# RENEWABLE ENERGY

# Medium-Term Market Report 2013

## Market Trends and Projections to 2018





International Energy Agency

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Renewable electricity generation increased strongly worldwide in 2012, and deployment is occurring in a greater number of markets. However, the story of renewable energy development is becoming more complex. Short-term indicators in some regions of the globe have pointed to increased challenges. Despite remaining high, global new investment in renewable energy fell in 2012. Policy uncertainties, economic challenges, incentive reductions and competition from other energy sources clouded the investment outlook for some markets. Some countries and regions have faced difficulties in integrating variable renewables in their power grids. The renewable manufacturing industry, particularly solar and wind, entered a deeper period of restructuring and consolidation.

Nevertheless, despite economic, policy and industry turbulence, the underlying fundamentals for renewable deployment remain robust. Even with challenges in some countries, more positive developments elsewhere continue to drive global growth. Competitive opportunities for renewables are emerging across traditional and new markets. While OECD countries remain a driver of renewable power development, non-OECD countries are increasingly accounting for overall growth. The roles of biofuels for transport and renewable heat are also increasing, though at somewhat slower rates than renewable electricity.

The *Medium-Term Renewable Energy Market Report 2013* assesses market trends for the renewable electricity, biofuels for transport and renewable heat sectors, identifying drivers and challenges to deployment, and making projections through 2018. The analysis features in-depth renewable electricity market analysis and forecasts for a slate of countries in the OECD and non-OECD. The report also presents an outlook for renewable electricity technologies, global biofuels supply, final energy use of renewables for heat and prospects for renewable investment.

**Market Trends and Projections to 2018**

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**Further data tables, including renewable electricity generation by technology, can be found at**

**https://www.iea.org/publications/medium-termreports/mtrenewable/**


## Market Trends and Projections to 2018

International Energy Agency

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## INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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# FOREWORD

Current world energy trends are clearly unsustainable. Global energy needs are growing; supply patterns are changing but still rooted in fossil fuels; and $CO_2$ emissions reached record highs in 2012. The International Energy Agency (IEA) carbon intensity index recently revealed a clear but disturbing picture: despite technological development and international efforts, the carbon intensity of the global energy supply has barely changed over the past 20 years.

In this context, the rapid growth of renewables continues to beat expectations and is a bright spot in an otherwise bleak assessment of global progress towards a cleaner and more diversified energy mix. That was the message I delivered to the Clean Energy Ministerial in April. The *Medium-Term Renewable Energy Market Report* (*MTRMR*) *2013* projects that renewable power is on track to meet global climate change mitigation objectives, in absolute generation and investment levels.

Despite a difficult economic context, the drivers of renewable electricity markets remain robust. Deployment is spreading around the globe and technologies are increasingly competing on their own merits in an increasing number of circumstances. This is particularly apparent in emerging economies, where deployment of renewables is driven by fast-rising demand, energy diversification needs and local pollution concerns, as well as by new opportunities for economic development. But that does not leave room for government complacency, especially among OECD countries. Today, policy uncertainty represents the largest barrier to investor confidence. Many renewables no longer require high economic incentives. But they do need long-term policies that continue to provide a predictable and reliable market and regulatory framework compatible with societal goals.

For mature renewable electricity markets and technologies, the challenge is for governments to maintain deployment momentum while optimising support costs and maximising benefits to consumers and society; and to enable the system integration of higher shares of variable renewables such as wind power and photovoltaics. For less developed markets and technologies, strategies should focus on stimulating early-stage deployment.

For other energy sectors, the messages differ. Although heat constitutes the largest part of global final energy use, renewable heat markets have received less attention. Greater progress is also needed in scaling up biofuels for transport markets. To meet a trajectory compatible with low-carbon scenarios, production needs to more than double from today's levels, and progress in advanced biofuels technologies must accelerate significantly.

This second *MTRMR* provides crucial analysis and projections of renewable energy market trends. This year's report has an expanded focus, with new sections on biofuels for transport and renewable heating, and increases the breadth of renewable power analysis, with a greater number of country studies. In all, the report provides a unique benchmark for policy makers, investors and other stakeholders to make crucial decisions regarding the fast-growing and dynamic renewables sector.

This report 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?

Please write us at IEA-MTRMR@iea.org.

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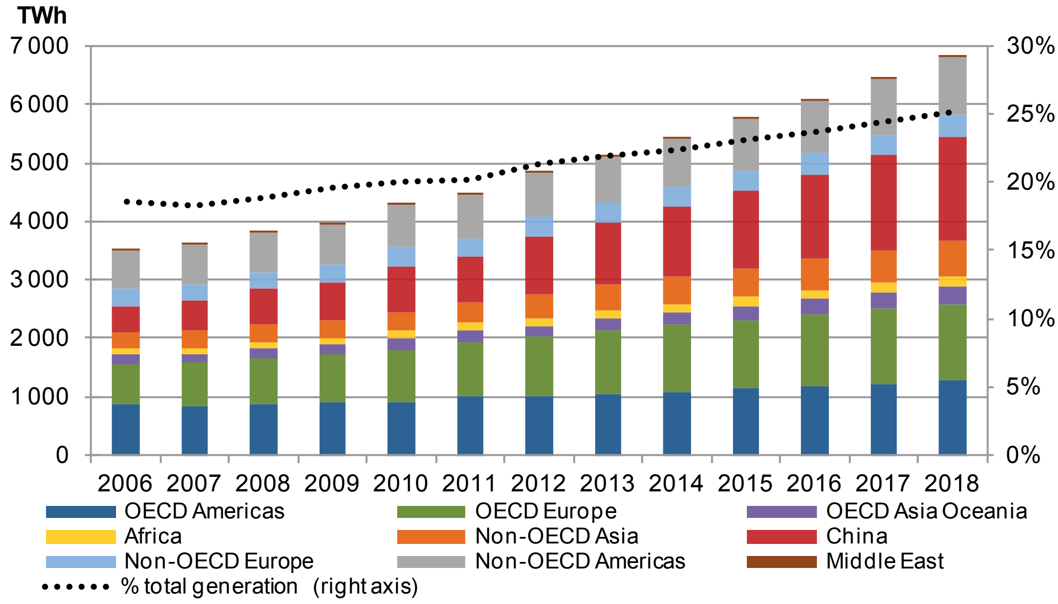
# EXECUTIVE SUMMARY

## *A growing role for renewables in the energy mix*

**The role of renewable sources in the global power mix continues to increase.** On a percentage basis, renewables continue to be the fastest-growing power source. As global renewable electricity generation expands in absolute terms, it is expected to surpass that from natural gas and double that from nuclear power by 2016, becoming the second most important global electricity source, after coal. Globally, renewable generation is estimated to rise to 25% of gross power generation in 2018, up from 20% in 2011 and 19% in 2006. Driven by fast-growing generation from wind and solar photovoltaics (PV), the share of non-hydro renewable power is seen doubling, to 8% of gross generation in 2018, up from 4% in 2011 and 2% in 2006. In the Organisation for Economic Co-operation and Development (OECD), non-hydro renewable power rises to 11% of OECD gross generation in 2018, up from 7% in 2012 and 3% in 2006.

**Figure 1** Global renewable electricity production by region




Notes: TWh = terawatt hours. Unless otherwise indicated, all materials in figures and tables in this chapter derive from International Energy Agency (IEA) data and analysis.

**Renewable electricity growth is expected to accelerate over the medium term.** From 2012-18 renewable electricity generation should rise by 40% (1 990 TWh or 6% per year [/yr]), from 4 860 TWh to 6 850 TWh. This growth in generation is 50% higher than the 1 330 TWh increment registered over the 2006-12 period. Generation in 2017 is seen 90 TWh higher than that projected in the *Medium-Term Renewable Energy Market Report 2012* (*MTRMR 2012*). Total renewable capacity is expected to grow from 1 580 gigawatts (GW) in 2012 to 2 350 GW in 2018. While hydropower remains the largest renewable source, a portfolio of non-hydro renewable sources – bioenergy, wind, solar PV, solar thermal electricity from concentrating solar power (CSP) plants, geothermal and ocean power – grows more rapidly.

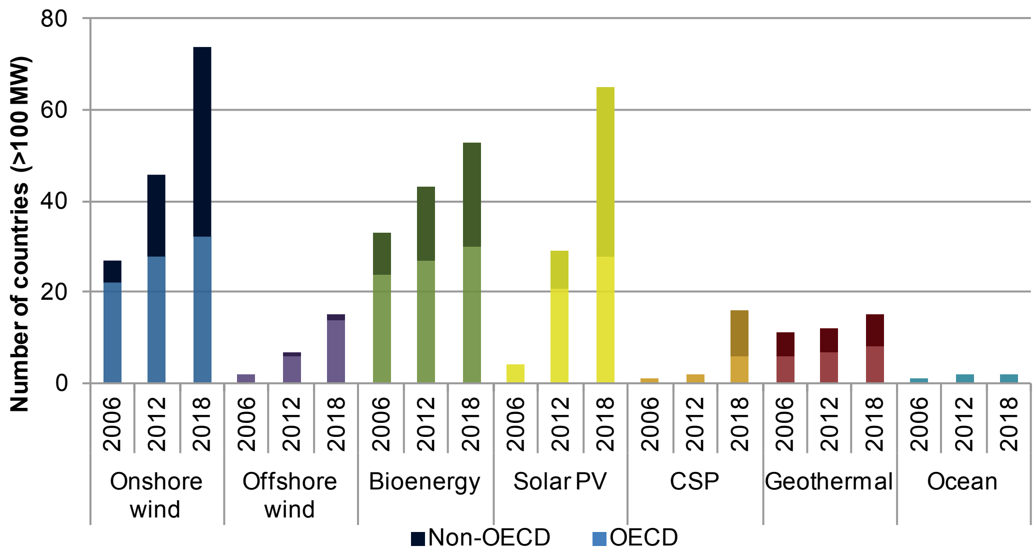
**The roles of biofuels for transport and renewable heat are also increasing, though at slower rates than renewable electricity.** Global biofuels production is expected to rise by over 25% from 2012 to 2018, reaching 2.4 million barrels per day (mb/d) in 2018. Biofuels output, adjusted for energy content, should account for 3.9% of global oil demand for road transport in 2018, up from an estimated 3.4% in 2012 and 1.5% in 2006. Still, biofuels face short-term production challenges, including the slow development of advanced biofuels, sluggish oil demand growth in some areas and policy uncertainty regarding the sustainability of feedstock supply chains. Global final energy use of renewable sources for heat, excluding traditional biomass, is expected to grow by 24% over 2012-18 to reach 18 exajoules (EJ). As a portion of final energy consumption for heat, renewable sources should rise to almost 10% in 2018, from over 8% in 2012 and under 8% in 2006.

## *Complex deployment dynamics and market transitions*

**Renewable energy development is becoming more complex as renewables increase their share in the global power mix.** Challenges have emerged in some regions since the *MTRMR 2012*. Despite remaining high, global new investment in renewable energy fell in 2012. Policy uncertainties continued to cloud the investment outlook for some key markets. In some countries, investment moderated in the face of macroeconomic uncertainties and incentive reductions, particularly in countries with strong deployment of solar PV. In some areas, integration challenges from higher penetrations of variable renewables emerged. Meanwhile, renewables faced strong competition from other energy sources in some markets (*e.g.* natural gas in the United States). In addition, manufacturing industries for renewables, particularly solar PV and wind, entered a more intense period of restructuring and consolidation.

**Nevertheless, the global deployment drivers of a portfolio of renewable sources have remained robust, despite economic, policy and industry turbulence.** Over the longer term, the expected persistence of supportive policy frameworks will be crucial to maintaining deployment momentum. In the near term, despite challenges in some countries, the global picture is more than compensated for by renewable deployment elsewhere.

**Figure 2** Number of countries with non-hydro renewable capacity above 100 megawatts (MW)




**Total renewable electricity generation grew strongly in 2012, increasing by 8.2% from 2011.** In absolute terms, global renewable generation in 2012 exceeded the electricity consumption of China. Part of the strength in 2012 growth stemmed from stronger-than-anticipated hydropower production, particularly in China. Yet it also reflected a continued rapid build-out of non-hydro sources, whose generation rose by 16% year-on-year. Among the OECD regions, non-hydro renewable generation was the second-largest source of power generation growth in 2012, expanding by 90 TWh. By comparison, gas-fired generation rose by over 150 TWh, while both coal and nuclear declined. Globally, the most dynamic sectors – solar PV and onshore wind – grew faster than expected in the *MTRMR 2012*, spurred by falling generation costs. Still, the expansion of other technologies – offshore wind, CSP, geothermal – remained more moderate, owing to relatively higher costs and more challenging financing situations.

**Renewable power deployment is expected to continue expanding geographically.** Non-hydro renewable electricity development is becoming increasingly widespread, with growth shifting beyond traditional support markets in Europe. In 2018, the number of countries with cumulative renewable electricity capacities above 100 MW is expected to increase significantly for many non-hydro technologies. Onshore wind, already widespread in 2012, is expected to be deployed in almost 75 countries by 2018. Deployment of solar PV at the 100 MW level should be reached in 65 countries by 2018, up from 30 in 2012, and of bioenergy at that level in over 50 countries by 2018, up from 40 in 2012. The spread of offshore wind, CSP, geothermal and ocean deployment should remain relatively slower, however.

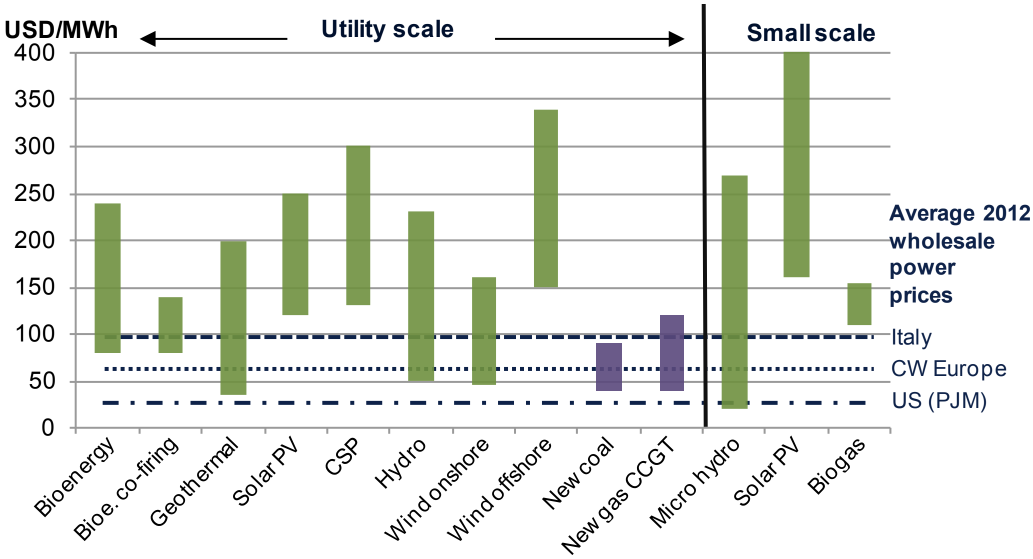
## *Competitiveness is improving, but market and policy frameworks are keys for investment*

**Renewable power sources are becoming more competitive in an increasing number of countries and circumstances.** Hydropower and geothermal in areas with good resources are already generally competitive versus new fossil-fuel power plants. Large-scale bioenergy plants are also competitive depending on feedstock prices and availability, while co-firing with biomass in coal and gas power plants has increased. Levelised costs for other renewables generally remain higher than new fossil-fuel generation; as such, these sources often require policy support to remain economically attractive. Yet the most dynamic technologies – onshore wind and solar PV – have reached, or are approaching, competitiveness in a number of markets without generation-based incentives.

**In some markets with good resources, the levelised cost of electricity (LCOE) for onshore wind is competitive or close to competitiveness versus new coal- and natural gas-fired power plants.** In Brazil, onshore wind competes well with new gas-fired plants and other historically less expensive renewable sources, such as hydropower and bioenergy. In Australia, wind is competitive versus the generation costs of new coal- and gas-fired plants with carbon pricing, and the best wind sites can compete without carbon pricing. In Turkey and New Zealand, onshore wind has been competing well in the wholesale electricity market for several years. With long-term power purchase agreements (PPAs), onshore wind costs are approaching that of new coal-fired plants in South Africa. In Chile and Mexico, onshore wind competes – or is close to competing – with new gas-fired plants. In the United States, although onshore wind remains more expensive than new gas-fired generation, long-term PPAs for wind power can provide cost-effective hedges against rising fuel prices over the long term, even without federal tax incentives.

**Falling system costs support the emergence of competitive market segments for solar.** Utility-scale solar – solar PV during the day, CSP in the evening – can be competitive in sunny countries when demand peaks are met by oil products (though oil subsidies may distort this picture). 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). Other emerging competitive segments are linked to the concept of grid or "socket" parity – when the LCOE of decentralised solar PV systems becomes lower than retail electricity prices that system owners would otherwise pay. Such markets are appearing in Spain, Italy, southern Germany, southern California, Australia and Denmark, and across residential and commercial segments. While this parity still requires support for the power system integration of solar PV, it is nonetheless a driver for increased investment in the sector.

**Figure 3** Global levelised costs of power generation ranges, first quarter of 2013




Notes: costs are indicative and ranges reflect differences in resources, local conditions and the choice of sub-technology. CCGT = combined-cycle gas turbine. Central-Western (CW) Europe = Austria, France, Germany, Switzerland. United States (US). PJM = regional transmission organisation covering 13 states and the District of Columbia (DC).

Source: IEA analysis with power price data from Bloomberg LP, 2013.

**Still, the competitiveness of renewables depends on the market and policy framework within which they operate.** Policy, market and technology risks can undermine project viability even when resources are good and technology costs are favourable. Policy uncertainty is chief among these risks, but non-economic barriers, integration challenges, counterparty 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 in Brazil and some other Latin American countries) is one way that is sustaining investment.

## *Non-OECD countries increasingly drive renewable power deployment*

**In 2018, non-OECD countries are expected to comprise 58% of total renewable generation, up from 54% in 2012 and 51% in 2006**. Deployment in most countries still hinges on cheap and abundant hydropower, but other technologies continue to scale up in countries with good resources and emerging support measures. Non-OECD regions account for two-thirds of global renewable generation growth over 2012-18 and over 50% of the non-hydro portion of new generation.

**China is expected to account for 40%, or 310 GW, of the growth in global renewable power capacity over 2012-18.** This deployment is supported by rising power demand, diversification needs and a favourable policy framework. While China is developing a portfolio of renewable sources, led by hydropower and onshore wind, a more positive outlook for solar PV is the largest change since the *MTRMR 2012*. A stronger policy push, improved financial incentives and grid access for small-scale projects amid continued falling system prices should make China the largest deployment market for solar PV over 2013-18. Nevertheless, the scale of existing and planned deployment of variable renewables (wind and solar PV) will continue to pose grid and system integration challenges.

**The remainder of the non-OECD countries are expected to account for 23%, or 175 GW, of renewable electricity capacity growth over the medium term**. India's deployment should be led by onshore wind, hydropower and solar PV. With acute rural electrification needs, distributed solar PV and bioenergy installations should also continue to grow. In Brazil, deployment should be led by hydropower, onshore wind and bioenergy. Thailand is expected to deploy a portfolio of renewable sources, including bioenergy, solar PV and onshore wind. In both Morocco and South Africa, tendering schemes drive growth in onshore wind, solar PV and CSP. Meanwhile, rapidly declining system costs should prompt increased solar PV deployment towards the end of the forecast period, particularly in Asia, the Middle East and the non-OECD Americas. Still, a number of challenges may weigh upon non-OECD development in some areas, including grid integration, non-economic barriers, and the relatively high cost and low availability of financing.

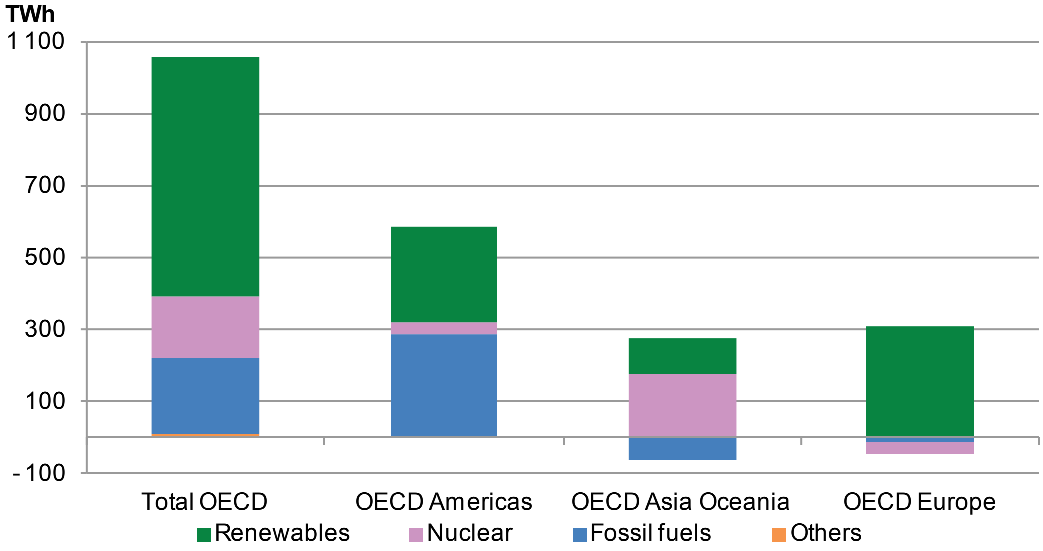
## *OECD countries grow robustly, but face distinct drivers and challenges*

**Renewable electricity is expected to account for 60% of the increase in OECD gross power generation over 2012-18.** In OECD Europe, new renewable generation is triple that of natural gas. In the OECD Americas, new renewable generation is expected to be second to fossil fuels (largely gas), but still accounts for over 40% of the increase in gross generation. In OECD Asia Oceania, renewable sources account for around 40% of the increase in gross generation, second to nuclear, assuming a partial return of nuclear power plants in Japan. In the OECD, renewable generation is seen growing to 24% of gross power generation in 2018, up from over 20% in 2012 and 16% in 2006.

**OECD countries are expected to remain a robust source of global growth**, accounting for 37%, or almost 290 GW, of new renewable electricity capacity over 2012-18. The drivers and challenges for OECD countries vary significantly. More mature markets – such as Germany, Italy and the United Kingdom – typically face low or negative growth in power demand, a need to integrate higher penetrations of variable renewables, and challenges in providing predictable policy frameworks that adapt to technology cost changes. Less mature markets – such as Chile, Mexico and Turkey – enjoy robust demand growth and excellent resource availability, but may face hurdles in scaling up deployment due to non-economic barriers, market design or the cost/availability of financing. Overall, onshore wind and solar PV should drive capacity additions in the OECD, with still-significant expansions expected in hydropower and bioenergy. Relatively higher cost offshore wind should grow more modestly, though OECD countries account for two-thirds of the expected global expansion. OECD countries are also expected to drive most developments in ocean power, which is currently at an early stage of maturity.

**Despite slowing growth, OECD Europe should lead deployment within the OECD over 2012-18,** with an expansion over 130 GW. Germany, the United Kingdom, Turkey and France are expected to drive growth. Germany is led by solar PV, onshore wind and offshore wind, though solar PV deployment has slowed with incentive adjustments. The United Kingdom should lead European offshore wind deployment. Turkey is buoyed by strong hydropower and onshore wind growth. France's growth is led by onshore wind. With adjustments to incentive schemes and more challenging economic conditions, renewable growth in Italy and Spain should moderate. Renewable capacity growth in the relatively smaller power sectors of Denmark and Ireland is focused largely on wind (onshore and offshore), while Denmark's coal-to-biomass conversions support a strong bioenergy increase.

**Figure 4** Changes in power generation by source and region, OECD, 2012-18




Notes: Other includes non-renewable municipal and industrial waste. In Europe, the expected decline in coal- and oil-fired generation is slightly larger than an expected increase in gas-fired generation, leading to a net negative change in fossil fuel generation.

**Renewable power capacity in the OECD Americas rises by over 100 GW over 2012-18.** The large US market size combined with state targets and good economic attractiveness in some areas should spur strong deployment of a portfolio of renewables, including onshore wind, solar PV and CSP, and geothermal. Still, the stability of federal incentives remains a key uncertainty, suggesting continued volatility in onshore wind additions there. Canada's capacity growth is led by onshore wind, hydropower, solar PV and bioenergy. Based on excellent resources and diversification needs, Chile's renewable capacity should almost double, led by wind and solar PV, though the cost and availability of financing will remain a constraint. Excellent resources and rising power needs should drive renewable growth in Mexico over 2012-18, led by onshore wind and solar PV. Yet, a relative lack of financial incentives and power sector barriers may limit expansion there.

**In OECD Asia Oceania, renewable electricity capacity is expected to rise by 55 GW over 2012-18.** Buoyed by generous feed-in tariffs, solar PV is expected to grow strongly in Japan, with onshore wind, hydropower, bioenergy and geothermal all making modest growth contributions in the region. Australia's renewable capacity should be boosted by competitive onshore wind and good economic attractiveness for distributed solar PV. Korea's growth is expected to be led by onshore and offshore wind development, hydropower, and solar PV. Korea is also expected to have the world's largest ocean power capacity in 2018.

## *Biofuels for transport and renewable heat continue to grow, despite uncertainties*

**World biofuels production is expected to reach 2.36 mb/d in 2018**, up 0.5 mb/d from 2012. Still, the sector faces some uncertainties. Globally, advanced biofuels capacity is expected to expand only slowly, though the first commercial-scale plants in the United States and OECD Europe were recently commissioned. Ethanol output in the United States is currently impacted by last year's severe drought and high corn prices. While the United States should remain the largest producer, technical and economic challenges related to blending more than 10% ethanol in the gasoline pool raise uncertainty over the outlook. In Brazil, more optimistic sugar cane harvest conditions and new government support measures should drive continued growth, though the ethanol sector there still faces financial difficulties. Meanwhile, high feedstock prices and poor margins continue to challenge biofuel producers in OECD Europe. The medium-term outlook there carries uncertainties associated with a European Commission proposal to limit blending requirements for food-based biofuels to 5% of transport energy demand, versus a current maximum 10%.

**Figure 5** Global biofuels supply, 2012-18

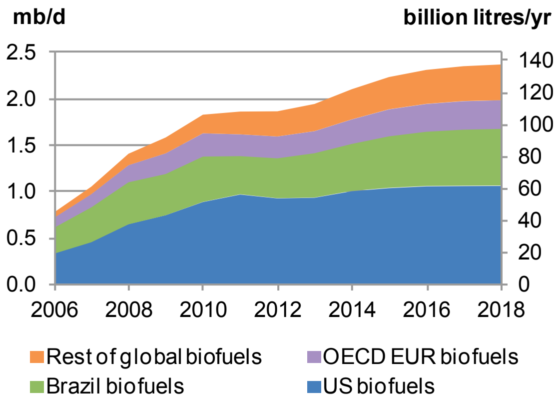
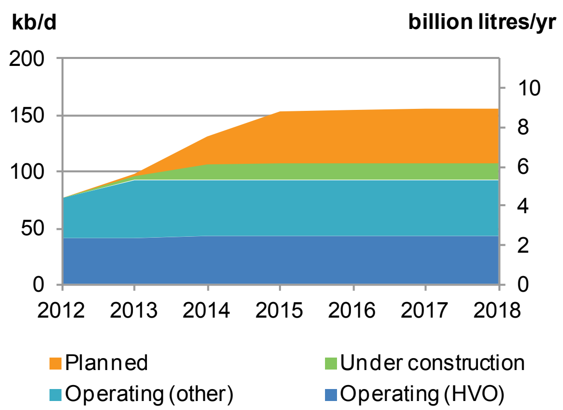
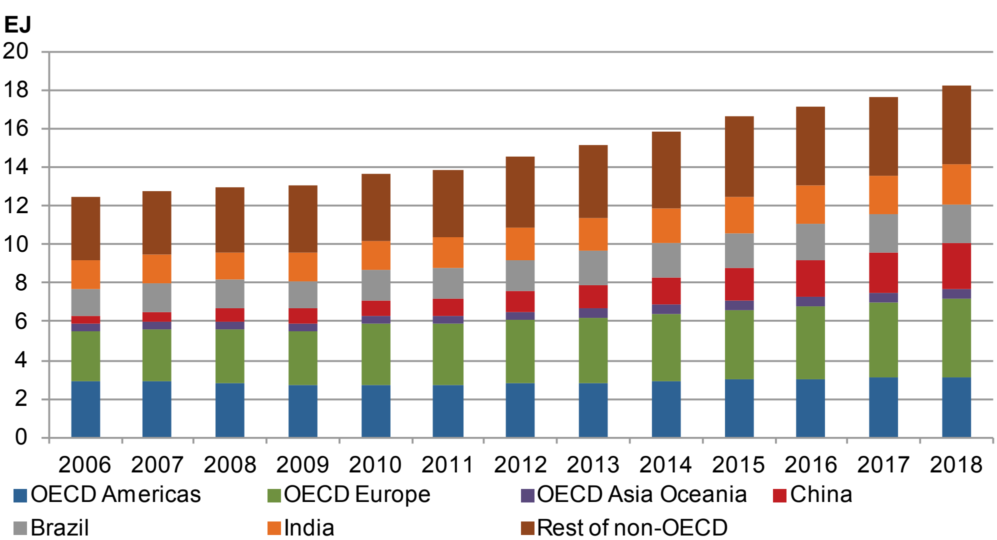



**Figure 6** Global advanced biofuel capacity




Note: kb/d = thousand barrels per day; HVO = hydrotreated vegetable oil.

**Figure 7** Global final energy use of renewable sources for heat (including commercial heat)




Note: excludes traditional biomass, *i.e.* the use of fuelwood, charcoal, animal dung and agricultural residues in stoves with very low efficiencies.

**Renewable sources are playing an increasing role in final energy use for heat.** Global final energy consumption of renewable sources for heat, excluding traditional biomass, is seen growing from 13.9 EJ in 2011 to 17.9 EJ in 2018. Renewable heat policy frameworks have evolved slowly, with relatively fewer countries with policies to support development in comparison to renewable electricity. To date, the most extensive policy drivers have emerged in OECD Europe, though comprehensive frameworks are generally still lacking. Over the medium term, OECD Europe should account for over

20% of growth, driven by 2020 targets in the European Union and increasing bioenergy, both for direct use and commercial heat, with solar thermal and geothermal growing from low bases. China should account for over 35% of global growth, driven by government targets and good competiveness of solar thermal heating. As a share of global final energy consumption for heat, renewable sources rise to almost 10% in 2018, from over 8% in 2012 and under 8% in 2006.

## *Renewable electricity broadly on track in clean energy scenarios*

**As a portfolio of renewable technologies continues to become more competitive, renewable power is on track to meet global climate change objectives**, *i.e.* the interim 2020 targets in the IEA *Energy Technology Perspectives 2012* (*ETP 2012*) 2 °C Scenario (2DS), in absolute generation and investment levels. That scenario assumes over 7 400 TWh of renewable generation in 2020, versus total generation of 27 165 TWh. Biofuels for transport face a more challenging path. Production must more than double from current levels to meet the 2DS target of 240 million litres per year in 2020. Advanced biofuels production, in particular, needs to accelerate to meet 2DS objectives.

**Figure 8** Global renewable electricity generation, the *MTRMR 2013* projection versus *ETP* 2DS

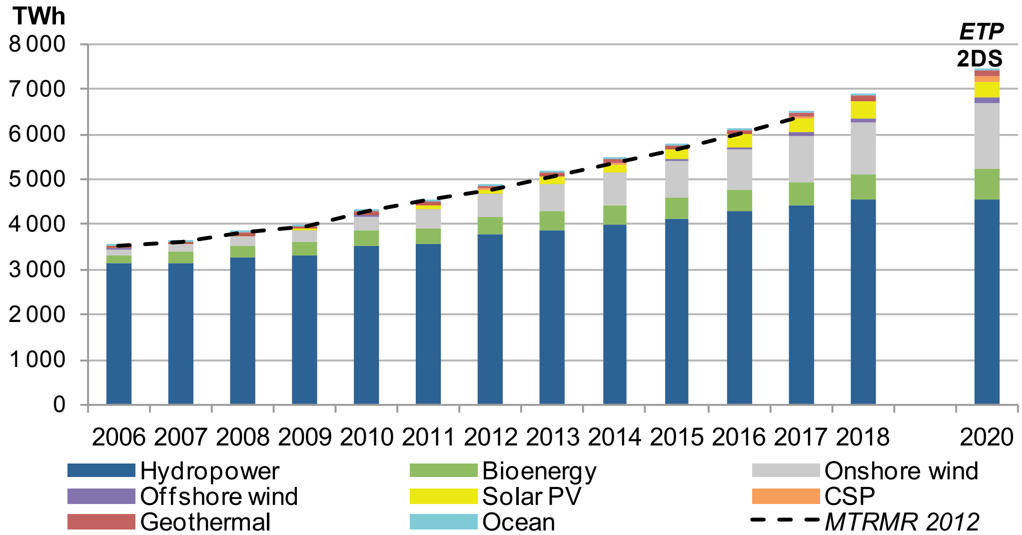



**Table 1** World renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 1 071 | 1 102 | 1 138 | 1 173 | 1 209 | 1 249 | 1 291 | 1 330 |
| Bioenergy | 75 | 82 | 89 | 96 | 105 | 112 | 119 | 125 |
| Wind | 236 | 282 | 321 | 368 | 413 | 459 | 508 | 559 |
| *Onshore* | 232 | 276 | 313 | 357 | 399 | 442 | 486 | 531 |
| *Offshore* | 4 | 5 | 8 | 11 | 14 | 17 | 22 | 28 |
| Solar PV | 69 | 98 | 128 | 161 | 194 | 230 | 268 | 308 |
| Solar CSP | 2 | 3 | 4 | 6 | 7 | 8 | 10 | 12 |
| Geothermal | 11 | 11 | 12 | 12 | 13 | 14 | 14 | 15 |
| Ocean | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total** | **1 465** | **1 579** | **1 693** | **1 815** | **1 941** | **2 073** | **2 211** | **2 351** |

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 (TWh)

| | 2006 | % of total gen, 2006 | 2011 | % of total gen, 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 3 122 | 16.4% | 3 567 | 16.1% | 3 792 | 3 888 | 4 010 | 4 136 | 4 276 | 4 423 | 4 570 |
| Bioenergy | 209 | 1.1% | 352 | 1.6% | 373 | 396 | 428 | 463 | 498 | 530 | 560 |
| Wind | 133 | 0.7% | 438 | 2.0% | 519 | 626 | 725 | 840 | 952 | 1 080 | 1 220 |
| *Onshore* | 131 | 0.7% | 428 | 1.9% | 505 | 606 | 697 | 803 | 906 | 1 020 | 1 144 |
| *Offshore* | 2 | 0.0% | 10 | 0.0% | 13 | 20 | 28 | 36 | 46 | 59 | 76 |
| Solar PV | 6 | 0.0% | 62 | 0.3% | 100 | 138 | 178 | 221 | 267 | 316 | 368 |
| Solar CSP | 1 | 0.0% | 3 | 0.0% | 6 | 9 | 14 | 18 | 22 | 28 | 34 |
| Geothermal | 60 | 0.3% | 70 | 0.3% | 72 | 77 | 80 | 83 | 88 | 93 | 97 |
| Ocean | 1 | 0.0% | 1 | 0.0% | 1 | 1 | 1 | 1 | 2 | 2 | 2 |
| **Total** | **3 531** | **18.6%** | **4 492** | **20.2%** | **4 862** | **5 136** | **5 436** | **5 762** | **6 104** | **6 471** | **6 851** |

Notes: gen = generation. Hydropower includes generation from pumped storage, which was reported at 75 TWh for 2011. Data for 2011 and 2012 are estimates; the split for onshore and offshore wind is estimated for historical data.

## References


Bloomberg LP (2013), accessed 25 April 2013.

IEA (2012a), *Energy Technology Perspectives 2012*, OECD/IEA, Paris.

IEA (2012b), *Medium-Term Renewable Energy Market Report 2012*, OECD/IEA, Paris.

# ANALYTICAL FRAMEWORK

The second edition of the *MTRMR* has expanded since the *MTRMR 2012.* In addition to projecting the evolution of renewable electricity, the 2013 edition now forecasts developments in renewable energy within the heat and transport sectors. Renewable electricity analysis focuses on eight technologies – hydropower, bioenergy for power, onshore wind, offshore wind, solar PV, solar thermal electricity from CSP plants, geothermal and ocean power. The renewable transport section of this report presents production forecasts for biofuels for transport, including ethanol, biodiesel and developments in advanced biofuels. Analysis of 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, in principle, include usage of renewable electricity, this report does not attempt to characterise these flows, which are difficult to ascertain.

## *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 non-Organisation for Economic Co-operation and Development (OECD) areas, 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 2012, may reflect estimates that are subject to revision. While official 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 International Energy Agency (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 (for further details, see Feature Box on hydropower in *Renewable Electricity: Technology Outlook*).

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 off-grid systems are included at the time of the installation. Except where noted, prices and costs are expressed in nominal terms; national currency conversions to United States dollars (USD) are made at market exchange rates, which are indicated on a case-by-case basis.

### *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 2013* examines in detail 21 key markets for renewable electricity, while identifying and characterising developments that may emerge in other important markets. Forecasts stem from both quantitative and qualitative analysis. For each of these 21 markets, *baseline case* projections are made for renewable electricity capacity by source through 2018. 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.

Country-level examinations start with a total power demand outlook 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 April 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 2013 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; |
| • public acceptance; | "not in my backyard" behaviour; |
| • environmental. | unclear impacts of new technologies. |
| • address system integration issues. | |

Source: IEA, 2011.

Aside from policy, the *MTRMR 2013* 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. Country sections analyse possible forecast changes in an *enhanced case*, where market-specific challenges – *e.g.* pertaining to policy, grids or attractiveness – are overcome.

### *Outlooks for technology and financing guide the global picture*

Key market assessments plus estimates for all other countries in the world under the *baseline case* are judged against the supply abilities of global technology and financial markets. In these sections, the *MTRMR 2013* focuses on identifying bottlenecks that could pose risks to the country forecasts.

The technology chapter features several forms of analysis. First, it describes system properties of different renewable technologies, their recent cost developments, and elaborates on their advantages and challenges. Second, the section characterises recent market developments by technology. Third, the chapter provides an outlook for market development through 2018. It consolidates, by technology, the country-level forecasts; identifies the key markets for each technology; and addresses potential deployment barriers that lie ahead. For wind and solar PV, the report attempts to characterise the supply ability of global manufacturing capacity in those sectors. The analysis of global financing reports on recent developments in renewable energy investment, using data from Bloomberg New Energy Finance. It then discusses key trends over the medium term from a top-down perspective, identifying the impacts of policy on investments and the degree to which the availability and cost of financing may enable or hinder renewable energy development.

### *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. While the analysis conservatively scrutinises future plants, it errs on the side of allowing potential capacity to grow faster than output.

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.[1]

## References

IEA (International Energy Agency) (2011), *Deploying Renewables: Best and Future Policy Practice*, OECD/IEA, Paris.

IEA (2012c), *World Energy Outlook 2012*, OECD/IEA, Paris.

IMF (International Monetary Fund) (2013), *World Economic Outlook, April 2013*, IMF, Washington DC.

[1] Later in 2013, the IEA will release an Insights paper on renewable heating and cooling, which will look more in-depth at technology, policy and market developments in this area.

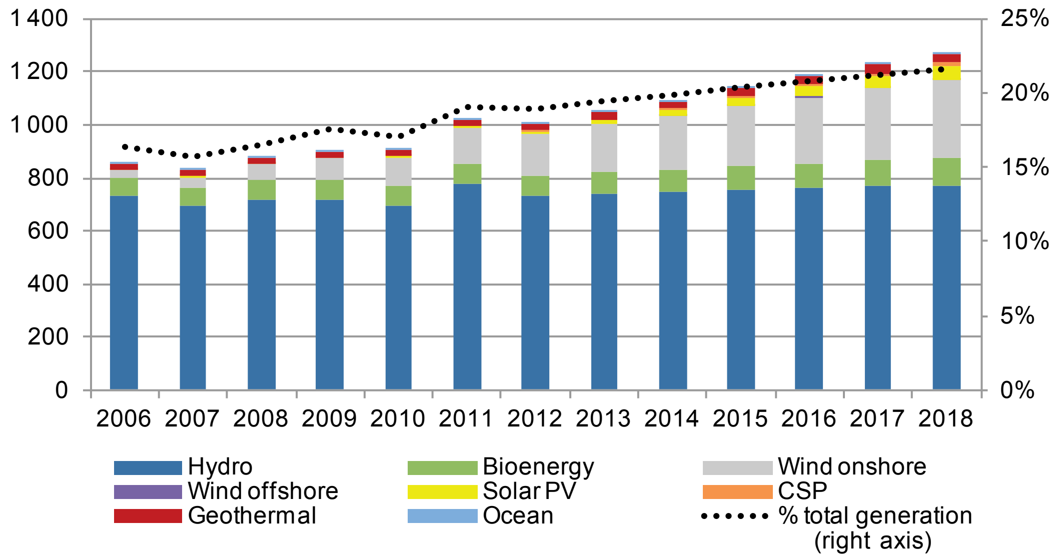
# RENEWABLE ELECTRICITY: OECD AMERICAS

## Summary


- **Despite steady growth in non-hydro sources, OECD Americas renewable electricity generation declined modestly in 2012, by 15 terawatt hours (TWh) versus 2011 (-1.5% year-on-year) due to lower hydropower generation.** Hydropower declined versus higher-than-normal output in the United States in 2011. Non-hydro technologies grew steadily, however. Onshore wind growth was supported by record capacity additions in the United States and strong growth in Canada and Mexico. Higher solar photovoltaics (PV) generation in the United States and Canada and concentrating solar power (CSP) and geothermal in the United States also contributed.

- **Over the medium term, OECD Americas renewable generation is projected to grow from 1 004 TWh in 2012 to 1 269 TWh in 2018 (+4.0% per year).** Renewable generation is seen rising from 19% of gross power generation in 2012 to over 21% in 2018. Onshore wind leads the growth, followed by hydropower, solar PV and bioenergy. CSP, geothermal and offshore wind should account for a smaller part of growth. Relative to global deployment in these technologies, OECD Americas additions to geothermal and CSP should be large. Overall, the forecast is 22 TWh higher in 2017 versus MTRMR 2012, with upward revisions for onshore wind, hydropower, and solar PV.

**Figure 9** OECD Americas renewable electricity generation and projection (TWh)




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.

- **United States (US) renewable electricity capacity should grow from 184 gigawatts (GW) in 2012 to 247 GW in 2018 (+5.1% per year).** Onshore wind and solar PV lead deployment. Bioenergy, CSP, geothermal and offshore wind also make notable additions. The large US market size combined with state targets and good economic attractiveness in some areas should spur strong deployment. Still, the stability of federal incentives remains a key uncertainty, suggesting continued volatility in onshore wind additions.

- **Other OECD Americas countries should grow strongly.** Canada's capacity rises from 86 GW in 2012 to 108 GW in 2018, led by onshore wind, hydropower, solar PV and bioenergy. Based on excellent resources and diversification needs, Chile's renewable capacity should grow by almost 5 GW over 2012-18, led by onshore wind and solar PV, though the cost and availability of financing will remain a constraint. Finally, excellent resources and rising power needs should drive renewable growth of 11 GW in Mexico over 2012-18, led by onshore wind and solar PV. Still, a relative lack of financial incentives and power sector barriers may limit expansion.

**Table 4** OECD Americas renewable electricity generation and projection (TWh)

| | 2006 | % of total gen, 2006 | 2012 | % of total gen, 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 730 | 14.0% | 729 | 13.7% | 739 | 745 | 754 | 763 | 770 | 773 |
| Bioenergy | 71 | 1.4% | 78 | 1.5% | 82 | 85 | 89 | 93 | 96 | 99 |
| Wind | 29 | 0.6% | 156 | 2.9% | 179 | 201 | 227 | 250 | 273 | 298 |
| *Onshore* | 29 | 0.6% | 156 | 2.9% | 179 | 201 | 227 | 249 | 271 | 296 |
| *Offshore* | - | 0.0% | - | 0.0% | - | 0 | 1 | 1 | 2 | 2 |
| Solar PV | 1 | 0.0% | 13 | 0.2% | 15 | 22 | 29 | 37 | 45 | 54 |
| Solar CSP | 1 | 0.0% | 2 | 0.0% | 3 | 6 | 8 | 10 | 11 | 12 |
| Geothermal | 23 | 0.4% | 25 | 0.5% | 28 | 28 | 29 | 30 | 31 | 32 |
| Ocean | 0 | 0.0% | 0 | 0.0% | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total** | **855** | **16.4%** | **1 004** | **18.9%** | **1 047** | **1 088** | **1 137** | **1 183** | **1 226** | **1 269** |

Notes: gen = generation. Hydropower includes generation from pumped storage. Data for 2012 are estimates; the split for onshore and offshore wind is estimated for historical data.

## Canada

Canada's large hydropower generation continues to grow, while wind and solar PV scale up aided by provincial support. Lack of a national renewable policy may hinder higher levels of growth.

### *Power demand outlook*

Canada's power demand is projected to grow by 1.7% annually over 2012-18, driven by a continuing economic recovery. Having contracted slightly in 2009 after the global financial crisis, Canada's gross domestic product (GDP) is expected to grow by 2.2% annually on average from 2012-18, in line with International Monetary Fund (IMF) assumptions (IMF, 2013). According to the National Energy Board, electricity prices for all users are expected to increase on average by 2% annually over the medium term (NEB, 2011).

### *Power sector structure*

#### Generation and capacity

Hydropower dominates the power sector in Canada and accounted for 59% of total electricity generation in 2012. Nuclear generation represented around 15% while coal and natural gas together provided 21% of total power output. Non-hydro renewable sources, mainly wind, bioenergy and solar PV, have risen in importance, accounting for around 4% of the power mix in 2012. At the end of 2011, total installed power capacity in Canada was 139 GW.

Power generation from onshore wind increased to 1.8% of the power mix in 2012, up from 1.6% in 2011. Onshore wind deployment of 0.9 GW was driven by incentive measures provided in the provinces of

Quebec and Ontario, which account for much of Canada's cumulative capacity of 6.2 GW. Alberta is another important province, accounting for 20% of wind output and over 1.1 GW of cumulative capacity. Bioenergy for power is mainly used by the industry for self-consumption needs with some plants operating as independent power producers (IPPs). In 2012, bioenergy accounted for 1.7% of total generation. Solar PV generation has remained small in terms of its generation share, but its capacity is growing fast. In 2012, cumulative capacity rose to 0.8 GW from 0.6 GW in 2011, supported by a generous feed-in tariff programme in Ontario. Canada is developing several small geothermal projects in British Columbia. In addition the country has 20 megawatts (MW) of cumulative ocean power capacity.

**Figure 10** Canada power demand versus GDP growth

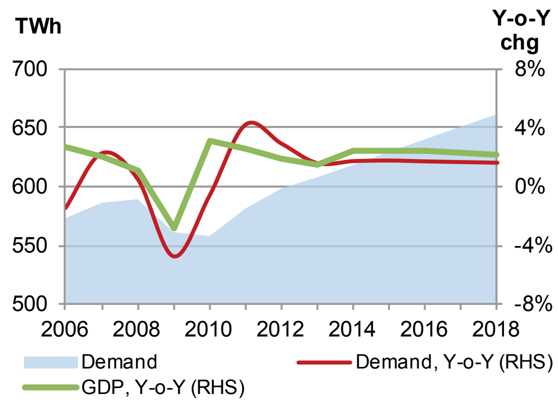
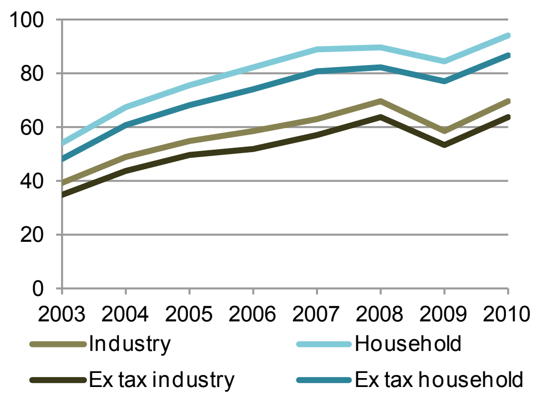
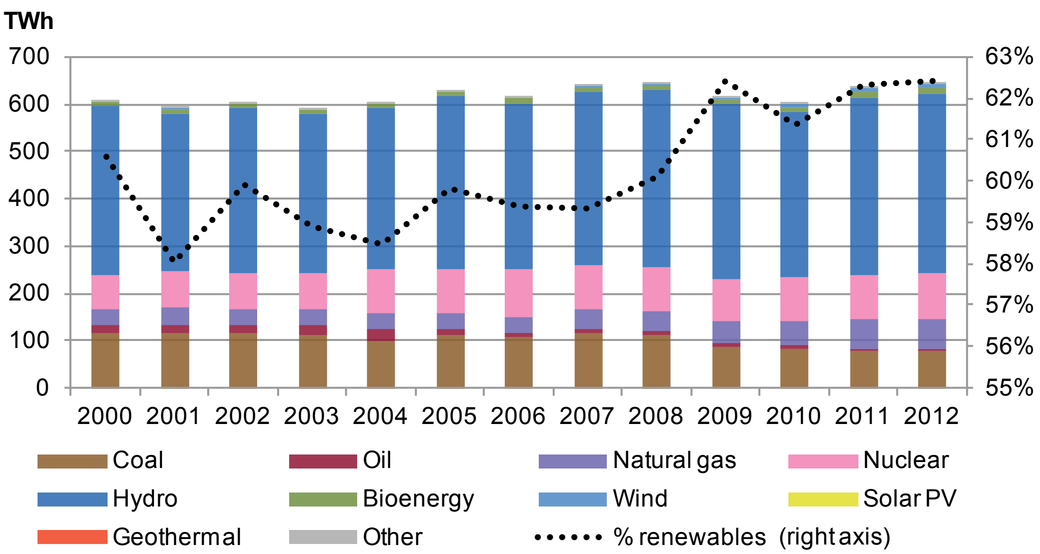



**Figure 11** Canada average retail power prices (USD per megawatt hour [/MWh])




Notes: Y-o-Y = year-on-year ; chg = change. Demand is expressed as electricity supplied to the grid. RHS = right-hand side. Except where noted, power prices include tax.

**Figure 12** Canada power generation by source and renewable share of total power generation




Over the medium term, hydropower is expected to rise gradually with over 5 GW under development, though actual generation will depend strongly on year-to-year reservoir availability. Coal generation should decrease with the retirement of some plants in Alberta and Saskatchewan in accordance with a federal regulation from 2015 capping plant life at 45 years. Ontario is slated to shut all of its coal plants by 2014. By contrast, low natural gas prices should spur new gas-fired generation. Meanwhile, a portfolio of non-hydro renewable sources should expand, based on a robust pipeline of onshore wind projects, continued bioenergy expansion and solar PV growth, chiefly in Ontario.

### Grid and system integration

The Canadian power system consists of three main interconnected power grids: the Western grid, the Eastern grid and the Quebec grid, which also includes the Atlantic grid. Provincial authorities regulate consumer electricity prices, generation, transmission and distribution. All Canadian provinces are connected to one another, and inter-provincial trade is increasing. A significant amount of trade also occurs with the United States – largely hydropower from Quebec and Manitoba – with net exports topping 47 TWh in 2012. Such exports may rise over the medium term, potentially boosted by the development of the 1.2 GW Northern Pass transmission line from Quebec to the US north east. Still, the regulatory approval of that transmission project currently remains uncertain.

**Table 5** Canada main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **General targets:**<br>Quebec: 4 GW wind by 2015;<br>Manitoba: 1 GW wind by 2014;<br>Ontario: 10.7 GW of RES-E (excluding hydro) by 2018, 9 GW of hydropower by 2030;<br>British Columbia: All new electricity projects to have zero net greenhouse gas emissions. Clean or renewable electricity generation will continue to account for at least 90% of total generation.<br>**RPS**:<br>Prince Edward Island: utilities to source 15% from renewables;<br>New Brunswick: 10% of electricity sales from renewable sources;<br>Nova Scotia: 25% renewable electricity by 2015; 40% by 2020. | **Feed-in tariffs (FITs):**<br>Nova Scotia: FIT for only community-owned small-scale projects;<br>Ontario: FIT for both small and large installations.<br>**Net metering:**<br>Available for residential and commercial installations with a generating capacity up to 0.5 MW – 1 MW in following provinces: British Columbia, New Brunswick, Nova Scotia, Ontario, Saskatchewan, Quebec.<br>Newfoundland and Labrador, and Yukon: net metering policy under development.<br>**Advantageous accelerated capital cost allowance (CCA):**<br>Available for all renewable energy equipment. CCA is allocated according to energy efficiency levels of the equipment purchased.<br>**Tenders:**<br>Quebec: Wind power tenders. Next tender will be held by autumn 2013 with 700 MW of capacity. | **Greenhouse gas (GHG) reduction targets:**<br>Many provinces have either binding or non-binding targets for GHG reductions mostly set to 2020. These were implemented in order to help Canada meet its 2020 target to reduce GHG emissions by 17% below 2005 levels.<br>By 2020, 90% of generated electricity must be produced from zero-emitting sources. |

Note: RES-E = electricity generated from renewable energy sources. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Over the medium term, Canada's grid should act as a moderate constraint to renewable deployment, with challenges from the integration of increased variable renewable sources. For example, the Independent Electricity System Operator (IESO) in Ontario expects that the total installed capacity for wind and solar will rise 6.8 GW by August 2014 (IESO, 2013). A study prepared for the Ontario Power Authority assessed that increased ramping needs for conventional generators could be accommodated with 5.0 GW of installed wind power capacity in Ontario, but would raise challenges as cumulative capacity approached 10 GW (Van Zandt, 2006).

## Current policy environment for renewable energy

Canada has no binding national renewable energy target, but eight provinces have introduced renewable portfolio standards or targets for some renewable sources. British Columbia, Alberta, Ontario, Quebec, Manitoba, Nova Scotia, New Brunswick and Prince Edward Island have either RPSs or targets for a portfolio of renewable energy sources. The federal government has offered some generation-based incentives in the past – *e.g.* under the ecoEnergy for Renewable Power programme from 2007 to 2011 – but most current incentives are provided by the provinces.

## Economic attractiveness of renewable energy and financing

Ontario introduced a FIT scheme with attractive incentive levels in 2009 and required wind and solar installations benefiting from the FIT to have 50% to 60% of project costs incurred in Ontario.[2] The province revised its FIT in March 2012 by reducing incentives for solar PV by 30% and for wind by 15%. Quebec has employed a capacity auction system, awarding two wind energy tenders in 2005 and 2008, which totalled 3 GW. Another call for tender for about 700 MW is expected in the autumn of 2013. Meanwhile, Alberta has a regulation that requires facilities emitting over 100 000 tonnes of carbon dioxide equivalent ($CO_2$-eq)/yr to reduce their emissions intensity by 12%. Facilities may comply with this regulation by purchasing carbon offsets. This programme has so far created significant additional revenue for wind developers.

The economic attractiveness of renewable energy is highly dependent on the level of incentive measures provided at the provincial level. With hydropower playing a large role in the generation mix, Canada enjoys relatively low wholesale electricity prices compared with most other OECD countries. One of the motivations, among others, behind the introduction of incentives for renewable energy by several provinces has been to diversify the generation mix.

With incentives, wind energy will likely remain economically attractive over the medium term. The costs of onshore wind in different provinces vary depending on their incentive scheme designs. Quebec has the lowest-cost wind power, mainly due to competitive auctions where developers try to outbid one another in order to obtain long-term power purchase agreements (PPAs). With over 60% of its electricity generated from coal, Alberta has a liquid carbon offset market providing significant additional revenue (around CAN 30/MWh) to wind developers. Although the cost of solar PV is still relatively high in Canada compared with wind power and bioenergy, the FIT programme in Ontario has succeeded in attracting some investment. For small-distributed capacity, Ontario's micro FIT programme has already received applications worth of 120 MW as of April 2013. While falling system costs and generous incentives should drive continued solar PV deployment over the medium term, a lack of incentives elsewhere should keep most deployment concentrated in Ontario.

The cost and availability of financing should not pose a significant challenge in provinces where robust renewable energy policies are in place. Ontario, Quebec and Alberta have already attracted significant amounts of foreign investment and are to continue to attract significant financing over the medium term. To facilitate the participation of localities in project development, Ontario offers a premium on top of the FIT in cases with the equity participation of local communities.

[2] The government recently announced a transition from feed-in tariffs to a competitive procurement process for large-scale projects.

## *Conclusions for renewable energy deployment: baseline case*

Renewable energy capacity is expected to expand by 22 GW, from 86 GW in 2012 to 108 GW in 2018. Alberta, Ontario and Quebec should lead this growth with their robust renewable energy policies and incentives. Onshore wind expansion looks the strongest, accounting for more than half of the new additional capacity (12.1 GW) over the medium term. Solar PV installations should take-off, expanding by around 3 GW, largely driven by attractive incentives in Ontario. Hydropower should continue to grow slowly over 2012-18. Bioenergy is expected to increase by 1.2 GW over 2012-18. Co-firing of coal and natural gas power plants with biomass in Ontario is expected to drive new additions due to the legislation mandating the closure of coal-fired plants by 2015. Canada's expansion of ocean energy over the medium term should be led by the province of Nova Scotia. The country should deploy only around 75 MW of new capacity in the projection period, but the long-term potential looks more robust. Notably, the roadmap of Marine Renewables Canada sees installed capacity of 250 MW by 2020 (Marine Renewables Canada, 2012).

**Table 6** Canada renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 75.7 | 76.7 | 77.4 | 78.0 | 79.6 | 81.3 | 81.8 | 82.3 |
| Bioenergy | 1.7 | 1.8 | 2.1 | 2.2 | 2.5 | 2.7 | 2.9 | 3.0 |
| Wind | 5.3 | 6.2 | 8.4 | 10.8 | 12.2 | 14.2 | 16.3 | 18.5 |
| *Onshore* | 5.3 | 6.2 | 8.4 | 10.8 | 12.2 | 14.2 | 16.1 | 18.3 |
| *Offshore* | - | - | - | - | - | - | 0.2 | 0.3 |
| Solar PV | 0.6 | 0.8 | 1.3 | 1.9 | 2.6 | 2.9 | 3.3 | 3.8 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| **Total RES-E** | **83.3** | **85.6** | **89.2** | **92.9** | **96.9** | **101.2** | **104.3** | **107.7** |

**Table 7** Canada main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • excellent resource availability across a portfolio of renewable sources, including hydropower, bioenergy and wind;<br>• robust provincial policy environment backed by FITs in Ontario, tenders in Quebec and carbon offsets in Alberta. | • lack of binding renewable energy targets and financial incentives nationally and in some provinces;<br>• increasing grid integration challenges in some provinces. |

## *Renewable energy deployment under an enhanced case*

The baseline forecast assumes no major policy changes concerning renewable incentives at the federal level. The introduction of a long-term federal strategy, with targets for renewable electricity, could buoy investment. In addition, the introduction of financial incentives in more provinces, particularly British Columbia, Saskatchewan and Manitoba, could support greater onshore wind deployment. Under these conditions total cumulative capacity for onshore wind could potentially be 2GW to 3 GW higher in 2018 than under the baseline case.

## Chile

Excellent resources and strong diversification needs drive deployment. Yet a lack of long-term power purchase agreements (PPAs) and/or stronger incentives may weigh on investment.

### *Power demand outlook*

Chile's power demand is seen growing on average by 4.3% annually over 2012-18. Chile's economy has boomed in recent years, and real GDP is projected to grow on average by 4.7% annually from 2012-18. Energy-intensive industries, such as mining and paper production, are the main drivers of Chile's economic growth, consuming a significant amount of the electricity generated in the country. Power prices in Chile have increased significantly since 2005 due to a long drought that has reduced hydropower production, reduced availability of cheap natural gas from Argentina due to supply interruptions and increased dependency on relatively costly imported liquefied natural gas (LNG).

**Figure 13** Chile power demand versus GDP growth

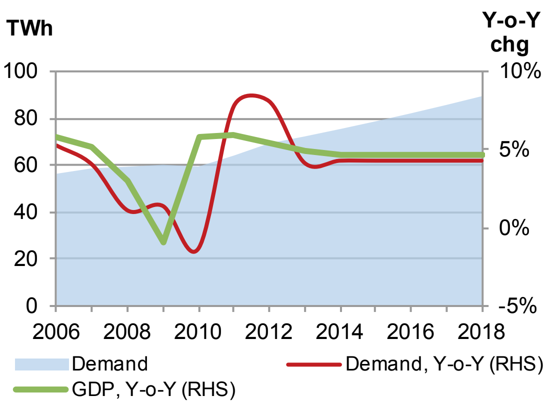
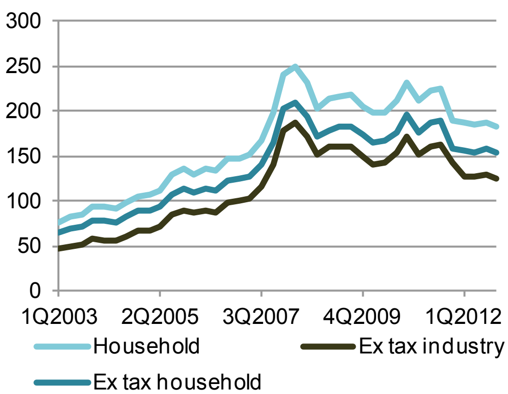



**Figure 14** Chile average retail power prices (USD/MWh)




Notes: demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax.

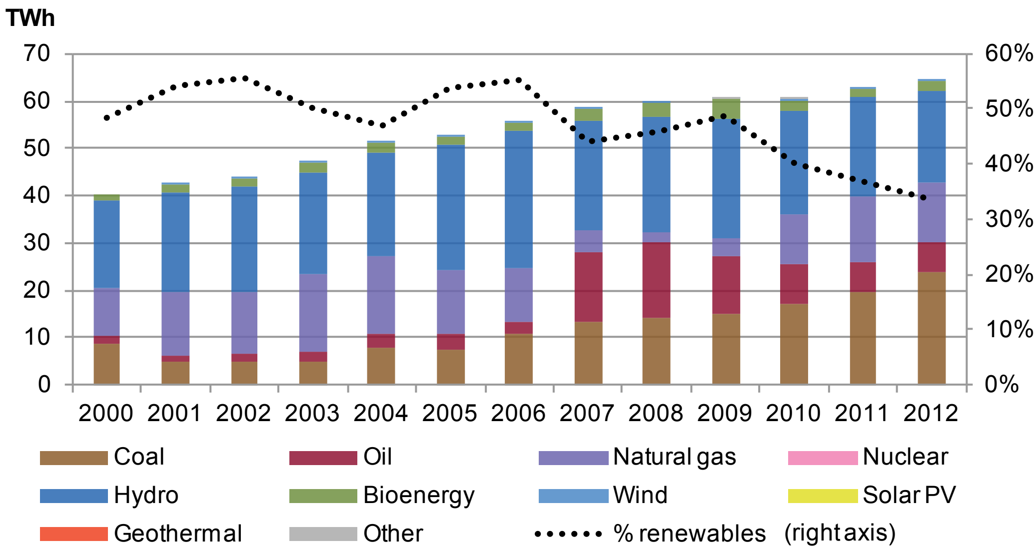
### *Power sector structure*

#### Generation and capacity

Chile's generation is dominated by coal and hydropower. Yet the share of hydropower has fallen since the mid-1990s, in part due to severe droughts and low rainfall levels. In 2012, the share stood at 30%. Since 2008, the share of coal, diesel and natural gas (*i.e.* LNG) in electricity generation has increased significantly; together they accounted for two-thirds of total power output in 2012. As of the end of 2012, Chile's renewable capacity, outside of hydropower, amounted to almost 1.0 GW, with generation from non-hydro sources accounting for around 4% of the current electricity mix. Bioenergy has led development with cumulative capacity of 0.6 GW. Wind cumulative capacity totalled over 0.2 GW and solar PV capacity remained marginal at 6 MW.

In 2008, the Chilean government introduced new targets to increase both the share of small hydropower (< 20 MW) and non-hydro renewable energy sources from 3% to 10% of the generation mix by 2024. According to the Centre for Renewable Energy (CER), 449 MW worth of small hydropower, wind, solar and biomass projects are under construction, and 7.5 GW have already received environmental approval from government authorities (CER, 2013).

**Figure 15** Chile power generation by source and renewable share of total power generation




## Grid and system integration

The integration of renewable sources represents a significant constraint to development. The Chilean grid consists of four distinct electrical systems. The SING (Northern Interconnected System) and the SIC (Central Interconnected System) are the two main systems, with SING covering 26% of electricity generation and SIC covering 74%. There are two smaller systems, the Aysen System in the south and the Magallanes System in the far south. Dispatching in the SIC and SING are managed by two separate system operators. Increasing generation to meet rapidly growing power demand and insufficient growth of the transmission infrastructure have created new points of congestion in the face of limited system flexibility in both the SIC and SING. Chile's geographic orientation also acts as a bottleneck, with a single north-south transmission corridor that makes the creation of a more robust system difficult. As new generation has mostly been located in the south and new demand is mostly in the north, congestion has emerged along this north-south route.

Transelec, a private company, owns 100% of the SING and 85% of the SIC trunk transmission systems. New investments in transmission are regulated by the government (though the sub-transmission segment is not regulated), and relevant projects were identified in the second transmission study released in 2011. Under this second transmission study, projects worth around USD 900 million have been tendered to reinforce the grid, only in the SIC and SING. However, the timeline for approvals for new transmission investments (which generators have the option to fund themselves) can take up to 20 months, posing challenges for the connection of new generation capacity to the grid. The southern region of Chile has significant potential for the development of wind but has limited grid capacity and connection to demand centres farther to the centre and north. As a result, only limited deployment in this area is expected over the medium term. Solar potential is concentrated more in the north, closer to demand centres.

### *Current policy environment for renewable energy*

Currently the main policy incentive for renewables is the Law 20.257 to Promote Non-Conventional Renewable Energy Sources that set a renewable portfolio standard launched in 2010. The portfolio standard applies to large consumers and utilities; it is currently set at 5% from 2010 to 2014, then increases 0.5% per year (/yr) to 10% in 2024.

**Table 8** Chile main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Law 20.257 to promote Non-Conventional Renewable Energy Sources (NCRES) (excludes large hydro):** Defines NCRES including biomass, geothermal energy, solar, wind, ocean and small hydropower (20 MW).<br><br>Established a renewable portfolio standard for utilities and large consumers operating in SIC and SING transmission areas, who must source 5% of electricity sold from NCRES between 2010 and 2014. Then the RPS increases 0.5% every year reaching 10% in 2024. | **Grants for feasibility studies and investments:** Grant administered by the Centre for Renewable Energy which provides for up to 40% of pre-investment studies, with a maximum of up to Unidad de Fomento 1 000 (about USD 50 000).<br><br>**Innovation in Renewable Energy:** Supports the development of NCRE self-consumption projects with grants that cover up to 50% of the total project amount (cap of around USD 1 million). Application process is closed, but there is to be a second call in 2014.<br><br>**Tender for CSP capacity:** The government recently launched a tender for a CSP project in the Atacama Desert. The winning bid would receive two grants from the government and the European Union totalling up to USD 38 million, and a USD 380 million loan, raised via international funds. | **National Energy Strategy 2012-2030:** Outlines needed reforms that will facilitate deployment of renewable energy sources in fulfilling targets.<br><br>**Centre for Renewable Energy Centre:** Was created in order to facilitate deployment of RES and to act as an information platform. The centre collects data on renewable energy projects in operation, construction or environmental approval process. |

For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

A new tendering system to incentivise the development of renewable projects is currently being discussed in the parliament and would complement the current portfolio standard. In March 2012, Chile released its national energy strategy, *Energy for the Future*, which aims at increasing the share of renewables, promoting energy efficiency, strengthening the role of hydropower, expanding the grid and creating a competitive electricity market (Gobierno de Chile, 2012). Although ambitious targets are penned by the renewable law and some financial supports are offered, long-term generation-based incentives or PPAs for renewable energy have been less available. Still, the government recently launched a tender for a CSP project in the Atacama Desert. The winning bid would receive grants from the government and the European Union.

## *Economic attractiveness of renewable energy and financing*

Although the current support policy framework has not been finalised yet, Chile's commitment to deploy renewable energy sources has already attracted a lot of attention from both domestic and foreign investors because of excellent resource potential. Increasing electricity prices since 2007 have also buoyed the economic attractiveness of renewable sources. Onshore wind is already competitive with new-build large hydropower and natural gas plants (Tringas, 2011). Solar PV and CSP are currently more costly than other technologies, but are still attractive in areas where irradiance is high, especially in the north. Solar PV is generally attractive versus LNG or diesel generation in key demand regions in the north, particularly for mining operations, though it is currently limited to daytime demand needs. The constant electricity demand pattern of the mining sector could make technologies with higher capacity factors and firm delivery such as CSP attractive.

However, the cost and availability of financing should remain a challenge to Chilean renewable energy development over the medium term. A lack of stronger financial incentives and long-term PPAs in addition to long permitting procedures can create hurdles to sourcing financing, particularly for less experienced developers, despite the presence of several Chilean and foreign banks in the market.

Project bankability would be improved with a stable revenue stream over the lifetime of the project. However, this can be difficult to demonstrate with projects selling into more volatile spot markets.

Still, the government's agreement with the Clean Technology Fund (CTF) to leverage up to USD 1.2 billion may address some of the financing barriers concerning project risk, cost and liquidity by providing concessional financing and technical assistance. The CTF investment plan was drafted in co-ordination with the Inter-American Development Bank (IDB), members of the World Bank Group and key Chilean stakeholders. Initially, the government has designed a USD 200 million plan to attract additional private funding for CSP, large-scale solar PV, renewable energy self-consumption and energy efficiency projects. The Clean Development Mechanism (CDM) provides additional revenue, mostly to large wind generators. As of January 2013, around 40% of wind power projects and some hydropower and biomass projects installed in Chile were registered to the CDM. However, with low prevailing carbon prices, the CDM's role in securing financing going forward may be limited.

### *Conclusions for renewable energy deployment: baseline case*

Renewable electricity capacity is expected to grow from 6.8 GW in 2012 to 11.7 GW in 2018. Onshore wind and solar PV are expected to lead this growth, expanding by 2.4 GW and 1.0 GW, respectively. As of April 2013, 3.2 GW of wind projects and 3.1 GW of solar projects (mostly solar PV, but also one CSP plant) had received environmental approval from the government; another 0.8 GW of solar projects are in the environmental approval process. Although most of the deployment in solar energy should come from solar PV, there are some locations that are suitable for CSP projects, especially in the Atacama Desert. Accordingly, Chile should install 0.2 GW worth of CSP by 2018. Bioenergy and geothermal are expected to grow slowly over the medium term; only 50 MW and 90 MW have received environmental approval, respectively. Geothermal capacity is expected to reach 0.1 GW in 2018 while biomass should expand to 0.8 GW.

This forecast assumes that a portion of projects that already received environmental approval are not likely to be constructed over the projection period. Environmental approval is only the first step that a project has to go through; there are still many crucial steps for a project to move forward, such as financing, contracts, studies for the grid connection, etc. So far, very few PPAs have been announced and are likely to come about only gradually, particularly those from the mining segment, which has 24-hour power needs. With relatively few strong, long-term financial incentives available, these challenges may have direct implications on finding financing that is required to start the construction of projects.

**Table 9** Chile renewable energy capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 5.9 | 6.0 | 6.3 | 6.5 | 6.6 | 6.7 | 6.9 | 6.9 |
| Bioenergy | 0.5 | 0.6 | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 | 0.8 |
| Wind | 0.2 | 0.2 | 0.3 | 0.5 | 1.0 | 1.4 | 1.9 | 2.7 |
| *Onshore* | 0.2 | 0.2 | 0.3 | 0.5 | 1.0 | 1.4 | 1.9 | 2.7 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.1 | 0.3 | 0.5 | 0.7 | 0.9 | 1.1 |
| Solar CSP | - | - | - | - | - | 0.1 | 0.2 | 0.2 |
| Geothermal | - | - | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **6.7** | **6.8** | **7.4** | **8.0** | **8.9** | **9.7** | **10.6** | **11.7** |

**Table 10** Chile main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • excellent renewable resources with long-term government targets;<br>• increasing electricity demand and rising dependency on costly LNG increase the need for diversification;<br>• good competitiveness for onshore wind and off-grid solar PV applications. | • lack of strong financial incentives and long-term PPAs creating hurdles to sourcing financing;<br>• increasing congestion levels and investment requirements in SING and SIC grids;<br>• long lead times in connecting new generation capacity to the system. |

### *Renewable energy deployment under enhanced case*

Chile's 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. More streamlined land concession procedures and faster grid connections would also aid deployment. Under these conditions, both onshore wind and solar PV cumulative capacity could be 1 GW to 2 GW higher in 2018. CSP capacity would also likely be higher. Given the current tender process along with a significant amount of CSP plants with environmental and grid access approval, capacity could be some 0.3 GW higher in 2018 if PPAs are forthcoming, particularly from the mining sector.

## Mexico

Excellent resources and good economic attractiveness drive strong growth of renewables. Still, non-economic barriers and a lack of strong financial incentives may limit medium-term expansion.

### *Power demand outlook*

In Mexico, power demand is expected to grow steadily, at 4.1%/yr over 2012-18. Mexico's strong expected economic growth and expanding industrial activity should underpin robust electricity demand growth over the medium term. The IMF sees Mexico's real GDP growth averaging 3.3% over 2012-18. Mexico's electricity price environment is also supportive of demand. Electricity prices do not cover the cost of generation and are regulated for seven types of end-user segments. Prices for Mexican households are the lowest in the OECD, due to heavy price regulation from the government. Industry prices, which benefit from smaller subsidies, are higher on average and have risen since 2006.

**Figure 16** Mexico power demand versus GDP growth

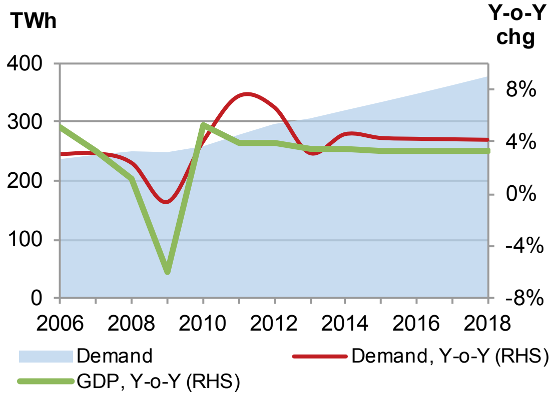
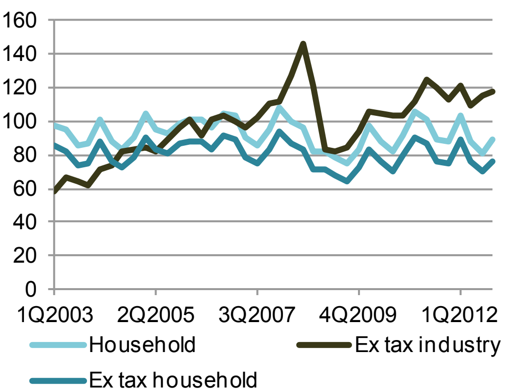



**Figure 17** Mexico average retail power prices (USD/MWh)



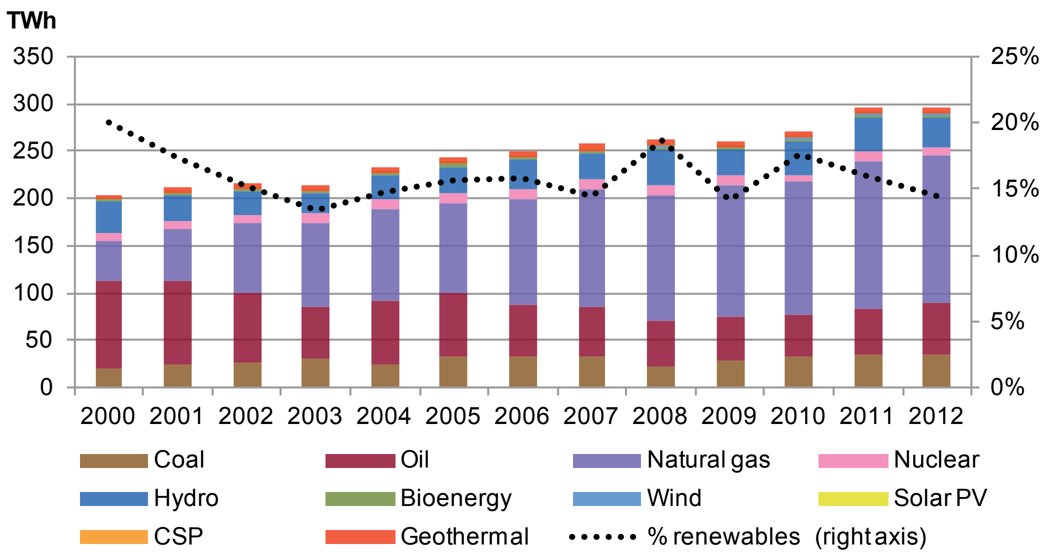

Notes: demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax.

## *Power sector structure*

### Generation and capacity

Mexico's power generation is largely met by fossil fuels. Natural gas accounted for 52% of generation in 2012, followed by oil (19%) and coal (12%). While oil's share has declined significantly over the past decade, natural gas has risen strongly. Hydropower (at 11% of 2012 generation) is the largest renewable source, and Mexico is one of the world's largest geothermal producers. Output from both of these sources has remained relatively steady over the past decade. Bioenergy generation has contracted somewhat in 2012. Although Mexico's peak load has risen strongly over the past decade, total generation additions have risen faster, helping reserve margins to rise. In 2011, total power generation capacity stood at 62 GW, with peak load at almost 40 GW.

**Figure 18** Mexico power generation by source and renewable share of total power generation



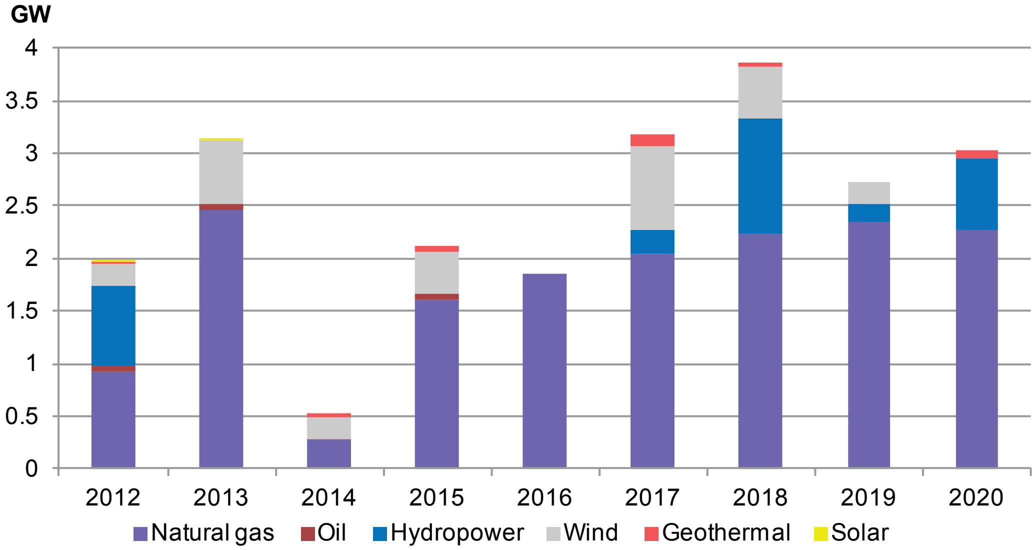

Generation from other renewable sources has so far remained small, but is expected to grow based on excellent wind and solar availability and attractive economics. Though small as a share of the total (1.1%), wind generation has grown rapidly over the past five years, primarily from projects for self-consumption. Onshore wind capacity more than doubled in 2012, rising from 0.6 GW to almost 1.4 GW. Solar PV's contribution has largely occurred in rural and off-grid applications, though utility-scale additions are expected over the medium term. CSP generation has yet to emerge, though utility-scale additions are expected by 2018. A 3 MW pilot ocean plant connected to a larger gas-fired plant in Baja California is also under development; commissioning was expected by February 2013.

Mexico's regulatory framework governs the way in which renewable capacity investments are made. IPPs enter into long-term PPAs with the state-owned utility, Comisión Federal de Electricidad (CFE), and small power producers (SPPs), < 30 MW, sell their output to CFE without long-term contracts. CFE also owns a portfolio of hydropower, geothermal and wind generation. IPP and CFE investments follow CFE's own generation planning and tendering, which see natural gas accounting for 70% and renewables comprising almost 30% of additions for public service over 2011-20. Investments can also take place outside of CFE's domain – for self-consumption in the private sector, for co-generation[3] or

[3] Co-generation refers to the combined production of heat and power.

for export. Self-consumption is attractive for industrial consumers facing rising electricity prices. Indeed, around half of existing wind and bioenergy capacity is for own use (CRE, 2012). Moreover, permits issued for new wind capacity for self-consumption and export, at 2.4 GW as of the end of 2012, compare well to the 2.9 GW of wind additions planned for public service by CFE over 2012-20.

**Figure 19** Mexico planned power generation additions under POISE 2012-26 (excludes self-consumption)




Notes: excludes capacity additions for SPPs, export and self-consumption. Solar capacity includes both solar PV and CSP. POISE = *Programa de Obras e Inversiones del Sector Eléctrico.*

Source: CFE, 2012.

## Grid and system integration

The Mexican power system needs to accommodate more generation capacity, reduce its high level of electricity losses and integrate increased renewable sources away from load centres, particularly variable sources (wind and solar). In 2011, grid losses totalled 17% of generation, with the government aiming to reduce this level to 8% by 2026 (SENER, 2012). By law, all activities related to the transmission, distribution and sale of electricity are concentrated within CFE. Renewable projects securing PPAs with CFE receive grid access and all projects enjoy priority dispatch. Self-consumption projects can be located anywhere on the grid and pay discounted wheeling charges (based on a postage stamp scheme[4]) to CFE to transport electricity. Such projects can sell excess electricity to CFE (at a discount to the electricity marginal cost). Net metering also exists for small projects. Overall, large-scale renewable development is sensitive to the transmission and distribution planning of CFE. While CFE is planning for large additions in hydropower and wind, development is more modest for geothermal, utility-scale solar PV and CSP.

Over the medium term, the pace of grid development should moderately challenge new wind generation. Overall, Mexico's large and growing gas-fired generation fleet should provide increased power system flexibility and balancing capabilities over the medium term. Still, the expansion of the grid to resource-rich areas remains a constraint. The best wind sites are located in the Isthmus of Tehuantepec (Oaxaca) in the south and Baja California in the northwest (areas away from major

[4] Wheeling is the transportation of power from one transmission or distribution area to another. "Postage stamp fees" are applied to transport a given amount of electricity over the national grid at a fixed price per energy unit, independent of the distance or the voltage level.

demand centres), with other promising sites in more centrally located regions and along the eastern coast. Some support should be provided through CFE's construction of a 2 GW, 300 kilometre (km), high-voltage transmission line for wind projects in Oaxaca. But in general, the process of expanding the grid to high potential wind areas has been slow. For export/import projects, the developer is in charge of the financing and construction of additional transmission infrastructure; ownership of these dedicated lines remains with the project developer/operator. So far, exports to the United States provide an outlet for wind evacuation from Baja California, though transmission constraints may emerge over the medium term.

The grid also presents constraints on the expansion of small-scale solar PV. Simplified grid-connection contracts exist, but only for projects up to 30 kilowatts (kW). Most solar PV development has occurred off-grid, with little on-grid distributed capacity. Since 2009, the government has financially supported the deployment of off-grid renewable sources to underdeveloped communities.

### *Current policy environment for renewable energy*

Mexico's policy environment supports renewable energy development, though generally lacks strong financial incentives. The legal framework for the electricity sector sets out circumstances in which private renewable investment can take place: self-consumption, co-generation, small production, exportation, importation and IPPs selling to CFE under long-term PPAs. To date, small producers (< 30 MW) have been excluded from PPAs with the CFE, though plans are under way to set up a tendering process for these projects. To this end, tendering rules were issued in late 2012, and dedicated tenders by technology and region are under consideration. Mexico's national energy strategy sees non-fossil electricity generation (including nuclear and large hydropower) rising to 35% in 2026, from 20% in 2011.

To date, financial incentives for renewables have been limited. Mexico provides tax relief through an accelerated depreciation regulation, which allows renewable projects to fully depreciate their assets during the first year of operation, as long as they operate for at least five years. The government also provides supports for rural development (*e.g.* biogas). In 2012, Mexico adopted a national climate change law with a 30% emissions reduction target by 2020. Once fully implemented, the framework will include carbon pricing, giving further support to renewable sources.

**Table 11** Mexico main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Energy Strategy 2013-27:** 35% non-fossil fuels in electricity generation by 2026: biogas: 0.3%; geothermal: 1.8%; hydropower: 9.2%; wind: 5.3%-20.9% (depending on the scenario). | **Net metering for distributed systems:** Available only for residential users and small businesses generating electricity from RES.<br>**Tax relief**: Accelerated depreciation allows projects to fully depreciate their assets during their first year of operation, as long as they operate for at least five years.<br>**Self-consumption projects:** Discounted wheeling charges based on postage stamp scheme. | **Framework policy:** Renewable Energies Exploitation and Energy Transition Financing Law (LAFAERTE) (2008).<br>**Grid access and priority dispatch:** Grid access under PPAs with CFE; priority dispatch guaranteed for all renewable projects. |

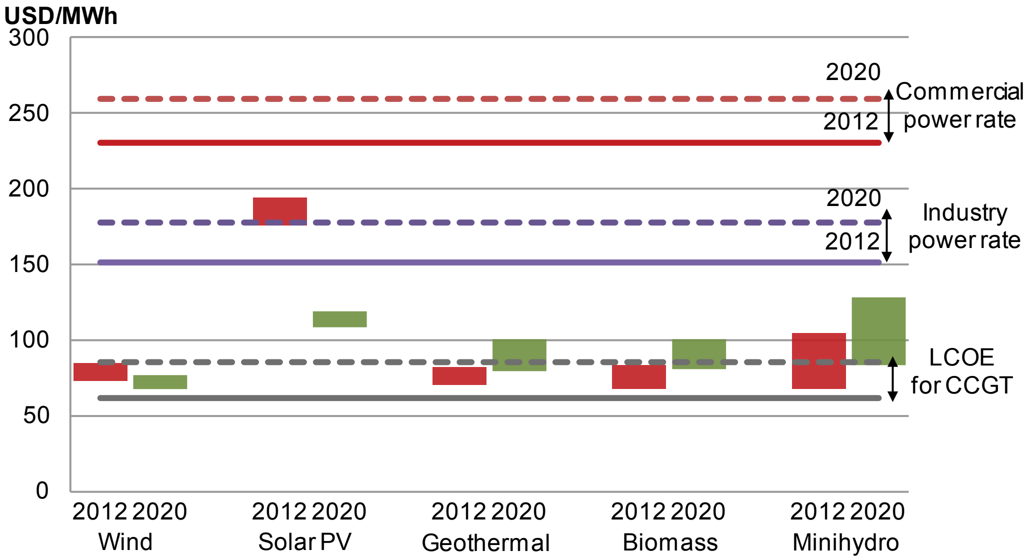
Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

## *Economic attractiveness of renewable energy and financing*

Economic attractiveness depends largely on the technology and generating arrangement, with few financial incentives for renewable projects. New gas-fired generation is economically attractive, benefiting from rising imports of cheap natural gas from the United States. But growing gas demand is also raising imports of more costly LNG, which is likely to raise the cost of gas generation over time. Given Mexico's excellent resources, levelised costs of electricity (LCOE) for onshore wind, geothermal, biomass and small hydropower are close to competitiveness versus combined-cycle natural gas generation; this position is likely to improve going forward, particularly for wind. Solar PV and CSP remain more costly, but solar PV currently competes well against commercial and some domestic power tariffs. Over the medium term, the competitive position of solar PV is likely to improve substantially, given excellent, widespread resource and rapidly falling system costs.

In general, self-consumption opportunities are more economically attractive than IPP sales to CFE given high electricity prices paid by industrial consumers and relatively low prices paid by CFE in its PPAs (IRENA, 2012). Wind and bioenergy projects have particularly benefitted; export projects are also economically attractive for wind. Still, there is strong competition among developers to secure self-consumption opportunities, which are essentially limited to large industrial users. This competition may erode project margins over time. For small-scale solar PV, subsidised residential electricity prices undermine the economic attractiveness of distributed generation. Still, distributed generation should become increasingly attractive for the commercial sector and "high consumption" residences, which face high retail electricity prices.

**Figure 20** Mexico levelised costs of renewable generation versus new-build gas plants and power prices, 2012 and 2020 expectation by SENER




Note: CCGT = combined-cycle gas turbine.

Source: SENER, 2013 based on analysis from Asociación Mexicana de Energía Eólica, AMEXHIDRO and PricewaterhouseCoopers.

Mexico's overall favourable investment climate and the cost and availability of finance are supportive for renewable investment. Development bank financing, both domestic and multilateral, has reduced financing risks, provided technical assistance and encouraged the involvement of private commercial banks in wind financing. The self-consumption model for development has attracted financing from large commercial companies. Many wind projects have also benefitted from carbon financing under the CDM. The Mexican government recently requested to shift funding from the CTF designated for energy efficiency and wind programmes to geothermal exploration risk mitigation; if implemented, the project could help further geothermal development. On a smaller scale, Mexico's rural development bank is pursuing novel financing approaches to develop biogas capacity (IRENA, 2012). Still, a number of general non-economic barriers – including not fully clear land-use rights, natural disaster risks (*e.g.* hurricanes, earthquakes) and security risks in the north – can undermine financial attractiveness. Moreover, hurdles can exist for local financing for small-scale solar PV.

### Conclusions for renewable energy deployment: baseline case

Over the medium term, Mexico's renewable capacity is expected to expand strongly, from 14.6 GW in 2012 to 25.8 GW in 2018, driven by excellent resources, good economic attractiveness and government targets. Onshore wind additions should be the largest in absolute terms, at around 5.8 GW over 2012-18. Most of this new capacity should come about under self-consumption and export arrangements. Although not official, the Mexican government is reportedly considering a national wind target of 12 GW for 2020. This target may be too optimistic without additional policy support, reduced non-economic barriers or better progress on-grid connections.

Hydropower additions are expected to be significant, largely on the basis of CFE's own expansion plans. Meanwhile, solar PV capacity should grow 3.4 GW over 2012-18. A few utility-scale projects should drive growth, with increasing small-scale development in the commercial and high-consumption residential sectors. CSP additions are expected to be small over the medium term, with a 14 MW electrical equivalent solar field integrated with a 464 MW gas plant (integrated solar combined cycle [ISCC]) under construction. Bioenergy growth is expected to be led by developments in sugar cane bagasse for co-generation and biogas. Mexico's geothermal potential is particularly strong on a global scale, and capacity is expected to reach 1.2 GW in 2018. Still, lack of well-defined development rights and CFE's exclusive authority over geothermal activities suggest that progress in this area will be limited to CFE plans, unless a dedicated geothermal regulation is approved.

**Table 12** Mexico renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 11.6 | 11.6 | 11.6 | 12.4 | 12.9 | 12.9 | 13.0 | 13.1 |
| Bioenergy | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 |
| Wind | 0.6 | 1.4 | 1.8 | 2.6 | 3.6 | 4.7 | 5.9 | 7.2 |
| *Onshore* | 0.6 | 1.4 | 1.8 | 2.6 | 3.6 | 4.7 | 5.9 | 7.2 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.1 | 0.2 | 0.7 | 1.5 | 2.5 | 3.5 |
| Solar CSP | - | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 1.0 | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 | 1.2 | 1.2 |
| Ocean | - | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **13.7** | **14.6** | **15.2** | **16.9** | **19.0** | **20.9** | **23.3** | **25.8** |

A number of broad challenges may limit the renewable deployment pace. With few financial incentives available and good attractiveness for gas, hydropower and wind generation, more costly technologies, such as large-scale solar PV and CSP, may develop only slowly over the medium term.

The heavily regulated nature of the Mexican power market can act as a barrier for new development. IPPs with CFE are often not attractive, given CFE's overriding mandate to deliver power at least cost. While self-consumption opportunities have stimulated significant activity, the risks and costs involved in securing an off-taker can limit development. CFE's own grid planning can act as a drag on projects requiring transmission upgrades. Moreover, small-distributed capacity faces competition against heavily subsidised residential retail electricity prices.

**Table 13** Mexico main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • excellent resource availability and good competitiveness for wind, hydropower and geothermal;<br>• long-term government targets for increasing the share of renewables in the power mix;<br>• strong demand for renewable projects for self-consumption from industrial entities facing high electricity prices. | • lack of robust financial incentives outside of accelerated depreciation tax provision;<br>• concentrated (sources and ownership) power system that presents institutional and economic challenges to new entrants;<br>• subsidised residential retail electricity prices undermine economics of small-distributed capacity for some segments;<br>• lack of dedicated framework for geothermal development. |

### *Renewable energy deployment under enhanced case*

While the self-consumption model has supported the development of significant wind capacity, its potential to scale-up deployment remains limited over the long term. To date, it also has been insufficient to stimulate the deployment of large-scale solar PV and CSP, for which Mexico has excellent resources. Improving the economic attractiveness of IPP projects, either through financial incentives or more attractive PPA terms offered by CFE, as well as the opening of tenders to smaller projects, could spur greater deployment. A faster pace of grid upgrades to connect wind and solar projects as well as the extension of simplified grid-connection procedures to a greater range of distributed solar PV would also help. Finally, Mexico's rich geothermal potential could be enhanced through greater inclusion in CFE planning, the provision of incentives to support IPP development and legal certainty for self-consumption. Overall, these actions could raise onshore wind cumulative capacity by 3 GW, solar PV capacity by 1 GW to 2 GW and geothermal capacity by 0.5 GW by 2018 versus the baseline case.

## United States

US market size combined with state targets and economic attractiveness in some areas should spur strong deployment. Uncertainty of federal incentives remains a challenge for investment.

### *Power demand outlook*

In line with IMF assumptions, US real GDP is expected to grow by 3.0% annually on average from 2012-18. Power demand is projected to grow on average by around 1.5% annually from 2012-18. Over the long run, increased efficiency and a shift away from energy-intensive industry has weakened the linkage between economic growth and electricity demand growth. Driven in large part by a strong domestic natural gas supply, end-user prices remained relatively steady in 2012 and continue to be low relative to most OECD countries. Expectations of low electricity prices going forward is stimulating industrial activity, with increased industry consumption expected to drive medium-term demand growth.

**Figure 21** US power demand versus GDP growth

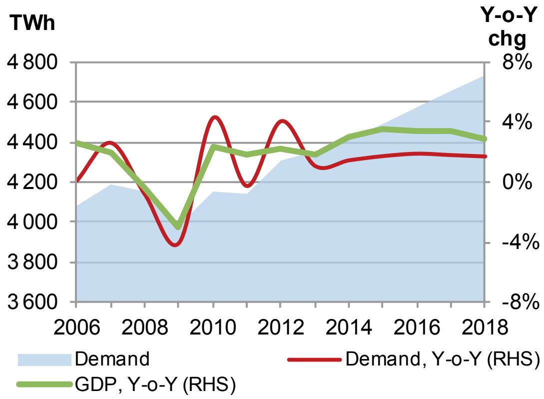
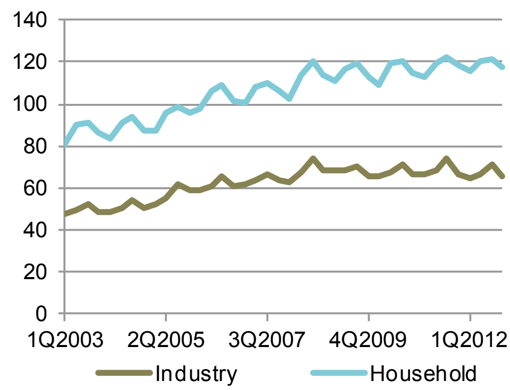



**Figure 22** US average retail power prices (USD/MWh)




Notes: demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax.

## *Power sector structure*

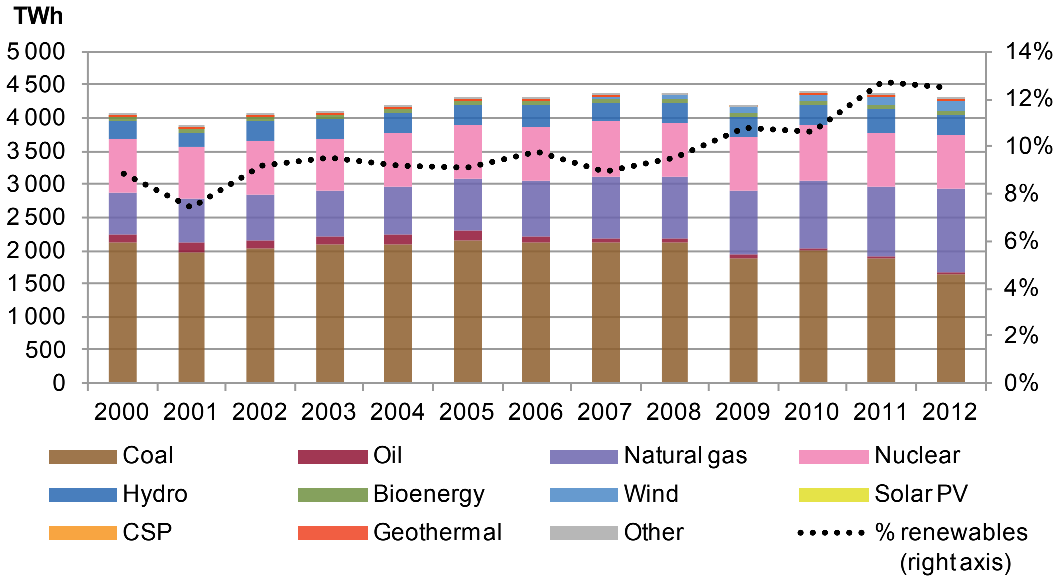
### Generation and capacity

A continued substitution away from coal towards natural gas and rising non-hydro renewable power underpin recent changes in US power generation. In 2012, coal-fired generation accounted for 38% of total power generation, down from 43% in 2011. Natural gas reached 30% of total generation for the first time, as its absolute level rose by over 20% year-on-year. Utilities continue to retire coal-fired capacity in response to existing and anticipated Environmental Protection Agency emissions regulations – the Mercury and Air Toxics Standards and Cross-State Air Pollution Rule (currently delayed) – and competition from cheap gas generation. These trends are expected to persist over the medium term. Over 2012-16, utilities have announced plans for net reductions of coal capacity exceeding 17 GW, versus net additions of over 32 GW of natural gas and 2 GW of nuclear (EIA, 2013). At the end of 2012, total power capacity in the United States stood at 1 067 GW.

Hydropower generation (7% of the power mix) declined in 2012, following a stronger-than-normal year of output in 2011. However, non-hydro renewable sources have continued to increase strongly, even with low natural gas prices and absent federal quotas. In 2012, wind power rose to 3.3% of power generation, from 2.8% in 2011. Onshore wind capacity additions topped 13 GW in 2012, with a rush of installations in December (over 5 GW) to qualify for the anticipated expiration of a key incentive, the production tax credit (PTC), at the end of the year. Still, this rush has left a significantly depleted onshore wind project pipeline for 2013, even with the temporary one-year extension of the PTC. Generation also rose from bioenergy (1.5% of the power mix) and geothermal (0.5% of power). Five new geothermal plants and two geothermal project expansions came on line in 2012, totalling almost 150 MW (GEA, 2013).

In 2012, solar PV still constituted a small part of the generation mix (<1%). However, capacity additions, at 3.3 GW, were 75% higher than those registered in 2011. Installations were led by utility-scale additions (+1.8 GW), followed by the commercial (+1.0 GW) and residential segments (+0.5 GW) (SEIA/GTM Research, 2013). The world's largest solar PV plant to date, Agua Caliente (290 MW alternating current) in Arizona, began operations with its full completion expected in 2014. As of March 2013, over 3 GW of utility-scale solar PV was under construction. In 2012, CSP capacity rose modestly, by 30 MW. The continued development of a large project pipeline (~2.3 GW under construction or in advanced development) suggests stronger CSP additions over the medium term.

**Figure 23** US power generation by source and renewable share of total power generation




At the state level, California and Texas have led deployment in solar PV and wind, respectively, though Washington's large hydropower still makes it the top state for renewable electricity capacity. California and Texas combined accounted for about one-third of solar PV and 25% wind installations in 2012. Other states, such as Arizona and New Jersey, which each have more 1 GW in cumulative solar PV capacity, and Iowa and Oklahoma for wind, continued to register strong additions in 2012. The interaction of state RPS and financial incentives (state and federal) will play a large role in shaping the medium-term renewable forecast.

**Table 14** Top ten US states, 2012 capacity additions (MW)

| State | Wind | State | Wind | State | Solar PV | State | Solar PV |
|---|---|---|---|---|---|---|---|
| Texas | 1 837 | Iowa | 811 | California | 1 033 | Massachusetts | 129 |
| California | 1 617 | Oregon | 640 | Arizona | 710 | Hawaii | 109 |
| Kansas | 1 439 | Michigan | 611 | New Jersey | 415 | Maryland | 74 |
| Oklahoma | 1 127 | Pennsylvania | 551 | Nevada | 198 | Texas | 64 |
| Illinois | 825 | Colorado | 501 | North Carolina | 132 | New York | 60 |

Sources: SEIA/GTM Research, 2013; IEA analysis based on AWEA, 2013.

## 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. From a technical standpoint, studies by the National Renewable Energy Laboratory (NREL) point to the grid's ability to absorb penetration rates of variable renewable sources of 20% to 35% (NREL, 2011). Wind and solar PV, combined, accounted for 3.6% of power generation in 2012, though some states, Iowa and South Dakota, attained average wind penetration levels as high as 24% in 2012. Current plans for transmission expansion look adequate to absorb new capacity. However, system constraints will increase over time, with complex regulatory structures and challenging institutional co-ordination among major stakeholders influencing developments.

The US power grid needs to expand and upgrade to accommodate more generation capacity and increased renewable sources away from load centres, particularly variable sources (wind and solar) and geothermal. To facilitate more co-ordinated grid development, Federal Energy Regulatory Commission (FERC) order No. 1000, introduced in 2011, encourages regional transmission planning that accounts for state and federal energy policies and better cost allocation among the beneficiaries of transmission projects. In 2013, FERC also proposed eased interconnection procedures for small generators (20 MW or less). If adopted, such reforms could help reduce the time and costs associated with integrating small-distributed capacity.

Other developments focus on regional level integration issues. The California Independent System Operator’s (CAISO) 2012-13 transmission plan assesses that current transmission projects and planned upgrades should be sufficient to meet California’s 33% renewable portfolio standard by 2020. Congestion has forced wind curtailment in some areas of the United States, though trends vary. In 2011, 8.5% of potential wind generation was curtailed in the Texas grid (ERCOT), up moderately from 2010 but lower than the 17% curtailed in 2009 (Wiser and Bolinger, 2012). Increased transmission capacity, in part from the competitive renewable energy zones (CREZ) programme, has helped increase wind load factors there. The planned Tres Amigas Superstation in New Mexico seeks to ultimately establish 30 GW of interconnection among the three major US interconnections (Eastern, Western and Texas), with the first phase (750 MW) starting from 2015. The project would help to better facilitate the transmission of renewable resources in the southwest to demand centres; still, funding issues have delayed the start of construction to sometime in 2013.

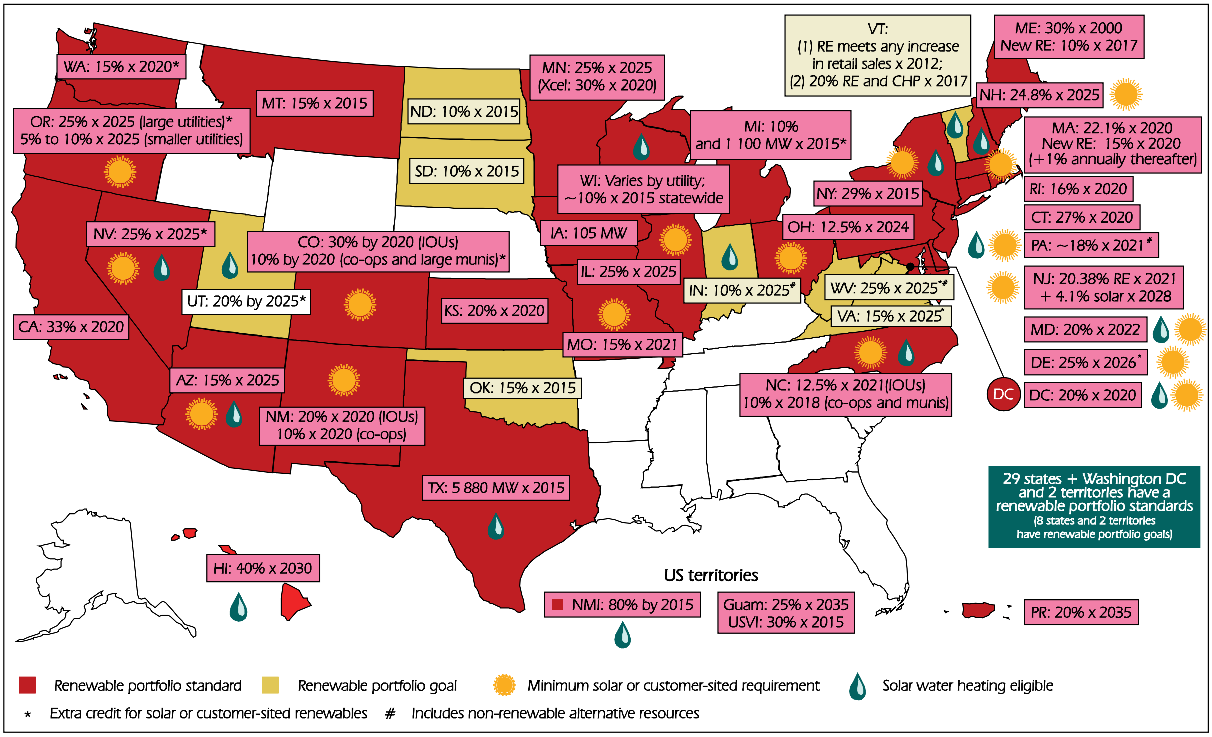
The Bonneville Power Administration (BPA), in the US Northwest, confronts, at times, the challenge of balancing wind with higher-than-expected hydropower generation. In addition to transmission being developed within the service area, BPA is exploring demand-side management and balancing options using heating and cooling systems and water heaters (Broad *et al.*, 2012). Transmission planning for the Mid-west ISO (MISO), which contains states with high wind penetration levels, includes multi-value projects that could connect up to 14 GW of wind capacity over the medium term (AWEA, 2012). MISO is also investigating flexibility products and practices. Finally, the Atlantic Wind Connection is planning to start construction on a 7 GW offshore backbone in 2016, which may help facilitate longer-term offshore wind integration along the US East Coast.

### *Current policy environment for renewable energy*

The US policy environment has experienced some volatility over the past year, though it remains broadly supportive. With no federal target, state renewable portfolio standards and federal financial incentives act as the main deployment drivers. The durability of federal tax incentives for renewable energy remains a persistent uncertainty. In early 2013, the US government extended, for one year, its renewable electricity PTC for wind, which expired at the end of 2012. It also extended the provision that allowed PTC-eligible wind geothermal and bioenergy and wave projects to alternatively claim the investment tax credit (ITC). The renewed credit removed its “placed in service” requirement for projects to qualify for its new deadline at the end of 2013. Instead, plants merely need to begin construction by that date, effectively allowing potential capacity to benefit from the extension for more than a year.

Recent federal efforts are also driving development through other mechanisms. The government has sought to facilitate the deployment of solar, wind and geothermal energy on public lands through prioritised permitting and environmental review processes. In early 2013, the Interior Department approved 1.1 GW of utility-scale solar PV and wind projects (three projects in total) in California and Nevada, and seeks to approve some 5.3 GW in total under the initiative by early 2015. The department has also announced plans to auction offshore wind sites (totalling 4 GW) in federal waters off the US East Coast sometime in 2013, though the tenders do not include PPAs. The US Department of Energy (DOE) announced grant awards in early 2013 to support the development of seven commercial offshore wind farms. The US Congress is also considering legislation to improve permitting processes for small hydropower.

## Map 1 US renewable portfolio standards by state (March 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.

Source: DSIRE, 2013.

At the state level, 29 states (and DC) employ a mandatory RPS and eight states have renewable energy goals. Eighteen states (and DC) offer performance-based financial incentives, including FITs or tradable renewable energy credits (RECs) schemes. Over the past year, only few changes occurred to state RPS schemes. In 2012, New Jersey increased its solar provision to 4.1% of electricity sales by 2028 (*i.e.* 3.5% by 2021), as part of a total 20.4% RPS for 2021. This measure may help support solar renewable energy certificate values there, which were under pressure from a rapid solar build-out and oversupply. According to media coverage in early 2013, legislatures in some states were considering rolling back RPS schemes to control policy costs. Still, no concrete changes had been made as of April 2013. Finally, in 2012, California launched its carbon trading market, a measure that should enhance renewable economic attractiveness. The state is ultimately seeking to link its scheme with several Canadian provinces.

**Table 15** US main targets and support policies for renewable electricity

| Targets and quotas | Financial support | Other support |
|---|---|---|
| **General targets:** Although there is no federal target, 29 out of the 50 states (and the District of Columbia [DC]) have a RPS in place.<br>**Largest RPS, by % of retail electricity sales:** Hawaii: 40% by 2030;<br>California: 20% by 2014, 25% by 2017, 33% by 2020;<br>Colorado: 30% by 2020 (investor-owned utilities [IOUs]);<br>New York: 29% by 2015. | **Corporate tax credits and depreciation:** ITC: 30% of system cost for solar PV, solar thermal, solar water heaters, wind, bioenergy, geothermal, small hydropower, tidal power; 10% of system cost for co-generation.<br>PTC: wind, bioenergy, geothermal, small hydropower, tidal power.<br>Asset depreciation as set out in Modified Accelerated Cost Recovery System (MACRS).<br>**Residential tax credits:** 30% of system cost for solar PV, solar water heaters, small wind, geothermal heat pumps, fuel cells.<br>**Performance-based incentives:** Adopted by 18 states (and DC); includes FITs and/or tradable renewable energy credits schemes. | **Regional Greenhouse Gas Initiative (RGGI):** Carbon dioxide ($CO_2$) cap-and-trade programme among nine states in the north east and mid-Atlantic.<br>**California Cap-and-Trade Program:** $CO_2$ cap-and-trade programme, which initially covers electricity suppliers and large industrial sources.<br>**Grid access and priority dispatch:** Grid access at transmission regulated by FERC, while states oversee distribution access. Interconnection policies in 44 states. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Source: DSIRE, 2013.

## *Economic attractiveness of renewable energy and financing*

With project viability dependent on local resources and policy incentives, it is difficult to make nationwide assessments of the financial viability of renewables. The extension of the USD 23/MWh PTC should keep a portfolio of new onshore wind, bioenergy and geothermal projects economically attractive in the short term, though with medium-term uncertainty. Including federal incentives, onshore wind PPAs have been struck at prices as low as USD 30/MWh in the US Midcontinent and Rocky Mountains. Still, low natural gas prices have restrained US wholesale electricity prices, which averaged from USD 20 per MWh to USD 40 per MWh in 2012. These price levels make it challenging for any type of new non-gas generator, even with incentives, to compete on wholesale markets (Bolinger, 2013). This report assumes, based on the forward curve, that average Henry Hub gas prices will rise but remain relatively low, increasing from USD 2.8 per million British thermal units (MBtu) in 2012 to USD 4.6 per MBtu in 2018, with prices reaching USD 4.0 per MBtu in 2013 (IEA, 2013).

Solar PV attractiveness should continue to improve. As of the fourth quarter of 2012, national average system prices for residential systems stood at USD 5.04 per watt (W) and commercial-scale systems stood at USD 4.27 per W, while utility-scale costs were at USD 2.27 per W (SEIA/GTM Research, 2013). These average levels indicated year-on-year price falls of 13% to 18% for residential/commercial and 29% for utility installations. While utility-scale solar PV still requires incentives to compete on wholesale markets, unsubsidised residential/commercial solar PV is beginning to compete with retail prices in areas with good resource and high retail prices (*e.g.* Hawaii, Southern California). Moreover, there is room for further cost reductions. Currently, small-scale solar PV system prices remain higher than in some other key markets, such as Germany, due to differences in "soft costs" (*e.g.* from financing, overhead, permitting, customer acquisition) (Carey and McCloskey, 2012; Seel, Barbose and Wiser, 2013).

The energy portfolio strategies of utilities and large corporate entities can drive renewable attractiveness beyond that suggested by current cost comparisons and policy incentives alone. The low marginal cost of wind power suggests that onshore wind PPAs can provide cost-effective hedges against rising fuel prices over the long term (*i.e.* 20 years), even in the absence of the PTC and with current low gas prices (Bolinger, 2013). Georgia Power recently adopted the largest voluntary solar procurement programme (210 MW) for a US investor-owned utility.[5] Despite its relatively high costs, CSP development can be attractive for utilities due to the technology's storage and hybridisation (with fossil fuels and in co-generation plants) capabilities.

The cost and availability of financing acts as a moderate deployment constraint. In 2012, investment in renewable electricity fell to USD 33 billion, from USD 52 billion in 2011. This decline stemmed from ongoing policy uncertainty over expiring incentives, cost reductions for renewable technologies and the financing of a large number of utility-scale solar projects in 2011, which made for a strong baseline. With ample low-cost financing available generally, future renewable investment will depend on policy predictability, the availability of tax equity financing and competition from the financing of natural gas-related assets – all of which could raise constraints. Notably, uncertainty over the long-term durability of the renewed PTC could slow some investment decisions.

Some innovations could enhance financing over the medium term. The US Congress is considering legislation that would allow renewable projects to qualify as Master Limited Partnerships (MLPs), a business structure that is traded like corporate equity, but is taxed as a partnership. MLPs have long facilitated fossil-fuel extraction and pipeline projects; if adopted, they could reduce the cost of capital for renewable projects and open renewable financing to new investors. In addition, some developers are seeking approval from the US Internal Revenue Service to allow the inclusion of solar PV projects in real estate investment trusts (REITs), which would also reduce financing costs. Asset-backed securities for renewable projects (*i.e.* financial securities that pool assets and are traded on secondary markets) may emerge in 2013 or 2014. A recent NREL study finds that increasing the use of public capital instruments described above could lower the LCOE of future projects (wind and solar PV) by roughly 8% to 16% versus benchmarked values under traditional, tax equity financing (Mendelsohn and Feldman, 2013).

Efforts by NREL to standardise documentation and develop a project default database along with market efforts to standardise project-level risk analysis could lead to greater renewable asset securitisation over the medium term. Finally, the emergence of crowdfunding platforms, which allow individual investors to directly finance shares of solar projects, may also play a role in enhancing the financing picture.

### *Conclusions for renewable energy deployment: baseline case*

The size and scope of the US market, combined with state and federal incentives, projects already under development, and increasing economic attractiveness of renewable generation, should result in strong deployment over the medium term. Renewable power capacity is expected to expand by 64 GW, from 184 GW in 2012 to 248 GW in 2018. Capacity is seen some 13 GW higher in 2017, versus the *MTRMR 2012*, largely due to stronger-than-expected additions in solar PV and onshore wind.

The onshore wind power expansion looks the strongest with 33.5 GW of additional capacity over 2012-18, followed by solar PV with around 23 GW. The forecast for offshore wind is seen somewhat higher versus the *MTRMR 2012*, assuming the start of construction of the 468 MW Cape Wind project by early 2014, in line with recent media announcements. The scale-up potential for the US offshore

[5] The state of Georgia has neither an RPS nor a renewable goal.

sector, nevertheless, remains highly uncertain over the medium term given persistent delays for some projects. The outlook for bioenergy and geothermal capacity is also more optimistic, with higher-than-expected capacity additions in 2012 for both categories. CSP capacity in 2017 is seen 1 GW lower than versus the *MTRMR 2012*, based on delays and PPA difficulties for some large projects. Still, some large plants are expected on line over 2013-14, effectively tripling US CSP capacity by the end of 2014.

**Table 16** US renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 100.9 | 101.0 | 101.2 | 101.4 | 101.5 | 101.6 | 101.7 | 101.7 |
| Bioenergy | 11.6 | 12.1 | 12.4 | 12.7 | 13.1 | 13.5 | 13.9 | 14.4 |
| Wind | 45.7 | 58.8 | 61.8 | 70.0 | 76.2 | 81.3 | 86.9 | 93.0 |
| *Onshore* | 45.7 | 58.8 | 61.8 | 69.8 | 75.8 | 80.8 | 86.3 | 92.3 |
| *Offshore* | - | - | - | 0.2 | 0.4 | 0.5 | 0.6 | 0.7 |
| Solar PV | 4.4 | 7.7 | 11.2 | 15.0 | 19.0 | 23.0 | 27.0 | 31.0 |
| Solar CSP | 0.5 | 0.5 | 1.3 | 2.3 | 2.6 | 2.9 | 3.2 | 3.5 |
| Geothermal | 3.1 | 3.4 | 3.5 | 3.5 | 3.6 | 3.7 | 3.8 | 3.9 |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **166.2** | **183.5** | **191.5** | **205.0** | **216.1** | **226.1** | **236.5** | **247.5** |

At the state level, the RPSs will continue to drive deployment according to policies in place as of May 2013. The US DOE has estimated that state RPS targets should provide renewable energy capacity additions of 4 GW/yr to 5 GW/yr from 2011-20 (Wiser and Bolinger, 2012). The federal policy environment in the United States remains a key variable, with financial supports still lacking predictability. In the baseline case, this report assumes that federal tax incentives will expire according to the schedule in place as of May 2013 with no allowance made for their renewal. The PTC is expected to expire at the end 2013, though given the removal of its "place in service requirement", wind projects that benefit from the measure should largely come on line over 2014-15. Solar tax incentives, which run through 2016, offer a somewhat longer support horizon. With system prices expected to continue falling over the medium term, solar PV generation costs in sunny states should become increasingly attractive versus the prices that households and industry pay for electricity. This improving economic attractiveness should drive solar PV additions in good resource areas even as federal incentives expire. Still, some uncertainties over existing net metering incentives and rate structures in some areas[6] could affect the economic attractiveness of distributed projects.

**Table 17** US main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • state-level RPSs combined with a slate of state and federal financial incentives;<br>• ample capacity for grid to absorb new renewable generation over the medium term, though need for grid upgrades in the long term;<br>• improving economic attractiveness for small-scale solar PV. | • significant uncertainty over the durability of federal tax incentives;<br>• competition from gas-fired generation and expectations for low gas prices over the medium term;<br>• scaling up deployment of less mature technologies (*e.g.* CSP and offshore wind). |

[6] Net metering regulations are set at the state and local level.

### *Renewable energy deployment under an enhanced case*

Much of the enhancement possible in the United States pertains to more stable renewable energy policy and planning. A longer-term federal strategy, with targets for renewable electricity, would buoy investment. Greater certainty over federal incentives and allowing renewable projects to be treated as MLPs would also help investment, though it is likely not realistic to expect continued tax credit renewals given the prevailing budget environment. Rather, a measure similar to a recent American Wind Energy Association proposal to extend 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 onshore wind capacity could be some 4 GW to 5 GW higher in 2018. The upside for offshore capacity looks more limited, though with faster project development, cumulative capacity could top 1 GW by 2018 (some 300 MW higher than forecast). In other sectors, solar PV capacity could be higher by 8 GW to 10 GW in 2018, with greater-than-expected uptake in the residential and commercial sectors. Finally, CSP capacity could be higher by up to 1 GW in 2018 with better progress in securing PPAs and overcoming delays for some large projects.

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# RENEWABLE ELECTRICITY: OECD ASIA OCEANIA

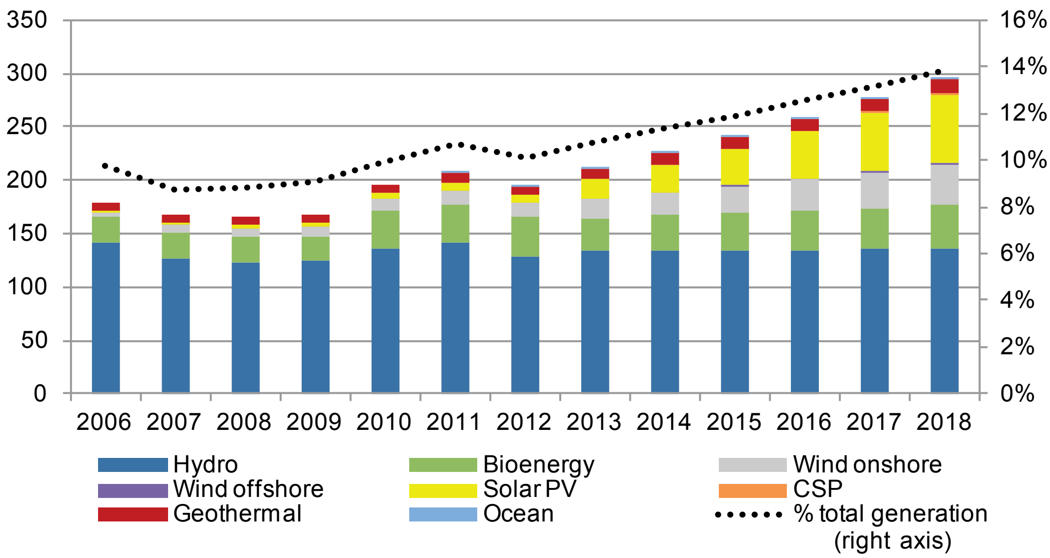
## Summary

- **Despite growth in non-hydro sources, Organisation for Economic Co-operation and Development (OECD) Asia Oceania renewable electricity generation declined by around 10 terawatt hours (TWh) in 2012 versus 2011 (-5.7% year-on-year) due to lower annual hydropower.** Though its overall renewable generation declined, Japan saw significant installations of new solar photovoltaics (PV) capacity while its onshore wind cumulative capacity rose modestly. Solar PV and onshore wind generation rose in Australia, while ocean power and bioenergy generation increased in Korea.

- **Over the medium term, OECD Asia Oceania renewable electricity generation is projected to grow from 195 TWh in 2012 to 295 TWh in 2018 (+7.2% per year [/yr]).** Renewable generation is seen rising from 10% of gross power generation in 2012 to 14% in 2018. Solar PV should lead this growth, with generation increasing by 57 TWh, followed by onshore wind, hydropower and bioenergy. Geothermal and offshore wind should expand moderately.

- **Japan's renewable electricity capacity should grow from 60 gigwatts (GW) in 2012 to 96 GW in 2018 (+8.0%/yr).** Buoyed by generous feed-in tariffs (FITs), solar PV is expected to grow strongly, by over 35 GW. Onshore wind, hydropower, bioenergy and geothermal should all make modest growth contributions. Japan's nuclear fleet status will remain a major forecast uncertainty going forward, with delays to capacity restart providing a potential upside for renewable deployment.

**Figure 24** OECD Asia Oceania renewable electricity generation and projection (TWh)




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

- **Other OECD Asia Oceania countries are expected to grow across a portfolio of renewables.** Australia's capacity is seen rising by 11 GW over 2012-18, driven by competitive onshore wind and rising economic attractiveness for distributed solar PV. Korea is expected to grow by almost 7 GW over 2012-18, boosted by onshore and offshore wind development, hydropower and solar PV. Korea is also expected to have the world's largest ocean power capacity in 2018. The relatively smaller power sectors of New Zealand and Israel[7] should also see renewable growth, supported by onshore wind development in New Zealand and onshore wind and solar PV additions in Israel.

**Table 18** OECD Asia Oceania renewable electricity generation and projection (TWh)

| | 2006 | % of total gen, 2006 | 2012 | % of total gen, 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 142 | 7.7% | 129 | 6.7% | 133 | 133 | 134 | 135 | 135 | 136 |
| Bioenergy | 23 | 1.3% | 36 | 1.9% | 31 | 33 | 35 | 37 | 39 | 41 |
| Wind | 5 | 0.3% | 13 | 0.7% | 17 | 21 | 26 | 30 | 35 | 40 |
| *Onshore* | 5 | 0.3% | 13 | 0.7% | 17 | 21 | 25 | 29 | 33 | 38 |
| *Offshore* | 0 | 0.0% | 0 | 0.0% | 0 | 0 | 1 | 1 | 1 | 2 |
| Solar PV | 2 | 0.1% | 7 | 0.4% | 19 | 26 | 34 | 44 | 54 | 64 |
| Solar CSP | 0 | 0.0% | 0 | 0.0% | 0 | 0 | 1 | 1 | 1 | 2 |
| Geothermal | 6 | 0.4% | 9 | 0.5% | 9 | 10 | 10 | 11 | 12 | 12 |
| Ocean | - | 0.0% | 1 | 0.0% | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total** | **179** | **9.7%** | **195** | **10.1%** | **211** | **225** | **241** | **258** | **277** | **295** |

Notes: hydropower includes generation from pumped storage. Data for 2012 are estimates; the split for onshore and offshore wind is estimated for historical data.

## Australia

The Renewable Energy Target (RET) and attractive economics should spur renewable deployment. Grid integration may emerge as a moderate challenge for variable renewables.

### *Power demand outlook*

In line with International Monetary Fund (IMF) assumptions, Australia's real gross domestic product (GDP) is expected to grow on average by 3.1% annually over 2012-18. Australia's electricity demand is expected to grow moderately, at an average 1.9%/yr over that period. The government sees somewhat slower demand growth in its long-term projections. Electricity demand has recently declined in the National Electricity Market (NEM), which accounts for 80% of generation. The strongest demand growth going forward is expected in off-grid areas in Western Australia and Northern Territory, where resource-extraction industries are growing strongly. Australia's peak demand has also strengthened over time, as the penetration of air conditioners in households reached almost 75% in 2011 (ESAA, 2012).

End-user electricity prices are regulated in all Australian states and territories except Victoria. Though prices have historically been low relative to other OECD member countries, average electricity prices have increased as much as 40% over the past five years. Rising network costs to finance distribution upgrades have been the main driver, although higher wholesale generation costs (on the back of rising fuel and carbon costs for gas and coal generators) have also contributed, with continued price rises expected over the medium term (DRET, 2012).

[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.

**Figure 25** Australia power versus GDP growth

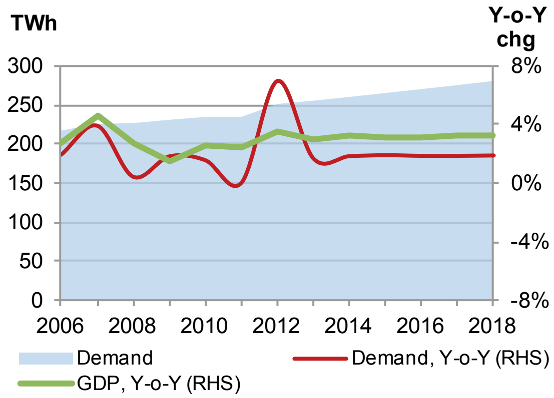
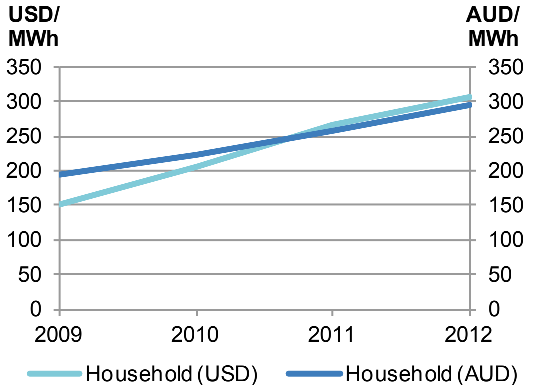



**Figure 26** Australia average retail demand power prices (USD per megawatt hour [/MWh])




Notes: Y-o-Y = year-on-year; chg = change; RHS = right-hand side. Demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax.

Source: for prices graph, IEA analysis based on AEMC, 2013.

## *Power sector structure*

### Generation and capacity

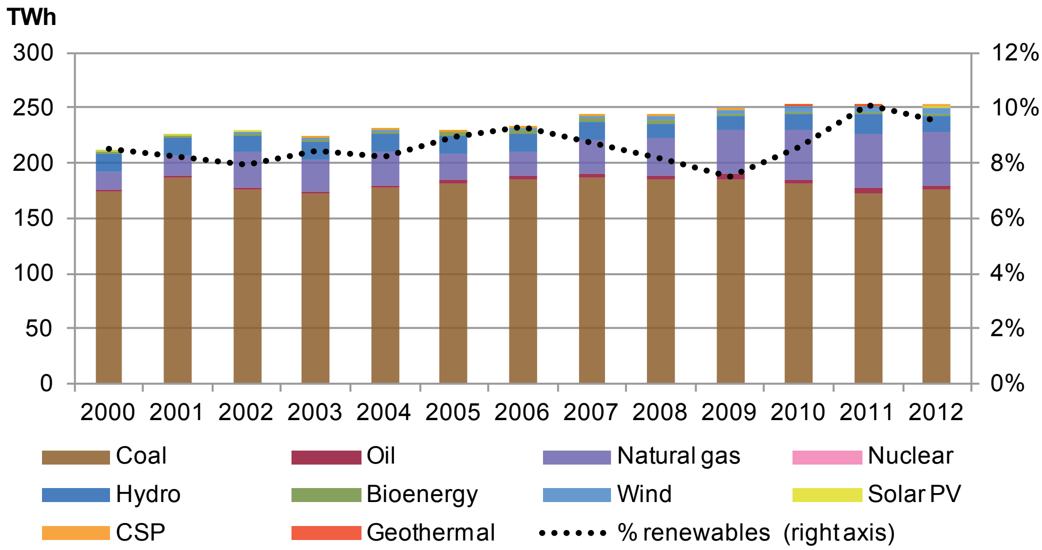
Australia's power generation is mainly met through fossil fuels. Coal, at 70% of generation in 2012, represents the largest source. Its share in the power mix has slowly declined over the last decade. Natural gas generation, at 19% of the power mix in 2012, has risen steadily in recent years. Renewable sources have also grown, though most strongly in the past two years. Hydropower generation remains the largest contributor, at 5.6% of power generation. Wind generation (2.4%) has risen rapidly while the share of bioenergy (sugar cane residue and wood waste), at 0.9%, has declined somewhat since 2005. Solar PV generation is limited, though distributed capacity (mostly residential) is scaling up rapidly. CSP and geothermal remain underdeveloped, but with excellent potential. In 2011, total power capacity stood at over 61 GW with peak load at over 42 GW; the reserve margin has increased steadily since 2005 with new gas and wind additions.

Australia's electricity planning sees the evolution of power generation dominated by renewable sources over the medium term. Expected moderate demand growth and ample capacity to meet peak demand suggest that few conventional, large-scale power additions will be needed in the NEM until 2020. Rising gas and coal prices as well as the imposition of carbon pricing from 2012 further undermine prospects for growth of more fossil-fuel generation, with increased open-cycle gas peaking capacity as the most likely option for non-renewable investment. Onshore wind is likely to account for the bulk of power sector growth, with distributed solar PV playing an increasing role, as renewable sources scale up to meet the RET (DRET, 2012).

### Grid and system integration

Australia's power system consists of three main networks: the NEM, which comprises five interconnected regions in the eastern half of the country; the South West Interconnected System (SWIS); and the North West Interconnected System. The NEM is the largest (in geographic coverage), and one of the most advanced, interconnected power systems in the world. The 2009 establishment of the Australian Energy Market Operator (AEMO) as the single electricity market operator of the NEM has helped facilitate transmission operation and planning.

**Figure 27** Australia power generation by source and renewable share of total power generation



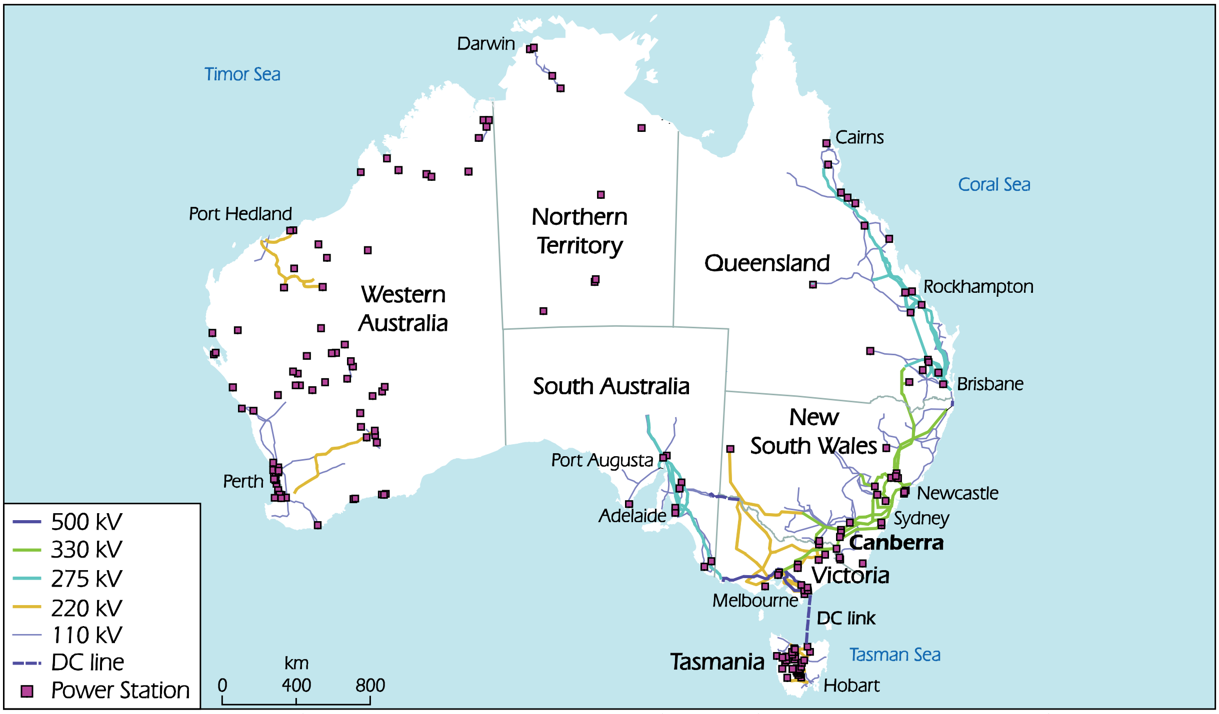

Integration of higher levels of wind in Australia may present moderate challenges over the medium term. The best wind resources are located in South Australia, Victoria and Tasmania in the NEM and Western Australia (SWIS). The NEM already employs an advanced approach to wind forecasting and balancing, enabled by hydropower and flexible gas generation. The National Transmission Network Development Plan does not see a requirement for new significant transmission investment, with the assumed upgrade of the South Australia-Victoria (Heywood) interconnection. However, the plan does not fully capture wind variability in its modelling (AEMO, 2012). As such, future upgrades may be needed, particularly in South Australia and Tasmania, where wind penetration rates are expected to be among the highest in the world (comparable to the Iberian peninsula) by 2020 (Ackermann and Kuwahata, 2011).

Solar generation may also face moderate integration barriers going forward. Most deployment to date has occurred in residential solar PV, close to demand centres, and net metering is available to most customers. Solar PV has also been important in off-grid applications, both for domestic and industry use. The solar generation peak coincides with high midday demand, and planned CSP plants will incorporate storage, which aids in integration. However, the best solar resources are often located away from population areas. The timing and costs associated with connecting remote generation may represent a challenge, particularly as Australia's first large-scale solar PV and CSP additions are developed over the medium term.

## *Current policy environment for renewable energy*

Deployment of renewable sources is mainly driven by the RET. The scheme requires 45 TWh of new renewable generation by 2020, supported by tradable certificates through the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). When added to pre-existing renewable generation of 15 TWh, the RET translates to 60 TWh, or around 20% of electricity from renewables by 2020. The RET also includes electricity "equivalent" technologies, such as solar water heaters.

**Map 2** Australia power transmission system




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.

Notes: kV = kilovolts. DC = direct current.

Source: DRET.

**Table 19** Australia main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Renewable Energy Target :** RET is designed to ensure that at least the equivalent of 20% of electricity supply will be generated from renewable energy sources by 2020 in Australia.<br>This translates into fixed 41 gigawatt hours (GWh) on top of 15 GWh of already existing renewable electricity in 2007.<br>RET consists of Large-Scale Renewable Energy Target (LRET) (which is obligatory) and SRES (voluntary participation).<br>The LRET will deliver the vast majority of the 2020 target. | **Tradable certificate system for RET:** Renewable energy producers receive certificates for renewable electricity generated. Those certificates are later sold to electricity retailers, which are obliged to purchase a certain number of these certificates each year.<br>**FITs:** Until January 2013 FITs schemes were available in most Australian jurisdictions supporting small-scale renewable installations (solar PV and wind). In January 2013 the state premium FIT schemes have all been closed for new applications.<br>**Carbon pricing mechanism:** Launched on 1 July 2012. For 2012 and 2013, carbon pricing mechanism is at a fixed price of AUD 23 per tonne (/t) rising at 5%/yr plus inflation, until flexible pricing commences in 2015-16. | **Policy framework:**<br>**2012 Clean Energy Future Plan** Pulls together a number of existing and future projects and programmes that will allow AU to achieve its RET as well as cuts in greenhouse gas (GHG) emissions (5% decrease by 2020 and 80% cut by 2050 in comparison with 2000 GHG emissions levels.)<br>**2000 Renewable Energy (Electricity) Act:** Basis legislation for RET scheme and renewable energy sector.<br>**Clean Energy Finance Corporation (CEFC):** Established in 2012, commencing operation on 1 July 2013, commercially orientated, facilitates financing of large-scale projects.<br>**ARENA:** Aims to increase supply of renewable energy supply in Australia. ARENA overtook responsibilities of Australian Centre for Renewable Energy, Department of Resources, Energy and Tourism (DRET) and Australian Solar Institute (ASI). |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Stronger-than-expected solar PV deployment – due to falling system prices, the imposition of the Solar Credits certificate multiplier and previously available high state-level FITs – sapped certificate prices and began discouraging large-scale investment from 2009. In response, the government separated large- and small-scale capacity under the RET, leaving the latter scheme uncapped in terms of deployment. The Solar Credits multiplier was reduced starting in 2011 and was phased out at the beginning of 2013. The SRES currently includes systems up to 100 kW. A recent recommendation to shift systems greater than 10 kW (*i.e.* medium-scale systems) to the LRET was rejected in March 2013, with the government citing concerns of the impact on the stability of the large-scale market and potential reduced investor confidence.

While the RET is seen as driving renewable deployment over the medium term, other national instruments support the longer-term picture. The new Australian Renewable Energy Agency (ARENA) seeks to support deployment of technologies not yet commercialised in Australia, such as utility-scale solar PV, CSP, geothermal and ocean. The creation of a national carbon tax from mid-2012 (with transition to an internationally linked emissions trading scheme in 2015) is expected to guide long-term clean energy development, in which government planning also sees contributions from carbon capture and storage (CCS). However, significant policy uncertainty exists over carbon pricing, with the results of the next national election in September 2013 potentially influencing its durability.

### *Economic attractiveness of renewable energy and financing*

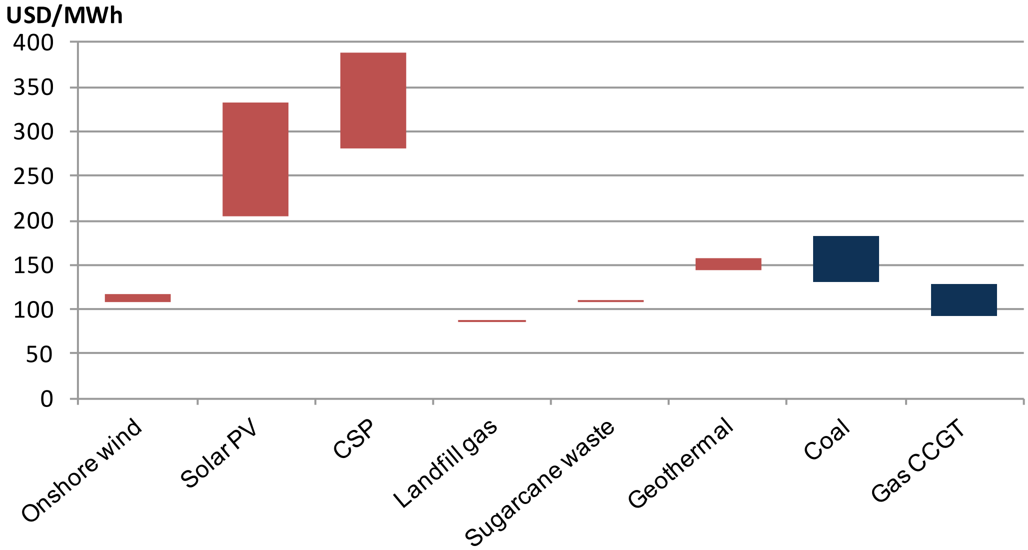
Australia's excellent resources combined with falling renewable technology costs and rising gas prices mean wind and bioenergy are economically attractive versus new fossil-fuel generation. The Australian Energy Technology Assessment 2012 (AETA) from the Bureau of Resources and Energy Economics found the levelised cost of electricity (LCOE) for onshore wind comparable to combined-cycle gas turbines (CCGT) and lower than coal when carbon pricing is included. In early 2013, Bloomberg New Energy Finance (BNEF) calculated that the LCOE for the best wind sites, at AUD 80/MWh is lower than that for new-build gas and coal generation without carbon pricing (Paton, 2013). Bioenergy generation also shows good competitiveness. While utility-scale solar PV and CSP remain more costly than new fossil-fuel generation, both AETA and BNEF analysis show LCOEs for best-in-class projects approaching (for CSP) or surpassing (for solar PV) mid-range LCOEs for new fossil builds with carbon pricing by 2020.

Despite this competitive position, the attractiveness of large-scale renewables over the medium term 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 most competitive renewable sources, wind and bioenergy, remain more expensive than prevailing wholesale power prices. Renewable generation requirements and certificate values under the LRET are expected to provide an important enhancement to project economics.

Over the past year, FITs for new small-scale solar PV systems were reduced in Queensland and Victoria, while the federal government's Solar Credits certificate multiplier was phased out. Still, the economic attractiveness of distributed solar PV is expected to remain strong over the medium term with continued falls in system prices and rising retail electricity prices. The substitution of solar generation for off-grid diesel generation looks increasingly attractive, particularly given high oil prices and potential ARENA support through its Regional Australia's Renewables programme.

The financing picture should generally help drive renewable deployment. Australia has a favourable investment climate with a generally low cost and good availability of capital for commercialised technologies such as onshore wind and bioenergy. Small-scale solar PV deployment should also benefit from business models emerging in the residential sector that offer leasing of solar systems from third parties. Still, financing barriers exist for technologies with less deployment history in Australia, such as CSP, geothermal and ocean. To this end, the government is establishing the Clean Energy Finance Corporation to facilitate financing in large-scale projects at later stages of development with ARENA providing grants to stimulate technologies at a more nascent level.

**Figure 28** Australia levelised costs of power generation for new plants, 2012




Notes: gas and coal generation includes carbon price of AUD 23/t. LCOEs converted to USD using AUD per USD in 2012 of 0.966.

Source: BREE, 2012.

### *Conclusions for renewable energy deployment: baseline case*

Australia's stable renewable policy environment, excellent resources and good economic attractiveness should help drive robust renewable deployment over the medium term. The first RET review by the Climate Change Authority reaffirmed the renewable generation target for 2020 and recommended deferring the next review until 2016. Both of these recommendations have been accepted by the government. These actions should provide adequate policy certainty for investment over the medium term. Australia's market framework looks less certain on carbon pricing, though this factor is more important for long-term deployment.

**Table 20** Australia main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • excellent resource availability and good economic attractiveness versus new fossil-fuel builds;<br>• strong policy framework backed by renewable targets and tradable certificates;<br>• good opportunities for distributed and off-grid applications, particularly in solar PV;<br>• ample availability of low-cost financing. | • grid constraints and integration issues may emerge for wind and solar PV;<br>• relatively high cost and slow deployment experience with CSP;<br>• state-level wind farm planning rules may cause project delays. |

Overall, renewable capacity is expected to rise from 14.6 GW in 2012 to 25.9 GW in 2018. Onshore wind is expected to lead capacity growth, rising by more than 5 GW over 2012-18. Onshore wind development is expected to be driven by attractive economics and the completion of major projects currently under development, including the 420 megawatt (MW) Macarthur wind farm, the 168 MW Musselroe wind farm and the 165.5 MW Gullen Range project. The pipeline of further permitted (~4 GW) and announced wind projects (~11 GW) is quite large, though much of this capacity is not likely to come on line over the medium term. In addition, wind farm siting rules adopted in Victoria in 2011 and under consideration in other states may challenge the pace of development.

**Table 21** Australia renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 |
| Bioenergy | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Wind | 2.1 | 2.6 | 3.2 | 4.2 | 5.1 | 6.0 | 6.8 | 7.7 |
| *Onshore* | 2.1 | 2.6 | 3.2 | 4.2 | 5.1 | 6.0 | 6.8 | 7.7 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 1.4 | 2.4 | 3.2 | 3.9 | 4.7 | 6.0 | 7.0 | 8.0 |
| Solar CSP | 0.0 | 0.0 | 0.1 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **13.1** | **14.6** | **16.2** | **18.0** | **19.7** | **22.0** | **23.9** | **25.9** |

Note: RES-E = electricity generated from renewable energy sources.

Solar PV capacity should also rise significantly, by 5 GW over 2012-18. Most of this deployment will occur in the small-scale, distributed segment, though with some off-grid additions. Australia's first large-scale solar PV plant (10 MW) was commissioned in 2012, with larger plants expected to come on line over the medium term. The outlook for CSP looks less robust, particularly with the suspension of the 250 MW Solar Dawn project in 2012 and the relatively lower prices of solar PV. Still, some CSP growth is expected, including the Kogan Creek Solar Boost project integrating solar thermal generation with a coal-fired plant. Bioenergy capacity is expected to grow moderately over the medium term, with development dependent on feedstock availability and supply chains. Meanwhile, geothermal and ocean should expand slowly from a low base. Several demonstration-scale projects as well as a 19 MW commercial-scale ocean plant are under development.

### *Renewable energy deployment under an enhanced case*

Enhanced deployment could occur with faster improvements in competiveness for large-scale solar PV and CSP as well as a faster-than-expected uptake of small-scale solar PV capacity. The large-scale solar additions could also be supported by an assurance of timely grid connections. Under these conditions, solar PV capacity could be 2 GW to 3 GW higher and CSP could be 0.5 GW to 1.0 GW higher versus the baseline case in 2018.

## Japan

An uncertain nuclear power situation combined with generous FITs should drive strong solar PV deployment. Grid integration challenges should limit wind growth, however.

### *Power demand outlook*

Overall, power demand should expand by 0.7% annually with real GDP growing by 1.3% annually over 2012-18. The Institute of Energy Economics of Japan estimated that power demand would remain roughly flat in 2013 compared with 2012. This report expects that power demand will start growing slightly again in 2014 and continue expanding over the medium term. This evolution will depend on the number of nuclear reactors that will be operational and the government's policy on energy efficiency and demand-saving measures. Over the past year, retail electricity prices have increased due to growing consumption of relatively costly oil and liquefied natural gas (LNG) for power generation, and prices remained among the highest in the OECD. The government estimates that several utilities may increase retail electricity prices by 15% in 2013. The peak demand measured during the summer of 2012 reached 157 GW, slightly lower than in 2011.

**Figure 29** Japan power demand versus GDP growth

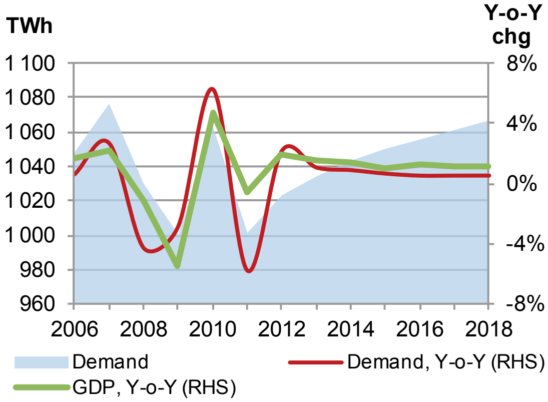
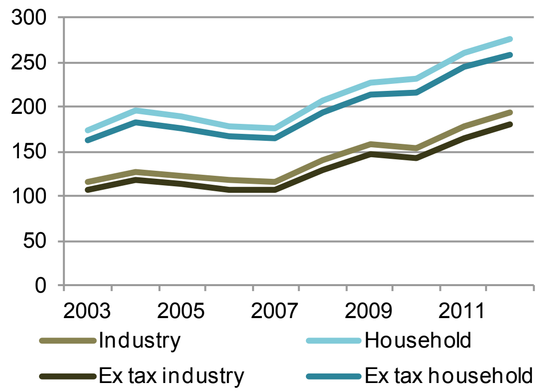



**Figure 30** Japan average retail power prices (USD/MWh)




Note: demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax.

## *Power sector structure*

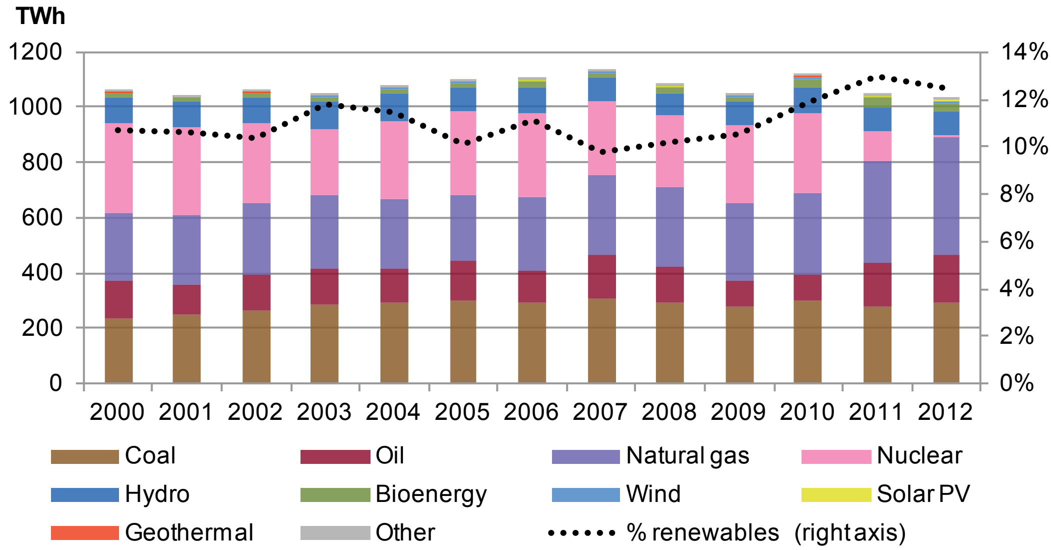
### Generation and capacity

In 2012, natural gas generation grew to over 41% of the power mix, with coal at 28% and oil at 17%. Hydropower's share increased to 8%. In July 2012, only two of Japan's 50 nuclear reactors started generating electricity. Over the past year, consumption of fossil fuels for power generation further increased in order to meet demand. The future of Japan's nuclear reactors will act as a major determinant of the power mix over the medium term. In line with assumptions in the IEA *Medium-Term Gas Market Report 2013 (MTGMR 2013),* this report assumes that the level of electricity generated by nuclear in 2018 will be around half of that generated in 2010 (about 290 TWh).

On the back of new FIT rates that came into force in July 2012, the deployment of non-hydro renewable energy resources has started to take-off from relatively low levels. Solar PV cumulative capacity grew by 2.0 GW in all of 2012 to reach a cumulative 6.9 GW. Before the introduction of the FIT scheme, the Japanese solar PV market consisted mostly of residential installations. Over the past year, thanks to the new incentive scheme, the number of commercial and utility-scale applications has increased. In comparison, onshore wind and bioenergy additions were more moderate in 2012.

The Japanese government has recently taken several steps to reform the power market, which is currently dominated by vertically integrated utilities responsible for generation, distribution and transmission in ten different regions. In February 2013, the Ministry of Economy, Trade and Industry's (METI) Electric Power System Committee proposed a reform plan that includes the centralisation of electricity dispatching under a national transmission system operator and the deregulation of retail power markets. In April 2013, the cabinet approved METI's reform, which is to be implemented over 2015-20. The reform mainly aims at increasing competition in the electricity market and should also improve the access of renewable energy producers to the electricity market.

**Figure 31** Japan power generation by source and renewable share of total power generation




Note: data refer to fiscal year (April to March).

### Grid and system integration

Over the past year the outlook for the grid and system integration of renewable sources has remained stable. As mentioned in the *MTRMR 2012,* the fragmented structure of the Japanese grid will pose a major challenge for the system integration of renewables over the medium term. Although announced electricity market reforms would establish a national system operator with better interconnections between different regions, its implementation will be both technically and economically challenging. In early 2013, the Japanese government approved a grid expansion plan for Hokkaido (an island) and the Tohoku region, which aims to boost the country's wind integration. The plan includes around USD 3.3 billion of new investment, half of which will be supported by the central government. Hokkaido also has a number of hydropower units that provide flexibility. Still, relatively few operational changes have been made in Hokkaido to incorporate wind generation.

More than 80% of all solar PV projects installed in Japan are 10 kW or less. However, larger projects have started to emerge over the past year. A number of large-scale solar PV projects have been concentrated in Hokkaido, which has a relatively good availability and lower cost of land. This may create congestion on the Hokkaido grid, which has a relatively low demand load. As such, METI has announced that it intends to adjust the integration policies for solar PV there. Also METI is planning to install the world's largest battery storage there for balancing purposes, with the consideration of the future development of wind as well.

### *Current policy environment for renewable energy*

In July 2012, the central government launched its FIT programme. According to the law, the FIT is subject to review every year. From April 2013, the tariff for solar PV was reduced by 10% for new projects. As of April 2013, METI had approved 7.4 GW of new renewable energy projects, of which over 90% were solar PV and 8% were wind. Applications for bioenergy, geothermal and hydropower have remained limited and focused on small-scale projects. Last year, the Japanese government eased the rules to enable test drillings in protected national parks, which is spurring some new development in geothermal power.

**Table 22** Japan main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Comprehensive review of Japanese energy policy 2010:** 10% of total primary energy supply from renewable sources by 2020. | **FITs:** Effective 1 July 2012. Apply to solar PV, wind, hydro (below 30 MW), geothermal and biomass. Generators with government certification are eligible.<br>Tariff ranges<br>Solar PV: as of April 2013, JPY 38.0 per kilowatt hour (/kWh) with net metering for systems below 10 kW, JPY 37.8 for systems above 10 kW.<br>In 2012, JPY 42.0 per kWh with net metering for systems below 10 kW, JPY 42.0 for systems above 10 kW.<br>Wind: JPY 23.10-JPY 57.75/kWh; geothermal: JPY 27.30-JPY 42/kWh; small hydro: JPY 25.20-JPY 35.70/kWh; biomass: JPY 13.65-JPY 33.60/kWh.<br>**Subsidy for residential PV:** METI and local governments provide grants for systems up to 10 kW. | **Environmental tax:** Introduced in October 2012 imposing a tax levy of JPY 289/t of carbon dioxide ($CO_2$) emitted. Revenues are allocated to renewable energy deployment and energy efficiency.<br>Comprehensive review of Japanese energy policy 2010.<br>**Grid access and priority dispatch:** Currently, electric utilities are obliged to allow grid connections under the FIT scheme; priority dispatch is guaranteed. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

### *Economic attractiveness of renewable energy and financing*

After the introduction of the FIT, the economic attractiveness of solar PV improved significantly, given the high level of the incentive. System costs, which are relatively expensive in Japan compared with international markets, have started to decrease slowly with more equipment providers competing in the market. Since 2010, investments in wind power have decreased significantly due to the government's decision to phase-out capital expenditure subsidies. Although the FIT made wind projects more attractive, the mountainous geography and the population density in Japan are still major challenges to deploying large projects. More than 80% of all projects installed in Japan are 10 MW or less. Smaller-scale plants increase both the investment and maintenance costs of projects. The same situation holds true for offshore wind deployment. The costs are relatively higher because Japan is surrounded by deep oceans. Two demonstration projects are ongoing to identify the cost structure of offshore wind technology. The government is aiming to deploy floating turbines, among other foundation types, which are currently more expensive than classical foundation methods.

Although bioenergy, especially biomass and waste, seems economically attractive with the new FIT, prices for domestically produced feedstock have been increasing. Despite attractive remuneration rates, exploration risk and a relatively long approval process at the local government level can undermine the attractiveness of geothermal projects. Small hydropower can also be subject to long approval processes by the central government.

The financing environment improved significantly after the introduction of the FIT in July 2012. Japanese banks have increased the number of loans provided for renewable energy projects. Many local banks have also introduced solar loan programmes in order to finance small installations. The Development Bank of Japan launched a solar project leasing programme, which is tied to FIT revenues received by system owners. Several other commercial banks have also introduced specific leasing programmes for solar projects.

### *Conclusions for renewable energy deployment: baseline case*

Japan's strong financial incentives and the country's need for additional electricity generation capacity should spur strong deployment over the medium term. Renewable energy capacity should expand from 61 GW in 2012 to over 96 GW in 2018. Given the still-generous tariff levels, the government will need to maintain a dynamic approach to adjustments to reflect international and national market developments.

**Table 23** Japan renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 48.4 | 48.8 | 48.8 | 49.0 | 49.3 | 49.4 | 49.4 | 49.4 |
| Bioenergy | 1.5 | 1.6 | 1.7 | 1.8 | 1.9 | 2.0 | 2.1 | 2.2 |
| Wind | 2.4 | 2.6 | 2.9 | 3.2 | 3.5 | 3.8 | 4.2 | 4.6 |
| *Onshore* | 2.4 | 2.6 | 2.8 | 3.1 | 3.3 | 3.6 | 3.9 | 4.2 |
| *Offshore* | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.4 |
| Solar PV | 4.9 | 6.9 | 11.4 | 15.9 | 20.9 | 26.9 | 32.9 | 38.9 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.7 | 0.8 | 0.8 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **57.8** | **60.5** | **65.3** | **70.4** | **76.2** | **82.8** | **89.4** | **96.0** |

Note: bioenergy capacity does not include plants that co-fire or have been converted from fossil-fuel-fired plants.

**Table 24** Japan main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • strengthened policy environment backed by generous FITs;<br>• acute need to replace nuclear power generation shortfalls amid restart uncertainty;<br>• good solar PV potential with peak shaving abilities and declining non-economic barriers;<br>• potential for increased competition in the electricity sector through planned reforms. | • currently, power system is fragmented among ten vertically integrated utilities with weak interconnections, which inhibits new renewable deployment;<br>• integration of variable renewables in certain fast-growing regions;<br>• relatively high costs for solar PV and wind installations compared with international markets;<br>• long development times for geothermal; wind resources away from load centres. |

Solar PV is expected to expand by 32 GW over the medium term. This brighter outlook is based upon the persistence of very generous incentive levels. Compared with the *MTRMR 2012*, the forecast for onshore wind power has been revised down somewhat for 2017 based on weaker-than-expected development in 2012. Onshore development is likely to proceed slowly, growing by only 1.7 GW over 2012-18 as sites remain far from demand centres and require transmission upgrades. Offshore deployment remains challenging given prevailing sea depths. Still, offshore development could accelerate in the second half of the forecast period with greater success in the deployment of floating turbines. The government is in the process of testing two such turbines, which may lead to further commercial developments. Although the government has taken several steps to ease the exploitation of geothermal resources in the periphery of national parks, the expansion of geothermal power is expected to be moderate given long project lead times and environmental impact concerns. Currently an environmental study is being conducted in the Shiramizusawa area while a developer plans to start a drilling survey in the Akita region in August 2013.

### *Renewable energy deployment under an enhanced case*

The Japanese government announced that it expects to launch electricity market reform in 2015, which includes unbundling of vertically integrated utilities and the establishment of a national dispatch market. Thus, it is expected that the reform will ease renewable energy deployment only over the long-term rather than over the projection period. Uncertainty over the nuclear situation remains a larger variable for Japan's outlook over the medium term. Under a slower nuclear scenario, the government would likely need to maintain FITs at high levels for longer periods of time in order to spur rapid renewable deployment, in addition to increased generation from other sources.

Onshore wind capacity could be higher by 0.5 GW to 1.0 GW in 2018 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 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. For solar PV, capacity could be some 3 GW to 5 GW higher in 2018 with measures to better facilitate system integration and increased uptake by high-rise buildings. The upside for geothermal looks limited given long project lead times.

## Korea

Korea's renewable portfolio standard should spur onshore wind and solar PV growth, with smaller increments from offshore wind and ocean. Grid connections and permitting may pose challenges.

### *Power demand outlook*

Korea's economy has boomed in recent years, with an average annual real GDP growth of 3.3% from 2006 to 2012. During the same period, power demand achieved even higher annual growth rates, averaging 4.7%/yr. According to the IMF, GDP growth is expected to remain strong, averaging 3.8% over 2012-18. Accordingly, electricity demand is expected to increase by 3.3% on average.

**Figure 32** Korea power demand versus GDP growth

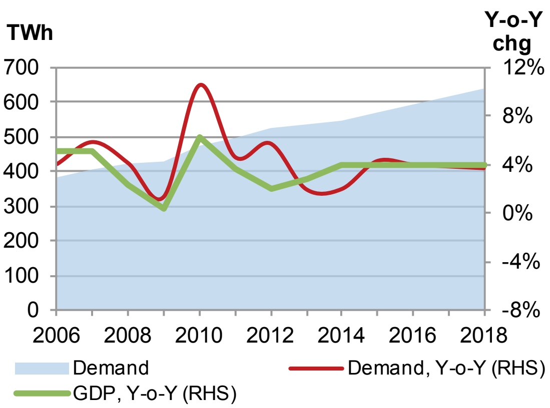
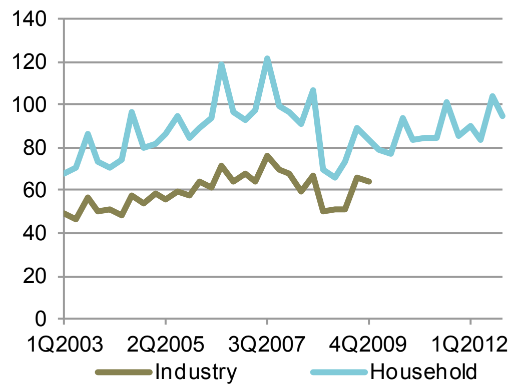



**Figure 33** Korea average retail power prices (USD per MWh)




Notes: demand is expressed as electricity supplied to the grid. Except where noted, power prices include tax. Industry prices not available from 2010 onwards.

Although electricity prices have been increasing since 2005 due to rising prices of LNG, oil and coal, Korea's electricity prices for industry and households are relatively low versus other OECD countries. In general, electricity prices charged to customers do not fully reflect underlying generation costs. Retail prices are, in general, still regulated by the government. Electricity prices among different sectors vary extensively, indicating significant cross-subsidies between consumers. Korea Electric Power Corporation, the country's monopoly distributor, has been announcing losses because the company cannot fully pass changing generation costs on to customers.

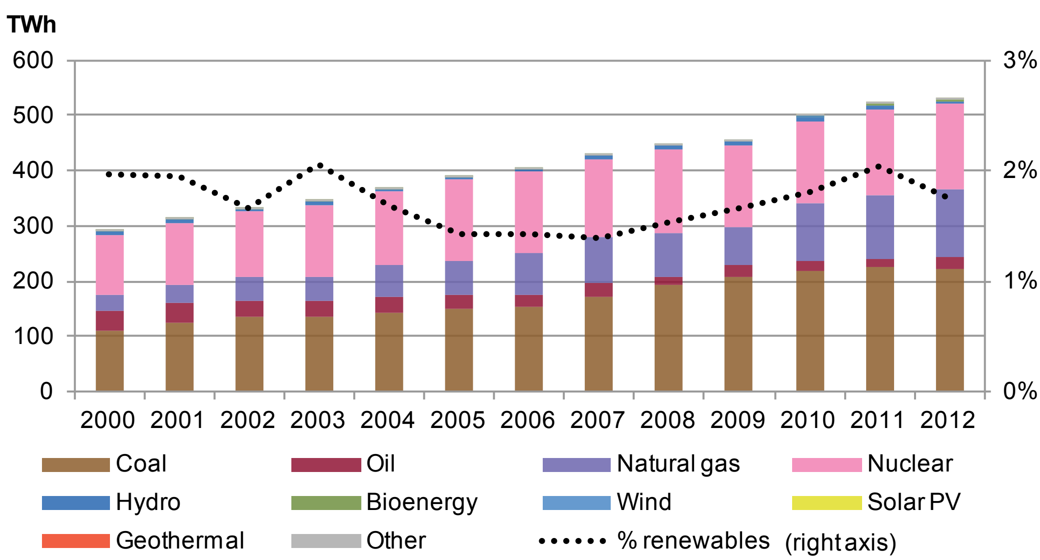
## *Power sector structure*

### Generation and capacity

In 2012, coal and nuclear energy dominated Korea's electricity generation, with coal accounting for 42% of total output and nuclear accounting for 29%, while natural gas provided around 23%. Generation from nuclear power plants has grown by 30% over the past decade. Output from gas-fired plants has tripled over the past ten years, reaching 120 TWh in 2012. Renewable sources accounted for only 1.7% of total generation in 2012, largely due to hydropower, whose output has remained relatively steady over the past decade. At the end of 2012, solar PV capacity stood at 1 GW while onshore wind capacity was 0.5 GW. The 254 MW Sihwa Lake tidal power station, the world's largest ocean project, was commissioned in August 2011.

Going forward, an increased need for power generation, and government targets should drive a renewable expansion. In 2011, total installed power capacity stood at 84 GW while peak load was 73 GW. Since the early 2000s, the reserve margin has decreased from 12.5% to 5.5%. The government expects to meet much of Korea's growing power needs through increased nuclear power, which is seen topping 48% of power generation by 2024 (Ministry of Knowledge Economy, 2010). By 2022, the government expects the contribution of renewables in electricity generation to increase to 10%. To meet this goal, the installed capacity of wind (both onshore and offshore) and solar PV is expected to increase significantly over the medium term along with ambitious plans to deploy ocean power. Solar PV projects that have already been announced mostly range from 1 MW to 20 MW.

**Figure 34** Korea power generation by source and renewable share of total power generation



### Grid and system integration

The Korean grid is owned and operated by the Korea Electric Power Corporation (KEPCO), which is also responsible for around 90% of total generation. Although the grid is well-connected domestically, it remains isolated from other markets. Investment plans have been outlined in the government's long-term electricity plan that take into account new renewable sources, particularly offshore wind, which will be located on the west coast, and nuclear power plants. One of the constraints to the integration of renewables is the permitting procedures, especially those associated with grid connections, over the medium term. The government is currently aiming at reducing these administrative barriers.

Korea has ambitious plans to deploy a smart grid nationwide by 2030. The project covers five different areas: smart power grid, smart consumer response and home appliances, smart transportation, smart renewables, and smart electricity service. The first test site has been established by KEPCO on Jeju Island off the south coast of Korea, and is expected to be fully operational by the end of 2013. The deployment of the smart grid technology will help to strengthen demand-side management and facilitate the integration of renewables into the power system.

## *Current policy environment for renewable energy*

In January 2012, the government replaced its FIT scheme (introduced in 2002) with a renewable portfolio standard (RPS). The RPS required selected utilities to source 2% of their total generation from renewables in 2012, rising to 10% by 2022. In order to reach this target, the quota will increase 0.5% every year until 2017, then 1% until 2022. The RPS is accompanied by a green certificate trading system. Certificates can be purchased by utilities to meet their requirements. In addition, the Korean government aims at launching a carbon trading regime by 2015.

Korea is dedicated to investing in offshore wind. The government is expected to open several tenders to procure offshore wind equipment and construction services. In addition to providing for generation needs, the government seeks to create a strong manufacturing industry that will export offshore technology. In 2010, the government decided to invest around KRW 10 trillion (USD 9 billion) in the development of a 2.5 GW offshore wind farm by 2019. Tidal energy is another strategic sector to which Korea provides incentives. In addition to the existing Sihwa Lake tidal power station, six other tidal power plant projects have been announced, amounting to 3.5 GW.

**Table 25** Korea main targets and support policies for renewable electricity

| Targets | Financial support | Other support |
|---|---|---|
| **Third Basic Plan for New and Renewable Energy 2008-2030:** 6% of total primary energy supply from renewable sources by 2020 and 11% by 2030.<br>**RPS:**<br>In 2012 RPS replaced FITs in Korea.<br>13 power utilities with capacity exceeding 500 MW are obliged to generate 2.5% of electricity production from renewable sources in 2013. This percentage will gradually increase, reaching 10% by 2020.<br>**RES-E building obligation:**<br>New public administration and enterprise buildings bigger than 100 square metres ($m^2$) must source 10% of their total energy demand (electricity and heat) from renewable sources. This percentage will gradually increase to reach 20% in 2020. | **Import duty** reduced by 50% for all equipment used in renewable energy power plants.<br>**One Million Green Homes** is a government subsidy programme for both heat and power generation. Programme covers solar thermal, solar PV, geothermal, biomass and small wind. | **Framework policy:** Act on the promotion of the development, use and diffusion of new and renewable energy (2004). |

For further information, refer to the IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

### *Economic attractiveness of renewable energy and financing*

Korea's upgraded policy framework, combined with falling costs for renewable technologies and excellent wind resources, should make renewable deployment economically attractive over the medium term. Though the former FIT levels were attractive, the inclusion of a 500 MW cap under the scheme did not spur significant solar PV growth. The new RPS policy is likely to make large-scale solar PV more attractive over the medium term because the government lifted the cap. Deployment should also benefit from Korea's already well-developed domestic solar equipment manufacturing capabilities. For distributed capacity, the One Million Green Home Project provides incentives that make residential applications (solar PV, small wind, geothermal and biomass) attractive. Almost all onshore wind turbines already installed in Korea are deployed by major utility companies, and manufactured locally. Thus, it is difficult to obtain cost data from these plants. In March 2013, SK Engineering announced an offshore wind power project of 198 MW with an estimated investment plan of USD 726 million, which will be commissioned in 2018.

Financing should not pose a major challenge to renewable energy deployment over the medium term, though much will depend on the balance sheets of Korea's utilities and large corporations. Large renewable energy projects are usually owned and operated by KEPCO and/or its affiliates. Large Korean conglomerates are also involved in offshore wind and tidal project development as suppliers of equipment and as construction or shipping contractors. However, this situation can also create entry barriers to smaller companies.

### *Conclusions for renewable energy deployment: baseline case*

With a supportive, long-term policy environment, renewable electricity capacity is expected to expand from 8.6 GW in 2012 to over 15 GW in 2018. This growth is mostly driven by onshore wind, solar PV and hydropower. Korea has great onshore and offshore wind energy potential. Although offshore wind is still expensive, the government's support has already attracted the attention of both foreign and domestic companies, which could scale-up deployment and reduce costs over time. Still, cumulative capacity in 2018 is likely to remain modest. Onshore wind is expected to expand faster over the medium term driven by the RPS, with capacity rising by 2.4 GW over 2012-18. The new RPS should spur growth for solar PV capacity, with growth of 1.5 GW expected over 2012-18. In addition, several ocean energy projects should be completed by 2018.

**Table 26** Korea main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • long-term, robust government targets through 2022 backed by renewable certificate scheme;<br>• strong electricity demand growth and need for new generation;<br>• government-backed large offshore wind and ocean projects;<br>• long-term development and investment plans in smart grid technology. | • long lead times associated with grid connection and permitting procedures;<br>• concentrated power system (sources and ownership) may present investment barriers for new entrants;<br>• low, regulated end-user electricity prices may not spur significant distributed development. |

**Table 27** Korea renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 6.4 | 6.6 | 6.6 | 6.6 | 6.6 | 7.0 | 7.4 | 8.0 |
| Bioenergy | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 | 0.5 | 0.6 |
| Wind | 0.4 | 0.5 | 0.9 | 1.3 | 1.8 | 2.3 | 2.7 | 3.5 |
| *Onshore* | 0.4 | 0.5 | 0.9 | 1.2 | 1.6 | 2.0 | 2.4 | 2.9 |
| *Offshore* | - | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.3 | 0.6 |
| Solar PV | 0.7 | 1.0 | 1.2 | 1.4 | 1.6 | 1.8 | 2.2 | 2.5 |
| Solar CSP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | - | - | - | - | 0.0 | 0.0 | 0.0 | 0.0 |
| Ocean | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.6 |
| **Total RES-E** | **8.1** | **8.6** | **9.3** | **10.0** | **10.7** | **12.0** | **13.2** | **15.1** |

### *Renewable energy deployment under enhanced case*

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 to be 0.5 GW to 1.0 GW higher in 2018 versus the baseline case. Faster-than-expected cost reductions could spur higher offshore wind deployment, with cumulative capacity in 2018 potentially 0.5 GW to 1.0 GW higher than the baseline case.

## Other OECD Asia Oceania countries

### *Israel*

Israel has a long history of deployment in solar water heating, but renewable sources have so far represented only a small share of its power generation, 0.4% in 2012. The government has set a target of 10% of power generated from renewable sources by 2020 with an interim target of 5% by 2014. As a result of a FIT for distributed systems and tenders for large-scale projects, solar PV installations have grown since 2008, and in 2011 cumulative capacity reached over 0.3 GW. Some 60 MW of large-scale PV projects are currently under construction, with a much larger pipeline of permitted and announced projects. Small-scale deployment should also progress over the medium term. In total, solar PV capacity is seen rising by 0.6 GW over 2012-18. Initial CSP developments are also taking place. In November 2012, a 121 MW CSP plant was tendered under Israel's 250 MW Ashalim solar tender. Onshore wind additions, at 0.4 GW, should be significant, putting Israel halfway towards meeting its 0.8 GW wind target by 2020.

### *New Zealand*

New Zealand has a high level of renewable penetration in its power system. In 2012 renewable sources represented 71% of power generation with hydropower as the largest share, 51%, followed by significant geothermal production at 14%. Other renewable sources such as wind and bioenergy accounted for 6% of power production. In general, renewable electricity sources are competitive with costly fossil-fuel alternatives and do not receive government financial support. There, onshore wind has already been competing in the wholesale electricity market for several years now.

New Zealand's excellent resource availability for geothermal and wind, as well as small hydropower, should support further deployment in these sectors while solar PV and bioenergy are likely to develop only slowly and at the distributed level. New Zealand possesses excellent resources for ocean energy. A number of New Zealand companies are actively engaged in exploring this potential with small-scale pilot or test systems. Some of their initial work was supported by government grants under a Marine Energy Deployment Fund.

Developments across all technologies will likely proceed at a moderate pace over the medium term, given only slowly rising power needs. Nevertheless, the government has retained a target of 90% of total power generation coming from renewable sources by 2025, which will act as a strong floor for deployment over the medium to long term. Renewable capacity is likely to expand by over 0.4 GW over 2012-18, led by developments in onshore wind, which has some 90 MW of plants under construction and a much larger pipeline of permitted projects.

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# RENEWABLE ELECTRICITY: OECD EUROPE

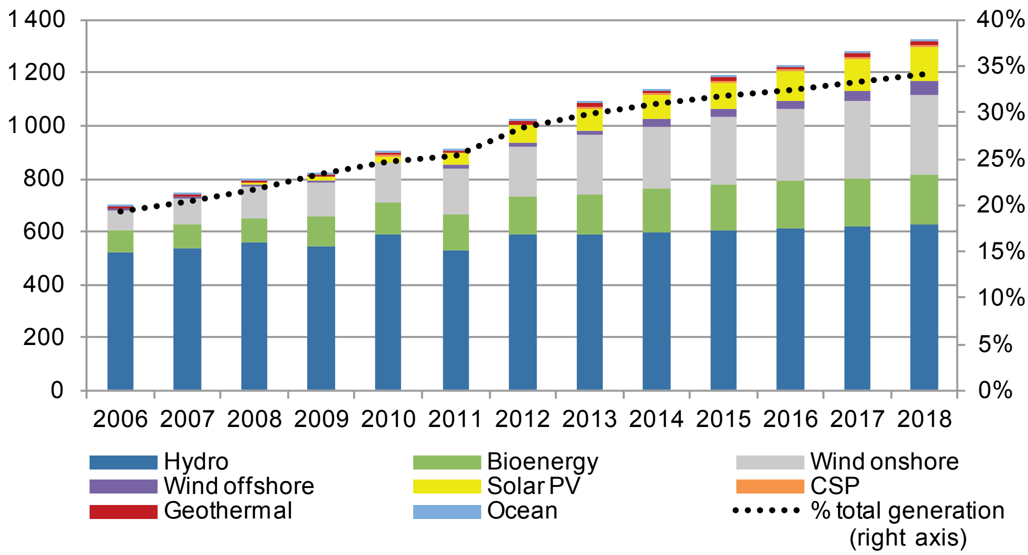
## Summary


- **In 2012, Organisation for Economic Co-operation and Development (OECD) Europe renewable electricity generation grew by a record 110 terawatt hours (TWh) versus 2011 (+12.0% year-on-year).** By comparison, total power generation growth was at only 15 TWh (+0.4%). Renewable growth was led by a rebound in hydropower (+55 TWh year-on-year), which was low in 2011 due to reservoir availability. Solar photovoltaic (PV) growth, at 24 TWh, was larger than 2011's record increment, supported by deployment in Germany and Italy. Onshore wind (+17 TWh) grew strongly, supported by a continued capacity build-out across a number of countries. Bioenergy and offshore wind also contributed to growth.

- **Over the medium term, OECD Europe renewable electricity generation is projected to grow from 1 020 TWh in 2012 to 1 320 TWh in 2018 (+4.4% per year).** Renewable generation is seen rising from 28% of gross power generation in 2012 to over 34% in 2018. Onshore wind will lead this growth, with generation increasing by 110 TWh, followed by solar PV, bioenergy, offshore wind and hydropower. Concentrating solar power (CSP), geothermal and ocean power should account for a smaller part of growth. Overall, the forecast is 3 TWh lower in 2017 versus the *MTRMR 2012,* with offshore wind downward revisions outweighing upward revisions to solar PV.

- **Germany, the United Kingdom, Turkey and France are expected to lead growth in renewable electricity generation** over 2012-18. Germany's growth of over 70 TWh is led by solar PV, onshore wind and offshore wind, though solar PV deployment has slowed with incentive adjustments. The United Kingdom leads European offshore wind deployment. Turkey is buoyed by strong hydropower and onshore wind growth. France's growth is led by onshore wind and solar PV.


**Figure 35** OECD Europe renewable electricity generation and projection (TWh)




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

- **With adjustments to incentive schemes and more challenging economic conditions, renewable generation growth in Italy and Spain should moderate.** Italy is seen expanding by 30 TWh over 2012-18, though with growth slowing over time in solar PV and onshore wind. With the moratorium on new Special Regime developments, Spain's growth is seen at only 14 TWh.

- **Renewable generation in the relatively smaller power sectors of Denmark and Ireland are expected to grow by 11 TWh and 5 TWh, respectively.** Developments in these countries focus largely on wind (onshore and offshore). Denmark's coal-to-biomass power plant conversions should also support a strong increase in bioenergy generation there.

**Table 28** OECD Europe renewable electricity generation (TWh)

| | 2006 | % of total gen, 2006 | 2012 | % of total gen, 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 523 | 14.5% | 588 | 16.3% | 588 | 598 | 606 | 612 | 618 | 625 |
| Bioenergy | 79 | 2.2% | 142 | 4.0% | 153 | 162 | 170 | 178 | 186 | 192 |
| Wind | 83 | 2.3% | 202 | 5.6% | 241 | 264 | 285 | 305 | 329 | 354 |
| *Onshore* | 81 | 2.2% | 190 | 5.3% | 223 | 239 | 256 | 272 | 287 | 302 |
| *Offshore* | 2 | 0.1% | 13 | 0.3% | 18 | 24 | 29 | 34 | 42 | 52 |
| Solar PV | 3 | 0.1% | 69 | 1.9% | 84 | 93 | 102 | 110 | 118 | 126 |
| Solar CSP | - | 0.0% | 3 | 0.1% | 5 | 5 | 5 | 6 | 6 | 6 |
| Geothermal | 8 | 0.2% | 12 | 0.3% | 12 | 12 | 13 | 14 | 14 | 15 |
| Ocean | 1 | 0.0% | 1 | 0.0% | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total** | **696** | **19.4%** | **1 018** | **28.3%** | **1 083** | **1 135** | **1 182** | **1 225** | **1 271** | **1 318** |

Notes: hydropower includes generation from pumped storage. Data for 2012 are estimates; the split for onshore and offshore wind is estimated for historical data.

## Denmark

With a strong long-term framework, Denmark's renewable power should grow rapidly. Offshore wind grid connections and supply chain bottlenecks are the largest medium-term uncertainty.

### *Power demand outlook*

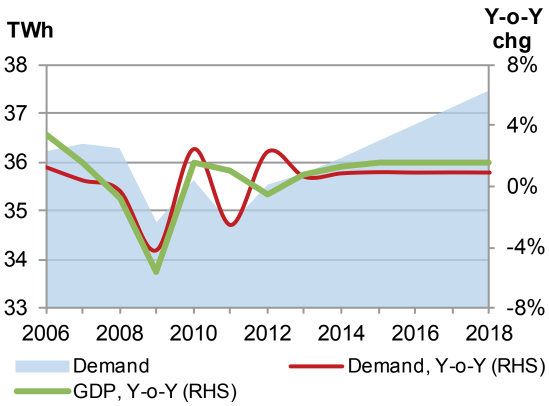
Power demand for Denmark is expected to grow only modestly over the medium term. In line with International Monetary Fund (IMF) assumptions, Denmark's gross domestic product (GDP) is projected to grow by 1.4% annually from 2012-18. Power demand is expected to increase modestly by 0.9% annually. Danish retail power prices declined modestly in 2012. Yet they still remained the highest in the Nordic power market and help make distributed generation economically attractive.

### *Power sector structure*

#### Generation and capacity

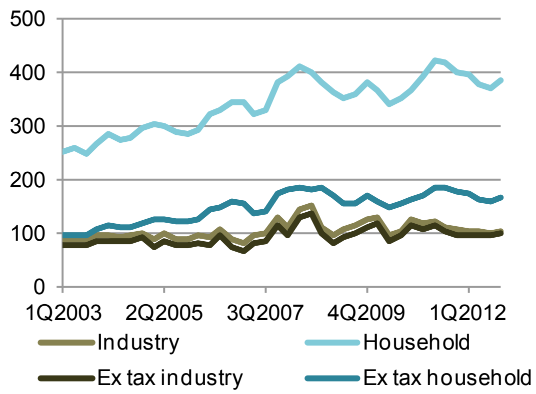
In 2012, the transition of the Danish power system from fossil fuels to renewable sources continued. Renewable sources accounted for 48% of electricity generation in 2012. Danish wind power continued to rise, reaching its highest annual output to date, at over 10 TWh, and accounting for a full one-third of total power generation. Cumulative wind capacity grew by over 200 megawatts (MW) in 2012, with offshore wind accounting for over 20% of these additions. Generation from bioenergy accounted for 14% of total power. Though it remained a small share of power generation, solar PV capacity grew rapidly to 460 MW at the end of 2012, with new installations of over 400 MW, driven by Denmark's net metering scheme. Coal-fired generation continued to decline amid the closure of capacity. In 2011, Denmark's total power capacity stood at 13.6 gigawatts (GW), with a peak load of 6.2 GW.

**Figure 36** Denmark power demand versus GDP growth




Note: Y-o-Y = year-on-year ; chg = change; RHS = right-hand side.

**Figure 37** Denmark average retail power prices (USD per megawatt hour [/MWh])



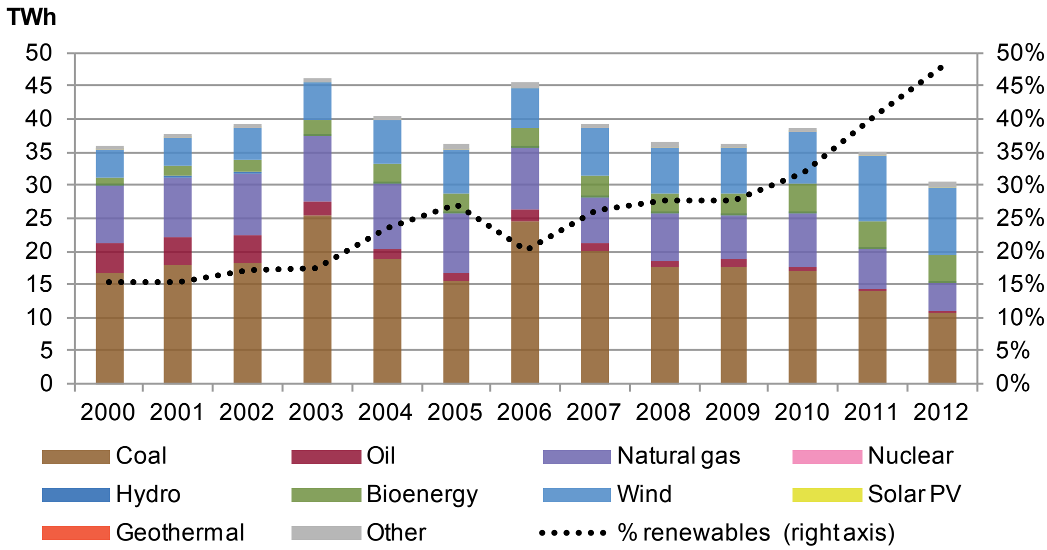

Over the medium term, renewable sources (mostly wind and biomass in co-generation[8]) will increasingly displace fossil fuels in the electricity mix, in line with the government's ambitious Energy Agreement. The Danish Energy Agency sees renewables rising to almost 70% of power supply by 2020, led by wind at 50%, en route to 100% renewable power and heat production by 2035. This transition will require higher integration with neighbouring markets to help cover balancing and supply requirements. Rising net imports from Sweden and Norway have increasingly filled domestic demand needs, particularly during peak periods. In 2012, Denmark's gross power generation fell to its lowest level in a decade, at 30.4 TWh, while net imports rose to over 5 TWh, due to the closure of domestic coal generation and good availability of low-cost hydropower from Norway and Sweden.

## Grid and system integration

As the country with the largest penetration of variable renewable energy in the world, Denmark continues to serve as an excellent example for the integration and balancing of renewable sources. Still, the addition of more wind power could be challenged by the pace of grid developments over the medium term. Robust interconnections with neighbouring countries (*i.e.* Norway, Sweden, Germany) have been a crucial enabler to deployment. With increased congestion in Germany's grid to the south, future developments focus on linkages elsewhere. Energinet.dk, the transmission service operator, is undertaking several grid expansion projects, including a 700 MW connection to Norway expected in late 2014 and a new north-south, high-voltage backbone to facilitate cross-border flows. However, a third major project, the 700 MW COBRA cable to the Netherlands, is not expected until at least 2017, with a final investment decision in 2014. The construction of a cable to the United Kingdom is also under discussion, though with no decision yet. Grid connections for offshore wind farms may also represent a development challenge. While the grid connection for the 400 MW Anholt project was realised ahead of schedule in the summer of 2012, those for some future additions, Horns Rev 3 (400 MW) and Kriegers Flak (600 MW), are suffering delays.

[8] Co-generation refers to the combined production of heat and power.

**Figure 38** Denmark power generation by source and renewable share of total power generation




Increasing Denmark's own domestic balancing abilities could yield a more flexible and secure system. To this extent, some unique developments are under way, though their impact may be small over the medium term. In recent years, electric boiler installations in co-generation plants have risen significantly, to 300 MW in 2012 (250 MW above 2009 levels), providing an outlet for excess wind generation via heat production and storage. Installations are likely to continue, though at a slower pace in the medium term, as the market has become increasingly saturated (Tang, 2013). Increasing biogas production could be injected into the natural gas grid for use in balancing wind power. A demonstration project is also under way to convert surplus power from variable renewable sources into methane gas, which can also be stored in the gas grid (Platts, 2013a).

### *Current policy environment for renewable energy*

Denmark's renewable energy policy framework remains a strong driver for deployment. The energy policy framework until 2020 was established through the Danish 2020 Energy Agreement by a very broad majority in the Danish parliament in March 2012. The government plans to tender for offshore wind projects totalling 1.5 GW to be built by 2020. Bidding for the two largest – Horns Rev 3 and Kriegers Flak – is to open later in 2013 while tenders for 500 MW of offshore wind closer to shore are expected to be announced soon. The government is also taking active steps to promote municipal-level planning and ownership of onshore wind farms through higher feed-in tariffs (FITs), which could help facilitate new plant development as well as the repowering of older turbines.

With respect to solar PV, the parliament has accepted a new bill that changes the net metering scheme from an annual net metering to hourly net metering and reduces the price paid for electricity fed into the grid over time. Denmark's strong solar PV deployment in 2012 far exceeded the government's announced goal of 200 MW by 2020. The new regulation further allows for greater commercial-scale development and deployment of solar PV in housing associations.

### *Economic attractiveness of renewable energy and financing*

Overall, the economic attractiveness of renewable sources remains good, given Denmark's commitment to promoting renewable energy deployment above conventional sources. Over the past year, falling system costs combined with net metering based on annual rates made distributed solar PV competitive versus Denmark's high retail power prices. With system prices likely to continue falling over the medium term, solar PV is likely to remain competitive versus retail prices, even as payments for electricity fed into the grid now have been reduced substantially.

**Table 29** Denmark main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Danish 2020 Energy Agreement:**<br>Target of 100% energy from renewable sources by 2050. 100% of electricity from renewable sources by 2035. 50% of electricity from wind by 2020.<br>**National Renewable Energy Action Plan (largely superseded by 2020 Energy Agreement):**<br>Binding target: 30% of renewable energy in gross final energy consumption in 2020.<br>Indicative 2020 split:<br>51.9% of electricity production from renewable sources provided by:<br>10 MW hydropower;<br>6 MW solar PV;<br>2.6 GW wind onshore;<br>1.3 GW wind offshore;<br>2.8 GW bioenergy. | **Feed-in premiums (FIPs):**<br>Established in the Law on the Promotion of Renewable Energy. Variable premiums on top of market price for renewable electricity production from onshore wind, bioenergy, hydro, solar PV (>6 kilowatts [kW]) and ocean technologies. Offshore wind is tendered with premiums.<br>**Net metering:**<br>For solar PV, net metering on an hourly basis was accepted by parliament in November 2012. Reduces the price paid for electricity fed into the grid over time for new installations.<br>**Tax credits:**<br>Investments in renewable energy in private homes can receive a 25% deduction on income taxes. | **Framework policy:**<br>Our Future Energy (Danish 2050 energy strategy);<br>The Green Growth Agreement;<br>Carbon Tax.<br>**Grid access and dispatch priority:**<br>No grid access priority but renewable energy (RE) electricity is given priority dispatch over conventional generation when grid capacity is sufficient. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Some technology-specific economic challenges remain. For example, the Danish government is making a targeted effort to improve the economic viability of biogas. Significant scope also remains for reductions in costs for offshore wind. No new power purchase agreements (PPAs) for offshore wind have been reported since the *MTRMR 2012*, but regional supply chain developments suggest that few cost reductions have taken place over the past year. Still, the technology continues to benefit from specific financial premiums, which make it attractive.

The financing environment for renewable energy remains strong in Denmark, given robust policy commitment, deep experience with wind and biomass technologies, the country's stable fiscal position, and a low cost of capital. Some uncertainty over investment remains for offshore wind. The availability for capital for construction-phase project development has emerged as a constraint in Denmark and other markets, given generally tight commercial bank lending conditions in Europe and risks in offshore development. New sources and structures may help to enhance project financing overall. For example, Danish pension funds have become involved in wind transactions, including offshore. Still, pension funds have tended to avoid financings involving construction risk.

### *Conclusions for renewable energy deployment: baseline case*

Renewable electricity capacity is expected to expand by 3.1 GW over 2012-18. This forecast is somewhat more optimistic than in the *MTRMR 2012*, with stronger outlooks for bioenergy and solar PV. Bioenergy capacity is seen growing by just over 1 GW over 2012-18 as coal-fired capacity is converted to biomass and small biomass co-generation plants continue to increase. Notably, Dong Energy has announced plans to convert almost 2 GW of existing coal generation (three plants) to biomass, though timelines and final investment decisions remain pending. On the back of stronger-than-expected deployment in 2012 and still-attractive economics, solar PV capacity is expected to rise by 0.7 GW over 2012-18, with increased deployment of commercial-scale systems even as financial incentives have been reduced under the net metering scheme.

**Table 30** Denmark renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Bioenergy | 1.3 | 1.4 | 1.6 | 1.8 | 1.9 | 2.1 | 2.3 | 2.4 |
| Wind | 4.0 | 4.2 | 4.6 | 4.7 | 4.7 | 4.8 | 5.2 | 5.6 |
| *Onshore* | 3.1 | 3.2 | 3.3 | 3.4 | 3.4 | 3.5 | 3.6 | 3.6 |
| *Offshore* | 0.9 | 0.9 | 1.3 | 1.3 | 1.3 | 1.3 | 1.6 | 2.0 |
| Solar PV | 0.0 | 0.5 | 0.7 | 0.8 | 0.9 | 1.0 | 1.1 | 1.1 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **5.3** | **6.1** | **6.8** | **7.2** | **7.6** | **7.9** | **8.5** | **9.2** |

Notes: though conversions are included in this forecast, it is important to note that reported capacity data from IEA statistics (2011 and earlier data points) may not include bioenergy capacity converted from fossil fuels, particularly in mixed plants. RES-E = electricity generated from renewable energy sources.

The outlook for wind capacity growth is largely in line with the *MTRMR 2012*. Onshore wind is expected to grow by almost 400 MW, though gross additions are likely to be larger with the ongoing repowering of older wind turbines. After 2020, most wind developments are expected to occur offshore. As Denmark is a relatively densely populated country, public acceptance issues for new onshore capacity are emerging in some areas, particular when turbines become larger. Offshore wind is seen expanding by 1.1 GW over 2012-18, with initial contributions from Horns Rev 3 (400 MW) appearing in 2017 and from Krieger's Flak (600 MW) appearing in 2018. Still, any revisions to the timetables for grid connections could undermine these projections.

**Table 31** Denmark main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • clear long-term energy strategy up to 2050 supported by an energy political agreement until 2020, including attractive economic incentives;<br>• excellent resource availability and long-standing wind and bioenergy deployment experience;<br>• good interconnections with neighbouring countries to provide system balancing. | • continued need to develop domestic balancing resources and interconnections;<br>• grid connections and regional supply chain bottlenecks in offshore wind deployment. |

## *Renewable energy deployment under an enhanced case*

Even with certain market enhancements, the outlook for renewable energy deployment is similar under both baseline and enhanced cases. An enhanced case would see Denmark increasing its own balancing abilities through increased use of smaller natural gas co-generation plants, heat storage in the district heating system and electric boilers. As such, there is potential upside for biomass of

0.5 GW in 2018 versus the base case. Similar to other countries in the region, should an offshore North Sea Grid begin to emerge towards the end of the forecast period, there could be potential upside to offshore wind capacity in 2018, about 0.5 GW higher compared with the baseline case. Finally, with faster-than-expected cost reductions and higher-than-expected uptake by the commercial sector, solar PV could be 0.5 GW higher in 2018 versus the baseline case.

## France

France's renewable deployment should proceed largely in line with policy targets, but activity is expected to face continued economic and non-economic barriers.

### *Power demand outlook*

Over 2012-18, France's real GDP is expected to grow by 1.3% annually while power demand is seen rising moderately by 1.0% annually. French end-users have enjoyed relatively low retail electricity prices compared with other European countries, mainly due to low costs of hydro and nuclear power generation and partly regulated retail tariffs. While in line with the OECD average electricity prices for households and industry, France's end-user tariffs are about 20% to 25% lower than the OECD Europe average. However, according to the French Energy Regulatory Commission, retail power prices should increase by 30% over the medium term in order to ensure necessary investment and competition in the market (Patel, 2013).

**Figure 39** France power demand versus GDP growth

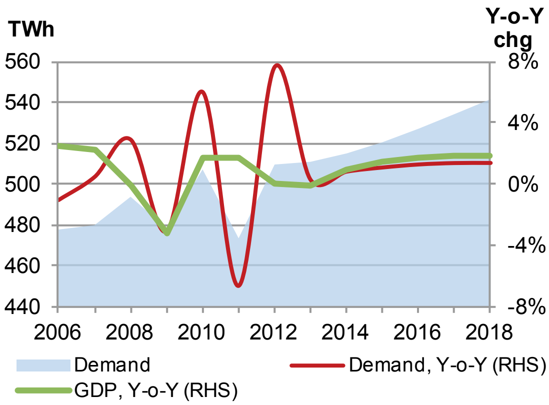
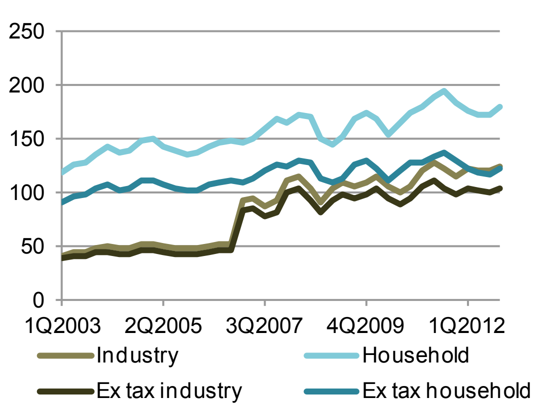



**Figure 40** France average retail power prices (USD/MWh)




### *Power sector structure*

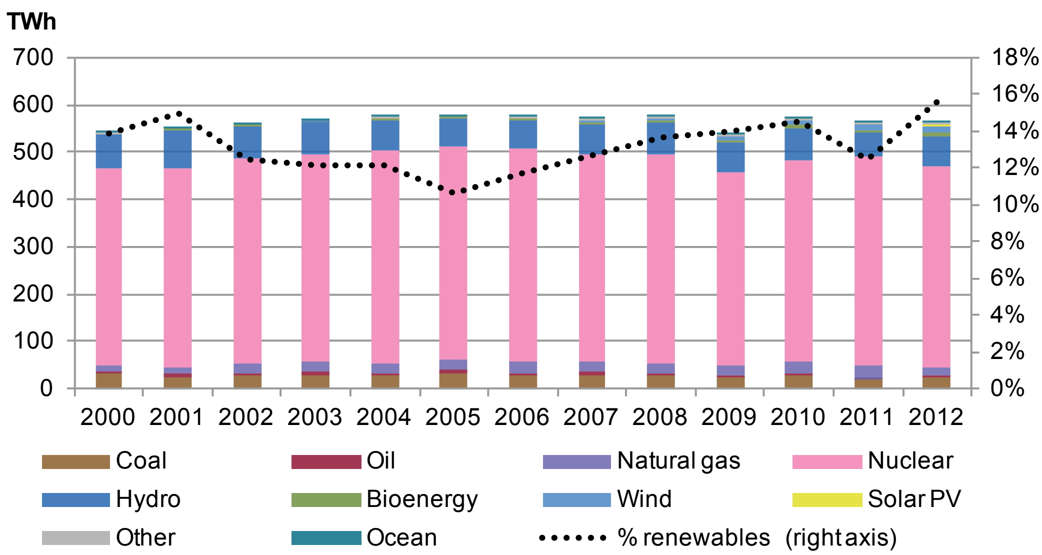
#### Generation and capacity

In 2012, although nuclear energy remained the largest source of generation, its share in the power mix decreased from 79% to 76% mainly due to scheduled maintenance work. Production from all renewable energy sources increased in 2012. Overall they accounted for almost 16% of total generation. With 1 GW of newly installed capacity, the output from solar PV doubled and represented 0.7% of total generation, while both wind and hydropower output expanded by around 25% each, representing 2.7% (wind) and 11.1% (hydropower) of generation. New wind installations in 2012, at 0.8 GW, were close to 2011, but down from 2010's 1.4 GW of growth.

In 2012, shares of coal power plants in total power generation stood at only 4.0%, and gas power plants stood at 3.6%. Over the past year, the electricity generated from coal power plants increased by around 30% while output from natural-gas-fuelled power plants decreased by around 24%, mainly due to favourable gas-to-coal switching economics (RTE, 2013). At the end of 2012, the total installed capacity stood at 128 GW. Peak load in 2011 was at 91 GW, but reached almost 102 GW in February 2012. France's net exports of electricity reached 44 TWh in 2012, around 20% less than in 2011.

Over the past year, some political uncertainty has emerged regarding the future of some of France's nuclear capacity. The government has voiced an intention to decrease the share of nuclear generation in the power mix to 50% by 2025, though concrete plans have not yet emerged. It is expected that the Fessenheim nuclear power plant with a capacity of 1.8 GW will be retired at either the end of 2016 or the beginning of 2017. Still, no other reactors are scheduled to cease their operations over the medium term, and the government is committed to finishing a new 1.65 GW plant in Flamanville, which is expected to be operational in 2016.

**Figure 41** France power generation by source and renewable share of total power generation




## Grid and system integration

The French grid should not present significant challenges to the deployment of renewables over the medium term. Still, several wind and solar PV industry representatives have reported increasing grid connection fees, especially at the distribution level (Dodd, 2012). In 2012, RTE invested around EUR 1.4 billion both in constructing new transmission lines and in reinforcing the grid, 10% higher than in 2011. An additional 1.4 GW interconnector between France and Spain (total connection capacity will be doubled, reaching 2.8 GW) will be operational by the beginning of 2014, and will enhance the integration of electricity markets in the European Union. Total investment in this interconnection is approximately EUR 700 million, half of which is financed by the European Investment Bank (EIB). In December 2012, EDF (Electricité de France) in co-operation with industrial partners and with the support of the French government launched a three-year project (so-called VENTEEA) with the objective to optimise the penetration of wind production in the French distribution grid.

## *Current policy environment for renewable energy*

Over the past year, the Ministry of Energy has released a new incentive measure for solar PV, which includes higher FITs (subject to revision every three months) for residential and commercial rooftop applications below 100 kilowatts (kW), whose deployment is limited to 400 MW annually. The government has launched two types of tenders for solar power: 1) a "simplified" tender for rooftop applications with capacity of 100 kW to 250 kW (the call is divided into three parts of 40 MW each); 2) a tender for 400 MW of solar PV from large-scale rooftops (>250 kW) and ground-mounted installations. For small solar PV projects, the new support measures also include a 10% bonus (5% for cells and 5% for panels) on top of FITs for those developers who install PV panels produced in the European Union. Regarding bioenergy, having opened the fourth biomass tender in the beginning of 2012, France awarded 15 biomass projects of 420 MW in total. Thirteen of these projects will use forestry residues and generate both heat and power.

**Table 32** France main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:**<br>Binding target: 23% of renewable energy in gross final energy consumption in 2020.<br>Indicative 2020 split:<br>27% of electricity production from renewable sources provided by:<br>28.3 GW hydropower;<br>80 MW geothermal;<br>4.9 GW solar PV;<br>540 MW CSP;<br>380 MW ocean;<br>19 GW wind onshore;<br>6 GW wind offshore;<br>3 GW bioenergy.<br>Under *Planification Plurianuelle des Investissements*, target is higher for solar PV (5.4 GW). | **FITs:**<br>Apply to onshore wind, offshore wind, geothermal, solar PV under 100 kW, bioenergy, hydropower, marine.<br>**Tenders:**<br>Offshore wind, solar PV above 100 kW, bioenergy above 12 MW, hydropower. | **Framework policy:**<br>*Le Grenelle de l'Environnement*;<br>*Planification Plurianuelle des Investissements*;<br>Energy Law.<br>**Grid access and priority dispatch:**<br>Grid connection provided to all generators on a nondiscriminatory basis. But no grid access priority for RE except in context of some regional schemes and pre-agreed cases such as offshore wind. RE electricity is given priority dispatch and EDF has the obligation to buy the production at the agreed-upon conditions ("*Obligation d'Achat*"). |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

France continues to support an offshore wind build-out with tenders. Having awarded four offshore zones over the past year, the government has launched a tender for a fifth and a sixth zone (1 GW). Companies are expected to submit their bids by November 2013, and the government is expected to award the tender in the beginning of 2014 with a goal of initial deployment by 2020-21. Some policy uncertainties cloud the outlook for onshore wind. Administrative delays and acceptance issues at the local level can slow deployment. In May 2012, France's highest administrative court, the Council of State, asked the European Court of Justice (ECJ) to rule whether the FIT for onshore wind constitutes prohibited state aid on the grounds that the French government had not previously notified the European Commission. Although a verdict is not expected soon, the situation may contribute to some investor uncertainty over the incentive scheme.

Still, in April 2013 the French parliament modified some administrative procedures for wind energy, relaxing requirements for new installations. The restriction for wind plants to be built only in the *Zone Développement Eolien* (identified geographical zones for the development of wind farms agreed by local communities) was removed, as well as the requirement for wind parks to have at least five turbines in order to receive a licence.

### *Economic attractiveness of renewable energy and financing*

With financial incentives and the tendering policy, renewable energy generally remains economically attractive in France, though new installations are largely limited to government deployment goals. In 2012, the realisation of projects that were in the pipeline since 2010 made solar PV the most developed energy technology with 1.1 GW of newly installed capacity, slightly higher than new gas-fired capacity. Despite recent changes in financial incentives for small-scale solar PV, installations are likely to be limited going forward due to deployment caps. By contrast, reduced FITs for large-scale solar PV (at EUR 85/MWh) may be currently too low to spur significant activity. Although government policy includes 10% local-content premium for solar PV panels and cells produced in the EU, the impact of this premium on system costs is difficult to predict given equipment pricing differentials. In 2012, onshore wind and biomass energy remained economically attractive. Onshore wind is competitive with newly built natural gas power plants in many locations, though it remains more expensive than wholesale power prices. Soft costs, such as administrative procedures, can raise project costs and increase financing risks. Nevertheless, the overall financing environment has remained stable and attractive over the past year.

The cost impact of FITs has been increasing since 2011 with more renewable deployment. The French Energy Regulator announced that EDF faces a shortfall of EUR 2.1 billion to finance the CSPE (Contribution au Service Public de l'Electricité), a tax that funds the development of renewable energy sources and the social tariff for low-income households and serves as a compensation mechanism for the extra costs of electricity in the overseas territories. The government decided to increase the tax from EUR 10.5/MWh to EUR 13.5/MWh as of January 2013.

### *Conclusions for renewable energy deployment: baseline case*

France's renewable energy deployment should be moderate over the medium term. The government's plan to have a more diversified electricity mix should create more opportunities for renewables. However, uncertainties in the forecast stem from policy uncertainties for onshore wind deployment and technical challenges that could slow offshore wind deployment.

**Table 33** France renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 25.3 | 25.4 | 25.4 | 25.5 | 25.7 | 26.0 | 26.2 | 26.5 |
| Bioenergy | 1.5 | 1.6 | 1.8 | 2.1 | 2.3 | 2.6 | 2.8 | 3.1 |
| Wind | 6.7 | 7.5 | 8.4 | 9.2 | 10.0 | 10.8 | 11.6 | 12.5 |
| *Onshore* | 6.7 | 7.5 | 8.4 | 9.2 | 10.0 | 10.8 | 11.6 | 12.4 |
| *Offshore* | - | - | - | - | - | - | - | 0.2 |
| Solar PV | 2.8 | 3.8 | 4.6 | 5.3 | 6.1 | 6.8 | 7.6 | 8.3 |
| Solar CSP | - | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Ocean | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Total RES-E** | **36.5** | **38.6** | **40.4** | **42.3** | **44.4** | **46.5** | **48.6** | **50.8** |

Overall, France's renewable capacity should increase by 12 GW over 2012-18. This projection is around 3.5 GW lower versus the *MTRMR 2012*, largely due to revised expectations for the offshore wind deployment timeline and a somewhat slower outlook for onshore wind growth. Though little offshore wind capacity should be installed by 2018, a significant amount of new installations are likely to occur in 2019-20, outside of the forecast period. Onshore wind should grow less than 5 GW over 2012-18, but cumulative capacity in 2017 is seen some 2 GW lower than in the *MTRMR 2012*. The forecast for solar PV has been raised on the basis of new policies. Solar PV should grow by 4.5 GW over 2012-18, with cumulative capacity in 2017 1 GW to 2 GW higher than in the *MTRMR 2012*. CSP additions, at 0.1 GW over the projected period, are expected to be small. The outlooks for other sectors are relatively stable, with growth in hydropower and bioenergy at 1.1 GW and 1.5 GW, respectively, over 2012-18.

**Table 34** France main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • policy environment backed by targets, feed-in tariffs and priority dispatch for RE;<br>• need to meet increased peak demand and potential retiring of some nuclear capacity;<br>• relative to other European countries, high remaining potential for a portfolio of renewable sources. | • concentrated (sources and ownership) power system that presents technical, institutional and cultural challenges to new entrants;<br>• significant non-economic barriers;<br>• renewable generation more costly than low prevailing wholesale prices. |

### *Renewable energy deployment under an enhanced case*

The enhanced case for France is similar to that in the *MTRMR 2012.* With several legal, regulatory and administrative enhancements France could deploy more renewables over the medium term. The simplification of permitting procedures for onshore wind projects could facilitate more deployment. For solar PV, more deployment could be possible with a stronger policy framework and higher 2020 targets, which are currently being debated. Moreover, the flexibility of the electricity sector could be improved by further development of pumped hydro storage, for example, which would also smooth renewable deployment.

Under an enhanced case, bioenergy, onshore wind and solar PV capacity could be higher in 2018. Bioenergy capacity could be 0.5 GW higher in 2018 versus the baseline case. Onshore wind capacity could be some 2 GW to 3 GW higher in 2018, while solar PV cumulative capacity could top 12 GW in 2018, some 3 GW to 4 GW higher than the baseline case.

## Germany

Onshore and offshore wind should continue to rise, though grid connection delays may weigh on the latter. Assuming lower FITs, solar PV growth should consolidate at lower levels.

### *Power demand outlook*

In Germany, power demand is expected to increase by 0.5% per year (/yr) over the medium term. According to the IMF, Germany's GDP should grow on average by 1.2% annually from 2012-18. Over the past year, residential retail power prices in Germany, among the highest in Europe, continued to rise, mainly due to increased network charges and the renewable energy surcharge (which makes up 14% of the total) while falling generation costs, partly due to increasing renewables generation, were not fully passed on to electricity consumers. The renewable surcharge for 2013 is EUR 0.523 per kilowatt hour (/kWh), 47% higher than the previous year. Currently, energy-intensive industries are entitled to a lower EEG (Erneuerbare Energien Gesetz – Renewable Energy Sources Act) surcharge. In February 2013, the government proposed a plan to slow further increases in electricity prices for residential consumers by redistributing the cost of the renewable surcharge across different consumer segments, mainly from residential to industrial rate payers.

**Figure 42** Germany power demand versus GDP growth

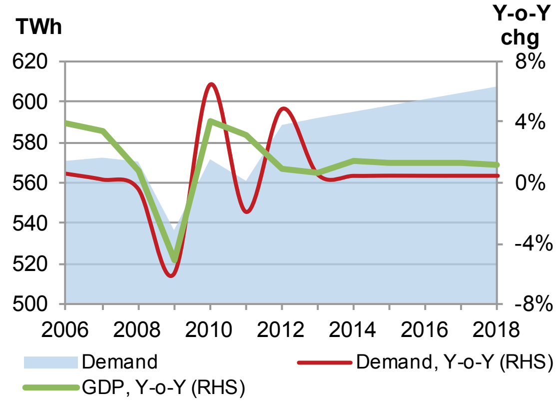
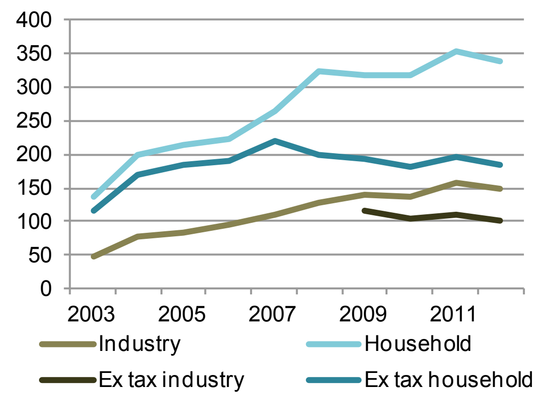



**Figure 43** Germany average retail power prices (USD/MWh)




Note: Ex-tax industry prices are available only after 2009.

## *Power sector structure*

### Generation and capacity

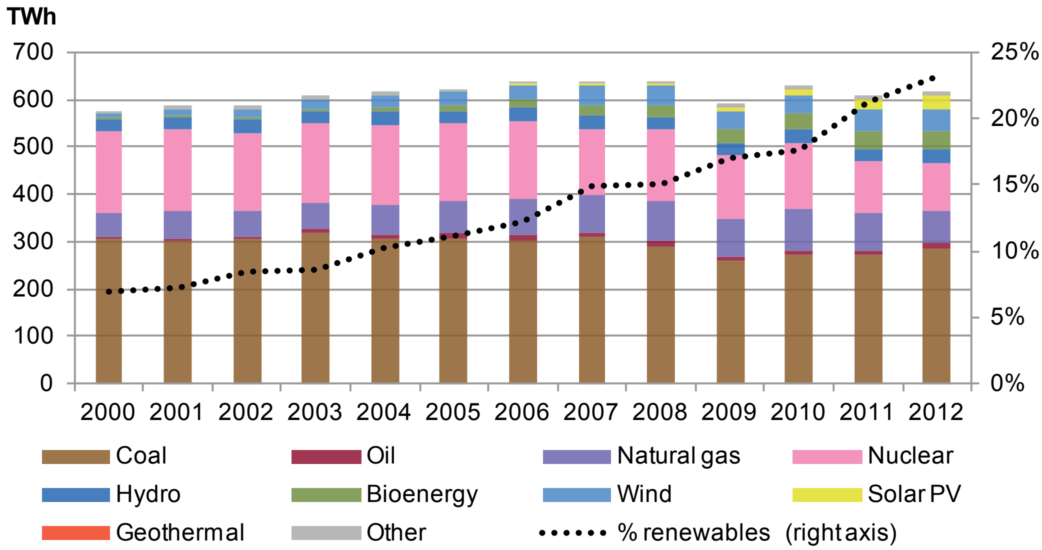
In 2012, renewable sources and coal accounted for most of the increase in power generation. Fossil-fuel generation increased slightly, accounting for 60% of the total electricity output. Yet, generation from natural gas decreased by 16%, while coal generation increased by 5% due to favourable gas-to-coal switching economics. The output from nuclear power further decreased. While solar PV rose to 4.5% share of total generation, wind power declined to a 6% share due to less favourable wind conditions versus 2011. Overall, renewable sources accounted for 23% of total power generation. In 2012, cumulative solar PV capacity surpassed total installed wind capacity. Germany solar PV capacity jumped by 7.7 GW, bringing cumulative capacity around 33 GW, while new wind power additions (onshore and offshore) were 2.3 GW, bringing cumulative capacity to 31 GW. Of the new wind capacity installed in 2012 only 80 MW (16 turbines) was offshore, lower than projected in the *MTRMR 2012*. In 2012, with 300 MW of additional capacity, the expansion of bioenergy for power was slightly lower than in 2011. As of the end of 2011, Germany's total installed power capacity stood at 172 GW. Going forward, a continued need to replace retiring nuclear and conventional capacity along with a strong policy framework should drive increases in renewable generation.

Repowering of old wind turbines has become an important market, helping to contribute to net capacity additions by increasing existing turbine size. Net additions attributed to repowering were 355 MW in 2012. The government provides incentives for repowering under certain conditions. By the year 2000, Germany had installed around 9 400 turbines with a total capacity of 6.1 GW and an average turbine capacity of around 0.7 MW, while the capacity of new turbines range from 2 MW to 3 MW. Over the medium term, developers are expected to repower their turbines, additions of which are reflected in this report's projections.

### Grid and system integration

Over the past year, both the impact of nuclear phase-out and the increasing deployment of variable renewables have augmented challenges to German system operators. These challenges are likely to increase over the medium term, taking into account the expected change in the German electricity generation mix. As mentioned in the *MTRMR 2012*, the transmission of wind power generated in the north and east of Germany to load centres in the south remains challenging due to insufficient internal connection among system operation areas. Increasing solar PV generation, largely situated in the south, partly compensates for this north-south mismatch, as do good interconnections with pumped hydro storage in Austria (though the growth potential in this area may be limited over the medium term).

**Figure 44** Germany power generation by source and renewable share of total power generation




Nevertheless, the major driver of new transmission investments is based on reinforcing the north-south part of the grid, and some progress has been made in this area. Accordingly, in May 2012, the first national ten-year grid development plan was presented by the four transmission system operators (TSOs). The plan includes measures to modernise, enhance and extend the German transmission network. Furthermore, some system operators have implemented more re-dispatching of power (a method used by TSOs to resolve transmission congestion by changing generator output levels) and increased curtailment of wind power plants over the past year. The amount of re-dispatched electricity increased almost twenty-fold from 120 GWh during the winter of 2010/11 to 2 295 GWh in 2011/12. In addition, the internal congestion has also had cross-border impacts. Unscheduled flows to Germany's neighbours during windy days, such as the Czech Republic, Poland and the Netherlands, have increased congestion levels in these countries over the past year. Both Poland and the Czech Republic are considering installing phase-shifting transformers on the border, which will help them to better manage cross-border flows.

Over the past year, Germany took some steps to increase the capacity of its interconnections. In July 2012, Statnett (Norwegian TSO), Tennet (German TSO) and KfW (the German Bank for Development and Reconstruction) signed an agreement to develop a 1 400 MW interconnection between Germany and Norway, which is expected to be operational by 2018. This new interconnection could allow Germany to export more of its wind power surplus generated in the north during windy days. In 2012, one of the German TSOs announced delays in the connection of eight offshore wind farms, resulting in significant financial losses to developers. In November 2012, the German government introduced a new liability regime for the connection of offshore wind farms, which aims at increasing investment security. In addition to these measures, the new bill also introduced an offshore network development plan, which includes necessary transmission investments to connect offshore wind projects.

In solar PV, given high deployment rates and ownership dominated by smaller, nontraditional players, (*e.g.* rooftop solar PV for households and farms), the task of grid operation is becoming more complex. According to the 2012 revision of the EEG, all new PV plants must install the technical equipment to allow for curtailment if needed. The only exceptions are small solar PV installations (up to 30 kW), which can opt for reducing feed-in to 70% of the peak capacity of the installation instead. This value was determined to be an optimal trade-off for allowing capacity to grow, while keeping curtailment low. The technical challenges of low-voltage grid adjustment are comparably small, but they are increasing in the Bavaria region. Aligning incentives for the different stakeholders (distribution system operators [DSOs], generators) will be important to ensure that deployment is not hindered.

**Table 35** Germany main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:**<br>Binding target: 18% of renewable energy in gross final energy consumption in 2020.<br>Indicative 2020 split:<br>38.6% of electricity production from renewable sources provided by:<br>4.3 GW hydropower;<br>0.3 GW geothermal;<br>51.7 GW solar PV;<br>35.8 GW wind onshore;<br>10 GW wind offshore;<br>8.8 GW bioenergy.<br>**Energy Concept 2010:**<br>Targets for renewable share in electricity supply: 35% by 2020; 50% by 2030; 65% by 2040; and 80% to 95% by 2050 at the latest. | **FITs:**<br>Established in EEG. Apply to hydropower, geothermal, bioenergy, solar PV, and wind onshore and offshore.<br>**KfW Offshore Wind Energy Programme:**<br>Promotional funds for offshore projects, up to 70% of debt capital required, not more than EUR 700 million per project.<br>**KfW Renewable Energies Programme:**<br>Long-term, low-interest loans for individuals and enterprises covering solar PV, bioenergy, wind, hydro and geothermal projects. Up to 100% of the investment costs are eligible for financing. | **Framework policy:**<br>Energy Transition (*Energiewende*);<br>EEG;<br>Grid Expansion Acceleration Act (NABEG);<br>Combined Heat and Power Act.<br>**Grid access and priority dispatch:**<br>Grid operators have the obligation to connect renewable power producers and purchase power produced for all sources of renewable electricity (established in EEG). |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

### *Current policy environment for renewable energy*

In July 2012, the government updated the EEG, which included significant changes compared with the previous incentive scheme. First, the government imposed a 52 GW total cap for PV installations under the scheme. Second, a volume-responsive monthly degression was introduced for solar PV under which the tariffs will decrease based on the amount of installations in the previous year. Third, tariff levels were revised downward for all renewable energy technologies except for geothermal, offshore wind and biomass. The EEG 2012 also encourages developers to sell their generation in the spot market through a market premium system. Thus the new law enables developers to switch to the market premium option on a monthly basis. The new remuneration method supplements the wholesale electricity price with a premium that varies with the average monthly electricity price. This measure aims at exposing some renewable plants to market price risks in order to start the transition from FITs to a market-based mechanism.

In February 2013, further measures were proposed by the government that aimed to decrease the total cost of the renewable surcharge and, consequently, retail electricity prices. However, these measures are still at an early stage of discussion. A thorough stakeholder consultation is expected in the coming months, which may lead to a significantly different outcome. Nevertheless, these discussions may cause some uncertainty that delays some investment decisions in the short term.

### *Economic attractiveness of renewable energy and financing*

Despite incentive adjustments, falling system prices and relatively high residential power prices continue to make solar PV economically attractive, with deployment in 2012 besting the government's 3.5 GW annual target. Recent market analysis suggests that unsubsidised residential and commercial applications will increase in attractiveness over the medium term, with the levelised cost of electricity (LCOE) for these installations approaching grid parity with retail prices (Hummel *et al.*, 2013). FITs for onshore wind and bioenergy are broadly in line with new-build gas and coal plants, an indicator of competitiveness for these renewable options. Still, changes in coal and gas prices as well as proposed changes to incentive schemes may alter this picture over the medium term.

The new liability regime for offshore plants should reduce financial risks for investors going forward and facilitate deployment of offshore wind. This development has already helped some offshore projects to raise additional financing. For example, the 288 MW Butendiek offshore wind farm (located in German waters near the Germany-Denmark border) was recently financed through a combination of Danish pension fund, loans from commercial and development banks (both national and multilateral), and other investors.

### *Conclusions for renewable energy deployment: baseline case*

Germany's predictable policy framework with clear targets and its robust financial support scheme, which offers incentives for a portfolio of renewables, should continue to support deployment. Renewable electricity capacity is expected to expand from 83 GW in 2012 to 117 GW in 2018. Overall, capacity is expected to be some 8 GW higher in 2017 versus the *MTRMR 2012*, largely due to higher-than-expected solar PV growth and higher expectations for onshore wind capacity.

**Table 36** Germany renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 11.6 | 11.6 | 11.6 | 11.6 | 11.7 | 11.7 | 11.8 | 12.0 |
| Bioenergy | 7.1 | 7.4 | 7.7 | 7.9 | 8.2 | 8.4 | 8.7 | 8.9 |
| Wind | 29.1 | 31.3 | 33.4 | 35.5 | 37.0 | 39.1 | 41.6 | 44.1 |
| *Onshore* | 28.9 | 31.0 | 32.5 | 34.0 | 35.5 | 37.0 | 38.5 | 40.0 |
| *Offshore* | 0.2 | 0.3 | 0.9 | 1.5 | 1.5 | 2.1 | 3.1 | 4.1 |
| Solar PV | 24.8 | 32.4 | 36.4 | 39.7 | 42.7 | 45.7 | 48.7 | 51.7 |
| Solar CSP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **72.6** | **82.8** | **89.1** | **94.8** | **99.6** | **104.9** | **110.8** | **116.7** |

Solar PV is expected to expand by 19 GW over 2012-18, with annual deployment settling at 3 GW/yr to 4 GW/yr, a level more in line with system planning. Onshore wind should expand around 9 GW. This growth may benefit in part from greater deployment challenges in offshore wind, which may rebalance some projects to the onshore sector. Offshore wind capacity should grow by 3.8 GW over 2012-18. However, cumulative capacity in 2017 is seen 0.9 GW lower than in the *MTRMR 2012*. Challenging weather during construction and the availability of debt finance, sea cables, environmental regulations, transport equipment and manpower may all act as factors keeping costs relatively high. Grid-connection delays may still pose financial challenges, even with the new liability rules. Bioenergy should grow by 1.5 GW, but additions from remaining renewable energy sources look relatively small. Overall, Germany has been effective in reducing non-economic barriers to renewable deployment with a robust financing environment. Nevertheless, grid and system integration issues will remain a hurdle for additions going forward, especially for new offshore and onshore wind plants.

**Table 37** Germany main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • robust policy environment backed by targets, FITs and priority dispatch for RE;<br>• need to compensate for retiring nuclear capacity;<br>• falling prices for solar PV equipment;<br>• ample availability of low-cost financing. | • maintaining a balance between policy flexibility, affordability and investor certainty;<br>• grid upgrades to accommodate increased wind and solar penetration, on both the transmission and distribution levels;<br>• technical and supply chain bottlenecks for offshore wind. |

### *Renewable energy deployment under an enhanced case*

Some market enhancements could result in stronger renewable energy deployment in Germany. An additional deployment of up to 2 GW by 2018 versus the baseline case could come from offshore wind over the medium term. This more optimistic outlook would require solutions to grid integration and connection issues. Notably, the new offshore liability regime with the offshore grid expansion plan may address some of the issues concerning the planning and standardisation of offshore grid connections and improve the financing situation more than expected. An enhanced scenario would also require the realisation of faster-than-expected north-south grid connections to facilitate the integration of additional wind capacity, both onshore and offshore.

## Ireland

With a robust 2020 target and FIT regime, onshore wind power should grow. High penetration of wind power may pose grid integration challenges over the medium term.

### *Power demand outlook*

Ireland's power demand is expected to rise by 2.3% annually from 2012 through 2018. It was significantly hit by the global financial crisis. Its GDP contracted for three consecutive years from 2008 through 2010.

**Figure 45** Ireland power demand versus GDP growth

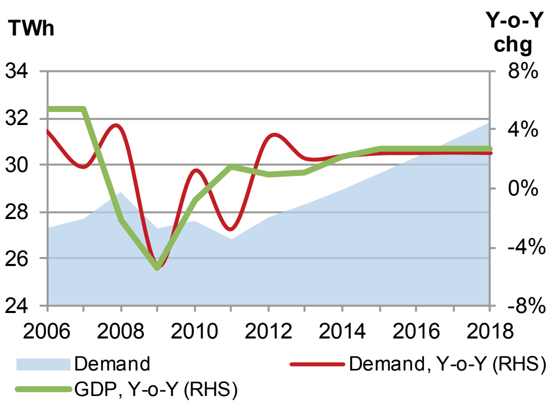
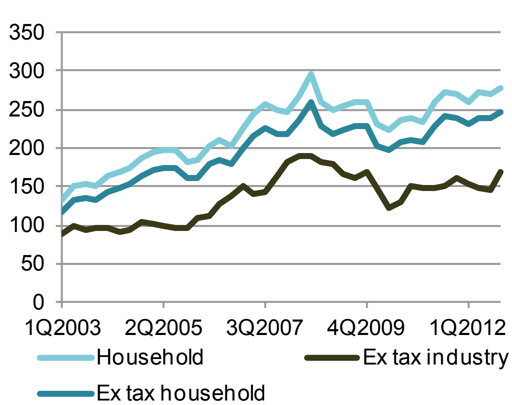



**Figure 46** Ireland average retail power prices (USD/MWh)



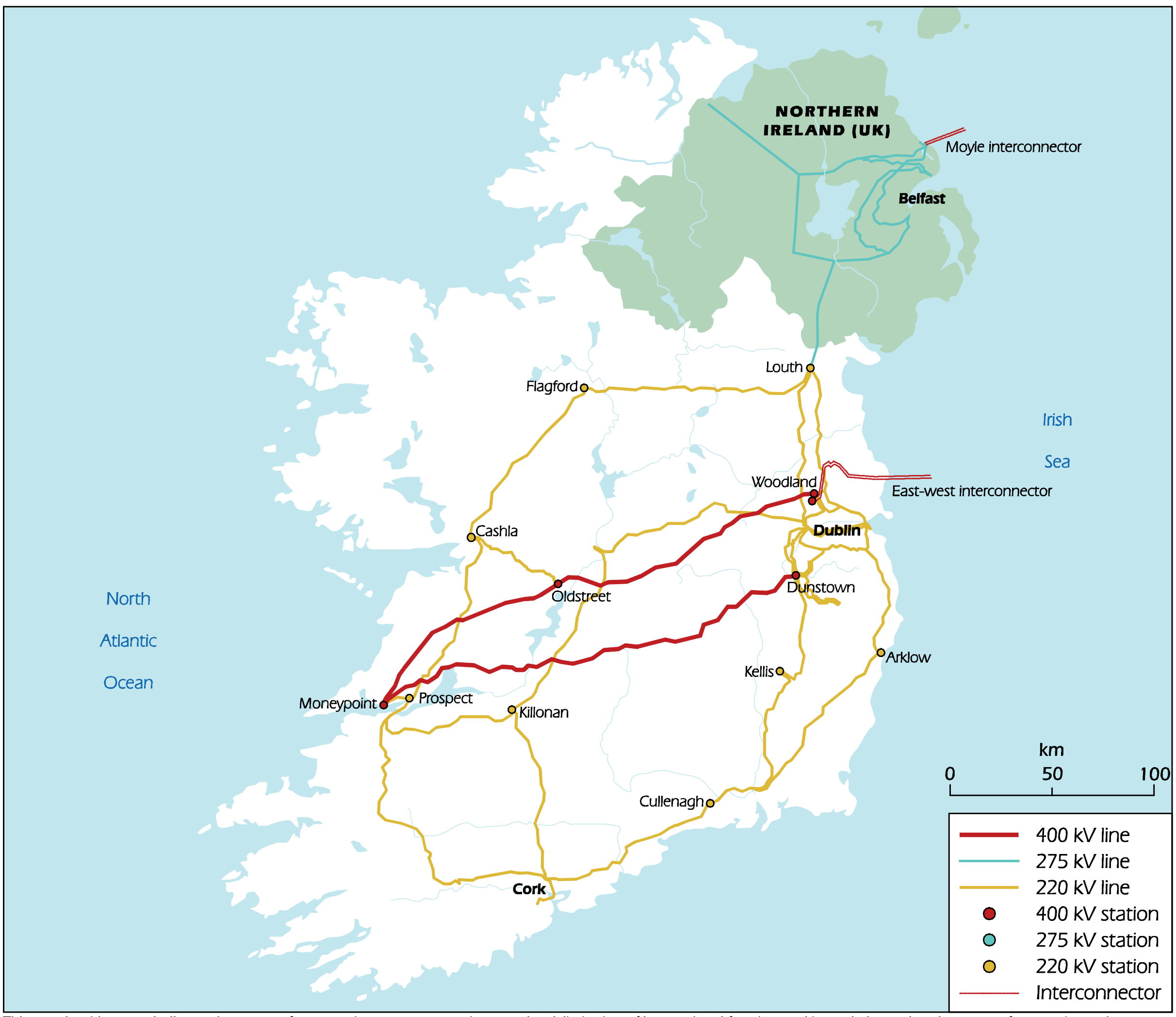
Following a slight recovery in 2011-12, the IMF projects that real GDP growth will rebound, expanding on average by 2.4% annually over 2012-18. Though the power demand increased on average by 1.2% annually from 2006-12, it contracted by 6% in 2009. Over the last decade, end-user electricity prices have almost doubled for households and have increased 50% for industry. Among the OECD countries, Ireland has relatively high electricity prices for both households and industry.

## *Power sector structure*

### Generation and capacity

Gas-fired generation is the dominant power source in Ireland. In 2012, it represented around 50% of the total output while coal-fired power plants provided around 30%. Renewable energy sources contributed almost 20% total electricity output in 2012. Wind has an important share in the generation mix with 14.5%, followed by hydropower (3.7%) and bioenergy (1.6%). As of 2012, Ireland's total power capacity had reached 8.7 GW with a peak demand of 4.6 GW (EirGrid, 2012).

**Map 3** Irish Power Grid

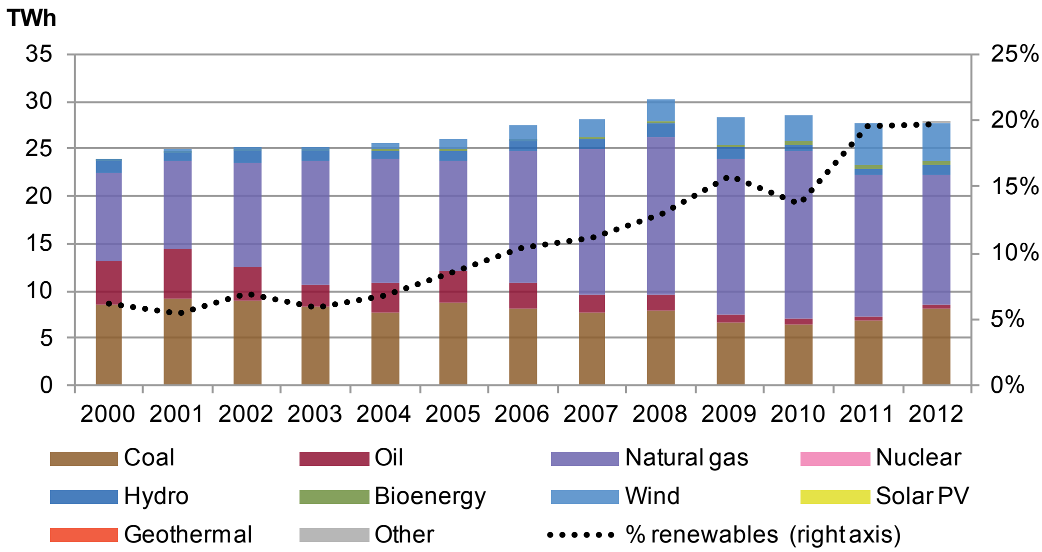



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: EirGrid, 2013.

Wind power generation has grown rapidly in Ireland, from 0.2 TWh in 2000 to 4.0 TWh in 2012. Ireland has only one offshore plant, Arklow Bank, 25 MW, which was commissioned in 2004. The government has ambitious goals to increase the share of renewables in the electricity generation mix to 40% by 2020, with wind alone providing 30%. As of 2012, the installed capacity of hydroelectricity stood at 237 MW. Ireland has limited hydropower resources that can be utilised to generate electricity, and almost all of its large-scale potential has already been exploited. Ireland also has a great potential for ocean energy development. However, development to date has been limited due to high technology costs.

**Figure 47** Ireland power generation by source and renewable share of total power generation




## Grid and system integration

The Irish electricity transmission and distribution networks are owned by a state-owned company, the Electricity Supply Board (ESB), and operated by EirGrid. Although ESB has applied for certification to unbundle its vertically integrated operations (generation, transmission and distribution) in line with the European Commission's Electricity Directive, neither the energy regulator of Ireland (Commission for Energy Regulation [CER]) nor the commission has yet given a final verdict. Ireland and Northern Ireland are part of a Single Electricity Market (SEM) which requires all generators over 10 MW to sell all their output through the power exchange.

With its sizeable gas-fired generation, Ireland's power system already offers a high level of flexibility. Still, the government's ambitious goals for 2020 and beyond will pose challenges for the grid integration of both offshore and onshore wind power. The Sustainable Energy Authority of Ireland forecasts that around 4 GW of additional renewable energy, mostly onshore and offshore wind, is required in order to ensure a 40% share of renewable generation by 2020 (Dennehy *et al.*, 2012). This situation will require the Irish authorities to consider new network infrastructure expansion, to review the existing electricity market design, and to revise grid connection mechanisms. EirGrid released its investment strategy and plans in 2010, *Grid 25*, to facilitate the connection and system integration of renewables. *Grid 25* includes investment of EUR 4 billion through 2025 for the construction and upgrade of the transmission and distribution network (EirGrid, 2010).

Ireland's situation as a small island country with only limited interconnection capacity raises further challenges to the integration of variable renewables. In addition to an existing 400 MW interconnection to Northern Ireland, an east-west interconnection (500 MW) between Ireland and Wales was commissioned in 2012 and is expected to facilitate the balancing of renewables in a wider geographical area. However, differences in electricity market design between two power exchanges, the BETTA (British Electricity Trading and Transmission Arrangements) and the SEM, are complicating operations. Gate closure times, the time when power exchanges stop accepting bids, are not aligned. BETTA accepts bids one hour before the actual dispatch of electricity while gate closure times in SEM are multiple hours ahead (IEA, 2012). Shorter gate-closure times are important to reduce the need for additional reserve capacity at higher levels of wind penetration.

### *Current policy environment for renewable energy*

The renewable energy feed-in tariff (REFIT) is the main support mechanism in Ireland. REFIT applies to all renewable energy sources (RES) technologies apart from offshore wind, tidal, wave and solar PV. Currently solar PV does not receive any incentive, while the Better Energy Homes scheme provides grants to homeowners for solar thermal systems. In February 2008, the government announced that a EUR 140/MWh) support will be provided to offshore wind projects, but this incentive is still waiting approval from the European Commission. In the future, the government also expects that the electricity generated by some Irish offshore wind farms will be exclusively exported to the United Kingdom. However, this would require developers to benefit from the support measure provided in the United Kingdom.

### *Economic attractiveness of renewable energy and financing*

Ireland's renewable energy development is likely to be led by onshore wind power, with a large number of windy locations available and good economic attractiveness from the REFIT. Offshore wind, however, is not generally attractive due to a lack of financial support in place from the government. Relatively low solar irradiation and an absence of government support schemes have thus far stymied solar PV development. Still, high retail electricity prices and falling system costs could improve distributed solar PV attractiveness over time. Finally, bioenergy, particularly biomass burned in co-generation plants, enjoys good economic attractiveness, with high tariffs from REFIT 3.

**Table 38** Ireland main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:** Binding target: 42.5% of renewable energy in gross final energy consumption by 2020. | **REFIT:**<br>REFIT 1 introduced in 2006 for small and large-scale onshore wind, biomass, landfill gas and other biomass, and small hydro projects;<br>REFIT 2, launched in 2009, covers large- and small-scale onshore wind, biomass, landfill gas and small hydro;<br>REFIT 3 covers biomass technologies such as anaerobic digestion (co-generation and non-co-generation), other biomass co-generation, and biomass combustion and co-firing.<br>FIT is granted for maximum of 15 years.<br>**Accelerated capital allowance (ACA):**<br>Companies investing in RES are eligible to write off 100% of the purchase value against their profit. Introduced in 2008, expires at the end of 2014. | **Grid access and priority dispatch:** Grid operators and distribution system operators are obliged to purchase RES-E and to give it priority dispatch. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

The cost and availability of financing may present some constraints for deployment over the medium term. Since 2008, Ireland has experienced a severe financial crisis, with its GDP contracting for three consecutive years. Although the economy has shown signs of recovery for the last two years, the credit-constrained status of Irish banks can pose a challenge to renewable energy deployment, especially for offshore wind. As such, foreign capital is needed. Recently, the EIB agreed to provide a EUR 155 million loan to Bord Gáis, a state-owned gas and power company, which will support the construction and operation of six onshore wind plants (141 MW total). Additional financing from such sources will be important to enable the deployment of renewable energy in Ireland.

**Table 39** Ireland renewable energy capacity and projection

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Bioenergy | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Wind | 1.6 | 1.7 | 2.0 | 2.3 | 2.5 | 2.9 | 3.3 | 3.7 |
| *Onshore* | 1.6 | 1.7 | 2.0 | 2.3 | 2.5 | 2.8 | 3.0 | 3.2 |
| *Offshore* | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.4 | 0.6 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | - | - | - | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **2.2** | **2.4** | **2.7** | **3.0** | **3.2** | **3.6** | **4.0** | **4.4** |

## *Conclusions for renewable energy deployment: baseline case*

With ambitious targets and robust policies in place, it is expected that Ireland should increase its renewable energy capacity significantly over the medium term, growing from 2.4 GW in 2012 to 4.4 GW in 2018. Onshore wind additions, at 1.5 GW, look the largest in absolute terms. Offshore wind is expected to expand only moderately, by around 0.5 GW. However, this increase depends on the availability of financing, which is dependent on a robust financial incentive scheme that is still under review by the European Commission. With 0.4 GW of additional capacity expected, bioenergy is the only other renewable energy resource with significant deployment.

**Table 40** Ireland main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • robust policy environment backed by binding targets and feed-in tariff;<br>• ambitious targets of the government to increase the share of renewables in the generation mix to 40% by 2020;<br>• high share of natural gas-fired power plants increases flexibility. | • lack of incentives and financing mechanisms for offshore wind projects;<br>• credit-constrained status of Irish banks due to strong impact of the crisis on Ireland's economy;<br>• increasing share of wind penetration requiring grid upgrades. |

## *Renewable energy deployment under an enhanced case*

Ireland's deployment could be higher with certain market enhancements. A greater harmonisation of grid operations to support interconnection with the United Kingdom could better facilitate the integration for onshore wind. Stronger economic incentives and faster development co-ordination with the United Kingdom could also spur more offshore wind development within the forecast period. In this case, both technologies could see deployment some 0.5 GW to 1.0 GW higher in 2018 versus the baseline case. Upside also exists for solar PV. Falling system costs and relatively high retail prices could spur deployment of 0.5 GW higher in 2018 versus the baseline case.

## Italy

Improving competitiveness for solar PV and incentives for other technologies drive deployment, but financing costs and fewer supports overall weigh upon the deployment outlook.

### *Power demand outlook*

Power demand growth is expected to be moderate, expanding on averaging just over 1% over 2012-18. Based on IMF assumptions, real annual GDP growth in Italy is expected to be 0.7% over 2012-18, slightly less optimistic than that seen in the *MTRMR 2012*. The economy is expected to contract in 2013, but then recover gradually over the medium term. In 2012, power demand contracted versus 2011, largely due to the challenging macroeconomic environment. Despite the tepid demand situation, end-user prices continued to rise in 2012. Italy's retail electricity prices remain among the highest in the OECD, with relatively costly gas-fired generation setting wholesale prices the majority of the time and rising taxes and network charges.

### *Power sector structure*

#### Generation and capacity

In 2012, gas-fired generation continued as the dominant source of power supply in Italy, accounting for 46% of gross generation, followed by coal at 16%. Unlike some other European markets where coal increased at the expense of gas due to favourable switching economics, Italy's gas-to-coal switching abilities are limited, a factor that has kept gas generation and, consequently, wholesale prices, relatively high. Growing renewable sources, however, continue to constitute a more important role in the power mix, accounting for 31% of gross generation in 2012. Overall, Italy still faces a situation of oversupply. In 2011, total capacity stood at 122 GW, with peak demand at over 56 GW. With weak expected demand growth, it is expected that Italy's capacity will remain some 40% above peak demand through the end of the decade (Ruiz, 2013a).

**Figure 48** Italy power demand versus GDP growth

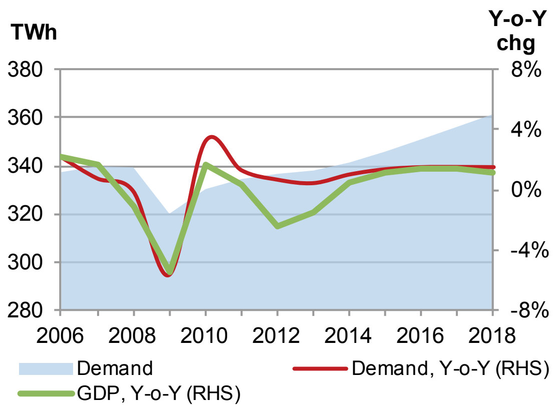
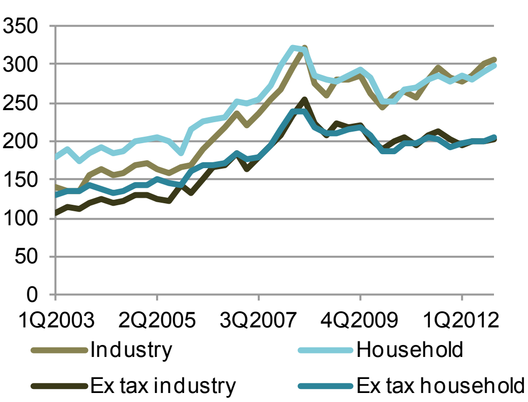



**Figure 49** Italy average retail power prices (USD/MWh)



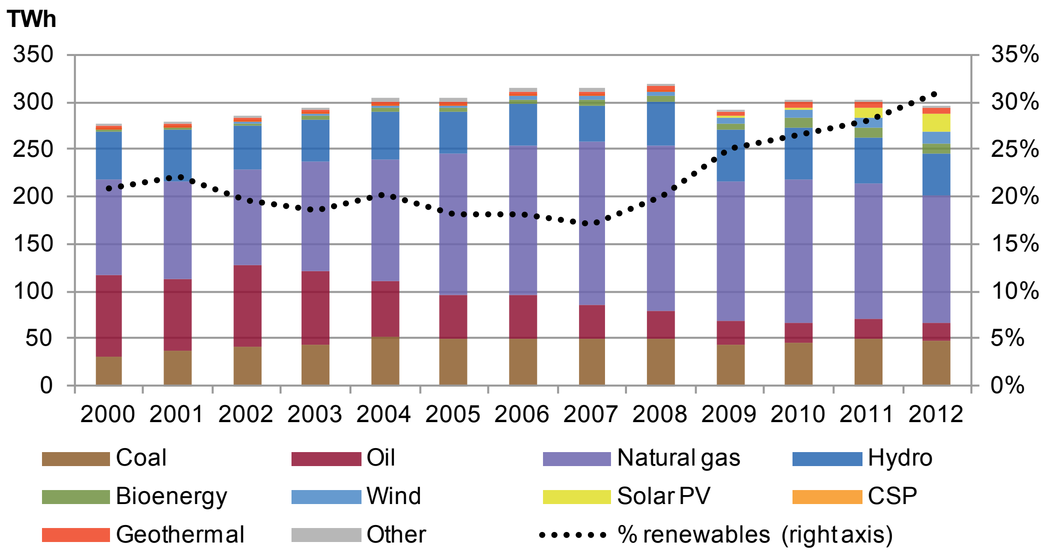
Renewable sources should account for most new power additions over medium term, though growth is likely to slow versus the rapid rise observed over 2006-12. To date, solar PV generation has grown the most rapidly, spurred by falling system costs and generous incentives. In 2012, it increased by 75% year-on-year, accounting for over 6% of power generation, as cumulative capacity rose by 3.6 GW to 16.4 GW. In capacity terms, commercial-scale installations (*i.e.* 20 kW to 1 MW) have grown the fastest in recent years. In June 2013, installations under Italy's FIT scheme had reached the annual budgetary cap imposed in 2012; in July, supports will not be available for new projects. As such, most solar PV growth over the medium term will likely come from competitive market segments not requiring significant financial support.

Onshore wind rose to 4.5% of total power generation in 2012, boosted by capacity additions of 1.1 GW. Part of the strength in capacity growth in 2012 stemmed from a rush to commission new projects before a reduction in incentives at the beginning of 2013. Going forward, growth is likely to be slower, driven by the government's new tender scheme for FIPs (projects >5 MW), which has been capped at 500 MW annually for onshore wind between 2013 and 2015. Notably, the first auction in early 2013 awarded a contract for what would be Italy's first offshore wind project (30 MW). Among other technologies, hydropower accounted for 14% of power in 2012, while bioenergy reached 3.4%, down from 3.6% in 2011. Italy also has significant geothermal generation. While geothermal has remained relatively stable over the past decade, development in demonstration-level enhanced geothermal projects is under way.

### Grid and system integration

The grid and system integration of variable renewables will remain a challenge for Italy over the medium term, though several positive developments are under way that will facilitate deployment. Grid congestion remains an issue for the evacuation of wind power from the south to relatively higher demand regions in the north.

**Figure 50** Italy power generation by source and renewable share of total power generation




Still, grid reinforcement work carried out by the transmission service operator Terna, as part of a larger network investment plan, is improving system operations and reducing curtailment in some southern areas (O'Brian, 2013). The interconnection with Sardinia and the mainland has been reinforced, and the timeline for the completion of a new transmission line to Sicily has been moved forward from 2017 to 2015. Wind generators may see a rising burden associated with system balancing, however. Though the measure remains difficult to evaluate in practice, from 2013, the electricity regulator, AEEG, requires plants to share in balancing costs when their power forecasts deviate from actual output.

Italy's rapid deployment of solar PV has been more evenly dispersed between northern and southern regions, facilitating integration. As of 2011, over 90% of solar PV capacity was connected at the low- to mid-voltage level; this continues to pose some integration problems for distribution networks and local utilities, particularly in southern areas. A concentration of large-scale plants in the south also creates stress on the grid, with a need to export excess power to the north. For 2013, the government announced simplified procedures for applying for net metering and calculating generation credits. Still, net metering currently remains only for systems up to 200 kW, and its availability is uncertain going forward. With FITs for new solar PV capacity reaching their budgetary limit, self-consumption will be a key driver for deployment over the medium term.

### *Current policy environment for renewable energy*

Over the past year, Italy has clarified the policy environment for renewable energy, approving decrees that were still in their proposal phase in the *MTRMR 2012*.

**Table 41** Italy main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **NES:**<br>Target of 35% to 38% (120 TWh to 130 TWh) renewables in electricity consumption by 2020.<br><br>**National Renewable Energy Action Plan:**<br>Binding target: 17% of renewable energy in gross final energy consumption in 2020.<br><br>Indicative 2020 split: 26.4% of electricity production from renewable sources provided by:<br>17.8 GW hydropower;<br>0.92 GW geothermal;<br>8 GW solar PV;<br>0.6 GW CSP;<br>3 MW ocean;<br>12 GW wind onshore;<br>0.68 GW wind offshore.<br><br>**Updated target for solar PV:**<br>23 GW of solar PV by 2016. | ***Conto Energia* (Ministerial Decree July 2012):**<br>Capped FITs for solar PV installations with premiums for electricity consumed on-site. Special tariffs are also provided for concentrating solar PV and other types of non-conventional installations.<br><br>**Support schemes for non-solar PV plants (Ministerial Decree July 2012):**<br>Applies from 1 January 2013. Provides:<br>• a FIT system for RES installations with a capacity ≤ 1MW;<br>• a sliding FIP for RES plants with a capacity > 1MW.<br><br>Three ways to access the incentives:<br>• directly for very small plants and other marginal cases (*i.e.* wind ≤ 60 kW; hydro ≤ 50 kW-250 kW; biogas ≤ 100 kW; biomass ≤ 200 kW);<br>• application to a registry for wind, bioenergy and wave/tidal plants under 5 MW, for hydropower under 10 MW, for geothermal under 20 MW;<br>• auction for wind and bioenergy plants over 5 MW, hydropower over 10 MW, geothermal over 20 MW.<br><br>The decree provides annual capacity caps to access to auctions and registries.<br><br>**Renewable energy quota obligation:**<br>Electricity producers and importers are required to supply a certain share of renewable power. Compliance with quota can be also satisfied by means of tradable green certificates. The system is to phase-out from 2013-15 with existing plants converted to a FIT.<br><br>**Net metering for distributed systems:** applies to renewable systems up to 200 kW and is provided as an alternative to support mechanisms described above. | **Grid access and priority dispatch:**<br>Grid connection and priority dispatch are guaranteed by the TSO/DSOs. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

In general, the government reduced generous economic incentives in order to control policy costs while increasing generation objectives. The government's National Energy Strategy (NES) (*Strategia Energetica Nazionale [SEN])* has increased the percentage of renewables in electricity consumption to 35% to 38% (120 TWh to 130 TWh) by 2020, versus the 26% target as initially set out in Italy's National Renewable Action Plan.

For solar PV, the fifth *Conto Energia* (launched in August 2012) reduced FIT levels for new installations while introducing a budgetary cap of EUR 6.7 billion/yr for total solar PV incentive payments and a registry requirement for new systems larger than 12 kW. Following the attainment of the budget cap, no new solar PV capacity is to be registered under the FIT scheme. Future development is likely to be driven by self-consumption (or net metering). The government still maintains a 23 GW target for cumulative solar PV capacity by 2016. The NES expects installations of 2 GW annually based on the attractiveness of self-consumption.

For non-solar PV sources, incentives for new installations were shifted from a quota obligation system to a feed-in system at the beginning of 2013. A tendering process for awarding FIPs to large-scale plants was introduced, applying to plants over 5 MW for wind and bioenergy and over 10 MW for hydropower and 20 MW for geothermal. Auctions are carried out annually, with capacity quotas for each technology. Onshore wind is limited to 500 MW for each tender from 2013-15 while bioenergy has a quota of 470 MW, allocated over the entire 2013-15 period. For medium-sized plants, FIPs are granted after application to a central registry, which itself has annual capacity quotas, while small-scale generators are automatically accredited.

### *Economic attractiveness of renewable energy and financing*

While generous incentives have, to date, made renewable deployment economically attractive, fewer supports will be available over the medium term. At the same time, falling system costs combined with relatively high electricity prices and the introduction of an auction system for non-PV technologies is likely to maintain attractiveness for some segments.

The awarding of FIPs under the auction system is likely to keep wind economically attractive, but its capacity quotas will limit annual deployment. The tenders include a floor price, and plants are also required to make bids at a minimum (2%) discount to a reference price and offer financial guarantees to participate. This should spur cost reductions in onshore wind over time. Results from the first bidding round revealed that total remuneration awarded for onshore wind averaged around EUR 117/MWh, with a bid as low as EUR 96/MWh, versus the reference price of EUR 127/MWh. Bids for only 442 MW of capacity, versus a limit of 500 MW, were presented. The attractiveness of offshore wind looks more uncertain. The offshore wind auction awarded only one project, at EUR 162/MWh versus a reference price of EUR 165/MWh.

As of the end of 2012, average solar PV system costs ranged from EUR 1.4 per watt (/W) for ground-based systems to EUR 2.1/W to EUR 2.6/W for rooftop systems. Industry sources indicate lower values in May 2013. While costs generally remain higher than in Germany, they can translate into attractive economics for self-consumption given high retail prices, which averaged around EUR 155 per MWh (without taxes) in 2012. LCOEs (without supports) for typical commercial-scale systems can range around EUR 140 per MWh to EUR 170 per MWh depending on resource availability (Althesys Strategic Consultants, 2013).

Despite some attractive project economics, the availability and cost of finance for renewable deployment may remain a significant constraint in Italy over the medium term. The challenging macroeconomic situation has resulted in finance becoming increasingly scarce and more expensive in general. This makes evaluating the renewable financing situation difficult. The introduction of the auction system should bring greater certainty to investors in large-scale projects, but details about remuneration and auction details after 2015 are still not yet available. For solar PV, deployment will depend on the ability of households and businesses to source capital for small-scale developments. Cyclically tight credit conditions may slow investment in self-consumption projects that would otherwise be viable.

### *Conclusions for renewable energy deployment: baseline case*

Italy's renewable capacity is expected to grow by 12 GW over 2012-18. Total renewable capacity is seen slightly higher in 2017 versus last year's forecast. Much of this change is due to stronger-than-expected solar PV growth in 2012, which has raised the capacity baseline. As the fifth *Conto Energia* neared its budgetary ceiling, deployment began to slow. As of April 2013, around 450 MW had been installed for the year, with room for only an additional EUR 65 million under the project cap of EUR 6.7 billion/yr. With falling system costs and favourable self-consumption economics, it is expected that solar PV annual capacity additions may settle near 1-1.5 GW over the medium term. Such a trajectory would bring cumulative capacity to around 24 GW in 2018.

The outlook for other technologies has changed slightly. With higher-than-expected deployment in 2012 and the clarification of the capacity auction system going forward, the outlook for onshore wind is somewhat higher, with growth of 2.6 GW and cumulative capacity reaching 10.6 GW in 2018. Still, this projection is cautious due to the annual auction capacity quotas of 500 MW as well as uncertainty over tendering details beyond 2015. Such uncertainty, combined with quotas on auction and register capacity as well, has also reduced the deployment outlook for bioenergy somewhat.

Overall, changes to the renewable policy environment over the past year have been important in helping Italy to rein in policy costs spurred by rapid renewable deployment. Still, it is unclear whether the current auction and registry system for non-solar PV technologies combined with new solar PV development based on self-consumption can propel total renewable generation to meet targets under the new NES. The cost and availability of finance for projects will also likely remain a key development constraint over the medium term.

**Table 42** Italy renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 21.7 | 21.8 | 21.9 | 22.1 | 22.2 | 22.3 | 22.4 | 22.6 |
| Bioenergy | 2.6 | 2.9 | 3.0 | 3.1 | 3.2 | 3.3 | 3.4 | 3.5 |
| Wind | 6.9 | 8.0 | 8.2 | 8.6 | 9.1 | 9.6 | 10.1 | 10.6 |
| *Onshore* | 6.9 | 8.0 | 8.2 | 8.6 | 9.1 | 9.6 | 10.1 | 10.6 |
| *Offshore* | - | - | - | - | - | 0.0 | 0.0 | 0.0 |
| Solar PV | 12.8 | 16.4 | 18.4 | 19.6 | 20.9 | 21.9 | 22.9 | 23.9 |
| Solar CSP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| Geothermal | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **44.8** | **49.8** | **52.2** | **54.1** | **56.1** | **57.8** | **59.6** | **61.4** |

**Table 43** Italy main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • clarification of policy environment, which includes stronger 2020 generation targets and incentive schemes for non-solar PV technologies;<br>• favourable economic attractiveness for solar PV under self-consumption;<br>• progress in delivering grid upgrades amid an ambitious grid investment plan. | • reduced availability and increased costs of finance amid weakening economy;<br>• capacity quotas under current auction/registry system and uncertainty over post-2015 details;<br>• continued need to deliver costly grid upgrades, particularly in the south. |

### *Renewable energy deployment under an enhanced case*

In Italy, capacity deployment could be enhanced with greater clarification over the post-2015 auction system. Combined with eased administrative procedures and a larger use of agricultural wastes in bioenergy, the upside for onshore wind could be 1 GW to 2 GW and for bioenergy 0.5 GW in 2018. The remaining enhancement relates to the competitive position of solar PV. Greater-than-anticipated improvements in system costs and support for net metering could prompt a faster deployment of solar PV for self-consumption in the residential and commercial sectors, with the potential for an additional 2 GW to 3 GW cumulative capacity by 2018 versus the baseline case.

## Spain

Due to economic challenges and the moratorium on new development under the Special Regime, Spain's renewable electricity generation growth should be moderate over the medium term.

### *Power demand outlook*

Based on the IMF, Spain's GDP growth is projected to average 0.8% annually from 2012-18. In 2012, electricity demand decreased versus 2011, but it is expected to start growing again from 2014, with an assumed economic recovery. Over 2012-18, electricity demand is expected to increase on average by 1.2% annually.

**Figure 51** Spain power demand versus GDP growth

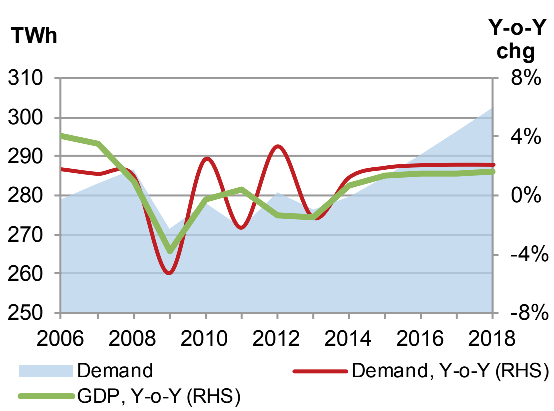



**Figure 52** Spain average retail power prices (USD/MWh)


Until 2009, retail power prices were partly regulated by the government, and over the past decade, did not reflect underlying system costs amid rising fossil-fuel prices. This situation created a so-called annual "tariff deficit", owed to the utilities. From 2009, a tariff of last resort was created, making a separation between energy prices and regulated costs. Energy prices are supposed to reflect generation costs, while regulated costs (transmission, distribution, subsidies to the islands and renewable premiums) are supposed to be recovered through the "access tariff". Since 2008, higher-than-targeted deployment of some renewable sources (*e.g.* solar PV) has exacerbated the tariff deficit, with the 2012 cumulative net burden rising to over EUR 27 billion. In response, the government has levied a 7% flat tax on output from all electricity generators, including renewables, plus specific additional taxes on hydropower production and nuclear waste.

## *Power sector structure*

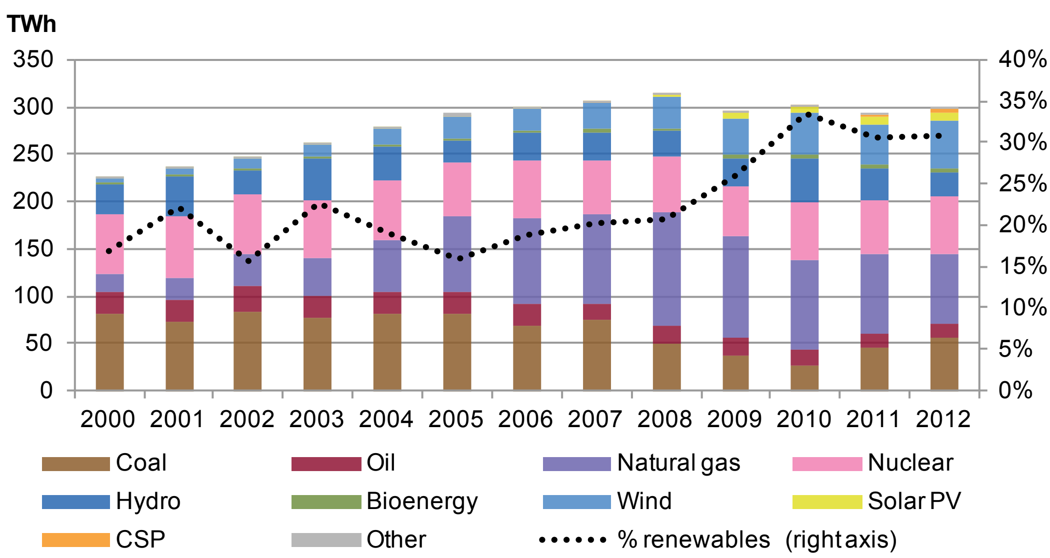
### Generation and capacity

Renewable generation continues to increase in Spain, though conventional sources still comprise the bulk of power generation. Although natural gas provided around 29% of total electricity generated in 2011, its share dropped to 25% in 2012. The share of nuclear energy was relatively steady at 21% and the share of coal grew to 19% (from 15% in 2011). Government incentives for the purchase of domestic coal as well as favourable gas-to-coal switching economics helped to drive this trend. In 2012, the share of renewables in total electricity generation was around 31%. Wind power production increased by 16% on an absolute basis, providing 16.5% of total power. Solar PV and CSP together covered 4.5%. Hydropower generation dropped slightly an 8% share. By the end of 2012, total power capacity stood at 102 GW with a peak demand of 44 GW. Although this indicates a sizeable overcapacity in the system, it is worth noting that the portion of firm capacity is lower.

### Grid and system integration

The grid is not expected to pose a significant barrier to deployment over the medium term, but it will need to continue to accommodate increasing penetration of variable renewables. Last year, wind generation broke another record on 24 September 2012. It covered more than 64% of total demand in the early morning. Moreover, in March 2013 (during the prior four months), wind energy was the largest contributor to Spain's monthly demand, providing around 28% of total generation.

**Figure 53** Spain power generation by source and renewable share of total power generation



Although the generation from more flexible gas-fired power plants decreased significantly while the output from relatively less flexible nuclear and coal power plants increased in 2012, Spain did not have any major integration or balancing issues due to its well-connected domestic network, well-established system operating procedures that facilitate variable renewables integration and geographically widely distributed variable generation.

The Iberian peninsula forms almost an island with respect to electrical interconnections. Over the medium term, an additional 1.4 GW of interconnection capacity between France and Spain should help facilitate the integration of renewables and foster Spain's integration into the forthcoming single European electricity market in 2014. Still, there are market concerns that the total interconnection capacity with France, 2.8 GW with the new line, will not be enough to evacuate surplus power during times of high hydropower and wind output (Ruiz, 2013b).

### *Current policy environment for renewable energy*

Having temporarily suspended incentives for new renewable energy installations under the Special Regime in January 2012, the Spanish government approved other incentive changes affecting already-commissioned projects in December 2012 and February 2013. The Royal Decree Law 15/2012 established a new tax of 7% on the production of electricity from all generators. The measure affects different generators differently, though the impact on renewables is likely to be a reduction of margins. The measure also raised challenges for CSP, as it reduced the premium received by existing projects in proportion to the energy produced from natural gas; this hybridisation was an important part of the financial structure of CSP plants.

**Table 44** Spain main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:**<br>Binding target: 20% of renewable energy in gross final energy consumption in 2020.<br>Indicative 2020 split:<br>40% of electricity production from renewable sources provided by:<br>22.4 GW hydropower;<br>50 MW geothermal;<br>8.4 GW solar PV;<br>5.1 GW CSP;<br>100 MW ocean;<br>35 GW wind onshore;<br>0.75 GW wind offshore;<br>1.6 GW bioenergy. | **Royal Decree 2/2013:**<br>Changes in annual FIT adjustments. FIP option is eliminated for existing and new generators.<br>**Royal Decree 15/2012:**<br>7% flat tax on output from all electricity generators. The measure also reduced the premiums to existing CSP plants for the energy production proportional to gas.<br>**Royal Decree 1/2012:**<br>Temporary suspension of public financial support for new electricity plants under the Special Regime.<br>**Royal Decree 14/2010:**<br>Correction of the tariff deficit in the electricity sector.<br>**Royal Decree 1565/2010:**<br>New tariff regulation for the production of PV electrical energy.<br>**Royal Decree 661/2007:**<br>FIT and FIP scheme. Applies to all renewable generation facilities up to 50 MW. | **Framework policy:**<br>Sustainable Economy Act 2011<br>Spanish Strategy on Climate Change and Clean Energy 2007.<br>**Royal Decree 6/2009:**<br>Establishes registry for new installations (except solar PV) in order to facilitate grid integration. The registry has yearly caps on the amount of new wind and CSP installations.<br>**Royal Decree 1028/2007:**<br>Establishes permitting procedures for offshore wind and bidding process for concessions.<br>**Grid access and priority dispatch:**<br>Guaranteed by the Royal Decree 2818/1998. Grid access of small power plants is regulated by the Royal Decree 1699/2011. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

In February, the Royal Decree Law 2/2013 phased out the FIP available to existing renewable projects in order to better manage the policy cost of renewables. Existing projects used to have the option to choose between a FIP and a FIT as the main financial support for their projects. Thus, all existing renewable energy generators were expected to either choose a FIT or sell their output in the spot market from February 2013 onward. In addition, the government also changed the annual adjustment of the FIT, which was based on the annual inflation rate, and calculated with the consumer price index (CPI). According to the Royal Decree Law 2/2013, the remuneration for regulated activities, including REFITs, shall be reviewed according to a new index. Although the index may be similar on average to the CPI over the long term, it was 3% lower than this measure in 2012. It is difficult to predict the real impact of this change, though the wind industry claims that this new method will further decrease the revenues of existing generators, in addition to the 7% tax.

### *Economic attractiveness of renewable energy and financing*

Under the moratorium, which temporarily suspended financial support for new renewable projects from early 2012, wholesale electricity prices have particular significance for new renewable energy projects because developers can sell their output in the spot market. Another option is to sign a bilateral power contract with large industrial consumers. However, finding these PPAs has become difficult due to the prevailing economic situation. In 2011, wholesale electricity prices increased, reaching on average EUR 50/MWh. However, they decreased in 2012, averaging EUR 47/MWh. With a LCOE over EUR 80/MWh, this situation does not make new wind projects economically attractive for investors. Some solar PV projects for self-consumption can still be attractive over the medium term taking into account increasing retail electricity prices, but this may depend on the adoption of net metering. Still, financing is expected to remain a major challenge to the deployment of renewables over the next few years.

### *Conclusions for renewable energy deployment: baseline case*

Assuming that the moratorium on new developments under the Special Regime remains in place through 2018 and given further changes to the policy environment to control the tariff deficit over the past year, the baseline forecast has been revised down compared with the *MTRMR 2012*. Renewable energy capacity should expand by around 3.5 GW over 2012-18, and 2017 capacity is seen some 3 GW less than in the *MTRMR 2012,* largely due to a lower outlook for onshore wind. Hydropower projects are expected to be commissioned over the medium term, with hydropower capacity growing by 1.2 GW. Solar PV should grow by 1.1 GW from favourable economics for residential and commercial installations while CSP should expand by 0.4 GW as the remaining projects initiated under the Special Regime are commissioned. Onshore wind is seen expanding by 0.7 GW.

**Table 45** Spain renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 18.5 | 18.5 | 19.6 | 19.6 | 19.8 | 19.8 | 19.8 | 19.8 |
| Bioenergy | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| Wind | 21.5 | 22.8 | 23.5 | 23.5 | 23.5 | 23.5 | 23.5 | 23.5 |
| *Onshore* | 21.5 | 22.8 | 23.5 | 23.5 | 23.5 | 23.5 | 23.5 | 23.5 |
| *Offshore* | - | - | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 4.9 | 5.1 | 5.3 | 5.4 | 5.6 | 5.8 | 6.0 | 6.2 |
| Solar CSP | 1.1 | 2.1 | 2.2 | 2.3 | 2.3 | 2.4 | 2.5 | 2.5 |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total RES-E** | **47.1** | **49.6** | **51.6** | **51.8** | **52.2** | **52.5** | **52.8** | **53.0** |

**Table 46** Spain main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • abundant renewable resources;<br>• strong grid and advanced integration of variable renewable sources. | • overcapacity of electricity system;<br>• need to correct for persistently high tariff deficit;<br>• recent policy changes may reduce economic attractiveness and investor certainty for some projects. |

### *Renewable energy deployment under an enhanced case*

The additional growth of renewables under an enhanced case would largely come from solar PV for self-consumption, enhanced by the introduction of a net metering regulation. With stronger-than-expected economic recovery and an improved financing picture, an additional 2 GW of solar PV could be installed by 2018. In the longer term, exports from Spain to central Europe could provide enhanced deployment for CSP; however, this factor does not look likely before 2018.

## Turkey

Strong demand growth, excellent renewable resources and an improved policy environment should drive deployment. Still, financial support levels may be insufficient to spur more rapid growth.

### *Power demand outlook*

Based on IMF assumptions, Turkey's GDP growth is projected to average 4.1% annually over 2012-18. Power demand is expected to expand by around 5.2% annually over the same period. In 2012, retail electricity prices increased by around 15% mainly due to costly natural gas imports and taxes.

**Figure 54** Turkey power demand versus GDP growth

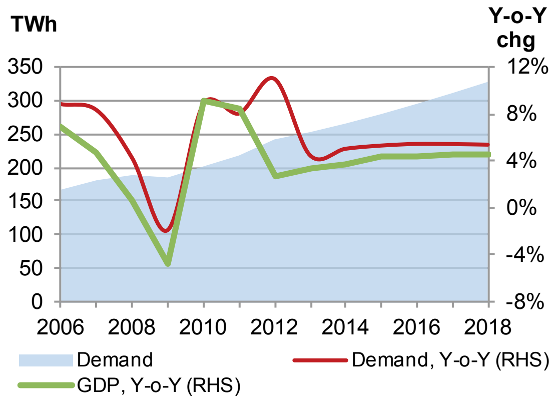
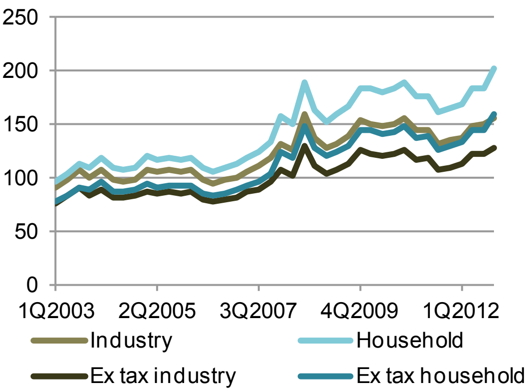



**Figure 55** Turkey average retail power prices (USD per MWh)

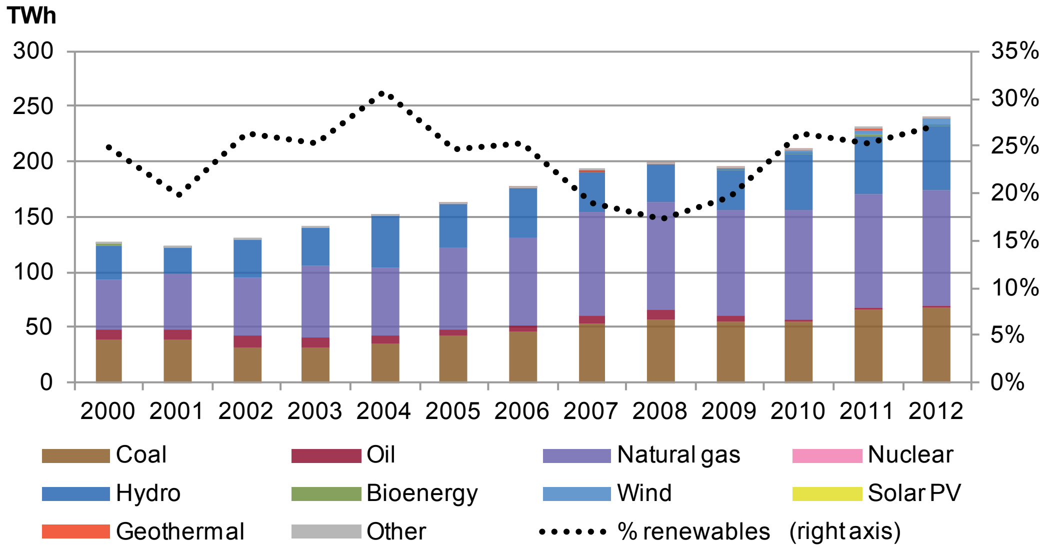



### *Power sector structure*

#### Generation and capacity

In 2012, electricity generation from natural gas was steady at around 44% of total generation while coal's share remained around 28%. Hydropower still dominates Turkey's renewable energy generation with 24% while the share of wind energy remained at 2.4%. By the end of 2012, Turkey's power capacity had increased by 10% over the year, reaching 55 GW, with peak demand also growing from 33 GW to 36 GW. The construction agreement of Turkey's first nuclear power plant with a total capacity of 3.6 GW was signed in 2012. The construction is scheduled to start in the second half of 2013, while the commissioning date is expected in 2020. In 2012, hydropower cumulative capacity stood at around 20 GW while onshore wind reached 2.3 GW, with 450 MW of new additions during the year. The installed capacity for both geothermal and bioenergy expanded slightly in 2012. Although some utility-scale solar PV projects were under construction in 2012, they are not expected to become operational until the end of 2013.

**Figure 56** Turkey power generation by source and renewable share of total power generation




### Grid and system integration

The integration of renewable electricity will remain as a moderate challenge for Turkey over the medium term with the increasing penetration of variable renewable energy sources. The Turkish TSO, TEIAŞ, has already announced that the current grid structure is capable of absorbing 11 GW of wind capacity. However, administrative and grid-connection delays remain an important challenge to connect additional wind capacity. In August 2012, TEIAŞ, in co-ordination with the Energy Markets Regulatory Agency (EMRA), announced a total of 0.6 GW connection capacity for large (above 1 MW) solar PV projects in 27 different locations. Licences for this capacity will be auctioned in June 2013. Although distributed solar PV projects below 1 MW do not need to obtain licences from the regulatory agency, their integration to the distribution grid will also still present some challenges.

## *Current policy environment for renewable energy*

Over the past year, the policy environment for renewable energy has remained stable overall with relatively positive developments concerning solar PV. EMRA and TEIAŞ defined suitable locations taking into account irradiation, land and grid-connection availability, and announced that they will auction 600 MW of licences for large-scale (larger than 1 MW) grid-connected solar PV capacity. Although the capacity is currently capped, this development has already attracted the attention of both foreign and domestic investors, who installed around 700 measurement stations as the regulation requires. For projects smaller than 1 MW, there is currently no renewable energy production licence requirement. This arrangement is particularly important for both small grid-connected projects and distributed residential solar PV installations. As of May 2013, the distribution companies had received applications for 980 small renewable energy projects, and approved 659 of them with a total capacity of 249 MW. Solar PV accounted for 65% of the approved projects.

### *Economic attractiveness of renewable energy and financing*

Over the past year, wholesale electricity prices have been on average higher than the base FIT for all renewable energy technologies. As such, around 70% of renewable energy generators sell their output either in the spot market or through bilateral contracts. Local-content premiums for several technologies can boost the FIT up to 40%, if all parts of the equipment used in projects are domestically produced, thus making the incentive more attractive. However, there are still various administrative hurdles concerning the certification of domestically produced equipment. Several European and Chinese solar PV panel producers have decided to invest in manufacturing facilities in Turkey. Combined with falling system prices, the incentive premium should make solar PV projects increasingly attractive over the medium term.

Another important issue that has emerged over the past two years affecting the economic attractiveness for wind and solar PV projects is the connection capacity auctions held by the Turkish TSO and EMRA, which enable companies to receive the renewable production licence. Initially wind developers had to compete for the limited connection capacity by submitting bids. Then TEIAŞ awarded the highest price per kilowatt hour, which developers had to pay for the lifetime of the project. In April 2013, the regulatory agency changed the rules for this competition. For upcoming capacity auctions, developers should pay grid fees as a lump sum per installed capacity instead of every kilowatt hour fed into the grid. However, this additional payment squeezes profits further and makes projects less economically attractive. In addition to selling their electricity to the spot market, some generators, mostly wind, also rely on voluntary carbon markets for additional revenue.

**Table 47** Turkey main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **General targets:**<br>30% of renewable energy in electricity generation by 2023.<br>Indicative split:<br>wind: 10 GW (2014), 20 GW (2023);<br>hydropower: “entire potential”, ~40 GW (2023);<br>geothermal: 300 MW (2014), 600 MW (2023);<br>solar: 600 MW by end of 2013. | **FITs:**<br>Established in the Renewable Energy Law 2010. Apply to bioenergy, geothermal, hydropower, solar and wind for first ten years of operation. Must be commissioned by 31 Dec 2015. Tariff supplements are available for domestic equipment use.<br>Wind and hydro: USD 0.073 per kWh;<br>geothermal: USD 0.105 per kWh;<br>biomass and biogas from organic waste: USD 0.133 per kWh;<br>solar: USD 0.133 per kWh.<br>Renewable energy installations from wind, solar PV and biomass up to 1 MW do not need renewable energy production licences.<br>**Industrial Development Bank of Turkey (TSKB):**<br>Low-interest loans for a number of renewable projects. | **Framework policy:**<br>Ministry of Energy and Natural Resources Strategic Plan 2010.<br>**Grid access and priority dispatch:**<br>Renewable energy projects have grid-connection priority. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Financing has remained a constraint for renewable energy development in Turkey. Although several international finance institutions and development banks have been active in the market over the past year, low FITs, uncertainty in local-content premiums and capacity auctions still pose challenges to finding financing.

### *Conclusions for renewable energy deployment: baseline case*

Increasing power demand, rich resource potential for a portfolio of renewable energy sources and deployment targets should spur growth over the medium term. Although the base FIT is still relatively low for several technologies, the government has taken several steps to promote small-scale projects without requiring developers to obtain a renewable energy production licence. Nevertheless the situation still remains challenging for large-scale projects with additional connection fees even though the government has recently changed the regulation. In addition, financing still remains a major challenge for renewable energy projects over the medium term.

**Table 48** Turkey renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 17.1 | 19.2 | 21.0 | 23.1 | 24.2 | 24.7 | 25.5 | 26.4 |
| Bioenergy | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 |
| Wind | 1.7 | 2.3 | 2.8 | 3.5 | 4.8 | 5.8 | 6.8 | 7.5 |
| *Onshore* | 1.7 | 2.3 | 2.8 | 3.5 | 4.8 | 5.8 | 6.8 | 7.5 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.4 | 0.7 | 1.0 |
| Solar CSP | - | - | - | - | - | - | - | 0.1 |
| Geothermal | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **19.1** | **21.8** | **24.2** | **27.2** | **29.8** | **31.5** | **33.7** | **35.7** |

Turkey's renewable energy capacity should expand by almost 14 GW over 2012-18. The projection is less optimistic than in the *MTRMR 2012*, with expected capacity some 4 GW less in 2017. Capacity has been revised down for almost all technologies mainly due to lower hydropower expectations, the low-level financial incentives, financing challenges and uncertainty over the certification of the domestic content premium. With 7 GW of expansion over the medium term, hydropower should represent the largest capacity increment followed by onshore wind with around 5.2 GW. Solar PV should start expanding slowly in 2013, mostly from residential installations. The overall growth should be faster in the latter half of the forecast period with the commissioning of some utility-scale projects. Solar PV capacity is expected to expand by 0.9 GW over 2012-18, though growth could be higher with eased licensing procedures. Relatively slow growth is expected for geothermal and bioenergy capacity; however, on a percentage basis, they should both rapidly increase.

**Table 49** Turkey main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • national renewable target combined with FITs;<br>• strong demand growth; desire to diversify power system away from costly fossil-fuel imports;<br>• excellent and diverse resource availability; wind and solar projects in some areas should compete well over the medium term, with or without FITs. | • level and duration of FITs may be too low to stimulate development;<br>• licensing for medium- and large-scale projects still acts as a bottleneck;<br>• cost and availability of finance. |

## *Renewable energy deployment under an enhanced case*

With certain enhancements in licensing procedures and the establishment of a net metering policy, the outlook for renewable energy deployment could be higher, especially for onshore wind and solar PV. The further deployment of solar PV will depend on the results of capacity auction results for utility-scale installations and on the government's decision to announce further capacity auctions. The introduction of a net metering scheme could also increase economic attractiveness for households and small commercial installations. Combined with falling module and system costs, solar PV cumulative capacity could be some 1.5 GW to 2.5 GW higher in 2018 versus the baseline case. Streamlining the licensing and permission procedures could facilitate the deployment of wind projects and put Turkey on a better path towards meeting its 2023 deployment target. In this case, wind capacity could increase by 3 GW to 5 GW in 2018 versus the baseline case.

## United Kingdom

Favourable renewable incentives and a need to compensate for conventional capacity retirements should spur strong deployment, but electricity market reform uncertainty may delay investments.

### *Power demand outlook*

The electricity demand outlook in the United Kingdom is moderately slower than in the *MTRMR 2012*. Electricity demand over this period is seen expanding modestly, by 0.4% annually on average. Over 2012-18, the IMF expects real GDP to grow on average by 1.8% annually. Economic growth and increasing electrification of the household (via heating) and transport (via rail) sectors are likely to some drive consumption growth, outweighing energy efficiency gains and the effect of high retail prices. End-user electricity prices rose in 2012, mostly due to rising wholesale energy costs (which represent almost 60% of electricity bills). Comments by Ofgem, the energy regulator, suggest that end-users will continue to face an elevated retail price environment over the medium term even as demand growth slows, due to tighter generation margins and an increasing share of relatively costly gas-fired generation (Platts, 2013b).

**Figure 57** United Kingdom power demand versus GDP growth

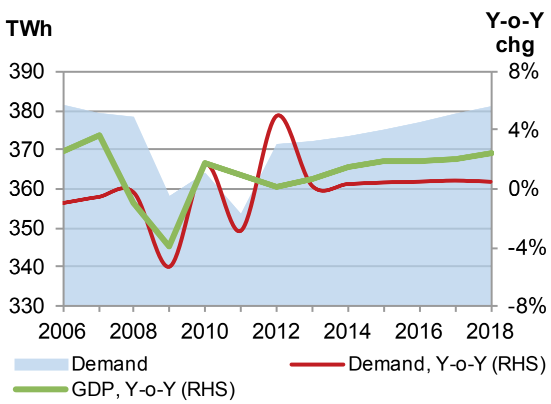
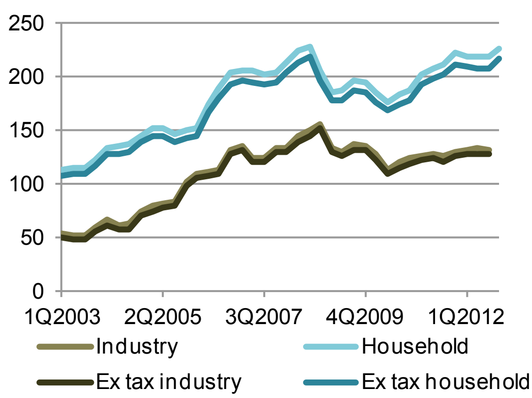



**Figure 58** United Kingdom average retail power prices (USD/MWh)




### *Power sector structure*

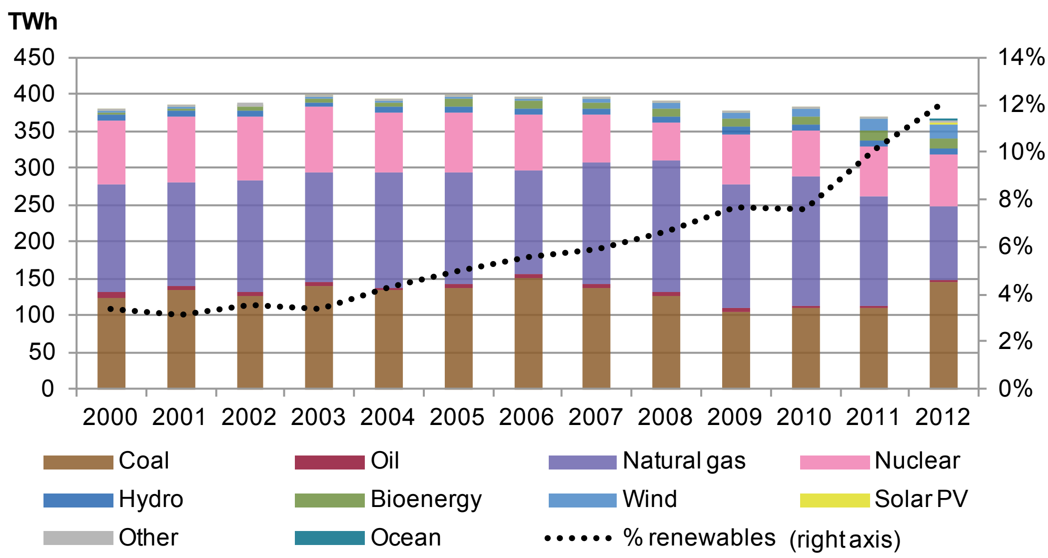
#### Generation and capacity

In 2012, the United Kingdom's power generation mix saw strong gas-to-coal switching and a continued rise in renewable sources. Coal generation rose to 40% of electricity generation in 2012, up from 30% in 2011, buoyed by attractive economics relative to costly gas generation, which fell to 27% of the mix from 40% in 2011. Nuclear followed at 20% of generation. Renewable sources rose to 12%, led by wind, which accounted for 5.3% of the power mix, versus 4.2% in 2011. Cumulative capacity grew strongly in both the onshore (+960 MW) and offshore wind segments (+940 MW), while strong winds boosted capacity factors, as reported by the government, to 27.8% and 36.2%, respectively. Bioenergy generation more than doubled on an absolute basis, boosted by a full year of output from the Tilbury B (750 MW), converted from coal-to-biomass in late 2011. Solar PV generation also showed marked gains, with capacity additions of almost 1 GW. In 2011, total power capacity was 94 GW, with peak load at 57 GW.

Over the medium term, the power sector should be dominated by the replacement of ageing plants (mostly coal and some nuclear) with rising gas and renewable generation, potentially supplemented by the intended importation of wind power from Ireland towards the end of the decade. The government's low-carbon strategy sees nuclear and carbon capture and storage (CCS) technologies also playing an increasing role, but significant additions are not expected until after 2020. In line with the government's Renewable Energy Roadmap (RER), much of the increase in domestic renewable power should come from offshore wind, onshore wind, bioenergy and solar PV, with small increases in ocean power, which has excellent long-term potential. Still, uncertainty over future financial incentive levels under the government's Electricity Market Reform (EMR) clouds some development.

As of January 2013, renewable projects under construction totalled 4.6 GW, with a further 11.9 GW permitted and over 16 GW in the planning stage. While this pipeline represents significant potential additions, not all projects will make it to completion. Much of the bioenergy project pipeline is focused on the conversion of existing coal plants and co-firing, with a soft cap (*i.e.* a cap that triggers an option for consultation on further deployment) of 400 MW recently introduced on dedicated biomass generation under the Renewable Obligation (RO) scheme. Since 2000, the Crown Estate has offered offshore wind exploitation rights to developers via three tendering rounds (47 GW in total). The RER estimates the offshore wind potential for 2020 as high as 18 GW (versus 2.9 GW in 2012), based on the prevailing pipeline and projects in pre-planning (DECC, 2012a). Still, meeting this milestone would require significant cost reductions and supply chain improvements that currently look challenging. For onshore wind, the RER sees installed capacity of 10 GW to 13 GW by 2020 (versus 5.5 GW in 2012), with most new deployment in Scotland. Meanwhile, the RER puts a wide range on potential solar PV capacity (7 GW to 20 GW by 2020, versus 1.5 GW in 2012), with cost reductions stimulating small-scale deployment and utility-scale projects starting to emerge.

**Figure 59** United Kingdom power generation by source and renewable share of total generation



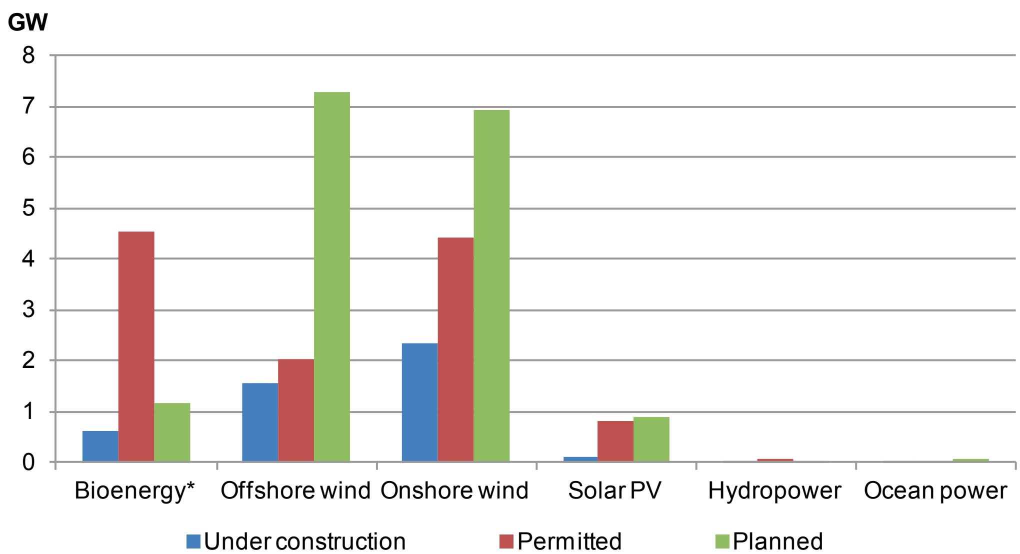
### Grid and system integration

Grid and system integration in the United Kingdom is expected to present some constraints over the medium term, with significant investment in grid reinforcement and extension needed to handle growing volumes of wind power. To facilitate this, the energy regulator, Ofgem, has recommended more integrated approaches to transmission development, with ongoing processes to put in place a new charging regime and incentivise larger, shared offshore infrastructure. The current grid looks adequate to accommodate solar PV up to 10 GW without significant balancing challenges (National Grid, 2012). Still, increased flexibility and distribution upgrades will be needed as deployment exceeds this level.

The Energy Networks Strategy Group (ENSG) reported that as of December 2012, 10.8 GW of new transmission capacity was under construction, with another 8.6 GW in planning and 17.4 GW in pre-planning (ENSG, 2012). Still, long permitting processes and delays confront some projects. These particularly concern upgrades and grid connections for wind and ocean power in Scotland, which has the most ambitious renewable electricity targets of any UK Devolved Administration and the most challenging geography. While the impacts are concentrated among a few developers, the ENSG has raised concerns over the wider effects of grid issues on general investor confidence (ENSG, 2013).

Other forms of flexibility should help the United Kingdom in meeting the balancing challenge. Rising gas-fired generation over the medium-term should provide increased generation flexibility. In 2012, a 0.5 GW interconnection with Ireland was added, bringing total interconnection to 4.0 GW, with links to France and the Netherlands and between Northern Ireland and Scotland. Plans for other projects (to Ireland, France, Belgium and Norway) could add 4 GW of interconnection by 2022. However, much will depend upon the evolving regulatory framework and the final treatment of interconnections under the EMR (DECC, 2012b).

**Figure 60** United Kingdom renewable capacity under development (January 2013)




* Includes bioenergy portion of co-firing, bioenergy conversions and non-renewable waste.

Source: DECC, 2013.

### *Current policy environment for renewable energy*

With the clarification of levels of technology support under the RO scheme and the presentation of the government's Energy Bill to parliament in late 2012, the United Kingdom has moved towards addressing some of the policy uncertainties raised in the *MTRMR 2012*. New remuneration levels for tradable certificates (ROCs) were announced in July 2012, with effect from April 2013 to March 2017. Automatic FIT degression mechanisms for small-scale generation (*e.g.* solar PV up to 5 MW) were also announced, with the aim of better matching incentive levels with cost changes.

The key support mechanism for renewables under the EMR will be FITs with contracts for difference (CFD), which allow projects to lock in a price for generation over 15 years. From 2014-17, new projects will be able to choose between remuneration under the RO or CFD scheme. After this time, the RO scheme will be closed to new entrants. The Energy Bill clarified several outstanding issues under the EMR. The bill established a single government-owned entity, to be funded by consumers (with an exemption for energy-intensive industries) via electricity suppliers, for making payments under the CFD, a significant development in reducing counterparty risk. It clarified a funding cap of GBP 7.6 billion annually by 2020 for low-carbon electricity investment under the CFD. It also set out elements for capacity market auctions to commence in 2014, aimed at encouraging new flexible generation (largely gas), demand-side response and storage.

Nevertheless, a number of uncertainties continue to characterise the policy environment in the short and medium term. Draft and final "strike prices" for the FIT-CFDs (for the 2014-18 period) have not yet been announced and will be revealed in the second half of 2013, leaving short-term uncertainty over the price that developers would receive for electricity generation. While the EMR proposal includes transition measures, the shares of new-build renewable capacity that would fall under the new scheme versus the RO scheme remain unclear. Design details over the capacity markets remain uncertain. Moreover, the bill must still be approved by the parliament. As such, the national policy environment will likely cause some uncertainty that delays some investment in the short term.

**Table 50** United Kingdom main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:**<br>Binding target: 15% of renewable energy in gross final energy consumption in 2020.<br>Indicative 2020 split:<br>31% of electricity production from renewable sources provided by:<br>2.1 GW hydropower;<br>0.92 GW geothermal;<br>2.7 GW solar PV;<br>1.3 GW ocean;<br>14.9 GW wind onshore;<br>13 GW wind offshore;<br>4.2 GW bioenergy. | **FITs for small-scale generation:**<br>Apply to hydro, wind, solar and anaerobic digestion technologies below 5 MW. Include micro co-generation pilot scheme.<br>**RO:**<br>Quota for suppliers to source a minimum percentage of their sales from renewable electricity. Quota is increasing over years. Tradable certificates for renewable generation are delivered, or the obligation can be fulfilled by paying a buyout price. Technology banding was introduced in 2009. | **Framework policy:**<br>Energy White Paper 2011 (presenting Electricity Market Reform);<br>Energy Act 2010<br>Renewable Energy Strategy 2009;<br>Climate Change Act 2008.<br>**Grid access and priority dispatch:**<br>Grid access granted. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Other, sub-national policy factors should impact upon deployment. Renewable targets by the United Kingdom's Devolved Administrations are a driver for new generation. In 2012, Scotland published an interim target of 50% of electricity demand from renewables by 2015, en route to 100% renewable electricity demand by 2020. Northern Ireland maintains a 40% renewable target by 2020, with an interim target of 20% by 2015. While planning permissions for onshore wind have generally improved at the national level, local consent processes remain an issue (Early and Daubney, 2013). Some local councils (*e.g.* in Scotland) are challenged by the volume of applications, while others are seeking to impose minimum separation distances between projects and residences.

### *Economic attractiveness of renewable energy and financing*

The current economic attractiveness of renewable electricity is largely driven by support under the RO scheme and FITs for small-scale projects. In 2012, monthly average ROC prices ranged from GBP 40/MWh to GBP 45/MWh. Recent ROC level changes and announced future adjustments have brought more clarity to support. Though ROC levels were generally lowered, they remain attractive for onshore wind, solar PV and bioenergy with continued cost decreases. Moreover, the lowest-cost onshore wind could be competitive with new-build gas generation "within the next few years" (DECC, 2012a). By contrast, reduced support for standard co-firing (< 50% biomass) is likely to make that practice unattractive in the near term (Hostert, 2013). The splitting of the solar PV ROC bands for rooftop versus ground-mounted should stimulate more activity in commercial-scale solar PV systems.

Support for offshore wind (two certificates per megawatt hour) remains strong, though it is slated to drop over time. Deployment will depend on the pace of cost reductions over the medium term. An industry Offshore Wind Cost Reduction Task Force (OWCRTF) has set the goal of bringing the LCOE to GBP 100/MWh by 2020, from GBP 149/MWh to GBP 191/MWh in 2012 (OWCRTF, 2012). Achieving such cost reductions will be challenging, particularly given still-high grid-connection costs.

Going forward, the economic attractiveness of new renewable projects presents some uncertainties. For investors, the choice of ROCs versus the FIT-CFD during the 2014-17 transition remains complex. FIT-CFDs provide lower price-risk and insulation from wholesale prices, but also lower potential returns than ROCs. FIT-CFD projects may help to attract new classes of investors (*e.g.* pension funds) seeking low, stable returns (Sherry, 2013). Ultimately, attractiveness will depend on the adopted FIT-CFD levels. Such economic uncertainty is particularly significant for some large Round 2 offshore wind projects that will come on line after the closure of the RO scheme (Early and Daubney, 2013).

The United Kingdom's financing environment should continue to act as an enabler for deployment. Policy uncertainty and the availability of financing for offshore wind remain challenges. However, certain measures are helping to lessen the risk of some investments. The government-sponsored Green Investment Bank aims to provide capital for the construction phase (which can carry significant risks) of offshore wind projects. It is also providing loans for Drax to undertake a 660 MW coal-to-biomass conversion, alongside loan guarantees from the UK Treasury. Meanwhile, the EIB has provided almost GBP 1 billion to help finance offshore grid connections.

### *Conclusions for renewable energy deployment: baseline case*

A continued need for additional generation to replace retiring capacity as well as a supportive policy environment should continue to propel strong renewable growth in the United Kingdom. Although the energy policy environment over the medium term has become clearer since the *MTRMR 2012*, significant uncertainties persist over the levels of financial supports under the FIT-CFD scheme. Combined with other unresolved details of the EMR, the UK policy environment still remains a moderate challenge for investment in the short term.

Renewable capacity is seen expanding by more than 21.5 GW over 2012-18. The projection is more optimistic than in the *MTRMR 2012*, with capacity in 2017 seen some 5 GW higher. The upward revisions stem largely from solar PV, which witnessed stronger-than-anticipated growth in 2012 and whose prospects have improved with falling system costs, still-strong incentive levels, and increased activity in the commercial and utility-scale segments.

Onshore wind growth, at 7.2 GW over 2012-18, should represent the largest absolute increment. Continued reductions in system costs and non-economic barriers and rising flexible generation (*i.e.* gas) should facilitate growth, though the pace of grid upgrades and local planning hurdles could present challenges. Offshore wind growth, at 5.7 GW over 2012-18, also appears strong. In the near term, a few large projects are expected to be operational in 2013, including the London Array Phase 1 (630 MW) and Lincs (270 MW), followed by Gwynt-y-Môr (576 MW) in 2014. Uncertainty over future cost reductions, potential supply chain bottlenecks and grid connections weigh upon the medium-term deployment trajectory, though, with the installation pace (1.0 GW annually) lagging that needed to reach 2020 National Renewable Action Plan targets (13.0 GW installed by 2020). Still, cost reductions in line with the CRTF goals could push deployment much higher.

**Table 51** United Kingdom renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 4.4 | 4.4 | 4.4 | 4.4 | 4.8 | 5.1 | 5.1 | 5.1 |
| Bioenergy | 3.3 | 3.4 | 3.6 | 3.8 | 4.1 | 4.1 | 4.1 | 4.2 |
| Wind | 6.5 | 8.4 | 10.4 | 12.2 | 14.3 | 16.6 | 18.9 | 21.3 |
| *Onshore* | 4.5 | 5.5 | 6.5 | 7.6 | 8.8 | 10.1 | 11.4 | 12.7 |
| *Offshore* | 2.0 | 2.9 | 3.9 | 4.6 | 5.5 | 6.5 | 7.5 | 8.6 |
| Solar PV | 1.0 | 2.0 | 3.0 | 4.0 | 5.0 | 6.0 | 7.0 | 8.0 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| **Total RES-E** | **15.1** | **18.3** | **21.5** | **24.4** | **28.2** | **31.9** | **35.2** | **38.6** |

Notes: bioenergy capacity in the United Kingdom does not include plants that co-fire. Though conversions are included in this forecast, it is important to note that reported capacity data from IEA statistics (2011 and earlier data points) may not include bioenergy capacity converted from fossil fuels, particularly in mixed plants.

Significant developments are expected in bioenergy, with growth of 0.8 GW over 2012-18, driven by coal-to-biomass conversions. Growth in dedicated biomass plants looks cautious, however, given the soft cap on development. Ocean power will remain small on an absolute basis, but growth prospects are strong. A number of 5 MW to 10 MW projects have applied for funding grants under schemes from the national and Scottish governments, and some are expected to be operational by 2018 (DECC, 2012a).

## *Renewable energy deployment under an enhanced case*

An enhanced case for renewable deployment would require rapid clarification of the policy uncertainties related to new financial support levels under the EMR, and those associated with permitting and grid connection. Better progress would need to come about in offshore wind developments, particularly in cost reductions and supply chain bottlenecks. The combination of swift policy resolution and more favourable supply-side developments could help deployment for offshore wind approach the more ambitious targets set out by the Crown Estate. Under these conditions, both offshore and onshore wind cumulative capacity could be 1 GW to 2 GW higher in 2018 versus the baseline, with most of the difference coming towards the end of the forecast.

**Table 52** United Kingdom main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • strong government commitment to clean power generation sources with ambitious targets;<br>• acute need to replace ageing conventional generation fleet;<br>• targeted financial support to offshore wind and bioenergy from newly created Green Investment Bank;<br>• improving economic attractiveness for solar PV and onshore wind. | • policy uncertainty over EMR and levels of new financial supports undermines current investment climate;<br>• technical and financial challenges for offshore wind development;<br>• significant investment needed for grid reinforcement and extensions. |

## Other OECD Europe countries

In **Norway, Sweden** and **Finland** the policy environment for renewable energy technologies has remained fairly stable over the past year. With abundant hydropower generation, Norway's share of renewable power generation stood at 98% in 2012. Sweden and Finland's renewable shares were 58% and 40%, respectively, and have risen in recent years. In 2012, Norway installed 166 MW of onshore wind power, reaching around 700 MW of cumulative installed capacity, while Sweden added around 850 MW of onshore wind power, expanding its cumulative installed capacity to 3.8 GW. Sweden and Norway launched a common green certificate market in January 2012 aimed at providing additional financial incentive to renewable energy developers. Although the prices for certificates have increased since July 2012, they remained at around EUR 25/MWh to EUR 29/MWh. Because power prices in the Nordic region are low, green certificates should improve economic attractiveness of some renewable energy technologies, especially onshore wind and biomass. Under this incentive scheme, the deployment of relatively more expensive technologies, such as offshore wind and solar PV, may remain limited. In 2012, onshore wind expanded significantly in Finland by around 90 MW, reaching 290 MW. Biomass should grow over the medium term, mainly with increasing co-firing in coal power plants with wood pellets.

Coal-fired power plants dominate **Poland**'s electricity mix, providing around 85% of generation, with renewables comprising 11%. While Poland is a promising market in terms of estimated recoverable shale gas resources, it is expected to bring only limited new shale gas supply to the market by 2018 (IEA, 2013). Since 2005, mandatory quotas for power companies and a green certificate market have encouraged the deployment of renewables. The support scheme has pushed many coal power plants to co-fire with biomass, mainly using wood and straw. Co-firing has almost quadrupled over the past five years. Apart from biomass, by the end of 2012 the country had installed 2.5 GW of cumulative wind power capacity, mostly in the north, which provided around 1.6% of total electricity output. However, the deployment of solar PV remained limited.

Since the end of 2011, the Polish government has been working on the new renewable energy law. The last draft, which was circulated in October 2012, included a FIT scheme for small renewable energy projects. The proposed tariff for residential solar PV is around EUR 0.32/kWh, which is relatively high on an international basis. This rate would stimulate significant solar PV deployment over the medium term. The new law also aims at revising the distribution of technology-specific green certificates. However, the delays in adoption of the new law have created uncertainty for investors. It is expected that the law will take effect in the beginning of 2014 (however, support mechanisms require review by the European Commission, which should take around six to eight months). Besides this policy uncertainty, the Polish grid should present challenges to renewable energy deployment over the medium term due to time-consuming grid connection procedures and generally weak grid infrastructure.

In **the Netherlands**, renewable energy sources represented 12% of total power generation in 2012 with biomass and wind having the lion's share. Total installed capacity of wind power reached 2.5 GW by the end of 2012, while solar PV installations remained slow due to limited financial incentives in earlier years. The Netherlands implements a FIP (SDE+) which pays the difference between the spot market price and the cost price for each technology. In 2013, the annual government budget was capped at EUR 3 billion for the incentive scheme. The Netherlands has a national target of 14% of renewable energy in total final consumption under the EU Renewable Energy Directive. In the 2012 coalition agreement of the government, the ambition was raised to 16% by 2020. For the 14% renewable energy target, a share of 38% renewable electricity in total electricity final consumption would be required under the National Renewable Energy Action Plan. Over the medium term, wind and biomass should grow fast while solar PV, especially residential installations, should rise slowly with the help of decreasing system costs. As the FIP support for biomass co-firing will stop shortly, there is a considerable risk that this practice will slow if no new support instruments for co-firing are implemented.

Hydropower plants generate more than half of the electricity output in **Switzerland** while nuclear power provides a large portion of the rest. In 2012, renewables accounted for 60% of total generation. Switzerland has taken the decision to gradually phase out nuclear power and to reduce by a fifth its greenhouse gas emissions by 2020 with domestic measures only. The country introduced a FIT in 2008 for wind, small hydro, solar PV, biomass and geothermal. Still, deployment has been limited due to a cap, which defines the total budget for renewable energy incentives, imposed by the government. In 2012, solar PV capacity stood at around 250 MW while cumulative wind power capacity remained at 54 MW. Switzerland revised FIT levels up for some technologies in 2012. The government increased the tariff for wind installations in less windy areas and for wood-fired biomass slightly. In early 2013, the Swiss lower house passed a bill to boost subsidies for solar PV installations, which should enable more projects to take advantage of the tariff starting from January 2014, if approved by the Parliament.

In **Belgium**, renewable generation accounted for 14% of total power generation in 2012. The regions of Brussels, Flanders and Wallonia provide incentives for renewable electricity generation based on a quota and green certificate system with a minimum guaranteed purchase price. The regional regulators are responsible for administrating the green certificate systems except that for offshore wind development, which is managed by the federal government. Solar PV and onshore wind are economically attractive in both regions, especially in Flanders. The region installed around 100 MW of new solar PV in 2012, reaching 2 GW of cumulative capacity, while the region of Wallonia commissioned 269 MW of solar PV. Together Flanders and Wallonia installed over 110 MW of onshore wind in 2012. Meanwhile, total offshore development totalled 185 MW in 2012. Over the medium term, onshore wind, offshore wind and solar PV should continue to grow despite the federal government's introduction of a new tax to cover costs incurred by the Belgian regulator to administer the green certificate system.

In **Austria**, renewable generation accounted for 75% of total power generation in 2012. Over the past year, Austria revised down its FITs for several technologies. While the government decreased the onshore wind tariff by only 0.5%, solar PV tariffs were cut on average by 10%. In 2012, Austria installed around 300 MW of wind power with cumulative capacity reaching 1.4 GW. With its robust financial incentives and targets, onshore wind and bioenergy should expand over the medium term. Although the government does not provide support for utility-scale applications, attractive FITs for commercial and residential installations should allow a moderate expansion of solar PV.

Since the retroactive tax on revenue generated by solar PV developers imposed by the government in 2010, renewable energy deployment has been modest in the **Czech Republic**. The tax is applicable until 2013 on solar PV capacity commissioned in 2009 and 2010 with installed capacity exceeding 30 kW. Some projects were commissioned in 2012 with 43 MW of wind power and around 115 MW solar PV installed. However, the tax makes few projects economically viable. As such, the expansion of renewables should remain limited over the medium term. **Slovakia** further decreased its incentives for solar PV after the government's move to limit the eligibility of FITs only to projects up to 100 kW installed capacity. In February 2013, the government approved another bill that reduces the support for systems only up to 30 kW.

In **Portugal**, renewables accounted for 44% of total power generation in 2012. Having imposed a moratorium on large renewable energy installations under its FIT scheme in 2012, Portugal announced new FIT rates for both micro (up to 3.68 kW) and small (up to 250 kW) solar PV installations for 2013, which are 30% lower than the previous tariff. However, financing should remain a barrier to deployment for smaller projects over the medium term due to difficult economic conditions. Although Portugal considered retroactive cuts to FITs over the past year, an agreement was reached in March 2013 between the government and the wind industry that existing wind farms under the old FIT regime (Decree Law 33-A/2005) can voluntary opt into (projects awarded under the competitive tenders are not subject to changes). In exchange for an annual, per megawatt, payment by developers over 2013-20, the government would introduce a new FIT scheme based on the daily average wholesale market price with a cap and floor mechanism. The scheme would extend the remuneration duration from 15 years to between 20 and 22 years. With such measures, the government hopes to reduce the total cost of remuneration in 2020 while maintaining investor certainty.

Despite the severe financial crisis, **Greece** doubled its solar PV capacity in 2012, reaching 1.4 GW cumulative capacity. Renewables accounted for 16% of generation there in 2012. Having introduced one of the highest FITs in Europe for solar PV in 2010, the country decided to levy a tax on existing solar PV plants, which may reduce project revenues by 25% to 35% depending on the year of the plant commissioning. The government already announced that a second tax on renewables may be administrated in 2013. Solar PV installations, at around 0.8 GW, were strong in the first quarter of 2013 as developers sought to complete installations before anticipated feed-in tariff cuts in March. Public Power Corporation (PPC) of Greece, the biggest utility, has opened several solar PV tenders for large-scale projects. However, financing and retroactive changes should remain as significant challenges to deployment. In September 2012, PPC had to cancel two deals because the company could not secure financing while some wind developers, who hold around 250 MW of licences, have already decided to withdraw from the market.

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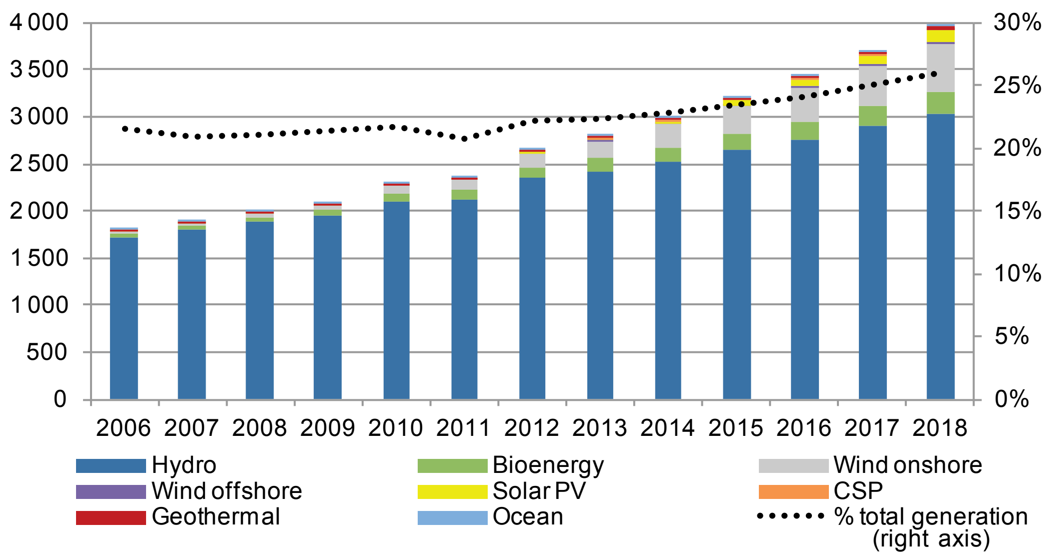
# RENEWABLE ELECTRICITY: NON-OECD

## Summary

- **Non-Organisation for Economic Co-operation and Development (OECD) renewable electricity generation is projected to grow from 2 645 terawatt hours (TWh) in 2012 to 3 970 TWh in 2018 (+7.0% per year [/yr]).** In general, non-OECD countries possess more abundant renewable energy potential than OECD countries. Hydropower will supply most of the forecasted growth, with generation increasing by 690 TWh, followed by onshore wind, solar photovoltaics (PV) and bioenergy. Offshore wind, concentrating solar power (CSP) and geothermal should grow more modestly in absolute terms. Overall, renewable generation is seen 65 TWh higher in 2017 versus the *MTRMR 2012*, with upward revisions in hydropower, onshore wind and solar PV outweighing downward revisions to offshore wind.

- **While some non-OECD countries are developing a portfolio of renewable energy capacity (*e.g.* Brazil, China and India), medium-term deployment in most countries still hinges on cheap and abundant hydropower resources.** Nevertheless, development of other technologies continues to scale up in countries with good resources and emerging support measures. Thailand is expected to deploy a portfolio of renewable sources, including bioenergy, solar PV and onshore wind. In both Morocco and South Africa, tendering schemes should drive growth in onshore wind, solar PV and CSP. Meanwhile, rapidly declining solar PV costs should prompt increased overall deployment towards the end of the forecast period, particularly in non-OECD Asia, the Middle East and the non-OECD Americas. In these areas, the growing attractiveness of solar PV stems from cost advantages, increased policy support and excellent resources.

**Figure 61** Non-OECD renewable electricity generation (TWh)




Notes: hydropower includes pumped storage; the onshore and offshore wind split is estimated. Unless otherwise indicated, all material in figures and tables in this chapter derives from International Energy Agency (IEA) data and analysis.

- **China's renewable electricity capacity should grow from 340 gigawatts (GW) in 2012 to 650 GW in 2018 (11.4%/yr), the largest increment in the world.** Deployment should be led by hydropower

(+110 GW), onshore wind (+110 GW) and solar PV (+62 GW), whose outlook has increased considerably since the *MTRMR 2012*. Offshore wind and CSP should increase rapidly from a low base, but with greater forecast uncertainty, given more limited deployment experience in China. Strong policy with ambitious targets underpins the outlook, but there is short-term uncertainty over some new policy measures.

- **Renewable electricity capacity in India should grow from 67 GW in 2012 to 108 GW in 2018 (8.3%/yr).** Onshore wind, hydropower and solar PV lead deployment. With rural electrification needs, distributed solar PV and bioenergy capacity should continue to advance. The renewable obligation combined with other financial incentives underpins the forecast, but policy uncertainties and grid integration and financing challenges weigh upon the outlook.

- **In Brazil, renewable electricity capacity should grow from 103 GW in 2012 to 138 GW in 2018 (5.0%/yr).** Deployment should be led by hydropower, onshore bioenergy and wind. Solar PV should grow moderately. However, the economics of distributed applications could cause faster-than-expected deployment. Hydropower continues as a cheap and ample mainstay of development, and government-sponsored auctions have driven a burst of recent wind contracts. Still, environmental licensing and project delivery from auctions may act as challenges.

**Table 53** Non-OECD renewable electricity generation (TWh)

| | 2006 | % of total gen, 2006 | 2011 | % of total gen, 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 1 727 | 20.6% | 2 115 | 18.7% | 2 345 | 2 427 | 2 533 | 2 643 | 2 765 | 2 900 | 3 037 |
| Bioenergy | 35 | 0.4% | 104 | 0.9% | 116 | 130 | 147 | 168 | 190 | 209 | 228 |
| Wind | 16 | 0.2% | 110 | 1.0% | 147 | 188 | 239 | 302 | 366 | 443 | 527 |
| *Onshore* | 16 | 0.2% | 109 | 1.0% | 146 | 187 | 236 | 296 | 356 | 428 | 507 |
| *Offshore* | - | 0.0% | 1 | 0.0% | 1 | 1 | 3 | 6 | 10 | 14 | 20 |
| Solar PV | 0 | 0.0% | 4 | 0.0% | 10 | 21 | 37 | 56 | 77 | 99 | 125 |
| Solar CSP | - | 0.0% | 0 | 0.0% | 0 | 1 | 2 | 3 | 6 | 9 | 14 |
| Geothermal | 22 | 0.3% | 25 | 0.2% | 26 | 27 | 29 | 31 | 33 | 36 | 38 |
| Ocean | 0 | 0.0% | 0 | 0.0% | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total** | **1 800** | **21.5%** | **2 358** | **20.8%** | **2 645** | **2 794** | **2 987** | **3 203** | **3 437** | **3 697** | **3 968** |

Notes: hydropower includes generation from pumped storage. Data for 2011 and 2012 are estimates; the split for onshore and offshore wind is estimated for historical data.

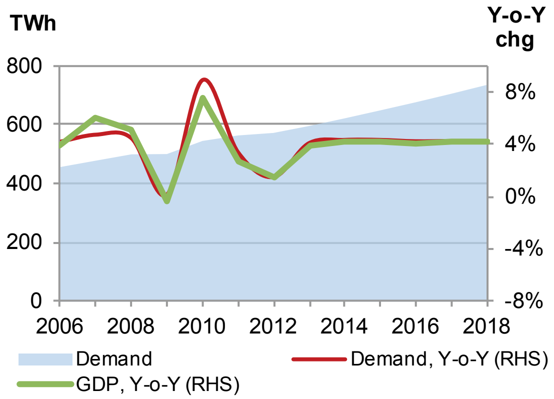
## Brazil

Long a champion of renewable energy, Brazil's hydro and wind power should grow significantly. Yet uncertainty over auction project delivery due to licensing issues may check some deployment.

### *Power demand outlook*

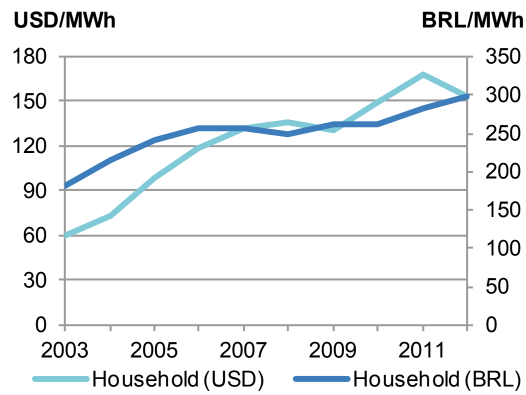
In line with assumptions from the International Monetary Fund (IMF), Brazil's real gross domestic product (GDP) is expected to rise on average by 3.9% annually over 2012-18. Power demand is expected to expand on average by 4.3% annually over the same period. End-user power prices in Brazil have continued to increase, averaging around BRL 300 per megawatt hour (/MWh) (USD 150/MWh) in 2012 for the residential sector. In January 2013, the government issued a new act to cut electricity tariffs, which will decrease on average by 18% for households and 30% for industrial users by the end of 2013.

**Figure 62** Brazil power demand versus GDP growth




Note: Y-o-Y = year-on-year; chg = change; RHS = right-hand side.
Demand is expressed as electricity supplied to the grid.

**Figure 63** Brazil average retail power prices



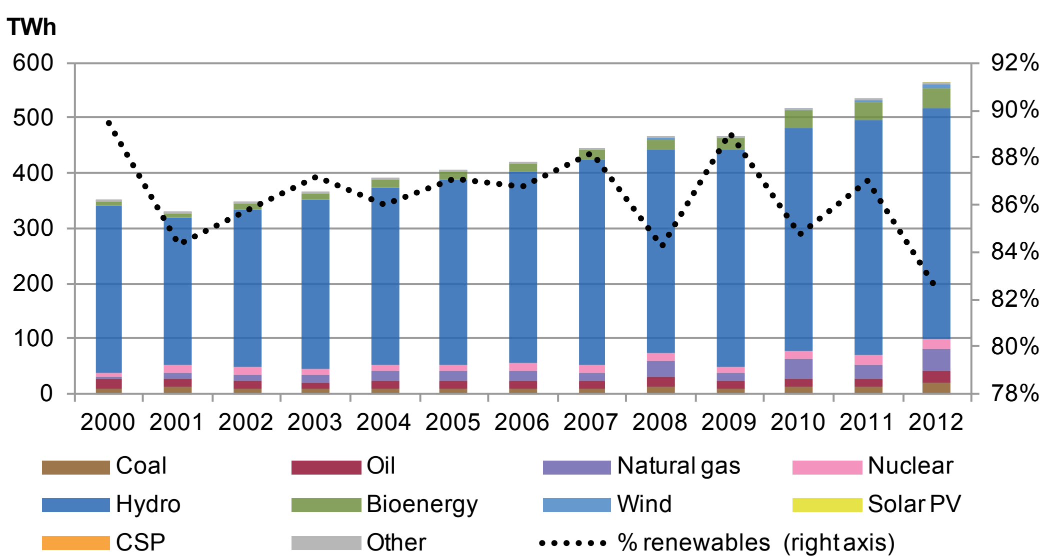

Source: ANEEL, (2013).

## *Power sector structure*

### Generation and capacity

In 2012, hydropower output accounted for around 75% of all generation. Brazil's largest hydropower plant, Itaipu, generated a record output in 2012 with 98 TWh, 4% more than the previous record in 2008. In 2012, bioenergy contributed 6.5% of the overall electricity generation. The contribution of wind and solar PV remained small (< 1% of generation), but both of these sources are expected to grow strongly over the medium term. Brazil installed 1.1 GW of new onshore wind capacity in 2012 with cumulative capacity reaching 2.5 GW. Deployment of solar PV remained negligible in 2012; still, Brazil has good potential to scale up both small- and large-scale solar PV capacity.

**Figure 64** Brazil power generation by source and renewable share of total power generation



Overall, renewable energy should play an increasing role in Brazil's power build-out. The government's Decennial Energy Plan (PDE 2021) sees renewable energy accounting for over 85% of new capacity over 2012-21. Going forward, hydropower additions are slated to account for the bulk of Brazil's overall power generation growth. One example is the Belo Monte hydropower dam (11.2 GW), located in the Amazon region, which – after a number of court decisions – is expected to start coming on line from 2015-16. With good competitiveness versus conventional sources and new power capacity auctions expected in 2013, wind capacity growth is likely to continue at a steady pace. Bioenergy capacity is anticipated to increase by around 50% under the plan. Though solar PV is not yet factored in the PDE targets, the government expects that both small- and large-scale solar PV capacity will expand with improving competitiveness versus other sources.

**Table 54** Brazil power generation capacity targets under the PDE 2021 (GW)

| GW | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|
| Hydropower | 85.2 | 87.6 | 89.2 | 93.5 | 98.2 | 103.0 | 106.8 | 108.9 | 111.8 | 116.8 |
| Nuclear | 2.0 | 2.0 | 2.0 | 2.0 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| Natural gas | 10.4 | 11.4 | 12.1 | 12.1 | 12.1 | 12.4 | 12.4 | 12.4 | 12.4 | 13.1 |
| Coal | 2.8 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 |
| Oil | 4.9 | 6.1 | 9.4 | 9.4 | 9.4 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 |
| Process gas | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Small hydropower | 5.0 | 4.2 | 5.4 | 5.4 | 5.4 | 5.6 | 5.9 | 6.2 | 6.7 | 7.1 |
| Biomass | 8.9 | 9.2 | 9.5 | 9.6 | 9.6 | 9.7 | 10.5 | 11.4 | 12.3 | 13.5 |
| Wind | 2.0 | 5.2 | 7.2 | 8.1 | 9.4 | 9.9 | 11.0 | 12.7 | 14.1 | 15.6 |
| **Total** | **121.8** | **130.6** | **138.5** | **143.9** | **151.4** | **157.0** | **162.9** | **167.9** | **173.6** | **182.4** |

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

Sources: MME, 2012.

### Grid and system integration

Overall, renewable energy is well integrated into the Brazilian power system, which has a high degree of flexibility. Brazil's large hydropower generation and extensive transmission system help to balance the seasonality of bioenergy generation and the variability of wind generation. These latter two sources, in turn, can help to balance hydropower, with strong output during dry winter periods, particularly for onshore wind in the northeast. Over the past year, some grid integration issues have emerged in wind while authorities have taken steps to better integrate solar PV. Some wind projects could not get connected to the transmission grid on time due to delays incurred by several utilities. For example, in May 2012, the major utility company in São Francisco failed to connect over 20 wind farms in the north-east region, which has great wind speed and low turbulence, by the scheduled time period, which was in April. The main reason behind this delay was challenges in obtaining environmental licences for transmission facilities.

In order to avoid such delays, the Ministry of Mines and Energy has introduced several new measures. The 2013 reserve auction authorised by the regulator will be divided into two phases. The first part will be a bidding process for the physical availability of connection points. Competing projects that would be connected at the same point on the grid must compete first amongst one another to ensure the alignment of project capacity with available connection capacity. The winners of this first stage will then compete in the traditional tender. Moreover, the regulator announced that developers that will participate in energy auctions in 2013 will be responsible for the costs and development of grid connections. The implementation of this new regulation may increase total project costs by 7% to 10%, with turbine prices increasing by around 20% (Nielsen, 2013). Certain measures have also been introduced to ease the integration of solar PV. In 2012, the electricity regulator in Brazil (Agência Nacional de Energia Elétrica) announced new rules for net metering for systems less than 1 megawatt (MW), which should help drive distributed solar PV development.

### *Current policy environment for renewable energy*

In recent years, government-sponsored energy auctions have remained the major policy to encourage renewable energy deployment. In these auctions both renewable and conventional generation technologies compete in order to be awarded a long-term (up to 30 years) power purchase agreement (PPA). Projects that meet certain local-content requirements can be supplemented with low-interest loans from the Brazilian Development Bank (BNDES), which are around 50% lower than market rates. Since the *MTRMR 2012*, Brazil has held only one capacity auction. In December 2012, it auctioned 574 MW of capacity with hydropower and wind power largely outbidding gas-fired plants. To date, solar PV has remained absent from the auctions, though it may be included in future tenders as its competitiveness continues to improve. Several auctions may take place during 2013, but their schedule was not available at the time of writing.

**Table 55** Brazil main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Decennial Plan for Energy Expansion (PDE 2021):** Targets for expected installed capacities in 2021: 16.0 GW wind; 116.8 GW large hydro; 13.0 GW bioenergy; 7.0 GW small hydro. | **Auctions of PPAs:** Energy distributors are required to enter into long-term contracts for their electricity demand via a reverse auction system. Auctions have included wind, bioenergy and hydropower.<br>**Brazilian Development Bank (BNDES):** Low-interest loans to a number of renewable projects.<br>**Programme for Incentives for Alternative Electricity Sources (PROINFA):** Capital subsidies, preferential loans and preferential PPAs.<br>**Net metering for distributed systems:** Solar PV, small wind, bioenergy. | **Framework policy:** Decennial Plan for Energy Expansion (PDE 2021); Brazil National Climate Change Plan Plano Brasil Maior.<br>**Grid access and priority dispatch:** Grid access and dispatch guaranteed under PPAs. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

### *Economic attractiveness of renewable energy and financing*

Over the past year, energy auction results indicate that biomass and wind have become even more economically attractive versus fossil fuels while large hydropower remains the most cost-competitive source of power in Brazil, even when factoring in corresponding transmission lines. After the last energy auction held in December 2012, wind developers signed PPAs totalling 282 MW at an average price of BRL 87.94/MWh (USD 44/MWh), 13% lower than the average in 2011 and 41% less than in 2009. These low average tariffs have raised issues around whether the winning wind project developers will be able to secure financing in order to start construction. In practice, it is likely that delivering projects at the most recent low bid prices will be challenging.

Large-scale solar PV, which has to date been absent from the energy auctions, appears to not yet be economically attractive. However, a combination of excellent resources, falling equipment costs, the introduction of a net metering scheme and rising average retail electricity prices in recent years suggest small- and medium-scale solar PV can be economically attractive for self-consumption in some areas. Still, retail price volatility and the cost and availability of financing for households may undermine attractiveness.

Overall Brazil's financing environment supports renewable energy deployment, but some recent changes may raise wind project costs going forward. BNDES plays a major role in financing renewables with low-interest loans that it provides to wind developers that purchase locally produced equipment through the Special Agency for Industrial Financing. In 2012, the bank lent BRL 3.4 billion (USD 1.72 billion) for wind projects, up from BRL 2.3 billion (USD 1.16 billion) in 2011. BNDES expects to provide more loans for renewable energy projects in 2013. Still, increasing local-content requirements on equipment as a requirement for BNDES loans may have an effect on project costs. In January 2013, the bank decided to increase the local-content requirement for wind projects receiving loans from 40% to 60%. Some developers had already faced problems in meeting the previous 40% local-content requirement. The new measure is likely to stimulate greater investment in Brazil's wind manufacturing industry, but this may raise project costs and auction bids in the short term. Higher auction bids may also arise from new integration measures requiring developers to bear the costs of their grid connections.

### *Conclusions for renewable energy deployment: baseline case*

The projection for Brazil is somewhat higher than in the *MTRMR 2012*. With increasingly favourable economics, renewable energy deployment should be driven by strong growth of hydropower, bioenergy and onshore wind power. Renewable electricity capacity should expand from 103 GW in 2012 to 138 GW in 2018. With the Belo Monte hydropower plant in the Brazilian Amazon expected to be fully operational by early 2019, hydropower should grow by 21.5 GW over 2012-18. Onshore wind capacity is expected to grow by 8.5 GW over 2012-18. Still, uncertainties over project viability at the latest low auction prices and construction and grid-connection delays for some projects could weigh upon the outlook. The baseline capacity for bioenergy has been revised up, and cumulative capacity is seen some 4 GW higher versus the *MTRMR 2012*. The forecast for solar PV is also revised up, supported by the introduction of a net metering scheme and falling system costs in the face of relatively high retail electricity prices. Capacity is seen growing from minimal levels in 2012 to over 1.7 GW in 2018.

**Table 56** Brazil renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 90.1 | 91.4 | 92.1 | 93.9 | 98.5 | 103.5 | 108.7 | 112.8 |
| Bioenergy | 7.0 | 8.9 | 9.7 | 9.9 | 11.2 | 11.7 | 12.0 | 12.3 |
| Wind | 1.4 | 2.5 | 4.5 | 6.5 | 8.0 | 9.0 | 10.0 | 11.0 |
| *Onshore* | 1.4 | 2.5 | 4.5 | 6.5 | 8.0 | 9.0 | 10.0 | 11.0 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.6 | 1.0 | 1.7 |
| Solar CSP | - | - | - | - | - | - | - | - |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **98.5** | **102.8** | **106.3** | **110.6** | **118.0** | **124.8** | **131.7** | **137.9** |

Note: RES-E = electricity generated from renewable energy sources.

**Table 57** Brazil main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • government-sponsored power auctions with long-term contracts have encouraged cost reductions, with wind recently outbidding natural gas projects;<br>• large hydropower potential with significant capacity in the medium-term project pipeline;<br>• ample availability of low-cost financing from private sector and development agencies;<br>• high retail electricity prices and net metering support distributed solar PV deployment. | • cost reductions through auctions may increase project vulnerability; head-to-head competition may price out some technologies;<br>• needed streamlining for environmental licensing;<br>• economic attractiveness of large-scale solar PV and exclusion, to date, from auctions. |

### *Renewable energy deployment under an enhanced case*

Certain market enhancements could increase the cumulative capacity of wind power and solar PV in Brazil. For onshore wind, the streamlining of environmental licensing and grid-connection procedures by the government without compromising social and environmental aims could result in an additional capacity. Moreover, the inclusion of floor prices in wind energy auctions could help to better ensure the financial viability of competing projects. Though this move may portend somewhat higher wind auction bid prices, it would also make for more certain financial margins and project delivery, particularly in the event of unexpected development delays. In all, cumulative wind capacity could be 2 GW to 3 GW higher in 2018 versus the baseline case. Significant upside exists 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 be 3 GW to 4 GW higher in 2018.

## China

China sees strong deployment across most renewable sources. Higher growth could arise from better variable renewable integration, institutional reform and more integrated policy approaches.

### *Power demand outlook*

The power demand outlook for China has slowed somewhat since the *MTRMR 2012*, though strong growth is still expected over the medium term. In 2012, China's power demand grew by an estimated 4.7% year-on-year. This rise was more modest than the double-digit average growth rates (+11% to 12% on average) that characterised the previous two years, owing to slower real GDP growth and falling energy intensity. The government's 12th Five-Year Plan (FYP) for Energy sees electricity consumption increasing on average by 8.0% over 2010-15 to reach an indicative target of 6 150 TWh. In line with the IMF, China's real GDP is seen expanding by 8.4% on average from 2012 to 2018. With these variables in mind, this report expects China electricity demand to expand by 5.8% on average over 2012-18, somewhat slower than the 5.9% average growth rate for 2011-17 posited in the *MTRMR 2012*. End-user prices remain regulated by the government and vary by province due to differences in transmission and distribution fees. In mid-2012, China introduced a tiered electricity pricing system for residential users, which raised rates for the largest (20% of household consumers) and could aid in dampening demand growth.

**Figure 65** China power demand versus GDP growth

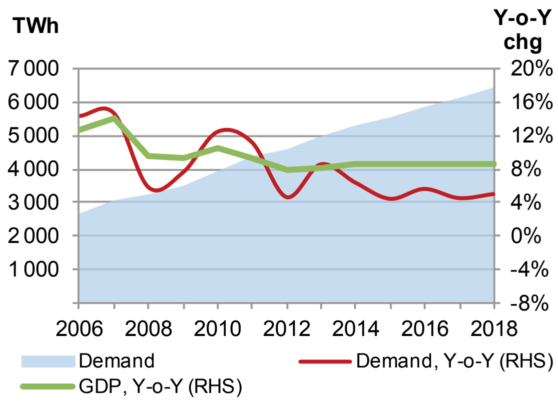
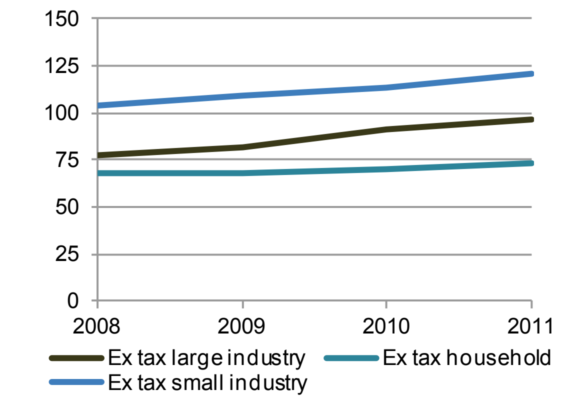



**Figure 66** China average retail power prices (USD/MWh)




Source: IEA analysis based on data from China Electricity Council.

## *Power sector structure*

### Generation and capacity

China's power generation continues to be dominated by coal, but renewable sources led growth in 2012. Good reservoir availability and the commissioning of 16 GW of new capacity boosted hydropower generation by 23% year-on-year, to nearly 860 TWh, almost 18.5% of the total power mix. With 14 GW of new installations bringing cumulative installed capacity to 76 GW, total wind power rose by 35% year-on-year, to 100 TWh (2% of the power mix). Still, the curtailment of wind power was high, at around 20 TWh, and some 20% of cumulative installed capacity had not yet been connected to the grid. With timelier grid connections and better grid operations, wind output could have been higher. Offshore wind remained a modest component, with cumulative capacity around only 0.3 GW. Other renewable sources saw smaller but significant growth – bioenergy generation rose by over 20% year-on-year with 1.0 GW of new capacity, while solar PV generation almost tripled year-on-year, with installations of 3.5 GW. On the conventional side, China's nuclear generation rose by 9% in 2012, while fossil-fuel generation (generation by fuel not available at the time of writing) remained relatively stable. Fossil fuels represented about 78% of the power mix. At the end of 2012, grid-connected power capacity stood at 1 144 GW, with fossil fuels accounting for over 840 GW.

**Table 58** China power generation capacity targets under the FYP (GW)

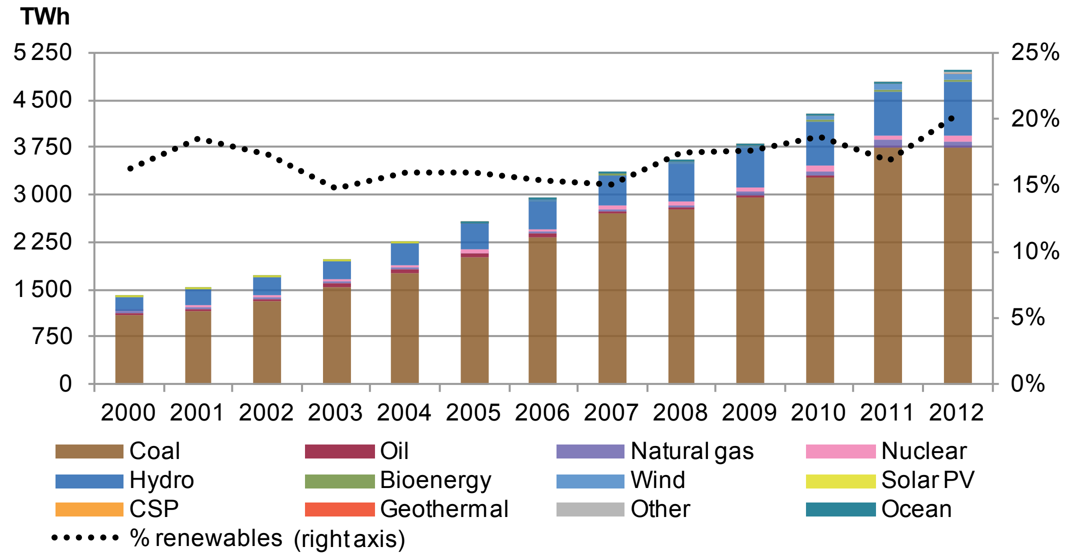
| | 2010 | 2015 | Annual rate of change |
|---|---|---|---|
| Coal | 660 | 960 | 7.8% |
| Gas | 26.4 | 56 | 16.2% |
| Nuclear | 10.8 | 40 | 29.9% |
| Hydropower | 220 | 290 | 5.7% |
| Wind (grid-connected) | 31 | 100 | 26.4% |
| Solar (PV and CSP) | 0.9 | 21 | 89.5% |
| Biomass | 5.5 | 13 | 18.8% |
| **Total power capacity** | **970** | **1 490** | **9.0%** |

Notes: hydropower includes pumped hydro storage capacity. Solar target calls for 20 GW of solar PV (10 GW large-scale, 10 GW distributed) and 1 GW of solar thermal power (CSP).

Source: China State Council, 2013.

Heavy coal-fired generation has increasingly impacted local air quality, with high levels of pollution registered in some cities. Chinese authorities have voiced intentions for conservation, reduced emissions and increased deployment of a portfolio of renewables. In January 2013, the government published its 12th Five Year Plan (FYP) for Energy Industry Development, which set mandatory 2015 targets for non-fossil energy use, energy intensity, carbon intensity and particulate emissions. Indicative targets for power generation capacity see coal's share dipping to around 65% of total capacity even as its level continues to rise. Strong contributions are seen from renewable sources, gas and nuclear. Notably, the solar target may turn out higher – in early 2013 a senior official from the National Energy Administration (NEA) signalled that the capacity target would be raised to 35 GW in 2015. Achieving a commensurate increase in overall renewable generation will be challenging given an electricity market framework which favours the selling of coal generation by grid operators. An announced renewable quota system and further integration measures could be key enablers.

**Figure 67** China power generation by source and renewable share of total power generation




## Grid and system integration

The scale of existing and planned wind and solar PV deployment will continue to pose integration challenges over the medium term. China's grid is still oriented towards the transmission of coal power, which can impede the accommodation of variable renewables. Though regulations require priority dispatch for renewables, coal generation often receives priority in practice in order to meet heat demand with co-generation[9] or for operators to reach their annual operating requirements. Nationwide full-load hours of wind were relatively stable in 2012 versus 2011, but high penetrations of wind power combined with rising conventional generation increased grid congestion and prompted large curtailment of wind power in some northern areas (*e.g.* Jilin, Eastern Inner Mongolia and Gansu). The same phenomenon began to occur in some southern regions, though to a lesser extent, with abundant hydropower. Curtailment of large-scale solar PV has also occurred, particularly in western regions of Qinghai and Tibet. Progress has been made in linking wind installations to the grid, aided by a tighter NEA approval process introduced in 2011. In 2012, an estimated 80% of cumulative wind capacity was grid-connected, versus less than 75% in 2011. Still, implied wind capacity factors for wind in China remained low, based on available generation and capacity data.

[9] Co-generation refers to the combined production of heat and power.

State Grid Corporation of China (SGCC), the grid operator for 26 of China's 31 administrative regions, and China Southern Power Grid Company (CSG) continue to invest in long-distance, ultra-high voltage (UHV) transmission lines to carry power in resource-rich areas in the west to demand centres in the east. The 12th FYP for the Power Grid Industry sees SGCC investing USD 270 billion and CSG investing USD 79 billion through 2015 to update and expand their networks (Interfax, 2013). Still, this build-out will take time, with institutional and financial constraints potentially weighing on expansions. Meanwhile, some wind developers are shifting focus to areas closer to demand centres and those less impacted by grid congestion, such as lower wind-speed sites in the south or offshore (Qi, 2013). Ultimately, the introduction of an announced quota system that requires grid operators to take on renewable power and better grid management will be important drivers for integration.

**Map 4** 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, city or area.

Recent developments have furthered the integration of distributed power, which can help take pressure off centralised power generation assets. In October 2012, SGCC announced it would begin providing technological assistance and waived fees for grid connections for solar PV systems less than 6 MW. Further announcements expanded this policy to other energy sources and indicated that SGCC would provide meters for net metering, waive backup power fees (for small-scale solar PV and wind) and grant grid-connection permissions in a timely manner (25 working days for solar PV; 40 days for other sources) (Wang, 2013). These moves, combined with announced generation incentives for self-consumption, should act as a major enabler for residential and commercial solar PV deployment. Still, some challenges remain, including the application of these policies in practice on a nationwide basis and the negotiation of suitable rooftops between developers and building owners.

### *Current policy environment for renewable energy*

Over the past year, the policy environment has evolved in a generally supportive fashion, though developments carry some uncertainty in the near term. Deployment of renewable power sources in China is still driven by official governmental targets published in the FYPs. Feed-in tariffs are in place for onshore wind, solar PV and bioenergy generation. Power producers receive the tariffs as capped feed-in premiums (FIPs) 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. The government is drafting a policy to establish a non-hydro renewable energy quota requirement, which would vary by province and would create formalised obligations for renewable generation and supply for utilities, grid operators and local governments. Still, the quota policy has yet to be finalised, and implementation details are uncertain at the time of writing.

**Table 59** China main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **12th FYP for Renewable Energy Development:**<br>11.4% of non-fossil resources in primary energy consumption by 2015 (and 15% by 2020).<br>Indicative cumulative capacity targets:<br>290 GW hydro by 2015 and 420 GW by 2020 (incl. pumped storage);<br>100 GW wind by 2015 and 200 GW by 2020 (of which offshore: 5 GW by 2015 and 30 GW by 2020);<br>21 GW solar by 2015 and 50 GW by 2020 (of which solar thermal – 1 GW by 2015 and 3 GW by 2020);<br>13 GW biomass power by 2015 and 30 GW by 2020;<br>100 MW geothermal and 50 MW ocean by 2015. | **Feed-in tariffs:**<br>Apply to onshore wind, solar PV and biomass. Effectively they are FIPs over province-specific prices of coal-based power.<br>**Incentives for small-scale generation:**<br>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 FIP on top of net metering for self-consumption and a FIP to the local coal-benchmarked price for electricity fed into the grid.<br>**Golden Sun programme:**<br>Subsidies per watt installed to grid-connected and off-grid solar PV projects.<br>**Import duty & value-added taxes removal:**<br>Applies to key technological equipment, including hydro and wind equipment. | **Strategic planning:**<br>Offshore Wind Development Plan.<br>**Grid access and priority dispatch:**<br>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. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

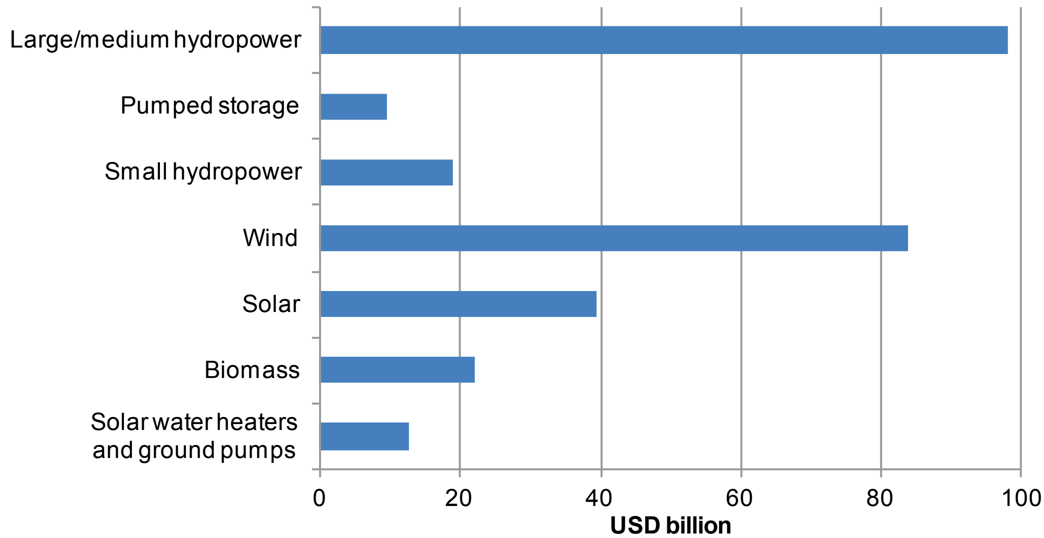
Other developments have focused on balancing policy cost-effectiveness with increased deployment of small-scale systems and the absorption of some of China's large solar PV manufacturing capacity. In late 2012, the government approved 2.8 GW of new small-scale solar projects under the Golden Sun programme, which provides capital subsidies for up-front system costs. Concerns over the durability of the programme have arisen given difficulties in project monitoring and assuring quality control. At the time of writing, there was no official word over the continuation of the programme beyond 2013.

Meanwhile, the government is drafting a new feed-in tariff (FIT) policy for large-scale solar PV and new generation-based incentives for distributed systems. Projects under the former would bid for 20-year FITs; benchmark incentives would now be differentiated by region, with some set lower than the current uniform national FIT, to reflect resource availability. Distributed solar PV systems would receive a FIP on top of net metering for self-consumption and a FIP to the local coal-benchmarked price for electricity fed into the grid. By better tying incentives to generation, together these measures are likely to improve overall solar project quality as they stimulate new deployment. Still, policy implementation timing and details remain uncertain at the time of writing.

## *Economic attractiveness of renewable energy and financing*

Though non-hydro renewable generation costs are still generally higher than coal-fired generation, the levels of FITs should make them economically 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. This situation would improve with the introduction of a renewable quota system, effectively offering a better guarantee of operating hours for renewable projects, particularly for onshore wind. Still, it is difficult to evaluate the extent of this driver without further details on the nature of the obligation and enforcement mechanisms.

**Figure 68** China renewable energy investment during the 12th FYP, 2011-15




Note: USD = 6.33 CNY.

Source: China NEA, 2012.

The economic attractiveness of self-consumption from solar PV appears to be improving with the introduction of grid access measures, announced financial incentives and a continued fall in system prices. For commercial entities and high-consumption households, which face relatively higher end-user prices, small-scale solar PV is likely to compete well versus retail power prices over the medium term. By contrast, the economic attractiveness of the relatively less mature technologies CSP and offshore wind has improved relatively little. Both areas face supply chain constraints and limited deployment experience.

China's financing environment should continue to enable renewable energy development. In 2012, investment in renewable energy rose to about USD 68 billion, from USD 57 billion in 2011. Investment needs for renewable generation are large, with requirements under the FYP implying USD 57 billion annually over 2011-15, including renewable heat. Domestic banks act as a significant source of loans; foreign investors play a role mainly in joint ventures with Chinese partners. As part of the government's list of strategic industries, "New Energy" technologies benefit from perceived lower risks and a degree of prestige for investors. As such, Chinese banks compete strongly with one another to finance renewable energy projects, which consequently benefit from attractive financing terms. Regional banks can further enhance terms with projects to be built in their region. Overall, the liquidity position looks favourable for renewable energy deployment in China. Still, the administrative push that renewable energy enjoys may increase risks that even non-viable projects get financed.

In addition, the China Development Bank offers low-interest loans to both renewable generation projects and associated manufacturing. Finally, international development banks, notably the World Bank (through the China Renewable Energy Scale-up Programme) and the Asian Development Bank, add a further layer of funds. However, this financing tends to go to demonstration and scale-up programmes. At present these focus on small biomass, biogas and CSP projects, helping these technologies to bridge pre-commercialisation funding gaps.

### *Conclusions for renewable energy deployment: baseline case*

China's generation needs as well as a favourable policy environment should drive strong renewable growth over the medium term. Renewable capacity is seen growing by almost 310 GW as it rises from 340 GW in 2012 to almost 650 GW in 2018. This forecast is more ambitious than the 12th FYP targets, notably for onshore wind and solar PV. It also assumes the implementation of a renewable quota system, which will act as a driver for the improved integration of renewable generation, and that the new, draft solar PV generation incentives will come into force sometime in 2013. Still, the development and operation of the grid as well as a general lack of robust and functioning market signals in the power sector will act as challenges.

**Table 60** China renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 233.0 | 248.9 | 270.0 | 285.0 | 300.0 | 320.0 | 340.0 | 360.0 |
| Bioenergy | 7.0 | 8.0 | 10.0 | 13.0 | 16.0 | 19.0 | 22.0 | 25.0 |
| Wind | 62.7 | 75.7 | 91.8 | 109.8 | 129.1 | 149.6 | 171.3 | 193.3 |
| *Onshore* | 62.4 | 75.3 | 91.3 | 108.3 | 126.3 | 145.3 | 165.3 | 185.3 |
| *Offshore* | 0.3 | 0.4 | 0.5 | 1.5 | 2.7 | 4.2 | 6.0 | 8.0 |
| Solar PV | 3.5 | 7.0 | 14.5 | 25.0 | 35.0 | 46.0 | 57.0 | 69.0 |
| Solar CSP | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.6 | 1.0 | 1.4 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Ocean | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| **Total RES-E** | **306.2** | **339.6** | **386.5** | **433.1** | **480.5** | **535.3** | **591.5** | **648.9** |

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

The projection in 2017 is seen 17 GW higher than in the *MTRMR 2012*, due to upward revisions in solar PV. The significantly stronger outlook for solar PV stems from a combination of a stronger policy push, improved financial incentives and grid access for small-scale projects. Solar PV is seen growing by 62 GW over 2012-18. The outlook for other technologies has changed only modestly versus the *MTRMR 2012*. Onshore wind is seen expanding by 110 GW (installed capacity) from 2012 to 2018. Future developments will likely include increased additions away from grid-congested areas in the north, at relatively lower wind-speed areas closer to demand centres in the south. While grid-connected capacity will still remain below the cumulative installed capacity in the near term, this differential is expected to narrow over time. Grid expansions and the adoption of a renewable quota system should help improve project generating hours over time. China's offshore wind plans remain ambitious, given current, low deployment levels. The offshore wind policy environment remains complex, given the governance of offshore areas involving multiple government agencies. In general, developments are moving farther from the coast to comply with regulatory rules. Capacity growth is likely to remain less than 8 GW over 2012-18 due to supply chain and construction challenges.

Hydropower additions over the medium term are expected to remain robust, in line with FYP targets. Notably, China's second-largest hydropower plant, Xiluodo (12.6 GW), is expected to come on line over 2013-14. Additions in bioenergy for power, at 17 GW, remain small with respect to the scale of China's system, but are strong in the context of global bioenergy growth. The forecast is somewhat lower than in the *MTRMR 2012* due to slower-than-expected additions in 2012 and public acceptance challenges for waste-to-energy plants. Still, renewable waste-to-energy plants are likely to play an important role in development, given limited landfill space in many Chinese cities. Other technologies – CSP, geothermal and ocean – are expected to grow only modestly. CSP's contribution, if realised, would be large on a global scale (over 10% of cumulative global capacity).

**Table 61** China main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • strong government backing through FYPs with expected implementation of a renewable quota system;<br>• eased rules for grid connections and announced generation incentives for small-scale projects;<br>• ample availability of low-cost financing;<br>• robust, dedicated manufacturing and technology development. | • lack of market pricing, in general, and priority dispatch, in practice, for renewable generation;<br>• grid planning and upgrading to integrate increased variable renewable power;<br>• supply chain bottlenecks and lack of deployment history for less mature technologies, *e.g.* offshore wind and CSP. |

## *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 the anticipated creation of a renewable quota system and improved grid connections, licensing procedures and financial incentives for distributed generation. Still, further implementation details, including enforcement mechanisms, on the quota system are needed. Moreover, China's deployment environment would 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 remains the same under both the enhanced and baseline cases. Better progress on-grid upgrades and faster offshore development could spur an additional 8 GW of wind capacity (onshore and offshore combined) by 2018. Faster-than-expected uptake in distributed systems could translate into over 100 GW of cumulative solar PV by 2020, implying an additional 5 GW by 2018. By contrast, the upside for CSP in 2018 looks more limited at 0.4 GW – even with a push for more flexibility and storage into the grid, 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.

## India

India sees strong renewable energy deployment across a portfolio of renewable sources. Policy uncertainties and grid integration challenges weigh upon the outlook, however.

### *Power demand outlook*

Buoyed by robust economic and population growth, India's power demand should expand strongly over the medium term. The latest IMF outlook sees Indian real GDP growing on average by 6.5% annually over 2012-18. Power demand is forecast to increase by 5.9% annually over 2012-18. Demand continues to be constrained overall by supply availability. 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 power capacity. India also continues to suffer from high supply and distribution losses. Through January 2013, the Central Electricity Authority (CEA) reported that the power sector fell short on average by 9.0% in meeting peak demand (135 GW) for fiscal year (FY) 2012/13. While still high, this figure is lower than the 10.9% shortfall versus the peak (128 GW) over the same period in FY 2011/12.

**Figure 69** India power demand versus GDP growth

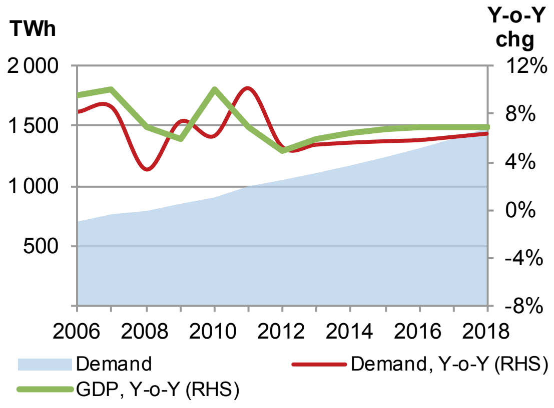
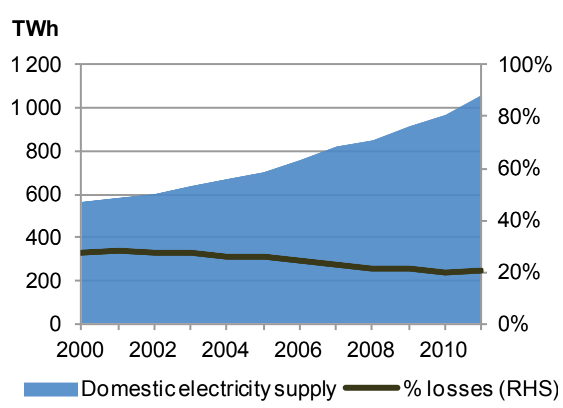



**Figure 70** India domestic electricity supply and distribution losses

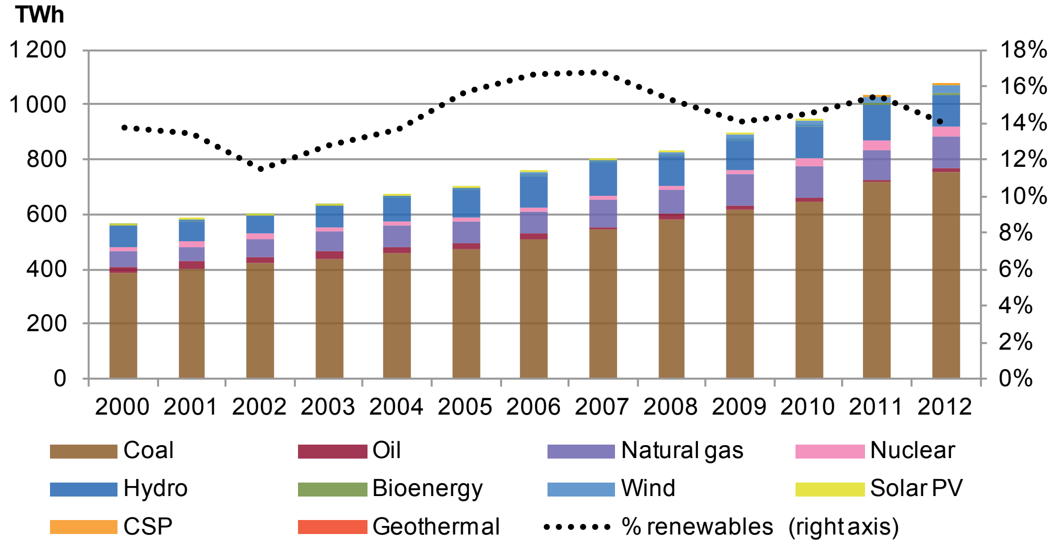



### *Power sector structure*

#### Generation and capacity

India's power capacity, both renewable and non-renewable, is expanding strongly to try to meet its demand needs. As of December 2012, total power capacity stood at 210 GW, up from 187 GW a year prior. Still, actual generation remains constrained relative to installed capacity. Fossil fuels continue to dominate capacity additions, but rising needs for relatively costly imported coal and liquefied natural gas make generation from these sources economically tenuous in the face of regulated end-user prices. In FY 2012/13, fossil fuels accounted for over 80% of total generation. Hydropower, the largest renewable source, saw its share drop to 10%, with low reservoir levels causing generation to decline by 13% year-on-year. A combination of insufficient coal and natural gas generation, reduced hydropower availability, and ineffective load management contributed to the large-scale power outages that affected the northern part of the country in July 2012.

**Figure 71** India power generation by source and renewable share of total power generation




Notes: data refer to fiscal year (April to March); 2011 data are estimated based on monthly data of CEA.

Wind power has continued to expand robustly. In FY 2012/13, it accounted for 2.7% of generation as installed capacity rose from 16.1 GW in December 2011 to 18.4 GW in December 2012. Still, capacity additions slowed during the year – only 1.7 GW were added during FY 2012/13 to reach a cumulative capacity of 19.1 GW by April 2013 – with the expiration of some key financial incentives. Bioenergy grew to 2.8% of total generation as capacity rose by 0.6 GW during the calendar year 2012, mostly from additions in biogass-fired co-generation. Solar PV remained small but its capacity rose by almost 0.8 GW. While CSP remained small in 2012, larger additions are expected in 2013 with the start of delivery of phase 1 projects under the Jawaharlal Nehru National Solar Mission (JNNSM). Off-grid renewable systems (included in total renewable capacity data) are playing a growing role in helping to electrify rural areas and meet captive industry needs. As of December 2012, combined off-grid biomass and biogas capacity stood at almost 0.6 GW, while off-grid solar PV topped 0.1 GW.

Over the medium term, India's 12th FYP (final draft released in December 2012) foresees an increase in total, grid-connected generation assets of over 118 GW, with 11 GW coming from large hydropower and 30 GW from other renewable sources (outside of large hydropower), by 2017. Notably, additions in relatively flexible gas-fired generation are seen at only 2.5 GW. Private investment will be a major key to achieving these goals, particularly given the cash-strapped positions of state generation companies, many of which are unable to recoup their generation costs through the electricity pricing system. Development of renewable sources, which largely exceeded deployment goals under the 11th Plan, has mostly occurred via private sector entities. The 12th Plan sees nearly 53% of new total capacity coming from private sector investment versus an expectation of only 19% under the 11th Plan.

**Table 62** India power generation capacity targets under the FYPs (GW)

| | 11th Plan, FY 2007/12 Targeted additions | 11th Plan, FY 2007/12 Achieved additions | 12th Plan, FY 2012/17 Targeted additions |
|---|---|---|---|
| Thermal (coal and gas) | 59.6 | 48.5 | 72.3 |
| Nuclear | 3.3 | 0.8 | 5.3 |
| Large hydropower | 15.6 | 5.5 | 10.8 |
| Wind | 9.0 | 10.2 | 15.0 |
| Solar | 0.1 | 0.9 | 10.0 |
| Other renewables | 3.1 | 3.5 | 5.0 |
| **Total power capacity** | 90.9 | 69.5 | 118.5 |

Source: Planning Commission, 2012.

### Grid and system integration

The upgrade and expansion of India's grid will continue to represent a significant challenge to the integration of renewable generation over the medium term. In 2012, the government's Power Grid Corporation, which develops and manages inter-state transmission, announced its "Green Energy Corridors" strategy that seeks to invest around USD 8 billion in the grid through 2017. About 44% of this investment will go towards the inter-state transmission system, with 48% directed to state-level grids, which are relatively finance constrained, and 5% to energy storage (Power Grid Corporation of India, 2012). Delays in grid connections and increasing grid congestion have contributed to slowing expansion in India's largest wind power state, Tamil Nadu (Chakrabarti and Das, 2013). Grid infrastructure investments, combined with planned upgrades in forecasting, scheduling and grid operations through the establishment of dedicated Renewable Energy Management Centres over the longer term, will be crucial to facilitating higher levels of variable renewable generation.

To date, most large-scale solar development has occurred in PV, which sees its highest output in the early afternoon. However, demand peaks in Gujarat and Rajasthan, where India's best solar resources are located, typically occur in the evening. The planned development of CSP with storage in these regions may help enhance load matching and grid flexibility. Small-scale solar PV, biomass and biogas development are helping to meet rural electrification needs through off-grid applications, though their deployment will remain smaller than on-grid systems. Distributed solar PV deployment requires upgrades in local grids and distribution networks, which suffer high levels of power losses, and would benefit from net metering, which has recently been introduced in Tamil Nadu.

## *Current policy environment for renewable energy*

The renewable energy policy environment remains supportive, but has experienced some volatility over the past year. The clarification of the 12th FYP targets at the end of 2012 boosted expectations of renewable additions versus the draft plans reported in the *MTRMR 2012*. The policy framework for solar was reinforced with the release of the draft policy for phase 2 of the JNNSM, which aims for a cumulative 10 GW grid-connected and 1 GW off-grid solar by 2017. CSP is to account for 30% of installations and 40% of the grid-connected capacity is to be developed under the central JNNSM, with state schemes responsible for the rest. The central government has proposed a 1.65 GW tender for solar PV in FY 2013/14 with bidding for 1.1 GW of CSP in FY 2014/15. Auctions would be supported by an expanded set of financial incentives, including capital grants under the Viability Gap Funding (VGF) scheme. Nine state governments have adopted solar policies and some have launched capacity tenders, though these have experienced some initial hurdles in execution.

**Table 63** India main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **General targets:**<br>Share in power by end of 12th FYP (2012/13 to 2017/18): 9% renewable power (excluding large hydropower). 12% large hydropower. | **FITs:**<br>At state level; for bioenergy, wind, small hydro, solar PV and solar thermal. | **Framework policy:**<br>2003 Electricity Act; 2005 National Electricity policy. |
| **Renewable portfolio obligation (RPO):**<br>Set at state level based on national goal of 15% of power generation from renewables by 2020.<br><br>**JNNSM:**<br>By 2013: 1.1 GW of grid-connected solar, 0.2 GW of off-grid solar (including solar lanterns), 7 million square metres ($m^2$) solar collectors.<br>By 2017: 10 GW grid-connected solar, 1 GW off-grid (with lanterns), 15 million $m^2$ solar collectors.<br>By 2022: 20 GW grid-connected solar, 2 GW off-grid (with lanterns), 20 million $m^2$ solar collectors. | **RPOs with tradable certificates mechanism:**<br>National obligations for minimum amount of renewable electricity as well as for minimal amount of solar electricity; certificates for renewable generation are delivered and can be traded to comply with the obligation.<br><br>**Preferential tariffs and tax exemptions:**<br>JNNSM. | **Grid access and dispatch priority:**<br>All renewable sources except for biomass plants above 10 MW have dispatch priority. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

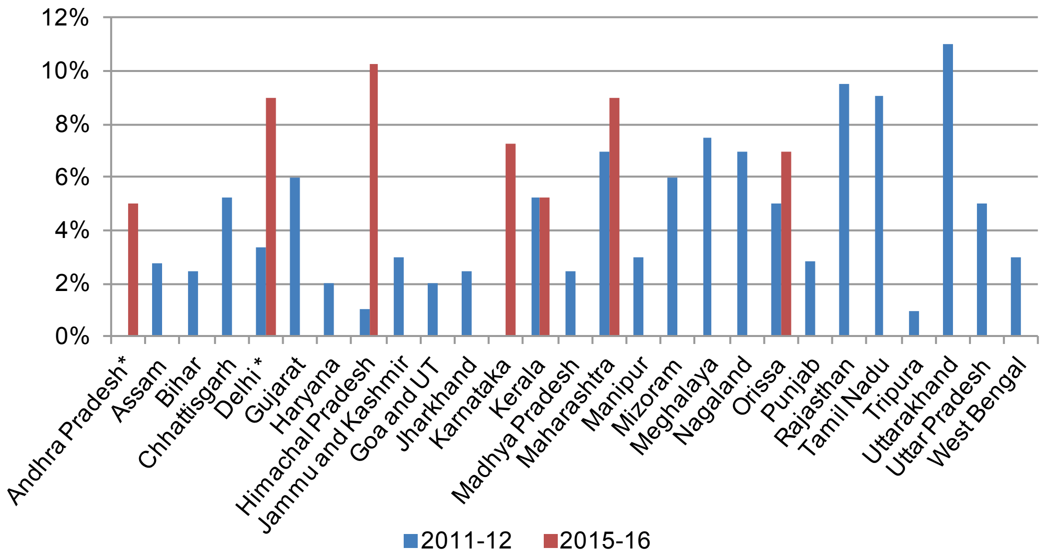
The robustness and predictability of policy frameworks in other areas has been tested. The expiration of the Generation Based Incentive (GBI) and the reduction of accelerated depreciation incentives for wind at the beginning of FY 2012/13 slowed wind deployment through the year. The government announced the reinstatement of the GBI for FY 2013/14, but its implementation and long-term durability remains uncertain. The RPO with tradable certificates scheme also faces challenges, including uneven participation by states and weak enforcement of utility purchase obligations. Implementation hurdles have translated into oversupply for non-solar renewable energy certificates (RECs). In early 2013, the central government extended the validity of RECs issued after November 2011 to two years and was seeking to step up enforcement of utility purchase obligations.

### *Economic attractiveness of renewable energy and financing*

Overall, renewable deployment remains economically attractive, but with challenges in some areas. Falling system costs have improved the economic attractiveness of solar PV over time. The JNNSM phase 1 auctions awarded power purchase contracts at prices (USD 0.14 per kilowatt hour [/kWh] to USD 0.17/kWh) only somewhat higher than electricity prices paid by large industrial and commercial entities in some Indian states. A 100 MW tender in Rajasthan in early 2013 featured a bid as low as INR 6.45/kWh (USD 0.12/kWh), though there is uncertainty over how viable such pricing is for development (Bridge to India, 2013). Some market analysts see the generation costs of solar PV at parity with wholesale power prices by 2017-19, with commercial-scale rooftop installations at parity with commercial end-user prices sooner (KPMG, 2012). The government sees solar PV generation costs at parity with wholesale prices by 2017-18 and with coal-fired power by 2025 (MNRE, 2012).

Still, high debt financing costs and the potential inclusion of thin film modules in domestic content requirements under the JNNSM could slow attractiveness gains for solar PV. Higher technology costs and a limited deployment track record in India pose a challenge for the economic attractiveness of CSP projects. Moreover, attractiveness for all solar projects may vary with the level of government interaction. In general, tenders and incentives under the central JNNSM scheme have carried less risk than state-level schemes, which have more limited deployment history and higher counterparty payment risks due to the economic situation of some state utilities. Policy execution at the state level will be important to maintaining economic attractiveness for solar over the medium term.

**Figure 72** India state-level RPOs, selected years




* Indicates draft RPO.

Note: absence of bar for a given year implies no RPO issued.

Source: Nelson *et al.*, 2012.

For wind, the outlook is more favourable than in the *MTRMR 2012*, assuming the ultimate implementation of the GBI in FY 2013/14. However, its duration beyond the current fiscal year remains unclear. Wind projects also benefit from tradable renewable credits under India's RPO. Unfortunately, an oversupply of certificates amid weak state-level RPO enforcement has depressed non-solar REC prices; as of February 2013, prices remained at their floor levels (~USD 28/MWh) for the seventh consecutive month (by contrast, solar REC prices have been more robust). Attempts at greater enhancement of long-term REC pricing may augment the economic impact of this mechanism over the medium term. In the meantime, wind projects can, for now, benefit from generally attractive state-level FITs.

Renewable electricity investment fell from around USD 12.5 billion in 2011 to under USD 7 billion in 2012, partly due to some of the policy-related challenges described above. While the equity financing environment is generally good, debt financing costs remain high (*i.e.* interest rates above 10%) compared with more developed markets due to high general interest rates and an underdeveloped project finance market. A study from the Climate Policy Initiative has found that financing costs can raise the levelised cost of electricity for solar PV and wind by 28% and 22%, respectively, versus similar, United States-based projects (Nelson *et al.*, 2012). Other sources, such as concessional loans from the Indian Renewable Energy Development Agency (IREDA), new grants under the JNNSM, increased grants for waste-to-energy projects and loans from international development banks should enhance investment. Still, the cost and availability of financing should pose a challenge for projects over the medium term.

## *Conclusions for renewable energy deployment: baseline case*

Fast-rising power needs and targeted policy support for a portfolio of renewable energy should encourage strong deployment of both on- and off-grid renewable capacity. However, India's generally high cost of debt financing, the capabilities of the power grid and the economic viability of state utilities, which are important for grid investment and the performance of state-level policy schemes, act as significant challenges. The predictability of policy initiatives and the robustness of policy execution will remain key variables for the deployment trend. To this end, planned reforms under the 12th FYP should act as an important driver.

Over 2012-18, cumulative renewable capacity should expand by over 40 GW. Capacity in 2017 is seen similar to the *MTRMR 2012*, with an upward revision to solar PV balancing a lower onshore wind outlook. Though onshore wind growth looks strong, at 16 GW over 2012-18, grid integration challenges, the uncertain implementation and duration of the GBI and the relatively weak state of current REC pricing bring caution to the outlook. The hydropower outlook (large and small) is largely in line with FYP expansion goals. However, it is worth noting that India's hydropower deployment fell short of deployment goals under the 11th FYP. As such, this forecast carries downside risks. Bioenergy is also expected to follow government plans, with increased bagasse-fired co-generation and off-grid applications.

**Table 64** India renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 41.6 | 42.8 | 44.9 | 48.2 | 50.4 | 52.3 | 54.7 | 55.9 |
| Bioenergy | 3.6 | 4.2 | 4.4 | 4.6 | 5.0 | 5.4 | 5.7 | 6.0 |
| Wind | 16.1 | 18.4 | 20.2 | 22.4 | 25.4 | 28.4 | 31.4 | 34.4 |
| *Onshore* | 16.1 | 18.4 | 20.2 | 22.4 | 25.4 | 28.4 | 31.4 | 34.4 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.2 | 1.3 | 2.1 | 3.6 | 5.1 | 6.8 | 8.8 | 10.8 |
| Solar CSP | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.4 | 0.5 | 0.6 |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | - | - | - | - | - | 0.0 | 0.0 |
| **Total RES-E** | **61.5** | **66.8** | **71.6** | **79.1** | **86.2** | **93.4** | **101.2** | **107.8** |

Solar PV capacity (including off-grid) is seen expanding by over 9.5 GW from 2012 to 2018, led by utility-scale additions under the JNNSM. Rooftop applications grow faster in the second half of the forecast period, with increasingly attractive economics supporting deployment for commercial captive use. The outlook for CSP remains more tepid. Though the forecast 0.6 GW of additions over 2012-18 would represent significant growth on a global scale, they are less than development plans and auctions would suggest. This more conservative outlook stems from delays to current projects, lack of deployment experience in India and still relatively high technology costs.

**Table 65** India main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • supportive policy environment with FYP targets, JNNSM and financial incentives;<br>• fast-growing electricity demand amid tenuous generation economics for fossil-fuel plants;<br>• captive and rural electrification needs support distributed solar PV deployment. | • stop-and-go policymaking and uneven policy execution can undermine incentive schemes;<br>• high distribution losses and regulated prices often do not cover supply costs, leaving many state utilities unable to make investments.<br>• significant grid strengthening and expansion needed to reinforce power system in general;<br>• high cost of debt financing. |

### *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 2018, 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 attractive self-consumption economics. There is also significant upside for CSP. With better project delivery and cost reductions, the fulfilment of the government's plans for solar thermal power under the JNNSM suggests CSP capacity could be 2 GW to 3 GW higher in 2018 than shown in the forecast above.

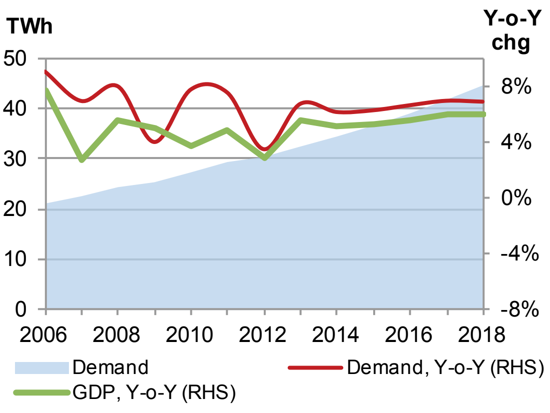
## Morocco

Strong growth for wind and CSP over the medium term through renewable energy tenders. Grid access and lack of financial incentives remain barriers to small-scale solar PV deployment.

### *Power demand outlook*

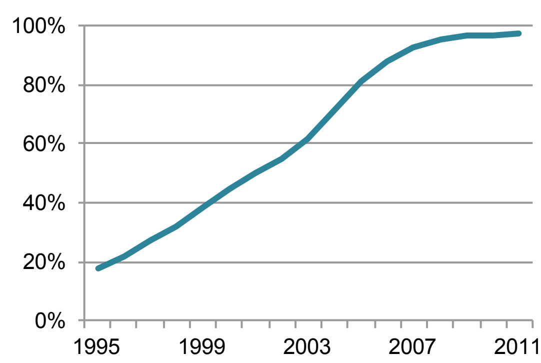
Morocco's economy boomed in recent years, with real GDP growing on average by 4.1% over 2006-12. A similar trend was observed in Morocco's power demand, which grew at an even stronger annual rate of 5.2% over the same period. Demand growth was driven by increased electrification of a growing population. Electrification rates rose from 18% in 1994 to almost 97% in 2011. In order to meet the demand, Morocco imported 15% of the power supply in 2011, almost entirely from Spain. Going forward, electricity demand is expected to grow by 6.6% annually over 2012-18, based on annual GDP growth of 5.2% over that period. Peak load was around 5 GW in 2012 and peak demand occurs in the evening, after sunset. Electricity prices are regulated by the government and do not fully cover generation and transmission costs. Furthermore, the government subsidises imported fossil fuels, including liquefied petroleum gas (LPG), diesel oil, gasoline and fuel oil. Pricing varies by consumer type and consumption level. Residential power prices, which are divided into four levels of consumption, averaged MAD 1 230 (~USD 140)/MWh in 2012. Despite rising fuel costs, residential fuel prices remained constant in recent years while industrial prices have increased to reflect the increase in generation costs.

**Figure 73** Morocco power demand versus GDP growth




Notes: demand is expressed as electricity supplied to the grid.

**Figure 74** Morocco rural electrification rate




Source: ONEE, 2012.

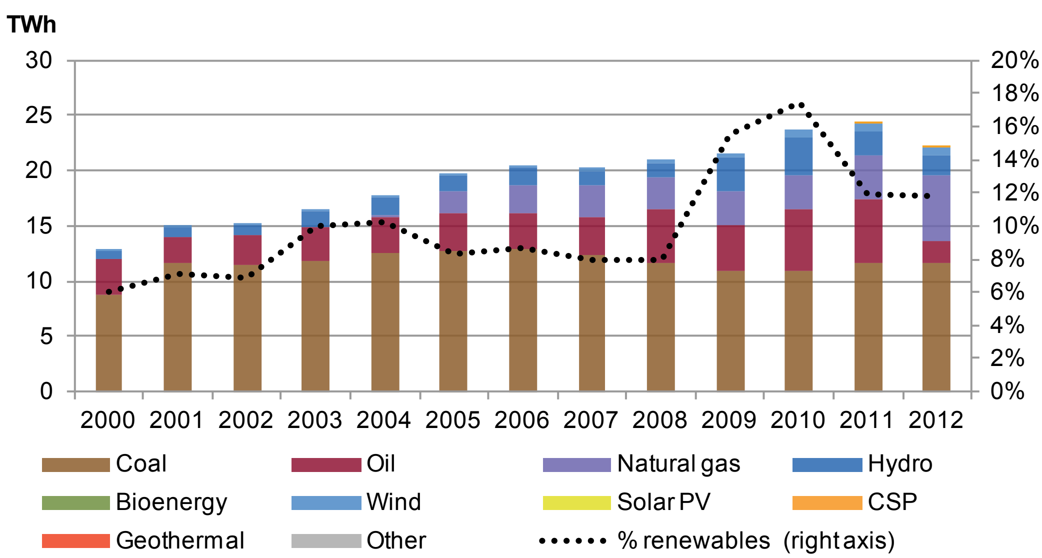
### *Power sector structure*

#### Generation and capacity

Morocco's power generation is heavily dependent on fossil fuels. In total, fossil fuels, mostly imported, made up almost 90% of Morocco's power generation in 2012. Coal and oil made up about 90% of the generation until 2005, when generation from natural gas began. The share of gas-fired power has since grown to 27% in 2012. Gas has displaced some coal generation as well as oil, whose share decreased to 9% of power generation in 2012. Renewable sources accounted for 12% of generation in 2012, a lower level than the 17% registered in 2010, which reflects the large role of hydropower and the impacts of its variability on the share of renewable generation. Generation from hydropower was 14.7% of electricity generation in 2010 and dropped to 8.8% in 2011 and 8.2% in 2012 because of lower precipitation levels. At present, 27 hydropower plants total 1 770 MW, 464 of that in Afourer's pumped storage plant. Wind, at 3.3%, accounted for much of the remaining renewable generation in 2012. Onshore wind cumulative capacity (at 0.3 GW in 2012) has more than tripled since 2006, primarily due to recent supportive policy changes to encourage more private investment. Completing the renewable portfolio was generation from one of the first integrated solar combined cycle (ISCC) plants in Africa, which combines 20 MW of CSP capacity with a gas-fired power plant that was commissioned in 2010. In 2012, total power capacity stood at 6.7 GW versus peak demand of 4.9 GW, which is largely met from costly oil-fired generation.

Going forward, strong demand growth and a desire to reduce dependency on fossil fuels are likely to drive strong renewable growth. Morocco is endowed with excellent wind and solar resources, and the government has announced ambitious plans to utilise these assets. Several large onshore wind projects are being developed; notably, the 300 MW Tarfaya wind farm expected to be Africa's largest should come on line in 2014. Additional projects should emerge over the medium term from the 1 000 MW Integrated Wind Project, launched by the government to achieve a wind target of 2 GW by 2020. CSP is expected to grow as several phases of Ouarzazate, the country's first project under the Moroccan Solar Energy Plan, progress. To date, solar PV deployment has been small and limited to off-grid applications and a handful of grid-connected projects. Thus far, private producers have not been allowed to connect to the low-voltage grid.

**Figure 75** Morocco power generation by source and renewable share of total power generation



### Grid and system integration

Over the medium term, Morocco's grid should present moderate constraints to the integration of renewables, particularly access to distributed capacity. In 1994, the production of electricity was deregulated and independent power producers (IPPs) were allowed to produce electricity and sell generation to the former state-run Office National de l'Electricité et de l'Eau Potable (ONEE). Currently, the electricity can be sold to the ONEE, to a customer or group of customers committed to take it for own use, or for export purposes. IPPs now account for almost half of generation. ONEE maintains full ownership and operation of the transmission network. There are plans to establish a regulating authority in 2014. The country has a 1.4 GW interconnection with Spain, which could ultimately be used for exporting renewable electricity to Europe. Still, domestic energy needs, generation overcapacity in Spain and limited interconnection between the Iberian peninsula and the rest of Europe in the near term suggests this may be a more viable option only over the long term.

Morocco's north-south grid orientation can present a challenge to the grid integration of renewables in remote areas, but ongoing developments should help alleviate this over time. ONEE has expanded the transmission grid on average by 2.5% annually over the past five years. Part of this extension was driven by Morocco's efforts to increase rural electrification, but also to supply areas of increased industrial activity. Further extensions to the grid are planned over the medium term. In particular, a high-voltage backbone line is to be extended along the coast to connect demand centres with the renewable resource areas in the south. Such a development would require significant investment.

**Table 66** Morocco main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Energy Plan 2020:** 42% of installed capacity from renewables by 2020; 2 GW of solar capacity by 2020; 2 GW of wind capacity by 2020; 2 GW of hydro capacity by 2020; | **Moroccan Solar Energy Plan (MSP):** Aims to install 2 GW of new solar capacity by 2020 with five identified sites: Ouarzazate, Ain Beni Mathar 2, Sebkate Tah, Foum Al Ouad, Boujdour<br><br>**Wind Energy Program:** Aims to install 2 GW of wind capacity by 2020, of which 1 000 MW fall under the "1000 MW Integrated Wind Energy Program" with five identified sites in two phases: Phase 1 – Taza (150 MW), Phase 2 – 850 MW in Tangier II (150 MW), Koudia Al Baida II (300 MW), Tiskrad (300 MW), Boujdour (100 MW).<br><br>**National Energy Development Fund (FDE):** Provides financial support to renewable energy projects.<br><br>**Hassan II Fund for Economic and Social Development (FHII):** Provides financial support to investors: up to 30% of building costs or up to 15% of equipment purchase costs for new investment projects over MAD 10 million.<br><br>**Société d'Investissements Energétiques (SIE):** Facilitates financing for renewable energy projects. | **Framework policy:**<br><br>**National Energy Strategy (NES) 2020-2030:** Adopted in 2008 with objective to increase share of renewable energy and energy independence. Established Solar and Wind Energy Programmes.<br><br>**Renewable Energy Law 13.09:** In force since 2009, allows the production of renewable energy for self-consumption and stipulates conditions for which private producers can export electricity back to the grid.<br><br>**Major Institutions:**<br><br>**Moroccan Solar Energy Agency (MASEN):** Established by Law 57-09 tasked with implementing the MSP.<br><br>**The National Agency for Renewable Energy and Energy Efficiency (ADEREE):** Implements Morocco's national renewable energy and efficiency plans. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

IPPs for utility-scale power production can enter into power purchase agreements (PPAs) with ONEE through competitive tenders. Projects above 2 MW can take place only in zones delineated by the government. Legally, self-consumption projects can connect to the medium-, high-, and very-high-voltage grids. The self-consumption framework has supported the development of Morocco's first wind farms. However, deployment of solar PV for self-consumption has been limited to date. Moreover, projects are still not permitted to connect to the low-voltage grid. As a result, almost all of the solar PV capacity is located off-grid, with less than 500 kilowatts (kW) of grid-connected solar PV plants.

### *Current policy environment for renewable energy*

Over the medium term, Morocco's policy environment should drive utility-scale renewable development, but may not stimulate activity in smaller segments. Its NES targets 42% of installed capacity from renewable sources by 2020, with specific targets for solar, wind and hydropower. 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. Currently, 420 MW of privately owned wind projects are under development under this regime. While the new law 13-09 grants the right to connect to the medium-voltage grid, the final framework for connection remains to be put in place, but is expected to occur in the medium term. Should access to the medium-voltage grid be realised, PV systems in the 20 kW to 2 MW range could experience rapid growth. There is also discussion over allowing the connection of small-distributed capacity to the low-voltage grid and the introduction of net metering, which could stimulate rapid growth in the commercial and residential solar PV sectors. However, it is unclear when such developments will occur.

To reach its ambitious targets, the government has launched two major projects – the MSP, which selected five sites for solar development, and the Wind Energy Plan, which identified another five sites for onshore wind development. The Moroccan Solar Energy Agency (MASEN) is tasked with implementing the MSP by securing financing, co-ordinating stakeholders, and holding the tendering processes for utility-scale solar projects. MASEN has awarded the first tender for the first phase of the first project of the MSP, Ouarzazate 1 (a 160 MW CSP trough plant with three-hour built-in storage). The ONEE has launched the 1000 MW Integrated Wind project to achieve the goals set out in the Wind Energy Plan. The project's first phase tendered 150 MW of onshore wind. In November 2012, the government pre-qualified six consortia of companies for the second phase of 850 MW.

### *Economic attractiveness of renewable energy and financing*

Excellent resources combined with long-term PPAs under the MSP and Integrated Wind Project should make utility-scale renewable projects attractive over the medium term. Wind projects for self-consumption are generally economically attractive without direct government incentives. Excellent wind resources and long-term PPAs have also attracted private investors to the wind projects announced by the government. The Clean Technology Fund, through the African development bank, has provided financing for ONEE to implement its 1000 MW plan. The qualification for Clean Development Mechanism credits for some wind projects can also aid project economics.

The story is somewhat different for small and medium-sized solar PV systems. With falling system costs and high solar irradiation, solar PV generation can be competitive versus power prices for large electricity consumers. For the smaller consumers in the residential sector, solar PV generation could be competitive versus residential electricity prices from 2014. However, this competitiveness has not yet translated into project bankability given significant challenges. Projects do not yet have access to the low-voltage grid and thus cannot benefit from financial incentives, such as net metering or FITs, which could help defray the high up-front investment costs. Commercial and industrial consumers in the 20 kW to 2 MW range have large potential for growth to sell excess generation to other industrial customers should connection to the medium-voltage grid be granted.

Economic attractiveness for CSP is also complex. While the availability of PPAs makes CSP attractive, concessional financing is necessary for project bankability. The results of the Ouarzazate phase 1 tender revealed that CSP attractiveness currently depends on the availability of public financing. The winning bid for the 160 MW plant was 1 620 MAD/MWh (USD 190/MWh), a rate achievable with a concessional financing arrangement from a number of sources. Generation costs from this project remain higher than the price at which ONEE will generate or purchase the electricity, which is based on inexpensive coal and subsidised fossil fuels. The government will finance this difference in price. In practice, this is achieved using two PPAs, the first between the project and MASEN, and the other between MASEN and ONEE at ONEE's purchase price. A third arrangement commits the state to cover MASEN's deficit. Even without subsidies for fossil-fuel power generation, the costs of this project would likely be higher than current electricity prices. Still, generation from CSP with adequate storage could be lower than the marginal cost of peak power based on unsubsidised oil.

Development bank financing from a number of sources, both domestic and multilateral, can reduce financing risks, provide technical assistance and encourage the involvement of private commercial banks in wind financing. The success of MASEN'S first tender has likely boosted investor confidence in the process (Falconer and Frisari, 2012). MASEN's innovative business model of using two PPAs, to spread the risk among three entities in the public and private sectors over a long period, should attract developers to the remaining CSP projects of Ouarzazate. The German KfW has already committed to provide a large amount of the financing of the subsequent CSP projects in Ouarzazate. For other projects, Morocco has also attracted financing from The Arab Fund for Economic and Solar Development. The Energy Development Fund has also been established, with donations from Saudi Arabia and the United Arab Emirates, to provide the government with financial support for renewable projects.

### *Conclusions for renewable energy deployment: baseline case*

Over the medium term, Morocco's renewable capacity is to grow strongly, from 2.1 GW in 2012 to 4.7 GW in 2018, driven by excellent resources, government targets and good economic attractiveness. Onshore wind additions should rise from 0.3 GW in 2012 to 1.5 GW in 2018. Most of this new capacity should come from the announced projects under ONEE's 1000 MW Integrated Wind project and the 300 MW IPP project at Tarfaya. The 150 MW park near Taza, which represents the first phase of the 1000 MW Integrated Wind Program of ONEE, has already selected developers and should come on line in 2014. The second phase of this programme will include five parks totalling 850 MW on five sites: Midelt (150 MW), Tanger II (100 MW), Jbel Lahdid (200 MW), Boujdour (100 MW) and Tiskrad (300 MW). Six consortia were selected in March 2013 to take part in this programme, which should be achieved in 2020. There are also 300 MW of sites for industrial customers according to the law 13-09 under construction or development, of which 200 MW are expected be on line at some point in 2013.

**Table 67** Morocco renewable electricity capacity and projection (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 1.8 | 1.8 | 1.8 | 1.8 | 1.9 | 2.3 | 2.3 | 2.3 |
| Bioenergy | - | - | - | - | - | - | - | - |
| Wind | 0.3 | 0.3 | 0.5 | 0.9 | 1.1 | 1.3 | 1.5 | 1.5 |
| *Onshore* | 0.3 | 0.3 | 0.5 | 0.9 | 1.1 | 1.3 | 1.5 | 1.5 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.4 |
| Solar CSP | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.2 | 0.3 | 0.5 |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **2.1** | **2.1** | **2.3** | **2.7** | **3.4** | **4.1** | **4.3** | **4.7** |

Hydropower additions are expected to be modest, with 215 MW in two large plants. There are also several small hydro projects announced, and a 350 MW pumped storage plant under development by ONEE at Abdelmoumen. On the assumption that connections to the medium-voltage grid are realised, it is expected that solar PV capacity will reach 0.4 GW in 2018. The majority of this is 0.3 GW from large rooftop and ground-mounted systems that would deliver to industrial customers. The remaining growth should be from both MASEN and ONEE pilot plants. Residential solar PV has large growth potential, but deployment is expected to be limited as long as access to the low-voltage grid is restricted. Still, small projects for self-consumption might emerge because of the progressive residential electricity tariffs.

**Table 68** Morocco main drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • diversification needs in the face of fast-growing demand and high costs of fossil fuels;<br>• long-term government targets for increasing share of renewables in the power mix;<br>• excellent resource availability and good competitiveness for wind and solar PV;<br>• availability of PPAs for CSP. | • concentrated ownership of transmission and distribution that presents barriers to entry;<br>• cost and availability of finance will remain a challenge to deployment;<br>• continued grid investment required to absorb planned capacity and transmit electricity to load centres far from resource areas;<br>• lack of grid access and incentives undermines attractiveness of small distributed capacity. |

Thus far, Morocco's solar tendering system is geared largely towards CSP capacity, with its storage capabilities to meet peak evening demand. CSP capacity should grow from 0.02 GW in 2012 to around 0.5 GW by 2018, as three projects from phase 1 and phase 2 of Ouarzazate are expected to be commissioned. The tender has closed for the first 160 MW and it is assumed a similar successful bidding process will occur for the remaining 300 MW of CSP for Ouarzazate (possibly being divided into two projects: 200 MW troughs, 100 MW tower). This 300 MW is likely to come on line later than the planned 2015 under the MSP, given project lead times. The timetable and availability of financing for CSP projects beyond Ouarzazate is unclear; it is expected projects will be commissioned after 2018.

### *Renewable energy deployment under an enhanced case*

Certain market enhancements could increase the cumulative capacity of solar PV and CSP in Morocco. The grid connection of small solar PV capacity remains a particular hurdle. The allowance of small projects to connect to the low-voltage grid with the introduction of financial incentives, such as net metering, could accelerate the deployment of commercial and residential-scale solar PV. Potential deployment of utility-scale solar PV remains more uncertain, pending the results of tenders under the MSP. In total, with the above enhancements, cumulative solar PV capacity could be 1 GW to 2 GW higher than the baseline case in 2018. For CSP, the upside to capacity relates to the availability of financing and the timeline of tenders for future projects following Ouarzazate. With faster-than-expected developments in these areas, CSP capacity could be around 300 MW higher in 2018 versus the baseline case. Wind could reach 1.6 GW should other private projects be developed.

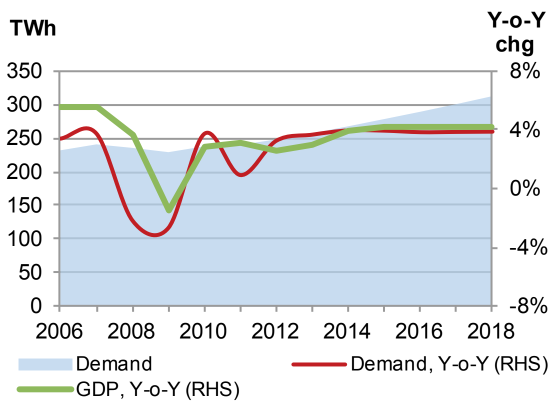
## South Africa

Diversification needs and renewable tenders should drive strong growth for wind and solar over the medium term. Yet grid connections may remain an important challenge for developers.

### *Power demand outlook*

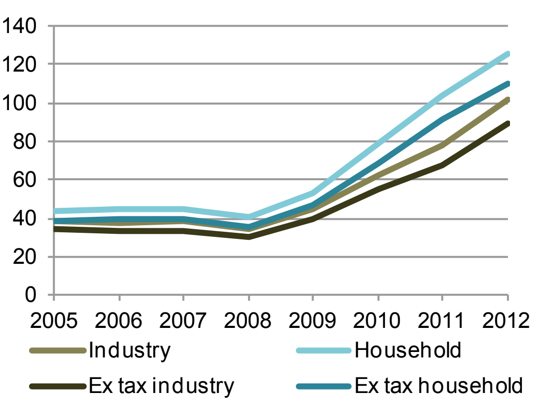
South Africa's economy has grown strongly in recent years, with real GDP averaging 4.9% annual growth over 2004-08 and contracting only slightly in 2009 due to the global financial crisis. The economy has recovered and growth averaged 3.1%/yr from 2009-12. Power demand grew at an average annual rate of 2.8% from 2006 through 2008. In January 2008, South Africa experienced a power supply crisis with Eskom (the vertically integrated utility company supplying 95% of electricity) imposing scheduled blackouts and load-shedding for more than six months because it did not have sufficient generation to meet the growing demand. The government responded by introducing demand management programmes and plans to increase generation capacity, including renewable sources. Looking forward, in line with IMF assumptions, South Africa's GDP is projected to grow on average by 3.2% annually over 2012-18. Power demand is expected to rise on average by 3.9%/yr over that period. As of April 2013, the retail electricity tariff for residential consumers stood at around ZAR 1180/MWh (USD 120/MWh). The regulatory agency of South Africa has approved an annual increase of retail prices by 8% over the next five years.

**Figure 76** South Africa power demand versus GDP growth




Note: demand is expressed as electricity supplied to the grid.

**Figure 77** South Africa average retail power prices (USD per MWh)




Source: ESKOM, 2013.

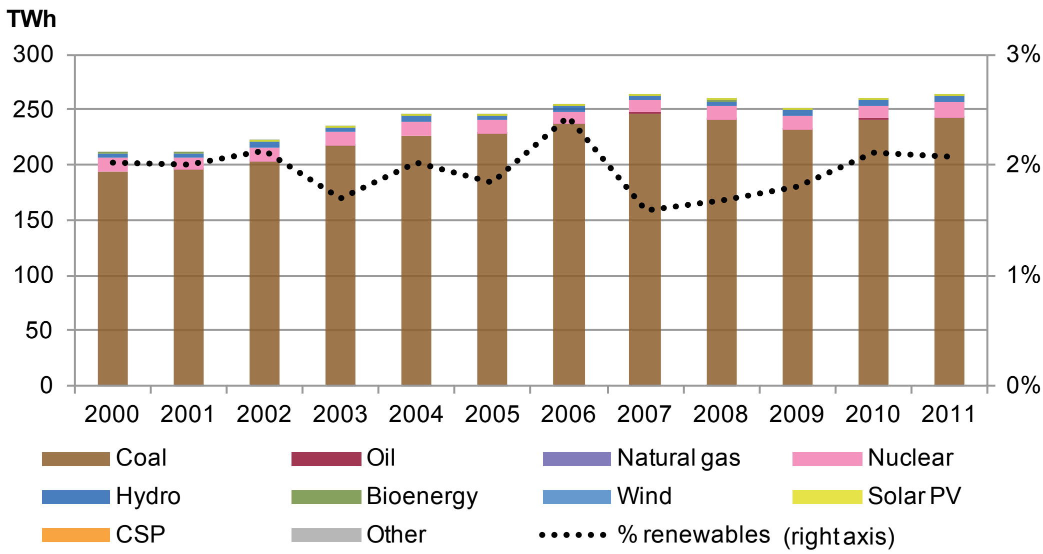
### *Power sector structure*

#### Generation and capacity

Coal is central to South Africa's ability to generate electricity, accounting for around 93% of all power output in 2011. The country's only nuclear power station, Koeberg, provides around 5% of output while the rest is generated mainly by bioenergy, hydropower and oil-fired plants. As of 2012, the country's total installed capacity amounted to 47 GW with a peak demand of 37 GW. The contribution of wind and solar energy is currently negligible. However, there are several large renewable energy projects under construction, including 100 MW of CSP, 100 MW of onshore wind, and several small bioenergy and hydropower projects. Eskom aims at decreasing the share of coal in the electricity mix from 93% to 70% by 2025 by increasing the installed capacity of renewable energy (mainly wind and solar) and nuclear.

In March 2011, South Africa's Department of Energy initiated the Renewable Energy Independent Power Producer Programme (REIPPP) in order to attract more private investment in renewable power generation. The REIPPP is designed to award renewable energy projects through a competitive tender mechanism with three major auctions aiming to deploy a total of 3.625 GW of renewable capacity. The programme has already staged two auctions, and successfully awarded 2.5 GW of renewable energy capacity (wind, solar PV and CSP). A significant part of the capacity is allocated to wind (1.2 GW) and solar PV (1.1 GW), while CSP received 200 MW. Based on the results of these bids, wind and solar PV are expected to expand significantly while the deployment of CSP plants will grow slowly over the medium term.

**Figure 78** South Africa power generation by source and renewable share of total power generation




## Grid and system integration

The South African grid should present some challenges to renewable energy deployment over the medium term. After the electricity crisis in 2008, the Department of Energy and Eskom planned additional grid investments through 2022 taking into account increasing demand and supply. The investment budget of Eskom's 10-year Transmission Development Plan (2013-22) takes into account new transmission lines and substations to connect winning renewable energy projects from the two auction rounds to the grid (Eskom, 2011). However, the tenders themselves did not specify grid connections for winning projects. Although the exact locations and sizes of these new plants are known, grid connections for most of these projects have not yet been approved by ESKOM. This situation can cause delays in the commissioning of these plants. Over the medium term, a major portion of awarded projects will be installed. In that sense, it is expected that the share of variable renewables in the power mix could reach 1.5% to 2.0% by 2018. These levels are not expected to cause major challenges to the South African transmission service operator in terms of balancing.

## *Current policy environment for renewable energy*

In 2010, the Department of Energy in South Africa announced ambitious targets for renewable energy which are outlined in the *Integrated Resource Plan for Electricity 2010-2030* (DOE, 2011). By 2030, the government envisages that wind energy would increase to 9.2 GW, comprising 10% of total power capacity, while solar PV would rise to 8.4 GW (9.4% of capacity). CSP would have 1.2 GW of capacity (1.3% of capacity). Despite having introduced a FIT in 2009 and adjusting it upwards in 2010, incentive levels were not sufficient to attract significant investments in renewable energy. In 2011, the government introduced a bidding procedure for renewable energy sources that awards long-term PPAs to winning projects. The tender procedures require developers to submit a detailed project plan, including pre-agreements with equipment providers that meet the local-content requirement, financing and more than 30 different licensing documents provided by various government institutions.

**Table 69** South Africa main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **Integrated Resource Plan for Electricity:** RES-E 10% of electricity generation by 2030 provided by: hydro: 4.7 GW; wind: 9.2 GW; PV: 8.4 GW; CSP: 1.2 GW. | **Renewable Energy Independent Power Producer Programme (REIPPP):** In March 2011 REIPPP, a public procurement programme, replaced the FIT system, which was introduced in 2009.<br>Qualifying technologies: onshore wind, solar PV, solar thermal, biomass solid, biogas, landfill gas and small hydro plants.<br>A ceiling tariff level is established for each technology in the auctions. Winning bidders sign PPAs, which are guaranteed for a period of 20 years.<br>**European Investment Bank (EIB) and Investec Renewable Energy Fund:** Established in 2011 with fund of EUR 100 million to distribute as soft loans to RES projects in South Africa.<br>**Tax incentives:** Accelerated capital allowance over a three-year period, on a 50/30/20 basis, for assets used in the generation of electricity from solar, wind, hydro or biomass. | **Renewable Energy Centre of Research and Development (RECORD):** Leads and facilitates R&D in RES sector. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Bids are made in relation to technology-specific ceiling prices. The first two tenders have awarded 2.5 GW worth of renewable energy projects and more than half of this capacity has already signed PPAs with Eskom. The remainder are expected to complete their documentation and bureaucratic procedure in order to sign their power contracts. The tenders include penalties for developers who sign PPAs with Eskom but are late in commissioning their projects. A third tender has been announced for onshore wind (653.6 MW), solar PV (401.3 MW), CSP (200 MW), small hydro (120.7 MW), landfill gas (25 MW), biomass (12.5 MW) and biogas (12.5 MW) projects. Developers are expected to submit their applications in August 2013.

## *Economic attractiveness of renewable energy and financing*

Solar PV and wind enjoy good economic attractiveness with excellent resource availability. In recent tenders, almost 95% of the capacity auctioned was allocated to wind and solar PV projects while the remaining went to CSP. The average prices bid for both solar PV and wind projects were significantly lower (22% for wind and 40% for solar PV) for the second bidding than for the first one (this result makes onshore wind almost competitive with new coal power plants). However, average bid prices may somewhat increase during the third round due to increasing local-content requirements in the face of a still-nascent renewable manufacturing industry in South Africa.

The cost and availability of financing should moderately challenge renewable energy deployment over the medium term. The REIPPP has attracted significant capital. However, projects are mostly financed by either local banks or local development corporations because of requirements for developers to employ local financing. Financing is highly dependent on the liquidity level of local private and public banks, which may tend to raise the cost of capital for renewable energy projects over the medium term. Standard Bank, Africa's largest lender, plays an important role in providing loans to both local and foreign investors. The bank has already allocated ZAR 27 billion (USD 3.5 billion) of funding, mostly senior debt, for the winners of the renewable energy tenders. The Development Bank of South Africa has also approved ZAR 9.6 billion (USD 1.25 billion) for new renewable energy projects. In addition to local sources of capital, international finance institutions, such as the World Bank, the EIB, International Finance Corporation, and several Europe development agencies and banks, have also agreed to provide low-interest financing.

**Figure 79** South Africa awarded renewable capacity under the REIPPP

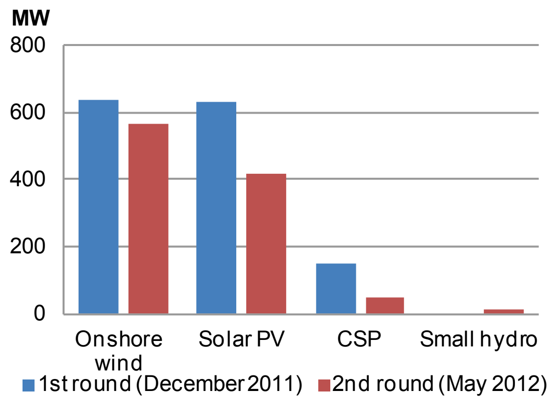
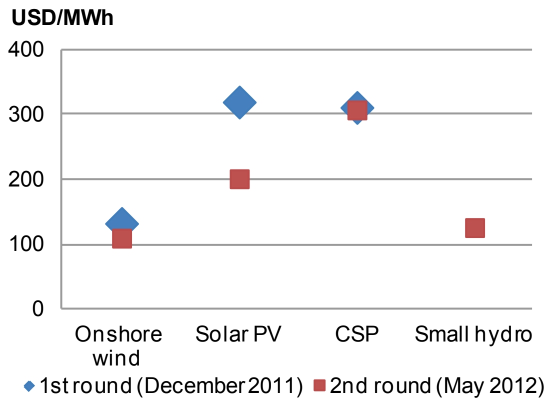



**Figure 80** South Africa average awarded tender prices under the REIPPP




Note: average exchange rates of USD per ZAR (/ZAR) 0.116 for December 2011 and USD/ZAR 0.123 for May 2012.

Source: DOE, 2012.

## *Conclusions for renewable energy deployment: baseline case*

Renewable energy capacity is expected to expand significantly over the medium term from 2.4 GW in 2012 to 7.6 GW in 2018, supported by strong electricity demand growth, increased diversification needs away from coal power and REIPPP. Solar, both PV and CSP, and onshore wind are expected to account for around 75% of renewable capacity growth over the period. Project delays and financing issues remain risks to the forecast. As such, capacity growth expectations may be slower than the capacity auction results themselves suggest. Solar PV capacity should grow from current minimal levels to 1.4 GW over the medium term. This growth should largely come from grid-connected utility-scale projects that are awarded by the government procurement programme. Residential and commercial installations should remain limited due to lack of financial incentives for these sectors.

Onshore wind capacity should increase from the current 10 MW to 1.8 GW. CSP is expected to grow more moderately, reaching 0.4 GW in 2018. Several small hydropower and pumped storage projects are under construction, which should help to boost hydropower capacity by 1.3 GW over 2012-18. The bioenergy project pipeline for the forecast period suggests cumulative capacity will rise from 25 MW to 0.4 GW in 2018.

**Table 70** South Africa renewable electricity capacity and projection

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 2.3 | 2.3 | 2.3 | 2.9 | 3.6 | 3.6 | 3.6 | 3.6 |
| Bioenergy | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.4 |
| Wind | 0.0 | 0.0 | 0.1 | 0.3 | 0.6 | 1.0 | 1.4 | 1.8 |
| *Onshore* | 0.0 | 0.0 | 0.1 | 0.3 | 0.6 | 1.0 | 1.4 | 1.8 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.0 | 0.0 | 0.1 | 0.3 | 0.5 | 0.8 | 1.1 | 1.4 |
| Solar CSP | - | - | 0.1 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 |
| Geothermal | - | - | - | - | - | - | - | - |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **2.4** | **2.4** | **2.6** | **3.8** | **5.1** | **5.8** | **6.7** | **7.6** |

**Table 71** South Africa drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • excellent wind and solar resources;<br>• strong demand growth and power sector diversification away from coal;<br>• government commitment to deploy renewables in long-term planning and a robust tendering mechanism with long-term PPAs. | • grid connection issues may cause delays for some renewable energy projects;<br>• increasing domestic-content requirements imposed both on financing and renewable energy equipment may raise project costs. |

### *Renewable energy deployment under an enhanced case*

Certain market enhancements could increase the cumulative capacity of wind power, solar PV and CSP in South Africa. Timelier grid connections, faster-than-expected cost reductions and improved financing could improve the outlook in all three of these areas by improving project delivery. The encouragement of greater solar PV use for self-consumption, for which South Africa has large potential, could also spur the development of greater small-scale solar PV capacity. Under these conditions, onshore wind could be 1 GW to 2 GW and solar PV could be 2 GW to 4 GW higher in 2018 versus the baseline case, and CSP could be some 0.5 GW to 1.0 GW higher.

## Thailand

Diversification needs and a supportive policy framework should drive strong growth of a portfolio of renewable sources. Still, uncertainty remains over the details of future support schemes.

### *Power demand outlook*

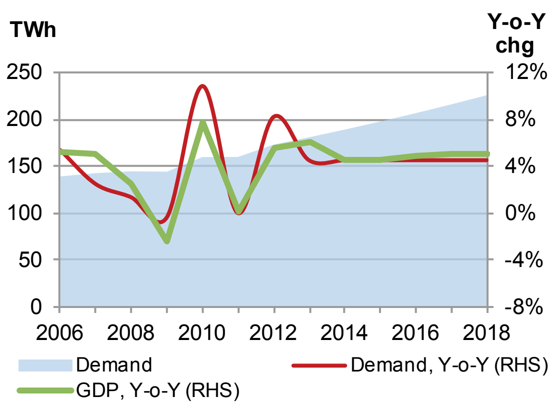
Thailand's strong expected economic growth and expanding industrial activity should underpin robust electricity demand growth over the medium term. In line with IMF assumptions, Thailand's real GDP growth is seen averaging 4.7%/yr over 2012-18. In 2012, Thailand's power demand surged by 8% year-on-year as the economy recovered from devastating floods that significantly disrupted activity across the north and central areas in 2011. Over 2012-18, power demand growth should return to more moderate levels, but still rise strongly. Notably, Thailand's peak demand continues to rise, reaching over 26 GW in 2012, versus 21 GW in 2006, on the back of increasing air conditioning and industrial needs. Regulated end-user prices, which at times have not kept pace with increases in generating costs, are also boosting demand growth and have burdened the transmission service operator, the Electricity Generating Authority of Thailand (EGAT), with a tariff deficit. Still, the government instituted a new pricing policy in 2011 that seeks to regularly adjust power prices more in line with fuel costs and eliminate EGAT's tariff deficit by the end of 2013.

## *Power sector structure*

### Generation and capacity

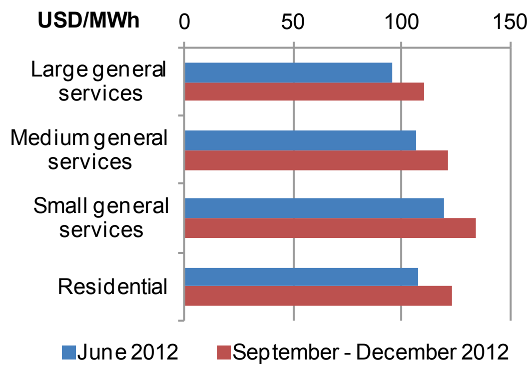
Thailand's power generation mix is dominated by natural gas, which provided 68% of total output in 2011. Gas generation has grown strongly in recent years with increased domestic gas supply. Still, about 25% of total gas needs are met by imports, which are rising. Thailand began importing costly liquefied natural gas (LNG) in 2011 and plans to increase requirements over the medium term. Coal accounted for 22% of generation in 2011, and coal power has remained relatively steady in recent years. The government's latest Power Development Plan (PDP), released in June 2012, sees a rising role for gas generation, with 10.7 GW of new capacity expected over 2013-18, while coal additions (both domestic and imports from Laos) appear smaller at 1.7 GW (MOE, 2012). In 2011, total system capacity stood at 31.4 GW, with peak load at 24.5 GW.

**Figure 81** Thailand power demand versus GDP growth




Note: demand is expressed as electricity supplied to the grid.

**Figure 82** Thailand average retail power prices

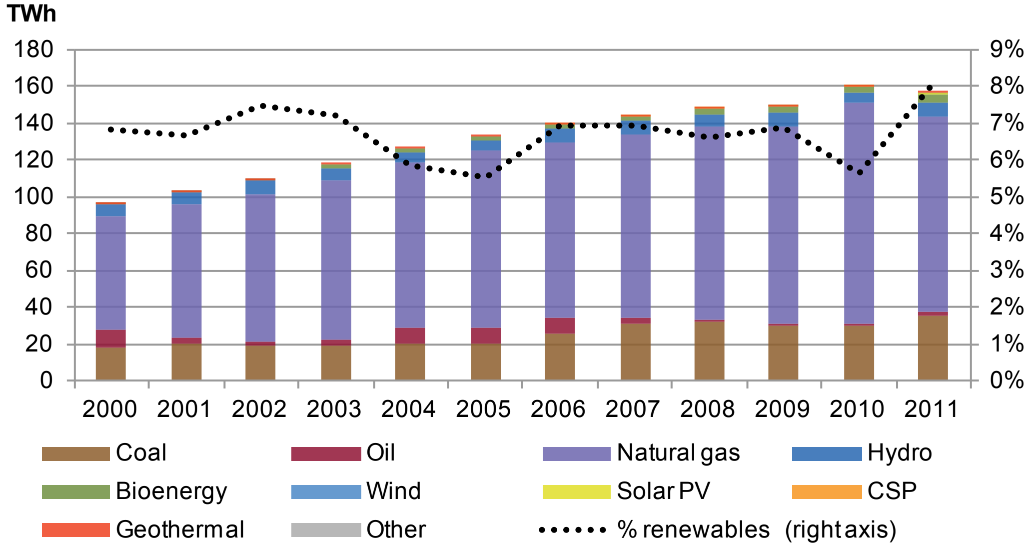



Source: IEA analysis based on Ruangrong, 2012.

Renewable sources play a small, growing role in the current power mix. Renewable investment takes place under the small power producer (SPP) programme (10 MW to 90 MW) or the Very Small Power Producer (VSPP) programme (<10 MW), which provide PPAs to projects with EGAT (SPP) or one of two distributors (VSPP). Hydropower, at 5.2% in 2011, is the largest renewable contribution. Bioenergy generation has risen from a 1.2% share in 2005 to 2.7% in 2011. Most growth has occurred in solid biomass, stimulated by the SPP, though a significant portion is located off-grid. Biogas has also accelerated since an expansion of the VSPP in 2006. Wind's share remains low, though deployment picked up in 2012 with capacity rising to 0.1 GW. The country's largest wind farm (103 MW) was due on line by early 2013. A small amount of geothermal capacity also exists. Solar PV generation has good potential, but still constitutes a small part of the power mix. Its development accelerated in 2011 as projects initiated under a solar FIP scheme began coming online. In 2012, solar PV capacity stood at 0.4 GW, with a pipeline of almost 0.7 GW of new projects having signed PPAs. CSP capacity, estimated at 20 MW in 2012, is much smaller, though with a pipeline of new projects with PPAs of over 1 GW.

Over the medium term, Thailand's power sector will face the challenge of meeting fast-growing demand and diversifying its generation mix. To this end, the latest Alternative Energy Development Plan (AEDP) and PDP see stronger roles for renewables compared with previous outlooks.[10] Over 2011-21, the AEDP sees renewable capacity expanding by 7.1 GW, with bioenergy (+2.5 GW), solar (+1.9 GW), small hydropower and pumped storage (+1.5 GW), and wind (+1.2 GW) playing the largest roles (DEDE, 2012). Geothermal and ocean power are expected to add small amounts. The PDP also sees a growing role for hydropower that includes imports (+3.1 GW over 2011-21).

**Figure 83** Thailand power generation by source and renewable share of total power generation




## Grid and system integration

Thailand's power grid and system will act as a moderate constraint to renewable deployment over the medium term. EGAT owns and operates 100% of the system, as well as about half of generation capacity. EGAT sells power to two state-owned distributors, with no third-party access. Grid access is guaranteed for renewables with PPAs within the SPP and VSPP programmes. Thailand's growing gas and bioenergy capacity and interconnections with neighbours provide good flexibility to balance growing variable renewable sources. However, the country will face the challenge of building out its grid to meet significant planned increases in generation. To this end, EGAT is undertaking a number of transmission projects, including links with neighbouring countries to bring more, relatively low-cost hydropower into the system.

The pace of grid development will likely challenge new wind generation. Thailand's southern coastline (an isthmus) harbours the best wind resources, but many sites lack grid connections. The isthmus has good north-south connectivity, but requires further development to reach specific points along the coast. Wind projects are also being built in the eastern part of the country. In this area, grid constraints are emerging as increasing amounts of hydropower from Laos are being transported to industrial demand centres near Bangkok. Plans for new pumped hydro storage in the northeast may help to ease constraints towards the end of the projection period (2017-18).

[10] The PDP focuses on grid-connected power and includes large hydropower and imports. The latest revision of the PDP was developed with "regard" to the AEDP targets, correcting a planning inconsistency between conventional and renewable sources that had plagued previous plans. Still, targets differ somewhat, with the PDP seeing higher wind and lower bioenergy capacity levels in 2021 versus the AEDP.

**Map 5** Thailand power transmission system and main hydropower plants


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: EGAT, 2010.

Thailand's solar and bioenergy development over the medium term is expected to face fewer system constraints. More so than wind, the best solar resource areas are better located near demand centres in the central and northern parts of the country. A large part of solar development should consist of distributed PV systems (including off-grid). The VSPP programme includes a net metering policy that should continue to facilitate small-scale system integration of both solar and bioenergy projects, though the costs and waiting times associated with grid connections may act as a constraint (Gamba and Lamers, 2009). In the short term, fast-rising contributions of solar PV and other VSPPs could also raise grid stability issues, requiring continued transmission and distribution upgrades.

### *Current policy environment for renewable energy*

Thailand's policy environment should act as a driver of renewable deployment over the medium term, though uncertainties persist in the short term. The AEDP foresees renewable energy accounting for 25% of energy consumption by 2021. Renewable electricity sources play a large role in meeting this target, with the AEDP seeing capacity expanding by 7.1 GW over 2011-21. Renewable targets within the AEDP appear to differ somewhat with those in the PDP, creating the risk of divergent goals with regard to conventional and renewable power planning. This discrepancy is smaller than in previous planning exercises, suggesting a more integrated approach, but Thailand still lacks a renewable energy law, which would better help enforce renewable development.

**Table 72** Thailand main targets and support policies for renewable electricity

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **AEDP 2012-2021:**<br>25% share of renewables in total energy consumption mix by 2021.<br>Targets for expected installed capacities in 2021:<br>4.4 GW bioenergy;<br>3.6 GW solid biomass;<br>0.6 GW biogas;<br>0.2 GW municipal solid waste;<br>2.0 GW solar;<br>1.0 GW rooftop;<br>1.6 GW small hydropower and pumped storage;<br>1.2 GW wind;<br>1 MW geothermal;<br>2 MW ocean. | **PPAs:**<br>VSPP programme – generators smaller than 10 MW.<br>SPP programme – generators with capacity 10 MW to 90 MW.<br>**FIPs:**<br>For VSPP and SPP programmes. FIP adder allocated for seven to ten years on top of the contracted tariff within PPAs.<br>**Net metering for distributed systems:**<br>Solar PV, bioenergy.<br>**Import duties exemption:**<br>Renewable energy machinery and materials are exempt from import duties.<br>**Tax incentives:**<br>Eight-year exemption of generation revenues from corporate income tax. Following that, projects benefit from 50% tax reduction for five years.<br>**Soft loans:**<br>Available for all renewable projects. Loans at 4% interest rate up to 50 million baht per project. | **Energy Conservation Promotion Fund (ENCON):**<br>Established in 1992; provides financial support to introduce and promote RES technologies.<br>**Petroleum products levy and levy on generation using fossil fuels:**<br>Revenues gathered support ENCON.<br>**Grid access and priority dispatch:**<br>Grid access guaranteed under PPAs. |

Note: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

A variety of financial incentives have encouraged rapid growth in renewable projects. Since 2007, the SPP and VSPP programmes include tariff "adders", which are seven-to-ten-year FIPs on top of the contracted EGAT "avoided cost" price (based on gas generation costs). Attractive FIPs and streamlined procedures spurred a larger-than-targeted number of VSPP projects, particularly in solar, raising concerns over the policy cost impact on consumer electricity bills. The government is deliberating a new FIT scheme to replace the FIP. Thailand offers a further set of tax incentives, investment grants, preferential financing, direct investment and technical assistance. Notably, projects benefit from import duty exemptions on renewable equipment and a tax holiday on generation income for eight years, followed by a 50% tax reduction during years 9 to 13.

Some policy uncertainties and administrative barriers have emerged, however. In 2010, a managing committee was created within the Ministry of Energy to centralise decision making and give greater oversight to all SPP and VSPP projects. New rules and regulations under this committee have significantly slowed application processing for new projects (Tongsopit and Greacen, 2012). Moreover, details for the new FIT scheme have yet to emerge at the time of writing. Permitting requirements have also acted as a barrier to investment in municipal solid waste (MSW) generation due to the local ownership of landfills and varying administrative needs (IRENA, 2012).

### *Economic attractiveness of renewable energy and financing*

Generally, renewable energy projects in Thailand enjoy good economic attractiveness with PPAs from the SPP and VSPP programmes and current financial incentives, including FIPs, tax benefits and grants. Solar PV system prices remain high compared with international markets, due to lack of scale in installation segments, though prices are expected to fall as deployment increases (De Silva, 2012). Despite good overall resource, biomass projects can face constraints related to local feedstock availability, which can also undermine attractiveness. To this end, the government is trying to promote residual biomass use and the development of feedstock supply chains. The economic attractiveness picture for renewable technologies is difficult to evaluate going forward, as details of the new FITs remain pending. Authorities will face the challenge of stimulating deployment while managing cost impacts on consumer electricity bills.

Thailand's overall favourable investment climate and the number and diversity of mechanisms to facilitate private renewable financing are drivers for deployment. With revenues raised through taxes on petroleum products, the government directly co-invests in projects through its ENCON, providing a mixture of venture capital, equity stakes, technical assistance, equipment leasing and credit guarantees. It also provides soft loans and technical assistance to commercial banks; these loans can then be lent to renewable projects at attractive financing terms (maximum 4%). Financing from international sources such as the Asian Development Bank and the International Finance Corporation has played a positive role in solar and bioenergy project development. Carbon finance under the CDM has also stimulated bioenergy investment, though low carbon prices and practical difficulties in securing revenues suggest this will not be a significant driver going forward (Siteur, 2012).

A number of financing challenges persist. General risk factors such as Thailand's susceptibility to damaging floods, as in 2011, political instability in the southeast (where there is good wind resource) and currency risk with the Thai baht tend to raise required project returns (De Silva, 2012). Smaller-scale developers or those without the backing of a large corporate entity with a stable balance sheet still have relatively limited access to project financing (Tongsopit and Graecen, 2012). Furthermore, current financial incentives expose projects to electricity price uncertainty under the FIP scheme. Though a switch to a FIT regime is pending, uncertainty over its details at the time of writing makes the financing picture difficult to evaluate over the medium term.

## Conclusions for renewable energy deployment: baseline case

Thailand's renewable sector has developed strongly under the SPP and VSPP programmes offering PPAs, attractive financial incentives and efficient application procedures. Development has proceeded so rapidly that a large backlog of projects has emerged. Over the medium term, much of Thailand's growth should stem from projects coming on line from this pipeline, with total renewable capacity expanding from 7.2 GW in 2012 to 12.1 GW in 2018. Uncertainty over deployment exists beyond this pipeline, however, with the pending transition of the incentive regime from FIPs to FITs and some technologies already approaching their longer-term targets by 2018.

Bioenergy additions should be the largest in absolute terms, with capacity rising by 2.2 GW to 3.7 GW in 2018. Most of this expansion should occur in solid biomass (*e.g.* residues from sugar cane, palm oil, cassava and corn), with smaller additions in biogas and MSW. Feedstock availability may remain a challenge. Though biogas capacity should continue to rise under the current pipeline of projects, future expansion opportunities look more limited barring further innovation. The biogas market for the starch and palm industries is saturated, and growth in other feedstocks requires technology development and cost reductions (Siteur, 2012).

**Table 73** Thailand renewable electricity capacity and projection

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 4.5 | 4.5 | 4.6 | 4.7 | 4.8 | 4.9 | 5.2 | 5.5 |
| Bioenergy | 2.0 | 2.2 | 2.4 | 2.7 | 2.9 | 3.2 | 3.4 | 3.7 |
| Wind | 0.0 | 0.1 | 0.3 | 0.4 | 0.5 | 0.6 | 0.7 | 0.9 |
| *Onshore* | 0.0 | 0.1 | 0.3 | 0.4 | 0.5 | 0.6 | 0.7 | 0.9 |
| *Offshore* | - | - | - | - | - | - | - | - |
| Solar PV | 0.1 | 0.4 | 0.6 | 0.9 | 1.2 | 1.5 | 1.7 | 1.9 |
| Solar CSP | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Ocean | - | - | - | - | - | - | - | - |
| **Total RES-E** | **6.6** | **7.2** | **8.1** | **8.8** | **9.5** | **10.2** | **11.1** | **12.1** |

Solar PV capacity is expected to rise by 1.5 GW to 1.9 GW in 2018. Although project applications under the VSPP almost reach the government's 2021 targets, not all are expected to come on line. Government mechanisms now allow the termination of contracts for projects that do not meet their scheduled commercial operation dates, which could affect delayed projects and solar PV applications that were originally speculative in nature (*e.g.* made in order to obtain a licence, which could then be sold in the market). The outlook for CSP is more conservative and uncertain, with additions of 0.1 GW assumed over 2012-18. Though a large pipeline of projects exists (1 GW), limited deployment history of this technology in Thailand suggests actual gains will be small.

Wind capacity, all onshore, is seen rising by 0.7 GW to 0.9 GW in 2018, though will continue to face risks related to grid development. In 2011, Thailand's hydropower stood at 4.5 GW, which includes large-scale plants, small-scale plants and pumped hydro storage. Most new developments will occur in small-scale plants and pumped hydro storage, with total hydropower capacity in 2018 expected at 5.5 GW. At the same time, Thailand will increase imports of large hydropower generation from neighbouring Laos, though these are not reflected in the capacity or generation forecast. Developments are also expected in geothermal, though capacity will remain small.

**Table 74** Thailand drivers and challenges to renewable energy deployment

| Drivers | Challenges |
|---|---|
| • good resource availability and national targets across a portfolio of renewable technologies;<br>• strong demand growth; desire to diversify power system away from costly fossil-fuel imports;<br>• attractive and diverse array of financial incentives and market frameworks for renewable project development. | • absence of a renewable energy law; potential conflicts between the planning of conventional and renewable generation;<br>• uncertainty over timing, levels and adjustments of pending new incentive regime, as FIPs are replaced by FITs;<br>• grid upgrades to accommodate new generation, particularly wind. |

### *Renewable energy deployment under an enhanced case*

Certain market enhancements could increase the cumulative capacity of bioenergy, onshore wind, solar PV and CSP in Thailand. Notably, a rapid clarification of new FIT levels to replace the FIP scheme would help stimulate activity. With better progress in advancing feedstock availability, bioenergy capacity could be 0.5 GW higher in 2018 versus the baseline case. The upside for solar PV looks limited, given an already saturated project pipeline under the SPP and VSPP programmes. Still, faster application processing and deployment could add up to 0.5 GW to the forecast by 2018. For CSP, cost reductions and greater evidence of deployment for projects already with PPAs could raise 2018 capacity to 0.5 GW to 1 GW. 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 2018 than under the baseline case.

## Other non-OECD countries and regions

Significant renewable energy progress should emerge in other non-OECD markets over the medium term. In general, non-OECD countries possess more abundant renewable energy potential than OECD countries. Past development has largely centred on hydropower, with deployment of non-hydro technologies hampered by high costs and institutional barriers. Still, falling costs, particularly in solar PV, and emerging policy support suggest a larger role for non-hydro technologies going forward, particularly in markets without significant hydropower resources.

### *Africa*

Africa holds an abundance of renewable energy potential, with excellent continent-wide solar and significant hydropower, wind, bioenergy and geothermal resources. Increasing power demand and a strong need for rural electrification – an area where renewable energy competes well with fossil alternatives – should provide macro supports to deployment. Notably, in April 2013, the largest PV plant (15 MW) in Africa was commissioned in **Mauritania**.

**Egypt** is planning for 20% generation from renewables by 2020, and in July 2012 adopted a solar plan – 3.5 GW by 2027 (2.8 GW CSP, 0.7 GW solar PV). Egypt's challenges include the cost and availability of finance and still-high renewable generation costs relative to fossil-fuel generation. In 2012, Egypt had almost 0.6 GW of onshore wind capacity with some sites having load factors almost comparable to offshore wind. Over 2012-18, Egypt is expected to add 0.7 GW to 0.8 GW of new onshore wind. Still, a lack of strong financial incentives and political risks may weigh on development.

In sub-Saharan Africa, **Kenya**, with FITs in place since 2008, is expected to have significant deployment in geothermal and onshore wind, driven by fast-growing demand and a need to diversify its hydropower-dominated power mix. Kenya's geothermal capacity stood at 0.2 GW in 2012. A number of geothermal developments are under way, including the 140 MW Olkaria IV project expected online in 2014 as well as the 400 MW Menengai Crater, which have both secured financing. The cost and availability of financing remains a key hurdle for development of additional capacity over the medium term; cumulative capacity is expected to reach 0.7 GW by 2018. Several large onshore wind and solar PV projects are also under construction. The 300 MW Lake Turkana wind farm has experienced construction delays, but is expected on line by the end of 2014 or early 2015.

**Ethiopia** is likely to have significant hydropower development over 2012-18, with capacity increasing from 2 GW to over 6 GW. Still, this expansion would depend on the beginning of commissioning for the 5.2 GW Grand Renaissance Dam, which faces technical and financial challenges and controversy with neighbouring states. With good resources, onshore wind capacity is likely to grow from its 50 MW cumulative level in 2012. The 150 MW Adama wind farm, partly developed by HydroChina, is expected on line in 2014. Ethiopia has also announced plans to develop up to 450 MW of geothermal capacity by 2019.

### *Asia and Oceania*

Hydropower is the most developed renewable source in Asia, and the region possesses large untapped hydropower potential. **Vietnam** and **Laos**, among others, are expected to add significant hydropower capacity over the medium term. Vietnam has set a target of 4.5% renewables in generation by 2020 and has fast-rising electricity demand. It also has a 1 GW wind target for 2020. Vietnam is in the process of reforming its electricity sector and phasing out electricity price subsidies, which should help encourage investment. Laos' relatively low domestic demand, central position in Southeast Asia and good resources should enable it to act as a regional battery, with a slate of planned interconnection projects with Thailand, Vietnam and Cambodia. Hydropower development will depend on successful management of cross-border water governance issues. The 1.285 GW Xayaburi dam is expected on line in 2019, but has faced some environmental acceptance challenges.

In 2011, renewable sources (excluding hydropower) accounted for less than 3% of **Chinese Taipei's** power generation. The country had almost 0.6 GW of onshore wind and over 0.1 of solar PV capacity at the end of 2012. Diversification needs, a FIT scheme and an already well-developed solar manufacturing industry should spur growth in a portfolio of renewable energy going forward. The government is targeting 130 MW of new solar additions in 2013.

**The Philippines** approved FITs for wind, bioenergy, solar and hydropower in 2012. The incentives should encourage deployment in onshore wind, in particular, supported by a government target of 200 MW of capacity between 2013 and 2015. The government maintains a solar PV target of only 85 MW by 2030. High retail electricity prices, diversification needs and falling solar PV system costs are likely to drive stronger growth than the target suggests, with good economic attractiveness in the commercial and utility-scale segments. However, developments will face the challenge of meeting heavy permitting and administrative requirements. The Philippines has significant geothermal capacity (almost 1.9 GW in 2012). Capacity could grow by around 0.3 GW over 2012-18, based on a number of projects under development.

**Indonesia** has significant geothermal capacity (estimated 1.3 GW in 2012) and raised FITs in 2012 to help meet ambitious geothermal development goals (4 GW to 5 GW of new capacity by 2015). While this report expects cumulative capacity to increase by around 50% over 2012-18, based on the prevailing project pipeline, a number of non-economic barriers weigh upon the outlook. Notably, heavy administrative procedures and regulations on the use of land in protected forests, where many potential geothermal resources are located, may slow the pace of development. Solar PV is also likely to develop in Indonesia from a low base. The government is planning to launch a 150 MW tender in 2013 as well as introduce a new solar FIT.

Diversification needs away from fossil fuels should drive renewable growth in **Malaysia**. Since the end of 2011, the country has had a FIT in place for bioenergy, small hydropower and solar PV. Bioenergy capacity stood at around 60 MW at the end of 2012 while other sources remained smaller. The falling cost of solar PV systems is likely to stimulate medium-term deployment activity in this area.

### *Europe and Eurasia*

Hydropower generation represents much of the renewable development in non-OECD Europe and Eurasia, though wind and solar PV capacity is growing in some areas. Hydropower plays a significant role in **Russia's** generation mix (16% in 2011) while other renewables accounted for 1% of power. In 2011, bioenergy for power capacity stood at 1.4 GW while other renewables (geothermal, wind and solar PV) constituted a combined 100 MW. The government is drafting renewable energy legislation that could result in tenders of up to 6 GW of new renewable capacity over the next decade.

Following the introduction of a very generous renewable certificate scheme in 2011, **Romania** emerged as a significant destination for renewable energy investment. Onshore wind capacity reached 1.9 GW in 2012, with a significant pipeline of projects under development, and solar PV stood at a relatively small 30 MW. The country maintains a target of 38% of renewables in generation by 2020. However, policy costs and the impact of renewable incentives on consumer electricity bills have prompted the government to announce incentive cuts. From 2014 Romania is planning to reduce certificates for new wind projects from 2 to 1.5 and those for new solar PV projects from 6 to 3. The country has also announced temporary retroactive support cuts to some existing projects, by withholding a certain number of certificates to wind and solar PV generators over the next five years. The moves are likely to reduce investor confidence and curb recent rapid growth rates in onshore wind, though falling system costs and the continued development of the existing project pipeline will still drive some growth going forward.

Over the past year, **Bulgaria** has gone through a boom-and-bust cycle in solar PV deployment. Solar PV cumulative capacity rose from minimal levels in 2009 to almost 1 GW in 2012 on the back of very generous FITs and falling system prices. In mid-2012, the government reduced FITs for new solar PV projects by more than 50% and announced that no new capacity would be available on the grid for projects until mid-2013. A few months later, it introduced temporary retroactive measures on existing projects, imposing taxes on generation from solar, wind, hydropower and bioenergy. While some reductions in incentives for new projects were needed to manage policy costs and grid integration concerns from the overly rapid deployment, the unpredictability of the incentive changes combined with the retroactive measures have significantly undermined investor confidence. As such, renewable deployment is expected to be low over the medium term.

By contrast, renewable growth looks more stable in **Ukraine.** At the end of 2012, the country had an estimated 275 MW of onshore wind capacity and near 375 MW of solar PV cumulative capacity, driven by generous FITs adopted in 2009. Over the past year, the government announced FIT reductions for new ground-mounted solar PV plants from 2013 at the same time that it introduced FITs for residential installations. The incentive cuts were in line with equipment cost reductions, which should keep deployment attractive. The government has also signalled a schedule for incentive cuts to take place in 2015 and 2020, giving investors an indication of future developments. Over 2012-18, solar PV capacity is expected to rise by 0.6 GW to 0.7 GW, while onshore wind should add 0.9 GW. Deployment could be higher with faster cost reductions.

### *Non-OECD Americas*

The non-OECD Americas have excellent hydropower resources. Excluding Brazil, covered elsewhere in the report, hydropower production in the region reached almost 290 TWh in 2011, representing 50% of all electricity production.

Other renewable sources are also beginning to expand. **Uruguay** has been developing its onshore wind and bioenergy sectors through capacity auctions. It is also planning to tender 200 MW of solar PV capacity in 2013. Auction prices suggest that renewable energy enjoys good competitiveness. Existing hydropower generation costs are on average USD 80/MWh, while new wind projects were tendered for USD 63/MWh in 2011 (similar to auction results in Brazil). The government is reportedly seeking bids of USD 90/MWh from solar PV projects in the upcoming auction.

**Peru** is developing a portfolio of renewable sources. A number of bioenergy, solar PV and small hydropower projects are under development following capacity auctions in 2010. Significant onshore wind development plans have also emerged in **Panama**, with the government promoting "wind only" capacity tenders as part of its energy diversification strategy. Meanwhile, **Argentina** has set goals for increased bioenergy generation and is also planning incentives for utility-scale solar PV, in support of a goal of 8% renewables in generation by 2016. The cost and availability of financing will act as a challenge to development, however, given political risks. To that end, Chinese developers have emerged as a source of capital and are developing several large onshore wind projects.

### *Middle East*

While renewable power generation is only starting to emerge in the Middle East, the region contains significant potential for solar PV and CSP deployment. Thus far, most development has occurred in the **United Arab Emirates**. In early 2013, a 0.1 GW CSP plant – the world's largest to date – was commissioned in the desert of Abu Dhabi. The country also has 10 MW of cumulative solar PV capacity. Over the medium term, the United Arab Emirates is likely to continue to develop its solar capacity (both PV and CSP). **Jordan**'s power diversification needs and good resources should support strong deployment of solar PV and wind over the medium term. In 2012, it announced net metering and FITs for solar PV, CSP and wind, aimed at allowing residential and commercial-scale installations to feed excess electricity into the grid. All households in Jordan are to be fitted with smart meters by the end of 2013.

**Saudi Arabia** has set ambitious, long-term goals for solar, wind and waste-to-energy. The country is expected to hold an introductory tender round in 2013, auctioning 500 MW to 800 MW of utility-scale capacity. Two tender rounds, whose dates are unknown, are to follow. The kingdom anticipates that 5.1 GW of capacity will be added over the first five years of the programme (KA CARE, 2013). Local-content rules will apply to the tenders, with rates of 50% in the introductory round rising to a relatively high 70% by the second round. Saudi Arabia's resource availability, policy framework and incentive to diversify its power mix given high usage of oil for generation are all strong drivers. Nevertheless, uncertainty exists over the pace and delivery of projects under the tenders, given a lack of deployment history in the country. While capacity could be higher for some technologies, this report projects 1.5 GW of solar PV, 1.0 GW of CSP and 0.7 GW of onshore wind in 2018.

**Qatar** is planning to tender 200 MW of solar capacity (PV and CSP) in 2013. The country has adopted long-term renewable generation targets and is seeking to install 1.8 GW of large-scale solar capacity by 2014. The 2014 goal may be overly ambitious, given lack of deployment history, but medium-term growth is likely to be robust.

**Table 75** Middle East countries' main targets and support policies for renewable electricity

| Country | Targets | Support policies |
|---|---|---|
| Jordan | 7% renewable capacity by 2015 (60 MW wind, 300 MW solar PV);<br>10% renewable capacity by 2020 (1.2 GW wind, 600 MW solar PV, 30-50 MW waste-to-energy). | FITs;<br>net metering;<br>tax incentives;<br>competitive tenders. |
| Kuwait | 1% renewable generation by 2015;<br>15% renewable generation by 2030. | None. |
| Qatar | 18% renewable generation by 2018;<br>20% renewable generation by 2024. | Competitive tenders. |
| Saudi Arabia | 24 GW renewable capacity by 2020;<br>54 GW renewable capacity by 2032;<br>(16 GW solar PV, 25 GW CSP, 9 GW wind, 3 GW waste-to-energy). | Competitive tenders:<br>Introductory round (500-800 MW).<br>First round (1.1 GW of solar PV, 0.9 GW of CSP and 0.65 GW of onshore wind, and 50 MW to 350 MW of other renewables).<br>Second round (1.3 GW of solar PV, 1.2 GW of CSP and 1.05 GW of onshore wind, and 50 MW to 350 MW of other renewables). |
| United Arab Emirates | 5% renewable generation by 2020;<br>7% renewable generation by 2030. | Public investments, loans, grants;<br>competitive tenders. |

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# INVESTMENT IN RENEWABLE ENERGY

## Summary


- **Global new investment in renewable energy (wind, solar, biofuels, biomass and waste, geothermal, ocean, and small hydropower) decreased to USD 244 billion in 2012**, down 12% year-on-year from 2011. The annual reduction was the first since 2009, when biofuels investment notably slowed. In 2012, 75% of investment stemmed from the United States, Europe and China. Yet regional trends differed. The United States, Europe, India and Brazil all saw lower investment in 2012; investment rose in China, Japan, Australia and South Africa.

- **The slowdown in investment reflects a mixture of policy uncertainty and "stop-and-go" policy decision making in key regions as well as falling equipment costs** – in particular for solar photovoltaics (PV) and wind – and challenging financing conditions in several markets, including Europe. Nevertheless, investment is expanding in many emerging markets, including other countries in Latin America, Asia, the Middle East and Africa, supported by attractive project economics.

- **Among technologies, solar accounted for the largest share, almost 60%, of investment.** Small-distributed solar capacity investment represented one-third of the total and continued to rise globally in 2012, despite the fall in total renewable investment. Wind accounted for over 30% of total investment in 2012, though its absolute level declined versus 2011, partly due to falling system costs and policy uncertainty in some key markets. Bioenergy for power and liquid biofuels combined accounted for just over 5% of investment. Still, both categories fell versus 2011, particularly given challenging economics for biofuels production.

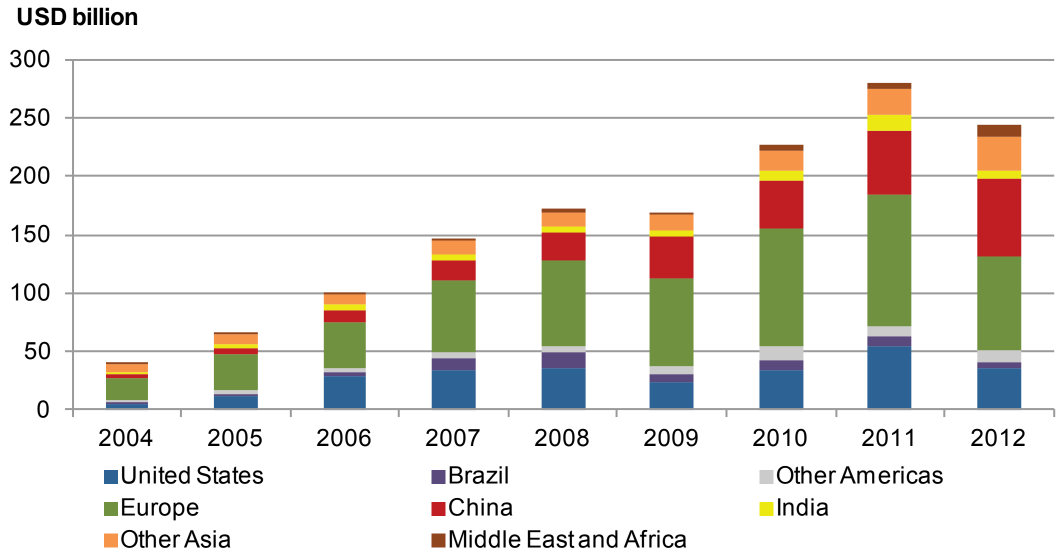
- **Going forward, increased macroeconomic risk and tighter bank capital requirements amid uncertainty about policy support in some areas may constrain funds from traditional sources** – bank project finance and utility balance sheet investment. Easing economic conditions combined with the emergence of new sources and structures of renewable finance may sustain overall investment over the forecast period. However, much will depend on the evolution of policy risks, the attractiveness of project economics and technology development.


## Recent market trends in renewable energy financing

In 2012, renewable energy investment – wind, solar, biofuels, biomass and waste, geothermal, ocean, and small hydropower – decreased to USD 244 billion in 2012, down 12% year-on-year from 2011, according to data from Bloomberg New Energy Finance (BNEF, 2013). The annual reduction was the first since 2009, when biofuels investment notably slowed. Still, the overall 2012 level remained high and resilient relative to historical trends. The total investment level also was impressive given a number of short-term challenges. In 2012, renewable energy markets, particularly the most dynamic segments – solar PV and wind – confronted several indicators of pressure. These included challenging macroeconomic and financing conditions in some areas, policy uncertainty in some key countries, reduced economic incentives in some markets (particularly where solar PV deployment had accelerated amid rapid cost reductions), competition from other energy sources (*e.g.* natural gas in the United States), and industry upheaval as well as integration challenges. At the same time, investment continued to expand in some Organisation for Economic Co-operation and Development (OECD) and emerging markets, including in Latin America, Asia and the Middle East and Africa, supported by attractive project economics.

China was the largest destination for new investment in renewable energy, and its level rose by 22% year-on-year, to USD 67 billion. Though Chinese wind investment slowed, a 70% increase in solar investment drove the total increase. Greater policy push and the granting of grid access for small-scale projects (<6 MW) are stimulating increased investment in solar PV there, even as system costs continue to fall. The United States was the second-largest renewable investment market in 2012, at USD 36 billion, but investment fell by 34% versus 2011. Wind investment remained far off its peak of almost USD 20 billion in 2010, due to ongoing uncertainty over the production tax credit (PTC) renewal. Biofuels investment was lower, with greater uncertainty over the US vehicle fleet's ability to absorb increased amounts of ethanol production and slow progress in the commercialisation of advanced biofuels. Investment in solar fell by 50%, however, even as solar PV deployment has risen strongly. This trend likely stemmed from cost reductions and fewer financings of very large concentrating solar power (CSP) and solar PV projects, which had boosted 2011 investment.

**Figure 84** New investment in renewable energy by region




Notes: financial new investment includes new-build asset finance, new investment by venture capital/private equity (VC/PE) investors in renewable energy companies, and new equity raised by renewable energy companies on the public markets, and is adjusted for equity reinvestment. Data exclude large hydropower.

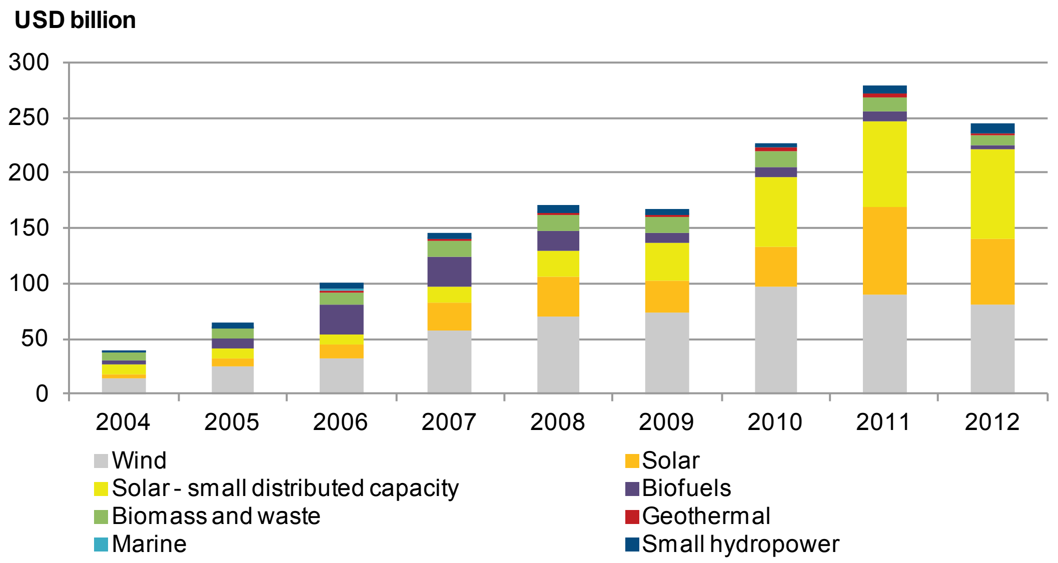
Source: Bloomberg New Energy Finance, 2013.

In 2012, renewable investment fell across most major European markets (Germany, Italy, the United Kingdom, France, Spain). Both wind and solar investment declined in Europe. A combination of cost reduction, integration and policy factors drove the changes, amid a more challenging general macroeconomic and financing environment. Reductions in financial support for solar PV and continued challenges in wind integration (both onshore and offshore) in Germany as well as a transition of support schemes in Italy have likely undermined some investment. Meanwhile, uncertainty over the future support levels under the United Kingdom's Electricity Market Reform have slowed some investment in offshore wind projects.

Elsewhere, the investment trend was mixed. The introduction of generous feed-in tariffs (FITs) in Japan buoyed investment there, particularly in solar PV, while attractive wind and solar production economics have boosted investment in Australia. India's investment climate faced considerable uncertainty in 2012 with the expiration of two key financial incentives for wind. Though one was restored in 2013, slowing wind investments drove part of India's 50% fall in total investment in 2012.

Finally, other emerging markets showed strong signs of growth, particularly in South Africa, supported by tendering schemes, and the Middle East, where stronger policy targets and measures were announced by several countries (*e.g.* Jordan, Qatar, Saudi Arabia).

**Figure 85** New investment in renewable energy by technology




Notes: investment volumes include new-build asset finance, new investment by VC/PE investors in renewable energy companies, and new equity raised by renewable energy companies on the public markets. Estimates for corporate research and development (R&D), government R&D and small-distributed capacity are not included here. There is no adjustment for reinvested equity. Data exclude large hydropower.

Source: Bloomberg New Energy Finance, 2013.

Among technologies, solar accounted for the largest share, almost 60%, of investment. Solar small-distributed capacity investment represented one-third of the total and continued to rise globally in 2012, despite the fall in total renewable investment. Wind accounted for over 30% of total investment in 2012, though its absolute level declined versus 2011, partly due to falling system costs and policy uncertainty in some key markets. Bioenergy for power and liquid biofuels combined accounted for just over 5% of investment. Still, both categories fell versus 2011, particularly given challenging economics for biofuels production.

## Medium-term enablers and challenges for renewable energy financing

A number of variables will shape the environment for renewable energy financing over the medium term. 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 needs for increased capital from other financial sources. The degree of this constraint will remain specific to markets and projects and may ease as macroeconomic conditions improve and new financial sources and structures emerge over the medium term. Still, investment trends will ultimately 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.

### *Macro risks point to continued tight financing picture*

The macro environment for renewable financing has remained challenging since the *MTRMR 2012*. Tight financial conditions and deleveraging have reduced bank lending globally, but particularly in euro area countries with more precarious sovereign positions. Given the prominent role of European markets and banks in renewable energy, this retrenchment represents a constraint, with an increasing scarcity of long-term project finance from European banks. Requirements imposed by Basel III, a global financial regulatory framework that seeks to reinforce the banking sector's ability to absorb economic shocks, are also a tightening factor. The associated rules, to be implemented at the country level from 2013-18, increase capital and liquidity requirements, which may reduce willingness to hold long-term loans (more than ten years) on bank balance sheets, undermining the availability of project finance. Lenders may increasingly turn to shorter-term loan periods, but these will tend to raise borrowing costs for renewable projects.

At the same time, utility balance sheets continue to face constraints, with a need to sell assets, raise more equity and exercise more caution with new investments such as renewable projects. In the United States, low natural gas prices and substitution needs for retiring coal plants are stimulating investments in gas-fired generation and related infrastructure. Although the trend remains difficult to quantify, it appears that such investments may be crowding out some renewable financing in the short term. In general, utilities are transitioning their roles from owners to developers and operators of renewable projects, marketing project stakes to other investors. While utility asset divestments have attracted new classes of investors, such as pension funds and sovereign wealth funds, the scale and number of transactions does not yet look sufficient to satisfy large renewable investment requirements over the medium term (Johns, 2013).

Government funds – from development banks and export credit agencies – continue to remain an important third traditional pillar of low-cost renewable financing. The European Investment Bank (EIB), the Brazilian Development Bank (BNDES), the European Bank for Reconstruction and Development (EBRD), and Kreditanstalt für Wiederaufbau (KfW) have accounted for the bulk of this investment. The emergence of new institutions, such as the United Kingdom's Green Investment Bank and Australia's Clean Energy Finance Corporation, continues to supplement these efforts. Nevertheless, the financial upside that development banks and export credit agencies can deliver over the medium term, particularly in the OECD, will remain constrained by fiscal pressures.

### *Financing to depend on policy risks and technology development*

Ultimately, the cost and availability of renewable energy finance going forward will depend most strongly on the prevailing policy, market and technology environments. Policy uncertainty is perceived by developers and investors as the main risk that they are unable to manage. To this end, countries that maintain durable targets and incentives over the medium term will continue to see strong financing for mature or near-mature technologies from both public and private sources. Under this assumption, financing should continue to flourish in places such as Germany, Denmark, California (and other US states with a strong renewable portfolio standard), Australia, Brazil and China. In other areas, good resource availability, technology cost reductions and a strong economic case for renewable deployment should attract financing, even in the face of more uncertain policy environments or higher levels of non-economic barriers. Such countries include India, Chile and Mexico. Still, the latter set of markets will face a relatively high cost of capital from international private sources. They may also face liquidity constraints from local sources of finance.

**Table 76** 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 | Medium-high | Early take-off | Demonstration/ early-stage investors |
| CSP, wind offshore | Medium | Low-medium | Early take-off | Consortia |
| Solar PV, wind onshore | Low | Low | Take-off | Asset/ project financing |
| Hydro, geothermal | Low | High | Consolidation | Very large/ consortia |

Note: unless otherwise indicated, all material in figures and tables in this chapter derives from International Energy Agency (IEA) data and analysis.

Some technology and cost issues may also act as constraints. Renewable energy investments continue to face the challenge that general investors lack experience in the sector. While technology risks continue to decline as a portfolio of renewable sources matures, perceptions of risk persist for some technologies. For example, some investors currently view grid access, construction risk and turbine availability as significant risks in offshore wind development, though these factors are expected to moderate over the next five years (Rubel *et al.*, 2013). In addition, the emergence of increased trade frictions (see Feature Box in *Renewable Electricity: Technology Outlook* chapter) may increase supply chain risks, raising concerns over the impact of potential countervailing duties on technology costs.

All the while, some technology-specific challenges to financing will persist, though the availability of some risk mitigation and/or minimisation mechanisms may help address them. Table 76 offers examples of hurdles faced by each technology and potential mechanisms that have been developed or are emerging to mitigate the associated risk. Aside from larger economic attractiveness considerations, the evolution of each of these mechanisms could act as a booster to the financing that each technology is able to attract over the medium term.

## *Continued emergence of new investment sources and structures*

Despite the constraints highlighted above, a large amount of capital is available in the market, and a number of other sources and structures are emerging to fill a growing financing gap. Still, their speed and degree of entry into renewable investments over the medium term remain uncertain. Banks, institutional investors and corporations from Asia are playing a larger role in financing projects, both at home and abroad. In the short term, relatively less-leveraged Japanese banks have stepped in to provide new project financing and acquire existing portfolios from European banks. In the medium term, strong potential exists for Chinese entities, which have access to significant amounts of low-cost finance, to enter the market. Chinese power companies, for example, have recently invested in renewable-linked companies and projects in Portugal and Australia.

New institutional and non-traditional corporate investors are becoming more active in renewable finance, though only gradually. With USD 28 trillion under management in 2009, private pension funds could play a large role (Della Croce, Kaminker and Stewart, 2011).[11] Their desire for steady, long-term returns mirrors the type of payments that renewable projects with purchasing power agreements can provide. So

[11] Assets held by private pension funds in OECD countries.

far their entry remains slow, with a need for financial instruments, such as asset-backed securities, to emerge that allow for investment that minimises exposure to construction risk. Infrastructure, sovereign wealth and insurance funds represent other large sources of funds, with investment profiles similar to pension funds. The first of these has better comfort with project risks, but represents a relatively smaller source of funds.

**Table 77** Technology-related financing challenges and potential financial mechanisms

| Technology | Primary challenge | Potential financial mechanism |
|---|---|---|
| Bioenergy | Securing long-term fuel supply. | Hedging contracts for feedstock. |
| CSP | Perceived technology risks by investors; relatively limited deployment to date. | Development bank direct lending and loan guarantees. |
| Geothermal | Exploration risk from wells with insufficient resource or temperature. | Exploration risk insurance. |
| Hydropower | Delays due to local opposition and/or environmental permitting. | Incorporation of environmental and social risk management tools, such as the Equator Principles, into investment decisions. |
| Offshore wind | Construction-phase risks, particularly as projects move farther offshore, and technology risks. | Development bank financing for certain project phases. |
| Onshore wind | General availability of project finance and economic attractiveness. | Managing production variability risk through insurance or weather-related instruments. |
| Solar PV | Household financing of high up-front system costs in residential PV. Availability of project finance for large-scale projects. | Third-party solar-leasing schemes. Development bank direct lending and loan guarantees. |

Note: examples are indicative – their inclusion in the table serves merely to demonstrate different types of financial innovation rather than to capture all potential mechanisms or suggest their suitability to a specific project.

The potential for non-utility corporate entities to fund renewable energy investments from their balance sheets remains large. Most corporate involvement to date has been indirect, through purchases of renewable energy certificates, for example. Corporations in the United States, largely banks, have provided tax equity financing to renewable projects, enabling them to monetise benefits from renewable energy tax credits in an up-front manner. However, as renewable capital costs have decreased, large corporate entities are taking more direct investing roles, through equity positions in renewable projects and contracting for energy through long-term power purchase agreements (Dominy and Barrett-Miles, 2013).

Some innovations could enhance financing over the medium term. Developments in the United States provide an example of potential enhancements. The US Congress is considering legislation that would allow renewable projects to qualify as Master Limited Partnerships (MLPs), a business structure that is traded like corporate equity, but is taxed as a partnership. MLPs have long facilitated fossil-fuel extraction and pipeline projects; if adopted, they could reduce the cost of capital for renewable projects and open renewable financing to new investors.

In addition, some developers are seeking approval from the US Internal Revenue Service to allow the inclusion of solar PV projects in real estate investment trusts (REITs), which would also reduce financing costs. Asset-backed securities for renewable projects (*i.e.* financial securities that pool assets and are traded on secondary markets) may emerge in 2013 or 2014. A recent study by the National Renewable Energy Laboratory (NREL) finds that increasing the use of public capital instruments described above could lower the LCOE of future projects (wind and solar PV) in the United States by roughly 8% to 16% versus benchmarked values under traditional, tax equity financing (Mendelsohn and Feldman, 2013).

### Box 1 IEA workshop: scaling up financing to expand the renewables portfolio

Meeting the challenge of ramping up renewable deployment quickly enough to be on track to reduce emissions requires high rates of deployment across the technology portfolio. The deployment of some renewable energy technologies has been growing strongly – particularly onshore wind and PV. The deployment of the some other technologies – notably offshore wind, CSP, bioenergy and geothermal – needs to be accelerated in order to meet long-term climate change goals. Finding financing solutions for the required broad portfolio of technologies is one of the major challenges in meeting these goals. Some of these technologies carry higher real or perceived risks, which tend to raise the costs of finance and decrease its availability.

This was the background for a workshop, organised in Paris on 9 April 2013 by the IEA Renewable Energy Working Party and with the active participation of members of its Renewable Industry Advisory Board. An invited audience of 140 senior decision makers from the key players worldwide – governments, project developers and investors across a range of asset classes – met to discuss and review the challenges and to identify financing solutions.

Some of the key conclusions reached during the discussions at the workshop are summarised below:

- Increased use of natural gas, including properly managed shale gas, has important benefits in reducing carbon dioxide ($CO_2$) emissions in replacing coal for power generation. Yet such reductions will not be sufficient to attain emission levels consistent with a temperature increase of less than 2 degrees Celsius. Renewables, along with improved energy efficiency, are an essential ingredient in any low-carbon energy mix.
- To realise favourable financing rates, risks must be mitigated or minimised and shared. For even the least-deployed technologies, technology risk is no longer seen as the main barrier to investment. Policy uncertainty is perceived by developers and investors as the main risk that they are unable to manage. This is why long-term predictable policies are absolutely critical. Retroactive measures must be avoided by all means as they undermine investment confidence in all technologies (not just renewables).
- The best-developed renewables technologies are increasingly cost-competitive. Commercial activity is growing in markets where there is an increasing need for energy, the resource is good and predictable long-term policies are in place. Where these conditions are met, the business case is strong and there are many circumstances in which renewables can be competitive. Some global players now make most of their investments in such unsubsidised markets.
- The competitiveness of renewables depends on the market design within which they operate. In markets which are based on short-term marginal pricing, the remuneration flow is uncertain. Such markets do not provide a secure investment climate for capital-intensive technologies such as renewables. By introducing risks, they put up prices and increase the need for financial support, even where technologies are able to provide energy at a competitive rate, as estimated by levelised cost of energy (LCOE) calculations. Market redesign based on competition over long-term contracts (as being developed in Brazil and some other Latin American countries for example) is one way to ensure sustained investment in capital-intensive low-carbon technologies.
- Financial support for renewables is still required to assist deployment of early-stage technologies, to introduce mature technologies into new markets and to compensate for market design failures. This support would be avoidable or much less costly if a level playing field was created by removing fossil-fuel subsidies and including external costs properly in accounting systems.
- Lowering the weighted average cost of capital can now have a significant impact on the price of renewables. This is why good financial engineering including the involvement of development banks and green funds is critical, in particular for technologies at the earlier stages of deployment.

The nature of renewable energy finance will evolve over the medium term as distributed capacity increases, supported by smaller-scale financial innovations. Such developments are most visible in the United States, where the advent of third-party leasing schemes has supported solar PV deployment for residential and commercial entities (leasing schemes have also emerged in Australia and Japan, for example). The emergence of crowdfunding platforms, which allow individual investors to directly finance shares of solar projects, may also play a role in enhancing the financing picture. Securitisation of small-scale solar PV has also emerged as an idea to enable financing. Efforts by NREL to standardise documentation and develop a project default database, along with market efforts to standardise project-level risk analysis, could lead to greater renewable asset securitisation over the medium term. While such arrangements may increase over the medium term, securitisation prospects look gradual in the United States.

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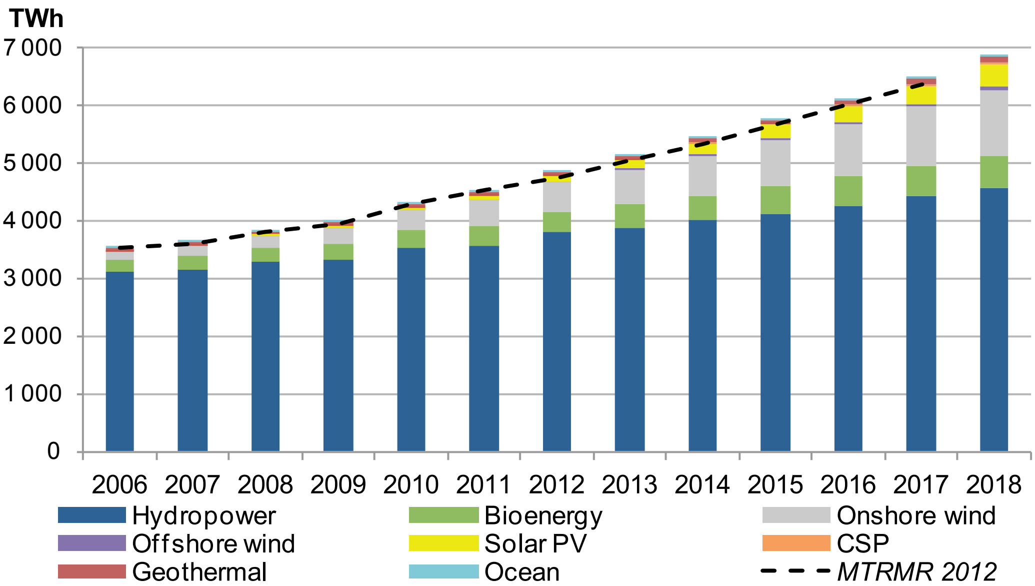
# RENEWABLE ELECTRICITY: TECHNOLOGY OUTLOOK

## Summary

- **In 2012, global renewable electricity generation rose by an estimated 370 terawatt hours (TWh) to 4 860 TWh (+8.2% year-on-year).** Growth was led by hydropower, particularly in China, which had a strong hydro year. Onshore wind expanded by over 77 TWh versus 2011 (+18.0%). Solar photovoltaics (PV) rose by almost 40 TWh to 100 TWh in total, on the basis of strong capacity deployment, while bioenergy power increased by over 20 TWh. Other technologies saw more modest growth, though in percentage terms growth was quite rapid in offshore wind and solar thermal electricity from concentrating solar power (CSP) plants.

- **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 1 580 GW in 2012 to 2 350 gigawatts (GW) in 2018 (growth of 49%), deployment should also spread out geographically. Second, renewable technologies are becoming increasingly competitive on a cost basis with their alternatives in a number of countries and circumstances.

**Figure 86** Global renewable electricity generation




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.

- **Global renewable electricity generation is projected to grow from 4 860 TWh in 2012 to 6 850 TWh in 2018 (+5.9% per year [/yr]).** Hydropower represents about 40% of total growth, 780 TWh, while non-hydro sources grow by 1 210 TWh between 2012 and 2018. Versus the *MTRMR 2012*, renewable generation is seen 95 TWh higher in 2017, led by upward revisions to hydropower, solar PV and onshore wind. China should lead growth within most categories: hydropower, onshore and offshore wind, solar PV, and bioenergy, as its total renewable generation grows by almost 790 TWh/yr (+10.1%). The United States has the highest increase in CSP and Indonesia has the highest increase in geothermal.

- **Hydropower remains the largest contributor to renewable power generation.** At 4 570 TWh in 2018, it should account for 67% of renewable electricity output. China accounts for 45% of generation growth over 2012-18. The rest of the non-Organisation for Economic Co-operation and Development (OECD), including Brazil and India, accounts for another 45% of growth. Among OECD countries, Canada, the United States and Norway remain the largest hydropower producers, but grow relatively slowly over 2012-18.

- **Onshore wind, bioenergy and solar PV also contribute significantly** and scale up over the medium term. In capacity terms, onshore wind is seen expanding by 255 GW over 2012-18, while solar PV increases by 210 GW and bioenergy rises by almost 45 GW. These three technologies are maturing and spreading out globally. Still, the bulk of growth continues to stem from China, Brazil, India and OECD countries. Falling costs are supporting the emergence of competitive market segments, particularly in solar PV and onshore wind.

- **Offshore wind and solar thermal electricity capacity are expected to grow rapidly,** reaching 28 GW and 12 GW in 2018, up from 5.4 GW and 2.7 GW in 2012, respectively. Still, deployment uncertainties characterise both technologies, with a continued need to overcome several technical and/or financing challenges. Greater deployment scale will be important for achieving cost reductions. Offshore wind developments concentrate in Europe and China. Meanwhile, CSP is expected to deploy in the United States with largely pure-solar designs and in China, India and North Africa.

- **Geothermal power grows moderately over the medium term,** with suitable resources located in only a few countries. High risk during the exploration phase also makes financing challenging. In principle, enhanced geothermal systems could help address some of these challenges, though development still remains at a nascent stage.

- **Ocean power should scale up from small- to medium-size demonstration projects in several countries, an important step towards commercialisation.** Due to its early stage of maturity, most developments remain at demonstration level with the exception of tidal barrages.

**Table 78** World renewable electricity capacity and projection (GW)

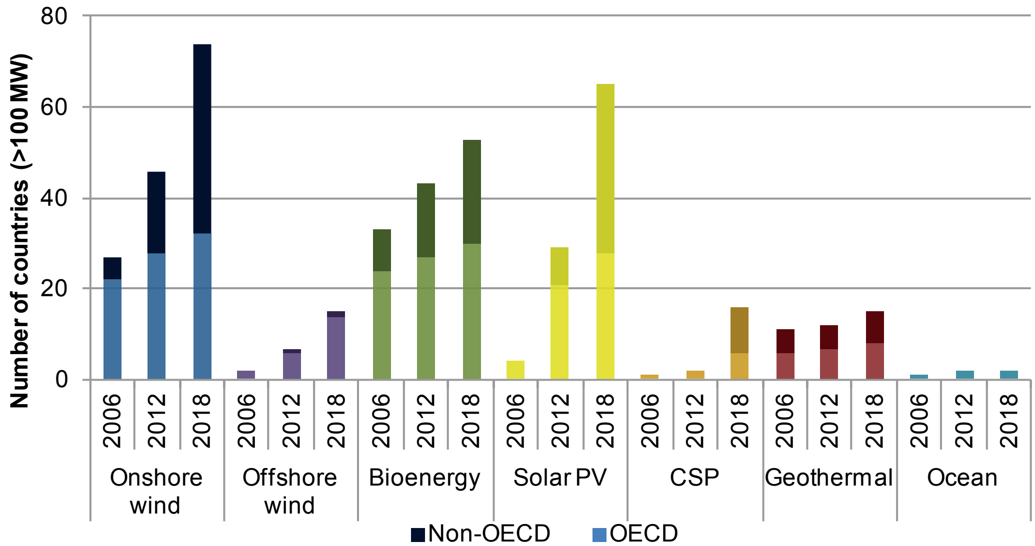
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Hydropower | 1 071 | 1 102 | 1 138 | 1 173 | 1 209 | 1 249 | 1 291 | 1 330 |
| Bioenergy | 75 | 82 | 89 | 96 | 105 | 112 | 119 | 125 |
| Wind | 236 | 282 | 321 | 368 | 413 | 459 | 508 | 559 |
| *Onshore* | 232 | 276 | 313 | 357 | 399 | 442 | 486 | 531 |
| *Offshore* | 4 | 5.4 | 8 | 11 | 14 | 17 | 22 | 28 |
| Solar PV | 69 | 98 | 128 | 161 | 194 | 230 | 268 | 308 |
| Solar CSP | 2 | 3 | 4 | 6 | 7 | 8 | 10 | 12 |
| Geothermal | 11 | 11 | 12 | 12 | 13 | 14 | 14 | 15 |
| Ocean | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total RES-E** | **1 465** | **1 579** | **1 693** | **1 815** | **1 941** | **2 073** | **2 211** | **2 351** |

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. Unless otherwise indicated, all material in figures and tables in this chapter derives from IEA data and analysis.

## Global trends in renewable power: geographical diffusion and competitiveness

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. In 2018, 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 2012, is expected to be deployed in almost 75 countries by 2018. Deployment of solar PV at the 100 MW level should be reached in 65 countries by 2018, up from 30 in 2012, and of bioenergy at that level in over 50 countries by 2018, up from 40 in 2012. The spread of offshore wind, CSP, geothermal and ocean deployment should remain relatively lower, however.

**Figure 87** Number of countries with non-hydro renewable capacity above 100 MW




Although the levelised cost of energy (LCOE) for some renewable energy technologies have further decreased, they remain generally more expensive than conventional electricity-generating technologies. However, opportunities for competitive opportunities are expanding. Having shown its competitiveness against new-built natural gas plants in Brazil's energy auctions last year, onshore wind power in good resource conditions has been deployed without robust financial support. In Australia, wind is competitive versus the generation costs of new coal- and gas-fired plants with carbon pricing, and the best wind sites can compete without carbon pricing. In Turkey and New Zealand, onshore wind has already been competing in the wholesale electricity market for several years now. With long-term power purchase agreements (PPAs), onshore wind costs are approaching that of new-build coal in South Africa. In Chile and Mexico, onshore wind competes or is close to competing with new natural gas plants. Geothermal and most hydropower remain competitive with their fossil-fuel alternatives with favourable resource conditions. As a proven mature technology, large-scale bioenergy plants are also competitive depending on feedstock prices and availability, while co-firing with biomass in coal and gas power plants has been increasing.

Over the past year, solar PV cell and module prices have further decreased, resulting in improvements in LCOEs for both utility and small-scale installations. Utility-scale solar PV costs are still higher than base-load electricity generation from conventional fuels; however, they approach competitiveness with peak power prices in locations with summer peak demand. Although small-scale solar PV installations are more expensive, they can still be economically attractive in several conditions. Moreover, geographic differences can oftentimes be tied to the level of incentives available, with overly generous support schemes tending to inflate costs in some markets. Off-grid installations are currently competitive in some locations where the only other option is to run a generator fuelled with fossil fuels. Grid-connected residential solar PV systems can achieve lower generation costs than retail electricity prices for households in countries with good solar resource and high retail power prices. It is worth noting that this situation may sometimes include the compensation of the fixed cost of grid connection by another party. Nonetheless, this competitive situation is a driver for increased investment in the sector. The competitiveness of solar PV should further improve over the medium term with decreasing module and system costs.

**Table 79** Top five countries, projected increase in generation (TWh) over 2012-18 by technology

| Hydropower | Onshore wind | Offshore wind | Bioenergy |
|---|---|---|---|
| China | China | China | China |
| Brazil | United States | United Kingdom | Brazil |
| India | India | Germany | United States |
| Canada | Germany | Denmark | United Kingdom |
| Vietnam | Canada | Belgium | Germany |

| Solar PV | CSP | Geothermal | Ocean |
|---|---|---|---|
| China | United States | Indonesia | Korea |
| Japan | China | Kenya | China |
| United States | Saudi Arabia | Mexico | Canada |
| Germany | Spain | United States | United Kingdom |
| Italy | India | Japan | Mexico |

Note: countries are ordered from highest to lowest.

**Table 80** Top five countries, projected increase in generation (%) over 2012-18 by technology

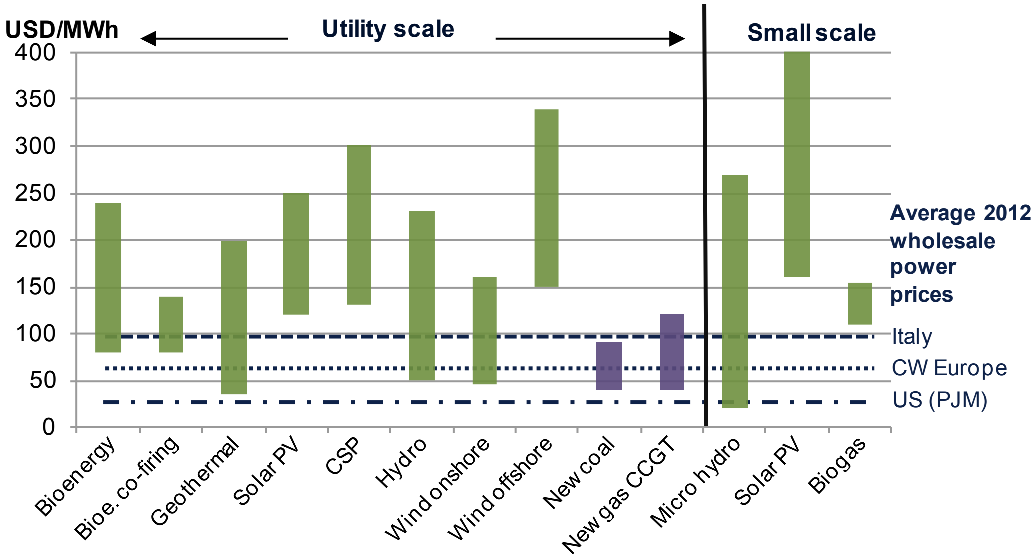
| Hydropower | Onshore wind | Offshore wind | Bioenergy |
|---|---|---|---|
| Cambodia | Saudi Arabia | United States | South Africa |
| Nicaragua | Namibia | Canada | Romania |
| Ethiopia | Mozambique | Estonia | Lithuania |
| Morocco | Kazakhstan | France | Latvia |
| Portugal | South Africa | Korea | Malaysia |

| Solar PV | CSP | Geothermal | Ocean |
|---|---|---|---|
| Saudi Arabia | Saudi Arabia | Chile | Mexico |
| Chile | South Africa | Australia | Sweden |
| Qatar | United Arab Emirates | Korea | Ireland |
| Turkey | Qatar | France | Australia |
| Oman | Jordan | Ethiopia | 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 2018.

Still, the competitiveness of renewables depends on the market and policy framework within which they operate. Even in situations of good competitiveness, policy, market and technology risks can undermine project viability. Policy uncertainty is chief among these risks, but non-economic barriers, integration challenges, counterparty 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.

**Figure 88** Levelised costs of power generation (USD per megawatt hour [/MWh]), first quarter 2013




Notes: MWh = megawatt hour; CCGT = combined cycle gasification turbine. Costs are indicative and ranges reflect differences in resources, local conditions and the choice of sub-technology. Wholesale power prices are expressed as the annual average of daily traded, day-ahead base-load power prices. CW 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 mid-west portion of the United States.

Source: IEA analysis with power price data from Bloomberg LP, 2013.

## Bioenergy for power

Bioenergy-based power production scales up with increased use of agricultural and municipal wastes. Co-firing starts to play an important role in countries with large coal power production.

### *Technology development*

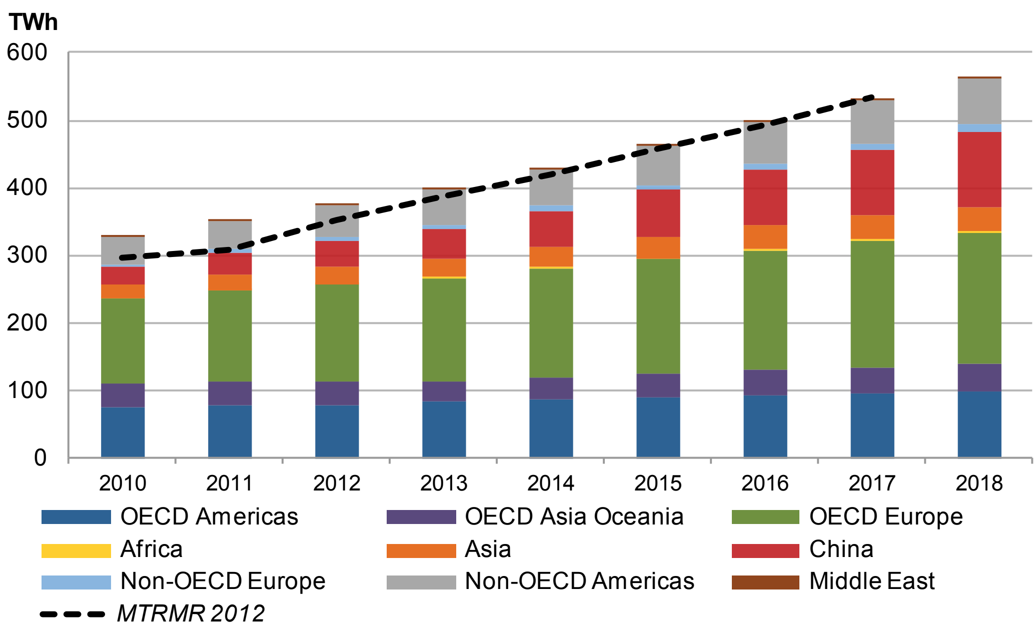
Bioenergy encompasses the use of solid biomass, biogas, liquid biofuels and renewable municipal waste for power generation. The most efficient use of bioenergy for power generation stems from operating plants in co-generation[12] mode, which requires stable heat demand, as employed, for example, in the pulp and paper industry. Co-firing with fossil fuels is becoming more prevalent in countries with large shares of coal-fired generation. Co-firing offers a transition towards bioenergy-only generation, particularly in markets moving away from coal-fired generation. In Europe, some coal-fired plants nearing the end of their lifetime are being converted to run entirely on biomass.

[12]Co-generation refers to the combined production of heat and power.

Above all, successful bioenergy projects require the establishment of a stable fuel supply chain. Not every country has great domestic bioenergy potential, but renewable municipal waste can contribute to power production anywhere. Some bioenergy feedstocks are internationally traded, which is rare among renewable energy sources. 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.

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. 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 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).

**Figure 89** Bioenergy generation and projection by region




The relationship between bioenergy power generation and capacity is not always straightforward from a statistical standpoint. Though co-generation plants produce both electricity and heat, the bioenergy power capacity and generation reported here corresponds to the electricity component. Co-firing capacity is reported by the dominant fuel, *e.g.* coal, and typically does not appear in bioenergy statistics. By contrast, the generation from these processes is often reported in bioenergy data. Though biomass conversions are included in this report's projections, reported capacity data from IEA statistics may potentially not include bioenergy capacity converted from fossil fuels, *e.g.* in mixed plants that are not reported on a unit basis. These phenomena vary by country. As such, this report's baseline data (IEA official statistics in the case of OECD countries) may carry a degree of error in counting bioenergy capacity. In addition, each bioenergy technology (co-fired or not) has a corresponding typical capacity factor, with the set of deployed technologies differing by country. This report's capacity factors are typically based on a country's historical data.

## *Market status and outlook*

In 2012, bioenergy contributed 373 TWh to global power production, up from 352 TWh in 2011 (+5.9% year-on-year). The United States led generation with an estimated 63 TWh, up by 1.6% versus 2011. China's output, at 38 TWh in 2012, continued to grow at a fast rate (+21% year-on-year). OECD Europe's bioenergy generation continued to expand, led by Germany, Italy and the United Kingdom, where output was boosted by a full year of output from the Tilbury B (750 MW) plant conversion completed in late 2011. Output from two other large producers, Sweden and Finland, also grew with increased use of forest biomass and renewable waste in co-generation. Among non-OECD countries, Brazil advanced its position as leading bioenergy producer and India continued to scale up its output.

Over the medium term, bioenergy generation and capacity are expected to scale up significantly. Global bioenergy production is expected to reach 560 TWh in 2018, up from 373 TWh in 2012 (+7% annually on average). Global cumulative capacity is seen increasing from 82 GW in 2012 to almost 125 GW in 2018. Much of this growth is led by China (+17 GW over 2012-18), with ambitious targets under its 12th Five-Year Plan (FYP). Renewable waste-to-energy plants are likely to play an important role in development, given limited landfill space in many Chinese cities. Other non-OECD countries – Brazil, India and Thailand – are also expected to add significant capacity. In India, biogas-fired co-generation and off-grid applications are likely to dominate deployment.

**Table 81** Bioenergy capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 47.9 | 50.8 | 53.8 | 56.5 | 59.5 | 62.0 | 64.3 | 66.5 |
| *OECD Americas* | 14.4 | 15.1 | 15.8 | 16.3 | 17.1 | 17.7 | 18.3 | 19.0 |
| *OECD Asia Oceania* | 2.7 | 2.8 | 3.0 | 3.2 | 3.4 | 3.5 | 3.7 | 3.9 |
| *OECD Europe* | 30.9 | 32.8 | 35.0 | 36.9 | 39.0 | 40.7 | 42.3 | 43.7 |
| Non-OECD | 27.4 | 31.5 | 35.2 | 39.7 | 45.3 | 49.9 | 54.4 | 58.8 |
| *Africa* | 0.1 | 0.2 | 0.2 | 0.3 | 0.4 | 0.5 | 0.6 | 0.8 |
| *Asia* | 10.1 | 11.1 | 11.8 | 12.5 | 13.4 | 14.3 | 15.0 | 15.7 |
| *China* | 7.0 | 8.0 | 10.0 | 13.0 | 16.0 | 19.0 | 22.0 | 25.0 |
| *Non-OECD Europe* | 1.5 | 1.7 | 1.9 | 2.1 | 2.3 | 2.4 | 2.6 | 2.7 |
| *Non-OECD Americas* | 8.6 | 10.6 | 11.4 | 11.8 | 13.1 | 13.7 | 14.1 | 14.6 |
| *Middle East* | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | 75.4 | 82.3 | 89.0 | 96.1 | 104.7 | 111.9 | 118.7 | 125.3 |

Note: bioenergy capacity does not include plants that co-fire; though conversions are included in this forecast, reported capacity data from IEA statistics (2011 and earlier data points) may not include bioenergy capacity converted from fossil fuels, particularly in mixed plants.

OECD growth is expected to be dominated by OECD Europe, driven by National Renewable Energy Action Plans (NREAPs). In the United Kingdom and Denmark, some additions involve large-scale conversions of coal-fired units. Elsewhere, Japan's waste-to-energy generation expansion should help raise capacity there. Both the United States and Canada are expected to grow, though the outlook remains more uncertain there, with low natural gas and wholesale power prices potentially slowing expansion. Still, both areas possess good availability of low-cost feedstock (*e.g.* wood pellets). The two countries are likely to remain large sources of wood pellet exports over the medium term.

## Geothermal

Geothermal advances, though its rate of growth is slower than most other renewable sources mainly due to up-front investment risks associated with drilling and exploration.

### *Technology development*

Geothermal power is a mature renewable technology that can provide base-load power from energy stored in rock, trapped vapour and liquids. Although geothermal's estimated resource potential is large, early-stage exploration and drilling risks remain a deployment challenge, with only a few developers able to finance these risks. Debt financing is typically not available for this stage of development, which carries an uncertain success rate associated with well drilling. Developers typically bear the risk. As such, the geothermal exploration market is highly concentrated with only a few financially solid players. So far, exploration risk insurance is available only in a few countries.

Technology development activities remain ongoing, with a focus on enhanced geothermal systems (EGS). EGS would allow projects to produce electricity in locations with low- or medium-heat value by pumping highly pressurised fluid into existing fractures of the hot rock in order to create a flowing reservoir that is used to generate electricity. Over the past year, a geothermal developer in the United States implemented this technology to an unproductive well next to the commissioned power plant that it drilled few years ago. In April 2013, the EGS technology enabled the company to increase its plant capacity by around 1.7 MW to 25 MW. Potentially, EGS can be used to upgrade existing wells or create geothermal reservoirs where there were none previously. A number of testing activities are under way in the United States. Still, 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 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 4 000/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). Generation costs for geothermal plants range from USD 35/MWh to USD 80/MWh, while generation costs of binary plants are usually higher.

### *Market status and outlook*

In 2012, geothermal power generation stood at 72 TWh while the cumulative capacity reached 11.4 GW. The new installed additions stood at 0.5 GW, significantly higher than in 2011. More than half of this capacity was commissioned in the United States, with around 0.3 GW mainly due to the anticipated expiration of the PTC. Indonesia added another 0.1 GW followed by Mexico with 50 MW and Kenya with 30 MW, while the Philippines installed 10 MW of new capacity.

Global geothermal power capacity is expected rise to 15 GW in 2018, up from 11.4 GW in 2012. The global outlook is broadly in line with the *MTRMR 2012*. The largest deployment should take place in Indonesia with around 750 MW of new plants coming online by 2018. The United States should add another 500 MW bringing its total to 3.9 GW, while the Philippines is expected to deploy 300 MW over the projection period, reaching around 2.2 GW. The market in Japan is expected to pick up due to generous feed-in tariffs and new regulations which made the exploration in the periphery of national parks relatively easier. Japan should add 300 MW over the medium term, bringing its total to 0.85 GW, though development could be greater over the long term due to long project lead times. Finally, Mexico is expected to deploy 240 MW, to reach 1.25 GW of cumulative capacity in 2018, and some capacity growth is expected in Chile.

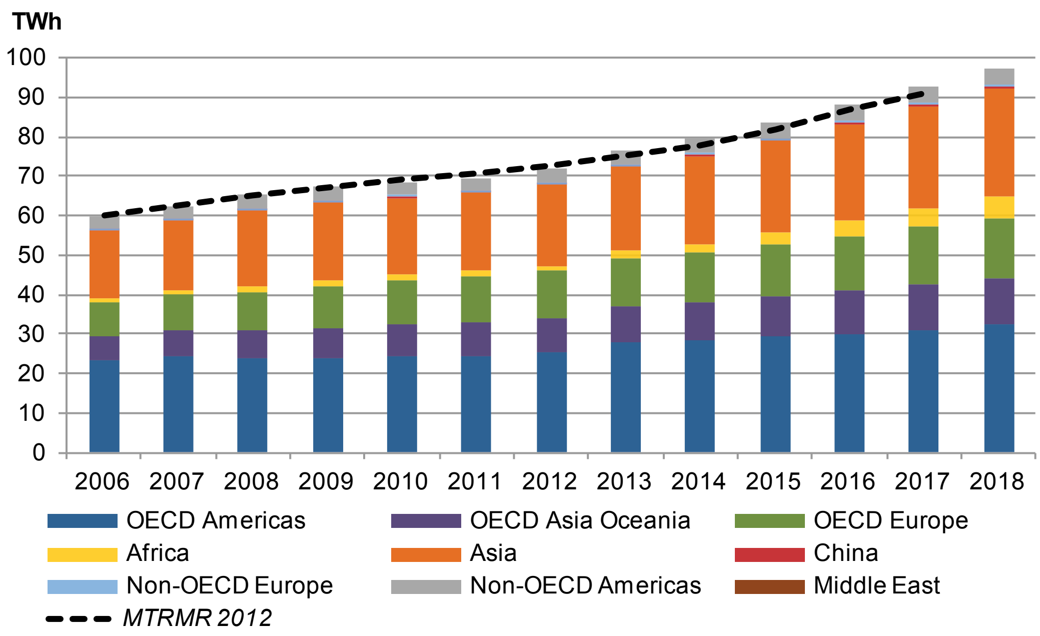
**Table 82** Geothermal capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 6.9 | 7.3 | 7.5 | 7.7 | 8.1 | 8.4 | 8.8 | 9.0 |
| *OECD Americas* | 4.1 | 4.4 | 4.5 | 4.6 | 4.8 | 4.9 | 5.1 | 5.2 |
| *OECD Asia Oceania* | 1.3 | 1.3 | 1.4 | 1.4 | 1.5 | 1.6 | 1.8 | 1.8 |
| *OECD Europe* | 1.6 | 1.6 | 1.6 | 1.7 | 1.8 | 1.9 | 2.0 | 2.0 |
| Non-OECD | 4.0 | 4.1 | 4.3 | 4.5 | 4.9 | 5.2 | 5.6 | 6.0 |
| *Africa* | 0.2 | 0.2 | 0.3 | 0.3 | 0.5 | 0.6 | 0.7 | 0.8 |
| *Asia* | 3.1 | 3.2 | 3.3 | 3.5 | 3.6 | 3.8 | 4.0 | 4.3 |
| *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 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 |
| *Middle East* | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **10.9** | **11.4** | **11.8** | **12.2** | **13.0** | **13.6** | **14.4** | **15.0** |

Sources: IEA analysis; 2011 data for OECD are reported IEA data; 2011 data for Non-OECD regions are IEA estimates based on BP, 2013.

On the generation side, geothermal resources should provide around 97 TWh globally in 2018. Around 60% of power production should come from OECD countries, while non-OECD markets, mainly in Southeast Asia, Africa and Latin America, should provide the remainder.

**Figure 90** Geothermal generation and projection by region



## Hydropower

Hydropower stays the largest renewable power generating source over the medium term. Addressing financing and sustainability issues will be important for future developments.

### *Technology development*

Hydropower is a fully commercial and mature technology. There are three main types of hydropower: reservoir, run-of-river and pumped storage. It is a very flexible renewable source of energy, able to provide base-load power as well as power for peak demand. Both reservoirs and pumped hydro storage can provide large-scale storage of electricity, providing valuable flexibility to power systems.

**Box 2** Pumped storage hydropower and total hydropower

In the *MTRMR 2013*, hydropower generation and capacity data include electricity generated from and capacity of pumped storage plants (PSPs) because it is difficult to separate out the storage component from the total hydropower capacity data. The 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, electricity output from pumped storage is typically excluded from power generation data and treated separately. However, this report calculates future hydropower generation from capacity that cannot always be separated into such discrete parts as in generation. For example, it is difficult to isolate pure PSP capacity because the same unit is sometimes used as a pumped storage unit and at other times as a conventional hydropower plant. These "mixed hydro" plants produce electricity from natural water flows and also have the capability to use extra capacity to pump water for storage. This use of capacity is difficult to estimate and project going forward. For now, this report takes the conservative approach of aggregating all hydropower capacity – PSP and conventional hydropower – for its projections. For that reason, hydropower generation data include output from pumped storage.

Nevertheless, it is instructive to offer historical hydropower estimates with reported pumped storage separated out. In 2011, according to statistics from the IEA Energy Data Centre, global total hydropower generation stood at 3 567 TWh. Of this, reported generation from pumped storage represented 75 TWh. As described above, characterising PSP capacity remains challenging. *MTRMR 2013* reports total global total hydropower capacity at 1 070 GW for 2011. IEA analysis shows that existing installed turbine capacity in PSP projects worldwide neared 140 GW in 2011, up from 98 GW in 2005 (IEA, 2012b).

Capital costs of hydropower plants vary depending on project. Civil works are an important cost component and depend on local materials and labour prices. An array of hydropower cost studies exist, with a range from as low as USD 1 050/kW to as high as USD 7 650/kW for large projects, and USD 1 300/kW to USD 8 000/kW for smaller projects (IRENA, 2012). Parameters affecting costs also include the project scale, ranging from over 10 GW to less than 0.1 MW; the location; and the presence and size of the reservoir. Generation costs of electricity from new plants vary widely, from USD 50/MWh to USD 100/MWh, but can fall as low as USD 20/MWh and as high as USD 230/MWh for small projects (IEA, 2012b). Plant generation costs are determined by construction costs, financing regime and capacity factor. Some plants are operated for peak-load demand and as backup for network frequency fluctuation, which raises costs but also the value of the electricity produced.

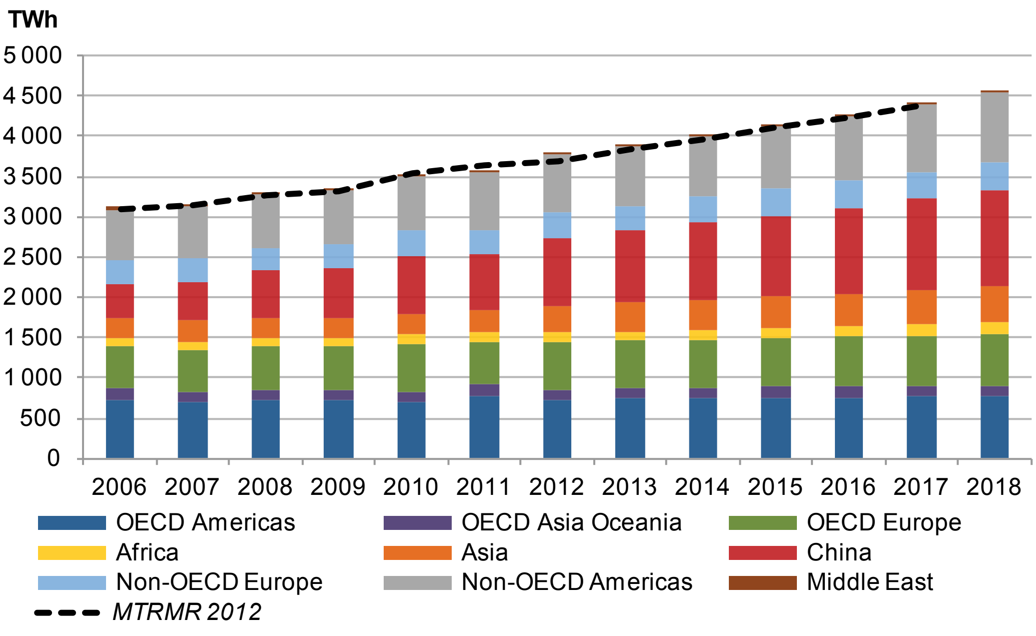
Over its history, sustainability and socio-economic concerns, related to local environmental impacts and resettlement, have coloured hydropower development, particularly large-scale plants. A number of new sustainability protocols have come about seeking to mitigate such concerns. Careful planning and measures to minimise negative externalities will remain important to activity going forward.

Tracking and forecasting hydropower capacity present several challenges. In practice, large hydropower plants come on line in multiple stages, as turbines are installed. Yet additions may show up in reporting data only once the entire plant has been commissioned. Small hydropower capacity poses difficulties in tracking due to size. Moreover, tracking problems also emerge as older hydropower plants, especially in Europe, are enlarged, repowered and relicensed. Hydropower production is dependent on weather and can exhibit significant yearly variability that cannot be anticipated. While weather phenomena stand out more in country-level data, the global total can also be affected, as in 2010, which was an exceptionally good year for hydropower production.

## *Market status and outlook*

Hydropower remains the largest source of renewable power. In 2012, global hydropower generation, including pumped storage, rose to an estimated 3 792 TWh. While year-to-year variations in hydropower output can vary based on weather patterns, it is worth noting that 2012's generation rise was also driven by a continued capacity expansion. Global hydropower cumulative capacity, including pumped storage, rose to over 1 102 GW in 2012, versus 1 071 GW in 2011 (+2.9% year-on-year). China, which added 16 GW of capacity, led the growth. Cumulative capacity rose by 4.8 GW in the OECD, led by Turkey, Canada and Japan, while the non-OECD outside of China expanded by over 10 GW, led by Brazil and India.

**Figure 91** Hydropower generation and projection by region




Note: hydropower generation includes pumped storage.

A significant amount of global resource potential remains. Especially in developing countries, where hydropower can provide a cheap and reliable electricity source, large exploitation potential exists. According to the Intergovernmental Panel on Climate Change (IPCC), Africa has developed only about 8% of its potential, while Asia has harnessed only about 20% of its resource potential and Latin America, 26% (Kumar *et al.*, 2011).

Emerging and developing countries, where there is still a huge untapped potential and strong electricity demand, drive most current expansions on a global scale. Much OECD development to date has occurred in large plants, though activity is taking place in smaller projects and in plant refurbishment. The European Union (EU) Water Framework Directive aims to optimise water body usage (conservation, flood protection, hydropower, transport needs, irrigation, etc.). For hydropower, its implementation may reduce generation in some EU member states, depending on how the directive is implemented. However, planned upgrades across some plants may offset this effect.

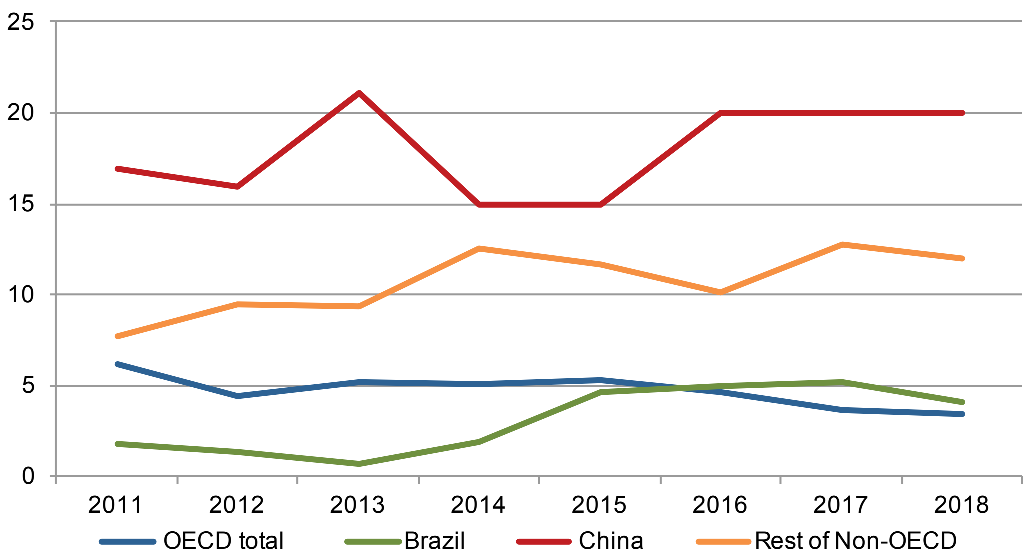
**Table 83** Hydropower capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 461 | 465 | 471 | 476 | 481 | 486 | 489 | 493 |
| *OECD Americas* | 194 | 195 | 197 | 198 | 201 | 203 | 203 | 204 |
| *OECD Asia Oceania* | 69 | 69 | 69 | 70 | 70 | 70 | 71 | 71 |
| *OECD Europe* | 198 | 201 | 205 | 208 | 210 | 212 | 215 | 217 |
| Non-OECD | 610 | 636 | 668 | 697 | 728 | 763 | 801 | 837 |
| *Africa* | 26 | 27 | 28 | 30 | 31 | 32 | 35 | 39 |
| *Asia* | 95 | 100 | 105 | 111 | 116 | 121 | 127 | 132 |
| *China* | 233 | 249 | 270 | 285 | 300 | 320 | 340 | 360 |
| *Non-OECD Europe* | 91 | 93 | 95 | 97 | 99 | 100 | 102 | 103 |
| *Non-OECD Americas* | 151 | 153 | 155 | 159 | 167 | 174 | 181 | 187 |
| *Middle East* | 14 | 15 | 15 | 16 | 16 | 16 | 16 | 17 |
| **Total** | **1 071** | **1 102** | **1 138** | **1 173** | **1 209** | **1 249** | **1 291** | **1 330** |

Note: hydropower capacity includes pumped storage.

Sources: IEA analysis; 2011 data for OECD are reported IEA data; 2011 and 2012 non-OECD data are IEA estimates based on multiple sources, including International Journal on Hydropower & Dams, 2012 and Platts, 2013.

**Figure 92** Hydropower annual capacity additions (includes pumped storage) by region (GW)




Hydropower production is expected to reach 4 570 TWh in 2018, up from 3 792 TWh in 2012. Overall, the global forecast is largely in line with that from the *MTRMR 2012*. This associated growth in capacity should also provide the flexibility needed for the integration of large numbers of variable renewable additions projected for some countries in this report. In 2018, China should represent 26% of global hydropower production, up from 20% in 2011. In a number of countries in Asia, Africa and Latin America, hydropower should also grow, driven by development and energy security concerns.

Global hydropower capacity should grow by 228 GW between 2012 and 2018, reaching 1 330 GW in 2018. Much of this growth is driven by China's additions of 15 GW to 20 GW/yr. Notably, China's second-largest hydropower plant, Xiluodo (12.6 GW), is expected to come on line over 2013-14. Brazil's additions are also significant, a total of 20.5 GW between 2012 and 2018. The construction of the Belo Monte Amazon Dam (11.2 GW), which began in 2011, is expected to come on line in phases from 2015-16. Other established large hydropower producers – the United States, Canada and Russia – are expected to expand at slower rates. Significant growth is expected from a number of non-OECD areas, including India and other countries in Asia and non-OECD Americas.

## Ocean power

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

### *Technology development*

Ocean power encompasses five different types of technologies that exploit the following phenomena: tidal rise and fall (barrages), tidal/ocean currents, waves, temperature gradients, and salinity gradients. 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 are modular and have smaller visual and environmental impact. Overall, the resource potential for ocean technologies is significant and widespread. Tidal and wave projects provide variable but highly predictable power. 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.

Over the past year, several tidal/wave technology development companies, utilities and research institutions have installed several full-scale testing devices. In addition, several governments and the European Union continued to fund technology demonstration projects. In 2012, three 100 kW units of a new wave technology, WaveRoller, were deployed in Portugal to collect validation data. There are several technologies with similar wave energy and tidal currents demonstration projects. In May 2012, the National Renewable Energy Centre of the United Kingdom launched its 3 MW marine drive test rig while Pentland Firth and Orkney Waters (PFOW) Marine Energy Park also become operational in July. In addition, the Crown Estate leased another seven seabed exploration sites for more demonstration projects. In the United States, a total of 5.5 MW demonstration projects were deployed over the past year testing different wave and tidal technologies. Several prototypes and demonstration plants have been launched in China as well.

In their demonstration stage, most ocean energy technologies remain relatively expensive. The US Department of Energy conducted a detailed cost analysis for wave energy and concluded that costs could decrease significantly as technology moves towards more commercial scale (IEA, 2013). 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.

### *Market status and outlook*

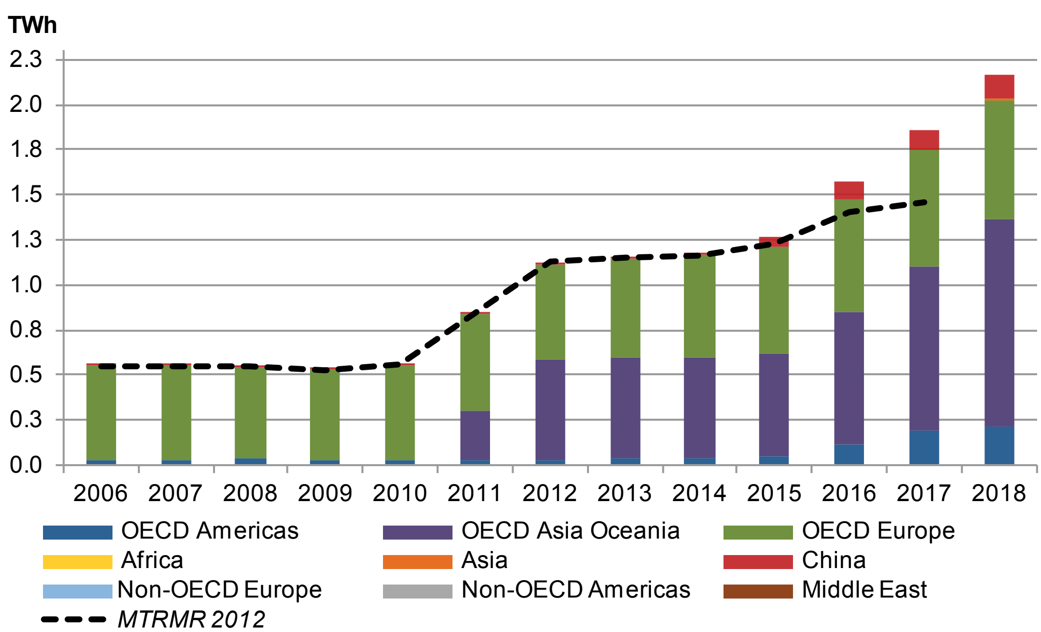
Since the commissioning of the Sihwa Lake tidal barrage (254 MW) in Korea in 2011, no large-scale projects have been deployed. In 2012, global cumulative capacity expanded by 10 MW with the deployment of several demonstration projects to reach 0.53 GW. While the largest share of this total capacity consists of two plants in France and Korea, some small projects, mainly in the United Kingdom, contributed as well. Total power generation increased by 0.3 TWh in 2012, to reach an estimated 1.1 TWh. This increase is mostly due to the availability of a full year of output from the Sihwa power plant, which was commissioned in August 2011.

**Table 84** Ocean power capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 0.52 | 0.53 | 0.54 | 0.55 | 0.58 | 0.81 | 0.85 | 1.07 |
| *OECD Americas* | 0.02 | 0.02 | 0.02 | 0.02 | 0.04 | 0.10 | 0.12 | 0.13 |
| *OECD Asia Oceania* | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 0.42 | 0.43 | 0.64 |
| *OECD Europe* | 0.24 | 0.25 | 0.25 | 0.26 | 0.28 | 0.29 | 0.30 | 0.31 |
| Non-OECD | 0.01 | 0.01 | 0.01 | 0.01 | 0.04 | 0.04 | 0.06 | 0.06 |
| *Africa* | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| *Asia* | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| *China* | 0.01 | 0.01 | 0.01 | 0.01 | 0.04 | 0.04 | 0.06 | 0.06 |
| *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 |
| **Total** | **0.52** | **0.54** | **0.54** | **0.55** | **0.62** | **0.85** | **0.91** | **1.14** |

Sources: IEA analysis; 2012 data are IEA estimates based on the Implementing Agreement for a Co-operative Programme on Ocean Energy Systems, 2013.

**Figure 93** Ocean power generation and projection by region




Over the medium term, ocean energy should expand by around 0.65 GW, with cumulative capacity reaching 1.1 GW in 2018. High costs and uncertainties over the deployment of commercial-scale capacity mean that expansion should be modest relative to other renewable technologies. Nevertheless, the forecast is more optimistic than in *MTRMR 2012.* This is mainly due to Korea's ambitious plans to deploy several large-scale tidal barrages over the medium term. Accordingly, Korea's ocean power capacity should increase by around 0.35 GW over 2012-18, though some developments will face the challenge of balancing environmental concerns related to local wetland impacts. Although many demonstration projects have been deployed in the United Kingdom, it remains to be seen whether any large projects will be fully deployed over the medium term. There, ocean cumulative capacity should expand by 55 MW to reach 65 MW in 2018.

The outlook for China is slightly more optimistic than projected in the *MTRMR 2012.* Cumulative capacity in China is expected to grow by 55 MW to reach 61 MW by 2018. Canada's expansion over the medium term should be led by the province of Nova Scotia, which is currently designing a tidal energy feed-in tariff (the first in the world) that is expected to be launched in 2013. Canada is expected to deploy around 75 MW of new capacity over the projection period. Finally, Mexico is expected to deploy the country's first wave project in late 2013 with an initial phase of 3 MW, to be increased to 33 MW by 2018.

In 2018, ocean power is expected to deliver around 2.2 TWh of power globally with the largest part of the generation coming from France and Korea, producing 0.5 TWh and 1.1 TWh, respectively.

## Offshore wind

The potential of offshore power remains high, but technical, financial and grid connection issues pose challenges to the deployment over the medium term.

### *Technology development*

Offshore wind turbines are deployed in coastal regions, typically exploiting wind resources that are significantly better than at onshore sites. Today's operating offshore wind turbines are essentially based on large land turbines customised for the ocean environment. Like their onshore counterparts, offshore wind turbines provide variable power, but can have some comparative advantages. Offshore wind farms can be located near large coastal demand centres, often avoiding long transmission lines to get power to demand, as can be the case for onshore renewable power installations – this can make offshore particularly attractive for countries with coastal demand areas and onshore resources located far inland, such as China. These locations also generally have higher wind resources than onshore, typically with less turbulence. While needing to satisfy environmental stakeholders, offshore wind farms generally face less public opposition and, to date, less competition for space compared with onshore developments. As a result, projects can be large, with 1 GW power plants likely to be achievable in the future.

With relatively higher capital costs and construction risks, offshore wind has great innovation potential over the medium term. In the past, competition in the offshore segment was relatively limited, with few turbine manufacturers offering few products. However, this situation has started to change with new manufacturers announcing new offshore models. In 2012, 31 companies announced plans for 38 new offshore wind turbine models with a few commissioned as prototypes (EWEA, 2013). Most of these announced models have a rated capacity over 5 MW. Although European companies still lead the industry, manufacturers from China, Korea and Japan are developing new models. In 2012, the average rated capacity of installed offshore wind turbines was 4 MW, higher than in the previous year (EWEA, 2013).

Not only are turbine sizes increasing but projects are moving farther from shore and into deeper waters, where wind resources are higher. However, these projects require more sophisticated planning, substructures (foundations) and turbine installation vessels. In 2012, monopole substructures dominated the market with 74% of all foundations while gravity-based substructures were the second-most-common choice of developers (BNEF, 2013). Floating substructures are receiving more attention, especially for planned projects in deeper waters. Currently there are two experimental and two full-scale floating substructures, which are being tested.

Installation vessels play a major role in construction time; their flexibility, size and capabilities are crucial for cost optimisation. In 2012, several new generation installations vessels became operational. They are capable of operating in deeper waters and in harsher sea conditions. In addition, they are able to carry more foundations, which reduce the number of trips to the harbour. The supply of installation vessels could represent a challenge for the industry. Although several new vessels entered operation in 2012, the availability of vessels over the medium term could be influenced by the demand of the offshore oil and gas industry.

Although competition has been increasing among turbine manufacturers and transport vessels, significant manufacturing bottlenecks still exist in some other parts of the offshore supply chain. The supply of high-voltage transmission cables currently does not match the demand for planned projects over the medium term. The manufacturing of these cables is limited to a few companies. Some of them already announced their plans to increase their production capacity. However, a possible lack of supply over the medium term may delay the connection of some projects.

**Table 85** Offshore wind capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 3.8 | 5.0 | 7.2 | 9.5 | 10.8 | 13.1 | 16.5 | 20.2 |
| *OECD Americas* | 0.0 | 0.0 | 0.0 | 0.2 | 0.4 | 0.5 | 0.8 | 0.9 |
| *OECD Asia Oceania* | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.5 | 0.5 | 1.0 |
| *OECD Europe* | 3.8 | 5.0 | 7.1 | 9.0 | 10.1 | 12.1 | 15.2 | 18.3 |
| Non-OECD | 0.3 | 0.4 | 0.5 | 1.5 | 2.7 | 4.2 | 6.0 | 8.0 |
| *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* | 0.3 | 0.4 | 0.5 | 1.5 | 2.7 | 4.2 | 6.0 | 8.0 |
| *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** | **4.0** | **5.4** | **7.7** | **10.9** | **13.6** | **17.3** | **22.5** | **28.2** |

Sources: IEA analysis; 2012 data are IEA estimates based on GWEC, 2013; and EWEA, 2013.

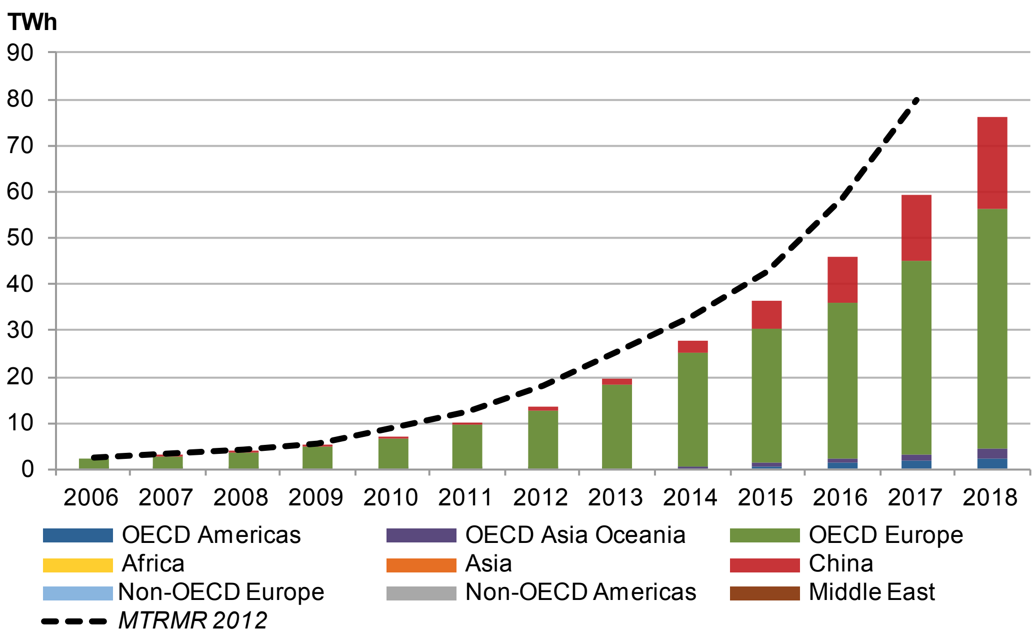
Characterising the range of recent capital costs for offshore wind plants remains problematic, due to the small number of projects from which to sample. In 2011, average offshore capital costs ranged from EUR 2.7 million/MW (USD 3.5 million per MW) in Denmark, to EUR 3.6 million/MW (USD 4.6 million/MW) in Germany (IEA Wind, 2012). With projects moving farther from shore into deeper waters, the range of capital costs in Europe appears to have narrowed and risen. From late 2011 to early 2013, projects were being financed from around EUR 3.5 million/MW (USD 4.5 million/MW) to EUR 4.9 million/MW (USD 6.2 million/MW). In the United States the cost of a reference offshore wind plant has been estimated at over USD 6.0 million/MW (Navigant, 2012). Data from Bloomberg New Energy Finance indicate that LCOEs in early 2013 for offshore wind projects range from around USD 150/MWh to USD 340/MWh (Bloomberg LP, 2013). However, overall costs of offshore projects are highly dependent on the type and size of the project, and construction delays due to harsh environmental conditions. Operation and maintenance (O&M) costs for offshore developments can also be higher than those for onshore projects.

### *Market status and outlook*

In 2012 global offshore wind generated an estimated 13.5 TWh, up 32% from the 10.2 TWh output registered in 2011. In 2012, global offshore wind installed capacity reached 5.4 GW with 1.4 GW of new additions versus 2011. Although the deployed capacity was lower than expected due to grid-connection delays, especially in Germany, it represented the highest annual capacity additions to date. More than 90 percent of this new capacity was installed in Europe while the remaining was deployed in China. The United Kingdom installed 0.95 GW with two large projects (Ormonde and Walney 2) commissioned, followed by Denmark with 0.35 GW. Belgium added 0.18 GW and China 0.13 GW. Germany only deployed 0.08 GW last year, lower than projected in the *MTRMR 2012*.

Global offshore wind power capacity is expected to expand from 5.4 GW in 2012 to 28.2 GW in 2018. 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 35 GW in 2018.

**Figure 94** Offshore wind generation and projection by region




Europe should represent two-thirds of the total offshore cumulative capacity in 2018, with significant contributions expected from the United Kingdom, Germany and Denmark. In China, the offshore wind policy environment remains complex, given the governance of offshore areas involving multiple government agencies. There, developments are moving farther from the coast to comply with regulatory rules. Capacity growth is likely to remain less than 8 GW over 2012-18 due to supply chain and construction challenges. The remaining projected capacity should come largely from the United States, Japan and Korea. The expansion in the United States assumes that construction of the 468 MW Cape Wind project commences by early 2014, in line with recent media announcements.

Compared with the *MTRMR 2012,* the forecast has been revised down by 3.5 GW in 2017 due to persistent policy environment uncertainties in several key countries, connection delays, challenging financing conditions and supply chain bottlenecks. The German offshore market has been affected by all of these challenges over the past year. By 2017, Germany is expected to have cumulative capacity of 3 GW, 1 GW less than forecast in the *MTRMR 2012*. The other major revision stems from France. Over the past year, the French Transmission System Operator announced that it would be challenging to connect turbines by 2018. Accordingly, the projection for France is revised down by 1.5 GW in 2018. In addition, Japan is likely to have around 0.8 GW less in 2017 than forecast in the *MTRMR 2012*, mainly due to technical challenges that the market is currently experiencing. By contrast, the forecasts for Ireland, the United Kingdom and Finland are somewhat more optimistic.

In 2018, offshore wind power should deliver 76 TWh of electricity globally, and 2017 is seen lower than forecast last year due to the revised capacity outlook. The United Kingdom should generate 23.5 TWh and China should generate 19.6 TWh in 2018. Germany follows with 13 TWh while offshore capacity in Denmark should generate 6.5 TWh.

## Onshore wind

Onshore wind remains the second-largest renewable energy generation source. Although manufacturers face several challenges, the deployment should be strong over the medium term.

### *Technology and manufacturing development*

Onshore wind power is a proven and mature technology. Typical load factors range from 20% to 35%, with exceptionally good sites exceeding 50%. Wind is a variable source of power and therefore can achieve high penetrations only in power systems with sufficient existing or anticipated flexibility. The ability of grids to accommodate high levels of variable renewables varies significantly by geography.

Over the last decade, the majority of innovations in onshore wind turbines were focused on blade design, electrical systems and generators. The focal aim of these innovations has been to design more efficient machines with higher towers and larger rotor diameters that can capture more wind. Over the past couple of years, wind turbine manufacturers have focused on low- and medium-wind turbines because they expect significant growth from this segment. In 2012, almost all wind turbine manufacturers launched new low- and medium-wind turbines, mainly in the 2.0 MW to 2.5 MW sector. In addition, turbine technology development has focused on efficiency, grid integration, transportation, and monitoring and controlling of wind turbines.

For larger turbines with higher towers and larger blades, transportation costs are increasing. Companies are investing in the use of advanced modelling tools to optimise the weight and transportability of materials used. With decreasing margins for both developers and manufacturers, and increasing competition, innovative transportation solutions have become more crucial. Recently, some innovation has also focused on the variability issue of wind power as the share of wind generation has been increasing significantly in many countries. Several manufacturers have moved from induction generator technology to permanent magnet synchronous generators, which allow for increased efficiency during high wind variability. Performance optimisation has been another innovation focus, which has a direct impact on O&M costs. O&M services with advanced software technology can increase the efficiency of wind power plants.

Turbine prices have been decreasing over the past decade. In 2012, they decreased slightly to EUR 0.85 million per megawatt (/MW) (USD 1.1 million/MW) from EUR 0.94 million/MW (USD 1.23/MW) in 2011. Annual O&M prices have been decreasing significantly since 2008 from EUR 31 000 (USD 40 500)/MW to around EUR 19 000 (USD 24 800)/MW (BNEF, 2013). While turbine and O&M costs remain largely similar around the globe (China and Japan are notably different from each other in this comparison, however) due to high competition in the industry and the increased build-out of wind globally, total capital expenditure costs (CAPEX) and the LCOE can vary significantly. While China and Brazil have the lowest CAPEX and LCOE, costs are significantly higher in Western Europe and much higher in Japan. In 2011, onshore wind project costs ranged from USD 1.2 million/MW to USD 3.8 million/MW (IEA Wind, 2012). In 2012 and early 2013, project costs were as low as USD 1.1 million/MW in China, while they are estimated to be higher in the United States (USD 1.6 million/MW), Western Europe (USD 1.7 million/MW) and Japan (USD 2.6 million/MW) (Lantz, Wiser and Hand, 2012; BNEF, 2013).

Globally, recent data points indicate that LCOEs can vary significantly, from around USD 45/MWh to USD 160/MWh. Over the past year, some projects signed PPAs with lower prices. The lowest estimated wind power contract in China was around USD 43/MWh (BNEF, 2013). The latest energy auction in Brazil resulted in a price of USD 42/MWh. In the United States, LCOEs calculated for new projects with standard technology range from USD 60/MWh to USD 92/MWh (NREL, 2012). In Germany, costs are slightly higher ranging between USD 78/MWh and USD 104/MWh (Fraunhofer, 2012). Japan records one of the highest LCOEs with USD 160/MWh (BNEF, 2013).

**Table 86** Onshore wind capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 147.8 | 173.6 | 188.3 | 208.4 | 226.1 | 242.9 | 260.3 | 278.7 |
| *OECD Americas* | 51.7 | 66.5 | 72.3 | 83.6 | 92.6 | 101.0 | 110.2 | 120.4 |
| *OECD Asia Oceania* | 5.5 | 6.3 | 7.7 | 9.3 | 11.0 | 12.6 | 14.2 | 16.1 |
| *OECD Europe* | 90.6 | 100.8 | 108.4 | 115.4 | 122.6 | 129.3 | 135.9 | 142.2 |
| Non-OECD | 84.6 | 102.9 | 124.6 | 148.4 | 173.1 | 198.8 | 225.6 | 252.5 |
| *Africa* | 1.0 | 1.1 | 1.6 | 2.6 | 3.5 | 4.4 | 5.2 | 6.1 |
| *Asia* | 16.8 | 19.5 | 21.7 | 24.2 | 27.5 | 30.8 | 34.1 | 37.4 |
| *China* | 62.4 | 75.3 | 91.3 | 108.3 | 126.3 | 145.3 | 165.3 | 185.3 |
| *Non-OECD Europe* | 2.2 | 3.5 | 4.3 | 5.0 | 5.5 | 6.0 | 6.7 | 7.3 |
| *Non-OECD Americas* | 2.1 | 3.3 | 5.6 | 7.9 | 9.9 | 11.7 | 13.4 | 15.2 |
| *Middle East* | 0.1 | 0.1 | 0.2 | 0.3 | 0.4 | 0.6 | 0.8 | 1.2 |
| **Total** | **232.5** | **276.5** | **313.0** | **356.7** | **399.3** | **441.7** | **485.9** | **531.2** |

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

Sources: IEA analysis; 2012 data are IEA estimates based on GWEC, 2013.

Turbine manufacturing capacity peaked in 2011 mainly due to record-level installations and new turbine contracts in the United States and China. For 2013, orders in the United States are lower than

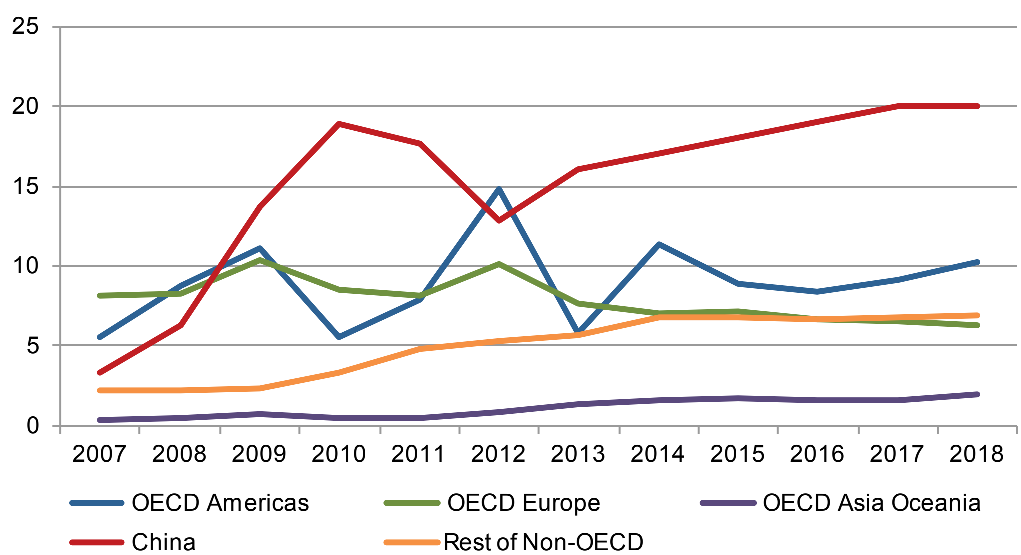
2012, but in China they are higher. Turbine manufacturing companies have been experiencing an oversupply for the last few years, and decreasing their margins to stay competitive in the global market. This situation has resulted in major annual losses and in heavy cost-cutting measures for many leading turbine manufacturers, mostly led by European companies. The demand for turbines is expected to pick up again in 2013 and 2014. Some companies have already closed several costly manufacturing facilities over the past two years in Denmark, Germany and Spain. Some of these companies will likely invest in new manufacturing plants in emerging markets, such as in Brazil and South Africa, where the market is expected to grow rapidly over the medium term.

### *Market status and outlook*

In 2012, onshore wind generation increased by almost 80 TWh to reach an estimated 505 TWh (+17% year-on-year). Global cumulative installed capacity expanded by over 46 GW, around 20% higher than in 2011, to reach 279 GW in total. New installations were led by the United States and China, which each installed around 13 GW. While additions in the United States were much higher due to a rush before the expected expiration of the PTC at the end of 2012, installations in China were lower versus 2011 with authorities putting more emphasis on permitting and planning and synchronising the build-out of the grid with new wind capacity. In 2012, OECD Europe added 10 GW of new capacity with Germany, Italy, Spain and the United Kingdom each installing more than 1 GW. In the non-OECD, cumulative capacity rose significantly in India, Brazil and Romania. In India, capacity additions slowed versus 2011 due to uncertainty over the renewal of some key financial incentives that expired in April 2012.

Over the medium term, global onshore wind capacity is expected to expand from 277 GW in 2012 to 531 GW in 2018. Versus the *MTRMR 2012,* expected cumulative capacity in 2017 has been revised up by 22 GW with more optimistic deployment, mostly in non-OECD markets. 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 570 GW to 585 GW in 2018.

**Figure 95** Onshore wind annual capacity additions by region (GW)

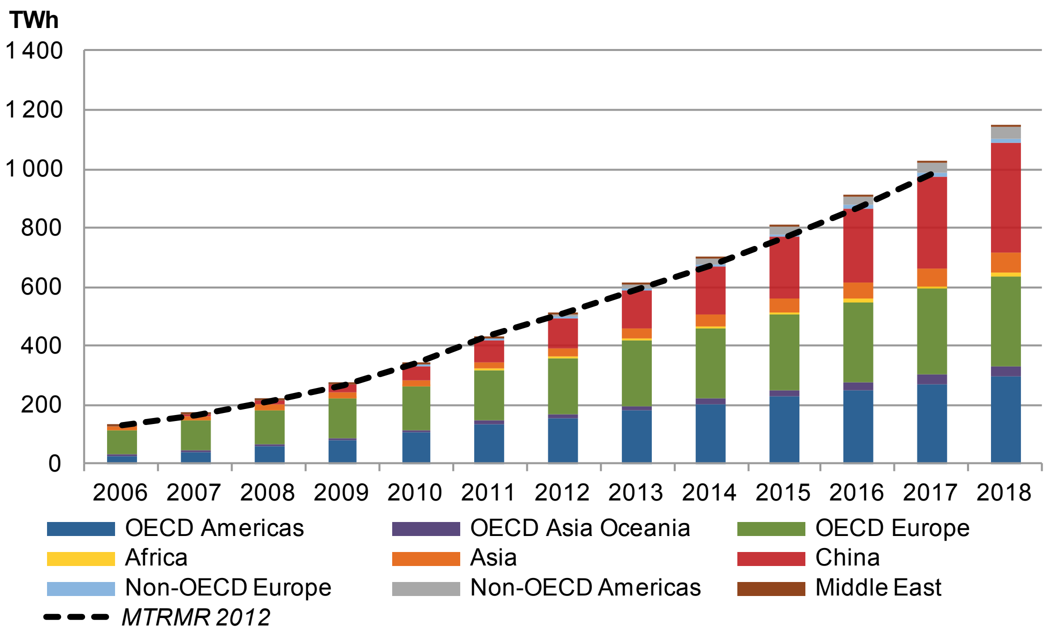



While the PTC was renewed in the United States in early 2013 and India announced the reinstatement of its generation-based incentive, these measures came too late for developers to establish a robust project pipeline for 2013. Moreover, there is uncertainty over the long-term durability of both measures. As a result, annual installations are expected to slow and global additions for 2013 are expected to be lower than in 2012. Annual installations are then expected to gradually rise over the medium term. In 2018, China is forecast to have the largest cumulative capacity with 185 GW followed by the United States at 92 GW. Germany and India should follow, with 40 GW and 35 GW, respectively.

Cumulative installed capacity in OECD Europe is seen expanding by 41 GW over 2012-18, though annual deployment is seen remaining stable (6 GW to 7 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 12 GW, Mexico 5.8 GW and Chile 2.5 GW over 2012-18. Several countries in OECD Asia Oceania should experience strong growth, led by Australia (+5.1 GW) and Korea (+2.4 GW). Development in Japan is likely to proceed more slowly, with cumulative capacity growing by only 1.7 GW over 2012-18 as sites remain far from demand centres and require transmission upgrades.

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. Global onshore wind production is expected to reach over 1 144 TWh in 2018, almost double the estimated global generation in 2012. The share of non-OECD countries will continue to increase in global generation, reaching 44.3% in 2018. The forecast assumes that China's current low implied capacity factors will increase over time as the difference between installed and grid-connected wind farms narrows over time and curtailment is progressively reduced. China's onshore wind output should reach around 370 TWh in 2018, followed by the United States at 238 TWh. Germany is expected to be the third producer with 77 TWh, while India should reach 63 TWh.

**Figure 96** Onshore wind generation and projection by region



## Solar photovoltaics

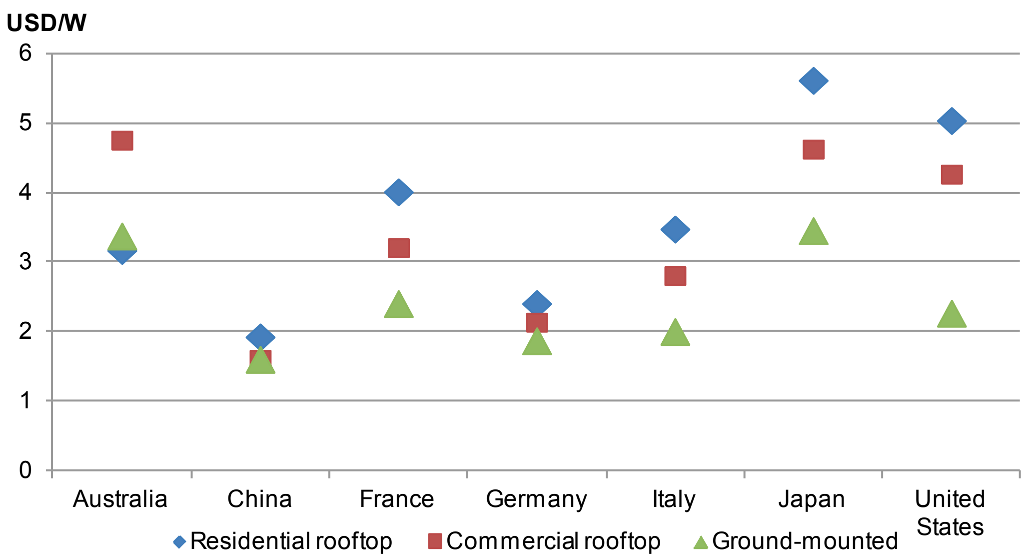
With system prices falling rapidly, solar PV booms and spreads to all world regions. The industry is restructuring as deployment transitions from subsidised markets to more competitive ones.

### *Technology and manufacturing development*

Recent developments in solar PV have been dominated by a trend of rapidly falling system prices, which is supporting high rates of capacity additions. In some markets, governments are lowering financial incentives at the same time that competitive applications for solar PV are increasing through greater self-consumption and/or market exposure. Meanwhile, manufacturing overcapacity and ongoing consolidation generally characterise the upstream sector.

Solar PV module prices continued to fall rapidly over the past year. Data from Bloomberg New Energy Finance show spot multicrystalline silicon module prices averaging USD 0.78 per watt (/W) in March 2013, with monocrystalline modules at USD 0.82/W. Both quotes were 22% lower than in March 2012 (Bloomberg LP, 2013). Multicrystalline modules made in China were even lower, averaging USD 0.67/W (-25% year-on-year). According to pvXchange, thin film module prices ranged from USD 0.55/W to USD 0.73/W in March 2013, lower on average by 21% year-on-year (pvXchange, 2013). Economies of scale and technological improvements, such as reduced polysilicon prices and usage, have driven cost reductions over time. Recent falling module prices are also explained by the vast oversupply situation – solar PV demand was close to 30 GW in 2012 versus global production capacity of about 55 GW, which may make current, very low module prices unsustainable over time. Thin film technologies are still improving but have not increased market shares given the price reductions of crystalline solar PV. As module prices fall, balance of system (BOS) becomes relatively more important for overall costs. This is driving the market towards higher-efficiency crystalline cells as they entail lower BOS expenditures.

**Figure 97** Typical solar PV system prices, by segment (Jan 2013)




Notes: data based on survey taken in January 2013; costs are indicative and may not represent all transactions.

Sources: IEA analysis based on the Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems, 2012; SEIA/GTM Research, 2013; and BREE, 2012.

Total system prices vary significantly depending on application type and market. Large-scale ground-mounted solar PV systems, as of early 2013, were as little as USD 1.5/W, including financing in optimal conditions. This was close to system prices that some market analysts expected – just two years ago – to apply in 2019. Even taking a more sustainable module price (*i.e.* sustainable from a manufacturing margins perspective) of USD 0.8/W into account would only bring the system price to USD 1.7/W, a 45% reduction in a two-year time period. Nevertheless, solar PV system costs continue to vary significantly across markets due to differences in labour costs, permitting costs, marketing costs, tax systems and financing costs, among other factors. Too-generous support systems can also partly explain cost inflation among markets. The variation between rooftop solar PV and ground-mounted systems can differ due to transaction costs, insurance costs, connection costs and feed-in tariff levels. In some cases, such as commercial rooftops in Australia, high costs stem from deployment that is still at a nascent level.

The LCOE of solar PV depends heavily on the quality of the resource, the initial cost of installation, the cost of capital and maintenance costs. At present, low financing costs, low system prices and good to excellent solar resource do not yet simultaneously apply in any specific market. Early-2013 generation costs ranged from USD 120/MWh to USD 250/MWh for large-scale systems and USD 160/MWh to USD 400/MWh for small-scale installations, depending on the solar resource. Recent utility-scale PPAs are as low as USD 130/MWh in areas with 1 300 full-load hours (or USD 77/MWh in sunny areas of the United States, with the presence of tax incentives). In India, solar PV auction bids have been made as low as INR 6 450/MWh (USD 120/MWh). France has cut its feed-in tariff for large-scale solar PV from EUR 105/MWh (USD 135/MWh), an attractive enough level for deployment, to EUR 85/MWh (USD 110/MWh), which may be currently too low to spur significant activity. Uruguay is looking to tender solar PV at USD 90/MWh in its auction this year, but it is unknown at time of writing if any bids have been made that low. Nevertheless, agreed purchase prices and bids may be only indirect indicators of LCOE.

Falling costs are supporting the emergence of competitive market segments. 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). Other emerging competitive market segments are linked to the concept of grid or "socket" parity – when the LCOE of decentralised solar PV systems becomes lower than retail electricity prices that system owners would otherwise pay. Net metering regulations facilitate this competitiveness when solar PV generation costs are near retail electricity prices. As generation costs fall, net metering may appear to grid operators as too advantageous for solar PV investors, with the grid serving as free "storage". A feed-in tariff may thus be set, at a lower level than retail electricity prices, thus making self-consumption appear attractive. In the absence of affordable storage capacity, competitiveness first emerges for commercial buildings, where there is a good temporal match between production and consumption. For other segments, such as households, competitiveness depends on the ability of an end-user to self-consume a significant portion of what systems produce, with the remainder sold to the grid. Socket parity markets are appearing in Spain, Italy, southern Germany, southern California, Australia and Denmark, and across residential and commercial segments. It is worth noting that this situation may sometimes include the compensation of the fixed cost of grid connection by another party. Nonetheless, this competitive situation is a driver for increased investment in the sector.

Meanwhile, the solar PV manufacturing industry is undergoing major consolidation. Manufacturing overcapacity and high inventory levels have created a significant imbalance between manufacturing supply capacity and demand along many parts of the upstream supply chain. Many companies, including in China, are selling their products with zero margins or at a loss just to keep their market shares. Over the past year, many companies scaled back their production or restructured, and some went out of business. As a result, some solar PV manufacturing capacity has gone offline. Still, it is not clear that the assets of bankrupt companies will always be decommissioned. For example, the recent bankruptcy of Chinese manufacturer Suntech (formerly one of the world's largest module makers) may not necessarily reduce its manufacturing capacity due to local employment concerns (Goossens and Roca, 2013).

As manufacturing overcapacity only slowly recedes, it is likely that solar PV module prices will remain low in the short term, with some volatility, and stabilise over the medium term as a significant number of players exit the industry. Still, two additional trends may affect this outlook. As a result of ongoing trade disputes, anti-dumping duties have been imposed in the United States against solar PV cells made in China. The European Commission is also considering import duties on Chinese-made components, and China is investigating duties on US- and Korean-made polysilicon. In May 2013, the commission recommended average import duties around 50% on Chinese manufactured modules. It is beyond this report's scope to assess the likelihood and price impact of such measures, as their implementation and impact remains complex. While trade actions are unlikely to create significant short-term pricing changes, they could further squeeze margins along the solar PV value chain while slowing rapid falls in system prices.

Ultimately, the emergence of new markets may emerge as the biggest factor to reduce industry pressures. To this end, the stimulation of solar PV demand in China, Japan and other emerging markets where competitive segments are emerging will be key. Still, the pace and degree of development will not likely stay the industry's painful consolidation over the medium term.

### *Market status and outlook*

In 2012, global solar PV cumulative capacity – including grid-connected and operating off-grid systems – grew by an estimated 29.4 GW (+42% year-on-year). Annual additions were similar to the 30 GW in 2011 and higher than the 22 GW projected for 2012 by the *MTRMR 2012*. Stronger-than-expected deployment occurred in a number of markets, but the largest contributors to the divergence were Germany, Italy and the United States (the three largest in cumulative installed capacity), whose cumulative capacity increased by a combined 5.3 GW higher than expectations.

Significant growth occurred in a number of other OECD markets, though with some expanding more slowly. The introduction of very attractive feed-in tariffs in Japan propelled installations of 2.0 GW in 2012 and has created a large pipeline of projects for future development. As of April 2013, the government had approved around 6.7 GW of new solar PV under the feed-in tariff regime that had not yet been installed. Australia emerged as a 1 GW market in 2012. Despite feed-in tariff reductions in some states designed to keep pace with falling costs, installations grew to 1.0 GW from 0.8 GW in 2011, led by residential development. The United Kingdom, Greece, Canada and Denmark also saw higher annual growth. By contrast, solar PV deployment slowed in Belgium, France and Spain.

The non-OECD was led by China, which installed an estimated 3.5 GW of new solar PV in 2012 and was the world's second-largest deployment market. New grid-connection rules for small-distributed capacity as well as the expected introduction of new financial incentives are driving increased activity in small-scale segments there. India's cumulative capacity rose by 1.1 GW, led by the commissioning of capacity under the Jawaharlal Nehru National Solar Mission (JNNSM). Several other significant markets emerged in 2012, though with mixed future prospects. Thailand and Ukraine installed an estimated 0.2 GW each of solar PV in 2012. Bulgaria added 0.8 GW, driven by an overly generous incentive scheme that drove deployment too rapidly in the eyes of the government. In 2012, the country cut incentives for new projects and introduced retroactive cuts for existing plants, significantly undermining new deployment potential.

**Table 87** Solar PV capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 64.3 | 87.5 | 107.6 | 125.5 | 144.8 | 165.0 | 185.5 | 206.1 |
| *OECD Americas* | 5.0 | 8.6 | 12.7 | 17.4 | 22.8 | 28.0 | 33.6 | 39.3 |
| *OECD Asia Oceania* | 7.2 | 10.5 | 16.1 | 21.7 | 27.8 | 35.4 | 42.8 | 50.3 |
| *OECD Europe* | 52.1 | 68.4 | 78.8 | 86.5 | 94.3 | 101.6 | 109.1 | 116.6 |
| Non-OECD | 4.7 | 10.8 | 20.7 | 35.1 | 49.2 | 65.3 | 82.3 | 101.6 |
| *Africa* | 0.2 | 0.3 | 0.4 | 0.7 | 1.2 | 1.7 | 2.3 | 2.9 |
| *Asia* | 0.6 | 2.0 | 3.4 | 5.6 | 7.9 | 10.5 | 13.5 | 16.7 |
| *China* | 3.5 | 7.0 | 14.5 | 25.0 | 35.0 | 46.0 | 57.0 | 69.0 |
| *Non-OECD Europe* | 0.4 | 1.4 | 1.9 | 2.5 | 2.8 | 3.1 | 3.6 | 4.1 |
| *Non-OECD Americas* | 0.0 | 0.1 | 0.4 | 0.8 | 1.4 | 2.2 | 3.1 | 4.5 |
| *Middle East* | 0.0 | 0.0 | 0.2 | 0.5 | 1.0 | 1.8 | 2.9 | 4.4 |
| **Total** | **69.0** | **98.3** | **128.4** | **160.6** | **194.0** | **230.3** | **267.9** | **307.7** |

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.

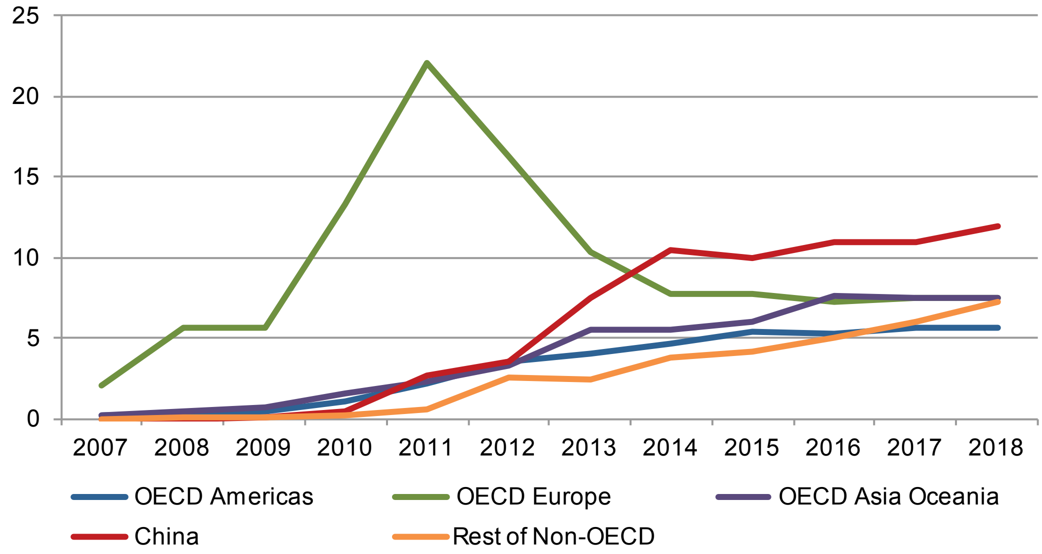
Source: IEA analysis; 2012 data are IEA estimates based on the Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems, 2012.

Going forward, global solar PV cumulative capacity is seen rising from 98 GW in 2012 to 308 GW in 2018 (+21% annually on average). The projection has been revised up by over 37 GW in 2017 versus *MTRMR 2012*, reflecting the higher 2012 baseline as well as more optimistic growth prospects across a number of markets. While 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 cumulative capacity could reach 370 GW to 390 GW in 2018.

On a regional basis, annual growth is seen moderating in OECD Europe while it picks up in all other regions, particularly in China and the rest of the non-OECD. Significant capacity additions are seen emerging from the Middle East region as global additions reach 38 GW/yr to 40 GW/yr by 2018. Global installations could also be higher, with more rapid than expected developments in Africa and the non-OECD Americas.

The largest upward revision to the capacity forecast stems from China, where cumulative solar PV capacity is expected to reach 57 GW in 2017 and 69 GW in 2018. By contrast, in the *MTRMR 2012*, cumulative capacity there was seen at only 35 GW in 2017. Improved economic attractiveness, reduced barriers for the integration of small-scale capacity and higher government targets are expected to drive growth there. Japan is also seen notably higher, driven by the retention of very high feed-in tariff levels. Capacity there is seen growing to almost 40 GW in 2018.

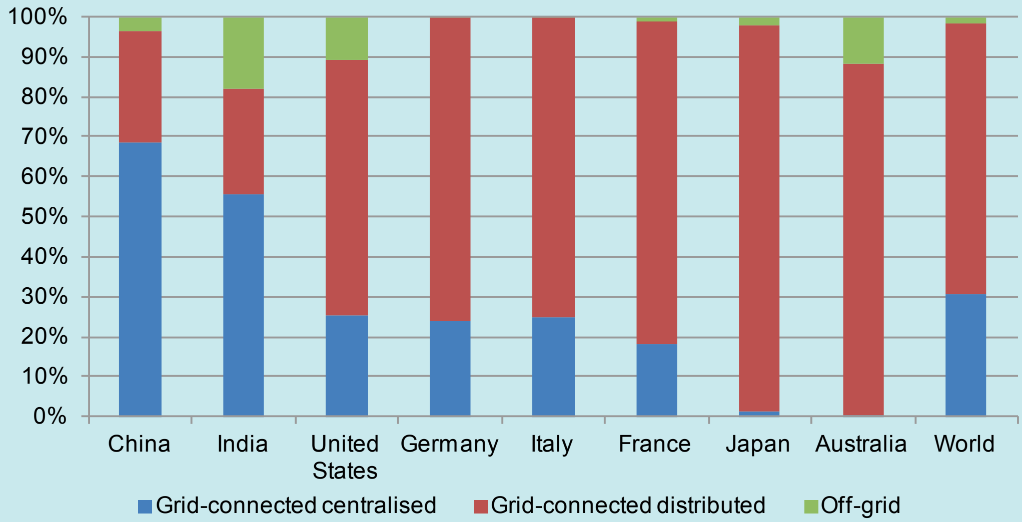
**Figure 98** Solar PV annual capacity additions, by region (GW)




### Box 3 Solar PV deployment segments vary by market

While deployment of solar PV has risen in many countries, the market segmentation of this 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 many cases there is significant overlap between these categories. For example, centralised solar PV systems are often ground-mounted utility plants of a size of at least 1 MW. However, exceptions can exist and reporting standards vary by country, making the characterisation and comparison of segment trends difficult across markets.

**Figure 99** Solar PV market segments by country in 2011, as percentage of cumulative capacity




Note: where necessary, estimates for segment split were made by system size.

Source: IEA analysis based on the Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems, 2012.

**Box 3** Solar PV deployment segments vary by market (continued)

Here, this report attempts to characterise solar PV deployment by the way that systems interact with the electricity system, following categorisations from the Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems (PVPS IA). Accordingly, country-level capacity data are classified as grid-connected centralised, grid-connected distributed or off-grid. Centralised systems correspond to centralised power stations, typically ground mounted, designed to supply bulk power. Distributed solar PV systems provide power directly to the distribution electricity network, and are increasingly being used for self-consumption purposes. While such applications are often small- and medium-scale, size is not a determining factor and distributed capacity can be ground mounted in nature. Finally, off-grid systems can provide electricity to both domestic and commercial entities not connected to the grid. Traditionally they have consisted of telecommunications applications and systems for rural electrification. New applications are beginning to emerge, ranging from small systems on mini-grids to larger applications (> 1 MW) that serve industrial uses. While this report attempts to allocate solar PV capacity to one of these categories, based on PVPS IA data and other IEA analysis, differences in reporting standards for underlying data suggest a margin of error in this exercise. As such, segment trends should be viewed as indicative only.

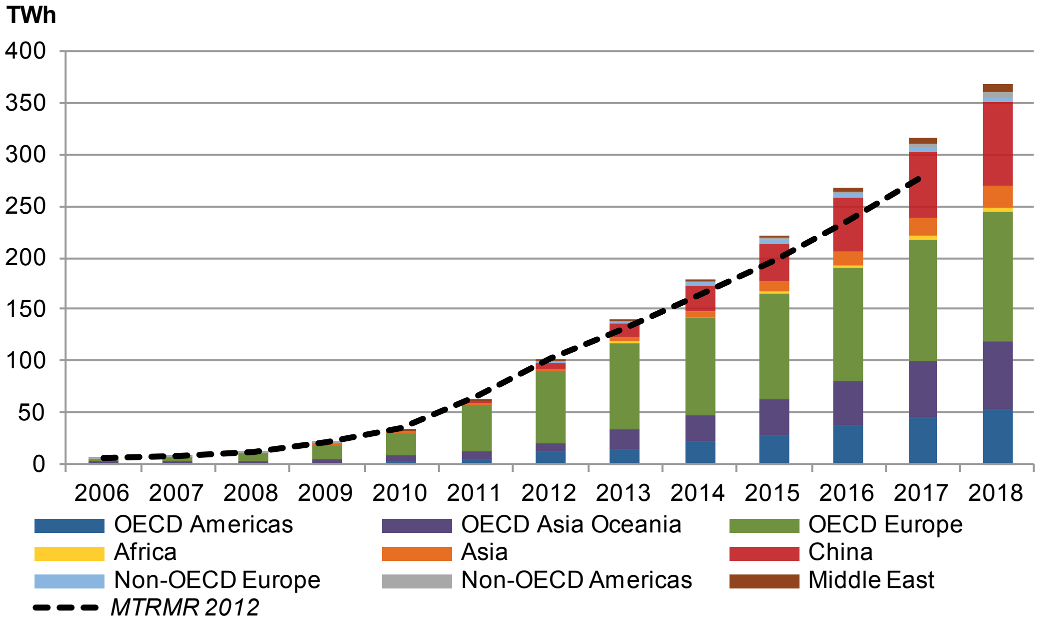
Globally, the vast majority of solar PV systems were grid-connected in 2011, with distributed capacity constituting almost 70% of the world total. The picture can vary significantly by country, however. In countries such as India, the United States and Australia, a significant amount of off-grid capacity is present, largely serving rural electrification needs (India) and stand-alone commercial/industrial applications. In China and India, most deployment to date has consisted of centralised, utility-scale systems. In many OECD countries, most capacity has consisted of smaller, distributed systems. In Europe, most distributed capacity corresponds to commercial/industrial applications, though some countries (*e.g.* the United Kingdom, the Netherlands, Denmark) have high levels of residential penetration (EPIA, 2013).

Increased deployment of distributed systems can require profound changes in power system operational patterns. For example, the presence of a large number of distributed solar PV installations can create a situation where power is fed from the low-voltage part of the grid all the way up to the high-voltage transmission grid. While this remains manageable from a technical perspective, operators need to incorporate operational system measures such as voltage control and frequency control at the distribution level. Moreover, solar PV deployment can change the profile of a power system's demand load, requiring increased balancing by operators. Such changes stem from structural trends – increased self-consumption and, consequently, less demand for utility-generated power – as well as fluctuations within the same day due to weather patterns. As such, systems need to incorporate interaction with the grid operator through smart grids, which sense and exchange information on real-time flows, to provoke demand-side response and use existing generation in a more cost-effective way.

Going forward, the outlook for different solar PV segments varies significantly by region. This report does not categorise forecast developments by segment. However, other market analyses give an indication of trends over the medium term. The European Photovoltaic Industry Association (EPIA) forecasts global rooftop versus utility-scale development. In Europe, development is likely to focus more on rooftop systems, given emerging competitiveness for self-consumption and weakening incentives for large-scale deployment. But globally, utility-scale solar PV systems should account for an increasing share of deployment under EPIA's Business-as-Usual scenario, rising from 38% of new capacity in 2013 to 44% in 2017, as solar PV expands to newer, sunnier markets (EPIA, 2013). Still, a significant amount of distributed growth should occur in some of these markets. In China, for example, additions at the distributed level should be large, based on new grid-connection rules and the expected introduction of new financial incentives for small-distributed capacity.

Electricity production from solar PV panels is directly dependent on solar irradiance levels within each country. In general, with PV expanding into sunnier countries, full-load hours should increase. Solar PV should deliver around 368 TWh globally in 2018. China is seen as the largest solar PV power producer in 2018, 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 non-OECD countries, incentives are smaller than in the OECD, while the resource is better. Solar PV's competitiveness with respect to retail electricity prices or with respect to costs of other generation underpins growth. In 2018, 12% of solar PV electricity should be generated in countries other than China and OECD countries, up from less than 2% in 2011.

**Figure 100** Solar PV generation and projection by region




## Solar thermal electricity

The added value of hybridisation and storage help CSP to grow strongly over the medium term, although competition with solar PV presents a challenge to deployment.

### *Technology development*

Solar thermal electricity from CSP plants is a proven renewable technology which can provide firm peak, intermediate or base-load capacity thanks to thermal storage and/or a hybrid system. Designs with a few hours of storage are particularly suitable for markets where the peak occurs in evening hours, as in many developing countries. CSP plants exploit direct solar irradiation and are generally situated only in arid and semi-arid regions of the world. Power plants consist of four different types: parabolic trough, linear Fresnel, tower and parabolic dish systems. Currently, most capacity in operation (over 2.5 GW) and under construction (about 1.8 GW) is parabolic trough, while construction of tower (0.5 GW to 0.6 GW) and Fresnel (0.1 GW to 0.2 GW) is smaller (CSP Today, 2013). CSP can also incorporate hybrid designs, which 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. Hybridisation makes CSP plants fully dispatchable while bringing environmental benefits and fuel savings compared with pure gas- or coal-fired plants.

For large (50 MW), state-of-the-art trough plants, investment costs are USD 3 800/kW to over USD 8 000/kW, depending on the solar field size, the storage size, and labour and land costs. Largely determined by capital costs and the amount of direct solar irradiation, LCOEs range between USD 130/MWh and USD 300/MWh. The LCOE of solar towers (with large storage) appears to be lower than that of trough plants, and below USD 150/MWh in markets such the United States. Stand-alone Fresnel plants without storage are still to demonstrate claims of lower costs, as a project in India has benefitted from feed-in tariffs at INR 12 000 (USD 220)/MWh. Project lead times can vary by market, with large-scale developments typically requiring at least two years.

Information about investment and generation costs is relatively scarce outside of Spain and the United States, where costs have remained high and stable in recent years. The PPA for the first CSP plant (parabolic trough) at Ouarzazate in Morocco will be made at MAD 1 620 (USD 190)/MWh, including three-hour storage that allows part of the output to displace oil-fired generation during evening demand peaks. The same company (from Saudi Arabia) also won a bid for a 50 MW plant in South Africa, but at the much higher cost of ZAR 2 500 (USD 300)/MWh, not benefiting from the low financing costs from development banks for Ouarzazate.

Similar to solar PV, competitiveness may appear for bulk power in regions with excellent sunshine and with costly competing energy sources. However, CSP currently has no significant market in decentralised, small-scale capacity that could grow on the basis of “socket parity”. During the day, CSP’s strongest competitor might be solar PV. Under pressure from the sharp cost decreases of solar PV, part of the CSP industry is developing a new market segment – hybridisation with fossil-fuel plants (*e.g.* solar boosters for coal- or gas-fired plants) – which could help scale-up deployment. Stand-alone CSP plants would find greater competitive opportunities, thanks to thermal storage, when the sun sets in countries with significant evening peak demand, where they can compete with oil-fired or gas-fired peaking and mid-merit plants.

**Table 88** CSP capacity and projection by region (GW)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| OECD | 1.6 | 2.6 | 3.5 | 4.8 | 5.2 | 5.8 | 6.4 | 7.0 |
| *OECD Americas* | 0.5 | 0.5 | 1.3 | 2.3 | 2.6 | 3.0 | 3.4 | 3.7 |
| *OECD Asia Oceania* | 0.0 | 0.0 | 0.1 | 0.2 | 0.2 | 0.3 | 0.5 | 0.6 |
| *OECD Europe* | 1.2 | 2.1 | 2.2 | 2.3 | 2.3 | 2.4 | 2.6 | 2.7 |
| Non-OECD | 0.1 | 0.1 | 0.5 | 0.8 | 1.5 | 2.5 | 3.8 | 5.4 |
| *Africa* | 0.1 | 0.1 | 0.2 | 0.2 | 0.4 | 0.6 | 0.8 | 1.1 |
| *Asia* | 0.0 | 0.0 | 0.1 | 0.3 | 0.4 | 0.5 | 0.6 | 0.8 |
| *China* | 0.0 | 0.0 | 0.1 | 0.2 | 0.3 | 0.6 | 1.0 | 1.4 |
| *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 | 0.1 | 0.1 | 0.4 | 0.7 | 1.4 | 2.1 |
| **Total** | **1.7** | **2.7** | **4.0** | **5.6** | **6.7** | **8.3** | **10.2** | **12.4** |

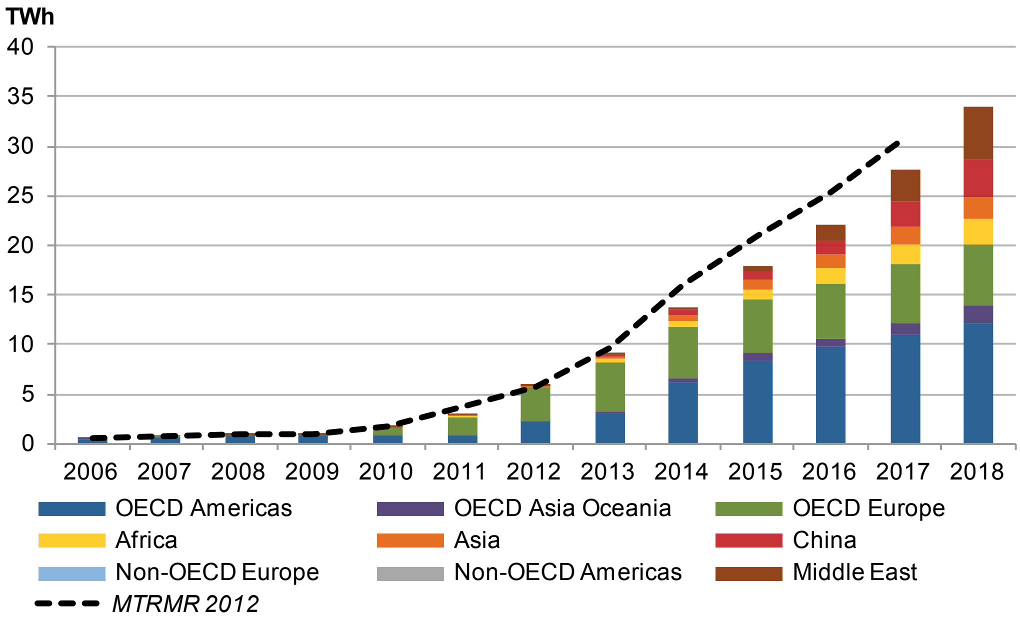
Sources: IEA analysis; 2012 data are IEA estimates based on ESTELA, 2012 and SEIA/GTM Research, 2013.

## *Market status and outlook*

CSP developments are currently concentrated in a few areas, with Spain and the United States having the most significant commercially operating capacity, though deployment is spreading out. In 2012, global CSP cumulative capacity grew by almost 1 GW to 2.7 GW, the highest annual deployment to date and more than double that registered in 2011. Growth was 0.1 GW higher than that projected by the *MTRMR 2012*, largely due to faster-than-expected deployment in Spain. In total, Spain's cumulative capacity rose by 0.9 GW in 2012. Still, a smaller amount of capacity remains in the project pipeline there. In an effort to reduce the country's tariff deficit, measures adopted over the past 18 months – a temporary moratorium on new developments under the Special Regime, the introduction of a 7% tax on all electricity generators and the removal of an option for market pricing plus a premium – have hurt CSP's economic attractiveness there.

Cumulative capacity grew modestly in the United States in 2012. A number of projects advanced in development, with five large plants expected to start over 2013-14. However, uncertainties have emerged for some others; notably, delays and difficulties in securing PPAs have put two 500 MW projects on hold during the last six months. Elsewhere, new capacity was added in the United Arab Emirates in early 2013, with the commissioning of a 0.1 GW plant. In India, seven CSP plants totalling 0.5 GW under the JNNSM are under construction, though only some will meet a May 2013 start deadline due to delays involving land availability, financing and other non-economic hurdles (CSP Today, 2013). In Australia, the Kogan Creek Solar Boost project integrating solar thermal generation with a coal-fired plant is expected online in 2013. Meanwhile, Saudi Arabia recently announced tenders for over 2 GW of CSP in two rounds over the next two to three years.

**Figure 101** CSP generation and projection by region




The year 2013 is expected to be decisive for CSP development. In the United States, completion of the first very large (250 MW) trough project is expected along with the commissioning of large (> 100 MW) tower projects of both designs (molten salts and direct steam generation). Over the medium term, CSP is expected to scale up, reaching 12.4 GW in 2018. While growth is led by the United States, significant developments also occur in China, India, Africa and the Middle East. The projection in 2017 has been revised down by 0.7 GW versus the *MTRMR 2012*. This change is largely due to lower expected growth in the United States and Spain. Project-level challenges (*e.g.* financing, supply chain bottlenecks, permitting) also confront some development in other areas. Yet significantly stronger growth versus the *MTRMR 2012* is expected in the Middle East over the period.

The pipeline in the United States represents 4 GW to 5 GW and cumulative capacity there is expected to rise to 3.5 GW in 2018. Still, CSP faces several challenges in the United States. The large-scale nature of projects and their typical situation in the desert southwest can make for more difficult environmental permitting and grid connections. The deployment flexibility and lower costs of solar PV can also provide an attractive alternative to some CSP projects. Nevertheless, some developers continue to develop CSP projects on the basis of PPAs with local utilities and the advantages conferred by CSP's storage capabilities. Elsewhere in the OECD, most growth is expected in Australia, Chile and Israel.[13] Despite the suspension of the 250 MW Solar Dawn project in Australia in 2012 and relatively lower prices of solar PV, some further CSP growth is expected. In Israel, 430 MW of projects have been announced, though none have yet secured financing. Mexico is also expected to have some development. In 2013, it should commission its first CSP capacity, a 12 MW unit hybridised with a gas-fired plant.

In the non-OECD, the Middle East should lead activity. Based on its recently announced tendering strategy, Saudi Arabia is now expected to reach 1.0 GW of cumulative CSP capacity by 2018. Saudi Arabia's resource availability, policy framework and incentive to diversify its power mix given its consistent high usage of oil for generation are all strong drivers. Still, uncertainty exists over the pace and delivery of projects under the tenders, given a lack of deployment history in the country. Elsewhere in the Middle East, Jordan, the United Arab Emirates (UAE) and Kuwait are all expected to increase capacity, based on new feed-in tariffs (Jordan) and on project pipelines (UAE and Kuwait). China is also expected to grow notably, with cumulative capacity rising to 1.4 GW by 2018. CSP's flexibility and hybridisation capability should allow for better integration, particularly with coal-fired generation. Still, development there is slower than FYP targets suggest, based on supply chain bottlenecks and still-limited deployment experience.

Most other non-OECD growth should come from India, Morocco and South Africa, with smaller additions in Thailand. In all cases, the cost and availability of financing will act as a forecast determinant. In India, the forecast 0.6 GW of additions over 2012-18 would represent significant growth on a global scale. The outlook is less than development plans and auctions would suggest, however, due to delays to current projects and still-high technology costs. In Morocco, CSP capacity should grow to over 0.5 GW by 2018, as phases 1 to 3 of Ouarzazate are commissioned. CSP capacity in South Africa should advance based on government-sponsored auctions.

**Box 4** Global trade in renewable energy technologies

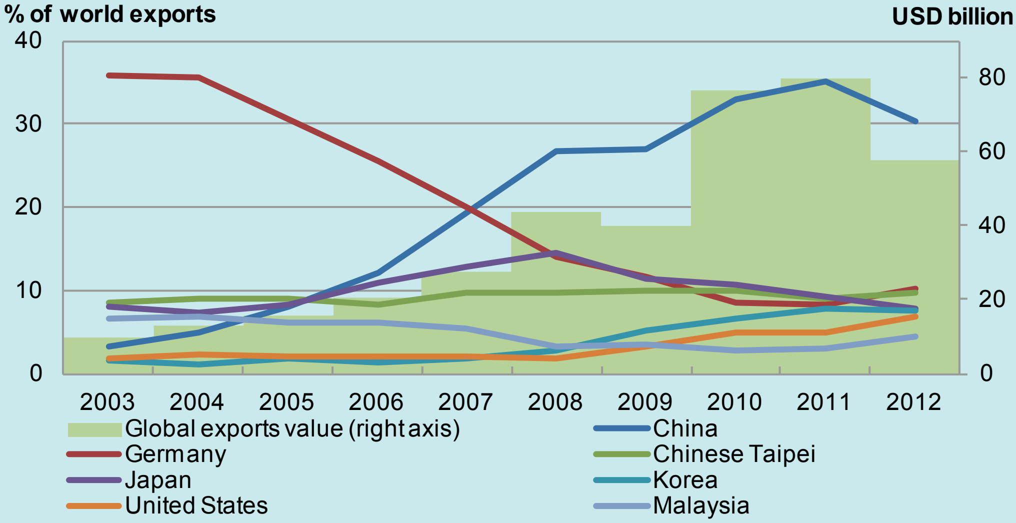
The large-scale deployment of renewable energy, in part due to robust policy incentives, has created new manufacturing and service industries. Manufacturing, especially wind and solar PV, was initially centralised in Europe with several governments initiating support measures for development and deployment. However, as more countries have introduced subsidies, supply chains for these technologies have become global and decentralised while international trade of related products has increased significantly. Governments have also realised that not only do renewable energy technologies help them "go green" but they can also stimulate economic development, increase exports and more importantly create jobs. Thus, in addition to increasing competition between renewable energy equipment manufacturers, countries have launched public policies that are specifically focused on attracting these manufacturing investments. Some of these policies depending on their design, however, may have direct impacts on international trade flows and on competition, and thus, have been subject to international trade disputes within the World Trade Organisation (WTO) since 2010. In 2010, two disputes emerged concerning support for the wind industry in Canada and China.

[13] 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.

**Box 4** Global trade in renewable energy technologies (continued)

First, the United States initiated a complaint against China's subsidies directed to wind turbine manufacturers under the Special Programme, which were based on the use of domestic content. Japan, with the European Union, then filed a WTO case against Canada over the Ontario's feed-in tariff programme that includes a local-content requirement. In 2011, after several consultations, China agreed to end subsidies directed to wind turbine manufacturers while the WTO panel ruled against Canada at the end of 2012.

**Figure 102** Value and share of global solar PV module and cell exports




Source: International Trade Center, 2013.

Although the wind industry was initially the target of trade disputes, similar polices have been introduced by many countries targeting the solar industry. In March 2012, after a long anti-dumping investigation, the US Department of Commerce imposed countervailing duties (CVDs) on most solar panels imported from China while the European Union initiated an anti-dumping investigation against China. In retaliation, China launched its own investigation of the US loan guarantee programme, and filed a complaint against the European Union concerning local-content requirements in Greece, Italy and France. Later, India launched an anti-dumping investigation against the United States, China, Chinese Tapei and Malaysia. A few months later, the United States initiated a complaint within the WTO against India's solar programme that includes local-content requirements. In June 2013, having completed its anti-dumping investigation, the European Union decided to impose a temporary provisional anti-dumping tariff of 11.8% on solar panels and cells imported from China, which may rise to 47.6% on average in August 2013.

Discriminatory subsidies are at the heart of these trade disputes either in the form of local-content rules or through direct or indirect financial support to renewable energy equipment manufacturers, especially solar PV cell and module producers. Local content rules, in general, are not the most effective means of supporting domestic industries, employment and economic development over the longer term. The solar PV industry has been subject to oversupply in recent years mainly due to production coming from China, which resulted in decreasing module and cell prices, even lower than costs. Although low module prices have facilitated the deployment globally, several large manufacturers in the United States and Europe declared bankruptcy in recent years. Chinese companies are not immune to this situation with the largest module manufacturer, Suntech, not able to pay its convertible bonds in March 2013.

Over the medium term, the resolution of these trade disputes will play a role in the consolidation of the solar PV industry, among others. However, a multiplication of trade disputes in the renewable industry could be damaging to renewable development, by raising uncertainty over supply chain costs and undermining investor confidence.

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# RENEWABLE TRANSPORT: GLOBAL BIOFUELS OUTLOOK

## Summary


- **World biofuel production stood at 1.86 million barrels per day (mb/d) [14] in 2012, the same level as the previous year**, as an extensive drought drove up corn prices in the United States and led to a significant drop in ethanol output.

- **World biofuel production is projected to reach 2.36 mb/d in 2018**, an increase of 503 thousand barrels per day (kb/d) from 2012. On an energy-adjusted basis, biofuels would supply 1.6 million barrels of oil equivalent per day (mboe/d),[15] slightly less than the crude oil production of the European Union in 2011. Biofuels could thus provide 4% of global road transport fuel demand in 2018, but uncertainty on support policies in the European Union and the United States provides a possible downside risk, and might undermine the sector's growth potential.

- **United States (US) ethanol output continues to be affected by last year's drought** that led to a 40 kb/d drop in production to 864 kb/d in 2012. Amid continued depressed ethanol output, 2013 production should reach only 853 kb/d, down 11 kb/d year-on-year. Due to challenges related to blending ethanol to the gasoline pool, among others, we see growth in US ethanol production slowing with total output reaching 979 kb/d in 2018. The **biodiesel sector** is better off amid a reintroduction of a USD 1/gallon blender's tax credit that should push production to 84 kb/d in 2013, the mandated volume under the Renewable Fuel Standard 2 (RFS2),[16] at which it is expected to stay through 2018.

- **Brazil's ethanol production is on the rise again, after a period of sagging production caused by high sugar prices and lack of competiveness with regulated gasoline prices, and volumes should increase from 386 kb/d in 2012 to 436 kb/d in 2013.** Ethanol output should increase by 150 kb/d in total until 2018, with more rapid growth limited by the sector's financial difficulties. Brazilian biodiesel output stood at 47 kb/d in 2012, and should remain at this level in 2013. By 2018, volumes should increase to 76 kb/d.

- **Organisation for Economic Co-operation and Development (OECD) Europe's biofuel output stood at 230 kb/d in 2012, and should increase to 239 kb/d in 2013.** Output should reach 306 kb/d in 2018, driven by the targets under the European Union (EU) Renewable Energy Directive. However, as a result of continued discussions on the sustainability of biofuels, the European Commission has launched a proposal to reduce the share of conventional biofuels allowed to count towards the 2020 renewable energy target, which could substantially undermine these projections if adopted.

- **The advanced biofuel sector continued to expand with operating capacity at 77 kb/d in 2012.** Recent commissioning of the first commercial-scale plants in the United States and Europe, and


[14] 1 b/d over 1 year = 58 030.255 litres per year.
[15] 1 boe = 240 litres of ethanol; 180 litres of biodiesel. Actual values can differ due to varying energy content of different crude oil qualities, as well as of different types of biodiesel.
[16] The Renewable Fuel Standard – originally established in 2005 under the Energy Policy Act – was expanded under the Energy Independence and Security Act of 2007. The RFS2 mandates volumes for different categories of biofuels that obligated parties such as oil refiners are required to blend into conventional gasoline and diesel each year until 2022. The RFS2 is under the responsibility of the Environmental Protection Agency (EPA), which announces volumes of specific fuels for each forthcoming year. For more information visit: www.epa.gov/otaq/fuels/renewablefuels/.

availability of new funding, should provide for further growth to 156 kb/d of operating capacity in 2018, despite some projects' recently being cancelled. However, this capacity – even if fully utilised – would be sufficient to provide only one-third of the volume of advanced biofuels required in 2018 to meet the International Energy Agency (IEA) 2°C Scenario (2DS).

**Figure 103** Global biofuels supply 2012-18

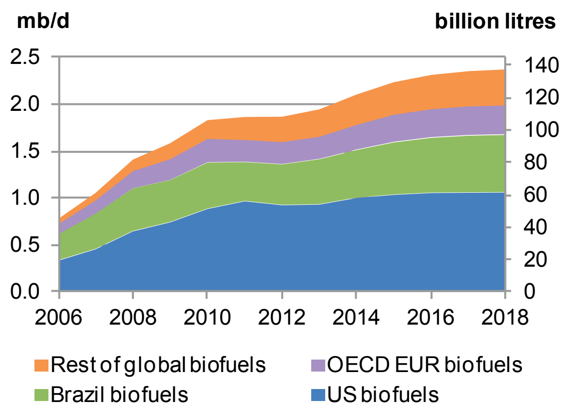
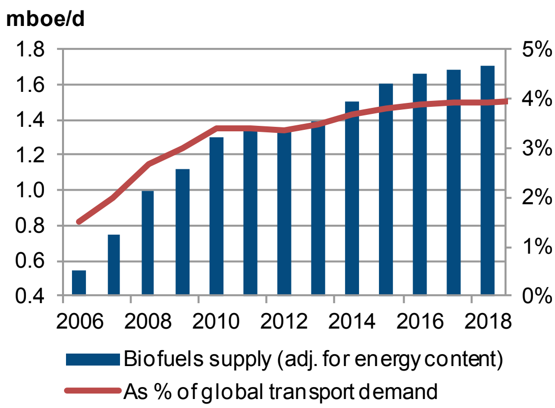



**Figure 104** Global biofuels supply adjusted for energy content versus oil




Note: unless otherwise indicated, all material in figures and tables in this chapter derives from IEA data and analysis.

## Global overview: weak short-term outlook impacts medium-term projections

Global biofuels production stalled at 1.86 mb/d in 2012, as a number of countries saw declining production in 2012. Total biofuel output in the US dropped 42 kb/d compared with 2011, due to an extensive drought that reduced last year's corn crop and drove up prices for this important ethanol feedstock. Slight year-on-year decline in biofuel output was also observed in OECD Europe, as a result of poor margins, and double-counted biodiesel[17] reducing physical demand for biodiesel. Output in other regions continued to rise, such as in Brazil where ethanol output increased almost 20 kb/d compared to 2011, setting the trajectory for further growth in the coming years.

Global biofuels production is expected to grow from 1.86 mb/d in 2012 to 2.36 mb/d in 2018. The United States will remain the biggest producer in terms of absolute volumes, but sees its share in global biofuel production decreasing from 50% in 2012 to 45% in 2018. In terms of volumes, ethanol remains the dominant biofuel with global output reaching 1.81 mb/d in 2018, versus 0.55 mb/d of biodiesel. The biggest risk to these projections is the growing uncertainty of future policy frameworks for the biofuel sector in the European Union and the United States, which impacts also on exporting countries such as Argentina, Indonesia and Brazil (see sections below).

Many of the drivers and challenges influencing the medium-term picture stem from ongoing developments in the short term. Global biofuel production should increase to 1.95 mb/d in 2013, despite a number of short-term challenges in some key producing countries. US ethanol production is still impacted from last year's drought, among others, and should decline 11 kb/d (1.2%) year-on-year. In addition, a drop in biodiesel production is projected in Argentina as the recent introduction

[17] The EU Renewable Energy Directive states that the contribution of biofuels made from wastes, residues, non-food cellulosic material and lingo-cellulosic material will count twice towards the national targets for 2020. This has led to increased volumes of biodiesel from used cooking oil and waste animal fats - and reduced demand for conventional biodiesel produced from vegetable oil.

of anti-dumping duties on biodiesel imports to the European Union result in reduced biodiesel exports to this key market. Brazilian biodiesel output in 2013 should remain at the same level as in the previous year, as the first biodiesel auctions this year did not deliver the full quota offered, and the biodiesel blending mandate remains at 5%, before a possible raise to 10% as of 2014. In Germany, 2013 biodiesel production is seen declining by 10 kb/d, amid continued negative margins and reduced physical demand caused by enhanced use of double-counted biodiesel.

**Table 89** World biofuels production, 2012-18

| kb/d | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| *OECD Americas* | 959 | 974 | 1 043 | 1 080 | 1 097 | 1 097 | 1 094 |
| *United States* | 927 | 937 | 1 005 | 1 039 | 1 058 | 1 061 | 1 063 |
| *OECD Europe* | 230 | 239 | 262 | 288 | 297 | 304 | 306 |
| *OECD Asia Oceania* | 15 | 17 | 20 | 20 | 22 | 22 | 23 |
| **Total OECD** | **1 205** | **1 230** | **1 324** | **1 389** | **1 416** | **1 423** | **1 423** |
| *Non-OECD Europe* | 8 | 8 | 8 | 8 | 8 | 8 | 9 |
| *China* | 45 | 51 | 58 | 59 | 62 | 62 | 63 |
| *Asia* | 87 | 96 | 106 | 113 | 118 | 129 | 133 |
| *Non-OECD Americas* | 511 | 558 | 594 | 647 | 686 | 706 | 717 |
| *Brazil* | 433 | 483 | 509 | 557 | 587 | 606 | 612 |
| *Middle East* | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| *Africa* | 4 | 6 | 8 | 12 | 14 | 15 | 16 |
| **Total Non-OECD** | **654** | **719** | **773** | **839** | **888** | **920** | **939** |
| **Total World** | **1 859** | **1 949** | **2 098** | **2 228** | **2 304** | **2 343** | **2 362** |

In our projections we see Brazilian ethanol production grow by 50 kb/d to 436 kb/d in 2013, whereas the Brazilian government takes a more optimistic view and expects ethanol production to reach 456 kb/d to 475 kb/d in 2013. The positive outlook comes as a result of an expected banner sugar cane harvest, a re-increase in the domestic ethanol mandate from 20% to 25% and improved competitiveness of ethanol production over sugar.

US biodiesel, supported by the reintroduced USD 1/gallon blender's tax credit and the 1.28 billion gallon mandate under the RFS2, should increase 21 kb/d compared with the previous year. Smaller increases in production are also projected for China (5 kb/d year-on-year), and other Asia (12 kb/d).

The advanced biofuel sector continues to expand with the recent commissioning of the first commercial-scale production units. In addition, new access to funding, for instance under the European Union's NER300 programme, has provided the required financial backing for a number of projects that are now likely to proceed and come on line over the next years. Global operating capacity in 2012 reached 77 kb/d and could increase to 156 kb/d in 2018. However, even if the installed capacity were fully utilised, which is unlikely in the first years of production, the resulting volumes of advanced biofuels would be sufficient to meet only one-third of the advanced biofuels volumes required in 2018 to meet the IEA 2DS.

## *Policy framework for biofuels*

Support policies have been responsible for the rapid growth of biofuel production over the last decade, and continue to aid the industry's existence in almost all countries in the world. Biofuel support policies have been adopted in more than 50 countries to date, with various measures being used to stimulate production and use of biofuels. The strongest drivers for policy makers to adopt support policies have been energy security (through reduced dependency on oil imports), emissions reduction efforts, and agricultural sector development, with objectives differing among markets.

**Table 90** Global main targets and support policies for liquid biofuels

<table>
<tr><th>Targets and quotas</th><th>Support scheme</th><th>Other support</th></tr>
<tr>
<td>
Regulatory frameworks:<br>EU Renewable Energy Directive (RED):<br>10% renewable energy in transport by 2020.<br>US RFS2: blending mandates for different categories of biofuels.<br>Canada: Federal renewable fuel standard: blending mandates for biofuels.<br><br>Biofuel mandates and targets:<br>For key producers
<table>
<tr><th>Country</th><th>Biodiesel</th><th>Ethanol</th></tr>
<tr><td>United States</td><td colspan="2">36 billion gallons biofuels by 2022</td></tr>
<tr><td>Brazil</td><td>5%</td><td>18-25%</td></tr>
<tr><td>EU</td><td colspan="2">10% renewable energy in transport by 2020</td></tr>
<tr><td>Argentina</td><td>7%</td><td>5%</td></tr>
<tr><td>China*</td><td></td><td>10%</td></tr>
<tr><td>Canada**</td><td>2%</td><td>5% to 8.5%</td></tr>
<tr><td>Indonesia</td><td>2.5%</td><td>3%</td></tr>
<tr><td>Thailand</td><td>5%</td><td></td></tr>
<tr><td>Colombia</td><td></td><td>8% to 10%</td></tr>
<tr><td>India</td><td>5%</td><td></td></tr>
<tr><td>Australia*</td><td>2%</td><td>5%</td></tr>
<tr><td>Philippines</td><td>2%</td><td>10%</td></tr>
</table>
</td>
<td>
Tax incentives on retail sales of ethanol:<br>Argentina, Australia, Austria, Bulgaria, Czech Republic, Denmark, Estonia, 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 (eight states).<br><br>Tax incentives on retail sales of biodiesel:<br>Argentina, Australia, Canada (Ontario, Quebec, Nova Scotia), Austria, Belgium, Bulgaria, Czech Republic (different exemptions for 5% and higher than 31% blends), Denmark, Estonia, 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).<br><br>Tax credits:<br>United States: Blender's tax credit for biodiesel (due to expire at the end of 2013); tax credit for cellulosic ethanol.<br><br>Production-linked payments:<br>Canada.
</td>
<td>
Sustainability standards for biofuels:<br>European Union: all biofuels need to be certified for compliance with sustainability criteria defined in the RED.<br>Switzerland: tax exemptions for renewable fuels meeting environmental and social standards.<br>United States: specific life-cycle emissions reduction standards under RFS2.<br><br>Incentives for infrastructure development:<br>Some EU member states have grant programmes for biofuels distribution infrastructure.<br>A number of US states provide incentives for new biofuel infrastructure.<br>Brazil: retail stations must sell E25 and E100.<br>Sweden: large retail stations must sell fuel from renewable sources.<br>Thailand: retail stations selling E20 receive financial premium.<br><br>Research, development and demonstration (RD&D) programmes:<br>A number of countries provide RD&D funds to support the development of new biofuels, as well as feedstocks and supply chains.
</td>
</tr>
</table>

* In some provinces.

** Federal: 5% ethanol, 2% biodiesel; up to 8.5% ethanol in some provinces.

Notes: E85 = blend of 85% ethanol and 15% gasoline; B100 = pure biodiesel. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Sources: IEA analysis; Bahar, Egeland and Steenblik, 2013

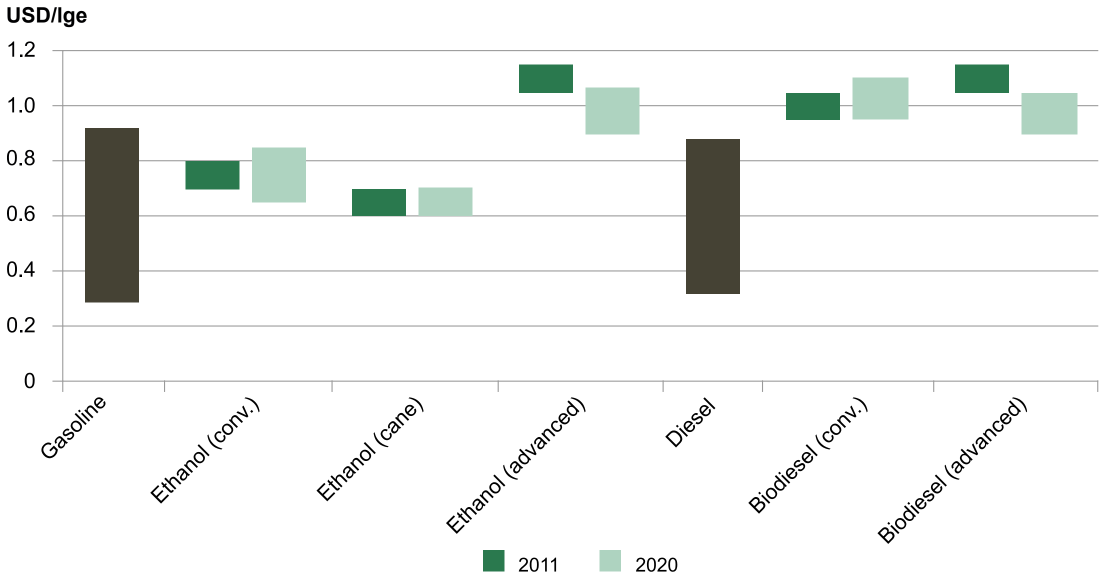
Among the common measures to support biofuel use are blending mandates that oblige fuel retailers to blend a certain share of biofuel in their total fuel sales. Blending mandates are often combined with tax exemptions on biofuel sales, aimed at providing an economic incentive to motorists to use biofuel (blends) instead of regular gasoline or diesel.

As a result of increasing concerns over the environmental impact of biofuel production, a number of countries have established sustainability requirements that biofuels must meet in order to count towards the respective blending mandates. In the United States, life-cycle greenhouse gas emission values for different biofuels are defined under the RFS2. In the European Union, the RED has set out a number of sustainability criteria, including minimum greenhouse gas reduction values for biofuels. In order to count towards the 2020 targets, biofuels need to be certified to ensure their compliance with the respective sustainability criteria. A number of countries provide RD&D funds to support the development of new fuels, feedstocks and supply chains. Infrastructure for biofuel distribution and use, is also supported through direct investment subsidies or tax credits in a number of countries.

## *Biofuel economic attractiveness*

Production costs for biofuels consist of a variety of fixed and variable costs with feedstock costs accounting for a considerable share of the total. The economic attractiveness of biofuels projects can vary with feedstock costs, differences in plant size and efficiencies, as well as expected oil prices. While conventional biofuel technologies are generally mature, and detailed cost information can be obtained, much less data on advanced biofuel production costs are available, with little experience to date from large commercial-scale production plants.

**Figure 105** Production costs of biofuels versus oil-based transport fuels




Notes: lge = litres of gasoline equivalent; conv. = conventional. Biofuel cost variations can be even larger than depicted here, depending on feedstock and region. The range of gasoline and diesel spot prices is taken from the monthly average spot price in the United States, Singapore and Rotterdam from 2009-11.

Source: IEA analysis based on the IEA Mobility Model, and IEA, 2012.

For conventional biofuels, such as sugar- and starch-based ethanol, as well as vegetable oil-based biodiesel, the main cost factor is feedstock, which accounts for 45% to 70% of total production costs today. The sale of co-products such as dried distiller's grains with solubles (DDGS), glycerine, bagasse, or waste heat can reduce biofuel production costs by up to 20% depending on the fuel type and use of co-product. In Brazil, for instance, sugar mills can sell bioelectricity produced from bagasse; the revenues represent around 15% of their total income. It is also important to note that in some cases (*e.g.* soy biodiesel) the biofuel is a by-product rather than the main product.

Sugarcane-based ethanol is typically the lowest-cost conventional biofuel, as the conversion process is relatively simple and the productivity of sugarcane is very high, particularly in Brazil where it has been produced commercially for several decades. Production of grain-based ethanol is more expensive, but can be competitive with gasoline in the United States and Europe at times of low grain prices and high gasoline prices. In recent years, elevated and volatile grain prices have often undermined ethanol's competitiveness with gasoline; these trends are expected to be present over the medium term. Feedstock prices are also a critical cost element of conventional biodiesel, produced from rapeseed, palm oil, or soy oil, amongst others, making it generally more expensive to produce than ethanol. Looking forward, there is limited potential to further reduce costs of conventional biofuels by improving the technological performance of production, whereas projected increases in feedstock prices could lead to rising production costs over the medium term.

For advanced biofuels, the main components of production costs are capital costs (35% to 50%), followed by feedstock (25% to 40%). Advanced biofuels production costs are currently well above those for fossil fuels, and also higher than those for conventional biofuels, due to the early stage of technology development and the current scale of production. Looking forward, considerable potential for cost reductions, in particular related to capital costs exists. Realising economies of scale will be vital for the advanced biofuel sector to achieve further cost reductions and move down the learning curve. Reduced feedstock cost volatility could be a cost advantage for advanced biofuels that use lignocellulosic biomass sourced from energy crops, waste and residues. The establishment of stable feedstock supply chains will be key to realising such benefits over the medium term.

## *OECD Americas market status and outlook*

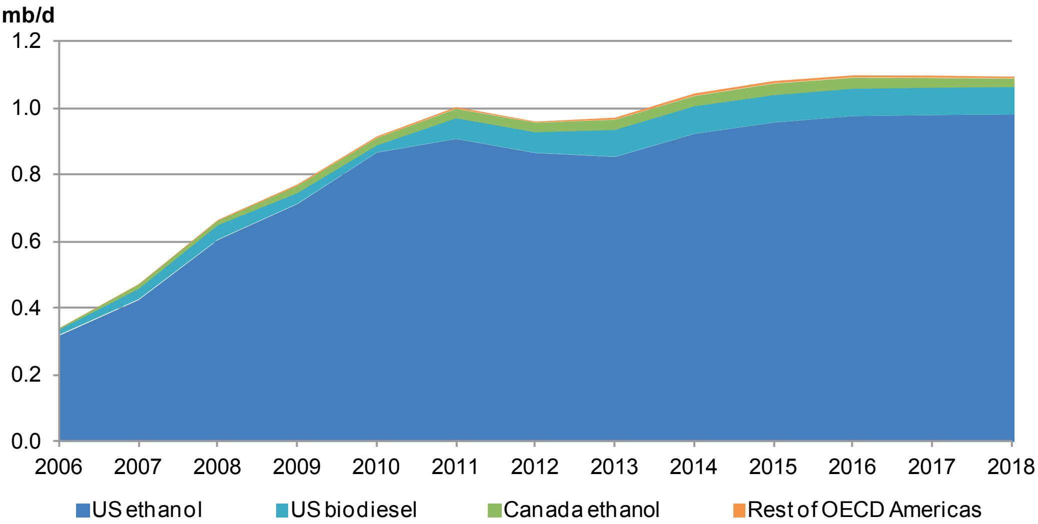
OECD Americas biofuels production reached 959 kb/d in 2012, with US production accounting for 97% of the total. Driven mainly by the US blending mandate under the RFS2, the region's biofuel output should grow by 135 kb/d to 1.1 mb/d in 2018.

### United States

The situation in the US ethanol sector is still depressed by the impact of last year's extensive drought in the form of high corn prices that reduced crushing margins and led many producers to temporarily stop production in the last months. In 2012, US ethanol production declined for the first time since ethanol became a widely used blending component, falling 4.5% year-over-year to 864 kb/d. Ethanol exports to Brazil, which reached a record high of 25 kb/d on average in 2011, slipped to an average 6 kb/d in 2012 as a result of the drought-depressed ethanol output (EIA, 2013a).

Over the medium term, we see US ethanol production increase from 864 kb/d in 2012 to 979 kb/d in 2018, driven by the RFS2 mandate but limited by challenges to get the ethanol into the market (see below). With 10% of the approximately 200 ethanol plants in the United States still temporarily idle, and ethanol production in the first quarter of 2013 averaging 800 kb/d (EIA, 2013b) (compared with 910 kb/d in the first quarter of 2012), this report sees 2013 output at 853 kb/d, down 11 kb/d y-o-y. The impact of high corn prices should be mitigated through the new harvest in autumn – forecast by the US Department of Agriculture at 370 million tonnes (Mt) (USDA, 2013) – and support an increase in ethanol production in 2014 to 921 kb/d. Over the medium term, ethanol output could grow to 979 kb/d in 2018, driven primarily by the mandate under the RFS2. However, in light of declining gasoline demand, and difficulties to overcome the 10% ethanol "blend wall", criticism of the RFS2 by different market participants is currently gaining momentum and could potentially undermine the policy support framework (see Box 5).

**Figure 106** OECD Americas biofuels supply, 2012-18




Biodiesel production is expected to reach 84 kb/d in 2018, an increase of 21 kb/d compared with 2012, with all of the gains concentrated in the short term. Short-term growth in biodiesel output is driven by the 0.28 billion gallon increase in the RFS2 biodiesel mandate to 1.28 billion gallons (84 kb/d) in 2013. In addition, the reintroduction of the USD 1/gal blender's tax credit also helps to significantly improve the framework for biodiesel in the United States in 2013. Production volumes should reach 84 kb/d in 2013 and remain at this level due to the RFS2 mandate for biomass-based biodiesel, as the blender's tax credit is scheduled to expire at the end of 2013.

**Box 5** "Blend wall" clouds medium-term outlook in the United States

The blending mandate under RFS2 – the principal policy instrument to promote biofuel production and use in the United States – is 16.55 billion gallons in 2013 (1 080 kb/d, of which 84 kb/d is biomass-based biodiesel), and is set to more than double to 36 billion gallons by 2022. Amid the considerable volumes of ethanol mandated under the RFS2, last year's drought led to increasing opposition towards the RFS2, in particular from livestock farmers who saw their margins disappear as a result of high corn prices.

Since the beginning of the year, the efficacy of the RFS2 has also been called into question by other market participants. Several parties, from gasoline retailers to automobile manufacturers, have flagged liability issues associated with using blends higher than E10 (a blend of 10% ethanol and 90% gasoline) in conventional gasoline vehicles. Extra costs and logistical challenges of reconfiguring pumps and storage at fuel stations have also been highlighted as important barriers to providing higher ethanol blends such as E85 for use in one of the 10.7 million flex-fuel vehicles currently in use in the US (EIA, 2013c). These factors together effectively create a "blend wall" that represents approximately a 10% share of ethanol in the gasoline pool (about 870 kb/d based on 2012 gasoline consumption).

Since US gasoline demand is projected to decline over the medium term – mainly as a result of enhanced fuel efficiency stipulated by the Corporate Average Fuel Economy Standards – the volume of ethanol that can be blended before surpassing the ethanol "blend wall" is decreasing. The volumes of ethanol mandated under the RFS2, however, are set to increase, creating a growing gap between the 10% blend wall and the total volume of ethanol required to be blended with gasoline (Figure 107). The need to overcome the blend wall is necessary for ethanol production to continue growing.

**Box 5** “Blend wall” clouds US medium-term outlook (continued)

One option for blenders to avoid raising the physical share of ethanol in gasoline is through the purchase of RINs[18] that are traded between obligated parties, as well as the Intercontinental Exchange in New York, among others. As a result of the depressed ethanol production, and discussions on the “blend wall”, prices for D6 RINs for “renewable fuel” skyrocketed in March 2013 to USD 1.05 up from a few cents some weeks earlier, and prices are currently still well above those at the beginning of 2013. RIN prices for advanced biofuels (D5) and biomass-based biodiesel (D4) increased in parallel, as these RINs can also be used to meet the renewable fuels blending requirements.

**Figure 107** US gasoline demand versus projected ethanol production and mandated ethanol use

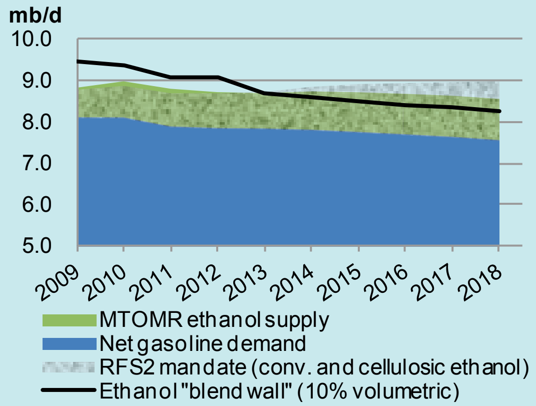
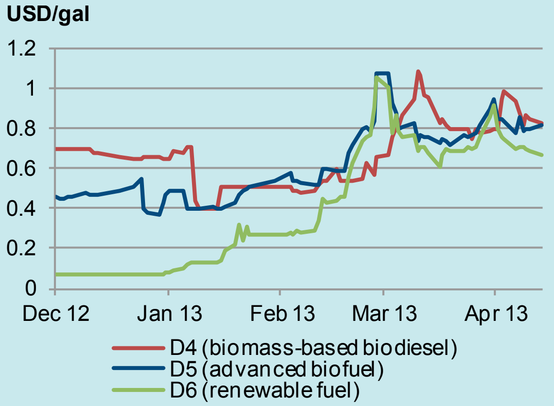



**Figure 108** Development of RIN prices between December 2012 and April 2013




Notes: MTOMR = IEA *Medium-Term Oil Market Report 2013;* RFS2 mandate does not include ethanol potentially blended under the “advanced biofuel” category. Renewable identification numbers (RINs) prices sourced from Bloomberg LP, 2013.

Barring a rebound in gasoline demand, many factors suggest that the RIN market will remain tight in the future due to the growing discrepancy between mandated volumes under RFS2 and the actual level of ethanol blending that can be achieved under current and forecasted market conditions. This is particularly true for the cellulosic fuels mandate, which was revised downward by the EPA from the original 1 billion gallons to 0.014 billion gallons (1 kb/d) in 2013, but still appears ambitious in light of only two operating commercial-scale production units. Looking forward, further revisions of the cellulosic fuels quota are likely given that the size of the industry is currently too small, and is expanding too slow in order to provide the 16 billion gallons in 2022 currently mandated under the RFS2.

Higher RIN prices for “renewable fuel” should improve the competitiveness of E85 compared with E10 and lead to a higher share of this fuel in the market, which could be absorbed by the 10.7 million flex-fuel vehicles in the United States (EIA, 2013c). In addition, the high price for D6 RINs could trigger blending of biodiesel within the “advanced biofuels” mandate, both of which could take some of the pressure off the RIN market. Ultimately, continued growth in US ethanol production may require measures that better stimulate the E85 market or incentivise market players to take on higher blends than 10%. Given the difficulties involved in these options, the recent political debate has focused on the potential for the Environmental Protection Agency (EPA) to revise the RFS2 mandate downwards. Though there is no clear indication whether the RFS2 will be amended, growing market perception of policy uncertainty introduces an additional downside risk to the *MTRMR 2013* medium-term forecast.

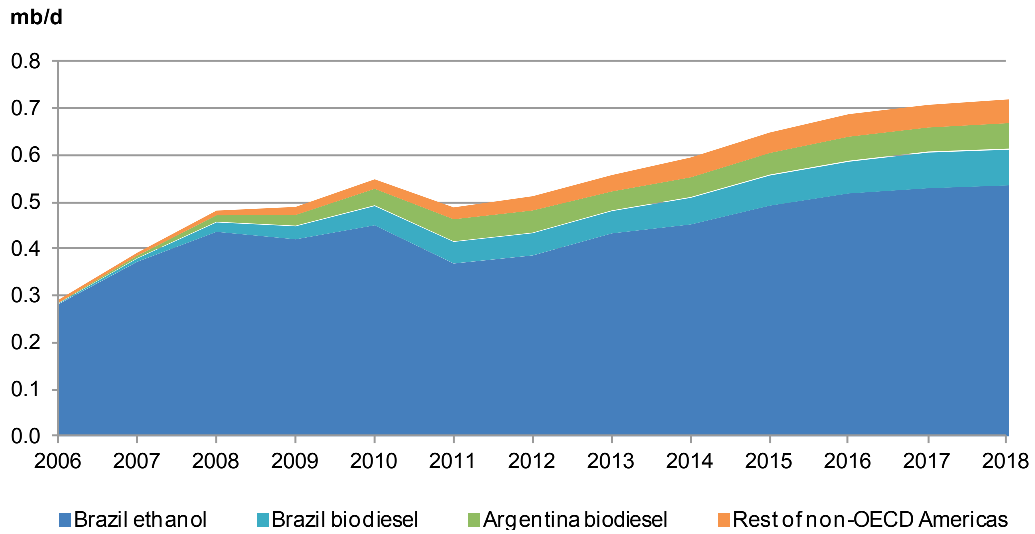
[18] The US EPA uses RINs to track renewable transportation fuels and monitor compliance with the RFS2. The RIN is attached to the physical gallon of renewable fuel as it is transferred to a fuel blender. After blending, RINs are separated from the blended gallon and are used by obligated parties (blenders, 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, *i.e.* any company that introduces finished gasoline into the retail marketplace, may also sell RINs among one another, with prices being determined by market factors.

In Canada ethanol production should grow from 29 kb/d in 2012 to 35 kb/d in 2015, before decreasing to 26 kb/d in 2018 as a result of the scheduled phase-out of biofuel subsidies under the ecoEnergy for Biofuels Programme in 2017. Projections for the biodiesel sector are similar, with volumes increasing from 2 kb/d in 2012 to 6 kb/d in 2015, before decreasing as a result of the subsidy phase-out.

## *Non-OECD Americas market status and outlook*

Non-OECD Americas biofuel production reached 511 kb/d in 2012, a 24 kb/d year-on-year increase. Looking ahead, the region's production should grow from 558 kb/d in 2013 to 717 kb/d in 2018, driven mainly by growth in Brazilian ethanol production.

**Figure 109** Non-OECD Americas biofuel production, 2012-18




### Brazil

Over the last two years the situation in Brazil's ethanol sector, the second-largest in the world, has been challenging. Poor sugar cane harvests that could not be compensated by high sugar prices, in addition to financial difficulties in the sugar cane sector made around 40 mills (representing 10 million tonnes of crushing capacity, *i.e.* 2% of the total) file for bankruptcy. The subsequent decline in ethanol supply led the government to lower the ethanol blending mandate to 20% in October 2011. Concurrently, the government's continued regulation of gasoline prices made ethanol relatively less competitive to owners of flex-fuel vehicles, dampening domestic ethanol demand, and led to an 80 kb/d decline in ethanol output from 2010 to 2011.

The 17 kb/d year-on-year increase in 2012 production was the first sign that the Brazilian ethanol sector is on the rise again. While a banner sugar cane harvest in 2013/14 and improved economics for ethanol versus sugar production support a growth in production looking forward, the financial status of several smaller and inefficient mills provides a dampener leading to a cautious projection of a 100 kb/d increase in ethanol output to 2018.

With Brazil's 2013/14 sugar cane harvest expected to increase 10% year-on-year to 650 Mt according to the government's crop supply agency CONAB (2013), and a global sugar surplus pushing down prices, Brazilian producers are likely to divert a higher share of their crushing capacity to ethanol rather than sugar production.[19] In addition, recently announced government policies stand to support ethanol

[19] Many of the combined sugar and ethanol mills in Brazil can shift the ratio of output between the two end products between 40:60 either way.

production going forward. First, the government increased gasoline prices sold from Petrobras' refineries by 6.6% (for São Paulo state this would translate into around USD 2.53/gallon before taxes and distribution fees), which could increase the ethanol price for final consumers by around 4%. Second, the government recently decided to waive taxes for contributions to the social integration programme and social security financing (PIS and COFINS) on ethanol, representing a nearly 10% value of the ethanol producer price (ex-tax). Part of this value will likely be used by mills to improve their revenues, while the other part will be passed on to consumers and will help make the fuel more attractive than gasoline to drivers of flex-fuel vehicles. Finally, the government has again raised the minimum blending mandate for ethanol back to 25% effective 1 May this year.

**Figure 110** Gasoline versus ethanol retail price, Brazil

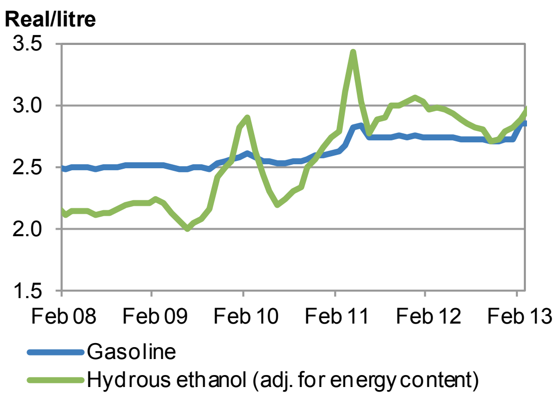
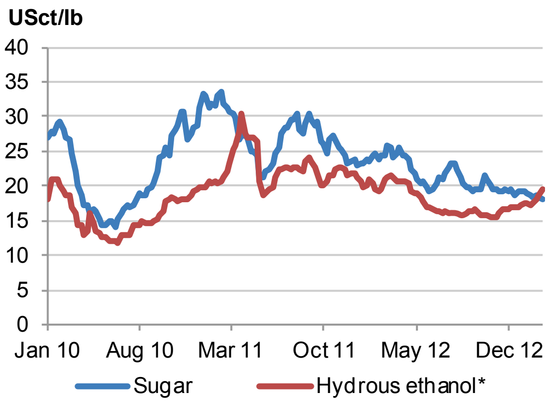



**Figure 111** Sugar price versus hydrous ethanol price, Brazil




* Ethanol shown as sugar equivalent (12.2 pounds per gallon).

Data: based on data from Bloomberg LP, 2013.

These measures are expected to improve mills' profitability and revive investment in Brazil's sugar cane ethanol industry at a time when mills have seen rising costs of input, labour and land. Although weather could still impact the amount of sugar cane harvested in 2013, ethanol output this year is projected at 436 kb/d, just shy of the 450 kb/d record in 2010. The Brazilian government's projections are more optimistic and see ethanol output between 456 and 475 kb/d in 2013.

With US ethanol production currently sagging, Brazilian ethanol exports to the United States in 2012 have been the highest in three years (35 kb/d on average) (EIA, 2013a), driven also by the RFS2 "advanced biofuels" mandate that requires increasing volumes of non-corn biofuels. In particular the latter should continue to support US demand for Brazilian ethanol imports over the medium term. The actual export potential will, however, be influenced by the domestic demand for hydrous ethanol, as well as the "blend wall" situation in the United States and its implications on the RFS2.

Despite the positive outlook for 2013, the sector's financial difficulties are likely to persist as low sugar prices might impact the profitability of smaller and outdated mills. According to industry sources, this might lead to closures of another 10 ethanol mills this year alone (FO Lichts, 2013a), which might however be acquired by other market participants. The financial situation of mills will also have an important impact on the expansion of the sugar cane area, and access to financing for mills will therefore be crucial to ensure the capacity additions needed in the next years.

Production of **biodiesel** in Brazil stalled at 47 kb/d last year after several years of rapid growth, and is set to stay at this level in 2013, although less than 50% of the sector's capacity is currently being utilised. The cautious projections result from the fact that the National Agency for Petroleum, Natural Gas and Biofuels (ANP) did not succeed in selling the full volumes offered at recent biodiesel auctions (517 million litres out of 715 million litres offered in the March auction; 488 million litres out of 750 million litres in the April auction [FO Lichts, 2013b]). The main reason for this appears to be large companies outbidding smaller producers by offering prices as low as USD 1/litre (20% below prices in the beginning of the year). Although the government has not taken any final decision regarding the introduction of a B10 mandate in 2014, as previously announced, the installed capacity and availability of raw material should be sufficient to meet such a mandate. Over the medium term, the IEA expects these short-term market challenges to be resolved, and sees biodiesel production reaching 76 kb/d in 2018.

#### Argentina

Argentina has become an important producer and exporter of biodiesel over the last years, with production increasing almost tenfold 2007-11. However, the expansion of the industry has come to a halt and 2012 biodiesel output stood at 47 kb/d, unchanged from the previous year.

A positive development for the industry is the recently released government order that obliges refiners and marketers to increase the level of biodiesel blended with regular diesel from the current 7% to 10% by 1 June this year. However, the B10 mandate only translates into roughly 20 kb/d of domestic demand based on current diesel consumption. This will not be sufficient to maintain the output levels seen in the last years. In addition, the introduction of new reference prices for domestic consumption of biodiesel, and their subsequent revision, have caused some insecurity in the sector.

In addition, the introduction of provisional duties on Argentine biodiesel exports to the European Union at the end of May, as part of an ongoing anti-dumping investigation by the European Commission, cloud the medium-term outlook. The ongoing investigation has already had a strong impact, with biodiesel exports in 2012 declining 7.5%, and first-quarter 2013 exports down 50% year-on-year (FO Lichts, 2013c). The decision to introduce import duties of up to EUR 65.24/ton weighs upon the medium-term outlook for Argentine biodiesel, for which growth of only 7 kb/d to 54 kb/d in 2018 is projected.

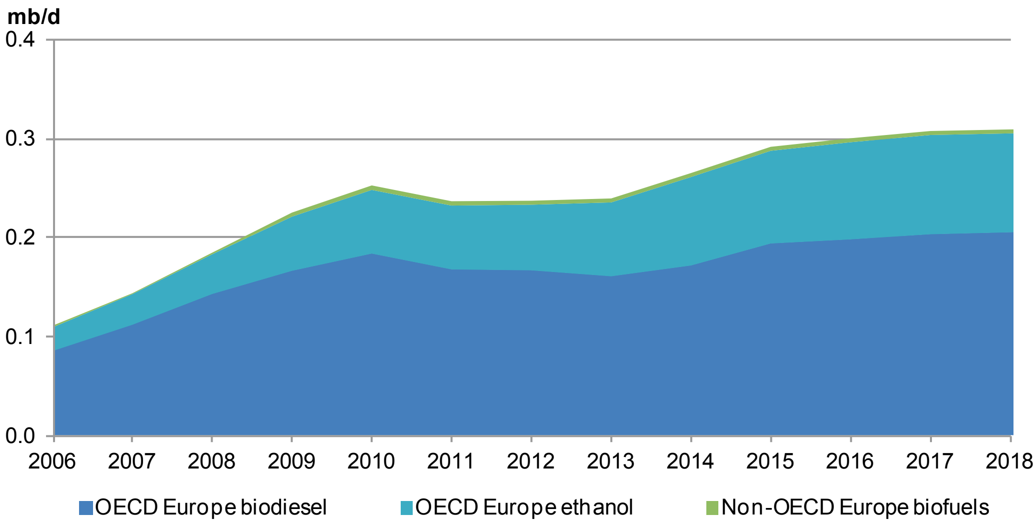
Developments in the **ethanol** sector in Argentina look more positive amid a 50% increase in production to 4 kb/d in 2012 and capacity additions in the next years leading to a projected production of 10 kb/d in 2018.

### *OECD Europe market status and outlook*

High feedstock prices and poor margins continue to provide a difficult environment for producers in OECD Europe and led to a small year-on-year decline in biofuel output, which stood at 230 kb/d in 2012. Over the medium term the *MTRMR 2013* sees production grow by 76 kb/d to reach 306 kb/d in 2018, although ongoing discussions on the future of biofuel support in the European Union provide a considerable downside risk to these projections.

Although a slight decline in near-term output is expected, as more double-counted biodiesel reaches the market and reduces physical demand for biodiesel, for instance in the United Kingdom and Germany, OECD Europe biodiesel production volumes are expected to reach 206 kb/d in 2018. High feedstock prices and poor margins continue to provide a difficult short-term environment for producers, and led to a 5 kb/d year-on-year drop in 2012 biodiesel production to 163 kb/d.

**Figure 112** European biofuel production 2012-18




Ethanol production stood at 67 kb/d in 2012, with high grain prices partially mitigated by a switch towards use of sugar beet as feedstock, and is projected at 100 kb/d in 2018. For 2013 capacity additions – such as the 7 kb/d Vivergo ethanol plant in the United Kingdom – should provide for a 10 kb/d increase in production.

The recent decision of the European Commission to introduce a 9.5% import tariff on US ethanol imports, and its ongoing anti-dumping investigations on Indonesian and Argentine biodiesel imports, are viewed as supportive developments from the European biofuel producers' perspective. The anti-dumping investigation on biodiesel imports from Argentina and Indonesia to the European Union, that led to the introduction of provisional import duties at the end of May 2013, has already significantly reduced biodiesel imports from Argentina and should also impact imports from Indonesia. This should provide some relief to producers in Spain and Italy in particular, as these two countries have been the main destinations for Argentine biodiesel in the past.

The medium-term outlook for EU biofuel production has nonetheless become more uncertain since the European Commission launched a proposal to amend the RED in October 2012, as a result of continued discussions regarding the sustainability of biofuels. The proposal suggests limiting the share of food-based biofuels that can count towards the targets under the RED to 5% of final energy consumption in the transport sector in 2020 (roughly the current average blending share in the European Union), *i.e.* only half of the 10% renewable energy target in transport currently stipulated in the RED. Furthermore the proposal suggests the phasing out of subsidies for conventional biofuels after 2020. Although discussions on the proposal are still ongoing, it has already affected the industry's confidence with likely negative implications for future investments in the sector. This uncertainty weighs upon the overall medium-term production forecast.

### *China market status and outlook*

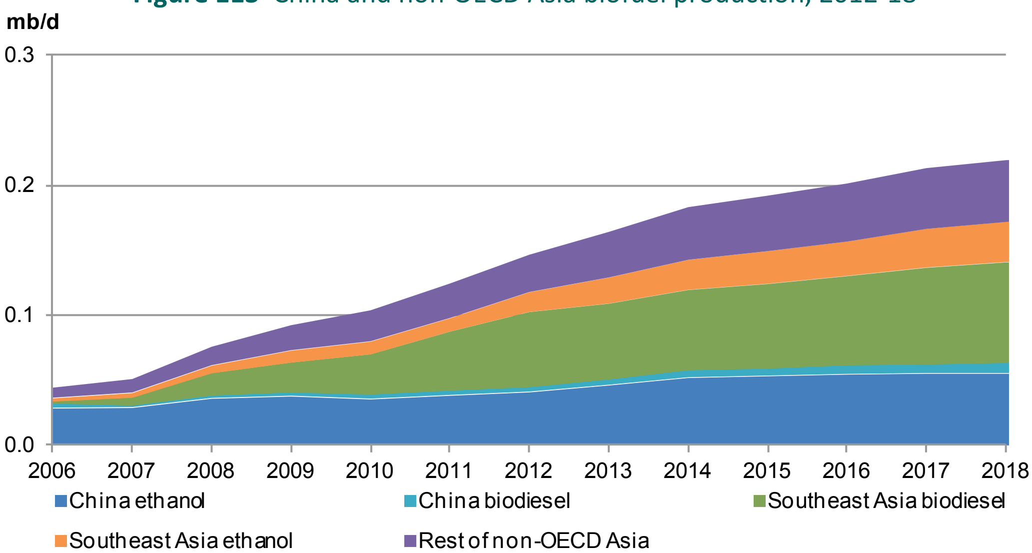
China is the biggest producer of ethanol in Asia, with 2012 production at 41 kb/d compared with 27 kb/d in all non-OECD Asia countries combined (see section below). Several provinces have adopted blending mandates for ethanol, which should in general drive demand. However, government policies preventing the use of food crops as feedstock in new-build plants limit the growth potential for conventional ethanol production, which is seen reaching 55 kb/d in 2018. Biodiesel currently plays only a minor role and stood at 4 kb/d in 2012, and the lack of suitable feedstocks and absence of policy support suggest that the sector will remain a niche market with output projected to reach 9 kb/d by 2018.

### Non-OECD Asia market status and outlook

Non-OECD Asia biofuel production (excluding China) continued to grow and stood at 87 kb/d in 2012. Ethanol accounted for 27 kb/d of the total, with Thailand (11 kb/d) and India (8 kb/d) as the biggest producers in 2012. While the two countries will remain the most important ethanol producers, the biggest relative growth is projected for the Philippines (330% over 2012-18), though starting from a low baseline of 3 kb/d. Over the medium term, total non-OECD Asia ethanol production should almost double and reach 52 kb/d in 2018, driven by blending mandates in several countries.

Non-OECD Asia biodiesel production – almost exclusively located in Southeast Asia – reached 59 kb/d in 2012, with Indonesia accounting for 45% of the total, followed by Singapore and Thailand at 20%. With 2013 production expected to remain flat, the *MTRMR 2013* projects the impressive growth in the past years to slow down over the medium term, with production reaching 81 kb/d in 2018.

**Figure 113** China and non-OECD Asia biofuel production, 2012-18




Domestic demand will be key to ensure further growth of the non-OECD Asia biofuels industry, as palm-oil-based biodiesel is excluded from counting towards the US RFS2, and sustainability requirements in the European Union impact the export potential to this region. Moreover, the European Commission's anti-dumping investigations on EU imports of Indonesian biodiesel, and the introduction of provisional import tariffs, will likely impact the future export potential to this important market. Some countries are increasing their efforts to stimulate biofuels use, such as the Philippines, which has just introduced an E10 mandate earlier this year, as well as Indonesia and Malaysia, which are planning to ramp up the existing B5 to B10 mandates later this year. But stimulating domestic demand can be challenging. In India, for instance, where a nationwide E5 mandate will take effect in June this year, refiners were forced to open a tender for foreign suppliers after domestic tenders secured only half of the 1.05 billion litres of ethanol required to fulfil the mandate.

### Other regions market status and outlook

Biofuel production in **OECD Asia Oceania** stood at 15 kb/d in 2012, and is projected to reach 23 kb/d in 2018. The limited growth prospects result from the absence of support policies, and only minor capacity additions foreseen in the coming years.

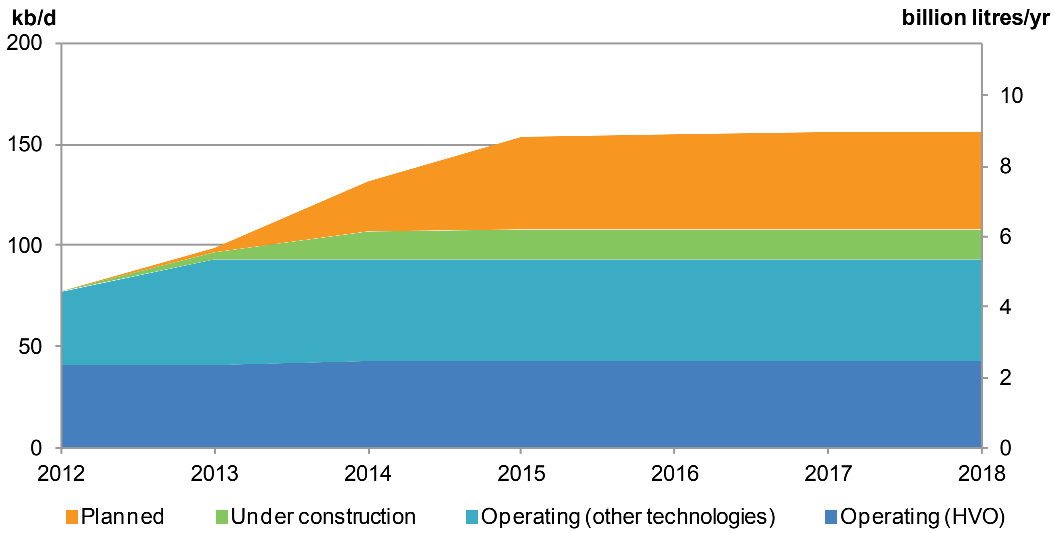
**Non-OECD Europe** biofuel output reached 8 kb/d in 2012, and will remain at this level through the medium term, as a result of the absence of policy drivers.

Biofuel production in **Africa** was negligible and stood at 4 kb/d in 2012. However, an increasing number of countries have adopted, or are in the course of adopting, biofuel targets, including Kenya (E10, B5), South Africa (B5, E2) and Zimbabwe (E5). With several production units scheduled to come on line in the near future, and favourable conditions for cultivation of sugar cane, oil palm, cassava and other biofuel feedstocks, production should reach 16 kb/d in 2018.

### Advanced biofuels

The advanced biofuels[20] sector expansion of production capacity continues, as a couple of the first commercial-scale plants have recently been commissioned in the United States and Europe (KiOR, United States; Chemtex, Italy). In addition, a number of projects are close to completion and scheduled to start within the next months. Additional access to capital, for instance through the European Union's NER300 funding programme, has provided the required financial backing for a number of commercial-scale advanced biofuel projects that are now likely to proceed and come on line in the European Union over the next years.

**Figure 114** Current and future advanced biofuel capacity




Notes: HVO = hydrotreated vegetable oil. No plants have yet been announced after 2016.

Global production capacity in operation in 2012 reached 77 kb/d, up from 55 kb/d in 2011, with 75% of this being diesel and kerosene-type biofuels, and 25% producing fuels to replace gasoline. More than half of the total installed capacity was for production of HVO, using vast amounts of conventional

[20] Advanced biofuels, also commonly referred to as second-generation biofuels, are defined as technologies still in the research, pilot, demonstration or early commercial stage. This category includes HVO as well as biofuels based on lignocellulosic biomass, such as cellulosic ethanol, and biomass-to-liquids diesel. Novel technologies such as algae-based biofuels and biofuels produced through conversion of sugar via biological or chemical catalysts are also included in this category.

biodiesel feedstock such as palm, canola or soybean oil. The remaining 35 kb/d in operation in 2012 included plants for production of cellulosic ethanol, biomass gasification to synfuels, and to a smaller extent algae-based biofuels.

Global advanced biofuel production capacity could increase to 156 kb/d in 2018, with production volumes likely to lie well below nameplate capacity in the first years of production. This reflects a 25 kb/d downward revision compared with the previous assessment published in the IEA *MTOMR 2012* (IEA, 2012). The revision stems from recent announcements of a number of companies, including oil majors, to step back from their projects for various reasons. Greater-than-expected technological challenges were among the most important reasons for the cancellation of projects. Additionally some commercial-scale projects were delayed or abandoned as a result of difficulties in ensuring the required financing. Overall, the policy framework for advanced biofuels in many countries seems to be insufficient to fully address the investment risks associated with first-of-their-kind commercial-scale production plants. Looking at longer-term IEA scenarios, the projected advanced biofuel capacity, even if operating at full utilisation rates, would be sufficient to meet only around one-third of the required volumes of advanced biofuels in the IEA 2DS.

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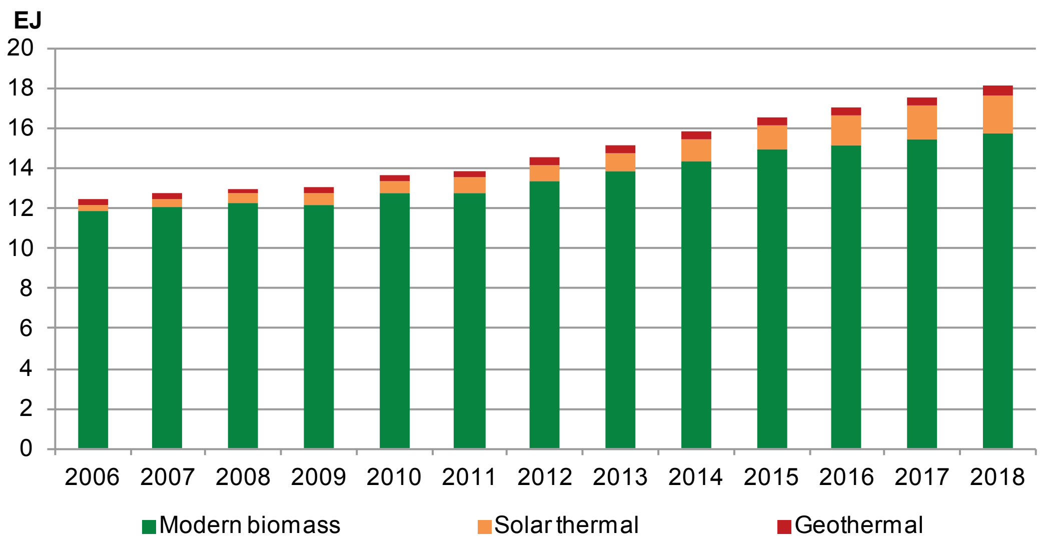
# RENEWABLE HEATING: GLOBAL OUTLOOK

## Summary


- **Renewable energy sources are playing an increasing role in final energy use for heat**, though their growth rates generally lag that of renewable generation for electricity. Some technologies have matured and are increasingly cost-competitive in a number of markets and circumstances. Renewable heat policy frameworks have evolved slowly and face distinct challenges to stimulate deployment, but continue to emerge in a greater variety of markets and sectors. To date, the most extensive policy drivers for renewable heat have emerged in Organisation for Economic Co-operation and Development (OECD) Europe, though comprehensive frameworks are generally still lacking.

- **From 2005 to 2011, global final energy use of renewable energy for heat rose from 12.0 exajoules (EJ) to 13.9 EJ (+2.4% annually).**[21] The renewable portion of heat in total final energy use (excluding traditional biomass use and non-renewable waste, but including consumption of renewable commercial heat) has risen slowly, reaching 8.1% in 2011 from 7.7% in 2005. Modern biomass constituted the largest part (12.8 EJ) of renewable heat use in 2011, followed by small but fast-growing amounts from solar thermal and geothermal.


**Figure 115** Global final energy use of renewable sources for heat (including commercial heat)




Note: modern biomass excludes traditional biomass use, *i.e.* the use of fuelwood, charcoal, animal dung and agricultural residues in stoves with very low efficiencies.


- **Global final energy use of renewable sources for heat is expected to rise from an estimated 13.9 EJ in 2011 to 17.9 EJ in 2018 (+3.7% per year).** The share of renewable sources in final energy use for heat should increase from 8.1% in 2011 to 9.6% in 2018. China should account for 37% of global growth, driven by government targets and good competiveness for solar thermal heating. OECD Europe should account for 22% of growth, driven by 2020 targets in the European Union and an expansion of bioenergy, both for direct use and commercial heat, with solar thermal and geothermal growing briskly from low bases.

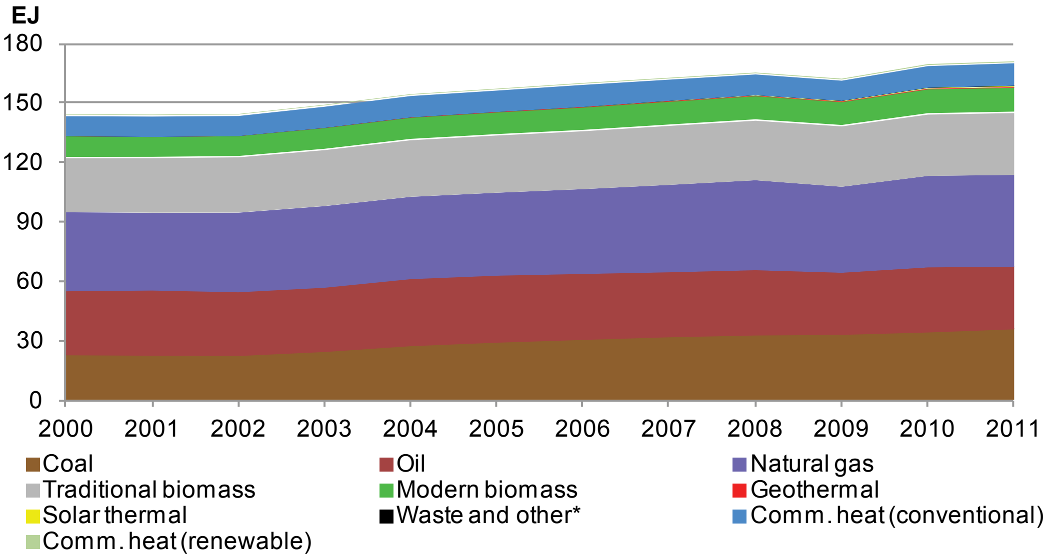

[21] This report expresses heat units in EJ. 1 EJ = 23.8846 million tonnes of oil equivalent (Mtoe); 1 EJ = 277.7777 terawatt hours thermal ($TWh_{th}$).

## Heat in total final energy use: sources and uses

Heat – defined as direct use of energy for heat plus consumption of commercial heat (heat produced and sold to a third party) – constitutes the largest portion of global final energy consumption. While heat could, in principle, include usage of electricity, this report does not attempt to characterise these flows, which are not separated out in International Energy Agency (IEA) statistics. Due to its more distributed, less centralised nature (compared with electricity) heat has often been under-emphasised by policy makers and analysts. Yet these actors are directing increasing attention to the sector, driven by the potential energy security, climate and cost benefits from more integrated policy approaches.

Final energy consumption for heat (including traditional biomass use[22]) stood at almost 171 EJ, or 4 080 Mtoe in 2011. The share of heat in total final consumption has remained relatively steady over the past decade and heat's share (46% in 2010) is much larger than either transport (27% in 2010) or electricity (17% in 2010).

**Figure 116** Global final energy consumption for heat by source




* Includes non-renewable waste and nuclear.

The renewable portion of heat in total final energy use (excluding traditional biomass and non-renewable wastes, but including consumption of renewable commercial heat) has risen only slowly over time, reaching over 8.1% in 2011 versus 7.7% in 2005. Fossil fuels continue to dominate the heat mix. Coal's share of heat in final energy use (including commercial heat) rose from 21% in 2005 to 24% in 2011. The natural gas share (30% in 2011) has remained relatively steady while oil (19%) has declined somewhat. Traditional biomass accounts for a significant source of heating and cooking in developing countries, with its share of heat in final energy use relatively steady over time at 18%.

Global final energy consumption for heat increased by 1.3% per year over 2005-11 driven by rising incomes and economic growth, though use declined in 2009 during the economic crisis. Most heat is used in the buildings sector (51% of total energy use for heat) where needs for cooking and water

[22] Traditional biomass use refers to the use of fuelwood, charcoal, animal dung and agricultural residues in stoves with very low efficiencies. No observed statistics are available and IEA estimates may differ from those of other international organisations. Traditional biomass use is calculated as the sum of all non-OECD solid biofuels for heat use in residential buildings, in line with assumptions from *World Energy Outlook* (IEA, 2012a).

and space heating have increased. Still, industrial heat is rising faster (46% of total), based on higher-temperature process heat consumption for the iron and steel and cement industries and medium/low temperature heat consumption in chemicals and petrochemicals, food, and the pulp and paper industries. Of course, heat usage in any given country depends highly on prevailing weather conditions in a given year, with colder climates more susceptible to annual variations.

Heating needs are met either through on-site production (direct use) or through commercial heat, often provided by co-generation[23] plants through district heating networks. Commercial heat consumption, mostly from conventional sources, represents about 7% of final energy use for heat. The absolute level of commercial heat continues to rise as countries increasingly take advantage of the energy efficiency benefits of district heating systems and co-generation.

In the OECD, a combination of economic slowing, increased energy efficiency in the industrial and buildings sectors, and an increased usage of electricity for heating in some countries caused heat use to decline by an average 1.1% annually over 2005-11. Over the medium term, OECD total heat use is expected to rise from 55 EJ in 2011 to 57 EJ in 2018 (+0.5% annually), driven by recovering economic conditions. Still, continued expected efficiency improvements will weigh upon this growth, with final energy use for heat in 2018 expected to remain below 2005 levels.

In the non-OECD, final energy consumption for heat is growing much faster. Increased usage in both industry and buildings drove 2.8% annual growth in heat over 2005-11. Economic and population growth should drive continued strong growth over the medium term. Non-OECD total heat use is expected to rise from 116 EJ in 2011 to 130 EJ in 2018 (+1.7% annually).

## Renewable heating: market trends, outlook and policy frameworks

### *Market status and outlook*

Renewable sources are playing an increasing role in final energy use for heat, though their growth rates lag that of renewable generation for electricity. Three sources – modern biomass, geothermal and solar thermal for heating – make up the renewable portion of global final energy use for heat, which includes both direct use and commercial heat.[24] Final energy use of renewables for heat rose from 12.0 EJ in 2005 to 13.9 EJ in 2011 (+2.4% per year). Of these sources, modern biomass constituted the largest portion (12.8 EJ) in 2010, followed by small but fast-growing contributions from solar thermal (0.7 EJ) and geothermal (0.3 EJ).

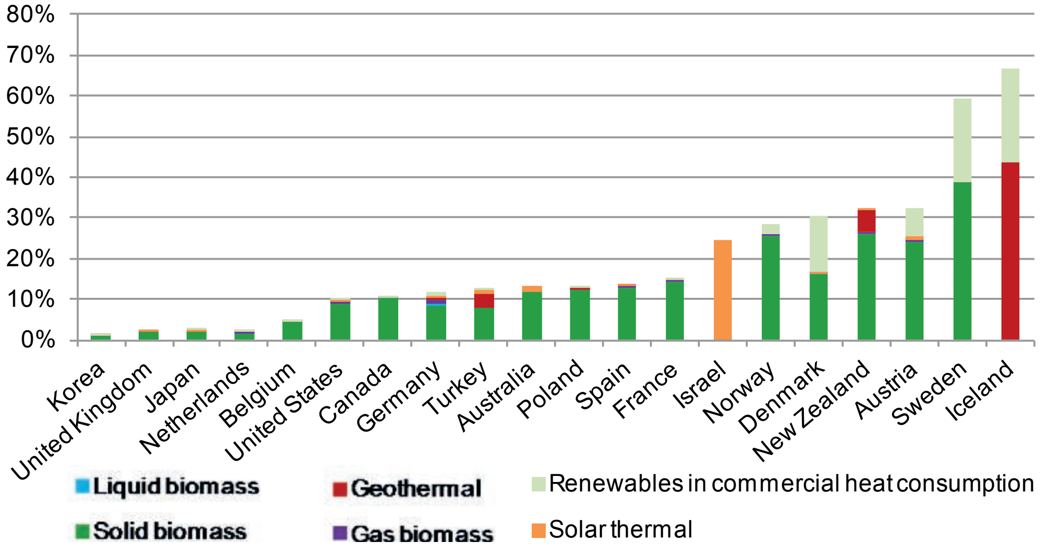
Traditional biomass use is excluded from this analysis due its very low energy efficiency and high associated pollutants. Its global use is expected to climb moderately, from 31.3 EJ in 2011 to 31.6 EJ in 2018. Rising domestic heating needs (*e.g.* for cooking) in sub-Saharan Africa, even as China and India switch to more modern fuels, should drive the increase (for more context, see IEA, 2012a). Still, in the long term, global traditional biomass use should begin declining, with large substitution potential from distributed renewable sources, such as modern biomass and solar thermal.

In the OECD, renewable heat plays a significant role, though its impact varies strongly by country. In Iceland and Sweden, renewables account for over 60% of final use of energy for heat. Renewable

[23] Co-generation refers to the combined production of heat and power.
[24] Ground-source heat pumps are not included in IEA statistics for renewable heat. See feature box on heat pumps later in this chapter.

sources meet over 20% of heat in New Zealand, Austria, Denmark, Norway and Israel.[25] Some countries, such as the United Kingdom and the Netherlands, have relatively low shares of renewable heat. Bioenergy provides the largest portion of renewable heat across the OECD and accounts for most commercial heat (*e.g.* in Scandinavian countries and Austria). However, geothermal (Iceland, New Zealand, Turkey) and solar thermal (Israel, Austria, Turkey, Spain, Australia) play significant roles in a range of markets.

**Figure 117** Share of renewable sources in final consumption of energy for heat in selected OECD countries, 2011

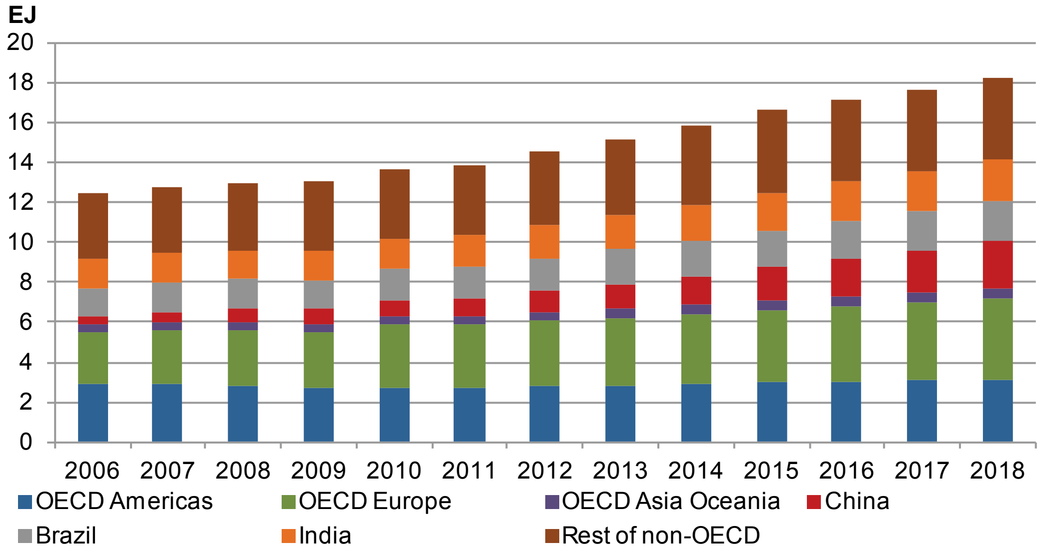



Renewable heat use has grown over time in the OECD, though the regional pictures differ. Over 2005-11, OECD renewable heat grew on average by 1.3% annually, as it rose from 5.8 EJ to 6.3 EJ. The share of renewable sources in final energy use for heat rose steadily, from under 10% in 2005 to over 11% in 2011. Of the three OECD regions, Europe grew the fastest, increasing by an average 3.3% annually, supported by generally stronger policy frameworks and increasing renewable heat use in both the residential and industrial sectors. OECD Asia Oceania grew by 0.7% annually over 2005-11, largely due to rising solar thermal use in the residential sectors of Australia and Israel. By contrast, renewable heat declined by 0.4% annually in the OECD Americas. Slow economic growth, reduced industrial use of bioenergy and low natural gas prices in the United States and Canada drove the trend. Still, the share of renewable sources in the OECD Americas remained steady at over 11%.

In the non-OECD, renewable heating data tend to vary in quality more than in the OECD. As such, the discussion here is less comprehensive. The share of renewable heat among non-OECD countries is particularly high in Brazil (43% in 2011), where bioenergy for heat meets a significant portion of industrial needs. Renewable sources also account for a large share of final energy use for heat in Thailand (20% in 2011), with significant bioenergy use in industry; India (11%), Indonesia (7%) and South Africa (6%). In China, renewable sources accounted for only 2% of total heat use in 2010. Still, China's renewable heat use has grown rapidly (+18% annually over 2005-11) and it remains the world's largest market for solar thermal heating.

[25] 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.

**Figure 118** Global final energy use of renewable sources for heat (including commercial heat)




Over the medium term, global renewable heat use is expected to rise by 29% from an estimated 13.9 EJ in 2011 to 17.9 EJ in 2018. Based on growth rates for total final energy use for heat from the IEA *World Energy Outlook 2012*, the share of renewable sources is expected to increase from 8.1% in 2011 to 9.6% in 2018. OECD Europe should account for 0.9 EJ, or 22%, of global growth, as its renewable heat use increases by 3.7% annually over 2011-18, driven by 2020 renewable energy targets in the European Union. Most of the rise in Europe stems from bioenergy, both for direct use and commercial heat, though solar thermal and geothermal grow briskly from low bases. OECD Americas and OECD Asia Oceania each grow by 0.4 EJ (10% of global growth), driven by increases in bioenergy and solar thermal for direct use.

In the non-OECD, China's renewable heat use is expected to grow by 1.5 EJ (37% of global growth), Solar thermal, driven by government targets and good competitiveness versus other sources, accounts for the largest portion of China's rise, though bioenergy and geothermal also make important contributions. India and Brazil each grow by around 0.5 EJ, largely from bioenergy for direct use. Still, solar thermal is expected to grow rapidly from a low base in both these markets. The rest of the non-OECD accounts for 0.5 EJ, or 10% of global growth. Bioenergy use should rise in a number of areas such as Russia, other non-OECD Europe/Eurasia countries, Latin America outside of Brazil and Southeast Asia. However, solar thermal should grow faster on a percentage basis, led by South Africa.

## *Current policy environment for renewable heating*

Renewable heat policy frameworks have evolved slowly and face distinct challenges to stimulate deployment, but continue to emerge in a greater variety of markets and sectors. At the national level, around 35 countries have policies in place to support renewable heat development, versus some 110 for renewable electricity, mostly aimed at the buildings sector, with additional markets having state-level and indirect policies that favour renewable heat generation.

To date, the most extensive policy drivers for renewable heat have emerged in **OECD Europe,** though comprehensive frameworks are generally still lacking. The European Union's (EU) RED requires renewable sources to meet 20% of EU-27 final energy consumption in 2020. No threshold is required for renewable heating, though given the high heating share in total final energy consumption, a number of countries have set ambitious heating (and cooling) generation targets.

**Table 91** OECD country main targets and support policies for renewable heating and cooling

<table>
<tr><th>Targets and quotas</th><th>Support scheme</th><th>Other support</th></tr>
<tr>
<td>
National Renewable Energy Action Plans for European Union countries:<br>Indicative 2020 split: share of total energy use for heating and cooling from renewable sources.
<table>
<tr><td>Austria</td><td>32.6%</td><td>Ireland</td><td>15.0%</td></tr>
<tr><td>Belgium</td><td>11.9%</td><td>Italy</td><td>17.1%</td></tr>
<tr><td>Czech Republic</td><td>15.5%</td><td>Luxembourg</td><td>8.5%</td></tr>
<tr><td>Denmark</td><td>39.8%</td><td>Netherlands</td><td>8.5%</td></tr>
<tr><td>Estonia</td><td>17.6%</td><td>Poland</td><td>17.1%</td></tr>
<tr><td>Finland</td><td>47.0%</td><td>Portugal</td><td>30.6%</td></tr>
<tr><td>France</td><td>33.0%</td><td>Slovakia</td><td>14.6%</td></tr>
<tr><td>Germany</td><td>14.0%</td><td>Slovenia</td><td>30.8%</td></tr>
<tr><td>Greece</td><td>20.0%</td><td>Spain</td><td>18.9%</td></tr>
<tr><td>Hungary</td><td>18.9%</td><td>Sweden</td><td>62.1%</td></tr>
<tr><td>Iceland</td><td>96.1%</td><td>United Kingdom</td><td>12.0%</td></tr>
</table>
Building obligations (BO):<br>Apply on national levels in: Czech Republic, Chile, Denmark, Germany, Ireland, Italy, Portugal, Slovenia and Spain and on sub-national level in Australia, Belgium, Mexico and United States.<br><br>BO targeting only solar thermal collectors apply in Greece, Denmark, Israel, Spain and the United States.
</td>
<td>
Feed-in tariffs:<br>Renewable Heat Incentive: in United Kingdom since April 2010 for non-residential installations and from 2014 for households. The Netherlands has a feed-in tariff since 2011.<br><br>Italy's Conto Termico:<br>Scheme for public and non-industrial private entities which supports up to 40% of investment costs. Technologies include heat pumps, biomass boilers, solar thermal systems. Cap of EUR 200 million for disbursements over one year for public projects and EUR 800 million for private entities.<br><br>Capital cost subsidies:<br>From 15% to 75% in Austria, Czech Republic, Estonia, Finland, Germany, Hungary, Italy, Korea, Luxembourg, Poland, Portugal, Slovakia and Slovenia.<br><br>Installation grants:<br>Ireland, France and United Kingdom in range of EUR 350 to EUR 4 200 per installation in households.<br><br>Tax incentives:<br>Belgium, Canada, Czech Republic, Denmark, France, Greece, Ireland, Italy, Netherlands, Spain, Sweden, United States.<br><br>Soft loans:<br>Canada (Alberta), Germany, Greece, Italy, Netherlands and Slovenia provide soft loans for all renewable heat projects. France provides loans only for solar thermal installations. Poland and Finland offer loan guarantees for RES-H installations.
</td>
<td>
Co-generation incentives (obligation, green certificates or financing): Austria, Belgium, Czech Republic, Denmark, Finland, Germany, Greece, Hungary, Netherlands, Poland, Portugal, Slovenia, Spain, United Kingdom, United States.<br><br>Carbon dioxide ($CO_2$) tax:<br>Australia, Denmark, Finland, Japan, Norway, Slovenia, Sweden, Switzerland, United Kingdom.<br><br>RES-H awareness:<br>Most OECD countries promote awareness information of renewable heat applications (via government websites).
</td>
</tr>
</table>

Notes: RES-H = final energy consumption for renewable energy sources for heat. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

A few European countries have adopted quantitative regulatory policies, such as renewable obligations (RO), though only in the buildings sector. In 2011, Germany extended its renewable heat obligation initially applying to new buildings (since 2008) to certain already existing public buildings. Spain, Italy, Ireland and Portugal also have solar thermal obligations. Still, these policies have only moderately stimulated overall deployment, given slow new building construction in Europe and the complexity in verifying heat output among many small producers. By contrast, with no obligation in place, robust solar thermal development has proceeded in Turkey based on competitiveness with alternatives.

To date, only the United Kingdom, under the Renewable Heat Incentive (RHI), and the Netherlands have adopted a dedicated heat feed-in tariff (FIT). Given the difficulties and costs in heat metering, the heterogeneous nature of heat output, the large number of (small) heat producers and an absence of a "grid" (*i.e.* district heating system), the RHI design presented barriers distinct from those in electricity markets. As such, the scheme is evolving over time. Originally applied to the non-domestic sector (industry, commercial and public sector), the UK programme is slated to expand to the residential sector in 2014.

At the end of 2012 Italy opened a financial scheme ("Conto Termico") for public and non-industrial private entities for the purchase of installations producing thermal energy from renewables. The scheme returns up to 40% of eligible investment costs in yearly installations over a variable period of two to five years depending on technology type and scale. Technologies eligible are heat pumps, biomass boilers, heaters and fireplaces, solar thermal systems, including those based on the solar cooling technology. A budget of EUR 200 million is allocated for disbursements over one year for projects carried out by public bodies and another EUR 800 millions for private beneficiaries. Once this cap is reached, the programme will be closed for new applications.

Many other European countries also offer capital cost subsidies for renewable systems, though these have sometimes been stop-and-go in nature, subject to budget availability, and not linked to actual heat output. Some governments have incentivised renewable heat through support to large-scale distribution or integrated approaches with electricity or $CO_2$ policies. Iceland constructed a large-scale district heating system that facilitates the transport and distribution of geothermal-based heat. Austria, Denmark, Finland, Germany and Sweden are also actively expanding their district heating networks. In Austria and Germany, for example, the electricity FIT supports bioenergy heat through a co-generation premium. In Sweden, Denmark, Finland and Norway, a tax on $CO_2$ emissions and fossil fuels has improved the competitiveness of renewable heat versus fossil-fuel alternatives.

In **OECD Asia Oceania**, Israel has had a successful solar thermal obligation on new buildings since 1980. This rule stimulated the market to such a point where growth became self-sustained – most of the current Israeli solar thermal market is from voluntary installations (Beerepoot, 2012). Some Australian states offer tradable certificates to support solar thermal use. In Korea, authorities are looking to implement a renewable heat obligation policy by 2014. In the **OECD Americas**, a tax rebate scheme has stimulated solar thermal development in Chile (the incentive is slated to expire at the end of 2013). In the United States, investment tax credits (ITCs) are available for renewable heating systems and co-generation plants from the federal and some state governments (the federal incentives are slated to expire at the end of 2016).

Policy initiatives in the **non-OECD** continue to grow, though remain concentrated in a few key markets. China's government has established targets under the 12th Five-Year Plan that see solar water heating capacity rising to 280 gigawatts thermal ($GW_{th}$) by 2015 and 560 $GW_{th}$ by 2020 versus 118 $GW_{th}$ in 2010. A number of localities have also introduced solar obligations. In summer 2012, the Chinese government implemented a one-year scheme to give financial rebates to high-efficiency solar water heater purchases, but it is unclear if this will be renewed. China has also employed a strategy to promote household biogas use since the 1980s. In India, the Jawaharlal Nehru National Solar Mission (JNNSM) sets targets for solar water heaters, solar cookers and concentrating solar plants for use in industry. The central government also provides financial support for household biogas systems. In Thailand, the government gives investment grants that have helped solar thermal systems and bioenergy use to increase. South Africa maintains a rebate programme for solar water heating and seeks deployment of 1 million systems by 2014. In Brazil, the government is supporting the build-out of solar water heaters for low-income families.

**Table 92** Non-OECD country main targets and support policies for renewable heating and cooling

| Targets and quotas | Support scheme | Other support |
|---|---|---|
| **National Renewable Energy Action Plan:** Indicative 2020 split (share of heating and cooling production from renewable sources):<br>Romania (20%); Bulgaria (23.8%); Latvia (53.4%); Lithuania (39%); Malta (6.2%).<br><br>**Solar thermal water heaters:** Brazil (2.86 million new units 2011-14); China (560 $GW_{th}$ by 2020); India (15 million $m^2$ by 2017, 20 million $m^2$ by 2022); Morocco (1.7 million $m^2$ by 2020); South Africa (1 million homes by 2014); Thailand (100 ktoe by 2022). Solar water heater targets also in Albania, Antigua and Barbuda, Chinese Taipei, Lebanon, Mozambique, Tunisia, Uganda, Uruguay.<br><br>**Building obligations:** Dominican Republic Kenya, Ghana, Namibia and Uruguay.<br>At local level in Brazil, China, India, United Arab Emirates. | **Capital cost subsidies:** Rebates available in Bulgaria, Chinese Taipei, Malta, Mauritius, Thailand and South Africa.<br><br>**Tax incentives:** Antigua and Barbuda, Barbados, Uruguay.<br><br>**Soft loans:** Available nationwide in Bulgaria, Lebanon, Montenegro, Mauritius and Tunisia. In Ukraine, available in Lviv region. | **Training programmes:** Albania, India, Malta.<br><br>**Equipment certification:** Albania, China, India, Lebanon and Malta. |

Notes: for further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/; $m^2$ = square metre; ktoe = thousand tonnes of oil equivalent.

## Outlook for renewable heating technologies

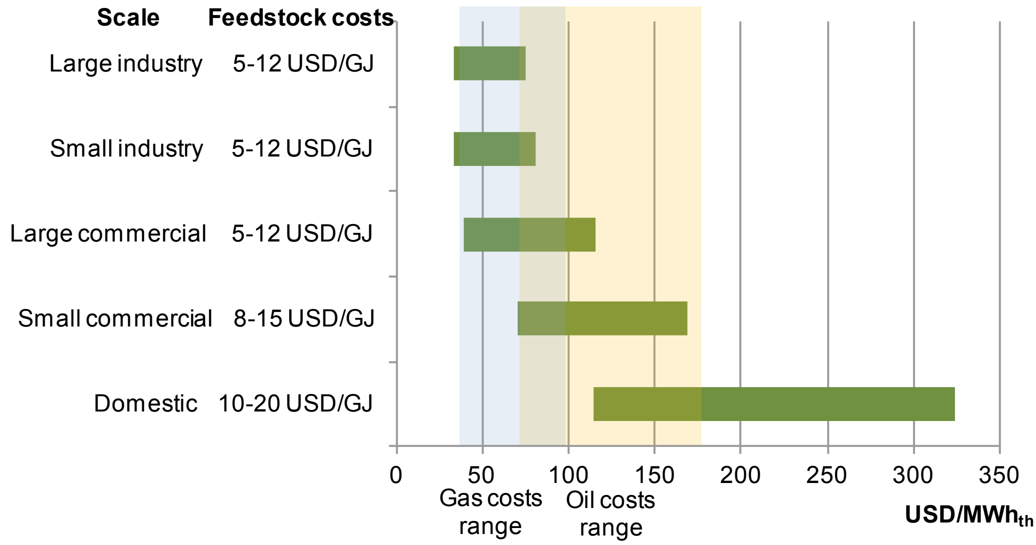
### *Modern biomass*

#### Technology background

Modern biomass heat production technologies are well established and encompass solid, liquid and gas-fired systems. **Solid biomass** heating systems exist for individual buildings (5 kilowatts thermal [$kW_{th}$] to 100 $kW_{th}$), farm and commercial buildings (100 $kW_{th}$ to 500 $kW_{th}$), and large plants for district heating (1 megawatt thermal [$MW_{th}$] to 50 $MW_{th}$). Boilers exist for solid wood logs, wood chips, and wood or straw pellets, with some technologies used in co-generation plants that can produce both heat and power. There are currently no specific technologies for biomass use in industry. Rather biomass is co-fired in existing installations. In Brazil, for instance, charcoal is used for iron production. Co-combustion of biomass in cement kilns is another option. All forms of biomass can be used in co-generation plants with a typical heat/power ratio of 1:2 to 1:3, and an overall efficiency of up to 90%. These plants have higher capital costs than heat-only installations, and at smaller scales (< 10 megawatts [MW]) the plant's electric efficiency is typically lower. It is important to find steady heat demand to make the investments worthwhile. In pulp and paper mills, for example, biomass co-generation is common as the heat is used in the production processes and the feedstocks are typically already-available process residues.

**Biogas** systems provide heat primarily in buildings. Household biogas systems are widespread in India and China. In these systems, organic household wastes, manure and faeces are digested into a methane containing biogas, which can be stored for cooking, heating and lighting purposes. Systems also exist at a larger scale (150 kilowatts [kW] to 20 MW), for example in Germany, Denmark and the Netherlands, where the biogas is derived from organic waste in landfills and wastewater treatment plants. More recently, the use of energy crops and manure in dedicated biogas installations is gaining momentum. While biogas is primarily used to generate electricity, the waste heat from go-generation plants is often used locally for drying processes or space heating. Another small but growing application is the upgrading of biogas to biomethane, which is injected into the natural gas grid. **Liquid biofuels** such as vegetable oil from rapeseed or oil palm and biodiesel can be used in oil burner heating systems instead of fuel oil. With some retrofitting, existing burners can use biodiesel or straight vegetable oil. Instead of vegetable-oil-based biofuels, pyrolysis oil could also be used for heat production.

**Figure 119** Bioenergy heat production costs versus heating oil and natural gas, 2010 (USD per megawatt hour [$MWh_{th}$])




Note: bioenergy cost bars correspond to applicable feedstock costs and system size; small commercial = 100 $kW_{th}$ to 200 $kW_{th}$, large commercial = 350 $kW_{th}$ to 1 500 $kW_{th}$, small industry = 100 $kW_{th}$ to 1 000 $kW_{th}$, large industry = 350 $kW_{th}$ to 5 000 $kW_{th}$.

Source: IEA, 2012b.

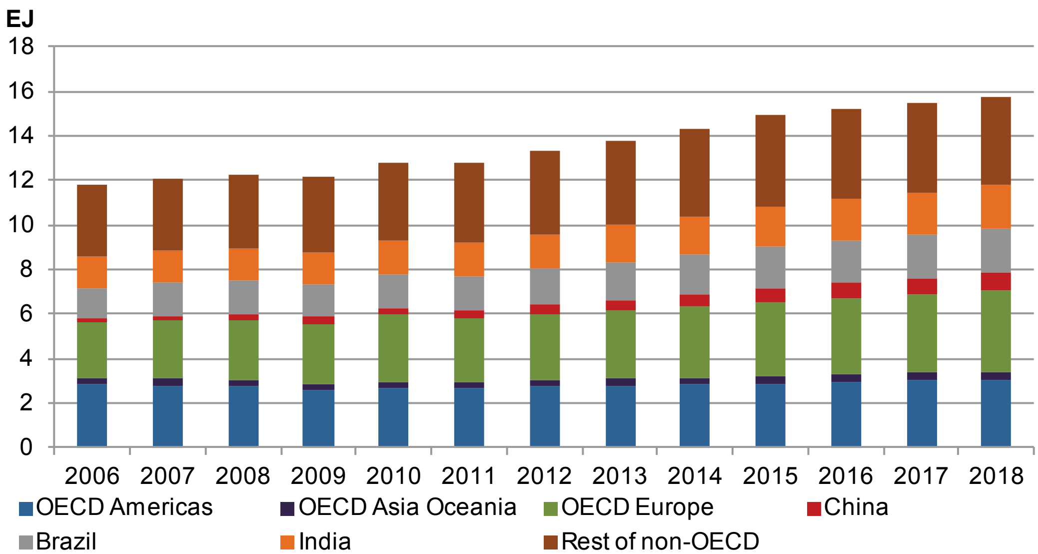
The capital and operating costs for biomass heat generating systems vary with scale, the constancy of the heat load, and the availability and costs of fuel inputs. The costs for household biogas systems occupy a large range, USD 500 per $kW_{th}$ to USD 5 000 per $kW_{th}$. The investment costs for solid biomass range from USD 900 per $kW_{th}$ to USD 1 500 per $kW_{th}$ for domestic systems, and USD 500 per $kW_{th}$ to USD 800 per $kW_{th}$ for industrial-scale heat plants (IEA, 2012b). Where biomass load factors are high and feedstock costs are low, solid biomass heat production costs compete well with oil-derived heat, and with natural gas when gas prices are high.

### Market status and outlook

In 2011, modern biomass heat use (which excludes traditional biomass use) stood at an estimated 12.8 EJ and accounted for 92% of total renewable heat use. Global modern biomass use for heat has risen slowly but steadily in recent years, from 11.5 EJ in 2005 (+1.8% annually over 2005-11). Growth has been driven largely by supportive policy frameworks and increased commercial heat and industrial use in OECD Europe. Biomass co-generation plants for district heating are particularly widespread in Nordic countries, Austria and Germany. Resource availability combined with the relatively high heat demand during the long winter season and extensive district heating networks provide a favourable environment for their deployment. Industrial use has also risen in major non-OECD countries (*e.g.* Brazil, India, China). In the OECD Americas, the economic crisis and persistently low natural gas prices in the United States and Canada have slowed demand for bioenergy-based heat in recent years.

Over the medium term, global bioenergy use for heat is expected to rise to almost 16 EJ (+3.1% annually over 2011-18). Growth on an absolute basis should be strongest in OECD Europe, as use increases from 2.8 EJ in 2011 to 3.6 EJ in 2018. A part of this rise is likely to occur in the buildings sector, with some substitution away from costly oil-fired heating towards small biomass-based sources. Still, most of the Europe increase should occur in the industrial sector and in commercial heat use. Supportive policy frameworks, EU 2020 targets for biomass-based heat and continued expansion of co-generation plants should prompt the most new activity in Austria, Germany, France, Italy, the Netherlands, Nordic countries, Poland and the United Kingdom. The availability and cost of solid biomass feedstocks will remain a key challenge, however, as the advent of larger-scale biomass and co-firing plants will require further development of feedstock supply chains.

**Figure 120** Modern bioenergy use for heat and projection




Note: includes renewable waste.

Elsewhere in the OECD, bioenergy use for heat is likely to grow more slowly. Low expected natural gas prices in North America are likely to limit increases there, even as federal and state-level incentives help to incentivise new biomass co-generation in the United States. Still, the United States and Canada are likely to continue emerging as major sources of biomass pellet exports, a trend that should increase global feedstock supplies and facilitate biomass-based generation in Europe.

**Table 93** Modern biomass heating main drivers and challenges to deployment

| Drivers | Challenges |
|---|---|
| • mature technology with good competitiveness versus alternatives;<br>• increasing commercial heat use from co-generation plants and co-firing in coal plants, particularly in Europe;<br>• generally good suitability for providing low-emissions, process heat in industry. | • availability and cost of feedstock, particularly for large-scale applications;<br>• cost competition versus low natural gas prices in North America;<br>• lack of awareness of technology options;<br>• ensuring the sustainability of biomass supply; uncertainty over sustainability criteria. |

In the non-OECD, Brazil should see strong gains in industrial heat use from bioenergy. The use of modern biomass in buildings is likely to increase in China and India as households substitute away from traditional biomass. Industry use is likely to increase in China and India, with biomass-based commercial heat developing more in the former. Still, a relative lack of feedstock supply chains will limit development in these two markets over the medium term.

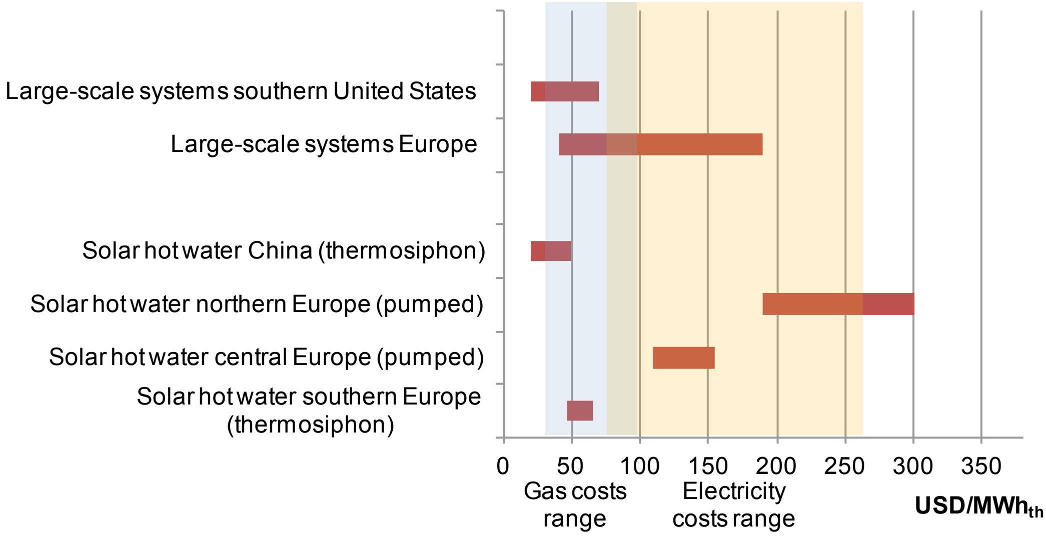
## *Solar thermal*

### Technology background

Solar thermal heating is a mature technology with excellent potential, not only in sunny climates. A variety of technologies exist to capture solar radiation and convert it into heat for a wide number of applications. Solar collectors provide heat for hot water and space heating for household use and can also provide air conditioning and cooling. Collectors are deployed at a larger scale for commercial and industrial uses or for district heating. Several types of collectors exist. For water and space heating, flat-plate and vacuum-tube collectors are the most popular, with unglazed systems used for swimming pool heating. Solar concentrating techniques can also provide higher-temperature heat or steam for industry and services in countries with good direct irradiance. Recently, non-tracking high-vacuum flat-plate collectors have also been introduced, which can provide heat in the temperature range up to 200 °C.

The costs associated with solar heating depend strongly on the type of technology, the system design and complexity, and the regional resource and supply chain. For systems at building scale, investment costs can range between USD 250 per $kW_{th}$ and USD 2 400 per $kW_{th}$ around the world. Larger systems benefit from economies of scale and costs are typically between USD 350 per $kW_{th}$ and USD 1 040 per $kW_{th}$ (IEA, 2012c). Deployment of solar water heating can therefore imply significant fuel savings versus fossil-fuel alternatives. Still, the relatively high up-front costs of systems can act as a barrier to investment for households.

**Figure 121** Solar thermal heat production costs versus gas and electricity, 2012




Source: IEA, 2012c.

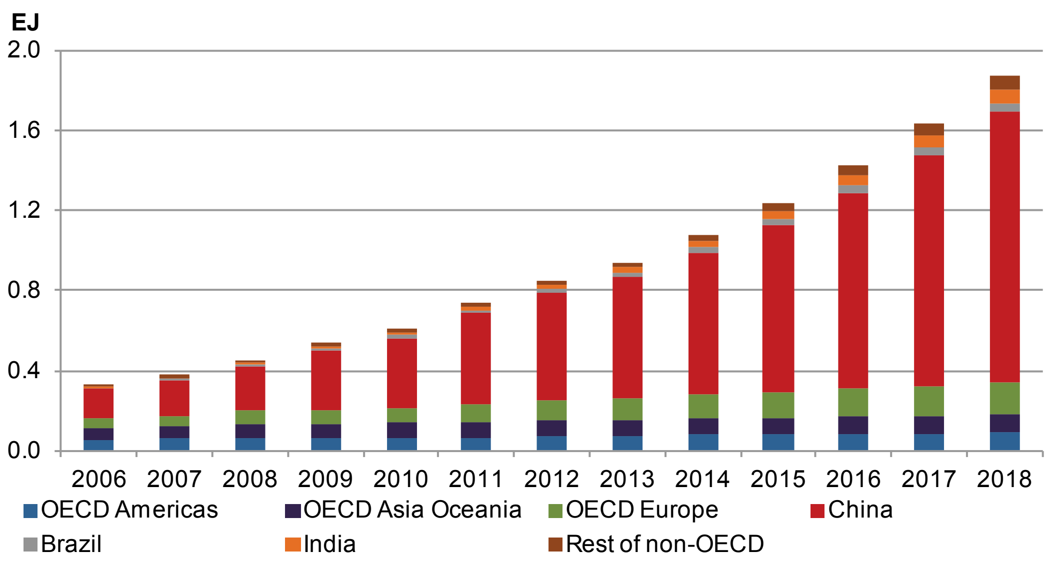
### Market status and outlook

Solar thermal heat use stood at an estimated 0.7 EJ in 2011. Though it remains a small portion of renewable heat (5%), its use has grown rapidly (+17% annually over 2005-11). Over the medium term, global solar thermal use for heat should continue to rise quickly to 1.9 EJ in 2018 (+14% annually on average). Solar thermal capacity is expected to almost triple, from 239 $GW_{th}$ in 2011 to over 635 $GW_{th}$ as strong deployment continues in a number of countries. This capacity forecast is more optimistic than in the *MTRMR 2012*, with global capacity in 2017 expected to be 50 $GW_{th}$ higher with stronger-than-expected contributions from non-OECD countries, such as China and South Africa.

Sources can differ significantly on historical solar thermal capacity and use (the latter is *estimated* at the country level due to measurement challenges). This report uses IEA official statistics, where available, for data consistency. For some countries, data are also sourced from the Implementing Agreement for a Programme to Develop and Test Solar Heating and Cooling Systems, which produces detailed statistics using standardised estimation methodologies and taking into account the lifetime of systems (SHC IA, 2012).

Overall, China is expected to lead growth, with capacity going from near 150 $GW_{th}$ in 2011 to 475 $GW_{th}$ in 2018. China's deployment is driven by attractive solar thermal economics in buildings versus other sources. The Chinese Solar Thermal Industry Federation estimates that the lifetime costs (typical lifetime of Chinese solar thermal system is ten years) of a solar water heater are 3.5 times less than an electric system and 2.6 times less than a natural gas-fired system (Epp, 2012). As China's large and fragmented solar thermal industry consolidates over the medium term, supply chains are likely to benefit from increased economies of scale, further enhancing system economic attractiveness. Meanwhile, deployment should continue to expand to segments beyond residential, low-rise buildings. Large-scale roof installations and balcony systems on new apartment and high-rise buildings should grow strongly driven by obligations in several major cities. Prospects for industrial, process heat over the medium term, however, look more uncertain.

**Figure 122** Solar thermal use for heat and projection




Source: IEA analysis based in part on information provided by the Implementing Agreement for a Programme to Develop and Test Solar Heating and Cooling Systems, 2012.

Overall in Europe, large-scale systems and solar thermal use in commercial heat and industry should continue to increase while new additions in the residential market should moderate due to slow new construction and retrofit projects (ESTIF, 2012). In Italy, the advent of new capital cost supports under the Conto Termico should support strong deployment. In Germany, solar thermal capacity growth is expected to remain steady over the medium term, rising in line with government targets. In Turkey, solar thermal capacity should increase strongly, driven by economic attractiveness versus alternatives. Capacity in Poland is also expected to grow rapidly, with an ambitious target of 10 $GW_{th}$ for 2020. Other countries with significant installed capacity – Greece and Spain – should see only moderate growth amid challenging economic conditions. In Austria, which already has high per capita solar thermal installations, deployment is expected to slow with the temporary suspension of financial incentives for new installations from the Lower Austria region.

**Table 94** Solar thermal heating installed capacity ($GW_{th}$)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| China | 152.2 | 180.4 | 212.0 | 249.1 | 292.7 | 343.9 | 404.1 | 474.8 |
| Germany | 10.7 | 12.0 | 13.4 | 15.0 | 16.8 | 18.7 | 20.8 | 23.1 |
| India | 3.5 | 4.5 | 5.6 | 7.1 | 9.0 | 11.5 | 14.5 | 16.0 |
| United States | 13.6 | 13.9 | 14.2 | 14.6 | 14.9 | 15.3 | 15.7 | 16.1 |
| Turkey | 12.6 | 13.1 | 13.6 | 14.2 | 14.7 | 15.3 | 16.0 | 16.6 |
| **World** | **238.8** | **274.5** | **314.8** | **361.7** | **416.5** | **480.2** | **552.9** | **635.6** |

Notes: 2011 and 2012 data are estimated.

Source: IEA analysis including historical estimates for non-OECD country capacities provided by the Implementing Agreement for a Programme to Develop and Test Solar Heating and Cooling Systems, 2012.

Elsewhere, the United States should continue growing strongly, supported by attractive economics, a federal ITC through 2016 and state level incentives, though lack of technology awareness may be a challenge to deployment. In OECD Asia Oceania, Australia is likely to lead growth, with Israel maintaining a high level of solar thermal penetration. Strong developments are also expected in several non-OECD countries. Rising hot water and cooking needs in India, combined with support under the JNNSM, should propel capacity growth there. In South Africa, a government target of 1 million solar thermal systems in residences by 2014 should drive strong activity, though deployment may lag this goal as the sector advances from a still-small base. In Brazil, increased residential use should support strong development.

**Table 95** Solar thermal heating main drivers and challenges to deployment

| Drivers | Challenges |
|---|---|
| • mature technology with good competitiveness versus alternatives;<br>• increased building construction and rising hot water needs in developing countries;<br>• supportive policy frameworks and financial incentives in many markets. | • high up-front investment costs;<br>• underdeveloped applications for industrial process heat;<br>• slow new building construction in OECD markets;<br>• split incentives for investment between owners and tenants in buildings; lack of awareness of technology competitiveness versus alternatives;<br>• stop-and-go policies, uncertainty in some markets. |

## *Geothermal*

### Technology background

Geothermal energy can be used directly, without using a heat pump, for heating and cooling purposes in buildings; for district heating, greenhouses, water heating in buildings and pools; and for industrial process heat. Hot water that is extracted from a hydrothermal resource or a deep aquifer can be used directly as heat transfer liquid in the system. Hot water can also pass by a heat exchanger, where the heat is transferred to a working fluid, before the water is discharged back to the ground via an injection well. The use of geothermal heat is mainly limited by the availability of resource in proximity to the heat demand, as heat is costly to transport over long distances. This is particularly important for industry, where only a few specific sites might be able to use geothermal energy. The development of enhanced or enhanced geothermal systems (EGS) could change the picture and allow for more industry use. EGS, still at the demonstration level of development, aim to use subterranean heat where no or insufficient steam or hot water exists. To date, all EGS projects have focused only on power generation.

Geothermal heat can be cost-competitive with sufficient high-temperature resource and efficient access to a district heating network or high, continuous heat demand. Capital costs for geothermal district heating plants range from USD 570 per $kW_{th}$ to USD 1 570 per $kW_{th}$ while use in greenhouses is at USD 500 per $kW_{th}$ to USD 1 000 per $kW_{th}$ (IEA, 2011). Geothermal heat could be generated at costs of USD 35 per $MW_{th}$ to USD 55 per $MWh_{th}$ when demand is stable and close to the heat source. Costs can go up to USD 85 per $MWh_{th}$ for heat provided through a district heating network. By comparison, average district heating prices in 2009 for OECD countries ranged from near USD 15 per $MWh_{th}$ to USD 125 per $MWh_{th}$ (Euroheat and Power, 2011). However, exploration risk (*i.e.* risk of not finding sufficient heat source) in well drilling is a significant cost risk for many projects, which can undermine investment. Moreover, environmental permitting can act as a challenge in some markets (*e.g.* Germany).

### Market status and outlook

In 2011, geothermal heat use, excluding ground-source heat pumps, stood at over 0.3 EJ. Geothermal heat remains a small but growing portion of renewable heat use (2%). Over the past decade, geothermal heat use rose steadily from 0.2 EJ in 2005. Much of this growth occurred in OECD Europe, led by increased direct use in Germany, Switzerland and Turkey (in bathing). Direct use of geothermal heat also remains important in Iceland (44% of total heat use), Japan (in bathing), Italy, New Zealand and the United States. Still, in these countries, use has remained relatively unchanged or has slightly declined in recent years. District heating use has increased quickly in Germany, Iceland, Austria and Denmark. China (which accounts for most non-OECD use) has emerged as a large user of both direct geothermal heat and district heating.

**Figure 123** Geothermal use for heat (excluding heat pumps) and projection

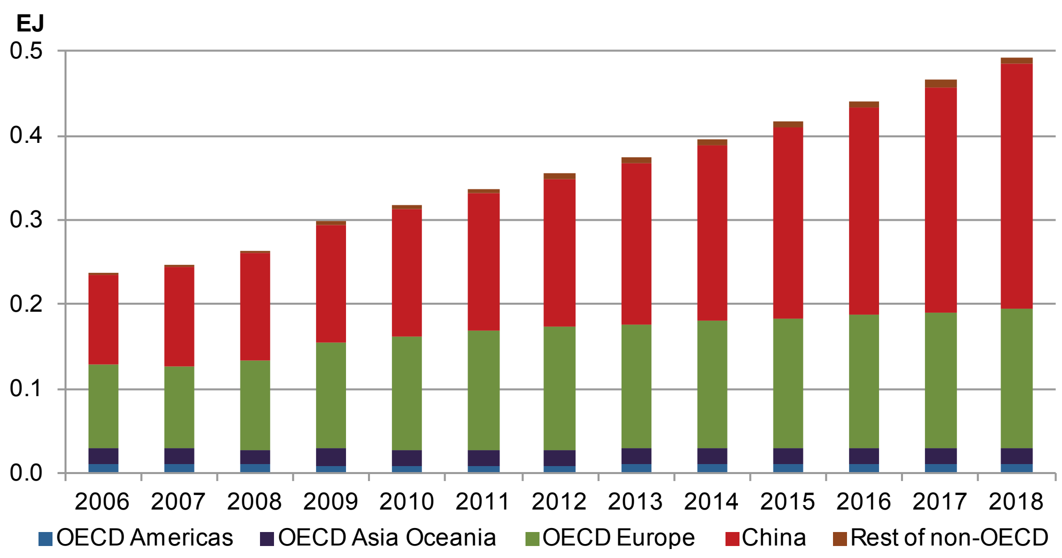



**Table 96** Geothermal heating main drivers and challenges to deployment

| Drivers | Challenges |
|---|---|
| • mature technology with good competitiveness versus alternatives;<br>• high capacity factors; can provide continuous supply in places with stable heat demand. | • exploration risk associated in new well drilling, which can be costly and difficult to finance;<br>• generally underdeveloped policy framework compared with other renewable sources;<br>• limited development for industrial use. |

Over the medium term, global geothermal use for heat should continue to rise, reaching almost 0.5 EJ in 2018 (+6% annually on average 2011-18). Some growth should occur in OECD Europe, where improved resource assessment and incentives should increase direct use and commercial heat from geothermal heat and co-generation plants. In France, 2020 targets for direct heat use and financing for projects in industry and buildings from the government's renewable heat fund should drive increased activity. However, the outlook for Germany looks less optimistic. Financing difficulties and public acceptance issues related to seismic events from drilling activity have significantly slowed geothermal development there. In China, good resource availability, rising heat demand and local air quality issues are expected to drive stronger direct use and commercial heat use.

**Box 6** Heat pumps: efficient heating and cooling solutions, though not necessarily renewable

Ground-source heat pumps, air-source heat pumps and water-source heat pumps can provide highly efficient means of heating and cooling. Heat pumps are mainly used in buildings for space heating, cooling and sometimes domestic hot water supply. Heat pumps allow transformation of heat from a lower temperature level to a higher one by using external energy (*e.g.* to drive a compressor). The amount of this external energy input, be it electric power or heat, has to be kept as low as possible to make the heat pump environmentally and economically desirable. In contrast to other heat pumps, such as air-to-air heat pumps, ground-source heat pumps can store extracted heat in summer and make this heat useful again in heating mode in winter.

The IEA collects statistics on large heat pumps for production of commercial heat, but not for small heat pumps at the end-user level. Furthermore, the IEA does not classify the inputs of a heat pump, given the difficulty in ascertaining the share of renewable sources. The inputs come from multiple sources, such as ground, air, water and electricity that may have a fossil-fuel component. As such, they are excluded from the analysis in this report. Still, it is worth noting that the European Union, under the Renewable Energy Directive, sets out a standardised methodology to calculate the share of renewable energy provided by heat pumps, which can be counted towards the renewable energy target in 2020. In any case, heat pumps are a significant and quickly growing source of heat. In 2011, their estimated global installed capacity was 42 $GW_{th}$ with an annual output of 0.3 EJ (REN 21, 2012). The United States, China, Sweden, Germany and the Netherlands had the largest capacity.

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# TABLES

## Table 97 Renewable electricity capacity (GW)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | CAGR 2012-18 |
|---|---|---|---|---|---|---|---|---|
| **OECD Total** | **793** | **839** | **888** | **936** | **984** | **1 032** | **1 081** | **5.3%** |
| OECD Americas | 291 | 303 | 323 | 341 | 358 | 375 | 393 | 5.1% |
| *Canada* | 86 | 89 | 93 | 97 | 101 | 104 | 108 | 3.9% |
| *Chile* | 7 | 7 | 8 | 9 | 10 | 11 | 12 | 9.4% |
| *Mexico* | 15 | 15 | 17 | 19 | 21 | 23 | 26 | 9.9% |
| *United States* | 184 | 191 | 205 | 216 | 226 | 236 | 247 | 5.1% |
| OECD Asia Oceania | 91 | 98 | 106 | 114 | 125 | 135 | 146 | 8.2% |
| *Australia* | 15 | 16 | 18 | 20 | 22 | 24 | 26 | 10.0% |
| *Japan* | 60 | 65 | 70 | 76 | 83 | 89 | 96 | 8.0% |
| *Korea* | 9 | 9 | 10 | 11 | 12 | 13 | 15 | 9.8% |
| OECD Europe | 412 | 438 | 460 | 481 | 501 | 522 | 543 | 4.7% |
| *Denmark* | 6 | 7 | 7 | 8 | 8 | 9 | 9 | 7.2% |
| *France* | 39 | 40 | 42 | 44 | 46 | 49 | 51 | 4.7% |
| *Germany* | 83 | 89 | 95 | 100 | 105 | 111 | 117 | 5.9% |
| *Ireland* | 2 | 3 | 3 | 3 | 4 | 4 | 4 | 11.0% |
| *Italy* | 50 | 52 | 54 | 56 | 58 | 60 | 61 | 3.6% |
| *Spain* | 50 | 52 | 52 | 52 | 53 | 53 | 53 | 1.1% |
| *Turkey* | 22 | 24 | 27 | 30 | 31 | 34 | 36 | 8.6% |
| *United Kingdom* | 18 | 21 | 24 | 28 | 32 | 35 | 39 | 13.3% |
| **Non-OECD Total** | **786** | **853** | **927** | **1005** | **1089** | **1179** | **1270** | **8.3%** |
| Africa | 29 | 30 | 34 | 37 | 40 | 45 | 51 | 10.0% |
| *Morocco* | 2 | 2 | 3 | 3 | 4 | 4 | 5 | 14.4% |
| *South Africa* | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 21.5% |
| Asia | 136 | 145 | 157 | 169 | 180 | 194 | 207 | 7.3% |
| *India* | 67 | 72 | 79 | 86 | 93 | 101 | 108 | 8.3% |
| *Thailand* | 7 | 8 | 9 | 10 | 10 | 11 | 12 | 8.9% |
| China | 340 | 386 | 433 | 480 | 535 | 591 | 649 | 11.4% |
| Non-OECD Americas | 167 | 173 | 180 | 192 | 202 | 212 | 222 | 4.8% |
| *Brazil* | 103 | 106 | 111 | 118 | 125 | 132 | 138 | 5.0% |
| Eurasia | 100 | 103 | 107 | 110 | 112 | 115 | 117 | 2.7% |
| Middle East | 15 | 15 | 17 | 18 | 19 | 21 | 24 | 8.5% |
| **World** | **1 579** | **1 693** | **1 815** | **1 941** | **2 073** | **2 211** | **2 351** | **6.9%** |

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-grid solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Historical 2012 data for capacity are IEA estimates derived from an amalgam of sources. Specific sources are referenced where data for individual technologies are presented.

## Table 98 Renewable electricity generation (TWh)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | CAGR 2012-18 |
|---|---|---|---|---|---|---|---|---|
| **OECD Total** | **2 217** | **2 341** | **2 449** | **2 559** | **2 667** | **2 774** | **2 883** | **4.5%** |
| OECD Americas | 1 004 | 1 047 | 1 088 | 1 137 | 1 183 | 1 226 | 1 269 | 4.0% |
| *Canada* | 403 | 408 | 418 | 429 | 443 | 454 | 462 | 2.3% |
| *Chile* | 22 | 28 | 30 | 32 | 34 | 36 | 39 | 10.1% |
| *Mexico* | 43 | 48 | 51 | 57 | 62 | 67 | 73 | 9.3% |
| *United States* | 537 | 563 | 589 | 619 | 645 | 669 | 695 | 4.4% |
| OECD Asia Oceania | 195 | 211 | 225 | 241 | 258 | 277 | 295 | 7.2% |
| *Australia* | 24 | 30 | 34 | 39 | 43 | 48 | 53 | 14.0% |
| *Japan* | 129 | 135 | 143 | 152 | 162 | 173 | 184 | 6.1% |
| *Korea* | 10 | 12 | 13 | 15 | 17 | 19 | 22 | 14.1% |
| OECD Europe | 1 018 | 1 083 | 1 135 | 1 182 | 1 225 | 1 271 | 1 318 | 4.4% |
| *Denmark* | 14 | 18 | 20 | 21 | 22 | 23 | 26 | 9.9% |
| *France* | 87 | 92 | 95 | 99 | 104 | 108 | 112 | 4.3% |
| *Germany* | 143 | 166 | 176 | 184 | 193 | 203 | 215 | 6.9% |
| *Ireland* | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12.1% |
| *Italy* | 92 | 106 | 109 | 113 | 116 | 119 | 122 | 4.9% |
| *Spain* | 92 | 101 | 104 | 104 | 105 | 105 | 106 | 2.4% |
| *Turkey* | 65 | 68 | 76 | 84 | 90 | 96 | 102 | 7.7% |
| *United Kingdom* | 44 | 54 | 60 | 68 | 76 | 84 | 92 | 13.0% |
| **Non-OECD Total** | **2 645** | **2 794** | **2 987** | **3 203** | **3 437** | **3 697** | **3 968** | **7.0%** |
| Africa | 119 | 125 | 132 | 141 | 151 | 164 | 181 | 7.3% |
| *Morocco* | 3 | 5 | 5 | 7 | 8 | 9 | 10 | 24.9% |
| *South Africa* | 6 | 6 | 8 | 11 | 13 | 15 | 17 | 20.1% |
| Asia | 406 | 439 | 468 | 501 | 533 | 568 | 605 | 6.9% |
| *India* | 150 | 167 | 181 | 198 | 214 | 230 | 246 | 8.6% |
| *Thailand* | 14 | 16 | 17 | 18 | 20 | 21 | 23 | 8.1% |
| China | 1 002 | 1 078 | 1 200 | 1 326 | 1 463 | 1 622 | 1 789 | 10.1% |
| Non-OECD Americas | 772 | 795 | 819 | 856 | 901 | 942 | 980 | 4.1% |
| *Brazil* | 462 | 477 | 491 | 514 | 544 | 573 | 599 | 4.4% |
| Eurasia | 324 | 334 | 344 | 353 | 361 | 368 | 375 | 2.4% |
| Middle East | 22 | 23 | 24 | 26 | 29 | 33 | 39 | 10.3% |
| **World** | **4 862** | **5 136** | **5 436** | **5 762** | **6 104** | **6 471** | **6 851** | **5.9%** |

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 co-fired 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, 2012 generation data are based on IEA statistics published in *Renewables Information* and are estimated by the *MTRMR* model for 2013-18. For non-OECD countries, generation are estimated by the *MTRMR* model for 2012-18.

**Table 99** Biodiesel production (kb/d)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | CAGR 2012-18 |
|---|---|---|---|---|---|---|---|---|
| **OECD Total** | **236** | **260** | **272** | **294** | **299** | **304** | **305** | **4.4%** |
| OECD Americas | 65 | 89 | 90 | 90 | 89 | 89 | 88 | 5.1% |
| *Canada* | 2 | 5 | 6 | 6 | 5 | 5 | 4 | 12.6% |
| *United States* | 63 | 84 | 84 | 84 | 84 | 84 | 84 | 4.8% |
| OECD Asia Oceania | 8 | 9 | 10 | 10 | 11 | 11 | 12 | 5.7% |
| *Australia* | 2 | 2 | 3 | 3 | 4 | 4 | 4 | 12.9% |
| OECD Europe | 163 | 161 | 172 | 195 | 199 | 204 | 206 | 4.0% |
| *Austria* | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 7.0% |
| *Belgium* | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 3.8% |
| *France* | 32 | 35 | 38 | 39 | 39 | 39 | 39 | 3.1% |
| *Germany* | 52 | 42 | 44 | 49 | 51 | 51 | 51 | -0.1% |
| *Italy* | 9 | 9 | 9 | 11 | 11 | 11 | 11 | 4.3% |
| *Netherlands* | 8 | 8 | 10 | 11 | 11 | 12 | 12 | 6.7% |
| *Poland* | 5 | 5 | 6 | 6 | 7 | 7 | 7 | 6.8% |
| *Spain* | 11 | 14 | 16 | 20 | 20 | 24 | 24 | 13.4% |
| *United Kingdom* | 3 | 4 | 4 | 5 | 5 | 6 | 6 | 12.0% |
| **Non-OECD Total** | **173** | **170** | **188** | **205** | **220** | **236** | **244** | **5.9%** |
| Africa | 0 | 1 | 3 | 4 | 4 | 5 | 5 | 76.8% |
| Asia | 59 | 60 | 64 | 67 | 71 | 78 | 81 | 5.3% |
| *India* | 1 | 1 | 2 | 2 | 2 | 3 | 3 | 20.4% |
| *Indonesia* | 26 | 21 | 23 | 23 | 23 | 24 | 26 | -0.2% |
| *Malaysia* | 5 | 6 | 6 | 7 | 8 | 10 | 8 | 10.1% |
| *Philippines* | 3 | 4 | 4 | 4 | 4 | 5 | 5 | 13.7% |
| *Singapore* | 13 | 15 | 15 | 16 | 18 | 18 | 19 | 6.8% |
| *Thailand* | 12 | 13 | 14 | 16 | 16 | 18 | 19 | 8.1% |
| China | 4 | 5 | 6 | 6 | 7 | 7 | 9 | 13.0% |
| Non-OECD Americas | 106 | 100 | 112 | 125 | 134 | 142 | 146 | 5.5% |
| *Argentina* | 47 | 40 | 42 | 46 | 51 | 51 | 54 | 2.4% |
| *Brazil* | 47 | 48 | 57 | 65 | 68 | 76 | 76 | 8.3% |
| *Colombia* | 7 | 7 | 8 | 9 | 10 | 10 | 11 | 6.3% |
| Eurasia | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 0.0% |
| Middle East | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| **World** | **409** | **429** | **460** | **500** | **518** | **540** | **549** | **5.0%** |

Notes: kb/d = thousand barrels per day. Production presented in volume; to convert to energy adjusted production, biodiesel is assumed to have 90% energy content of fossil diesel.

**Table 100** Ethanol production (kb/d)

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | CAGR 2012-18 |
|---|---|---|---|---|---|---|---|---|
| **OECD Total** | **968** | **970** | **1 053** | **1 095** | **1 117** | **1 119** | **1 118** | **2.4%** |
| OECD Americas | 894 | 884 | 953 | 991 | 1 008 | 1 008 | 1 006 | 2.0% |
| *Canada* | 29 | 31 | 31 | 35 | 33 | 29 | 26 | -2.0% |
| *United States* | 864 | 853 | 921 | 955 | 975 | 977 | 979 | 2.1% |
| OECD Asia Oceania | 7 | 8 | 10 | 10 | 11 | 11 | 12 | 8.4% |
| *Australia* | 7 | 8 | 9 | 9 | 9 | 10 | 10 | 6.2% |
| OECD Europe | 67 | 77 | 90 | 94 | 98 | 100 | 100 | 6.9% |
| *Austria* | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 0.4% |
| *Belgium* | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0.0% |
| *France* | 13 | 15 | 18 | 18 | 20 | 20 | 20 | 6.9% |
| *Germany* | 14 | 13 | 14 | 15 | 15 | 15 | 15 | 2.2% |
| *Italy* | 1 | 2 | 3 | 3 | 3 | 3 | 3 | 35.5% |
| *Netherlands* | 4 | 5 | 5 | 6 | 6 | 6 | 6 | 7.6% |
| *Poland* | 5 | 5 | 6 | 6 | 7 | 7 | 7 | 6.8% |
| *Spain* | 7 | 8 | 9 | 9 | 9 | 9 | 9 | 4.6% |
| *United Kingdom* | 5 | 8 | 11 | 12 | 14 | 15 | 15 | 20.5% |
| **Non-OECD Total** | **482** | **549** | **585** | **634** | **668** | **684** | **695** | **6.3%** |
| Africa | 3 | 5 | 6 | 8 | 10 | 10 | 11 | 22.3% |
| Asia | 27 | 36 | 42 | 46 | 47 | 51 | 52 | 11.4% |
| *India* | 8 | 10 | 11 | 12 | 12 | 13 | 13 | 8.9% |
| *Indonesia* | 1 | 2 | 2 | 3 | 3 | 3 | 4 | 31.2% |
| *Malaysia* | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17.1% |
| *Philippines* | 3 | 3 | 5 | 6 | 7 | 9 | 9 | 22.1% |
| *Singapore* | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 7.8% |
| *Thailand* | 11 | 14 | 15 | 15 | 15 | 17 | 17 | 7.5% |
| China | 41 | 46 | 52 | 53 | 54 | 55 | 55 | 5.1% |
| Non-OECD Americas | 405 | 459 | 482 | 522 | 552 | 563 | 571 | 5.9% |
| *Argentina* | 4 | 5 | 8 | 8 | 10 | 10 | 10 | 17.9% |
| *Brazil* | 386 | 436 | 452 | 492 | 519 | 530 | 536 | 5.6% |
| *Colombia* | 6 | 7 | 8 | 8 | 8 | 8 | 9 | 6.7% |
| Eurasia | 5 | 4 | 4 | 5 | 5 | 5 | 5 | 0.9% |
| Middle East | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| **World** | **1 450** | **1 520** | **1 638** | **1 728** | **1 785** | **1 803** | **1 813** | **3.8%** |

Notes: production presented in volume; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of gasoline.

# GLOSSARY OF DEFINITIONS, TERMS AND ABBREVIATIONS

## Regional definitions

**OECD Americas**: Canada, Chile, Mexico and the United States.

**OECD Asia Oceania**: Australia, Israel,[26] 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, 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, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

**Asia**: Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Democratic People's Republic of Korea, Laos, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Vietnam and other non-OECD Asian countries (Afghanistan, Bhutan, Cook Islands, East Timor, Fiji, French Polynesia, Kiribati, Laos, Macau, Maldives, Micronesia, New Caledonia, Papua New Guinea, Palau, Samoa, Solomon Islands, Tonga and Vanuatu).

**Non-OECD Europe and Eurasia**: Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[27] Georgia, Gibraltar, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, 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 and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman

[26] 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.

[27] 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: 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.

Islands, Dominica, Falkland Islands, 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.

## Abbreviations and acronyms

| | |
|---|---|
| CSP | concentrating solar power |
| DC | direct current |
| DDG | decentralised distributed generation |
| DNI | direct normal irradiance |
| EIA | Energy Information Administration |
| EMEC | European Marine Energy Centre |
| EPIA | European Photovoltaic Industry Association |
| EU | European Union |
| EU-ETS | European Union Greenhouse Gas Emissions Trading Scheme |
| ESTELA | European Solar Thermal Electricity° Association |
| 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 |
| IEA Wind | International Energy Agency Wind Energy Systems Programme |
| 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 |
| TGC | tradable green certificate |
| 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 | barrels |
| GW | gigawatt, 1 gigawatt equals $10^9$ watt |
| GWh | gigawatt hour, 1 gigawatt hour equals $10^9$ watt hours |
| $GW_{th}$ | gigawatt thermal |
| kW | kilowatt, 1 kilowatt equals $10^3$ watt |
| kWh | kilowatt hour, 1 kilowatt hour equals $10^3$ watt hours |
| $kW_p$ | kilowatt peak |
| $kW_{th}$ | kilowatt thermal |
| MW | megawatt, 1 megawatt equals $10^6$ watt |
| $MW_{th}$ | megawatt thermal |
| MWh | megawatt hour, 1 megawatt hour equals $10^6$ watt hours |
| $m^2$ | square metre |
| TWh | terawatt hour, 1 terawatt hour equals $10^{12}$ watt hours |
| W | watt |

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