



RENEWABLE ENERGY Medium-Term Market Report Market Report



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Market Analysis and Forecasts to 2020



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FOREWORD

The rapid growth of renewables has been one of the most promising features in otherwise sluggish progress towards a more secure and sustainable energy future. In 2013, renewable power generation continued to grow strongly, reaching almost 22% of the global mix. Renewables now produce as much electricity worldwide as gas and more than twice that from nuclear. Investment in new renewable power topped USD 250 billion in 2013. Biofuels for transport and renewables for heat continued to grow, but more slowly and with persistent policy challenges.

Still, the *Medium-Term Renewable Energy Market Report 2014* identifies growing risks. Renewables are a necessary part of energy security. Yet, just when they are becoming cost-competitive options in an increasing number of cases, policy and regulatory uncertainty is rising in some key markets. This uncertainty is slowing growth. In the countries of the Organisation for Economic Co-operation and Development (OECD), the rapid deployment of renewables often requires scaling down part of the existing energy system, which can put incumbent utilities under severe pressure. In non-OECD countries, there is more room for renewables to meet rising electricity demand and expanding system needs. Still, these markets can present investment risks, including high non-economic barriers. Muddled signals from OECD markets also send the wrong messages at a time when newer markets have a golden opportunity to leapfrog to more flexible and cleaner power systems.

The policy uncertainty stems mainly from concerns about the costs of deploying renewables. But governments must distinguish more clearly between the past, present and future, as costs are falling over time. The initial deployment phase did require significant investment to advance technology learning. The future expansion of renewables hinges less on high levels of financial support. New deployment can be done at much lower unit investment costs than in the past. It would be unfortunate to scale back development plans now, after much of the hard work has been done.

Rather than high incentive levels, renewables, given their capital-intensive nature, need a market context that assures a reasonable and predictable return for investors. The costs of renewable generation depend on the cost of capital, which is determined by risk perceptions. Policy uncertainty is one risk that investors cannot well manage. But policy makers can provide the solution. Creating a stable investment climate with long-term policy certainty would go a long way to reduce this risk and the cost of financing for renewable investments. Recognising this context calls for serious reflection on how a right market design is needed to achieve a more sustainable world energy mix.

This report provides a unique insight into trends in the fast-changing renewable world. Exceptionally, given the importance of 2020 for policies in Europe and elsewhere, the forecasts of this third edition extend to six rather than the five years in other International Energy Agency (IEA) medium-term reports. It has also extended analysis of renewable use for heat – an area with considerable potential for cost-effectively improving energy security, but which lacks attention from policy makers. I am sure this work will provide value to decision makers in government, industry and the finance sector.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven Executive Director International Energy Agency

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Questions or comments?

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EXECUTIVE SUMMARY

- In 2013, new renewable power capacity expanded at its fastest pace to date. Globally, renewable generation was estimated on par with that from natural gas.
- Over the medium term, renewables face a transition period. Despite strong anticipated generation growth, new generation, capacity additions and investment in renewable power are all expected to level off through 2020. Biofuels for transport and renewable energy use for heating and cooling face slower growth and persistent policy challenges.
- Even with growing competitiveness, policies remain vital to stimulating investment in capital-intensive renewables. Scaling up deployment to higher levels would require stable, long-term policy frameworks and market design that prices the value of renewables to energy systems and increases power system flexibility to ensure system adequacy with greater variable renewables.

The role of renewables in the energy mix continued to expand in 2013

In 2013, global renewable electricity generation rose by an estimated 240 terawatt hours (TWh) (+5.0% year-on-year) to reach nearly 5 070 TWh and accounted for almost 22% of total power generation. The expansion was somewhat slower than that predicted in the *Medium-Term Renewable Energy Market Report 2013* (*MTRMR 2013*), largely due to lower-than-expected annual hydropower availability and slower-than-expected growth in bioenergy generation. However, the renewable capacity expansion was faster than that foreseen in *MTRMR 2013*, with larger-than-expected deployment of hydropower and solar PV.

Globally, renewable generation was on par with that of natural gas, whose generation declined slightly in 2013, but remained behind coal, which was almost double the size of renewables. This result stems from the strength of the continued renewable expansion as well as difficult economics for gas generation in many member countries of the Organisation for Economic Co-operation and Development (OECD) in 2013 and difficulty to access affordable gas supplies in non-OECD regions (see IEA, 2014a for discussion on recent gas market trends).

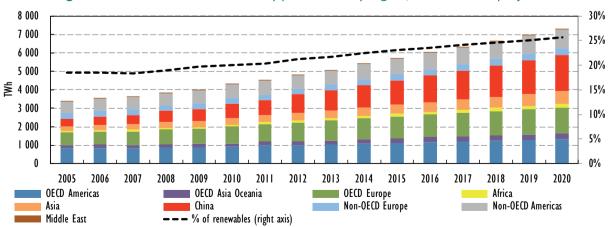


Figure 1 Global renewable electricity production by region, historical and projected

Notes: unless otherwise indicated, all material in figures and tables in this chapter derive from International Energy Agency (IEA) data and analysis. Hydropower includes pumped storage; the onshore and offshore wind split is estimated; total generation is gross power generation.

The percentage change in renewable generation was somewhat slower than in 2012, despite record annual renewable deployment of nearly 123 gigawatts (GW). Hydropower deployment reached 41 GW in 2013, partly due to the early commissioning of new capacity in China. But the return of hydro availability to more normal levels in China and the effects of drought in Brazil caused global hydropower generation to expand by less than 2% year-on-year compared to over 4% in 2012. Non-hydropower renewable generation grew rapidly by almost 16% year-on-year, similar to the rate in 2012. New solar photovoltaic (PV) capacity (+39 GW) surged in 2013, led by China and Japan, where deployment is incentivised through attractive feed-in tariffs (FITs). Onshore wind additions (+34 GW) were their lowest since 2008, largely due to a drop in new capacity in the United States stemming from policy uncertainty over the renewal of federal tax incentives at the end of 2012. Though smaller, solar thermal electricity (STE) additions were equivalent to the record level achieved in 2012, and offshore wind was deployed at its highest level to date, with the start of several large projects long under development.

Global biofuels production rose by almost 7% in 2013 to reach over 115 billion litres (L), 3 billion L higher compared with that predicted by *MTRMR 2013*. In Brazil, ethanol output was boosted by a higher-than-expected sugar cane harvest that led to a 2 billion L additional ethanol production compared to the previous forecast. In the United States, ethanol production rose marginally in 2013, as the effect of elevated corn prices resulting from an extensive drought in the previous year was mitigated after the 2013 corn harvest. Biofuels output, adjusted for energy content, accounted for 3.5% of global oil demand for road transport in 2013, versus 3.4% in 2012 and 2.0% in 2007. Meanwhile, the geography of biofuels policy support is shifting; while backing for increased biofuels volumes is waning in several key markets – the United States, the European Union and Brazil – it is expanding in newer non-OECD markets, such as Southeast Asia.

World final energy use for heat (FEH) accounts for more than half of final energy consumption, with three-quarters of this met with fossil fuels. FEH has a significant impact on energy security and is responsible for around one-third of global energy-related carbon dioxide emissions. Global final energy use of renewable sources for heat, excluding traditional biomass, rose by over 2% in 2013 to 14.5 exajoules (EJ), accounting for only 8% of world energy use for heat, only slightly higher than in 2012 and 2007. Final energy use of renewable energy for heating and cooling is rising globally, driven by support policies and increasingly by cost-competitiveness with fossil fuels, but policy frameworks are generally underdeveloped compared with the electricity and transport sectors.

Strong market drivers, but increased risks for renewable power deployment ahead

Over the medium term, global renewable electricity generation is projected to grow by almost 45%, or 2 245 TWh, to over 7 310 TWh in 2020 (+5.4% per year). Hydropower, including output from pumped storage, represents about 37% of total growth, followed by onshore wind at 31% of total growth. Compared with the *MTRMR 2013*, renewable generation is seen 180 TWh lower in 2018, due less optimistic outlooks for hydropower, bioenergy, wind (onshore and offshore) and STE. The hydropower forecast versus *MTRMR 2013* has been revised down largely due to a slower-than-expected expansion in China and in the non-OECD Americas. Bioenergy is seen growing more slowly in China. For wind, onshore and offshore, the forecast has been revised down in China, OECD Europe, the United States and Australia. Growth in STE is likely to be slower-than-expected in the United States, China and the Middle East over the forecast period. By contrast, the outlook for solar PV has been revised up in many areas, notably China and Japan.

Two global trends should help drive the deployment of renewable power capacity, which is expected to rise from a global total of 1690 GW in 2013 to 2555 GW in 2020 (growth of 50%). First,

deployment should spread out geographically as renewable electricity capacity scales up. Second, renewable technologies are becoming increasingly competitive on a cost basis with alternatives in a number of countries and circumstances.

Still, compared to *MTRMR 2013*, increased policy and market risks cloud the development picture, raising concerns over how fast renewables can scale up to meet long-term deployment objectives. In this report's **baseline case** forecast, annual growth in new renewable power capacity is expected to stabilise over 2013-20, a departure from the previous decade's upward trend of rapidly increasing annual growth in some technologies. This trajectory reflects growing risks to deployment in some key OECD markets. At the same time that barriers to development remain in a number of non-OECD areas, including China, and deployment is not expected to proceed as fast as envisaged in *MTRMR 2013*. Nevertheless, this conservative outlook is not inevitable – with certain market and policy enhancements, the most dynamic renewable technologies could grow faster through 2020 than in this report's baseline case (see "Enhanced Case" below).

Under the baseline case forecast, non-OECD markets are expected to account for around 70% of new renewable power generation from 2013-20. Many non-OECD countries have dynamic power systems, with fast-growing demand and diversification needs providing strong drivers for renewables, which are increasingly competitive versus other new generation. To this end, a number of markets have adopted long-term policy frameworks. Combined with good resources and the falling costs of some technologies, such as solar PV, these conditions should support increasing levels of deployment with reduced financial incentives. Renewables are seen as the largest new source of non-OECD generation through 2020. Yet, they meet only 35% of fast-growing electricity needs, illustrating the still-significant role of fossil fuels and large upside for greater renewable growth. Many non-OECD countries, such as those in the Middle East, remain at the inception or early take-off phase of development, with deployment likely to accelerate to high levels only over the long run.

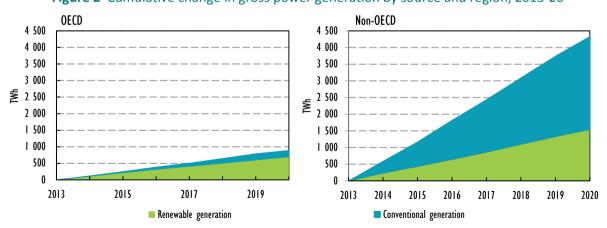


Figure 2 Cumulative change in gross power generation by source and region, 2013-20

China remains the anchor of renewable capacity deployment, accounting for almost 40% of the global expansion and over 60% of non-OECD growth. Strong generation needs, pollution reduction goals and a favourable policy environment with ambitious targets support China's deployment. There, renewables should account for nearly 45% of incremental power generation over the medium term, ahead of coal. In addition to hydropower and onshore wind, whose significant deployment should continue, solar PV, whose costs have fallen rapidly, has become a strategic pillar of the energy

system. Still, several challenges have emerged. In China, the outlook for power demand has notably slowed versus *MTRMR 2013*. Moreover, the pace of new hydropower approvals has reduced, integration challenges remain for large amounts of new onshore wind, and questions have emerged over whether conditions are favourable for an ambitious planned expansion of distributed solar PV.

Among other non-OECD regions, the Americas and the rest of Asia should make the largest growth contributions. The steady expansion of hydropower, onshore wind and bioenergy capacity in Brazil, supported by the government's long-term auction scheme, underpins the outlook in the Americas. India's diverse set of targets and financial incentives supports the growth of hydropower, onshore wind, solar PV and bioenergy, underpinning the Asia forecast. Other emerging markets, such as Thailand and Indonesia, are also expected to contribute. In Africa, non-OECD Europe and Eurasia, and the Middle East, growth remains more nascent. Some markets should scale up from low bases, such as South Africa, backed by a long-term auction scheme, and Saudi Arabia, which has announced aggressive long-term targets backed by auctions. However, non-economic barriers, needed grid upgrades, and high costs and reduced availability of financing may represent persistent risks and constraints in many non-OECD areas.

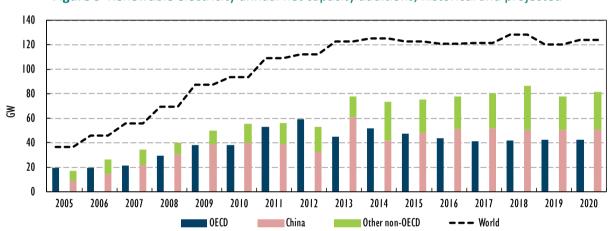


Figure 3 Renewable electricity annual net capacity additions, historical and projected

In the OECD, after several years of rapidly increasing growth, renewables are transitioning to a slower but stable annual capacity expansion. Renewable generation is expected to account for near 80% of new power generation from 2013-20. While a significant share, there is limited upside potential to growth given overall sluggish demand and policy risks in key markets. Within the OECD, the growth of renewables has been driven by strong policy support for decarbonisation, a desire for diversification and retirements of conventional power plants. In many cases, the rapid deployment of renewables requires scaling down of part of the existing energy system, which is putting incumbent utilities under severe pressure. In addition, while renewables are now much more competitive with other forms of electricity, all power generators are struggling in OECD markets where there is oversupply and low wholesale prices. These trends are particularly marked in Europe.

OECD power markets increasingly fall into three categories: dynamic systems with rising demand and new generation needs; stable systems with sluggish demand growth and overcapacity; and markets in between, usually with slow demand growth, but a need for capacity replacement due to diversification aims or retirements. Dynamic markets (e.g. Chile, Mexico, Korea and Turkey) have strong drivers for renewable deployment, but face hurdles in scaling up deployment due to non-economic barriers or the

cost/availability of financing. Other systems, such as those with relatively stable demand but diverse supply-side needs (e.g. the United States, Japan, some European markets) face challenges to maintain regulatory frameworks that offer a reasonable degree of remuneration certainty while shifting towards lower levels of economic incentives and integrating higher penetrations of variable renewables.

Policy risks in the latter group of countries represent a significant factor behind an expected stabilising of new renewable growth. In the European Union, uncertainties remain over the precise nature of the post-2020 renewable policy framework and the build-out of a pan-European grid to facilitate the integration of variable renewables. In Japan, there is considerable uncertainty over the future evolution of the FIT scheme and grid integration issues pertaining to solar PV. In the United States, announced federal regulations on existing power plant emissions should help support renewables going forward, but questions persist over the durability of renewable tax incentives, and heated debates are occurring in a number of states over renewable portfolio standards and rules for promoting distributed generation.

Higher renewable electricity deployment possible under enhanced case conditions

This report includes an enhanced case in order to show the potential impacts on deployment from certain market and policy enhancements that help to address challenges to renewable deployment. Under the enhanced case, the most dynamic renewable electricity sources (i.e. solar and wind) could grow faster than the baseline case. A number of country-specific developments, as described within each regional outlook, would need to occur for this result to occur, making it difficult to anticipate and more approximate in nature than the baseline case. The enhanced case is represented by a range and is indicative of the potential upside for cumulative capacity in the year 2020.

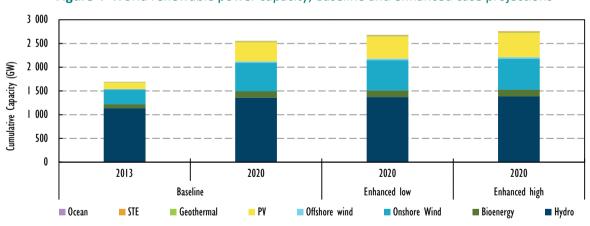


Figure 4 World renewable power capacity, baseline and enhanced case projections

Broadly speaking, achieving enhanced renewable deployment would require alleviating some of the challenges enumerated above and repeated through this report. These include, but are not limited to, the rapid clarification of policy uncertainties in some markets; the implementation of stable and sustainable policy frameworks that give greater certainty about the long-term revenue streams of renewable projects; greater measures to ensure the grid and system integration of variable renewables; the implementation of fair rules and appropriate electricity rate design for allocating the costs and benefits from fast-growing distributed solar PV; improved reductions in non-economic barriers; and faster-than-expected decreases in renewable technology and generation costs.

Under the enhanced case, renewable capacity could be 125-205 GW higher in 2020 than the baseline case. Solar PV and onshore wind, with relatively short development times, have the largest upside. In the enhanced case, solar PV could reach a cumulative 465-515 GW in 2020 while onshore wind could climb to 635-655 GW. Further details are in the regional and technology chapters in this report.

Improving competitiveness, but market and policy frameworks keys for investment

Supported by long-term policy frameworks, renewable investment has risen to high levels, from a variety of financing sources. Still, the capital-intensive nature of projects can make the risk/return profile of such assets challenging for investors. In 2013, global new investment in renewable power capacity was estimated over USD 250 billion, down slightly versus that in 2012, and lower than the near USD 280 billion registered in 2011. Despite overall higher global capacity additions (123 GW), declining unit investment costs in solar PV and onshore wind put downward pressure on investment levels. Over the medium term, annual investment in new renewable power capacity is seen averaging a somewhat lower level, at above USD 230 billion annually, in real terms, through 2020. In 2014, investment is seen just under USD 250 billion as total renewable capacity additions remain around 125 GW, but annual investment slows for several years thereafter. The forecast stems from slowing global capacity growth, but also from expectations of reduced unit investment costs going forward for some renewable technologies.

Reductions in investment costs have helped the levelised cost of energy (LCOE), without incentives, for some renewable technologies to further decrease over the past year. Although renewables remain generally more expensive than conventional electricity-generating technologies, this gap is expected to further narrow over the medium term. Still, LCOE provides only a partial indication of competitiveness, and investment decisions are usually based on additional financial information. While comparing the cost of energy for various electricity-generating technologies, LCOE may not take into account the value of electricity, which depends on the time and location of production, the market frameworks under which different technologies compete, or the recovery of fixed network costs. The market conditions in which renewables operate can have a significant impact on their bankability. For example, in markets with good resources, good financing conditions and rising demand, some renewables are able to compete under a market design of wholesale pricing. For other markets, renewables may find it difficult to recoup their costs with wholesale prices, even as their generation costs decline.

With decreasing system costs, competitive opportunities are expanding for some renewable energy technologies under some country-specific market conditions and policy frameworks. In Brazil, with good resource and financing conditions, onshore wind has consolidated its competitive position, continuing to outbid new-build natural gas plants in auctions over the last year. In South Africa, with good wind resource and long-term power purchase agreements (PPAs), onshore wind is preferred against new gas and coal power plants to meet growing demand. In Chile, high wholesale electricity prices and good irradiation levels have opened a new merchant solar PV market. There, the world's first merchant utility-scale solar PV plant was interconnected and another was financed over the past year; both projects are to sell electricity to the wholesale market without a PPA.

Falling solar PV costs are supporting the emergence of competitive market segments in both commercial and residential sectors linked to the concept of socket parity – when the LCOE of distributed PV systems becomes lower than the variable portion of retail electricity prices that system owners would otherwise pay (see "Special focus: Solar PV reaching socket parity" in chapter "Renewable electricity: Global technologies"). Increasingly strong deployment is raising debates over the system integration of distributed generation, especially in the United States and Europe. As more rate-payers generate their own electricity from PV,

they consume less grid electricity, contributing less to remuneration of overall grid costs when these are charged per unit of energy consumed. This situation is raising issues concerning fair rules and appropriate electricity rate design for allocating the costs (e.g. recovery of fixed grid costs) and benefits from distributed PV.

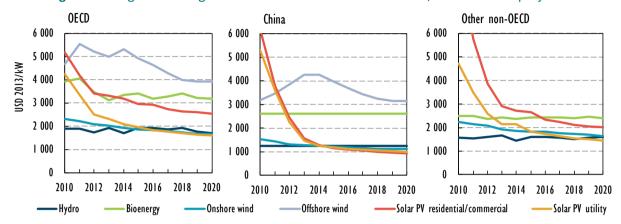


Figure 5 Weighted average annual renewable investment costs, historical and projected

Note: kW = kilowatt. Average unit investment costs are based on gross additions, which include capacity refurbishments that are typically lower cost than new capacity. Costs vary over time due to technology changes as well as where deployment occurs in a given year.

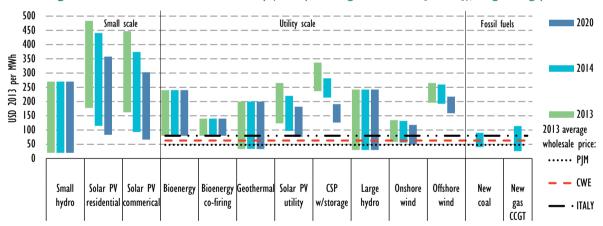


Figure 6 Levelised costs of electricity (USD per megawatt hour [MWh]), beginning year

Notes: CSP = concentrated solar power; CCGT = combined cycle gas turbine. Wholesale power prices are expressed as the annual average of daily traded, day-ahead base-load power prices. CWE (Central Western Europe) refers to annual average of power prices in France, Germany, Austria and Switzerland. United States (US) PJM refers to the regional transmission organisation covering parts of 13 states in the mid-Atlantic and Midwest portion of the United States. LCOEs reflect typical system costs for selected technologies. Costs are indicative and ranges reflect the system cost, resource and financing differences among countries. Geothermal LCOE range includes only conventional and binary plants.

Source: IEA analysis with 2013 wholesale electricity price data from Bloomberg LP (2014), accessed 01 June 2014; and EIA (Energy Information Administration) (2014), Wholesale Electricity and Natural Gas Market Data accessed 20 May 2014, Washington D.C.

Overall, policy remains vital to the competitiveness of renewable technologies. Even in situations of good competitiveness, policy, market and technology risks can undermine project viability. Policy uncertainty remains a key challenge to renewable deployment. Unanticipated changes to incentive schemes represent a risk that investors cannot manage, and can lead to elevated financing costs and boom-and-bust development patterns. In addition, non-economic barriers, integration challenges, grid connection risk, and macroeconomic and currency risks can all increase financing costs and weigh upon investments. In markets based on short-term marginal cost pricing, remuneration flows can be uncertain,

and capital-intensive technologies, such as renewables, can often require policy incentives. By contrast, renewable power capacity is being deployed with little financial support in some areas with rising energy needs, good resources and predictable long-term policies. Market design based on competition over long-term contracts (as being developed in Brazil and some other Latin American countries, for example) is one way that is sustaining investment.

Biofuels for transport and renewable heat expanding, though with challenges

After a period of rapid growth, biofuel production and consumption in the United States, the European Union and Brazil appear to be shifting gears. In the United States, the design shortcomings of previous biofuel mandates have become manifest, leading to policy reviews that have introduced uncertainty in the market. In Brazil, the ethanol industry's economic situation is worsening, partly due to inflation-targeted gasoline price regulations that undermine ethanol economics. In the European Union, ongoing controversy about the sustainability of biofuels has led to a proposed cap on conventional biofuel use that is leaving the industry in limbo until a final decision on the proposal is taken. At the same time, policy support is burgeoning in non-OECD countries, notably oil-importing economies in Southeast Asia and Africa that subsidise fuel consumption, where rising domestic biofuel production promises a valuable option to lowering fuel import bills.

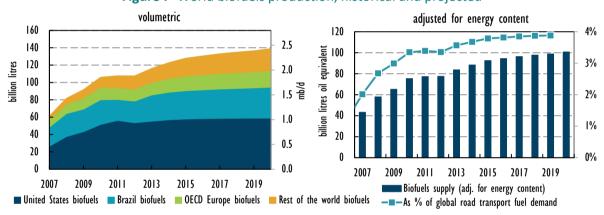


Figure 7 World biofuels production, historical and projected

Global biofuel production is seen reaching 139 billion litres in 2020. For 2018, the forecast is 2 billion L lower than in *MTRMR 2013*. With a less optimistic outlook for the United States and Brazil, world ethanol output is now forecast to reach 104 billion L in 2020. For 2018, the ethanol forecast has been cut by almost 4 billion L from levels projected last year. By contrast, expectations of biodiesel production have been revised marginally upwards. World biodiesel production is expected to edge up to 33 billion L, roughly 0.6 billion L higher than projected in the *MTRMR 2013*, as stronger growth in non-OECD Asia outweighs downward revisions in the non-OECD Americas. Meanwhile, the advanced biofuels industry faces headwinds, but capacity is expanding. Operating capacity reached almost 2 billion L in 2013, and could reach 4 billion L in 2020, if projects under development come on line as planned. Growth is slower than projected in *MTRMR 2013*. A number of companies have cancelled or postponed projects as they struggle to secure investments in light of an increasingly uncertain policy framework in the two key markets, the European Union and the United States. Developments in advanced biofuels also continue to remain limited to these two regions.

Global renewable energy use for heat, including traditional biomass, is expected to grow by 3.5 EJ¹ to 49.7 EJ in 2020 (1.0% per year). This year's projections for renewable heat are based on a new bottom-

¹ 1 EJ = 23.9 million tonnes of oil equivalent = 277.8 terawatt hours thermal = 947*10⁶ million British thermal units.

up modelling structure, which allows for projections of the energy use of different renewable energy sources by sector (industry, buildings, and others) on a country-by-country basis. While traditional biomass use is expected to decline in most non-OECD countries as a result of urbanisation and enhanced access to modern energy sources, modern renewable energy sources are expected to grow from 14.5 EJ in 2013 to 17.9 EJ in 2020 (3.0% per year), driven by support policies in 50 countries around the world, as well as increasing cost-competitiveness with fossil fuel-based heating in a growing number of countries. Modern renewable energy use for heat in the buildings sector grows from 6.1 EJ in 2013 to 8.3 EJ in 2020 (5.1% per year), much stronger than in the industry sector, where the continued absence of policy drivers leads to only a 0.8 EJ increase to 8.9 EJ in 2020.

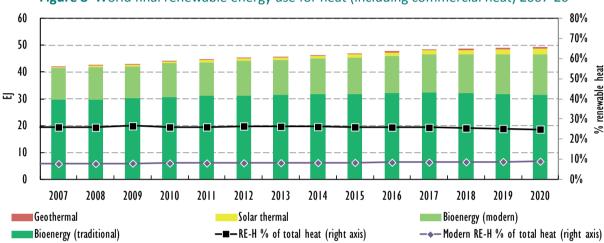


Figure 8 World final renewable energy use for heat (including commercial heat) 2007-20

Note: RE-H = renewable heat. Traditional biomass is estimated here — in line with the methodology used in the IEA World Energy Outlook (WEO) — as the use of solid biomass in the residential sector of non-OECD countries, excluding countries in non-OECD Europe and Eurasia.

Renewables at risk of falling short versus long-term clean energy scenarios

Despite the growing competitiveness of a portfolio of renewable technologies, renewable power is increasingly at risk of falling short of global climate change objectives, i.e. the interim 2020 and 2025 targets in the IEA *Energy Technology Perspectives 2014 (ETP 2014)* 2°C Scenario (2DS), in absolute generation levels (IEA, 2014b). That scenario assumes nearly 8 100 TWh of renewable generation in 2020 (versus total generation of 27 720 TWh) and over 10 900 TWh in 2025 (compared with total generation of 30 315 TWh). Biofuels for transport face a more challenging path. Overall biofuels production must triple, and advanced biofuels need to increase 22-fold to meet 2DS targets by 2025.

Among renewable power technologies, solar PV is the only source expected to exceed global 2DS targets in 2020, boosted by cost declines and an increasingly rapid scale-up in non-OECD markets. Meanwhile, notable shortfalls may occur in bioenergy for power, onshore wind and hydropower, which are all mature and relatively cost-effective technologies. Policy support for bioenergy has waned in some OECD countries, and developments face the challenge of establishing sustainable feedstock supply chains. Onshore wind can face challenges related to local acceptance, as in some European markets, and requirements for the build-out of the grid and further integration measures to reach higher levels of penetration, as in China and Europe. Hydropower, with long development lead times, is experiencing challenges in some emerging markets related to environmental licensing and financing. Other technologies at risk of falling short, offshore wind and solar thermal electricity (STE), require faster cost reductions to achieve higher levels of development. To meet 2025 objectives, a more rapid rate of scale-up would be needed across a number of technologies.

12 000 Scenario analysis Historical reported data and estimates Medium-term forecast 10 000 2DS targets Generation (TWh) 8 000 6 000 4 000 2 000 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2025 2006 2007 STE Geothermal Solar PV Offshore wind Onshore wind Bioenergy ■ Hydro **--** - *MTRMR 2013*

Figure 9 Global renewable electricity generation, the MTRMR 2014 forecast versus ETP 2014 2DS

Note: MTRMR 2014 data and forecasts as well as the 2DS targets include output from pumped hydro storage.

Overall, policies will remain vital to stimulating investment in capital-intensive renewables and stimulating greater development. To realise the high levels of renewables required to meet long-term climate change objectives, as in the WEO 450 scenario (which models similar objectives as the 2DS), cumulative investment of almost USD 9 trillion would be needed by 2035 (IEA, 2014c).

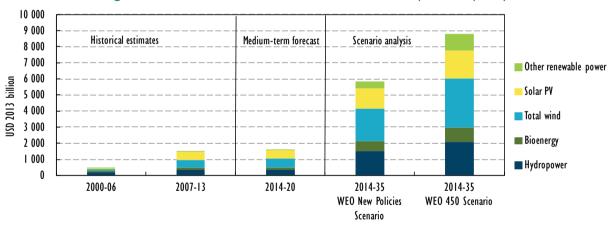


Figure 10 Cumulative investment in new renewable power capacity

Note: New Policies and 450 Scenario data are reported in USD 2012 billion.

Sources: 2014-20 investment is derived from MTRMR 2014 estimates, while New Policies and 450 Scenario data are from IEA (2014c), World Energy Investment Outlook, OECD/IEA, Paris.

Mobilising this high-level capital would require resolving some of the specific challenges described above. More generally, it would need stable, long-term oriented policy frameworks from governments and a market design that more effectively prices the value that renewable investments can bring to energy systems and increases power system flexibility to ensure system adequacy with higher levels of variable renewables. Recent IEA research – *The Power of Transformation* – suggests that such aims can be achieved in a secure and cost-effective manner (IEA, 2014d). However, this result would require a system-wide approach to energy policy, one that promotes the deployment of integration-friendly variable renewables, fosters better operation of existing power assets and creates incentives for investment in additional flexibility options – grid infrastructure; dispatchable generation, such as gas-fired or hydro power; demand-side integration; and storage – when needed.

Table 1 World renewable electricity capacity and projection (baseline case) (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	1 133	1 168	1 203	1 237	1 270	1 307	1 333	1 360
Bioenergy	88	93	97	104	111	118	125	133
Wind	319	363	407	449	491	536	583	630
Onshore	312	354	396	435	475	517	559	602
Offshore	7	8	11	13	16	20	24	29
Solar PV	137	176	214	253	289	326	364	403
STE	4	5	5	6	7	8	10	11
Geothermal	12	12	13	13	14	15	15	16
Ocean	1	1	1	1	1	1	1	1
Total	1 692	1 817	1 940	2 061	2 182	2 311	2 431	2 555

Notes: capacity data are rounded to the nearest GW and are generally presented as cumulative installed capacity, irrespective of grid-connection status. Grid-connected solar PV capacity (including small distributed capacity) is counted at the time that the grid connection is made, and off-grid solar PV systems are included at the time of the installation.

Table 2 World renewable electricity generation and projection (baseline case) (TWh)

	2007	% of total gen, 2007	2012	% of total gen, 2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	3 166	15.9%	3 756	16.5%	3 828	3 982	4 104	4 223	4 340	4 469	4 581	4 669
Bioenergy	233	1.2%	379	1.7%	396	433	457	483	514	547	581	615
Wind	171	0.9%	521	2.3%	633	721	830	936	1 042	1 156	1 279	1 409
Onshore	168	0.8%	505	2.2%	612	695	797	896	992	1 095	1 204	1 318
Offshore	3	0.0%	15	0.1%	21	26	32	40	50	61	75	90
Solar PV	7	0.0%	97	0.4%	131	188	237	286	334	382	431	482
Solar CSP	1	0.0%	5	0.0%	6	11	14	16	19	23	27	32
Geothermal	62	0.3%	70	0.3%	73	78	81	85	90	94	99	104
Ocean	0	0.0%	1	0.0%	1	1	1	1	1	2	2	2
Total	3 641	18.3%	4 829	21.2%	5 068	5 414	5 724	6 030	6 340	6 672	7 000	7 313

Notes: gen = generation. Hydropower includes generation from pumped storage, which was reported at 84 TWh for 2012. Data for 2013 are estimates; the split for onshore and offshore wind is estimated for historical data.

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ANALYTICAL FRAMEWORK

This third edition of the *Medium-Term Renewable Energy Market Report* (*MTRMR*) forecasts renewable energy developments within the electricity, heat and transport sectors. Renewable electricity focuses on eight technologies – hydropower, bioenergy for power, onshore wind, offshore wind, solar photovoltaic (PV), solar thermal electricity (STE) from concentrated solar power plants, geothermal and ocean power. The renewable transport section forecasts for biofuels for transport production, including ethanol, biodiesel and advanced biofuels. Final energy use of renewable sources for heat focuses on bioenergy (excluding traditional biomass), geothermal and solar thermal technologies. While renewables for transport and final energy use of renewable sources for heat could, include use of renewable electricity, this report does not attempt to characterise these flows.

Renewable energy data present unique challenges

As a relatively young and rapidly evolving sector, renewable energy presents a number of statistical challenges. The size and dispersion of some renewable assets create measurement problems. Small-scale and off-grid applications, such as in solar PV and bioenergy, are difficult to count and can often be under-represented in government reporting. Identifying the renewable portion from multi-fuel applications, such as in co-firing with fossil fuels or municipal waste generation, also remains problematic. Moreover, the increased geographic spread of renewable deployment, particularly within areas outside the Organisation for Economic Co-operation and Development (OECD), creates the challenge of tracking developments in less transparent markets.

This report aims to provide a complete view of renewable generation and capacity trends over time. Still, historical data points, including 2013, may reflect estimates that are subject to revision. While official International Energy Agency (IEA) statistics provide the basis for much of the data analysis, they also carry measurement limitations. As such, this report's historical series are determined by consulting multiple sources, including official IEA statistics, work by IEA Implementing Agreements, reporting by industry associations and consultancies, and direct contact with governments and industry.

Hydropower generation data include output from pumped hydropower. Electricity output from pumped storage is generally not considered primary power generation because the inputs of electricity used to pump the water have already been generated and accounted for under the primary energy source (e.g. coal, wind, solar PV, etc.). As such, in other analyses, electricity output from pumped storage is typically excluded from power generation data and treated separately. However, this report projects hydropower generation from capacity that cannot always be separated into such discrete parts as in generation.

In general, capacity data for renewable sources are presented as cumulative installed capacity, irrespective of grid-connection status. Solar PV, however, is a notable exception. Grid-connected solar PV capacity (including small distributed capacity) is counted at the time that the grid connection is made, and offgrid systems are included at the time of the installation. Except where noted, prices and costs are expressed in real, 2013 United States dollars (USD).

Country-level approach underpins the renewable electricity analysis

Given the local nature of renewable development, the approach begins with country-level analysis. For renewable electricity analysis, the *MTRMR 2014* examines in detail key markets and regions for renewable electricity, while identifying and characterising developments that may emerge in other

important markets. Forecasts stem from both quantitative and qualitative analysis. Country-level examinations start with an assessment of the prevailing renewable project pipeline, which is established using various country-level sources as well as the renewable energy projects database of Bloomberg New Energy Finance. This pipeline is analysed in the context of a country's power demand outlook, power generation situation, grid and system integration issues, and current policy environment and the economic attractiveness of renewable deployment. Based on IEA analysis for each of the key regions and markets, baseline case projections are made for renewable electricity capacity by source through 2020. Generation projections are then derived using country- and technology-specific capacity factors, while recognising that resource quality, the timing of new additions, curtailment issues and weather may cause actual performance to differ from assumptions. Country-level generation projections can be found in the online data appendix of the report.

A country's total power demand outlook is based on expectations for real gross domestic product (GDP). This analysis is done in close co-ordination with other IEA medium-term reports. Assumptions for GDP growth stem from the International Monetary Fund's (IMF's) World Economic Outlook, released in October 2013. For some countries, e.g. emerging markets, power demand growth acts as a driver for renewable generation; for others, e.g. more mature markets, demand growth (or lack thereof) can act as a neutral variable or even a constraint on development.

Forecasts at the country level under the report's baseline case are carried out in the context of the policy environment, including announced policies, as of May 2014 and generally do not try to anticipate future policy changes. At the time of writing, some uncertainties characterise the electricity market frameworks and renewable policies for several countries, such as China, India, Japan, the United Kingdom and the United States, complicating the analysis. For each country, the policy environment is benchmarked against IEA best-practice principles, as in Deploying Renewables 2011, helping to determine the degree that prevailing policies may enable or hinder deployment.

Table 3 IEA best-practice policy principles

- predictable renewable energy policy framework, integrated into overall energy strategy
- portfolio of incentives based on technology and market maturity
- dynamic policy approach based on monitoring of national and global market trends

tackle non-economic barriers

Examples

administrative large number of permits needed

regulatory stop-and-go policy approach; retroactive policy changes

infrastructure weak power grids

"not in my backyard" behaviour public acceptance environmental. unclear impacts of new technologies.

address system integration issues.

Source: IEA. 2011.

Aside from policy, the MTRMR 2014 looks at economic attractiveness and power system integration as deployment factors. Attractiveness assessments stem from a number of variables, including levelised costs of electricity, policy incentives, economic resource potentials, macroeconomic developments, and the market design of the power system. For each country, an assessment is made as to whether the power grid can absorb the projected generation mix and variability. For many countries the potential exists for policy improvements or non-economic barrier changes over the medium term.

This report includes an **enhanced case** in order to show the potential impacts on deployment from certain market and policy enhancements that help to address challenges to renewable deployment. Under the enhanced case, the most dynamic renewable electricity sources (i.e. solar and wind) could grow faster than the baseline case. A number of country-specific developments, as described within each regional outlook, would need to occur for this result to occur, making it difficult to anticipate and more approximate in nature than the baseline case. The enhanced case is represented by a range and is indicative of the potential upside for cumulative capacity in the year 2020.

Outlooks for technology and investment guide the global picture

Key market assessments under the baseline case are judged against developments in renewable technologies and investment. The technology chapter features three sections of analysis. First, it describes system properties of different renewable technologies and their recent cost developments, including discussion of levelised costs of electricity (LCOE). The primary assumptions used to display the ranges for the main LCOE graphs are listed in the table at the end of this "Analytical Framework" chapter. Further discussion on the advantages and disadvantages of LCOEs to determine competitiveness is featured in the "Renewable Electricity: Global Technologies" section. Second, the section characterises recent market developments by technology. Third, the chapter provides an outlook for market development through 2020. It consolidates, by technology, the country-level forecasts; identifies the key markets; and addresses potential deployment barriers that lie ahead.

The investment analysis reports on recent developments in renewable power investment and forecasts investment needs over the medium term. All investment data presented, unless otherwise noted, are derived from IEA analysis on renewable electricity capacity additions and unit investment costs, historical and projected. Investment is defined as overnight capital expenditures on new renewable power plants or the replacement of old plants. When a renewable technology comes to the end of its *technical* lifetime, it is replaced or refurbished with an equal amount of capacity at a reduced cost. Further details on the calculations are provided in the "Investment in Renewable Power" chapter.

Table 4 Economic and technical lifetime assumptions in MTRMR 2014 (years)

Technology	Economic lifetime	Technical lifetime
Hydropower	35	70
Solar PV buildings	20	20
Solar PV utility	20	25
STE/CSP	25	30
Onshore wind	20	25
Offshore wind	20	25
Geothermal	35	50
Bioenergy	20-25	40
Ocean	20	20

Note: CSP = concentrated solar power.

Biofuels for transport and renewable heat round out the analysis

The biofuel supply analysis is based on a capacity-driven model, and its results have in the past been fed into the IEA oil market analysis. The core of the model is a plant-level database. Future production is modelled based on installed capacity and a utilisation factor in a given country, which is based on historic trends and expected economic and policy developments. Given their small and fragmented

nature, biofuels plants are difficult to track. The industry also remains volatile, with company exits and consolidations. Still, biofuels capacity can quickly change in response to market conditions.

Table 5 Central assumptions for global LCOE ranges by technology (beginning of 2014)

Bioenergy	Typical system costs (USD 2013/kW)	Full load hours	Annual O&M (% of system cost)	Discount rate (% real)	Economic lifetime
Solid biomass	1 500 – 5 000	7 000	2.5 – 6.5	7 – 8	20
Waste-to-energy	1 200 – 10 000	7 000	2.5 - 6.5	7 – 8	20
Hydropower					
Large plants	900 – 3 500	2 200 – 6 600	2.5	8 – 12	35
Small plants	1 000 – 6 000	2 200 – 6 600	2.5	8 – 12	35
Geothermal					
Flash plants	2 000 – 4 000	7 450	2.5	9 – 10	35
Binary plants	2 400 – 5 900	7 450	2.5	9 – 10	35
Offshore wind					
China	4 300 – 4 400	2 950	3.5	7.5 – 8.5	20
Germany	5 600 – 5 800	3 900	3.5	7.5 – 8	20
United Kingdom	5 150 – 5 250	3 900	3.5	8.5 - 9.5	20
Onshore wind					
China	1200 – 1300	1 900	1.5	7 – 8	20
Germany	1950 – 2050	2 000	1.5	3.5 - 4	20
Japan	2300 - 2500	2 200	1.5	7 – 8	20
United States	1700 – 1800	2 800	1.5	7 – 8	20
PV - utility					
China	1 200 – 1 300	1 500	1.0	6.5 – 7	20
Germany	1 400 – 1 500	1 050	1.0	2.5 - 3.0	20
Japan	2900 - 3000	1 075	1.0	2.5	20
United States	1 900 – 2 000	1 450	1.0	7 – 8	20
PV - commercial					
China	1 200 – 1 300	1 050	1.0	6.5 – 7	20
Germany	1 900 – 2 000	1 050	1.0	4.5 - 5.0	20
Japan	3 500 – 3 600	1 075	1.0	2.5	20
United States	3 600 – 3 700	1 300	1.0	8.5 - 9.5	20
PV residential					
China	1 450 – 1 550	1 050	1.0	6.5 – 7	20
Germany	2 200 – 2 300	1 050	1.0	2.5	20
Japan	4 600 – 4 700	1 075	1.0	1.5 - 2.0	20
United States	4 500 – 4 600	1 300	1.0	9.5 - 10.0	20
STE (6-hour storag	e)				
South Africa	5 100	3 250	1.0	10.5 – 11.0	25
United States	7 500	3 370	1	8	25

Note: Assumptions for construction time; bioenergy – 3 years, large hydro – 5 years, small hydro – 3 years, geothermal – 3 years, offshore wind – 3 years, onshore wind – 2 years, solar PV – 1 year, STE – 2 years

The renewable heat chapter analyses historical trends and projects final energy use of renewable sources for heat based on policy and market frameworks, and technology choices. Projections for modern biomass (traditional biomass is excluded from the analysis), solar thermal and geothermal heating are made within the context of both direct use for heat and commercial heat. The analysis

and projections take a more top-down, regional approach than in the renewable electricity chapters due to data availability and resource constraints. Regional growth rates from the IEA *World Energy Outlook 2012* New Policies Scenario underpin the analysis. However, the chapter does feature some country-level analysis, particularly in solar thermal heating, for which more disaggregated capacity data exist.

References

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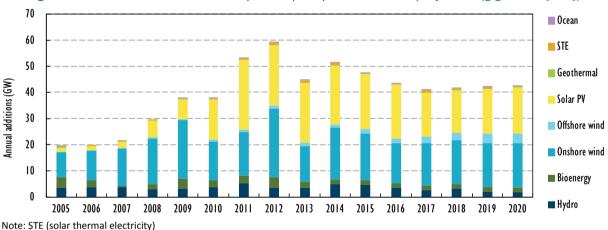
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RENEWABLE ELECTRICITY: OECD

Summary

• After several years of rapidly increasing growth, markets in the Organisation for Economic Cooperation and Development (OECD) face a transition to a slower but stable annual renewable expansion. This is due to increased policy and market risks since MTRMR 2013. OECD power markets increasingly fall into three categories: dynamic systems with rising demand and new generation needs; stable systems with sluggish demand growth and overcapacity; and markets in between, usually with slow demand growth, but a need for capacity replacement due to diversification aims or retirements. Dynamic markets (e.g. Chile, Mexico, Korea and Turkey) have strong drivers for renewable deployment, but sometimes face hurdles in scaling up deployment due to non-economic barriers or the cost and availability of financing. Other systems, such as those with relatively stable demand but supply-side needs (e.g. the United States, Japan, some European markets) face diverse challenges to maintain long-term policy frameworks while shifting from high levels of incentives and integrating higher penetrations of variable renewables. Rising uncertainties over policies in this last group of countries is a significant factor behind an expected stabilising of OECD renewable capacity additions, even as the costs of the most dynamic technologies, solar photovoltaic (PV) and onshore wind, continue to decline.





- OECD renewable electricity generation increased by 100 TWh in 2013 versus 2012 (4.8% year-on-year) to 21.5% of total power generation. The majority of the increase stemmed from non-hydro sources. Hydropower grew by 18 TWh in 2013 with reservoir levels near more normal levels. Non-hydro technologies grew steadily in generation, led by onshore wind and solar PV. Still, onshore wind capacity gains were notably slower due to the effects of policy uncertainty in the United States.
- Over the medium term, OECD renewable electricity generation is projected to grow from 2 340 terawatt hours (TWh) in 2013 to 3 040 TWh in 2020 (+3.8% per year). Versus MTRMR 2013, renewable generation is seen some 40 TWh less in 2018, due to less optimistic forecasts for wind (onshore and offshore) and hydropower. Renewable generation is seen rising to over 26% of total generation in 2020 from 21.5% in 2013 and is expected to account for over 80% of new power generation from 2013-20. While a significant share, there is limited upside potential to growth

given overall sluggish demand and policy risks in key markets. Solar PV is expected to lead capacity growth, with deployment around 22 GW in each of 2014 and 2015, followed by somewhat lower annual additions thereafter as deployment in Japan, in particular, slows. Onshore wind is also seen expanding strongly, yet after an expected 21 GW of deployment in 2014, annual additions are seen stabilising around 16 GW to 18 GW through 2020. Capacity growth in other renewable technologies remains lower, though offshore wind additions are expected to pick up more strongly in the second half of the forecast period.

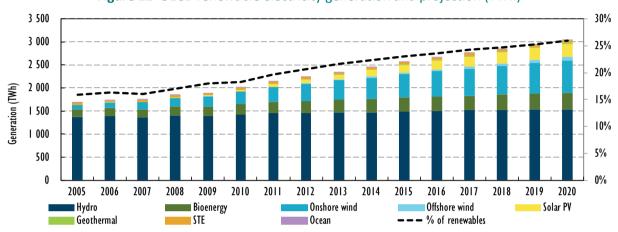


Figure 12 OECD renewable electricity generation and projection (TWh)

- OECD Americas renewable electricity generation is seen rising by 285 TWh, from 1 035 TWh (19.5% of gross electricity generation) in 2013 to 1 320 TWh (23% of generation) in 2020. The United States (+180 TWh) should represent more than 60% of new renewable generation in the region, led by onshore wind. Canada's renewable generation is expected to rise strongly by about 42 TWh, followed by Mexico with 38 TWh, with Chile's growth will be more modest at 6 TWh. OECD Americas renewable electricity grew by 30 TWh in 2013 versus 2012 (+3%). The largest capacity gains came from solar PV with 5.9 GW. Regional onshore wind additions fell to 3.5 GW in 2013, due to uncertainty over the extension of the production tax credit (PTC) in the United States, a small fraction of more than 15 GW added in 2012. With a one-year PTC extension granted in early 2013, a more robust US onshore wind project pipeline has been emerged for 2014 and 2015.
- OECD Asia Oceania renewable electricity generation is seen rising by over 110 TWh, from 212 TWh (11% of gross electricity generation) in 2013 to 325 TWh (15% of generation) in 2020. More than half of this expansion should come from solar PV. Japan's renewable electricity is seen rising by 71 TWh to reach 207 TWh. Australia's renewable generation is seen growing by more than 21 TWh over 2013-20, led by onshore wind and solar PV. However, considerable policy uncertainty exists over new utility-scale renewable additions in Australia, putting this forecast at risk. Korea's expansion is more moderate with 13 TWh. OECD Asia Oceania renewable electricity rose by 14 TWh in 2013 versus 2012 (+7%). Hydropower led this growth, with reservoir levels going back to their normal levels in the region. Solar PV generation also increased significantly with record deployment in Japan (+6.9 GW), followed by a modest expansion of onshore wind.
- OECD Europe renewable electricity generation is seen rising by over 300 TWh from 1 095 TWh
 (30% of gross electricity generation) in 2013 to nearly 1 400 TWh (36.5% of generation) in 2020.
 More than half of OECD Europe's new renewable generation to 2020 is seen coming from three

markets: Germany, the United Kingdom and Turkey. The largest capacity growth is expected to be in onshore wind, followed by solar PV. Regional renewable electricity grew by 58 TWh in 2013 versus 2012 (+5.7%). Onshore and offshore wind power together accounted for the majority of this growth, while solar PV's contribution was also significant. Offshore wind had its largest annual increase in output to date, rising by more than 5 TWh.

• Under this report's enhanced case – depicted within each region – total OECD cumulative capacity for solar PV could be some 30-50 GW higher and total wind (onshore plus offshore) could be some 15-25 GW higher in 2020 than under the baseline case. Besides faster-than-expected reductions in renewable technology costs, this result could come about through the rapid clarification of policy uncertainties in some markets; the implementation of stable and sustainable policy frameworks that give greater certainty about the long-term revenue streams of renewable projects; greater measures to ensure the grid and system integration of variable renewables and the implementation of fair rules and appropriate electricity rate design for allocating the costs and benefits from fast-growing distributed solar PV. Finally, STE capacity in the United States could be up to 1 GW higher in 2020 with better progress in securing PPAs and overcoming delays for some large projects.

OECD Americas

Recent trends

In OECD Americas, renewable power increased by more than 3% in 2013 over 2012 to reach 1 034 TWh, about 19.5% of total power generation. In the United States, renewables represented 13% of power generation in 2013, up from 12.5% in 2012. Still, new installations decreased from 18 GW in 2012 to 7 GW in 2013 mainly due to land-based (onshore) wind installations tumbling to 1 GW, a small fraction of the record 13 GW in 2012. Developers rushed to finish projects before an expected expiration of the renewable electricity PTC at the end of 2012, leaving an empty pipeline for 2013. Wind accounted for 4% of the power mix and output rose by 28 TWh. Backed by a federal investment tax credit and state-level incentives for net metering, solar PV installations surged by almost 4.8 GW. While solar PV generation increased to 11 TWh, it still accounts for less than 1% of overall generation. A slate of CSP projects that had benefitted from the US loan guarantee programme came on line over the past year, marking the largest STE additions to date. Over 0.4 GW of CSP capacity was added in 2013 and a further 0.6 GW came on line in early 2014. Hydropower increased somewhat, while its contribution to the power mix remained stable at 7%. Other renewables experienced a quieter market; geothermal capacity increased by 90 megawatts (MW) and its share of total generation remained near 0.5%.

At the state level, California led the deployment in both solar PV and land-based wind in 2013. Close to half of new solar PV additions in the United States came from California, followed by Arizona and North Carolina. Two states, California and Kansas, installed around 50% of overall US land-based wind deployment in 2013. Although Arizona's and New Jersey's solar PV additions decreased versus 2012, North Carolina and Massachusetts achieved significant growth. The interaction of financial incentives (state and federal), state renewable portfolio standards (RPS), and the evolution of debates over rules for distributed solar PV will play a large role in shaping the medium-term forecast with proposed federal emissions regulations likely to provide a boost in the longer term.

In 2013, Canada's renewable energy generation expanded thanks to higher-than-normal water levels that made hydropower generation rise by 3% to over 390 TWh, or around 60% of total generation. With a strong push in Quebec and Ontario, onshore wind marked its highest annual deployment to

Texas

Nebraska

date with 1.6 GW, and contributed to 1.8% of overall generation. Solar PV generation grew slightly, and reached 0.3 TWh, thanks mostly to 440 MW deployment in Ontario. Bioenergy capacity expanded slightly by 130 MW to reach 1.7 GW in total. Its contribution to the power mix remained stable at 1.4%.

Solar Solar Wind Wind State **State** State **State** PV PV California 269 45 California 2 621 146 Iowa Hawaii 254 Kansas Colorado 32 Arizona 421 Georgia 91 Michigan 175 Massachusetts 3 North Carolina 335 Texas 75 141 Massachusetts

237

236

New York

Colorado

69

56

3

1

Table 6 Top ten US states, 2013 capacity additions (MW)

Sources: GTM Research/SEIA (Solar Energy Industries Association) (2014), US Solar Market Insight Report Q1 2014, GTM Research/SEIA, Washington, DC.; IEA analysis based on AWEA (American Wind Energy Association) (2014), AWEA US Wind Industry Annual Market Report Year Ending 2013, AWEA, Washington DC.

New Jersey

Mexico's renewable energy generation somewhat decreased from 43 TWh to 41 TWh mainly due to the dry season, which resulted in low hydropower production. Still, renewables represented over 13.6% of overall power generation. In 2013, onshore wind installed capacity expanded by more than 600 MW while its generation reached over 5.6 TWh, or 2% of generation. Mexico's geothermal power capacity expanded by 15 MW in 2013. Renewable generation in Chile remained stable at 26 TWh in 2013 due to low reservoir levels, although hydropower capacity expanded by more than 200 MW. Renewable power contributed 34% of overall generation. Onshore wind capacity expanded more than 130 MW and generation reached close to 0.5 TWh in 2013. Solar PV additions remained limited, but several utility-scale projects were under construction throughout 2013 with power purchase agreements (PPAs) already signed.

Medium-term outlook - regional baseline case summary

Alaska

Indiana

75

Overall, OECD Americas' renewable generation is seen rising by over 284 TWh, or 27%, from 2013-20. Renewables are expected to account for 23% of total generation in 2020, up from 19.5% in 2013.

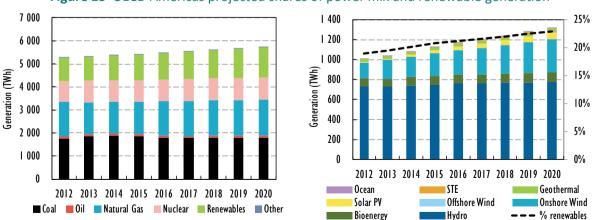


Figure 13 OECD Americas projected shares of power mix and renewable generation

The capacity outlook for the region indicates that onshore wind is likely to lead capacity growth, with 56 GW of additions over 2013-20. Onshore wind is expected to grow most strongly in the United States, with a significant number of projects coming on line over 2014-15. Canada and Mexico are also expected to add sizeable new capacity. Still, the regional onshore wind outlook is seen stabilising at a lower level after 2015, due to expectations that the PTC will no longer be available for new projects. At the regional level, solar PV is seen rising by around 39 GW over 2013-20. Utility-scale developments in the United States guide the outlook, though these begin to slow following the reduction in the investment tax credit (ITC) in 2016. Meanwhile, stringent proposed federal emissions regulations may begin providing a broad boost to renewable deployment, but their effect is likely to be felt more in the long term. Rising deployment in the distributed segment in the United States, plus new deployment in Canada, Chile and Mexico, helps solar PV to stabilise at a somewhat lower level during the second half of the forecast period.

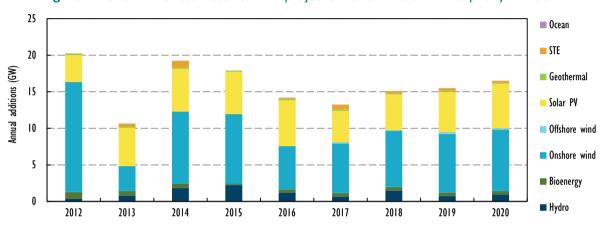


Figure 14 OECD Americas historical and projected renewable annual capacity additions

Other technologies are seen growing more slowly, though with significant additions on a global scale. Regional hydropower is seen expanding by more than 9 GW, led by new developments in the United States and Canada, but also in Mexico and Chile. Bioenergy for power should rise by 3 GW, with continued expansion in the United States. Although the outlook for STE is slower than in the *Medium-Term Renewable Energy Market Report 2013 (MTRMR)*, due to relatively high costs and challenges over project delivery, several large-scale additions are expected in the United States over 2013-20, with cumulative capacity expected to more than triple versus 2013. Geothermal power is seen expanding by more than 1 GW (+25%) over 2013-20, led by the United States and Mexico. In addition, the first offshore project in OECD Americas, the Cape Wind project in the United States, is expected to partly come on line starting from 2017.

Medium-term outlook – detailed analysis

Power demand

OECD Americas' power demand is expected to grow by 1.6% annually over 2013-20 but the outlook differs among markets. Power demand is seen to expand modestly in the United States and Canada. Although the International Monetary Fund (IMF) has foreseen a better economic recovery for the United States, with real gross domestic product (GDP) growing 3.1% annually over the medium term, the country's power demand is slightly revised down compared with *MTRMR 2013*. It is seen expanding on average 1.3% annually due to increased efficiency and weakened linkage between economic growth and electricity demand growth. Over the past two decades, energy use per GDP has decreased due to the shift within the US economy from manufactured goods to the service sectors, which are

less energy intensive. A similar situation holds true for Canada; its power demand is expected to grow annually by 1.5%, slightly lower than foreseen in *MTRMR 2013*, while its GDP is expected to grow by 2.2% annually.

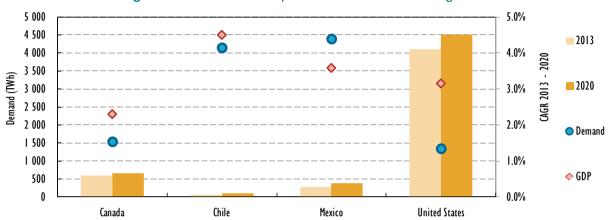


Figure 15 OECD Americas power demand versus GDP growth

In Mexico and Chile, power demand should grow relatively faster as their expected economic growth and the expansion of industrial activity should underpin robust electricity demand for both countries. Mexico's power demand is expected to expand by 4.4% annually, while the IMF sees the country's GDP growth averaging 3.5% over 2013-20. Meanwhile, Chilean electricity demand is seen growing by a robust 4.1% per year driven by energy-intensive industrial activities such as mining and paper production as its GDP grows on average 4.4% annually.

Power generation and capacity

OECD America countries will need new generation capacity over the medium term but with different drivers. Mexico and Chile are dynamic power markets with growing demand that is expected to drive generation needs. While the United States and Canada are expected to have sluggish growth in power demand, the retirement of coal power plants should create needs for additional generation. Overall, the United States and Canada have a secure capacity margin while, with growing demand, reserve margins have been decreasing in Chile and Mexico. The role of renewables in OECD Americas is expected to be strong and growing over the medium term. Still, the clarification of certain policy questions would help better guide their role in the power mix.

In the United States, the strong economic coal-to-gas switching trend in electricity generation observed in recent years paused in 2013 with rising natural gas prices. The share of coal power in the total power generation slightly increased from 38% to 40%, while the natural gas contribution declined. However, gas substitutions for coal generation on a structural basis should continue with the retirement of planned coal-fired power plants. Compliance with anticipated Environmental Protection Agency (EPA) emissions regulations together with weak electricity demand growth have led utilities to announce the retirement of around 60 GW of coal-fuelled plants between 2012 and 2020 (EIA, 2014a). This power sector situation, combined with federal and state policy incentives, should help support deployment of renewables even as electricity demand is expected to grow slowly. The majority should come from wind, with 14 GW to 15 GW of financed projects under construction (GWEC, 2014). Utility-scale solar PV also has a significant project pipeline. As of the first quarter of 2014,

some 12.5 GW of new utility-scale solar PV capacity was under development with a signed PPA, and 3.4 GW was under construction (GTM Research/SEIA, 2014). Meanwhile, another large CSP project under construction (280 MW) is expected to be commissioned by the end of 2014.

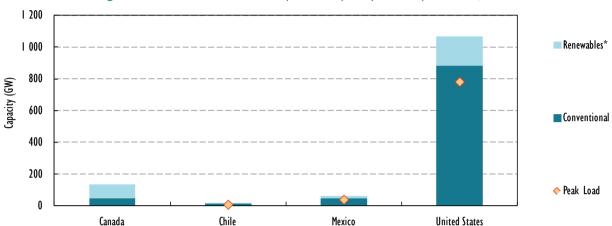


Figure 16 OECD Americas total power capacity versus peak load, 2012

Box 1 Emissions reduction proposals could give longer-term renewable boost in the United States

Following a proposal in 2013 which would cap carbon emissions on new power plants, in June 2014 the US EPA released its Clean Power Plan, guidelines that would cut, for the first time, carbon pollution from existing power plants. The plan aims at reducing carbon dioxide emissions of the power sector 30% by 2030 compared with 2005 emission levels. It proposed goals for reduction of emission intensity for 49 US states, ranging from 72% in Washington to 11% in North Dakota. Targets differ among states based on their existing power generation, energy efficiency, and the outlook for coal power plant retirements. The EPA introduced a new regulatory standard called the best system of emission reduction (BSER), which is based on "four building blocks" – efficiency improvements for existing coal power plants, using natural-gas-fuelled plants more efficiently, increasing generation from renewables and nuclear, and improving end-user energy efficiency. These building blocks are not required actions but methods that the EPA considers in defining a state's target.

Following this proposal, the EPA aims to finalise the proposed standards by June 2015 with states submitting action plans by June 2016, which would become regulation by 2019. Clarifications over state-level calculation methods and targets are expected in months ahead. These proposals carry risk of legal challenge. Although recent US Supreme Court decisions have upheld the EPA's authority to regulate greenhouse gases and cross-state air pollution, such challenges could cause implementation delays. For now, a degree of uncertainty exists over how the final rules will look and their ultimate timeline.

While quantifying the impacts remains difficult at this stage, these changes should provide a broad boost for renewables over the medium to long term. The rules would stimulate greater retirements of coal plants than currently planned and increase demand for zero- to low-emission generation. While natural gas would likely continue to play a large part, the attractiveness of renewables outside of existing state-level portfolio standards and incentive frameworks would grow. Indeed, with the PTC no longer available for new projects, the ITC expected to be reduced for new projects at the end of 2016, and 20 states having renewable portfolio standards that come due by 2022, these rules could provide a framework that spurs the adoption of longer-term state targets and boosts the value of renewables (and energy efficiency) as they transition to an environment of lower financial incentives.

Power generation in Canada is still dominated by hydropower. Over the medium term, its capacity is expected to rise gradually over 5 GW, based on projects under construction or in development, though actual output will strongly depend on year-to-year reservoir availability. The retirement of fossil-fuel generation and existing incentives should continue to drive renewable deployment in some provinces. In December 2013, the Nanticoke Generating Station, one of the largest coal plants in North America with 1.9 GW of capacity, was shut down. In April 2014, the last coal-fired power plant in Ontario, Thunder Bay Generation Station, was shut down. The shutdown of other plants is expected in other provinces due to provincial actions and the federal government's greenhouse-gas regulations for coal-fired electricity released in September 2012. This situation will create opportunities for both renewables and natural gas. Some retired plants in Ontario are being converted to biomass power. Still relatively low natural gas prices should also spur new gas-fired generation

A strong need for diversification away from imported coal, diesel and natural gas and insufficient generation in the face of rapidly growing demand should continue to drive renewable deployment in Chile. In October 2013, the government approved a new renewable energy target increasing the share of non-hydro renewables in overall electricity generation from 10% to 20% by 2025. A new national energy policy including strategies to achieve new renewable energy targets is expected soon. Chile's renewable pipeline consists of about 1.6 GW worth of small hydropower, wind, solar and biomass projects under construction, and 11 GW with environmental approval, led by onshore wind (4.3 GW) and solar PV (5.5 GW) (CER, 2014). In June 2014, the Chilean government cancelled the permit of the 2.7 GW Aysén hydropower project due to environmental and social concerns.

In Mexico, the government approved a new energy reform policy in August 2014 that included provisions to end the monopoly of the vertically integrated state-owned utility Comisión Federal de Electricidad (CFE). The next major steps concerning the creation of an independent energy regulator and grid operator are expected by the end of 2014. The reform would allow generation by independent power producers without the requirement to sign a PPA with CFE. The new law requires the establishment of an independent transmission system operator (TSO) and a capacity market where new power contracts are to be negotiated. The new power market structure should help encourage increased private investment in the generation sector, which could support greater uptake of renewables to meet Mexico's 35% clean energy target (which also includes nuclear and co-generation² power plants) by 2024 from around 13.6% in 2013. Mexico also established an interim clean energy generation target of 24.9% by 2018, which is outlined in the government's Special Programme on Renewable Energy 2014-18 released in May 2014.

Grid and system integration

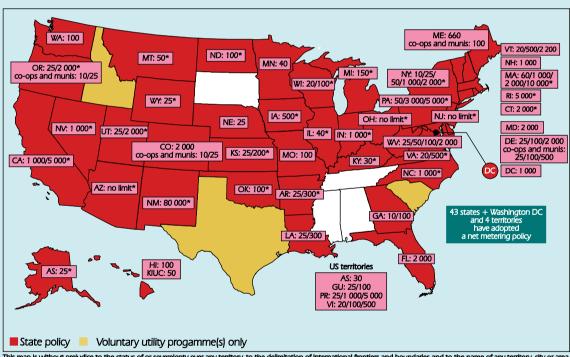
Over the medium term, the US grid should not act as a significant barrier to renewable energy deployment, though constraints may remain at the regional and state levels. According to a National Renewable Energy Laboratory integration study on the US Western Grid (WECC), which includes parts of Canada, the United States and Mexico, the integration of 35% wind and solar PV into the electric power system will not require extensive infrastructure if changes are made to operational practices. The report also points out that the existing transmission capacity can be better used in order to reduce new transmission investment needs (Lew et al., 2013).

² Co-generation refers to the combined production of heat and power.

However, system constraints may persist in other regional grids at lower shares of variable generation. For instance, ERCOT, the Electric Reliability Council of Texas, may experience periods of insufficient flexibility to balance variable renewables starting at around 25% of annual variable renewable penetration, compared with 9% in 2013 (IEA, 2014c).

Box 2 As deployment ramps up, US states debate rules for distributed solar PV

Increasingly strong growth of solar PV in the United States is raising debates over the system integration of distributed generation (for fuller treatment of the investor and system implications of distributed solar PV, see "Special focus, Solar PV reaching socket parity", in chapter "Renewable electricity: Global technologies"). As of early 2014, 45 US states offered net energy metering, an arrangement that allows the netting on a consumer's bill of the solar PV output injected into and the electricity consumed from the grid. Combined with falling solar PV costs, this rate structure has been an important driver for the scale-up of small-scale solar PV. Increasingly favourable economics for self-consumption are also creating new opportunities for deployment, without explicit subsidies. These trends are reinforced by the advent of third-party leasing schemes that help defray high up-front investment costs of ownership.



Map 1 Net energy metering in the United States, status by state, July 2013

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

Note: numbers indicate individual system capacity limit in kilowatts (kW). Some limits vary by customer type, technology and/or application. Other limits might also apply. This map generally does not address statutory changes until administrative rules have been adopted to implement such changes.

* State policy applies to certain utility types only (e.g. investor-owned utilities).

Source: DSIRE (Database of State Incentives for Renewables & Efficiency) (2014), www.dsireusa.org, accessed May 2014.

In reaction to these trends, there is ongoing debate in at least fifteen states over fair rules, total net metering program capacity levels and appropriate electricity rate design for allocating the costs (e.g. recovery of fixed grid costs) and benefits from fast-growing distributed solar PV. These considerations are complex and have provoked various regulatory responses that may impact future solar PV deployment.

Box 2 As deployment ramps up, US states debate rules for distributed solar PV (continued)

For example, Arizona regulators have chosen to institute fixed charges on solar net metering, approving in 2013 a hotly contested fee of USD 0.70/kW per month to be administered by the state utility. Minnesota, by contrast, is employing an alternative to net metering. In 2014 it implemented a value of solar tariff (VOST) policy, where utilities would remunerate distributed PV owners for all their production according to long-term, transparent pricing that values the environmental benefits of solar produced. At the same time, solar owners would consume and pay for all their electricity from the grid. Still, the offering of VOST versus net energy metering remains a voluntary choice of utilities.

Recent developments in California may be indicative of more balanced policy measures. Faced with an impending cap on new solar PV capacity under net energy metering, a bill adopted by the state legislature in September 2013 removed that cap and required the public utility commission to develop a new standard contract of tariff for new net metering customers based on the electrical system costs and benefits. At the same time the bill allowed investor-owned utilities to eventually employ a time-of-use pricing option for residential customers. Moreover, the bill would allow the adoption of a fixed charge for all rate payers to help recover investment costs, up to USD 10 per month (about 10% of household electricity bills) – a level that will not likely threaten the economics of solar PV deployment.

For many states, the penetration of distributed solar PV remains low and the current system impact is minor. Still, over the medium term, this report sees the residential and commercial segments accounting for 55% of the 37 GW of new solar PV in the United States expected over 2013-20. This deployment could be higher, with stronger-than-expected system cost reductions or an enabling breakthrough in battery storage technology. As such, states may need to continually address system concerns as they arise. Ultimately, policy makers may need to consider more fundamental changes to the electricity tariff structure in order to better recover fixed grid investment costs and decrease system costs. However, evolutions would need to be done with care, avoiding retroactive measures, and strike a balance among various risks in order to continue providing a supportive framework for solar PV growth.

Improved co-ordination among different grid operators in the United States would facilitate the integration of high shares of variable renewables, and optimise regional transmission investments. The Edison Electric Institute projects transmission investments totalling USD 51 billion from 2013-23 (EEI, 2013). More than half of this investment would develop large inter-state transmission projects. Since the Federal Energy Regulatory Commission's (FERC) issuance No 1000 in 2011, TSOs have been developing compliance proposals that provide a cost allocation method for new inter-regional transmission facilities. However, challenges remain over the co-ordination and cost allocation of these inter-state projects among different stakeholders. In March 2014, FERC approved the Coordinated Transaction Schedule between PJM (the regional transmission organisation covering parts of 13 states in the mid-Atlantic and mid-west portion of the United States) and New York Independent System Operator (NYISO) that will improve scheduling efficiency and maximise transmission utilisation to enhance trading of electricity among the interconnected areas. Further improvements in curtailment levels were recorded in 2013, particularly in congested grids. In 2013, only 1.2% of wind generation was curtailed in ERCOT, down from 3.8% in 2012, 8.5% in 2011 and 17% in 2009 (DOE, 2014. Increased transmission capacity, in part from the competitive renewable energy zones programme, has helped increase wind load factors there.

In Canada, some provinces have experienced increased integration challenges over the last year, and the grid may act as a moderate constraint to renewable deployment going forward. Ontario's Independent

Electric System Operator (IESO) announced new market rules in September 2013 to curtail surplus wind output in order not to stop nuclear stations, which are less flexible. IESO made an offer to wind power developers to compensate for the curtailed generation. In Quebec, curtailment has been limited, usually caused by technical faults. However, fast deployment in Gaspésie Peninsula might be challenging over the medium term as the grid is already congested there.

In Chile, the grid represents a significant challenge to renewable deployment. First, Chile's transmission deployment plan, published in 2010, which covers grid upgrades and new investments by the end of 2014, did not take into account renewable deployment. The new government announced that the expansion of renewables will be included in the new 2014-18 planning, to be published in late 2014. The connection of new wind power plants, which are usually far from load centres, has been an issue over the past year with difficult certification requirements usually varying among different privately owned TSOs. Moreover, congestion persists in the two major transmission areas (SING and SIC) covering around 98% of country's electricity dispatch.

With uncertainties over the timing and execution of the new energy reform in Mexico, including structural changes on grid investment and operation, the transition process is expected to pose challenges to renewables, as well as other generators. Limited interconnections among different regions and, in some cases, isolated small grids where wind and solar resources are located remain a major integration constraint not only for renewables but also for any power generating capacity. The role of the new independent system operator, so-called CENACE, and its concrete investment plans to more timely and efficiently connect renewables was not published at the time of writing. The reform requires CENACE to redesign former power supply contracts between CFE and independent generators. It is expected that the reform will facilitate the entrance of independent renewable generators into the market over the medium term. However, the expansion of both the transmission and distribution grids to accommodate this new variable capacity might pose technical, operational and investment challenges.

Current policy environment for renewable energy

Overall, the policy environment remains supportive for renewable deployment in OECD Americas. In the United States, with no national target, federal production and/or investment tax credits and state level RPSs and incentives support renewable deployment while Canada's policy support stems from targets and incentives provided at the provincial level.

In the United States, the late renewal of the PTC at the beginning of 2013 created investor uncertainty, leaving a significantly reduced project pipeline as developers rushed to commission most of their projects in 2012. Still, many new projects started to develop over the past year and would qualify for the renewed PTC if they were under construction by early 2014. In addition, the ITC is expected to be reduced from 30% to 10% at the end of 2016. Lack of long-term durability associated with these incentives represents a challenge for investment in new developments. Proposed federal emissions regulations may begin providing broad, indirect support to renewable deployment over the medium term. But uncertainties remain over their precise implementation and their effect is likely to be felt more in the long term.

At the state level, 29 states (and DC) employ mandatory RPSs and eight states have renewable energy goals. Legislators in some states have drafted proposals to roll back RPS schemes to control policy costs, though none have rescinded the obligations. In Ohio, a bill was recently adopted that pushes

back its RPS compliance year from 2025 to 2027 and reduces the obligation of utilities to source instate renewable production. As of early 2014, 45 states (and DC) have adopted a net metering policy, which is one of the main drivers for small-scale solar PV deployment. California's cap-and-trade programme completed its first year of operation in January 2014 with carbon prices fluctuating around USD 11. Prices were stable over the last year after five quarterly auctions showing a good balance of demand and supply for allowances. As a result, the state collected around USD 530 million, which will be re-invested in clean energy and energy efficiency projects.

 Table 7 OECD Americas main targets and support policies for renewable energy

OECD Americas	Regul	atory sı	upport	Economic support							
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Canada	0	0	0	0	Х	Х	Х	0			Х
Chile	Χ	Χ	Χ		Χ			Х		Х	Χ
Mexico	Χ	Χ	Χ		Χ		Χ	X		Χ	
United States	0	0	0	0	Χ	X	Χ	0	0	0	0

Note: RE = renewable energy; x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

In Canada, policies in Quebec and Ontario are the main drivers of renewable deployment, though other provinces also have policy measures promoting renewable electricity. Ontario recently updated its Long-Term Energy Plan, setting a target of 10.7 GW of new wind, solar and bioenergy on line by 2021 (OME, 2013). Moreover, the existing hydroelectric target of 9 GW by 2018 will be increased to 9.3 GW by 2025. In June 2013, Ontario abolished the FIT for new projects greater than 500 kW, and replaced this incentive with a competitive procurement programme. However, the FIT still exists for small installations of onshore wind and solar PV. The province also eliminated its local-content requirement in order to comply with the World Trade Organisation (WTO) ruling of May 2013. Quebec's 450 MW of wind procurement applications were opened to developers and are expected to be awarded in 2014 and 2015.

Both Chile and Mexico have supportive policy environments for renewables, though they still lack strong financial incentives. In October 2013, the Chilean government approved the new renewable energy mandate, which requires 20% of generation to come from non-hydro renewable sources by 2025, up from the former target of 10%. The new president, who took office in March 2014, already endorsed the new target. In May 2014, the new government released the *Agenda de la Energía*, which underlined the importance of renewable energy in Chile's power mix. Accordingly, 45% of newly installed capacity between 2014 and 2025 is foreseen coming from renewables. Under proposed tax reforms, a carbon tax of USD 5 per tonne would be imposed on all power generation plants larger than 50 MW by the end of 2014.

Although Mexico's new energy reform is expected to introduce new incentives, such as renewable-technology specific auctions, or a quota system (renewable portfolio standards), none of these proposed measures have yet been approved by the Congress. Reportedly, the plan also proposes a new law on

geothermal energy that aims at providing a risk management mechanism which would decrease risks associated with the drilling and exploration phases for private investors. The current renewable policy environment is still driven by the national target (35% non-fossil electricity generation, including nuclear and large-hydro, by 2024 from 13.6% in 2013), accelerated depreciation, net metering and discounted transmission tariffs. In December 2013, Mexico introduced a carbon tax, which could affect prices for fossil fuels for power generation. However, uncertainty remains over the implementation of this tax.

Economic attractiveness of renewable energy and financing

In the OECD Americas region, dynamics behind the economic attractiveness of renewable energy differ. In the United States, with low wholesale prices, project viability is dependent on local resources and policy incentives while the federal PTC still plays an important role in the deployment of land-based wind, geothermal and bioenergy. The estimated levelised cost of electricity (LCOE) for land-based wind, without incentives, ranges from USD 64 per megawatt hour (MWh) to USD 124/MWh. While this level can be higher than wholesale prices, land-based wind is still being developed due to its hedge value against future fluctuations in uncertain fossil-fuel prices. In 2013, with the PTC (USD 23/MWh), the lowest PPA prices ranged on average from USD 25/MWh to USD 35/MWh. These contract prices still show the importance of the PTC in improving land-based wind competitiveness.

Onshore wind LCOE without PTC and average wholesale prices Onshore wind LCOE with PTC and wholesale prices 175 175 150 150 JSD 2013/MWh 125 125 100 100 75 75 50 50 25 25 0 0 2012 2012 2011 2013 2011 2013 LCOE range -PIM New England -Southwest LCOE range ▲ Lowest PPA price

Figure 17 United States land-based wind LCOE ranges versus selected average wholesale prices

Notes: LCOE ranges are indicative and reflect low-cost, typical and high-cost projects, which vary primarily due to differences in system costs, resources and the cost of financing. Cost of capital is assumed at 7% to 8%. Lower PPA prices have been observed, however, due mainly to higher real world capacity factors and more favourable financing conditions than modelled in LCOE calculations. PJM refers to the regional transmission organisation covering parts of 13 states in the mid-Atlantic and mid-west portion of the United States. Wholesale prices are annual averages that do not reflect hourly or daily variations that might provide a different competitiveness picture.

Source: IEA analysis with wholesale prices from EIA (2014b), Wholesale Electricity and Natural Gas Market Data accessed 20 May 2014, Washington D.C. http://www.eia.gov/electricity/wholesale/and PPA data from DOE (Department of Energy) (2014), 2013 Wind Technologies Market Report (forthcoming), US DOE, Washington DC.

Rooftop solar PV system prices are 30% to 40% more expensive in the United States than in markets such as Germany and Italy mainly due to balance of system costs (see Box 2), "Why do solar PV system prices vary so much among markets?" in chapter "Renewable energy: Global Technology Outlook"). They also carry a relatively high cost of capital, around 9% to 10% in real terms (Ardani et al., 2013). At the beginning of 2014, the estimated LCOE, without incentives, for most residential- and commercial-scale systems remains relatively high, and is estimated between USD 270/MWh and USD 440/MWh,

depending on resources, underscoring the importance of the ITC in helping to augment the attractiveness of solar PV. The LCOE of most utility-scale projects ranged from below USD 110/MWh to over USD 160/MWh.

In Canada, the details of Ontario's new public procurement programme for large-scale renewable projects related to bidding were not public at the time of writing. Thus it is currently difficult to assess the economic viability of new projects. However, it is worth noting that LCOEs for onshore wind in Canada are estimated to be similar to those in the United States, ranging from USD 62/MWh to USD 125/MWh. In Quebec, the public procurement programme has proven to be effective in deploying renewables with HydroQuebec awarding long-term contracts for 20 to 25 years. For the new tender, the utility set the maximum price at CAD 90 (USD 87.5) per MWh. Ontario's micro FIT programme has so far driven solar PV deployment in Canada. Although the province has recently revised tariffs down to account for decreasing system costs, incentives remain attractive.

In Chile and Mexico, excellent resource availability creates an opportunity for renewable energy development. Good sites with high capacity factors for both onshore wind and solar PV have not yet been exploited. Neither Chile nor Mexico has direct financial incentives for renewable electricity, but they both have high power prices — wholesale and retail, depending on the tariff structure — which should make some renewable projects, especially utility scale, attractive with few incentives. In Chile, for instance, high wholesale electricity prices and good irradiation levels have opened a new merchant solar PV market. Over the past year, the world's first merchant utility-scale solar PV plant was interconnected and another was financed; both projects are to sell electricity to the wholesale market without a PPA.

Structural changes that have been planned should increase the economic attractiveness of renewable sources. Mexico's new power market structure should facilitate competition between several renewable technologies (onshore wind, bioenergy and geothermal) and fossil fuel-run power plants. Subsidised power prices still pose challenges on the deployment of residential-scale solar PV projects while relatively high power tariffs for commercial and industrial customers should enhance the competitiveness of commercial-scale projects. Still, financing remains a major challenge in both Chile and Mexico. Over the past year, only a few developers were able to sign PPAs with large power consumers, mainly mining companies, which have facilitated project financing.

Conclusions for renewable energy deployment: Baseline case

With close to 180 TWh of increase, the United States should represent more than 60% of the gains driving the regional outlook. The US forecast is revised down by around 12 TWh in 2018 compared with MTRMR 2013. The outlook for land-based wind is slightly lower, but strong, with more than 43 GW of additional capacity by 2020. Solar PV deployment is expected to be robust and is seen expanding by 32.5 GW, reaching a cumulative installed capacity of 45 GW in 2020. The federal policy environment remains challenging in the United States, with financial supports still lacking predictability. In the baseline case, this forecast assumes the non-reinstatement of the PTC and the reduction of the ITC from 30% to 10% at the end of 2016. A few large CSP projects are being commissioned over 2013 and 2014, and capacity is expected to expand by more than 2 GW in total over 2013-20. Still, high system costs and challenging financing have reduced the outlook by 1 GW in 2018 versus MTRMR 2013. With high system prices and current regulatory and administrative challenges, the offshore wind forecast revised slightly down, with only 500 MW expected to come on line by 2020. The deployment of geothermal power in the United States should continue steadily, adding over 600 MW from 2013-20, reaching an overall capacity of 4.1 GW.

Canada's renewable generation is expected to rise by about 41 TWh over 2013-20, but the forecast is somewhat less optimistic than in *MTRMR 2013*, largely due to downward revisions in onshore wind deployment. Most of the projects under Quebec's 2009 wind procurement programme and Ontario's former FIT measure should be completed by 2015. New tenders, both in Quebec and Ontario, included lower onshore wind capacities. Other provinces, such as Alberta, British Columbia and Nova Scotia, should also contribute with smaller new additions. Still, Canada's onshore wind capacity is seen expanding by 9.2 GW from 2013-20. Solar PV installations have already taken off in Ontario and are expected to expand by 2.2 GW, reaching 3.5 GW in 2020. This forecast could be higher, if other provinces decide to introduce financial incentives. Bioenergy is expected to increase by more than 500 MW over 2013-20. Canada's expansion of ocean energy should be led by the province of Nova Scotia. Though ocean power remains at nascent levels, 25 MW of new capacity could potentially come on line by 2020.

Table 8 OECD Americas cumulative renewable energy capacity in 2013 and 2020

Total			2013		2020						
capacity (GW)	Canada	Chile	Mexico	United States	Canada	Chile	Mexico	United States			
Hydropower	75.8	6.3	11.7	101.4	80.9	7.5	13.9	101.9			
Bioenergy	1.7	0.7	0.5	12.8	2.2	8.0	0.6	15.1			
Onshore wind	7.8	0.3	1.9	60.2	17.2	2.7	10.0	96.7			
Offshore wind	-	-	-	-	0.3	-		0.5			
Solar PV	1.2	0.0	0.1	12.5	3.5	2.1	2	45.0			
STE/CSP	-	0.0	-	0.9	0.0	0.6	0.1	3.0			
Geothermal	-	-	0.9	3.5	-	0.1	1.2	4.1			
Ocean	0.0	-	-	0.0	0.0	-	-	0.0			
Total	86.5	7.3	15	191.3	104.9	13.8	27.8	266.2			

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

Chile's renewable generation is seen expanding by 6 TWh over 2013-20; the outlook is about 5 TWh higher in 2018 versus *MTRMR 2013*. This slight increase is mainly due to technology-specific revisions, both upwards and downwards, although the total capacity projection is similar to *MTRMR 2013*. Solar projections for both CSP and PV have been revised up. With high retail and wholesale prices, and excellent solar resource, this report has a more optimistic projection for utility- and residential-scale solar PV deployment, which is expected to pick up. Solar PV capacity should reach 2.5 GW in 2020 from a negligible capacity in 2013. CSP capacity could reach 400 MW with the commissioning of two large additions by the end of the decade. The onshore wind outlook is revised down mainly due to challenges concerning financing, public land acquisition, transmission scarcity and lack of financial incentives. Onshore wind capacity should expand by 2.4 GW, reaching 2.7 GW in 2020. Hydropower capacity is expected to increase from 6.3 GW in 2013 to 7.5 GW in 2020.

In Mexico, renewable power generation should expand by 38.5 TWh, slightly lower compared with *MTRMR 2013*. Uncertainties over the implementation of the new energy reform weigh over the outlook even though the country has great wind, solar and geothermal resources with relatively high electricity prices. This report anticipates that onshore wind capacity will expand by 8 GW and reach 10 GW in 2020. Meanwhile, solar PV capacity is seen growing by 2 GW over 2013-20. A few utility projects should drive the growth, with increasing commercial- and high-consumption residential-scale projects. Mexico's geothermal resources and capacity are large on a global scale. This report expects 350 MW of new geothermal capacity coming on line with total capacity reaching over 1.2 GW. With CFE's expansion plans, hydropower capacity should grow significantly by over 2.2 GW, and is expected to reach 14 GW by 2020.

Table 9 OECD Americas main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
United States	State-level RPS combined with federal financial incentives and longer-term, emissions-reductions goals. Improving economic attractiveness for solar PV and onshore wind.	Uncertainty over the durability of federal tax incentives. Expectations for relatively low gas prices.
Canada	Robust provincial policy supported by combination of tenders and FITs. Expected retirement of fossil-fuel generation over the medium term.	Lack of binding renewable targets in some provinces. Decreasing onshore wind capacity announced for new tenders in Ontario and Quebec.
Chile	Rising power demand and excellent renewable resources combined with government targets. High wholesale and retail electricity prices.	Lack of financial incentives and long-term PPAs. Grid bottlenecks in populated areas.
Mexico	Excellent resource availability with long-term government targets. Energy reforms should facilitate new entrants and generation in the electricity sector.	Concentrated power system that represents challenges for new entrants. Uncertainty over implementation details of the energy reform.

Renewable energy deployment under an enhanced case

Much enhancement is possible in the OECD Americas region with improvements in policy and regulatory environment. In the United States, greater durability of federal incentives and allowing renewable projects to be treated as Master Limited Partnerships would help investment, though it is likely not realistic to expect continued tax credit renewals given the prevailing budget environment. A possible extension of the PTC for five years while gradually reducing its level to zero could provide greater investor certainty and spur continued reductions in wind costs. In this case, cumulative land-based wind capacity could be some 6 GW to 7 GW higher in 2020. The upside for offshore capacity looks more limited, though with faster project development, cumulative capacity could top 1 GW by 2020 (some 300 MW higher than forecast). In other sectors, solar PV capacity could be higher by 8 GW to 10 GW in 2020, with greater-than-expected uptake in the residential and commercial sectors spurred by more favourable conditions for deployment under self-consumption. In addition, should a draft bill in California be approved as law which would require utilities to produce 500 MW additional base-load geothermal power in the state by 2024, geothermal capacity could be 250 MW higher in 2020. Finally, STE capacity could be up to 1 GW higher in 2020 with better progress in securing PPAs and overcoming delays for some large projects.

In Canada, the baseline forecast assumes no major policy changes concerning renewable incentives. Although power demand growth is expected to be sluggish in many provinces, some provincial-level policy and market enhancements could result in stronger renewable energy deployment, especially for onshore wind. An increase in Alberta's carbon levy applied to industrial emitters might help boost onshore wind deployment in the province, which still has a high potential. In British Columbia, Saskatchewan and Nova Scotia there is still upside potential with regulatory and policy improvements. Under these conditions, total cumulative capacity for onshore wind could potentially be 2 GW to 3 GW higher in 2020 than under the baseline case.

The successful execution of Mexico's new energy reform could spur more investment in renewable energy deployment as the confidence of private investors increases. Onshore wind cumulative capacity could increase by 3 GW, solar PV capacity by 1 GW to 2 GW, and geothermal capacity by 0.5 GW by

2020 versus the baseline case. In Chile, renewable energy deployment could be enhanced with greater certainty about the long-term revenue streams of renewable projects. To this end, the introduction of stronger financial incentive levels and a market framework that better facilitates long-term power contract arrangements for renewables would spur more deployment. Under these conditions, both onshore wind and solar PV cumulative capacity could be 2 GW to 3 GW higher in 2020. CSP capacity could also be higher, though gains would likely be concentrated in the long run given still-nascent deployment there.

OECD Asia Oceania

Recent trends

In OECD Asia Oceania, renewable power increased by over 9% in 2013 to reach near 212 TWh, about 7% of total power generation. The largest gains occurred in hydropower and solar PV, particularly in Japan, where the power sector was characterised by constricted nuclear output, rising costs of imports of liquefied natural gas (LNG) and growing coal generation. Renewables in Japan represented almost 13% of power generation in 2013 with hydropower accounting for 8%. On the back of generous incentives and a 6.9 GW surge in new installations, solar PV generation rose by over 3 TWh, increasing its share to 1% of power generation. Other renewable sources saw slower progress. Onshore wind capacity increased by only 35 MW, and its share of total generation remained near 0.5%. Though additions remained small, offshore wind developments were significant compared with prior years, with several demonstration floating turbines commissioned and 16 MW (fixed foundation) brought online at Kamisu. Bioenergy expanded by 100 MW, led by waste-for-power, and accounted for 3% of total generation.

As power generation needs increased strongly in 2013, particularly in the summer amid a reduction in nuclear generation, Korea's renewable generation grew by 18% to over 13 TWh, or 2.4% of total generation. Supported by an RPS with a solar carve-out that commenced in 2012, solar PV marked its highest annual deployment to date, at over 440 MW. Wind installations, mostly onshore, totalled only 80 MW, though a larger project pipeline has begun to emerge, partly in response to an anticipated rise in the country's long-term wind target. Although no new capacity was commissioned, the continued ramp-up of the world's largest tidal barrage plant at Lake Sihwa continued in 2013.

Amid softening power demand and emerging overcapacity in the power sector, Australia's renewable generation increased by 35% year-on-year to reach over 33 TWh, or 13% of total generation. Annual variation in hydropower accounted for around half of the growth. But solar PV output tripled versus 2012 and accounted for 1.5% of generation. New solar PV installations, concentrated in the residential sector, totalled 690 MW and were slightly lower than in 2012 as the last of state-level premium FIT schemes closed for new projects. Still, the economics for deployment with reduced incentives continued to improve, and solar PV's role grew in helping to meet peak summer demand needs, as during an early 2014 heat wave. Onshore wind generation rose to 7.5 TWh from 6 TWh in 2012 and accounted for 3% of power generation. At over 650 MW, annual capacity additions reached their highest level to date, buoyed by the commissioning of the 420 MW Macarthur wind farm.

Israel's³ renewable generation stood at 1.4% of total generation in 2013, up from 0.8% in 2012. Solar PV capacity, mostly utility scale, grew by over 180 MW in 2013, the highest annual deployment to date.

³ 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.

The capacity of solar thermal electricity and onshore wind remained relatively steady, though future development is expected. Finally, New Zealand's relatively high level of renewable penetration, at 75%, continued to grow in 2013. The most significant development came with the completion of a 100 MW geothermal facility, the world's largest binary plant. With improving economics, solar PV installations also continued to ramp up in 2013, though at less than 10 MW cumulative capacity, development remains nascent.

Medium-term outlook – regional baseline case summary

OECD Asia Oceania renewable generation is seen rising by over 110 TWh, or 53%, from 2013-20. This growth rate is higher than other OECD regions due to a relatively low renewable baseline. Renewable power is expected to account for 15% of total generation in 2020, up from 11% in 2013.

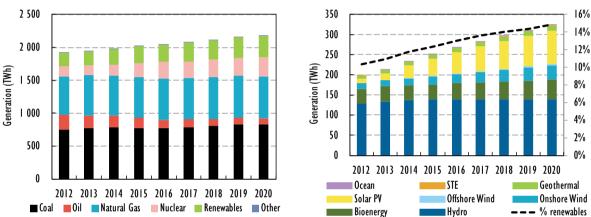
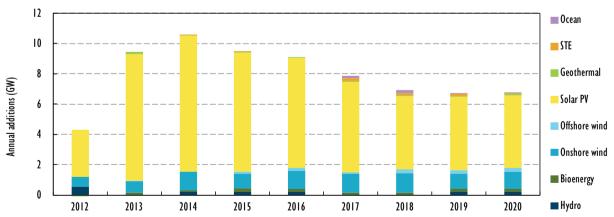


Figure 18 OECD Asia Oceania power generation mix and renewable generation





Over the medium term, capacity growth in OECD Asia Oceania is expected to be led by solar PV, which expands by around 45 GW from 2013-20. The majority of this growth comes from Japan, supported by high FIT levels and from rooftop solar PV in Australia, whose deployment is driven largely by attractive economics for self-consumption. Still, the solar PV outlook carries some risk and may be volatile on a year-to-year basis, owing to uncertainty over how Japan's FIT scheme will evolve over the next five years and challenges related to grid and system integration. Regional onshore wind

growth, of more than 8 GW over 2013-20, is led by Australia and Korea, but also carries risk due to increasingly uncertain political support for renewables in the former. Other renewable sources grow more slowly, but notable developments are expected to occur in STE in Israel, geothermal in New Zealand and ocean power in Korea.

Medium-term outlook – detailed analysis

Power demand

OECD Asia Oceania power demand is expected to grow by 1.4% annually over 2013-20, but the outlook differs sharply among countries. Growth in Japanese power demand is likely to be modest, increasing by 0.5% annually from 2013-20, slightly slower than foreseen in *MTRMR 2013*. Persistent supply constraints in the power sector, the success of energy efficiency measures and slow expected GDP growth of just over 1.0% per year from 2013-20 weigh upon any expansion. Meanwhile, Korean electricity demand is seen expanding by a robust 3.0% per year over 2013-20 as GDP is expected to grow by 3.9% annually. In 2013, electricity consumption rose by 1.8%, with the industrial sector expanding by over 3.0%. Rising exports spurred higher growth rates for industrial use in early 2014.

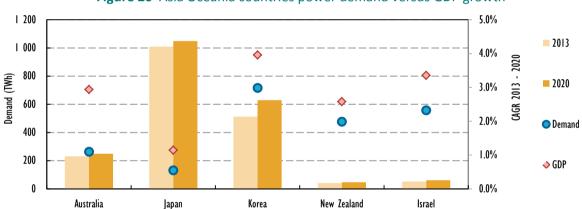


Figure 20 Asia Oceania countries power demand versus GDP growth

The expansion of demand is likely to be moderate in Australia, rising by 1.1% per year, on the back of annual GDP growth of 1.6% over 2013-20. Still, the picture differs by geography. In the National Electricity Market (NEM), which accounts for 80% of generation, grid-supplied electricity has declined annually since 2008 due to a combination of increased efficiency, weaker economic growth, reduced consumption from industry and rising output from distributed solar PV. Despite a strong increase in household air-conditioning use over the past five years and very hot summers during 2012-13 and 2013-14, peak demand has remained steady or has declined in the NEM over this period (AER, 2013). By contrast, in Western Australia and Northern Territory, demand is rising more strongly with the growth of resource-extraction industries.

Power generation and capacity

The evolution of the power mix in OECD Asia Oceania will depend as much on the operational status of some forms of generation and the clarification of certain policy questions as the demand picture presented above. The power system of Korea remains relatively dynamic, with strong demand growth and a need for new capacity. Australia's power system is relatively stable, with slowing demand, emerging overcapacity and increasing policy uncertainty. Japan's power sector lies in between, with

stable demand but a strong need for new generation capacity. Overall, the role of renewables is expected to remain robust and growing, but with uncertainties in some areas.

In Japan, significant uncertainty remains over the timing and extent of nuclear power's ramp-up over the medium term, potentially prolonging a tight power situation. During 2013, two units from the Ohi plant that had been restarted in 2012 were taken back off line for regular inspection. As of May 2014, all 48 commercial nuclear reactors remained idle with no clarity over the restart of several plants expected during the summer. In line with assumptions in the IEA Medium-Term Gas Market Report 2014, published in June, this report assumes that nuclear output reaches a maximum 59 TWh by 2016 and remains at this level over the projection period (IEA, 2014a). This level would represent a downward revision of some 70 TWh in 2018 versus the assumption used in MTRMR 2013.

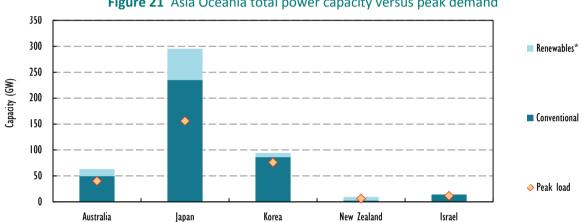


Figure 21 Asia Oceania total power capacity versus peak demand

Note: renewable and conventional capacity is as reported by countries to IEA Energy Data Centre.

A need for new power supply, combined with the negative economic impacts of using costly LNG for generation, acts as a strategic drFiver for renewables expansion, though current generous feed-in tariffs are a more proximate catalyst for deployment for investors. Indeed, a portfolio of renewables features prominently in the recently issued 4th Strategic Energy Plan of Japan. Upcoming reforms should help improve access and the integration of renewables in electricity markets, though their impacts will emerge over time (Box 3). The current project pipeline for renewable expansion is skewed towards solar PV. As of March 2014, of the more than 68 GW of projects registered but not yet brought into operation under Japan's FIT scheme, solar PV represented almost 96% (METI, 2014). Permitted new wind projects totalled almost 1 GW. While most new wind developments are occurring onshore, Japan's large offshore wind potential could help fill supply needs should its economic attractiveness improve. Permitted bioenergy projects amount to over 700 MW. Though small in total, construction plans for a number of mid-sized geothermal plants, which require fewer environmental assessments than larger plants, have emerged.

A need for new power generation capacity should continue to function as a driver for renewables in Korea over the medium term. In 2012, total power capacity stood at 94 GW while peak load was at 76 GW, and the reserve margin has decreased steadily over the past decade. The power sector suffers from insufficient generation investment in general, with regulated retail prices inhibiting the pass-through of generation costs, which have risen in recent years.

Box 3 Transition ahead for Japan's power sector

The implementation of electricity market reform and the 4th Strategic Energy Plan of Japan should create profound changes in Japan's power sector that facilitate the deployment and integration of renewables over the next decade. The passage of the Electricity Business Act in late 2013 signalled the most ambitious electricity reform effort in Japan in 60 years in a market that is currently dominated by vertically integrated utilities responsible for generation and transmission in ten different regions. Such a system has in the past raised barriers to entry for new energy sources into Japan's mix, suffers from a lack of interconnection among regions and has limited competition within regions, contributing to generally high retail electricity rates. The act seeks to overcome these challenges through three agendas. First, the government aims to establish a national co-ordinating body for TSOs by 2015. Second, it plans to introduce full retail competition to the residential sector starting around 2016, with the phase-out of regulated tariffs from the ten big vertically integrated utilities by 2018-20. Finally, the act would unbundle the transmission and distribution sectors by 2018-20.

Electricity system reform was highlighted as a key pillar of the Strategic Energy Plan, released in April 2014. The plan sets the period until 2020 as a transition stage to implement larger policies and reforms that would ultimately create a more flexible and diversified energy system on both the supply and demand sides. To this end, it seeks to accelerate the introduction of renewables in the period of 2013-16, followed by "continuous active promotion" thereafter. Higher targets for renewable deployment versus previous Strategic Energy Plans are to be introduced, as well as clarification over the role of other power sources, such as nuclear, and the promotion of potential flexibility measures such as smart meters, storage and "next-generation automobiles". However, the quantification of these aims in the future energy mix remains pending. The strategy also puts forth additional measures to promote specific renewable power sources:

- onshore wind: shorten time for environmental assessment and install large battery storage
- offshore wind: promote pilot projects for floating wind turbines, with commercialisation by 2018
- geothermal: reduce investment risks and shorten the period for environmental assessment
- distributed generation: support self-consumption from solar PV, simplify water rights procedures to spur small hydropower and promote generation from solid biomass.

Overall, these reforms should, in principle, help to boost renewable deployment over time and improve the system and grid integration for variable renewables, in particular. In practice, however, the implementation of electricity market reform and the new strategic plan will be both technically and economically challenging. As such, these developments may have greater impact over the long term.

In Australia, overcapacity has emerged in the power sector with weak demand expansion, a decade of strong investment in gas-fired generation and robust renewable growth under the Renewable Energy Target (RET). In the NEM, declining demand combined with rising natural gas and coal prices, increased low-marginal-cost renewables, and carbon pricing have contributed to lower operating hours for thermal generation. Still, coal continues to represent the majority of power output. Going forward, in the NEM, the only new, large-scale power projects that are "committed" are renewable, mostly from onshore wind (over 800 MW) and solar (145 MW) (AEMO, 2014). The market operator reports a further 15.8 GW of onshore wind that is proposed, and distributed solar PV is seen rising, suggesting ample scope for continued renewable expansion. Still, the overcapacity situation and uncertainty associated with ongoing policy reviews represent an increasing challenge for new renewable investment.

Grid and system integration

While Japan's ambitious electricity market reforms could improve the integration of renewables over time, their implementation will be both technically and economically challenging. IEA analysis shows that Japan's power system appears flexible enough to accommodate shares of variable renewables up to 25% to 30% in annual generation without curtailment (IEA, 2014b) (n.b. analysis pertains to Japan East system). In 2020, generation from variable renewables is anticipated to rise to around 6% of total annual generation. Still, the fragmented structure of the Japanese grid, with weak interconnections between utility supply areas and a transmission system occupying two separate frequency areas, poses a challenge to development over the medium term. Insufficient transmission, grid congestion and the availability of grid connections may act as constraints to new renewable deployment. For example, Hokkaido accounts for 3.0 GW of planned solar PV projects (and 140 MW of wind), which are mostly utility scale, yet actual deployment has been slow. Hokkaido's peak load of only 6 GW and interconnection of only 600 MW DC to the rest of Japan act as constraints. The planned installation of large-scale battery storage, supported by the government in 2015, and expansion of the interconnection will be important for integrating solar PV and wind, but may not be enough to realise planned levels of deployment.

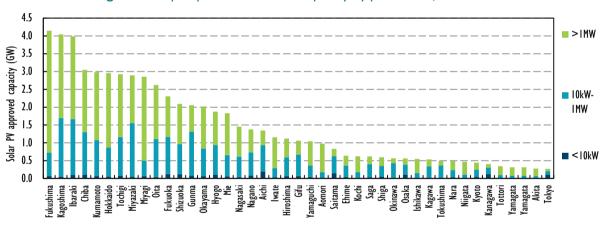


Figure 22 Japan planned solar PV capacity by prefecture, March 2014

Source: METI (Ministry of Economy, Trade and Industry) (2014), Renewable Energy Equipment Certification Status, March 2014, METI, Tokyo, www.enecho.meti.go.jp/category/saving_and_new/saiene/kaitori/index.html

In Australia, the integration of wind may present moderate challenges over the medium term, and some inter-regional grid congestion in the NEM is emerging. The share of wind in total generation has risen most strongly in South Australia, where it totalled 28% in 2012-13 (AER, 2013). In 2013, the Australia Energy Regulator approved the upgrade of the South Australia-Victoria (Heywood) interconnection, raising its capacity to 650 MW by 2016, which should help the movement of wind power between those states. Residential-scale solar PV, the majority of solar deployment, can play a role in helping to reduce network congestion, particularly in its ability to reduce peak summer demand, as during a heat wave in South Australia and Victoria in early 2014 (Brazzale, 2014). Still, its contribution varies depending on the location and the timing of the generation and peak demand.

Current policy environment for renewable energy

Overall, the policy environment remains supportive for renewable deployment in the region, though uncertainties have emerged in some areas. Japan's electricity market reforms and the 4th Strategic

Energy Plan of Japan represent positive new drivers for development. Japan continues to maintain a set of generous FITs to support renewable development. Since their implementation in 2012, these supports have spurred a boom in solar PV installations and an even larger set of approved projects. Government concerns have emerged over approved projects that have not yet been built, with land rights, equipment certification and delays by developers to take advantage of falling equipment prices all cited as constraints. In response, the Ministry of Economy, Trade and Industry (METI) is exercising greater scrutiny over FIT eligibility for unbuilt projects. In April, METI cut the solar PV FIT for new projects for fiscal year 2014 from JPY 38/kWh to JPY 37/kWh for systems below 10 kW, and from JPY 36/kWh to JPY 32/kWh for larger projects. These levels for solar PV remain high by global standards, though the FIT duration for systems below 10 kW applies for only ten years while that for larger projects runs for 20 years. The government also established a separate FIT for offshore wind, at JPY 36/kWh.

Table 10 Asia Oceania countries main targets and support policies for renewable energy

OECD Asia Oceania	Regulatory support Economic support										
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Australia	Χ	Χ		0	Χ				Χ	Χ	
Israel		Χ	X	Χ			X				Χ
Japan		Χ		Χ	Χ		Χ	Х			
Korea		Χ	Χ				Х		Χ		
New Zealand		Χ								Χ	

Note: x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

Korea has maintained long-term deployment targets and financial support for renewables under the RPS, which sees renewables rising to 10% of power generation by 2022. In late 2013, the government was reportedly considering establishing a long-term wind target of 12 GW by 2030. However, no measure has yet been put into law. The government recently announced plans to reduce non-economic and administrative barriers, particularly for onshore wind. Still, further implementation details were to be revealed only in the second half of 2014.

Over the past year, significant uncertainties have emerged over the stability of Australia's national renewable framework. The new governing coalition that came into power in 2013 has introduced legislation that would repeal carbon pricing and close the Clean Energy Finance Corporation (CEFC) and Climate Change Authority. The government has also brought forward the review of the RET, composed of the Large-Scale Renewable Energy Target and the Small-Scale Renewable Energy Scheme, from 2016 to this year and will issue a new Energy White Paper in September. It has also expressed intent to reduce funding for the Australian Renewable Energy Agency (ARENA). It is unknown what the results of these policy positions and reviews will be, particularly regarding the quantitative targets of the RET. Nevertheless, the national policy environment is, at a minimum, causing uncertainty that is likely to delay investment in new renewable capacity.

Economic attractiveness of renewable energy and financing

Japan's power system generating costs and end-user prices remain elevated due to rising imports of costly LNG for generation. However, lack of market competition in Japan's electricity sector creates non-economic barriers and inhibits price signals that could enhance the attractiveness of renewables. As such, FITs remain a more proximate factor in stimulating deployment. Japanese policy makers face the challenge of maintaining incentive levels at a high enough level to bring renewables towards competitiveness with other generation sources while managing the total programme costs.

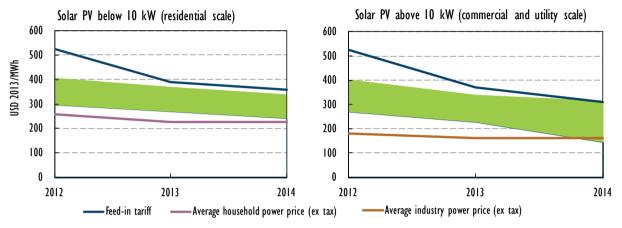


Figure 23 Japan solar PV LCOE ranges versus FIT and end-user price levels

Notes: LCOEs are beginning year; FIT is as of mid-year; end-user prices are annual averages. end-user prices for 2014 were not available and are held equal to 2013 prices. The ranges reflect low-cost, typical and high-cost projects, which vary primarily due to differences in system costs, resources and the cost of financing. In 2013, JPY/USD = 97.6.

Generous FITs make solar PV development economically attractive in Japan, even with high prevailing unit investment costs. At the beginning of 2014, the estimated LCOE (in 2013 real terms) for typical new residential solar PV was around USD 320/MWh while that for typical commercial- and utility-scale projects was USD 220/MWh to USD 260/MWh. Both of these cost ranges depend on a low assumed cost of capital, 2% to 3%, and appear attractive for the FIT levels on offer for 2014. However, other challenges, such as permitting requirements, land acquisition and grid access, can represent barriers to development, particularly for larger-scale projects.

With continued deployment, solar PV LCOEs could fall through 2020 to levels that compare favourably to household and industry retail prices, potentially creating incentives for deployment with substantially reduced incentives and for purposes of self-consumption in both the residential and commercial sectors.

The onshore wind LCOE also appears attractive in relation to FIT levels, a business case that appears to hold even with average conditions (15 MW to 30 MW, 25% to 30% capacity factors, 8% to 12% cost of capital) (Veiga et al., 2013). Still, the range of onshore wind cost estimates is high by global standards. Moreover, limited availability of sites with good resources, due to mountainous geography and public acceptance; small project sizes, required environmental assessments; and grid connections all pose challenges to deployment. A separate FIT level for offshore wind was set in March 2014 and was designed to reflect the higher risks of offshore development. However, given Japan's nascent level of offshore wind development, it is difficult to assess the boost this incentive will give over the medium term, particularly given other challenges, such as required long-term environmental assessments.

In Australia, wholesale prices vary by state and in fiscal year 2012/13 averaged AUD 49/MWh (USD 47/MWh) to AUD 74/MWh (USD 71/MWh), with Tasmania at the low end and South Australia at the high end. While increased renewable generation contributed to historically low prices in 2011/12, the introduction of carbon pricing and price spikes from localised incidents of network congestion and lower-than-expected reserves at times caused prices to rise on average by AUD 31/MWh (USD 30/MWh) in the NEM in 2012/13 (AER, 2013). End-user electricity prices, which are regulated in all states and territories except Victoria and South Australia, have increased as much as 40% over the past five years, driven largely by rising network costs, but also increasing generation costs.

Australia's excellent resources combined with falling costs of renewable technology have made the LCOEs of wind and bioenergy comparable to new fossil-fuel generation while utility-scale solar PV and CSP remain more expensive (for further analysis, see MTRMR 2013). Nevertheless, the attractiveness of large-scale renewables still depends on incentives. Given ample total power capacity to meet expected demand growth, renewable investments will compete more against existing generation than new fossil-fuel plants. To this end, the least costly renewable sources, wind and bioenergy, remain more expensive than prevailing wholesale power prices. Lack of clarity over the future of carbon pricing, which has helped buoy wholesale prices, and the future of the RET, which provides financial support through renewable energy certificates, means that renewable investments increasingly face an increasingly uncertain remuneration picture, undermining their bankability. Moreover, uncertainty over the future of the CEFC and ARENA raises questions over the availability of financing for large-scale solar PV and CSP and more nascent developments in geothermal and ocean technology.

The economic attractiveness of residential- and commercial-scale solar PV in Australia appears to be less affected by this policy uncertainty. Investment costs in Australia have fallen to among the lowest in the world, at around USD 2 000/kW for a typical residential system. More detailed local-level analysis shows that even at high sensitivities of discount rates, the LCOE of new residential solar PV installations is lower than retail prices in most major Australian cities (ESAA, 2014). This situation suggests good economic attractiveness for deployment under self-consumption with few incentives. Still, this attractiveness will depend on the time match between a consumer's demand and the solar PV system output as well as the level that excess power is remunerated when fed into the grid. With the end of Australia's state-level premium FITs, states are trying to identify fair and reasonable remuneration for solar PV generation injected into the grid, which is currently lower than the LCOE, at around AUD 80/MWh.

Conclusions for renewable energy deployment: Baseline case

Japan's renewable generation should expand by 72 TWh over 2013-20, with a strong policy environment backed by robust financial incentives and a need for additional power generation capacity driving the outlook. Realising this forecast will require progress in the implementation of planned electricity market reforms as well as greater clarity over renewable provisions in the 4th Strategic Energy Plan. Given still-generous FIT levels, the government will need to maintain a dynamic approach to adjustments to reflect international and national market developments.

The Japan forecast is somewhat more optimistic than in *MTRMR 2013*, with renewable generation in 2018 revised up by 7 TWh versus *MTRMR 2013*. This change is largely due to solar PV. Backed by supportive incentives and a need for additional generation, solar PV is expected to expand by 35 GW from 2013 to reach a cumulative capacity of almost 49 GW in 2020. Moreover, the deployment

pattern may be volatile, with high levels expected in 2014 and 2015 and lower annual levels from 2016 onwards due to an assumed transition from current high FIT levels. Overall, the growth outlook is much lower than is suggested by the pipeline of government-accredited projects (65 GW not yet in operation as of March 2014). It is expected that much of this capacity may not reach fruition, with an unknown number of speculative applications (i.e. those that may not be real, but registered to take advantage of incentive levels) in the mix and real projects still facing challenges related to grid constraints and non-economic barriers described above. Still, with the timely and effective implementation of electricity market reforms and adequate availability of grid connections, deployment could be higher than forecast here (see "Enhanced Case" description below).

Table 11 OECD Asia Oceania, selected countries renewable energy capacity in 2013 and 2020

Total		2	2013		2020				
Capacity (GW)	Australia Japan Korea		Korea	New Zealand	Australia	Japan	Korea	New Zealand	
Hydropower	8.8	49.0	6.5	5.3	8.8	50.0	6.5	5.3	
Bioenergy	0.8	1.6	0.3	0.1	0.9	2.3	8.0	0.1	
Onshore wind	3.2	2.6	0.6	0.6	7.7	3.3	2.5	0.9	
Offshore wind	-	0.0	0.0	-	-	0.3	8.0	-	
Solar PV	3.1	13.5	1.5	0.0	8.9	48.8	4.4	0.1	
STE/CSP	0.0	-	0.0	-	0.3	-	0.0	-	
Geothermal	0.0	0.5	-	0.8	0.0	0.7	-	1.0	
Ocean	0.0	-	0.3	-	0.0	-	0.7	-	
Total	16.0	67.3	9.0	6.8	26.8	106.0	15.7	7.5	

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

The outlook for wind, both onshore and offshore, is somewhat lower than in *MTRMR 2013* due to weaker-than-expected deployment in 2013. Onshore wind deployment is likely to proceed slowly, growing by 1.2 GW over 2013-20, with transmission upgrades required and non-economic barriers challenging development. Offshore wind, though now benefitting from a dedicated FIT, remains difficult to assess given Japan's current nascent level of development. Growth of only 0.5 GW is seen over 2013-20, but deployment could accelerate with greater commercialisation, particularly for floating turbines. Some bioenergy and geothermal development is also expected.

Korea's renewable generation is seen rising by about 13 TWh over 2013-20, but the outlook is somewhat lower than in *MTRMR 2013* due to weaker-than-expected wind deployment. Korea's growing need for additional generation to meet fast-growing demand and long-term policy orientation, backed by the RPS, should act as drivers for deployment. Still, further measures to reduce non-economic barriers as well as the clarification of long-term wind deployment targets would be beneficial. Korea's solar PV capacity is seen rising almost 3 GW over 2013-20 while onshore wind is seen growing by almost 2 GW over that period. Although offshore wind remains relatively expensive, a large pipeline of potential projects has emerged and growth is seen at around 0.8 GW over 2013-20. Finally, while it is difficult to forecast developments in relatively nascent ocean technology, the presence of a pipeline of financed projects suggests Korea is likely to lead global growth in this area.

Australia's renewable generation is seen expanding by more than 21 TWh over 2013-20, but the outlook is about 5 TWh lower in 2018 versus *MTRMR 2013*. Emerging overcapacity in the power sector and increased uncertainty over the renewable policy environment at the national level act as

increasing challenges in a market with excellent renewable resources and where some renewable sources are cost-comparable to new fossil-fuel generation. This report's forecast assumes the retention of the current RET, though the government's review this year could lead to changes or a shift in the 2020 target. This uncertain situation impacts onshore wind the most. Currently, onshore wind is seen growing 4.5 GW over 2013-20, but this is slower than growth posited in *MTRMR 2013* and the outlook could well be lower should delays to investments emerge. The outlook for other large-scale technologies, such as CSP and utility-scale solar PV, is also less optimistic versus last year's forecast, though some growth is expected, including the Kogan Creek Solar Boost project integrating solar thermal generation with a coal-fired plant. Overall solar PV is expected to grow by almost 5 GW over 2013-20, largely driven by the residential and commercial sectors where the economics increasingly support deployment for self-consumption with few policy incentives.

Table 12 OECD Asia Oceania main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Japan	Strong policy environment backed by generous FITs and need for new generation. Potential for increased competition in the electricity sector through planned reforms.	Integration of variable renewables in certain regions and maintaining a dynamic approach to FIT adjustments. Implementation of planned electricity sector reforms and new strategic plan.
Korea	Need for generation to meet fast-growing demand. Long-term policy orientation, backed by RPS.	Concentrated power system presents investment barriers to new entrants. Non-economic barriers; long lead times associated with permitting and grid connections.
Australia	Attractive economics for distributed solar PV deployment for self-consumption. Good economic attractiveness for renewable technologies versus new fossil-fuel builds.	Increased policy uncertainty and questions over the durability of present renewable support schemes. Emerging overcapacity in the power sector.

Finally, New Zealand and Israel are likely to both continue expanding renewable generation. New Zealand's total growth of 4 TWh is largely driven by geothermal and wind additions, though solar PV has also began to ramp up. The Israeli government has recently shifted part of its tendering allocation to solar PV away from other sources to take advantage of more attractive economics. Israel's growth of 3.5 TWh should largely come through utility-scale solar PV, though with some CSP and onshore wind additions.

Renewable energy deployment under an enhanced case

The evolution of the FIT scheme as well as uncertainty over the nuclear situation remain large variables for Japan's outlook over the medium term. Under an enhanced case for development, the government would need to maintain a dynamic approach to incentive adjustments. It would also need to make rapid progress in implementing overarching electricity reforms, introducing greater market competition, reducing non-economic barriers and achieving stronger build-out of the grid and other forms of flexibility, such as storage. In such a case, solar PV capacity could be some 10 GW to 15 GW higher (i.e. reach 60 GW to 65 GW) in 2020, with a more stable deployment profile over time. Increased deployment for purposes of self-consumption and increased uptake by high-rise buildings could also spur faster-than-expected solar PV development. Onshore wind capacity in Japan could be higher by 0.5 GW to 1.0 GW in 2020 versus the baseline with faster-than-expected grid upgrades.

Offshore wind capacity could also be 0.5 GW higher with a faster-than-expected deployment, including greater cost reductions and the potential commercialisation of floating turbines. Still, significant impacts on offshore capacity are more likely to occur over the long term given long project lead times. The upside for geothermal looks limited given long development times.

With certain developments, Korea's renewable deployment could be higher over the medium term. Most of the upside pertains to onshore and offshore wind. More streamlined grid connection and permitting procedures could help onshore wind cumulative capacity be 0.5 GW to 1.0 GW higher in 2020 compared with the baseline case. Faster-than-expected cost reductions could spur higher offshore wind deployment, with cumulative capacity in 2020 potentially 0.5 GW to 1.0 GW higher than the baseline case.

In Australia, enhanced deployment could occur with a rapid clarification of the policy uncertainties related to the RET, renewable financing institutions such as the CEFC and ARENA, and the future of carbon pricing. Given the current political environment, however, it is difficult to anticipate a realistic enhanced outcome. The largest upside to Australia's outlook relates to solar PV. More favourable economics and a greater uptake of distributed solar PV for self-consumption could result in cumulative solar PV capacity in 2020 that is 1 GW to 2 GW higher than the baseline case.

OECD Europe

Recent trends

In OECD Europe, renewable power increased by over 6% in 2013 to reach 1 095 TWh, more than 30% of total power generation. This rise occurred even as total power sector output decreased by 1% year-on-year. In the European Union member states (EU-28),⁴ renewable generation increased by 9.5% to reach 875 TWh (see Box 4, "EU renewable power faces challenges to meet 2020 targets and beyond", in this chapter). OECD Europe accounted for 20% of global renewable generation growth. The largest gains occurred in onshore wind, where capacity rose by 9.2 GW year-on-year. Hydropower, solar PV and bioenergy followed in terms of the generation increase. Offshore wind had its largest annual increase in output to date, rising to over 19 TWh, on capacity additions of 1.6 GW.

Germany led the renewable expansion in Europe, with generation rising by 5.5% to 158 TWh, or 25% of total generation. Total wind (onshore plus offshore) accounted for 8.5% of electricity generation. Onshore wind cumulative capacity rose by over 2.7 GW (including repowering, gross additions were at 3 GW), its largest annual deployment since 2006, with developers seeking to lock in higher incentive levels before anticipated changes in 2014. Offshore wind capacity increased by 240 MW with the commissioning of the remainder of the BARD Offshore farm. Solar PV accounted for 4.5% of total generation as its capacity rose by 3.3 GW. Smaller additions were also made in bioenergy and geothermal capacity.

Italy's renewable generation rose by 14% year-on-year in 2013 to 107 TWh. Much of the increase was due to a rebound in hydropower output, but also reflected a full year of output in 2013 from Italy's strong solar PV deployment over 2012. Solar PV led capacity additions, growing by an estimated 1.5 GW. However, there is some uncertainty over the true level of growth. While remaining installations under Italy's *Conto Energia* tallied only 1.2 GW, there was likely additional capacity added under net

⁴ While there is much overlap, the precise composition of the European Union-28 and OECD Europe differ. Please see this report's Annex for the geographical breakdown.

metering and for purposes of self-consumption given favourable economics. Onshore wind (+0.4 GW) grew at its slowest pace since 2006, with the introduction of capacity-capped feed-in premiums.

The United Kingdom's renewable generation rose by over 26% year-on-year to over 56 TWh, or 15.5% of total generation. Wind power increased by over 8 TWh, with growth split evenly between onshore and offshore sources. Total wind now represents 7.7% of UK power generation. Onshore wind capacity grew by almost 1.2 GW, while offshore wind increased by 0.7 GW. UK offshore installations represented about half of the global total and were boosted by the full commissioning of the 0.6 GW London Array. Supported by favourable policy incentives, solar PV grew by 1 GW, its highest deployment to date, and continued to expand rapidly in 2014, growing by over 1 GW in the first quarter alone.

Notable generation and capacity developments occurred in other markets. In Spain, the final phase of the largest pumped hydro storage plant in Europe (La Muela II, 0.9 GW) was brought on line as well as the remaining 300 MW of STE under Special Regime incentives. In 2013, onshore wind accounted for 19.5% of total power generation, one of the highest penetrations globally, while solar PV was at 3%. Yet new capacity additions for wind and solar PV in Spain were small, and existing renewable generators came under increasing economic pressure with some retroactive changes made to remuneration schemes.

Sixteen countries in OECD Europe saw onshore wind deployment of at least 0.1 GW. With 0.9 GW of growth, Poland registered the region's second-largest growth in onshore wind capacity as developers sought to lock in incentives before an expected incentive scheme transition. This was followed by Sweden (+0.7 GW), Turkey (+0.6 GW) and France (+0.6 GW). Significant offshore additions also occurred in Denmark (+0.4 GW), with the commissioning of the 400 MW Anholt farm, and Belgium (+0.2 GW), with the commissioning of the second and third phases of Thornton Bank (325 MW total).

Ten countries in Europe registered solar PV deployment of at least 0.1 GW. Greece increased its capacity by 1.0 GW, with a run-up in installations in the first half of the year before significant cuts were made to incentives for utility-scale plants. France (+0.6 GW), the Netherlands (+0.3 GW) and Switzerland (+0.3 GW) also saw significant growth. Overall, European solar PV deployment continues to shift towards smaller-scale solar PV installations; in 2013, residential- and commercial-scale projects accounted for an estimated 80% of total solar PV capacity growth.

Medium-term outlook – regional baseline case summary

Overall, renewable generation in OECD Europe is expected to grow by more than 302 TWh, or 28%, over 2013-20. Renewable power is seen accounting for close to 37% of total generation, up from near 30% in 2013. The number of OECD Europe countries and variety of deployment patterns, policy frameworks and economic attractiveness make summarising conclusions from the region a difficult task. Compared with *MTRMR 2013*, OECD Europe's renewable generation in 2018 is expected to be some 8 TWh lower. This is partly due to a lower baseline for hydropower, whose output is heavily dependent on annual weather patterns. But it also reflects a less optimistic outlook for capacity growth in offshore wind, in particular, and bioenergy to a lesser extent.

Overall, OECD Europe renewable capacity is expected to grow by over 141 GW from 2013-20. Annual capacity additions stabilise at a lower level, however, due to persistent uncertainties over the longer-term renewable policy framework. The largest additions are expected in onshore wind, +55 GW over

2013-20, led by Germany, the United Kingdom and Turkey, with some 12 other countries with deployment over 0.5 GW. Solar PV is the second-largest source of capacity growth, with additions near 49 GW over 2013-20. Outside of the United Kingdom where the utility-scale segment is still growing, most new solar PV deployment is expected to be in residential- and commercial-scale developments, supported by FIT schemes in some markets and increasingly attractive conditions for self-consumption in some areas such as Germany and Italy (see "Special focus: Solar PV reaching socket parity" in chapter "Renewable electricity: Global technologies"). Still, annual solar PV deployment is seen stabilising at much lower levels than in 2012, for example.

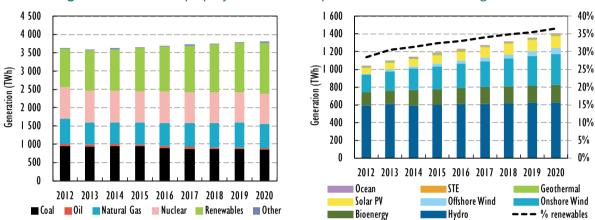
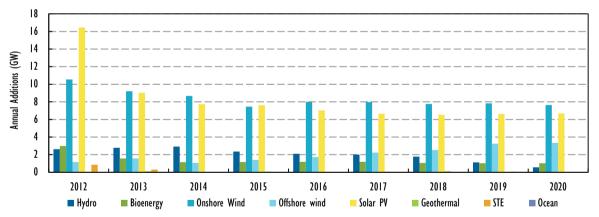


Figure 24 OECD Europe projected shares of power mix and renewable generation





Offshore wind in Europe expands more moderately due to slow cost reductions, in part from increasing project complexity, and uncertainties over long-term incentive schemes in some markets. Offshore wind capacity for the region is seen rising to 22 GW in 2020 from 6.6 GW in 2013, but this is contingent upon the timely delivery of a number of projects currently in the project pipeline. Bioenergy faces difficulties in growing rapidly due to challenges in establishing sustainable feedstock supply chains and less supportive policy frameworks in some countries. In this area, only moderate annual growth is expected, with some conversions and dedicated biomass plants being developed.

Medium-term outlook - detailed analysis

Power demand

Power demand in OECD Europe is expected to grow by only 0.8% annually over 2013-20, with most countries expanding only modestly. In 2013, demand fell by 0.8% for the region. Increased energy efficiency and sluggish economic growth characterise many of the markets. Trends in peak demand are divergent. In many markets, peak load has declined or remained stable since the start of economic crisis in 2008. In some, such as Turkey, it has increased on the back of economic growth. In others, such as France, it continues to rise due to structural factors, such as electrification of heating.

Some of the demand growth outlook is attributed to an expected rebound in electricity consumption in countries such as Italy, Spain, Portugal and Greece, which have witnessed steep cyclical demand declines in recent years. There is a significant risk that these markets may recover more slowly than forecast, with greater-than-expected structural demand destruction taking place. Almost 45% of Europe's demand growth is expected to come from Turkey, whose expected annual GDP growth of 4.2% is expected to drive still-robust power demand growth. Poland, whose GDP outlook is also robust, is another notable source of demand growth.

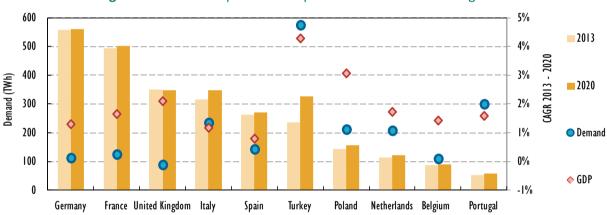


Figure 26 OECD Europe countries power demand versus GDP growth

Power generation and capacity

Power markets in Europe increasingly fall into three categories: dynamic systems with rising demand and new generation needs; stable systems with sluggish demand growth and overcapacity; and markets in between, usually with slow demand growth, but a need to replace capacity going offline. Due to decarbonisation and diversification aims, the role of renewables is expected to remain robust and growing across the region, though deployment will vary strongly by market situation.

In dynamic markets, a need for new power generation and diversification of the energy mix is driving the expansion of renewables. In Turkey, power generation continues to be met mostly by natural gas (44%), which is largely imported, and coal (27%). In 2013, the government announced a need to double total power capacity by 2023 from its level of 55 GW. Current targets for 2023 suggest that renewables would account for around 70% of this new growth. Turkey's project pipeline is significant, with over 5 GW of hydropower under construction, 1.5 GW of onshore wind financed and 600 MW of utility-scale solar PV licensed in last year's auction.

In Europe's stable systems with overcapacity, there is less generation investment needed to meet demand, though diversification aims and good resources support renewable expansion in some markets. Italy's power needs are mostly met by gas generation (38% of total), in which there is an overcapacity and a reliance on costly fuel imports. Strong diversification and decarbonisation aims are expressed through its National Energy Strategy, which sees a steady role for gas (35% to 40%) by 2020 and a rising role for renewables (35% to 38%) and energy efficiency. Still, the large-scale renewable project pipeline there is moderate in size, with auctions allocating around 400 MW of onshore wind annually while solar PV growth is driven more by small-scale additions for net metering and self-consumption. Despite high penetrations of renewables in Spain and Portugal, the power sector situation is less supportive. These markets face the challenge of reducing outstanding tariff deficits at the same time that demand is weak and overcapacity is sizeable.

In the Netherlands, the power system is dependent on a high share of fossil fuels, with gas at 53% of total generation and coal at 29% in 2013. Over the past decade, strong growth in new coal- and gasfired plants has produced significant surplus capacity, with additions planned in 2007-09 that came online over 2012 and 2013. When domestic capacity is added to maximum potential import capacity, the Netherlands has a healthy reserve margin over peak demand of around 84%, and generation adequacy is expected to remain strong even with 12 GW of variable renewables (wind and solar PV) in 2020 (IEA, 2014b). Diversification aims have spurred the country's National Energy Agreement for Sustainable Growth, which set ambitious targets for wind (8 GW, of which 2 GW offshore) and small-scale solar PV (4 GW) by 2020.

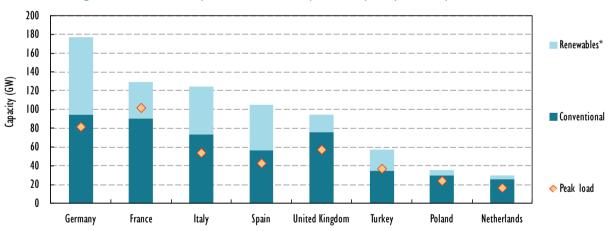


Figure 27 OECD Europe countries total power capacity versus peak load, 2012

Note: renewable and conventional capacity is as reported by countries to IEA Energy Data Centre.

A number of European markets face slow growing demand, but with less overcapacity and greater needs for new generation. In Germany, fossil-fuel generation declined to below 59% of power output, but coal increased while gas fell due to favourable gas-to-coal switching economics. From 2015, the phase-out of nuclear generation is again expected to resume, providing a driver for new capacity, and the government's revision to the Renewable Energy Sources Act (EEG) sees a power system increasingly reliant on renewable energy, which is to account for 35% of electricity demand in 2020. The large-scale project pipeline is oriented around wind (2.6 GW of offshore and 1.4 GW of onshore financed), with some bioenergy and a still sizeable potential for small-scale solar PV.

In Poland, power generation is dominated by coal (85%), with an increasingly ageing fleet. The TSO has suggested that power shortages to meet peak demand may emerge by 2017, due to insufficient capacity to offset retirements. Around 1 GW of onshore wind and 100 MW of bioenergy (not including co-firing) have been financed or permitted, but uncertainty over the transition of the current renewable support scheme has limited further plans.

In the United Kingdom, both gas- and coal-fired generation declined in 2013, and fossil fuels fell to around 64% of generation. The replacement of ageing plants (coal and nuclear) should guide the power sector over the medium term, with rising gas and renewables. Wind additions dominate the project pipeline, which reflects a portfolio of renewables, and has been boosted with clarifications of the government's Electricity Market Reform (EMR). Developments are likely also being accelerated to take advantage of the Renewable Obligation scheme before a transition to the contracts for difference (CFD) in 2017.

GW **Under construction Permitted Planned** Bioenergy 0.8 4.0 0.6 Offshore wind 1.4 2.5 11.5 Onshore wind 1.5 5.1 6.5 Solar PV 0.5 1.7 1.2 Hydropower 0.0 0.1 0.0 Ocean power 0.0 0.2 0.3 Total 4.3 13.5 20.2

Table 13 UK renewable capacity under development (February 2014)

Note: bioenergy includes portion of co-firing, bioenergy conversions and non-renewable waste. Numbers are rounded to nearest 0.1 GW. 20 MW of ocean power is reported as under construction.

Source: DECC (Department of Energy and Climate Change) (2014), Renewable Energy Planning Database, DECC, London, https://restats.decc.gov.uk/cms/planning-database.

France's power sector continues to be dominated by nuclear generation, at 74% of total output in 2013. The TSO sees the closure of 8 GW of coal- and oil-fired capacity by the end of 2015, and low utilisation rates for gas-fired plants is encouraging seasonal closures and the mothballing of some units (RTE, 2013). One new nuclear unit, 1.65 GW at Flamanville, is scheduled to come on line by the end of 2016, while the 1.8 GW Fessenheim nuclear plant is expected to be retired then. All the while, France's demand sensitivity to cold spells continues to rise due to increased electric space heating in the residential sector and other segments. France faces a longer-term decision on its nuclear plants, of which about half will reach current 40-year lifetime limits in the decade after 2020. Final clarity on whether to extend plant lifetimes may not come until 2018-19, however (Rose, 2014).

The current renewable project pipeline in France is moderate in size, with a 100 MW hydropower plant under construction, over 500 MW of onshore wind financed and more than 150 MW of utility-scale solar PV financed. Still, a total of 3 GW of offshore zones have been tendered, with the first offshore wind capacity on line from 2019. Significant offshore capacity is also under development in Belgium (1.6 GW financed or permitted) and Denmark (0.2 GW).

Box 4 EU renewable electricity faces challenges to meet 2020 targets and beyond

Under the Renewable Energy Directive 2009/28/EC, EU member states (EU-28) aim to achieve a 20% share of renewable energy in final energy consumption by 2020. The electricity sector plays a large role in meeting this outcome, with an estimated contribution of around 35% renewables as a portion of gross electricity generation by 2020. The mandatory national targets and National Renewable Action Plans (NREAPs) required by the directive have been broadly effective in providing investment certainty and stimulating mass deployment and cost reductions in renewables (especially onshore wind and solar PV). Still, implementation has sometimes come at significant cost, concentrated in some countries where specific policies failed to keep solar PV deployment in line with plans.

In 2012, renewable electricity accounted for an estimated 24% of total electricity generation in the EU-28, versus 15% in 2005. Over the medium term, this report sees EU-28 renewable electricity rising from an estimated 860 TWh in 2013 to over 1 110 TWh in 2020. This forecast is derived from the forecasts and country-level analysis found in the OECD Europe and non-OECD Europe and Eurasia sections of this report. To date, the EU-28 has exceeded its projections for total renewable electricity in terms of absolute generation as part of the overall target fulfilment. However, as future incremental renewable generation requirements grow more steeply, this report anticipates that the EU-28 will fall short by around 12% (percentage difference in generation, not percentage points) versus the indicative targets in 2020. It is worth noting that this comparison is very preliminary in nature and by no means certain. NREAPs were published in 2010 under more optimistic assumptions of economic growth and electricity demand. They may well be updated in light of revised needs for new electricity generation to meet a given renewable share. Moreover, individual country trajectories will vary in relation to their own objectives. Nevertheless, the trends are instructive in identifying areas where greater market and policy emphasis may be needed to better realise a portfolio of renewable development on a Europe-wide level.



Figure 28 EU-28 renewable electricity generation and projection and NREAPs in 2020

Notes: 2020 NREAPs = indicative targets in terms of absolute generation as published in the National Renewable Energy Action Plans. Both *MTRMR* data and NREAPs as calculated here include output from pumped storage within hydropower.

Source: IEA analysis based on ECN (Energy Research Centre of the Netherlands) (2011), Renewable Energy Projections as Published in the National Renewable Energy Action Plans of the European Member States, ECN, Amsterdam. for NREAPs.

⁵ The data and analysis presented in *MTRMR* are indicative and not an official assessment of EU-28 progress in meeting 2020 targets. While broadly consistent, data and calculation methods presented here may differ from Eurostat. For an official treatment, please see EC, 2013.

Box 4 EU renewable electricity faces challenges to meet 2020 targets and beyond (continued)

The overall outlook is lower than the current 2020 objectives suggest primarily due to slower growth in electricity demand and lower-than-expected deployment of wind (onshore and offshore), bioenergy, and to a lesser degree, geothermal and STE. Policy framework uncertainties, supply chain bottlenecks and persistently high project costs have all weighed upon offshore wind deployment, whose relatively long development lead times will make a larger scale-up through 2020 challenging. Bioenergy faces difficulties in growing in line with objectives due to challenges in establishing sustainable feedstock supply chains and less supportive policy frameworks in some countries. Developments in co-firing, which could lend additional upside to the outlook, are difficult to forecast. By contrast, solar PV is expected to exceed its indicative target by 55%. This is based in part on early, rapid growth in some markets where incentive levels were set too high, but also on sustained deployment and greater cost competitiveness over the medium term.

The long-term European policy environment will act as a key driver for sustaining momentum in overall renewable growth and scaling up technologies where growth has been more sluggish. In January 2014, the European Commission (EC) published a communication on a possible post-2020 renewable policy framework (EC, 2014a). This communication suggests an EU-28 target of at least 27% renewables in final energy consumption by 2030.

Overall, the EC anticipates that the share of renewables in the electricity sector will increase to a level of at least 45% in 2030. Unlike the 2020 renewable energy target, this aim would not be binding on individual member states; rather, countries would voluntarily set renewable commitments. The absence of binding national targets raises questions about how effective the overall EU target can be; more details on the nature of the governance framework overseeing these commitments would thus be critical. The 2030 policy options are being debated among member states, and the eventual policy tools adopted may differ from the Commission's original package. Sufficient clarity over a stable and sustainable policy and regulatory framework would need to come in a timely manner in order to sustain investment.

In the meantime, the EC has published its binding guidelines on state aid for renewables (EC, 2014b). The guidelines recognise the increasing cost-competitiveness of renewables and foresee a transition towards fewer incentives, a move away from FITs and greater need for participation in electricity markets for new installations. Specific provisions begin to apply to incentive schemes granting aid to new renewable projects over the medium term:

- From 2016, financial support should be provided through feed-in premiums or green certificates, and generators are subject to balancing responsibilities. From 2017, supports should be granted through competitive bidding processes, which can be technology-specific.
- Projects less than 500 kW (and wind smaller than 3 MW or three generation units) are still allowed to
 receive FITs and are exempt from the electricity market participation noted above. Similarly, installations
 below 1 MW (6 MW or six generation units for wind) are not required to go through bidding processes
 to receive aid.

The guidelines also permit countries to provide for aid to energy infrastructure and generation adequacy measures. The latter point addresses the trend of European countries' considering establishing national capacity markets. The guidelines advise states to consider other flexibility measures to achieve generation adequacy – such as demand-side management, interconnection and storage – before providing subsidies that would lock in fossil-fuel generation capacity. Such measures should also be awarded through competitive bidding and further the integration of balancing markets.

Box 4 EU renewable electricity faces challenges to meet 2020 targets and beyond (continued)

Lastly, the guidelines tackle exemptions to the payment of renewable energy surcharges, which are granted particularly to energy-intensive industries. They limit eligibility for exemptions to sectors that meet certain thresholds of electricity intensity and exposure to international trade. In those cases, industries are expected to pay at least 15% of the renewable surcharge, though states can further limit this burden for undertakings unable to bear it. These rules need to be applied by the start of 2019. Overall, the state aid guidelines are an important step to promote more competitive and flexible electricity systems, but raise some questions as to whether the policy transitions envisioned can sustain a large-scale penetration of low-marginal-cost, capital-intensive technologies such as renewables. The introduction of more market-oriented mechanisms based on competition is important for meeting decarbonisation goals in a cost-effective manner. For some technologies, a degree of convergence between support scheme designs among member states (in the case of offshore wind for example, this is likely to be a sliding premium based on an auction process) could also help reduce transaction costs for investors. Still, market participation may challenge smaller projects, and competitive bidding requirements for projects only moderately larger than prescribed thresholds, such as commercial-scale solar PV or bioenergy projects, may be challenging. In this respect, much will depend on the exact design of bidding processes for which member states retain a significant degree of flexibility with only basic principles prescribed in the guidelines. Moreover, it may be important not to constrain policy options too far for individual states while there is little experience on which to design the optimum policy framework for large shares of renewables. Such flexibility may be particularly important for a more rapid scale-up of technologies where progress is lagging.

Grid and system integration

With significant shares of wind and solar PV, many OECD Europe countries already serve as examples of the successful integration and balancing of variable renewables. In 2013, several power regions had variable renewable shares (wind plus solar PV) of total generation near 10% or higher on an annual basis. Denmark, which benefits from a high level of interconnection, was the highest individual country at over 40%. Ireland, a small island country with limited interconnection, achieved a penetration of over 17%. Over the medium term, based on analysis elaborated in this section, some power regions are expected to rise to above 15% on average, with the Iberian peninsula as high as 26% on an annual basis. IEA analysis suggests that all of these regions have sufficient flexibility to support a penetration level of at least 25% without any deficit in flexibility supply, with Iberia (35%) and Northwest Europe (NWE) (40%) able to achieve higher levels (IEA, 2014c). These results are conditioned upon the prioritisation of flexibility in system operations as well as strengthened interconnection within NWE, particularly with flexible hydropower resources in the Nordic countries, and between regions.

In practice, grid reinforcements and expansion in some areas are needed to realise the penetrations shown here, and grid constraints are likely to remain a challenge to deployment over the medium term. The European Network of Transmission System Operators for Electricity (ENTSO-E) is expected to publish an update of its Ten-Year Network Development Plan (TYNDP) in summer 2014, providing long-term guidance on needed new grid investments and refurbishments. Still, realising investments on the scale of the current version of the TYNDP (>EUR 100 billion) may require notable improvements in permitting and local acceptance of grid projects, regulatory rules that facilitate financing, and a stable, long-term European renewable policy framework. In Germany, the energy regulator has suggested that progress to upgrade north-south corridors bringing onshore and offshore wind power to industrial

demand centres in the south has moved slower than planned (Eckert, 2014). Realising investments under Germany's Electricity Grid Development Plan and Offshore Grid Development Plan presented last year can be challenging due to local acceptance issues (for land-based developments) and administrative hurdles. Progress is being made in a number of markets to ensure the integration of offshore wind farms; still, delays and costs associated with grid connections represent a constraint to development.

Finally, strong growth in distributed solar PV can also raise integration issues, including distribution network upgrades, more complex grid operations and the regulatory treatment of generation for self-consumption (Barth et al., 2013). Regulators increasingly need to determine fair rules for the allocation of the costs and benefits from solar PV for self-consumption (for more analysis, see "Special focus: Solar PV reaching socket parity" in chapter "Renewable electricity: Global technology outlook"). Over 2013-20, roughly 70%, or 34 GW, of expected new solar PV capacity in OECD Europe is likely to come from the residential and commercial segments, spurred by a mixture of self-consumption, net metering and other policy incentives. Aligning incentives for the different stakeholders (distribution system operators, generators) will be important to ensure that deployment is not hindered.

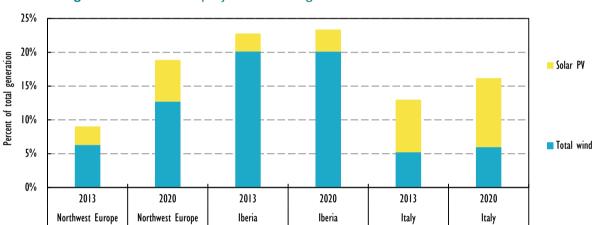


Figure 29 Current and projected annual generation shares of wind and solar PV

Current policy environment for renewable energy

Overall, the policy environment remains supportive for renewable development in the region. Yet policy risks and uncertainties are growing. In general, markets are transitioning to lower levels of financial support and greater intended use of competitive auctions to award incentives. During the past year, clarification has emerged in some countries on policy questions highlighted in *MTRMR 2013*. Still, the post-2020 policy framework for the EU-28 and ongoing policy transition in several markets remain to be finalised. Non-economic barriers to development persist in some countries. Moreover, in some markets, existing renewable generators are being squeezed by retroactive changes to incentives.

In June, Germany's Bundestag approved a significant revision of the EEG, which went into force in August 2014. The law seeks to strike a balance among limiting electricity price increases, maintaining security of supply and achieving an energy market design that supports high levels of renewables (35% of power generation by 2020; 55% to 60% by 2035). It defines capacity corridors for deployment (to be achieved through incentive adjustments), requires feed-in premiums and electricity market participation for new projects over 500 kW (this size threshold declines to 100 kW by 2016), and promises to deliver competitive bidding by 2017 for these projects to access incentives. For small-scale solar PV,

where deployment is largely driven by self-consumption, producers over 10 kW would be required to pay an initial 30% of the EEG surcharge (EUR 0.0624/kWh in 2014), rising to 40% by 2017, on self-consumed power.

Table 14 Germany renewable deployment capacity corridors under the EEG

Technology	Corridor
Bioenergy	0.1 GW annually
Offshore wind	6.5 GW until 2020; 15 GW until 2030
Onshore wind	2.5 GW annually (does not include repowering)
Solar PV	2.5 GW annually

Source: BMWi (Bundesministerium fur Wirtschaft und Energie) (2014), www.bmwi.de/DE/Themen/Energie/Erneuerbare-Energien/eeg-reform,did=616706.html

In the United Kingdom, the parliament approved its Energy Bill in late 2013 that launched the CFD scheme under the country's EMR. The government aims for at least 30% of renewable power in total generation by 2020, and sees 10 GW of offshore wind as "achievable" and the potential for 20 GW of solar PV by early next decade (though these are not targets). Final strike prices for the CFDs were published, clarifying an important uncertainty over project economics, and the government revealed the first eight projects awarded under the scheme – 4.5 GW of combined offshore wind, coal-to-biomass conversions and a dedicated biomass plant with co-generation. Final regulations on the EMR are expected by summer, and further awards are to be made in the autumn.

In the meantime, some policy uncertainties have arisen for utility-scale solar PV and onshore wind. The UK government has proposed excluding new solar PV plants over 5 MW from the tradable certificates (ROCs) scheme from 2015, two years earlier than the required transition to CFDs, in response to stronger-than-expected deployment. The energy minister has also made public comments that, should the current government be re-elected in 2015, financial support may be discontinued for new onshore wind projects not already permitted (Lee, 2014). Planning decisions for new developments could also devolve more to local governments.

In 2013, the Netherlands adopted its Energy Agreement, which places renewables as a pillar of future energy supply and confirms the Sustainable Energy Incentive Scheme (SDE+) (feed-in premium with a technology-neutral budget) as its main support mechanism. The Energy Agreement places a priority on developing wind power, with installation targets for onshore wind of 6 GW by 2020 (7 GW by 2023) and offshore wind of 2 GW by 2020 (4.45 GW by 2023), and distributed generation (e.g. solar PV). Biomass use in co-firing is capped at 25 petajoules pending the final outcome of the EU agreement on sustainability criteria for biomass. In the case that the SDE+ does not stimulate enough offshore wind development within a technology-neutral budget, separate tenders could be held from 2015 onwards (IEA, 2014b). A production tax credit was introduced in 2014 to support community-level distributed generation, and net metering is available to small-scale consumers. The Netherlands also intends to open the SDE+ scheme to non-domestic renewable production.

The policy environment has made improvements in France. In March 2014, the European Commission ruled that France's FITs for onshore wind constitute state aid that can be declared compatible with competition law; question marks over the legitimacy of the scheme had contributed in part to declining onshore wind investment in France. Despite the removal of some non-economic barriers to

Reform,

BMWi,

Berlin,

development (e.g. a requirement to site projects in *Zones de Développement Eolien*, wind development zones) in 2013, challenging permitting processes can make onshore wind project development times as long as five to six years in France, compared with four years in Germany and the United Kingdom (Hostert, 2014). To help reduce this burden, the government has started a test programme in seven regions to reduce permitting requirements down to a single permit, from various institutions, for new onshore wind projects. More wide-ranging energy reforms may lie ahead, however. The government has indicated that a bill on *transition énergétique* (energy transition) would be presented to parliament during the summer, which may signal fundamental changes to support schemes. The current draft reportedly includes the offering of feed-in premiums via an auction scheme for new renewable deployment.

Table 15 OECD Europe countries main targets and support policies for renewable energy

OECD Europe	Regula	atory s	upport	Economic support							
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Austria	Х	Χ		Х	Х		Х				
Belgium		Χ	ΧО		ΧО			0	ΧО		
Czech Republic	Χ	Χ			Χ	Χ					
Denmark	Χ	Χ	Χ	Χ	Χ	X	Χ	X			Χ
Estonia		Χ		Χ	Χ		Χ				
Finland		Χ		Χ	Χ						
France	Χ	Χ		Χ	Χ	Χ	Χ				Χ
Germany	Χ	Χ		Χ	Χ	X	Χ				
Greece	Χ	Χ		Χ	Χ		Χ	Χ			
Hungary		Χ		Χ	Χ						
Iceland		Χ			Χ						
Ireland		Χ		X			X		X		
Italy	Χ	Χ	Χ	Χ			Χ	X	Χ		Χ
Luxembourg	Χ	Χ		Χ	Χ		Χ				
Netherlands		Χ		Χ		Χ	Χ	X			
Norway		Χ	Χ		Χ				Χ	X	
Poland		Χ	Χ		Χ		Χ		Χ		
Portugal		Χ		Χ							
Slovak Republic	Χ	Χ		X	Χ		Χ				
Slovenia		Χ		X	Х	X					
Spain		Χ									
Sweden		Χ	Χ		Χ		Χ		Χ	Х	
Switzerland		Χ		Χ	Χ						
Turkey	X	Χ		Χ							
United Kingdom		Χ	Χ	Χ		Χ	Χ				

Note: x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

Poland has moved closer to clarifying uncertainty over the adoption of its new renewable energy law, which has been in the works since the end of 2011. The draft law was approved by the government

in April 2014 and is awaiting final approval from the parliament and president. The new incentive scheme in the law portends a shift for new projects from tradable green certificates to the awarding of 15-year, technology-specific feed-in premiums through competitive bidding. In this manner, the scheme could reduce the total costs of support and encourage electricity market participation while providing greater long-term remuneration certainty to developers. Still, some technologies, such as biomass co-firing, large biomass projects (>50 MW) and hydropower above 5 MW, would not be included. In addition, investor certainty will depend on the level of the auction reference prices and the timeline for the auctions themselves, which may not be clear until the law is finally adopted.

In Sweden and Norway, the agreement on a common market for electricity certificates establishes that the first *Kontrollstasjon* (progress review) in the joint green certificate market shall take place by the end of 2015. A progress review is the conduct of joint reviews and discussions between the countries concerning matters such as the need for amendment or adjustment of the regulations governing electricity certificates. For this purpose the Swedish Energy Agency and the Norwegian Water Resources and Energy Directorate have each prepared a report with recommendations to support the achievement of the overall target of 26.4 TWh new renewable electricity production by 2020.

Few changes have occurred in Italy's policy framework over the past year. Since July 2013, no new FITs for solar PV have been awarded under the fifth *Conto Energia* following attainment of the programme's budget cap. Future development in solar PV is likely to be driven by self-consumption or net metering, which is currently limited to 200 kW systems. Plants above 200 kW are allowed to supply electricity under private PPAs. Non-solar PV sources are supported by feed-in tariffs (for small-scale generators) and feed-in premiums accessed through tenders or a central registry (small-scale generators are automatically accredited) with capacity quotas running through 2015. Uncertainties remain over the details of the post-2015 auction system, however.

In several markets, the policy environment for renewables has become less supportive for both existing and new renewable generation. As described in more detail in *MTRMR 2013*, Spain has in recent years approved incentive changes to operating renewable projects and suspended incentives for new renewable installations in an effort to help control the power sector's tariff deficit, whose origins are multifaceted and complex. In June 2014, the government instituted measures to retroactively revise the remuneration given to existing renewable generators, imposing a "reasonable profitability" return that replaces FITs and feed-in premiums with annual remuneration based on a project's estimated investment cost. In Greece, more permanent retroactive cuts to FITs have recently been made to existing wind and solar generation. Anticipation of previous incentive cuts had stimulated a spike in solar PV deployment in the first half of 2013; since then deployment has been modest. In late 2013, the Greek government did approve the introduction of net metering, however, which could spur deployment of residential systems of less than 10 kW.

Economic attractiveness of renewable energy and financing

In OECD Europe, the economic attractiveness of renewables varies strongly by market and technology, with some incentives still generally needed to support development. In Turkey, with relatively high wholesale electricity prices, onshore wind has been sold with few direct incentives on the spot market or in bilateral contracts for several years. For OECD Europe overall, the LCOE for onshore wind, bioenergy, geothermal and hydropower projects is comparable to that of new fossil-fuel generation, suggesting that these technologies can be deployed with few direct financial supports.

Still, policy support frameworks, including indirect support in the form of grid integration measures, for example, remain important for investment. The introduction of increasing amounts of low-marginal-cost renewables, in addition to the weak demand picture, have tended to moderate wholesale prices, particularly in markets with overcapacity. This is the case of onshore wind in Germany, for example, where wholesale prices are often not sufficient to recover the up-front capital expenditure. As such, to remain economically attractive, even relatively low-cost renewables would require policy incentives that help to reduce market price risk and guarantee a certain level of remuneration.

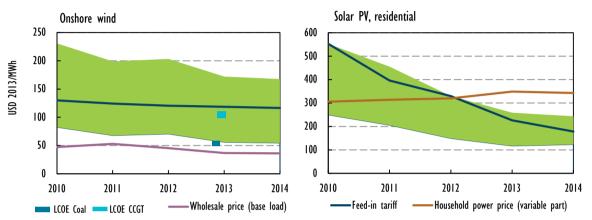


Figure 30 Germany estimated levelised costs of power generation ranges, beginning year

Notes: CCGT = combined-cycle gas turbine. The LCOE ranges for onshore wind and solar PV reflect low-cost, typical and high-cost projects, which vary primarily due to differences in system costs, resources and the cost of financing. Wholesale power prices are day-ahead, baseload prices as reported on the European Energy Exchange. Household electricity prices are averages across end-user segments and are estimated to exclude fixed charges, which are assumed to represent 10% of average power price as seen on a consumer's bill. For 2014, both wholesale and household prices are held constant from 2013 due lack of full-year data. FITs are as of January in each year and reflect initial tariff levels without bonuses. Cost of capital used for onshore wind LCOE is 4.0%, and that for solar PV is 2.5%, in line with Kost et al., 2013.

Source: IEA analysis with power price data from Bloomberg LP (2014), accessed 01 June 2014.

The LCOE for utility-scale solar PV has steadily decreased with falling system prices. In locations with good resources in southern Europe, utility-scale plants are estimated at around USD 110/MWh. Even at this level, costs remain higher than prevailing wholesale prices. In general, utility-scale developments in Europe have grown less attractive, outside of the United Kingdom, as FITs have been reduced and wholesale prices have trended downwards. By contrast, the attractiveness for small-scale solar PV continues to improve even as FITs have been reduced or phased out for new plants across a number of markets, supported by rising retail prices and the availability of net metering in some markets. In Germany and Italy, residential- and commercial-scale solar PV for self-consumption has emerged as an attractive option for consumers facing relatively high end-user electricity prices. Still, these comparisons can mask important value considerations from the system perspective, such as the variability of the solar output and the recovery of fixed network costs. Nevertheless, they do show an emerging investment case with fewer subsidies for these segments (for more analysis, see "Special focus: Solar PV reaching socket parity" in chapter "Renewable electricity: Global technologies").

Offshore wind costs remain significantly higher than underlying wholesale prices and new-build fossil-fuel plants. System prices have stayed elevated, or have risen, in recent years as water depths have increased and farms have moved farther offshore. To this end, several European developers have aimed to reduce offshore wind generation costs by 40% by 2020, which would require reductions in turbine costs, improved turbine performance and cost reductions in other parts of the supply chain

(see section on "Offshore Wind" in chapter "Renewable electricity: Global technologies"). Achieving cost reductions on this order will be challenging, but are necessary for deployment to accelerate. STE also remains relatively expensive. With the suspension of incentives for new plants in Spain, it is not expected that large new CSP investments will be attractive over the medium term, given Europe's relatively weak resource availability.

Conclusions for renewable energy deployment: Baseline case

In OECD Europe, the strongest renewable growth is expected to occur in countries with dynamic power systems or in those relatively stable systems undergoing significant transitions in their electricity sectors. More than half of OECD Europe's new renewable generation to 2020 is seen coming from three markets – Germany, the United Kingdom and Turkey – where, among other examples, these trends are evident. By contrast, in markets where policy support has been substantially reduced or retroactive changes to support schemes have taken effect, new renewable development is expected to grow only slowly or stagnate.

Table 16 OECD Europe, selected countries renewable energy capacity in 2013 and 2020

Total		20	013		2020				
Capacity (GW)	Germany Italy Turkey		United Kingdom	Germany	Italy	Turkey	United Kingdom		
Hydropower	11.3	21.9	21.0	4.4	11.6	22.5	27.6	4.4	
Bioenergy	7.6	4.0	0.1	3.4	8.3	4.2	0.3	4.1	
Onshore wind	33.8	8.5	2.9	6.6	48.3	11.3	8.2	14.6	
Offshore wind	0.5	-	-	3.7	4.2	0.0	-	10.6	
Solar PV	35.9	17.9*	0.0	3.0	52.2	25.4	2.3	10.0	
STE/CSP	0.0	0.0	-	-	0.0	0.0	0.1	-	
Geothermal	0.0	8.0	0.2	-	0.0	0.8	0.4	-	
Ocean	-	-	-	0.0	-	0.0	-	0.0	
Total	89.1	53.0	24.3	21.2	124.6	64.3	38.8	43.8	

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report. *The latest estimate from Gestore dei Servizi Energetici has Italy solar PV capacity at 18.1 GW for end-2013; this datapoint was not able to be incorporated in this report's dataset.

Germany's power system is attempting an ambitious transition towards high levels of renewables while at the same time trying to balance affordability and market design challenges. The country is expected to account for over 20% of OECD Europe's renewable generation growth. Onshore wind is seen expanding slightly slower than the government's capacity corridor due to the continued challenge of building out the grid. Offshore wind is also expected to lag behind its 2020 target, with uncertainties over whether developments can achieve difficult cost reductions. Meanwhile, solar PV growth is seen somewhat higher than the capacity corridor, with attractive economics for self-consumption potentially stimulating faster-than-expected deployment.

The United Kingdom is also undertaking an ambitious power sector transformation. It is expected to account for about 15% of OECD Europe's renewable growth. While onshore wind is seen leading capacity growth, uncertainties have arisen over the durability of its support scheme, and local acceptance continues to be a challenge for deployment. The United Kingdom is likely to lead global deployment of offshore wind. The outlook for 2020 of just over 10 GW is consistent with the government's view of realistic deployment. Still, faster cost reductions and integration improvements could spur greater development.

Table 17 OECD Europe main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Germany	Strong policy environment with ambitious decarbonisation aims. Growing attractiveness of solar PV for self-consumption.	A need to balance affordability and market design challenges in reforms. Continued build-out of grid.
United Kingdom	Ambitious renewable targets backed by support measures under CFD scheme. Need to replace ageing conventional generation fleet.	Some uncertainties remain over policy environment, including some implementation details of CFD scheme. Technical and financial challenges of offshore wind development.
Turkey	Strong need for new capacity to meet demand. Good competitiveness of renewable sources.	Overall low financial supports and current quota limits of the solar PV auction programme. The cost and availability of financing.
Italy	Strong diversification aims through national energy strategy. Good economic attractiveness of solar PV for self-consumption.	Overcapacity in the power sector. Capacity quotas under current auction/registry system and uncertainty over post-2015 details.
France	Potential need for new capacity to meet plant retirements and rising peak demand. Tenders support offshore wind deployment.	Reducing non-economic barriers. Clarifying future policy framework under transition énergétique.

Note: only expected top five European generation growth markets included here.

Turkey, the best example of a dynamic system in Europe, is expected to account for 15% of the region's growth as it scales up a portfolio of hydropower, onshore wind and solar PV along with some geothermal and bioenergy. Good competitiveness of renewable sources and a strong need for new capacity to meet demand are drivers, though overall low financial supports, current quota limits of the solar PV auction programme, and the cost and availability of financing remain constraints.

A number of other markets are also expected to register strong renewable growth. In addition to the countries listed above, 11 countries could see solar PV deployment of at least 0.5 GW over 2013-20, while onshore wind should grow by at least 0.5 GW in 12 countries. Offshore wind deployment is more concentrated, but Belgium, the Netherlands, Sweden and Ireland should all see growth at this level, while Denmark's recent strong growth begins to slow by the end of the decade. Bioenergy expansion remains slower overall than solar PV and wind, but notable developments are expected in Denmark, France, Poland, Finland and Austria.

Renewable energy deployment under an enhanced case

Enhancements to the market and policy situation in Europe could spur greater renewable deployment over the medium term versus the baseline case. Analysing and accounting for all these possible variations at the country level is difficult in the space provided here, so these points and their potential impacts are mostly made in the broad sense.

At the regional level, timely clarification over the EU-28 post-2020 framework, with a credible mechanism to spur states to comply with a new EU-28 2030 renewable target, could help enhance investor certainty and spur new investment. In the dynamic power systems in the region, countries would need to further reduce non-economic barriers to development. Notably, in Turkey, solar PV deployment could be higher with the acceleration of further capacity auctions for utility-scale capacity. In more

stable power systems facing significant electricity sector transitions, some policy uncertainties persist. A clarification by governments of wide-ranging reforms ahead (such as in France, where a draft of the *transition énergétique* has been made public), the finalisation of draft renewable legislation (such as in Poland), and the clarification of remaining policy questions under new support schemes (such as in the United Kingdom) could enhance investor certainty. Power systems with clear overcapacity and reduced prospects for new renewable deployment need to avoid retroactive measures on existing generators.

On the technology side, greater-than-expected development of grid connections, transmission capacity, interconnections, other forms of flexibility (such as storage) and improved grid codes and operations would be needed for the timely scale-up of wind power, with further cost reductions required for offshore wind in particular. Faster-than-expected cost reductions could also drive an acceleration of distributed solar PV deployment for self-consumption under conditions of grid parity. Lastly, greater progress in the establishment of sustainable feedstock supply chains could raise the outlook for bioenergy. Broadly, these enhancements could raise the regional outlook for onshore wind by 2 GW to 3 GW in 2020 and by 1 GW to 2 GW for offshore wind versus the baseline case. The upside for solar PV is larger, particularly for Turkey and residential/commercial segments in Europe under socket parity; total solar PV deployment could be 4 GW to 5 GW higher versus the baseline case. Meanwhile, bioenergy could scale up by 0.5 GW to 1.0 GW versus the baseline case, putting deployment more in line with EU-28 targets.

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RENEWABLE ELECTRICITY: NON-OECD

The latest available historical electricity generation data for non-OECD countries is 2012. Estimates for 2013 generation were calculated in the MTRMR 2014 power generation model based off of recent trends. Data for 2013 should be considered preliminary.

Summary

• Renewable capacity growth in markets outside the Organisation for Economic Co-operation and Development (OECD) continues to rise. Fast-growing power demand and power sector diversification needs represent strong drivers for increasing renewables in many non-OECD countries. A number of markets have adopted long-term renewable policy frameworks. Combined with good resources and the falling costs of some technologies, such as solar photovoltaic (PV), these conditions should support increasing levels of deployment with reduced financial incentives. Nevertheless, outside of established markets such as China, India and Brazil, many non-OECD countries remain at the inception or early take-off phase of renewable deployment. In 2013, China accounted for 78% of non-OECD capacity growth and is seen driving over 60% of gains through 2020. Non-OECD countries where renewables are just taking off often face hurdles in scaling up deployment due to non-economic barriers, grid constraints, market design or the cost/availability of financing. Their impact suggests that non-OECD renewable capacity additions may rise only gradually over the medium term, and at a slower pace than that predicted in MTRMR 2013, with a faster scale-up occurring over the long term.

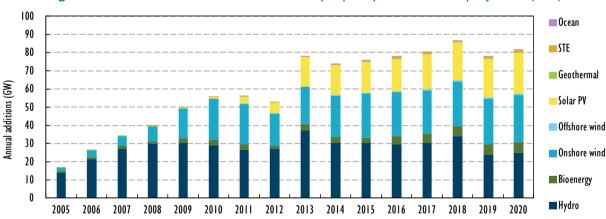


Figure 31 Non-OECD renewable net electricity capacity additions and projection (GW)

Note: GW = gigawatts; STE = solar thermal electricity. Unless otherwise indicated, all material in figures and tables in this chapter derive from International Energy Agency (IEA) data and analysis.

• Non-OECD renewable electricity generation increased by an estimated 136 TWh in 2013 versus 2012 (5.3% year-on-year) to 22% of total power generation. Hydropower accounted for roughly 39% of the increase, and was boosted by exceptionally large capacity additions in China (+31 GW). Non-hydro sources grew most strongly in onshore wind, with a rebound in China's capacity additions (+16 GW) and stable growth in Brazil. Solar PV had its largest annual growth to date in the non-OECD, boosted by additions of over 12.9 GW in China. At an estimated 25 TWh, solar PV's generation still remained below that of other, more long-standing sources such as bioenergy and geothermal, which grew more slowly.

• Over the medium term, non-OECD renewable power generation is projected to grow by 1546 terawatt hours (TWh) from an estimated 2727 TWh in 2013 to 4274 TWh 2020 (+6.6% per year). Compared to MTRMR 2013 renewable generation expectations in 2018 are revised down by 140 TWh, largely due to a slower hydropower and wind (onshore and offshore) outlook in China. Renewable generation is seen rising to 25% of total generation in 2020 from 22% in 2013. Renewables are seen as the largest new source of non-OECD generation through 2020. Yet, they meet only 35% of fast-growing electricity needs, illustrating the still-significant role of fossil fuels and large upside for greater renewable growth. Hydropower is expected to lead capacity growth, with deployment of 25 GW to 35 GW annually, depending on the commission timelines of large projects, led by China and Brazil. Onshore wind represents the next-largest source of growth, with annual deployment rising steadily from 21 GW in 2013 to 26 GW by 2020. With falling costs; strengthened targets in China, in particular; and increased activity in new markets, such as the Middle East, solar PV deployment is expected to accelerate, from annual growth of 16 GW in 2013 to 22 GW in 2020. Growth in other technologies, such as bioenergy, STE (CSP) and geothermal is seen rising as well, though more slowly.

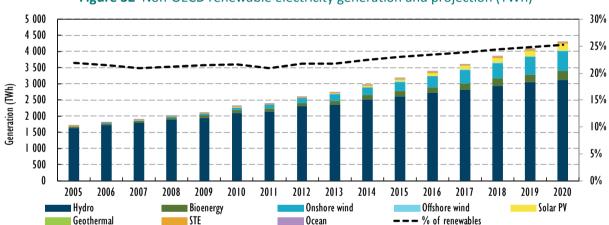


Figure 32 Non-OECD renewable electricity generation and projection (TWh)

Note: the most recent power generation data for non-OECD countries from the IEA Energy Data Centre are for 2012. Data for 2013 are IEA estimates from modelling and market research. Hydropower includes pumped storage; the onshore and offshore wind split is estimated; total generation is gross power generation.

- China's renewable generation is seen rising by 881 TWh from an estimated 1 097 TWh (20% of gross electricity generation) in 2013 to 1 978 TWh (27% of generation) in 2020. China accounts for more than 56% of the total non-OECD renewable generation increase. Deployment should be led by onshore wind (+118 GW), hydropower (+105 GW) and solar PV (+94 GW), whose outlook has continued to improve with the setting of higher short- and medium-term deployment targets. Still, the expansions of both hydropower and onshore wind are slower than in the Medium-Term Renewable Energy Market Report 2013 (MTRMR 2013). Offshore wind and STE are also both seen expanding less than in MTRMR 2013 due to slower-than-expected progress in commercial project development. Strong policy with ambitious targets underpins the outlook, but with short-term uncertainty in some areas, notably the development of distributed solar PV.
- Other non-OECD regions vary in terms of their renewable development. The non-OECD Americas
 and Asia outside of China represent the largest contributions to growth over the medium term.
 Steady growth in hydropower, onshore wind and bioenergy capacity in Brazil, supported by the

government's long-term auction scheme, underpins the outlook in the Americas. India's diverse set of targets and financial incentives supports the growth of hydropower, onshore wind, solar PV and bioenergy, which underpins the Asia forecast. A number of other emerging markets, such as Thailand and Indonesia, are also expected to contribute. In Africa, non-OECD Europe and Eurasia, and the Middle East, growth remains more nascent. However, some markets should scale up strongly, such as South Africa, backed by a long-term auction scheme, and Saudi Arabia, which has announced aggressive long-term targets backed by auctions. Still, non-economic barriers, needed grid upgrades and the cost/availability of financing may represent persistent constraints.

• Under this report's enhanced case — depicted within each region — total non-OECD cumulative capacity for solar PV could be some 35-60 GW higher and total wind (onshore plus offshore) could be some 20-30 GW higher in 2020 than under the baseline case. Besides faster-than-expected reductions in renewable technology costs, this result could come about through greater measures to reduce non-economic barriers and improve the system and grid integration of variable renewables, particularly distributed solar PV. Hydropower in China could also be higher some 10-20 GW in 2020 with an acceleration of environmental approvals and the rapid establishment of a more robust project pipeline.

Africa

Recent trends

In Africa, renewable power increased by an estimated 2.9% in 2013 to reach 125 TWh, or 16.3% of the continent's total power generation. Hydropower dominates the renewable power in Africa and can fluctuate from year to year. In 2012, generation grew by 1.2% in part due to higher reservoir levels versus drought conditions in 2011 while preliminary estimates for 2013 growth were relatively constant despite an expansion of over 400 MW. Roughly half of hydropower is generated from just five countries (Mozambique, Egypt, Zambia, Ghana, and Ethiopia), therefore their specific reservoir conditions can largely influence 2013 growth estimates for the continent. Wind saw increased activity across the continent, with generation expanding by more than 50% in 2013 from the addition of 100 megawatts (MW) in Morocco and a 200 MW flagship wind farm in Ethiopia. Solar PV also had an important year, with some 0.1 GW added from the first grid-connected plants coming on line in South Africa, Ghana and Mauritania. Bioenergy saw 0.1 GW commissioned, mostly scattered throughout West Africa. As a whole, Africa's non-hydropower renewable generation saw an increase of 46%, year-on-year, due to a number of important developments in each region.

South Africa's renewable generation is estimated to have remained relatively constant in 2013, but 2014 has already seen significant developments. Two privately owned 10 MW solar PV projects were commissioned in 2013. However, by the year's end, the 75 MW utility-scale plant at Kalkbult, the continent's largest, was grid-connected. Shortly following were several others sized 50 MW and 75 MW, which commenced in early 2014. These are some of the first solar PV plants to be commissioned under South Africa's first round of the Renewable Energy Independent Power Producer Procurement Programme (REIPPP). Onshore wind capacity from the first REIPPP round has also started operation, with 0.2 GW connected in early 2014.

In North Africa, Egypt's renewable generation remained relatively constant in 2012 while Morocco moved ahead on plans for major wind projects in 2013. Morocco's renewable power grew 27% in 2013, from 2.5 TWh to 3.2 TWh, largely due to increased hydropower output from the recovery of lower

levels the previous year. But by the end of 2013, Morocco had connected two 50 MW independent power producer (IPP) wind plants and by early 2014, the largest wind farm constructed at once in Africa, 300 MW at Tarfaya, was commissioned.

In East Africa, Ethiopia's and Kenya's generation growth was largely a reflection of seasonal variations in hydropower, yet both countries commissioned utility-sized non-hydro plants. Ethiopia saw an increase in renewable generation in 2012 from a rebound in hydropower reaching 6.7 TWh. However, some 90 MW onshore wind capacity was commissioned in 2013 from additions at Ashegoda, bringing the total plant to 120 MW, the largest wind farm in Africa until eclipsed by Tarfaya in Morocco in 2014. Kenya's renewable generation also grew in 2012 to 6.2 TWh, largely from hydropower. A 36 MW geothermal plant also came on line in early 2014, from phase 2 of Olkaria III.

A number of other countries throughout the continent have also witnessed activity. Mozambique, Mauritius, Mauritania and Ghana have connected utility-scale PV plants ranging from 1.3 MW up to 15 MW. Mali, the Democratic Republic of Congo, Zimbabwe and Tanzania have commissioned small hydro plants ranging from 1 MW to 18 MW. Also in the last year, Côte d'Ivoire has commissioned a 3 MW biomass plant, and Uganda has commissioned one for 12 MW.

Medium-term outlook - regional baseline case summary

Overall, renewable generation in Africa is expected to rise by 88 TWh, or 70%, over 2013-20, driven largely by national policies geared at utilising excellent resource potentials for diversification and meeting growing demand. The share in renewables in the power mix is expected to rise from 16% in 2013 to almost 20% in 2020. Overall, the number of countries with renewable targets is growing; some countries have established supportive long-term frameworks based on auction schemes, while others have feed-in tariff (FIT) schemes either already enacted or in draft form. Still, levels of financial incentives sometimes remain insufficient to attract private developers in some markets, and auctions can remain difficult for smaller projects to access. Non-economic barriers to entry characterise the power systems of some countries, and infrastructure upgrades, including grids, are also generally needed. Innovative policy and business models, public-private partnerships, and unique project finance structures have surfaced to attract foreign investment. Distributed and off-grid generation has a large potential, particularly in rural applications for diesel abatement. However, the high up-front costs of such systems and the high cost of capital in the region can act as constraints.

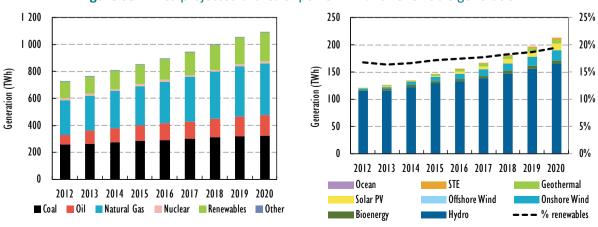


Figure 33 Africa projected shares of power mix and renewable generation

The majority of Africa's growth is expected from hydropower, which is seen expanding by about 15 GW with several large projects expected to start coming on line in Ethiopia, Nigeria, Mozambique and Angola. Though hydropower is a relatively mature technology, a large potential remains to be exploited in Africa, and future developments for large hydropower will depend on supportive policy frameworks and the cost and availability of financing.

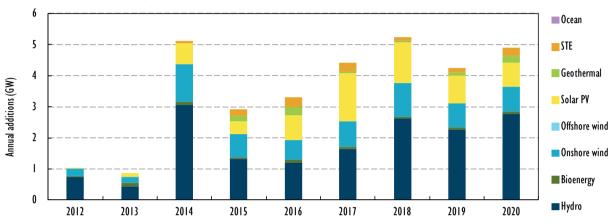


Figure 34 Africa historical and projected capacity additions

Solar PV is expected to grow by 6.5 GW from 2013-20, driven by the auction scheme in South Africa, and rising use in mini-grids and off-grids in other countries where it is more economically attractive than costly diesel generators. Onshore wind should also see strong growth, rising by nearly 6 GW, with most additions expected to come from the results of auction schemes in South Africa, Morocco and Egypt. On a global scale, Africa's expected addition of 1.4 GW of STE (CSP) over 2013-20 is significant, with its storage capabilities providing added flexibility to meet peak demand. South Africa and Morocco are expected to lead developments. Finally, geothermal is expected to grow by 0.8 GW, led by Kenya, while a number of countries contribute to the regional increase of bioenergy capacity of 0.5 GW over 2013-20.

Medium-term outlook - detailed analysis

Power demand

Power demand in Africa is expected to grow by 5.2% annually over 2013-20, with most markets expanding strongly. Many countries struggle to meet electricity demand with grid-connected power, let alone provide power to populations in rural areas. Approximately 50% of the continent's population is without electricity, although those shares vary drastically depending on the country. Meeting current and future demand in the most cost-effective way should continue to act as a driver for renewable deployment in Africa over the medium term.

Morocco's demand continued to expand in 2012 with 8.6% more than 2011 and reaching 29 TWh, of which 15% is met by importing electricity from Spain. Demand grew 7.2% annually over 2007-12, due to economic growth and the end results of a massive electrification initiative, achieving almost 98% electricity access. Total power capacity stood at 6.7 GW, and peak demand was 4.9 GW in 2012. Power demand is seen increasing 5.9% annually from 2013-20, a continuation of the growth seen in recent years and in line with robust growth of the gross domestic product (GDP) expected at 5% over 2013-19.

Egypt's demand increased 4.7% in 2012, continuing the strong 5.8% annual growth seen between 2007 and 2012, largely driven by economic growth and changes in consumption patterns. Total power

capacity stood at 29.7 GW and peak demand was 25.7 GW in 2013, with slim reserve margins. Almost 100% of the population has access to electricity, and with continued economic growth, at 3.8% annually over 2013-19, the government expects demand to grow 8.5% per year over 2013-20.

Ethiopia's demand grew a staggering 12.5% annually over 2007-12, reaching 5.6 TWh in 2012, primarily from a low starting point but also due to strong economic and population growth. With population set to rise further and GDP growth expected at 7.2% over 2013-19, the government is preparing for massive demand growth, estimated roughly at 16% annually over 2013-30. However, this growth is a result of two factors: a low baseline due to only 23% of the country having access to electricity in 2011, and the goal to raise that rate to 75% by 2030 against a continuing increase in the population.

Kenya sees increased demand from population growth and electrification as well as strong economic growth and expanding industrial activity. Demand reached 8.3 TWh in 2012, up from 7.8 TWh in 2011. Peak demand was 1.6 GW in 2013 and is expected to reach 5.3 GW by 2017 and 18 GW by 2030 in the Least Cost Power Development Plan (LCPDP) for 2011-31 (GoK, 2011b). Total capacity in 2013 stood at 1.6 GW and is insufficient to meet the demand when hydro availability is inadequate. Only 19% of the population has access to power. Driven by the objective to achieve 100% electrification by 2030 and in anticipation of a strong GDP growth of 6.2% annually from 2013-19, the government expects demand to grow by 14% annually over 2012-30.

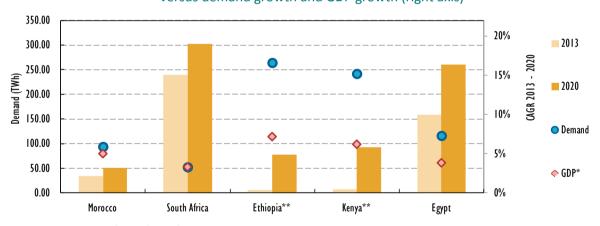


Figure 35 Africa selected countries power demand (left axis) versus demand growth and GDP growth (right axis)

Note: CAGR = compound annual growth rate.

South Africa's demand declined by 0.6% annually over the period of 2007-12, even as GDP grew. There is often a tendency to explain this decoupling as the economy's structural shift away from energy-intensive industries, but in the case of South Africa, this may be misleading. Large industrial consumers were incentivised to reduce consumption through Eskom's buy-back programme in 2011 and 2012 due to a severely constrained supply that stems back to the energy crisis in 2008. Additional reasons for suppressed demand include high electricity prices and imposed power cuts amid increased energy efficiency efforts, which in turn, could have reinforced the sluggish GDP growth. The demand picture carries uncertainties going forward. In the draft update of the 2010 Integrated Resource Plan (IRP), the government is considering revising down long-term demand growth assumptions from 3.4% to

^{*}GDP is over 2013-19 and

^{**}Demand projections and CAGR to 2030.

1.9%-2.9% over the period 2012-30, based on recent observations (DOE, 2013). Despite the debate over the future correlation of demand and economic growth in South Africa, this report assumes demand growth of 3.3% consistent with assumptions in the IEA *Medium-Term Gas Market Report 2014*, published in June, and in line with the International Monetary Fund's (IMF) forecast of 3.3% GDP growth over 2013-19.

Power generation and capacity

In Africa, diversification needs and increasing access to electricity are both expected to act as strong drivers for increasing renewable deployment over the medium term. Development will depend on the broader energy strategy of individual markets and the nature of their power sector. Rural electrification efforts, difficulties in building out the grid and diversification away from diesel generators also create drivers for distributed generation, in particular.

Morocco's strong demand growth and desire to reduce dependency on fossil fuels are likely to drive renewable growth over the medium term. Morocco is highly fossil-fuel dependent, totalling 90% of power generation, of which 43% was from coal, 25% was from oil and 23% was from natural gas in 2012. Hydropower accounts for around 7%, while wind makes up 3%. As a net energy importer with a majority of electricity generated from fossil fuels, and further aggravated by fuel subsidies, Morocco's energy bill is costly (although a partial phase-out of fuel subsidies is expected to start in 2014). Furthermore, its need to import electricity to meet a growing demand further increases the vulnerability and potential cost to the power sector. As such, energy diversification is one of the main objectives of the National Energy Strategy. To achieve this, the government outlines a plan to capitalise on the excellent wind and solar resources by setting a target of 42% renewable energy of total capacity by 2020. By 2012, renewable capacity made up 31% of the 6.7 GW of total capacity in Morocco, of which 25% is owned by IPPs, one of the highest shares in Africa (RCREE, 2013). Morocco is classified as a single-buyer market, but Law 09-13 enacted in 2009 permits IPPs to sell renewable electricity directly to third parties for self-consumption. The first projects (two 50 MW wind farms) under this law came on line in 2013 and a further 320 MW are under development. From the government's ambitious Solar Plan is the Noor I, a 160 MW STE plant, currently under construction at Ouarzazate after a competitive bidding process in 2012.

Egypt's rising power demand and uncertain future of indigenous fossil-fuel supply should be the main drivers for renewable deployment over the medium term. Egypt has a high dependence on fossil fuels, with 76% of generation from gas and 15% from oil in 2012. Hydropower stood at 8%, with little unexploited potential remaining. Wind makes up only 1% of power generation. With growing peak demand and insufficient power capacity, reserve margins are slim and load shedding occurs during the summers. End-user electricity prices are regulated and fuel subsidies exist. Oil production is declining, and uncertainties are growing over the source of future gas supply. With demand set to rise, the government's energy strategy is to ensure enough supply to meet future demand in a cost-effective manner. The government has targeted 20% of generation from renewables by 2020, of which 12% would come from wind with significant private participation (NREA, 2013). Despite legally being liberalised in 1996, the Egyptian Electricity Holding Company owns 93% of the generating capacity, and the power sector currently remains a single-buyer market. Still, changes are under way to allow bilateral contracts between large industrial consumers and producers, and in 2013, grid access was granted to Egypt's first private generator, a 120 MW wind farm, under this arrangement. Egypt's renewable project pipeline consists mainly of wind, of which around 0.4 GW is under construction (NREA, 2014).

Ethiopia's strong demand growth, diversification needs and the government's desire to export electricity should help drive renewable deployment over the medium term. At 99% of total power generation in 2012, hydropower remains the dominant source. Such a high dependency can make Ethiopia vulnerable to droughts, resulting in lower supply and unmet demand, which is expected to rise strongly over the next 20 years from electrification and economic growth. The primary objective of the government's energy strategy, as outlined in the Growth and Transformation Plan, is to meet the rising demand and increase electrification (GoE, 2010). As a second objective, Ethiopia also plans to position itself to export surplus power to the region (GoE, 2010). Planning for the power sector is done by the state and Ethiopian Electric Power Corporation (EEPCO), and despite the partial liberalisation that opened up generation to private producers ten years ago, there was no IPP participation yet in 2013. Still, this picture is changing. The country's first power purchase agreement (PPA) was signed in 2013 for 1 000 MW of geothermal from the Corbetti project, which is expected to come on line in phases over the next five to ten years. The remainder of the country's renewable pipeline are publicly owned projects planned by EEPCO with 6.8 GW of hydropower, 0.7 GW of geothermal and some wind.

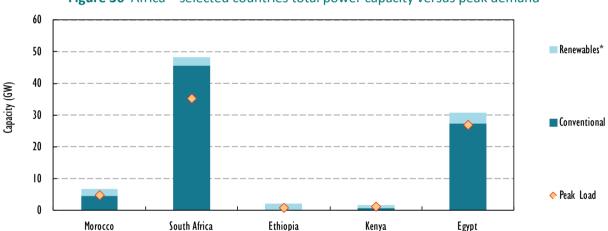


Figure 36 Africa – selected countries total power capacity versus peak demand

Notes: in South Africa, total capacity stood at 48 GW in 2012, but 10 GW to 12 GW of ageing plants were out of service for maintenance in 2013. The remaining 35 GW available was insufficient to meet the forecast peak demand several times throughout the year.

Kenya is in the process of updating its power sector planning to meet rising demand needs, diversify its electricity mix and provide lower-cost power to consumers. Power generation is dominated by hydropower, 52% in 2012, followed by oil at 25%, geothermal at 19% and bioenergy at 4%. The dependence on hydropower has left Kenya vulnerable to weather variations with occasional unmet demand and power rationing, while the use of diesel generators as a backup has resulted in high electricity prices for the consumer that the government seeks to drive down (Gok 2011a, GoK, 2014). With current capacity at 1.6 GW, the draft National Energy Policy proposes to add 5 GW by 2016 with geothermal, natural gas, coal and wind playing a major role (GoK, 2014). The government seeks to increase privatisation as a way to finance the additional capacity needed to meet the rapidly growing demand. Kenya's power sector has gradually developed from a complete vertically integrated system to a relatively open system with seven IPPs accounting for 24% of the installed capacity as of December 2013 (GoK, 2014).

In the context of the national energy strategy, and in line with Vision 2030, Kenya's overall economic development strategy, the government is promoting renewable resources on a least-cost and efficiency criteria. Kenya is endowed with excellent untapped geothermal potential, which is regarded as an

economical source of base-load power and a hedge against the seasonal variability in hydropower (GoK, 2011b). In the draft energy policy, Kenya targets 5.5 GW of cumulative installed geothermal capacity by 2030; in the current project pipeline some 0.3 GW is under construction and 0.4 GW is planned. Wind potential is also very high and has also been prioritised by the government, with a target of 3 GW by 2020. Set to be the largest wind farm in Africa, the 300 MW at Lake Turkana closed its financing in March 2014 and is slated to start construction by year's end. Renewable generation is also seen playing a role in the country's goal to achieve 100% electrification by 2030. Current goals in the draft energy policy include the installation of an additional 100 000 units of solar PV in the residential sector by 2017 (GoK, 2014). As of December 2013, the conversion of 11 MW of several isolated diesel plants to hybrid solar/diesel mini-grids had already started, and there were plans to construct an additional 13 MW of mini-grids using hybrid solar/wind or solar/diesel.

South Africa's generation from renewables was only 2.1% in 2012, mostly from hydropower. Coal dominated the generation mix, accounting for 93% of power, with the remaining 5% coming from nuclear. Generating capacity stood at 48 GW in 2012, but approximately 10 GW to 12 GW of ageing plants were out of service for maintenance the following year in 2013. The remaining 35 GW available was insufficient to meet the forecast peak demand several times throughout the year. As a result of the extremely slim reserve margins, power rationing resumed briefly in 2013 and 2014, and additional capacity is needed. A draft of the updated IRP 2010, released in November 2013, proposes a downward revision to the demand trajectory and several possible scenarios resulting in as much as 6.6 GW less capacity by 2030, due to new underlying economic assumptions. Given the uncertainty over future demand, the South African Department of Energy (DOE) proposes the prioritisation of technologies and pathways that offer flexibility in decision making. As a result, proposals in the draft IRP include postponing additional nuclear capacity, increasing gas capacity and continuing the renewable energy auctions, albeit under different technology targets. Increasing electricity trade and distributed generation are also mentioned as options.

Through 2020, renewable deployment will be largely driven by the results from the country's REIPPP, a competitive bidding scheme introduced in 2011 to auction 3.725 GW of capacity over five rounds. Since then, the DOE has held three rounds and allocated 1.5 GW of PV, 2.0 GW of wind, 0.4 GW of concentrated solar power (CSP), and 0.4 GW of small hydro and bioenergy. Of this amount, 0.3 GW of PV and 0.2 GW of wind from the first round were commissioned over the past year while the remaining 3.9 GW is under construction, and 2.4 GW planned should be on line by around 2017. The total amount auctioned at the end of round three, 3.9 GW, was almost 200 MW more than planned, and in April 2014 the DOE announced that it is still considering allocating additional capacity under the third window due to the high demand from bidders and low prices offered.

Grid and system integration

In Morocco, the grid may present moderate constraints to the integration of renewables over the medium term. Synchronising the rate at which the infrastructure is built out with project plans may cause delays. This report sees wind expanding from less than 1 TWh to 4 TWh by 2020 (a 400% increase) in Morocco. As such, balancing variable renewable output may emerge as a challenge. Yet options for balancing do exist, with 0.4 GW of pumped hydro in operation and 350 MW under construction. Storage is being emphasised in new CSP capacity. Connection with the low-voltage grid is not yet permitted in Morocco and is seen as one of the main barriers to small-scale PV deployment.

In Kenya, the integration of large-scale renewable generation may be challenged by an underdeveloped grid. Kenya currently has a weak transmission and distribution network, which is severely constrained during peak hours. The geothermal and wind resources intended for the planned capacity additions are located far from load centres and require new transmission and distribution lines. KETRACO (Kenya Electricity Transmission Company) plans to extend the transmission network by 4 800 kilometres (km) by 2017, and 19 projects have started construction. Yet there are concerns over the completion time of the extensions as well as the ability of the existing grid to absorb the planned capacity additions within the short time period. Uncertainty over the completion of new transmission lines can act as a risk for projects and was one reason for the delay in financing of the 300 MW Lake Turkana project. On a smaller scale, the government sees the integration of renewable generation into mini-grids as a cost-effective solution to electrify rural communities. In exploring the feasibility of net metering, three pilot projects in Nairobi, Merti, and Mombasa have connected to the distribution grid, demonstrating that feeding into the grid is technically possible (Kenya Renewable Energy Association, 2013).

In South Africa, the grid should not pose a challenge to the integration of utility-scale renewable generation up to 2016, yet beyond that is largely dependent upon the location of additional capacity and planning. In October 2013, Eskom assessed the extent to which the transmission network could absorb the additional renewable capacity from the first two rounds of the REIPPP up to 2016 (Eskom, 2013). While the study found that the transmission network as a whole can integrate the new capacity, local constraints may emerge if too many projects are concentrated in areas with insufficient substation capacity, which could cause some delays for projects emerging from the third round and future rounds. The tendering of CSP with storage under the REIPPP may help to provide flexibility to the power system to meet evening peak demand. The draft IRP has also identified distributed generation as a potential way to partly offset a need for new utility-scale generation and a build-out of the transmission grid. Still, the lack of national net-metering legislation for capacities less than 100 kilowatts (kW) to connect to distribution grids, which may be managed by either Eskom or municipalities, is a barrier for distributed solar PV, which has significant potential in South Africa (GIZ, 2013).

Current policy environment for renewable energy

Renewable energy support policies are in various stages depending on the country and their overall drivers for energy planning. Thirteen countries in Africa have announced renewable energy targets, seven countries have enacted FITs and three countries have auction schemes. Most support policies favour large, centrally planned utility-scale projects, and frameworks are less developed for small distributed capacity.

Morocco continues to maintain a supportive policy environment that should drive utility-scale renewable growth over the medium term. The National Energy Strategy aims to achieve 42% of installed capacity from renewables by 2020, with specific targets for achieving 2 GW of wind and 2 GW of solar. To reach its ambitious targets, the government has launched two major projects – the Moroccan Solar Plan (MSP), which selected five sites for solar development, and the Wind Energy Plan, which identified another five sites for onshore wind development. Both programmes employ competitive tenders with PPAs signed with ONEE, a public utility, using a public-private partnership model. The Moroccan Solar Energy Agency (MASEN) implements the MSP by securing financing, coordinating stakeholders and tendering for utility-scale solar projects. MASEN has awarded the first tender of 160 MW to Noor I, which is already under construction and has selected prequalified bidders for Phase II, which is made up of Noor II (150 MW-200 MW) and Noor III (100 MW-150 MW), with the final amounts determined by the bids selected after the tender close, set for the second half of

2014 (Missfeldt and Kathinka, 2014). The 1 000 MW Integrated Wind programme is procuring 1 000 MW of wind across five sites. In 2014, a 150 MW plant at Taza from Phase I received approval for financing, while the remaining 850 MW under Phase II were opened for tender.

The Renewable Energy Law 13-09 was passed in 2009 and encourages generation from renewable sources by establishing the right for private entities to produce renewable electricity and the right for projects 20 kW and above to access the medium-, high- and very-high-voltage grid with various authorisation procedures according to project size. It also grants the right to export electricity and sell to a customer or group of customers for own use. ONEE also offers to purchase excess electricity at an incentivised tariff through a PPA.

South Africa's competitive bidding environment should drive renewable deployment over the medium term, yet there are some uncertainties over the long-term picture. The government is currently revising both the Integrated Energy Plan, published in 2003, and the IRP from 2010. While still under discussion, renewable capacity targets for 2030 have been revised in the draft IRP: up by 1.4 GW (from 8.4 GW) for PV and by 2.1 GW (from 1.2 GW) for CSP, but down by 4.8 GW (from 9.2 GW) for wind. While bioenergy targets are absent from the IRP, there is a sense that policy makers have recognised the contribution that bioenergy, specifically municipal waste, can make to diversifying the power supply. The Renewable Energy Strategy Formulation has identified 57 feasible landfill sites with an estimated potential of 598 gigawatt hours of electricity per year from sites, with potential capacities ranging from 656 kW up to 4 MW in size (SANEDI, 2014). Yet over the medium term, auctions under the REIPPP should guide new capacity additions. Currently after three rounds, 3.9 GW have been allocated, and while the DOE has announced a fourth round for 1 GW, to close August 2014, it is also still considering taking additional capacity under the third window, which may create uncertainty for bidders. There is no indication yet of the details for future rounds for capacity beyond 2017, when REIPPP projects should be complete.

The policy framework for smaller-scale renewables and distributed capacity remains underdeveloped. While the Small REIPPP programme supports capacity in the 1-5 MW market, substantial interest has not emerged due to the up-front costs associated with the procurement process. For less than 100 kW, no direct financial incentives exist, although the potential for rooftop PV in the commercial and residential sector is significant. The main barrier appears to be a lack of a regulatory framework for purchasing excess electricity from smaller distributed systems (Fritz, 2013). A handful of net metering pilot projects at the municipal level are being explored.

Kenya has made a commitment to renewable energy with a portfolio of support policies. In its LCPDP for 2011-31, the government has identified geothermal as the least-cost choice for additional capacity to meet the growing demand and sets a cumulative capacity target of 5.5 GW by 2030 (GoK, 2011b). To this end, the government created the Geothermal Development Company (GDC), a state-owned firm formed in 2009 to expedite development. Funded by the government budget and able to obtain international development aid, the GDC drills the wells for steam, which it plans to sell to IPPs either through an auction or direct negotiations, effectively shouldering the bulk of exploration and development risk for developers. GDC tendered the first 100 MW of the 400 MW Menengai project in late 2013.

The government also aims to install 3 GW of wind, 0.5 GW of solar PV and 0.3 GW of small hydro by 2030 as announced in the new Draft National Energy Policy, released in 2014 (GoK, 2014). To support

this deployment, FITs were introduced in 2008, then revised in 2010 and again in 2012, with updated tariffs and the introduction of two classes of standardised PPAs depending on developer size. While the standardised PPA procedures streamline the tariff negotiations, questions have emerged over whether the FIT levels are high enough to spark development. The government intends to introduce regulations for net metering, and draft legislation has been prepared.

Table 18 Africa countries main targets and support policies for new renewable energy capacities

Africa	Regul	atory suppo	rt		E	conomi	c supp	ort		
Country	RE law	Targets Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Algeria	Х	Χ	Х							
Botswana			Χ							
Burkina Faso		X				Χ				
Egypt		X					Х			Х
Ethiopia			Χ							
Gambia	Χ			Χ		Х	Х			
Ghana	Χ	X	Χ	X		Χ				
Kenya			Χ			Χ				
Mali		X								
Mauritius		X	X			X				
Morocco	Χ	X		Χ		Χ				Χ
Namibia			Χ							
Niger		X				Χ				
Nigeria		X	Χ							
Rwanda			Χ							
Senegal	Χ	X				Χ				
Seychelles		Χ				Χ				
South Africa	Χ	Χ			X	Х				Х
Tunisia	Χ	Χ		Χ	X	X	X			
Uganda		Χ	Х	Χ						
United Republic of Tanzania			Х	Χ						

Note: x = national-level policy; o = state/provincial-level policy; RE = renewable energy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

Economic attractiveness of renewable energy and financing

Africa is endowed with excellent renewable resources. While a number of public projects are moving forward, economic attractiveness for private developers depends on long-term policy frameworks and sufficient financial incentives, particularly in the face of often-subsidised fossil fuels and power prices. Non-economic barriers combined with a high cost of capital can create project costs that are above what some single-buyer markets are willing to pay, underscoring the importance of funding from development banks, and other sources, to help bridge the gap.

In Morocco, excellent resources combined with long-term PPAs from the procurement processes should make utility-scale renewable projects attractive over the medium term. Thus far, wind projects,

both within and outside of the procurement process, have not had difficulty in obtaining financing from commercial banks, development banks and special funds. The winning bids for Noor II and Noor III from the Phase II tender of Ouarzazate will reveal if CSP costs have come down relative to the MAD 1 620/MWh (USD 190/MWh) PPA signed in the first round in 2012. Development and international bank finance are likely to play a key role in financing the CSP projects under the MSP, and financing can depend on the suitable location of projects.

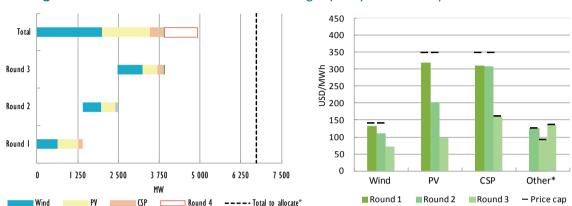


Figure 37 South Africa awarded and remaining capacity and tender prices under REIPPP

Notes: Total to allocate* refers to 6 724 MW which is the sum of the capacity allocated in Rounds 1 through 3 plus the remaining to allocate as listed in the Preferred Bidders' announcement published November 4, 2013 (DOE, 2013). This amount differs from the sum of the capacity announced in the two ministerial determinations (2 735 MW and 3 200 MW). Other* refers to small hydro in Round 2 and landfill gas and biomass in Round 3. Price caps and average prices were converted using average exchange rates of ZAR/USD 0.116 from December 2011 for Round 1, ZAR/USD 0.123 from May 2013 for Round 2, and ZAR/USD 0.098 from November 2013 for Round 3.

Source: DOE (Department of Energy)(2013), Bid Window 3, Preferred Bidders' announcement, Pretoria, 4 November.

In South Africa, solar PV and wind enjoy good economic attractiveness, with excellent resource availability combined with long-term PPAs available under the auction scheme. Competition among developers increased in round three of the REIPPP as they placed 6 GW worth of bids for the allocation of 1.4 GW worth of capacity. Prices for wind and solar PV dropped for the third consecutive round to their lowest levels yet, despite the removal of their ceiling maximums. Tariffs for solar PV were signed at ZAR 864/MWh to ZAR 1 100/MWh (USD 85/MWh to USD 108/MWh) and for wind at ZAR 664/MWh to ZAR 795/MWh (USD 65/MWh to USD 78/MWh); for solar PV, those prices are 64% lower than Round 1, and for wind, 36% lower. Also coming down in price compared with the second round was CSP, with tariffs signed between ZAR 1630/MWh and ZAR 1650/MWh (USD 160/MWh and USD 162/MWh) with the added benefit of a 270% multiplier at peak times to remunerate the value of storage. Also attracting interest for the first time, as a result of raised tariff ceilings, were biomass at ZAR 1 400/MWh (USD 137/MWh) and landfill gas at 940/MWh (USD 92/MWh). One-third of the financing was from foreign investors in a different currency, which exposes investors to currency fluctuations since the loans from local banks and PPAs are in local currency. Rand volatility, among other risks pertaining to the grid and non-economic barriers, can keep the cost of capital high in South Africa and undermine project bankability. Local content requirements increasing with subsequent rounds may create bottlenecks during construction of future projects.

In Kenya, geothermal electricity appears economically attractive, yet the financial incentives for other utility-scale renewable power projects may not be high enough to stimulate significant activity. For geothermal, by performing the resource assessment and initial drilling of the wells, the GDC eliminates

the bulk of the up-front costs that are typically associated with the exploration phase and can offer developers a risk-free supply of steam ready to generate electricity. Market estimates put the levelised cost of electricity (LCOE) for geothermal between USD 0.06/kilowatt hour (kWh) and USD 0.07/kWh, suggesting it can compare well to the costs of generation from the existing mix, estimated at USD 0.12/kWh in the LCPDP (Simiyu, 2013 GoK, 2011b). The FIT for geothermal, set at USD 0.08/kWh, may provide an incentive for projects between 30 MW and 70 MW. Also aiding project economics are several funds and programmes set up by development banks and public institutions to help mitigate the risks associated with geothermal exploration, though these may vary in their terms and applicability. However, for other renewable technologies, the FITs may be too low to attract private investors. FITs cannot exceed the long-run marginal cost of USD 0.12/kWh as established in the LCPDP, which does not reflect the real costs incurred by private investors, who face higher interest rates and overall capital costs than public projects. The FIT for wind at USD 0.12/kW is considered attractive only with high capacity factors. Uncertainty over the completion of new transmission lines can act as a risk for projects and was one reason for the delay in financing of the 300 MW Lake Turkana project, which is now reportedly benefitting from a partial guarantee from the African Development Bank for the construction of its transmission link.

Solar PV for self-consumption for large consumers has become more attractive due to falling PV prices and the high price of electricity from backup diesel generators (Hille, 2013). The largest solar PV plant in East Africa, 1 MW, came on line in 2014 on a tea farm to reduce the dependency on costly diesel generators. Large consumers, greater than 0.5 MW, should also find favourable economics once the net metering regulations are finalised. A pipeline of several industrial consumers exists in anticipation of the implementation. Non-economic barriers include ambiguous land rights governance, and insufficient number of years for the tax allowance. Revenues are too small to maximise the use of the tax allowance in the first few years.

Conclusions for renewable energy deployment: Baseline case

Morocco's renewable generation should expand by 5.6 TWh over 2013-20, driven by the projects under the wind and solar programmes launched by the government. By 2020, wind is seen reaching 1.8 GW from 0.3 GW under the Law 09-13 and 750 MW emerging from the competitive tenders. CSP is seen expanding by 0.6 GW over 2013-20 with the commissioning of projects under Noor I-III as well as some additional capacity. While there is excellent potential for solar PV, lack of access to the distribution grid is a current barrier to deployment. Solar PV is expected to reach 0.2 GW by 2020, limited to municipal-scale projects and utility-scale projects under the MSP. Hydropower is expected to reach 2.3 GW in 2020.

Table 19 Africa, selected countries renewable energy capacity in 2013 and 2020

Total		20	13			202	2020		
capacity (GW)	Morocco Kenya		South Africa	Total Africa Morocco		Kenya	South Africa	Total Africa	
Hydropower	1.8	0.8	2.3	27.2	2.3	8.0	3.6	42.1	
Bioenergy	0.0	0.1	0.3	1.2	0.0	0.1	0.4	1.8	
Onshore wind	0.4	0.0	0.0	1.4	1.8	0.4	2.8	7.4	
Offshore wind									
Solar PV	0.02	0.0	0.1	0.2	0.2	0.2	4.1	6.7	
STE/CSP	0.02		0.0	0.1	0.6		8.0	1.5	
Geothermal		0.2		0.2		0.7		1.0	
Ocean									
Total	2.2	1.1	2.7	30.4	4.8	2.3	11.6	60.5	

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

Kenya should grow by 5.3 TWh over 2013-20, driven by the national policy focused on meeting increased demand while diversifying beyond hydropower and expensive fossil-fuel power. Geothermal capacity is seen expanding by almost 0.5 GW by 2020, from both state-led projects (Olkaria units I and IV totalling 240 MW) and private investors. Wind is seen expanding by 0.4 GW by 2020, pending the timely completion of the 300 MW at Lake Turkana by 2017, with the remainder from a project pipeline that has secured financing. However, major challenges for large-scale wind projects are the access to finance, risk guarantees, lengthy PPA negotiations, needed grid upgrades and the risks of project delays to associated infrastructure, such as new roads to transport equipment during construction. The government's objective to increase the electrification rate with technologies suited for off-grid or isolated mini-grids should drive the deployment of PV, micro-hydropower and biomass due to their modular nature. For solar PV, financial incentives in Kenya will need to be coupled with an increased availability of lower-cost financing for projects to be attractive. Yet in some cases, an added driver to their deployment is they are cheaper in nature than current diesel generators used in rural areas. Solar PV should grow, albeit slower than other technologies, from small current levels to 0.25 GW incrementally over the medium term. Deployment should primarily be driven by self-consumption projects at the commercial level, the added economic attractiveness of net metering for large consumers, and the government-led initiatives to set up hybrid mini-grids to provide lower-cost power to rural communities. Bioenergy capacity should also grow slightly to 0.1 GW from self-consumption projects in rural areas.

Table 20 Africa countries main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Morocco	Excellent resources, desire to diversify away from costly fossil-fuel imports. Long-term government targets backed by auction scheme with PPAs.	Cost and availability of finance. Lack of grid access and incentives undermines attractiveness of small distributed capacity.
Kenya	Growing power demand and strong need for power sector diversification. Government commitment to deploying renewables in long-term planning.	Grid upgrades needed to accommodate new generation, particularly wind. Cost and availability of financing.
South Africa	Excellent resources and power needs to meet demand. Government incorporates renewables into power sector planning combined with robust tendering mechanism with long-term PPAs.	Uncertainty over longer-term capacity targets and future auction schemes. Grid-connection challenges and increasing local content requirements may cause delays.

South Africa's renewable generation should increase by 19 TWh, driven by the REIPPP procurement process. The entire 6.9 GW, including the 3.2 GW announced by the ministerial determination that is assumed to be procured, should be on line by 2020. The split by technology of the remaining 3 GW is not known and will be determined by the fourth and fifth rounds. This report assumes that 1 GW will be given to PV, 1 GW to wind, and 200 MW to CSP by default. However, there is much uncertainty over the allocation that will likely only be decided after each round, as was in the case in Round 3, for example, where the DOE allocated an additional 34 MW for solar PV and 133 MW for wind after viewing the low prices offered in the bids. Assuming projects outside of the REIPPP will come on line due to increasing economic attractiveness and Eskom's need for reserve capacity, additional capacity under each technology is likely to grow. By 2020, CSP could grow to 0.8 GW, wind should reach 2.8 GW and solar PV could reach 4 GW, assuming some scale-up in the commercial and residential segments. Hydropower is seen growing to 3.6 GW by 2020 from the small hydropower capacity procured under the REIPPP and the 1.2 GW Ingula pumped hydro plant.

Renewable energy deployment under an enhanced case

Given excellent resources, strong diversification needs and rising power demand, the outlook in some African countries could be much higher over the medium term. Clarification of the regulations surrounding feed-in to the distribution grid would open up the possibility of commercial and residential sector—scale solar PV to grid connection. Coupled with financial incentives such as net metering, small distributed PV for self-consumption could also accelerate deployment. Timelier PPA negotiations, easier access to financing and reliable grid connections could encourage larger amounts of wind deployment. Additional capacity auctioned under tenders for CSP and geothermal targets could also drive stronger growth over the medium term. Overall, solar PV could be some 2 GW to 3 GW higher than the baseline forecast in 2020, onshore wind could also be 2 GW to 3 GW higher, and CSP and geothermal combined could be 0.3 GW to 0.4 GW more.

Asia

Recent trends

Renewable power in Asia (excluding China) increased by an estimated 10% in 2013 to reach 423 TWh, or 17% of total power generation. The largest gains occurred in hydropower, bioenergy, and onshore wind, with smaller additions in solar PV and geothermal. In general, power generation in non-OECD Asia countries remains dependent on coal, which accounted for 50% of regional generation in 2013.

India remains the region's largest source of renewable generation. In fiscal year 2013, renewable sources represented an estimated 17% of power generation. At 12% of total generation, hydropower still represents the bulk of India's renewable power. Hydropower generation increased strongly in 2013, growing by over 8% year-on-year on the back of higher reservoir levels for existing generation and some capacity additions. Onshore wind, at an estimated 3% of total generation in 2013, grew by 2 GW, a level comparable to the growth seen in 2010 and 2011 prior to the brief slowdown in 2012 where capacity expanded by less than 2 GW. This slowdown was partly caused by uncertainty related to the reinstatement of the Generation Based Incentive (GBI) and accelerated depreciation scheme. In 2013, solar PV had its largest growth to date, expanding by 1 GW, with the commissioning of a number of utility-scale projects. The largest CSP plant (50 MW) in India (and Asia) was also commissioned in 2013, though some expected CSP additions continued to experience delays. Bioenergy also continued to expand, with over 1 GW of additions, mostly in bagasse co-generation. Off-grid and captive power applications remain important for electricity generation, with renewables playing an important role. Of the total additions described above, some 50 MW came from solar PV and over 70 MW came from bioenergy for off-grid and captive power use.

In Thailand, renewable generation accounted for an estimated 8% of power generation in 2013. Hydropower was the largest renewable source, at around 4% of total generation, followed by bioenergy, at 2%, though capacity additions in both of these areas were modest. The strongest capacity growth came from solar PV, which expanded by almost 320 MW, and onshore wind, which added over 110 MW, including a 104 MW wind farm in Nakhon Ratchasima, Southeast Asia's largest.

In Indonesia, renewable power account for an estimated 14% of power generation in 2013. Hydropower and geothermal are the main renewable sources, with hydropower contributing 6.5% and geothermal contributing 5.2% of total electricity in 2013. Hydropower capacity has expanded slowly in recent

⁶ Co-generation refers to the combined production of heat and power.

years, and grew by less than 100 MW in 2013. Geothermal capacity has steadily grown over the past decade and is estimated to have reached near 1.4 GW in 2013. Bioenergy is also a significant renewable source, accounting for 1.9% of power generation in 2013. Thus far, solar and wind have played only a marginal role in Indonesia's renewable mix, though future development is expected.

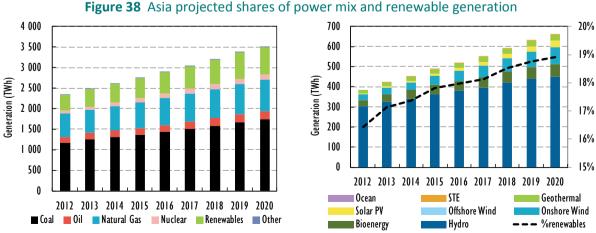
In Chinese Taipei, renewables accounted for 4.8% of power generation in 2012. The Bureau of Energy announced in 2013 a strategy to prioritise development of rooftop solar PV installations in order to reach a long-term target of 3.1 GW in 2030. In 2013, the country deployed 170 MW of solar PV, supported by a FIT scheme, to reach over 370 MW. There were also over 40 MW of onshore wind additions. Chinese Taipei also announced it would raise its long-term renewable energy target from 6.50 GW to 9.95 GW in 2025.

In Malaysia, solar PV capacity increased by over 40 MW to near a cumulative 80 MW in 2013, supported by developments under the country's FIT scheme. In the Philippines, cumulative solar PV capacity increased to 5 MW in 2013 and in early 2014 the government raised its cumulative installation target under its FIT scheme from 50 MW to 500 MW. In Viet Nam, hydropower continued to expand, with the commissioning of the 220 MW Ban Chat plant, the 180 MW Hua Na plant and several smaller additions. Laos also added hydropower with the start of the 128 MW Xekaman-3.

Medium-term outlook – regional baseline case summary

Overall, non-OECD Asia renewable generation is expected to rise by about 240 TWh, or 57%, from 2013-20. Renewable power should account for nearly 19% of total generation in 2020, up from 17% in 2013.

Underscoring its good resource availability and ability to provide cost-effective base-load power, hydropower is likely to lead the capacity expansion, growing by over 37 GW on a regional basis. The largest hydropower additions should come from India and Viet Nam, with a number of other countries also adding new generation. Gains in onshore wind are likely to be significant with an additional 24 GW by 2020 led by India and followed by Thailand and the Philippines. Solar PV additions are also likely to be significant, at around 22 GW over 2013-20, with deployment rising over time spurred by expected cost reductions. In addition to India, Thailand and Indonesia, presented in more detail below, notable deployment in solar PV is likely to occur in Chinese Taipei, Malaysia, the Philippines, Pakistan and Bangladesh. Regional bioenergy capacity is also expected to expand significantly, though deployment is more concentrated in Thailand and India.



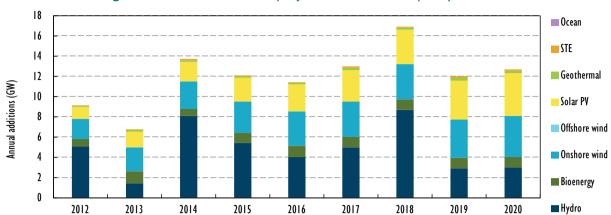


Figure 39 Asia historical and projected renewable capacity additions

Medium-term outlook – detailed analysis

Power demand

Non-OECD Asia power demand is expected to grow by 5.1% annually over 2013-20, with most markets expanding strongly. India's power demand is seen rising by 5.2% per year, buoyed by economic growth and increasing electrification. Still, this outlook is lower than in *MTRMR 2013*, with more moderate GDP growth of 6.3% per year expected. Peak demand continued to rise in the fiscal year 2013/14, reaching 136 GW, up somewhat from 135 GW the prior year. In India, demand continues to be constrained by supply limits. Part of the constraint stems from cross-subsidised power prices – with industrial users paying more to support agricultural and other consumers – that do not generally cover the costs of generation, in addition to grid losses and geographical mismatches between demand and installed power capacity. India also continues to suffer from high distribution losses. Still, it appears progress is being made to address some of these issues. The average shortfall in meeting peak demand, for electrified consumers, declined in 2013 to 4.5% from 9.0% the previous year (CEA, 2014).

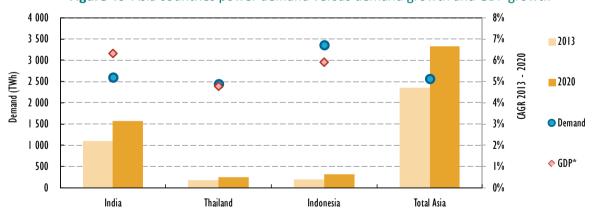


Figure 40 Asia countries power demand versus demand growth and GDP growth

Note: CAGR = compound annual growth rate.

*GDP is over 2013-19

Thailand's power demand is seen rising by 4.9% per year over 2013-20, buoyed by strong economic growth and expanding industrial activity. The outlook is largely in line with MTRMR 2013, with similar

GDP growth seen over the period. Peak demand has increased in recent years on the back of increased air-conditioning and industrial needs. In 2013, it reached nearly 27 GW, up from 26 GW in 2012 and 21 GW in 2006.

In Indonesia, power demand is expected to rise strongly, by 6.7% annually over 2013-20, boosted by expected GDP growth of 5.9% per year. Indonesia's state-owned electricity company, Perusahaan Listrik Negara (PLN), sees faster demand growth of 10.1% per year to 2031 in its power development plan. The government's aim to increase the electrification rate from its current level of 80% to near 100% by 2020 should also drive demand growth. Indonesia's electricity consumption is constrained by supply availability due to a lack of capacity in both generation and networks. End-user prices are regulated and are generally lower than the cost of generation, which facilitates access to low-income users but may also encourage inefficient consumption. Still, the government has instituted reforms in recent years, including a quarterly adjustment mechanism that has raised prices for some consumers. In 2011, peak load was at 26.6 GW, having risen steadily since near 19 GW in 2005 (MEMR, 2012).

Power generation and capacity

Non-OECD Asia power systems are generally dynamic, with a strong need for new generation to meet growing demand. Many are dominated by coal-fired generation and could benefit from increased diversification for energy security, economic and environmental reasons. As such, strong drivers exist for greater renewable penetration. Still, some markets suffer from high levels of non-economic barriers and challenging investment environments.

India's power system must continue to expand and diversify to meet its fast-growing demand. As of March 2014, total capacity stood at 243 GW (not including captive generation of around 40 GW), up from 210 GW a year prior. The majority of new additions continue to come from fossil fuels, but costly imported coal and liquefied natural gas (LNG) can make generation economically tenuous in the face of regulated end-user prices. Coal supply shortages remain an energy security concern, with new plants struggling to secure supply contracts and existing plants sometimes having inadequate inventory to produce during times of peak demand (IEA, 2013a; Sen, 2013).

Over the medium term, the evolution of the power mix should be guided by India's 12th Five-Year Plan (FYP) (see *MTRMR 2013* for details). Renewables play a large role, reaching over 20% of power generation, including large hydropower, by 2017. To this end, over 11 GW of hydropower is under construction and almost 4 GW of potential new onshore wind has been financed. A pipeline of solar projects, PV and solar thermal has emerged from auction schemes, and plans for mega-projects (phases of 0.5 GW to 1.0 GW) starting from 2016 have been announced by the central government. Still, some policy implementation and project delays have characterised development.

Thailand is in the process of updating its power sector planning to meet rising demand needs and diversify its electricity mix. Total power capacity stood at over 33 GW in 2013. Natural gas accounted for an estimated 70% of generation in 2013, with a significant portion coming from imports. The government is reportedly considering an amendment to its Power Development Plan (PDP) that would seek to reduce the role of gas in the long term, given energy security concerns (Van Zuylen, 2013). Coal may play a larger role in power generation going forward, but faces some public opposition due to pollution concerns, while most new hydropower will likely be imported. The government's update of its Alternative Energy Development Plan (AEDP) in 2013 suggests non-hydro renewables will play a greater role than foreseen in *MTRMR 2013*.

In Indonesia, a need for new power capacity should function as a driver for renewables over the medium term. Indonesia's power is largely met through fossil fuels, with coal accounting for almost 50% of generation in 2013, followed by natural gas and oil at 19% each. Inexpensive domestic coal is readily available and Indonesia is a large exporter of LNG. Still, rising demand is spurring the government to reduce coal and gas exports. While this shift may increase the availability of supplies for domestic use, it may make attracting long-term private investment in these sectors more difficult, given regulated domestic energy prices. All the while, the short-term provision of electricity remains a challenge due to lack of power infrastructure, long investment lead times and challenging island geography. The dominance of Indonesia's power sector by a single vertically integrated utility, PLN, has generally resulted in opaque wholesale price formation, inefficient investment planning and a restricted investment environment for outside players. Still, the government has taken steps to encourage private investment, with Law No. 30/2009 allowing private participation in generation.

The Indonesian government's draft National Energy Policy sees total power capacity rising to 115 GW in 2025, versus only 47 GW in 2013. It sees a growing role for renewables to help meet goals for energy security, economic development and environmental protection. Indonesia has excellent resources in a portfolio of renewables, particularly in geothermal with almost 40% (29 GW) of the world's potential and in bioenergy with a potential of 50 GW. Still, realising a large increase in renewables will be challenging given the investment environment. Only 90 MW of geothermal capacity is under construction, with a much larger pipeline of planned projects (2.3 GW). Some 1.5 GW of hydropower capacity is under construction, including the 1.0 GW Upper Cisokan pumped hydro storage plant. Given their small-scale nature, bioenergy developments remain more difficult to track; it appears at least 100 MW has been financed and is under development.

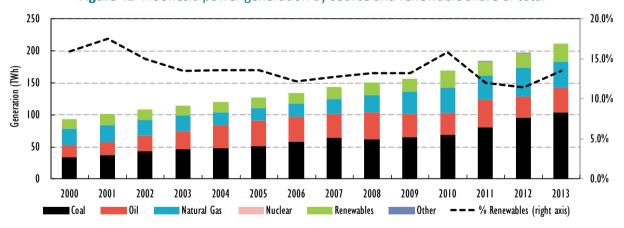


Figure 41 Indonesia power generation by source and renewable share of total

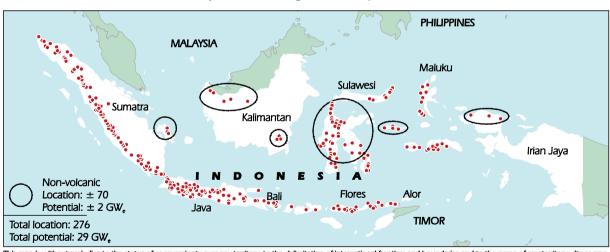
Grid and system integration

The upgrade and expansion of India's grid continues to present a significant challenge to renewable development, though the system is making progress. At the end of 2013, the Southern Grid was synchronised with the remainder of the country, facilitating the bulk transfer of power across regions. Interconnection among regions remains underdeveloped, at 34 GW at the end of March 2014, but inter-regional transmission capacity has risen steadily from 14 GW in 2007 and is seen almost doubling by 2017 under the government's Green Energy Corridors Strategy. The build-out of state-level grids is also continuing apace. However, grid congestion, weak distribution networks and needed improvements

in grid operations all represent state-level challenges to integrate growing variable renewables. In 2013, a rule was issued by the central government requiring wind farms larger than 10 MW to predict their day-ahead output in 15-minute intervals within a 30% margin of error, with penalties for deviation outside this band. However, this degree of forecasting proved to be unworkable in practice, with potential fines threatening to undermine the revenues of some existing generation. The rule was temporarily suspended in March 2014 pending a review by the Central Electricity Regulatory Commission.

Indonesia's underdeveloped grid, widespread location of resources across a large archipelago and poor interconnection make the integration of renewable generation a challenge. In general, grid planning and investment have been insufficient and transmission constraints have emerged related to the geographical mismatch between large-scale power supply and demand. A large portion of Indonesia's hydropower resources are located in the eastern part of the country in Papua, away from demand centres (ACE, 2014a). Geothermal resources look better situated near demand areas, but project lead times tend to be relatively long.

This situation, along with a need for electrification on remote islands, suggests significant potential for distributed and off-grid applications, such as bioenergy and solar PV. Still, the distribution network requires upgrading the local low-voltage grid, and planning co-ordination between PLN and regional entities can be a challenge. In the past, grid access has been a barrier to renewable integration given PLN's monopoly. In 2011, a government regulation obliged PLN to purchase electricity from tendered geothermal power plants. In 2012, a new regulation obligated PLN to off-take electricity produced from small- and medium-scale bioenergy and hydropower plants up to 10 MW. PLN is also implementing plans to facilitate grid connections for these plants as well as develop small-scale solar PV on the outer islands.



Map 2 Indonesia geothermal potential

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

Note: GW_e = gigawatt electrical capacity.

Source: Geological Agency/Ministry of Energy and Mineral Resources (2010), Exploitable Volcanic Geothermal Resources and Prospect of other Geothermal Systems in Indonesia, Presentation at 3rd Geothermal Roadmap Workshop, 29 November 2010, Bandung, Indonesia.

Current policy environment for renewable energy

India's renewable policy environment has strengthened in certain areas over the past year, but remains complex, with overlapping initiatives at the central government and state levels and challenges in policy implementation. The responsibility for power sector policy is shared equally between the central

government and the states. Closer co-operation in setting policy frameworks and closer co-operation between the central regulator (CERC) and the state regulators (SERCs) are important for a more supportive policy framework. Over the past year, the central government reinstated some incentives for onshore wind deployment while signalling a more comprehensive strategy ahead for that technology. In the second half of 2013, the government confirmed the restart of the GBI, whose timing of implementation was uncertain in *MTRMR 2013*. In January, the government announced it would launch its first National Wind Energy Mission (NWEM) to commence in mid-2014. While details remain forthcoming, announcements in January indicated that the government would reportedly act as a facilitator for project development, helping to ease land permitting, strengthen grid infrastructure and regulate tariffs, in an effort to reach 100 GW of cumulative wind capacity by 2022.

In solar, the government recently awarded permits for 750 MW of new solar PV capacity under the Phase II, Batch I, auction of the Jawaharlal Nehru National Solar Mission (JNNSM); these projects will receive Viability Gap Funds to cover up to 30% of their capital costs and are expected on line by April 2015. Further auctions are slated to take place in 2014, involving both solar PV and CSP projects. While the solar policy framework remains supportive, delays in commencing Phase II auctions and difficulties in finalising contracts with state utilities have acted to slow project development at times. Moreover, local content provisions, which are currently being challenged at the World Trade Organization (WTO), have made the timely provision of equipment a challenge for some developers.

Table 21 Thailand's renewable energy targets for 2021 (MW)

	REDP 2008	AEDP 2012	AEDP 2013
Solar	500	2 000	3 000
Wind	800	1 200	1 800
Small hydropower	324	324	324
Biomass	3 700	3 630	4 800
Biogas	120	600	3 600
Municipal solid waste	160	160	400
New energy (geothermal and ocean)	4	3	3
Total	5 608	9 201*	13 927

Note: *includes 1 284 of large hydropower and pumped storage not in AEDP 2013. REDP = Renewable Energy Development Plan.

Source: Department of Alternative Energy Development and Efficiency (2013), Energy in Thailand: Facts & Figures Q1-Q2/2013, Ministry of Energy, Bangkok.

Since MTRMR 2013, Thailand has raised its 2021 renewable deployment targets by 50% and has clarified some uncertainties about the transition of its incentive scheme. The update to the AEDP issued in 2013 now sees 13.9 GW of renewable sources in 2021 versus 9.2 GW previously. The ratio of alternative energy in the total energy mix was kept at 25%, with some cuts to biofuels production offsetting the increase in power capacity. The largest upward revisions were made to bioenergy and solar. In 2013, Thailand announced the first FITs to begin replacing its "adder" scheme of feed-in premiums. FITs were introduced for residential- and commercial-scale solar PV (the first rooftop-focused scheme) with a quota of 200 MW, and for community-owned, ground-mounted solar PV with a quota of 800 MW. Licensing requirements were an initial hurdle for some of the residential developments, resulting in delays, though these have been recently eased. Going forward, some uncertainties remain over the transition to FITs from adders for utility-scale projects. Thailand also faces the challenge of harmonising its power sector planning and reducing non-economic barriers. Resolving these issues may be difficult with an ongoing political transition as of May 2014.

Indonesia's renewable policy environment has strengthened in recent years and is supported by ambitious long-term targets backed by a FIT scheme. The draft of the updated National Energy Policy sees renewable energy growing to 23% of primary energy supply from less than 6% currently, with large roles for geothermal (11%) and bioenergy (9%, including biofuels for transport). The policy does not include specific power sector targets. The Directorate General for New, Renewable Energy and Energy Conservation (DGNREEC) has incorporated some power-specific objectives in its planning, including an aim for cumulative geothermal power of 7.2 GW by 2025.

Indonesia's FITs cover hydropower, geothermal, biomass and waste, and solar. In 2013, the government introduced an auction programme to award FITs to utility-scale solar projects, with a quota of 140 MW set for 2013-14 and ceiling prices of USD 0.25/kWh to USD 0.30/kWh, depending on local content. Ostensibly, these incentives should stimulate renewable deployment over the medium term. However, permitting and licensing of projects can act as bottlenecks. Though progress has been made, complex rules persist regarding land acquisition. Still, Indonesia is revising its geothermal law so that projects will no longer be considered as mining operations, which had hindered their development in protected forests.

Table 22 Non-OECD Asia countries main targets and support policies for new renewable energy capacities

Non-OECD Asia	Regul	atory su	ipport			E	conomi	c supp	ort		
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	X Auction schemes
Bangladesh	Х	Х				Х	Х				X
Chinese Taipei	Х	Х		Х							
Fiji		Χ					Χ				
India		0	0	0	Χ	Х	0	0	Х	ΧО	Х
Indonesia		Χ		Χ			Χ				
Laos		Х					Х				
Malaysia	Χ	Χ		Χ		Χ	Χ				Χ
Maldives		Χ					Х				
Mongolia	Χ	Χ		Χ							
Nepal					X	X					
Pakistan	Χ	Χ		Χ			Χ	Χ			
Philippines	Χ	Χ		Χ			Χ	Χ			
Samoa		Χ									
Singapore					Χ		Х				
Solomon Islands		Χ									
Sri Lanka		Х		Х		Х	Х	Х			
Thailand		Χ		Χ	Χ		X				
Vanuatu		Х									
Viet Nam		Χ		Χ		Χ	Χ				

Note: x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: http://www.iea.org/policiesandmeasures/renewableenergy.

Economic attractiveness of renewable energy and financing

Excellent resources and falling system prices are improving the attractiveness of renewables in India, though policy support remains important for project bankability. The estimated LCOE for new onshore wind, without incentives, remains generally higher than the average power market clearing price. Other market sources have assessed that the best new wind projects have an LCOE comparable to that of new-build coal plants (Sethia, 2012). Estimated LCOEs, without incentives, for new utility-scale solar PV are relatively higher. Still costs continue to fall rapidly and already compare favourably with peak power pricing. In the Phase II, Batch I, auction, a winning solar PV bid was observed as low as INR 6.5/kWh (USD 0.105/kWh), though this includes support from the Viability Gap Fund, underlying the continued importance of incentives for deployment.

For some wind and utility-scale solar plants, RECs have been an important economic enhancement. Still, REC prices have remained at their floor level since June 2013 (longer for non-solar RECs). The fulfilment of renewable purchase obligations remains challenging given the cash-strapped positions of some state electricity boards, though regulators are trying to step up enforcement. Finally, with industrial and commercial electricity prices ranging from INR 3/kWh to INR 10/kWh (USD 0.05/kWh to USD 0.17/kWh), depending on state, and captive diesel power remaining expensive, commercial-scale solar PV installations have begun to emerge with few incentives outside of accelerated depreciation (Bridge to India, 2014; Ramesh, 2014).

Renewable Energy Certificates, monthly cleared price LCOE of onshore wind and utility-scale solar PV 350 350 300 300 250 250 2013/MWh 200 200 150 150 S 100 100 50 50 0 2013 2014 |an/2011 |ul/2011 |an/2012 |ul/2012 Jan/2013 Jul/2013 2012 Onshore wind Utility-scale solar PV ——Average power market clearing price

Figure 42 India LCOE of onshore wind and solar PV versus power market price and renewable energy certificates (RECs)

Note: power market clearing price refers to the price discovered before accounting for congestion in the transmission corridor. The LCOE ranges reflect low-cost, typical and high-cost projects, which vary primarily due to differences in system costs, resources and the cost of financing. LCOEs are based on a real cost of capital of 7% to 9% for both solar PV and onshore wind.

Source: IEA analysis with price data from IEX (Indian Energy Exchange) (2014), www.iexindia.com (accessed in May 2014).

In all cases, a high cost of capital acts as a factor keeping renewable costs relatively high in India. India's interest rate environment is relatively high, with nominal ten-year government bond rates averaging over 8% in 2013. Domestic lenders still have insufficient familiarity with renewable projects, and requirements for performance history of renewable technologies can slow development. Other sources, such as concessional loans from the Indian Renewable Energy Development Agency (IREDA), grants under the JNNSM and loans from international development banks, are important to enhance investments. Still, the stability of the policy environment and policy implementation remain keys for driving the cost and availability of financing over the medium term.

In Thailand, renewable electricity remains attractive with the support of incentives. The cost of electricity sales for the state-owned utility, Electricity Generating Authority of Thailand (EGAT), was around THB 2.5/kWh (USD 0.08/kWh) in 2012. End-user electricity prices for residential users range from THB 1.86/kWh to THB 5.27/kWh (USD 0.06/kWh to USD 0.17/kWh), and those for commercial/industrial entities are THB 2.15/kWh to THB 5.27/kWh (USD 0.07/kWh to USD 0.17/kWh) (ACE, 2014b). These values suggest that bioenergy, small hydropower and wind, with good resources, could be competitive with few incentives against existing utility and new-build fossil-fuel generation. Still, financial and regulatory support is needed to incentivise investment in a market dominated by EGAT with restricted access to outside players. To that extent, details over the switch from adders to FITs for these technologies will be important for their attractiveness. The introduction of solar PV FITs in 2013 reduced incentives for solar PV, but their level remains attractive, given continued global falls in solar PV generation costs.

For Indonesia, PLN reported the average generation costs in 2012 of existing steam power plants (largely coal-fired) at IDR 810/kWh (USD 0.087/kWh), hydropower at IDR 156/kWh (USD 0.017/kWh) and the fleet average at IDR 1 217 (USD 0.130/kWh) (PLN, 2013). These prevailing price levels suggest there may be some economic incentive for PLN to invest in hydropower, geothermal and bioenergy. Solar PV and onshore wind are currently economic as replacement for diesel generation on small islands, which account for about 15% of Indonesia generation. Still, PLN's ten-year power development plan sees most of its new investment in coal- and gas-fired power, with smaller developments in renewable sources. To meet the government's long-term renewable goals, significant private sector investment will thus be required. Traditionally, PLN has benefitted from right of first refusal for all new generation capacity, and investment opportunities passed on to private investors are often less financially attractive. To that extent, the FIT scheme serves as an important economic enhancement and a mechanism for project origination by IPPs.

Still, financial incentives in Indonesia will need to be coupled with an increased availability of lower-cost financing and a reduction of non-economic barriers for projects to be attractive. Indonesia's relatively high interest rates (nominal ten-year government bond rates averaged around 7% in 2013) and non-familiarity within the banking sector with some technologies, such as solar PV, suggest that a high cost of capital can act as a barrier to deployment. The development of geothermal presents particular challenges, given the up-front risks associated with exploration and drilling. Financing from development banks can serve as an important financial enhancement in the presence of such risks. The recent financing of the 320 MW Sarulla geothermal plant – Indonesia's first commercially financed, independent, utility-scale geothermal project in more than a decade – was realised in part through funds from the Asian Development Bank and Clean Technology Fund (ADB, 2014).

Conclusions for renewable energy deployment: Baseline case

India's renewable generation should grow by 128 TWh over 2013-20, with a strong need for generation and a supportive policy environment driving the outlook. The India forecast is more optimistic than in *MTRMR 2013*, with renewable generation in 2018 revised up by almost 40 TWh. This change is largely due to higher baseline bioenergy generation, but also from more optimistic outlooks across several technologies. Hydropower is seen expanding by 17 GW over 2013-20. Onshore wind is expected to rise by near 21 GW over 2013-20 with the reinstatement of the GBI and efforts to improve integration and reduce non-economic barriers under the NWEM.

The forecast for solar PV sees capacity rising by 12.4 GW over 2013-20. Though auctions under the JNNSM have proceeded slowly, plans for new mega-projects have emerged, and growing attractiveness for commercial-scale installations is likely to spur significant development in rooftop solar PV. The forecast for CSP, however, carries more risks. The first plants allocated under the JNNSM have faced setbacks, including the downgrading of the solar resource for plants in many areas. Development should proceed incrementally over the medium term. Still, as the sector scales up and if costs come down, the value of CSP with storage to meet evening peak demand can make it a very attractive power source in the long run. Finally, bioenergy is expected to grow by over 2 GW over 2013-20, with developments in solid biomass power, bagasse co-generation and biogas.

Thailand's renewable generation is expected to rise by almost 14 TWh from 2013-20, with average growth of 11% per year. The expansion is seen led by bioenergy and solar PV, both of whose targets were raised significantly in last year's AEDP update. Further developments in biogas, in particular, are expected with increased use of napier grass feedstock for gasification. Still, bioenergy projects in general are likely to face constraints related to local feedstock availability, and overall deployment is seen less than targets would suggest. Solar PV capacity should grow by 2.7 GW over 2013-20, supported by the new FIT for distributed generation. Still, uncertainties over the pending change to FITs from adders for utility-scale projects and quotas for deployment are likely to cap overall development in line with the 2021 target. Meanwhile, onshore wind is expected to rise by 1.1 GW over 2013-20, somewhat slower than the target given a need for continued grid upgrades.

Table 23 Non-OECD Asia, selected countries renewable energy capacity in 2013 and 2020

		20)13		2020			
Total capacity (GW)	India	Indonesia	Thailand	Non- OECD Asia	India	Indonesia	Thailand	Non- OECD Asia
Hydropower	42.7	5.1	4.4	100.7	59.9	6.3	5.0	138.0
Bioenergy	5.0	1.7	2.2	10.6	7.1	1.9	5.4	17.6
Onshore wind	21.1	0.0	0.2	22.4	41.9	0.0	1.3	46.4
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	2.8	0.0	0.7	4.2	15.1	0.6	3.3	25.6
STE/CSP	0.1	-	0.0	0.1	0.8	-	0.1	0.9
Geothermal	-	1.4	0.0	3.4	-	2.5	0.0	4.8
Ocean	-	-	-	-	-	-	-	0.0
Total	71.6	8.3	7.5	141.4	124.7	11.4	15.1	233.3

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

Indonesia's renewable generation is seen expanding by near 12 TWh over 2013-20 with average growth of over 5% per year. Indonesia's excellent resources, need for new power capacity to meet fast-growing demand, improved long-term renewable targets and attractive financial incentives should support a portfolio of renewable development. Still, significant challenges related to strengthening the grid, reducing non-economic barriers to development, and the cost and availability of financing need to be addressed. Given the long lead times associated with hydropower and geothermal developments, in particular, delays in policy implementation could undermine the realisation of 2025 renewable targets.

Against this backdrop, this report forecasts slow but steady growth in renewable capacity in Indonesia, with hydropower seen expanding by 1.2 GW over 2013-20 and geothermal rising by 1.1 GW. Solar PV is expected to contribute 0.6 GW of additions, but deployment could be higher with faster-than-expected

uptake of distributed systems. For bioenergy, development of 0.2 GW is expected with increased bagasse-fired capacity, municipal solid waste and biogas use. Use of palm oil for co-firing is also expected to rise, though this trend would be evident more in generation than in capacity, where it is difficult to track. Overall, the provision of sustainably sourced bioenergy feedstock will represent a persistent challenge.

Table 24 Non-OECD Asia main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
India	Supportive policy environment with targets, JNNSM and financial incentives. Fast-growing electricity demand; captive and rural electrification needs support distributed solar PV deployment.	Stop-and-go policy making can undermine incentive schemes; financing costs remain high. Grid strengthening and expansion and better grid management needed to reinforce power system in general.
Thailand	Stronger deployment targets under AEDP; new FIT for distributed solar PV. Strong demand growth; desire to diversify power system away from costly fossil-fuel imports.	Uncertainty over timing, levels and adjustments of transition from remaining feed-in premiums to FITs. Grid upgrades to accommodate new generation, particularly wind.
Indonesia	Excellent resources; need for new power capacity to meet fast-growing demand. Ambitious long-term renewable targets backed by a FIT scheme.	Non-economic barriers and concentrated power system presents investment barriers to new commercial entrants. Underdeveloped grid, widespread location of resources across a large archipelago and poor interconnection.

Renewable energy deployment under an enhanced case

With greater progress in grid strengthening and more predictable policy frameworks and execution, the outlook for renewable energy deployment in India could be higher over the medium term. Specifically, for onshore wind, cumulative capacity could be around 4 GW higher in 2020, with expectations of rising yearly additions towards the end of the forecast period. Solar PV cumulative installed capacity could come out 3 GW to 5 GW higher with stronger-than-anticipated deployment of distributed systems based on greater adoption of enabling policies, such as net metering, and attractive conditions for self-consumption. There is also upside for CSP, though longer lead times limit the potential gains. With better project delivery and cost reductions, CSP capacity could be 1 GW higher in 2020 than in the baseline forecast.

In Thailand, certain market enhancements could increase the cumulative capacity of bioenergy, onshore wind and solar PV. Notably, a rapid clarification of new FIT levels to replace the feed-in premium scheme would help stimulate activity. With better progress in advancing feedstock availability, bioenergy capacity could be 1 GW to 2 GW higher in 2020 versus the baseline case. The upside for solar PV looks limited, given an already-saturated project pipeline under existing policy schemes. Still, higher quotas could add up to 0.5 GW to 1.0 GW to the forecast by 2020. Finally, onshore wind deployment could proceed faster with better-than-expected progress in grid upgrades, particularly in the southern and eastern parts of the country. In that case, onshore wind capacity could be up to 0.5 GW higher in 2020 than under the baseline case.

In Indonesia, the upside for hydropower and geothermal looks limited over the medium term, given extensive development lead times. Longer-term developments for all technologies could be enhanced through greater consolidation of permitting procedures and stronger advances in upgrading the power

grid. Over the medium term, the largest upside pertains to solar PV and bioenergy. Combined with improving economics, the implementation of higher quota levels for awarding solar PV FITs and the formulation of policy to encourage the uptake of small-distributed capacity for residential and commercial rooftops could result in capacity in 2020 that is 1 GW to 2 GW higher than under the baseline case. For bioenergy, progress in ensuring feedstock availability and greater deployment of small, distributed systems could translate into 2020 capacity some 0.5 GW to 1 GW higher than under the baseline case.

China

Recent trends

In 2013, China's renewable power generation increased by 9%, reaching an estimated 1 097 TWh. Renewables' share in the power mix improved to 20%, up slightly from 2012. In 2013, China installed its highest annual renewable power capacity to date (61 GW), 86% more than in 2012. More than half of this capacity came from hydropower (31 GW). The partial commissioning of Xiluodu (13.9 GW), the largest hydropower plant in China after the Three Gorges plant, and the finalisation of the Xiangjiaba plant (6.4 GW) contributed to the significant hydropower expansion in 2013. Despite these capacity gains, the overall generation from hydropower plants expanded by only 3.7%, lower than generation growth in 2012, due to reservoir levels. China's onshore wind installations increased to 16 GW, with more than 14 GW connected to the grid. With these new additions and increasing full-load hours, onshore wind capacity generated 136 TWh in 2013, a 43% year-on-year increase. The development of solar PV in 2013 outstripped MTRMR 2013 expectations. According to the National Energy Administration (NEA), China installed over 12.9 GW of solar PV capacity, the world's largest annual growth to date. Chinese developers rushed to complete projects before the end of the year, when a CNY 1.0/kWh (USD 0.17/kWh) incentive expired in January 2014. With new installations, China more than doubled its solar PV generation, reaching 17 TWh. Offshore wind installations were lower than expected with only a 50 MW intertidal project in Jiangsu commissioned. Relatively high project costs and technical challenges remain significant barriers to deployment. China also added an estimated 500 MW of bioenergy and 25 MW of CSP.

Medium-term outlook – regional baseline case summary

China's generation needs, pollution concerns stemming from a coal-dominated power system and a favourable policy environment with ambitious targets should drive strong renewable growth over the medium term. Renewable generation is seen rising by over 880 TWh from 2013 to 2020, and its share of power generation is expected to increase to over 26%, from 20% in 2013. Renewables are expected to account for over 40% of China's incremental power generation over the medium term, followed by coal, nuclear and gas.

Compared to MTRMR 2013, the generation outlook for 2018 is revised down by over 70 TWh, a sizeable change. This result stems from a slower demand outlook than in MTRMR 2013, a slower-than-expected expansion of hydropower and wind (onshore and offshore) and more refined analysis of capacity factors for hydropower and wind going forward (see "Conclusions" below for more details).

Overall, renewable capacity is seen growing by more than 342 GW over 2013-20. After an exceptionally strong rise in 2013, hydropower additions, including pumped storage, are seen stabilising around 15 GW to 18 GW annually, but this will depend on the pace of permitting and environmental approvals. Onshore wind is seen expanding by around 17 GW per year, based on a strong underlying project pipeline. Solar PV is seen growing by 13 GW to 14 GW per year over 2013-20, with deployment

driven by increased targets, rising potential for distributed generation, decreasing costs and improved financial incentives. The capacity forecast is generally more ambitious than the 12th FYP targets for onshore wind and solar PV due to recent-year deployment trends and higher government targets set over the past year for solar. Still, the development and operation of the grid and the system integration of such large amounts of new variable renewable capacity will pose challenges. Bioenergy is expected to expand by 2 GW to 4 GW per year, in line with FYP targets, though the establishment of sustainable feedstock supply and local opposition for waste-to-energy plants could act as constraints. Other technologies, such as CSP, which faces relatively high costs, and offshore wind, which faces licensing difficulties, are likely to see relatively slow growth.

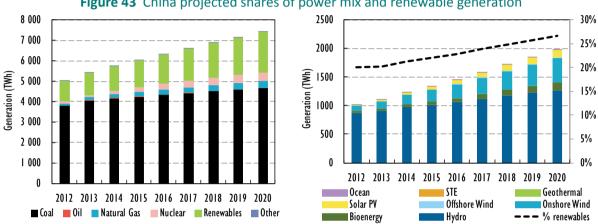
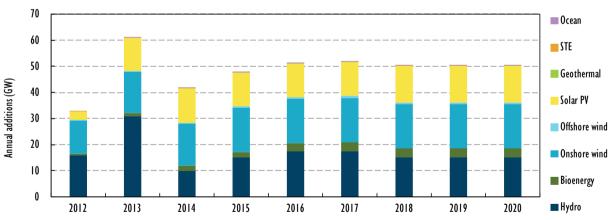


Figure 43 China projected shares of power mix and renewable generation





Medium-term outlook – detailed analysis

Power demand outlook

The power demand outlook for China has been revised down since MTRMR 2013 mainly due to slower expected GDP growth. In 2013, China's power demand grew by an estimated 8.2% year-on-year. According to the NEA, China's power consumption grew around 5.5% in the first quarter of 2014. China Electricity Council (CEC) expects power consumption to grow 7% in 2014. According to the IMF economic outlook from April 2014, China's real GDP is expected to expand on average by 7.1% over 2012-18, lower than last year's prediction of 8.4% for the same period. Over the medium term, this

report expects China's growth in electricity demand to slow over time, expanding by only 4% on average over 2013-20, less than the 5.8% average growth rate for 2012-18 posited in *MTRMR 2013*, largely due to the lower GDP assumptions.

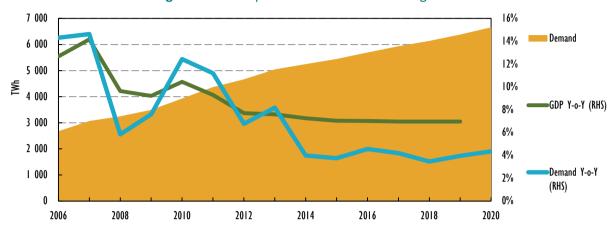


Figure 45 China power demand versus GDP growth

China's retail power prices remain mostly regulated for both industry and household consumers. Having introduced a tiered electricity pricing system for residential users in 2012, the government decided to implement a similar measure for aluminium smelters as of January 2014, in order to tackle the energy inefficiency and overcapacity issues in this industry. Over time, more flexible pricing adjustments such as these could also help to dampen demand growth.

Power generation and capacity

China's power market is dynamic, with a need for new capacity to meet its growing demand. China's power sector continues to be dominated by coal, but renewable sources have increased their contribution in the power mix. The share of renewables in total power generation reached near 20% in 2013, a slight improvement from 2012. Coal's share remained relatively stable, while natural gas has emerged as a small but rising part of the power mix. In 2013, China added 96 GW of new power-generating capacity, of which around 60% came from renewables. Fossil-fuel additions were led by coal power (36 GW), with much smaller amounts of natural gas and nuclear capacity. At the end of 2013, grid-connected power capacity stood at over 1 240 GW, with fossil fuels accounting for over 875 GW.

Pollution concerns stemming from heavy coal generation are driving changes in China's power sector. In September 2013, China's State Council announced a new action plan to combat air pollution. The plan included a ban on new coal-fired power plants in three industrialised regions: Beijing, Shanghai and Guangzhou. In early 2014, the NEA announced its plans to ban imports of coal with high ash and sulphur and relatively low heating values. The plan also proposes moderate targets to curb coal consumption: by 2017, the proportion of coal in total primary energy consumption in China should be reduced to 65% (from 67% in 2012), while the proportion of non-fossil energy consumption should be increased to 13% (from 9.1% in 2012).

Against this backdrop, renewables are expected to play a rising role in the power market over the medium term. China's commitment to increasing renewable power capacity was strengthened in 2013 with revised solar targets (see "Policy Discussion" below). A significant project pipeline of onshore wind

and hydropower projects should also underpin growth going forward. For example, in March 2014, the NEA gave initial approval for the construction of 27.5 GW of new onshore wind projects.

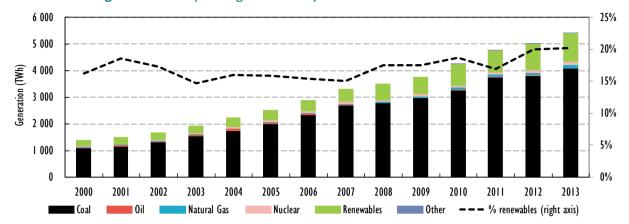


Figure 46 China power generation by source and renewable share of total

Grid and system integration

With current installed and planned wind and solar PV capacity, grid integration will continue to pose challenges over the medium term. In 2013, China showed improvements in both connection and operation of wind power plants. An estimated 90% of newly installed wind capacity was connected to the grid, higher than the 80% in 2012. According to the CEC, average onshore wind full-load hours increased by around 10% from 1 890 hours in 2012 to 2 074 hours in 2013. It is worth noting that this improvement is partly due to higher wind speeds in 2013. Thus it is difficult to assess real operational gains. In addition, the Chinese transmission system operator curtailed only around 11% of onshore wind generated, significantly less than 17% in 2012.

Still, as in previous years, curtailment of onshore wind reached significant levels in China's northeast provinces where there is large coal-fired generation and in the northwest region. Around 20% of wind generation was curtailed in Gansu, Jilin and Eastern Inner Mongolia, while wind power plants in Yunnan, Hebei and Heilongjiang experienced around 15% curtailment. In March 2014, the NEA approved the next round of wind farm projects totalling 27 GW, which is expected to be constructed over the medium term. However, Inner Mongolia, Jilin and Heilongjiang provinces were excluded in this round due to their congested grid with current variable capacity. There is a robust construction pipeline of pumped-hydro storage in several provinces; part is expected to be built over the medium term. This additional capacity should increase the flexibility in some regions where wind generation has reached relatively high penetration.

In order to relieve congestion and transport electricity from the west to the eastern and southern provinces, State Grid Corporation of China (SGCC) continues the construction of the third ultra-high voltage transmission (UHV) line that will transport power from Xiluodu hydropower plant to Zhejiang province. The company plans on investing around USD 100 billion by 2017 on completing 20 UHV lines as long as 20 000 km. In early 2014, SGCC announced that it completed 4 600 km, and 6 400 km is being built.

Most utility-scale solar PV projects are constructed in the central and western regions. While grid constraints in western regions, away from demand centres, may cause local bottlenecks, ample opportunities for construction exist in the central provinces, closer to demand centres. On the distributed

generation side, after the NEA's policy document encouraging SGCC to facilitate permitting and connection procedures, the company announced in 2012 that it will connect distributed solar installations smaller than 6 MW without additional connection fees. Although transmission grid—connected projects dominated PV deployment in 2013, the NEA's new planning for 2014 includes 8 GW of distributed generation projects and only 6 GW of utility-scale installations. Distributed solar PV is supported by a financial premium for all electricity produced, including that self-consumed. However, challenges (as described below) remain for the scale-up this segment.



Map 3 China main wind resource sites and load centre

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

Current policy environment for renewable energy

China's policy environment continues to evolve in a generally supportive fashion, though developments carry some uncertainty. Deployment of renewable power sources in China is still driven by official governmental targets published in the FYPs. FITs are in place for onshore wind, solar PV and bioenergy generation. Power producers receive the tariffs as capped feed-in premiums added to the coal-benchmarked price of electricity. While there is a policy in place to guarantee priority dispatch, grid companies do not always apply this in practice. Having published a draft policy on a renewable energy quota obligation in early 2013, which would create formalised obligations for renewable generation and supply for utilities, grid operators and local governments, the law has yet to be enacted, at the time of writing, and details concerning its implementation remain uncertain.

The most significant developments over the past year concern solar PV. In July 2013, China increased its solar target as published in the FYP from 21 GW to 35 GW by 2015. In early 2014 it announced a corridor for development in 2014, of which up to 14 GW (of which 8 GW is distributed) would receive government support, and in May 2014 the government announced it was targeting a cumulative 70 GW by 2017. These goals are backed by attractive national FITs and some local generation-based incentives for utility-scale projects. In January 2014, the FIT for most new utility-scale solar PV projects was revised down somewhat from CNY 1/kWh (USD 0.16/kWh) to CNY 0.9/kWh (USD 0.15/kWh). For distributed solar PV, in August 2013 the government introduced a premium of CNY 0.42/kWh (USD 0.07/kWh) for all electricity produced, including that self-consumed, in addition to the local coal power price (varies, but usually around CNY 0.4/kWh or USD 0.07/kWh) available for power injected into the grid.

Table 25 China main targets and support policies for renewable energy

Targets and quotas	Support scheme	Other support
12th FYP for renewable energy development: 11.4% of non-fossil resources in primary energy consumption by 2015 (13% by 2017* and 15% by 2020). Indicative binding cumulative capacity targets by 2015: 290 GW hydro (incl. pumped storage) 100 GW wind (of which 5 GW offshore) 35 GW solar (of which 1 GW solar thermal) 13 GW biomass 100 MW geothermal 50 MW oceans By 2020: 420 GW hydro 200 GW wind (of which offshore 30 GW) 50 GW solar (of which solar thermal 3 GW) 30 GW biomass Indicative non-binding cumulative capacity targets by 2017*: 330 GW hydro 150 GW solar 11 GW biomass	FITs: Apply to onshore wind, solar PV and biomass. Effectively they are feed-in premiums over province-specific prices of coal-based power. Incentives for small-scale generation: Grid connection fees waived and net metering provided for distributed systems <6 MW. For solar PV <6 MW, government is drafting a policy to provide a feed-in premium on top of net metering for self-consumption and a feed-in premium to the local coal-benchmarked price for electricity fed into the grid. Premium for distribution-grid connected PV projects receive CNY 0.42/kWh. Additionally, scheme allows for excess electricity to be sold to the grid at the price of coal power. Import duty & value-added taxes removal: Applies to key technological equipment, including hydro and wind equipment. Carbon-trading scheme pilots were launched in seven provinces** as a first phase in introducing country-wide emissions trading scheme programme (planned to be launched in 2016).	Strategic planning: Offshore Wind Development Plan 12 th FYP for national strategic industries Solar Industry Development Plan Framework policy: Renewable Energy Law 12 th FYP for climate change Grid access and priority dispatch: Projects approved by government are granted access to grid in the Renewable Energy Law. Priority dispatch guaranteed by law, but often not applied in practice.

^{*} targets for 2017 announced in May 2014 by China's NDRC.

In February 2014, China's National Development & Reform Commission (NDRC) announced plans to decrease the current feed-in premium (CNY 0.51/kWh to CNY 0.61/kWh, or USD 0.08/kWh to USD 0.10/kWh) for onshore wind projects, which was introduced in 2009, considering that equipment prices have dropped significantly over the last few years. A final decision is expected to be published at the end of 2014. In addition, in June 2014, China released new FIT levels for offshore wind. The tariff for inter-tidal projects is set at CNY 0.75/kWh (USD 0.12/kWh) while the nearshore tariff is at CNY 0.85/kWh (USD 0.14/kWh).

^{**} as of June 2014. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy.

Over the course of 2013 and 2014, seven provincial-level pilot carbon exchange markets became operational. In June 2013, the first carbon trading scheme was launched in Shenzhen, which involves 635 companies accounting for about 38% of local carbon dioxide emissions. This scheme has been followed by markets in Shanghai, Beijing, Guangdong, Hubei, Tianjin and Chongqing. A few provinces plan on launching inter-regional trading products. Although these pilot projects may serve as precursors to a national trading system that the government expects to launch in 2016, a number of co-ordination issues would need to be resolved to achieve this aim.

Economic attractiveness of renewable energy and financing

As non-hydro renewable energy generation costs remain generally higher than coal-fired generation (around CNY 0.4/kWh or USD 0.07/kWh), financial incentives are necessary to make them attractive. In practice though, it is difficult to make assessments of the financial viability of renewable energy even under the presence of FITs. For incumbent generators, due to a lack of priority dispatch in practice, renewable projects are not guaranteed access to the grid, and operators have few incentives to grant it, given their preference to sell coal-based generation. In addition, delays in subsidy payments by the central government have affected revenues for some projects. Overall, China's onshore wind annual capacity factors fluctuate between 17% and 23% (1 500 and 2 000 hours), lower than in many countries. Expectations of decreasing curtailment levels and increasing connection rates should help improve project viability over the medium term. Moreover, a binding renewable power quota system would offer a better guarantee of operating hours for projects, particularly for onshore wind.

This report's estimated range of LCOE for utility-scale solar PV (as low as USD 90/MWh to upwards of USD 125/MWh, with real cost of capital assumed at 6% to 8%) suggests that technology is attractive versus FITs currently in place. The economic attractiveness of residential- and commercial-scale PV is more complex. Assuming industry electricity prices of CNY 0.7-0.9/kWh (USD 0.15/kWh), some commercialscale solar PV for self-consumption appears attractive based on an estimated LCOE of USD 110 to USD 170 (with 6% to 8% assumed cost of capital) and the CNY 0.42/kWh (USD 0.07/kWh) premium available for produced electricity, whether self-consumed or injected into the grid. The economics do not yet appear attractive for households, which enjoy much lower end-user electricity prices. Some uncertainties exist over this economic assessment, including the threshold required rate of returns and the willingness of commercial entities to invest in an activity (self-production of electricity) outside their core business. Developers who own and operate a distributed solar PV system and sell the electricity to a commercial off-taker under a long-term agreement face risks associated with the potential off-taker default. The availability of financing for a still-nascent market segment and of suitable rooftops may also act as barriers to deployment. Moreover, much will depend as well on the implementation of the policy and distribution of incentives by local grid companies. Overall, these risks may require measures to facilitate access to attractive financing and stronger incentives to make distributed solar PV projects bankable.

The economic attractiveness of relatively less mature technologies, CSP and offshore wind, also remains uncertain. With limited deployment and relatively high costs, both technologies would require higher specific incentives compared with solar PV and onshore wind. In June 2014, China introduced a new FIT for offshore plants. Accordingly, inter-tidal plants will receive a tariff of RMB 0.75 (USD 0.12) per kWh while near offshore tariff is defined as RMB 0.85 (USD 0.14) per kWh. However, with administrative challenges in place, it is currently uncertain whether this new tariff will attract developers.

China's financing environment should continue to enable deployment of renewable energy, though with some uncertainties. The majority of the financing of renewable projects is still provided by the China Development Bank and Chinese local banks. China is estimated to need more than USD 435 billion for new renewable capacity coming on line from 2014 to 2020. In addition to commercial and development banks, other sources of financing may be needed in the short and medium term, especially for the fast-growing domestic solar PV deployment. To this end, some solar PV equipment manufacturers have announced their plans to invest in local downstream projects. As "New Energy" is part of the Chinese government's strategic industries, private and regional banks have been competing in financing renewable projects extensively by offering favourable rates. However, low capacity factors, high curtailment levels and delays in subsidy payments have affected the revenue stream of several onshore wind projects. Over the medium term, this situation may increase the risk profile of some renewable projects, leading to higher costs of capital.

Conclusions for renewable energy deployment: Baseline case

China's generation needs, pollution concerns stemming from a coal-dominated power system, and a favourable policy environment with ambitious targets should drive strong renewable growth over the medium term. Renewable generation is seen rising by over 880 TWh from 2013 to 2020 and its share of power generation is expected to increase to over 26.5%, from 20% in 2013. Renewables are expected to account for over 40% of China's incremental power generation over the medium term, followed by coal, nuclear and gas.

2014 2015 2016 2017 2018 2019 2020 2013 Hydropower 279.9 289.9 304.9 322.4 339.9 354.9 369.9 384.9 Bioenergy 8.5 10.5 12.5 15.5 19.0 22.5 26.0 29.5 Wind 91.5 107.7 125.3 142.9 160.5 178.1 195.8 213.5 Onshore 91.0 107.0 124.0 141.0 158.0 175.0 192.0 209.0 Offshore 0.7 0.5 1.3 1.9 2.5 3.1 3.8 4.5 Solar PV 19.6 32.9 45.9 58.9 71.9 85.9 99.9 113.9 Solar CSP 0.0 0.1 0.2 0.2 0.3 0.3 0.4 0.5 0.0 Geothermal 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 RES-E** 399.5 441.2 488.9 540.0 591.7 641.8 692.1 742.5

Table 26 China renewable electricity capacity and projection (GW)

Notes: wind capacity corresponds to installed capacity. In practice, grid-connected capacity may be lower due to delays.

Versus MTRMR 2013, the renewable generation outlook for China in 2018 is revised down by over 70 TWh, a sizeable change. This result stems first from a slower power demand outlook than in MTRMR 2013. Second, it arises from a slower anticipated expansion in hydropower and wind capacity (onshore and offshore). Finally, the change stems from a more refined analysis of capacity factors for hydropower and wind going forward. On the hydropower side, pumped storage (included in this report's totals) is expected to make up a quarter of hydro additions through 2020, and its utilisation is now modelled in a more differentiated manner versus conventional hydropower. Still, the utilisation rate of pumped hydro storage carries significant uncertainties and can range from less than 10% to 20%, versus higher rates for conventional hydropower. In onshore wind, MTRMR 2014 has taken a more nuanced approach to modelling expected capacity factor improvements for new additions and the overall system. It is assumed that, every year, newly added capacity will have

slightly higher capacity factors thanks to improved machines, and better dispatching, operations and maintenance. In addition, the curtailment improvements are separately factored in at the overall system level. That said, uncertainty still exists over some aspects of the current and future performance of the onshore wind fleet. The upshot of all this analysis has been to reduce the generation profile from MTRMR 2013, which was too optimistic.

Overall, China's renewable capacity is seen growing by almost 343 GW (40% of the global total) over 2013-20. The projection in 2018 is 7 GW lower than *MTRMR 2013*, due to downward revisions in onshore and offshore wind, and hydropower. After an exceptionally strong rise in 2013, hydropower additions, including pumped storage, are seen stabilising around 15 GW annually. Cumulative hydropower capacity is seen reaching 385 GW in 2020, lower than China's 420 GW FYP targets, with the pace of permitting and environmental approvals acting as challenges. Solar PV is seen growing by around 94 GW over 2013-20. Increased targets, the potential for distributed generation, decreasing costs and improved financial incentives should drive this deployment. Significant uncertainties persist over how fast residential-and commercial-scale solar PV will scale up. Still, given authorities' strong desire to stimulate the sector, it is assumed that around 50% of this increase will come from the distributed segment.

The onshore and offshore wind forecasts are revised down. Compared with the *MTRMR 2013*, onshore and offshore are down by 10 GW and 5 GW respectively in 2018. For onshore, the current discussion on cutting incentives, financing challenges and curtailment is expected to have a minor impact on deployment. Offshore wind deployment has been slow. High costs, complicated administrative permission procedures and the absence of project pipeline are the main reasons for the revision. Thus, onshore wind should grow by 118 GW, supported by attractive economics and a robust underlying pipeline, to over 209 GW in 2020. Offshore wind total capacity, by contrast, is seen reaching 4.5 GW.

Table 27 China main drivers and challenges to renewable energy deployment

Drivers	Challenges
 strong government backing through FYPs with expected implementation of a renewable quota system stronger targets for solar PV eased rules for grid connections and new incentives for distributed solar PV ample availability of low-cost financing. 	 lack of market pricing, in general, and priority dispatch, in practice, for renewable generation uncertain economic attractiveness and non-economic barriers for distributed solar PV grid integration and upgrades required on both the transmission and distribution sides.

Bioenergy is expected to expand by 2 GW to 4 GW per year, in line with FYP targets, though the establishment of sustainable feedstock supply remains a challenge. Renewable waste-to-energy plants are likely to play an important role in development, given limited landfill space in many Chinese cities. However, local opposition for new plants could act as a constraint to their development.

The CSP forecast was revised down from 1.4 GW to 0.3 GW in 2018. The system cost of this technology has remained high, with a relatively low level of commercialisation in China, leading to a lack of project pipeline over the medium term. It is expected that only 500 MW of CSP will be commissioned by 2020. Other technologies – geothermal and ocean – should grow only marginally.

Renewable energy deployment under an enhanced case

Institutional reform as well as a more integrated approach to policy and planning could further increase deployment of renewable energy in China. To some extent, China is already moving in this direction, with improved grid connections, licensing procedures and financial incentives for distributed generation. Still, further implementation details, including enforcement mechanisms, on the quota system are needed as well as a stronger framework for the deployment of distributed solar PV. China's deployment environment would also benefit from a move towards market-based electricity pricing. Improved grid operations could facilitate the grid integration of variable renewables. Further development of CSP, whether hybrid designs with coal or pure solar, would also be a positive mechanism for providing storage and flexibility.

Quantifying the upside potential for China remains challenging, especially given its size. While an enhanced case assumes progress towards resolving the issues laid out in the preceding paragraphs, grid constraints will persist. Hydropower deployment could be some 10 GW to 20 GW higher in 2020 and more in line with FYP targets for 2020 with an acceleration of environmental approvals and the rapid establishment of a more robust project pipeline. Better progress on grid upgrades and faster offshore development could spur an additional 10 GW of wind capacity (onshore and offshore combined) by 2020. Faster-than-expected uptake in distributed systems could translate into implying an additional 10 GW to 20 GW of solar PV by 2020. In particular, the risks associated with distributed solar PV development may require measures to facilitate access to attractive financing and stronger incentives to make projects bankable. With the setting of a support framework that remunerates based on the time of delivery of electricity, the attractiveness of CSP could improve, potentially raising capacity by 0.2 GW to 0.3 GW by 2020, though the deployment gains are likely to be felt more over the long term, due to long project lead times. Finally, the encouragement of decentralised generation could help bioenergy to improve by 3 GW versus the base case, mainly through more small-scale biogas and waste-to-energy developments.

Europe and Eurasia

Recent trends

Renewable power in non-OECD Europe and Eurasia expanded by an estimated 10% in 2013, reaching 325 TWh, about 18% of total power generation. The largest gains occurred in hydropower and bioenergy, with smaller additions in onshore wind and solar PV. In general, power generation in non-OECD Europe and Eurasia is mainly dominated by natural gas and coal.

Russia remains the region's largest source of renewable generation. In 2013, hydropower represented more than 97% of total renewable output in Russia and contributed to around 17% of its overall generation. The country added close to 2 GW of hydropower last year, which included both new installed capacity and refurbishments. A new 640 MW unit of the Sayano-Shushenskaya hydropower plant was added in 2013 as part of the rehabilitation and modernisation programme. Upon the completion of the overall programme, the plant is expected to reach 6.4 GW of total capacity in 2014 from 4.5 GW in 2013 (International Water Power & Dam Construction, 2014). While Russia has very little solar PV and wind capacity, its first capacity tenders held in 2013 portend future development in these areas.

In Romania, renewable generation accounted for an estimated 25.7% of power generation in 2012, up from 26.6% in 2011. Hydropower was the largest renewable source, at 79% of total renewable generation, followed by onshore wind and solar PV. As the government decreased incentives for both

solar PV and onshore wind starting from January 2014, developers rushed to finish their projects by the end of 2013. Solar PV had strongest growth with 1.1 GW new capacity added, while new onshore wind installations reached 700 MW.

In Ukraine, renewable power accounted for an estimated 6% of power generation in 2012. Hydropower accounts for the bulk of this output, and its capacity expanded by 162 MW in 2013. Solar PV additions were strong and stood at 375 MW. Onshore wind deployment was moderate, with only 95 MW new capacity added.

In Bulgaria, which went through a boom-and-bust cycle in solar PV deployment, very little new renewable development has occurred since retroactive changes to incentives were made in 2012. The country's 2014 budget reportedly included a new 20% surcharge on existing wind and solar power, which has further undermined the attractiveness of the sector.

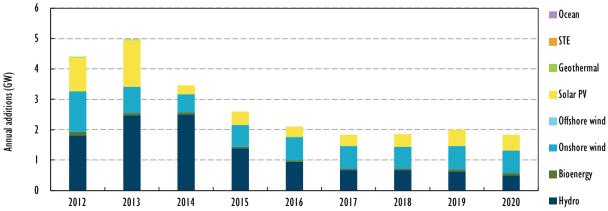
Medium-term outlook - regional baseline case summary

Renewable generation in the non-OECD Europe and Eurasia region is expected to grow by 13%, or on average 1.8% annually, over 2013-20, expanding by 43 TWh. The lack of financing availability, policy uncertainty, weak grid infrastructure and fossil-fuel subsidies are the main reasons behind the weak growth of renewables versus other regions.

2500 400 20% 350 16% 2000 300 250 Generation (TWh) 12% Generation (TWh) 1500 200 8% 150 1000 100 4% 50 500 2012 2013 2014 2015 2016 2017 2018 2019 2020 ■ Ocean STE Geothermal 2012 2013 2014 2015 2016 2017 2018 2019 2020 Solar PV Offshore wind Onshore wind ■ Coal ■ Oil ■ Natural gas ■ Nuclear ■ Renewables ■ Other ■ Bioenergy Hydro %renewables

Figure 47 Non-OECD Europe and Eurasia power generation mix and renewable generation





Hydropower is likely to lead the capacity expansion over 2013-20, largely through refurbishment of existing capacity. Onshore wind is expected to be the second-largest source of growth, based on the results of Russia's recent capacity auctions, but also due to FITs on offer in Ukraine. Notable solar PV development is expected to occur in a number of markets, led by Romania, Ukraine, Kazakhstan and Russia. Still, the overall trajectory of capacity growth in the region appears depressed versus that which occurred in 2012 and 2013.

Medium-term outlook – detailed analysis

Power demand

Non-OECD Europe and Eurasia's power demand is expected to grow by 2.4% annually over 2013-20. The outlook differs in general between Russia and the rest of the region. Russia's power demand is expected to grow around 1.5%, significantly lower than region's average, mainly due to an expected slowdown of the country's GDP growth over the medium term. Over the past year, Russia's inflation has been increasing more than the Russian Central Bank's expectations. In order to control this situation, the government decided to freeze all utility tariff rates including electricity and gas during 2014, which could provide some support for the demand picture.

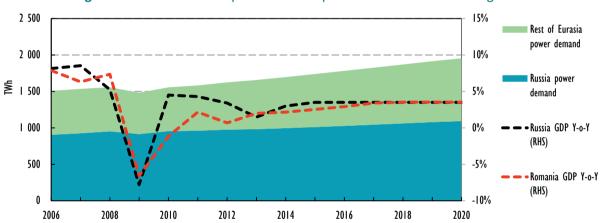


Figure 49 Non-OECD Europe and Eurasia power demand versus GDP growth

The rest of the region's power demand is expected to grow stronger by 3.6% annually over 2013-20. This growth rate is mostly driven by countries that are rich in natural resources and that have high annual GDP growth rates ranging from 4% to 6%, while non-OECD European countries, mostly in Eastern Europe, mark relatively slower GDP growth of 2% to 4% mostly due to limited industrial demand connected to the sluggish economic recovery in the European Union. Romanian GDP, for instance, is expected to grow on average 3% annually over the projection period.

Power generation and capacity

Russia's power generation is mostly dominated by the country's abundant resource, natural gas, which accounted for half of overall electricity generation in 2013. Nuclear and hydropower provide the rest, while the generation from non-hydro renewables remained negligible. Around 60% of Russia's generation capacity is still in the hands of government-owned utilities, and the majority of them enjoy priority dispatch (IEA, 2013b). The privatisation of government assets is an ongoing process under Russia's electricity reform. Still, the experience with IPPs' participation in the Russian electricity

market is limited, and can be challenging for new renewable energy entrants, especially for small and medium-size companies, over the medium-term. According to Russia's power planning document, the General Scheme for the Location of Electricity Generating Facilities to 2030, 68 GW of existing capacity is expected to be decommissioned due to age, while 173 GW to 229 GW of new capacity must be constructed between 2009 and 2030 (IFC, 2011). Thus, Russia will need additional generation over the medium term that could act as a renewable driver.

In Romania, hydropower dominates renewable power generation, followed by coal and nuclear power. Still, fossil fuels' share in power generation remained high at 55% in 2012. Diversification needs should drive non-hydro renewable generation over the medium term. In 2013, with good reservoir levels, Romania was a net exporter of electricity, selling around 5% of its generation to neighbouring countries (ENTSO-E, 2014).

Ukraine's power generation in 2012 was dependent upon nuclear (45%) and coal (40%), with natural gas providing 8%, mostly from imported supplies from Russia. With the current political situation and potential energy security-related risks to gas supplies, Ukraine has a strong motivation to diversify its power mix, creating opportunities for renewable generation. In October 2013, Ukraine adopted the law on liberalisation of the wholesale electricity market, which aims to contribute to the sector's reform and regional market integration.

Grid and system integration

With high levels of relatively flexible gas-fuelled generation in the region, grid and system integration of renewables should pose only moderate challenges to deployment over the medium term. However, the majority of countries in the non-OECD Europe and Eurasia region need to upgrade their grid infrastructure, not only to connect new renewable power plants but also to refurbish ageing grid assets. Moreover, countries need to avoid the creation of renewable hotspots, as with the too-rapid deployment of solar PV in Bulgaria in 2012.

Despite the low penetration of variable renewables, system balancing has faced challenges in Russia, especially during winters. Around 45% of Russia's heat is provided by co-generation plants, which enjoy priority dispatch. However, during the winter there are times when there is a high demand for heat but not for electricity (IFC, 2011). To accommodate must-run co-generation, the system operator sometimes needs to curtail other generation assets. The increasing penetration of variable renewables could exacerbate this situation in some regions where co-generation and wind plants are concentrated. In Ukraine, the integration of wind and solar PV also poses challenges. The transmission system from the Black Sea coast, where there is a great wind potential, to more populated areas requires upgrades to accommodate more capacity over the medium term. More significantly, the current political situation has made the state of present PPAs with the Ukrainian state-owned utility uncertain for a number of solar PV plants and wind farms near the Black Sea coast.

In Romania, the system integration of renewables should pose moderate challenges over the medium term. Wind generation is mostly concentrated in one region, Dobrogea, where the grid is congested during high wind periods. The grid requires reinforcement in this area in order to relieve the congestion. The Romanian Electricity Operator (OPCOM) introduced intra-day trading, which could lead to improvements in balancing, and should facilitate the integration of renewables. Power markets in Eastern Europe also co-operate on harmonising rules in order to boost electricity exchange and trading in the region.

The transmission system operators in Romania and some OECD member countries (Hungary, Czech Republic, Poland and Slovakia) signed a memorandum of agreement in July 2013 in order to integrate regional day-ahead power markets.

Current policy environment for renewable energy

In 2010, Russia adopted a renewable target of 4.5% of total electricity generated to be provided by renewables by 2020 (large hydro excluded), versus less than 1% currently. At the beginning of October 2013, results of the first renewable electricity auction held in Russia were announced. Projects with combined generation capacity of 504 MW were awarded contracts. Solar PV projects secured 339 MW out of a potential 700 MW allowed by the government. The tender was organised as a requirement of the newly enacted mechanism supporting renewable electricity in Russia. The scheme promotes renewable power on the basis of the ability of power plants to produce electricity on demand (expressed in megawatts) and not on the basis of the electricity output (megawatt hours). Contracts are awarded to projects with the lowest capital costs. Eligible proposals also have to comply with high local content requirements of 60%. The requirements differed depending on technology and year of commissioning, increasing yearly up to 2020, reaching 65% for wind and small hydropower plants and 70% for solar PV. In order to control the increase of newly added renewable generation capacities, and thus the mechanism's impact on electricity prices and the costs of the mechanism, Resolution No. 861 of May 2013 has been adopted. The resolution established yearly limits for new renewable generation capacity up to 2020 (expressed in megawatts). Selected projects must be operational and grid-connected by 2017.

Table 28 Non-OECD Europe and Eurasia main targets and support policies for new renewable energy capacities

Non-OECD Europe and Eurasia	Regul	Regulatory support Economic support									
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Armenia		Х		Х	X	Х					
Azerbaijan		Х									
Bosnia and Herzegovina		Χ		Χ			Χ				
Bulgaria		Χ		Х	Х	Х					
Croatia		Χ		Χ		Χ					
Kazakhstan		Χ		Х	Х		Х				
Latvia		Χ		Χ			Х				
Lithuania	Х	Χ		Х	Х	Х	Х				
Romania		Χ	Χ		Χ				Χ		
Russia		Х	Х								Χ
Serbia		Χ		Χ							
Ukraine		Х		Х			Х				

Note: x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

In Romania, in March 2014, the president signed a law approving the government's emergency ordinance to cut the number of green certificates allocated to various renewable technologies, including

already-operational assets. This measure will be valid as of February 2014 until March 2017 in the case of hydropower and solar power plants and until 2018 for wind farms. Already-operating onshore wind plants will still benefit from two green certificates until 2018, but one certificate will be postponed and tradable from 2018 to 2020. New wind installations will get only one green certificate instead of two until 2018 and 0.75 certificates thereafter; small hydropower plants will receive one instead of three and solar projects two instead of six. The new law also removed the guarantee fund that was purchasing excess green certificates at a minimum market price, while the validity of certificates was reduced from 16 to 12 months. With these changes, having experienced booming solar PV and onshore wind deployment in 2013, it is expected that the number of new installations over the medium term will decrease significantly.

Ukraine's renewable policy is based on a euro-linked green tariff, which varies by renewable technology and the size of its application. In order to be eligible for the tariff, there is a local content requirement of 30%, which is planned to increase to 50% by July 2014. A tariff degradation is also established that adjusts the tariff down 10% every five years after the commissioning of the project. However, the current political situation, with many renewable projects located along the Black Sea coast, has made the support framework more tenuous, with significant economic uncertainty for some projects.

Economic attractiveness of renewable energy

In Russia, with a high level of local content requirements, the system costs bid by developers during the auction were relatively high. On average, the utility-scale solar PV system cost was RUB 110 000/kW (USD 3 450/kW), around two and a half times higher than in Germany. Few wind projects submitted bids, because the local supply chain has not yet developed to comply with the 50% local content requirement for onshore wind in order to supply winning projects.

The cost and availability of financing should present challenges for the region in general. In Russia, tender results showed that developers won projects with high system costs. Although the government promised a green tariff to renewable projects as a special remuneration, it is currently unclear how this tariff is calculated by utilities. Uncertainty over the revenue stream of energy produced may create financing challenges for capital-intensive renewable projects. In Ukraine, the green tariff provided for up to 20 years provides a more stable per-energy remuneration while leading to relatively lower cost of capital. However, with the current political crisis in the region, the risk premiums for all investment, not only renewables, have increased significantly. On the supportive side, in both countries, international finance institutions, such as the International Finance Corporation (IFC) and the European Bank of Reconstruction and Development, are active in providing relatively cheap financing to support the development of renewable energy projects.

In Romania, recent policy changes have increased investor uncertainty. In the beginning of 2013, retroactive changes to existing certificates and cuts to future green certificates were proposed. It was only in early 2014 that the law was approved by the president. During this period, many investors rushed to finish their projects without knowing the details of a new remuneration policy. With the new allocation of technology-specific green certificates, only some renewable projects with high capacity factors will be eligible to be built taking into account ongoing wholesale market prices. Thus, it is expected that some onshore wind projects and just a few utility-scale solar PV projects will be able to find financing.

Table 29 Non-OECD Europe and Eurasia main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Russia	Long-term PPAs awarded through competitive renewable energy auction.	General investment barriers and high local content requirements for renewable energy projects.
Romania	Good resources availability for onshore wind and solar PV.	Retroactive changes to policy supports; delays between policy announcements and approvals.
Ukraine	Renewable energy policy support by FIT regime.	General political turmoil affecting the investment environment.

Conclusions for renewable energy deployment: Baseline case

In Russia, renewable generation should grow by 17 TWh, mostly driven by hydropower, onshore wind and solar PV projects. The largest expansion is expected from hydropower, with more than 3.2 GW additional capacity deployed, mostly as a result of refurbishment of ageing assets. It is also expected that projects that won contracts at the first renewable energy auction will be partly built. Thus, solar PV should reach 0.4 GW in 2020, while onshore wind power should rise to over 0.6 GW. Ukraine's renewable capacity should grow with the need for diversification and existing policy mechanisms. The strongest additions should come from solar PV and hydropower, both with 0.8 GW new capacity commissioned over the medium term. Onshore wind should expand moderately with 700 MW of new deployment. However, this outlook remains highly uncertain, given current political turmoil in the region.

Table 30 Non-OECD Europe and Eurasia, selected countries renewable capacity in 2013 and 2020

		20	2020					
Total capacity (GW)	Romania	Russia	Ukraine	Europe and Eurasia	Romania	Russia	Ukraine	Europe and Eurasia
Hydropower	6.7	50.7	5.6	96.0	6.9	53.9	6.4	103.3
Bioenergy	0.0	1.4	0.0	1.8	0.1	1.5	0.0	2.2
Onshore wind	2.6	0.0	0.4	4.4	3.7	0.7	1.1	9.4
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	1.1	0.0	0.7	3.0	1.5	0.4	1.4	5.9
STE/CSP	-	-	-	-	-	-	-	-
Geothermal	-	0.1	-	0.1	-	0.1	-	0.1
Ocean	-	-	-	-	-	-	-	-
Total	10.4	52.2	6.7	105.2	12.2	56.5	9.0	120.9

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

In Romania, with the change of the incentive scheme, it is expected that wind deployment will significantly slow down over the medium term. Thus, onshore wind should grow from 2.6 GW in 2013 to 3.7 GW in 2020, with already-financed projects coming on line followed by several licensed projects in locations where capacity factors are high. Solar PV growth is expected to remain limited, expanding by 300 MW with some large utility projects coming on line over the medium term. Residential and commercial projects should also contribute to this expansion. Renewable deployment in other parts of Eastern Europe should be limited, with many incentives for new projects reduced over the past year. In Croatia and Bulgaria, although a moderate FIT programme is in place, either a grid connection is not available for onshore wind projects or government renewable quotas have already been reached.

Renewable energy deployment under enhanced case

With certain developments, the deployment of renewables in the non-OECD Europe and Eurasia region could be higher. However, the upside is difficult to quantify at this point. In Russia, the implementation of the new energy reform that facilitates foreign investment in the energy industry could enhance the deployment of renewables. In Ukraine, much depends on the evolution of the current political situation. In Romania, increasing grid investment in congested areas to transport electricity to demand centres could facilitate onshore wind deployment.

Middle East

Recent trends

Renewables remain a small source of generation in the Middle East, but are starting to scale up. In 2013, total renewable power in the Middle East was relatively steady at over 22 TWh, or 2.5% of total power generation. Notable gains occurred in solar PV and STE, with the commissioning of a large CSP plant in the United Arab Emirates. Iran remained the largest source of renewable generation in the region, based on its sizeable hydropower output. Still, renewables account for only a small fraction of the power mix there.

In the United Arab Emirates, renewables grew from a low base with the commissioning of the 100 MW Shams 1 CSP plant. A 13 MW solar PV project was also commissioned. In Jordan, renewable power represented a small source of total generation in 2012 (0.4%), and capacity remained relatively steady. Still, several large-scale solar PV and wind projects secured financing in 2013 under Jordan's renewable policy framework, suggesting significant developments ahead. In Saudi Arabia, renewable generation began in 2012 and is estimated to have remained a marginal source of power in 2013 (less than 1%). However, Saudi Arabia's most significant solar PV capacity expansion occurred in 2013 with the commissioning of two utility-scale plants (13.5 MW in total).

Medium-term outlook – regional baseline case summary

Renewable generation in the Middle East is expected to double in size over 2013-20, growing by 22 TWh, or at an annual rate of nearly 10%. Still, this outlook is much less than the expected increase in power demand or the region's longer-term renewable potential. Despite the adoption of supportive renewable policies that include long-term PPAs, some regulatory and policy frameworks require further clarification to unlock greater investment, and a number of non-economic barriers persist. Meanwhile, the economic attractiveness picture continues to be distorted by the presence of fossilfuel subsidies. All these factors suggest that, over the medium term, renewable development is likely to proceed at an incremental pace.

Initially over the forecast period, renewable capacity additions are led by hydropower, with capacity coming on line in Iran. However, a portfolio of renewable sources is expected to develop over time. Solar PV should account for most additions over the medium term, as it expands by almost 5 GW, led by Saudi Arabia, Jordan and the United Arab Emirates. The Middle East is also expected to emerge as the world's largest deployment market for new STE capacity by 2020, with most new developments occurring in Saudi Arabia. However, this growth is contingent upon the timely execution of intended renewable auctions in support of the kingdom's long-term targets. Finally, onshore wind is seen expanding at an increasing rate, with most new development again hinging on Saudi Arabia and Jordan.

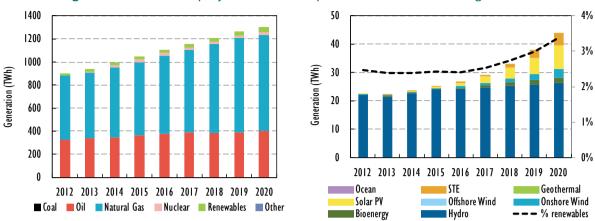
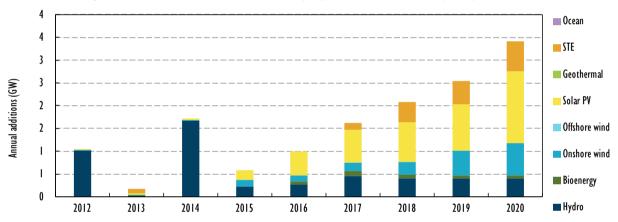


Figure 50 Middle East projected shares of power mix and renewable generation





Medium-term outlook - detailed analysis

Power demand

Middle East power demand is expected to grow strongly, by 4.9% annually over 2013-20. Most markets are expanding due to economic growth. Further support to demand is provided by low, subsidised power prices, rising air-conditioning usage and a need for energy-intensive desalination plants for freshwater production. In Saudi Arabia, electricity demand is expected to rise by over 6% annually on the back of GDP growth of 4.3% per year and very low end-user prices. Peak demand has increased rapidly from 24 GW in 2002 to over 48 GW in 2011.

Power demand in the United Arab Emirates is seen rising by 5% annually over this period on the back of GDP growth of 3.5% per year. The country has a relatively high per capita consumption of electricity, with cheap end-user prices due to subsidies and high air-conditioning use during the summer months. Peak demand has risen steadily, to almost 18 GW in 2011, up from 13 GW in 2007. Jordan's power demand is expected to increase by 4.7% annually over 2013-20, based on GDP growth of 4.2% per year. Its peak demand rose to 2.8 GW in 2012, up from 2.7 GW in 2011 and 2.3 GW in 2009. Though end-user electricity prices remain regulated, Jordan has been increasing them since 2012 in an effort to cut the fiscal burden of subsidies.

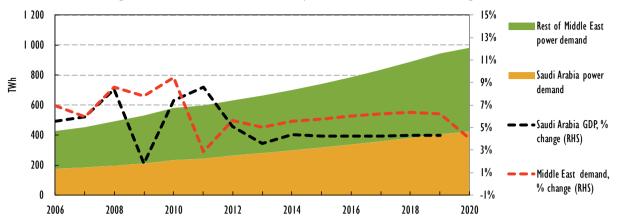


Figure 52 Middle East countries power demand versus GDP growth

Power generation and capacity

Middle East power systems are dynamic, with an increased need for new capacity to meet fast-growing demand and a rising recognition of the benefits of diversifying away from fossil fuels amid excellent potential for renewable sources. Still, these markets often have regulatory frameworks that restrict access to private players and can be challenging for outside investment.

Power generation in the United Arab Emirates is heavily reliant on natural gas, which accounted for an estimated 98.6% of generation in 2012, with some contribution from oil. Though a significant producer of natural gas, the country has been a net importer since 2007 and is taking an increasing amount of LNG. Power capacity in the United Arab Emirates stood at over 26 GW in 2011. Regulation and planning for the power sector is done at the emirate level, with the two largest, Abu Dhabi and Dubai, taking different approaches. Abu Dhabi employs a single-buyer model with subsidiaries of the Abu Dhabi Water and Electricity Authority (ADWEA) overseeing generation, transmission and distribution, and IPPs owning a portion of generation. Dubai's system is more bundled, with all functions falling under Dubai Electricity and Water Authority (DEWA) and, so far, more limited access for IPPs (Koryakovtseva and Bamieh, 2013).

The United Arab Emirates are planning to expand their combined power capacity to 40 GW by 2020, with a large portion of generation still to be supplied by natural gas (Matsumoto, 2013). Still, moves to greater diversification of the power sector are afoot, with Abu Dhabi seeking 25% of its electricity from nuclear and 7% from renewable sources in 2020. Dubai aims for 12% nuclear, 12% coal (with carbon capture and storage) and 5% renewables (solar) by 2030. To this extent, a pipeline of announced large-scale renewable projects has emerged, including a 100 MW waste-to-energy plant in Abu Dhabi and a 1 GW solar park in Dubai.

With relatively few domestic fossil-fuel resources, Jordan has clear incentives for power sector diversification based on energy security. Oil met an estimated 81% of power generation in 2012, with a marginal contribution from a portfolio of renewable sources. Total power capacity stood at 3.4 GW in 2012. Since 2002, IPPs have been authorised to participate in generation, though around 75% of capacity is owned by state-backed utilities Central Electricity Generating Company (CEGCO) and Samra Electric Power Company (SEPCO). Jordan's power planning sees a growing role for renewables, with 1.85 GW targeted by 2020, backed by financial incentives. The country has recently awarded PPAs to the 117 MW Tafila wind farm, the 53 MW Shams Ma'an solar PV plant and several smaller solar PV developments.

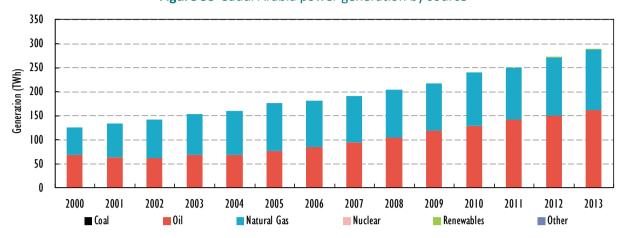


Figure 53 Saudi Arabia power generation by source

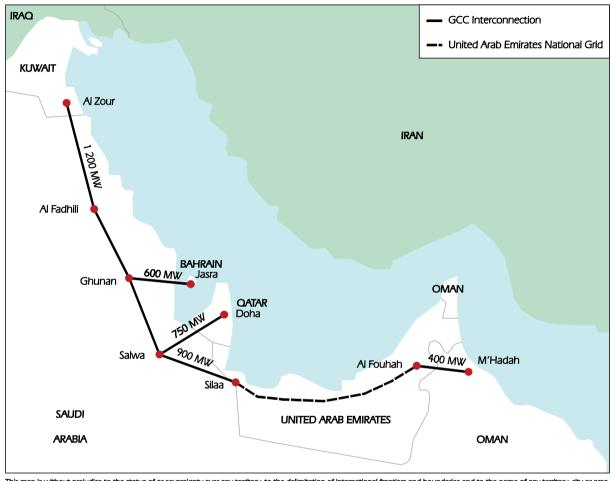
While Saudi Arabia's power system is dependent on a high level of gas-fired generation, the use of oil is playing a more prominent role. In 2012, oil accounted for an estimated 55% of power generation, with gas feeding 45%. This oil-fired generation is costly in terms of potentially forgone exports and carries negative pollution impacts. Total power capacity stood at 53.6 GW in 2012. Generation, transmission and distribution are currently all overseen by the state-owned Saudi Electricity Company (SEC). Still, the government is undertaking reforms to unbundle and privatise parts of SEC. This process is expected to be completed by the end of 2014, but a number of non-economic barriers to entry remain, and questions persist over how the generation market will operate (Migally, 2013). SEC's current power generation planning sees 28 GW of new capacity by 2021, most of which will be met by new thermal plants. Diversification aims have spurred long-term plans for new generation outside of fossil fuels, with an ambition to install 54 GW of renewables and 18 GW of nuclear by 2032. These ambitious goals should imply large development of renewables over the medium term. However, only a small pipeline of renewable projects has emerged to date, owing to still-pending actions on the policy side.

Grid and system integration

With the current low levels of variable renewables in most Middle East countries, high levels of relatively flexible gas-fired generation and good load-matching of renewable output, grid and system integration should present only moderate challenges to development over the medium term. However, Middle East countries need to continue building out their grid infrastructure to connect and transmit output from new generation, meet ever-growing peak demand, and integrate large amounts of variable renewable capacity expected over the long term. The Gulf Cooperation Council (GCC) power grid has, over the past decade, interconnected Kuwait, Saudi Arabia, Bahrain, Qatar, the United Arab Emirates and Oman. Further interconnection developments are planned between Saudi Arabia and Egypt (REN21, 2013). Jordan is interconnected with Egypt and Syria, but not with GCC countries. An emphasis on solar power development in most countries should help to meet burgeoning summer peak demand associated with afternoon air-conditioning needs. Plans for the build-out of CSP with storage, particularly in Saudi Arabia, should also help to enhance the flexibility of renewables to cover evening peak demand needs.

Grid access for renewable projects by IPPs remains a concern, and clear regulations on priority access and dispatch are needed to facilitate investment. While some Middle East countries anticipate grid access in principle, details in realising this outcome in practice are left to negotiation by developers,

raising uncertainty over project economics (Dii, 2013). Moreover, few Middle East countries have created frameworks to facilitate the introduction of small distributed capacity. Thus far only Jordan has enacted and implemented regulation allowing private generation for purposes of self-consumption with net metering or the selling of excess electricity to the grid (RCREEE, 2013).



Map 4 Interconnection of GCC countries

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

Source: Gulf Cooperation Council Interconnection Authority (2014), *The Interconnection Project Geographical Map*, accessed June 2014, http://www.gccia.com.sa.

Current policy environment for renewable energy

In the Middle East, the renewable policy environment consists primarily of long-term targets backed by a combination of public investments, competitive tenders and FITs in some locales. Some countries have oriented these policies to stimulate domestic manufacturing capabilities in renewables. While supportive overall, a large use of public bodies and deliberative processes to determine investments suggests that some frameworks may stimulate development only at an incremental pace. Few policy supports exist for small distributed capacity.

In the United Arab Emirates, individual emirates have adopted long-range targets, with Abu Dhabi aiming for 7% renewables in the power mix by 2020 and Dubai foreseeing 5% renewables by 2030. To

meet these goals, Abu Dhabi has tasked the privately structured, state-backed investment entities of Masdar and Taqa to execute renewable projects. Dubai is carrying out its renewable investments through DEWA. These entities employ competitive tenders to encourage private partnerships in their projects.

Table 31 Middle East countries main targets and support policies for renewable energy

Country	Targets	Support policies
Jordan	7% renewables in primary energy by 2015 (60 MW wind, 300 MW solar PV); 10% renewables in primary energy by 2020 (1.2 GW wind, 600 MW solar, 30-50 MW waste-to-energy).	FITs; net metering; tax incentives; competitive tenders
Kuwait	5% renewable generation by 2020; 10% renewable generation by 2030. (3.5 GW solar PV, 1.1 GW CSP, 3.1 GW wind)	None
Iran	5 GW of wind and solar power.	FITs, capital subsidies, soft loans
Qatar	640 MW (solar) by 2020.	Competitive tenders
Saudi Arabia	Proposed deployment roadmap: 24 GW renewable capacity by 2020; 54 GW renewable capacity by 2032; (16 GW solar PV, 25 GW CSP, 9 GW wind, 3 GW waste-to-energy, 1 GW geothermal).	Competitive tenders
United Arab Emirates	7% renewable capacity by 2020 (Abu Dhabi); 5% renewable generation by 2030 (Dubai).	Public investments, loans, grants; competitive tenders
Yemen	15% renewable generation by 2025	None

Jordan has set a target of 10% renewables in primary energy by 2020, with capacity of 1.85 GW of renewables in the power sector. Two-thirds of this capacity target is seen coming from wind, followed by solar PV, CSP and bioenergy. In 2012, the government adopted FITs that are awarded to renewable projects through competitive bidding rounds. Jordan has also adopted net metering, with excess electricity purchased at the FIT rates.

In Saudi Arabia, an ambitious long-term plan of 54 GW of renewables by 2032 with proposed competitive tenders that would award PPAs to winning bids. The King Abdullah City for Atomic and Renewable Energy (KACARE) issued a white paper in 2013 to get feedback on the procurement process and lay out a draft plan for auctions. An introductory round is to invite bidding for 500 MW to 800 MW of utility-scale capacity, followed by two rounds of larger size. Still, dates of the tenders had yet to be announced as of May 2014, with site identification and resource measurement work ongoing. Although the long-term policy environment appears supportive, lack of clarity over the timeline and implementation details of the programme represent significant sources of uncertainty to renewable development through 2020.

Economic attractiveness of renewable energy and financing

Excellent resource availability, robust availability of public financing and the availability of long-term PPAs should make utility-scale renewable deployment attractive in the Middle East over the medium term. Still, a limited track record of development, lack of transparent data on technology and generation costs, the presence of non-economic barriers, and uncertainties over grid access for IPPs make an evaluation of economic attractiveness difficult. Tendering rules, such as those proposed by KACARE in Saudi Arabia, that include high local content provisions may also represent economic challenges to development. Outside of Jordan, the attractiveness of small distributed capacity likely remains low,

with few supportive policy frameworks implemented. Given the very low end-user power prices in other Middle East countries, the encouragement of small distributed capacity would likely require a phase-out of subsidies in addition to regulatory changes.

To give more context on the economics of generation, one study estimates the LCOE for conventional power in the Middle East/North Africa region at EUR 40/MWh (USD 53/MWh) for coal, EUR 60/MWh (USD 80/MWh) for combined-cycle gas turbine plants and up to EUR 200/MWh (USD 266/MWh) for oil (Dii, 2013). Still, subsidised fossil fuels can distort the picture and make the cost of conventional generation much cheaper in reality. For fossil-fuel exporters, utility-scale renewable sources can be competitive versus conventional bulk power when the opportunity cost of not selling fuels on the international market is taken into account. By comparison, this report estimates the LCOE of new utility-scale solar PV installations in GCC countries currently at around USD 150/MWh to USD 170/MWh, a level that would be competitive with peak generation, with costs likely to decline to USD 100/MWh to USD 110/MWh by 2020 with falling system prices.

The large role played by public investment, from governments or state-backed utilities, in some Middle East countries suggests that the cost and availability of financing should not be a major constraint to medium-term plans for renewable development. Still, meeting longer-term development targets will require a large scale-up of private investment, which may be a challenge for some local banking sectors. While Saudi Arabia has a developed and liquid project finance market, with participation from foreign investors and banks, Jordan's banking sector remains less liquid and developed for large infrastructure projects (Dii, 2013). Foreign private financing, complemented by lending from international development banks, will be key to scaling up renewable investments, but its cost and availability will depend on the evolution of some of the non-economic barriers described above.

Conclusions for renewable energy deployment: Baseline case

Saudi Arabia is likely to lead regional deployment, with renewable generation growing by more than 8 TWh over 2013-20. Saudi developments should be led by solar PV, which is seen expanding by 2.5 GW, followed by onshore wind (+1.3 GW) and STE/CSP (+1.0 GW). This expansion is contingent on the timely execution of announced intentions for competitive tenders.

Table 32 Middle East, selected countries renewable energy capacity in 2013 and 2020

		2	013			20)20	
Total capacity (GW)	Jordan	Saudi Arabia	United Arab Emirates	Middle East	Jordan	Saudi Arabia	United Arab Emirates	Middle East
Hydropower	0.0	-	-	14.5	0.0	-	-	18.3
Bioenergy	0.0	-	0.0	0.1	0.0	0.1	0.3	0.4
Onshore wind	0.0	-	0.0	0.1	0.5	1.3	0.1	2.1
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	0.0	0.0	0.0	0.1	1.0	2.5	0.5	5.1
STE/CSP	-	-	0.1	0.1	0.3	1.0	0.4	1.9
Geothermal	-	-	-	-	-	-	-	-
Ocean	_	-	_	-	-	-	-	_
Total	0.0	0.0	0.1	14.8	1.9	4.8	1.3	27.8

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

Both the United Arab Emirates and Jordan are expected to grow around 3 TWh over 2013-20. In the Emirates, most deployment should occur in solar PV (+0.5 GW) with smaller additions in STE (+0.3 GW) and bioenergy (+0.3 GW), mostly from waste-to-energy plants. Jordan's FIT regime and framework for small distributed capacity should support deployment in solar PV, wind and STE. In addition to these countries, renewable output in Iran should rise on the back of new hydropower capacity, while Qatar, Oman and Kuwait should all see increased development in solar power.

Table 33 Middle East main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Jordan	Few domestic fossil-fuel resources and strong need for power sector diversification. Attractive FIT regime and framework for small distributed capacity.	Low interconnection with other countries in the region. Cost and availability of financing.
Saudi Arabia	Excellent renewable resources, fast-growing demand and strong need for power sector diversification. Long-term policy framework with aggressive targets backed by auction scheme with PPAs.	Uncertainty over timing and implementation of auction scheme. Non-economic barriers and high local content provisions.
United Arab Emirates	Fast-growing demand and strong need for power sector diversification.	Non-economic barriers can present investment challenges to new entrants.

Renewable energy deployment under an enhanced case

Given excellent resources, strong diversification needs and rising power demand, the outlook in some Middle East countries could be much higher over the medium term. The acceleration of competitive tender plans and the rapid clarification of regulatory questions related to grid access, dispatch and land ownership, for example, could help to speed development over the medium term. Greater adoption of policy frameworks to support small distributed capacity would also act as a deployment driver, though a reform of fossil-fuel subsidies looks more realistic over the long term. It is difficult to quantify the upside should such market enhancements emerge, particularly given lead times associated with utility-scale developments. Overall, solar PV could be some 3 GW to 4 GW higher than the baseline forecast in 2020, onshore wind could be 2 GW to 3 GW higher and CSP deployment could be 0.5 GW to 1.0 GW more.

Non-OECD Americas

Recent trends

Renewable power in non-OECD Americas decreased by an estimated 3% in 2013 to 734 TWh, mainly due to low hydro reservoir availability in the region. Still, the share of renewables in power generation remains the highest among all regions in the world.

With its large hydropower capacity, Brazil remains the largest source of renewable generation, accounting for about 60% of region's overall renewable output. Renewable sources represented more than 73% of power generation in 2013. Brazil's hydropower generation decreased around 7% year-on-year as the drought reduced water supply of reservoirs significantly over the past year. Still, in 2013, hydropower generation accounted for around 66% of overall electricity generation. The country added more than 1.7 GW of new hydropower capacity, reaching close to 90 GW in total. Onshore wind capacity expanded by around 950 MW, slightly lower than country's additions in 2012. Brazil also added 860 MW of bioenergy capacity in 2013, one of the highest new additions over the last decade.

In Argentina, renewable generation decreased by 4.6% in 2012 to 32.5 TWh representing 24% of overall generation. Natural gas provided more than 53% of total generation followed by hydropower, which contributed an estimated 22% in 2012. The share of wind generation increased slightly but still remained below 1% of total generation. The country added close to 80 MW of new onshore wind capacity, reaching 220 MW in 2013. Despite good solar PV potential, new additions totalled only around 40 MW last year.

In Peru, renewable power accounted for an estimated 55% of overall power generation in 2012. Hydropower is the largest renewable energy source in the country, representing 55% of overall electricity generation, while natural gas accounts for 40%. In March 2013, the country added its first grid-connected solar PV plant in the Tacna region, with a capacity of 47 MW. With the commissioning of this project, total solar PV capacity in Peru stood at around 70 MW by the end of 2013, while no onshore wind projects were commissioned.

Medium-term outlook – regional baseline case summary

Overall, non-OECD Americas renewable energy generation is expected to rise by 274 TWh, or 37%, from 2013-20. Around 72% of renewable generation gain should come from hydropower. Renewable power is expected to account for 65% of total generation in 2020, up from 62% in 2013.

Overall, the regional annual capacity forecast pattern is strongly determined by the timing of hydropower additions, which have long lead times, and the expected commissioning of onshore wind under Brazil's auction timeline. Hydropower underpins the regional capacity expansion, growing by over 35 GW from 2013 to 2020, led by Brazil with notable additions from Ecuador and Colombia. Onshore wind is expected to be the next largest source of new capacity, rising by 16 GW over 2013-20. Onshore wind growth is led by Brazil, supported by a stable policy environment based on auctions and the awarding of long-term PPAs, though notable additions above 100 MW are expected by eight other countries, including Peru and Uruguay. Non-OECD Americas possesses a large potential for solar PV and bioenergy, though these technologies are expected to grow more slowly over the medium term. Solar PV deployment is expected to rise by almost 4 GW in the region. The majority of new additions should come from Brazil, though this would be contingent on the successful auctioning of utility-scale solar PV by the central government and a faster uptake of distributed solar PV. Bioenergy is largely led by new bagasse-fired generation in Brazil.

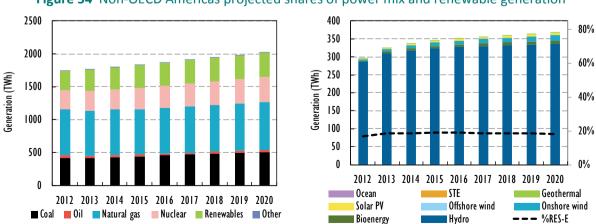


Figure 54 Non-OECD Americas projected shares of power mix and renewable generation

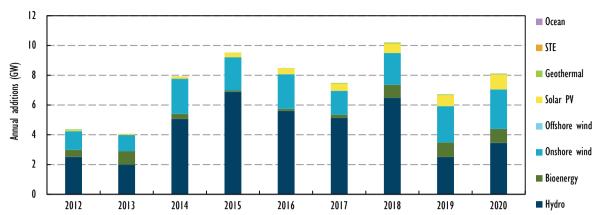


Figure 55 Non-OECD Americas historical and projected renewable capacity additions

Medium-term outlook – detailed analysis

Power demand

Non-OECD Americas power demand is expected to grow by 3.4% annually over 2013-20, with most countries achieving annual growth rates ranging from 2% to 4%. Brazil's power demand is seen expanding by 3.3% per year. This outlook is slower than in *MTRMR 2013* mainly due to moderate GDP growth of 3.2% estimated by the IMF. The downward revision of the economic growth in Brazil is tied to slowing infrastructure investments, low private investment, a high level of inflation and weakening exports (IMF, 2013). In order to deal with economic slowdown and improve the country's competitiveness, the Brazilian government issued a new act in January 2013 addressed to utilities to cut electricity tariffs on average by 18% for households and 30% for industrial consumers in exchange for the renewal of their concession contracts (Soto and Goy, 2013). This helped support demand even as generation costs rose due to the low availability of hydropower (see below for further details).

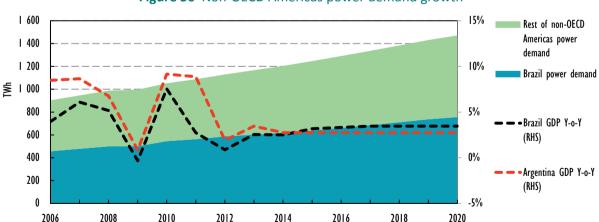


Figure 56 Non-OECD Americas power demand growth

Argentina's power demand is seen rising by 3.5% per year over 2013-20, buoyed by relatively strong economic growth. Even with the withdrawal of several subsidies provided to rate payers in 2013, retail electricity prices remain lower than those of neighbouring countries. For example, power prices in Brazil are on average three times higher than those in Argentina. In Peru, power demand is seen rising by 9% per year over 2013-20 and is expected to be strong, mainly driven by high economic

growth, largely due to the copper and mining sector (IFC, 2012). Retail electricity prices are relatively low thanks to natural gas costs being artificially low due to the government's pricing policy, which does not take into account exploration costs (IFC, 2012).

Power generation and capacity

Non-OECD Americas power systems are generally dynamic, buoyed by strong economic growth with need for new generation to meet rising power demand. Although Brazil's hydropower capacity dominates the region's overall power generation, many countries still rely on imported fossil fuels, mainly natural gas, oil and diesel. Thus, energy security and diversification are important motivations for many countries to expand the role of renewables in their power mix.

In Brazil, hydropower reservoir levels dropped to record-low levels due to the drought over the past year. This caused hydropower generation to drop by over 5% in 2013, which was partly replaced by gas-fired power. Brazil's consumption of LNG increased significantly in 2013. As the majority of utilities decreased their retail prices in response to the government's pricing policy (see description above), the combination of unexpectedly high temperatures, low hydropower availability, and increased generation from costly natural gas and oil power plants led to record-high spot electricity prices (BRL 820/MWh or USD 370/MWh) at certain peak hours. As the majority of retail power prices are still regulated or capped in Brazil, utilities could not pass increasing prices to rate payers. In response, the government announced a USD 5 billion aid package in order to help utilities deal with high spot market prices. The power sector situation underscores the benefits of continued diversification, which is likely to drive increased onshore wind, bioenergy and solar PV deployment over the medium term, supported by the government's auction scheme. The government's Decennial Energy Plan (PDE 2022) expects renewable energy to account for 92% of new capacity additions over 2012-22. Hydropower and onshore wind together should represent the majority of new additions, while bioenergy also contributes. Utility-scale solar PV is not yet factored in the PDE generation targets; however, the document does outline a trajectory for residential- and commercial-scale solar PV, which, combined, are assumed to rise to 1.4 GW by 2022.

Table 34 Brazil power generation capacity targets under the PDE 2022 (GW)

GW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Hydropower	88.7	90.6	94.7	98.4	102.2	106.9	108.5	111.1	113.6	119.0
Nuclear	2.0	2.0	2.0	2.0	2.0	3.4	3.4	3.4	3.4	3.4
Natural gas	11.2	12.2	12.2	12.2	12.6	13.1	13.3	13.7	14.1	14.1
Coal	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Oil	4.9	4.8	4.9	4.9	4.5	4.5	4.5	4.5	4.5	4.5
Process gas	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Small hydropower	5.3	5.5	5.5	5.5	5.7	6.0	6.2	6.4	6.7	6.9
Biomass	9.5	9.6	9.6	9.6	9.7	10.4	11.3	12.1	13.1	13.8
Wind	3.9	6.6	9.1	10.8	12.1	13.1	14.1	15.1	16.3	17.5
Total	129.5	135.1	141.9	147.3	152.6	161.3	165.1	170.2	175.6	183.1

Note: hydropower includes imports from the Itaipu hydropower plant not consumed by Paraguay.

Source: Ministry of Energy and Mines (2013), Plana Decenal de Expansao de Energia 2022, Government of Brazil, Brasilia.

In Argentina, a need for new capacity to meet increasing summer peak demand and the diversification of the power mix could act as drivers of renewable power growth over the medium term. With regulated power prices kept low despite high domestic inflation rates, reaching more than 10%

(official rate; unofficial rates show around 25% inflation), Argentina's power infrastructure has been suffering from persistent under-investment. Over the past year, Argentina experienced blackouts during episodes of peak demand.

Peru faces similar challenges concerning new investment in transmission and generation assets. With a booming economy driven by the copper and mining industries, the country's power consumption reached 10% growth rates while the increase in generation capacity has remained limited due to administrative bottlenecks and a need to address environmental opposition. Since the commissioning of the Camisea natural gas fields in the early 2000s, the government has encouraged the construction of natural gas—fuelled power. However, since then, the price of gas has increased and the additional pipeline investment that was supposed to deliver gas to additional power plants has been delayed.

Renewables could help address some of Peru's energy challenges concerning diversification and increasing power consumption expected over the medium term; still, they would require a supportive policy environment that helped to reduce non-economic barriers. Recent estimates released to the Peruvian media by Osinergmin and Comité de Operación Económica del Sistema Interconectado Nacional (COES), the state organisation in charge of the national power grid, projects moderate renewable deployment in the next five years. By the end of 2017, COES projects that renewable energy will provide 7% of the national energy supply following the installation of 300 new MW of power over the next five years (US Commercial Service, 2013).

Grid and system integration

Overall, renewable energy is well integrated into the Brazilian power system, which provides a high degree of flexibility. Brazil's large-scale hydropower generation and extensive transmission system help to balance variable renewable generation. Brazil's natural gas—fuelled generation provides additional flexibility to the system at drought periods, while bioenergy and wind power may also help to balance hydropower at low reservoir levels. After the delay in connecting over 20 wind farms to the grid in mid-2012, the Brazilian national grid operator (ONS) released a study with all available substations for planned generation projects to connect by 2015. These include secured grid connections for onshore wind projects that won the energy auction held in December 2013. The cost of connection to the transmission grid is currently under developers' responsibility, as the Ministry of Mines and Energy changed the regulation after the connection delays in 2012. Still, around 50 wind farms could not get connected to the grid in 2013.

In Argentina and Peru, grid and system integration of renewables should serve as a major challenge over the medium term. Both countries' grids require investment in expansion and refurbishment. With an electrification level around 87%, some of Peru's rural areas still lack connection to the national grid. Off-grid renewables, mainly solar PV, might help in this respect, especially in the Andes and Amazon regions. In general, Argentina's grid suffers from under-investment, because regulated utility rates have remained the same over the last decade, while the power demand and inflation have risen significantly (Romig, 2014). Thus, with the heat wave over the past year, Edesur and Edenor, two major utilities in Argentina serving the densely populated capital of Buenos Aires and surrounding areas, have reported record losses: Edesur of ARS 1.1 billion (USD 137 million) and Edenor of ARS 738 million (USD 92 million) (Edenor, 2014). In Argentina, many good wind sites are far away from densely populated areas where the demand is growing. The Patagonia region, for instance, has one of the best wind sources in the world but it is mostly isolated from the main grid.

Current policy environment for renewable energy

Brazil's policy environment has strengthened in certain areas over the past year. Government-sponsored energy auctions have remained the major policy to encourage renewable deployment offering long-term PPAs (20 to 30 years) with competitive bidding procedure. In 2013, overall, Brazil held four auctions and contracted over 6 GW of renewable capacity. Some projects are expected to be commissioned in 2015-16 while others would come on line in 2018-19. With 4.7 GW capacity, onshore wind won the majority of contracts in 2013, followed by large hydro (1.1 GW) biomass (0.8 GW) and small hydro (0.5 GW). Although solar PV was included in both the A-3 auction that was held November 2013 and the A-5 auction in December 2013, no projects were selected. Still, the government has indicated it will hold a dedicated solar PV auction later in 2014. The Brazilian state of Pernambuco held a solar-only auction in late 2013 with a ceiling price of BRL 250/MWh (USD 112/MWh), contracting 122 MW of capacity. At the distribution level, although the Brazilian Federal Energy Regulatory Agency (ANEEL) enacted new rules for net metering at the end of 2012, its implementation has remained limited due to technical barriers concerning the deployment of smart meters that would enable customers to sell surplus electricity to the grid.

Argentina has a renewable electricity generation target of 8% by 2016. In order to reach this target, the Ministry of Energy held a renewable energy auction in 2009, and awarded 760 MW of onshore wind, 110 MW of biomass, 20 MW of solar PV and 10 MW of small hydropower plants. Many of these projects have yet to be built, however, due to challenges in obtaining financing. Argentina also provides a value-added tax rebate on the purchase of renewable equipment in addition to the accelerated depreciation.

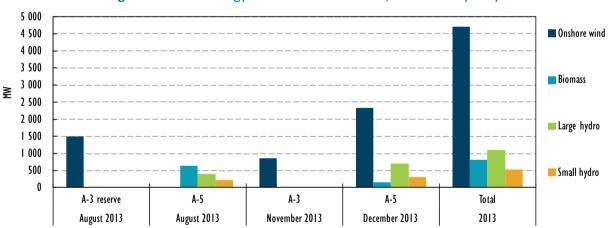


Figure 57 Brazil energy auction results in 2013, tendered capacity

Peru reached its 2013 target of 5% non-hydro renewable generation early in 2010. Peru has so far held two renewable energy auctions, contracting a total of 39 projects with a total capacity of 440 MW with 20-year PPAS. Small hydropower won the majority of contracts with 180 MW of capacity, followed by onshore wind (145 MW), solar PV (85 MW) and bioenergy (30 MW). The government also offers an accelerated depreciation of up to 20% for equipment used in renewable energy generation.

Uruguay is an emerging renewable market and has a target of 15% renewable energy capacity by 2015. Since 2011, the National Administration of Power Plants and Electrical Transmissions of Uruguay (UTE) has held three auctions awarding 880 MW of wind capacity with 20-year PPAs. The country

also has a net metering programme. In 2013, the government opened a solar PV tender, and received 166 MW of applications. The UTE announced that it would sign 20-year PPAs ranging from USD 87/MWH TO USD 92/MWh with winning projects; however, the results were not known at the time of writing.

Table 35 Non-OECD Americas countries main targets and support policies for new renewable energy capacities

Non-OECD Americas	Regul	atory sı	upport			E	conomi	supp	ort		
Country	RE law	Targets	Quotas/RPS	Feed-in tariff/premium	capital grants and subsidies	Soft loans	Tax relief	Net metering	Tradable green certificates	Carbon pricing	Auction schemes
Argentina		Х		Х			Х				Х
Brazil		Χ			Χ	Χ	Χ	Χ			Χ
Colombia		Χ					Χ				
Nicaragua		Χ					Χ				
Peru			Χ				Χ				Χ
Uruguay		Χ		Х		Χ	Χ	Χ			Χ

Note: x = national-level policy; o = state/provincial-level policy. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: http://www.iea.org/policiesandmeasures/renewableenergy.

Economic attractiveness and financing

In non-OECD Americas, renewable deployment is mostly driven by auction schemes, which provide long-term PPAs. While the Brazilian National Development Bank (BNDES) plays a significant role in Brazil and other countries in the region, the cost and availability of financing can remain an impediment to development in many countries. High capacity factors for both onshore wind and solar PV projects play an important role in improving economic attractiveness of renewable energy in the region.

In Brazil, over the past year, the result of energy auctions strengthened the position of onshore wind, biomass and hydropower against conventional technologies. During the wind-only auction that was held in August 2013, 1.5 GW of projects signed PPAs with an average price of BRL 110.5/MWh (USD 47/MWh), higher than last year's result (BRL 88/MWh or USD 44/MWh), but still among the world's lowest. Biomass and small hydropower won the majority of the contracts in the A-5 auction, also held in August 2013, against conventional technologies. The average PPA price of biomass plants was BRL 135.5/MWh (USD 57/MWh), while small hydro power plants signed contracts at BRL 127/MWh (USD 54/MWh). In December 2013, the average price for wind further increased to BRL 119/MWh (USD 51/MWh), while biomass contracts settled on average at BRL 134/MWh (USD 57.5/MWh) and small hydro projects at BRL 137/MWh (USD 59/MWh).

Table 36 Brazil energy auctions, average contracted capacity prices (BRL/MWh)

BRL (nominal)	December 2012	August 2013	December 2013
Onshore wind	88	111	119
Small hydropower	_	127	137
Biomass	-	135	134

Although average capacity factors for onshore wind projects submitted to energy auctions (around 49% on average) were similar to those that were held in 2012, developers bid higher prices in 2013. This upward trend partly reflects the increasing level of local content requirements by BNDES imposed on wind turbine manufacturers in order to be eligible for the bank's relatively low-cost financing. In July 2013, BNDES announced new guidelines for turbine manufacturers, imposing tighter local content rules. It required manufacturers to provide a degree of local content for three out of four turbine components (towers, hubs, nacelles and blades). In January 2014, additional requirements were announced. Manufacturers need to provide local content for all four parts of the wind turbine. Towers must be 100% produced locally, while the requirement is 40% for blades, and two out of four hub components must be sourced locally. Although nacelles do not need to be produced in Brazil, manufacturers have to submit a business plan to establish a production facility in order to qualify for BNDES financing. Thus, in these conditions, it is expected that some manufacturers may not be able to qualify for the low-cost financing by the end of 2014.

In Peru, the spot electricity price is mostly defined by natural gas power plants. In 2013, the average marginal cost of electricity in the country was around USD 26.5/MWh while retail electricity prices stood at USD 100/MWh (COES, 2014). With cheap natural gas prices and subsidised retail electricity rates, renewables are not yet competitive without supports in the Peruvian electricity market. However, renewable-specific auctions that award PPAs should drive deployment over the medium term. In late 2013, the Peruvian government launched an electrification programme that will provide free solar panels to poor households. This incentive might increase the deployment of off-grid solar PV installations over the medium term.

Table 37 Non-OECD Americas main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Brazil	Growing power demand and government- sponsored power auctions with long-term PPAs. Availability of low-cost financing from BNDES.	Increasing local content requirements may challenge economic attractiveness of developments. Scale-up of utility-scale solar PV through the auction scheme; acceleration of distributed solar PV deployment.
Argentina	Renewable auctions supported by long-term PPAs.	Weak macroeconomic environment also affecting renewable financing.
Peru	Strong power demand growth with excellent wind and solar resources.	Under-invested grid creating constraints over the connection of renewables.

In Argentina, macroeconomic instability poses significant challenges on financing renewable energy projects. Many renewable projects that won the tender in 2009 have not yet been built due to lack of financing, although the contracted energy price was one of the highest in the region at USD 127/MWh for onshore wind projects.

Availability of financing and high cost of capital remain important challenges in the region with the exception of Brazil. Over the past few years, several international development banks and finance institutions have been active in the region, providing low-cost financing to renewable energy projects. Overseas Private Investment Corporation (OPIC) announced that it would loan up to USD 96 million supporting the 50 MW Melowind project in Uruguay. BNDES and IFC are also active in the region.

Conclusions for renewable energy deployment: Baseline case

Brazil's renewable generation should rise by more than 207 TWh over 2013-20, with continuous hydropower deployment and growing onshore wind power generation. While the ten-year historical average is assumed for hydropower capacity factors, in practice, year-to-year generation is heavily dependent on reservoir availability. The forecast is similar to *MTRMR 2013* with minor technology-specific adjustments. With a lower capacity baseline and slower progress in some large hydropower projects, the hydropower forecast is 7 GW lower in 2018 compared with *MTRMR 2013*. Thus this report sees hydropower capacity reaching over 110 GW in 2020. Onshore wind and solar PV forecasts are slightly higher than in *MTRMR 2013*. With solar-only auctions expected by the central government and increasing residential and commercial installations expected to pick up, solar PV should expand by 1.8 GW from a negligible capacity in 2013. Onshore wind is seen rising by 13 GW, reaching 16.4 GW in 2020. Finally, bioenergy capacity should expand by 2.6 GW.

Argentina's renewable generation is seen expanding by 5 TWh over 2013-20, mostly driven by hydropower and bioenergy. However, this report does not expect Argentina to reach its 6% renewable power generation target by 2016 with the forecast deployment over the medium term. The availability and the high cost of financing related to the country's macroeconomic situation represent significant challenges to renewable investment.

Peru's renewable energy is expected to grow by 7.2 TWh over 2013-20. More than half of renewable generation gains should come from hydropower, which is seen expanding by 700 MW over the projection period. This report also expects onshore wind power to reach 0.7 GW by 2020. With high irradiation levels, utility-scale solar PV is expected to grow fast as well, with capacity expanding close to 500 MW and reaching 0.6 GW in 2020. Still, financing remains an important challenge that needs to be tackled over the medium term.

Table 38 Non-OECD Americas, selected countries renewable energy capacity in 2013 and 2020

Total	2013				2020			
capacity (GW)	Argentina	Brazil	Peru	Non- OECD Americas	Argentina	Brazil	Peru	Non- OECD Americas
Hydropower	12.4	86.0	3.5	145.7	13.2	110.4	4.2	180.8
Bioenergy	0.6	9.5	0.0	11.6	0.9	12.1	0.1	15.2
Onshore wind	0.2	3.5	0.0	4.6	0.6	16.4	0.7	20.3
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	0.0	0.1	0.1	0.2	0.3	1.9	0.6	3.9
STE/CSP	_	-	-	-	_	-	-	-
Geothermal	-	-	-	0.6	0.1	-	-	0.9
Ocean	_	-	_	_	_	-	-	-
Total	13.2	99.0	3.6	162.6	15.0	140.7	5.5	221.1

Note: for further country-level forecast data, please see the Excel workbook that accompanies this report.

Renewable energy deployment under enhanced case

Certain market enhancements could increase the cumulative capacity of wind power and solar PV in the region, especially in Brazil. Faster-than-expected new auctions and the streamlining of licensing

procedures without compromising social and environmental aims could help boost the result for onshore wind. By 2020, 1 GW to 2 GW of additional wind capacity could be commissioned. A significant upside is possible for solar PV given Brazil's large market and excellent resources. With faster-than-expected uptake of distributed systems and the rapid inclusion of large-scale projects in capacity auctions, cumulative solar PV capacity could also be 2 GW to 3 GW higher in 2020 versus the baseline case.

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RENEWABLE ELECTRICITY: GLOBAL TECHNOLOGIES

Summary

- Global renewable electricity generation is projected to grow by 2 245 terawatt hours (TWh) from an estimated 5 070 TWh in 2013 to 7 315 TWh in 2020 (+5.4% per year). Hydropower, including output from pumped storage, represents about 37% of total growth, followed by onshore wind at 31% of total growth. Compared with the *Medium-Term Renewable Energy Market Report 2013* (*MTRMR 2013*), renewable generation is seen 180 TWh lower in 2018, due less optimistic outlooks for hydropower, bioenergy, wind (onshore and offshore) and solar thermal electricity (STE). China should lead growth within most categories: hydropower, onshore wind, solar photovoltaics (PV), and bioenergy, as its total renewable generation grows by 880 TWh (+8.8% per year). The United Kingdom has the highest increase in offshore wind, the United States has the highest increase in STE, and Indonesia has the highest increase in geothermal power.
- In 2013, global renewable electricity generation rose by an estimated 240 TWh (+5.0% year-on-year) and accounted for almost 22% of total power generation. Renewable capacity expanded by its highest amount to date, at 123 gigawatts (GW). Capacity growth was led by hydropower, supported by an exceptionally high expansion in China of 31 gigawatts (GW). Solar PV capacity rose by 39 GW, led by a surge in installations in China and Japan, as well as continued growth in the United States. Onshore wind additions, at 34 GW, were their lowest since 2008, largely due to a drop in new capacity in the United States, stemming from policy uncertainty over the renewal of federal tax incentives at the end of 2012. Solar thermal electricity (STE) additions were equivalent to the record level achieved in 2012, and offshore wind was deployed at its highest level to date, with the start of several large projects long under development.
- Two significant global trends should help drive the deployment of renewable technologies over the medium term. First, as renewable electricity capacity scales up, from a global total of 1 690 GW in 2013 to 2 555 GW in 2020 (growth of over 50%), deployment should also spread out geographically. Second, renewable technologies are becoming increasingly competitive on a production cost basis with their alternatives in a number of countries and circumstances. Still, compared to MTRMR 2013, increased policy and market risks cloud the development picture. The global annual capacity additions trend under this report's baseline case forecast remains relatively stable after 2014, after a decade of increasing growth. Uncertainties over long-term policies are a significant factor behind an expected slower but stable trend for renewable capacity additions in member countries of the Organisation for Economic Co-operation and Development (OECD). In the non-OECD, fast-growing power demand and power sector diversification needs should spur a rising trend for additions. However, non-OECD countries where renewables are just taking off often face hurdles in deployment due to non-economic barriers, grid constraints, market design or the cost/availability of financing. As a result, deployment is not expected to proceed as fast as in MTRMR 2013.
- **Under this report's enhanced case**, renewable capacity could be 125-205 GW higher in 2020 than the baseline case. Solar PV and onshore wind, with relatively short development times, have the largest upside. In the enhanced case, solar PV could reach a cumulative capacity of 465-515 GW in 2020 while onshore wind could climb to 635-655 GW.

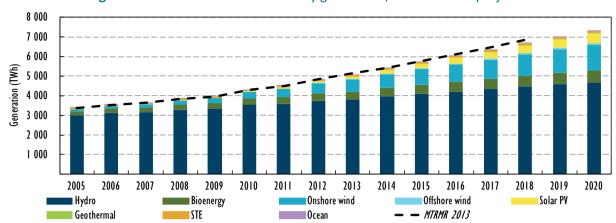


Figure 58 World renewable electricity generation, historical and projected

Notes: unless otherwise indicated, all material in figures and tables in this chapter derive from International Energy Agency (IEA) data and analysis. Hydropower includes pumped storage; the onshore and offshore wind split is estimated. CSP = concentrated solar power.

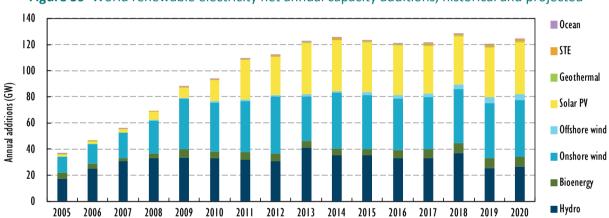


Figure 59 World renewable electricity net annual capacity additions, historical and projected

Table 39 World renewable electricity capacity and projection (GW)

	2005	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	874	1 133	1 168	1 203	1 237	1 270	1 307	1 333	1 360
Bioenergy	49	88	93	97	104	111	118	125	133
Wind	59	319	363	407	449	491	536	583	630
Onshore	59	312	354	396	435	475	517	559	602
Offshore	1	7	8	11	13	16	20	24	29
Solar PV	4	137	176	214	253	289	326	364	403
STE	0	4	5	5	6	7	8	10	11
Geothermal	9	12	12	13	13	14	15	15	16
Ocean	0	1	1	1	1	1	1	1	1
Total RES-E	997	1 692	1 817	1 940	2 061	2 182	2 311	2 431	2 555

Notes: capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Grid-connected solar PV capacity (including small distributed capacity) is counted at the time that the grid connection is made, and off-grid solar PV systems are included at the time of the installation. RES-E = electricity generated from renewable energy sources.

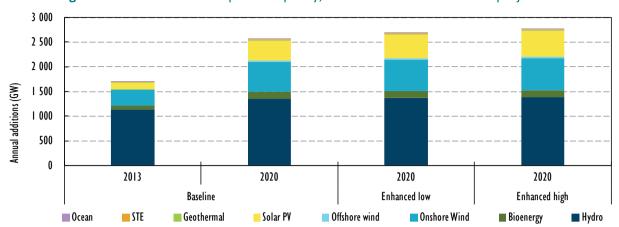


Figure 60 World renewable power capacity, baseline and enhanced case projections

Global trends in renewable power: Geographical diffusion

Renewable power deployment continues to transition from development in some key countries to deployment in a greater number of markets. Non-hydro renewable electricity development is becoming increasingly widespread, with growth shifting beyond traditional support markets in Europe and the United States to non-OECD countries. In 2020, the number of countries with cumulative renewable electricity capacities above 100 megawatts (MW) is expected to notably increase for many non-hydro technologies. Onshore wind, already widespread in 2013, is expected to be deployed in almost 75 countries by 2020. The deployment of solar PV at the 100 MW level is expected to also be reached in almost 75 countries by 2020, a steep jump up from 30 in 2013. Bioenergy at that level is expected in almost 60 countries by 2020, up from 50 in 2013. However, the spread of offshore wind, STE, geothermal and ocean deployment should remain relatively lower.

Table 40 Top five countries, projected increase in generation (TWh) over 2013-20 by technology

Hydropower	Onshore wind	Offshore wind	Bioenergy
China	China	United Kingdom	China
Brazil	United States	China	United States
India	Brazil	Germany	India
Turkey	India	Belgium	Poland
Viet Nam	Germany	Netherlands	Brazil
Solar PV	STE/CSP	Geothermal	Ocean
China	United States	Indonesia	Korea
Japan	Saudi Arabia	United States	France
United States	South Africa	Kenya	Canada
Germany	India	Mexico	United Kingdom
India	Chile	New Zealand	China

Note: countries are ordered from highest to lowest.

Table 41 Top five countries, projected increase in generation (% change) over 2013-20 by technology

Hydropower	Onshore wind	Offshore wind	Bioenergy
Cambodia	Peru	United States	Tunisia
Nicaragua	Algeria	Korea	United Arab Emirates
Ethiopia	Kazakhstan	France	Saudi Arabia
Nigeria	South Africa	Canada	Jordan
Nepal	Bolivia	Ireland	Ghana

Solar PV	STE/CSP	Geothermal	Ocean
Kazakhstan	Saudi Arabia	Chile	Korea
Chile	South Africa	Ethiopia	Ireland
Poland	Chile	France	United Kingdom
Ethiopia	Israel ⁷	Thailand	Norway
Jordan	Australia	Kenya	United States

Note: countries are ordered from highest to lowest; for hydropower, onshore wind, offshore wind, bioenergy, solar PV and CSP, percentage increase calculated only for countries with expected capacity of at least 100 MW in 2020. For ocean energy, a lower baseline of 1 MW is used to calculate percentage increase.

80 70 60 Number of countries (>100 MW) 50 40 30 20 10 2006 | 2013 | 2020 2006 | 2013 | 2020 2006 2013 | 2020 2006 | 2013 | 2020 2006 | 2013 | 2020 2006 2013 2020 2006 2013 2020 Onshore wind Offshore wind Solar PV STE/CSP Geothermal Bioenergy 0cean Non-OECD 0ECD

Figure 61 Number of countries with non-hydro renewable capacity above 100 MW

Global trends in renewable power: Economic competitiveness

The levelised cost of electricity (LCOE), without incentives, for some renewable energy technologies has further decreased over the past year. Although renewables remain generally more expensive than conventional electricity-generating technologies, this gap is expected to further narrow over the medium term. Still, LCOE only provides a partial indication of competitiveness, and investment decisions are usually based on additional financial information. In practice, real-world investors consider the net present value (NPV) of a project, among other financial ratios, to assess whether its expected cash flows satisfy their risk-adjusted return expectations (IEA, 2014a).

While comparing the cost of energy for various electricity-generating technologies, LCOE may not take into account the value of electricity, which depends on the time and location of production, the market frameworks under which different technologies compete, or the recovery of fixed network

⁷ 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.

costs. The market conditions in which renewables operate can have a significant impact on their bankability. For example, in markets with good resources, good financing conditions and rising demand, some renewables are able to compete under market design of wholesale pricing. For other markets, renewables may find it difficult to recoup their costs with wholesale prices, even as their generation costs decline. In such markets, renewables would be remunerated at marginal prices according to the prevailing, short-term demand-and-supply balance. Furthermore, the presence of an increasing share of low-marginal-cost renewables in the power mix can put downward pressure on wholesale prices. This competitiveness picture differs from market to market, with underlying demand patterns, the nature of the existing generation mix, and the presence of interconnections and storage playing a role in determining the value that renewables bring to the power system. As such, LCOE comparisons may present a simplistic view of competitiveness. Nevertheless, they can remain a useful metric to give broad indications of technology cost movements over time.⁸

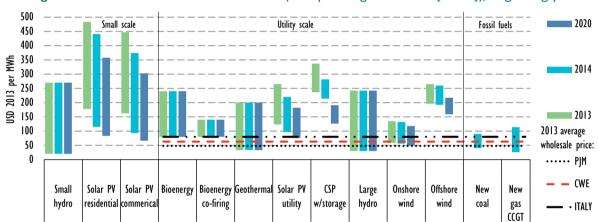


Figure 62 Historical and forecasted LCOEs (USD per megawatt hour [MWh]), beginning year

Notes: CSP = concentrated solar power; CCGT = combined cycle gas turbine. Wholesale power prices are expressed as the annual average of daily traded, day-ahead base-load power prices. CWE (Central Western Europe) refers to annual average of power prices in France, Germany, Austria and Switzerland. United States (US) PJM refers to the regional transmission organisation covering parts of 13 states in the mid-Atlantic and Midwest portion of the United States. LCOEs reflect typical system costs for selected technologies. Costs are indicative and ranges reflect the system cost, resource and financing differences among countries. Geothermal LCOE range includes only conventional and binary plants.

Source: IEA analysis with 2013 wholesale electricity price data from Bloomberg LP (2014), accessed 01 June 2014; and EIA (Energy Information Administration) (2014), Wholesale Electricity and Natural Gas Market Data accessed 20 May 2014, Washington D.C.

With decreasing system costs, competitive opportunities are expanding for some renewable energy technologies under country-specific market conditions and policy frameworks in place. In Brazil, with good resource and financing conditions, onshore wind has consolidated its competitive position, continuing to outbid new-build natural gas plants in auctions over the last year. In Australia, wind is already competitive with new-build coal- and gas-fired power plants. In Turkey and New Zealand, onshore wind has been competing with other technologies in the wholesale power market without strong economic incentives. In South Africa and Chile, with good wind resource and long-term power purchase agreements (PPAs), onshore wind is the preferable option against new gas and coal power plants to meet growing power demand.

⁸ A more detailed discussion on the methodological approach to LCOEs can be found in the study *Projected Cost of Generating Electricity* (IEA and NEA, 2010). An updated version of this study is to be released in 2015.

Geothermal and most hydropower remain competitive with their fossil-fuel alternatives under favourable resource conditions. As a proven mature technology, large-scale bioenergy plants are also competitive depending on feedstock prices and availability, while the attractiveness of co-firing with biomass in coal and gas power plants has been increasing.

Falling system prices and rising annual deployment mark the trend for solar PV development. While module price decreases have flattened somewhat, cost reductions in other supply chain parts are stimulating more competitive applications through greater self-consumption and/or market exposure. Utility-scale solar PV can be competitive in sunny countries with daytime peak demand, particularly when peaks are met by burning oil products (though oil price subsidies may distort this perception). In oil-exporting countries, solar generation is cheaper when the opportunity cost of not selling oil on the international market is considered (e.g. Saudi Arabia). In Chile, high wholesale electricity prices and good irradiation levels have opened a new merchant solar PV market. There, the world's first merchant utility-scale solar PV plant was interconnected and another was financed over the past year; both projects are to sell electricity to the wholesale market without a PPA.

Falling distributed solar PV costs are supporting the emergence of competitive market segments in both commercial and residential sectors linked to the concept of grid or "socket" parity – when the LCOE of distributed solar PV systems is lower than the variable portion of retail electricity prices that system owners would otherwise pay (see "Special focus: Solar PV reaching socket parity" later in the chapter). Still, increasingly strong growth of solar PV is raising debates over the system integration of distributed generation, especially in the United States and Europe. As more rate-payers generate their own electricity from solar PV, they consume less electricity from the grid, contributing less to the remuneration of overall grid costs where these are charged per unit of energy consumed. This situation has raised several issues concerning fair rules and appropriate electricity rate design for allocating the costs (e.g. recovery of fixed grid costs) and benefits from fast-growing distributed solar PV. Off-grid installations are often competitive in locations where they compete with diesel generators, especially in Africa and India. The cost and availability of financing remains a major challenge in such remote areas. Yet innovative financing methods, such as "pay-as-you-go" business models, have emerged to facilitate investment in off-grid applications supporting rural electrification.

Still, policy remains vital to the competitiveness of renewable energy technologies. Even in situations of good competitiveness, policy, market and technology risks can undermine project viability. Policy uncertainty remains a key challenge to renewable deployment. Unanticipated changes to incentive schemes represent a risk that investors cannot manage, and can lead to elevated financing costs and boom-and-bust development patterns. In addition, non-economic barriers, integration challenges, grid connection risk, and macroeconomic and currency risks can all increase financing costs and weigh upon investments. In markets based on short-term marginal pricing, remuneration flows can be uncertain, and capital-intensive technologies, such as renewables, can often require financial incentives. By contrast, renewable power capacity is being deployed with little financial support in some areas with rising energy needs, good resources and predictable long-term policies. Market design based on competition over long-term contracts (as being developed in Brazil and some other Latin American countries, for example) is one way that is sustaining investment.

Bioenergy for power

Technology development

Bioenergy for power generation, including the use of solid biomass, biogas, renewable waste and liquid biofuels, is a generally mature technology, though some conversion routes such as the biomass integrated gasification with combined-cycle have not yet reached full commercial market penetration. Limited by the availability of biomass in relative proximity to the power plant, most bioenergy projects are small to medium size (10 MW to 50 MW), and are typically operated in co-generation plants are common in biomass-processing industries such as pulp and paper, or the sugar cane industry, where process residues are available free of charge and heat from the co-generation plant can be used directly for the production processes (see "Renewable Heat" chapter for more details).

In recent years, a number of utilities have invested in biomass power generation, in particular in the form of co-firing, where a share of biomass is co-fed into a coal-fired power plant. Co-firing offers a transition towards bioenergy-only generation, particularly in markets moving away from coal-fired generation. In addition, some coal-fired plants in the United Kingdom and also in France, which are nearing the end of their lifetime due to new emission regulations, are being converted to run entirely on biomass.

Due to transportation costs, small-scale power plants are typically supplied with biomass residues available on-site or biomass sourced in relative proximity (up to 100 kilometres [km]) of the plant. With annual biomass demand in the order of mega-tonnes, large-scale plants typically rely on wood pellets that are often shipped internationally and are delivered to the plant via ship or train. Wood pellet supplies are usually secured through long-term supply contracts, but some utilities started to invest in wood pellet production capacity, such as RWE, which operates a plant in the US state of Georgia. As a result, trade in wood pellets has accelerated, particularly from Canada and the United States to Europe, to meet increasing demand from biomass conversions and co-firing (Box 5).

The costs of bioenergy power generation depend on the technology and operational scale as well as the quality, type, availability and cost of biomass feedstocks. They also vary with the pattern of energy demand (e.g. if there is steady demand for heat from co-generation). The investment costs for a biomass plant with capacity above 50 MW are between USD 2 400 per kilowatt (kW) and USD 4 200/kW. The capital costs of co-firing are much lower (USD 300/kW to USD 700/kW, depending on configuration). In both cases, plants will be operated as mid-merit or base load – the latter particularly in co-generation (seasonal operation patterns can occur for plants linked to a district-heating scheme). In favourable circumstances, generation costs from co-firing of internationally traded fuels (USD 80/MWh to USD 140/MWh) can be close to coal generation. Dedicated biomass electricity generation costs (USD 110/MWh to USD 240/MWh) are currently competitive with fossil-based electricity with high carbon prices. The use of residues as feedstock can reduce costs to USD 80/MWh (IEA, 2012a).

Market status and outlook

In 2013, biomass power generation reached an estimated 396 TWh, up from 379 TWh in 2012 (+4.3% year-on-year). The United States remained the largest producer (64 TWh in 2013), followed by Germany, where 48 gigawatt hours of bioenergy power were generated, supported by feed-in tariffs (FITs) under the Renewable Energy Sources Act (EEG). OECD Europe bioenergy power generation in

 $^{{}^{9}\}text{Co-generation}$ refers to the combined production of heat and power.

general continues to increase, driven primarily by targets established under National Renewable Energy Action Plans of EU member states. Growth was slow in 2013, however, reaching an estimated 152 TWh, up from 151 TWh a year earlier.

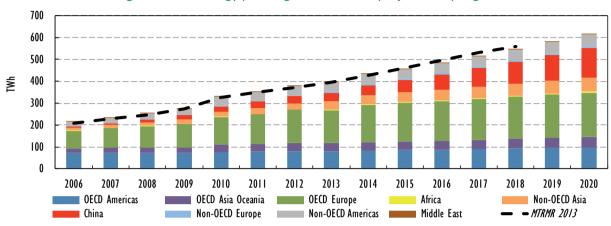


Figure 63 Bioenergy power generation and projection by region

Note: includes generation from renewable municipal solid waste.

Box 5 Wood pellets – a niche product becoming an energy commodity

Current status

Driven by the increasing demand for bioenergy heat and power, world wood pellet production grew from less than 2 million tonnes (Mt) in 2000 to around 22 Mt in 2012, with global production capacity reaching 42 Mt (AEBIOM, 2013). Wood pellets are typically produced from sawmill residues and increasingly from low-quality wood. As they provide a relatively energy-dense standardised fuel with low moisture content (<10%) and high combustion efficiency, wood pellets are well suited for long-distance transport by train or ship.

The strongest increase in production has taken place in the European Union, at the same time the biggest consumer of wood pellets, due to support policies for renewable electricity, including co-firing, and incentive mechanisms for pellet heating systems in a number of member states. North America, led by the United States, is the second major producer of wood pellets, with much of the growth in production driven by increasing demand in the European Union. Emerging markets such as Russia, China and others have only recently started pellet production and thus produce only comparably small volumes to date.

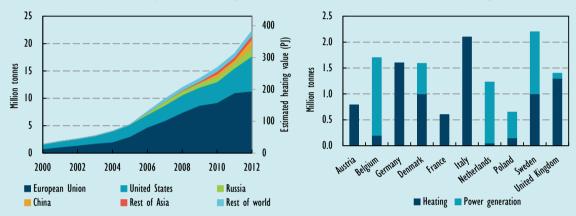
In the European Union, demand for wood pellets grew at an average of 25% per year and reached an estimated 19 Mt in 2013. Overall, demand is split equally between power generation and heat production, but this ratio varies significantly among countries. In markets with rapid growth in wood pellet heating systems, such as Austria, Germany, Italy and France, pellets are mainly used for heating. Their use for power generation dominates in markets with strong growth in co-firing as well as bioenergy power generation in dedicated biomass plants, such as Belgium, the United Kingdom, the Netherlands and Poland (AEBIOM, 2013). As some countries are reaching their pellet production limits due to constraints in resource availability, imported wood pellets are gaining importance. As a result, around 8 Mt of wood pellets were traded internationally in 2012, with much of those being imported to Europe from North America and Russia. In addition, new importing markets in Japan and South Korea are slowly gaining importance and see increasing volumes of pellets being imported.

Box 5 Wood pellets – a niche product becoming an energy commodity (continued)

Market Outlook

Over the medium term, global wood pellet demand is expected to continue to increase and may reach up to 45 Mt in 2020 (Pöyry, 2013). Amid large feedstock potential, production in North America can still be expanded significantly, whereas expansion potential is more limited in Europe, Russia and Oceania. Rather, new market players are expected to enter the arena, with China becoming one of the largest producers of pellets, including from agricultural residues driven by increasing domestic demand (IEA, 2014b). Wood pellet production is also expected to grow in Brazil and other non-OECD Americas markets, with export opportunities being the main driver.

Figure 64 Global wood pellet production 2000-12 (left) and wood pellet consumption by energy sector in the major consuming countries in the European Union 2012 (right)



Note: a lower heating value of 17 gigajoules per tonne of wood pellets is assumed here.

Sources: REN21 (Renewable Energy Policy Network for the 21st Century) (2013), *Renewables 2013: Global Status Report*, REN21, Paris; AEBIOM (European Biomass Association) (2013), *European Bioenergy Outlook 2013*, AEBIOM, Brussels.

The European Union should remain the largest consumer of wood pellets globally driven by a significant increase in wood pellet demand in the United Kingdom resulting from the conversion of several coal-fired power plant units, as well as the continued growth in wood pellet heating installations throughout a number of EU member states. Furthermore, growth in bioenergy power generation and, to a smaller extent, heating in Japan and Korea will drive demand in these countries that is likely to be met by mostly by imports.

In China, bioenergy power generation was up 5 TWh year-on-year (+15%) and reached an estimated 39 TWh in 2013. Developments in China continue to be driven by incentives for co-firing of agricultural residues and waste-to-energy projects, among others. India, too, continues to expand its bioenergy power generation, and generated an estimated 24 TWh in 2013, up 4 TWh compared with 2012. Brazilian bioenergy power generation reached an estimated 38 TWh in 2013, driven among others by a bumper sugar cane crop that boosted bagasse-fired co-generation. Total non-OECD generation was up by an estimated 16 TWh year-on-year and stood at 127 TWh in 2013.

Over the medium term, bioenergy power generation capacity is expected to further increase in both OECD and non-OECD markets, reaching over 130 GW globally in 2020, up from 88 GW in 2013. Bioenergy capacity in the non-OECD is expected to surpass that in the OECD by 2020. Global bioenergy

power generation is projected to reach 615 TWh in 2020, up 220 TWh from 2013 (+6.5% per year). Much of this growth is coming from China, where capacity increases more than threefold to 30 GW in 2020 driven by targets in the 12th Five-Year Plan, with generation reaching an expected 135 TWh. Other non-OECD markets such as India (38 TWh in 2020), Thailand (7 TWh in 2020) and Indonesia (5 TWh in 2020) continue to grow on the back of good biomass potential combined with growing demand for electricity, and in some cases support policies for biomass power generation. Waste-to-energy projects, too, play an increasing role in many emerging economies. In Brazil, growth in bioenergy power generation is expected to slow down compared with recent years, as sugar cane bagasse-fired co-generation is not expected to grow substantially due to the sugar cane sector's difficult economic situation (see "Renewable Transport" for more details), which is expected to limit substantial new investments in the coming years.

Table 42 Bioenergy capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	53.9	55.7	57.3	59.1	60.9	62.6	64.3	66.0
OECD Americas	15.7	16.2	16.4	16.9	17.3	17.8	18.3	18.8
OECD Asia Oceania	2.8	2.9	3.2	3.3	3.5	3.7	3.9	4.1
OECD Europe	35.4	36.5	37.7	38.9	40.1	41.1	42.1	43.2
Non-OECD	33.8	37.0	40.2	44.6	49.6	55.2	61.0	66.6
Africa	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.8
Non-OECD Asia	10.6	11.3	12.3	13.4	14.4	15.5	16.5	17.6
China	8.5	10.5	12.5	15.5	19.0	22.5	26.0	29.5
Non-OECD Europe	1.8	1.8	1.9	1.9	2.0	2.1	2.1	2.2
Non-OECD Americas	11.6	11.9	12.0	12.1	12.4	13.2	14.2	15.2
Middle East	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.4
Total	87.6	92.7	97.4	103.7	110.5	117.8	125.3	132.7

Note: does not include co-firing capacity; though conversions are included in this forecast, reported capacity data from IEA statistics may not include bioenergy capacity converted from fossil fuels, particularly in mixed plants.

OECD bioenergy electricity generation is expected to reach near 350 TWh in 2020, up from 270 TWh in 2013. Targets for renewable energy in OECD Europe will continue to act as the main driver for this growth and drive a roughly 50 TWh increase in generation from 152 TWh in 2013 to 202 TWh in 2020. Strong growth is projected in particular for Denmark and Poland, with Poland focussing on co-firing in coal-fired power plants. Furthermore, well-established markets such as Finland, Sweden and the United Kingdom continue to grow, the latter driven in a large part through conversions of coal-fired power units to bioenergy. In Germany, where growth in bioenergy, and particularly biogas-based generation, was steady in recent years, a draft on the revision of the EEG includes a limit for capacity additions of 100 MW per year, thus potentially significantly slowing an increase in generation over the medium term.

In other OECD regions, Japan continues to expand its waste-to-energy generation in addition to an increasing use of wood pellets for co-firing as well as in dedicated biomass power plants. In North America, low natural gas prices continue to challenge bioenergy's competitiveness versus existing generation, but legislation such as the phase-out of coal-fired generation in Ontario and the expected retirement of large amounts of coal capacity in the United States is expected to continue to drive some growth over the medium term. Thanks to the vast availability of relatively low-cost biomass feedstocks, both the United States and Canada are expected to continue to expand production capacity for wood pellets for export to Europe and elsewhere.

Geothermal power

Technology development

With a large estimated resource potential, geothermal technology can provide base-load power from energy stored in rock, trapped vapour and liquids. Typically, the development of a geothermal project takes five to seven years from exploration stage to commercialisation. This long lead time raises particular challenges for project development. As the early-stage development costs consist of around half of total project investment, developers need to raise and spend capital before being confident that a site is economically feasible to generate electricity continuously over the economic lifetime of the project. However, debt financing is typically not available for this stage. Thus, developers need to initially finance with equity and bear the investment risk, which can act as a barrier to deployment. While only a few governments in developed countries currently provide exploration risk insurance, the International Finance Corporation (IFC) has started to co-operate with private insurance firms in order to offer products in developing countries, which aim at decreasing early-exploration risks. In April 2013, the IFC and Munich Re, an insurance firm, signed an agreement to provide insurance to four pilot projects in Turkey.

Enhanced geothermal systems (EGS) have remained the main research, demonstration and development (RD&D) area in the industry over the last few years. In 2013, Geodynamics' Haberno geothermal project (1 MW) generated electricity from an EGS development, the first in Australia. There is another 1.5 MW demonstration project in France that is generating electricity from deep fractured rocks. Although many countries are involved in cross-cutting RD&D activities, EGS technologies are currently nascent. The degree to which commercial-scale deployment in existing plants or on a stand-alone basis will transpire over the next five years is uncertain.

Costs of geothermal plants are site- and project-specific. Typical operation and maintenance (O&M) costs vary significantly depending on the plant. Typical capital costs of a high-temperature geothermal electricity plant range from USD 2 000/kW to USD 5 000/kW. The capital costs of binary plants range from USD 2 400/kW to USD 5 900/kW. Still, generation costs from high-temperature geothermal resources are competitive with fossil-fuel alternatives, in part due to high capacity factors (average capacity factors range from 60% to 90%, depending on area) and when taking into account levels of exploration and development priced into the investment costs above. Generation costs for geothermal plants range from USD 35/MWh to USD 200/MWh, with generation costs of binary plants at the high end of the range.

Market status and outlook

In 2013, geothermal power generation stood at 73 TWh, while the cumulative capacity reached near 12 GW. Newly installed capacity was around 0.5 GW in 2013. The United States, Indonesia and New Zealand together accounted for more than two-thirds of global additions.

Global geothermal power capacity is expected to rise to over 16 GW in 2020. The global outlook is broadly in line with the *MTRMR 2013*. The largest deployment should take place in Indonesia with over 1 GW of new plants coming on line by 2020. The United States should add another 600 MW, bringing its total to 4 GW, while the Philippines is expected to deploy 420 MW over the projection period, reaching around 2.3 GW. Japan's forecast is revised down due to expectations of slower development of large-scale projects, which have significant permitting requirements, though the FIT is still in place. Some medium-sized developments, which enjoy higher FIT levels and have lower permitting requirements, are under way. Thus, Japan should add 160 MW over the medium term,

bringing its total capacity to 0.7 GW. Finally, Mexico is expected to deploy 300 MW, to reach 1.25 GW of cumulative capacity in 2020, and some capacity growth is expected in Chile as well.

Table 43 Geothermal power capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	7.4	7.6	7.9	8.2	8.5	8.8	9.0	9.3
OECD Americas	4.3	4.5	4.6	4.8	5.0	5.1	5.3	5.4
OECD Asia Oceania	1.4	1.4	1.4	1.5	1.5	1.6	1.7	1.8
OECD Europe	1.7	1.8	1.8	1.9	1.9	2.1	2.1	2.1
Non-OECD	4.3	4.5	4.8	5.3	5.6	6.0	6.4	7.0
Africa	0.2	0.2	0.4	0.6	0.7	0.7	8.0	1.0
Non-OECD Asia	3.4	3.5	3.7	3.8	4.1	4.3	4.6	4.8
China	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Non-OECD Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-OECD Americas	0.6	0.6	0.6	0.7	0.7	8.0	8.0	0.9
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	11.8	12.1	12.7	13.5	14.1	14.7	15.4	16.3

Sources: IEA analysis; 2013 data are IEA estimates based on IEA statistics, BP (2013), BP Statistical Review of World Energy 2013, BP, London; and Platts (2014), World Electric Power Plants Database December 2013 edition, McGraw-Hill Companies, New York.

On the generation side, geothermal resources should provide around 104 TWh globally in 2020. Over the medium term, OECD's share in overall generation slightly decreases while the generation in non-OECD markets, mainly in Southeast Asia, Africa and Latin America, should expand, reaching 44 TWh in 2020.

120 100 80 ¥ 60 40 20 0 2016 2011 2013 2018 2006 2007 2008 2009 2010 2012 2014 2015 2017 2019 2020 **OECD** Americas OECD Asia Oceania OECD Europe Africa Non-OECD Asia Non-OECD Americas MTRMR 2013 Non-OECD Europe China Middle East

Figure 65 Geothermal power capacity and projection by region (TWh)

Hydropower

Technology development

Hydropower is a mature technology, and is the largest current source of renewable power in the world. Plants come in many different shapes and sizes and are often classified by three parameters: function, size and hydraulic head. Classification by function falls broadly into three categories: run-of-river, reservoir and pumped storage plants (PSPs). The difference between them depends largely on the quantity and availability of water to generate power. In size, the names "large", "medium" and "small" are used to demarcate magnitudes of the capacity, which can range from a few kilowatts up to gigawatts. However, the naming conventions are subjective because a harmonised classification

system of the sizes does not exist. Finally, one of the most important categorisations is by the hydraulic head, a parameter related to the potential energy of the falling water. Hydraulic heads can be as high as 1 800 metres (m) or less than 20 m, and often dictate the type of turbine employed. These characteristics enable hydropower plants to play a versatile role in the power system, ranging from a source of base-load power to meeting peak demand from storage.

Box 6 Evolving landscape for pumped storage hydropower

Pumped storage hydropower plants (PSPs) are often overlooked in energy policies, yet their flexibility in balancing generation from variable renewables has drawn attention in recent years. Most PSPs pump water up to reservoirs during off-peak periods when excess power supply is available and electricity prices are low. Electricity is then "stored" as potential energy until demand is high and the water is released back down to generate electricity for sale when it has a higher value during peak periods. Although the system is a net consumer of electricity, the ability to provide electricity on demand for frequency regulation, load following, peak reduction and other ancillary services provides it value.

Estimates of current global installed capacity range from 129 GW to 140 GW, a wide span due to the difficulty in classifying PSPs (Platts, 2013; IEA, 2014c). At the most general level, PSP capacity can either be designated as pure or mixed, the difference being the presence of a natural inflow of water. Pure PSPs do not have natural inflows. They pump water from one reservoir to a separate, second reservoir and release it back down to generate electricity.

Mixed hydropower plants, on the other hand, use both a natural inflow of water and a pumping system between two reservoirs to generate electricity. Yet even this criterion can be ambiguous to use as the inflow may or may not be substantial and can be located in the upper reservoir and/or lower reservoir. In one study, as many as seven different topologies for PSP have been identified (Gimeno-Gutiérrez and Lacal-Arántegui 2013). Furthermore, the ability of mixed plants to act as both a conventional hydropower plant and a PSP can introduce considerable uncertainty in accounting for PSP capacity and result in large variations in statistics (Punys et al., 2013). In 2014, the IEA Energy Data Centre and Eurostat began separate accounting for the two PSP topologies in OECD countries in an attempt to better monitor deployment and understand their evolution in different markets.

Total PSP deployment in the OECD grew at 0.9% over the period of 2001-11, reaching 100 GW in 2011, of which 71% were classified as pure PSP and 29% mixed. In OECD Americas' largest market, the United States, saw roughly the same growth, with total PSP capacity expanding at only 1% over 2000-11. A boom in relatively cheap natural gas power generation and the effect on peak prices has likely undermined the business model of PSPs there.

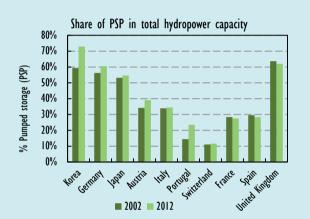
Outside of the United States, individual countries experienced different dynamics that lead to recent PSP growth. In Austria, Germany, Portugal, Switzerland, Japan and Korea, the share of PSPs in hydropower capacity grew in 2012 relative to 2002, driven by several factors. In Portugal and Germany, the need for greater flexibility to balance the variability from increasing shares of wind generation in both countries drove expansion. Portugal also has national targets to double PSP capacity by 2020.

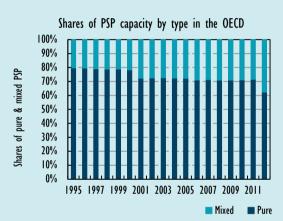
Both Switzerland and Austria have geographical topologies with natural elevations well suited for inexpensive PSPs that remain unexploited. They are also strategically positioned within Europe for power trading and regional balancing. Rising demand and the continent's need to balance system-wide increases in wind penetration increase the attractiveness of PSPs for these countries. In Japan, a need to meet local rising peak demand has been the driver in recent years. The ability of PSPs to ramp up when needed to provide power on demand is a main driver of deployment.

Box 6 Evolving landscape for pumped storage hydropower (continued)

The growth of PSPs depends on many factors, one of which is economic attractiveness of the plant's topology. Capital costs for PSPs are site-specific and can range from USD 500/kW to USD 4 600/kW, depending upon the amount of storage at the site (IEA, 2012b). New PSP plants require feasibility studies, extensive permitting, and construction of new reservoirs and supporting infrastructure, which have a cost. Recent studies have shown a trend towards the refurbishment of existing plants and conversion of conventional hydropower to mixed plants because the existing infrastructure lowers the overall cost of civil works (Deane, Gallachóir, McKeogh, 2010). Modifying existing plants is also more attractive because it is likely to require less permitting. Some estimates of current LCOEs for PSPs are less than USD 200/MWh (IEA, 2014c), although the plant's ability to generate electricity from a natural inflow of water during excess flow may have a large influence on the range.

Figure 66 Shares of PSP capacity in hydropower capacity in selected OECD countries in 2002 and 2012 (left) and share of mixed and pure PSP capacity in the OECD total 1995-2012 (right)





Ultimately, the economic attractiveness of PSPs depends on the available revenue streams that can recover these costs, which can be uncertain. Historically the main revenue stream for pumped storage has been electricity trading or energy arbitrage when electricity was bought low to pump and sold high when prices were attractive. For arbitrage to be profitable though, the ratio of pumping price to selling price should be roughly 67% to 75% (Deane, Gallachóir, McKeogh, 2010). Yet in some markets, these margins are shrinking. In the United States, cheap natural gas for power generation has driven down peak power prices, while in Europe the flattening of the differential between low and high prices has been driven by increased penetration of low-marginal-cost renewable sources.

Remuneration of the ancillary services that PSPs provide to help balance the system is sometimes insufficient or non-existent in some markets. PSP flexibility is not properly valued in some markets due to regulatory barriers. Furthermore, the overall system cost savings that PSPs can provide by prevention of costly thermal plant ramp-ups is not paid to PSP plants. Double grid fees for producing and consuming can function as additional constraints on project bankability. Yet there is some progress to overcome market barriers. For example, FERC Order No. 755 issued in the United States obliges the remuneration of PSPs for providing frequency response.

Over the medium term, the drivers for PSP deployment include the need for more flexibility to accommodate increasing penetrations of variable renewables and the need to meet a growing peak demand. However, the high cost of PSPs against insufficient financial incentives and valuation for the services they provide can undermine their economic attractiveness and project bankability. This may create an uncertain future for the development and deployment of new PSPs over the medium term.

The costs of hydropower plants span a wide range. Parameters such as size, site and technology vary with each new plant, making the final expenditures project-specific. Costs for typical, new large hydropower plants can range from around USD 900/kW to USD 3 500/kW and even higher in some cases. Smaller projects can range from as low as USD 1 000/kW to over USD 6 000/kW, with some smaller and higher values observed on both ends of the range. Other particular costs can include feasibility and environmental assessments as well as the building of new infrastructure to accommodate project construction. Generation costs depend on several parameters such as capital cost, financing and full load hours. Estimated LCOEs for new plants range from as low USD 20/MWh to USD 230/MWh based on size, with smaller plants in Europe potentially more expensive. Refurbishment of older plants with newer turbine technology available can substantially increase the efficiency of generation and decrease the cost per unit output. In sub-Saharan Africa, where many of the plants are quite old and inefficient, refurbishment of older plants may offset the need to invest in newer projects.

While controversy over some hydropower plants has raised socio-economic concerns in the past, some large projects have drawn attention again in a more positive light as "cross-border" projects. Cross-border projects are those where a plant is constructed in one country with high-quality resources and the electricity is sold to a neighbouring country with a high demand (Doran and Christensen, 2014). These projects are often part of regional initiatives in Latin America, Asia and Africa to increase power supply and stimulate economic development of the region. With support from multiple stakeholders, they usually have less difficulty finding financing than other large hydropower projects, as the risk can be split over multiple off-takers. Projects such as the 1 GW Nam Theun 2 hydroelectric project between Laos and Thailand, the 1.5 GW Mphanda Nkuwa scheme in Mozambique, and the Inga III (3.6 GW) in the Democratic Republic of Congo are all considered transformational projects for their respective regions and have attracted financiers more easily than others of similar size. Still, such projects are not without challenges; for example, the 4.8 GW Grand Ethiopian Renaissance dam under development faces technical and financial challenges and controversy with neighbouring states.

Market status and outlook

Hydropower capacity grew by approximately 41 GW in 2013, almost entirely from non-OECD countries, bringing the global total to almost 1 135 GW, including pumped storage. China continued to lead the growth by adding 31 GW alone, including 7 GW of the partially complete Xiluodu, which began operation in mid-2013. When complete, estimated by 2015, the plant will total 10 GW and be the third-largest station globally behind Three Gorges and Itaipu. Brazil added roughly 1.7 GW in 2013. The OECD added 3.6 GW, led by Spain and Turkey, which each commissioned over 1 GW of projects in 2013.

Over the medium term, capacity is seen expanding by 225 GW, growing by 2.6% annually over 2013-20. Almost half of the growth, 105 GW, is expected from China, which is targeting 420 GW cumulative hydropower capacity by 2020. Non-OECD Americas and Asia are each expected to add roughly 35 GW to 37 GW each. Africa is expected to add approximately 15 GW, and have the highest annual growth rate at 6.6% over 2013-20, due to the lower baseline. A fair amount of unexploited potential remains in Africa, which has attracted interest in major projects such as the 1.9 GW Gilgel Gibe III, the 3.7 GW Mambilla, and the 1.5 GW Mphanda Nkuwa, which are under development and expected to be commissioned by 2020. Canada and Turkey should also see several gigawatts of growth, 11.7 GW combined, making up more than 50% of the hydropower growth in the OECD over the medium term. Sustainability and socio-economic concerns can still represent a challenge for development. For example, in June 2014, the Chilean government cancelled the environmental permit for the planned 2.7 GW HidroAysén plant, citing potential negative externalities on the local environment and population that the project could not sufficiently mitigate.

Table 44 Hydropower capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	469	474	479	482	485	488	490	492
OECD Americas	195	197	199	200	201	203	203	204
OECD Asia Oceania	69	70	70	70	70	70	70	71
OECD Europe	204	207	210	212	214	216	217	217
Non-OECD	664	694	725	754	785	818	842	867
Africa	27	30	32	33	34	37	39	42
Asia	101	109	114	118	123	132	135	138
China	280	290	305	322	340	355	370	385
Non-OECD Europe	96	98	100	101	101	102	103	103
Non-OECD Americas	146	151	158	163	168	175	177	181
Middle East	14	16	16	17	17	17	18	18
Total	1 133	1 168	1 203	1 237	1 270	1 307	1 333	1 360

Sources: IEA analysis; 2013 data are IEA estimates based on IEA statistics; Platts (2014), World Electric Power Plants Database December 2013 edition, McGraw-Hill Companies, New York; and International Journal on Hydropower & Dams (2013), 2013 World Atlas & Industry Guide, Aqua Media International Ltd., Surrey, United Kingdom.

Figure 67 Hydropower capacity and projection by region

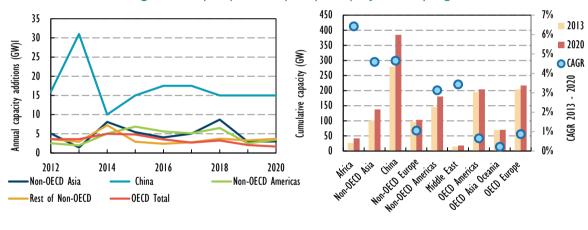
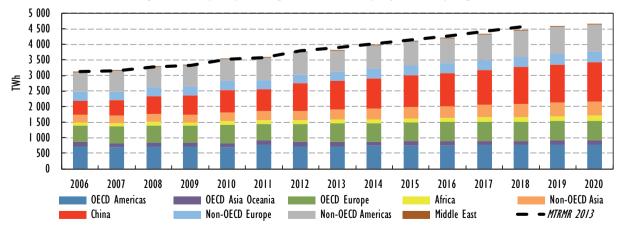


Figure 68 Hydropower generation and projection by region



Global hydropower generation, including output from pumped storage, is expected to grow at a similar pace as capacity additions at 2.9% annually over 2013-20, although the dynamics vary by country.

Total hydropower generation should reach 4 670 TWh by 2020 with non-OECD accounting for two-thirds of the output. China alone should account for 27% of global hydropower generation by 2020, expected to reach almost 1 270 TWh. However, this number is largely dependent upon how China plans to use its pumped storage capacity over the medium term. Of the 105 GW additional hydropower capacity expected by 2020, around one-quarter of this is expected to be pumped storage, which has a utilisation rate lower than conventional hydropower plants. Historical utilisation rates in China show load factors around 10%, but with larger penetration of variable renewables expected over the medium term, China could rely more upon the pumped storage units that are planned. Higher capacity factors in the range of 15% to 20% would have a substantial impact on the overall total hydropower generation by 2020.

Ocean power

Technology development

With a small absolute contribution, ocean power is expected to scale up from small to medium-size demonstration projects in several countries, an important step towards commercialisation.

Overall, the resource potential for ocean technologies is significant and widespread. Ocean power encompasses different types of technologies that could exploit the following phenomena: tidal range (rise and fall), tidal and ocean currents, waves, ocean thermal energy conversion, and salinity gradients. Tidal and wave projects provide variable but highly predictable power. Only tidal barrages, exploiting tidal rise and fall, are a mature technology, with global installed capacity of 0.5 GW. The technology can face environmental controversy, as tidal barrages consist of large dam-like structures, so far built across bays or estuaries.

Most other ocean power technologies would be modular and would have smaller visual impact. Tidal/ocean currents and wave power are at the demonstration stage, with multiple megawatt-scale projects being tested. Temperature and salinity gradient technologies remain at the research and development (R&D) stage. As of 2013, there were ten wave and tidal single-device test machines operational ranging from 250 kW to 1 000 kW in the European Marine Energy Centre (EMEC), the largest ocean energy test centre in the world. The SeaGen device in the United Kingdom, commissioned in 2008, remains the largest operational tidal stream generating capacity. Since mid-2011, the 300 kW Mutriku wave plant has been in operation in Spain. Several governments and the European Union continue to fund technology demonstration projects. Over the medium term, activities are likely to focus on moving development from the device level to constructing more arrays and, ultimately, commercial-scale projects.

In their demonstration stage, most ocean energy technologies remain relatively expensive. A detailed cost analysis for wave energy that was conducted for the US Department of Energy concluded that costs could decrease significantly as technology moves towards more commercial scale. The study estimated that the total capital expenditure for a 5 MW wave energy plant is around USD 7 000/kW; however, costs could be decreased to around USD 4 500/kW for a 50 MW plant (Previsic, 2012). Generation-cost data remain sparse. The UK government has estimated the LCOE in 2025 at GBP 230/MWh to GBP 275/MWh for wave; GBP 150/MWh to GBP 250/MWh for tidal stream, depending on depth; and GBP 120/MWh to GBP 190/MWh for tidal barrage projects (DECC, 2013). The IEA Implementing Agreement for a Co-operative Programme on Ocean Energy Systems (IEA-OES) has commenced a project to deliver a reliable and credible LCOE assessment for ocean technologies (IEA-OES, 2014).

Market status and outlook

Ocean power has a large potential to scale up in the long run, but faces challenges in the transition period towards widespread commercialisation. Broadly, the greatest barriers pertain to the relatively high investment costs of ocean technologies, difficulty in sourcing economically attractive financing, and challenges obtaining grid connections and permitting for both individual devices and, ultimately, larger, interconnected offshore energy systems involving many projects. Government incentives would need to play a key role in helping to overcome these issues, but beyond R&D and technology testing programmes, ocean-specific support policies remain generally underdeveloped across a number of markets with good potential.

2014 2016 2013 2015 2017 2018 2019 2020 0.53 0.89 **OECD** 0.53 0.53 0.53 0.69 0.95 1.02 **OECD** Americas 0.02 0.02 0.02 0.02 0.02 0.03 0.03 0.03 OECD Asia Oceania 0.26 0.26 0.26 0.26 0.41 0.61 0.66 0.71 OECD Europe 0.25 0.25 0.25 0.25 0.26 0.26 0.27 0.28 Non-OECD 0.00 0.00 0.00 0.00 0.01 0.01 0.01 0.01 Africa 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 Non-OECD Asia 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 China 0.00 0.00 0.00 0.00 0.01 0.01 0.01 0.01 Non-OECD Europe 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 Non-OECD Americas 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 Middle East 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.53 0.53 0.70 **Total** 0.53 0.54 0.90 0.96 1.02

Table 45 Ocean power capacity and projection by region (GW)

Sources: IEA analysis; 2013 data are IEA estimates based on IEA-OES (Implementing Agreement for a Co-operative Programme on Ocean Energy Systems) (2014), Annual Report 2013, IEA-OES, Lisbon.

Since the commissioning of the Sihwa Lake tidal barrage (254 MW) in Korea in 2011, no large-scale projects have been deployed. In 2013, global cumulative capacity is estimated at 0.5 GW. While the largest share of this total capacity consists of two plants in France and Korea, megawatt-sized capacity exists in other markets, including China, Canada, the United Kingdom and Australia. Total power generation was estimated at almost 1.0 TWh.

Over the medium term, ocean energy should expand by around 0.5 GW, with cumulative capacity reaching over 1.0 GW in 2020. High costs and challenges for the deployment of commercial-scale capacity mean that expansion should be modest relative to other renewable technologies, and the outlook has been revised down versus *MTRMR 2013* due to slower-than-expected project development. Indeed, anticipating developments carries a degree of uncertainty. For example, a 3 MW wave project expected in *MTRMR 2013* in Mexico for late 2013 appears to be no longer under development. Although a number of countries have established R&D and ocean technology testing programmes, medium-term growth is likely to be led by Korea, the United Kingdom, Canada, France and Ireland, where investor plans and support policies appear most robust.

In Korea, development is supported by a renewable portfolio standard with technology-specific tradable certificates for tidal barrages (but not other ocean technologies) and a national energy master plan. Developers have announced ambitious plans (around 3 GW) to deploy several large-scale tidal barrages over the medium term, but it is unknown how many of these will proceed. Accordingly, Korea's ocean

power capacity is seen increasing by more than 0.4 GW over 2013-20, though some developments will face the challenge of balancing environmental concerns related to local wetland impacts.

Many demonstration projects have been deployed in the United Kingdom, but it remains to be seen whether any large projects will be fully deployed over the medium term. There, new ocean developments would primarily benefit from the government's contract for difference scheme, whose strike prices published in December 2013 indicate that new wave and tidal stream projects coming on line from 2014-19 would receive GBP 305/MWh (USD 510/MWh). Two developers have plans to deploy a 10 MW wave array at the Wave Hub testing site from 2015. Four tidal projects have received funding from the UK government and the European Union towards deployment by 2016 of the first tidal arrays. In total, some 40 MW of wave power projects and 96 MW of tidal currents projects have been consented (IEA-OES, 2014). This report anticipates some 20 MW of installed ocean power by 2020, up from less than 10 MW in 2013.

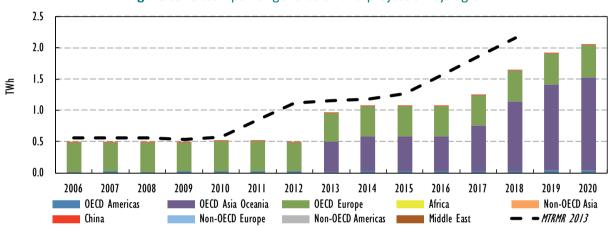


Figure 69 Ocean power generation and projection by region

Canada's development is supported by the Marine Energy Technology Roadmap, which targets 250 MW by 2020 and 2 GW by 2030 for installed in-stream tidal, river-current and wave energy. Nova Scotia has targeted 5 MW to 60 MW of in-stream tidal capacity by 2015 and 300 MW by 2030. The province also released in 2013 its decision for tidal FITs, which are available for up to a 15-year duration and range from an initial CAD 375/MWh to CAD 575/MWh depending on project size and development stage (i.e. developmental or testing) (IEA-OES, 2014). A community FIT scheme for small-scale devices has been available since 2011. Canada has some 5.5 MW of consented tidal and river current projects, but further development plans have been announced, including a 9 MW project near Montreal (IEA-OES, 2014). Still, given the pace of current developments, it is expected that Canada's capacity may only reach just over 25 MW by 2020, up from 20 MW in 2013.

In France, a call to tender for small pilot tidal farms was recently launched that aims for 30 MW to 40 MW of operational capacity by 2020, and a test site at Paimpol-Bréhat aims to have a total of two or three units installed by 2015. A number of small demonstration projects are under development for wave technologies as well, with a test site operational in the Atlantic waters.

In Ireland, the government has put in place the Prototype Development Fund to support deployments and aims to have a marine energy testing site operational from 2016. Ireland's Offshore Renewable

Energy Development Plan was published in 2014 and recommended the introduction, in 2016, of an initial market support scheme, limited to 30 MW, of EUR 260/MWh for wave and tidal generation.

In 2020, ocean power is expected to deliver around 2.0 TWh of power globally, with the largest part of the generation coming from France, producing 0.5 TWh, and Korea, producing 1.5 TWh.

Offshore wind

Technology and manufacturing development

The deployment of large projects far from the coast and the installation of test turbines with higher rotor diameter have continued to mark the trend for offshore wind deployment. However, costs of investment for offshore wind systems remained relatively high over 2013. As the lead time for offshore wind projects is relatively long, system costs for some projects under construction are expected to be even higher as the majority of those installations are farther from the coasts and in deeper water. Although offshore technology possesses significant potential for cost reduction, grid connection delays, the cost and availability of financing, and the need for a long-term stable market and regulatory framework remain current challenges to deployment.

So far, the majority of offshore turbines installed in Europe are essentially based on large land-based turbines, customised for the ocean environment. However, the design of these turbines will continue to deviate from that of onshore turbines with less focus on issues such as visual, sound and aesthetics to offshore specific designs. Over the past year, several companies either installed or announced the testing of new-generation offshore turbines which have larger rotor diameters, ranging from 6 to 8 MW rated capacity, compared with 3 MW to 5 MW currently. Vestas' new 8 MW prototype offshore turbine started to produce electricity at the Danish National Test Centre for Large Wind Turbines while Siemens installed its new-generation gearless 6 MW turbine at Hunterston Test Centre in the United Kingdom. Furthermore, Alstom installed its 6 MW test turbine for the Belwind project in Belgium, while Areva announced the production of a new 8 MW turbine.

As the offshore deployment is expected to grow both in and outside of Europe, non-European companies also introduced new offshore turbines. In April 2014, the joint venture between Mitsubishi Heavy Industries and Vestas was finalised. The venture will focus on the design, development, manufacturing and installation of an 8 MW offshore wind turbine. Samsung Heavy Industries installed its first 7 MW offshore test turbine at Energy Park Fife in Scotland. The Chinese manufacturer Ming Yang announced its entry to the market with 6.5 MW prototype turbine while Hyundai Heavy Industries is expected to install its first offshore test turbine in Korea by the end of 2014.

The supply chain of the offshore wind industry is evolving as turbine manufacturers continue investing in larger turbines that are expected to operate in more difficult meteorological conditions farther from the coast. The majority of commissioned plants and those under construction chose monopole foundation structure, which is relatively simple to install and requires less labour time and cost (EWEA, 2014). However, the combination of diverse seabed conditions, deeper water and larger turbines is expected to push the deployment of innovative alternatives such as jackets, tripods, and gravity-based or floating structures. New foundation designs are able to support turbine constructions at water depths of 40 m to 70 m, but with higher costs than monopole.

The supply of installation and maintenance vessels remains an important part of the offshore wind supply chain, and their availability could pose challenges over the medium term. Only a few large vessel companies having offshore wind–specific vessels dominate the market, mostly owned by oil and gas companies. There are currently 29 vessels operational in Europe, all booked for the construction of ongoing projects. In addition, five more vessels are expected to become operational by the end of 2015 (BNEF, 2013). However, with current contracted projects, the current supply of vessels may fall short over the medium term. This situation may cause delays in construction and commissioning of these projects, especially in Europe. A few companies announced the construction of new vessels, such as Seajacks International in the United Kingdom, Samsung Heavy Industries in Korea and Marubeni in Japan. The vessels, which are being built in Korea and Japan, are expected to serve the Asian offshore market. Over the medium term, the commissioning of wind-specific vessels might decrease the dependency on oil and gas installation vessels.

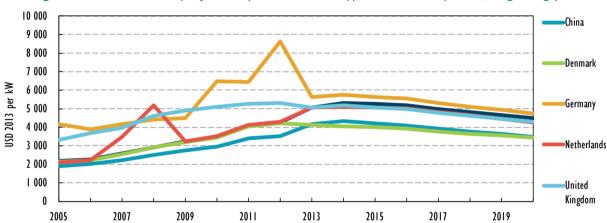


Figure 70 Historical and projected system costs for typical offshore systems, beginning year

Note: as the number of commissioned offshore projects is limited, spikes in the dataset may reflect cost data related to specific projects that are commissioned in a given year.

Offshore wind investment costs vary significantly depending on the project's distance to the shore, the water depth, the geography of the seabed and grid connection time. The majority of commissioned and planned projects in Europe are 35 km to 50 km offshore with a water depth of 25 m to 30 m (EWEA, 2014). The total investment costs for these projects ranged from USD 4 000/kW to USD 5 750/kW in the beginning of 2014. However, there are a couple of projects commissioned in Germany that are 80 km to 90 km farther from the coast with a water depth of 40 m. For these projects, total system costs can elevate to USD 7 000/kW to USD 8 000/kW. With a relatively higher cost of financing and O&M, LCOEs for new offshore wind power plants in Europe remained high, ranging from USD 170/MWh to USD 300/MWh.

Going forward, offshore wind investment costs are likely to decrease with the deployment of larger power plants that require the scale-up of the manufacturing of all supply chain elements, including turbines, vessels, foundations and cables. In the United Kingdom, the government regards offshore wind power as an opportunity to create a sustainable and competitive industry. The Offshore Wind Cost Reduction Task Force of experienced industry practitioners was formed to consider ways in which costs could be reduced, with a target cost of energy of GBP 100/MWh (USD 156/MWh) by 2020. This suggests around 40% of cost reduction versus current levels. According to its study, turbines

have the greatest cost reduction potential, followed by increasing competition in the supply chain, frontend activities (project design, seabed analysis etc.), economies of scale and productivity improvement, the optimisation of current installation methods, and mass-produced support structures (DECC, 2012).

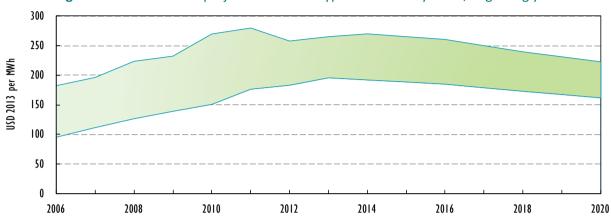


Figure 71 Historical and projected LCOEs of typical offshore systems, beginning year

Notes: Costs are indicative and ranges reflect differences in resources and local conditions. Learning rates are applied to system costs starting from 2015 because projects that will come on line before 2016 are already contracted, with already estimated costs available. For more data assumptions behind the calculations, see table in "Analytical Framework" chapter.

This generation cost outlook suggests a continuous strong deployment in Europe and moderate additions in Asia and small additions in North America. Although cost reductions are expected by 2020, persistent policy environment uncertainties in several key countries, connection delays, relatively high costs of capital connected to project risks and supply chain bottleneck remain challenging for cost reduction potential. Thus, this report expects that the low end of the LCOE range for offshore wind will decrease to USD 160/MWh in 2020 from around USD 190/MWh in 2014.

Market status and outlook

In 2013, global offshore wind generated an estimated 21 TWh, up 38% from the 15 TWh output registered in 2012. In 2013, global installed capacity of offshore wind reached over 7 GW, with 1.7 GW of new additions versus 2012, around 500 MW less than the *MTRMR 2013* forecast. Still, this increase represented the highest annual capacity additions to date, with several large projects commissioned in the United Kingdom, Germany and Belgium.

In 2013, the world's largest wind farm was fully commissioned in the United Kingdom (the London Array – 630 MW) while large offshore plants became operational in Belgium (400 MW) and Denmark (400 MW). Although the commissioning of some large projects was delayed, especially in Germany, some offshore wind farms started their operation earlier than expected in Germany, Sweden and Belgium. In the United States, Cape Wind announced that it had raised around USD 1.3 billion for the country's first offshore wind project, which is expected to cost around USD 2.5 billion in total (Ailworth, 2014).

With the exception of 50 MW commissioned in China and 25 MW in Japan, all new capacity was installed in OECD Europe. The United Kingdom installed 0.75 GW with the commissioning of the London Array plant (630 MW), the world's largest offshore wind farm, followed by Denmark (400 MW), Germany (240 MW) and Belgium (192 MW) (EWEA, 2014).

Table 46 Offshore wind power capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	6.6	7.7	9.3	11.2	13.7	16.6	20.4	24.2
OECD Americas	0.0	0.0	0.0	0.0	0.2	0.3	0.6	8.0
OECD Asia Oceania	0.1	0.1	0.2	0.4	0.5	8.0	1.0	1.3
OECD Europe	6.6	7.6	9.0	10.8	13.0	15.5	18.8	22.1
Non-OECD	0.5	0.7	1.3	1.9	2.5	3.1	3.8	4.5
Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.5	0.7	1.3	1.9	2.5	3.1	3.8	4.5
Non-OECD Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-OECD Americas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	7.1	8.4	10.6	13.1	16.2	19.7	24.2	28.7

Note: IEA analysis; 2013 data are IEA estimates based on GWEC (Global Wind Energy Council) (2014), *Global Wind Statistics 2013*, GWEC, Brussels; and EWEA (European Wind Energy Association) (2014), *The European Offshore Wind Industry – Key Trends and Statistics 2013*, EWEA, Brussels.

Compared with the MTRMR 2013, the forecast has been revised down significantly by almost 9 GW in 2018 due to persistent policy environment uncertainties in several key countries, connection delays, challenging financing conditions and supply chain bottlenecks. The major downward revision came from China, with its forecast cut by 3.5 GW in 2018 versus MTRMR 2013. China's deployment has been slow, mainly due to high project costs, lengthy application procedures for construction permits and the absence of strong incentives. None of the projects that were tendered (1 GW) in the Jiangsu province in 2010 has so far started construction. Thus it seems currently difficult for China to reach its 2015 target of 5 GW. In addition, the baseline case of this report does not expect Chinese offshore deployment to pick up significantly at the second half of the decade to reach its 30 GW target in 2020.

100 90 80 70 60 ₹ 50 40 30 20 10 2007 2010 2011 2012 2013 2014 2016 2019 2020 OECD Asia Oceania OECD Europe Non-OECD Asia **OECD Americas** Africa China Non-OECD Europe Non-OECD Americas Middle East - MTRMR 2013

Figure 72 Offshore wind generation projection by region (TWh)

The German offshore market has been affected by uncertainties over the new draft incentive regime. Although there was an improvement in timely connection of some plants over the past year, the issue still remains challenging and increases project risk considerably. Thus, this report is less optimistic on the German offshore deployment over the medium term, and delayed its projection of 4.2 GW of total installed capacity in 2018 to 2020, a 1.3 GW downward revision. Another revision stems from

France, with only few developments observed in the market since the first French offshore tender. Accordingly, the offshore projection for France was delayed another year. It is expected that 150 MW of capacity will be connected to the French grid in 2019 and another 150 MW in 2020. In addition, Japan's forecast was also revised down by 250 MW in 2018 versus *MTRMR 2013*. Although the country doubled its offshore wind tariff in March 2014, administrative and technical challenges should remain important barriers to deployment.

Global offshore wind power capacity is expected to expand from 7.1 GW in 2013 to over 28 GW in 2020. Although the discussion below concerns the outlook under the baseline case, it is worth noting that under the enhanced case conditions described earlier in the country-level outlooks, global capacity could top 33 GW in 2020.

Onshore wind

Technology and manufacturing development

Onshore wind power is a proven mature technology with an extensive global supply chain. In some countries, onshore wind is also referred to as land-based wind, mainly for installations that are located inland, far from the shore. Typical load factors range from 20% to 35%. New classes of wind turbines for lower-speed winds are emerging, which are supporting capacity factors in sites without high winds. Exceptionally good wind sites can have capacity factors of around 50% or higher. For example, average capacity factors for winning bids in Brazil's latest wind-only auction in September 2013, which awarded 1.5 GW of capacity, reached around 47%. Wind is a variable renewable technology and can achieve high penetration levels only in power systems with sufficient existing and anticipated flexible capacity.

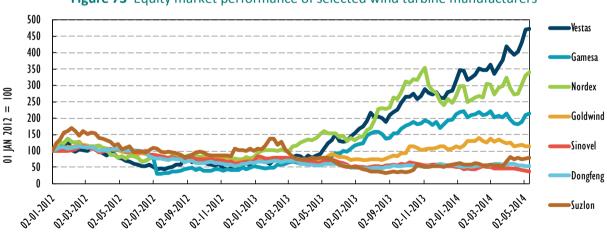


Figure 73 Equity market performance of selected wind turbine manufacturers

Source: IEA analysis based on data from Bloomberg LP (2014), (accessed 01 June 2014).

Over the last few years, the European wind turbine manufacturers have been implementing a strategy of cost reduction and consolidation, which resulted in the loss of many jobs and closure of some production facilities in both Europe and the United States. In general, companies are aiming at decreasing both fixed and variable costs with strategies including merging and diverging production facilities, and outsourcing components. As a result of these measures, some European manufacturers' profit margins have continued to increase and their equity prices have showed significant gains over the last year.

However, the increasing competition in the Chinese domestic market and ongoing supply glut of turbines has pushed many local turbine manufacturers to squeeze their profit margins. Ambitious international expansion plans have so far not met shareholders' expectations even though Chinese turbine exports grew by more than 50% from 430 MW in 2012 to 690 MW in 2013. Sinovel, for instance, has shut down eight of its ten foreign branches since April 2013 as the company could not meet its export targets. Goldwind's export strategy has so far worked, as the company more than quadrupled its exported capacity to seven countries, and accounted for 60% of Chinese wind turbine exports. While relatively smaller turbine manufacturers in China have gained market share from large suppliers, a possible consolidation in the market is expected, which could stabilise prices and ensure efficient and sustainable internationalisation over the medium term.

Meanwhile, almost all manufacturers have continued to invest in innovation, mainly focusing on product diversification in low- and medium-wind turbine segments. As the availability of high-wind sites will continue decreasing in some countries, the demand for this segment is seen growing fast, and further cost reductions are expected. Since the beginning of 2012, prices for these new turbines have in general increased but, at the end of 2013 and the beginning of 2014, prices dropped slightly. The latest data from Bloomberg New Energy Finance show that prices decreased from EUR 1 million in 2013 to EUR 0.96 million in 2014 for new low- and medium-wind turbines. Prices have continued decreasing from EUR 0.82 million in 2013 to EUR 0.78 million in 2014 for old-generation turbines with relatively smaller rotor diameters as demand for those showed a downward trend, especially in the United States (BNEF, 2014b).

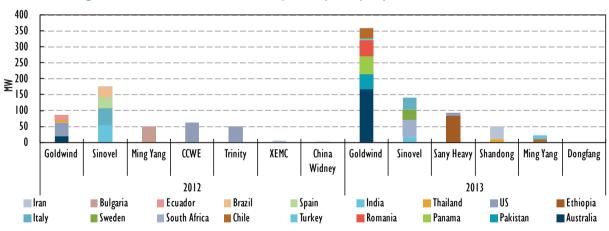


Figure 74 Chinese wind turbine exports by company and destination 2012-13

Source: CWEA (Chinese Wind Energy Association) (2014), Annual Report 2013, CWEA, Beijing, in Chinese.

Still, onshore wind investment costs can vary significantly among countries and regions. In 2013, the lowest costs were observed in China and India, as low as USD 1.2 million/MW, while the highest costs were seen in Japan, as high as USD 2.5 million/MW, mainly due to difficult geographical (mountainous) conditions in windy areas of the country. Costs in Europe and the United States were similar, ranging from USD 1.7 million/MW to USD 2.0 million/MW over the past year. However, total system costs are one of many variables in the calculation of the LCOE for onshore wind power. O&M costs could play a more important role over the medium term, as significant capacity will reach its 10th and 12th year of operation globally over 2014-20, when O&M costs may peak due to issues related to gearboxes. It is estimated that around 155 GW of global capacity will reach half of its economic lifetime (ten years)

during the projection period. Gearbox replacements or repairs are usually expensive, and more importantly, may cause 5 to 15 days' downtime for a turbine (Sheng, 2013). As more turbines are expected to be installed in low- and medium-wind sites, it is expected that maintenance needs for new generation turbines will continue decreasing.

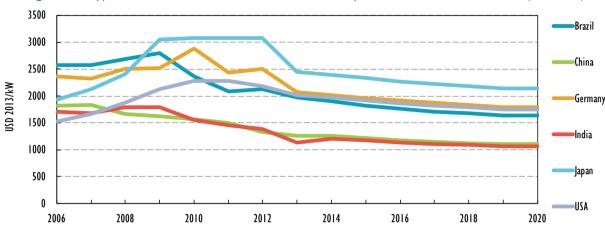
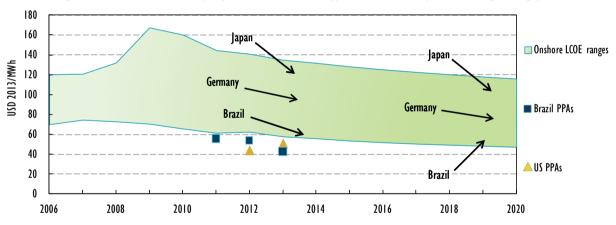


Figure 75 Typical onshore wind total investment costs per kW in selected countries (2006-20)





Notes: Costs are indicative and ranges reflect differences in resources and local conditions. Learning rates are applied at the system cost level starting from. For more data assumptions behind the calculations, see table in "Analytical Framework" chapter.

Globally, in the beginning of 2014, typical LCOEs ranged from USD 55/MWh to USD 130/MWh. With the combination of relatively low-interest loans offered by the Brazilian Development Bank and high capacity factors, Brazil currently has achieved some of the lowest onshore wind PPAs, as low as USD 44/MWh. However, proposed capacity factors for some of these projects are close to 50%, while this might not necessarily be achieved in practice for some projects. As such, the LCOEs of typical projects estimated here are based on capacity factors of around 40%. Although having low system costs, Chinese developers still struggle with low capacity factors, due to curtailment, and challenges in the O&M of currently installed turbines. Thus, China's LCOEs can range from USD 70/MWh to USD 115/MWh. The cost of financing is another major component affecting LCOE results significantly. In the United States, LCOEs ranged from USD 60/MWh, in states with high full-load hours, to USD 110/MWh in relatively low wind sites. With the low cost of capital, Germany's LCOEs for typical projects are around

USD 80-100/MWh, though projects have costs as low as around USD 60/MWh. Higher LCOEs are observed in Japan, with typical projects ranging from around USD 125/MWh to USD 145/MWh. Globally, wind turbine technology has evolved, with more efficient machines deployed. This report expects that system costs will continue to decrease in line with wind turbine innovation. By 2020, the global range for onshore wind LCOEs is seen decreasing by around 15 to 20%, ranging from USD 48/MWh to USD 115/MWh.

Market status and outlook

In 2013, onshore wind generation increased by 110 TWh to reach over 610 TWh (+21% year-on-year). Global cumulative installed capacity expanded by 34 GW, around 30% lower than in 2012, to reach above 310 GW in total. New installations were led by China, which installed around 16 GW. Additions in the United States tumbled to around 1 GW due to a rush before the expected expiration of the production tax credit (PTC) at the end of 2012, which left the project pipeline empty for 2013. The US market is expected to recover in 2014. In 2013, OECD Europe added 9 GW of new capacity, 1 GW lower than in 2012, with Germany (3.2 GW) and the United Kingdom (1.9 GW) leading. Some part of the additional capacity in Europe and in the United States should come from repowering of old turbines. In the non-OECD, cumulative capacity rose significantly in India and Brazil. In India, capacity additions slowed versus 2012 due to uncertainty over the renewal of some key financial incentives.

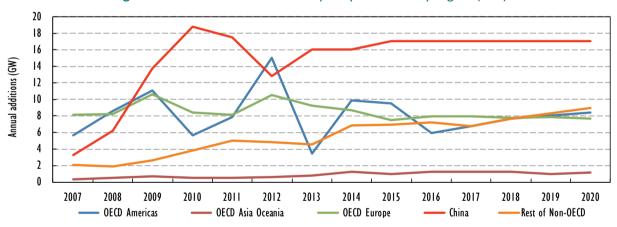


Figure 77 Onshore wind annual capacity additions by region (GW)

Over the medium term, global onshore wind capacity is expected to nearly double from 312 GW in 2013 to around 600 GW in 2020. Versus the *MTRMR 2013*, expected cumulative capacity in 2018 has been revised down by 15 GW, mainly due to a lower baseline and somewhat more conservative outlooks in China and the United States. Although the discussion below concerns the outlook under the baseline case, it is worth noting that under the enhanced case conditions described earlier in the country-level outlooks, global capacity could reach 635 GW to 655 GW in 2020.

While the PTC was renewed in the United States in early 2013, the measure came too late for developers to establish a robust project pipeline for 2013. Global additions for 2014 are expected to be higher than in 2013 with the recovery of deployment in the United States. However, with its expiration, the PTC will no longer be available for projects that did not start construction before the end of 2013. As a result, annual installations are expected to slow and they are then expected to gradually rise over the medium term, supported by falling system costs, increased demand for renewables to meet anticipated emissions regulations and retirements of coal plants, and for hedging purposes against

the price volatility of natural gas. In 2020, China is forecast to have the largest cumulative capacity with 209 GW, followed by the United States at 97 GW. Germany should follow with 48 GW, then India with 42 GW.

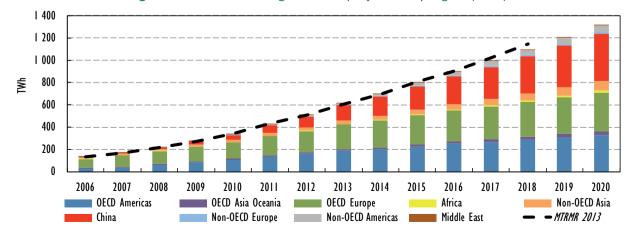
Table 47 Onshore wind capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	187.5	207.3	225.2	240.4	256.3	273.0	289.9	307.0
OECD Americas	70.2	80.1	89.6	95.5	102.3	110.0	118.0	126.4
OECD Asia Oceania	7.0	8.2	9.1	10.3	11.6	12.8	13.8	15.0
OECD Europe	110.4	119.0	126.5	134.5	142.5	150.2	158.0	165.7
Non-OECD	124.0	147.1	171.0	195.1	218.9	243.6	268.8	294.8
Africa	1.4	2.6	3.4	4.0	4.8	5.9	6.7	7.4
Asia	22.4	25.1	28.3	31.7	35.1	38.6	42.4	46.4
China	91.0	107.0	124.0	141.0	158.0	175.0	192.0	209.0
Non-OECD Europe	4.4	5.0	5.7	6.5	7.2	7.9	8.6	9.4
Non-OECD Americas	4.6	7.1	9.4	11.5	13.1	15.2	17.7	20.3
Middle East	0.1	0.1	0.3	0.4	0.6	0.9	1.4	2.1
Total	311.5	354.4	396.3	435.4	475.2	516.6	558.7	601.8

Note: IEA analysis; 2013 data are IEA estimates based on GWEC (Global Wind Energy Council) (2014), *Global Wind Statistics 2013*, GWEC, Brussels; and EWEA (European Wind Energy Association) (2014), *The European Offshore Wind Industry – Key Trends and Statistics 2013*, EWEA, Brussels.

Cumulative installed capacity in OECD Europe is seen expanding by 55 GW over 2013-20, though annual deployment is seen remaining stable (7 GW to 8 GW) over those years. There, increased macroeconomic uncertainties have exacerbated financing challenges for several projects over the past year. Other countries in OECD Americas – Canada, Chile and Mexico – are all expected to grow significantly. Canada should add around 9 GW, Mexico 8.1 GW and Chile 2.4 GW over 2013-20. Several countries in OECD Asia Oceania should experience strong growth. Australia's onshore capacity should expand by 4.5 GW, but current policy uncertainty remains an important risk factor for this expected deployment. Development in Japan is likely to proceed more slowly, with cumulative capacity growing by only 1.2 GW over 2013-20 as sites remain geographically challenging and far from demand centres, and require transmission upgrades. Korea's onshore capacity should increase by 2 GW over the projection period. Meanwhile, cumulative capacity should rise in a number of other non-OECD markets outside of China and India, led by Brazil, South Africa, Ukraine, Thailand, Egypt and Kenya.

Figure 78 Onshore wind generation projection by region (TWh)



Global onshore wind production is expected to reach over 1 320 TWh in 2020, more than doubling the estimated global generation in 2013. The share of non-OECD countries should continue to increase in global generation, reaching over 45% in 2020. The forecast assumes that China's onshore wind utilisation rates will improve over time. Newly added capacity is expected to have slightly higher capacity factors thanks to improved machines and better dispatching and O&M. Curtailment of the overall fleet is also seen declining over time with improved power system operations. That said, uncertainty still exists over some aspects of the current and future performance of the onshore wind fleet. China's onshore wind output should reach over 420 TWh in 2020, representing one-third of all generation, followed by the United States at 260 TWh. Germany is expected to be the third producer with 92 TWh, while India should reach 73 TWh.

Solar PV

Technology and manufacturing development

Falling system prices and increasing annual global deployment continue to mark the trend for solar PV development. Though module price decreases have flattened somewhat, cost reductions in other parts of the supply chain are stimulating more competitive applications through greater self-consumption and/or market exposure. A good deal of the overcapacity characterising the manufacturing sector in recent years has receded, and some manufacturers are planning capacity expansions. The acceleration of deployment in several markets, notably China, has helped to reduce industry pressures, though some uncertainties lie ahead.

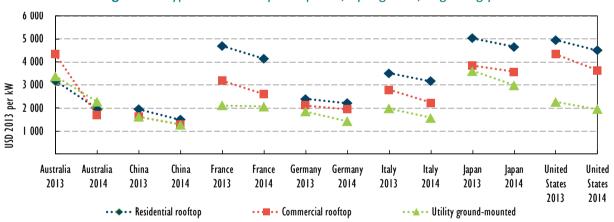


Figure 79 Typical solar PV system prices, by segment, beginning year

Notes: costs are indicative and may not represent all transactions. Prices included value-added tax or sales tax where relevant. National currencies converted to USD at average 2013 exchange rates.

Sources: IEA analysis based on IEA-PVPS (Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems) (2014a), PV Cost Data for the IEA, personal communication; SEIA (Solar Energy Industries Association)/GTM Research (Greentech Media) (2014), US Solar Market Insight, GTM and SEIA, Washington, DC.

From 2008 to 2012, solar PV module prices were divided by five, and solar PV system prices divided by three in mature markets such as Italy. In 2013 and 2014, module prices more or less stabilised, indicating that prices were not fully reflecting underlying costs. As too many modules began to be produced, many were sold at prices too low to recover investment, as the deterioration of the balance

¹⁰ For further analysis on the solar PV sector, including more detailed technology analysis, please see the IEA Technology Roadmap: Solar Photovoltaic Energy 2014 Edition.

sheets of most solar PV companies (up to bankruptcy for some) demonstrated. But improvements in technology and the scaling up of manufacturing were by far the main factors driving cost reductions.

In April 2014, data from Bloomberg New Energy Finance showed average spot multicrystalline silicon module prices around USD 0.76/W to USD 0.80/W, roughly even with quotes from April 2013 (BNEF, 2014a). Data from pvXchange show spot prices for crystalline modules in April 2014 down by 15% year-on-year in Germany and Japan, but slightly higher in China compared with April 2013 (pvXchange, 2014).

Despite the more moderate price movements in module prices, prices of solar PV systems have continued to decline across a number of markets. Decreasing balance of system (BOS) costs have spurred solar PV system price reductions even as module prices stabilised. In early 2014, typical utility-scale solar PV prices were estimated as low as USD 1 300/kW in China and USD 1 400/kW in Germany. Commercial-scale solar PV prices were at USD 1 300/kW in China and USD 1 900/kW to USD 2 200/kW in Germany and Italy. Meanwhile, residential-scale systems were as low as USD 1 500/kW in China and USD 1 950/kW in Australia. Still, prices both below these levels have also been observed in these markets, and significant differences remain between markets and segments. In France, for example, FITs favour building integrated solar PV systems, which are relatively expensive. Falling BOS costs have not impacted all markets equally, and learning has been slower in markets such as the United States.

Box 7 Why do solar PV system prices vary so much among markets?

As global module prices have fallen sharply in recent years, local factors have grown in importance in determining the trajectory of solar PV system prices. Particularly in rooftop segments, these prices continue to vary significantly across markets due to differences in supply chains, local building regulations, labour, permitting, customer acquisition, tax systems and financing, among other factors. Determining the impact of these factors remains a persistent challenge for analysts, though bottom-up evaluations are increasingly shedding light on the drivers and challenges, which are often tied to the prevailing policy environment.

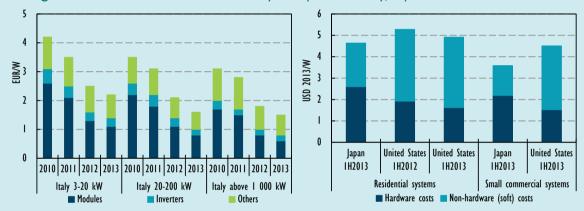
Due to sticky local factors, often related to market structure or administrative requirements, the learning associated with complete solar PV systems is usually slower than that for modules. Some markets have benefitted from strong decreases in both areas. In Italy, previous generous incentive levels for new installations had contributed to high supply chain margins. Yet module, inverter and other costs have all declined significantly, benefitting from learning in global equipment manufacturing and recent policy adjustments that tightened financial supports. In Germany, solar PV prices are among the lowest globally, in part due to low customer acquisition costs, fast installation time, and eased permitting, interconnection and inspection procedures (PII). Germany's regularly adjusted FIT scheme has been a factor in driving cost reductions, by providing a straightforward value proposition to customers while also forcing installers to reduce prices as incentives are decreased (Seel, Barbose and Wiser, 2014). In emerging markets, non-module costs can shrink rapidly as installers gain experience and as project density and supplier competition increase. Still, the economics remain opaque in many areas; increased analysis is needed on solar PV price drivers in countries where deployment is starting to take off.

Several markets should face challenges in reducing prices of solar PV systems over the medium term. In Japan, a complex distribution supply chain, a preference for domestically produced equipment and generous financial incentives have led to high module costs for end users, even as important economies have been realised in BOS costs (Friedman et al., 2014). An acceleration of solar PV deployment is leading to greater entry by foreign suppliers and increased module imports, which should help to reduce margins over time. However, generous FIT levels, local regulations and elevated non-hardware costs (when compared with Germany) are likely to keep total system prices high over the medium term.

Box 7 Why do solar PV system prices vary so much among markets? (continued)

In the United States, non-hardware costs remain a large inflation factor for residential and commercial systems even as module costs have declined. Compared with both Germany and Japan, the United States typically faces high expenditures related to customer acquisition, installation and PII. Greater market fragmentation, a more uncertain value proposition for consumers, less standardised system designs, more onerous PII requirements and higher financing costs all generally contribute to higher US end-user system prices. The advent of third-party leasing models has helped improve the attractiveness of solar PV to customers, though at the same time has increased transaction costs associated with the use of tax equity financing (Ardani et al., 2013). The realisation of a roadmap for BOS cost reduction could help reduce non-hardware costs to USD 0.65/W for residential systems and USD 0.44/W for commercial systems under the US SunShot targets (Ardani et al., 2013). A reduction to such levels, which would be low by international standards, may be challenging to achieve by 2020, however, given the myriad stakeholders involved.

Figure 80 Cost breakdown of solar PV system prices in Italy, Japan and the United States



Notes: Italy system prices exclude value-added tax; Japan and United States figures include sales tax.

Sources: Gestore dei Servizi energetici (GSE) (2014), *PV in Italy: Generation Costs and Value Chain*, May, Rome; Friedman B., T. James, R. Margolis and J. Seel (2014), *Comparing Photovoltaic (PV) Costs and Deployment Drivers in the Japanese and U.S. Residential and Commercial Markets*, US DOE/NREL, Golden.

IEA analysis suggests that system price differences among countries could narrow significantly over the long run as local markets mature. Under the IEA *ETP 2014* 2°C Scenario, the market variation in costs would narrow to less than USD 1 000/kW for utility-scale systems and to less than USD 2 000/kW for rooftop systems by 2030. These differentials are still high, but the ranges are much less than currently.

Going forward, solar PV investment costs are likely to decline due to a combination of continued global learning in module production and local improvements in BOS costs. Manufacturers are working on improvements in module technology, which should allow for thinner designs and the use of fewer materials. Still, rising demand and the reduction of overcapacity in manufacturing is keeping module prices relatively stable in the near term; a return to historical rates of learning (i.e. 20% to 22%) is not expected until 2015. Average crystalline module prices are expected to reach around USD 0.60/W by 2020 given this report's expected solar PV deployment outlook. While it is beyond the scope of this book to assess the likelihood and impact of such measures, further trade actions could have the impact of slowing this reduction even as they support some industrial players.

The learning approach is not as well proven for BOS. Still, improvements in BOS are anticipated in line with historical trends. In particular, continuous improvements in modules, with greater shape

diversification and better integration abilities, should help to reduce installation costs. In some cases, such as in the United States, faster-than-expected developments in BOS could push system investment costs lower. The upshot of this analysis is that typical utility-scale solar PV systems could dip as low, in real terms, as USD 1 000/kW in China and USD 1 500/kW in the United States by 2020. Commercial rooftop systems could reach, in real terms, near USD 1 000/kW in China and USD 1 200 in Australia. Still, global average investment costs are likely to remain higher.

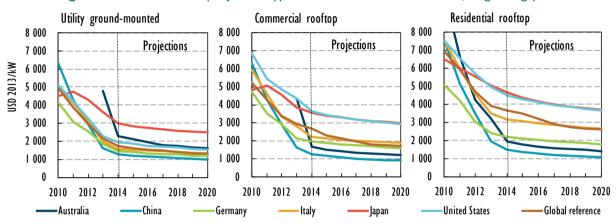


Figure 81 Historical and projected typical solar PV investment costs, beginning year

Notes: investment costs are overnight costs and include value-added tax or sales tax where relevant; costs are indicative and may not represent all transactions. National currencies converted to USD at average 2013 exchange rates. Historical data points omitted for Australia where market was not well established. Global reference is the estimated global weighted average.

Source: IEA analysis based on IEA-PVPS (Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems) (2014a), *PV Cost Data for the IEA*, personal communication; SEIA (Solar Energy Industries Association)/GTM Research (Greentech Media) (2014), *US Solar Market Insight*, GTM and SEIA, Washington, DC.

The solar PV LCOE depends heavily on the quality of the resource, the initial cost of installation and the cost of capital. At present, the combination of low financing costs, low system prices and excellent solar resources remains rare. Early 2014 generation costs for typical utility-scale projects, without incentives, are estimated to range from USD 100/MWh to USD 220/MWh, with Japan at the high end of the range. LCOEs are estimated as low as USD 100/MWh in China, which has excellent resources and a real cost of capital of around 7% and as low as USD 110/MWh in Germany (assumed real cost of capital of 3%). Some recent PPA announcements - which can include incentives and may not be directly comparable to LCOEs - show even lower values. In the United States, Austin Energy signed a PPA to procure 150 MW of solar PV in Texas from 2016 at less than USD 50/MWh, including the Investment Tax Credit (ITC), which followed several announcements of other PPAs below USD 70/MWh, also including the ITC (Hall, 2014).

The investment cost outlook, as well as utility-scale deployment continuing to shift from Europe towards markets with better resources, suggests that utility-scale LCOEs should improve over time, with the global reference reaching around USD 100/MWh in real terms and the best projects, with excellent resources and attractive financing, as low as USD 60/MWh to USD 70/MWh.

This generation cost outlook suggests a growing economic competitiveness of solar PV, with fewer incentives, versus other bulk power sources. Utility-scale solar PV can be competitive in sunny countries with daytime peak demand, particularly when peaks are met by burning oil products (though oil price subsidies may distort this perception). In oil-exporting countries, solar PV generation is cheaper when the

opportunity cost of not selling oil on the international market is considered (e.g. Saudi Arabia). In Chile, high wholesale electricity prices and good irradiation levels have opened a new merchant solar PV market. There, the world's first merchant utility-scale solar PV plant was interconnected and another was financed over the past year; both projects are to sell electricity to the wholesale market without a PPA.

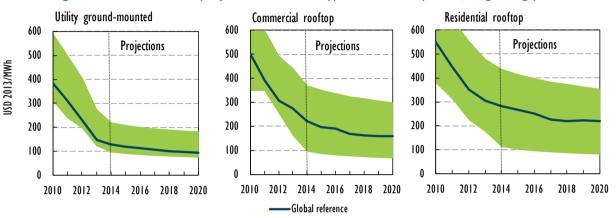


Figure 82 Historical and projected LCOEs for typical solar PV systems, beginning year

Notes: Costs are indicative and ranges reflect differences in resources and local conditions. For more data assumptions behind the calculations, see table in "Analytical Framework" chapter.

Rooftop generation costs are also seen improving. The global reference, in real terms, for new commercial-scale projects is seen moving from USD 220/MWh in early 2014 to below USD 160/MWh in 2020. Costs at or below this average are seen in markets such as Italy and Germany. In China and Australia, generation costs for typical systems are seen below USD 100/MWh in 2020. Strong deployment in new markets with excellent resources, such as Mexico and Brazil, could potentially spur low generation costs by 2020 (USD 115/MWh to USD 155/MWh), but regulated end-user prices, uncertainties over regulatory support and few financial incentives remain a challenge for scaling up development in these locations. For new residential-scale projects, the global reference is seen moving from USD 280/MWh in early 2014 to USD 220/MWh in 2020, with much lower values expected in China, Australia and Germany.

Falling costs are supporting the emergence of competitive market segments in both commercial and residential sectors linked to the concept of grid or "socket" parity – when the LCOE of distributed solar PV systems becomes lower than the variable portion of retail electricity prices that system owners would otherwise pay (see "Special focus: Solar PV reaching socket parity" later in this chapter). The advent of financial innovations and business models, such as third-party leasing schemes, is also enhancing the economic attractiveness and supporting the deployment of distributed solar PV in markets such as Australia, Japan and the United States.

Meanwhile, the solar PV manufacturing industry continues to consolidate. In recent years, the industry has made a large geographical shift from Europe, particularly Germany, to Asia, mostly China and Chinese Taipei. In 2013, manufacturers in China exported over 15 GW of modules, of which 30% went to Europe, 22% to Japan and 10% to the United States. A combination of increased demand in China, stimulated by ambitious near-term deployment goals, and the spectre of trade actions by several countries against Chinese-made equipment is prompting Chinese manufacturers to increasingly turn towards the domestic market. The growth of new markets in Japan, Latin America, Africa and soon, the Middle East, and the exit of some players is helping to gradually erode overcapacity in the manufacturing

sector. This trend is providing a cushion that has allowed some solar PV companies, which were selling at zero margins or at a loss, to regain their footing in the market. Still, it is worth highlighting that solar PV cells and module manufacturing now constitute a minority part of the value chain. Upstream activities, from R&D to building production lines, and downstream activities linked to installation and services account for the largest portion (IEA, 2014d).

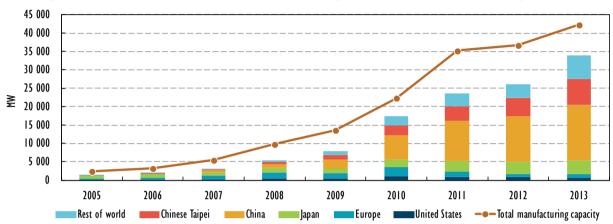


Figure 83 Solar PV manufacturer shipments by region versus total manufacturing capacity

SPV (Solar PV) Market Research (2014), Photovoltaic Manufacturer Shipments, Capacity, Price & Revenues 2013/2014, SPV Market Research, San Jose.

Market status and outlook

In 2013, global solar PV cumulative capacity – including grid-connected and operating off-grid systems – grew by an estimated 39 GW (+34% year-on-year). Annual additions were larger than the 29 GW recorded in 2012 and higher than the 30 GW projected for 2013 by the *MTRMR 2013*. Stronger-than-expected deployment occurred in a number of markets, but the largest contributors to the divergence were China, Japan and the United States.

Solar PV capacity installations continued to transition from historical growth markets in Europe to expanding markets in Asia and the Americas. In the OECD, Japan led capacity additions, adding 6.9 GW in 2013 on the back of a full year of availability of a FIT scheme for new projects that began in July 2012. In 2013, roughly 50% of Japan's addition came in the commercial-scale segment, with 25% from utility-scale projects and 25% in residential-scale. As of March 2014, of the over 68 GW of projects registered, but not yet brought into operation, under Japan's FIT scheme, solar PV represented almost 96%. A large part of approved, but not built, capacity is in the utility-scale segment, where grid and land constraints and development delays are raising uncertainties over project delivery.

The United States was the second-largest OECD market in 2013, with deployment of 4.75 GW. Growth continued to be led by the utility-scale segment, which accounted for 60% of additions, supported by falling system costs and the solar investment tax credit (ITC). In early 2014, Austin Energy signed a PPA to procure 150 MW of solar PV in Texas from 2016 at less than USD 50/MWh, including the ITC, which followed several announcements of other PPAs below USD 70/MWh, including the ITC (Hall, 2014). Residential and commercial additions also continued to ramp up, supported by net metering in 43 states and growing attractiveness for solar PV for self-consumption.

Table 48 Solar PV capacity and projection by region (GW)

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	110.1	132.6	153.9	174.4	191.4	207.6	224.6	242.2
OECD Americas	13.9	19.7	25.5	31.8	36.1	41.0	46.5	52.6
OECD Asia Oceania	18.7	27.6	35.5	42.7	48.7	53.5	58.3	63.2
OECD Europe	77.5	85.3	92.9	99.9	106.6	113.1	119.7	126.4
Non-OECD	27.2	43.7	60.4	78.1	97.3	118.0	139.1	161.1
Africa	0.2	0.9	1.3	2.1	3.7	5.0	5.9	6.7
Asia	4.2	6.1	8.5	11.1	14.2	17.6	21.4	25.6
China	19.6	32.9	45.9	58.9	71.9	85.9	99.9	113.9
Non-OECD Europe	3.0	3.3	3.7	4.1	4.4	4.9	5.4	5.9
Non-OECD Americas	0.2	0.3	0.6	1.1	1.5	2.2	2.9	3.9
Middle East	0.1	0.1	0.3	0.8	1.6	2.4	3.5	5.1
Total	137.3	176.3	214.3	252.5	288.7	325.6	363.6	403.3

Note: grid-connected solar PV capacity (including small distributed capacity) is counted at the time that the grid connection is made, and off-grid solar PV systems are included at the time of the installation.

Source: IEA analysis; 2013 data are IEA estimates based on IEA-PVPS (2014b), A Snapshot of Global PV 1999-2013, IEA-PVPS, St. Ursen, Switzerland.

Other markets in the OECD continued to expand, led by Germany (+3.3 GW) and Italy (estimated +1.5 GW), where reduced support for new projects means that growth is increasingly dependent upon favourable conditions for self-consumption. In early 2014, one of Italy's first commercial-scale projects (700 kW) for self-consumption was reportedly commissioned (Business Wire, 2014). The United Kingdom grew by 1.1 GW in 2013, mostly in utility-scale additions, supported by favourable economics from renewable obligation certificates. Strong growth already in 2014 (over 1 GW in the first quarter) and ambitious 2020 deployment goals suggest the United Kingdom will remain a key deployment market in Europe over the medium term.

Elsewhere in the OECD, Australia grew by 0.7 GW. This deployment was down versus the previous year due to the end of Australia's state-level premium FITs. Still, with low system prices and excellent resources, there is good economic attractiveness for deployment under self-consumption with few direct incentives (see "Renewable electricity: OECD"). Several other markets had notably stronger deployment in 2013 versus 2012, including Canada, Korea, the Netherlands and Switzerland.

The non-OECD was led by China, which installed more than 12.9 GW (as reported by the National Energy Administration) of new solar PV in 2013 and was the world's largest deployment market. In an effort to reduce local pollution and overcapacity in its solar PV manufacturing, China has steadily increased its deployment ambitions over the past year, confirming a cumulative solar target of 35 GW in 2015 (versus 21 GW previously); announcing a corridor for development in 2014, of which up to 14 GW (of which 8 GW distributed) would receive government support; and announcing in May 2014 a 70 GW cumulative target for 2017. These goals are backed by attractive national FITs and some local generation-based incentives for utility-scale projects, most of which are constructed in the central and western regions. While grid constraints in western regions, away from demand centres, may cause local bottlenecks, ample opportunities for construction exist in the central provinces, closer to demand centres.

The development situation of distributed solar PV is somewhat more uncertain. For China, solar PV systems categorised as distributed can go up to 6 MW (which partly explains similar investment cost estimates for commercial- and utility-scale systems). Since 2012, they have benefitted from waived

grid connection fees from State Grid Corporation of China. Since 2013, a policy has been in place for distributed solar PV systems to receive a CNY 0.42/kWh (USD 0.07/kWh) feed-in premium for electricity generated, including that which is self-consumed, making it particularly attractive for commercial entities. The economics do not yet appear attractive for households, who enjoy much lower end-user electricity prices. Some uncertainties exist over this economic assessment, including the threshold required rate of returns and the willingness of commercial entities to invest in an activity (self-production of electricity) outside their core business. Developers who own and operate a distributed solar PV system and sell the electricity to a commercial off-taker under a long-term agreement face risks associated with a potential off-taker default. The availability of financing for a still-nascent market segment and of suitable rooftops may also act as barriers to deployment. Moreover, much will depend as well on the implementation of the policy and distribution of incentives by local grid companies. Overall, these risks may require measures to facilitate access to attractive financing and stronger incentives to make distributed solar PV projects bankable.

Elsewhere in the non-OECD, India's cumulative capacity during fiscal year 2013 rose by almost 1.0 GW, led by the commissioning of capacity under the Jawaharlal Nehru National Solar Mission (JNNSM). Deployment picked up in a number of other non-OECD markets in 2013. Ukraine's capacity rose by almost 0.4 GW, spurred by attractive FIT rates. Thailand deployed over 0.3 GW, with the introduction of the first FITs for residential and commercial installations to replace the previous adder scheme. In Chinese Taipei, the government announced a strategy to prioritise development of rooftop solar PV installations to reach a long-term target of 3.1 GW in 2030. In 2013, the country deployed 170 MW of solar PV, supported by a FIT scheme, to reach over 370 MW in total.

In South Africa, solar PV deployment was around 0.2 GW as the first utility-scale plants came on line under the government's Renewable Energy Independent Power Producer Procurement Programme (REIPPP). Other countries had notable developments suggesting stronger deployment in the years ahead. The Brazilian state of Pernambuco launched a dedicated solar auction for 123 MW of capacity by 2015, and the Brazilian government announced it would hold a dedicated solar auction in the second half of 2014. Meanwhile, Saudi Arabia issued a white paper in 2013 laying out a plan for auctions for solar PV and other renewable sources, though there is still lack of clarity over the timeline and implementation details.

Going forward, global solar PV cumulative capacity is seen rising from 135 GW in 2012 to 403 GW in 2020 (+18% annually on average). The projection has been revised up by over 18 GW in 2018 versus MTRMR 2013, reflecting the higher 2013 baseline, more optimistic growth prospects across a number of markets and expectations of improving economics. Still, a number of country-specific risks need to be resolved for deployment to accelerate to higher levels, and the annual deployment market remains volatile due to uncertainties, in particular in Japan and the United States.

On a regional basis, annual growth is seen strongest in China and OECD Asia Oceania, led by Japan, in the early years. China's outlook is guided by an expected annual market of 13 GW to 14 GW per year, as the country ramps up to meet its 70 GW target in 2017. The majority of development should occur in the utility-scale segment. While slow, to date, development of residential and commercial capacity in China poses a forecast risk; it is likely that authorities will make some regulatory adjustments to stimulate the sector, given its strategic importance. Even so, commercial-scale projects are likely to dominate developments in the distributed sector, given relatively high end-user prices for industry and commercial entities versus households.

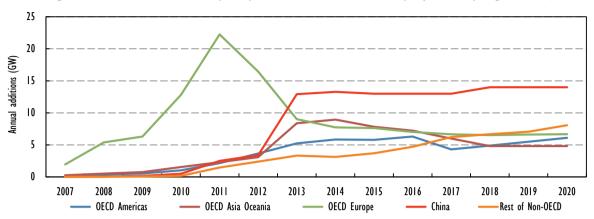


Figure 84 Solar PV annual capacity additions, historical and projected by region (GW)

In Japan, backed by supportive incentives and a need for additional generation, solar PV is expected to expand by 36 GW from 2013 to reach a cumulative capacity of almost 50 GW in 2020. Moreover, the deployment pattern may be volatile, with high levels expected in 2014 and 2015 and lower annual levels from 2016 onwards due to an assumed transition from current high FIT levels. Overall, the growth outlook is much lower than the pipeline of government-accredited projects (65 GW not yet in operation as of March 2014) suggests. It is expected that many of these projects may not reach fruition due to grid constraints and non-economic barriers. Still, with the timely and effective implementation of electricity market reforms and adequate availability of grid connections, deployment could be higher than forecast here (see chapter "Renewable electricity: OECD" for further details). Elsewhere in the region, Australia, based on competitiveness of rooftop solar PV with current retail prices, Korea and Israel are all anticipated to grow significantly.

In the OECD Americas, the United States is expected to grow by more than 32 GW over 2013-20, driven by a robust pipeline of utility-scale projects and growing attractiveness of rooftop systems, supported by net energy metering and advances in financing and business models, such as third-party leasing schemes. Still, a number of risks remain. The expected reduction of the ITC from 30% to 10% means that deployment may spike somewhat in 2016 before settling at more stable 3 GW to 5 GW per year over 2017-20. The US Commerce Department's recent preliminary ruling to impose duties on Chinese modules from Chinese Taipei potentially represents a risk to project economics going forward. Moreover, the US forecast is conditioned upon deployment spreading out more from California, which has accounted for a large part of development to date. The outcomes of ongoing debates over rules governing net energy metering and distributed solar PV and renewable portfolio standards in some states represent a further policy risk to the outlook. Should the distributed segment take off faster than expected, however, overall deployment could be higher.

Mexico, Canada and Chile are all expected to grow strongly as well. Mexico's development, however, is largely predicated on an anticipated rise in the commercial and high-consumption residential sectors, where conditions for self-consumption appear favourable.

The outlook in OECD Europe appears stable at 7 GW to 8 GW per year over 2013-20. Deployment in markets such as Germany and Italy is likely to be driven by improving conditions for self-consumption, but the pace will depend on developments in the regulatory treatment for distributed generation, the remuneration of electricity still injected into grids and the management of system integration challenges. The United Kingdom is also seen expanding strongly, while Turkey remains a wild card.

Good economic attractiveness for solar PV and a strong need for new capacity to meet demand are drivers in Turkey, though current quota limits of the solar PV auction programme and the cost and availability of financing remain constraints.

In the non-OECD outside of China, deployment is seen rising rapidly over the medium term. India is expected as the largest deployment market, with cumulative capacity seen rising over 12 GW through 2020. Though auctions under the JNNSM have proceeded slowly, plans for new megaprojects have emerged, and growing attractiveness for commercial-scale installations is likely to spur significant development in rooftop solar PV. South Africa is expected to increase by over 4 GW, primarily due to large-scale projects under the REIPPPP, but with the potential for distributed capacity to start rising. On the assumption that dedicated solar auctions are held in Brazil this year, capacity there is also seen rising over 4 GW. Saudi Arabia should deploy more than 2 GW over 2013-20, also on the assumption of renewable capacity auctions commencing this year. Elsewhere, Chinese Taipei, Jordan, Ukraine and Russia are all expected to deploy more than 1 GW of solar PV over 2013-20.

While the discussion above concerns the outlook under the baseline case, it is worth noting that under the **enhanced case** conditions described earlier in the regional chapters, global cumulative solar PV capacity could reach 465 GW to 515 GW in 2020. Achieving enhanced deployment would require alleviating some of the challenges enumerated above and repeated through this report. These include, but are not limited to, the rapid clarification of policy uncertainties in some markets; the implementation of stable and sustainable policy frameworks that give greater certainty about the long-term revenue streams of renewable projects; greater measures to ensure the grid and system integration of variable renewables; the implementation of fair rules and appropriate electricity rate design for allocating the costs and benefits from fast-growing distributed solar PV; improved reductions in non-economic barriers; and faster-than-expected decreases in solar PV technology and generation costs.

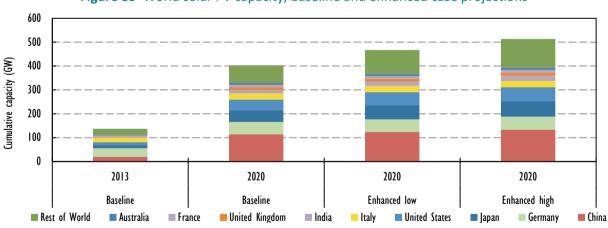


Figure 85 World solar PV capacity, baseline and enhanced case projections

Under the enhanced case, the largest upside pertains to China, Japan and the United States. In China, Faster-than-expected uptake in distributed systems could translate into implying an additional 10 GW to 20 GW of solar PV by 2020 than under the baseline case. In particular, the risks associated with distributed solar PV development may require measures to facilitate access to attractive financing and stronger incentives to make projects bankable. In Japan, rapid progress in implementing overarching electricity reforms, reducing non-economic barriers and achieving a stronger build-out of the grid and other forms of flexibility, such as storage, could help solar PV capacity be some 10-15 GW higher

than under the baseline case in 2020. In the United States, solar PV capacity could be higher by 8 GW to 10 GW in 2020, with greater-than-expected uptake in the residential and commercial sectors spurred by more favourable conditions for deployment under self-consumption.

Box 8 Solar PV deployment segments vary by market

The market segmentation of solar PV deployment can vary significantly by geography. Market segmentation of solar PV can be described a number of ways – by system size, by installation type (e.g. rooftop versus ground-mounted), by building segment (e.g. residential, commercial, utility) or by the way that solar PV systems interact with the electricity system (e.g. distributed, centralised, off-grid).

In order to better illustrate broad trends in solar PV deployment segments, *MTRMR 2014* has refined its categorisation of solar PV capacity to correspond to the four categories. These categories represent a simplification of how systems may actually be deployed in a given market and segment. In many cases there is significant overlap. For example, centralised systems are often ground-mounted utility plants of a size of at least 1 MW. Yet exceptions can exist, and reporting standards vary by country, making the characterisation of segment trends difficult across markets. In many cases, insufficient data and resources exist to assign these categories at the country level. This report has determined breakdowns for key reference markets and has applied them to larger regional dynamics. As such, these category assumptions should be taken as a proxy for actual trends.

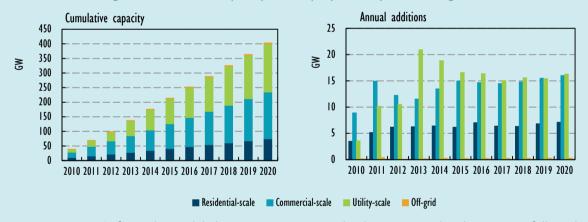


Figure 86 Solar PV capacity and deployment by market segment

In 2013, over 40% of cumulative global capacity was estimated to be commercial-scale in nature, followed by utility (37%), residential (20%) and off-grid (1%). Going forward, based on the solar PV forecast presented in this section, utility-scale and commercial-scale systems should each account for roughly 40% of capacity growth, followed by residential (17%) and off-grid (1%). In Europe, development is likely to focus more on commercial and residential systems, given emerging favourable conditions for self-consumption and weakening incentives for large-scale deployment. Utility-scale systems are expected to be driven by new deployment in markets with excellent resources, such as Western China, the US Southwest, India, the Middle East, Africa and the non-OECD Americas. Still, a significant amount of distributed growth should occur in some of these markets. For example, China remains a large wild card for the development of commercial-scale solar PV, in particular, with the resolution of certain economic uncertainties potentially boosting growth higher than forecasted here. The United States is likely to also see increased growth in both the residential and commercial segments, supported by net metering and the emergence of deployment for self-consumption in states where retail prices are relatively high. Still, outcomes of ongoing debates over rules governing net energy metering and distributed solar PV and renewable portfolio standards in some states represent a policy risk to the US forecast.

Box 8 Solar PV deployment segments vary by market (continued)

Finally, though off-grid represents a small portion of expected development, it may have more upside than suggested here. Rural electrification and captive power for industry remain large needs in places like India and Africa, where grids are underdeveloped. However, off-grid and mini-grid developments are inherently difficult for governments and market analysts to track and forecast. Some of the developments forecast in other, grid-connected segments may very well occur off-grid, but may not be adequately represented in statistical reporting.

Table 49 Solar PV deployment category assumptions in MTRMR 2014

	Size	Interaction with the grid	Typical installation type
Residential-scale	<20 kW	Grid-connected distributed	Rooftop
Commercial-scale	20 kW - <1 MW*	Grid-connected distributed	Rooftop or ground-mounted
Utility-scale	1 MW and above	Grid-connected centralised	Ground-mounted
Off-grid	Any, but typically less than 1 MW	Off-grid or mini-grid	Rooftop or ground-mounted

Note: *in China, solar PV systems up to 6 MW can be classified as commercial-scale.

Electricity production from solar PV is directly dependent on solar irradiance levels within each country. In general, with solar PV expanding into sunnier countries, global average full-load hours should increase. Solar PV should deliver over 480 TWh globally in 2020. China is seen as the largest solar PV power producer in 2020, followed by Germany and the United States. The forecast for China stays on the conservative side, taking into account that small-scale installations will not always be located in ideal solar resource spots while utility-scale installations may be slightly curtailed due to the variability of power produced, which is not always easily handled by Chinese grid operators. In 2020, 13% of solar PV electricity should be generated in countries other than China and OECD countries, up from less than 5% in 2012.

600 500 400 ₹ 300 200 100 2007 2008 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2006 2009 OECD Europe OECD Americas OECD Asia Oceania Africa Non-OECD Asia Non-OECD Europe Non-OECD Americas - MTRMR 2013 China Middle East

Figure 87 Solar PV electricity generation and projection by region

Special focus: Solar PV reaching socket parity

The term "grid parity" is used in a number of different ways. Sometimes it implies that competitiveness of solar PV (or other technologies) is reached vis-à-vis alternative options. Other uses relate to retail prices. In order to avoid any possible confusion, the following discussion is based on the notion of socket parity.

A distributed generation technology reaches socket parity when its LCOE falls to or below the perkilowatt-hour costs for electricity obtained from the grid, i.e. the variable part of a consumer's electricity bill. With socket parity, a customer can potentially save money by generating electricity him- or herself rather than buying it from the grid.

Socket parity is emerging as a possibly important driver for the uptake of distributed solar PV in several markets and segments. Ostensibly, this trend suggests stronger deployment of solar PV ahead, with significantly reduced direct incentives. Still, this possible transition raises challenges, both in the assessment of socket parity economics and the potential impact of widespread distributed solar PV adoption on the electricity system.

Socket parity is not reached at the same time globally, due to large differences in generation costs of PV, which depend on local PV system prices, resource conditions, financing arrangements, etc., as well as large differences in prices for grid electricity among countries, which may range between around USD 0.01/kWh (subsidised retail rates, for example in the Middle East) and USD 0.40/kWh and above (for example, unsubsidised retail rates in small island power systems running on diesel). Tariffs also differ depending on customer group (residential, commercial, industrial). In addition, the pricing structure of tariffs for the same customer group may differ. Some tariffs may have larger fixed monthly or annual payments combined with lower per-kilowatt-hour rates, while others have lower or no fixed charges and high per-kilowatt-hour rates. Displacing kilowatt-hour consumption from the grid will save only on the variable component of the electricity bill. Hence, the LCOE of a solar PV system needs to be compared to the variable component of a tariff to assess socket parity.

Drivers and challenges for private consumers

Analysis of socket parity economics needs to distinguish clearly among three different quantities: a customer's electricity consumption, the amount of electricity produced by the self-owned PV system, and the amount of "presumed" electricity (or just prosumption), i.e. the quantity of electricity that is self-produced *and* self-consumed. Two metrics for calculating the share of prosumption can be considered.

- The first metric is the share of **self-use**. This measures the amount of directly used electricity out of all self-generated electricity. The higher the share of self-use is, the easier it is to recover the cost of a PV system without relying on remuneration of production surpluses.
- The second metric is the degree of **self-sufficiency**. This measures how much of the total electricity demand of a customer is self-supplied. The more self-sufficient a customer is, the larger the amount of money that can be saved on the electricity bill.

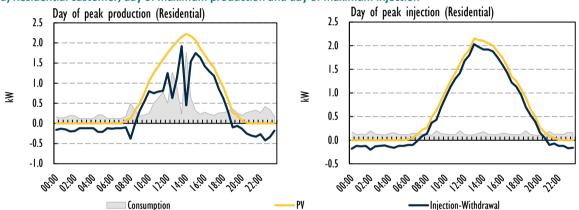
In general, there is a trade-off between maximising these shares. High shares of self-use are easier to achieve with small systems. The reason for this is simple: the smaller the system is, the less likely PV generation will exceed a customer's power demand at any point in time. In the case of residential consumers, achieving 100% self-use would limit system size to the minimum daylight demand. This can be very low, in particular when nobody is at home (Figure 88). Using a very small system will offset only a small quantity of grid electricity. Consequently, the degree of self-sufficiency will be low in this case. Only where there is a very good temporal match between electricity demand and solar PV generation can high shares of self-use and self-sufficiency be achieved jointly. This is the case in the commercial sector much more than the residential sector, for example in supermarkets or office buildings (Figure 88).

¹¹ By reference to the notion of "prosumer", i.e. producers that are also consumers.

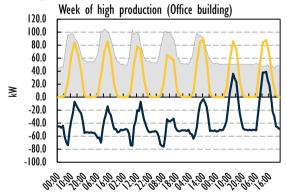
What shares of self-use and self-sufficiency result from the above examples? Considering the household consumer, sizing the system for 100% self-use results in a system size of 0.13 kW and a self-sufficiency rate of only 4% (Figure 89). If excess production can be fed into the grid, higher shares of self-sufficiency are feasible. Installing a 3 kW system will increase self-sufficiency from 4% to 22%. However, self-use drops from 100% to 37%; two-thirds of the PV generation are injected as surplus electricity. These examples are purely illustrative; the real-world shares depend on the specific circumstances and the size that gives an optimal trade-off between self-use and self-sufficiency will be somewhere between these figures. They do highlight an important point, however: even when socket parity is reached, the remuneration of excess production is a key factor determining how large the resulting market for residential PV systems will be. Turning to the office building, things look quite different. The excellent match of PV supply and electricity demand allows for 29% of self-sufficiency while self-use is still at 94% (Figure 89). In an office where there is activity over the weekend, the self-use share would be even higher. This example illustrates a case where deployment of PV would be attractive without remunerating the injection of excess. However, the customer is still far away from full self-sufficiency.

Figure 88 Match of PV supply and power demand for a residential/commercial customer in France





b) Commercial customer (office building)



Note: residential consumer located in northern France, no electric heating or electric hot water provision; office building situated in Mediterranean southern France.

Source: EDF (Électricité de France) (2014), Estimation de l'autoproduction PV « naturelle » : étude de cas Présentation au Groupe de Travail autoproduction de la Direction Générale de l'Énergie et du Climat, Paris, 5 February.

In summary, reaching socket parity is a precondition for prosumption to present an economic opportunity. In the absence of remuneration for injecting PV electricity into the grid, the temporal match between

electricity consumption and PV production determines the size of this opportunity. This match may be excellent (example of office building above) or poor (example of residential consumer). Anecdotal evidence suggests that this may be generally true, i.e. that prosumption may be more attractive for commercial applications. Additional analysis is needed to confirm this hypothesis. In any case, a natural constraint on self-sufficiency is the amount of demand occurring during daylight hours. Storage and demand-side response are the two options available to increase the match of supply and demand. They would facilitate the increase of both shares, self-use and self-sufficiency, simultaneously. In principle, they can allow for reaching full self-use and self-sufficiency. However, given current storage costs, reaching full self-sufficiency, i.e. becoming totally independent from the grid, via PV is likely to be prohibitively expensive in most cases.

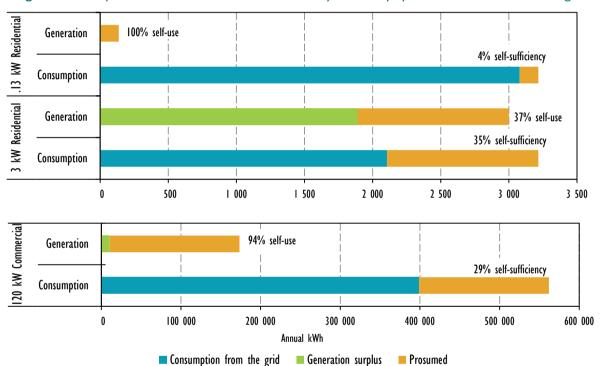


Figure 89 Comparison of self-use and self-sufficiency shares by system size and customer segment

Status of the market

The primary indicator for reaching socket parity is a comparison of the variable component (per kilowatt-hour charge) of typical electricity contracts and the LCOE of distributed PV. Owing primarily to the rapid reduction of PV system costs and aided by rising electricity prices, solar PV has reached socket parity in a number of markets.

As mentioned above, in the absence of remuneration of excess electricity, it is important that a sufficient share of electricity generated from the PV system be directly consumed, i.e. the self-use share needs to be high enough. Where the gap between PV system costs and electricity tariffs is particularly large, the threshold of self-use for reaching a profitable investment can be as low as 40% with a cost of capital of 3.5% (Figure 91).

This analysis explains the profitability as a function of what percentage of the electricity generated by the PV system can be directly used (self-use). However, it does not contain any information about

what size PV system will be profitable (this depends on the match of demand and PV supply, as illustrated with the two examples above). In the absence of more detailed information on what consumer groups show what quality of match, it is not possible to calculate the resulting market potential. A more detailed analysis is the subject of ongoing IEA work but beyond the scope of this publication. Moreover, in many circumstances there is, indeed, a remuneration of surplus production, which will also determine what size PV system is commercially attractive. As such, the remuneration of excess electricity is an important lever to control PV deployment even in times of socket parity.

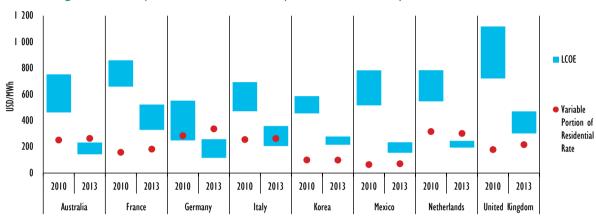
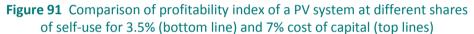
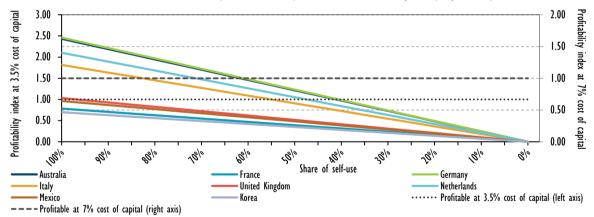


Figure 90 Comparison of variable component of electricity tariffs and solar PV LCOE





Note: profitability index = 1 + NPV/investment; a value above one means the investment is profitable.

In summary, the economic viability of a PV system for a customer and the maximum size of this system depend on the interplay of the following factors:

- the per-kilowatt-hour avoided costs by displacing grid electricity with self-generated PV. This is zero¹² at socket parity and rises as the LCOE falls below the variable component of the electricity rate;
- the remuneration of excess electricity injections into the grid;
- the cost of demand-side response or storage.

¹² An LCOE calculation already includes a return on the PV investment. So even if the avoided cost per kilowatt-hour appears to be zero, the investment in the PV system would already be attractive at socket parity, given that the customer's minimum rate of return has been used as a discount rate in the LCOE calculation.

Policy options to influence the financial attractiveness of prosumption

Given this backdrop, policies and regulation can significantly impact the uptake of distributed solar PV even when socket parity is reached by:

- influencing the avoided per-kilowatt-hour costs via adjusting customer rates, taxes and levies as well as providing low-interest financing for PV systems and reducing the cost of buying a PV system for the consumer
- setting the remuneration of injections and regulating the maximum amount of energy (kilowatt hours) and capacity (kilowatts at any point in time) fed into the grid
- changing the cost of measures to shift demand or store generation via incentives or taxation.

All of the above options have been used in practice by policy makers and regulators, often by using a number of levers in combination. However, most if not all of the above measures can be highly contentious. Probably the most common lever used has been the remuneration of generation surpluses. Generally, three typical approaches can be identified: self-consumption plus remuneration of injected (excess) power, net energy metering and "buy all, sell all".

Power flow ЬшПшш Consumer Generator ____ Grid Prosumer Buy all - sell all Self-consumption and Net-metering separate ÉP rate Specific rate for PV production Avoided cost SC grid electricity rate Avoided cost SC grid electricity rate Remuneration EP special EP tariff Remuneration EP grid electricity rate

Figure 92 Three different models for incentivising customer-owned PV

Note: SC = self-consumption, EP = excess power; blue shading in payments corresponds to surcharge to recover PV generation incentives.

Net energy metering

Net energy metering allows the netting on a consumer's electricity bill of the PV output injected into the grid and the electricity consumed from the grid, often over a long period – one month or several. It can rely on the use of one single meter, which turns backwards when the PV output exceeds instantaneous power demand. Net metering forms the basis of support for solar PV across most US states (43 of them) and Australian states. Since the end of its FIT regime for new solar PV in July 2012, Italy also has an equivalent net metering system. All schemes have limited the system size to which it is applicable, with limits ranging from 20 kW to 2 MW (e.g. 200 kW in Italy) or expressed in proportion

to customer's energy use. Some allow any net excess generation in a given billing period to be credited to the next bill – indefinitely – so that credits for months with high production can balance months with high consumption. From the consumer perspective, net metering schemes can be very attractive. This has been the case particularly in Denmark and Italy.

From the policy perspective, remuneration under net metering raises challenges. This is because remuneration of the excess production from solar PV systems is made at a retail electricity price that often exceeds the value of that PV production to the electricity system. The attractiveness of net metering in Denmark created a surge in deployment in 2012 that ultimately led policy makers to move to a system which allows netting withdrawals with injections only on an hourly basis – allowing much less netting to occur – in order to limit development. This challenge also explains why net metering is capped in most US states. In the United States, most states have put a limit on the capacity available under net metering programmes – most often expressed as a percentage of aggregate consumer peak demand, ranging from 0.1% to 20% with a concentration of values in the 1% to 5% range. Some important – and very sunny – states (e.g. Arizona, Colorado, New Mexico) have not set any limit, though. In California, the largest US solar market, a bill is about to implement a new net metering scheme after the current limit of 5% – 5 256 MW for the three investor-owned utilities – is reached.

Self-consumption and remuneration of excess production

This model mixes self-consumption and FITs for electricity injected into the grid. This is typically the case for households in Germany where, since April 2012, FITs have moved below the variable portion of retail price levels, making self-consumption relatively attractive (IEA, 2013). As of July 2013, FITs in Germany provided remuneration between EUR 0.1044/kWh and EUR 0.1507/kWh. These FITs are available for 90% of a solar PV system's production, with the remainder self-consumed, curtailed or sold at market value. Given much higher retail electricity prices in Germany, this situation creates a strong incentive for consumers to increase their share of self-consumption versus remuneration at FIT levels. Still, unless the PV system is very small, it is often difficult for households to significantly scale up their share of self-consumption given a mismatch between their load profile and the solar PV output, although load management could help in this regard. Commercial and industrial consumers, by contrast, may have load profiles better suited to a large self-consumption proportion, as well as more available load management options.

One interesting policy consequence of self-consumption is that it may allow reducing the level of remuneration through FITs. If PV systems allow for 25% self-consumption, getting a substantial implicit remuneration through savings on customers' electricity bills, then the electricity injected into the grid could be remunerated at a level lower than the LCOE – and installing PV systems would still be attractive. Mechanisms in use to fund the FITs, such as the EEG surcharge in Germany, could thus be reduced in both levels and quantities (for similar PV deployment) thanks to self-consumption compared to a case with no self-consumption.

"Buy all, sell all" models

This model maintains the status quo for paying consumption. PV production cannot offset grid electricity consumption but is rewarded at a specific rate. The city of Austin, Texas, and the state of Minnesota in the United States have already introduced this model, basing the rates on the notion of "the value of solar tariffs (VOS)", which have to be approved by energy regulators. In Minnesota, it is currently only optional, at the choice of utilities. This model is more compatible with existing market arrangements, and is claimed to avoid creating cross-subsidies.

Table 50 Comparison of select distributed solar PV policy frameworks, June 2014

Market	Austin, Texas	Denmark	Germany
Framework	Buy all, sell all	Net metering	Self-consumption and separate EP rate
Eligibility	Residential systems <20 kW	Any system connected to a private supply or if installation is located at place of consumption	Systems <500 kW, with systems <10 kW exempt from EEG surcharge
Avoided cost of prosumption	All output remunerated at value of solar, USD 0.128/kWh	Retail electricity price available as credit if consumed within one hour of production	Retail electricity price
Remuneration for injections	All output remunerated at value of solar, USD 0.128/kWh	Wholesale price plus a bonus (USD 0.07/kWh to USD 0.26/kWh)	Degressing FIT, EUR 0.130/kWh for systems <10kW in June 2014
Programme cap	N/A	20 MW per year for systems <6 kW	2.5 GW target for new installation per year
PV specific fixed charges	N/A	N/A	N/A
Challenge	Complexity in determining the solar "value"	Remuneration at retail prices may exceed value of solar to system	Balancing economic attractiveness of self-consumption vs. grid injections

Market	Hawaii	Minnesota	Queensland, Australia
Framework	Net metering	Buy all, sell all	Self-consumption and separate EP rate
Eligibility	Residential systems <10 kW Systems <100 kW with special review	Residential systems <20 kW Communal systems <1 MW	Residential or commercial systems <100 kW
Avoided cost of prosumption	Retail electricity price	None – all energy demand is purchased from the grid	Retail electricity price
Remuneration for injections	Retail credit valid for a 12-month period	All solar production is exchanged to the utility at the VOS rate (USD 0.145 for first three years) for billing credit	FIT determined for each year by the state utilities regulator AUD 0.08/kWh in 2014
Programme cap	15% of aggregate consumer peak demand, 5% of which is reserved for residential consumers	Solar production capped at 120% of on-site annual consumption	N/A
PV specific fixed charges	N/A	N/A	Consumers must install bi-directional meters
Challenge	Remuneration at retail prices may exceed value of solar to system	Methodology is very reliant on a vertically integrated, state regulated utility market	Balancing economic attractiveness of self-consumption vs. grid injections

However, it requires calculating the system value of PV, which requires an open debate relative to the methodology. The VOS in Minnesota explicitly includes a carbon value, which brings it slightly over the retail prices. When larger penetration shares are achieved, the energy and capacity values of PV will decline, however, and carbon pricing may no longer prevent the VOS from falling below retail prices.

Implications for the power system

Socket parity is a result of relative prices from the perspective of *individual customers*. It remains a concept based on private costs. Consequently, it does not inform about whether or not the deployment of distributed PV will help to reduce total power system costs or not. In general, additional analysis is required to assess the system impact of increased uptake of distributed PV. Such an analysis would need to specify which benefits and costs of distributed PV are to be taken into account on the level of the power system. Only where net benefits are positive (which may include aspects such as technology learning and environmental externalities) will deployment of distributed PV reduce total system costs.

The determination if the system-wide value of PV outweighs its cost depends on a number of factors, including: avoided fuel costs, increased or decreased transmission and distribution costs, capacity value (i.e. extent to which PV deployment reduces the need for building other generation capacity), reductions of transmission and distribution losses, and the pricing of externalities (carbon dioxide [CO₂] and other emissions etc.). It is important to note that the avoided costs, i.e. the value, of an additional amount of PV generation is not a fixed quantity over time. As with any other economic good, its value tends to decrease at higher shares of PV in the system. In the absence of using cost-effective flexibility options (flexible generation, demand-side integration, storage, grid infrastructure) and additional system transformation strategies (system-friendly variable renewable deployment, changed operations), the decrease in value can be accelerated as a consequence of variability (IEA, 2014e).

Only where electricity tariffs accurately signal the cost of electricity (which tends to be different depending on time and location), reaching socket parity is a solid indication that deployment of distributed PV will actually reduce total system costs. However, in practice, electricity tariffs do not reflect costs with sufficient temporal and spatial accuracy. They frequently fail to price negative externalities of the electricity system (such as CO₂ emissions and local pollutant emissions) and may contain a significant share of taxes and levies. Moreover, for reasons of efficiency, tariff simplicity and fair cost allocation, electricity tariffs tend to recover a significant part of fixed infrastructure costs – which may or may not be reduced by distributed PV – via per-kilowatt-hour charges.

Consequently, there is an increasingly lively debate about the soundness of the economic foundations of policy designs and business models that rely on PV reaching socket parity as an economic driver. These concerns cover all cost components that can be found on electricity bills: grid costs, generation costs, energy-related charges and cross-subsidies as well as taxes.

Grid cost concerns

The economic soundness of PV deployment spurred by grid parity is often questioned on the basis of its impact on grid costs. The cost of the transmission and distribution grid is determined by a number of factors, including population density, geographical properties and grid design. In any case, the grid needs to be designed to accommodate times of peak utilisation, i.e. those hours of the year when a maximum amount of electricity is flowing through the lines.

The largest costs for the grid are incurred when it is built; they outweigh operational costs, such as the cost of inevitable electricity losses and maintenance costs. As such, distributed PV will contribute strongly to reduce grid costs only where local consumption of PV electricity implies a reduction in peak power flows. This will be the case only in countries where demand peaks occur during daylight.

Fixed costs of grid infrastructure can make up roughly one-quarter to one-half of the total cost of electricity to end customers. However, the fixed component of electricity prices, i.e. the part of the bill that has to be paid even if not a single kilowatt hour is consumed, is usually much lower. The rationale for this mismatch is twofold. Firstly, if the per-kilowatt-hour charge for electricity is too low, this will incentivise wasteful consumption. Secondly, those consumers that have a high kilowatt-hour consumption are more likely to be consuming power also during the hours of peak demand. Simply put, by paying per kilowatt hour, the ones that are consuming many kilowatt hours are considered to be responsible for a larger part of the fixed cost. To the extent that this holds in practice, allocating part of the fixed cost to the variable component of the electricity bill ensures a simple way to allocate costs to those who cause them.

So, is it fair and economically sound if owners of PV systems can avoid the payment of grid costs? The answer to this question depends on the degree to which the PV system helps reduce grid flows during hours of peak utilisation. If this is the case, it can be economically efficient and fair to allow offsetting payments for fixed infrastructure costs. However, where PV does not reduce the customer's reliance on the grid during times of peak demand, avoiding payments for the grid via self-consumption would be unfair. Consumers would still be responsible for the same amount of infrastructure costs, but pay much less to recover such costs.

While one may be tempted to think that fixed costs should simply be recovered by fixed charges, this is probably not the right answer, for the reasons explained above. While a limited and progressive increase of fixed charges is conceivable, it may be part of a balanced portfolio of measures, possibly including time-based pricing.

Time-based pricing allows tariffs to better reflect the impact of electricity consumption patterns on grid costs. It can take the form of time-of-use pricing, usually with four to eight distinct prices according to hours in the day, days in the week and seasons, or real-time pricing with smart metering. Such a design could also help to rectify other cross-subsidies which can be observed, for example where owners of air conditioners are not exposed to the actual costs that they impose on others for grid reinforcement.

Generation costs: Balancing cost and energy value concerns

Two different concerns are related to the cost of generating electricity. One has to do with dealing with PV forecast errors, the other with the type of power generation that is displaced by PV production.

In liberalised markets, electricity suppliers are responsible for balancing the amount of electricity bought from generators and the amount sold to consumers. The amount of contracted electricity is adjusted several times, reflecting more and more accurate demand forecasts as the time of delivery approaches. Any mismatch between the planned amount of generation and consumed electricity has to be corrected using specific short-term mechanisms, so-called balancing energy. In principle, the required amount and price for balancing energy can increase due to PV deployment. Under standard rate designs, consumers will not be exposed to this cost increase. However, these costs will tend to be quite small, on the order of USD 0.002/kWh to USD 0.005/kWh (IEA, 2014e).

An issue that is potentially more relevant economically relates to the value of energy that is substituted via PV generation and self-consumption. The following consideration illustrates this point. When overall power demand is low, only those power plants with very low generation costs are called upon to generate. As such, the value of electricity tends to be low during these times. Conversely, when

demand is high, units with very high generation costs may be needed to meet demand. Furthermore, additional plants may need to be built to meet peak demand. During peak periods, the value of electricity is particularly high, reflecting high capacity and energy costs. This is reflected in the differences in wholesale market prices across time. In most cases, retail customers are not exposed to this difference and electricity rates are the same throughout the day and year. In this case, the retail tariff will reflect average generation costs.

If PV production occurs during those hours when the value of electricity is low, PV generators may be overcompensated, if PV generation is valued at retail rates. In the absence of time-based pricing, the owners of PV systems will enjoy savings (avoided electricity bill) corresponding to average supply costs. However, the avoided costs on the system level would be below average. Furthermore, the portion of electricity demand that the owner of the PV system still obtains from the grid would, by implication, have above-average costs, while he or she would be paying only the regular tariff, reflecting average costs. In short: self-consumption would be overvalued and grid withdrawals would be underpaid in this case. Conversely, if PV production occurs when the value of electricity is high, PV is undervalued and electricity withdrawn from the grid is overpaid. Finally, if PV production spreads over both times, PV generation might well be paid for its value.

The actual value of PV generation depends on the match with overall electricity demand, the amount of PV generation on the system and the degree to which the system as a whole is designed for large shares of PV (IEA, 2014e). In many systems, power demand has a midday peak and PV thus tends to initially have a value that is above average. In these cases, PV may include a significant capacity value at the onset of deployment. However, the fact that PV systems tend to all generate at the same time – when it is sunny – puts a penalty on the value of PV-generated electricity at growing shares. As such, the marginal value of solar PV may drop below average, if PV accounts for double-digit shares in the power mix. However, a number of strategies (combining demand-side response, grid infrastructure, storage) exist to preserve the value of PV generation at growing shares (IEA, 2014e). One issue with net metering when high shares are reached is precisely that it does not by itself provide an incentive for those strategies.

Energy-related charges: Forgone renewable energy surcharge concerns

Where PV deployment has occurred over the past years in the absence of grid-parity-based models, customers frequently pay a per-kilowatt-hour charge on their electricity bill to recover the cost of existing installations. In countries such as Germany, Italy and the Czech Republic, these cost components can be significant.

The market expansion that occurred in the last years and that will still be paid for during years to come by these surcharges is generally recognised as a precondition for achieving the PV cost reductions via learning which have brought about socket parity. Self-consumption may allow offsetting these surcharges. This would lead to the peculiar situation where those customers that can avoid paying for past cost reductions are precisely those who are reaping the benefits of PV cost reductions.

Other surcharges must be considered case by case. An example where an exemption is fully warranted would be a charge for the CO_2 emissions of the power system. Charges instituted to control electricity consumption as an indirect way to control the emissions of thermal plants could possibly be considered in the same way. It is useful to recall that energy efficiency measures may raise similar concerns, for example where the surcharge is used to pay energy efficiency measures.

Forgone cross-subsidy concerns

In a number of emerging countries, electricity prices for residential consumers tend to be below full cost of electricity supply. The difference is often covered by a surcharge that is collected from other consumer groups, such as industrial and commercial consumers. In these cases, the economics of grid parity in the industrial and commercial sectors may be based on avoiding the cross-subsidy payment. If a large number of industrial and commercial consumers opt for self-consumption, the remaining system will be left with a structural deficit that other sources would need to cover. A general reform of the pricing structure with a view to remove distortive effects of such subsidies while sheltering vulnerable consumers from adverse impacts should be a priority in such cases.

Forgone tax revenue concerns

Electricity obtained from the grid is metered for commercial purposes. In the past, customers had no cost-effective alternative to grid-based electricity. As a result of both factors, electricity is a popular target for taxation. As such, the savings that PV system owners can achieve via self-consumption may contain a fairly large share of avoided taxes. However, in many countries, value-added tax constitutes a large share of the taxes on electricity. It should be noted that prosumers will usually have paid value-added tax on their PV system. Hence, tax revenues are merely shifted, not significantly changed.

With respect to other taxes, PV deployment may reduce the sum of tax revenues and power system costs, rather than power system costs alone. Put differently: PV generation would partly derive its value to the consumer as a tax-saving mechanism. Governments may choose to encourage this as a way to support deployment. In any case, the legal basis and legitimacy for imposing taxes related to self-consumption may prove to be very thin.

Conclusions and longer-term considerations

Reaching socket parity is a necessary condition on the way to solar PV deployment in the absence of direct economic incentives, such as FITs. However, electricity tariffs usually provide a poor reflection of the value of electricity, which varies with location and time. Consequently, reaching socket parity does not inform about whether or not the deployment of distributed PV will help to reduce total power system costs or increase them.

From a private consumer perspective, reaching socket parity may or may not be sufficient to trigger deployment. Where the match between PV generation and power demand allows for self-use of all or most PV electricity, reaching socket parity is sufficient to make a PV investment profitable. However, this will be the case only for a subset of customers, such as certain commercial or industrial consumers. As such, even where socket parity is reached, the remuneration for injected generation surpluses will be a critical element determining PV economics.

From the perspective of total power system costs, socket parity is not an indicator of the point when net avoided system costs (system value of PV) exceed LCOE. This may happen before socket parity is reached or after.

Reaching socket parity dramatically increases the relevance of cost-reflective electricity tariff design. As the above discussion has highlighted, the concerns expressed about PV deployment spurred by socket parity are essentially linked to issues of tariff design. In addition, if tariff design leads to overpaying prosumers, socket parity can lead to a self-reinforcing effect: the more prosumers there

are, the higher prices for the remaining consumers would need to be to still cover costs. In turn, this creates an even stronger incentive to become a prosumer. The economic relevance of this "spiral" depends on the degree of self-sufficiency prosumers can achieve.

Socket parity at its current stage does not make support policies obsolete. It opens the possibility of a self-sustaining shift to distributed PV, but only when certain other conditions are met. In any case, it marks an important change in the available options policy makers have to support solar PV and influences the effectiveness of existing tools.

In order to manage this change in an proactive way, a first step is to monitor the evolution of PV LCOEs, electricity tariffs, achievable shares of self-consumption and the costs of increasing this share, for example via storage. This is important to anticipate possibly rapid uptake of PV generation once socket-parity has been reached. Moreover, the design of grid tariffs may have to evolve towards higher fixed charges and lower variable charges, in a progressive and limited manner, where mature PV markets lead to high shares of penetration. More importantly, more sophisticated tariff structures may help to incentivise grid-friendly consumer behaviour. The design of electricity tariffs may need to provide a higher temporal resolution to appropriately value PV generation and signal the cost of grid-based electricity during the times it is consumed.

Reaching socket parity may open the possibility to avoid paying renewable energy surcharges. There may be a mismatch between what measures are legally possible and what is politically sustainable. There may be legal difficulties with collecting a surcharge via prosumed electricity. But it may be politically unsustainable to allow owners of PV systems to avoid paying in the next years a share of refunding the learning investments of PV from the past by putting a disproportionate burden on those consumers that do not have a PV system. Anticipating the impact of increasing shares of self-supply on tax revenue may also prove relevant. Allowing PV system owners to avoid such costs may be a desirable way to continue supporting PV deployment, while not putting a burden on other electricity consumers.

STE

Technology development

STE¹³ from CSP plants is a proven renewable technology that can provide firm peak, intermediate or base-load capacity thanks to thermal storage and/or a hybrid system. With the commissioning of a slate of new plants in the United States, and activity in several newer markets, the next few years could be pivotal for development. However, a number of risks remain and the technology needs to move further down the cost curve to achieve a more rapid scale-up.

CSP plants exploit direct solar irradiation and are generally situated only in arid and semi-arid regions. Power systems consist of four different types: parabolic trough, linear Fresnel, tower and parabolic dish. Of existing CSP capacity at the end of 2013, roughly 2.3 GW is without storage while 1.3 GW has thermal storage. However, going forward, over 80% (or 6.6 GW) of the new capacity expected by this report through 2020 will likely incorporate storage.

Designs with several hours of storage (defined as hours at rated capacity from the thermal storage) are particularly suitable for markets where the peak occurs in the evening hours, as in many developing

¹³ For further analysis on the solar thermal electricity sector, please see the IEA Technology Roadmap: Solar Thermal Electricity 2014 Edition.

countries. Hybridisation also makes CSP plants fully dispatchable while bringing environmental benefits and fuel savings compared with pure gas- or coal-fired plants. Hybrid designs can take two forms: a relatively small solar power component can be added to an existing fossil-fuel power plant or integrated during the construction phase. CSP plants can also have a relatively small fossil-fuel or biomass backup unit. In the United States, the world's first commercial-scale CSP-geothermal hybrid system is being developed where a 17 MW CSP unit is integrated with an existing 33 MW geothermal plant, providing power and heat reinjection that better helps to manage the geothermal reservoir (Hashem, 2014).

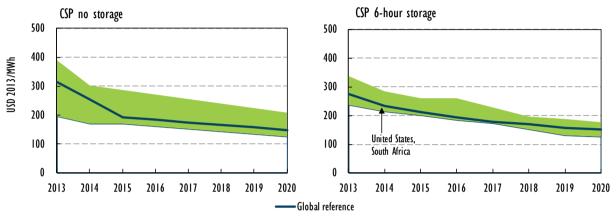


Figure 93 Historical and projected LCOEs for STE, beginning year

Notes: Costs are indicative and ranges reflect differences in resources and local conditions. For more data assumptions behind the calculations, see table in "Analytical Framework".

Storage and hybridisation features enable CSP to provide significant value in meeting evening peak demand and offering a variety of additional ancillary services to power systems that could not currently be covered by solar PV, for example. Still, the relatively high up-front investment costs of CSP can make project bankability difficult. For large plants (at least 50 MW) investment costs are USD 4 000/kW to USD 9 000/kW, depending on the solar field size, the storage size, and labour and land costs. The lumpy nature and technological variety of CSP additions make costs difficult to track and harmonise; recent plant start-ups and financings provide an indicator of the trend. For example, in the United States, the 280 MW Solana plant, with six hours of storage, was completed in 2013 at an approximate cost of USD 7 600/kW. The 250 MW Genesis plant, without storage, was fully commissioned in 2014 at an approximate cost of USD 5 000/kW.

Over the medium term, the investment costs of CSP plants are expected to decline with further deployment, following a learning rate of 10% (i.e. 10% cost reduction for each doubling of cumulative capacity). This could allow investment costs of a plant with six-hour storage to be reduced to around USD 5 000/kW in real terms in the United States. However, such cost reductions face several challenges related to technology development over the medium term. For example, the solar field, whose size is linked to the amount of electric output, represents about half of the CSP system cost. Some developers are seeking to increase electric conversion efficiency, mainly through higher temperatures, in order to downsize the solar field. Achieving this would require the replacement of current heat transfer fluid (synthetic oil) with direct steam generation or molten salts (IEA, 2014f).

The LCOE of STE varies widely with the location, technology, design and intended use of the plant. The LCOE, while providing a useful indicator, does not capture the entire economic balance of a CSP

plant, which depends on the value of the generated electricity. Public data points relative to FIT levels and PPAs provides indirect information relative to LCOEs, although they might significantly differ. Spanish plants had benefitted from FITs near EUR 300/MWh (USD 400/MWh), and 40% of them have seven-hour storage. Recent PPAs in sunnier countries are at half that level or below. One widely quoted figure is of the PPA of the first phase of the Noor I CSP plant at Ouarzazate in Morocco, at MAD 1.62/kWh (USD 0.19/kWh) for a 160 MW trough plant with three-hour storage. A recent CSP plant in the United States secured a PPA at USD 0.135/kWh, but taking investment tax credit into account sets the level of actual remuneration at about USD 0.190/kWh (IEA, 2014f). Over the medium term, STE LCOEs are expected to decline in line with assumed capital cost reductions.

Market status and outlook

STE developments are currently concentrated in a few areas, with Spain, followed by the United States, having the most significant commercially operating capacity, though deployment is spreading out. In 2013, global CSP cumulative capacity grew by 900 MW to 3.5 GW, the highest annual deployment to date. Growth was somewhat slower than that projected by *MTRMR 2013*, with several expected large additions in the United States occurring in the first half of 2014, rather than by the end of 2013.

The United States added over 400 MW in 2013, with the commissioning of the 280 MW Solana and the first phase (125 MW) of the 250 MW Genesis plant. In early 2014, over 600 MW was added, with Ivanpah (392 MW), the second phase (125 MW) of Genesis and Crescent Dunes (110 MW) entering commercial production. These projects had benefitted from the US Department of Energy's former loan guarantee programme, which helped investors to access more attractive financing terms than in its absence. Spain's cumulative capacity rose by 300 MW to 2.3 GW in 2013, with the last remaining projects coming on line under the Special Regime. No new CSP projects are in the development pipeline there, and existing CSP generators in Spain have come under increased economic stress. In an effort to reduce the country's tariff deficit, the government has, over time, instituted a series of retroactive changes to incentives. It has adopted measures to revise the remuneration given to existing renewable generators, imposing a "reasonable profitability" return that replaces FITs.

 Table 51 STE capacity and projection by region (GW)

 2013 2014 2015 2016 2017 20

	2013	2014	2015	2016	2017	2018	2019	2020
OECD	3.2	4.2	4.2	4.4	5.2	5.7	6.2	6.5
OECD Americas	0.9	1.8	1.8	2.0	2.6	2.9	3.3	3.6
OECD Asia Oceania	0.0	0.1	0.1	0.1	0.2	0.4	0.5	0.5
OECD Europe	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
Non-OECD	0.3	0.6	1.0	1.4	2.1	2.7	3.6	4.7
Africa	0.1	0.1	0.3	0.7	1.0	1.1	1.2	1.5
Asia	0.1	0.3	0.4	0.4	0.6	0.6	0.7	0.9
China	0.0	0.1	0.2	0.2	0.3	0.3	0.4	0.5
Non-OECD Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-OECD Americas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middle East	0.1	0.1	0.1	0.1	0.3	0.7	1.2	1.9
Total	3.5	4.8	5.2	5.8	7.3	8.4	9.8	11.3

Sources: IEA analysis; 2013 data are IEA estimates based on Crespo, L. (2014), *Overview of current market trends for solar thermal electricity plants*, presentation at Technology Roadmap workshop, International Energy Agency (IEA), Paris, 3 February; and SEIA (Solar Energy Industries Association)/GTM Research (Greentech Media) (2014), *US Solar Market Insight*, GTM and SEIA, Washington, DC.

Elsewhere, new capacity was added in the United Arab Emirates in early 2013, with the commissioning of a 0.1 GW plant. In India, the first plant (50 MW) under the JNNSM came on line in 2013, followed by the reported start of a 125 MW plant in early 2014. An additional 0.3 GW is under development, but some are experiencing delays due to some economic, technical and supply chain challenges, and there is uncertainty over their ultimate completion. The first plants allocated under the JNNSM have faced setbacks, including the downgrading of the solar resource for CSP plants in many areas. China also had new capacity come on line in 2013, some 15 MW in total, led by the first phase (10 MW) of a 50 MW tower plant.

Over the medium term, CSP is expected to scale up, reaching 11.3 GW in 2020. This outlook is less optimistic than that posited in *MTRMR 2013*, with capacity in 2018 now expected to be 4 GW less, largely due to slower expected growth in the United States, China and the Middle East.

The pipeline in the United States represents 4 GW to 5 GW, but there is significant uncertainty over the timing of some large additions. For example, the 500 MW Palen project has faced a challenging approval process to change its permit from trough to tower technology, with a series of new hearings to address concerns over wildlife impacts expected in the second half of 2014 (Parnell, 2014). Such permitting issues, combined with high up-front financing needs, competition from solar PV, which has experienced more rapid cost declines, and the looming reduction of the ITC at the end of 2016 all make the development situation challenging. Still, cumulative capacity is expected to reach over 2.9 GW by 2020, from 0.9 GW in 2013, based on projects already commissioned and under development in 2014.

Elsewhere in the OECD, notable deployment is expected in Chile, Australia and Israel, with smaller additions in France, Mexico and Turkey. The Chilean government recently completed its first tender for a CSP project in the Atacama Desert, with a 110 MW tower plant selected to receive government grants and concessional financing. In Australia, the 44 MW Kogan Creek Solar Boost project integrating solar thermal generation with a coal-fired plant is expected on line in 2014. Still, the outlook in Australia for large-scale renewable technologies such as STE has grown more pessimistic, given emerging overcapacity in the power sector and increased uncertainty over the renewable policy environment at the national level. Finally, Israel has several projects under development, including the 110 MW Ashalim Thermo plant that was awarded a 25-year PPA in 2013 through the government's auction scheme.

In the non-OECD, the outlook for China has also been revised downward. Despite a deployment target of 3.0 GW by 2020, development to date has been slow, with few commercial-scale capacity additions. Part of the challenge to greater scale-up stems from insufficiently attractive economics. CSP plants benefit from a FIT only roughly equally to that of solar PV, which has not stimulated significant deployment. Still, CSP's flexibility and hybridisation capability could provide value in terms of power market integration, particularly with coal-fired generation. The outlook in China is thus seen as modest, with only 0.5 GW expected through 2020. India's outlook is also somewhat reduced, with uncertainties over project delivery and the timing of future tenders under the JNNSM. India's cumulative deployment is seen at 0.8 GW in 2020, but there is considerable risk to the downside should any delayed projects currently under development be cancelled.

By contrast, the outlook for STE in South Africa has improved. In its 2013 draft update to the Integrated Resource Plan, the government recommended increasing the long-term deployment goal for CSP to 3.3 GW in 2030, from 1.1 GW previously. In late 2013, South Africa's REIPPPP announced 200 MW of winning CSP capacity in its third bidding round, versus 200 MW total in the previous two

rounds. South Africa offers an excellent policy example of encouraging CSP with storage to generate during peak times – the third auction round included a time-of-delivery tariff, with a base tariff that applies during the day and a higher tariff (base tariff multiplied by 2.7) in the evening. Over the medium term, South Africa's CSP capacity is expected to rise to over 0.7 GW by 2020.

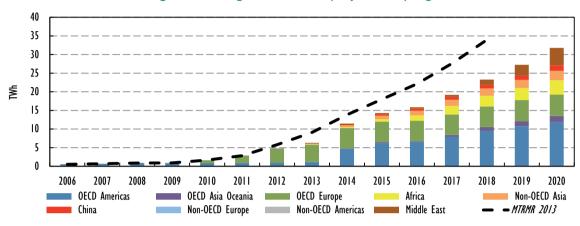


Figure 94 STE generation and projection by region

Elsewhere in the non-OECD, CSP capacity should grow to almost 0.7 GW by 2020 in Morocco, as phases I to III of Noor are commissioned and additional development is expected. Noor I is under construction, and Noor II has received financing and pre-qualified bidders have been announced. Significant activity is also likely in the Middle East, but the outlook is slower than that seen in *MTRMR 2013*. Based on its announced tendering strategy in 2013, Saudi Arabia is now expected to reach 1.0 GW of cumulative CSP capacity by 2020 (versus 1.0 GW in 2018 in *MTRMR 2013*). Uncertainty over the timeline and details of the tenders have resulted in the more gradual outlook. Elsewhere in the Middle East non-OECD countries, Jordan, the United Arab Emirates and Kuwait are all expected to increase capacity, based on FITs (Jordan) and on project pipelines (Emirates and Kuwait).

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INVESTMENT IN RENEWABLE POWER

Summary

- This report estimates that global new investment in renewable power capacity was over USD 250 billion in 2013, down slightly versus that in 2012, and lower than the near USD 280 billion registered in 2011. In 2013, global renewable net capacity additions reached their highest level, at 123 gigawatts (GW), to date. The falling investment stems from two broad trends. First, cost reductions continued in solar photovoltaics (PV) and onshore wind. Second, annual capacity additions and investment in the Europe and Americas regions of the Organisation for Economic Co-operation and Development (OECD) fell due to uncertainties over the long-term policy framework in some countries and challenging financing conditions. Investment expanded in the non-OECD, largely due to China.
- Over the medium term, renewable investment needs are expected to remain high by historical standards, but stabilise at somewhat lower levels through 2020. Required investment in new renewable power capacity under this report's baseline case forecast should average above USD 230 billion annually, in real terms, through 2020. In 2014, investment is seen at almost USD 250 billion as total annual net capacity additions remain around 125 GW, but annual investment slows for several years thereafter.
- The investment forecast stems from two factors: first, slowing capacity growth, overcapacity in some power markets and uncertainties over long-term policy frameworks are likely to limit investment gains in the OECD, even with a need to replace retiring conventional capacity in some markets. This more sluggish outlook for the OECD is compensated by generally expanding investment in non-OECD countries. Yet many non-OECD countries, such as those in the Middle East, remain at the inception or early take-off phase of renewable development, with deployment likely to accelerate to high levels only over the long run. Non-OECD countries also generally face still higher costs of capital and domestic financing constraints.
- Second, reduced unit costs for some renewable technologies, such as solar PV and onshore wind, are likely to act as a ceiling on investment expenditures, even as annual deployment in some technologies continues to grow. The unit costs of more mature technologies such as hydropower, whose capacity grew exceptionally in 2013, and bioenergy are seen to remain relatively stable. Increased deployment of higher-cost technologies, offshore wind and solar thermal electricity (STE), would support greater investment needs towards the end of the forecast period.
- Cost of capital reductions could help relatively high-cost renewable technologies and markets to
 close the gap with other generating technologies. While a number of actions could help to
 reduce risks that keep financing costs high, long-term policy frameworks that offer a degree of
 revenue certainty are particularly important for capital-intensive renewable technologies.
- In the long term, International Energy Agency (IEA) analysis suggests that renewable investment needs are likely to strengthen, even as unit costs fall. Rising deployment in non-OECD countries and increased development of relatively higher-cost technologies, such as offshore wind, should help to boost investment levels over time. Repowering and replacements of existing renewable

capacity are also expected to play a larger role, particularly in the OECD. To realise the high levels of renewables required to meet long-term climate change objectives, as in the *World Energy Outlook (WEO)* 450 Scenario, cumulative investment of almost USD 9 trillion would be needed by 2035. Mobilising this high-level capital would require stable, long-term-oriented policy frameworks from governments, a market design that more effectively prices the value that renewable investments can bring to energy systems and increases power system flexibility to ensure system adequacy with higher levels of variable renewables.

Trends in renewable electricity capacity investment

In 2013, investment in renewable power was estimated over USD 250 billion, down slightly from 2012. Renewables accounted for around 60% of the estimated USD 400 billion invested in new power generation in 2013 (IEA, 2014a). Moreover, global renewable capacity additions reached their highest level to date in 2013, at 123 GW, with capacity surging in several new market segments (e.g. solar PV in China and Japan). By historical standards, the renewable investment sum represents a still-high amount. Since 2005, the global annual investment expenditure on new renewable generation has almost tripled, while annual net capacity additions have more than tripled. Outside of hydropower, the OECD has historically represented the vast majority of renewable investment, supported by more developed long-term policy frameworks for renewables, backed by financial incentives. However, non-OECD annual investment in onshore wind has been comparable to that of the OECD in recent years (except 2012, when installations in the United States surged by over 13 GW). In 2013, total non-OECD investment jumped to a level almost equivalent to that of the OECD, boosted by much stronger year-on-year capacity growth in hydropower and solar PV in China.

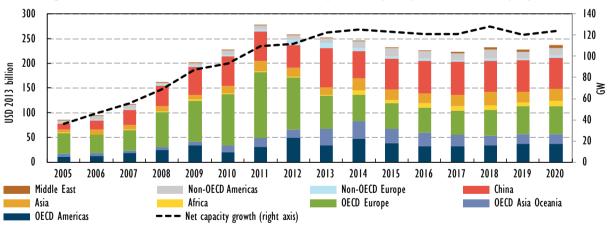


Figure 95 World investment in new renewable power capacity, historical and projected

Note: unless otherwise indicated, all material in figures and tables in this chapter derive from IEA data and analysis.

Investment continues to spread geographically, as technology costs decline

Investment movements stem from broad trends related to markets and technology costs. On the markets side, annual capacity additions and investment in OECD Europe and the Americas fell due to changes and uncertainties over the long-term policy framework in some countries. In OECD Europe, investment declined by some USD 30 billion, largely due to lower deployment of solar, bioenergy and onshore wind. Some European markets face slow demand growth and overcapacity in the power sector, making continued policy support important for investment bankability in capital-intensive, low-marginal-cost renewables. In some cases, the policy environment has grown less supportive with

the phase-out of incentive schemes for new capacity, such as the *Conto Energia* for solar PV in Italy. In others, such as the United Kingdom, it reflected uncertainties over implementation of future support schemes. Similar volatility exists in the United States, where wind deployment plummeted in 2013, due to uncertainty during the prior year over the extension of the production tax credit, though this was somewhat cushioned by rising solar PV installations.

Box 9 Guide to the renewable investment outlook

All investment data presented in this chapter, unless otherwise noted, are derived from IEA analysis on renewable electricity capacity additions and unit investment costs, historical and projected. Investment is defined as overnight capital expenditures on new renewable power plants or the replacement of old plants. When a renewable technology comes to the end of its *technical* lifetime, it is replaced or refurbished with an equal amount of capacity at a reduced cost (for table of lifetime assumptions, see "Analytical Framework"). Investment outlays are counted in the year that a capacity addition becomes operational and is expressed in this report in year-2013 US dollars. Investment does not include operating and maintenance expenditures, financing costs or spending on transmission and distribution grids. Following this methodology, the power plant investment outlook and underlying assumptions presented here are broadly consistent with longer-term IEA scenario analysis, such as the recently published *World Energy Investment Outlook* (IEA, 2014a). Still, minor differences may remain with other IEA work, due to the timing of the analysis, the time period of focus, and the level of underlying detail on unit costs and capacity used to make the calculations.

In all this analysis, bioenergy represents a particular challenge. The availability and accuracy of reported capital costs for bioenergy technologies is limited, and the gathering of comprehensive, technology- and country-specific investment costs is often prohibitive. Given the variety of conversion technologies, and the resulting capital costs, combined with the differences in scale and configuration (electricity only versus co-generation ¹⁴), broad regional ranges for capital costs are used as a basis for investment projections. The situation is further complicated by the fact that availability of bioenergy capacity data, in particular in non-OECD countries, is sometimes limited. In addition, certain types of plants, such as conversions from coal- to biomass-fired generation, are potentially not included in official IEA statistics, if only one of several units is being converted. Furthermore, co-firing capacity is reported by the dominant fuel, e.g. coal, and thus typically does not appear in bioenergy statistics. While these phenomena vary from country to country, baseline capacity data for bioenergy are subject to some error margin that subsequently impacts the accuracy of the investment analysis.

The investment analysis, for now, excludes investment in biofuels for transport and renewables in energy use for heat. Overall, this calculation of investment represents only an approximation of real-world investment practice. In reality, investment in new plants will be spread over the years preceding the installation of capacity. For this reason, some market sources, such as Bloomberg New Energy Finance, collect detailed data on financial deals and estimate investment at the time that new projects are financed. Moreover, the assumption of replacements and refurbishments being made according to the end of their technical lifetime could sometimes lead to an undercounting of repowering expenditures that may be occurring sooner for some technologies, as in onshore wind. Despite these drawbacks, the outlook presented here represents an important first step in trying to better quantify and characterise the renewable investment environment over the medium term.

The overall reduction in investment in Europe and the United States was largely compensated by new investment in other OECD and non-OECD markets and higher deployment of more nascent technologies.

¹⁴ Co-generation refers to the combined production of heat and power.

Solar PV investment in Japan rose strongly due to deployment spurred by generous feed-in tariff levels. Stronger deployment of hydropower, onshore wind and solar PV in China underpinned the rise of non-OECD investment. In some non-OECD markets, renewables are starting to be deployed with fewer financial incentives. Tendered capacity in Brazil and South Africa, based on competition over long-term contracts, is starting to raise investment in non-OECD Americas and Africa and portends a stronger investment forecast ahead in both of those regions. Meanwhile, higher deployment of offshore wind in Europe and STE in the United States has provided an additional investment support.

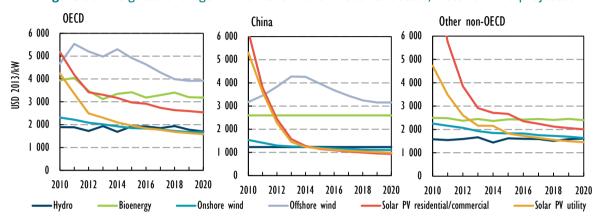


Figure 96 Weighted average annual renewable investment costs, historical and projected

Note: kW = kilowatt. Average unit investment costs as presented here are based on gross additions, which include capacity refurbishments that typically cost less than new capacity. Costs can vary over time due to technology changes as well as the markets in which deployment is occurring in a given year.

On the technology side, cost reductions continued in solar PV and onshore wind, lowering the required investment per unit of capacity in these technologies. These reductions are apparent in both OECD and non-OECD markets, though a wide variation in investment costs exists at the country level, in large part due to differences in balance of system costs (e.g. land, labour, permitting). Further detail on the evolution of individual technology capital costs can be found in the "Renewable electricity: Global technology outlook" chapter. Going forward, it is assumed that investment costs for solar PV and onshore wind will continue to decline, though at slower rates than in the past, based on learning calculated from the MTRMR 2014 capacity forecast. Per-unit investment requirements in offshore wind are also expected to decline over time with further deployment.

Renewable financing remains challenging though new sources are emerging

Supported by long-term policy frameworks, renewable investment has risen to high levels, from a variety of sources. Still, the capital-intensive nature of projects can make the risk/return profile of such assets challenging for investors. Some sources with less experience of large-scale financing and deployment, such as offshore wind and CSP, carry higher real or perceived technology risks, which can raise the cost or reduce the availability of financing. The further development of a portfolio of financing sources remains a key for scaling investment.

Non-hydro renewables rely to a large extent on external funding, particularly debt finance from banks and project finance. Small-scale developers (e.g. households, municipalities, small businesses), particularly in Europe, often play an important role in solar PV and onshore wind investments. IEA analysis of data from Bloomberg New Energy Finance suggests that the financing of renewable capital

expenditures through retained earnings and equity remains well below that seen in the financing of conventional power plants in OECD countries (IEA, 2014a). Despite low long-term interest rates across a number of OECD markets, access to long-term debt for renewable projects can be challenging. Part of this trend stems from requirements imposed by Basel III, a global financial regulatory framework that requires increased capital and liquidity holding levels on banks, potentially reducing their willingness to hold long-term loans on their balance sheets. Moreover, the cost of debt can vary widely by market and is affected by larger economic risks; the spread among ten-year government bonds provides an indication.

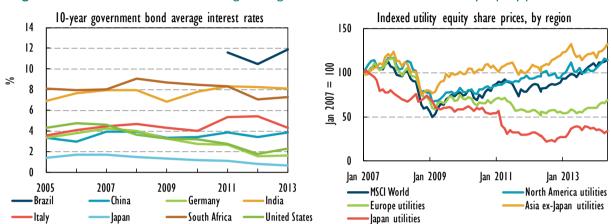


Figure 97 Investment indicators: Long-term government bond rates and utility equity performance

Notes: ten-year government bond interest rates not available for Brazil before 2011. Equity series are indexed monthly averages of MSCI equity price indices. MSCI World is a global, cross-sector equity market benchmark.

Source: IEA analysis based on data from Bloomberg LP (2014), (accessed June 2014).

The extent to which utilities can provide investment also faces constraints. In addition to new project development, utilities have often played an important role in acquiring operating renewable assets, allowing developers to recycle their capital for new projects. In Europe, utility cash flows are squeezed by reduced operating hours for conventional plants, stemming from a perfect storm of low demand, high natural gas prices, low carbon and coal prices, and increased shares of low-marginal-cost renewables. In the United States, proposed government emissions rules are likely to put cost pressures on coal generators. Still-low natural gas prices and substitution needs for retiring coal plants are stimulating investments in gas-fired generation and related infrastructure, which can have the effect of crowding out renewable investments. Moreover, utilities in both regions increasingly confront disruptions to the traditional business model of centralised electricity provision with the fast growth of distributed solar PV (see "Special focus: Solar PV reaching grid parity" in the chapter "Renewable electricity: Global technologies").

Other sources of capital are increasingly helping to supplement the role of utilities. In some segments where they have played a particular role in development, such as offshore wind, utilities are increasingly turning to project finance structures. Nevertheless, utilities are likely to remain key investors in renewable assets, and their credit worthiness will play an important role in attracting external funding and providing off-take contract security. For many, the long-term price stability of renewable generation can provide an attractive hedging option to the short-term volatility of gas generation, for example, as with some US onshore wind development.

 Table 52
 Renewable technologies, risks and types of investors

Renewable energy technology	Perceived technology risk	Resource risk	Policy deployment phase	Typology of investors
Ocean	High	Medium	Inception	Demonstration/ early-stage investors
Advanced biofuels	High	Low-medium	Early take-off	Demonstration/ early-stage investors
Conventional biofuels	Low	Medium	Take-off	Asset/project financing/large consortia/oil companies
CSP, wind offshore	Medium	Low-medium	Early take-off	Consortia/utilities
Solar PV, wind onshore	Low	Low	Take-off	Asset/project financing/utilities
Hydro, geothermal	Low	Medium-high	Consolidation	Very large/ consortia/utilities

Government-backed sources, such as development banks (e.g. European Investment Bank, KfW), green banks (as in the United Kingdom) and export credit agencies play a major and growing role in helping to scale up investment, particularly in Europe and non-OECD countries. Among the 26 leading players, development and export-import banks' annual investment in new renewable generation totalled more than USD 58 billion in 2012, with the largest disclosed outlays going to hydropower projects; since 2007, annual renewable financing from this group has more than tripled (Louw, 2013). Still, concessional financing arrangements can sometimes be complex in nature and difficult to scale and repeat over time in a given market (Dii, 2013).

The advent of a portfolio of financing options for renewable projects remains crucial for scaling up investment, but other sources remain mixed in terms of their development. Institutional investors (i.e. pension funds, insurers and sovereign wealth funds) represent a potential large and diverse pool of funds, whose desire for steady, long-term returns can mirror the type of inflation-linked payment streams that renewable projects with purchasing power agreements (PPAs) can provide. Asset allocation to direct investments in infrastructure by such actors are small (less than 1% for OECD pension funds) and green investments remain smaller, though some notable deals have occurred recently. OECD analysis suggests that with long-term policy frameworks, better information-sharing on risks and the development of suitable investment vehicles, among other steps, institutional funds could emerge as larger financing sources for renewables (Kaminker et al., 2013).

Investment vehicles that facilitate access to debt and equity capital markets could allow renewable projects to connect with larger pools of funds, including from institutional investors, at a lower cost of capital than traditional bank lending or project finance. Examples include project bonds, green bonds, yield company equity ("yieldcos") and asset-backed securities, which can offer predictable earnings and liquidity for investors. Bloomberg New Energy Finance estimates that the global market for corporate-issued green bonds, green asset-backed securities, clean energy project bonds, and green bonds from international organisations and governments totalled over USD 16 billion in the first half of 2014, more than the USD 14 billion in all of 2013 (BNEF, 2014). The attractiveness of such securities depends largely on having secure, long-term revenues from underlying assets (from a PPA), standardised structures and risk metrics to minimise transaction costs, and competition from investment alternatives.

Table 53 Examples of emerging investment vehicles for renewables

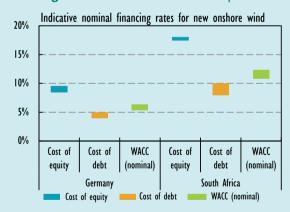
Security	Description	Example	Challenge
Project bonds	Debt securities issued on an individual project.	Bonds issued by Desert Sunlight, 550 MW solar PV project, which benefitted from loan guarantees.	More suitable for large projects with credit enhancements to secure credit rating.
Green bonds	Debt securities issued by corporations to support green investments.	EDF issuance of bond to finance future renewable projects through EDF Energies Nouvelles.	Tracing proceeds to green investments. Guidelines such as Green Bond Principles may be used.
Yield companies	Listed investment companies with equities that pay dividends based on underlying assets.	NRG Yield, which pooled existing renewable and conventional assets from parent NRG Energy.	Credit implication for parent company by moving performing assets into separate entity. Too illiquid and small for some investors.
Asset- backed securities	Debt securities that pool assets such as mortgages or auto loans.	SolarCity issuance of bonds linked to the revenue streams of a portfolio of distributed solar PV assets leased to households.	Securing a credit rating for bonds based on limited historical performance data of the leasing scheme.

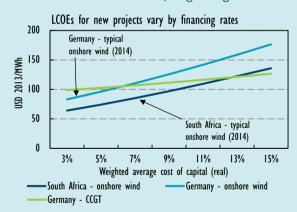
Source: IEA analysis based on Eckhart, M. (2014), From Billions to Trillions: New Business and Finance Models, presentation at Renewable Energy Working Party Workshop, International Energy Agency (IEA), Paris, March.

Box 10 Cost of capital a key to reducing renewable generation costs

The capital-intensive nature of renewables means that financing costs play a large role in determining LCOEs. The cost of capital is the risk-adjusted rate of return that investors require to make the use of their capital. Renewable investments are usually financed with a mixture of equity and debt. The costs of these components reflect the investor type, the project risk profile and the project sponsor's ability to raise capital, among other factors; together they represent the WACC.

Figure 98 Indicative costs of capital and LCOEs for new onshore wind, beginning 2014





Notes: MWh = megawatt hours; CCGT = combined-cycle gas turbine. WACC is based on financing structure of 70% debt/30% equity. WACC for South Africa based on rand financing. Typical Germany onshore full-load hours assumed at 2 000; South Africa assumed at 2 800. LCOEs calculated here are indicative and may not be directly comparable to announced PPAs under South Africa's REIPPPP, which are denominated in rand and increase annually based on an inflation-linked index.

Source: IEA analysis based on Kost, C., J. Mayer, J. Thomsen, N. Hartmann, C. Senkpiel, S. Philipps, S. Nold, S. Lude, N. Saad, T. Schlegl (2013), *Levelized Cost of Electricity: Renewable Energy Technologies*, Fraunhofer ISE, Freiburg; and Waissbein, O., Y. Glemarec, H. Bayraktar and T. Schmidt (2013), Derisking Renewable Energy Investment, United Nations Development Programme (UNDP), New York.

Box 10 Cost of capital a key to reducing renewable generation costs (continued)

In practice, the WACC for a given project is typically not observable, though it can be estimated using a variety of computation methods (CFA Institute, 2009). While it is beyond the scope of this report to make such calculations, *MTRMR 2014* does try to incorporate "real-world" assumptions of WACCs, where available, into its LCOE calculations. These are sourced from various published works (see, for example, Veiga et al., 2013; Kost et al., 2013; DECC, 2013) that survey investors as well as conversations with market participants. Such assumptions are indicated in the chapter on 'Analytical Framework' and in the text and graphical notes (in real, pre-tax terms) when individual country and technology LCOEs are being described. However, they are meant only to give broad indications of how WACCs can vary for a given market and technology, and may not represent the full range of financing costs for a given project. Further study in this area is needed to produce more robust data sets and indicators.

The impact of financing on generation costs is illustrated with onshore wind in Germany and South Africa. In Germany, the presence of a long-term policy framework that helps reduce exposure to market price risks, low non-economic barriers, well-developed financial markets and a stable currency and macroeconomic environment, among other factors, keep WACCs relatively low. In South Africa, despite having a long-term policy framework that awards power purchase contracts to renewable projects, the presence of non-economic barriers and grid integration risks keep the cost of capital relatively high (Waissbein et al., 2013). In South Africa, currency volatility can act as a significant factor to raise the cost of capital when project revenues are earned in local currency and financing comes from foreign sources.

Meanwhile, domestic capital markets may not be developed enough to provide ample, attractively priced capital. Overall, these factors can create a notable WACC differential between the two markets and explains why onshore wind LCOEs, for typical plants, can remain at comparable levels, despite better wind resources in South Africa.

Cost of capital reductions could help relatively high-cost renewable technologies and markets to close the gap with other generating technologies. Recent IEA analysis suggest the impact of an across-the-board reduction in WACC of 3% from 2015 could result in global savings of some USD 800 billion, or 40% of the additional subsidies estimate for new renewable capacity built through 2035 (IEA, 2014a). While a number of actions by policy makers could help to reduce risks that keep financing costs high, sustainable long-term policy frameworks that offer a degree of revenue certainty, as well as the avoidance of retroactive measures, are particularly important for capital-intensive renewable technologies.

To become effective financing tools, project bonds often require scale and simplicity while green bonds may need to demonstrate price attractiveness with other bonds of the same risk. Debt instruments can face the challenge of securing credit ratings based on limited historical performance data of underlying assets, particularly in the wake of the subprime mortgage crisis. Moreover, capital markets have remained less utilised for energy investments outside of the United States, where they are more liquid and deep. As such, they may take time to evolve into more mainstream sources of financing.

Non-OECD markets face particular issues regarding the financing of renewable projects. Unlocking domestic commercial capital remains a key for future development. In general, local banking markets remain less well developed than in OECD countries, and non-economic barriers can present entry challenges for foreign sources of financing, constricting the availability of capital. The creditworthiness of off-takers, often state-owned utilities, and currency risks that cannot be hedged can often raise project risks. Together, these factors work to raise the weighted average cost of capital (WACC). This has been the case of India, for example, where baseline interest rates are relatively high and renewable projects can face debt-borrowing costs of 10% to 14%, versus a 5%-to-7% range typical in the United

States (Nelson et al., 2012). Some policy measures are aiming to help to address the risks above. Moreover, concessional finance from government sources, such as the China Development Bank and Brazilian Development Bank, can complement these policy approaches, though they also raises risks tied to budgetary availability and administrative goals for these institutions.

Medium-term outlook for investment in new renewable power capacity

Over the medium term, renewable investment needs are expected to remain high by historical standards, but stabilise at somewhat lower levels through 2020. Required investment in new renewable power capacity under this report's baseline case forecast should average above USD 230 billion annually, in real terms, through 2020. In 2014, investment is seen at almost USD 250 billion as total annual net capacity additions remain around 125 GW, but annual investment slows for several years thereafter. The largest investment needs are seen in onshore wind, followed by solar PV, hydropower and bioenergy. Technologies with relatively high costs, STE and offshore wind, see rising investment needs towards the end of the forecast period.

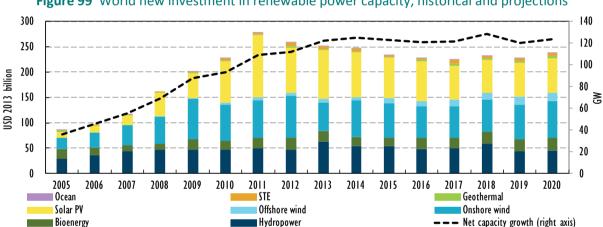


Figure 99 World new investment in renewable power capacity, historical and projections

The overall stable renewable investment outlook stems from two factors. First, slowing capacity growth in the OECD, due to overcapacity in some power markets, challenges related to the build-out of grids to integrate higher penetrations of variable renewables, and uncertainties over long-term policy frameworks are likely to limit investment gains. This more sluggish outlook for the OECD is compensated by higher growth in China and other emerging economies, such as Brazil and India. Yet many non-OECD countries, such as those in the Middle East, remain at the inception phase of renewable development, with deployment likely to accelerate to high levels only over the long run. Non-OECD countries also generally face still-high costs of capital and domestic financing constraints, which can also slow investment. Still, measures to reduce risks, such as the provision of long-term PPAs complemented by concessional financing, are helping to support investment in some markets.

Second, expectations of continued falls in unit costs for some renewable technologies, such as solar PV and onshore wind, are likely to act as a ceiling on investment expenditures, even as annual deployment in some technologies continues to grow. Moreover, over the medium term, hydropower is generally not seen maintaining the same exceptionally high capacity growth rate achieved in 2013, which provided a strong investment support.

10 000 9 000 Historical estimates Medium-term forecast Scenario analysis 8 000 7 000 Other renewable power 6 000 JSD 2013 billion Solar PV 5 000 4 000 Total wind 3 000 ■ Bioenergy 2 000 1 000 ■ Hydropower 0 2000-06 2007-13 2014-20 2014-35 2014-35 WEO New Policies WEO 450 Scenario Scenario

Figure 100 Cumulative new investment in renewable power capacity

- historical, forecast and scenario analysis

Note: New Policies and 450 Scenario data are reported in USD 2012 billion.

Sources: 2014-20 investment is derived from MTRMR 2014 estimates, while New Policies and 450 Scenario data are from IEA (2014a), World Energy Investment Outlook, OECD/IEA, Paris.

A number of variables will shape the environment for renewable energy financing over the medium term. Ultimately, investment trends will depend on the evolution of risks, chief of which is durability of prevailing policy support regimes, as well as technology developments, including costs and supply chain developments. In general, the cost and availability of finance from traditional sources – utilities, commercial bank project finance and governments – may represent a constraint on global deployment, with increased capital from other financial sources only beginning to emerge. New distributed technologies – particularly solar PV – may continue deploying rapidly should cost reductions continue, leading to novel and disruptive market solutions that challenge existing utility business models. Existing incumbents would need to recognise coming changes and adapt, finding ways to co-exist and leverage the value that such models can provide to customers and the system. To facilitate this transition, regulators have an important role to play in establishing market rules that allow for a fair return on existing distribution and transmission assets. The creditworthiness of incumbent energy firms (e.g. utilities, distribution companies) will remain an important factor in channelling future investment in renewables, with these entities remaining as major investors and providing offtake contract security.

Over time, the cumulative investment needs for new renewable capacity have risen from billions to trillions of dollars. To meet long-term deployment scenarios from the IEA WEO, renewable investment needs would likely strengthen, even as unit costs fall. Rising levels of deployment in non-OECD countries and increased development of relatively higher-cost technologies, such as offshore wind and STE, are likely to boost investment over time. Repowering and replacements of existing renewable capacity are also expected to play a larger role in supporting investment needs, particularly in the OECD.

To realise the high levels of renewables required to meet long-term climate change objectives, as set out in the WEO 450 Scenario, cumulative investment of almost USD 9 trillion would be needed. Attracting this high level of capital would require stable, long-term-oriented policy frameworks from governments and a market design that more effectively prices the value that renewable investments can bring to energy systems and increases power system flexibility to ensure system adequacy with higher levels of variable renewables. Recent IEA research – The Power of Transformation – suggests that such aims can be achieved in a secure and cost-effective manner (IEA, 2014b). However, this

result would require a system-wide approach to energy policy, one that promotes the deployment of integration-friendly variable renewables, fosters better operation of existing power assets and creates incentives for investment in additional flexibility options – grid infrastructure, dispatchable generation, such as gas-fired or hydro power, demand-side integration and storage – when needed.

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RENEWABLE HEAT

Summary

World final energy use for heat (FEH) accounts for more than half of final energy consumption, with three-quarters of this being met with fossil fuels. FEH therefore has a significant impact on energy security and is responsible for around one-third of global energy-related carbon dioxide (CO₂) emissions. Final energy use of renewable sources for heat is rising globally, driven by support policies and increasingly by cost-competitiveness with fossil fuels. However, growth rates are generally lagging those of renewable electricity.

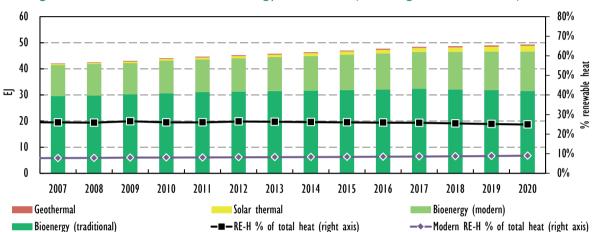


Figure 101 World final renewable energy use for heat (including commercial heat) 2007-20

Note: EJ = exajoules; RE-H = renewable heat. Traditional biomass is estimated here – in line with the methodology used in the International Energy Agency (IEA) World Energy Outlook – as the use of solid biomass in the residential sector of non-member countries of the Organisation for Economic Co-Operation and Development (OECD), excluding countries in non-OECD Europe and Eurasia.

Source: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

- World renewable energy use for heat rose from 41.7 EJ¹⁵ in 2007 to an estimated 45.8 EJ in 2013¹⁶ (+1.6% per year). Most of this was traditional biomass use¹⁷ in buildings in non-OECD countries (31.5 EJ in 2013), however. Modern renewable energy technologies such as modern bioenergy, solar thermal and geothermal, provided an estimated 14.3 EJ in 2013, up from 12.4 EJ in 2007 (+2.4% per year).
- In the **buildings sector**, renewable energy use for heat stood at 37.4 EJ in 2013, up from 33.7 EJ in 2007 (+0.9% per year). Modern renewable energy technologies, led by bioenergy (4.7 EJ), solar thermal (1.0 EJ) and geothermal energy (0.3 EJ), provided 5.9 EJ of the total. In the **industry sector**, renewable energy use for heat remained relatively stable between 2007 (7.4 EJ) and 2013 (7.7 EJ; +0.6% per year), with bioenergy providing 99% of the total.

¹⁵ This report expresses final energy use for heat in EJ. 1 EJ = 23.9 million tonnes of oil equivalent = 277.8 terawatt hours thermal = 947*10⁶ million British thermal units.

¹⁶ Please note that official IEA statistics are available only up to 2012 at the time of writing. The 2013 data presented here are therefore estimates based on analysis undertaken for this publication.

Traditional biomass use refers to the use of fuelwood, animal dung and agricultural residues in simple stoves with very low combustion efficiencies. No observed statistics are available and IEA estimates may vary from those of other international organisations. Traditional biomass use is estimated here – in line with the methodology used in the IEA WEO – as the use of solid biomass in the residential sector of non-OECD countries, excluding countries in non-OECD Europe and Eurasia.

• Over the medium term, global renewable energy use for heat is projected to grow from 45.8 EJ in 2013 to 49.3 EJ in 2020 (+1.1% per year), with traditional biomass use reaching only 31.6 EJ, due to a projected decline in many non-OECD countries. Use of modern renewable energy technologies for heat continues to grow from 14.3 EJ in 2013 to 17.7 EJ in 2020 (3.1% per year). In buildings it is expected to reach 8.3 EJ in 2020, up 5.9 EJ from 2013 (4.9% per year), with China accounting for two-thirds (1.6 EJ) of this growth. Due to the absence of strong drivers, renewable energy use for heat in industry is expected to grow from 7.7 EJ in 2013 to 8.7 EJ in 2020 (1.6% per year).

Total FEH today

FEH accounts for more than 50% of world total final energy consumption. Heat use per capita varies considerably less than total energy use per capita among different world regions, underlining the importance of the sector in all countries. Despite this importance, the heating sector receives less attention than the electricity and transport sectors.

FEH is defined here as direct use of energy for heat plus the use of commercial heat (heat produced and sold to a third party). This includes waste heat from power plants and industrial processes. Though heat can be, and is, used for cooling purposes, no reliable data exist that would allow for a solid analysis. This is an important constraint given that cooling demand is expected to increase in many regions around the world. Furthermore, heat can be derived from electricity and through heat pumps, both of which are not included here due to a lack of detailed data. A more detailed discussion on the methodology and potential limitations, as well as a detailed overview of recent market developments, is given in the recently published IEA publication *Heating Without Global Warming: Market Developments and Policy Considerations for Renewable Heat* (IEA, 2014). ¹⁸

Total FEH reached 171 EJ in 2012, with three-quarters (125 EJ) of this being met with fossil fuels (Figure 101). Around 40% of primary supply of natural gas, as well as 20% each of oil and coal, are being used for heat production, with important impacts on energy security and world CO_2 emissions: the production of heat accounted for around one-third (10 gigatonnes of carbon dioxide) of global energy-related CO_2 emissions.

The **buildings sector**, including both residential and commercial buildings, accounts for the largest consumption of heat in most countries. The most important uses within the sector are for cooking, and for water and space heating, most of which requires low-temperature heat at less than 100°C. Total FEH in buildings stood at 84 EJ in 2012, and grew at an average rate of 1% per year between 2000 and 2012, with some slight variations mainly due to prevailing weather conditions. Fossil sources, namely natural gas (27 EJ) and oil (13 EJ), make a considerable contribution to FEH in the buildings sector, accounting for 32% and 15% of the total, respectively. Coal plays only a minor role, contributing 8% (7 EJ) to the total. Renewable energy sources, including traditional biomass use, provide a large share of global FEH in the buildings sector, accounting for 44% (37 EJ) of the total in 2012 (Figure 102) around 85% (32 EJ) of which is traditional biomass use.

The heat demand structure in the **industry sector** varies among the different sub-sectors and might be continuous, variable as a result of batch processes, or seasonal due to availability of raw material. In addition, heat demand profiles vary among the different sub-sectors and range from low-temperature (<100°C) to medium-temperature (100°C to 400°C) and high-temperature processes (>400°C).

¹⁸ This Featured Insights Paper is available for free at: www.iea.org/publications/freepublications/publication/FeaturedInsight_ HeatingWithoutGlobalWarming_FINAL.pdf

Global FEH in industry stood at 78 EJ in 2012, accounting for 45% of world total energy use for heat in that year. This was up from 60 EJ in 2000, reflecting an average growth of 1.6 EJ per year. The main source of energy use for heat in industry was coal (33 EJ), accounting for 42% of total energy use for heat in 2012, up from 33% in 2000. Natural gas (23 EJ) and oil (13 EJ) also made considerable contributions (Figure 102) Renewable energy sources provided 10% (8 EJ) of the total energy use for heat in industry in 2012, with more than 99% of this being bioenergy. Geothermal (0.03 EJ) and solar thermal energy (0.01 EJ) made only minor contributions.

A mere 45% of total renewable energy use for heat is reported under the non-specified industry category, which puts a serious constraint on a more detailed analysis. Outside this category, the major share of total renewable energy use for heat in industry is concentrated in biomass-processing industries, led by pulp and paper, food processing, and the wood and wood products sector.

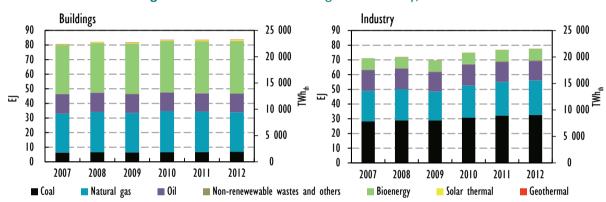


Figure 102 Total FEH in buildings and industry, 2007-12

In the **OECD**, FEH declined at a rate of 0.6% per year between 2007-13, with a stronger reduction in industry than in buildings. This was partly due to the economic crisis, and partly due to increased energy efficiency in buildings and industry, as well as the enhanced use of electricity for space heating in buildings in some countries. Despite continued improvements in energy efficiency, FEH in the OECD is projected to grow from 55 EJ in 2013 to 58 EJ in 2020 as economic growth recovers.

Non-OECD FEH has been growing much faster, at 2.4% per year 2007-13. This was primarily driven by growing demand in the industry sector (+3.5% per year) and to a smaller extent by the buildings sector (+1.4% per year). Economic growth as well as an increase in population should provide strong drivers for FEH in the non-OECD, leading to 2.2% annual growth on average. Total FEH should reach 140 EJ in 2020, with 70 EJ of this stemming from the industry sector, and 61 EJ in the buildings sector, in addition to 9 EJ in other sectors (agriculture, fisheries and others).

Renewable energy use for heat: Market trends, forecast and policy frameworks Market status and forecast

There is a range of renewable energy sources that can contribute to provide heat through three main routes. They can contribute either through the direct use of renewable energy sources for heat in buildings or industry, or through the feeding of renewable heat into district heating networks for use in households

and industry. The third option, which is not discussed in detail here, is to use renewable energy to generate electricity, which can then be turned into heat either directly or by operating a heat pump. ¹⁹

Box 11 Renewable cooling in industry and buildings

While data on final energy use for cooling are scarce, there is no doubt that cooling demand will increase in the future, mainly as a result of the expected economic growth in tropical and sub-tropical developing countries. Renewable energy technologies have already begun to contribute to global energy use for cooling, mainly in the buildings sector, and can make a considerable contribution to reducing emissions from growing cooling demands.

While renewable electricity provides options to decarbonise energy used for cooling, thermal renewable technologies also have considerable potential to provide space cooling through a set of technologies. These include direct cooling systems in which water, ice or snow can act as a cold source. Indirect cooling systems include electrically or thermally driven air-conditioning systems, or evaporative cooling systems. Furthermore, sorption cooling systems that operate on a similar cycle as heat pumps, but use heat instead of electricity to drive the system, open up interesting opportunities to use for instance solar thermal heat for cooling purposes in buildings and industry (for a more detailed overview see IEA, 2014). Jakob (2013) estimates that by the end of 2012, around 1 000 solar cooling systems were installed worldwide, with 80% of these installations found in Europe (mainly Spain, Germany and Italy). While solar cooling remains a niche market, the market has grown by 40-70% in recent years.

District cooling networks can be a suitable way to reach a better economy of scale and make use of renewable energy sources for cooling in a cost-efficient manner. According to Euroheat & Power (2013), at least 18 countries worldwide already have district cooling networks in place with 16 GW_{th} installed in the United States alone.

While there is great potential to use renewable heat, or waste-heat form co-generation plants and industrial processes, for cooling purposes, the costs for renewable cooling via thermally driven cooling technologies are relatively high. For instance, solar thermal cooling systems are currently in the range of USD 1 600- 3 200/KW $_{\rm th}$. and thus five to ten times higher than for standard air-conditioning systems. In addition, the cost-efficiency of solar thermal cooling systems is low and quality assurance and system certification procedures will be needed to help stimulate the market by building customer confidence (Mugnier and Jakob, 2012). Due to the rapid cost reductions for photovoltaic (PV) systems, a PV cell with storage coupled to an electric air-conditioning system could be a more economically attractive system in many circumstances, however.

In order to achieve a higher penetration of renewable energy use for cooling in buildings and industry, further technology development is needed to reduce costs. These cost reductions are crucial for the uptake of renewable heat-driven cooling systems. Some key RD&D needs for renewable cooling have been identified by EC/RHC-Platform (2013) and others:

- optimisation of sorption materials and efficiency improvements
- standardisation of equipment to develop plug-in-ready, small-scale renewable cooling systems
- integration of thermal cooling systems in smart cooling networks
- further improvement and cost reductions of cold storage.

This box draws on a section from the recently published IEA publication Heating Without Global Warming (IEA, 2014).

¹⁹ It should be noted that a heat pump can also produce renewable heat when operated on electricity of non-renewable origin, as long as the co-efficient of performance, i.e. the heat output to electricity input ratio, is greater than 1.

World renewable energy use for heat grew from 41.7 EJ in 2007 to an estimated 45.8 EJ in 2013 (+1.6% per year), and accounted for 26% of world total FEH. The growth was driven primarily by an increase in modern bioenergy, and to a smaller extent by growing use of traditional biomass, as well as solar thermal and geothermal energy use for heat. Modern renewable energy use for heat, i.e. excluding traditional biomass use, stood at an estimated 14.3 EJ in 2013, up 1.9 EJ from 2007 (+2.4% per year). Bioenergy (13.0 EJ) provided the lion's share of the total with smaller but fast-growing contributions from solar thermal (1.0 EJ), and geothermal (0.3 EJ).

Over the medium term, global renewable energy use for heat is expected to grow by 3.5 EJ to 49.3 EJ in 2020 (+1.1% per year). While traditional biomass use is expected to decline in most non-OECD countries as a result of urbanisation and enhanced access to modern energy sources, modern renewable energy use for heat is projected to grow from 14.3 EJ in 2013 to 17.7 EJ in 2020 (+3.1% per year), driven by support policies in around 50 countries around the world, as well as increasing cost-competitiveness with fossil-fuel-based heating in a growing number of countries. Modern renewable energy use for heat in the buildings sector grows from 5.9 EJ in 2013 to 8.3 EJ in 2020 (+4.9% per year), much stronger than in the industry sector, where the lack of suitable, cost-competitive renewable heating technologies in combination with the continued absence of policy drivers leads to only a 1.1 EJ increase, to 8.7 EJ in 2020 (+1.6% per year).

Box 12 Heat pumps: Efficient heating and cooling solutions, though not necessarily renewable

Heat pump systems consist of an air, water or ground heat source, the heat pump unit, and a distribution system for the generated heat or cold. They allow transferring heat from a low-temperature system to a higher-temperature system, by using an external source of energy (electricity, heat) as work. Heat pump systems are based on a cycle where the refrigerant is compressed on the side where the heat is needed, and heat is transferred via a heat exchanger. In the other half of the cycle, the refrigerant pressure is lowered and passes a second heat exchanger (called an evaporator), where it absorbs heat and thus cools the surrounding air or transfer liquid. Heat pump systems can be used for heating as well as cooling when a specific reverse system is installed that provides both heat and cold with the same heat pump (for more details, see IEA, 2014).

Heat pumps can provide efficient means of heating and cooling and are mainly used for space heating, cooling and domestic hot water supply in buildings, as well as in low-temperature heat and cooling applications in industry. Due to the external energy input needed for operating the heat pump, it is important to assess and account for only the actual share of renewable energy provided from the air, ground or water source.

In the European Union, heat generated by hydrothermal and air- and ground-source heat pumps is considered renewable under the Renewable Energy Directive (Directive 2009/28/EC). According to the directive, heat pumps can be considered a renewable technology as long as they result in a primary energy efficiency of at least 115%, which corresponds to a seasonal performance factor of 2.875 at an average efficiency of the electricity production of 40%. The energy considered renewable is the heat delivered, minus the electricity consumption of the pump.

Data availability and consistency on global market developments, installed capacity, and heat pumps' contribution to FEH and cooling are limited. Since official IEA statistics do not include heat pumps unless the heat is sold as commercial heat, this report does not cover the dynamically growing heat pump market that could potentially cover low-temperature heat demand in buildings and industry in the future. According to REN21 (2013), global ground-source heat pump capacity alone has doubled since 2005. In 2012, the estimated global installed capacity stood at 50 gigawatts thermal (GW_{th}) with an annual output of around 0.3 EJ of heat. The United States, China, Sweden, Germany and the Netherlands had the greatest installed capacities. In Sweden around 9% of district heat were provided by heat pumps in 2012.

OECD market status and forecast

In the **OECD**, total renewable energy use for heat grew at an average 0.9% per year, from 6.0 EJ in 2007 to 6.4 EJ in 2013, with bioenergy accounting for more than 90% of the total in 2013. Regional shares of renewable energy in total FEH reached 14.7% in OECD Europe, 11.2% in OECD Americas, and 5.1% in OECD Asia Oceania in 2013, which is rather low compared with most non-OECD regions (Figure 103). Growth from 2007-13 was strongest in OECD Europe (+3.3% per year), where the EU renewable energy targets for 2020 were a key driver for enhanced use of renewable energy for heat. OECD Asia Oceania also saw an increase in the use of renewable energy for heat (+2.3%) whereas it decreased in OECD Americas (-1.8% per year), mainly as a result of a 0.3 EJ decline in bioenergy consumption in industry (-3.4% per year) that is linked to the overall decline in industrial FEH due to the economic downturn after 2007, as well as a drop in production of pulp and paper and wood products in the same period.

In the OECD, the **buildings** sector accounts for more than half (3.5 EJ) of total renewable energy use for heat in the region. Biomass is the main source of energy for heat (3.1 EJ in 2013, of which 0.3 EJ is in the form of commercial heat), whereas solar thermal energy (0.3 EJ) and geothermal energy (0.1 EJ) make only a relatively small contribution to total renewable energy use today. OECD Europe is the largest consumer (2.2 EJ in 2013), with 17% of total energy demand for heat in buildings being met with renewable energy. Second is OECD Americas (1.1 EJ; 9% of total FEH in buildings), followed by OECD Asia Oceania (0.2 EJ; 5% of total FEH in buildings). Renewable energy use for heat shows steady growth rates, in particular in OECD Europe (+4.0% per year) and OECD Asia Oceania (+2.2% per year). Growth is driven primarily by support policies aiming at an enhanced use of renewable energy in general, as well as by policies promoting the use of specific renewable heating technologies (e.g. solar hot water).

Over the medium term, OECD renewable energy use in buildings is expected to grow at 2.1% per year on average, from 3.5 EJ in 2013 to 4.0 EJ in 2020. Renewable energy would then meet 13% of buildings total FEH. Growth in the OECD is driven by OECD Europe, where EU policies in particular drive a 0.4 EJ increase in renewable energy use for heat in buildings. OECD Americas renewable energy use in buildings increases more moderately (0.2 EJ over 2013-20) due to the lack of a comprehensive policy framework for renewable heat in the region and availability of cheap fossil fuels, in particular natural gas in both United States and Canada. The strongest relative increase in renewable energy use in buildings is expected in OECD Asia Oceania (+2.3% per year), driven among others by an increase in geothermal energy use for heat in Korea, and growth in solar thermal energy use in Australia. The absolute increase is small compared with other regions (0.03 EJ over 2013-20).

Consumption of renewable energy for heat in the **industry** sector of the OECD stood at 2.6 EJ in 2013, down from 2.9 EJ in 2007. Renewable energy contributed 12% to total industrial energy use for heat in 2013, with 98% of this generated from biomass. Renewable energy use for heat in industry grew in both OECD Asia Oceania (+2.3% per year over 2007-13) and OECD Europe (0.5% per year). At the same time, renewable energy use for heat declined considerably in the OECD Americas (-3.4% per year over 2007-13), amid a decline in overall industry FEH and more specifically a decline in pulp and paper production – the main sub-sector for bioenergy use for heat.

Industry use of renewables for heat, namely in the form of bioenergy, is projected to increase by around 0.4 EJ over 2013-20 (+2.2% per year). This includes a 0.1 EJ contribution of renewable heat provided in the form of commercial heat in 2020. Renewable FEH in industry also grows in OECD

Americas (0.2 EJ), as an expected recovery in economic growth fuels demand for enhanced use of bioenergy for heat. OECD Europe sees a 0.1 EJ increase in renewable FEH in industry whereas industry renewable FEH grows at 2.1% per year on average over 2013-20 in OECD Asia Oceania, from 0.26 EJ in 2013 to 0.30 EJ in 2020.

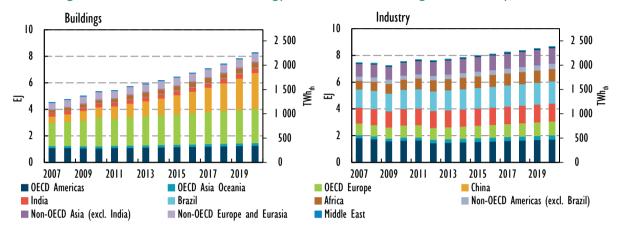


Figure 103 Modern renewable energy use for heat in buildings and industry, 2007-20

Non-OECD market status and forecast

In **non-OECD** countries, renewable energy use for heat grew at 1.5% per year on average over 2007-13 and accounted for one-third (40 EJ) of total FEH in 2013. Considerably higher shares of renewable energy in total FEH exist in regions with a large use of traditional biomass for heat (predominantly for cooking), including in Africa (78%), non-OECD Asia and India (50% each) (Figure 104). The use of modern renewable energy sources for heat, such as biogas and liquid biofuels, as well as solar thermal and geothermal energy, grew at 3.6% per year over 2007-13, and contributed 21% (8.0 EJ) of total renewable energy use for heat in 2013. Growth was particularly strong for solar thermal energy use for heat, which grew from 0.2 EJ in 2007 to 0.7 EJ in 2013 (22% per year), driven primarily by rapid deployment of solar water heaters in China.

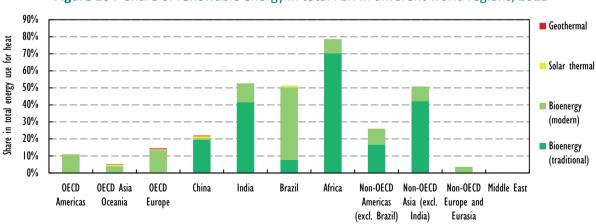


Figure 104 Share of renewable energy in total FEH in different world regions, 2012

Due to the considerable role of traditional biomass (estimated at around 32 EJ in 2013), the share of renewable energy in total FEH in the non-OECD **buildings sector** stood at 44% in 2013. The buildings

sector thus accounts for the lion's share of renewable energy use for heat in the non-OECD region. Modern renewable energy use for heat grew from 1.5 EJ in 2007 to an estimated 2.4 EJ in 2013, driven in particular by a rapid increase in solar thermal energy use for heat (+0.5 EJ over 2007-13), which is expanding in China (+22% per year 2007-13) and from a lower basis also in India (+23% per year over 2007-13) and Brazil (+27% per year). In addition, modern bioenergy (1.6 EJ in 2013) and geothermal energy (0.1 EJ in 2013) make growing contributions.

Over the medium term, there are two divergent trends in many non-OECD regions. First, the use of traditional biomass for cooking is projected to decline in a number of regions, due to economic development and continued urbanisation that allow for access of more efficient fuels. At the same time, the use of modern renewable energy is set to increase as a result of the same dynamics, as well as the impact of support policies in an increasing number of countries. The strongest decline in traditional biomass use is projected in China, where it is expected to decline at -1.4% per year from 7.8 EJ in 2013 to 7.1 EJ in 2020. Similar dynamics are expected for the non-OECD Americas (-2.9% per year) and some countries in non-OECD Asia. Albeit at lower speed than in past years, this publication projects an increase in traditional biomass use in Africa (1.1% per year over 2013-20 versus 2.7% per year over 2007-13) and India (0.1% per year versus 1.2% per year), underscoring the difficulty in providing modern energy services in the face of continued rapid population and economic growth.

Modern renewable energy use for heat in buildings follows a more positive growth path and is projected to grow at an average of 8% per year, from 2.4 EJ in 2013 to 4.2 EJ in 2020. With a total increase of 1.8 EJ over the 2013-20 time horizon, China alone is responsible for 90% of the increase in renewable FEH in buildings outside the OECD. This is in particular due to a projected 1 EJ increase in use of solar thermal energy for heat in the buildings, and to a smaller extent due to an increase in the use of biogas (0.6 EJ) in buildings. Absolute growth in the other non-OECD regions is more modest, with India (0.05 EJ) and Brazil (0.01 EJ) seeing the largest increase in use of modern renewable energy for heat in buildings, driven by targets for solar thermal installations, as well as modest increases in modern bioenergy use for heat. In most other non-OECD regions, modern renewable energy use for heat is driven primarily by an increased use of bioenergy and to a smaller extent solar thermal energy and geothermal.

In the non-OECD **industry** sector, renewable energy use for heat grew at 2.0% per year on average between 2007 and 2013, from 4.5 EJ in 2007 to 5.1 EJ in 2013. Bioenergy dominates the renewable energy use for heat in industry with a contribution of 5.1 EJ, whereas geothermal energy (0.01 EJ) and solar thermal energy (0.01 EJ) made only minor contributions. Of all non-OECD countries — with the exception of China, which does not report any bioenergy use in industry — Brazil had the largest consumption of bioenergy in industry in 2013 (1.5 EJ), thanks to its large sugar cane industry, its pulp and paper industry, and the use of charcoal in the production of pig iron. India, too, uses a sizeable amount of bioenergy for heat in industry (1.3 EJ in 2013). Africa (0.9 EJ) also has a considerable use of bioenergy in the industry sector. As in the OECD, too, this use is primarily the result of availability of process residues at competitive prices, and in some cases lack of access to alternative sources of heat, and is generally not linked to any support policies.

Growth in the industrial use of renewable energy for heat will remain slow over the medium term, as specific drivers that would enhance the use of these sources are generally lacking throughout the non-OECD countries. Total industry renewable FEH thus grows only 0.5 EJ, driven by an overall increase in industrial energy use for heat. With 5.6 EJ in 2020, bioenergy remains by far the most important source of renewable heat in industry, though geothermal and solar thermal are growing at a much faster rate.

Policy environment for renewable heat

In contrast to the renewable electricity sector, renewable heat has received significantly less attention by policy makers in the past. Only around 50 countries worldwide have adopted polices for the promotion of renewable heat (see below), most of which are member states of the European Union — whereas more than 100 countries have enacted policy frameworks to promote the use of renewable electricity.

The heating sector offers particular challenges for policy makers. Heat is much less amenable to regulation than electricity, as most electricity is distributed via regulated grids and the whole production, transmission and distribution process is centralised and often has a public ownership history. Heat, on the other hand, cannot be transported over large distances due to heat losses. The heat sector is thus much less regulated since heat is produced through a multitude of separate installations of widely varying sizes, at different temperatures, from several different and competing fuels, and across the full range of end-use sectors: industry, commerce, the public sector and private households. Reliable data on heat production, its utilisation patterns and the production costs are much more difficult to obtain than those for electricity. Heat metering is less practised and more costly than that for electricity. This makes the development of renewable heat policies, as well as the assessment of their effectiveness, much more difficult. A further complication for policy makers is the interaction between policies in the buildings sector designed to promote and encourage renewable heat production, and energy efficiency programmes aimed at reducing overall energy use and its carbon footprint.

The strongest policy drivers today have been adopted in OECD Europe as a result of the European Union's mandatory 2020 targets for renewable energy. A number of countries within the European Union have adopted ambitious targets for renewable heat or cooling within their NREAPs, and have put different support measures in place to reach these targets. There is uncertainty, however, about how the European Union policy framework relevant to renewable heat will evolve after 2020. In the recent Communication by the European Commission on a policy framework for 2020-30 (COM[2014] 15 final), the role of heat is largely overlooked. Also in other OECD countries, such as the United States, renewable heat support measures have been adopted, but without setting specific targets (Table 54).

A number of countries have introduced specific investment support schemes for different renewable energy technologies, including Austria, Germany, Norway, Italy and Sweden. The Netherlands, and the United Kingdom have both introduced FITs for renewable heat that should promote the adoption of renewable heating installations. The Netherlands' feed-in premium scheme applies notably to larger systems, whereas the Renewable Heat Incentive (RHI) in the United Kingdom was first introduced for businesses and industry in 2011 and was expanded to domestic customers in April 2014. It now provides incentives per kilowatt hour of renewable heat over a 20-year horizon. It is still too early to say if the RHI will be effective in stimulating renewable energy use for heat and provide sufficient incentive for the most effective combinations of renewable heating technologies. Nonetheless, this policy measure can be welcomed as one of the most innovative approaches worldwide. In Italy, the recently adopted incentive scheme for renewable heat, *Conto Termico*, is now taking off with 6 000 applications submitted by June 2014, despite availability of other incentive schemes such as the white certificate scheme and fiscal mechanisms.

Outside the OECD, policy initiatives remain concentrated in a few key countries, and no "spillover effect" on neighbouring countries is currently taking place. Renewable energy use for heat in China is growing rapidly, and ambitious targets in the 12th Five-Year Plan (FYP) play an important role in

sustaining this growth, in particular for solar thermal heat (560 GW $_{\rm th}$ by 2020). Incentives for the use of biomass residues in large power and co-generation plants in combination with a rapidly expanding district heating network, as well as investment subsidies for pellet stoves in some regions and an ambitious biogas programme, all drive the development of bioenergy use for heat.

Table 54 OECD country main targets and support policies for renewable heating and cooling

OECD	Regul	atory su	ipport			Ecor	nomic su	pport		
Country	NREAP*	SWH targets	Building obligations	Feed-in tariff/premium	Capital grants and subsidies	Soft loans	Tax incentive	Installers certification	Training programmes	Exemplary role of public buildings
Australia					Χ					
Austria	32.6%		Χ		Χ			Х	Χ	Χ
Belgium	11.9%		Χ	0	0		Χ	Χ	Χ	Χ
Canada		0			0		Х			
Chile							Χ			
Czech Republic	14.1%		Х		Χ		Х	Х		Χ
Denmark	39.8%		Χ	Χ			Χ		Χ	Χ
Estonia	17.6%				Χ			Χ	Х	Χ
Finland	47.0%		Χ	Χ	Χ			Χ	Χ	Χ
France	33.0%		Х		Χ	Χ	Χ	Χ	Х	Χ
Germany	15.5%		Χ		Χ	Χ		Χ	Χ	
Greece	19.7%		Χ		Χ	Χ	Х	Х		Χ
Hungary	18.9%		Χ		Χ			Χ	Χ	Χ
Ireland	12.0%		Χ	Χ	Χ		Х		Χ	
Italy	17.1%		Χ	Χ	Χ	Χ		Χ	Χ	Χ
Korea			Χ							
Luxembourg	8.6%		Χ	Χ	Χ				Χ	
Mexico			Χ							
Netherlands	8.7%			Χ		Χ	Χ	Χ	Χ	
Poland	17.1%				Χ	Χ		Χ	Χ	
Portugal	30.6%		Χ					Χ	Χ	Χ
Slovakia	14.6%		Х		Χ			Х	Х	
Slovenia	30.1%		Χ		Χ	Χ		Χ	Χ	
Spain	18.9%		Χ					Х	X	
Sweden	62.1%		Χ				Χ		Χ	Χ
United Kingdom	12.0%			Χ	Χ	Χ		Х	X	
United States					0	0	0			

Notes: x = national-level policy; o = state/provincial-level policy. RES-H = final energy consumption for renewable energy sources for heat; NREAP = national renewable energy action plan; SWH = solar water heating. For further information, refer to IEA/IRENA Joint Renewable Energy Policy and Measures Database, www.iea.org/policiesandmeasures/renewableenergy.

In addition, India has set a target for 20 million square metres (m²) of solar thermal collectors by 2022 in its Jawarhalal Nehru National Solar Mission (JNNSM), and supports the development of household biogas systems with investment grants. Brazil, too, has adopted targets for solar water heaters, and wants to install 2.9 million new units through 2014, mainly targeting low-income households. In South Africa, a target for equipping 1 million homes with solar water heaters by 2014 with a longer-

term target of installing 4 million solar water heaters by 2030 has been established, driven by the need to cut peak-load electricity demand. However, by January 2014 only 395 000 installations had been realised, with the Department of Energy planning to install the remaining 600 000 systems over the next three years (People's Assembly, 2014).

Table 55 Non-OECD country main targets and support policies for renewable heating and cooling

Non-OECD	R	egulatory support				Econ	omic sı	pport		
Country	NREAP*	SWH targets	Building obligations	Feed-in tariff/premium	Capital grants and subsidies	Soft loans	Tax incentive	Installers certification	Training programmes	Exemplary role of public buildings
Albania			Χ				Х			
Argentina										Χ
Belarus			Х							
Brazil		2.86 mln 2011-14								
Bulgaria	23.8%		X		Χ	Χ	Х	Χ	Χ	
China		560 GWth by 2020	Ο		Χ					
Croatia	19.6%		Х							
Cyprus*	23.5%		Χ		Χ					
India		20 mln m2 by 2022	0		Χ					
Kenya			X							
Kosovo	45.65%									
Latvia	53.4%		X				X		Χ	
Lithuania	39%		Х		Χ		Χ	Χ	Χ	
Malta	6.2%		Χ		Χ			X	Χ	
Moldova	27.19									
Montenegro						Χ			Χ	
Romania	22.05%		Χ		Χ			Χ	Χ	
Serbia	30%									
Uganda		30 000 m2 by 2017								
Uruguay					Χ	Χ				Χ

Notes: x = national-level policy; o = state/provincial-level policy. ktoe = thousand tonnes of oil equivalent. For further information, refer to IEA/IRENA Joint Renewable Energy Policy and Measures Database, www.iea.org/policiesandmeasures/renewableenergy.

The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

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.

In both OECD and non-OECD countries, there have been few efforts to enhance the use of renewable energy in the industry sector in the past. A few countries introduced policies that promote the use of renewable heat in industry years ago, such as some of the Nordic countries with a CO₂ tax. More recently, the European Union introduced an Emissions Trading Scheme (ETS) that includes CO₂ emissions from co-generation plants and energy-intensive industry sectors such as iron and steel and cement production. However, due to the low carbon price of less than USD 10 per tonne, the ETS

^{* 1.} Footnote by Turkey

^{2.} Footnote by all the European Union Member States of the OECD and the European Union

does not currently provide a strong enough incentive to promote the use of renewable heat in these sectors. Some incentives for large-scale solar thermal installations, including in industry, have been introduced in countries such as Austria, Germany, Thailand, and Tunisia, but solar thermal energy use in industry is yet at an early stage. Rather, some renewable electricity policies may lead to enhanced use of process residues in co-generation plants that then allow for some of the generated heat to be used on-site or sold via a district heating network. This is one reason renewable energy in industry is generally lagging the growth in the buildings sector.

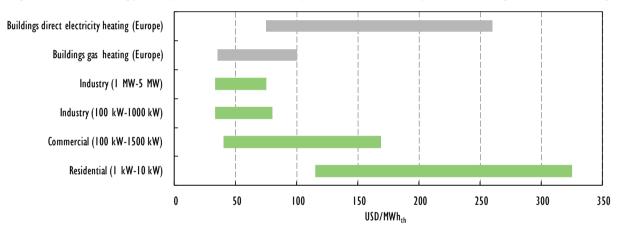
Renewable heating technologies

Bioenergy

Technology background

Biomass has been the basic source of energy for mankind for millennia, and some traditional biomass use today is still similar to the use of biomass for cooking in the Stone Age. In particular rural areas of many developing countries, biomass such as fuel wood, agricultural residues and dung is still used for cooking in open fires or simple stoves, and converted to useful heat at very low efficiencies.

Figure 105 Bioenergy heat production costs compared with electricity and natural gas-based heating



Note: MW = megawatt; kW = kilowatt; MW h_{th} = megawatt hour thermal.

Source: IEA (2012a), Technology Roadmap: Bioenergy for Heat and Power, OECD/IEA, Paris.

In many countries, however, modern biomass heating systems are spreading. These comprise domestic stoves or boilers run on wood logs, wood chips or wood pellets, as well as household biogas systems or oil burners run on vegetable oil. Solid biomass heating and co-generation systems are also common in commercial buildings and industry. In particular in the pulp and paper industry and in the food processing sector, the conversion of biomass residues offers an economically attractive source of process heat.

Capital costs for modern solid biomass heating systems vary depending on the scale, and lie in the range of USD 900 per kilowatt thermal (kW_{th}) to USD 1 500 kW_{th} for domestic systems, and USD 500/kW_{th} to USD 800/kW_{th} for industrial-scale heat plants. Typical heat generation costs are in the range of USD 0.08 per kilowatt hour thermal (kWh_{th}) to USD 0.30/kWh_{th} for domestic systems, which can in many cases be competitive with heat derived from heating oil. On the larger industrial scale, heat production costs are in the range of USD 0.03/kWh_{th} to USD 0.08/kWh_{th} and thus often competitive with oil- and natural gas-derived heat (Figure 105).

Most bioenergy heating technologies are already mature, but further cost reductions can be achieved through enhanced globalisation of the equipment market, and the expansion of large-scale supply chains for sustainable biomass, among others. The recently published IEA publication *Heating Without Global Warming* (IEA, 2014) provides a more detailed overview of different technologies.

Market status and forecast

Bioenergy is by far the most important source of renewable heat in the buildings sector, and its use grew steadily during the last decade, from 33.6 EJ in 2007 to an estimated 36.2 EJ in 2013 (1.3% per year), with 4.7 EJ of this (13%) being modern bioenergy in 2013. Although the numbers are subject to some uncertainty (see discussion on traditional biomass above), they clearly underline the importance of bioenergy in global energy use for heat, particularly in many developing countries. Another 7.7 EJ of bioenergy are used for heat in industry, mainly in the pulp and paper and food processing industries.

In the **OECD**, bioenergy use for heat in buildings has been growing at 2.5% per year over 2007-13, and reached 3.1 EJ in 2013, less than 10% of world final bioenergy use for heat in **buildings**. However, in some countries, including Chile and Sweden (each around 60% of total FEH in buildings in 2012), and Norway (around 55%), bioenergy is indeed the most important source of heat in the buildings sector today. OECD Europe saw the strongest increase in bioenergy use for heat in buildings over 2007-13 (0.4 EJ) and now accounts for roughly 65% of the OECD total. The increase was driven by the ambitious European Union targets for renewable energy that led many EU governments to introduce support policies for renewable heat, and was also helped by the steep increase in costs of fossil heating fuels over the last decade. Relatively weaker growth rates in OECD Americas (+0.8% per year over 2007-13) and OECD Asia Oceania (+0.3% per year) reflect the lack of strong policy drivers in these regions.

Over the medium term, continued strong growth in bioenergy use for heat is expected in buildings in OECD Europe, with the EU 2020 targets for renewable energy being the most important driver. Total bioenergy use for heat in buildings increases from 2.0 EJ in 2013 to 2.3 EJ in 2020. Growth in OECD Americas (0.2 EJ over 2013-20) is less than that of OECD Europe and is driven by a number of non-bioenergy-specific support policies such as buildings obligations (Chile, Mexico, United States) and tax incentives for renewable heat (United States). OECD Asia Oceania should also see an increase of more than 20% in total bioenergy use for heat in buildings, albeit from a rather low basis (0.1 EJ in 2013).

OECD industry use of bioenergy for heat stood at 2.6 EJ in 2013, and has been declining at -1.7% per year on average over the last decade due to the economic crisis. Bioenergy is mainly used in the pulp and paper industry, as well as the food industry, where process residues are available free of charge and thus provide a competitive source of heat for on-site use. The growth of biogas in some countries, e.g. Germany, has also helped to enhance the use of heat in industry, but to a much smaller extent.

In absence of strong policy drivers, little growth in industrial bioenergy use for heat is expected, with the OECD total growing by 0.5 EJ to 3.0 EJ in 2020. The projected demand growth is based on a continuation of historic growth that follows an increase in total energy use for heat in industry. The strongest increase takes place in the OECD Americas, where bioenergy use of heat in industry reaches 1.7 EJ in 2020, up from 1.5 EJ in 2013. In OECD Europe, industry's bioenergy use for heat grows at an average 2.1% per year, from 0.9 EJ in 2013 to 1.1 EJ in 2020.

Non-OECD countries account for almost 90% (39 EJ) of global bioenergy use for heat, and in several developing countries biomass accounts for more than 90% of total FEH in buildings. In Africa, for

instance, 80% of water and space heating demand is met with bioenergy in the buildings sector, with most of this being traditional biomass use. Considering the poor quality of data on biomass use in the non-OECD, and acknowledging that the definition of traditional biomass use used here is only a proxy, these numbers should be interpreted with care.

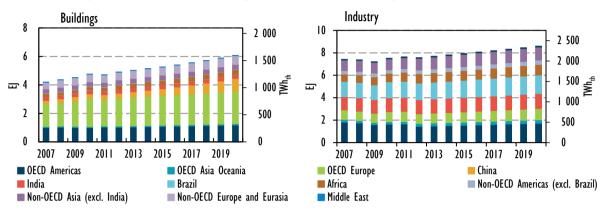


Figure 106 Modern bioenergy use for heat in buildings and industry, 2007-20

Modern bioenergy FEH is growing at 4.7% per year, but still provided only an estimated 1.6 EJ (less than 5%) of non-OECD bioenergy use for heat in the **buildings** sector in 2013. Non-OECD Europe (0.6 EJ), followed by China (0.5 EJ), were the biggest consumers of bioenergy for heat in buildings in 2013. In China, an ambitious household biogas programme has led to a growing use of biogas in buildings, so that biogas provides the major share (0.4 EJ) of modern bioenergy use for heat in buildings.

Over the medium term, non-OECD modern bioenergy use for heat in the buildings sector is projected to increase to 2.2 EJ in 2020. Most of this growth (0.7 EJ) stems from China, where ambitious targets for biogas in the 12th FYP, and increasing demand for biomass heating, including a small share of biomass used in district heating networks, are driving the growth. Biogas use in households is also set to increase in India, driven by capital grants for new installations. In most other regions the growth is more modest, as the transition from traditional biomass use to modern bioenergy is expected to proceed only slowly, and ongoing urbanisation leads to use of fuels other than bioenergy.

Non-OECD **industry** use of bioenergy for heat stood at 5.1 EJ in 2013. It should be noted though that this picture might be incomplete, given the fact that China does not report any use of bioenergy for heat in industry despite its huge pulp and paper industry. Brazil is the largest consumer of bioenergy for heat in industry (1.5 EJ in 2013) thanks to its large sugar cane and pulp and paper industries, where the use of biomass residues for generation of process heat is common. In addition, charcoal is used in pig iron production. India, too, has a considerable use of bioenergy for heat in industry (1.3 EJ), comparable to non-OECD Asia (1.1 EJ), and considerably more than Africa (0.9 EJ).

Over the medium term, non-OECD growth of industrial bioenergy use for heat is projected to grow by 0.5 EJ (1.3% per year), to 5.6 EJ in 2020, with similar growth rates in most regions. Growth is almost entirely driven by an expected increase in industry energy demand, since no strong policy drivers for the industry sector exists. Brazil will remain in a leading position, despite a significant slowdown in the expansion of ethanol and sugar production (see "Renewable Transport" for more details).

Solar thermal

Technology background

Various solar thermal technologies are available today, including direct hot water systems, combined hot water and space heating systems, and large-scale systems for district heating and industrial applications. Different collector designs exist, ranging from unglazed flat-plate collectors used mainly for swimming pool heating, to flat plate and vacuum tube collectors and concentrating collectors that track the sun. Most solar hot water systems are mature, and are now cost-competitive with heat from fossil fuels and electricity in China, Israel²⁰ and several other countries.

Direct electricity heating (Europe) Gas heating (Europe) District heating (Central Europe) Large-scale system (Southern United States) Industr.process heat (South and Central Europe) Hot water and space heat (Central Europe) Hot water, pumped (Central and Northern. Hot water, thermosiphon (Southern Europe) Solar hot water, thermosiphon (China) 0 50 100 150 200 250 300 350

Figure 107 Solar thermal heat production costs compared with electricity and natural gas-based heating

Sources: Based on IEA (2012b), Technology Roadmap: Solar Heating and Cooling, OECD/IEA, Paris; RHC-Platform (2013), Strategic Research Priorities for Solar Thermal Technology, RHC-Platform, Brussels.

USD/MWhth

The costs associated with solar space and water heating depend on the type of technology, system design and complexity, and specific regional circumstances (resource availability, installations costs, etc.). For systems at building scale, investment costs can range between USD 240/kW_{th} and USD 2 400/kW_{th} around the world. Larger systems benefit from economies of scale, and costs are typically between USD 350/kW_{th} and USD 1 040/kW_{th} (IEA, 2012b). The resulting heat production costs depend on the size of the installation, as well as the region in which they are installed. Solar hot water thermosiphons in China can generate heat in the range of USD 20/MWh_{th} to USD 50/MWh_{th}, competitive with both gas and electricity heating systems. Domestic systems with forced circulation in Central Europe produce heat at considerably higher costs of USD 110/MWh_{th} to USD 145/MWh_{th}, which should still be competitive with electricity-derived heat in most circumstances (Figure 107). The most cost-effective solar thermal application in Europe is solar district heating in Denmark (see Box 13 for more details). The ground-mounted collector fields of 10 000 m² and more cost around USD 390/kW_{th} installed and piped, and heat prices as low as USD 43 per megawatt hour can be reached (Solarthermalworld.org, 2014b).

Medium- and high-temperature technologies for industrial applications are still in the development phase and face a number of hurdles that need to be overcome before greater market penetration

²⁰ 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.

can be achieved. A detailed overview on the various technologies and economics of different solar thermal heating installations can be found in the recently published IEA publication *Heating Without Global Warming* (IEA, 2014).

Market status and forecast

Solar thermal heating installations have been growing considerably around the globe in the last decade. Global installed solar thermal capacity reached 271 GW $_{th}$ in 2012, including district heating and industry installations (Table 56). The market for industrial applications is growing slowly, but still only around 120 operating solar thermal systems with a total installed capacity of about 88 MW $_{th}$ (125 600 m 2) were dedicated to industrial process heat in early 2014, according to the IEA Solar Heating and Cooling Implementing Agreement project database (SHIP, 2014). However, data on project for industrial heat in China and India are currently still scarce, and the contribution of solar thermal to industry FEH in those countries might therefore be potentially underestimated.

Table 56 Solar thermal heat installed capacity (GW_{th})

	2012	2013	2014	2015	2016	2017	2018	2019	2020
China	180.4	207.4	238.6	274.4	315.5	362.8	417.3	479.8	551.8
Germany	11.4	12.2	13.1	14.0	15.0	16.0	17.1	18.3	19.6
India	4.5	5.4	6.4	7.7	9.2	11.0	12.1	13.2	14.5
South Africa	1.0	2.6	4.2	6.1	8.7	10.0	11.5	13.2	15.1
Turkey	12.6	13.1	13.6	14.1	14.6	15.1	15.7	16.3	16.9
United States	13.6	13.8	14.0	14.3	14.5	14.8	15.0	15.3	15.5
Rest of world	47.9	51.7	55.4	59.2	63.2	67.6	72.5	78.1	84.3
World	271.3	306.2	345.3	389.7	440.7	497.3	561.2	634.2	717.8

Note: 2013 data are estimated.

Source: IEA analysis including historical estimates for non-OECD country capacities provided by IEA Solar Heating and Cooling Implementing Agreement (Mauthner and Weiss, 2014).

As was the case in last year's *Medium-Term Renewable Energy Market Report*, our analysis of solar thermal energy use for heat relies on official IEA statistics, where available, and sources data for some countries from the IEA Solar Heating and Cooling Implementing Agreement, which produces an annual report with detailed country-level data on installed solar thermal heat capacity (Mauthner and Weiss, 2014).

Global solar thermal energy use for heat in buildings grew at 16% per year on average over 2007-13, and reached an estimated 1.0 EJ in 2013. The buildings sector accounts for virtually all solar thermal energy use for heat worldwide (0.9 EJ), whereas industry use is currently negligible (0.01 EJ). Solar thermal energy use for heat in the **OECD** member countries' **buildings sector** grew modestly, from 0.2 EJ 2007 to 0.3 EJ in 2013 (+6.1% per year). OECD Americas and OECD Asia Oceania were traditionally the regions with the largest solar thermal energy use for heat in buildings. The United States is still the leading OECD member country in terms of total consumption (0.07 EJ); however, most solar thermal energy there is currently used for swimming pool heating rather than for space heating or hot water provision in buildings. Israel, which has supported use of solar hot water systems since the 1980s, is now among the best-developed markets for solar thermal, with 80% of all households equipped with a solar thermal system (IEA, 2014).

Box 13 Solar thermal district heating in Denmark

An increasing number of solar thermal installations are connected to district heating networks in countries such as Denmark (where the world's largest solar thermal district heating plant opened in February 2014), Austria and Germany. In Europe, more than 300 MW_{th} of solar district heating capacity has been installed (RHC-Platform, 2013).

With more than 260 MW_{th} of capacity installed, Denmark is now the global leader in solar thermal district heating. The success of large-scale solar thermal plants for district heating in Denmark over the last decade is remarkable. Support policies, including low-interest loans for municipalities and a carbon tax on fossil fuels, have been an important driver for the development, but Denmark's already-extensive district heating network with relatively high costs for conventional district heat was a crucial pre-condition. The strong local solar collector industry created opportunities to integrate solar thermal installations into the existing district heating system, as well as to establish new solar thermal heating networks (Dalenbäck, 2010).

System costs of Danish large-scale solar thermal installations are now in the range of USD 350/kW_{th} to USD 400/kW_{th}, with production costs of heat as low as USD 43/MWh_{th} in some cases, whereas in other European countries costs are up to USD 1 040/kW_{th} (IEA, 2012b). In order to replicate the Danish example of solar district heat, the presence of a district heating network, and operational experience with it, is certainly an advantage, but it is not imperative. For new solar thermal district heating schemes, a dedicated low-temperature heating network is often built to ensure efficient distribution and use of the solar thermal heat. The recent developments in solar thermal district heating have already led to significant cost reductions for large-scale solar thermal installations, enhancing the opportunity for further deployment of the technology in an increasing number of geographical and economical contexts.

Source: IEA (2014), Heating Without Global Warming: Market Developments and Policy Considerations for Renewable Heat, OECD/IEA, Paris.

Recent growth in the OECD was driven primarily by capacity additions in EU member states that brought total use of solar thermal energy for heat in buildings in OECD Europe to 0.1 EJ in 2013. Germany is the leading market in terms of new additions, driven primarily by the EU 2020 targets for renewable energy. However, growth in capacity additions slowed over the last years, with 2013 seeing only around 1 million m² being added, whereas an estimated 2 million m² would be needed to reach targets in the NREAP. In other countries in Europe, market growth has slowed recently, as the economic crisis affected the construction sector and led to reduction in support schemes (e.g. in Portugal), in addition to a decline in capacity additions in mature markets such as Greece and Austria. Most of the growth in the European Union was for water heating, but "combi-systems" for water and space heating are now spreading, and have recently reached a 50% market share for instance in Germany (for more details see ESTIF, 2014).

Over the medium term, solar thermal energy use for heat in buildings is expected to continue to grow solidly in the OECD region. The strongest growth over the 2013-20 period is projected for OECD Europe (+0.1 EJ), where the EU 2020 targets for renewable energy have led to adoption of various support measures for renewable heat (Tables 54 and 55) that – if continued – should drive solar thermal installations in many EU member states. In OECD Americas, growth is more modest (0.02 EJ) although the federal investment tax credit in the United States should support solar thermal capacity addition until 2016. In OECD Asia Oceania, growth in solar thermal energy use for heat in buildings is led by Australia, whereas Israel's use will remain at the relatively high level it reached in the past.

In the **industry** sector, solar thermal energy use for heat is yet in its infancy, as relatively high costs compared with conventional technologies, as well as integration challenges and lack of standardised equipment, among others, prevent a rapid adoption. OECD solar thermal energy use for heat in industry thus stood at an estimated 0.01 EJ in 2013, with most of this coming from OECD Europe, where a number of demonstration projects have been installed thanks to EU funding. ²¹ As current barriers are expected to prevent a rapid growth of solar thermal energy use for heat in industry, only a 0.01 EJ increase is projected over 2013-20, with most of this growth expected to occur in OECD Europe.

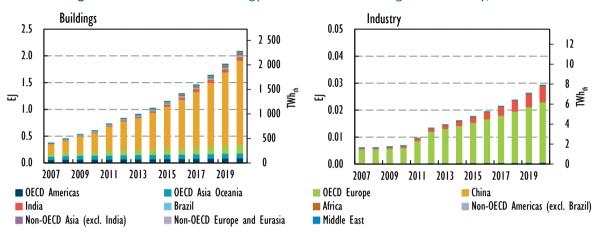


Figure 108 Solar thermal energy use for heat in buildings and industry, 2007-20

Non-OECD use of solar thermal energy for heat has been growing only slowly in almost all non-OECD countries. A clear exception is China, which has become the global leader in solar thermal energy use for heat, with a total installed solar thermal energy capacity at 180 GW $_{th}$ in 2012 (Mauthner and Weiss, 2014). Due to rapid growth in China, non-OECD solar thermal energy use for heat has been growing at an average 22% per year, from 0.2 EJ in 2007 to an estimated 0.6 EJ in 2013.

The **buildings** sector is by far the largest consumer of solar thermal energy for heat (0.7 EJ) in the non-OECD region. China accounted for 90% of this use, thanks to the rapid growth of solar water heaters over the last decade. Installed solar thermal capacity in China more than doubled between 2007 and 2012, driven by policy support by the Chinese national government as well as by provinces and cities. Thanks to significant cost reductions, the attractive economics of solar hot water systems, which are now considerably cheaper than gas- or electricity-based systems, is now a key driver for the market. Use of solar thermal energy in buildings is much smaller in India and Brazil (0.02 EJ each), but still higher than in all other non-OECD countries combined.

Continued strong growth is projected over the medium term in China where – despite slowing growth rates (+15% per year on average) – solar thermal energy use for heat in buildings should grow from 0.6 EJ in 2013 to 1.6 EJ in 2020. The increase is driven by the economic attractiveness of solar hot water systems, and the introduction of solar obligations for larger building complexes in several cities and municipalities – including the city of Beijing – under the Renewable Energy Law of 2006 (Solarthermalworld.org, 2013). Solar thermal energy use for heat in South Africa is projected to increase more than ten-fold to 0.05 EJ in 2020 (+29% per year) driven by the targets for solar hot water systems. India should also

²¹ See for instance www.solar-process-heat.eu

see solid growth (+15% per year) thanks to the JNNSM published in 2010 with the long-term objective of installing 14 GW_{th} (20 million m²) of solar thermal capacity by 2022. Solar thermal energy use in India is thus expected to reach 0.06 EJ in 2020, almost twice as high as in Brazil (0.03 EJ), and almost as high as that in all other non-OECD countries combined (0.07 EJ in 2020).

Virtually no use of solar thermal energy for heat is reported for **industry** in the non-OECD, despite considerable potential in low-temperature applications in many sunnier countries. This may be in part due to the lack of accurate data on industrial process heat applications for solar thermal. A number of commercial kitchens in India use solar thermal energy to produce steam for cooking, and many other sectors in several non-OECD countries would have potential for enhanced use of this resource. However, given the slow uptake of solar thermal installations in industry, only small growth is expected in the non-OECD industry sector over the medium term.

Geothermal

Technology background

Geothermal energy can be used directly for heating and cooling purposes in buildings, district heating, greenhouses, pools, and industrial process heat. The hot water extracted from a hydrothermal resource or a deep aquifer can be used directly and be distributed through pipes to buildings, industry or other applications, for instance in a district heating network. Alternatively, heat from the hot water of a geothermal well is transferred to a working fluid via a heat exchanger. The working fluid is then piped to the demand location, and circulated back to the heat exchanger after use. Direct-use systems are particularly widespread in Iceland, where geological conditions are ideal for the use of geothermal energy for heat.

Direct electricity heating (Europe)

Gas heating (Europe)

Geothermal (greenhouses)

Geothermal district heating

0 50 100 150 200 250 300

USD/MWh_{th}

Figure 109 Geothermal heat production costs compared with electricity and natural gas-based heating

Source: IEA (2014), Heating Without Global Warming: Market Developments and Policy Considerations for Renewable Heat, OECD/IEA, Paris.

The temperature ranges that can be achieved with the direct use of geothermal energy for heat are in the range of 60° C to 180° C, and can reach up to 300° C in ideal locations (IEA, 2011). The production costs of heat derived from geothermal energy differ depending on the resource, distance to the location of consumption, and heat demand. Geothermal heat can be generated at costs of USD $35/MWh_{th}$ to USD $55/MWh_{th}$ when the heat demand is stable and close to the heat source. Costs can go up to USD $85/MWh_{th}$ for heat provided through a district heating network (Figure 109). A more detailed overview on the technologies and economics of geothermal energy use for heat can be found in the recent IEA publication *Heating Without Global Warming* (IEA, 2014).

Market status and forecast

Global use of geothermal energy for heat has increased from 0.2 EJ in 2007 to an estimated 0.3 EJ in 2013 (6.5 % per year). Most of the global use of geothermal energy for heat is in the buildings sector in OECD Europe and China. Total **OECD** use of geothermal energy for heat reached an estimated 0.16 EJ in 2013, with 0.11 EJ of this being used in the buildings sector. Within OECD member countries, Italy and France have a long history of exploiting high-enthalpy geothermal resources; however, Iceland has by far the highest share of geothermal energy use for heat in the buildings sector: more than 95% of FEH is met with geothermal energy provided primarily through district heating networks today. Turkey nonetheless accounts for the largest share of final geothermal energy use in buildings within OECD member countries, thanks to the considerable expansion of district heating networks that allow the country's vast geothermal potential to be tapped.

OECD use of geothermal energy in buildings should increase by 20% to 0.14 EJ in 2020, driven by continued growth in OECD Europe, and to a smaller extent by the OECD Americas. Turkey is the fastest-growing OECD market thanks to its considerable geothermal potential, but further growth is also expected in Japan, as well as in a number of countries in OECD Europe. Based on historic growth rates, only little growth is expected to occur in OECD Americas.

OECD use of geothermal energy for heat in industry stood at around 0.01 EJ in 2013, and thus represented 60% of the global total industrial use. Geothermal heat is used in low-temperature applications in various industry branches (pulp and paper, chemicals, food and beverages) and is the result of resource availability at competitive cost, rather than any policy efforts. The up-front investment and operating costs associated with the exploitation of geothermal resources at greater depth are the main barriers today to further expansion of geothermal production. Due to the geographically limited resource availability of cost-competitive geothermal energy sources, in absence of specific policy drivers, no significant increase in geothermal energy use for heat in industry is expected over the medium term.



Figure 110 Geothermal energy use for heat in buildings and industry, 2007-20

Non-OECD geothermal energy use for heat in buildings is growing steadily, driven almost entirely by developments in China. China has been developing geothermal energy since the 1970s, and is today

²² Please note that ground-source heat pumps are not included in this category. See IEA, 2014, for more details on heat pumps.

the world's largest user of direct geothermal energy for heat in the buildings sector (an estimated 0.15 EJ in 2013). A large share is used for spa and swimming pool heating, with a smaller share distributed through the rapidly expanding district heating network and used for space heating. In other non-OECD countries, the use of geothermal energy for heat in buildings is almost negligible today. None of the non-OECD countries with considerable geothermal power generation (such as the Philippines, Indonesia and El Salvador) uses geothermal energy for heat, primarily due to the relatively low demand for space heating and the subsequent absence of a district heating network.

Due to its considerable geothermal resources in the form of hot aquifers and hot rocks, and with ambitious targets for the expanded use of geothermal energy for heat included in its 12th FYP (through 2015), China will drive global growth in geothermal energy use for heat in buildings. Total use should increase 0.1 EJ between 2013 and 2020, whereas almost no increase in geothermal energy use for heat is forecast for the rest of the non-OECD.

At 0.01 EJ in 2013, industrial use of geothermal energy for heat in the non-OECD region is small in comparison. China accounts for virtually all of this use, and will keep this position over the medium term, as geothermal energy use for heat in industry is projected to grow only marginally due to the absence of any strong drivers throughout the non-OECD countries.

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RENEWABLE TRANSPORT

Summary

- The geography of policy support for biofuels is changing. After a decade of fast growth, policy support is waning in member countries of the Organisation for Economic Co-operation and Development (OECD), notably the United States and the European Union, but burgeoning in new non-OECD markets such as Southeast Asia. Although growth projections have been trimmed, global biofuel production is still expected to grow to about 139 billion litres (L) in 2020, up roughly 20 billion L or 20% from 2013 levels. These projections are around 2 billion L below the production levels projected for 2018 in the Medium-Term Renewable Energy Market Report 2013 (MTRMR 2013).
- After a period of rapid growth, biofuel production and consumption in the United States, the European Union and Brazil appears to be shifting gears. In the United States, the design shortcomings of previous biofuel mandates have become manifest, leading to policy reviews that have introduced a measure of uncertainty into the market. In Brazil, the ethanol industry's poor economic situation is worsening, as costs for land and labour rise and margins from sugar and ethanol production fall. In the European Union, ongoing controversy about the sustainability of biofuels has led to a proposed cap on conventional biofuel use that leaves the industry in limbo until a final decision on the proposal is taken, making new investments in production capacity very unlikely.
- At the same time, policy support is burgeoning in non-OECD countries, notably oil-importing economies in Southeast Asia and Africa that subsidise fuel consumption, where rising domestic biofuel production promises a valuable option to lowering fuel import bills.

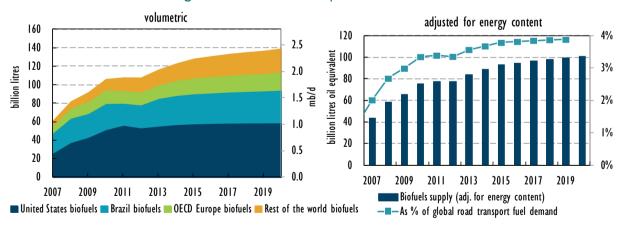


Figure 111 World biofuel production 2007-20

Source: unless otherwise indicated, all material in figures and tables derives from International Energy Agency (IEA) data and analysis.

• Due to the less optimistic forecast for the United States and Brazil, world ethanol output is now forecast to reach 104 billion L in 2020. For 2018, the forecast has been cut by almost 4 billion L from levels projected last year. By contrast, expectations of biodiesel production have been revised marginally upwards. World biodiesel production is expected to edge up to 35 billion L in 2020, roughly 0.6 billion L higher in 2018 than projected in the MTRMR 2013, as stronger growth in non-OECD Asia outweighs downward revisions in the non-OECD Americas.

- The **advanced biofuels** industry faces headwinds but capacity is expanding. In 2013, operating capacity reached almost 2 billion L,²³ and could reach 4 billion L in 2020, if all projects currently under construction and announced come on line as planned. Growth is slower than projected in last year's *MTRMR*, as a number of companies have cancelled or postponed projects as they struggle to secure investments in light of an increasingly uncertain policy framework in two key markets, the European Union and the United States.
- While liquid biofuels are the only sizeable source of renewable energy in transport today, biogas is
 entering the market in some countries (Sweden, Germany). Another option, which is not discussed
 in detail here, is to use renewable electricity in electric vehicles and other transport modes (e.g.
 rail), an option that is discussed in Box 14 below.

Global overview

The policy framework for biofuels is shifting

The biofuel sector's future remains heavily dependent on policy support in virtually all markets around the world. More than 60 countries worldwide have adopted support measures for biofuels, in the form of blending mandates or targets, often complemented with financial support tools such as tax exemptions (Table 58).

Two main policy trends can be distinguished globally: in the more mature markets of the United States, the European Union and Brazil, where the biofuels industry underwent dramatic growth in the last decade, political support for biofuels appears to be waning and production growth shifting into a lower gear. At the same time biofuels production and use are being supported in "frontier" markets by financial and fiscal policies designed primarily to reduce those markets' state energy import bills and redress their trade balance. Oil-import dependent countries in Southeast Asia and Africa that can ill afford the fiscal burden of transport fuel subsidies and/or high import bills amid stubbornly high oil prices beef up support measures for home-grown biofuels to replace imported diesel or gasoline.

Table 57 World biofuels production 2013-20

Billion L	2013	2014	2015	2016	2017	2018	2019	2020	CAGR
OECD Americas	57.3	59.0	60.1	60.5	60.6	60.5	60.6	60.4	0.8%
United States	55.3	56.9	57.8	58.3	58.5	58.7	58.8	58.8	0.9%
OECD Europe	14.3	16.0	16.9	17.5	17.9	18.2	18.5	19.3	4.4%
OECD Asia Oceania	1.1	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.6%
Total OECD	72.7	76.2	78.3	79.3	79.7	80.0	80.3	81.0	1.6%
Non-OECD Europe	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	1.5%
China	2.3	2.6	2.8	3.0	3.2	3.2	3.4	3.5	6.6%
Non-OECD Asia	6.3	7.0	7.8	8.4	9.0	9.5	9.8	10.3	7.2%
Non-OECD Americas	34.2	36.0	37.7	38.5	39.5	40.4	41.1	42.1	3.0%
Brazil	30.1	31.7	32.7	33.2	33.9	34.3	34.8	35.7	2.4%
Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	9.8%
Africa	0.2	0.5	8.0	1.0	1.1	1.3	1.3	1.5	29.5%
Total Non-OECD	43.5	46.6	49.7	51.4	53.4	55.0	56.3	58.1	4.2%
Total World	116.3	122.8	128.0	130.7	133.1	135.0	136.6	139.1	2.6%

²³ In contrast to the previous medium-term analysis, hydrotreated biodiesel is not included in this number, because hydrotreated biodiesel technology has reached maturity, and main feedstocks are conventional biofuels feedstocks such as vegetable oils.

Table 58 Global main targets and support policies for liquid biofuels

Regulatory frameworks: European Union Renewable Energy Directive (RED): Argentina, Australia, Austria, Bulgaria, Czech Republic, Denmark, France, Germany (only ethanol exceeding quota and E85), Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Romania, Slovakia, Slovenia, Spain, Sweden, Japan, Korea, New Zealand, Thailand, United States biolicules by 2022 Brazil 6% (7% in 2015) European Union 2015 European Union 2015 European Union 2015 Argentina 10% 5% Germany, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Romania, Slovakia, Slovenia, Spain, Sweden, Japan, Korea, New Zealand, Thailand, United States (eight states). Tax incentives on retail sales of ethanol: European Union 2015 European Union 2015 Canada** 2% 5-8.5% Indonesia 10% 3% Thailand 7% Colombia 10% 8-10% India 5% Australia* 2% 5% 5% European Union Renewable energy in transport by 2020 Argentina 10% 3% Spain, Sweden, Japan (B100), Korea, New Zealand, Thailand, United States (eight states). Tax credits: US: specific life-cycle emissions envivrommental and social standards. US: specific life-cycle emissions envivrommental and social standards. US: specific life-cycle emissions envivrommental and social standards. US: specific life-cycle emissions of biodiues! European Union alloif tax exemptions for renewable fuels meeting envivrommental and social standards. US: specific life-cycle emissions envivrommental and social standards. US: specific life-cycle emissions envivrommental and social standards. US: specific life-cycle emissions of biodiues! European Union alloif tax exemptions for renewable fuels meeting envivrommental and social standards. US: specific life-cycle emissions envidence of biodiues. European Union alloif tax exemptions for renewable fuels meeting envivrommental and social standards. US: specific life-cycle emissions envidence of biodiues. European Union alloif tax exemptions for renewable fuels meeting envivrommental and social standards. US: specific life-cycle emissions envidence of biodiues. Europea	Targ	ets and quo	tas	Support scheme	Other support/specific requirements
For key producers Country Biodiesel Ethanol United 36 billion gallons States biofuels by 2022 Brazil 6% (7% 18-25% in 2015) European Union Diomiesel Energy in transport China* 10% 5% Canada** 2% 5-8.5% Indonesia 10% 3% Spain, Sweden, Japan (B100), Thailand 7% Colombia 10% 8-10% India 5% Australia* Positives on retail sales of biodiesel: Argentina, Australia, Canada (Quebec, Nova Scotia), Austria, Belgium, Bulgaria, Czech Republic (different exemptions for 5% and higher-than-31% blends), Denmark, France, Germany, Hungary, Ireland, Italy, Latvia, Lithuania, Poland, Romania, Slovakia (limited to 5% blends), Spain, Sweden, Japan (B100), Korea, New Zealand, Thailand, United States (six states). Tax credits: Zealand, Thailand, United States (eight states). Tax incentives on retail sales of biodiesel: Argentina, Australia, Canada (Quebec, Nova Scotia), Austria, Belgium, Bulgaria, Czech Republic (different exemptions for 5% and higher-than-31% blends), Denmark, France, Germany, Hungary, Ireland, Italy, Latvia, Lithuania, Poland, Romania, Slovakia (limited to 5% blends), Slovakia (limited to 5% blends), Slovakia (limited to 5% blends), Spain, Sweden, Japan (B100), Korea, New Zealand, Thailand, United States (six states). Tax credits: Zealand, Thailand, United development: Some European Union member states have grant programmes for biofuels distribution infrastructure. A number of US states provide incentives for new biofuel infrastructure. Sweden: large retail stations must sell fuel from renewable sources. Thailand: retail stations selling E20 receive financial premium. RD&D programmes: European Union: funding available through Seventh Framework Programme, NER 300, Horizon 2020. A number of US states have grant programmes for biofuels distribution infrastructure. Some European Union ember states have grant programmes for biofuels distribution infrastructure. Some European Union ember states have grant programges for biofuels distribution infrastructure. Sweden: large retail stations selling the fuel	Regulatory European U Energy Direct 10% renewal by 2020. US RFS2: bidifferent cate Canada: Fect standard: ble biofuels.	frameworks nion Renewa ctive (RED): able energy in lending mane egories of bid deral renewa ending mand	able n transport dates for ofuels. ble fuel ates for	Tax incentives on retail sales of ethanol: Argentina, Australia, Austria, Bulgaria, Czech Republic, Denmark, France, Germany (only ethanol exceeding quota and E85), Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Romania, Slovakia, Slovenia, Spain,	Sustainability requirements for biofuels: European Union: all biofuels used to meet RED 2020 target need to be certified for compliance with sustainability criteria defined in the RED. Switzerland: tax exemptions for renewable fuels meeting environmental and social standards. US: specific life-cycle emissions
United States biofuels by 2022 Brazil 6% (7% in 2015) 18-25% in 2015) 10% renewable energy in transport by 2020 10ma* China* China* Canada** China* 2% 5-8.5% Indonesia 10% 3% Chombia 10% 8-10% India 5% Australia* Argentina 5% Australia* Colombia 10% 8-10% India 5% Australia* United 36 billion gallons biofuels on retail sales of biodiesel: Argentives on retail sales of biodiesel: Argentia, Australia, Canada (Quebec, Nova Scotia), Austria, Belgium, Bulgaria, Czech Republic (different exemptions for 5% and higher-than-31% blends), Denmark, France, Germany, Hungary, Ireland, Italy, Latvia, Lithuania, Poland, Romania, Slovakia (limited to 5% blends), Spain, Sweden, Japan (B100), Korea, New Zealand, Thailand, United States (six states). Tax incentives on retail sales of biodiesel: Argentina, Australia, Canada (Quebec, Nova Scotia), Austria, Belgium, Bulgaria, Czech Republic (different exemptions for 5% and higher-than-31% blends), Denmark, France, Germany, Hungary, Ireland, Italy, Latvia, Lithuania, Poland, Romania, Slovakia (limited to 5% blends), Slovenia (limited to 5% blends), Spain, Sweden, Japan (B100), Korea, New Zealand, Thailand, United States (six states). Tax incentives on retail sales of biodiesli stribution infrastructure. A number of US states provide incentives for new biofuel infrastructure. Sweden: large retail stations must sell fuel from renewable sources. Thailand: retail stations selling E20 receive financial premium. RD&D programmes: European Union member states have grant programmes for biofuels distribution infrastructure. A number of US states have grant programmes for biofuels distribution infrastructure. A number of US states have grant programmes for biofuels distribution infrastructure. A number of US states have grant programmes for biofuels distribution infrastructure. A number of US states have grant programmes for biofuels distribution infrastructure. A number of US states have grant programmes for biofuels distribution infrastructure. A number of US states have gra			argets:	Zealand, Thailand, United	Incentives for infrastructure
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Note: *in some provinces; **federal: 5% ethanol, 2% biodiesel; up to 8.5% ethanol in some provinces. E85 = blend of 85% ethanol and 15% gasoline; B100 = pure biodiesel; RFS2 = Renewable Fuels Standard 2. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy.

Source: IEA analysis; Bahar, H., J. Egeland and R. Steenblik (2013), "Domestic incentive measures for renewable energy with possible trade implications", OECD Trade and Environment Paper No. 2013/01, OECD Publishing, Paris.

In view of those trends, this year's projections of biofuel supply have been, on balance, adjusted downwards. Projections have been revised down for the United States, or in the case of the European Union, kept at the conservatively low level previously forecast by the *MTRMR 2013*. Despite upward adjustments for Asia, global biofuel supply is now forecast to reach only 135 billion L in 2018 (down 2 billion L compared with last year's projections), inching marginally up to 139 billion L in 2020.

Box 14 Electric vehicles and renewable energy: Opportunities for synergy

While biofuels are the only sizeable renewable fuel source used in transport today, opportunities exist for enhanced use of renewable electricity in both road and rail transport. In the road segment, electric vehicles could play an important role in enhancing the use of renewable electricity, with potential benefits in terms of electricity grid interaction and the integration of variable renewable sources.

Box 14 Electric vehicles and renewable energy: Opportunities for synergy (continued)

The value proposition of an electric vehicle (EV) is more than switching an engine block for a battery. If done strategically, the interaction between electric vehicles and the grid could not only drive the development of cleaner vehicles and a smarter grid, but may also produce synergistic benefits for both.

Vehicle-to-building configurations, where an EV draws from the building's power supply during off-peak hours (when electricity is cheaper) and supplies electricity from its battery during peak hours, can be smart options for charging and provide flexibility to the grid. The electricity storage capabilities of EVs could also help facilitate the integration of distributed solar photovoltaic (PV), for example. On a broader and more dynamic level, vehicle-to-grid configurations could create a system where EVs communicate with the grid and their batteries are smartly charged and discharged according to power system needs. Neither of these options is strictly necessary for EV deployment, but they do increase the potential applications and carry the benefits of enhancing power system flexibility. The potentially negative impact on battery lifetime needs to be considered, however, to assess the feasibility of such a system.

Even with today's carbon intensity, the IEA Energy Technology Perspectives 2014 (ETP 2014) finds that more than 27% of countries worldwide could today obtain savings in carbon dioxide (CO_2) emissions from EVs, across all modes (IEA, 2014). However, the abatement costs per tonne of CO_2 are generally still higher than those of other measures such as energy efficiency or use of biofuels, due to the relatively high investment costs for EVs. In the longer run, as electricity supply is projected to become less carbon-intense, EVs become an increasingly attractive option, in particular in the light-duty vehicle segment, to abate CO_2 emissions in the transport sector (IEA, 2014).

Market Development

20 000

0

USA

2008

Electric vehicles, as defined here, exclude non-plug-in hybrid electric vehicles, but do include both plug-in hybrid electric vehicles and full battery electric vehicles. As EVs are more efficient than their conventional counterparts using internal combustion engines, both the fuel use and cost per kilometre are lower. However, significant challenges remain, including higher up-front investment costs for the vehicle, uncertain infrastructure business models and consumer acceptance.

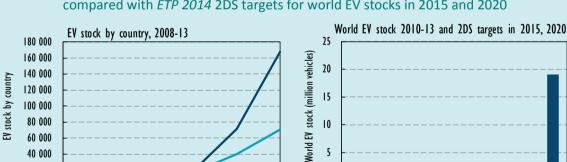


Figure 112 EV stock development in different countries 2008-13 compared with *ETP 2014* 2DS targets for world EV stocks in 2015 and 2020

 $Source: Mark Lines\ Database\ (2014), \textit{Automotive Industry Portal,}\ www.mark lines.com.$

China

2011

2012

France

Sales of passenger car EVs doubled between 2011 and 2012, albeit from a low starting point, and continued to grow more than 50% (170 000 sold in 2013) to 350 000 EVs on the road by the end of 2013. That is still equal to only 0.04% of world passenger car stock and far from the 20 million EVs on the road that are necessary to achieve the targets in the ETP 2014 2°C Scenario (2DS) in 2020 (Figure 112).

2013

Norway

0

2009

2010

2011 2012

2008

2009

Japan

2010

2015

(2DS) (2DS)

2020

Box 14 Electric vehicles and renewable energy: Opportunities for synergy (continued)

By region, the United States, Western Europe, China and Japan are the key players driving EV market deployment. In the United States alone, almost 100 000 EVs were sold in 2013, almost 60% of all sales that year. In the Netherlands, Norway and the United States, sales of EVs accounted for more than 1% of total vehicle sales in 2013.

At least 12 countries have financial incentives to promote EV market uptake, ranging from full tax exemptions on vehicle sales (Denmark, Norway), to tax credits (United States), and direct "supercredits" (Sweden). In California and Japan, there are programmes designed to link the usage of renewable electricity with electric vehicles by offering package deals with a rooftop solar kit included when buying an EV, or an option to source from renewable electricity only for charging. This form of packaging has been shown to increase the likelihood of a consumer buying an EV (Baumhefner, Pike and Klugescheid, 2012).

Other transport modes

Sales of passenger car EVs pale in comparison to electric two- or three-wheelers. In China alone, a major market has developed over recent years that now encompasses more than 150 million electric two-wheelers – more than half the country's motorised two-wheeler stock. This growth was driven primarily by banning of gasoline-fuelled two-wheelers to reduce air pollution. Electric two- or three-wheelers have not yet taken off to similar degree elsewhere, though fast rates of growth are seen in Western Europe and India.

Other types of electric vehicles include buses, trucks and trains. Rail transport is the most electrified transport segment today (40% of stock), and further electrification potential exists, especially in interurban rail transport. Buses have the most options to go fully electric, including battery charging (slow and fast), battery swapping, induction (static and conductive), and overhead lines (catenary). There is less potential for fully electric ships and airplanes (except for small configurations), due to the long distances covered, though there is potential to reap efficiency through higher levels of electrification.

Challenges

The key challenges to EV deployment remain the same as they have in past years: the reduction of battery costs while improving their energy storage performance metrics, and optimising the deployment and usage of EV infrastructure.

For infrastructure, the key is to not only maximise the number of charging points, but optimise their location and usage. At the same time, research shows that many charging points, especially public ones, are not used but rather support EV deployment as a "safety net" to combat so-called range anxiety.

For EV costs to come down, improvements in batteries are paramount, as they are estimated to account for almost half of total EV cost. In this area, there are encouraging signs. Battery costs have moved quickly down from around USD 1 000 per (/kWh) in 2008 to less than USD 400/kWh today. ²⁴ The target range is hard to define to achieve up-front cost parity with conventional vehicles, but experts name cost ranges from USD 125/kWh to USD 300/kWh. While it is beyond the scope of this report to assess whether such costs are achievable in the medium term, it is worth noting that ambitious manufacturing plans have emerged from vehicle-maker Tesla that, if realised, aim to more than double the current global production of lithium ion batteries and could result in significant battery cost reductions (Tesla Motors, 2014). Such a trend could have positive knock-on effects on the economics of battery storage for distributed solar PV, for example. Combined with potential flexibility benefits to the electricity grid and the increased attractiveness to consumers of coupling EVs and renewable energy, the potential dual scale-up of EVs and renewable systems over the medium term could ultimately serve to enhance the value proposition for both technologies.

Note: this box draws from extensive work undertaken for the *Global EV Outlook* (available for download at: www.iea.org/publications/globalevoutlook_2013.pdf), which provides a more detailed overview of current market trends.

²⁴ According to personal communication with the US Department of Energy, battery cost is based on development efforts costing USD 400/kWh of usable energy at the end of 2013. Costs do not include warranty costs or profit, and are based on a production volume of at least 100 000 batteries per year.

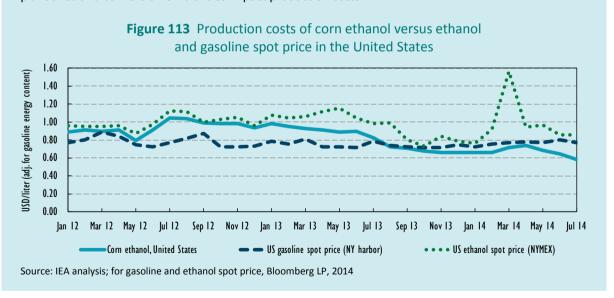
Regional forecasts

Established markets face slower production growth

In the **United States**, which is the world's largest producer of biofuels, ethanol production remained slightly constrained during the first half of 2013, as a result of the extensive drought witnessed the previous year. Corn prices remained elevated until mid-2013, before prospects of the new harvest let corn futures decline considerably. As a result, estimated average corn ethanol production costs saw a substantial drop that brought them in close proximity to the United States spot price for gasoline (Figure 113). Ethanol production consequently increased in 2013, to volumes slightly above those in the previous year (50.3 billion L in 2013 versus 49.8 billion L in 2012).

Box 15 IEA biofuel production cost analysis

Over the last year, the IEA has expanded its analysis of biofuel production costs. Based on current and historical market data, in particular related to feedstock prices, the analysis allows estimates of production costs of different biofuels in a number of key markets to be generated. The analysis combines data on capital and operation costs, as well as plant sizes and efficiencies, from the IEA Mobility Model with feedstock prices as tracked by Bloomberg and other relevant sources. In this manner, monthly average production costs for different types of ethanol and biodiesel can be generated, covering the major share of biofuels in the market today. Production costs can then be compared to prices for reference fossil fuels, as well as to biofuels trading prices, in order to assess the competitiveness of different biofuels and the profitability of their production. The production costs presented below should be understood as approximate, and might vary somewhat in reality. This is, for instance, due to price differences between feedstocks that are traded from those supplied locally to a biofuel plant. Furthermore, differences in plant sizes and conversion efficiencies impact production costs.



Meanwhile, the framework for the biofuels sector changed after the US Environmental Protection Agency (EPA) in late 2013 published a proposal to substantially lower the required volumes of biofuels under the RFS2, the principal instrument that sets the minimum annual volume of renewable fuel (including ethanol and biodiesel) to be used in the United States (see Table 59 and IEA Oil Market Report, dated December 2013). The proposal to substantially reduce the volumetric targets for the RFS 2014 effectively acknowledges the challenges related to blending increasing amounts of ethanol into the gasoline

pool. When the RFS adopted in 2005 was extended through 2022 under the Energy Independence and Security Act of 2007, United States gasoline consumption was assumed to continue to grow, as it had done until then. In fact, United States gasoline demand has since actually contracted and, despite a partial rebound in 2014, current projections are for a renewed decline mainly due to the increasing adoption of tighter fuel economy standards that is leading to largely improved vehicle fuel efficiency.

While contracting demand reduces the overall size of the gasoline fuel pool, blending constraints are further limiting ethanol use. Ethanol already accounts for roughly 10% of the US gasoline pool, and several parties, from gasoline retailers to automobile manufacturers, have flagged liability issues associated with using ethanol blends higher than E10 (10% blend). Additionally, the extra costs and logistical challenges of reconfiguring pumps and storage at fuel stations that would allow for use of higher-level blends, such as E85 (containing 85% ethanol), pose barriers to blending ethanol at higher levels. In combination, those factors have effectively raised an ethanol "blend wall" suggesting that ambitious policy targets of rapid and steady growth in ethanol consumption may not be attainable.

Table 59 RFS2 volumes for different biofuels

Billion gallons (billion L)	2013	2014 (current EPA proposal)	2014 (as proposed in 2010 RFS2)
Renewable fuel (net)	13.8 (52.2)	13.01 (49.2)	14.4 (54.5)
Advanced biofuel	2.75 (10.4)	2.2 (8.3)	3.75 (14.2)
biodiesel	1.28 (4.8)	1.28 (4.8)	1.0 (3.8)*
cellulosic biofuel	0.006 (0.02)	0.017 (0.06)	1.75 (6.6)
Other advanced biofuel	1.46 (5.5)	0.90 (3.4)	1.0 (3.8)
Total renewable fuel	16.55 (62.6)	15.21 (57.6)	18.15 (68.7)

Note: *this was a minimum requirement.

Source: EPA (2014a), Renewable Fuel Standards for Renewable Fuel Standard program (RFS2): Notice of Proposed Rulemaking, US EPA, Washington, DC, www.epa.gov.

RFS2 targets for advanced biofuel consumption are also proving to have been unrealistically optimistic. In practice, the availability of domestically produced advanced biofuels, ²⁵ in particular that of cellulosic fuels, has fallen short of volumetric targets in the original RFS2. While the final 2014 rule had yet to be set at the time of writing, changes proposed by the EPA in November 2013 suggest that future volumetric targets for both conventional and advanced biofuels may be lowered and brought broadly in line with a 10% ethanol share in gasoline. At the same time volumetric targets for cellulosic biofuels are likely to continue being revised down to bring requirements in line with actual volumes available on the market. Acknowledging the challenge to meet the quota for cellulosic fuels under the RFS2, the EPA in July 2014 released a new rule that allows for the use of biogas in natural gas vehicles as well as the use of electricity produced from biogas in electric vehicles to count towards the mandated volumes (EPA, 2014b).

With the volume of ethanol that can be blended before reaching the "blend wall" set to shrink due to a reduction in US gasoline consumption over the medium term, and biofuels qualifying for the "advanced biofuels" category under the RFS2 available only at limited volumes in the United States, the projections on US ethanol output in this report are substantially lower than in previous estimates. With only a few drivers remaining, such as the export potential for ethanol to Canada and other countries, US

²⁵ Note that under the RFS2, advanced biofuels are defined as non-corn-based biofuels with a greenhouse-gas (GHG) reduction of 50% compared with the reference fossil fuel. For cellulosic fuels, produced from lignocellulosic biomass, a 60% GHG reduction threshold applies.

ethanol output is now projected to grow at an average of only 0.9% per year, from 52 billion L in 2013 to 55 billion L in 2020, thus around 3 billion L lower in 2018 than projected in *MTRMR 2013*. A potential upside risk to these projections results from proposals for the introduction of clean fuel standards (also referred to as low-carbon fuel standards) aiming at reducing transport-related emissions through lowering carbon intensity of fuels. California introduced such a standard in 2010, and more than ten states are currently in the phase of adopting clean fuel standards (Center for Climate and Energy Solutions, 2014). These standards, once adopted, could provide an additional stat-level driver for biofuels, depending on the final design of the standard.

OECD Americas biofuels production United States biodiesel production and imports 70 600 120 1.2 60 500 100 1.0 50 400 80 nillion litres ح 8.0 40 P/q 300 60 30 200 40 20 0.4 100 20 10 0.2 May Jul Sep Nov Jan Mar May Jul Sep Nov Jan Mar May 12 12 12 12 13 13 13 13 13 13 14 14 14 2009 2011 2013 2015 2017 2019 2007 ■ Biodiesel production ■ Argentina Indonesia ■ US ethanol ■ US biodiesel ■ Canada ethanol ■ Rest of OECD Americas European Union Other origins

Figure 114 OECD Americas biofuel production 2007-20 and US biodiesel production and imports 2012-14

Source: IEA analysis; for biodiesel imports: EIA (US Energy Information Administration) (2014), US Imports by Origin, EIA, Washington, DC.

Meanwhile, despite having enjoyed a bumper year in 2013, the United States biodiesel industry is also facing fresh challenges on the policy front following the expiration of the USD 1/gallon blender's tax credit at the end of 2013. In May 2014, the Expiring Provisions Improvement Reform and Efficiency Act that included the reintroduction of the blender's tax credit did not pass the Senate, which means that biodiesel producers will have to stand their ground without additional financial incentives for now.

The reintroduction of the credit in early 2013, which had been allowed to expire at the end of 2011, was an important driver to fuel a 1.4 billion L year-on-year increase in United States biodiesel output that year, to 5.1 billion L. In addition, it also supported biodiesel imports to climb to an average 1.2 billion L, with monthly imports rallying to 3.3 billion L in December 2013 before the expiration of the tax credit. In the absence of the blender's tax credit, biodiesel production is projected to drop by 400 million L year-over-year in 2014 as physical demand is reduced by carry-over Renewable Identification Numbers (RINs)²⁶ generated in 2013. Over the medium term, output should stabilise at 4.9 billion L per year, in line with the current RFS2 mandate for biomass-based diesel, unless the blender's tax credit is reestablished or the RFS2 quota for biodiesel is altered.

In the **European Union**, too, policy uncertainty has become a key element in the biofuels forecast. Since the European Commission (EC) first published a proposal in October 2012 to limit the share of

²⁶ The US EPA uses RINs to track renewable transportation fuels and monitor compliance with the RFS. The RIN is attached to the physical gallon of renewable fuel as it is transferred to a fuel blender. After blending, RINs are separated from the blended gallon and are used by obligated parties (blenders, refiners or importers) as proof that they have sold renewable fuels to meet their RFS mandated volumes. RINs may be used to satisfy volume requirements for the current year or up to 20% of the following year's required RFS volumes. Obligated parties may also sell RINs among each other, with prices being determined by market factors.

conventional biofuels allowed to count towards its target of 10% renewable energy in transport by 2020, the biofuel sector has remained in limbo. The proposal was triggered by an unresolved controversy over the sustainability of biofuels, focusing in particular on the difficulty of properly accounting in existing legislation for the potential impact of indirect land-use change on biofuels' GHG balances. The proposal suggested capping the share of biofuels in road transport fuel consumption at 5%, corresponding to the current average blending level in the European Union, rather than up to 10% originally mandated under the 2009 Renewable Energy Directive (Directive 2009/28/EC). After a vote in the European Parliament in September 2013 followed by discussions among member states, the EU Energy Council in June 2014 agreed to a proposal that would cap biofuel's share in transport eligible to count towards the European Union's 2020 targets, at 7% in 2020, and suggests a 0.5% voluntary quota for advanced biofuels. While the proposed cap – if adopted – would limit the sector's growth prospects, it would still allow for an increase in both ethanol and biodiesel production over the medium term.

There have been some positive policy changes from the EU biofuel industry's perspective, too, over the last year. After introducing anti-dumping tariffs on ethanol imported from the United States in 2012, the European Union in late 2013 established similar tariffs for biodiesel imported from Argentina and Indonesia for the coming five years. This should provide some relief for biodiesel producers that in previous years were facing growing competition with fuel imported from these two key biodiesel producers (see below for an analysis of the impact on Argentinian and Indonesian biodiesel production).

In addition, European biodiesel producers saw the production costs of rapeseed biodiesel decline during the course of 2013, with positive effects on producer margins. Compared to our estimated production costs of Malaysian palm-oil biodiesel, European biodiesel production costs were lower than those for Malaysian palm oil-based biodiesel in late 2013 and early 2014, though still substantially higher than spot prices for fossil diesel (Figure 115). The price gap versus the spot price for fossil diesel underlines the importance of a policy framework in order for biodiesel to be able to compete in the current environment.

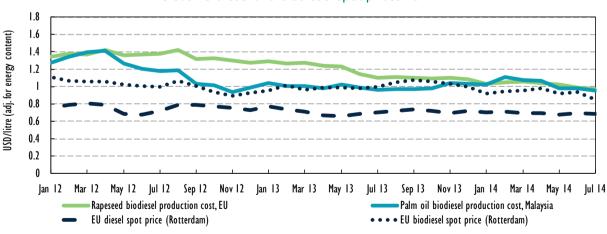


Figure 115 EU and Malaysian biodiesel production costs versus EU diesel and biodiesel spot prices 2012-14

Source: IEA analysis; for diesel and biodiesel spot price, Bloomberg LP (2014).

Despite the EU Energy Council's proposal to introduce a 7% cap on conventional biofuels, 10% renewable energy in transport remains the official 2020 target in the European Union until the new proposal has passed the parliament. The ongoing policy uncertainty reinforces the conservative growth projections

for EU biofuels production adopted in last year's *MTRMR*. OECD Europe **biodiesel** production is projected to increase from 10.2 billion L in 2013 to 12.9 billion L in 2020, broadly in line with last year's projections. Germany (3.1 billion L in 2020) followed by France (2.3 billion L in 2020) remain the region's largest biodiesel producers. **Ethanol** production is projected to grow at an average 6.6% per year, twice as fast as biodiesel output, driven in part by two new plants with a combined capacity of 800 million L per year that recently came on line in the United Kingdom. Ethanol output is projected to grow to 6.4 billion L in 2020 from 4.1 in 2013, as production in the United Kingdom jumps to 1.0 billion L from 0.3 billion L over the same period, letting the country catch up with the two top producers, France (1.1 billion L in 2020) and Germany (1.0 billion L in 2020).

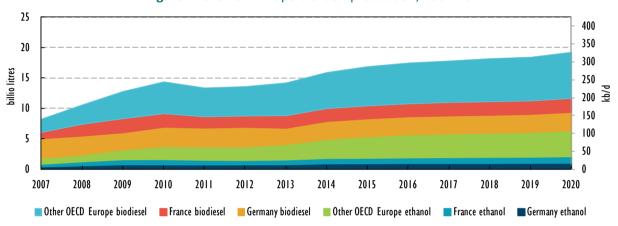


Figure 116 OECD Europe biofuels production, 2007-20

In light of the uncertain policy environment in combination with significant overcapacity in particular in the biodiesel industry, major capacity additions in the European Union look unlikely. Even in the longer run, the EC's recently published proposal for a post-2020 policy framework makes it unlikely to see any new plants for these fuels coming on line even in the longer run (Box 16).

The ongoing discussions on a revision of the 2020 biofuel target and the absence of a longer-term policy framework for biofuels are also important challenges for the advanced biofuels industry. Advanced biofuels companies in Europe struggle to attract investments in their first commercial-scale projects, as highlighted for instance by the decision of Finnish company Vapo to shelve its 120 million L Ajos BtL project in Northern Finland despite being awarded EU funding of EUR 88 million.

In the **non-OECD Americas**, steady or increasing blending mandates should in theory provide a better environment for the industry. However, the biofuel industries in the region's two largest-producing countries – Brazil and Argentina – are currently experiencing difficult operating conditions.

In **Brazil**, the world's second-largest ethanol producer, output exceeded expectations in 2013, reaching 27.4 billion L – around 2 billion L higher than projected in *MTRMR 2013* – on the back of a higher-than-expected sugar cane harvest. The medium-term forecast for Brazilian ethanol looks nonetheless gloomier than projected last year, for a number of reasons.

After suffering from a poor sugar cane harvest in the 2011/12 crushing season, the sugar and ethanol industry has now fallen victim to a global bumper sugar crop that extended the global sugar surplus to a fifth year, and subsequently depressed sugar prices (Figure 117). Low sugar prices led most mills

to favour ethanol over sugar production and to shift more of their capacity towards biofuel production. However, with price controls on gasoline in place designed to rein in inflation – a major government priority – the price competitiveness of ethanol in retail markets is undermined unintentionally and leaves producers with narrow profit margins. In combination with rising costs for labour and land, the current situation further exacerbates the already critical economic state of many sugar and ethanol producers. The government's decision taken last year, to waive of contributions to the social integration programme and social security financing (PIS and COFINS) on ethanol in order to improve the income situation in the sector, has not noticeably improved this situation.

Box 16 EU long-term policy outlook

In January 2014, the EC published its communication on the post-2020 renewable energy policy framework (EC, 2014). This proposal calls for an EU-28 target of 27% renewables in final energy consumption by 2030. Unlike the 2020 target, this aim would not be binding on individual member states; rather, countries would voluntarily set renewable commitments.

With regards to renewable energy in transport, no specific target for renewable energy or GHG intensity of transport fuels is included in the proposal. Instead, the draft states that discussions on indirect land-use changes made clear that conventional biofuels can play only a limited role in the future, and governments' focus should be on improving transport efficiency and development of EVs and advanced biofuels.

The absence of binding targets raises questions about how effective the overall target can be; more details on the nature of the governance framework overseeing these commitments would thus be critical. The 2030 proposals are being debated among member states, and the eventual policy tools adopted may differ from the original package. Sufficient clarity over a stable policy and regulatory framework would need to come in a timely manner in order to sustain investment.

In the meantime, the EC has published its binding guidelines on state aid for environmental protection and energy (SWD[2014]139), which significantly affects the operating environment for conventional biofuels:

- The guidelines state that due to overcapacity of conventional, food-based biofuels, investment aid in such production is not justified except for the conversion of food-based plants into advanced biofuel plants. Other than that, only advanced biofuel plants are allowed to receive investment aid.
- Furthermore, operating aid for food-based biofuels is eligible only until 2020, and for such conventional biofuels plants that started operation before the end of 2013. In addition, the guidelines lay out that such aid must not be granted for biofuels that are already subject to a supply or blending mandate, unless they are sustainable and thus subject to higher production costs that would otherwise prevent market access.

The current proposals for the EU policy framework post-2020 suggest that policy support for conventional biofuels will disappear, leaving many in the biofuels industry disillusioned. In absence of a specific target for biofuels or renewable energy in transport, and with many potential investors alarmed by the European Union's change in direction with regards to biofuels, further investments in advanced biofuels seem increasingly unlikely.

Looking ahead, there is no clear sign that the situation in the sugar cane sector will improve in the near future. Most analysts doubt that the government will revisit its gasoline pricing policies before the presidential election scheduled for October. Whether gasoline price controls can promptly be

²⁷ Many of the combined sugar and ethanol mills in Brazil can shift the ratio of output of the two end products between 40:60 either way.

lifted after the election, regardless of its outcome, is an open question, despite a USD 2 billion trade deficit caused by gasoline imports in 2013. A rise in the 25% mandatory gasoline blend, which could provide some support to the sector, is currently not in sight, despite industry groups' lobbying efforts. Further plant closures, in particular of smaller and old mills, are therefore likely in the next years. Furthermore, the current situation makes investments in new mills and sugar cane fields unlikely as rising land prices have considerably reduced the attractiveness of greenfield developments.

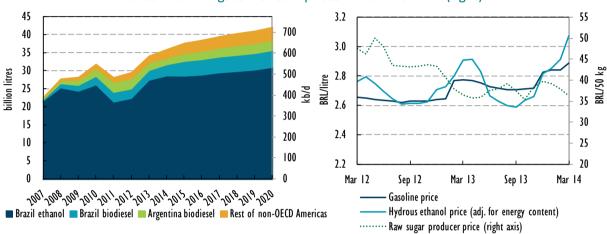


Figure 117 Non-OECD Americas biofuels production 2007-20 (left) and comparison of ethanol and gasoline retail prices in Brazil 2012-14 (right)

Source: IEA analysis; data source for ethanol and gasoline prices, ANP (Agência National do Petróleo, Gás Natural e Biocombustíveis) (2014), *Preços*, www.anp.gov.br; data source for sugar prices, UNICA (2014), *UNICADATA*, www.unicadata.com.br.

Short-term export opportunities for ethanol producers emerged early this year, when a cold spell reduced rail transport of ethanol to consumption centres, and ethanol prices in the United States surged (Figure 113). However, the medium-term prospects for exports to the United States have substantially worsened since last year's *MTRMR*, in light of the suggested revision of the United States RFS2 advanced biofuels quota (see above). Despite the 2013 upward revisions in Brazilian ethanol production, this publication's medium-term forecast of ethanol output is less optimistic. Due to a drought during the winter season, 2014 cane production is expected to be slightly higher than last season's harvest at best. Brazilian ethanol is thus projected to increase by 1.3 billion L to 28.7 billion L in 2014. Over the medium term, output is projected to reach 30.0 billion L in 2018 (-1.2 billion L versus *MTRMR 2013*) and 31.0 billion L in 2020, with growth in gasoline demand being an important driver.

Brazil's biodiesel output in 2013 reached 2.7 billion L, in line with last year's *MTRMR* projections. The Brazilian biodiesel industry's hope to see an increase in the nationwide 5% biodiesel blending mandate, which would help reduce the estimated USD 8 billion diesel trade deficit, have now materialised. In late May 2014, the government announced it was raising the biodiesel mandate to 6% as of July, and to 7% as of January 2015. This publication therefore projects a solid increase in biodiesel production to 4.7 billion L in 2020.

In neighbouring **Argentina**, biodiesel production took a hit from both domestic and international policy developments, after five years of rapid growth. The industry's situation started changing last year, when the European Union – Argentina's principal biodiesel export market – introduced provisional antidumping measures on Argentinian biodiesel imports that were later adopted for five years. Some of

the potential exports to the European Union were directed towards the United States, with volumes reaching 1.7 billion L in November and December (Figure 117 above), thanks to the attractive market for biodiesel in the United States. But since this temporary outlet could not entirely compensate for the loss of the export market in the European Union, 2013 production dropped by 800 million L year-over-year to 2.0 billion L, 400 million L lower than our projections in *MTRMR 2013*. The short-term forecast for Argentinian biodiesel production continues to be bleak. With the expiration of the US blender's tax credit, there will be little scope for exports to this market, and despite the Argentinian government's efforts to tackle the anti-dumping tariffs on biodiesel imports to the European Union at the World Trade Organization (WTO), this market is not expected to open up again in the near future.

The recent increase in the biodiesel blending mandate from 7% to 10% as of February 2014, and an additional 10% biodiesel mandate for oil-fired power plants, should in theory help to keep up the sector's production. However, the domestic reference prices for biodiesel are well below production costs of soybean-based biodiesel (Figure 118), forcing many small producers to halt production. Biodiesel output is therefore expected to drop by 250 million L year-over-year in 2014, to 1.7 billion L. Though some of the short-term challenges could be overcome, the medium-term forecast is less optimistic than in the previous *MTRMR* and biodiesel production is seen increasing to only 2.7 billion L in 2020.

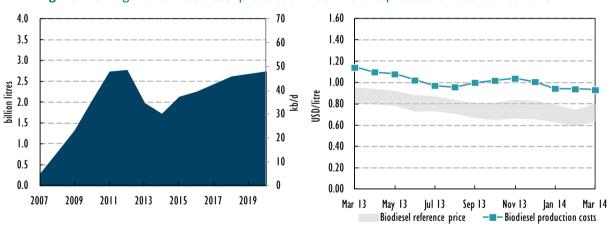


Figure 118 Argentinian biodiesel production 2007-20 and production economics 2013-14

Source: IEA analysis; for biodiesel reference price: Secretaría de Energía (2014), *Precios de Biodiesel*, www.energia.gov.ar/contenidos/verpagina.php?idpagina=3716.

The considerably smaller ethanol sector in Argentina has been growing solidly in the last couple of years. With a 5% blending mandate for ethanol in place, and a number of corn-ethanol plants scheduled to come on line in the next years, we see ethanol output more than doubling, from more than 300 million L in 2013 to 900 million L in 2020.

Ambitious policies support growth in emerging biofuel markets

While some of the traditional markets in the United States, the European Union and Latin America are seeing political support fade, several countries in non-OECD Asia and Africa have adopted new blending mandates, or ramped up existing targets for biofuels. Energy security, support for rural economies and/or changes in the competitiveness in export markets have triggered these developments, which should spur increased biofuel production in these markets.

Indonesia, the biggest biodiesel producer in non-OECD Asia, has ramped up its domestic biodiesel mandate from B7 to B10 (10% biodiesel blend) as of February 2014. The increase in the mandate followed the introduction of anti-dumping tariffs in the European Union, which significantly reduced Indonesia's export potential to this key market, and also aims to cut the domestic consumption of subsidised diesel fuel. Biodiesel output in 2014 is nonetheless projected to drop 100 million L year-over-year to 1.7 billion L, as a combination of the European Union anti-dumping tariffs, the expiration of the US blender's tax credit and a dry spell at the beginning of this year combined with signs of an El Niño year that could reduce crude palm oil production and raise prices. With such short-term challenges expected to be overcome, and the B10 mandate materialising, biodiesel output is projected to grow to 2.5 billion L in 2020, up 1 billion L in 2018 from last year's medium-term projections.

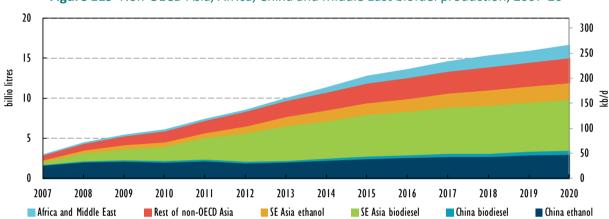


Figure 119 Non-OECD Asia, Africa, China and Middle East biofuel production, 2007-20

India is set for a growing ethanol production amid the relatively ambitious E5 (5% blend) mandate that has been in place since late 2012, and which slowly starts to materialise. Oil companies have reportedly secured the first ethanol supplies through tenders, but are not yet on track to secure the full volume of ethanol needed to meet the mandate. One of the key problems in ensuring the required volumes appears to be the gap between the lower prices offered by the oil companies and those requested by the ethanol producers. Therefore, the domestic production, forecast to reach only 700 million L in 2014, increasing to 1.2 billion L in 2020, is insufficient to cover the E5 mandate.

Malaysia and the Philippines are following a similar pathway and are planning to raise policy support for biofuel use. The Philippines already introduced a new E10 mandate in April 2013 and a B5 mandate in October 2013. Malaysia has adopted plans to expand its B5 mandate nationwide in July this year, with a possible further increase in the mandate to B7 as of January 2015 in order to stabilise prices for crude palm oil. Amid these ambitions, Malaysian biodiesel supply is predicted to almost triple from 300 million L in 2013 to 900 million L in 2020, up 300 million L in 2018 from our previous forecast. In the Philippines, we see biodiesel output grow less rapidly, from 250 million L in 2013 to 400 million L in 2020, due to limited biodiesel production capacity in the country. Spurred by the new E10 mandate, ethanol output should triple from roughly 100 million L in 2013 to almost 400 million L in 2020.

Thailand, the largest ethanol producer in Southeast Asia, is also seeing growing demand for both ethanol and biodiesel. The government's decision to phase out 91 octane gasoline, and to subsidise

use of E20, has prompted a number of oil companies to offer the 20% ethanol blend at their retail stations, and should support further growth in ethanol output over the medium term to 1.5 billion L in 2020, up from 0.9 billion L in 2013.

Signs of a new era for biofuels are seen also in Africa and the Middle East. Among the key emerging markets in the region is **South Africa**, which will introduce long-awaited E2 and B5 mandates as of October 2015, and **Zimbabwe**, which mandated use of E10 in October 2013 and E20 as of later in 2014. Both countries should see an increase in biofuels production over the medium term, though a number of issues such as details on financial incentives in South Africa, and the availability of feedstocks in both countries, still need to be addressed. Nonetheless, African ethanol output is seen growing from less than 200 million L in 2013 to 900 million L in 2020, and biodiesel production to increase from around 100 million L to around 600 million L over the same period. Biofuel production on the continent should be driven by the suitable conditions for the cultivation of biofuel feedstocks such as sugar cane, in combination with a rapidly growing fuel demand in many countries. The considerably smaller total investment needs compared with a conventional oil refinery make biofuel plants an attractive option for countries looking to reduce their import bill for refined transport fuels.

Biofuels production is starting even in the Middle East, namely in the United Arab Emirates and Saudi Arabia, where an abundance of fossil fuels and the lack of biofuel feedstocks provide a rather challenging environment for the industry. This is the reason the few projects that are on line, or scheduled to be commissioned in the next years, are all based on waste feedstocks, typically used cooking oil. Since availability of waste feedstocks is limited, this report does not expect much growth in biofuel production and total volumes of ethanol and biodiesel combined, which together reach only around 150 million L over the medium term.

Advanced biofuels industry

The advanced biofuels industry faces strong headwinds but continues to grow as past investments come to fruition. Operating capacity – excluding hydrotreated biodiesel²⁸ – reached almost 2 billion L in 2013. Companies such as Beta Renewables, backed up by chemical producer Mossi & Ghisolfi, opened commercial-scale plants last year, and more companies are scheduled to open their first commercial-scale production units this year. Among them are GranBio's 80 million L per year cellulosic-ethanol plant in Brazil, Abengoa's 95 million L per year, POET's 95 million L per year and DuPont's 105 million L per year cellulosic ethanol plants in the United States, as well as UPM's 115 million L per year advanced biodiesel plant in Finland. Globally, we see the installed production capacity for advanced biofuels increase 500 million L year-over-year to 2.5 billion L per year in 2014.

Growth has been slower than expected, though, due to the complex technical challenges involved. The industry's struggle is reflected in a number of companies going bankrupt, or shelving their projects amid greater-than-expected technological challenges, a difficult economic environment, or the lack of a long-term policy framework needed to justify capital-intensive investments. One of the latest examples is the advanced biodiesel and gasoline producer KiOR, which commissioned its first precommercial facility last year, but has since struggled to meet production targets and announced in April 2014 that it might have to file for bankruptcy in a few months unless new funding can be secured.

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²⁸ In contrast to the methodology employed in the 2013 *MTRMR*, estimates of advanced biodiesel capacity exclude hydrotreated biodiesel, capacity of which is assessed at 60 thousand barrels per day, as the technology has reached full maturity and fuels are often produced from conventional feedstock such as vegetable oils.

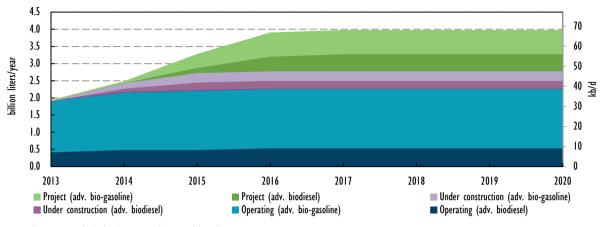


Figure 120 Advanced biofuel production capacity, 2013-20

Note: does not include hydrotreated vegetable oil.

Based on announced projects and plants currently under construction, global capacity could grow to almost 4 billion L in 2020. This is around 500 million L lower than projected last year, as a number of large-scale projects have either been cancelled or postponed, or will be initially operated on non-renewable feedstocks. Global developments in the advanced biofuels industry are mainly dependent on two key markets – the United States and the European Union. In both markets, policy uncertainty is growing, as mentioned above. The ambitious target for cellulosic fuels under the RFS2, and the double-counting of advanced biofuels towards the European Union 2020 targets, were not sufficient to trigger rapid deployment of advanced biofuels. The absence of a longer-term policy framework for biofuels beyond 2020 in the European Union and beyond 2022 in the United States, combined with current discussions on revising down current targets for biofuels, will make it very difficult for advanced biofuel producers to secure the necessary investments to scale up production. This is one of the important downside risks that could undermine this report's projections. On the other hand, advanced biofuel plants have relatively short lead times of a couple of years, and new projects that are not yet on the horizon might come on line in the later years of these projections.

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TABLES

Table 60 Ethanol production (billion litres)

	2013	2014	2015	2016	2017	2018	2019	2020	CAGR 2013-20
World	89.6	95.0	97.2	98.9	100.3	101.4	102.5	104.0	2.1%
OECD Total	56.4	59.4	60.7	61.4	61.7	61.7	61.9	62.1	1.4%
OECD Americas	52.0	54.1	54.9	55.3	55.5	55.4	55.5	55.4	0.9%
Canada	50.3	52.3	53.0	53.4	53.7	53.8	53.9	53.9	1.0%
United States	1.7	1.8	1.9	1.9	1.8	1.5	1.5	1.4	-2.8%
OECD Asia Oceania	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.1%
Australia	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5%
OECD Europe	4.1	4.9	5.4	5.7	5.8	5.9	6.1	6.4	6.6%
Austria	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0%
Belgium	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.8%
France	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.1	4.0%
Germany	8.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0	4.5%
Italy	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	26.1%
Netherlands	0.3	0.3	0.4	0.5	0.5	0.5	0.5	0.5	10.3%
Poland	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	3.2%
Spain	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	3.1%
United Kingdom	0.3	0.6	0.7	8.0	8.0	0.9	0.9	1.0	17.2%
Non-OECD Total	33.2	35.6	36.5	37.5	38.6	39.7	40.5	41.8	3.4%
Africa	0.2	0.3	0.5	0.6	0.7	8.0	8.0	0.9	28.6%
Asia	1.9	2.3	2.6	2.8	3.0	3.4	3.6	3.8	10.3%
India	0.6	0.7	8.0	0.9	1.0	1.0	1.1	1.2	11.1%
Indonesia	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	14.3%
Malaysia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Philippines	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	20.1%
Singapore	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	2.9%
Thailand	0.9	1.0	1.0	1.1	1.2	1.3	1.4	1.4	6.9%
China	2.1	2.3	2.5	2.6	2.7	2.7	2.9	3.0	5.6%
Non-OECD Americas	28.8	30.4	30.6	31.1	31.8	32.3	32.9	33.7	2.3%
Argentina	0.3	0.5	0.6	0.7	0.7	8.0	8.0	0.9	16.1%
Brazil	27.4	28.7	28.6	28.9	29.5	29.9	30.3	31.0	1.8%
Colombia	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7	9.0%
Eurasia	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	4.9%
Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0%

Notes: Production presented in volume; to convert to energy adjusted production, bioethanol is assumed to have 2/3 energy content.

Table 61 Biodiesel production (billion litres)

	2013	2014	2015	2016	2017	2018	2019	2020	CAGR 2013-20
World	26.6	27.8	30.9	31.8	32.8	33.6	34.1	35.1	4.0%
OECD Total	16.3	16.8	17.6	17.9	18.1	18.3	18.4	18.9	2.1%
OECD Americas	5.3	4.9	5.1	5.1	5.1	5.1	5.1	5.0	-0.7%
Canada	5.1	4.6	4.9	4.9	4.9	4.9	4.9	4.9	-0.5%
United States	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.1	-5.3%
OECD Asia Oceania	8.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0%
Australia	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1.2%
OECD Europe	10.2	11.1	11.6	11.8	12.0	12.3	12.4	12.9	3.4%
Austria	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.7%
Belgium	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1.5%
France	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.3	1.3%
Germany	2.7	3.0	3.0	3.0	3.0	3.0	3.0	3.1	1.7%
Italy	0.5	0.5	0.5	0.6	0.6	0.6	0.6	8.0	6.3%
Netherlands	1.2	1.4	1.4	1.5	1.5	1.5	1.5	1.6	4.2%
Poland	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	3.2%
Spain	0.5	0.7	0.9	0.9	1.0	1.0	1.1	1.2	11.7%
United Kingdom	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	7.4%
Non-OECD Total	10.3	11.0	13.2	13.9	14.8	15.3	15.7	16.2	6.7%
Africa	0.1	0.2	0.3	0.4	0.4	0.5	0.5	0.6	31.2%
Asia	4.4	4.7	5.3	5.5	5.9	6.1	6.3	6.5	5.6%
India	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	10.6%
Indonesia	1.8	1.7	2.0	2.1	2.3	2.4	2.4	2.5	4.7%
Malaysia	0.3	0.5	0.6	0.7	8.0	8.0	8.0	0.9	14.6%
Philippines	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	6.3%
Singapore	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	3.4%
Thailand	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	4.5%
China	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	14.3%
Non-OECD Americas	5.4	5.6	7.1	7.4	7.7	8.0	8.2	8.4	6.5%
Argentina	2.0	1.7	2.1	2.2	2.4	2.6	2.7	2.7	4.7%
Brazil	2.7	3.1	4.1	4.3	4.4	4.5	4.6	4.7	8.2%
Colombia	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.7	6.6%
Eurasia	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.2%
Middle East	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	91.2%

Notes: Production presented in volume; to convert to energy adjusted production, biodiesel is assumed to have 90% energy content.

Table 62 Total renewable electricity capacity (GW)

	2013	2014	2015	2016	2017	2018	2019	2020	CAGR 2013-20
World	1692.5	1817.5	1940.3	2061.2	2182.4	2310.7	2430.7	2554.5	6.1%
OECD Total	838.4	889.8	937.2	980.6	1021.8	1063.6	1105.8	1148.4	4.6%
OECD Americas	300.2	319.4	337.3	351.5	364.7	379.8	395.3	411.8	4.6%
Canada	86.5	90.0	93.7	96.5	98.1	100.7	102.6	103.9	2.7%
Chile	7.3	8.1	8.8	9.5	10.5	11.5	12.6	13.8	9.4%
Mexico	15.0	17.0	18.7	20.2	22.3	24.0	25.7	27.8	9.2%
United States	191.3	204.3	216.1	225.2	233.8	243.6	254.5	266.2	4.8%

OECD Asia Oceania	99.7	110.2	119.7	128.8	136.6	143.6	150.3	157.1	6.7%
Australia	16.1	17.9	19.2	20.7	22.2	23.5	24.8	26.0	7.1%
Israel*	0.4	0.6	0.7	0.9	1.2	1.6	1.8	2.1	24.6%
Japan	67.3	75.3	82.2	88.7	93.8	97.7	101.9	106.0	6.7%
Korea	9.0	9.6	10.5	11.5	12.4	13.6	14.6	15.6	8.2%
New Zealand	6.8	6.9	7.0	7.0	7.1	7.1	7.2	7.3	1.0%
OECD Europe	438.6	460.2	480.2	500.3	520.5	540.2	560.2	579.5	4.1%
Austria	17.9	18.8	19.6	20.2	20.9	21.6	22.1	22.6	3.4%
Belgium	7.1	7.5	8.1	8.6	9.2	9.8	10.4	10.9	6.3%
Czech Republic	5.2	5.3	5.3	5.4	5.4	5.4	5.5	5.5	0.7%
Denmark	7.0	7.4	7.7	8.1	8.4	8.8	9.4	9.9	5.0%
Estonia	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	7.6%
Finland	5.7	5.9	6.1	6.3	6.7	7.1	7.4	7.6	4.1%
France	39.8	41.0 95.2	42.6 100.1	44.3 105.2	46.1 110.3	47.8 114.9	49.6 119.7	51.4 124.6	3.7% 4.9%
Germany Greece	89.1 7.8	95.2 8.0	8.2	8.4	8.7	9.1	9.4	9.8	4.9% 3.3%
Hungary	0.9	0.9	1.0	0. 4 1.1	0. <i>1</i> 1.1	1.2	1.3	1.3	5.1%
Iceland	2.5	2.6	2.7	2.7	2.7	2.8	2.8	2.8	1.2%
Ireland	2.7	2.9	3.3	3.6	4.0	4.5	4.9	5.4	10.6%
Italy	53.0	54.7	56.4	57.9	59.4	61.1	62.8	64.3	2.8%
Luxembourg	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	2.0%
Netherlands	5.0	5.5	6.0	6.7	7.2	8.0	8.8	9.8	9.9%
Norway	31.0	31.2	31.6	32.1	32.5	32.8	33.1	33.5	1.1%
Poland	6.6	7.4	8.2	8.8	9.3	10.0	10.7	11.4	8.1%
Portugal	11.3	11.5	11.9	12.2	12.6	13.0	13.3	13.6	2.7%
Slovakia	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	0.8%
Slovenia	1.6	1.6	1.7	1.8	2.0	2.1	2.2	2.3	5.6%
Spain _.	50.9	51.0	51.2	51.3	51.3	51.3	51.3	51.4	0.1%
Sweden	25.5	26.6	27.2	28.2	28.9	29.6	30.4	30.9	2.7%
Switzerland	16.9	17.2	17.6	17.9	18.6	19.7	20.3	20.9	3.1%
Turkey United Kingdom	24.3	27.2	29.8	32.5	34.5	36.0	37.5	38.8	6.9%
Non-OECD Total	21.5 854.0	25.4 927.6	28.6 1003.1	31.8 1080.6	35.0 1160.6	38.2 1247.1	41.7 1324.9	45.1 1406.1	11.2% 7.4%
Africa	30.4	35.5	38.4	41.8	46.2	51.4	55.7	60.5	10.3%
Morocco	2.2	2.5	3.0	3.8	4.1	4.2	4.4	4.8	12.0%
South Africa	2.7	4.8	5.9	6.6	8.3	9.7	10.7	11.6	23.3%
Asia (excluding China)	141.4	155.2	167.3	178.7	191.7	208.6	220.6	233.3	7.4%
India	71.6	79.6	86.3	93.0	99.7	110.4	117.3	124.7	8.3%
Indonesia	8.3	8.6	8.9	9.3	9.6	10.0	10.7	11.4	4.6%
China (region)	399.5	441.2	488.9	540.0	591.7	641.8	692.1	742.5	9.3%
Europe and Eurasia	105.2	108.7	111.3	113.4	115.2	117.1	119.1	120.9	2.0%
Russia	52.2	53.6	54.4	54.9	55.3	55.7	56.1	56.5	1.1%
Non-OECD Americas	162.6	170.6	180.1	188.6	196.1	206.3	213.0	221.1	4.5%
Brazil	99.0	103.3	109.4	115.3	120.9	128.8	134.0	140.7	5.2%
Middle East	14.8	16.6	17.1	18.1	19.8	21.8	24.4	27.8	9.4%
Saudi Arabia	0.0	0.0	0.1	0.4	0.9	1.7	2.9	4.8	110.9%

Notes: 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. Historical 2013 data for capacity are IEA estimates derived from an amalgam of sources. Specific sources are referenced where data for individual technologies are presented in previous chapters.

Table 63 Renewable energy use for heat (EJ)

	2013	2014	2015	2016	2017	2018	2019	2020	CAGR
World	14,3	14,7	15,1	15,6	16,0	16,6	17,1	17,7	3,1%
Buildings	5,9	6,2	6,4	6,7	7,1	7,4	7,8	8,3	4,9%
Industry	7,7	7,9	8,0	8,1	8,2	8,4	8,5	8,7	1,6%
OECD	6,4	6,5	6,6	6,8	6,9	7,1	7,2	7,4	6,5%
Buildings	3,5	3,6	3,6	3,7	3,8	3,9	4,0	4,0	2,1%
Industry	2,6	2,7	2,8	2,8	2,9	2,9	3,0	3,1	2,2%
OECD Americas	2,6	2,7	2,7	2,8	2,9	2,9	3,0	3,0	2,0%
Buildings	1,1	1,1	1,2	1,2	1,2	1,2	1,2	1,3	1,8%
Industry	1,5	1,5	1,5	1,6	1,6	1,7	1,7	1,7	2,2%
OECD Asia Oceania	0,4	0,5	0,5	0,5	0,5	0,5	0,5	0,5	2,2%
Buildings	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	2,3%
Industry	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,3	2,1%
OECD Europe	3,3	3,3	3,4	3,5	3,6	3,7	3,7	3,8	2,3%
Buildings	2,2	2,2	2,3	2,3	2,4	2,5	2,5	2,6	2,2%
Industry	0,9	0,9	0,9	1,0	1,0	1,0	1,0	1,0	2,2%
Non-OECD	8,0	8,2	8,5	8,8	9,1	9,5	9,9	10,3	3,8%
Buildings	2,4	2,6	2,8	3,0	3,3	3,6	3,9	4,2	8,3%
Industry	5,1	5,2	5,2	5,3	5,4	5,4	5,5	5,6	1,3%
China	1,2	1,3	1,5	1,7	1,9	2,2	2,5	2,8	13,3%
Buildings	1,1	1,3	1,4	1,6	1,9	2,1	2,4	2,7	13,4%
Industry	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	8,2%
India 	1,6	1,6	1,6	1,6	1,6	1,6	1,7	1,7	1,0%
Buildings	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,3	2,1%
Industry	1,3	1,3	1,3	1,3	1,3	1,3	1,3	1,3	0,7%
Brazil	1,7	1,7	1,7	1,7	1,8	1,8	1,8	1,9	1,6%
Buildings	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	4,1%
Industry	1,5	1,5	1,5	1,6	1,6	1,6	1,6	1,7	1,5%
Africa	1,3	1,4	1,4	1,4	1,4	1,5	1,5	1,5	1,9%
Buildings	0,3	0,3	0,3	0,3	0,4	0,4	0,4	0,4	2,6%
Industry Non-OECD Americas (excl. Brazil)	0,8 0,4	0,9 0,4	0,9	0,9	0,9	0,9	0,9 0,5	0,9	1,3% 1,9%
Buildings	0,4	0,4	0,4 0,0	0,4 0,0	0,4 0,0	0,5 0,0	0,0	0,5 0,0	-3,8%
Industry	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	2,3%
Non-OECD Asia (excl. India)	1,1	1,2	1,2	1,2	1,2	1,2	1,2	1,3	1,4%
Buildings	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,1	3,6%
Industry	1,1	1,1	1,1	1,1	1,1	1,1	1,1	1,2	1,3%
Non-OECD Europe and Eurasia	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	1,8%
Buildings	0,6	0,7	0,7	0,7	0,7	0,7	0,6	0,7	1,7%
Industry	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1,7 %
Middle East	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	6,8%
Buildings	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	7,1%
Industry	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	14,3%

Notes: Data in this table are for the total modern renewable energy use for heat where Total is the sum of the FEH in the industry, buildings, and other sectors (agriculture/forestry, fishing, and non-specified other sectors) and modern renewable energy is the sum of modern bioenergy, geothermal, and solar thermal. Other sectors are not shown in the table.

Table 64 Total renewable electricity generation (TWh)

	2013	2014	2015	2016	2017	2018	2019	2020	CAGR 2013-20
World	5068.1	5414.4	5723.7	6029.6	6340.3	6672.3	6999.7	7312.7	5.4%
OECD Total	2340.8	2451.6	2559.1	2657.8	2750.3	2844.9	2942.1	3039.2	3.8%
OECD Americas	1033.7	1080.1	1127.2	1167.2	1201.1	1237.9	1277.8	1317.8	3.5%
Canada	412.4	408.9	419.5	429.7	435.7	441.8	449.0	453.5	1.4%
Chile	25.6	32.6	35.1	37.6	40.5	43.9	47.3	50.8	10.3%
Mexico	41.0	49.1	54.2	58.9	64.0	69.2	74.0	79.4	9.9%
United States	554.8	589.4	618.4	641.1	660.9	683.0	707.5	734.1	4.1%

OECD Asia Oceania	212.4	233.8	250.9	267.5	283.0	297.5	311.3	325.0	6.3%
Australia	32.5	34.5	38.0	41.0	44.4	47.6	50.5	53.3	7.3%
Israel*	0.8	1.1	1.3	1.7	2.2	3.0	3.8	4.3	26.5%
Japan	134.9	151.9	163.4	174.1	183.7	191.6	199.0	206.6	6.3%
Korea	12.7	13.1	14.6	16.7	18.7	20.9	23.2	25.4	10.4%
New Zealand	31.5	33.3	33.6	34.0	34.1	34.4	34.9	35.4	1.7%
OECD Europe	1094.7	1137.7	1181.0	1223.1	1266.2	1309.5	1353.0	1396.4	3.5%
Austria	54.1	53.8	55.7	57.1	58.3	59.7	60.7	61.5	1.9%
Belgium	12.4	13.4	14.5	16.0	17.5	19.0	20.5	22.0	8.5%
Czech Republic	10.3	9.6	9.7	9.9	10.0	10.0	10.1	10.1	-0.2%
Denmark	15.8	18.9	19.8	20.7	21.6	22.7	24.0	25.7	7.2%
Estonia	1.2	1.8	2.0	2.1	2.3	2.5	2.7	2.8	12.6%
Finland	24.9	27.5	28.1	28.6	29.7	31.1	32.1	32.8	4.0%
France	102.9	92.0	94.2	97.1	100.3	103.4	106.5	110.0	1.0%
Germany	157.7	177.2	186.0	193.8	202.6	211.2	219.9	229.2	5.5%
Greece	13.5	14.3	14.7	15.2	15.7	16.3	17.0	17.8	4.0%
Hungary	2.7	3.1	3.1	3.3	3.4	3.5	3.7	3.8	4.9%
Iceland	18.1	17.6	18.1	18.3	18.3	18.6	18.8	18.8	0.6%
Ireland	5.9	6.9	7.7	8.6	9.7	10.9	12.2	13.6	12.8%
Italy	107.2	110.6	113.1	115.5	117.9	120.5	123.3	125.8	2.3%
Luxembourg	1.4	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.0%
Netherlands	12.0	14.0	14.9	16.1	17.2	18.6	20.6	22.9	9.6%
Norway	131.4	134.0	135.0	136.2	137.4	138.3	139.0	140.0	0.9%
Poland	17.6	25.7	27.7	29.6	31.3	33.1	35.0	36.9	11.1%
Portugal	30.6	26.8	27.5	28.2	28.9	29.7	30.4	31.0	0.2%
Slovakia	6.5	6.0	6.1	6.1	6.2	6.3	6.3	6.4	-0.2%
Slovenia	5.4	5.5	5.7	5.8	6.1	6.4	6.6	6.8	3.4%
Spain	115.2	104.4	104.7	105.0	105.1	105.2	105.4	105.6	-1.2%
Sweden	81.1	92.3	94.4	96.3	98.4	100.3	102.1	103.7	3.6%
Switzerland	41.9	40.1	40.6	41.1	41.9	43.7	45.3	46.3	1.4%
Turkey	68.9	79.3	87.3	94.7	101.3	106.2	110.3	114.2	7.5%
United Kingdom	55.7	61.6	69.0	76.4	83.7	91.0	98.9	107.3	9.8%
Non-OECD Total	2727.3	2962.8	3164.6	3371.9	3590.0	3827.4	4057.6	4273.6	6.6%
Africa	124.8	134.1	146.2	155.8	167.6	182.2	196.9	212.7	7.9%
Morocco	3.2	3.8	4.7	6.1	7.1	7.6	8.1	8.8	15.4%
South Africa	5.0	7.3	10.9	12.9	15.5	18.9	21.5	23.7	25.0%
Asia (excluding China)	423.1	452.2	488.5	519.0	551.5	593.4	632.2	662.8	6.6%
India	194.7	211.1	230.2	246.4	262.3	284.4	306.4	322.6	7.5%
Indonesia	28.6	29.8	31.1	32.6	34.1	35.7	37.9	40.6	5.1%
China (region)	1097.5	1226.2	1329.0	1448.8	1581.1	1715.5	1847.9	1978.0	8.8%
Europe and Eurasia	325.4	336.4	344.5	350.3	355.0	359.3	363.7	367.9	1.8%
Russia	184.8	191.0	194.9	196.9	198.2	199.2	200.4	201.6	1.2%
Non-OECD Americas	734.1	790.2	831.2	871.3	905.5	944.0	979.0	1008.0	4.6%
Brazil	428.9	475.6	500.5	527.7	553.1	583.8	612.1	636.4	5.8%
Middle East	22.4	23.7	25.3	26.7	29.3	33.1	38.0	44.1	10.2%
Saudi Arabia	0.0	0.1	0.2	0.4	1.2	2.7	5.1	8.6	117.8%

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, 2013 generation data are based on IEA statistics published in *Renewables Information* and are estimated by the MTRMR model for 2014-20. For non-OECD countries, generation is estimated by the MTRMR model for 2013-20.

^{*} 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.

GLOSSARY OF DEFINITIONS, TERMS AND ABBREVIATIONS

Regional definitions

OECD Americas: Canada, Chile, Mexico and the United States.

OECD Asia Oceania: Australia, Israel, ²⁹ Japan, Korea and New Zealand.

OECD Europe: Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

OECD: OECD Asia Oceania, OECD Americas and OECD Europe regional groupings.

China refers to the People's Republic of China, including Hong Kong.

Africa: Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, , Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

Asia: Bangladesh, Brunei Darussalam, Cambodia, India, Indonesia, Democratic People's Republic of Korea, Laos, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Chinese Taipei, Thailand, Viet Nam and other non-OECD Asian countries (Afghanistan, Bhutan, Cook Islands, East Timor, Fiji, French Polynesia, Kiribati, Laos, Macao China, Maldives, Mongolia (until 1984), New Caledonia, Palau (from 1994), Papua New Guinea, Samoa, Solomon Islands, Tonga and Vanuatu.

Non-OECD Europe and Eurasia: Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Former Yugoslav Republic of Macedonia, Cyprus, ³⁰ Georgia, Gibraltar, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Malta, Republic of Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Non-OECD Americas: Argentina, Bolivia, Brazil, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela, and other Latin American countries (Antigua

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The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
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.

and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname, and Turks and Caicos Islands).

Middle East: Bahrain, Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Non-OECD: Africa, Asia, China, non-OECD Europe and Eurasia, non-OECD Americas, and the Middle East.

The European Union - 28 (EU-28): Austria, Belgium, Bulgaria, Croatia Cyprus, ³¹ the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

Abbreviations and acronyms

CHP combined heat and power CSP concentrating solar power

DC direct current

DDG decentralised distributed generation

DNI direct normal irradiance

EIA Energy Information Administration EMEC European Marine Energy Centre

EPA Environmental Protection Agency (United States)
EPIA European Photovoltaic Industry Association

EU European Union

EU-ETS European Union Greenhouse Gas Emissions Trading Scheme

ESTELA European Solar Thermal Electricity Association

EV electric vehicle

EWEA European Wind Energy Association

FIPs feed-in premiums
FIT feed-in tariff
FLH full-load hours

GDP gross domestic product
GWEC Global Wind Energy Council

HPP hydropower plant

IEA International Energy Agency

IEA OES International Energy Agency Ocean Energy Systems Programme
IEA PVPS International Energy Agency Photovoltaic Power Systems Programme
IEA SHC International Energy Agency Solar Heating and Cooling Programme

³¹ 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 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

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IEA Wind International Energy Agency Wind Energy Systems Programme

IMF International Monetary Fund

IPCC Intergovernmental Panel on Climate Change

IPP independent power producer
ISCC integrated solar combined cycle

ITC investment tax credit LCOE levelised cost of electricity

NPV net present value

NREAP National Renewable Energy Action Plan

OECD Organisation for Economic Co-operation and Development

PPA power purchase agreement

PTC production tax credit

PV photovoltaics

R&D research and development

RD&D research, development and demonstration

RE renewable energy

RECs renewable energy certificates
RES renewable energy sources

RES-E electricity generated from renewable energy sources

RES-H final energy consumption of renewable energy sources for heat

RES-T renewable energy sources used in transport

RPS renewable portfolio standard ROC renewable obligation certificate

ROW rest of world

STE solar thermal electricity
TGC tradable green certificate
UAE United Arab Emirates

US United States

WACC weighted average cost of capital

WEO World Energy Outlook

Currency codes

AUD Australian dollar BRL Brazilian real CAD Canadian dollar

CNY Chinese yuan renminbi

DKK Danish krone

EUR Euro

GBP British pound
INR Indian rupee
KRW Korean won

MAD Moroccan dirham
USD United States dollar
ZAR South African rand

Units of measure

bbl/d barrels per day

bbloe barrels of oil equivalent

EJ exajoule gal gallon

GW gigawatt, 1 gigawatt equals 10⁹ watt

GWh gigawatt hour, 1 gigawatt hour equals 10⁹ watt hours

GW_{th} gigawatt thermal GWh_{th} gigawatt hour thermal

kW kilowatt, 1 kilowatt equals 10³ watt

kWh kilowatt hour, 1 kilowatt hour equals 10³ watt hours

kW_p kilowatt peak kW_{th} kilowatt thermal

L litre

MW megawatt, 1 megawatt equals 10⁶ watt

MW_{th} megawatt thermal

MWh megawatt hour, 1 megawatt hour equals 10⁶ watt hours

m² square metre

TWh terawatt hour, 1 terawatt hour equals 10¹² watt hours

W watt

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In 2013, renewable power capacity expanded at its fastest pace to date. Renewable power generation continued to grow strongly, reaching almost 22% of the global mix, compared with 21% in 2012 and 18% in 2007. Globally, renewable electricity generation is now on par with that of natural gas, which remained relatively stable in 2013. Investment in new renewable power capacity topped USD 250 billion globally in 2013 and is likely to remain at high levels.

Nevertheless, policy and market risks increasingly cloud the development picture, raising concerns over how fast renewables can scale up to meet long-term deployment objectives. Just when renewables are becoming a cost-competitive option in an increasing number of cases, policy uncertainty is rising in some key OECD markets. Renewables continue to spread in emerging markets, where fast-growing power demand and diversification needs provide strong deployment drivers. Still, barriers to development remain in a number of non-OECD areas, including China. As a result, despite strong anticipated generation growth, renewable power capacity additions and investment are expected to level off through 2020. Meanwhile, biofuels for transport and renewables for heat continue to grow, though at slower rates than renewable electricity and with persistent policy challenges.

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