RENEWABLE ENERGY

Medium-Term Market Report 2012

Market Trends and Projections to 2017

International Energy Agency

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FOREWORD

This *Medium-Term Renewable Energy Market Report* is the first IEA publication dedicated to projecting global renewable energy developments over the next five years. While other IEA reports, the *World Energy Outlook 2011* and *Energy Technology Perspectives 2012*, have identified renewable energy as a crucial pillar of the long-term global energy mix, this report analyses the complexities and variables that will shape the transition of the sector through 2017. It completes a new series of medium-term reports for the four main primary energy sources: oil, gas, coal and renewable energy.

This publication comes at a time of profound changes in renewable energy markets and uncertainties in the face of both economic crisis and subsidy reductions in some key markets. Still, renewable electricity generation is growing rapidly and deployment opportunities are expanding. The renewable industry is going through a period of dramatic upheaval, with supply chains restructuring and shifting geographically. Meanwhile, several key markets are deliberating significant changes to renewable policies and deeper electricity market reforms. Now, more than ever, energy market stakeholders need clear indications of the major drivers and barriers to renewable deployment, with analysis that combines country-level studies with wider technology and financing assessments.

Ultimately, renewable electricity generation is expected to continue its rapid expansion over the medium term, buoyed by supportive policy and market frameworks as well as increased economic attractiveness in a variety of geographies and situations. It is striking that emerging and developing markets outside the OECD are driving much of the expected growth, with their contribution to accelerate over the coming years. Moreover, the overall growth of renewable sources reflects the continued maturing of these technologies, with deployment transitioning from support driven markets to new and potentially more competitive segments in other countries.

This report forecasts renewable energy generation and capacity across eight technologies – hydropower, bioenergy for power, onshore wind, offshore wind, solar photovoltaics (PV), concentrating solar power (CSP), geothermal and ocean. This first edition focuses on renewable energy in the power sector, though solar thermal heating is also examined. Future editions will aim to expand the analysis, to include renewable heat and biofuels for transport (for this year, the latter remains in the *Medium-Term Oil Market Report*, to be published in October).

The outlook presented in this report reflects several years of data gathering, modelling and research efforts. Renewable energy represents an emerging and fast-growing area of energy market analysis. Forecasting renewable markets will require continued advances in the reporting and collection of renewable technology statistics as well as increased detail on a widening set of geographic markets. The analysis has benefitted from an extensive review process that included input from governments, industry and other international organisations. Given the oftentimes localised nature of renewable energy markets, these insights have been crucial. This report and future editions endeavour to provide a better understanding of the workings of renewable energy markets and enable stakeholders to make critical decisions that lead to more secure and sustainable energy mixes.

This report is published under my authority as Executive Director of the IEA.

Maria van der Hoeven

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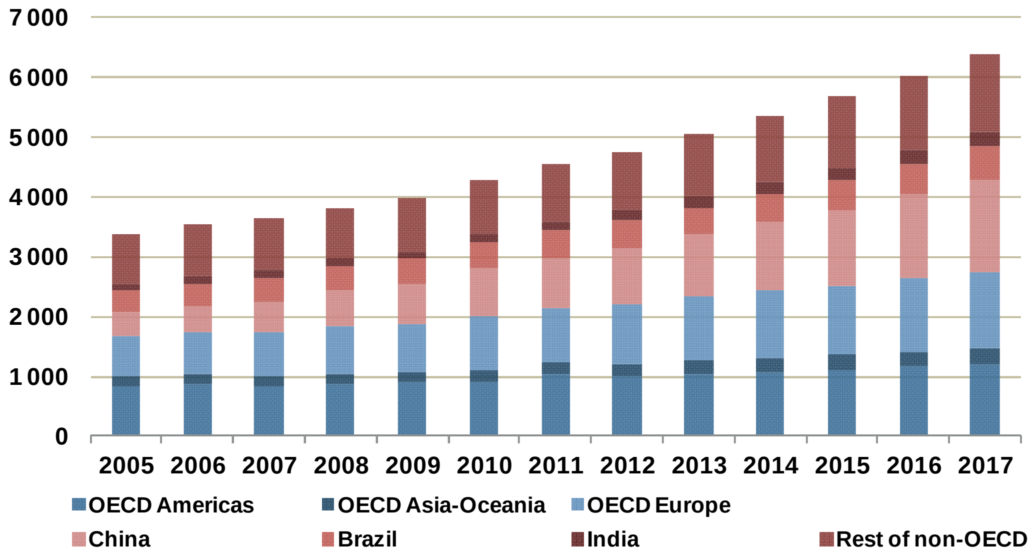
EXECUTIVE SUMMARY

Building on several years of strong deployment, renewable electricity growth should accelerate over the medium term. From 2011 to 2017 renewable electricity generation should expand by 1 840 terawatt-hours (TWh), almost 60% higher than the 1 160 TWh growth registered over the 2005-11 period. Global power generation from renewable sources stood at 4 540 TWh in 2011, 5.8% higher than in 2010, and is projected to reach almost 6 400 TWh in 2017 (+5.8% annually). Even as the annual average growth in renewable generation accelerates – to 5.8% over 2011-17 versus 5.0% over 2005-11 – expansion trends and geographies remain specific to technologies. For non-hydropower sources (solar photovoltaics [PV], concentrating solar power [CSP], wind, bioenergy for power, geothermal and ocean), the average percentage increase, at 14.3% annually, is somewhat slower than the 16.2% growth from 2005-11 as technologies continue to mature. Yet absolute growth for these sources is much higher (+1 100 TWh from 2011-17 versus +530 TWh over 2005-11).

The outlook stems from the persistence of supportive policy and market frameworks as well as increased economic attractiveness for renewable technologies in an increasing range of countries and circumstances. Moreover, technology cost developments, grid and system integration issues, and the cost and availability of financing will also weigh as key variables. Overall, a high level of economic and policy uncertainty in some key areas of the world characterises the forecast. At the time of writing, the outlook for the global economy, particularly in Europe, remains cautious while several countries are debating significant changes to renewable energy policy or deeper electricity market reform.

Figure 1 Global renewable electricity production, by region (TWh)



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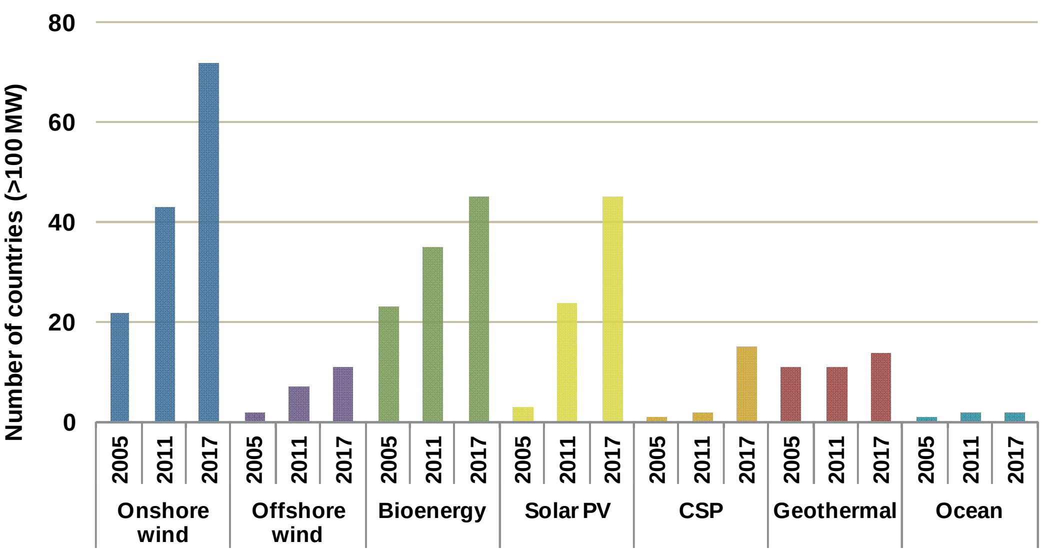
Non-hydro renewable deployment is becoming increasingly widespread, with growth shifting beyond traditional support markets in Europe. In 2017, the number of countries with cumulative renewable electricity capacities above 100 megawatts (MW) increases significantly for most non-hydro technologies. Onshore wind, already widespread in many countries in 2011, is deployed in at least 70 countries in 2017. Deployment of solar PV and bioenergy at the 100 MW level is reached in around 45 countries by 2017, up from about 25 and 35 in 2011, respectively. Geothermal and CSP are deployed in roughly 15 countries each by 2017, while offshore wind should be in 11 countries.

Of the 710 gigawatts (GW) of global renewable electricity capacity additions expected over 2011-17, China accounts for almost 40%, or 270 GW, with the United States (+56 GW), India (+39 GW), Germany (+32 GW) and Brazil (+32 GW) following as the largest deployment markets. In 2017, non-OECD countries should account for 65% of hydropower generation and almost 40% of non-hydro generation. Ambitious policy targets, fast-growing electricity demand and ample financing underpin China's expansion. In the United States, state-level renewable mandates combined with improving economics will drive growth, even amid uncertainty about federal incentives and persistently low natural gas prices. India's favourable policy environment and rural electrification needs should encourage strong deployment of on- and off-grid renewable electricity capacity. In Germany, wind power should grow strongly while annual growth of solar PV slows with assumed decreased feed-in tariffs. With favourable economics, Brazil's hydropower and wind should grow strongly.

Figure 2 Number of countries with non-hydro renewable capacity above 100 MW



Hydropower production has grown by 630 TWh since 2005, and in 2011 it accounted for 80% of total renewable generation. Going forward, hydropower will remain the largest contributor to total renewable generation. Although its share should diminish over time, the absolute increase in hydropower generation accelerates versus the previous decade. At 4 380 TWh in 2017, it should account for almost 70% of renewable electricity output. Over 2011-17, hydropower generation should grow on average by 120 TWh per year (or +3.1%) as capacity rises from 1 070 GW to 1 300 GW.

Hydropower represents an economically attractive source of renewable energy in countries with good resource potential. Indeed, untapped hydropower potential remains large on a global scale. For emerging and developing countries, deployment of hydropower is a good option for scaling up renewable generation and meeting power needs. For many of the countries highlighted in this report, hydropower growth should also provide the flexibility needed for the integration of a projected, large amount of variable renewable electricity. On the regional level, non-OECD Asia grows by 150 GW, with China (+110 GW) and India (+13 GW) accounting for most of the expansion. Large capacity additions should also take place in Latin America (+32 GW), with 21 GW in Brazil; OECD Europe (+19 GW); and Africa (+14 GW).

Figure 3 Global hydropower historical cumulative additions (2005-11)

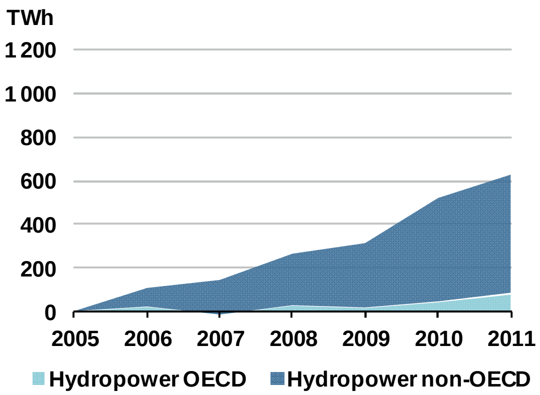
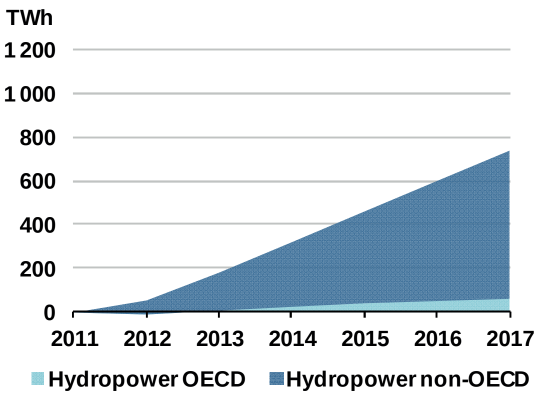


Figure 4 Global hydropower forecast cumulative additions (2011-17)



Renewable energy technologies outside of hydropower continue to grow at a faster rate. Of these, wind power (onshore and offshore) should make the largest contribution to global renewable electricity generation in 2017, at 16.7%. Over 2011-17, wind power should grow on average by 100 TWh per year (+15.6%). Onshore wind accounts for 90% of this growth, as its capacity rises from 230 GW to over 460 GW. Onshore wind has emerged as a mature technology, which is increasingly competitive with conventional alternatives. The current availability of global manufacturing capacity combined with the maturity of the manufacturing industry suggests that supply-side availability should not act as a deployment bottleneck. Other factors, such as licensing procedures, policy uncertainty and financing costs, may have a more profound impact. China should lead capacity growth, adding 104 GW over 2011-17. Despite uncertainty over the durability of a federal production tax credit, the United States should add 27 GW over this period. India (+17 GW), Brazil (+8 GW) and the United Kingdom (+7 GW), among others, should also see significant deployment.

As a more nascent technology, offshore wind faces larger deployment challenges. Capacity should increase significantly from a low base, from 4 GW in 2011 to 26 GW in 2017, supported by generous incentives from governments committed to offshore development. Though the availability of wind turbines should not act as a bottleneck, tight markets for other supply chain components, such as subsea transmission cables and construction vessels, may constrict development in some cases. Offshore projects also carry increased construction and technology risk. All these challenges tend to raise costs and restrict the availability of project financing. Capacity growth should be led by China (+6.7 GW), the United Kingdom (+5.3 GW), Germany (+3.8 GW) and France (+1.5 GW).

Bioenergy should account for 8.3% of renewable power in 2017. Power generation from bioenergy, which includes solid biomass, biogas, liquid biofuels and renewable municipal waste, should rise on average by 37 TWh per year (+9.6%) as capacity grows from 70 GW in 2011 to 119 GW in 2017. Increased use of agricultural and municipal wastes in dedicated power and co-generation (*i.e.* electricity and heat production) plants should drive the expansion, with ample feedstock availability acting as an enabler. Bioenergy co-firing with conventional fuels should play an increasing role in countries with large coal-fired assets. Capacity growth in bioenergy should occur across a range of countries, given the widespread nature of feedstock. The largest increments are projected in China (+18 GW), the United States (+3 GW), Brazil (+3 GW), Austria (+2 GW) and India (+2 GW).

Figure 5 Global non-hydropower cumulative additions (2005-11)

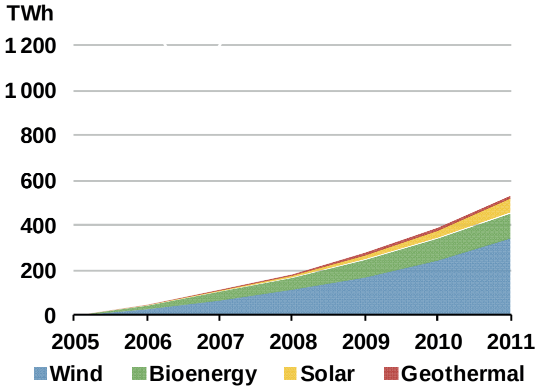
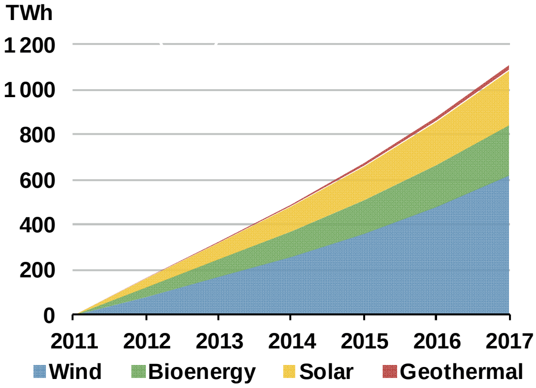


Figure 6 Global non-hydropower cumulative additions (2011-17)



In 2017, solar technologies should make a contribution of 4.9% to renewable generation. Of these, solar PV should scale up the quickest. Over 2011-17, solar PV generation should grow on average by 35 TWh per year (+27.4%) as capacity rises from 70 GW to 230 GW. Improved competitiveness with retail electricity prices and ease of installation should guide strong deployment of solar PV systems in the residential and commercial sectors in a number of countries, in addition to expected utility-scale expansions in areas with good resources. The supply availability of panels and components should remain ample, helping system costs to continue falling over the medium term. Still, the solar PV manufacturing sector should experience several years of consolidation in the face of weak profit margins. Installed capacity growth should be led by China (+32 GW), the United States (+21 GW), Germany (+20 GW), Japan (+20 GW), and Italy (+11 GW). Given past boom-and-bust cycles in several countries, the degree of dynamic approach to policy support will remain a key forecast variable.

Concentrating solar power should grow from near 2 GW total capacity in 2011 to 11 GW in 2017, a rapid increase from a low base, but slower than the industry has anticipated. Projects are typically utility scale and concentrated in arid and semi-arid areas. The technology faces several challenges, including increased price competition from solar PV, which has more deployment flexibility; complex environmental permitting; and grid connections. Still, the storage and hybridisation (*i.e.* merging with a fossil fuel plant) capabilities of CSP provide value that is enhancing project attractiveness. Over the medium term, deployment should be led by the United States (+4 GW), Spain (+1 GW) and China (+1 GW), with smaller developments taking place in the Middle East, North Africa and South Africa.

While outside of this edition's primary focus on renewable electricity, it is important to note that solar thermal heating, a mature technology, should continue to grow strongly over the medium term. Installed capacity should rise from 196 gigawatt thermal capacity (GW_{th}) in 2010 to over 500 GW_{th} in 2017, led by China, Germany, the United States, Turkey and India.

Power from geothermal sources should remain a small segment of renewable generation, at 1.4%, though output is expected to increase steadily over the medium term. Geothermal generation should grow by 3 TWh per year (+4.2%) as capacity rises from 11 GW in 2011 to 14 GW in 2017. A long-standing source of base-load power, geothermal technology should continue to enjoy low power production costs and high capacity factors, aiding its deployment in areas with good resources. However, projects are characterised by long lead times and a high degree of exploration risk, for which associated financing is scarce. As such, medium-term additions are modest and concentrated in only a few countries; Indonesia, Kenya, the United States, Japan and New Zealand should lead deployment.

Given its relatively early stage of maturity, ocean power does not contribute significantly to renewable generation over the medium term. Most deployment should continue at the demonstration level. However, projects should scale up from single- to multi-device plants, representing an important step towards commercialisation of tidal and wave technologies. Canada, the United Kingdom, China, the United States and Sweden should all see small additions over the medium term.

While renewable electricity remains generally more expensive than conventional sources and economic incentives play a large role in sustaining development, leading technologies are becoming increasingly attractive. Indeed, renewable deployment is starting to transition from a phase in which it is more reliant on subsidy support to one in which projects are competing on their own merits. In general, established technologies such as large and small hydropower, geothermal and onshore wind compete well with new coal- and gas-fired plants in many areas. Small-scale distributed and off-grid applications, such as biogas and solar PV, enjoy good economic attractiveness versus small diesel generators. Moreover, residential solar PV competes increasingly well with retail prices in areas with good solar resources. Ultimately, the competitiveness of renewable generation depends on local conditions, cost structures, resources and the prices of alternatives, making global comparisons difficult. Yet renewable sources are clearly becoming more economically attractive in an increasing number of countries and circumstances.

Table 1 World renewable electricity generation (TWh)

	2005	% Total Gen	2011	2012	2013	2014	2015	2016	2017
Hydropower	3 018	16.5%	3 644	3 698	3 824	3 962	4 102	4 239	4 378
Bioenergy	198	1.1%	308	352	387	421	457	494	532
Wind	103	0.6%	447	527	617	705	807	927	1 065
Onshore	102	0.6%	434	509	591	672	765	868	985
Offshore	1	0.0%	12	18	26	33	43	58	80
Solar PV	4	0.0%	65	102	131	164	198	236	279
Solar CSP	1	0.0%	4	6	10	16	21	25	31
Geothermal	58	0.3%	71	73	75	78	82	87	91
Ocean	1	0.0%	1	1	1	1	1	1	1
Total RES-E	**3 381**	**18.4%**	**4 539**	**4 759**	**5 046**	**5 347**	**5 668**	**6 009**	**6 377**

Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. Hydropower includes pumped storage; 2011 data are estimates; the split for onshore and offshore wind is estimated for 2005 and 2011; RES-E = electricity generated from renewable energy sources.

The cost and availability of financing will act as a key variable to renewable electricity investment over the medium term. In 2011, global new investment in renewable electricity generation increased to USD 250 billion, a rise of 19% from USD 210 billion in 2010. The quarterly pattern showed a fall-off in global new investment during the first quarter of 2012, though part of this drop could relate to cost reductions and the exclusion of small distributed capacity from the data. Looking ahead, increased macroeconomic risk and tighter bank capital requirements amid uncertainty about policy support in some areas could constrain funds from traditional sources – European bank project financing and utility balance sheet investment. An assumption of easing economic conditions combined with the emergence of new sources and structures of renewable financing should sustain overall investment over the forecast period. However, the attractiveness of new investment will depend on the evolution of policy and technology risk going forward. In those countries with more uncertain policy supports, the cost of capital tends to remain relatively high, undermining project economics. Moreover, investors still perceive some renewable technologies as risky, particularly offshore wind and CSP.

Table 2 World renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	1 033	1 067	1 103	1 142	1 184	1 223	1 263	1 302
Bioenergy	63	70	77	85	93	102	110	119
Wind	194	234	276	311	350	392	439	490
Onshore	191	230	270	303	339	378	420	464
Offshore	3	4	6	8	11	14	20	26
Solar PV	40	70	91	115	140	167	197	231
Solar CSP	1	2	3	4	7	8	9	11
Geothermal	11	11	11	12	12	13	14	14
Ocean	0	1	1	1	1	1	1	1
Total RES-E	**1 342**	**1 454**	**1 562**	**1 670**	**1 786**	**1 905**	**2 032**	**2 167**

Notes: capacity data are presented as cumulative installed capacity, irrespective of grid connection status. However, solar PV capacity corresponds to installed, grid-connected capacity, which includes small distributed capacity.

Box 1 Defining the analytical framework for the *Medium-Term Renewable Energy Market Report*

This first edition of the *Medium-Term Renewable Energy Market Report* (*MRMR*) forecasts developments in renewable energy across eight technologies – hydropower, bioenergy for power, onshore wind, offshore wind, solar photovoltaics (PV), concentrating solar power (CSP), geothermal and ocean. The analysis focuses on renewable energy in the power sector, though solar thermal heating is also examined. For 2012, biofuels for transport remain in the *Medium-Term Oil Market Report*, to be published in October. Data availability and resource constraints drove this year's *MRMR* focus. Future editions will aim to expand the analytical breadth, including renewable heat and biofuels for transport.

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 the non-OECD, creates the challenge of tracking developments in less transparent markets.

This report aims to provide a complete view of renewable generation and capacity trends over time. Still, historical data points, including 2011, 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 represent an amalgam from multiple sources, which include work by IEA implementing agreements, reporting by industry associations and consultancies, and direct contact with governments and industry operating in a given area.

Box 1 Defining the analytical framework for the *Medium-Term Renewable Energy Market Report* (continued)

Hydropower generation data include output from pumped hydropower. While electricity used for pumping may not necessarily come from renewable origins, this accounting corresponds to that of IEA annual renewable statistics. 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 – capacity corresponds to grid-connected capacity, which includes small distributed capacity.

Country-level approach underpins the analysis

Given the local nature of renewable development, the approach begins with country-level analysis. For this edition, *MRMR* examines in detail 15 key markets for renewable energy, which currently represent about 80% of renewable generation, while identifying and characterising developments that may emerge in other important markets. Forecasts stem from both quantitative and qualitative analysis. For each of these 15 markets, *baseline case* projections are made for renewable electricity capacity by source through 2017. 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 examinations start with a total power demand outlook based on expectations for real gross domestic product (GDP). This analysis is done in close coordination with other IEA medium-term outlooks. Assumptions for GDP growth stem from the International Monetary Fund's *World Economic Outlook*, released in April 2012. For some countries, *e.g.* emerging markets, power demand growth acts as a driver for renewable generation; for others, *e.g.* more developed countries, demand growth (or lack thereof) can act as a neutral variable or even a constraint on renewable development.

Forecasts at the country level under the report's *baseline case* are carried out in the context of the current policy environment as of May 2012 and do not try to anticipate policy changes going forward.

The electricity market frameworks and renewable policies for several countries, such as Germany, India, Italy, Japan and the United Kingdom, remain in flux as of writing, complicating the analysis. For each country, the policy environment is benchmarked against IEA best-practice principles, as set out in *Deploying Renewables 2011*, helping to determine the degree that prevailing policies may enable or hinder deployment.

Aside from policy, *MRMR* looks at country-level issues of economic attractiveness and power system integration as deployment factors. Attractiveness assessments stem from a number of variables, including policy incentives, economic resource potentials, macro-level economic developments, and the structure and market design of the power system. Moreover, for each country forecast, an assessment is made as to whether the power grid can absorb the projected generation mix and variability.

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.
• Infrastructure	Weak power grids.
• Public acceptance	"Not in my backyard" behaviour.
• Environmental	Unclear impacts of new technologies.
• Address system integration issues.	

Source: IEA *Deploying Renewables 2011*.

Box 1 Defining the analytical framework for the *Medium-Term Renewable Energy Market Report* (continued)

For many countries the potential exists for policy improvements or non-economic barrier changes over the medium term. As such, 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

The key market assessments plus estimates for other countries in the world under the *baseline case* are judged against the supply abilities of global technology and financial markets. In these sections, *MRMR* focuses on identifying bottlenecks that could pose risks to the country-level forecast.

The technology chapter features several forms of analysis. First, it describes system properties of different renewable technologies, elaborates on their advantages and challenges, and makes judgement on their further exploitable potential. Second, the section characterises market developments by technology since 2005. Third, the chapter provides an outlook for market development through 2017. 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 electricity 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.

MEDIUM-TERM OUTLOOK: OECD AMERICAS

Summary

- **OECD Americas renewable electricity generation is projected to grow from 1 029 TWh in 2011 to 1 204 TWh in 2017 (+2.7% per year).** Onshore wind will lead this growth, with generation increasing by 107 TWh, followed by solar photovoltaics (PV) (+36 TWh) and bioenergy (+31 TWh). Concentrating solar power (CSP), geothermal and offshore wind should account for a smaller part of the overall growth. Relative to global deployment in these technologies, OECD Americas additions to geothermal and CSP should be quite large. Hydropower declines slightly over the period, even as capacity expands, due to stronger-than-normal United States output in 2011.

- **United States renewable electricity capacity should grow from 167 GW in 2011 to 223 GW in 2017 (+4.9% per year).** Deployment should be led by onshore wind (+27 GW), solar PV (+21 GW) and CSP (+4 GW). Bioenergy (+3 GW) and geothermal (+0.4 GW) should also make notable additions. The large size of the United States market 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. Notably, forecast growth for onshore wind slows sharply in 2013 with the expiration of a production tax credit.

- **Other OECD Americas countries are expected to grow from a combined 104 GW in 2011 to 136 GW in 2017 (+4.6% per year).** A reduction in feed-in tariffs in Ontario should have only a minor impact on Canadian deployment, with growth expected to continue in solar PV and onshore wind. Meanwhile, Mexico and Chile should increasingly exploit their rich resources across many technologies. In the former, near-term activity will be led by wind, with solar additions emerging in later years. The latter is developing wind, solar, biomass, geothermal and hydropower projects. Financing and integration constraints will weigh upon deployment though.

Table 4 OECD Americas renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	716	13.7%	784	14.7%	740	745	751	757	761	765
Bioenergy	72	1.4%	71	1.3%	82	86	90	94	98	102
Wind	19	0.4%	142	2.7%	156	176	189	205	227	251
Onshore	19	0.4%	142	2.7%	156	176	189	205	226	249
Offshore	-	0.0%	-	0.0%	-	0	0	0	1	2
Solar PV	1	0.0%	5	0.1%	9	14	19	25	32	41
Solar CSP	1	0.0%	2	0.0%	2	4	8	11	14	15
Geothermal	24	0.5%	25	0.5%	26	26	26	27	28	29
Ocean	0	0.0%	0	0.0%	0	0	0	0	0	0
Total RES-E	**832**	**16.0%**	**1 029**	**19.3%**	**1 015**	**1 051**	**1 083**	**1 119**	**1 160**	**1 204**

Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. Hydropower includes pumped storage; the split between onshore and offshore wind for 2005 and 2011 is estimated; CSP = concentrating solar power; RES-E = electricity generated from renewable energy sources.

United States

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.

Table 5 United States renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	298	6.9%	351	8.1%	304	305	306	306	306	307
Bioenergy	58	1.4%	61	1.4%	67	69	72	75	78	80
Wind	18	0.4%	120	2.8%	134	148	152	160	172	187
Onshore	18	0.4%	120	2.8%	134	148	152	159	171	186
Offshore	-	0.0%	-	0.0%	-	0	0	0	1	2
Solar PV	1	0.0%	5	0.1%	8	12	16	20	26	32
Solar CSP	1	0.0%	2	0.0%	2	4	8	10	12	14
Geothermal	17	0.4%	18	0.4%	18	19	19	19	19	20
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**392**	**9.1%**	**556**	**12.8%**	**534**	**556**	**572**	**590**	**614**	**641**

Power demand outlook

Amid continued economic recovery, United States power demand is expected to rise slowly over the medium term. In line with International Monetary Fund (IMF) assumptions, real gross domestic product (GDP) is expected to grow by 2.9% annually on average from 2011-17 (IMF, 2012). Power demand is projected to grow on average by 0.8% annually from 2011-17, driven by increased residential and commercial use. Although retail electricity prices rose during the previous decade, they should not significantly dampen demand going forward. While nominal prices are seen rising over the medium term, low expected natural gas prices should keep end-user price levels relatively steady (EIA, 2012).

Figure 7 United States power demand versus GDP growth

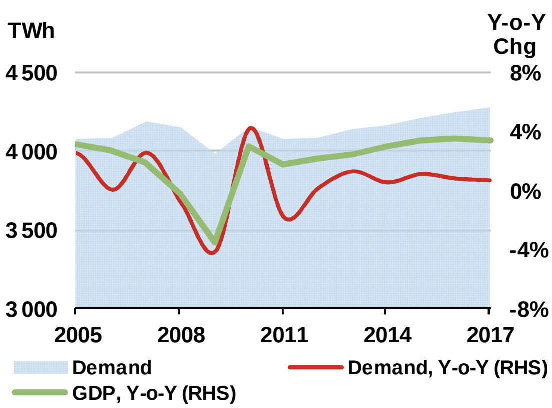
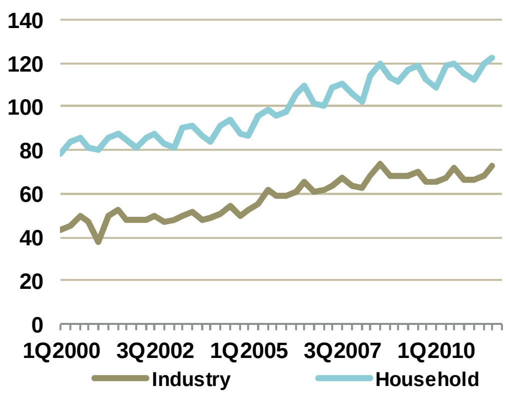


Figure 8 United States average retail power prices (USD per MWh)



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

Power sector structure

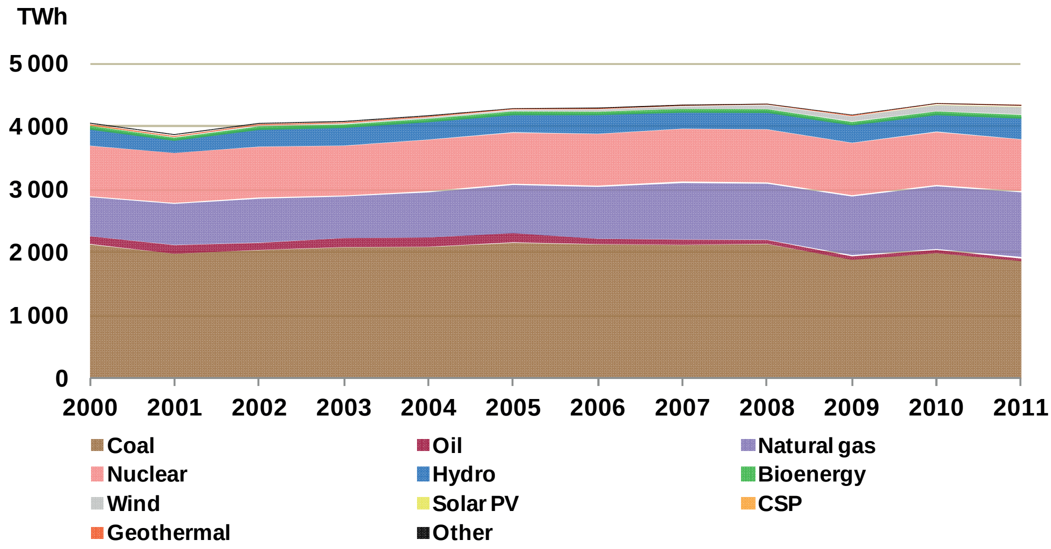
Generation and capacity

Fossil fuels have dominated United States power generation, but renewable sources are playing an increasing role. In 2011, coal accounted for 43% of generation while natural gas plants produced 23%

of total electricity. Renewable energy sources represented 13% of generation in 2011. Hydropower – long a mainstay in the United States power system – stood at 8%, following a stronger-than-normal year of output. At the end of 2010, United States power capacity stood at 1040 GW, with peak demand at 768 GW.

Though still remaining the dominant fuel over the medium term, coal's share should decline. Of existing coal capacity (near 320 GW), almost three-quarters is more than 30 years old. A combination of cheap natural gas prices and increasingly stringent Environmental Protection Agency (EPA) emissions regulations should translate into a steady stream of coal plant retirements with generators planning to retire some 24 GW over 2012-17 (DiSavino and O'Grady, 2012). Much of the substitution for this capacity should come from new-build combined cycle gas plants. Nuclear power (19% of 2011 generation) should also expand slowly with the 1.2 GW Watts Bar-2 reactor under construction.

Figure 9 United States power generation by source



Renewable generation

An array of measures has supported the deployment of non-hydro renewable energy technologies, even with falling natural gas prices and absent federal quotas. Wind power additions have been strong in recent years and generation rose to 3% of power output in 2011. Though generation remains small, solar PV deployment has occurred across residential, commercial and utility sectors. While solar CSP and geothermal also look small compared with the total generation picture, their size is large by global standards. Meanwhile, bioenergy output has remained relatively steady at 1% of total generation.

At the state level, California and Texas have led deployment in solar PV and wind, respectively, though Washington's large hydropower make it the top state for renewable electricity capacity (see Box 2). In 2011, California added 540 MW of solar PV and 920 MW of wind while those categories grew by 50 MW and 300 MW, respectively, in Texas. Yet, these two states only accounted for about 30% of solar PV and 20% wind installations in 2011 as significant capacity has emerged across a number of states. Going forward, the retirement of coal plants and rising demand will help to create an opening for new power generation capacity. However, the interaction of state renewable portfolio standards and financial incentives (state and federal) will play a larger role in shaping the medium-term renewable forecast.

Table 6 Top ten US states, 2011 capacity additions (MW)

State	Wind	State	Wind	State	Solar PV	State	Solar PV
California	921	Colorado	501	California	542	Pennsylvania	88
Illinois	693	Oregon	409	New Jersey	313	New York	60
Iowa	647	Washington	367	Arizona	273	North Carolina	55
Minnesota	542	Texas	297	New Mexico	116	Texas	47
Oklahoma	525	Idaho	265	Colorado	91	Nevada	44

Sources: AWEA (2012), SEIA (2012a), IEA analysis.

Grid and system integration

Over the medium term, the United States grid should overall 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 point to the grid's ability to absorb penetration rates of variable renewable sources of 20% to 35% (NREL, 2011). By comparison, wind and solar PV, combined, accounted for 3% of power generation in 2011. Moreover, 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 continental United States power system functions within three weakly interconnected parts: the Eastern Interconnection, the Western Interconnection and the Texas Interconnection[1]. In general, the federal government regulates wholesale, interstate transmission. State public utility commissions oversee intrastate transmission and distribution. Regional transmission operators/independent service operators (RTO/ISOs) cover parts of the country and overlap both transmission and distribution. Since the Federal Energy Regulatory Commission's (FERC) deregulation ruling in 1996, service operators need to provide non-discriminatory access to interstate wholesale markets. A number of states have applied this principle to intrastate transmission and distribution. However, state-level liberalisation has proceeded slowly and unevenly due to reliability and price concerns.

The United States power system needs to accommodate more generation capacity and increased renewable sources away from load centres, particularly variable sources (wind and solar) and geothermal. Yet localised transmission bottlenecks exist. Despite increased planning and management provided by RTO/ISOs, interconnection policies within regions and harmonisation across regions remain fragmented. At the transmission level, investment responsibilities for long-distance power lines remain unclear. Moreover, congestion acts as a constraint on renewable operations – the United States Department of Energy (US DOE) reported wind curtailment rates versus potential generation of 7.7% for the Texas grid (ERCOT) and 4.4% in the Midwest ISO in 2010 (Wiser and Bolinger, 2011).

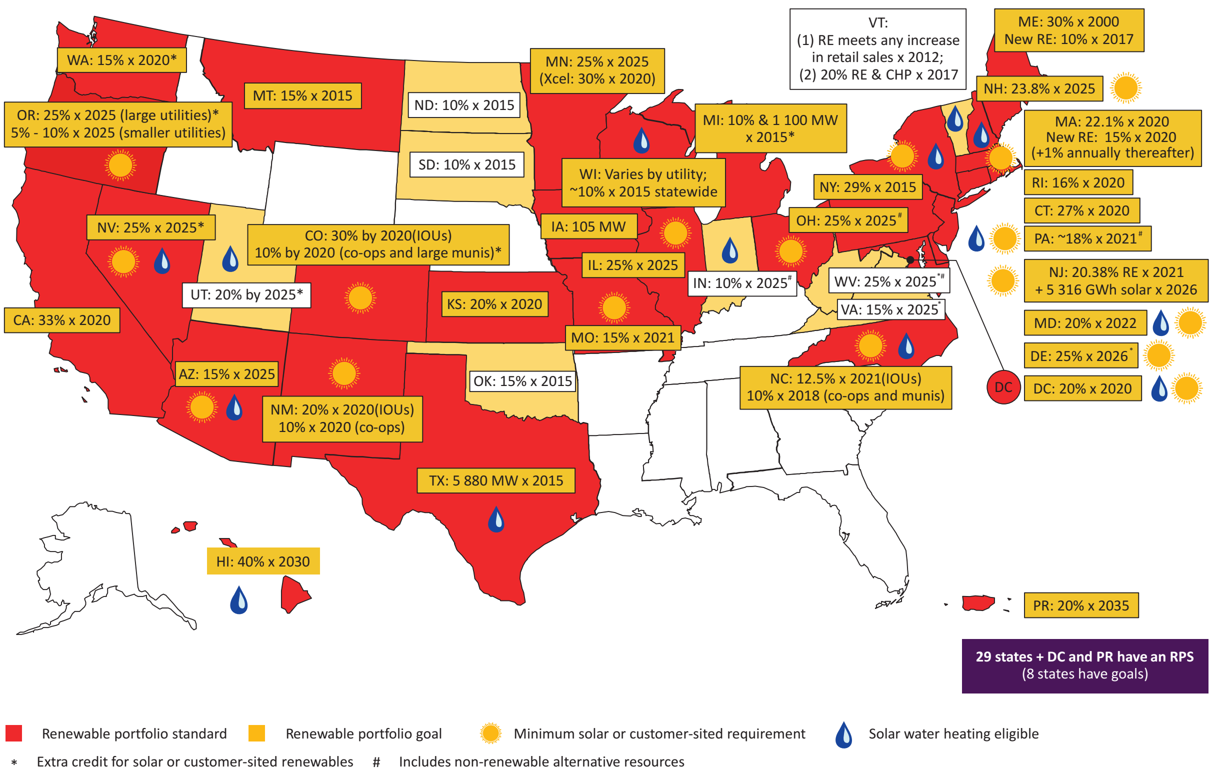
Efforts are under way to better coordinate grid planning and integrate renewable electricity. A recent FERC order (No. 1000) encourages regional transmission planning and better allocates costs to consumers that benefit from given transmission upgrades. PJM, an RTO covering 13 states from the mid-Atlantic to the Midwest, is pushing standardised interconnection procedures for wind. And investment that can help renewable power transmission, such as the 3.5 GW Rock Island Clean Line in the Midwest, is being carried out by non-utility, private developers. Still, the United States lacks an overall unifying strategy that may provide the best means for encouraging long-term investment.

[1] The grids of Alaska and Hawaii operate independently and are not interconnected with the rest of the United States.

Current policy environment for renewable energy

With no federal target, state renewable portfolio standards and federal financial incentives act as the main deployment drivers. The United States federal government employs a range of financial incentives, largely tax credits or favourable depreciation deductions, which vary by technology. The durations of these incentives are not aligned and lack long-term predictability. Moreover, their attractiveness can depend on the ability of developers to monetise credits through tax equity financing.

Map 1 United States state renewable portfolio standards (as of March 2012)



Source: DSIRE (2012).

To address a shortage of third-party tax equity demand (described under the *Finance* heading), a 2009 program (Section 1603) allowed projects to receive an up-front cash grant in lieu of tax credits. However, it expired at the end of 2011. Looking forward, the durability of key incentives looks uncertain. The production tax credit (PTC) for wind is set to expire at the end of 2012 while that for biomass, geothermal and hydropower terminates at end-2013. Solar projects enjoy an investment tax credit (ITC) that runs through 2016.

While targets vary widely, 29 states (and DC) employ a mandatory RPS and eight states have renewable energy goals. Eighteen states offer performance-based financial incentives, including feed-in tariffs or tradable renewable energy credits (RECs) schemes.

Table 7 United States main targets and support policies for renewable electricity

Targets	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 renewable portfolio standard (RPS) in place. **Largest RPS, by % of retail electricity sales:** Hawaii: 40% by 2030 California: 20% by 2014, 25% by 2017, 33% by 2020 Colorado: 30% by 2020 (investor-owned utilities [IOUs]) New York: 29% by 2015	**Corporate tax credits and depreciation:** Investment tax credit: 30% of system cost for solar PV, solar thermal, solar water heaters, wind (<100 kW), geothermal and combined heat and power. Production tax credit: wind, bioenergy, geothermal, small hydropower. Asset depreciation as set out in Modified Accelerated Cost Recovery System (MACRS). **Residential tax credits:** 30% of system cost for solar PV, solar water heaters, small wind, geothermal heat pumps, fuel cells. **Loans:** DOE Loan Guarantee Program (1703). **Performance-based incentives:** Adopted by 18 states; includes feed-in tariffs 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 Northeast and mid-Atlantic. **Grid Access and Priority Dispatch:** Grid access at the transmission level regulated by FERC, while states oversee access to distribution. Interconnection policies are in place in 44 states.

For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.
Source: DSIRE (2012).

Economic attractiveness of renewable energy

With project viability very much dependent on local resources and policy incentives, it is difficult to make nationwide assessments of the financial viability of renewable energy. The greatest competition comes from natural gas fired plants, which set wholesale prices in many parts of the country and are generally more economically attractive than unsubsidised renewable sources. As noted in the IEA *Medium-Term Gas Market Report*, United States natural gas prices are expected to rise, but remain relatively low over the next five years. The report assumes, based on the forward curve, that Henry Hub gas prices will increase from USD 4 million British thermal units (MBtu) in 2011 to USD 4.7 MBtu in 2017 (IEA, 2012). As an indicator, the Energy Information Administration's *Annual Energy Outlook* shows expectations across technologies for levelised cost of utility-scale electricity generation, without tax incentives. For plants entering service in 2017, combined cycle gas plants are expected to have the lowest average levelised costs among all sources (EIA, 2012). However, considerable local cost variation exists within different technologies.

The picture becomes more complicated at the project level. Strong resource availability, falling system costs and policy incentives should continue to make renewable energy attractive in many circumstances. For commercial solar PV, federal tax incentives (the ITC plus accelerated depreciation) can significantly enhance project attractiveness; this combination can account for about 56% of the installed cost of a solar PV system (Bolinger, 2009). Nevertheless, economic attractiveness going forward depends on several variables. Permitting procedures and environmental licensing requirements, which may come from several layers of government, tend to raise costs for solar PV, wind and transmission projects. The uncertain staying power of some financial incentives should also have major impacts on project economics and deployment over the medium term. Notably the looming wind PTC expiration has already prompted developers to suspend activities for projects that would be completed after 2012.

Financing

The cost and availability of finance acts as a deployment constraint in the United States, though evolving activities suggest improved conditions over time. Given a predominance of tax-based financial incentives and the expiration of the Section 1603 grants, renewable energy developers will need increased tax equity financing. Under this arrangement, corporations provide funds to projects and then use the associated renewable tax credits to offset their own tax burden. Tax equity financing enables projects to monetise benefits in an upfront manner. Yet, it also tends to raise financing costs and availability remains a constraint. A shortfall exists between tax equity demand and supply – the United States Partnership for Renewable Energy Finance (US PREF) estimates the mismatch at USD 3.6 billion for 2012 (US PREF, 2011). Filling this gap will require an expansion of tax equity providers beyond the usual financial institutions. While utilities and non-traditional entities such as Google have emerged as players, the scope for other corporations to supply the market remains large.

Very 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, anecdotally it appears that such investments may be crowding out some renewable financing in the short term. Still, going forward, utility finance in renewable energy should continue, particularly given mandated state renewable portfolio requirements.

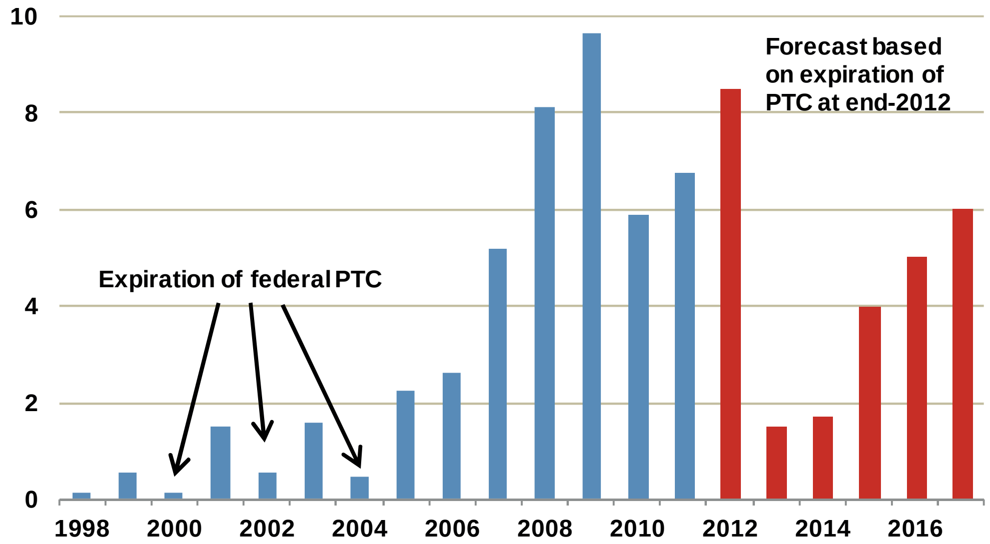
State-level incentives, specifically solar RECs, also play a positive role in attracting financing. In the short-term, solar REC markets are under pressure in some states – rapid build outs and certificate oversupply caused prices to fall in Pennsylvania, for example, from USD 250 per MWh in early 2011 to USD 20 per MWh in April 2012. Yet, from 2011-20, at least 3.8 GW of new solar should be supported by capacity required in REC markets in about ten states (Bird, Heeter and Kreycik, 2011).

The United States also continues to benefit from a high level of financial innovation. The advent of third-party financing models for solar PV and Property Assessed Clean Energy (PACE) programs, where municipalities help owners finance systems through property tax adjustments, illustrate emerging mechanisms. The latter program has run into hurdles related to the seniority of its loans versus residential mortgages underwritten by the Federal Housing Finance Agency. Nevertheless, the issue is being worked out and commercial-level PACE financings continue to advance.

Conclusions for renewable energy deployment: baseline case

The size and scope of the United States 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. This report expects renewable generation capacity to expand by 56 GW, from 167 GW in 2011 to 223 GW in 2017. Wind power expansion looks the strongest with 27 GW of additional capacity, followed by solar PV with 21 GW. Growth in geothermal, hydropower and bioenergy should be small in absolute terms, though capacity in these categories will remain large with respect to other countries. Based on projects under construction and in development, CSP is expected to grow by 3.6 GW. Though this technology remains relatively costly in the short term, much of its deployment attractiveness stems from its storage capabilities, which can complement the variability of solar PV. Offshore wind growth will likely remain low, with little deployment expected over the medium term.

Figure 10 United States annual wind capacity growth (GW)



At the state level, we assume that RPSs will continue to drive deployment according to policies in place as of May 2012. The US DOE has estimated that state RPS targets should provide renewable energy additions of 4 GW to 6 GW per year from 2011-20 (Wiser and Bolinger, 2011). Still, large prior-year build-outs in some states suggest that capacity additions over the medium term may be slower than this pace. Moreover, given budgetary pressures, there is a risk that state RPS targets or compliance dates may shift, which could lend downside pressure to this outlook.

The federal policy environment in the United States remains a key variable, with financial supports lacking predictability. In the baseline case, this report assumes that federal tax incentives will expire according to the schedule in place as of May 2012 with no allowance made for their renewal. The PTC for wind has expired on three previous occasions, causing installations to plummet the following year. This report projects a similar trajectory for wind in 2013, with additions gradually recovering over the medium term based on state RPS requirements and improving project economics.

Table 8 United States renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	101.0	101.1	101.2	101.4	101.7	101.7	101.8	102.3
Bioenergy	11.2	11.6	12.0	12.5	13.0	13.5	14.0	14.5
Wind	40.2	46.9	55.4	56.9	58.6	62.9	68.1	74.1
Onshore	40.2	46.9	55.4	56.9	58.6	62.6	67.6	73.6
Offshore	-	-	-	0.0	0.0	0.2	0.5	0.5
Solar PV	2.1	4.0	6.5	9.3	12.3	15.8	19.9	24.9
Solar CSP	0.5	0.6	0.6	1.7	2.7	3.2	4.0	4.2
Geothermal	3.1	3.1	3.2	3.3	3.3	3.3	3.4	3.5
Ocean	-	-	0.0	0.0	0.0	0.0	0.0	0.0
Total RES-E	**158.1**	**167.2**	**178.8**	**185.0**	**191.6**	**200.3**	**211.1**	**223.4**

By contrast, solar tax incentives, which run through 2016, should act as an important floor for development. With system prices expected to continue falling over the medium term, solar PV generation costs in sunny states may fall below 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. Finally, with fewer projects in the pipeline, the outlook for geothermal and hydropower should be affected less by the end of their PTCs at the end of 2013.

Table 9 United States main drivers and challenges to renewable energy deployment

Drivers	Challenges
• State-level RPSs combined with a slate of state and federal financial incentives. • Ample capacity for grid to absorb new RE generation over the medium term, though need for grid upgrades in the long term. • Innovative financing mechanisms and the entry of non-traditional players into RE development.	• Significant uncertainty over the durability of federal tax incentives. • Competition from gas-fired generation and expectations for low gas prices over the medium term. • Cost and availability of tax equity finance.

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. However, an extension of tax credits may be a more likely enhanced case. While solar deployment benefits from the eight-year lifetime of current tax credits, the one-to-five-year availability for other technologies hampers their long-term development. As such, an enhanced scenario would include the renewal of the wind PTC (most likely after federal elections in November) and the extension of other technology tax credits. It could also include stronger-than-expected uptake of solar PV, particularly in residential and commercial sectors, with better progress in system cost reductions and financing. In this case, cumulative wind capacity could be some 9 GW higher in 2017, while solar PV and bioenergy could be higher by 8 GW and 2 GW, respectively.

Box 2 California and Texas: key states for the United States renewable outlook

California and Texas hold the largest non-hydropower renewable electricity capacity in the United States. While activity will grow in other states, particularly those with an aggressive RPS (*e.g.* Colorado and Hawaii), favourable economics and rising power needs keep California and Texas as key medium-term deployment centres. Differences between these two states – on policy, grid, costs and non-economic barriers – illustrate well the variables shaping United Statesrenewable energy markets.

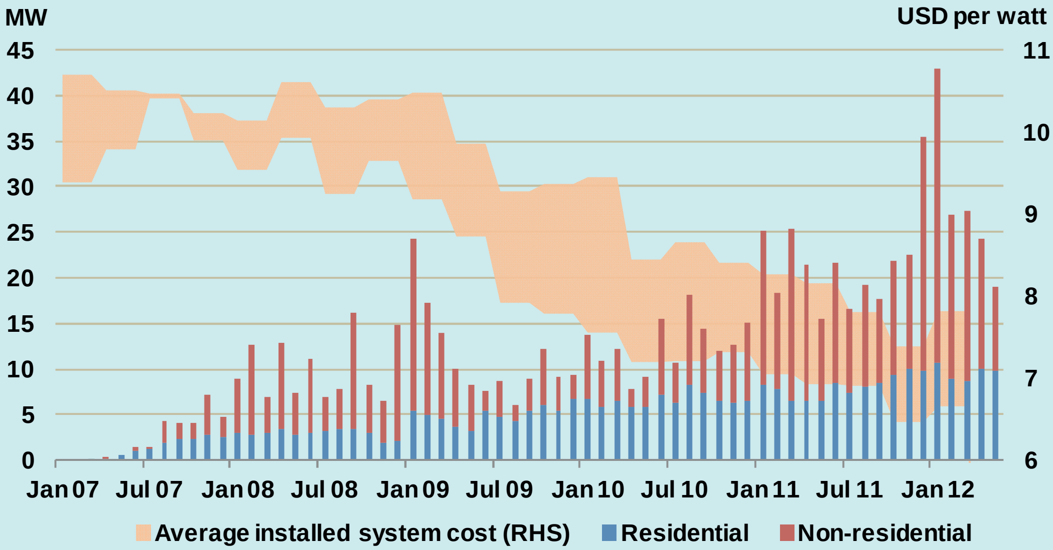
Bright solar outlook propels California's growth

Good resource availability, a strong RPS (33% by 2020) and financial incentives amid high retail electricity prices will drive California's growth. The state also has an emissions trading scheme that came into force in January 2012. The California Public Utility Commission reported that IOUs met 20.6% of 2011 retail sales with renewable power. Most activity going forward should take place in solar, though important additions should also occur in geothermal: the Geothermal Energy Association lists 560 MW in advanced-stage development there.

Since 2007, the California Solar Initiative (CSI) has supported solar development through direct cash grants, with a 3 000 MW solar PV target by the end of 2016. As of April 2012, the program had spurred installation of 810 MW. Pending applications (360 MW) should drive near-term activity and a fund injection for non-residential systems should support deployment of the remaining 1 830 MW. The Renewable Auction Mechanism should further boost distributed renewable capacity, with the state's three IOUs contracting for 1 000 MW (projects up to 20 MW) over 2011-13. Moreover, falling technology costs will help spur larger-scale solar projects. The Solar Energy Industries Association reported 3 450 MW of utility-scale solar PV and CSP under construction as of March 2012 (SEIA, 2012b).

Box 2 California and Texas: key states for the United States renewable outlook (continued)

Figure 11 CSI, monthly solar PV capacity installations versus system cost



Note: cost range reflects difference between systems above and below 10 KW; data are adjusted for California consumer price Index (CPI) from most recent quarter (1Q12).
Sources: California Public Utilities Commission and California Energy Commission.

A few risks persist. Strong policies have increased demand, but have also boosted the negotiation power of developers, keeping installed prices high for solar PV. Combined with stringent permitting and environmental requirements, California represents a relatively high-cost state for renewable energy projects. High installed costs also make the outlook for wind relatively tepid, particularly with the federal PTC expiration this year. However, excellent resource availability, incentives and high retail prices suggest that solar attractiveness will continue to increase over time.

Grid constraints and project uncertainties may also slow progress in large-scale additions. The California ISO has warned of grid capacity shortages emerging by 2017. And major transmission projects face long lead times, which could hinder solar developments in desert areas. The state's Renewable Energy Transmission Initiative and the federal government's designation of two solar energy zones in California should facilitate grid planning and project approval. Still, uncertainties have emerged in some key utility-scale projects, illustrating the range of risks confronted by developers. Financial woes have put the 1 GW Blythe solar PV plant (formerly a CSP project) on hold and construction on the 250 MW Genesis CSP project has slowed with the discovery of tribal artefacts and impacts on local wildlife.

Wind outlook looks moderately positive in Texas while solar capacity remains underdeveloped

The outlook for Texas arises from a different market environment for renewable energy, with growth dependent on project economics, to include federal incentives, and grid developments, as state policy targets remain relatively weak. To wit, both the renewable electricity mandate (5 880 MW by 2015) and target (10 000 MW by 2025) for Texas have already been surpassed, in 2008 and 2009, respectively, largely with wind power. Over the medium term, project economics and local purchasing initiatives will drive deployment. On this front, the wind outlook looks only moderately positive, with a lapse of the federal PTC and low natural gas and electricity prices undermining attractiveness. Still, with low capital costs, large project sizes, good capacity factors and streamlined permitting procedures, some wind projects will compete well.

Box 2 California and Texas: key states for the United States renewable outlook (continued)

Grid congestion will represent a barrier for wind projects in the near-term. Rapidly increasing generation capacity in the western part of the state combined with insufficient transmission to load centres in the north and east have resulted in wind curtailments and negative pricing situations. Since 2008, the state utility commission has encouraged transmission planning and upgrades through the designation of Competitive Renewable Energy Zones (CREZ), which seek to ultimately accommodate 18 500 MW of wind generation in the state (versus 10 340 MW in 2011). The effort has helped so far – ERCOT reports that 7.7% of wind generation potential was curtailed in 2010, down from 17.1% in 2009 – but projects will see more relief once the effort is fully completed in 2013/14.

Finally, the development of solar PV in Texas remains an uncertainty. The state benefits from a low overall cost environment, excellent resource availability and good load matching due to high midday summer air-conditioning needs. Texas also has significant power generation investment needs amid rising demand and peak loads. As such, the potential for both distributed and utility-scale generation is high. Still, most development has been limited and concentrated in utility installations. The state does employ a 500 MW non-wind goal by 2015 and adopted a homeowner solar rights provision in 2011. However, policy tools remain weaker than in other states, particularly in net metering, third-party PPA authorisation and financial incentives for solar PV.

Other OECD Americas countries

While the United States remains the dominant site for developments, significant renewable energy progress should emerge in other OECD Americas markets over the medium term.

Canada

Canada's power system already relies to a great extent on hydropower, which accounted for almost 59% of total generation in 2011. This large hydropower potential should be further developed over the medium term. Non-hydropower renewable developments will take place mostly in solar PV and onshore wind, with Ontario and Quebec providing the largest growth. In 2011, cumulative installed capacity stood at 560 MW for solar PV and 5.3 GW for onshore wind, mostly located in these two provinces. From 2011-17, growth in these two technologies is expected at 3 GW and 9 GW, respectively.

Despite an announced reduction in provincial feed-in tariffs, which were previously considered among the most generous in the world, deployment of wind and solar PV projects should continue in Ontario. In March 2012, the provincial government proposed reducing the feed-in tariffs for solar and wind projects by up to 32% and 15%, respectively. Rising local content requirements for projects – at 60% for solar and 50% for wind – may also weigh on economics. Still, the tariffs will remain attractive as solar capital costs continue to decline. Moreover, Ontario's decision to phase out coal power by 2014 provides a further boost to development.

The Canadian Wind Energy Association (CanWEA) reports over 2 GW of wind projects contracted or under construction in Quebec. CanWEA sees larger capacity under development in Alberta (9.7 GW). However, low electricity prices and an absence of power-purchase agreements in that province may ultimately undermine the economics of a number of projects. For example, Shell Wind recently shelved its 775 MW Wild Steer Butte project due to a lack of a long-term sales agreement.

Finally, activity should also occur in bioenergy and ocean power. Rich resources in biomass pellets should support further capacity additions as well as an expansion of feedstock exports. Canada should also see development of ocean generation with the completion of a 40 MW tidal project in Nova Scotia in 2016.

Chile

Chile's excellent resource availability across a number of technologies should make it a fertile development ground for renewable electricity in the long term. Over the medium term, the government sees overall demand needs growing quickly, by 6% to 7% per year. The country's electricity system faces a need to diversify away from hydropower generation, which has recently underperformed due to persistent drought conditions. Generators have turned to importing more coal, liquefied natural gas (LNG) and diesel to support the country's energy-intensive mining industry. As such, retail electricity prices for households have risen sharply.

To this end, the government has proposed expansion of both large hydropower and "non-conventional renewable energy" (NCRE), which includes small hydropower (<20 MW). Further development of the former, largely centred on construction of the 2 750 MW HidroAysen project, remains controversial, with strong environmental opposition. As of March 2012, Chile's cumulative development of NCRE amounted to 650 MW, according to renewable energy association ACERA. The government's formal target sees these sources contributing 5% of electricity from 2010 to 2014, thereafter rising by 0.5% annually to 10% by 2024.

As of January 2012, some 870 MW of wind, smaller hydropower and biomass projects were under construction. Spanish companies, in particular, have made inroads into wind and solar, with Grupo Ibereolica planning to start construction on a 360 MW CSP plant in late 2012. And Chile's rich geothermal resources are closer to development, with construction on a 40 MW plant by Enel Green Power starting this year. Given good resource availability and high fossil fuel prices, economic attractiveness for NCRE technologies should improve over time.

Nevertheless, development will still face barriers over the medium term. The government's energy strategy, so far, does not offer projects much assistance in financing and obtaining long-term purchasing power agreements. Integration also remains a persistent constraint given the high market concentration of incumbents and Chile's power system composition of four distinct grids. Good wind and biomass resources in the extreme south and rich solar in the Atacama Desert in the far north face transmission challenges to demand centres in the south-centre and north, respectively.

Mexico

Mexico also possesses excellent resource availability across a number of technologies, which makes its long-term potential attractive. In 2011, Mexico's renewable energy capacity consisted of 11.5 GW of hydropower, 1.0 GW of geothermal, 0.9 GW of onshore wind and 0.5 MW of biomass. Despite excellent solar resources, capacity in this category has remained small, with only 40 MW online. The government has three overlapping goal initiatives for renewable energy deployment, which foresee rising capacity through 2024. Still, they are generally not accompanied by specific financial incentives.

A number of onshore wind projects are under way, with at least 500 MW expected to come on line in 2012. Moreover, financing from the Inter-American Development Bank and a purchasing power agreement has been secured for a large, 396 MW wind farm in Oaxaca, with construction starting this year. Near-term (one to two years) solar development should proceed slowly in absolute terms. Still, a few major projects are in development, with significant capacity coming on line in phases over the medium term – these include a 200 MW PV plant in Durango and a 450 MW CSP project in Baja California.

Table 10 Mexico goals for renewable electricity

Programme	Term	Goal
National Energy Strategy	2009-24	35% of electricity generation capacity with "clean technologies" (includes large hydropower and nuclear).
Energy Sector Programme	2007-12	Increase share of renewable energy capacity in generation from 23% to 26% (includes large hydropower).
Special Programme for the Development of Renewable Energy	2009-12	Renewable capacity at 7.6% and generation between 4.5% and 6.6% of the total (excludes large hydropower).

Source: Secretaría de Energía.

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MEDIUM-TERM OUTLOOK: OECD ASIA-OCEANIA

Summary

- **OECD Asia-Oceania renewable electricity generation is projected to grow from 193 TWh in 2011 to 270 TWh in 2017 (+5.8% per year).** Solar photovoltaics (PV) should lead this growth, with generation increasing by 35.0 TWh, followed by onshore wind (+19.0 TWh) and bioenergy (+16.5 TWh). Geothermal and offshore wind should expand moderately.

- **Japan's renewable electricity capacity should grow from 57 GW in 2011 to 82 GW in 2017 (+6.1% per year).** With the introduction of generous feed-in tariffs and the shut-in of significant nuclear power in the short term, solar PV is expected to grow strongly, by 20 GW. Onshore wind (+2 GW), offshore wind (+1 GW), hydropower (+1 GW) bioenergy (+0.6 GW) and geothermal (+0.3 GW) should all make modest growth contributions. The status of Japan's nuclear fleet will remain a major forecast uncertainty going forward, with delays to the restart of capacity providing a potential upside to renewable deployment.

- **Other OECD Asia-Oceania countries are expected to grow from a combined 29 GW in 2011 to 44 GW in 2017 (+7.1% per year).** Wind and solar should grow strongly in Australia, buoyed by excellent resources, a national generation target and several large-scale solar projects. Israel's and Korea's renewable capacities should grow from a low base. Both should see developments in solar and wind, with a national target in Israel and a renewable portfolio standard in Korea guiding deployment. The start of a large tidal barrage plant in 2011 has given Korea the world's largest ocean capacity, though further additions in this category are likely to be minimal in the medium term. Meanwhile, New Zealand should slowly expand its diverse renewable offerings from an already high level of power market penetration (76% in 2011, largely from hydropower and geothermal) towards a government target of 90% in 2025.

Table 11 OECD Asia-Oceania renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	131	7.2%	139	7.3%	135	135	136	137	137	137
Bioenergy	23	1.3%	24	1.2%	28	31	33	35	38	40
Wind	3	0.2%	13	0.7%	15	18	21	25	30	37
Onshore	3	0.2%	13	0.7%	15	18	21	24	28	32
Offshore	0	0.0%	0	0.0%	0	0	1	1	2	5
Solar PV	2	0.1%	8	0.4%	13	18	24	30	36	43
Solar CSP	0	0.0%	0	0.0%	0	0	0	0	1	1
Geothermal	6	0.4%	9	0.5%	9	9	10	10	11	11
Ocean	-	0.0%	0	0.0%	1	1	1	1	1	1
Total RES-E	**165**	**9.1%**	**193**	**10.0%**	**200**	**211**	**224**	**238**	**253**	**270**

Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. Hydropower includes pumped storage; the split between onshore and offshore wind for 2005 and 2011 is estimated; CSP = concentrating solar power; RES-E = electricity generated from renewable energy sources.

Japan

An uncertain nuclear generation situation combined with generous proposed feed-in tariffs should drive strong solar PV deployment and stimulate longer-term geothermal activity.

Table 12 Japan renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	86.4	7.9%	91.5	8.7%	89.0	89.4	89.7	90.3	90.5	90.5
Bioenergy	18.5	1.7%	18.5	1.7%	22.0	24.0	26.0	28.0	30.0	32.0
Wind	1.8	0.2%	4.3	0.4%	5.2	5.8	6.6	7.5	8.7	10.9
Onshore	1.8	0.2%	4.3	0.4%	5.1	5.7	6.3	6.8	7.4	8.2
Offshore	0.0	0.0%	0.1	0.0%	0.1	0.1	0.3	0.6	1.3	2.7
Solar PV	1.5	0.1%	5.8	0.6%	8.1	12.0	16.6	21.1	25.7	30.2
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	3.2	0.3%	2.6	0.3%	3.0	3.0	3.0	3.2	3.8	4.3
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**111**	**10.1%**	**123**	**11.6%**	**127**	**134**	**142**	**150**	**159**	**168**

Power demand outlook

Under the assumption of a gradual return of nuclear power, Japan's electricity demand should moderately increase over the medium term, after declines in 2011 and 2012. The International Monetary Fund (IMF) sees real gross domestic product (GDP) growing by 1.5% annually on average over 2011-17. The largest growth occurs in 2012 as part of a rebound following the earthquake and tsunami of 2011, when power demand declined 4.7%. In the short term, with reduced availability of nuclear power supply, the government and utilities continue to push energy efficiency and demand-saving measures. Moreover, increased use of costly oil and gas-fired generation has pushed up retail prices. On the condition that nuclear power gradually returns, starting in the second half of 2012, demand should rise. Yet, in 2017, total electricity supplied is still 3.5% lower than 2010 levels.

Figure 12 Japan power demand versus GDP growth

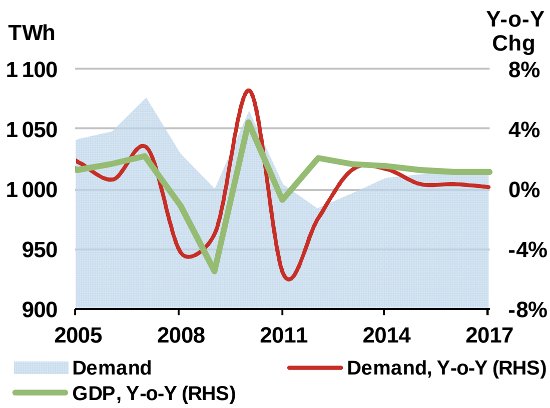
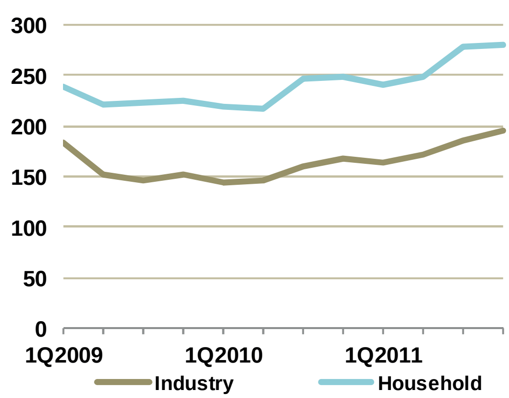


Figure 13 Japan average retail power prices (USD per MWh)



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

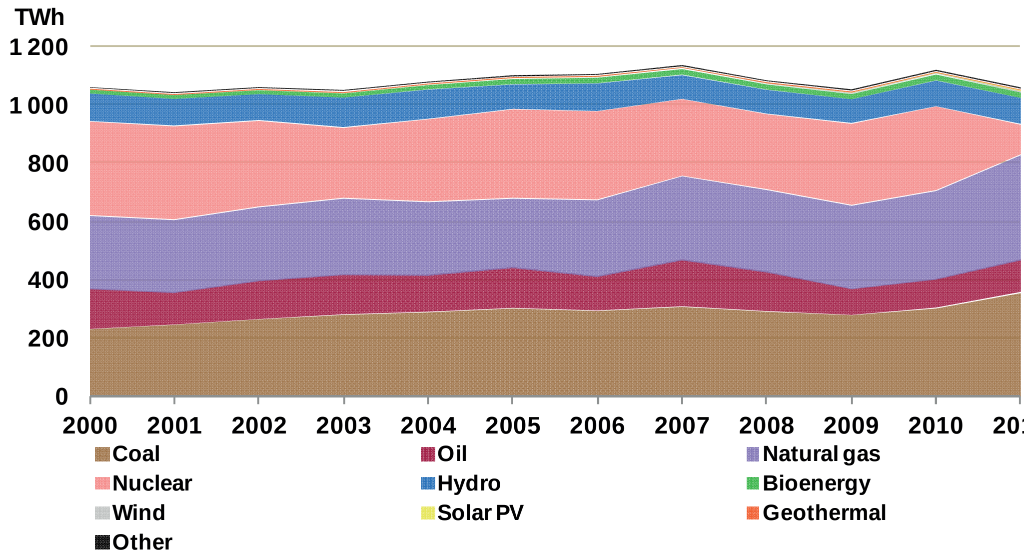
Power sector structure

Generation and capacity

The future of Japan's nuclear reactors will be the major determinant of the power system and renewable development over the medium term. Prior to 2011, Japan's power mix was well diversified, with coal, natural gas and nuclear occupying roughly the same share (26% to 27%) of generation in 2010. Oil represented a significant portion, at 9%, followed by hydropower (8%), with bioenergy, wind, geothermal and solar PV supplying the small remaining amount. In 2010, total electricity capacity stood at 287 GW with peak demand at 180 GW.

Last year's earthquake and tsunami and consequent stress tests of nuclear power plants produced a structural break in generation trends. In 2011, natural gas grew to 34% of the power mix, with coal also at 34% and oil at 10%. Hydropower's share increased to 9%.

Figure 14 Japan power generation by source



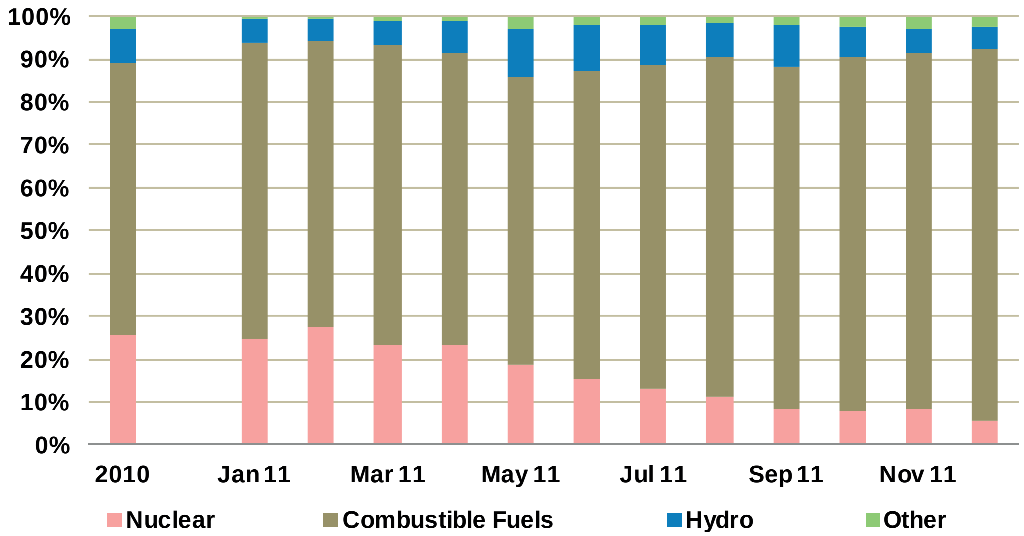
Note: data refer to fiscal year (April-March).

As of June 2012, all 54 of Japan's nuclear power units remain off line and the decisions for restart have not yet been taken. This report assumes in its baseline case that some capacity should restart after this summer, as discussed in the *Oil Market Report* (OMR) scenario "some nuclear" (IEA, 2012). Over the course of the following year, additional capacity is assumed to return on line. Still, the total units authorised to restart should only represent slightly less than half of the historical nuclear production (around 280 TWh in 2010). Moreover, this assumption of returning nuclear capacity is still rooted in a degree of uncertainty. The energy policy environment in Japan remains delicate; as such, nuclear power could very well return at a slower pace than expected.

Renewable generation

Ostensibly, this situation should spur rapid increases in renewable energy penetration. In 2011, the build-out of renewable electricity was largely consistent with prior-year growth trends, with generation at 11% of total power output. New contributions from bioenergy, wind and geothermal remained relatively small. Cumulative solar PV capacity (mostly residential) rose to 4.9 GW in 2011 (versus 3.6 GW in 2010) with an increasing profile through the year. Given quick installation times, good peak shaving abilities during Japan's summers, favourable global supply conditions, and the introduction of a generous feed-in tariff scheme from this summer, the solar PV outlook over the medium term looks more robust. From April 2012, the government has also allowed utilities to include solar power in annual supply plans.

Figure 15 Japan power generation by share, 2011



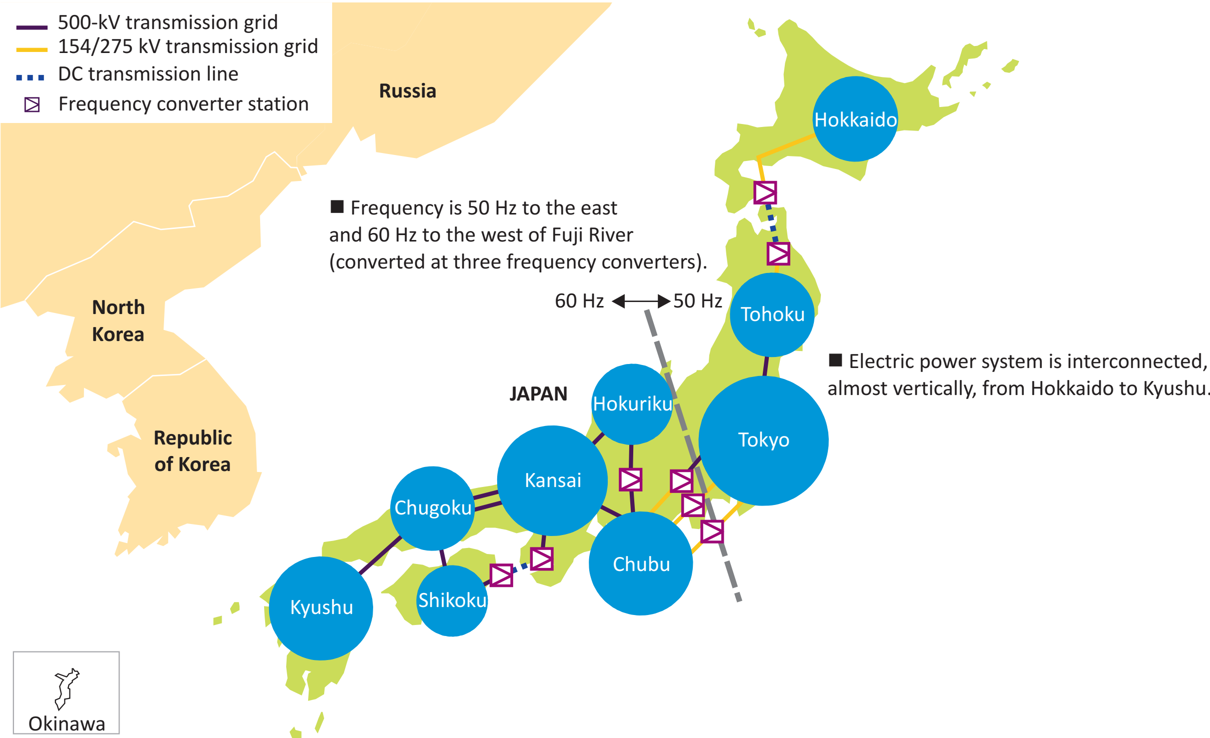
Grid and system integration

Integration of higher levels of renewable sources in Japan will present some challenges, largely related to the institutional nature of generation and grid operation that can act as a barrier to entry. The power system consists primarily of ten vertically integrated utilities, which act as both generators and network operators. In addition there is one large wholesale supplier (J-Power), several smaller ones, municipal suppliers and autonomous generators. Overall, the market is relatively concentrated, with incumbents traditionally concerned with the potential adverse consequences of increased variable renewable sources on the grid.

Historically, the ten vertically integrated utilities, which own and operate all high-voltage transmission lines, were required to maintain self-sufficiency within their area. As such, interconnections among the ten supply areas are weak and primarily serve system security purposes. Japan's transmission system occupies two separate frequency areas, a northern system operating at 50 hertz (Hz) and a southern system at 60 Hz. Frequency converters connect the two areas, but north-south transmission potential remains limited to about 1 GW, with frequent congestion.

For the most part, increased installation of distributed solar PV will not face significant challenges in the medium term, given its deployment near demand centres and its generation peak coinciding with high midday demand. Grid infrastructure will be a challenge for wind development in Japan, however. Tohoku and Hokkaido in the north of the country and Kyushu in the south are the leading wind resource regions. These areas sit away from major load centres and possess relatively weak grid capacity.

Map 2 Japan power transmission system



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Current policy environment for renewable energy

To date, deployment of renewable energy sources in Japan has been driven by the Renewable Portfolio Standard (RPS) introduced in 2003 as well as a feed-in tariff scheme introduced in 2009 for purchasing surplus electricity from small-scale PV. However, a new, more generalized feed-in tariff scheme has been agreed to, which should further speed development. With final approval expected by the Ministry of Economy, Trade and Industry (METI), the scheme will start in July and include solar PV, wind, small hydropower (<30 MW), geothermal and biomass generation for certified entities. METI will set the rates, and the scheme does not include a cap on capacity. The feed-in tariff levels are slated to be reviewed at least once per year.

In preparation for the tariff scheme, the government in March 2012 started relaxing certain environmental permitting procedures for large-scale solar PV power plants, acknowledging their minimal adverse impact. It has also allowed utilities to include solar in their power supply scheduling. Moreover, the government has expanded access for geothermal projects, opening certain areas in national parks to development. Together, all these reductions in non-economic barriers should facilitate solar PV and geothermal development over the medium term. For wind, an environmental assessment of wind farms over 10 MW is to be required after October 2012, which may slow development in this area.

Table 13 Japan main targets and support policies for renewable electricity

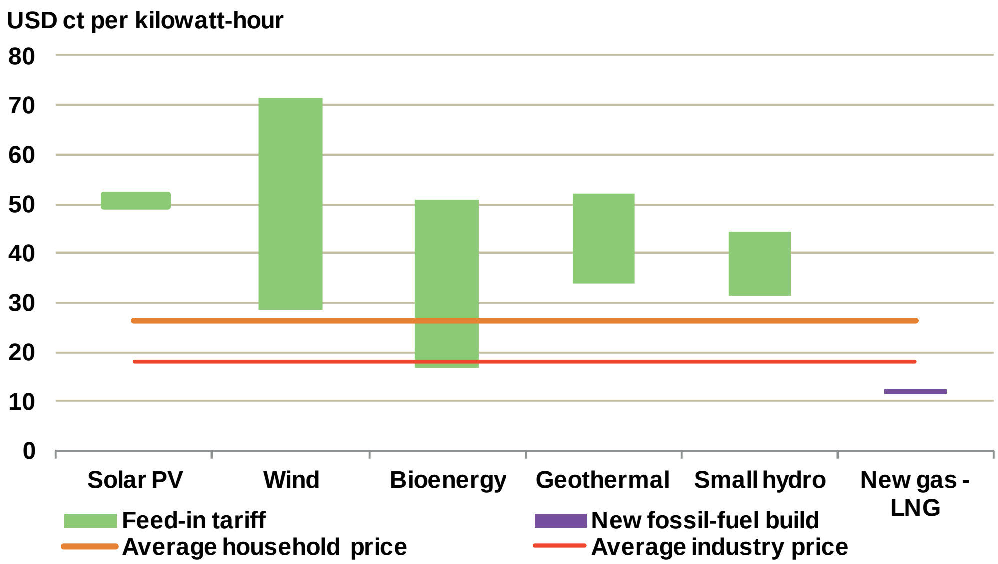
Targets	Financial support	Other support
Comprehensive review of Japanese energy policy 2010: 10% of total primary energy supply from renewable sources by 2020. **Renewable Portfolio Standard:** Includes certificates trading scheme. Covers electricity from all renewable sources except large hydro. Scheme to be discontinued at end-June 2012 with the introduction of feed-in tariffs.	**Feed-in tariffs:** Effective 1 July 2012. Apply to solar PV, wind, hydro (below 30 MW), geothermal and biomass. Generators with government certification are eligible. Tariff ranges: Solar PV: USD 0.52 per kilowatt hour (kWh), with net metering, for systems below 10 kilowatts [kW]; USD 0.50 for systems above 10 kW Wind: USD 0.29–USD 0.76 per kWh Geothermal: USD 0.34-USD 0.52 per kWh Small Hydro: USD 0.31-USD 0.44 per kWh Biomass: USD 0.17-USD 0.51 per kWh **Subsidy for residential PV:** METI provides grants for systems up to 10 kW.	**Strategic planning:** Comprehensive review of Japanese energy policy 2010. **Grid access and priority dispatch:** Currently, electric utilities are obliged to allow grid connections under the feed-in tariff scheme; priority dispatch is guaranteed except in must-run cases for other plants.

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

Economic attractiveness of renewable energy

The introduction of the new feed-in tariffs has greatly improved the economic attractiveness of renewable energy. The tariffs for solar PV should adequately compensate for the relatively high system costs in Japan versus international markets. To date, the Japanese solar market has generally lacked competition within equipment, sales and installation segments, keeping observed costs higher than in other markets. However, going forward, system costs are likely to move downward towards international prices as more foreign suppliers, enticed by the feed-in tariffs, enter the market.

Figure 16 Japan FIT tariffs (2012), fossil-build costs (2012) and power prices (2011)



Note: LNG = liquefied natural gas. Household and industry prices are inclusive of tax.

Wind projects in Japan also face high costs due to weak competition within the segment. Ostensibly, the high levels of feed-in tariffs should compensate for this barrier and boost project economics significantly. Still, other considerations are likely to weigh upon project attractiveness. Wind farms in Japan face restricted grid connection opportunities and other non-economic barriers, such as local opposition, space constraints and strict planning codes. Among other technologies, the benefits to bioenergy, specifically biogas and municipal waste, look strong. Geothermal projects should also prosper, especially given good resource availability and the government's efforts to open new areas to development. Still, given high exploration risks and long lead times associated with this technology, improved attractiveness may spur higher capacity additions only over the long term.

Meanwhile, the proposed tariff levels, among the world's highest in most technologies, may pose economic sustainability concerns over the medium term. Consumers will fund the tariffs through a supplement on their electricity bills, with energy-intensive industries exempted from 80% of the surcharge. With no cap on capacity under the feed-in tariffs, there is large potential for deployment, and the corresponding impact on end-user bills, to rise rapidly. Ultimately, the durability of the scheme over the medium term may depend on household ability and willingness to bear increasing programme costs and the ability of policy makers to manage them. Still, the inclusion of increased renewable sources should help to reduce peak power needs, which are typically met through expensive LNG generation, thereby helping to reduce peak prices.

Financing

Japan's policy environment should act as an enabler for renewable energy financing over the medium term. The presence of attractive feed-in tariffs will help to stimulate investment. Though project development has been slow in recent years, Japanese banks are in relatively strong lending positions relative to European counterparts, and the long-term cost of capital in Japan is low. Despite generally high savings rates, Japanese consumers may face difficulty in financing the high up-front costs associated with residential solar PV systems. To this end, banks have increasingly provided low-interest loans for residential PV installations or for houses equipped with PV systems. METI and local governments also provide direct subsidies to individuals to defray capital costs for residential PV.

Conclusions for renewable energy deployment: baseline case

Japan's need for additional generation capacity to compensate for nuclear shortfalls in the short term and its increasingly favourable renewable energy economics should spur strong deployment over the medium term. The baseline case assumes that a significant portion of nuclear capacity will gradually return over the medium term, as set out above. Renewable electricity capacity should expand from 57 GW in 2011 to 82 GW in 2017. With 20 GW of growth expected, the outlook for solar PV looks the most robust. Additions to bioenergy and wind (onshore and offshore) should total 0.6 GW and 3.0 GW, respectively. Despite a more favourable outlook for geothermal projects due to recent policy changes and geothermal's ability to fill base load power needs, growth should be slow in this category given long associated lead times.

The start of the feed-in tariff scheme should greatly augment Japan's investment environment, giving greater predictability to developers. Given the high initial tariff levels, however, the government will need to maintain a dynamic approach to adjustments to reflect international and national market developments and keep deployment sustainable for consumer electricity bills. The country also has a long history of solar PV deployment. Although deployment has not kept up with more dynamic markets, such as Germany, in recent years, this experience should be an asset for jump-starting efforts over the medium term.

Table 14 Japan renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	47.7	47.6	48.1	48.1	48.4	48.6	48.6	48.6
Bioenergy	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2
Wind	2.3	2.5	2.8	3.2	3.5	3.9	4.5	5.5
Onshore	2.3	2.5	2.8	3.1	3.4	3.7	4.0	4.5
Offshore	0.0	0.0	0.0	0.1	0.1	0.2	0.5	1.0
Solar PV	3.6	4.9	6.9	10.4	13.9	17.4	20.9	24.4
Solar CSP	-	-	-	-	-	-	-	-
Geothermal	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.8
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**55.7**	**57.2**	**60.0**	**64.0**	**68.3**	**72.6**	**76.9**	**81.6**

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

Japan's other large variables for renewable deployment relate to grid and system integration and technology-specific issues. The vertical integration, high market concentration, centralised decision-making and weak regional interconnections that characterise Japan's power system tend to inhibit competition and the deployment of new technologies, particularly those with variable output. This feature should act as a dampening element to medium-term deployment. On the technology side, a successful expansion of geothermal power may need mechanisms to finance exploration and drilling risks (see Chapter *Medium-term outlook: renewable technologies*). Although likely to ease over the medium term, solar PV costs remain higher than in other markets, requiring continued mechanisms to help consumers defray up-front payments. Finally, wind power development will remain difficult over the medium term. Good onshore sites remain far from demand centres, and offshore deployment is challenging given prevailing sea depths.

Table 15 Japan main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Strengthened policy environment backed by generous feed-in tariffs. • Acute need to replace nuclear power generation shortfalls amid restart uncertainty. • Good solar PV potential with peak shaving abilities and declining non-economic barriers.	• Power system fragmentation among ten vertically integrated utilities with weak interconnections inhibits new RE deployment. • Relatively high costs for solar PV and wind installations compared to international markets. • Long development times for geothermal; wind resources away from load centres.

Renewable energy deployment under an enhanced case

Uncertainty over the nuclear situation remains the major variable for Japan's outlook. While the baseline case sees a return of a significant portion of nuclear power, delay – or lack of restart at all – over the medium term could spur more renewable deployment than anticipated. To be sure, the situation would not represent an enhancement in the traditional sense, as Japan's power system would fall under increased strain and demand would be supply-constrained. Under a slower or no-nuclear scenario, the government would likely need to maintain feed-in tariffs at high levels for longer periods of time in order to spur rapid renewable deployment.

Most of the capacity upside would pertain to solar PV, where cumulative capacity in 2017 could top 28 GW, some 4 GW higher than our baseline case. With long lead times for base-load technologies – geothermal and hydropower – and more persistent hurdles for wind, potential forecast changes in these areas look minimal. Given solar PV's suitability to Japan's energy situation, deployment could be accelerated with more aggressive cost reductions. The former could come about through increased competition – from both foreign and domestic companies – in panel manufacturing, sales and installations. Still, given space constraints and limits for the Japanese market to realise economies of scale, cost structures may still exceed those of international markets.

General reform of the electricity system could also enhance the picture over the long run. An unbundling of the utility system combined with competitive markets and reduced regulatory burdens at all levels of the power system could greatly facilitate acceptance of variable renewable sources. Specifically, reform could include mechanisms to enhance balancing with the power system and transmission capacity upgrades to load centres, both of which would benefit wind deployment. However, developments remain too preliminary and uncertain at this stage to incorporate into the medium-term outlook.

Other OECD Asia-Oceania countries

Australia

In Australia, renewable energy sources accounted for 10.5% of total power generation in 2011. Around 6% of generation stemmed from hydropower, while the remaining renewable contribution came from wind, solar PV and bioenergy. Solar PV has grown quickly from a low base, supported by feed-in tariffs from state governments and the national Renewable Energy Target (20% of electricity supply from renewable power by 2020) mechanism with tradable certificates. Over the past two years solar PV capacity grew rapidly, from 0.2 GW in 2009 to 1.3 GW at the end of 2011. On top of the government incentives and good economic attractiveness, financial innovation in the form of third-party leasing models continues to spur solar PV growth in the residential sector.

A few newly announced measures that have not yet been implemented should also guide renewable deployment over the medium term. From mid 2012, a carbon tax starting at AUD 23 per tonne of carbon dioxide equivalent (tCO_2-eq) will be introduced and will apply to about 500 large polluting entities. The government has also established the Australian Renewable Energy Agency (ARENA), which will start in July 2012. Finally, authorities plan to establish a financing agency, the Clean Energy Finance Corporation. The institution should commence operations in mid-2013 and will provide funding support for large-scale renewable, energy efficiency and low emissions technology projects.

In terms of deployment, Australia should continue to exploit excellent wind and solar resources, through both large-scale and small-scale projects. Specifically, the government has directed funds to support a few large-scale solar installations. Both Solar Dawn in Queensland (250 MW solar CSP with additional gas backup capacity) and the Moree Solar Farm in New South Wales (150 MW solar PV) are expected to come on line in 2015.

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, 0.5% in 2011.[2] 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 feed-in tariff for distributed systems and tenders for large-scale projects, solar PV installations have grown since 2008 and in 2011 cumulative capacity reached 0.2 GW. More than 30 MW of large-scale PV projects are currently under construction, and residential deployment should also progress over the medium term. Developers have planned several

[2] 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.

hundreds of megawatts of onshore wind in the Golan Heights, where resource conditions are excellent, while 370 MW of CSP developments are in planning for the Negev desert.

Korea

With only 2.1% of total power from renewable sources in 2011, Korea's market remains relatively underdeveloped. At the end of 2011 solar PV capacity stood at 0.8 GW while onshore wind capacity was 0.4 GW. The 254 MW Sihwa Lake tidal barrage, the world's largest ocean project, came on line in August 2011. The Korean government has replaced its feed-in tariff scheme, which did not result in significant deployment, with an RPS scheme effective 1 January 2012. The scheme requires the 13 largest public and private utilities to generate or purchase (through tradable certificates) 2% of their total generation as renewable energy in 2012, rising to 10% by 2022.

Over the medium term Korea should further develop its solar and wind resources. Within the wind category, both onshore and offshore capacity should grow, reaching 1.0 GW and 0.7 GW in cumulative capacity, respectively. Grid access and permitting procedures should remain persistent constraints, though the government is seeking ways to reduce these barriers. In ocean technology, several large tidal barrages are also under consideration, but they may face opposition on environmental grounds. As such, they do not enter the medium-term forecast.

New Zealand

New Zealand has a high level of renewable penetration in its power system. In 2011 renewable sources represented 76% of power generation with hydropower as the largest share, 56%, 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.

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 slow pace over the medium term, given only moderately rising power demand. Nevertheless, the government has retained a target of 90% of total power generation coming from renewable sources by 2025, which will act as a floor for deployment over the medium to long term.

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MEDIUM-TERM OUTLOOK: OECD EUROPE

Summary

- **OECD Europe renewable electricity generation is projected to grow from 905 TWh in 2011 to 1 271 TWh in 2017 (+5.8% per year).** Onshore wind will lead this growth, with generation increasing by 121 TWh, followed by hydropower (+83 TWh), solar photovoltaics (PV) (+62 TWh), and bioenergy (+52 TWh). Concentrating solar power (CSP), geothermal and offshore wind should account for a smaller part of the overall growth. Still, relative to global deployment in these technologies, OECD Europe additions to offshore wind should be quite large.

- **Germany, Italy and Spain led the growth in renewable electricity generation in OECD Europe between 2005 and 2011, and are projected to grow by 58 TWh, 34 TWh and 20 TWh, respectively, from 2011-17.** Past buoyant development has brought concerns about control of growth of renewable sources in these countries. Germany and Italy are currently adjusting their solar PV policies to contain the growth, while Spain imposed a moratorium on Special Regime developments, significantly slowing expansion over the medium term.

- **The United Kingdom, Turkey and France should also see strong renewable electricity generation growth between 2011 and 2017**. The United Kingdom should increase by 46 TWh, mostly from wind, both on- and offshore. Turkey continues to quickly develop its abundant and economically attractive hydropower and onshore wind resources as total renewable generation increases by 43 TWh. Meanwhile, France deploys a wide portfolio of renewable sources; its renewable electricity generation should grow by 43 TWh over the medium term.

- **Austria, Denmark, Norway and Sweden see relatively less absolute growth due to their smaller power sectors and already well-developed renewable power generation.** Developments in these countries focus mostly on hydropower, wind and bioenergy.

Table 16 OECD Europe renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	528	14.9%	534	14.9%	574	585	597	606	612	618
Bioenergy	70	2.0%	133	3.7%	140	149	158	166	175	185
Wind	71	2.0%	180	5.0%	212	237	262	285	311	341
Onshore	70	2.0%	168	4.7%	195	215	234	252	270	289
Offshore	1	0.0%	12	0.3%	17	23	28	33	41	52
Solar PV	1	0.0%	45	1.3%	66	74	82	90	98	107
Solar CSP	-	0.0%	2	0.1%	3	5	6	6	6	6
Geothermal	7	0.2%	11	0.3%	11	12	12	12	13	13
Ocean	1	0.0%	1	0.0%	1	1	1	1	1	1
Total RES-E	**679**	**19.1%**	**905**	**25.3%**	**1 007**	**1 063**	**1 117**	**1 166**	**1 215**	**1 271**

Notes: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. Hydropower includes pumped storage; split between onshore and offshore wind for 2005 and 2011 is estimated; RES-E = electricity generated from renewable sources.

Austria

A leader in the portfolio approach to renewable deployment, Austria is expected to expand over the medium term. Pumped storage expansions should improve regional balancing capabilities.

Table 17 Austria renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	39.0	58.8%	37.3	56.6%	41.9	42.7	43.4	43.4	43.9	44.4
Bioenergy	2.6	3.9%	5.7	8.7%	7.8	8.4	8.9	9.5	10.2	11.0
Wind	1.3	2.0%	2.1	3.2%	2.7	3.2	3.6	4.0	4.3	4.6
Onshore	1.3	2.0%	2.1	3.2%	2.7	3.2	3.6	4.0	4.3	4.6
Offshore	-	0.0%	-	0.0%	-	-	-	-	-	-
Solar PV	0.0	0.0%	0.1	0.2%	0.3	0.4	0.5	0.7	0.8	1.0
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	0.0	0.0%	0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**43.0**	**64.7%**	**45.2**	**68.7%**	**52.7**	**54.7**	**56.5**	**57.5**	**59.2**	**60.9**

Power demand outlook

Austria's gross domestic product (GDP) is projected to grow on average by 2.0% annually from 2011-17. Over the past decade electricity demand has generally increased, with a moderate retrenchment in 2008-09. At 66.7 TWh in 2011, demand has recovered to pre-recession levels. Austrian retail power prices, available for households, have risen steadily over the past decade with a dip during the economic crisis. As a mature economy with energy efficiency measures and moderate economic growth, we expect demand in Austria to increase moderately over the medium term, rising from 66.7 TWh in 2011 to 70.8 TWh in 2017 (+1.0% annually).

Figure 17 Austria power demand versus GDP growth

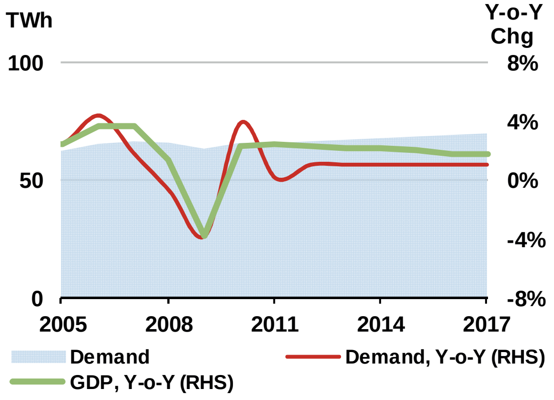
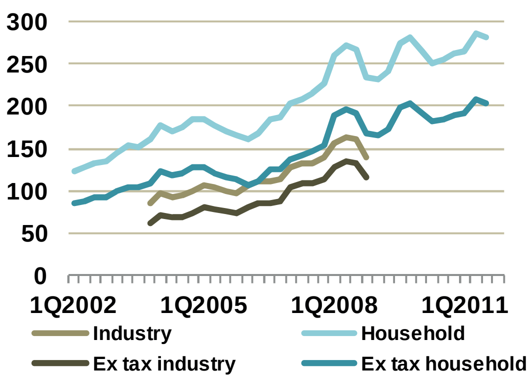


Figure 18 Austria average retail power prices (USD per MWh)



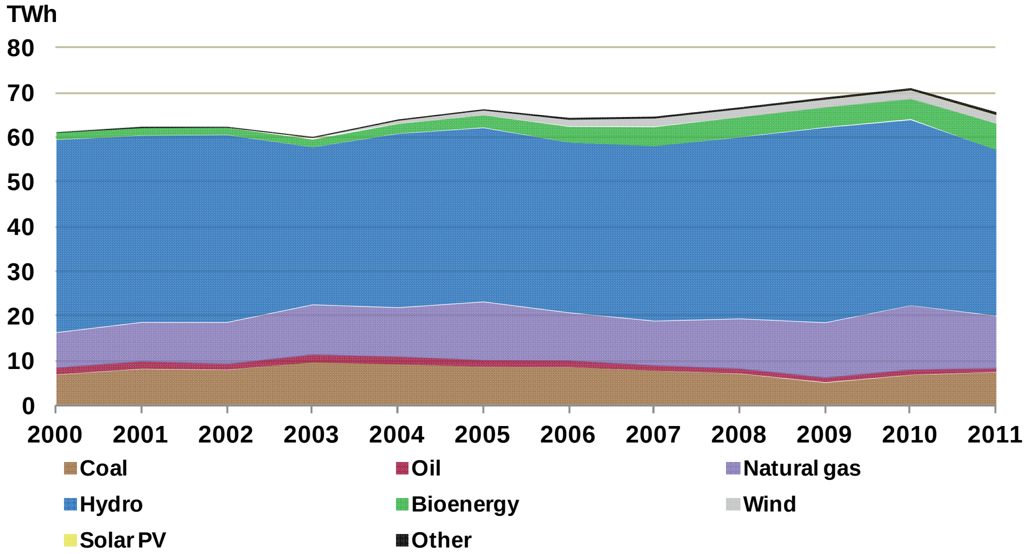
Note: demand is expressed as electricity supplied to the grid. RHS is right hand side. Except where noted, power prices include tax. For Austria, industry prices are not available for 2009-11.

Power sector structure

Generation and capacity

Austria's power generation has grown increasingly diversified over the past decade, with renewable electricity playing a larger role. In 2011, over half of the power supply came from hydropower, with fossil fuels accounting for a 30% share. While these ratios have fluctuated over time based on hydro availability, the trend within the latter category has pointed to a falling coal share and increasing natural gas. Non-hydro-based renewable power has grown fast over the past decade and accounted for a 12% generation share in 2010, with bioenergy and wind at 9% and 3%, respectively. Nuclear power developments were banned in Austria by a 1978 referendum. In 2010, total power generation capacity was 21 GW, with peak load at 9.7 GW.

Figure 19 Austria power generation by source



Looking forward, renewable energy penetration is expected to increase, particularly given Austria's commitment to reversing its net power importer status, with further development of wind, hydropower and bioenergy. This desire stems as much from sustainability as energy security reasons – collectively, Austrian rate payers have asked for visibility on power sources, with concern over nuclear power imported from neighbouring countries. In January 2012, power providers were required to start showing the origin of power supplies on customer bills. Such transparency should help reinforce public support for renewable generation going forward.

Grid and system integration

Though constrained in the short term, the Austrian power grid should not act as a major deployment bottleneck over the medium term. As electricity consumption has increased by almost fivefold since its original construction, the grid has now reached its maximum capacity. North-south connections, in particular, are significantly overstretched. Austrian Power Grid AG, since 1 January 2012 the transmission service operator (TSO) for all of Austria, maintains current operations by means of congestion management. Nevertheless, some relief is on the way – the TSO is constructing power lines that will close a gap in the transmission ring that serves as the backbone of the high-voltage system. Moreover, the western part of the grid is well interconnected with neighbouring Germany.

Furthermore, with a central location in Europe and suitable sites for pumped hydropower extensions and new developments, Austria also aims to position itself as a regional "green battery". The country seeks to provide increased pumped-storage hydropower to balance regional wind and solar output. This build-out should help power system flexibility in central Europe as well as improve the electricity trade balance of Austria. However, this deployment faces some hurdles. Pumped storage operators currently face network tariffs associated with pumping electricity and power feed-in. In neighbouring countries – Germany, Italy and Switzerland – pumped storage remains exempt from these charges. Austria also limits cross-border marketing of pumped-storage electricity in the balancing markets, with generally only intraday marketing to Germany possible. However, in May 2012, the Ministers for Economy in Germany, Switzerland and Austria signed a declaration to co-operate closely and accelerate the development of new pumped storage power plants.

Current policy environment for renewable energy

Austria's policy framework is supportive of renewable energy deployment. In line with the European Union's Renewable Energy Directive, Austria's National Renewable Energy Action Plan originally envisaged 70% of the country's power coming from renewable sources by 2020. However, based on the introduction of an updated incentives scheme, renewable energy sources could meet 85% of power demand in 2020. The previous scheme, adopted in the 2009 Green Electricity Act, spurred strong growth, but the rapid increase in renewable energy applications exceeded yearly budget allocations – which are paid through consumer electricity bills – for feed-in tariff support, particularly in PV. This resulted in a waiting list for projects to be commissioned at a later stage.

Table 18 Austria main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 34.2% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 70.6% of electricity production from renewable sources from: 9 GW hydropower 1 MW geothermal 0.2 GW solar PV 2.2 GW wind onshore 1.2 GW bioenergy **2012 Green Electricity Act (increase in capacity in 2020 versus 2010 baseline):** +2.0 GW onshore wind +1.2 GW solar PV +1.0 GW hydropower +0.2 GW biomass and biogas	**Feed-in tariffs:** Apply to electricity from wind, bioenergy, geothermal, small hydropower and solar PV plants. Co-firing of biomass is also incentivised. **Green Electricity Act:** Investment grants for small-scale hydropower (<2 MW) and solar PV (<5 kilowatts [kW]). **Combined Heat and Power Law:** Subsidies to new co-generation plants (except for those covered in Green Electricity Act).	**Framework policy:** Energy Strategy of Austria Green Electricity Act **Grid access and priority dispatch:** Approved projects are connected to grid and purchase obligation is guaranteed in Green Electricity Act.

Note: co-generation refers to the combined production of heat and power. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

New incentives will fully come into force in July 2012 under the 2012 Green Electricity Act. Parts of it already in place since mid-2011 introduced one-off budget allocations to shift some wait-listed applications into development, albeit at lower feed-in tariffs than under the previous scheme. For new installations, the scheme keeps feed-in tariffs relatively steady for wind and bioenergy while reducing those for solar

PV. Notably, the scheme increases the yearly budget allocation for renewable electricity support from EUR 21 million to EUR 50 million, which should spur development. It also discontinues waiting lists for solar PV, instead requiring projects that fall outside this allocation to reapply the following year.

Economic attractiveness of renewable energy

In general, a combination of feed-in tariffs and investment grants help make renewable generation economically attractive. Small solar PV below 5 kW can apply for investment grants. These are attractive for household self-consumption because with the grant, the generation costs are comparable to retail electricity prices. In addition, the new incentive scheme aims to reduce the impact on consumer electricity bills through greater cost-sharing with energy-intensive industries. Overall, given Austria's commitment to promoting renewable energy deployment above conventional sources, renewable energy should remain economically attractive, supporting medium-term deployment.

Financing

Given strong Austrian policy commitment to renewable energy, considerable experience with hydropower and biomass technologies, the country's stable fiscal position, and a low cost of capital, the financing environment should remain supportive over the medium term.

Conclusions for renewable energy deployment: baseline case

With robust and dynamic policy support and strong consumer level preferences for renewable energy, deployment faces very few real barriers outside of grid capabilities. We expect renewable electricity capacity to expand by 4.9 GW over the medium term, from 18 GW in 2011 to 23 GW in 2017. With 2.1 GW of additional capacity expected, the outlook for bioenergy is the most robust. On the back of supportive feed-in tariffs and falling system prices, solar PV should grow by 0.9 GW, while onshore wind should increase by 1.1 GW from 2011-17.

Table 19 Austria renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	12.7	12.8	12.8	13.2	13.2	13.2	13.5	13.5
Bioenergy	3.4	3.9	4.3	4.6	4.9	5.2	5.6	6.0
Wind	1.0	1.1	1.4	1.6	1.7	1.9	2.0	2.2
Onshore	1.0	1.1	1.4	1.6	1.7	1.9	2.0	2.2
Offshore	-	-	-	-	-	-	-	-
Solar PV	0.1	0.2	0.3	0.5	0.6	0.8	0.9	1.1
Solar CSP	-	-	-	-	-	-	-	-
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**17.2**	**17.9**	**18.8**	**19.9**	**20.5**	**21.1**	**22.1**	**22.8**

Table 20 Austria main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Policy targets for renewable energy (RE) deployment combined with feed-in tariffs and investment grants. • Strong consumer support for RE development in lieu of nuclear power imports. • Good resources and economic attractiveness for bioenergy and hydropower.	• Continued need for domestic grid upgrades. • Network tariffs and limited opportunity for cross-border marketing for pumped storage hydropower. • Lengthy authorisation process for new power plants.

Renewable energy deployment under an enhanced case

Given the already favourable environment for renewable energy in Austria, the outlook for deployment looks similar under both baseline and enhanced cases. An enhanced case would see Austria increasing its balancing capabilities available to the region through increased pumped storage hydropower and less restriction on its cross-border marketing. Such an outcome could better facilitate regional balancing capabilities, though would largely not affect Austria's own deployment trajectory for renewable energy.

Denmark

With strong 2020 and 2050 targets, Denmark's renewable power is expected to grow rapidly. Supply chain bottlenecks for offshore wind are the biggest uncertainty over the medium term.

Table 21 Denmark renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	0.0	0.1%	0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Bioenergy	3.2	8.9%	4.2	12.1%	5.2	5.7	6.5	7.2	8.0	8.3
Wind	6.6	18.2%	9.8	28.0%	9.7	10.6	11.6	12.1	13.0	13.6
Onshore	5.9	16.2%	6.8	19.4%	6.7	6.9	7.1	7.4	7.6	7.8
Offshore	0.7	2.1%	3.0	8.6%	3.0	3.7	4.4	4.8	5.5	5.8
Solar PV	0.0	0.0%	0.0	0.0%	0.0	0.0	0.0	0.1	0.1	0.1
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**9.9**	**27.3%**	**14.0**	**40.1%**	**14.9**	**16.4**	**18.1**	**19.4**	**21.1**	**22.0**

Power demand outlook

Denmark's GDP is projected to grow by 1.5% annually from 2011-17. Power demand has fallen since 2006, decreasing by almost 5% from 2008-09. In 2011, demand stood at 35.9 TWh, still below pre-economic crisis levels. Danish retail power prices, the highest in the Nordic power market, have risen steadily over the past decade. Their impact has been felt more by households than by industry, due to a heavier tax burden. As a mature economy with energy efficiency measures, high electricity prices and moderate economic growth, we expect demand in Denmark to increase modestly, from 35.9 TWh in 2011 to 37.7 TWh in 2017 (+0.8% annually).

Figure 20 Denmark power demand versus GDP growth

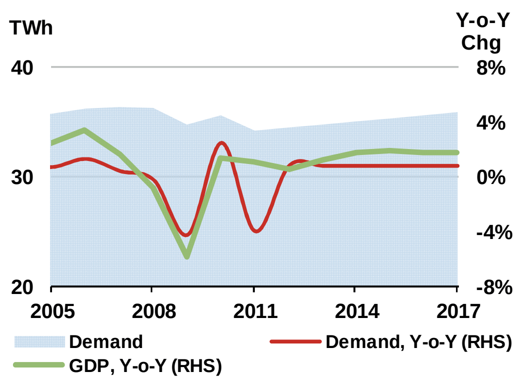
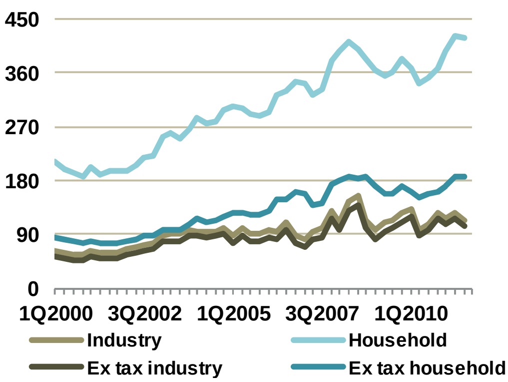


Figure 21 Denmark average retail power prices (USD per MWh)

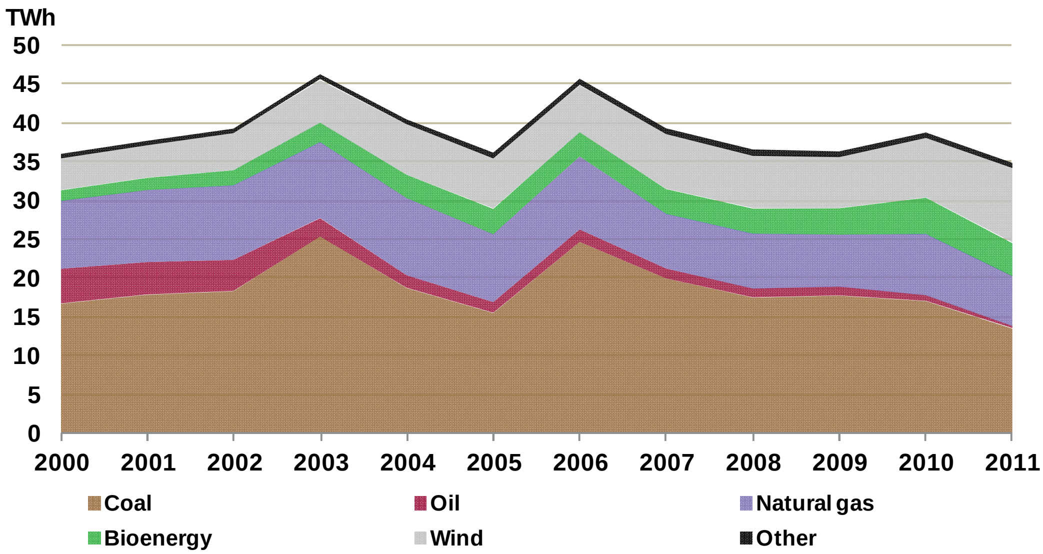


Power sector structure

Generation and capacity

Danish power generation has largely stemmed from fossil fuel sources (almost 60% of electricity in 2011) with no nuclear production. However, renewable energy has accounted for an increasing share. In 2011, it represented 40% of power production (up from 30% in 2009), with 28% of total generation from combined onshore and offshore wind (up from 18% in 2009) and 12% from bioenergy. Notably, bioenergy power generation occurs largely through co-generation plants. In 2010, Denmark's total power capacity stood at 13.7 GW, with peak load of 7.3 GW.

Figure 22 Denmark power generation by source



With a government commitment to a 100% renewable-based energy system by 2050 and 100% renewable power and heat production by 2035, the share of renewable electricity will continue to rise over the medium term. In 2020, Denmark expects wind and bioenergy to account for 50% and 20%, respectively, of electricity generation with fossil fuels down to 30%. Denmark's status as either electricity importer or exporter changes from year to year and depends partly on the prevailing wind resource availability. Moreover, Denmark continues to move towards an energy system that is increasingly electrified while pursuing efforts to use renewable sources for heating and in the transport sector.

Denmark's wind deployment should act as a key variable in power sector development over the medium term. The country's commitment to wind energy is long-standing, with commercial installations and associated industry dating back to the 1970s. Wind's large role in the system means that surplus production can occur at times of low demand and high wind speeds, typically at night. During periods of low temperatures, the running of co-generation plants to provide heat can further exacerbate the electricity surplus. However, the surplus electricity can be sent through interconnections to other countries, typically Norway, where it is used in pumped storage. Moreover, co-generation plants, benefiting from a reduction of taxes on electricity used for heat, have begun using this excess electricity to heat district heating water.

Solid biomass, and increasingly biogas, should also play a key role in renewable energy growth going forward. There will likely be increases in bioenergy-based power generation, alongside higher direct use for industry and residential applications and in transport. Wastes, both renewable and non-renewable, are already employed in a large number of co-generation plants – Denmark will likely remain a leader in such usage going forward.

Although capacity has remained low relative to the size of the power sector, Denmark has recently experienced a mini boom in solar installations. From 1 January to 10 May 2012, installed capacity tripled from 12 MW to 35 MW. This acceleration, ongoing at the time of writing, stems from price declines in solar PV systems and a new tax credit for PV systems. These incentives reinforced the existing net-metering system remuneration (EUR 0.27 per kilowatt hour [kWh]) for small-scale installations.

Grid and system integration

As the country with the largest penetration of variable renewable energy in the world and with this share increasing over the medium term, Denmark's system has evolved to confront the balancing challenge. The country's small size and robust interconnections with Norway, which is well endowed with balancing capabilities, have enabled Denmark's exclusive development success. Going forward, these characteristics will continue to facilitate renewable energy deployment. However, increasing Denmark's own balancing abilities through more biogas-to-power or heat storage could yield a more flexible and secure system.

Table 22 Denmark main targets and support policies for renewable electricity

Targets	Financial support	Other support
Danish 2020 Energy Agreement: Target of 100% energy from renewable sources by 2050. 100% of electricity from renewable sources by 2035. 50% of electricity from wind by 2020. **National Renewable Energy Action Plan (largely superseded by 2020 Energy Agreement):** Binding target: 30% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 51.9% of electricity production from renewable sources provided by: 10 MW hydropower 6 MW solar PV 2.6 GW wind onshore 1.3 GW wind offshore 2.8 GW bioenergy	**Feed-in premiums:** 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 kW) and ocean technologies. Offshore wind is tendered but is also guaranteed specific premiums. **Net metering:** All renewable sources, except geothermal, are eligible for net metering. For solar PV net metering on an annual basis applies to residential PV systems (<6 kW) and non-commercial buildings (<6 kW per 100 square metres [m^2]). **Tax credits:** Investments in renewable energy in private homes can receive a 25% deduction on income taxes.	**Framework policy:** Our Future Energy (Danish 2050 energy strategy) The Green Growth Agreement Carbon Tax **Grid access and dispatch priority:** No grid access priority but RE electricity is given priority dispatch over conventional generation when grid capacity is insufficient.

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

Denmark's grid and interconnections act as important enablers for renewable energy deployment. Moreover, grid expansion over the medium term is focused on integrating larger amounts of variable renewable energy into the system. A new 400-kilovolt (kV) circuit, expected by 2014 from north to south (Tjele to Kassø), will provide an enhanced national backbone and increased net transfer capacity to Germany and Norway (see Map 3). In addition, a fourth link to Norway through Skagerrak 4 (700 MW) is scheduled to be commissioned in 2014. The COBRA cable (600 MW to 700 MW) to the Netherlands is under consideration, but no investment decision has been taken yet.

Current policy environment for renewable energy

Denmark has a strong renewable energy policy framework. In early 2012, a 2020 Energy Agreement was formed with wide support across Denmark's political parties. The targets largely supersede those already present in Denmark's National Renewable Energy Action Plan, with an ambitious goal of 100% electricity from renewable sources by 2035 and 50% of electricity from wind by 2020.

Economic attractiveness of renewable energy

Given Denmark's commitment to promoting renewable energy deployment above conventional sources, renewable energy looks economically attractive over the medium term. Overall, so long as the policy environment remains stable, any disadvantageous competitive position of renewable energy versus fossil fuels should not act as a major barrier to deployment. In addition, the Danish government is making a targeted effort to improve the economic viability of biogas.

With respect to offshore wind generation, the costs will likely continue to exceed wholesale power prices. In previous offshore wind tenders, the power purchase price for Horns Rev II (200 MW) was fixed at USD 87.8 per MWh (DKK 510 per MWh) for 10 TWh electricity generation, while Rødsand II (200 MW) ended at a tariff of USD 106.6 per MWh (DKK 629 per MWh) for 10 TWh. Most recently the tender for the Anholt Offshore wind farm (400 MW) contracted for USD 178.1 per MWh (DKK 1 051 per MWh) for 20 TWh of electricity generation. However, offshore generation benefits from several premiums above the fixed prices. New offshore wind turbines receive a premium of USD 42.4 per MWh (DKK 250 per MWh) for 22 000 full-load hours. An additional USD 3.9 per MWh (DKK 23 per MWh) is provided for the turbine lifetime to compensate for the cost of balancing.

Financing

Given strong Danish policy commitment to renewable energy, considerable experience with wind and biomass technologies, the country's stable fiscal position, and a low cost of capital, the financing environment should remain supportive over the medium term. In addition, Danish pension funds have started to invest directly in offshore wind projects, providing another source of financing in an otherwise challenging overall market for risk capital.

Conclusions for renewable energy deployment: baseline case

We expect renewable electricity capacity to expand by 2.5 GW over the medium term, from 5.1 GW in 2011 to 7.6 GW in 2017. With 1.0 GW of additional capacity expected, the outlook for bioenergy is the most robust. With around 0.6 GW to 0.8 GW of increased capacity expected for each category, the additions for onshore and offshore wind are strong. Notably, offshore wind should be boosted by the addition of the 400 MW Anholt farm, expected on line by 2014. Solar PV should make a smaller growth contribution of 0.1 GW. Additions from remaining renewable energy sources look negligible.

Table 23 Denmark renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bioenergy	1.2	1.3	1.4	1.6	1.8	2.0	2.2	2.2
Wind	3.8	3.9	4.0	4.5	4.6	4.9	5.2	5.3
Onshore	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6
Offshore	0.9	0.9	0.9	1.3	1.3	1.5	1.7	1.7
Solar PV	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Solar CSP	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**5.0**	**5.1**	**5.4**	**6.1**	**6.4**	**6.9**	**7.4**	**7.6**

Table 24 Denmark main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Clear long-term energy strategy up to 2050 combined with attractive economic incentives. • Excellent resource availability and long-standing wind and bioenergy deployment experience. • Good interconnections with neighbouring countries to provide system balancing.	• Continued need to develop domestic balancing resources. • 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 biogas or heat storage. As such, there is potential upside for biomass of 0.5 GW in 2017 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 we could expect potential upside to offshore wind capacity in 2017, about 0.6 GW higher compared with 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.

Table 25 France renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	56.5	9.8%	50.2	8.9%	63.5	64.1	64.8	65.4	66.0	66.6
Bioenergy	3.4	0.6%	4.9	0.9%	5.5	6.3	7.1	7.9	8.8	9.6
Wind	1.0	0.2%	12.2	2.2%	13.9	15.5	17.4	19.6	23.0	28.3
Onshore	1.0	0.2%	12.2	2.2%	13.9	15.5	17.4	19.6	22.1	24.8
Offshore	-	0.0%	-	0.0%	-	-	-	-	0.9	3.5
Solar PV	0.0	0.0%	2.0	0.4%	4.2	5.1	5.7	6.3	7.0	7.6
Solar CSP	-	0.0%	-	0.0%	-	0.0	0.0	0.1	0.1	0.2
Geothermal	-	0.0%	-	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Ocean	0.5	0.1%	0.5	0.1%	0.5	0.5	0.5	0.5	0.5	0.5
Total RES-E	**61.3**	**10.6%**	**69.8**	**12.4%**	**87.6**	**91.6**	**95.5**	**99.9**	**105.3**	**112.8**

Power demand outlook

From 2011-17, France's GDP is expected to grow by 1.5% annually, with higher growth during the second half of the period versus the first half. Over the past decade French power demand has risen steadily, by 1.0% on average annually from 2000-10. Low power prices relative to most other European countries have supported this profile. But a large part of this rise stems from ongoing structural changes in France's heating sector, with electric heaters substituting for oil-fired units. Over the medium term, power demand should grow moderately, by 0.9% on average from 2011-17.

Figure 23 France power demand versus GDP growth

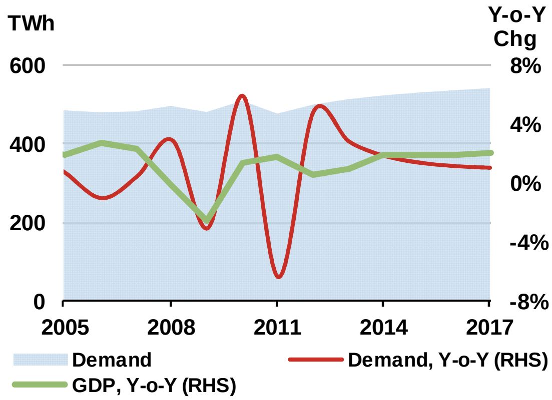
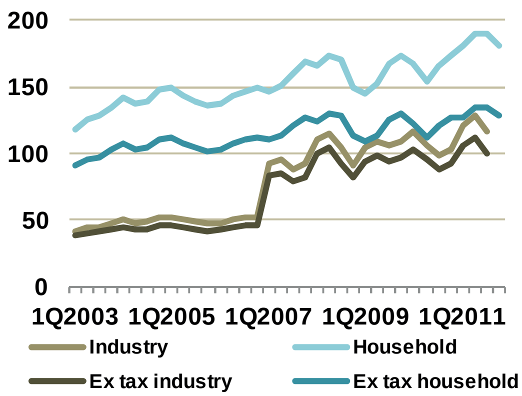


Figure 24 France average retail power prices (USD per MWh)



Power sector structure

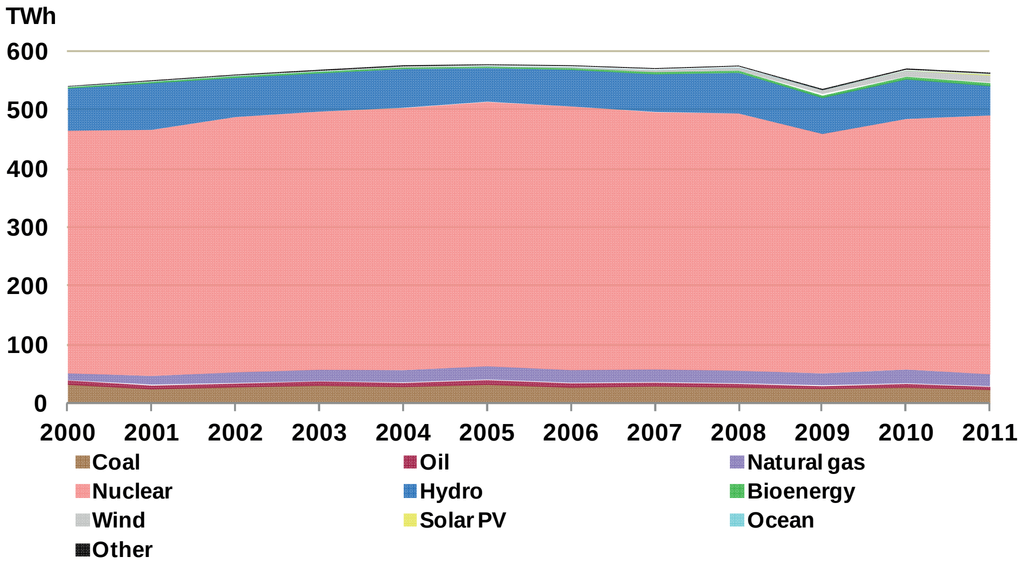
Generation and capacity

Nuclear power largely dominates French electricity generation. In 2011, it accounted for 79% of output, followed by hydropower (9%), which had a particularly weak output year. Power production from natural gas (4% share in 2011) has increased in recent years while coal output has moderately declined. Renewable energy accounted for 12% of production in 2011. Wind, biomass and solar generation have all grown rapidly for the past decade. Nevertheless, their shares of electricity have remained small, at 2.2%, 0.9% and 0.4%, respectively, in 2011. Notably, France has the world's second-largest ocean-powered generating station, a 240 MW tidal barrage facility operating for over 45 years.

In 2010, power sector capacity stood at 124 GW. Peak load in 2009 was at 92 GW, but reached almost 102 GW in February 2012. France's position as an electricity net exporter, typically exporting base-load power and importing at peak times, has narrowed in recent years. Increased consumption combined with augmented peak load has raised domestic peaking requirements, particularly during the winter evenings. According to industry sources, a drop in temperature of 1°C can translate into 2.3 GW of additional demand during winter evenings. Meeting an increased winter peak load will challenge the French system going forward, with a need to add new capacity or to augment interconnections to facilitate more imports.

At the same time, France's nuclear and coal base-load power plants are aging. Some 19.8 GW of nuclear capacity has less than ten years left under current 40-year lifetime rules. Based on announcements from the new French administration that took office in May, it is expected that the Fessenheim nuclear power plant will close over the medium term. Still, it remains to be seen how the lifetimes of other nuclear power plants may be addressed over the medium to long term.

Figure 25 France power generation by source



The structure of France's power system presents challenges to renewable deployment. In general, the system is strongly oriented towards a single form of electricity generation. Despite liberalisation of the generation sector, competition is still limited, with the main generator and nuclear technology as incumbent entities constituting barriers to entry. As such, government policy will likely act as the primary determinant of renewable deployment over the medium term.

Grid and system integration

Overall, the French grid should not act as a significant bottleneck to renewable energy deployment in the medium term. In general, the grid has well-developed domestic transmission and relatively strong interconnections with neighbouring countries. Connections with Spain have, to date, remained relatively underdeveloped. However, they should be boosted with the 1.4 GW Inelfe interconnector coming on line in mid-2014. The transmission system operator RTE (a 100% publicly owned subsidiary of Electricité de France [EDF]) owns and operates 100% of the network and must provide non-discriminatory access to transmission networks to third parties. Renewable sources enjoy priority dispatch. Furthermore, a number of transmission and interconnection projects are under way to enhance grid capacity and performance.

Regarding offshore wind, the Energy Ministry has defined the first five offshore zones, which will facilitate the integration of volumes contracted through the government's tendering process. Of those, four zones have been recently awarded contracts for a total of 2 GW and a new tender is expected to be launched in the second half of 2012. Successful bids will need to bear the grid connection costs for their projects, but a pre-allocation of transmission capacities by RTE should speed up the connection process.

Current policy environment for renewable energy

France's policy environment generally gives support to renewable energy deployment. The country has fixed 2020 targets and established them through both the *Grenelle de l'environnement* law and the *Planification Pluriannuelle des Investissements*, the national plan that sets targets for emerging technologies. Incentives are provided through a feed-in tariff scheme and a government tendering process; the latter applies only to larger-scale renewable plants. There is also a set of targets communicated in the National Renewable Energy Action Plan (NREAP) in support of the European Union's Renewable Energy Directive. While they converge in 2020, the Grenelle plan puts deployment on a more ambitious pace in the medium term. The NREAP, by contrast, delays deployment in order to take advantage of anticipated reductions in technology costs.

In 2010, very generous feed-in tariffs for solar PV, not aligned to the reductions registered in the real costs of the installations, boosted the request for authorisations to install solar PV capacity well beyond the 2020 target. The government dampened these stronger-than-anticipated expansions through moratoriums and caps. It suspended the registration of solar PV projects above 3 kW for three months in December 2010 to control costs arising from strong capacity growth. It then imposed a cap of 500 MW per year on deployment under the auto-adjusting feed-in tariffs and new tendering processes, which will influence the size of the solar PV market over the medium term.

Table 26 France main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 23% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 27% of electricity production from renewable sources provided by: 28.3 GW hydropower 80 MW geothermal 4.9 GW solar PV 540 MW CSP 380 MW ocean 19 GW wind onshore 6 GW wind offshore 3 GW bioenergy Under *Planification Plurianuelle des Investissements*, target is higher for solar PV (5.4 GW).	**Feed-in tariffs:** Apply to onshore wind, offshore wind, geothermal, solar PV under 100 kW, bioenergy, hydropower, marine **Tenders:** Offshore wind, solar PV above 100 kW, bioenergy above 12 MW, hydropower **Flexible depreciation:** Industrial companies investing in renewable energy projects have the opportunity to apply for accelerated depreciation of their investments (100% in one year).	**Framework policy:** *Le Grenelle de l'Environnement* *Planification Plurianuelle des Investissements* Energy Law **Grid access and priority dispatch:** Grid connection provided to all generators on a non-discriminatory 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/.

In addition, wind power faces particular non-economic barriers for both on- and offshore projects. Procedures to obtain construction permits grew more complex in 2008-09. Projects face administrative requirements at multiple government levels, which tend to lengthen the process of development and increase opportunities for legal challenges based on local opposition.

The offshore wind tendering process may result in delays compared to NREAP planning. Tenders for the first 3 GW were delayed and just took place in 2011, and finally only 2 GW of projects were awarded. The first offshore turbines are not expected to be up and running until 2015.

Economic attractiveness of renewable energy

In France, wholesale electricity prices are low and generation costs for existing nuclear plants are even lower. However, estimated costs for an under-construction new nuclear plant, the Flamanville EPR, range from EUR 70 to EUR 90 per MWh (Cour des Comptes, 2012). From an economic perspective, non-hydropower renewable energy development generally looks attractive within the deployment limits of available incentive schemes. Deployment will largely rely on the presence of feed-in tariffs or contracts offered through tendering processes. Without financial incentives, onshore wind production costs are near those of new-build gas, while offshore wind remains more expensive. Notably, France's large, robust agricultural sector (and availability of associated waste) provides a boost to biomass economics, with deployment potential particularly good in this area. Overall, given deployment to date of renewable power sources in France, the cost impact of the feed-in tariff scheme, which is ultimately paid by consumers through their electricity bills, has been limited. Finally, it is worth noting that activity has occurred outside of these incentive schemes, with a first power purchase agreement recently signed in solar PV in Poitou-Charentes.

Financing

France will face a moderate challenge in financing renewable energy deployment over the medium term. Despite the presence of financial incentives and renewable project auctions, non-economic barriers to onshore wind projects and heavy barriers to entry into the power generation market could discourage would-be private investors. Given tightened availability of project finance in Europe, France's relatively less-favourable renewable energy environment for large projects (in comparison with other large European or emerging markets) could result in higher costs of capital or reduced liquidity from private sources.

Development will still benefit from the balance sheet of EDF, which with 85% ownership by the French state would qualify as a quasi-public source of funds. Notably, the utility, in a partnership with the Danish utility DONG, was awarded three of four contracts to develop France's first offshore wind farms. Projects should also benefit from other public funds, recently illustrated by the involvement of the Marguerite fund (backed by the European Investment Bank and Germany's KfW) in financing France's largest solar project.

Conclusions for renewable energy deployment: baseline case

We expect renewable energy capacity growth of 15 GW from 2011-17. A combination of tendering schemes and attractive project opportunities should cause capacity to grow by 6.8 GW in onshore wind. Solar PV should increase by 3.5 GW. The outlooks for other sectors are relatively tepid with growth in hydropower and bioenergy at 1.5 GW and 1.4 GW, respectively. In offshore wind, France delayed its second 3 GW tender, and at the same time awarded only 2 GW of projects in the first 3 GW tender. These contracted projects need to go through feasibility studies, due by the end of 2013, with construction starting by 2015. Under this assumption, France could have maximum 2 GW of capacity online by 2017. However, given potential for delays, only 1.5 GW are forecast.

The overall renewable electricity forecast results, except for offshore wind, are largely consistent with the French government's targets. However, with a new administration recently taking power, there is a great deal of policy uncertainty going forward, both in respect to renewable energy and conventional power generation developments. To date, France has conformed favourably to several best-practice renewable energy policy principles with a predictable framework and a dynamic approach by the government. System integration issues are being addressed, though balancing challenges may appear over the medium term as variable renewable output increases.

However, sizeable barriers exist to renewable energy deployment. Some limits to deployment pertain to less tangible elements. Long-running experience and reliance on nuclear power combined with a centralised power system tend to make entry – from a technical, institutional and cultural standpoint – difficult for new technologies. Moreover, in France the relatively higher cost of renewable sources compared with current wholesale prices reinforces their still-weak position in the public discourse relative to incumbent, conventional options.

Table 27 France renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	25.2	26.1	26.3	26.6	26.8	27.1	27.3	27.6
Bioenergy	1.4	1.6	1.7	1.9	2.2	2.4	2.7	2.9
Wind	6.0	6.8	7.6	8.5	9.6	10.8	12.6	15.1
Onshore	6.0	6.8	7.6	8.5	9.6	10.8	12.1	13.6
Offshore	-	-	-	-	-	-	0.5	1.5
Solar PV	1.1	2.7	3.7	4.2	4.7	5.2	5.7	6.2
Solar CSP	-	-	-	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	**33.9**	**37.3**	**39.5**	**41.4**	**43.5**	**45.7**	**48.6**	**52.1**

Table 28 France main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Policy environment backed by targets, feed-in tariffs and priority dispatch for RE. • Need to meet increased peak demand and potential retiring of some nuclear capacity. • 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. • Significant non-economic barriers. • Renewable generation more costly than low prevailing wholesale prices.

Renewable energy deployment under an enhanced case

Given growing electricity demand, particularly peak demand, and France's remaining renewable potential, good drivers exist for a stronger-than-anticipated deployment of renewable sources. This could come about from the simplification of administrative procedures and shorter lead times associated with obtaining construction permits for wind projects. Moreover, the flexibility of the electricity sector could be improved, by further development of pumped hydro, for example, which would also smooth renewable development.

Specifically, bioenergy, wind (both onshore and offshore) and solar PV, capacity could be higher in 2017 versus the baseline case. Bioenergy capacity in 2017 could be slightly higher, at around 3.5 GW. Onshore wind capacity could be 3 GW higher in 2017 versus the baseline case. Meanwhile, the upside for offshore wind looks limited, given lead times, with 2 GW representing the maximum expected installed capacity by 2017. The outlook for solar PV remains the most uncertain, but has the largest upside, with the potential for cumulative installed capacity to top 10 GW in 2017 under stronger deployment conditions.

Germany

Onshore and offshore wind should increase strongly, though grid connection delays will weigh on the latter. Assuming lower feed-in tariffs, solar PV growth should consolidate at lower levels.

Table 29 Germany renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	26.7	4.3%	24.6	4.0%	28.6	28.6	28.7	28.8	28.9	28.9
Bioenergy	13.5	2.2%	36.9	6.0%	35.4	36.8	38.2	39.4	40.7	41.9
Wind	27.2	4.4%	46.5	7.6%	53.1	57.6	61.3	63.5	67.4	72.5
Onshore	27.2	4.4%	46.0	7.5%	52.1	54.5	56.4	58.2	59.6	60.6
Offshore	-	0.0%	0.5	0.1%	1.1	3.1	4.8	5.4	7.8	11.9
Solar PV	1.3	0.2%	18.6	3.0%	26.6	30.1	32.9	35.8	38.6	41.5
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	0.1	0.1	0.2	0.2	0.2
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**68.8**	**11.1%**	**126.6**	**20.6%**	**143.7**	**153.3**	**161.2**	**167.7**	**175.8**	**185.1**

Power demand outlook

Germany has seen robust growth despite economic moderation in the rest of the European Union. Its GDP is projected to grow on average by 1.2% per annum from 2011-17. Power demand is expected to increase by a modest 0.6% annually from 2011-17. Retail power prices, with data available for households since 2007, have generally risen over the past five years. However, we expect that renewable energy deployment will occur largely independently of power demand trends over the medium term, with strong deployment combined with the priority dispatch status of renewable electricity pushing other sources out of the generation mix.

Figure 26 Germany power demand versus GDP growth

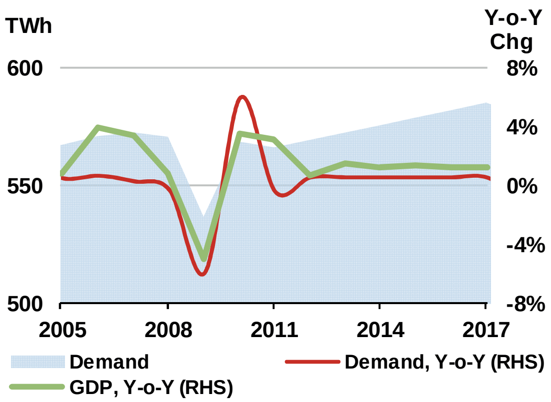
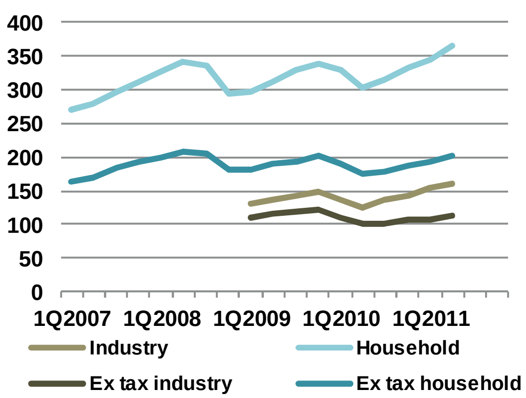


Figure 27 Germany average retail power prices (USD per MWh)



Note: Industry prices are available only after 2009.

Power sector structure

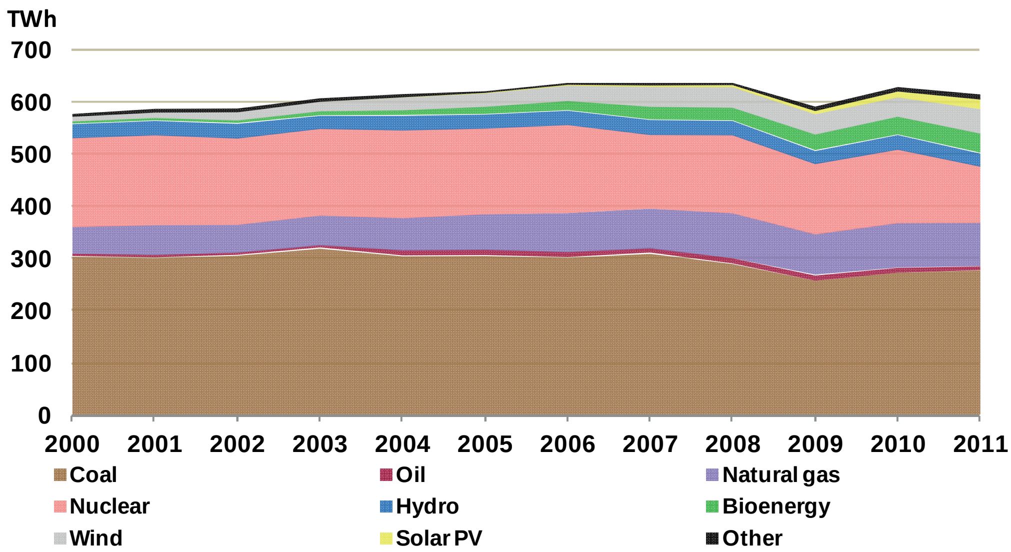
Generation and capacity

Fossil fuels have traditionally dominated the German power system, but renewable energy is making significant inroads. In 2011, fossil fuels accounted for 62% of generation, with renewable power at

21%, up from 11% in 2005. The share of nuclear power, at 18%, dropped significantly compared with its 23% level in 2010, falling below renewable electricity for the first time in the past decades. In 2010, Germany's total power sector capacity stood at 157 GW.

Following the earthquake and tsunami that struck Japan in March 2011, the German government decided to immediately halt the generation of the country's oldest nuclear plants, with over 8 GW (eight facilities) closed. In the months thereafter, the lifetime extensions of the country's other nuclear power plants, which had been decided only some six months before, were retracted. The process of total nuclear phase-out (decided originally in year 2000) is now occurring at an accelerated pace, with the last power plant due to shut down by 2022.

Figure 28 Germany power generation by source

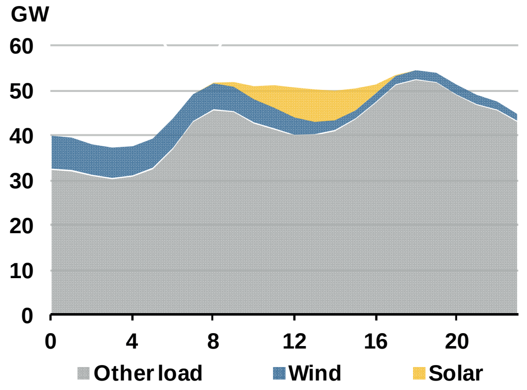


Renewable generation

The growing role of renewable sources in the power generation mix is reflected by recent capacity additions. In 2011, onshore wind accounted for 8% of total generation and capacity rose by 1.8 GW. Solar PV installations saw another record year, with 7.5 GW of new capacity bringing cumulative capacity to near 25 GW. In 2011, Germany maintained its overall power net export position, though volumes dropped from 17 TWh in 2010 to 5 TWh. During a Europe-wide severe cold snap in February 2012, Germany remained a net exporter, with solar PV compensating for lost nuclear during peak-demand midday periods in France. In addition, wind power contributed to peak demand in the evening.

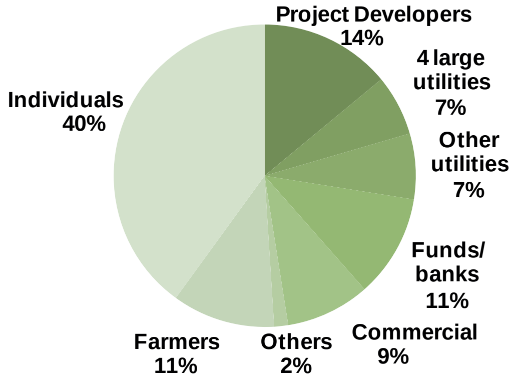
Going forward, the power system must continue to compensate for lost nuclear capacity and the decommissioning of conventional power plants. To this end, the government is seeking to speed deployment of renewable sources, particularly offshore wind. Government plans also envisage expansions in fossil fuel-fired capacity, in particular some 10 GW of flexible conventional generation to facilitate the system integration of fluctuating renewable sources. Support to co-generation has been extended past 2016, and further energy efficiency measures have also been adopted.

Figure 29 Germany load curve on 8 Feb 2012



Source: IEA analysis based on data from ENTSO-E.

Figure 30 Germany ownership shares of renewable generation, Oct 2011



Source: BMU (2011a).

Grid and system integration

The German very-high-voltage grid is split among four TSOs, which were unbundled from their respective generation companies in 2005. Since 2006, the Federal Network Agency (Bundesnetzagentur) has been the national regulator. Grid expansions are not paid by the TSOs directly; rather they are funded through a regulated additional tariff that is paid by all electricity consumers. The costs for grid reinforcement and development are strictly controlled through the incentive regulation (Anreizregulierung). Investment budgets have to be permitted by the Federal Network Agency.

So far, the German grid has not acted as a significant bottleneck to renewable energy deployment, but challenges may increase with respect to wind and solar deployment. The relative weakness of the grid in northern Germany is impacting upon wind. Curtailment of generation for grid stability reasons has emerged as an issue for onshore wind power. In 2010, between 0.2% and 0.4% of total wind generation was curtailed, largely due to overloads at medium voltage level lines and substations (110 kV, where most wind is connected to in Germany). This phenomenon may increase over time as wind penetration rises, in particular because 2010 was a mild wind year.

Moreover, timely grid connections for offshore wind power are proving particularly difficult. Over the past year, TenneT – the TSO responsible for offshore grid installations in the North Sea – has announced connection delays for several projects due to lack of financing and labour resources and supply bottlenecks for high-voltage direct current (HVDC) hardware and sea cables. It has proposed measures (including the creation of a direct-current grid operator) that could facilitate planning and assist in making the large amount of capital more easily available.

Another grid and system integration issue relates to the mismatch between wind installation density in the north (Lower Saxony) – particularly for offshore – and east (Saxony Anhalt) and the load centres in the west and south, combined with insufficient internal connection among the four supply areas in Germany. The phase-out of nuclear power will further exacerbate this mismatch as nuclear capacity has been largely located in the south of Germany. However, the ascendancy of solar power, largely situated in the south, and good interconnections with pumped hydro storage in Austria, partly compensates for this discrepancy.

In solar PV, given high deployment rates and ownership dominated by smaller, non-traditional 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 Renewable Energy Sources Act, all new PV plants must install the technical equipment to allow for curtailment if needed. The only exceptions are small solar PV installations (sized 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. Aligning incentives for the different stakeholders (distribution system operators [DSOs], generators) will be important to ensure that deployment is not hindered.

Overall, the ambitious renewable plans of the government require grid developments. The National Grid Expansion Acceleration Act (NABEG) of 2011 has been adopted to simplify and accelerate permitting procedures of national and cross-border lines while ensuring a high level of public participation. Moreover, a new grid planning process has been introduced, with a ten-year national grid development plan defining the need for new transport lines and considering new technologies to be drafted by the TSOs and adopted by the Federal Network Agency.

Current policy environment for renewable energy

Germany's policy framework for renewable energy deployment is generally strong, underpinned by a stable set of feed-in tariffs. Federal targets – codified in the NREAP and Renewable Energy Sources Act (EEG) – conform to European Union 2020 targets, but the government's renewable energy planning spans a longer time horizon to 2050 and is integrated within its larger industry strategy. Public education on the benefits of renewable energy has further reinforced these efforts, facilitating high deployment levels despite the increased costs borne by the ratepayers.

Table 30 Germany main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 18% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 38.6% of electricity production from renewable sources provided by: 4.3 GW hydropower 0.3 GW geothermal 51.7 GW solar PV 35.8 GW wind onshore 10 GW wind offshore 8.8 GW bioenergy **Energy Concept 2010:** 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.	**Feed-in tariffs:** Established in EEG. Apply to small hydropower, geothermal, bioenergy, solar PV, and wind onshore and offshore. **KfW Offshore Wind Energy Programme:** Promotional funds for offshore projects, up to 70% of debt capital required, not more than EUR 700 million per project. **KfW Renewable Energies Programme:** 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:** Energy Change (Energiewende) Renewable Energy Sources Act (EEG) Grid Expansion Acceleration Act (NABEG) Combined Heat and Power Act **Grid access and priority dispatch:** 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/.

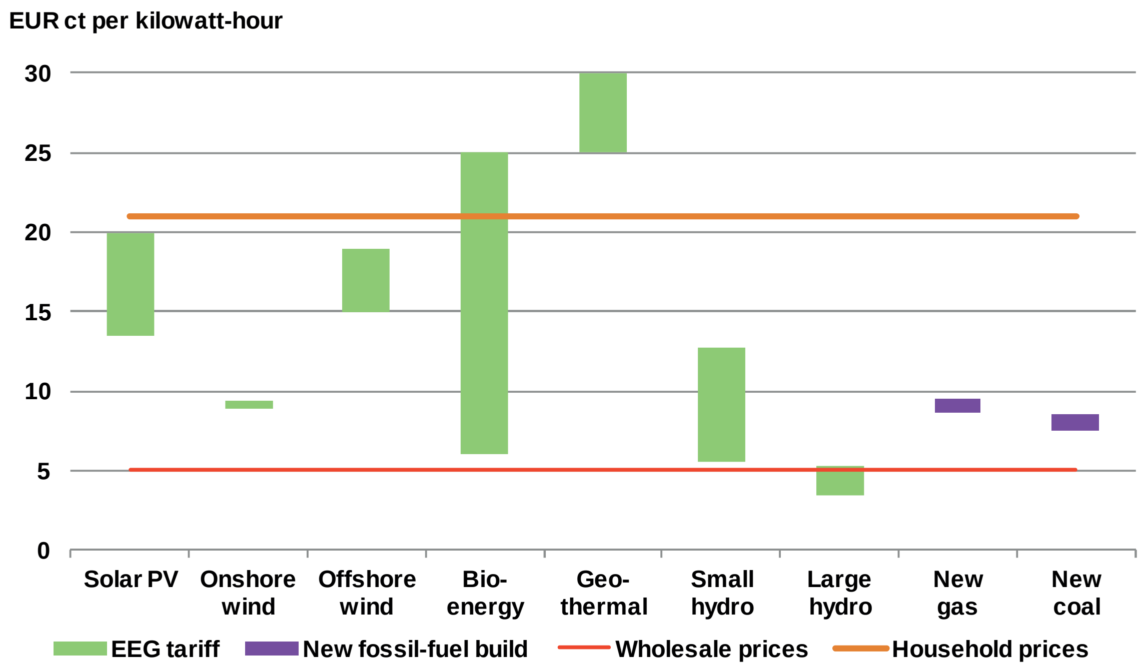
Since the return to the nuclear phase-out schedule in 2011, the government has placed even more emphasis on rapid renewable energy deployment. On one hand, authorities would like to speed up the process of offshore wind deployment. Germany aims to reach total capacity of 10 GW by 2020 using a set of adjusted incentives and accelerated planning procedures as well as a dynamic response to emerging issues (such as a risk-sharing mechanism for grid connection delays).

On the other hand, authorities have recognised that recent growth in solar PV was too rapid, moving out of line with both the 2020 NREAP indicative target of 52 GW and overall energy system planning. Feed-in tariffs were not adjusted as fast as falling system prices, leading to excess returns on solar investments and deployment. The government recently proposed the tightening of solar PV incentives (effective as of April 2012, subsidies were to be cut by 20% to 30% depending on installation size) and the reduction of the time between tariff adjustments to one month, from six months previously. Before the new tariffs were slated to take effect, the anticipated large one-off cuts led to a boom of installations, with 1.9 GW deployed in the first quarter of 2012.

As of early June 2012, the proposed tariff cuts have still not been implemented. The German parliament's upper house has raised objection to the measure and negotiations are ongoing within the government. The projections in this report are based on the new tariffs that were to take effect in April. However, the final outcome over their precise levels remains highly uncertain, with the potential for the cuts in support to be smaller than assumed.

Economic attractiveness of renewable energy

Figure 31 Germany feed-in tariffs (2012), fossil-build costs (2012) and power prices (2011)



Notes: feed-in tariffs correspond to those in place as of January 2012, except for solar PV, which reflects changes proposed to take effect in April 2012. FIT ranges reflect initial tariffs where applicable and show tariff differences based on installation size/type. Average wholesale prices are shown at base load; average household prices are shown net of turnover tax.
Sources: IEA analysis based on data from BMU (2011b) and Bloomberg LP (2012).

Given the prevailing feed-in-tariff structure, renewable energy sources are attractive compared with conventional energy investments, as generators face no market risk and they can be sure to sell electricity even during a contraction of demand. Feed-in tariff levels for hydropower, bioenergy and onshore wind new development are broadly in line with costs of new coal and gas projects. Offshore wind remains relatively less competitive. Meanwhile, the tariffs for solar PV installations have dropped below the average electricity retail prices for households (*i.e.* retail grid parity is reached in Germany), if projects go ahead under the new tariff rates. A continued decrease in the price of solar panels and other system components (in particular mounting structures), both within Germany and globally, suggests that the costs of solar PV projects will continue to decline over the medium term.

However, increased renewable deployment and higher renewable energy tariff spending, which is funded through electricity bills, have raised concerns over the impact on consumers. In 2010, EEG payments (based on a surcharge of EUR 0.023 per KWh) represented almost 10% of consumer electricity bills, with the charge moving to EUR 0.0353 per KWh in 2011 and EUR 0.0359 per KWh in 2012. Nevertheless, the overall impact of deployment on prices remains complex, particularly with high shares of variable renewable energy decreasing wholesale market prices in periods of high insolation or wind levels, reflecting merit-order effects.

Financing

In general, Germany's financing environment supports renewable energy deployment. A mixture of public and private entities has increasingly directed capital to projects in recent years. In 2011, renewable energy investments in Germany totalled USD 31.9 billion (EUR 22.9 billion), an amount that trailed only China and the United States. German renewable energy projects enjoy a relatively low cost of capital compared with other countries.

Availability of debt capital remains a barrier, particularly for offshore wind, although it is likely to slow rather than stall growth. Germany should retain several financial advantages over the medium term. First, KfW – the German reconstruction and development bank, which set up a EUR 5 billion loan program for offshore wind in 2011 – continues to expand its offerings of low-interest direct loans for renewable energy projects. Second, the involvement of another state-backed fund, the European Investment Bank, has reinforced efforts in financing offshore wind. Finally, Germany's stable regime of feed-in tariffs helps reduce project finance risks, potentially making entry attractive for other institutional investors. This effectiveness is illustrated by the fact that 88% of renewable energy investments in 2011 stemmed from power generation installations qualifying for assistance under the EEG.

Conclusions for renewable energy deployment: baseline case

Germany's robust policy environment and increasingly favourable renewable economics should sustain strong renewable growth from 2011-17. Overall, renewable electricity capacity is forecast to expand by 31.6 GW over the medium term, from 70.9 GW in 2011 to 102.5 GW in 2017. Among different technologies, the outlook for solar PV looks the most robust, with 20.0 GW of additional capacity. Notably, this projection assumes the tariff levels proposed by the government that were to take effect from April 2012. If negotiations result in a tariff that is higher than assumed, solar PV deployment could be higher. Onshore and offshore wind should make growth contributions of 6.0 GW and 3.8 GW, respectively, with the latter representing a more uncertain forecast variable. Bioenergy should grow by 1.6 GW. Additions from remaining renewable energy sources look relatively small, however.

Overall, Germany conforms favourably to best-practice renewable energy policy principles, which act as a large support to deployment. The country maintains a predictable policy framework that is integrated into the overall energy strategy and offers a portfolio of incentives based on technology and market maturity. Recent downward adjustments to solar PV tariffs demonstrate dynamism to this approach based on prevailing market trends. Germany has been effective in reducing non-economic barriers to renewable deployment. Nevertheless, grid and system integration issues will remain a hurdle for additions going forward.

Table 31 Germany renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	11.0	10.6	10.6	10.6	10.6	10.7	10.7	10.7
Bioenergy	6.4	6.6	6.9	7.2	7.5	7.7	8.0	8.2
Wind	27.2	29.1	31.0	33.1	34.1	35.3	37.2	38.8
Onshore	27.1	28.9	30.6	31.7	32.8	33.6	34.4	34.8
Offshore	0.1	0.2	0.4	1.4	1.4	1.7	2.8	4.0
Solar PV	17.2	24.7	29.7	32.7	35.7	38.7	41.7	44.7
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	0.1	0.1	0.1	0.1
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**61.8**	**70.9**	**78.2**	**83.6**	**88.0**	**92.4**	**97.6**	**102.5**

With strong government commitment to offshore wind, its deployment potential looks robust in the long term. Authorities also support the development of German industry in this sector. Globally, offshore wind turbines are, for the moment, produced by only very few manufacturers with the potential for expansion. But the offshore forecast looks more uncertain over the medium term due to the potential for project delays. An increasing number of technical and supply chain challenges are emerging for offshore wind projects, which will keep medium-term upside limited. Challenging weather during construction and availability of debt finance, sea cables, transport equipment and manpower may all act as bottlenecks. Moreover, grid connections may remain difficult.

On the whole, these forecast results are largely consistent with the German government's action plan. With a reduction in feed-in tariffs under the current policy framework solar PV deployment is seen slowing from recent rapid deployment rates (to include the first part of 2012 before the tariffs were due to take hold) to a more moderate 3 GW per year from 2013 onwards.

Table 32 Germany main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Robust policy environment backed by targets, feed-in tariffs and priority dispatch for RE. • Need to compensate for retiring nuclear capacity. • Falling prices for solar PV equipment. • Ample availability of low cost financing.	• Maintaining a dynamic approach to feed-in tariff adjustments. • Grid upgrades to accommodate increased wind and solar penetration, on both the transmission and distribution levels. • Technical and supply chain bottlenecks for offshore wind.

Renewable energy deployment under an enhanced case

With certain market enhancements, the outlook for renewable energy deployment could be higher overall. The largest upside potential lies within wind. Specifically, offshore wind capacity could reach 6.0 GW in 2017, 2 GW higher than in our baseline case and onshore wind could top 40 GW. This more optimistic outlook would require grid strengthening and improved interconnections to better integrate the output from wind. Specifically, it could arise with efforts by policy makers to enhance the planning and standardisation of offshore grid connections, helping to offset some of the costs borne by TSOs, and better internal connections among the four supply areas. An enhanced scenario would necessitate expansion of grid connections between the northern portion of Germany, where most new wind capacity is located, and the southern portion, where the bulk of demand and closed nuclear plants are situated. Moreover, it would require increased finance availability and an easing in the supply chain bottlenecks that are constricting offshore wind projects.

A potential enhanced case for solar PV reflects uncertainty over the implementation of tariff reductions in Germany. In the case where higher tariff levels than those assumed in the baseline case are agreed upon, solar PV deployment should also be larger. To this end, cumulative capacity in 2017 could be some 3 GW higher than under the baseline case.

Italy

Despite persistent government support and improving competitiveness for solar PV, rising financing costs and a weakening economy weigh upon the deployment outlook.

Table 33 Italy power generation by source (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	42.9	14.1%	48.2	16.1%	47.9	48.1	48.4	48.7	48.9	49.2
Bioenergy	4.7	1.5%	10.9	3.6%	11.0	11.9	12.9	13.8	14.7	15.6
Wind	2.3	0.8%	10.1	3.4%	12.2	13.1	14.0	15.0	16.1	17.2
Onshore	2.3	0.8%	10.1	3.4%	12.2	13.1	14.0	15.0	16.1	17.2
Offshore	-	0.0%	-	0.0%	-	-	-	-	-	-
Solar PV	0.0	0.0%	10.7	3.6%	19.3	20.9	22.8	25.3	28.1	31.4
Solar CSP	-	0.0%	-	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	5.3	1.8%	5.7	1.9%	5.8	5.8	5.8	5.8	5.8	5.8
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**55.3**	**18.2%**	**85.6**	**28.5%**	**96.2**	**99.9**	**103.9**	**108.7**	**113.7**	**119.3**

Power demand outlook

Italy's power demand increased steadily over the past decade, though it dipped by 5.7% in 2009 during the economic crisis. Despite a 3.2% rebound in 2010, demand still stands below pre-crisis levels. Retail electricity prices are high in Italy and have risen over the past decade. Unlike in many other OECD member countries, household and industry prices have largely converged with each other. Since 2007, electricity customers have been free to choose their supplier, but despite progressive changes competition has been limited. The International Monetary Fund (IMF) sees Italy's GDP growing by only 0.3% annually from 2011-17, with the economy shrinking over 2012-13. As such, medium-term power demand looks tepid, with 0.3% average annual growth and levels remaining below that of 2008 for the duration of the forecast.

Figure 32 Italy power demand versus GDP growth

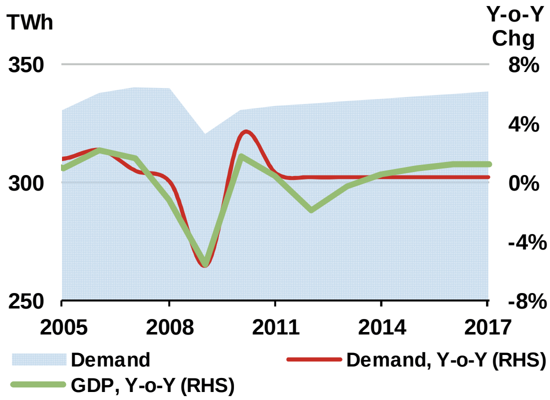
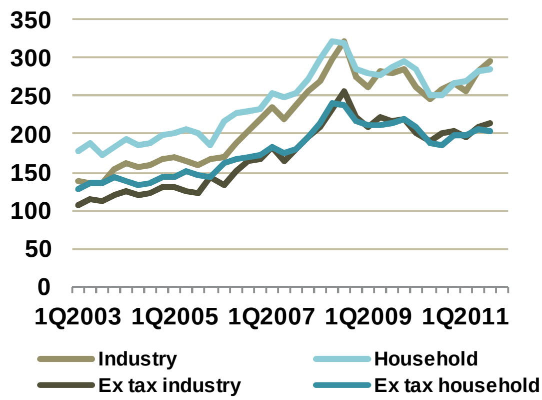


Figure 33 Italy average retail power prices (USD per MWh)

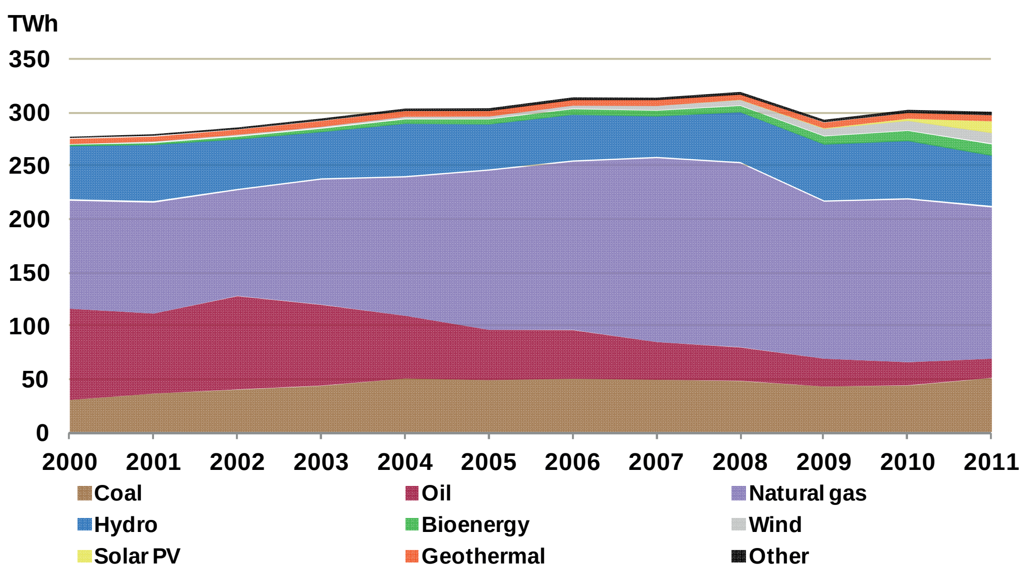


Power sector structure

Generation and capacity

As a result of the market liberalisation process and urgent government actions after the blackouts of 2003, the Italian generation mix has modernised in the last decade, in particular with a big fuel switch from oil to gas. The other sources have remained fairly stable in percentage shares. Gas-fired generation is a dominant source of power supply in Italy. In 2011 it represented 47% of the total. Coal was the second-largest source of power generation, 17%, followed by hydropower at 16%. In 2011 solar PV, wind and bioenergy each contributed 3-4%. Italy is one of the few OECD member countries with sizeable geothermal power production, which contributed 2% of the total in 2010.

Figure 34 Italy power generation by source



Italy is importing 10% to 15% of its electricity consumption, mostly from Switzerland and France. But booming renewable power sources could change this situation over time. The imports are currently driven by economics, not by a lack of power generation sources in Italy. Indeed, Italy's total power system capacity grew from the year 2000, from 76 GW to over 105 GW in 2010, while peak load has been basically stable at 55 GW to 56 GW since 2005.

Renewable generation

Spurred by generous incentives and policies, Italy's renewable generation increased from 55.3 TWh in 2005 to 85.6 TWh in 2011, an average annual rise of 5 TWh. Total renewable capacity has increased rapidly, from 24.6 GW in 2005 to 44.2 GW in 2011. Non-hydropower sources have grown in particular, evolving from 15% of renewable capacity in 2005 (6% in 2000) to 51% in 2011. As a consequence, Italy has moved ahead of its indicative targets for renewable electricity in the NREAP.

Figure 35 Italy renewable power generation (TWh)

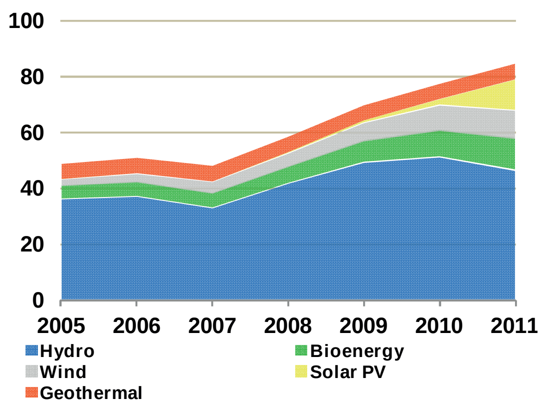
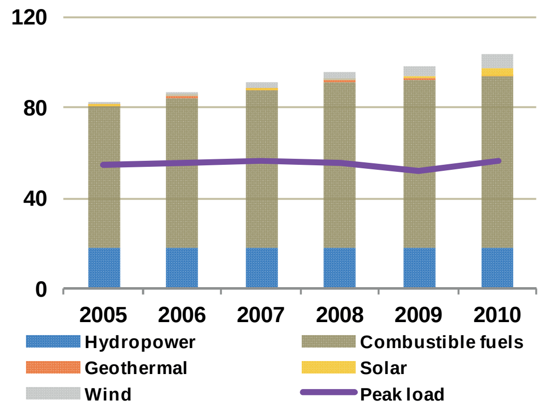


Figure 36 Italy power generation capacity versus peak load (GW)



In terms of capacity, the original government target of 8 GW of solar PV by 2020 has been surpassed. A new target set in 2011 aims for 23 GW by 2016. In 2011, solar PV installations increased strongly, with cumulative connected capacity going from 3.5 GW at the end of 2010 to 12.8 GW at the end of 2011, making Italy the top market for PV installations in that year. In total, 330 000 PV systems have been installed cumulatively, covering 95% of Italian communities (versus only 11% in 2006). The vast majority of these installations (320 000) are small scale (<200 KW), corresponding to 4.2 GW, mostly in the north. By contrast, the remaining larger-scale plants are concentrated in the south (*e.g.* Puglia and Sicily), where solar irradiation is particularly good. Still, with relatively lower demand in the south, the 8.5 GW represented by these plants cannot be easily consumed; the need to export this power tends to put stress on a relatively weak grid.

Grid and system integration

Due to its geographical shape, Italy's high-voltage lines run along the two coasts, with weaker interior connections and interconnections from the mainland to Sicily and Sardinia. This structure represents a challenge for the transmission and balancing of variable renewable sources, given the southern situation of most wind capacity and a significant share of solar PV, while the largest part of demand is in the central and northern part of the country. This trend may worsen with planned additions for wind mostly concentrated in the south. The situation is slightly easier with solar PV, with planned capacity additions more widely dispersed. However, the large number of recent installations poses some problems for distribution networks and local utilities.

In order to address this situation and facilitate the contribution of renewable energy sources in its development plan, the TSO Terna is planning to strongly reinforce its 400 kV lines in the south and interconnections with the islands, develop new transforming substations, upgrade high-voltage direct current lines with Sardinia, and reinforce the 150 kV network. In the Transmission Network Development Plan 2012, Terna has also planned the installation of about 240 MW of batteries around substations in order to tackle congestion issues. This measure is proposed due to its much shorter implementation time as opposed to the extension and improvement of grid. Overall the planned investment would represent over EUR 2.5 billion.

The timely implementation of the transmission plan is a key enabler for the further development of renewable energy sources in Italy. Otherwise, grid and system integration will become a major barrier. The massive penetration of PV is posing new challenges at the low-mid voltage distribution level. Distribution in Italy is assured by around 170 companies, with some active only at the municipal level. However, the vast majority of electricity is actually distributed by Enel Distribuzione, which has developed considerable experience with PV.

Italy is a world leader in smart metering, having installed 36 million smart counters. The development of net metering systems, as well as more sophisticated demand-side response measures and smart grids in the future, could further improve the integration of solar PV systems there.

Current policy environment for renewable energy

The rapid deployment of renewable electricity in Italy has been spurred by very generous economic incentives. These incentives have caused a large deployment, but at a high cost. Recent IEA analysis shows, for instance, that Italy provided a higher remuneration (at an equivalent number of full load hours) to wind generators than the majority of other countries (IEA, 2011). This imbalance is even more evident in the case of PV, which has triggered a boom in policy costs in 2011. Today, the official estimate reports renewable energy to account for EUR 9 billion (of which EUR 5.5 billion was just for solar PV) over a total EUR 42 billion yearly total electricity bill for Italian consumers. According to analysis from the Ministry of Economic Development, these costs are much higher than the estimated benefits, *i.e.* EUR 2 billion to EUR 2.5 billion for fuel saving (mostly gas) and EUR 0.4 billion for the merit-order effect.

Against this background, the government proposed two new decrees in April 2012 – one for PV and another for all other renewable electricity sources – with the main objective of optimising growth of renewable energy in a more cost-efficient way, and avoiding overly rapid deployment, while continuing to support the Italian renewable industry. If approved, the decrees would confirm renewable sources as a main pillar of the Italian power mix. Their objective is to increase the indicative target of renewable energy share in 2020 from 26%, as initially set in the NREAP, up to 32% to 35% (120 TWh to 130 TWh). The aim is to increase the support to a maximum of EUR 12 billion per year and stabilise it.

For non-solar PV sources, this action posits a move from a quota obligation system to a feed-in system. Power plants with a capacity lower than 1 MW will be subsidised through a feed-in tariff scheme, while larger plants will be subsidised through a sliding feed-in premium scheme. An annual cap has been introduced in order to stabilise annual expenses around EUR 5 to EUR 5.5 billion per year. Power plants larger than 5 MW are required to go through a tendering process, while power plants with a capacity lower than 5 MW will need to apply for inclusion in a new registry in order to qualify for the incentives. Small plants (up to 50 kW) are exempted from the registry.

For solar PV, the reform launches the fifth *Conto Energia*. As originally proposed, the bill decreases tariffs compared with the fourth, and introduces six-month caps for all systems more than 12 kW, through new registers. The changes increase the annual support up to EUR 6.5 billion per year over five to six month periods after going into effect (corresponding to additional EUR 100 million per six months compared with the fourth *Conto Energia*). The fifth *Conto Energia* is to go into effect when the total expense reaches EUR 6 billion per year. As of the time of writing, the decrees are still in their legislative inception phase and could be therefore subject to substantial changes.

Table 34 Italy main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 17% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 26.4% of electricity production from renewable sources provided by: 17.8 GW hydropower 0.92 GW geothermal 8 GW solar PV 0.6 GW CSP 3 MW ocean 12 GW wind onshore 0.68 GW wind offshore **Updated target for solar PV:** 23 GW of solar PV by 2016	***Conto Energia*:** Feed-in tariff system for solar PV installations with premiums for concentrating solar PV and other types of non-conventional installations. **Feed-in tariff for small systems:** Applies to onshore wind (plants under 200 kW) and geothermal, wave and tidal, hydro, and bioenergy plants under 1 MW. **Renewable energy quota obligation:** 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. In 2011 the quota was 6.8%, while in 2012 it will be 7.55%. The scheme has had technology-specific banding since 2009. With the new proposed decrees, the system is to phase out from 2013-15 and move to a new feed-in tariff/feed-in premium scheme for plants larger than 5 MW, and will apply to power plants commissioned from 1 January 2013.	**Grid access and priority dispatch:** 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/.

Economic attractiveness of renewable energy

Generous incentives have, to date, made the deployment of renewable energy economically attractive. This is due both to high certificate prices or feed-in-premiums and to high wholesale electricity prices (EUR 72 per MWh on average in 2011). As shown for onshore wind in the recent IEA publication *Deploying Renewables 2011*, total remuneration at an equivalent number of full-load hours was almost double those in Spain and Germany, and more than double that in Denmark. Even more striking, solar PV remuneration was more than double the remuneration in Germany in 2009. Since then the gap has increased as German tariffs decreased considerably and those of Italy did not. Consequently, system prices remained at artificially high levels.

Tariffs proposed by the two main decrees discussed above should still render new renewable electricity additions attractive per kWh generated. However, the mechanism of capping the total program costs raises a good deal of project risk, given uncertainty over the future availability of supports and their implementation.

At the same time costs are falling, particularly for solar PV, and new market segments that do not need financial support are emerging. While observed solar PV system prices remain higher than in Germany, they have fallen to levels as low as EUR 1 800 per kW for large utility-scale systems and EUR 2 500 per kW for rooftops. This means that levelised costs of production (without supports) for rooftop systems are at EUR 165 per MWh for one that produces 1 500 full-load hours per year, or at EUR 207 per MWh if it produces at 1 200 hours per year. In the meantime, household retail prices (without taxes) stood at EUR 144 per MWh in 2011.

Financing

With the generous incentives, the availability of finance has not emerged as a major issue until recently. In 2011, renewable deployment expanded across several technologies, particularly in solar PV. However, the challenging macroeconomic situation in Italy has resulted in finance becoming increasingly scarce and more expensive, in general. Anecdotally, credit spreads for renewable projects in Italy have widened versus other major renewable deployment grounds such as Germany and the United Kingdom. This situation will likely persist over the short term (one to two years) as the IMF has forecast a contraction in the economy over 2012 and 2013.

The proposed new feed-in tariff/premium system for all renewable technologies could bring greater certainty to investors. However, the programme cost cap and the project registry add layers of risk to deployment that could reinforce cyclically higher financing costs and worsen the attractiveness of renewable investment. As such, over the medium term, the availability and cost of finance for renewable deployment may remain a significant constraint in Italy.

Conclusions for renewable energy deployment: baseline case

We expect renewable energy capacity growth of 16 GW from 2011-17. A combination of incentives and competitiveness with retail prices in some segments should imply solar PV capacity growth of 10.5 GW over the medium term. Other technologies grow at a much smaller pace. Onshore wind expands by 3.4 GW, while bioenergy and hydropower grow by 1.1 GW and 0.7 GW, respectively.

Table 35 Italy renewable electricity capacity (GW)

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Hydropower	21.5	21.7	21.8	21.9	22.1	22.2	22.3	22.4
Bioenergy	1.6	2.1	2.3	2.5	2.7	2.9	3.1	3.2
Wind	5.8	6.7	7.2	7.7	8.3	8.9	9.5	10.1
Onshore	5.8	6.7	7.2	7.7	8.3	8.9	9.5	10.1
Offshore	-	-	-	-	-	-	-	-
Solar PV	3.5	12.8	14.3	15.3	16.8	18.8	20.8	23.3
Solar CSP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**33.3**	**44.2**	**46.5**	**48.3**	**50.7**	**53.6**	**56.5**	**60.0**

The Italian government has indicated the objective for solar PV growth of 2 GW to 3 GW per year, with a 23 GW target by 2016. With major policy changes on the horizon, one would expect a strong, short-term increase in installations, mimicking behaviour in other markets where this is taking place (*e.g.* Germany). Yet in the first quarter of 2012, only 400 MW was installed, a rate more in line with 1.5 GW per year. This lower-than-expected activity may indicate that the constricted availability and increased costs of finance, combined with a deteriorating macroeconomic situation, may be limiting deployment.

Aside from uncertainty over the policy situation and the challenging economic outlook, renewable deployment will face challenges related to grid development. The realisation of ambitious upgrade plans by Terna will be important for expanding renewable capacity, particularly in the south where the best wind and solar resources are situated. Nevertheless, the high investment costs associated with such plans may prove difficult to meet.

Overall, the forecast for deployment, particularly solar PV, remains highly uncertain given pending policy changes, the potential for increased associated administrative complexity and a challenging economic situation. Still, advances in competitiveness for solar PV, with levelised costs of residential and commercial systems approaching retail prices, would tend to support deployment.

Table 36 Italy main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Government policy commitment to strong renewable deployment. • Improving competitiveness in good resource areas.	• Reduced availability and increased costs of finance amid weakening economy. • Need for costly grid upgrades, particularly in the south.

Renewable energy deployment under an enhanced case

In Italy, most potential enhancement relates to the competitive position of solar PV. Greater-than-anticipated improvements in system costs could prompt a faster deployment of solar PV for self-consumption in the residential and commercial sectors, with the potential for an additional 3.5 GW cumulative capacity by 2017 versus the baseline case. Eased administrative procedures and larger use of agricultural wastes could also stimulate onshore wind and bioenergy deployment, respectively, with the 2017 upside for each at around 1 GW.

Norway

With a power sector already dominated by ample, low-cost hydropower, deployment over the medium term should be moderate, concentrated in hydropower and wind additions.

Table 37 Norway renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	136.5	98.9%	122.1	95.3%	130.6	131.9	132.4	132.7	132.9	133.1
Bioenergy	0.3	0.2%	0.4	0.3%	0.5	0.5	0.6	0.7	0.8	0.9
Wind	0.5	0.4%	1.3	1.0%	1.5	1.7	2.0	2.4	2.8	3.2
Onshore	0.5	0.4%	1.3	1.0%	1.5	1.7	2.0	2.4	2.8	3.2
Offshore	-	0.0%	0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	-	0.0%	-	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Total RES-E	**137.3**	**99.5%**	**123.7**	**96.6%**	**132.5**	**134.1**	**135.0**	**135.8**	**136.5**	**137.2**

Power demand outlook

Norway's GDP is projected to grow by 2.1% annually from 2011-17. Buoyed by export revenues from elevated oil and gas prices, Norway's economy should remain one of the strongest-growing in

Europe. Over the past decade electricity demand has remained relatively steady, with a dip during the recession in 2009; at 121 TWh in 2011 it stood below pre-crisis levels. Relative to its neighbours, Norway enjoys low retail power prices, though prices have risen steadily over the past decade. As a mature economy with moderate economic growth, we expect demand in Norway to stay level over the medium term, going from 121 TWh in 2011 to 127 TWh in 2017 (+0.8% annually).

Figure 37 Norway power demand versus GDP growth

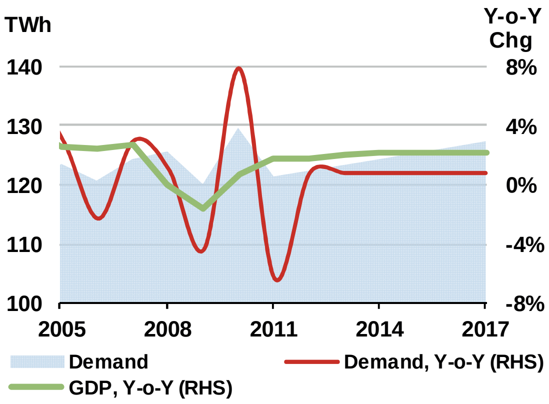
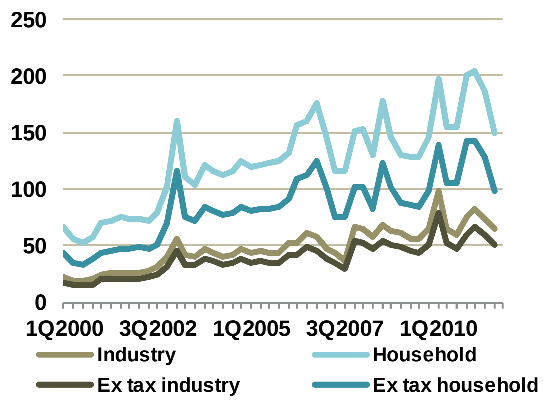


Figure 38 Norway average retail power prices (USD per MWh)



Power sector structure

Generation and capacity

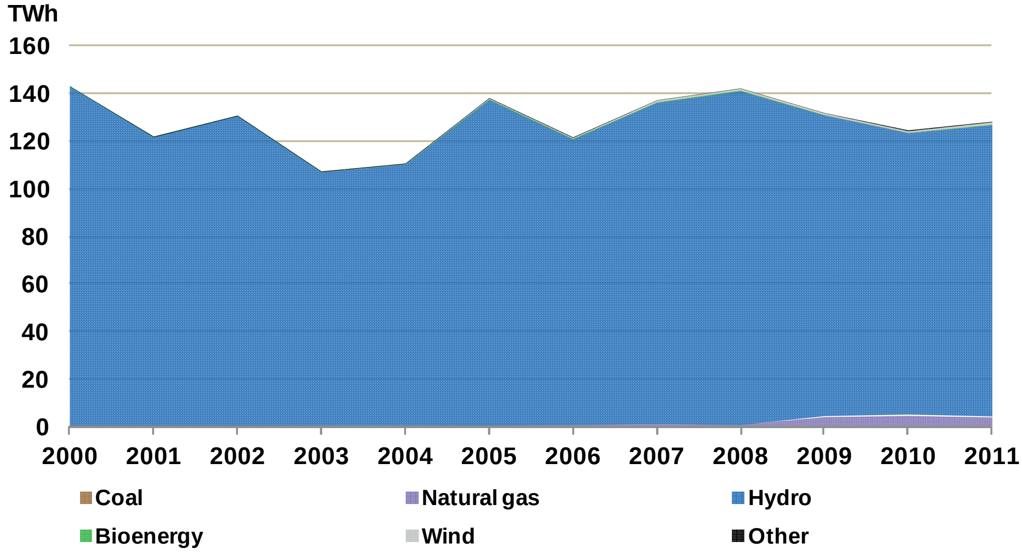
Norway's electricity is generated almost exclusively from hydropower sources, representing around 95% of total power production, depending on hydro availability in a given year. Natural gas, wind and bioenergy represent supplementary sources of power generation; of these three, gas has grown the most in recent years, from only 0.4 TWh in 2008 to 4 TWh in 2011. As a result of having ample and low-cost hydropower, the Norwegian energy system has a very high level of electrification, with most heating needs met through electricity.

Norway's status as either electricity importer or exporter changes from year to year and largely depends on the prevailing hydro resource availability. Typically the system exports power during the day and imports it at night and during the weekends. This trade takes place within the framework of the regional Nordic Power System. Norwegian hydropower plants provide crucial flexibility to this system, particularly when it comes to balancing Danish wind production. Should the country wish to develop increased electricity export capabilities to provide flexibility to the region – potentially more of a long-term goal – this would necessitate the build-out of a more robust regional grid.

Despite the low cost and regional benefits, an overwhelming reliance on hydropower subjects Norway to energy security risks during years of low hydro reservoirs. As such, the country's energy system could benefit over the medium term from increasing capacity in other forms of generation and further interconnections to neighbouring countries.

Indeed, Norway does have potential for offshore wind development. However, given the expected demand trends, strong and relatively low-cost hydropower potential and difficult sea depths, actual offshore deployment should proceed very modestly over the medium term. Norway's interest in offshore wind relates more to its long-term industrial strategy of exporting manufactured components, leveraging the considerable experience of its own offshore oil and gas industry. In 2011, capacity stood at just 2.3 MW (a demonstration floating turbine).

Figure 39 Norway power generation by source

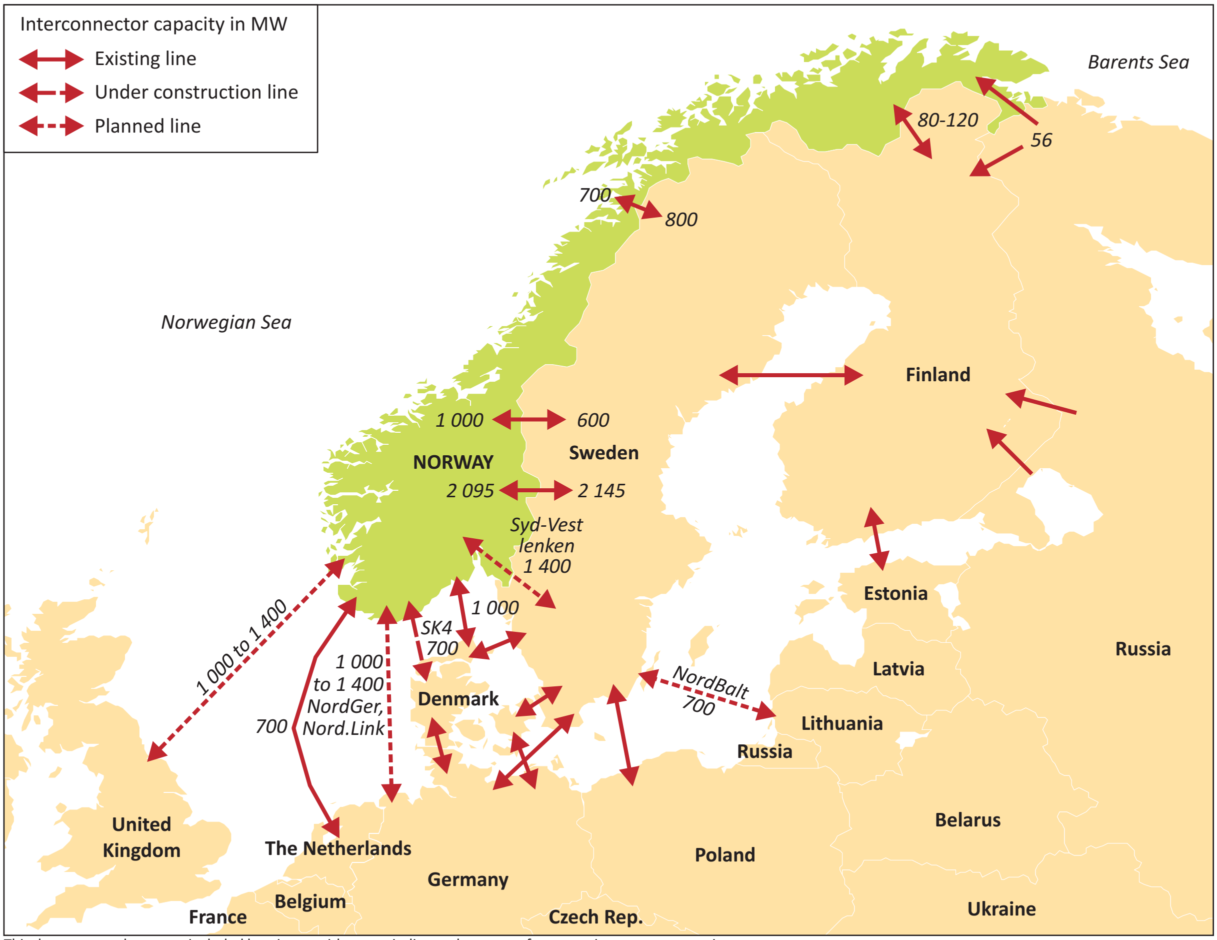


Grid and system integration

In general, Norway's grid enables renewable energy deployment. However, given discussion of increased integration across the region and the role of Norway's hydropower as a source of balancing for its neighbours, the country may gain from increasing its interconnections. Norway could also derive increased energy security benefits given its almost exclusive orientation towards hydropower. This expansion would put pressure on the domestic system. As such, Norway would also need to upgrade and expand its own grid. Yet, two sets of domestic opposition exist. First, the general public tends to oppose transmission line build-outs due to reasons of nature preservation. Moreover, energy-intensive industries may become concerned that a higher level of integration could cause electricity prices to converge upwards towards those of Norway's neighbours.

Still, the Norwegian TSO Statnett is making progress on upgrading the voltage on a number of lines as well as constructing new ones. Plans through 2020 foresee a doubling of the current 3.7 GW of physical interconnection to other countries. This development depends on the resolution of interests between a diverse set of industry stakeholders and the political goals and market design of several countries. Finally, it remains to be seen to what extent an offshore North Sea Grid will emerge. Such development could advance Norway's goal towards carbon neutrality in 2050, notably by electrifying offshore oil and gas production processes.

Map 3 Main interconnection lines in the Nordic Grid



This document and any map included herein are 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: Ministry of Petroleum and Energy.

Current policy environment for renewable energy

Given Norway's unique situation of ample hydropower potential, both exploited and unexploited, the policy environment tends to stay technology-neutral and oriented towards the most economic options. For example, Norway missed its 2010 target for onshore wind generation (3 TWh) with Enova, the public agency promoting new renewable sources of energy, not contracting enough projects due to high costs compared with low electricity prices. The common Green Certificates scheme with Sweden, which started in January 2012, may ultimately help to speed up wind development. However, initial results from the certificate scheme suggest that hydropower will still constitute a significant portion of Norway's participation in the medium term. The government has taken steps towards an offshore grid in the North Sea and signed a political declaration on regional co-operation to this end.

Table 38 Norway main targets and support policies for renewable electricity

Targets	Financial support	Other support
General targets: Norway to become the first carbon-neutral country by 2050.	**Norway-Sweden Green Certificates Scheme:** In force since January 2012. Aims to increase renewable electricity production in the two countries by 26.4 TWh, equally shared, by 2020. **Offshore Energy Act:** Investment and demonstration grants. Regulation of licensing processes and infrastructure deployment.	**CO_2 Tax:** CO_2 tax exemption for carbon-neutral energy generation. **Grid access and priority dispatch:** The TSO must connect all generators and consumers with regulatory approval. Dispatch is done by merit order.

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

Economic attractiveness of renewable energy

Norway's renewable energy development over the medium term is likely to be led by hydropower, which enjoys a competitive position versus all other forms of generation. Costs of wind power, both onshore and offshore, still largely exceed forward prices on the Nord Pool. While the Green Certificates scheme may ultimately help to improve the attractiveness of renewable energy sources outside of hydropower, the upside to deployment from this factor looks limited in the medium term.

Financing

Norway has a strong renewable energy financing environment, underpinned by support from public institutions and the stable balance sheet of state-owned electricity company Statkraft. On the back of Norway's net export position in oil and gas, Statoil and the Norwegian Government Pension Fund – the world's second-largest sovereign wealth fund – recycle fossil fuel revenues into renewable energy investments, though most of this investment occurs abroad. Moreover, the Nordic Investment Bank is pursuing its own mandate to support renewable energy projects. Jointly with Sweden, Norway operates a tradable Green Certificates scheme, which should provide long-term enhancement to renewable energy financial returns.

Conclusions for renewable energy deployment: baseline case

We expect renewable electricity capacity to expand by 1.8 GW over the medium term, from 30.2 GW in 2011 to 31.9 GW in 2017. Hydropower, wind and bioenergy account for all of the growth. Additions of 0.8 GW in hydropower are expected while onshore wind also grows by 0.8 GW. Bioenergy should contribute 0.2 GW of new capacity.

Table 39 Norway renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	29.5	29.5	29.9	30.1	30.2	30.2	30.3	30.3
Bioenergy	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3
Wind	0.4	0.5	0.6	0.7	0.9	1.0	1.2	1.3
Onshore	0.4	0.5	0.6	0.7	0.9	1.0	1.2	1.3
Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.0	0.0	0.0	0.0
Total RES-E	**30.1**	**30.2**	**30.7**	**31.0**	**31.2**	**31.5**	**31.7**	**31.9**

Table 40 Norway main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Ample, low-cost hydropower availability. • Policy target of carbon neutrality by 2050 and adoption of Green Certificates scheme.	• High costs of onshore and offshore wind development relative to electricity prices. • Domestic opposition to upgrades and expansions of transmission lines.

Renewable energy deployment under an enhanced case

From Norway's perspective, renewable energy deployment under the baseline and enhanced cases should be identical, due to limited demand upside for additional power generation (either renewable or conventional). In an enhanced case, greater connection to Norway's balancing assets could further enhance deployment of variable renewable energy sources in the region as a whole.

Spain

Due to macroeconomic challenges and the moratorium on the Special Regime, Spain's renewable electricity generation growth slows over the medium term but remains sizeable in absolute terms.

Table 41 Spain renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	23.0	7.8%	32.9	11.3%	33.1	33.2	33.3	33.3	33.4	33.5
Bioenergy	2.7	0.9%	4.5	1.5%	4.7	4.7	4.7	4.7	4.7	4.7
Wind	21.2	7.2%	42.4	14.5%	49.6	53.2	55.3	55.9	55.9	55.9
Onshore	21.2	7.2%	42.3	14.5%	49.5	53.2	55.3	55.8	55.8	55.8
Offshore	-	0.0%	0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0%	8.2	2.8%	8.1	8.4	8.6	8.9	9.2	9.6
Solar CSP	-	0.0%	1.8	0.6%	3.4	4.8	5.6	6.0	6.0	6.0
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**46.9**	**15.9%**	**89.8**	**30.8%**	**98.8**	**104.2**	**107.5**	**108.8**	**109.2**	**109.7**

Power demand outlook

Based on the IMF, Spain's GDP growth is projected to average 0.8% annually from 2011-17. Demand is expected to recover to pre-recession levels in 2014, rising moderately over the medium term (+1.0% annually). Still, macroeconomic uncertainty could undermine this picture. 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, prices have more closely reflected electricity costs, though the "access tariff" (for transmission, distribution and renewable premiums) is still regulated. Since 2008, higher-than-targeted deployment of some renewable sources has exacerbated the tariff deficit, with the 2011 cumulative net burden rising to EUR 24 billion.

Figure 40 Spain power demand versus GDP growth

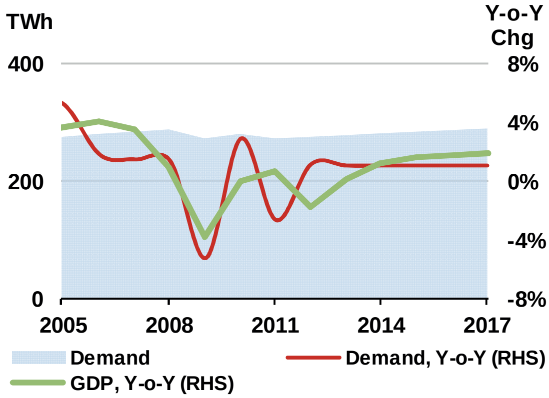
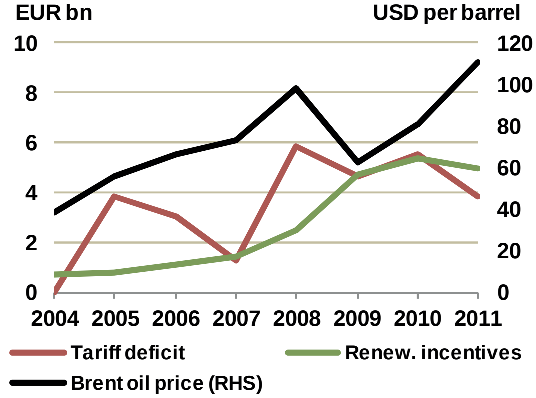


Figure 41 Spain power system economic indicators



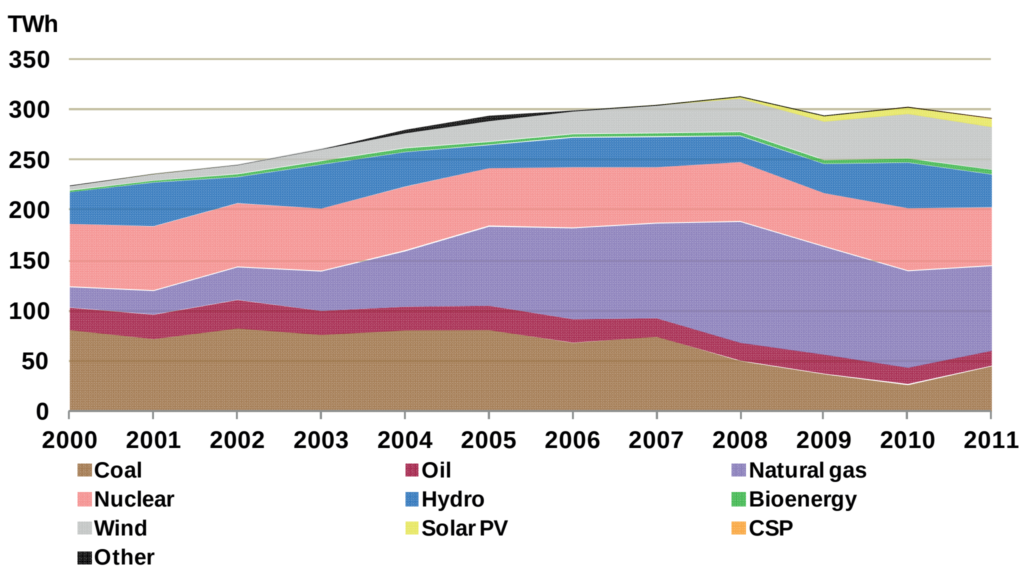
Sources: CNE (2012a), CNE (2012b), REE (2012), Bloomberg (2012).

Power sector structure

Generation and capacity

Spain's power production is provided by a well-diversified portfolio of generation sources. In 2011 power production dropped 3.6% compared with the 2010 level. The largest share of generation was covered by gas, 29%, followed by nuclear, 20%, and coal, 15%, which experienced a large increase compared with 2010, due to domestic coal having preference in the merit order. Renewable power represented 31% of the total, with the largest contributions from wind and hydropower, 15% and 11%, respectively.

Figure 42 Spain power generation by source



Generation capacity in Spain is divided into two groups: Ordinary Regime and Special Regime. Ordinary Regime capacity generates based on long-term contracts or competes on the wholesale electricity market. Capacities under the Special Regime, which include renewable installations up to 50 MW (excluding large hydropower) and co-generation, can choose between selling their electricity directly to the market (via wholesale or power purchase agreements), where they get a market price and a premium, or directly to distributors at the feed-in tariff level. The Special Regime represented one-third of power generating capacity at the end of 2011.

Renewable power generation increased by an impressive 43 TWh between 2005 and 2011. In fact, this difference was even stronger in 2010, up by 55 TWh compared with 2005, but 2010 was an extraordinary hydropower year.

The conventional part of the power system has also developed significantly. Major utilities made large investments in gas capacity in the early 2000s, when the economy was booming. Some of this capacity has stood idle since the economic crisis hit the country. Indeed, Spain's overcapacity is striking, making the economics of power generation even more complicated. Peak load has averaged around 45 GW for several years now while total generation capacity was 105 GW in 2011.

Figure 43 Spain renewable power generation (TWh)

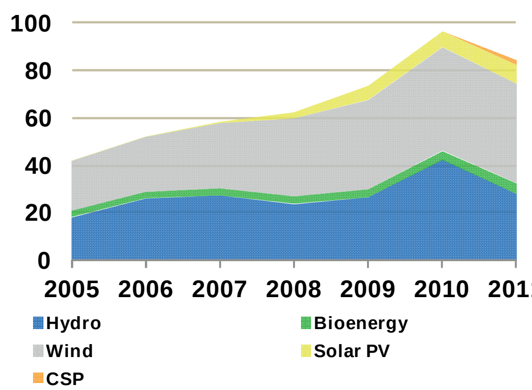
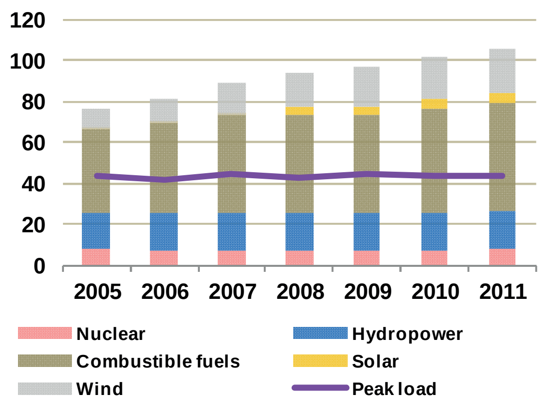


Figure 44 Spain power generation capacity versus peak load (GW)



Grid and system integration

The Iberian peninsula, *i.e.* Spain and Portugal, form almost an island with respect to electrical interconnections. There is a synchronous connection to Morocco with a physical capacity of 1.5 GW, used primarily for exports to that country. The connection to France is scheduled to double with the 1.4 GW Inelfe interconnector coming on line in mid-2014, after more than two decades of planning.

Spain is one of the front runners in integrating variable renewable sources into its electricity system. This is enabled by ample gas generation capacity and large pumped hydropower storage capacity, which provide flexibility to the system in order to balance variability of wind and solar generation. Moreover, TSO, Red Eléctrica de España, maintains an advanced approach to system balancing.

The domestic grid is quite meshed and strong. Spain has among the highest wind penetrations in the world (15% in 2011). To illustrate a recent example, wind supplied 60% of consumption during the early morning hours of 16 April 2012 and 50% of consumption during the afternoon of 18 April 2012. Meanwhile, curtailment on the transmission level is negligible (0.03% in 2011), with scheduled line maintenance being the primary reason. The situation in some parts of the distribution level is less comfortable with slightly higher levels of curtailment (0.09% in 2011). No record of curtailment has been found for solar PV. Spain generally has a midday peak, thus leading to a match of solar generation and load (42 GW in summer). However, annual peaks still occur in winter evenings (45 GW). In aggregate, the grid should not pose a barrier for deployment over the outlook period.

Current policy environment for renewable energy

On 27 January 2012, the Spanish government approved Royal Decree Law 1/2012, which imposes a temporary suspension of additional economic support approvals for new generation capacity under the Special Regime. This decision stemmed from three primary factors: general overcapacity in the power sector, an overshoot of renewable objectives in solar technologies vis-à-vis the NREAP and the increasing tariff deficit borne by the power system. Regarding the deployment of different renewable technologies, it is worth highlighting that wind power almost perfectly fulfilled its 2010 objectives, and other technologies (outside of solar) have lagged behind their goals. By contrast, solar PV and CSP overshot their objectives by a factor of ten and five, respectively. Overall, prevailing economic distress and fiscal austerity have negatively impacted upon government budgets and payment abilities. As such, the temporary suspension represents a first step towards addressing this situation.

Table 42 Spain main targets and support policies for renewable electricity

Targets	Financial support	Other support
As a result of the new macroeconomic previsions for Spain, and the new Royal Decree Laws approved in 2012, targets will change in the future, both in total and in disaggregated figures. This new scenario is now under analysis by the government. **National Renewable Energy Action Plan:** Binding target: 22.7% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 40% of electricity production from renewable sources provided by: 22.4 GW hydropower 50 MW geothermal 8.4 GW solar PV 5.1 GW CSP 100 MW ocean 35 GW wind onshore 0.75 GW wind offshore 1.6 GW bioenergy	**Royal Decree Law 13/2012, Electricity and Gas Directives:** Implementation and measures to correct deviations between costs and incomes in both sectors. **Royal Decree Law 1/2012:** Temporary suspension of public financial support for new electricity plants under the Special Regime. **Royal Decree 1565/2010:** New tariff regulation for the production of photovoltaic electrical energy. **Royal Decree Law 14/2010:** Correction of the tariff deficit in the electricity sector. **Royal Decree 661/2007:** Feed-in tariff and feed-in premium scheme. Applies to all renewable generation facilities up to 50 MW.	**Framework policy:** Sustainable Economy Act 2011 Spanish Strategy on Climate Change and Clean Energy 2007 **Royal Decree Act 6/2009:** 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. **Royal Decree 1028/2007:** Establishes permitting procedures for offshore wind and bidding process for concessions. **Grid access and priority dispatch:** 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/.

The National Energy Commission (CNE), the national regulator, believes that due to declining power demand, the moratorium will not jeopardise attaining the European Union's 2020 targets, set in terms of shares in final consumption. Over the last two years renewable sources represented 30% to 33% of electricity production in Spain, while a tentative target for 2020 is 40%. Indeed, if power demand does not pick up, the targets for renewable electricity may well be fulfilled because renewable projects that were approved before the moratorium should still come on line. For onshore wind this represents 2.7 GW of installed capacity to become operational in the next two years, for CSP around 1.1 GW and for solar PV almost 0.8 GW. Still, the possibility of a long-lasting moratorium will impact upon further wind and solar developments.

Economic attractiveness of renewable energy

Under the moratorium, and therefore without financial support, only a few renewable sources look attractive in Spain over the projection period. That is the case of solar PV, especially in the south where the resource is the best. We can therefore expect some projects for self-consumption to appear, especially in the commercial sector (*e.g.* rooftops of supermarkets) and the residential sector, in line with an assumption of economic recovery from 2014 onwards.

Financing

In general, the availability and cost of finance represents a major deployment challenge in Spain, at least over the next two years. This stems from three factors: the increasingly credit-constrained status of Spain's banking sector, the imposition of the moratorium on renewable development under the Special Regime and likely reduced interest by Spanish utilities in financing new domestic projects.

Conclusions for renewable energy deployment: baseline case

Spain's overcapacity in the power generation sector, the tariff deficit and the consequent moratorium imposed by the government on the new projects under the Special Regime have significant consequences on the baseline projection. The forecast assumes that the moratorium applies until 2017 and therefore only already-approved renewable capacity should come on line by 2017. Solar PV should remain an exception with some minor growth not requiring support, driven by self-consumption.

Table 43 Spain renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	18.5	19.9	19.9	19.9	20.0	20.0	20.1	20.2
Bioenergy	1.0	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Wind	20.6	21.7	23.6	25.0	25.5	25.5	25.5	25.5
Onshore	20.6	21.7	23.6	25.0	25.5	25.5	25.5	25.5
Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	4.0	4.4	4.6	4.7	4.9	5.0	5.2	5.4
Solar CSP	0.7	1.2	1.8	2.2	2.5	2.5	2.5	2.5
Geothermal	-	-	-	-	-	-	-	-
Ocean	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total RES-E	**44.9**	**48.2**	**50.9**	**53.0**	**54.0**	**54.2**	**54.5**	**54.7**

Renewable capacity should expand from 48 GW in 2011 to 55 GW in 2017. With an increase of 3.8 GW, the growth of onshore wind is the most robust. Meanwhile, hydropower progresses by 0.3 GW, CSP by 1.3 GW and solar PV by 1 GW. This growth should bring total renewable production to 112 TWh in 2017. Onshore wind is expected to contribute the most, 56 TWh, followed by hydropower, 34 TWh, and solar PV and CSP, delivering 9.6 TWh and 6.0 TWh, respectively, in 2017.

The Spanish government is currently preparing updated renewable deployment targets that represent the prevailing state of the power generation system and an outlook for power demand. While the results of this analysis are unknown at the time of writing, the posting of new targets and any associated incentive scheme, depending on the level, could further influence renewable deployment beyond this forecast.

Table 44 Spain main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Abundant renewable resources. • Strong grid and advanced integration of variable renewable sources.	• Overcapacity of electricity system. • Need to correct for persistently high tariff deficit.

Renewable energy deployment under an enhanced case

The Spanish political situation keeps evolving and new solutions to the problem of the tariff deficit may be put forward. Still, the problem of overcapacity of the power system is real and with low power demand, coming back to pre-recession levels only in 2014, there is little need for new generating assets, whether renewable or not.

The upside for renewable electricity still looks possible, though predominantly for solar PV. Spain is endowed with excellent solar resources while household power prices are around EUR 0.20 per kWh. This implies that self-consumption-motivated installation of solar PV could be profitable. These possible developments could be further enhanced with net metering regulation. Assuming that the economic recovery materialises, an additional 2 GW of solar PV could be installed by 2017 versus the baseline forecast.

Sweden

With an already large hydropower base, renewable energy sources should grow only moderately over the medium term, led by onshore wind and hydropower additions.

Table 45 Sweden renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	72.9	46.0%	66.3	43.4%	66.4	67.8	69.5	69.8	69.8	69.8
Bioenergy	7.5	4.7%	11.0	7.2%	11.3	11.4	11.4	11.5	11.5	11.6
Wind	0.9	0.6%	6.1	4.0%	6.5	8.0	9.3	10.1	10.5	11.1
Onshore	0.9	0.6%	5.5	3.6%	6.0	7.3	8.3	8.9	9.2	9.4
Offshore	0.0	0.0%	0.6	0.4%	0.6	0.7	1.0	1.2	1.2	1.7
Solar PV	0.0	0.0%	0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**81.3**	**51.3%**	**83.4**	**54.5%**	**84.3**	**87.1**	**90.1**	**91.3**	**91.8**	**92.5**

Power demand outlook

Sweden's GDP is projected to grow on average by 2.4% annually from 2011-17. Over the past decade electricity demand has generally remained level, with a moderate retrenchment in 2008-09. Swedish retail power prices, available since 2007, have risen steadily since a dip during the economic crisis. As a mature economy with energy efficiency measures and moderate economic growth, we expect demand in Sweden to increase moderately over the medium term, rising from 141 TWh in 2011 to 148 TWh in 2017 (+0.8% annually).

Figure 45 Sweden power demand versus GDP growth

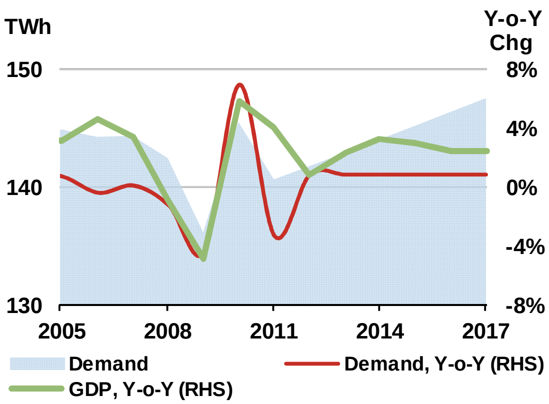
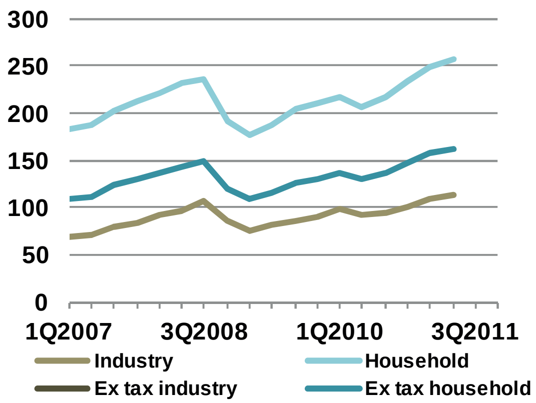


Figure 46 Sweden average retail power prices (USD per MWh)



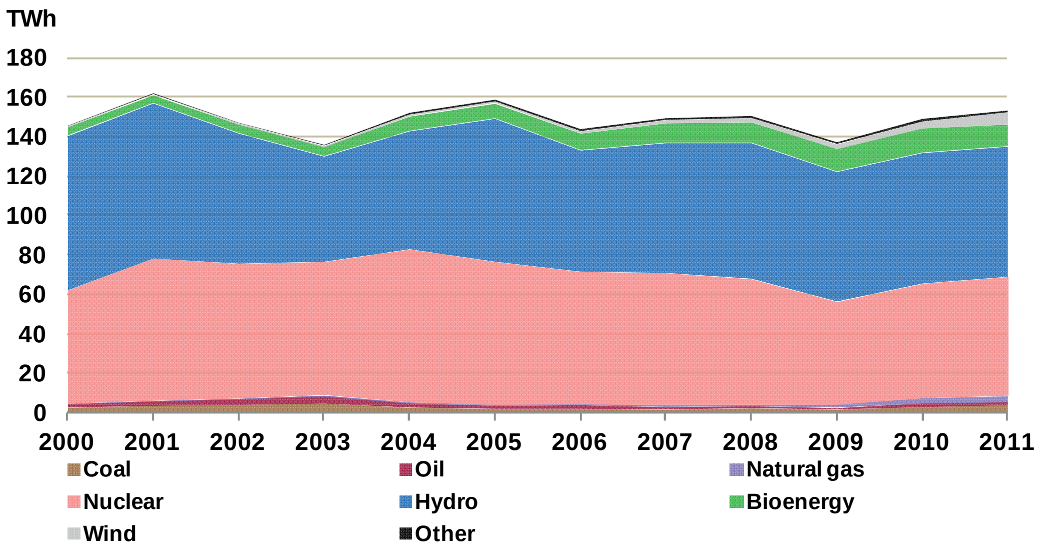
Note: taxes for industry are negligible (around 0.8 USD per MWh).

Power sector structure

Generation and capacity

Sweden's power generation depends very little on fossil fuels, whose share accounted for only 6% in 2011. Rather, hydropower and nuclear act as the largest electricity sources, representing 43% and 39% of power generation in 2011, respectively. Bioenergy serves as the third-largest source of power, with a 7% share in 2011, mainly produced in about 160 co-generation plants. The resource availability for forest biomass in Sweden is excellent, and biomass-based electricity, heat and biofuels production enjoy significant government support. Wind power has increased rapidly over the past five years, accounting for a 4% share of power generation in 2011. In 2010, Sweden's overall power sector capacity was 36 GW, with a peak load of 26 GW.

Figure 47 Sweden power generation by source



Overall, with a large reliance on nuclear and co-generation plants, there is a degree of rigidity built into the Swedish power system, despite the presence of large hydropower capacity. During periods of low hydro reservoirs and cold weather, when co-generation plants are producing heat, the system could benefit from increased flexibility to balance the load. Current solutions also revolve around expanding interconnections to neighbouring countries, particularly Norway. Further solutions could include expanding use of excess electricity from co-generation in electric boilers and feeding hot water into district heating systems. System flexibility could also be improved by building more biogas-fired capacity, from waste gasification in large cities or agriculture. Several projects are under development, but this is currently a relatively expensive option.

Grid and system integration

As a member of the Nordic Power System, Sweden is undertaking a number of interconnection and grid expansion projects to accommodate increased capacity of variable renewable energy expected over the medium term. The Swedish TSO Svenska Kraftnät currently lists 12 ongoing expansion projects, including two submarine HVDC links to support increased trade with Lithuania and Finland. The single largest project, the South West Link, will upgrade the main transmission backbone to facilitate renewable energy integration and reduce market price differentials between zones.

Current policy environment for renewable energy

In line with the European Union's Renewable Energy Directive, Sweden's NREAP envisages almost 63% of the country's power coming from renewable sources by 2020, compared with 55% in 2011. In addition, Sweden has had a green certificates scheme in place since 2003, which provides a quota for renewable electricity generation over the medium term. As of January 2012, Sweden has a common certificate market with Norway, which will require 26 TWh of additional renewable electricity production split evenly between the two countries by 2020.

Economic attractiveness of renewable energy

Renewable generation support is provided through the green certificates scheme. In 2011, certificate prices averaged around USD 29 per MWh (SEK 187 per MWh). Given expectations of no new nuclear builds over the medium term, wind, bioenergy and small hydropower should be economically attractive options for increasing generation capacity.

Table 46 Sweden main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 50% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 62.9% of electricity production from renewable sources provided by: 16.4 GW hydropower 8 MW solar PV 4.4 GW wind onshore 182 MW wind offshore 2.9 GW bioenergy	**Sweden-Norway Green Certificates Scheme:** In force since January 2012. Aims to increase renewable electricity production in the two countries by 26.4 TWh, equally shared, by 2020. Builds up on the existing Swedish green certificates scheme. **Grants:** Investment grants for market introduction of onshore and offshore wind energy. Installation grants for on-grid solar PV systems. Investment grants for generation, distribution and use of renewable gases.	**Grid access and priority dispatch:** Grid access granted.

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

Financing

Sweden's financing environment should enable renewable energy development over the medium term. The presence of a tradable green certificate scheme enhances returns to renewable projects. The government has a stable fiscal position and the cost of capital is low. Municipalities, and more recently the paper and pulp industry, have played a large role in renewable energy finance, accounting for a significant portion of financing for bioenergy-based co-generation.

Conclusions for renewable energy deployment: baseline case

We expect renewable electricity capacity to expand by 3.6 GW over the medium term, from 23.2 GW in 2011 to 26.8 GW in 2017. With 2.2 GW of additional capacity expected, the outlook for onshore wind is the most robust; offshore wind should grow by 0.4 GW. Hydropower (+0.8 GW) and bioenergy (+0.1 GW) account for most other activity.

Overall, Sweden's policy environment serves as an enabler for renewable energy development. The country maintains a predictable framework and a dynamic approach to policy. Deployment will face several challenges, however, with a grid infrastructure geared more towards centralised supply and non-economic barriers (*e.g.* permitting procedures and local opposition) hampering some developments.

Table 47 Sweden renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	16.7	16.4	16.4	17.0	17.2	17.2	17.2	17.2
Bioenergy	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0
Wind	2.2	2.9	3.6	4.4	4.8	5.1	5.2	5.5
Onshore	2.0	2.7	3.4	4.1	4.4	4.7	4.8	4.9
Offshore	0.2	0.2	0.2	0.2	0.4	0.4	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
Total RES-E	**22.8**	**23.2**	**23.9**	**25.3**	**25.9**	**26.3**	**26.4**	**26.8**

Table 48 Sweden main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Policy targets for RE deployment combined with a green certificates scheme. • Excellent resource availability and economic attractiveness for bioenergy. • Ongoing grid expansion and interconnection efforts.	• Degree of rigidity built into the system owing to high level of nuclear and co-generation deployment. • Non-economic barriers, particularly regarding wind and transmission projects.

Renewable energy deployment under an enhanced case

The outlook for renewable energy deployment in Sweden is broadly similar under both baseline and enhanced conditions. An enhanced case would introduce greater power system flexibility by increasing balancing capabilities and reducing wind power curtailment. This could result from better management of wind capacity and the deployment of more storage (*e.g.* increased water heating). Flexibility could also be improved with more biogas deployment and transmission upgrades, with the latter requiring improved public and industry acceptance. An enhanced case may see somewhat higher capacity for bioenergy for power, by about 1 GW in 2017, versus the baseline case.

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.

Table 49 Turkey renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	39.6	24.4%	52.1	22.8%	55.4	61.3	68.0	73.0	74.8	76.8
Bioenergy	0.0	0.0%	0.3	0.1%	0.6	0.7	0.9	1.0	1.1	1.3
Wind	0.1	0.0%	4.7	2.1%	5.5	7.3	9.9	13.0	16.6	20.5
Onshore	0.1	0.0%	4.7	2.1%	5.5	7.3	9.9	13.0	16.6	20.5
Offshore	-	0.0%	-	0.0%	-	-	-	-	-	-
Solar PV	-	0.0%	-	0.0%	0.0	0.1	0.2	0.4	0.6	1.1
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	0.1	0.1%	0.7	0.3%	0.7	0.8	1.0	1.0	1.2	1.6
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**39.7**	**24.5%**	**57.8**	**25.3%**	**62.2**	**70.2**	**79.9**	**88.3**	**94.3**	**101.2**

Power demand outlook

As a fast-growing economy with a rising population, Turkey's power demand should grow strongly over the medium term. Real GDP growth is expected to average 3.8% and power consumption is projected to grow 4.0% annually from 2011-17. Real retail electricity prices have risen steadily during much of the previous decade, with a growing dependence on increasingly costly fossil fuel imports. Overall, the demand and price picture supports the case for increased production from renewable sources. Rising air-conditioning needs and increasingly pronounced summer peak demand suggest that small-scale solar PV deployment, in particular, could offer an important relief valve.

Figure 48 Turkey power demand versus GDP growth

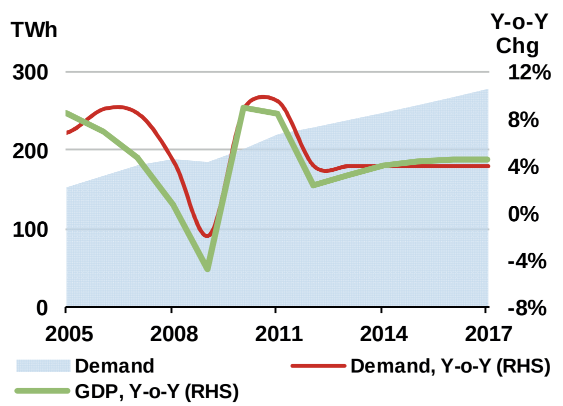
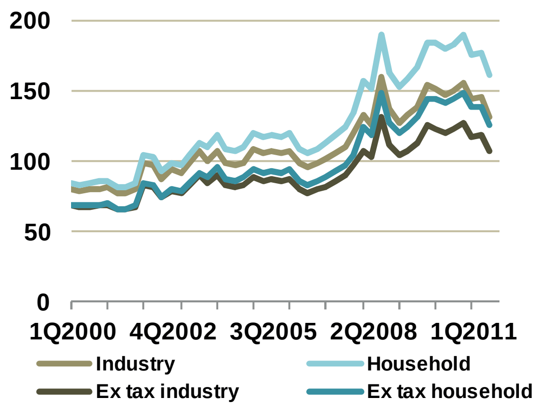


Figure 49 Turkey average retail power prices (USD per MWh)



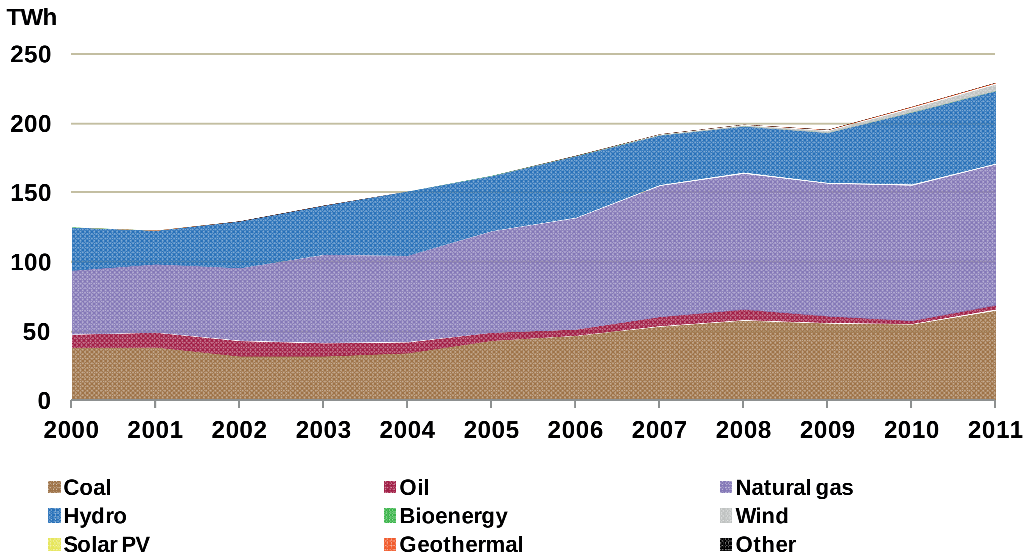
Power sector structure

Generation and capacity

Fossil fuels dominate Turkey's power generation, but renewable sources are playing an increasing role. A need for increased generation capacity, in general, to meet demand; a desire to reduce energy imports; and excellent renewable resource availability should drive deployment going forward. In 2010, natural gas accounted for 45% of generation while coal plants produced 28% of total electricity. Renewable energy sources represented 25% of generation, mostly due to hydropower (23%), but also from rising wind and bioenergy. At the end of 2010, Turkey's power capacity stood at 50 GW, with peak demand at 33 GW, up from 25 GW in 2005.

Going forward, Turkey's energy strategy sees most renewable capacity additions in hydropower and wind, with these two sources rising to approximately 40 GW and 20 GW, respectively, by 2023. Solar PV is also expected to ramp up quickly from a low base. Hydropower capacity has grown steadily over the past decade, reaching 18 GW in 2011. Wind capacity, all onshore, has increased quickly in recent years. At the end of 2011, onshore wind stood at 1.8 GW, with additions of 470 MW during the year. Given good resource availability and high capacity factors, much of this wind development has been competitive on the spot market and has occurred independent of feed-in tariff levels. So far, solar PV development has proceeded slowly – installed capacity amounted to less than 10 MW in 2011. With good potential in both categories, Turkey has also developed some of its geothermal and bioenergy assets. Geothermal capacity stood at 95 MW in 2011 while bioenergy accounted for 120 MW in 2010.

Figure 50 Turkey power generation by source



Grid and system integration

Over the medium term, system integration of renewable electricity will remain a challenge for Turkey, acting as a moderate check on deployment. By law, the TSO, TEIAŞ, must give priority to grid connection requests from renewable generation facilities. With wind power expected to grow strongly over the next ten years, Turkey will require increased transmission capacity, grid connections and better grid management. To this end, TEIAŞ is undertaking investments to accommodate increased capacity and ensure grid reliability and stability. Turkey's synchronous operation with the European Network of Transmission Service Operators for Electricity (ENTSO-E), which started in 2011, should enhance flexibility by facilitating power flows in and out of the country. Moreover, the concurrent build-out of hydropower will complement and help to balance increased wind capacity.

The integration of distributed solar PV generation will present both challenges and benefits. Turkey lacks a net-metering policy, which given high retail prices and good solar irradiation would act as an important enabler to deployment. Even without such a policy, however, small-scale systems could greatly ease pressures on the overall grid, helping to meet demand during peak summer periods.

Current policy environment for renewable energy

Turkey's renewable energy generation targets and system of feed-in tariffs, which provide a purchase guarantee for renewable energy generation, act as the main policy incentives for renewable energy deployment. In January 2011, these tariffs were revised upwards and were differentiated across technologies in order to stimulate greater activity. Under the current system, the tariffs would apply for ten years (by comparison, feed-in tariffs in other markets typically last for 20 years) to facilities commissioned before the end of 2015 and that choose, on an annual basis, to participate in the program. Still, plants need not necessarily opt in. They can decide (at the beginning of the year) to sell into the spot market or sign bilateral purchase contracts instead.

Table 50 Turkey main targets and support policies for renewable electricity

Targets	Financial support	Other support
General targets: 30% of renewable energy in electricity generation by 2023. Indicative split: Wind: 10 GW (2014), 20 GW (2023) Hydropower: "entire potential", ~40 GW (2023) Geothermal: 300 MW (2014), 600 MW (2023)	**Feed-in tariffs:** Established in 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. Wind and hydro: USD 0.073 per KWh Geothermal: USD 0.105 per KWh Biomass and biogas from organic waste: USD 0.133 per KWh Solar: USD 0.133 per kWh; up to 600 MW new utility-scale capacity per year. **Industrial Development Bank of Turkey (TSKB):** Low-interest loans to a number of renewable projects.	**Framework policy:** Ministry of Energy and Natural Resources Strategic Plan 2010 **Grid access and priority dispatch:** Renewable energy projects have priority for grid connection.

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

In any case, generators are required to hold a renewable energy resources certificate, which is obtained through government auctions, to qualify for the purchase obligation. Current licensing for utility-scale solar is limited to 600 MW and does not allow for deployment of that category to take place until the last quarter of 2013. However, solar projects up to 500 kW are exempted from this licensing requirement.

Economic attractiveness of renewable energy

Large hydropower and wind enjoy good economic attractiveness, with resource availability and falling system costs of the latter providing competitiveness on the spot market. While Turkey has rich solar resources, the economics of solar PV projects have generally not been favourable, with feed-in tariff levels not high enough to stimulate significant development. Continued falling system costs over the medium term and the recent lifting of licence requirements for small systems should stimulate activity, though up-front financing costs will still represent a significant constraint. For all other renewable projects, however, licensing fees and issuance will still weigh upon economics.

Financing

Financing should remain a constraint for renewable energy development over the medium term. A relative lack of financing mechanisms makes covering the high up-front costs of solar PV systems difficult for many small entities. While an increased diversity of private sector finance has entered the market, spurred by attractive resource potential, concerns over high inflation have tended to make investors prefer projects with short payback times and demand high internal rates of return.

The increasing involvement of development bank finance may help. The Industrial Development Bank of Turkey (TSKB) has provided low-interest loans to a number of projects. As of the end of 2010 TSKB was financing 2.9 GW of renewable capacity, of which 830 MW was already installed. The bank has also entered into financing agreements with the World Bank's International Finance Corporation, KfW and the Islamic Development Bank in order to direct funds to renewable energy development. The European Bank for Reconstruction and Development, in coordination with the European Investment Bank, has also launched a financing facility to invest in renewable energy in Turkey.

Conclusions for renewable energy deployment: baseline case

Turkey's rich resource potential combined with robust growth of economic demand and deployment targets should spur strong deployment over the medium term. We expect renewable generation capacity to expand from 20 GW in 2011 to 38 GW in 2017. Hydropower and onshore wind expansions looks the strongest, at 9 GW and 7 GW, respectively. Solar PV will begin to accelerate, with capacity rising by 0.8 GW, but the strongest additions will occur in the latter half of the forecast period. Notably, the country's already-strong experience in solar-thermal collectors for water heating should act as an enabler for small-scale PV deployment.

Table 51 Turkey renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	16.1	18.1	20.5	22.3	25.2	25.7	26.4	27.1
Bioenergy	0.1	0.3	0.4	0.5	0.6	0.7	0.8	0.9
Wind	1.3	1.8	2.4	3.1	4.3	5.5	7.0	8.5
Onshore	1.3	1.8	2.4	3.1	4.3	5.5	7.0	8.5
Offshore	-	-	-	-	-	-	-	-
Solar PV	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.8
Solar CSP	-	-	-	-	-	0.1	0.1	0.1
Geothermal	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**17.7**	**20.3**	**23.4**	**26.1**	**30.4**	**32.4**	**35.0**	**37.6**

Table 52 Turkey main drivers and challenges to renewable energy deployment

Drivers	Challenges
• National RE generation target combined with feed-in tariffs. • Strong demand growth; desire to diversify power system away from costly fossil fuel imports. • 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 feed-in tariffs may be too low to stimulate development. • Licensing for medium- and large-scale projects acts as a bottleneck. • Cost and availability of finance.

While the policy environment in Turkey has continued to strengthen with respect to renewable energy, shortcomings remain. Industry observers have pointed to the low level and relatively short duration of feed-in tariffs as insufficient to spur development in line with the government's long-term planning goals. Though progress has been made in lifting permitting barriers for small-scale systems, licensing requirements for larger projects will still remain a bottleneck. Moreover, financing will remain a persistent challenge, with a continued need for development bank funding.

Renewable energy deployment under an enhanced case

Much of the enhancement possible in Turkey pertains to accelerating wind, solar PV and CSP development. Streamlining licensing procedures would aid the deployment in onshore wind. The establishment of a net-metering policy would help advance solar PV by increasing the economic attractiveness for households and small commercial entities. In this case, we expect that wind capacity could be 4 GW higher and solar PV capacity could be 1.5 GW higher in 2017. Increased hybridisation of CSP technologies with fossil fuel plants could also result in modestly higher CSP deployment.

United Kingdom

A need for capacity to compensate for conventional retirements and favourable renewable support should spur strong deployment, but reform outcome uncertainty may delay investments.

Table 53 United Kingdom renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	7.9	2.0%	8.6	2.4%	8.7	8.8	8.9	9.0	9.0	9.1
Bioenergy	9.1	2.3%	13.3	3.6%	13.3	14.2	15.0	16.5	18.1	20.0
Wind	2.9	0.7%	15.5	4.3%	22.6	28.0	32.7	38.7	45.1	52.1
Onshore	2.7	0.7%	9.5	2.6%	12.7	15.1	18.1	21.4	24.6	28.0
Offshore	0.2	0.1%	6.0	1.6%	9.9	12.9	14.6	17.4	20.6	24.1
Solar PV	0.0	0.0%	0.3	0.1%	0.9	1.3	1.4	1.6	1.9	2.1
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	0.0	0.0	0.0	0.1	0.1	0.1
Total RES-E	**19.9**	**5.0%**	**37.7**	**10.3%**	**45.6**	**52.3**	**58.2**	**65.9**	**74.3**	**83.4**

Power demand outlook

The United Kingdom's electricity demand should increase by 1.1% annually on average over the medium term, amid moderate economic growth outweighing increased energy efficiency. United Kingdom real GDP is seen growing by 2.3% annually from 2011-17. Increasing electrification of household heating will provide some support to demand going forward, with the electrification of the transport sector potentially weighing larger in the long term. Still, relatively high retail prices and expected stagnation in industrial electricity usage should keep overall medium-term demand growth moderate.

Figure 51 United Kingdom power demand versus GDP growth

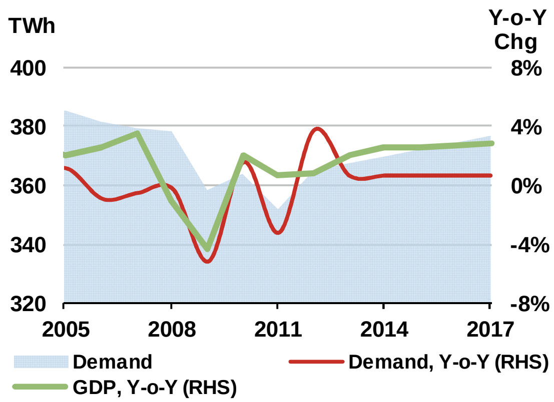
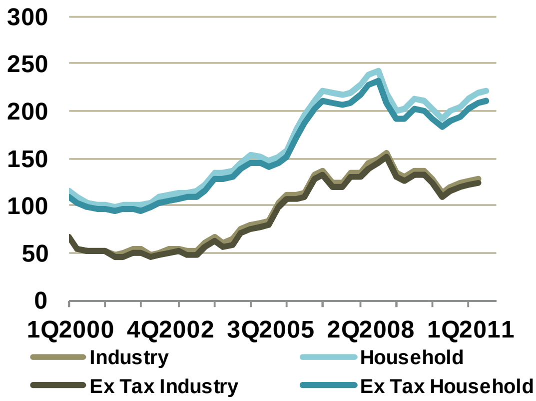


Figure 52 United Kingdom average retail power prices (USD per MWh)

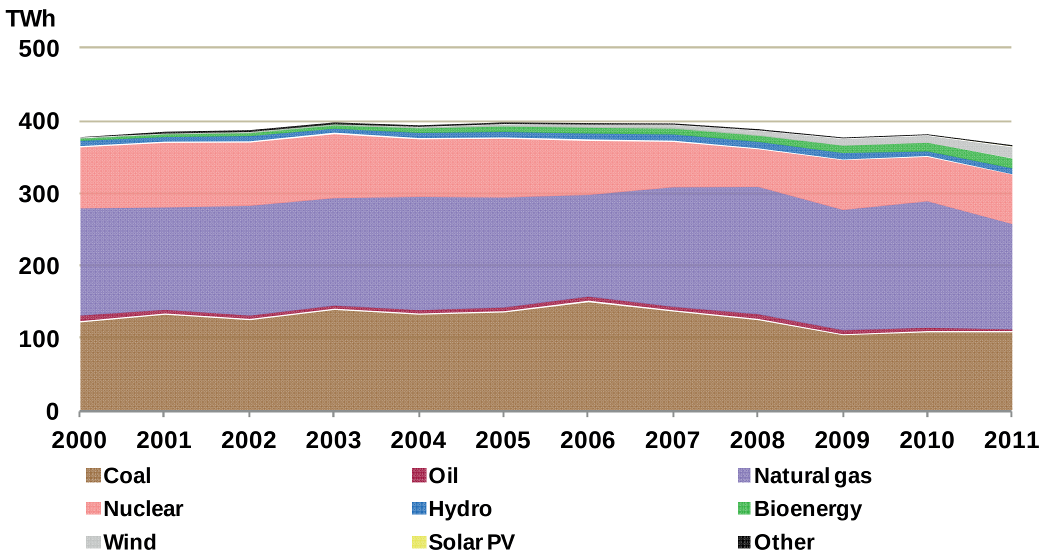


Power sector structure

Generation and capacity

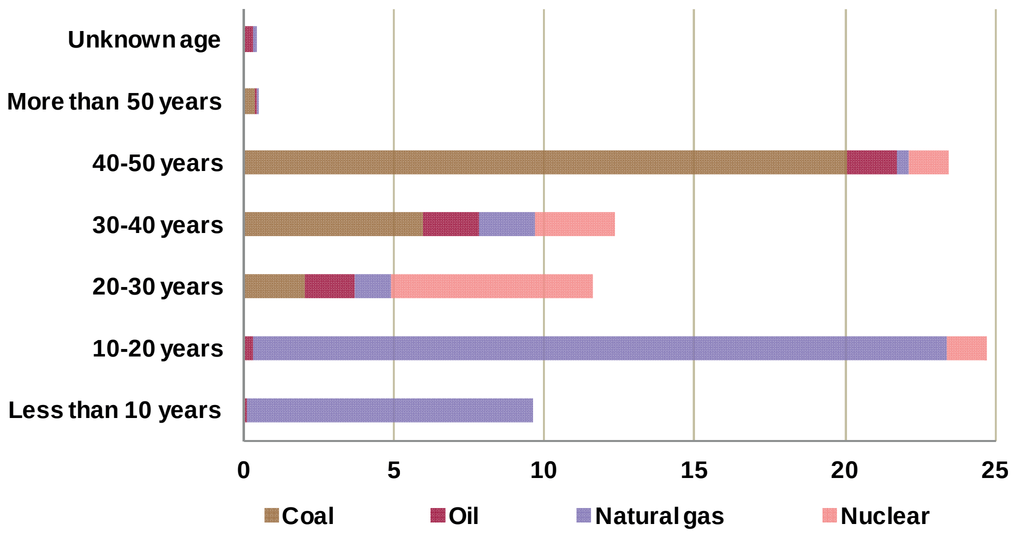
The United Kingdom's power generation mix is well diversified, but the replacement of ageing conventional generation will drive the system's evolution over the medium term, creating a need for increased renewable energy penetration. In 2011, natural gas accounted for 40% of output, followed by coal (30%) and nuclear (19%). Renewable sources represented 10% of power generation, led by bioenergy and onshore wind.

Figure 53 United Kingdom power generation by source



In 2011, the United Kingdom had a total of 95 GW of generating capacity, and peak demand has been relatively stable over the last decade, near 61 GW. Over the medium term, the power sector will enter a period of major change. Compliance with the European Union's Large Combustion Plant Directive will require closure of 12 GW of coal- and oil-fired generation capacity by 2015. In addition, around 3.8 GW of nuclear capacity will reach the end of its operational lifetime by 2017. Gas supplies from the North Sea are tightening, requiring higher levels of imports. All these factors should increase cost pressures and create significant capacity needs. Part of this should be met by new gas-fired generation, with some 5.5 GW in the project pipeline. Increased natural gas capacity will also have the benefit of providing capabilities to balance more variable renewable sources.

Figure 54 United Kingdom age distribution of conventional power plants in 2011 (GW)



Source: Platts World Electric Power Plants Database (2012).

Renewable generation

As a part of the United Kingdom's low-carbon strategy, the government has committed to supporting the deployment of renewable sources (particularly wind), nuclear, and carbon capture and storage (CCS). But significant capacity additions from the latter two categories should not emerge over the medium term due to long lead times, putting the power system under pressure. Fulfilling the National Renewable Energy Action Plan, requiring 31% of electricity in 2020 from renewable sources, will depend on expanding wind power capacity, with ambitious targets both for onshore and offshore, and increasing bioenergy production.

So far, wind development has proceeded strongly. In 2011, the United Kingdom added 580 MW of onshore wind and 750 MW of offshore wind to bring cumulative capacity to 4.4 GW and 2.1 GW, respectively. The Crown Estate, a government body that holds the rights to the United Kingdom seabed, is coordinating efforts to stimulate greater offshore wind capacity in cooperation with potential developers, the Department of Energy and Climate Change (DECC) and other government departments. They have offered exploitation rights to developers via three tendering rounds (together 47 GW), each offering successively more technically and commercially challenging zones in terms of water depth and distance from the shore.

While not large in absolute terms, bioenergy developments have also been significant. Notably, the United Kingdom leads in large-scale co-firing, with Drax's plant in North Yorkshire, the largest co-firing facility in the world, providing a good example of biomass generation in a coal-fired electricity plant. Even more ambitiously, the Tilbury B power plant was converted in 2011 from a coal-fired plant to a 100% biomass-fuelled site of unprecedented capacity, 750 MW, and started operation in 2012. The plant falls under the Large Combustion Plant Directive and should close by 2015, but serves as a useful test of converting coal-fired plants as well as a means of establishing a supply chain for large amounts of sustainable biomass.

Though its prospects look limited over the medium term, solar PV capacity has also grown. In 2011, the United Kingdom added 680 MW to reach cumulative capacity of 750 MW. This deployment was largely underpinned by a feed-in tariff scheme for small-scale generation adopted in April 2010. However, due to higher-than-expected additions, the tariffs were reduced first for projects above 50 kW and later for smaller projects. These actions led to two waves to connect to the grid before the cuts took hold during 2011.

Box 3 Electricity Market Reform should bring major changes to United Kingdom power system

The UK government has proposed a wide-reaching Electricity Market Reform (EMR) that aims to address several power system challenges over the medium and long term. The EMR seeks to provide a strategy for renewing a significant part of an ageing generation fleet. It also seeks to tackle integration hurdles related to a planned rapid increase in variable generation (largely wind) in the face of a still-sizeable share of inflexible generation (presently nuclear, but potentially CCS in the long term). The reforms need to allow for anticipated increasing electrification of the heat and transport sectors. All the while, the government is seeking to address energy security concerns by focusing development on three core technologies – wind, nuclear and CCS – that carry resource availability advantages.

To date, only a few concrete details have emerged regarding the reforms, implying a significant degree of uncertainty over how the EMR will be implemented over the medium term. Central to the EMR will be the establishment of a capacity market. The government also seeks to create a market framework that will deliver increased investments in low-carbon generation.

The announcement of feed-in tariffs with contracts for difference (FIT-CFD) against the market electricity price, in 2013, should bring long-term contracts both for low-carbon energy and for capacity by providing a stable stream of revenues for investors. At the same time the government plans to introduce a carbon price floor by 2013. These measures will be accompanied by an emissions performance standard, effective by 2014, aimed at limiting carbon emissions of new fossil fuel plants. In effect, this initiative guarantees that no new coal-fired plants can be built without CCS equipment. On the demand side, plans include equipping residential sector users with smart electricity and gas meters.

As part of the transition from existing policy, the Renewable Obligation (RO) scheme is slated to continue until the end of March 2017, with new projects choosing between the RO and FIT-CFD schemes, once it is in place. Projects under the RO will carry forward the certificate rate applicable on 31 March 2017 through their remaining economic lifetimes.

Grid and system integration

The integration of renewable sources in the United Kingdom will present some challenges over the medium term, with investment in grid reinforcement and extension needed. A report from the Electricity Networks Strategy Group (ENSG) has stated that additional investments of GBP 8.8 billion in the transmission grid are needed to accommodate expected total new generation capacity (38.5 GW) by 2020, of which offshore wind would represent sizeable component (ENSG, 2012). The investment rate will need to significantly rise to achieve this level, relative to the preceding 20 years.

Through Project Transmit, Ofgem, the British regulator, is currently reviewing the transmission connection and charging regime to establish whether it provides a sufficiently strong signal to attract needed investment. Among other aspects, the project will assess the benefits of location-based electricity pricing to reflect the need for reinforcement in key weak spots.

The growing proportion of distributed generation; the need to extend the high-voltage grid to renewable resource-rich locations, including offshore wind; and the ability of the system to manage greater variability will act as crucial investment challenges. The Crown Estate estimates that a significant amount of investment (GBP 10 billion) will be needed to connect all third-round offshore wind projects (IEA, 2012).

Current policy environment for renewable energy

To date, deployment of renewable energy sources in the United Kingdom has been driven by the RO scheme and a feed-in tariff scheme for small-scale generation. The latter, adopted in April 2010, stimulated rapid growth in solar PV, though tariffs were cut in two phases during 2011 due to much-stronger-than-anticipated activity.

A number of uncertainties characterise the policy environment in the short and medium term. A review of the levels of support for technologies under the RO is in progress, and reduced levels of support for key technologies, including onshore and offshore wind, may affect investment levels. In addition, a major policy overhaul is taking place in the form of the EMR, for which many details have yet to be established. While the EMR proposal includes transition measures, the shares of new-build renewable capacity that would apply under the new scheme versus under the RO scheme remain unclear. Moreover, the "strike price" for the FIT-CFDs will be set only in 2013, leaving short-term uncertainty over the price that developers would receive for electricity generation under the scheme. In itself, the change in policy environment will likely cause some uncertainty that delays some investment decisions in the short term.

Table 54 United Kingdom main targets and support policies for renewable electricity

Targets	Financial support	Other support
National Renewable Energy Action Plan: Binding target: 15% of renewable energy in gross final energy consumption in 2020. Indicative 2020 split: 31% of electricity production from renewable sources provided by: 2.1 GW hydropower 0.92 GW geothermal 2.7 GW solar PV 1.3 GW ocean 14.9 GW wind onshore 13 GW wind offshore 4.2 GW bioenergy	**Feed-in tariffs for small-scale generation:** Apply to hydro, wind, solar and anaerobic digestion technologies below 5 MW. Include micro co-generation pilot scheme. **Renewable Obligation:** 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:** Energy White paper 2011 (presenting Electricity Market Reform) Energy Act 2010 Renewable Energy Strategy 2009 Climate Change Act 2008 **Grid access and priority dispatch:** Grid access granted.

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

Economic attractiveness of renewable energy

Going forward, the economic attractiveness of renewable energy in the United Kingdom will heavily depend on the level of feed-in tariffs proposed as part of the EMR and their start date. In the meantime, tradable certificates (ROCs) associated with projects under the RO and feed-in tariffs for small-scale generation have helped improve renewable economics, though the latter are decreasing over time. Offshore wind gets a particular boost in the RO scheme, with projects receiving two certificates per MWh generated, but with ROC levels decreasing over time. Nevertheless, the attractiveness of projects going forward will depend on overcoming a number of potential supply chain and technical challenges.

Financing

In general, as a country with a relatively low cost of capital and a high degree of financial innovation, the United Kingdom's financing environment should act as an enabler for renewable deployment. However, overall policy uncertainty may be delaying some investment decisions in the short term. Over the medium term, the availability and cost of debt capital, particularly important for offshore wind projects, should remain a moderate barrier, though it is likely to slow rather than stall growth. Given ambitious deployment targets and prevailing constraints in financial markets (see *Investment in Renewable Electricity* chapter), the creation of a government-sponsored Green Investment Bank should act as a key boost. The bank, initially endowed with GBP 3 billion financing activities, will benefit the large required investments in offshore wind, and focuses on just three sectors: offshore wind, waste and energy efficiency.

Conclusions for renewable energy deployment: baseline case

The United Kingdom's need for additional generation capacity to compensate for conventional capacity retirements and favourable renewable policies should spur strong deployment over the medium term. Renewable electricity capacity should expand from 14.2 GW in 2011 to 29.9 GW in 2017. With 12.2 GW of growth expected, the total outlook for wind is the most robust. Of these additions, 5.3 GW are expected to come from offshore projects. Solar PV and bioenergy are also expected to grow, but by a more moderate 1.8 GW and 1.4 GW, respectively.

Table 55 United Kingdom renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	4.4	4.5	4.6	4.6	4.6	4.7	4.7	4.7
Bioenergy	2.3	2.3	2.5	2.6	2.8	3.0	3.3	3.7
Wind	5.2	6.5	8.8	10.1	12.1	14.1	16.4	18.7
Onshore	3.9	4.4	5.2	6.2	7.5	8.7	10.0	11.4
Offshore	1.3	2.1	3.5	3.8	4.5	5.4	6.4	7.4
Solar PV	0.1	0.9	1.3	1.7	1.8	2.1	2.4	2.7
Solar CSP	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-
Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Total RES-E	**12.0**	**14.2**	**17.1**	**19.0**	**21.3**	**23.9**	**26.8**	**29.9**

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

There are two major variables to this forecast, however. First, the energy policy environment over the medium term still remains unclear. Details for the review of both RO scheme banding and the EMR are still pending. Second, achieving the planned targets will depend heavily on rapid deployment of offshore wind. With 7.4 GW of projected offshore capacity in 2017, installed capacity is expected to be less than the 8.3 GW announced for 2017 in the NREAP. The delivery of offshore projects remains technically and commercially challenging. Projects may face installation and commissioning delays due to bad weather conditions, and from potential bottlenecks in the supply chain. Still, The Crown Estate's facilitation efforts, if successful, could ultimately lead to much higher levels of offshore wind deployment than envisaged in the NREAP – the Crown Estate is aiming for 25 GW to be operating or under construction by 2020 – perhaps offsetting NREAP shortfalls elsewhere (for example in the challenging renewable heat sector) (The Crown Estate, 2011).

Deployment of bioenergy capacity will be particularly influenced by the results of the current review of banding within the RO, which removes the cap on co-firing, and introduces a band aimed at plant conversion. In the longer term the level of support (from feed-in tariffs and carbon pricing) within the EMR proposals will also be important. Deployment could also be affected by the development and application of sustainability criteria to bioenergy feedstocks to be used for electricity generation. Given these uncertainties, our forecast for bioenergy growth over the medium term remains conservative.

Table 56 United Kingdom main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Strong government commitment to clean power generation sources with ambitious targets. • Acute need to replace ageing conventional generation fleet. • Targeted financial support to offshore wind from newly created Green Investment Bank.	• Policy uncertainty over EMR and levels and start dates of new financial supports undermines current investment climate. • Technical and financial challenges for offshore wind development. • Significant investment needed for grid reinforcement and extensions.

Renewable energy deployment under an enhanced case

An enhanced case for renewable deployment would require rapid clarification of the policy uncertainties related to the review of ROC banding, the EMR process, and those associated with permitting and grid connection. Better progress would need to come about in offshore wind developments, particularly in terms of alleviating 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 almost 1 GW higher in 2017 versus the baseline, with most of the difference coming towards the end of the forecast period.

Other OECD Europe countries

For completeness of the regional picture, the following section briefly covers other OECD Europe countries with significant or interesting renewable developments in recent years, or that are expected to become significant areas for renewable deployment in the medium term.

The world champion in share of renewable power production is **Iceland**. This island country uses its excellent renewable energy potential to fully cover its electricity demand. Only less than 0.1% of the country's power is produced from oil, with the rest covered by provided hydropower and geothermal resource supplies. The country does not have any fossil fuel reserves, and its geographical situation make hydropower and geothermal natural options to develop. Due to the technological maturity of these technologies and a lack of other alternatives, hydro and geothermal developments do not need any special policy push. We do not expect this situation to change in the medium term; hydro and geothermal sources should be the choices for additional power generation in the future.

One of the best examples of a portfolio approach to renewable energy sources is **Portugal**. The country increased its share of renewable power from 30% in 2000 to near 50% in 2011 by developing all sources of renewable energy, including ocean projects. Hydropower and wind are the most significant resources there, with potential that can still be further developed. Portugal is a front runner in wind penetration, which reached more than 17% in 2011. This penetration poses significant integration challenges that are dealt with on a regional level. Further development in renewable energy is currently under threat as Portugal is facing serious economic problems. Since summer 2011, discussions are ongoing about imposing retroactive cuts to feed-in tariffs or an extraordinary tax on existing renewable capacities. Such measures, if adopted, would be harmful both for existing renewable power producers and future investment. For the moment a moratorium on new renewable power generation capacity has been put in place. The final decision on dealing with the total cost of renewable policies will be a crucial determinant of the medium-term outlook.

Another country with high wind penetration is **Ireland**, which has fully invested its efforts to develop a strong wind industry. The country had 1.6 GW of wind capacity installed in 2011. A major challenge going forward will be the integration of variable power generated by increased wind capacity. The grid will require strengthening and improved interconnections with the United Kingdom.

Finland has well-established hydropower and bioenergy-based power production that together contribute more than 30% of power production. Further expansion of the renewable power sector is expected to be based on biomass and wind, both on- and offshore.

Greece has made sizeable progress over the last 10 years in hydropower and wind development. Despite its great solar potential, solar PV is proceeding more slowly, mainly due to a difficult policy environment in which permitting is not streamlined. Meanwhile, private rooftops have been largely taken over by solar water heaters, for which procedures are less tedious. Significant solar PV development may ultimately come with the Helios Solar Project (10 GW), which would transmit electricity to countries such as Germany or Austria, who are hungry for power imports that can be labelled as renewable. However, the technical details of this project and its financial viability remain to be seen over the medium term. In wind, significant barriers to planning and grid access have been overcome with reforms, prompting strong interest in the planning of new projects. Yet here too, the constrictive financing picture remains a major bottleneck.

Solar PV development progressed rapidly between 2009 and 2011 in **Belgium**, **the Czech Republic** and **the Slovakia**, despite low solar irradiation. The Czech Republic and Slovakia followed the German model for feed-in tariffs, but did not effectively incorporate rapid cost improvements for systems into their laws, leading to overly generous tariffs that produced a solar PV bubble in both countries. The Czech Republic halted solar PV development in 2010 once the total capacity was already over 2 GW and the impact on power prices became significant. Subsequent introduction of retroactive measures applicable to PV plants was detrimental to the industry and 2011 saw only 10 MW of new installations. Slovakia brought changes to solar PV legislation in mid-2011, keeping total installed capacity at a more manageable 0.5 GW while allowing for further expansion of the buildings segment and installations below 100 kW. Belgium has enjoyed a strong market for three years, installing more than 1.0 GW in 2011 to reach a total capacity of 2.0 GW.

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MEDIUM-TERM OUTLOOK: NON-OECD MARKETS

Summary

- **Non-OECD renewable electricity generation is projected to grow from 2 412 TWh in 2011 to 3 632 TWh in 2017 (+7.1% per year).** 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 more than 670 TWh, followed by onshore wind (+300 TWh) and bioenergy (+120 TWh). Geothermal, offshore wind, solar photovoltaics (PV) and concentrating solar power (CSP) should account for a smaller part of the overall growth, though individual growth rates for offshore wind and solar will be high as these technologies grow from a small base.

- **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 accelerate in countries with good resources and emerging support measures. Onshore wind is becoming attractive in some areas, and rapidly declining solar PV costs should prompt deployment beyond China and India towards the end of the forecast period. In particular, this growing attractiveness of solar PV stems from its cost advantage in distributed applications and increased policy support.

- **China's renewable electricity capacity should grow from 303 GW in 2011 to 574 GW in 2017 (11.2% per year), the largest increment in the world.** Deployment should be led by hydropower (+110 GW), onshore wind (+104 GW) and bioenergy (+18 GW). Solar PV (+32 GW) and offshore wind (+7 GW) should increase rapidly, yet with growth proceeding from a low base, there is more forecast uncertainty in these areas. Strong policy with ambitious targets underpins the outlook, but institutional approaches to pricing, grid expansion and licensing will act as key variables.

Table 57 Non-OECD renewable electricity generation (TWh)

	2005	% Total Gen	2011	2012	2013	2014	2015	2016	2017
Hydropower	1 643	21.2%	2 186	2 250	2 359	2 478	2 602	2 729	2 857
Bioenergy	32	0.4%	80	102	121	140	162	183	205
Wind	10	0.1%	112	143	185	233	291	359	436
Onshore	10	0.1%	112	142	183	229	283	345	415
Offshore	-	0.0%	0	1	2	4	8	14	21
Solar PV	0	0.0%	8	15	26	39	53	69	88
Solar CSP	-	0.0%	0	0	1	2	4	5	8
Geothermal	20	0.3%	26	27	28	30	33	36	37
Ocean	-	0.0%	0	0	0	0	0	0	0
Total RES-E	**1 705**	**22.0%**	**2 412**	**2 537**	**2 720**	**2 923**	**3 145**	**3 381**	**3 632**

Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. Hydropower includes pumped storage; 2011 data are estimates; RES-E = electricity generated from renewable energy sources.

- **Renewable electricity capacity in India should grow from 62 GW in 2011 to 101 GW in 2017 (8.5% per year).** Deployment should be led by onshore wind (+17 GW), hydropower (+13 GW) and solar PV (+7 GW). With acute rural electrification needs, distributed solar PV and bioenergy installations should continue to advance. The renewable obligation mechanism combined with other financial incentives underpins the forecast, but India's development will hinge significantly on grid strengthening and expansion.

- **In Brazil, renewable electricity capacity should grow from 96 GW in 2011 to 128 GW in 2017 (4.9% per year).** Deployment should be led by hydropower (+21 GW), onshore wind (+8 GW) and bioenergy (+3 GW). Relatively higher-cost solar PV (+1 GW) should grow moderately, with activity picking up over the forecast period. Hydropower continues as a cheap and ample mainstay of development, and government-sponsored auctions have driven a burst of recent wind contracts. Still, challenges related to environmental licensing and uncertainty over project delivery from auctions act as key variables.

Brazil

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

Table 58 Brazil renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	337	83.7%	449	86.3%	417	428	436	449	471	496
Bioenergy	15	3.7%	22	4.2%	28	30	32	33	35	36
Wind	0	0.0%	3	0.6%	5	9	12	15	18	20
Onshore	0	0.0%	3	0.6%	5	9	12	15	18	20
Offshore	-	0.0%	-	0.0%	-	-	-	-	-	-
Solar PV	-	0.0%	0	0.0%	0	0	0	0	1	1
Solar CSP	-	0.0%	-	0.0%	-	-	-	-	-	-
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	-	-	-	-	-	-
Total RES-E	**352**	**87.4%**	**474**	**91.0%**	**451**	**467**	**480**	**498**	**524**	**554**

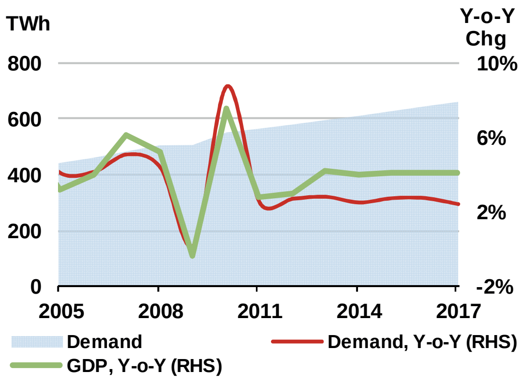
Note: 2011 data are estimates.

Power demand outlook

Brazil's economy has boomed in recent years, with gross domestic product (GDP) growth averaging 3.7% from 2000-10 and contracting only slightly in 2009 during the economic crisis. Such growth has been energy-intensive, with power demand expanding by 2.9% annually. Consumption growth has at times been constrained by supply availability, as in the energy crisis of 2001, when low hydro reservoirs prompted nationwide rationing. Power sector reforms and rising retail prices have all worked to reduce energy intensity over time. Still, electricity prices remain quasi-regulated by the government, with large, subsidised industrial customers providing a demand boost. The industrial sector represents the bulk of demand, accounting for nearly 45% of electricity consumption in 2011.

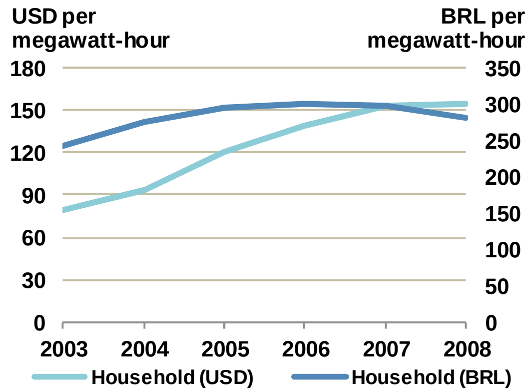
Looking forward, GDP growth, according to the International Monetary Fund (IMF), is expected to moderate at 3.0% in 2012, versus 2.7% in 2011 (IMF, 2012). The economy is expected to expand on average by 4.1% per year from 2013-17. As such, Brazil's electricity demand is expected to grow annually by an average 2.6% from 2011-17. During this period, Brazil will host two major showcase events – the World Cup in 2014 and the Olympics in 2016 – which will both boost power demand.

Figure 55 Brazil power demand versus GDP growth



Note: demand is expressed as electricity supplied to the grid, RHS is right-hand side.

Figure 56 Brazil average retail power prices



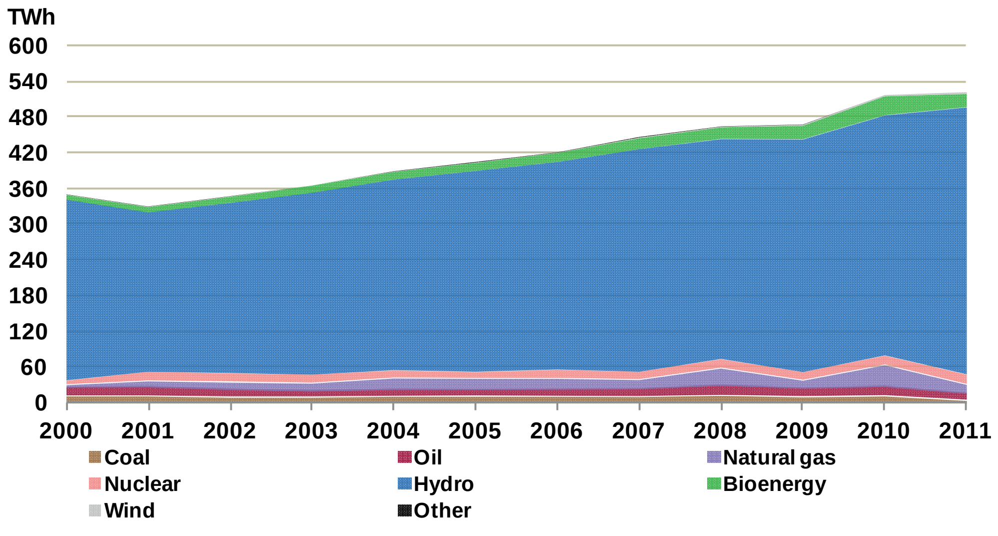
Source: MME (2009).
Note: post-2008 prices are not available.

Power sector structure

Generation and capacity

Renewable energy traditionally dominates Brazil's power generation. In 2011, hydropower output, the country's primary base-load source, was strong and accounted for 86% of generation. Much of this hydropower is large scale, with one facility, the 14 GW Itaipu plant, providing over 16% of total generation[3]. Further hydropower expansions should keep this share high over the medium term.

Figure 57 Brazil power generation by source

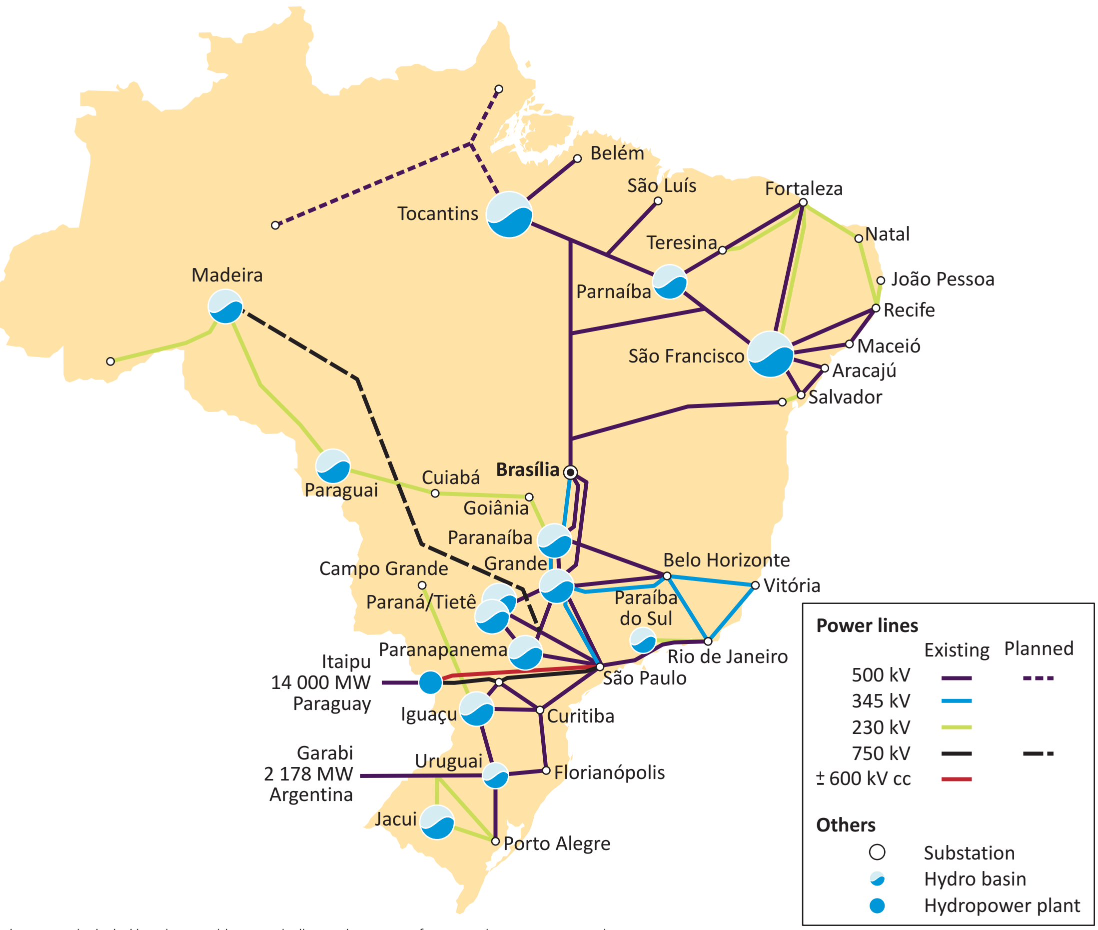


In 2011, bioenergy, largely sugar cane bagasse-fired generation, provided 4% of electricity generation. The contribution of wind and solar PV remained small, but this situation looks to change. Recent turbine price reductions and successful auction biddings by projects suggest that wind power will expand rapidly through 2017. Based on relatively high costs, solar PV development should proceed more slowly. Still, Brazil has good potential for small, off-grid applications. Overall, renewable energy

[3] Brazil owns a 50% share in the plant with Paraguay accounting for the other half. Paraguay exports a significant portion of its output to Brazil.

should play an increasing role in Brazil's power build-out. The government's Decennial Energy Plan (PDE 2020) sees renewable energy accounting for 80% of new capacity from 2011-20, led by large hydropower (MME and EPE, 2011).

Map 4 Brazil power transmission system and main hydro basins



This document and any map included herein are 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: ONS (2012).

Table 59 Brazil power generation capacity targets under the PDE 2020 (GW)

GW	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	82.9	84.7	86.7	89.0	89.9	94.1	98.9	104.4	109.4	111.6	115.1
Nuclear	2.0	2.0	2.0	2.0	2.0	2.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	9.2	9.4	10.2	11.3	11.3	11.7	11.7	11.7	11.7	11.7	11.7
Coal	1.8	2.5	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Oil	3.9	5.2	6.6	10.3	10.3	9.9	9.9	9.9	9.9	9.9	9.9
Process Gas	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Small Hydropower	3.8	4.2	4.2	4.4	4.6	5.0	5.2	5.5	5.7	6.0	6.4
Biomass	4.5	5.4	6.3	6.7	7.1	7.4	7.7	8.0	8.3	8.7	9.2
Wind	0.8	1.3	3.2	5.3	6.2	7.0	7.8	8.7	9.5	10.5	11.5
Total	**109.6**	**115.5**	**123.2**	**132.8**	**135.2**	**140.9**	**148.4**	**155.4**	**161.9**	**165.8**	**171.1**

Note: hydropower includes imports from Itaipu hydropower plant not consumed by Paraguay.
Sources: MME and EPE, 2011.

Nevertheless, conventional fuels will continue to play an important role over the medium term, partly to mitigate hydro variability. The conventional fuel share of power generation was around 10% in 2011, consistent with values of the previous decade. According to the PDE 2020, natural gas, coal and nuclear power should expand modestly over the next decade, with oil-fired generation, an important source for meeting peak demand and in rural electrification efforts, also rising.

Grid and system integration

Renewable energy is well integrated into the Brazilian power system, which has a high degree of flexibility. Brazil has considerable experience constructing long-distance, high-voltage transmission lines to deliver hydropower to demand centres along the coast. Bioenergy, traditionally the second-largest renewable power source, is concentrated near sugar cane production in the centre-south region where most electricity is consumed. And the best wind resources, in the south and northeast regions, also benefit from a location close to these demand centres. Furthermore, wind can play an important balancing role for hydropower, with strong output during dry winter periods, particularly in the northeast.

Current policy environment for renewable energy

Unlike many countries in this report, Brazil does not currently employ quotas or feed-in tariffs. The PDE 2020 provides planning guidance for the power sector capacity. Over 2010-20, authorities envisage that large hydropower will grow by 32 GW, followed by wind at over 10 GW. Still, these milestones are not binding. Since 2002, the government has offered power purchase agreements with Electrobras to wind, biomass and small hydro (up to a combined target of 3.3 GW) under the Promotion of Alternative Sources of Electric Energy (PROINFA) programme. It also imposed a 60% local content requirement for wind equipment, which along with other permitting and grid connection issues delayed some projects. As of 2011, 1 325 MW of wind capacity had been installed and connected under the programme, though one 135 MW project is still pending.

Table 60 Brazil main targets and support policies for renewable electricity

Targets	Financial support	Other support
Decennial Plan for Energy Expansion (PDE 2020): Targets for expected installed capacities in 2020: 11.5 GW wind 115.1 GW large hydro 9.2 GW bioenergy 6.4 GW small hydro	**Auctions of Power Purchase Agreements (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. **Brazilian Development Bank (BNDES):** Low-interest loans to a number of renewable projects. **Programme for Incentives for Alternative Electricity Sources (PROINFA):** Capital subsidies, preferential loans and preferential PPAs. **Net metering for distributed systems:** Solar PV, small wind, bioenergy	**Framework policy:** Decennial Plan for Energy Expansion (PDE 2020) Brazil National Climate Change Plan Plano Brazil Maior **Grid access and priority dispatch:** Grid access and dispatch guaranteed under power purchase agreements.

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

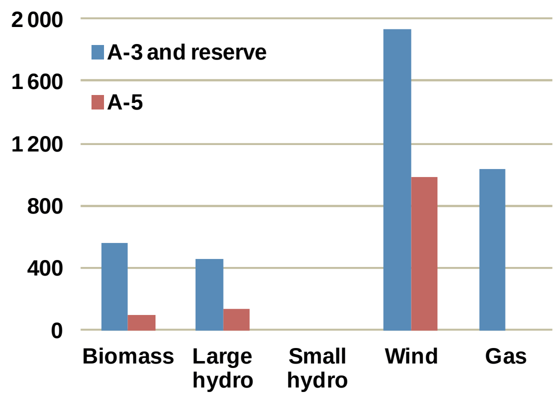
More recent policy focuses on government-sponsored power auctions, which award long-term (up to 30-year) power purchase agreements with all distributors. Until 2010, wind, biomass and small-hydro projects would participate in renewable-only auctions. Now, these sources compete with conventional fuels. The auctions encourage competition and cost reductions. The long-term nature of the contracts also creates greater revenue certainty for investors. Over the past year these auctions have awarded contracts to an impressive number of renewable projects, with onshore wind often outbidding natural gas on a cost basis. For example, in December 2011, wind energy accounted for more than 80% of the 1.2 GW of contracted projects for delivery in 2016, with biomass and small hydropower accounting for the remainder.

Outside of rural electrification efforts, solar PV has remained largely absent from renewable energy development, partly due to the government's scepticism on its economic viability compared with other sources. Indeed, the PDE, thus far, has not factored this technology into its capacity projections. Nevertheless, some policy initiatives are under way. The proposed Carta do Sol (Sun Charter), from Rio de Janeiro state authorities, foresees increased financial incentives along the entire solar PV supply chain and targeted auctions. Some federal lawmakers have also called for targets, dedicated auctions, tax reductions and transmission incentives for solar energy under a proposed Prosolar programme. Moreover, the power regulator, Agencia Nacional de Energia Elétrica (ANEEL), has recently implemented net metering rules, which should stimulate deployment of distributed solar PV.

Economic attractiveness of renewable energy

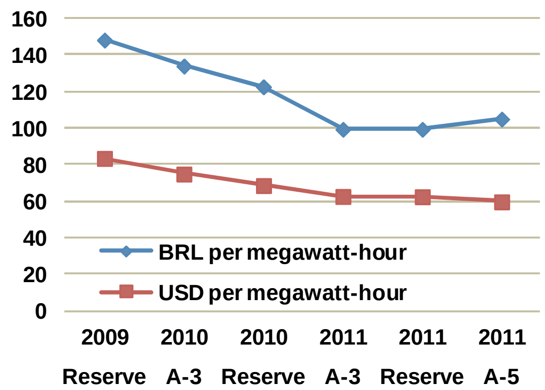
Hydropower, biomass and wind generation are all economically attractive versus fossil fuels. Large hydropower should remain the most cost competitive source of power in Brazil, even when factoring in corresponding transmission lines. Recent power auctions have demonstrated the economic attractiveness of wind and biomass. For wind, contracted dollar prices have fallen by almost 30% since 2009, a decline that is somewhat less than in Brazilian real terms due to exchange rate effects. Nevertheless, these prices mask additional required costs in grid connections and transmission fees, which are funded through public sources.

Figure 58 Brazil contracted auction capacity in 2011 (MW)



Source: EPE.

Figure 59 Brazil average contracted auction price for new wind projects



Note: exchange rate is 90-day average.
Source: IEA analysis based on data from EPE.

Financing

Brazil's financing environment helps renewable energy deployment. The country's power sector, in general, has attracted a significant capital influx in recent years with the auction system providing an attractive entry mechanism. Moreover, the state-backed Brazilian Development Bank (BNDES) plays a large role in renewable energy investments by offering low-interest loans to a significant number of projects. In 2011, BNDES funded USD 3.7 bn worth of renewable electricity projects, representing some 5% of its total outlays. Funds from the international financial initiatives of German development bank KfW and investments under the Clean Development Mechanism (CDM) have also played role in deployment.

Investment in Brazil appears to be partially benefiting from shifting financial flows resulting from recent economic and policy uncertainty in Europe. However, the viability of these flows going forward will depend on the evolution of Brazil's economy and several internal developments: the success rate of projects contracted under auction, the degree to which the environmental permitting process can be improved and the evolution of Brazil's larger internal infrastructure.

Conclusions for renewable energy deployment: baseline case

Brazil's need for additional generation capacity to meet demand growth and increasingly favourable renewable energy economics should spur strong deployment over the medium term. Renewable electricity capacity should expand from 96 GW in 2011 to 128 GW in 2017. With 21 GW of growth expected, the outlook for hydropower growth is the most robust. The construction of the Belo Monte Amazon Dam, which began in 2011, will add 11.2 GW starting in 2015 with capacity coming online in phases through the end of the decade. Meanwhile, onshore wind capacity should grow from 1.5 GW in 2011 to 9.0 GW in 2017. Biomass projects should add 2.6 GW over that time period. Growth contributions from solar are expected to be small, at 0.9 GW.

Table 61 Brazil renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	88.2	88.9	91.0	93.3	94.5	99.0	104.1	109.8
Bioenergy	5.4	5.4	6.3	6.7	7.1	7.4	7.7	8.0
Wind	0.9	1.5	3.0	4.5	6.0	7.0	8.0	9.0
Onshore	0.9	1.5	3.0	4.5	6.0	7.0	8.0	9.0
Offshore	-	-	-	-	-	-	-	-
Solar PV	0.0	0.0	0.1	0.2	0.3	0.4	0.7	0.9
Solar CSP	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-
Ocean	-	-	-	-	-	-	-	-
Total RES-E	**94.5**	**95.9**	**100.3**	**104.7**	**107.8**	**113.8**	**120.4**	**127.7**

Table 62 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. • Large hydropower potential with significant capacity in the medium-term project pipeline. • Ample availability of low-cost financing from private sector and development agencies.	• Cost reductions through auctions may increase project vulnerability; head-to-head competition may price out some technologies. • Needed streamlining for environmental licensing. • Economic attractiveness of solar PV.

In general, the country maintains a predictable policy framework. Given the market mechanisms at work, auctions have served to improve Brazil's dynamic approach to renewable policy. Still, its auction approach has tended to lump technologies together in head-to-head competition, where most recently, wind's success has marginalised bioenergy and small hydropower projects, which could possibly undermine a portfolio approach. Moreover, important non-economic barriers and system integration issues remain.

The forecast stems largely from identified hydropower in the project pipeline as well as wind and biomass projects contracted through the auction system. However, our projections are more conservative than headline capacity additions (and the PDE 2020) would suggest due to some question marks. It remains to be seen whether actual renewable capacity will grow as quickly as the auction results suggest. The pace of competition to reduce costs may be increasing project vulnerability. With unforeseen construction delays or lower-than-anticipated operational performance, potential thinner financial margins could undermine the financial viability of some projects. And Brazil's sometimes-challenging logistics and infrastructure add a further layer of risk.

Environmental licensing, a pre-condition for auction participation, raises non-economic hurdles to investment and may delay some projects already under way. Given a desire to minimise negative environmental externalities, this process is particularly difficult for hydropower projects and transmission line expansions, though reports have also emerged of missing licences for wind developments. Moreover, grid integration could become an issue, with increasingly dispersed wind projects requiring timely transmission upgrades and expansions, particularly in the north.

Renewable energy deployment under an enhanced case

Although strong renewable energy growth is already expected in Brazil, capacity could grow faster. Specifically, versus the baseline forecast, cumulative capacity in bioenergy, solar PV and wind capacity could each come out 1 GW to 2 GW higher in 2017 with certain market enhancements. This more optimistic scenario could stem, first, from the streamlining of environmental licensing procedures by the government without compromising social and environmental aims, helping to facilitate grid upgrades. A number of policy measures are already under way to facilitate the licensing process, though further improvements could come about.

Second, there is potential for improvements in the investment environment for renewable energy. While the auction system has provided an attractive platform for investors, the competition may be increasing project delivery risks for still-nascent technologies in Brazil, such as wind, and inhibiting the development of more costly biomass and solar projects. Technology-specific renewable energy auctions could potentially enhance deployment across all renewable energy sources. This could increase project reliability and yield energy security benefits. Still, such structures may lead to higher contracted costs in the short term.

Finally, an enhanced scenario would see greater deployment of solar PV. Technology-specific auctions and implementation of the types of incentives outlined under the proposed Prosolar programme could help. Stronger-than-anticipated deployment of distributed solar PV could also occur under the newly implemented net metering rules. Moreover, the potential for oil-to-solar PV substitution remains strong, particularly in the Amazon and other rural regions where grid connections remain difficult and local economies often rely on diesel generators.

China

China sees strong renewable energy deployment across most technologies. Still, growth could be higher with grid strengthening, institutional reform and more integrated policy approaches.

Table 63 China renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	397	15.6%	736	15.6%	789	842	900	963	1 030	1 096
Bioenergy	2	0.1%	34	0.7%	46	59	73	87	101	114
Wind	2	0.1%	73	1.6%	93	121	154	195	241	294
Onshore	2	0.1%	73	1.5%	91	118	150	187	227	273
Offshore	-	0.0%	0	0.0%	1	2	4	8	14	21
Solar PV	0	0.0%	3	0.1%	7	12	17	24	31	39
Solar CSP	-	0.0%	0	0.0%	0	0	0	1	1	3
Geothermal	0	0.0%	0	0.0%	0	0	0	0	0	0
Ocean	-	0.0%	0	0.0%	0	0	0	0	0	0
Total RES-E	**401**	**15.8%**	**847**	**17.9%**	**934**	**1 034**	**1 145**	**1 269**	**1 404**	**1 547**

Note: 2011 data are estimates.

Power demand outlook

Buoyed by robust economic growth, China's power demand should expand strongly over the medium term. According to the IMF, real GDP growth is expected to average 8.6% annually from 2011-17. Power demand is projected to grow on average by 5.9% with increased industrial and household use. The government regulates electricity prices at the generation and distribution levels. Unlike in many countries, industry faces higher prices than households and industry prices have risen in recent years. Price increases for households have remained more limited, partly due to inflation concerns. Still, the government has voiced an intention to introduce a tiered pricing system for residential users, which would raise rates for the largest (20% of household consumers), helping to dampen demand growth.

Figure 60 China power demand versus GDP growth

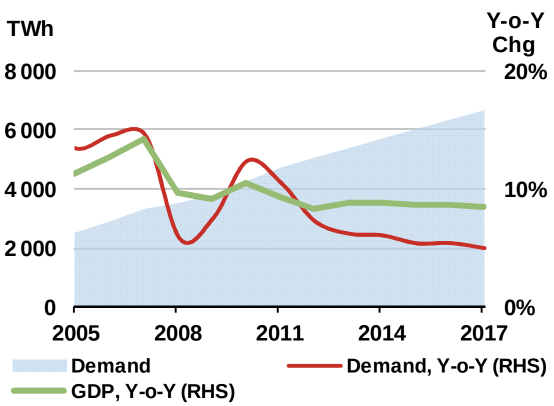
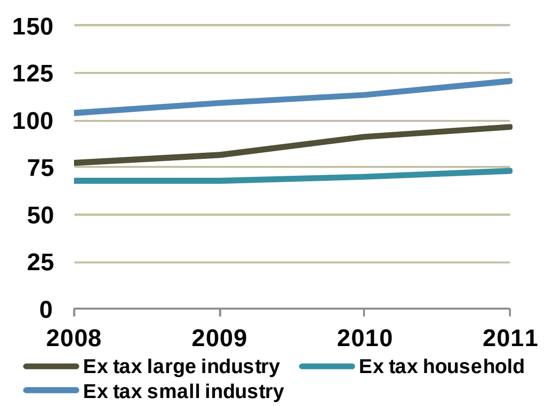


Figure 61 China average retail power prices (USD per MWh)



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

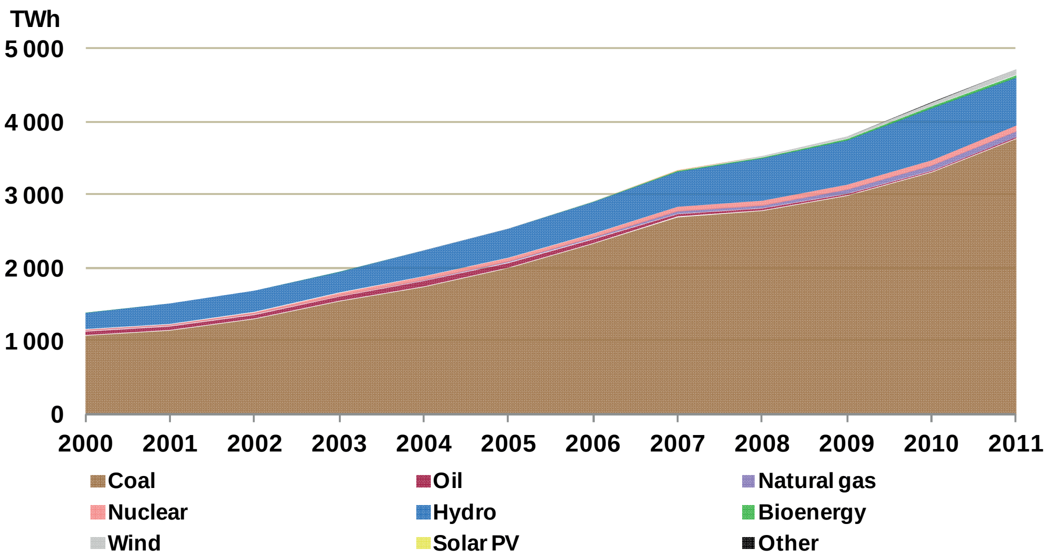
Despite construction of hundreds of GW of coal-fired generation capacity over the past decade, China's different approaches to pricing coal and electricity can act as a check on the availability of generation assets, which can curtail demand. While end-user prices are capped, coal prices can vary according to market dynamics. Given the system's strong reliance on coal, increases in the market prices of coal – both domestic and imported – can sap production economics and prompt the shut-in of coal-fired generation. The China Electricity Council has warned that the country could face electricity shortages of 40 GW this year, partly due to this pricing mismatch. Barring reform, this phenomenon could worsen over the medium term. Still, Chinese authorities have voiced an intention to gradually move towards a more market-based pricing system over the next few years.

Power sector structure

Generation and capacity

China's power mix has traditionally been dominated by coal, which accounted for 80% of 2011 generation. Hydropower, at 14%, stood as the second largest source in 2011, with nuclear and natural gas around 2%. At the end of 2011, power generation capacity stood above 1 050 GW, with thermal sources, at 760 GW. Power producers in China are a mixture of state-owned, local government and private generators with holdings concentrated among a few players. Though there are 14 power-generating companies with a portfolio larger than 5 GW, the five largest (China Power Investment, Datang, Guodian, Huadian and Huaneng) represent about 40% of generating assets.

Figure 62 China power generation by source



The National Development and Reform Commission (NDRC) sets the price that generators receive – either a coal-benchmarked price specific to the province or this price plus a feed-in premium – with grid companies controlling scheduling. Aside from coal, nuclear power has strong state support with a target of over 40 GW by 2015, from 12 GW in 2011. While current policy calls for promoting gas, significant pricing reform will be needed if generating capacity is to grow rapidly from the nearly 33 GW now installed.

Renewable generation

Ostensibly, a lack of market pricing combined with no guaranteed priority dispatch for renewable energy suggests that the Chinese power system is not fully accommodating for renewable energy penetration. Despite this challenging backdrop, power generators are indeed rapidly adding renewable generation into their portfolios. The government has signalled that it will introduce a renewable energy quota system for generators, grid operators and provinces, though these obligation levels have yet to be determined. Moreover, wind, solar and biomass generators receive financial incentives in the form of the coal-benchmarked price plus a capped feed-in premium. Still, with priority dispatch not assured in practice, it is unclear how many hours such installations can operate, an uncertainty that undermines their economic attractiveness.

From a macro perspective, renewable energy can help to meet fast-growing demand and avoid shortages. To that end, its deployment has been large-scale and rapid. From 2000 to 2011, while consumption more than tripled, renewable energy maintained its 16% share in power generation, keeping up with fossil fuel increases. China is a world leader in hydropower and onshore wind deployment with capacity at 230 GW and 62 GW (47 GW grid-connected), respectively, as of the end of 2011.[4] Bioenergy and solar PV have also developed quickly, with the former at 7.5 GW and the latter at 3 GW, after adding 2 GW in 2011. Offshore wind capacity has advanced, but modestly. At the end of 2011 there were two functioning offshore wind farms (one of which was intertidal) with combined capacity over 250 MW.

Going forward, we expect China to continue advancing deployment in all these areas. Wind and solar PV will continue to be facilitated by a dedicated, domestic manufacturing base. Indeed, commitment to the development of such technologies is demonstrated in the National 12th Five-Year Plan for Energy Science and Technology. The plan identifies several goals for renewable power, such as the development of large wind turbines (6 MW to 10 MW), increased efficiency and reduced costs for solar cells, and the utilisation of agricultural waste for biogas production. Several utility-scale demonstration projects (50 MW to 300 MW) for solar thermal power generation should also be developed.

Grid and system integration

The grid integration of this capacity presents another hurdle, however. China's grid consists of three weakly interconnected parts: a large central grid managed by the State Grid Corporation of China, a southern grid covering five provinces managed by China Southern Grid Company, and the grid serving the western part of Inner Mongolia (the eastern part of Inner Mongolia belongs to State Grid). Within these grids, power is transmitted and distributed by provincial and local utilities, which sell electricity to consumers at fixed retail prices determined by the NDRC. The scale of existing and planned wind deployment poses challenges for grid planning and upgrades in order to integrate large amounts of variable power. This challenge will increase with large-scale solar PV deployment potentially rising.

Already, the penetration of wind generation in the western part of Inner Mongolia has reached around 10%, a level comparable to the most advanced countries in Europe.[5] Such penetration levels pose a problem given the region's low local demand and small transmission capacity to other regions. As such, wind power, which is managed as a load rather than power generation source, is often curtailed. This phenomenon occurs in other parts of China as well. Overall, implied capacity factors for wind in China appear low, based on available generation and capacity data.

4 Historically, the grid connection of wind farms has been an issue. From 2011, new wind projects require approval from the National Energy Administration. A grid connection should follow project completion within three months. Projects without an approval need to negotiate with the grid operator, making connection times more uncertain.
5 The situation is roughly comparable to Ireland, both in wind penetration and interconnection of the region with other grids.

Improved integration is crucial for remedying this inefficiency. China's large hydropower assets can provide some assistance in load management and variable resource balancing. However, with wind and solar resources (concentrated mostly in the north, northeast and west) often located far from load centres in regions with low local demand, a more comprehensive solution would involve transmitting the power closer to high demand areas.

Map 5 China main wind resource sites and load centre

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

China's already considerable experience with long transmission lines for its hydropower assets suggests that expansion will depend on overcoming institutional and financial, rather than technical, issues. Grid companies have few incentives to allow transmission from other grids, as this potentially brings more variable power and increases management complications and costs. They often have reduced willingness and means to invest in new transmission for variable renewable power. Dedicated lines for such generation could be financed through the renewable energy surcharge paid by all consumers, but this may not represent an efficient use of funds given that these lines would be used only 2 000 to 2 500 hours per year. Allowing such subsidised transmission lines to carry coal-fired power as well may help increase their attractiveness and cut down on future infrastructure requirements for shipping coal from mines to power plants near load centres.

Despite these hurdles, the signals from the government have been clear. China has voiced its commitment to construct a "unified strong and smart grid" by 2020. In this context, a smart grid means building an ultra-high-voltage transmission network in the country. To this end, a number of lines have been planned or are under construction by the grid operators (Cheung, 2011). Still, the scale of the task remains large given the size of the power sector and its expected growth. As such the integration of renewable energy will continue as an ongoing challenge over the medium term.

Deployment of solar PV in the residential sector could help to take some pressure off the grid, but progress is held back by two factors. First, licences are needed for all power generators in China, even very small ones. Second, the rigidity of electricity pricing discourages distributors from allowing grid access to such generation, which could potentially infringe upon their established markets.

Current policy environment for renewable energy

Deployment of renewable power sources in China is driven by official governmental targets published in the Five-Year Plans. Feed-in tariffs are in place for wind, solar PV and bioenergy generation. Power producers receive the tariffs as capped feed-in premiums added to the coal-benchmarked price of electricity. Consumers finance the tariffs through a renewable electricity surcharge on their bills, which currently stands at CNY 0.008 per kWh and represents roughly 1% to 3% of the residential electricity price. While there is a policy in place to guarantee priority dispatch, grid companies do not always apply this in practice.

For small-scale solar PV, the Golden Sun programme has provided subsidies that cover 50% to 70% of costs to spur on- and off-grid installations. However, these benefits are not linked to the actual generation of power so programme accountability has suffered. For large-scale installations, the government introduced feed-in tariffs in 2011. The projects that can benefit from the tariff require approval by the National Energy Administration (NEA). Projects that have approval are typically connected to the grid more easily than those without. Growth of solar PV capacity, in particular, has picked up markedly since the introduction of the scheme.

Table 64 China main targets and support policies for renewable electricity

Targets	Financial support	Other support
12th Five-Year Plan for National Economic and Social Development: 11.4% of non-fossil resources in primary energy consumption by 2015 (and 15% by 2020). Start construction of additional 120 GW of hydro by 2015. Cumulative 100 GW of wind by 2015. Cumulative 15 GW of solar by 2015. **Medium and Long-Term Development Plan for Renewable Energy:** Cumulative 30 GW of bioenergy-to-power by 2020.	**Feed-in tariffs:** Apply to onshore wind, solar PV and biomass. Effectively they are feed-in premiums over province-specific prices of coal-based power. **Golden Sun programme:** Subsidies per watt installed to grid-connected and off-grid solar PV projects. **Import duty & value-added taxes removal:** Applies to key technological equipment, including hydro and wind equipment.	**Strategic planning:** Offshore Wind Development Plan **Grid access and priority dispatch:** Projects approved by government are granted access to grid in 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/.

Bioenergy projects can benefit from feed-in tariffs so long as they have a bioenergy-only input. Plants that co-fire with coal cannot apply for the tariff, mainly because the government has no means to control the share of biomass in power plants. Given the high share of coal-fired capacity in the country and the low cost of bringing bioenergy into the generation mix via co-firing, the policy, as such, does not maximise the potential for accelerating the deployment of bioenergy.

Economic attractiveness of renewable energy

Ostensibly, given the levels of feed-in tariffs, renewable energy sources look economically attractive versus coal-fired generation, which acts as the power price benchmark. In practice though, it is difficult to make general assessments of renewable energy financial viability even under the presence of feed-in tariffs. 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. For industrial players, who largely are prohibited from feeding into the grid, self-generation from solar PV for own consumption can often compete versus peak industry electricity prices. For residential users, the largest variable concerns licensing requirements for power generation, which act as a barrier for widespread deployment of distributed solar PV and bioenergy.

Financing

China's financing environment should continue to enable renewable energy development, with domestic banks acting as a significant source of loans. Foreign investors play a role, but 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 each other to finance renewable energy projects, which consequently benefit from attractive financing terms. Regional banks can further enhance financing terms with projects to be built in their region.

Moreover, 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 Program) 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.

Overall, the liquidity position looks favourable for renewable energy deployment in China. For example, according to data from China Electricity Council, over 20% of total investment into the electricity sector in 2011 went to renewable generation, largely hydropower and wind. However, the administrative push that renewable energy enjoys may be increasing risks that even non-viable projects get financed.

Conclusions for renewable energy deployment: baseline case

China's need for additional generation capacity and its increasingly favourable renewable energy policy environment should spur strong deployment over the medium term. We expect renewable generation capacity to expand by 271 GW, from 303 GW in 2011 to 574 GW in 2017. Not surprisingly, hydropower expansion looks the most vigorous with 110 GW of additional capacity, closely followed by onshore wind with 104 GW. Additions in bioenergy for power, at 18 GW, remain small with respect to the scale of China's system, but are strong given worldwide bioenergy expansions. Solar

PV and offshore wind should also grow at impressive rates, by 32 GW and 7 GW respectively. Additions from geothermal, CSP and ocean technologies look relatively small, at a combined 1 GW.

A variety of factors influence this development. In general, the country maintains a predictable policy framework – though developers must heed government signals on future scheme changes in addition to current codified plans – and a portfolio of incentives. However, the context for development of renewables in China lacks robust and functioning market signals, as overall reforms of the power sector have been deferred after completing the separation of generation from transmission and distribution nearly a decade ago. As such, policy approaches and pricing are generally not dynamic, particularly in comparison with global market developments. Moreover, the fragmentation of interests among stakeholders in the power sector and the government can hamper policy changes.

Table 65 China renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	213.4	230.0	245.0	262.0	280.0	300.0	320.0	340.0
Bioenergy	5.5	7.5	10.0	13.0	16.0	19.0	22.0	25.0
Wind	44.7	62.4	77.6	93.0	110.7	130.1	151.1	173.1
Onshore	44.6	62.1	77.1	92.1	109.1	127.1	146.1	166.1
Offshore	0.2	0.3	0.5	0.9	1.6	3.0	5.0	7.0
Solar PV	0.9	3.1	6.9	11.2	16.1	21.7	28.1	35.1
Solar CSP	0.0	0.0	0.0	0.1	0.2	0.3	0.6	1.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total RES-E	**264.6**	**303.0**	**339.5**	**379.3**	**423.0**	**471.1**	**521.8**	**574.3**

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

China's electricity pricing system administration, lack of priority dispatch (in practice) for renewable energy and difficult permitting for distributed generation can act as potent non-economic barriers. Finally, the integration of renewable energy into the grid will remain a challenge. Still, with grid connections improving and plans for the construction of multiple long-distance transmission lines, progress is being made on this front.

In the 11th Five-Year Plan period (2006-10), growth in renewable energy far outpaced the guidance targets, and in recent years the government has had to issue upwardly revised interim objectives. Because of the favourable factors anticipated to be in place, our forecast is more ambitious than the 12th Five-Year Plan targets, notably for onshore wind and solar PV.

Table 66 China main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Strong government backing through Five-Year Plans with potential for quota system. • Ample availability of low-cost financing. • Robust, dedicated manufacturing and technology development.	• Lack of market pricing, in general, and priority dispatch for renewable generation. • Grid planning and upgrading to integrate increased variable renewable power. • Prohibitive licensing procedures for distributed generation.

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 over the projection period. Notably, China could accelerate its move towards a quota system, creating formalised obligations for renewable generation and supply. Moreover, it could better facilitate licensing, move more quickly towards market-based electricity pricing and provide incentives, such as feed-in-tariffs that include grid access and priority dispatch, for distributed generation.

Integrated approaches could help to fully exploit solar power potential. In regions with good direct solar irradiance, building CSP plants, whether hybrid designs with coal or pure solar, could better integrate existing renewable sources by providing storage and flexibility. In cities, China could expand on its experience in residential solar water heater deployment to high-rise buildings (see Box 5). It could promote best-practice design for both water heater collector and PV systems that match prevailing heat and power load profiles. Such deployment would take pressure off centralised power generation assets and grids and help to improve local air quality.

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. Due to favourable economics and the already sizeable experience of grid operators with the technology, deployment would be maximised under either scenario.

The introduction of a quota obligation, better progress on grid upgrades and faster offshore development could spur an additional 7 GW of wind capacity (onshore and offshore combined) by 2017. The advent of a quota, the licensing of decentralised generation and the incentivisation of solar PV in buildings could potentially add 13 GW to the projection for this technology. By contrast, the upside for CSP 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 small-scale biogas developments.

India

India sees strong renewable energy deployment across hydropower, wind and solar. However, grid constraints will represent a major challenge to further development on a countrywide basis.

Table 67 India renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
Hydropower	102	14.6%	116	11.6%	124	135	144	148	150	154
Bioenergy	2	0.3%	4	0.4%	4	5	5	5	6	6
Wind	7	0.9%	26	2.5%	30	35	39	44	49	54
Onshore	7	0.9%	26	2.5%	30	35	39	44	49	54
Offshore	-	0.0%	-	0.0%	-	-	-	-	-	-
Solar PV	0	0.0%	1	0.1%	1	3	4	6	8	11
Solar CSP	-	0.0%	0	0.0%	0	0	0	1	1	1
Geothermal	-	0.0%	-	0.0%	-	-	-	-	-	-
Ocean	-	0.0%	-	0.0%	-	-	0	0	0	0
Total RES-E	**110**	**15.8%**	**147**	**14.6%**	**161**	**177**	**193**	**205**	**215**	**227**

Note: 2011 data are estimates.

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 7.5% annually during this period. Power demand is forecast to increase by 7.0% annually on average over 2011-17. Rural electrification efforts – estimates vary, but the IEA *World Energy Outlook* reported that 25% of the population had no access to electricity in 2009 – will provide a continued structural boost to demand (IEA, 2011a).

Nevertheless, demand is constrained overall by supply availability. Insufficient generation and transmission capacity, coal shortages, and distribution losses have all made blackouts a common occurrence in some areas. Consequently, according to the World Bank, over 60% of firms and some households use captive power or some form of backup generation. In 2011-12, India's Central Electricity Authority expects an average shortfall of 10.3% in meeting base-load demand and a 12.9% shortage for peak demand.

Figure 63 India power demand versus GDP growth

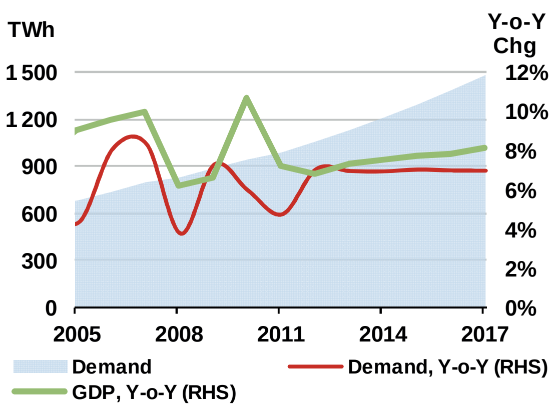
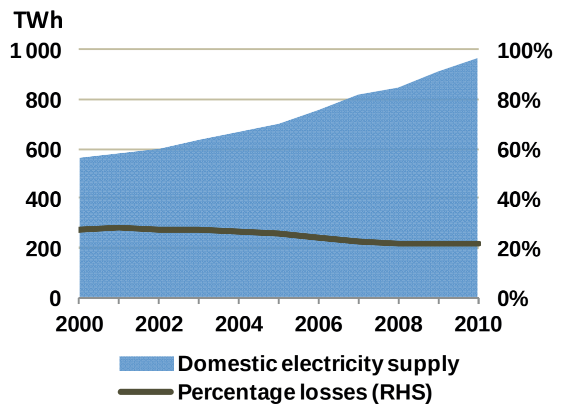


Figure 64 India domestic electricity supply and distribution losses



Power sector structure

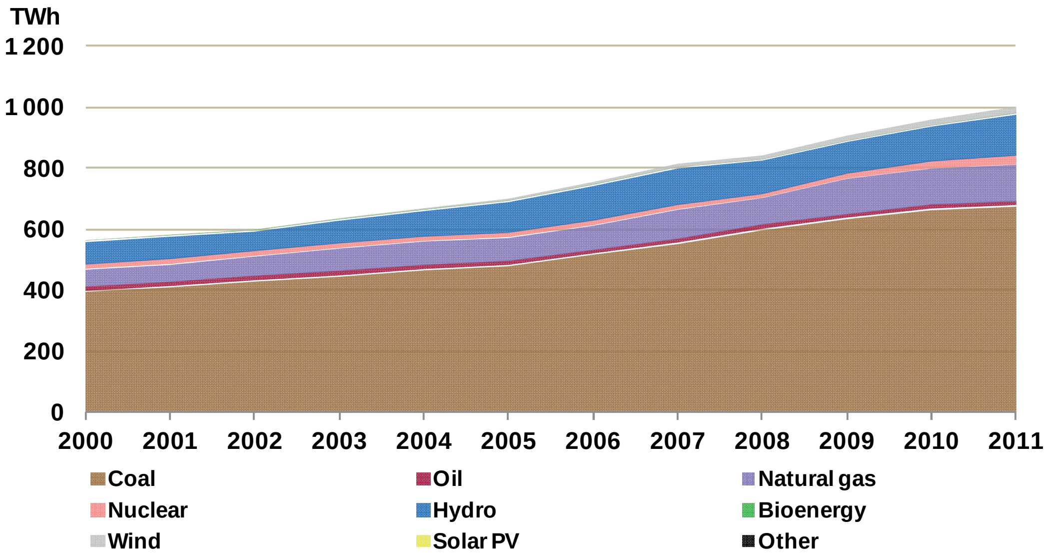
Generation and capacity

India's power generation is heavily dominated by fossil fuels. Coal acts as the primary power source, accounting for 67% of output in 2011. Natural gas and oil accounted for 12% and 2%, respectively, with the former rising strongly over the last decade and the latter declining. India has 4.5 GW of nuclear capacity, which contributed 3% of power generation in 2011. Renewable power accounted for 14% of power generation in 2010. Hydropower serves as the largest source of renewable power, with 40 GW installed at the end of 2011 that accounted for 13.5% of power production. Still, hydropower's untapped potential remains large and capacity should increase markedly over the medium term.

Wind is the second-largest renewable energy resource in India. In 2011 capacity reached 16 GW, up from 4.5 GW in 2005. New installations have progressed steadily over the past six years, with annual additions between 1.5 GW and 3 GW. This growth has stemmed from good wind resources, a strong policy push and the development of a large wind manufacturing base in India. Other renewable energy sources have seen more tepid growth. In 2011, biomass-based power generation stood at 3.6 GW, which included large-scale plants using combustion or gasification, bagasse co-generation and waste-to-energy plants.

Despite a small absolute position, solar PV registered impressive growth in 2011, from just 22 MW to 270 MW. Moreover, the pipeline of projects with completed purchasing power agreements or already under construction stands at about 2.5 GW (Bridge to India, 2011). This development is largely focused on grid-connected capacity and is driven by targets under the Jawaharlal Nehru National Solar Mission (JNNSM), state-level feed-in tariffs and a national portfolio obligation scheme with tradable certificates. Going forward we expect solar energy to play a stronger role in power generation, with growing off-grid and mini-grid installations helping to meet rural electrification needs and distributed power helping industry to meet its own captive needs.

Figure 65 India power generation by source (TWh)



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

Table 68 India draft power generation capacity targets under the Five-Year Plans (GW)

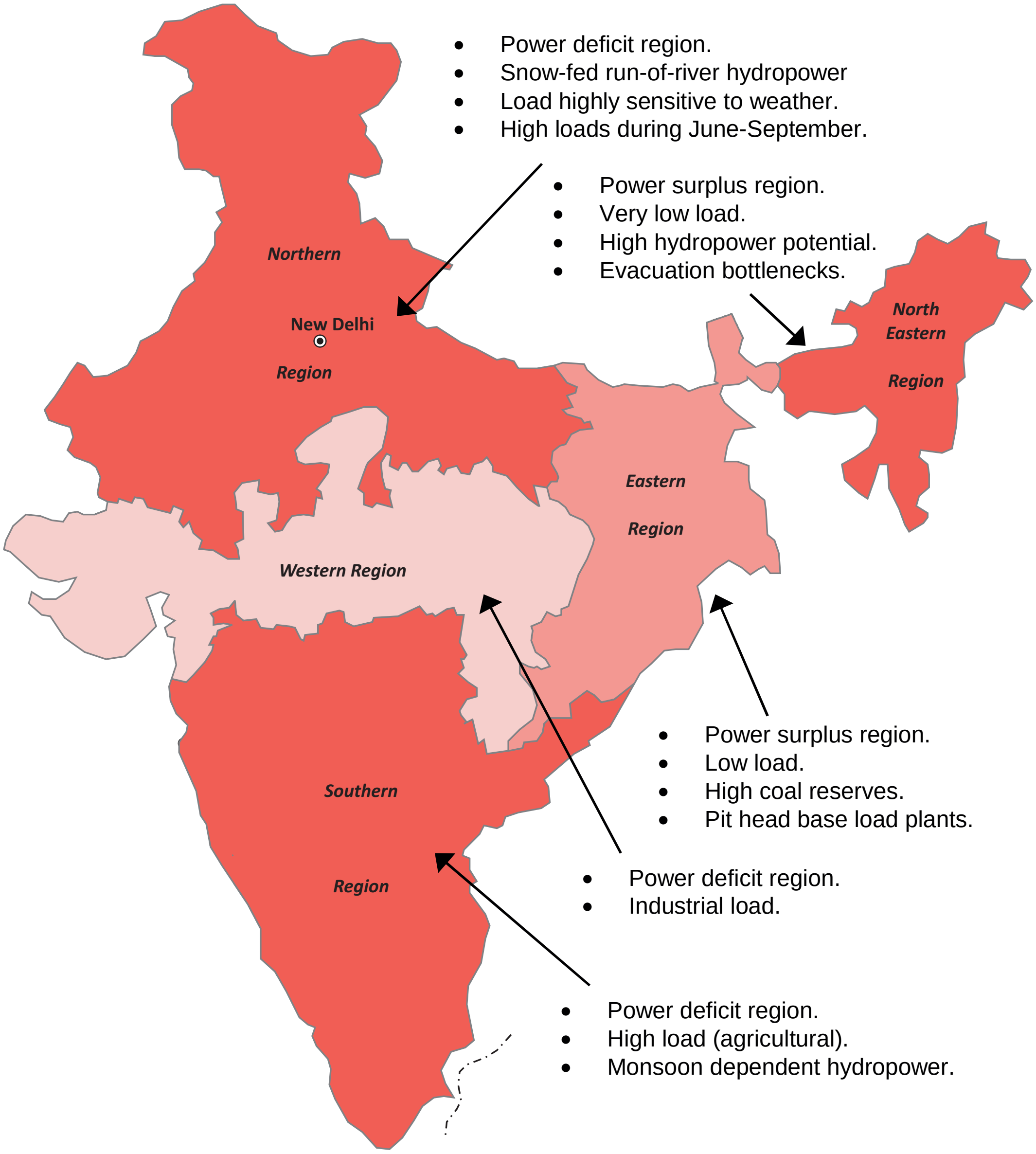
	2007 End of 10th Plan	2012 End of 11th Plan (target)	2017 End of 12th Plan (target)	2012-17 12th Plan additions
Renewable energy power capacity	10.3	22.7	41.3	18.6
Conventional power capacity	122.1	200.0	283.0	83.0
Total power capacity	132.3	222.7	324.3	101.7

Notes: the official 12th Five-Year Plan targets are still being finalised at the time of writing. The Indian government includes large hydropower as part of Conventional Power for the purposes of the Five-Year Plans.
Source: MNRE (2011).

Overall, India will face the challenge of increasing its capacity to narrow the gap between supply and fast-growing demand. To this end, the 12th Five-Year Plan is expected to foresee an increase in total generation assets of 102 GW, with 19 GW coming from renewable sources (outside of large hydropower), by 2017 (note: these targets are indicative; the 12th Five-Year Plan has not been finalised at the time of writing). This growth will need to occur within the framework of a complex power system where electricity shortages are common. India's power sector is composed of publicly owned power plants and independent power producers. Auto-producers of power are present in the industry sector. Independent power producers typically sell their production to transmission and distribution companies that sell it to the retail market or directly to consumers. Many transmission and distribution companies are often not financially viable for a variety of reasons, including pricing policies that impose tariffs for some customer groups that are below costs of supply. As a consequence these companies generally lack funds for infrastructure and performance upgrades.

Grid and system integration

Map 6 India power regions and associated challenges



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Source: Power Grid Corporation of India.

Grid strength and integration represent major hurdles for renewable energy deployment. In India, national transmission lines are developed and managed by the government's Power Grid Corporation. State-level systems fall under the authority of each state, with each differing in rules and regulations. Overall, the transmission and distribution network in India suffers from persistently high electricity losses. In 2009 these losses totalled some 25% of generation.

The task of ensuring adequate grid expansion is a challenging one, as bodies in charge of grid investment differ from the generators. The electricity transmission system is divided into five regional grids, each of which faces unique challenges. Since August 2006, four of the regional grids – the Northern, Eastern, Western and North Eastern – have been integrated and renamed the NEWNE grid. Only the Southern grid still operates independently, but it is scheduled to be synchronised with NEWNE by the end of 2017.

The transfer of wind power generated in remote areas to load centres represents a particular bottleneck. Ongoing grid planning, which incorporates the construction of new long-distance transmission lines, should help, but this is largely undertaken at the national level and not for state grids. Federal resources directed at helping cash-strapped state grid operators to reinforce local distribution networks represent a significant need as well. Increased distributed solar PV generation could help to alleviate grid congestion problems on the distribution level, particularly for the northern region of the country. However, even with spare grid capacity, the system overall needs to develop better forecasting, scheduling and balancing capabilities in order to accommodate a growing amount of variable renewable output.

Rural electrification

A need to expand electricity access to India's large rural population underscores challenges related to upgrading the grid. The government has put in place several rural electrification programmes, with the aim of realising unmet demand for irrigation pumps, lighting and micro-enterprise development, among others. While investments are ongoing to extend the grid into rural areas, many projects face economic and technical hurdles. Overall, the scale of rural electrification needs is large.

The government is promoting decentralised distributed generation (DDG) systems. These systems represent a variety of technologies, which include diesel generators powered by biofuels, solar PV systems and small hydro plants. In addition, mini grid biomass-to-power has been promoted by the government's Biomass Gasifier programme in rural areas where rice husk, corncob/stalk and cotton stalk availabilities are good. While these systems produce electricity for off-grid applications, they are also encouraged to be grid-compatible with an eye towards their eventual connection to the grid. Nevertheless DDG systems are not always available in all rural areas. In these cases, the government encourages, by means of central grants, solar PV home-lighting systems.

Current policy environment for renewable energy

Deployment of renewable power sources in India is driven by official governmental targets published in the Five-Year Plans. At the time of writing, the 12th Five-Year Plan targets are not finalised. Current reported draft proposals may differ from the targets reported here and have not been formally incorporated, pending further clarification. Several types of financial incentives support these targets, namely the Renewable Portfolio Obligation, feed-in tariffs, and fiscal and tax incentives under the JNNSM.

The Renewable Portfolio Obligation scheme contains a tradable certificates mechanism to overcome the mismatch, often geographic, between renewable resource availability and the power-generating entities obligated under the scheme. It allows distribution companies to buy their obligations in a cost-effective way through certificate purchases from renewable generators located outside of their state. By contrast, feed-in tariffs are state-specific, with the Central Electricity Regulatory Commission (CERC) imposing rules how to calculate them. Notably, these financial incentives remain mutually exclusive, with power producers either choosing to sell their power under the feed-in tariffs or taking advantage of the national certificate scheme.

Table 69 India main targets and support policies for renewable electricity

Targets	Financial support	Other support
General targets: Power from renewable energy (excluding large hydro): By end of 11th Plan (2007/08-2011/12): 4.4% By end of 12th Plan (2012/13-2017/18): 5.4% **Jawaharlal Nehru National Solar Mission:** By 2013: 1.1 GW of grid-connected PV, 0.2 GW of off-grid PV (including solar lanterns), 7 million m^2 solar collectors. By 2017: 4 GW grid-connected PV, 1 GW off-grid (with lanterns), 15 million m^2 solar collectors. By 2022: 20 GW grid-connected PV, 2 GW off-grid (with lanterns), 20 million m^2 solar collectors.	**Feed-in tariffs:** At state level; for wind, small hydro, solar PV and solar thermal. **Renewable portfolio obligations with tradable certificates mechanism:** 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. **Preferential tariffs & tax exemptions:** Jawaharlal Nehru National Solar Mission	**Framework policy:** 2003 Electricity Act 2005 National Electricity policy **Grid access and dispatch priority:** All renewable sources except for biomass plants above 10 MW have dispatch priority.

Note: the official 12th Five-Year Plan targets are still being finalised at the time of writing. For further information, refer to IEA Policies and Measures Database: www.iea.org/policiesandmeasures/renewableenergy/.

Table 70 India selected state-level renewable portfolio obligations and deployment

State	Wind RPO	Wind capacity (Dec. 2010), MW	Solar RPO	Solar capacity (Nov. 2011), MW	Total RPO
Gujarat	5.5% (2012/13)	2 010	1.0% (2012/13)	51	7.0% (2012/13)
Karnataka	NS	1 580	126 MW target (2013)	6	11% (2010/11)
Maharashtra	7.0% (2011/12)	2 200	0.25% (2012/13)	7	8.0% (2012/13)
Rajasthan	7.5% (2011/12)	1 350	300 MW target (2013)	5	9.5% (2011/12)
Tamil Nadu	NS	5 500	NS	7	14.0% (2010/11)

Note: NS = non-specified.
Sources: MNRE (2011), GWEC (2011b), Bridge to India (2011).

The Jawaharlal Nehru National Solar Mission (JNNSM) sets out ambitious solar capacity targets and awards licences and purchasing power agreements with transmission or distribution companies through an auction system.[6] One big difference between the JNNSM and existing state-level feed-in tariffs is the inclusion of a local content requirement for solar PV equipment (excluding thin film modules) by the JNNSM.

[6] Initially the program provided a Power Purchase Tariff. However, due to oversubscription, the policy switched to a reverse bidding process.

Economic attractiveness of renewable energy

In general, the economic attractiveness of renewable energy continues to grow in India, supported by financial incentives at the federal and state level. The medium-term outlook for wind economics, however, looks uncertain. A government provision for accelerated depreciation – which allows investors to deduct capital write-downs from their taxes sooner – as well as the Generation Based Incentive (GBI) scheme, which pays a premium to feed-in tariffs for wind farms, acted as significant economic enhancements. In March 2012, the government reduced accelerated depreciation allowances for wind projects from 80% to 15% of capital while the GBI programme expired. As a result, some industry sources see 15% to 25% of new projects at risk in the short term. The Ministry of New and Renewable Energy has requested an extension of the GBI, but at the time of writing, prospects for its reinstatement remain uncertain.

The economic case for solar projects looks clearer with preferential tariffs from the JNNSM spurring growth in grid-connected plants. Moreover, falling system prices have made off-grid solar applications less costly and comparable to diesel generators. A consultancy, Bridge to India, estimated off-grid solar generation costs at USD 0.28 to USD 0.30 per kWh. While higher than the cost of grid electricity (USD 0.10 to USD 0.13 per kWh), installations compete well with diesel power (USD 0.25 to USD 0.38 per kWh) (Bridge to India, 2011).[7]

Financing

Ostensibly India's financing environment should act as a moderate challenge for renewable energy development. The country features a relatively high cost of capital versus the rest of Asia, underdeveloped infrastructure, and a generally complex regulatory environment. Nevertheless, India's renewable energy sector has attracted an impressive influx of capital – with USD 10.3 billion of investment in 2011, Bloomberg New Energy Finance estimated India as the fastest-growing market for clean-energy projects. Private sector investors have played a large role, with market sources pointing to India as an increasingly favoured destination for venture capital and private equity investment. Some of India's attractiveness derives from its overall growth potential. Still, an increasingly favourable incentives and regulatory environment for renewable energy have played a crucial role in attracting funds.

At the same time, a number of state-backed funding sources have emerged. The Indian Renewable Energy Development Agency (IREDA) offers low-cost loans and from its inception in 1987 through 2009, it financed some 4.5 GW of capacity. Other governmental agencies – the Power Finance Corporation, the Rural Electrification Corporation, and the National Bank for Agricultural and Rural Development – also provide funding. Moreover, international agencies are playing a growing role, with German development bank KfW and the US Export-Import Bank both providing sizeable loans to fund solar projects.

Conclusions for renewable energy deployment: baseline case

India's favourable policies for wind, solar and biomass power as well as ample availability of financing should encourage strong deployment of both on- and off-grid renewable energy capacity. We expect renewable generation capacity to expand by 39 GW over the medium term, from 62 GW in 2011 to

[7] These costs are indicative; tariffs ultimately depend on the state and the type of consumer.

101 GW in 2017. Onshore wind additions, at 17 GW, look the largest in absolute terms. Such a forecast would be consistent with draft Five-Year Plan proposals currently reported in the media that call for 15 GW of additions from 2012/13 to 2017/18. Still, the near-term outlook for onshore wind remains uncertain, pending the recent expiry of certain financial supports.

Hydropower should expand by 13 GW. Solar should ramp up quickly from a low base, with solar PV increasing from 460 MW in 2011 to 7.8 GW in 2017 and CSP reaching 0.55 GW in 2017. Bioenergy is expected to contribute to the power mix with growth of 1.7 GW.

Table 71 India renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
Hydropower	40.1	41.6	45.7	49.2	52.0	52.3	53.4	54.6
Bioenergy	2.5	3.6	3.8	4.0	4.2	4.6	5.0	5.3
Wind	13.1	16.1	18.6	21.1	23.6	26.6	29.6	32.6
Onshore	13.1	16.1	18.6	21.1	23.6	26.6	29.6	32.6
Offshore	-	-	-	-	-	-	-	-
Solar PV	0.1	0.5	1.3	2.2	3.2	4.5	6.0	7.8
Solar CSP	-	0.0	0.0	0.0	0.3	0.3	0.4	0.6
Geothermal	-	-	-	-	-	-	-	-
Ocean	-	-	-	-	0.0	0.0	0.0	0.0
Total RES-E	**55.8**	**61.8**	**69.4**	**76.5**	**83.2**	**88.2**	**94.3**	**100.7**

Note: Solar PV installed capacity is grid-connected capacity; off-grid solar PV developments are not explicitly captured in the forecast.

In general, the country maintains a favourable policy framework and a diverse portfolio of incentives. Thus far, targets have functioned effectively, with deployment goals under the 11th Five-Year Plan largely already attained. However, there are questions about the predictability of policy initiatives – for example, the recent expiration of accelerated depreciation and GBI provisions for wind may slow development in this area in the short term. Moreover, policy formulation and adjustments can often proceed slowly, owing to India's complex regulatory environment and myriad competing stakeholder interests. Non-economic barriers, such as the lengthy approval process for land acquisition, also act as hurdles. Finally, the integration of renewable energy into the grid will remain a challenge.

Table 72 India main drivers and challenges to renewable energy deployment

Drivers	Challenges
• Supportive policy environment with Five-Year Plan targets, financial incentives and priority dispatch. • Ample availability of low-cost financing from private sector and development agencies. • Rural electrification needs support distributed solar PV deployment.	• High distribution losses and regulated prices often do not cover supply costs, leaving many state utilities unable to make investments. • Significant grid strengthening and expansion needed to reinforce power system in general. • Complex administrative requirements for renewable energy projects.

Renewable energy deployment under an enhanced case

With greater progress in grid strengthening and expansion, the outlook for renewable energy deployment in India could be higher over the medium term. Specifically, for onshore wind, cumulative capacity could be around 3 GW higher in 2017, with expectations of rising yearly additions towards the end of the forecast period. Solar PV cumulative installed capacity could come out 2 GW to 3 GW higher with stronger-than-anticipated deployment of distributed systems. Notably, the resultant 10 GW of solar PV capacity in 2017 would be consistent with current draft Five-Year Plan proposals reported in the media.

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 (see Box 4) – should provide macro supports to deployment.

In North Africa, onshore wind is the most developed renewable energy source. Over 1 GW of wind farms operate in the region, mainly in **Egypt**, **Morocco** and **Tunisia**, with good regional potential going forward as some sites have load factors almost comparable to offshore wind. Egypt and Morocco should lead further deployment. Morocco and Tunisia are supporting the build-out of solar PV and CSP through the Integrated Solar Energy Generation Project (Morocco) and the Tunisian Solar Plan. Progress has been relatively slow, with only 20 MW of CSP installed in Morocco and 125 MW under construction. Small CSP plants, 20 MW each, are also in operation in **Algeria** and Egypt. Looking ahead, the region is expected to continue developing its solar PV and CSP potential.

In Sub-Saharan Africa, **Kenya**, with feed-in tariffs in place since 2008, leads deployment activities. There, several wind projects, over 250 MW, and a 50 MW solar PV project are under construction. In Kenya, geothermal is a well-established power source that provided roughly 20% of total power production in 2009. Geothermal resources should be further exploited over the medium term, with almost 300 MW of capacity under construction.

Sub-Saharan Africa possesses a portfolio of unexploited renewable resources, with hydropower, solar and bioenergy potential in all parts of the region and excellent geothermal and wind resources in the east. Hydropower represents the most developed renewable source, with 86 TWh produced in 2010. Yet only 5% of its potential has been exploited. Over the medium term we expect several large-scale hydropower projects to begin coming on line, representing 15 GW of new capacity. The largest projects are located in **Ethiopia**, **Nigeria**, and **Zambia**.

South Africa has the largest power generation sector on the continent. While the current penetration of renewable power sources is very low, ambitious targets for hydropower, wind, solar PV and CSP should spur their development going forward. The targets are accompanied by grid expansion plans and a competitive tender mechanism. The mechanism initially covers 3.725 GW of renewable generation capacity, with 1.85 GW and 1.4 GW allocated to onshore wind and solar PV, respectively. Since December 2011, the government has approved over 2.4 GW of projects during two bidding rounds. Outside of the tender scheme there are several relatively large renewable projects under construction, including 100 MW of CSP, 100 MW of onshore wind and several small bioenergy projects. We expect the country will have a portfolio of renewable power sources deployed by 2017, onshore wind representing the largest capacity (2.4 GW), followed by solar PV (1.2 GW) and CSP (0.5 GW), while bioenergy and additional hydropower will play smaller roles.

Asia and Oceania

Hydropower is the most developed renewable source in Asia and the region possesses large untapped hydropower potential. In 2010, hydropower represented 13% of total power production in Asia, excluding China and India. In some countries hydropower accounts for impressive shares of power generation: Nepal (100%), Myanmar (68%), North Korea (62%), Sri Lanka (52%) and Pakistan (34%). Vietnam is expected to experience significant growth in its already sizeable hydropower generation, with 15 GW projected in 2017.

Southeast Asian countries are starting to rapidly develop non-hydropower renewable sources. Indonesia and the Philippines, with their combined capacity accounting for around 30% of the global total in 2011, are expected to further develop their excellent geothermal potential, reaching a combined 4 GW in 2017. Thailand adopted a portfolio approach to exploiting renewable sources. Since 2007, feed-in premiums have spurred development in solar PV, wind, biomass, biogas and waste-to-power applications. Thailand's bioenergy sector has emerged as the most developed in the region. Over the medium term we expect the Southeast Asian countries to continue to further exploit waste products, *e.g.* from their palm oil industry, for power production.

In Oceania, some island countries, *e.g.* Micronesia, Palau, Papua New Guinea and Samoa, already use renewable sources for power generation, mostly hydropower and geothermal. Excellent potential also exists for solar PV.

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. While not traditionally thought of as a renewable energy producer, **Russia's** hydropower output, at 168 TWh in 2010, represented 18% of its total power generation and was the fifth-largest in the world. Hydropower accounted for more than half of the power production in **Albania** (100%), **Tajikistan** (97%), **Georgia** (93%), **Kyrgyzstan** (91%), **Montenegro** (66%), **Croatia** (60%) and **Latvia** (53%). However, solar PV and wind deployment have started in some areas, with 0.6 GW and 1 GW of wind developed by 2011 in **Bulgaria** and **Romania**, respectively, and 140 MW of solar PV in **Ukraine**. We expect growth in these three countries to continue over the projection period. Meanwhile, wind developments are expected to pick up in the Caspian region.

Latin America

Latin America has excellent hydropower resources. Excluding Brazil and Chile, covered in other parts of the report, hydropower production in the region reached 269 TWh in 2010, representing 50% of all electricity production. In Central American countries such as **Costa Rica**, **El Salvador** and **Nicaragua,** geothermal resources provide significant portions of power generation (12%, 26% and 8%, respectively), producing a combined 3 TWh in 2010. There is further ample exploitable potential for relatively cheap hydropower and geothermal resources. However, other renewable sources, particularly onshore wind, are starting to make a contribution to electricity production in the region.

Middle East

Renewable power generation is only starting to emerge in the region. Abundant renewable resources exist only for solar PV and CSP. **United Arab Emirates** has led deployment in the region, with a

10 MW solar PV power plant operational since 2009 and a 100 MW CSP plant under construction. Deployment should also emerge in **Jordan** and **Saudi Arabia**. Saudi Arabia's recently announced ambitious targets to replace oil-fired generation with solar power may cause significant deployment there, but mostly over the long term. The economic crisis slowed down solar developments in the region, but with excellent solar resource availability regional activity is expected to accelerate in solar PV and CSP with results becoming tangible more in the second half of the forecast period.

Box 4 Renewable generation and power systems: how they interact

At growing penetration levels, renewable energy technologies have an increasing impact on the structure and operation of power systems and grids, at four distinct levels:

- the transmission of renewable generation to demand centres, sometimes over long distances;
- the direct feed into distribution networks from distributed renewable power systems;
- the deployment of off-grid and mini-grid systems, particularly in remote areas; and
- the need for system flexibility to balance fluctuating output from variable renewable sources.

Long-distance transmission can connect resources located far from demand centres

Renewable generation may necessitate the long-distance transport of power to bring electricity from resource areas to demand centres. Most of the countries featured in this report face this challenge with respect to at least one renewable source. Transporting electricity over long distances is not a new problem. Moreover, relative to building new capacity for power generation, investment in land-based transmission lines represents a relatively inexpensive option. Long-distance transmission lines of several hundred kilometres are already used, for example, in Brazil and China to bring large quantities of hydropower generation located inland to cities along the coast.

Still, the build-out of long-distance transmission to transport renewable electricity faces two hurdles. First, strong social opposition to the construction of new electricity lines, in general, exists in many countries, often on environmental grounds. Second, insofar as lines would be constructed for the dedicated use of variable renewable electricity (*i.e.* from wind and solar PV), transmission economics would look tenuous. The relatively low capacity factors of variable sources means lower utilisation rates for transmission lines, particularly versus non-variable sources. To justify an investment in single-source, renewable-dedicated lines, operators would need to charge higher transmission costs for the power, undermining the economics of renewable generation investment. Surmounting this hurdle requires planning to match a generation *portfolio* with new transmission and potentially new business models.

Other issues confront the transport of electricity from offshore sources (wind or ocean) via subsea cables. Rather than having individual generators connect directly to shore, it is typically more cost-effective for projects to feed into large "backbone" lines that are linked to the coast in only several places. Subsea cables are more costly, and generally in more limited supply, than onshore transmission lines. The deployment of these cables represents a particular financing challenge, with incentives needed for system operators or other entities to bear their high up-front deployment costs. In Europe, ten countries (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the United Kingdom) around the North Sea have signed The North Sea Countries Offshore Initiative to facilitate co-ordinated and cost-effective development of an offshore grid. In the United States, a private consortium is developing a 7 GW, 300-mile backbone line along the mid-Atlantic coast.

Box 4 Renewable generation and power systems: how they interact (continued)

System management challenges increase with distributed generation

Renewable electricity generation encompasses many system sizes, ranging from 5 kW for rooftop solar PV to 10 000 MW for a large hydropower dam. Consequently, generation feeds into different levels of the power grid, with small- and medium-scale systems interacting at the distribution level. Small- and medium-scale solar PV systems are largely used for self-consumption purposes, with excess electricity often fed into the distribution grid. Increased deployment of such systems requires profound changes in power system operational patterns. For example, the presence of a large number of distributed 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 system enhancements such as voltage 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 intra-day fluctuations due to weather patterns. As such, systems need to incorporate 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.

Off-grid and mini-grid generation can supply electricity in remote areas

Renewable energy production may also take place in mini-grid (village- and district-level networks with loads up to 500 kW) and off-grid situations. The electrification of small islands or remote rural areas represents typical deployment situations. Several examples of islands that are fully renewable powered exist in the world, for example, El Hierro in the Canary Islands of Spain. A combination of renewable sources feeding into a mini-grid increases the likelihood of a more stable overall power supply versus having just one source. Moreover, the incorporation of batteries (*i.e.* storage) or a fossil fuel backup (*e.g.* a diesel generator) can enhance the level of firm capacity.

Distributed renewable power generation can help provide access to electricity in less developed regions. According to the IEA *World Energy Outlook 2011,* 587 million people in Africa had no access to electricity in 2009. In India, this number stood at 289 million, with the rest of developing Asia at 386 million. A majority of these people live in rural areas, where extension of the established grid is often costly and technically challenging. In such areas, mini-grid and off-grid applications offer a better solution to improving electricity access, with renewable sources playing a large role. Indeed, small renewable sources – small hydropower, bioenergy, small wind or solar PV – can often supply electricity at a lower cost than diesel-fired alternatives, making their deployment attractive over the long term.

Above all, power system flexibility remains a key to integrating renewable sources

High shares of variable renewable energy technologies (wind, solar PV, tidal and wave) complicate power system management, as their fluctuations cannot always be accurately predicted. A recent IEA analysis, *Harnessing Variable Renewables*, posits that renewable integration critically depends on the flexibility of the underlying power system (IEA, 2011b).

To wit, power systems that can quickly react to changes in supply and demand, in general, can more efficiently supplement lulls in generation (*e.g.* when the sun goes down) and dispose of surpluses (*e.g.* in a windy night) from variable renewable sources. Flexibility derives from four principal sources: readily dispatchable power plants (*e.g.* hydropower and gas), availability of storage (*e.g.* pumped hydropower reservoirs), interconnections (between systems and countries), and demand side management/response that can arise through smart grids. The need for flexibility is not new. Power systems have always needed to develop flexibility to ensure that demand, which also fluctuates, is served reliably. But an increase in variable renewable energy reinforces this requirement.

Box 4 Renewable generation and power systems: how they interact (continued)

The IEA has developed a methodology to assess the flexibility of power systems. The IEA Flexibility Assessment Tool, described in *Harnessing Variable Renewables*, shows that the maximum share of variable sources that can be integrated in existing power systems differs substantially across different markets. The degree of integration derives from a given power system's flexibility, mode of operation and market design. Strictly speaking, there is no purely technical ceiling on the maximum share of variable renewable power. The availability of flexible resources can usually be increased and, if necessary, new flexible resources can be deployed, subject to economic considerations.

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INVESTMENT IN RENEWABLE ELECTRICITY

Summary

- **Global new investment in renewable electricity generation (wind, solar, biomass and waste, geothermal, ocean, and small hydropower) increased to USD 251 billion in 2011,** a rise of 19% from USD 211 billion in 2010. Wind and solar in Europe and the United States accounted for about 60% of new finance. Supportive policy environments, cost reductions, shifting generation patterns and desire to take advantage of looming benefit expirations all encouraged investment in these areas. Investment also continued to grow strongly in China, India and Brazil based on strong policy backing and improving project economics.

- **The quarterly pattern shows a fall-off in global new investment during the first quarter of 2012.** Faltering macroeconomic and credit conditions, particularly in Europe, combined with policy uncertainty in a number of OECD markets has weighed upon short-term financing activity. Falling technology costs and the timing of some large-scale projects financed in 2011 may be reinforcing this pattern. In any case, the falling investment trend may not capture the full picture, given that sizeable deployment continues in distributed solar PV, which is excluded from short-term data.

- **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 should sustain overall investment over the forecast period. However, much will depend on the evolution of the attractiveness of project economics and technology risks.

Recent market trends in renewable electricity financing

In 2011, renewable electricity investment – wind, solar, biomass and waste, geothermal, ocean, and small hydropower – surged to its highest level ever, USD 251 billion, according to data from Bloomberg New Energy Finance. In many ways, 2011's strength reflected the continuation of underlying trends. Technologies such as wind (largely onshore) and solar (largely photovoltaics [PV]) have matured over time, with system costs falling globally and risk premiums decreasing for projects in developed markets. Excluding large hydropower, these two technology categories led total new investments in renewable electricity by a wide margin. Moreover, combined wind and solar investment in the relatively established markets of Europe and the United States accounted for around 60% of total investment, about the same level as in 2010. Europe has historically offered the most stable and supportive policy environments for deployment.

Nevertheless, several new trends emerged during the year, with varying impacts on investment. The aftermath of an earthquake and tsunami that hit Japan in March 2011 has prompted some shifts away from nuclear power, notably by German utilities, theoretically opening a gap for increased renewable generation. However, the macroeconomic picture in Europe became more ominous and fiscal concerns began to weigh on the generous financial support schemes from some governments in developed markets. In some cases, notably in the United States, growing expectation by investors of the eventual phase-out of some government support mechanisms buoyed investments during

2011. All the while, renewable energy financing has increased in developing country markets, with Brazil, China and India all seeing larger investment. Financings in China, for example, rose from USD 44 billion in 2010 to USD 52 billion in 2011.

Figure 66 Investment in renewable electricity capacity (USD billion)

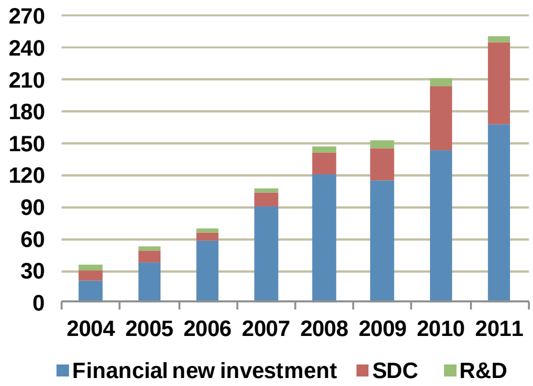
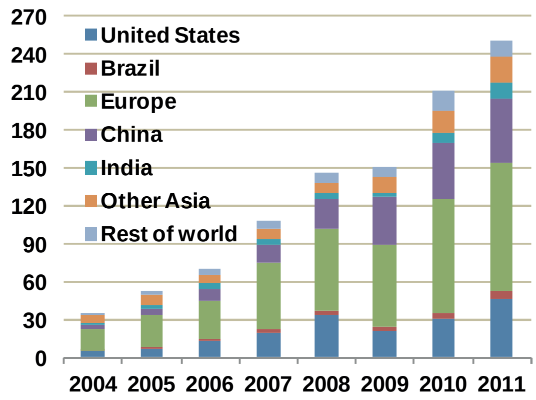


Figure 67 Investment in renewable electricity capacity (USD billion)



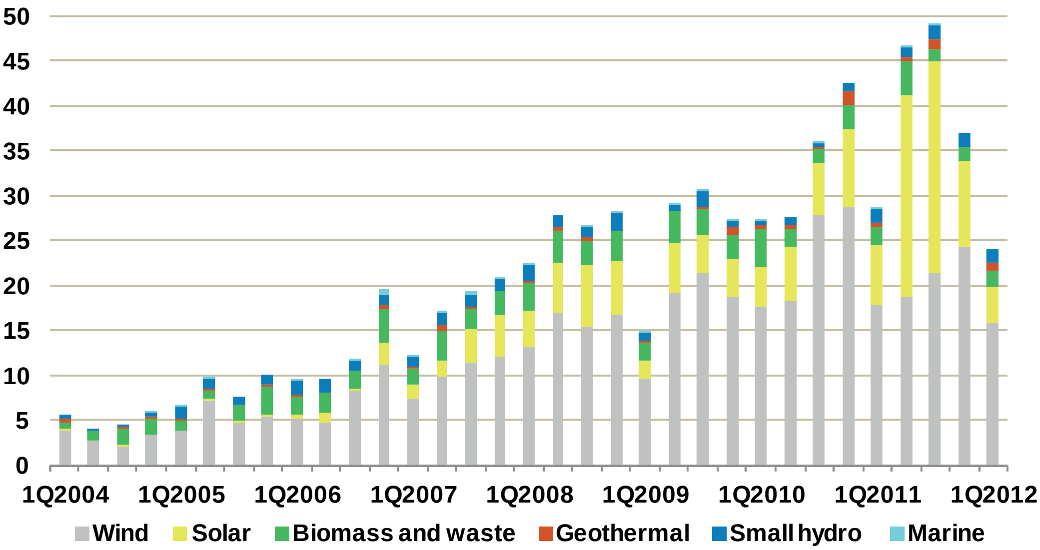
Notes: financial new investment includes new build asset finance, new investment by venture capital/private equity (VC/PE) investors in renewable energy companies, and new equity raised by renewable energy companies on the public markets, and is adjusted for equity reinvestment. SDC = small distributed capacity. R&D = research and development and includes corporate and government sources. ROW = rest of world. Data excludes large hydropower.
Source: Bloomberg New Energy Finance (2012).

The more recent, quarterly trend has shown a fall-off in global investments. In the first quarter of 2012, new investments in renewable electricity dipped by 35% quarter-on-quarter, to their lowest level since the first quarter of 2009. This period followed a fourth quarter of 2011 that itself was down by 25% versus the third quarter of that year. Notably, these data do not take into account small distributed capacity – although investment levels are not known for this sector, deployment of rooftop solar PV over the fourth quarter of 2011 and the first quarter of 2012 was strong in major markets such as California, Germany, Italy and Japan.

Still, a few factors are weighing upon overall activity and are expected to persist over the medium term. First, general macroeconomic and credit concerns are increasing capital costs, reducing risk appetites, and prompting investor preferences for higher returns and shorter payback periods, which tend to work against renewable technologies. Second, short-term policy uncertainty in some markets is undermining renewable project economics due to potential changes in financial support. In some cases, looming changes are already priced in by investors. For example, the presumed expiration of the wind production tax credit at the end of 2012 in the United States is starting to reduce investment in this area (note: United States wind installations should grow strongly in 2012, but from investments made prior to 2012), a situation exacerbated by sustained low natural gas prices there.

Third, dips in investments may partially stem from ongoing cost reductions and the nature of investment patterns (renewable project investment outlays are often made and reported as large, discrete units). On the latter point, it is worth noting that, according to Bloomberg New Energy Finance deal data, financings for a number of large projects (including three offshore wind farms in Europe and several utility-scale solar projects in United States) were completed in the third quarter of 2011, making for a strong baseline relative to subsequent quarters.

Figure 68 New investment in renewable electricity capacity, excluding small distributed capacity (USD billion)



Note: 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 R&D, government R&D and small distributed capacity are not included here. There is no adjustment for re-invested equity. Data excludes large hydropower.
Source: Bloomberg New Energy Finance (2012).

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, a decreased availability and an increased cost of financing from traditional sources, such as European bank project finance and utility investment, should represent a constraint on global deployment. The degree of this constraint will remain specific to markets and projects. This general hurdle should ease as macroeconomic conditions improve and new financial sources and structures emerge over the medium term. Still, investment trends will ultimately depend on the durability of prevailing policy support regimes and the evolution of technology risks, including costs and supply chain developments.

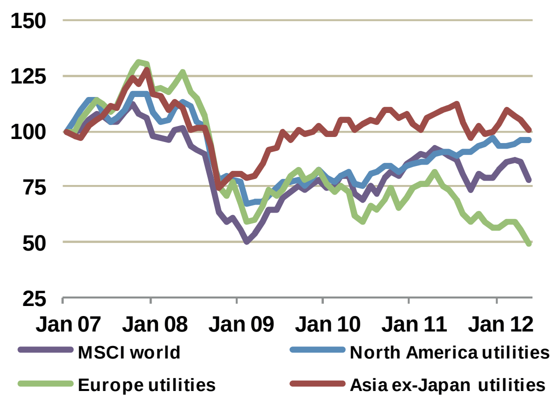
Macro risks point to tighter financing, particularly in Europe

Tighter 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. Projects with attractive economics or supported by target mechanisms are securing funds, particularly in lower capital cost areas such as Germany and the United Kingdom (though in the latter, uncertainty over Electricity Market Reform details may be slowing investment). Yet, technologies with more limited deployment histories and large financing needs, such as offshore wind, face higher short-term barriers.

With global gross domestic product (GDP) growth averaging 4.4% over 2013-17 (versus 3.6% over 2011-12), the International Monetary Fund (IMF) foresees a gradual easing of global financial conditions over the medium term (IMF, 2012). Recovery should occur at a slower pace in the euro area. Still, current developments in Europe cast uncertainty over the outlook. On one hand, sovereign risks have risen in recent months in euro area peripheral countries. On the other hand, the evolving policy environment may lead to measures that could impact renewable energy investment in particular. For example, the European Union Parliament and Council reached political agreement in May 2012 on the Europe 2020 Project Bond Initiative pilot phase. The programme would provide credit enhancement, via the European Investment Bank (EIB), to project bonds, with the aim of attracting private investment to infrastructure and energy projects.

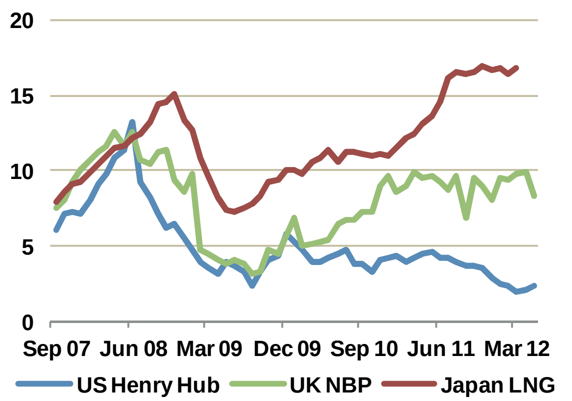
A longer-term challenge for renewable energy project finance will stem from the requirements imposed by Basel III, a global financial regulatory framework that seeks to reinforce the banking sector's ability to absorb economic shocks. The associated rules, to be implemented at the country level from 2013-18, increase capital and liquidity requirements for banks. European banks, given their relatively weak capital positions, should face more impact on their operations versus United States or Asian counterparts. In short, the rules 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.

Figure 69 Regional utility equity performance versus broader equity market



Notes: all series are indexed monthly averages of MSCI equity price indices. 100 = Jan 2007.
Source: IEA calculations based on data from Bloomberg LP (2012).

Figure 70 Monthly average natural gas prices (USD/MBtu)



Notes: MBtu = million British thermal units, NBP = National Balancing Point, LNG = liquefied natural gas.
Source: IEA calculations based on data from Bloomberg LP (2012).

At the same time, utility balance sheets in OECD markets are under increasing scrutiny. A decade of strong capital outlays by Europe's major utilities has left many of their credit ratings near minimum levels (*i.e.* an A- rating, as viewed by most utilities) (Ernst and Young, 2011a). This tends to raise capital costs and suggests a need for utilities to sell assets, raise more equity and exercise more caution with new investments, such as renewable projects. In the United States, very 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, anecdotally it appears that such investments may be crowding out some renewable financing in the short term.

Nevertheless, going forward, utility finance in renewable energy should continue, particularly given mandated renewable sales and generation requirements in OECD markets. However, companies may increasingly need to raise financing by marketing stakes in projects to other investors, particularly those in emerging markets.

Other sources and structures should increasingly fill the financing gap

The macroeconomic and credit picture points to increased challenges for traditional, European bank project finance and utility finance going forward. At the same time, 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, constituting a persistent check on deployment.

First, 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.

Table 73 Development bank financing of renewable energy projects (USD million)

Development bank	Country/region	2007	2008	2009	2010
European Investment Bank (EIB)	European Union	1 128	1 361	2 682	5 409
Brazilian Development Bank (BNDES)	Brazil	1 554	6 206	2 240	3 149
European Bank for Reconstruction and Development (EBRD)	multilateral	934	982	1 317	2 164
Kreditanstalt für Wiederaufbau (KfW)	Germany	697	968	1 207	1 525
Asian Development Bank	multilateral	121	208	612	819
World Bank	multilateral	207	205	474	748
China Development Bank	China	119	417	500	600
Agence Française de Développement (AFD)	France	254	141	245	294
African Development Bank (AfDB)	multilateral	0	0	68	108
Overseas Private Investment Corporation (OPIC)	United States	19	0	121	95
Indian Renewable Energy Development Agency (IREDA)	India	94	68	87	115
Nordic Investment Bank (NIB)	Nordic countries*	163	378	235	113
Inter-American Development Bank	multilateral	128	662	264	83
Total		**5 418**	**11 596**	**10 052**	**15 222**

*Denmark, Estonia, Finland, Iceland, Latvia, Lithuania, Norway and Sweden.
Note: Excludes investment in large hydropower.
Sources: Czajkowska and Louw (2011), and IEA (2012).

Second, development banks and export credit agencies should continue to represent a key source of funds for renewable investments, particularly in project finance, over the medium term. Over time, such institutions have expanded their portfolios into renewable energy, providing lower-cost loans than could be obtained from private sources. In 2010, this funding amounted to over USD 15 billion. The EIB, Brazilian Development Bank (BNDES), European Bank for Reconstruction and Development (EBRD), and Kreditanstalt für Wiederaufbau (KfW) have accounted for the bulk of this investment, about 80%. But new institutions continue to emerge, often with more focused missions. The United Kingdom's creation of a Green Investment Bank, for example, will target a potential GBP 3 billion of investments in three areas: offshore wind, waste and energy efficiency. In Australia, the government is establishing the AUD 10 billion Clean Energy Finance Corporation, which will invest in renewable projects starting in 2013.

To be sure, the financial upside that development banks and export credit agencies can deliver, particularly in the OECD, will remain constrained by fiscal pressures. Multilateral banks, such as the EIB, also continue to devote parts of their spending to general power system investment, which may not include renewable generation. Some of this portfolio may support the financing of conventional power, but other outlays include investments in transmission systems, which can benefit renewable deployment without showing up in renewable investment numbers.

Third, 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).[8] Their desire for steady, long-term returns mirrors the type of payments that renewable projects with purchasing power agreements can provide. So 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. Meanwhile, insurance companies have started acquiring completed renewable assets, with Europe's biggest insurer, Allianz, for example, owning a wind portfolio of 658 MW.

The potential for non-utility corporate entities to fund renewable energy investments from their balance sheets remains large. Most corporate involvement to date has involved voluntary purchases of renewable power, largely through renewable electricity certificate procurement. Direct investment in generation has remained relatively small (Bloomberg New Energy Finance and Vestas, 2011). 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 upfront manner. These credits are then used by the corporation to offset their tax burden. The availability of tax equity from traditional sources going forward will likely remain a persistent uncertainty. However, over the medium term, information technology companies, in particular, are likely to increase their investment, given rapidly rising electricity needs associated with data servers and growth in global internet usage. Google, for example, has so far invested over USD 900 million in 1.8 GW of renewable generation capacity.

Finally, 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. The availability of third-party leasing in Southern California, for example, has opened solar PV markets to new demographics and increased total demand for systems by defraying the up-front costs associated with project financing (Drury *et al.*, 2012). Securitisation of small-scale solar PV – the pooling of assets to sell as financial securities on secondary markets – has also emerged as an idea to enable financing. While such arrangements may increase over the medium term, securitisation prospects look gradual in the United States.

However, financing cost and availability will depend on policy and technology

Ultimately, the cost and availability of renewable energy finance going forward will depend most strongly on the prevailing policy and technology environments. 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. As such, financing should continue to flourish in places such as Germany, Denmark, California (and other US states with a

[8] Assets held by private pension funds in OECD countries.

strong renewable portfolio standard), 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. Such countries include India and Turkey. Still, the latter set of markets will face a relatively high cost of capital from private sources.

Table 74 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 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 further 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.	Third-party solar leasing schemes.

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.

All the while, technology-specific challenges to financing will persist, though a number of new financing trends may emerge to address them. Table 74 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. Still, these 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.

In addition, more general technology and cost issues should persist. For one, renewable energy investments will continue to face the challenge that general investors lack experience in the sector. Advisory institutions, such as credit rating agencies, are continuing to understand and price associated risks in the face of often-limited performance information. In addition, the emergence of increased trade frictions, illustrated in recent announcements by the United States and Chinese governments on solar PV and wind, may increase supply chain risks, raising concerns over the impact of potential countervailing duties on technology costs.

The financing of offshore wind projects should act as a large variable within the outlook for renewable energy finance. A recent survey by Clean Energy Pipeline (2012) identified the securing of project finance as the largest obstacle, among other supply chain issues, facing current offshore wind deployment in Europe. The report estimates that European offshore wind financing fell by 26% in 2011 to USD 5.4 billion from USD 7.3 billion in 2010. Short-term financing needs for European projects look adequately filled, given the timing of investment patterns. In three to five years when major additional financing is needed, in the United Kingdom for example, improved macroeconomic conditions should better facilitate investment, along with the help of some of the emerging sources of financing mentioned above (*e.g.* Asian and non-traditional investors). However, given the high perceived risks for offshore projects, relative to other technologies, financing will continue to depend on a backstop of strong policy support and a gradual easing of costs and supply chain bottlenecks.

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MEDIUM-TERM OUTLOOK: RENEWABLE TECHNOLOGIES

Summary

- **Global renewable electricity generation is projected to grow from 4 539 TWh in 2011 to 6 377 TWh in 2017 (+5.8% per year).** Hydropower represents less than half of this growth, 734 TWh, while non-hydro sources grow by 1 104 TWh between 2011 and 2017. China should lead growth within most categories: hydropower, onshore and offshore wind, solar photovoltaics (PV), and bioenergy-based power production, as well as solar thermal heating, as its total renewable generation grows by 700 TWh (+10.6%) per year. The United States and Indonesia have the highest increases in concentrating solar power (CSP) and geothermal, respectively.

- **Hydropower remains the largest contributor to total renewable power generation. At 4 378 TWh in 2017 it should account for 69% of renewable electricity output.** China leads the hydropower market, representing 25% of generation in 2017. Brazil accounts for 11% of generation in 2017, following vibrant growth over the medium term. Canada, the United States and Russia also account for sizeable generation shares, but grow more slowly over 2011-17.

- **Onshore wind, bioenergy and solar PV also contribute significantly and together generate 1 797 TWh in 2017, up from 808 TWh in 2011 (+14.3% per year).** Onshore wind output reaches 985 TWh in 2017 while bioenergy and solar PV generate 532 TWh and 279 TWh, respectively. These three technologies are maturing and at the same time are spreading out to all regions of the world. Still, growth remains largely driven by OECD countries, China, Brazil and India. Over the medium term these technologies should compete with fossil-fuel alternatives under increasing circumstances.

- **Offshore wind and concentrating solar power grow rapidly, reaching 26 GW and 11 GW in 2017, up from 4 GW and 2 GW in 2011, respectively.** Both need to overcome several technical and financing challenges and prove their capability to significantly decrease costs. Centres of activity for the two technologies differ. Offshore wind developments concentrate in Europe. Meanwhile, CSP needs to prove its viability in the United States with largely pure-solar designs and in China, India, and North Africa with mostly hybrid designs.

- **Geothermal power grows moderately over the medium term,** with suitable resources located in only few countries. High risk during the exploration phase makes financing challenging.

- **Ocean power grows only marginally over the medium term.** Due to its relatively early stage of maturity, most developments remain at demonstration level with the exception of tidal barrages.

- **Two significant global trends should characterise the deployment of renewable technologies over the medium term.** First, as renewable electricity technologies scale up, from a global total of 1 454 GW in 2011 to 2 167 GW in 2017, they 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.

Bioenergy for power

Bioenergy-based power production scales up from increased use of agricultural and municipal wastes. Co-firing starts to play an important role in countries with large coal power production.

Technology background

Bioenergy for power encompasses the use of solid biomass, biogas, liquid biofuels and renewable municipal waste for power production. Biomass is not only used in dedicated power and co-generation[9] plants, but is also co-fired with other dominant fuels such as coal. The most efficient use of bioenergy resources for power generation stems from operating plants in co-generation mode, which requires stable heat demand, as employed in the pulp and paper industry. The process of co-firing with fossil fuels is becoming more prevalent in countries with large shares of coal-fired generation. Co-firing likely represents a transition phase of development towards bioenergy-only generation, particularly in markets that are moving away from coal-fired generation. 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 renewable power production anywhere in the world. Moreover, some bioenergy feedstocks, such as wood pellets, are internationally traded, which is rare among renewable energy sources.

The costs of power production from bioenergy depend not only on the technology and operational scale (ranging from a few kilowatts to hundreds of megawatts) but also on the quality, type, availability and cost of biomass feedstocks. They also vary with the pattern of energy demand (especially whether there is a steady demand for heat in case of co-generation). For example, the investment costs for a biomass plant with a capacity above 50 MW are between USD 2 400 per kW and USD 4 200 per kW. The capital costs of co-firing are much lower (USD 300 per kW to USD 700 per kW, depending on configuration). In both cases, plants will be operated as mid-merit or base load – the latter particularly in the case of co-generation. The range of generation costs is also large, with dedicated large scale bioenergy plants producing at USD 110 per MWh to USD 240 per MWh and co-firing costs at USD 80 per MWh to USD 140 per MWh. The use of residues as feedstock can decrease generation costs to as low as USD 80 per MWh.

The relationship between bioenergy power generation and capacity is not always straightforward from a statistical standpoint. 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. This phenomenon varies by country. As such, this report's baseline data (IEA official statistics in the case of OECD countries) 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

In 2011, bioenergy contributed 308 TWh to global power production. The United States led generation at 61 TWh produced, though growth in recent years has been slow. Germany and China,

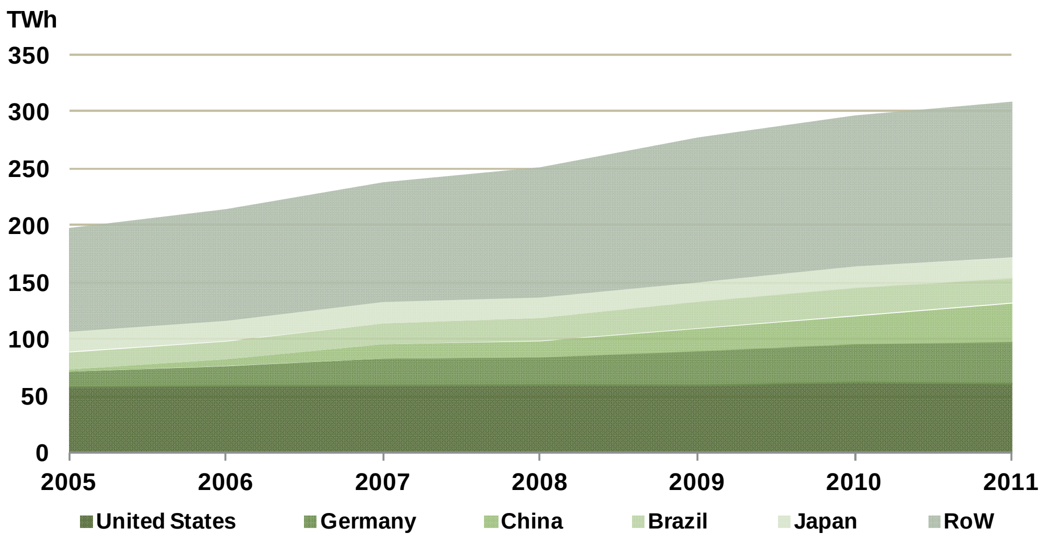
[9]Co-generation refers to the combined production of heat and power.

at 37 TWh and 34 TWh in 2011, respectively, have been growing at faster rates. German growth is driven by biogas, which increased from 4.7 TWh in 2005 to 19.2 TWh in 2011. China is driven by an ambitious target of 30 GW of bioenergy-to-power applications in 2020. Brazil produced 22 TWh in 2011 and its bagasse-to-power continues to grow. In recent years, Japan's growth has been slow, with generation reaching 18 TWh in 2011.

Other important players in the market are Nordic countries, with their biomass- and waste-based co-generation plants producing both electricity and heat for district heating systems. The United Kingdom is taking a lead in co-firing with coal and is also testing the conversion of coal-fired plants. These conversions imply a need for large amounts of biomass feedstock. As such, the establishment of a sustainable large-scale supply chain of feedstock is also being tested.

Southeast Asia tops developments among non-OECD regions, with Thailand accounting for half of regional installed capacity, followed by Malaysia and Indonesia. These countries are taking advantage of ample available wastes from the palm oil and sugar cane industries.

Figure 71 Bioenergy electricity generation by country



Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

Market outlook

In 2017, bioenergy is expected to provide 532 TWh of electricity globally. China should generate 114 TWh in 2017, with growth driven by aggressive targets as well as ample availability of feedstocks such as straw, other agricultural wastes and renewable municipal waste. The United States, at 80 TWh generated in 2017, and Germany, at 42 TWh, follow. Brazil's output should rise to 36 TWh as bagasse-based power generation continues to develop. Japan's aggressive waste-to-energy generation push helps bring total bioenergy power output to 32 TWh in 2017.

Global bioenergy capacity for power production should reach 119 GW by 2017, up from 70 GW in 2011. The bulk of this growth comes from China, 18 GW between 2011 and 2017, and OECD Europe countries, driven by National Renewable Energy Action Plans (NREAPs).

Table 75 Bioenergy electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	71	82	86	90	94	98	102	6.2%
OECD A/O	24	28	31	33	35	38	40	9.2%
OECD EUR	133	140	149	158	166	175	185	5.7%
Non-OECD	80	102	121	140	162	183	205	16.9%
World	**308**	**352**	**387**	**421**	**457**	**494**	**532**	**9.6%**
China	34	46	59	73	87	101	114	22.2%
United States	61	67	69	72	75	78	80	4.9%
Germany	37	35	37	38	39	41	42	2.1%
Brazil	22	28	30	32	33	35	36	8.9%
Japan	18	22	24	26	28	30	32	9.6%

Table 76 Bioenergy installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	14.6	15.2	15.9	16.7	17.4	18.2	19.0	4.5%
OECD A/O	2.9	3.1	3.3	3.5	3.7	3.9	4.1	5.9%
OECD EUR	30.7	32.9	35.2	37.5	39.9	42.2	44.6	6.4%
Non-OECD	21.9	26.2	30.8	35.4	40.6	45.8	51.1	15.2%
World	**70.0**	**77.4**	**85.2**	**93.0**	**101.6**	**110.1**	**118.9**	9.2%
China	7.5	10.0	13.0	16.0	19.0	22.0	25.0	22.2%
United States	11.6	12.0	12.5	13.0	13.5	14.0	14.5	3.8%
Germany	6.6	6.9	7.2	7.5	7.7	8.0	8.2	3.7%
Brazil	5.4	6.3	6.7	7.1	7.4	7.7	8.0	6.6%
Austria	3.9	4.3	4.6	4.9	5.2	5.6	6.0	7.4%

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

Concentrating solar power

Although competition with solar PV presents a challenge to deployment, the added value of hybridisation and storage help CSP to grow strongly over the medium term.

Technology background

Concentrating solar power is a proven technology, with the first commercial power plants existing in the United States for almost 30 years. Concentrating solar power capacity produces power from sunshine and storage, when present. Storage is currently a common feature for many CSP developments in Spain and some plants in the United States. CSP plants can provide firm peak, intermediate or base-load capacity thanks to thermal storage and/or a backup 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.

Concentrating solar power 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. CSP plants produce power by concentrating solar radiation to heat, which is transformed to mechanical energy and then electricity. Apart from parabolic dish systems, CSP plants consist of a field of solar collectors, receivers and a power block. A cooling system is also necessary. CSP plants using wet cooling systems have large water needs, which can create development constraints in water-scarce areas. However, systems can also incorporate dry cooling or be integrated with desalination plants in dry coastal areas. Plants may include heat storage devices, which can act as electricity generators when solar resources are unavailable.

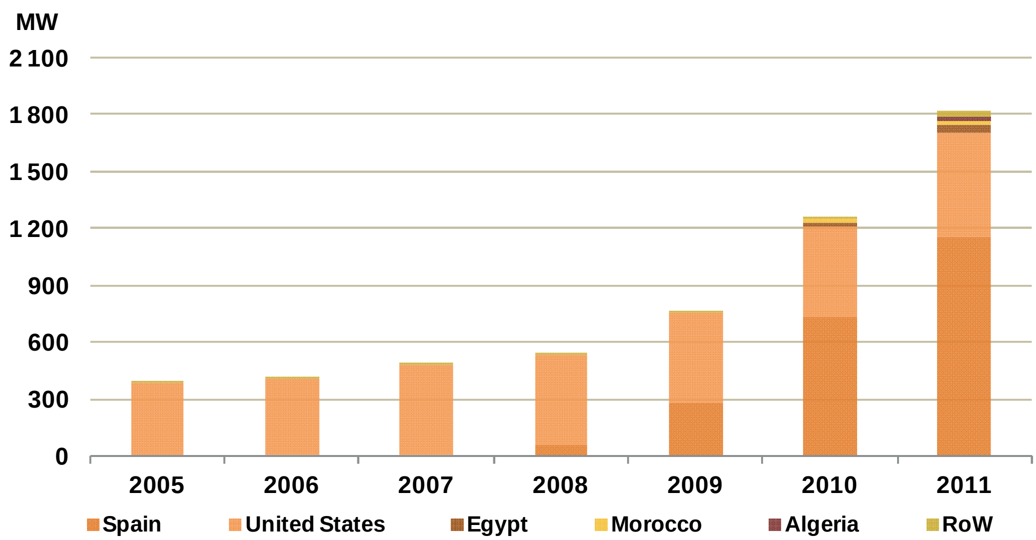
CSP plants can also incorporate a backup or hybrid design, which adds a solar power component to an existing fossil fuel power plant or integrates the two during the construction phase. Hybridisation makes CSP plants fully dispatchable while bringing environmental benefits and fuels savings compared with pure gas or coal-fired plants. Deployment of hybrid combustion-CSP plants (either with fossil fuel or bioenergy combustion) would allow immediate reduction of the cost of solar thermal electricity. At the same time, the development of the CSP industry's supply chain would bring economies of scale to the solar part of the design and may spur more economic deployment of pure solar plants in the future. The recently commissioned Al Kuraymat hybrid solar and natural gas plant in Egypt provides a notable example. In heavily coal-dependent Australia, China, India and South Africa, hybridisation would have excellent potential with supportive policies or a mechanism to take the solar production of such plants into account under renewable obligation schemes.

For large (50 MW), state-of-the-art trough plants, current investment costs are USD 3 800 per kW to over USD 8 000 per kW, depending on the size of the solar field, the size of storage and labour and land costs. Largely determined by capital costs and the amount of direct solar irradiation, costs of electricity generation can range between USD 160 per MWh and USD 300 per MWh. The inclusion of storage capacity has comparably lower impact on generation costs, but can enhance revenues by allowing operators to shift output to mid-peak or peak hours.

Market status

CSP developments are currently concentrated in a few areas, with Spain and the United States being the only two countries with significant commercially operating capacities. Global installed capacity stood at 1.8 GW in 2011. Spain is the market leader with 1.2 GW of capacity and the United States follows with 0.6 GW. Other countries only have smaller operational projects; several 20 MW plants exist in Algeria, Egypt and Morocco, and a 17 MW plant operates in Iran. Several other countries have demonstration plants sized at only a few megawatts.

Figure 72 CSP installed capacity by country



Sources: IEA statistics, Protermosolar (2012), SEIA (2012b), World Bank (2010) and IEA analysis.

Market outlook

Over the medium term, CSP should scale up significantly, reaching almost 10.9 GW in 2017, up from 1.8 GW in 2011. Still, this increase is less than the industry has anticipated. The pipeline of projects in the planning and development stage is concentrated in Spain, the United States, the Middle East and North Africa, areas with the best resources for CSP developments. Australia, India, China and South Africa have also started planning and constructing projects.

While the pipeline in the United States and Spain represents tens of gigawatts, only a small fraction of these projects is expected to come into fruition by 2017. CSP faces several challenges in the United States. The large-scale nature of projects and their typical situation in the desert southwest make for more difficult environmental permitting and grid connections. The deployment flexibility and lower costs of solar PV have provided an attractive alternative to some CSP projects. Already several developers have converted their plans for CSP plants to PV, including a portfolio of 2.3 GW. Still, some developers continue to develop CSP projects on the basis of power purchase agreements with local utilities and the advantages conferred by CSP's storage capabilities. In 2017, United States installed capacity should reach 4.2 GW, representing almost 40% of the global installed capacity.

In Spain, new plants face a moratorium on renewable energy development within the Special Regime, which provides feed-in tariffs or feed-in premiums. Elevated CSP development costs should keep development minimal outside of this regime over the next five years. Still, with capacity already in the pipeline under the Special Regime, several plants should come on line over 2012-14. As such, capacity in 2017 is seen at 2.5 GW.

Based on strong planning, targets and availability of low-cost financing, China should become the third most important CSP player by 2017, with 1.0 GW of cumulative installed capacity. The 12th Five-Year Plan for Energy Technology, published in December 2011 by the Chinese National Energy Administration, has identified CSP as one of its focus elements. The Plan specifies that several CSP demonstration projects, with sizes ranging from 50 MW to 300 MW, should be developed in China by 2017. Several technologies are being tested, with pure-solar designs as well as fossil fuel hybrid configurations. The latter would help reduce fuel consumption in existing coal-fired plants, while hypothetically contributing to an expected renewable obligation scheme. The dispatch ability of these plants should also facilitate grid operations, with a relatively low likelihood of curtailment.

Table 77 CSP installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	0.6	0.6	1.7	2.8	3.6	4.4	4.6	42.3%
OECD A/O	0.0	0.0	0.0	0.0	0.1	0.3	0.4	115.4%
OECD EUR	1.2	1.8	2.2	2.5	2.6	2.6	2.7	14.8%
Non-OECD	0.1	0.2	0.3	1.1	1.3	1.9	3.2	80.3%
World	**1.8**	**2.6**	**4.3**	**6.5**	**7.6**	**9.1**	**10.9**	**34.7%**
United States	0.6	0.6	1.7	2.7	3.2	4.0	4.2	40.1%
Spain	1.2	1.8	2.2	2.5	2.5	2.5	2.5	13.8%
China	0.0	0.0	0.1	0.2	0.3	0.6	1.0	149.0%
India	0.0	0.0	0.0	0.3	0.3	0.4	0.6	115.4%
Morocco	0.0	0.0	0.0	0.2	0.2	0.2	0.5	72.1%

India should emerge as a significant CSP player over the medium term, with 0.6 GW of cumulative capacity in 2017, spurred by an ambitious total solar target of 22 GW by 2022. Moreover, a number of activities are under way in North Africa and the Middle East. Morocco is expected to have 0.5 GW in place by 2017, buoyed by the start-up of the Ouarzazate plant and a total solar target of 2 GW by 2020. Deployment should also increase in Algeria, Egypt, Israel and Jordan. In Saudi Arabia, recently announced ambitious targets to replace oil-fired generation with solar power may cause significant deployment there, but mostly over the long term.

Table 78 CSP electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	2	2	4	8	11	14	15	43.5%
OECD A/O	0	0	0	0	0	1	1	108.4%
OECD EUR	2	3	5	6	6	6	6	23.0%
Non-OECD	0	0	1	2	4	5	8	85.1%
World	**4**	**6**	**10**	**16**	**21**	**25**	**31**	**41.7%**
United States	2	2	4	8	10	12	14	41.3%
Spain	2	3	5	6	6	6	6	22.2%
China	0	0	0	0	1	1	3	147.9%
India	0	0	0	0	1	1	1	133.9%
Morocco	0	0	0	0	1	1	1	61.1%

Geothermal power

Geothermal advances, though percentage growth is slower than most other renewable sources. The technology should enjoy continued low generation costs and high capacity factors.

Technology background

Geothermal technologies exploit energy stored in rock, trapped vapour and liquids, such as water and brines. Geothermal resources can be used for power and heat generation. Conventional geothermal power plants, which require a high-temperature resource (over 180°C), use steam separated from geothermal fluid to drive a turbine and produce electricity. High-temperature hydrothermal resources are located along tectonic plate boundaries. Binary geothermal plants use medium temperature (80°C to 180°C) fluid in a heat exchanger to boil a secondary fluid with a low boiling point to drive a turbine. Though medium-temperature resources are more widely available than high-temperature, the relatively higher cost of binary plants means that they occupy only a minority of existing capacity.

Costs of geothermal plants are site and project specific. Typical operation and maintenance costs also vary significantly depending on the plant. Still, generation costs from high-temperature geothermal resources are competitive with fossil-fuel alternatives. Typical capital costs of a high-temperature geothermal electricity plant range from USD 2 000 per kW to USD 4 000 per kW. The capital costs of binary plants range from USD 2 400 per kW to USD 5 900 per kW. Consequently, the lowest generation costs for geothermal plants range from USD 35 per MWh to USD 80 per MWh, while generation costs of binary plants are usually higher.

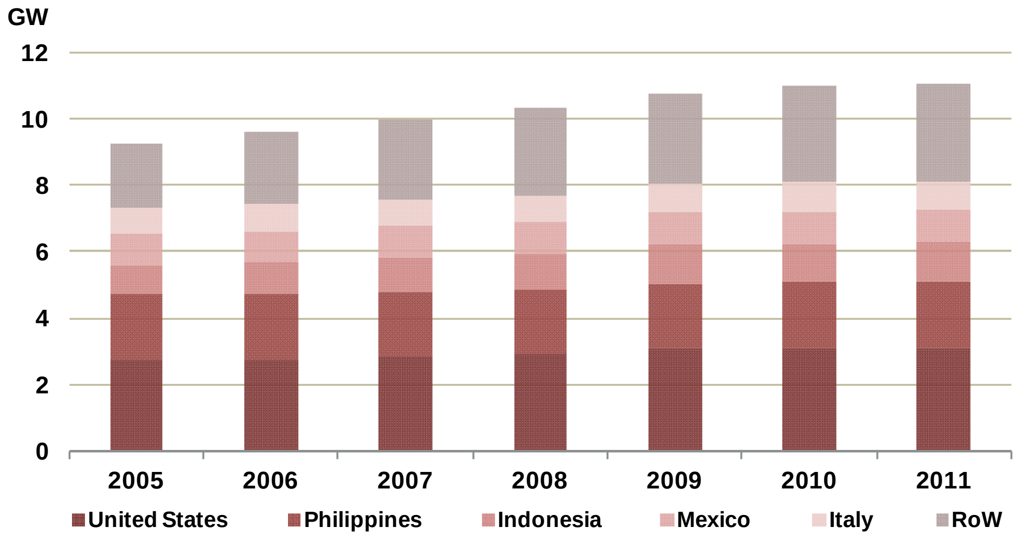
Geothermal plants provide base-load power, which is immune from weather effects and does not vary seasonally. Capacity factors in geothermal plants typically reach 80% to 90%. In places with stable heat demand, *e.g.* Iceland, plants can feed hot water remaining from power generation into district heating networks, improving overall production economics.

Exploration risk constitutes a bottleneck for development. Debt financing is typically not available for this stage of development, which is considered risky due to the 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.

Market status

Geothermal power production stood at 71 TWh in 2011. Global additions remained small, with only about 60 additional megawatts coming online in Indonesia, the United States and Costa Rica combined. In some countries with good resources, geothermal represented a significant fraction of power generation, *e.g.* Iceland (27%), El Salvador (26%), Kenya (19%) and the Philippines (15%). The United States had the largest cumulative installed capacity in 2011, with 3.1 GW. The Philippines and Indonesia followed, with 2.0 GW and 1.2 GW, respectively. Mexico and Italy closed the top five in 2011 with 1 GW and 0.9 GW, respectively.

Figure 73 Geothermal installed capacity by country



Sources: IEA statistics, MEMR Indonesia (2012), GEA (2012) and IEA analysis.

Market outlook

Over the medium term, global geothermal power capacity rises to 14.2 GW in 2017, up from 11.1 GW in 2011. The largest portion of development should take place in the United States, where plants benefit from a production tax credit, and in Indonesia, which has the world's largest estimated geothermal power resource potential, at 28.5 GW, and fast-growing power demand.

In the United States, about 200 MW of capacity are currently under construction, with another 1.8 GW planned. The looming expiration of the production tax credit at the end of 2013 combined with long project lead times add an element of uncertainty to the forecast. As such, the United States should add only about 400 MW of installed capacity between 2011 and 2017, bringing its total to 3.5 GW.

Capacity in the Philippines should grow moderately to 2.2 GW in 2017. Meanwhile Indonesia should add 650 MW, bringing its total to 1.8 GW in 2017. Indonesia has tried for several years to unlock its vast geothermal potential, but developments have been hampered by institutional bottlenecks and exploration risk. In April 2012, the government entered into a co-operation arrangement with New Zealand, which has extensive experience with geothermal exploitation. This arrangement should help with policy and technology development as well as improve workforce education in this area.

Mexico is expected to add 235 MW over the medium term, while New Zealand is expected to increase its capacity by 130 MW, bringing their total installed capacities to 1.2 GW and 0.9 GW, respectively, in 2017. Though its capacity is not expected to evolve over the medium term, Italy remains another sizeable source of geothermal power, with capacity of 0.9 GW in 2017.

Table 79 Geothermal installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	4.1	4.2	4.2	4.3	4.4	4.6	4.8	2.9%
OECD A/O	1.3	1.3	1.4	1.4	1.5	1.6	1.7	5.0%
OECD EUR	1.6	1.6	1.6	1.7	1.7	1.8	1.9	3.2%
Non-OECD	4.1	4.3	4.5	4.7	5.4	5.5	5.8	5.8%
World	**11.1**	**11.4**	**11.8**	**12.1**	**13.0**	**13.5**	**14.2**	**4.3%**
United States	3.1	3.2	3.3	3.3	3.3	3.4	3.5	1.9%
Philippines	2.0	2.0	2.0	2.0	2.1	2.2	2.2	1.9%
Indonesia	1.2	1.3	1.5	1.5	1.6	1.7	1.8	7.5%
Mexico	1.0	1.0	1.0	1.0	1.1	1.2	1.2	3.7%
New Zealand	0.7	0.8	0.9	0.9	0.9	0.9	0.9	2.8%

Finally, in Japan, the government has approved geothermal development in parts of its national parks, bringing total exploitable potential in the country to some 12 GW. Geothermal development should get a boost from this and the adoption of a new, generous set of feed-in tariffs starting in July 2012. Due to the long lead times of projects, however, we expect 300 MW of additions over the medium term, bringing cumulative capacity to 0.8 GW.

Table 80 Geothermal electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	25	26	26	26	27	28	29	2.8%
OECD A/O	9	9	9	10	10	11	11	4.0%
OECD EUR	11	11	12	12	12	13	13	2.7%
Non-OECD	26	27	28	30	33	36	37	6.1%
World	**71**	**73**	**75**	**78**	**82**	**87**	**91**	**4.2%**
United States	18	18	19	19	19	19	20	1.6%
Indonesia	9	10	11	12	12	13	14	7.0%
Philippines	11	11	11	11	11	11	12	1.7%
Mexico	7	7	7	7	8	8	9	4.6%
New Zealand	6	6	6	7	7	7	7	1.6%

On the generation side, geothermal sources should provide 91 TWh globally in 2017: 59% from OECD countries and 41% from non-OECD countries, located in Southeast Asia, Africa and Latin America.

Hydropower

Hydropower stays the largest renewable power generating source over the medium term. Addressing sustainability issues will remain an important feature for future developments.

Technology background

Hydropower is derived from the energy in moving water, from rivers or from man-made installations where water flows from a reservoir. Turbines placed in water flow extract energy and convert it into mechanical energy and then electricity. There are three main types of hydropower: storage/dam, run-of-river and pumped storage. Hydropower is a fully commercial and mature technology. It is a very flexible renewable source of energy, able to provide base-load power as well as peak power. Both reservoirs and pumped hydro storage can provide large-scale storage of electricity, providing valuable flexibility to power systems.

Hydropower production is dependent on weather and can exhibit significant yearly variability that cannot be anticipated in the forecast. While the weather phenomena stand out more in country-level data, the global total can also be affected. For example, 2010 was an exceptionally good year for hydropower production at the global level.

Capital costs of hydropower plants vary widely depending on site and project. In particular, civil works represent an important cost component and heavily depend on local prices of materials and labour. Construction costs for new hydropower projects are usually less than USD 2 000 per kW (as low as USD 1 000 per kW in non-OECD countries) for large-scale and USD 2 000 per kW to USD 4 000 per kW for small- and medium-scale plants. Parameters affecting investment costs also include the project scale, which can range from over 10 000 MW to less than 0.1 MW; the location; and the presence and size of the reservoir. The generation costs of electricity from new hydro power plants vary widely. They often range from USD 50 per MWh to USD 100 per MWh, but can fall as low as USD 20 per MWh. Plant-specific generation costs are determined by its construction costs, financing regime and capacity factor. Some hydropower plants are operated for peak-load demand and as backup for network frequency fluctuation, which increases the generation 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. To this end, a number of new sustainability protocols have come about seeking to mitigate such concerns. Careful planning and measures to minimise negative externalities will remain an important feature of hydropower activity going forward.

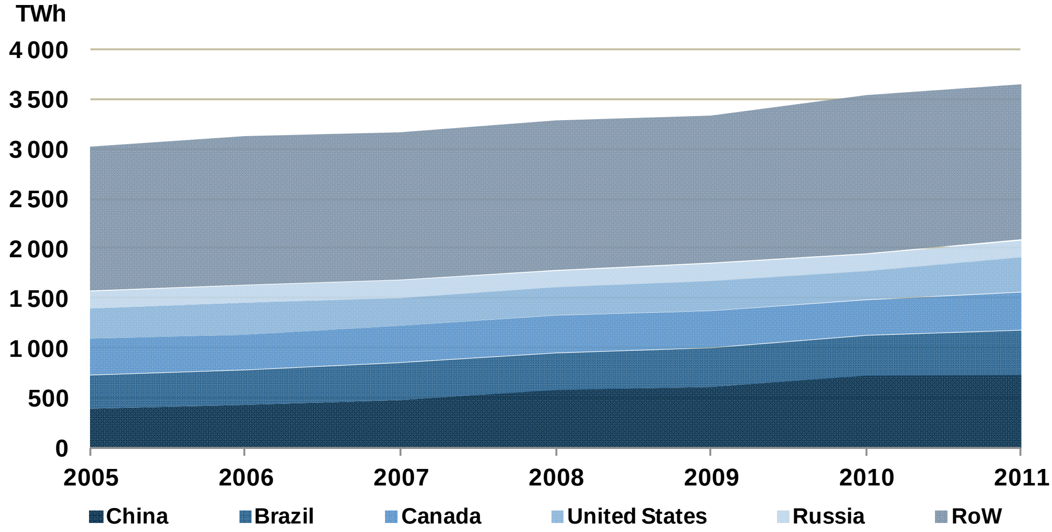
Tracking and forecasting hydropower capacity present several challenges. In practice, large hydropower plants come on line in multiple stages, as turbines are installed. However, additions may show up in reporting data only once the entire plant has been commissioned. Small hydropower capacity poses difficulties in tracking due to its size. Moreover, tracking problems also emerge as older hydropower plants, especially in Europe, are enlarged, repowered and relicensed. In light of these statistical drawbacks, both reported and projected data carry a degree of error.

Market status

Hydropower is the largest source of renewable power, producing around 3 644 TWh in 2011, which represents more than 80% of total renewable power production. China stands as the largest hydropower producer, generating around 740 TWh in 2011. China has also experienced impressive growth over the last few years, with production almost doubling from 400 TWh in 2005. In Brazil, hydropower, at roughly 450 TWh, represented 86% of power production in 2011. Canada, the United States and Russia complete the top five. Compared with China and Brazil, hydropower production in these countries has not grown significantly in recent years.

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 and Latin America have harnessed only about 20% and 26%, respectively, of their resource potential (Kumar *et al.*, 2011).

Figure 74 Hydropower generation by country



Note: hydropower generation includes pumped storage.

Other OECD countries, notably Norway, Japan, Sweden and France, generate significant amounts of hydropower. Much OECD development to date has occurred in large plants, though activity is taking place in smaller projects and in plant refurbishment. The 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.

Emerging and developing countries, where there is still a huge untapped potential, drive most current expansions on a global scale. In developing countries endowed with good resources, hydropower has become the primary power source. It represents more than 95% of national power production in Paraguay, Albania, Mozambique, Zambia and Tajikistan, for example.

Market outlook

Hydropower production should reach 4 378 TWh in 2017, up from 3 644 TWh in 2011. 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 2017, China should represent 25% 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 economic development and energy security concerns.

Table 81 Hydropower electricity generation(TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	784	740	745	751	757	761	765	-0.4%
OECD A/O	139	135	135	136	137	137	137	-0.2%
OECD EUR	534	574	585	597	606	612	618	2.4%
Non-OECD	2186	2250	2359	2478	2602	2729	2857	4.6%
World	**3644**	**3698**	**3824**	**3962**	**4102**	**4239**	**4378**	**3.1%**
China	736	789	842	900	963	1030	1096	6.9%
Brazil	449	417	428	436	449	471	496	1.7%
Canada	377	376	378	382	387	390	393	0.7%
United States	351	304	305	306	306	306	307	-2.2%
Russia	173	174	179	186	189	190	190	1.6%

Note: hydropower generation includes pumped storage.

Global hydropower capacity should grow by around 235 GW between 2011 and 2017, reaching 1 302 GW in 2017. Much of this growth is driven by China's additions of 15 GW to 20 GW per year. Brazil's additions are also significant, a total of 21 GW between 2011 and 2017. Notably, the construction of the Belo Monte Amazon Dam, which began in 2011, will add 11.2 GW starting in 2015, with capacity coming online in phases through the end of the decade. Other countries in the top five, the United States, Canada and Russia, are expected to expand at slower rates.

Table 82 Hydropower installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	194.3	195.8	196.9	198.6	199.4	200.2	201.3	0.6%
OECD A/O	68.9	69.4	69.4	70.2	70.8	70.9	71.2	0.6%
OECD EUR	198.1	202.0	205.9	210.0	212.4	215.0	217.0	1.5%
Non-OECD	605.9	635.4	669.7	705.3	740.7	776.8	812.5	5.0%
World	**1067.2**	**1102.6**	**1141.9**	**1184.1**	**1223.3**	**1263.0**	**1302.1**	**3.4%**
China	230.0	245.0	262.0	280.0	300.0	320.0	340.0	6.7%
Brazil	88.9	91.0	93.3	94.5	99.0	104.1	109.8	3.6%
United States	101.1	101.2	101.4	101.7	101.7	101.8	102.3	0.2%
Canada	75.9	76.5	76.9	78.2	78.8	79.6	80.0	0.9%
Russia	47.7	48.1	50.7	52.0	52.1	52.3	52.5	1.6%

Note: hydropower capacity includes pumped storage.

Ocean power

With a small absolute contribution, ocean power should scale up from single- to multi-device projects, an important step towards commercialisation of tidal and wave technologies.

Technology background

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 built across bays or estuaries. Most other ocean power technologies are modular and have smaller visual and environmental impact.

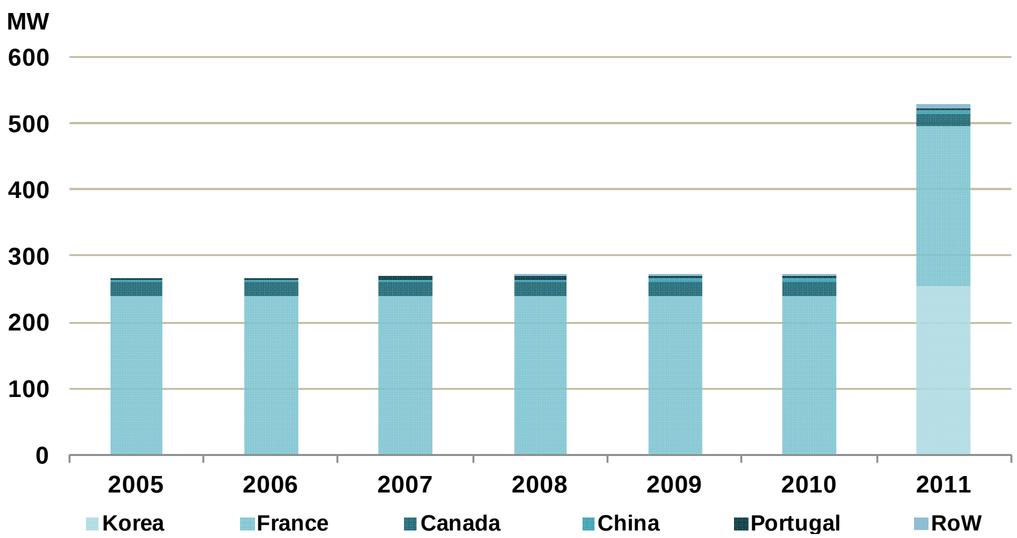
Overall, the potential for ocean technologies is significant and widespread. Tidal and wave projects provide variable but highly predictable power. Tidal/ocean currents and wave power are at the demonstration stage, with multiple megawatt-scale projects being tested. Temperature and salinity gradient technologies remain at the research and development stage.

The predominance of tidal barrage projects over the forecast period implies capacity factors of 25%. Wave and tidal currents are expected to deliver somewhat higher capacity factors (30% to 36%).

Market status

In August 2011, the largest commercial ocean project came on line, with the Sihwa Lake tidal barrage (254 MW) in Korea starting operations. Other existing commercial installations in the world include tidal barrages in France (240 MW) and Canada (20 MW).

Figure 75 Ocean power installed capacity by country



Sources: IEA statistics, IEA-OES (2012) and IEA analysis.

A few smaller ocean projects have become operational elsewhere. In the United Kingdom, the European Marine Energy Centre (EMEC) now has 12 of its 13 full-scale test berths contracted to leading wave and tidal energy developers from several countries. At the end of 2011 it had 10 different prototypes undergoing trials with 6.4 MW of total capacity. EMEC has been set up to concentrate activities related to ocean energy on one site, to bring together manufacturing and other activities related to marine energy to help the sector to reach the commercial stage. Similar testing centres exist in Canada – the Fundy Ocean Research Centre for Energy in Nova Scotia – and in Portugal – the Wave Energy Centre in Lisbon. The United States has set up three National Marine Renewable Energy Centers, in the northwest, the southeast and Hawaii. Individual demonstration projects exist in a number of other countries.

Market outlook

Based on existing plants, Korea and France should remain the countries with the largest installed ocean power capacity in 2017. Several European countries as well as Canada, South Korea and the United States see ocean energies as a part of their long-term energy strategies. Yet due to the early developmental stage of these technologies, and associated high costs, the global market is not expected to scale up significantly over the medium term. A notable exception would be further development of tidal barrages in South Korea, which would be economical. But this development faces opposition due to its potential impact on wetland preservation areas.

Demonstration power plants for other ocean technologies are also scaling up. Until recently, only single devices were tested. At present, developers are proceeding with the installation of arrays of devices that have tested successfully. The United Kingdom's Islay tidal project, for example, consisting of ten devices of 1 MW capacity, is expected to be operational in 2013.

In the medium term, Canada's capacity is expected to reach 75 MW, adding a 40 MW tidal project and a few smaller projects, driven a CAD 652 per MWh community feed-in tariff (COMFIT) in Nova Scotia. The Fundy Ocean Research Centre for Energy already has all 11 kilometres (km) of subsea cables needed for the site, allowing for transmission capacity of 64 MW.

Table 83 Ocean installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	0.02	0.02	0.02	0.02	0.03	0.08	0.09	27.3%
OECD A/O	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.3%
OECD EUR	0.25	0.25	0.26	0.27	0.29	0.30	0.32	4.1%
Non-OECD	0.01	0.01	0.01	0.01	0.01	0.01	0.04	43.3%
World	**0.53**	**0.53**	**0.55**	**0.56**	**0.60**	**0.65**	**0.71**	**4.9%**
Korea	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.0%
France	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.0%
Canada	0.02	0.02	0.02	0.02	0.03	0.08	0.08	24.6%
United Kingdom	0.00	0.00	0.01	0.02	0.03	0.04	0.05	56.5%
China	0.01	0.01	0.01	0.01	0.01	0.01	0.04	41.3%

The United Kingdom is positioning itself as the European leader in ocean power development. The government is supporting wave and tidal power technologies with five Renewables Obligation Certificates (ROCs) per megawatt hour under the Renewables Obligation scheme. The Crown Estate, the owner of the seabed exploitation rights, has already leased more than 30 sites for ocean projects around the United Kingdom, with a total potential capacity of these projects of 1 600 MW. But deployment over the projection period is expected to stay relatively modest, with capacity reaching only 50 MW in 2017. Significant growth is expected to start only around year 2020.

Sweden is expected to put into operation a 10 MW wave demonstration park, Seabased, in 2015, financed by the state funds from the Swedish Energy Agency. France has launched a public-private partnership that aims to bring on line five marine test sites over 2012-13, of which three are oriented to ocean technology and two are geared towards offshore wind.

Table 84 Ocean electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	0.03	0.03	0.03	0.03	0.07	0.22	0.22	41.0%
OECD A/O	0.28	0.55	0.55	0.55	0.55	0.55	0.55	12.2%
OECD EUR	0.53	0.54	0.55	0.57	0.59	0.61	0.63	3.1%
Non-OECD	0.01	0.01	0.01	0.02	0.02	0.02	0.06	31.6%
World	**0.84**	**1.13**	**1.14**	**1.17**	**1.22**	**1.40**	**1.46**	**9.6%**
Korea	0.28	0.55	0.55	0.55	0.55	0.55	0.55	12.2%
France	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.0%
Canada	0.03	0.03	0.03	0.03	0.07	0.22	0.22	41.0%
United Kingdom	0.00	0.01	0.02	0.04	0.05	0.08	0.10	-
China	0.01	0.01	0.01	0.01	0.01	0.01	0.05	28.4%

In 2017, ocean power is expected to deliver 1.5 TWh of power globally in 2017, with South Korea and France leading in generation, producing 0.55 TWh and 0.53 TWh, respectively.

Onshore wind

Onshore wind preserves its place as the second largest renewable power generation source. The expiration of the production tax credit in the US notably slows the near-term growth outlook.

Technology background

Wind turbines extract kinetic energy from moving airflow and convert it into electricity via an aerodynamic rotor connected to an electric generator. The electricity output of a turbine is roughly proportional to the rotor area; therefore fewer, larger rotors (on taller towers) produce more power than more numerous smaller machines.

Onshore wind power is a proven and mature technology. Typical load factors range from 20% to 35%, with exceptionally good sites exceeding 40%. Wind is a variable source of power and therefore can achieve high penetrations in power systems with sufficient existing or anticipated flexibility. The ability of grids to achieve high levels of variable renewable power penetration varies significantly by geographical area. Country-specific discussions can be found within this report's country chapters while Box 4 describes further system integration issues.

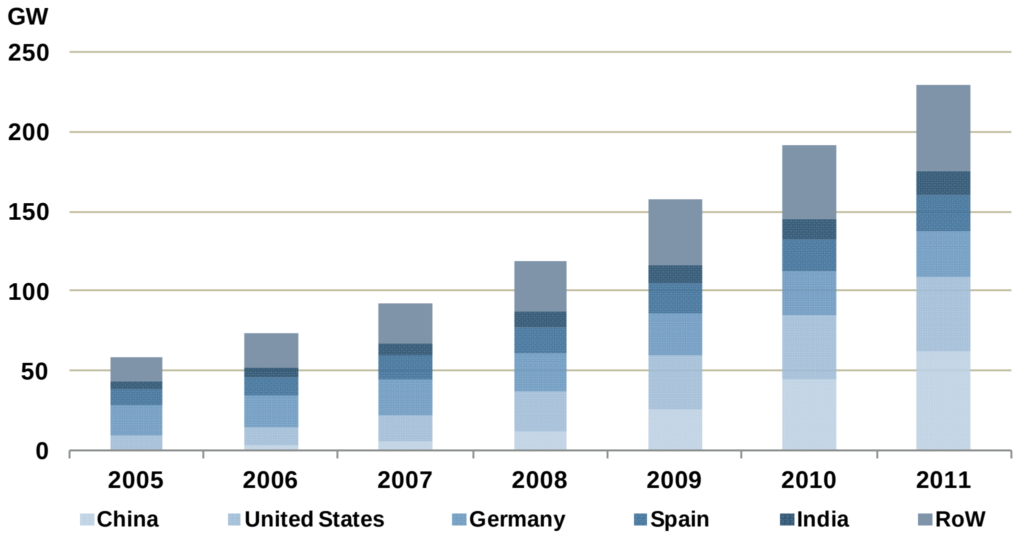
In good wind resource areas, wind power is one of the most cost-competitive renewable energy technologies. Project costs vary, with typical average costs of USD 1 800 per kW; in China, costs reportedly stand below USD 1 500 per kW. Depending on turbine prices, the financing regime and available wind resources, the generation costs of onshore wind power typically range from USD 50 per MWh to USD 140 per MWh.

Market status

In 2011, onshore wind power was the second-largest contributor to renewable power, after hydropower, producing 434 TWh. The cumulative global installed capacity has grown at an impressive yearly average growth rate of 25.6% since 2005 and reached 230 GW in 2011. China became the world's wind capacity leader in 2010. In 2011, it had a total 62 GW installed, but only about 47 GW was reportedly grid-connected. The United States kept its second position with yearly additions of almost 7 GW and a total 47 GW installed at the end of 2011. The largest wind producers in Europe, Germany and Spain, added 1.8 GW and 1.1 GW in 2011 and finished the year with totals of 29 GW and 22 GW, respectively. India grew rapidly in 2011 with 3 GW, bringing total installed capacity there to 16 GW.

Over time, the onshore wind market has become more diversified. In 2011, at least 40 countries possessed more than 100 MW of wind capacity installed. The sector also made important strides in competitiveness last year. For example, in Brazil, wind projects competed well in auctions, beating out other renewable sources and new gas-fired generation bids on a cost basis.

Figure 76 Onshore wind installed capacity by country



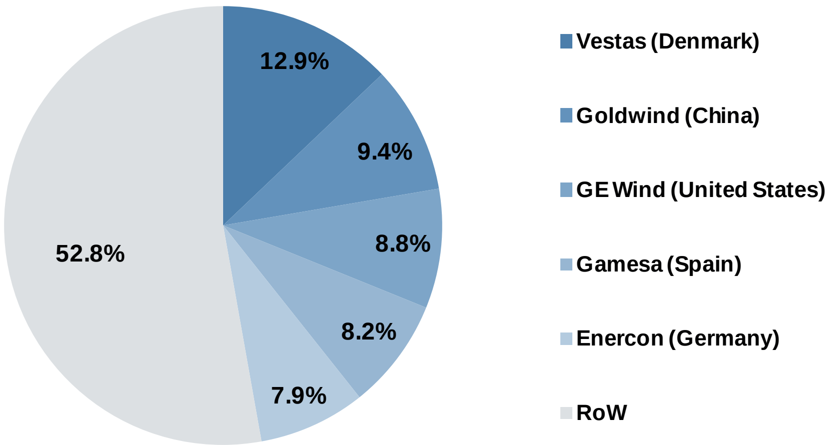
Sources: IEA statistics, IEA-Wind (2011), EWEA (2012), GWEC (2012) and IEA analysis.

Manufacturing

After experiencing bottlenecks from 2006-08, particularly in special components such as gearboxes, the wind supply chain has reached a state today where production capacity exceeds yearly installations. Based on the Bloomberg New Energy Finance "effective supply" model, the actual number of turbines available to the market in 2011 reached 73.4 GW (BNEF, 2012). Meanwhile, the supply to the market reached around 40 GW in 2011. Vestas was the largest supplier in 2011 while Chinese wind turbine suppliers advanced, occupying four positions in the top ten.

Overall, major bottlenecks in the supply of turbines are not expected over the medium term. The production of turbine components has grown increasingly standardised and economies of scale have been realised for turbines of standard size (*e.g.* below 2 MW). However, the deployment of turbines has become more sophisticated, with increased demand for components more adjusted to local conditions (*e.g.* low wind speed sites) to maximise power generation of the wind farms. Manufacturers have often positioned themselves to cater to one market or the other (*i.e.* standardised with cheaper prices versus specialised with better performance). As such, shortages may occur in certain market segments, particularly those oriented towards customised turbines. However, other factors, such as licensing procedures, policy uncertainty and the availability of financing, will have a more profound impact on deployment dynamics.

Figure 77 Market shares of wind turbine suppliers in 2011



Sources: IEA analysis based on BMT Consult (2012) and Bloomberg (2012).

Market outlook

By 2011, onshore wind had been incorporated into the energy mix of many countries. It is considered to be an established technology that is becoming more competitive with alternatives, including conventional generation. From a global perspective, the prospects for onshore wind look generally positive. Still, global annual installations are expected to slow in 2013 under the assumption that the production tax credit in the United States will not be extended (though this should spur strong additions in 2012, before its expiration at the end of the year). Moreover, increased macroeconomic uncertainties as well as changing policy environments (*e.g.* Italy, the United Kingdom) have exacerbated financing challenges for projects in some areas of Europe.

Table 85 Onshore wind installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	53.3	64.0	68.1	72.9	80.0	88.3	97.6	10.6%
OECD A/O	5.8	6.7	7.9	9.1	10.4	12.0	13.7	15.4%
OECD EUR	90.9	100.3	108.8	117.9	125.7	134.0	142.4	7.8%
Non-OECD	79.7	99.0	118.2	139.5	161.9	185.4	210.1	17.5%
World	**229.7**	**270.0**	**302.9**	**339.3**	**377.9**	**419.7**	**463.7**	**12.4%**
China	62.1	77.1	92.1	109.1	127.1	146.1	166.1	17.8%
United States	46.9	55.4	56.9	58.6	62.6	67.6	73.6	7.8%
Germany	28.9	30.6	31.7	32.8	33.6	34.4	34.8	3.2%
India	16.1	18.6	21.1	23.6	26.6	29.6	32.6	12.5%
Spain	21.7	23.6	25.0	25.5	25.5	25.5	25.5	2.7%

Note: wind capacity corresponds to installed capacity. In practice, grid-connected capacity may be lower in some countries due to delays.

By 2017, global installed capacity of onshore wind should reach 464 GW, up from 230 GW in 2011. China is forecast to have the largest capacity in 2017 with a total of 166 GW. Despite the assumed expiration of tax incentives, the United States will remain the second-largest onshore wind market with total capacity of 74 GW in 2017. Germany and India follow, with 35 GW and 33 GW, respectively, in place by the end of the projection period. Spain suffers from the moratorium on subsidised developments under the Special Regime as well as from broader overcapacity in its power sector. As such, its capacity increases only modestly, bringing the total to 26 GW in 2017.

Table 86 Onshore wind electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	142	156	176	189	205	226	249	9.9%
OECD A/O	13	15	18	21	24	28	32	16.3%
OECD EUR	168	195	215	234	252	270	289	9.5%
Non-OECD	112	142	183	229	283	345	415	24.5%
World	**434**	**509**	**591**	**672**	**765**	**868**	**985**	**14.6%**
China	73	91	118	150	187	227	273	24.6%
United States	120	134	148	152	159	171	186	7.5%
Germany	46	52	55	56	58	60	61	4.7%
Spain	42	50	53	55	56	56	56	4.7%
India	26	30	35	39	44	49	54	13.5%

Global production of onshore wind power should reach 985 TWh in 2017. China's contribution is the largest forecast uncertainty. Its production in 2017 is expected at 273 TWh, which corresponds to a relatively low capacity factor (20%). Implied capacity factors for 2010 and 2011 were roughly 13%, due to grid connection delays and curtailment. This report assumes that capacity factors in China rise over time, as grid connection and curtailment issues improve, though they remain low compared to theoretical potential. The United States should remain the second-largest onshore wind producer at 186 TWh in 2017. Germany, Spain and India follow with 61 TWh, 56 TWh and 54 TWh, respectively.

Over time, production should expand within more non-OECD countries. In 2011, the non-OECD produced around 26% of global onshore wind power. By 2017 this percentage is expected to rise to 42%. If China makes greater-than-anticipated progress in resolving its grid connection and curtailment issues by 2017, the non-OECD onshore wind production could reach 50% of the global total while the absolute global level would surpass 1 000 TWh for the first time.

Offshore wind

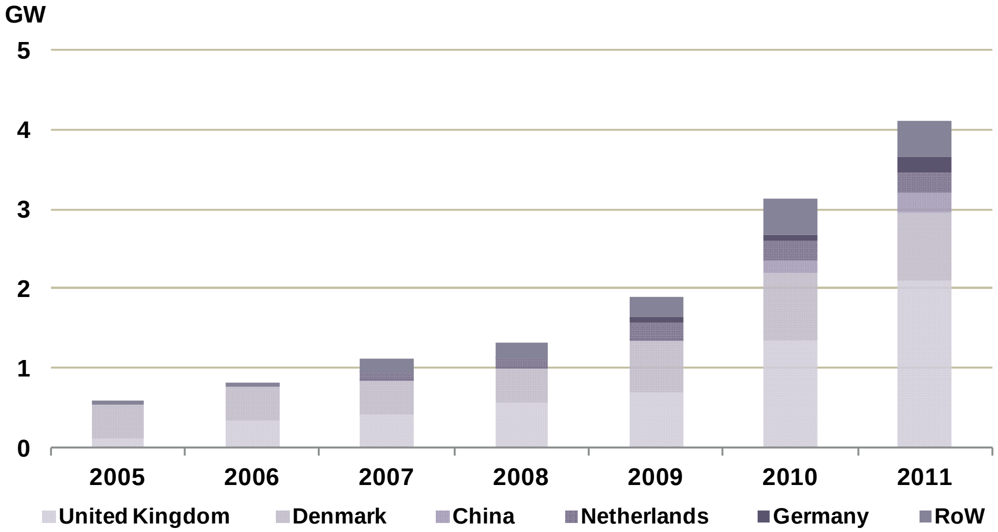
With strong support in some countries, offshore wind progresses significantly, but its viability over the medium term ultimately depends on tackling certain technical and financial challenges.

Technology background

Offshore wind turbines are deployed in coastal regions, typically exploiting wind resources that are significantly better than onshore sites. Today's operating offshore wind turbines are essentially based on large land turbines (typically 3 MW to 5 MW) customised for the ocean environment. But a specific offshore wind industry is emerging. It focuses on turbines explicitly suited for an offshore environment as well as on support structures for these turbines. Current monopile structures are suitable for water depths of 10 metres (m) to 30 m. Jacket, tripod and tripile structures enable access to water depths up to 50 m. For deeper waters floating turbines are typically needed, but these are not yet commercially available.

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. These locations also 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 likely achievable in the future.

Figure 78 Offshore wind installed capacity by country



Sources: EWEA (2012), GWEC (2012) and IEA analysis.

Generation costs of offshore wind are driven primarily by site characteristics and the financing regime with investment costs of current projects ranging from USD 3 000 per kW to USD 6 000 per kW. As offshore wind resources yield capacity factors above 35%, generation costs can range between USD 140 per MWh to USD 300 per MWh. These figures are very sensitive to delays in construction, because early revenues are discounted less in determining potential project returns.

Market status

Global offshore wind installed capacity reached 4.1 GW in 2011. More than half of this capacity, 2.1 GW, is located in United Kingdom waters. Denmark, long a major player in wind technology development, follows with 0.9 GW, a large number relative to the size of the country. China follows with 0.26 GW, of which more than half is an intertidal wind farm. The Netherlands (0.25 GW installed) and Germany (0.20 GW installed) close the top five.

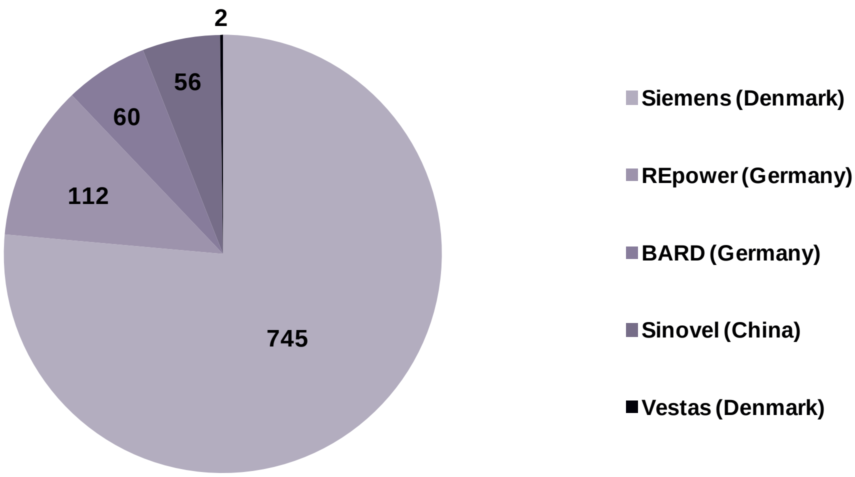
In 2011, offshore wind faced several new challenges. In Europe, projects under construction moved farther away from the shore and to deeper waters. The European Wind Energy Association (EWEA, 2012) reports that European projects under construction reached average depths of 25.3 m and distance to shore of 33.2 km. These exceed average water depths of 22.8 m and distance to shore of 23.4 km for projects commissioned in 2011, implying increased needs for subsea cables, longer access for operations and maintenance, and the need for low-cost deep-water foundation technology going forward. Practical experience during construction also shows that projects can face significant delays in the case of bad weather conditions offshore, which, depending on contract strategy, can have significant financial impacts.

In China, the "Double Ten" regulation of the State Oceanic Administration slowed down offshore wind developments. The regulation stipulates that projects must be constructed at least 10 km from the shore and in water depths of at least 10 metres. It aims to avoid disputes over different uses of coastal areas. The regulation delayed the start of construction of several wind farms allocated during the first licensing round in 2010 that were supposed to be operational by 2013. Yet, China's commitment to offshore wind development is likely to remain firm. And developers are finding ways to deal with the regulation, for example by shifting projects to different locations.

Manufacturing

Based on the 2011 EWEA report *Wind in our Sails*, trends observed over the past year point to the increasing maturity of the offshore industry. In the early 2000s, turbine manufacturers offered turnkey offshore farms to developers, taking over the full scope of an "Engineer-Procure-Construct-Install" contract. Starting in the middle of the past decade, with recognition of the specific challenges associated with offshore development, turbine manufacturers shied away from offering the full set of services in one contract. Developers were thus forced to contract with more than one party to cover all aspects of developing the project. This can range from two to multiple contracts depending on how interface risk is managed. In recent years, in particular with the entrance of established offshore oil and gas as well as the more traditional maritime industry players, a trend of more comprehensive contracts has come about.

Figure 79 Offshore wind turbine supplied in 2011, by company (MW)



Source: IEA analysis based on EWEA (2012).

To date, offshore turbines have been slightly adapted versions of their onshore counterparts, with a small number of manufacturers producing for the comparably much smaller offshore segment. In the past, shortages in the onshore supply chain have spilled over to offshore. With established manufacturers releasing dedicated offshore turbine models and new entrants specialising in the offshore market, such spill-over of constraints will become less relevant going forward.

In summary, EWEA does not expect wind turbines themselves to be a major constraint. However, shortages of other critical components may occur in the coming years. The availability of certain types of high-voltage subsea cables may represent a key constraint. With only a limited number of manufacturers in the market, a high up-front capital demand for expanding production capacity, and comparably long lead times for bringing new capacity on line, a critical bottleneck could emerge if investments do not go ahead in due time. Another issue that has driven up costs in the past is the availability of different types of construction vessels, which are needed for offshore construction. While their availability has been a constraint in the past, new builds are coming on line, which may ease medium-term bottlenecks in this category.

Market outlook

Over the medium term, offshore wind should scale up significantly, reaching 26 GW in 2017, up from 4 GW in 2011. Europe is driving much of the growth, representing almost two-thirds of total cumulative capacity by the end of the projection period. China (27% of cumulative capacity) and potentially small contributions from the United States, Japan and Korea account for the rest of installed capacity in 2017.

The United Kingdom is forecast to have 7.4 GW online in 2017, somewhat less than 8.3 GW announced for 2017 in the NREAP. This is a consequence of offshore projects proving to be technically and financially more challenging than initially expected. China is expected to be the second-largest player in the offshore market by 2017 with 7 GW installed. But the uncertain impact of recent regulatory changes are delaying developments, bringing uncertainty to the forecast.

Germany and France will likely also install slightly less than what was envisaged in their respective NREAPs. On top of technical and financial challenges common to all European developments, Germany is facing challenges in transmission of power from the north to south. Germany should therefore have around 4 GW of offshore wind capacity by 2017. France delayed its second 3 GW tender and at the same time awarded the first 3 GW tender to only 2 GW of projects. These contracted projects need to go through feasibility studies, which are due by the end of 2013, implying that construction may start by 2015. Under this assumption, France could have maximum 2 GW of offshore capacity on line by 2017. However, given potential for delays to this process, only 1.5 GW are forecast.

Denmark should hold the fifth-largest offshore wind installed capacity at the end of 2017, reaching 1.7 GW. Based on the release of its new 2020 Energy Agreement which posits more aggressive goals for wind development, Denmark will likely install slightly more than what is stated in its NREAP.

Table 87 Offshore wind installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	0.0	0.0	0.0	0.0	0.2	0.5	0.5	-
OECD A/O	0.0	0.0	0.1	0.2	0.3	1.0	1.7	102.5%
OECD EUR	3.8	5.6	7.5	8.7	10.2	13.1	16.7	27.9%
Non-OECD	0.3	0.5	0.9	1.6	3.0	5.0	7.0	73.3%
World	**4.1**	**6.1**	**8.4**	**10.6**	**13.8**	**19.6**	**25.9**	**35.9%**
United Kingdom	2.1	3.5	3.8	4.5	5.4	6.4	7.4	23.4%
China	0.3	0.5	0.9	1.6	3.0	5.0	7.0	73.3%
Germany	0.2	0.4	1.4	1.4	1.7	2.8	4.0	64.7%
Denmark	0.9	0.9	1.3	1.3	1.5	1.7	1.7	11.6%
France	0.0	0.0	0.0	0.0	0.0	0.5	1.5	-

In 2017, offshore wind should deliver 80 TWh of electricity globally. Offshore resources exploited by 2017 will probably not differ significantly in the leading countries, and therefore power production should correspond to capacities in roughly the same way across the countries. In China, some curtailing may occur. The United Kingdom and China should generate 24 TWh and 21 TWh, respectively, in 2017. Germany's production should reach around 12 TWh in the same year. Denmark's production should be roughly 5.8 TWh in 2017 while France is expected to produce 3.5 TWh.

Table 88 Offshore wind electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	0.0	0.0	0.0	0.0	0.4	1.2	1.7	-
OECD A/O	0.1	0.1	0.1	0.5	1.0	2.4	4.8	95.0%
OECD EUR	11.9	16.5	22.9	28.3	33.1	40.8	52.2	28.0%
Non-OECD	0.4	1.3	2.5	4.4	8.1	14.0	21.0	91.2%
World	**12.4**	**18.0**	**25.5**	**33.3**	**42.6**	**58.5**	**79.7**	**36.4%**
United Kingdom	6.0	9.9	12.9	14.6	17.4	20.6	24.1	26.0%
China	0.4	1.3	2.5	4.4	8.1	14.0	21.0	91.2%
Germany	0.5	1.1	3.1	4.8	5.4	7.8	11.9	69.0%
Denmark	3.0	3.0	3.7	4.4	4.8	5.5	5.8	11.7%
France	0.0	0.0	0.0	0.0	0.0	0.9	3.5	-

Note: for offshore wind, implied capacity factors are often lower than theoretical estimates, reflecting the commissioning of new capacities over the course of a year. Over time, capacity factors are expected to improve. However, given a relative lack of experience in offshore maintenance, achievable capacity factors could vary significantly.

The scale-up of offshore wind requires cost reductions over time. For the moment, government incentives in countries committed to offshore development are driving the growth. However, supports will need to be gradually reduced to contain associated financial burdens as the technology scales up. Installing and operating offshore may also bring additional unexpected challenges. Overcoming the above hurdles could help offshore wind realise its advantages versus more mature technologies.

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 background

Solar PV systems directly convert solar energy into electricity. They use not only direct sunlight, like CSP, but also the diffused component of sunlight. The basic building block of a solar PV system is a PV cell. Solar PV cells are interconnected to form a PV module (50 watts-250 watts). The modules are combined with a set of application-dependent components (inverters, batteries, electrical components and mounting systems) to form a PV system. These systems are highly modular and can be linked to provide power ranging from a few watts to hundreds of megawatts. There are two major sets of commercial PV technologies: silicon-based systems (currently more than 85% of the global market) and thin film systems. Crystalline silicon systems typically have higher energy conversion efficiencies than thin film systems; yet, the latter tend to have a lower cost per unit of capacity.

Module prices currently comprise about half of the system cost. According to Solarbuzz, a solar market research and analysis company, the lowest retail module prices in March 2012 reached USD 1.06 (EUR 0.78) per watt for multicrystalline silicon modules and USD 1.10 (EUR 0.81) per watt for monocrystalline silicon modules (Solarbuzz, 2012). The lowest thin film module price in March 2012 was USD 0.84 (EUR 0.62) per watt. Module prices for large scale projects can be lower, with factory-gate selling prices at USD 0.85 per watt for multicrystalline silicon modules from China and USD 1.01 per watt for other multicrystalline silicon modules in April 2012 (Bazilian *et al.*, 2012).

Apart from the cost of the physical PV system, generation costs depend on financing terms and solar irradiance, with capacity factors ranging from below 10% in northern Germany to near 25% in Africa. For large PV systems, the current lowest observed capital costs stand at USD 1 900 per kW. For small scale systems, capital costs are as low as USD 2 500 per kW. Current generation costs range from USD 155 per MWh to USD 220 per MWh for large-scale systems and USD 185 per MWh to USD 260 per MWh for small-scale installations, depending on the solar resource. These costs correspond to more mature markets, Germany and Italy, where capital costs are relatively low but the irradiance is not optimal. In less mature markets, there is good potential to achieve lower generation costs once they develop.

Solar PV output is limited to hours when the sun is shining, but its variability is less challenging to grid operators than, for example, the variability of wind power. Solar PV has the best potential in places where peak demand occurs during the sunniest hours (*e.g.* heavy air-conditioning usage). Solar PV combines two advantages. On one hand, manufacturing can be done in large plants, allowing for economies of scale. On the other hand, PV is a very modular technology, allowing for a wide range of applications.

Market status

Solar PV is the fastest-growing renewable energy technology. From 2005-11, solar PV cumulative capacity grew on average by 54% per year. The cumulative grid-connected capacity reached 69.7 GW at the end of 2011.

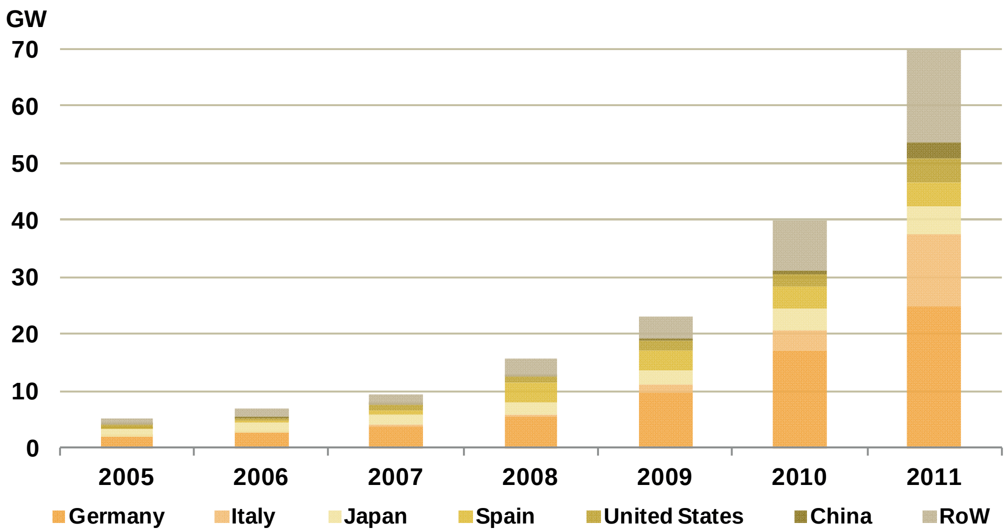
In 2011, Germany was the largest cumulative market, with total capacity of almost 25 GW. The country added 7.5 GW in 2011, similar to additions in 2010. In one month (December 2011), 3 GW were grid-connected in Germany, bringing serious concerns within the government about how to get PV deployment on a more sustainable path. Italy, thanks to generous incentives, had the largest annual growth in 2011, with over 9 GW connected during the year, bringing the total capacity to 12.8 GW, the second-largest in the world. Currently, Italy is adjusting its policy environment in response to such higher-than-expected growth.

Japan went through rapid development, though slower than Germany and Italy. At the end of 2011, capacity in Japan was 4.9 GW (versus 3.6 GW in 2010) with an increased deployment profile in the second half of the year versus the first half. Going forward, the introduction of a feed-in tariff in July 2012 should spur more rapid deployment. Spain had 4.4 GW installed at the end of 2011. The country has seen a significant slowdown of PV installations since 2008, the year of its PV bubble when it added 2.6 GW, and it grew only 370 MW in 2011.

In the United States, federal tax incentives and state-level generation-based policies spurred high solar PV deployment in several states, including California and New Jersey. Overall, the United States added almost 1.9 GW during 2011 and finished the year with total installed capacity of 4.0 GW.

The third-largest annual growth in 2011 was achieved by China. Given the country's enormous manufacturing base, this should not come as a surprise. At the end of 2010, the total installed capacity in China stood at 0.9 GW and 2011 additions turned out to be roughly 2.2 GW. The growth in China is driven by several incentives programmes as well as expectations that a renewable energy quota system will be established.

Figure 80 Solar PV installed capacity by country



Note: Solar PV capacity corresponds to grid-connected capacity, which includes small distributed capacity.
Sources: IEA-PVPS (2012), EPIA (2012), SEIA (2012a) and IEA analysis.

During 2011, many countries emerged as new players on the PV market. While their annual growth remains small for the moment, the potential should increase as supply chains develop. Diversification of the market to more countries should stem not only from the effect of generous incentives, but from the improved competitiveness of solar PV in more circumstances. Indeed, in sunny countries solar PV can compete without any incentives in off-grid and isolated grid applications. It is also competitive with bulk power on-grid from unsubsidised oil-fired generation. More importantly, in mature markets with high electricity prices, the unsubsidised solar PV generation costs of commercial and residential installations can be competitive with retail electricity prices, *e.g.* the south of Italy, southern Germany, some states of Australia and California.

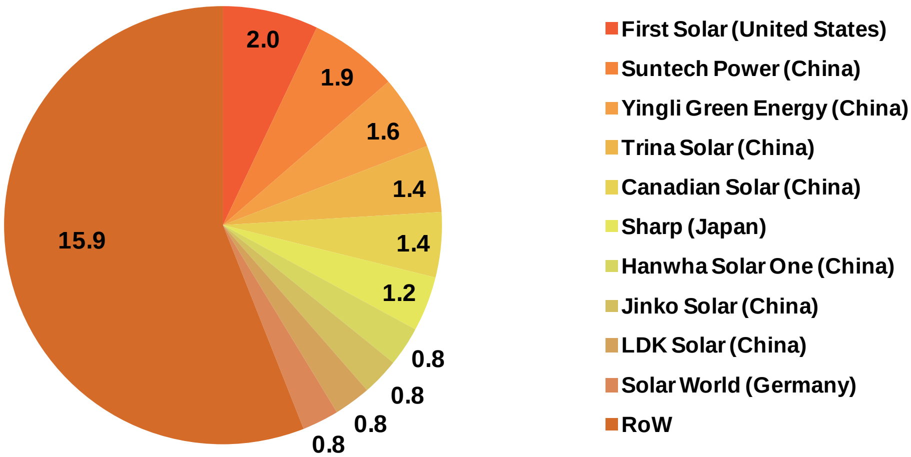
Manufacturing

Amid a period of major restructuring, the solar PV manufacturing industry has begun to transition from markets in which government supports play a pivotal role to new and more competitive, power-hungry markets.

The European Photovoltaic Industry Association reports that 29.7 GW of capacity was added globally in 2011 (EPIA, 2012). According to Lux Research (Lux Research, 2012a), an emerging technologies consultancy, 28.4 GW of PV modules were produced globally, with the top ten manufacturers representing 44% of the market. First Solar and Suntech Power were market leaders, both with production around 2 GW in 2011. Based on shipments, Suntech with over 2 GW led the market slightly ahead of First Solar, reports IMS Research (IMS Research, 2012), an electronics market consultancy.

Due to a large degree of overcapacity, the solar PV manufacturing industry is undergoing major consolidation. In 2011, many companies scaled back their production or restructured, and some went out of business. Competition is fierce, with companies selling their products with zero margins or at a loss just to keep their market shares. Chinese-based companies are taking increasingly large market share, as several United States and European companies have been unable to compete on a cost basis. Moreover, companies are tending to locate manufacturing facilities closer to demand centres, which are increasingly found in emerging markets. Still, at the end of 2011, the global manufacturing capacity as estimated by Lux Research was 50 GW (Lux Research, 2012b).

Figure 81 Global PV modules production in 2011, by company (GW)



Source: IEA analysis based on Lux Research (2012a).

In an environment of rapidly rising annual installations, manufacturers that want to preserve their market shares need to rapidly scale up their production or acquire smaller competitors. That requires sizeable investments. Reinvesting earnings is not an option in the current market environment, with prices sometimes below costs of production. At the same time, capital seems to be less costly and more easily accessible in Asia than in Europe or the United States. This explains, at least in part, the evolution of manufacturing towards Asia.

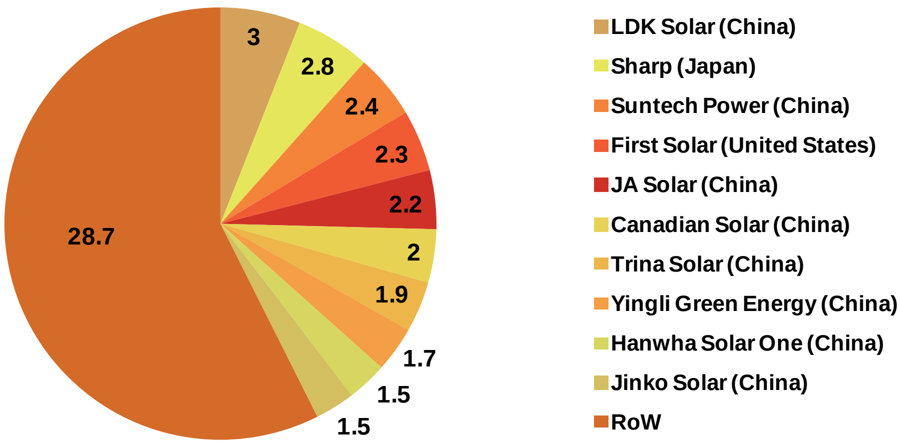
Strategically, manufacturers will likely position themselves closer to high growth markets in Asia, with the Chinese and Indian markets expanding strongly and Southeast Asia likely to follow. Manufacturers are starting to move towards markets where they can rely on sustainable and predictable growth in an environment that does not or soon will not need subsidies. That, in general, means going outside of Europe to sunnier countries of Asia, and also the Middle East and Africa.

The large Chinese manufacturing sector is also undergoing major restructuring. Small, higher-cost companies with older equipment are less interesting for potential acquirers and may simply go out of business. Large companies invested upstream between 2009 and 2011 in order to improve their supply of polysilicon. Indeed, based on the contribution of China to the 2011 Annual Report of the IEA Photovoltaic Power Systems Programme, the share of polysilicon imported to China decreased from 92.5% in 2006 to an estimated 33.3% in 2011.

The Chinese manufacturing industry was relying too heavily on exports to European and other markets, which turned out to be volatile. It now sees an opportunity to produce for its potentially huge domestic market. Based on the 12th Five-Year Plan for the Photovoltaic Industry, published in

February 2012 by the Chinese Ministry of Industry and Information Technology, the government expects leading PV companies to reach production capacity of 50 000 tonnes of polysilicon per year by 2015. Module and cell capacities should reach 5 GW for market leaders.

Figure 82 Global PV modules manufacturing capacity in 2011, by company (GW)



Sources: IEA analysis based on Solarplaza (2012) and Lux Research (2012b).

Going forward, the global solar PV industry potentially faces a few difficult years ahead. Currently, margins are almost non-existent and many companies are posting losses due to the highly competitive environment. Some are also incurring costs associated with restructuring. At the same time, this environment brings cheap solar PV modules to the market.

Market outlook

Global solar PV capacity in 2017 should reach 231 GW. Germany retains the largest capacity with 45 GW, followed by China, at 35 GW in 2017. Behind the top two countries, the United States, Japan and Italy are expected to reach 25 GW, 24 GW and 23 GW, respectively.

In the United States, the current federal tax incentives for PV run through 2016. At the same time, many states provide generation-based incentives and have renewable portfolio standards in place. The deployment environment for solar PV is therefore positive. Indeed, the United States forecast for 2017 appears conservative with respect to its potential. In several states with large populations, *e.g.* California and Florida, PV generation costs should fall below retail electricity prices, making a case for installation of PV panels for self-consumption, supported by net-metering schemes.

Japan has put in place a new feed-in tariff scheme effective on 1 July 2012. The level of tariff fixed for solar PV seems too generous, but PV system prices in Japan have been traditionally much higher than in other markets. It remains to be seen how much growth these tariffs will deliver and whether they will cause another unsustainable solar PV bubble, as already seen in Spain or the Czech Republic, heavily burdening power consumers in Japan.

Italy's development is slightly behind its 23 GW target for 2016. Despite a proposed, significant adjustment of incentives, financial support should remain high enough to provide sufficient margin for profitable investments. Moreover, given the high solar resource in southern Italy and prevailing high retail electricity prices, installing solar PV panels should become attractive even without incentives. This would come about, in particular, for self-consumption of commercial and residential users, possibly supported by net metering. However, given the tentative economic situation in the near term, these effects may start to become visible only after an assumed economic recovery from 2014 onwards.

Table 89 Solar PV installed capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	4.6	7.6	11.2	15.3	19.8	25.2	31.5	37.7%
OECD A/O	7.2	9.9	14.2	18.6	23.1	27.7	32.5	28.6%
OECD EUR	51.30	60.8	67.2	73.9	81.0	88.4	96.3	11.1%
Non-OECD	6.6	13.0	22.1	32.4	43.1	55.5	70.3	48.3%
World	**69.7**	**91.3**	**114.8**	**140.1**	**167.0**	**196.7**	**230.5**	**22.1%**
Germany	24.7	29.7	32.7	35.7	38.7	41.7	44.7	10.4%
China	3.1	6.9	11.2	16.1	21.7	28.1	35.1	49.9%
United States	4.0	6.5	9.3	12.3	15.8	19.9	24.9	35.9%
Japan	4.9	6.9	10.4	13.9	17.4	20.9	24.4	30.6%
Italy	12.8	14.3	15.3	16.8	18.8	20.8	23.3	10.5%

Note: solar PV capacity corresponds to grid-connected capacity, which includes small distributed capacity.

By 2017, solar PV should spread out to significantly more countries, almost doubling in geographic coverage compared with 2011. While the share of total capacity outside of the OECD and China should reach only 15%, this still represents some 35 GW of solar PV capacity, more than the world total in mid-2010. Over the medium term, self-consumption should be an important driver that supports deployment in other sunny OECD countries, *e.g.* Australia and Israel.

Table 90 Solar PV electricity generation (TWh)

	2011	2012	2013	2014	2015	2016	2017	CAGR
OECD AM	5	9	14	19	25	32	41	41.4%
OECD A/O	8	13	18	24	30	36	43	33.2%
OECD EUR	45	66	74	82	90	98	107	15.5%
Non-OECD	8	15	26	39	53	69	88	50.7%
World	**65**	**102**	**131**	**164**	**198**	**236**	**279**	**27.4%**
Germany	19	27	30	33	36	39	41	14.3%
China	3	7	12	17	24	31	39	55.0%
United States	5	8	12	16	20	26	32	38.1%
Italy	11	19	21	23	25	28	31	19.6%
Japan	6	8	12	17	21	26	30	31.6%

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 279 TWh globally in 2017. Germany remains the largest solar PV power producer in 2017, followed by China. 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. Italy, the United States and Japan round out the top five power production countries.

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. Indeed, solar PV today already provides cheaper electricity than fossil alternatives, if they are not subsidised, in off-grid and isolated grid situations. These positive circumstances for PV should grow over time. Naturally, this competitiveness comes more easily in places with excellent solar resource. In 2017, almost 50 TWh of solar PV electricity should be generated in countries other than China and OECD countries.

Box 5 The outlook for solar thermal heating

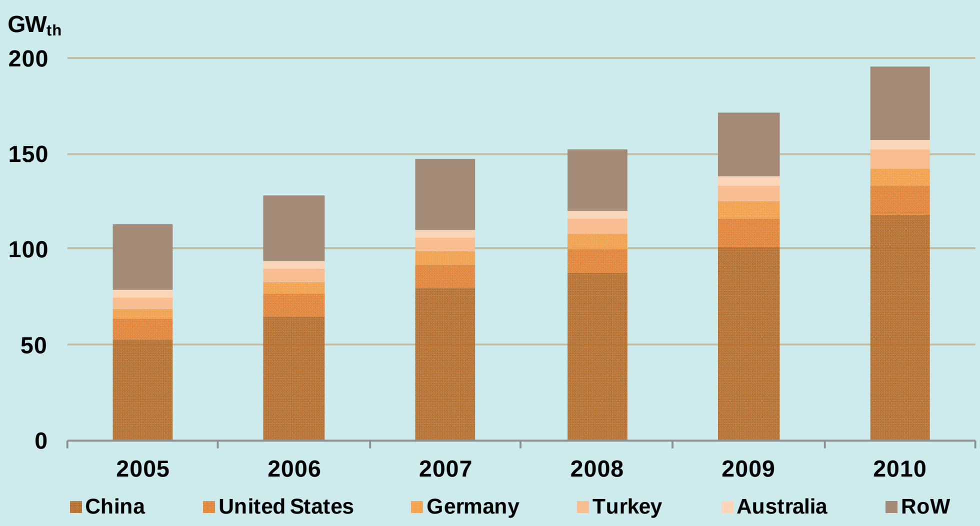
In its first edition, this report focuses largely on electricity generating technologies, while renewable sources can also contribute significantly in the heating and transport sectors. As a feature, this edition covers one of the more dynamic renewable heating technologies – solar thermal heating.

Technology background

Solar heating technologies use solar energy to provide heat. Collectors provide heated water for household use but are deployed at a larger scale for commercial and industrial uses or for district heating systems. Several types of collectors exist. For water and space heating, flat-plate and vacuum-tube collectors are 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.

Solar thermal heating is a mature technology with excellent potential in sunny climates. Its deployment can have significant effects on local electric systems and fuel markets. In richer developing countries, electric water heating can often represent a significant share of household power consumption. Deployment of solar water heating can therefore imply significant fuel savings and in some systems can free electricity load for more economically profitable activities.

Figure 83 Solar heating installed capacity by country



Sources: IEA-SHC (2012) and IEA analysis. 2011 country-level data are not available.

Market status

Solar thermal heating reached a global installed capacity of 195.8 gigawatt thermal (GW_{th}) in 2010. Over the period 2005-10 the sector grew at an average rate of 11.6%. Much of this growth stemmed from China, where developments have occurred largely in low-rise buildings and rural applications. In 2010, China represented 60% of world capacity with 117.6 GW_{th} installed versus 52.5 GW_{th} in 2005. The rapid growth has been spurred by strong supply chain development and competitiveness with alternatives. At the end of 2010, the United States had 15.3 GW_{th} installed, mostly unglazed collectors for swimming pool heating. The United States market grew around 6% per year from 2005 to 2010.

Box 5 The outlook for solar thermal heating (continued)

Germany had the third-largest capacity in 2010, with 9.6 GW_{th} installed. The market has grown rapidly due to the mandatory use of renewable energy for heating in new buildings. Turkey stood at 9.3 GW_{th} of capacity at the end of 2010. With no formal renewable heat obligations in place, solar thermal development has proceeded largely based on its competitive advantages versus alternatives. Australia had 5.8 GW_{th} of installed capacity at the end of 2010, with around 65% as unglazed collectors for swimming pool heating.

In Western Europe, solar thermal applications have grown more sophisticated. These include hot water preparation, space heating of single- and multi-family houses and hotels, large-scale plants for district heating, and a growing number of air-conditioning, cooling and industrial applications. In sunny non-OECD countries, solar thermal provides numerous benefits. Many designs of solar collectors are widely available and they compete well with other alternatives even in the absence of incentives. Establishing a well-functioning supply chain is a major enabler for the creation of solar thermal water heating market.

Of note, the world's largest system with a capacity of 25.4 megawatt thermal capacity (MW_{th}) (36.305 m^2) was commissioned in April 2011 in Saudi Arabia. The system is providing hot water and heat for a university campus through a district heating network. Special glass as well as a special mounting system were used for the collectors to help protect them from sandstorms common in the region.

Market outlook

Over the medium term, the solar thermal heating market should grow at roughly the same pace as from 2005-10, reaching over 500 GW_{th} in 2017. China should remain the deployment leader with 364 GW_{th} in 2017, representing 72% of global capacity. Solar thermal water heating should spread further in high-rise buildings there with more sophisticated designs, using forced circulation and collector placements on facades and balconies. Industrial applications will likely remain small, however, which explains why the projection of total capacity in 2015 trails the industry target of 280 GW_{th}.

Table 91 Solar thermal heating installed capacity (GW_{th})

	2010	2011	2012	2013	2014	2015	2016	2017
China	117.6	138.0	163.0	191.0	224.0	263.0	310.0	364.0
Germany	9.6	10.9	12.4	14	15.9	18.1	20.5	23.2
United States	15.3	16.0	16.5	17.0	17.5	18.0	18.5	19.0
Turkey	9.3	10.1	11.0	12.0	13.0	14.2	15.4	16.8
India	2.8	3.7	4.8	6.2	8.0	10.0	12.2	14.5
World	**195.8**	**218.7**	**249.7**	**285.2**	**327.4**	**378.3**	**436.6**	**503.5**

In 2017, total installed capacities in Germany and the United States should reach 23 GW_{th} and 19 GW_{th}, respectively. Turkey keeps its fourth place globally with almost 17 GW_{th} by the end of 2017. India becomes the country with the fifth-largest total installed capacity in 2017, at 15 GW_{th}, in line with the 2017 targets of Jawaharlal Nehru National Solar Mission.

Other non-OECD countries should increasingly drive global growth with activity occurring in Brazil, the Middle East, Southeast Asia, South Africa and several other African countries. In Europe, several industrial uses should start to appear and large-scale installations feeding into district heating networks should become more widespread, though their impact on global numbers should be relatively small compared with developments in the non-OECD.

Global trends in renewable technology: diffusion and competitiveness

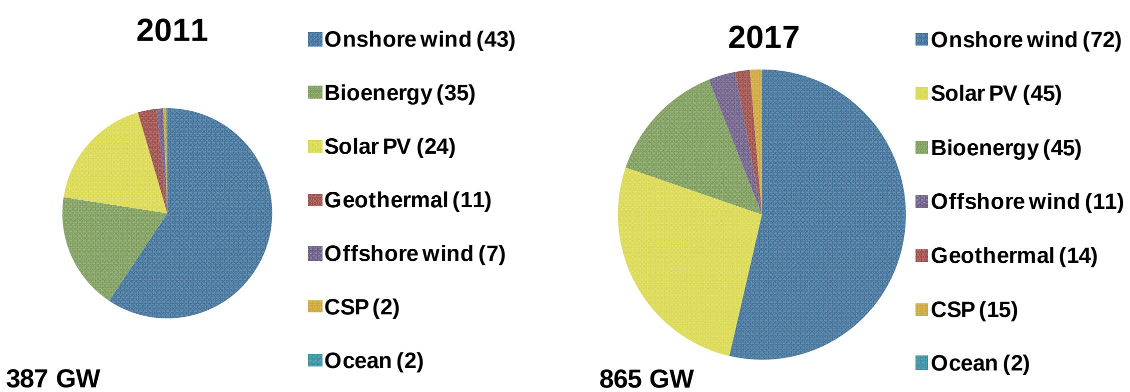
Two significant global trends should characterise the deployment of renewable technologies over the medium term. First, as renewable electricity technologies scale up, from a global total of 1 454 GW in 2011 to 2 167 GW in 2017, they should also spread out geographically. Second, renewable technologies are becoming increasingly competitive on a cost basis with their alternatives in a number of countries and circumstances.

Renewable deployment expands to a wider set of geographies …

In general, the deployment of non-hydropower renewable sources is becoming more widespread, with growth shifting beyond traditional support markets in Europe and other OECD countries. This technological spread is important in several respects. At the country level, this spread indicates an increased portfolio approach, which has positive implications for energy security as countries diversify their energy mix. Moreover, as technologies gain a foothold in emerging markets, their deployment will better coincide with the strongest sources of growth in electricity demand going forward. For example, the deployment of renewable sources in India should help diversify the power generation mix away from increasingly costly coal and meet fast-growing demand needs there.

On the industry side, the economic robustness of renewable industries should improve as they depend less on the particular market and policy conditions of a few countries. Moreover, a diversity of target markets should create more competition on the side of manufacturers, developers and installers and help drive costs down. Solar PV provides an example of an industry where costs have fallen with increased international competition. Though this has caused some upheaval on the upstream side, the overall industry is displaying flexibility in shifting deployment to emerging markets. Finally, deployment in different resource and weather environments can help spur further technological improvements, particularly in more nascent technologies such as offshore wind.

Figure 84 Non-hydro technologies, total cumulative capacity and number of countries with capacities more than 100 MW, by technology, in 2011 and in 2017



In 2011, OECD countries represented 51% of global installed renewable capacity. However, as deployment progresses in other regions, non-OECD countries are expected to hold the majority share of global installed renewable capacity, at 54% in 2017. China's growth underpins much of the non-OECD rise. In 2011 China accounted for 21% of global installed renewable electricity capacity, but this rises to 27% in 2017 (50% of non-OECD capacity), with particularly large positions in hydropower and onshore wind. In some technology markets, China, due to its size and rapid growth, has installed capacity that is an order of magnitude larger than other leading players.

The number of new countries with installed renewable capacity (100 MW or more) rises significantly over the medium term as well. Onshore wind, already widespread in many countries in 2011, is deployed in at least 70 countries in 2017. Significant deployment of solar PV and bioenergy is reached in around 45 countries by 2017, up from 24 and 35 in 2011, respectively. Geothermal and CSP are deployed in roughly 15 countries by 2017, while offshore wind should reach 11 countries.

Table 92 Geographical concentration per deployed technology

	2005	2011	2017
Bioenergy	green	green	green
CSP	red	red	yellow
Geothermal	yellow	green	green
Hydropower	green	green	green
Onshore wind	yellow	green	yellow
Offshore wind	red	red	yellow
Ocean	red	red	red
Solar PV	yellow	yellow	green

Note: green circles indicate unconcentrated market, yellow indicate moderate concentration and red indicate high concentration.

A more sophisticated look at diffusion analyses the geographical concentration of renewable energy by calculating Herfindahl-Hirschman indices by technology for 2005, 2011 and 2017 based on country-level capacity positions.[10] The results show that the cumulative installed capacity of many renewable technologies has become less geographically concentrated over time. Mature technologies such as hydropower and bioenergy were already diversified in 2005. Geothermal power and onshore wind improved their position between 2005 and 2011 as they expanded to more markets. The remaining technologies did not significantly expand their footprints between 2005 and 2011, staying moderately or highly concentrated. Notably, persistent concentration can have negative consequences. In solar PV a combination of high, country-level economic incentives and a relative concentration of deployment in those countries likely helped to bring about boom-and-bust cycles in markets such as Spain in 2008.

Over the medium term, solar PV should significantly expand its presence, with around 45 countries expected to have installed capacity above 100 MW by 2017. Offshore wind and CSP should stay moderately

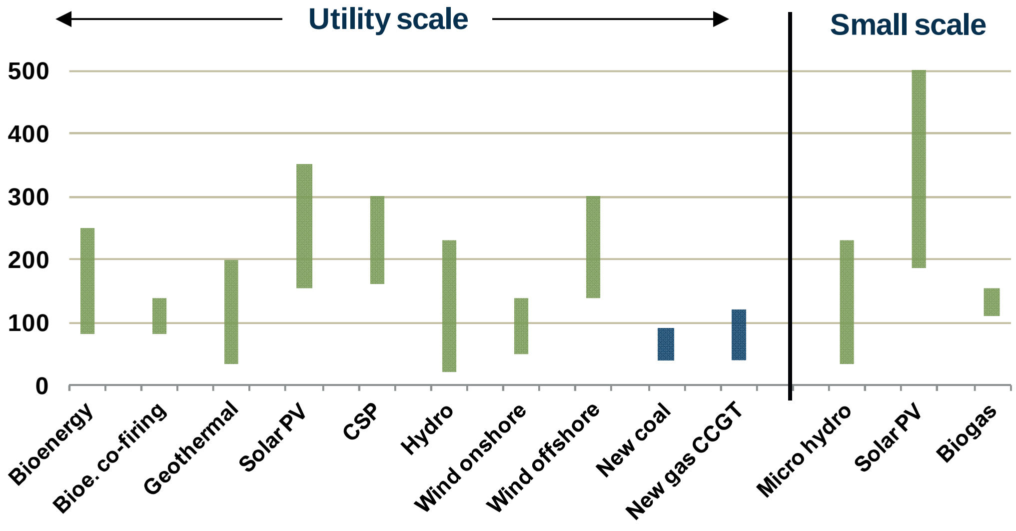
[10] The Herfindahl-Hirschman Index is a standard tool used in economics and competition law to assess the level of market power of individual market players. The calculation takes the market shares of respective market competitors, squares them and adds them together. The market is considered unconcentrated if the index is below 0.15 and concentrated if the index is above 0.25.

concentrated in 2017. However, onshore wind is expected to reverse its trend of diversification. While over 70 countries are expected to have significant cumulative capacity by 2017, China's share is projected at such a high level (36%) that the situation moves back to a position of moderate concentration.

... as technologies compete better in a wider range of circumstances

While renewable electricity remains generally more expensive than conventional bulk power and economic incentives play a large role in sustaining development, leading technologies are becoming increasingly attractive. As shown by recent capacity auctions in Brazil, onshore wind can compete with natural gas as well as other historically less expensive renewable sources such as hydropower and bioenergy. Onshore wind has been competitive in New Zealand for several years now, thanks to excellent wind resource conditions and relatively expensive fossil-based alternatives. Geothermal and most hydropower are already competitive with their fossil alternatives in places with favourable resource conditions. Large scale bioenergy plants can also be competitive depending on feedstock prices.

Figure 85 Levelised costs of power generation (USD per MWh)



Note: cost ranges reflect differences in resource, local conditions and choice of sub-technology. Calculations are based on a 7% discount rate and may not reflect differences in financing costs among countries. Source: IEA analysis.

While utility-scale solar PV costs are still significantly higher than base-load electricity generation from conventional fuels, they approach competitiveness with peak power prices in places with summer peak demand (*e.g.* due to air-conditioning needs) and unsubsidised fossil-fuel alternatives. Small-scale solar PV systems are more expensive, but in mini-grid and off-grid applications, they are already competitive with alternatives in many cases. Grid-connected residential PV systems can achieve lower generation costs than retail electricity prices for households in countries with good solar resource and high retail prices. Still, this level of competitiveness assumes that the fixed cost for grid connection is paid by another party. With PV expanding in new markets in all world regions, the combination of decreasing capital costs, better irradiation and favourable financing conditions is expected to further decrease generation costs in the short term.

Offshore wind and CSP are still relatively expensive but costs are expected to fall as deployment scales up. With excellent wind speeds and availability for offshore wind and storage available in CSP applications, these technologies should provide a valuable contribution to the generation mix because they provide relatively higher full load hours than other renewable technologies.

Ultimately, levelised cost of electricity comparisons may not necessarily offer the best lens through which to assess renewable competitiveness. The attractiveness of renewable generation depends on a number of factors – local conditions, cost structures, resources and the prices of alternatives –making global comparisons of levelised costs difficult. Renewable sources are diverse and can compete in different market frameworks even when generalised cost estimates may suggest otherwise.

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TABLES

Table 93 OECD renewable electricity generation (TWh)

	2005	% Total Gen	2011	% Total Gen	2012	2013	2014	2015	2016	2017
OECD AM	**832**	**16.0%**	**1 029**	**19.3%**	**1 015**	**1 051**	**1 083**	**1 119**	**1 160**	**1 204**
Canada	374	59.8%	403	63.4%	403	405	413	423	434	443
Chile	28	53.9%	25	37.7%	25	31	33	37	41	46
Mexico	38	15.6%	45	16.4%	45	46	49	51	54	57
United States	392	9.1%	556	12.8%	556	534	556	572	590	614
OECD A/O	**165**	**9.1%**	**193**	**10.0%**	**200**	**211**	**224**	**238**	**253**	**270**
Australia	20	8.9%	25	10.5%	28	30	33	36	40	45
Israel	0	0.1%	0	0.5%	1	1	1	1	2	2
Japan	111	10.1%	123	11.6%	127	134	142	150	159	168
Korea	6	1.4%	11	2.1%	12	12	14	15	17	19
New Zealand	28	64.2%	34	75.9%	33	34	35	35	35	35
OECD EUR	**679**	**19.1%**	**905**	**25.3%**	**1 007**	**1 063**	**1 117**	**1 166**	**1 215**	**1 271**
Austria	43	64.7%	45	68.7%	53	55	57	58	59	61
Belgium	3	3.9%	10	11.0%	11	13	16	18	19	21
Czech Republic	4	4.6%	8	9.1%	8	9	9	10	11	11
Denmark	10	27.3%	14	40.1%	15	16	18	19	21	22
Estonia	0	1.1%	1	9.2%	1	1	1	2	2	2
Finland	23	33.2%	23	31.7%	26	27	27	28	28	30
France	61	10.6%	70	12.4%	88	92	96	100	105	113
Germany	69	11.1%	127	20.6%	144	153	161	168	176	185
Greece	7	11.7%	8	15.4%	11	13	14	16	17	19
Hungary	2	5.2%	3	7.3%	3	3	4	4	4	4
Iceland	9	99.9%	17	100%	16	17	17	17	17	18
Ireland	2	8.5%	5	19.8%	6	7	8	8	9	10
Italy	55	18.2%	86	28.5%	96	100	104	109	114	119
Luxembourg	1	24.1%	1	35.2%	1	1	2	2	2	2
Netherlands	7	7.4%	12	10.8%	14	15	16	17	18	19
Norway	137	99.5%	124	96.6%	133	134	135	136	136	137
Poland	5	3.5%	13	8.0%	15	16	18	19	20	22
Portugal	9	18.6%	25	47.0%	25	26	28	30	32	35
Slovakia	5	15.2%	5	19.5%	6	6	6	6	7	7
Slovenia	4	23.6%	4	25.0%	5	5	5	5	5	5
Spain	47	15.9%	90	30.8%	99	104	107	109	109	110
Sweden	81	51.3%	83	54.5%	84	87	90	91	92	92
Switzerland	34	57.2%	36	55.1%	39	39	40	41	42	43
Turkey	40	24.5%	58	25.3%	62	70	80	88	94	101
United Kingdom	20	5.0%	38	10.3%	46	52	58	66	74	83
OECD Total	**1 676**	**15.9%**	**2 127**	**19.7%**	**2 222**	**2 326**	**2 424**	**2 523**	**2 628**	**2 744**

Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis. In some cases, historical data are estimates based on IEA analysis, which can differ from IEA statistics publications.

Table 94 OECD renewable electricity capacity (GW)

	2010	2011	2012	2013	2014	2015	2016	2017
OECD AM	**259.0**	**271.3**	**287.3**	**298.1**	**310.5**	**324.7**	**341.3**	**359.4**
Canada	81.1	83.6	86.2	88.8	92.4	95.2	98.2	100.8
Chile	6.2	6.6	7.0	8.2	9.7	11.3	12.7	14.2
Mexico	13.6	13.9	15.3	16.0	16.9	18.0	19.3	21.0
United States	158.1	167.2	178.8	185.0	191.6	200.3	211.1	223.4
OECD A/O	**81.8**	**86.4**	**90.8**	**96.6**	**103.4**	**110.2**	**117.7**	**125.6**
Australia	12.6	13.8	14.8	15.8	17.2	18.7	20.5	22.5
Israel	0.1	0.3	0.4	0.6	0.7	0.8	1.2	1.3
Japan	55.7	57.2	60.0	64.0	68.3	72.6	76.9	81.6
Korea	6.8	8.2	8.5	8.9	9.9	10.7	11.6	12.6
New Zealand	6.6	7.0	7.1	7.3	7.3	7.4	7.5	7.5
OECD EUR	**340.1**	**377.8**	**405.1**	**428.6**	**452.3**	**473.7**	**497.3**	**521.7**
Austria	17.2	17.9	18.8	19.9	20.5	21.1	22.1	22.78
Belgium	4.5	5.7	6.6	7.6	9.0	9.4	10.0	10.54
Czech Republic	4.8	4.8	5.0	5.2	5.4	5.6	5.8	5.99
Denmark	5.0	5.1	5.4	6.1	6.4	6.9	7.4	7.64
Estonia	0.2	0.3	0.4	0.2	0.5	0.6	0.6	0.61
Finland	5.3	5.5	5.6	5.8	6.0	6.1	6.5	7.07
France	33.9	37.3	39.5	41.4	43.5	45.7	48.6	52.12
Germany	61.8	70.9	78.2	83.6	88.0	92.4	97.6	102.51
Greece	4.6	5.3	6.3	7.0	7.8	8.6	9.5	10.25
Hungary	0.9	1.0	1.0	1.1	1.2	1.2	1.3	1.51
Iceland	2.5	2.5	2.5	2.6	2.6	2.6	2.7	2.65
Ireland	2.0	2.2	2.4	2.7	2.9	3.2	3.5	3.70
Italy	33.3	44.2	46.5	48.3	50.7	53.6	56.5	59.97
Luxembourg	1.2	1.2	1.3	1.5	1.5	1.6	1.6	1.61
Netherlands	3.8	4.0	4.2	4.7	4.9	5.3	5.5	5.84
Norway	30.1	30.2	30.7	30.9	31.1	31.3	31.5	31.77
Poland	3.6	4.4	5.1	5.7	6.4	7.2	7.8	8.43
Portugal	9.7	10.0	10.7	11.2	11.7	13.1	14.1	15.12
Slovakia	2.9	3.2	3.2	3.2	3.4	3.6	3.7	3.73
Slovenia	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.65
Spain	44.9	48.2	50.9	53.0	54.0	54.2	54.5	54.71
Sweden	22.8	23.2	23.9	25.3	25.9	26.3	26.4	26.77
Switzerland	14.3	14.7	15.0	15.2	15.7	16.2	16.7	17.27
Turkey	17.7	20.3	23.4	26.1	30.4	32.4	35.0	37.58
United Kingdom	12.0	14.2	17.1	19.0	21.3	23.9	26.8	29.85
OECD Total	**680.8**	**735.5**	**783.2**	**823.2**	**866.2**	**908.7**	**956.4**	**1 006.6**

GLOSSARY OF DEFINITIONS, TERMS, AND ABBREVIATIONS

Regional definitions

OECD Asia Oceania comprises Australia, Israel, Japan, Korea and New Zealand.

OECD Americas comprises Canada, Chile, Mexico and the United States.

OECD Europe comprises 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 includes OECD Asia Oceania, OECD Americas and OECD Europe regional groupings.

China refers to the People's Republic of China, including Hong Kong.

Africa comprises 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).

Non-OECD Asia and Oceania comprises Bangladesh, Brunei Darussalam, Cambodia, China, 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 comprises Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Republic of Moldova, Romania, Russian Federation, Serbia[1], Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Non-OECD Latin America comprises 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 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 comprises Bahrain, Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Non-OECD includes Africa, non-OECD Asia and Oceania, non-OECD Europe and Eurasia, non-OECD Latin America and Middle East regional groupings.

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 Emission Trading Scheme
EWEA	European Wind Energy Association
FIP	feed-in premium
FIT	feed-in tariff
FLH	full load hours
GDP	gross domestic product
GWEC	Global Wind Energy Council
HPP	hydropower plant
Hz	hertz
IEA	International Energy Agency
IPP	independent power producer
ITC	investment tax credit
IEAOES	International Energy Agency Ocean Energy Systems Programme
IEAPVPS	International Energy Agency Photovoltaic Power Systems Programme
IEASHC	International Energy Agency Solar Heating and Cooling Programme
IEAWind	International Energy Agency Wind Energy Systems Programme
IPCC	Intergovernmental Panel on Climate Change
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
RES	renewable energy sources
RES-E	electricity generated from renewable energy sources

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	Yuan renminbi
DKK	Danish krone
EUR	Euro
GBP	British pound
SEK	Swedish krona
USD	United States dollar

Units

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

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RENEWABLE ENERGY

Medium-Term Market Report 2012

Renewable energy has emerged as a significant source in the global energy mix, accounting for around a fifth of worldwide electricity production. Much of this success has stemmed from economic incentives and significant policy effort by countries, particularly those in the OECD. Massive investment has taken place on a global scale, with costs for most technologies falling steadily. As a result, renewable energy technologies are becoming more economically attractive in an increasing range of countries and circumstances, with China, India and Brazil emerging as leaders in deployment.

While renewable energy has been the fastest growing sector of the energy mix in percentage terms, its continued growth will depend upon the evolution of policy and market frameworks. Further technology development, grid and system integration issues and the availability of finance will also weigh as key variables.

This new annual IEA publication, *Medium-Term Renewable Energy Market Report 2012*, provides a key benchmark, assessing the current state of play of renewable energy, identifying the main drivers and barriers to deployment and projecting renewable energy electricity capacity and generation through 2017. Starting with an in-depth analysis of key country-level markets, which represent 80% of renewable electricity generation today, the report examines the prospects for renewable energy finance and provides a global outlook for each renewable electricity technology. The report analyses enablers and barriers to renewable energy deployment in detail, examining larger electricity market issues that have implications for renewable development, including country-level demand projections, anticipated changes in conventional generating capacity and power system integration.

Market Trends and Projections to 2017

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