IRENA
International Renewable Energy Agency










RENEWABLE POWER GENERATION COSTS IN 2014

JANUARY 2015

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. www.irena.org

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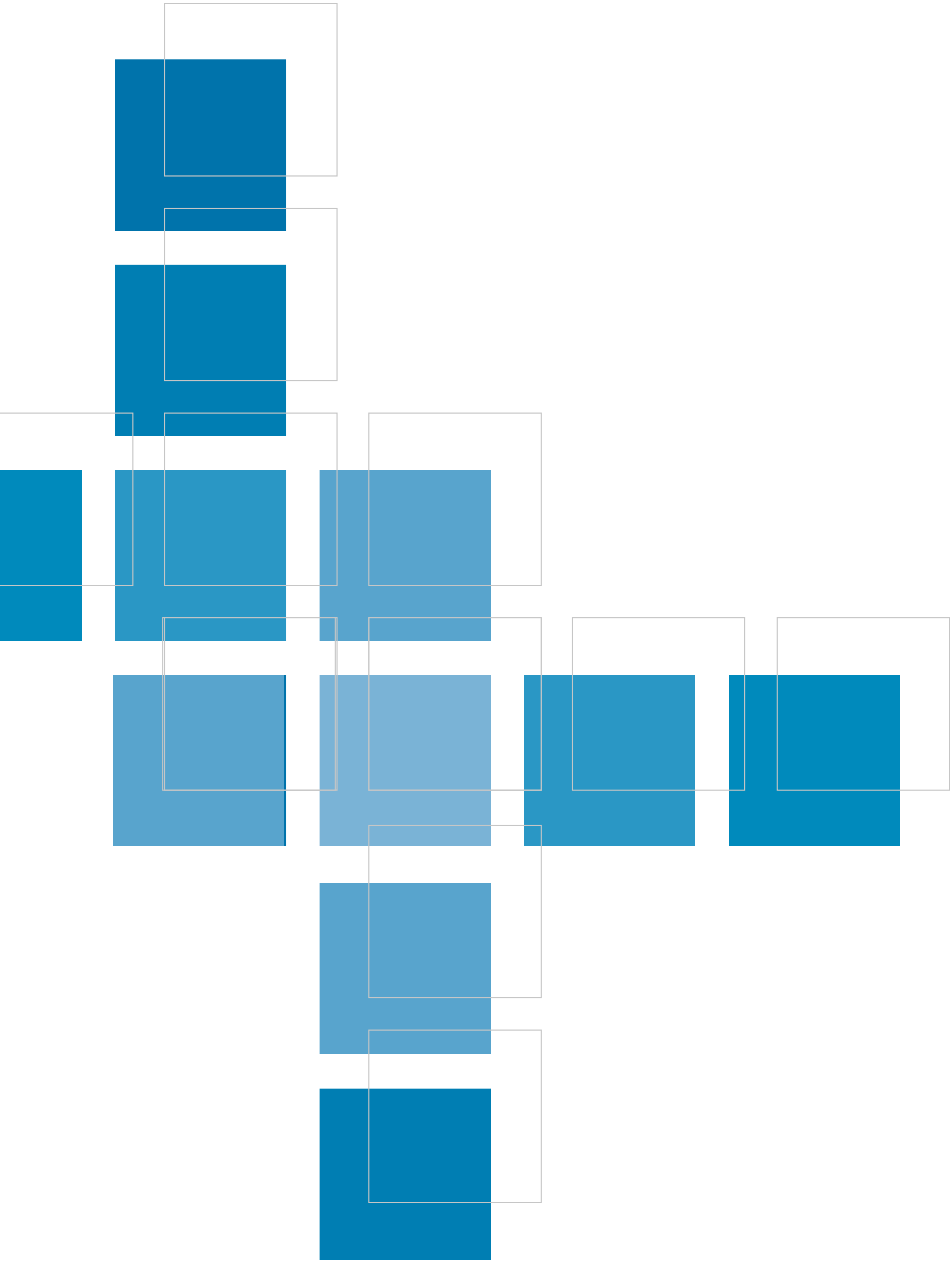

FOREWORD

Among the most transformative events of the current decade has been the dramatic, and sustained, improvement in the competitiveness of renewable power generation technologies. Everywhere, renewables – if not already more competitive than was widely recognised – have benefited from a cycle of falling costs spurred on by accelerated deployment. Beyond mere economic and technological progress, this welcome trend holds the genuine promise of a new era in human development, powered by clean, increasingly decentralised, and sustainable energy.

In many countries, the world's brighter energy future is already evident. In 2014, renewable energy brought greater security, better health and growing opportunities to billions of people worldwide. Its accelerated development has become the central pillar in international efforts to combat climate change.

Most remarkably, renewable power generation technologies have made this achievement in markets in which their benefits are not fully accounted for, and against massive subsidies for fossil fuels. Yet even in this uneven playing field, renewables now account for around half of all new capacity additions, as investors place billions of dollars in what are increasingly the best performing energy investments around the world.

This transformation has moved well beyond the developed countries of the Organisation for Economic Co-operation and Development. China and India boast some of the most competitive development costs for renewable technologies anywhere, while South America is emerging as a dynamic new market for renewable power generation. In Africa, governments are putting in place plans for a renewable energy corridor stretching from the Cape to Cairo.

Yet despite these extraordinary trends, many of the world's decision-makers have yet to grasp how competitive renewables have become. Often, vested interests lead to propagation of the myth of "costly" renewable energy. But in other cases, the change has simply come so fast, and so unexpectedly, that public information has yet to catch up. That is the reason for this publication.

Renewable Power Generation Costs in 2014 is one of the most comprehensive studies yet made on the renewable energy price revolution in the power sector. Its findings are striking. Solar photovoltaic (PV) modules in 2014 cost three-quarters less than in 2009, while wind turbine prices declined by almost a third over the same period. The cost of electricity from utility-scale PV systems has fallen by around half since 2010.

Still, wide price disparities remain among renewable energy technologies, as well as between different countries and regions. While such gaps sometimes relate to resource availability, they also reflect an array of market conditions, balance-of-system costs, regulations and risk perceptions. Major challenges remain to bring down the cost of finance , especially in developed countries, and the high transaction costs for small-scale projects.

Nonetheless, the trend is clear. Renewable power generation will keep getting cheaper over time, even in a period of falling oil prices, which history tells us will in all probability be transitory. Renewables development and deployment represents the most secure long-term hedge against fuel price volatility, the best route to reducing greenhouse gas emissions, and a sound financial investment. Their future is bright indeed.

Adnan Z. Amin
Director-General
International Renewable Energy Agency

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Executive Summary

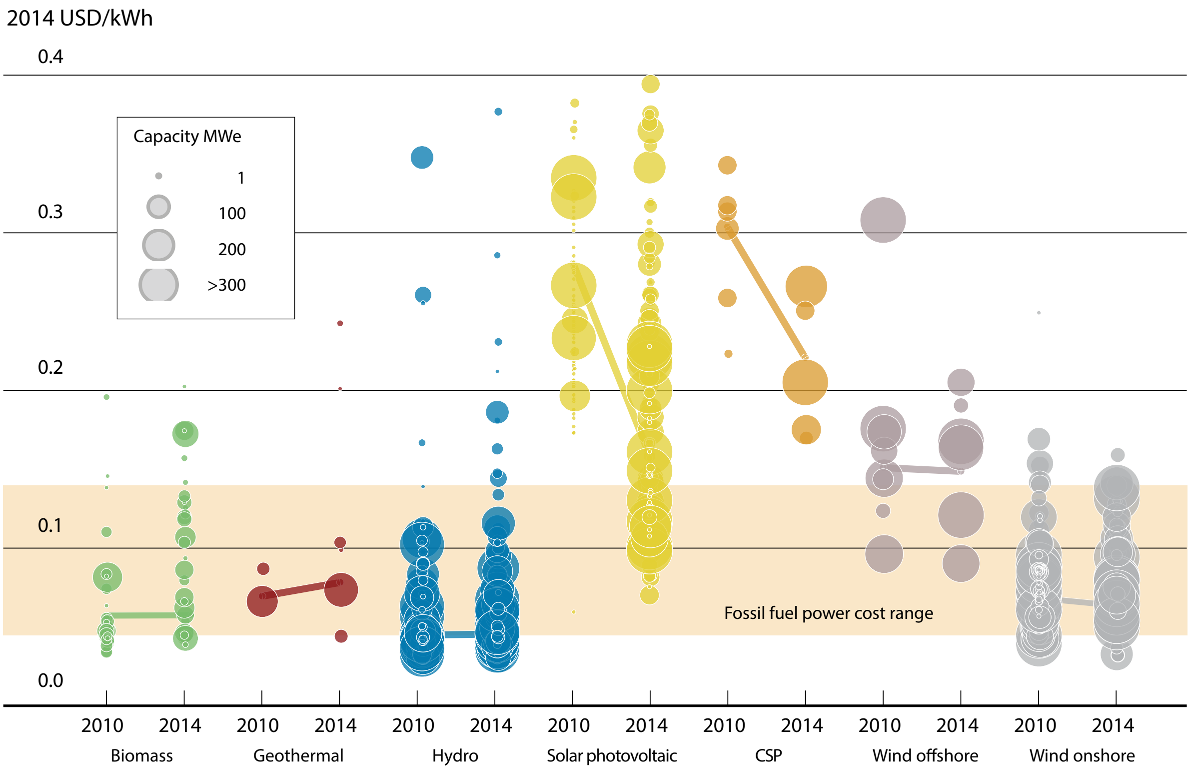
The competitiveness of renewable power generation technologies continued improving in 2013 and 2014.

The cost-competitiveness of renewable power generation technologies has reached historic levels. Biomass for power, hydropower, geothermal and onshore wind can all now provide electricity competitively compared to fossil fuel-fired power generation (Figure ES 1). Most impressively, the levelised cost of electricity (LCOE)[1] of solar PV has halved between 2010 and 2014, so that solar photovoltaics (PV) is also increasingly competitive at the utility scale.

Installed costs for onshore wind power, solar PV and concentrating solar power (CSP) have continued to fall, while their performance has improved. Biomass for power, geothermal and hydropower have provided low-cost electricity – where untapped economic resources exist – for many years.

Solar PV module prices in 2014 were around 75% lower than their levels at the end of 2009. Between 2010 and 2014 the total installed costs of utility-scale PV systems have fallen by 29% to 65%, depending on the region. The LCOE of utility-scale solar PV has fallen by half in four years. The most competitive utility-scale solar PV projects are now regularly delivering electricity for just USD 0.08 per kilowatt-hour (kWh) without financial support, compared to a range of USD 0.045 to USD 0.14/kWh for fossil fuel power

E.S. 1: The levelised cost of electricity from utility-scale renewable technologies, 2010 and 2014



Source: IRENA Renewable Cost Database.
Note: Size of the diameter of the circle represents the size of the project. The centre of each circle is the value for the cost of each project on the Y axis. Real weighted average cost of capital is 7.5% in OECD countries and China; 10% in the rest of the world.

[1] *The LCOE of a given technology is the ratio of lifetime costs to lifetime electricity generation, both of which are discounted back to a common year using a discount rate that reflects the average cost of capital. In this report all LCOE results are calculated using a fixed assumption of a cost of capital of 7.5% real in OECD countries and China, and 10% in the rest of the world unless explicitly mentioned.*

plants. Even lower costs for utility-scale solar PV, down to USD 0.06/kWh, are possible where excellent resources and low-cost finance are available.

Onshore wind is now one of the most competitive sources of electricity available. Technology improvements, occuring at the same time as installed costs have continued to decline, mean that the LCOE of onshore wind is now within the same cost range, or even lower, than for fossil fuels. The best wind projects around the world are consistently delivering electricity for USD 0.05/kWh without financial support.

LCOEs of the more mature renewable power generation technologies – biomass for power, geothermal and hydropower – have been broadly stable since 2010. However, where untapped, economic resources remain, these mature technologies can provide some of the cheapest electricity of any source.

Regional, weighted average costs of electricity from biomass for power, geothermal, hydropower and onshore wind are all now in the range, or even span a lower range, than estimated fossil fuel-fired electricity generation costs. Because of striking LCOE reductions, solar PV costs also increasingly fall within that range.

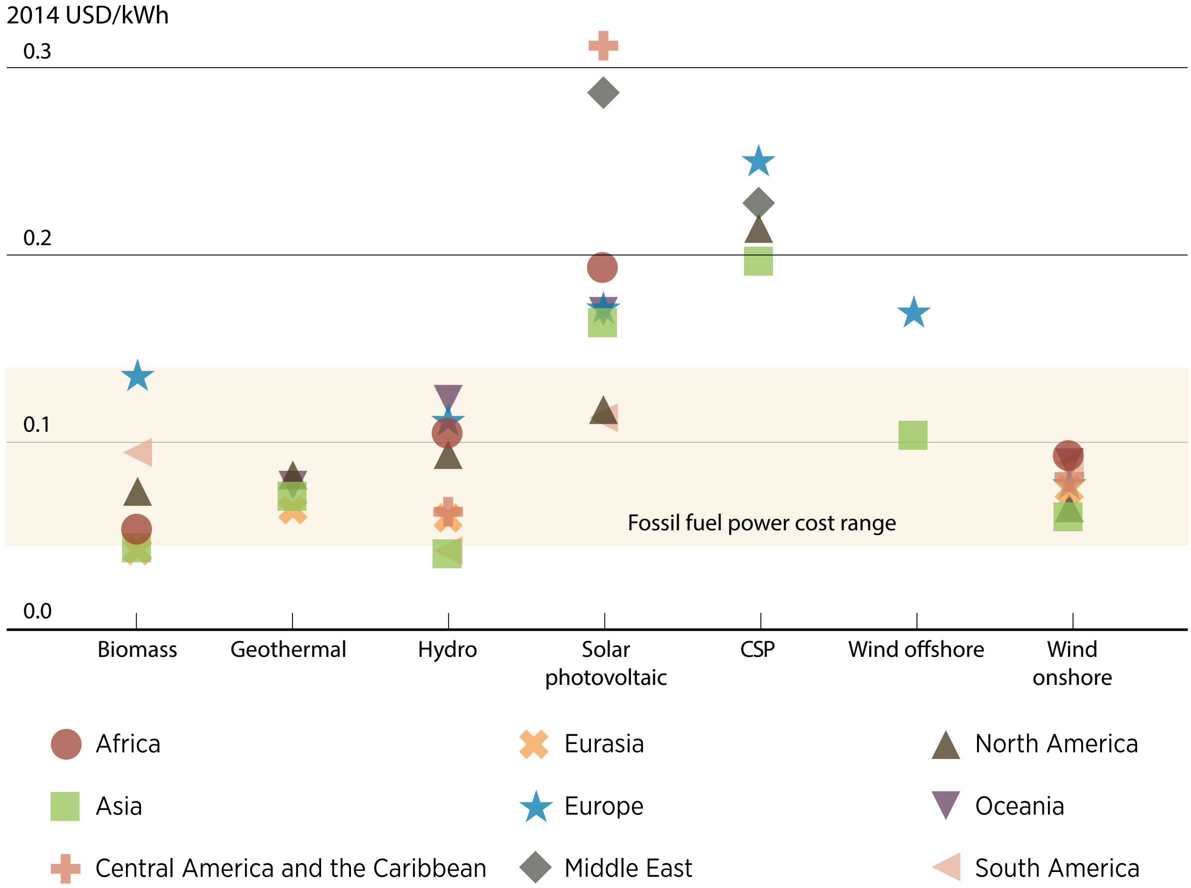
Given the installed costs and the performance of today's renewable technologies, and the costs of conventional technologies, renewable power generation is increasingly competing head-to-head with fossil fuels, without financial support (Figure ES 2).

The weighted average LCOE of utility-scale solar PV in China and North America – the world's two largest power-consuming markets – and in South America, has also now fallen into the range of fossil fuel-fired electricity costs. For utility-scale solar PV projects installed in 2013 and 2014, the weighted average LCOE by region ranged from a low of around USD 0.11 to USD 0.12/kWh (in South and North America, respectively) to over USD 0.31/kWh (in Central America and the Caribbean). But for individual projects, the range of costs is much wider. In various countries with good solar resources, projects are now being built with an LCOE of USD 0.08/kWh, while a recent tender in Dubai, in the United Arab Emirates, resulted in a successful bid for a solar PV power purchase agreement (PPA) for just USD 0.06/kWh, without financial support. Where good resources exist and low-cost financing is available, utility-scale solar PV projects that are now being built (*e.g.*, in Dubai, Chile and other parts of the world) will provide electricity at a lower cost than fossil fuels, without any financial support. PV's growing competitiveness holds just as true in regions where indigenous fossil fuels are abundant.

Onshore wind costs continue to decline, albeit more slowly than for solar PV. The weighted average LCOE for wind ranged from a low of USD 0.06/kWh in China and Asia to a high of USD 0.09/kWh in Africa. North America also has very competitive wind projects, with a weighted average LCOE of USD 0.07/kWh due to excellent resources and a good cost structure. For hydropower, the estimated weighted average LCOE by region varies between USD 0.04/kWh in Asia and South America to a high of USD 0.12/kWh in Oceania.

CSP and offshore wind are still typically more expensive than fossil fuel-fired power generation options, with the exception of offshore wind in tidal flats. But these technologies are in their infancy in terms of deployment, with 5 GW of CSP and 8 GW of offshore wind installed worldwide at the end of 2014. Both represent important renewable power sources that will play an increasing part in the future energy mix as costs come down. The weighted average LCOE of CSP by region varied from a low of USD 0.20/kWh in Asia to a high of USD 0.25/kWh in Europe. However, as costs fall further, projects are being built with LCOEs of USD 0.17/kWh, and power purchase agreements are being signed at even lower values where low-cost financing is available. Historically, offshore wind costs rose after 2005, but this was as projects shifted further offshore and into deeper water; those costs now appear to be stabilising. The regional

E.S. 2: Weighted average cost of electricity by region for utility-scale renewable technologies, compared with fossil fuel power generation costs, 2013/2014



Source: IRENA Renewable Cost Database.

Note: Real weighted average cost of capital of 7.5% in OECD countries and China; 10% in the rest of the world.

weighted average LCOE for offshore wind varied from a low of USD 0.10/kWh for near-shore projects in Asia, where development costs are lower, to USD 0.17/kWh for projects in Europe.

The story of increased competitiveness, however, remains a nuanced one. This is because renewable power generation LCOEs per project span a wide range, due to site-specific cost factors (*e.g.*, availability of existing infrastructure, grid connection costs, local labour rates, etc.) and the fact the quality of the renewable resource varies from one site to another. What is clear is that most renewable energy projects being built today, even with less mature technologies, are highly competitive in market terms.

There are no technical barriers to the increased integration of variable renewable resources, such as solar and wind energy. At low levels of penetration, the grid integration costs will be negative or modest, but can rise as penetration increases. Even so, when the local and global environmental costs of fossil fuels are taken into account, grid integration costs look considerably less daunting, even with variable renewable sources providing 40% of the power supply. In other words, with a level playing field and all externalities considered, renewables remain fundamentally competitive.

The cost of electricity from different power generation technologies can be measured in a number of ways, and each accounting method has its merits. LCOE is a static measure of costs, which provides useful insights, but to determine the true least-cost pathway for any country's electricity sector requires detailed system modelling. Variable renewables raise different questions for the electricity system, but the principle is the same: a mix of technologies in a range of locations will be required to meet demand that varies every day. Hydropower, biomass for power, geothermal and CSP, with thermal energy storage to allow dispatchability, pose no special problems for grid operation.

There are no insurmountable technical hurdles to the integration of the variable technologies of solar PV and wind power either, and additional system costs that might be considered over and above the LCOE are modest. Cost implications for transmission and distribution systems are typically minimal. However, additional spinning reserve to meet voltage fluctuations, to allow for intermittency and provide the capacity to ride out longer periods of low sunshine or wind, can add to overall system costs. Estimates of these costs depend on a range of factors, including: the specific electricity-system configuration, existing generation assets, share of variable renewable penetration, distribution of renewable resources and their covariance, and existing market structures. However, estimated values are in the range of USD 0.035 to USD 0.05/kWh with variable renewable penetration of around 40%. While these figures must be treated with caution and are not a substitute for detailed system modelling, they give an idea of the order of magnitude to be expected.

However, even taking a systems-based approach does not adequately address the environmental and health externalities of the fossil fuels used for power generation. Without such analysis, renewables do not face a level playing field. If damage to human health from fossil fuels in power generation is considered in economic terms, along with the externalities associated with CO_2 emissions (assuming USD 20 to USD 80/tonne of CO_2), the cost of fossil fuel-fired power generation rises by USD 0.01 to USD 0.13/kWh, depending on the country and technology. In an analysis covering 26 countries that represent about three-quarters of global power consumption (IRENA, 2014), the cost of fossil fuel-fired electricity rises to between USD 0.07 and USD 0.19/kWh if these health and environmental factors are taken into account (Figure ES 3).

The power generation sector is being actively transformed, in a virtuous cycle with support policies stimulating increased deployment, which in turn results in technological improvements as well as continual cost reductions. Despite this, deployment is not increasing fast enough to meet the world's ambitious goals for a truly sustainable power system.

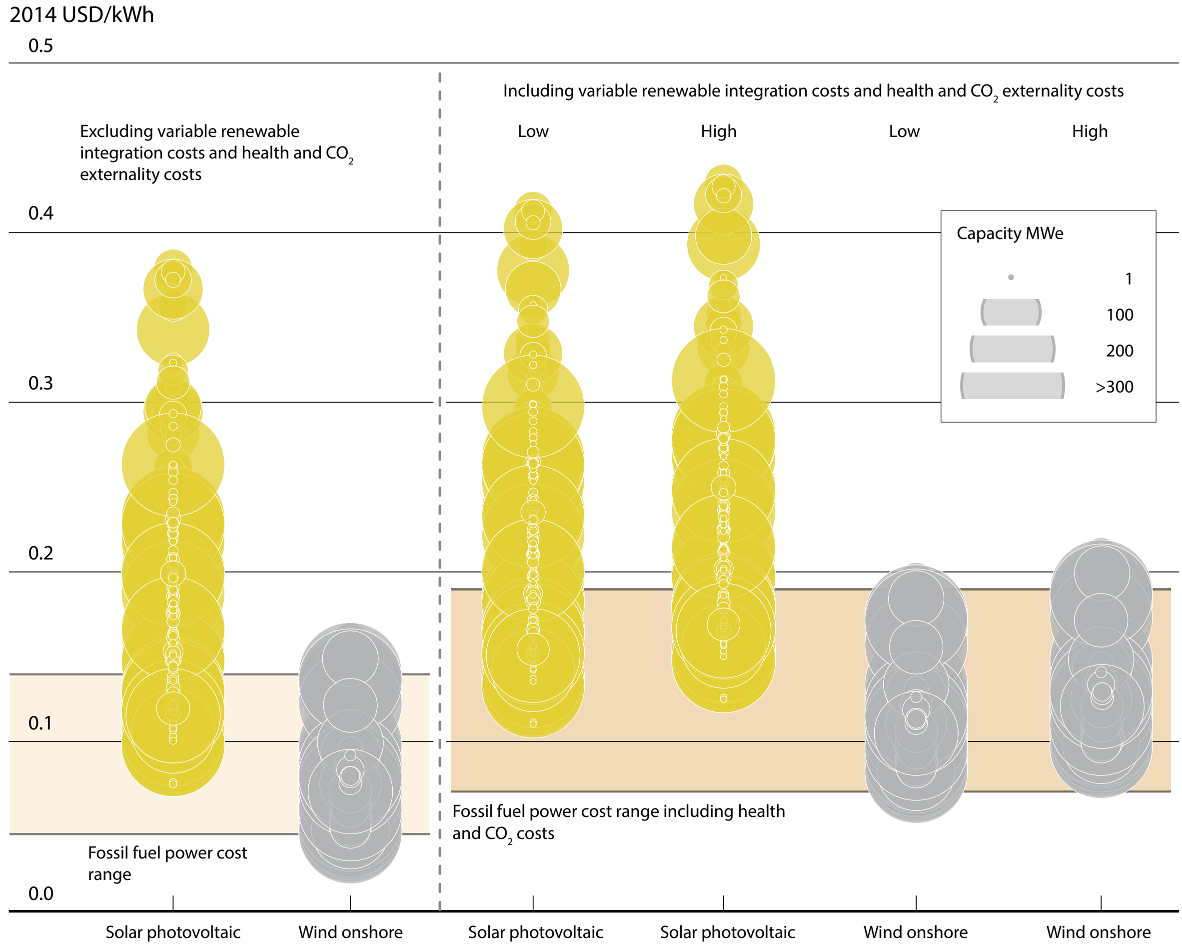
This transformation is being driven by the high learning rates for a range of renewable power generation technologies, particularly solar PV. For instance, with every doubling of cumulative installed capacity, solar PV module prices are expected to fall by 18% to 22%.

The LCOE of a power generation technology reflects multiple factors: resource quality, equipment cost and performance (including capacity factor), the balance of project costs, fuel costs (if any), operation and maintenance costs, the economic lifespan of the project, and the cost of capital. Renewable power generation equipment costs are falling, even as the technologies themselves continue becoming more efficient. The combination of these two factors has led to the continual, often rapid, decline in the cost of electricity from renewable-based technologies. Supported by forward-looking policies, learning investments in renewables have now paid off, and renewables are now highly competitive in a range of markets.

The year 2013 was a landmark year for renewables. Despite inconsistent policymaking and weak economic growth, overall renewable capacity additions reached a new record high of more than 120 gigawatts (GW), with new solar deployment exceeding wind for the first time. Figures for 2014 are still not finalised, but new capacity additions for both solar PV and wind are both estimated to have exceeded 40 GW each, suggesting another year of new renewable capacity additions exceeding 120 GW.

Despite renewable technologies accounting for around half or more of new power generation capacity additions globally from 2011 onwards, deployment is not increasing fast enough to achieve the Sustainable

E.S. 3: The LCOE of variable renewables and fossil fuels, including grid integration costs (at 40% variable renewable penetration) and external health and CO_2 costs



Source: IRENA Renewable Cost Database and analysis.
Note: Fossil fuel power costs for 26 REMAP countries. Real weighted average cost of capital of 7.5% in OECD countries and China; 10% in the rest of the world.

Energy for All goal of doubling the share of renewable energy in the global energy mix by 2030. Much work, therefore, remains to be done for the world to unlock the potential of renewables.

Total installed costs of renewable power generation technologies vary significantly by country and region, as well as between technologies. The systematic collection of comprehensive installed cost data is necessary if electricity costs and cost-reduction potential are to be analysed with confidence.

There is no single "true" LCOE value for a given power generation technology. Just as for non-renewable power generation technologies, the installed costs and capacity factors for renewable energy are highly technology- and site-specific. Despite the convergence in costs of renewable technologies, they can still vary widely not only within each country, but between countries. Collecting national data to analyse current costs and the cost reduction potential of renewable power technologies, therefore, is crucial and needs to be a policy priority. Such information is necessary not only to identify the reasons for differences in electricity costs, but to make policy recommendations for how to reach efficient cost levels.

The approach taken in this report is to analyse equipment costs, total installed costs, and LCOE, in order to break down changes in competitiveness into distinct factors.

Total installed costs in China and India are typically lower than in the rest of the world and range within a narrower band (Figure ES 4). Average total installed costs for renewable power generation technologies in the countries of the Organisation for Economic Co-operation and Development (OECD) are higher than in China and India, with the rest of the world lying somewhere in between — except for onshore wind and solar PV, where installed costs in the rest of the world are higher.

In China and India, average installed costs for biomass for power, hydropower and onshore wind average between USD 1 240 and USD 1 390/kW. Remarkably, given that module costs alone averaged USD 2 646/kW in the fourth quarter of 2009, average installed costs for large-scale solar PV have fallen dramatically in China and India, to around USD 1 670/kW in 2013 and 2014. In the OECD, average total installed wind costs are estimated to be around USD 2 000/kW, with average installed costs for utility-scale solar PV of around USD 2 330/kW.

The more efficient and cleaner burning biomass power plants in the OECD have average installed costs of around USD 4 300/kW. Average total installed costs for offshore wind are estimated to have averaged around USD 4 500/kW in recent years, with CSP installed costs somewhat higher at around USD 6 740/kW, reflecting additional costs to incorporate thermal energy storage. Total installed costs for solar PV and onshore wind are now typically similar to, or lower than, the installed costs for the average coal-fired plant in OECD countries.

Renewable power generation technologies are now the economic solution for isolated off-grid and small-scale electricity systems, such as on islands, that are reliant on diesel-fired generation.

The volatility of oil prices and the high costs of small-scale diesel-fired electricity generation are further exacerbated in remote locations, where poor, or even non-existent, infrastructure can mean that transport costs increase the cost of diesel by 10% to 100% compared with prices in major cities.

For islands or other markets facing comparable energy challenges, the recent decline in the LCOE of renewable power generation technologies represents a historic development.

For many of the over 1.3 billion people worldwide who currently lack electricity access, renewable energy can provide their first introduction to modern energy services, largely through decentralised off-grid and mini-grid solutions. Moreover, this crucial transformation can be justified on purely economic grounds.

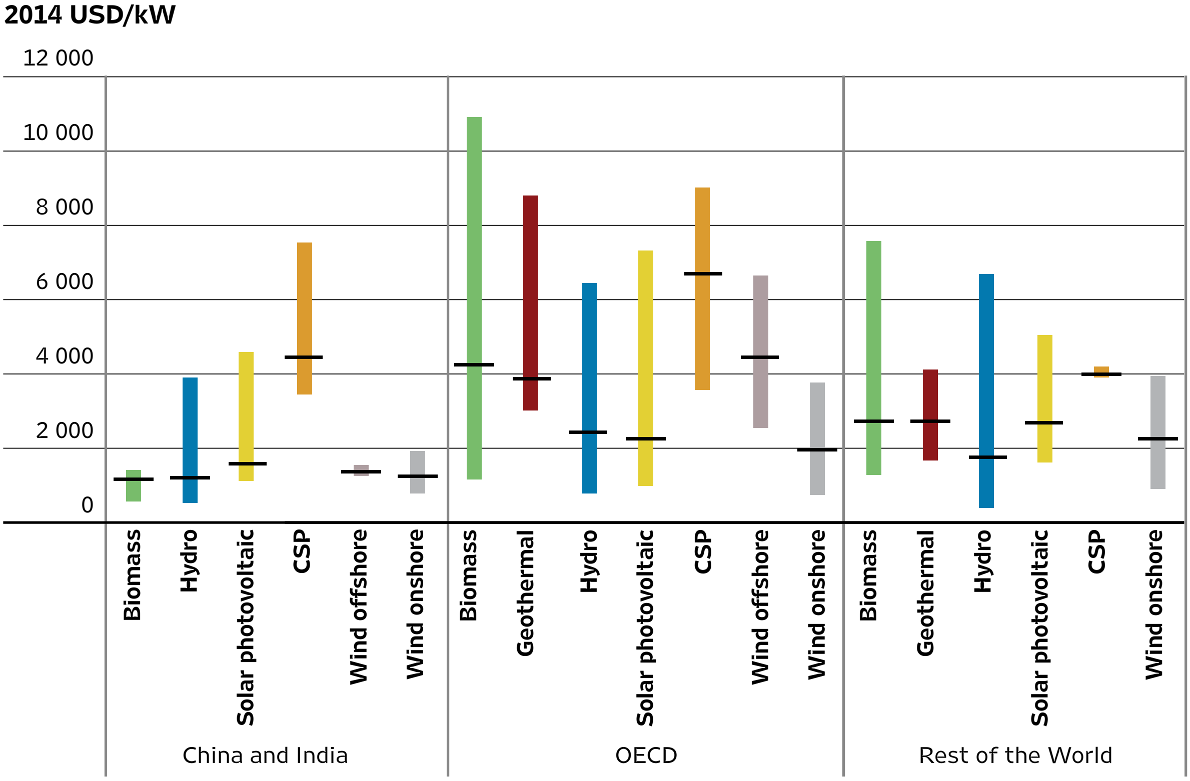
However, it is not just off-grid electricity systems that remain dependent on diesel at present. Given the trend in technology costs, electricity systems based predominantly on oil-fired generation – such as on most islands and in a number of mainland countries – will witness reduced system generation costs with the integration of renewables.

Renewables are likely to remain the most economic off-grid electricity solution, despite the recent drop in oil prices at the end of 2014 and the beginning of 2015. Oil prices remain volatile. Over 2014, they averaged around USD 98/barrel despite the drop, and they remain much higher than they were 15 years earlier. As with any commodity market, the difference between undersupply and oversupply is often on a knife edge, and price swings can be dramatic. However, history has shown that periods of low oil prices tend to be transitory, as long as the world's thirst for these finite resources rises. So for an investment with a lifetime of 25 years or more, today's oil prices are not an accurate measure on which to base an investment decision in electricity generation.

For renewables, further cost reductions can still be expected into the future, which will further lower the weighted average LCOE. With equipment costs reaching low levels; future cost reductions could be driven by reduced balance-of-project costs, lower operation and maintenance and finance costs.

Hydropower, geothermal and most biomass-combustion technologies are mature, with limited cost-reduction potential. The technologies with the largest remaining cost-reduction potential are CSP, solar

Figure E.S. 4: Typical ranges and weighted averages for the total installed costs of utility-scale renewable power generation technologies by region, 2013/2014



Source: IRENA Renewable Cost Database.
Note: Ranges and weighted averages are calculated for 2013 and 2014 to ensure representative ranges for biomass, CSP and offshore wind. Weighted averages for solar PV, CSP and onshore wind would be lower if only data for 2014 was used.

PV and wind power. With today's low equipment costs, cost reduction opportunities in absolute terms will increasingly hinge on non-equipment factors, such as balance-of-project, operations and maintenance and finance costs.

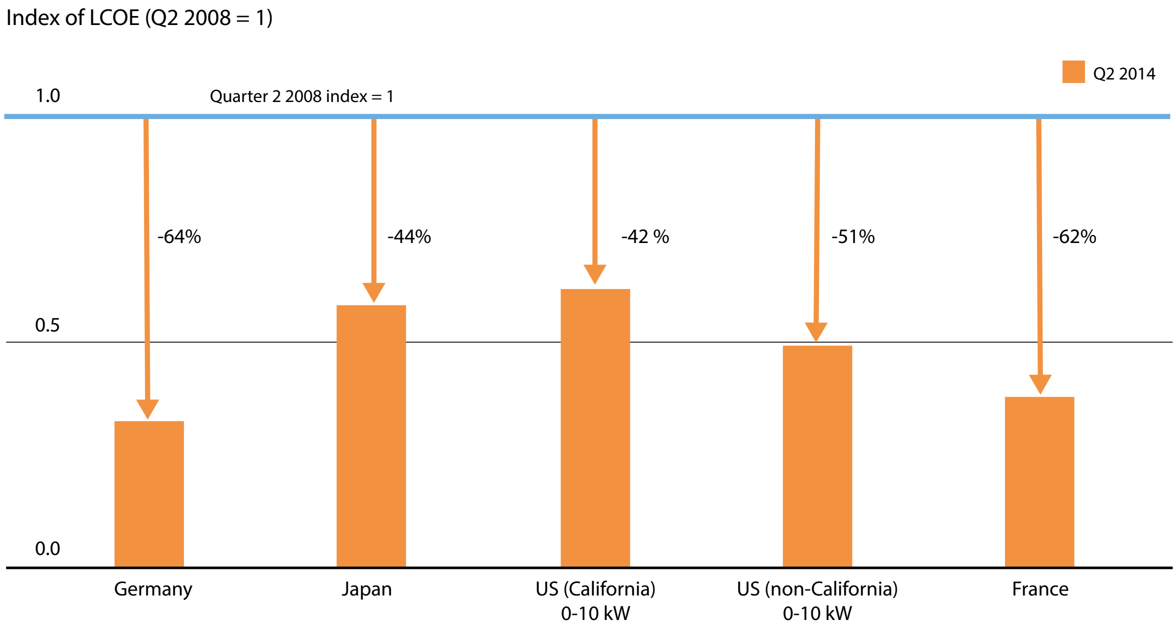
The industry is already shifting its cost reduction focus to these areas. Yet much more detailed cost data is required, so that ongoing cost analysis can support policy-makers in ensuring that policy and regulatory frameworks are streamlined and optimised. This is particularly important, because future cost reductions will be more difficult to unlock and will depend on a more diverse range of stakeholders, not just equipment manufacturers. Careful analysis will be needed to remove the myriad of small barriers, and policy settings must be tailored to ensure all stakeholders along the value chain are incentivised and able to bring down costs.

In line with cost reductions for solar PV modules, small-scale residential solar PV costs have also declined rapidly in recent years, so that "plug parity" or "socket parity" is increasingly the norm.[2]

Germany and China have developed, on average, the most competitive small-scale residential rooftop systems in the world (Figure ES 5). Germany's residential system costs have fallen from just over USD 7 200/kW in the first quarter of 2008 to USD 2 200/kW in the first quarter of 2014, a decline of 70%. Between 2008 and 2014, the average solar PV LCOE in Australia, China, Germany, Italy and the United States of residential systems fell by between 42% and 64%. The average LCOE of many systems in

[2] The terms "plug parity" or "socket parity" refer to when the LCOE of residential systems is lower than the retail tariff of electricity. In this report, the comparison is made excluding all financial support. Adding in the financial support for small-scale solar PV, where available, would make the comparison even more favourable from a consumer perspective.

E.S. 5: LCOE reductions for small-scale residential solar PV, Q2 2008 to Q2 2014



Source: IRENA Renewable Cost Database.

Germany is now up to 40% lower than the residential price. Residential-scale solar PV's continuing cost reductions pose significant challenges to the traditional utility model.

The goal of this report is to reduce uncertainty about the true costs of renewable power generation technologies, so that governments can be more ambitious and efficient in their policy support for renewables. As this comprehensive report clearly demonstrates, any remaining perceptions that renewable power generation technologies are expensive or uncompetitive are at best outdated, and at worst a dangerous fallacy.

1 GLOBAL RENEWABLE POWER MARKET TRENDS

Introduction

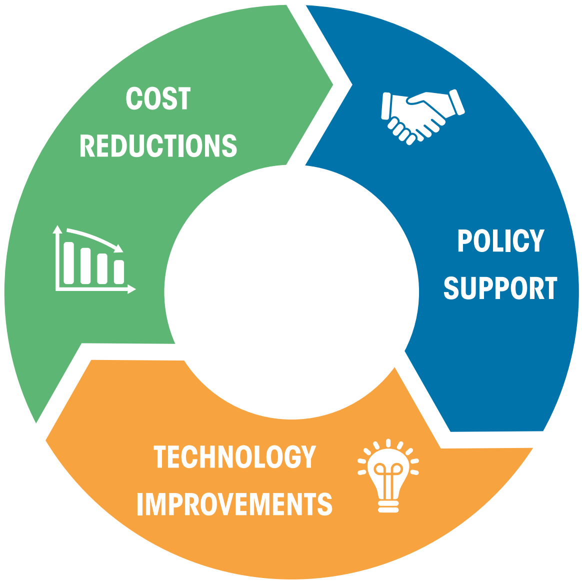
Renewable energy technologies can help countries meet their policy goals for secure, reliable and affordable energy, electricity access for all, reduced price volatility and the promotion of social and economic development. What is not widely appreciated is that with recent cost reductions, renewable power generation technologies can achieve these at a lower cost than alternatives.

The reality is that today we are witnessing the beginning of what will one day be the complete transformation of the energy sector by renewable energy technologies. This transformation is being driven by a virtuous cycle of long-term support policies accelerating the deployment of renewables, which leads to technology improvements and cost reductions (Figure 1.1). This increased deployment increases the scale and competiveness of the markets for renewable technologies, and with every doubling in cumulative capacity of a renewable technology, costs can come down by as much as 18% to 22% for solar PV and 10% for wind.[3] The result is striking: renewable energy technology equipment costs are falling and the technologies themselves are becoming more efficient. The combination of these two factors is leading to declines, sometimes rapid ones, in the cost of energy from renewable technologies.

To date, this transformation is most visible in the power generation sector, where dramatic cost reductions for solar photovoltaic (PV), but also, to a lesser extent, for wind power are driving high levels of investment in renewables. At the same time, where untapped economic hydropower, geothermal and biomass resources exist, these technologies can still provide the lowest-cost electricity of any source.

[3] *This is often measured by "learning rates", a percentage reduction in costs for every doubling of cumulative installed capacity. These learning rates are high for renewables, as although they are commercially mature, they still have significant cost reduction potential unlike fossil fuels and nuclear.*

Figure 1.1: Renewables are experiencing a virtuous cycle of cost reductions



This report summarises historical trends in the cost and performance of renewable power generation technologies (biomass for power generation, concentrating solar power, hydropower, solar photovoltaics and wind) and details information on the latest cost estimates available for 2014. This report is the eighth report on the costs and performance of renewable and draws heavily on the data in IRENA's world-class resource, the IRENA Renewable Cost Database. This database contains project data on the cost and performance of over 9 000 utility-scale[4] renewable energy projects and over 750 000 small-scale solar PV projects. The analysis is supported by earlier IRENA work, which analysed in more detail some of the technology and performance characteristics of renewable power generation technologies that underpin the economics of renewable power generation.[5]

[4] *The database also includes partial data for around 6 000 other renewable power generation projects. For most of these projects the capacity factor is typically missing, although sometimes it is the total investment costs, and so the levelised cost of electricity cannot be accurately calculated.*

[5] *See the IRENA **Renewable Energy Technologies: Costs Analysis Series**, Volumes 1 to 5 (IRENA, 2012a-e).*

In the past, deployment of renewables was hampered by a number of barriers, including their high up-front costs. Today's renewable power generation technologies are increasingly cost-competitive and are now the most economical option for any electricity system reliant on oil products (*e.g.* some countries and for off-grid electrification); in locations with good resources, they are the best option for centralised grid supply and extension. However, the public debate around renewable energy continues to suffer from an outdated perception that renewable energy is not competitive.

The aims of this report are to:

» Provide up-to-date, verified data on the range of costs and performance of renewable power generation technologies by country and region;

» Highlight the increasing competiveness of renewables and the fact that with a level playing field, renewables are now often the most economical choice for new capacity;

» Present clearly the business case for renewables, based on real-world project costs;

» Ensure that decision makers in government and the energy industry have the latest, fact-based data to support their decisions; and

» Provide powerful communications messages about the continued declining costs of renewables and their increasing competitiveness.

By reducing uncertainty about the true costs of renewable power generation technologies, governments can be more ambitious and efficient in their policy support for renewables. Better information about cost reductions are also an important component in communicating that the support policies for renewables are working and deployment is driving down costs.

This is particularly important, because although renewable power generation technologies now account for around half of all new power generation capacity additions worldwide (IRENA, 2014a), deployment is still too slow to achieve the ambitious goals that countries have set for a sustainable energy future that will prevent dangerous and costly climate change.

The following sections of this paper outline the principle findings of the six renewable power generation technologies analysed in this report – wind power, solar PV, concentrating solar power (CSP), hydropower, biomass for power and geothermal – and highlight the key insights for policy-makers.

Rationale for IRENA's cost analysis

The real costs of a project are one of the foundations investment decisions stands on and are critical to understanding the competitiveness of renewable energy. Without access to accurate, comparable, reliable and up-to-date information on the actual project costs and performance of renewable energy technologies, it is difficult, if not impossible, for governments to arrive at an accurate assessment of which renewable energy technologies are the most appropriate for their circumstances. IRENA's cost analysis programme is a response to a call from Member States for better and more objective cost data. Providing this information, with an accompanying analysis, will help governments, policy-makers, investors and utilities make informed decisions about the role renewables can play in their energy sector.

The rapid growth in installed capacity of renewable energy technologies and the associated cost reductions mean that data from even one or two years ago can significantly overestimate the cost of electricity from renewable energy technologies. In the case of solar PV, even data six months old can significantly overstate costs in some markets.

Therefore, there is a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate and can even be misleading. At the same time, a lack of transparency in the methodology and assumptions used by many to make cost calculations can lead to confusion about the comparability of data. By analysing a global dataset, this report provides one of the most comprehensive overviews of renewable power generation costs using a consistent methodology and set of assumptions.

IRENA plans to collect renewable energy project cost data for all sectors, although the work has commenced with the power generation sector (IRENA, 2012a-e; IRENA, 2013a) and the transport sector (IRENA, 2013b). Work on stationary applications, air and sea transport will be started in 2015. The data and analysis in these publications are designed to assist countries with their renewable energy policy development and planning. The analysis includes projections of future cost reductions and performance improvements so that governments can incorporate likely future developments into their policy decisions. This work is ongoing and further efforts are required to overcome significant challenges in data collection, verification and analysis. The underlying analysis and data collected on the costs and performance of renewable energy technologies and fuels can also support more detailed, policy-relevant products that provide decision makers with information about ongoing cost trends or future cost reduction potentials. As an example, IRENA is developing the IRENA PV Parity Indicators to help policy-makers track the evolution of solar PV competitiveness. The IRENA Renewable Cost Database can also support important analyses that update out-of-date analyses that policy-makers, industry and energy and climate sector modellers rely heavily on.

As an example, IRENA is in the process of undertaking a comprehensive update of the learning curve analysis for wind across 11 countries that account for 85% of cumulative installed wind capacity. This analysis will update the learning rate for wind (existing estimates are not comprehensive or only use data up to around 2006, two to three years before wind turbine price peaks) and extend it for the first time to the levelised cost of electricity and decompose the drivers for the evolution between capital costs, technology improvements, wind resource quality and changes in operations and maintenance (O&M) costs.

Different cost metrics

It is important to note that the cost of power generation technologies can be measured in a number of ways, and each way of accounting for the cost brings its own insights. The analysis summarised in this paper represents a static analysis of costs. The optimal role of each renewable technology in a country's energy mix requires a dynamic modelling of electricity system costs to take into account the many complexities of operating an electricity grid (this is discussed in more detail in Chapter 2).

This report compares the cost and performance of renewable power generation technologies, and the data across technologies, countries and regions. It takes a range of simple metrics analysed using a consistent boundary in order to ensure robust analysis, comparability of the data and the possibility of conveying simple messages (see Annex for a discussion of the approach). The analysis focuses on equipment costs, total installed cost and the levelised cost of electricity (LCOE) of renewable power generation options, given a number of key assumptions.

The LCOE analysis requires a significant amount of additional data or assumptions, such as economic life, cost of capital, efficiency, technology impacts and O&M. Where project-specific data are available (*e.g.* for capacity factors, which are often driven by a mix of technology, renewable resources and economic factors), these are presented in the appropriate chapters. Table 1.1 presents the range of assumptions that are required to calculate the LCOE of different renewable power generation technologies for which project-specific data are not discussed in the appropriate chapters.

The assumptions used are relatively conservative when considering the technical lives of many of these technologies, but reflect the economic realities that investors' scarce capital requires significantly shorter payback periods, as well as the times between major costly refurbishments and upgrades that are not covered in O&M costs.

The weighted average cost of capital

The analysis in this report assumes a weighted average cost of capital (WACC) for a project of 7.5% (real) in Organisation for Economic Co-operation and Development (OECD) countries and China, where borrowing costs are relatively low and stable

Table 1.1: Assumptions for the calculation of the levelised cost of electricity not derived from project data

	Economic life	Weighted average cost of capital, real	
		OECD and China	Rest of the world
Wind power	25	7.5%	10%
Solar PV	25		
CSP	25		
Hydropower	30		
Biomass for power	20		
Geothermal	25		

regulatory and economic policies tend to reduce the perceived risk of renewable energy projects, and 10% in the rest of the world.[6] These assumptions are average values, but the reality is that the cost of debt and the required return on equity, as well as the ratio of debt-to-equity, varies between individual projects and countries depending on a wide range of factors. This can have a significant impact on the average cost of capital and the LCOE of renewable power projects. It also highlights an important policy issue: in an era of low equipment costs for renewables, ensuring that policy and regulatory settings minimise perceived risks for renewable power generation projects can be a very efficient way to reduce the LCOE by lowering the WACC.

The key factor that determines the cost of capital is risk. A project with greater risk (*e.g.* of non-payment of electricity sales, currency risk, inflation risk or country risk) will require a higher rate of return. Capital can come in the form of equity and loans, while the project may be structured in a variety of ways. Equity is more expensive than secured loans, all else being equal, because it carries more risk in the eventuality that the project underperforms or goes bankrupt.

The key benchmark for assessing the relative cost of risk is the "market risk premium", which is the difference between the average market expected rate of return and the risk-free rate (*e.g.* government bonds). The energy sector is often less risky than the market as a whole, and therefore may have a lower risk premium than the market average, but the inverse is also possible, depending on the market. Researchers have compiled a set of estimated market risk premiums for 51 countries by surveying finance professionals in the respective countries. The average estimated market risk premium for 28 out of 34 OECD countries was at 6.07% (Fernandez et al., 2011).

The cost of capital for renewable projects is affected by the nature of the market, government policy, technological maturity and capacity factors. Policy risk is scrutinised by investors and can render computations of risk investments highly variable (Oxera, 2011).

Governments and private sector companies can develop projects. Governments can generally borrow at a lower rate because the risk is generally, but not always, considered to be lower. However, projects developed by governments tend to be more expensive than commercial projects, whose cost pressures are more intense,[7] which can negate the benefit of lower capital costs. An additional complication is that small projects from private investors or communities may have trouble finding finance and, if they do, generally pay higher fees than large established companies developing large-scale projects.

Countries with lower perceived political and country risk, a proven track record and respected institutions benefit from more generous terms

[6] *All references to discount rates, interest rates, return on equity and the WACC in this report are real unless otherwise indicated.*

[7] *This is not always the case, as private utilities with a monopoly or in a market with little competition may also have little incentive to minimise costs.*

Table 1.2: Categorisation of energy sector project risk factors

Phase	Pre-construction	Constuction	Operation	Country risk
Risks	• Technology risk • Project design • Debt and equity financing	• Constuction delays • Cost overruns • Environmental mitigation plans • Social mitigation plans	• Operation and maintenance plans • Output quality/ volume • Resource fluctuations • Electricity sales payments (PPA contracts, etc.)	• Currency devaluation • Currency convertibility/ transfer • Political force majeure • Environmental force majeure • Regulatory risk

and are more likely to be able to attract private investors and arrange commercial loans. Efforts to minimise the sources of risk (Table 1.2), wherever possible, will help to reduce the cost of capital and improve the project economics.

The financial structure of renewable generation projects and the cost of capital vary widely by technology, country, project developer and region. As an example, in the United States, between the fourth quarter of 2009 and the fourth quarter of 2010 the quarterly average required return on equity for wind projects ranged from a low of 9% to a high of 15%; while over the same period, the quarterly average cost of debt for wind projects ranged from a low of 4.9% to a high of 11% (REFTI, 2011). Making the simple assumption that the debt-to-equity ratio is between 50% and 80%, and that debt maturity matches project length, results in project discount rates of between 5.8% and 11% for wind projects. This has a dramatic impact on the LCOE of wind projects, as the LCOE of wind with a capital cost of 11% will be 45% higher than one with a cost of 5.8%, assuming a 35% capacity factor and USD 0.015/kWh for O&M.

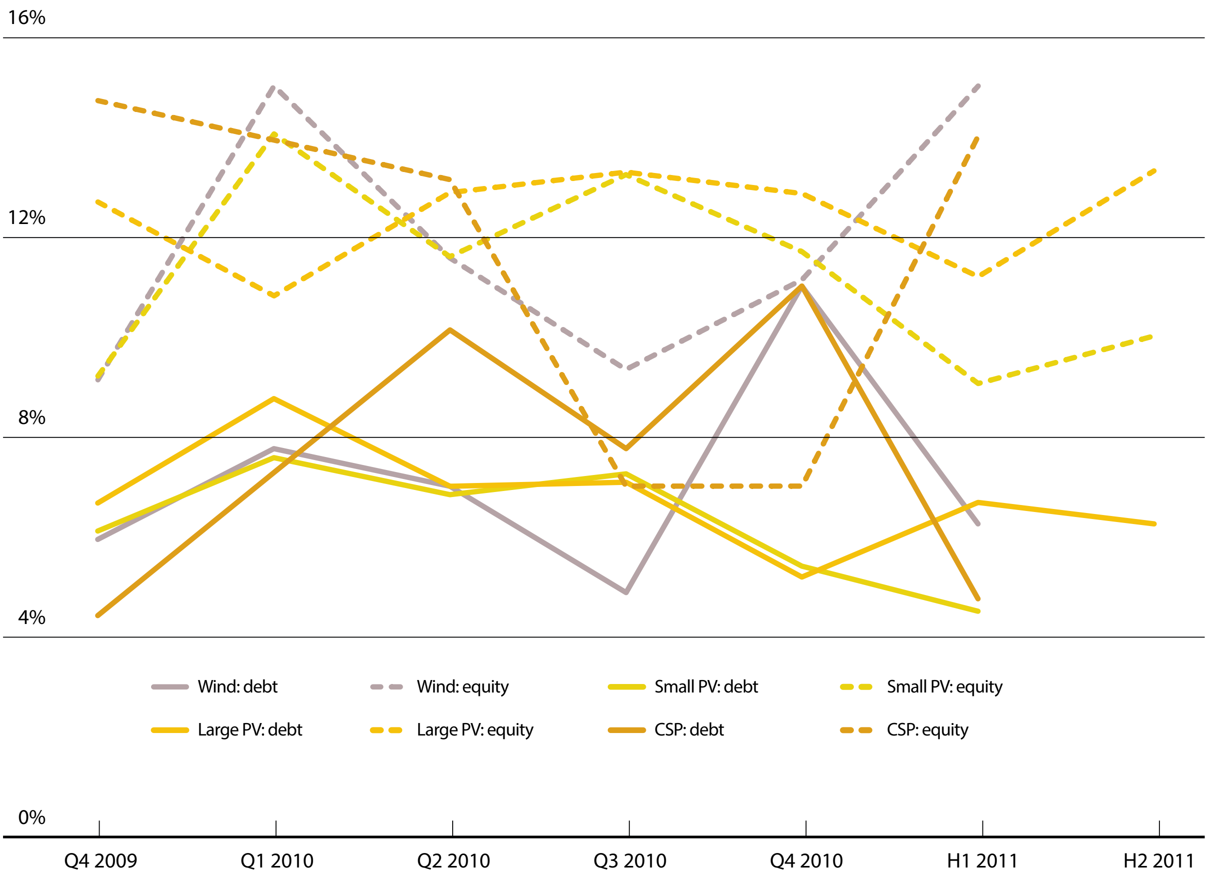
The data for the projects examined in the United States between the fourth quarter of 2009 and the second half of 2011 are presented in Figure 1.2. The volatility of the data suggests that project-specific factors and the nature and experience of project developers have a significant impact on financing costs and return on equity expectations. This suggests that very comprehensive data sets will be required to gain a clear understanding of the underlying contribution of different risk factors to financing costs.

It is illuminating to note that from 2009 to 2011, for the projects that were part of the analysis, just 12% of projects identified project economics as the largest barrier to the project and 7% stated there was no large barrier to their project (REFTI, 2012). However, 13% of projects cited the difficulty of raising capital as the largest barrier, along with 12% that identified finding a tax equity investor. A further 12% cited the power purchase agreement (PPA) or creditworthiness of the off-taker as the largest barrier.[8]

The situation can be very different in developing countries, as various risks can often make it difficult for project developers to mobilise the funds necessary to bring a project to fruition, or if they can, the financing costs mean the economics of the project will not be sufficient to provide an adequate return on equity. In these cases, multi-lateral and bi-lateral lending can be critical to unlocking commercial funding and terms that are not so onerous that they undermine the project economics. For instance, a reasonable weighted average cost of capital for African projects is 15-20%, except where strong guarantees are in place. This is significantly higher than the average cost of capital for renewable energy projects in OECD countries, typically between 6% and 12%. Bringing down these costs will dramatically

[8] Note that the single largest barrier identified by 16% (or 80 projects) wasn't listed among the nine options given, but fell under "other", suggesting that project financing faces a wide range of challenges.

Figure 1.2: Debt and equity costs for wind, solar PV and CSP in the United States, 2009 to 2011



Source: Renewable Energy Finance Tracking Initiative

improve the economics of renewable power generation projects in Africa.

Public sector involvement (government, multi-lateral or bi-lateral lenders) and guarantees can help to reduce risks that the developer has little or no control over and encourage the private sector to invest based on the project's technical and economic merits. As a result, interest in public-private partnerships (PPPs) has been growing, with efforts to develop appropriate public policies and regulatory frameworks that will leverage multi-lateral and bi-lateral lending to increase private sector investments in renewables and climate finance in general. As commercial lenders gain experience in funding renewable energy projects in robust regulatory and economic frameworks, then access to finance and the terms offered should improve. This would have a very important impact on the deployment of renewables in developing countries where there is huge untapped potential waiting to be unlocked to meet the growing demand for electricity.

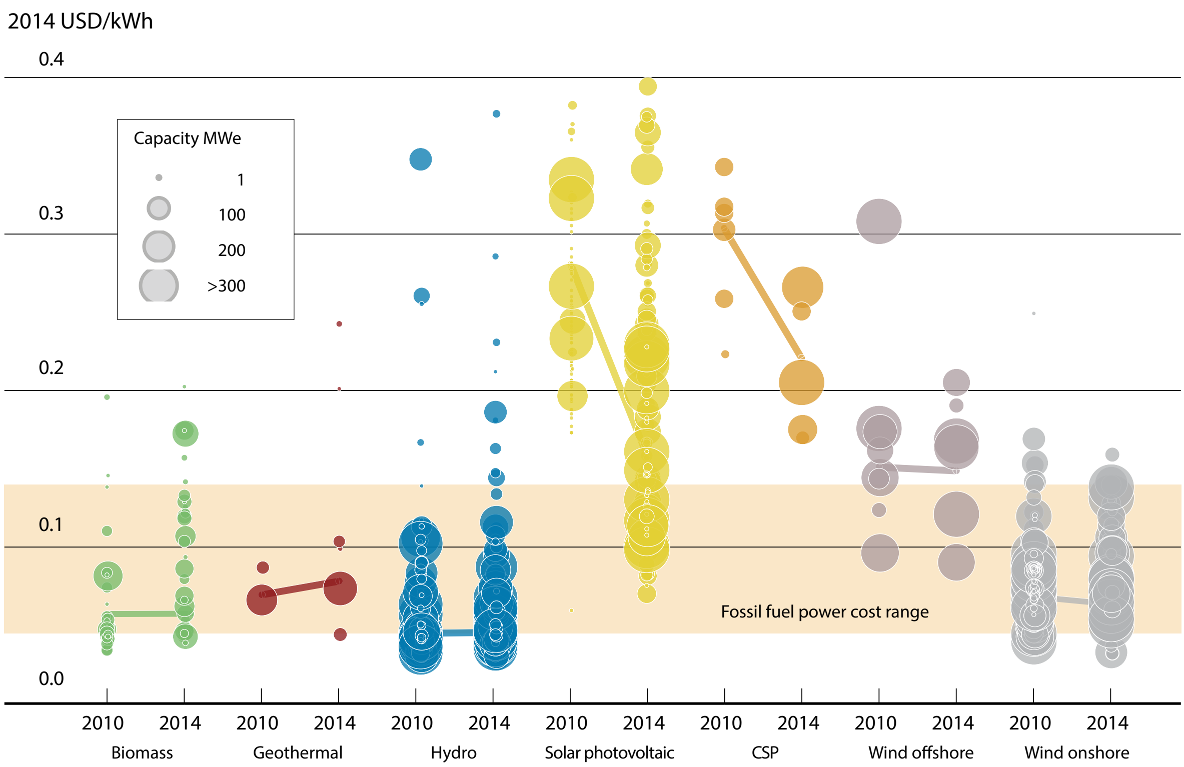
2 RENEWABLE POWER GENERATION COSTS IN 2014

Introduction

The relentless decline in the costs of a range of renewable power generation technologies continued in 2013 and 2014. The competitiveness of renewable power generation technologies has reached historic levels; onshore wind power, solar photovoltaic (PV) and concentrating solar power (CSP) installed costs have continued to fall as their performance has improved, significantly lowering the cost of electricity from these sources. At the same time, biomass for power, geothermal power and hydropower are all mature technologies that, where unexploited economic resources exist, can provide the lowest cost electricity of any source. Renewable power generation technologies are now competing head-to-head with fossil fuel-fired electricity generation options (Figure 2.1).

Solar PV module prices in 2014 were 75% lower than their levels at the end of 2009, while the total installed costs of utility-scale PV systems have fallen by between 29% and 65% between 2010 and 2014 depending on the region. Figure 2.1 presents the evolution of the LCOE of renewable power generation technologies between 2010 and 2014 where the size of the circle is the project size and the centre of the circle represents the LCOE on the Y axis. The levelised cost of electricity (LCOE) of utility-scale solar PV projects has fallen as low as USD 0.08/kWh in 2014 (Figure 2.1). Where good resources exist and low-cost financing is available, utility-scale PV projects are now being built that provide electricity at a lower cost than fossil fuels (*e.g.* in Dubai, Chile and a range of other countries) without any financial support,

Figure 2.1: The levelised cost of electricity from utility-scale renewable technologies, 2010 and 2014



Source: IRENA Renewable Cost Database.

Note: Size of the diameter of the circle represents the size of the project. The centre of each circle is the value for the cost of each project on the Y axis. Real weighted average cost of capital is 7.5% in OECD countries and China; 10% in the rest of the world.

even where indigenous fossil fuels are abundant. A similar story is unfolding in the residential solar PV sector, as the LCOE of solar PV has fallen by between 42% and 64% between the beginning of 2008 and 2014.

Onshore wind is now one of the most competitive sources of electricity available as continued technology improvements have increased capacity factors at the same time as installed costs have been declining. As a result, the LCOE of wind is now typically in the same cost range, or lower, than that of fossil fuel power generation. As an example, the best wind projects in the United States are delivering electricity for USD 0.05/kWh without financial support.

Although the story is nuanced, given the LCOE range for renewable projects, it is clear that on average the mature, commercially available renewable power generation technologies have costs similar to or less than fossil fuels in many regions as costs have fallen and technologies improved. With continued cost reductions in the future there will be a growing wedge opening between renewables and their more expensive fossil fuel options for power generation.

The increased competitiveness of renewables will require policy-makers to shift their emphasis from individual technology support to a system-wide approach to facilitate the transition to a sustainable electricity sector. This shift will be vital due to increasing power system level integration issues which will require advance planning as economies head towards 30% or more of variable renewables. The shift in policy focus will require broader policy changes that also adapt the market structure and align stakeholder incentives to minimise overall system costs, yet still support renewables in an equitable fashion while the externalities and risks of fossil fuels and nuclear power are still not realistically priced. As the share of variable renewables grows, the importance of the more mature renewable power generation technologies (*e.g.* biomass for power, geothermal and hydropower) as well as CSP with thermal energy storage may grow and their ability to provide ancillary grid services and shift generation through time will become highly valuable for minimising overall system costs.

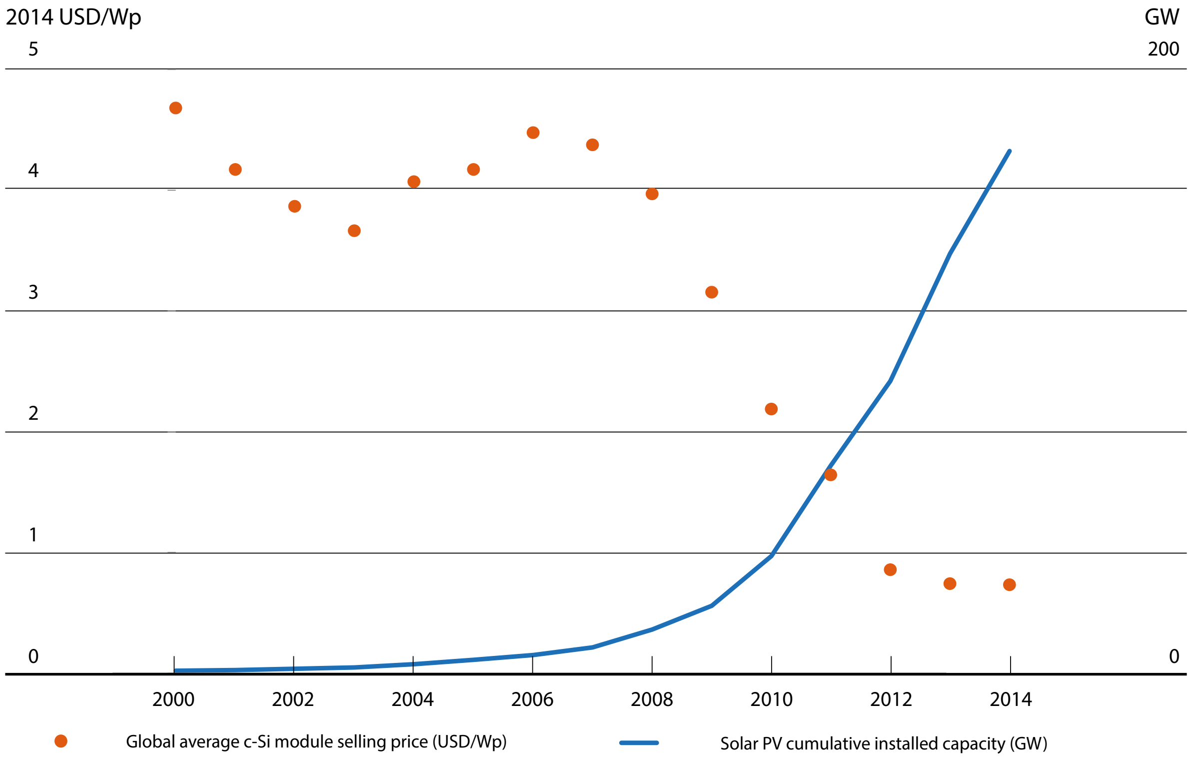
With utility-scale renewable power generation options now competitive in a growing number of markets, renewables have never been more competitive. However, much remains to be done to ensure that decision makers are aware of just how competitive renewables are. A wide disparity still exists between the most competitive renewable electricity generation projects for a given technology and the most expensive. This is also true of the ranges between countries and regions. Part of this variation is due to differences in renewable resource quality between different locations. It is also due to the wide variation in total installed costs for projects, and for a number of reasons.

One factor is site-specific issues, which can have an important impact on overall project development costs (*e.g.* quality and availability of local infrastructure, distance of the project from existing transmission lines, etc.). Differences in installed costs also arise because markets for individual technologies in different countries, and even within regions of a country, can be at very different stages of maturity.

As a result, cost structures can vary quite significantly, but typically decline as small under-developed markets grow and gain a core of experienced project developers and supporting contractors who can work together to lower project development costs as the market grows to "local" maturity.

Despite the theoretical understanding of the impact of these factors on cost variations, there are also examples of wide cost variations within an individual, relatively mature market (*e.g.* small-scale residential PV systems in California). With the declines in equipment costs in recent years and the growing importance of balance of system costs (BoS) as a large source of future cost reductions, much more research needs to be done in this area. A better understanding of why cost differentials exist may provide policy-makers with indications about what relatively simple regulatory or institutional changes could significantly reduce average costs by shifting system costs to the lower end of today's ranges.

Figure 2.2: Cumulative global solar photovoltaic deployment and solar photovoltaic module prices, 2000 to 2014



Sources: IRENA and pvXchange, 2014.

Renewable power generation costs, policy support and deployment

The energy sector is currently undergoing a transformation that represents the beginning of the transition to the renewables-dominated, truly sustainable power sector required to avoid the dangerous effects of climate change. The transformation of the energy sector is most evident in the power sector, where renewables are now estimated to have added around half or more of global new capacity required every year from 2010 on. Renewable energy capacity additions have risen six-fold between 2001 and 2013, to reach around 120 GW, with over 100 GW added every year between 2011 and 2013.

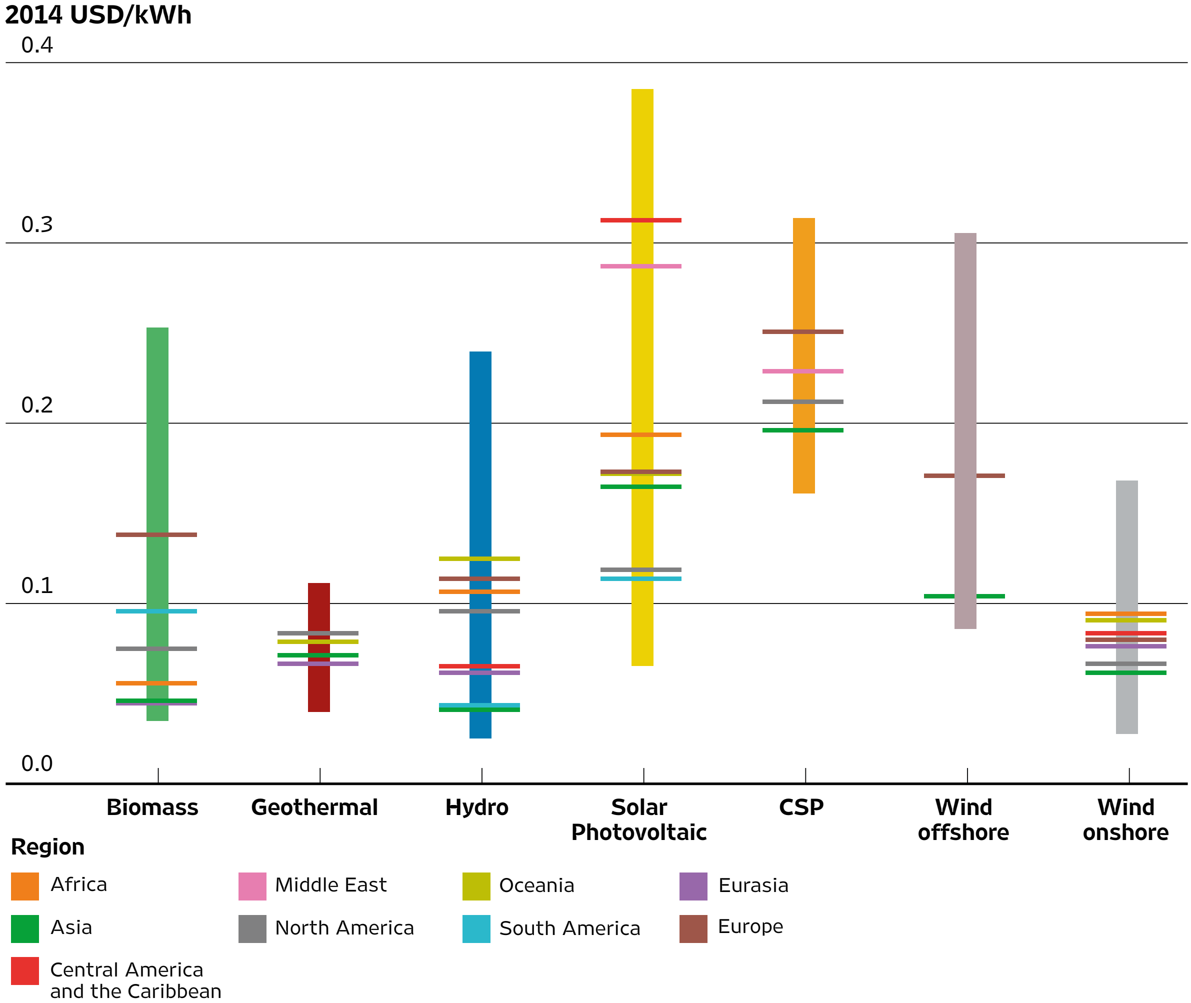
This is an active transformation; the policy support for renewables to meet countries' long-term goals for secure, reliable, environmentally friendly and affordable energy is bearing fruit. Learning investments have been made that have driven down the LCOE of renewable technologies, as a virtuous cycle of high levels of new capacity additions has unlocked technology improvements and driven down installed costs at the same time.

The sometimes rapid declines in the LCOE of renewable power generation technologies are possible because, although most renewable power generation technologies are mature, commercially proven products, they are not yet mature from a cost perspective. Thus, unlike fossil fuel and nuclear technologies, where installed costs are at best stable and often rising due to increasing environmental or safety performance requirements, renewable technologies have significant or even very high learning rates.[9]

Solar PV modules, for instance, have learning rates of between 18% and 22%, and the growth in cumulative installed capacity of solar PV relative to PV module cost declines is striking (Figure 2.2). It is notable that at the end of 2000 cumulative installed capacity was less than 1 GW globally. At the end of 2014, cumulative installed capacity has likely exceeded 180 GW with strong growth likely in 2015.

[9] Learning rate refers to the fixed percentage reduction in equipment or installed costs for each doubling of cumulative installed capacity. The concept can also be applied to trends in LCOE, but there is significantly less research on this topic.

Figure 2.3: Typical levelised cost of electricity ranges and regional weighted averages by technology, 2013/2014



Source: IRENA Renewable Cost Database.

Renewable power generation costs by technology

The typical LCOE range and regional weighted averages of today's renewable power generation technologies are highlighted in Figure 2.3. Given today's installed costs, the performance of renewable power generation technologies and current prices for fossil fuels and conventional technologies, renewable technologies are now the most economic solution for off-grid electrification and for new centralised grid supply in locations with good resources.

The high costs of small-scale diesel-fired electricity generation are made even higher in very remote locations where poor, or even non-existent, infrastructure can mean that transport costs increase the cost of diesel by 10% to 100% compared with the prices in cities. The recent decline in the LCOE of renewable power generation technologies represents a historic development, as it means that renewable technologies should provide the first introduction to modern energy services for 1.3 billion people currently without access to electricity on economic grounds.

It is not just off-grid that electricity systems remain dependent on diesel-fired generation. The falling cost of renewables means that virtually any electricity system based predominantly on oil-fired generation – such as on islands and in many countries – will see system generation costs fall by integrating renewables.

Reinforcing the earlier IRENA analysis of the LCOE of renewable power generation technologies (IRENA, 2013), it is apparent that the regional weighted averages for the LCOE of the projects in the IRENA Renewable Cost Database for many technologies now typically fall within the same cost range as for fossil fuel-fired electricity. What is remarkable is that the rapid declines in solar PV module prices and installed costs now mean an increasing number of solar PV projects are economic at the utility-scale without subsidies.

The average LCOE of utility-scale solar PV has fallen by around half in the four years between 2010 and 2014, as solar PV module prices have declined by two-thirds to three-quarters in that time. The weighted average LCOE by region for utility-scale solar PV projects that were installed in 2013 and 2014 ranged from a low of between USD 0.11 and USD 0.12/kWh in South and North America to over USD 0.30/kWh in Central America and the Caribbean. Projects are now being built with an LCOE of USD 0.08/kWh, while even lower values are possible where low-cost financing is available. For example, a recent tender in Dubai saw a successful bid for a purchase power agreement (PPA) without financial support of just USD 0.06/kWh.

The average LCOE of residential solar PV systems was estimated to be between USD 0.38 and USD 0.68/kWh in 2008. This declined to between USD 0.14 and USD 0.46/kWh in 2014. The LCOE for residential systems declined by 40% to 66% between 2008 and 2014.

Hydropower produces some of the lowest-cost electricity of any generation technology. The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, while average costs are around USD 0.05/kWh where untapped economic resources remain. Small-scale hydropower can also be very economic, although typically it has higher costs and is sometimes more suitable as an option for electrification that can provide low-cost electricity to remote communities or for the local grid.

There is a clear cost dichotomy for hydropower between regions with remaining economic resources to exploit and those where most of the economic resources have been exploited already. Asia, Africa and South America all experience LCOEs for hydropower projects of on average USD 0.04 to USD 0.05/kWh. In contrast, in regions which have exploited their most economic resources, weighted average LCOE ranges are around USD 0.09 to USD 0.10/kWh (*e.g.* in Europe, Eurasia, North America and Oceania). In addition to the higher costs, these regions are also constrained in the amount of economic capacity that still remains to be added.

Onshore wind now rivals hydropower, geothermal and biomass as a source of low-cost electricity. The weighted average regional values for the LCOE of onshore wind in 2013 and 2014 ranged from a low of USD 0.06 to USD 0.07/kWh in Asia, Eurasia and North America to around USD 0.08/kWh in the rest of the world's regions that are deploying significant amounts of wind. Where excellent resources and low cost structures exist, wind power projects are now routinely achieving costs of just USD 0.05/kWh without any financial support.

Biomass-generated electricity can be very competitive where low-cost feedstocks are available onsite at industrial, forestry or agricultural processing plants. In such cases, biomass power generation projects can produce electricity for as little as USD 0.06/kWh in the OECD countries and as low as USD 0.03/kWh in developing countries. The typical LCOE range for biomass-fired power generation projects is between USD 0.05/kWh and USD 0.15/kWh, but where expensive feedstocks, such as woodchips or pellets, or expensive gasifier technology are used, the LCOE can rise to as much as USD 0.20 to USD 0.25/kWh and will require financial support to be economic. The weighted average LCOE by region varies from a low of around USD 0.04/kWh in Asia and Eurasia to USD 0.14/kWh in Europe.

Geothermal electricity generation is a mature, baseload generation technology that can provide very competitive electricity where high-quality resources are well-defined. The LCOE of conventional geothermal power varies from USD 0.05 to USD 0.10/kWh for recent projects. However, the LCOE can be as low as USD 0.04/kWh for the most competitive projects, such as those which utilise excellent well-documented resources or brownfield developments. Most recent projects have been brownfield in nature and past experience with the geothermal reservoir can reduce development risks

BOX 2.1

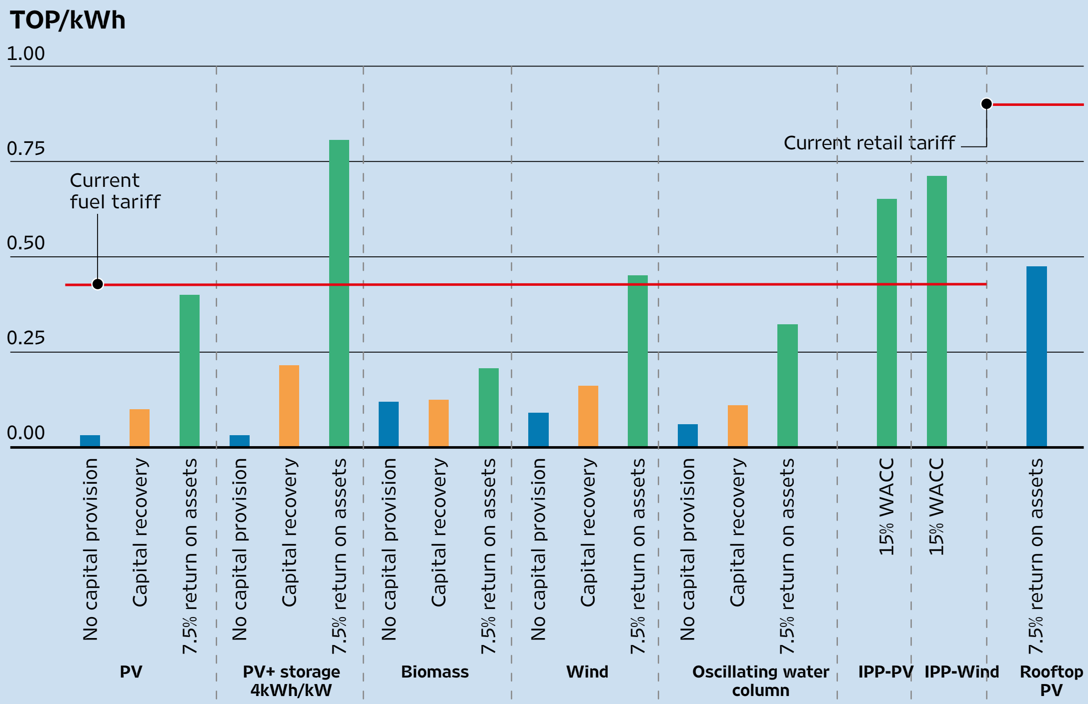
Renewables now the economic solution off-grid and on islands

Despite the fact that installed costs for small-scale projects off-grid, in remote locations and on many islands are higher than in areas close to major markets and with good infrastructure, there is now almost always a renewable solution that costs less than diesel-fired electricity (Figure 2.4). This will have economic, environmental and social benefits. Remote communities and islands will see cost reductions (tariffs range from USD 0.35/kWh to USD 1/kWh or more on remote islands), reduced imports of expensive fossil fuels, improved security of supply and be able to more rapidly meet electricity needs of remote communities due to the highly modular nature of renewables.

By combining renewable technologies in mini-grids to electrify isolated villages and extend grid networks, the variability of supply can be reduced to low levels, thus providing a high-quality, low-cost solution. As an example of the potential of renewables to reduce costs on islands, IRENA has worked with the Government of Tonga to analyse cost reductions from introducing renewables (IRENA, 2015). Depending on whether the projects are financed by grants from development aid (with or without cost recovery so that the asset can be replaced by the country not donors at the end of its life) or privately at a 7.5% real weighted average cost of capital (WACC), the costs for some technologies are significantly lower than current generation tariffs and the distributed generation cost is significantly lower than retail tariffs.

However, the major challenges are often finance-related, as the high cost of capital (which can be two to three times higher for these projects than in developed countries) and high transaction costs for small-scale projects can sink the viability of these projects, even if financing is available for them. Much work therefore needs to be done to address the financing challenges before the economic and environmental benefits of renewables off-grid and on islands can be realised.

Figure 2.4: Renewable power generation options for Tonga compared to generation costs and residential tariffs

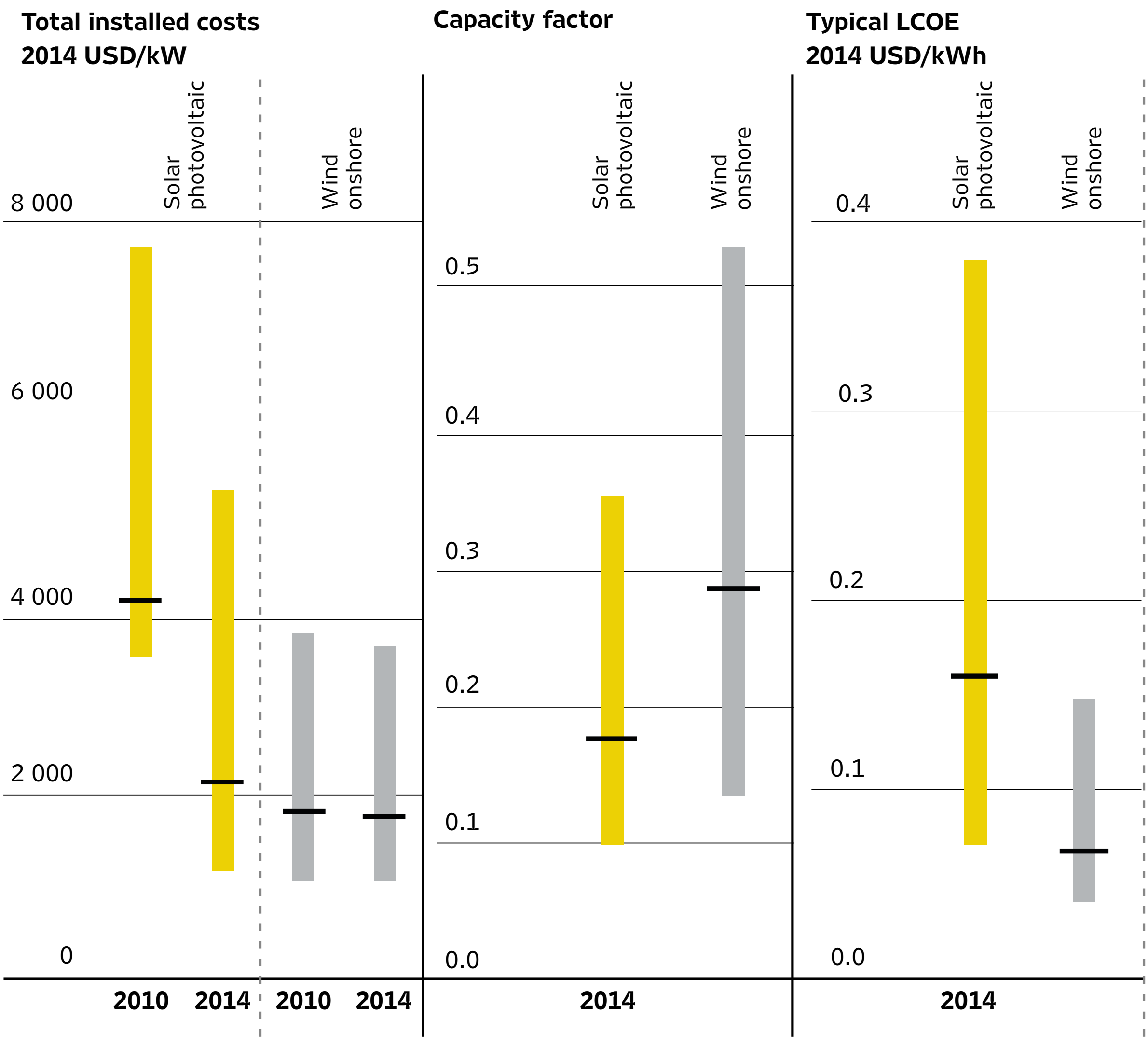


Source: IRENA, 2015.

and some existing infrastructure may already be in place which will also reduce costs. It is important to note that geothermal projects carry a very different risk profile than the other renewable technologies and tailored support policies will typically be required to accelerate geothermal deployment.

The two main CSP systems are parabolic trough and solar towers, although linear Fresnel collector

Figure 2.5: Global typical installed cost, capacity factor and LCOE ranges with weighted averages for utility-scale solar photovoltaic and onshore wind projects, 2010 and 2014

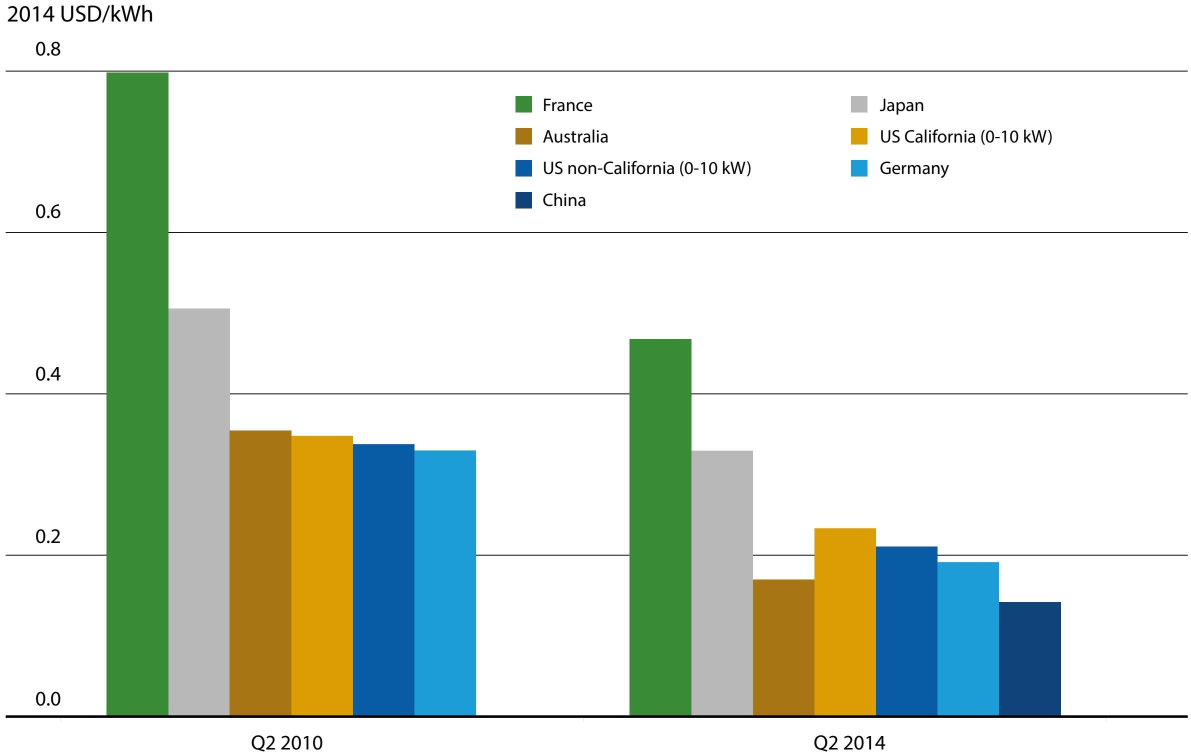


Source: IRENA Renewable Cost Database.

systems and dish systems are beginning to be deployed commercially. The majority of commercial experience so far has been with parabolic trough systems, which have typical LCOE ranges of between USD 0.17 and USD 0.35/kWh, although PPAs have been signed for as low as USD 0.14/kWh where low-cost financing is available. The LCOE of solar towers are estimated to be similar, in the range of USD 0.17 to USD 0.29/kWh. However, given that only a handful of plants with capacity of 10 MW or more were operating at the end of 2014, care needs to be taken in making any comparison with the more numerous parabolic trough plants until more data are available. Looking to the future, and given their modest deployment at commercial scale to date, solar towers appear to have a greater potential for cost reduction. The ability for solar towers to achieve higher operating temperatures with molten salt will also help to improve efficiency and translate into lower costs for thermal energy storage per unit of energy stored. These factors will help drive the LCOE down and make solar towers attractive solutions for providing flexible electricity generation and helping to facilitate the penetration of wind and solar PV by providing dispatchable generation to balance the variability of wind and solar PV when equipped with thermal energy storage.

Although the range of costs for renewable power generation technologies is wide for a given technology, and even for a technology within a particular region, it is striking that virtually all renewable power generation technologies now include significant numbers of projects which

Figure 2.6: Levelised cost of electricity of residential solar photovoltaic systems by country, 2010 to 2014



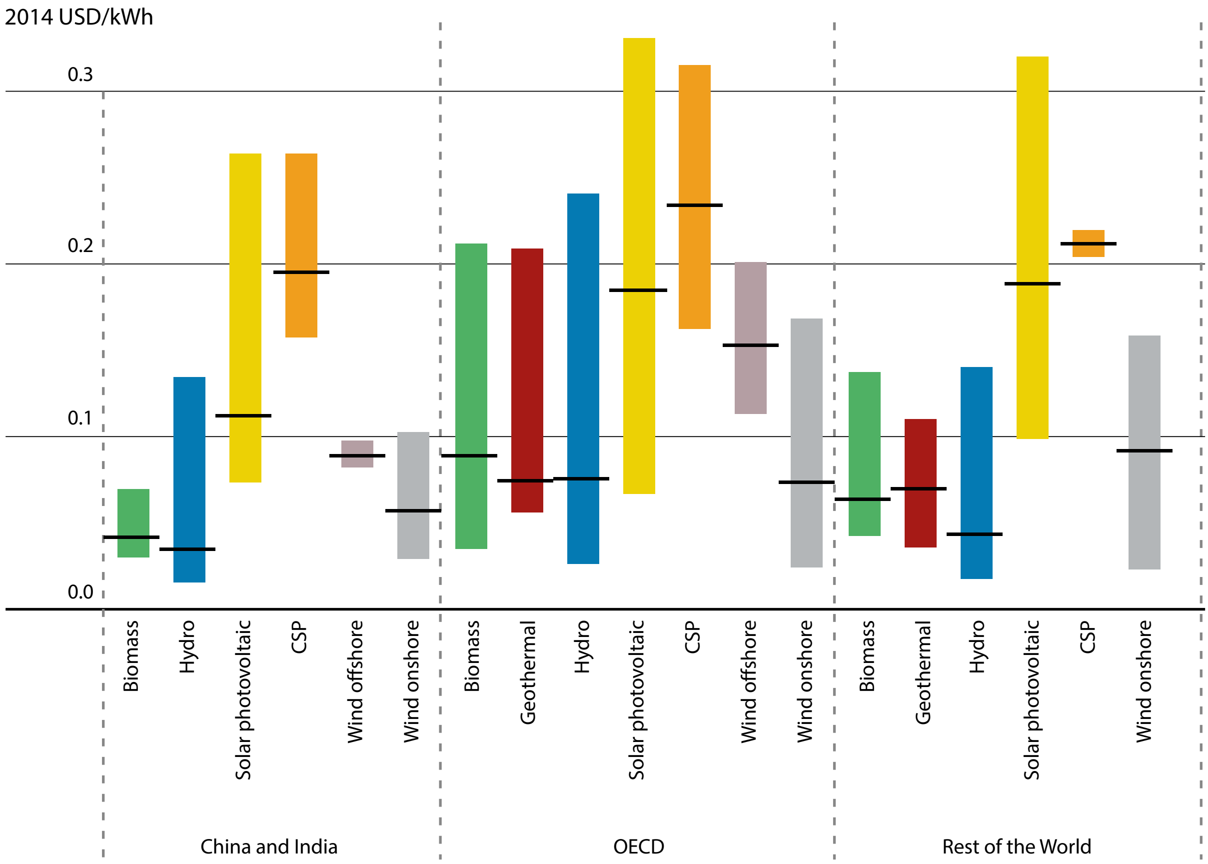
Sources: IRENA Renewable Cost Database; BSW, 2014; CPUC, 2014; GSE, 2014; LBNL, 2014; and Photon Consulting, 2014.

are competitive with fossil fuels without financial support, despite the fact that fossil fuels still do not pay for the local and global environmental damage they cause, or their negative health impacts. Including these costs would significantly improve the economics of renewable power generation costs and has been shown to mean that a doubling of the share of renewables in the energy mix could be achieved at a net saving to society (IRENA, 2014). This is also now true for solar PV, although to a lesser extent than for the other technologies. The exception to this is CSP, which with just 5 GW of installed capacity is in its infancy and will see continued significant cost reduction with continued policy support.

The decline in total installed costs has been driving the decline in the LCOE of solar PV between 2010 and 2014 (Figure 2.5). Although total installed project costs for onshore wind span a narrower range, the lower ends of the total installed cost ranges for utility-scale solar PV and onshore wind in 2014 are now very similar. In 2014, there is also little difference in the global weighted average of total installed costs for the two technologies, despite the fact that total installed costs of utility-scale solar PV were 110% higher on average in 2010. What drives the difference in the LCOE in 2014, given similar average total installed costs, are the different capacity factors that can be achieved by the two technologies. The global weighted average capacity factor for new onshore wind power projects in 2014 was estimated to be around 35%, almost twice that of the estimate for solar PV in that year.

As a result of the lower capacity factors for solar PV, the global weighted average LCOE of utility-scale solar PV is slightly more than twice that of onshore wind projects, despite total installed costs being on average only 25% higher for solar PV. However, the LCOE range for individual solar PV projects since 2012 has increasingly begun to overlap with onshore wind. In 2014, a handful of solar PV projects are estimated to have had a LCOE that matched the global average LCOE of onshore wind. In areas with excellent solar resources, utility-scale solar PV is now likely to provide electricity more cheaply than onshore wind, except where there are also excellent wind resources. However, with more rapid reductions for installed costs expected for solar PV than for onshore wind up to 2020,

Figure 2.7: The levelised cost of electricity by region and technology and their weighted average, 2013/2014



Source: IRENA Renewable Cost Database.

the average gap between the two technologies in terms of LCOE will continue to narrow. The gap would be reduced even more quickly if more solar PV capacity were to be deployed in regions with excellent solar resources than is the case today.

Figure 2.6 presents the evolution of the LCOE for small-scale residential solar PV systems between 2010 and 2014. Similar to the experience in the utility-scale sector, the LCOE for these small-scale systems has fallen rapidly with the declines in solar PV module prices. The average system LCOE of the systems in Figure 2.6 has reached residential electricity price parity in Germany, Italy and parts of Australia. Germany and China have, on average, the most competitive small-scale residential rooftop systems in the world. Germany's residential system costs have fallen from just over USD 7 200/kW in the first quarter of 2008 to USD 2 200/kW in the first quarter of 2014. This is reflected in their low LCOE. The LCOE of solar PV in Australia, despite higher installed costs, is also highly competitive due to the country's excellent solar resources. The LCOE of residential solar PV has declined to between USD 0.14 and USD 0.46/kWh in 2014 in eight major residential markets IRENA has data for. Between 2008 and 2014, the average LCOE in these markets declined by between 42% and 64%.

The levelised cost of electricity by region

In the past, there was a clear hierarchy of costs for renewable power generation technologies, with established renewable technologies, such as hydropower, biomass and geothermal able to provide electricity at low costs at the best sites. However, the large-scale deployment of wind and solar PV since 2000 has seen their installed costs driven down by learning investments at the same time that technology improvements have improved yields, resulting in LCOE declines. This resulted first in onshore wind and now, to an increasing extent, in solar PV becoming sources of low-cost electricity. Solar PV on average still remains more expensive, but costs are continuing to fall and the same generalised competitiveness of solar PV in areas of excellent solar resources will emerge in the next three to five years.

Figure 2.7 compares the weighted average LCOE and range of renewable power generation technologies by country/region. There are significant differences in the cost ranges for different technologies in different regions due to the very site-specific nature of renewable resources and project costs. A regional and country-level analysis of costs is therefore critical to understanding costs and their implications for policy-makers.

There is no substitute for collecting up-to-date cost data from local markets. It is inadvisable to assume that local costs for different technologies in local contexts can be extrapolated from data in neighbouring countries or regions, as there are a range of variables that mean local cost structures are likely to differ. These can include: the maturity of the local market for a given renewable technology; local infrastructure availability; local materials prices; the number of local project developers with renewable project development experience; labour rates; regulations and permitting procedures; skills shortages; and a range of other factors. Not collecting these data can lead to unrealistic current cost and cost reduction potential assumptions that can result in poor policy-making and in inefficient policies.

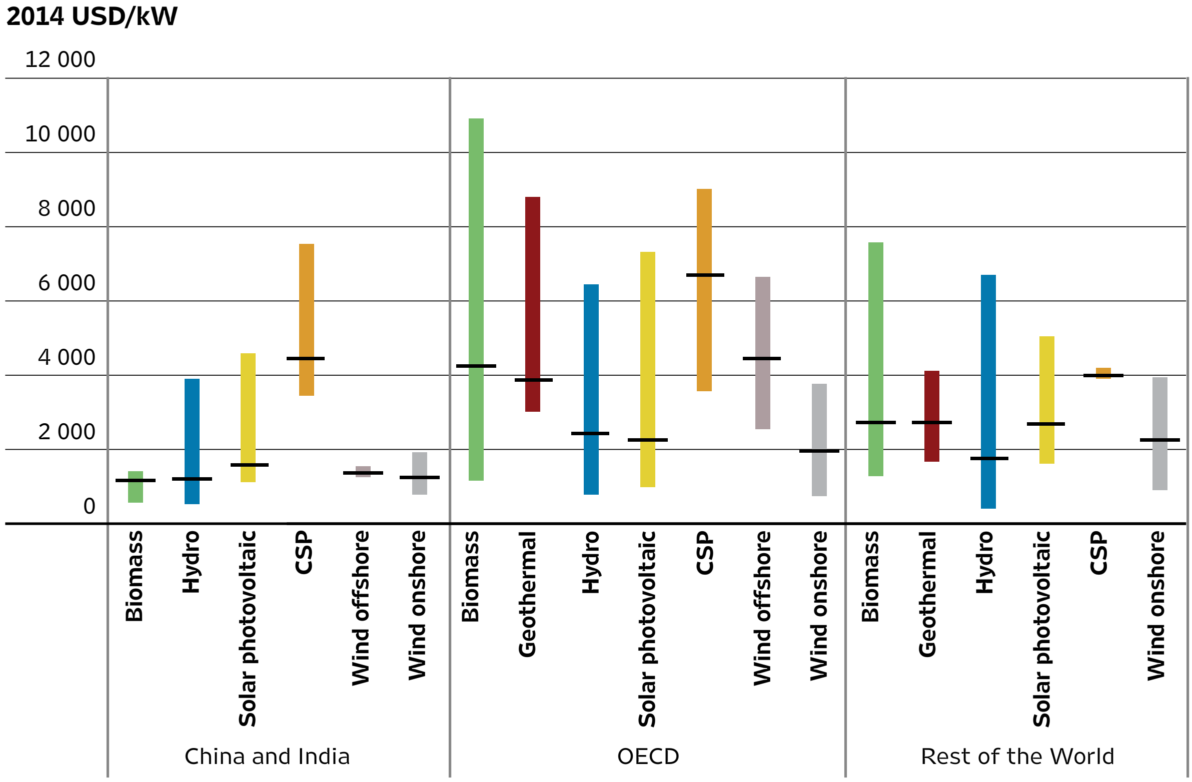
China and India, where IRENA has been able to collect a large number of project data points, have some of the most competitive renewable power generation project development costs in the world and this translates into very competitive LCOEs, even for wind where the local resource quality is not ideal. Elsewhere, South America is emerging as a dynamic new market for renewable power generation, as efficient policies are ensuring that competitive installed costs are being combined with world-class renewable resources to produce very competitive LCOEs.

China is the largest global market for renewable power generation technologies. In China, the large- and small-scale hydropower projects are the most competitive, followed by biomass, wind power, and solar PV. However, with China's abundant coal reserves and relatively low installed costs for fossil fuel-fired plants, the renewable energy industry still in some cases needs support to compete with incumbent technologies. Hydropower in China has a weighted average LCOE of around USD 0.04/kWh while the range for biomass is between USD 0.05 and USD 0.06/kWh. Wind is also very competitive by global standards, with project costs in the range of USD 0.05 to USD 0.10/kWh and weighted average costs of around USD 0.06/kWh. The LCOE of utility-scale solar PV has declined rapidly from an average of around USD 0.24/kWh in 2010 to just USD 0.11/kWh in 2014, although the data for 2014 have yet to be confirmed and are subject to revision.

India, like China, benefits from a competitive cost structure for renewables, although currently to a lesser extent for solar PV. The financing costs in India, however, are somewhat higher than in China and this has a material impact on the LCOE of projects. With a number of projects coming online, hydropower is still the lowest-cost renewable power generation option in India, with weighted average hydropower costs of between USD 0.04 and USD 0.05/kWh for small- and large-scale projects. Large-scale wind projects have average costs of around USD 0.08/kWh, with a range between USD 0.05 and USD 0.10/kWh, while small-scale (<5 MW) projects have weighted average costs of USD 0.09/kWh. Biomass-fired power generation costs averaged between USD 0.045 and USD 0.06/kWh, assuming feedstock costs of between USD 1.3 and USD 2.5/GJ. The weighted average LCOE of utility-scale solar PV has fallen to around USD 0.13/kWh in 2014, but a wide range in costs still exists and projects are still being built that have an LCOE of twice this average.

In the rest of Asia the weighted average costs for biomass, solar PV and wind are all higher than in India and China, given their competitive materials costs and large engineering bases, low cost manufacturing and local content costs. The Philippines and Indonesia both make extensive use of their excellent geothermal resources and the estimated LCOE for their brownfield geothermal power projects is around USD 0.05/kWh, assuming these projects can meet their projected high capacity factors of 80% to 90% over the entire project life. The average LCOE of hydropower

Figure 2.8: Typical ranges and weighted averages for the total installed costs of utility-scale renewable power generation technologies by region, 2013/2014



Source: IRENA Renewable Cost Database.

projects in other Asian countries are very similar to those in China and India and are estimated to be around USD 0.05/kWh.

New renewable power generation capacity additions in Central and South America used to be almost exclusively based on biomass and hydropower, given abundant resources, allowing very competitive electricity generation. However, the region also has world-class wind and solar resources. As the long lead times and environmental requirements make adding more hydropower difficult and time-consuming, the fall in wind and solar PV costs has seen a growth in their deployment to meet growing demand and/or to help stabilise electricity supplies in the face of challenging hydrological conditions. This is typically occurring against a background of no, or minimal financial support.

The installed costs for wind in Central and South America are higher than in China and India, but good wind resources in many locations mean the weighted average LCOE is around USD 0.08/kWh, with a typical range between just USD 0.05/kWh and USD 0.10/kWh. Brazil's very successful auction system will see these average costs fall in the next few years as the contracted-for capacity is built. Although only a small sample of large-scale solar PV projects have provided sufficient data to be analysed, excellent solar resources in Peru and Chile have resulted in exciting developments in South America. In Chile, solar PV plants are now being built as merchant plants to feed into the grid, as the excellent resources and low installed costs mean they are a competitive option to feed into the daily power market. The average LCOE for the projects in the IRENA Renewable Cost Database is estimated to be just USD 0.11/kWh in 2014. The large-scale projects in areas with excellent solar resources allow very high capacity factors (27% or more) compared to the global average, and mean that Central and South America will see strong growth in solar PV deployment in the coming years, with projects as competitive as anywhere in the world, most without any significant financial support.

The available data for renewable projects in Africa are thinner than for some other regions, but the costs follow a similar pattern to Latin America, with the exception that the LCOE of large hydro tends to be higher than for small hydro. Insufficient data are available to provide a definitive explanation of this finding, but poorer infrastructure, high grid connection/reinforcement costs for remote projects and multi-purpose dams probably all contribute. Collecting more data for Africa to verify whether these data are accurate and the reasons for the observed pattern is a priority.

The total installed cost ranges for renewable projects (Figure 2.8) in different regions follow a similar pattern to the LCOE cost ranges presented in Figure 2.7, with the exception of solar PV and biomass for power generation. The total installed cost ranges for solar PV are narrower than the LCOE as the wide variation in capacity factors results in wider LCOE ranges. A different pattern occurs for biomass-fired power generation in OECD countries, where a wider range of installed costs are associated with higher capacity factors resulting in a narrower range in the LCOE than that implied by total installed costs.

The recent declines in installed costs for wind and solar PV mean that renewables now often have total installed costs per kW similar or lower than fossil fuel technologies, except where low-cost gas-fired plants are being installed.

From the levelised cost of electricity to electricity system costs

As discussed in Chapter 1, this report uses a range of cost metrics to analyse the evolution of the costs of renewable power generation technologies. Each metric, whether it be equipment costs, total installed costs or LCOE, brings its own insights and can be used to identify differences in costs and their evolution over time. However, there is no one "true" cost metric that can provide all the information required to analyse the competiveness of renewables.

Different metrics can identify significant cost differences between projects of a given technology within a country, between different technologies within a country and between the same and different technologies across countries. However, just because one cost metric is higher in one region or country than another or different between technologies doesn't mean that the cost structure is necessarily less efficient. As already discussed, site-specific factors can have a significant impact on overall costs, as do local materials prices, infrastructure, etc. A detailed analysis of equipment costs and local cost drivers is required to attempt to identify general levels of competiveness. However, large datasets that contain a detailed breakdown of different cost components (*e.g.* installation, project development costs, land costs, etc.) for different cost metrics utilising the same boundaries across technologies and countries are extremely rare. The end result is that any analysis of the costs and relative competitiveness of renewables must come with a significant disclaimer that the comparisons made are only indicative, due to the imperfect information available and the limitations of individual metrics.

This is in part why a range of cost metrics are used in this report. Although the underlying reasons for cost differences may not be evident, large differences in costs (*e.g.* BoS costs for PV systems) can at least be identified and provide the basis for future, more detailed analysis of why these cost differentials exist and – critically, from a policy-making perspective – what might be possible to reduce cost differentials to the lowest feasible level. The "lowest feasible level" is measured while taking into account differences in fundamental underlying cost drivers (i.e. resource quality, local materials and labour costs, maturity of the local market, etc.), although this "normalisation" is in itself a difficult analytical exercise that is only approximate.

Cost metrics and minimising electricity system costs

As a metric, the LCOE of electricity is a useful tool for comparing technologies with similar characteristics and generation profiles in a specific market. However, it has limitations and is not a definitive metric for discussing relative costs. In particular, in its simplest form, it doesn't take into account the value of electricity generated at different times, the implications for the electricity transmission and distribution system or the risks to the project's total costs over the project's life (*e.g.* the risks associated with fuel price volatility, physical disruptions to fuel supplies, or drilling risks for geothermal projects). These issues can have a material impact on the LCOE between different projects and also the risks associated with the actual LCOE of the project over its economic life diverging significantly from the estimated LCOE at the time the decision to invest is taken, whether it be renewable, fossil fuel-fired or nuclear.

The only robust way to identify the lowest-cost combination of new capacity to build over time is to undertake detailed system level modelling. Using the best possible input assumptions for the costs and performance of renewables is critical to the quality of the results from these types of modelling exercises.

This leads to one of the key benefits of collecting detailed cost and performance data for renewable power generation technologies. They can be used as input assumptions for the detailed system modelling to minimise overall electricity system generation costs in the long-run[10] when adding new capacity, subject to constraints on local and global environmental pollutant emissions (where applicable), energy security goals, etc.

This modelling needs to take into account: highly granular load curves (demand) through time (down to as short as 15-minute time intervals) that vary by day and season, as well as their projected growth over time; existing generation plants and their characteristics (*e.g.* efficiency, fuel and O&M costs, feasible ramp rates, availability, etc.); as well as the characteristics of potential new capacity. Such simulations can provide a better estimate of the lowest-cost expansion plan for an electricity market, but can't remove all uncertainties, such as unexpected changes in demand growth, load profiles, fuel costs, cost overruns on projects, etc. As a result, even these simulations are subject to significant uncertainty and scenario analysis needs to be used to identify the sensitivity of the results to the underlying risk factors affecting total system costs. In centrally planned electricity systems this process will be used to determine expansion plans. However, where electricity markets are open to new entrants with few or no barriers, the decision of whether to invest, in what and when, is a commercial decision that also contends with the uncertainties of what other potential market actors may do. In either a centrally driven system or a more liberalised one, miscalculations are not uncommon, leading to increased costs for consumers and/or to shareholders losing money.

Detailed system level modelling is required to understand the dynamics of an individual market and the lowest-cost expansion pathway. These results are, by definition, only applicable to the market; however, there are three essential components of this modelling that are relevant to moving beyond a simple LCOE. These are:

» The value of electricity varies over time for the existing generation mix, and will vary in the future as new capacity is added or retired.

» System level interactions occur when new capacity is added; these can reduce costs or increase them.

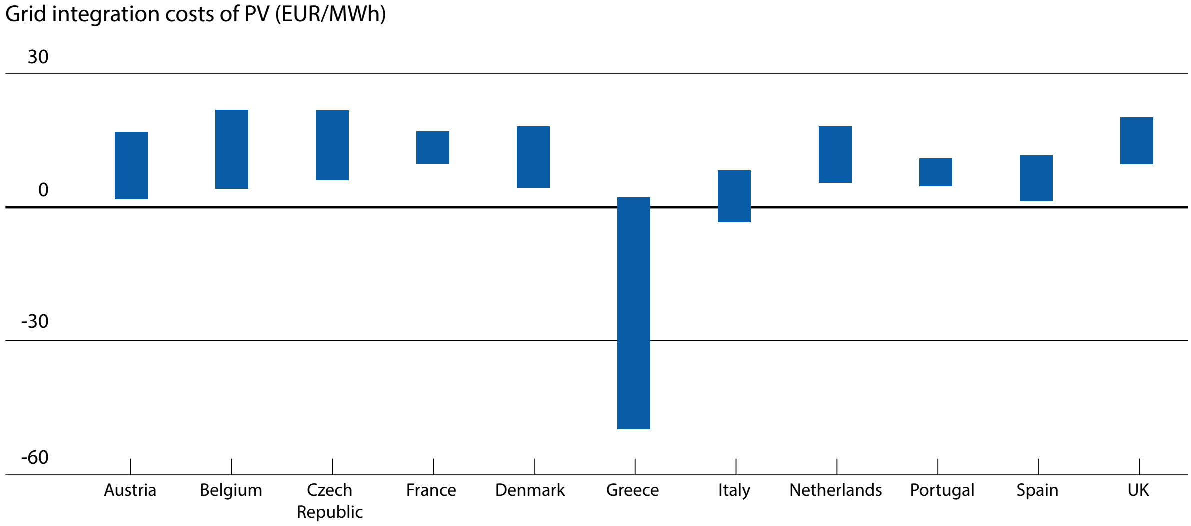
» The risk profiles of different technologies need to be taken into account. Certainty around costs and performance should be rewarded, but sometimes it is not.

The first point is critical; the simplest version of LCOE assumes that all electricity generated is of equal value. However, due to system constraints, peak loads and demand change rates, this is not true and the value of generation will vary over the course of each day. Given that peak electricity demand is more expensive to meet than more constant demand (as plants will operate for relatively shorter periods throughout the year), the value of electricity during these peak times is typically higher. As a result, plants that can ensure a higher share of their generation occurs during these peak periods will receive greater remuneration.

For renewables, when system peaks occur and the ways they coincide with different renewable power generation production profiles will have a large impact on the additional value over and above average system prices. In hot climates with high air conditioning loads, solar PV can help significantly reduce afternoon peaks and its production profile is quite complementary. However, it doesn't address

[10] The optimisation of the electricity system in the short run assumes a time frame when no new capacity can be added and is not relevant to the discussion in this report, which compares the costs of new capacity options.

Figure 2.9: Integration costs for solar PV in the European Union for between 2% and 18% of electricity generation with demand response



Source: Pudjinato, 2013.
Note: The lower range limit is for 2% solar PV penetration and the upper limit is for 18% solar PV penetration.

the typical early evening peak demand as families return to their homes and this will require a mix of technologies to meet those demands at lowest cost. Thus, relatively more flexible plants will more often have the opportunity to capture this extra value of meeting peak demand.

A couple of examples are useful to understand these points and to highlight the complex interactions as new capacity is added and the need for integrated system modelling. In California, time-of-use tariffs for electricity customers incentivise them to adjust to peak system constraints or the cost of generation. Solar PV's generation profile means that the value of the electricity generated by solar PV is 30% to 50% higher than what a flat tariff structure would imply (Borenstein, 2007). However, adding significant amounts of solar PV to the system will alter the timing of peak demands so that as solar PV penetration grows, the time of the net peak (after subtracting solar PV output) will shift. This can be addressed in a number of ways: by improving demand response; by adding storage to solar PV systems; or by other generating options that can meet these new peaks. CSP,[11] with its ability to add low-cost thermal energy storage, could be an important part of the solution to these emerging flexibility needs, despite higher LCOE metrics than some other renewable technologies today, but it is competing with rapidly falling battery costs for solar PV. Following the California example, the marginal value of additional CSP with storage at a 40% renewables target would be between USD 0.096 and USD 0.109/kWh, while the marginal value of new solar PV when already contributing about 14% of the total generation target of 40% (i.e. slightly more than one-third) would drop to only be between USD 0.032 to USD 0.047/kWh (Jorgenson, 2014). Thus, once a high level of penetration of variable renewables is reached, more flexibility will be rewarded.

[11] This would also be true to a different extent for other flexible renewable technologies such as geothermal and biomass for power.

Adding new power generation capacity to an electricity system has an impact on electricity flows and system costs; this is true for any type of power generation technology. The key impacts are:

» Impact of electricity flows across transmission networks, which may cause or alleviate transmission constraints or be absorbed without major issue.

» Impact on local distribution network flows, which may cause or alleviate distribution system constraints or be absorbed without major issue.

» Impact on overall system management, stability and reserve requirements.

Adding new power generation capacity will have an impact on electricity flows over the system depending on their location. Renewables have an advantage in this respect in that they are more modular and can be added in economic sizes (*e.g.* 5-20 MW) that are smaller than fossil fuels (where unit sizes are 250 MW or more) or nuclear, where economic sizes are one GW or more. This allows them to be more easily integrated into the grid and nodal pricing on the transmission grid can provide an economic incentive to locate them to alleviate grid constraints. The same types of issues play out at the distribution level, although the issues of dealing with distributed generation attached to the low voltage distribution network are somewhat different. In particular, some investments will be needed to allow for two-way flows where previously only consumption occurred and to manage flows at the distribution level.

In addition, spinning reserve requirements may be lower with renewables, as the loss of any single, relatively small wind farm or solar plant (e.g. due to the plant tripping offline, sub-station loss, etc.) will result in a smaller disruption than loss of larger blocks of fossil fuel or nuclear capacity. The system will still need adequate flexibility to deal with the variability of solar PV and wind generation, much like it needs to deal with demand changes, but the geographic dispersion and the smoothing effect of two different renewable resources and technologies can reduce this requirement.

A partial analysis of the additional costs of integrating significant levels of solar PV generation in Europe, taking into account capacity adequacy and reserves, upgrading of the main European Union (EU) transmission network, the cost of reinforcing the distribution network and the impact of solar PV on network losses (beneficial at low penetration rates), indicated average integration costs of around USD 0.02/kWh for 10% of EU generation from solar PV, rising to around USD 0.025/kWh for 18% of EU generation coming from solar PV. Taking a more holistic approach to integrating solar PV by including demand response as an additional source of flexibility would reduce these costs by an average of 20% (Figure 2.9). This also has to be put in context of today's retail electricity rates in the EU, which range from a low of around USD 0.11/kWh to USD 0.40/kWh and averaged USD 0.27/kWh in the first half of 2014.

The integration costs are lower and even negative for low levels of solar PV penetration in Greece and Italy, because the production profile of solar PV helps alleviate peak electricity demand. The difference between Greece and Italy in integration costs also highlights the need for system specific modelling, as the order of magnitude of savings at low levels of penetration and then costs at higher levels are very different.

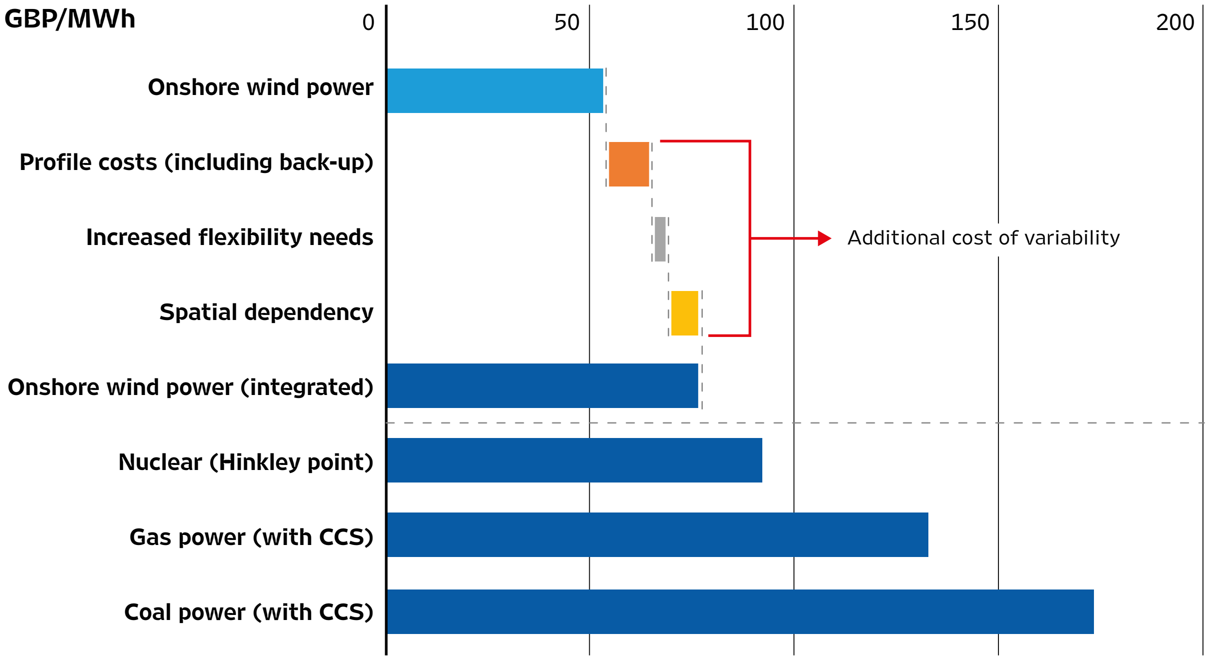
A range of studies have been undertaken that try to account for the additional benefits and/or costs of adding variable renewables to the electricity mix by extending the LCOE analysis beyond generation only. The drawback of many of these analyses is that they often simulate the system in a static way, or one that is not related to the overall policy context.[12] However, these analyses may provide useful insights for future analysis.

There is much debate about the additional system integration costs of variable renewables. It is important to note that all new capacity, not just renewable capacity, has an impact on the way the system operates and will impose costs and benefits on existing generators and the system as a whole. Solar PV and wind power are often suspected of significantly increasing system operation costs because of their variable nature. This misses the point that baseload nuclear and coal-fired plants lack the flexibility (either technically or from an economic perspective) to respond to the existing variation in demand and are supplemented by "mid-merit", "shoulder" or "peaking" plants that can meet this variability. These more flexible plants, typically gas- or oil-fired today, generally have lower installed costs and much higher fuel costs. Some will run for several thousand hours a year and others for just several hundred hours a year to meet exceptional peaks in demand.

In a system with higher shares of variable renewables, the inflexible plants will become more of a drag on the electricity system. The role of plants that operate at constant rates throughout the year will decline and greater value will be

[12] A common problem remains the tendency to simulate renewables penetration by a single technology, without taking into account the broader policy context. For instance, looking at system costs when raising the share of an individual renewable technology (e.g. to 15%), will yield very different system cost results than examining changes in overall system costs when meeting overall goals for renewable energy penetration (e.g. raising overall renewable shares to 50%). This can lead to bias in the comparison of analysis as the results of individual studies are typically not linear or additive, overestimating total costs.

Figure 2.10: The LCOE of onshore wind including integration costs, nuclear and gas-fired power plants with CCS



Sources: Grubb (1991), Hamidi et al. (2011) and Hirth et al. 2015.

Note: Generation cost data is based on the UK Department of Energy and Climate (DECC) calculator for low carbon scenarios (assumed discount rate of 10 %). For nuclear power, costs are estimated from the guaranteed strike price for the planned Hinkley Point C nuclear plant (GBP 92.5 per MWh for 35 years, fully indexed to inflation). Wind integration costs are estimated conservatively according to the higher cost values in Grubb (1991), Hamidi et al. (2011) and Hirth et al. 2015; assuming wind shares of 30-40%. For lower shares integration costs would be much less. Also, additional measures such as smart grid technologies, demand response, energy storage and more flexible generation technologies would reduce integration costs

placed on a heterogeneous mix of plants with more flexible capabilities. What is critical is that this mix of plants provides the lowest-cost solution for overall electricity generation.

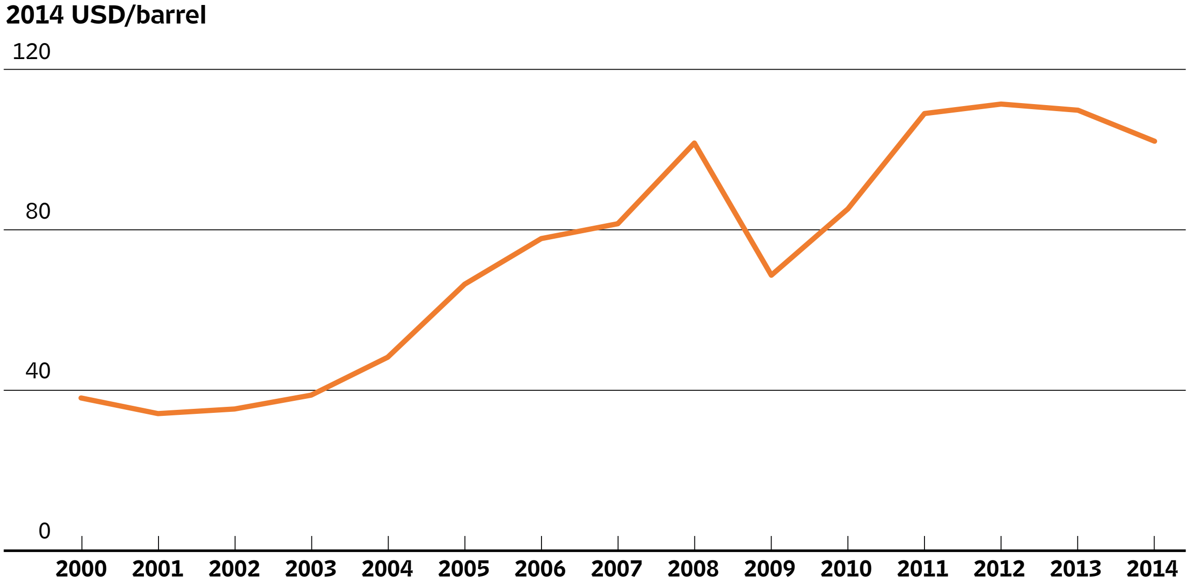
In 2013, Denmark, Germany and Spain had a generation share of renewable electricity of 56%, 25% and 42%, respectively, with at least half of power generation capacities being renewable. The examples of Denmark, Germany and Spain show that up to about 20% to 25% variable renewable energy (VRE), specifically solar PV and wind, in total annual electricity supply do not pose a major challenge and can be easily accommodated in most power systems. Higher VRE shares pose challenges and increasingly require rethinking of the power system operation and planning. Already at moderate average VRE shares, instantaneous penetration levels can become very high in some hours of a year, and VRE supply can sometimes even exceed electricity demand.

However, these challenges can be met and there is wide consensus that the challenges of VRE variability create no insurmountable technical barriers to high VRE shares, however, the specific properties of VRE cause additional costs at the system level (Sims et al. 2011, Milligan and Kirby 2009, Holttinen et al. 2011, Milligan et al. 2011, Katzenstein and Apt 2012, Ueckerdt et al. 2013, IEA 2014, Hirth et al. 2015).

Integration costs are not specific to VRE. In principle, every generation technology imposes additional costs on the power system. However, variable renewables have three characteristics that may require specific measures and additional costs to integrate these technologies into current power systems, they are:

» Geographic location: In large countries, increased investment in transmission and distribution lines might be required if the best renewable resources are located far from demand centres. In transmission networks, the resulting grid costs tend to be less than around USD 0.013/kWh of VRE at high wind shares of about 30% to 40% (DENA 2010, Holttinen

Figure 2.11: Brent Crude Oil Price (Annual Averages), 2000 to 2014



Sources: World Bank, 2015 and US EIA, 2015.

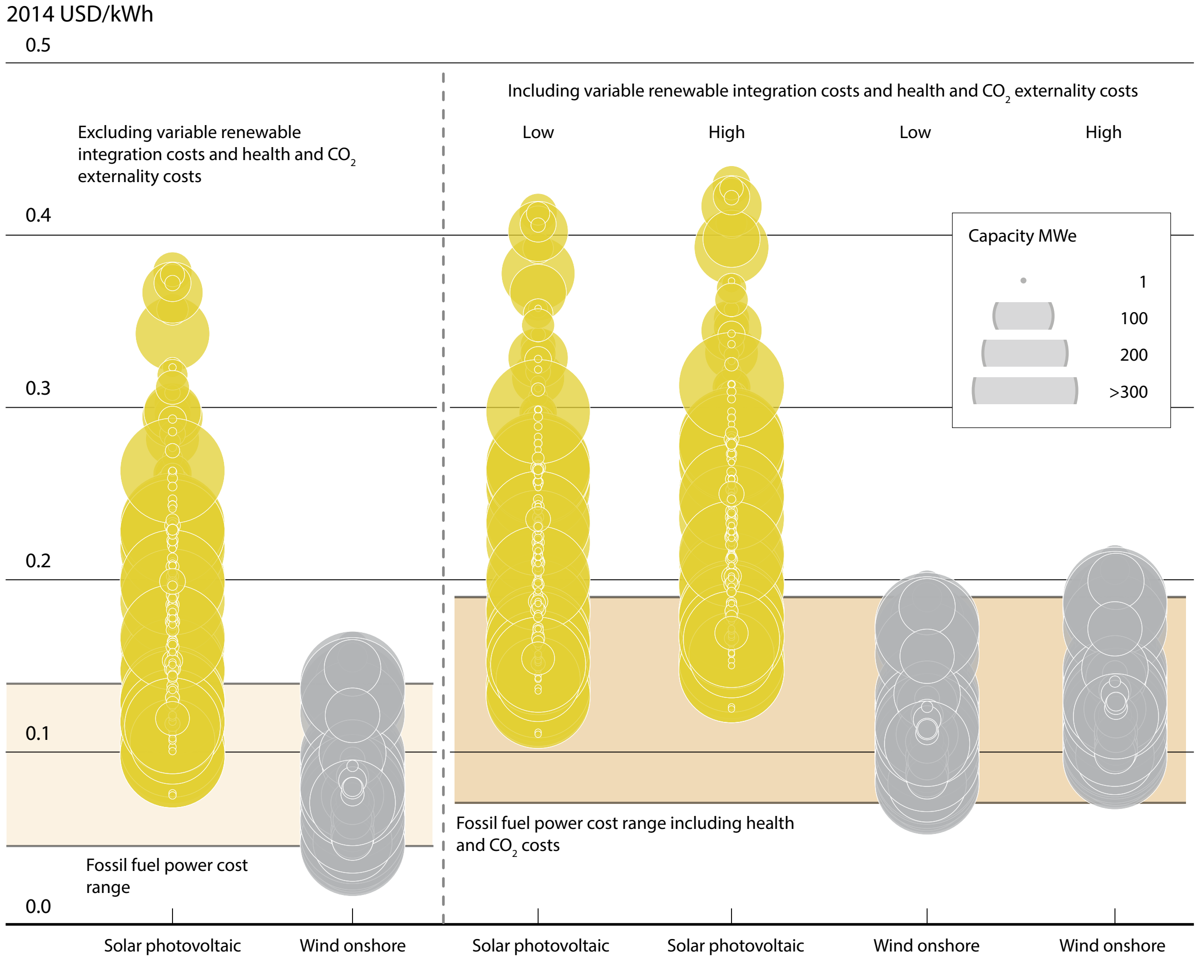
et al 2011, NREL 2012, Hirth et al. 2015). In distribution networks, small wind turbines or solar PV systems can actually decrease the costs of grid enhancement at low levels of penetration. The estimated savings in Europe for low levels of penetration are between USD 0.003 to USD 0.007/kWh, but costs increase to up to USD 0.012/kWh with VRE penetration levels above 15% (Pudjianto, et al. 2014).

» Unplanned short-term variability: If forecast VRE generation deviates from actual production in day ahead markets, bearing in mind that the electricity system has to be balanced in real-time to ensure voltage remains within limits (i.e. over seconds and minutes) additional spinning reserve will be required. Improved forecasting techniques and bundling VRE generation with hydropower or biomass can reduce these variability costs to very low levels, yet some unpredictability remains. Even though this impact receives much attention in the literature and public debate, the required flexibility costs USD 0.008/kWh even at high wind shares (Holttinen et al., 2011, IEA 2014; Hirth et al. 2015).

» Long-term variability: By definition, VRE doesn't provide an even level of generation over the year. The system therefore has to have in place sufficient capacity to meet demand when the sun isn't shining and the wind isn't blowing (VRE has a low so-called "capacity credit"). If the combination of VRE and this additional capacity has higher average system costs than a traditional system with baseload, mid-merit and peak plant, then costs may increase. These are sometimes referred to as profile costs and can range from USD 0.02 to USD 0.033/kWh at high wind and solar power shares of 30% to 40% (IEA, 2014; Hirth et al. 2015). Note that a mix of wind and solar PV significantly decreases these costs. This cost component can also be reduced by peak shaving through demand-side management (IRENA, 2013).

Taking into account the interaction of these factors, integration costs are estimated to range from negative or very small values for low levels of VRE penetration, but can rise to between USD 0.035 to USD 0.05/kWh for 40% penetration of VRE. These integration costs are simply a guide, as actual costs will vary significantly depending on system configurations and where the renewables are deployed. In a VRE-friendly power system consisting of flexible generation plants, flexible demand (including demand side management), and strong grids then costs will be much lower even at these high levels of penetration. Most importantly, as can be seen in Figure 2.10 and Figure 2.12, although VRE integration costs can increase the LCOE of renewables, they are still typically the lowest-cost solution for a low carbon future. That is before

Figure 2.12: The LCOE of variable renewables and fossil fuels, including grid integration costs (at 40% variable renewable penetration) and external health and CO_2 costs



Sources: IRENA Renewable Cost Database and IRENA, 2014.

taking into account that innovative grid operations and regulatory frameworks can significantly reduce grid integration costs by harnessing the existing technical flexibility potential.

Another important factor that needs to be taken into account when using LCOE as a metric is that it often isn't used in a way that takes into account the additional costs of unpredictable future prices for fossil fuels.[13] Renewable power generation technologies typically have relatively lower risk profiles than for fossil fuel plants, as most of their costs are known upfront and variable O&M costs typically evolve in predictable ways related to overall labour costs and inflation in the economy. This has important implications, because all else being equal, more predictable costs and hence rates of return should expect lower rates of return than risky investments. Investors should in principle demand higher rates of return to allow for unpredictable future costs associated with fossil fuel prices and CO_2 prices (EWEA, 2009). What this means in practice is that the discount rates used for discounting future fuel expenditures back to current values are too high and don't adequately take into account the fuel price risk.

Greater uncertainty about future fuel prices means that these future costs should not be discounted at the same rate as more predictable cash flows. For gas prices, the historical fuel price variation is significant and using an appropriate discount rate to take into account these risks, rather than a single discount rate for capital and fuel expenditures, increases the LCOE of a gas-fired power plant by as much as 85% (EWEA, 2009). However, even this approach is limited in that it is still capable of

[13] The important issue here is the difference between risk and uncertainty. In economic parlance, risks are characterised by some statistical relationship that allows investors to price in the variability due to risk and demand an appropriate rate of return. Uncertainty or unpredictability can't be systematically accounted for and can lead to sub-optimal decisions, or deferment of investment in the hope of learning more.

underestimating the true costs of fossil fuel price volatility over the life of the project if volatility over the period departs significantly from the long-run average.

These issues should be taken into account when comparing the LCOE of renewable technologies to today's costs for fossil-fuel fired electricity generation technologies. For a gas- or coal-fired power plant with an economic life of 25 to 30 years, these fossil fuel price risks can be very significant. This is particularly true for natural gas, as forward markets don't come close to providing generators the opportunity to hedge their future fuel costs for the life of the plant. Coal-fired power plants that have captive sources of coal can insulate themselves to a greater extent, but with an increasing percentage of new coal-fired plant build being based on imports, price volatility for these plants remains a real risk.

Falling oil and gas prices at the end of 2014 therefore don't substantially alter the emerging competiveness of renewables. They may or may not be a short-term decline, but the market doesn't know with any certainty what the trend will be for the life of a new power plant built in 2015. With supply and demand for oil and gas relatively evenly balanced, price swings can be large and sudden in either direction. It is also important to remember that Brent oil priced at USD 50 or 60/barrel is not cheap compared to what was the norm 10 to 15 years ago (Figure 2.11) and a similar story is true for natural gas prices in Europe and Japan. As a result of future price uncertainty and volatility, relatively low current oil prices do not fundamentally alter the conclusion that renewables are the economic solution off-grid for the life of the project. At the same time, the growing decoupling of natural gas prices from oil prices means that lower oil prices will not necessarily have a large impact on natural gas prices, as these are increasingly driven by regional market fundamentals.

From electricity system costs to societal costs

LCOE is often formulated based on costs to individuals and corporations and doesn't factor in costs arising from market failures. In the energy sector, the largest externalities that are typically not priced by the market are the local and global environmental and health damages caused by fossil fuel use. These costs are not borne by the energy supplier or consumer, but they are paid for by society as a whole, for example through higher healthcare costs, increased natural disaster costs, lower labour productivity, reduced life expectancy and premature deaths.

There has been extensive analysis of the external costs of negative health impacts associated with outdoor air pollution from fossil fuel combustion and indoor air pollution from the use of coal and traditional biomass. Significant analysis has looked at the premature deaths attributable to urban outdoor air pollution due to energy-related emissions from vehicles and from power generation. Other important external costs, such as damage to ecosystems due to air pollution or noise from urban transport, have received somewhat less attention and are more difficult to analyse (IRENA, 2014).

The impacts are hugely significant. About 1.1 million people – mainly women and children – are dying annually from illnesses related to indoor air pollution from the use of different types of solid fuels. A further 0.9 million people per year die of indoor air pollution from the inefficient, poorly ventilated combustion of traditional biomass in the home. In Africa, pneumonia attributable to cooking smoke kills 500 000 children younger than five years old each year.

Another 1.5 million people die each year from pollution (mainly particulate matter) caused by urban transportation. According to the World Health Organisation (WHO, 2008), coal-related air pollution deaths have reached 1 million people per year. China accounts for half of this total.

The indicative external cost range associated with these human health impacts is estimated at USD 325-825 billion per year worldwide in 2010 (IRENA, 2014). This includes the effects for emissions of particulate matter (PM 2.5), mono-nitrogen oxides (NOx) and sulphur dioxide (SO_2) from fossil power generation, as well as PM 2.5 and NOx emissions from light-duty vehicles and indoor air pollution associated with domestic use of coal and traditional biomass.

Added to these costs are the external costs associated with carbon dioxide (CO_2) emissions stemming from the costs of climate change. The range of costs associated with climate change externalities is high, reflecting uncertainty about the rate and severity of the negative impacts of climate change under different scenarios. To manage this uncertainty, IRENA has analysed the impact of the estimated avoided external costs of CO_2 emissions for 26 countries, assuming external costs of USD 20/tonne of CO_2 and also USD 80/tonne of CO_2 to allow for uncertainty over the potential costs of climate change.

The combined costs from the health costs of fossil fuel use and CO_2 emissions increase average power generation costs by at least USD 0.01/kWh for countries with electricity generation systems that are relatively less carbon-intensive and up to USD 0.13/kWh for systems that are carbon-intensive (IRENA, 2014). This increases costs for fossil fuels from a range of USD 0.045 to USD 0.14/kWh a range of USD 0.07 to 0.19/kWh, given that the lowest values without external costs are some of the most polluting technologies.

Figure 2.12 presents the LCOE by project ranges for the VRE technologies solar PV and wind onshore compared to fossil fuel-fired electricity generation costs. It also then presents the LCOE for solar PV and wind onshore including VRE costs assumptions for 40% VRE of USD 0.035 to USD 0.05/kWh and the fossil fuel-fired cost range including the external health and climate change costs of their use. When the local and global environmental costs of fossil fuels are taken into account, grid integration costs look considerably less daunting, even with variable renewable sources providing 40% of the power supply. In other words, with a level playing field and all externalities considered, renewables are fundamentally competitive. Accounting for the very real external costs that fossil fuels currently don't pay for demonstrates why renewables need support to level the playing field. When externalities are taken into account, renewables are virtually always the cheapest option for society.

3 GLOBAL RENEWABLE POWER MARKET TRENDS

The year 2013 was a landmark year for renewables. In 2013, despite inconsistent policymaking and weak economic growth, overall capacity additions reached a new record high of more than 120 gigawatts (GW), with new solar deployment exceeding wind for the first time. Figures for 2014 are still not finalised, but new capacity additions for both solar photovoltaic (PV) and wind are estimated to have exceeded 40 GW each.

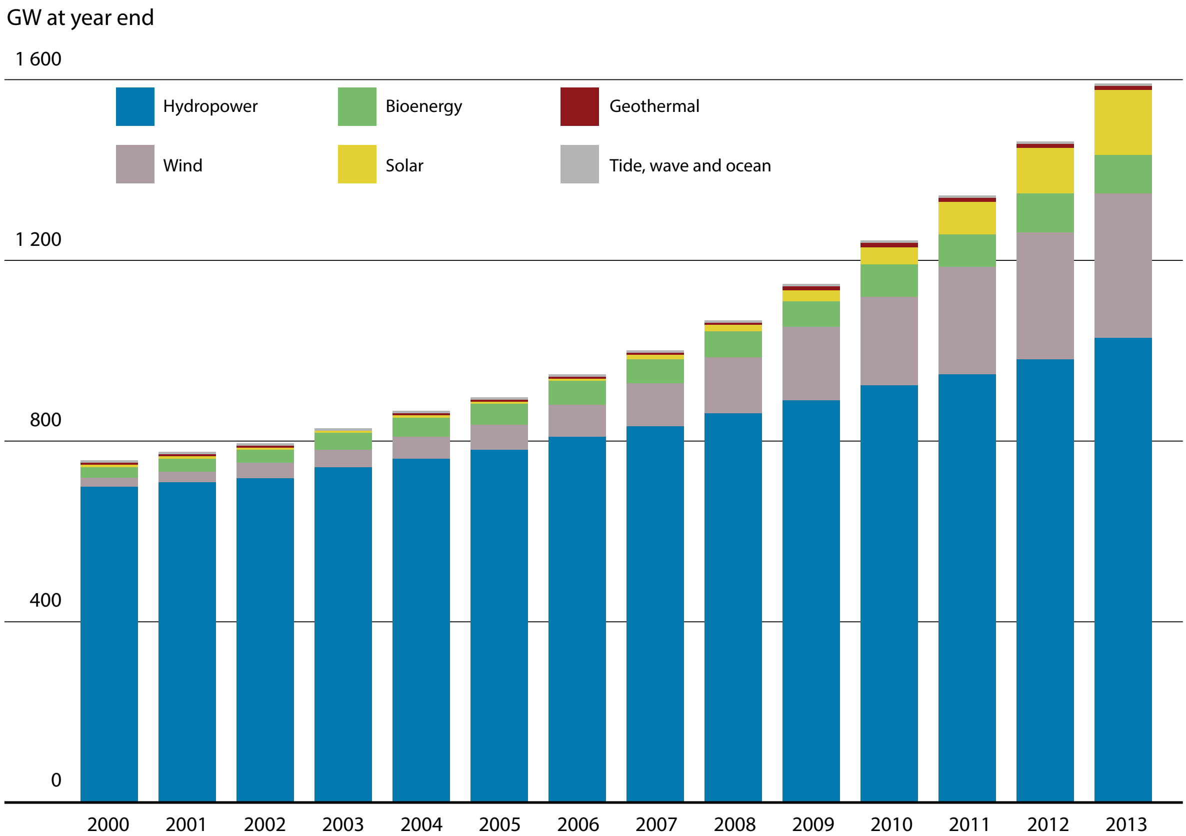
Renewable energy markets are increasingly deeper and broader than in the past and fluctuations in one market in recent years have often compensated movements in others. Improving cost competitiveness continues to drive the deployment of both wind and solar technologies and lies behind this maturing of renewable markets.

However, markets for renewable power generation technologies are still too narrow, relative to their economic potential. New and deeper markets need to be unlocked if the world is to shift to a truly sustainable power generation sector before dangerous climate change becomes inevitable.

Cumulative installed renewable power generation capacity at the end of 2013

At the end of 2013, renewable power generation capacity had risen to around 1 560 to 1 580 GW, excluding pumped storage hydro. Although hydropower still dominates this total, the rapid growth in wind and solar PV means that hydro's share is slowly declining. However,

Figure 3.1: Global cumulative installed renewable power generation capacity, 2000 to 2013



Source: IRENA

the rate of decline is slower for hydro's share of renewable power generation than for its capacity, as the capacity factors of wind and solar PV are on average lower than hydropower.

Hydropower capacity, excluding pumped storage (all hydropower data in this chapter exclude pumped storage unless specifically stated) reached around 1 025 GW at the end of 2013 – representing approximately two-thirds of all renewable power generation capacity – after strong growth in new capacity added in 2013 (Figure 3.1). Hydropower accounted for around 16% of the world's electricity and around 75% of the world's renewable electricity in 2013. Pumped storage hydro capacity now stands at somewhere between 135 and 157 GW, of which approximately 25 GW have been identified as mixed plants that are also conventional resevoir-based hydropower dams (GlobalData, 2014 and REN21, 2014).

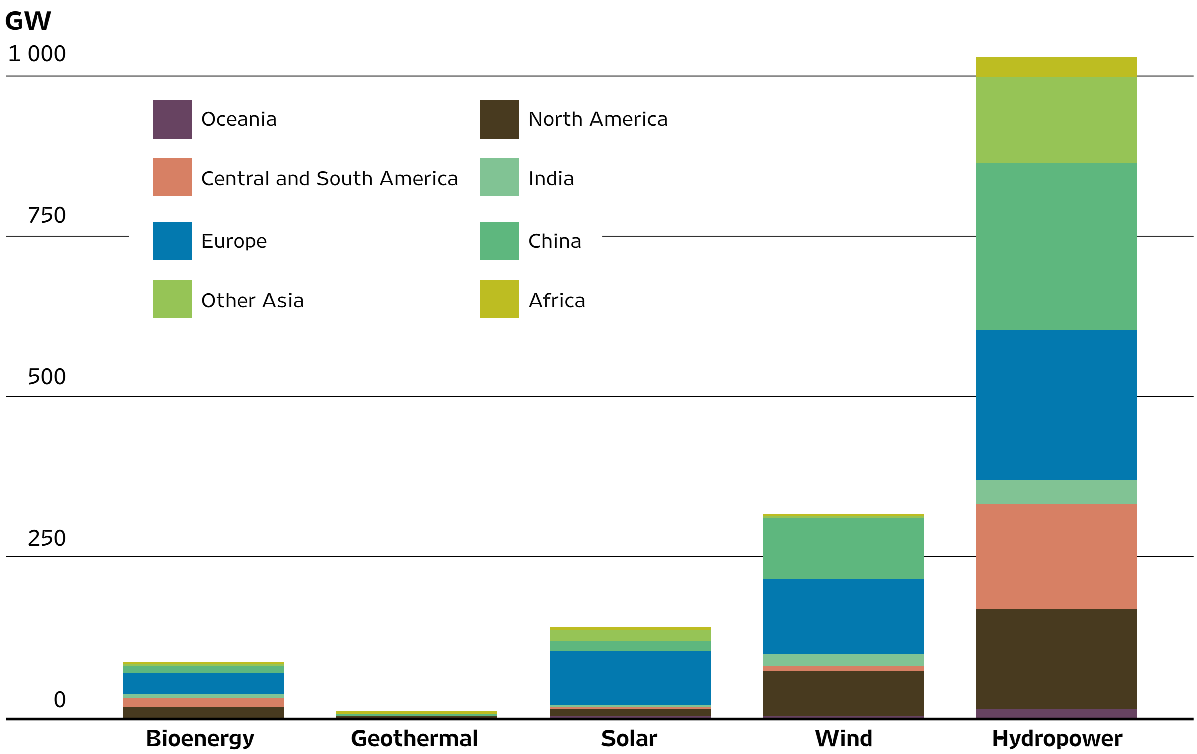
China, Brazil, the United States, Canada, the Russian Federation and India have the largest hydropower generation capacity. China accounts for just over one-quarter of global installed hydropower capacity, Europe for 23%, Central and South America for 16%, North America for 15% and Asia, excluding China, for 13%.

The installed capacity of non-hydro renewables reached around 560 GW at the end of 2013, with wind accounting for 318 GW (20% of the total, of which offshore wind provided 7 GW), solar PV accounting for 139 GW, biomass power generation capacity for 87 GW, geothermal for 12 GW and concentrating solar power (CSP) for 3.4 GW.

Globally, Europe accounted for 30% (473 GW) of total installed renewable power generation capacity at the end of 2013. China, with 377 GW installed at the end of 2013, accounted for 24%, while North America accounted for 16%, with 258 GW of installed renewable capacity (Figure 3.2).

At the end of 2013, Europe had the largest installed capacity of biomass for power generation (35 GW), solar PV (80 GW), onshore wind (112 GW) and CSP (2.3 GW). "Other Asia" (excluding China and India) accounts for the largest share of geothermal installed capacity (4 GW), with North America accounting for the next largest share (3.4 GW). Europe and Other Asia each account for around 250 MW of the global tidal, wave and ocean energy

Figure 3.2: Global cumulative installed renewable power generation capacity by technology and country/region, 2013



Source: IRENA

Table 3.1: Top five countries for cumulative installed renewable power generation capacity by technology, 2013

Biomass for power		Geothermal		Hydropower		Offshore Wind	
United States of America	12.7	United States of America	3.4	China	258.5	United Kingdom	3.7
Brazil	11.5	Philippines	1.9	Brazil	86.0	Denmark	1.3
China	8.5	Indonesia	1.3	United States of America	82.8	Germany	0.9
Germany	8.2	New Zealand	0.9	Canada	75.5	Belgium	0.6
India	4.7	Mexico	0.8	Russian Federation	49.0	China	0.4
Onshore Wind		**Solar Photovoltaic**		**Solar CSP**		**Tide, Wave & Ocean**	
China	91.0	Germany	36.3	Spain	2.3	Republic of Korea	0.3
United States of America	60.2	China	18.6	United States of America	0.9	France	0.2
Germany	33.8	Italy	17.9	United Arab Emirates	0.1	Canada	0.0
Spain	23.0	Japan	13.6	India	0.1	United Kingdom	0.0
India	20.2	United States of America	12.1	Algeria	0.0	China	0.0

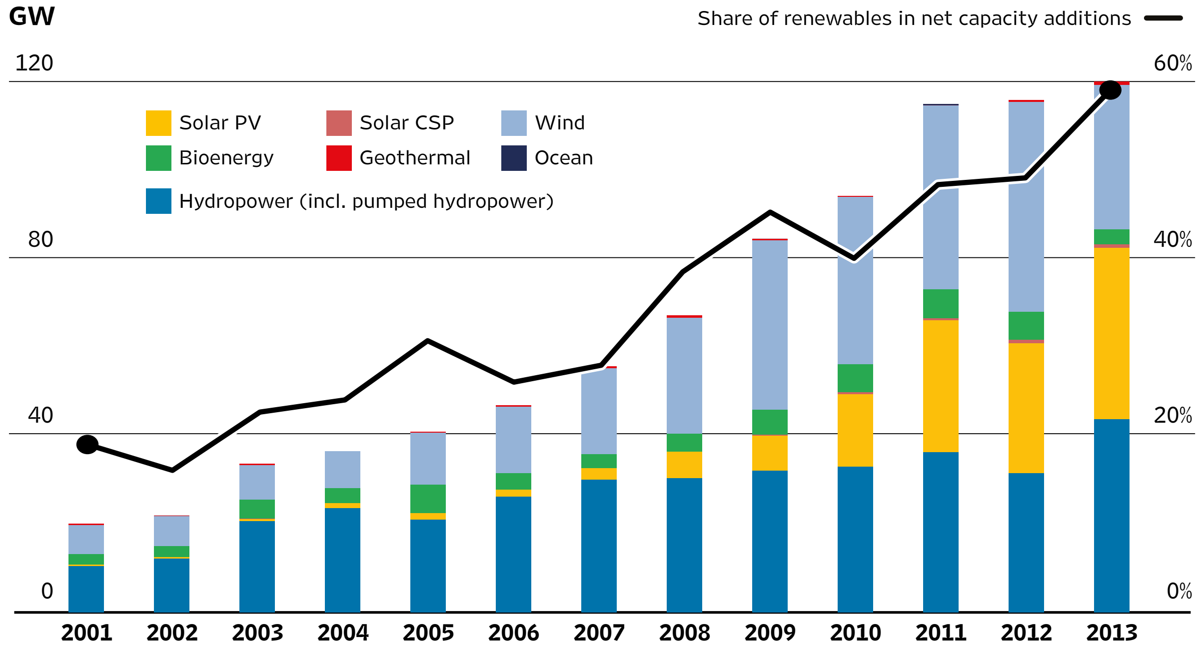
capacity. This capacity stood at around 526 MW at the end of 2013, virtually all of that capacity being tidal.

Despite the fact that policy uncertainty in 2013 affected a number of wind markets, notably the United States, wind capacity rose to around 318 GW at the end of 2013, with 7.4 GW of this capacity being offshore. After hydropower, wind capacity is the next largest renewable contribution to global installed power generation capacity. China has the world's largest installed onshore wind capacity for a single country and at around 91 GW accounts for 29% of global installed capacity. This has been driven by new capacity additions of between 13 GW and around 18 GW per year since 2009. The traditional drivers of wind deployment in Europe and the United States account for second through fourth place for onshore wind, while the rapidly growing markets in India mean that it now has the fifth largest global installed capacity of wind. Offshore wind capacity is dominated by the United Kingdom, which has half of the world's total installed capacity.

Solar PV, with 139 GW of installed capacity at the end of 2013, is the third largest source of renewable power generation capacity. Germany, the pioneer in solar PV deployment, retained the largest share of global capacity (27%), but based on current trends it will be rapidly overtaken by China, which had the second largest capacity – of 18.6 GW – installed by the end of 2013. Italy, Japan and the United States round out the top five countries with respect to solar PV deployment. Of these three, Japan and the United States have the most dynamic markets and Japan will soon overtake Italy for third place.

CSP deployment is still at a very early commercial stage and total installed capacity at the end of 2013 was around 3.4 GW, with around two-thirds of this capacity located in Spain and approximately another quarter in the United States. Spain and the United States will remain the largest sources of CSP capacity in the near future, despite growing deployment in coming years in a number of countries, including, but not limited to, India and South Africa in particular. With strong capacity additions in 2014, the total installed deployment of CSP at the end of 2014 is estimated to have reached 5 GW.

FIGURE 3.3: ANNUAL NEW RENEWABLE POWER GENERATION CAPACITY ADDITIONS BY TECHNOLOGY INCLUDING PUMPED STORAGE, 2001 TO 2013



Source: IRENA and GlobalData, 2014

Globally, the distribution of biomass for power generation is not as concentrated as wind or solar, with the top five countries accounting for just over half of total installed capacity at the end of 2013. The United States (15%), Brazil (13%), China (10%), Germany (9%) and India (5%) have the largest concentrations of biomass for power generation. Geothermal capacity is concentrated in a few countries as well. The United States (29%), the Philippines (16%), Indonesia (11%), New Zealand (8%) and Mexico (7%) have the largest installed capacity of geothermal power generation. Tidal, wave and ocean energy make only a small contribution to global power generation capacity today, with virtually all capacity concentrated in tidal projects in France and the Republic of Korea.

ANNUAL NEW RENEWABLE POWER GENERATION CAPACITY ADDITIONS BY YEAR

The years 2013 and 2014 have seen record growth in renewable power generation capacity. In 2013 new renewable capacity additions reached a new record of at least 120 GW, with strong growth from hydropower and solar PV more than offsetting a small decline in new wind capacity additions. Solar PV deployment grew to around 39 GW for the year, led by strong growth in China and Japan in particular.[14] Hydropower was also estimated to have had a strong year, with between 40 and 48 GW of new capacity added (IRENA and GlobalData, 2014).[15]

New wind deployment was slightly lower in 2013 than in 2012 at 35.5 GW, as policy uncertainty delayed projects, notably in the United States (GWEC, 2014 and WWEA, 2014). However, wind is expected to bounce back, and 2014 looks likely to be another year where wind deployment exceeds 40 GW.

With firmer policy support, new solar PV installations look set to have exceeded 40 GW in 2014, with some estimates closer to 50 GW in 2014 (BNEF, 2014; IRENA analysis and Photon Consulting, 2014).

[14] Some uncertainty still exists about the exact total; although data are available for most major markets, total deployment estimates vary between 37 GW and 39 GW (EPIA, 2014; BNEF, 2014 and Photon Consulting, 2014).

[15] This exceeds early estimates of around 40 GW added in 2013 (REN21, 2014). However, some uncertainty remains about net capacity additions for hydropower in 2013 due to the time lags in full reporting of net capacity changes for the large number of existing dams. There are over 5 800 dams over 15 m in height used for hydropower worldwide (International Commission on Large Dams, 2014) and 65 000 small hydropower installations in China alone (UNIDO and ICSHP, 2014), making timely collation and reporting of data difficult.

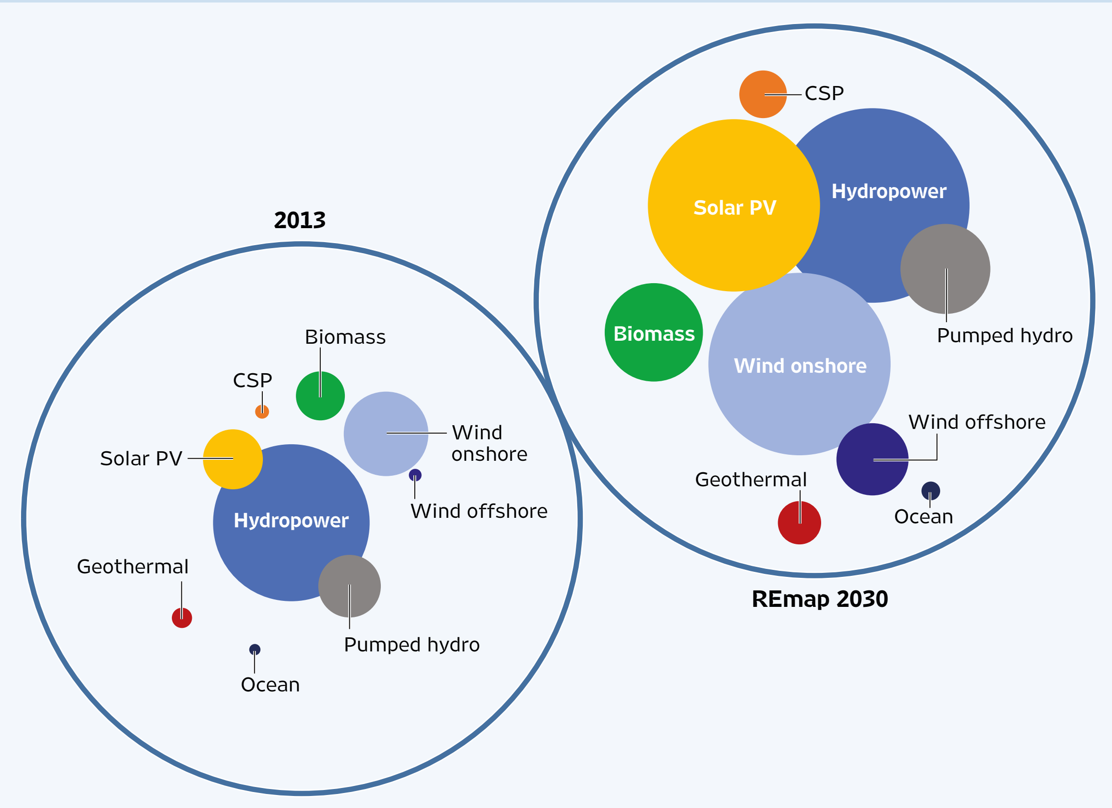
BOX 3.1

What the future holds: Renewable power generation in 2030 in IRENA's REmap analysis

IRENA's REmap analysis, which examines how to double the share of renewables by 2030, highlights just how rapidly the power sector landscape is changing (IRENA, 2014). At the end of 2013, hydropower dominated total cumulative installed renewable capacity, with around 1 025 GW of capacity (Figure 3.2). Wind power contributed around 318 GW and solar PV capacity reached around 139 GW of cumulative installed capacity.

To double the share of renewables, although hydropower will grow to 1 600 GW in 2030 in the REmap 2030 case, wind capacity growth is so rapid that wind power capacity will exceed hydropower by 2030, with 1 630 GW of installed capacity and 231 GW of that total offshore. Solar PV growth will exceed that of wind, but from a lower base, to reach 1 250 GW in 2030, with CSP growing to 83 GW in 2030 in the REMAP scenario. With significantly more untapped economic potential than hydropower, wind and solar will continue to outpace hydropower growth and grow in importance in terms of installed capacity and, in the case of wind, electricity generation as well.

Figure 3.4: Total cumulative installed renewable capacity, 2013 and REMAP 2030

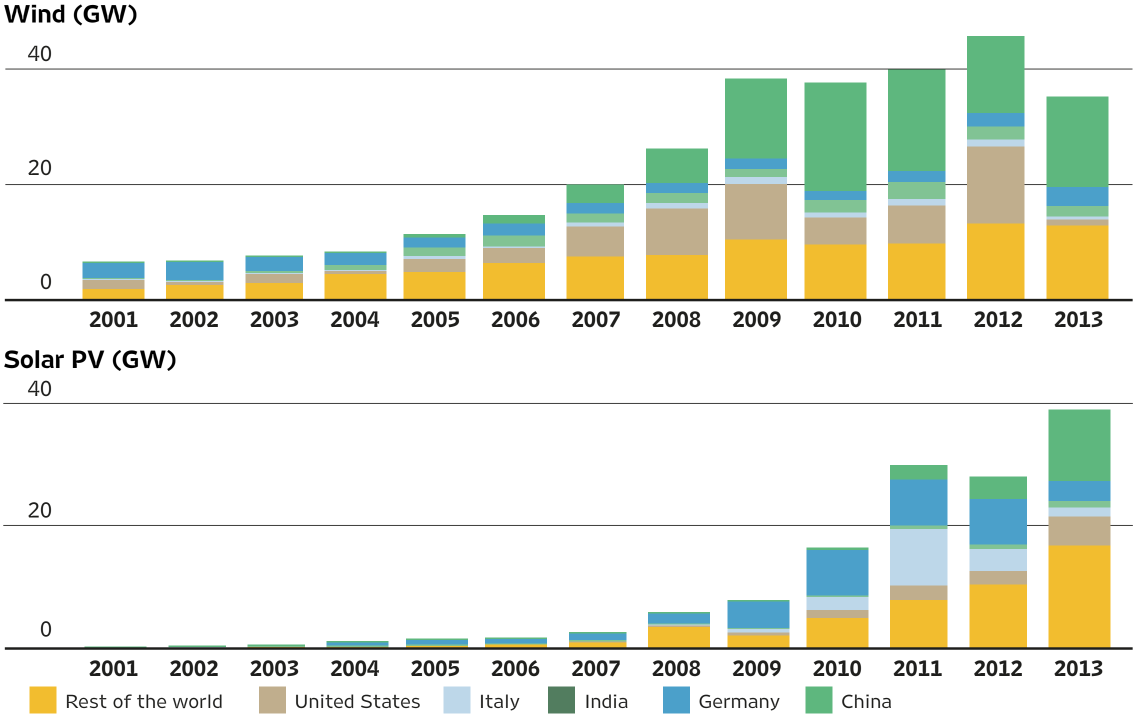


Source: IRENA statistics and IRENA, 2014

Renewable energy capacity additions have risen six-fold between 2001 and 2013, and have accounted for around half of all new power generation capacity added each year from 2011 to 2013. New renewable capacity additions have been around 100 GW per year or more since 2010.

In that time, annual new solar PV capacity additions have grown from insignificant levels to around 39 GW in 2013, representing around one-third of new renewable capacity additions and 19% of all new capacity additions in 2013 globally.

Figure 3.5: Annual new capacity additions for wind and solar PV, 2001 to 2013



Source: IRENA

New annual wind power capacity additions grew by around 450% between 2001 and 2013, from 6.5 GW to 35.5 GW, and with projections for 2014 of at least 40 GW (BNEF, 2014; WWEA, 2014 and IRENA analysis) new wind power additions could be up to six or seven times higher in 2014 than in 2001. In 2013, new wind capacity additions constituted 27% of total renewable additions and 17% of total new capacity additions worldwide.

In 2013, China added the most new capacity for hydropower (30 GW), onshore wind (16 GW) and solar PV (13 GW). China's support for solar PV since 2011 has spurred growth in domestic solar PV deployment and China is now the leading country for new capacity additions of renewable power generation technologies. In 2013, China is estimated to have accounted for as much as 45% of total new capacity additions of renewable power generation technologies worldwide.

The global wind power market was essentially flat in 2009 and 2010 as high wind turbine prices and economic uncertainty slowed growth. 2011 and 2012 saw new capacity additions of 40 GW and 45 GW, respectively. New installed capacity dropped in 2013 to 35.5 GW of new capacity added, due in large part to a rush to add new capacity in 2012 in the United States before the scheduled expiry of the production tax credit for wind in that country. New capacity additions dropped to just 1.3 GW in 2013 in the United States, a similar experience to what was seen in 2009/2010 due to the same circumstances, but on a more extreme scale.

In 2013 this meant the United States dropped out of the top five countries for newly installed capacity additions (Figure 3.5 and Table 3.2). China accounted for 44% of global wind power installations in 2013, installing 16 GW. In 2013, the European market added around 12 GW of new capacity, down from 12.4 in 2012. Most drastic was the reduction in new installations for North America, which went from 14.3 GW in 2012 to 2.7 GW in 2013 due to the decline in new capacity additions in the United States.

Onshore wind still dominates new capacity additions for total wind and accounted for around 98% of all new wind capacity in 2013. However, the offshore wind market is growing rapidly, with around 1.9 GW added in 2013. The total global installed capacity of offshore wind reached 7.4 GW at the end of 2013 and with an estimated 1.2 GW added in 2014 may have reached 8.5 GW by the end of 2014.

BOX 3.2

Cumulative installed capacity and new capacity additions in 2013 per capita

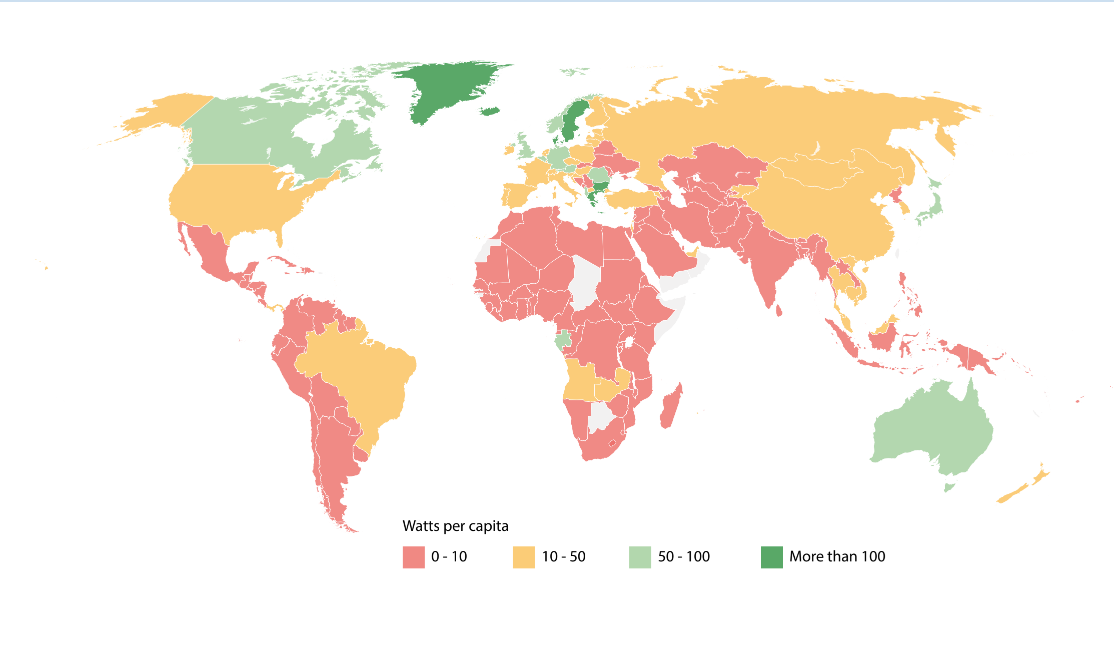
An alternative method of looking at both new capacity additions and total cumulative installed capacity of renewable power generation technologies is to examine their per capita values by country. This yields a significantly different view of the leading countries in terms of renewables deployment.

Using these metrics, Iceland emerges as a renewable energy powerhouse, with 8.2 MW of renewable electricity per 1 000 inhabitants, having added 341 kW per 1 000 inhabitants of new renewable power generation capacity in 2013 (Figure 3.6).

Norway, Sweden, Canada and Austria all also have more than 2 MW of renewable capacity per 1 000 inhabitants. For cumulative installed capacity per capita in all of these top five countries, it is their large hydropower resources relative to modest populations which set them apart. However, even excluding hydropower from these calculations, Iceland remains the leading country per capita due to that country's geothermal developments, while Sweden only drops from third to fourth place due to its significant wind and biomass for power deployment. What is interesting, but not surprising, is that Denmark, Germany and Spain appear in places two, three and five.

In terms of newly installed capacity per capita in 2013, Iceland is followed by Bulgaria (170 kW/per capita), Denmark (139 kW/per capita), Greece (111 kW/per capita) and Sweden (105 kW/per capita).

Figure 3.6: Annual new capacity additions of renewable power per capita, 2013



Source: IRENA and World Bank, 2014

Table 3.2: Top five countries for new installed renewable power generation capacity by technology, 2013

Biomass for power		Geothermal		Hydropower		Offshore Wind	
Brazil	1.5	Turkey	0.1	China	29.9	United Kingdom	0.7
United Kingdom	0.7	New Zealand	0.1	Turkey	2.7	Germany	0.6
Germany	0.6	United States of America	0.1	Vietnam	2.4	Denmark	0.3
China	0.5	Kenya	0.0	France	1.8	Belgium	0.2
Italy	0.5	Philippines	0.0	Brazil	1.7	Sweden	0.0

Onshore Wind		Solar Photovoltaic		Solar Thermal	
China	15.7	China	12.9	Spain	0.3
Germany	2.8	Japan	2.8	United States of America	0.4
India	1.7	United States of America	1.7	United Arab Emirates	0.1
United Kingdom	1.6	Germany	1.6	India	0.1
Canada	1.6	Australia	1.6	Algeria	0.0

Source: IRENA

New solar PV capacity soared in 2013 to around 39 GW as markets in China, Japan and the United States showed strong growth. 2013 represented a seismic shift in new solar PV capacity deployment, as leadership for deployment shifted from Europe to the Asia-Pacific region. China, Japan, the United States and Australia together accounted for around two-thirds of new capacity additions in 2013 (Table 3.2). This stands in contrast to 2012, when Europe added around 59% of total new capacity. With the German and Italian new capacity additions expected to be lower again in 2014 than in 2013, the trend towards market growth being driven by the Asia-Pacific region will be confirmed in 2014.

Newly installed CSP capacity in 2013 totaled around 0.9 GW, with the United States, Spain, the United Arab Emirates and India adding the most new capacity. The outlook for CSP remains delicate as the regulatory environment in Spain, a major driver of growth in recent years, is currently significantly less favourable than in previous years. Growth will diversify somewhat, but most growth will come from the United States in the next few years as significant new capacity is either committed or planned.

New capacity additions of biomass for power generation were slightly lower, at 5.5 GW, in 2013 than in 2012. Brazil, the United Kingdom, Germany, China and Italy led the way in 2013, adding a combined total of 3.7 GW, or around two-thirds of the total for 2013.

4 WIND POWER

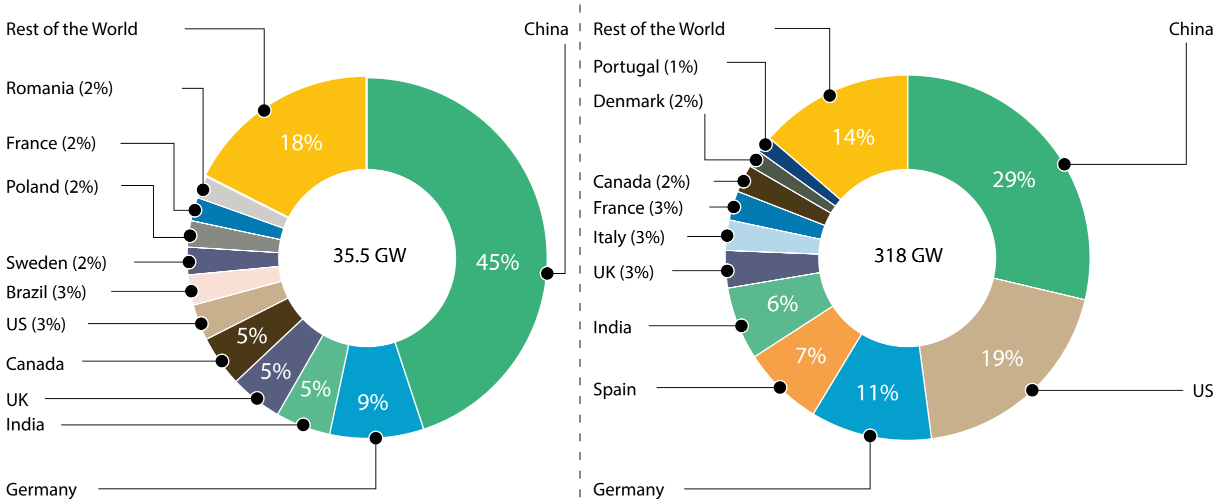
	2010		2013		2014		2010-2014 (% change)	
	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore
New capacity additions (GW)	1.0	37	2.0	33	1.2	40+	n.a.	n.a.
Cumulative installed capacity (GW)	3.2	193	7.4	310	8.6	350+	169%	81%
Weighted average installed cost ranges (2014 USD/kW)	3 700 – 5 600	1 330 – 3 060	2700 – 6 530	1 340 – 2 330	2 700 – 5 070	1 280 – 2 290	-9% to -27%	-4% to -25%
Weighted average LCOE range (2014 USD/kWh)	0.10 – 0.32	0.06 – 0.13	0.13 – 0.20	0.06 – 0.12	0.10 – 0.21	0.06 – 0.12	n.a.	-7% to -12%

Notes: 2014 deployment data are estimates. n.a. = data was not available or not enough data to provide a robust estimate. Offshore wind cost ranges are for all projects. Onshore wind cost ranges are for regional weighted averages.

Highlights

- Onshore wind is now one of the lowest-cost sources of electricity available, with weighted average LCOE by region of between USD 0.06 to USD 0.09/kWh.
- The best wind projects around the world are consistently delivering electricity for USD 0.05/kWh without financial support.
- Technological improvements at the same time as installed cost declines mean that the LCOE of onshore wind is now within the same cost range, or even lower, than for fossil fuels.
- Wind turbine prices in developed countries have fallen by around 30% since their peak in 2008/2009, while Chinese wind turbine prices fell by 35% from their peak in 2007.
- The regional weighted average installed costs for onshore wind range from around USD 1 280 to USD 2 290/kW. China and India have weighted average installed costs 35% to 44% lower than in other regions.
- The installed costs and the LCOE of offshore wind projects has stabilised, after rising through much of the last decade. Cost reductions are expected by project developers out to 2020, but offshore wind will remain more expensive than onshore.

Figure 4.1: New capacity additions in 2013 and cumulative installed capacity at the end of 2013 by country.



Source: IRENA Renewable Cost Database

Introduction

Wind power technologies are differentiated based on the axis of the wind turbine – vertical or horizontal – and their location – onshore or offshore.[16] The amount of power generated by a wind turbine is predominantly determined by the nameplate capacity (in kW or MW), the intensity of the wind resource, the height of the turbine tower and the diameter of the rotor.

The main factors driving the evolution of the levelised cost of electricity (LCOE) of wind power systems are capital costs, financing costs, operation and maintenance (O&M) costs and the expected annual energy production. The cost of wind power must take into consideration a careful assessment of all of these components over the life of the project. The following sections look at the latest trends for these LCOE drivers.

Wind power deployment

Total installed wind capacity reached 318 GW globally by the end of 2013 (IRENA Database, 2014). Cumulative installed capacity has increased by around one-fifth per year for a decade. China has the largest share of installed wind capacity – 29% at the end of 2013. It is followed by the United States (19%), Germany (11%), Spain (7%) and India (6%).

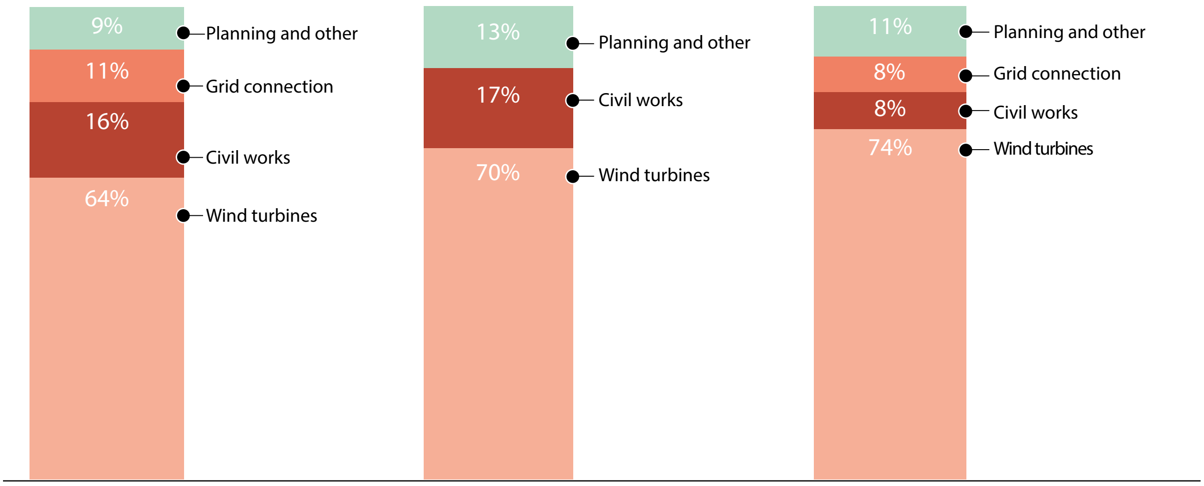
[16] *For the utility-scale market horizontal axis turbines are used exclusively.*

China accounted for around 45% of new annual capacity additions in 2013, followed by Germany with 9%, Canada, India and the United Kingdom, each with 5% of the total new capacity added in 2013 (Figure 4.1). The year 2013 was the first year since 2000 in which global new capacity additions for wind were lower than the previous year (by 24%). Policy uncertainty in key European markets and the United States was the main driver behind this slowing in growth in 2013. However, the wind market is set for a recovery in 2014, as new capacity added in 2014 looks set to be at least 40 GW and may be even higher (BNEF, 2014b; WWEA, 2014). Depending on the final figures, new capacity additions in 2014 could be 18% to 40% higher than in 2013. China, the United States, India and Germany will account for most of this installed capacity. However, Canada, Brazil and Mexico are expected to have installed record capacities in 2014 (BNEF, 2014b). Thus, it is expected that global wind installed capacity rose to at least 360 GW at the end of 2014 (BNEF, 2014b and GWEC, 2014).

Wind power capital costs

Wind turbines (including towers and installation) are the main cost item in developing a wind project. At the upper end of the cost range, wind turbines can account for as much as 84% of the total installed cost for onshore wind farms, although higher values are possible (Table 4.2). The capital

FIGURE 4.2: COMPARISON OF ONSHORE WIND FARM'S INSTALLED COST BREAKDOWN



Sources: Blanco, 2009; E. on Climate & Renewables, 2013; and UNFCCC CDM Database, 2014

costs of a wind power project can be distilled into the following major categories:

» Turbine cost: This includes rotor, blades, gearbox, generator, power converter, nacelle, tower and transformer;

» Civil works: This includes construction costs for site preparation and the foundations for the towers;

» Grid connection costs: This includes transformers and sub-stations, as well as the connection to the local distribution or transmission network;

» Planning and project costs: These can represent a significant proportion of total costs;[17] and

» Other capital costs: These include the construction of roads, buildings, control systems, etc.

The most important developments in the wind market are related to technology improvements to ensure a range of wind turbine options are available that allow project developers to choose the designs that yield the lowest LCOE given the local site characteristics. Original equipment manufacturers (OEMs) are therefore focusing on the following:

[17] *These include costs such as development costs and fees, licenses, financial closing costs, feasibility and development studies, legal fees, rights of way fees, owners insurance, debt service reserve, and construction management not associated with the engineering, procurement and construction contract.*

» Maximising blade lengths and aerodynamics, while minimising weight, to achieve the highest capacity factors at the lowest possible cost.

» Meeting the increasing demand for taller towers, especially from European markets, with tower technology development adapted to this new demand.

With wind turbine cost reductions slowing, rotor diameter growth remains the main tool for achieving LCOE gains moving forward, with the exception of markets such as Brazil and others, where good quality wind resources allow for different strategies for attaining low LCOE. European markets are driving the demand for taller towers to enable the development of marginal wind sites and to take advantage of forested land available for development (MAKE Consulting, 2013).

Figure 4.2 presents the breakdown in total costs for onshore wind farms from three sources. For these three examples, wind turbines account for between 64% and 74% of total installed costs. Furthermore, grid connection costs can vary between 8% and 11%, construction and civil works from 8% and 16%, while other capital costs typically range between 4% and 10%.

Table 4.1 presents a detailed capital cost breakdown for the 20 MW San Matias wind farm in Mexico. The wind turbine accounts for around 60% of total installed costs, civil works and grid connection for 22%, planning and other project development costs for 10%.

Offshore wind farms have significantly higher grid connection and construction costs, and other project costs than onshore wind farms. These items account for a higher share of total installed costs than in onshore wind farms, lowering the cost share of wind turbines to between 30% and 50% for typical projects (Table 4.2). The offshore location significantly increases construction and grid connection costs due to the nature of offshore work, but also due to the increased costs to protect equipment and installations from the harsh marine environment. However, offshore wind projects benefit from less intermittent wind and can often have higher capacity factors; thus, they harvest more energy than onshore projects.

Table 4.1: Capital cost breakdown for a 20 MW onshore wind farm in Mexico

		2014 USD million	Share
Civil works and grid connection	**Civil works of wind turbines**	8.15	18.2%
	Measurement tower	0.09	0.2%
	Construction costs	0.31	0.7%
	Construction indirects costs	1.11	2.5%
	Land rent	0.17	0.4%
Sub-total		**17.57**	**22.0%**
Wind turbines and installation	**Turbines price**	20.64	46.1%
	Transportation of the wind turbines	2.27	5.1%
	Electrical infrastructure of wind turbines	7.74	17.3%
Sub-total		**22.91**	**68.5%**
Planning & management	**Management cost**	0.46	1.0%
	Administrative cost	3.80	8.5%
Sub-total		**4.27**	**9.5%**
TOTAL COST		**44.74**	**100.0%**

Source: IRENA Renewable Cost Database

Table 4.2: Comparison of capital cost breakdown for typical onshore and offshore wind power systems in developed countries

Cost share of:	Onshore (%)	Offshore (%)
Wind turbine[1]	64-84	30-50
Grid connection[2]	9-14	15-30
Construction[3]	4-10	15-25
Other capital[4]	4-10	8-30

Sources: Blanco, 2009; EWEA, 2009; Douglas-Westwood, 2010; and MAKE Consulting, 2011

[1] Wind turbine costs include the turbine production, transportation and installation.

[2] Grid connection costs include cabling, substations and buildings.

[3] Construction costs include building roads and other related infrastructure required for installation of wind turbines.

[4] Other capital costs include development and engineering costs, licensing procedures, consultancy and permits, SCADA (Supervisory, Control and Data Acquisition) and monitoring systems.

Wind turbine costs

The wind turbine is the largest single cost item of the total installed cost of a wind farm. Wind turbine prices have fluctuated with economic cycles and with the price of commodities such as copper and steel, which can make up a sizeable part of the final cost of a wind turbine. The average turbine price in the United States for projects higher than 100 MW was USD 755/kW for projects delivered between 2000 and 2002 (Wiser and Bollinger, 2014). In 2009, the cost of wind turbines peaked in the United States at USD 1 728/kW and in Europe at around USD 1 890/kW.

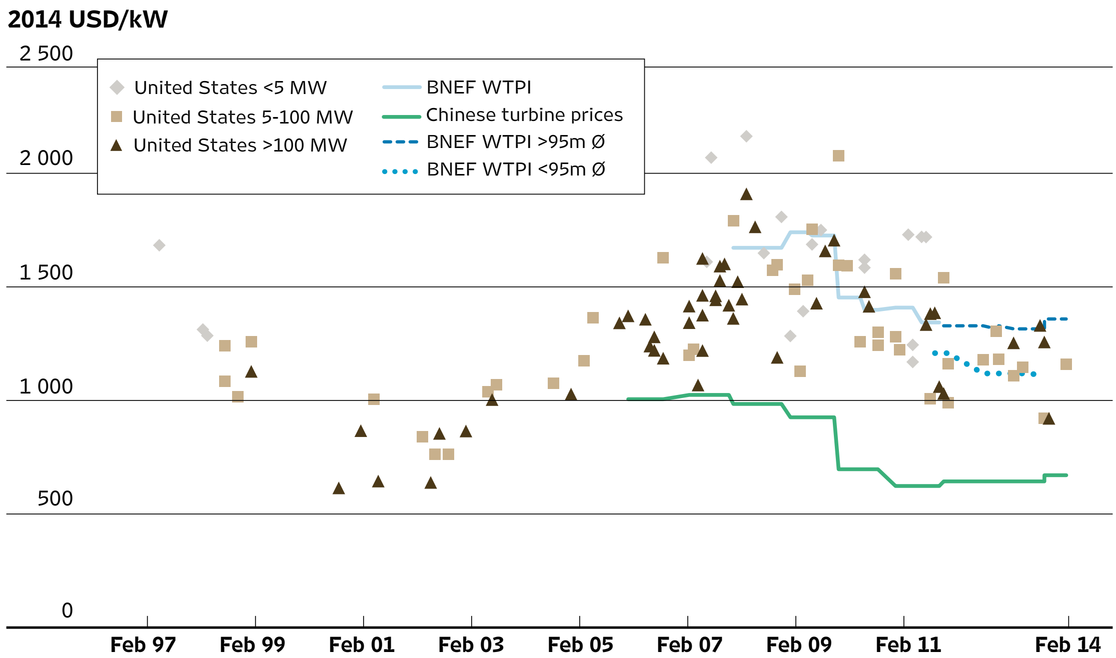
This cost increase was driven by three components. First of all, it followed the rising costs for materials (e.g. steel and cement), labour and for civil engineering. Secondly, tight supply drove up prices and allowed higher profit margins for wind turbine manufacturers, who started receiving more orders and struggled initially to meet new demand. Finally, technology improved; wind turbine manufacturers introduced larger, more expensive turbines, with higher towers and more capital-intensive foundations, but which also achieved higher capacity factors.

As presented in Figure 4.3, wind turbine prices began to decrease after the peaks of around USD 1 890/kW in Europe and USD 1 728/kW in the United States for contracts signed in 2008/2009 (Wiser and Bollinger, 2014).

Preliminary data for projects in 2014 suggest prices of between USD 931 and USD 1 174/kW in the United States, which would represent a decline of more than 30% compared with peak prices (Wiser and Bollinger, 2014). Bloomberg New Energy Finance (BNEF) has introduced separate turbine price indices for turbines with rotors of less than 95 metres in diameter and those with a diameter greater than 95 metres. The BNEF wind turbine price index (WTPI) decreased 35% for wind turbines of less than 95 metres in diameter and 20% for wind turbines with rotor diameters greater than 95% metres, resulting in an overall average decrease of 28%, which is in line with data from the United States (Figure 4.3).

The decline in wind turbine prices occurred at a time when wind turbine technology had improved significantly due to larger rotor diameters and higher towers, allowing for higher electricity output. However, the period after the Great

Figure 4.3: Wind turbine prices in the United States and China, compared to the BNEF turbine price index, 1997-2014



Sources: Wiser and Bollinger, 2014; CWEA, 2013; BNEF, 2014c; and Global Data, 2014.

Note: BNEF WTPI represents the half-year average for non-Asian markets, while the United States data are for the specific month of a particular turbine contract and the Chinese data are annual averages.

Recession has meant less pressure on commodity prices. In addition to lower materials costs than at the peak of turbine prices, the market for turbines has also become more of a buyers market.

These events have driven down costs and increased competition in the wind markets. Manufacturers from emerging markets, especially China, have added to this downward pressure as once renewable energy rose higher on the agenda of policy-makers in China, the push to develop domestic wind turbine manufacturers led to an increase of production capacity above internal demand. Wind turbine prices in China were at USD 1 036/kW in 2007 and experienced a steep decline to USD 628/kW in 2011, only to rebound to USD 676/kW in 2014. Thus, Chinese wind turbine prices have dropped 35% in comparison to peak prices in 2007 (CWEA, 2014).

As mature wind markets approach plateaus in deployment and policy uncertainty weighs on developed markets, new sources of higher growth in installed wind capacity are expected to increasingly come from emerging wind markets such as Mexico, Brazil and South Africa, among others. Chinese wind turbine manufacturers will face pressure to develop international markets, as their planned output is unlikely to be met by domestic demand. This is likely to add downward pressure on wind turbine prices internationally and is already allowing developing countries to reap the benefits of deploying wind power systems at the lowest possible cost. In this way, countries less endowed with financial resources to develop strong wind sectors could enjoy a latecomer advantage in wind markets, as learning investments have been made.

Total installed costs onshore

The cost reductions in wind turbine prices have been flowing into installed project costs. Data for 2013 suggest that total installed costs in the United States have fallen from a peak average of around USD 2 300/kW in 2009 to USD 1 657/kW in 2013, a 28% drop from peak prices (Wiser and Bollinger, 2014). However, these data are from a

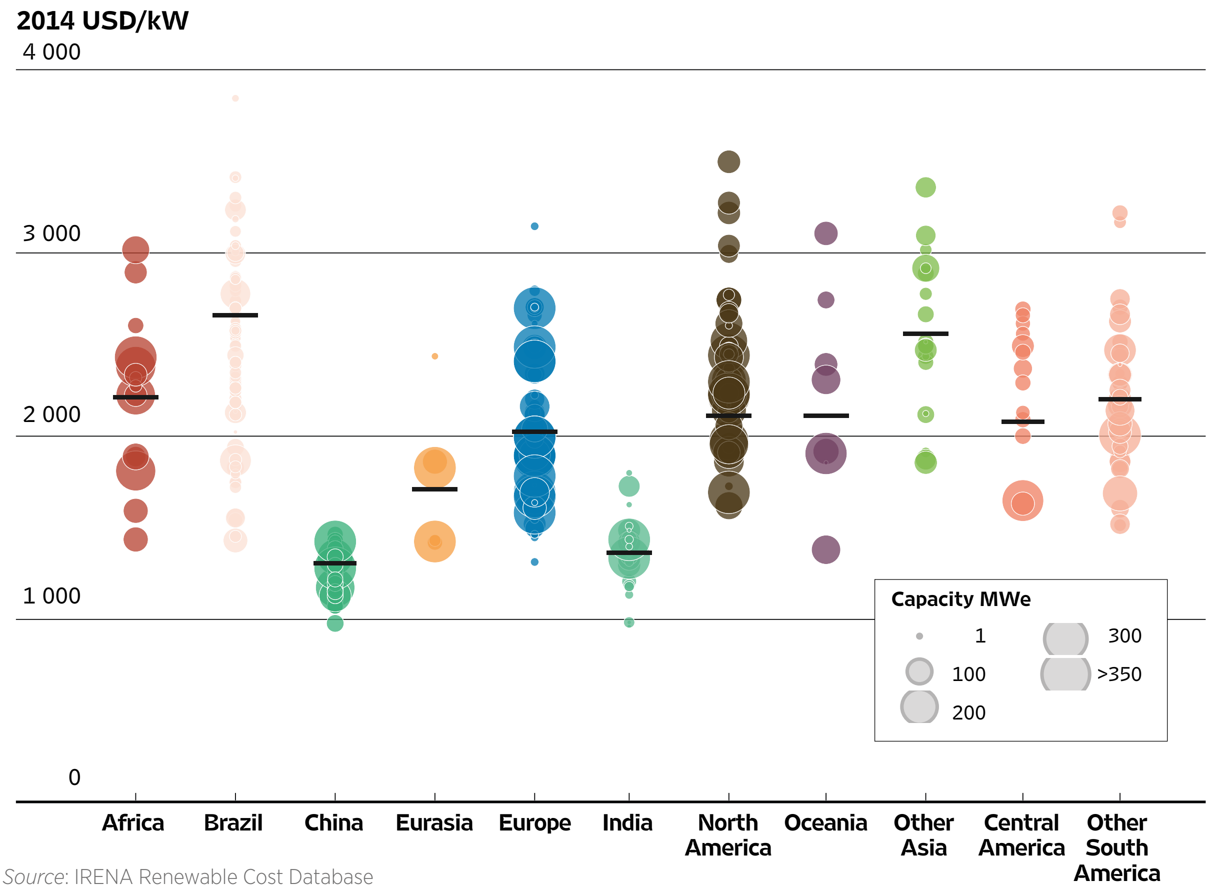
Table 4.3: Average total installed costs of new wind farms in selected OECD countries, 2013

	New capacity in 2013 (GW)	Cost (2014 USD/kW)
Australia	0.68	1 427 - 2 384
Austria	0.37	2 403
Canada	1.60	2 296
France	0.73	2 065
Germany	2.95	1 999
Italy	0.45	2 452
Japan	0.05	2 900
Mexico	0.62	2 102
Netherlands	0.24	1 928
Norway	0.07	1 978
Portugal	0.31	1 891
Switzerland	0.01	2 900
United Kingdom	1.64	1 874
United States	1.13	1 657

Sources: IEA Wind, 2014; IRENA Renewable Cost Database; Global Data, 2014; and Commission de Regulation de l'Energie, 2014

Note: Data for the United Kingdom is for 2012/2013.

Figure 4.4: Total installed costs and weighted averages of commissioned and proposed wind farms by country and region, 2013-2014



Source: IRENA Renewable Cost Database

small sample of projects built in 2013 and may not be fully representative. Early data for 16 projects accounting for 2 GW to be commissioned in 2014 and 2015 suggest average costs of installed wind at USD 1 779/kW, still significantly below peak prices in 2009. Costs vary as a function of project size, turbine size and region. Economies of scale are observed as project costs at the lower end of the ranges for project and turbine size exhibit higher costs (Wiser and Bollinger, 2014).

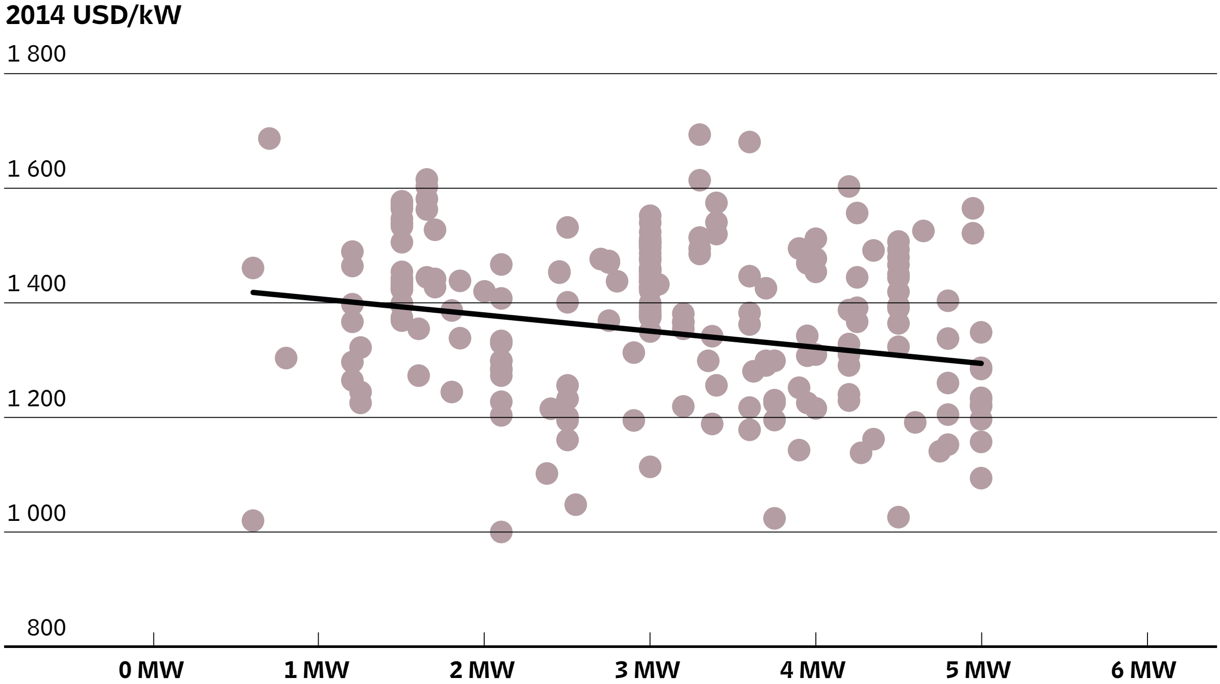
Average installed costs in China between 2011 and 2014 were the lowest in the world and averaged USD 1 310/kW in 2013 and 2014. India also has low installed costs, which averaged around USD 1 370/kW in 2013 and 2014 (Figure 4.4). It should be noted that total installed cost ranges outside of China and India are very wide. China and India benefit from a low-cost local manufacturing base, some policy support for deployment and low materials and labour costs. It will be difficult, if not impossible, for other countries to replicate these cost advantages, so price differentials are likely to persist.

Average total installed costs in Eurasia were USD 1 710/kW in 2013 and 2014 and USD 2 200/kW in South America, excluding Brazil. Average installed costs in Chile in 2013 and 2014 are estimated to have averaged USD 2 010/kW, while in Argentina they were around USD 2 340/kW. Average installed costs in Brazil are estimated to have averaged USD 2 650/kW in 2013 and 2014, with preliminary data for 2014 suggesting a trend to significantly lower values. Brazil's highly competitive and sustained auction system will see installed costs drop rapidly. The total installed costs in 2015 are projected to average USD 1 840/kW in Brazil, and by 2017 they might be as low as USD 1 600/kW.[18]

With modest deployment in much of Other Asia, average costs remain relatively high. The

[18] *Note that throughout this chapter where project level data is presented, if in a given year the coverage of the IRENA Renewable Cost Database is not high enough to be statistically representative the data is supplemented by a "balance" entry based on the national average for that year.*

Figure 4.5: Total installed costs of commissioned small wind farms in India (<5 MW), 2000-2013



Source: IRENA Renewable Cost Database

average cost of installed wind farms in Other Asia averaged around USD 2 560/kW in 2013 and 2014. Deployment in Oceania for which data is available in the IRENA Renewable Cost Database is concentrated in Australia, where a wide range of costs were in evidence, with average installed costs of USD 2 110/kW. The average installed cost of wind farms in Africa was around USD 2 210/kW, with some projects proposed having quite competitive cost structures.

India has deployed large numbers of small wind farms of up to 5 MW. Figure 4.5 presents data for proposed and commissioned small wind farms in India for the period 2000 to 2013. The average cost of these projects is around USD 1 344/kW. There is some evidence of economies of scale even for these small wind projects.

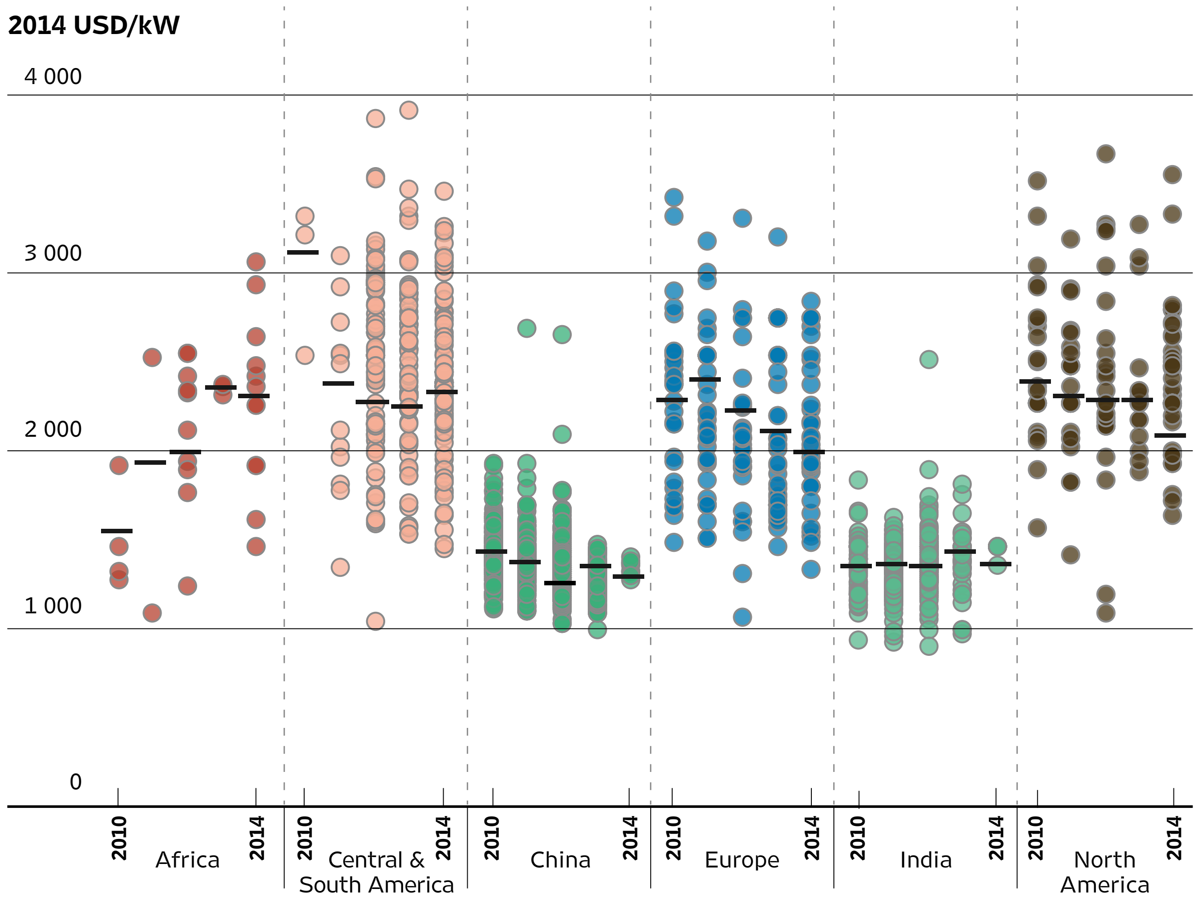
Figure 4.6 shows that between 2010 and 2014 the ranges of installed costs have shown a slight tendency towards narrowing in China and India, while this is not true in other regions. In comparison to installed costs in 2010, all countries and regions in Figure 4.6 have experienced cost declines except Africa and India. However, the market in Africa is very thin and the results are heavily dependent on the country of new projects and their site specific cost characteristics. Installed costs in India in 2014 were fractionally higher than in 2010. The decline in installed costs by 9% between 2010 and 2014 in China, with costs in India broadly stable, suggests that onshore wind costs are approaching a mature level in these markets. This is most likely due to the lower cost structure of onshore wind in China and India compared to the rest of the world.

In South America, total installed costs fell by 25% between 2010 and 2014, although for the period 2011 to 2014 (where more data are available for comparison) the decline is 2%. In the more mature markets of Europe and North America, total installed costs are estimated to have fallen by around 12% between 2010 and 2014.

For the eight developed countries presented in Figure 4.7 for which data is available between 2011 and 2014, the range in installed cost declines in 2014 compared with 2011 is between 8% and 30%. However, the spread in installed costs among the eight selected countries is relatively important, as installed costs in France are USD 1 430/kW in 2014 and in Australia they are higher than USD 2 500/kW.

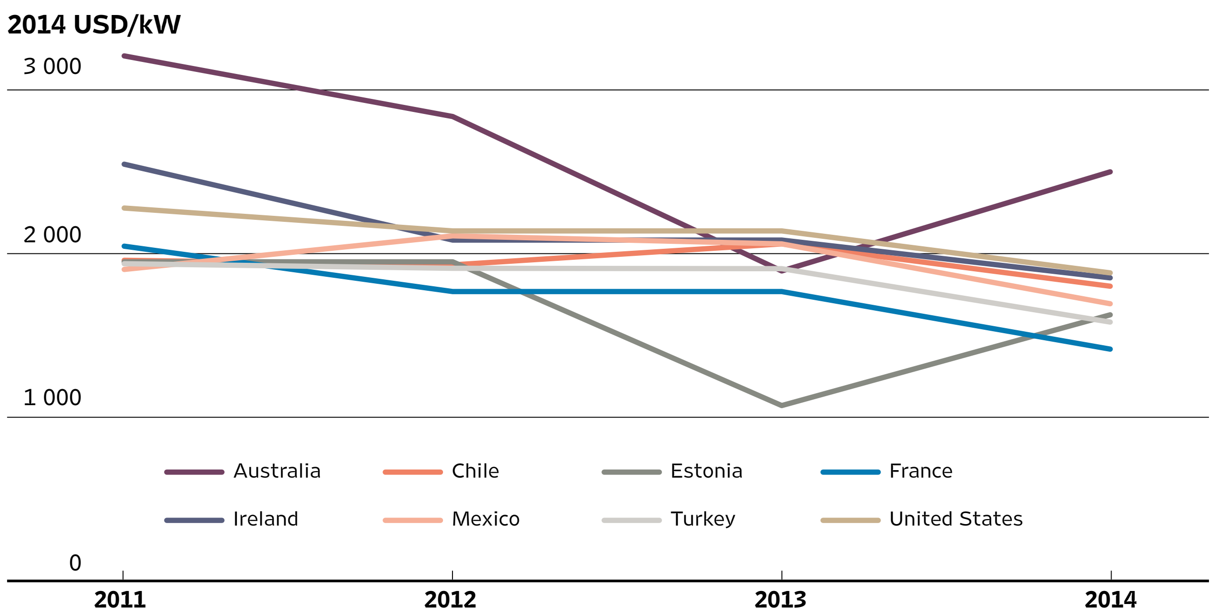
Installed costs of wind farms are declining with the exception of Africa and India as already discussed, pointing to the fact that markets for onshore wind have become more competitive and are passing through wind turbine cost reductions. The potential for positive spillovers from India and China with their

Figure 4.6: Evolution of total installed costs and weighted averages of commissioned and proposed large wind farms by country and region, 2010-2014



Source: IRENA Renewable Cost Database

Figure 4.7: Evolution of total installed costs of commissioned and proposed large wind farms in selected OECD countries, 2011-2014



Source: IRENA Renewable Cost Database

low-cost turbines to other developing countries is possible, but will be dependent on local market features and policy decisions. The wide range in installed costs among different regions is one indicator that a global market for wind systems is still in its infancy, but also reflects country-specific cost structures that are likely to ensure the degree of convergence in costs will be limited in a number of cases.

Total installed costs offshore

There were 7 GW of installed offshore wind systems at the end of 2013, 2.2 % of total installed capacity (IRENA, 2014) with an estimated 1.2 GW added in 2014. Europe accounted for around 6.6 GW of the capacity at the end of 2013, while China and Japan accounted for the remainder. Most of the installed offshore turbines in Europe use monopile foundations (76%), followed by gravity foundations (12%), tripod systems (5%) and jacket foundations (5%) (EWEA, 2014). Offshore wind technology is hampered by higher costs than onshore wind. The higher cost is the result of increased investment in deploying cables offshore, building foundations at sea, transportation of materials to more remote areas, and installing foundations, equipment and the turbines at sea. The turbines are also somewhat more expensive as they are designed to withstand the harsh marine environment. Higher upfront investments are also required in order to avoid expensive O&M costs due to interventions at sea. Still, O&M costs are higher than for onshore turbines (Douglas-Westwood, 2010).

Offshore total installed costs have risen over time, in part due to projects shifting further offshore, towards deeper water and increased site complexity. The average nameplate capacity has increased, from 2.9 MW in 2007 to 4.1 MW in 2012 as larger machines reduce installation costs per MW and can also help reduce O&M costs. Increased capacity factors due to higher hub heights and rotor diameters, in addition to other technology improvements, will help to mitigate the increase in installed costs of offshore wind if projects continue to be sited further from logistics bases and in deeper water (Navigant Consulting, 2013).

The wind turbine remains the largest cost component for an offshore wind project, but its share typically accounts for less than half (30-50%) of the total capital costs (Douglas-Westwood, 2010). The foundations, electrical infrastructure, installation and project planning account for the remainder (Table 4.2). The average installed costs between 2000 and 2014 for commissioned and proposed offshore wind projects were slightly more than USD 4 700/kW in OECD countries, while in China the cost was approximately USD 2 400/kW, as a result of the deployment of cheaper tidal projects (Figure 4.9). The proposed projects for 2015 to 2020 are targeting lower costs, of around USD 4 100/kW on average, but rely on large projects to achieve economies of scale. It remains to be seen whether these projects can deliver on their cost estimates.

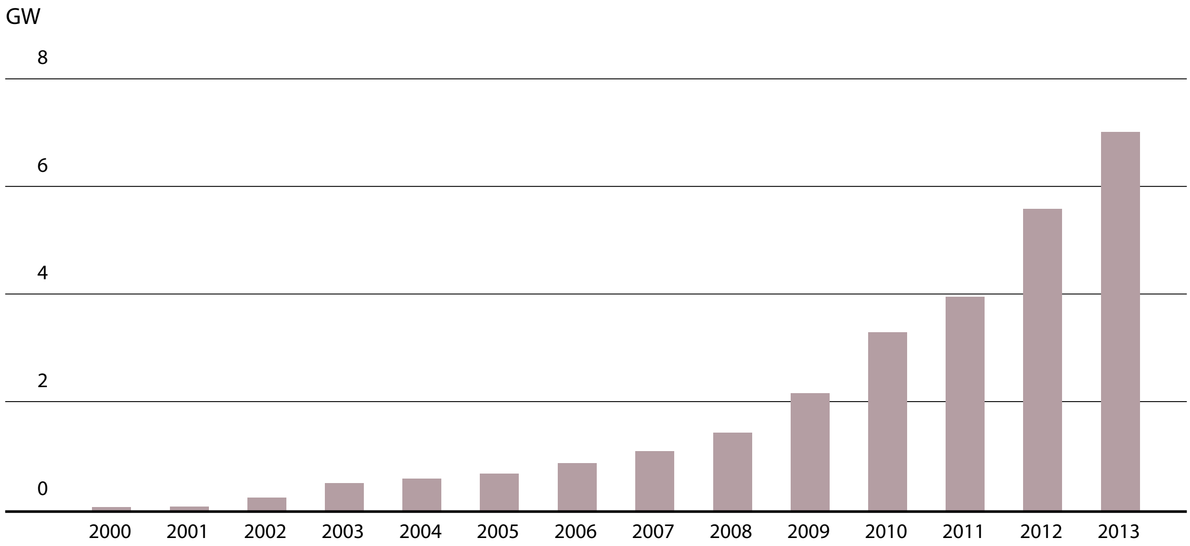
Wind power capacity factors

With increasing wind speeds, the amount of kinetic energy available for a wind turbine increases, which allows for an improved electricity output. The kinetic energy in wind is a cubic function of wind speed. A doubling of wind speed could therefore, potentially, increase the power output of a wind turbine by a factor of eight (EWEA, 2009). Thus, developers have an incentive to place wind farms in areas with high average wind speeds.

In addition, at greater heights, the wind speed is higher. For instance, a fivefold increase in the height of a wind turbine above the prevailing terrain can double its electricity output. Increased height also allows for larger rotor blade diameters, which is important because the maximum energy that can be harnessed by a wind turbine is roughly proportional to the swept area of the rotor. By doubling the rotor diameter, the swept area – and therefore the potential power output – is increased by up to a factor of four.

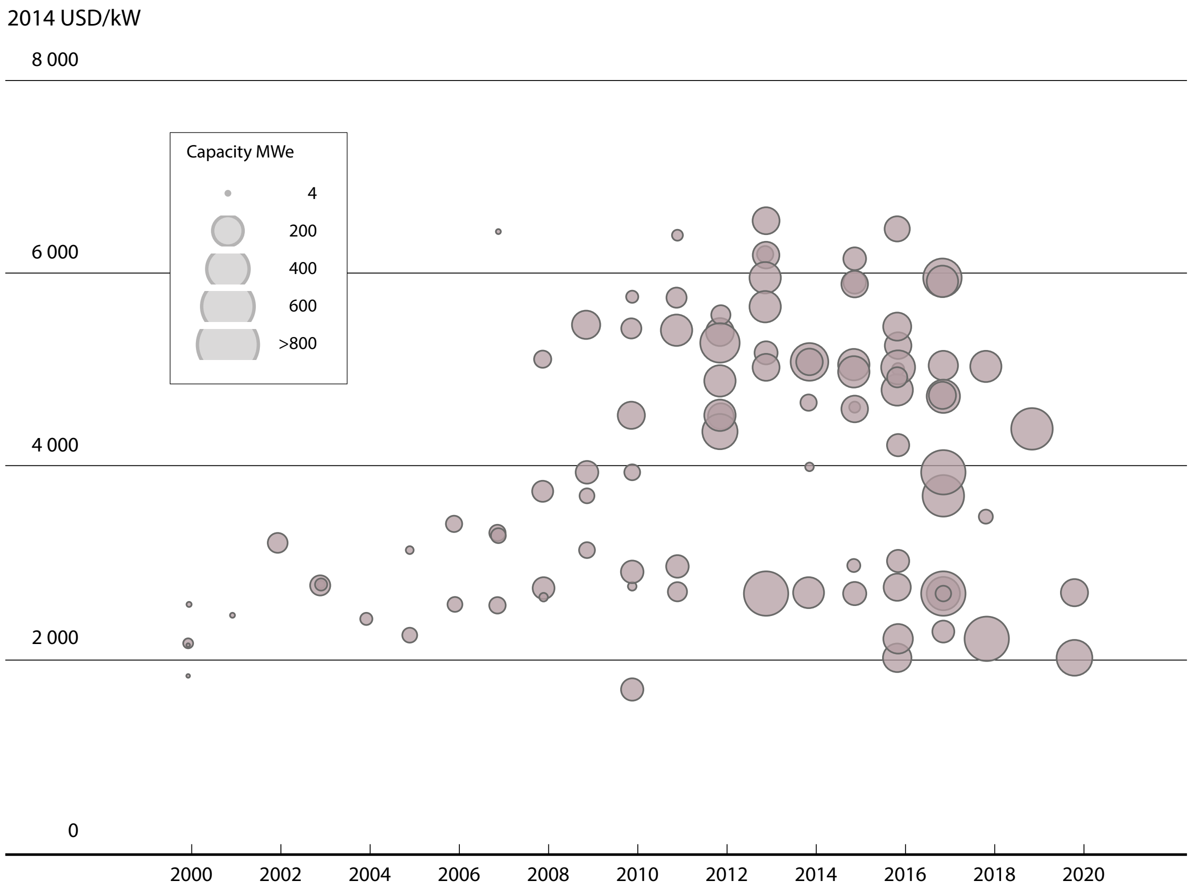
For these reasons, higher hub heights and larger swept areas have played a role in increasing the average capacity factors of wind farms. However, capacity factors are also driven by the overall quality of the wind resource at the site (e.g. annual average wind speed), inter-annual variability in the resource quality and curtailment (if any) of

Figure 4.8: Cumulative offshore wind installed capacity at the end of 2013



Source: IRENA

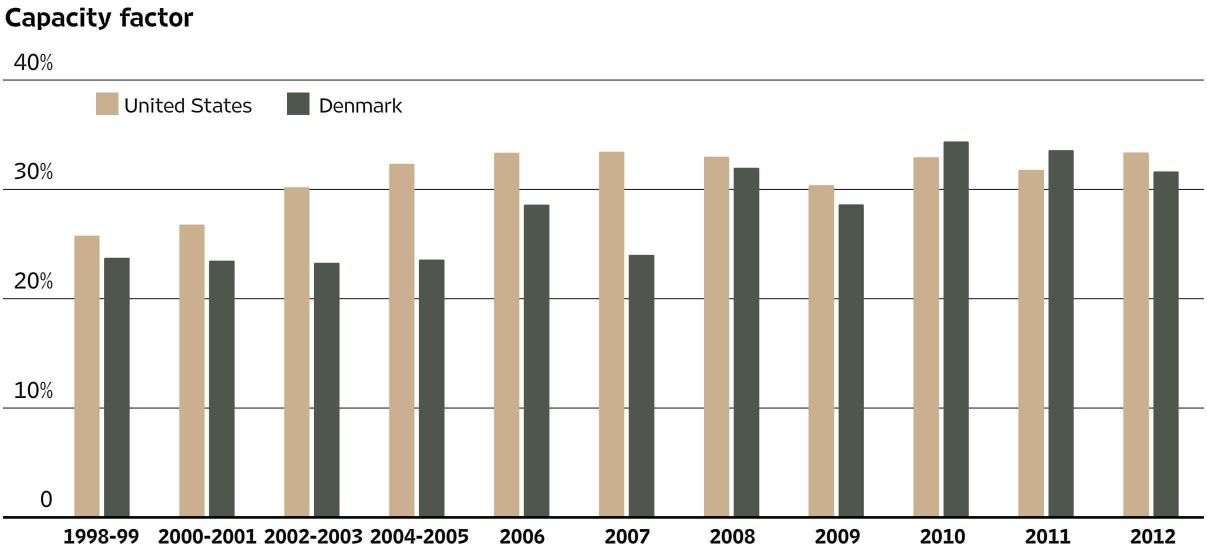
Figure 4.9: Weighted average total investment costs for commissioned and proposed offshore projects, 2000-2020



Source: IRENA Renewable Cost Database

wind output due to limitations in the flexibility of the local electrical system. Data for the United States show that capacity factors have risen less than technology advancements might suggest, an average of 32.1% for 2006 to 2013 compared with 30.3% for 2000 to 2005 (Figure 4.10). The primary driver for this more modest increase in capacity factors than what might otherwise have been expected is that lower wind speed technologies have allowed projects to increasingly be sited at somewhat lower quality wind resource sites. Also impacting this trend has been wind project output

Figure 4.10: Project capacity factors by commercial operation date



Note: Data for the United States present capacity factors in 2013 for wind turbines installed from 1989 onwards. Data for Denmark present average capacity factors for wind turbines installed from 1998 onwards.

Sources: Wiser and Bollinger, 2014; Danish Energy Agency, 2014; and GlobalData, 2014

curtailment in the United States as penetration levels have increased (Wiser and Bollinger, 2014).

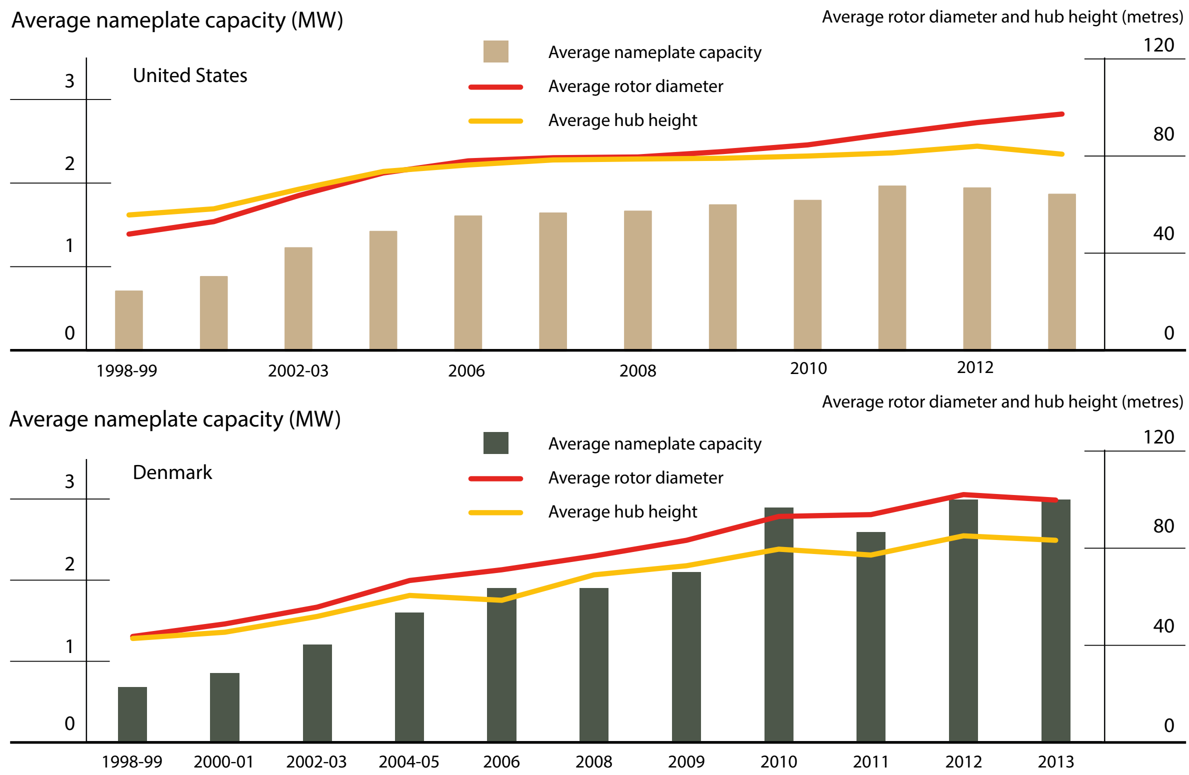
In this respect, the data for Denmark more clearly show that improved technology has led to higher capacity factors, assuming that the average wind resource exploited has been stable or been poorer. Wind turbines in Denmark had an average capacity factor of 23.7% in 1998-1999 and 31.6% in 2012, an increase of one-third (Figure 4.10). Figure 4.11 presents the technological features that have led to improved capacity factors in both the United States and Denmark. In the United States, nameplate capacity has increased by 161% in 2013 in comparison to 1998, and average rotor diameter has increased by more than 100% during the same period, while hub height increased by 44%. In Denmark, the average nameplate capacity has increased by more than 340% in 2013 in comparison to 1998. Furthermore, average rotor diameter increased by 129% and average hub height by 95% in the same period.

Figure 4.12 presents the ranges for wind farm capacity factors for current and proposed projects by country and region. Weighted average capacity factors varied by region from around 24% in China and India to around 43% in Brazil. In China, curtailments due to grid constraints mean that average capacity factors for dispatched generation are often closer to 20%. By comparison, projects commissioned in 2012 in the United States had average capacity factors of 33.4% in 2013, with ranges of between 18% and 54% (Wiser and Bollinger, 2014). The capacity factor ranges for Africa and South America excluding Brazil are similar to those in the United States.

Figure 4.13 presents the data in the IRENA Renewable Cost Database for total installed costs, plotted against capacity factors. A strong correlation is apparent, when examining data at a global level, suggesting that project developers look to site projects in a manner that minimises LCOE, by accepting more expensive project development costs to access better resources. However, the correlation is much weaker at a regional level. This suggests that it is typically the overall resource quality and the opportunities for project development in a given area that are driving the trade-off between costs and capacity factors, although there is some evidence that project developers will search for opportunities to tap a better resource at the expense of higher grid connection and/or project development costs.

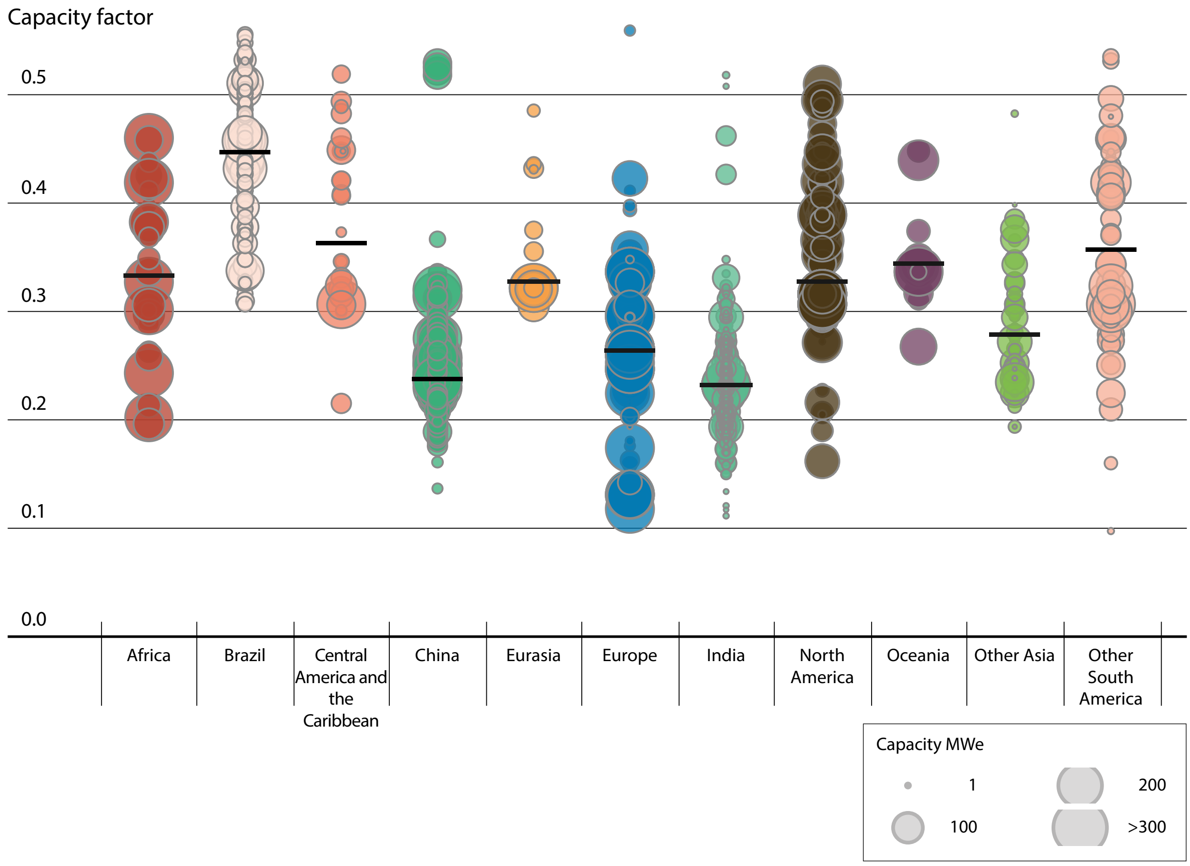
One of the most interesting recent technological developments within the wind industry is the launch of wind turbines capable of yielding higher electricity outputs at sites with lower quality wind

Figure 4.11: Average turbine nameplate capacity, rotor diameter and hub height for turbines >100 kW (1998-2013) in the United States and Denmark



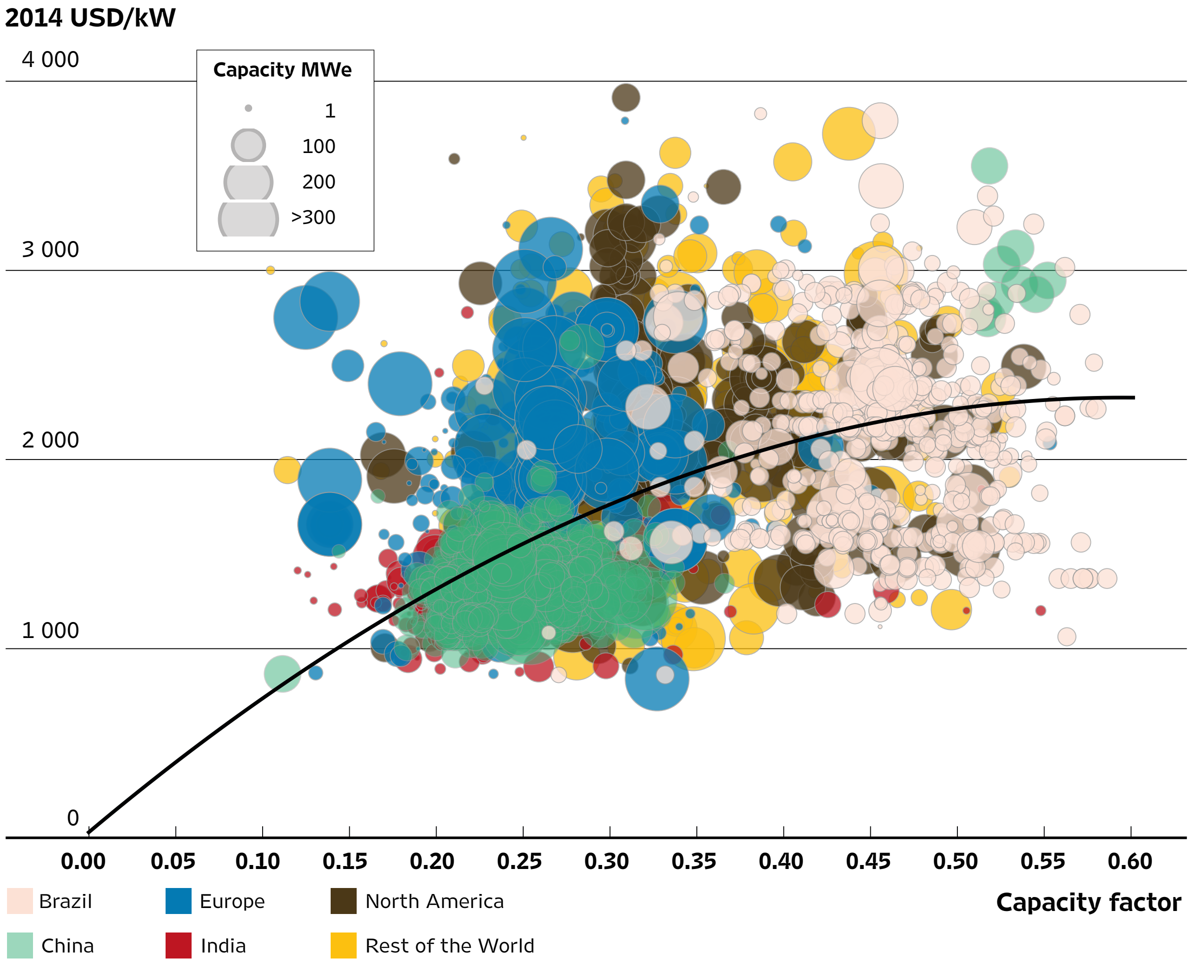
Sources: Wiser and Bollinger, 2014; Danish Energy Agency, 2014; and GlobalData, 2014

Figure 4.12: Capacity factors by project and weighted averages for commissioned and proposed wind farms, 2010-2014



Source: IRENA Renewable Cost Database

Figure 4.13: Total installed onshore wind farm costs relative to project capacity factors by region



Source: IRENA Renewable Cost Database.

resources. Given the low-hanging fruit of high wind speed sites has often been harvested in the first push of wind deployment in some countries, these technological improvements might bring a new impetus to deployment in lower wind speed sites. These new turbines provide capacity factors in low wind speed sites that are equal to those previously observed at high wind speed sites, with earlier technology. These developments are already giving a second life to markets that were struggling with poorer wind resource sites and may help launch exciting new markets (Chabot, 2014).

Operations and maintenance costs of wind power

The fixed and variable O&M costs are a significant part of the overall LCOE of wind power. O&M costs typically account for 20% to 25% of the total LCOE of wind power systems (EWEA, 2009).

Data for actual O&M costs from commissioned projects are not widely available. Even where data are available, care must be taken in extrapolating from historical O&M costs, given the dramatic changes that have occurred in wind turbine technology over the last two decades. Another issue is that although data for maintenance costs are often available, the cost data for operations (e.g. management costs, fees, insurance, land lease payments, local taxes, etc.) is not systematically collected. As a result, good data on total O&M costs is not typically available.

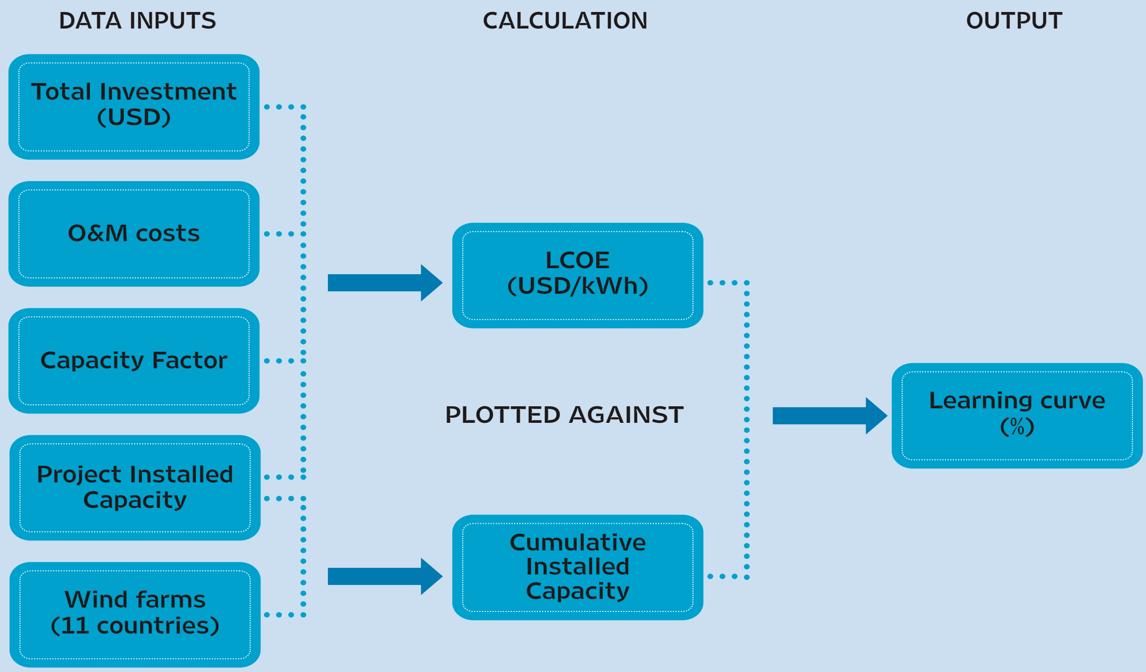
However, given these caveats, it is clear that annual average O&M costs of wind power systems have declined substantially since 1980. BNEF has compiled data for the maintenance costs of more than 6.4 GW of installed onshore wind capacity, and concluded that between 2008 and 2013 full-service contract prices fell by 36% (Figure 4.15). The BNEF index and recent data for reported

BOX 4.1

Updating the analysis of the global wind learning curve

IRENA is in the process of updating the out-of-date learning curve analysis for onshore wind installed costs. IRENA is also extending the analysis by developing a comprehensive global learning curve for the levelised cost of electricity for onshore wind power systems. The learning rates for wind are used extensively by the industry, energy and climate modellers, and policy makers in their analysis. Unfortunately, the current analysis either relies on outdated data or is not globally comprehensive, IRENA is aiming to fill this gap in wind deployment knowledge in order to improve decision-making related to wind deployment. The aim is to create the most comprehensive learning curve for wind technology to date, which will cover the period from the late 1970s to 2013 and more than 85% of cumulative installed capacity. The second part of the project aims at decomposing the cost reductions of wind systems by wind turbine price contribution, technology improvement, balance of system costs and operations and maintenance costs. Figure 4.14 presents a stylised overview of the project.

Figure 4.14: The process for developing a learning curve for wind based on LCOE

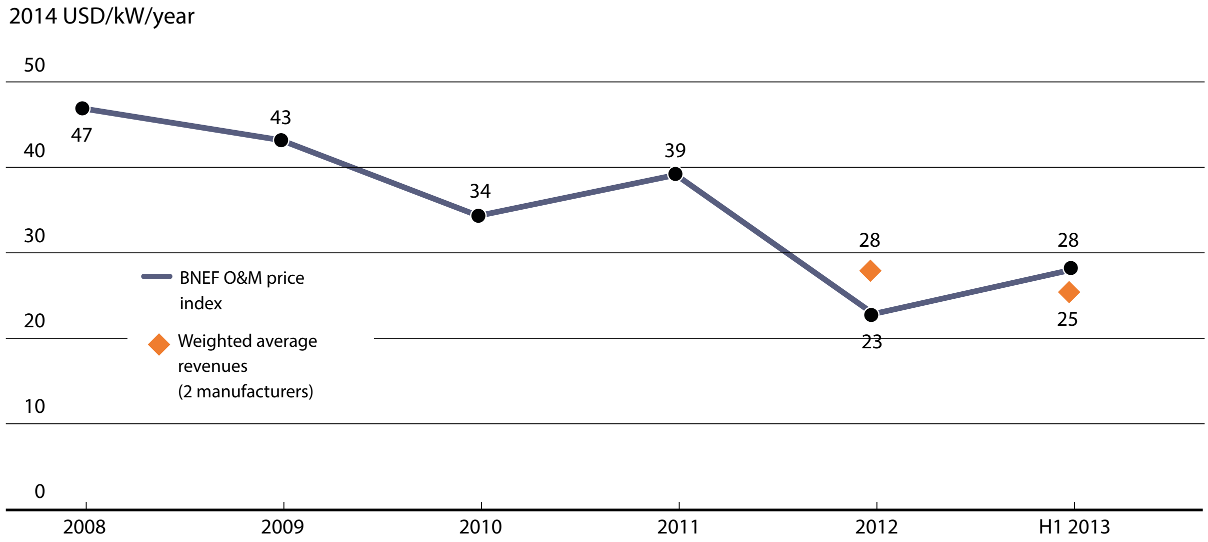


revenues from O&M contracts by two major manufacturers are around the same level, but show different trends.

In contrast, data compiled by the Energy Regulation Commission in France for total O&M costs, not just maintenance and local operations as in the BNEF index, in France between 2008 and 2012 were mostly stable at around 3% of total installed costs per year (Commission de Régulation de l'Energie, 2014). Total O&M costs reported by publicly traded developers in the United States were around USD 0.024/kWh in 2013, suggesting a lower cost structure than the average of the BNEF index. The order of magnitude in the United States for these total O&M costs suggest that half, or more, of total O&M costs come from operations costs, as reported maintenance costs for a large sample of installed projects compiled in the United States average around USD 0.01/kWh (Wiser and Bollinger, 2014).

Both the year a project was developed and the age of the project has an impact on O&M costs. In the United States, O&M costs for projects installed in the last decade are on average lower than for older projects in their first years of operation. However, O&M costs for all projects tend to increase as wind turbines get older.

Figure 4.15: Full-service O&M pricing 2008-2013 vs. weighted average O&M revenues of two manufacturers



Sources: BNEF, 2014 and GlobalData, 2014

Table 4.4 presents data for the O&M costs reported for a range of OECD countries. Data is not consistently reported and comparisons are made more difficult by uncertainty about whether the same boundaries are applied to O&M costs. An average value of around USD 0.02 to USD 0.03/kWh would appear to be the norm, but more systematic data collection is required to confirm these values.

O&M costs for offshore wind farms are significantly higher than for onshore wind farms due to higher costs involved in accessing and performing maintenance for wind turbines, cabling and towers offshore. Maintenance costs are also higher as a result of the harsh marine environment and a higher expected failure rate for some components. Overall, O&M costs are expected to be in the range of USD 0.027 to USD 0.054/kWh (ECN, 2011).

Table 4.4: Estimated O&M costs in selected OECD countries

	Variable (2014 USD/kWh)	Fixed (2014 USD/kW)
Austria	0.04	
Denmark	0.0152-0.019	
Finland		37-40
Germany		67
Italy		49
Japan		75
The Netherlands	0.0137-0.0179	37
Norway	0.0211-0.039	
Spain	0.0284	
Sweden	0.0105-0.0348	
Switzerland	0.0453	

Source: IEA Wind, 2011b

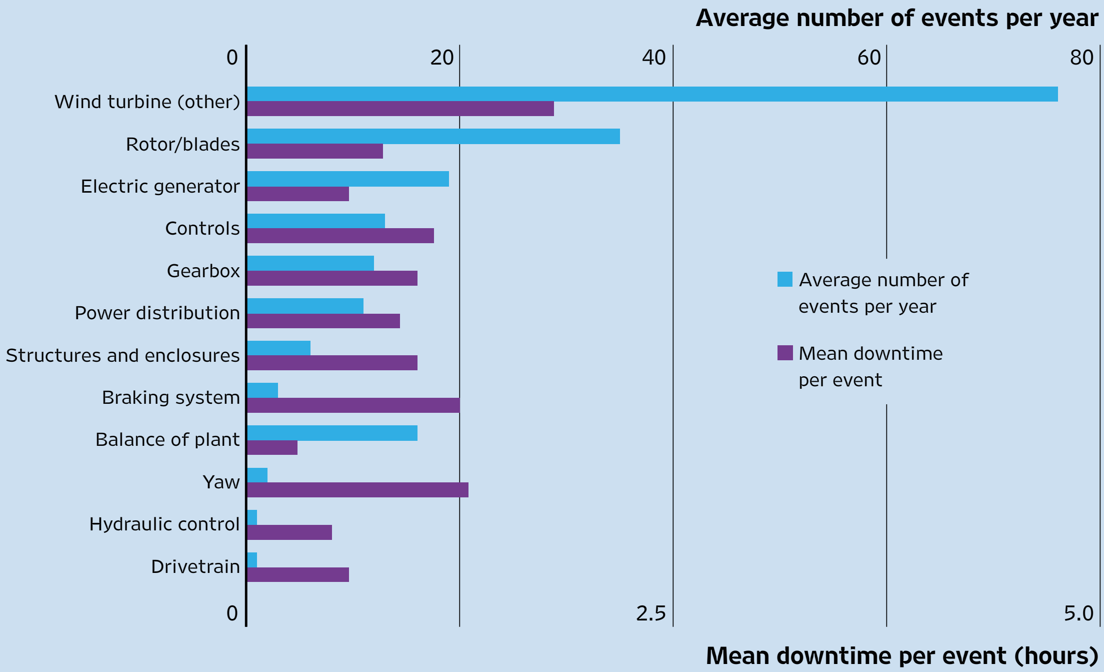
BOX 4.2

Wind turbine reliability and downtime

An analysis conducted by Sandia National Laboratories on a sample of 2.7% of large US wind turbines, equivalent to 2.4% of total installed capacity, has shown that the operational availability of wind turbines has increased from 94.8% in 2011 to 97.6% in 2013. Utilisation has increased from 78.5% in 2011 to 83% in 2013 and the capacity factor has increased from 33.4% in 2011 to 36.1% in 2013 for the plants surveyed. At the same time, the mean time between outage events is longer, rising from 28 hours in 2011 to 39 hours in 2013, while mean downtime has decreased from 2.5 hours in 2011 to 1.3 hours in 2013 (Figure 4.16).

Overall, a wind turbine is generating power 83% of the time, while 17% of the time is accounted for mostly by reserve shutdowns due to extreme wind speeds or other reasons (Hines, 2013).

FIGURE 4.16: AVERAGE NUMBER OF EVENTS PER YEAR PER TURBINE AND MEAN DOWNTIME PER EVENT FOR SURVEYED PLANTS IN THE UNITED STATES, 2013



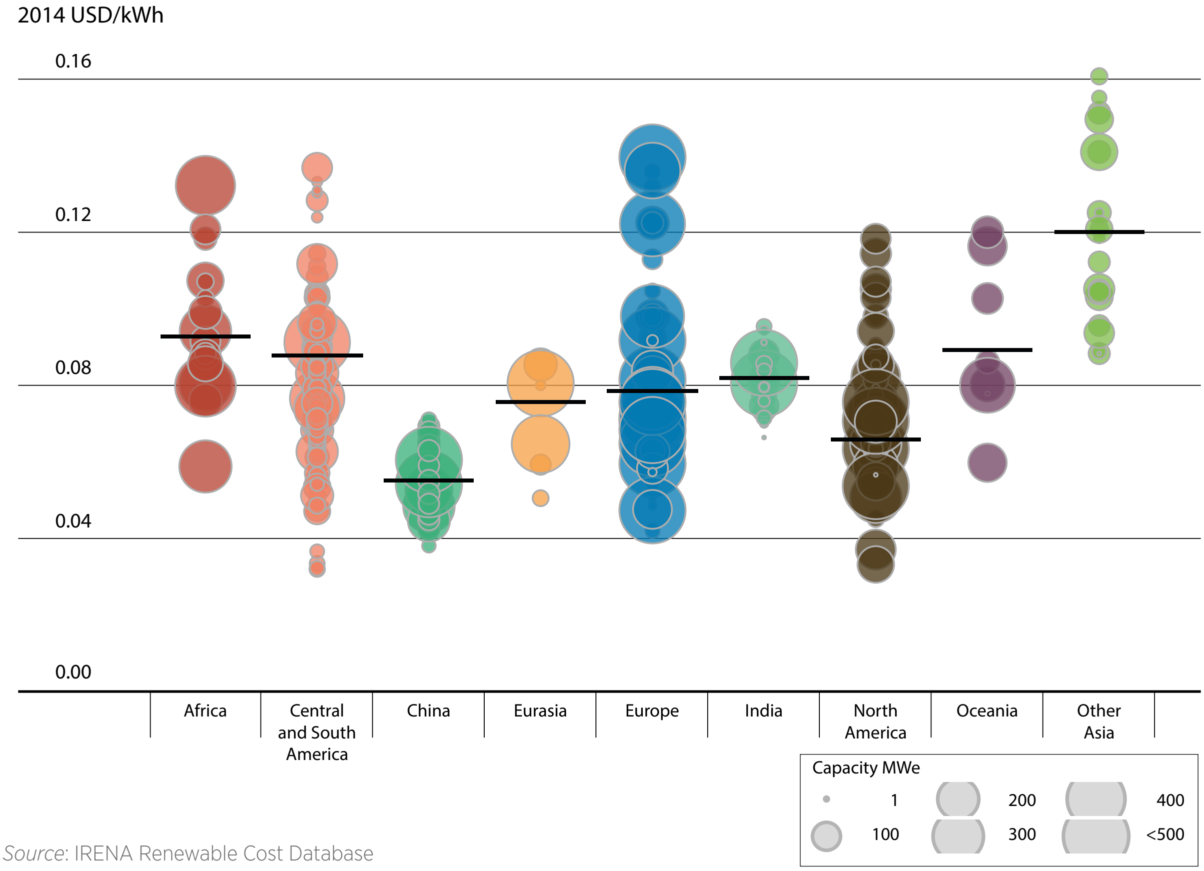
Source: Hines, 2013

The O&M market has become more dynamic, particularly in Europe, given the aging of the existing turbine fleet (MAKE Consulting, 2012) and the fact that an increasing number of turbines are coming to an end of their original O&M contract. At the same time, increased competition for O&M contracts has led to a decline in O&M costs as O&M contractors look to lock-in long-term service contracts (MAKE Consulting, 2012).

As turbines roll off warranty, OEMs have also become more flexible in their offering of services, offering more yield-based guarantees and aggressively trying to renew and extend existing contracts. Another important driver in the development of this market is that the cost of failure becomes larger with increased turbine sizes (MAKE Consulting, 2012). On a different note, emerging market countries rely extensively on OEMs for O&M services as local independent service providers (ISPs) have not developed significant market share yet. If their share of the market increases, this could translate into lower O&M costs (MAKE Consulting, 2012).

O&M strategies are increasingly relying on data analytics in order to indicate potential system problems that can lead to downtime or replacement costs. Equipped with these data, asset owners are increasingly able to use predictive analytics in order to manage their O&M strategies (Ingham, 2013). Analysis of wind turbines with a cumulative 100 000 years of operations data for onshore wind farms has determined that the most common failures are

Figure 4.17: The LCOE and weighted averages of commissioned and proposed wind projects by country and region, 2013 and 2014



Source: IRENA Renewable Cost Database

due to equipment breakdown and lightning strikes. The analysis concludes that most of the failures occurring on a wind farm are due to the electrical system, followed by mechanical issues, blades, gearboxes, generators and structural issues. The consolidated average downtime from these failures averaged 2.62 days per year.

The levelised cost of wind electricity

The LCOE of a wind power project is determined by total capital costs, wind resource quality, technical characteristics of the wind turbines, O&M costs, the economic life of the project and the cost of capital.

More specifically, the LCOE of wind power depends mainly on four items:

» Capacity factor: This is the result of the interaction of multiple variables, such as wind turbine design, operational availability, potential power curtailment and – most importantly – the quality and nature of the wind resource.

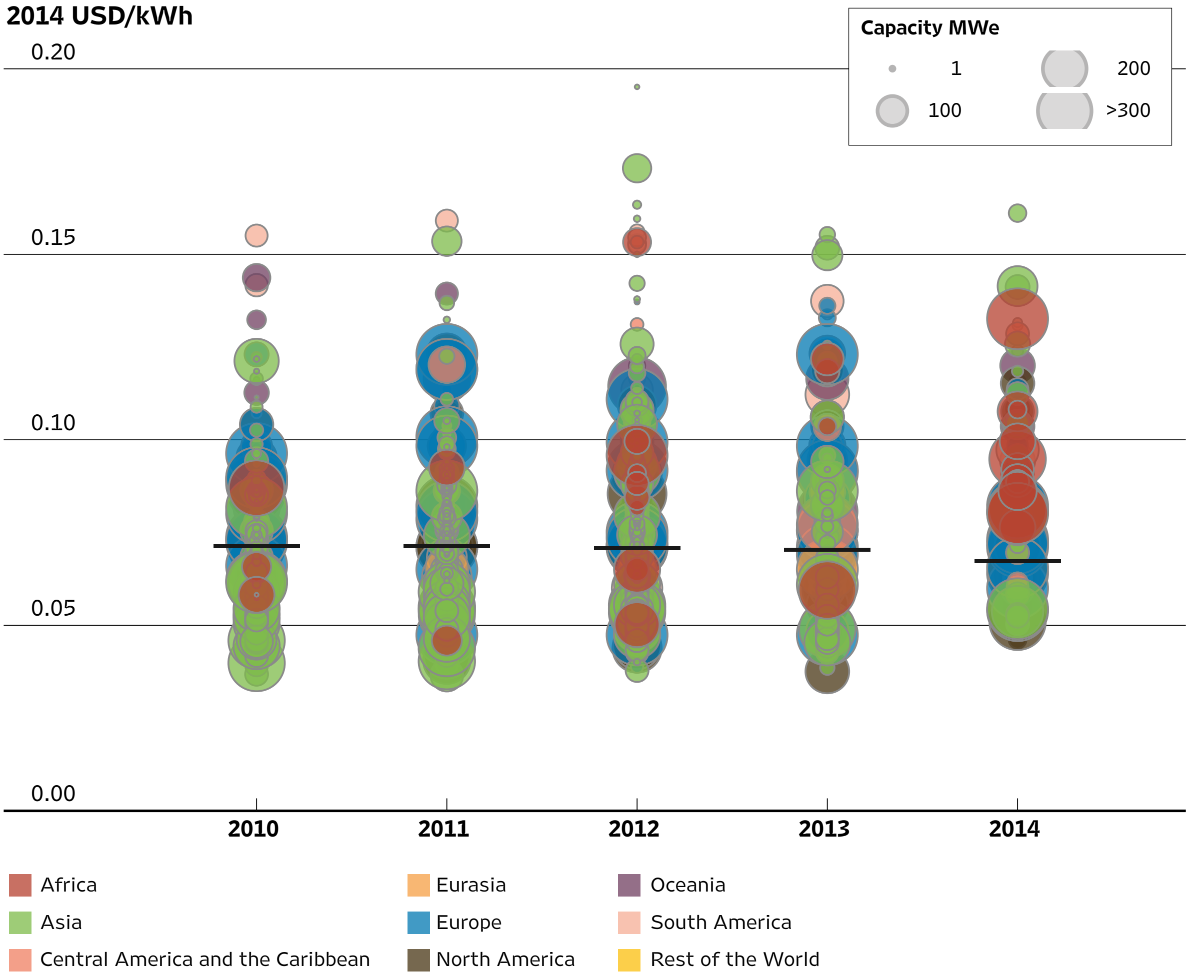
» Capital expenditure: The turbine cost has the greatest impact on the installed cost of a wind project. However, depending on the project, the infrastructure and grid connection costs can also contribute significantly to total costs.

» Weighted average cost of capital (WACC): This has an important impact on the LCOE calculations. The availability and cost of equity and debt, as well as their respective shares of total project funding and costs will determine the WACC.

» Operations and maintenance: Operational expenditures consist of both fixed and variable costs and can represent up to 20% to 25% or more of the total LCOE.

Based on the data and analysis presented in the earlier sections of this chapter, wind turbine costs in 2013 ranged from around USD 649/kW in China to around USD 1 360/kW (>95m) in developed countries. Wind turbine prices in 2014 are likely to be slightly higher than their 2013 values, in the range of USD 1 127/kW to USD 1 376/kW in developed countries.

FIGURE 4.18: THE GLOBAL LCOE AND WEIGHTED AVERAGE OF COMMISSIONED AND PROPOSED LARGE WIND FARMS (>5 MW), 2013 AND 2014



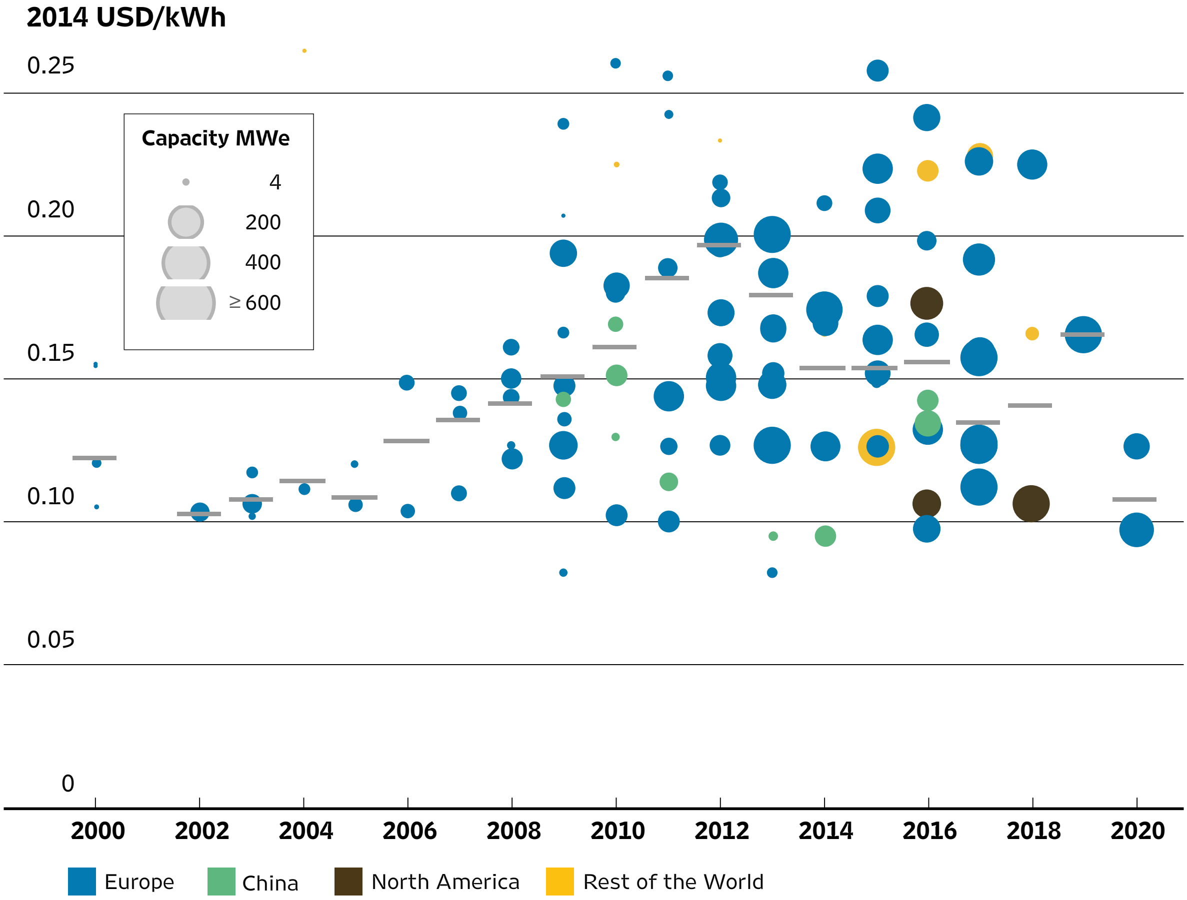
Source: IRENA Renewable Cost Database

Total installed costs continued to decline between 2010 and 2014, following lower wind turbine prices, with initial data for the United States suggesting that total installed costs have declined from around USD 1 993/kW in 2012 to around USD 1 675/kW for the projects with data for 2013, but may be closer to USD 1 780/kW for a more representative sample of projects in 2014 and early 2015. Similar cost reductions have occurred in other OECD wind markets.

Figure 4.17 presents the LCOE of wind power by region and country in 2013 and 2014, assuming a 7.5% or 10% WACC. As can be seen, the weighted average LCOE by country or region range from USD 0.06/kWh in China to USD 0.12/kWh in Other Asia. North America, with a weighted average LCOE of USD 0.067/kWh in 2013 and 2014, has the lowest average LCOE after China. Eurasia (USD 0.076/kWh), Europe (USD 0.08/kWh) and India (USD 0.08/kWh) had slightly higher LCOE structures than China and North America, but still have a range of very competitive projects. With weighted average LCOE of between USD 0.09 and USD 0.095/kWh Central and South America, Oceania and Africa are not far behind. The LCOE of individual projects typically spans a wide range within a region, but it is now common to see wind energy projects being built that deliver electricity at USD 0.05/kWh in 2014, with some projects perhaps achieving USD 0.04/kWh.

The combined effect of installed cost declines, technology improvements and deployment patterns on the LCOE of wind is presented in Figure 4.18. The global weighted average LCOE of wind has fallen by 7% between 2010 and 2014, which is slightly lower than the average decline in total installed costs over this period. In China and India, the range of wind power project LCOE is narrower

Figure 4.19: The LCOE and weighted averages of commissioned and proposed offshore wind projects, 2000 to 2020



Source: IRENA Renewable Cost Database

than in other regions, reflecting the narrower range of installed costs and capacity factors. In contrast, the wide range of project LCOE in other regions reflects the wider range of installed costs and, in particular, the wide range of capacity factors from 25% to 50%.

The global average LCOE of wind is driven by cost developments in China, given that China has been accounting for just under half of new capacity added for a number of years. As a result, although some regions have seen quite rapid LCOE declines, the global average has only declined by about 8% since 2009 and 7% since 2010, due to the fact that the very low project development costs in China and India have not fallen as rapidly as in other regions with higher cost structures. However, when examining the developments outside of Asia, a very different pattern emerges. For the rest of the world, excluding wind farm developments in Asia, the LCOE of wind has fallen by 16% between 2010 and 2014, despite the growth of deployment in new markets with higher cost structures than the average. Recent declines in the LCOE of wind power have been modest, but this has to be compared to just how competitive onshore wind is today. Most wind power projects developed today fall within or below the range of fossil fuel-fired electricity generation costs of USD 0.045 to USD 0.14/kWh, and wind is now one of the most competitive sources of electricity generation.

The LCOE of offshore wind has risen through time as total installed costs increased with greater distances from shore, increased water depths and increasingly complex projects (Figure 4.19). However, the LCOE of recent projects has stabilised in the USD 0.12 to USD 0.20/kWh range for most projects. The expectation is that in the future large projects planned to 2020 will achieve lower average costs. However, it remains to be seen if these ambitious projects can deliver on their proposed cost structure.

5 SOLAR PHOTOVOLTAICS

	2010	2013	2014	2010-2014 (% change)
New capacity additions (GW)	16	39	40+	150%+
Cumulative installed capacity (GW)	39	139	179+	360%+
Regional weighted average installed cost utility-scale (2014 USD/kW)	3 700- 7 060	1 690 – 4 250	1 570 – 4 340	-39% to -58%
Regional weighted average utility-scale LCOE (2014 USD/kWh	0.23 – 0.5	0.12 – 0.24	0.11 – 0.28	-44% to -52%
Residential LCOE in selected countries (2014 USD/kWh)	0.33 – 0.92	0.15 – 0.49	0.14 – 0.47	-49% to -58%

Notes: 2014 deployment data are estimates. n.a. = data were unavailable or not enough data to provide a robust estimate.

Highlights

- Solar PV module prices in 2014 were around 75% lower than their levels at the and of 2009.
- Between 2010 and 2014 the total installed costs of utility-scale PV systems have fallen by 29% to 65%, depending on the region.
- The global average LCOE of utility-scale solar PV has fallen by half in four years.
- The most competitive utility-scale solar PV projects are now regularly delivering electricity for just USD 0.08 per kilowatt-hour (kWh) without financial support. Even lower costs are being realised, down to USD 0.06/kWh, for utility-scale solar PV where excellent resources and low-cost finance is available.
- LCOE reductions have seen the costs for utility-scale solar PV increasingly fall within the fossil fuel-fired electricity cost range in 2014, without financial support.
- The LCOE of residential systems in selected countries has fallen by between 42% and 64% since 2008.
- With today's very low solar PV module prices, the greatest source of future cost reduction potential is in the balance of system costs, notably the soft costs, and through reduced finance costs.

Introduction

Solar photovoltaics (PV), also called solar cells or just PV, are electronic devices that convert sunlight directly into electricity. The modern form of the solar cell was invented in 1954 at Bell Telephone Laboratories. The term "photovoltaics" is derived from the physical process whereby the conversion of light (photons) to electricity (voltage) occurs, the so-called "PV effect".

In 1966, the National Aeronautics and Space Administration (NASA) of the United States launched the first Orbiting Astronomical Observatory, powered by a 1 kilowatt (kW) photovoltaic array. In 1977, global PV production capacity exceeded 500 kW. In 2002, total installed solar PV capacity exceeded 2 GW and 10 years later, in 2012, it surpassed 100 GW. In 2013, new additions of solar PV alone came to 39 GW and for the first time exceeded the new capacity additions of wind in a given year. The year 2014 was estimated to have been another record year, with total installed PV capacity likely to have exceeded 180 GW worldwide at the end of the year. In short, solar PV has come of age and mature commercial solutions are now available to provide competitive power in a complete range of applications from outer space, off-grid and on-grid, from solar lanterns to utility-scale PV parks at the scale of hundreds of MW.

Solar PV systems are one of the most "democratic" renewable technologies, in that their modular size means that they are within the reach of individuals, co-operatives and small- or medium-sized businesses that want their own generation facilities and the ability to lock in electricity costs. These small-scale systems represent the largest number of solar PV systems installed, but utility-scale ground-mount projects still represent the largest share of total installed capacity.

Solar PV is now a mainstream and mature technology. However, unlike most mature technologies, its costs are continuing to decline and solar PV is increasingly commercially attractive to project developers and to small-scale residential or commercial consumers. Its competiveness is compounded by the fact that many major markets are experiencing significant year-on-year increases in electricity prices.

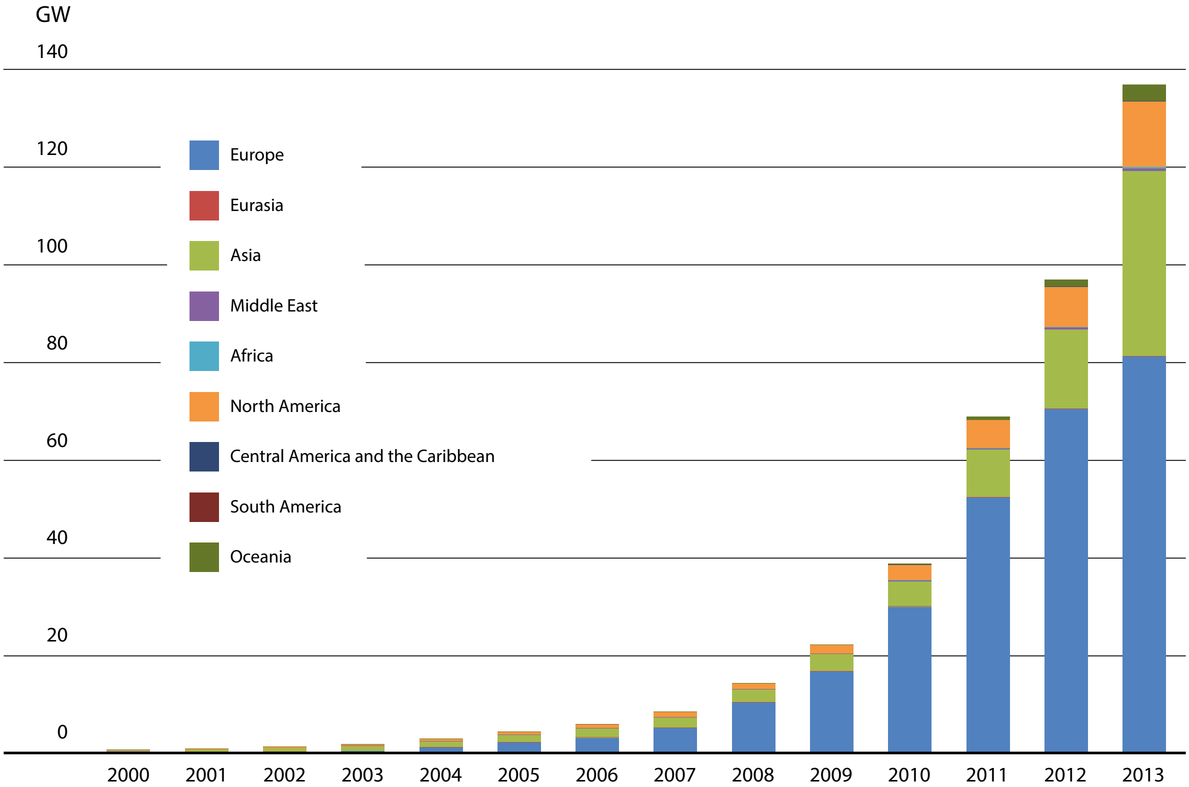
A solar PV system consists of the module, other electrical and hardware components (i.e. the inverter, electrical cabling, module mounts, controls, etc.). The solar PV systems are then mounted on rooftops or in fields.

Unlike Concentrating Solar Power (CSP) systems, solar PV systems operate in the presence of both direct and diffuse solar irradiation. The higher the level of solar resource, all other things being equal, the lower the system's levelised cost of electricity (LCOE) will be. Siting solar PV systems in areas with high solar resources (usually expressed as annual mean figures in kWh/m^2/year or as kWh/m^2/day) will therefore minimise the cost of electricity.

A wide range of PV cell technologies are available on the market today, using different types of materials, and an even larger number will be available in the future. PV cell technologies are usually classified into three generations, depending on the basic material used and their level of commercial maturity:

- First-generation PV systems (fully commercial) use the wafer-based crystalline silicon (c-Si) technology, either single crystalline (sc-Si) or multi-crystalline (mc-Si).
- Second-generation PV systems are based on thin-film PV technologies and generally include three main families: 1) amorphous (a-Si) and micromorph silicon (a-Si/μc-Si); 2) Cadmium-Telluride (CdTe); and 3) Copper-Indium-Selenide (CIS) and Copper-Indium-Gallium-Diselenide (CIGS). They are called "thin-film" because the semiconducting materials used for the production of the cell are only a few micro-metres thick. Some of these technologies are being deployed at commercial scale, but others are at an earlier stage of development.
- Third-generation PV systems include technologies, such as concentrating PV (CPV) and organic PV cells, which are still in a demonstration phase or have not yet been widely commercialised, as well as novel concepts under development.

Figure 5.1: Global cumulative installed solar photovoltaic capacity, 2000-2013



Source: IRENA

First and second generation PV technologies dominate the market today and will continue to do so in the near future, so they are the focus of this report.

Crystalline silicon-based PV modules currently dominate the solar PV market (around 90% of new installations by capacity), as their mature nature, relatively high efficiency and low cost make them a very attractive commercial choice.[19] The thin-film solar PV sector has undergone significant consolidation in recent years and deployment appears to be stabilising at around 4 GW, with 4.1 and 3.9 GW deployed in 2012 and 2013, respectively (GlobalData, 2014). Thin-film technologies have some advantages under specific operating conditions, so they are likely to continue to play an important role in the suite of technology options in order to maximise yield and minimise LCOE, despite the fact they have struggled to displace c-Si modules to date.

[19] Standard c-Si PV modules are estimated to have accounted for 89% of solar capacity installed in 2014, with premium c-Si suppliers contributing a further 3%. Thin-film panel manufacturers, led by a few major players, supplied nearly 8% of the end-market demand in 2014. (Photon Consulting, 2014).

Solar PV trends since the year 2000

Since 2013, the leading countries for PV deployment have shifted from Europe to Asia, due to the rapidly growing installation rates in both China and Japan. India is also one of the faster growing markets, with a total of 1 GW of new capacity in 2013.

China is now the largest market in the world for new solar PV, surpassing Germany, although Germany still has the largest cumulative installed capacity – at 38 GW. In late April 2014, China's National Energy Administration (NEA) announced that over 12.9 GW of solar PV capacity had been installed in 2013 (NEA, 2014). The Japanese solar PV market grew quickly following the introduction of Feed-in Tariffs (FiT) in July 2012. Japan installed 7 GW of solar capacity in 2013 alone. The United States has remained among the top three countries, having added 4.7 GW of new PV capacity in 2013. The outlook in Germany is for lower new installed capacity in 2014, as the German Federal Network Agency announced a significant drop in figures for newly installed capacity compared with the previous year, with around 2 GW of new PV capacity likely to have been added in Germany in 2014 (PV magazine, 2014).

Table 5.1: Solar photovoltaics deployment in China and Japan by market segment, 2012 and 2013

	China		Japan	
	2012 (MW)	2013 (MW)	2012 (MW)	2013 (MW)
Utility-scale	1 050	12 120	17	3 648
Commercial	910	750	17	1 899
Residential	1 540	130	1 684	1 406
Total Installed	**3 500**	**13 000**	**1 718**	**6 953**

Source: GlobalData, 2014.

Table 5.2: Detailed breakdown of solar PV cost components

PV Module	Inverter	BOS/Installation
Semiconductor • Raw materials (Si feedstock, saw slurry, saw wire) • Utilities, maintainence, labour • Equipment, tooling, building, cost of capital • Manufacturer's margin **Cell** • Raw materials (eg. metallization, SiNX, dopants, chemicals) • Utilities, maintainence, labour • Equipment, tooling, building, cost of capital • Manufacturer's margin **Module** • Raw materials (eg. glass, EVA, metal frame, j-box) • Utilities, maintainence, labour • Equipment, tooling, building, cost of capital • Shipping • Manufacturer's margin • Retail margin	• Magnetics • Manufacture • Board and electronics (capacitors) • Enclosure • Power electronics	• Mounting and racking hardware • Wiring • Other • Permits • System design, management, marketing • Installer overhead and other • Installation labour

Source: GlobalData, 2014.

Up to now, solar PV deployment has undergone challenges and changes but overall deployment has been increasing continuously. The total installed capacity of solar PV most likely surpassed 180 GW worldwide in 2014 (BNEF, 2014a; Photon Consulting, 2014; and IRENA analysis) with over 40 GW added in 2014.

Different support schemes can lead to very different trends in deployment by market segment within a country. As shown in Table 5.1, in 2013 the Chinese market focused very heavily on utility-scale projects, adding 10 GW within a year. In contrast, the Japanese market which grew strongly at the same time experienced a more even distribution between the utility, commercial and residential markets.

Solar PV capital costs

PV is a mature, proven technology that has achieved grid parity in a number of markets.[20] With continued cost reductions, grid parity will soon be the norm, rather than the exception. PV is a renewable, secure energy source with very high plant reliability and is not exposed to any fuel price volatility.

The capital cost of a PV system is composed of the PV module cost and the BoS cost. The cost of the PV module – the interconnected array of PV cells – is determined by raw material costs, notably silicon costs, cell processing/manufacturing costs and module assembly costs. The BoS cost includes items such as the cost of the structural system (e.g. structural installation, racks, site preparation and other attachments), the electrical system costs (e.g. the inverter, transformer, wiring and other electrical installation costs) and the soft costs of system development (e.g. customer acquisition, permitting, labour costs for installation, etc.). The cost of the battery or other storage system, if any, in the case of off-grid applications also needs to be added. Table 5.2 presents a detailed breakdown of the components that make up the total installed cost of a solar PV system.

As solar PV module prices have declined, the importance of the BoS cost is increasing, particularly the soft costs. This has important ramifications for policy-makers, as price declines for solar PV modules will now be more modest in absolute terms and will no longer be a major driver of cost reductions for solar PV systems in the future. Policy-makers must now turn their attention to driving down BoS costs. This will bring a new set of challenges, as a much more diverse range of cost drivers have an important role in the BoS, from permitting procedures and costs, to installation labour, to customer acquisition costs.

[20] The term "grid parity" is often used loosely and inconsistently. In this report, it is used to represent the point at which the LCOE of PV, without financial support, is the same or lower than the relevant electricity price (i.e. residential electricity tariff for small-scale systems), excluding taxes, over the period during which solar PV generates electricity. Other definitions include a price equal to, or lower than, the price of peak, shoulder or base-load electricity generation. In some cases, it will include or exclude taxes and subsidies.

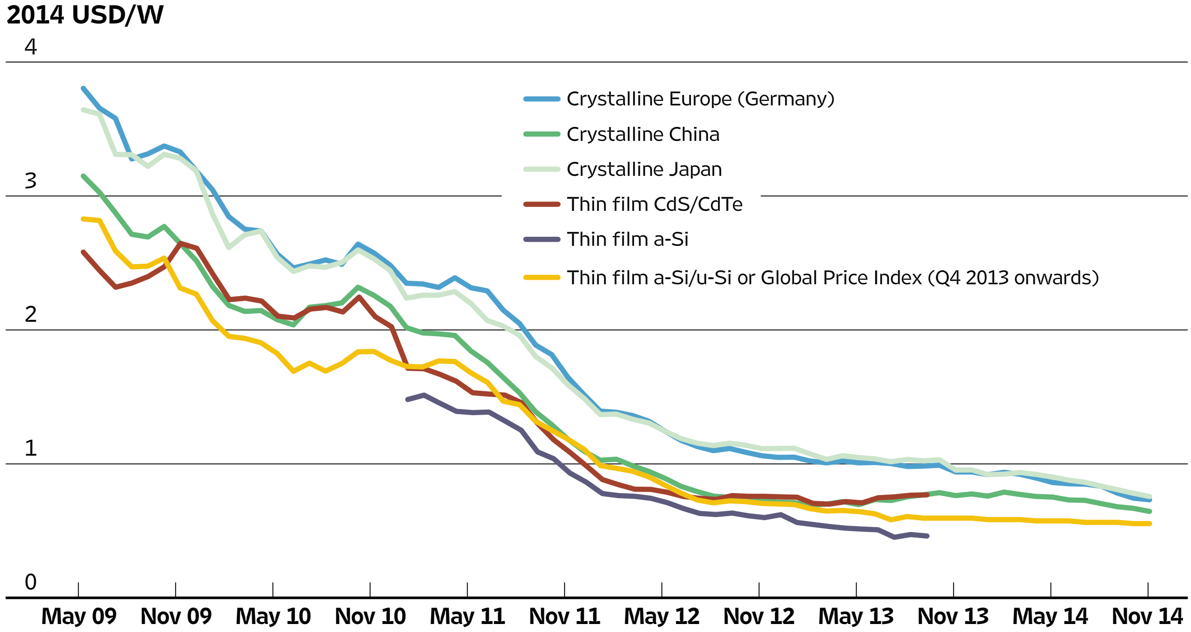
Solar PV module prices

Solar PV modules have high learning rates (18% to 22%) and rapid deployment – around 40% growth in cumulative installed capacity in each of 2012 and 2013. These factors have resulted in PV module prices declining by around 75% between the end of 2009 and the end of 2014 (Figure 5.2). In 2010, solar PV module prices declined by between 13% and 29%, depending on the market and manufacturing country source for the modules. In 2011, price declines accelerated and reductions of 39% to 49% occurred. In 2012, module price declines slowed down somewhat, to between 15% and 29%, and in 2013 price declines were between 12% and 18%, although exchange rate fluctuations and trade dispute results saw Chinese module prices actually rise by around 7% over the year. In 2014, the downward trend has been restored, to a range of between 7% for thin-film modules and 22% for German-manufactured modules. In the years 2013 and 2014, higher-cost module manufacturers in Europe and Japan experienced faster reductions in PV module costs than their low-cost competitors in China, which contributed to reducing the gap in prices.

The slowdown in the rate of price reductions in 2013 and 2014 was driven by solar PV module manufacturers consolidating margins and, in many cases, trying to return to positive margins after a period of manufacturing overcapacity and severe competitive pressures in the industry.

There is a growing international market for solar PV modules. However, although to some extent they are becoming "commoditised", important differences remain in costs and performance of modules from different manufacturers. For this reason, and due to different local conditions relating to importation and taxes, there will be a range of prices among individual markets. These variations by country can be significant. Figure 5.3 presents the evolution in the ratio of average solar PV module prices sold in various countries, relative to the average price in China. The ratio of module prices in other countries to those in China

FIGURE 5.2: AVERAGE MONTHLY SOLAR PV MODULE PRICES BY TECHNOLOGY AND MANUFACTURING COUNTRY SOLD IN EUROPE, 2009 TO 2014



Sources: GlobalData, 2014 and pvXchange, 2014.

experienced increased variation between 2011 and 2013, but the differentials – for Japan in particular – have narrowed in late 2013 and into 2014.

In addition to variations in the average selling price of solar PV modules by country, there is also variation within a country depending on the size of the system. Small-scale systems will typically have higher module prices than large-scale systems, where margins over wholesale market prices can be reduced significantly. This variation can be considerable – in Italy in 2013, small-scale rooftop systems were between 2.2 and 1.8 times as expensive as large-scale (> 1 MW) ground-mount PV systems. As the price of modules has declined, this premium for small-scale system module prices has increased, and has become particularly pronounced for sub-3 kW systems in 2013. The declines in average module prices by system closely reflect the average decline in PV module selling prices in Europe at the wholesale level – of around three-quarters. The exception, which has resulted in the increasing price premium shown in Table 5.3, was for the smallest systems of 3 kW or less, which saw price reductions of 69%. These price ratios are specific to Italy and other markets experience different ratios.

Solar PV is based on semi-conductor technology which helps to explain, in part, its high learning rate and sustained cost reductions as deployment has increased. The main drivers of the cost reductions in solar PV modules include:

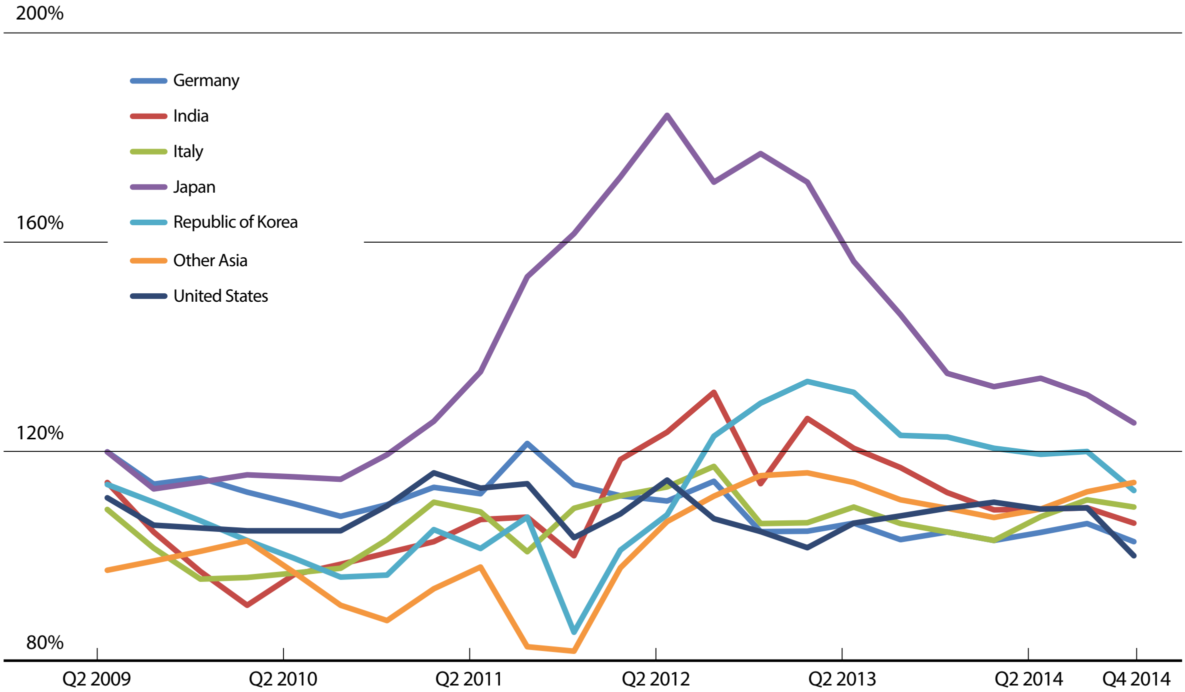
» Efficiency improvements: These occur in two areas – materials efficiency (i.e. reducing materials use and hence costs) and the efficiency of the solar PV module in converting sunlight into electricity (which also reduces materials costs by reducing the area required per watt).

» Economies of scale: Larger, integrated factories can achieve significant cost reductions by scaling up processes to a large scale, providing more competitive equipment prices, amortisation of fixed costs over larger throughput, etc.

» Production optimisation: This is an ongoing source of cost reduction opportunities based around more efficient processes and their integration, leading to optimisation of production at each phase.

With learning rates of 18% to 22% for solar PV modules and cumulative installed capacity doubling every couple of years, solar PV module prices would be expected to have fallen rapidly. Between the fourth quarter of 2010 and that of 2012, when the major price drop occurred, the main driver of the solar PV module price reduction,

Figure 5.3: Average differentials relative to China for solar PV module selling prices in various countries, by quarter



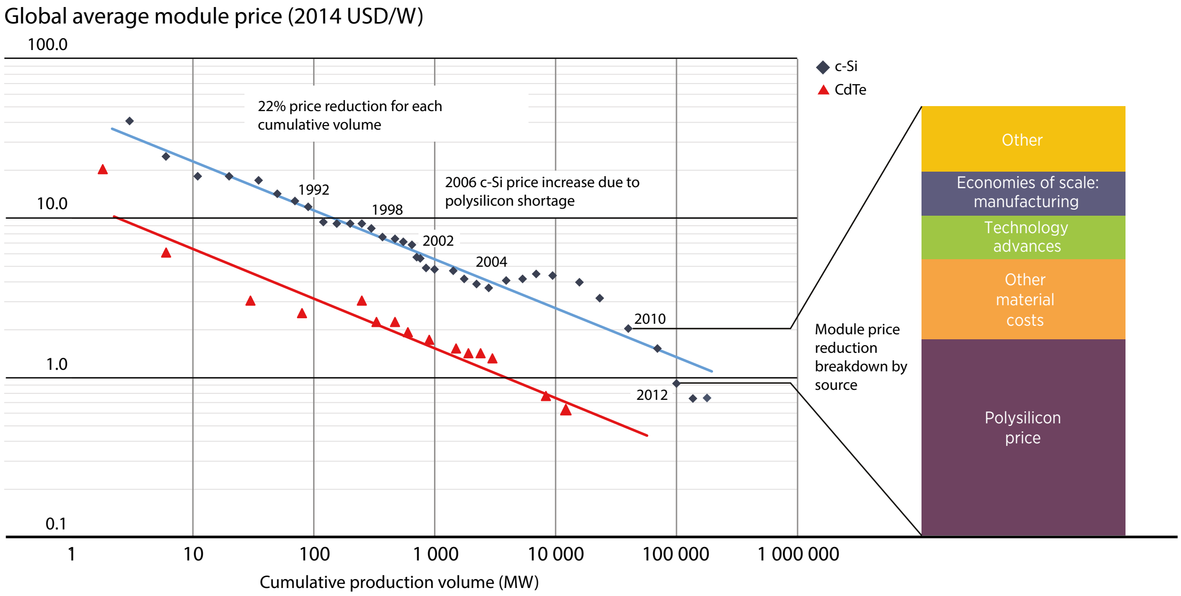
Source: GlobalData, 2014.

Table 5.3: Solar PV module prices by PV system size in Italy, 2008 to 2013

	Module price by size (2014 USD/W)						
	Rooftop			Ground-mount			
	1-3 kW	3-20 kW	20-200 kW	200-1000 kW	>1000 kW	Price premium (1-3 kW/> 1000 kW)	Price premium (3-20 kW/> 1000 kW)
2008	6.6	6.4	5.8	5.0	4.5	46%	43%
2009	5.6	5.4	4.7	4.1	3.5	61%	57%
2010	4.0	3.7	3.1	2.8	2.4	65%	53%
2011	3.2	3.1	2.6	2.2	2.2	47%	40%
2012	2.0	1.7	1.5	1.2	1.1	88%	63%
2013	1.8	1.5	1.1	0.9	0.8	117%	83%
Decline, 2009 to 2013	-69%	-73%	-77%	-77%	-77%		

Source: IRENA Renewable Cost Database/GSE.

Figure 5.4: Solar PV crystalline silicon and thin-film module cost learning curve



Sources: Based on data from EPIA and the Photovoltaic Technology Platform, 2011; GlobalData, 2014; GTM Research, 2014; Liebreich, 2011; pvXchange, 2014 and IRENA analysis.

accounting for almost half of the reduction, was a decline in polysilicon prices (45%), followed by other material costs (19%), greater economies of scale in module manufacturing (11%) and technology advancements (10%), while all other factors contributed a total of 16% (GTM Research, 2014).

With prices of solar PV modules at all-time lows, prices in 2012 significantly overshot the expected learning curve (Figure 5.4). This was the result of significant overcapacity in module manufacturing and cut-throat competition that saw many module transactions occur at cash-cost, or in some cases even lower, as financially stressed manufacturers tried to maintain cash flows. In 2013, despite record solar PV installations of around 39 GW, global PV manufacturing capacity, including c-Si and thin-film, exceeded 63 GW (Photon Consulting, 2014). An additional 10 GW of new module production capacity may have been added in 2014 (GTM Research, 2014). The competitive pressures in the solar PV module manufacturing industry are therefore likely to remain intense, although – unlike in recent years – profitability for the major manufacturers has improved and is now on a more sustainable footing.

The rapid decline in c-Si PV module prices due to manufacturing overcapacity has reduced the price advantage of thin-film PV module manufacturers. This has led to considerable consolidation in the thin-film industry, which should put the remaining manufacturers on a more secure financial footing. However, it remains to be seen whether the specific technological advantages – such as better performance in low-light conditions or hot climates – are sufficient for thin-film modules to substantially increase their share of new installations from current levels.

Despite the pause in reductions in average module selling prices in 2014, current prices are still significantly below the learning curve. They are also now so low that continued cost reductions, based on learning rates of 18% to 22%, will not yield large absolute cost reductions, as in the past. This means – in most countries – that BoS costs, and in particular the soft costs, will provide the largest opportunity for future cost reductions in absolute terms and represent the next great challenge for the solar PV industry.

Balance of system costs

BoS costs include all the cost components required for a solar PV system, excluding the module costs and includes the hardware costs (e.g. inverters, electrical cabling, racking, etc.) and the soft costs

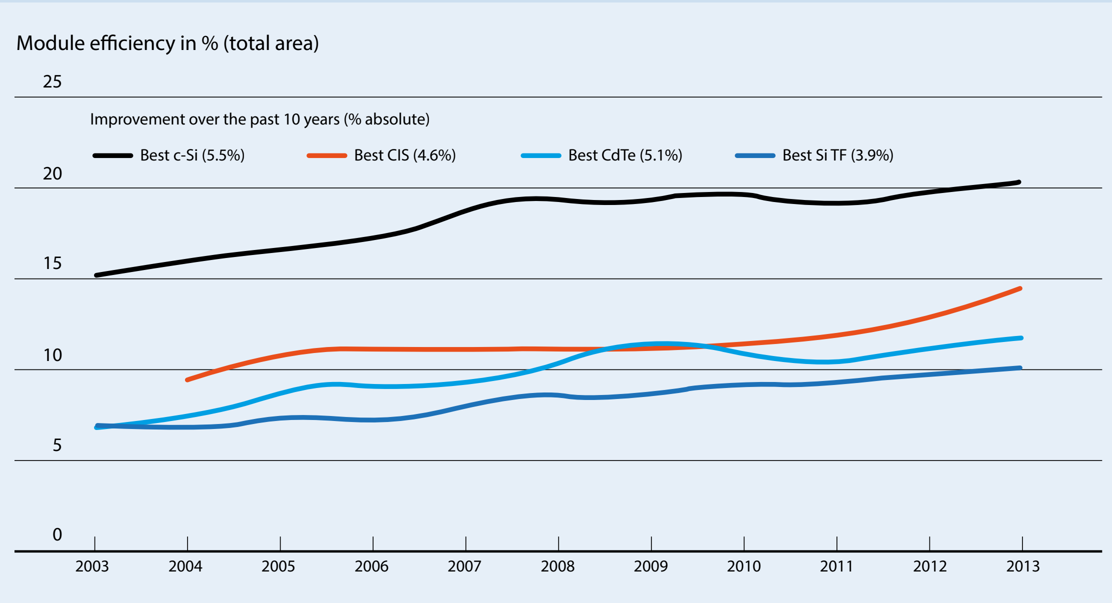
BOX 5.1

Solar photovoltaic module efficiency trends and their impact on costs

The efficiency of solar PV modules has increased in absolute terms over the past ten years. Crystalline silicon PV modules are not only the most efficient, but saw the greatest absolute increase in efficiency from around 15% to almost 21% in 2012. The increase in efficiency in percentage terms for the different technologies, represented an improvement of between one-third and two-thirds. (Fraunhofer ISE, 2014). These practical efficiency levels for modules that have been commercialised and are available for sale are significantly lower than the best results that can be achieved at the cell level in the laboratory, under ideal conditions and production processes that are not necessarily economic at a commercial scale. For instance, III-V multi-junction concentrator solar cells are capable of achieving efficiencies of around 44% at the cell level and new records continue to be set.

The impact of solar PV efficiency is somewhat different than conventional electricity technologies, where knowing the efficiency and capital cost is essential for determining the LCOE. With solar PV modules, efficiency improvements have a direct impact on capital costs in kW terms and it is through this effect that efficiency improvements reduce the LCOE of solar PV. As the efficiency of a solar PV module increases, less surface area is required to create a module of a given wattage, thus reducing the price per kW. Thus, although module efficiency trends will be a critical source of cost reductions in the future, for the purposes of examining historical trends in cost competitiveness, it is not necessary to discuss efficiency trends in detail, as their impact has already been largely captured in observed module prices.

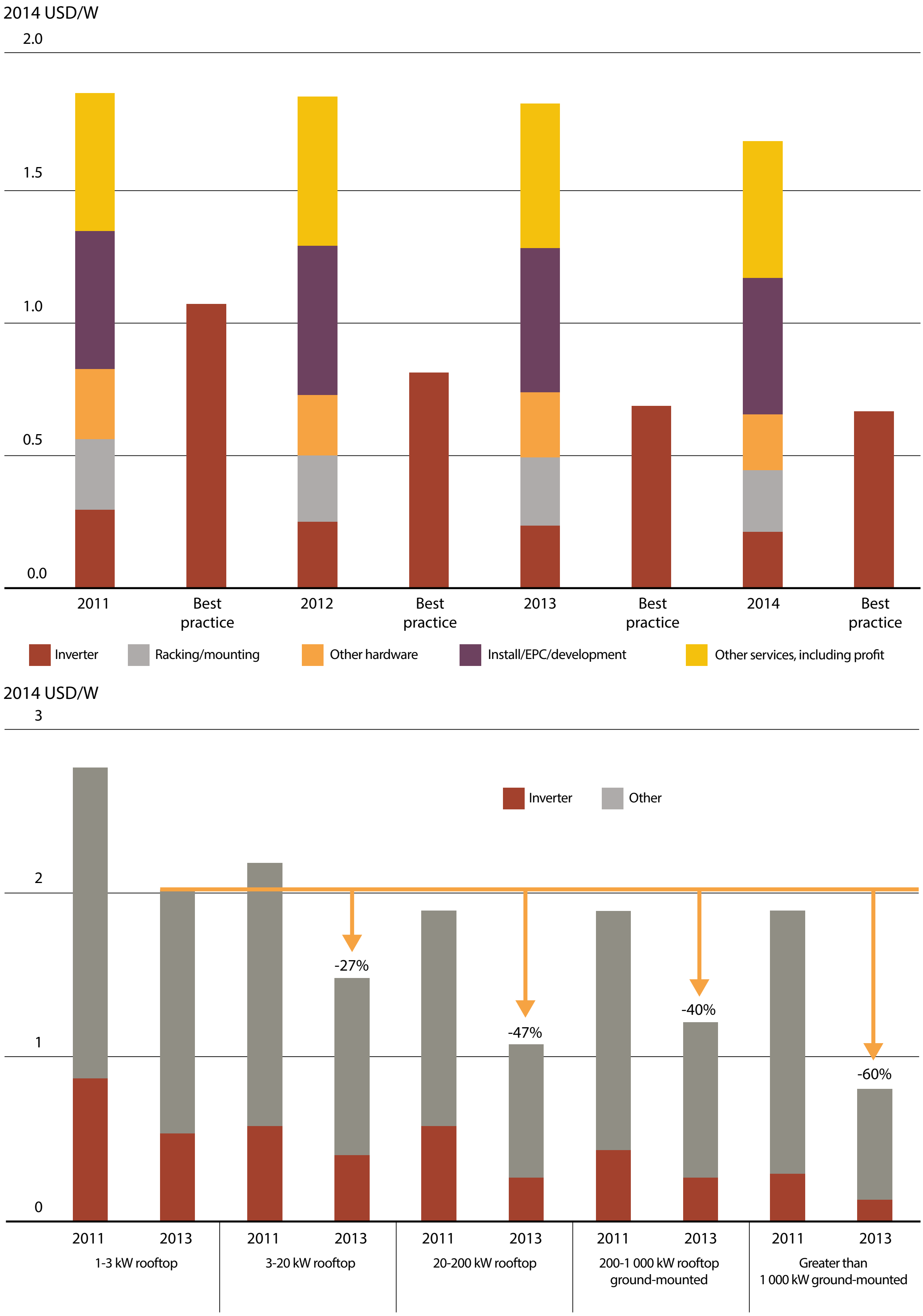
Figure 5.5: Solar photovoltaic module efficiency trends, 2003 to 2012



Source: Fraunhofer ISE, 2014.

(e.g. customer acquisition, installation, permitting, etc.). The order of magnitude of the BoS costs per kW for a solar PV system varies significantly by country and also by market segment. All other things being equal, small residential rooftop systems will have on average higher BoS costs than large rooftop installations on commercial buildings or multi-family dwellings, while large ground-mounted commercial systems will have even lower BoS costs than these large rooftop systems. Large utility-scale projects will typically have the lowest BoS costs per kW, as important economies of scale and purchasing power accrue to these systems. However, there can be some exceptions, notably the addition of single or two-axis tracking systems on utility-scale projects in order to raise their capacity factor. This hierarchy of cost levels will typically hold true on average within a country; however, differences in BoS costs for the same market segment can still be large.

Figure 5.6: Global average balance of system cost breakdown and global best practice and BoS costs in Italy by project size, 2011-2014



Source: GSE, 2014; Photon Consulting, 2014.
Note: Global average figures are rough estimates.

BoS and installation costs include:

- The inverter, which converts the direct current (DC) PV output into alternating current (AC);
- The components required for mounting and racking the PV system;
- The combiner box and miscellaneous electrical components;
- Site preparation and installation (i.e. roof preparation for residential systems, or site preparation for utility-scale plants), labour, costs for installation and grid connection;
- Battery storage for off-grid systems; and
- System design, management, installer overheads, permit fees, project development costs, customer acquisition costs and any up-front financing costs.

Local market conditions and the regulatory environment can have a significant impact on the BoS costs and wide variations typically exist within a country and between countries. The variation is typically largest for small-scale residential systems, while for utility-scale projects BoS costs will typically converge rapidly as the market in an individual country grows and project development experience and market scale push down costs.

Figure 5.6 presents the trend in the global weighted BoS costs of solar PV systems, to give an order of magnitude for BoS costs and show the trend between 2011 and 2014. Between 2011 and 2014, inverter costs declined by 29%, other hardware costs by 20% and racking and mounting of PV systems by 12%. Installation, engineering, procurement, construction and development costs, as well as other service costs, have only declined by around 1% in this period as growth in small-scale systems in relatively high-cost markets in North America and Japan accelerated, at the same time that lower-cost markets slowed in 2013 and 2014. Best practice BoS overall costs have been reduced by about 38% from 2011 to 2014. Best practice BoS costs in 2014 were around 60% lower than the global average, indicating a widening in the gap since 2011, when the difference between global average and best practice costs was 43%.

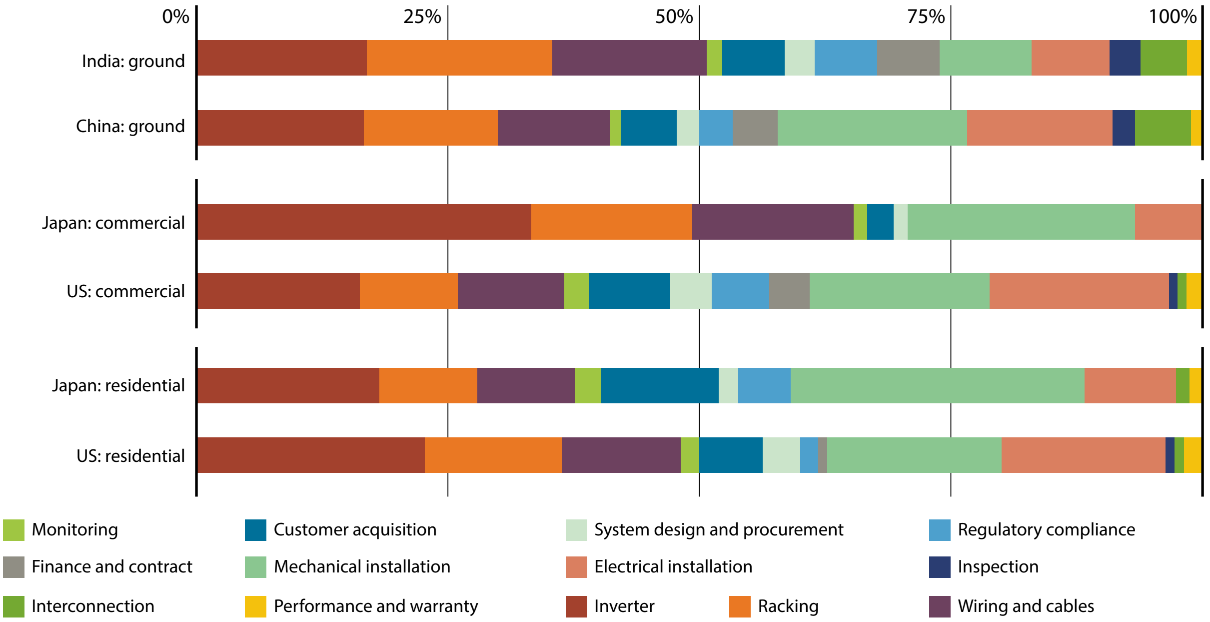
Although global averages are useful to track, BoS costs vary depending on whether the project is rooftop or ground-mounted and on the scale of the system. The data on the bottom of Figure 5.6 present the difference between BoS costs per watt in Italy according to the size of the system and whether it is mounted on the ground or a rooftop. Between 2008 and 2013, BoS costs fell by 55% for the smallest systems and 77% for the largest systems. In 2013, BoS costs for rooftop systems in the 3 to 20 kW range were 26% lower than for rooftop systems in the 1 to 3 kW range. Rooftop systems in the 20 to 200 kW range had BoS costs 47% lower than the 1 to 3 kW range systems, while ground-mounted systems in the 200 to 1 000 kW range had BoS costs that were 40% lower and utility-scale ground-mounted systems above 1 000 kW had BoS costs 60% lower.

BoS costs in 2014 were estimated to have averaged around USD 0.8/W in China, India and Italy for utility-scale ground-mounted systems, and USD 0.84/W in Germany (Photon Consulting, 2014). Other major markets for utility-scale projects in 2014 had higher BoS costs, with Spain estimated to have had average BoS costs for utility-scale ground-mounted systems of USD 1.07/W, while in the United Kingdom they were estimated to be USD 1.35/W, in South Africa they were USD 1.5/W and in Romania they were USD 1.56/W. These variations reflect the maturity of markets and supply chains, but also in many cases the efficiency of support mechanisms since solar system pricing is often value-based to some extent and influenced by the support levels in place.

Although BoS costs for smaller-scale commercial and residential systems are typically higher than utility-scale systems, the BoS costs of large commercial rooftop installations can still be quite competitive. For instance, in 2013, the average BoS costs for large commercial rooftop systems (20 to 200 kW) in Italy were lower, at around USD 1.08/W, than for utility-scale ground-mounted systems in the United Kingdom, South Africa and Romania.

Figure 5.7 provides a more detailed breakdown of BoS costs for two countries in each market segment: utility-scale ground-mounted, commercial sector rooftop and residential rooftop. Inverters and

Figure 5.7: Detailed balance of system cost breakdown for indicative utility-scale, commercial and residential systems in selected countries, 2014



Source: Photon Consulting, 2014

mechanical installation typically represent a smaller share of the BoS costs in utility-scale systems compared with smaller-scale projects in the commercial and residential sectors, while financing costs, interconnection and inspection costs tend to take up a larger share.

With module prices at all-time lows, future reductions in module prices in absolute terms will be modest. BoS cost reduction opportunities, and an understanding of their evolution over time, will be critical to unlocking reductions in the LCOE of solar PV. Figure 5.8 presents the evolution of an index of BoS costs for residential solar PV systems plotted against the cumulative deployment of solar PV in the residential sector in each country.[21] While there is a clear downward trend in all cases, there are two very distinct groups of countries for which data is available. The data for Germany and Italy suggest that they have been able to achieve a much more efficient cost structure for residential BoS costs through FiT declines and raising the scale of the residential sector market to ensure competition

[21] *The absolute values of these BoS calculations should be treated with caution, as reliable data for small-scale residential system module prices are not always available. Another point to note is that, although the BoS costs are plotted against residential deployment only, there is some argument for using total deployment in a given country as it could be expected that there are some spillover benefits from the total scale of deployment of solar PV in a country in terms of cost for small-scale residential systems.*

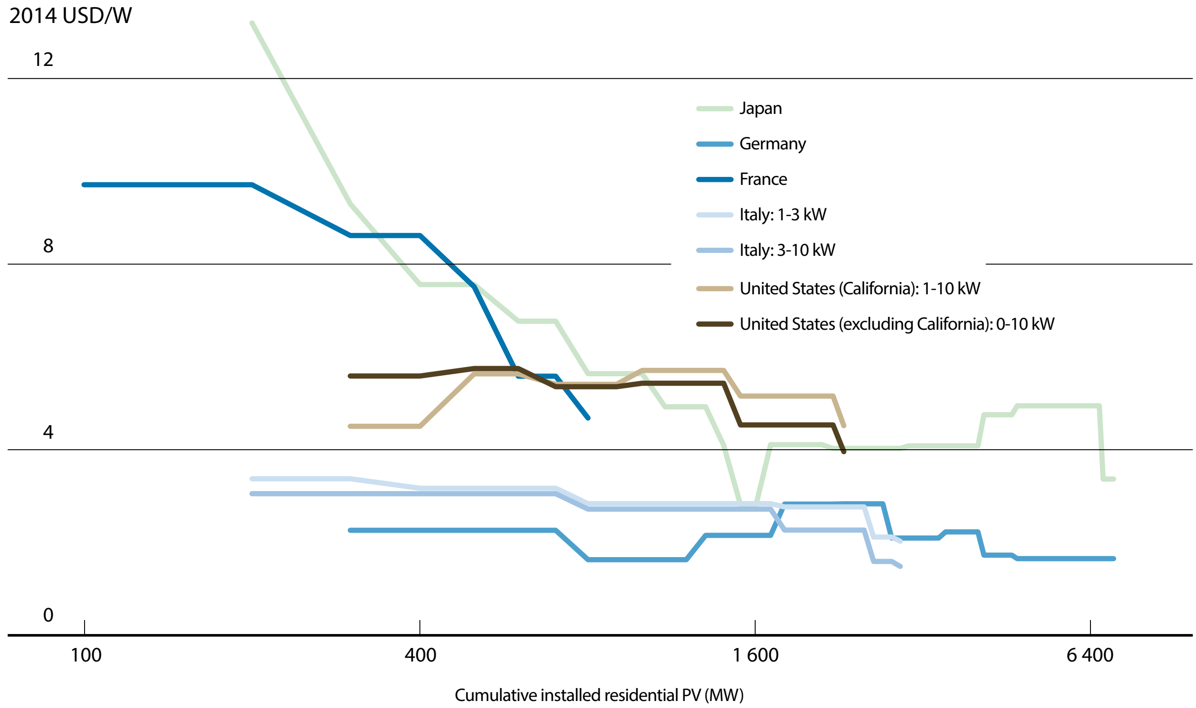
and economies of scale. Given the slowing of both these markets in 2014, the evolution of their BoS costs in 2015 and beyond will yield important information on BoS system reduction potentials under more challenging market conditions.

The case in Germany in particular will be pivotal to discovering what are the realistic lower limits of BoS costs. Germany has one of the most competitive residential solar PV markets in the world and has led the way in showing just how competitive small-scale PV can be in the right conditions, but the BoS costs in Germany have been largely flat in 2013 and 2014. This raises a number of interesting questions about BoS costs that will have a critical impact on future cost reductions for small-scale PV and their competitiveness. Of particular concern is whether the current BoS costs in Germany represent a lower limit with today's solar PV systems for small-scale projects, given current regulatory and business models.[22]

If this is the case, urgent research needs to be undertaken to identify what needs to change in order to ensure continued BoS cost reductions in Germany. At a global level, this is currently not a

[22] *This is not a concern per se for Germany, as solar PV has already reached grid parity and with residential electricity prices projected to continue to rise, the competitiveness of solar PV is set to improve in any event.*

Figure 5.8: Residential solar PV system balance of system cost evolution by country, 2008 to 2014



Source: IRENA Renewable Cost Database, with additional data from CPUC, 2014; GSE, 2014 and Photon Consulting, 2014.

threat to continued cost reductions for small-scale solar PV, as highlighted in Figure 5.8, because reducing BoS costs to the competitive levels seen in Germany and China will yield large cost reductions and improved competitiveness. However, the evolution of BoS costs in Germany and China for small-scale residential systems over the next few years could provide important information about medium- to long-term cost reduction expectations.

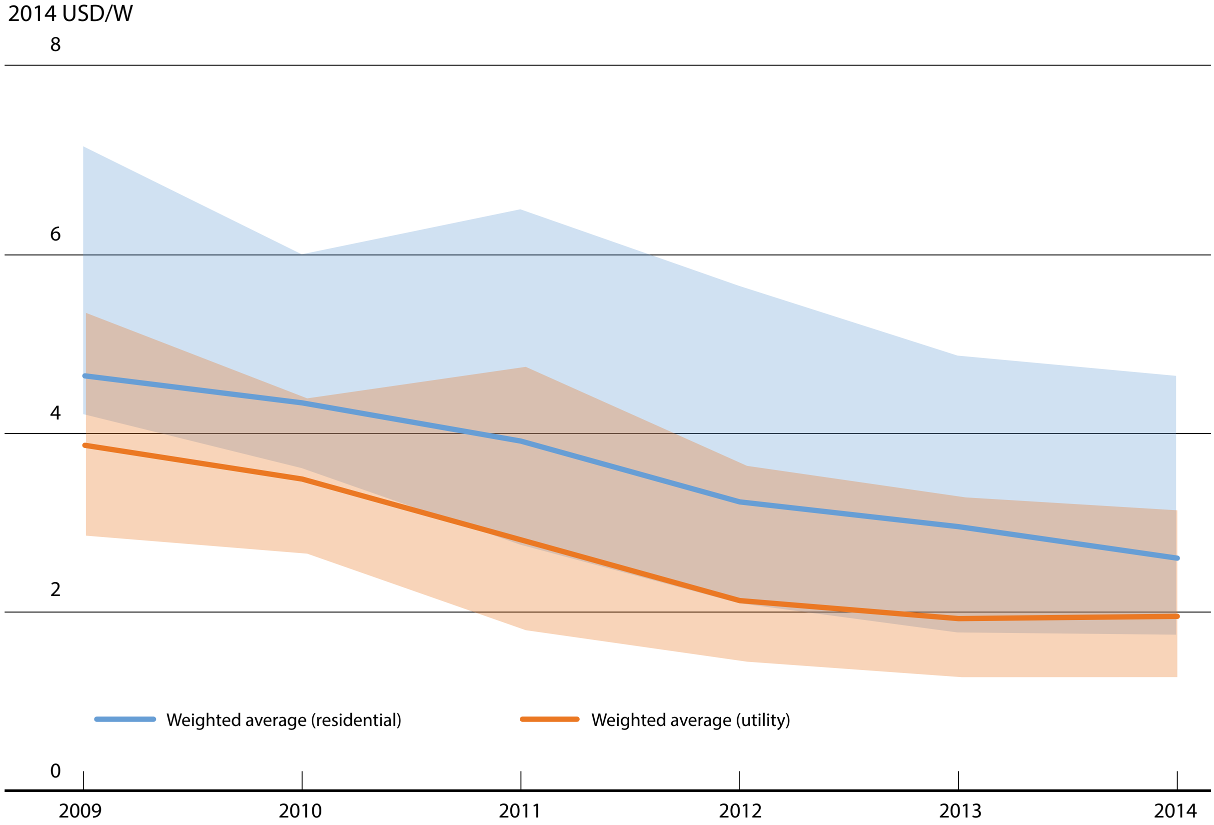
Total installed costs

Total installed costs for solar PV systems have fallen rapidly since 2008 as deployment has experienced exponential growth, driving down not only module costs, but BoS costs as well (Figure 5.9). Figure 5.9 presents the range for country average installed costs by year for all major PV markets for utility-scale projects (turnkey project costs) and residential projects. This does not represent the true range of project costs, as significant variation around the average country value exists (this will be discussed in more detail below), but it provides an indication of the trend in total installed costs in these two market segments. The total installed costs for residential systems have continued to decline into 2014, as opportunities to reduce BoS costs have allowed continued cost reductions even as module price reductions slowed to very low levels. The situation for utility-scale projects is somewhat different, as BoS cost reduction opportunities in competitive local markets for utility-scale projects have been relatively limited in comparison to residential systems.

However, examining high level trends in global aggregated solar PV installed costs is of limited value. The reality is that all of the individual markets for solar PV at the residential and utility scales are evolving at different rates and their respective maturities and local support policy structures have a significant impact on their current cost structures. Even within individual markets there is a huge variation in reported costs for solar PV systems and the reasons for this are often not well understood.

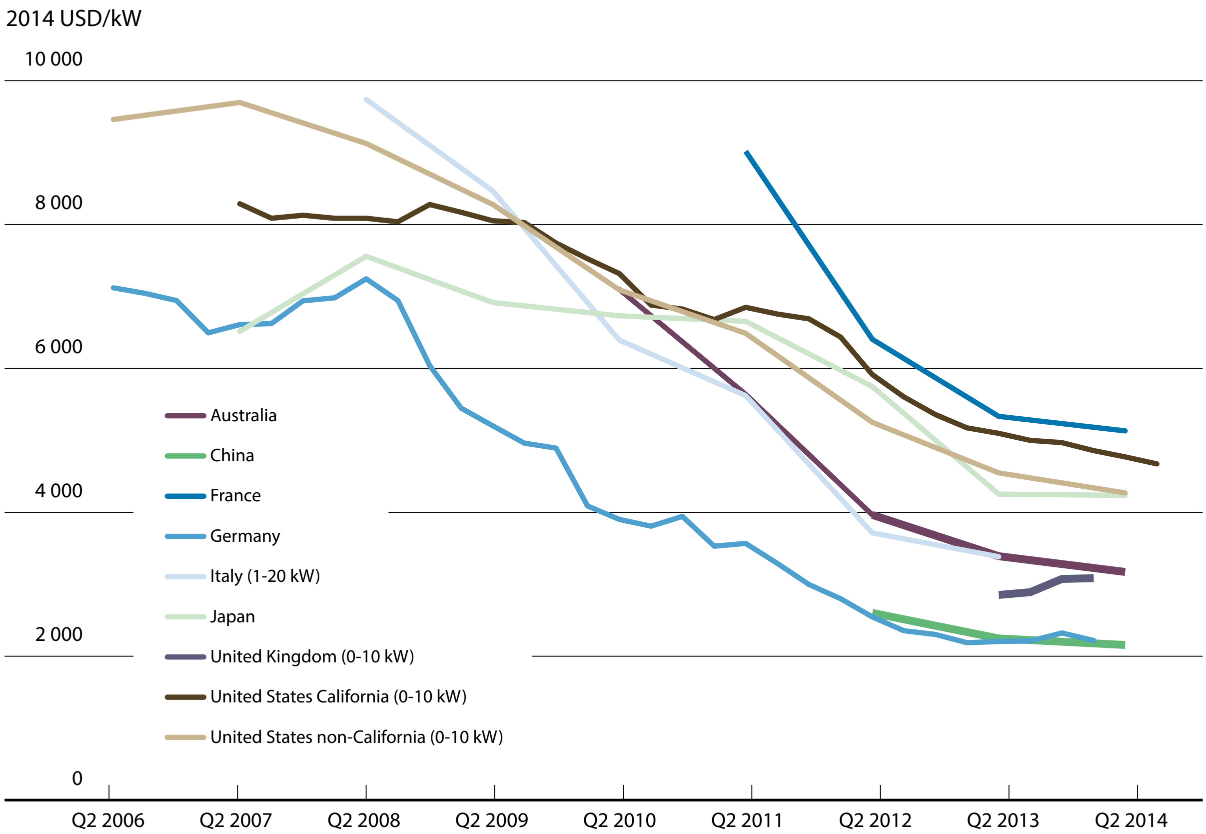
Figure 5.10 presents the evolution of the average total installed cost for residential sector solar PV systems between 2006 and 2014. Germany and China have, on average, the most competitive small-scale residential rooftop systems in world. Germany's residential system costs have fallen from just over USD 7 200/kW in the first quarter of 2008 to USD 2 200/kW in the first quarter of 2014.

Figure 5.9: Estimated global average installed costs for utility-scale and residential solar PV systems and the range of country averages, 2009 to 2014



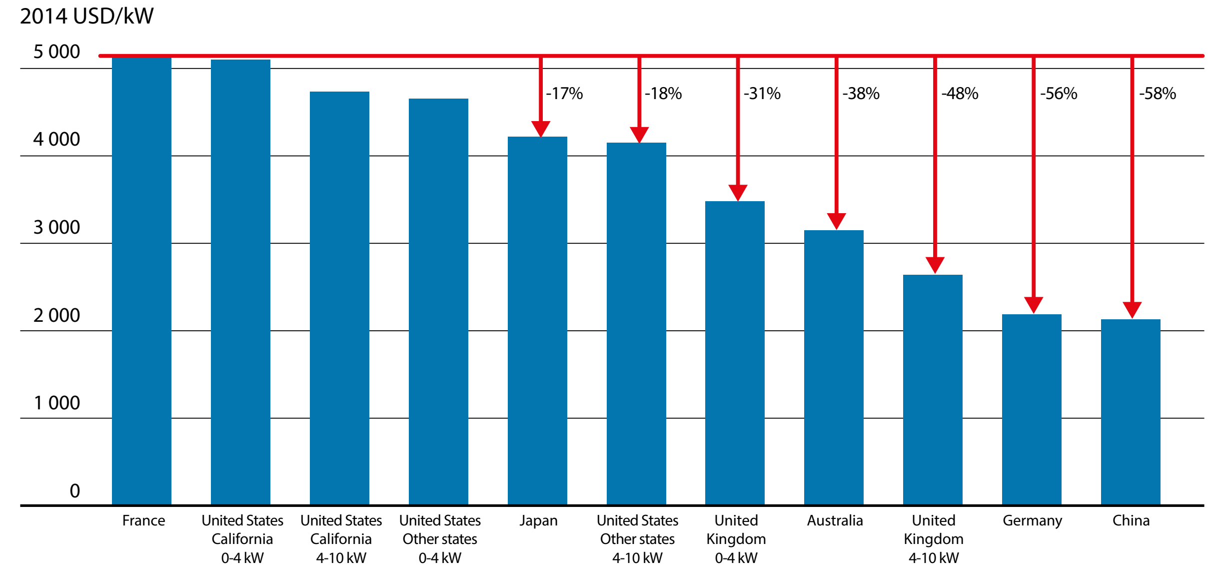
Source: IRENA Renewable Cost Database and Photon Consulting, 2014.

Figure 5.10: Average total installed cost of residential solar PV systems by country, 2006 to 2014



Source: IRENA Renewable Cost Database; CPUC, 2014; GSE, 2014; IEA PVPS, 2014; and Photon Consulting, 2014.
Note: Annual data for Australia, China, and Italy; quarterly data for the remaining countries.

Figure 5.11: Estimated average total installed PV system costs in the residential sector by country, 2014



Source: IRENA Renewable Cost Database; DECC, 2014; GSE, 2014; IEA PVPS, 2014; and Photon Consulting, 2014.

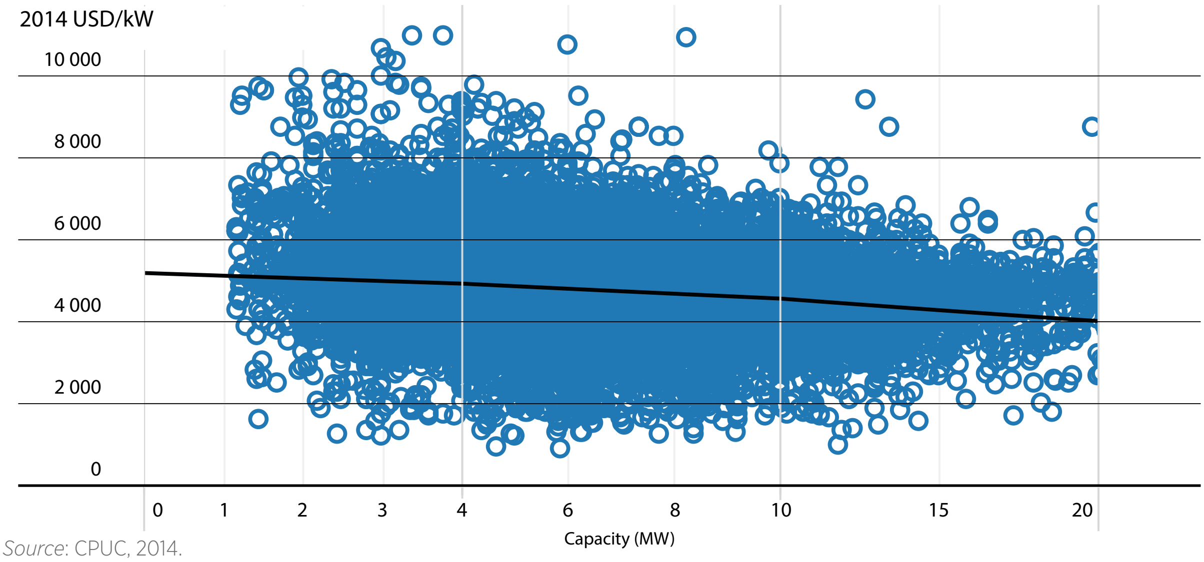
Residential systems in the United States (outside of California), Italy and France all experienced similar rates of decline, but total installed costs remain significantly higher, at an average of around USD 4 300/kW, USD 3 300/kW and USD 5 100/kW, respectively, in 2014. This ranges from around 50% to more than 130% higher than in Germany and China. The United Kingdom is an interesting case with respect to the evolution of deployment and installed costs in the residential sector. Large-scale deployment in the residential sector in the United Kingdom began in 2011, and in 2013 and early 2014 costs were at quite competitive levels of between USD 2 800 to 3 100/kW.

Figure 5.11 provides a more detailed comparison of market segments in 2014. In 2014, the highest country average for residential PV system total installed costs was almost 2.4 times higher than the lowest country average. At an average of around USD 2 200/kW, the residential PV systems in Germany and China were the cheapest and were lower in cost than utility-scale projects in many countries. The difference in installed costs between small systems of up to 4 kW and slightly larger residential systems of 4-10 kW is significant and ranged from 22% to 31% in 2013 and early 2014 in Italy and the United Kingdom. The difference is lower in the United States, with 1-4 kW systems having costs of between 2% and 11% higher than the larger 4-10 kW systems in 2013 and 2014.

However, given the wide range of variation in costs within individual country markets, there will be some overlap of the total installed costs even in countries at opposite ends of the average total installed cost range. Comparing the average total installed costs of residential systems in the United States and Germany provides an extreme example of this, as demonstrated by the data for residential systems in California (Figure 5.11 and 5.12). The bulk of installations in California are plus or minus 50% of the weighted average, but outliers are numerous. This wide variation in costs for residential systems in absolute terms in California is difficult to explain, as it extends to variations within individual cities, so is not a function of geographic location. Recent analysis is shedding more light on these issues, finding that they are due to state and federal policies, differences in market structure, and other factors that influence demand and costs (Gillingham, 2014). Interestingly, in addition to system characterisitcs (discussed below) it was concluded that search costs, installer density, financial support levels and imperfect competition have a significant impact on solar PV prices.

Part of the variation in installed costs relates to scale and system characteristics for the smaller-scale systems, site-specific costs and also the fact that any variations in total project costs are magnified with small-scale systems on a per kW basis. The data for the evolution of total installed costs by

Figure 5.12: Total installed PV system costs for residential systems in California by system size, 2014



Source: CPUC, 2014.

size tend to support this idea for solar PV systems installed in the residential sector in California (Figure 5.12). There is a clear downward trend in total installed system costs by size in the residential sector, with a narrowing of the variation, particularly beyond system sizes of 12 kW, where perhaps more competition and better-informed customers, given the magnitude of the investment, may combine to narrow the range of total installed costs.

Figure 5.13 presents the total installed costs of utility-scale solar PV projects in the IRENA Renewable Cost Database.[23] Similar to the case in the residential sector, the total installed costs of utility-scale solar PV vary significantly but, according to the data available, they have experienced a downward trend between 2011 and 2014. Globally, smaller utility-scale systems (1-5 MW) have seen their weighted average installed costs fall by 37% between 2011 and 2014, while large-scale utility plants of 5 MW or more have seen weighted average installed costs fall by 35%. This is slightly more than the reduction of 30% implied by the global average calculations for utility-scale projects in Figure 5.9 – where central estimates of turnkey prices (not individual project costs) for systems in all major utility-scale markets were compared.

Between 2011 and 2014, the most competitive projects have continuously reduced costs – from lows of around USD 3 200/kW for small-scale projects and USD 2 200/kW for large-scale projects in 2011, to lows of around USD 1 300 for both size groups in 2014. This is a decline of 65% for smaller utility-scale projects (1-5 MW) and 41% for larger (> 5 MW) projects in just three years, with a trend to large-scale projects with available cost data, at least in the IRENA Renewable Cost Database.[24]

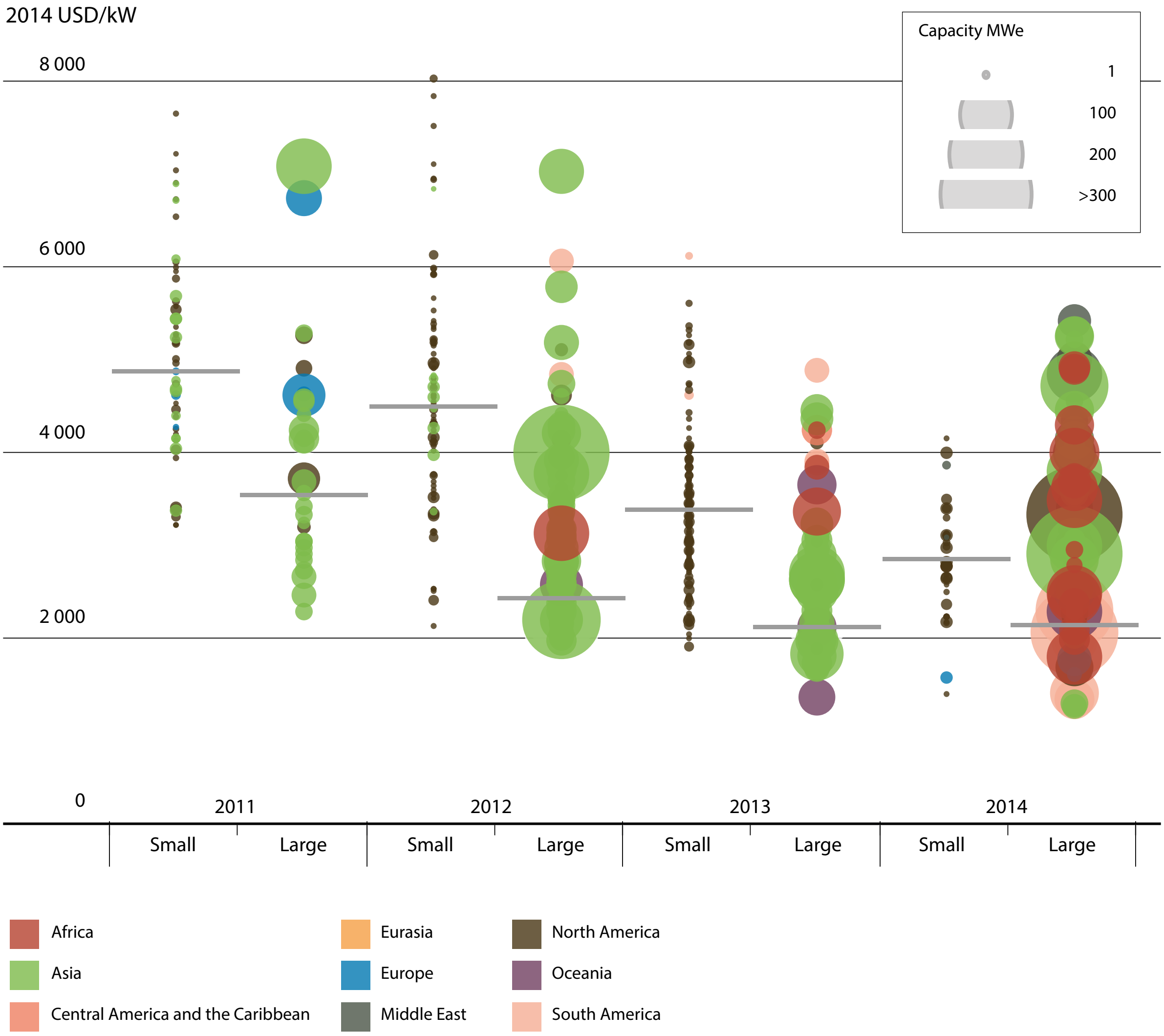
The range of installed costs for small utility-scale projects in 2011 was between USD 3 200 and USD 7 600/kW, while for large-scale utility projects the range was between USD 2 200 and USD 7 050/kW. By 2014, the range for smaller utility-scale projects had declined to between USD 1 300 and USD 6 800/kW (based on data from CPUC, 2014 and Photon Consutling, 2014 to supplement the IRENA Renewable Cost Database) and for larger projects it had declined to between USD 1 300 and USD 5 400/kW.

The data in the IRENA Renewable Cost Database by region for utility-scale projects show a wide range of installed costs in 2013 and 2014 (data for 2013 and 2014 is presented to provide a more representative sample from the database), where module prices were little changed (Figure 5.14). It is noticeable that regions and countries with large land masses

[23] Where the IRENA Renewable Cost Database does not have a representative sample of projects installed for a country in a given year, a balance total has been added for that county to ensure average costs are representative. Nevertheless, care must still be taken in interpreting the results presented here.

[24] The data in the IRENA Renewable Cost Database are not necessarily a representative sample of project sizes however, so care must be taken in implying any contribution from economies of scale for larger projects to the trend in average costs.

Figure 5.13: Total installed PV system costs and weighted averages for small and large utility-scale systems, by region and capacity, 2011 to 2014



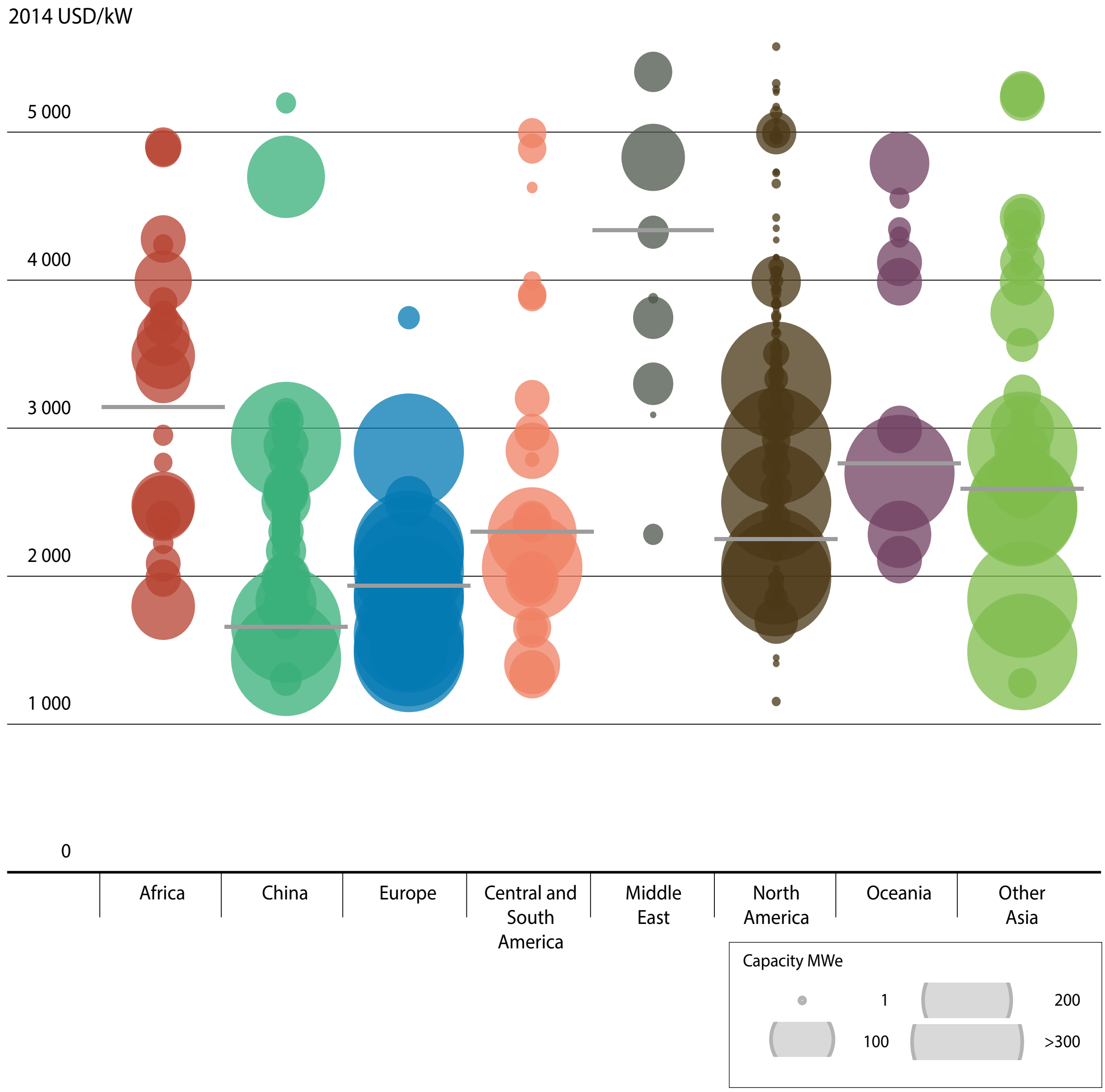
Source: IRENA Renewable Cost Database; CPUC, 2014; NREL, 2014; and Photon Consulting, 2014.

and competitive tendering or auction systems have seen a trend towards larger-size systems, notably in the United States, in China and in Central and South America. The most competitive projects have installed costs as low as USD 1 300/kW, while the upper cost range for projects is around USD 5 400/kW. In Africa, the total installed costs for utility-scale projects in 2013 and 2014 spanned the range from USD 1 820 to USD 4 880/kW, while in Central and South America the range was from USD 1 350 to USD 5 000/kW and in Other Asia (including Japan) the range was from USD 1 290 to USD 5 240/kW. The typical range for total installed costs of utility-scale projects in Europe and North America in 2013 and 2014 was between USD 1 300 and USD 3 750/kW, and USD 1 300 and USD 5 580/kW, respectively (IRENA and LBNL, 2014). The data in the IRENA Renewable Cost Database for total installed costs of utility-scale projects in China ranged from USD 1 320 to USD 3 090/kW for typical installations, but there remain outliers. The data available for other regions are modest and indicative at best.

Solar PV capacity factors

Capacity factors vary with the solar resource available and whether or not the systems have tracking systems (single or two-axis). Capacity factors for PV are typically in the range of 10% to 25% for fixed tilt systems, but values outside of this range are possible for exceptional sites or where siting is not optimal (e.g. tilt-angle or shading).

Figure 5.14: Total installed PV system costs by project and weighted averages for utility-scale systems by region and capacity, 2013 and 2014



Source: IRENA Renewable Cost Database; CPUC, 2014; NREL, 2014; and Photon Consulting, 2014.

However, average values can be very misleading for a country or a region, as solar resources are very site-specific (Table 5.3) and "micro-climates" can mean that even sites that are geographically very close together can show a wide discrepancy in capacity factors. Accurate solar resource mapping is therefore essential to the identification of the best sites for solar.

The weighted average capacity factor for utility-scale projects in Asia, outside of China and India, is around 14%, while in China it is around 17%, in Africa around 22%, and in India around 21% (Figure 5.15). In South America, where excellent resources are being exploited at present, the average capacity factor for utility-scale projects is around 27%. In North America, where utility-scale deployment in 2013 was concentrated in California and Arizona, average capacity factors have been around 22%. Adding tracking systems can significantly raise these capacity factors but this must be traded off against the additional cost of the tracking system.

The Levelised Cost of Electricity of Solar PV

The rapid decline in the total installed costs of small- and large-scale solar PV systems is mirrored

Figure 5.15: Utility-scale solar photovoltaic capacity factors by regionSource: IRENA Renewable Cost Database.

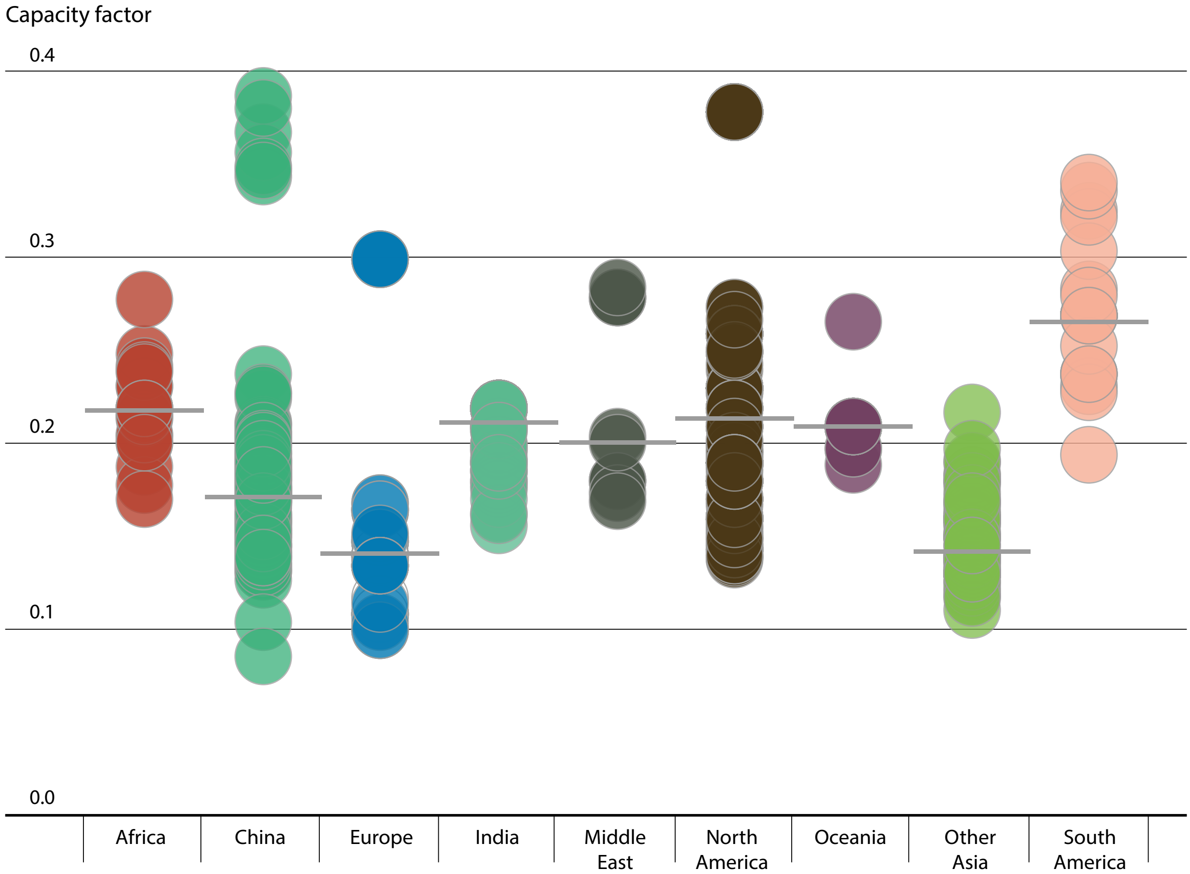


Table 5.4: Solar PV capacity factors by location and tracking system in the United States

	Fixed tilt	One-axis tracking	Two-axis tracking
Seattle, WA	14%	18%	19%
Miami, FL	20%	25%	26%
Phoenix, AZ	24%	31%	33%

Source: NREL, 2011.

in the trends for the LCOE of solar PV. With residential electricity tariffs rising around the world since 2000, as the result of increases in fossil fuel prices, residential grid parity (sometimes referred to as "socket" or "plug" parity) is becoming the norm rather than an exception. The challenge for utility-scale deployment remains real, but in areas of excellent solar resources and high electricity spot prices, even the once long-off goal of competitive utility-scale solar PV has been achieved. Solar PV merchant plants are being developed in Chile without any financial support, to meet growing demand, while power purchase agreements in the southwestern part of the United States are being signed at prices competitive with fossil fuels.

Promoting the development of competitive markets for solar PV in regions with the best solar resources will help to lower the LCOE of solar PV and meet the growing, and sometimes currently unserved, electricity demand in emerging economies that often have excellent solar resources. However, transport costs and poor local infrastructure are serious barriers in many parts of Africa and elsewhere in the sunbelt to achieving competitive installed cost levels.

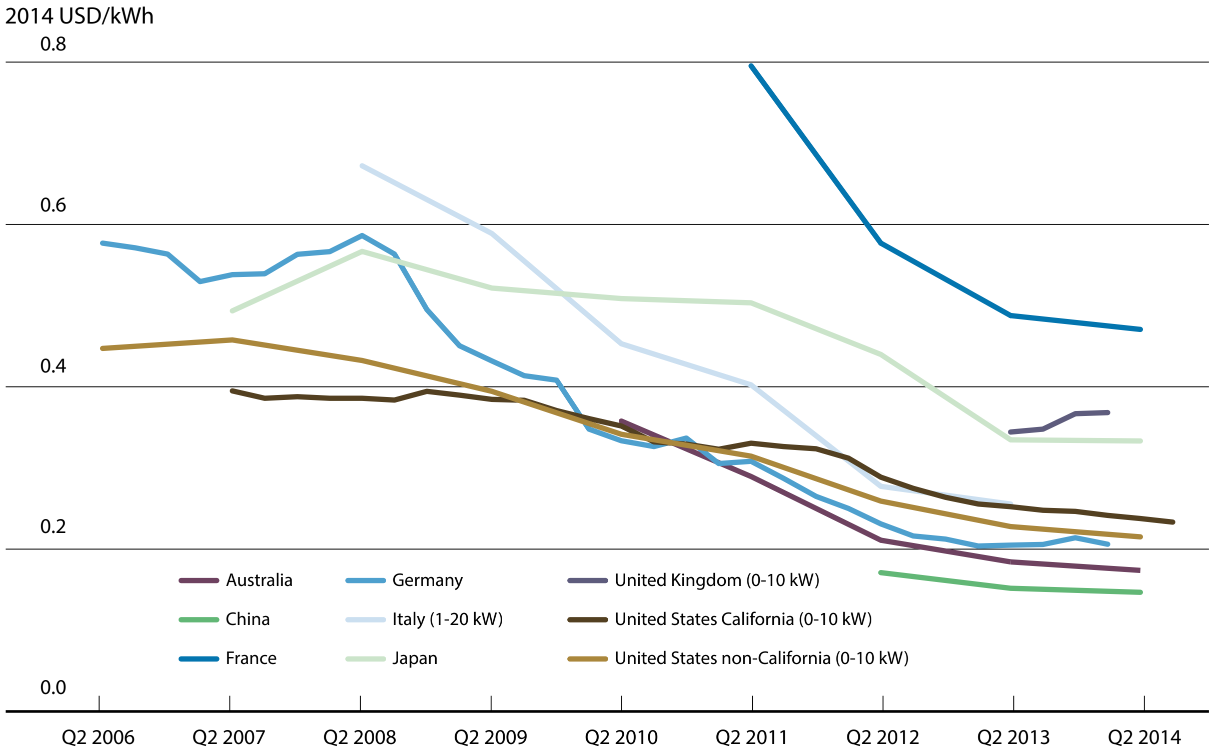
The global average utility-scale LCOE of solar PV is estimated to have declined by around half between 2010 and 2014, from around USD 0.32/kWh to just USD 0.16/kWh in 2014. The estimated global average LCOE of utility-scale solar PV declined by

14% between 2010 and 2011, 34% between 2011 and 2012 and by a further 8% between 2012 and 2013. The LCOE was little changed between 2013 and 2014, despite continued modest declines in installed costs in virtually every major market. The reason for this is the estimated continued shift in market growth in 2014 away from traditional low-cost markets, such as Germany, to some markets with higher cost structures, notably Japan and the United States. This has resulted in the estimated global average installed costs, and hence LCOE, being little changed in 2014 compared with 2013 despite continued declines in individual countries. This result needs to be treated with caution, however, as full data were not available for 2014 and both deployment and cost numbers are likely to change from what is presented here. It remains to be seen what impact those changes will have on the global average LCOE for utility-scale solar PV in 2014.

The average LCOE of residential PV systems without battery storage was estimated to be between USD 0.38 and USD 0.67/kWh in 2008 for the data presented in Figure 5.16. But this declined to between USD 0.14 and USD 0.47/kWh in 2014 with the reduction solar PV module prices seen since 2008 in the countries examined in Figure 5.16. The LCOE of electricity for residential systems declined by around 42% between 2008 and 2014 for small systems (0-4 kW) in California and by 44% for the larger 4-10 kW systems; in other parts of the United States the decline was 52% and 54%, respectively, for these residential systems. The LCOE of French residential systems is estimated to have declined by 61% between 2008 and 2014, while the LCOE of Japanese residential systems fell by 42%. The estimated LCOE of residential systems in Italy fell by 59% between 2008 and 2013 for systems of 1-3 kW in size, while they fell by 66% for larger systems of 3-20 kW in size, for an average decline of around 63%. Between 2010 and 2014, the average LCOE of residential systems in Australia declined by 52%. A shorter time series is available for China, which has very competitive LCOE levels.

Cost reductions mean that the LCOEs of the latest utility-scale projects in 2014 are increasingly competitive. Figure 5.18 presents the LCOE ranges and capacity-weighted averages for utility-scale PV projects between 2010 and 2014. The range of the LCOE has declined from between USD 0.18 and USD 0.61/kWh in 2010 to between USD 0.08 and USD 0.50/kWh in 2014. The ranges remain wide, but there has been a rapid reduction in the global weighted average LCOE of utility-scale solar

Figure 5.16: Levelised cost of electricity of residential solar photovoltaic systems by country, 2006 to 2014



Source: IRENA Renewable Cost Database; BSW, 2014; CPUC, 2014; GSE, 2014; LBNL, 2014; and Photon Consulting, 2014.

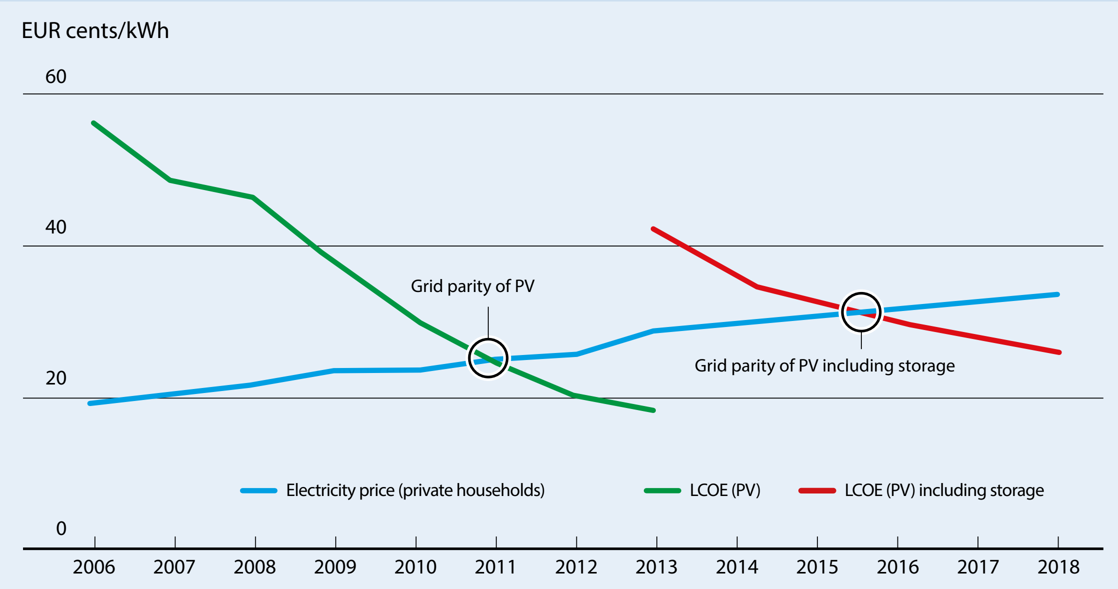
BOX 5.2

Declining feed-in tariff rates and battery costs

As FiTs for residential solar PV systems are reduced, there will be a growing number of countries where the FiT is significantly below the retail electricity price. For instance, in Germany, new systems installed at the end of 2014 will receive an approximate FiT value of between EUR 0.12 and EUR 0.15/kWh, depending on their size (Bundesnetzagentur, 2014), while retail tariffs are around EUR 0.30/kWh. The value of self-consumption has therefore increased significantly, as the value of the electricity saved is now twice that of the revenue received from the FiT.

When combined with the falling costs of lithium-ion (li-ion) battery systems, which offer better performance than lead-acid batteries, the economics of self-consumption will potentially become very favourable. Recent analysis suggests that by 2016 these factors will work together to result in PV-storage parity in Germany, assuming a 5 kWh battery pack and a starting point of EUR 2 300/kWh in 2013 for li-ion battery packs, with costs declining over time (Figure 5.17). This analysis excludes any subsidies, so any government support for PV-storage systems would bring forward the point of competitiveness. This coming PV-storage parity will further increase the pressure on existing power generation utilities. Although it will not make sense for consumers to become totally self-sufficient, they will have an incentive to increase the level of self-consumption and market growth could potentially decouple from financial support levels and become self-sustaining.

Figure 5.17: Grid parity of PV-storage in Germany

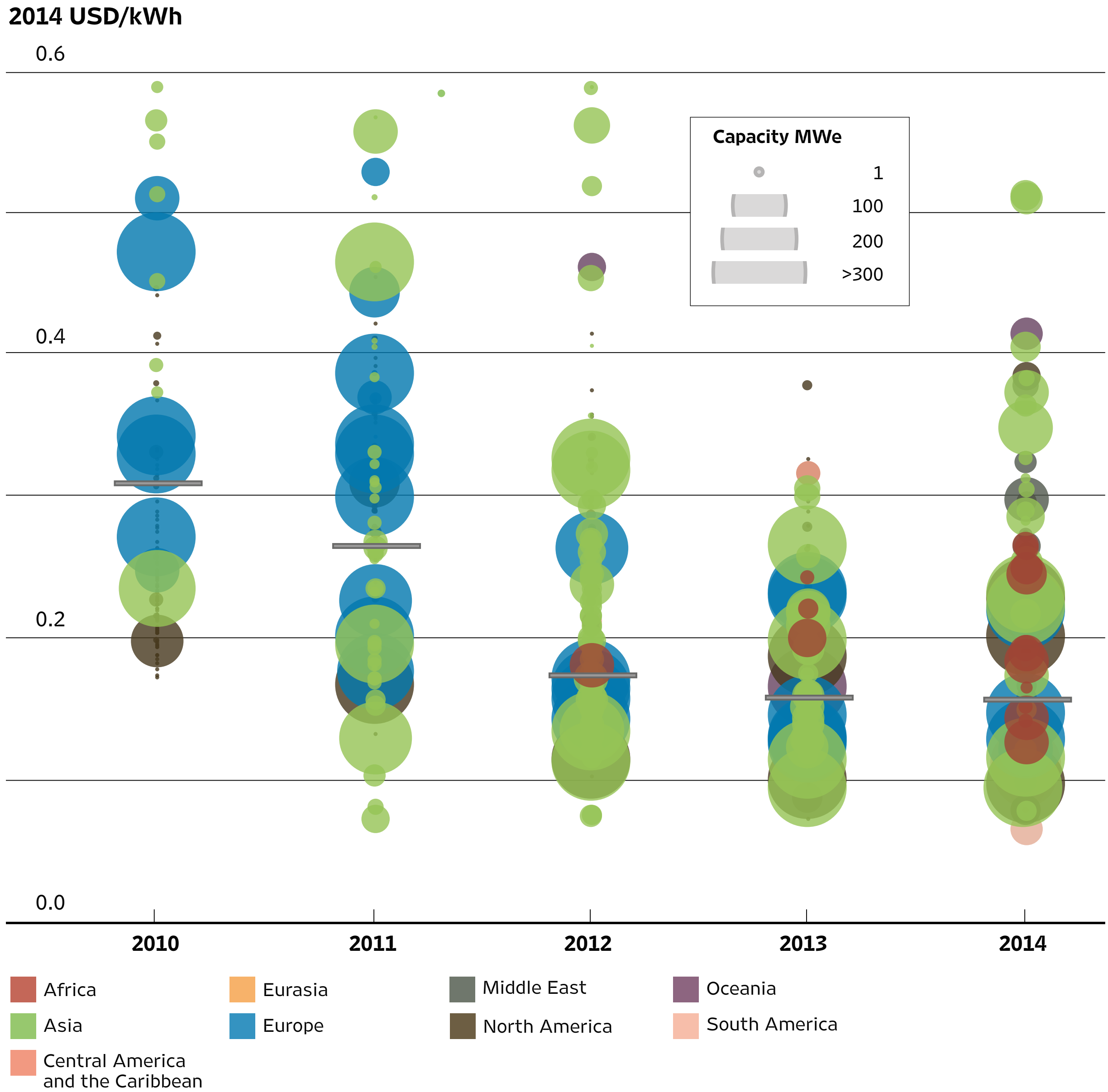


Source: EuPD Research/ BDEW 2013.

PV as module prices declined rapidly to 2012. The slowing in LCOE reductions in 2013 and 2014 reflects the slowing in module price declines and also a trend to greater deployment in some higher cost markets.

Figure 5.19 presents the LCOE data by country and region, but only for 2013 and 2014 when module prices were similar. Central and South America have the lowest estimated weighted average LCOE, of around USD 0.11/kWh; while, North America – specifically the United States – is also very competitive with a weighted average LCOE of USD 0.12/kWh. Average installed costs are somewhat higher in the United States than in China, but the excellent solar resources in the United States compensate for this to some extent. South America is also emerging as a very competitive

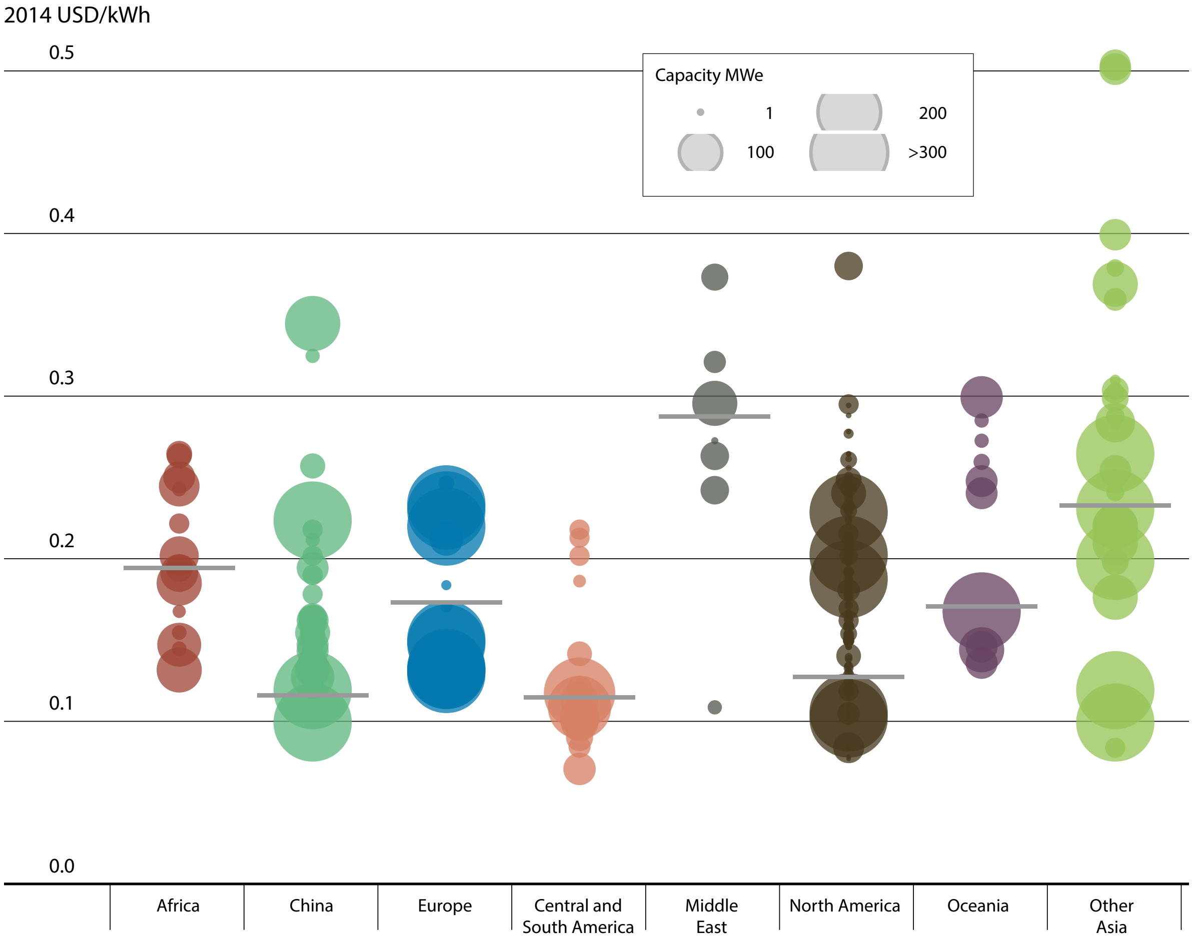
Figure 5.18: Levelised cost of electricity of residential solar photovoltaic systems by country, 2010 to 2014



Source: IRENA Renewable Cost Database and Photon Consulting, 2014.

solar PV market, where excellent resources and competitive cost structures are emerging to make highly competitive projects. As already noted, utility-scale solar PV in parts of Chile is competitive with wholesale electricity prices and no financial support is required. This trend will become increasingly the norm as witnessed by the recent PPA announcement in Dubai that saw the winning bid for a 100 MW solar PV plant come in at just USD 0.06/kWh (DEWA, 2014).

Figure 5.19: Levelised cost of electricity of utility-scale solar photovoltaic systems by country and region, 2013 and 2014



Source: IRENA Renewable Cost Database and Photon Consulting, 2014.

6 CONCENTRATING SOLAR POWER

	2010	2013	2014	2010-2014 (% CHANGE)
NEW CAPACITY ADDITIONS (GW)	0.5	0.9	1.1	136%
CUMULATIVE INSTALLED CAPACITY (GW)	1.3	3.5	4.8	286%
TYPICAL GLOBAL TOTAL INSTALLED COST RANGE (2014 USD/KW)	3 420 – 11 740	3 550 – 8 760	N.A.	N.A.
GLOBAL LCOE RANGE (2014 USD/KWH)	0.33 – 0.44	0.19 – 0.39	0.20 – 0.35	N.A.

Notes: 2014 deployment data are estimates. n.a. = data not available or not enough data to provide a robust estimate.

HIGHLIGHTS

- CSP is in its infancy in terms of deployment compared to the other renewable power generation technologies, with 5 GW of CSP installed worldwide at the end of 2014.
- The current CSP market is dominated by parabolic trough technologies (around 85% of cumulative installed capacity). However, increasing numbers of solar towers are being built and offer the promise of lower electricity costs.
- CSP can integrate low-cost thermal energy storage in order to provide dispatchable electricity to the grid and capture peak market prices.
- The weighted average LCOE of CSP by region varied from a low of USD 0.20 in Asia to a high of USD 0.25/kWh in Europe in recent years, with the LCOE of individual projects varying significantly depending on location and level of storage.
- However, as costs are falling, recent projects are being built with LCOEs of USD 0.17/kWh, and power purchase agreements are being signed at even lower values where low-cost financing is available. Future cost reductions can be expected if deployment accelerates, but policy uncertainty is hurting growth prospects.
- Total CSP installed costs have ranged from USD 3 550 to USD 8 760/kW in 2013 and 2014. The wide variation is driven by different cost structures in different countries, but mostly reflects the wide variation between plants with and without energy storage and the amount of storage.

Introduction

Concentrating solar power (CSP) is a power generation technology that uses mirrors to concentrate the sun's rays and, in most of today's CSP systems, to heat a fluid that is used to produce steam. The steam is then used to drive a conventional steam turbine and generate power in the same way as conventional thermal power plants that use steam cycles. However, other concepts are being explored and not all future CSP plants will necessarily use a steam cycle.

CSP is at its infancy in terms of deployment, with total installed capacity at the end of 2014 of around 5 gigawatts (GW). New capacity additions in 2013 were estimated to have reached 0.9 GW, a new record. Total installed capacity has grown rapidly since 2010, but policy uncertainty has reduced growth prospects in key markets.

CSP plants can be divided into two groups, based on whether the solar collectors concentrate the sun's rays along a focal line or on a single focal point (with much higher concentration factors). Line-focusing systems include parabolic trough and linear Fresnel plants, and have single-axis tracking systems. Point-focusing systems include solar dish and solar tower plants, and include two-axis tracking systems to concentrate the power of the sun.

Parabolic trough collectors (PTC) dominate the total installed capacity of CSP plants and consist of solar collectors (mirrors), heat receivers (tubes), heat transfer fluid and system, and support structures. A single-axis tracking mechanism is used to orient both solar collectors and heat receivers toward the sun (A.T. Kearney and ESTELA, 2010). Most existing parabolic troughs use synthetic oils as heat transfer fluid, which are stable up to around 360 to 400°C. High temperatures are an important development goal for all CSP plants as they improve the system's thermal storage performance and allow more efficient steam cycles to be used, thereby reducing the levelised cost of electricity (LCOE) from CSP plants.

Solar tower technologies use a ground-based field of mirrors (heliostats) that track the sun individually in two axes to focus direct solar irradiation onto a receiver mounted high on a central tower where the light is captured and converted into heat. The heat then drives a thermodynamic cycle, in most cases a water-steam cycle, to generate electric power. Solar towers can achieve higher temperatures than parabolic trough and linear Fresnel systems, because more sunlight can be concentrated on a single receiver and the heat losses at that point can be minimised. There are two proven types of solar tower concepts. Direct steam generation (DSG) plants have been developed by Abengoa and avoid the need and costs of a heat transfer fluid.

Table 6.1: A comparison of CSP technologies

	Parabolic trough	Solar tower	Linear Fresnel	Dish-Stirling
Maturity of technology	Commercially proven	Commercially proven	Early commericial projects	Demonstration projects
Operating temperature (°C)	350-400	250-565	250-350	550-750
Collector concentration	70-80 suns	> 1 000 suns	> 60 suns (depends on secondary reflector)	up to 10 000 suns
Receiver/absorber	Absorber attached to collector, moves with collector	External surface or cavity receiver, fixed	Fixed absorber, no evacuation secondary reflector	Absorber attached to collector moves with collector
Application type	On-grid	On-grid	On-grid	On-grid/Off-grid
Suitability for air cooling	Low to good	Good	Low	Best
Storage with molten salt	Commercially available	Commercially available	Possible, but not proven	Probably, but not proven

Table 6.2: Bottom up engineering estimates of different configurations of parabolic trough and solar power plants

	Heat transfer fluid	Solar mutiple	Storage (hours)	Capacity factor (%)	Cost (2014 USD/kW)
Parabolic trough	Synthetic oil	1.3	0	26	4 950
	Synthetic oil	1.3	0	23	7 688
	Synthetic oil	2	6	41	8 604
	Synthetic oil	2	6.3	47-48	9 626-10 552
	Synthetic oil	2	6	43	8 320
	Molten salt	2.8	4.5	50	7 936
		2.5	9	56	8 120
		3	13.4	67	9 826
Solar power	Molten salt		7.5		7 825
	Molten salt	1.8	6	43	6 772
	Molten salt	2.1	9	46	7 983
	Molten salt	1.8	6	48	8 025
	Molten salt	2	9	54	8 299
		3	12	68	9 742
		3	15	79	11 311

Sources: Fichtner, 2010; Hinkley, 2011; Kolb, 2011; Turchi, 2010a; and Turchi, 2010b.

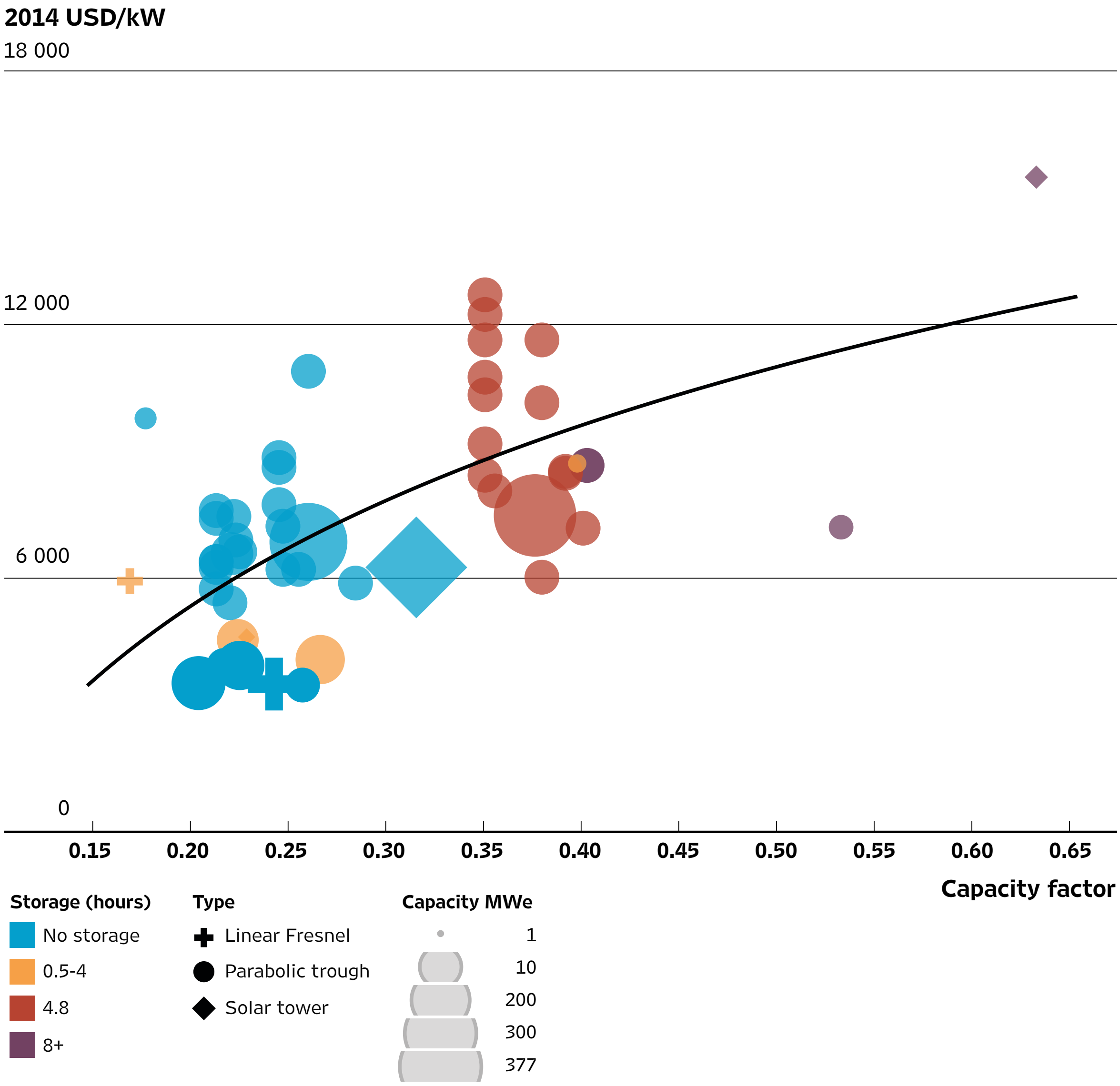
An alternative approach uses molten salts for the heat transfer fluid. By using molten salt as the heat transfer fluid the potential operating temperature could rise with more research and development (R&D) to between 550 and 650°C, sufficient to allow higher efficiency supercritical steam cycles. Although still at the R&D phase, supercritical cycles could improve efficiencies and lower the cost of thermal energy storage.

The key advantage of solar towers is their higher operating temperatures, which allow low-cost thermal energy storage to raise capacity factors and to achieve higher efficiency levels. This also allows a more flexible generation strategy to be pursued in order to maximise the value of the electricity generated. Given this and other advantages, if costs can be reduced and operating experience gained, solar towers could potentially achieve significant market share in the future, despite PTC systems having dominated the market to date.

Linear Fresnel collectors (LFCs) are similar to PTCs, but instead of parabolic mirrors LFCs use a series of long, flat or slightly curved mirrors placed at different angles on each side of a fixed receiver (located several metres above the primary mirror field) to concentrate sunlight on the receiver. The focal line of Fresnel collectors is somewhat distorted, unlike parabolic mirrors, and requires either that a mirror be installed above the receiver tube (a secondary reflector) to refocus any rays missing the tube, or several parallel tubes forming a multi-tube receiver that is wide enough to capture most of the focused sunlight without a secondary reflector. The advantage of LFCs is that they can use cheaper mirrors and lighter and less expensive support structures than PTC systems, resulting in lower capital costs than PTC systems. This is offset to some extent by their lower solar efficiency. As a result, there doesn't appear to be a clear advantage to either PTC or LFC systems at this stage of their development.

Solar dish systems consist of a parabolic dish-shaped concentrator (like a satellite dish) that reflects direct solar irradiation onto a receiver at the focal point of the dish. In order to convert this heat into electricity the receiver may incorporate a Stirling engine or a micro-turbine. This configuration avoids the need for a heat transfer fluid and cooling water. Stirling dish systems require the sun to be tracked in two axes,

Figure 6.1: Installed costs and capacity factors of CSP projects by their quantity of storage



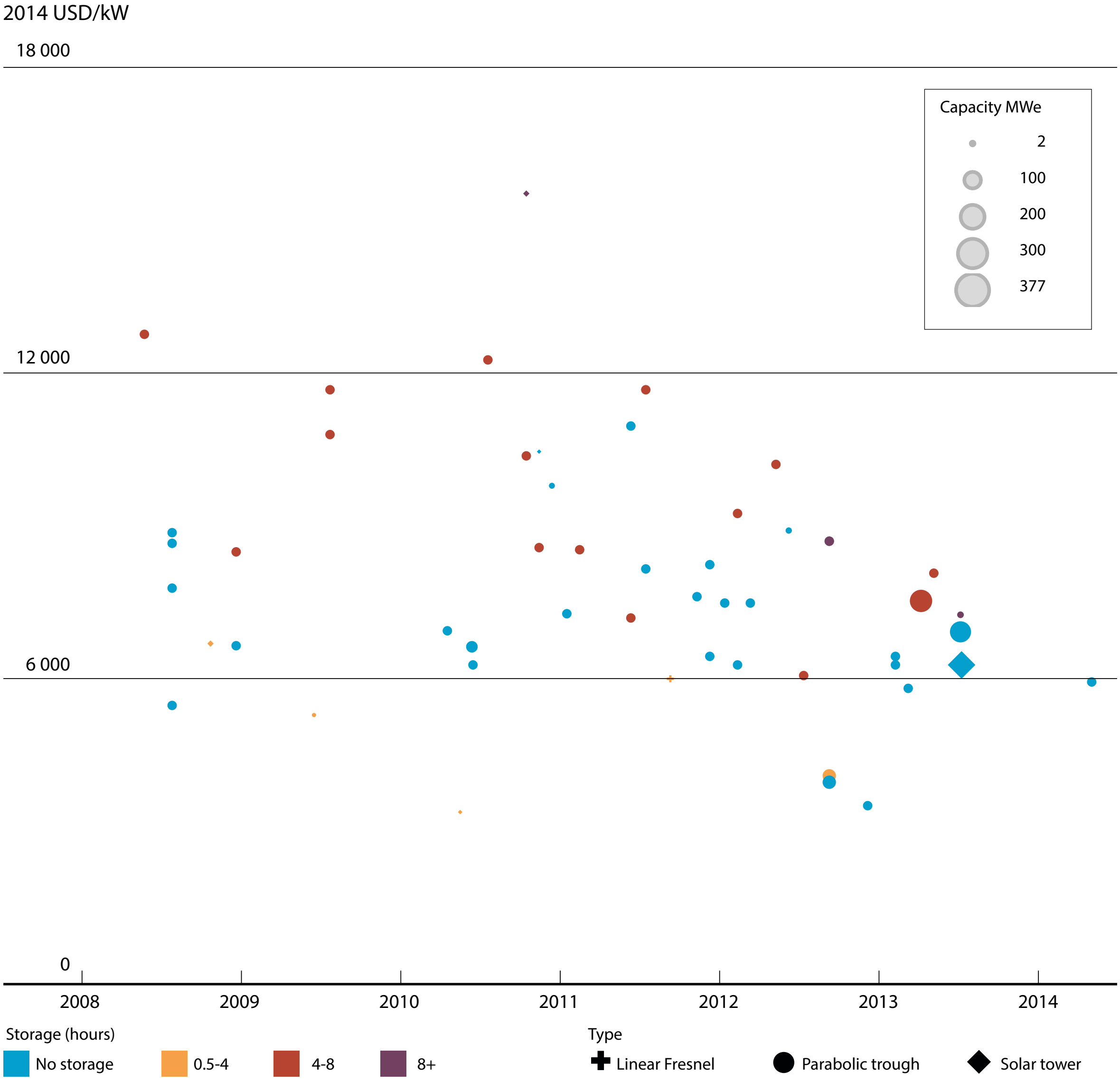
Sources: IRENA Renewable Cost Database; BNEF, 2014e; GlobalData, 2014; and NREL/SolarPACES, 2014.

but the high energy concentration onto a single point can yield very high temperatures, helping to improve efficiency. Their advantages are their very modular nature, which allows for small-scale systems (10s of kW), the fact that they can be used on broken or sloped terrain and their very low water requirements. Their disadvantages are they are expensive relative to other CSP technologies and not dispatchable. Stirling dish systems are just beginning to be deployed at scale, with a 1 megawatt (MW) system at the Maricopa plant in Arizona, and a 1.5 MW system under construction in Utah, both in the United States.

CSP capital costs

Despite around 15 solar tower projects or more in operation, the current CSP market is dominated by PTC technologies, both in terms of number of projects and total installed capacity (around 85% of capacity). PTC technology's share of total installed capacity will decline slowly in the near future, as around one-third of the capacity of plants currently under construction are either solar tower projects or linear Fresnel systems (SolarPaces, 2014).

Figure 6.2: CSP installed costs by project size, collector type and amount of storage; 2009 to 2014



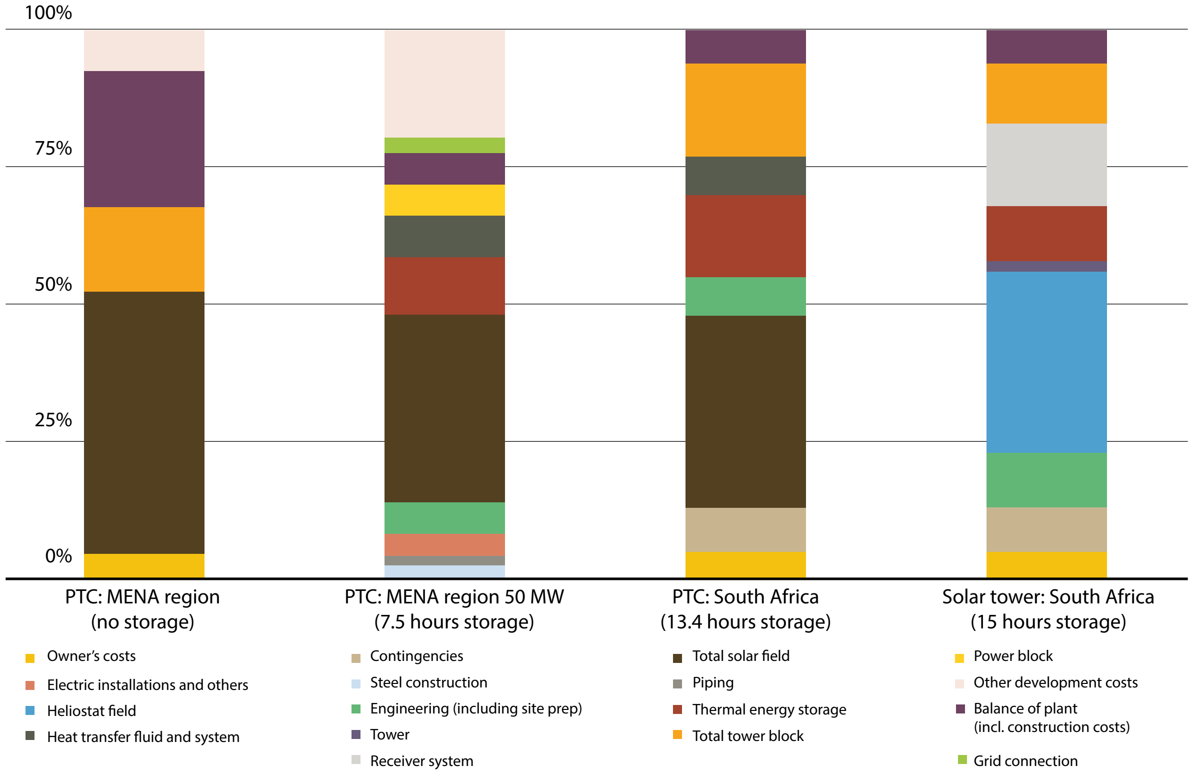
Sources: IRENA Renewable Cost Database; BNEF, 2014e; GlobalData, 2014; and NREL/SolarPACES, 2014.

The current situation means that, although solar towers are a very promising avenue for reducing the LCOE of CSP plants, most of the available operating experience and cost information refers to PTC systems. Limited cost data for solar tower systems at this early stage of their deployment means that it is difficult to draw robust conclusions about what their cost structure may look like once their deployment accelerates.

The current situation for PTC plants is somewhat clearer and current investment costs for PTC plants without storage in the OECD countries are typically between USD 4 600 and USD 8 000/kW, which compares reasonably closely with bottom-up, engineering cost estimates presented in Table 6.2.[25] PTC plants without storage in non-OECD countries have been able to achieve a lower cost structure, with capital costs between USD 3 500/kW and USD 7 300/kW. Current expectations are that, with experience and scale-up, notably in India, the installed cost could be reduced to as little as USD 3 100/kW (German CSP Association, 2014) for the next series of PTC plants without storage to come online.

[25] This is a typical range, although three plants in the IRENA Renewable Cost Database have experienced higher costs – around USD 8 700 to USD 8 900/kW for two and USD 11 000/kW for one project. However, these are not representative projects and have therefore been excluded.

Figure 6.3: Indicative breakdown of CSP installed costs by technology and amount of storage



Sources: IRENA Renewable Cost Database; Ernst & Young, ISE and ISI, 2011; and Fichtner, 2010.

CSP plants with thermal energy storage tend to have higher investment costs, but they allow higher capacity factors (Figure 6.1), dispatchability and typically lower LCOEs (particularly for molten salt solar towers). They also have the ability to shift generation to when the sun is not shining and/or the ability to maximise generation at peak demand times. There are a small number of PTC, linear Fresnel and solar tower projects around the world with modest storage capacity of between 0.5 and 4 hours. These plants have estimated installed capital costs of between USD 3 400 and USD 6 700/kW, but the small sample size (four plants) relative to the total number of projects in the IRENA Renewable Cost Database doesn't allow any firm conclusions about why this range is narrower than for PTC plants without storage. Given that few plants with these small levels of storage are ever likely to be built, the reasons may not become clearer, but at the same time the implications are less important if, as expected, CSP plants with more thermal energy storage become the norm.

The costs of PTC and solar tower plants with thermal energy storage of between 4 and 8 hours are typically between USD 6 800 and USD 12 800/kW for projects for which data are available. This cost range is wider than the bottom-up engineering estimates obtained from the available literature (Table 6.2) of between USD 6 400 and USD 10 000/kW. There is a slight downward trend in the installed costs for plants with 4 to 8 hours of storage over time, but with so few data points this is not statistically significant (Figure 6.2). A similar problem exists for the costs of projects with greater than 8 hours of storage, where first-of-a-kind commercial projects are only just now being deployed. Bottom-up engineering cost estimates suggest a range of around USD 7 600 to USD 10 700/kW. Two of the projects for which IRENA has data fall within this range. The third project – the Gemasolar solar tower project in Spain – was a first-of-a-kind solar tower project using high-temperature molten salt with a record-breaking 15 hours of storage (NREL/SolarPACES, 2014). This project broke new ground in CSP development and has provided invaluable technology insights and operating experience that will benefit future solar tower developments; however, it can't be considered representative from a cost perspective.

The total installed costs per kW of CSP plants since 2011 have been trending downwards as more industry experience has been gained. The scaling-up of plant sizes and a more challenging economic environment (including reductions in support measures) have seen installed costs for more recent projects trend lower than in the past. The limited data available suggest that caution should be applied in drawing any firm conclusions that cost reductions are becoming more generalised as the deployment of CSP grows, but the initial signs are very encouraging.

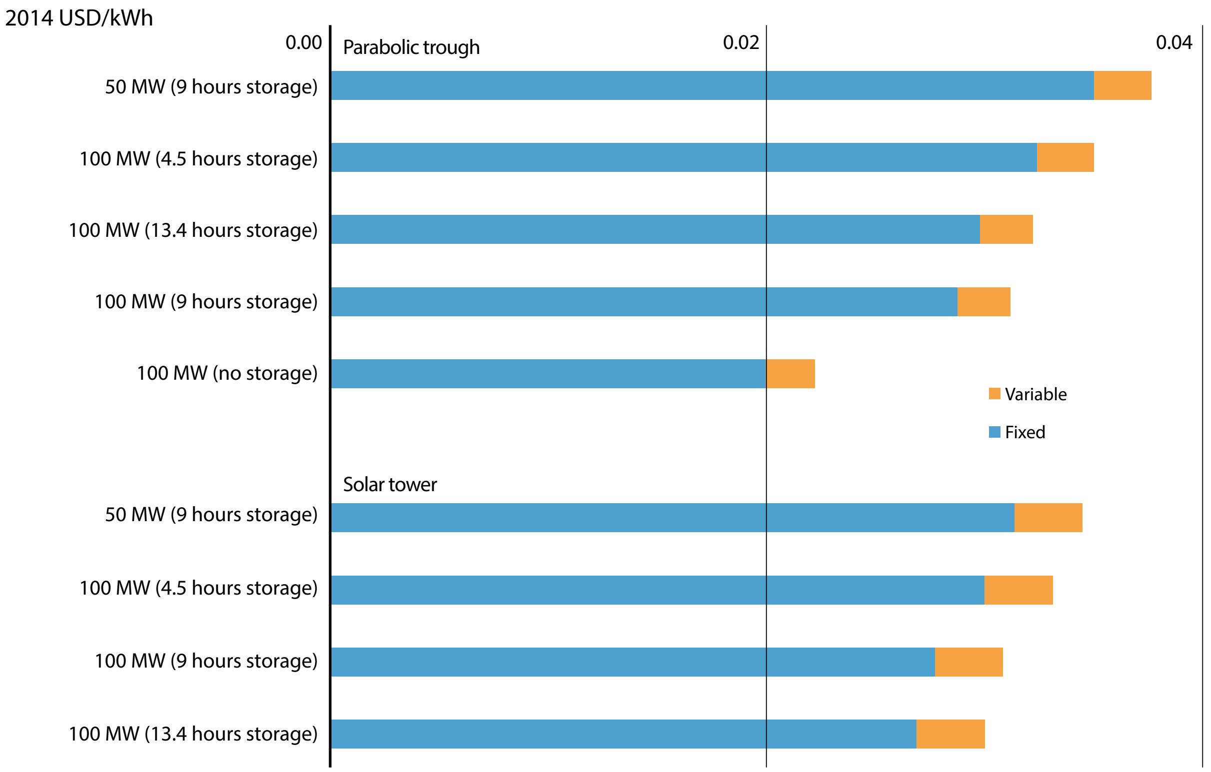
A summary of the breakdown of the capital costs for three parabolic trough plants and one solar tower plant is presented in Figure 6.3. The PTC and solar tower plants in South Africa have very similar total capital investments – USD 914 million for the parabolic trough system and USD 978 million for the solar tower system. The capital costs for the

Table 6.3: Total installed equipment cost breakdown for a PTC plant without storage in the Middle East and North Africa region

	Share (%)
Civil and Structural	**5**
Solar field preparation and other solar field civil work	1
Solar collector pylon foundations	2
Power block and balance of plant structures	2
Solar Field	**64**
Heat collection elements (HCE)	10
Reflectors	14
Metal support structures	20
Drives, electronic and controls	2
Heat transfer fluid (HTF) piping between collectors	1
HTF header piping	2
HTF fluid initial filling	3
Transport, erection and commissioning	11
Heat transfer fluid system, including solar heat exchangers	**9**
HTF heat exchangers and tanks	5
HTF pumps	2
Transport, erection and commissioning	2
Power Block	**23**
Steam turbine generators	7
Cooling system including condenser	7
Fuel gas system including back-up	1
Balance of plant	1
Wastewater treatment	0
Fire protection	1
Electrical and installation	4
Transport, erection & commissioning and other	2
Total	**100**

Source: IRENA Renewable Cost Database
Note: Some totals may not add up, due to rounding.

Figure 6.4: Operations and maintenance costs for parabolic trough and solar tower CSP plants



Sources: IRENA Renewable Cost Database and Fichtner, 2010.

solar field and receiver system represent a larger percentage of the total costs in solar tower systems than in PTC systems. This is because the solar tower project requires a larger solar field (solar multiple) in order to provide the heat for the larger storage system (15 hours) than was proposed for the PTC plant (13.4 hours). In contrast, because of the improved efficiency of the thermal energy storage system as a result of higher operating temperatures in the solar tower, the share of costs for the thermal energy storage system are lower in the solar tower plant. The total costs of CSP plants without thermal energy storage are dominated by the costs associated with the solar fields.

A detailed breakdown of the total installed equipment costs for a PTC plant is presented in Table 6.3. Within the solar field costs, which dominate the total, the metal support structures alone account for one-fifth of total installed costs and almost a third of the solar field costs. The reflectors, transportation to site, erection and commissioning, and the heat collection receivers each account for 10% or more of total equipment costs. After the solar field, it is the power block that accounts for the largest share of the total installed equipment costs.

In addition to their potential higher operating temperatures and improved efficiency for power generation and thermal energy storage, solar towers may offer greater economies of scale in the longer term. However, for current plants, both PTC and solar tower systems appear to offer economies of scale of around 10% when shifting from a 50 MW scale plant to a 100 MW scale plant (Fichtner, 2010). The breakdown of this reduction differs, with the 100 MW PTC plant having higher specific costs for the solar field and proportionately larger savings in specific costs for the other cost components than a solar tower plant.

Operations and maintenance costs for CSP plants

Virtually no data are available in the public domain on the actual operations and maintenance (O&M) costs of recently built CSP plants. However, a detailed assessment of the O&M costs of the pioneering Californian "Solar Electricity Generating

System" (SEGS) plants that were built between 1982 and 1990 estimated their O&M costs to be USD 0.04/kWh. One of the largest areas of expenditure was found to be the replacement of receivers and mirrors as a result of glass breakage (Cohen, 1999). Materials advances and new designs have helped to reduce the failure rate for receivers, but mirror breakage is still an important cost component. The cost of mirror washing, including water costs, is also significant. Plant insurance can also be a large expense and its annual cost can be between 0.5% and 1% of the initial capital cost, with even higher costs possible in particularly unsecure locations.[26]

The O&M costs of the recent CSP plants built in Spain, the United States and elsewhere are estimated to be lower than those of the Californian SEGS plants. Technology improvements have reduced the requirement to replace mirrors and receivers, while increased automation has reduced the cost of other maintenance procedures by as much as 30%. As a result, bottom-up engineering estimates of today's maintenance costs for a parabolic trough system in the United States are around USD 0.015/kWh, which comprises fixed costs of USD 70/kW/year and around USD 0.003/kWh in variable costs (Turchi, 2010b). For solar towers these costs are estimated at around USD 65/kW/year for the fixed costs (Turchi, 2010a). However, these estimates exclude insurance (typically 0.5% to 1% of total capital costs per year) and other potential costs also reported in total O&M cost estimates, so care should be taken in interpreting these values. Taking these points into consideration, the range of USD 0.02 to USD 0.04/kWh seems a robust estimate of the total O&M costs, including all other miscellaneous costs, but costs will vary significantly by plant size.

Two proposed PTC and solar tower projects in South Africa have estimated O&M costs (including insurance) of between USD 0.03 and USD 0.035/kWh for a 100 MW plant. A smaller 50 MW plant would have O&M costs of 7% higher for the PTC plant and 5% higher for the solar tower project (Fichtner, 2010). Parabolic trough systems and solar tower plants benefit from important economies of scale in O&M costs relative to the level of thermal energy storage when moving from 4.5 hours to 9 hours of storage, although adding more storage does not yield any further significant reductions and even increases the O&M costs in the case of the parabolic trough plant.

Overall, given recent experience and as a result of improved O&M procedures, in the long run it should be possible to reduce total O&M costs of CSP plants to USD 0.025/kWh or less, even in OECD countries.

Capacity factors of CSP plants

Although the global solar resource is distributed widely, CSP technologies require large quantities (>5 kWh/m^2/day) of direct normal irradiance (DNI) in order to function and be economic. This is in contrast to solar photovoltaic technologies, which can also operate on diffuse or scattered irradiance as well. This reduces the number of regions where CSP can be used, or at least reduces their economic attractiveness. However, as already discussed, the advantages of CSP mean that it still has an important role to play.

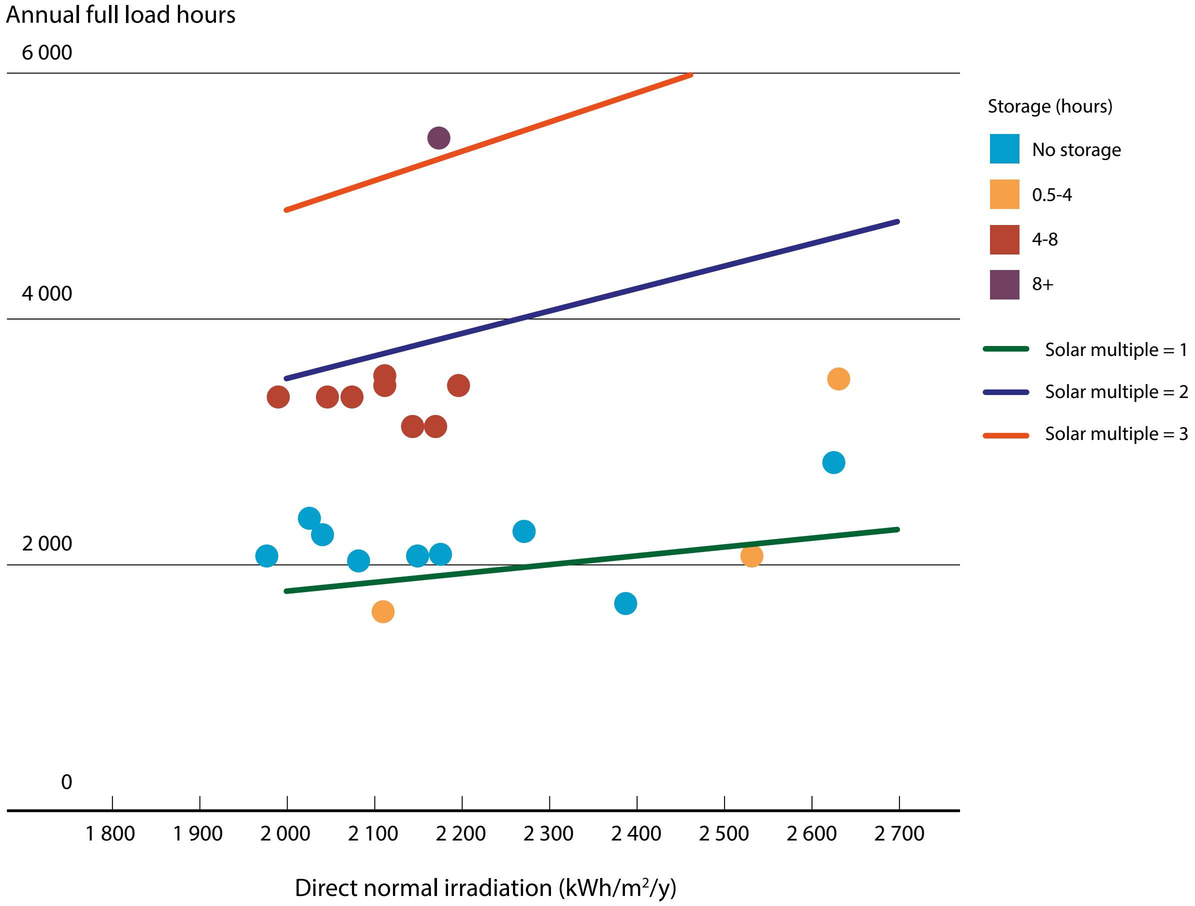
The generation potential of a solar CSP plant – and its competitiveness – are largely determined by the prevailing DNI. This depends on average meteorological conditions over a year. However, on any given day, the generation profile will often be strongly influenced by local meteorological factors (e.g. cloud cover, humidity) and local environmental factors (e.g. local air pollution, dust). The incorporation of thermal energy storage helps to smooth out these fluctuations in DNI over the day due to local, transient meteorological factors, and provide a more stable generation pattern or ability to meet peak demands as required.

Another important aspect for CSP is that tracking the sun provides a significantly greater energy yield for a given DNI than using a fixed surface, which is why tracking is so important to CSP plants. Unlike in solar photovoltaic technology, tracking is not merely an option to improve yield, but a necessity.

In theory, the relationship between DNI and energy output – and hence LCOE values – is strong. Sites with higher DNI will yield more energy, allow greater

[26] Local security issues will also raise capital costs slightly, due to the need for more secure enclosures, and will also raise operating costs as additional security personnel will be required.

Figure 6.5: Full load hours for CSP projects as a function of direct normal irradiance and storage capacity



Sources: IRENA Renewable Cost Database and Trieb et al., 2009.
Note: Full load hours, direct normal irradiance and storage capacity are individual project data. The solar multiples are generic estimates and not based on individual project data.

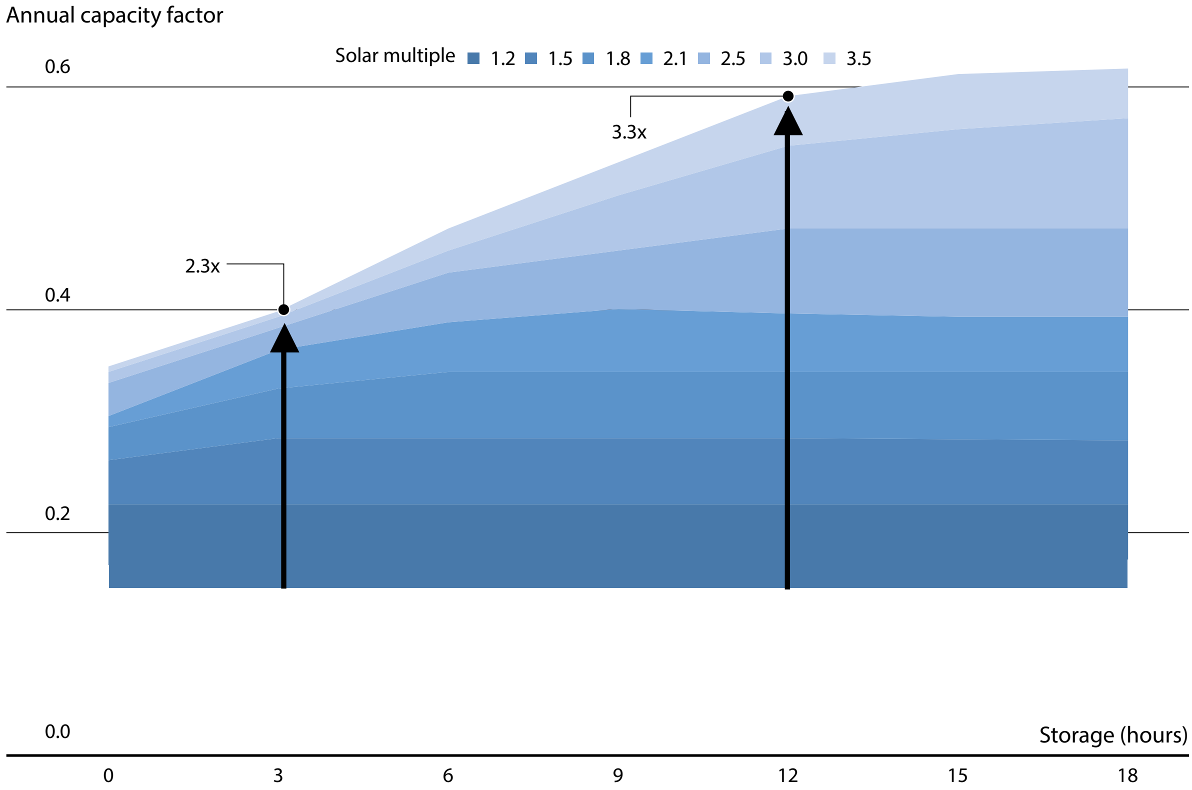
electricity generation and have a correspondingly lower LCOE. High DNI sites yield more electricity for a given solar multiple (the size of the collector field relative to what is required to drive the power block), but also make the concept of higher solar multiples to feed thermal energy stores more attractive.

The practical impact of higher DNI on the LCOE of CSP plants with identical design and capital costs is significant. For instance, the LCOE of identical CSP plants will be around one-quarter lower for good sites in the United States, Algeria or South Africa, where the DNI is around 2 700 kWh/m^2/year, than for a site in Spain with a DNI of 2 100 kWh/m^2/year (A.T. Kearney and ESTELA, 2010).

However, given the range of technology solutions and the relatively modest number of projects for which data are available, the empirical evidence suggests that many other variables are in play in the real world that can affect this result. The available data suggest that these factors can predominate over even relatively significant DNI ranges. For plants without storage, there is not enough evidence to conclude whether other factors are dominating over the resource, as the expected positive relationship yield with a solar multiple of one is modest (Figure 6.5).

However, for plants with significant amounts of storage (4 to 8 hours) and larger solar multiples, a stronger positive expected relationship exists. The limited data, although not sufficiently numerous to prove statistically relevant, suggest that, for this early stage of deployment of CSP, differences in technologies, design solutions, actual solar multiples, operation and local meteorological conditions can negate the expected positive relationship between DNI and capacity factor over a significant DNI range (e.g. between 1 950 and 2 200 kWh/m^2/year). Given that CSP deployment is in its infancy, the expectation is

Figure 6.6: Capacity factor for a 100 MW PTC plant as a function of solar multiple and thermal energy storage



Sources: Based on IRENA Renewable Cost Database and Trieb et al., 2009.

that with increased deployment and replication of plant designs in numerous different locations, the positive relationship between DNI and output will emerge.[27]

Figure 6.6 shows the relationship between capacity factor and thermal energy storage in hours (h) for different solar multiples in regions with a good solar resource. Increasing the solar multiple (e.g. having a larger solar field relative to the power block capacity) will significantly increase solar field costs and introduce thermal energy storage system costs if going from a design with no storage. An important consideration, therefore, is the likely yield for the additional investment. The analysis in Figure 6.6 suggests that the relative increase in output when moving from lower solar multiples to higher ones is significantly larger as the size of storage is increased. The decision about what solar multiple and level of storage to develop for a given plant will depend on the additional costs of expanding the solar field and the cost of thermal energy storage, relative to the additional value unlocked by the greater ability to schedule dispatch in peak periods.

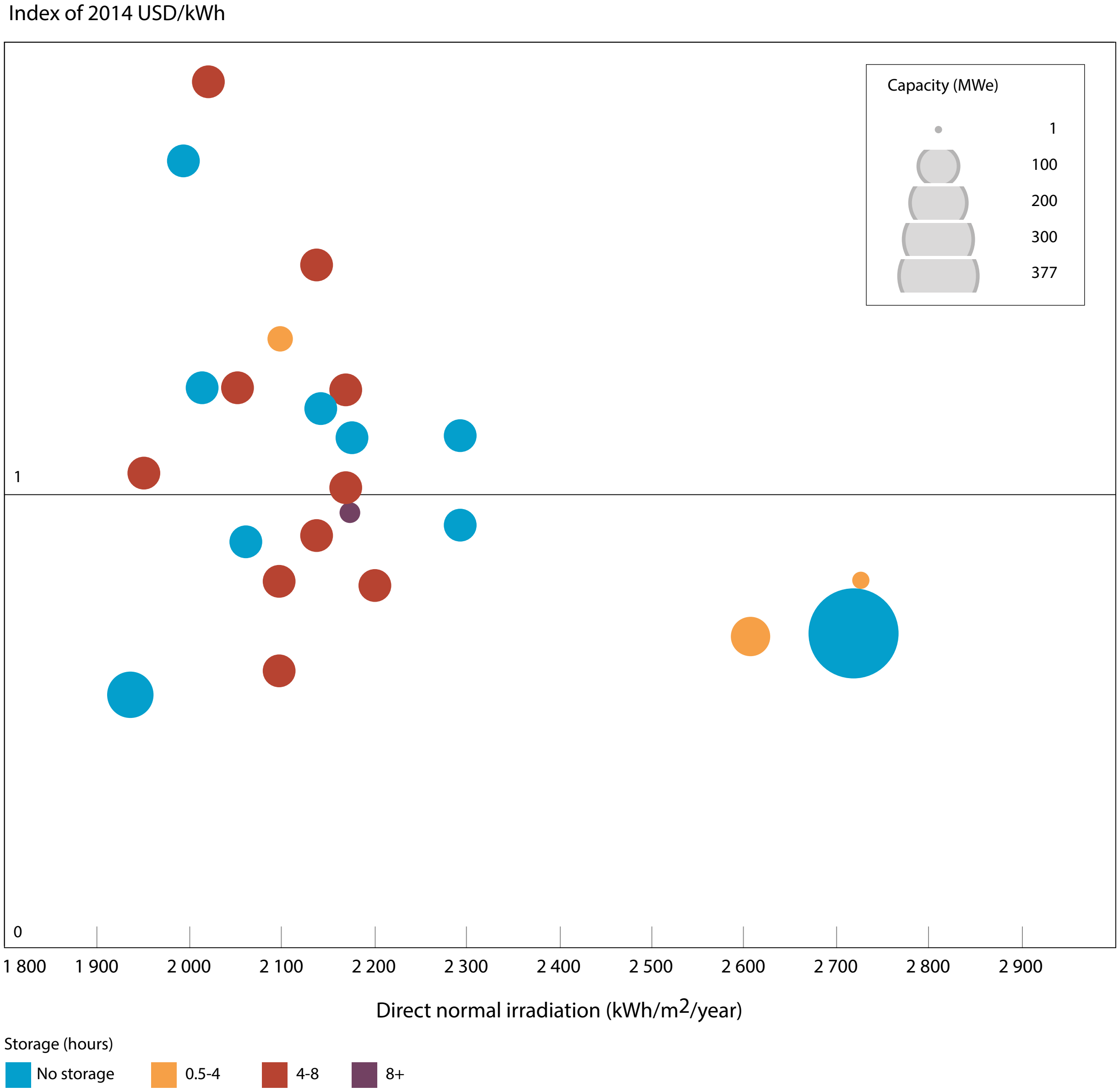
It is important to remember that the calculations for the LCOE of CSP assume that all electricity generated has the same value. However, this is not the case, so plants with higher storage levels are likely to provide more flexibility to capture the increased value of peak prices. For instance, CSP with thermal energy storage has been estimated to provide between 26% and 41% more value when added to a model of the Colorado and Wyoming electricity system than a "flat block" of power generation (Denholm and Hummon, 2012).

The levelised cost of electricity of CSP

CSP is at the beginning of its commercial deployment in terms of installed capacity, with only wave and ocean technologies having less installed capacity. The costs of CSP plants are therefore expected to come down and their performance is expected to improve as the industry scales

[27] Additional data on the technical specifications of the existing plants would be needed in order to come to a conclusion about the exact reasons for the current distribution of capacity factors at different DNI levels and is beyond the scope of this report.

Figure 6.7: Index of the levelised cost of electricity as a function of direct normal irradiance for a range of CSP projects



Source: IRENA Renewable Cost Database.

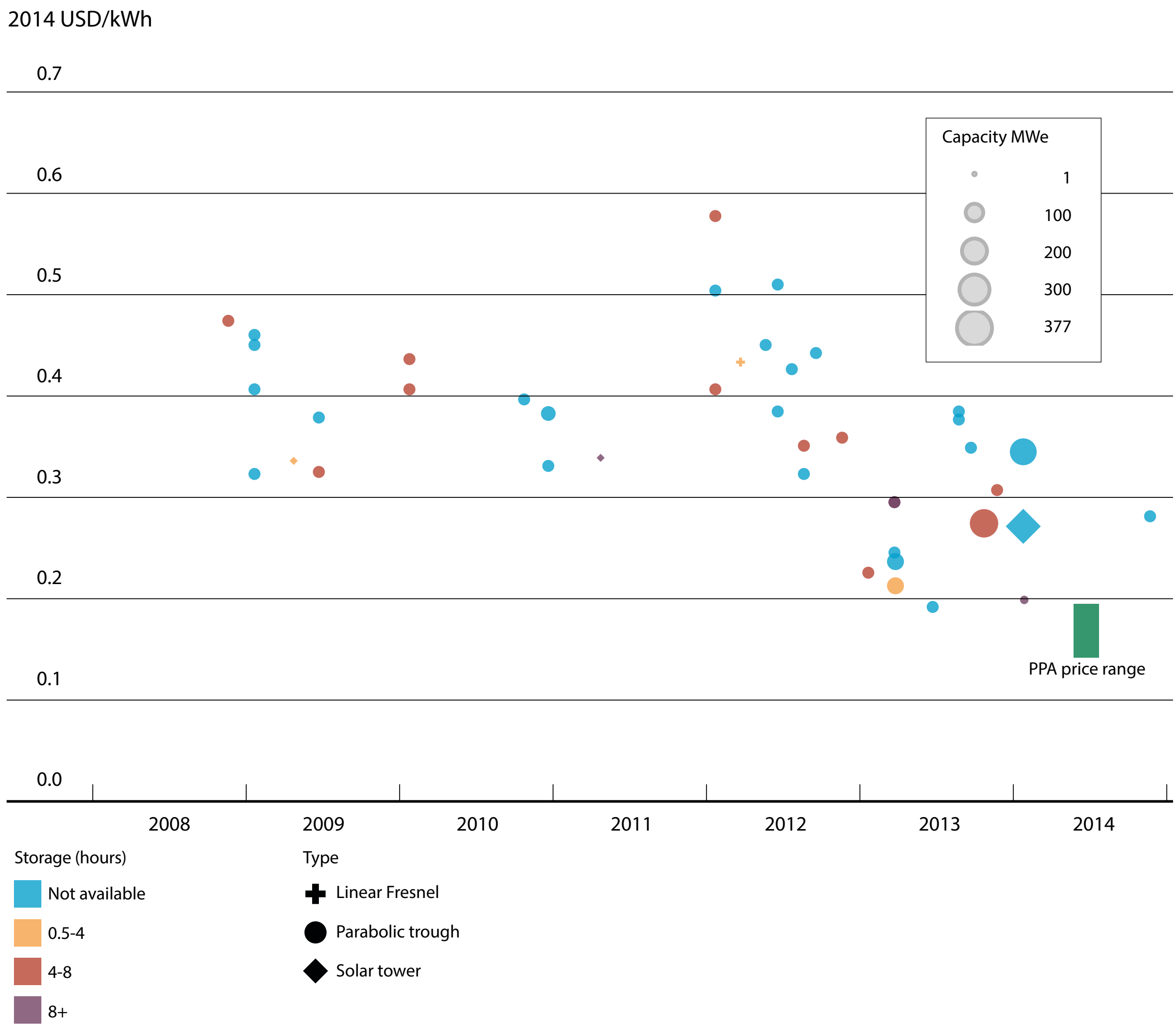
up, operating experience improves, technology improvements are deployed and a larger and more competitive supply chain develops, both locally and globally.

The key assumptions behind the LCOE costs not otherwise discussed in this chapter are the economic life of the plant and the weighted average cost of capital (WACC). All the calculations in this section assume a 25-year economic life and a WACC of 7.5% in OECD countries and China, and 10% elsewhere unless otherwise stated.

Although capacity factors did not exhibit a strong correlation relative to the solar DNI resource, this is not the case for the LCOE. For the limited subset of projects in the IRENA Renewable Cost Database for which complete data exist, there is the expected correlation between the DNI and project LCOE for plants without storage (Figure 6.7). Care needs to be taken in coming to any firm conclusions given the limited data available and the fact that not enough technical data are available to control for design characteristics other than project size and storage.

The evolution of the LCOE between 2008 and 2014 is presented in Figure 6.8. There was little change in the LCOE range for CSP projects between 2008 and 2012, although the range widened and

FIGURE 6.8: THE LEVELISED COST OF ELECTRICITY FOR CSP PROJECTS, 2008 TO 2014



Source: IRENA Renewable Cost Database.

grew somewhat with the burst in growth in 2012. Between 2012 and 2014, the LCOE of the projects in the IRENA Renewable Cost Database and other sources has trended downwards. The LCOE for recent parabolic trough plants without storage is in the range of USD 0.19/kWh to USD 0.38/kWh. Adding storage narrows this range to USD 0.20 to USD 0.36/kWh. The fact that recent power purchase agreement (PPA) prices where no direct subsidies are supplied have been between USD 0.14 to 0.19/kWh suggests that government guarantees and development financing have been able to reduce financing costs for some CSP plants to below a 7.5% WACC.

With few data points available for large-scale solar towers, current estimates of project LCOEs fall within the expected range from bottom-up engineering estimates (Figure 6.8).

7 HYDROPOWER

	2010	2013	2014	2010-2014 (% change)
New capacity additions (GW)	32	48	36	13%
Cumulative installed capacity (GW)	886	1 025	1 061	20%
Total installed costs (2014 USD/kW)	450 – 3 500	450 – 3 500	450 – 3 500	n.a.
Global LCOE range (2014 USD/kWh)	0.02 – 0.15	0.02 – 0.15	0.02 – 0.15	n.a.

Notes: 2014 deployment data are estimates. n.a. = data not available or not enough data to provide a robust estimate.

Highlights

- Hydropower produces some of the lowest-cost electricity of any power generation technology. The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, while average costs are around USD 0.05/kWh.
- Small hydropower projects have an average LCOE of 0.05/kWh and can be a very attractive electrification option, providing low-cost electricity to remote communities or for the grid.
- Hydropower is a mature technology, with limited cost reduction potential in most settings. However, significant low-cost potential remains to be exploited in many countries outside the countries of the OECD.
- Hydropower, excluding pumped storage, is currently the largest renewable power generation source, with a global installed capacity of around 1 025 GW at the end of 2013. At good sites it provides the cheapest electricity of any generation technology.

INTRODUCTION

Hydropower is a mature technology and the LCOE of currently installed projects and those coming online are generally low. Although cost reduction opportunities are low and typically tied to advances in civil engineering practices, hydropower can provide some of the lowest-cost electricity of any source, as well as grid services, in places where economic resources remain untapped. Hydropower is unique among other renewable power generation technologies in that it also provides other services, such as water storage, irrigation opportunities and flood control. However, it is important that hydropower developments respect the three pillars of sustainability; economic, environmental and social. Sustainable development of hydropower and early consultation with local stakeholders are crucial to reducing project lead times, reducing project development risks and accelerating the deployment of hydropower.

When hydropower schemes have storage that is manageable – for example, in the reservoir behind the dam – hydropower can contribute to the stability of the electricity system by providing flexibility and grid services. It can help with grid stability, as spinning turbines can be ramped up more rapidly than any other generation source to provide additional generation or voltage regulation to maintain voltage within the system quality limits. Pumped storage hydropower is specifically designed to provide these services, as well as to provide an arbitrage between periods of low and high electricity prices. However, the LCOE analysis does not include an estimate of the value of these services, as they are very system-specific.

With large reservoirs, hydropower can also store energy over weeks, months, seasons or even years. Hydropower can therefore provide the full range of ancillary services required to allow high penetration of more variable renewable energy sources, such as wind and solar photovoltaic. The importance of hydropower is likely to grow over time as the shift to a truly sustainable electricity sector accelerates, not just for the low-cost electricity it can provide, but for the flexibility it brings in order to integrate high levels of variable renewables at minimal cost.

HYDROPOWER CAPITAL COSTS

Hydropower is a renewable energy source based on the natural water cycle. It is the most mature, reliable and cost-effective renewable power generation technology available today, with a history of exploitation that goes back to the beginning of the use of electricity. Hydropower schemes often have significant flexibility in their design; they can be designed to meet baseload demands with relatively high capacity factors, or to have higher installed capacities and a lower capacity factor but meet a much larger share of peak electricity demand.

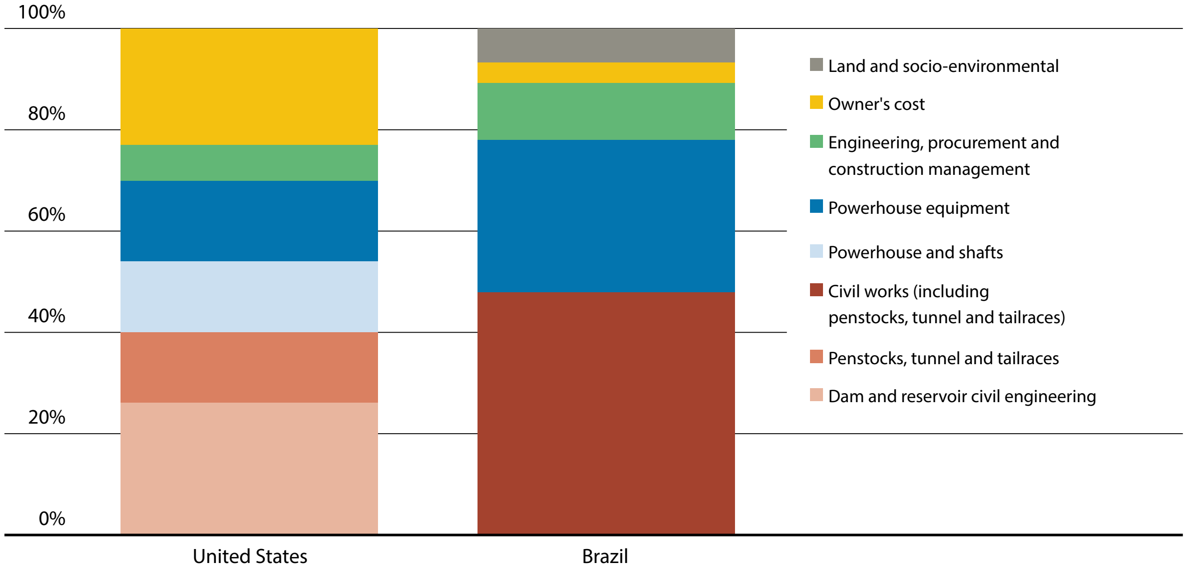
An advantage of hydropower is its ability to meet load fluctuations minute by minute – indeed hydropower can have the most rapid ramp-up rates of any power generation technology[28] – making hydropower an ideal complement to variable renewables such as wind- or sun-based technologies. Hydropower can thus meet the demands that arise when large ramping up or down of supply is needed due to increases or decreases in solar or wind generation.

Hydropower is the only large-scale and cost-efficient electricity storage technology available today, despite cost reductions for a range of electricity storage options in recent years. The promising developments in other energy storage technologies may one day challenge hydropower's monopoly on low-cost electricity storage, but for the moment hydropower is still the only technology offering economically viable large-scale storage. It is also a relatively efficient energy storage option.

Hydropower plants can be constructed in a variety of sizes and with different characteristics. There are a range of technical characteristics that affect the choices for turbine type and size, as well as the generation profile (e.g. height of the water drop to the turbine – "head" – seasonal inflows, potential reservoir size, minimum downstream flow rates, etc.). Hydropower schemes can be broadly classified into the following categories:

[28] Some electricity storage devices, such as flywheels, can match or even exceed these rates, but are more expensive and, in general, the more responsive they are, the less time they can be used before needing to be recharged.

Figure 7.1: Cost breakdown of an indicative 500 MW greenfield project in the United States and a 3 150 MW hydropower project in Brazil



Note: Penstocks are tunnels or pipelines that conduct the water to the turbine, while the tailraces are the tunnels or pipelines that evacuate the water after the turbine.

- Run-of-river hydropower projects have no, or very little, storage capacity behind their dams and generation is dependent on the timing and size of river flows.
- Reservoir (storage) hydropower schemes have the ability to store water behind the dams in order to de-couple generation from hydro inflows. Reservoir capacities can be small or very large, depending on the characteristics of the site and the economics of dam construction.
- Pumped storage hydropower schemes use off-peak electricity to pump water from one reservoir to a higher reservoir, so that the pumped storage water can be used for generation at peak times and provide grid stability and flexibility services.

Hydropower is a capital-intensive technology with long lead times for development and construction due to the significant feasibility assessments, planning, design and civil engineering work required. There are two major cost components for hydropower projects:

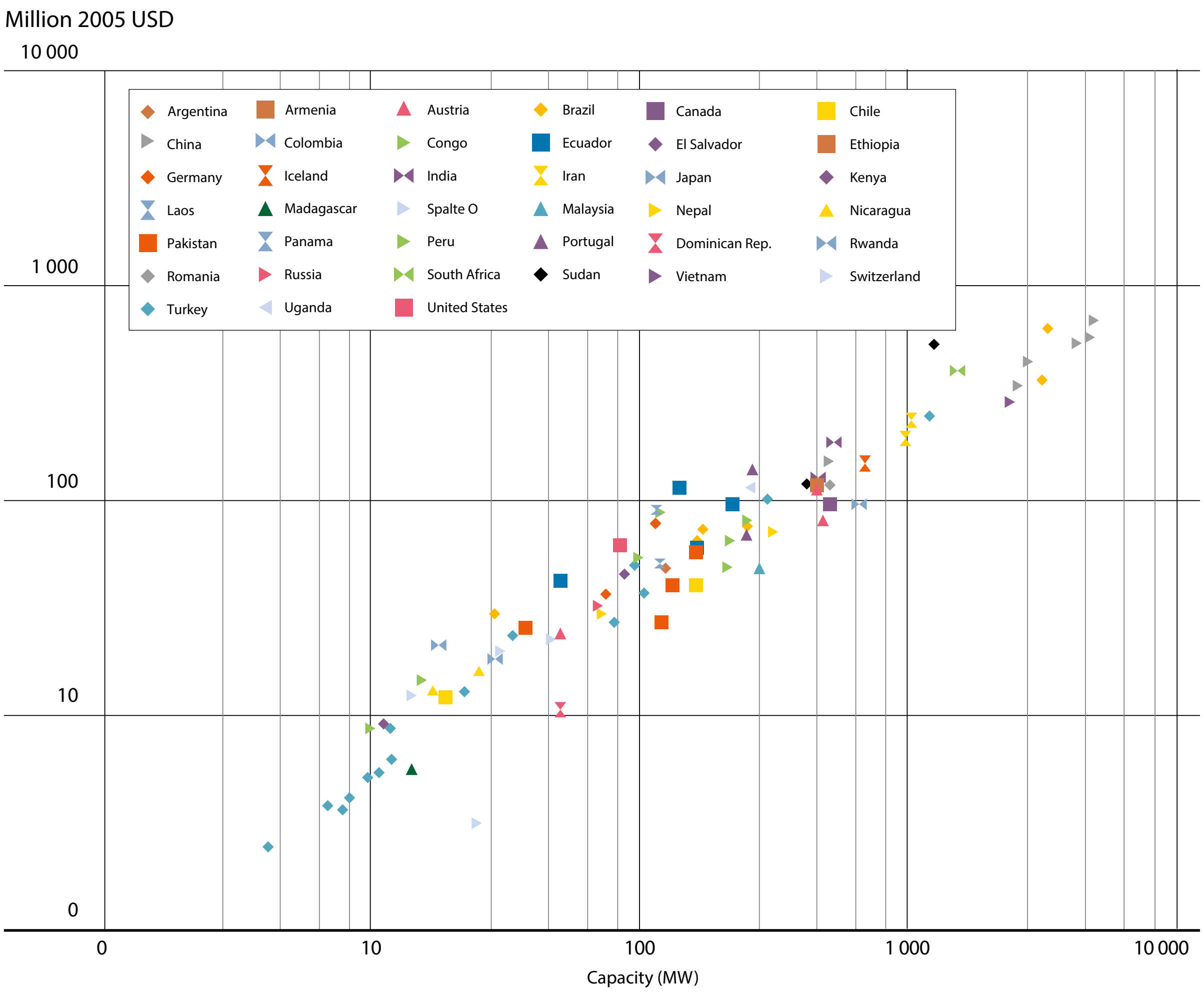
- The civil works for the hydropower plant construction, including any infrastructure development required to access the site and the project development costs; and
- The costs related to electro-mechanical equipment.

Project development costs include planning and feasibility assessments, environmental impact analyses, licensing, fish and wildlife/biodiversity mitigation measures, development of recreational amenities, historical and archaeological mitigation, and water quality monitoring and mitigation.

The cost breakdowns of an indicative 500 MW new greenfield hydropower project in the United States and a 3 150 MW hydropower project in Brazil are presented in Figure 7.1. In both projects, civil engineering represents the majority of costs. In the United States-based project, the civil works associated with the dam/reservoir account for just over one-quarter of the total costs, while penstocks, tailraces and tunnelling add another 14%. The Brazil-based project shows a similar breakdown, with civil works – including penstocks, tunnelling and tailraces – representing just under half of the total cost.

The largest share of installed costs for large hydropower plants is typically for civil construction works (such as the dam, tunnels, canal and construction of power house). Following this, costs for the power house (including shafts and electro-mechanical equipment in the case of the United States project) are the next largest capital outlay and account for around 30% of the total costs.

Figure 7.2: Electro-mechanical equipment costs for hydropower as a function of capacity (log-scale)



The long lead times for these types of hydropower projects (7-9 years or more) mean that owner costs (including the project development costs) can be a significant portion of the overall costs due to the need for working capital and interest during construction. Additional items that can add significantly to overall costs include the pre-feasibility and feasibility studies, consultations with local stakeholders and policy-makers, environmental and socio-economic mitigation measures and land acquisition.

The electro-mechanical equipment costs for hydropower plants are strongly correlated with the capacity of the plant and exhibit economies of scale (Figure 7.2). Although electro-mechanical equipment costs usually contribute less to the total cost in large-scale projects, the opposite is true of small-scale projects (with installed capacity of less than 5 MW). For small-scale projects the electro-mechanical equipment costs can represent 50% or more of the total costs, due to the higher specific costs per kW of small-scale equipment. The proposed capacity of a hydropower plant can be achieved by using a combination of a few large turbines or many small turbines and generating units. There is an economic trade-off between the economies of scale of larger units and the revenue lost when a turbine goes offline due to unexpected problems or for regular maintenance. Regular maintenance of the turbine blades, as well as for the penstocks, will mean the turbine is offline.

The cost breakdown for small hydro projects in developing countries reflects the diversity of hydropower projects and their site-specific constraints and opportunities (IRENA, 2013). It would require a large dataset to identify the specific reasons for the wide variation in project cost breakdowns and to identify “efficient” levels. Electro-mechanical equipment costs tend to be higher for small-scale projects than for large-scale projects, but the range is very wide – from an estimated 18% to as much as 50% of total costs (IRENA, 2013). Infrastructure costs can account for up to half of total costs for projects in remote or difficult to access locations. It is also possible to have projects in remote locations where good infrastructure exists but there are no transmission lines nearby, resulting in significant grid connection costs.

Total installed costs of hydropower

The capital costs of large hydropower projects are dominated by the civil works and equipment costs, which can represent between 75% and as much as 90% of the total investment costs. Civil works costs are influenced by numerous factors pertaining to the site, the scale of development and the technological solution that is most economic. Hydropower is a highly site-specific technology and each project is designed for a particular location within a given river basin to meet specific needs for energy and water management based on local conditions and inflows into the catchment basin. Proper site selection and hydro scheme design are therefore key challenges, and detailed work at the design stage can avoid expensive mistakes (Ecofys et al., 2011).

The total installed costs for large-scale hydropower projects typically range from a low of USD 1 000/kW to around USD 3 500/kW (Figure 7.3). However, it is not unusual to find projects with costs outside this range. For instance, installing hydropower capacity at an existing dam that was built for other purposes (e.g. for flood control, water provision, etc.) may have costs as low as USD 450/kW. On the other hand, projects at remote sites, without adequate local infrastructure and located far from existing transmission networks, can cost significantly more than USD 3 500/kW due to higher logistical and grid connection costs.

Total installed costs are lowest in China and India and the highest in Central America and the Caribbean. In regions that have exploited most of their economic resources, most of the low-cost hydropower potential has already been exploited and installed costs are higher. In areas with poor infrastructure, higher costs will be due to the fact that many projects are in remote areas with poor access and thus have higher transport and logistical, as well as grid connection costs.

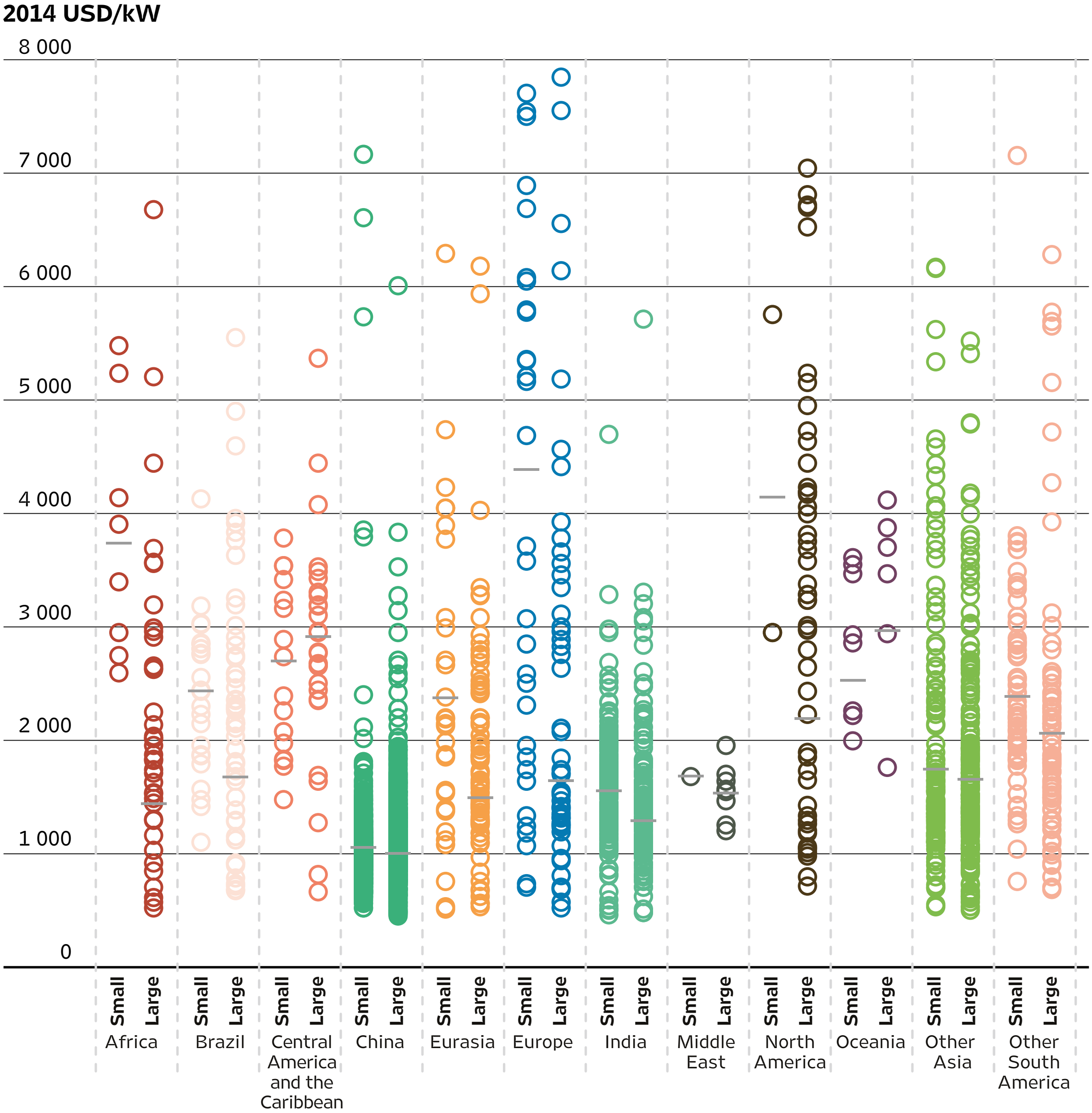
Weighted average installed costs for commissioned or proposed small hydropower projects are very similar to those for large-scale hydropower projects in China, India and other Asian countries. In Oceania and Central America and the Caribbean, weighted average installed costs are actually lower for small-scale hydro projects, but this is not statistically significant.

An important conclusion from this analysis is that, although the installed cost range for hydropower is wide, weighted average installed costs are typically low in regions with significant remaining potential and can provide electricity at very competitive prices. This is true despite the fact that costs for the other services they provide, such as potable water, flood control, irrigation and navigation are included in the hydropower project costs and are typically not remunerated. In addition, plants with higher installed costs are often associated with higher capacity factors, reducing their LCOE. This also does not take into account the additional value of grid services provided by hydropower in terms of short-term flexibility and long-term energy storage, which may have significant value over and above a simple LCOE analysis.

Capacity factors for hydropower

Weighted average capacity factors are around 50% for both small and large hydropower projects, with most projects in the range of 25% to 80% (Figure 7.4). Given the design flexibility of hydropower, depending on inflows and site characteristics, this wide range is to be expected. It is also unique to hydropower, where low capacity factors are a design choice to meet peak demands, not a handicap for project economics. In South America and Brazil, where there are significant excellent – but as yet unexploited – hydropower resources, average capacity factors for new small and large hydropower projects are 63% and 66% and 52% and 61%, respectively. In most regions, capacity factors for large hydro projects are higher than for small hydro projects, but not by a significant margin in China or India.

Figure 7.3: Total installed cost ranges and capacity weighted averages for commissioned or proposed small and large hydropower projects by country/region

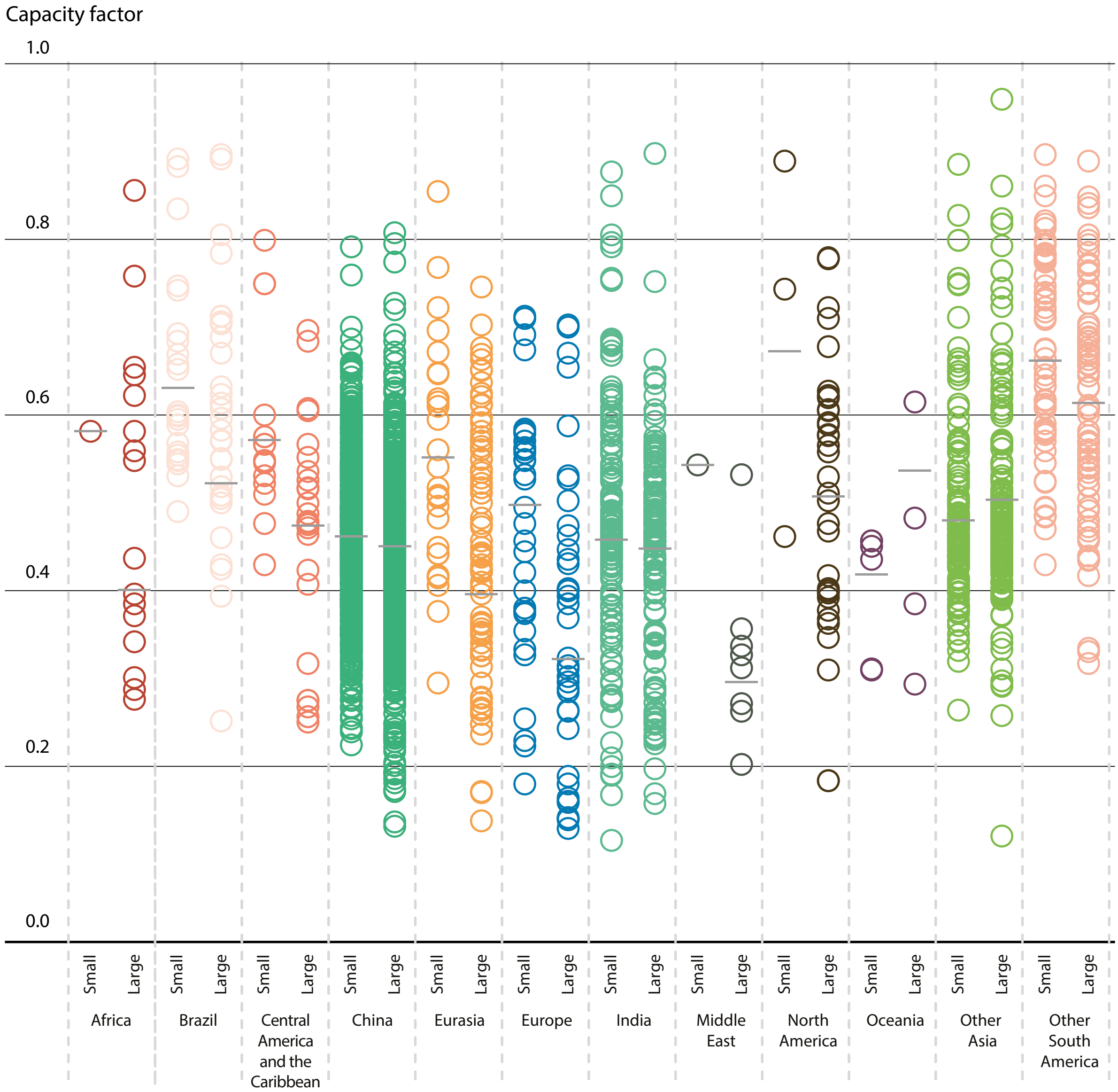


Operations and maintenance costs for hydropower

Hydropower plants typically have low operations and maintenance (O&M) costs over their lifetimes and large-scale hydropower plants have O&M costs similar to those for wind, but not as low as for solar PV. When a series of plants are installed along a river, centralised control, remote management and a dedicated operations team to manage the chain of stations can reduce O&M costs to very low levels.

Annual O&M costs are often quoted as a percentage of the investment cost per kW per year, or as USD/kW/year. Typical values range from 1% to 4%. The International Energy Agency (IEA) assumes 2.2% for large and 2.2% to 3% for smaller hydropower projects, with a global average of around 2.5% (IEA, 2010). Other studies (EREC/Greenpeace, 2010) indicate that fixed O&M costs represent 4% of the total capital cost. This figure may be appropriate for small-scale hydropower plants but large hydropower plants will have significantly lower values. An average value for O&M costs of 2% to 2.5% is considered the norm for large-scale projects (IPCC, 2011), which is equivalent to average costs of between USD 20 and USD 60/kW/year for the average project by region in the IRENA Renewable Cost Database. This will usually include an allowance for the periodic refurbishment

Figure 7.4: Capacity factor ranges and weighted averages for commissioned or proposed small and large hydropower projects by country/region



of mechanical and electrical equipment, such as turbine overhaul, generator rewinding and reinvestments in communication and control systems.

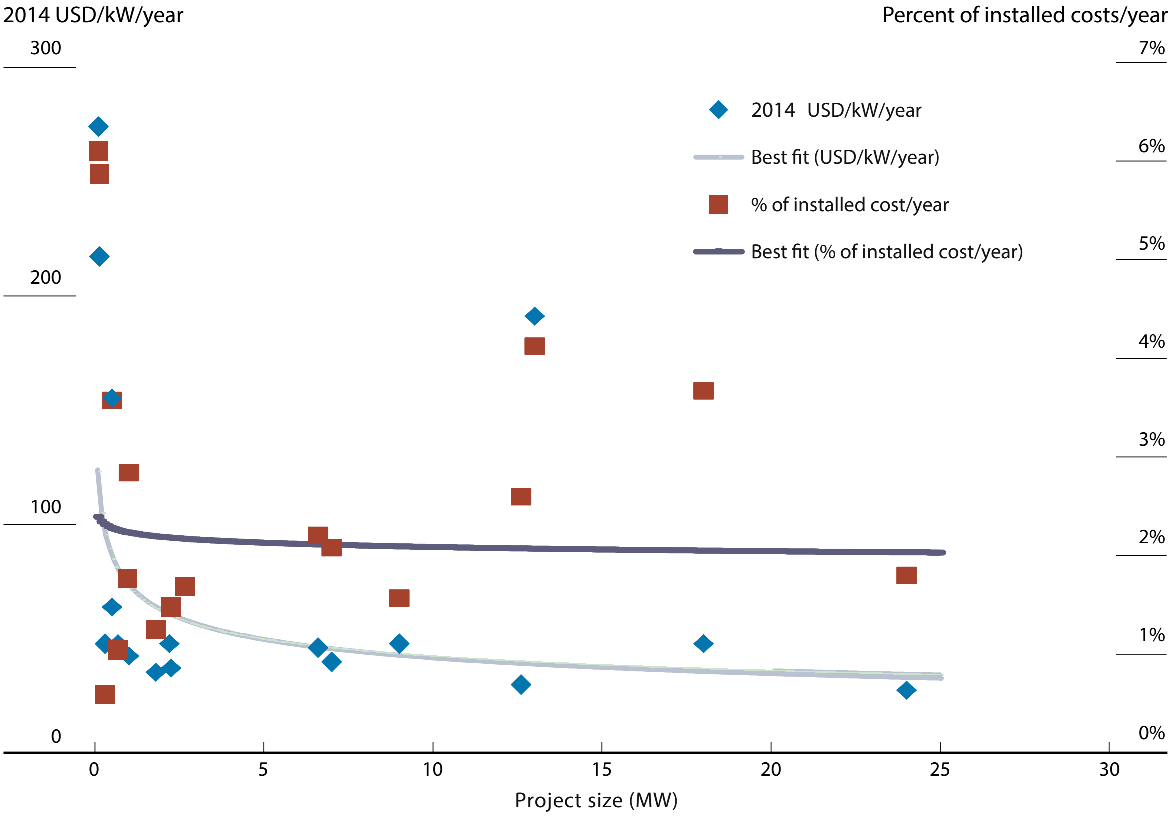
These values are consistent with data collected by IRENA and GIZ for small hydropower projects in developing countries (Figure 7.5).[29] Average O&M costs for mini- and pico-hydro projects can be significantly above the average, as the fixed O&M costs can be significant for these very small projects, which don't benefit from the economies of scale for O&M costs that are presented by large hydropower projects.

The O&M costs reported do not typically cover the replacement of major electro-mechanical equipment or refurbishment of penstocks, tailraces, etc.[30] These replacements are infrequent and these components have design lives of 30 years or more for electro-mechanical equipment, and 50 years or more for penstocks and tailraces, meaning that the original investment has been completely amortised by the time these investments need to be made and therefore they are not included in the LCOE

[29] The high values in the 13 to 18 MW size range, in terms of percentage of installed capital costs per year for O&M costs, appear to be partly explained by the remote location of these projects.

[30] Penstocks are tunnels or pipelines that conduct the water to the turbine, while the tailraces are the tunnels or pipelines that evacuate the water after the turbine.

Figure 7.5: Operations and maintenance costs for small hydropower projects in developing countries



analysis here. They may, however, represent an economic opportunity before the full amortisation of the hydropower project, in order to boost generation output.

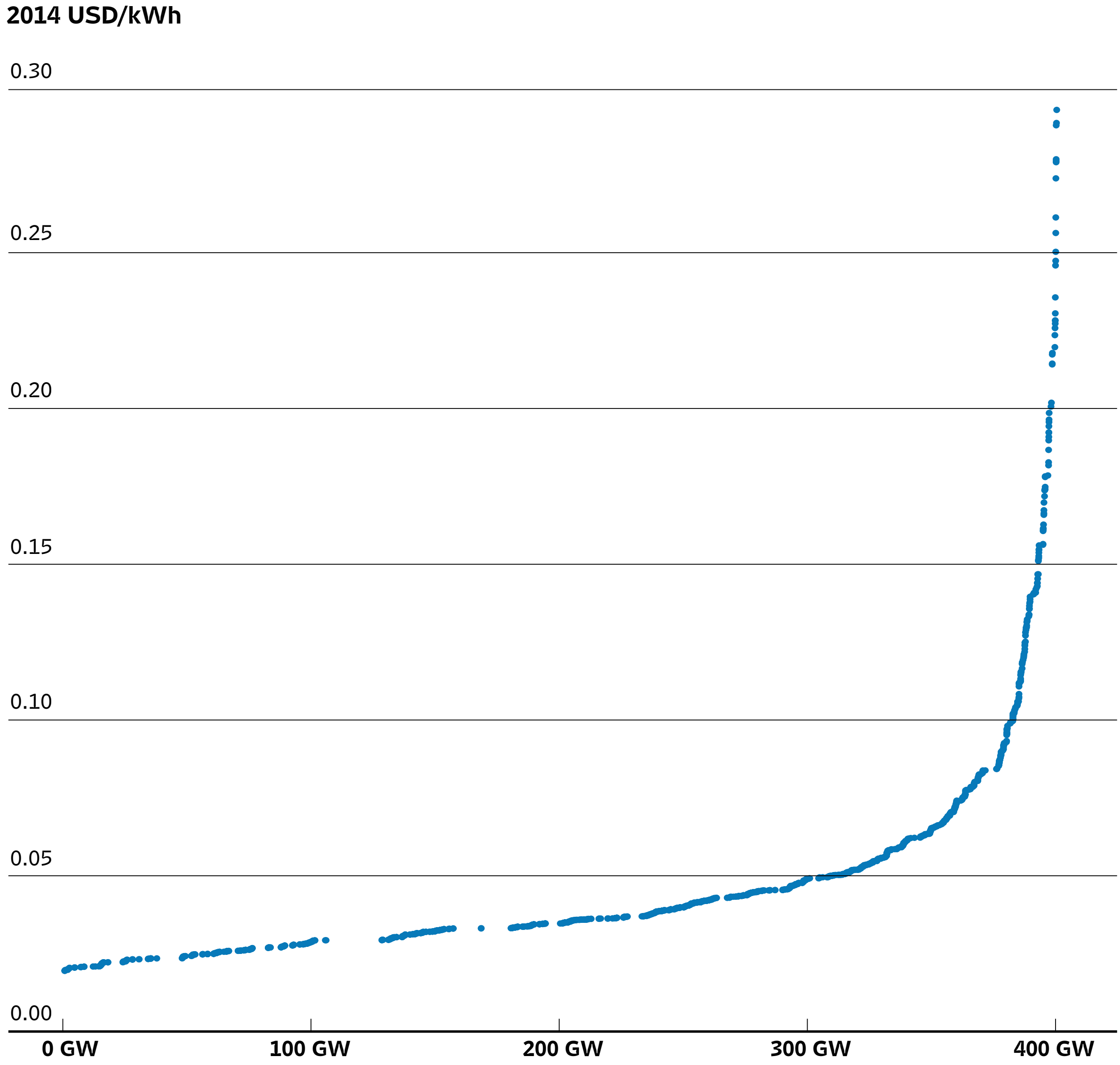
The levelised cost of hydropower electricity

Hydropower is a proven, mature, predictable technology and can be a very low-cost source of electricity. Although the weighted average total installed costs of hydropower are typically quite low for large-scale projects in regions with unexploited economic resources, installed cost ranges are quite wide and are highly dependent on location and site conditions. However, on average, the low investment costs, good capacity factors and very long economic lives (with parts replacement), as well as low O&M costs, mean that hydropower is typically very competitive. As a result, the average LCOE from hydropower is typically low and excellent hydropower sites offer the lowest cost electricity of any generating option.

Hydropower projects can be designed to perform very differently, which complicates a simple LCOE assessment of hydropower. Installed capacity can be low relative to inflows where storage is possible, in order to ensure that the plant is nearly always generating and achieves high average capacity factors. Alternatively, a scheme could have relatively high installed electrical capacity that is not designed to run continuously and would have a lower annual capacity factor, but would meet peak demands by providing large amounts of capacity at short notice, as well as providing a spinning reserve and/or other ancillary grid services. The latter strategy would involve higher costs and lower capacity factors, but where system flexibility is required it is likely to be the cheapest and most effective solution to minimising total electricity system generation costs and hydropower could capture a large part of this extra value.

Deciding which strategy to pursue for any given hydropower scheme design is highly dependent on the local market, structure of the power generation pool, grid capacity and constraints, the value of providing grid services, etc. Perhaps more than in the case of any other renewable energy, the true

Figure 7.6: Levelised cost of electricity of unexploited hydropower resources in the IRENA Renewable Cost Datbase



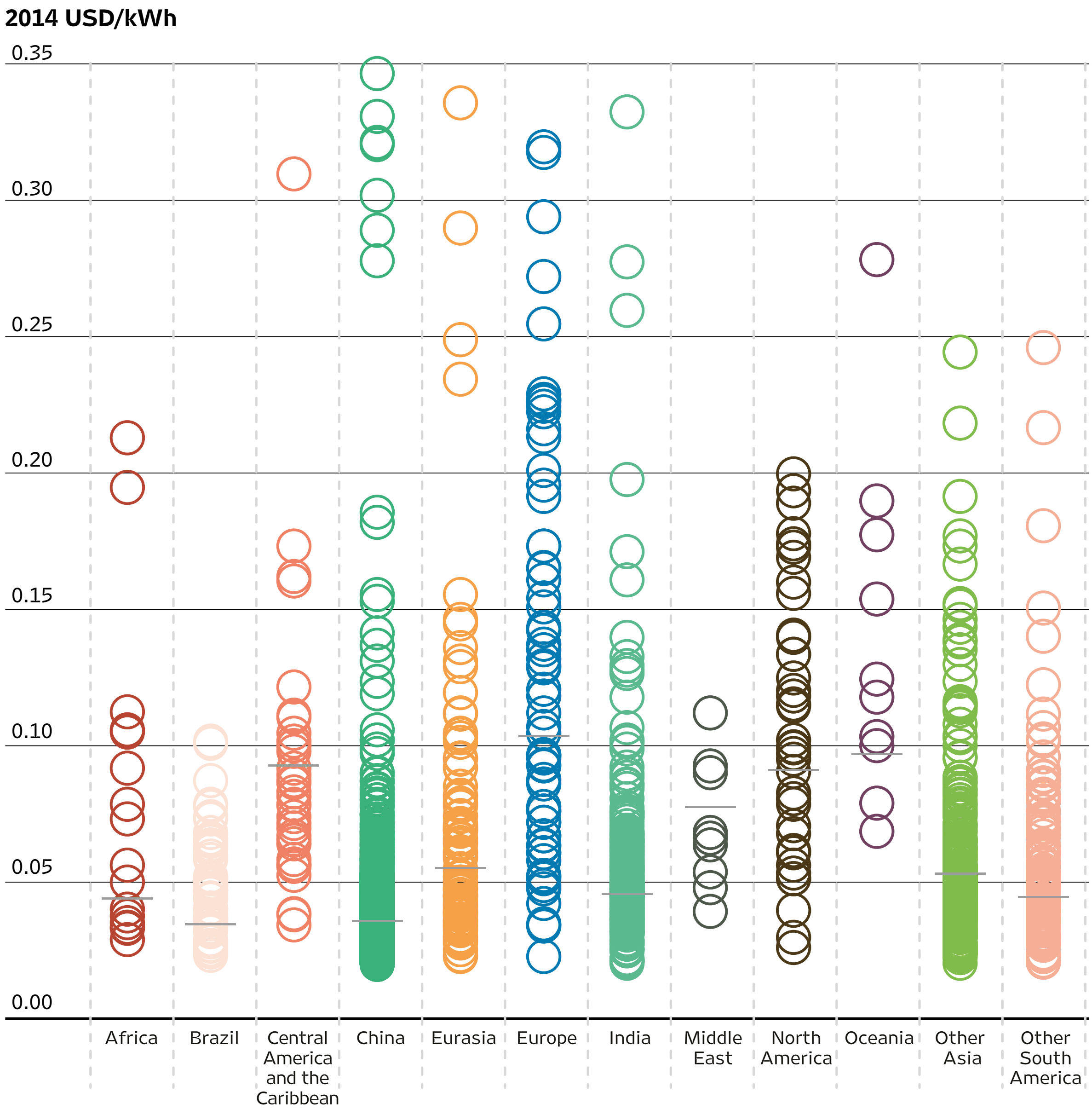
economics of a given hydropower scheme will be driven by these factors, not just by the number of kilowatt hours (kWhs) generated relative to the investment, as the value of peak generation and the provision of ancillary grid services can have a large impact on the economics of a hydropower project.[31]

Figure 7.6 presents the supply curve for the LCOE of 2 444 hydropower projects contained in the IRENA Renewable Cost Database – for all projects commissioned and proposed. It shows that many new hydropower projects are expected to be highly competitive. The LCOE of the evaluated projects ranged from a low of around USD 0.02/kWh to a high of USD 0.35/kWh for a 680 MW large hydro project with a capacity factor of 37%. The weighted average cost of all the sites evaluated was USD 0.042/kWh. The LCOE for 90% of the projects was below USD 0.09/kWh and for roughly 70% it was below USD 0.05/kWh. If the data were available, it would be interesting to compare these ex-ante project cost estimates with ex-post data to identify whether there are systematic errors in project cost estimations as is suggested in an analysis of 245 dams installed between 1934 and 2007 (Ansar, 2014). However, even if there were systematic under estimation in ex-ante cost estimates, hydropower would still remain the cheapest of electricity generation sources.

Data for the LCOE range of hydropower in countries with the largest installed capacity are

[31] This is also without taking into account the other services being provided by the dam (e.g. flood control) that are not typically remunerated but are often an integral part of the project's purpose.

FIGURE 7.7: LEVELISED COST OF ELECTRICITY RANGES AND WEIGHTED AVERAGES OF SMALL AND LARGE HYDROPOWER PROJECTS BY REGION



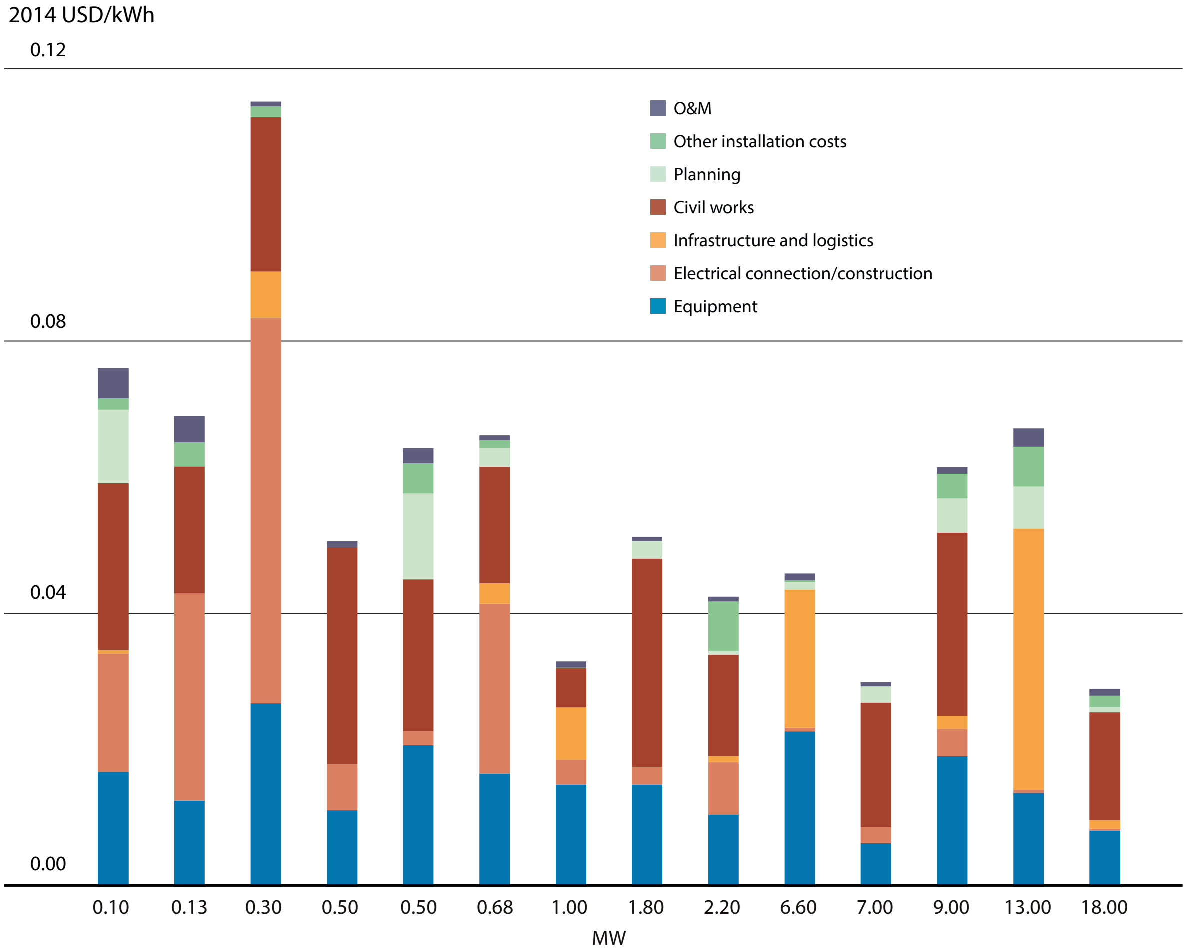
revealing. At the best sites, the LCOE of hydro is very competitive and can provide the cheapest electricity available in the world today (Figure 7.7). Although the range of estimated costs is wide, the weighted average LCOE of projects is very low, suggesting that the smaller-scale projects with higher LCOE are typically being built because they are the least costly supply solution in remote areas or are providing valuable grid services.

Figure 7.7 highlights that the weighted average costs for new capacity are low, typically ranging between USD 0.04 and USD 0.06/kWh in regions with remaining untapped economic resources.

In Europe and North America, where a large proportion of the economical hydropower potential has already been exploited, the situation is quite different. In these two regions, new projects are relatively few in number, face long lead times to develop and have higher weighted average LCOE – USD 0.09/kWh for large hydro and USD 0.11/kWh for small hydro in North America and USD 0.10/kWh and USD 0.14/kWh for large and small hydro, respectively, in Europe.

Figure 7.8 presents the LCOE of small hydropower projects in developing countries, broken down by size, and highlights just how competitive

Figure 7.8: The levelised cost of electricity breakdown by cost component for 14 small hydropower projects in developing countries



small hydropower can be for grid supply, rural electrification and economic development. The LCOE ranged from a low of around USD 0.03/kWh to USD 0.115/kWh, while the share of O&M costs in the LCOE of the hydropower projects examined ranged from 1% to 6%. The largest share of the LCOE is taken up by costs for the electro-mechanical equipment and civil works. The share of the electro-mechanical equipment in the total LCOE ranged from a low of 17% to a high of 50%, with typical values falling in the range of 21% to 31%.

However, the cost of civil works made the highest contribution to the total LCOE in nine of the projects examined, with a share across all projects that ranged from zero (for an existing dam project) to a high of 63%. In some remote projects, grid connection and electrical infrastructure dominated costs, and they were significant, without being dominant, in a number of other projects. Similarly, infrastructure and logistical costs can be a significant contributor to overall costs where site access is difficult and/or far from existing infrastructure.

8 BIOMASS FOR POWER GENERATION

	2010	2013	2014	2010-2014 (% change)
New capacity additions (GW)	7.7	5.5	3.0+	-61%
Cumulative installed capacity (GW)	68	86	89+	31%
Typical total installed cost range: OECD (2014 USD/kW)	1 880 – 6 820	1 880 – 6 820	1 880 – 6 820	n.a.
Typical total installed cost range: non-OECD (2014 USD/kW)	400 - 2000	400 - 2000	400 - 2000	n.a.
Global LCOE range (2014 USD/kWh)	0.03 – 0.14	0.03 – 0.14	0.03 – 0.14	n.a.

Notes: 2014 deployment data are estimates. n.a. = data not available or not enough data to provide a robust estimate.

Highlights

- A range of biomass power generation technologies are mature and biomass is a competitive power generation option wherever low-cost agricultural or forestry waste is available. In addition, new technologies are emerging that show significant potential for further cost reduction.

- Biomass-fired power generation technologies range from mature solutions to emerging technologies that have not yet been deployed on a large scale. The total installed costs of biomass power generation technologies reflect this diversity, varying between USD 1 880 and USD 6 820/kW in the OECD. Costs are significantly lower in developing countries where cheaper, less efficient technologies are more typical and costs range from USD 400 to USD 2 000/kW.

- Secure, long-term supplies of low-cost, sustainably sourced feedstocks is critical to the economics of biomass power plants. Feedstock costs can be zero for some wastes, including those produced onsite at industrial installations, such as black liquor at pulp and paper mills or bagasse at sugar mills. Sometimes their use actually saves disposal costs.

- Biomass can provide dispatchable baseload electricity at very competitive costs. The regional or country weighted LCOE ranged from a low of USD 0.04/kWh in India and USD 0.05/kWh in China to USD 0.085/kWh in Europe and North America over the last ten years. Individual projects typically generate electricity that costs between USD 0.03 and USD 0.14/kW. But higher values exist, up to USD 0.25/kWh, particularly for waste incineration projects in the OECD where the primary purpose of the process is not electricity generation, but waste disposal.

Introduction

A range of technologies are currently available to transform biomass into electricity. Many of these biomass power generation technologies – including direct combustion in stoker boilers, low-percentage co-firing, anaerobic digestion, municipal solid waste incineration, landfill gas and combined heat and power – are mature, commercially viable technologies with long track records. These technologies can provide low-cost, reliable electricity where low-cost feedstocks are available and they have relatively modest future cost reduction potentials.

A set of less mature technologies, such as atmospheric biomass gasification and pyrolysis, are still in the initial commercial deployment phase. Technologies such as integrated gasification combined cycle, bio-refineries and bio-hydrogen are in the demonstration or research and development (R&D) phases. These technologies have correspondingly greater cost reduction potentials, but play a much smaller role in today's power generation system.

Cumulative worldwide installed capacity at the end of 2013 was around 86 GW (Figure 8.1) and is anticipated to reach 130 GW by the end of 2025 (GlobalData, 2014). Around one-third of the installed capacity is located in Europe, 29% in the Asia Pacific region and almost 20% in North America (GlobalData, 2014).

The potential for biomass cost reductions remains highly heterogeneous as a result of the different stages of development of the various technologies. Cost reduction potentials are relatively small for established technologies; however, the long-term potential for cost reductions for less mature technologies remains good, taking into consideration the estimated future installation and the annual growth rate of cumulative installed capacity of 13% per year between 2000 and 2013.

The process of biomass power generation is dependent on three main components:

- Biomass feedstocks: Feedstock for biomass generation varies from region to region and different feedstocks have different properties that impact their use for power generation.
- Biomass conversion: Conversion is a process through which feedstocks are transformed into energy used to generate heat and/or electricity (e.g. gasification, pyrolysis, digestion into biogas and combustion).
- Power generation technologies: An extensive range of commercially viable power generation technologies are available that can use the useful energy generated by biomass as a fuel input.

The current analysis focuses on the costs of the conversion and power generation technologies, and touches on the available feedstock costs. One of the most important determinants of the economic success of biomass projects is the availability of a secure and sustainable fuel supply (i.e. feedstocks) for conversion.

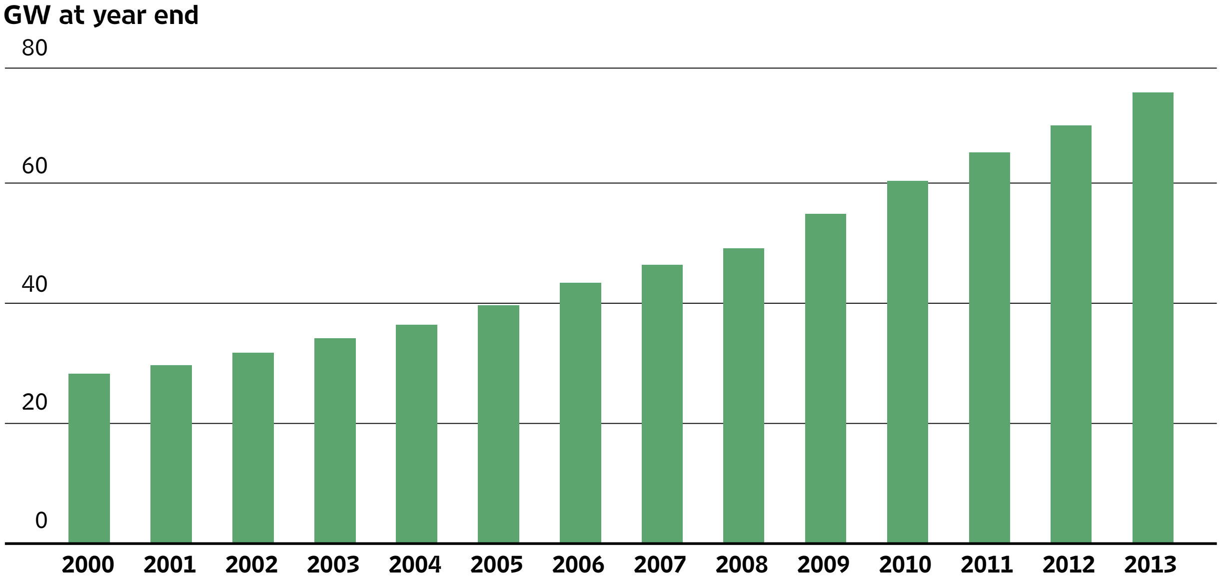
Given the critical importance of biomass to virtually all future scenarios for a low-cost transition to a sustainable energy sector, the current very poor understanding of the country-level, regional and global supply curves for sustainable biomass feedstocks represents a significant risk to the world's ability to avoid dangerous climate change effects at a reasonable cost.

Biomass feedstocks

Biomass is defined as organic material of recently living plants, such as trees, grasses and agricultural crops. As shown in Table 8.1, biomass feedstocks are very diverse and their chemical compositions vary from species to species. There are combustion technologies that run on a variety of biomass feedstocks, but some specific technologies can only operate on a limited selection, or relatively homogeneous set, of feedstocks, which can add complexity to the planning and economic viability of biomass-based power plants.

Biomass power plants require sustainably sourced, low-cost, adequate and predictable biomass feedstock supplies. The range of costs for feedstocks is highly variable, from zero for wastes produced as a result of industrial processes – and even negative prices for waste that would

Figure 8.1: Global cumulative installed capacity, 2000-2013



Source: Global Data, 2014

otherwise have incurred disposal costs (e.g. black liquor at pulp and paper mills) – to potentially high prices for dedicated energy crops if productivity is low and transport costs are high. More modest costs are incurred for agricultural and forestry residues that can be collected and transported over short distances, or are available at processing plants as a by-product. Transport costs add a significant amount to the costs of feedstocks if the distances become large, as a result of the low-energy density of biomass. As a result, the trade in biomass, such as wood chips and pellets, is particularly sensitive to transportation costs and is unlikely to ever represent a large share of biomass use. Transforming wet biomass into higher-density forms (e.g. through torrefaction or conversion into biofuels) will help reduce transportation costs per unit of energy, but the transformation costs must be taken into account.

Feedstock costs typically account for between 20% and 50% of the final cost of electricity based on biomass technologies. Agricultural residues, such as straw and sugarcane bagasse, tend to be the least expensive feedstocks, as they are a harvest or processing byproduct, but they are correlated with the price of the primary commodity from which they are derived and they have registered increased costs over the past five years. Biomass power generation plants incur the risk of being adversely affected by volatile commodity prices unless they have secure supplies (e.g. vertically integrated agricultural processing industries that also produce their own power) or have contracted long-term for supplies.

Collection and transport costs dominate the costs of feedstocks derived from forest residues. The density of forestry residues in a given area determines the placement of biomass power plants and their economic size. This is because at a certain point the additional feedstock transport costs will offset the economies of scale of a larger plant that requires feedstock from a larger radius. The effect of this limitation is that economies of scale for biomass power plants are typically limited and a larger number of geographically dispersed biomass plants can be more economic than one large one.

Prices for biomass sourced and consumed locally are difficult to obtain, which renders it almost impossible to realise comparisons over time. A notable exception is India, which tracks the evolution of the price of bagasse through an index. Feedstock prices are dependent on the energy content of the fuel, moisture content and other chemical properties that affect the costs of utilisation at the power plant and the efficiency of generation. The range of costs can be quite wide and very site-specific (Table 8.1). Spot prices for wood chips on North American markets ranged between USD 5.5 and USD 6.6/GJ in July 2014, while forward prices for wood chips in Europe for the third and fourth

Table 8.1: Biomass feedstock characteristics and costs in the United States

		Typical moisture content	Heat value MJ/kg (LHV)	Price (2014 USD/GJ)
Forest residues	**Pine residues**	30 - 40%	17.5 - 20.8	1.2 - 1.5
	Hardwood residues	30 - 40%	17.5 - 20.7	0.9 - 1.4
Wood waste		5 - 15%	19.9	1.1 - 3.2
Agricultural residues		20 - 35%	15.1 - 18.1	1.4 - 3.5
Energy crops	**Poplar**	10 - 30%	17.7	1.5 - 3.6
	Switchgrass and other	20%	16.8 - 18.6	2.4 - 3.4
	Miscanthus	15%	17.8 - 18.1	2.8 - 8.2
	Bagasse	10 - 30%	17.7 - 17.9	2.2
	Sorghum	20%	14.3 - 18.3	2.3 - 2.9
	Willow	10 - 30%	16.7 - 18.4	3.1 - 3.4

Sources: Frank W. Norris Foundation, 2014; and United States DOE, 2011

quarters ranged between USD 8.2 and USD 8.4/GJ (Argus Media Biomass Markets, 2014).

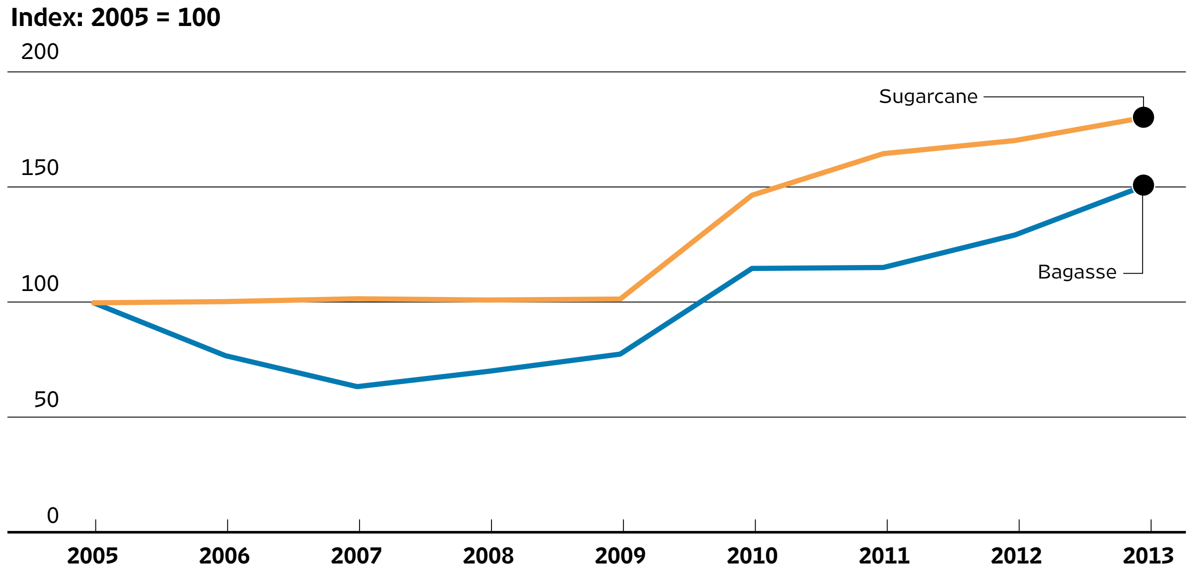
Some prices for feedstocks in developing countries are available, but the information is relatively limited. In the case of Brazil, the price of bagasse varies significantly depending on the harvest period and appears to be volatile. The price of bagasse was between USD 43 and USD 52/tonne in 2014 – significantly higher than the USD 11-13/tonne price in 2009 (PCH Portal, 2014; and Business Standard, 2014). Despite the increase in the price of bagasse in the last five years, there was a substantial growth in annual bagasse generation capacity, at an average of more than 1 300 MW installed per year from 2009 to 2013 (Global Data, 2014). The price increase since 2009 may have had an important impact on the economics of bagasse-based power plants, most likely motivating potential developers to consider other feedstocks, such as eucalyptus (Bhatia et al., 2013). Despite this, bagasse-based generation in 2012 accounted for around 80% of all electricity generation from biomass in Brazil (Bhatia et al. 2013).

In India, the Office of the Economic Adviser within the Ministry of Commerce and Industry compiles bagasse and sugarcane price data, which are then transformed into an index. Prices were estimated to have increased from USD 19/tonne in 2005 to around USD 26/tonne (USD 1.5/GJ) of bagasse in 2014 (PCH Portal, 2014; and Business Standard, 2014), and they have followed the price trend of sugarcane (Figure 8.2).

Biomass capacity deployment in India appears to be dependent on the price and availability of bagasse; annual new capacity additions were around 600 MW on average between 2009 and 2013. According to the Ministry of New and Renewable Energy, almost 55% of biomass installed capacity used bagasse in 2012.

The analysis in this report for OECD countries examines feedstock costs of between USD 10/tonne for low-cost residues to above USD 180/tonne for internationally traded pellets (Tables 8.1 and Argus, 2014). This compares to forward prices and spot prices for pellets at ARA (Amsterdam, Rotterdam, Antwerp) that ranged between USD 180 and USD 184/tonne during May-July 2014 (Argus Media Biomass Market, 2014). Environmental policies in the European Union have fostered an international wood pellet market in which the United States and Canada play a significant role in supplying pellets to Europe (NREL, 2013).

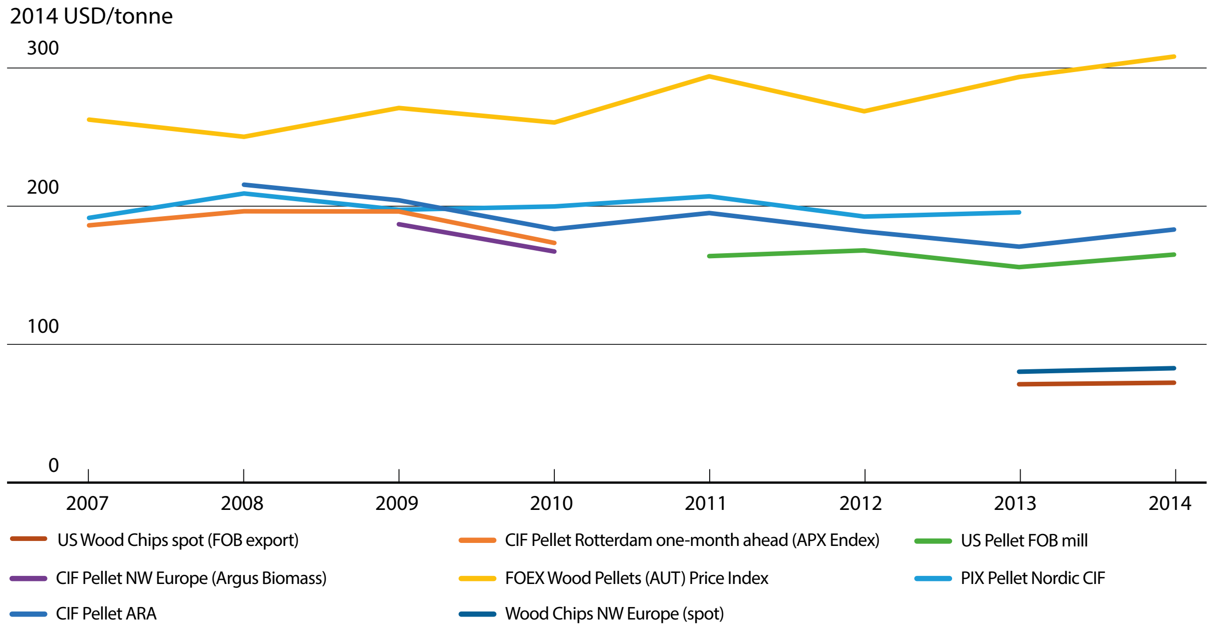
Figure 8.2: Evolution of the price of sugarcane and bagasse in India, 2005-2013



Note: 2005 baseline = 100

Source: Office of the Economic Adviser, Ministry of Commerce and Industry, 2014

Figure 8.3: Biomass pellet prices for large-scale consumers in Austria, the Netherlands, Scandinavia and the United States



Note: CIF = cost insurance and freight. FOB = free on board.

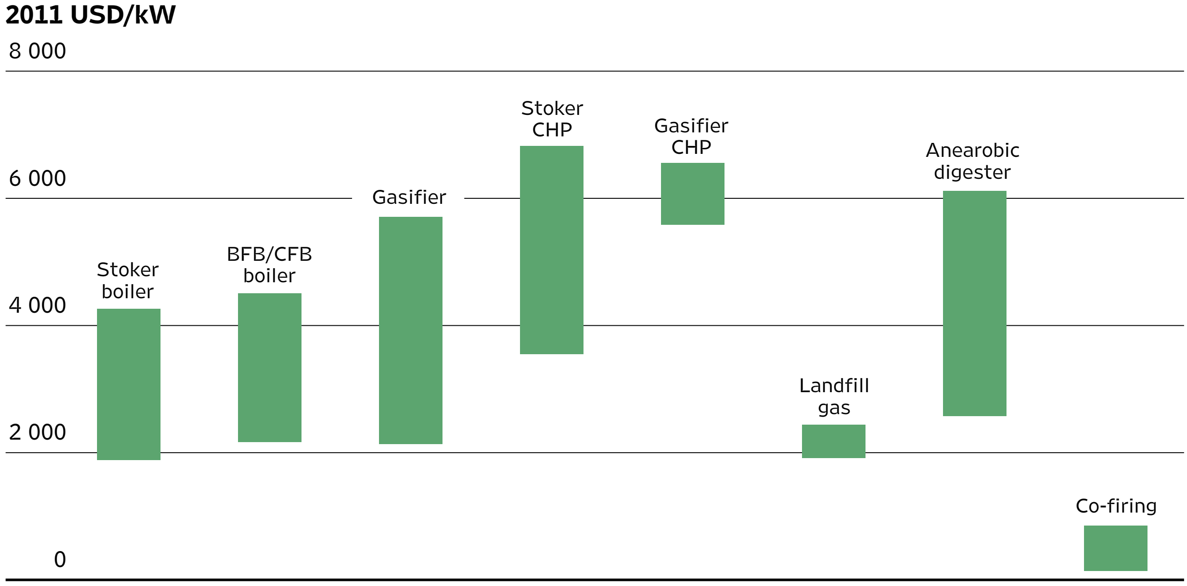
Sources: Own calculations based on Sikkema et al., 2010, Foex Indexes, 2014, Argus Media 2013 & 2014 and IEA, 2014.

Figure 8.3 presents the evolution of pellet prices and wood chips in selected European and North American markets. Pellet prices at ARA have decreased by almost 15% since 2008. Pellet prices for Scandinavian markets have seen a smooth evolution since 2007 having registered a 2% increase since 2007. Pellet prices in the United States were 10% lower than ARA prices making the United States a competitive exporter for European markets. The same difference can be observed for wood chips as well. Inland markets such as Austria are penalised by transport costs which account for a significant proportion of the final prices. In 2013, Austrian prices were around 50% higher than the ARA price.

Biomass-fired power generation capital costs

Technology options largely determine the cost and efficiency of biomass power generation

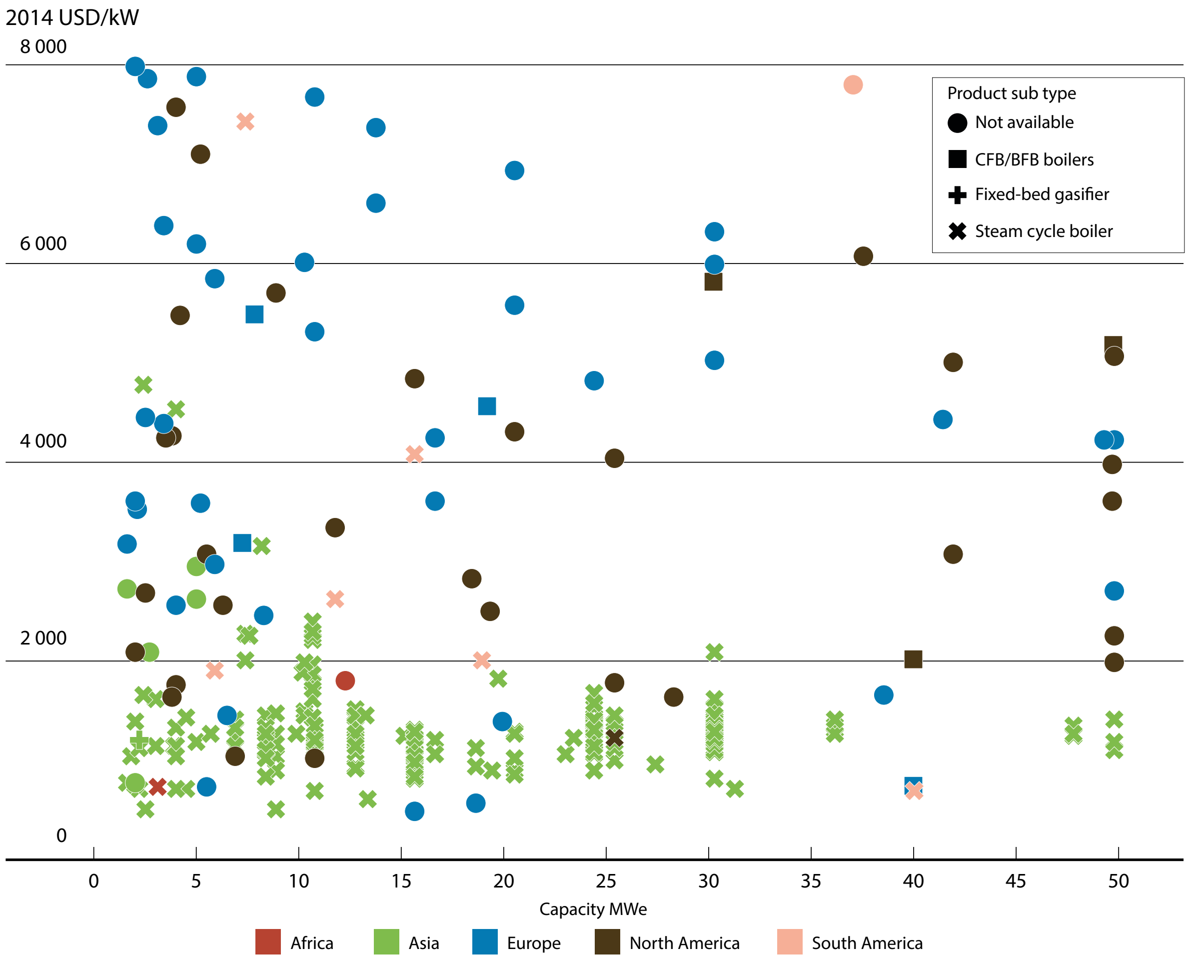
Figure 8.4: Typical total installed capital costs of biomass-fired electricity generation technologies in OECD countries



Note: BFB = bubbling fluidised bed; CFB = circulating fluidised bed

Source: IRENA Renewable Cost Database, 2014

Figure 8.5: Total installed costs of biomass power generation technologies



Source: IRENA Renewable Cost Database and GlobalData, 2014.

equipment, although equipment costs for individual technologies can vary significantly, depending on the region, feedstock type and availability, and how much feedstock preparation or conversion happens on site.

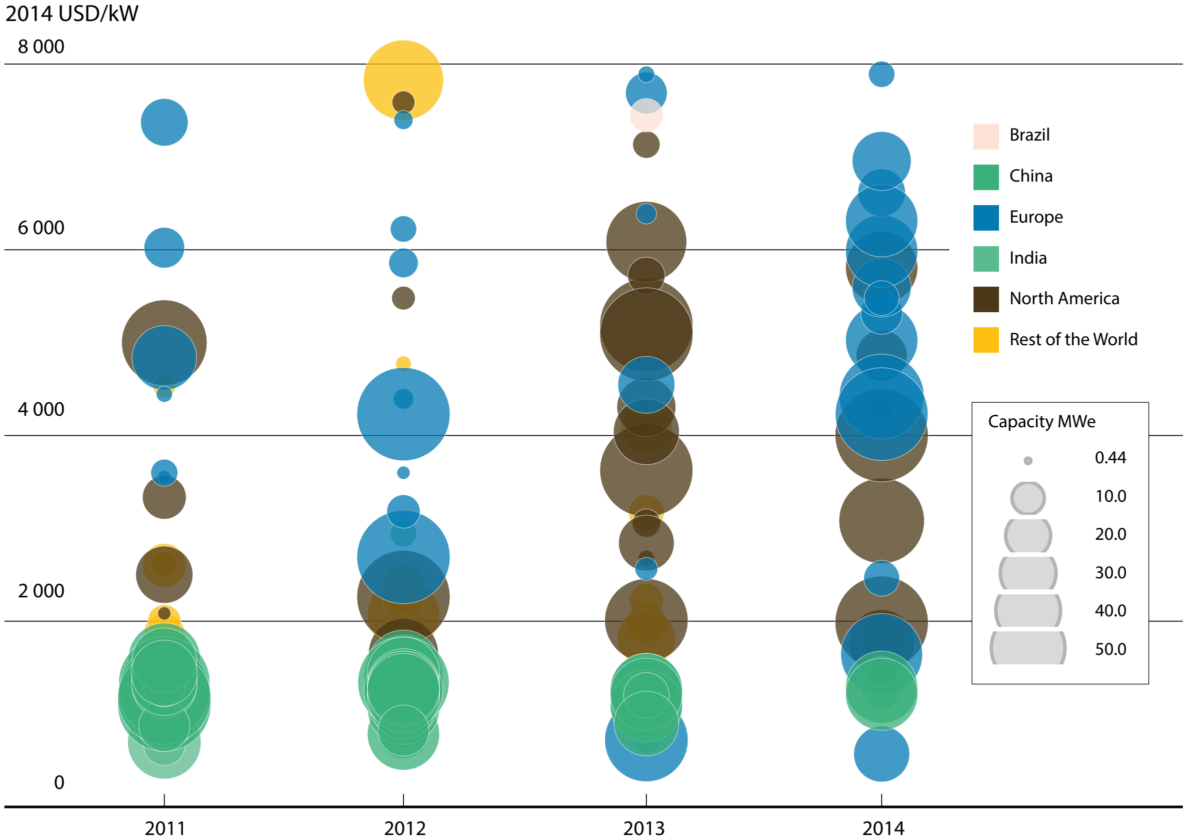
Planning, engineering and construction costs, fuel handling and preparation machinery, and other equipment (e.g. prime mover and fuel conversion system) represent the major categories of the total investment costs – or capital expenditure (CAPEX) – of a biomass power plant. Additional costs are derived from grid connection and infrastructure (e.g. roads). Figure 8.4 presents the range of capital costs for selected technologies in OECD countries. Combined heat and power (CHP) biomass installations have higher capital costs, but the higher overall efficiency (around 80% to 85%) and the ability to produce heat and/or steam for industrial processes or for space and water heating through district heating networks can significantly improve the economics.

Biomass power plants in developing countries can have significantly lower investment costs than the cost ranges for OECD projects, due to lower local content costs and the cheaper equipment allowed by less stringent environmental regulations. For example, the range of capital costs for a set of 124 manure and wastewater systems associated with electricity generation was between USD 500/kW and USD 5000/kW in developing countries.

Figure 8.5 and Figure 8.6 highlight the relatively low cost of biomass combustion technologies for projects in Asia and South America. Although small-scale projects can have higher capital costs, the majority of larger projects have installed capital expenses in the range of USD 450 to USD 2 000/kW. The data to which IRENA has access is dominated by steam cycle boiler systems, although in many cases the technology is not disclosed.

Individual projects can have very different cost components, infrastructure being particularly project-sensitive. A set of 12 projects from Africa and India had infrastructure costs of between 1% and 58% of total investment costs. Equipment costs can account for 8% to 86%, while grid connection

Figure 8.6: Total installed costs of biomass-fired power generation projects, 2011 to 2014



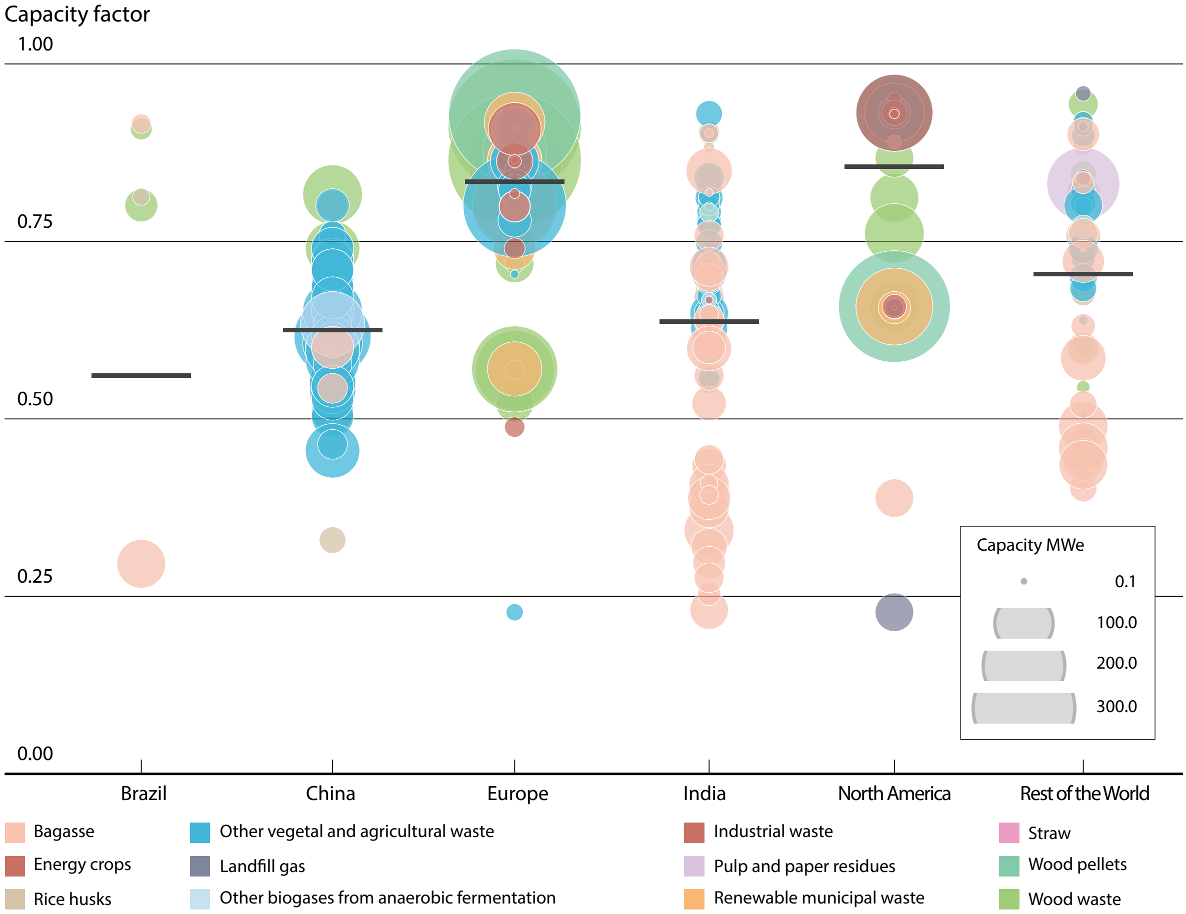
Source: IRENA Renewable Cost Database

Table 8.2: Fixed and variable operations and maintenance costs for biomass power

	Fixed O&M (% of CAPEX/YEAR)	Variable O&M (2014 USD/MWh)
Stoker/BFB/CFB boilers	3.2	4-4.93
Gasifier	3-6	4
Anaerobic digester	2.1-3.2 2.3-7	4.4
Landfill gas	11-20	n.a.

Sources: United States DOA, 2007; United States EPA, 2009; and Mott Macdonald, 2011

Figure 8.7: Project capacity factors and weighted averages of biomass-fired electricity generation systems by country and region



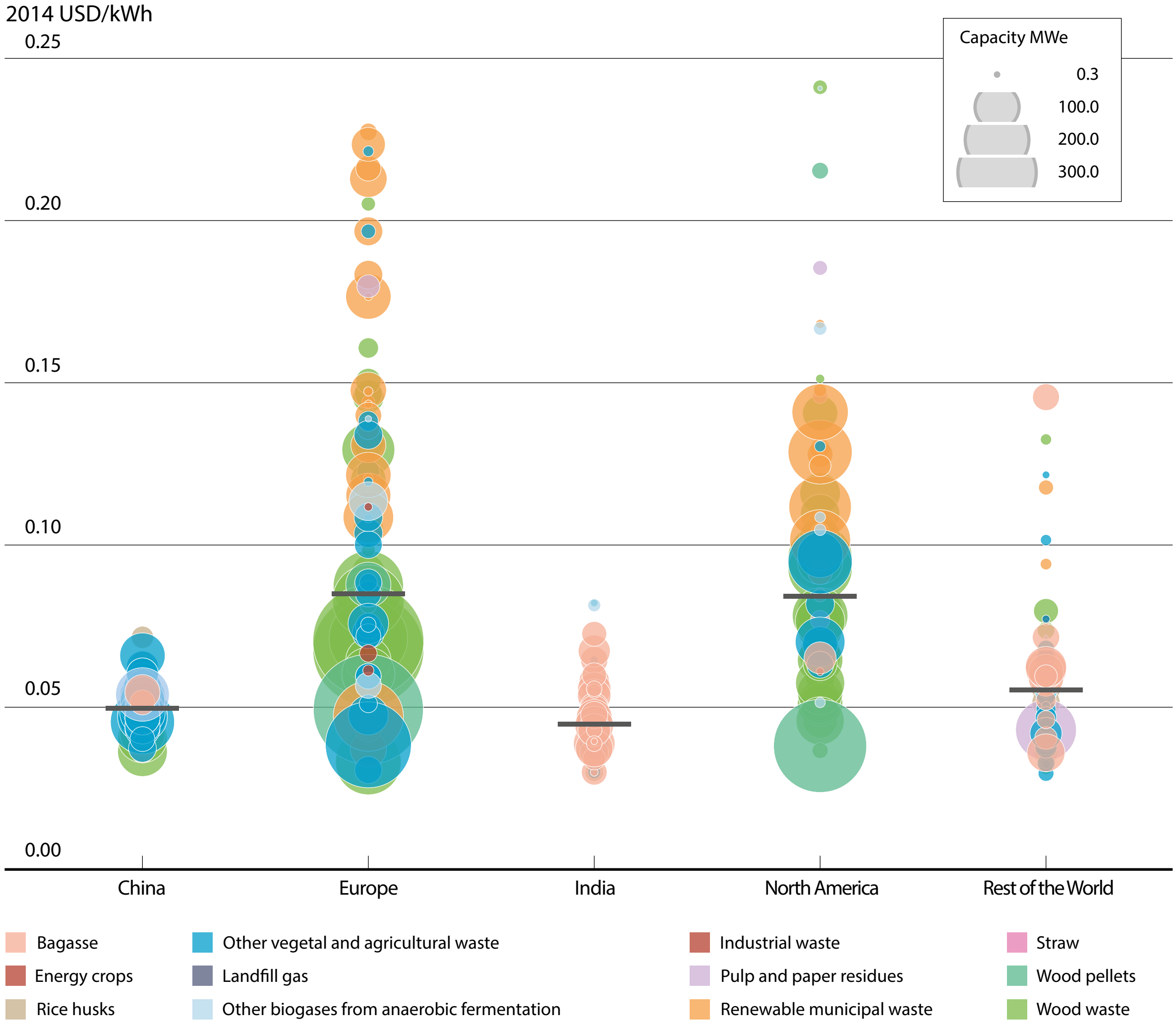
Source: IRENA Renewable Cost Database

can be as high as 41% of total investment costs (IRENA, 2013).

Biomass-fired power generation operations and maintenance costs

Fixed operations and maintenance (O&M) costs for biomass power plants typically range from 2% to 6% of the initial CAPEX per year, while variable O&M costs are typically relatively low at 0.005/kWh (Table 8.2). Fixed O&M costs include labour, scheduled maintenance, routine component/equipment replacement (for boilers, gasifiers, feedstock handling equipment, etc.), insurance, etc. The fixed O&M costs of larger plants are lower per kilowatt (kW) due to economies of scale, especially for labour. Variable O&M costs are determined by the output of the system and are usually expressed as USD/kWh. Non-biomass fuel costs, such as ash disposal, unplanned maintenance, equipment replacement and incremental servicing costs are

Figure 8.8: Levelised electricity cost ranges and weighted averages of biomass-fired electricity generation by feedstock and country/region, 2000 to 2014



Source: IRENA Renewable Cost Database

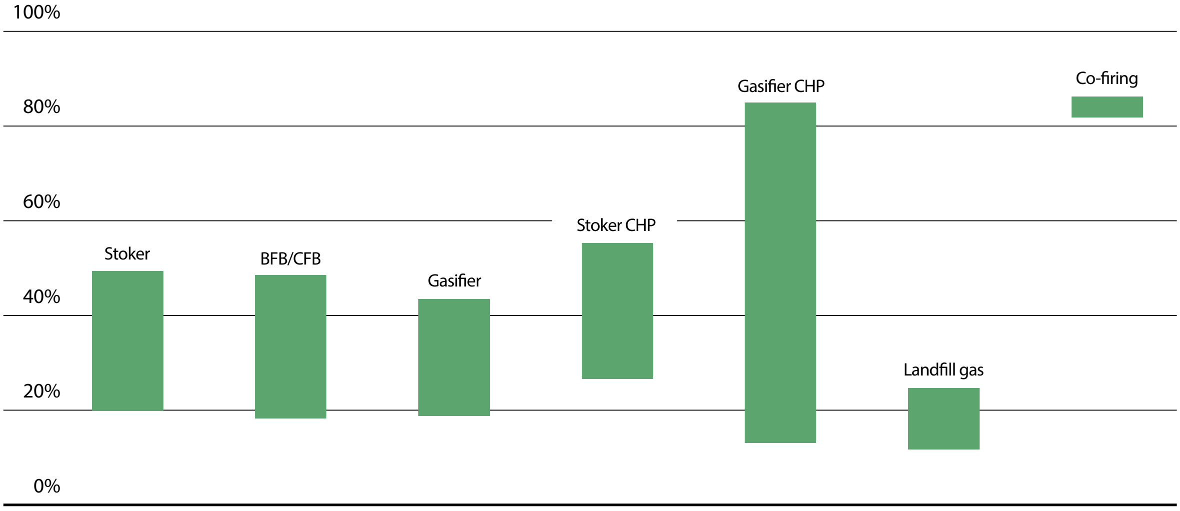
the main components of variable O&M costs. Unfortunately, the available data often merge fixed and variable O&M costs into one number, thus rendering a breakdown between fixed and variable O&M costs impossible.

Biomass-fired power generation capacity factors and efficiency

Technically, it is possible for biomass-fired electricity plants to achieve capacity factors of 85% to 95%. In practice, most plants do not regularly operate at these levels. Feedstocks may be a constraint on capacity factors in cases where systems relying on agricultural residues may not have year-round access to low-cost feedstock and buying alternative feedstocks might make plant operation uneconomical. This is illustrated in Figure 8.7, where the lower capacity factors for projects in India represent the impact of a large number of bagasse-fired projects that will operate only during and after the harvesting period until they exhaust the available feedstock supply. In contrast, the higher capacity factors observed in Europe and North America are a consequence of these plants relying on steady supplies of wood pellets and wood waste provided by a functional, buyer-driven international market for such feedstocks (NREL, 2013, Argus Biomass Markets, 2014), as well as waste-to-energy plants and those using forestry or pulp and paper residues.

The assumed net electrical efficiency (after accounting for feedstock handling) of the prime mover (generator) averages around 30%, but varies from a low of 25% to a high of around 36%. In developing countries, cheaper technologies

Figure 8.9: The share of feedstock costs in the levelised cost of electricity of biomass-fired electricity generation by technology



and sometimes poor maintenance result in lower overall efficiencies that can be around 25%, but many technologies are available with higher efficiencies, with 31% for wood gasifiers to a high of 36% for modern well-maintained stoker, circulating fluidised bed (CFB), bubbling fluidised bed (BFB) and anaerobic digestion systems (Mott MacDonald, 2011). Biomass integrated gasification combined cycle (BIGCC) systems are able to achieve higher efficiencies, but require much higher capital investments. To date, the hoped for development of BIGCC systems has not materialised.

The levelised cost of electricity from biomass-fired power generation

The wide range of biomass-fired power generation technologies and feedstock costs translates into a broad range of observed LCOE of biomass-fired electricity. Figure 8.8 summarises the estimated range of costs for biomass power generation technologies in a range of countries and regions where the IRENA Renewable Cost Database has good coverage. Assuming a cost of capital of 7.5% to 10%, and feedstock costs between USD 1 and USD 9/GJ, the weighted average LCOE of biomass-fired electricity generation is around USD 0.04/kWh in India and USD 0.05/kWh in China. The weighted average LCOE in North America and Europe is higher, reflecting more sophisticated technology with more stringent emissions controls and higher feedstock costs. The weighted average of projects in Europe and North America was around USD 0.085/kWh. Where capital costs are relatively low, and low-cost feedstocks are available, bioenergy can provide competitively priced, dispatchable electricity generation with an LCOE as low as around USD 0.04/kWh.[32] The most competitive projects make use of agricultural or forestry residues already available at industrial processing sites where marginal feedstock costs are minimal or even zero. Where industrial process steam or heat loads are also required, the ability to integrate CHP systems can reduce the LCOE of electricity to as low as USD 0.03/kWh.

Low-cost opportunities to develop bioenergy-fired power plants present themselves at sites where low-cost feedstocks and handling facilities are available to keep feedstock and capital costs low. Where this is not the case, or where these feedstocks need to be supplemented by additional feedstocks (e.g. outside seasonal harvesting periods), then competitive supply chains for feedstocks are essential for making biomass-fired power generation economically sound.

This is the pattern seen outside Europe and North America, where biomass costs for most projects can range from negligible for agricultural or forestry processing residues, up to USD 2.25/GJ. They may sometimes exceed these values and rise to as much as USD 4/GJ where additional feedstocks are purchased to achieve higher capacity factors. These projects, using simple and cheap combustion

[32] However, many of these low-cost technologies will not meet stringent air quality standards.

technologies can have very competitive LCOEs (Figure 8.8). As an example, auctions in Brazil organised in August 2013 saw developers win contracts for 647 MW to be delivered in 2018 at average prices of USD 0.056/kWh (BNEF, 2013). However, even higher-cost projects in certain developing countries, will be attractive because they provide security of supply where brownouts and blackouts can be particularly problematic for the efficiency of industrial processes.

Many of the higher cost projects instituted in Europe and North America are using municipal solid waste as a feedstock. It is important to note that the primary objective of these projects is not power generation, but to dispose of waste. Capital costs are often higher as greater sorting of heterogeneous feedstocks is required, as well as expensive technologies to ensure local pollutant emissions are reduced to acceptable levels. Excluding these projects, which are typically not the largest projects, reduces the weighted average LCOE in Europe and North America by around USD 0.01/kWh and narrows the gap with the LCOE of non-OECD regions.

Figure 8.9 highlights the importance of the feedstock costs in OECD countries, where feedstock costs range from USD 1/GJ for residues to USD 10/GJ or more for pellets. Feedstock costs account for 20% to 50% of the LCOE power-generation-only options (co-firing is a particular case and is excluded.) Gasifier-based CHP presents wider ranges for the weight of the feedstock in the final LCOE – between 14% for locally sourced, low-cost feedstocks up to 85% for some imported feedstocks, such as pellets.

9 GEOTHERMAL POWER GENERATION

	2010	2013	2014	2010-2014 (% change)
New capacity additions (MW)	221	389	528	139%
Cumulative installed capacity (GW)	10.9	11.6	12.6	15.6%
Typical global total installed cost range (2014 USD/kW)	1 900 to 5 500	1 900 to 5 100	1 850 to 5 100	n.a.
Global LCOE range (2014 USD/kWh)	0.05 to 0.15	0.07 to 0.15	0.04 to 0.10	n.a.

Notes: 2014 deployment data are estimates. n.a. = data not available or not enough data to provide a robust estimate.

Highlights

- Geothermal power generation is a mature, commercially available solution to provide low-cost base load capacity in areas with excellent high-temperature resources that are close to the surface.
- Between 2007 and 2014, the LCOE of geothermal varied from as low as USD 0.04/kWh for second-stage development of a field to as high as USD 0.14/kWh for greenfield developments.
- Geothermal power plants are capital intensive, but they have very low and predictable running costs. Development costs have increased over time as engineering, procurement and construction (EPC) costs and commodity prices have risen, as well as because of the rise in drilling costs, which is in line with trends in the oil and gas sectors.
- Total installed costs appear to have stabilised, but deployment remains modest, and not enough data is available to identify if this is statistically significant.
- Projects that are planned for the period 2015 to 2020 expect to be able to reduce installed costs below recent levels.

Introduction

Geothermal resources consist of the thermal energy available from the Earth's interior, which is stored as heat in rocks, as steam or hot water (hydrothermal resources) in the Earth's crust, or in active geothermal areas on the Earth's surface. Geothermal development reached a total installed capacity of around 12 gigawatts (GW) at the end of 2013, with virtually all of this development in active geothermal areas with good resources.

Geothermal power generation is a mature, commercially available solution to provide low-cost baseload capacity in areas with excellent high-temperature resources that are close to the surface. The wider deployment of geothermal power outside areas of active geothermal activity, using the so-called "enhanced geothermal" or "hot dry rocks" approach, is much less mature and the costs are typically significantly higher, making the economics much more challenging.

High-temperature water or steam-based resources (>180°C) are the most efficient for electricity generation, as the liquid can be used directly by dropping the pressure to create steam (in the "flashing" process) that can drive a turbine. Where only medium-temperature resources are available, more expensive "binary" plants are required. These use a heat exchanger to create steam from a liquid with a low boiling point for subsequent use in a steam turbine. These plants have higher capital costs and somewhat lower efficiency, which also raises costs for a given desired output due to the higher energy input needs.

The availability of existing geothermal resource mapping can help to reduce the costs of development, as it reduces the uncertainty about where initial exploration should be conducted. At this point a programme of baseline environmental monitoring is recommended. The initial exploration (e.g. surface seismic) is then used to map the sub-surface in more detail and identify promising geothermal reservoirs suitable for electricity production. This is then followed by exploratory drilling, which will provide additional information on sub-surface conditions. The exploratory drilling helps to define the extent of the reservoir and its characteristics (e.g. pressures, temperature, flow rates, etc.). This is a time-consuming and expensive process, and presents a barrier to the uptake of geothermal power generation, as poorer than expected results may require additional drilling or indicate that wells will be needed over a larger geographic area in order to generate the desired level of electricity.

However, with this information a field development programme can then be elaborated, which involves the siting and design of the production and re-injection, reservoir management programme, infrastructure and power plant design. However, the geothermal system management programme will evolve over time as a better understanding emerges regarding the reservoir and its flows and characteristics when in production. In addition, regular "make-up" wells will need to be drilled as the productivity of individual wells declines over.[33]

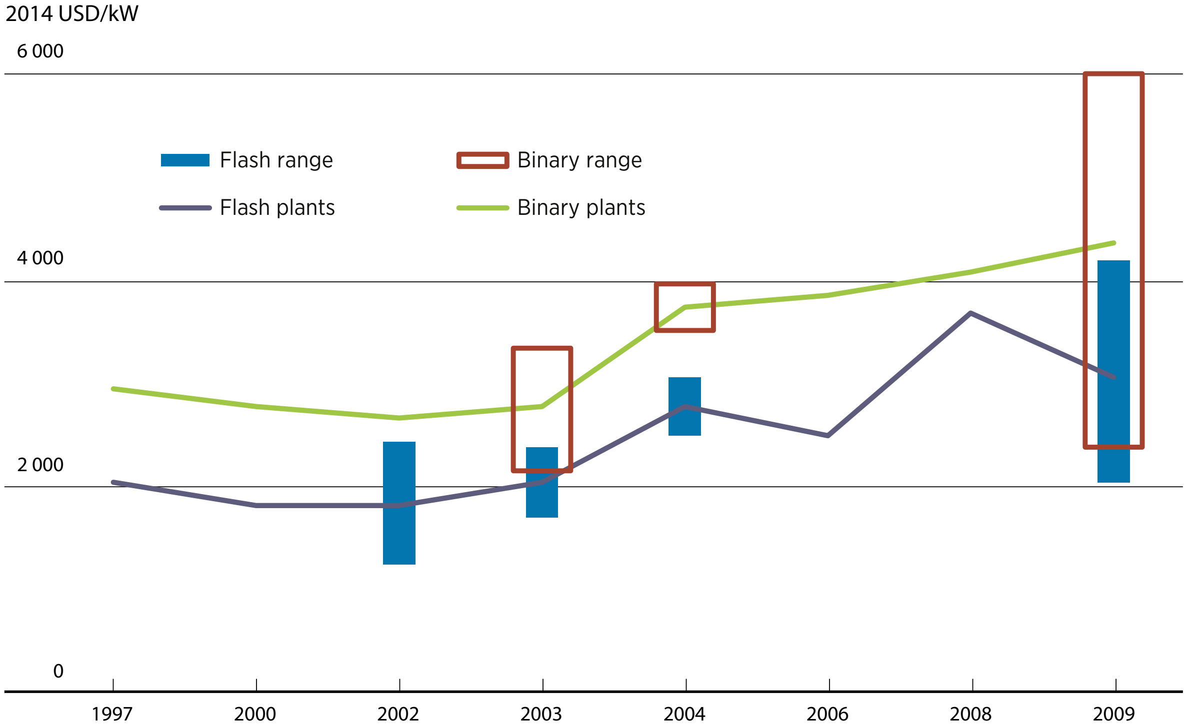
Geothermal power generation installed costs

Geothermal power plants are capital-intensive, but they have very low and predictable running costs. Development costs have increased over time as engineering, procurement and construction costs (EPC), commodity prices and drilling costs have risen (which is in line with trends in the oil and gas sectors). The total installed costs of a geothermal power plant are composed of the following:

- Exploration and resource assessment costs;
- The drilling of production and re-injection wells. This requires a contingency plan, as a success rate of 60% to 90% is the norm for production (Hance, 2005; GTP, 2008);
- Field infrastructure, the geothermal fluid collection and disposal system, and other surface installations;
- The power plant and its associated costs; and
- Project development and grid connection costs.

[33] The alternative is to let capacity factors decline over time as the energy available from existing wells drops. This is an economic question and the trade-off will depend on the cost of additional wells, balanced against the revenue from higher output.

Figure 9.1: Total installed costs for geothermal power stations, 1997 to 2009



Source: IPCC, 2011.

The geothermal field characteristics will have a significant influence on what type of power plant can be used (flash or binary), on well productivity and energy delivery,[34] and on the capacity for which it is economic to provide steam, given the quality of the geothermal field and its geographic distribution.

Between 2000 and 2009, total installed costs for geothermal power plants increased by 60% to 70% (IPCC, 2011). Project development costs rose with general increases in civil engineering and EPC costs over that time, and also as a result of the above average level of inflation in drilling costs experienced over this period – the result of cost inflation in the drilling business tied to rising oil and gas prices. The total installed costs of conventional condensing "flash" geothermal power generation projects grew to between USD 1 900 and USD 3 800/kW in 2009 (Figure 9.1). The more expensive binary power plants saw installed costs for typical projects increase to between USD 2 250 and USD 5 500/kW in 2009 (IPCC, 2011).

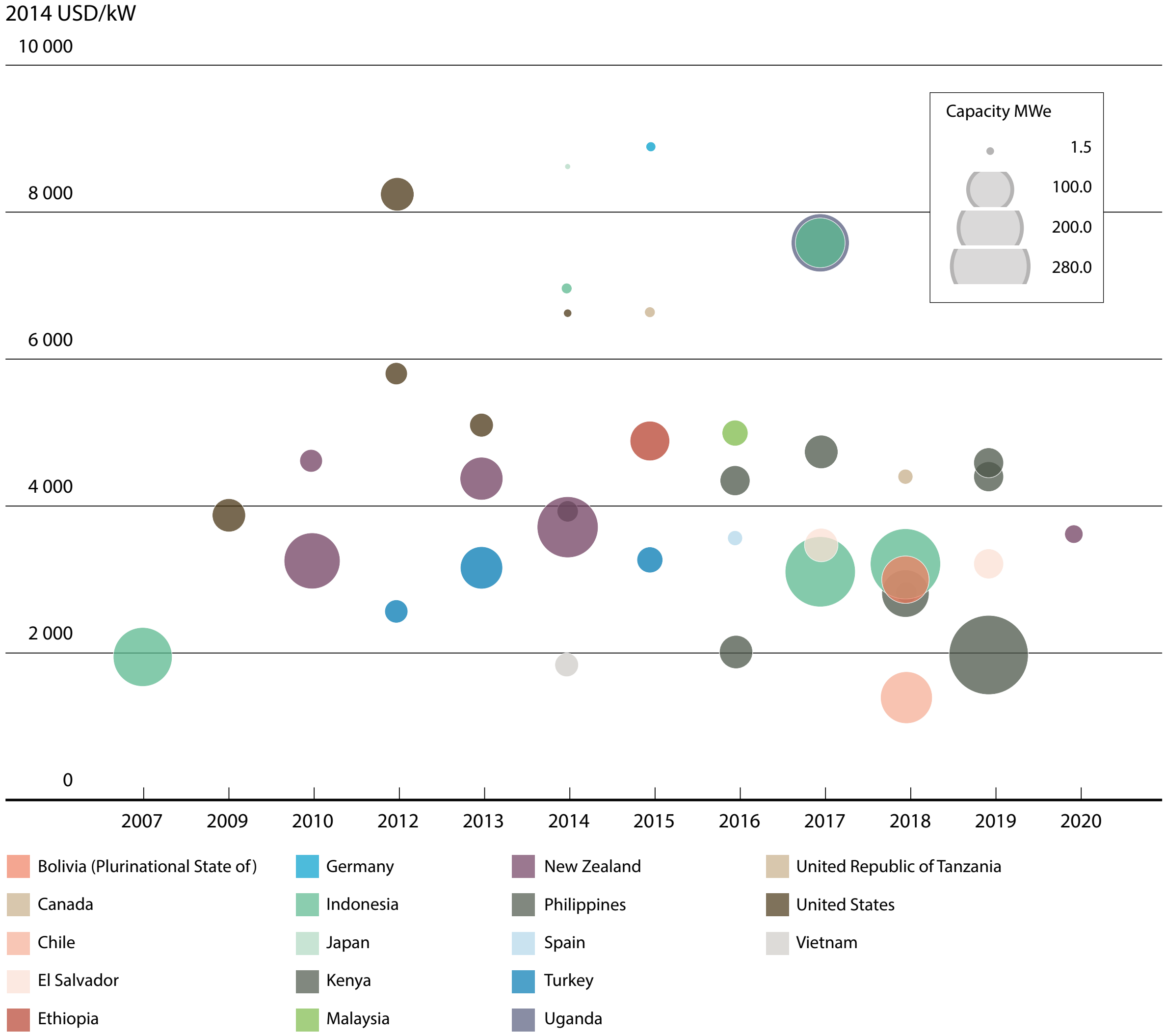
[34] *The well productivity and energy delivery will affect the number of wells required for a given capacity of electricity. These factors, and the geographic spacing of these wells, will have a significant impact on overall development costs.*

Project costs can be as low as USD 1 500/kW where capacity is being added to a geothermal reservoir which is already well characterised and where existing infrastructure can be utilised, but such cases are exceptional. Data for recent projects (Figure 9.2) fit within the general range band in Figure 9.1, but there are also small projects in new markets for geothermal power for which costs are higher.

However, the cost ranges in Figure 9.1 are narrow compared with some of the analysis in the literature and may represent the lower end of the cost range when exploiting the best geothermal resources. Analysis for the United States (Figure 9.3) suggests a wider range for binary plants exploiting low-temperature resources, based on the power plant costs alone (i.e. excluding production and injection wells) (NREL, 2012).

The estimates of total installed costs for the remaining geothermal resources in the United States cover a very wide range – from around USD 1 500/kW to over USD 10 000/kW (Augustine, 2011). Much of this supply curve for the United States is not economic and does not represent typical geothermal project costs, but it does show the importance of identifying the best

FIGURE 9.2: INSTALLED CAPITAL COSTS FOR GEOTHERMAL POWER PROJECTS, 2007 TO 2020



Source: IRENA Renewable Cost Database and GlobalData, 2014.

geothermal reservoirs and geothermal resources for project development. Cost ranges for small-scale, low-temperature resource binary plants are therefore likely to be higher than those for excellent geothermal reservoirs and resources, and are typically in the range from USD 5 000 to USD 10 000/kW.

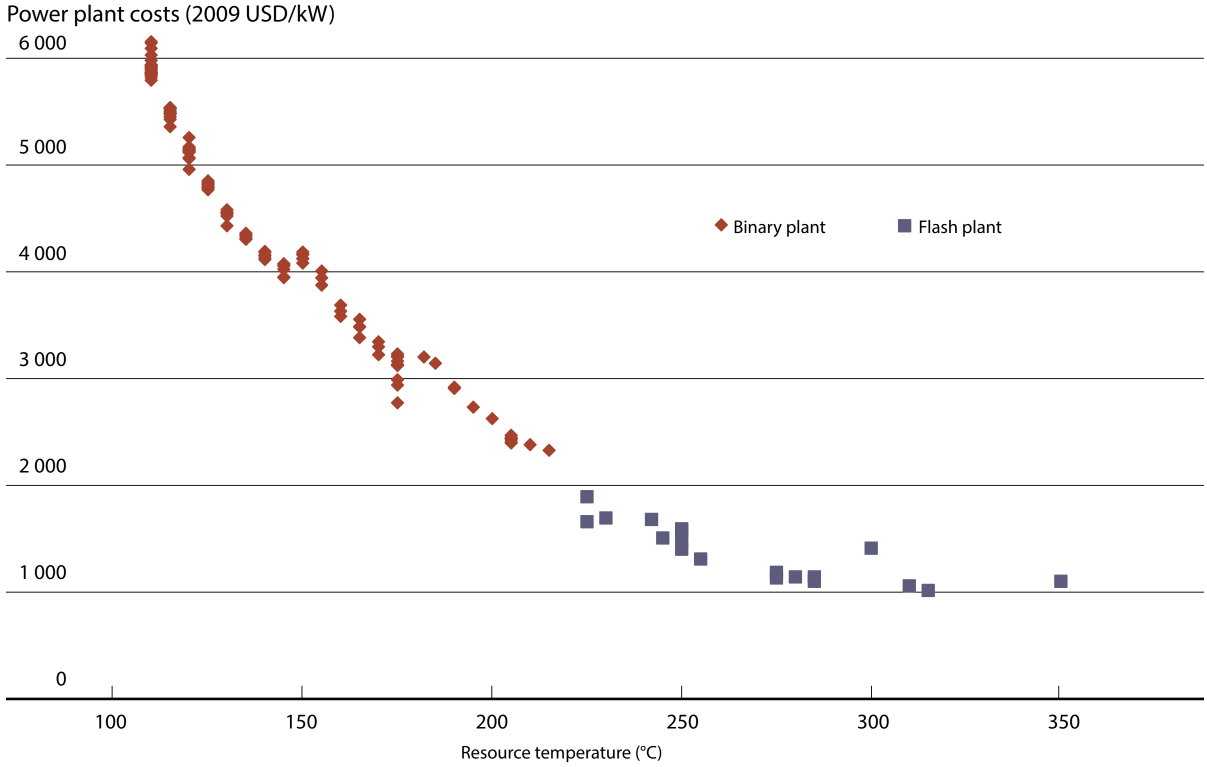
Figure 9.4 presents the estimated breakdown of capital costs for the development of two 110 MW flash geothermal power plants in Indonesia with total installed costs of around USD 3 830/kW. With total power plant costs of USD 1 560/kW, the power plant accounts for 42% of the total installed costs. Production wells, injection wells and smaller test wells together account for around one-fifth of the total cost, while the steamfield development accounts for 14%.

THE LEVELISED COST OF ELECTRICITY OF GEOTHERMAL POWER GENERATION

The levelised cost of electricity (LCOE) of a geothermal plant is determined by the usual factors, such as installed costs, operations and maintenance (O&M) costs, economic lifetime and the weighted average cost of capital. However, geothermal power presents more dynamic questions than for some other renewables and projects must be carefully managed in order to optimise the resource.

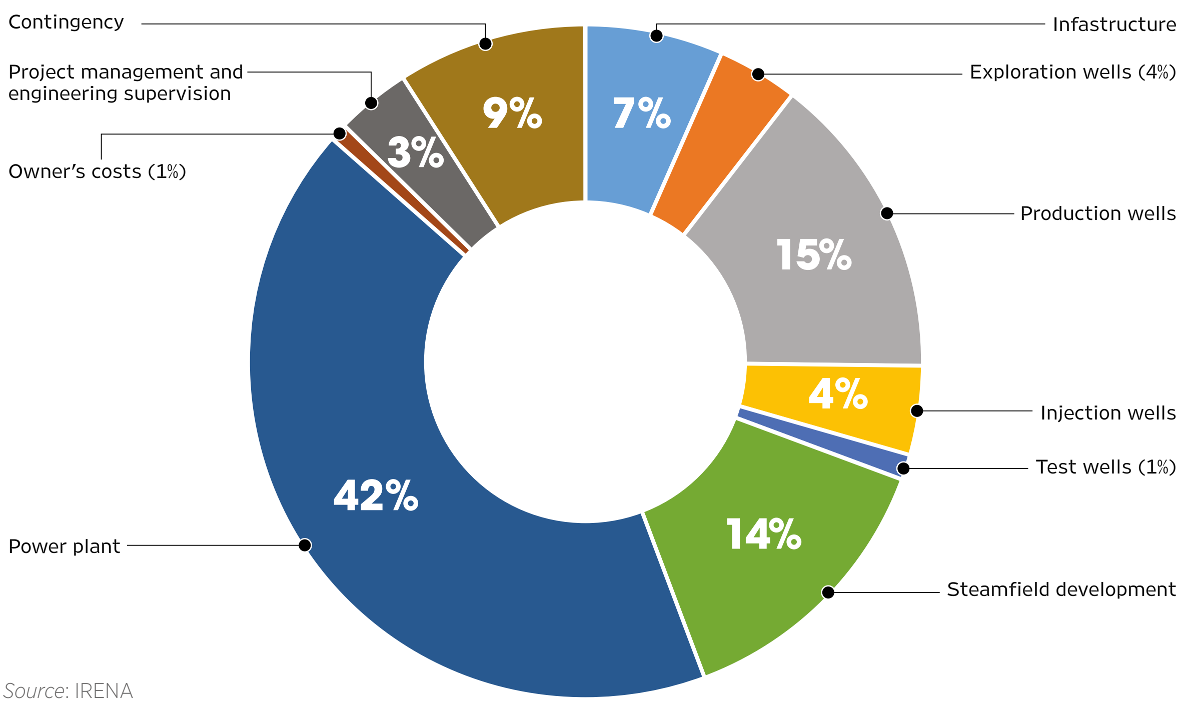
There is an ongoing requirement for expert professional and technical staff to manage a programme of reservoir monitoring, well testing and maintenance and drilling. A lack of understanding of these factors can introduce greater uncertainty into the development of

FIGURE 9.3: INDICATIVE POWER PLANT ONLY COSTS FOR GEOTHERMAL PROJECTS BY RESERVOIR TEMPERATURE



Source: NREL, 2012

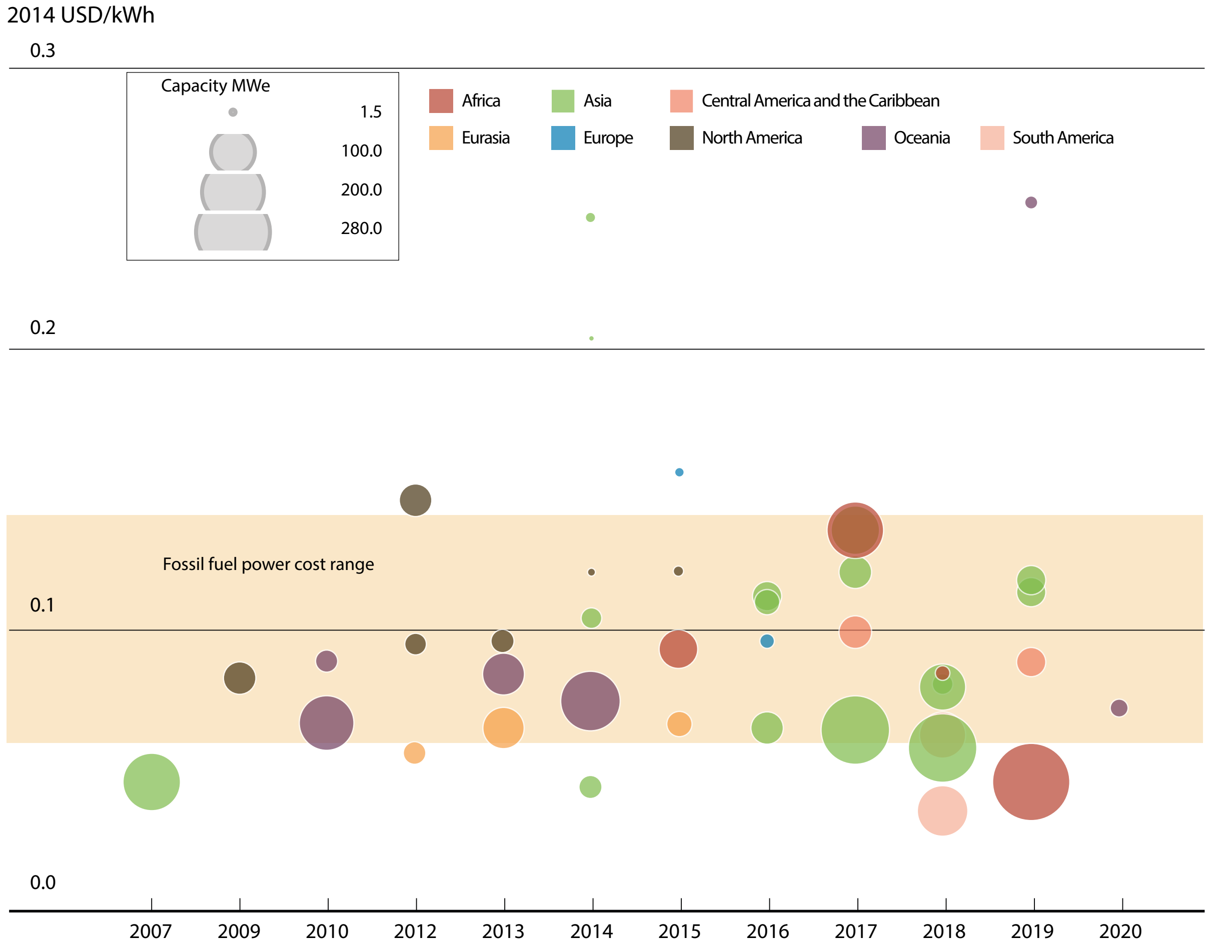
FIGURE 9.4: TOTAL INSTALLED COST BREAKDOWN FOR TWO PROPOSED 110 MW GEOTHERMAL PLANTS IN INDONESIA



Source: IRENA

geothermal projects and may increase financing costs, compared with technologies such as wind. However, this uncertainty is typically manageable in mature geothermal markets where financing institutions have had previous experience with the industry and where there are sufficiently experienced professional and technical experts working on the project. The LCOE calculations presented here must be considered an indicative estimate of the *ex ante* LCOE. The actual LCOE will only be known at the end of the project's

Figure 9.5: The levelised cost of electricity of geothermal power projects by region and size



Source: IRENA Renewable Cost Database and Global Data, 2014

economic life, but would be expected to differ from the values presented here.

Figure 9.5 presents the LCOE for geothermal projects assuming a 25-year economic life, O&M costs of USD 110/kW/year, [35] capacity factors based on project plans (or national averages where data are lacking), two sets of make-up and re-injection wells over the 25-year life and the capital costs outlined in Figure 9.2. Between 2007 and 2014, according to the data available, the trend in LCOE was increasing in line with trends in capital costs (Figure 9.1 and 9.2), and the LCOE varied from as low as USD 0.04/kWh (Figure 9.5) for second-stage development of a field to as high as USD 0.14/kWh for greenfield developments. Looking beyond 2014 to proposed projects between 2015 and 2020, there is an expectation that a range of large projects might see the LCOE of geothermal plants being developed start to decline. It remains to be seen whether these projects can be developed at the cost levels indicated in Figure 9.2, and if they will perform as expected to deliver the projected LCOEs in Figure 9.5.

[35] *Lower costs of USD 68 to USD 92/kW/year are reported for some countries (Sinclair Knight & Merz, 2014) but these exclude make-up and re-injection wells and it is not clear that they are indicative for average projects.*

10 COST REDUCTIONS TO 2025

The virtuous cycle of policy support for renewable power generation technologies leading to accelerated deployment, technology improvements and cost reductions has had a profound effect on the power generation sector. Renewables are now the economic solution off-grid and are increasingly the least-cost option for grid supply. This is changing the nature of electricity generation systems and how they are managed. Solar PV is democratising electricity production and bringing it within reach of individual households, as millions of people around the world now have rooftop PV systems. In some countries, this growth of distributed solar PV is starting to call into question the viability of traditional utility business models. The challenges faced by utilities, sometimes amplified by inflexible or outdated electricity markets, will only increase as renewable power generation costs continue to fall.

The broad reasons for this transformation of the electricity sector are simple. In the past, the most economic renewable power generation options were hydropower, biomass for power and geothermal where unexploited economic resources existed, but resources were limited. However, as a result of the cost declines for solar PV and wind, future growth can be sustained on the much larger and more widely distributed resources of solar and wind. Past barriers to the growth in new renewable power generation deployment are therefore being removed. However, new challenges are emerging, such as outdated market structures, inflexible market mechanisms for managing the electricity system, and utility business models that have not adapted to the new reality. In this context, but also because renewables still do not face a level playing field, it is important to understand the potential for future cost reductions for renewable power generation technologies in order to understand the economic potential to accelerate renewable power generation deployment.

The recent declines, and in the case of solar PV dramatic declines, in the LCOE of renewables reflect the increasing maturity of non-hydro technologies and represent a remarkable achievement. However, for a transition to a truly sustainable energy sector to be achieved, continued cost improvements need to be unlocked. This is required to ensure that in all major electricity markets renewable power generation options are, on average, the least-cost solution for almost all new electricity generation capacity required worldwide to meet either demand growth or plant retirements.[36] The fact that a large share, and in some cases the entire share, of total new annual capacity additions of a given renewable power generation technology is accounted for by the top five countries highlights how much more work is required to broaden and deepen the markets for renewable power generation technologies. This will require significant work to remove barriers, grow domestic markets to ensure competitive cost structures and setting the right market and regulatory structures. However, continued improvement in the competitiveness of renewables will also be required even if the market barriers unrelated to price, which hinder the accelerated deployment of renewable power generation technologies, are removed given the lack of a level playing field for renewables.

Cost reduction potentials by technology

Fortunately the outlook for cost reductions is good, particularly for the average cost of new projects. However, due to the rapid cost declines seen for solar PV modules and to a lesser extent wind turbines in recent years, the absolute cost reduction opportunities in the future will increasingly need to come from balance of system costs or balance of project costs, operations and maintenance

[36] It also needs to be true in the long run for high shares of variable renewable electricity penetration if the electricity sector is to play its part in preventing dangerous climate change.

cost optimisation and reduced financing costs. Unlocking these future cost reductions will require a shift in policy focus and may also be more difficult to unlock, since they represent more fragmented stakeholders than major equipment manufacturers and project developers. Future work by IRENA in 2015 will look in much greater detail at the cost reduction opportunities and the barriers facing their realisation for the power sector.

The technologies with the largest cost reduction potential are CSP, solar PV and wind. Hydropower and most biomass combustion and conventional geothermal technologies are mature and their cost reduction potentials are not as large. There are exceptions to this, such as advanced biomass gasification technologies, enhanced geothermal, etc, but these are beyond the scope of this report.

The LCOE of wind has declined significantly, and wind power is now one of the most competitive renewable power generation options. This decline was driven by technology improvements and falls in wind turbine prices. Wind turbine prices have declined by as much as 30% since their peak in 2008/2009, with prices of between USD 930 and USD 1 376/kW in 2014 for project for which data are available (Wiser and Bollinger, 2014 and BNEF, 2014). These are 37% to 104% higher than average wind turbine prices in China. However, there is continued convergence in average prices for wind turbines, as modest declines continue in OECD countries and Chinese turbine prices stay relatively constant. In addition, there is increasing demand for today's "state of the art" technologies, and large turbines with the greatest swept areas command a price premium. The additional costs are required for more advanced materials to retain structural integrity at acceptable blade weights for the longer blades, for sturdier and quieter gear boxes and other increased structural costs to deal with greater heights and weights. Future cost reductions will therefore increasingly depend on cost trends for the larger machines, as 80 to 100 metre diameter and 100 to 120 metre diameter bladed machines will dominate the market by 2015 (MAKE Consulting, 2013).

Wind turbines are not necessarily interchangeable commodities – even at the same capacity rating – given their design characteristics, quality and their manufacturer's warranty terms and reliability guarantees vary. The extent to which wind turbine prices can converge is therefore limited. An additional issue is that the particularly low-cost characteristics of turbines in China and India are to a certain extent due to the lower materials costs (e.g. cement, steel) and labour costs in these markets, which cannot be replicated in other markets.

By 2025 installed costs for wind farms in the United States could fall to around USD 1 450/kW from their preliminary estimates of around USD 1 780/kW in 2014, assuming wind turbine prices stabilise at around USD 850/kW. Total installed costs in Europe are likely to follow similar trends, with values for 2025 of between USD 1 400 and USD 1 600/kW for the major markets. There is likely to be little change in the already very competitive cost structures in China and India, as installed cost reductions are likely to be offset by a shift to larger turbines with greater swept areas and improved capacity factors.

Average capacity factors for new wind farms may continue to rise, as the average size and hub-height of turbines grow. However, this effect may be less than implied by technology improvements if a trend to lower quality wind resource sites occurs in some major markets due to the best sites already having been exploited. As a result the LCOE of wind will continue to fall, but this may slow if, on average, poorer wind sites are being developed. With turbine cost reductions likely to slow closer to 2020, the importance of reducing balance of project costs, O&M costs and financing costs will grow. Maintenance costs in the United States are around USD 0.01/kWh, although overall O&M costs are higher and most markets have costs of around USD 0.015 to USD 0.025/kWh. If these costs cannot be brought down, they will account for an increasing share of the LCOE of wind and act as a brake on cost opportunities. Further analysis and data are needed to try to identify policy recommendations to drive down O&M costs to best-practice levels.

Despite solar PV module prices that are now significantly below the learning curve, cost reductions are likely to resume in 2015 as the market continues to grow and manufacturing innovations and economies of scale are exploited. With price reductions having been brought forward to some extent, future cost reductions will be lower in absolute terms. However, the continued growth in new capacity additions means that in percentage terms, cost reductions should not slow dramatically. By 2025, c-Si modules could be retailing for between USD 0.40 and USD 0.45/W with full recovery of capital costs. However, given even small changes in the projections of future deployment, these projections are extremely uncertain.

What is clear is that now that PV module prices have fallen so far, BoS costs and financing costs are becoming the crucial determinants of the LCOE of solar PV. This can easily be seen by comparing one of the most competitive markets, Germany, with the United States. The higher BoS costs in the United States raises the LCOE of solar PV above what it otherwise could be. Further analysis to better understand the reasons behind these differences and how to eliminate them could accelerate the rate of installed cost reductions in many markets. Reducing BoS costs to the most competitive levels will determine as much as 80% of the cost reduction potential for solar PV, outside of the most competitive markets, to 2025. This structural shift in the cost-cutting focus of the PV market is beginning, but will require significant investment in data collection and analysis in order to identify policy measures to accelerate convergence in BoS costs. Total installed costs for utility-scale projects could fall to between USD 1 100 to USD 1 200/kW by 2025 on average, although this will be heavily dependent on convergence of BoS costs to the most competitive levels. A similar dynamic could play out in the small-scale rooftop market. If BoS costs can be pushed down to very competitive levels, average installed costs could range from USD 1 600 to USD 2 000/kW by 2025.

For CSP plants, the overall capital cost reductions for parabolic trough plants by 2025 could be between 20% and 45% (IRENA analysis; Hinkley, 2011; Kutscher, 2010). For solar towers the cost reduction potential could be as high as 28% on a like-for-like plant basis (Hinkley, 2011). Alternative analysis suggests that the evolution of costs and performance is a little more complex, with the possibility that capital costs might decline by between 10% and 20% by 2017, depending on the components, although from an LCOE perspective, a better solution would be to have overall installed costs that are around the same as today, and instead use the cost reductions to increase the thermal energy storage and solar field size to increase the capacity factor from 48% to 65% (Kolb, 2011). Looking slightly further ahead to 2025 and assuming higher cost reductions (from one-fifth to one-third, depending on the components) and the switch to super-critical steam cycles, capital costs could be reduced by 30% and the capacity factor raised to 72% (IRENA analysis and Kolb, 2011).

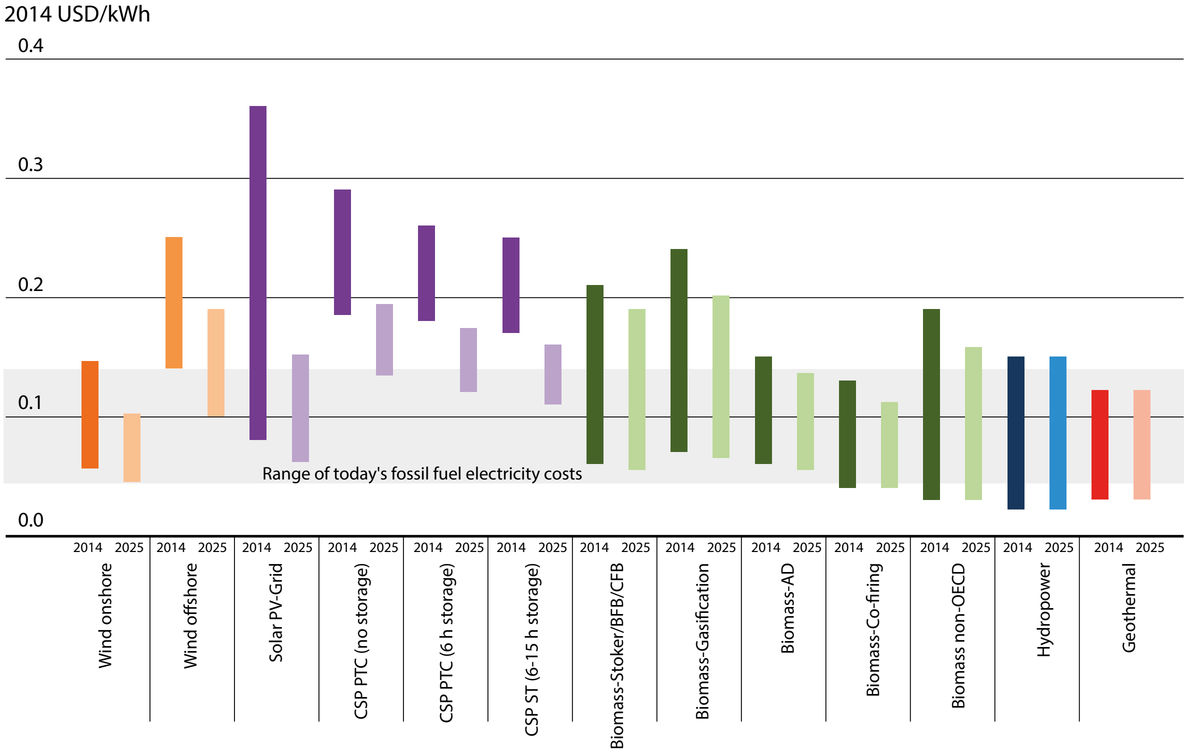
The current solar thermal electricity roadmap of the International Energy Agency, elaborated in consultation with industry, targets a capital cost range for plants with six hours' energy storage of between USD 3 250 and USD 4 800/kW in 2030 (IEA, 2014), suggesting installed costs in 2025 of perhaps USD 4 500 to USD 5 000/kW.[37]

It is assumed that there will be no decline in hydropower and geothermal costs by 2025 and that any changes in costs are due to underlying commodity price variations and general civil engineering costs. Most biomass combustion technologies are mature, although the projected growth in the market will allow modest capital cost reductions of between 10% and 15% to be possible by 2025 for the higher-cost markets for stoker, bubbling fluidised bed, and circulating fluidised bed technologies. The cost reduction potential for gasification technologies, excluding anaerobic digestion, is higher, and if deployment accelerates, capital cost reductions of 10% to 20% might be possible by 2025.

Figure 10.1 presents the cost ranges for wind, solar PV, CSP, geothermal and biomass today as well as projections for 2025 based on the assumptions already presented. For onshore wind, the lower end of the LCOE range does not shift significantly, given the already very competitive costs of today's most competitive projects. However, depending on where new installed capacity is built, the installed cost reductions projected will significantly lower the weighted average LCOE.

[37] *This would result in capacity factors of between 40% and 45% depending on the location.*

Figure 10.1: LCOE ranges by renewable power generation technology, 2014 and 2025



The typical LCOE range for solar PV will decline from between USD 0.08 and USD 0.36/kWh in 2014 to between USD 0.06 and USD 0.15/kWh in 2025. Grid parity for residential applications will increasingly be the norm in competitive PV markets and utility-scale projects will be routinely reaching wholesale grid-parity in regions with good solar resources and/or expensive fossil-fired electricity generation.

The reduction in LCOE for CSP will depend to a large extent on success in improving the current investment climate and longer-term commitments to policy support measures that can underpin deployment and learning investments. Given the low level of current deployment, just 5 GW at the end of 2014, if deployment can be accelerated, then costs will come down. Solar towers show perhaps the greatest potential for LCOE reduction. By 2025 solar towers could be producing electricity for between USD 0.11 and USD 0.16/kWh on average.

Biomass technologies will not see the lower end of their LCOE range shift significantly by 2020, given that today's cheapest options rely on low capital costs and on very cheap or even free feedstocks. However, for less mature technologies such as gasification, capital cost reductions will drive down the upper end of the range.

ANNEX
METHODOLOGY

Different measures of cost

Cost can be measured in a number of different ways, and each way of accounting for the cost of power generation brings its own insights. The costs that can be examined include equipment costs (e.g. PV modules), financing costs, total installed cost, fixed and variable operating and maintenance costs (O&M), fuel costs (if any) and the levelised cost of energy (LCOE).

The analysis of costs can be very detailed, but for comparison purposes and transparency, the approach used here is a simplified one. This allows greater scrutiny of the underlying data and assumptions, improves transparency and confidence in the analysis, and also facilitates the comparison of costs by country or region for the same technologies in order to identify the key drivers in any differences.

The three indicators that have been selected are:

» Equipment cost (factory gate, FOB, and delivered at site);

» Total installed project cost, including fixed financing costs[38];

» Capacity factor by project; and

» The levelised cost of electricity, LCOE.

The analysis in this paper focuses on estimating the costs of renewables from the perspective of private investors, whether they are a state-owned electricity generation utility, an independent power producer or an individual or community looking to invest in small-scale renewables. The analysis excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect[39], except where explicitly discussed at the end of Chapter 2. Furthermore, the analysis does not take into account any CO_2 pricing, nor the benefits of renewables in reducing other externalities (e.g. reduced local air pollution or contamination of the natural environment, except where explicitly discussed at the end of Chapter 2). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important, but are covered by other programmes of work at IRENA.

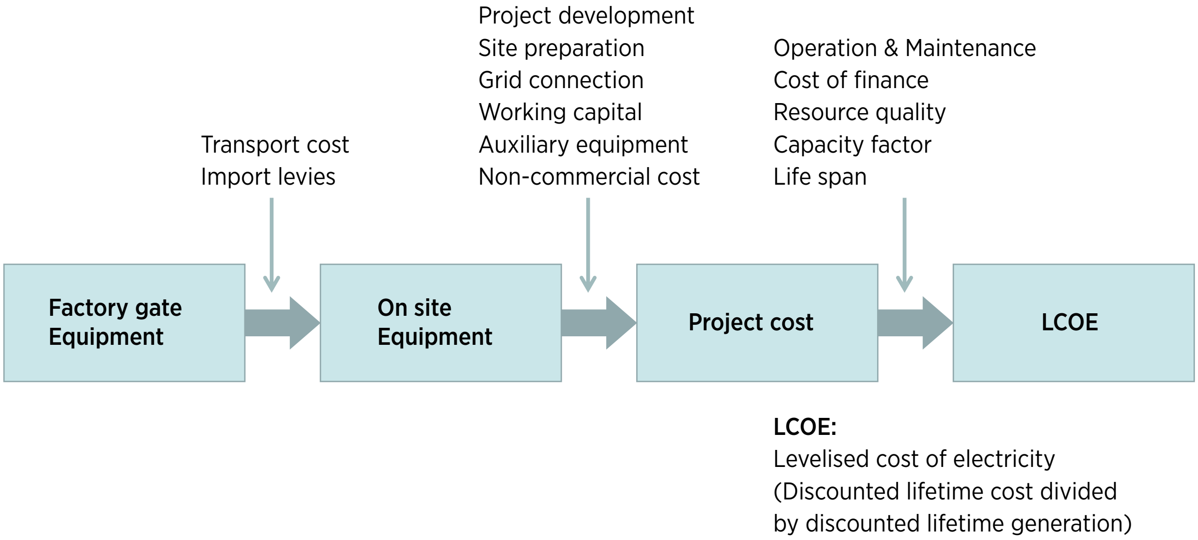
Clear definitions of the technology categories are provided, where this is relevant, to ensure that cost comparisons are robust and provide useful insights (e.g. off-grid PV vs. utility-scale PV). Similarly, it is important to differentiate between the functionality and/or qualities of the renewable power generation technologies being investigated (e.g. concentrating solar power with and without thermal energy storage). It is important to ensure that system boundaries for costs are clearly set and that the available data are directly comparable. Other issues can also be important, such as cost allocation rules for combined heat and power plants, and grid connection costs.

The data used for the comparisons in this paper come from a variety of sources, such as business journals, industry associations, consultancies, governments, auctions and tenders. Every effort has been made to ensure that these data are directly comparable and are for the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data or assumptions. It is planned that this data will be complemented by detailed surveys of real world project data in forthcoming work by IRENA.

[38] Banks or other financial institutions will often charge a fee, such as a percentage of the total funds sought, to arrange the debt financing of a project. These costs are often reported separately under project development costs.

[39] See EWEA, Wind Energy and Electricity Prices, April 2010 for a discussion.

FIGURE A1.1: RENEWABLE POWER GENERATION COST INDICATORS AND BOUNDARIES



An important point is that, although this paper tries to examine costs, strictly speaking, the data available are actually prices, and are often not even true market average prices, but price indicators. The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market. The rapid growth of renewables markets from a small base means that the market for renewable power generation technologies is rarely well-balanced. As a result, prices can rise significantly above costs in the short term if supply is not expanding as fast as demand, while in times of excess supply, losses can occur and prices may be below production costs. This makes analysing the cost of renewable power generation technologies challenging and every effort has been made to indicate whether current equipment costs are above or below their long-term trend.

The cost of equipment at the factory gate is often available from market surveys or from other sources. A key difficulty is often reconciling different data sources to identify why data for the same period differ. For example, the balance of capital costs in total project costs tends to vary even more widely than power generation equipment costs, as it is often based on significant local content, which depends on the cost structure of where the project is being developed. Total installed costs can therefore vary significantly by project, country and region depending on a wide range of factors.

LEVELISED COST OF ELECTRICITY GENERATION

The LCOE of renewable energy technologies varies by technology, country and project, based on the renewable energy resource, capital and operating costs, and the efficiency/performance of the technology. The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money. Given the capital-intensive nature of most renewable power generation technologies and the fact that fuel costs are low, or often zero, the weighted average cost of capital (WACC), often also referred to as the discount rate, used to evaluate the project has a critical impact on the LCOE.

There are many potential trade-offs to be considered when developing an LCOE modelling approach. The approach taken here is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions.

However, this has the additional advantage that the analysis is transparent and easy to understand. In addition, more detailed LCOE analyses result in a significantly higher overhead in terms of the granularity of assumptions required. This often gives the impression of greater accuracy, but when it is not possible to robustly populate the model with assumptions, or to differentiate assumptions based on real world data, then the "accuracy" of the approach can be misleading.

The formula used for calculating the LCOE of renewable energy technologies is:

$$\text{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE = the average lifetime levelised cost of electricity generation;

It = investment expenditures in the year t;

Mt = operations and maintenance expenditures in the year t;

Ft = fuel expenditures in the year t;

Et = electricity generation in the year t;

r = discount rate; and

n = life of the system.

All costs presented in this paper are real 2014 USD; that is to say, after inflation has been taken into account unless otherwise stated.[40] The LCOE is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital, while a price below it would yielder a lower return on capital, or even a loss.

As already mentioned, although different cost measures are useful in different situations, the LCOE of renewable energy technologies is a widely used measure by which renewable energy technologies can be evaluated for modelling or policy development. Similarly, more detailed DCF approaches taking into account taxation, subsidies and other incentives are used by renewable energy project developers to assess the profitability of real world projects.

[40] An analysis based on nominal values with specific inflation assumptions for each of the cost components is beyond the scope of this analysis. Project developers will develop their own specific cash-flow models to identify the profitability of a project from their perspective.

REGIONAL GROUPINGS

- Asia: Afghanistan; Bangladesh; Bhutan; Brunei Darussalam; Cambodia; China; Democratic People's Republic of Korea; India; Indonesia; Japan; Kazakhstan; Kyrgyzstan; Lao People's Democratic Republic; Malaysia; Maldives; Mongolia; Myanmar; Nepal; Pakistan; Philippines; Republic of Korea; Singapore; Sri Lanka; Tajikistan; Thailand; Timor-Leste; Turkmenistan; Uzbekistan; Viet Nam.

- Africa: Algeria; Angola; Benin; Botswana; Burkina Faso; Burundi; Cabo Verde; Cameroon; Central African Republic; Chad; Comoros; Congo; Côte d'Ivoire; Democratic Republic of the Congo; Djibouti; Egypt; Equatorial Guinea; Eritrea; Ethiopia; Gabon; Gambia; Ghana; Guinea; Guinea-Bissau; Kenya; Lesotho; Liberia; Libya; Madagascar; Malawi; Mali; Mauritania; Mauritius; Morocco; Mozambique; Namibia; Niger; Nigeria; Rwanda; Sao Tome and Principe; Senegal; Seychelles; Sierra Leone; Somalia; South Africa; South Sudan; Sudan; Swaziland; Togo; Tunisia; Uganda; United Republic of Tanzania; Zambia; Zimbabwe.

- Central America and the Caribbean: Antigua and Barbuda; Bahamas; Barbados; Belize; Costa Rica; Cuba; Dominica; Dominican Republic; El Salvador; Grenada; Guatemala; Haiti; Honduras; Jamaica; Nicaragua; Panama; Saint Kitts and Nevis; Saint Lucia; Saint Vincent and the Grenadines; Trinidad and Tobago.

- Eurasia: Armenia; Azerbaijan; Georgia; Russian Federation; Turkey.

- Europe: Albania; Andorra; Austria; Belarus; Belgium; Bosnia and Herzegovina; Bulgaria; Croatia; Cyprus; Czech Republic; Denmark; Estonia; Finland; France; Germany; Greece; Hungary; Iceland; Ireland; Italy; Latvia; Liechtenstein; Lithuania; Luxembourg; Malta; Monaco; Montenegro; Netherlands; Norway; Poland; Portugal; Republic of Moldova; Romania; San Marino; Serbia; Slovakia; Slovenia; Spain; Sweden; Switzerland; the former Yugoslav Republic of Macedonia; Ukraine; United Kingdom of Great Britain and Northern Ireland.

- Middle East: Bahrain; Iran (Islamic Republic of); Iraq; Israel; Jordan; Kuwait; Lebanon; Oman; Qatar; Saudi Arabia; Syrian Arab Republic; United Arab Emirates; Yemen.

- North America: Canada; Mexico; United States of America.

- Oceania: Australia; Fiji; Kiribati; Marshall Islands; Micronesia (Federated States of); Nauru; New Zealand; Palau; Papua New Guinea; Samoa; Solomon Islands; Tonga; Tuvalu; Vanuatu.

- South America: Argentina; Bolivia (Plurinational State of); Brazil; Chile; Colombia; Ecuador; Guyana; Paraguay; Peru; Suriname; Uruguay; Venezuela (Bolivarian Republic of).

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AC Alternating current

ARA Amsterdam, Rotterdam, Antwerp

a-Si Amorphous crystalline

BFB Bubbling fluidised bed

BIGCC Biomass integrated gasification combined cycle

BNEF Bloomberg New Energy Finance

BOP Balance of plant

BoS Balance of system

CAPEX Capital expenditure

CdTe Cadmium-Telluride

CFB Circulating fluidised bed

CHP Combined heat and power

CIGS Copper-Indium-Gallium-Diselenide

CIS Copper-Indium-Selenide

CO_2 Carbon dioxide

CPUC California Public Utilities Commission

CPV Concentrating photovoltaic

c-Si Crystalline silicon

CSP Concentrating solar power

DC Direct current

DNI Direct normal irradiance

DOE Department of Energy

DSG Direct steam generation

EPA Environmental Protection Agency

EPC Engineering, procurement and construction

EU European Union

FiT Feed-in tariff

GIZ Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH (The International Cooperation Agency of Germany)

GJ Gigajoule

GW Gigawatt

HCE Heat collection elements

HTF Heat transfer fluid

IEA International Energy Agency

ISP Independent service provider

kW Kilowatt

kWh Kilowatt hour

LCOE Levelised cost of electricity

LFC Linear Fresnel collectors

li-ion Lithium-ion

mc-Si Multi-crystalline silicon

MENA Middle East and North Africa region

MW Megawatt

NASA National Aeronautics and Space Administration (US)

NEA National Energy Administration

NOx Oxides of nitrogen

NREL National Renewable Energy Laboratory (US)

O&M Operations and maintenance

OECD Organisation for Economic Co-operation and Development

OEM Original equipment manufacturer

OPEX Operations expenditure

PM Particulate matter

PPA Power purchase agreement

PPP Public-private partnership

PTC Parabolic trough collectors

PV Photovoltaic

R&D Research and development

SCADA Supervisory, control and data acquisition

Sc-Si Single crystalline silicon

SEGS Solar energy generating system

SO_2 Sulphur dioxide

uc-Si Micromorph silicon

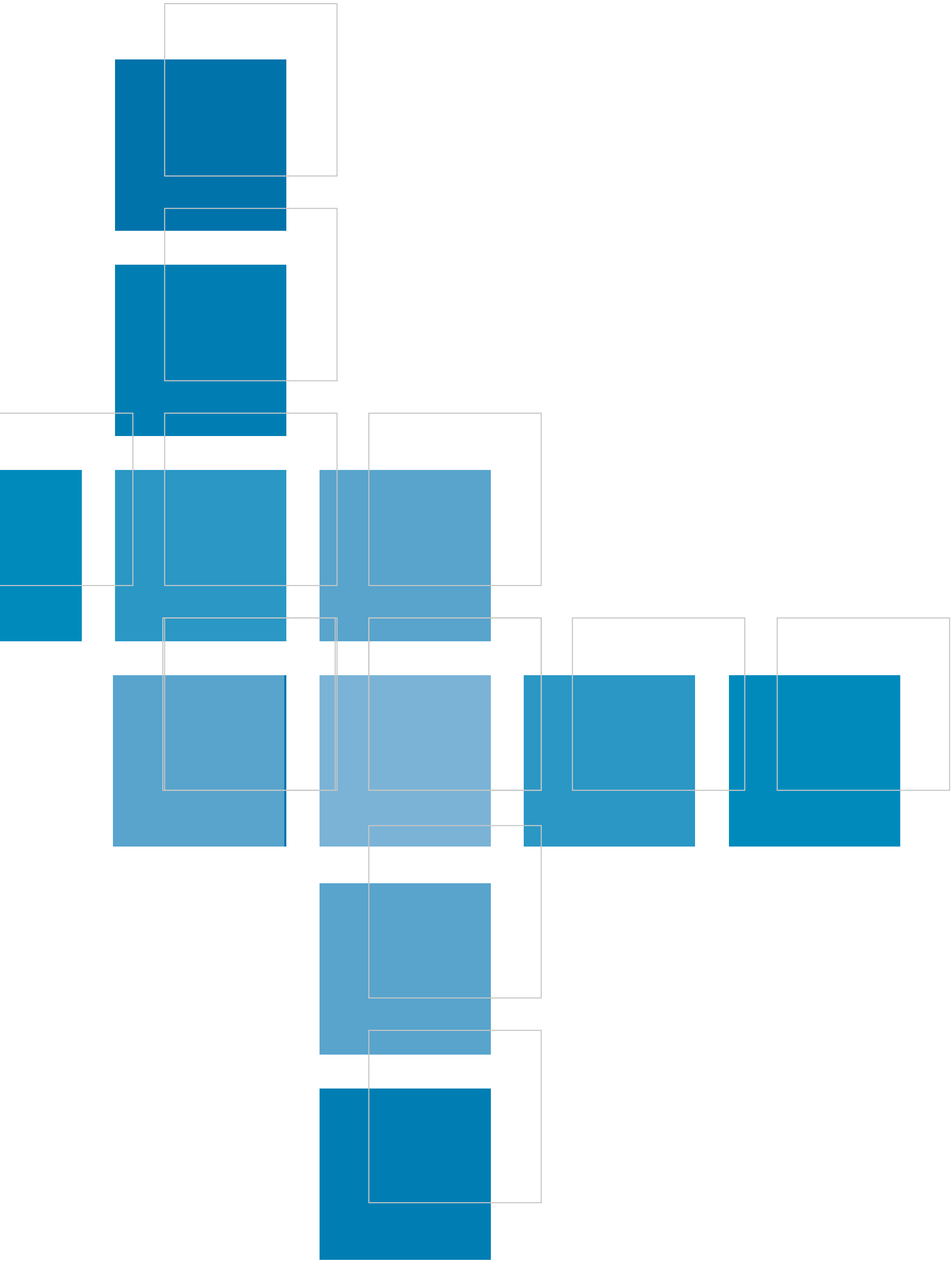
US United States

USD United States dollars

WACC Weighted average cost of capital

WHO World Health Organization

WTPI Wind turbine price index



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