tech, Engie, Solar Heat Europe, European Commission (Directorate-General for Energy, European Geothermal Energy Council (EGEC), Joint Research Centre), European Heat Pump Association (EHPA), GE Hydro, Global Offgrid Lighting Association (GOGLA), Hawkins Wright Ltd., International Council on Clean Transportation (ICCT), International Institute for Sustainability Analysis and Strategy (IINAS), International Renewable Energy Agency (IRENA), Leibniz Institute for Applied Geophysics, Neste Oy, Novozymes, Organization of Economic Cooperation and Development (OECD), Pro Pellets Austria, Solrico, SPV Market Research, World Bank.

The authors would also like to thank Justin French-Brooks for skillfully editing the manuscript, and the IEA Communication and Information Office: in particular, Muriel Custodio, Astrid Dumond, Rebecca Gaghen, Christopher Gully, Jad Mouawad, Katie Russell, Bertrand Sadin, Robert Stone, and Therese Walsh for their assistance.

Questions or comments?

Please write to us at IEA-REMR@iea.org

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF BOXES

EXECUTIVE SUMMARY

Photovoltaics grew faster than any other fuel in 2016, opening a new era for solar power

Renewables broke new records in 2016, largely as a result of booming solar photovoltaics (PV) deployment in the People's Republic of China (hereafter, "China") and around the world, driven by sharp cost reductions and policy support. This performance forms the bedrock of our 2017-22 electricity forecast. Renewables represented almost two-thirds of new net electricity capacity additions in 2016, with almost 165 gigawatts (GW) coming online.

Last year, new solar PV capacity around the world grew by 50%, reaching over 74 GW, with China accounting for almost half of this expansion. For the first time, solar PV additions rose faster than any other fuel, surpassing the net growth in coal. This deployment was accompanied by the announcement of record-low auction prices as low as USD 30/megawatts per hour (MWh). Annual capacity growth of wind declined by almost one-fifth in 2016, following the 2015 boom caused by a developer rush in China. Hydropower capacity expansion was lower than in 2015 as the Chinese market declined for a third year in a row, while Brazil saw strong growth. The growth of other renewable technologies such as bioenergy, concentrating solar power (CSP), and geothermal was relatively slow, and it represented only 4% of 2016 global renewable capacity additions.

China is the undisputed renewable growth leader, holding the key to the future of solar PV

Between 2017 and 2022, we expect global renewable electricity capacity to expand by over 920 GW, an increase of 43%. This forecast is more optimistic than last year, mainly because of upward revisions for solar PV in China and India. China alone is responsible for 40% of global renewable capacity growth, which is largely driven by concerns about air pollution and capacity targets that were outlined in the country's 13th five-year plan to 2020. In fact, China already surpassed its 2020 solar PV target, and we expect it to exceed its wind target in 2019. China is also the world market leader in hydropower and, bioenergy for electricity and heat, as well as electric vehicles.

Solar PV is entering a new era. For the next five years, solar PV represents the largest annual capacity additions for renewables, well above wind and hydro. This marks a turning point and underpins our more optimistic solar PV forecast which is revised up by over one-third compared to last year's report. This revision is driven by continuous technology cost reductions and unprecedented market dynamics in China as a consequence of policy changes. As a result, by 2022, total solar PV capacity around the world reaches 740 GW in our main case forecast, which is more than the combined total power capacities of India and Japan today.

China is a critical actor in the market development and prices for solar PV worldwide. Today, the country represents half of global solar PV demand, while Chinese companies account for around 60% of total annual solar cell manufacturing capacity globally. As such, market and policy developments in China will have global implications for solar PV demand, supply, and prices.

If uncertainties and barriers are addressed, solar PV growth could accelerate even more. Two important challenges in China – the growing cost of renewable subsidies and grid integration – limit growth in the main case forecast. China's renewable energy policies are being modified quite substantially in order to address these challenges. China is moving away from its feed-in-tariff (FIT) programme to a quota system with green certificates. Together with ambitious power market reform, new transmission lines, and the expansion of distributed generation, these new policies are expected to speed up deployment of solar (and wind). However, the timing and implementation of this policy transition remains uncertain.

Our accelerated case forecast assumes that governments address policy challenges and lift barriers to deployment, leading to more rapid growth. Accordingly, solar PV in China could reach a total of 320 GW by 2022, equivalent to the total capacity of Japan. This also has global implications: combined with possible policy and regulatory improvements in other key countries such India, Japan and the United States, world solar PV cumulative capacity could almost triple to 880 GW by 2022.

The United States remains the second-fastest growing market, while renewable electricity growth in India surpasses the European Union

Despite policy uncertainty, the United States remains the second-largest growth market for renewables. The main drivers remain strong for new onshore wind and solar capacities, such as multi-year federal tax incentives combined with renewable portfolio standards as well as state-level policies for distributed solar PV. Still, the current uncertainty over proposed federal tax reforms, international trade, and energy policies could have implications for the relative economics of renewables and alter their expansion over our forecast period.

India's forecast is more optimistic as it moves to address the financial health of its utilities and to tackle grid-integration issues. By 2022, India is expected to more than double its current renewable electricity capacity. For the first time, this growth over the forecast period is higher than the European Union. Solar PV and wind together represent 90% of India's capacity growth as auctions yielded some of the world's lowest prices for both technologies. In some Indian states, these recent contract prices are comparable to coal tariffs. India's accelerated case indicates that renewable capacity expansion could be boosted by almost a third, providing that existing grid integration and infrastructure challenges are addressed, policy and regulatory uncertainties are reduced, and costs continue to fall. This deployment path could put India's growth on par with the United States, thus becoming the joint second-largest growth market after China.

In the European Union, renewable growth over the forecast period is 40% lower compared with the previous five-year period. Overall, weaker electricity demand and overcapacity remain challenges to growth while limited visibility on forthcoming auction capacity volumes in some markets presents a forecast uncertainty. Beyond 2020, policy uncertainty remains. However, if adopted, the new EU Renewable Energy Directive covering the post-2020 period would address this challenge by requiring a three-year visibility over support policies, thereby improving market predictability for investors.

The growth in solar PV helps bridge the electrification gap in developing Asia and sub-Saharan Africa. For the first time, our report tracks off-grid solar PV applications more closely in developing Asia and sub-Saharan Africa. Over the forecast period, off-grid capacity in these regions will almost triple – reaching over 3 000 MW in 2022 – from industrial applications, solar home systems (SHSs), and mini-grids driven by government electrification programmes, and private sector investments. Although this growth represents a small share of total PV capacity installed in both regions, its socio-economic impact is nonetheless significant. We estimate that over the next five years, SHSs – the most dynamic sector in the off-grid segment – will bring basic electricity services to almost 70 million more people in Asia and sub-Saharan Africa. It will also lead to new business players bringing innovative payment solutions that allow low-income populations initial access to electricity services.

Renewable generation becomes more competitive, closing the gap with coal

By 2022, global renewables electricity generation is expected to grow by more than one-third to over 8 000 terawatts per hour, equal to the total consumption of China, India and Germany combined. The share of renewables in power generation will reach 30% in 2022, up from 24% in 2016. Despite slower capacity growth, hydropower will remain the largest source of renewable electricity generation in our forecast, followed by wind, solar PV and bioenergy. In the next five years, growth in renewable generation will be twice as large as that of gas and coal combined. While coal remains the largest source of electricity generation in 2022, renewables close in on its lead. In 2016, renewable generation was 34% less than coal but by 2022 this gap will be halved to just 17%.

Renewable policies in many countries are moving from government-set tariffs to competitive auctions with long-term power purchase agreements (PPAs) for utility-scale projects. Increased competition has reduced remuneration levels for solar PV and wind projects by 30-40% in just two years in some key countries such as India, Germany and Turkey. This competitive price discovery mechanism has squeezed costs along the entire value chain making tenders a cost-effective policy option for governments. Auctions can also enable a better control of deployment, total incentives, and system integration aspects. Almost half of the renewable electricity capacity expansion over 2017-22 is expected to be driven by competitive auctions with PPAs, in contrast to just over 20% in 2016.

Announced auction prices for wind and solar have continued to fall although average generation costs of new-built projects remain higher. Over the period 2017-22 global average generation costs are estimated to further decline by a quarter for utility-scale solar PV; by almost 15% for onshore wind; and by a third for offshore wind. Still, these average costs for solar PV remain relatively high because of high FITs in China and Japan as well as relatively elevated investment costs in the United States. Meanwhile, announced auction prices indicate much steeper possible cost reductions, ranging from USD 30-45/MWh for solar PV (India, Mexico, United Arab Emirates, Argentina) to USD 35-50/MWh for onshore wind (India, Morocco, Egypt, Turkey, Chile). Auctions are also proving effective in rapidly reducing costs of offshore wind and CSP. While auction announcements (in terms of both volumes and prices) need to be verified over time, they suggest that expanding competitive pricing could result in even lower average costs in coming years.

As growth of wind and solar accelerates, system integration becomes increasingly important

Wind and solar together will represent more than 80% of global renewable capacity growth in the next five years. By 2022, Denmark is expected to be the world leader, with almost 70% of its electricity generation coming from variable renewables. In some European countries (Ireland, Germany and the United Kingdom), the share of wind and solar in total generation will exceed 25%. In China, India and Brazil, the share of variable generation is expected to double to over 10% in just five years. These trends have important implications going forward. Without a simultaneous increase in system flexibility (grid reinforcement and interconnections, storage, demand-side response and other flexible supply), variable renewables are more exposed to the risk of losing system value at increasing shares of market penetration since wholesale prices are depressed precisely when wind and solar production is abundant and demand is low. Market and policy frameworks need to evolve in order to cope simultaneously with multiple objectives, including providing long-term price signals to attract investment, ensuring efficient short-term electricity dispatching, pricing negative externalities, and unlocking sufficient levels of flexibility as well as fostering a portfolio of dispatchable renewable technologies, including hydropower, bioenergy, geothermal and CSP.

Biofuels remain the champion of renewables in transport while the share of electric vehicles grows

The share of renewables in road transport is expected to increase only marginally, from over 4% in 2016 to almost 5% in 2022. Biofuels and electric vehicles (EVs) are complementary options to achieve transport sector decarbonisation with renewables. Despite strongly rising sales, the share of EVs remains limited, and biofuels are still expected to represent over 90% of total renewable energy consumption in road transport by 2022. Biofuels production is expected to grow by over 16% over the forecast period. Asia leads this growth due to the rising demand for transport fuel, the availability of feedstocks, and supportive government policies. Brazil makes a key contribution as a result of its efforts to increase sustainable biofuels consumption in line with its national target for 2030. In the United States, ethanol and biodiesel production also expands as a result of supportive policy frameworks. Modest growth is expected in the European Union given that the policy landscape after 2020 is not expected to encourage industry investment. Advanced biofuels (such as cellulosic ethanol) have made important progress in recent years but are not yet competitive with petroleum products. Production is expected to increase sevenfold from a low base, which is still just over 1% of total biofuels production.

With a more favourable market and policy landscape, biofuel production could be 14% higher. For the first time, we provide accelerated case forecast for biofuels that assumes additional investment in new production capacity in Brazil; scaling up fuel distribution infrastructure in the United States; and roll-out of a blending programme in India. Still, in this accelerated case, the share of renewables in road transport fuel demand would only reach just over 5% by 2022.

Renewables account for 30% of electricity consumption of EVs by 2022, up from 26% today. Globally, electricity consumed by EVs – including cars, two- and-three wheelers, and buses – is expected to double by 2022 but will still account for less than 1% of total electricity generation. China is the largest consumer of renewable electricity in EVs, thanks to the expansion of two- and three-wheelers and the increasing share of renewables in its power mix. The second-largest consumer is Europe due to the deployment of electric cars in markets with high shares of renewables such as Norway and Germany. Despite the United States being the third-largest electric car market, renewable consumption is relatively lower than China and Europe because of the less prominent role of renewables in its electricity supply.

Renewable heat grows by a quarter, but its share increases only marginally

The share of renewables in heat consumption increases slowly, from 9% in 2015 to almost 11% in 2022. Almost 40% of global energy-related CO_2 emissions comes from heat used for water and space heating in buildings and for industrial processes; therefore, decarbonising heat remains an important challenge. The building sector is expected to lead the growth in renewable heat consumption, with the fastest growth in this sector seen in China, the European Union and North America. In industry, China and India see a significant growth in renewable heat consumption. In terms of sources, bioenergy will lead renewable heat consumption growth over the outlook period, followed by renewable electricity for heat. Global solar thermal energy consumption is also expected to increase by over a third, although growth is projected to be slower than in previous years. China alone provides over a third of overall renewable heat growth over the outlook period, driven by strengthened targets for solar thermal, bioenergy and geothermal as well as by increasing concerns over air pollution in cities. The European Union is the second-largest growth market as a result of the binding targets of the Renewable Energy Directive, and it remains the global leader in terms of absolute renewable heat consumption.

1. RECENT RENEWABLE ENERGY DEPLOYMENT TRENDS

Highlights

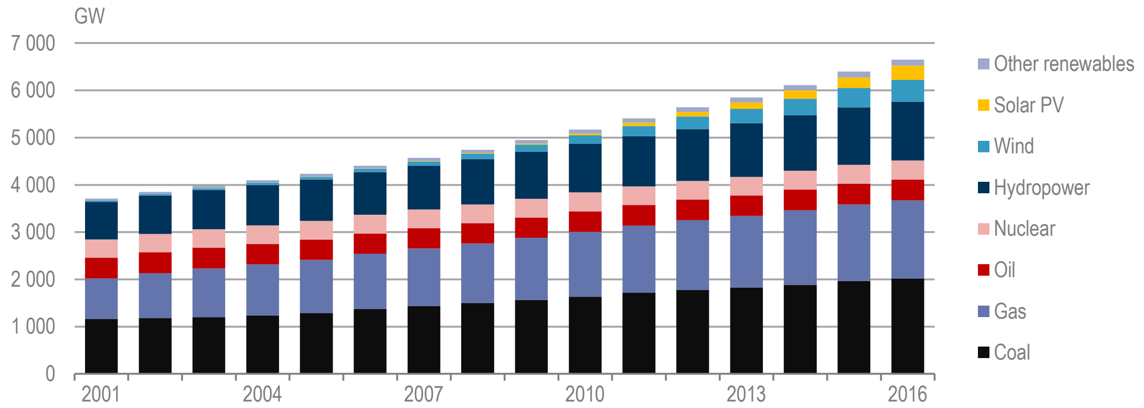
- In 2016, net additions to total renewable energy capacity set another world record, growing by 165 gigawatts (GW), 6% higher than additions in 2015. Renewables accounted for about two-thirds of global growth in net electrical capacity in 2016, while cumulative capacity reached an estimated 2 134 GW, remaining the largest source of power globally.
- Solar photovoltaic (PV) capacity grew by 74 GW in 2016, 50% higher than 2015, driven by a record 34 GW of installations in the People's Republic of China (hereafter, "China"). For the first time, the net capacity growth of a single renewable technology was larger than any other fuel. Global wind additions declined by over 20% to 52 GW from 2015 boom levels, following support cuts in China. Hydropower additions fell to 32 GW, followed by bioenergy (6.6 GW), concentrated solar power (CSP) (0.3 GW) and geothermal (0.3 GW).
- China remained the largest market globally in 2016, accounting for 41% of renewable additions. Annual expansion of 24 GW in the United States was 44% higher than in 2015, surpassing the European Union for the first time, where additions declined to 21 GW. India and Brazil added almost 9 GW each, representing 27% and 43% higher growth than in 2015 respectively. Renewable additions declined by a third in Japan due to slower PV growth. In sub-Saharan Africa, record levels of capacity (4.4 GW) were deployed in 2016 driven by hydropower, while growth was slower in the Middle East and North Africa (1 GW), led by PV.
- Renewable power generation grew by 7% to an estimated 6 012 terawatt hours (TWh) in 2016 and represented over 24% of the global electricity mix, second only to coal. Hydropower leads renewable power generation at 4 144 TWh in 2016, followed by wind (958 TWh), bioenergy (500 TWh) and solar PV (312 TWh), while CSP, geothermal and ocean provided the rest.
- In 2016 conventional biofuel production increased by around 2.5% year-on-year (y-o-y) to reach 136 billion litres (L). In the United States ethanol exceeded 10% of gasoline demand, occasionally crossing the "blend wall", while India reached a record high fuel ethanol blend of 4.4%. In Europe, hydrotreated vegetable oil (HVO) demand and production increased, while biodiesel output rebounded in Indonesia with the implementation of the global high blending mandate. Advanced biofuel production was estimated to be less than 500 million L with most technologies still in development. The share of renewables in electrified road transport reached 26% (36 TWh) globally, up by one-fifth from 2015. The largest consumption of renewable electricity by electric vehicles (EVs) occurred in China, mostly from two- and three-wheelers, while Europe was the leader in the electric car sector.
- Renewable heat consumption has grown on average by 2.7% per year since 2008, reaching 18.5 exajoules (EJ) in 2015 and accounting for 9% of total heat consumption. Progress was most rapid in the buildings sector (32% growth since 2008), while the industrial sector continued to lag behind (10% growth). Bioenergy accounted for more than 70% of renewable heat consumption in 2015. Solar thermal has grown fastest in the last few years, mainly due to large additions in China, although annual additions slowed in 2015 for the second year in a row.

Electricity

Technology deployment summary

In 2016, global total cumulative electricity capacity grew by 4%, or 255 GW, and reached a total of 6 650 GW (Figure 1.1). Renewables provided almost two-thirds of this growth with record additions of 165 GW, 6% higher compared to 2015. Renewables remain the largest source of cumulative capacity at 2 135 GW, followed by coal (2 020 GW), natural gas (1 650 GW), oil (445 GW) and nuclear (400 GW).

Figure 1.1. Global total electricity capacity, 2001-16

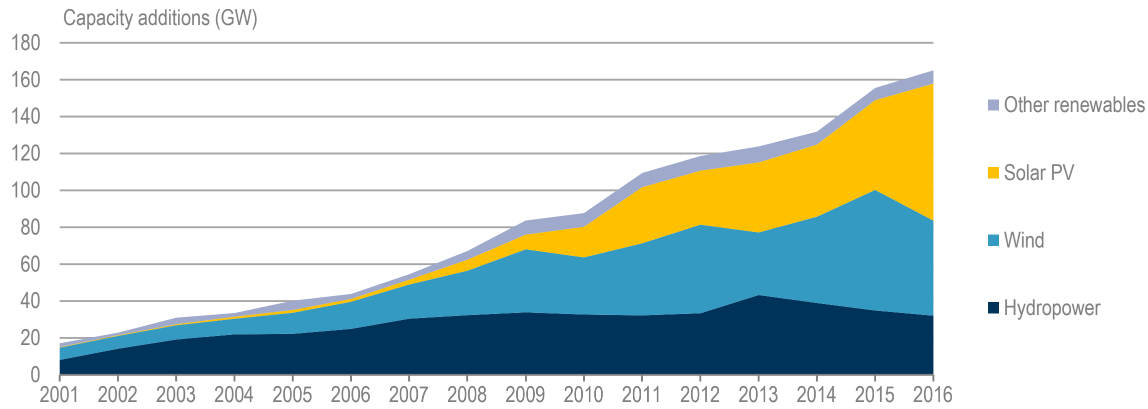


Sources: Fossil fuel capacity calculations based on Platts (2017), *World Electric Power Database*. Historical renewable capacity data for OECD countries based on IEA (2017d), *Renewables Information 2017*.

Annual renewable capacity additions have continued to grow since the early 2000s, expanding more than eightfold over the last fifteen years. In 2016, solar PV net additions grew by more than 50% compared to 2015, reaching over 74 GW, with China accounting for almost half. This marks the first time that the net capacity expansion of a single renewable technology was larger than any other fuel, higher than coal (57 GW).[1] Utility-scale projects provided almost 75% of all solar PV growth, followed by commercial (17%) and residential (9%) applications. Annual onshore wind additions declined to 49 GW in 2016, down one-fifth from the 2015 boom, which was caused by a developer rush in China in order to benefit from higher feed-in tariffs (FITs). In 2016, hydropower capacity grew by 32 GW, 8% lower than 2015 despite strong growth in Brazil, as the Chinese market declined for a third year in a row (Figure 1.2). Annual deployment of pumped storage projects (PSPs) continued to increase, achieving net additions of 5.8 GW in 2016, 50% higher than in 2015, with China accounting for more than half of the deployment. Bioenergy (6.6 GW), offshore wind (2.3 GW), CSP (0.27 GW), and geothermal (0.35 GW) contributed smaller additions.

[1] Net growth or net additions refers to the year-on-year difference in cumulative installed capacity which differs from gross capacity additions because of plant retirements. Globally, coal remained the largest source of gross capacity additions in 2016; however, with approximately 30 GW of capacity retired during the year, coal net additions with 57 GW were less than solar PV which grew by 75 GW.

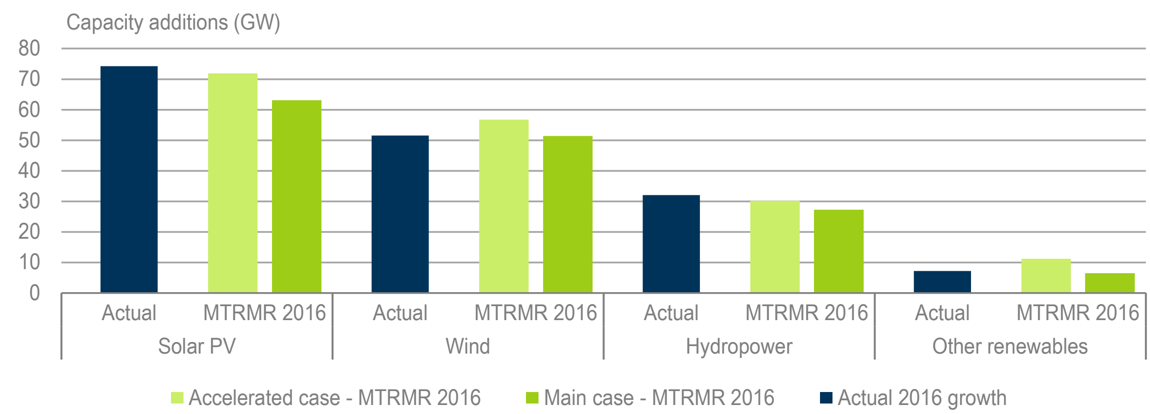
Figure 1.2. Net renewable capacity additions by technology, 2001-16



Source: Historical capacity data for OECD countries based on IEA (2017d), *Renewables Information 2017*.

The forecast for capacity growth in the market year[2] has become more challenging as deployment trends are highly influenced by policy changes and developers' reaction to them. In order to reflect these policy and market uncertainties, this report presents both main and accelerated case forecasts. The *Medium-Term Renewable Energy Market Report (MTRMR) 2016* estimated global annual additions for 2016 between 150 GW (main case) and 170 GW (accelerated case), with the range reflecting uncertainty over the pace of commissioning projects, mainly in China and the United States. The *MTRMR 2016* main case correctly estimated market expansion in 2016 for wind and other renewables. For solar PV and hydropower, the actual market growth was in line with the *MTRMR 2016* accelerated case. For hydropower, large projects in Brazil and China were commissioned faster than expected in the main case. For solar PV the difference was largely due to China. The *MTRMR 2016* main case assumed China's FIT reduction in June 2016 would cause growth to slow in the second half of 2016 compared with the first half, while the accelerated case, which reflects the observed 2016 figures, assumed growth would continue despite the decrease in support levels (Figure 1.3).

Figure 1.3. Renewable capacity additions in 2016 and *MTRMR 2016* forecasts

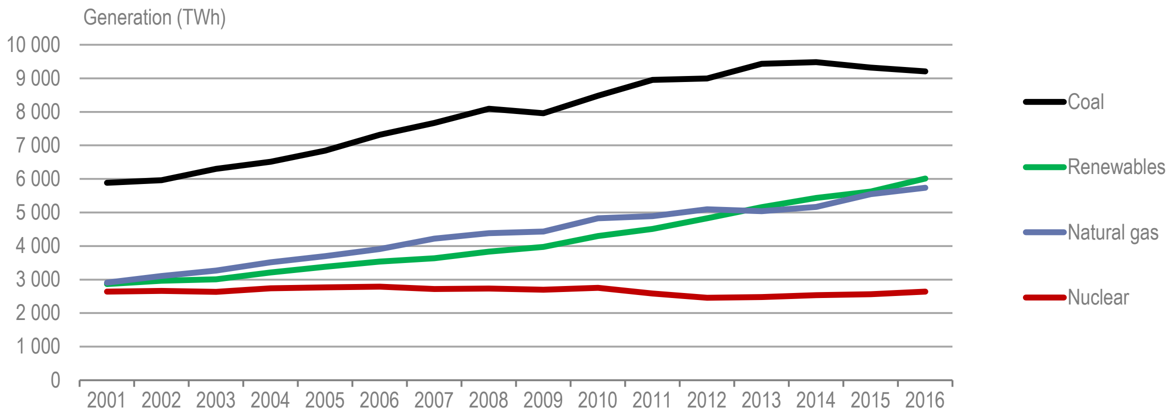


Source: IEA (2016), *Medium-Term Renewable Energy Market Report 2016*.

[2] Market year refers to the year in which our forecast is published. The market year is 2016 for the *MTRMR 2016* forecast and 2017 for this year's forecast (*Renewables 2017*).

In 2016, renewable power output grew by an estimated 7% y-o-y and reached 6 012 TWh. With this rapid expansion, renewables represented an estimated 24% of global electricity generation. They remain the second largest electricity generation source after coal, which provided about 35% of global power output last year. However, the output of some renewables, notably hydropower, wind and solar PV, is climate and weather dependent and can fluctuate from one year to the next. Hydropower remained the largest source of renewable generation, accounting for more than two-thirds of the total. Despite declines in some regions due to low precipitation, overall global hydropower output grew by over 4% in 2016. While only accounting for 5% of the world's total generation, output from wind and solar PV grew substantially, by 14% and 27% respectively, thanks to their significant increase in capacity over the last two years. For the first time, however, onshore wind generation in Europe, did not grow owing to a lack of wind in the region. Despite lower cumulative installed capacity than both solar PV and wind, bioenergy was still able to account for 2% of global electricity generation (500 TWh) in 2016 as a result of much higher average capacity factors.

Figure 1.4. Global electricity generation by technology, 2001-16



Note:Coal generation refers to that from primary products (anthracite, lignite, coking coal, sub-bituminous coal and other bituminous coal).

Source: Historical generation data based on IEA (2017e), *World Energy Statistics and Balances 2017, www.iea.org/statistics.*

Regional deployment summary

China was the largest market for renewables in terms of net capacity additions, with 68 GW becoming operational in 2016, representing 41% of the global market. The majority of this growth was driven by technology-specific FITs and national targets. The country led annual renewable market growth for all three major renewable technologies: solar PV, onshore wind and hydropower (Table 1.1). In 2016, China's solar PV additions more than doubled (34 GW) compared with 2015 as developers rushed to complete their projects before the planned FIT reduction in July 2016. Utility-scale projects dominated the annual market (90%) followed by commercial/industrial applications, while the residential segment remained small as retail prices are relatively low, hampering projects' economic attractiveness. Onshore wind additions declined by over 40% y-o-y to almost 19 GW in 2016 as developers rushed to commission their projects in 2015 to benefit from higher FITs. With this expansion, China surpassed the European Union in terms of cumulative onshore wind capacity and became the global leader. The average curtailment rate for onshore wind increased from 15% in 2015 to 17% in 2016, with almost 50 TWh curtailed last year, almost equivalent to Greece's total annual power consumption.

In 2016, hydropower capacity additions declined by 14% with an estimated 12.6 GW installed, of which 3.7 GW came from pumped storage projects (PSP). Bioenergy capacity saw another strong year with 1.8 GW added, making China the second-largest market after Europe, mostly due to energy-from-waste projects driven by increasing urbanisation. The offshore wind market grew by almost two-thirds, or 600 megawatts (MW), in 2016, although it remains nascent compared to onshore wind. Overall, China's renewable electricity generation grew by an estimated 11% to reach over 1 572 TWh and accounted for 26% of the country's electricity in 2016. Hydropower contributed most to China's overall renewable output, but wind and solar generation saw the most rapid growth, 30% and 46% y-o-y respectively.

North America was the second-largest growth market for new renewable capacity, led by the **United States**. New additions in the United States were about 45% higher compared to 2015, with almost 24 GW becoming operational in 2016. Solar PV accounted for over half of new capacity additions, which doubled from 7 GW in 2015 to over 14 GW in 2016. Project developers rushed to advance their projects before the anticipated expiration of the federal tax incentives in December 2015. Many projects that had already received grid connection approval were commissioned during 2016, resulting in a boost to deployment. Annual additions for all solar PV applications grew, but growth in the utility-scale segment more than doubled and represented 72% of the solar PV market, followed by residential (17%) and commercial (11%). Onshore wind capacity additions were stable at around 8.2 GW, with Texas, Oklahoma and Kansas leading the way. In 2016, America's first offshore wind farm (30 MW Block Island) began to produce electricity. Overall, renewable generation increased by 12.5% and their share of total power output expanded from 13.6% in 2015 to 15.3% in 2016.

Table 1.1. Top five countries/regions for renewable capacity additions by technology in 2016

Solar PV	GW	Onshore wind	GW	Hydropower	GW	Bioenergy	GW
China	34.2	China	18.7	China	12.6	China	1.8
United States	14.8	United States	8.2	Brazil	5.3	Brazil	0.9
Japan	7.9	Germany	4.3	Ecuador	1.8	Denmark	0.6
India	4.0	India	3.6	Ethiopia	1.7	India	0.4
United Kingdom	2.4	Brazil	2.5	Peru	1.1	Japan	0.3
Offshore wind	**MW**	**Geothermal**	**MW**	**CSP**	**MW**	**Ocean**	**MW**
Germany	813	Turkey	197	Morocco	160	Canada	1.6
Netherlands	691	Indonesia	99	South Africa	100	France	1.0
China	592	Guatemala	15	Australia	3	Norway	0.3
Viet Nam	83	Kenya	10	United States	2	Korea	0.2
United Kingdom	56	Nicaragua	10	France	2	China	0.2

Note: GW = gigawatt; MW = megawatt. For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/renewables2017/data.

Source: Capacity data from multiple sources; see Chapter 2, "Renewable Electricity Forecast" sources for more detail.

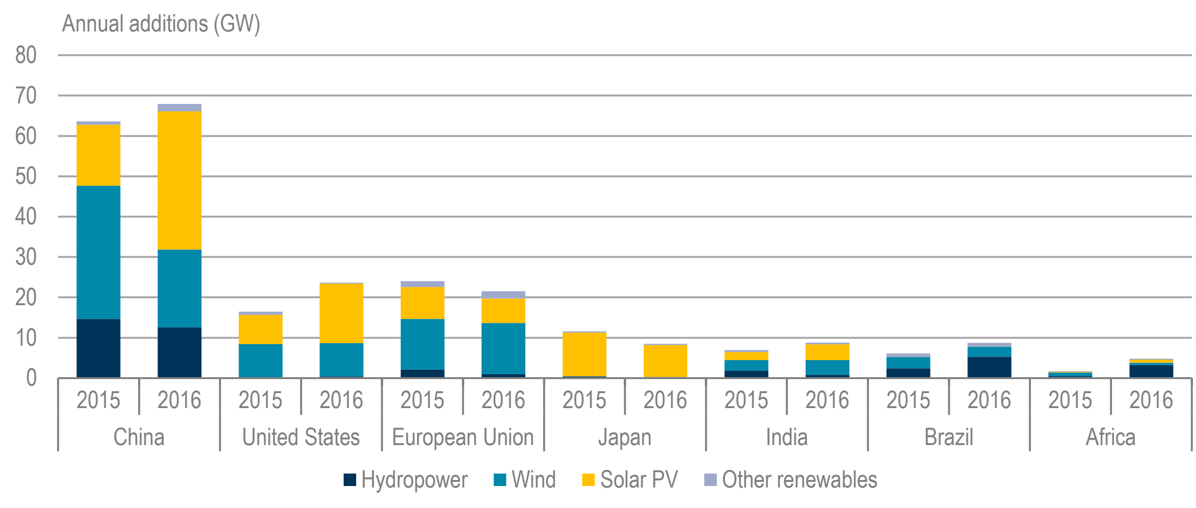
Canada's renewable capacity additions decreased by 83% y-o-y as fewer hydropower, solar PV and wind projects were commissioned in 2016. Overall, onshore wind additions represented two-thirds of new additions with 0.7 GW, followed by solar PV (0.14 GW), hydropower (0.17 GW) and bioenergy (0.1 GW). At the same time, the share of renewables in Canada's electricity generation exceeded 65%

in 2016, one of the highest globally, with hydropower representing 90% of the country's renewable output. In **Mexico,** renewables represented 15% of power generation in 2016. Renewable additions stood at around 0.7 GW in 2016, 12% lower than in 2015, led by onshore wind (0.45 GW) and solar PV (0.2 GW), and mostly from power purchase contracts with the Federal Electricity Commission before implementation of energy reform.

Renewable capacity in **Asia and Pacific**, excluding China, grew by 26 GW in 2016, slightly less than additions in 2015. **India** accounted for about 9 GW of that growth, while renewables as a proportion of total generation in the country grew from just over 15% in 2015 to 16% in 2016. While India witnessed higher annual capacity growth in 2016 due to record additions for both wind (3.6 GW) and solar PV (4 GW), it was not enough to offset **Japan's** annual solar PV market, which contracted by almost 30% from 10.8 GW in 2015 to 7.9 GW in 2016. Hydropower growth in the region also slowed by over 1 GW compared to 2015 due to lower additions in India, ASEAN countries and Japan. In **Korea,** the renewable portfolio standard continued to drive strong solar PV (0.9 GW) and bioenergy growth (0.2 GW). In addition, significant co-firing activity from obligated power generation companies continued to boost bioenergy generation by over 40% year on year.

In **Association of Southeast Asian Nations (ASEAN) countries,** renewable capacity expanded by almost 3.5 GW in 2016, 14% lower than 2015. Annual additions to solar PV capacity increased by two-thirds to 1.6 GW and surpassed hydropower capacity growth (1.3 GW), followed by wind (0.3 GW) and bioenergy (0.2 GW). For the first time, solar PV provided the largest net additions in the region. **Thailand** connected the largest amount of new renewable capacity among all ASEAN countries in 2016, led by solar PV (0.75 GW), bioenergy (0.16 GW) and wind (0.15 GW). **Viet Nam** was the second-largest market in the region, commissioning almost 1 GW of new hydropower capacity. Renewable capacity grew by record levels in the **Philippines** with the commissioning of 0.75 GW of solar PV. In **Indonesia,** geothermal capacity expanded by 0.1 GW on the commissioning of the first phase of the Sarulla plant, the country's highest growth since 2012. Overall, hydropower remained the largest source of renewable generation in ASEAN countries, accounting for an estimated 71% in 2016, followed by bioenergy (10%) and geothermal (14%).

Figure 1.5. Renewable capacity additions in 2015 and 2016 by country/region and technology



Source: 2015 capacity data for OECD countries based on IEA (2017d), *Renewables Information 2017,* www.iea.org/statistics/.

Europe's annual capacity additions declined by over 10% to 25 GW in 2016 compared to the previous year. The European Union represented 85% of this growth, with the majority of the rest in Turkey. **Germany** represented a quarter of the region's renewable additions, with record net onshore wind additions (4.3 GW) due to a developer rush to lock in support under the feed-in premium before the switch to competitive auctions in 2017. In addition, the country was the largest market for offshore wind (0.8 GW) and solar PV (1.5 GW) in Europe last year. In 2016, the **United Kingdom** was the second-largest annual market in Europe despite almost one-quarter decline in the country's net renewable additions to 4.2 GW, attributable to lower solar PV additions (2.4 GW) primarily due to the FIT revision and closure of the Renewables Obligation scheme for utility-scale projects. In 2016, annual onshore wind installations doubled to 1.4 GW as developers rushed to commission projects before the incentives were phased out. In **Turkey,** the third-largest market**,** onshore wind projects represented the largest renewable capacity additions in 2016 with 1.4 GW, 60% higher than in 2015. Hydropower and solar PV followed onshore wind at 0.8 GW and 0.6 GW respectively. In addition, Turkey saw the largest annual growth in geothermal capacity globally in 2016. The fourth-highest growth was in **France,** with a record increase in onshore capacity of 1.3 GW in 2016, although the country's annual solar PV additions declined by 48% y-o-y to 0.6 GW, reflecting the commissioning of the 300 MW Cestas Solar PV plant that boosted growth in 2015. In addition, record levels of bioenergy capacity (0.2 GW) were added with the commissioning of a large-scale coal-to-biomass conversion.

Latin America remains the region with the highest share of renewable generation among all *Renewables 2017* regions, led by hydropower. **Brazil** provided over half of the region's renewable electricity generation. After decreasing four years in a row since 2012 as a result of severe drought, Brazil's hydropower generation increased in 2016. The country also added record levels of new hydropower capacity (5.3 GW), with the commissioning of the first turbines at the Belo Monte power plant, followed by onshore wind (2.5 GW) and bioenergy (0.9 GW). In 2016 **Chile's** renewable generation decreased by over 7% compared to 2015 as a result of lower hydropower generation. New capacity additions were led by solar PV (0.6 GW), onshore wind (0.32 GW) and hydropower (0.13 GW). In 2016, renewables in **Argentina** represented about 27% of overall generation, dominated by hydropower, which saw 60 MW of growth. **Ecuador** and **Peru** both added record levels of renewable capacity in 2016, mainly from the commissioning of two large hydro plants (1.5 GW Coca Codo Sinclair and 0.5 GW Cerro del Águila, respectively).

Sub-Saharan Africa's cumulative capacity grew by a record 15%, or 4.4 GW, in 2016. However, the region represented less than 3% of global renewable additions. Hydropower provided 75% of this expansion with the commissioning of large plants mainly in Ethiopia and South Africa, followed by solar PV (0.5 GW) and wind (0.4 GW). **South Africa** led the regional renewable expansion in onshore wind (0.4 GW) and solar PV (0.4 GW) and also commissioned the region's only CSP capacity (0.1 GW) in 2016. **Ethiopia** commissioned the region's largest hydropower project (1.7 GW Gilgel Gibe III), while **Kenya** added the region's sole geothermal expansion. In addition, **Ghana**, **Senegal** and **Namibia** connected their first utility-scale solar PV projects in 2016.

The **Middle East and North Africa** saw the smallest renewable capacity growth in 2016 among all *Renewables 2017* regions, with 1 GW becoming operational. **Jordan** alone provided a third of the region's annual additions as the country commissioned record solar PV capacity (0.3 GW), with projects auctioned in 2013/14 connected to the grid. **Morocco** commissioned 0.3 GW of renewables, 60% of which came from CSP, followed by 0.1 GW of onshore wind capacity. In addition, smaller capacity additions came from **Algeria**, mainly from solar PV.

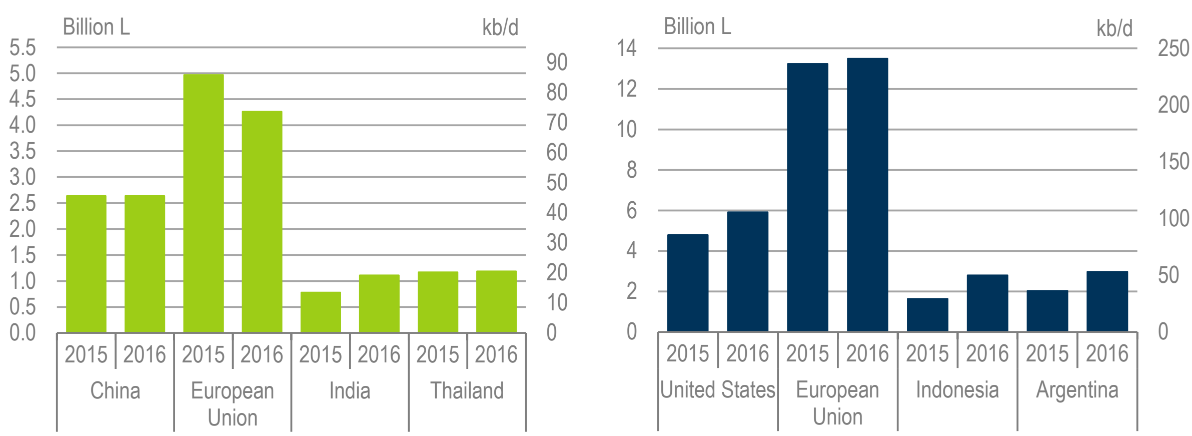
Transport

In 2016, conventional biofuel production increased by 2.5% y-o-y to reach over 136 billion L (2.35 million barrels per day), composed of around 100 billion L of fuel ethanol and 36 billion L of biodiesel and HVO. Consequently, conventional biofuels accounted for around 4% of world road transport fuel demand. Global ethanol production was stable compared to 2015 levels, while biodiesel and HVO production increased by 11% to reach record output. Advanced biofuel production was estimated to be less than 500 million L in 2016. However, progress in scaling up production was reported from some commercial-scale cellulosic ethanol plants, and India stepped up its interest in cellulosic ethanol significantly with five projects in development.

Ethanol markets

In the **United States**, ethanol production increased by over 3% in 2016 to 58 billion L. Growth was supported by another bumper corn crop in conjunction with very high capacity utilisation rates. Ethanol's share of overall gasoline demand over 2016 rose above 10%, effectively crossing the "blend wall"[3] as a result of growing consumption of higher ethanol blends such as E15 and E85. Ethanol production in **Brazil** contracted by 6% in 2016 to 28 billion L as a rebound in international sugar prices resulted in a higher share of sugar production at the expense of fuel ethanol. During 2016 price competitiveness generally tipped in favour of gasoline, resulting in a reduction in hydrous ethanol consumption, only partially compensated by higher consumption of anhydrous blended ethanol. In **China**, the world's third-largest fuel ethanol producer, production was stable at almost 2.6 billion L in 2016 (Figure 1.6), with a notable increase in fuel ethanol imports.

Figure 1.6. Ethanol (left) and biodiesel (right) production in selected markets, 2015 and 2016



Notes: United States and European Union production data for biodiesel includes HVO output; kb/d = thousand barrels per day.

Sources: IEA (2017b), *Monthly Oil Data Service (MODS)*, www.iea.org/statistics/; IEA (2017c), *Oil Information* (database), www.iea.org/statistics/; US EIA (2017), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

[3] The "blend wall" refers to the challenge of increasing biofuel consumption in the United States considering the suitability of the vehicle fleet and absence of widespread fuel distribution infrastructure for biofuel blends higher than E10 (gasoline with 10% ethanol by volume). Subsequent mentions of E10, E20, E15 and E85 refer to the percentage (by volume) of fuel ethanol blended with gasoline. B20 refers to 20% biodiesel blending by volume.

Fuel ethanol production in the **European Union** fell by 14% in 2016 versus 2015, with around 4.3 billion L of output. The largest reductions in output were observed in France, Spain, the Netherlands and the United Kingdom. However, consumption of both E10 and E85 blends continued to increase in France supported by more widespread availability. Fuel ethanol production in **India** grew by over 40% y-o-y to reach 1.1 billion L in 2016, supported by a range of measures to strengthen the ethanol blending programme. As a result, best ever performance against the 5% blending mandate was achieved for the 2015/16 year, with 4.4% ethanol blending on average. The ongoing fuel ethanol production growth trend in **Thailand** continued in 2016, with 1.2 billion L of production and further growth in demand for higher E20 and E85 ethanol blends.

Biodiesel markets

Record biodiesel production of 5.9 billion L was achieved in the **United States** during 2016 (Figure 1.6), representing an increase of more than 20% on 2015. Output was supported by a strong soybean harvest coupled with demand from the Renewable Fuel Standard (RFS2) policy mechanism. The RFS2 also stimulated a step up in biodiesel imports in 2016. The USD 1/gallon blenders' tax credit, which supported profitability in the biodiesel supply chain, expired at the end of 2016. HVO consumption was also supported by the RFS2, where just over 2 billion L were used for compliance.

In 2016, **EU** biodiesel production reached record levels of 13.5 billion L, although output increased only by a marginal 2% on 2015. France, Germany, Spain and the Netherlands combined accounted for almost 70% of production. With 3.5 billion L of production, Germany was Europe's major biodiesel producer, with around a quarter of output from low-carbon used cooking oil feedstocks. HVO accounted for over 20% of combined HVO and biodiesel production in 2016, an increase from around 4% in 2010, indicating growing demand for the fuel in Europe. Availability has also increased, with HVO blends and unblended HVO100 widely available at service stations in Sweden and Finland.

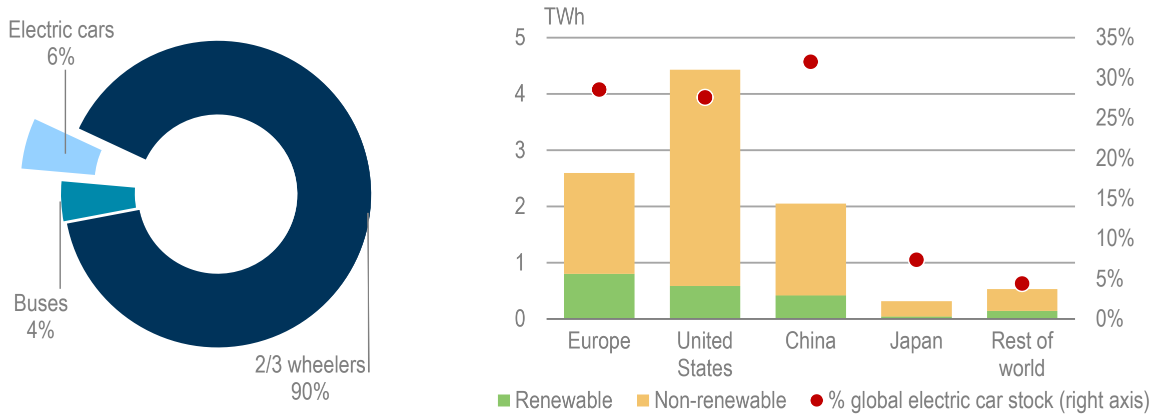
Biodiesel production in **Brazil** remained roughly stable at 3.8 billion L in 2016, aided by a high soybean harvest. Biodiesel output in **Argentina**, also principally from soybean oil, rebounded to around 3 billion L in 2016. Nationally, biodiesel blending stood at around 8.5%, just below the 10% mandate. However, more than half of domestic output was destined for export, principally to the United States as a result of demand from the RFS2 and the aforementioned blender's tax credit. In **Indonesia**, biodiesel output rebounded in 2016 to reach 2.8 billion L, levels broadly in line with demand associated with the country's B20 mandate, the highest in the world. This represented an increase of more than 70% on 2015 levels but remained below 2014 production, which was underpinned by higher export demand. Biodiesel output in **Malaysia**, predominantly from palm oil, declined by 9% to 900 million L in 2016 due to rising palm oil feedstock prices as a result of El Niño climatic conditions, falling production competitiveness and reducing exports to the European Union.

Electric vehicles

In 2016, approximately 0.6% of the world's total electricity generation was consumed by passenger electric vehicles (EVs), a segment of road transport comprised of electric cars, buses, and two- and three-wheelers. Renewables accounted for an estimated 26% of EV electricity consumption, which is heavily influenced by the share of renewables in China's power sector due to the magnitude of the country's EV fleet compared to deployment in other key EV markets. China was by far the world's largest consumer of electricity for EVs in 2016, mostly due to its rapidly growing two- and three-wheeler fleet, which alone accounted for 88% of the world total. The second-largest consumer was Europe's EV fleet, driven by a mix of electric cars and two- and three-wheelers, followed by the United States, almost entirely from electric cars.

Electricity consumed by EVs continued to grow in 2016, up 14% compared to 2015. While two- and three-wheelers accounted for most of the increase, the fastest growth occurred in electric cars, where consumption grew more than 50% y-o-y as the fleet passed the 2 million mark in 2016. China surpassed the United States to have the world's largest electric car fleet in 2016, but the greatest renewable electricity consumption occurred in Europe (Figure 1.7). This is due to EV penetration in markets with relatively higher shares of renewable electricity generation, notably Norway, Europe's largest EV market where hydropower accounts for over 90% of total generation.

Figure 1.7. Global renewable electricity consumption by EVs (left) and electric cars (right) in 2016



Source: IEA analysis based on forecasts from IEA (2016), *Medium-Term Renewable Energy Market Report 2016* and IEA (2017a), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version.

Heat

Heat accounts for more than 50% of total final energy consumption but is mostly produced by fossil fuels (Figure 1.8). In 2015, renewable heat consumption[4] represented 9% of total global heat consumption and reached 18.5 EJ. It increased by just 1.3% compared to 2014, with 71% of the increase in the buildings sector which grew at 2%. Growth in industrial renewable heat consumption was only 0.6% y-o-y. While there was higher annual growth in certain countries and regions (e.g. a 5.2% increase for total renewable heat in the **European Union**), the **United States** saw a 7.5% reduction due to record warm winter temperatures in late 2015. Renewable heat consumption is highly sensitive to variations in winter temperatures. This is particularly the case for technologies used as supplementary heating during colder periods, such as biomass stoves. Cooling is a rapidly growing energy end use, but at present accounts for only around 2% of final energy consumption and data availability is poor. This report therefore addresses heat only.

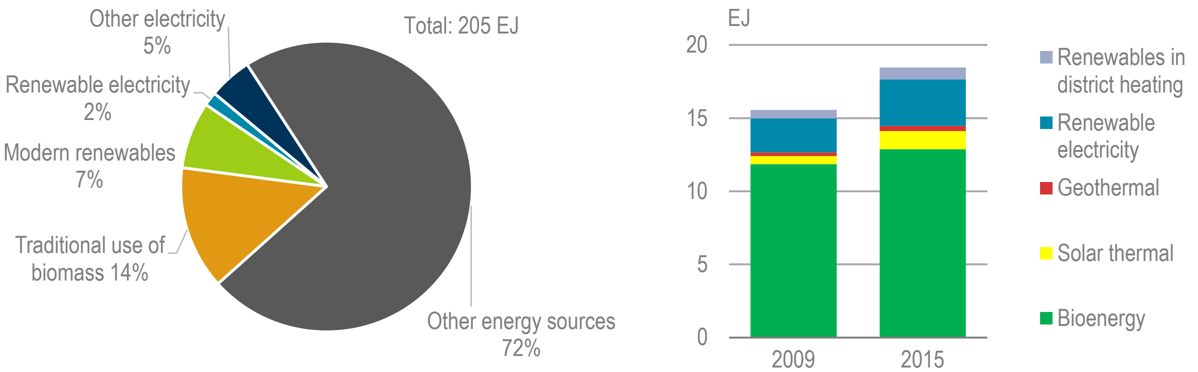
Over 2008-15, global renewable heat consumption increased by 20% from 15.4 EJ to 18.5 EJ (Figure 1.8). Solar thermal grew fastest and doubled from 0.5 EJ to 1.2 EJ, reaching 7% of renewable heat consumption in 2015. Modern bioenergy[5] continued to dominate renewable heat consumption, with 12.9 EJ in 2015. Bioenergy additionally supplied the majority of renewables to district heating, which increased from 0.6 EJ to 0.8 EJ. Growth was also dynamic for renewable electricity used for

[4] Within this report, the term renewable heat refers to "modern" renewable heat technologies (see chapter 4), i.e. excluding the traditional use of biomass. 2015 is the latest year for which IEA heat data are available.

[5] Excluding the traditional use of biomass.

heat (up 44% to 3.2 EJ in 2015) and for geothermal (up 40%), although at 0.4 EJ its contribution remains low. **China** witnessed particularly rapid growth in renewable heat for buildings, primarily in solar thermal, which increased by over 200% during 2008-15. In 2015, renewables contributed over 9% of building heat consumption in China. By contrast in the **Russian Federation**, renewable heat only accounted for 3% of the country's substantial heat consumption in buildings. Over 2008-15, growth in renewable heat was slower in buildings (7%) than industry (32%) and the overall potential remains largely unexploited at a 2% share for renewable heat.

Figure 1.8. Total global energy consumption for heat (left) in 2015 and modern renewable heat consumption by source (right) 2009 and 2015



Note: The right-hand graph breaks down the 7% of modern renewables from the graph on the left by source.

Sources: IEA (2017e), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2017.*

References

IEA (International Energy Agency) (forthcoming), *World Energy Outlook 2017,* OECD/IEA, Paris.

IEA (2017a), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version, www.iea.org/etp/etpmodel/transport/.

IEA (2017b), *Monthly Oil Data Service (MODS)*, OECD/IEA, Paris.

IEA (2017c), *Oil Information* (database), OECD/IEA, Paris.

IEA (2017d), *Renewables Information 2017,* OECD/IEA, Paris.

IEA (2017e), *World Energy Statistics and Balances 2017*, OECD/IEA, Paris.

IEA (2016), *Medium-Term Renewable Energy Market Report 2016*, OECD/IEA, Paris.

US EIA (United States Energy Information Administration) (2017), *Petroleum and Other Liquids*, DOE, Washington, DC.

Platts (2017), *World Electric Power Database*, Platts, Washington, DC.

2. RENEWABLE ELECTRICITY FORECAST

Highlights

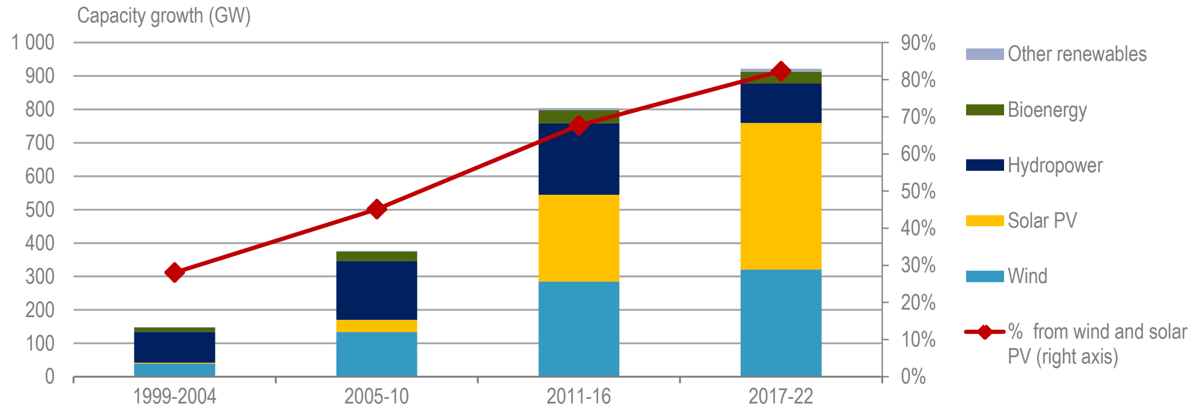
- In the main case forecast, renewable electricity capacity is expected to grow by 43%, or 922 gigawatts (GW), over 2017-22, driven by strong policy support and cost reductions primarily for solar photovoltaic (PV) and wind. Overall, this growth is 12% more optimistic versus last year's forecast, led by an improved solar PV forecast (up 36%) mainly in India and the People's Republic of China (hereafter, "China").
- Globally, renewable capacity growth is more dependent on solar PV and wind, which together represent 82% of new additions over 2017-22. Solar PV leads this growth with 438 GW, for the first time surpassing wind development, which is expected to expand by 321 GW. Hydropower is forecast to grow by 119 GW, 45% lower compared to the previous five years, due to a slowdown in project development in China, followed by bioenergy (35 GW), concentrating solar power (CSP) (5 GW) and geothermal (4 GW).
- Renewable electricity generation is anticipated to grow by 36% over the forecast period to reach 8 169 terawatt hours [TWh] in 2022, with its share of the global power mix increasing from 24% in 2016 to 29% in 2022. The increase in renewable generation over 2017-22 is twice the growth in coal and gas combined. In 2022, hydropower remains the largest renewable generation source, accounting for 56% (declining from 69% in 2016) followed by wind (22%), solar PV (11%) and bioenergy (9%).
- China remains the leader in renewables expansion, providing 39% (363 GW) of global capacity growth over 2017-22. With its booming market, China reaches its 2020 solar PV target set last year by the end of 2017. However, the policy transition from feed-in tariffs (FITs) to a quota system and grid integration challenges remain forecast uncertainties. The United States is the second-largest growth market globally, with 123 GW of new capacity expected over the forecast period, primarily from solar and wind. Despite current policy uncertainties, multi-year federal tax incentives with a clear phase-out schedule, strong state-level policies and further cost reduction potential remain strong drivers.
- India's renewable capacity more than doubles over the next five years, with 107 GW of new additions led by solar PV and wind. Policy improvements addressing the financial health of utilities and grid integration challenges drive a more optimistic forecast. For the first time, India's renewable capacity growth surpasses that of the European Union, where expansion is anticipated to be one-third lower (106 GW) than the previous five years as weaker demand and limited visibility on forthcoming auction capacity volumes remain important constraints. In Latin America, Brazil's forecast is revised down by over a third owing to financing challenges and weak demand growth. In sub-Saharan Africa (SSA) financing and grid integration challenges hamper the region's potential, while in the Middle East and North Africa (MENA) project delays and financing risks result in a less optimistic forecast.
- In the accelerated case forecast, renewable capacity growth is 27% higher than in the main case based on enhanced policies, market improvements and faster cost reductions. Growth would be 28% higher in China, 31% in India, 21% in the European Union and 17% in the United States. Cumulative capacity could be 22% in Africa and one-third in the Middle East.

Technology forecast summary

Renewable generation capacity is forecast to expand by 922 GW over 2017-22 in the *Renewables 2017* main case (Figure 2.1). This growth is expected to account for over 60% of global net additions to total electricity capacity over the forecast period. Overall, renewable expansion becomes increasingly dependent on wind and solar, as together they represent 82% of global growth in the next five years, considerably higher than historical levels (Figure 2.1).

Solar PV leads renewable capacity growth for the first time in the coming five years, with its expansion surpassing that of wind. *Renewables 2017* expects over 438 GW of solar PV to become operational over 2017-22, driven by continuous policy support and cost reductions. Overall, the size of the Chinese PV market dominates global additions, while PV growth in the United States and Japan is expected to slow, especially in the short term. Meanwhile India becomes the new growth market. Utility-scale projects represent the majority of solar PV additions, providing 59% of the growth, driven by a FIT scheme in China, federal tax incentives in the United States and auction schemes in India, while competitive tenders drive a more cost-effective PV growth in other parts of the world. Commercial projects are forecast to lead the growth in distributed solar PV capacity and represent 28% of global PV capacity expansion over the forecast period, followed by residential applications (12%). In addition, off-grid capacity is expected to grow by 3.5 GW (less than 1% of global PV capacity expansion by 2022) mostly in developing Asia and SSA, bringing basic electricity services to millions (see Box 2.1 below for detailed analysis).

Figure 2.1. Global net renewable capacity growth by technology, historical and forecast



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Wind capacity is expected to expand by 321 GW over 2017-22, of which offshore accounts for 26 GW, or 8%. **Onshore wind** capacity growth is higher versus the previous five years in every region except the European Union. China, the United States, the European Union and India together represent 84% of onshore wind capacity growth over the forecast period. Annual additions in global onshore wind range from 48 GW to 53 GW, with 2020 expected to see the highest annual growth in the forecast period. This trend is driven primarily by the production tax credit phase-out scheduled in the United States and slower growth in the European Union, especially after 2019. **Offshore wind** capacity additions are forecast to increase from over 14 GW in 2016 to over 41 GW in 2022, with the growth dominated primarily by the European Union, but picking up rapidly in China in the second half of the forecast period.

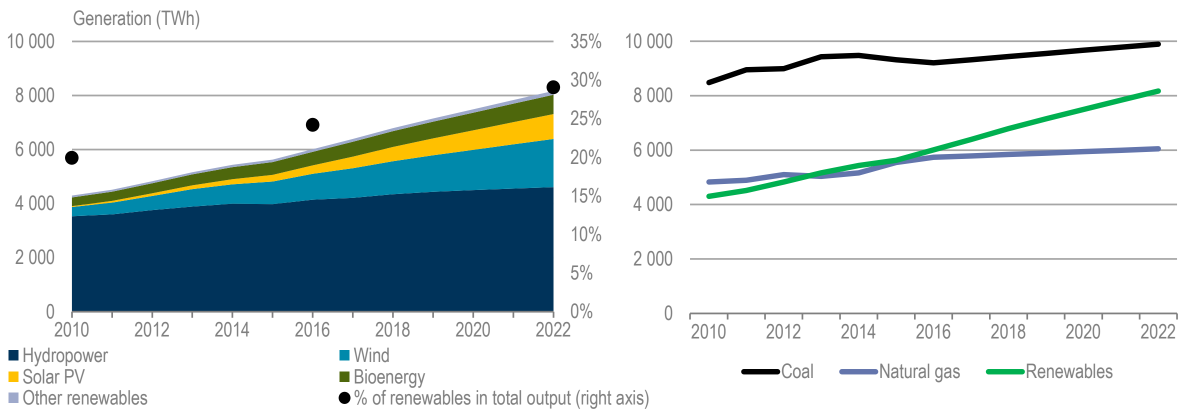
Hydropower capacity growth is seen slowing over 2017-22, with over 119 GW becoming operational over the forecast period, 45% lower than deployment over 2011-16. Pumped storage plants (PSP) account for one-fifth (25 GW) of the growth, mostly in China followed by Europe, although challenging economics limit their deployment and generation potential322. Overall, the hydropower forecast is revised down compared to last year's report due to lower expectations for growth over 2017-22 in China and Brazil. In China, the pipeline of large hydropower projects has decreased due to concerns over social and environmental impacts and overcapacity amid a relatively slower demand outlook, and grid integration challenges. The current macroeconomic environment in Brazil, coupled with a sluggish project pipeline due to lower demand, also challenge growth.

Bioenergy capacity is expected to increase by 35 GW over 2017-22. Stable growth, with annual additions in the range of 5-7 GW throughout the forecast period, indicates that while bioenergy plays a prominent role in the electricity generation portfolios of a select number of countries, it is not expanding strongly into new markets. Opportunities for accelerated growth are constrained by the absence of strong technology cost reductions. While Europe was the key source of bioenergy deployment historically, moving forward, Asian countries (notably China, India, Japan, Korea and Thailand) are expected to drive global capacity growth, accounting for nearly half of bioenergy additions over 2017-22. Despite these additions being relatively small compared to variable renewable technologies, bioenergy remains an important contributor to renewable electricity generation in 2022 thanks to higher achievable capacity factors versus onshore wind and solar PV.

Concentrating solar power (CSP) capacity is expected to grow by over 5 GW over 2017-22, with new deployment moving into nascent markets, most notably Chile, Kuwait, Morocco, South Africa and the United Arab Emirates, as well as continued growth in China. Projects with larger storage capacity and decreasing investment costs for experienced developers mark the trend for the coming five years. **Geothermal** capacity is expected to grow by almost 4 GW over 2017-22, a 10% upward revision in comparison to the previous forecast, with a more favourable outlook for Indonesia. Over the forecast period, growth in the geothermal market is expected to shift from Organisation for Economic Co-operation and Development (OECD) countries to emerging economies and developing countries, providing over two-thirds of the expansion, led by Indonesia, the Philippines and Kenya. Overall, pre-development risks remain an important barrier to achieving much faster deployment of the large untapped global potential. **Ocean** continues to account for the smallest portion of the renewable growth over 2017-22 (0.17 GW), with the majority coming from small-scale demonstration projects in the United Kingdom, France and Korea.

With this capacity growth, renewable electricity generation, including PSP, is estimated to increase by 36% from over 6 000 TWh in 2016 to almost 8 200 TWh in 2022. The share of renewables in electricity output is forecast to increase from over 24% to 29% over the forecast period. Coal is expected to remain the largest source of electricity generation in 2022 (almost 9 900 TWh or 35%), but renewables are anticipated to rapidly close the gap (17.5% by 2022) (Figure 2.2). In 2022, hydropower is forecast to provide 56% of renewable electricity generation, its share declining as its output grows by only 11% over the forecast period.

Figure 2.2. Global renewable electricity generation by technology (left) versus coal and gas generation (right)

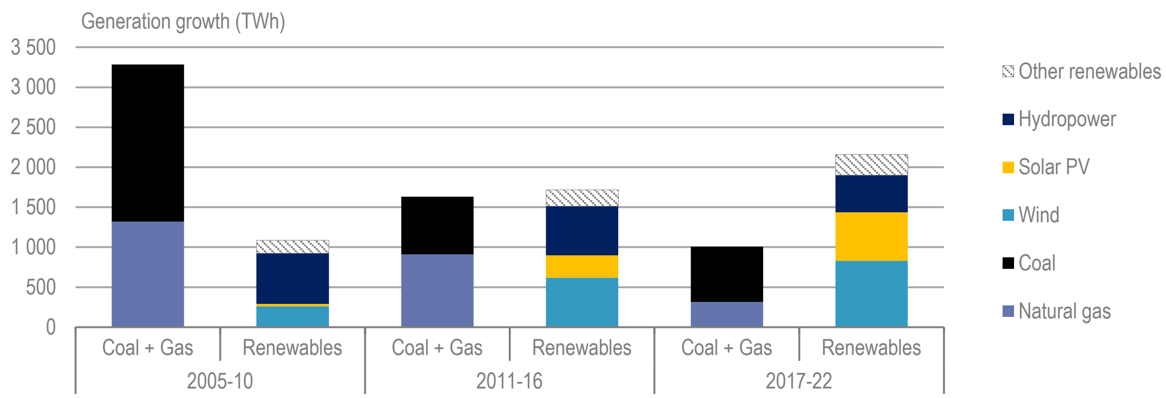


Note: Coal generation refers to that from primary products (anthracite, lignite, coking coal, sub-bituminous coal and other bituminous coal).

Source: Historical generation data based on IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

In 2022, hydropower is estimated to account for 16% of global electricity generation, followed by wind (6%), solar PV (3%) and bioenergy (2.5%). In 2020, solar PV electricity generation should surpass that of bioenergy, but with four times more installed capacity. Overall, the growth in renewables generation over the forecast period amounts to double that of coal and natural gas combined (Figure 2.3).

Figure 2.3. Global growth in net generation of renewable and fossil fuel electricity

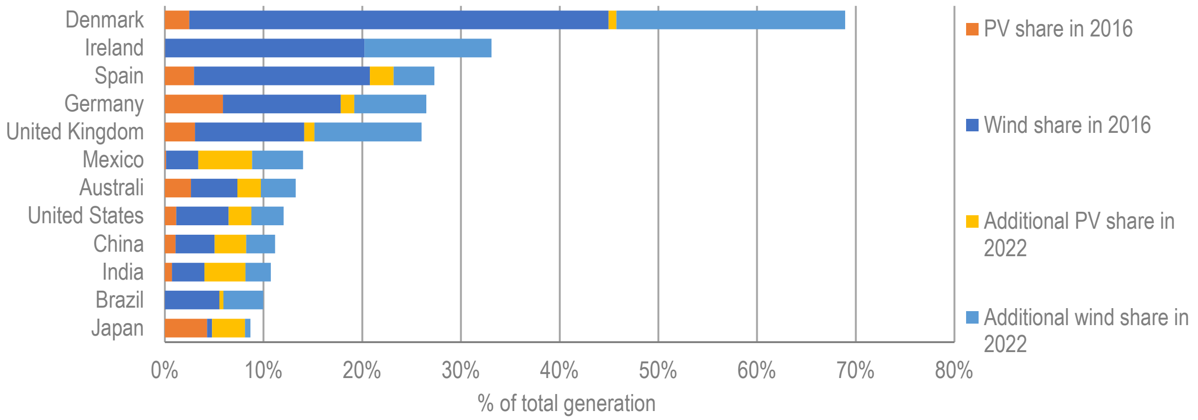


Note: Coal generation refers to that from primary products (anthracite, lignite, coking coal, sub-bituminous coal and other bituminous coal).

Source: Historical generation data based on IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

Over 2017-22, electricity output from wind grows by 86%, while solar PV generation triples. Variable technologies account for two-thirds of renewable generation growth over 2017-22, and their contribution to power systems in many developed countries and emerging economies is therefore expected to move rapidly from marginal to mainstream in just five years (Figure 2.4). In 2022, Denmark is expected to remain the country with the highest share of variable generation globally, with almost 70% of its total generation from variable sources, while in some European countries (Ireland, Germany and United Kingdom) the share of wind and solar in total generation should reach over 25% in 2022. In certain emerging economies (China, India and Brazil) the share of variable generation is anticipated to double to over 10% in just five years. Overall, system integration emerges as a key area of focus with an increasing need for flexible generation, better grids, storage and demand-side response in order to integrate larger shares of wind and solar in a secure and cost-effective way.

Figure 2.4. Variable renewable electricity generation in selected countries, 2016 and 2022



Source: 2016 generation data for OECD countries based on IEA (2017b), *World Energy Statistics and Balances 2017*, www.iea.org/statistics/.

Note: The shares represent variable renewable electricity generation as a percentage of total electricity output, not of total electricity consumption. In countries with high shares of variable generation, such as Denmark, generation and consumption differences may be large as a result of electricity trading.

Regional forecast summary

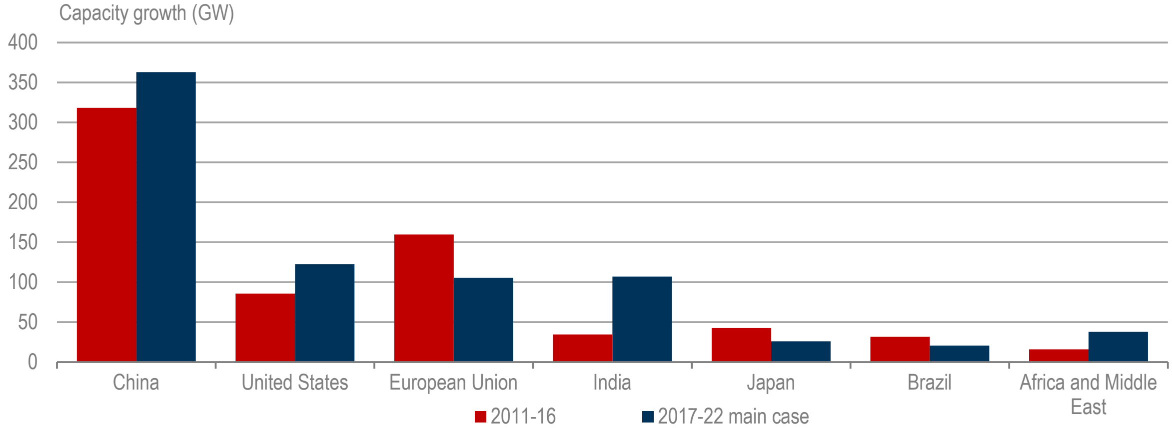
In the main case, cumulative renewable electricity capacity is forecast to expand by 43% from 2 134 GW in 2016 to 3 057 GW in 2022, driven by strong policy support across all *Renewables 2017* regions and by cost reductions, primarily for solar PV and wind technologies. Overall, the forecast is more optimistic than last year's report, with 12% more capacity growth expected over the next five years. This is mainly due to policy and market improvements in India and China leading to more optimistic forecasts for solar PV in both countries.

China's renewable capacity is expected to grow by over 363 GW through to 2022, equivalent to 39% of global capacity growth, driven by strong policy support and increasing air pollution concerns (Figure 2.5). The outlook is more optimistic than last year's forecast, mainly driven by the faster expansion of solar PV despite targets announced in the new 13th Five-Year Plan (FYP) being lower than expected by industry. Over the forecast period, China is expected to exceed all of its technology-specific capacity targets by 2020, except bioenergy and hydropower, as the latter sees its growth slow down with increasing social and environmental pressures affecting large-scale project development. FITs for solar PV, wind and bioenergy will continue to drive capacity growth over the forecast period with smaller contributions from CSP. However, the increasing cost of renewable subsidies and grid integration remain two important challenges to deployment. In order to address them, China is expected to move away from FITs to a quota system with green certificates. However, the exact details of this policy and its timing were unknown at the time of writing and it remains a forecast uncertainty.

In **Asia and Pacific**, excluding China, energy diversification needs, excellent resource availability and rising power demand are driving renewable energy growth, which is expected to expand by over 190 GW over the forecast period. India leads the growth in the region with 107 GW expected to become operational over 2017-22, driven by favourable targets, incentives for utility-scale solar PV and the introduction of the country's first-ever auction scheme for wind (Figure 2.4). While the revision of Japan's FIT scheme will slow solar PV deployment, the new auction scheme for utility-scale projects is anticipated to drive down costs and result in more cost-effective deployment. More ambitious targets in Korea to mitigate energy security and pollution concerns will drive faster renewable deployment over the forecast period, especially for solar PV. In Association of Southeast Asian Nations (ASEAN) countries, renewable capacity additions will slow compared to last year's forecast due to a number of stalled policies and incentives across the region, but capacity is expected to increase by nearly 18 GW thanks to higher deployment of utility-scale solar PV in Thailand and the Philippines, and continued hydropower development in Indonesia and Viet Nam.

In **North America,** the United States leads renewables expansion with the commissioning of 123 GW of additional capacity over the forecast period. The country also remains the second-largest renewables growth market globally. Drivers for onshore wind and solar remain strong, with federal tax incentives combined with renewable portfolio standards (RPSs) and additional policies targeting distributed solar PV at the state level. With record deployment in 2016 and faster-than-expected cost reductions, the solar PV outlook is more optimistic than last year's forecast. Proposed tax reforms and announced trade and energy policies could all change the economic attractiveness of renewables and hamper their growth. However, the details of these policies were unknown at the time of writing and are therefore not included in the *Renewables 2017* main case. Outside the United States, Mexico's forecast remains robust, driven by a green certificate scheme and energy auctions in which solar and wind projects have offered prices in the range of USD 30-50 per megawatt hour (MWh). Canada's forecast is less optimistic compared to last year's report due to recent changes in auctions schemes in Ontario and Quebec.

Figure 2.5. Net additions to renewable power capacity by selected countries and regions



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

In the **European Union**, renewable capacity is expected to grow by almost 106 GW over 2017-22, driven by continued cost reductions, mainly for solar PV and wind, and various policy support tools to reach longer-term climate goals. Overall the outlook for capacity growth remains relatively unchanged from our previous forecast as weaker demand, overcapacity, and limited visibility on forthcoming auction capacity volumes in some markets remain important constraints. Many European countries are switching from administratively set tariffs to competitive auctions with volume or budget controls, in order to comply with EU guidelines regarding state aid. As a result, annual deployment trends may be volatile during this near-term transition. Beyond 2020, the pace of growth in certain markets is uncertain due to a lack of visibility over auction schedules. However, if adopted, the proposed revision to the EU Renewable Energy Directive will address this challenge by requiring three-year visibility for support policies, thereby improving predictability. Further clarity should emerge by the end of 2017, when countries will submit draft ten-year action plans to meet voluntarily set 2030 targets. However, uncertainty remains over the governance of the wider EU 2030 target and how it will be reconciled with the contributions proposed by the member states.

In **Latin America**, with great resource availability, renewables (including hydropower) remain one of the cheapest options for adding new electricity capacity in many of the region's countries, especially where imported fossil fuels remain expensive. Brazil leads renewable capacity growth in the region, with 21 GW expected to become operational over 2017-22. However, the country's forecast is revised down for all renewable technologies due to current macroeconomic and financing challenges, which have led to slower growth in power demand and therefore to the cancellation of renewable auctions. Argentina emerges as a new growth market in the region over the forecast period, with the successful implementation of their new auction scheme, although financing may be challenging for some developers despite de-risking measures. In Chile, energy auctions remain the main driver for renewables growth, but grid integration challenges persist.

In **SSA,** cumulative renewable energy capacity expands by 71%, from 33 GW in 2016 to 58 GW in 2022, with large-scale hydropower projects providing almost half of the growth while wind and solar are both expected to scale up quickly. Deployment in the region will be driven by new capacity needs, coupled with supportive policies. However, the pace of deployment remains constrained versus the region's potential due to weak grid infrastructure, land acquisition issues and the limited availability of affordable financing. In **MENA,** wind, solar PV and CSP account for 83% of regional capacity growth over the forecast period, with hydropower providing the rest.

Table 2.1. Top five countries for renewable capacity growth by technology, 2017-22

Solar PV	GW	Onshore wind	GW	Hydro	GW	Bioenergy	GW
China	182.4	China	120.0	China	42.2	China	8.1
United States	72.6	United States	48.3	Brazil	10.1	India	2.6
India	61.5	India	32.9	India	9.9	Japan	2.6
Japan	20.5	Germany	16.4	Ethiopia	4.8	United Kingdom	2.4
Mexico	10.3	France	6.8	Turkey	3.4	Brazil	1.9
Offshore wind	**GW**	**Geothermal**	**GW**	**CSP**	**GW**	**Ocean**	**MW**
China	7.5	Indonesia	1.1	China	2.7	France	99
United Kingdom	6.1	Philippines	0.5	Morocco	0.5	United Kingdom	33
Germany	2.8	Kenya	0.4	South Africa	0.5	Korea	8
Netherlands	2.5	Turkey	0.4	Chile	0.4	Canada	6
Denmark	1.6	New Zealand	0.3	Israel[1]	0.3	China	5

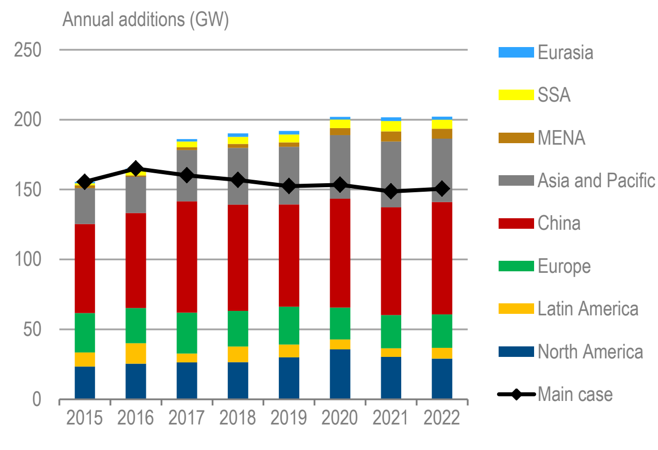
Note: GW = gigawatt; MW = megawatt. For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/renewables2017/data.

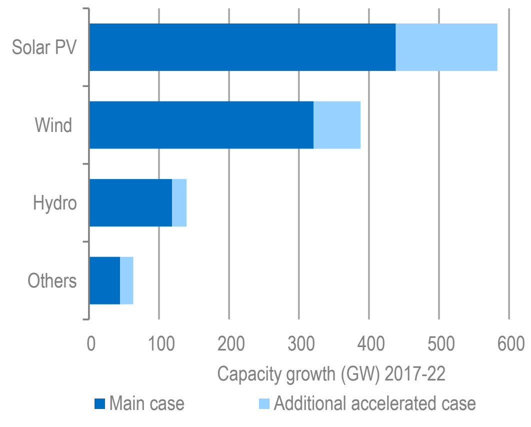
[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

In *Renewables 2017* accelerated case forecast, renewable capacity growth over 2017-22 could be 27% higher (252 GW) over the main case reaching 1 174 GW. Solar PV accounts for almost 60% of the accelerated case additional growth, followed by wind (27%) and hydropower (8%), with other technologies providing the rest (Figure 2.6). Under the *Renewables 2017* accelerated case, China's cumulative renewable capacity would be 11% higher, or 101 GW, versus the main case. This additional growth will depend on faster implementation of broader power sector reform, including a smooth transition from a FIT to a proposed quota obligation with green certificates. Improvements in grid integration of utility-scale wind and solar PV projects, and implementation of policies addressing financing and legal obstacles for distributed solar PV generation, are also needed to achieve a much higher growth rate. The faster commissioning of large-scale hydropower projects already under development is also included in China's accelerated case. India's additional growth depends on the pace of solar PV auctions and on their commissioning over the forecast period. Improvements in the financial health of state utilities under the UDAY scheme,[2] clarification of policies for distributed generation and resolution of grid integration challenges will also enable India's accelerated case.

In the **United States,** the accelerated case upside is limited by increasing policy uncertainty over the implementation of the Clean Power Plan. A rapid ramp-up of the project pipeline to qualify for federal tax incentives will be needed for both wind and solar PV to achieve faster deployment. For the **European Union**, deployment in markets driven by auctions is rather limited by the fixed volume caps, and acceleration would depend on additional auctions beyond 2020. Overall, more rapid deployment of renewables would also be enabled by improved regional interconnection to facilitate trade, and continual upgrades to transmission capacity to ease grid constraints.

Figure 2.6. Net additions to renewable power capacity under accelerated and main cases by region (left) and technology (right)





Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

[2] Ujwal DISCOM Assurance Yojana (UDAY) is the financial turnaround and revival package for electricity distribution companies of India (DISCOMs) initiated by the government of India.

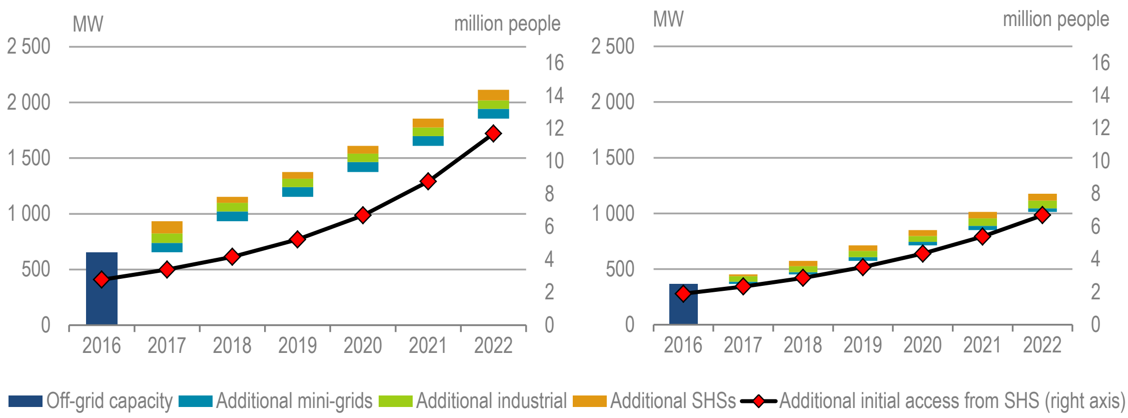
Box 2.1. Off-grid solar PV: an initial step to electrification in developing Asia and SSA

Around 1.2 billion people, or 16% of the world's population, were estimated to lack access to electricity in 2014, with Africa and Asia accounting for 97% of the unelectrified global population. SSA currently has the lowest electrification rate, with 65% of the region's population (over 630 million people) living outside of the electricity network. In India, 20% of the population (over 240 million) do not have access to electricity (IEA, 2016b). The rate of electrification is changing only marginally year-on-year as increasing birth rates outpace the increase in population benefitting from grid expansions.

Historically, electrification by grid has generally been the most cost-effective method of providing reliable electricity services. However, the distance between off-grid communities and the nearest point of the network is important, as beyond a certain range the costs of grid extension become prohibitive. The density of the off-grid population, paired with demographic trends, determine whether investment in the necessary infrastructure will be economically viable. Finally, the current state of the existing infrastructure and financial health of transmission companies responsible for expansion and maintenance of the grid remain key determinants as to if and when a community will be connected and receive a reliable service (IEA, 2014). With significant cost reductions, along with private sector and government initiatives, off-grid solar PV is slowly bridging the electrification gap in Asia and SSA. **Mini-grids, industrial/commercial applications** or **solar home systems (SHSs)** can provide an immediate solution for initial or improved access to electricity for households, small businesses and industrial users.

In 2016, an estimated almost 1 100 MW of cumulative off-grid PV capacity was in operation in developing Asia and SSA, which represents around 6% of total PV capacity installed in both regions. Over 2017-22, total off-grid solar PV capacity is expected to more than triple in these regions, reaching a combined 3 350 MW (Figure 2.7). *Renewables 2017* estimates that industrial applications represent over 36% of this growth, followed by SHSs larger than 8 watts (W) (33%) and mini-grids (31%).

Figure 2.7. Off-grid PV capacity additions and additional initial access per year from SHSs in Asia (left) and SSA (right), 2016-22

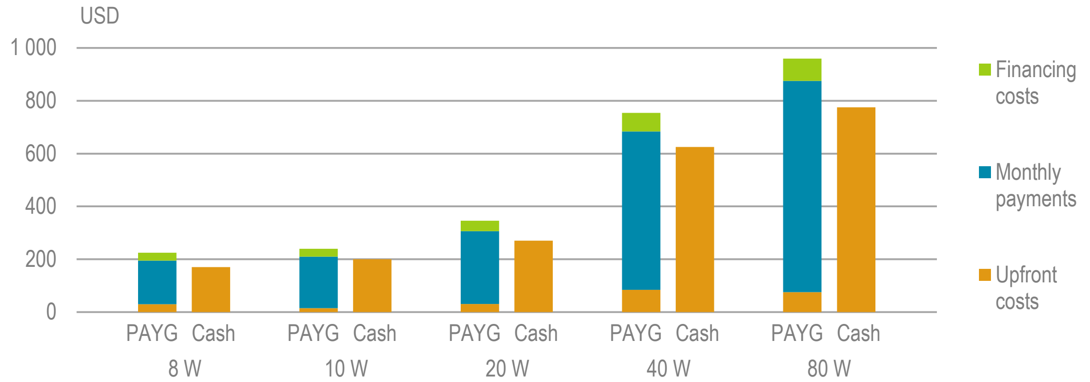


Source and note: Historical analysis concluded by IEA based on GOGLA (2017), *Global Off-Grid Solar Market Sales Dataset for the IEA*; forecast IEA analysis.

SHSs, which comprise solar PV units combined with a battery, usually in the range of 8 W to 100 W, are expected to expand by estimated 750 MW over 2017-22. Although this growth remains less than 0.2% of global solar PV capacity growth, its impact on providing initial access to electricity and basic electricity services to millions is significant. *Renewables 2017* estimates that SHS will bring basic electricity services to over 65 million additional people in developing Asia and SSA over the forecast period, mainly driven by government programmes and private-sector involvement. Overall, reductions in the cost of solar PV, batteries and energy-efficient appliances are an important enabler of this expansion. In Asia, India and Bangladesh will lead the uptake with strong government targets combined with supportive electrification programmes through SHSs. India has an ambitious goal to electrify all its population by 2022. Bangladesh aims to reach a full electrification rate by 2021 with SHS providing basic electricity services in remote rural areas, supported by soft loans and rebate programmes.

In SSA, on the other hand, private-sector initiatives have taken the lead and are starting to bridge the electricity access gap via new business models, especially in Ethiopia, Kenya, Tanzania and Nigeria. Despite relatively high initial system costs, which range from below USD 100 to USD 1 000 depending on the unit size, coupled with low average income levels in these countries, most of the SHS units bought in 2016 were purchased with cash (Hystra, 2017). However, in order to lower the barrier of high initial SHS costs and unlock a larger pool of customers, companies offer SHS with pay-as-you go (PAYG) plans. In a PAYG system, the customer obtains the SHS unit upon payment of the subscription fee and a commitment to one- to three-year payment instalments. The level of the subscription fee usually ranges from 10% to 15% of the cost of the system. In this business model, companies not only provide the product, but also an entire range of services that take the investment risk away from the client. In order to recover costs associated with the services provided, the total price the client pays for the unit purchased via a PAYG system is usually 15% to 30% higher than those bought by cash (Figure 2.8). It is estimated that PAYG users reached over 1 million in Africa and Asia at the end of 2016.

Figure 2.8. Breakdown of SHS prices for units purchased with PAYG vs. cash, split by size and provider



It is expected that PAYG sales will increase over the forecast period as they facilitate the purchase of SHS units. Additionally, companies aim to upgrade the size of the system and services provided to clients who demonstrate regular on-time payments for prolonged periods of time. Nevertheless, the scaling up of PAYG sales will depend on how much finance these companies are able to raise to support their expansion and local operations, including customer acquisition, training and system maintenance. In respect of government policies, predictable, long-term tax discounts and waivers on imported SHSs and components remain important drivers to keep these services affordable.

For industrial applications, off-grid solar PV growth is estimated at 830 MW over 2017-22. India leads this growth with the transformation of telecom towers to operate on battery-solar hybrid technology, especially those in remote areas. Mining companies in Africa also contribute to the growth of industrial off-grid PV applications, especially in South Africa, Namibia and Botswana. Diesel generators usually provide electricity to off-grid mines in Africa, while solar PV offers an attractive alternative by decreasing costs associated with diesel fuel, which is usually expensive and subject to supply disruptions. With recent cost reductions, solar PV generation costs can be around 50% lower than diesel generation.

Consequently, the combination of diesel and solar PV systems has become popular, particularly in the mining industry where cost savings can range from 5% to 15%.

Mini-grid applications using solar PV are also expected to add a further 710 MW of capacity over 2017-22. Mini-grids are predominantly deployed for commercial applications, such as local businesses, or government institutions, such as schools or health care centres, located in remote areas where arrival of the grid is not expected. Diesel generators currently provide electricity to these communities. Similar to industrial applications, hybrid systems combining diesel, solar PV and batteries could provide savings on diesel costs.

Regulatory, administrative and financing challenges remain important barriers to mini-grid deployment, particularly in SSA. In general, uncertainty over the permitting structure and access to electricity distribution licenses for private companies present obstacles to expansion. In addition, investment risks remain high, as companies lack long-term visibility over the remuneration of their assets and uncertainty remains whether mini-grid applications will be stranded by the eventual arrival of the grid. However, governments are beginning to recognise the important role of mini-grids in electrification, as the first regulatory measures emerge to address some of these challenges. In 2015, Kenya's Regulatory Commission granted a utility concession to Power Hive, a private company, to generate, distribute and sell electricity from its mini-grids. In 2016, Nigeria adopted the mini-grid regulation exempting small systems (<100 kilowatts [kW]) from a requirement to obtain a permit and allowing for larger systems to be bought out in case of grid arrival, thus shielding investors from a possible loss of their asset value. In the same year, Uttar Pradesh (India) adopted a mini-grid policy offering developers the option of operating in two different business models. In the first, the developer receives a 30% capital grant for project construction in exchange for a distribution company selecting the location of the project, customer tariff and technical specifications of the mini-grid. In the second model, the developer is free to choose the location of the project along with other project specifications, but is not entitled to the capital grant support (IEA/IRENA, 2017). The impact of these policies on the accelerated deployment of mini-grids remains to be seen.

China

Main case forecast

China's total renewable electricity capacity is forecast to grow by 64% or 363 GW over 2017-22, driven by strong government targets, robust economic incentives and increasing local air pollution concerns. Overall, the forecast is more optimistic than last year, mainly due to stronger solar PV expansion as a result of higher-than-expected recent deployment trends and faster cost reductions. China remains by far the world's largest renewable market, and represents 39% of global renewable capacity growth over the forecast period. The forecast is led by solar PV (182 GW) and wind (128 GW), followed by hydropower (42 GW), while bioenergy (8 GW) and CSP (3 GW) are also expected to contribute. Overall, renewable electricity generation is anticipated to grow by over 40%, representing 30% of the electricity mix in 2022, 4 percentage points higher than in 2016. Meanwhile, the share of wind and solar in power output is forecast to reach 11% in 2022. Overall, two important challenges and uncertainties mark China's forecast for the coming five years: first, a changing renewable policy environment to achieve a more cost-effective deployment; and second, tackling grid integration challenges.

New renewable energy targets under China's 13th FYP reflect concerns over the rapid pace of renewable expansion amid power sector challenges. In January 2017, China announced targets for its energy development over 2016-20, which included new capacity targets for renewables to 2020

(Table 2.2). Official wind and solar PV targets were lower than industry based on earlier drafts (250 GW for wind and 150 GW for solar PV). However, these targets are indicative and reflect current challenges concerning electricity demand growth, curtailment and the increasing cost of renewable subsidies. Overall, *Renewables 2017* forecasts that China will comfortably exceed its wind and solar targets by 2020, considering current deployment and cost trends (Table 2.2).

Table 2.2. China renewable energy targets and achievements under 12th FYP, 13th FYP targets and *Renewables 2017* main case forecast for 2020

GW	12th FYP 2011-15, targets for 2015	2015 achievements	13th FYP 2016-20 targets for 2020	*Renewables 2017* forecast for 2020
Hydropower	290 GW	320 GW	380 GW (including 40 GW PSP)	362 GW (including 40 GW PSP)
Onshore wind	100 GW	128 GW	205 GW	224 GW
Offshore wind	5 GW	1 GW	5 GW	6 GW
Solar PV	34 GW	43 GW	105 GW	206 GW
CSP	1 GW	0.02 GW	5 GW	2 GW
Bioenergy	13 GW	10.3 GW	23 GW	18 GW
Geothermal	0.1 GW	0.03 GW	N/A	N/A

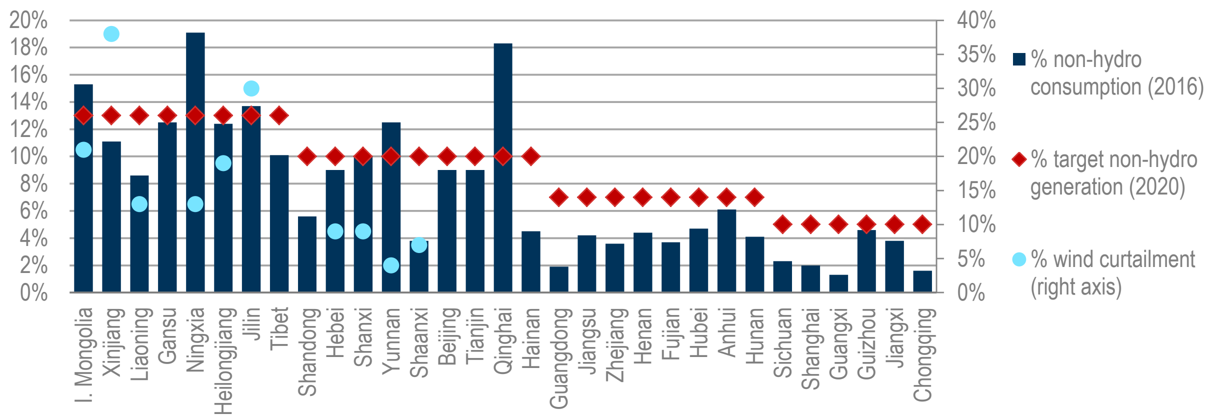
Note: N/A = not applicable.

Electricity generation in China grew by 3.7% in 2016, lower than the average annual growth of above 8% over the last decade. China's electricity demand is expected to grow by around 3.3% annually over 2017-22, reflecting the country's plans to shift economic growth away from energy-intensive industries. Despite relatively slower demand growth, China's pipeline for new nuclear, coal, natural gas and renewable plants remains large, increasing the overcapacity in the power market. This could affect future revenues of existing and new thermal assets, as they may run fewer hours than previously planned. For renewables, slower power demand growth and the overcapacity situation, combined with the limited flexibility of the current coal fleet, contribute to increasing system integration challenges. China's nationwide average curtailment of wind generation increased from 15% in 2015 to 17% to 2016, with a slight decline in the first half of 2017. However, the government is currently pushing for the early retirement of inefficient coal capacity and banning new plants located in provinces with high pollution levels, in addition to efforts to make existing coal plants more flexible, especially in Northern China. Furthermore, factors anticipated to improve curtailment rates include the shifting of renewables deployment to demand centres, the commissioning of additional transmission capacity, and implementation of electricity market reforms that could provide better price signals to power generators.

China's growing concern over the increases in renewable energy subsidies and curtailment are the most important drivers for its transition to a new renewable incentive scheme (Table 2.3). Over 2009-16, the renewable surcharge almost quadrupled as China installed more than 200 GW of solar and wind capacity in the same period, supported mostly by FITs. Since 2015, China has cut its FIT for onshore wind by 8-16% (from USD 75-92 to USD 65-86/MWh) and for solar by 15-28% (from USD 135-150/MWh to USD 98-128/MWh) depending on the resource potential of different provinces. However, the government plans to move away from FITs to provincial renewable quotas with tradable renewable energy certificates (RECs). Overall, the goal of this policy transition is to shift the financial burden of renewable subsidies from consumers to large polluters. For electricity, the non-hydro renewable energy consumption quota is set at 9% in 2020 (from 4.5% in 2015), with provincial targets ranging 5-13% depending on current power consumption levels and the status of renewable generation (Figure 2.9). In July 2017, China launched voluntary trading in RECs, the government issuing almost 5 million RECs, which represent less than 0.2% of total wind and solar generation. Renewable developers sold RECs mostly to government entities, but also to some local and foreign companies. Initial results show that REC prices were very close to maximum capped prices, which is the difference between government-set grid price and FIT. It is expected that the REC market will become mandatory for polluters in 2018/19.

As of 2016, six provinces (Inner Mongolia, Ningxia, Jilin, Yunnan, Qinghai and Shanxi) have already surpassed their 2020 targets (Figure 2.9). All of these except Qinghai had wind curtailment levels ranging from 6% to 38% in 2016. In addition, the majority of other provinces with high curtailment rates were very close to reaching their 2020 targets (Figure 2.9). The new regulation restricting renewable project development in provinces with high curtailment levels should encourage renewable deployment in major demand centres such as Guangdong, Shangdong, Jiangsu and Zhejiang where there is no, or very low, curtailment. However, uncertainty over the policy transition from FITs to a REC system remains. This report expects that FITs will continue to support deployment in the short term, while the policy transition is anticipated to take place sometime between 2018 and 2020. Overall, this policy transition remains challenging for developers and increases forecast uncertainty, particularly for solar PV and onshore wind, and especially after 2018.

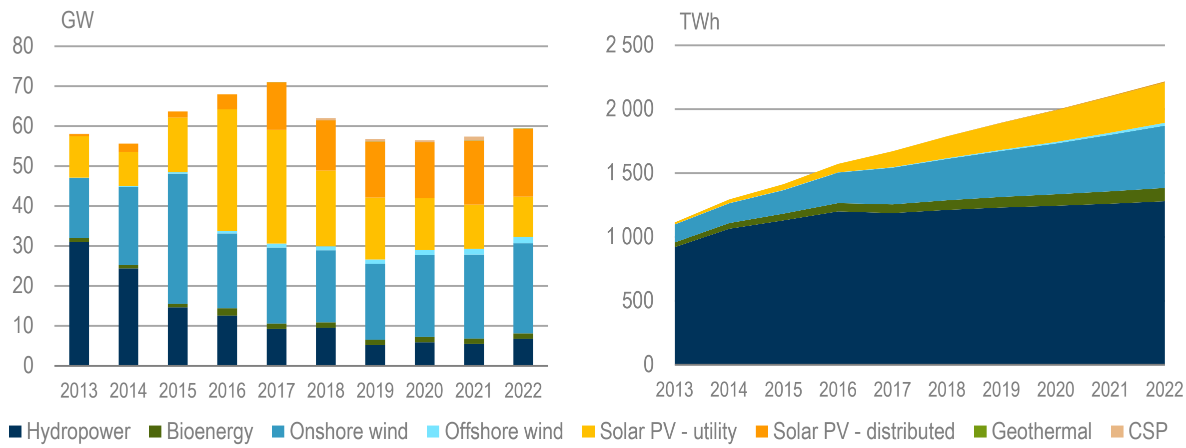
Figure 2.9. China renewable electricity consumption in 2016, targets for 2020 and percentage wind curtailment in 2016



Sources: NEA (2016), *Renewable Consumption Targets and Guidance*. NEA (2017), *Bulletin of Monitoring and Evaluation of National Renewable Energy Power Development*.

Solar PV growth is forecast to surpass that of onshore wind, with over 182 GW becoming operational over 2017-22 (Figure 2.10). Overall, utility-scale projects will continue to lead PV expansion, representing 53% of all new PV additions over the forecast period. However, further FIT reductions, policy transition to a REC system and curtailment challenges remain as forecast uncertainties for the annual deployment trend, especially for utility-scale projects after 2017, as these changes may all affect the bankability of projects. In 2016, China's annual solar PV market more than doubled to over 34 GW compared to 2015, with utility-scale projects providing 90% of this growth as developers rushed to commission their projects before the planned FIT reduction. A similar rush is expected in 2017, as FIT rates were reduced again as of July 2017. In addition, provincial solar PV auctions were introduced, which should support more cost-effective deployment in the near future. In 2016, the first solar PV tender awarded 1 GW of large-scale PV capacity, with some developers offering bids 20-40% lower (USD 75-85/MWh) than current FIT levels, although the majority of bids were very close to provincial FITs. This report anticipates that the administration will continue to support larger competitive tenders for utility-scale projects, preferably closer to demand centres, in order to reduce subsidies and curtailment.

Figure 2.10. China renewable capacity annual additions (left) and generation (right), 2013-22



Source: Historical generation data from IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

Distributed PV capacity is anticipated to increase its share of overall solar PV deployment, accounting for over half of all solar PV expansion over the forecast period. To date, the deployment of distributed solar PV has been slow due to relatively low retail prices in the residential sector and policy uncertainties over self-consumption and third-party ownership in the commercial sector. For the commercial and industrial PV segments, regulatory uncertainties over self-consumption rules and financing remain important barriers as a result of legal challenges concerning the ownership and creditworthiness of developers. However, on the basis of increasing curtailment rates in Northern and Western China, the government is likely to continue supporting distributed generation that shifts generation to demand centres in Eastern provinces. Consequently, *Renewables 2017* expects that the share of distributed solar PV in annual installations will increase over the forecast period, driven by further cost reductions but also supported by electricity market reforms increasing retail competition.

Onshore wind growth is expected to be stable with annual installations in the range of 18-23 GW over 2017-22, lower than the record level additions in 2015. China's annual onshore wind additions declined by over 40% from 32.6 GW in 2015 to 18.7 GW in 2016 as developers rushed to complete their projects to take advantage of higher FIT rates, which were reduced at the end of 2015. This rush contributed to an increase in curtailment rates, as two-thirds of new additions were located in Northern and Western provinces with already high curtailment levels. In February 2017, NEA released a warning mechanism to prevent deployment in provinces where curtailment rates are highest, including Jilin, Ningxia, Gansu, Xinjiand, Inner Mongolia and Heilongjiang. Over the forecast period, new wind deployment is likely to be located mostly in medium to low wind speed sites closer to demand centres in Eastern and Central China, while the commissioning of transmission lines will dictate new development in Northern provinces, which is expected during the second half of the forecast period. **Offshore wind** is anticipated to contribute smaller additions (7.5 GW) as it remains a relatively nascent market in China. However, the forecast is revised upwards compared to last year based on recent cost reduction and deployment trends.

Table 2.3. China main drivers for and challenges to renewable energy deployment

Drivers	Challenges
Strong government policy backing for power sector reforms and growing concern over air pollution	Increasing cost of renewable subsidies and uncertainties over the renewable policy transition
Long-term renewable targets backed by FITs and provincial renewable auctions	Administrative barriers and financing challenges to the deployment of distributed PV
Ample availability of low-cost financing	Grid integration and upgrades on both the transmission and distribution infrastructure

Hydropower capacity is forecast to expand by 42.2 GW, driven mostly by the commissioning of large-scale conventional and PSP facilities that are currently under construction. PSP plants account for over 35% of this expansion. Overall, the forecast is revised down compared to the previous edition as concerns over social and environmental impacts, increasing costs and grid integration challenges have created a smaller pipeline of multi-gigawatt conventional projects under construction. The completion date of the 16 GW Baihetan project remains a forecast uncertainty as *Renewables 2017* expects that it will partially come online by 2022.

The remaining renewable capacity growth in China is expected predominantly to come from bioenergy and CSP. For **bioenergy**, a steady continuation of current deployment trends is anticipated, with annual additions in the region of 1.4 GW per year. As a result, cumulative capacity is expected to make progress against the 13th FYP target for 2020 of 23 GW. Bioenergy deployment is principally from agricultural residue (mainly straw) and energy from waste (EfW) fuels, which both benefit from unified national FIT support. Looking ahead, EfW is anticipated to become the key contributor.

Accelerated case forecast

With current uncertainties associated with the policy transition from FITs to the proposed quota system with tradable RECs, China's accelerated case remains difficult to estimate since the details of the new policy were mostly unknown at the time of writing. However, considering the size of China's renewables market and recent deployment trends, the upside potential remains high and growth in the accelerated case over the forecast period could be 28% higher than in the main case (Table 2.4). Overall, clarification of the new REC scheme, faster implementation of electricity market reforms and additional measures to tackle grid integration challenges are considered three main policy improvement areas for more rapid uptake of renewables in China.

Solar PV holds the largest upside potential, with possible additional growth of 60 GW by 2022 versus the main case, and could reach 320 GW by 2022. The accelerated deployment of utility-scale projects would mostly depend on the smooth implementation of the new REC system facilitating deployment closer to demand centres. For distributed generation, the accelerated case assumes policy improvements to address legal, administrative and financing challenges, especially for industrial applications. Wind capacity could be 25 GW higher in 2022, with an accelerated commissioning of transmission lines (both for onshore and offshore projects), which would facilitate new development and reduce curtailment. For hydropower, capacity growth could be 11 GW higher, with the faster commissioning of large-scale conventional (16 GW Baihetan project) and PSP projects.

Table 2.4. China renewable electricity capacity projection (GW), main and accelerated case

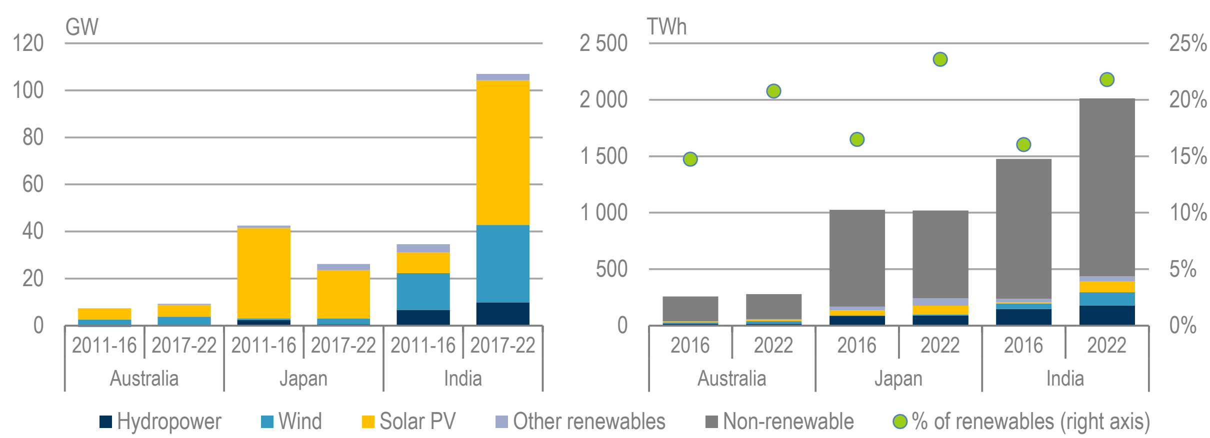
Total capacity (GW)	2016	2017	2018	2019	2020	2021	2022	2022 Accelerated
Hydropower	332.1	341.4	350.9	356.1	362.0	367.5	374.3	385.0
Bioenergy	12.1	13.5	14.8	16.2	17.5	18.9	20.2	25.9
Wind	148.6	168.6	187.6	207.7	229.4	251.9	276.1	300.9
Onshore	147.0	166.0	184.0	203.0	223.5	244.5	267.0	289.0
Offshore	1.6	2.6	3.6	4.7	5.9	7.4	9.1	11.9
Solar PV	77.4	117.7	149.2	178.8	205.8	232.8	259.8	319.5
CSP	0.0	0.0	0.6	1.2	1.7	2.7	2.7	2.8
Geothermal	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**570.4**	**641.3**	**703.3**	**760.1**	**816.5**	**873.9**	**933.3**	**1034.3**

Notes: Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "–".

Asia and Pacific

In Asia and Pacific, excluding China, renewable power generation is expected to expand by 60%, or just over 448 TWh, over 2017-22 in the main case. This is driven by energy diversification needs, excellent resource availability and rising power demand, especially in ASEAN countries. Supportive policy frameworks in Japan and Korea and new policies in India should boost deployment of renewables. Solar PV (105 GW) is expected to lead capacity growth in Asia and Pacific over the forecast period, with generation more than tripling, followed by onshore wind (43 GW) with its output doubling (Figure 2.11).

Figure 2.11. Asia and Pacific renewable electricity capacity growth, 2010-22 (left) and generation by source, 2016 and 2022 (right)



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017.* Historical generation data from IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

Hydropower annual additions are expected to slow, with nearly 27 GW becoming operational over 2017-22, driven by ASEAN countries and India's focus on small hydropower. Bioenergy capacity is forecast to expand by almost 11 GW, with growth spread throughout the region. Overall, India and Japan remain the main drivers of renewable capacity growth, representing 70% of the region's expansion. India alone accounts for over half (56%) of total renewable additions over 2017-22, followed by Japan (14%), ASEAN countries (9%), Korea and Australia (6% and 5% respectively).

India: main case forecast

Renewable capacity in India is forecast to expand by 107 GW over 2017-22, led by solar PV and onshore wind. This expansion is driven by a robust and supportive policy environment at both the national and state level, supported by ambitious targets and competitive auction schemes. In light of this growth, the share of renewables in India's electricity mix is expected to increase from 16% in 2016 to nearly 22% in 2022. The forecast is revised up by over 31 GW compared to last year as a result of policy improvements for both wind and solar PV. The introduction of wind auctions, which are anticipated to drive down costs, and an increase in the solar park target from 20 GW to 40 GW by 2022, are both expected to partially address challenges concerning land acquisition and grid integration. In addition, the country's objective of restoring the financial health of distribution companies (DISCOMs) is seeing success in improving their financial capacity to make timely payments to power generators.

India is putting into place the right policies to address the financial concerns in the transmission and distribution sector, as well as improve investors' confidence in the renewable energy market. In May 2017, the country launched its first Green Energy Corridor project in an effort to expand the transmission network across the country (Dutta, 2017). Another 56 interstate power transmission projects are already approved to better support the increasing challenge of integrating variable renewables. Stronger efforts to provide financial (and operational) support to distribution utilities through the country's UDAY scheme, established November 2015, are enabling some states to lower the gap between their costs and revenues, partly due to improvements in reducing technical and commercial losses for DISCOMs (Figure 2.12).[3] A total of 27 states and union territories had signed up to the UDAY scheme as of May 2017, and it is estimated that bonds equivalent to 86% of the total outstanding debt were issued as of July 2017 (Ministry of Power, 2017).

In order to mirror this progress, further efforts to improve off-take risk and provide more confidence in the country's renewable energy sector are also being implemented. In early 2017, the Solar Energy Corporation of India (SECI)[4] was included as a beneficiary in an agreement[5] between the government of India, state governments and the Reserve Bank of India in an effort to deter payment default by state government undertakings and boost its financial credibility. NTPC Limited,[6] which consistently brings in solar tariffs lower than those of SECI, has benefitted from this payment security agreement since 2002 (Bridge to India, 2017a). Similar efforts are also under way in the wind sector in parallel with the introduction of competitive auctions.

[3] States such as Andhra Pradesh, which is targeted to install a significant increase in solar PV capacity by 2022, already achieved a reduction in aggregate technical and commercial (AT&C) losses for two of their distribution companies.

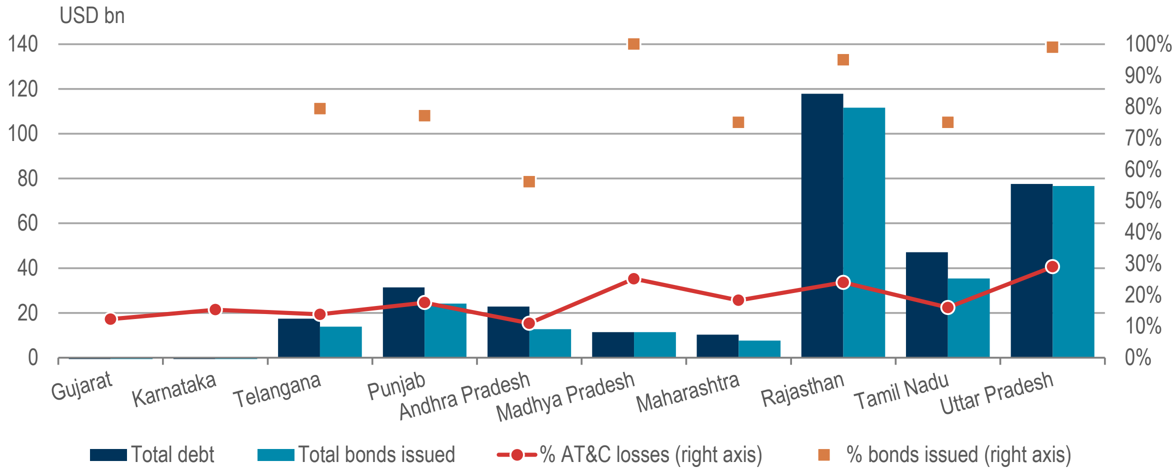
[4] SECI is the largest financial off-taker of solar power in India.

[5] The tripartite agreement serves as a payment security mechanism for central government undertakings whereby, in the event of a payment default by any state government undertakings including DISCOMs, they can withhold funds from the centre's financial assistance to the states.

[6] NTPC Limited, formerly the National Thermal Power Corporation, changed names in 2005 to reflect the diversification of their business operations beyond thermal power generation to include other types of generation, including renewable energy.

Solar PV is forecast to provide close to 60% of renewable capacity additions, with 62 GW expected to become operational over 2017-22 (Figure 2.13). By 2021, cumulative solar PV capacity is expected to surpass that of wind and should account for half of India's total non-hydro renewable capacity, a significant jump from only 20% in 2016. Despite an easing of new tender announcements starting in mid-2016, developers are rushing to scale up investments. Over the forecast period, over 80% of new additions are expected to come from the roll-out of utility-scale solar projects, most notably in large solar parks, which are now supported by an increased government target of 20 GW to 40 GW by 2022. A continued reduction in module prices and a downward trend in domestic interest rates are providing the impetus for solar market growth, as tenders continue to witness record low bids – the lowest to date seen in the Kadapa tender in Andhra Pradesh at USD 38/MW, although SECI cancelled a large amount of these tenders as it seeks to renegotiate with states for lower tariffs.

Figure 2.12. Current state-level status of India's UDAY scheme



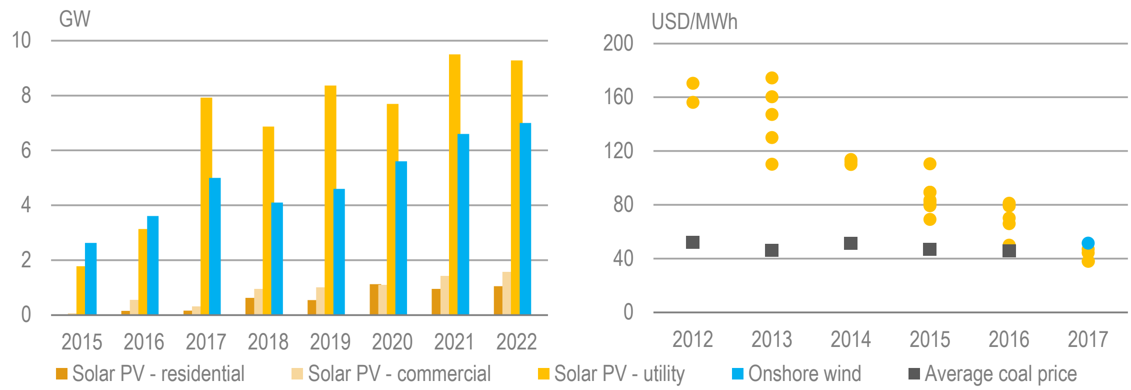
Source: Ministry of Power (2017), *UDAY National Dashboard*, www.uday.gov.in/home.php.

Note: Total debt, bonds issued and AT&C losses reflect the current state of India's distribution companies under the UDAY scheme as of 22 June 2017; Gujarat and Karnataka do not require debt takeover as they signed a memorandum of understanding for operational parameters only (as opposed to operational and financial parameters) and are therefore not included.

India's distributed solar PV capacity is forecast to expand almost elevenfold, or 11 GW, over 2017-22 (Figure 2.13). Commercial and residential capacity passed the 1 GW mark in September 2016, while the government continues to target an ambitious 40 GW by 2022, although discussion is under way on reconsidering the target. Historically, India's focus was almost solely on commercial and industrial installations, which benefitted from the accelerated depreciation (AD) scheme. Now, with states such as Tamil Nadu currently leading in rooftop installations (Bridge to India, 2017a), several other states have already implemented net metering schemes along with capital subsidies (30% from the government) to support residential applications. However, despite a majority of states adopting supportive net metering policies, the combined lack of clarity in implementation, trained utility staff to implement these policies and guidelines for spurring consumer awareness remain important barriers to deployment. In a new effort to encourage off-take, India's Ministry of New and Renewable Energy (MNRE) envisaged financial support for DISCOMs, but is also imposing a long list of mandatory and restrictive financing conditions which some states are not able to meet. In addition, the central government introduced solar rooftop auctions to help drive further deployment on government buildings, although these were delayed and capacity reduced from 1 GW to 0.5 GW.

Off-grid solar PV in India is forecast to grow by over 1 GW over the forecast period to reach 1.4 GW by 2022, after achieving an estimated 405 MW in 2016, the largest in the world. Industrial installations, such as micro-/mini-grid and telecom base transreceiver systems, are growing thanks to companies such as Airtel, which transitioned over 40 000 telecom towers by early 2016 to operate on battery-solar hybrid technology (Airtel, 2016). Likewise, small systems such as solar lanterns and street lights are increasingly becoming the first step on the energy ladder for off-grid communities, as 20% of the population still lacks access to electricity (IEA, 2016b). Over the forecast period, the government's electrification programme is expected to continue supporting mini-grid and small SHSs, while off-grid solar is witnessing increased support under Phase II of the Jawaharlal Nehru National Solar Mission in an effort to reach the government's target of "24 x 7" power for all by 2022.

Figure 2.13. India solar PV and onshore wind annual net capacity additions (left), announced solar and wind auction prices versus average coal tariffs (right)



Note: Coal tariffs and solar PV and wind tariffs are not fully comparable as they are not based on long-term contracts with the same off-taker.

Onshore wind is forecast to expand by nearly 33 GW over 2017-22. The forecast is more optimistic compared to last year, driven by the introduction of new auctions in an effort to mirror the success of solar PV. India added 3.6 GW of wind capacity in the first three months of 2017, the same amount installed in all of 2016, due to a developers' rush before the government reduced the 80% AD incentive to 40%. The MNRE set a goal to auction a total of 10 GW of wind power by 2019 through reverse bidding. The country's first wind tender took place in February 2017 and was significantly oversubscribed, with projects awarded (1 GW) at bids as low as USD 50/MWh. The auctioning of wind projects brings a unique set of rules that can help incentivise the increased procurement of wind power and upend the traditional business model based on national tax incentives. Under the MNRE's guidelines, payment security for project developers is prioritised to ensure timely utility payments to generators, while some project developers are also eligible to receive compensation if they are unable to feed into the grid due to inadequate transmission capacity or curtailment. Under the auction scheme, the onus of buying power from developers and signing power purchase agreements (PPAs) with distribution companies will lie with PTC India Limited, India's largest electric services company, instead of developers having to reach agreement with distribution companies. This is anticipated to reduce project revenue risks.

Despite these policy improvements, a number of challenges remain for wind developers. India's switch to a reverse bidding scheme for wind means the phase-out of state-level FITs. A number of developers with FIT contracts under the old system are now being requested by utilities to retroactively match the lower auction prices. This could leave a number of projects stranded, although MNRE draft auction guidelines enable projects under construction to bid for new PPAs. Furthermore, despite some improvements, grid integration is expected to remain an important challenge for wind developers, especially in states with a large project pipeline still to be installed. In Tamil Nadu, where roughly 70% of the capacity from the first 1 GW wind auction is expected to be built, the curtailment rate for wind power was estimated at between 33% and 50% in 2016 (CERC, 2016a; CERC 2016b). Delays in payments by state-owned distribution companies, namely in Rajasthan and Tamil Nadu, also continue to pose a challenge to wind developers.

Hydropower is expected to grow by almost 10 GW over 2017-22, with a contribution from small hydropower,[7] which reached 4.3 GW at the end of 2016, just shy of the government's 2022 target of 5 GW. A renewed push for hydropower by the Ministry of Power seeks to include, for the first time, hydropower as a renewable energy in the 2017/18 budget. This would entitle new and under-construction projects to the sharply lower tax rate already enjoyed by other renewable energy projects. Overall, the share of hydropower in renewable generation is expected to fall from 62% in 2016 to 41% by 2022, as solar PV, onshore wind and bioenergy generation grow. **Bioenergy** is expected to expand by 2.6 GW to reach over 8.6 GW by 2022, due primarily to the co-generation of bagasse from the sugar industry. Despite abundant volumes of agricultural residues, bioenergy projects in India still face key market barriers related to a lack of affordable finance and the mobilisation of fuel supply chains for seasonal and dispersed biomass resources.

Japan: main case forecast

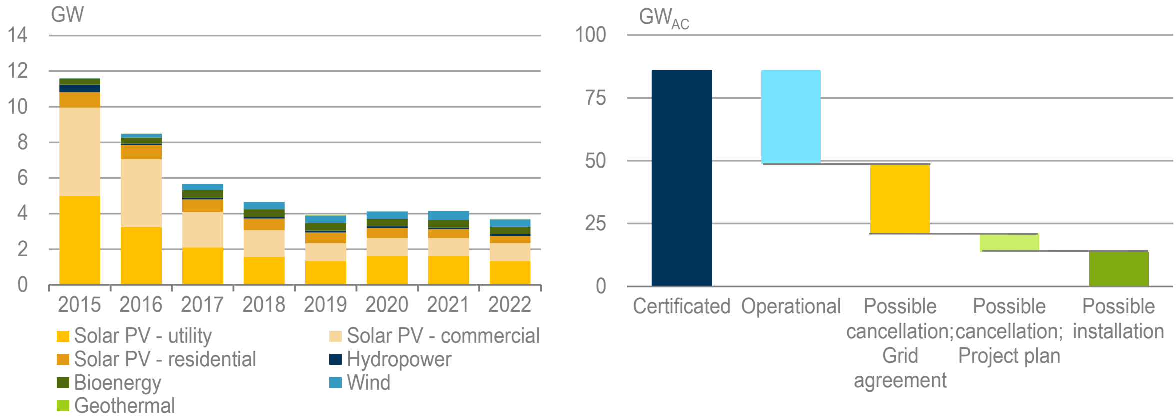
Japan's renewable capacity is expected to grow by 26 GW over 2017-22, led by solar PV, which is forecast to represent 78% of the growth. Japan's forecast is revised down versus last year due primarily to a major revision of the country's FIT scheme, which is expected to result in slower solar PV growth. However, the introduction of an auction scheme for utility-scale solar PV projects should make renewable expansion more cost-effective, while generous FIT levels will continue to drive the deployment of distributed solar PV and other renewable technologies over the forecast period. With fast-growing solar PV capacity, the share of variable renewables in total generation is expected to increase from 5% to almost 9% in just five years, which is anticipated to increase grid integration challenges.

Solar PV remains central to renewable capacity growth, with 21 GW expected to become operational over 2017-22. Changes to the FIT regulation were introduced in April 2017 and signal 23% slower capacity growth than foreseen in last year's forecast, but the changes are anticipated to make solar PV expansion more cost-effective. Japan's solar PV additions had already declined by 27% to 7.9 GW in 2016 from almost 11 GW in 2015. The new regulation is aimed at cancelling non-operational projects that already received FIT approval, and requires developers to submit grid connection agreements and business plans by April 2017 in order to remain eligible for the FIT. While current submissions were still under review by the Ministry of Economy, Trade and Industry (METI) at the time of writing, additional requirements, including long-term operation and maintenance (O&M) service contracts, will be needed for the next round of projects, to be submitted by September 2017. Overall, *Renewables 2017* expects more than half of all previously FIT-approved but non-operational solar PV projects (about 48 GW) to be cancelled after METI's

[7] Small hydropower in India is classified as any project of 25 MW or less.

review. The rate of cancellation and a slowdown in new FIT approvals remains an important forecast uncertainty for all PV segments (Figure 2.14).

Figure 2.14. Japan annual net renewable capacity additions, 2015-22 (left) and estimated cancellation and possible installation of solar PV project pipeline (right)



Notes: Right-hand figure represents operational status of solar PV as of December 2016; AC = alternating current.

Source: METI (2017b), *Statistics of Renewable Energy in the Feed in Tariff scheme*; METI (2017a), *Estimated solar PV cancellation with enforcement of revision of Feed in Tariff Act*. Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Utility-scale projects are expected to represent nearly half of total solar PV growth (9.6 GW) over 2017-22. In line with the recent revision of the FIT scheme, Japan launched an auction system for utility-scale applications as a way to ensure more cost-effective and sustainable deployment. The auction scheme is anticipated to initially target between 1 GW and 1.5 GW of capacity, with 500 MW to be awarded at the end of 2017 and another 0.5-1 GW in 2018-19. With strict participation requirements, *Renewables 2017* expects the majority of awarded projects to be commissioned over 2019-22. Overall, competitive auctions for utility-scale projects are anticipated to drive down prices significantly from current FIT levels (JPY 210 per kilowatt hour [kWh] [USD 190/MWh]), one of the highest globally. After the auctions, the government may also consider reducing FIT rates for the residential and commercial segments. For distributed generation, commercial applications are expected to lead the forecast with 7.5 GW over 2017-22, followed by residential projects (3.4 GW). However, growth is expected to slow significantly for both segments as a result of cancellations and increasing curtailment risks in certain regions that have limited interconnection capacity and where solar PV generation is already higher than local demand can accommodate.[8]

Bioenergy capacity is forecast to grow by 2.6 GW over the forecast period to reach 5.7 GW by 2022, mainly driven by the country's generous FIT scheme. At the time of writing, 3.2 GW of capacity received FIT approval but had yet to become operational. These projects are not anticipated to be subject to significant cancellation, as anticipated for solar PV, as the government is aiming to diversify its dispatchable renewable energy portfolio. However, some projects face challenges related to the re-approval of their business plans under the new FIT scheme rules. In addition, mobilising biomass fuel supply chains for some projects remains an important barrier to deployment.

[8] In Japan, managing the use of interconnection lines remains a challenge for exporting renewable generation in areas where generation is higher than local demand, leading to issues of curtailment.

Other renewables are expected to account for only 12% of capacity growth, or an added 3.1 GW over 2017-22. This is led by **wind**, which is forecast to expand by 2.5 GW, of which 0.5 GW is from offshore projects, a slight upward revision from last year. The wind market demonstrated record growth in 2016 (0.2 GW), with over 4 GW of wind projects currently in the latter stages of environmental impact assessment, although some are expected to face delays due to grid integration challenges, especially in regions like Hokkaido and Tohoku. **Hydropower** is forecast to grow by around 0.6 GW over the forecast period, accounting for only 2% of renewable capacity growth. With the majority of large-scale hydropower resources already developed, growth is expected to come from small and medium-sized hydropower, promoted by the FIT (e.g. JPY 200/kWh [USD 180/MWh]). And despite great resource availability, the growth of **geothermal** remains limited by social acceptance issues, only growing by 70 MW over 2017-22.

Other countries in Asia and Pacific: main case forecast

In **Korea,** renewable capacity is expected to expand by 12 GW over 2017-22. The forecast is more optimistic than last year due to the introduction of more ambitious renewable energy targets and a strategic government plan in response to energy security and pollution concerns. The proposed national target aims for a 20% share of renewables in the electricity mix by 2030, up from the 13% target enacted in 2014. An extension of the RPS scheme is anticipated with the new target, but its design is expected to see modification. Since its introduction in 2012, the RPS design primarily favoured bioenergy and solar PV deployment in Korea. However, as biomass co-firing was the lowest cost option to meet RPS requirements, the country's wood pellet fuel imports dramatically increased, raising energy security concerns. As a result, Korea introduced a voluntary implementation plan in February 2016 to place a cap on the extent to which obligated parties can meet their RPS requirements through biomass co-firing and therefore encourage greater uptake of other renewable technologies. In line with these developments, dedicated bioenergy capacity is expected to grow by 1.7 GW over 2017-22.

Solar PV is expected to lead the growth (8.8 GW) over the forecast period to reach 13.2 GW by 2022. The forecast is revised up due to growth in both utility-scale solar PV, driven by increased targets, and distributed segments supported by the proposed FIT scheme. However, *Renewables 2017* main case growth remains conservative because the details of new RPS rules and the FIT were not published at the time of writing. Wind capacity is expected to grow by 1.3 GW over 2017-22. However, challenges concerning environmental permits and grid integration remain, which could hamper much faster expansion.

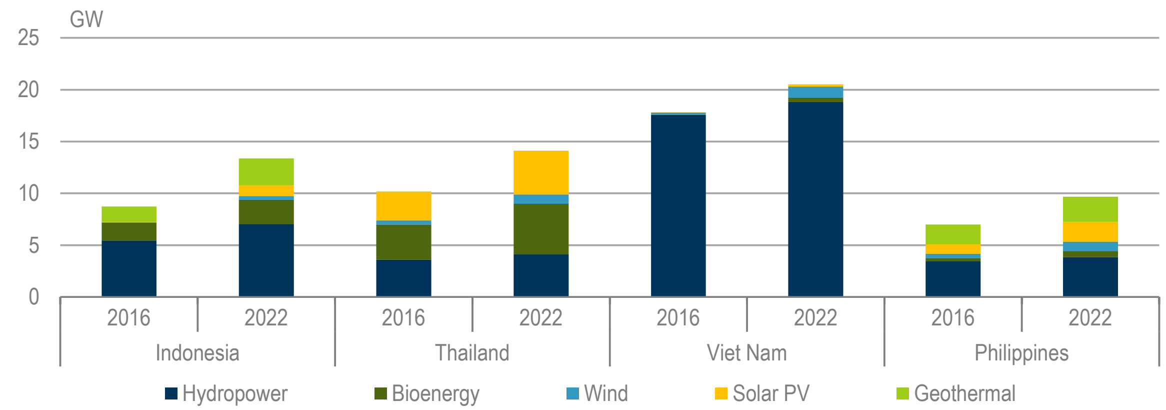
In **Thailand,** renewable capacity is forecast to grow by just under 4 GW over 2017-22 (Figure 2.15), a significant decline from the 6.5 GW forecasted last year, due to challenges facing faster uptake of bioenergy and onshore wind, as well as policy uncertainty in the solar PV sector. Bioenergy is expected to increase by 1.5 GW over the forecast period. However, uptake in Thailand's first bioenergy auction held in 2016 was low (only 46 MW was awarded from the 552 MW auctioned). Higher growth is anticipated in the second round, expected for delivery in 2020. Onshore wind is also forecast to witness slower growth, with only 0.5 GW expected over 2017-22 due to uncertainty over the new policy to ban the use of agriculturally designated land for project development.

Solar PV is expected to expand by 1.4 GW over 2017-22, down 0.6 GW versus last year's forecast, due to a policy transition that favours a reduced FIT for utility-scale projects and a move to a self-consumption-driven market for distributed solar PV. Despite this transition, Thailand's self-consumption scheme is proving economically unattractive as uncertainty remains over the implementation of net metering. Utility-scale solar is anticipated to drive deployment over the forecast period driven by the FIT, reduced from USD 170/MWh to USD 120/MWh to reflect technology cost reductions. Meanwhile, the Agro-Solar programme, with a target of 800 MW of solar PV in Phase 1 and 518 MW in Phase 2, should also contribute to growth.

Indonesia's renewable capacity is expected to grow by 4.6 GW over 2017-22, driven by hydropower, geothermal and solar PV (Figure 2.15). Geothermal capacity is anticipated to expand by 1.1 GW, more optimistic compared to last year's forecast, thanks to additional investment funding from the World Bank in Pertamina Geothermal Energy (WB, 2017), the country's largest private developer. In other efforts, the government moved to boost generation by encouraging full foreign ownership of plants larger than 10 MW and 67% foreign ownership for smaller plants. However, uncertainty remains over the direct impact of these changes on additional geothermal development. Likewise, the government passed a law declassifying geothermal as a mining activity, thereby opening up new areas believed to contain about two-thirds of Indonesia's geothermal reserves for exploration, but at extremely high costs. Hydropower is expected to grow by 1.6 GW, with plans to install over 1 GW of PSP in Java-Bali over 2021-22.

Solar PV is expected to grow by nearly 1 GW, from a nascent stage of only 70 MW in 2016, led by utility-scale solar installations. This is due to the issuance of the second ever comprehensive renewable energy regulation in January 2017, which allows FITs to be negotiated between the state-owned power utility (PLN) and independent power producers. Bioenergy is forecast to increase by 650 MW over the forecast period due to deployment within the FIT scheme and industrial biomass residue-fuelled projects. The bioenergy forecast is revised upwards due to the removal of capacity restrictions, lower currency risk through indexation to the US dollar, and streamlined permitting and regulatory processes for independent power producers in the FIT scheme.

Figure 2.15. ASEAN cumulative renewable capacity, 2016 and 2022



In **Viet Nam,** renewable capacity is expected to grow by 2.7 GW over 2017-22, witnessing slower growth versus last year's forecast due primarily to a reduction in the hydropower forecast. This follows an announcement by the Ministry of Industry and Trade of the possible cancellation of the development of nearly 2.1 GW of small and cascade hydropower plants. Bioenergy capacity is expected to increase by 390 MW, driven primarily by 125 MW paper mill and 100 MW forest plantation-fuelled projects. However, the largest contributor to non-hydro renewable capacity growth is expected from nearshore wind farms. With the completion of the country's first wind project (99.2 MW Bac Lieu) in January 2016, an additional 540 MW is forecast to come on line over

2017-22 driven by the proposed FIT revision. Although this revision is expected to improve the economic attractiveness of wind projects, its implementation remains a forecast uncertainty. In addition, challenges remain concerning the availability of financing with the maximum tenure for debt financing standing at around 10 years, hampering the bankability of projects.

Table 2.5. Asia and Pacific drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
India	Robust and supportive policy environment with ambitious targets and competitive auction schemes; improvements in financial status of distribution companies.	Grid integration and availability; lack of clarity in net metering implementation; uncertainty in financial situation of current wind projects.
Japan	Introduction of competitive auction scheme for large-scale solar PV; generous FIT scheme; energy diversification needs.	Uncertainty over PV project cancellations; long lead times for environmental assessments; grid integration challenges.
Korea	Ambitious targets driven by energy security and pollution concerns, reliance on fossil fuel imports, RPS and new FITs.	Lack of established local agreements on wind projects; uncertainty over the co-firing of biomass.

Australia's renewable capacity is expected to expand by over 9 GW over 2017-22, mainly driven by solar PV (5 GW) and onshore wind (3.8 GW). This growth is driven by cost reductions and the country's Renewable Energy Target, which aims for around 23% renewable energy by 2020. Since the Large-scale Renewable Energy Target (LRET) was adjusted in 2015, investment in large-scale renewable projects increased by nearly 50%. Despite a slowdown in the country's small-scale solar PV segment (the residential solar sector contracted by 11% in 2016), distributed PV accounted for 86% of new solar PV additions in 2016. Over the forecast period, distributed applications are forecast to witness steady growth, but to account for 73% (3.7 GW) of additional solar PV capacity as a reflection of the large pipeline of utility-scale solar PV projects funded by the Australian Renewable Energy Agency's (ARENA) large-scale solar round (ARENA, 2016). Onshore wind capacity is forecast to grow by nearly 3.8 GW, driven strongly by recovering certainty in the LRET and the near record-level financing of wind projects already seen in 2017. The Australian Capital Territory's reverse auction for large-scale renewable energy generation is also expected to support this growth, as are scheduled auctions of 400 MW respectively in Queensland and Victoria. Over the forecast period, wind will be considered the fastest-growing renewable energy source for electricity generation in Australia, with a share of 40% by 2022.

Asia and Pacific: accelerated case forecast

Overall, the potential for additional renewable deployment in Asia and Pacific is large, and renewable capacity growth could be up to 35% (66 GW) higher over 2017-2022 than in the main case (Table 2.6). India alone represents half of the regional additional growth, followed by Japan (30%), Korea (10%) and ASEAN countries (8%). In **India,** onshore wind and solar PV could grow by another 8.5 GW and 20 GW respectively, depending on the pace of auctions and commissioning of projects, as well as on improvements in grid integration and the financial health of DISCOMs in key states. Distributed solar PV could grow by an additional 3 GW over 2017-22 if reforms are carried out to net metering policies and regulations in several states. **Japan's** solar market could witness an additional

17 GW of capacity over 2017-22 compared to the main case, with accelerated growth dependent on higher project approval rates under the new FIT regulation and improvements in grid integration. Bioenergy could also witness an added 1.2 GW if project developers ensure appropriate biomass fuel supply chains. In **Korea**, solar PV could be 3.5 GW higher and wind 1.7 GW higher compared to the main case. This depends on the announcement of a FIT for distributed solar PV to encourage stronger project implementation, as well as further clarification of the renewable incentive schemes and RPS under the new 2030 targets for utility-scale projects.

Table 2.6. Asia and Pacific main and accelerated cases summary, 2016 and 2022

Total capacity (GW)	India			Japan			ASEAN			Australia		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	46.8	56.7	59.2	50.1	50.7	50.8	40.6	45.6	45.8	8.7	8.7	8.7
Bioenergy	6.0	8.6	10.3	3.1	5.7	6.9	6.4	9.5	10.1	0.8	1.2	1.2
Onshore wind	28.7	61.6	70.1	2.9	4.9	6.7	0.9	2.6	3.4	4.4	8.2	8.9
Offshore wind	-	-	-	0.1	0.5	0.6	0.1	0.6	0.6	-	-	-
Solar PV	9.0	70.5	90.8	42.0	62.5	79.4	4.2	10.1	13.6	5.2	10.2	10.8
CSP	0.2	0.3	0.3	-	-	-	0.0	0.0	0.0	0.0	0.2	0.2
Geothermal	-	-	-	0.5	0.6	0.6	3.4	5.0	5.2	0.0	0.0	0.0
Ocean	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Total	**90.8**	**197.8**	**230.7**	**98.8**	**125.0**	**144.9**	**55.5**	**73.4**	**78.7**	**19.1**	**28.4**	**29.8**

Note: Acc. = accelerated. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

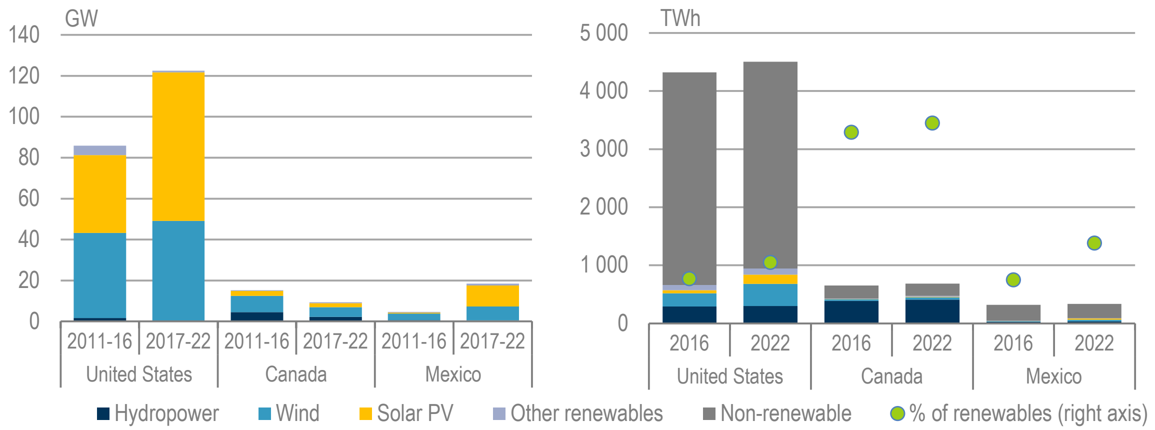
In **ASEAN** countries, renewable capacity could be 5.3 GW higher versus the main case due primarily to an extra 3.5 GW of solar PV. **Thailand** could account for 2.4 GW of this additional solar PV growth if the government is able to rapidly address the planning and regulatory hurdles already associated with the new self-consumption scheme for distributed solar PV. Coupling regulatory incentives with a supportive national policy framework could allow Thailand to achieve 0.3 GW of additional distributed solar PV. Bioenergy in Thailand could expand by an additional 0.4 GW through enhanced waste management and community engagement to maximise the potential of EfW. **Indonesia** could account for 27% of additional utility-scale solar PV, depending on the success of the country's first ever FIT scheme, as some regions may struggle to obtain attractive rates, which are established using PLN's electricity base price[9] and are adjusted dependent on location.

North America

In North America, renewable capacity is expected to expand from 358 GW in 2016 to 509 GW in 2022, over 40% higher growth compared to the previous five-year period (Figure 2.16). Solar PV accounts for 57% of the regional renewable capacity growth, followed by wind (40%), with smaller contributions from other renewable technologies. Over the forecast period, incremental renewable power generation growth is expected to outpace overall growth in electricity generation across the region. Canada leads North America as the country with the highest share of renewable generation in its electricity mix, owing to its large hydropower fleet. Mexico is expected to see the region's most rapid growth in renewables share during the forecast period, with strong expansion of solar PV and wind driven by the country's green certificate auction scheme.

[9] PLN's electricity base price is the marginal production cost that would be incurred by PLN to produce electricity at the location of the renewable energy project, often referred to as the avoided costs of production.

Figure 2.16. North America renewable electricity capacity growth, 2011-22 (left) and generation by source, 2016-22 (right)



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017.* Historical generation data from IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

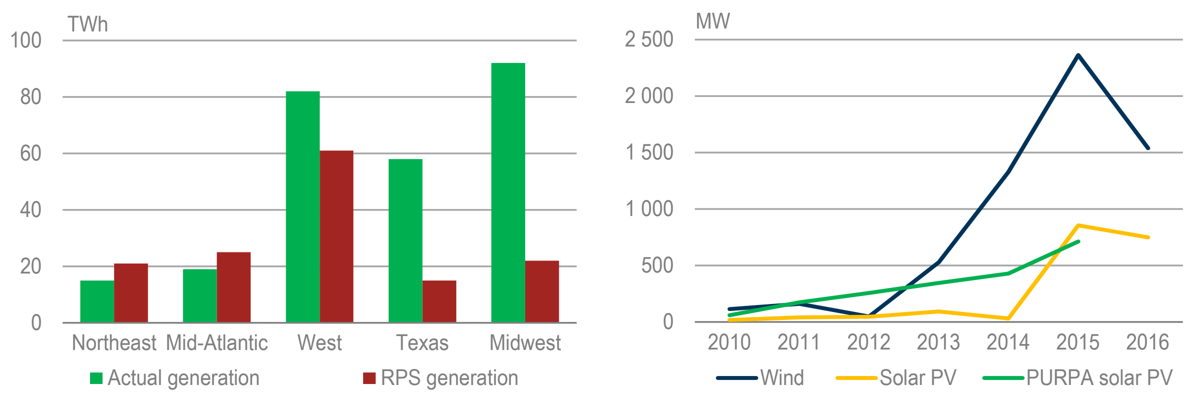
United States: Main case forecast

Cumulative renewable capacity in the United States is forecast to grow by half (123 GW) over 2017-22, led by solar PV and onshore wind. The country will experience the world's second-largest increase in renewable capacity after China. With this growth, the share of renewables in the US electricity mix is expected to increase from 15% in 2016 to 21% in 2022. The forecast takes into account both federal and state-level incentives for renewables in place at the time of writing. Despite policy uncertainties associated with the new US administration, the main drivers for solar PV and onshore wind growth over the forecast period remain strong: the multi-year extension of federal tax credits in 2015, continuous support at the state-level through RPSs, and technology-specific incentives. In addition, cost reductions for solar PV and onshore wind should continue to improve their economic attractiveness alongside the incentives in place. Overall, the forecast has been revised upwards by over 15 GW compared with last year, reflecting a larger utility-scale solar PV pipeline as a result of the accelerated deployment in 2016 and recent cost reduction trends.

With increasing uncertainty over the implementation of the Clean Power Plan (CPP), state-level RPSs will continue to be an important enabler of renewable deployment over the forecast period. As of April 2017, RPS policies in 29 states and the District of Columbia (DC) covered 50% of total US retail electricity sales (LBNL, 2017a). Recent RPS changes over 2016/17 indicate a robust demand for renewables. New York, DC, Massachusetts, Michigan, Oregon, Rhode Island and Maryland either increased or extended their RPS targets, while only Kansas replaced its mandatory RPS with a voluntary goal. With these recent changes, RPS-stimulated demand is estimated to grow by over half through to 2022, led by California (LBNL, 2017a). Overall, RPSs should continue to remain an important driver of deployment over the forecast period, especially in the Northeast, Mid-Atlantic and West states where RPS targets are strong (Figure 2.17).

In addition, corporate PPAs, long-term hedge contracts and merchant plants, primarily driven by cost reductions, are all expected to continue supporting renewable deployment beyond RPSs in some states. Actual renewable generation (mostly wind) is four times higher than RPS requirements in Texas and the Midwest, with some states having already reached their RPS targets and others not having a mandate at all (LBNL, 2017b). This expansion is mostly driven by increasing economic attractiveness of wind as a result of high capacity factors in addition to the production tax credit (PTC). Corporate PPAs for wind and solar projects increased from below 50 MW in 2012 to over 3 GW in 2015, but declined slightly in 2016 due to a lull in the project pipeline as a result of a tax credit extension in late 2015 (Figure 2.17). In addition, merchant and hedging contracts are common in some regional transmission organisations (mostly in PJM [Pennsylvania New Jersey Maryland] and ERCOT [Electric Reliability Council of Texas]). In 2016, 17% of all commissioned wind projects were either merchant or had a hedging contract (AWEA, 2017). In some states (California, North Carolina, Arizona and Nevada) the Public Utility Regulatory Policies Act (PURPA) has become a driver for qualifying small utility-scale projects offering competitive prices.[10] However, recently proposed changes to PURPA in some states may alter this trend over the forecast period.

Figure 2.17. United States RPS-driven generation (left) and announced corporate PPAs (right)



Source: LBNL (2017b), *U.S. Renewables Portfolio Standards: 2016 Annual Status Report*, https://emp.lbl.gov/projects/renewables-portfolio.

Solar PV alone is forecast to provide 59% of renewable capacity additions in the United States, with 73 GW expected to become operational over 2017-22. The multi-year investment tax credit (ITC) remains the most important driver for solar PV deployment, along with rapid cost reductions. Since 2010, weighted average investment costs for commissioned utility-scale projects have declined by over 50%. However, further potential for cost reduction exists given that investment costs in the United States remain higher than the global averages for all installation segments.

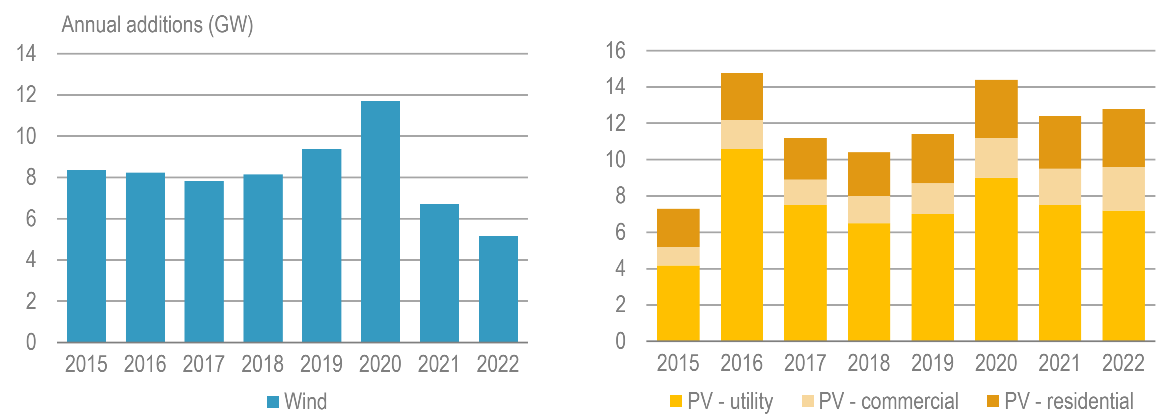
While the multi-year ITC gives better visibility to developers, its phase-out scheduled after 2020 is expected to have an impact on annual addition trends towards the end of the forecast period (Figure 2.18). In 2016, PV developers rushed to commission their projects, assuming that ITCs would expire at the end of 2015. This trend led to record utility-scale additions in 2016 (11 GW), but also decreased the number of projects in the pipeline due to be commissioned in 2017. Consequently this forecast expects smaller capacity additions in 2017, with a further slowdown in 2018 as developers qualified with full ITCs (30%) will have time to complete their projects until 2020, when another deployment rush is expected. Over 2021/22, the annual PV market is expected to slow down again as ITC reductions kick in. Overall, this report expects that utility-scale projects will continue to provide 62% of all solar PV additions through to 2022. Deployment is expected to continue shifting from California to Texas, Nevada, Arizona and Utah, but some

[10] PURPA is an act that requires utilities to purchase power generated by small qualifying plants at the rate of the utility's avoided cost defined at state level.

states in the South, such as North Carolina, Georgia and Florida, should also see growth over the forecast period driven by cost reductions and federal tax credits.

For residential and commercial applications, ITC and net metering policies remain driving forces of deployment, but challenges related to the design of utility electricity rates and changes in net metering regulations remain throughout the United States. Overall, capacity in the commercial and residential segments is expected to expand by 28GW over 2017-22. The annual residential market grew by 22% in 2016, but growth is expected to slow down over the forecast period. California is anticipated to see a slowdown in distributed solar PV expansion due to a shift from net metering rules to time-of-use rates and market saturation (over 8% of residential roofs had PV panels at the end of 2016). Last year, Arizona suspended its retail net metering programme following similar actions in Hawaii, Louisiana and Nevada. However, increasing RPS targets (with solar carve-outs) and new residential programmes in New York, Florida and Massachusetts should drive growth outside California. For commercial applications, availability of affordable financing remains a significant challenge. While most potential residential customers in the United States have credit ratings as part of their mortgage programmes, the majority of small and medium-sized companies do not have a rating, which is considered a risk premium for banks. This results in a higher cost of capital, hampering the economic attractiveness of these projects.

Figure 2.18. United States annual net wind and solar PV capacity additions, 2015-22



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Onshore wind is forecast to grow by 48 GW over 2017-22, driven by multi-year extension of the PTC, which will be reduced progressively over 2017-19, affecting the annual deployment trend in a similar way to solar PV. In May 2016, the Internal Revenue Service released rules extending the timeline of qualification for the full PTC, which is expected to result in a larger project pipeline. *Renewables 2017* expects new capacity additions to reach almost 12 GW in 2020 as all projects qualifying for the PTC have to come on line by the end of that year. This growth is expected to slow down over 2021-22 as a result of the PTC phase-out. Texas is forecast to remain the largest growth market, along with Iowa and Kansas. Growth is expected to slow down in Oklahoma as the state tax credit, which contributed to strong capacity growth from 2013, was repealed in April 2017. Expansion should be strong in some emerging states, especially New Mexico, Montana and Michigan. As the majority of new projects are expected to come on line in ERCOT, the availability of transmission capacity may emerge as a challenge as a result of possible delays in the commissioning of new lines under construction.

For other renewables, federal tax incentives for bioenergy and geothermal projects expired last year, hampering their economic attractiveness. For bioenergy, the forecast is revised down from last year's report, with 0.7 GW expected to come on line over 2017-22. Additional capacity will utilise diverse biomass fuel sources such as secondary industrial residues, municipal solid wastes and, to a lesser extent, forestry biomass. A strong pipeline of landfill gas projects is in place, but these are of relatively low capacity. For CSP, the US market is expected to slow down significantly over the forecast period compared to the previous five years, despite historical federal government funding (USD 9 billion) and a multi-year ITC. To date, large-scale CSP plants in the United States have primarily been built through full support of the DOE loan programme, of which USD 25 billion is under discussion for withdrawal at the time of writing.

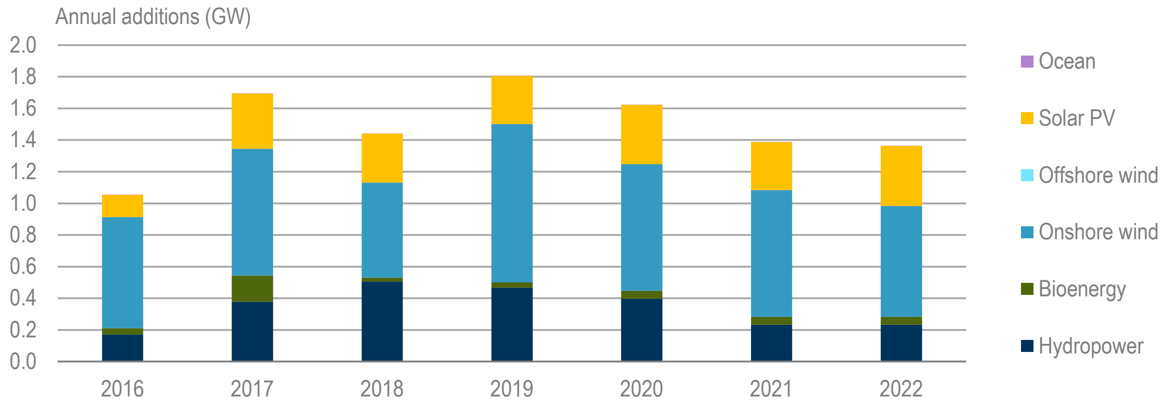
Proposed policies that have yet to be implemented at the time of writing remain important forecast uncertainties, not taken into account in the main case. First, planned tax reform may affect the economics of wind and solar projects. Proposed tax cuts for corporations may decrease the tax base on which the ITC and PTC are monetised. These cuts could reduce the capacity of tax equity providers and limit the availability of this type of financing, thus raising the cost of capital. Second, increasing trade enforcement rules against China and Chinese companies may have an impact on the price of solar PV panels in the United States. Domestic solar module manufacturing capacity currently meets only around 15% of US demand. The majority of the rest is imported either from China or Southeast Asia. Further trade restrictions and import taxes could result in higher module prices. Third, renewables have enjoyed very low interest rates since 2008, contributing to their economic attractiveness. In March 2017, interest rates increased from 0.75% to 1%, while further rate increases are expected in 2017/18, which could increase generation costs for new projects.

Canada: Main case forecast

Canada's renewable capacity is expected to grow by over 9 GW (or 10%) over the forecast period, driven by provincial-level policy measures mainly in Quebec, Ontario, Alberta and British Columbia. Onshore wind is expected to lead the forecast, followed by hydropower, solar PV and bioenergy (Figure 2.19). Compared to last year's report, Canada's forecast is revised down as Quebec and Ontario cancelled their anticipated tenders for large-scale wind and solar PV projects, which were included in our previous forecast. Over the forecast period, renewable generation is forecast to grow by 10% to reach 472 TWh in 2022, providing around 69% of overall power generation, one of the highest globally.

Onshore wind leads new capacity additions, with 4.7 GW expected to come online over 2017-22, but the forecast is revised down compared with last year's report. In late 2016, Ontario decided to suspend the second phase of the Large Renewable Procurement (LRP) programme, highlighting the province's oversupply situation. In the first phase, Ontario awarded 300 MW at an average price of CAD 85/MWh (USD 65/MWh), 35% lower than the province's first FIT programme. Still, Ontario has almost 1.5 GW of projects under development, which are expected to come on line over the forecast period. In Quebec, uncertainty remains over the announcement of additional onshore wind tenders under the province's new long-term energy plan. Alberta's first tender is expected to contract 300-400 MW of onshore wind, to be commissioned in 2019, while the province is expected to procure similar capacities annually over the forecast period. Smaller additions are expected in Saskatchewan, with SaskPower's recent request for 200 MW of new wind capacity.

Figure 2.19. Canada annual net renewable capacity additions, 2016-22



Hydropower expansion is expected to continue with 2.2 GW of additional capacity becoming operational over 2017-22. Three large hydropower plants are expected to be fully connected to the grid over the forecast period: Keeyask plant (700 MW) in Manitoba, Muskrat Falls (824 MW) in Newfoundland and Labrador, and Romaine 3 and 4 stations in Quebec. The forecast also includes the upgrade to the John Hart hydropower plant (140 MW) in British Columbia, in addition to smaller stations in various provinces. With the commissioning of these projects, Canada's hydropower pipeline is expected to slow significantly, especially in 2021/22. Canada's **bioenergy** capacity is forecast to expand by 380 MW over 2017-22. Almost half of this capacity is anticipated in 2017, as two 40 MW projects in British Columbia and other smaller projects under the Ontario FIT and tender are delivered. For the remainder of the forecast period, additions fall to a lower level due to limited supportive policy frameworks.

Canada's **solar PV** capacity should expand by 2 GW, reaching 4.7 GW in 2022, mostly driven by Ontario's FIT programmes and Alberta's tenders. In 2016, Ontario awarded over 130 MW of solar PV, mostly for residential and commercial applications, with another 130 MW expected in 2017. However, the province's solar PV forecast is revised down due to the suspension of the LRP. Although wind is expected to receive the majority of Alberta's utility-scale procurement, this forecast includes a contribution from solar PV projects as well.

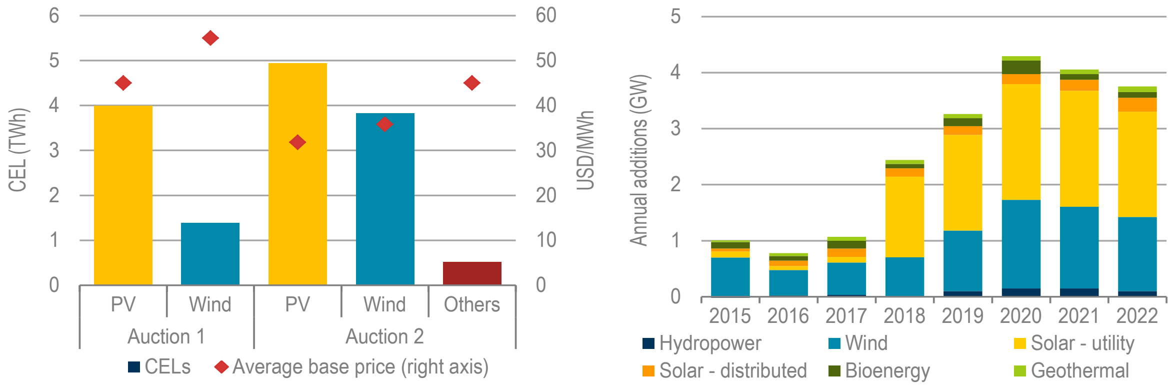
Mexico: Main case forecast

Mexico's renewable capacity is forecast to expand by almost 19 GW over 2017-22, driven by clean energy certificate (CEL) tenders (Figure 2.20).. Utility-scale solar PV projects are expected to lead the forecast, representing 50% of Mexico's renewable additions over 2017-22, followed by onshore wind (36%). The forecast for distributed solar PV is slightly more optimistic, mainly due to recent regulatory changes clarifying remuneration schemes for different consumer segments. Hydropower and geothermal projects are expected to contribute, with a combined 0.6 GW becoming operational over the forecast period. Overall, the share of renewables in electricity generation should increase from 15% in 2016 to 28% in 2022, in line with the government's target of 35% by 2024, which also includes nuclear and co-generation.

As part of its electricity market reform, Mexico held two auctions (the first in April 2016 and the second in September 2016) and awarded long-term CELs (20 years) and electricity contracts (15 years) for projects to be operational in 2018/19. With these auctions, Mexico awarded close to 14.7 TWh of clean energy certificates (CELs). *Renewables 2017* expects upcoming auctions to award

9-11 TWh of new CELs annually over 2017-19, depending on the country's demand growth, nuclear generation and output from co-generation plants that qualify for CELs.

Figure 2.20. Mexico CEL auction results and annual net renewable capacity additions, 2015-22



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

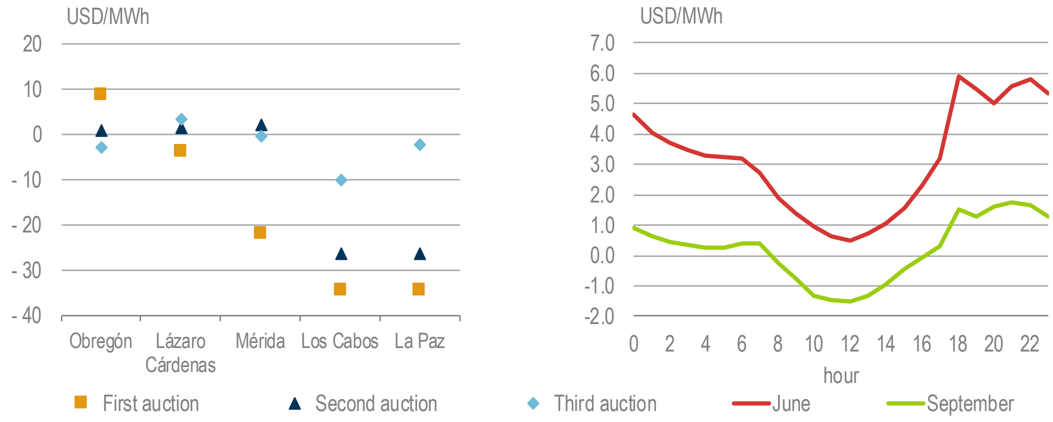
Solar PV capacity is expected to expand by 10.3 GW over 2017-22, with large utility-scale projects providing 90% of this growth, although distributed generation will slowly pick up over the forecast period. Solar PV developers won the majority of contracts in the two auctions, with 3.7 GW of capacity offering the lowest prices. The average contract price for solar PV decreased from USD 45/MWh in the first auction to USD 32/MWh in the second, with the lowest contract awarded at USD 27/USD, a level that might be slightly increased by hourly adjustment factors. In the second auction, the government changed locational and hourly adjustment factors taking into account local development factors, nodal prices and grid infrastructure, which resulted in different geographical distribution of awarded projects versus the first auction (Box 2.2). Considering further cost reduction potential and resource availability, this report expects that solar PV will continue to offer competitive prices and receive the majority of CELs over the forecast period. However, delays are expected with the commissioning of some projects due to grid connection and permitting matters, especially for those located in Yucatan where grid infrastructure is weak.

Box 2.2. Mexican energy auction design and grid integration

The Mexican long-term energy auctions for procuring variable (wind and solar) capacity are designed to reflect the time- and location-dependent value of electricity, aiming to enhance the system value of variable generation while providing investment certainty. Mexico's long-term energy auctions for renewables incorporate expected price differences (*Diferencias Esperadas por Zona de Precios*), to reflect the nodal pricing of electricity and the regional transmission constraints in different regions, highlighting the locational value of the projects. The energy regulator (Centro Nacional de Control de Energia [CENACE]) weighs final bids according to these locational price differences in order to select projects with higher system value. The expected price differences are only used to select projects, not to determine final remuneration of winning bids.

In addition, once in operation, the remuneration is time-dependent. CENACE models anticipate future local electricity prices for each node, which are published before each auction, allowing bidders to estimate their remuneration. These calculated prices are then used for setting month- and region-specific hourly adjustment factors (*Factores de Ajuste Horarios*) for the entire length of PPAs. These factors are defined as the difference between the expected hourly price of electricity and the average price of electricity of the PPA. In hours when the expected price of electricity is above average, the developer receives the value of the bid plus the adjustment factor. Similarly, if the project feeds power into the grid at a moment when the expected price is below average, the adjustment reduces the effective payment. For example, a wind power plant in the area of Laguna with a PPA price of USD 40/MWh would be remunerated USD 38.50/MWh at 13:00 in September 2026, while in the evening at 19:00 in June of the same year the final revenue would be USD 45.9/MWh (Figure 2.21).

Figure 2.21. Price differences in Mexican auctions for selected zones (left), example of month- and region-specific hourly adjustment factors, area of Laguna in 2026 (right)



Source: IEA (2016a), *Next Generation Wind and Solar power – full report*; CENACE (2017), "Largo Plazo" [Long term].

Locational price differences and hourly adjustment factors are modified for each auction taking into account the evolution of local supply and demand trends (considering the commissioning of previously awarded projects) and grid infrastructure constraints. CENACE has adjusted these parameters significantly over the first three energy auctions. For example, the price difference for the Obregón node decreased from USD 8.62/MWh in the first auction to USD -2.67/MWh in the third (Figure 2.21). A more impressive change happened in the La Paz node, where the price difference shifted from USD -34.28/MWh to USD -2.30/MWh. These adjustment factors reveal a wide discrepancy in awarded contract prices, with ranges of USD 35.5-68.8/MWh and USD 42.8-66.9/MWh observed for solar PV and wind respectively. The spread reflects the differences in locational expected prices: more expensive bids were awarded in those regions where electricity prices are forecast to be higher. Because of this, a large number of successful projects from the first CEL auction are located in Yucatan state.

The change in locational expected price differences and hourly adjustment factors between the first and the second auctions resulted in more diverse geographic distribution; Yucatan state saw no successful bids in the second round. In turn, Tamaulipas state saw a fourfold increase in wind energy allocation (from 585 gigawatt hours [GWh] to 2 222 GWh), and Aguascalientes state, to the north-west of Mexico City, experienced a tenfold increase in solar energy (from 141 GWh to 1 420 GWh). This structure enables developers to adjust their bids based on locational and hourly adjustment factors. If locational adjustment factors and hourly price adders are properly designed, the Mexican auctions will attract investment in areas most fit for new variable renewables, with technologies or design elements enabling electricity generation in periods when energy is more valuable. For instance, considering the price adders in Figure 2.21, an east/west-facing PV plant, avoiding excessive production at midday, could obtain a higher remuneration than a traditional south-facing plant.

In February 2017, CENACE released new rules for distributed solar generation with shorter application review and connection processes. For residential and small commercial applications (up to 50 kW), excess solar energy is remunerated at variable retail rates under the net metering scheme. For larger systems (up to 500 kW), excess generation is valued at the hourly local marginal price to the nearest distribution node under the net billing regulation. Over the last year, retail prices have increased by 15-20% for residential and 25-35% for commercial and industrial customers. In view of increasing retail prices, some commercial and residential applications under the net metering scheme could be economically attractive, but access to low-cost financing remains an important challenge. Overall, *Renewables 2017* forecasts 1.1 GW of additional distributed generation over 2017-22.

Onshore wind capacity is forecast to grow from 3.7 GW in 2016 to 10.4 GW in 2022. In the second auction, wind developers offered more competitive prices and won three times more CELs compared to the first auction, with the average contract price decreasing from USD 55/MWh to USD 36/MWh. It is expected that wind developers will continue to increase their share of awarded CELs over 2017-22, which is reflected in the *Renewables 2017* forecast. In addition, two wind farms have signed PPAs in the last year, with HSBC and Mars Inc. signing PPAs for 10 and 15 years respectively for part of their plants' production. With increasing retail prices, corporate PPAs could play a complementary role to CEC auctions and help developers to diversify their revenues.

Table 2.7. North America drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
United States	Multi-year federal tax credits; state-level RPS and incentives; improving economic attractiveness of onshore wind and solar.	Uncertainty over the implementation of the CPP; state-level debates over net energy metering; proposed tax reform and trade measures.
Canada	Provincial carbon prices; competitive tenders and FITs for distributed solar PV in multiple provinces.	Reduced large-scale tender capacity in Quebec and Ontario; limited provincial support for bioenergy projects.
Mexico	Power demand growth; excellent resource availability; long-term clean energy target to 2024; regular clean certificate auctions.	Weak grid infrastructure in some states; high cost of local financing; short commissioning lead times in auctions.

Bioenergy capacity is forecast to increase by 0.8 GW over 2017-22 in an upward revision of the last year's forecast. Principal contributors to new biomass capacity include bagasse plants linked to the sugar industry, mainly in the states of Veracruz and Jalisco, a number of EfW projects and a small but growing biogas industry. **Hydropower** capacity is forecast to expand by over 0.5 GW over 2017-22. However, the figure is revised down compared to last year as delays are expected for some large-scale projects due to challenges concerning their environmental impact. **Geothermal** should also contribute, with 0.1 GW expected to be commissioned over the forecast period driven by capacity auctions.

North America: Accelerated case forecast

Overall, cumulative capacity in North America could be 5% higher in 2022, with onshore wind and solar PV leading the accelerated case (Table 2.8). In the **United States**, renewable capacity growth could be over 21 GW higher, led by solar PV and onshore wind. Compared to last year's forecast, the upside is limited as a result of increasing uncertainty over the implementation of the CPP, which incentivised states to accelerate deployment before 2022 through early-compliance credits, and proposed federal policy changes. For utility-scale solar and wind projects, the accelerated case assumes an increasing pipeline of projects qualifying for federal tax incentives before the phase-out. For commercial and residential solar PV, capacity growth over the forecast period could be almost 6 GW higher as a result of a more rapid reduction in balance-of-system costs and improving state-level policies.

Table 2.8. North America main and accelerated cases summary, 2016 and 2022

Total capacity (GW)	United States			Canada			Mexico			North America		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	102.7	102.9	102.9	79.6	81.8	82.3	12.2	12.8	12.8	194.5	197.4	198.0
Bioenergy	14.4	15.0	15.0	2.1	2.5	3.8	0.8	1.6	2.7	17.3	19.1	21.5
Onshore wind	80.8	129.1	134.4	11.9	16.6	17.6	3.7	10.4	10.9	96.4	156.2	162.9
Offshore wind	0.0	0.6	0.6	-	-	0.1	-	-	-	0.0	0.6	0.7
Solar PV	40.8	113.4	129.0	2.7	4.7	4.7	0.5	10.9	13.0	44.0	129.0	146.7
CSP	1.8	1.8	1.9	0.0	0.0	0.0	-	-	-	1.8	1.8	1.9
Geothermal	3.6	3.8	3.9	-	-	-	0.9	1.0	1.0	4.5	4.8	4.9
Ocean	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0	0.0	0.0
Total	244.0	366.5	387.6	96.3	105.6	108.5	18.2	36.7	40.3	358.5	508.8	536.5

Note: Acc. = accelerated. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

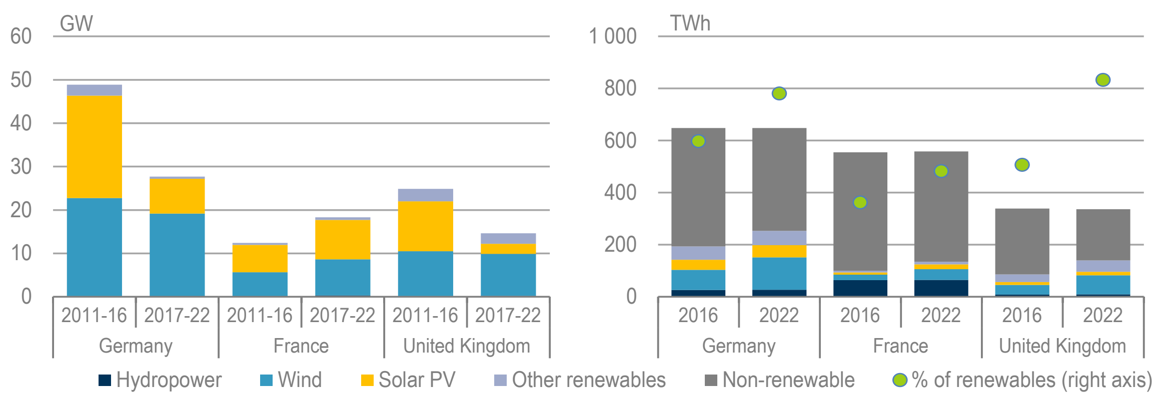
In **Mexico**, the accelerated case for utility-scale wind and solar projects assumes that all auctioned projects become operational without cancellation or delay, with capacity being 2 GW higher. For residential and commercial-scale applications, the upside potential could be unlocked by further clarity on net metering and net billing schemes, and improved access to affordable financing. Bioenergy capacity could be 1.1 GW higher based on a stronger pipeline of EfW projects, in addition to initiatives to modernise bagasse generation at sugar mills. In **Canada**, bioenergy capacity represents the majority of the upside in the accelerated case, with an added 1.1 GW, based on industrial facilities utilising biomass co-generation to meet their power and heat loads and coal-to-biomass conversion projects in Alberta. In addition, onshore wind capacity could be 1 GW higher, with Alberta holding the greatest potential. Accelerated deployment in the province would be led by faster implementation of the planned coal phase-out driven by the increasing carbon price.

Europe

Europe's renewable capacity is expected to grow by 125 GW over 2017-22, driven by continued cost reductions, mainly for solar PV and wind, and various policy support tools to reach longer-term climate goals (Figure 2.22). However, annual capacity additions are seen to decrease from 25 GW in 2016 to 18 GW by 2022, as overcapacity, a weaker demand outlook and limited visibility on forthcoming auction capacity volumes in some markets remain important constraints in the European Union. Many European countries are switching from administratively set tariffs to competitive auctions with volume or budget controls in order to comply with EU guidelines on state aid. As a result annual deployment trends may be volatile during this near-term transition. Beyond 2020, the pace of growth in some markets is uncertain due to a lack of visibility over auction schedules. However, if adopted, the proposed revision to the EU Renewable Energy Directive will address this challenge by requiring a three-year visibility over support policies, thereby improving predictability. Further clarity should emerge by the end of 2017, when countries will submit draft ten-year action plans to meet their voluntarily set 2030 targets. However, uncertainty remains over the governance of the wider EU 2030 target and how it will be reconciled with those proposed by the member states.

Overall the outlook for capacity growth remains relatively unchanged from last year. Wind is expected to lead capacity additions (65 GW), mostly from onshore wind (49 GW), followed by solar PV (39 GW). Distributed PV is seen outpacing utility-scale PV, accounting for almost 60% of total PV growth, due to continued support from FITs and feed-in premiums (FIPs) in many markets. Combined, bioenergy and hydropower account for 16% of the capacity growth. Almost two-thirds of Europe's renewable capacity growth is expected in four markets: Germany (28 GW), France (18 GW), the United Kingdom (15 GW) and Turkey (13 GW). The renewable share of electricity generation is seen to increase from 33% in 2016 to over 40% by 2022, driven by the rapid increase in solar PV and wind, which account for almost over 70% of new renewable generation. The share of variable renewables ranges across individual markets, but is seen to reach 26% of total generation in the United Kingdom and Germany, in part due to baseload retirements, and as high as 70% in Denmark with the utilisation of different flexibility options including cross-border interconnection and flexible conventional power plants.

Figure 2.22. Europe renewable electricity capacity growth, 2011-22 (left) and generation by source, 2016 and 2022 (right)



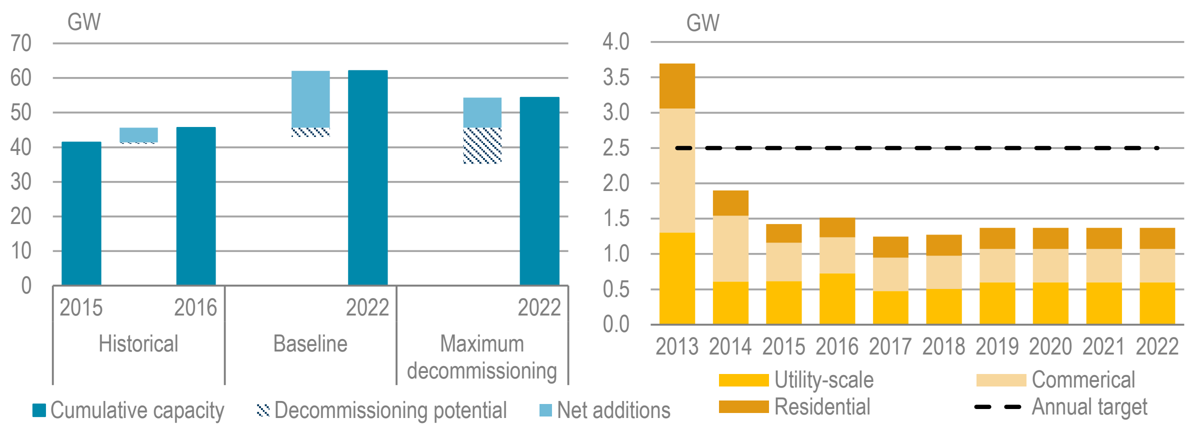
Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017.* Historical generation data from IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

Germany: Main case forecast

Germany's renewable capacity is forecast to grow by 28 GW over 2017-22, in line with last year's forecast led by onshore wind (16 GW), followed by solar PV (8 GW), offshore wind (3 GW) and bioenergy (0.5 GW). However, annual deployment is expected to slow during the transition of support schemes from administratively set tariffs to competitive auctions with volume control. Overall, deployment continues to be driven by a supportive policy environment designed to cost-effectively achieve decarbonisation goals, but uncertainty over the economic attractiveness of ageing wind plants and distributed solar PV could challenge the pace of capacity expansion. From 2019 onwards, renewable capacity deployment will mostly be driven by tender volumes outlined in the latest energy reform (Renewable Energy Act [EEG] 2017) which came into force in January 2017.

Onshore wind is expected to lead net capacity additions over 2017-22 with over 16 GW anticipated to come online, driven by FIPs in the near term and by competitive auctions from 2019 onwards. Higher annual deployment is expected until the end of 2018 due to a developer rush to lock in the guaranteed FIP before auctions began in 2017. These transition projects should drive most of the growth in 2017 and, to a slightly lesser extent, in 2018 due to 2018 year-end commissioning deadlines and decreasing FIP rates. From 2019 onwards, annual growth is expected to slow and be driven by the pace of the competitive auctions capped at 2.8–2.9 GW. However, deployment levels may be slightly volatile due to the uncertainty over the commissioning times of citizen wind projects. Over 90% of capacity in each of the first two rounds in 2017 was from citizen projects, which still need to obtain permits and have a up to four years to commission projects instead of two for normal developers. Average bid prices from the second oversubscribed auction in May 2017 were EUR 42.8/MWh, almost 40% below the ceiling price of EUR 70/MWh, but actual support levels may be higher or lower as bids will be adjusted according to the site's wind resource.

Figure 2.23. Germany onshore wind capacity (left) and PV annual additions by segment (right)



Notes: In left-hand graph, decommissioned capacity is assumed to be a maximum, based on a 20-year life time; in right-hand graph, dotted line at 2.5 GW represents the annual target as outlined in deployment corridors.

Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Cumulative onshore wind capacity is expected to reach 62 GW by 2022; however, this figure is highly sensitive to the pace of decommissioning of projects coming to the end of their support. Over 2017-22, roughly 10 GW of capacity will reach 20 years in operation and see support under the FIT expire, prompting developers to weigh the costs of remaining in operation against available remuneration options. Since the latest energy reform, support for these projects is only available through auctions, where annual volumes are limited to 2.8-2.9 GW. Competition in the north, where many of the older projects may be located, is expected to be particularly strong due to high wind speeds and a 0.9 GW annual cap on winning bids imposed by grid constraints. The highest bid from this region in the last auction was EUR 56/MWh, 2% lower than the average winning bid for the entire auction. Outside auctions, developers can enter the wholesale electricity market, but will have to weigh the cost of increasing O&M expenditure against revenue uncertainty where monthly wholesale prices averaged between EUR 22-38/MWh in 2016 (GME, 2017). Repowering decisions may also be affected by reforms for priority development zones, hub height restrictions and distance-to-housing regulations. Under an extreme case of maximum decommissioning, cumulative capacity could be 17% lower by 2022 (Figure 2.23).

Offshore wind capacity is expected to reach 6.9 GW by 2022, with 2.8 GW of new capacity entirely from projects in the advanced stages of development that have secured FIP support under the previous EEG. The winning projects from Germany's first 1.5 GW offshore wind auction held in March 2017 are not expected to be commissioned until after the forecast period, but the results highlight offshore wind's increasing competiveness. Three projects totalling 1.4 GW (out of 1.5 GW allocated) bid a "zero" premium on wholesale market prices; this does not include the cost of grid connection, which will be built by the transmission system operator and paid for by consumers. These prices were likely to have resulted from several factors, including significant cost reductions in O&M due to park clustering, larger and more efficient turbines, and the expectation of higher wholesale electricity prices in the future.

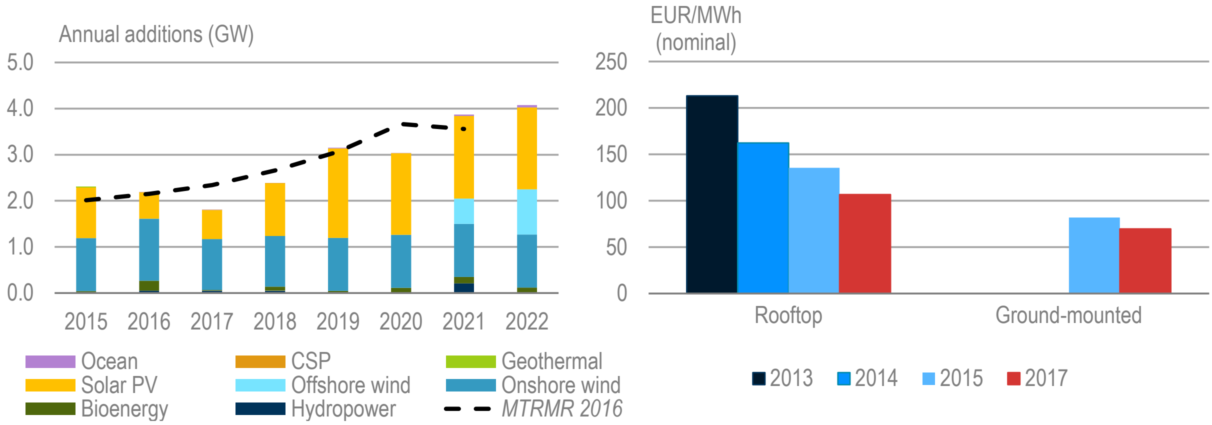
Solar PV is expected to increase by 8 GW by 2022, although annual growth is expected to remain below targeted levels as auction volumes limit expansion for utility-scale projects and sluggish growth continues for distributed applications. Since 2015, over 1.3 GW have been auctioned with winning bids falling 38% from EUR 92/MWh in the first round to EUR 56/MWh in the eighth round held in June 2017. Looking ahead, auctions will continue to drive utility-scale deployment, but the pace of expansion will be limited by the annual tender volumes, which are capped at 600 MW. This implies that distributed systems should account for the remaining 2.5 GW annual target, a challenging prospect given the slowing growth in the commercial segment.

In 2016, commercial PV growth continued to slow, down 7% compared to 2015, as low electricity tariffs coupled with insufficient support levels and self-consumption charges challenged the economics of the segment. This trend is expected to continue over the forecast period as recent developments suggest the economic attractiveness is becoming increasingly uncertain. In Q2 2017, support levels under the FIP/FIT were further lowered for the first time since September 2015 due to tariff digressions triggered by a developer rush in the utility segment. Furthermore, under the EEG2017, large commercial systems (>750 kW) are required to compete in auctions with larger utility-scale systems from 2017 onwards and may find winning support challenging. Annual deployment in the residential sector is expected to remain stable, with a total of 1.8 GW added over the next five years as high electricity tariffs and storage incentives increase the attractiveness of self-consumption.

France: Main case forecast

France's renewable capacity is expected to grow by 18 GW on the back of a favourable new policy environment with deployment targets supported by competitive auctions, although annual deployment may fluctuate during the transition from government-set tariffs. Overall the forecast is revised up slightly from last year due to a more optimistic outlook for solar PV and bioenergy after recent regulatory and policy changes. Annual deployment is forecast to increase over 2017-22, supported by the long-term target for 40% renewable electricity by 2030 and individual technology-specific capacity targets for 2018 and 2023, introduced in the country's first ten-year review plan released in 2017. In the near term, annual growth is expected to come from solar PV and onshore wind projects supported by a mix of incentive schemes including FITs, FIPs and tenders. The deployment of smaller systems is expected to rise from an increasingly supportive environment for self-consumption. In 2016, the first technology-neutral tenders for 60 MW of self-consumption were held for systems sized 100-500 kW, and 450 MW are planned by 2020. Furthermore, a clear framework for grid connection for self-consumption was introduced in 2017.

Figure 2.24. France annual net renewable capacity additions, 2015-22 (left) and average solar PV winning bids, 2013-17 (right)



Note: Average winning bids for ground-mounted auctions in 2013 and 2014 are not available.

Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Renewable capacity growth in France is led by **solar PV**, anticipated to increase by 9 GW, mostly driven by auctions for utility and commercial systems. However, annual deployment may be volatile due to uncertainty over the impact of various policy transitions on the project pipeline. In May 2016, the FIT for systems over 100 kW ended, followed by the announcement to resume auctions for ground-mounted and large rooftop solar PV systems, with plans to tender 3 GW over 2017-20. By early 2017, auctions for both categories were held, with average winning bids falling by 15% and 20% respectively since 2015 (Figure 2.24). While the new auction scheme is expected to drive growth over the next five years, the absence of an auction schedule after 2019 introduces uncertainty to the forecast post 2020. The main case forecast assumes additional auctions will be held to reach the minimum 18 GW target for 2023, supported by cost reductions. Additional solar PV deployment is also expected from technology-neutral self-consumption auctions and from innovative PV design tenders.

Recent policy and regulatory changes indicate a more optimistic outlook for distributed solar PV applications, particularly for self-consumption. Systems up to 1 MW will now be exempt from the CSPE (renewable and social surcharge on electricity bills) and other taxes for electricity produced and consumed on site. This should attract large industrial consumers since the previous threshold was limited to 240 GWh per year. The changes are also considered to be a positive development for smaller systems (<100 kW), as new investment rebates will be available and they can also benefit from lower grid charges. However, quantifying the upside is difficult as relatively low retail electricity tariffs and higher selling prices under the sell-all FIT scheme, which remains available, may challenge the business case for self-consumption.

Onshore wind is expected to grow by almost 7 GW over 2017-22, although there are uncertainties over the contribution from small wind projects and how annual deployment will be affected by the transition from guaranteed FIPs to competitive auctions. In 2016, the government announced that the FIP support scheme would end by December 2016, one year early due to legal challenges under EU law, prompting the new auction scheme to begin one year early, by end 2017. The impact of this change on the project pipeline for 2017 and 2018 is uncertain as it may cause both a developer rush to lock in expiring FIP support at EUR 82/MWh before auctions begin, as well as lulls in the project pipeline until the first tenders are held at the end of 2017. From 2019 onwards, deployment should largely be guided by auctions for 1 GW per year, although additional growth is expected to come from smaller projects outside the auction process. Projects with fewer than six turbines are still eligible for support under the FIP, which, coupled with the simplified permitting procedures, should drive some growth, although to what extent remains a forecast uncertainty.

The forecast for **offshore wind** is revised down after developers announced they anticipated commissioning delays until 2021. **Bioenergy** capacity is forecast to grow by 500 MW over 2017-22, an increase of 30% on 2016 capacity. Deployment is driven by tenders for biomass co-generation and biogas projects, with the first auction delivering just under 70 MW of capacity.

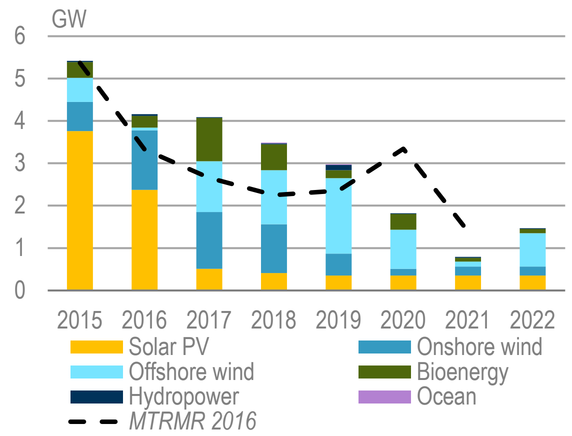
United Kingdom: Main case forecast

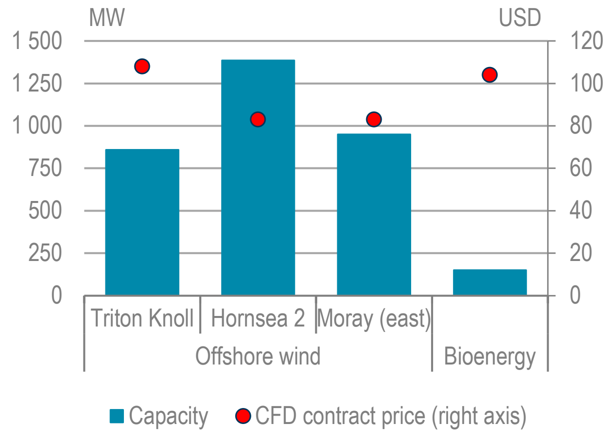
Renewable electricity capacity in the United Kingdom is expected to increase by around 14.5 GW over 2017-22, a slight downward revision from last year's forecast (Figure 2.25). Offshore wind is the main contributor to growth as a result of policy support via the Contracts for Difference (CfD) scheme, followed by onshore wind, bioenergy and solar PV.

CfD auctions for 15-year power purchase contracts will be the principal policy framework for renewable electricity support over the forecast period. The second CfD auction in 2017 awarded 3.2 GW of offshore wind and 150 MW of bioenergy capacity for commissioning over 2021-23. Based on previous government announcements, two further auctions are anticipated by 2020, although winning capacity would most likely be commissioned outside the forecast period.

Meanwhile, the Renewables Obligation (RO) support scheme was closed to new applications from all technologies in March 2017, following an early closure for onshore wind and solar PV technologies in 2016. Five specific "grace period" conditions allow applications to the scheme up until early 2019, and are anticipated to facilitate some residual bioenergy, onshore and offshore wind capacity within the forecast. For PV, wind, hydro and biogas technologies below 5 MW, the FIT scheme is anticipated to continue to support deployment over the forecast period, albeit at a lower level than the past due to the introduction of deployment caps.

Figure 2.25. UK annual net renewable capacity additions, 2015-22 (left) and 2017 CFD auction results (right)





Source: BEIS (2017), Contracts for Difference second allocation round results. Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org.

Offshore wind is expected to account for 42% (6 GW) of net additions to renewable capacity in the United Kingdom over the next five years. The majority of new offshore wind capacity is anticipated to be delivered from the CfD auction mechanism, complemented by some lower-level deployment from residual grace period projects under the RO scheme. The UK offshore wind industry surpassed the joint government and industry levelised cost of electricity (LCOE) target of GBP 100/MWh (USD 111), set for 2020, four years early due to a combination of the transition to larger and more efficient turbines, competitive CfD auctions and access to cheaper capital (ORE Catapult, 2017).

Onshore wind capacity is expected to grow by 3.6 GW over 2017-22, but annual growth is seen slowing due to the absence of policy support. The majority of deployment occurs in the first half of the forecast period from RO grace period projects and the delivery of capacity awarded contracts in the 2015 CfD auction. No further policy support for onshore wind is expected post 2019 and as such lower deployment levels are forecast. With wind speeds unlikely to be sufficient to deliver profitable projects without policy support in England, the best prospects for development without policy support could occur in Scotland, where over 2 GW of projects are already permitted and the government has challenged the industry to develop the country’s first subsidy-free wind farm.

Lower **solar PV** growth is expected over 2017-22 with 2.3 GW of deployment, down 80% compared to the 11.5 GW added over 2011-16. Annual additions are expected to slow to 350-500 MW, much lower than observed during 2013-16, due the closure of the RO scheme compounded by technology deployment caps and tariff reductions in the FIT scheme. Most deployment is anticipated in applications below 10 kW, mostly in the residential sector, as this segment has the highest deployment cap limits.

Bioenergy capacity is anticipated to grow by 2.4 GW by 2022, a 46% increase on 2016 levels. Major projects that feature prominently in the forecast include a 395 MW coal to biomass conversion project, and a 299 MW electric co-generation project, both of which have been awarded CfD support and are under construction. **Hydropower** capacity is anticipated to increase by 220 MW through the delivery of a 100 MW PSP, augmented by small-scale hydro projects receiving FIT support.

Box 1.1. Implications of Brexit on the UK renewable energy market

The outcome of the June 2016 referendum, that the United Kingdom will leave the European Union (termed “Brexit”), has wider implications for the European energy landscape. Brexit will require a renegotiation of the future energy relationship between the United Kingdom and remaining EU member states. However, energy represents just one of many areas subject to agreement within the negotiations of the United Kingdom’s departure, and it is unlikely the outcome of energy-related negotiations will be clear until 2018 at the earliest. This means that energy markets will face some additional uncertainty, which may in turn have an impact on the United Kingdom’s attractiveness in respect to the private-sector investment required to modernise its ageing electricity generation fleet and meet its decarbonisation and energy security challenges.

The finer details of Brexit’s implications for renewable capacity deployment in the United Kingdom remain to be seen. However, some key areas of impact have already come to light. Firstly, since the referendum decision, the value of the pound sterling has dropped against both the US dollar and the euro. Consequently, fuel and electricity imports (via the country’s existing three interconnectors with EU countries) have become relatively more expensive, as have imported plant and equipment. In addition, uncertainty over the negotiations is increasing perceived investment risk. For instance, one major turbine manufacturer stated in 2016 that it was freezing new investment in the UK wind industry pending further clarity on the country’s future trading relationship with the European Union. This is accompanied by potential disruption to the UK energy sector's workforce associated with changes to the right of EU expatriates to remain and work in the United Kingdom after its exit.

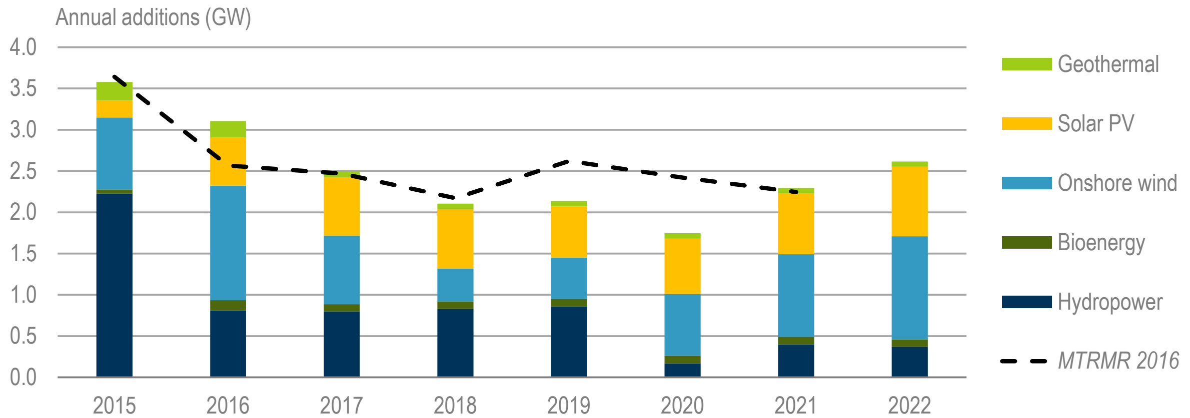
Brexit may also have implications for UK electricity security and prices. In 2015, 23 TWh of electricity, (around 7% of total UK demand) was imported from EU countries via existing interconnectors (which have a capacity of 3.5 GW). The importance of electricity interconnectors with EU and other European countries will increase due to their value to the UK's electricity system in balancing supply and demand within a generation portfolio comprising higher shares of variable renewable generation and reduced dispatchable capacity due to baseload retirements. Greater interconnector capacity is also considered a key means of limiting increases in electricity prices. New projects are in various stages of development with France, Belgium, Norway (which sits outside the European Union) and potentially Denmark. While strong drivers remain for the United Kingdom to retain links to an integrated EU electricity market, these major infrastructure projects could potentially face delays due to uncertainty regarding the future status of the United Kingdom within the EU energy union.

The obligation of the United Kingdom to comply with its EU 2020 Renewable Energy Directive target for renewable energy consumption after its departure in 2019 is also unknown. Nevertheless, ongoing activity on energy system decarbonisation will be required because of the United Kingdom's own legally binding carbon emissions reduction target of 57% (on 1990 levels) by 2030. Ongoing participation within the EU Emissions Trading System is also called into question by Brexit.

Turkey: Main case forecast

Renewable capacity is expected to grow by 13.4 GW over 2017-22, led by onshore wind (4.7 GW), solar PV (4.3 GW) and hydropower (3.4 GW), with smaller contributions from geothermal and bioenergy (Figure 2.26). The forecast is revised down slightly from last year's report as a result of a more pessimistic outlook for onshore wind. Overall, Turkey is on track to reach its 2023 capacity targets for solar PV, geothermal and bioenergy, while onshore wind trails behind.

Figure 2.26. Turkey annual net renewable capacity additions, 2015-22



Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017,* www.iea.org/statistics/.

Onshore wind capacity is expected to grow from almost 6 GW in 2016 to 10.6 GW in 2022, falling short of Turkey's 20 GW 2023 target. Despite the record growth seen in 2016 (1.4 GW), annual additions are forecast to decline over 2017-18 due to a lull in the project pipeline resulting from delays in both new licence approvals under the FIT scheme and the start of the new auction scheme

(Renewable Energy Resource Areas, or YEKA). In June 2017, the government finally opened the competition for new licences and awarded 0.7 GW of capacity. However, there are concerns whether these projects will be commissioned as some would receive only the wholesale market price, challenging their bankability. Meanwhile in August 2017, the government held a YEKA auction and awarded 1 GW capacity at USD 35/MWh, half the ceiling price. This price is one of the cheapest globally despite a requirement to build a local nacelle assembly facility, underscoring the economic attractiveness of the technology. Annual growth is expected to rebound in the second half of the forecast under the assumption that additional auctions will be held in 2018 and 2019 for 1 GW each.

Solar PV capacity is forecast to expand by 4.3 GW over 2017-22, led by utility-scale projects driven by both FITs and newly opened competitive auctions. In the near term, annual growth is expected to remain rather stable, driven mostly by FITs. However, uncertainty exists over the pace of growth of the unlicensed project segment (which accounted for most of the PV industry's recent growth) due to the introduction to stricter regulations and increased grid fees. By the end of the forecast period, most of the growth should originate from competitive auctions. In March 2017, an auction for a 1 GW single project was opened with an added requirement to build a 500 MW panel manufacturing plant. The winning bid, USD 70/MWh, was 40% lower than the previous FIT and is expected to account for most of the growth over 2020-21. For distributed generation, FITs should continue to drive the growth of large-scale rooftop systems, while for residential projects the clarification of self-consumption regulations remains a barrier.

For other technologies, **hydropower** is forecast to grow by 3.4 GW over 2017-22, mostly driven by the commissioning of large-scale projects such as Ilisu, Yukari Kalekoy and Yusufeli in the first half of the forecast period. However, after the commissioning of these projects, the pipeline remains relatively small, leading to a decline in annual additions after 2019. **Geothermal** capacity should continue to grow over the next five years (by 0.4 GW) supported by FITs. With this growth, Turkey alone represents about 10% of global geothermal capacity growth over 2017-22.

Table 2.9. Europe drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Germany	Targets combined with support schemes and predictability from a clear timeline of fixed-volume auctions.	Grid constraints and transmission capacity; ageing onshore wind fleet; self-consumption surcharge for commercial PV.
France	Ambitious targets supported by auctions, with a clear schedule for solar PV up until 2019; regulatory and financial support for self-consumption.	Non-economic barriers and unclear auction schedule for onshore wind; lengthy permitting times for offshore wind.
United Kingdom	Strong pipeline for offshore wind and bioenergy coupled with policy support; new capacity needs.	Policy uncertainty regarding CfD auction timeline; reduced support and visibility for onshore wind and solar PV; unclear policy outlook post-2020.
Turkey	Robust power demand growth; competitive renewable resources; auctions for large-scale solar and wind projects.	High grid connection and usage costs for utility-scale wind and solar PV; administrative and regulatory challenges for self-consumption.

Other countries in Europe: Main case forecast

The Netherlands' renewable capacity is forecast to grow by over 8 GW over 2017-22, led by solar PV (3.7 GW) due to the increasing number of projects winning support in competitive auctions and the attractiveness of residential systems under the net-metering scheme. Stable growth across all segments is expected, although permitting challenges and land constraints pose a downside risk. Competitive auctions also drive the robust wind growth (4 GW), led by offshore projects driven by increasing economic attractiveness. Winning bids dropped 25% between the first two rounds held in 2016 and 2017 signalling the technology's cost reduction potential. Bioenergy is expected to be the largest single source of renewable generation over the next five years (7 TWh) due to support won in auctions for co-firing in existing coal plants and co-generation and gasification in new plants.

Spain's renewable capacity is expected to grow by over 9 GW by 2022, led by onshore wind and followed by solar PV. The forecast is a significant upward revision to last year's edition due to a series of auctions held over 2016-17 to reach 2020 targets. Annual deployment is expected to peak between 2018 and 2019 due to the auction deadlines for commissioning by 2020. Stable deployment is expected for distributed solar PV, mostly in residential systems driven by self-consumption and the exemption from the variable grid charges, which have applied to commercial-scale systems since 2016.

Belgium's renewable capacity is forecast to expand by almost 3.7 GW over 2017-22, driven by federal and community quota systems based on the trading of certificates. Over 70% of the expansion (2.6 GW) is expected to come from wind, almost evenly split between offshore and onshore projects. The remainder of the growth is anticipated to be from distributed PV and bioenergy capacity.

Denmark's renewable capacity is forecast to grow by 3.5 GW, driven by long-term goals to cover 100% of energy needs from renewables by 2050. However, recently announced plans to transition from FIPs to a market-based support scheme have emerged as a forecast uncertainty. Almost half of the growth is from offshore wind (1.6 GW), followed by bioenergy (1.0 GW) driven partly by large-scale biomass conversions in 2017 (390 MW) and 2019 (150 MW), and onshore wind (0.6 GW).

Compared to 2011-16 when 22 GW of renewable capacity was installed, **Italy's** growth over 2017-22 is expected to slow, increasing by only 3.5 GW. Nearly half of the growth is forecast from residential PV where good resource potential coupled with a net metering scheme make investments attractive, while onshore wind is expected to increase by 1 GW, supported by the auction scheme.

Sweden's renewable capacity is expected to grow by 2.7 GW, driven by the technology-neutral quota system shared with Norway. Onshore wind leads the growth (1.8 GW). Bioenergy is forecast to grow by around 500 MW, mostly from co-generation projects linked to industry or municipality district heating schemes, with both biomass and waste fuels as sources. Renewable capacity expansion in **Portugal** will be led by hydropower (1.8 GW out of 2.3 GW), due to the commissioning of several PSPs over 2017-22. Meanwhile, annual hydropower capacity additions slow in **Norway** over the forecast period due to challenging economics from low wholesale electricity prices and high taxes on hydropower plants. **Ireland's** renewable capacity is forecast to grow by 1.6 GW, led almost entirely by onshore wind, driven by 2020 targets and a supportive regulatory environment to ensure power system flexibility.

Europe: Accelerated case forecast

In the accelerated case, Europe's renewable capacity growth could reach 152 GW over 2017-22, 22% higher than the 125 GW expected in the main case, mostly from increased solar PV and wind deployment, with contributions from bioenergy and hydropower (Figure 2.10). The upside for deployment in markets driven by auctions is rather limited given the current auction schedules and fixed volume caps or pre-determined funding allocations. Accelerated growth in major markets would depend on additional auctions held beyond 2020, improved network interconnections, and would be facilitated by further cost reductions in certain technologies.

Table 2.10. Europe main and accelerated cases cumulative capacity, 2016 and 2022

Total capacity (GW)	Germany			France			United Kingdom			Turkey		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	11.4	11.4	11.4	25.3	25.6	25.6	4.5	4.8	4.8	26.7	30.1	30.8
Bioenergy	9.1	9.6	9.9	1.8	2.3	2.3	5.1	7.5	8.0	0.4	0.9	0.9
Onshore wind	45.6	62.1	62.7	11.6	18.4	22.6	10.6	14.2	14.2	5.9	10.6	11.8
Offshore wind	4.1	6.9	7.8	-	1.5	1.5	5.2	11.2	11.2	-	-	0.0
Solar PV	41.2	49.2	54.6	7.3	16.4	19.4	11.6	13.9	13.9	0.8	5.1	6.0
CSP	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.8	1.2	1.2
Ocean	-	-	-	0.2	0.3	0.3	0.0	0.0	0.0	-	-	-
Total	**111.4**	**139.1**	**146.4**	**46.3**	**64.0**	**70.3**	**37.0**	**51.6**	**52.0**	**34.6**	**48.0**	**50.9**

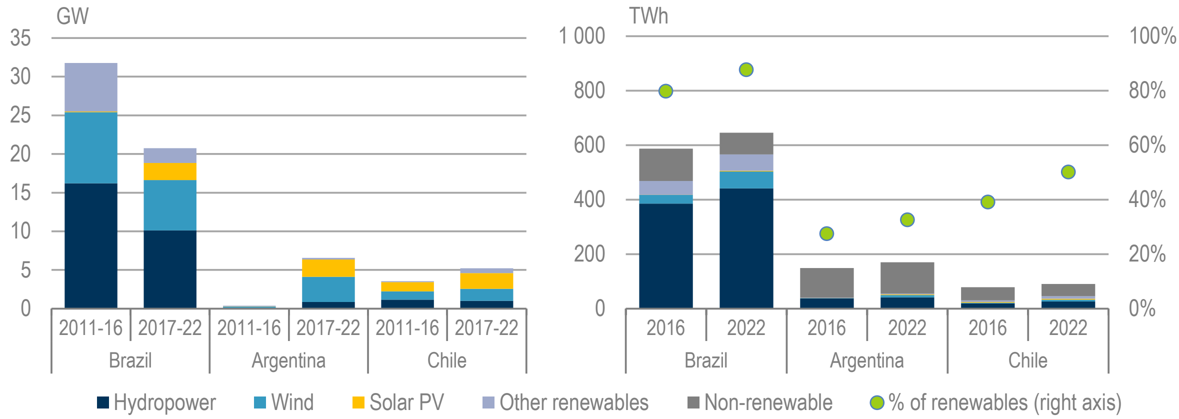
Note: Acc. = accelerated. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

An additional 11 GW of solar PV could be deployed, particularly from improved economics for distributed PV in Germany and additional auctions held toward the end of the forecast period for utility-scale systems in France. Onshore wind could be 10.4 GW higher from rapid financial close and commissioning of winning projects from Spain's auction and a clear timeline for tenders in France, while offshore wind could be 3.5 GW higher by 2022 from faster development of projects in Germany, the Netherlands, Belgium, Ireland and France. Overall, improved regional interconnection to facilitate trade and continual upgrades to transmission capacity to ease grid constraints would also facilitate faster wind development in Europe.

Latin America

In Latin America, renewable capacity in the main case is expected to grow by 42 GW over 2017-22, led principally by hydropower (15.4 GW), onshore wind (13.5 GW) and solar PV (9.4 GW), mostly driven by competitive auctions with the exception of large hydro projects. With great resource availability, robust competition, and high imported fossil fuel prices, wind and solar projects in certain countries have achieved record-low contract prices – lower than fossil fuel alternatives. However, renewable growth is expected to be slower in the region compared to the previous five-year period. This trend is mainly dictated by Brazil's more pessimistic outlook, as the government cancelled renewable energy auctions and de-contracted previously signed renewable PPAs due to economic recession. With the successful implementation of renewable auctions, Argentina's forecast is more optimistic with renewable expansion expected to surpass that of Chile over 2017-22, where grid integration and financing challenges remain. Overall, the share of renewables is expected to increase fastest in Chile, followed by Brazil and Argentina (Figure 2.27).

Figure 2.27. Latin America renewable electricity capacity growth, 2011-22 (left) and generation by source, 2016 and 2022 (right)



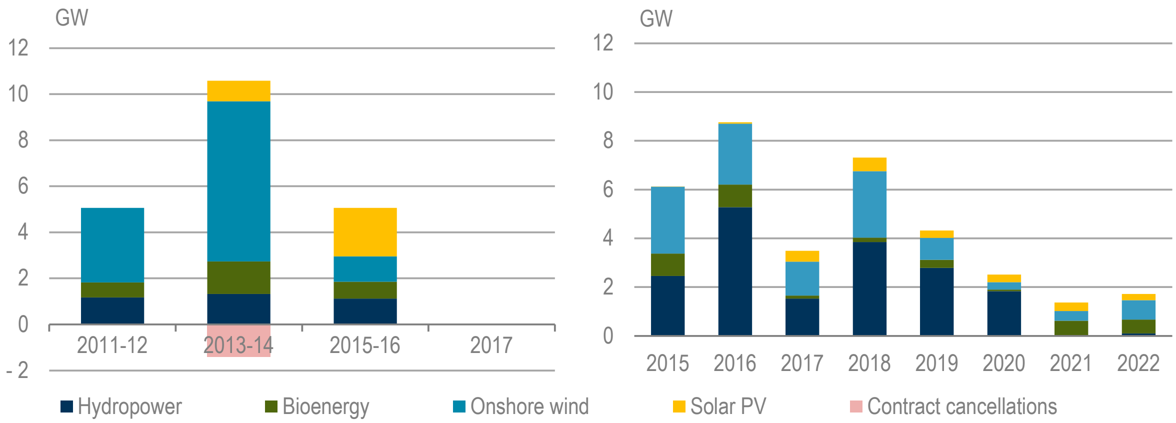
Source: Historical capacity data for OECD countries based on IEA (2017a), *Renewables Information 2017.*

Brazil: Main case forecast

Renewable capacity in Brazil is expected to grow from 121 GW in 2016 to 142 GW in 2022, driven by new additions to hydropower (10.1 GW), wind (6.5 GW), bioenergy (1.9 GW) and solar PV (1.6 GW). Overall, the share of renewables in Brazil's electricity output is anticipated to increase from 80% in 2016 to over 85% in 2022. Energy auctions with long-term PPAs, combined with low-cost financing from the Brazilian Development Bank (BNDES), have been major drivers for the expansion of both the new capacity and renewable manufacturing industry since 2009. However, the current macroeconomic situation and challenging investment environment have increased forecast uncertainty. As a result, the forecast is lower compared to last year's report for all renewable technologies.

In 2014, the Brazilian power market experienced supply shortages due to severe drought and high electricity demand growth. Two years later in 2016, the same market was oversupplied due to economic recession. As a result of lower demand, and having postponed them twice, the Ministry of Energy and Mines (MME) cancelled its wind and solar PV auctions in December 2016. The government awarded only 0.6 GW of new capacity from hydropower and bioenergy projects in 2016, low when compared to the 5-7 GW awarded annually 2013-15. In May 2017, distribution companies announced about 4 GW of surplus electricity capacity as a result of lower demand growth. In June 2017, Brazil held de-contracting auctions, which awarded the right to cancel or reduce PPAs signed in previous auctions. Contract holders with about 1.4 GW of power capacity cancelled or reduced their obligations, with wind projects representing the majority, followed by hydropower and bioenergy. *Renewables 2017* does not anticipate much new renewable capacity being awarded over 2017-19, leaving the pipeline for new build projects limited over the forecast period and resulting in a decline in annual additions after 2019 (Figure 2.28).

Figure 2.28. Brazil renewable electricity auction results, 2011-17 (left) and annual net renewable capacity additions, 2015-22 (right)



Hydropower expansion leads the forecast with 10.1 GW expected to become operational between 2017 and 2022, mostly from already-financed large-scale projects contributing to the current oversupply situation of the power market. The majority of this growth should come from the full commissioning of Belo Monte and Baixo Iguacu plants, with contributions from smaller projects auctioned since 2009. Overall, hydropower remains the largest source of electricity generation in Brazil with its share still forecast to increase from 66% in 2016 to over 68% in 2022.

Onshore wind is expected to expand by 6.5 GW, mostly driven by projects that have already signed PPA contracts and closed financing. However, in the recent de-contracting auctions, developers reduced contracts for 1.4 GW of capacity, of which over 1 GW will not be built. The majority of wind additions still subject to contract obligations is anticipated to be commissioned over 2017-19, leaving the project pipeline relatively empty in the second half of the forecast. Although the main case assumes some additional wind capacity is awarded around 2018-19, financing and grid connection challenges remain forecast uncertainties that may result in commissioning delays. Furthermore, additional contract cancellations are still possible, which may reduce the pipeline further.

Solar PV is expected to grow from only 80 MW in 2016 to over 2.3 GW in 2022. The government awarded close to 1 GW of solar PV capacity in 2014 and 2 GW in 2015, which are scheduled to become operational in 2017 and 2018 respectively. However, it is estimated that only 300-500 MW of these projects have reached financial close and commenced construction. Some project developers have requested cancelling their contracts, but solar PV was not included in the first de-contracting auction. While BNDES indicated that it could increase its debt participation for contracted solar PV projects, uncertainty remains over their financing and commissioning. The majority of Brazil's solar PV capacity is anticipated to come from utility-scale projects, while distributed generation is also anticipated to contribute capacity of over 0.6 GW over the forecast period. For distributed applications, tax exemptions in more than 20 Brazilian states, high retail power prices – which have increased by over 50% since 2014 – and the net metering scheme are expected to drive some growth. However, affordable financing remains an important challenge to deployment.

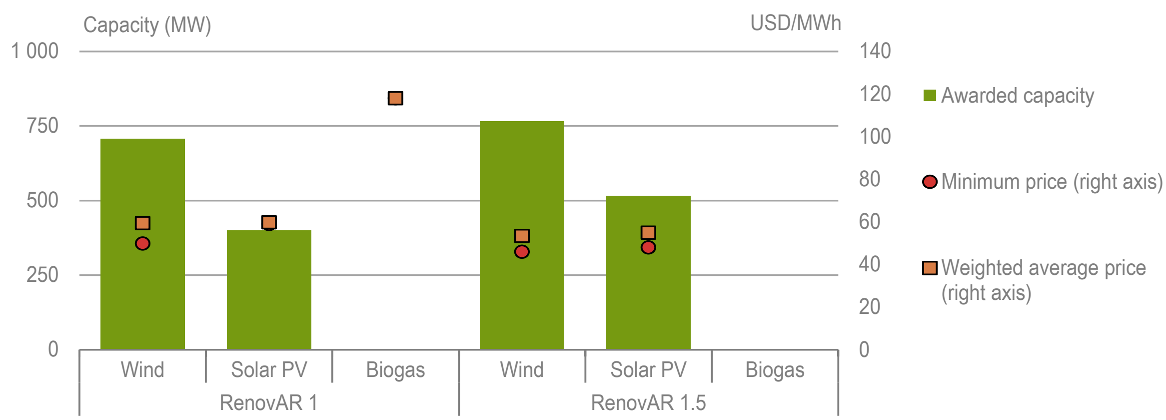
Lower annual deployment is anticipated for **bioenergy** with an overall increase of 1.9 GW expected over 2017-22, a reduction on the last year's forecast. Prospects for large-capacity industrial projects, developed outside the PPA auction framework, and at facilities which produce biomass residues, are diminished due to the wider economic outlook. In addition, the weaker Brazilian real versus the US dollar makes imported equipment, such as turbines, relatively more expensive and can challenge project economics. It is anticipated that growth in bioenergy capacity will be underpinned by bagasse co-generation linked to additional ethanol production capacity, supported by the forthcoming federal RenovaBio plan. In addition, São Paolo state enacted legislation to add a percentage of biomethane to natural gas supplies, which may invigorate biogas deployment.

Argentina: Main case forecast

Argentina's total renewable capacity is forecast to grow by 49%, or over 6.5 GW, during 2017-22, driven by the government's ambitious renewables target and the auction programme launched in 2016. Overall, the forecast is more optimistic compared to last edition due to successful implementation of two auction rounds and the approval of the World Bank financing. With great resource availability, wind and solar PV are expected to lead the renewable expansion, but financing and grid connection are expected to remain challenging for some projects.

In 2016, Argentina awarded 2.4 GW of renewable capacity in two auction rounds. In the first round, 0.7 GW of wind and 0.4 GW of solar PV capacity won the auction with average contract prices of USD 59/MWh and USD 60/MWh respectively. As the first auction was oversubscribed, the government decided to open the second round immediately and awarded 0.76 GW of wind and 0.52 GW of solar projects. Due to strong competition, the average prices declined in the second round by 10% for wind and 8% for solar (Figure 2.29). Developers of winning bids included local governments, domestic independent power producers (IPPs) and utilities, as well as some Chinese and Spanish renewable companies.

Figure 2.29. Argentina RenovAR 1 and 1.5 auction results



Source: MINEM (2016), *Proyectos Adjudicados del Programa RenovAR Rondas 1 y 1.5* [Projects Awarded in Programme RenovAR 1 and 1.5].

Considering Argentina's current macroeconomic challenges, development financing and payment guarantee measures are expected to play a key role in Argentina's renewable expansion. In order to facilitate the financing of renewable projects, Argentina established the Fund for the Development of Renewable Energies (FODER), which is expected to provide payment guarantees for PPAs tendered by the off-taker (CAMMESA), and offers project financing assistance. In January 2017, the World Bank approved a 20-year USD 480 million guarantee payment in case of off-taker defaults, while the Green Climate Fund (GCF) announced a loan of USD 130 million for renewable projects. In addition, the new regulation allowing developers to sign PPAs with third parties other than CAMMESA is being drafted at the time of writing, which was not considered in the main case forecast, but could enable additional deployment.

Onshore wind is expected to lead the forecast with an anticipated 3.3 GW becoming operational over 2017-22, followed by **solar PV** with 2.3 GW, mostly driven by RenovAR tenders. Overall, the majority of winning bids in the first two auction rounds signed PPAs with CAMMESA, and are expected to become operational mostly on time. However, financing is anticipated to remain a challenge for projects awarded in the second round with lower prices, which could lead to commissioning delays and/or cancellations. In addition, grid infrastructure in Argentina remains weak in some areas, which may be a challenge for certain projects and may also influence capacity auctioned in future tenders. Apart from wind and solar PV, **hydropower** is anticipated to expand by almost 0.9 GW, mostly from two large-scale projects (Jorge Copernic and Presidente Nestor Kirschner) under construction.

Chile: Main case forecast

Chile's renewable capacity is expected to expand by over 5.2 GW over 2017-22, driven mostly by competitive and technology-neutral energy auctions held over the last three years. Solar PV is anticipated to lead the forecast, followed by wind, hydropower and CSP. Overall, the forecast is revised down compared to last year as grid integration and financing challenges for new projects are expected to persist. Despite these challenges, the share of renewables in Chile's electricity mix is expected to increase from 39% in 2016 to 50% in 2022.

Auctions remain the main driver for wind and solar PV, but the lack of contract price stability remains an important challenge for project financing. During the auctions held both in 2015 and 2016, renewables offered very competitive prices ranging from USD 29/MWh to USD 85/MWh, lower than natural gas, and won contracts to deliver an estimated 2 TWh annually starting from 2018, and another 6 TWh from 2021. However, the long-term PPAs awarded in these energy auctions do not fully guarantee price stability over the contract period. Developers have to account for the price difference risk between the generation and distribution nodes. Therefore, the main case forecast expects that financing will remain challenging for some projects that won contracts in previous auctions, resulting in delays or cancellations. In January 2017, the government announced new rules for upcoming energy auctions, with higher penalties for project cancellations, in order to minimise unrealistic bids and ensure project delivery.

Solar PV is anticipated to grow by more than 2 GW over 2017-22, mostly from utility-scale projects. The majority of commissioned and planned solar PV projects are concentrated in the north of Chile. As a result, prices in some nodes have been dropping to zero frequently on sunny days. Accordingly, developer revenues have decreased, especially for merchant projects, which currently seek PPAs or bilateral contacts with mining companies. In addition, curtailment rates increased from 0.5% in September 2015 to 2.3% in April 2016, which also contributed to revenue declines for some solar plants. The commissioning of two transmission lines (Cordanes-Polpaico and Copiapo-Santiago), which is expected to address some of the integration challenges, was delayed due to opposition from local communities and financing issues. This report assumes that these lines will be commissioned in 2019, resulting in connection delays for some PV projects in the north of Chile.

Onshore wind is expected to grow by 1.5 GW over 2017-22. In August 2016, wind developers won the majority of contracts auctioned, with prices ranging from USD 40/MWh to USD 53/MWh and plants to be commissioned in 2021. However, these low prices have raised issues concerning their bankability, especially considering limited resource potential, relatively high financing costs, and grid integration risks. Similar to solar PV, it is expected that some of these projects will experience financing challenges or commissioning delays. In addition, some developers can fulfil their contract obligations through existing projects.

For other technologies, the forecast is also revised down in the face of financing challenges. Hydropower is expected to expand by 1 GW with the commissioning of projects under construction. Chile has a large pipeline of CSP projects with storage, but their development has been slow due to high investment costs. For geothermal, predevelopment risks remain a challenge for developers seeking to enter auctions with strict project delivery dates.

Table 2.11. Latin America drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Brazil	Energy auctions with long-term PPAs; low-cost financing from BNDES; state-level tax incentives for distributed PV.	Increasing investment and currency risk; overcapacity of electricity market; grid integration.
Argentina	Long-term targets with competitive tenders; great resource availability; concessional financing.	High country risk and weak grid infrastructure in some locations.
Chile	Excellent resources and competitive tenders.	Financing challenges; increasing curtailment and delays in grid infrastructure development.

Latin America: Accelerated case forecast

In Latin America, renewable capacity growth over 2017-22 could be 13% higher under the accelerated case compared with the main case (Table 2.12). In **Brazil**, renewable growth could be 3.5 GW higher in 2022 with wind and solar accounting for the majority of this upside. This extra growth would depend on the timely delivery of already-auctioned capacity and continuing BNDES financing. For distributed solar applications, accelerated growth would require an alternative financing mechanism that offers relatively low interest rates. For hydropower, the upside is limited but faster-than-expected commissioning of small hydropower projects could contribute to the accelerated case. Bioenergy in Brazil could increase by 0.5 GW as a result of additional auctions delivering capacity post-2020, as well as heightened sugar and ethanol industry investment driving new bagasse co-generation plants. In **Argentina**, onshore wind and solar PV account for almost all additional growth potential, which would require timely financing and grid connection of all auctioned projects, and the government’s ability to attract additional funds for FODER. The additional expansion of renewables in **Chile** will mainly depend on timely grid connection of wind and solar projects, as the delivery dates of new auctions are outside the *Renewables 2017* forecast period.

Table 2.12. Latin America main and accelerate cases summary, 2016 and 2022

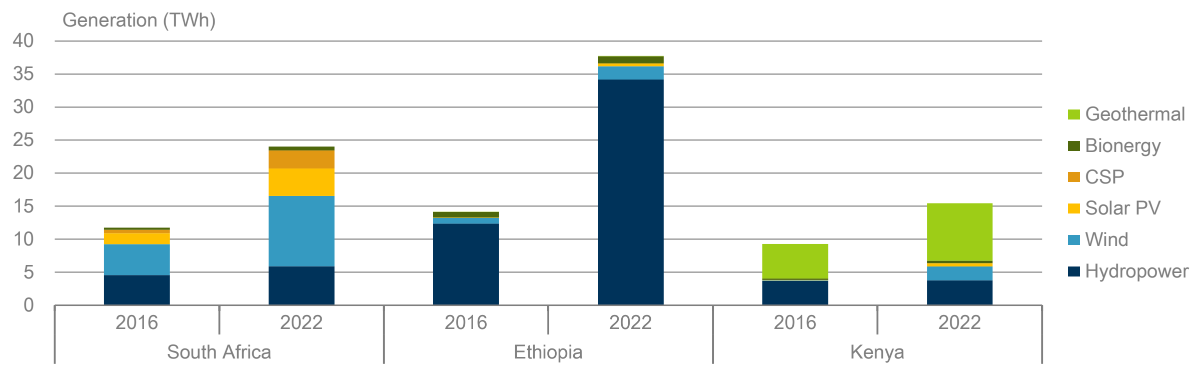
Total capacity (GW)	Brazil			Argentina			Chile			Latin America		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	96.9	107.0	107.4	12.5	13.3	13.3	6.6	7.6	7.6	170.2	185.6	186.0
Bioenergy	14.2	16.1	16.7	0.7	0.8	0.8	0.7	0.8	0.8	19.0	22.0	22.6
Onshore wind	10.1	16.6	17.8	0.2	3.5	3.8	1.2	2.8	3.3	14.5	28.0	30.0
Solar PV	0.1	2.3	3.7	0.0	2.3	3.1	1.2	3.2	3.6	2.6	12.0	14.5
CSP	-	-	-	-	-	-	-	0.4	0.4	-	0.4	0.4
Geothermal	-	-	-	-	0.0	0.0	-	0.1	0.1	0.7	1.2	1.2
Total	**121.3**	**142.1**	**145.6**	**13.4**	**19.9**	**21.1**	**9.7**	**14.9**	**15.8**	**207.0**	**249.1**	**254.7**

Note: Acc.= accelerated. Rounding may cause non-zero data to appear as “0.0” or “-0.0”. Actual zero-digit data is denoted as “-“.

SSA

In SSA renewable capacity is expected to grow by 73% (24.4 GW) over 2017-22, in line with last year’s forecast. Deployment will be driven by new capacity needs as a result of growing power demand and increasing electrification, coupled with supportive policies and de-risking measures in various markets to address financing challenges. However, the pace of deployment remains constrained, considering the region’s potential, due to weak grid infrastructure, land acquisition issues and the limited availability of affordable financing as risks associated with off-taker reliability and policy uncertainties persist. Hydropower leads the forecast in SSA (up 12.4 GW) with Ethiopia representing a third of regional additions. Non-hydropower technologies are expected to ramp up, with solar PV (7.2 GW) adding twice as much as onshore wind (3.2 GW), with South Africa leading the growth in these sources (Figure 2.30).

Figure 2.30. SSA renewable electricity generation by source, 2016 and 2022

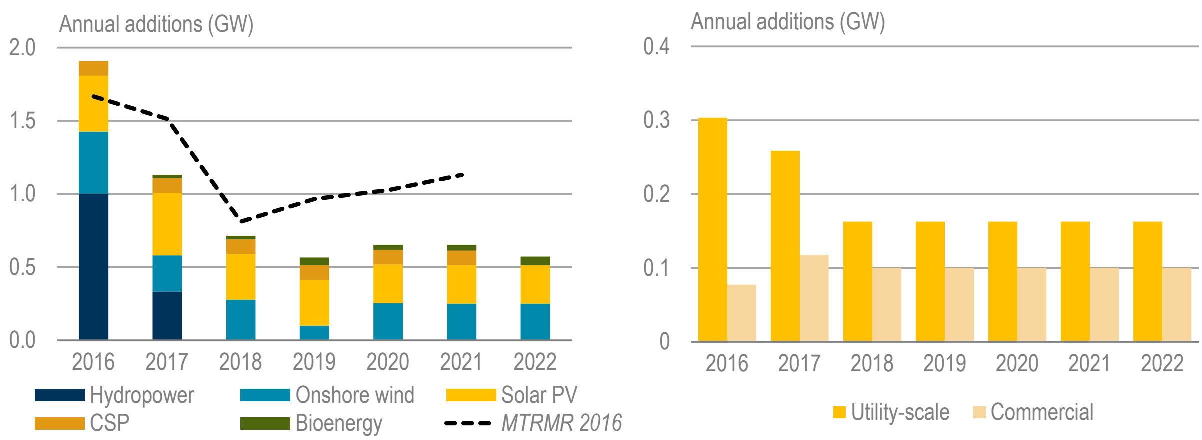


Grid-connected utility-scale projects in the region face a number of challenges arising from administrative delays and network expansion. To this end, off-grid systems, in particular mini-grids and SHS, are witnessing growth as they are able to provide basic electrification services faster. The private sector will play a key role in scaling up this growth. Overall, off-grid PV capacity is forecast to more than triple to reach 1.2 GW by 2022, driven by electrification efforts for the 65% of the regional population that remains without access (IEA, 2016b).

South Africa: Main case forecast

South Africa's renewable capacity is expected to grow by 4.3 GW over 2017-22, driven by projects from competitive auctions under the Renewable Energy Independent Power Producer Procurement Program (REIPPPP). Solar PV leads the growth (1.8 GW) with over a third of the deployment expected from commercial-scale projects, which are seen rapidly growing under municipal policies for net metering. Overall, the forecast is revised down from the last year's report as grid constraints and policy uncertainty raise questions over the pace of utility-scale deployment.

Figure 2.31. South Africa annual net renewable capacity additions (left), and solar PV annual net additions by segment (right)



Despite achieving record annual renewable growth in 2016 (1.9 GW) (Figure 2.31), the pace of annual deployment over the next five years is increasingly uncertain and depends on the restart of the stalled REIPPPP, which remains a key factor affecting the forecast. At the time of writing, at least 2 GW of solar PV and wind projects awarded in 2015 under Round 4 were still awaiting the signing of PPAs, while the status of another 1 GW procured in a following expedited round remains unknown. The main reason for the delays is uncertainty over the ability of the state utility (ESKOM) to afford grid connection costs and electricity purchase from the winning projects given the limited increases allowed to electricity prices. Future growth will depend on the rate at which cost-recovery resolutions are reached so that projects can reach financial close. However, policy uncertainty over longer-term energy needs, which impacts the pace of new capacity procurement, may exacerbate these challenges. The country's long-term capacity expansion plan currently in force, the Integrated Resource Plan 2010, was introduced in 2011 and requires an update with more realistic assumptions for electricity demand growth and technology costs. A draft update was released for public consultation in 2016 with capacity expansion by technology proposed through to 2050. However, the timeline for the final plan remains unknown.

Solar PV leads South Africa's renewable capacity expansion (1.8 GW) mostly from utility-scale projects driven by competitive auctions, although the rapidly growing commercial segment is also anticipated to contribute over 30% of the expansion. Economic attractiveness is the main driver for this growth due to rising electricity prices and the emergence of net metering policies at the municipal level in the absence of a national incentive programme. However, challenges concerning the incompatibility between municipal and federal regulations regarding small-scale generation remain. A draft for licensing distributed PV projects is pending approval at the national level, while it is uncertain how this document will align with the existing municipal regulations.

Onshore wind is expected to grow by 1.4 GW, although the forecast is highly dependent on the pace of signing PPAs and lead times for projects that may need network extension to complete their grid connections. Technologies with storage are also expected to play an increasing role: **CSP** should grow by 0.5 GW from the REIPPPP projects and **hydropower's** expansion, 0.3 GW, will come mostly from **PSP** with the remaining units of the 1.3 GW Inguala plant. **Bioenergy**, both from competitive auctions and EfW projects, is anticipated to see an additional growth of 0.2 GW.

Ethiopia: Main case forecast

Over 2017-22, Ethiopia's renewable capacity is expected to expand by 5.6 GW, the largest growth in SSA, surpassing South Africa. This is led by hydropower, accounting for 86% of all new renewable capacity, followed by wind and solar PV (Figure 2.30). Overall, the forecast is more optimistic than last year's report due to faster progression toward the completion of large hydropower projects, the implementation of competitive tendering and the adoption of renewable and electrification targets in 2016. Renewable power generation is forecast to increase from 14 TWh in 2016 to 38 TWh in 2022, positioning Ethiopia as a power exporter in the region, provided that the country's growth is matched by the completion of interconnection lines with neighbouring countries. Overall, financing and timely grid connections remain important challenges to renewable deployment.

Hydropower capacity is expected to grow by 4.8 GW over the forecast period, driven by excellent resource potential, national goals to become a regional hub for power trade, and the prospect of increased electricity export revenues. Several large government-owned projects are nearing completion, particularly the 6.5 GW Grand Ethiopian Renaissance Dam (GERD), the largest hydropower plant in the continent. This report forecasts a phased commissioning of the GERD, with the first units of 1.5 GW becoming operational in 2018. Overall, hydropower generation should nearly triple and reach 34 TWh in 2022. Ethiopia is currently negotiating power supply contracts with Djibouti, Kenya, Tanzania and Sudan as well as expanding its interconnection capacity. However, delays in project commissioning and grid build-out, including interconnections, remain forecast uncertainties, especially for estimating hydro generation in 2022.

Wind capacity is expected to expand by 0.45 GW over 2017-22 driven by auctions introduced in 2016, when Ethiopian Electric Power (EEP) held its first renewable tender, seeking 0.55 GW of new wind capacity. This report's main case estimates that around 80% of this capacity will be commissioned before 2022 as financing and grid connection remain challenges. In the same auction round, EEP also tendered 0.1 GW of **solar PV**. Additional auctions for solar PV are due to open later in 2017, supported by the Scaling Solar programme backed by the World Bank. Overall, solar PV is anticipated to grow from only 30 MW in 2016 to 0.25 GW in 2022, mostly from utility-scale projects commissioned under the current auction framework. However, the pace of commissioning depends on policies addressing off-taker risks and availability of affordable financing. **Off-grid solar PV** is estimated to double from 30 MW in 2016 to 60 MW in 2022, mostly for residential electrification and driven by increasing private-sector initiatives to supply the large share of the population without access. **Other renewables** account for 2% of additions over 2017-22, with Ethiopia to commission its first geothermal plant since 1999 with the Aluto Langano (70 MW) plant extension.

Kenya: Main case forecast

In Kenya, renewable capacity is forecast to almost double over 2017-22 in the main case to reach a cumulative capacity of 2.9 GW in 2022. This is driven by great resource potential, a strong need for additional power supply and government targets to reach full electrification, supported by policies aiming to improve the economic attractiveness of renewables. This expansion is led by onshore wind and geothermal which together account for three-quarters of all renewable additions over the forecast period, followed by solar PV and smaller additions from hydropower. While Kenya has a robust renewable project pipeline and strong interest from the private sector, deployment is challenged by delays in signing PPAs with off-takers, land acquisition issues, slow grid development and a lack of basic infrastructure in the country.

Onshore wind is expected to expand from only 30 MW in 2016 to over 0.5 GW in 2022 driven by PPAs available under the FIT scheme, although grid connection delays and land acquisition challenges hamper growth. After nine years of development, the 310 MW Lake Turkana Wind Power plant was fully installed in early 2017, but will not be fully grid connected until the end of 2017 as the transmission line was still under construction by Kenya Transmission Company (KETRACO) at the time of writing. Having signed a 20-year PPA with Kenya Power in early 2017, the Kipeto plant (102 MW) is estimated to come on line in 2019. In addition, the first phase of the 0.4 GW Meru wind project is working to complete its land acquisition and expected to come on line in stages over 2019-22.

Geothermal capacity stood at 0.6 GW in 2016 and should expand to 1.1 GW in 2022, driven by Kenya's strong need for baseload power generation and excellent geothermal resources, backed by the government's commitment to further deployment and availability of concessional financing. *Renewables 2017* anticipates that the Olkaria I extension (70 MW), Olkaria V (140 MW) and Menagai II (105 MW) will be commissioned over the forecast period.

Solar PV is anticipated to grow by 0.3 GW over the forecast period to reach 0.33 GW in 2022, of which 70 MW will come from off-grid applications. On-grid development will be driven by the improving economic attractiveness of the FIT scheme. However, high cost of capital due to elevated investment risks, long project lead times and grid connection delays are all expected to slow the pace of deployment. Furthermore, policy uncertainty may cause annual additions to be volatile in the near term. At the end of 2016, Kenya expressed its intent to switch from a FIT to a competitive auction system. While the exact timeline of this transition had not been announced at the time of writing, developers could rush to complete projects in the short term, anticipating a possible decline in FIT levels from USD 110/MWh, which remain unchanged since 2012. In addition, installations in SHSs and mini-grids driven by improved cost-effectiveness and private sector initiatives are expected to lead **off-grid PV** deployment.

Nigeria: Main case forecast

Renewable capacity in Nigeria's main case forecast is expected to expand by 1.4 GW over 2017-22, led by solar PV, hydropower and wind. The forecast is revised upwards compared to last year, largely due to a more optimistic outlook for solar PV as a result of policy changes. In 2016, the country approved adjustment of FIT rates while simultaneously introducing an auction system for renewable projects larger than 30 MW and adopting a mini-grid policy to speed up the electrification process. While an improved policy and regulatory framework support a more optimistic forecast in Nigeria, macroeconomic challenges remain as a result of decreasing oil revenues, which represent the main of source of gross domestic product. In 2016, Nigeria's central bank devalued its currency by 30%. In addition, exchange rate fluctuations and the lack of affordable financing can hamper the bankability of renewable projects. The macroeconomic environment paired with the off-taker risks, weak transmission network and policy uncertainties remain challenges to deployment.

Solar PV capacity is forecast to grow from a low base of 18 MW to 1 GW over 2017-22. In July 2016, Nigerian Electricity Bulk Trading signed PPAs with 14 different solar PV companies for a combined capacity of 1.1 GW of utility-scale projects, and country has a substantial project pipeline. The *Renewables 2017* forecast remains conservative, as the impact of the recent macroeconomic situation on project development and financing remains an important forecast uncertainty despite the introduction of auctions. **Off-grid solar PV** capacity is anticipated to reach 40 MW in 2022, with the deployment of residential and industrial/commercial applications increasing electrification. Private companies are offering SHS solutions with cash sales and PAYG business models driving small units. In October 2016, Nigeria's Electricity Regulation Commission approved regulation of mini-grids, allowing developers to charge cost-reflective tariffs and to be compensated for a depreciated value of the assets in case of grid arrival.

Wind is anticipated to grow by 0.1 GW over the forecast period, from 10 MW in 2016. The deployment will come from one project benefiting from the FIT scheme. However, the volatility of the local currency, the poor financial state of the off-taker and slow improvements in the grid infrastructure add uncertainty to the forecast and limit additional growth.

Table 2.13. SSA main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
South Africa	Need for new capacity; supportive policy environment with long-term PPAs; rising power prices.	Cost and pace of grid expansion to integrate new capacity; financial health of the off-taker; weakening macroeconomic environment effect on financing.
Ethiopia	Fast-growing power demand; excellent resources; long-term targets for renewable capacity and electrification.	Market access for IPPs; lack of cost-reflective tariffs; availability of financing for large infrastructure plans; grid delays.
Kenya	Robust power demand growth; diversification needs; supportive policy framework; high end-user electricity prices.	Administrative and regulatory barriers; late closing of the PPA with the off-taker; financing costs; land acquisition and grid connection delays.

Other countries in SSA: Main case forecast

Tanzania's renewable capacity is forecast to almost double from 0.6 GW in 2016 to 1 GW in 2022. Overall, the country's expansion is mainly driven by a newly introduced FIT and auction scheme, electrification targets (50% by 2025 and 75% by 2035) and continuous financial support from international development institutions. Solar PV leads the growth (0.23 GW) accounting for almost half of the country's additions with the introduction of the FIT and tenders. In addition, growing affordability of solar systems, private-sector involvement in mini-grid development and SHS distribution, and the introduction of the government's Rural Electrification Expansion Programme are all anticipated to support off-grid solar PV deployment, which is seen tripling to reach over 40 MW by 2022. Onshore wind is expected to grow by only 0.1 GW through the commissioning of one project

(Signida), with construction work scheduled to begin in 2017. Overall, off-taker risk remains a key challenge to renewable deployment underscoring the importance of affordable financing, while administrative and financing barriers add uncertainty over the pace of project development.

Zambia's renewable capacity is expected to grow by one-third (0.9 GW) over 2017-22, led by solar PV additions of 0.5 GW. The forecast is revised upwards compared to last year's report due to the opening of new rounds of competitive auctions. In 2016, Zambia held its first utility-scale solar PV tender, awarding contracts for 73 MW of projects with the lowest prices reaching USD 60/MWh. In early 2017, the second round of tenders was opened for 500 MW of solar PV projects. Both auctions were supported by a World Bank Scaling Solar initiative, which is expected to mitigate some of the investment risks that keep financing costs high.

Renewable capacity in **Ghana** is anticipated to expand by 0.5 GW over 2017-22 to a cumulative capacity of 2.1 GW, with growth led by solar PV and the commissioning of the country's first onshore wind project. Ghana is currently drafting a regulation prolonging its FIT support from 15 to 20 years in order to improve project bankability of renewables. In early 2017, **Namibia** completed its first competitive tender for 45 MW of solar PV to be commissioned over 2018/19. In parallel, the government published new net metering rates for ground-mounted solar PV. These developments are expected to result in solar PV growing by 0.5 GW over 2017-22.

SSA: Accelerated case forecast

Overall, the potential for additional renewable deployment in SSA is significant and, under an accelerated case, capacity growth could be 42% higher (10.3 GW) over 2017-22 (Table 2.14) as against the main case under certain enhanced conditions. Solar PV and wind together could add 62%, or 6.4 GW, of additional capacity, further unlocking the non-hydropower potential of the region. This extra growth would depend on the adoption of clear and reliable policy frameworks with clear timelines across major markets. Timely signing of PPAs between project developers and off-takers, access to affordable financing in local currencies, and improved regulations regarding land rights and acquisition remain critical to achieving accelerated growth. This would shorten long project lead times, increasing overall investment attractiveness.

South Africa's renewable expansion could be nearly 50% stronger, growing by up to 6.3 GW over the forecast period should the REIPPPP resume, and progress be made with planned auctions. This would require a rapid resolution regarding the cost of grid integration for the delayed projects, as well as a co-ordinated approach between planning agencies when awarding capacity under future rounds to minimise administrative lead times. **Ethiopia** could grow by an additional 1.4 GW subject to faster construction times for the 0.25 GW Genale Dawa VI dam, as well as quicker grid connections for the country's robust wind pipeline (0.4 GW). **Kenya's** capacity could grow by an additional 2.1 GW with contributions from solar PV, wind and geothermal. This would require faster PPA contract signing, overcoming grid connection challenges and a smooth transition from a FIT to competitive auctions. **Tanzania's** capacity growth could be 0.2 GW higher due to the commissioning of additional hydropower and wind projects currently at the feasibility stage. In particular, hydropower capacity could be higher with the partial commissioning of the 300 MW Kikonge dam. **Nigeria** could experience higher growth through faster commissioning of 2 GW of hydropower plants and by adding 1 GW of additional solar PV capacity. More robust solar PV growth could be possible depending on timely land acquisition and the commissioning of projects that signed PPAs in 2016.

Table 2.14. SSA main and accelerated case summary, 2016 and 2021

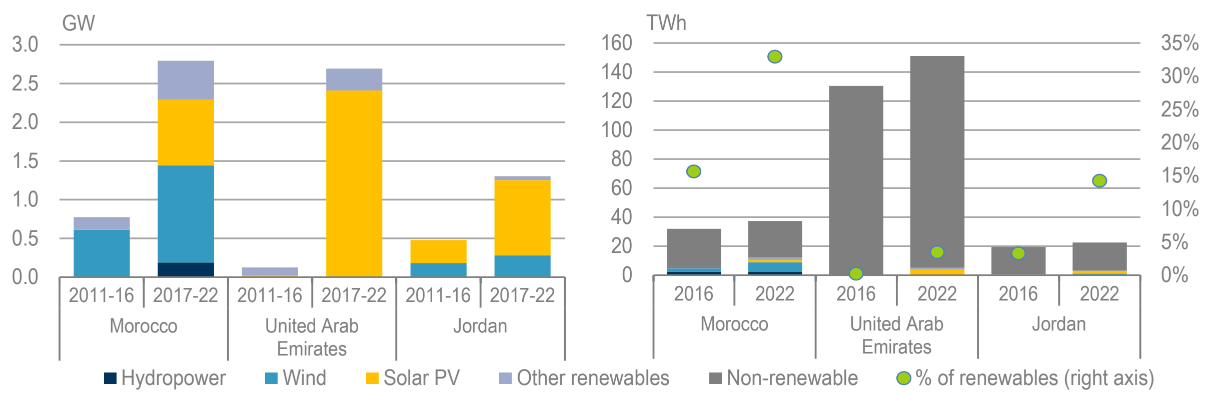
Total capacity (GW)	South Africa			Kenya			Ethiopia			SSA		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	3.3	3.6	3.6	0.8	0.8	1.0	3.8	8.6	8.7	26.7	39.2	41.8
Bioenergy	0.3	0.5	0.6	0.1	0.2	0.4	0.2	0.2	0.4	1.6	2.2	3.0
Onshore wind	1.5	2.9	3.9	0.0	0.5	1.4	0.3	0.8	1.3	1.9	5.2	8.2
Offshore wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	1.5	3.3	3.9	0.0	0.3	1.2	0.0	0.3	0.6	2.1	9.3	12.7
CSP	0.2	0.7	1.0	-	-	-	-	-	-	0.2	0.7	1.0
Geothermal	-	-	-	0.6	1.1	1.1	0.0	0.1	0.3	0.6	1.1	1.4
Ocean	-	-	-	-	-	-	-	-	-	-	-	-
Total	**6.8**	**11.1**	**13.1**	**1.6**	**2.9**	**5.1**	**4.4**	**9.9**	**11.3**	**33.3**	**57.7**	**68.0**

Note: Acc.= accelerated. Rounding may cause non-zero data to appear as “0.0” or “-0.0”. Actual zero-digit data is denoted as “-“.

MENA

Cumulative renewable capacity in MENA is expected to grow by almost 60%, increasing from 26 GW in 2016 to over 40 GW by 2022, driven by fast-growing power demand and energy diversification needs. Almost half of the growth is forecast to be from solar PV, mostly from utility-scale projects, although distributed systems will contribute as well, followed by onshore wind, hydropower and CSP. Iran leads the region’s growth, accounting for over 20% of the added capacity mostly from large hydropower projects, while Morocco is the regional leader for non-hydropower renewable expansion, followed by Morocco, the United Arab Emirates, Egypt, and Jordan (Figure 2.32).

Figure 2.32. MENA renewable electricity capacity growth, 2011-22 (left) and generation by source, 2016 and 2022 (right)



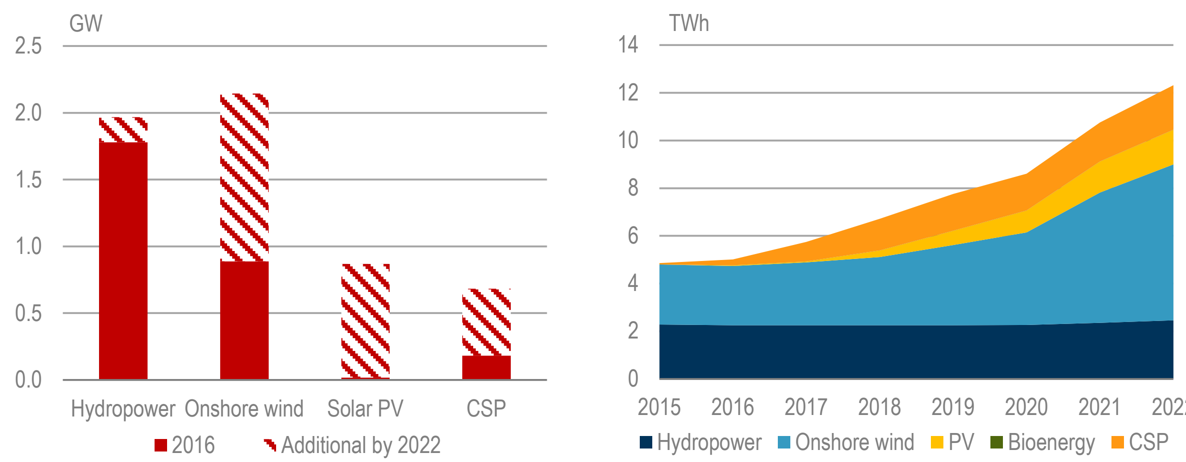
Given the structure of electricity markets across the region, the pace of utility-scale renewable capacity deployment depends heavily on the speed at which the various renewable support mechanisms (IPP competitive auctions, engineering procurement and construction [EPC], and third-party sales) procure new power, particularly in Morocco, Jordan and the United Arab Emirates where most of the non-hydro deployment is expected. New utility-scale auctions in Israel, Algeria and Saudi Arabia are also anticipated to contribute. Net metering in the United Arab Emirates and Jordan are seen driving distributed solar PV deployment for larger consumers. In other markets, distributed solar PV deployment is expected to be slow as grid access and a lack of cost-reflective end-user prices challenges the business case for many residential consumers. Overall, the forecast is less optimistic compared to last year's report due to downward revisions in Iran and Egypt as a result of uncertainties concerning FIT programmes and high financing costs. Affordable financing remains critical for growth in markets where remuneration levels are competitively set. Meanwhile, determining support levels that accurately reflect the financing risks faced by developers remains a challenge in markets where they are administratively set.

Morocco: Main case forecast

Morocco's capacity is expected to grow by 2.8 GW, driven by new capacity needs to meet rapidly growing demand while diversifying away from fossil fuel imports. Deployment is led by onshore wind, solar PV, CSP and hydropower from a mix of IPP competitive auctions, government-owned EPC projects and IPP third-party sales to industrial consumers. The share of renewable generation is seen to double from 16% in 2016 to 33% by 2022, supported by long-term targets and a robust policy environment, although grid access and project development times remain challenges.

Solar PV and **CSP** combined account for almost half of Morocco's renewable growth (1.4 GW) over 2017-22, largely due to favourable financing conditions, which have contributed to competitive bids. In 2016, the weighted average of winning bids for the first 170 MW solar PV tender was MAD 460/MWh (USD 43/MWh). Concessional financing from KfW and Morocco's first green bonds, issued by the Moroccan Agency for Sustainable Energy (MASEN) in 2016, helped fund the project. Concessional financing has also played a role in all three CSP tenders totalling 510 MW for NOOR Ouazarzate, which resulted in MAD 1 360-1 600/kWh (USD 145-170/MWh), as well as approximately 500 MW of government-owned EPC projects for solar PV. Public-private partnerships also played a major role in achieving affordable financing by optimising risk allocation among stakeholders.

Figure 2.33. Morocco total renewable capacity, 2016 and 2022, and generation, 2015-22



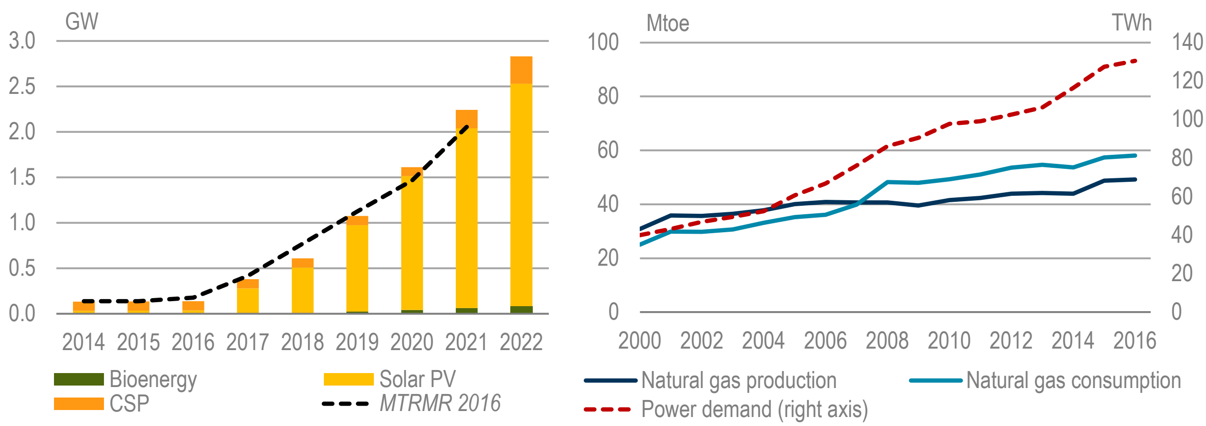
The capacity of **solar PV** and **CSP**, forecast to reach 0.9 GW and 0.7 GW respectively by 2022 (Figure 2.33), depends heavily on the results of the upcoming technology-neutral solar auctions. Competitive tenders for Midelt Phase 1 are planned for 300-500 MW of solar PV and CSP combined. However, at the time of writing, the exact technology-specific volumes have not been specified, although at least 150-190 MW for CSP is targeted (MME, 2017; MASEN, 2017). The amounts of PV and CSP will be decided from the bids in order to identify the least-cost combination to meet the seasonal load profile. Historically, Morocco's peak demand has been in the winter evening, but another midday summer peak is emerging due to changing consumption patterns associated with economic development. This hybrid tender approach seeks to optimise the benefits from both technologies: the ability to meet evening demand from CSP with storage and the low-investment costs of solar PV to meet daytime demand. By 2022, CSP is expected to generate about 30% more electricity than solar PV despite having around 20% less capacity installed due higher capacity factors. In addition to the IPP competitive tenders, solar PV growth should also be driven by state-owned EPC projects, while distributed solar PV growth remains limited due to barriers to grid access.

Economic attractiveness, achieved with good wind speeds and supportive financing conditions, drives **onshore wind** deployment, seen expanding by 1.3 GW, although uncertainty over project lead times and grid access limit the pace of growth. Over 70% of new capacity additions are expected from projects under the country's first competitive auctions for 1 GW of wind, of which the second phase of 850 MW was awarded at record low prices (USD 30/MWh) in 2016. However, the prolonged tendering process characterised by limited transparency and lengthy negotiations also raises questions over project delivery times. The remaining 40% of the growth is expected to be from IPP projects for third-party supply to large consumers, under law 13-09. Still, grid access challenges remain a barrier to accessing potential consumers and limit faster deployment (RCREEE, 2016).

United Arab Emirates: Main case forecast

The **United Arab Emirates'** share of renewable power in total electricity generation is expected to grow from less than 1% in 2016 to 3% by 2022 in an effort to lessen reliance on natural gas imports, which have been rising to meet fast-growing power demand (Figure 2.34). The country is expected to add 2.7 GW of capacity, mostly from auctions for solar PV and CSP over 2017-22. The forecast is more optimistic than last year due to the increasing economic attractiveness of both utility-scale and distributed solar PV. However, given the barriers to new market entrants, utility-scale deployment depends on the timing of auctions.

Figure 2.34. United Arab Emirates cumulative renewable capacity (left) and natural gas supply vs power demand (right)



Note: Mtoe = million tonnes of oil equivalent.

Source: Natural gas and power demand data from IEA (2017b), *World Energy Statistics and Balances 2017,* www.iea.org/statistics/.

The pace of renewable deployment over 2017-22 will largely be dictated by the government's announcement and implementation of auctions, given the current market structure. The lack of a clear auction schedule is a forecast uncertainty; however, the country's recently announced first unified energy strategy, the UAE Energy Plan 2050, which targets 50% clean energy by 2050, is seen as a positive development and suggests further growth. Yet without further details regarding the strategy's governance, its planned implementation, or a specific breakdown of the target by technology, it remains challenging to assess the plan's impact on deployment over 2017-22.

The **solar PV** forecast is more optimistic with 2.4 GW to be added over 2017-22, more than 50% above the forecast of last year. Most of the revision is due to an accelerated scale-up after more solar PV capacity was allocated in Abu Dhabi's latest auction than originally tendered (from 0.35 GW to 1.1 GW); this was presumably driven by the attractive economics offered by the winning project, which signed a PPA at USD 24/MWh. However, it is difficult to identify cost reduction trends since a price premium (1.6 times the base tariff) will be applied to electricity supplied from June to September to meet higher summer demand. Still, the projects' estimated LCOE (USD 29/MWh) is comparable to the previous bid (USD 30/MWh) and underscores the impact that low-cost financing and economies of scale have on competitive bidding.

A more optimistic forecast also exists for distributed applications, accounting for 18% of the total solar PV growth in the main case, based on the progress of net metering in Dubai and the introduction of a new scheme in Abu Dhabi in 2017. Dubai's Shams roof-top net metering programme began in 2015 and by 2016 had already installed 6 MW. The increasing number of announcements for planned projects in the commercial and industrial sectors suggests large consumers find the economics under the scheme attractive and should drive growth over the next five years. Deployment should also be supported by the recent developments in Abu Dhabi, where in early 2017 a new net metering scheme was launched and electricity pricing reforms were announced across all consumer segments (Oxford Institute for Energy, 2017). However, the forecast for the residential segment, with smaller consumption, is less certain and depends on the evolution of remaining electricity subsidies.

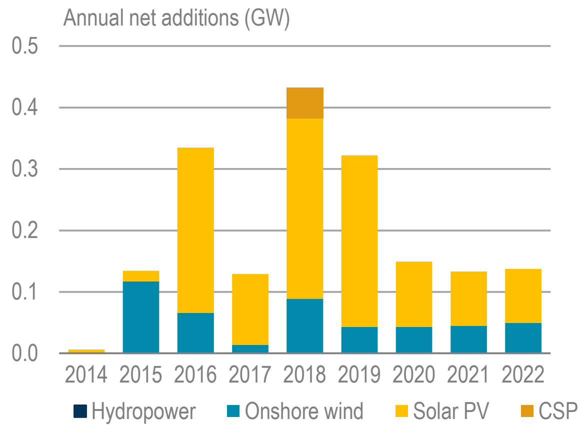
CSP capacity is forecast to expand modestly over 2017-22, by 200 MW, although uncertainty over the pace of future auctions limits growth. While plans to develop 1 GW by 2030 have been announced, only 200 MW have been tendered, albeit with a record low bid of USD 94.5/MWh. Whether these results are considered cost-effective enough to trigger future auctions remains to be seen.

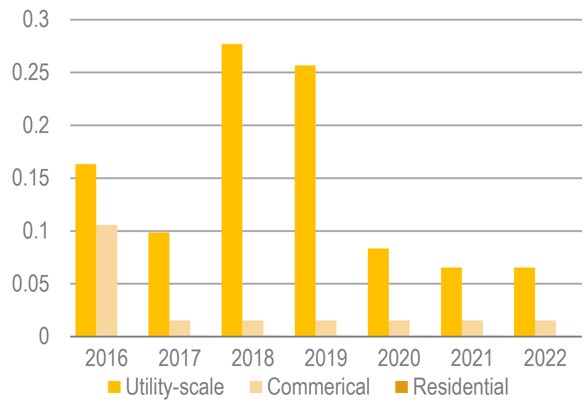
Jordan: Main case forecast

Jordan's renewable capacity is expected to more than triple over the next five years, expanding by 1.3 GW and driven by rapidly growing demand, diversification and a supportive policy environment. Growth is led by **solar PV**, accounting for almost 75% (0.8 GW) of additions, with the remaining 25% (0.3 GW) from **onshore wind** and **CSP**, although grid integration remains a challenge.

Most of the deployment is likely to be driven by the country's IPP direct proposals scheme (DPS), a form of competitive bidding. However, the pace depends on the progress of network upgrades to ease grid constraints, integrate winning projects and open future rounds. Previous DPS rounds were suspended in 2015 due to limited transmission capacity. However, the scheme has since resumed – the third round was opened in late 2016, tendering 200 MW of solar PV and 100 MW of wind after funding was secured for the grid upgrades. These developments are assumed to facilitate deployment over the forecast period, but the pace and magnitude depends on the progress of network expansion to integrate additional capacity. Outside the DPS, deployment is also expected from other mechanisms such as IPP-initiated negotiations, state-owned EPC and net metering.

Figure 2.35. Jordan annual net renewable capacity additions (left) and solar PV additions by segment (right)





Robust distributed solar PV growth is expected over the next five years, driven by economic attractiveness for large electricity consumers under the net metering programme. High electricity tariffs from gradual subsidy phase-outs, falling system costs and innovative leasing models have all spurred a number of installations in hotels, schools, hospitals and energy-intensive industries. The introduction of a new surcharge on electricity bills pegged to the oil price may also improve the business case if oil prices rise. However, growth may be limited by grid constraints as lengthy permitting and connection times from distribution companies reflect concerns over available network capacity.

Table 2.15. MENA drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Morocco	New capacity and diversification needs; long-term targets supported by auctions with PPAs.	Project development times; limited access to grid for distributed solar PV.
United Arab Emirates	Fast-growing power demand; competitive auctions and net metering for distributed solar PV.	Restricted market access for IPPs; limited visibility over auction schedule; subsidised end-user electricity tariffs.
Jordan	Power sector diversification needs; competitive auctions and net metering.	Grid integration challenges cause delays; lengthy permitting for distributed PV.

Other countries in MENA: Main case forecast

Iran's renewable capacity is expected to grow by 3.3 GW over 2017-2022, driven by diversification needs to meet robust demand growth, air pollution concerns and untapped resource potential. **Hydropower** leads the growth (2.2 GW), followed by **solar PV** and **wind** (0.6 GW each) from the recently launched FIT scheme. However, compared to last year, the forecast is revised down due to a less optimistic outlook for non-hydro renewables as financing and policy uncertainty remain important challenges.

An easing of trade restrictions and revised FITs in 2016 have created a robust potential for growth over the coming five years. Targets for 5 GW by 2020 – supported by attractive rates in the range of USD 100-260/MWh for utility-scale PV and USD 110-180/MWh for onshore wind – have prompted a number of investors to announce development plans in recent years. However, information on the number of approved projects under the scheme is unclear and makes quantifying the potential pipeline difficult. In addition, uncertainty remains over the timing of potential FIT revisions and plans to switch to competitive bidding.

A difficult financing environment is the main challenge to attracting non-hydro renewable investment. The cost of capital is high from domestic banks, which are unfamiliar with renewable projects and have limited liquidity, while international lenders remain reluctant to finance the first projects given the risk of violating remaining trade restrictions. Furthermore, support from the National Development Fund, set up to use hydrocarbon profits to finance renewables, is limited due to the impact of decreasing oil revenues.

Egypt's renewable capacity is expected to grow by 1.6 GW over 2017-22, led by onshore wind (750 MW), solar PV (0.7 GW) and CSP (0.1 GW) from various policy/support schemes: IPP competitive auctions, state-owned EPC tenders, FITs and merchant plants. The forecast is less optimistic than last year due to lengthy contractual negotiations under the competitive bidding scheme and uncertainty over the economic attractiveness of projects under the FIT scheme. Currency risks and the inability to secure foreign financing due to domestic arbitration clauses in the PPA prompted the withdrawal of multiple planned projects under Round 1 of the FIT scheme launched in 2014. The second round of the FIT scheme opened in 2016 with modifications to address these arbitration concerns, but revenue uncertainty remains. Remuneration levels were revised down and it remains to be seen how partial tariff indexing at a fixed exchange rate (30% to 40% at 1 USD = 8.88 EGP) and the recent flotation of the Egyptian pound will affect project bankability.

However, improved financing conditions should help attract developers, as the revised terms allowing international arbitration have opened access to foreign debt and should drive some capacity growth over the next five years. Since then, approximately 450 MW have reached financial close and signed PPAs, the highest amount under the FIT scheme to date. Yet deployment under the competitive bidding scheme is less certain as administrative delays and prolonged contractual agreements risk deterring investors. Insufficient developer interest was cited as one of the reasons for postponing the latest 200 MW solar PV tender. Overall, the forecast is cautious relative to the project pipeline with a high upside potential, to the extent that these challenges are addressed.

Saudi Arabia's renewable capacity is expected to grow modestly by 0.45 GW over 2017-22, from solar PV, CSP and wind projects driven by competitive auctions to reach newly announced targets. Excellent resource potential and the country's larger economic reform strategy to diversify away from hydrocarbon revenues are the main drivers of renewable expansion.

Several developments point to a step-change in Saudi Arabia commitment towards creating an enabling environment for renewable deployment, signalling growing momentum and a positive outlook. In early 2017, the kingdom's new National Renewable Energy Plan (NREP) was announced, which identified interim 2020 renewable capacity targets (3.5 GW by 2020) supported by three rounds of competitive auctions (700 MW, 1 020 MW, and 1 730 MW) (MEES, 2017). Round 1 for 300 MW of PV and 400 MW of wind was opened immediately. The timing of the NREP and auction plans illustrate concrete implementation efforts towards longer-term goals unveiled under the economic reform strategy (the Vision2030) one year prior. Furthermore, the creation of the

Renewable Energy Project Development Office, a dedicated entity tasked with overseeing the NREP and managing the tender processes, should strengthen the institutional capacity to support the implementation of these new policies.

While these developments are expected to drive growth in solar PV and wind capacity over the next five years, the forecast is conservative compared to the potential pipeline given the challenges in translating ambitious targets into deployment. Plans to open auctions announced in 2013 have been slow to materialise, with the first finally opening in 2016 for 100 MW of solar PV but cancelled shortly after in early 2017. While it is likely this was replaced by Round 1 of the newly launched NREP, the *Renewables 2017* forecast is cautious on the basis of the uncertainty over the pace of scheduled tenders, particularly amid planned power sector reforms.

Israel's[11] cumulative renewable capacity is forecast to more than double by 2022, from the addition of 1.3 GW. Solar PV leads the growth (0.8 GW), followed by CSP (0.3 GW) and onshore wind (0.2 GW). Good resource potential and commitments made under the Paris agreement to reach 10% and 17% renewables by 2020 and 2030, respectively, are seen as drivers for growth. While deployment has been slow in the absence of a clear and stable support scheme, the increasing economic attractiveness of solar PV in the MENA region has triggered plans for competitive auctions. The first round for 235 MW was recently awarded and further tenders are planned for 150-300 MW each, which underpin most of the PV forecast. Yet the pace of growth is uncertain given the land and grid constraints for large-scale renewable installations near demand centres.

Elsewhere in MENA, solar PV accounts for almost 60% of the 1.3 GW of additional growth expected over 2017-22, mostly from new competitive auctions for utility-scale systems in **Algeria** and **Tunisia.** Net metering schemes are expected to drive growth from distributed systems in **Lebanon** and more recently **Oman**, from the launched Siam scheme.

MENA: Accelerated case forecast

Under the accelerated case, MENA's renewable capacity expansion could reach 27 GW over the next five years, 86% higher than under the main case (Table 2.16). This would result from increased government support to speed up progress through auction rounds, to conduct faster contract negotiations, and to accelerate and clarify regulatory reforms. The largest upside potential for accelerated deployment exists in **Egypt**, where growth over the next five years (5 GW) could be more than three times higher than in the main case (1.6 GW). Egypt has a large pipeline of solar PV and wind projects in various stages of development, and commissioning them would require faster implementation of tendering procedures and improved bankability of the PPAs under the FIT scheme. Growth in **Iran's** accelerated case could reach over 6 GW, more than twice as much as in the main case, with faster hydropower development and more favourable financing conditions and streamlined support policy procedures for solar PV and onshore wind. Accelerated renewable capacity growth in **Morocco** could reach 4.6 GW, more than twice that of the main case, with faster implementation of competitive auctions for utility-scale solar PV and CSP and an increase in deployment outside competitive auctions for onshore wind and distributed PV. This would require clarification of grid access regulations, which would unlock the potential of wind for third-party consumer sales and open up the possibility of a net metering scheme for distributed PV.

[11] 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 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.

Table 2.16. MENA main and accelerated cases summary, 2016 and 2021

Total capacity (GW)	Morocco			United Arab Emirates			Jordan			Rest of region		
	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.	2016	2022 Main	2022 Acc.
Hydropower	1.8	2.0	2.4	-	-	0.3	0.0	0.0	0.0	19.4	21.6	23.1
Bioenergy	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.2	0.2	0.3
Onshore wind	0.9	2.1	2.2	0.0	0.0	0.1	0.2	0.5	0.6	1.2	3.3	5.8
Offshore wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	0.0	0.9	1.7	0.0	2.4	3.4	0.3	1.3	2.2	1.3	4.4	7.9
CSP	0.2	0.7	1.1	0.1	0.3	0.3	-	0.1	.2	0.0	0.7	1.2
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Ocean	-	-	-	-	-	-	-	-	-	-	-	-
Total	**2.9**	**5.7**	**7.5**	**0.1**	**2.8**	**4.2**	**0.5**	**1.8**	**3.2**	**22.1**	**30.1**	**38.3**

Note: Acc.=accelerated. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

Saudi Arabia's renewable capacity growth could reach almost 2 GW from the completion of the planned auctions introduced under the NREP. Achieving the accelerated pace of deployment depends upon the timely completion of a new IPP tender process amid wider electricity sector reform to unbundle the vertically integrated state utility. The **United Arab Emirate's** renewable capacity expansion could be 50% higher than the main case, with over 4 GW of growth possible from additional solar PV and CSP auctions, while continued electricity price reforms could improve the economics for distributed PV under net metering schemes. Additional capacity could also come if plans for a 250 MW PSP, EfW plants and wind tenders are realised over the next five years. More than 2.6 GW of renewable capacity could be deployed in **Jordan** if the network expansion project advances more quickly than expected to integrate new capacity from the auction scheme and distributed PV deployment accelerates under net metering.

References

Airtel India (2016), "Bharti Airtel's focus on Green network initiatives transforms 40,000 telecom towers across India", Airtel India media centre, www.airtel.in/about-bharti/media-centre/

ARENA (Australian Renewable Energy Agency) (2016), "Historic day for Australian solar as 12 new plants get support", media release, https://arena.gov.au/assets/2017/02/160908_MEDIA-RELEASE-ARENA_Historic-day-for-Australian-solar-as-12-new-plants-get-support.pdf.

AWEA (American Wind Energy Association) (2017), *U.S. Wind Industry Annual Market Report 2016*, AWEA, Washington, DC.

BEIS (Department for Business, Energy and Industrial Strategy) (2017), *Contracts for Difference Second Allocation Round Results*, www.gov.uk/government/uploads/system/uploads/attachment_data/file/643560/CFD_allocation_round_2_outcome_FINAL.pdf (accessed 14 September 2017).

Bridge to India (2017a), *India Rooftop Solar Map 2017*, www.bridgetoindia.com/wp-content/uploads/2017/07/India-Solar-Rooftop-Map-2017.pdf.

Bridge to India (2017b), "SECI gets a significant boost to its credit rating", Bridge to India, New Delhi, www.bridgetoindia.com/seci-gets-significant-boost-credit-rating.

CENACE (National Energy Control Centre) (2017), “Largo Plazo” [Long term], www.cenace.gob.mx/Paginas/Publicas/MercadoOperacion/SubastasLP.aspx.

CERC (Central Electricity Regulatory Commission) (2016a), Petition No. 91/MP/2014, CERC, New Delhi, www.cercind.gov.in/2016/orders/SO91.pdf.

CERC (2016b), Statement of Reasons 6 May 2016, CERC, New Delhi, www.cercind.gov.in/2016/regulation/SOR123.pdf.

Dutta, A. (2017), “Work begins on India’s first green energy corridor project”, *India Times* and *ETEnergyWorld*, http://energy.economictimes.indiatimes.com/news/renewable/work-begins-on-indias-first-green-energy-corridor-project/58792079 (accessed 13 July 2017).

GME (Gestore dei Mercati Energetici S.p.A.) (2017), *Online Statistical Data – Comparison of European Exchanges* (database), www.mercatoelettrico.org/En/Statistiche/ME/BorseEuropee.aspx.

GOGLA (Global Off-Grid Lighting Association) (2017), *Global Off-Grid Solar Market Sales Dataset for the IEA*, dataset provided to the IEA.

Hystra (2017), *Reaching Scale in Access to Energy*, Hystra, Paris.

IEA (International Energy Agency) (forthcoming), *World Energy Outlook 2017,* OECD/IEA, Paris.

IEA (2017a), *Renewables Information 2017,*www.iea.org/statistics/.

IEA (2017b), *World Energy Statistics and Balances 2017*, www.iea.org/statistics/.

IEA (2016a), *Next Generation Wind and Solar Power*, full report, OECD/IEA, Paris.

IEA (2016b), *World Energy Outlook 2016*, OECD/IEA, Paris.

IEA (2014), *Africa Energy Outlook: World Energy Outlook Special Report*, OECD/IEA, Paris.

IEA/IRENA (International Renewable Energy Agency) (2017), *Joint Policies and Measures Database for Renewable Energy*, www.iea.org/policiesandmeasures/renewableenergy/.

LBNL (Lawrence Berkeley National Laboratory) (2017a), *RPS Demand Projections*, LBNL, Berkeley, CA, https://emp.lbl.gov/projects/renewables-portfolio.

LBNL (2017b), *U.S. Renewables Portfolio Standards: 2016 Annual Status Report*, LBNL, Berkeley, CA, https://emp.lbl.gov/projects/renewables-portfolio.

MASEN (Moroccan Agency for Sustainable Energy) (2017), “Five pre-qualified consortia for Noor Midelt Phase I”, MASEN, Rabat, www.masen.ma/media/uploads/documents/2017_06_08_CP_PreQualif_Noor_Midelt_Phase_I_NgS8jUJ.pdf.

MEES (Middle East Economic Survey) (2017), “Abu Dhabi breaks records with expanded Sweihan Solar PV Project”, Middle East Petroleum and Economic Publications Ltd., 3 March 2017, Cyprus.

METI (Ministry of Economy, Trade and Industry) (2017a), “Estimated solar PV cancellation by the enforcement of revision of Feed in Tariff Act”, METI, Tokyo, www.meti.go.jp/press/2017/04/20170421003/20170421003.html.

METI (2017b), *Statistics of Renewable Energy in the Feed in Tariff Scheme*, METI, Tokyo, www.enecho.meti.go.jp/category/saving_and_new/saiene/statistics/index.html.

MINEM (Ministry of Energy and Mining) (2016), *Proyectos Adjudicados del Programa RenovAr. Rondas 1 y 1.5* [Projects Awarded in Programme RenovAr 1 and 1.5], MINEM, Buenos Aires, www.minem.gob.ar/www/833/25897/proyectos-adjudicados-del-programa-renovar.html.

Ministry of Power (2017), *UDAY National Dashboard*, Government of India, New Delhi, www.uday.gov.in/home.php (accessed 7 August 2017).

MME (Ministry of Energy and Mines) (2017), *Programme Marocain de l'Energie Solaire* [Moroccan Programme for Solar Energy], MME, Rabat, www.mem.gov.ma/SitePages/GrandsChantiers/DEEREnergieSolaire.aspx.

NEA (National Energy Administration) (2017), *Bulletin of Monitoring and Evaluation of National Renewable Energy Power Development*, NEA, Beijing, http://zfxxgk.nea.gov.cn/auto87/201704/t20170418_2773.htm.

NEA (2016), *Renewable Consumption Targets and Guidance*, NEA, Beijing, http://zfxxgk.nea.gov.cn/auto87/201603/t20160303_2205.htm.

ORE Catapult (2017), "Offshore wind on target to become lowest-cost, large scale clean energy source", press release, https://ore.catapult.org.uk/press-release/offshore-wind-target-become-lowest-cost-large-scale-clean-energy-source/.

Oxford Institute for Energy (2017), *Oxford Energy Forum: MENA Energy Pricing Reforms*, Issue 108, Oxford Institute for Energy, Oxford, www.oxfordenergy.org/wpcms/wp-content/uploads/2017/04/OEF-108.pdf.

RCREEE (Regional Center for Renewable Energy and Energy Efficiency) (2016), *Arab Future Energy Index*, RCREEE, Cairo.

WB (World Bank) (2017), "World Bank approves $55.25 million grant to help develop geothermal power in Indonesia," press release, www.worldbank.org/en/news/press-release/2017/02/09/world-bank-approves-5525-million-grant-to-help-develop-geothermal-power-in-indonesia.

3. RENEWABLE TRANSPORT

Highlights

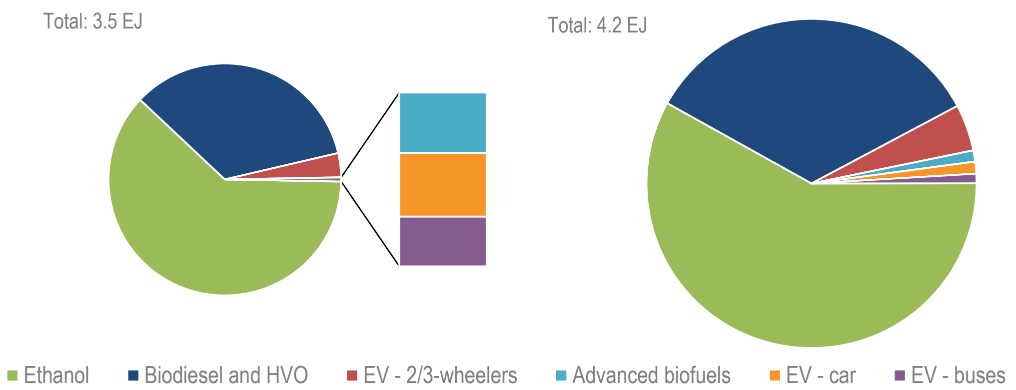
- *Renewables 2017* has assessed the relative contribution of both biofuels and electric vehicles (EVs) to renewable energy in road transport. In 2016, biofuels accounted for just over 96% of all renewable energy consumed in road transport globally, with the remainder attributable to EVs. Relatively faster growth sees EVs command a larger share by 2022, although their contribution remains under 7% at the end of the forecast period.
- Conventional biofuel production is expected to increase by over 16% from 2016 levels to reach 159 billion litres (L) by 2022. Over a third of this growth occurs in Asia due to increasing transport fuel demand, available feedstocks and supportive policies. Brazil makes a key contribution as a result of efforts to increase sustainable biofuel consumption in line with its national target for 2030, while US ethanol and biodiesel production also expands. Conversely, modest growth is expected in the European Union as the anticipated policy landscape post 2020 is not conducive to industry investment.
- A limited increase in the conventional biofuel share of road transport fuel demand is seen in the main case, up from 4% in 2016 to 4.5% in 2022. Higher growth in this share is not achieved because of upward trends in fossil gasoline and diesel demand in many markets. For biofuels to offset this growth in petroleum product demand, consumption of higher biofuel blends and unblended “drop-in” biofuels would need to increase further still.
- The *Renewables 2017* main case anticipates advanced biofuel production increasing almost sevenfold, reaching 1.8 billion L by 2022. Recent positive developments for the sector include the proposed strengthening of policy support for advanced biofuels post 2020 in the European Union, and a surge of interest in India with five plants in active development.
- In the accelerated case, conventional biofuel production could increase to 180 billion L in 2022 with more favourable market and policy conditions, a 14% increase on the main case. Ethanol output rises to 125.5 billion L (up 9% on the main case), and biodiesel and HVO reach 55 billion L (up 26% on main case). Accelerated case production sees the conventional biofuel share of road transport fuel demand rise to 5%, while advanced biofuel output reaches close to 3 billion L by 2022. Although this only represents 1.8% of total biofuel production.
- Road freight accounts for over 30% of global transport-related energy demand and is the main consumer of diesel among all energy sectors. Utilisation of alternative fuels is currently minimal despite the availability of a portfolio of technically mature high energy density biofuels and road freight vehicles suitable for their use.
- Electricity consumption by EVs is expected to double over 2016-22, with over 80% of the growth occurring in the People’s Republic of China. Globally, two- and three-wheelers remain the leading mode of electricity consumption in road transport in 2022, but the share consumed by electric cars increases from 6% to 17% due to deployment across a wider range of markets. The share of renewables in electricity consumed in road transport is forecast to grow from 26% in 2016 to 30% by 2022, driven mostly by the rapid growth of two- and three-wheelers in China, but also by electric cars in European markets with high shares of renewable electricity generation.

Overview of renewable energy consumption in road transport

Renewables 2017 has compared the relative contributions to renewable energy use in road transport[1] of biofuels and renewable electricity consumed in EVs.[2] In 2016, renewable energy accounted for 4.2% of total energy consumed in road transport from all sources. Conventional biofuels accounted for 96% of all renewable energy in road transport, with a further 3.4% attributable to the electric two- and three-wheeler fleet, predominantly located in China (Figure 3.1). Advanced biofuels and electric cars and buses combined contributed less than 0.6%, in roughly equal measure.

Key determinants of renewable electricity consumption in EVs are the vehicle stock and share of renewables in total electricity generation. The share of renewables in global electricity generation in 2016 stood at 24%. However, the rapid scaling up of the global EV stock is occurring from a low base – for example, in 2016 electric cars accounted for just 0.2% of the total light-duty vehicle fleet.

Figure 3.1. Overall renewable energy consumption in road transport 2016 (left) and 2022 (right)



Notes: Biofuels data are based on the *Renewables 2017* main case biofuels production forecast using the assumption that all biofuels produced are consumed within the same year; in reality some biofuel production will be carried forward as stocks, and some consumption within the year will be sourced from the previous year's stocks; EJ = exajoule; HVO = hydrotreated vegetable oil.

Sources: IEA (2017c), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version; IEA (2017d), *Monthly Oil Data Service (MODS)*, May 2017, www.iea.org/statistics/; IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; MAPA (2017), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2017), *Petroleum and Other Liquids,* www.eia.gov/petroleum/data.cfm.

The dominant share of conventional biofuels is also explained by the fact that growth in the industry started earlier, received policy support and is facilitated by compatibility with existing internal combustion engine (ICE) vehicle fleets and fuelling infrastructure via blending. Conversely, increasing renewable energy consumption in EVs requires a parallel shift in the vehicle fleet, the roll-out of charging infrastructure and an increasing share of renewables in electricity generation portfolios. EVs also have a two to three times higher fuel economy than ICE vehicles, which is also a contributing factor to lower renewable energy consumption compared to biofuels. This transition to new vehicles

[1] While this analysis only covers road transport, rail accounted for over 50% of total transport electricity consumption in 2015.

[2] The term EVs refers to three vehicle types: electric two- and three-wheelers, electric buses and electric cars. The subset of electric cars refers to both battery-electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) that fall within the classification of passenger light-duty vehicles (PLDVs). Given their lower level of deployment, fuel-cell electric vehicles (FCEVs) are not included within the scope of this report.

and fuelling infrastructure is also required by certain advanced and conventional biofuels when used unblended or in high blends, which is a contributing factor to lower levels of deployment for these.

In 2022 renewables in the form of biofuels and EVs are anticipated to reach 4.8% of total energy consumption for road transport. Sustained vehicle deployment and higher shares of renewables in national electricity generation portfolios sees EVs account for one-fifth of the growth in renewable energy consumption for road transport over the forecast period. By 2022, electric cars only account for just over 1% of renewable energy consumption for road transport, a level comparable to advanced biofuels, while conventional biofuels still contribute around 92%.

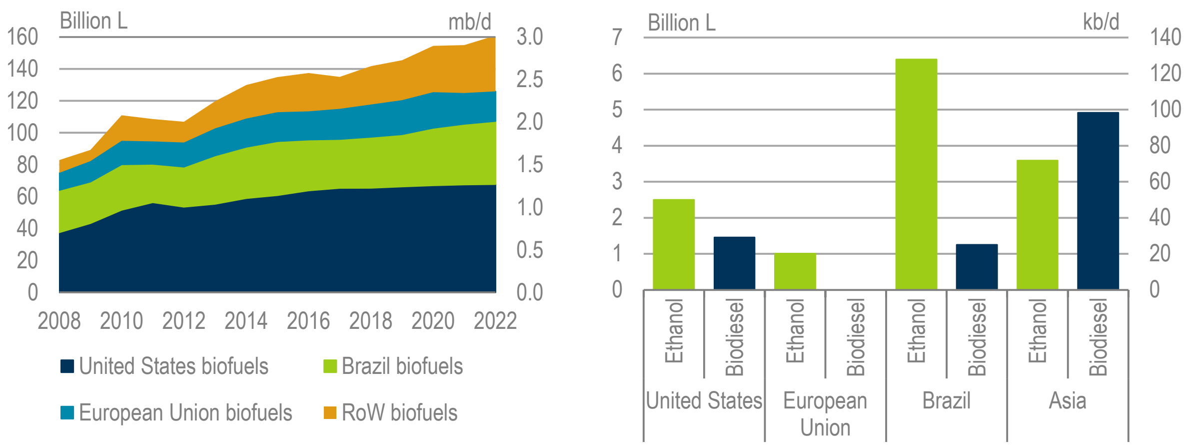
Even under an accelerated case scenario where all countries meet their electric car deployment targets, the share of total renewable energy consumption for road transport attributable to electric cars rises only modestly to 1.8% in 2022. Under such a scenario total electricity consumed by electric cars would account for 0.2% of total road transport fuel demand in 2022. This highlights that even high levels of electric car deployment in line with the Paris Declaration on Electro-Mobility and Climate Change and Call to Action would result in a minor displacement of demand for petroleum products during the forecast period.

Conventional biofuel markets

Global overview

In 2016, conventional biofuel production increased by around 2.5% year-on-year (y-o-y) to reach 136.5 billion L, or 3.3 EJ, slightly above the output anticipated in last year's report, but lower than the 4% average annual growth rate seen during 2010-16. For further details regarding 2016 biofuel markets refer to Chapter 1. World biofuel production is estimated to grow by around 16% over 2017-22 to reach 159 billion L (3.9 EJ), output in line with last year's forecast.

Figure 3.2. Global conventional biofuel production 2008-22 (left) and forecast output growth in key regions 2017-22 (right)



Notes: kb/d = thousand barrels per day; mb/d = million barrels per day; RoW = rest of world; HVO included in biodiesel growth in United States, European Union and Asia; Asia refers to the Asia and Pacific region including China, but does not include Australia or New Zealand; EU biofuels grow to 2020 and decline thereafter, explaining the zero growth shown for biodiesel.

Sources: IEA (2017d), *Monthly Oil Data Service (MODS)*, May 2017, www.iea.org/statistics/; IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; MAPA (2017), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2017), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Over a third of biofuel production growth occurs in Asian countries (Figure 3.2) due to the combination of increasing transport fuel demand, drivers to limit dependency on imports of crude oil and petroleum products, ample feedstock resources and supportive policy frameworks. Brazil also makes a significant contribution to forecast growth as a result of ongoing efforts to strengthen both ethanol and biodiesel consumption and achieve progress towards the national target of increasing the share of sustainable biofuels in the energy mix to 18% by 2030. Conversely only modest (5%) growth is expected in the European Union as the anticipated policy landscape post 2020 is not conducive to investment in new conventional biofuel production capacity.

Table 3.1. Global conventional biofuel production

Billion L	2016	2017	2018	2019	2020	2021	2022	CAAGR
North America	65.9	67.5	67.7	68.6	69.5	70.1	70.3	1.1%
United States	63.8	65.4	65.4	66.3	67.0	67.5	67.8	1.0%
Latin America	38.0	33.2	35.1	38.5	42.1	44.2	45.8	3.2%
Brazil	31.9	30.6	32.0	32.7	36.0	38.0	39.5	3.6%
European Union	17.7	19.0	20.3	21.4	22.4	19.4	18.6	0.8%
Asia and Pacific	10.0	10.9	12.9	14.1	15.4	16.1	16.6	8.8%
ASEAN	7.9	9.0	10.5	11.4	12.3	12.7	13.1	8.9%
India	1.1	0.8	1.2	1.3	1.7	2.0	2.1	10.6%
China	3.6	4.3	4.5	4.7	5.0	5.2	5.5	7.4%
Rest of world	1.2	1.3	1.5	1.8	2.0	1.9	1.9	8.3%
Total world	**136.4**	**136.2**	**142.0**	**149.1**	**156.4**	**156.9**	**158.8**	**2.6%**

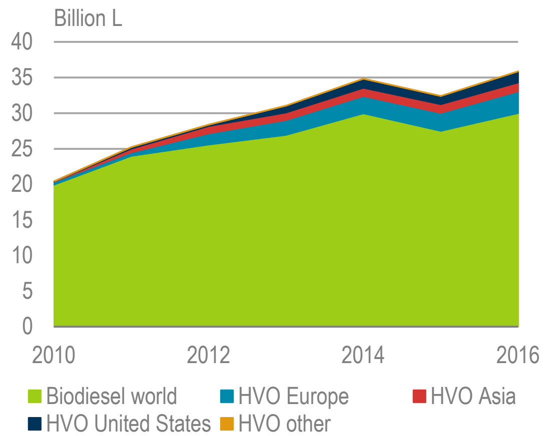
Note: Asia and Pacific excludes China; Latin America excludes Mexico, which is included in North America; ASEAN = Association of Southeast Asian Nations; CAAGR = compound average annual growth rate.

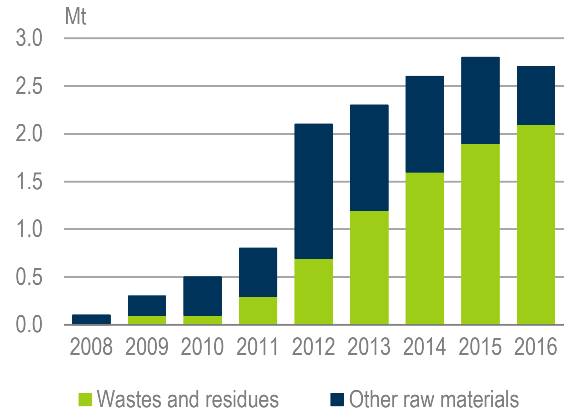
Sources: IEA (2017d), *Monthly Oil Data Service (MODS)*, May 2017, www.iea.org/statistics/; IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; MAPA (2017), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2017), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Ethanol is forecast to account for two-thirds of 2017-22 growth in conventional biofuel production. Global fuel ethanol production remained stable in 2016 compared to 2015 levels at 100.5 billion L. Output is forecast to grow at an average annual rate of just over 2% to reach 115 billion L by 2022, an upward revision to last year's forecast. Growth is mainly driven by Brazil, followed by the United States and expanding markets in India and Thailand. In 2022, the United States and Brazil still dominate ethanol production, accounting for over 80% of global output (Table 3.1).

As anticipated in last year's forecast, combined biodiesel and HVO production rebounded from 2015 levels, with record output of almost 36 billion L in 2016, representing y-o-y growth of over 10%. Almost all of this 3.5 billion L increase was accounted for by record output in the United States, and a rebound in production in Argentina and Indonesia. Global production is expected to grow at an average annual growth rate of 3% until 2022, reaching about 43.5 billion L. Market expansion over the next five years is driven by higher mandated demand in the United States, Brazil and some ASEAN countries, notably Indonesia. HVO, also known as renewable diesel, is increasingly prominent in the *Renewables 2017* biofuel forecasts. In 2016, 5.9 billion L of HVO accounted for 16% of global combined HVO and biodiesel production (Figure 3.3).

Figure 3.3. Global biodiesel and HVO production 2010-16 (left) and feedstock use for HVO production by Neste 2008-16 (right)



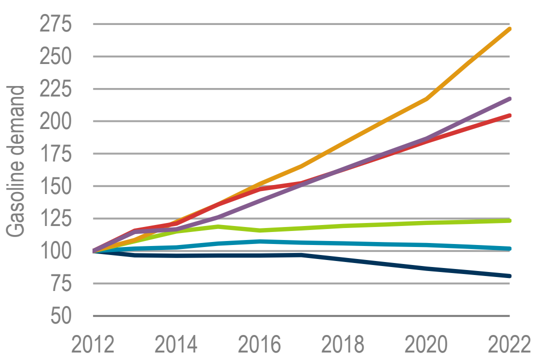


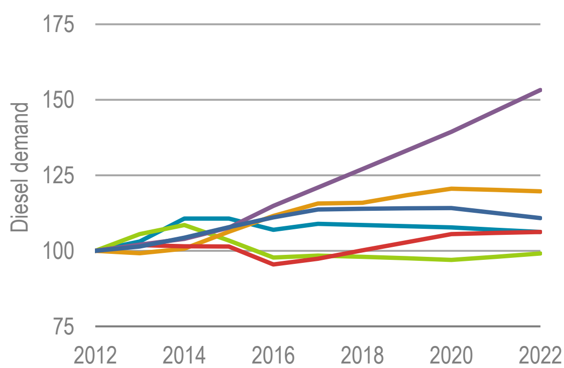
Notes: Mt = million tonnes of feedstock; wastes and residues includes food processing fats and oils and technical corn oil; other raw materials includes virgin vegetable oils.

Source: F.O. Lichts (2017a), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanol-and-biofuels-report/ (subscription service); Neste official company data provided by personal communication August 2017.

In the United States, the biomass-based diesel category of the Renewable Fuel Standard (RFS2) scheme and California's Low Carbon Fuel Standard (LCFS) are expected to provide ongoing policy support for HVO consumption. Under the LCFS, the vast majority of HVO and biodiesel consumed is derived from waste and residue feedstocks. These offer greater reductions in greenhouse gas (GHG) emissions than crop-based alternatives, and are growing in importance within the HVO industry due to policy frameworks that create demand for lower-carbon fuels and technical advances in feedstock processing. This is demonstrated by the increase in the share of such feedstocks for HVO production by Neste, a corporation accounting for over half of global production capacity (Figure 3.3).

Figure 3.4. Indexed gasoline and diesel demand trends for selected countries, 2012-22





Europe United States Brazil India China ASEAN

2012 = 100

Source: IEA (2017b), *Market Report Series: Oil 2017*.

Biofuel's contribution to global demand for road transport fuel is anticipated to grow modestly from 4% in 2016 to 4.5% by 2022. A more significant increase is not forecast due to ongoing growth in demand for fossil gasoline and diesel in many markets. Overall, global demand for road transport fuel is projected to grow by 8% over 2017-22, principally driven by higher consumption in Asian countries associated with increased levels of vehicle ownership. Demand trends vary by country and fuel, however (Figure 3.4). As most biofuels are used blended with fossil fuels (Table 3.2), increasing transport fuel demand supports growth in the biofuels industry, although not necessarily transport sector decarbonisation. For instance, based on 2016 demand levels, India's 5% blending mandate for ethanol in gasoline equates to about 1.6 billion L of captive fuel ethanol demand. Given projected growth in demand for gasoline, a 5% share in 2022 equates to 2.9 billion L.

Table 3.2. Mandates, targets and support policies for biofuels in selected countries

Country	Ethanol	Biodiesel	Advanced biofuels	CI reduction policy
United States	71 billion L of renewable fuels in 2017 and 136 billion L by 2022		Cellulosic biofuel category within RFS2	LCFS in states of California and Oregon
Canada	5%	2%	-	LCFS in British Columbia, Federal clean fuel standard proposed nationally
European Union	10%* renewable energy in transport by 2020 (T) with 7% cap for conventional biofuels		Double counted in renewable energy target, 0.5%* by 2020 (T)	GHG intensity of fuels to reduce 6% by 2020
France	7.5%*	7.7%*	From 2018, 1.6% in petrol and 1% in diesel	-
Germany	-	-	-	Climate Protection Quota (4%)
Italy	6.5%* biofuels		1.2%* from 2018	-
Denmark	5.75%* biofuels		0.9%* from 2020	-
Finland	30%* biofuel blending in road transport by 2030			
China	10%	-	-	-
India	5%	-	-	-
Indonesia	20%	3%	-	-
Malaysia	-	7%	-	-
Thailand	24% by 2026 (T)	7%	-	-
Mexico	10%	-	-	-
Argentina	12%	10%	-	-
Brazil	27%	8%	-	-

Notes: Dark green indicates policy changes since last year's report; light green colour indicates no recent policy changes; values are mandates unless (T) specified to indicate target; percentage values are by volume except where a * is shown to indicate by energy; mandate values in Canada are federal, provincial requirements vary; China's 10% ethanol mandate for gasoline only applies in certain provinces; value for Mexico is the maximum permissible ethanol volume, not a mandate or target; CI = carbon intensity, meaning the GHG emissions produced from a fuel on a lifecycle basis.

For biofuels to obtain a markedly greater share of global transport fuel demand, stronger growth will be required in the consumption of unblended biofuels and fuels with higher biofuel blend shares, e.g. E85,[3] to replace petroleum products. This will require both a) an increase in the supply of drop-in biofuels suitable for use without modification to vehicle engines or fuel supply infrastructure, or b) a transition in vehicle fleets (for example to flexible-fuel vehicles [FFVs] suitable for unblended hydrous

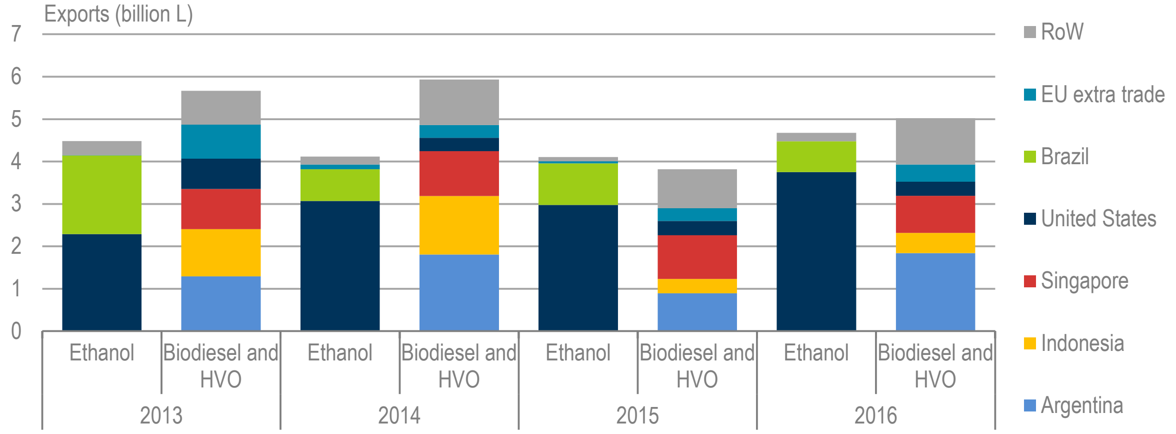
[3] E85 equates to 85% ethanol by volume blended with fossil gasoline. Subsequent references to E5, E10, E15 and E20 within the chapter refer to the volume share of ethanol blended with fossil gasoline. References to B5, B7, B10 and B20 etc. refer to the volume share of biodiesel blended with fossil diesel. B100 and HVO100 refer to unblended pure biodiesel and HVO respectively. Hydrous ethanol is utilised unblended.

ethanol) combined with changes to fuelling infrastructure such as pipelines and storage vessels. In either case the transition to such fuels will require their adherence to relevant technical standards and co-operation between fuel suppliers and vehicle original equipment manufacturers (OEMs) to establish fuel suitability so that vehicle warranties are not compromised.

Could new import tariffs in key markets constrain biofuel trade prospects?

The majority of global biofuel output is utilised in the country of production to satisfy national mandate policies (Table 3.2). However, international trade exists for both fuel ethanol and biodiesel. In 2016 estimates indicate trade in fuel ethanol of around 4.7 billion L, representing around 5% of global production (F.O. Lichts, 2017b) (Figure 3.5). Around 80% of fuel ethanol exports are accounted for by the United States, where production exceeds national demand and higher exports, for example to Brazil, India,[4] Mexico and the Philippines, are a key component of the ethanol industry's growth strategy. Around 5 billion L of biodiesel and HVO were traded in 2016 (14% of global production). Argentina is by far the major exporter (37% of global exports), followed by Singapore (17% of global exports) and Indonesia (9% of global exports). Neither fuel ethanol nor biodiesel and HVO trade exhibit strong upward trends (Figure 3.5). Fuel ethanol trade exports in 2016 were only marginally higher than in 2013, and 2016 biodiesel and HVO exports were below 2013-14 levels.

Figure 3.5. Global biofuel exports, 2013-16



Notes: Fuel ethanol export data based on qualified estimates; EU extra trade refers to trade with countries outside the European Union, as only EU trade with third countries is included.

Source: F.O. Lichts (2017a), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanoland-biofuels-report/ (subscription service); F.O. Lichts (2017b), "World ethanol trade will be hit by surge in protectionism", www.agra-net.com/agra/world-ethanol-and-biofuels-report/features/world-ethanol-trade-will-be-hit-by-surge-in-protectionism-549092.htm.

Import tariffs and anti-dumping duties[5] act as a constraint on biofuel trade, and the recent application of these in a number of fuel ethanol and biodiesel markets has shifted the trade landscape. In 2016 China emerged as the third-largest importer of US corn ethanol. However, from the start of 2017 the application of a 30% import tariff has effectively closed this market. Brazil has not imposed an import tariff on fuel ethanol since 2010. However, increased imports from the United States since October 2016 have prompted the introduction of a 20% tax on ethanol imports

[4] India's blending programme does not allow fuel ethanol imports. However, increased blending of nationally produced fuel ethanol would divert production away from industrial ethanol markets, potentially opening up the need for imports to service these.

[5] A tariff imposed on foreign imports of a given product where it is believed these are priced below their current fair market value.

above a tax-free quota of 600 million L per year. Conversely, the recent increase in the permissible ethanol blend in Mexico to E10 increases the potential for imports from the United States.

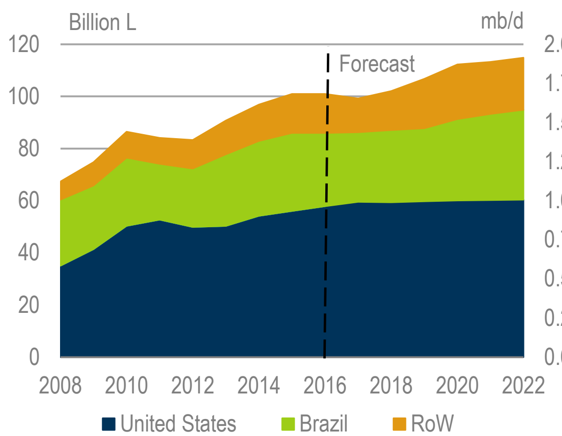
A similar trend is developing for biodiesel. In the United States, after a preliminary determination from the Department of Commerce to impose countervailing duties on imports from Argentina and Indonesia, the International Trade Commission is currently assessing the case for the introduction of anti-dumping duties. A final decision is expected by the end of the year. In addition, potential reform of the expired biodiesel blenders' tax credit to a biodiesel producer credit is under consideration in the United States. This would strengthen the economic case for domestic consumption compared to imports, and could bring idle plants back into operation.

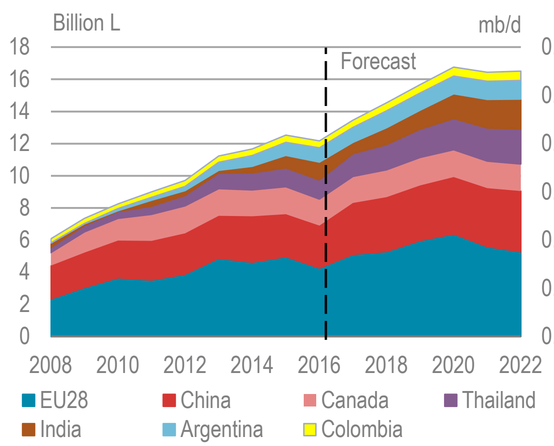
A combination of these factors would be challenging for the Argentinian biodiesel industry, where over half of 2016 production was exported, primarily to the United States. However, demand from the RFS2 and California's LCFS means imports could still continue. Conversely, in 2016 the World Trade Organization (WTO) ruled in Argentina's favour with regard to claims against EU anti-dumping duties on Argentinian biodiesel imports. As a result these were revised down by the European Commission in September 2017, raising the prospect of increased biodiesel imports from Argentina.

Ethanol markets regional outlook

Annual ethanol production in the **United States** is expected to stabilise at around 60 billion L during the second half of the forecast period, an increase of 5% on 2016 levels (Figure 3.6). This is due to limited investment in new capacity compared to previous growth in the industry, a stabilisation of gasoline demand due to the increasing fuel efficiency of the vehicle fleet, and RFS2 volumes for total renewable fuels that indicate the limit for corn-based ethanol will be reached in 2017. Although the US government reiterated its support for renewable fuels in 2017, the prospect of reform of the RFS2 over the forecast period cannot be ruled out. Currently, however, this is only speculation and no concrete details have emerged to gauge any possible impact on the *Renewables 2017* forecast.

Figure 3.6. Annual fuel ethanol production in major (left) and other key markets (right), 2008-22





Sources: IEA (2017d), *Monthly Oil Data Service (MODS)*, May 2017, www.iea.org/statistics/; IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; *MAPA (2017), Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2017), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Fuel ethanol production in **Brazil** is forecast to increase at an average annual growth rate of 3.5% to reach 34.5 billion L by 2022, a downward revision on last year's forecast. Output in 2017 is anticipated to reduce y-o-y due to ongoing prioritisation of sugar production over ethanol and a lower quantity of sugar cane crushed. The expiry of ethanol tax exemptions at the end of 2016 is also likely to affect hydrous ethanol demand in 2017 by reducing competitiveness with gasoline at the pump. Uncertainty surrounding hydrous ethanol demand is also heightened due to Petrobras's move to regular price revisions for petroleum products, with a new pricing methodology based on crude oil prices plus a margin for taxation, profit and operational risk.

The number of operating sugar and ethanol mills is anticipated to be stable in 2017 against 2016 levels. However, the fragile economic state of many of these represents a core challenge to increasing output, for example where mills cease to operate or lower investment in facilities reduces ethanol yields. Nevertheless, industry investment is occurring. This is most prominently related to increasing the capacity of existing facilities, with the anticipated commissioning of two corn ethanol plants increasing ethanol production during the sugar cane inter-crop season.

Growth prospects in Brazil are primarily based on its nationally determined contribution (NDC) objective to increase the share of sustainable biofuels in its energy mix to 18%. This could translate into in excess of 50 billion L of domestically produced fuel ethanol consumption per year by 2030, offsetting future gasoline imports. While some demand is anticipated to be met from cellulosic feedstocks, sugar cane ethanol would be expected to grow considerably under such a scenario. Demand growth is also expected from the expanding share of FFVs in the vehicle fleet, which reached 72% in 2016, and an anticipated increase in gasoline demand by 2022. *Renewables 2017* anticipates investment in new production capacity to be facilitated by the RenovaBio 2030 plan to expand biofuel markets, although this currently remains in development with no measures finalised.

In **China**, the world's third-largest fuel ethanol producer, output is forecast to grow at an average annual rate of 6% to around 3.8 billion L in 2022, undershooting the 13th Five-Year Plan (FYP) target of 4 million tonnes (around 5 billion L) of annual production by 2020. While no mandate increases are expected in the provinces that have 10% ethanol blending in place, 6% average annual growth in gasoline consumption is expected to boost ethanol demand. Previous corn stockpiling policies have led to large grain reserves that are now unfit for human consumption. As a result, several provinces have introduced subsidies to encourage the production of corn ethanol. This will improve capacity utilisation and reverse a trend that saw fuel ethanol imports increase over 2015-16. Production growth is mainly anticipated from cassava in southern regions and corn in the northeast.

Fuel ethanol production in the **European Union** is expected to peak in 2020 at around 6.4 billion L, as national policies support a scaling up of production towards 2020, in line with the EU Renewable Energy Directive (RED) target of 10% renewable energy in transport. Higher production is undermined by declining EU gasoline demand. The main feedstocks used for fuel ethanol production in Europe are corn and wheat, with sugar beet making a lower contribution. However, the abolition of sugar production quotas in the European Union in 2017 could reshuffle the ethanol feedstock mix, with higher sugar beet cultivation in key producer countries France, Germany and Poland. Increased fuel ethanol output is principally from higher capacity utilisation at existing plants, with limited new ethanol capacity anticipated as EU policy support for conventional biofuels weakens. Consequently, EU ethanol production declines post 2020 after the milestone RED target passes, with a scaling down of conventional biofuels' contribution to EU renewable energy targets proposed thereafter (Box 3.1).

Fuel ethanol production in **India** is expected to fall y-o-y from 2016's record output due to drought conditions in key sugar cane harvest areas increasing molasses feedstock prices, relatively lower regulated procurement prices compared to those for competing ethanol uses and the removal of the excise duty exemption for ethanol blending. Consequently, there was low interest from sugar mills in oil marketing company (OMC) fuel ethanol tenders and volumes secured were less than required to reach the 5% blending mandate in 2016/17. Long-term drivers for fuel ethanol industry expansion remain strong, and over the forecast period annual production is anticipated to rise to 1.9 billion L. Average annual growth in gasoline demand is estimated at 10% and domestically produced fuel ethanol is viewed as a means to offset petroleum product imports and improve security of supply, with a 10% blending target in place for the major ethanol-producing states.

Prospects for the ethanol industry in **Thailand** remain very positive as progress towards the Alternative Energy Development Plan long-term target of 32% ethanol blending continues. New production capacity is anticipated to come on line over 2017-18 and output is forecast to increase at an average annual rate of over 10% to reach 2.2 billion L by 2022. Production is primarily from molasses; however, over the forecast period cassava feedstock ethanol will command an increasing market share. Multiple drivers support forecast growth: first, over 2016-22 gasoline demand is anticipated to rise at an annual average rate of around 4.5%; second, E10 availability is widespread and coverage of subsidised E20 and E85 blends is rising, with an increasing number of service stations offering them in 2016; and third, demand is also supported by tax incentives for the purchase of FFVs.

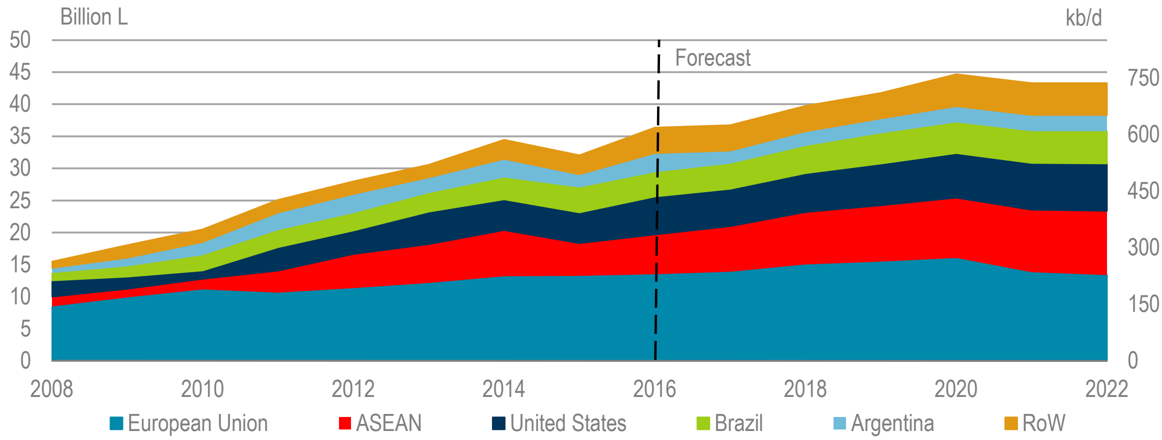
Biodiesel markets regional outlook

In the **United States** a strong soybean harvest and existing stocks should maintain low feedstock prices in 2017. However, expiry of the USD 1/gallon blenders' tax credit at the end of 2016 will affect production economics. Biomass-based diesel volumes required by the RFS2 are expected to increase annually, and biodiesel is also eligible to contribute to the advanced biofuel and total renewable fuels categories of the scheme, providing demand certainty over the forecast period. California's LCFS also creates demand for biodiesel and HVO. Due to these policies, annual output is forecast to reach 7.4 billion L in 2022, a 25% increase on 2016 despite stagnant diesel demand (Figure 3.7).

Biodiesel production in **Brazil** is expected to see average annual production growth of around 5%, with output scaling up to 5 billion L by 2022. Higher production should go some way towards reducing current biodiesel plant overcapacity. Demand is supported by a staged increase in the blending mandate, which increased from 7% to 8% in March 2017, and will rise by one percentage point annually to 10% in 2019. Higher demand is dampened by a stabilisation of diesel consumption.

In the **European Union**, annual biodiesel production is forecast to increase to 16 billion L by 2020 as a result of policy support measures to reach the aforementioned EU RED target for 2020. In 2017, biofuels mandate increases in the Czech Republic, Italy, Netherlands and Spain should support higher demand. Post 2020, production is anticipated to fall since no support is anticipated for conventional biofuels under European Commission state aid rules, and due to the proposal to reduce the contribution of food-based biofuels towards the EU renewable energy target within a revised RED for 2020-30 (Box 3.1). In this context, prospects for new biodiesel capacity investment in the European Union during the forecast period appear severely limited. HVO production will increase further in 2018 with the commissioning of a large refinery in France.

Figure 3.7. Global biodiesel production, 2008-22



Note: Production numbers include HVO.

Sources: IEA (2017d), *Monthly Oil Data Service* (MODS), May 2017, www.iea.org/statistics/; IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; MAPA (2017), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2017), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

In **Indonesia**, the biodiesel market is in transition from an export-driven focus towards higher domestic consumption. The cost premium of blending biodiesel faced by fuel distributors is subsidised via a plantation fund using levies on crude palm oil and palm oil product exports. By 2022, a significant increase in annual biodiesel production to 5.3 billion L is forecast. Growth is underpinned by a number of new plants coming on line, complemented by a ramp-up in production from underutilised capacity. Demand is ensured by new legislation to expand coverage of the B20 market segment, eligible for subsidies and subject to non-compliance penalties, and steady growth in diesel consumption of around 3% per year. The share of production exported is anticipated to decrease, but exports will remain an important part of Indonesia's biodiesel market structure.

Annual biodiesel output in **Malaysia** is forecast to increase from 900 million L in 2016 to around 1.3 billion L by 2022, as a result of the planned increase in the road transport blending mandate to B10 and a steady upward trend in diesel demand. The timescale for the aforementioned mandate increase is currently unknown but is anticipated to occur during the forecast period, as is the implementation of a B7 blending target for the industrial sector. Production output growth is achievable without additional new plants given current overcapacity in the industry.

Conventional biofuels accelerated case

Global conventional biofuels production increases to around 180 billion L in 2022 in the accelerated case, 14% higher than the main case, as a result of a more favourable market and policy landscape. Within the accelerated case the share of biofuels in road transport fuel demand increases to 5%. Annual ethanol production increases by 10 billion L to 125.5 billion L in 2022 (up 9% on the main case) (Table 3.3) and biodiesel and HVO output increases by 11 billion L to reach 55 billion L in 2022 (up 26% on the main case) (Table 3.4).

Brazil, India and the United States are key contributors to the fuel ethanol accelerated case. In **Brazil**, reaching annual production of 38 billion L by 2022 (up 10% on the main case) will require a package of measures to support new investment in production capacity. The RenovaBio plan is considering a mandate system that places an obligation on fuel distributers to meet biofuel consumption and carbon dioxide (CO_2) reduction targets. The combination of a sustainable expansion of the sugarcane planted area, yield improvements and low-level capacity losses from mills in a fragile financial position would also support higher production.

Accelerated case production in the **United States** would increase by 2.5% to reach 62 billion L in 2022, due to higher consumption of E15 and E85 ethanol blends. As many suitable vehicles for these higher blends are already on the road, unlocking their growth potential principally rests with scaling up fuel distribution infrastructure. In this respect, service stations offering E15 and E85 both increased by more than 100 in 2016, with coverage expected to expand more rapidly in 2017. Growing exports is also fundamental to industry expansion.

Fuel ethanol production could increase to 3 billion L by 2022 (up 58% on the main case) in **India**, putting the country on a firmer path towards compliance with its 5% national blending mandate and 10% blending target for major ethanol-producing states. Key actions to scale up output include mitigating barriers relating to interstate permits and taxes as well as constrained storage at refineries. Broadening the feedstock base beyond molasses and facilitating low-cost finance to sugar mills would also support growth.

Table 3.3. Annual fuel ethanol production: accelerated case (billion L)

Country	Feedstock and Fuel	2016	2022 main	2022 acc.	Brief explanation of accelerated case
United States	C ethanol	57.9	60.4	62.0	Higher exports; increased E15 and E85 uptake; integrated technologies to increase output.
Brazil	SC ethanol	28.1	34.5	38.0	Concrete measures to deliver investment in RenovaBio plan; low levels of lost capacity.
European Union	MF ethanol	4.3	5.3	6.6	Roll-out of E10 to new member states; no scale-down post 2020 in finalised RED update.
China	C ethanol	2.6	3.8	5.0	13th FYP target met, feedstock diversification, measures to stimulate investment.
Thailand	MF ethanol	1.2	2.2	2.7	Higher E20 and E85 uptake via fuel infrastructure roll-out; growing cassava feedstock availability.
India	M ethanol	1.1	1.9	3.0	Mitigating inter-state logistical barriers; broadening feedstock base beyond molasses.
Argentina	MF ethanol	0.9	1.2	2.1	Mandate increase to 26%; investment to scale up corn ethanol capacity; FFV roll-out.
Philippines	SC ethanol	0.2	0.4	0.6	5% mandate achieved; switch from industrial to fuel ethanol output; increased cane planting.
Additional fuel ethanol production in 2022:				**10.3**	

Notes: C = corn; SC = sugar cane; MF = mixed feedstocks; M = molasses.

The main production increases in the biodiesel and HVO accelerated case occur in Indonesia, India and the United States. In **Indonesia**, biodiesel production would increase to 8.5 billion L by 2022 (up 60% on the main case). Current overcapacity means most of the production scale-up could be achieved by existing plants. Meeting this output level would require full compliance with the B20 transport mandate as well as meeting the mandates for industry (20%) and power generation (30%). In addition, new export markets would need to open up. Crude oil prices would also play a role as these dictate the quantity of biodiesel subsidised by the plantation fund.

In the **United States**, combined biodiesel and HVO production could increase by over 20% above the main case to reach 9 billion L of annual production. This requires ongoing policy support from the RFS2, complemented by the tightening GHG emissions reduction requirements in the California and Oregon LCFS frameworks. Current biodiesel capacity could deliver the majority of accelerated case production, and a reform and subsequent reintroduction of the biodiesel blenders' tax credit as a producers' tax credit would likely spur higher capacity utilisation.

In the accelerated case, **India's** limited biodiesel production is kick-started to achieve 1.5 billion L of output by 2022, a sevenfold increase on the main case. Meeting this ambitious scale-up would require a formalised B5 mandate, and its application in a more widespread area than the six states currently covered. Greater consumption of B100 within rail would also support growth, as currently less than 15% of rail fuel depots blend biodiesel. In addition, mobilisation of waste oil feedstock supply chains and identification of the most suitable oil crop feedstocks would be required.

Table 3.4. Annual biodiesel and HVO production: accelerated case (billion L)

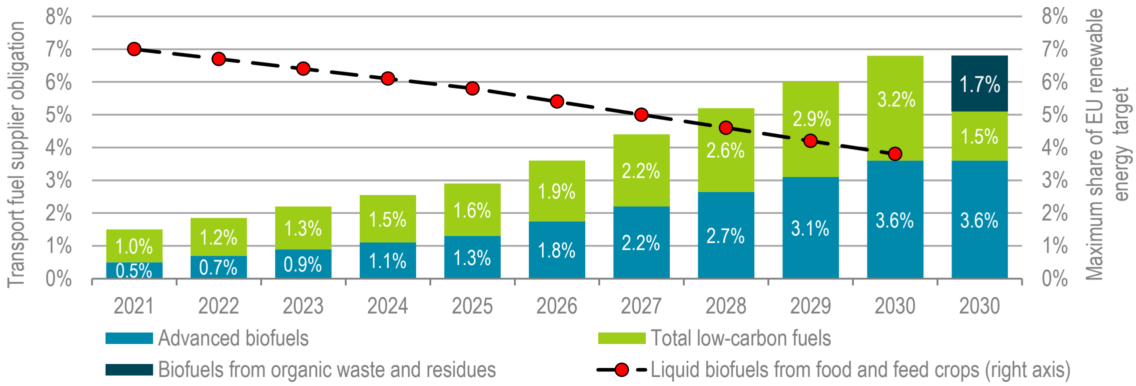
Country	Feedstock and Fuel	2016	2022 main	2022 acc.	Brief explanation of accelerated case
United States	MF Biodiesel / MF HVO	5.9	7.4	9.0	Increase in HVO capacity; switch to producer tax credit; continuation of RFS2 support.
Brazil	SB biodiesel	3.8	5.0	6.2	Stronger diesel demand growth; higher B20 consumption in fleets and public transport.
European Union	MF biodiesel	13.5	13.4	16.0	Further HVO refinery conversion projects; no scale-down post 2020 in finalised RED update.
China	WR biodiesel	0.9	1.7	2.2	13th FYP target met; mobilise waste and residue feedstocks; new provincial mandates.
India	WR biodiesel	0.0	0.2	1.5	Formalisation of B5 mandate and roll-out of blending programme; use in rail transport.
Indonesia	PO biodiesel	2.8	5.3	8.5	Lowering underutilised capacity; ongoing exports and fully enforced B20 mandate.
Malaysia	PO biodiesel	0.9	1.3	1.8	Move to B15 as outlined in 11th Malaysia plan; ongoing consultation with motor vehicle OEMs.
Argentina	SB biodiesel	3.0	2.5	3.5	Improved export prospects with United States and European Union, as well as new markets.
Singapore	MF HVO	1.1	1.1	1.4	New HVO capacity and debottlenecking of current production capacity to increase output.
Additional biodiesel and HVO production in 2022:				**11.2**	

Notes: SB = soybean; WR = waste and residue oils and animal fats; MF = mixed feedstocks; PO = palm oil; total accelerated case production is less than the sum of individual countries shown in the table as it is considered that accelerated production levels in Argentina and the United States are not mutually achievable.

Box 3.1. Key biofuels proposals within the European Commission's 2016 "Energy Winter Package"

The European Commission's proposals for the updated Renewable Energy Directive covering the period post 2020 suggest contrasting implications for conventional and advanced biofuel markets. These include the removal of the current 10% sub-target for renewable energy in the transport sector by 2020, and the retention of the cap on conventional (food-crop) biofuels' contribution to this renewable energy consumption target, the latter as a result of the European Commission's concerns regarding the indirect land-use change (ILUC) impacts of conventional biofuels. Starting at the current 7% limit in 2021, it is proposed that the cap gradually reduces to 3.8% by 2030 (Figure 3.8).

Figure 3.8. Advanced and conventional biofuel proposals in the Energy Winter Package



Notes: Total low-carbon fuels includes renewable electricity, renewable fuels of non-organic origin, e.g. hydrogen, biofuels from organic wastes and residues, and advanced biofuels; percentage values shown for total low-carbon fuels is the net value after the mandatory share from advanced biofuels has been met; the right-hand 2030 column shows fuel category contributions where a maximum share of biofuels from organic wastes and residues is filled.

Source: European Commission (2017), "Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast)", http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0767R(01).

Conversely, the proposed strengthening of policy support for advanced biofuels should support investment in less mature technologies. This includes an obligation on transport fuel suppliers to provide an increasing share (by energy) of EU road and rail demand from a range of advanced renewable and low-carbon fuels. The level of this obligation increases from 1.5% in 2021 to 6.8% in 2030. The contribution of biofuels produced from used cooking oils, molasses and certain categories of animal fats to the obligation is capped at 1.7%. The obligation also includes a dedicated sub-target for advanced biofuels produced from a specific list of feedstocks outlined within the legislation, which includes the biomass fraction of municipal wastes as well as agricultural and forestry residues. This sub-target increases from 0.5% in 2021 to 3.6% by 2030. In addition, advanced aviation biofuels have their energy content multiplied by an additional 20%. All new advanced biofuels must reduce GHG emissions by at least 70% compared to fossil fuels. It should be noted that all of these proposals, for both conventional and advanced biofuels, are not finalised and could be subject to change.

Advanced biofuel markets

Within *Renewables 2017*, advanced biofuels are sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant lifecycle GHG 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.

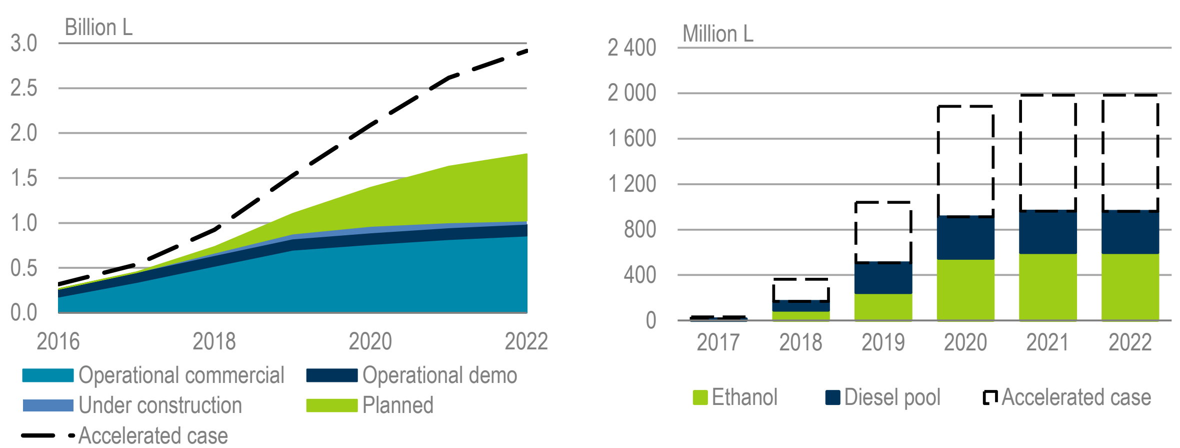
Advanced biofuels main case forecast

The *Renewables 2017* main case forecasts annual production of advanced biofuels to reach 1.8 billion L in 2022 (Figure 3.9), a sevenfold increase on estimated 2016 production. However, this is equivalent to just 1.1% (by volume) of total biofuel production, indicating that a significant contribution from advanced biofuels in the transport sector is not anticipated over the forecast period. Cumulative advanced biofuel production over 2017-22 in the main case is 7 billion L. Cellulosic ethanol accounts for 60% of production within the main case forecast, with the remainder attributed to advanced biofuels for use within the diesel pool and aviation biofuels.

In the main case, technological learning sees currently low utilisation rates in already-commissioned commercial-scale advanced biofuel plants increase to an average of around 70%, therefore delivering a scale-up to 800 million L of production in 2022. In excess of 60 smaller capacity plants, constructed for demonstration purposes, are also included in the forecast. Production data for these are hard to obtain, and within the main case it is assumed that only 50% of these are operational and output is below nameplate capacity. Due to the aforementioned scale-up in commercial plants, and new advanced biofuel facilities coming on line during the forecast period, the contribution of smaller-scale demonstration facilities to the forecast decreases from 33% of production in 2016 to just 7% in 2022. The main case also considers that five corn ethanol plants per year in the United States are retrofitted with technology to produce cellulosic ethanol from corn fibre residues.

The main case forecast assumes 40% of announced projects are delivered, adding the remaining 850 million L of advanced biofuel production in 2022. In respect of the project pipeline, the number of announced projects far outweighs those facilities that are currently in the construction phase (less than 150 million L of capacity). This highlights the challenge currently faced by many projects in obtaining the necessary finance to proceed beyond the early stages of development. The greatest additions during the forecast period are expected in 2020, where around 400 million L of additional capacity is commissioned. The project pipeline includes a number of replication projects building on learning obtained from the first-of-a-kind commercial projects commissioned over 2013-16. These are assumed to ramp up production more quickly, with utilisation rates reaching 80% in three years.

Figure 3.9. Forecast annual advanced biofuels production (left) and capacity additions (right)



Notes: HVO plants are included within the advanced biofuel forecast where waste and residue feedstocks are exclusively utilised for production; where a mix of oil crop feedstocks and wastes and residues are used, these are counted within the conventional biofuel forecast; demo = demonstration.

Advanced biofuels accelerated case forecast

With a supportive market and policy context, the *Renewables 2017* advanced biofuels accelerated case forecast reaches close to 3 billion L of production by 2022 (Figure 3.9), over 60% higher than the main case, and equivalent to 1.8% of all biofuel production when compared to main case conventional biofuel production levels. Over 2017-22, 10.6 billion L of cumulative advanced biofuel production is delivered under accelerated conditions, a 50% increase on main case production.

Higher output is delivered by the first commercial advanced biofuel plants contributing 1 billion L by 2022 due to reaching higher utilisation rates (90% on average), levels indicative of technically mature conventional biofuel plants in markets with strong demand. Delivering this higher availability will require operational learning, improved pretreatment processes and improved integration of core fuel production processes within wider elements of advanced biofuel facilities. Furthermore, it is assumed that two idle plants under new ownership come back on line and ramp up production. In the accelerated case, 75% of demonstration plants are operational due to supportive policies providing guaranteed demand and making production from these more cost-effective.

A more favourable investment climate means 80% of the project pipeline is realised within the accelerated case, delivering 1.6 billion L of production by 2022. This requires efficient and reliable performance from the first commercial advanced biofuel plants, to lower investment risk for new projects. In the accelerated case, replication plants scale up production more quickly, reaching an 85% utilisation rate in three years and 90% thereafter, as operational experience gained from first-of-a-kind facilities is exploited. Stronger policy support is also needed in the form of more widespread quotas providing guaranteed fuel offtake and the availability of financial de-risking measures.

Research, development and demonstration activities to accelerate technical progress are also required to meet the accelerated case. For HVO, development of pretreatment processes to expand the range of suitable waste and residue feedstocks supports higher output. In addition, research to maximise ethanol and co-product yields from a given quantity of feedstock and energy inputs improves the viability of cellulosic ethanol plants. Furthermore, ten corn ethanol plants a year in the United States are fitted with corn fibre to cellulosic ethanol technology, double main case uptake.

Box 3.2. Two new global initiatives could support accelerated biofuel market growth

The “Below50” collaboration from the World Business Council for Sustainable Development has a target to offset 10% of fossil fuel consumption across all transport modes by means of low-carbon fuels by 2030, with a focus on growing corporate procurement. Qualifying fuels must deliver a 50% reduction on CO_2 emissions compared to fossil fuels and meet a set of sustainability principles. Members of the initiative span the whole fuel supply chain. In addition, the country-led “Biofuture” platform was launched in late 2016 with the aim of promoting collaboration and policy dialogue to facilitate an enabling environment for market growth of sustainable low-carbon fuels. Currently 20 countries participate in the initiative. The International Energy Agency (IEA) is actively supporting both initiatives.

Status update on advanced biofuel projects

Cellulosic ethanol

Most of the first-of-a-kind commercial-scale advanced biofuel plants which came on line over 2013-16 remain in an extended commissioning phase as they undergo an intensive learning curve, which includes “debottlenecking” to increase yield and utilisation rates as well as reduce investment and operational costs for the next generation of projects. Transparency is lacking as regards the actual production volumes at many of these plants. However, indications are that the portfolio of commissioned commercial-scale cellulosic ethanol plants exhibit mixed performance.

Plants in Europe, Brazil and the Unites States have reported increased availability, utilisation rates and yields. This was achieved through a range of measures, such as core process optimisation, design improvements and further modifications to improve process reliability. A switch in feedstock from agricultural residues to woody biomass at one plant also appears to have correlated with higher availability. Increased output can be anticipated at these plants in 2017, with one producer indicating that should performance continue to improve investment in further plants could follow. Conversely, other commercial-scale plants were off line due to technical difficulties and changes in ownership. In the United States, compliance data from the RFS2 indicates 14.5 million L of cellulosic ethanol production in 2016, a 75% increase y-o-y from a low base. However, most of this production is from smaller-capacity plants with output from commercial-scale facilities well below rated capacity.

Plants using other technologies

In 2016, a production scale-up was reported for a tall oil-based HVO plant in Finland, and aviation biofuel from a Californian facility was supplying regular flights by major airlines. A municipal solid waste-based facility in Canada currently producing industrial methanol is in the process of making technical adjustments to produce advanced fuel ethanol. Two new commercial-scale facilities producing advanced diesel biofuels, from tallow and corn oil respectively, and a small-scale Fischer–Tropsch plant using landfill gas were also commissioned in 2016, the latter indicating progress in thermochemical biofuel production.

Biomethane production continued to expand in Europe, where there were in excess of 450 plants in operation in 2015 (EBA, 2016).[6] However, policy support measures for biomethane, for example Germany's feed-in tariff and the Renewable Heat Incentive in the United Kingdom, result in the majority of biogas production being directed for heat, power or co-generation rather than upgraded to biomethane for transport. Within Organisation for Economic Co-operation and Development (OECD) countries, less than 1.5% of biogas production in 2015 was utilised in transport, with consumption most notable in Germany, Norway and also Sweden, where over 50% of biogas was used in transport (IEA, 2017h). In the United States, biomethane consumption in the RFS2 grew fivefold in 2016 compared to 2014 levels (US EPA, 2017).

Project pipeline

The investment environment for advanced biofuels remains challenging for a number of reasons. Advanced biofuel facilities are typically capital intensive, which, coupled with the risk profile associated with technologies unproven at commercial scale, can make sourcing finance a problematic and slow process. In addition, current low oil prices mean policy support remains crucial to guarantee offtake for projects once constructed. As such, prospects for project development are tied to the pace at which stronger and more widespread policy support is introduced. As a result of these factors, delayed, stalled and cancelled projects are observed. This also explains the low share of projects under construction compared to those in the planning phase.

Nevertheless, new projects continue to be announced in those markets where policy support is evident, notably the United States as a result of the RFS2, and Sweden and Finland, where strong national frameworks for transport sector decarbonisation and fossil fuel phase-out are in evidence. The proposed target for advanced biofuels in the European Union for 2030 (Box 3.1) and aforementioned production scale-up at some commercial cellulosic ethanol plants should also facilitate further project delivery.

Activity in new markets is also occurring, with the most notable development over the last year a marked step up in cellulosic ethanol interest in India. This is being driven by security of supply

[6] Biomethane from waste and residue feedstocks qualifies for the definition of an advanced biofuel. However, biomethane production is not included within the advanced biofuel forecast due to lack of data availability regarding cases where waste and residue feedstocks are used and the biomethane subsequently produced is utilised within the transport sector.

concerns in response to increasing import demand for crude oil, and targets for 10%, and then 22%, ethanol blend levels in gasoline. Meeting these ambitious targets can only be achieved by a combination of conventional and cellulosic ethanol. Following the commissioning of India's first demonstration-scale plant in 2016, nine cellulosic facilities are planned by 2021 in conjunction with India's state-run OMCs. Of these, four plants appear to be in active development and one began construction in late 2016.

Other new markets include Eastern Europe, where three projects are reportedly nearing construction. However, announced projects in China, Malaysia and Thailand are at an earlier stage of development. Moving into new markets will entail exploitation of different feedstocks, including rice straw in India and cassava fibres and pulp in Thailand. In Brazil, a number of mills are utilising energy cane, and trials indicate that productivity (on a tonne of sugarcane per hectare basis) can increase by 190% or more, producing additional bagasse suitable for bioenergy or cellulosic ethanol production.

Integrating advanced biofuel technologies into conventional biofuel facilities

Exploiting synergies with the conventional biofuel industry can place advanced biofuels on a firmer path to reaching accelerated production. Notable progress is being made in retrofitting cellulosic ethanol technology into existing conventional biofuel facilities. Deployment of these technologies is gathering pace in the United States due to the supportive policy framework for cellulosic biofuel production via the RFS2 and LCFS in California. In addition, the large production base for corn ethanol allows for the use of corn fibre residue, the lowest value co-product of corn ethanol production, as a feedstock for cellulosic ethanol production. The relatively low volume of corn fibre residue produced results in a smaller-scale solution with a lower investment cost.

Cellulosic ethanol from corn fibre technology appears set for further roll-out across the US corn ethanol industry. It has already been installed at six ethanol plants, four of which are registered to produce cellulosic (D3) renewable identification numbers (RINs) used for RFS2 compliance. Eligibility for D3 RINs and use of the output for compliance with California's LCFS provide a premium value for US cellulosic ethanol production, estimated in the region of USD 1.15/litre (Biofuels Digest, 2017). Currently the technology is delivering an increase in total ethanol production volume of 1-2% from cellulosic feedstocks at these facilities, with scope for further increase (Edeniq, 2017). In Europe prospects for the use of such integrated technologies in corn ethanol plants are impeded by the uncertain policy context surrounding conventional biofuels.

Advanced biofuel policy developments

Additional policies will be required to facilitate growth in the advanced biofuel industry and deliver output levels outlined in the *Renewables 2017* main case, and support will need to be significantly stronger to realise accelerated case production levels. Given a typical 3-year construction period for an advanced biofuel facility, and subsequent 15-20 year operational life, policies already need to look beyond 2020 to encourage industry growth in the forecast period.

Strong and consistent demand signals are required in order to facilitate private-sector investment in biofuel production facilities. This is especially the case for less technically mature advanced biofuels, with significant long-term decarbonisation potential but currently high investment and production costs. The application of quotas to provide guaranteed demand is most prominent in Europe, since the European Commission has specified that member states should adopt a national sub-target for advanced biofuel consumption. EU member states that have established these include Denmark (from 2020), France (from 2018), Italy (from 2018) and Slovakia (from 2019).

Further proposals can be expected from other EU member states in 2017. Germany has released a proposal for a binding sub-target of 0.05% advanced biofuels in 2020, increasing to 0.5% by 2025. The United Kingdom is in the process of updating its Renewable Transport Fuel Obligation, and has proposed a specific sub-target for advanced "development fuels" that increases annually until 2030. The proposed 2022 value within this sits at 0.4% of total fuel supply. Norway has proposed an 8% advanced biofuels volume share by 2020, and the Netherlands is considering introducing a 0.3% advanced biofuel sub-target by 2018. For the policy implications for advanced biofuels of the European Commission's RED proposals post 2020, refer to Box 3.1. Outside Europe, both Brazil's and India's ambitions to scale up biofuel production anticipate an increasing share from cellulosic ethanol, and China's 13th FYP also endorses its vigorous development.

In respect of demand for aviation biofuel, regional fuel supply chain development and actions to reduce cost premiums over fossil jet kerosene are needed to stimulate demand growth and drive further offtake agreements. In 2016, a global "Carbon Offset and Reduction Scheme for International Aviation" was adopted by the International Civil Aviation Organisation. This is set to commence voluntarily from 2021, and is therefore expected to have a limited effect on prospects for aviation biofuels in the *Renewables 2017* forecast period.

Box 3.3. A portfolio of biofuels offers diesel alternatives in road freight transport

Road freight is an increasingly key element of efforts to decarbonise the transport sector, currently accounting for over 30% of global transport-related energy demand (36 EJ in 2015), with consumption growing by two-thirds since the turn of the century. Over 95% of associated fuel demand is supplied by petroleum products and the sector accounts for almost half of global diesel demand (IEA, 2017f). Alternative fuels can complement improved operations, logistics and vehicle efficiency in decarbonising road freight, and a portfolio of high energy density biofuels represents currently available alternatives to fossil diesel for use in heavy and medium freight trucks. Production processes for biodiesel, HVO and biomethane are technically mature and commercialised, and heavy-duty vehicles suitable for their use are available from major OEMs. There may also be a role for the use of fuel ethanol, in the form of ED95, pending wider availability of suitable vehicles.

Both biodiesel and HVO benefit from compatibility with existing vehicle fleets and fuel distribution infrastructure. Biodiesel in road freight is commonly blended with fossil diesel at levels between B5 and B20. Higher blends, e.g. B50 or B100, can also be used with vehicle modifications. HVO is technically a drop-in fuel, meaning that it can be used unblended (HVO100) in heavy-duty diesel engines and fuelling infrastructure. However, blends with fossil diesel (e.g. 30-50% HVO by volume) are more common.

Biomethane can be used in natural gas-fuelled vehicles either as compressed natural gas (bio-CNG) or more energy dense liquefied natural gas (bio-LNG), which enables trucks to operate over extended ranges. Several road freight vehicle manufacturers offer CNG- and LNG-fuelled engine models compatible with natural gas and biomethane, and these generally provide engine power and torque comparable to diesel or liquid biofuels. ED95, which consists of 95% fuel ethanol alongside lubricants and additives, can be used within adapted diesel (compression ignition) engines. As ED95 and biomethane are not drop-in fuels and cannot be blended with fossil diesel, measures to increase suitable vehicle fleet and fuel distribution infrastructure deployment are especially important.

The need to improve local air quality in certain regions and cities can support biofuel consumption in road freight. Air quality benefits from biomethane can include reduced hydrocarbons, carbon monoxide, nitrogen oxides and particulate matter emissions compared to diesel fuels. Biomethane can also provide reduced vehicle noise. In addition, there are indications that HVO and biodiesel hold potential to reduce carbon monoxide, hydrocarbon and particulate emissions compared to fossil diesel. However, this is most relevant to less sophisticated engines. Where advanced exhaust gas after-treatment is in place the effects of fuel specification on emissions is reduced.

Biodiesel consumption in road freight is growing in diverse markets. Brazil authorised the voluntary use of 20-30% biodiesel blends in captive fleets as well as for agricultural and industrial users. In the European Union, the EN 16709 standard allows for consumption of B30 blends in fleets, while Indonesia's B20 mandate covers all road transport. Increased consumption of biodiesel in road freight will require a transition to blends above B20, and B100 where climate, costs and feedstock availability allow. This will hinge on working with OEMs to secure vehicle warranty approvals.

HVO100 consumption in various engine families has approval from several European heavy-duty vehicle manufacturers, and the European standard EN 15940 covers fuels from hydrotreatment, raising the prospect of higher uptake in heavy-duty transport. HVO also meets the American Society of Testing and Materials (ASTM) B975 diesel standard in the United States, while in California HVO is available via public refuelling stations and several cities use the fuel in municipal fleets.

Prospects for biomethane within road freight are coupled with the uptake of natural gas as a fuel. Globally, over 18 million gas-driven vehicles are in circulation, with established markets in Brazil, China, Italy and Pakistan (Billig et al., 2015). However, only a small fraction of these are freight vehicles. In Italy for example, only around 0.5% of all gas-fuelled vehicles in 2015 were buses and trucks.

Fuel ethanol consumption in freight transport is primarily utilised in light commercial vehicles. ED95 is less widely commercialised, although consumption has been demonstrated. In Sweden, in addition to ED95 municipal bus fleets, a dairy delivery fleet of ethanol-fuelled trucks has been operational, while such vehicles have also been used in Brazil. Looking ahead, the security-of-supply benefits offered by domestic fuel ethanol production compared to imported petroleum products could drive ED95 demand in Brazil and India. However, exploiting the potential of ethanol use in heavy-duty freight transport will require a wider offering of suitable vehicles from OEMs.

Captive fleets, which operate on established routes and are refuelled at specific locations, e.g. depots, are envisaged to play a key role in supporting initial market growth of biofuels in road freight. In France, a major supermarket chain is producing biomethane from food waste to fuel logistics operations. More widespread expansion of biofuel consumption within long-haul freight will require a strategic demand-led roll-out of refuelling infrastructure along key road freight corridors. A key example in this area is the EU Alternative Fuels Infrastructure Directive, which obligates member states to ensure refuelling infrastructure availability, and covers biomethane.

Biofuel consumption in road freight transport is currently lower than in PLDVs due to a lack of policy measures specifically aimed at supporting consumption in the sector, coupled with the need for more widespread availability of suitable vehicles. Therefore, obtaining approvals from engine OEMs and the development of applicable fuel quality standards will play an important role in increasing uptake. Similarly important will be market and policy measures to increase refuelling infrastructure coverage along key road freight corridors and improve cost competitiveness versus fossil diesel. Overall, a combination of these market developments could deliver higher road freight biofuel demand and an upward revision of the *Renewables 2017* conventional and advanced biofuel forecasts.

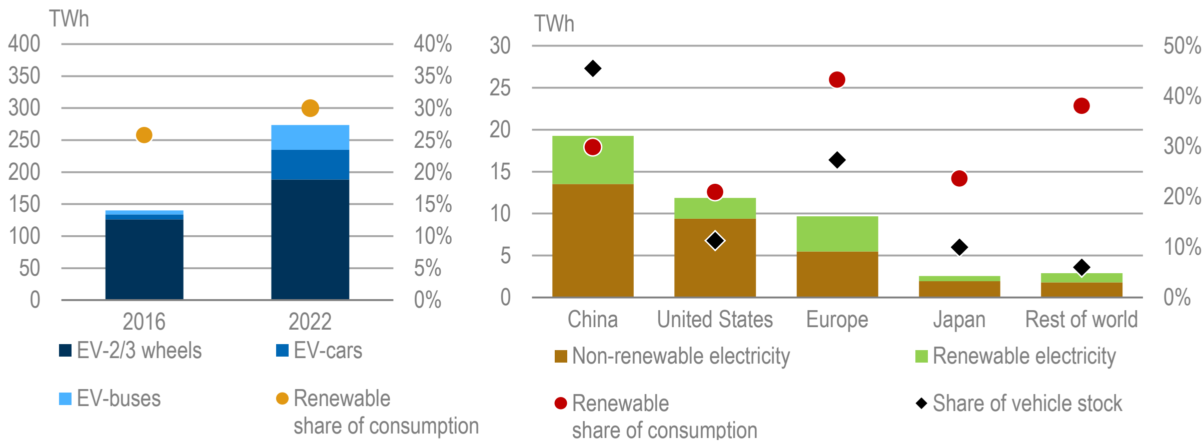
Depending on future technological progress to achieve higher production levels and reduce investment costs, a further set of biofuels that are not currently widely available could supply road freight transport. These include dimethyl ether (bio-DME), the upgrading of synthetic natural gas from gasification to biomethane (bio-SNG) and biomass-to-liquid (BtL) fuels from thermochemical processes. It is not anticipated these fuels will play a significant role within the *Renewables 2017* forecast period, however.

Renewable energy consumption by EVs

Global overview

The number of passenger EVs, a segment comprised of electric cars, buses, and two and three-wheelers, is expected to grow rapidly over the next five years. Between 2016 and 2022, electricity consumption by the entire EV segment is expected to roughly double (Figure 3.10), but still consume less than 1% of the world's electricity generation by 2022. This growth is largely due to China, which is seen accounting for almost 90% of EV electricity consumption by 2022, mostly from continued deployment of two- and three-wheelers, and to a lesser extent, buses and cars. Consequently, China largely influences the global share of renewables in EV electricity consumption, which is expected to reach 30% by 2022.

Figure 3.10. Electricity consumption in EVs globally (left) and in electric cars by major market in 2022 (right)



Note: TWh = terawatt hour. Renewable share of consumption in EVs (left) and cars (right) refers to the share of electricity consumption that is renewable.

Source: IEA analysis based on forecasts from *Renewables 2017* and IEA (2017c), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version.

Box 3.4. Estimation of EV renewable electricity consumption: methodology explanation

To provide an overview of the renewables contribution to electrified road transport over 2016-22, *Renewables 2017* has estimated renewable electricity consumption by EVs. This highlights countries where EV deployment and increased penetration of renewables in electricity generation are both occurring, as well as providing an insight into the decarbonisation potential of EVs up to 2022.

Renewable electricity consumption by road transport was estimated for each country by multiplying the total electricity consumption per year by EVs with the corresponding annual share of electricity generation from renewable sources. The first parameter, the total electricity consumption by EVs within a given year, was calculated using the following formula:

EV stock × estimate of annual mileage driven on the electric motor × average fuel economy of EV stock

Data and assumptions were used from the "Reference Technology Scenario" of the IEA Mobility Model (IEA, 2017c). The second parameter, the annual share of renewable electricity generation for each country and year, comes directly from the *Renewables 2017* electricity market forecasts.

This calculation was performed across 22 geographical regions and three EV categories: two- and three-wheelers, cars and buses. For electric cars and buses, the calculation was also disaggregated into BEVs and PHEVs with an assumption of mileage driven in electric mode for the latter. A global total of renewable electricity consumption by EVs per year was then obtained by summing across all regions and vehicle types. It should be noted that this statistical accounting exercise does not consider the time of vehicle charging and corresponding technologies and fuels used for electricity generation. In addition, while the analysis covers three EV categories, country stock data is most robust for electric cars. Further information regarding this approach is outlined within the *Renewables 2017* analytical framework.

Electric cars

Electric cars are being deployed rapidly in a number of key markets. Their share of total EV electricity consumption is forecast to almost triple from 6% in 2016 to 17% by 2022 as global vehicle stock grows from 2 million to 16 million. Almost 95% of the growth in vehicle stock during the forecast period occurs in four markets, led by China, followed by Europe, Japan and the United States. The share of renewables in global electricity consumption by cars is expected to reach 31% by 2022. This is slightly larger than the 30% across all EV segments due to electric car deployment in European markets where higher shares of renewable electricity generation are forecast, such as Germany, Norway, and the United Kingdom.

By 2022, **Europe** is forecast to have the world's highest share of renewable consumption by electric cars, at 43%, due to vehicle registrations in countries where renewables are expected to be a substantial part of electricity supply. Roughly one-fifth of Europe's electric car fleet in 2022 is expected to be in Nordic countries, where the share of renewable generation is expected to range from a minimum of 50% in Finland, led by bioenergy, to as high as 90% in Norway, almost exclusively from hydropower. Another 40% of the region's fleet is expected to be in Germany and the United Kingdom, where the share of renewable generation is forecast to reach 40% and 42% respectively. In Germany, the rising share is mostly due to increased renewable capacity deployment, while the UK's share is influenced by both renewable electricity deployment and reduced coal generation.

By 2022, Europe is expected to have the world's second-largest electric car stock, forecast to reach 4 million by 2022, driven by increased policy support across a wide range of countries and cities. Binding EU vehicle emissions targets are also expected to drive growth as manufacturers increase model availability, offering customers more choice. By July 2017, several major European car manufacturers had already announced targets to increase electric car sales (EVI, 2017).

In absolute terms, **China** is expected to surpass Europe to have the largest consumption of renewable electricity in cars by 2022. This is owing both to its anticipated share of the global fleet (45%) and an increasing contribution of renewables to electricity generation, which reaches 30% by the end of the forecast period, driven by strong policy support and increasing concerns over local air pollution. China is forecast to retain the world's largest electric car stock, reaching over 7 million in 2022 due to robust sales supported by exemption from regulations restricting the licensing of ICE vehicles, as well as long-term targets to bolster automobile production and improve affordability.

The **United States** is forecast to account for 26% of the world's electricity consumption by cars by 2022, despite accounting for only 11% of the vehicle stock. This is mostly due to longer annual distances driven by the vehicle fleet compared to other countries. However, the consumption of renewable electricity in cars is expected to be smaller than in China and Europe, due to the lower share of renewables in the United States' power supply, which is expected to reach 21% in 2022.

State-level policies are expected to play a key role in the contribution of renewables to electrified road transport in the United States, as several policy uncertainties at the federal level may impact the growth of electric cars, and to a lesser extent renewable electricity generation. For electric cars, uncertainty exists as to whether federal tax credits will be extended once manufacturers reach their support caps corresponding to a cumulative sales volume of 200 000 vehicles. Several major manufactures are expected to reach this ceiling by 2020, which would trigger a one-year phase-out of this support. As such, state-level policies, such as zero-emission mandates, which exist in about ten states, and direct incentives will be key drivers for continued electric car growth. For renewable electricity, multi-year federal tax incentives combined with state-level renewable portfolio standards remain key drivers for expansion. However, proposed tax reform and trade policies may hamper the economic attractiveness of renewable electricity technologies.

Electric car country targets scenario

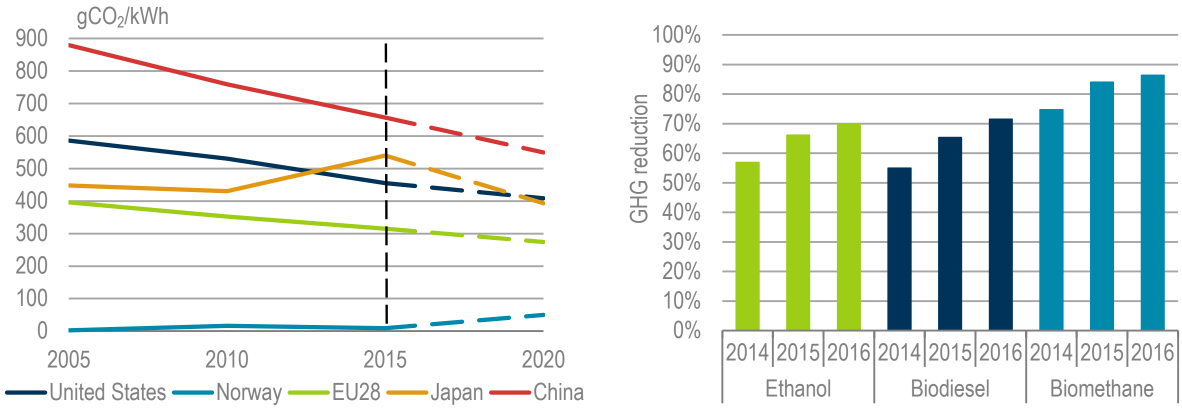
By 2016, 15 countries had established electric car deployment targets for 2020. Cumulatively these account for around 13 million vehicles. By comparison, global electric car stock in 2020 in the main case forecast is 8.9 million, reflecting current deployment trends that suggest these targets may not be achieved in a number of countries. If supportive conditions were established that resulted in market expansion to meet these targets in 2020, and then continue growth at a similar pace, global electric car stock could reach just under 25 million vehicles in 2022. This would put deployment on a firmer path to meeting the Paris Declaration on Electro-Mobility and Climate Change and Call to Action's ambition to exceed 100 million electric cars by 2030 (UNFCCC, 2015).

With such deployment, the corresponding electricity consumption of electric cars would reach 62 TWh in 2022 (33% higher than the main case), with 20 TWh from renewable sources (40% higher than the main case). As a consequence, the share of renewable electricity consumed by electric cars would increase to 32%, as opposed to 31% in the main case. This is principally due to higher deployment in European countries, such as Germany and the United Kingdom, which have higher shares of renewables in electricity generation than the global average.

Assessing transport decarbonisation from EVs and biofuels

Biofuels and EVs represent complementary options for transport sector decarbonisation for which market development currently requires policy support. This includes co-ordinated interventions to facilitate the transition in vehicle fleets towards suitable vehicles and the availability of fuel supply infrastructure. Therefore, understanding the potential decarbonisation achievable from biofuels and EVs is essential for policy makers. In several countries carbon intensity-based policies have been established. These technology-neutral approaches create demand for those fuels that can offer the highest levels of decarbonisation relative to cost. For example, Germany switched from an energy-based biofuels mandate to the Climate Protection Quota (CPQ), which required a 3.5% reduction in the carbon intensity of transport fuels over 2015-16. Consequently, relative to fossil fuels, the GHG emissions reduction from biofuels used for compliance increased (Figure 3.11).

Figure 3.11. Carbon intensity of electricity generation in selected EV markets (left) and GHG emissions reduction from selected biofuels under Germany's CPQ (right)



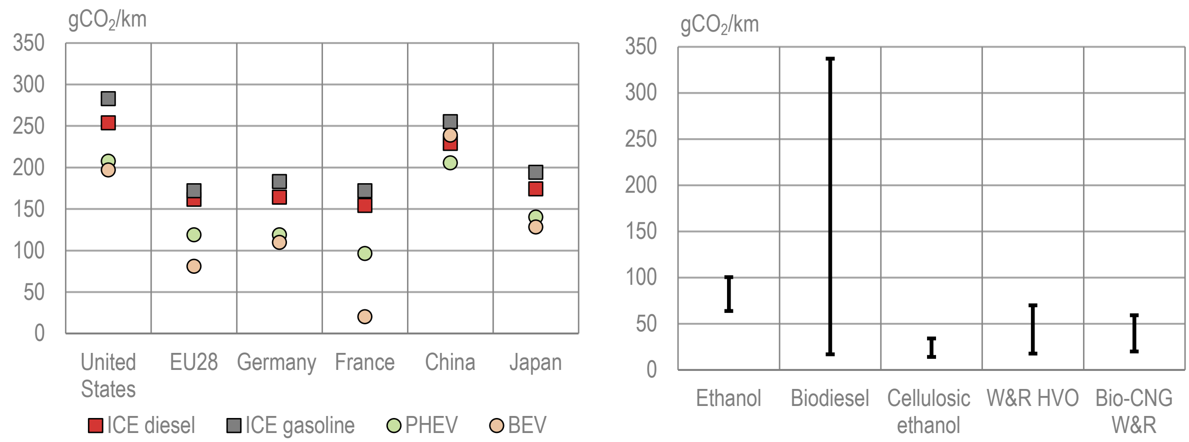
Notes: Projected future electricity generation CI values for 2020 are based on the IEA's *Energy Technology Perspectives (ETP)* reference technology scenario (RTS); GHG reduction in Germany's CPQ compared to fossil fuels at 83.8 grams of CO_2 per megajoule (MJ).

Sources: IEA (2017a), *CO_2 Emissions from Fuel Combustion* (database); F.O. Lichts (2017c), "Germany – GHG savings of biofuels continue to rise", www.agra-net.com/agra/world-ethanol-and-biofuels-report/biofuel-news/biodiesel/germany---ghg-savings-of-biofuels-continue-to-rise-553313.htm.

The decarbonisation potential of EVs is linked to the carbon intensity of electricity generation, measured in grams of CO_2 per kilowatt hour (gCO_2/kWh), and is therefore strongly tied to progress in reducing GHG emissions within the electricity sector. The carbon intensity of electricity generation varies significantly across countries as a result of differences in the overall portfolio of fuels and technologies utilised for electricity generation (Figure 3.11). For instance, the prominence of hydropower in Norway's electricity generation and a high share of nuclear generation in France result in low GHG emissions from EVs. Higher utilisation of renewables is a key reason for downward trends in the carbon intensity of electricity generation observed in many key EV markets, with such trends anticipated to continue in many countries over the *Renewables 2017* forecast period. However, despite renewables accounting for 26% of electricity generation in 2016, high coal consumption for electricity generation in China challenges EVs' decarbonisation potential.

Determining well-to-wheel (WTW) CO_2 emissions, measured in grams of CO_2 per kilometre travelled (gCO_2/km), allows the decarbonisation potential of electric cars in different markets to be assessed. This takes into account the fuel economy of the vehicle powertrain and, for PHEVs, the ratio of driving undertaken using the electric motor compared to the ICE. A comparison for a range of countries reveals that generally electric cars were capable of delivering lower WTW CO_2 emissions compared to fossil gasoline and diesel in 2015 (Figure 3.12). However, the decarbonisation potential of electric cars varies significantly by country. In China the aforementioned high CO_2 emissions from power generation meant that BEV emissions were actually higher than those from PHEVs in 2015, with neither offering significant emissions reduction on fossil transport fuels. However, in China as with other key EV markets, reducing urban air pollution through the uptake of EVs in place of ICE vehicles is also a key factor in increasing deployment trends. Decarbonisation potential from EVs should not be considered static, and is anticipated to increase over time due to a combination of vehicle technology improvements and decarbonisation of electricity generation in many countries.

Figure 3.12. On-road WTW CO_2 emissions from electric cars for selected countries and regions in 2015 (left) and reference WTW CO_2 emissions from selected biofuels (right)



Notes: PHEV assumes 30% electric driving; W&R = waste and residue feedstocks; bio-CNG = compressed biomethane; conventional fuel ethanol and biodiesel values take account of modelled land-use change (LUC) and ILUC values; biodiesel range is for fatty acid methyl ester (FAME) based on sunflower, soybean and W&R feedstocks.

Sources: IEA (2017c), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version; European Commission (2015), "Directive 98/70/EC of the European Parliament and of the Council of 13 October 1998 relating to the quality of petrol and diesel fuels", http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32015L1513; CARB (2016), *LCFS Pathway Certified Carbon Intensities*, www.arb.ca.gov/fuels/lcfs/fuelpathways.htm; Valin et al. (2015), *The Land Use Change Impact of Biofuels Consumed in the EU*.

For biofuels, an even greater number of factors must be taken into account to assess WTW GHG emissions, which vary according to the characteristics of each fuel production pathway, e.g. location, feedstock, logistics. When considered on a WTW basis, CO_2 emissions per kilometre travelled from various biofuels compare favourably with those from fossil gasoline, diesel and electric cars in the countries and regions covered (Figure 3.12). The exception is conventional biodiesel where the inclusion of modelled LUC emissions results in upper-end estimates of WTW CO_2 emissions higher than fossil fuels, although other biodiesel production pathways can result in lower emissions.

Feedstock is a key factor in the levels of decarbonisation offered by biofuels compared to petroleum products. Crop-based feedstocks are widely available; however, lifecycle GHG emissions from these also need to take into account crop cultivation and LUC, both direct and indirect. Assessment of ILUC-related GHG emissions from biofuels is an area of considerable and ongoing debate. However, where waste and residue feedstocks are used LUC emissions are largely negated. For comparison on a like-for-like basis a full lifecycle analysis should be applied to all technologies and fuels. For example, as electric car deployment grows, the lifecycle GHG emissions of battery production and end-of-life recycling or disposal will be increasingly scrutinised.

Harnessing the decarbonisation potential of both biofuels and EVs will require co-ordinated policies that consider both a transition in vehicle fleets and the availability of fuel supply infrastructure. The majority of biofuel consumption is currently achieved through blending with fossil transport fuels in low volumes (<10% by volume or energy), limiting the overall level of emissions reduction that can be achieved. Taking the case of E10 blends in the United States, the addition of 10% corn ethanol would only reduce the weighted-average WTW emissions of the subsequent blend by around 8%; although ethanol also acts as a valuable fuel oxygenate.

Therefore, for biofuels to realise deeper decarbonisation, a combination of low-carbon advanced biofuels used in higher blend percentages or unblended would deliver the highest GHG reductions. For example, cellulosic ethanol used unblended in a FFV in the United States could reduce GHG emissions by around 85%. However, a shift from low-level blending to unblended use of advanced biofuels requires the rollout of fuel infrastructure and changes to the vehicle fleet. This is also the case for EVs, which require a transition away from incumbent ICE vehicles, which in turn is supported by greater availability of charging infrastructure. Looking ahead, it is possible that transport polices and industry efforts may focus biofuel deployment within the heavy-duty vehicle, aviation and marine sectors, where electrification is more challenging due to the anticipated size, weight and cost of batteries required for longer travel distances.

References

Billig, E. et al. (2015), “The standardization, production and utilization of biomethane in Europe and China – A comprehensive analysis”, presentation at the International Bioenergy Exhibition and Asian Bioenergy Conference, Shanghai, 23 October 2015.

Biofuels Digest (2017), “Cellulosic hits $4.33 /gallon”, www.biofuelsdigest.com/bdigest/2017/06/13/dont-spill-that-ethanol-those-cellulosic-fuels-are-worth-4-33-a-gallon/.

CARB (California Environmental Protection Agency Air Resource Board) (2016), *LCFS Pathway Certified Carbon Intensities*, www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

EBA (European Biogas Association) (2016), *European Biogas Association Statistical Report 2016*, EBA, Brussels.

European Commission (2017), “Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast)”, European Commission, Brussels, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0767R(01).

European Commission (2015), “Directive 98/70/EC of the European Parliament and of the Council of 13 October 1998 relating to the quality of petrol and diesel fuels”, European Commission, Brussels, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32015L1513.

Edeniq (2017), “Edeniq secures $5 million in growth equity, has 27 plants in cellulosic ethanol pipeline”, www.edeniq.com/pdf/2017_0619.pdf.

EVI (Electric Vehicles Initiative) (2017), *Global EV Outlook 2017: Two Million and Counting*, OECD/IEA, Paris.

F.O. Lichts (2017a), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanoland-biofuels-report/ (subscription service – accessed June 2017).

F.O. Lichts (2017b), “Germany – GHG savings of biofuels continue to rise”, www.agra-net.com/agra/world-ethanol-and-biofuels-report/biofuel-news/biodiesel/germany---ghg-savings-of-biofuels-continue-to-rise-553313.htm.

F.O. Lichts (2017c), “World ethanol trade will be hit by surge in protectionism”, www.agra-net.com/agra/world-ethanol-and-biofuels-report/features/world-ethanol-trade-will-be-hit-by-surge-in-protectionism-549092.htm.

IEA (International Energy Agency) (2017a), *CO_2 Emissions from Fuel Combustion* (database), www.iea.org/statistics/ (accessed July 2017).

IEA (2017b), *Market Report Series: Oil 2017*, OECD/IEA, Paris.

IEA (2017c), *Modelling of the Transport Sector in the Mobility Model* (MoMo), March 2017 version, www.iea.org/etp/etpmodel/transport/.

IEA (2017d), *Monthly Oil Data Service (MODS)*, May 2017, www.iea.org/statistics/ (accessed May 2017).

IEA (2017e), *Oil Information* (database), www.iea.org/statistics/ (accessed May 2017).

IEA (2017f), *The Future of Trucks – Implications for Energy and the Environment*, OECD/IEA, Paris.

IEA (2017g), *Renewables Information 2017,* OECD/IEA, Paris.

IEA (2017h), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics (accessed June 2017).

MAPA (Ministry for Agriculture, Livestock and Supply) (2017), *Produção* [Production], MAPA, Brasilia, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao.

UNFCCC (2015), *Paris Declaration on Electro-Mobility and Climate Change and Call to Action*, http://newsroom.unfccc.int/lpaa/transport/the-paris-declaration-on-electro-mobility-andclimate-change-and-call-to-action.

US EIA (United States Energy Information Administration) (2017), *Petroleum and Other Liquids* (database), www.eia.gov/petroleum/data.cfm.

US EPA (United States Environmental Protection Agency) (2017), *2016 Renewable Fuel Standard Data*, www.epa.gov/fuels-registration-reporting-and-compliance-help/2016-renewable-fuel-standard-data.

Valin, H. et al. (2015), *The Land Use Change Impact of Biofuels Consumed in the EU*, Ecofys, Utrecht.

4. RENEWABLE HEAT

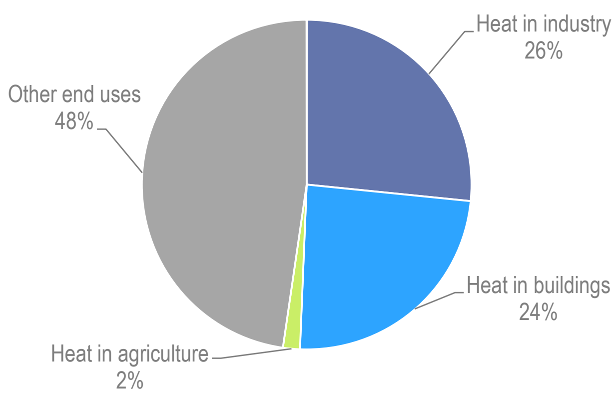
Highlights

- Heat dominates energy end use, accounting for 52% of total final consumption in 2015. Around half of heat is consumed in industry while most of the rest is used to heat buildings and water, with some also used for cooking and in agriculture. Fossil fuels continue to supply most heat, with modern renewable heat (excluding the traditional use of biomass) meeting only 9% of global heat demand.
- A number of countries strengthened their renewable heat policies over the past year. The most significant development has been the inclusion of ambitious new solar thermal, biomass and geothermal heat targets in China's 13th Five Year Plan (FYP). These targets will be a key driver of global growth in modern renewable heat consumption, which is expected to grow by 24% over 2016-22. This would push the share of renewable heat in total heat consumption to almost 11% in 2022.
- In China, renewable heat consumption is anticipated to grow most rapidly in industry, with an increase of almost 250% by 2022. Industrial renewable heat consumption is also expected to grow elsewhere in Asia: by 28% in India and 14% in Southeast Asia. The European Union is currently the region that consumes the largest amount of renewable heat, which is anticipated to see an increase of 18% over 2016-22, with buildings accounting for the majority of this growth. North America is expected to have a similar growth rate, mostly in buildings.
- Most renewable heat is produced from bioenergy. In 2015, almost two-thirds of modern bioenergy for heat was used in industry, and three countries (Brazil, India and the United States) accounted for almost half of industrial consumption. By 2022, bioenergy consumption for heat is expected to grow by 15%, with more rapid growth in industry than in buildings. China and India will account for just over half of the industrial bioenergy consumption growth.
- Growth in global solar thermal capacity continued to slow in 2016 for the third year in a row, with gross annual additions falling to an estimated 36.7 gigawatts thermal (GW_{th}), down 8% against 2015. Cumulative installed capacity reached 456 GW_{th} in 2016, with over 70% of this located in China. Over the outlook period, global solar thermal energy consumption is expected to increase by over a third, although this would represent slower growth than in previous years. Overall, China is seen leading the growth, followed by North America, Europe, Asia and the Middle East and North Africa (MENA).
- Geothermal heat is expected to experience the highest growth rate of all renewable heat technologies, with a 72% increase over the outlook period, mainly in the European Union and China. However, its contribution remains small at 0.6 exajoules (EJ) in 2022.
- Heat pumps are witnessing increased deployment, especially in Europe due to stricter energy performance standards for new buildings and renovations. An estimated 9.5 million units had been installed in Europe by 2016, accounting for 40% of the global heat pump stock. As renewables increase their share of national power supply, heat pumps are utilising more renewable electricity, while higher-efficiency units capture more renewable heat from the air, ground or water. In both cases deeper cuts in greenhouse gas emissions are achieved.

Global overview and outlook

Heat is the largest energy end use, accounting for 52% of total final consumption (Figure 4.1). Around half of this heat is consumed in industry, for instance to produce steam to drive industrial processes. The other half is used to heat buildings and water and for cooking, with a small share also utilised in agriculture for uses such as drying. In 2015, global heat consumption is estimated at 205 EJ, 14% of which was from the traditional use of solid biomass, which continues to be widely used in rural areas of sub-Saharan Africa and in parts of Asia. Within this report, the term renewables refers to "modern" renewable heat technologies (Box 4.1), i.e. excluding the traditional use of biomass, unless otherwise stated.

FIgure 4.1. Heat in total final consumption, 2015



Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming a), *World Energy Outlook 2017*.

Heat production remains heavily fossil fuel-based, with more than 70% produced from natural gas, oil and coal. As a result, heat consumption is a significant contributor to CO_2 emissions accounting for 39% (12.5 gigatonnes of CO_2) of total annual energy-related emissions globally. Renewables currently play a minor role, accounting for only around 9% of global heat consumption, with the rest from non-renewable electricity.

Renewable heat consumption increased from 15.4 EJ in 2008 to 18.5 EJ in 2015, with a compound average annual growth rate of 2.7%. Over 2016-22, average annual growth is expected to increase to 3.2%, with renewable heat consumption anticipated to reach 23 EJ in 2022, accounting for 10.6% of total heat consumption.[1]

Modern bioenergy is forecast to lead the growth in renewable heat consumption with a 2 EJ increase over the outlook period, followed by renewable electricity for heat, which is driven by increased use of electricity for heat in buildings and in industry, combined with a greater share of renewables in the power mix. Solar thermal growth is expected to slow in comparison with 2008-15, while the fastest growth is expected from geothermal, albeit from a low base (Figure 4.2 and Table 4.1).

Between 2016 and 2022, renewable heat growth is expected to be faster in buildings (28%) than in industry (21%) (Figure 4.2). 70% of the increase in buildings renewable heat is expected to come

[1] Figures to 2022 are based on modelling for the *World Energy Outlook 2017*, New Policies Scenario.

from China, the European Union and the United States, while China and India together account for more than half of growth in industry (Figure 4.3).

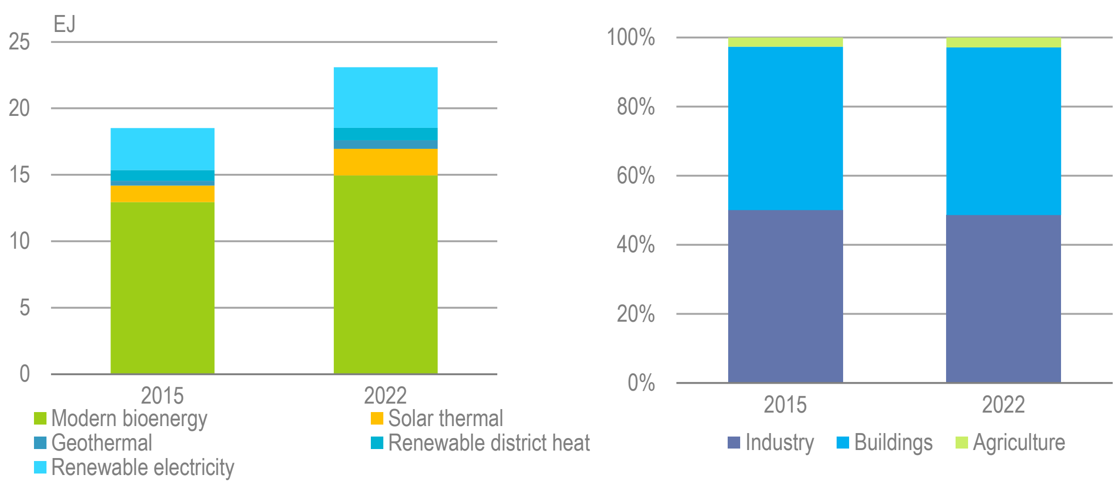
Box 4.1. Modern renewable heat technologies

Renewable heat technologies are mainly deployed directly in buildings and industry, but can also be used to produce heat for distribution through district heating networks. They include:

- Bioenergy – comprises a range of options such as solid biomass boilers, solid biomass or biogas co-generation systems, utilisation in district heating or biomethane injection into natural gas grids.
- Solar thermal – used for water heating and some space heating in buildings, but also increasingly in large-scale applications to supply district heating systems and for some industrial applications.
- Geothermal – direct use of geothermal heat in district heating systems, buildings, swimming pools, greenhouses or in industry.
- Heat pumps – make use of solar heat stored in the air or the ground, but need electricity to operate; can be deployed in residential, commercial, industrial and district heating applications, and coupled with solar photovoltaic (PV) sources to meet part of their electricity needs.[2]

In addition, the definition of renewable heat used here includes some renewable electricity, based on an estimate of electricity used for heat and the share of renewables in electricity generation.

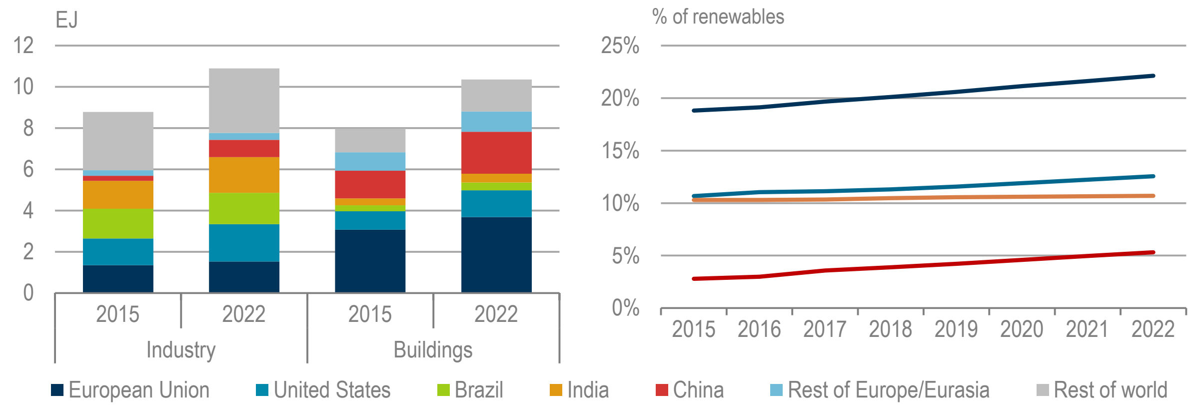
FIgure 4.2. Global final renewable heat consumption (left) and split between sectors (right), 2015 and 2022



Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming a), *World Energy Outlook 2017*.

[2] International Energy Agency (IEA) energy balances at present do not include the heat extracted from air or water used by heat pumps. Furthermore, no global figures are available for electricity consumption by heat pumps. While therefore not included in the heat figures, the importance of heat pumps in reaching renewable and energy efficiency targets is recognised by the IEA. This report uses an estimate of electricity use for heat (6% of total final energy consumption) and the share of renewable electricity to provide an estimate of renewable electricity used for heat.

Figure 4.3. Renewable heat consumption (left) and share of renewables in heat consumption (right), selected countries/regions, 2015-22



Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming a), *World Energy Outlook 2017*.

China's renewable heat consumption is expected to grow most rapidly, especially in industry where consumption is expected to increase by 248%, compared to 48% in buildings. Currently, China does not report any renewable heat use in industry within its statistics, although some use is likely, especially of bioenergy. Two-thirds of the increase in industry is expected to come from bioenergy, with some growth also expected in renewable electricity for heat. In the buildings sector, growth is primarily from solar thermal and renewable electricity (including a roll-out of heat pumps), with increases also in geothermal.

The **European Union** is currently the largest regional consumer of renewable heat, with the Renewable Energy Directive (RED) as an important driver for deployment. Consumption is expected to continue rising to 2022 when it will reach 5.3 EJ, 18% higher than in 2015. The majority of this growth comes from buildings, where 20% growth is expected 2016-22, with 13% in industry. The largest absolute increase would be from bioenergy, consumption of which is seen growing by 0.3 EJ from 2016 to 2022. The most rapidly growing source is expected to be geothermal (223% increase), reflecting the very dynamic market for geothermal district heating in the European Union, while solar thermal consumption is also expected to double.

Table 4.1. Global trends and forecast for renewable heat, 2010-22

	2015 (EJ)	Share of total	Growth 2008-15	Growth 2016-22	CAAGR 2016-22
Total energy consumption for heat	205	N/A	10%	6%	0.9%
Total modern renewables for heat	18.5	9%	20%	24%	3.2%
Of which: Renewable district heat	0.8	4%	46%	16%	2.2%
Modern bioenergy	12.9	70%	8%	15%	2.0%
Solar thermal	1.2	7%	166%	56%	6.6%
Geothermal	0.4	2%	54%	72%	8.1%
Renewable electricity for heat	3.2	17%	44%	45%	5.5%

Notes: All figures for heat correspond to final energy consumption in the buildings, agricultural and industrial sectors; the heat produced from renewable district heat in 2015 was 95% bioenergy; CAAGR = compound annual average growth rate; N/A = not applicable.

Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming a), *World Energy Outlook 2017*.

North America is expected to have a growth rate similar to the European Union (19%) over 2016-22, again mostly in buildings (29%). The growth in buildings is primarily due to the increasing share of renewables in the electricity mix, with almost 20% of buildings' heat demand being met by electricity across the region. In the **United States**, renewable electricity for heat in buildings is expected to grow by 63% by 2022, primarily due to the greater penetration of renewables in electricity generation. Solar thermal is expected to double due to the ongoing availability of tax credits (see solar thermal technology section). Solar thermal will also grow in **Mexico**.

The renewable heat potential in the **Russian Federation** and **Eurasia**, which are large heat consumers (9% of global heat consumption), will remain largely unexploited by 2022. Their combined renewable heat share is currently just 3.4%, with only a minor change expected by 2022. The region has very few renewable heat policy drivers, especially in the oil- and gas-producing countries where fossil fuels for heating are cheap.

Both **Brazil** and **India** have relatively high use of renewable heat in industry. Brazil already meets half of its industrial heat demand through renewables, for example through the use of sugar cane bagasse for process energy in the sugar and ethanol industries. However, prospects for further growth to 2022 are limited, reflecting projections for slow economic growth. An increase in industrial renewable heat consumption of only around 5% is expected. In India, by contrast, renewable heat in industry is anticipated to increase by 28%, mainly through bioenergy. A similar percentage increase is likely in buildings in India, but the overall share of renewable heat increases only marginally from 10.3 to 10.7% due to the rapid growth in heat demand in both sectors.

Elsewhere, some growth over the outlook period is expected in industrial renewable heat consumption in countries belonging to the **Association of Southeast Asian Nations** (ASEAN) (14%) and in buildings in **Africa** and the **Middle East** (32%). For instance, solar thermal in buildings is expected to increase by a factor of six in the Middle East. Furthermore, a 20% increase in the consumption of renewable heat in buildings is foreseen in Latin America (excluding Brazil), mainly through biomass and increased heat electrification.

Outlook for renewable heat technologies

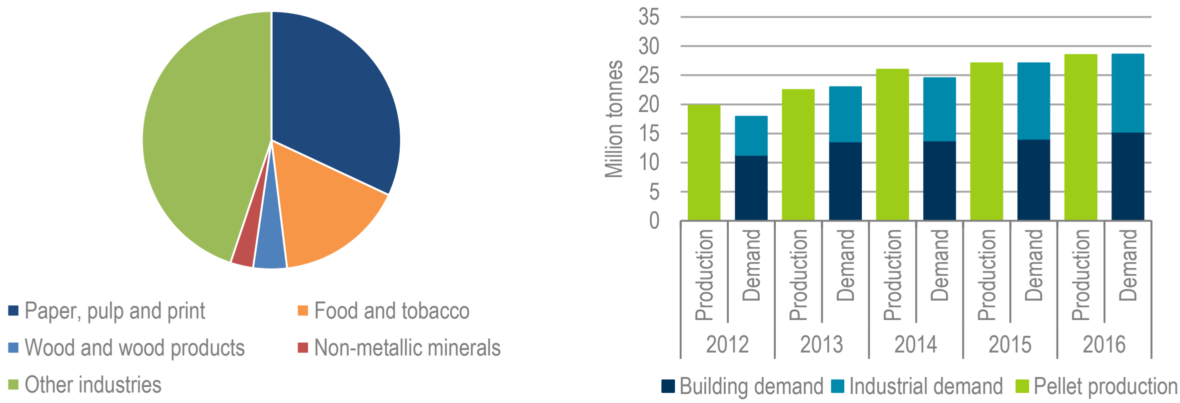
Bioenergy for heat

Global overview

Biomass fuels account for the vast majority of renewable heat consumption. Globally, modern bioenergy use for heat reached 12.9 EJ in 2015. Brazil, the European Union, India and the United States together accounted for over 60% of global bioenergy heat consumption in 2015. Almost two-thirds of bioenergy is used for heat in industry, with a further third used directly in buildings and smaller contributions from district heating and agriculture. Modern bioenergy use for heat is expected to increase at an annual average growth rate of 2% to 14.8 EJ by 2022, with higher growth anticipated in the industrial sector than in buildings. While last year's report focused on biomass in the residential heating market, this year the focus is on industrial and district heating applications.

Bioenergy is well-placed to meet the temperature, pressure and quantity of heat and steam required by many industrial processes, and its potential is highest within industries that produce biomass wastes and residues as part of their operations, such as the pulp, paper and print, food and tobacco, and wood product industries where bioenergy deployment is already evident (Figure 4.4). Bioenergy use is less common in energy-intensive industries that require high-temperature heat than those with low and medium heat demand, with the notable exception of charcoal use in the iron and steel industry in Brazil. In addition, deployment is less evident in industries where biomass waste and residues are not produced and fuel supply chains need to be mobilised.

FIgure 4.4. Final energy consumption of bioenergy by industry sector in 2015 (left) and global wood pellet production and demand by end use (right)



Notes: Other industries is comprised of multiple industries which individually have relatively low bioenergy consumption, e.g. the largest of which is "chemical and petrochemical", which accounts for less than 0.5% (by energy) of bioenergy consumption in industry; industrial pellet demand comprises consumption in large-scale co-generation plants and plants generating electricity, while building demand relates to both residential and commercial buildings.

Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; wood pellet market data from Hawkins Wright Ltd. analysis based on Food and Agriculture Organization data, sourced via personal communication May 2017.

Further development of bioenergy within industry and district heating has a number of drivers and challenges, which vary by country and industry sector (Table 4.2).

Table 4.2. Bioenergy drivers and challenges: industrial and district heating applications

Drivers	Challenges
On-site availability of secondary biomass residues in certain industries.	Mobilising biomass fuel supply chains in industries where biomass residues are not produced on site.
Heat decarbonisation objectives leading to financial incentives for biomass heating systems in Europe.	The typically higher capital costs of biomass boilers compared to fossil fuel alternatives.
Suitability for high-temperature and tightly controlled heat demand from industrial processes.	Further development of governance and certification needed to provide end users with confidence regarding the sustainability of biomass fuels used.
Fossil heating fuel taxation, particularly in Nordic countries, and diversification drivers in countries reliant on imported natural gas for heating.	Low costs and lack of widespread carbon taxation for fossil heating fuels, particularly heating oil in the current low oil price environment.
Growth of global wood pellet markets and development of recognised fuel standards.	Fuel resource availability in certain countries; local supply chain development required in some markets to ensure security of fuel supply.
Existing fossil fuel district heating networks suitable for conversion to bioenergy.	The larger size of biomass boilers and fuel storage compared to fossil fuel systems .

District heating that serves heat demand from buildings and industry in urban areas is a proven facilitator for the consumption of biomass and waste fuels. While small-scale biomass boilers and stoves can be used effectively in buildings, there are a number of advantages to using biomass-fuelled district heating. District heating infrastructure allows for economies of scale in the capital costs of biomass heating compared to individual building systems and, in addition, higher-volume fuel procurement can lower fuel costs. Both of these factors strengthen the financial case for biomass fuels. Furthermore, barriers associated with the availability of sufficient space for biomass heating systems and associated fuel storage and fuel delivery in the residential market are minimised via district heating. Nordic countries, for example, have extensive utilisation of biomass district heating systems based on wood chips, wood pellets and municipal wastes, while Denmark sees extensive utilisation of agricultural residues.

Outlook for selected industrial and district heating bioenergy markets

Brazil, India and the United States currently account for half of global bioenergy heat consumption in industry. Over 2016-22, 17% growth in bioenergy consumption in the industrial sector is expected globally, over half of which will be delivered in China and India. Additionally, growth of 15% is expected in the rest of Asia (excluding China and India) and 11% in the European Union.

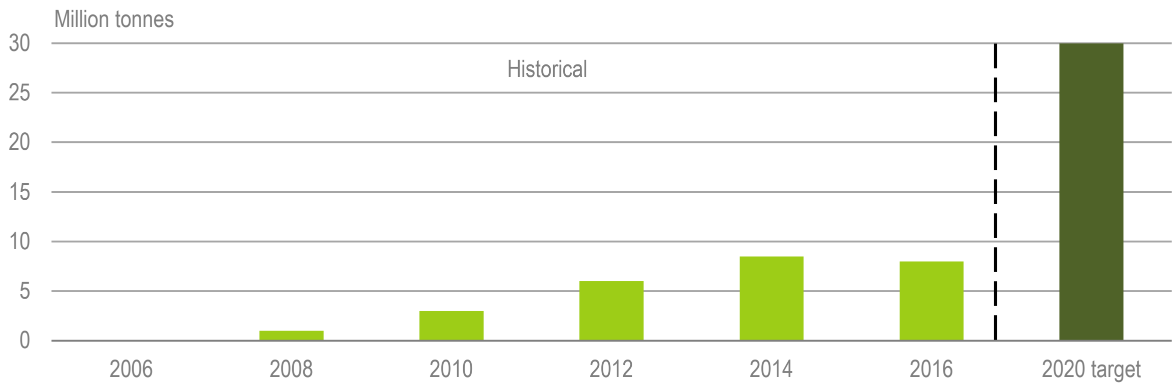
In the **United States,** bioenergy use for heat in industry experienced a decline of 14% between 2007 and 2009 and no growth since. This is mainly due to a downturn in the pulp and paper industry, caused by increased global competition and digitalisation among other factors, which resulted in a reduction in the operation of mills. Modest growth of 4% is expected to 2022, with low natural gas prices undermining prospects for biomass uptake in areas with access to the gas supply network. In both New York City and state, legislation has been introduced to mandate blending of biodiesel in heating oil. There is interest within Northeastern and Midwestern states in the production of biomethane and its subsequent injection into the natural gas network. However, the difficulty of mobilising dispersed biogas feedstocks and regulatory barriers mean the potential for this is largely untapped.

Brazil had the highest use of bioenergy for heat in the industrial sector in 2015, with 1.4 EJ consumed. The principal use is in the food and drink industry, with Brazil being the world's largest sugar producer. The utilisation of bagasse secondary residues produced from sugar and ethanol mills for energy purposes is well-established, and the efficiency of bagasse use has increased at many facilities with the transition to modern higher-efficiency co-generation systems. Additionally, Brazil used 132 terajoules (TJ) of charcoal in the iron and steel industry in 2015 (IEA, 2017b). Prospects for bioenergy use for heat in industry are modest with just over 4% growth expected by 2022, as deployment is constrained by the wider macroeconomic context and fragile economic state of many sugar and ethanol mills.

In **India**, the world's second largest sugar producer, the utilisation of bagasse also makes a key contribution to renewable heat. Bioenergy heat consumption is expected to grow by 24% in the industrial sector by 2022. Biomass resources pose no constraint on growth as India's significant agricultural sector creates abundant volumes of residues. To realise this growth, agricultural residue storage (to account for production seasonality) and mobilising supply chains for the collection and transportation of dispersed resources will be required. Completed projects have faced incidences of fuel price escalation, undermining confidence in the sector. Maximising bagasse generation from within the sugar industry requires access to low-interest finance, although existing capital subsidies for co-generation plants support growth.

China has established a market for solid biomass heating fuels such as biomass pellets and briquettes, with current demand primarily from the industrial sector. The feedstock choice for biomass fuel production differs by geographic location, with pellets produced domestically from forestry residues, peanut shells and straw feedstocks, and briquettes primarily utilising agricultural residue resources. China's significant agricultural residue resources are estimated to have an energy potential of 12.7 EJ, or almost 10% of primary energy supply in China (Gao et al., 2016). However, these are currently underutilised, mainly due to challenges associated with mobilising supply chains, and in some cases are burnt in the field, which results in significant particulate matter (PM) emissions without obtaining value from these resources.

FIgure 4.5. Solid biomass consumption for heating in China, 2006-16, and 2020 target



Notes: China does not report the use of bioenergy for heat in industry; given its significant pulp and paper industry, it is likely that biomass residues are used for heat, but not reported in official statistics submitted to the IEA; as a result the consumption reflected in the figure above is not reflected in IEA statistics.

Source: China National Renewable Energy Centre (CNREC) (March 2017), email to author.

China's 13th FYP includes an ambitious target to scale up solid biomass consumption within the heating sector from around 8 million tonnes (Mt) in 2016 to 30 Mt by 2020 (Figure 4.5). While China possesses sufficient agricultural and forestry residue resources to support this scale-up, this remains a significant increase in the context of 2016 global wood pellet consumption of around 28.5 Mt. Given the substantial energy consumption within the northern urban heating area (in excess of 5 EJ), biomass currently makes a relatively minor contribution, around 2%, to this overall demand. If the 30 Mt target is met, this could increase to around 5-8%, depending on the energy content of the biomass fuels used and how robustly energy efficiency targets are delivered and therefore reduce heat demand.[3] Achieving the 30 Mt target would require policy action in a number of areas (Box 4.2).

Box 4.2. Scaling up solid biomass heating in China

The best opportunities for solid biomass use for heating in China are initially expected in industry and the district heating networks of towns and villages with nearby biomass resources. Cross-comparison of provinces and municipalities in the northern urban heating area with biomass resource availability and the strongest requirements to phase out coal indicates that the highest potential to scale up biomass use in district heating exists in Beijing, Tianjin, Hebei, Shandong and Henan. Biomass consumption could also experience growth in other provinces outside the northern urban heating area where industrial heat demand and biomass resources overlap. To deliver air quality benefits, biomass systems must offer efficient combustion and possess emissions-control equipment to significantly mitigate PM emissions.

[3] The northern urban heating area is planned to be controlled at a maximum of 20 billion square metres (m^2); a 5% biomass share has been determined based on heat demand from this area and the 2014 national average heat demand of 0.54 gigajoules per m^2 as well as an average calorific value for biomass fuels of 15 gigajoules per tonne.

For the ambitious target of 30 Mt of solid biomass consumption in heating by 2020 to be met, action will be needed across a number of areas, such as:

- mobilising supply chains for agricultural residues to scale up fuel production
- development and application of biomass fuel standards to ensure consistent fuel quality
- increased availability of more sophisticated small and medium-sized biomass boilers which offer higher degrees of automation and emissions-control equipment[4]
- quality standards with regard to emissions from biomass boilers.

These considerations indicate that increased biomass heating system manufacturing capacity is likely to be needed to meet the 2020 target for solid biomass.

In addition, more robust policy support will be required. Clean energy heat planning is undertaken at a national level, with local governments then responsible for the implementation of heating policy. The National Energy Administration (NEA) five-year plan for biomass development released in 2016 allocated USD 2.5 billion to the development of solid biomass fuel consumption, and outlined support to increase private-sector investment in the industry. How this funding will be used is currently unknown. A subsidy was previously in place for the production of solid biomass heating fuels. This has since been discontinued but could be re-established. Alternatively, a financial incentive for the substitution of coal by biomass could be introduced, as has been applied for the substitution of coal by natural gas.

In the **European Union**, bioenergy use is primarily in the buildings sector, with domestic buildings the largest end user. Industrial use is lower, accounting for one-third of bioenergy heat consumption. Over the outlook period, the RED remains a key driver for bioenergy heat growth in the European Union, expected at 11%. Biomass-fuelled district heating is commonplace in the Nordic and Baltic countries, where it commands a prominent share of the heat supply. In Lithuania, over 60% of heat generation in district heating is sourced from biomass, with around 50% in **Sweden** and **Denmark**, 45% in **Estonia**, and 32% in **Finland**.[5] While biomass-fuelled district heating has been established for a long period of time in these countries, new projects continue to be delivered. A 280 megawatt thermal (MW_{th}) biomass co-generation plant came on line in Stockholm in 2016, and a >200 MW_{th} biomass and waste co-generation project in Vilnius is due to be commissioned in 2018. In Helsinki, a 92 MW_{th} pellet boiler is also due to start operation in 2018 and further biomass capacity is planned due to municipal coal phase-out policies.

Biomethane production continues to expand in Europe, with in excess of 450 plants in operation in 2015. While biomethane can be injected into natural gas networks for subsequent use for heating or co-generation, alternative dedicated electricity-only and transport uses also exist, with the end use heavily influenced by support provided by subsidy regimes in the country of production.

Solar thermal

Global overview

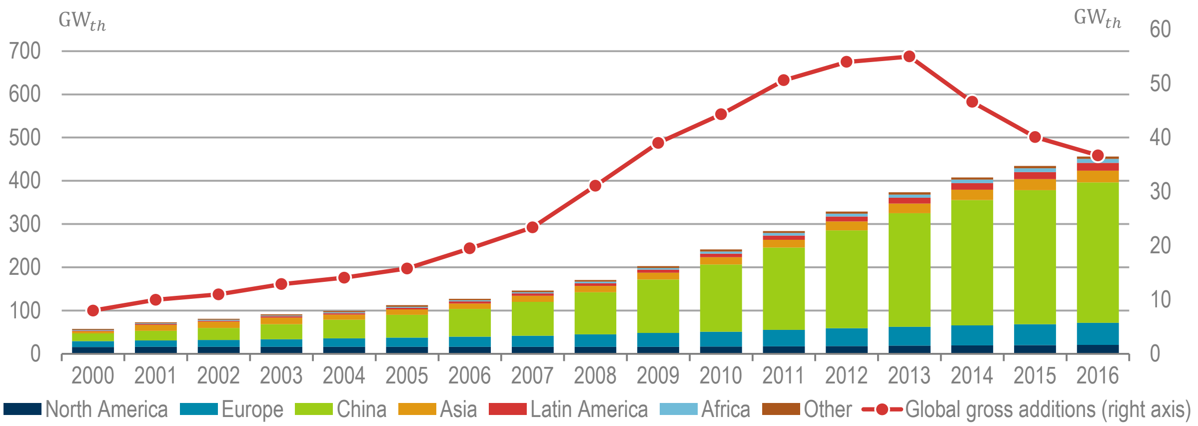
Global solar thermal capacity growth continued to slow in 2016 for the third year in a row, with gross annual additions falling to an estimated 36.7 GW_{th}, down 9% compared to 2015. Most of the decline was due to the slowdown in China, which accounts for over 75% of the annual growth. After China, 16% of the global annual growth was concentrated in five major markets, led by the European Union

[4] Many biomass systems currently in use in China are adapted from coal boilers.

[5] Values for Denmark (Lauersen, 2017) and Estonia (IEA, 2016) are for 2015; Finland is 2016 (Fyhr, 2017).

and followed by Turkey, Brazil, India and the United States. Economic attractiveness is the main driver for the growth observed in India, Mexico and Denmark, while inadequate policy support amid lower fossil fuel prices in the European Union and slower building development in Brazil caused installations to decline.

Figure 4.6. Solar thermal cumulative capacity by region and global gross additions, 2000-16



Sources: Analysis based on IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA-SHC (2017), Solar Heat Worldwide: *Global Market Development and Trends in 2016*, www.iea-shc.org/data/sites/1/publications/Solar-Heat-Worldwide-2016.pdf; REN21, *Renewables 2017 Global Status Report*.

By the end of 2016, global cumulative installed capacity reached 456 GW$_{th}$, with over 70% of the capacity located in China, followed by Europe (11%). Most of the world's cumulative installed capacity comprises small systems for providing hot water in single-family homes. However recent trends suggest the deployment of larger systems is accelerating due to the more favourable economics achieved with larger heat demands such as for commercial hot water, space and water heating combined, industrial process heat and district heating. Combined, these systems made up more than half (56%) of the world's newly installed collector capacity in 2015 (IEA-SHC, 2017), and are considered dynamic market segments in China, Europe, India, Mexico and MENA. While solar process heat installations and district heating make up only a fraction (less than 0.1%) of the current installed solar thermal capacity in 2016, (0.3 GW$_{th}$ and 1.1 GW$_{th}$ respectively), both market segments experienced positive developments, with new installations spreading out geographically (REN21, 2017; IEA-SHC, 2017). Pool heating is the main application in the United States, Canada and Australia, where annual installations have been generally stable in recent years.

Over 2017-22, solar thermal energy consumption is expected to increase by over a third globally, growing from 1.4 EJ in 2016 to 1.9 EJ by 2022. While the buildings sector drives most of the increase, a slower pace is forecast compared to the previous five years due to the expectation of a continued decline in small domestic systems for hot water in China, a market which largely influences the global totals. However, solar thermal consumption is seen accelerating in the industrial and agricultural sectors driven by increasing cost-effectiveness of systems to supply process heat. Most of the growth is expected to be in applications where high heat demands that are currently met by fossil fuels coincide with good solar insulation, such as in India, which leads the growth in industrial solar thermal consumption over the next five years. Yet the deployment of applications for solar process heat largely depends on the ability of new business models, such as energy service companies

(ESCOs), to address the needs of industrial consumers. Uncertain market conditions for some industries, particularly for commodities, cause limited visibility over future heat demands, leaving them hesitant to commit to the long-term contracts ESCOs need to make the business case for investment.

Table 4.3. Solar thermal heating drivers and challenges

Drivers	Challenges
Low-carbon source of heat.	Insufficient incentive levels; intermittent support schemes tied to fluctuating annual budgets.
Attractive in markets with good insolation and high electricity prices or to replace fossil consumption in high heat demand applications.	High investment costs compared to alternatives; installations can be complex; a lack of qualified installers; competition from lower-cost technologies.
Lower operation and maintenance costs, particularly for thermosiphon systems or large-scale solar fields. Innovative business models such as leasing or ESCOs.	Lack of public awareness about the technology; confusion with solar PV; lack of business models for large-scale systems.

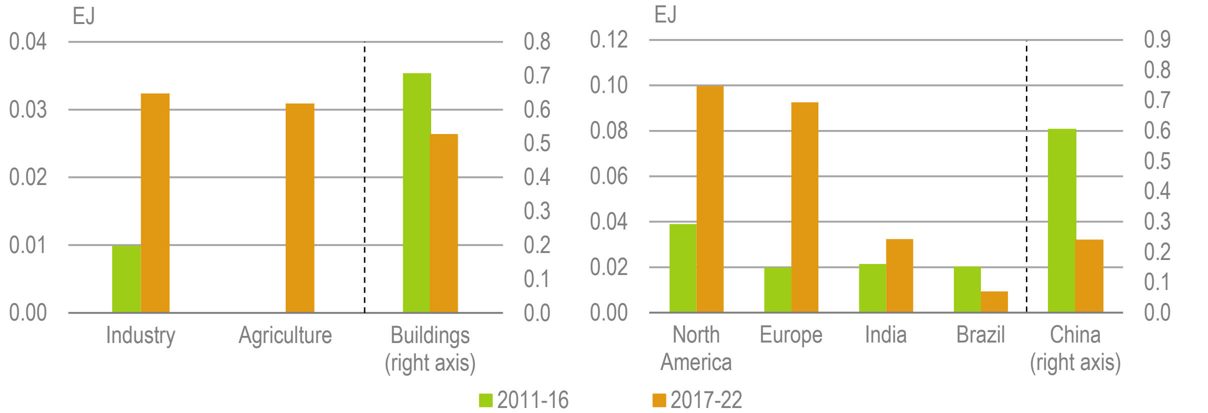
Outlook in selected markets

China continued to lead global annual capacity additions, installing approximately 27.7 GW_{th} in 2016, down 9% from 2015 as growth declined for the third year in a row (REN21, 2017). Annual gross installations have slowed after three government support programmes ended in 2013. This has particularly affected the deployment of small low-cost thermosiphon systems for domestic hot-water systems, which account for the majority (65%) of the cumulative installed capacity (IEA-SHC, 2017), as have a weakening housing market and the impact of end-user preference for more sophisticated heating systems as living standards improve. Deployment has increasingly depended on the pace of new building development and municipal regulations, either in the form of building codes or faster licensing and permitting, depending on the locality.

By 2022, China's solar thermal consumption is expected to grow by 25%, with 98% of the increase in the buildings sector in an effort to reduce air pollution amid rising heat demand. While the 2020 targets under the 13th FYP are expected to remain strong drivers for growth over the outlook period, the pace of expansion is expected to be significantly slower than the previous five-year period, with only 0.2 EJ added over 2017-22 compared to 0.6 EJ over 2010-16. This is mostly due to the continued slowdown in single-family hot water systems in the residential sector, which saw a 26% decline in newly installed collector area in 2016 (SolarThermalWorld, 2017a). The absence of robust support programmes, uncertainty over the pace of new housing development and questions over consumer preferences as living standards increase are expected to challenge the pace of deployment for small hot-water systems. However, an opposite trend is expected for larger systems, including those for non-domestic use where collector area for new systems increased in 2016 by 1% (SolarThermalWorld, 2017a). Over 60% of new installations in 2016 were for space and hot water heating in multi-family and commercial buildings, industrial process heat and district heating (IEA-SHC, 2017). Over 2017-22, solar thermal consumption in both the industrial and agricultural sectors is seen growing, increasing by 4 PJ by 2022, up from marginal levels in 2016.

In **Brazil**, the third-largest market, gross annual installations fell to an estimated 0.9 GW_{th} in 2016, a 7% decline compared to 2015, due to a weakening economic environment and a slowing public housing programme (REN21, 2017). Solar thermal deployment in Brazil has largely been driven by the need to reduce peak electricity demand where supply is constrained, or to provide first-time access to hot water. High electricity prices and local building codes remain key drivers for solar thermal consumption, forecast to increase by 26% by 2022, although less growth is expected than the previous five years. Uncertainty over the impact of a weaker public housing programme poses a downside risk to solar thermal consumption in buildings, where 95% of the growth is expected over the outlook period.

FIgure 4.7. Net solar thermal consumption growth by sector (left) and by region (right), 2011-22



Note: Data for buildings and China are plotted on the right axis due to their larger magnitudes.

Sources: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming a), *World Energy Outlook 2017*.

In general, growth remained robust in **India** in 2015 and 2016, although it is difficult to identify exact deployment figures due to contradictory preliminary data. Overall, annual installations are estimated to have increased by 30% in 2015, and remained strong in 2016 (IEA-SHC, 2017; REN21, 2017). The largest market for solar thermal systems in India has been domestic hot water, but industrial process heat is a fast-growing application for low-, medium- and high-temperature needs in the food, dairy, and textiles sectors. Solar thermal consumption is anticipated to almost double by 2022, with over 70% of the increase in buildings and 25% in industry. The fastest expansion is expected in industry, where solar process heat is anticipated to grow more than five times, from 2 petajoules (PJ) in 2016 to 10 PJ by 2022, due to improving cost-effectiveness. Industries that use liquefied petroleum gas for water heating and have high hot-water demand during the day are finding the economics favourable, with relatively short payback periods.

In **Europe**, estimates indicate that annual installations continued to slow in recent years, mostly due to the continuing decline in the European Union. Growth in the European Union was estimated to have declined by 6% in 2016 compared to 2015 (1.8 GW_{th} in 2016) (REN21, 2017). It is estimated that annual installations in major markets such as **Germany** and **Italy** continued to decline, as policy support was ineffective at reversing the trend. However, annual installations grew in **Denmark**, which saw record growth of 347 MW_{th} from solar thermal district heating applications. Economic attractiveness is the main driver due to taxes on fossil-fuelled heating, affordable land and compatibility with operating temperatures of pre-existing district heat networks (REN21, 2017). Outside the European Union, the cost-effectiveness of less-expensive thermosiphon systems to meet the heat demands of a Mediterranean climate continued to drive stable growth in **Turkey** (1.5 GW_{th}).

Over 2017-22, solar thermal energy consumption in Europe will depend on the dynamics of growth of different solar thermal market segments in warmer versus colder climates. Stable growth is expected in Turkey, mostly for hot water in domestic applications, but with an increasing trend towards commercial applications as well as space heating. Overall, Turkey's trend is likely to depend on the rate of urbanisation, the housing market and the economic health of consumers. However, as colder climates require more expensive solar thermal systems, deployment in the remaining European markets will depend on the extent to which policy support can improve solar thermal's economic attractiveness across different market segments in buildings and industry. High upfront costs, complex installations and a lack of consumer awareness about the technology or available incentives remain key barriers for the small domestic segment, while larger systems for industrial process heat or district heating have strong potential.

North America's solar thermal growth has been relatively stable in recent years, and consumption over 2017-22 is expected to increase by 80% as a result of increased deployment in Mexico and the United States. Total annual installations continued to increase in **Mexico** in 2015, one of the few markets that experience an increase, up by 8% compared to 2014, driven by federal tax deductions and targeted loan programmes. Continued support coupled with ambitious new targets for 26 GW_{th} of capacity by 2027 and good insolation are considered drivers for further deployment in Mexico. Solar thermal is emerging in the agricultural and industrial sectors as a cost-effective alternative to diesel boilers for process heat (SolarThermalWorld, 2017b).

Heat pumps

Global overview

The global market for heat pumps (HPs)[6] is dominated by two heat source technologies. Air source heat pumps (ASHPs) will remain the dominant technology and are considered in this report to comprise both reversible air-air systems and air-water systems, while ground source heat pumps (GSHPs) will continue to see increased deployment due to their higher achievable efficiency, and therefore ability to provide more renewable heat per unit of input electricity. As higher shares of renewables are utilised in national electricity generation portfolios, HPs are able to offer deeper greenhouse gas emission savings.

The global market continues to be governed by several trends. HPs are witnessing increased deployment due to more countries implementing strict new energy performance standards for new buildings and renovations, as well subsidies on the purchase of HPs, which will drive their increased use in the residential sector. Europe continues to be one of the largest markets in HP sales, accounting for around 40% of global installations in 2016, and it remains the primary focus of this report given the accurate and timely data available.

In Europe, HP sales grew by nearly 1 million in 2016, the highest growth in a decade and a 12% increase from 2015 levels (Figure 4.8). Total cumulative HP sales reached 9.5 million, with France, Italy and Sweden leading. ASHPs accounted for around 82% of total sales, with uptake supported by lower investment costs and compatibility with a wider share of building stock. ASHP deployment is dominated by reversible air-air systems (4.9 million), which are giving a boost to the cooling market and remain the dominant HP technology in Northern European countries for both cooling and

[6] HPs are considered in this report to include reversible air-air HPs that are used for either heating or cooling, or both, although emphasis is generally placed on systems used in colder climates for heating, air-water HPs and ground-source HPs. Air-air refers to HPs using the air as a heat source and delivering heat via an air heat distribution system; air to water refers to heat distribution via a "wet" water-based heat distribution system.

heating. This is followed by air-water systems for heating (1.7 million) and GSHPs, which account for around 1.4 million sales (EHPA, 2016). GSHPs have been declining marginally over the last decade but, due to their higher achievable efficiency, remain a strategically important technology for decarbonising heat.[7] For example, HPs accredited within the United Kingdom's renewable heat incentive (RHI) programme witnessed an average seasonal performance factor (SPF) of 3.5 for GSHPs compared to 3.1 for ASHPs (BEIS, 2017), although SPFs can be much higher depending on the technology used.[8]

Table 4.4. HP drivers and challenges

Drivers	Challenges
New building and renovation sectors receiving policy support to install HPs and phase out oil and gas.	Difficulty in evaluating the performance of the technology.
Policy support in European markets to increase renewable heat shares in accordance with RED targets.	High installation costs and lack of consumer awareness regarding GSHPs, primarily in the residential sector.
High-efficiency operation ensures competitive operational/running costs versus most fossil-fuelled heating fuels, and hybrid solutions enable augmentation of existing heating systems with HPs.	Inefficiently insulated housing stock increases heat demand and peak loads, potentially requiring backup electric heating and resulting in higher capital cost and reduced coefficients of performance, increasing operational costs.

Outlook for selected markets

The growth of HPs in European markets remains heavily supported by financial incentives, especially in Germany and the United Kingdom, while a mix of incentives and specific building requirements in southern Europe favour the dual use of HPs for cooling and heating. The recovery of the construction market is also driving growth in many countries. In some countries, such as Denmark, Germany and Switzerland, the energy sector is adopting new business models, including a move from commodity sales to a service-based business model headed by utility providers. Moreover, large-scale systems are being considered for use in district heating and in buildings with a dual use for heating and cooling, all of which should drive HP deployment over the forecast period.

In Nordic countries, HPs boast Europe's highest market penetration per 1 000 households as they continue to benefit from a lack of extensive gas distribution grids, bans on the use of heating oil and higher awareness of the benefits of efficient use of electricity for heating purposes (European Commission, 2016). These are expected to remain drivers for HP growth. **Norway** has the highest market penetration at just over 30% of the population, of which over 90% of the stock is reversible air-air systems utilised primarily for heating purposes. **Sweden** has a higher stock of GSHPs than any other country in the European Union. However, the GSHP market slowed slightly in 2016 due to a reduction in the ROT (repair, conversion, extension) tax allowance for private homeowners, which penalised relatively more expensive heating solutions such as GSHPs.[9] However, ASHPs should continue to witness stronger growth over the outlook period with current policies in place. **Finland's** HP market contracted by 8% after 2010 due to a sharp fall in oil prices and slower residential home construction. Deployment picked up in 2016 and more than half of new-build single-family houses were fitted with GSHPs, although market uncertainty remains over the outlook period. While most

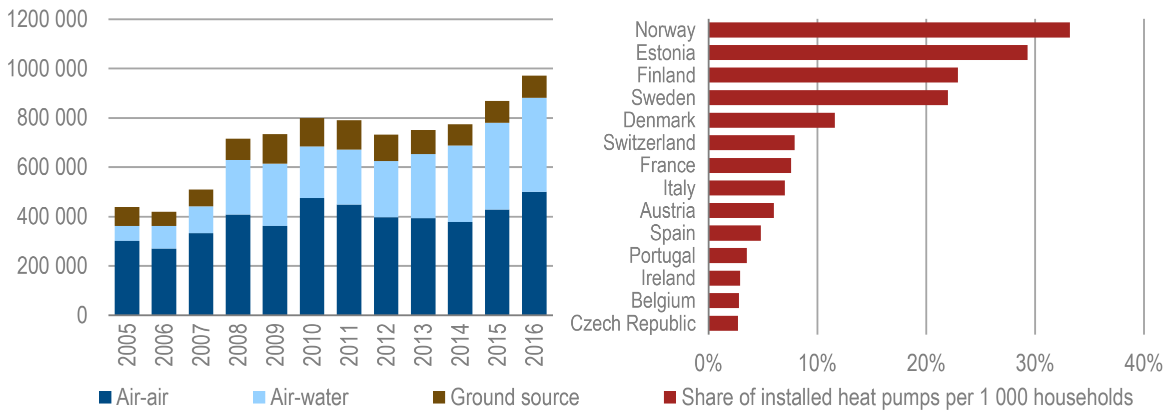
[7] While GSHPs only accounted for about 9% of total HP sales in 2016, and have been declining in comparison, their share in avoiding CO_2-equivalent emissions remained over 30% compared to ASHPs.

[8] SPF is an indicator of the efficiency of the HP over time taking account of variable loads and source temperatures.

[9] ROT refers to repair, conversion, extension, and is the home renovation tax allowance in Sweden that is helping to drive the HP market.

HP segments are showing slower growth, air-water ASHPs sales nearly doubled, utilised primarily to replace electric or oil-fired heating systems in the renovation sector (SULPU, 2017).

FIgure 4.8. HP sales in Europe by technology, 2005-16 (left) and share of heat pumps per 1 000 households (right)



Source: EHPA (2016), *EHPA Market and Statistics Report 2016*.

In **Denmark,** the HP stock is dominated by reversible air-air ASHPs (EHPA, 2016), driven by the need for HPs to provide grid stability (particularly achieved by integrating large HPs in district heating systems) (EC, 2016). The Danish HP market is supported primarily by the 2013 ban on the installation of oil and natural gas boilers in new buildings and a target for 100% fossil fuel-free heating by 2035. To achieve this ambitious target, new technologies are being introduced such as HPs connected to a common ground collector, hybrid solutions, gas-fuelled HPs and HPs combined with low-temperature district heating. New business models are also being tested with district heating companies and ESCOs to offer "packaged deals".[10] With strong policies in place, the Danish HP market will continue to witness stable growth over the outlook period.

In **Germany,** the penetration of HPs remains low to date, and they currently only operate in 2% of homes. However, total HP sales reached over 880 000 in 2016, an increase of around 9% over 2015 (EHPA, 2016), and show great potential, especially in the new-build market. As of January 2016, new rules under the revised German building code (*Energieeinsparverordnung*) require new-build properties to meet a primary energy requirement that is 25% lower than the previous threshold. In addition, the renewable heat law requires that a certain percentage of heat demand is met by renewable energy. These requirements make oil and gas heating extremely challenging for the majority of new buildings and should result in a higher penetration of HP installations over the outlook period.

In the **United Kingdom,** the heat sector is dominated by natural gas, which supplies more than 80% of all heating systems. Natural gas prices are amongst the lowest in Europe, making it difficult for HPs to compete. However, in buildings that are off the gas grid, there is a good potential for HP deployment. While challenges remain in the form of high upfront capital costs, an old and inefficient building stock and power distribution network inadequacies in some places, HP deployment has

[10] "Packaged deals" refers to companies offering heat as a service to increase the integration between the HP product and instalment of the device. This could include a Product-Service System (PSS) business model in which a power retailer or energy company is responsible for creating a price model, sharing the risk and providing services to a customer, as opposed to the traditional sales model of product ownership by the customer which faces barriers of high start-up cost and pricing uncertainty.

accelerated since the introduction of the RHI in 2011 (for industrial and commercial installations) and 2014 (for domestic systems). The tariffs for HPs for domestic installation were increased in April 2017, which should continue to drive growth.

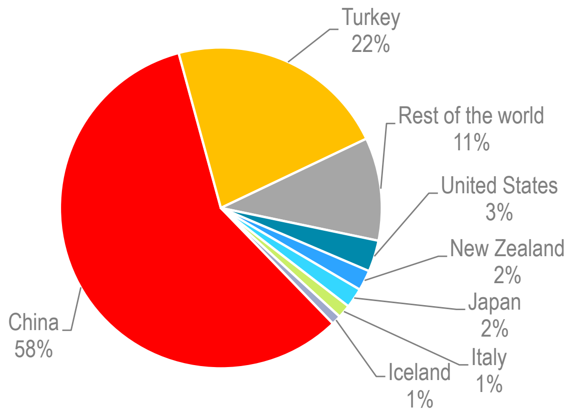
Geothermal

Global overview

The direct use of geothermal is currently the smallest source of renewable heat globally, accounting for 0.4 EJ (2% of renewable heat) in 2015. Geothermal direct use harnesses the heat generated by the earth's geological processes and can be extracted from shallow geothermal resources, warm aquifer systems or deep geothermal reservoirs. GSHPs, which exploit solar heat stored in the ground, were covered in the previous section.

The significant majority of the world's geothermal heat is used in a few countries, mostly those with easily accessible high-temperature geothermal aquifers. China and Turkey together account for almost 80% of global geothermal heat use (Figure 4 9). Geothermal heat is primarily used for bathing and swimming (45%) and space heating (34%), while industrial use accounts for only 4% of geothermal direct use (Lund and Boyd, 2015). Use in agriculture, especially for heating greenhouses, is significant in certain countries. In Turkey, for instance, agriculture accounts for 30% of geothermal direct use. Over the period to 2022, geothermal direct use is expected to grow by 72%, with consumption increasing from 0.4 EJ to 0.6 EJ. However, a large unexploited potential remains across the globe, with the 2011 IEA *Geothermal Technology Roadmap* having identified a potential of 5.8 EJ by 2050 (IEA, 2011). Exploiting this potential faces a number of challenges (Table 4.5).

FIgure 4.9. Geothermal direct use by country, 2015



Note: *Rest of the world* includes Korea and Switzerland where 0.02 EJ of geothermal heat is reported, but which is primarily from GSHPs rather than direct use.

Source: IEA (2017b), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/.

Table 4.5. Geothermal heating drivers and challenges

Drivers	Challenges
Resource availability, especially where there are shallow resources such as hot thermal springs that are easy and cheap to exploit; potential from deep aquifers is more widespread.	Extraction from deep resources such as hot aquifers is technically more difficult; geological and drilling expertise is needed and upfront costs can be very high, while success is not necessarily guaranteed; expertise may not exist in developing countries – technical co-operation programmes can be important.
Financial incentive programmes.	Need to make funding available for expensive drilling operations that may not be successful (e.g. risk guarantees).
Carbon targets and requirements to decarbonise the heating sector.	Need district heating infrastructure in the right locations to exploit geothermal (e.g. from hot aquifers); potentially high infrastructure costs if necessary to build/extend district heating.

Outlook for selected markets

The **European Union** has the most dynamic market globally for geothermal in the district heating and cooling sector. Between 2012 and 2016, 51 new geothermal district heating plants entered into operation, with an average annual growth rate in installed capacity of 10%. Currently, there are 190 plants in the European Union, including co-generation systems, with a total installed capacity of approximately 1.7 GW_{th}. France has the highest annual production, at 1 335 GWh in 2015. The European Geothermal Energy Council (EGEC, 2017) reports that over 200 projects are planned and capacity is estimated to grow by up to 6.5 GW_{th} by the end of this decade, with the main markets in France, the Netherlands, Germany and Hungary. For example, Paris has seen major expansion, and a new geothermal-based district heating scheme is due to begin operation in Bordeaux in 2019. In Hungary, the extension of geothermal district heating is an important part of achieving renewable energy targets and cutting gas imports (Box 4.3).

Box 4.3. Geothermal district heating in Hungary

Hungary has excellent geothermal potential and its thermal waters have long been used in spas. The country's agricultural sector is also a large user of geothermal heat, with more than 300 MW_{th} installed capacity, mainly to heat greenhouses (Nádor, Kujbus and Tóth, 2016). However, it is the district heating sector which has seen the most rapid development in recent years, with Hungary experiencing the largest capacity additions in geothermal district heating in the European Union during the period 2012-16 (EGEC, 2017). Hungary now has the third-largest geothermal district heating capacity in the European Union after France and Germany, with over 250 MW_{th} installed. Geothermal sources supplied 12% of district heating demand in 2016 and 3% of total heat demand.

Recent additions to Hungary's geothermal heat capacity include a 52 MW_{th} district scheme in Győr, which opened in 2015 and supplies up to 60% of the heat requirements of a local Audi car manufacturing plant, as well as around 24 000 households and other customers (ThinkGeoenergy, 2015). In 2017, project financing was secured for Hungary's first geothermal co-generation plant in Tura, which is due to generate 2.7 MW of power and 7 MW of heat.

Further growth is expected due to a positive policy environment for geothermal. As a follow-up to its 2011 *National Energy Strategy*, the Hungarian government has drafted a *District Heating Development Action Plan*, which is pending approval. This plan highlights the role of geothermal energy and identified a list of around 30 settlements with district heating infrastructure in place and favourable geothermal conditions (EGEC, 2017).

Elsewhere, geothermal district heating is a major plank in **China**’s effort to reduce harmful air pollution in major cities. The country is aiming to connect a further 1.1 billion m^2 of buildings’ floor space to geothermal district heating by 2020, reaching a total of 1.6 billion m^2. The National Development and Reform Commission (NDRC), China’s economic planner, mentioned guidelines for geothermal energy for the first time in the 13th FYP. This implies that the sector could eventually get state subsidies to help it achieve its targets. According to government geothermal energy plans, in the Beijing-Tianjin-Hebei region the geothermal heating area will reach 450 million m^2 by 2020, which would account for around 20% of space heating consumption in the area (ThinkGeoenergy, 2017).

New Zealand has excellent geothermal resources, yet three-quarters of its heat demand is met by fossil fuels and only 6% from geothermal. Geothermal direct use remains an area with much unexploited potential. Industry accounts for three-quarters of national heat consumption and there is a long history of using geothermal heat for certain industrial applications (e.g. in timber mills and paper and pulp manufacturing). In 2011, the New Zealand government set a target to increase the use of heat from woody biomass or direct geothermal use by 9.5 PJ compared to 2005. However, direct use of geothermal actually saw a 22% reduction over 2005-15, primarily due to reduced consumption in the pulp and paper industry. The government released a new energy strategy in June 2017, with renewable and efficient use of process heat identified as one of three priority areas (MBIE, 2017). A process heat action plan is to be produced. In principle, this new policy focus should benefit geothermal direct use, but without specific policy support, progress is likely to remain slow.

Policy developments in key heat markets

Due to the presence of a range of economic and non-economic barriers, policy intervention is often needed to accelerate the deployment of renewable heat. The most common policy instruments employed include financial support instruments, such as grants and tax credits, and regulatory mechanisms such as building code requirements for renewable heat (IEA, forthcoming b).

The RED has been the key driver for the **European Union’s** leadership in renewable heat. Under the RED, member states have binding targets for achieving a certain share of renewables in final energy consumption by 2020. In 2015, renewable energy accounted for 18.6 % of total energy use for heating and cooling in the European Union, up from 18.1% in 2014.

The European Union has agreed a new renewables target for 2030 of at least 27% of renewables in final energy consumption, but without binding targets for individual member states. In late 2016, the European Commission produced a clean energy package, which included proposals for how the 2030 renewable target is to be achieved. For heating and cooling, it proposes that member states should:

- Increase the share of renewable heating and cooling in final energy consumption by 1 percentage point per year.
- Be required to carry out an assessment of their national potential of renewable energy sources and the use of waste heat and cold for heating and cooling.
- Open access rights to local district heating and cooling systems for producers of renewables, under certain conditions.

In addition, the clean energy package also included a number of energy efficiency measures. The package is likely to be adopted later in 2017, but it is too early to assess what kind of impact it will have on the market for clean and efficient heating solutions beyond 2020. Some member states have set their own targets for 2030 and beyond, which should drive deployment. For example, France has adopted a 38% target for renewables in final heat consumption by 2030 (compared to 19.8% in 2015), while Denmark aims to achieve fossil fuel-free heating by 2035.

Some European countries have made adjustments to their existing renewable heat policies over the last year:

- **Germany** published a new strategy for supporting energy efficiency and renewable heat, with the aim of better aligning financial support programmes in those two areas, especially in the buildings sector. In addition, there will be a new focus on heat infrastructure (heating and cooling networks, as well as large renewable heat installations). The proposed changes will be implemented gradually over the next three years (BMWi, 2017).
- Changes to **Italy**'s *Conto Termico* (which promotes energy efficiency and renewable heat) were introduced in May 2016. The main changes include a simplified procedure, higher levels of support and an increase in the size of eligible systems. Applications have increased significantly since the changes were introduced.
- In **Spain**, the Andalucia region introduced a new incentive programme, "Sustainable Construction", covering energy efficiency measures and renewable heat for both small installations in individual dwellings and larger, district-level plant.
- The **United Kingdom** increased some tariffs under its RHI scheme from April 2017, most notably for ASHPs and GSHPs in domestic applications. Biomass and biogas tariffs were digressed from July 2017.
- **Norway** has decided to ban oil-fired heating in both existing and new buildings from 2020.

Elsewhere, the most significant development has been the inclusion of several renewable heat targets in **China's** 13th FYP (2016-20):

- solar thermal: a further 400 million m^2 to be installed by 2020
- geothermal: a total of 1.6 billion m^2 to be connected by 2020
- biomass heating: 30 Mt by 2020.

Furthermore, under the objective of reducing air pollution from coal, a coal boiler replacement scheme has been put in place in China, and 160 000 coal boilers have recently been replaced with heat pumps. For 2017, the replacement of 400 000 units is planned in Beijing and there are plans to extend this programme to other provinces.

In **India**, the revised building code published in March 2017 has the potential to drive solar thermal deployment. It proposes a share of between 20% and 40% of hot water demand to be met by solar thermal – for all new buildings in cold climate zones, and for new hotels and hospitals elsewhere. While the Indian national building code is not mandatory, it is generally used by states and municipalities to regulate construction activity.

In the **United States**, several states have adopted renewable heating and cooling plans or roadmaps. For example, Vermont's 2016 comprehensive energy plan establishes a goal to increase the share of renewable heat from 20% to 30% by 2025.

References

BEIS (Department for Business Energy and Industrial Strategy) (2017), *RHI Deployment Data: May 2017,* Official Statistics, BEIS, London, www.gov.uk/government/statistics/rhi-deployment-data-may-2017.

BMWi (Federal Ministry for Economic Affairs and Energy) (2017), *Förderstrategie Energieeffizienz und Wärme aus erneuerbaren Energien*, [Support strategy energy efficiency and renewable heat], BMWi, Berlin, www.bmwi.de/Redaktion/DE/Publikationen/Energie/foerderstrategie-energieeffizienz.html.

European Commission (2016), "EHPA Secretary General Thomas Nowak talks to SETIS", Interview, Brussels, 28 September 2016, https://setis.ec.europa.eu/newsroom/interviews/ehpa-secretary-general-thomas-nowak-talks-setis.

EGEC (European Geothermal Energy Council) (2017), *EGEC Geothermal Market Report 2016*, EGEC, Brussels, www.egec.org/media-publications/egec-geothermal-market-report-2016.

EHPA (European Heat Pump Association) (2016), *EHPA Market and Statistics Report 2016*, EHPA, Brussels.

Fyhr, K. (2017), "Fortum and renewable heating and cooling", presentation at IEA Renewable heating and cooling workshop, Paris, 7 February 2017.

Gao, J. et al (2016), "An integrated assessment of the potential of agricultural and forestry residues for energy production in China", *Bioenergy*, Vol. 8 (5), September 2016, pp. 880–893.

IEA (International Energy Agency) (forthcoming a), *World Energy Outlook 2017*, OECD/IEA, Paris.

IEA (forthcoming b), *Renewable Heat Policy Insights Paper*, OECD/IEA, Paris.

IEA (2017a) *Renewables Information 2017*, OECD/IEA, Paris.

IEA (2017b), *World Energy Statistics and Balances* (database), www.iea.org/statistics/ (accessed June 2017).

IEA (2016), *Medium-Term Renewable Energy Market Report 2016*, OECD/IEA, Paris.

IEA (2011), *Technology Roadmap: Geothermal Heat and Power*, OECD/IEA, Paris.

IEA-SHC (IEA Solar Heating and Cooling Programme) (2017), *Solar Heat Worldwide: Global Market Development and Trends in 2016*, AEE – Institute for Sustainable Technologies and IEA-SHC, Gleisdorf, Austria, www.iea-shc.org/data/sites/1/publications/Solar-Heat-Worldwide-2016.pdf.

Lauersen, B. (2017), "Renewables in Danish heating and cooling – the case of district heating", presentation at IEA Renewable Heating and Cooling Workshop, Paris, 7 February 2017.

Lund, J. and T. Boyd (2015), "Direct utilization of geothermal energy 2015 worldwide review", Proceedings World Geothermal Congress 2015, Melbourne, 19 April 2015, https://pangea.stanford.edu/ERE/db/WGC/papers/WGC/2015/01000.pdf.

MBIE (Ministry of Business, Innovation and Employment) (2017), *Unlocking our energy productivity and renewable potential,* MBIE, Wellington.

Nádor, A., A. Kujbus A. and A. Tóth (2016), "Geothermal energy use: country update for Hungary", European Geothermal Congress 2016, Strasbourg, 19-24 September 2016, www.researchgate.net/publication/308596653_Geothermal_Energy_Use_Country_Update_for_Hungary (accessed 13 July 2017).

REN21 (Renewable Energy Policy Network for the 21st Century) (2017), *Renewables 2017 Global Status Report*, REN21, Paris.

SolarThermalWorld (2017a), "*China: Solar process heat and space heating and cooling rack up market shares"*, www.solarthermalworld.org/content/china-solar-process-heat-and-space-heating-and-cooling-rack-market-shares.

SolarThermalWorld (2017b), "*Mexico: Solar process heat beats fossil-fuel boiler in energy cost"*, www.solarthermalworld.org/content/mexico-solar-process-heat-beats-fossil-fuel-boiler-energy-cost.

SULPU (Finish Heat Pump Association) (2017), "The heat pump industry back on track towards growth in Finland", press release, January 2017, www.sulpu.fi/in-english (accessed 9 August 17).

ThinkGeoenergy (2017), "China highlighting the tremendous role of geothermal heating for the country", www.thinkgeoenergy.com/china-highlighting-the-tremendous-role-of-geothermal-heating-for-the-country/ (accessed 12 July 17).

ThinkGeoenergy (2015), "Hungarian geothermal heating system starts supply to community and Audi factory", www.thinkgeoenergy.com/hungarian-geothermal-heating-system-starts-supply-to-community-and-audi-factory/ (accessed 13 July 2017).

5. RENEWABLE ENERGY TECHNOLOGY TRENDS AND COSTS

Highlights

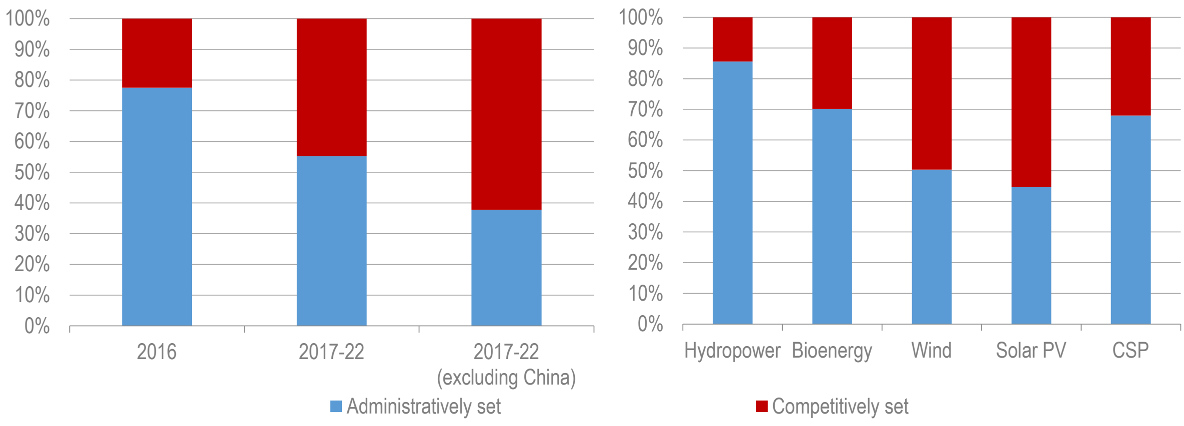
- Renewable electricity policies in many countries are transitioning from government-set tariffs to competitive auctions with long-term power purchase agreements (PPAs) for utility-scale projects. Almost half of the expansion in renewable capacity over 2017-22 is expected to be driven by competitive price-setting mechanisms (two-thirds, excluding China).
- Over 2017-22, global average estimated generation costs (LCOE) are expected to drop by almost a quarter for utility-scale solar photovoltaic (PV), 13% for onshore wind and a third for offshore wind, making them increasingly affordable. For concentrating solar power (CSP), learning is expected to result in falling overall generation costs over the forecast period.
- Average LCOEs remain significantly higher compared to record-low auction prices announced for both solar PV and onshore wind (USD 30-50 per megawatt hour [MWh]) projects due to come on line over 2018-20. While these auction prices need to be verified and still apply to a minor share of the market, they suggest that expanding competition for long-term contracts could further accelerate cost reductions in coming years, making renewables comparable or lower than LCOEs of new-build fossil fuel power plants in an increasing number of countries.
- PV module prices declined by an average 20% in 2016, while global manufacturing capacity reached a record level of 80 gigawatts (GW). However, major PV manufacturers remain under financial stress as their profit margins decrease due to low prices. While the PV manufacturing industry is expected to sustain its growth, market volumes and prices strongly depend on China, which represents around half of both solar PV demand and manufacturing capacity.
- With major mergers and acquisitions completed last year, consolidation continued in the wind industry, especially in the United States and European Union. *Renewables 2017* expects increasing competition in the maintenance market, with annual spending forecast to grow from USD 9 billion in 2016 to almost USD 19 billion in 2022.
- Hydroelectric pumped storage plant (PSP) capacity stood at 149 GW in 2016, accounting for 95% of global storage capacity. PSP capacity is expected to grow by 17% over 2017-22, potentially generating 120 terawatt hours (TWh) in 2022. Market designs that inadequately value system flexibility continue to challenge the economics of PSPs.
- Advanced biofuels made important progress in recent years, but are not currently competitive against petroleum products. Technological learning offers scope to reduce production costs, but deployment and consequent economies of scale require strong policy interventions.
- Renewable heat costs span a wide range, depending on the sector, location and application. Some installations, such as solar thermal energy systems in countries with high levels of insolation and biomass heat in the pulp and paper industry (Finland, United States), are already competitive while others find it hard to compete against fossil fuels. Deployment of larger-scale renewable heat installations provides opportunities for investment cost reductions, while running costs are most competitive where gas prices are higher due to taxation.

Electricity

A changing policy environment will support more cost-effective deployment of wind and solar. Over the last decade, onshore wind and solar PV have achieved significant investment cost reductions. Feed-in tariff (FIT) policies have played an important role in driving initial deployment, economies of scale, technology innovation and cost reductions. The most significant policy development over the last few years has been the shift from government-set FITs to competitive auctions with long-term PPAs. This approach to remuneration has emerged as a more cost-effective policy option for capital-intensive renewables, thanks to the use of a competitive price discovery mechanism combined with volume control, thus containing total renewable support costs.

Renewables 2017 anticipates that half of the renewable capacity which is expected to be commissioned over 2017-22 will have its remuneration set competitively, but China's policy transition away from FITs may change this picture. Excluding China, this proportion increases to up to two-thirds (Figure 5.1). Competitive tenders with long-term PPAs provide long-term revenue certainty, which is an important driver for reducing project risk levels for capital-intensive renewable technologies. While competitively set remuneration dominates solar PV and wind projects, remuneration levels are set administratively for the majority of hydropower deployment, as vertically integrated utilities are usually responsible for developing large-scale projects in emerging economies and developing countries. China is the largest market for bioenergy and CSP, and therefore remuneration is skewed toward administratively set FITs. Outside China, competitive auctions are expected to drive CSP deployment.

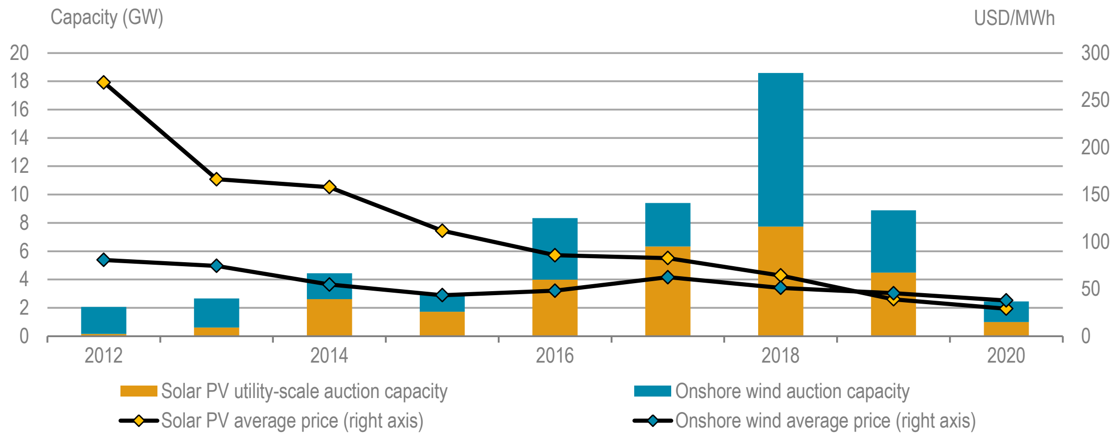
Figure 5.1. Fixed remuneration contract type for utility-scale renewable capacity commissioned in 2016 and 2017-22 (left) and by technology (right)



Note: Type indicates how the fixed contract price is set, either administratively by government entities or competitively through auctions or tenders.

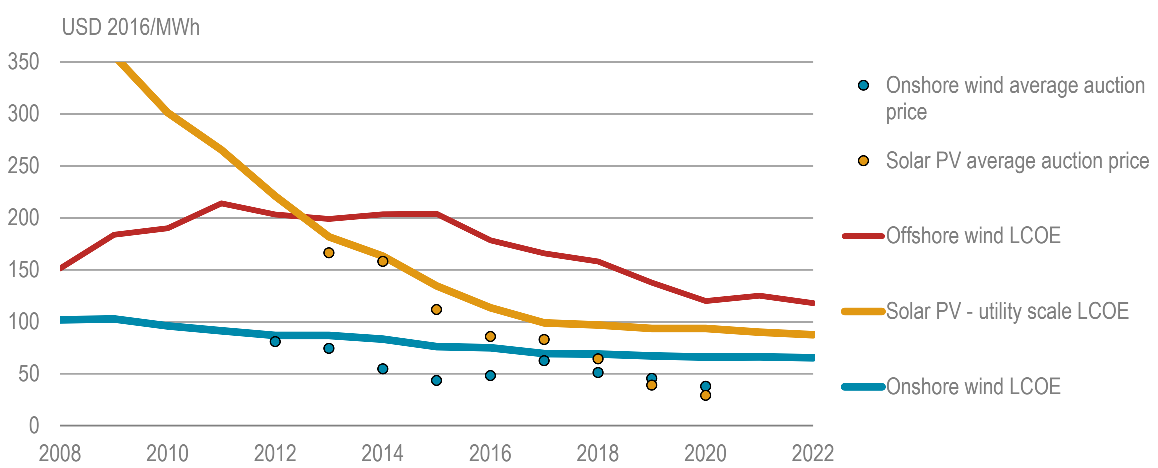
Competitive auctions are accelerating cost reductions, in particular for solar PV. The IEA renewable auction database tracks around 60 GW of renewable capacity awarded since 2013 and expected to be commissioned over 2017-20. Solar PV and onshore wind projects together represent over 90% of the awarded auction capacity, with hydropower, bioenergy and CSP/STE accounting for the rest. Capacity-weighted average auction prices for solar PV projects declined from almost USD 160/MWh for those commissioned in 2014 to below USD 30/MWh for plants due to be commissioned in 2020/21 (Figure 5.2). For onshore wind, average auction prices dropped from USD 70/MWh in 2014 to below USD 50/MWh in 2020. For the first time, solar PV projects auctioned over the last year (and expected to be commissioned from 2019) have offered, on average, lower prices than onshore wind (Figure 5.2). While auction prices need to be verified over time and still apply to a minor market share, they suggest that expanding competitive pricing could further accelerate cost reductions in the coming years.

Figure 5.2. Onshore wind and solar PV auction capacity and average price by project commissioning date



Average LCOEs for wind and solar are expected to continue decreasing, but to remain significantly higher than auction prices over the forecast period. Both administratively set FITs and feed-in premiums (FIPs) and competitive auctions will continue to focus on the most dynamic wind and solar technologies over the forecast period. Wind and solar PV are anticipated to account for about 80% of global renewable capacity growth over 2017-22. Their economic attractiveness will continue to improve due to increasingly cost-effective policy support, continued technology improvements, expansion into newer markets with better resources, and favourable financing conditions. Between 2017 and 2022, global average generation costs are expected to drop by almost a quarter for utility-scale solar PV, 13% for onshore wind and a third for offshore wind (Figure 5.3).

Figure 5.3. Global average LCOEs and auction results for projects by commissioning date



Average LCOEs remain significantly higher compared to record-low announced auction prices, in particular for solar PV. This is mainly the consequence of high FITs in two of the world's largest PV markets over the forecast period: China and Japan. This may change in the future as power market reforms and renewable policies are expected to evolve in both countries.

Other renewables require policies that address technology-specific challenges. Cost trends for hydropower, geothermal and bioenergy technologies remain less dynamic compared to wind and solar. In some regions, technology-specific factors have pushed their investment costs up over the last decade. For hydropower, site availability and increasing costs associated with environmental and social impacts of projects have increased the project investment required in some regions. In addition, long lead times for large-scale projects are challenged by the short delivery dates stipulated in most of the current auction schemes, while also increasing investment risk and the cost of financing. For geothermal, drilling costs have been increasing over the last decade in some regions resulting in higher risks at the pre-project development phase, which in general prevents projects from competing in electricity auctions unless they are at an advanced stage of development. For bioenergy, fuel price variation and availability remain important risk factors that need to be factored into a competitive auction scheme. Overall, the higher generation costs of these technologies need to be compensated by remuneration schemes that value their dispatchable nature, while the potential for wider benefits associated with rural development and waste management for bioenergy, water management, flood protection and irrigation for hydropower, must also be taken into consideration.

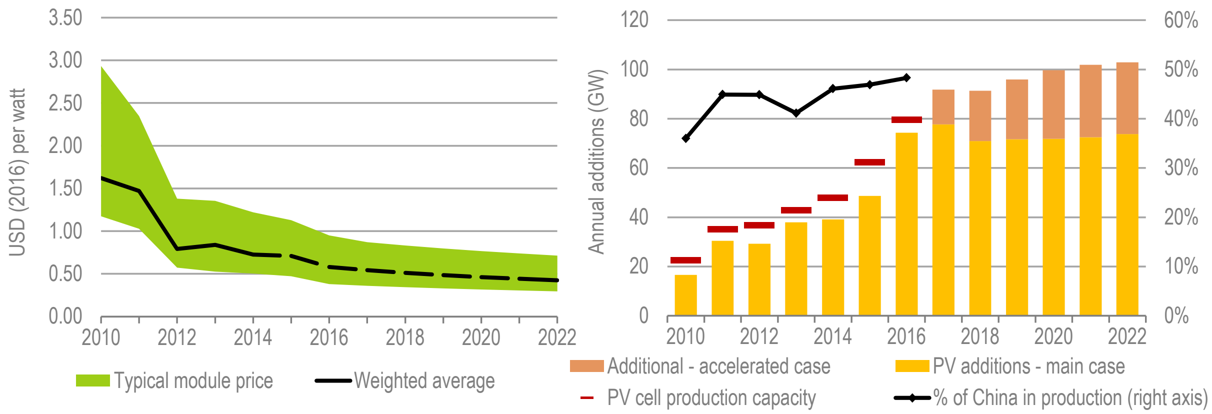
LCOEs for some renewables are increasingly comparable to or lower than new-build fossil fuel alternatives in a number of countries, which does not necessarily mean they are fully competitive. In Latin America, solar PV and onshore wind projects offered lower prices than natural gas plants in recent energy auctions in Brazil, Chile, Uruguay and Peru. In India, a solar PV project won a recent auction with a record-low price of USD 46/MWh, which is comparable to fixed coal tariffs in some states. In Spain, onshore wind projects won a recent energy auction with no subsidies, accepting the wholesale market price. In Germany, developers bid zero premium at the recent offshore wind auction, meaning that they will only receive wholesale market prices as remuneration for projects to be commissioned over 2024-25. In South Africa, winning bids for wind and solar projects under the Renewable Energy Independent Power Producer Procurement Program offered lower prices than baseload coal independent power producers (IPPs). While comparing auction results with LCOEs should be made with great care, announced prices reflect the general trend that wind and solar are becoming increasingly affordable and comparable to conventional plants. This does not automatically imply that they are competitive; however, since this will depend on specific market design, system integration costs and the degree to which externalities are priced into fossil fuels.

Looking ahead, a further increase in the share of wind and solar in the power mix will increasingly hinge on appropriate market design and a shift in the policy paradigm to focusing on system value. Over the forecast period, onshore wind and solar PV will no longer need high direct financial incentives, but will still require a proper market framework in order to attract new investment. Without a simultaneous increase in system flexibility (grid reinforcement and interconnections, storage, demand-side response and other flexible supply), variable renewables are more exposed to the risk of losing system value at increasing shares of market penetration, as wholesale prices are depressed precisely when wind and solar production exceeds demand. Market and policy frameworks need to evolve in order to simultaneously cope with multiple objectives, including providing long-term price signals to attract investment, ensuring efficient short-term electricity dispatching, pricing negative externalities and unlocking sufficient levels of flexibility.

Solar PV

In 2016, solar PV module prices declined sharply because of growing global manufacturing capacity and competitive pricing strategies, despite a record level of new additions (74 GW). At the end of 2016, global PV cell manufacturing capacity stood at 80 GW with its utilisation rate reaching an all-time high of around 90% (SPV Market Research, 2017a). However, the global weighted average price of modules declined by 20% in 2016 compared with 2015, to below USD 0.60 per watt (W), with more aggressive prices in the range of USD 0.35-0.40/W quoted in some markets, notably India (Figure 5.4). In 2017, despite these low prices, module manufacturing capacity is anticipated to expand by another 15%, reaching around 90 GW, and is expected to sustain its expansion over the forecast period. However, market volumes and prices will strongly depend on China.

Figure 5.4. PV module prices (left), manufacturing capacity and net annual additions (right), 2010-22



Sources: SPV Market Research (2017a), "Photovoltaic manufacturer capacity, shipments, price and revenues 2016/17"; SPV Market Research (2017b), *The Solar Flare – Issue 1*.

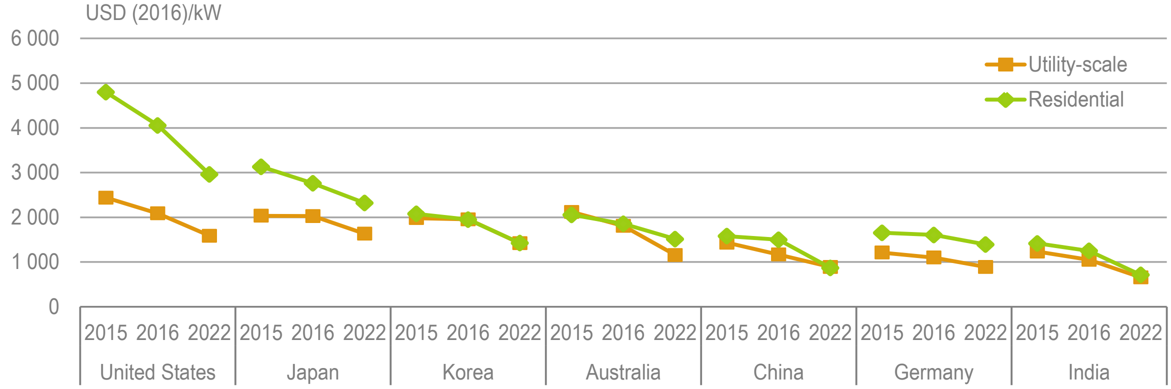
China's domestic demand for new capacity has become almost as important for a sustainable solar PV market as its role in global manufacturing. In 2012, China represented about 45% of global solar PV manufacturing, while the country accounted for only 11% of global annual installations. Since 2013, China's increasing domestic demand has partly absorbed excess manufacturing capacity. At the end of 2017, China not only consolidated its role in solar PV manufacturing, representing almost half of global production capacity (over 60% including Chinese companies' manufacturing capacity outside of China), but also significantly increased its share of global installations to over 50% with its demand expected to reach over 40 GW. While China is anticipated to see its demand for solar PV increase in 2017, deployment over 2018-22 is clouded by several challenges causing forecast uncertainty: renewable policy transition from FITs to a quota system with green certificates, timely subsidy payments and grid integration. Accordingly, the solar PV demand and supply balance, and module prices over the forecast period remain difficult to predict. The *Renewables 2017* main case expects solar PV expansion in China to slow after 2018, reflecting these forecast uncertainties, which may cause a module supply glut globally unless demand in markets outside China picks up rapidly. The accelerated case forecast anticipates growing annual additions reaching over 100 GW by 2022, which can lead to a more sustainable solar PV demand and supply balance (Figure 5.4).

Renewables 2017 expects average module prices to decline by a further one-quarter under the main case forecast (Figure 5.4). Meanwhile module efficiencies continue to increase over the next five-year period. In 2016, commercial mono- and polycrystalline modules together represented around 95% of global shipments, with their efficiencies increasing from around 12-14% in 2006 to 16-18% in 2016 and high-efficiency N-type modules reaching an average efficiency of over 21% (SPV Market Research, 2017b). In 2022, typical prices for high-efficiency modules could range between USD 0.30-0.77/W, with both lower and higher prices possible outside this range depending on local and global factors, including demand-supply balance, competition and trade measures.

Recent pricing trends signal further market consolidation in the solar PV manufacturing and assembly industries. Over the last year, the margins of most manufacturers have declined, mainly because of aggressive pricing strategies and a global supply glut in 2015. Some Chinese manufacturers (JA Solar, Jinko Solar, Canadian Solar and Trina Solar) recorded significant declines in profits during Q3 and Q4 2016. The majority of the top-ten module manufacturers, which represent around 40% of the global market, accumulated significant debt and remain under financial stress. In May 2017, the German manufacturer SolarWorld, with 1.3 GW of production capacity (1 GW in Europe, 0.3 GW in the United States), and US manufacturer Suniva (0.3 GW capacity) both filed for bankruptcy, raising concerns over the sustainability of current low profit margins. This situation is not unprecedented. Over 2010-12, the industry went through consolidation and major bankruptcies due to a supply glut and aggressive pricing. Under the main case, further market consolidation in both the module assembly and panel manufacturing sectors is likely over the forecast period, although it is difficult to estimate its size and impact on supply, demand and prices.

Module price reductions have contributed to the decline in overall solar PV system costs, although modules usually account for 20-50% of total investment. In 2016, the global weighted average investment cost of fully commissioned utility-scale projects declined by around 12% and ranged from USD 1 050 per kilowatt (kW) to USD 2 320/kW (IRENA, 2017). Within this wide range, the lowest investment costs are seen in China, India and Germany, where the balance of system (BoS) costs are lowest globally and modules represent around 40-55% of total investment (Figure 5.5). Germany has one of the lowest BoS and installation costs due to the high density of projects. This compensates for relatively higher module costs because of the EU trade measures against Chinese modules. Costs associated with modules and labour are lowest in China and India, where utility-scale projects are larger compared to many other countries. In Korea and Japan, developers mostly prefer locally manufactured high-efficiency modules, which are more expensive but also generous incentive schemes and costly land and grid connection challenges have led to higher BoS and installation costs.

Figure 5.5. Average solar PV system prices for commissioned projects, 2015-22



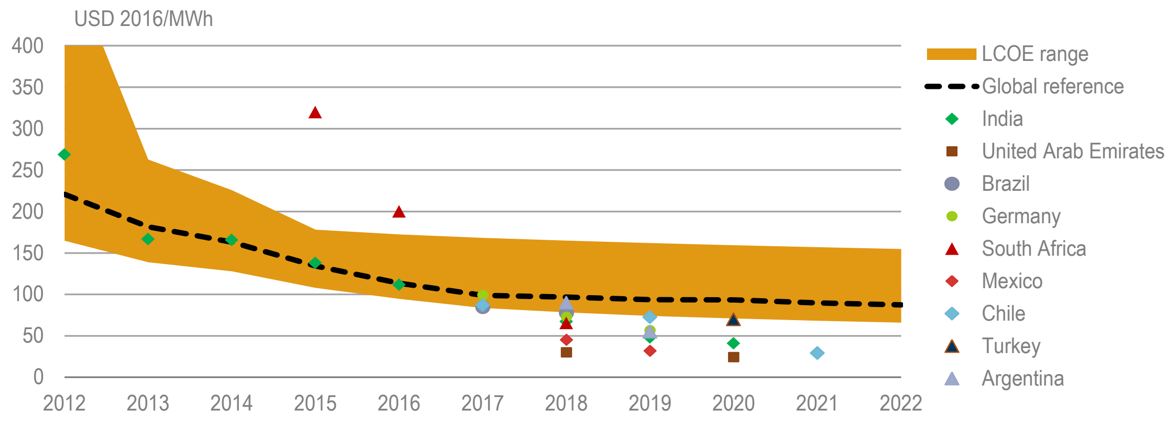
Source: Analysis based on IRENA (2017), *Costing Alliance,* dataset provided to the IEA.

In 2016, the United States recorded one of the highest average investment costs for utility-scale projects globally for various reasons. First, the investment cost presented in this report takes into account only commissioned projects. In the United States, the time between final investment decision and the actual commissioning date may vary significantly (from 1.5 to 4 years) depending on the size of the project. Second, the majority of US utility-scale projects commissioned in 2015 and 2016 had tracking systems, which can increase overall system costs by 10-15% (LBNL, 2016). Over the forecast period, global average investment costs for utility-scale projects are expected to decline by around 25% due to a combination of module price reductions and continuous competitive pricing, as auctions are expected to dominate utility-scale solar PV expansion over the forecast period, especially outside China.

For residential systems, average investment costs are usually higher than utility-scale projects. In 2016, they declined by 5-16% year-on-year and ranged from USD 1 200/kW in India to over USD 4 000/kW in the United States (Figure 5.5). This large range between countries is mainly due to differences in business models, the regulatory environment and the nature of financial incentives provided. In residential systems, the share of BoS and installation costs in overall investment costs is much higher compared to utility-scale projects. Installation costs are highly country- or even state/province-specific. Large differences among countries/states also represent an opportunity to minimise these costs where possible. *Renewables 2017* expects that the total investment cost of residential systems could decline by between 15% and 30% over 2017-22, with BoS and installation costs representing the largest cost reduction potential. Commercial rooftop prices are generally between residential and utility-scale applications, although they can be closer to utility-scale projects if the project size is relatively large, especially in India and China.

Globally, LCOEs without subsidies for typical utility-scale projects fully commissioned in 2016 are estimated to range from USD 95/MWh to USD 172/MWh (Figure 5.6). Weighted average generation costs for projects commissioned in 2016 are estimated at around USD 110/MWh, corresponding to a reduction of more than half versus 2012. With continued BoS and installation cost reductions, low module prices and further capacity expansion into markets with better resources, LCOEs for typical utility-scale projects are anticipated to range from USD 66/MWh to almost USD 155/MWh, with the global reference for weighted average deployment being USD 87/MWh.

Figure 5.6. Historical and forecast LCOE range for typical utility-scale solar PV plants versus recent auction results

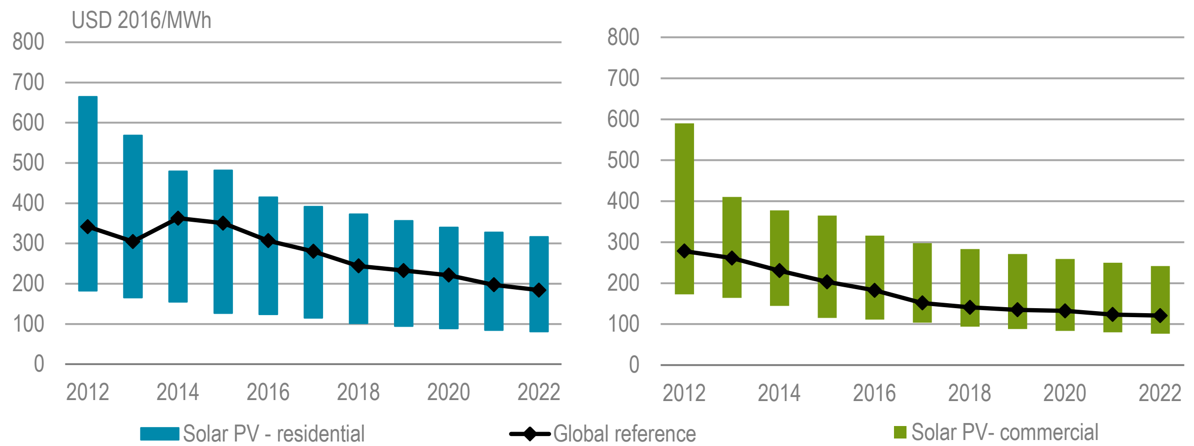


Notes: Global reference is the estimated global weighted average based on *Renewables 2017* generation forecast. Tendered prices are nominal values based on auction announcements and correspond to dates when commissioning of auctioned capacity is expected.

Recent PPA announcements indicate much lower generation costs, ranging from as low as USD 29/MWh to USD 85/MWh, for projects to be commissioned over the forecast period. Over 2016-17, prices for winning bids in countries where multiple auctions were awarded were between 20% and 50% lower than in 2014. In India, since January 2016, auction prices have declined on average by a third and reached USD 45/MWh in July 2017. In Mexico, average winning bids for solar projects declined by 30% from USD 45/MWh in the first auction to USD 35/MWh in the second, both held in 2016. In Denmark, on the occasion of the first international Danish-German auctions, the winning project signed for a FIT of EUR 54/MWh (USD 60/MWh) over 20 years for a 50 MW plant. In Argentina, the average price difference between RenovAR 1 and 1.5 auctions, both held in the second half of 2016, was 8%, decreasing from USD 60/MWh to USD 55/MWh. In September 2016, the global record low bid of USD 24/MWh (USD 29/MWh with adjustments) was accepted in United Arab Emirates for the Sheikh Maktoum Solar Park Phase 3 project. These contract prices indicate that new utility-scale solar PV plants could become cheaper than new fossil fuel alternatives in some countries, especially where imported fossil fuel prices are relatively high.

Overall, it is difficult to compare these auction results with average LCOEs due to limited information available on developers' cost reduction expectations, the cost of financing and the level of aggressive bidding as a company strategy to gain market share. In addition, subsidies related to land acquisition, grid connection and financing might be already included in these bid prices. Moreover, it is important to note that these announced auction results may indicate the base price, which could increase over the lifetime of the project depending on various contract design features. Still, this price trend indicates increasing competition and investor confidence, and signals further acceleration in the reduction of generation costs over the forecast period.

Figure 5.7. Historical and forecast LCOEs for commercial and residential solar PV applications, 2012-22

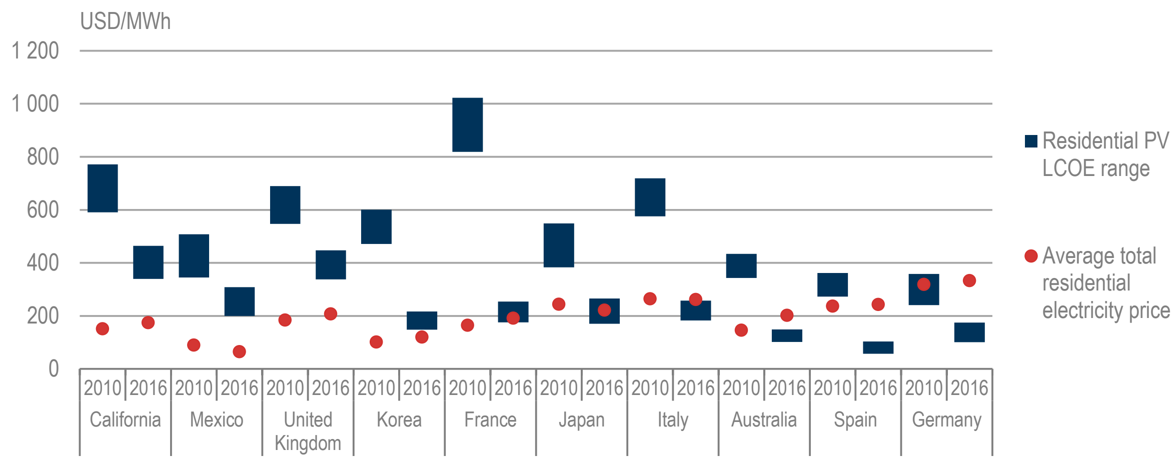


Note: Analysis based on IRENA (2017), *Costing Alliance,* dataset provided to the IEA.

For distributed generation, LCOEs are expected to continue to improve for both commercial and residential segments over 2017-22. In 2016, LCOEs for commercial applications ranged from around USD 110/MWh to USD 315/MWh, with a global average reference at over USD 180/MWh (Figure 5.7). This wide LCOE range represents differences in investment costs and project sizes, but also the cost of financing. With relatively low financing and investment costs, the generation cost of commercial projects in Australia, Germany and Italy are below the global reference. LCOEs remain higher in United States and Japan, where investment costs remain high due to relatively high incentive levels. Over the forecast period, average LCOEs are expected to decline by over 30% globally and estimated at USD 120/MWh in 2022. It is important to note that this global average could decline further if deployment in the commercial sector picks up faster than expected in China and India, where costs are currently lower than global averages, but regulatory, financing and administrative barriers remain. For residential applications, the global average reference for newly installed projects declined from USD 362/MWh in 2014 to USD 310/MWh in 2016, with sensible cost decreases in Europe, Japan and Australia (Figure 5.7). The global average reference is expected to move to USD 184/MWh in 2022, with much lower values expected in Australia, China, India, Germany and Italy, where both investment and financing costs are relatively low.

The generation costs for residential solar PV applications are already in line with, or even lower than, the average variable part of the retail price of electricity for residential customers in countries such as Australia, Belgium, Germany, Italy, France, Japan and Spain (Figure 5.8). This "socket parity" situation is a necessary, but not always sufficient, condition for the uptake of distributed PV in a country. When evaluating the profitability of an investment in a PV system, the share of self-consumption remains an important factor, unless homeowners can benefit from net energy metering. However, the share of self-consumed electricity in residential applications is often low, especially in temperate countries due to typically low residential electricity consumption in solar peak hours (12:00-15:00), unless electricity is stored (e.g. in batteries) or more demand is shifted to sunny hours (e.g. with air-conditioning systems including some thermal storage). In addition to self-consumption, the remuneration scheme for surplus electricity injected into the grid is an important factor in assessing whether a project is profitable.

Figure 5.8. LCOE of residential PV vs. average residential electricity price in selected states countries, 2010-16



Note: Average residential price includes fixed components as it is difficult to estimate average fixed charges due to different tariff structures based on location and contract type; however, fixed charges usually represent 5-10% of total residential electricity bills in many countries.

Source: IEA analysis based on investment cost data IRENA (2017), *Costing Alliance,* dataset provided to the IEA.

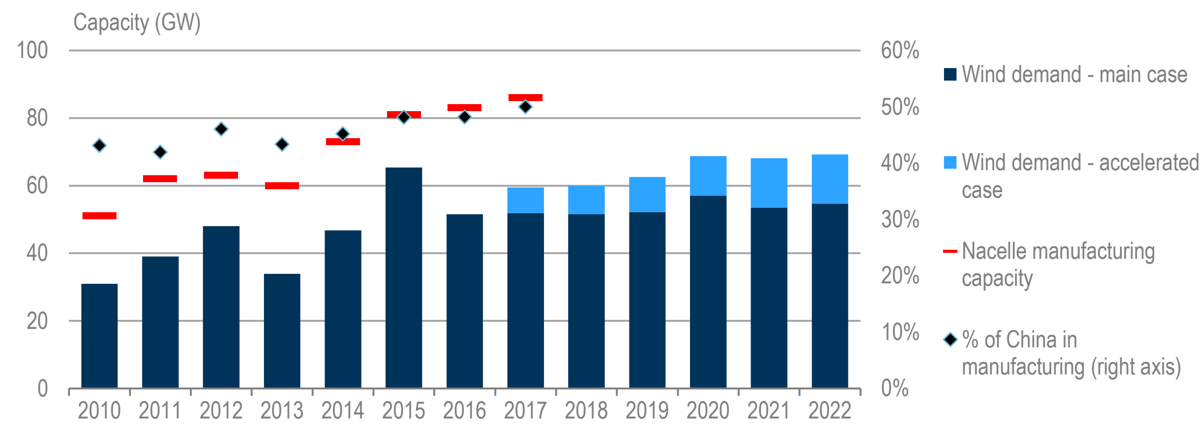
In regions where PV self-consumption is eroding the profits of utilities and distribution system operators, utilities often advocate an increase in the fixed elements of electricity bills (per household and/or per kW), and a decrease in their variable elements (per kilowatt hour [kWh]). This would reduce the profitability of residential PV investments, not only for new installations but also for those already installed. Policies targeting residential PV systems should therefore consider measures to increase the share of self-consumption, incentivising demand shaping (e.g. stimulating thermal storage, which may cost-effectively move demand to periods of higher insolation).

Onshore wind

Over 2016-17, the wind industry saw further consolidation with the completion of several major mergers and acquisitions of turbine and blade manufacturers. In April 2017, Siemens' wind division merged with Gamesa to form one of the largest global turbine manufacturers. In April 2016, competition authorities approved the merger of two relatively smaller manufacturers, Acciona and Nordex. In February 2017, the same merged entity also acquired Danish rotor blade producer, SSP Technology. Having acquired Alstom's energy division in 2015, General Electric completed another merger with the Danish LM Wind Power, the largest rotor blade manufacturer globally. Overall, the majority of these large acquisitions took place among European and American manufacturers.

Currently, wind manufacturing capacity stands well above global demand. China accounts for almost half of global turbine manufacturing capacity, which stood at over 80 GW in 2016 (Figure 5.9). The significant majority of turbines manufactured in China are installed locally. The utilisation rate of China's turbine manufacturing capacity remained at below 50% in 2016, as domestic demand declined by a third compared to 2015. In contrast to the solar PV industry, China is not a major exporter of wind turbines and the country's exports remained limited at around 1 GW in 2016, less than 3% of its total manufacturing capacity. Overall, the supply glut continues in China's turbine market and consolidation is still expected over the forecast period. In addition, Chinese companies are also anticipated to look for further export opportunities in new markets to bridge the local supply-demand gap.

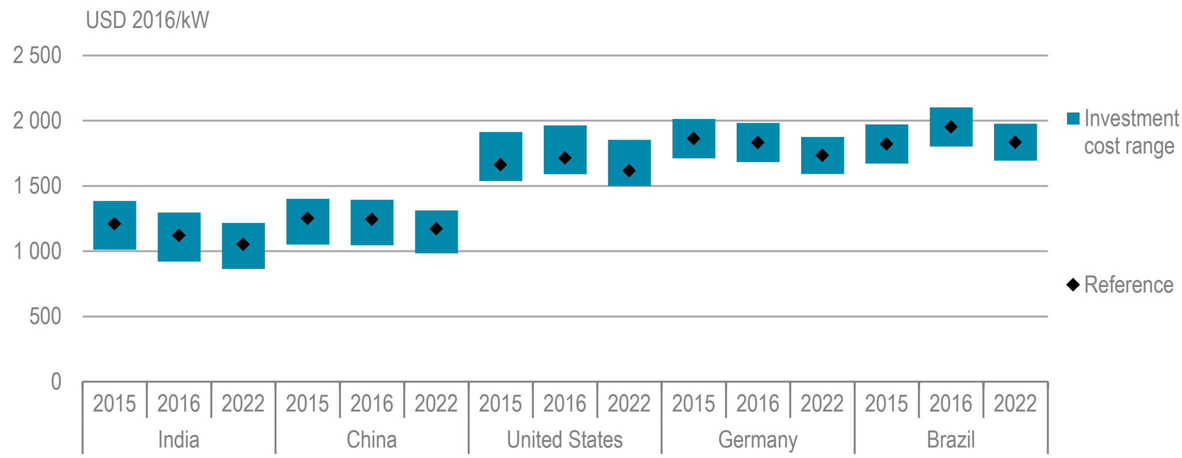
Figure 5.9. Onshore wind annual demand and nacelle manufacturing capacity



Source: Nacelle manufacturing data compiled from BNEF (2017), *Wind Manufacturing Plants Database*.

In 2016, average onshore wind investment costs, including transmission costs, varied by country/region depending on the type of turbine used, local demand-supply dynamics, and recent exchange rate developments. Average investment costs for typical onshore wind projects ranged from USD 1 050/kW to just over USD 2 000/kW (Figure 5.10). India and China represent the lower end of this range, with local manufacturers quoting competitive turbine prices. In China, turbine prices remained stable in 2016, as more turbines with larger rotor diameters were commissioned, offsetting the price reduction impact of lower demand. In the United States and Germany average investment costs were more or less stable, ranging from USD 1 650/kW to USD 1 800/kW. In Brazil, investment costs increased by about 9.5% in 2016 compared to 2015, partly due to significant depreciation of the Brazilian real and local turbine supply dynamics. Over the forecast period, average investment costs are expected to decline by 7%, driven by further learning and increased competition amongst manufacturers to supply large-scale projects awarded in competitive auctions.

Figure 5.10. Onshore wind investment costs in selected countries, 2015-22

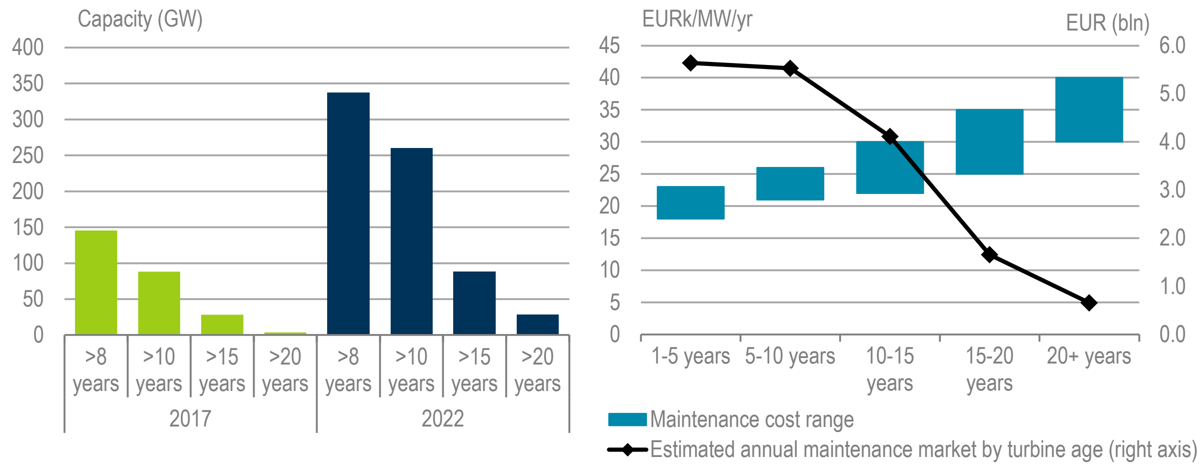


Source: Analysis based on IRENA (2017), *Costing Alliance,* dataset provided to the IEA.

Maintenance business activity is expected to grow over the forecast period, with an increasing number of ageing turbines and new capacity coming on line. In 2017, almost 90 GW of onshore wind capacity has been operational for more than 10 years, with only 4 GW operational for 20 years or more (Figure 5.11). By 2022, *Renewables 2017* expects onshore wind capacity older than 10 years to have tripled to 260 GW, or close to 250 000 turbines, while close to 30 000 turbines (28 GW) will be more than 20 years old. This trend indicates a growing maintenance market over the forecast period. In general, maintenance costs increase as the turbine gets older (Figure 5.12). Turbine sales usually include 4-7-year initial service agreements. The cost of this initial service usually ranges from EUR 18k to EUR 23k per megawatt (MW) per year (USD 20k-25k/MW/year) and could double to EUR 30k-40k/MW/year when turbines reach older than 20 years. This report's top-down calculation estimates that the annual turbine maintenance market was worth around EUR 10 billion (USD 11 billion) in 2016. By 2022, the annual market is estimated to reach almost EUR 18 billion (USD 19 billion), representing almost a quarter of annual investment in new onshore wind capacity.

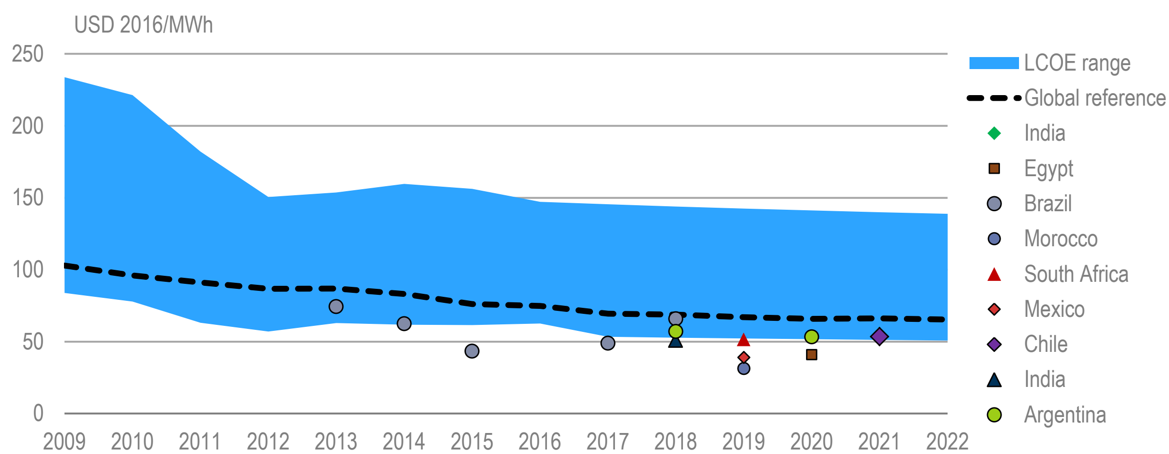
Maintenance services are usually provided by turbine manufacturers, but some developers and pure-play service companies also offer them. In order to capture a higher share of this market, some turbine manufacturers have acquired pure-play turbine servicing companies. For instance, Vestas Wind Systems has acquired two turbine-servicing companies over the last two years (UpWind Solutions based in the United States and Availon based in Germany). Overall, the maintenance market is expected to become a key long-term revenue stream for manufacturers during the forecast period.

Figure 5.11. Onshore wind capacity by age, 2017 and 2022 (left), and maintenance cost ranges and annual maintenance market in 2022 by turbine age (right)



Typically, LCOEs without subsidies for onshore wind projects ranged from USD 62/MWh to over USD 147/MWh in 2016, with the global weighted average estimated at USD 75/MW. Over the forecast period, average LCOEs are expected to decline by another 13%, reaching around USD 65/MWh in 2022 (Figure 5.12). This trend is mainly driven by China, the largest growth market for onshore wind, where LCOEs are expected to be in the range USD 45-76/MWh in 2022 depending on the plant's location. In the United States, onshore wind generation costs are relatively low due to competitive financing and high capacity factors (35-45%) in the interior region, where the majority of onshore wind capacity is expected to be commissioned over 2017-22. In the European Union, generation costs are anticipated to decline further with increasing competition resulting from the introduction of auction schemes in major wind markets.

Figure 5.12. Onshore wind LCOEs for typical systems and recent auctions results, 2009-22



Note: Global reference is the estimated global weighted average based on *Renewables 2017* generation forecast. Tendered prices are nominal values based on auction announcements and correspond to dates when commissioning of auctioned capacity is expected.

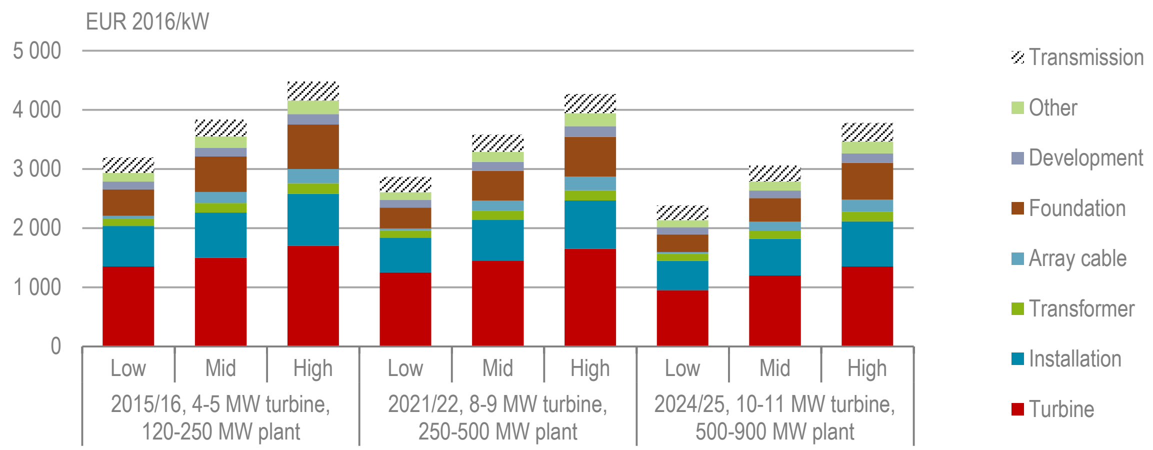
Recent auction results in emerging countries with great resource availability indicate long-term contract prices lower than the LCOE ranges presented above. In 2016/17, winning bids in Morocco, Egypt and Mexico for onshore wind projects to be commissioned over 2018-20 were below USD 50/MWh, with the lowest price at around USD 30/MWh. In these markets, wind generation costs are lower than new coal generation. In India, the average price in its first reverse wind auction held in March 2017 was just below USD 50/MWh, on a par with coal generation tariffs in some states. In Mexico, weighted average contract prices declined from USD 55/MWh to below USD 36/MWh between two auctions. It remains difficult to replicate these results on a hypothetical basis, with limited information available publicly concerning PPA structure, the cost of financing, developers' bidding strategies to increase market share and other types of cost such as land and grid connection, which may not be included in these announced prices. While these contracts can indicate an acceleration in the reduction of onshore wind generation costs, it is important to note that grid connection and integration of these projects are expected to remain challenging, especially in India, Morocco and some states in Mexico.

Offshore wind

The installation of larger turbines and record-low, long-term contract prices have been characteristic trends for the offshore wind industry over the last year. While Europe will remain the largest offshore wind market and technology leader for manufacturing capacity, demand in China is expected to pick up over the coming five years.

Total investment costs for offshore wind projects vary significantly depending on the project size, its water depth, its distance to shore and onshore grid connection point. Over the last decade, the average wind farm size in Europe increased by more than eightfold from around 50 MW in 2006 to 400 MW in 2016 (WindEurope, 2017). The average water depth of European offshore wind farms in 2016 was over 29 metres and the average distance to shore was about 43.5 kilometres (km) (WindEurope, 2017). China remains the second-largest offshore wind market after Europe, but the industry remains relatively nascent with smaller project sizes (50-100 MW) which are relatively closer to the shore.

Figure 5.13. Offshore wind investment costs for fully commissioned projects, 2015-25



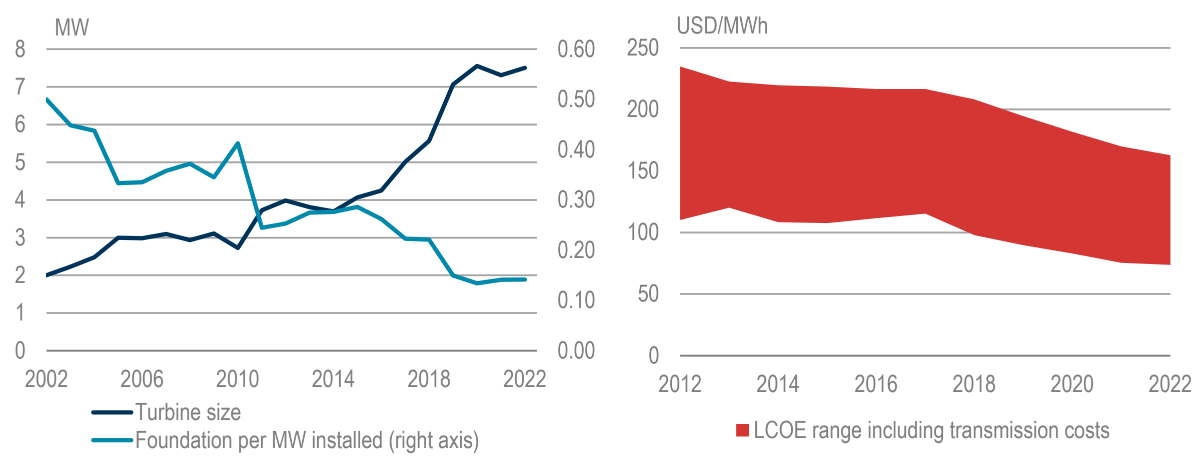
Notes: With regard to investment cost estimates in 2024/25, offshore developers expect to be installing 12-15 MW turbines by then, which may result in lower investment costs than are presented above; however, the development of these turbines had not been announced at the time of writing.

Total investment costs for typical offshore wind projects that became fully operational in 2016 are estimated at EUR 3 300-4 500/kW including both onshore and offshore transmission costs (Figure 5.13). However, some near-shore and intertidal projects commissioned over the last year in China may have lower costs compared to this range. Turbine supply usually accounts for about 33-40% of total project costs, followed by total installation costs (20-25%) and foundation supply (15-18%). Transmission expenditure outside the plant's boundary, which usually includes offshore and onshore transformers, export cable(s) and onshore connection, are estimated to represent 10-20% of total investment costs.

Over the forecast period to 2022, investment costs are expected to decrease by 15-20%, with larger cost reductions anticipated to 2025. Two main factors will drive them. First, capacity-weighted average turbine sizes for new projects globally are expected to increase from about 4 MW in 2016 to almost 8 MW in 2022 (Figure 5.14). Accordingly, the installation of larger turbines means that fewer foundations per MW will be installed, bringing installation costs down. In 2002, developers installed 0.5 foundations per MW commissioned, while this number decreased to 0.3 in 2016. The installation of larger turbines is expected to bring the average foundations per MW installed down to 0.15 in 2022 (Figure 5.14). Second, larger projects will bring further economies of scale, standardisation and clustering, which will support the cost reduction trend further.

Investment costs represent only a proportion of the generation costs of offshore wind projects. Improvements in capacity factors and reductions in operation and maintenance (O&M) and financing costs are all expected to result in lower generation costs. The average capacity factor for new projects in the North Sea is expected to reach over 50% as new turbines with larger rotor diameters are anticipated to give higher yields. O&M costs represent about a quarter of generation costs for a typical offshore wind project. With fewer turbines and foundations per plant, O&M costs are expected to decline for projects that will be commissioned over 2017-22. In addition, offshore wind plants that are located close to one another are considering signing joint O&M contracts to achieve further cost reductions.

Figure 5.14. Offshore wind turbine size, foundation per MW (left) and LCOE range (right)

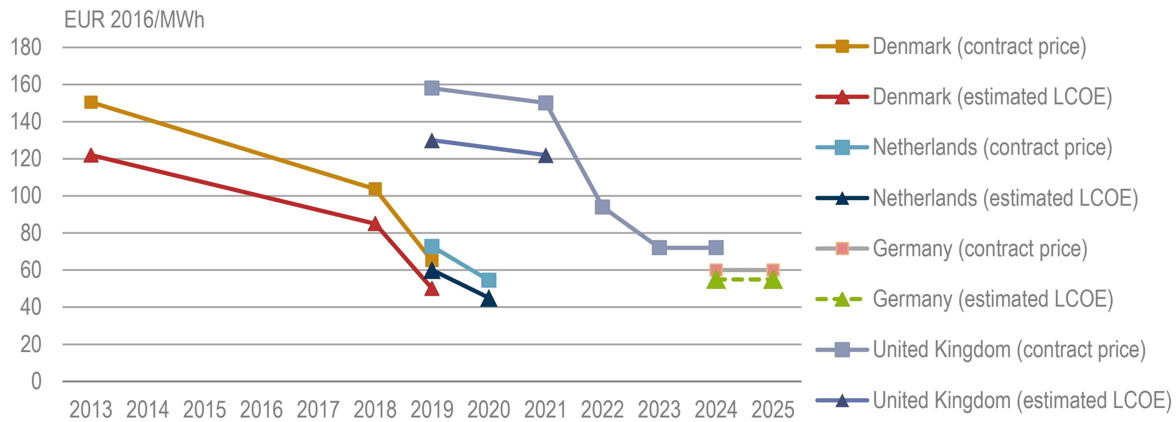


Notes: LCOE values are real in USD 2016. The IEA global offshore wind project database tracks commissioned, permitted and announced projects; assumptions used for turbine types and sizes of some projects in China, Japan and Korea, which were not announced at the time of writing.

In 2016, estimated LCOEs for typical offshore wind plants were USD 110-215/MWh, the lower end of the range representing nearshore plants in China (Figure 5.14). Over the forecast period, generation costs, including all transmission infrastructure, are expected to decrease on average by a third and are estimated to be USD 75-163/MWh. The LCOEs in relatively nascent markets such as France, the United States and Korea are expected to remain on the high side of this range, while projects in Germany, Denmark and the Netherlands should be on the lower side.

Recent offshore wind tender results in the Netherlands, Denmark, Germany and the United Kingdom for projects to be commissioned over 2019-25 indicate lower generation costs, driven by increasing competition, technology improvements and lower financing costs. Generation costs for winning bids in recent tenders in Denmark and the Netherlands are actually lower than the announced auction prices, as contract lengths are shorter than the economic lifetime of the projects (Figure 5.15). In Denmark, offshore wind contract prices have declined by more than half since the commissioning of the Anholt offshore farm in 2013. Recently tendered projects have fixed-price PPAs for only 11-13 years, while they will receive the wholesale price for the rest of their economic lifetime. In the Netherlands, Borssele 1 and 2 (700 MW) and 3 and 4 (700 MW) tenders, which are expected to be commissioned in 2020/21, resulted in record low contract prices (excluding transmission costs) with tariffs set at EUR 73/MWh (USD 81/MWh) and EUR 55/MWh (USD 61/MWh), respectively, for only 15 years. Actual generation costs for these two projects over their economic lifetime (25 years) are lower than these contract prices and are estimated in the range of EUR 45-60/MWh (USD 50-66/MWh), which is lower than onshore wind LCOEs in some European countries. In September 2017, developers in the United Kingdom's second CfD auction were awarded contracts in the range of EUR 72-94/MWh, including all transmission costs.

Figure 5.15. Offshore wind auction results and LCOEs by expected commissioning date



Notes: UK projects include all transmission costs, which usually account for about 10-15% of total generation costs; in other countries, national transmission system operators are responsible for building the offshore and onshore transmission infrastructure; LCOE estimates for bids in Germany are based on the Gode Wind project bid price as other projects will receive wholesale electricity price.

In April 2017, Germany awarded four offshore wind projects via 20-year contracts with a total capacity of 1.5 GW to be commissioned over 2024-25. Although the commissioning date of these projects is outside the *Renewables 2017* forecast period, the auction results point to a remarkable industry development. Three projects (1.4 GW in total) bid at zero, meaning that they will only receive wholesale market prices as remuneration. A relatively small project (Gode Wind 3, 120 MW) won the auction with a EUR 60/MWh (USD 66/MWh) strike price. The Gode Wind 3 developers expect wholesale electricity prices to increase from about EUR 30/MWh (USD 34/MWh) today to around EUR 55/MWh (USD 61/MWh) on average over the lifetime of the project. In addition, they expect to install turbines with 13-15 MW rated capacity. These contract prices require investment costs (excluding transmission infrastructure) to fall below EUR 1 800/kW (USD 2 000/kW), lower than that of many European onshore wind projects today. In addition, it is likely that developers assumed a capacity factor of 55%, with annual O&M costs per kW below 2.5% (which is usually 3.5-4%) of total investment costs and weighted average costs of capital below 6%. For these zero-bid projects, uncertainty remains whether cheap financing will be available, as their revenue stream will be based solely on wholesale power prices, which are extremely difficult to predict as their formation depends on many factors including the decommissioning of nuclear plants in Germany and France.

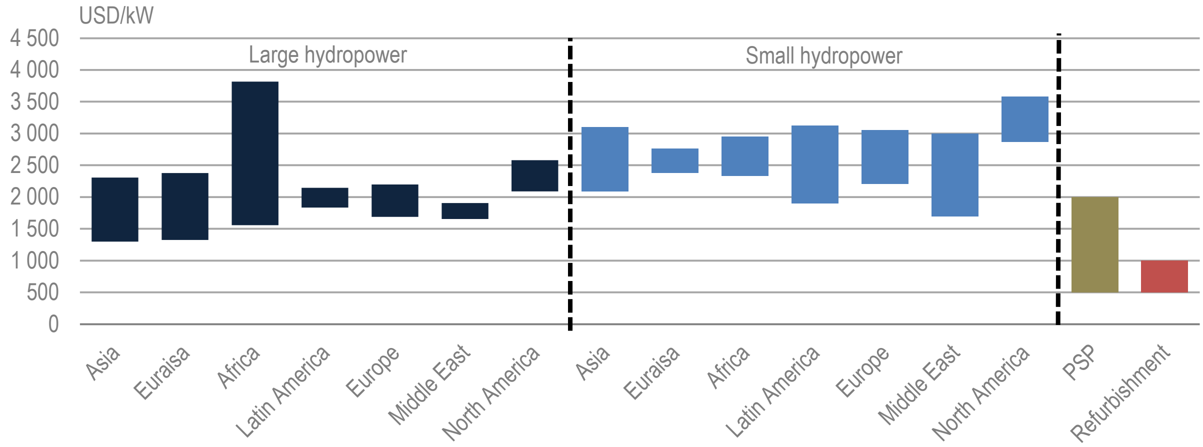
Hydropower

Hydropower investment costs span a wide range since they are extremely site-specific, with equipment and civil works together accounting for around 75-90% of total expenditure (IRENA, 2017). The remaining costs are also project-specific and include expenses that are local in nature such as feasibility and socio-environmental assessments, grid connections, licensing and permitting.

In 2016, investment costs for new-build conventional large hydropower projects typically ranged from USD 1 300/kW in Asia to USD 2 500/kW in North America, although costs for some commissioned projects in Africa reached almost USD 4 000/kW. For small hydropower, the cost range was slightly higher, from around USD 2 000/kW in Asia and Latin America to USD 3 500/kW in North America. In general, year-on-year costs have been relatively stable, with only limited declines observed from technological innovation given that hydropower is a mature technology. Recently, however, costs in certain markets have started to increase. Since 2013, investment costs for large hydropower in China have started to rise, in part due to gradually increasing costs for labour and materials (BNEF, 2015). In addition, increases in resettlement expenses, taxes paid to local government and the construction of transmission lines for projects located far from demand centres also contributed to rising costs. In markets with ageing fleets and limited potential for new-build hydropower, refurbishment projects may become increasingly economically attractive over the next five years due to the improvement in performance relative to the low investment required (USD 500/kW to USD 1 000/kW).

The latest developments in hydropower technology focus on maximising efficiency and adapting technology to improve system flexibility, especially in PSPs, currently the most cost-effective form of large-scale storage. PSP investment costs span a wide range (USD 500-USD 2 000/kW) due to the specific nature of each site (IEA and MME, 2012). The cost of variable-speed turbines, which can be up to USD 3 200/kW in the United States (US DOE, 2017), tend to be higher than for fixed-speed. Recent announcements point to an increasing trend towards converting inactive mines into PSPs in order to take advantage of existing infrastructure to lower reservoir construction costs and facilitate permitting. The 1.3 GW Eagle Mountain PSP project in the United States was the largest PSP in several decades to receive licensing in 2014, in part due to the low environmental impact that the closed-loop design was able to achieve by using two vacant mines as reservoirs (CEC, 2016). Several other projects planning to transform former mines into PSPs are being explored in Germany and the United Kingdom.

Figure 5.16. Hydropower investment costs, 2016



Source: Analysis based on IRENA (2017), *Costing Alliance*, dataset provided to the IEA; IEA (2017), *World Investment Report*; IEA and MME (2012), *Technology Roadmap: Hydropower*; HEA (2016), *Global Technology Roadmap*.

However, regulatory barriers and market designs that inadequately value system flexibility continue to challenge the economics of PSPs. The original business case for PSP was developed from the economics achieved with energy arbitrage in systems where coal and nuclear were the main sources of baseload power. These plants were costly to ramp down in the evening when demand was low. PSPs were built to keep these plants running by consuming low-cost electricity for pumping and then able to make a profit by selling output when demand, and consequently prices, were higher. However, the impact of increasing variable renewables on wholesale electricity prices, coupled with weaker overall power demand and overcapacity in some countries, has decreased the differential between peak and off-peak prices and challenged new investment in the absence of sufficient remuneration options for other grid ancillary services that PSPs can provide.

PSP capacity and generation forecast

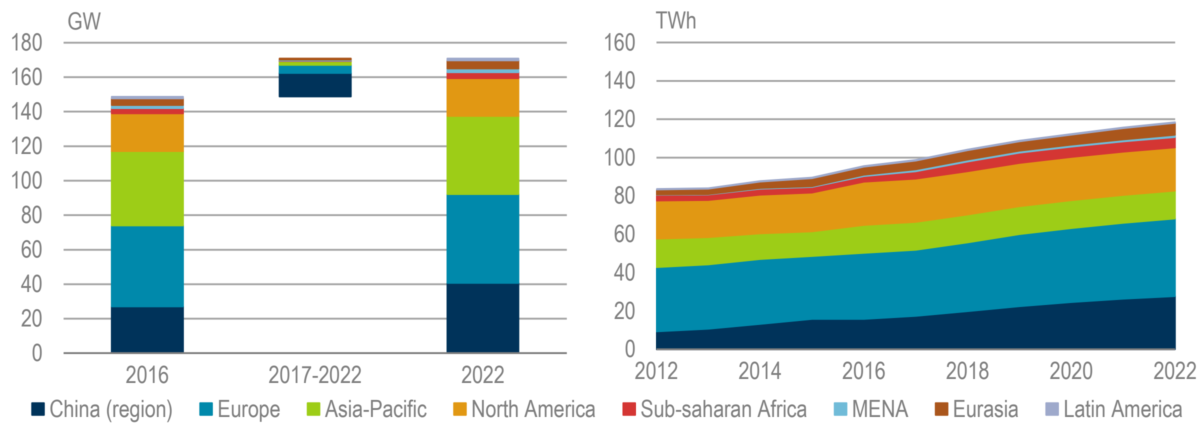
The cumulative installed capacity of hydropower PSP reached 149 GW in 2016, representing over 95% of global storage capacity[1] (and approximately 12% of total hydropower capacity). PSPs are concentrated mostly in Asia, Europe, and North America, with over 75% of the fleet accounted for in just ten countries (Japan, China, the United States, Italy, Germany, Spain, India, Korea, Austria and France). Annual PSP additions continued to grow, with new capacity of 5.8 GW in 2016, over twice the growth than in 2015, led by China (3.7 GW) and followed by South Africa, Austria, Ukraine, Portugal and the Russian Federation.

Over 2017-22, total PSP capacity is expected to increase by 17% (25 GW), reaching 174 GW, driven by deployment in China, Europe and Asia, with annual additions fluctuating around 5 GW and anticipated to slow after 2020. This slowdown is due to uncertainty over the pace of PSP development in China and a weaker European pipeline from challenging economics. China leads global PSP capacity growth (15 GW), driven by 2020 capacity targets under the 13th five-year plan (FYP) and the need for improved power system flexibility. *Renewables 2017* expects China to reach its 2020 PSP target of 40 GW cumulative installed capacity, as grid companies are seeking to improve

[1] The overall storage estimate refers to large scale storage only, which is comprised of mostly pumped hydro storage, batteries, flywheels, and compressed air energy storage; it does not include behind-the-meter storage.

their overall system performance by reducing curtailment of PV and wind. However post-2020, the pace of deployment is expected to slow, due to a weaker project development pipeline and uncertainty over policymakers' plans for PSP in the longer term.

Figure 5.17. Global PSP capacity (left) and generation forecast (right)



Note: MENA = Middle East and North Africa.

Sources: PSP capacity is from an IEA unit level project database compiled from Platts (2017), *World Electric Power Plants Database*; US DOE (2017), *Global Energy Storage Database*; Geth (2015), "An overview of large-scale stationary electricity storage plants in Europe: Current status and new developments", *Renewable and Sustainable Energy Reviews*, Vol. 52, pp. 1212-1227; Buss et al. (2016), "Global distribution of grid-connected electrical energy storage systems", *International Journal of Sustainable Energy Planning and Management*, Vol. 9, pp. 31-56.

Europe's PSP capacity is expected to grow by 10% (5 GW) over 2017-22 from the completion of new or extension projects in Switzerland, Portugal, Austria, France and the United Kingdom. However, fewer projects are expected to be commissioned by the end of the forecast period as PSP's economic attractiveness in Europe may be challenged by expectations of overall weaker demand growth for the region, a continuation of current low electricity prices and insufficient remuneration mechanisms for ancillary services. Meanwhile, deployment is anticipated to grow in Asia Pacific, with a combined 2.5 GW of new capacity expected from India, Indonesia and Thailand by 2022.

Global PSP capacity holds the potential to generate 120 TWh by 2022, a 24% increase from 2016 levels. However, this generation forecast depends strongly on the future capacity factors of both existing and new plants, which remain highly uncertain as they are influenced by many factors such as wholesale electricity price spreads, market framework and the potential for trade via interconnectors. Average PSP fleet capacity factors over the last five years have ranged from as low as 2-3% in Italy and Japan, where PSP generation has declined in recent years, to as high as 10-13% in France, Germany and the United States, with higher utilisation factors observed in some years in other markets.

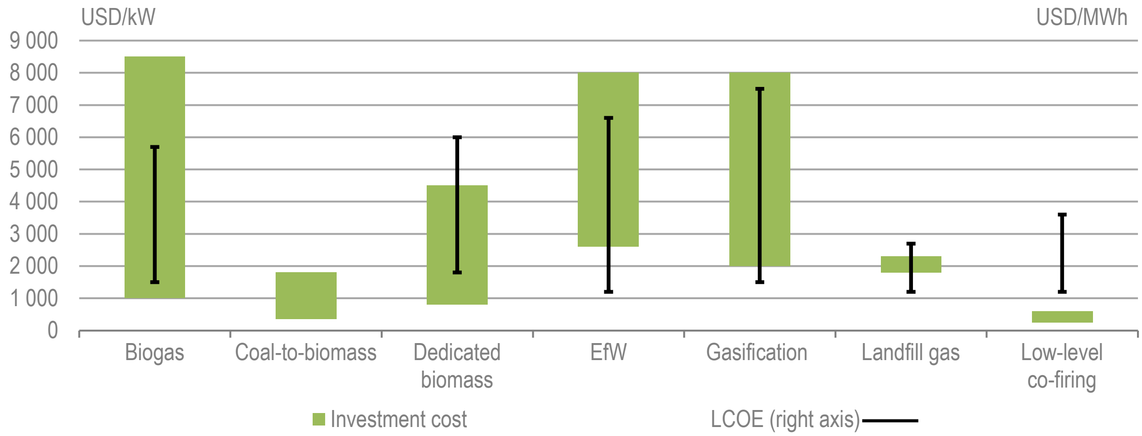
In China, capacity factors, which currently average around 6% for the fleet, will largely depend on the location of future PSP build-out relative to demand and renewable integration needs. Unlike other markets, China's PSPs tend to be closed-loop systems, not connected to a natural inflow, which allow them to be located closer to demand centres. The extent to which higher utilisation rates can be achieved is likely to depend on whether they are also sufficiently connected to areas with high curtailment levels.

Looking ahead, PSP capacity factors in Europe are highly unpredictable given the uncertainty surrounding future wholesale electricity prices, particularly due to the dynamics of a weaker regional demand outlook, the merit-order effect of greater renewable generation and the retirement of ageing conventional plants. These factors will continue to influence the business plans of PSPs. In addition, the changing fleet profile also affects the variability of the load profile and consequently, the grid services needed to increase system flexibility and maintain reliability. An increase in interconnector capacity in Europe could also affect PSP generation levels. Overall, the potential operating hours for PSPs will largely depend on the extent to which price signals that value and remunerate flexibility and grid services exist. For instance, 2.7 GW of existing PSPs won contracts in the United Kingdom's 2016 capacity market for 2020-21.

Bioenergy

The variation in different bioenergy technologies in the power sector results in a range of associated investment and generation costs. Even considering the same technology type, these costs vary globally (Figure 5.18) depending on capacity, level of technical sophistication, and locational factors such as the cost of capital and compliance with applicable regulatory regimes. Generally speaking, and especially at larger capacities, project costs are determined by the specifics of the plant and fuel or feedstock used. Larger capacity plants can offer economies of scale. As bioenergy technologies are considered mature, key areas for further cost reduction include access to more economic fuel supply and non-technical factors such as lower cost finance. It should also be noted that within *Renewables 2017*, bioenergy encompasses electricity generation from waste fuels.

Figure 5.18. Global investment cost and LCOE ranges for bioenergy technologies



Notes: Costs reflect electricity-only technologies; EfW = energy from waste; lower end of EfW cost range reflects gate fee income for receipt of waste; costs are indicative, and ranges reflect the system cost, fuel/feedstock and finance differences among countries; range boundaries may not be illustrative of the cost at which the majority of deployment occurs; furthermore, specific project investment or LCOE values can be above or below ranges provided; co-firing costs refer to use of biomass fuels in existing coal plants; no data available for coal-to-biomass conversion LCOE values.

Bioenergy auction results in 2016-17

Bioenergy electricity generation projects in industrial sectors that generate secondary biomass residues (e.g. paper, pulp and print, food and tobacco), and EfW projects where gate fees[2] are received and fuel costs are effectively negative, can often proceed without subsidy support. However, aside from these cases where very low-cost waste and residue resources are available, most bioenergy electricity deployment is driven by policy support mechanisms.

Table 5.1. 2016-17 bioenergy auction results

Country	Bioenergy technology	Awarded capacity (MW)	Price (USD/MWh)	Details
France	Multiple	70	135	2016 auction; co-generation and biogas.
Spain	Unspecified	200	N/A	2016 auction; 200 MW allocated to biomass; remuneration at market prices.
Spain	Unspecified	20	N/A	2017 technology-neutral auction.
Poland	Biogas	<7	140	First pilot auction.
Netherlands	Multiple	783	<120	Results from two 2016 auctions; mainly co-generation and gasification.
United Kingdom	Advanced conversion	64	100	Six projects. For delivery 2021-22.
United Kingdom	Biomass co-generation	86	106	Two projects. For delivery 2021-22.
Brazil	Multiple	200	60-70	Fuel types include bagasse, woodchips and one biogas plant. To come online in 2021.
Argentina	Biogas	1	118	For delivery in 2018.
Peru	Biogas	4	77	Two projects awarded.
Thailand	Multiple	38	97-110	Auctions for 20-year FIT; 36 MW of solid biomass and 2 MW of biogas; due 2018.
Thailand	EfW	31	160	10-year FIT awarded through a lottery process.

Notes: Spain's 2016 auction also included a variable payment linked to fuel costs and indications are that not all the 200 MW of capacity will be delivered; price for France is average of winning bids; in the Netherlands 1 277 MW of co-firing capacity was also awarded in 2016 auctions; advanced conversion refers to gasification and pyrolysis of biomass and waste; N/A = not applicable.

The transition to technology-neutral auctions for renewable energy support in many countries is likely to focus bioenergy deployment on projects that benefit from lower investment costs and a low-cost fuel supply e.g. bagasse in Brazil (Table 5.1). However, generation costs need to be considered alongside the dispatchable nature of bioenergy and its potential to support wider policy objectives such as rural development, best practice waste management and security of supply. Therefore, how the design of auction frameworks accounts for the flexible generation potential and aforementioned socio-economic benefits will be crucial in shaping bioenergy deployment.

Prospects for biomass co-generation in Europe in light of lower electricity prices

Policy support for bioenergy in Europe is increasingly prioritising co-generation over power-only projects, mainly due to its higher achievable efficiency of biomass resource use. For instance, the European Commission has proposed to limit financial support, and the ability to contribute to 2030 renewable energy targets, to biomass electricity from high-efficiency co-generation. In addition,

[2] A gate fee (or tipping fee) is the charge levied upon a given quantity of waste received at a waste processing facility.

renewable energy auctions in France and the United Kingdom are only open to biomass co-generation. However, European power prices have declined, with average end-user electricity prices in the industrial sector over 2013-14 of EUR 147/MWh (USD 163/MWh), reducing to EUR 117/MWh (USD 129/MWh) in 2016. Consequently the lower value of electricity produced challenges the economic case for some co-generation projects. This applies both where electricity from co-generation is used on site for self-consumption and when sold into wholesale markets.

Co-generation plants are principally designed to meet the heat demand of the required load. Therefore, where electricity produced is of lower value, re-evaluation may be required to determine whether the additional investment and O&M costs associated with co-generation are justified when compared with a heat-only plant. Taking the case of investment costs, while these are bespoke to each project, an indicative range for biomass co-generation in Europe of EUR 1 500-2 450 per kilowatt thermal (kW_{th}) (USD 1 650-2 700/kW_{th}) is generally above reference costs for heat-only biomass boilers of EUR 500-1 500/kW_{th} (USD 550-1 650/kW_{th}).

Although generation costs vary on a plant-by-plant basis, data from a selection of European plants (IEA, 2015) indicates the LCOE of biomass co-generation at EUR 80-160/MWh (USD 88-177/MWh) when the value of heat produced is taken into account. This suggests that, at 2016 electricity prices, a proportion of industrial and commercial biomass co-generation projects would not be economic. A significant share of biomass fuel purchases takes place through bilateral contracts, therefore limiting fuel price transparency in the sector. However, there is no evidence of a sustained increase in European industrial wood pellet prices to further squeeze co-generation economics. Wood pellet prices in the range of EUR 100-150 per tonne (t) (USD 110-163/t) would result in fuel costs in the region of EUR 21-30/MWh (USD 23-33/MWh).

Opportunities for biomass co-generation will continue to arise in Europe, not least where adequate heat remuneration and access to low-cost fuel supply, e.g. secondary process residues, coincide. For some projects, however, lower electricity prices may result in examination as to whether a heat-only biomass system provides a more attractive investment case. Prospects in industry may be more attractive than in district heating due to higher operational full load hours, where heat demand from industrial processes is often constant over the year. In addition, room for innovation continues to exist in biomass co-generation. New small-scale technologies, such as solid oxide fuel cells using biomethane, may offer attractive greenhouse gas reduction potential, load flexibility and low O&M cost. However, investment costs remain high and it is considered that policy interventions, such as the investment support available in Germany, will be required to stimulate deployment.

CSP

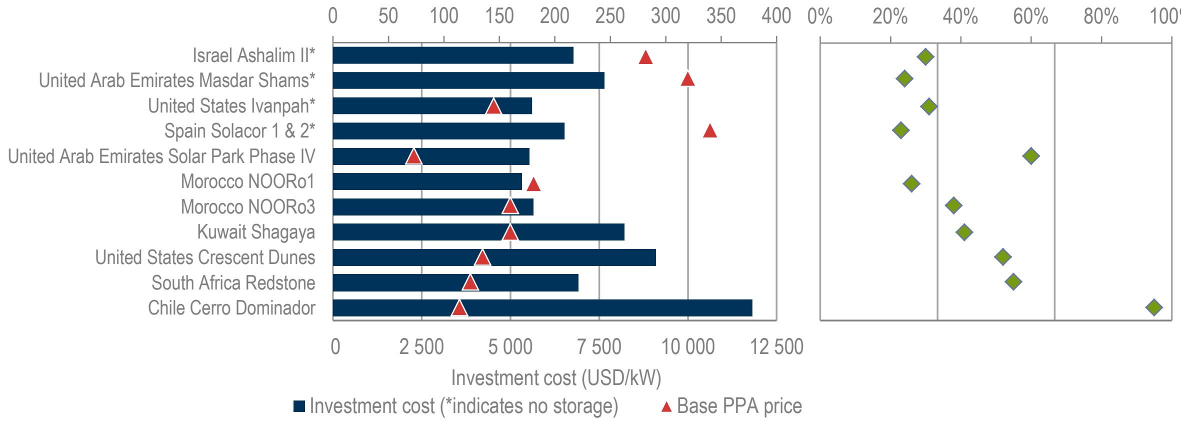
In 2016, global CSP investment reached approximately USD 1.8 billion, with higher efficiencies and effective capacity factors favouring the business landscape in new markets. In the same year, nearly 270 MW of new CSP capacity was commissioned, 80% of which was tied to parabolic troughs, largely due to the commissioning of Morocco’s 160 MW $NOOR_O1$ parabolic trough plant (3 hours of molten salt storage). Over 2017-22, capacity additions are expected to be concentrated in newly expanding markets, including, but not limited to, Chile, China, Israel, Kuwait, Morocco, South Africa and the United Arab Emirates. The share of parabolic trough projects is likely to fall to 50% of total cumulative capacity to make room for growth in solar towers, which will account for one-third.

A variety of CSP technologies exist globally, demonstrating that it is a multi-dimensional and complex technology with a number of possible applications. While the parabolic trough currently remains the dominant design with a proven deployment and operational track record, solar tower deployment is growing due to its relatively higher thermal to electric conversion rate and efficiency. Heat transfer fluids (HTFs) remain key to this conversion, and while they do not heavily dictate cost (HTF accounts for around 2% of investment costs), they can influence the efficiency and operational value of electric output. Direct-steam generation (DSG), oil (in trough plants) and molten salts (nascent in solar towers) remain the most prominent HTFs. In parabolic troughs, oil remains the dominant HTF but is limited by the temperature at which it can operate. In solar towers, DSG is less flexible as it allows for very limited storage, while molten salt is quickly gaining favour due to its ability to reach higher temperatures. Likewise, using molten salt as a storage medium is becoming the standard among developers in new markets to increase storage hours and efficiency. In 2016, storage hours for commissioned parabolic trough plants reached either 7 or 9 hours. Over the forecast period, projects boasting 10 or more hours of storage – mostly towers utilising molten salt storage – are expected to become the new norm, led by several plants including two in Chile, the Cerro Dominador molten salt tower project (17.5 hours of storage), scheduled to come on line in 2019, and the Copiapo molten salt tower project (13 hours of storage), expected to be operational in 2022.

Investment costs remain high for CSP when compared to conventional power plants and some other renewable technologies. Parabolic troughs tend to have a lower initial investment cost due to experience and learning leading to technological and performance improvements related to their greater deployment to date. Up to 2016, parabolic trough plants with any type of storage saw investment costs range from USD 5 300/kW to USD 10 100/kW. Over the forecast period, reported project costs indicate investment costs ranging from USD 5 500/kW to USD 7 250/kW. In comparison, solar towers historically witnessed marginally higher investment costs of USD 7 800-10 400/kW (Figure 5.19). While a larger pipeline of projects is required to further standardise these costs across solar towers utilising molten salt, some investment cost reductions are expected. In 2015, SolarReserve's 110 MW Crescent Dunes solar tower project in the United States (10 hours of molten salt storage) cost around USD 9 000/kW, a higher cost due to the fact this plant was the first of its kind. However, SolarReserve's 100 MW Redstone solar tower project in South Africa (12 hours of storage) is expected to become operational in 2020 with costs anticipated around USD 7 000/kW, due largely to a 30% decrease in the cost of heliostats, which account for roughly 50% of the investment cost of solar towers, over previous projects.

Parabolic troughs are witnessing a decline in LCOE due to scale-up, mass production and learning. For example, Morocco's 160 MW NOOR$_{O}$1 trough (3 hours of storage), commissioned in 2016, is estimated to cost USD 190/MWh, while the 200 MW NOOR$_{O}$2 (7 hours of storage) is expected to see generation costs fall to USD 140/MWh. In September 2017, Saudi Arabia's ACWA Power and China's Shanghai Power submitted the lowest successful bid (and record low CSP price globally) in an ongoing tender for the fourth phase of Dubai's Sheikh Mohammed bin Rashid al-Maktoum solar park. The now-700-MW CSP plant, which saw a winning bid of USD 73/MWh, is expected to generate electricity from 16h00 to 10h00, directly complementing the power that the PV plants in the same solar park will deliver. Once both phases are complete, the plant is expected to boast a 100 MW solar tower, while the remaining 600 MW should utilize parabolic trough technology.

Figure 5.19. Announced investment costs and base PPA price of historical and forecast CSP projects (left) and corresponding estimated capacity factors (right)



Notes: Depicted plants are generally large-scale in design for commercial operation and range from 100 MW to 392 MW, while Kuwait's Shagaya plant is 20 MW. Furthermore, adjustment multipliers may exist for some projects, indicating a higher cost per MWh.

Sources: Analysis based on NREL (2016), *Concentrating Solar Power Projects* (database), www.nrel.gov/csp/solarpaces/; BNEF (2016), *Renewable Energy Projects* (database), www.bnef.com/projects/search.

LCOEs are also expected to fall further for solar towers. However, LCOE comparisons across projects remain a challenge given the small number of plants installed to date. Looking to public data on PPAs for specific projects offers some indirect insight into declining LCOEs. In the United States, generation costs for SolarReserve's 2015 110 MW Crescent Dunes solar tower (10 hours of storage) is estimated at USD 135/MWh. Chile's twin solar towers that make up the 260 MW Copiapo plant (13 hours of storage) is expected to reach record low generation costs closer to USD 100/MWh due to cost reductions associated with technology learning from SolarReserve's Crescent Dunes and Redstone projects. Chile also boasts a direct normal irradiance (DNI) of nearly 8.2 kWh per square metre (m^2) per day, the highest in the world, which plays a critical role in LCOE.[3] Overall, cost reductions are likely to become realisable for most technological varieties of CSP, which, although still a nascent sector, points to a strong roadmap for performance improvements, optimisation and cost reductions as global deployment accelerates.

Geothermal

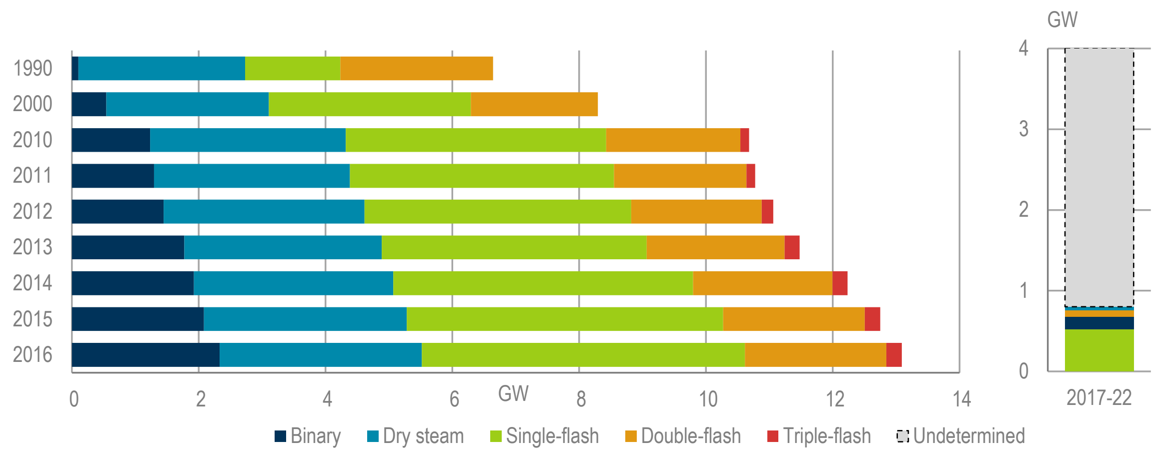
Geothermal generation installations were dominated by dry steam and single flash technologies, accounting for over half of all geothermal projects commissioned up to 2015, followed by binary (18%) and double flash (17%) installations. In 2016, of the 0.35 GW capacity additions, almost 70% applied binary technology, which is able to operate at moderate-resource temperatures, while the flash system plants perform best at high-temperature sites (Figure 5.20). Global geothermal capacity is anticipated to increase by nearly 4 GW over 2017-22. *Renewables 2017* was able to track technology details for only around 20% of the projects expected to become operational. The limited data indicate that single-flash technology will be the dominant choice, followed by binary plants.

Initial investment costs for geothermal plants vary widely by project and are largely driven by site-specific conditions, such as resource temperature (determining the type of technology and turbines used), depth of the pool, chemistry and rock permeability. Typical investment costs for single-flash

[3] Plants located in areas with high DNI will always have a lower LCOE, all else being equal.

geothermal power plants that came on line between 2010 and 2015 ranged from around USD 1 400/kW to USD 5 700/kW. Over the forecast period, investment costs for announced projects indicate that the lower end could be around USD 1 300/kW, with the high end reaching USD 4 300/kW. Historically, investment costs for binary geothermal projects were higher than single-flash plants, ranging from around USD 2 100/kW to USD 5 000/kW, and could remain around 20% higher over 2017-22, ranging from around USD 1 600/kW to USD 6 700/kW. Nevertheless, given the limited availability of cost information, reported ranges are estimates and could change should larger datasets become available.

Figure 5.20. Geothermal capacity segmentation by technology (left) and forecast (right)

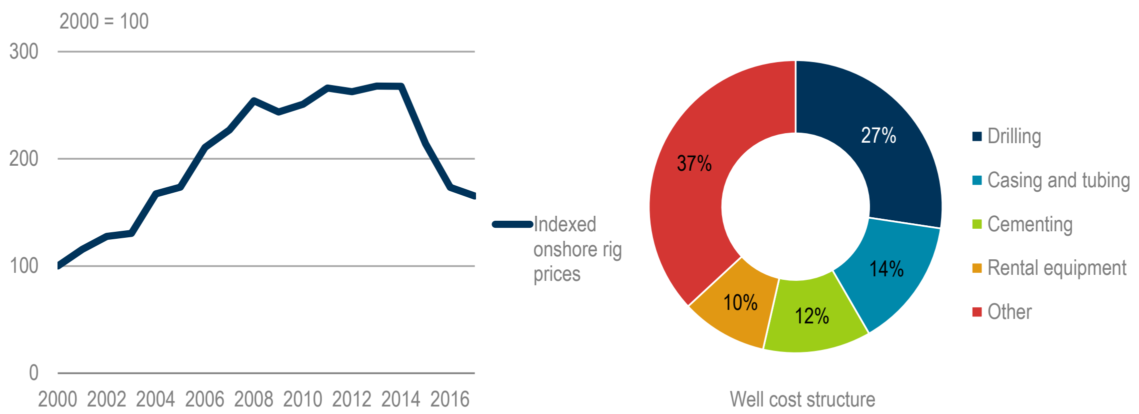


Source: Analysis based on GEA (2016), *Capacity Dataset for the IEA.*

Investment costs for geothermal plants are heavily influenced by the costs associated with well drilling and may vary significantly according to the number of wells required to be drilled throughout the project development. The exploration phase ends with the drilling of the first commercial production well. During the confirmation phase, additional wells are drilled to test production flows, since at least 25% of the resource potential must be confirmed in order to clear the project as viable, enabling the developer to raise financing. At least 40% of the costs associated with the confirmation phase are spent on unsuccessful well drilling, elevating overall project costs and increasing project risk levels at the pre-development stage (GEA, 2005). Debt financing is typically not available for the pre-development phase activities, which are usually financed by equity investors or government institutions that can bear elevated risks. Investment de-risking policies at the pre-development phase of geothermal plants are crucial to achieving faster deployment over the forecast period. The site development stage covers all other activities leading to commissioning of the plant.

The combined costs of well drilling and well construction range from 50% to 75% of total geothermal investment costs. Costs associated with geothermal well drilling are partly influenced by demand and supply dynamics in the oil and gas sector, as similar materials and processes can be used. After 2010, well drilling costs increased, driven by growing complexity of well designs and the increasing depths of geothermal sources, but also partially by a rapid rise in demand for drilling in gas and oil sectors (Figure 5.21). Onshore oil and gas rig costs, which include drilling costs, more than doubled between 2000 and 2014 with increasing demand for drilling activities resulting from high oil prices. Since 2014, onshore rig costs have declined by around 40% as oil prices plummeted. Low demand for well drilling in the oil and gas industry may also reduce drilling costs for geothermal projects in some countries over the forecast period. In addition, drilling, casing and tubing accounts for 35% of the well costs, followed by cementing (10%) and equipment rental (8%). Thus, geothermal well costs are also susceptible to global macroeconomic trends such as development of commodity prices (steel, cement, and demand in the oil and gas sector), the availability of drilling equipment and skilled workforce.

Figure 5.21. Indexed costs of onshore oil and gas rigs (left) and well cost structure (right)



Sources: IEA (2017), *World Energy Investment*; Lukawski, Silverman and Tester (2016), "Uncertainty analysis of geothermal well drilling and completion costs", *Geothermics*, No. 64.

Geothermal plants usually have high capacity factors (60% to 90%), among the highest of all renewable technologies, paired with long economic plant lifetimes, with a stream of production that is constant over the day and the seasons, meaning they are not susceptible to climate change effects such as prolonged droughts. This makes geothermal highly suited to baseload operations. Overall, LCOEs of geothermal plants range between USD 35/MWh to USD 200/MWh. This wide range reflects differences in investment costs in addition to the availability of affordable financing, which remains an important challenge in developing countries and emerging economies.

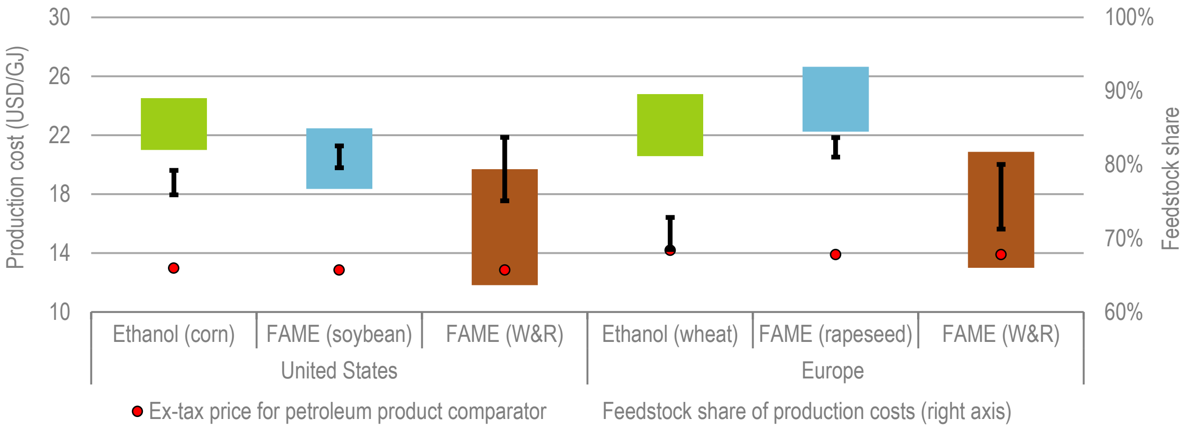
Transport biofuels

Although the majority of global biofuel consumption is currently driven by blending mandates, the assessment of biofuel production costs allows for quantification of their market competitiveness against petroleum products and alternative fuels, and also determines the level of subsidy required to meet mandated volumes, which reached USD 26 billion in 2015 (IEA, 2016b).

Agricultural feedstocks are a core determinant of conventional biofuel production costs, with around 65-90% of the levelised cost of production accounted for by the feedstock used (IEA, 2016b). For instance, oil crop feedstocks, such as soybean oil in the United States or rapeseed oil in Europe, typically account for more than three-quarters of the production costs of crop-based biodiesel and hydrotreated vegetable oil (HVO) (Figure 5.22). In turn, feedstock prices are determined by the balance of overall food and biofuel market demand against harvest output.

Conventional biofuel production processes are technically mature and investment costs account for a relatively smaller share of the total cost of biofuel production compared to feedstocks. Investment costs, however, do vary in relation to the feedstock utilised. In the case of fuel ethanol, investment costs account for around 5% of production costs with wheat feedstock, up to 20% for sugar-derived fuels (IEA, 2016b). In addition, investment costs also vary by country.

Figure 5.22. Levelised production costs and feedstock share of production cost for selected conventional biofuels in the United States and Europe



Notes: GJ = gigajoule; FAME = fatty acid methyl ester biodiesel; W&R = waste and residue, e.g. used cooking oil and animal fats; petroleum product comparator is gasoline for ethanol and diesel for FAME.

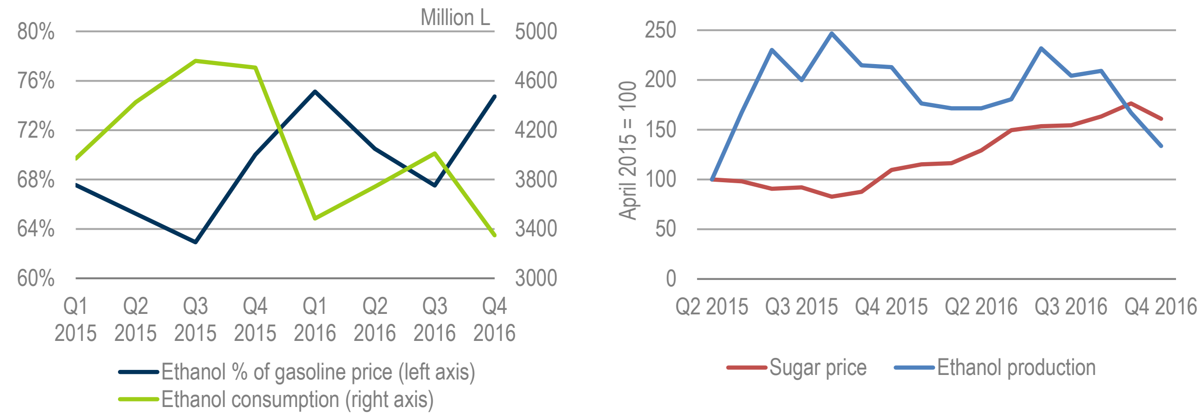
Source: OECD/FAO (2017), *OECD-FAO Agricultural Outlook*; Hugues, Assoumou and Maizi (2016), "Assessing GHG mitigation and associated cost of French biofuel sector: Insights from a TIMES model", *Energy*, Vol 113, pp. 288-300; Gerssen-Gondelach et al. (2014), "Competing uses of biomass: Assessment and comparison of the performance of bio-based heat, power, fuels and materials", *Renewable and Sustainable Energy Reviews*, Vol. 40, pp. 946-998.

Waste and residue feedstocks, e.g. waste oils and animal fats, can be available at lower costs than virgin vegetable oils, and therefore generally account for a lower percentage of overall production costs than crop-based alternatives. This can be advantageous as lower cost shares reduce feedstock price volatility risk. However, waste and residue feedstocks generally present additional challenges in processing due to their variable composition and the presence of impurities. In the United States, low natural gas prices have reduced the cost of producing the hydrogen required for HVO production, and support lower overall production costs.

In Brazil fuel consumers are sensitive to the price ratio between hydrous ethanol and gasoline (C grade, blended with 27% fuel ethanol) at the pump. While hydrous ethanol is cheaper on a volume basis than gasoline C, it also has a lower energy content. As a result consumers typically apply a rule of thumb of value parity between the two fuels, where hydrous ethanol is 70% of the gasoline C price, switching consumption to ethanol below 70% and to gasoline C above this level.

With regard to ethanol production, when international sugar prices are low, Brazilian sugar and ethanol mills favour ethanol production, whereas at higher sugar prices they maximise sugar output at the expense of ethanol production (Figure 5.23). During the 2015/16 harvest season, ethanol accounted for 59% of recoverable sugar consumption in the centre-south region. In the second half of 2016, global sugar prices increased and as a result the ethanol share of recoverable sugar consumption dropped to 57% over the 2016/17 centre-south harvest (UNICA, 2017).

Figure 5.23. Brazilian hydrous ethanol consumption and price relative to gasoline (left) and fuel ethanol production versus international sugar price (right), 2015-16



Notes: Ethanol consumption refers to unblended hydrous ethanol consumption only; ethanol production refers to all fuel ethanol, both hydrous and anhydrous; sugar price is based on No. 11 raw sugar benchmark contract price; production and sugar prices are only shown for months between April and November, the period of highest production in the centre-south region; L = litre.

Sources: F.O. Lichts (2017), *F.O. Lichts Interactive Data* (database), www.agra-net.com (subscription service); UNICA (2017), *Unica Data* (database), www.unicadata.com.br; MAPA (2017), *Produção*., www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao.

Prospects for advanced biofuel competitiveness versus fossil transport fuels

A diverse number of countries have either established, or are in the process of establishing, policy frameworks to facilitate advanced biofuels to deliver a more prominent contribution to the decarbonisation of the transport sector. This raises the question of whether advanced biofuel consumption over the next five years will only occur as a result of policies that mandate demand, or if certain advanced biofuels could compete with petroleum products on a cost basis given supportive market conditions. *Renewables 2017* has assessed the key market parameters that will influence the competitiveness of cellulosic ethanol, HVO from waste and residue feedstocks (hereby referred to as W&R HVO) and biomethane compared to petroleum products. Advanced biofuels from thermochemical production processes are not included due to the low levels of commercial production anticipated over the next five years.

For the three advanced biofuels considered, and particularly cellulosic ethanol, scope exists for innovation and technical learning to reduce current production costs. Reducing feedstock costs is more challenging, but, given the significant influence these have on production costs, will be crucial in lowering the cost of production. Feedstock cost reductions are possible through optimising and scaling up supply chains, as well as operating in geographical areas where lower cost feedstocks are available. Should production costs not reduce significantly over the next five years, it is considered that policy frameworks which mandate demand for advanced biofuels are likely to remain crucial to achieving advanced biofuel industry expansion during the forecast period; this is particularly the case in the current context of low oil prices and the lack of widespread carbon emissions pricing.

Technological improvements and investment costs

Technological learning offers scope to reduce investment costs for the three advanced biofuels assessed. The largest cost reduction potential is applicable to cellulosic ethanol due to its lower technical maturity compared to more established W&R HVO and biomethane technologies. For example, commercial-scale cellulosic ethanol replication plants could offer the scope to reduce investment costs by a factor of three compared to the first plants commissioned over 2013-16.

There are limits to the cost reductions available from replication projects, however, as biofuel plants need to be specifically designed according to the chemical composition and physical characteristics of the biomass feedstock used, plant scale and site conditions (for example, available infrastructure). As a result, even replication projects are likely to have bespoke elements that entail additional resources during the design and engineering phases. These affect investment costs even when undertaken by an established technology provider. Aside from technical learning, co-location of advanced and conventional biofuels facilities offers a means to reduce investment costs, while for HVO plants, fossil-to-biorefinery conversions can reduce investment costs by more than half compared to new facilities.

Current high investment costs for certain advanced biofuel facilities, coupled with the risk profile associated with investing in new technologies, can make securing project finance challenging. In turn, this can result in elevated costs of capital, highlighting the importance of investment support to the sector. This is anticipated to be more relevant to cellulosic ethanol plants than W&R HVO refineries, which have higher levels of commercial production, while biomethane plants are smaller in scale and therefore entail lower levels of capital investment.

Process energy overheads offer less scope for reduction. For some advanced biofuels, process residues can be combusted to supply energy demand, e.g. the use of lignin for energy in cellulosic ethanol plants.[4] Conversely, where petroleum products are used there is less scope to control energy costs. For cellulosic ethanol, enzyme costs have reduced sharply over the past five years and it is understood that additional scope exists for further reductions in the future. In addition to reducing investment costs, technological improvements also offer scope to improve yield.

Feedstocks

For most advanced biofuel production pathways, feedstocks are the main determinant of production costs (Table 5.2). The share of total production costs attributable to feedstocks varies on a plant-by-plant basis. However, the feedstock cost share is likely to be highest for W&R HVO, with waste oils and animal fats accounting for 70-80% of total production costs. For cellulosic ethanol production pathways based on agricultural residue (e.g. bagasse, corn stover), feedstocks are estimated to account for 40-70% of production costs. A key determinant of costs is whether feedstocks are purchased from third parties or produced on site and therefore effectively free e.g. bagasse secondary residues from the sugar industry. Reducing feedstock costs can be challenging, and it is anticipated that the feedstock cost share across all technologies will increase over time as other production cost elements reduce with technological progress.

It should be noted that feedstock costs are variable by country and region. Taking the example of cellulosic ethanol, it is anticipated that the availability of low-cost agricultural residues in India offers scope for considerably lower production costs than achieved with higher-cost feedstocks in Europe or the United States. However, this assumes all other variables remain the same, whereas in reality other factors, such as cost of capital or technological sophistication, will influence operational costs.

[4] Higher value markets may exist or open up for process residues currently used for energy purposes.

Innovation in feedstock supply through the application of optimised equipment for collection and pre-treatment, as well as improved logistics, can be employed to reduce feedstock costs. In addition, co-operative business models and improved contracting processes could lower prices. In order to avoid cost escalation, multi-feedstock strategies may also be required as a means of negotiating with suppliers. In this respect, pre-treatment process development to expand the range of low-carbon waste oil and animal fat feedstocks suitable for use in W&R HVO production will be doubly beneficial, increasing available feedstock volumes and controlling costs. Given the distributed nature of these resources, aggregators and traders may have a role in ensuring biofuel producers are not required to move beyond their core business model to obtain supply.

Table 5.2. Cellulosic ethanol and W&R HVO feedstock cost estimates

Fuel	Feedstock	Reference cost (USD/GJ)	Comment
Cellulosic ethanol	Corn stover	2-5	USD 40-80/t (United States)
Cellulosic ethanol	Straw	2-5	USD 33/t (Southeastern Europe) to 90/t (Northern Europe)
Cellulosic ethanol	Bagasse	2-3.5	USD 40-60/t (Brazil)
W&R HVO	Waste oils	17-26	Used cooking oil USD 640-950/t (Europe)
W&R HVO	Animal fats	11-16	USD 440-615/t (Europe and United States)
W&R HVO	PFAD	9-16	USD 360-620/t (Malaysia)

Notes: PFAD = Palm fatty acid distillate; prices are indicative only as feedstock prices will vary depending on the specific supply chain in question and commercial agreements; a wider range of feedstocks can be used for the production of cellulosic ethanol and W&R HVO; approximate calorific value of 17 GJ/tonne applied to agricultural residue feedstocks, 36.5 GJ/tonne for waste oils and 40 GJ/tonne for animal fats and PFAD.

Sources: Harrison et al. (2014), *Wasted: Europe's Untapped Resource*; US DOE (2016), *U.S. Billion-Ton Update – Crop Residues and Agricultural Wastes*; F. O. Lichts (2017), F.*O. Lichts Interactive Data* (database), www.agra-net.com (subscription service).

The cost structure of anaerobic digestion of wastes and residues differs, with the large variety of lower-priced feedstocks (e.g. organic municipal waste, straw or animal manure) expected to account for a lower share of production costs than for cellulosic ethanol or W&R HVO. In addition, certain wastes can be obtained for free, or even generate revenue where a gate fee is charged for receipt.

Oil price

Crude oil prices determine the price of petroleum products against which advanced biofuel competitiveness can be gauged.[5] In the current low oil price environment, without policy support all three biofuels are uncompetitive versus petroleum products.[6] The reduction in crude oil prices from levels above USD 100 per barrel (bbl) as recently as mid-2014, to prices that have oscillated in the USD 45-55/bbl range in the first half of 2017, has lowered petroleum product prices and provided a more challenging context for the competitiveness of biofuels without policy support. At early 2014 crude oil prices, current mid-range production costs for biomethane and lower-end production costs for W&R HVO would be competitive; with the possibility of cost parity with fossil fuels for the best-performing cellulosic ethanol should very low-cost feedstocks be available.

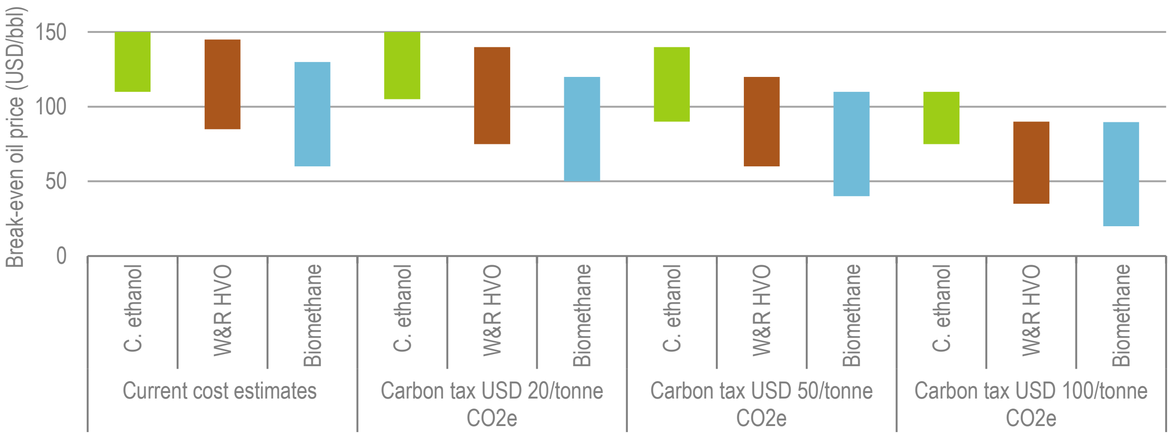
[5] It should be noted that the crude oil price alone cannot be used to assess the break-even price for advanced biofuels, as the difference between the crude oil price and the selling price of petroleum products (termed "crack spread") also needs to be factored in.

[6] With the exception of some production pathways based on zero or negative cost waste and residue feedstocks.

Carbon taxation of transport fuels

Carbon taxation and emissions trading schemes offer a means by which the externality of CO_2 emissions can be monetised and factored into the cost of fossil transport fuels. Advanced biofuels can either be made exempt or charged at the appropriate rate according to their carbon intensity. In either case, incorporating the cost of CO_2 emissions levels the playing field with fossil gasoline, diesel and jet kerosene and supports growth of the advanced biofuels industry.

Figure 5.24. Impact of carbon taxation on advanced biofuel break-even crude oil price



Notes: Maximum break-even crude oil price of USD 150/bbl considered in the analysis; at current cost estimates some cellulosic ethanol production may be above this level; C. ethanol = cellulosic ethanol; cellulosic ethanol and biomethane break-even compared against gasoline, W&R HVO against diesel.

Sources: IEA analysis based on IRENA (2016), *Innovation Outlook: Advanced Liquid Biofuels*; European Commission (2017), *Building up the Future Cost of Biofuel*; IPPC (2006), *IPCC Guidelines for National Greenhouse Gas Inventories*.

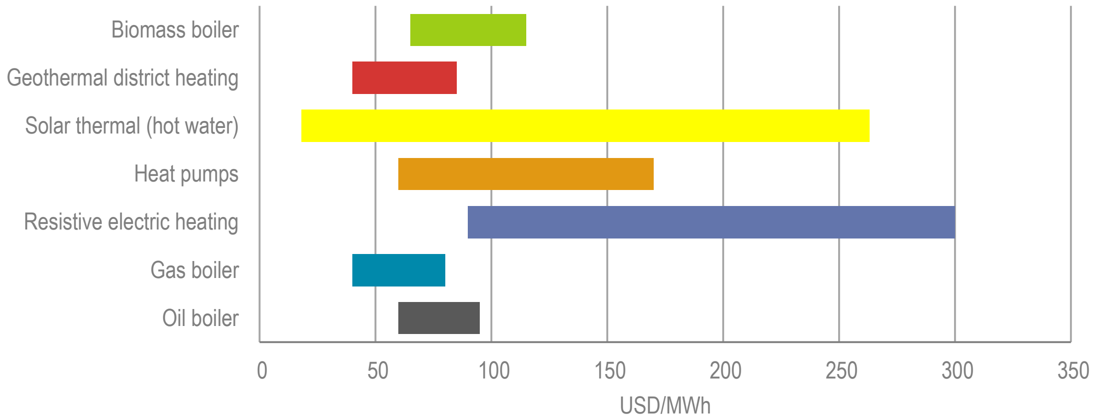
The application of carbon taxation to fossil transport fuels at levels of USD 20/tCO_2e would add less than USD 2/GJ to fuel costs, but this would increase to in excess of USD 10/GJ with aggressive carbon taxation of USD 150/tCO_2e. In the absence of an increase in crude oil prices and strong cost reduction trends, fossil transport fuel carbon taxation above USD 100/tCO_2e would be required to widen the portfolio of competitive advanced biofuels. Such taxation levels would deliver cost parity for some W&R HVO production and more widespread competitiveness for biomethane; although still not result in competitive cellulosic ethanol at 2017 crude oil prices (Figure 5.24).

As of 2017, over 40 national and 25 subnational jurisdictions are putting a price on carbon. Taxation levels span a wide range; for example France's carbon tax equates to USD 33 per tonne of carbon dioxide equivalent (tCO_2e), Finland's USD 66/tCO_2e and Sweden's USD 126/tCO_2e (World Bank and Ecofys, 2017). While all three of these cover fossil transport fuels, this is not the case for all carbon pricing initiatives.

Renewable heat

Both the costs of renewable heat options and those of fossil fuel alternatives span a wide range, even for applications in the same sector. They depend on many factors, such as installation costs, local climatic factors (e.g. insolation levels), local resource availability (e.g. for biomass) and energy prices (including taxation). Figure 5.25 shows indicative ranges for residential renewable heat systems.

Figure 5.25. Indicative cost ranges for residential renewable heat and fossil fuel alternatives (delivered heat)



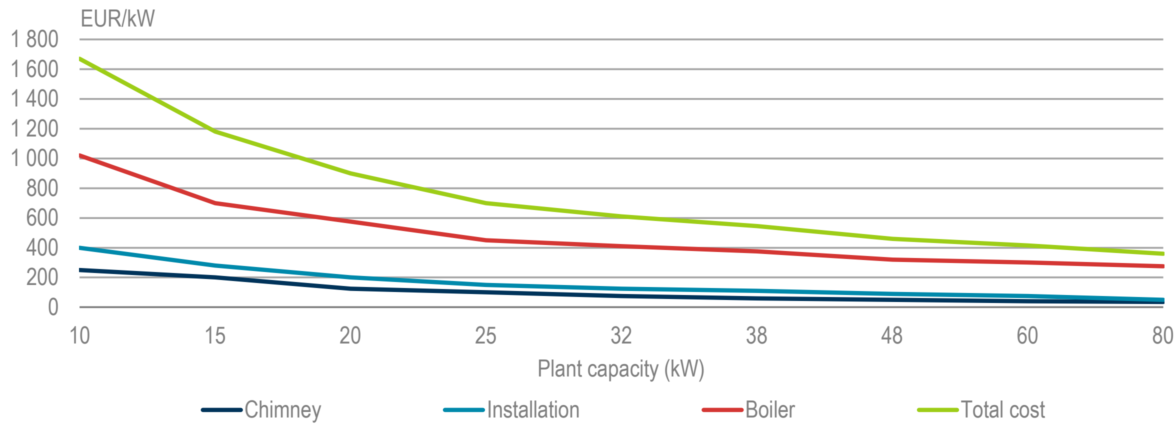
Notes: Delivered heat costs include investment and operational costs and assume a range of fuel and electricity prices. The range for heat pumps includes both air source and ground source systems, as delivered heat costs for these were relatively aligned.

Typically, the competitiveness of renewable heat options depends on both the investment and operating costs of the fossil fuel alternatives. Generally, upfront costs for renewable heat options are higher than those for fossil fuel boilers. However, there are cases where renewable heat options can easily compete with fossil fuels and are even the preferred option. This is, for example, the case in the food or pulp and paper industries, where often co-products are available as a free or low-cost fuel and compensate for the generally higher investment costs of biomass boilers. Renewable heat options are already well-established in these industries, but there is often scope to increase efficiencies (e.g. bagasse co-generation in Brazil and India) and enhance the cost-effectiveness of these options.

Economies of scale

Deployment of larger-scale renewable heat installations provides good opportunities for investment cost reductions (Figure 5.26). For instance, for biomass boilers in the United Kingdom installed under the Renewable Heat Incentive (RHI) scheme, median costs per kW installed for medium- and large-scale boilers are, respectively, 20% and 35% below those for small boilers (<200 kW) (BEIS, 2017). For solar thermal, installation costs can make up as much as 50% of system costs for small residential systems, but they can be significantly reduced in larger-scale systems. This is demonstrated in Denmark, where during the last few years a number of large-scale solar thermal systems have been installed to supply district heating schemes. While the average levelised cost of heat for typical small domestic applications in Denmark ranges between USD 130/MWh and USD 210/MWh, the average cost for large-scale systems (>10 000 m² of collector area), including the cost for diurnal storage, falls to USD 40/kWh (IEA-SHC, 2017).

Figure 5.26. Biomass boiler investment costs by capacity



Source: Reproduced from Rakos, C. (2017), "Pellet boiler markets – perspectives for the future".

The importance of fossil fuel and electricity prices

In many countries, natural gas is the incumbent heating fuel against which renewable heat options have to compete. Gas prices, especially for residential consumers, vary considerably between countries, primarily due to different tax rates. For example, the United Kingdom boasts the lowest tax rates on gas in the European Union and also has the lowest share of renewable heat at 5.5% in 2015. Even with financial support available through the RHI, there is little uptake of renewable heat options amongst the more than 80% of homes on the gas grid, with 72% of renewable heat systems deployed off the gas grid where the incumbent fuel is higher cost heating oil (BEIS, 2017). Meanwhile, in countries like Sweden and Denmark, taxation of natural gas and heating oil has been a major driver of renewable heat deployment.

The competitiveness of heat pumps also depends on the cost of input electricity to the heat pump unit. In many countries, electricity is relatively expensive as the cost of renewable support schemes are loaded onto electricity tariffs as surcharges, in addition to electricity carrying a carbon price under the EU Emissions Trading System. This creates the paradoxical situation where programmes to support certain renewables can make others less attractive, especially as similar surcharges rarely apply to natural gas prices. To address this, some countries apply special heat pump tariffs. In Switzerland, for example, most utilities offer such tariffs, reducing costs by up to 40% compared to normal tariffs but also allowing utilities to manage heat pump use at peak times (e.g. through time variable tariffs) (EHPA and Delta Energy & Environment, 2013). As a result, heat pumps have become so attractive that they now lead the market for new heating appliances in Switzerland. Heat pumps can also be coupled with solar PV to reduce running costs, although some purchase of grid electricity is likely to be necessary, given the mismatch between solar irradiation and thermal energy demand during the peak heating season. In Germany, the "tenant electricity" concept allows the use of PV electricity for in-house heat demands (e.g. for heat pumps) using smart metering, which by-passes several surcharges imposed on residential electricity tariffs, and makes heat pumps supplied by renewable electricity more competitive.

Substituting coal with biomass for heating in China

Policies to phase out coal consumption in China's heating sector are opening the door to alternative fuels, such as solid biomass, as substitutes. Coal is currently the dominant heating fuel in northern regions where there is high space heating demand. However, its use for heating is a major contributor to China's air pollution problems, and the 13th FYP establishes targets to reduce its consumption in areas most affected by air pollution. Biomass fuels have lower sulphur and generally less nitrogen content compared to coal, and therefore result in reduced sulphur dioxide (SO_2) and nitrogen oxide (NO_X) emissions. However, the incomplete combustion of biomass can result in particulate matter (PM) emissions. As such, in order to deliver air quality benefits, biomass systems must offer efficient combustion and possess emissions-control equipment to mitigate PM.

This strong resolve to improve air quality has resulted in provincial polices that do not permit coal use to meet new heating demand and also favour its substitution with alternative fuels. Such policies are in effect in densely populated areas and areas with a high intensity of coal use, including the Beijing-Tianjin-Hebei city clusters, Shandong and Guangdong provinces, and the Yangtze River Delta. The replacement of coal consumption by small-scale industry in rural areas is also an area of focus due to high associated PM emissions. For both technical and economic reasons, inefficient small- and medium-scale coal boilers are challenging to retrofit. Estimates indicate that around 0.5 million of these boilers could be phased out, creating an opportunity for alternative fuels (IEA, 2016a).

Solid biomass can serve as an alternative fuel for use in district heating systems at varying scales in urban areas within the 15 provinces with colder climates that comprise the northern heating area.[7] *Renewables 2017* has analysed the comparative economic case for solid biomass and natural gas as substitutes for coal (Box 5.1), although other low-carbon alternatives, such as municipal wastes and heat pumps, are also available.

Box 5.1. China solid biomass and natural gas economic assessment

City gate[8] natural gas prices are determined by the Chinese National Development and Reform Commission (NDRC), and vary by province. For example, in 2015 natural gas prices ranged from USD 12.9/GJ, or USD 13.6 per million British thermal units (MBtu), in Shanghai and Guangdong to USD 8.3/GJ in Xinjiang (USD 8.7/MBtu). Local governments then set natural gas prices for residential and non-residential consumers as well as district heating companies. Generally, residential gas prices are the cheapest, followed by those for district heating companies, with non-residential users subject to the highest gas charges. Conversely, solid biomass prices are market determined according to the calorific value of the fuel, which is in turn linked to the feedstock used.

Table 5.3 indicates that coal is the cheapest heating fuel. However, where air quality and decarbonisation drivers result in policies that dictate that diversification of heating fuels should occur, biomass fuels can deliver heat at the lower end of the natural gas cost range and therefore offer more competitive fuel costs in most provinces. Comparative analysis of project economics lies outside the scope of this analysis; however, for megawatt-scale natural gas heating boilers in China, investment costs in the region of USD 100 per kW of capacity are below lower-end global estimates for biomass boilers, which begin at USD 300/kW. In addition, other factors outside the scope of this analysis need to be considered, such as the availability of biomass resources in a given area (procurement is only permitted within a 100-km radius) and natural gas infrastructure by location.

[7] Guangdong province and the Yangtze River Delta sit outside the northern heating area and therefore do not have district heating networks. However, industrial heat demand is present.

[8] City gate refers to the location or measuring station where a natural gas distributor connects to the natural gas transmission system.

Table 5.3. End-user heating fuel price comparison

Fuel	Calorific value (GJ/t)	Fuel cost (USD/GJ)	Assumed boiler efficiency (%)	Delivered heat fuel cost (USD/GJ)
Natural gas (non-residential)	0.036*	8.4-19.2	92%	9.1-20.9
Natural gas (DH company)	0.036*	6.7-13.4	92%	7.3-14.5
Heating oil	41.9	16.5	88%	18.8
Coal	20.9	3.6-5	65%	5.5-7.8
Biomass briquettes	12.6	7.2	80%	9
Wood pellets	18	9.2	85%	10.8

* Calorific values for natural gas on a GJ per cubic metre basis, to convert gas prices to MBtu divide per-GJ price by 0.947.

Notes: DH = district heating; non-residential natural gas price ranges based on minimum and maximum values across 24 provinces; DH company price range from minimum and maximum values across 7 provinces.

Sources: IEA analysis based on China National Renewable Energy Centre (CNREC) (27/04/2017), email to author; Hong, H. (2017), "The development of biomass heating in China".

Local city governments set the heat prices that district heating companies charge to domestic and public buildings on a per-square-metre basis. Different charges apply for buildings that meet new efficiency standards and analysis indicates that these pay more per unit of heat supplied than older building stock.

For the cities of Beijing, Taiyuan and Xian, *Renewables 2017* has assessed whether current heat charges would allow for public buildings and district heating companies to realise profit using solid biomass and natural gas. In public buildings, only lower-cost biomass briquette fuels were competitive in Beijing, with neither fuels viable at current heat prices in Taiyuan and Xian. In all three cities analysed, district heating companies would not yield a profit using biomass or natural gas at current heat prices within the existing building stock, except for biomass briquette fuels in Xian.

In more efficient new residential buildings that pay more per unit of heat supplied, both alternative fuels could deliver a profit based on current heat prices with the exception of natural gas in Taiyuan. This suggests that current heat prices are determined based on the lower fuel costs offered by coal and industrial waste heat, which can deliver a profit based on current fuel and allowable heat charges. Therefore, diversifying away from coal towards natural gas and biomass fuels will require a revaluation of heat charges, most likely complemented by a continuation of ongoing efforts to improve building efficiency. In addition, in certain cities environmental regulations would require modification to allow the use of biomass technologies fitted with sophisticated emissions control equipment.

References

BEIS (Department for Business, Energy and Industrial Strategy) (2017), *RHI Deployment Data: March 2017*, BEIS, London, www.gov.uk/government/statistics/rhi-deployment-data-march-2017 (accessed 24 April 2017).

BNEF (Bloomberg New Energy Finance) (2017), *Wind Manufacturing Plants Database*, BNEF, London.

BNEF (2016), *Renewable Energy Projects* (database), www.bnef.com/projects/search (accessed June 2017).

BNEF (2015), "Focus: $20 billion of $60 billion? The large hydro investment puzzle", BNEF, London.

Buss, K. et al. (2016), "Global distribution of grid-connected electrical energy storage systems", *International Journal of Sustainable Energy Planning and Management*, Vol. 9, pp. 31-56.

CEC (California Energy Commission) (2016), *Bulk Energy Storage in California*, CEC, Sacramento, www.energy.ca.gov/2016publications/CEC-200-2016-006/CEC-200-2016-006.pdf.

European Commission (2017), *Building up the Future Cost of Biofuel*, European Commission, Brussels.

EHPA (European Heat Pump Association) and Delta Energy & Environment (2013), *Unleashing the Opportunity: European Best Practice in Building Successful Heat Pump Markets*, EHPA, Brussels and Edinburgh.

F. O. Lichts (2017), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanoland-biofuels-report/ (subscription service – accessed February 2017).

GEA (Geothermal Energy Association) (2016), *Capacity Dataset for the IEA*, dataset provided to the IEA.

GEA (2005), *Factors Affecting Costs of Geothermal Power Development*, GEA, Washington, DC.

Gerssen-Gondelach, S.J. et al. (2014), "Competing uses of biomass: Assessment and comparison of the performance of bio-based heat, power, fuels and materials", *Renewable and Sustainable Energy Reviews*, Vol. 40, Elsevier, pp. 964-998.

Geth, F. et al. (2015), "An overview of large-scale stationary electricity storage plants in Europe: Current status and new developments", *Renewable and Sustainable Energy Reviews*, Vol. 52, pp. 1212-1227.

Harrison, P. et al. (2014), *Wasted: Europe's Untapped Resource*, ICCT (International Council on Clean Transportation), Berlin.

HEA (Hydro Equipment Association) (2016), *Global Technology Roadmap*, HEA, Brussels.

Hong, H. (2017), "The development of biomass heating in China", presentation at the 5th Central European Biomass Conference and Nordic Baltic Bioenergy Conference, Graz, 18 January 2017.

Hugues, P., E. Assoumou and N. Maizi (2016), "Assessing GHG mitigation and associated cost of French biofuel sector: Insights from a TIMES model", *Energy*, Vol. 113, Elsevier, pp. 288-300.

IEA (International Energy Agency) (2017), *World Investment Report*, OECD/IEA, Paris.

IEA (2016a), *Medium-Term Gas Market Report 2016*, OECD/IEA, Paris.

IEA (2016b) *World Energy Outlook 2016*, IEA/OECD, Paris.

IEA (2015), *Projected Costs of Generating Electricity 2015*, OECD/IEA, Paris.

IEA and MME (Ministry of Mines and Energy, Brazil) (2012), *Technology Roadmap: Hydropower*, OECD/IEA, Paris.

IEA-SHC (Solar Heating and Cooling Programme) (2017), *Solar Heat Worldwide*, AEE INTEC and IEA-SHC.

IPPC (Intergovernmental Panel on Climate Change) (2006), *IPCC Guidelines for National Greenhouse Gas Inventories*, IPPC, Geneva.

IRENA (International Renewable Energy Agency) (2017), *Costing Alliance*, dataset provided to the IEA, IRENA, Abu Dhabi.

IRENA (2016), *Innovation Outlook: Advanced Liquid Biofuels*, IRENA, Abu Dhabi.

LBNL (Lawrence Berkeley National Laboratory) (2016), *RPS Demand Projections*, LBNL, Berkeley, CA, https://emp.lbl.gov/projects/renewables-portfolio.

Lukawski, A., R. Silverman and J. Tster (2016), "Uncertainty analysis of geothermal well drilling and completion costs", *Geothermics*, No. 64, Elsevier, Amsterdam.

MAPA (Ministry for Agriculture, Livestock and Supply) (2017), Produção [Production], MAPA, Brasilia, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao.

NREL (National Renewable Energy Laboratory) (2016), *Concentrating Solar Power Projects* (database), www.nrel.gov/csp/solarpaces/, (accessed June 2017).

OECD/FAO (Organisation for Economic Co-operation and Development/Food and Agriculture Organization) (2017), *OECD-FAO Agricultural Outlook, OECD Agriculture statistics* (database), doi: dx.doi.org/10.1787/agr-outl-data-en (accessed June 2017).

Platts (2017), *World Electric Power Plants Database*, March 2017 edition, McGraw-Hill Companies, New York, NY.

Rakos, C. (2017), "Pellet boiler markets – perspectives for the future", presentation at the 5th Central European Biomass Conference and Nordic Baltic Bioenergy Conference, Graz, 18 January 2017.

SPV Market Research (2017a), "Photovoltaic manufacturer capacity, shipments, prices and revenues 2016/17", SPV Market Research, San Jose.

SPV Market Research (2017b), *The Solar Flare – Issue 1*, SPV Market Research, San Jose.

UNICA (Brazilian Sugarcane Industry Association) (2017), *UNICA Data* (database), www.unicadata.com.br (accessed June 2017).

US DOE (United States Department of Energy) (2017), *Global Energy Storage Database*, US DOE, Washington, DC, www.energystorageexchange.org/ (accessed June 2017).

US DOE (2016), *U.S. Billion-Ton Update – Crop Residues and Agricultural Wastes*, US DOE, Washington, DC.

WindEurope (2017), *The European Offshore Wind Industry: Key Trends and Statistics 2016*, WindEurope, Brussels.

World Bank and Ecofys (2017), *Carbon Pricing Watch 2017*, www.ecofys.com/files/files/world-bank-ecofys-carbon-pricing-watch-2017.pdf

6. DATA TABLES

Table 6.1. Ethanol production (billion litres)

	2016	2017	2018	2019	2020	2021	2022	CAAGR
World	**100.5**	**99.5**	**102.0**	**106.9**	**111.8**	**113.6**	**115.3**	**2.3%**
North America	**59.5**	**61.2**	**61.1**	**61.6**	**62.0**	**62.2**	**62.3**	**0.8%**
Canada	1.6	1.6	1.7	1.7	1.7	1.7	1.7	0%
United States	57.9	59.5	59.4	59.8	60.1	60.2	60.4	1%
EU28	**4.3**	**5.1**	**5.3**	**6.0**	**6.4**	**5.6**	**5.3**	**4%**
France	0.8	1.0	1.0	1.0	1.1	0.9	0.9	3%
Germany	0.9	0.9	1.0	1.0	1.0	0.9	0.9	-1%
Eurasia	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**6%**
China	**2.6**	**3.2**	**3.4**	**3.4**	**3.5**	**3.6**	**3.8**	**6%**
Asia and Pacific	**3.0**	**2.9**	**3.8**	**4.3**	**4.9**	**5.3**	**5.5**	**10%**
India	1.1	0.7	1.1	1.2	1.5	1.8	1.9	9%
Thailand	1.2	1.4	1.6	1.8	1.9	2.1	2.2	11%
Latin America	**30.4**	**26.4**	**27.6**	**30.5**	**33.8**	**35.7**	**37.2**	**3%**
Argentina	0.9	0.9	1.0	1.1	1.1	1.1	1.2	5%
Brazil	28.1	26.7	27.7	28.0	31.2	33.0	34.5	3%
Africa	**0.2**	**0.2**	**0.3**	**0.5**	**0.6**	**0.6**	**0.7**	**21%**
Rest of World	**0.7**	**0.7**	**0.8**	**1.0**	**1.1**	**1.2**	**1.2**	**10%**

Notes: Production presented in volume; to convert to energy an approximate calorific value of 21 MJ/litre can be used. Sources: IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; IEA (2017d), *Monthly Oil Data Service (MODS) [May 2017]*, www.iea.org/statistics/; MAPA (2017), *Ministério da Agricultura – Agroenergia;* US EIA (2017), *Petroleum & Other Liquids*.

Table 6.2. Biodiesel production (billion litres)

	2016	2017	2018	2019	2020	2021	2022	CAAGR
World	**35.9**	**36.6**	**40.0**	**42.2**	**44.6**	**43.3**	**43.5**	**3.2%**
North America	**6.3**	**6.3**	**6.6**	**7.0**	**7.5**	**7.9**	**8.0**	**3.9%**
Canada	0.4	0.5	0.5	0.5	0.6	0.6	0.6	6%
United States	5.9	5.8	6.1	6.5	6.9	7.3	7.4	4%
EU28	13.5	13.9	15.0	15.5	16.0	13.8	13.4	0%
France	2.6	2.2	2.6	2.9	2.8	2.4	2.3	-3%
Germany	3.5	3.7	3.6	3.5	3.8	3.2	3.0	-2%
Eurasia	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0%**
China	**0.9**	**1.1**	**1.1**	**1.2**	**1.4**	**1.6**	**1.7**	**10%**
Asia and Pacific	**6.9**	**7.9**	**9.1**	**9.7**	**10.4**	**10.8**	**11.1**	**8%**
Malaysia	2.8	3.7	4.3	4.6	4.9	5.1	5.3	11%
Indonesia	0.9	1.0	1.1	1.1	1.2	1.2	1.3	6%
Latin America	**7.6**	**6.8**	**7.5**	**8.0**	**8.3**	**8.5**	**8.6**	**2%**
Argentina	3.0	2.0	2.3	2.3	2.5	2.5	2.5	-3%
Brazil	3.8	3.9	4.3	4.7	4.8	5.0	5.0	5%
Africa	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**11%**
Rest of World	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.4**	**0.4**	**2%**

Notes: Production presented in volume; to convert to energy an approximate calorific value of 33 MJ/litre can be used. Sources: IEA (2017e), *Oil Information* (database), www.iea.org/statistics/; IEA (2017d), *Monthly Oil Data Service (MODS) [May 2017]*, www.iea.org/statistics/; MAPA (2017), *Ministério da Agricultura – Agroenergia;* US EIA (2017), *Petroleum & Other Liquids*.

Table 6.3. Total renewable electricity capacity (GW)

	2016	2017	2018	2019	2020	2021	2022	CAAGR
World	**2134.4**	**2294.5**	**2451.4**	**2603.9**	**2757.3**	**2906.0**	**3056.6**	**6.2%**
North America	**358.5**	**380.4**	**402.9**	**428.9**	**461.0**	**485.7**	**508.8**	**6.0%**
Canada	96.3	98.0	99.4	101.2	102.9	104.2	105.6	1.6%
Mexico	18.2	19.2	21.6	24.8	29.0	33.0	36.7	12.4%
United States	244.0	263.2	281.9	302.9	329.1	348.4	366.5	7.0%
Asia Pacific	**317.9**	**347.5**	**378.0**	**408.5**	**440.3**	**475.0**	**508.3**	**8.1%**
Australia	19.1	20.5	22.3	23.8	25.7	27.0	28.4	6.8%
India	90.8	107.0	122.3	139.5	157.1	177.4	197.8	13.9%
Indonesia	8.7	9.1	9.9	10.5	11.1	12.2	13.4	7.4%
Japan	98.8	104.5	109.1	113.1	117.2	121.3	125.0	4.0%
Korea	14.1	15.5	16.9	18.4	20.4	23.0	26.0	10.8%
Thailand	10.2	10.9	11.7	12.5	13.0	13.5	14.1	5.6%
Europe	**536.5**	**561.4**	**583.7**	**606.0**	**625.3**	**643.0**	**661.3**	**3.5%**
Austria	19.3	19.7	20.2	20.6	21.0	21.4	21.8	2.0%
Belgium	8.1	8.7	9.2	9.9	10.8	11.5	11.8	6.4%
Czech Republic	5.4	5.4	5.4	5.5	5.5	5.5	5.6	0.5%
Denmark	8.2	8.9	9.4	10.1	10.7	11.1	11.7	6.1%
Finland	6.7	7.7	7.9	8.1	8.4	8.7	9.0	5.1%
France	46.3	48.1	50.5	53.6	56.7	60.5	64.6	5.7%
Germany	111.4	118.4	122.9	126.8	131.0	135.0	139.1	3.8%
Greece	8.4	8.6	8.6	8.7	8.8	8.9	9.0	1.2%
Iceland	2.7	2.7	2.7	2.7	2.7	2.7	2.7	0.6%
Ireland	3.4	3.8	4.0	4.2	4.4	4.7	5.0	6.5%
Italy	55.7	56.4	57.1	57.7	58.2	58.7	59.2	1.0%
Netherlands	7.6	8.5	9.5	11.0	12.8	14.4	16.1	13.4%
Norway	32.8	33.0	33.5	34.0	34.4	34.4	34.5	0.8%
Poland	9.2	9.4	9.6	9.8	10.1	10.3	10.6	2.3%
Portugal	12.7	13.4	14.0	14.0	14.7	14.8	15.0	2.8%
Spain	51.4	52.5	55.8	59.1	59.7	60.4	60.4	2.7%
Sweden	28.3	28.7	29.1	29.6	30.0	30.5	31.0	1.5%
Switzerland	16.0	17.5	18.0	18.8	19.5	19.8	20.1	3.8%
Turkey	34.6	37.1	39.2	41.4	43.1	45.4	48.0	5.6%
United Kingdom	37.0	41.1	44.6	47.5	49.4	50.2	51.6	5.7%
Latin America	**207.0**	**212.8**	**223.4**	**231.9**	**237.8**	**242.7**	**249.1**	**3.1%**
Argentina	13.4	13.5	14.7	16.0	17.0	18.2	19.9	6.9%
Brazil	121.3	124.8	132.1	136.4	139.0	140.3	142.1	2.7%
Chile	9.7	10.5	11.2	12.3	13.1	13.7	14.9	7.5%
Uruguay	2.2	2.6	2.7	2.8	3.0	3.1	3.3	6.7%
China Region	**570.4**	**641.3**	**703.3**	**760.1**	**816.5**	**873.9**	**933.3**	**8.6%**
MENA	**25.6**	**27.3**	**29.5**	**31.8**	**34.5**	**37.6**	**40.4**	**7.9%**
Egypt	3.7	3.8	3.9	4.3	4.7	5.1	5.3	6.0%
Jordan	0.5	0.6	1.1	1.4	1.5	1.7	1.8	23.9%
Morocco	2.9	3.1	3.6	3.9	4.6	5.2	5.7	12.0%
Saudi Arabia	0.0	0.0	0.1	0.2	0.2	0.3	0.5	59.5%
United Arab Emirates	0.1	0.4	0.6	1.1	1.6	2.2	2.8	65.3%
Sub-Saharan Africa	**33.3**	**37.0**	**41.2**	**44.9**	**48.4**	**52.7**	**57.7**	**9.6%**
Kenya	1.6	2.1	2.1	2.4	2.7	2.8	2.9	10.5%
South Africa	6.8	7.9	8.6	9.2	9.8	10.5	11.1	8.5%
Eurasia	**85.3**	**87.0**	**89.4**	**91.8**	**93.4**	**95.4**	**97.7**	**2.3%**
Russian Federation	52.3	52.7	53.5	54.5	54.7	54.7	54.8	0.8%
Ukraine	6.9	7.4	8.0	8.4	8.9	9.4	9.8	6.0%

Notes: MENA = Middle East and North Africa; GW = gigawatt. Capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Renewable electricity capacity includes capacity from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Grid-connected solar PV capacity (including small-distributed capacity) is counted at the time that the grid connection is made, and off-gird solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Specific sources are referenced where data for individual technologies are presented in previous chapters.

Table 6.4. Total renewable electricity generation (TWh)

	2016	2017	2018	2019	2020	2021	2022	CAAGR
World	**6012.0**	**6392.4**	**6791.5**	**7149.6**	**7488.9**	**7832.2**	**8168.7**	**5.2%**
North America	**1139.0**	**1199.2**	**1264.2**	**1320.3**	**1381.6**	**1454.8**	**1508.2**	**4.8%**
Canada	429.4	439.0	453.1	458.2	463.3	468.1	472.1	1.6%
Mexico	47.5	54.1	58.2	64.7	72.3	83.7	93.0	11.9%
United States	662.2	706.2	752.9	797.4	846.0	903.1	943.1	6.1%
Asia Pacific	**748.3**	**816.2**	**904.5**	**973.0**	**1042.9**	**1120.4**	**1196.3**	**8.1%**
Australia	38.0	40.2	43.7	47.3	51.5	55.0	57.9	7.3%
India	236.5	261.4	292.7	324.9	358.0	397.6	438.3	10.8%
Indonesia	29.5	31.0	33.5	36.1	38.7	41.4	45.1	7.3%
Japan	169.0	188.2	200.5	210.6	220.5	230.5	240.3	6.0%
Korea	21.4	25.8	29.1	32.0	35.8	41.0	46.8	13.9%
Thailand	18.6	20.5	23.3	25.0	26.3	27.5	28.8	7.6%
Europe	**1271.0**	**1338.2**	**1408.5**	**1471.6**	**1527.2**	**1570.9**	**1616.3**	**4.1%**
Austria	53.8	53.0	53.8	54.9	55.8	56.9	58.1	1.3%
Belgium	14.6	16.5	17.7	19.4	22.0	24.4	25.6	9.8%
Czech Republic	10.6	10.8	10.8	10.9	11.0	11.2	11.3	1.1%
Denmark	18.2	21.6	23.4	25.1	27.2	29.0	30.8	9.1%
Finland	30.5	32.4	34.8	35.6	36.3	37.3	38.5	4.0%
France	100.4	106.0	109.7	114.4	119.4	126.0	134.4	5.0%
Germany	193.7	212.6	223.5	231.3	238.4	245.6	253.1	4.6%
Greece	14.9	15.1	15.4	15.6	15.8	16.0	16.2	1.4%
Iceland	18.5	18.7	18.7	18.9	18.9	18.9	18.9	0.3%
Ireland	7.6	9.5	10.6	11.2	11.9	12.6	13.6	10.1%
Italy	110.0	104.9	111.6	118.7	119.8	120.5	121.4	1.7%
Netherlands	14.9	18.6	21.0	27.0	32.0	36.5	40.8	18.3%
Norway	146.3	142.8	143.7	145.1	146.5	147.2	147.5	0.1%
Poland	23.3	30.7	32.7	34.6	38.2	40.9	43.6	11.0%
Portugal	33.4	31.9	33.3	33.9	34.6	35.6	36.0	1.3%
Spain	108.0	108.1	112.6	119.6	125.5	125.7	126.6	2.7%
Sweden	87.7	92.1	98.4	99.6	100.7	102.0	103.5	2.8%
Switzerland	39.9	41.7	45.9	47.3	48.9	49.8	50.2	3.9%
Turkey	90.0	100.8	106.6	112.0	116.5	122.4	128.9	6.2%
United Kingdom	85.7	100.5	113.4	124.0	133.6	136.5	140.1	8.5%
Latin America	**826.8**	**883.5**	**915.3**	**953.5**	**983.6**	**996.4**	**1016.0**	**3.5%**
Argentina	40.9	42.0	43.4	46.0	48.8	51.3	55.2	5.2%
Brazil	468.2	494.6	515.1	537.8	556.4	559.1	565.8	3.2%
Chile	30.6	31.8	36.2	38.2	40.8	42.3	45.3	6.7%
Uruguay	11.1	12.0	12.5	12.9	13.2	13.6	14.1	4.0%
China Region	**1572.6**	**1671.5**	**1788.9**	**1895.3**	**1994.7**	**2104.0**	**2217.4**	**5.9%**
MENA	**45.6**	**49.7**	**53.6**	**58.2**	**62.9**	**70.6**	**77.0**	**9.1%**
Egypt	16.3	16.4	16.8	17.5	18.4	19.7	20.6	3.9%
Jordan	0.6	1.0	1.6	2.2	2.7	2.9	3.2	30.8%
Morocco	5.0	5.7	6.7	7.8	8.6	10.8	12.3	16.2%
Saudi Arabia	0.1	0.1	0.2	0.4	0.5	0.6	1.0	64.4%
United Arab Emirates	0.3	0.5	0.9	1.5	2.5	3.9	5.2	62.6%
Sub-Saharan Africa	**130.2**	**141.4**	**156.2**	**170.6**	**183.6**	**198.4**	**215.3**	**8.7%**
Kenya	9.3	10.4	11.6	12.5	13.7	14.9	15.5	8.9%
South Africa	11.7	15.0	17.2	18.8	20.5	22.3	24.0	12.7%
Eurasia	**278.5**	**292.8**	**300.3**	**307.1**	**312.4**	**316.6**	**322.2**	**2.5%**
Russian Federation	178.2	188.9	190.9	194.0	195.8	196.1	196.2	1.6%
Ukraine	10.2	13.1	15.8	16.8	17.9	18.8	19.7	11.6%

Notes: TWh = terawatt hour. Generation data refer to gross electricity production and include electricity for own use. Renewable electricity generation includes generation from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Generation from bioenergy includes generation from solid, liquid and gaseous biomass (including cofired biomass), and the renewable portion of municipal waste. The time series for onshore and offshore wind generation is estimated because wind generation data are only available at the aggregate level. Please refer to regional definitions in the glossary. For OECD member countries, 2016 generation data are based on IEA statistics published in *Renewables Information 2017*

GLOSSARY

Regional and country groupings

ASEAN

Brunei, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam.

Asia and Pacific

Australia, Bangladesh, Brunei, Cambodia, India, Indonesia, Japan, Korea, Lao PDR, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Viet Nam.

China

Refers to the People's Republic of China, including Hong Kong.

Europe

Austria, Albania, Belgium, Bulgaria, Croatia, Cyprus[41], Czech Republic, Denmark, Estonia, Finland, France, the Former Yugoslav Republic of Macedonia, Germany, Greece, Hungary, Iceland, Montenegro, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Sloval Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Middle East and North Africa (MENA)

Algeria, Bahrain, Egypt, Iran, Iraq, Israel[42], Jordan, Kuweit, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates and Yemen.

North America

Canada, Mexico and the United States.

[41] 1. Footnote 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 the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

2. Footnote 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.

[42] 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 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.

Sub-Saharan Africa (SSA)

Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritious, Mozambique, Namibia, Niger, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe, and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibuti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mauritania, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Zwaziland, Uganda).

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

AC	alternating current
acc.	accelerated
AD	accelerated depreciation
ARENA	Australian Renewable Energy Agency
ASEAN	Association of Southeast Asian Nations
ASHP	air source heat pump
ASTM	American Society of Testing and Materials
AT&C	aggregate technical and commercial
BEV	battery-electric vehicles
BNDES	Brazilian Development Bank
BoS	balance of system
BtL	biomass-to-liquid
CAAGR	compound annual average growth rate
CEL	clean energy certificate (Mexico)
CENACE	Centro Nacional de Control de Energia (Mexico)
CfD	contracts for difference
CI	carbon intensity
CO2	carbon dioxide
CPP	Clean Power Plan (United States)
CPQ	Climate Protection Quota
CNG	compressed natural gas
CSP	concentrating solar power
CSPE	renewable and social surcharge on electricity bills (France)
DME	dimethyl ether

DNI	direct normal irradiance
DPS	direct proposals scheme
DSG	direct-steam generation
EEG	Renewable Energy Act (Germany)
EEP	Ethiopian Electric Power
EfW	energy from waste
EPC	engineering procurement and construction
ERCOT	Electric Reliability Council of Texas
ESCO	energy service company
ETP	Energy Technology Perspectives
EV	electric vehicle
FAME	fatty acid methyl ester
FCEV	fuel-cell electric vehicle
FFV	flexible-fuel vehicle
FIP	feed-in premium
FIT	feed-in tariff
FODER	Fund for the Development of Renewable Energies (Argentina)
FYP	Five-Year Plan
GCF	Green Climate Fund
GERD	Grand Ethiopian Renaissance Dam
GHG	greenhouse gas
GSHP	ground source heat pump
HP	heat pump
HTF	heat transfer fluid
HVO	hydrotreated vegetable oil
ICE	internal combustion engine
IEA	International Energy Agency
ILUC	indirect land-use change
IPP	independent power producer
ITC	investment tax credit
LCFS	Low-Carbon Fuel Standard (California)
LCOE	levelised cost of energy

LNG	liquefied natural gas
LRET	Large-scale Renewable Energy Target (Australia)
LRP	Large Renewable Procurement (Canada)
LUC	land-use change
MASEN	Moroccan Agency for Sustainable Energy
MENA	Middle East and North Africa
METI	Ministry of Economy, Trade and Industry (Japan)
MME	Ministry of Energy and Mines (Brazil)
MNRE	Ministry of New and Renewable Energy (India)
NDC	nationally determined contribution
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NREP	National Renewable Energy Plan (Saudi Arabia)
N/A	not applicable
OECD	Organisation for Economic Co-operation and Development
OEM	original equipment manufacturer
OMC	oil marketing company (India)
O&M	operation and maintenance
PAYG	pay-as-you go
PFAD	palm fatty acid distillate
PHEV	plug-in hybrid electric vehicle
PLDV	passenger light-duty vehicle
PM	particulate matter
PPA	power purchase agreement
PSP	pumped storage plant
PTC	production tax credit
PURPA	Public Utility Regulatory Policies Act (United States)
PV	photovoltaic
REC	renewable energy certificate
RED	EU Renewable Energy Directive
REIPPPP	Renewable Energy Independent Power Producer Procurement Program (South Africa)
RFS2	Renewable Fuel Standard (United States)

RHI	Renewable Heat Incentive (United Kingdom)
RIN	renewable identification number
RO	Renewables Obligation (United Kingdom)
ROT	property repair, conversion, extension tax allowance (Sweden)
RoW	rest of world
RPS	renewable portfolio standard
RTS	reference technology scenario
SECI	Solar Energy Corporation of India
SNG	synthetic natural gas
SPF	seasonal performance factor
SHS	solar home system
SSA	sub-Saharan Africa
STE	solar thermal energy
(T)	target
TBC	to be confirmed
UDAY	Ujwal DISCOM Assurance Yojana (India)
WTO	World Trade Organization
WTW	well-to-wheel
W&R	waste and residue
YEKA	Renewable Energy Resource Areas (Turkey)
y-o-y	year-on-year

Currency codes

BRL	Brazilian real
CAD	Candaian dollar
CNY	Chinese Yuan renminbi
EUR	euro
GBP	British pound
INR	Indian rupee
JPY	Japanese yen
MAD	Moroccan dirham
USD	United States dollar

ZAR	South African rand

Units of measure

bbl	barrel (of oil)
EJ	exajoule
gCO_2/km	grams of CO_2 per kilometre
gCO_2/kWh	grams of CO_2 per kilowatt hour
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
GWth	gigawatt thermal
kb/d	thousand barrels per day
km	kilometre
kW	kilowatt
kWh	kilowatt hour
kWth	kilowatt thermal
L	litre
MBtu	million British thermal units
mb/d	million barrels per day
MJ	megajoule
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt hour
MWth	megawatt thermal
M^2	square metre
PJ	petajoule
t	tonne
tCO_2e	tonne of carbon dioxide equivalent
TJ	terajoule
TWh	terawatt hours
W	watt

IEA Publications,
International Energy Agency
Website: www.iea.org

Contact information: www.iea.org/aboutus/contactus

Typeset in France, October 2017

Cover design: IEA. Photo credits: © Shutterstock

IEA/OECD possible corrigenda on: www.oecd.org/about/publishing/corrigenda.htm

RENEWABLES 2017

Analysis and Forecasts to 2022

The renewable electricity market has witnessed an unprecedented acceleration in recent years, and it broke another annual deployment record in 2016. The market's main driver last year was solar photovoltaics, which is boosting the growth of renewables in power capacity around the world. As costs decline, wind and solar are becoming increasingly comparable to new-build fossil fuel alternatives in a growing number of countries. China remains the dominant player, but India is increasingly moving to the centre stage. Government policies are introducing more competition through renewable auctions, further reducing costs.

The IEA's newly renamed *Renewable 2017* (formerly titled *Medium-Term Renewables Market Report*) provides a detailed market analysis and overview of renewable electricity capacity and generation, biofuels production, and heat consumption, as well as a forecast for the period between 2017 and 2022. This year's report also provides additional analysis on the contribution of electric vehicles to renewable road transport and on the off-grid solar market in Africa and developing Asia.

Finally, the report identifies a set of policy improvements in key markets that could accelerate the growth of renewables in the electricity sector as well as the growth of transport biofuels for the first time. These are needed to accelerate decarbonisation in all sectors in order to be on track to meet long-term climate goals.

€80 (61 2017 28 1E1)
ISSN: 2520-2774
ISBN: 978-92-64-28389-3

MARKET REPORT SERIES