# Renewable Power Generation Costs in 2017

IRENA
International Renewable Energy Agency

ISBN 978-92-9260-040-2

**Citation:** IRENA (2018), *Renewable Power Generation Costs in 2017*, International Renewable Energy Agency, Abu Dhabi.

## 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**

## ACKNOWLEDGEMENTS

This report benefited from the reviews and comments of numerous experts, including Ana Andrade (DGEG Portugal), Volker Berkhout (Fraunhofer IWES), Rina Bohle (Vestas), Heather Brent (EPRI), Henrik Breum (Danish Energy Agency), Luis Crespo (Estelasolar), Jürgen Dersch (DLR), Anthony Drummond (EPRI), Morten Dyrholm (Vestas), Lisa Ekstrand (Vestas), Pilar Gonzalez (Iberdrola), Claudia Grotz (Siemens Windpower), Daniel Gudopp (deea Solutions), Tomas Kåberger (Renewable Energy Institute), Keiji Kimura (Renewable Energy Institute), Simon Le Clech (Aldwych International Ltd), Roberto Lacal Arántegui (JRC), Eckhard Lüpfert (DLR), Christoph Pfister (Fraunhofer IWES), Simon Price (Exawatt), Mathis Rogner (IHA), with comments from EDF, Mott Macdonald and Sarawak Energy, Andreas Wade (First Solar) and Michael Waldron (IEA). Dolf Gielen (Director, IRENA Innovation and Technology Centre) also provided valuable input to the study.

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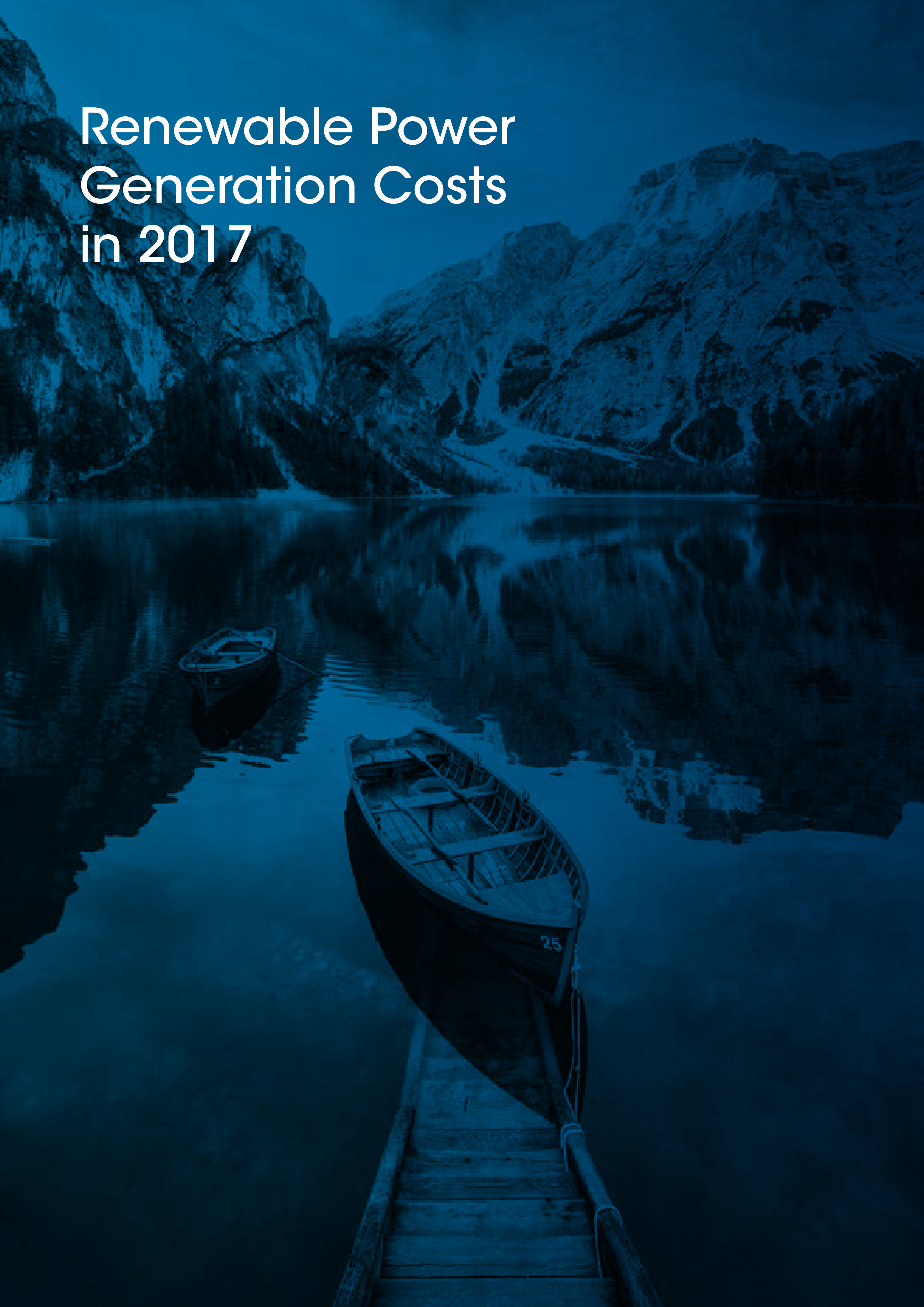
# Renewable Power Generation Costs in 2017



Today, countries around the world are more firmly committed than ever to accelerating renewable energy deployment. Technological innovation, enabling policies and the drive to address climate change have placed renewables at the centre of the global energy transformation. Yet alongside these developments, the chief driver of renewable energy is its strong business case, which offers increasingly exciting economic opportunities.

With rapidly falling renewable power generation costs, policy makers and investors need to confront the economic opportunities, as well as challenges, arising from a scale-up of renewable energy. Informed decision-making about the role of renewables in future electricity systems depends on reliable cost and performance data. In this context, the International Renewable Energy Agency (IRENA) has developed one of the most comprehensive datasets available on renewable power generation technology costs and performance. This detailed cost data confirms latest auction prices, showing renewables to be cost-competitive in a growing array of markets and conditions.

The rate of cost reduction has been wholly impressive. Solar photovoltaic (PV) modules are more than 80% cheaper than in 2009. The cost of electricity from solar PV fell by almost three-quarters in 2010-2017 and continues to decline. Wind turbine prices have fallen by around half over a similar period, depending on the market, leading to cheaper wind power globally. Onshore wind electricity costs have dropped by almost a quarter since 2010, with average costs of USD 0.06 per kilowatt-hour in 2017.

Such cost reductions are driven by continuous technological improvements, including higher solar PV module efficiencies and larger wind turbines. Industrialisation of these highly modular technologies has yielded impressive benefits, from economies of scale and greater competition to improved manufacturing processes and competitive supply chains.

Simultaneously, various new cost reduction drivers are emerging. Competitive procurement, notably auctions, has resulted in more transparent costs, while global competition has brought the experience of a myriad of project developers to new markets. Their combination of expertise, purchasing power and access to international financial markets is further driving down project costs and risks, and a string of record-low auction prices for solar PV, concentrating solar power (CSP), onshore wind and offshore wind power were set in 2016-2017.

The trend is clear: by 2020, all mainstream renewable power generation technologies can be expected to provide average costs at the lower end of the fossil-fuel cost range. In addition, several solar PV and wind power projects will provide some of the lowest-cost electricity from any source.

As renewables go head-to-head with fossil-based power solutions to provide new capacity without financial support, key opportunities exist to open cost-effective technology pathways. This is especially true in developing countries, where much of the world's future energy demand growth will occur.

Renewable energy increasingly makes business sense for policy makers and investors. For this reason, renewables will continue driving the global energy transformation, while benefiting the environment and our collective future.

**Adnan Z. Amin**

***Director-General***

International Renewable
Energy Agency

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# ABBREVIATIONS

| | |
|---|---|
| **ACP** | Alternative Compliance Payment |
| **CAD** | Canadian dollar |
| **CARICOM** | Caribbean Community |
| **CCS** | carbon capture and storage |
| **CEER** | Council of European Energy Regulators |
| **CfD** | Contract for Difference |
| **CSP** | concentrating solar power |
| **DNI** | direct normal irradiance |
| **EC** | European Council |
| **ECOWAS** | Economic Community of West African States |
| **EJ** | exajoule |
| **EU** | European Union |
| **EUR** | euro |
| **FIT** | feed-in tariff |
| **GBP** | British pound |
| **GDP** | gross domestic product |
| **GSR** | Global Status Report |
| **GW** | gigawatt |
| **GWh** | gigawatt-hour |
| **GWth** | gigawatt-thermal |
| **ILUC** | indirect land-use change |
| **INR** | Indian rupee |
| **IPP** | independent power producer |
| **IRENA** | International Renewable Energy Agency |
| **IRP** | integrated resource plan |
| **kW** | kilowatt |
| **kWh** | kilowatt-hour |
| **LSE** | load-serving entities |
| **MDG** | Millennium Development Goal |
| **MEMEE** | Ministry of Energy, Mines, Water and Environment (Morocco) |
| **MENA** | Middle East and North Africa |
| **Mtoe** | million tonnes of oil equivalent |
| **MW** | megawatt |
| **MWh** | megawatt-hour |
| **NDRC** | National Development and Reform Commission |
| **NREL** | National Renewable Energy Laboratory (US) |
| **OECD** | Organisation for Economic Co-operation and Development |
| **PPA** | Power Purchase Agreement |
| **SDG** | Sustainable Development Goal |
| **TWh** | terawatt-hour |
| **VRE** | Variable Renewable Electricity |

# KEY FINDINGS

- **After years of steady cost decline for solar and wind technologies, renewable power is becoming an increasingly competitive way to meet new generation needs.**
- For projects commissioned in 2017, electricity costs from renewable power generation have continued to fall.
- **Bioenergy-for-power, hydropower, geothermal and onshore wind projects commissioned in 2017 largely fell within the range of generation costs for fossil-based electricity.**[1] Some projects undercut fossil fuels, data collected by the International Renewable Energy Agency (IRENA) shows.
- The global weighted average cost of electricity was USD 0.05 per kilowatt-hour (kWh) from new hydropower projects in 2017. It was USD 0.06/kWh for onshore wind and 0.07/kWh for bioenergy and geothermal projects.
- The fall in electricity costs from utility-scale solar photovoltaic (PV) projects since 2010 has been remarkable. The global weighted average levelised cost of electricity (LCOE) of utility-scale solar PV has fallen 73% since 2010, to USD 0.10/kWh for new projects commissioned in 2017.
- Three key cost reduction drivers are becoming increasingly important:
  1. technology improvements;
  2. competitive procurement;
  3. a large base of experienced, internationally active project developers.
- **Continuous technological innovation remains a constant in the renewable power generation market.** With today's low equipment costs, however, innovations that unlock efficiencies in manufacturing, reduce installed costs or improve performance for power-generation equipment will take on increasing significance.
- **These trends are part of a broader shift across the power generation sector to low-cost renewables.** As competitive procurement drives costs lower, a wide range of project developers are positioning themselves for growth.
- **The results of recent renewable power auctions – for projects to be commissioned in the coming years – confirm that cost reductions are set to continue through 2020 and beyond**. Auctions provide valuable price signals about future electricity cost trends.
- Record low auction prices for solar PV in Dubai, Mexico, Peru, Chile, Abu Dhabi and Saudi Arabia

*1. The fossil fuel-fired power generation cost range for G20 countries in 2017 was estimated to be between USD 0.05 and USD 0.17/kWh.*

in 2016 and 2017 confirm that the LCOE can be reduced to USD 0.03/kWh from 2018 onward, given the right conditions.

- **Onshore wind is one of the most competitive sources of new generation capacity.** Recent auctions in Brazil, Canada, Germany, India, Mexico and Morocco have resulted in onshore wind power LCOEs as low as USD 0.03/kWh.
- **The lowest auction prices for renewable power reflect a nearly constant set of key competitiveness factors.** These include: a favourable regulatory and institutional framework; low offtake and country risks; a strong, local civil engineering base; favourable taxation regimes; low project development costs; and excellent resources.
- **Electricity from renewables will soon be consistently cheaper than from most fossil fuels.** By 2020, all the renewable power generation technologies that are now in commercial use are expected to fall within the fossil fuel-fired cost range, with most at the lower end or undercutting fossil fuels.
- **The outlook for solar and wind electricity costs to 2020 presages the lowest costs yet seen for these modular technologies, which can be deployed around the world.** Based on the latest auction and project-level cost data, global average costs could decline to about USD 0.05/kWh for onshore wind and USD 0.06/kWh for solar PV.
- Auction results suggest that concentrating solar power (CSP) and offshore wind will provide electricity for between USD 0.06 and USD 0.10/kWh by 2020.
- **Falling renewable power costs signal a real paradigm shift in the competitiveness of different power generation options.** This includes cheaper electricity from renewables as a whole, as well as the very low costs now being attained from the best solar PV and onshore wind projects.
- **Sharp cost reductions – both recent and anticipated – represent remarkable deflation rates for various solar and wind options.** Learning rates[2] for the 2010-2020 period, based on project and auction data, are estimated at 14% for offshore wind, 21% for onshore wind, 30% for CSP and 35% for solar PV.
- Reductions in total installed costs are driving the fall in LCOE for solar and wind power technologies to varying extents. This has been most notable for solar PV, CSP and onshore wind.

*2. The learning rate is the percentage cost reduction experienced for every doubling of cumulative installed capacity.*

# EXECUTIVE SUMMARY

**For new projects commissioned in 2017, electricity costs from renewable power generation have continued to fall. After years of steady cost decline, renewable power technologies are becoming an increasingly competitive way to meet new generation needs.**

In 2017, as deployment of renewable power generation technologies accelerated, there has been a relentless improvement in their competitiveness. Bioenergy for power, hydropower, geothermal and onshore wind projects commissioned in 2017 largely fell within the range of fossil fuel-fired electricity generation costs (Figure ES.1), data collected by the International Renewable Energy Agency (IRENA) shows. Indeed levelised cost of electricity (LCOE)[1] for these technologies was at the lower end of the LCOE range for fossil fuel options.[2]

The global weighted average LCOE of new hydropower plants commissioned in 2017 was around USD 0.05 per kilowatt-hour (kWh), while for onshore wind plants it was around USD 0.06/kWh. For new bioenergy and geothermal projects, the global weighted average LCOE was around USD 0.07/kWh.

**The fall in electricity costs from utility-scale solar photovoltaic (PV) projects since 2010 has been remarkable.** Driven by an 81% decrease in solar PV module prices since the end of 2009, along with reductions in balance of system (BoS) costs, the global weighted average LCOE of utility-scale solar PV fell 73% between 2010 and 2017, to USD 0.10/kWh. Increasingly, this technology is competing head-to-head with conventional power sources – and doing so without financial support.

Offshore wind power and concentrated solar power (CSP), though still in their infancy in terms of deployment, both saw their costs fall between 2010 and 2017. The global weighted average LCOE of offshore wind projects commissioned in 2017 was USD 0.14/kWh, while for CSP, it was USD 0.22/kWh. However, auction results in 2016 and 2017, for CSP and offshore wind projects that will be commissioned in 2020 and beyond, signal a step-change, with costs falling to between USD 0.06 and USD 0.10/kWh for CSP and offshore wind.

*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 real cost of capital of 7.5% in OECD countries and China, and 10% in the rest of the world, unless explicitly mentioned. All LCOE calculations exclude the impact of any financial support.*

*2. The fossil fuel-fired electricity cost range in 2017 was estimated to range from a low of USD 0.05 per kilowatt-hour (kWh) to a high USD 0.17/kWh, depending on the fuel and country.*

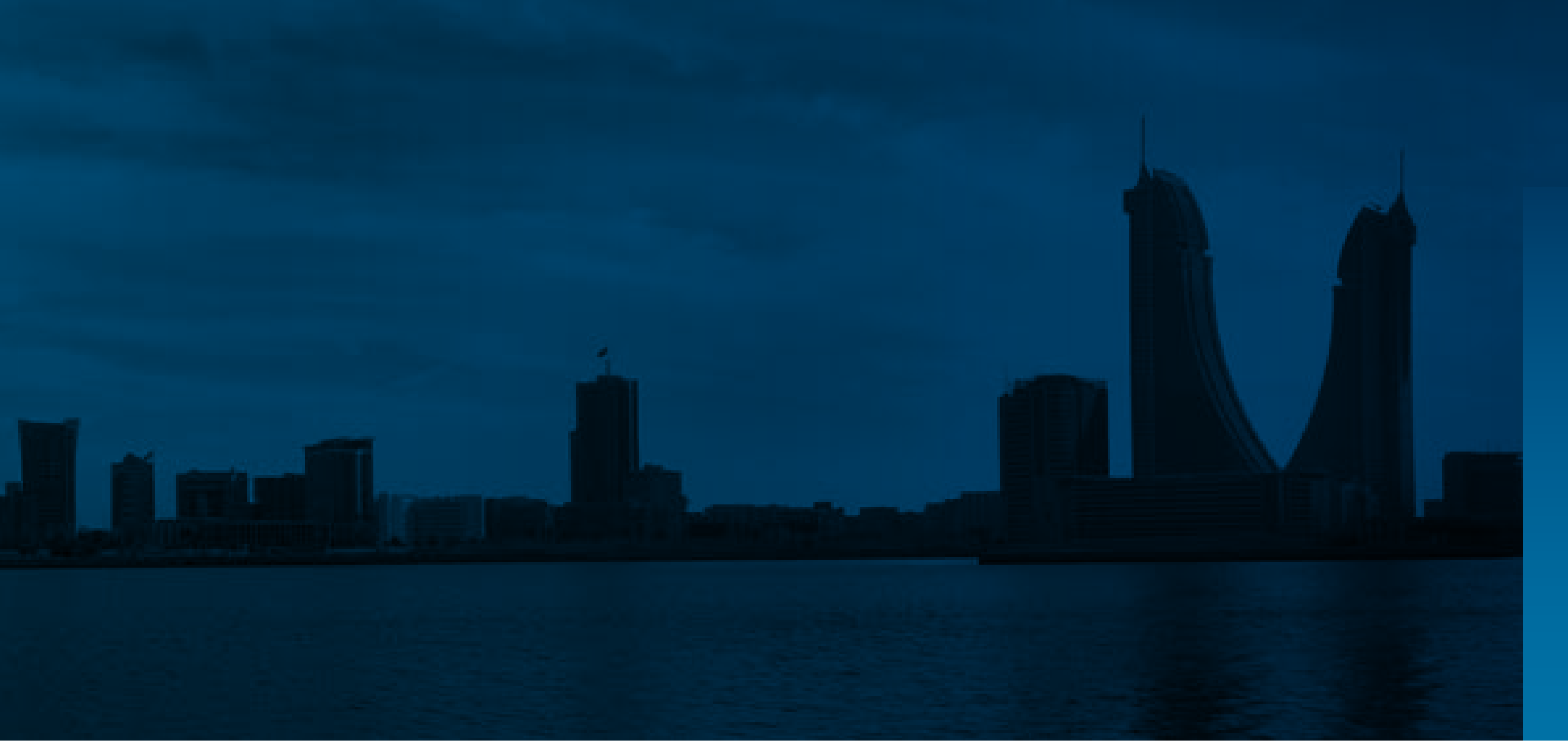
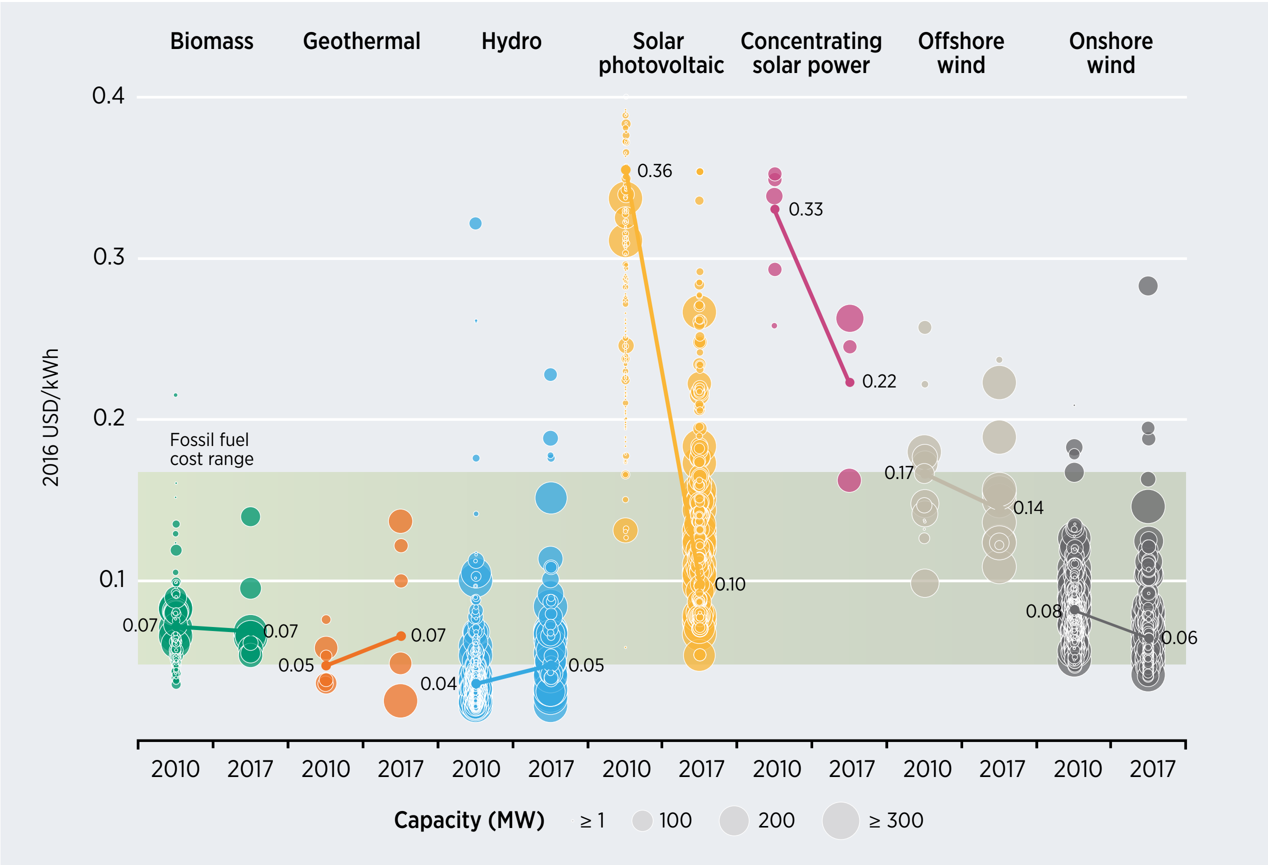


**Figure ES.1** Global levelised cost of electricity from utility-scale renewable power generation technologies, 2010-2017




*Source: IRENA Renewable Cost Database.*

*Note: The diameter of the circle represents the size of the project, with its centre the value for the cost of each project on the Y axis. The thick lines are the global weighted average LCOE value for plants commissioned in each year. Real weighted average cost of capital is 7.5% for OECD countries and China and 10% for the rest of the world. The band represents the fossil fuel-fired power generation cost range.*

**Three main cost reduction drivers have emerged for renewable power: 1) technology improvements; 2) competitive procurement; and 3) a large base of experienced, internationally active project developers.**

Historically, technology improvements have been vital to the performance increases and installed cost reductions which have (in addition to industrialisation of the sector and economies of scale) made solar and wind power technologies competitive. Competitive procurement — amid globalisation of the renewable power market — has emerged more recently as another key driver. Along with this comes the emergence of a large base of experienced medium-to-large project developers, actively seeking new markets around the world. The confluence of these factors is increasingly driving cost reductions for renewables, with effects that will only grow in magnitude in 2018 and beyond.

Continuous technology innovation remains a constant in the renewable power generation market. Indeed, in today's low equipment cost era, technology innovations that unlock efficiencies in manufacturing, as well as power generation equipment — in terms of performance improvements or installed cost reductions — will take on increasing importance. Bigger wind turbines with larger swept areas harvest more electricity from the same resource. New solar PV cell architectures offer greater efficiency. Real-time data and 'big data' have enhanced predictive maintenance and reduced operation and maintenance (O&M) costs. These are just a few examples of the continuous innovation driving reductions in installed costs, unlocking performance improvements and reducing O&M costs. Technology improvements, therefore, remain a key part of the cost reduction potential for renewable power. At the same time, the maturity and proven track record of renewable power technologies now reduces project risk, significantly lowering the cost of capital.[3]

**These trends are part of a larger dynamic across the power generation sector, prompting a rapid transition in the way the industry functions.** In many parts of the world, renewable power technologies now offer the lowest cost source of new power generation. In the past, typically, there was a framework offering direct financial support, often tailored to individual technologies (e.g., solar PV) and even segments (e.g., varying support for residential, commercial and utility-scale sectors, sometimes differentiated by other factors such as whether they are building-integrated or not). Now, this is being replaced by a favourable regulatory and institutional framework that sets the stage for competitive procurement of renewable power generation to meet a country's energy, environmental and development policy goals. Around the world, medium-to-large renewable project developers are adapting to this new reality and increasingly looking for global opportunities to expand their business. They are bringing, not only their hard won experience, but access to international capital markets. In competition with their peers, they are finding ways to continuously reduce costs.

**The results of recent renewable power auctions – for projects to be commissioned in the coming years – confirm that cost reductions are set to continue to 2020 and beyond.**

In addition to the IRENA Renewable Cost Database, which contains project level cost data for around 15 000 utility-scale projects, IRENA has compiled a database of auction results and other competitive procurement processes for around 7 000 projects. Although care must be taken in comparing the results of these two databases, as an auction price is not necessarily directly comparable to an LCOE calculation,[4] analysis of the results of the two databases provides some important insights into the likely distribution of renewable electricity costs over the next few years.

*3. The generally low cost of debt since 2010 has combined to enhance this effect as not only have risk margins fallen, but the base cost of debt as well.*

*4. At a minimum, the weighted average cost of capital (WACC) is not going to be the same. For an LCOE calculation, the WACC is a fixed and known value, whereas the WACC of a project in an auction is unknown and subsumed in the range of other factors that determined the price bid by an individual project developer.*

Record low auction prices for solar PV in 2016 and 2017 in Dubai, Mexico, Peru, Chile, Abu Dhabi and Saudi Arabia have shown that an LCOE of USD 0.03/kWh is possible from 2018 and beyond, given the right conditions. These include: a regulatory and institutional framework favourable to renewables; low offtake and country risks; a strong, local civil engineering base; favourable taxation regimes; low project development costs; and excellent solar resources.

Similarly, very low auction results for onshore wind in countries such as Brazil, Canada, Germany, India Mexico and Morocco have shown that onshore wind is one of the most competitive sources of new generation capacity. For CSP and offshore wind, 2016 and 2017 have been breakthrough years, as auction results around the world have confirmed that a step change in costs has been achieved and will be delivered in projects commissioned in 2020 and beyond. Indeed, auction results in 2016 and 2017 suggest that projects commissioned from 2020 onwards for both technologies could fall in the range USD 0.06 and USD 0.10/kWh.

Competitive procurement, particularly auctions, is spurring further cost reductions for power from solar and wind power technologies. Still, achieving low costs depends on supporting factors, such as access to low-cost finance, a conducive policy environment and good auction design. The key policy drivers (IRENA, 2017e, Renewable Energy Auctions: Analysing 2016) are confirmed by the latest auction results.

**Electricity from renewables will soon be consistently cheaper than from fossil fuels. By 2020, all the power generation technologies that are now in commercial use will fall within the fossil fuel-fired cost range, with most at the lower end or even undercutting fossil fuels.**

Even by 2020, projects contracted via competitive procurement will represent a relatively small subset of annual new renewable power generation capacity additions – and trends in auction results may not remain representative of LCOE trends at a project level. Nevertheless, recent auction results show that cost reductions will continue for CSP, solar PV, onshore and offshore wind through 2020 and beyond. While the validity of comparing LCOE and auction prices for individual projects must be done with caution, the volume of data available and the consistent trends between the two datasets provide some confidence in the overall trend.

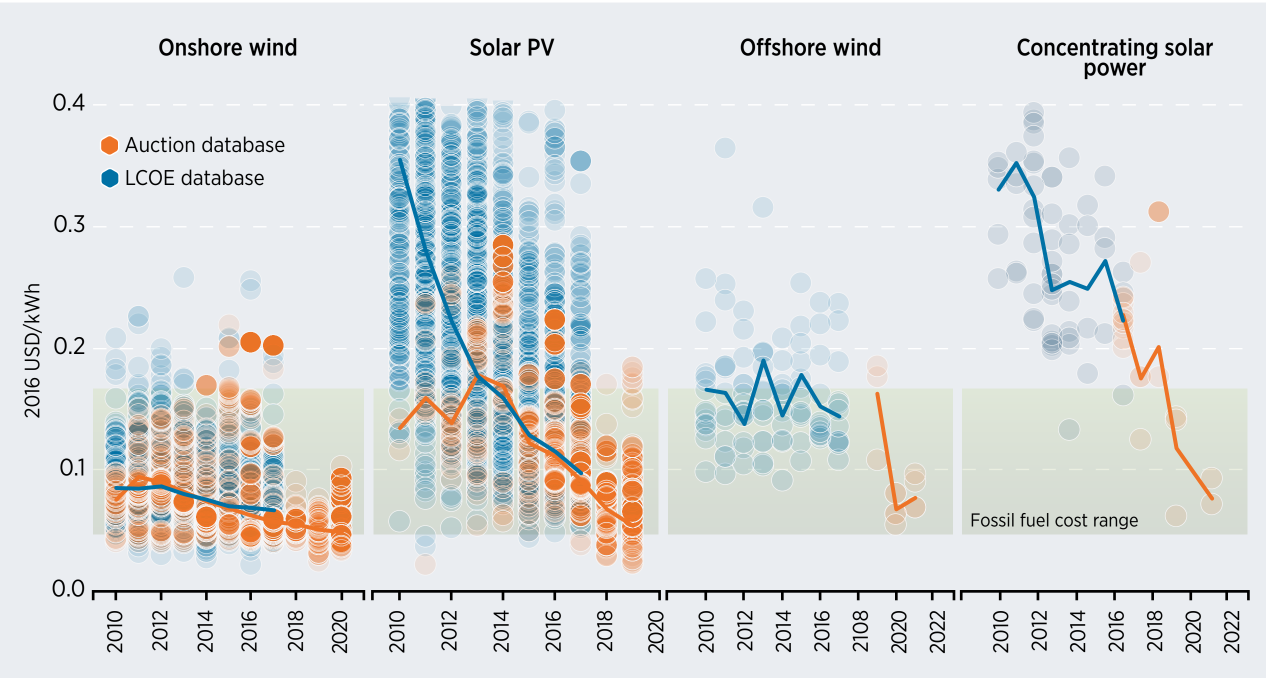
Analysing the the trends in the LCOE of projects and auction results to 2020 suggests that average costs for onshore wind could fall from USD 0.06/kWh in 2017 to USD 0.05/kWh by 2020. The recent auction results for offshore wind from 2016 and 2017 in Belgium, Denmark, the Kingdom of the Netherlands, Germany and the United Kingdom suggest that for projects that will be commissioned in 2020 and beyond, costs could fall in the USD 0.06 to USD 0.10/kWh range. Indeed, in Germany, two projects that will be commissioned in 2024 and one in 2025 won with bids that did not ask for a subsidy over market rates. A similar story has emerged for CSP, where a project in South Australia to be commissioned from 2020 will have a cost of USD 0.06/kWh, while in Dubai, a project that will be commissioned from 2022 onwards will have a cost of USD 0.07/kWh.

Solar PV auction data needs to be treated with somewhat more caution. This is because the distribution of projects is concentrated in higher-irradiation locations than recent capacity-weighted deployment. Even so, if the auction results available do accurately represent global deployment trends, then by 2019 or 2020, the average LCOE for solar PV may fall to below USD 0.06/kWh, converging to slightly above that of onshore wind, at USD 0.05/kWh.

**The outlook for solar and wind electricity costs to 2020, based on the latest auction and project-level cost data, presages the lowest costs yet seen for these modular technologies that can be deployed around the world.**

By 2019, the best onshore wind and solar PV projects will be delivering electricity for an LCOE equivalent of USD 0.03/kWh, or less, with CSP and offshore wind capable of providing electricity very competitively, in the range of USD 0.06 to USD 0.10/kWh from 2020 (Figure ES.2). Already today, and increasingly in the future, many renewable power generation projects can undercut fossil fuel-fired electricity generation, without financial support. With the right regulatory and institutional frameworks in place, their competitiveness should only further improve.

**Figure ES.2** The levelised cost of electricity for projects and global weighted average values for CSP, solar PV, onshore and offshore wind, 2010-2022




*Source: IRENA Renewable Cost Database and Auctions Database.*

*Note: Each circle represents an individual project or an auction result where there was a single clearing price at auction. The centre of the circle is the value for the cost of each project on the Y axis. The thick lines are the global weighted average LCOE, or auction values, by year. For the LCOE data, the real WACC is 7.5% for OECD countries and China, and 10% for the rest of the world. The band represents the fossil fuel-fired power generation cost range.*

**Decreasing electricity costs from renewables as a whole, and the low costs from the best solar PV and onshore wind projects, represent a real paradigm shift in the competitiveness of different power generation options.** Solar and wind power will provide very affordable electricity, with all the associated economic benefits. Furthermore, their low costs mean that previously uneconomic strategies in the power sector can become profitable. Curtailment – previously an unthinkable economic burden for renewables – could become a rational economic decision, maximising variable renewable penetration and minimising overall system costs.

Similarly, very low prices in areas with excellent solar and wind resources could open-up the economic potential of "power-to-X" technologies (e.g., power to hydrogen or ammonia, or other energy dense, storable mediums). At the same time, low prices make the economics of electricity storage more favourable. This could turn a potential drawback of electric vehicles (EVs) – their potentially high instantaneous power demand for recharging – into an asset. In effect, EVs can take advantage of cheap renewable power when it is available, while potentially feeding electricity back into the grid when needed.

This, however, needs to be balanced against the increased costs of integrating variable renewables and the increased flexibility required to manage systems with very high levels of variable renewable energy (VRE). To date, these integration costs have remained modest, but they could rise as very high VRE shares are reached (IRENA, 2017f, Chapter 3 in Perspectives for the Energy Transition), especially without complementary policies across the power sector. For instance, if transmission expansions fail to keep pace with deployment, renewable power sources could face curtailment.

**The sharp cost reductions for CSP, solar PV, onshore and offshore wind – both recent and anticipated – represent remarkable deflation rates.**

Conventional wisdom has been a poor guide in estimating the rate of cost reductions from solar and wind power technologies. It has underestimated the capacity of technology improvements, the industrialisation of manufacturing, economies of scale, manufacturing efficiencies, process innovations by developers and, competition in supply chains to all continuously drive down costs faster than expected in the right regulatory and policy setting.

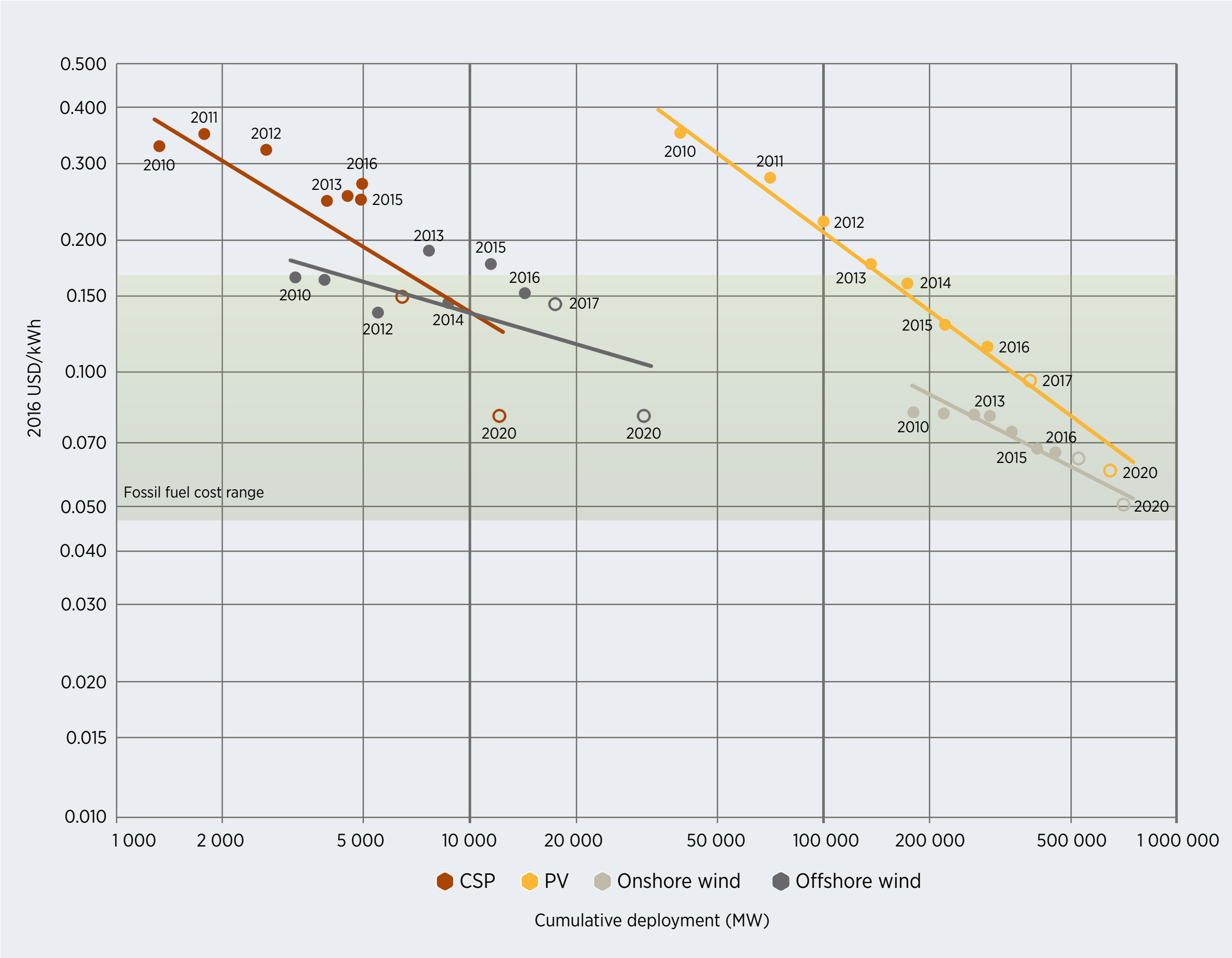
The decline in the cost of electricity experienced from 2010 to 2017, and signalled for 2020 from auction data, is plotted against cumulative installed capacity in Figure ES.3 for the four main solar and wind technologies. A log-log scale is used to allow easy interpretation as learning curves. The learning rate for offshore wind (i.e. the LCOE reduction for every doubling in global cumulative installed capacity) could reach 14% over the period 2010-2020, with new capacity additions over this period estimated to be around 90% of the cumulative installed offshore wind capacity that would be deployed by the end of 2020.[5]

For onshore wind, the learning rate for 2010 to 2020 may reach 21%, with new capacity added over this period covering an estimated 75% of cumulative installed capacity at the end of 2020. CSP has a higher estimated learning rate of 30%, with deployment between 2010 and 2020 representing an estimated 89% of cumulative installed capacity by the end of that period.[6] Solar PV has the highest estimated learning rate – 35% between 2010 and 2020 – with new capacity additions over this timescale that are estimated to be 94% of cumulative capacity by its conclusion.

5. *Global cumulative installed capacity of CSP is projected to be 12 GW by 2020, for offshore wind 31 GW, solar PV 650 GW and onshore wind 712 GW. This is based on IRENA (2017a), GWEC (2017), WindEurope (2017), SolarPower Europe (2017), and MAKE Consulting, 2017a.*

6. *Extending the horizon to 2022 to take into account the likely commissioning of the Dubai Electricity and Water Authority project increases uncertainty over total deployment values, but in most scenarios would not materially change the learning rate.*

**Figure ES.3** Learning curves for the global weighted average levelized cost of electricity from CSP, solar PV and onshore and offshore wind, 2010-2020




*Based on IRENA Renewable Cost Database and Auctions Database; GWEC, 2017; WindEurope, 2017; MAKE Consulting, 2017a; and SolarPower Europe, 2017a.*

*Note: Each circle represents an individual project, or, in some cases, auction result where there was a single clearing price at auction. The centre of the circle is the value for the cost of each project on the Y axis. The thick lines are the global weighted average LCOE or auction values by year. For the LCOE data, the real WACC is 7.5% for OECD countries and China, and 10% for the rest of the world. The band represents the fossil fuel-fired power generation cost range.*

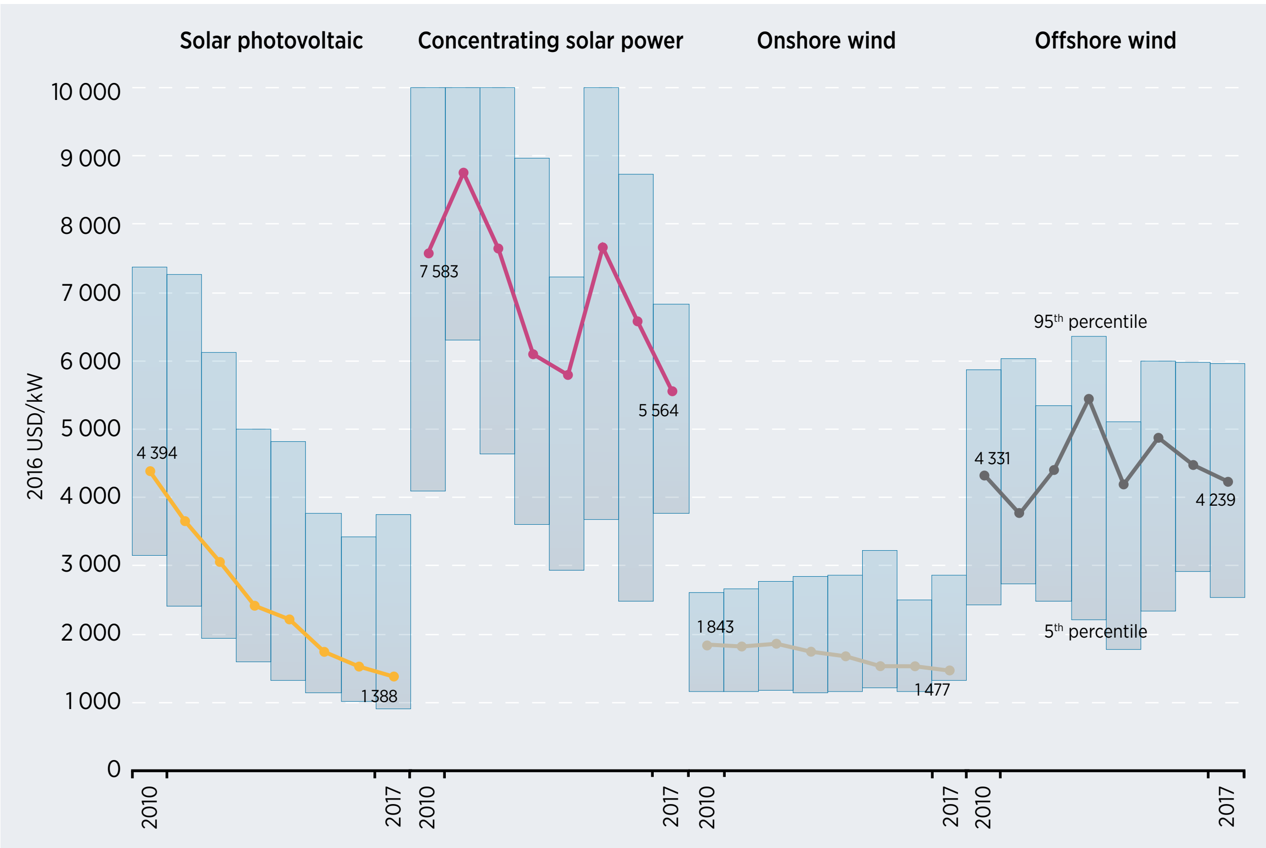
Onshore wind is one of the technologies with the longest histories of available cost data. Data in the IRENA Renewable Cost Database shows that the learning rate for the cost of electricity from this source is higher for the period 2010-2020 than the learning rate estimated for the period 1983-2016. This will, in all probability, be in part due to a lower WACC from the auction results than is used in the LCOE calculations. This is unlikely to explain all of the difference, however. The data therefore tends to suggest that the learning rate for onshore wind, at least, is currently higher than the long-term average.

The modular, scalable nature solar and wind power generation technologies, and the replicability of their project development process, rewards stable support policies with continuous cost reductions. This has already made onshore wind and solar PV highly competitive options for new generation capacity. Auction results suggest that CSP and offshore wind should follow a similar path. A comparable process is playing out for electricity storage. Wherever renewable power technologies can be modular, scalable and replicable, decision makers can be confident that industrialisation and the opening of new markets will yield steady cost reductions in the right regulatory and policy environment.

**Reductions in total installed costs are driving the fall in the LCOE for solar and wind power technologies, but to varying extents. They have been most important for solar PV, CSP and onshore wind.**

On the back of price declines for solar PV modules, the installed costs of utility-scale solar PV projects fell by 68% between 2010 and 2017, with the LCOE for the technology falling 73% over that period. The total installed costs of newly commissioned CSP projects fell by 27% in 2010-2017, with a 33% LCOE reduction overall. Installed costs for newly commissioned onshore wind projects fell by 20%, with a 22% reduction in LCOE. For offshore wind, the total installed costs fell by 2%, with a 13% reduction in LCOE over the same period.

**Figure ES.4** Global weighted average total installed costs and project percentile ranges for CSP, solar PV, onshore and offshore wind, 2010-2017




*Source: IRENA Renewable Cost Database.*

# 1. INTRODUCTION

The electricity sector is undergoing a period of rapid, unprecedented change in the scale and breadth of deployment of renewable power generation technologies. Since 2012, these have accounted for more than half of new electric power generation capacity additions, worldwide. At the end of 2016, total renewable power generation capacity surpassed 2 000 GW, meaning that it had more than doubled in the space of nine years (IRENA, 2017a). New capacity additions of renewables in 2016 reached 162 GW, with 36 GW of new hydropower capacity added, 51 GW of wind power, 71 GW of solar photovoltaic (PV) capacity, 9 GW of bioenergy power generation capacity and a combined 1 GW from concentrating solar power (CSP), geothermal and marine energy.

This growth is set to continue, with accelerating deployment of renewables, notably for solar PV in China, set to continue. Global solar PV capacity additions in 2017, in all probability, will flirt with, or exceed, 90 GW, while new capacity additions for wind power are likely to exceed 40 GW, setting the scene for another record year for renewable power generation deployment.

Renewable power generation is currently benefitting from a virtuous cycle, in which policy support for renewable power generation technologies leads to accelerated deployment, technology improvements and cost reductions, with these then reducing the cost of electricity from renewable power generation technologies and encouraging greater uptake of these technologies. In 2016, in many regions of the world, the commissioned biomass for power, hydropower, geothermal and onshore wind projects consistently provided new electricity at competitive rates – compared to fossil fuel-fired power generation – excluding the impact of any financial support.

It is growth in the "new" renewable power generation technologies of solar and wind, however, that has pushed renewable power generation capacity additions to record levels. The levelised cost of electricity (LCOE) of solar PV fell 73% between 2010 and 2017, making it increasingly competitive at the utility scale. Technology improvements and installed cost reductions have made onshore wind one of the most competitive sources of new power generation. Despite the fact that CSP and offshore wind are in their deployment infancy, these technologies have seen their costs come down. Tender and auction results in 2016 and 2017 show increasingly that even without financial support, these technologies will be able to compete directly with fossil fuels from 2020 onwards if the right policy and regulatory frameworks are in place.

Crucially, the drivers behind lower equipment and installed costs – and performance improvements – have not yet run their course, either. Continued cost reductions for solar and wind power technologies can therefore still be expected (IRENA, 2016a).

The renewable energy industry thus has a track record of delivering on cost reductions. These have been achieved by unlocking economies-of-scale, investing in more efficient manufacturing processes, improving the efficiency of technologies, and by demonstrating a technological maturity that reduces financing costs and drives down costs in supply chains. Auction results around the world in 2016 and 2017 for future delivery graphically highlight this. Record low prices for solar PV in Abu Dhabi, Chile, Dubai, Mexico, Peru and Saudi Arabia highlight just how far renewables have come, with results around USD 0.03/kWh on an LCOE basis now setting the benchmark. The full cost of some onshore wind and solar PV projects that will come online in 2018 and beyond will be less than only the variable costs of many existing fossil fuel-fired generators.

Yet, the public debate around renewable energy often continues to suffer from an outdated perception that renewable energy is not competitive. This report demonstrates that the blanket assumption that renewable power generation is expensive is outdated given that renewable power generation is increasingly providing electricity at costs that are competitive, or even lower than, fossil fuel-fired power generation costs.

*Renewables increasingly provide electricity at costs competitive with, or lower than, fossil-based power*

## 1.1 RENEWABLE ENERGY COST ANALYSIS AT IRENA

Since 2012, IRENAs cost analysis programme has been collecting and reporting the cost and performance data of renewable energy technologies. Having reliable, transparent, up-to-date cost and performance data from a reliable source is vital, given the rapid growth in installed capacity of these technologies. The associated cost reductions mean that data from even one or two years ago can be significantly erroneous, and, indeed, in the case of solar PV, in some markets, even data six months old can significantly overstate the costs.

IRENA has previously reported on costs in the power generation sector (IRENA, 2012a-e; IRENA, 2013a; IRENA, 2015) and the transport sector (IRENA, 2013b). IRENA analysis is not restricted to historical costs or global analysis, either. It is also increasingly focused on answering questions about the future cost and competitiveness of renewables and their cost structures in new and emerging markets. IRENA has released reports on the cost reduction potential for solar PV, CSP and onshore and offshore wind out to 2025 (IRENA, 2016a), along with a regional report on solar PV costs in Africa (IRENA, 2016b). IRENA has also leveraged its cost data to provide analytical products that support policymakers in understanding the implications of cost trends, including the IRENA Cost and Competitiveness Indicators for Rooftop Solar PV (IRENA, 2017b). In 2017, IRENA also released its analysis of electricity storage costs and markets out to 2030 (IRENA, 2017c). This represents the beginning of IRENA's efforts to analyse the cost and performance of the technologies that will help facilitate the energy transition. IRENA has also started to analyse the flow of cost and performance data that is becoming available from the increased use of auctions to competitively procure renewable power generation capacity.

This analysis has contributed to more transparent cost data in the public domain, allowing policy makers, key decision makers, industry players, researchers and the media to have a better understanding of the true costs for renewable energy today and their continued cost reduction potential. Given the rapid cost reductions being experienced, especially by solar and wind power technologies, the importance of this data being in the public domain should not be underestimated, as 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. This problem is often compounded by a lack of transparency in the methodology and the assumptions used by many commentators in their cost calculations, which can lead to confusion about the comparability of data. This report, based on the IRENA Renewable Cost Database – with its a large global dataset – provides one of the most comprehensive overviews of renewable power generation costs using a consistent methodology and set of assumptions.

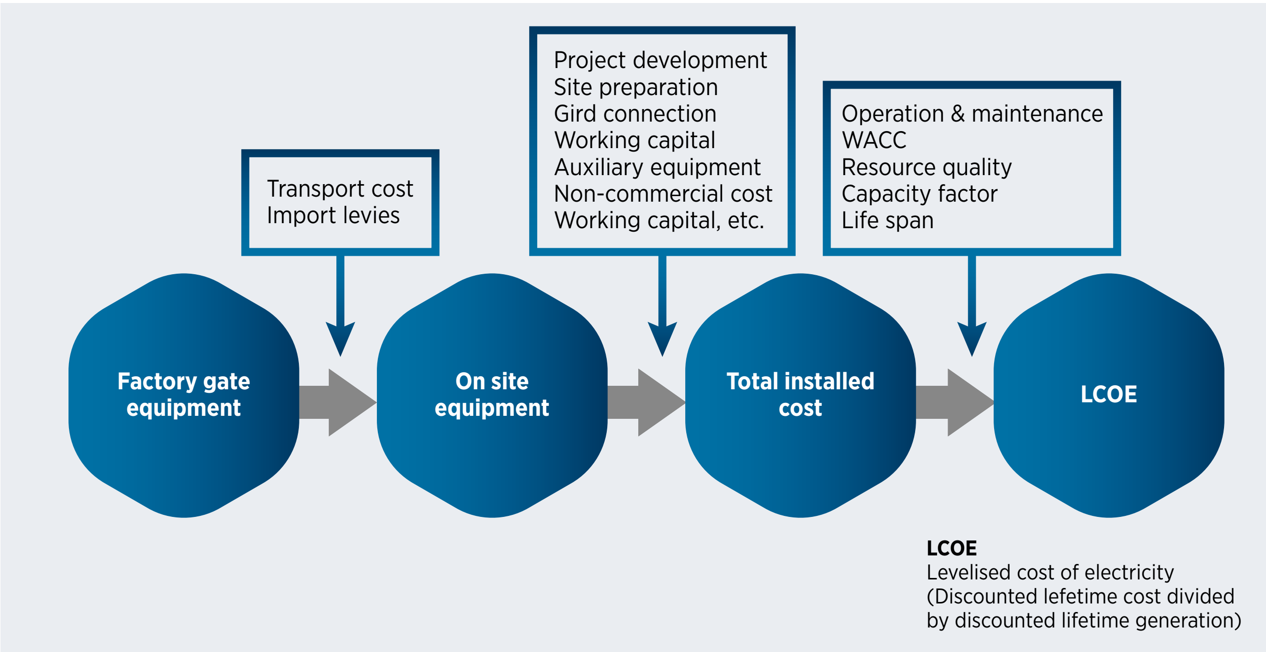
## 1.2 COST METRICS FOR RENEWABLE POWER GENERATION TECHNOLOGIES

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. IRENAs work in this report focuses on analysing the impact of technology and market development on the LCOE. To understand the drivers of these changes requires an analysis of the equipment costs, total installed costs, performance (capacity factors), operation and maintenance (O&M) costs and weighted average cost of capital (WACC) (Figure 1.1). It also requires an analysis of trends in technology developments and their market share, manufacturing innovations and supply chain capacities, and an understanding of developments in the drivers of the different markets for each technology.

The LCOE is an indicator of 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 or WACC. An electricity price above this would yield a greater return on capital, while a price below it would yield a lower return on capital, or even a loss (see Annex One for a detailed discussion of the LCOE and other cost metrics). 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 to assess the LCOE in this report is based on a simple discounted cash flow analysis. This method of calculating the cost of electricity 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-to-zero, the WACC (or discount rate) used to evaluate the project has a critical impact on the LCOE.

The total installed cost for projects in the IRENA Renewable Cost Database represent all of the costs of developing a project. They thus differ from "overnight" capital costs in that they include interest during construction (including on working capital needs), project development costs and any upfront financing costs.

**Figure 1.1** Cost metrics analysed to calculate the levelised cost of electricity.




*Source: IRENA.*

The analysis is designed to inform policy makers and decision makers about the recent trends in the relative costs and competitiveness of renewables. It therefore excludes the impact of government incentives, or financial support for renewables. The analysis also excludes any system balancing costs, or benefits associated with variable renewables, and any system-wide cost savings from the merit order effect.[1]

Furthermore, the analysis does not take into account any $CO_2$ pricing, or the benefits of renewables in reducing other externalities, such as reduced local air pollution or contamination of the natural environment. 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.

The starting point for the analysis presented in this report is the IRENA Renewable Cost Database. This contains information on the installed costs, capacity factors and LCOEs of over 15 000 utility-scale renewable power generation projects around the world. This project-level data covers around half of all installed renewable power generation capacity, but where data gaps for an individual technology in an individual year and country exist, national secondary sources of data are used to ensure a comprehensive result.

In addition to calculated LCOEs based on project level data, IRENA has also collected data from auction results to complement the LCOE data. They are not necessarily directly comparable to LCOE values, given that key assumptions relative to their calculation will differ (e.g., the remuneration period, cost of capital, project specific operations and maintenance costs, etc.). The database contains auction results for almost 6 000 auctions/ projects and complements the project database, while also providing forward-looking indicators of future commissioned project costs, with the caveat already mentioned regarding the potential difference between LCOE and auction prices.

There are a number of important points to remember when interpreting the data presented in this report:

- The analysis is for utility-scale projects (>1 MW for solar PV, >5 MW for onshore wind, >50 MW for CSP and >200 MW for offshore wind), unless explicitly mentioned. Projects below these size levels may have higher costs than those quoted in this report.
- All cost data in this report from the IRENA Renewable Cost Database refers to the year in which the project was commissioned, unless explicitly mentioned otherwise. For data from the Auction Database, a standard assumption of technology for the time from auction announcement to commissioning is used, unless a specific date is available.
- All data are in real 2016 USD – that is to say, it is corrected for inflation.
- When average data is presented, it consists of weighted averages based on new capacity deployed in that year unless explicitly stated otherwise.
- Data for costs and performance for 2017 is preliminary and subject to change. Revisions are almost certain for most countries and technologies as additional data is reported.
- Cost data in the IRENA Renewable Cost Database used for calculating LCOEs excludes any financial support by governments (national or subnational) to support the deployment of renewables, or to correct for non-priced externalities.
- The raw data in the IRENA Auctions Database includes the impact of financial support policies that reduce the price required by a project developer to make its expected rate of return (e.g. it includes the impacts of tax credits in the United States or other favourable taxation treatment).

*1. The merit order effect, is the impact zero marginal cost renewables have on lowering wholesale electricity market prices by displacing higher marginal cost plant (typically fossil fuel-fired).*

- The impact of grid constraints and curtailment is not accounted for in this analysis. This is a market issue beyond the scope of this report.
- The WACC is fixed over the period examined in this report.
- The LCOE of solar and wind power technologies is strongly influenced by resource quality; higher LCOEs don't necessarily mean inefficient capital cost structures.

It should be clear from this presentation that given the complexities involved in collecting and reporting the cost data presented in this report, care should be taken in interpreting the results.

As already mentioned, different cost measures provide different information. These measures therefore need to be considered in the context of what question is being asked. For instance, comparing the installed cost of an individual technology across different markets can highlight cost differentials, but not identify the causes of these variations. Higher costs in one market do not necessarily imply cost "inefficiency", but may be due to structural factors, such as greater distances to transmission networks, or higher material and labour costs. Only a detailed country-specific analysis, supported by very detailed cost breakdowns, can hope to provide fuller explanations for cost variance.

Similarly, although the LCOE is a useful metric for a first-order comparison of the competitiveness of projects, it is a static indicator that does not take into account interactions between generators in the market. The LCOE does not take into account either that the profile of generation of a technology may mean that its value is higher or lower than the average market price it might receive. As an example, CSP with thermal energy storage has the flexibility to target output in high cost periods of the electricity market, irrespective of whether the sun is shining. The LCOE also fails to take into account other potential sources of revenue or costs. For example, hydropower can earn significant revenue in some markets from providing ancillary grid services. This is not typically the case for stand-alone variable renewable technologies, but improved technology for solar and wind technologies is making these more grid friendly. Hybrid power plants, with storage, or other renewable power generation technologies, plus the creation of "virtual" power plants that mix generating technologies, can all transform the nature of variable renewable technologies into more stable and predictable generators.

Thus, although LCOE is a useful metric as a starting point for deeper comparison, it is not necessarily the most useful indicator of cost between different power generation technologies. Nor is the LCOE necessarily the most useful tool in identifying the optimal role of each renewable power generation technology in a country's energy mix, over the medium- to long-term. Over the year, electricity systems need a balance of resources to meet overall demand and minute-by-minute variation, in the most economic way. To meet peaks, a system may therefore simultaneously need to add a base low-cost source of electricity at the same time as needing a plant that will only run for a few hundred hours each year, at costs perhaps four or even ten times higher, in LCOE terms. This is would be the lowest cost solution to minimising the average cost of electricity over the year. This highlights not only the importance of system modelling in capacity expansion, but also the critical importance of using the correct input assumptions for different cost metrics that are provided in this report. The cost data in this report represent the building blocks for a robust, dynamic modelling of the electricity system that can take into account all the specificities of demand and the network, as well as the existing generators' costs. This report provides a robust dataset that includes current, as well as near-future costs of renewable power generation technologies. These can be used in dynamic energy sector models to ensure that the many complexities of operating an electricity grid are adequately assessed in determining the potential future role of renewables.

## 1.3 THE IRENA RENEWABLE COST DATABASE

The data presented in this report is predominantly drawn from the IRENA Renewable Cost Database and IRENA Auctions Database.[2] The IRENA Renewable Cost Database contains the project level details for almost 15 000 utility-scale renewable power generation projects around the world, from large GW-scale hydropower projects to small solar PV projects (those down to 1 MW). The database also covers small-scale rooftop solar PV in the residential sector and larger rooftop systems in the commercial sector (in the sub-1 MW category) with aggregate results derived from over one million installed systems amongst Organisation for Economic Co-operation and Development (OECD) member states.

The data available by project varies, but always contains the total installed costs and lifetime capacity factor.[3] The IRENA Auctions Database tracks the results of competitive procurement of renewable power generation capacity, as well as other power purchase agreements (PPAs) that are in the public domain. The Auctions Database contains information on successful individual projects, or bundled projects when results are not individually disclosed, including information on the project, technology, price of winning bids, currency for payment, remuneration period and indexation. Not all this information is available from all auctions, but the maximum detail available has been collected. The Auctions Database currently contains auctions results for around 7 000 projects.[4]

Figure 2 presents an overview of the two databases. The IRENA Renewable Costing Database's nearly 15 000 projects account for 1 017 GW of capacity, or around half of all renewable power generation capacity installed up to the end of 2016. In addition to these already commissioned projects, the database also contains an additional 37 GW of as-yet unrealised project proposals for commissioning between 2018 and 2025 (not shown in Figure 1.2). The database contains data on hydropower projects going back to 1961, with significant numbers of onshore wind projects from 2004 and solar PV from 2008.

The IRENA Auction Database includes a number of projects that overlap with the main IRENA Renewable Cost Database, so the totals are not additive. The Auctions Database contains a total of 293 GW of projects around the world. Of this, 92 GW (32% of the total) of the projects are in Brazil, 78 GW of the projects are in the United States (26%), 48 GW in India (16%), 10 GW in Chile (3%), 6.5 GW in Argentina and South Africa (2% each), 5.5 GW (2%) in the United Kingdom and around 5 GW (2% each) in China and Germany. In terms of technologies, onshore wind is the largest contributor, with data for projects totalling 114 GW (39%) to date. The next largest contributors are solar PV with 85 GW (29%), hydropower, with 44 GW (15%), biomass and offshore wind with 9 GW (3%) each, CSP with 4 GW and geothermal with 0.1 GW. Where fossil fuels have also been auctioned, this data has also been collected and the database contains 28 GW of fossil fuel-fired projects.

In this report, where auction data is compared to LCOE data, auction prices are corrected for the impact of financial support that directly reduces the price required by project developers (e.g. the wind production tax credit in the United States) or the data is excluded from the discussion where an accurate correction is not easily calculated.

Given that the data for 2017 is still coming in and that a full and robust assessment of cost trends for 2017 is not yet possible for all technologies and all individual countries, data for 2017 is only presented at a global level for each technology. Where IRENA has assessed that the data available for 2017 is already representative at a country level and unlikely to be significantly revised as new data becomes available, however, country or regional level data is also provided.[5]

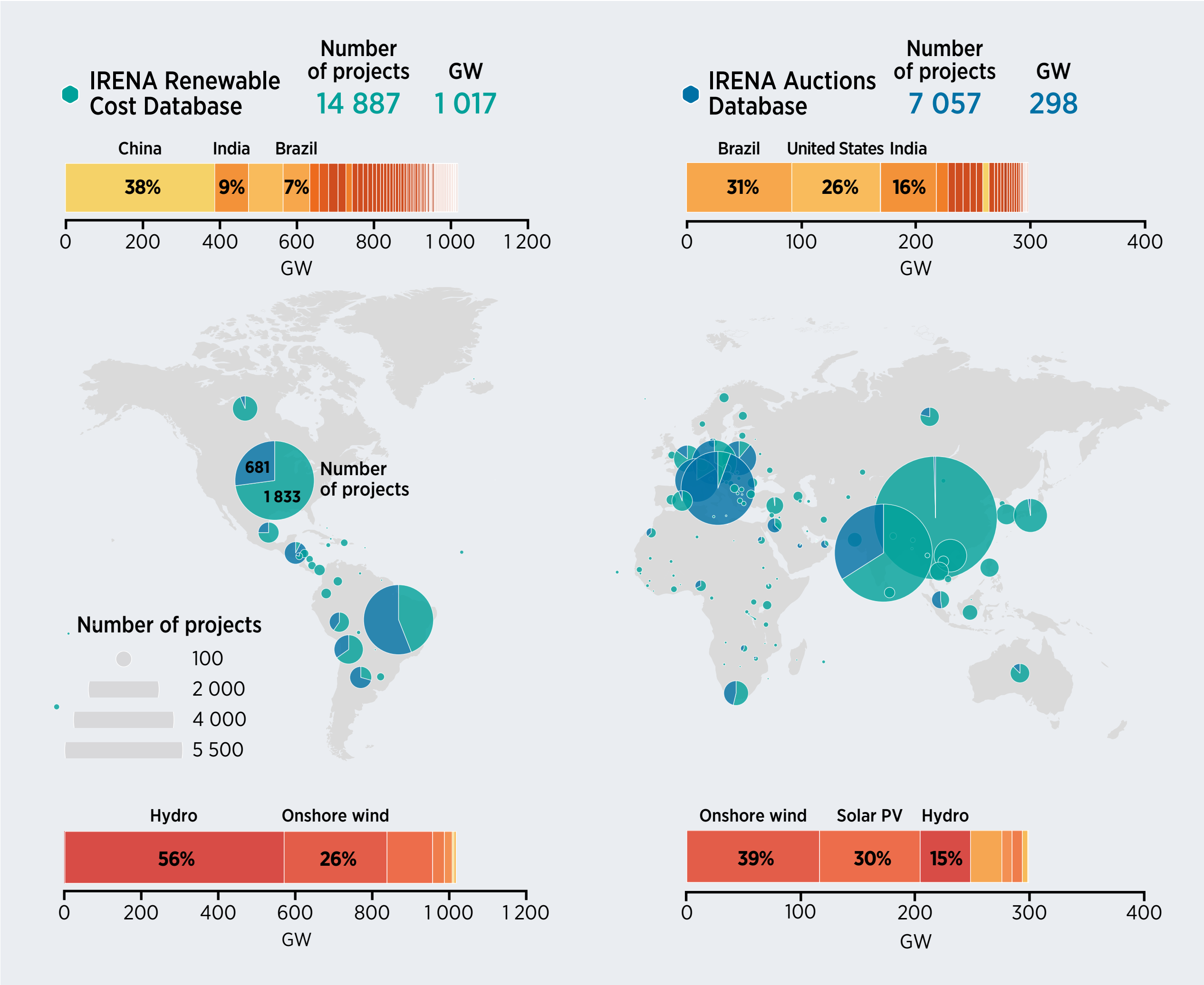
*2. This database includes results from a range of competitive procurement processes, including auctions, tenders, power purchase agreements (PPA), contracts for differences, etc. For simplicity, and given auctions are the dominant competitive procurement process, the database has been called the "Auctions Database".*

*3. Projects without even this basic level of data are not included in the main database.*

*5. Given that final deployment numbers for each technology by country and region for 2017 were not available at the time of this analysis, this is by necessity a qualitative judgement by IRENA based on current expectations for deployment in 2017.*

*4. In some cases where there are multiple individual winners that are not disclosed, the database entry is not a single project, but the average result.*

**Figure 1.2** Distribution of projects by technology and country in the IRENA renewable cost database and auctions database.




*Based on IRENA data*

# 2. COST TRENDS IN GLOBAL RENEWABLE POWER GENERATION

As deployment of renewable power generation technologies accelerates, a continuous and relentless improvement in their competitiveness has also been maintained throughout 2016 and 2017. This has led to the fact that in virtually every region of the world, bioenergy for power, hydropower, geothermal and onshore wind projects commissioned in 2016 and 2017 largely fell within the range of fossil fuel-fired electricity generation costs.

With very rapid reductions in solar PV module and balance of system costs, utility-scale solar PV is now increasingly competing head-to-head with alternatives – and without financial support. Offshore wind power and CSP, despite having significantly lower installed capacity compared to other renewable technologies, have also seen their costs fall, with auction results in 2016 and 2017 indicating that they too are on track to achieve cost competitiveness for projects commissioned between 2020 and 2022.

These cost reductions are being driven by:

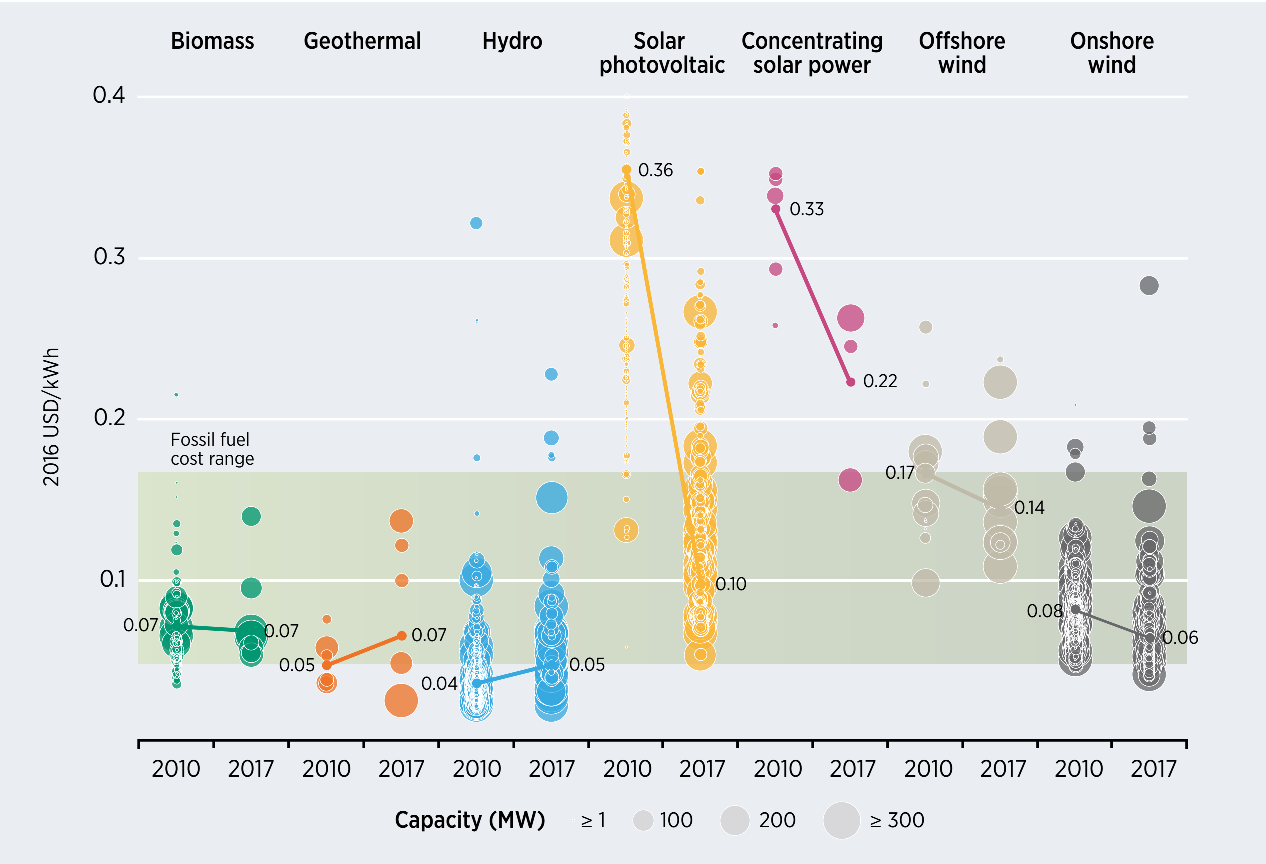
- Increasing economies of scale in manufacturing, vertical integration and consolidation among manufacturers.
- Manufacturing process improvements that reduce material and labour needs, while optimising the utilisation of capital.
- More competitive, global supply chains that are increasingly optimised to provide tailored products that best suit local market and resource conditions.
- Technology improvements that are raising capacity factors and/or reducing installed costs.
- Experienced project developers that have standardised approaches to project development and who have minimised project development risks.
- Optimised O&M practices and the use of real-time data to allow improved predictive maintenance, reducing O&M costs and generation loss from planned and unplanned outages.
- Low barriers to entry and a plethora of experienced medium- to large-scale developers competing to develop projects, worldwide.
- Falling or low cost of capital, driven by supportive policy frameworks, project de-risking tools and the technological maturity of renewable power generation technologies.

All of this has been taking place against a backdrop of increasing competitive pressure that is driving innovation in technology, but also in business models. With the newer solar and wind technologies benefiting from support policies, there has been a steady – and sometimes dramatic – increase in their deployment in the last 10 years. This has been accompanied by growth in the number of markets for solar and wind.

The global weighted-average LCOE of utility-scale solar PV projects commissioned in 2017 was 73% lower than those commissioned in 2010 (Figure 2.1).[1] This was driven by an 81% reduction in solar PV module prices since the end of 2009, with learning rates[2] for solar PV modules in the range of 18-22%, or even higher, if only more recent deployment is taken into account (Theologitis & Masson, 2015). Balance of system costs have also fallen, but not to the same extent, meaning the global weighted-average total installed costs of newly commissioned projects fell by 68% between 2010 and 2017.

The period 2010-2017 saw the global-weighted average cost of electricity from onshore wind fall by 23%. Indeed, wind power has experienced a somewhat unnoticed revolution since 2008-09 as wind turbine prices have declined. Between 2008 and 2015, a virtuous cycle of improved turbine technologies, as well as higher hub heights and longer blades with larger swept areas, has increased capacity factors for a given wind resource. As a result, the global weighted average capacity factor for newly commissioned projects increased from an average of 27% in 2010

**Figure 2.1** Global levelised cost of electricity from utility-scale renewable power generation technologies, 2010-2017




*Source: IRENA Renewable Cost Database.*

*Note: Each circle represents an individual project in the IRENA Renewable Cost Database, with the centre of the circle representing the LCOE value on the Y-axis and the diameter of the circle the size of the project. The lines represent the global weighted average LCOE value for a given years newly commissioned projects, where the weighting is based on capacity deployed by country/year.*

*1. All cost data in this chapter, unless explicitly mentioned otherwise, is from the IRENA Renewable Cost Database or Auctions Database. All references to a specific year for equipment costs, total installed costs, capacity factors or LCOE refer to the data associated with newly commissioned projects (e.g. new additions only) in that year unless explicitly stated otherwise.*

*2. Learning rates for technologies are the average percentage cost or price reduction that occurs for every doubling in cumulative installed capacity of that technology.*

to 30% in 2017, with many countries experiencing much more dramatic increases than the average. Installed cost reductions have been driven by declines in wind turbine prices which, which fell by between 39-58%, depending on the market, from their peaks in 2007-2010. The balance of project costs for onshore wind have also declined, with these factors all driving down the LCOE of wind and spurring increased deployment.

Hydropower has historically produced some of the lowest-cost electricity of any generation technology – and continues to do so, where untapped economic resources remain. The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, with the majority of projects falling between this and USD 0.10/kWh. Schemes for electrification in remote areas can see higher costs, however. A shift to more challenging projects with higher civil engineering and project development costs has pushed up the global weighted average total installed cost in recent years. This has in turn driven up the global weighted average cost of electricity for hydropower, with this rising from USD 0.036/kWh to USD 0.046/kWh between 2010 and 2017.

Small-scale hydropower can also be very economic, although typically it has higher costs than large scale and is sometimes more suitable as an option for electrification, providing lower-cost electricity to remote communities, or for the local grid.

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 0.03/kWh, when waste heat is also used for productive purposes in combined heat and power plants (CHP). The global weighted-average LCOE for biomass-fired power generation projects fell slightly between 2010 and 2017 to just below USD 0.07/kWh. The 5$^{th}$ and 95$^{th}$ percentiles for projects have typically ranged between USD 0.05 and USD 0.13/kWh. However, deployment is quite thin and this varies significantly by year.

By the end of 2016, geothermal global cumulative installed capacity was still relatively modest at 12.6 GW and was surpassed in installed capacity terms by offshore wind in that year. 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 0.04/kWh to around USD 0.13/kWh for recent projects.

Offshore wind and CSP had cumulative installed capacity at the end of 2016 of around 14 GW and 5 GW respectively, and have higher costs than the other more mature technologies. Costs are falling, however, and between 2010 and 2017 the cost of electricity of newly commissioned CSP projects fell by 33% to USD 0.22/kWh and those for offshore wind by 13% to USD 0.14/kWh. The years 2016 and 2017 saw a breakthrough for both technologies, with auction results for projects to be commissioned from around 2020 onwards anticipated to have significantly lower LCOEs than in 2017.

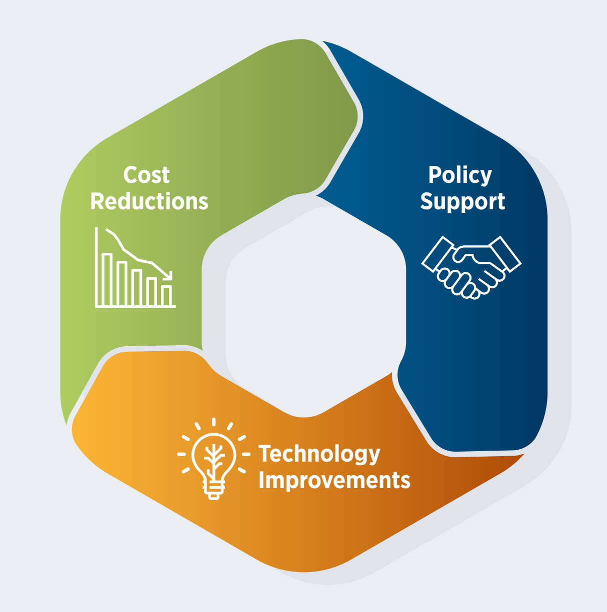
## 2.1 THE NEW COST REDUCTION DRIVERS: COMPETITIVE PROCUREMENT, INTERNATIONAL COMPETITION AND IMPROVED TECHNOLOGY

The power sector is currently undergoing a transformation that represents the beginning of the transition to a renewables-dominated, truly sustainable power sector. This is required in order to avoid the dangerous effects of climate change. The power generation sector is leading this transformation, with renewables estimated to have added around half or more of global new capacity required every year, from 2012 onwards (IRENA, 2017d). At the end of 2001, the total global capacity of solar PV was less than 1 GW; by end of 2016, it had surpassed 291 GW and by the end of 2017 should have grown to around 381-386 GW. Similarly, wind power capacity at the end of 2001 was 24 GW, but by the end of 2016 had reached 467 GW. Meanwhile, annual new capacity additions of renewable power generation technologies increased from 16 GW in 2001 to 167 GW in 2016, a ten-fold increase, with total new capacity additions in 2017 likely to surpass this record.

The virtuous cycle of long-term support policies accelerating the deployment of renewables – which in turn leads to technology improvements and cost reductions (Figure 2.2) – has led to the increased scale and competitiveness of markets for renewable technologies. The transformation of the power generation sector is therefore an active one, where the policy support for renewables to meet countries' long-term goals for secure, reliable, environmentally friendly and affordable energy is bearing fruit.

As equipment costs for solar and wind power technologies have fallen, notably for solar PV modules and onshore wind turbines, a shift in emphasis in cost reduction drivers is also emerging. As equipment costs fall, the importance of addressing balance of system costs, improving the performance of the technologies, reducing O&M costs and driving down the cost of capital all start to take on greater importance (IRENA, 2016a). At the same time, markets and business models are not standing still. In recent years, as the compelling case for renewable power generation's competitiveness has grown, so too has deployment.

**Figure 2.2** Renewables are experiencing a virtuous cycle of technology improvement and cost reduction




Yet it has not just grown, but also experienced a welcome broadening in geographical scope. In some cases, this has been accompanied by slowing or stagnant markets for new projects in mature markets (notably Europe), resulting in a large number of very experienced medium- and large-scale developers now increasingly looking for international opportunities.

This confluence of factors has been driving recent cost reduction trends for renewables, with effects that will only grow in magnitude in 2018 and beyond. The three main emerging drivers that are starting to increasingly drive cost reductions are:

- *Competitive procurement of renewable power generation*: As renewable power generation technologies have matured and cost reductions have exceeded expectations, there is a growing shift towards auctions and other competitive procurement processes (IRENA, 2017e). In mature markets, with limited volumes on offer, this has led to intense competition for projects and has resulted in falling costs. Similarly, reduced support levels have also forced developers to implement best practices in terms of project development, utilise newer innovative technology solutions, and generally reduce margins.

- *Increasing international competition for projects*: With the sustained growth in renewable power generation deployment, a large number of very experienced medium- to large-scale project developers have emerged around the world. Many have seen their original markets slow and have looked to new markets to maintain a pipeline of projects and grow their businesses. This has allowed new markets to benefit from previous, hard-won business acumen in the field of renewable project development. In conjunction with local partners, in many cases, to help navigate the local regulatory and business landscape; these project developers are enabling even new markets to achieve very competitive pricing, where the regulatory and policy framework is conducive to renewables.

- *Continuous technology innovation*: As economies of scale in manufacturing and materials efficiency have been unlocked in recent years, continued cost reductions are beginning to be more heavily driven by improvements in technology. This is particularly true for wind, where larger turbines with larger swept areas are harvesting more electricity for the same resource. Larger turbines also enable the amortising of project development costs over greater capacities and allow greater economies of scale in O&M. At the same time, wind turbine manufacturers are offering an increasing range of products to allow optimisation for individual wind sites, while the utilisation of real-time data and "big data" to enhance predictive maintenance and reduce O&M costs and lost energy from downtime are also playing a role. For solar PV modules, the continued efforts to commercialise cell architectures with greater efficiency are helping to reduce module installed costs and balance of system components. These are but a few examples of the constant innovation that is helping to drive down costs.

*Technology providers and project developers have reduced costs to remain competitive*

These trends are not new, but their importance has grown significantly in recent years. They are part of a larger dynamic across the power generation sector, driven by the fact that in many regions of the world, renewable power generation technologies often offer the lowest cost source of new power generation. The industry is thus rapidly transitioning. In the past, typically, there was a framework offering direct financial support, often tailored to individual technologies (e.g., solar PV) and even segments (e.g., varying support for residential, commercial and utility-scale sectors, sometimes differentiated by other factors such as whether they are building-integrated or not). Now, this is being replaced by a favourable regulatory and institutional framework that sets the stage for competitive procurement of renewable power generation to meet countries energy, environmental and development policy goals.

In many parts of the world, utilities, industry players, project developers and asset owners have rapidly embraced this new dynamic and are finding ways to profitably navigate this new landscape. In the absence of direct financial support, project developers are also using new business models to grow. Companies are identifying strategies that will allow subsidy-free projects to be profitable in different markets. Examples of this range from utilising corporate or utility PPAs to provide revenue certainty, or merchant solar PV plants being built in certain locations where wholesale market forecasts support their economics. Other examples include looking at new opportunities, such as also including storage to better access peak prices and potentially achieve new revenue streams by providing ancillary services to the grid.

This section will now examine their impact on recent cost trends, according to each technology, through 2017 and beyond, using data both from the IRENA Renewable Cost Database and the Auctions Database.

### Box 1 A Cautionary Tale: When is an LCOE not a FiT or a PPA Price?

The LCOE metric used in this report represents an indicator of the price of electricity required for a project in which revenues would equal costs over the life of an asset. This includes making a return on the capital invested equal to the discount rate, while excluding the impact of existing government incentives or financial support mechanisms. For solar and wind technologies in particular, various power purchase agreement (PPA) prices have been announced recently in different locations. With such developments, it can become harder to distinguish between these "record" prices and the LCOE concept as discussed in this report.

Though these very low PPA prices point to the increasing competitiveness of renewable energy sources compared to fossil fuel alternatives, they often cannot be directly compared to the LCOE, nor necessarily to feed-in tariffs (FiTs). The end auction or PPA prices depend on a set of obligations and contract-defined terms that are very dependent on the specific market situation of the project setting. Assumptions made to calculate these prices usually differ from the more standardised ones used for the LCOE indicator calculations in this report. There is also the chance that if these conditions are not fulfilled, the PPA price may not materialise – if, for example, the independent power producer (IPP) does not fulfil the output requirements or electricity quality. In extreme cases, the deficiencies in the initial winning bid may see a developer walk away from the project, as the financial penalties incurred are lower than the expected loss if the project is completed.

As an example of the potential differences between auction and PPA prices compare to LCOEs, in 2015 a United States solar PV developer agreed to sell power at a record low headline price of USD 0.0387/kWh from a 100 MW solar plant to utility NV Energy. It was not widely quoted, however, that this price included a 3% escalation clause and that according to a filing with the Public Utilities Commission of Nevada, the LCOE of the project was estimated at about USD 0.047/kWh after the Investment Tax Credit (Public Utilities Commission of Nevada, 2015). Allowing for the impact of the 30% Investment Tax Credit raises the electricity price to around USD 0.066/kWh (70% higher than the headline value). In the case of FiTs, they are also not directly comparable to the PPA contract set prices. For instance, in Germany the current FiT for solar PV is nominal and payable for a period of 20 years, below the economic life of 25 years.

The starting point for any comparison of an LCOE metric against a FiT or PPA price should therefore be one that assumes they are not directly comparable. The exception would be one where the weighted average cost of capital (WACC) of a project equals that assumed for the LCOE calculation, the remuneration period equals the economic life of the asset, the remuneration is "complete" in terms of the fact no other revenue streams are available (e.g. potential revenue from green certificates or capacity payments that are not included in the headline remuneration figure), and that remuneration is indexed to inflation. It should therefore be clear that a lower PPA price than the LCOE may not necessarily represent a lower cost of project. Care should thus be taken in comparing LCOE, FiT levels and auction/PPA prices, as they can be very different cost metrics.

### Box 2 Tracking Innovation trends: A look at patent data for renewables

The past decade has seen robust growth of innovation and inventions for renewable energy technologies. Patents are an important mechanism to foster such innovation. They support revenue generation (through licences), encourage partnerships, and can create market advantages while balancing the interests of inventors and the general public (IRENA, 2013c).

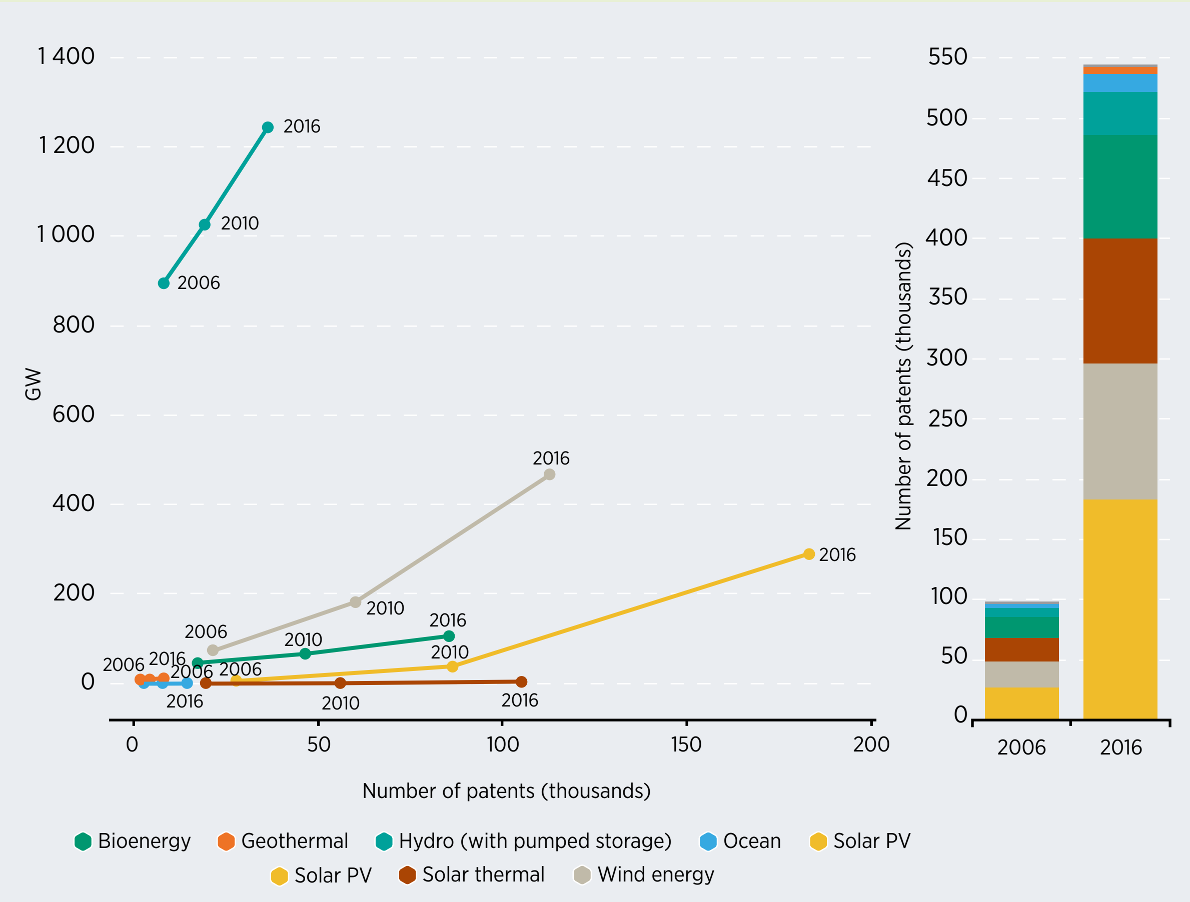
Reliable patent data provides a means to track renewable energy innovation worldwide, heightening the key role of patents in the technology life cycle and new technology uptake. In order to facilitate such global tracking, IRENA has developed a web-based tool, INSPIRE (www.irena.org/inspire), that facilitates such global tracking and helps to assess trends in research, development and demonstration.

The tool aims to support technology and innovation strategies among IRENA's Member States by furnishing comprehensive, reliable, regularly updated information on renewable energy patents and technical standards. Such information facilitates standardisation, quality management and technology risk reduction as countries pursue the transition to renewables.

In developing the INSPIRE platform, IRENA worked closely with the European Patent Office to shed light on trends in climate-change mitigation technologies, as reflected in recent renewable energy patents. As the resulting data showed, the total number of renewable energy patents filed worldwide at least tripled between 2006 and 2016.

This represents compound annual growth of 17%, with more than half a million patents filed for these technologies by the end of 2016 (www.irena.org/inspire). Along with the intensification of inventive activity, renewable energy has achieved sharp cost reductions and sustained deployment growth. For example, solar PV-related patent filings reached 183 000 while cumulative deployment for the technology barely exceeded 290 GW. A more mature technology, hydropower, had a more modest 36 000 patent filings, despite its much higher cumulative deployment of about 1 250 GW (Figure B2.1).

**Figure B2.1** Development of patent data for renewable energy technologies, 2010-2016




*Based on INSPIRE web platform (www.irena.org) and IRENA (2017a).*

Solar PV held the largest share of patents among all renewable energy technologies at the end of 2016, following a five-fold increase – also the fastest patent growth in renewables – since 2006. Solar PV and solar thermal technologies together account for more than half of patents filed, while wind patents contribute another fifth of the total, and bioenergy just over one sixth, followed by hydropower and other technologies with smaller shares.

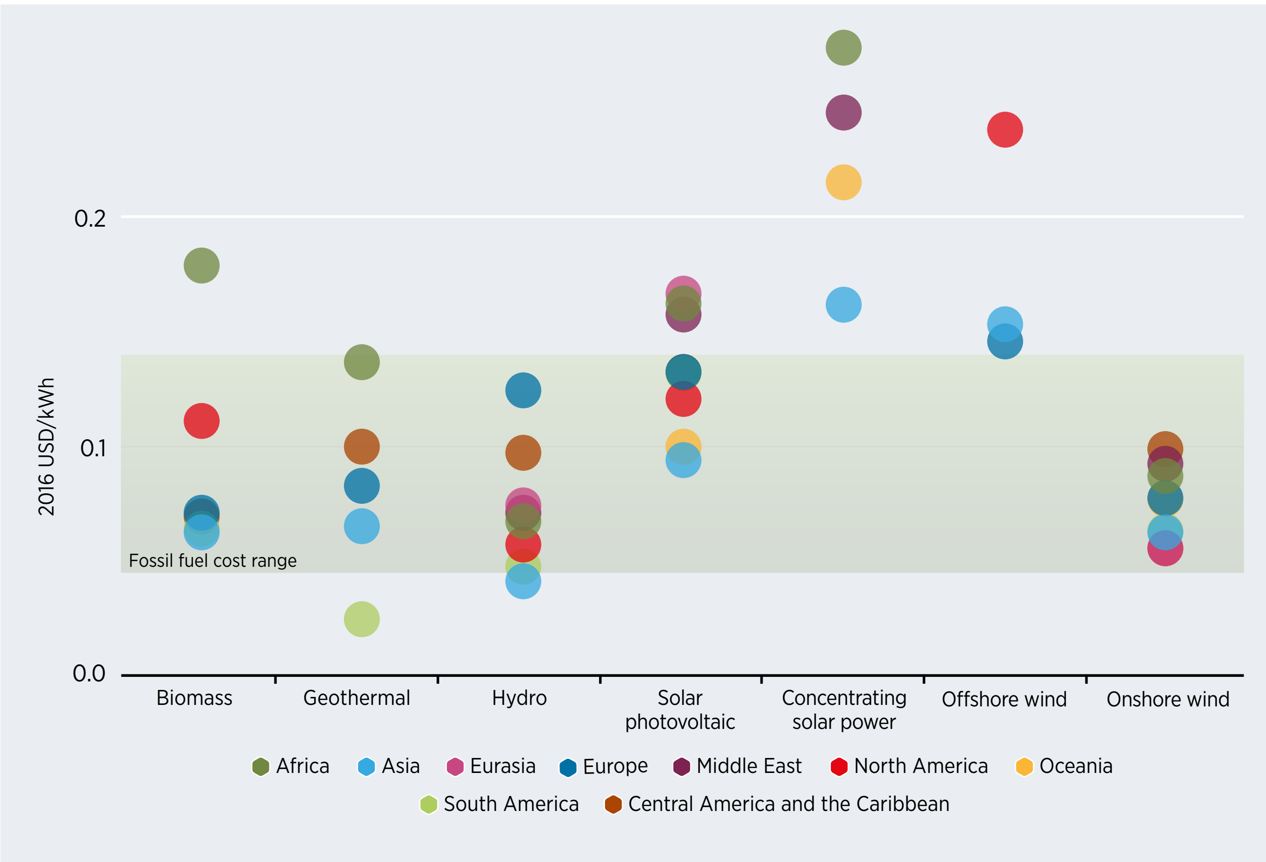
## 2.2 RENEWABLE ELECTRICITY COST TRENDS BY REGION AND TECHNOLOGY

Figure 2.3 highlights the regional weighted average LCOE by technology for an average of 2016 and 2017 to ensure maximum representativeness for all technologies and regions. While the range of these projects' individual electricity costs spans around these points, the chart serves to highlight just how competitive renewable power generation technologies have become. For bioenergy, geothermal, hydropower and onshore wind all regions with meaningful deployment have weighted averages within the range of fossil fuel-fired power generation costs. Only CSP, solar PV and offshore wind still see weighted averages by region outside the fossil fuel-fired cost range. As will become apparent when examining the LCOE data and the impact of auction results on upcoming project costs, however, this will very soon be a thing of the past.

Asia stands out as a region with particularly competitive average costs across all of the technologies. This is due to a mixture of excellent resource endowment and lower than average installed costs, notably for solar PV and onshore wind in China and India, which dominate deployment in the region.

In solar PV, what has been truly remarkable is that rapid declines in module prices and installed costs have resulted in an increasing number of regions having weighted average LCOEs that are increasingly competitive at the utility-scale, without financial support. These projects now fall within the fossil fuel-fired cost range. This is a truly impressive transition, given that in 2010 the regional weighted average LCOE of solar PV projects ranged from 65% higher than the upper range of fossil fuel-fired costs in North America, to 236% higher in Africa – albeit where expensive projects in more remote areas had raised costs. The weighted average LCOE by region for utility-scale

**Figure 2.3** Regional weighted average levelised cost of electricity by renewable power generation technology, 2016 and 2017




*Source: IRENA Renewable Cost Database.*

solar PV projects that were installed in 2016 and 2017 ranged from a low of around USD 0.09/kWh in Asia to a high of USD 0.17/kWh in Eurasia. In Central America, the Caribbean and South America the average was USD 0.13/kWh. Projects are now being built with an LCOE of as low as USD 0.05/kWh, and as presented in Figure 2.1, with the costs continuing to fall, the global weighted average for 2017 alone has fallen to USD 0.10/kWh. While even lower values are going to be seen in the coming years, as the record breaking auction results in Dubai, Chile, Abu Dhabi, Mexico and Saudi Arabia come online. These are all at around USD 0.03/kWh or lower.

Focussing on the global weighted average trends for new utility-scale solar PV projects by year (Figure 7), the LCOE reduction of 73% between 2010 and 2017 is put in context. By far the main driver has been the reduction in total installed costs for utility-scale solar PV, with a 68% reduction in total installed costs between 2010 and 2017. But there has not just been a reduction in average costs that has been significant, there has also been a shift in the distribution of projects around the weighted average that has occurred as the weighted average has shifted to the lower end of the 5th and 95th percentile ranges.

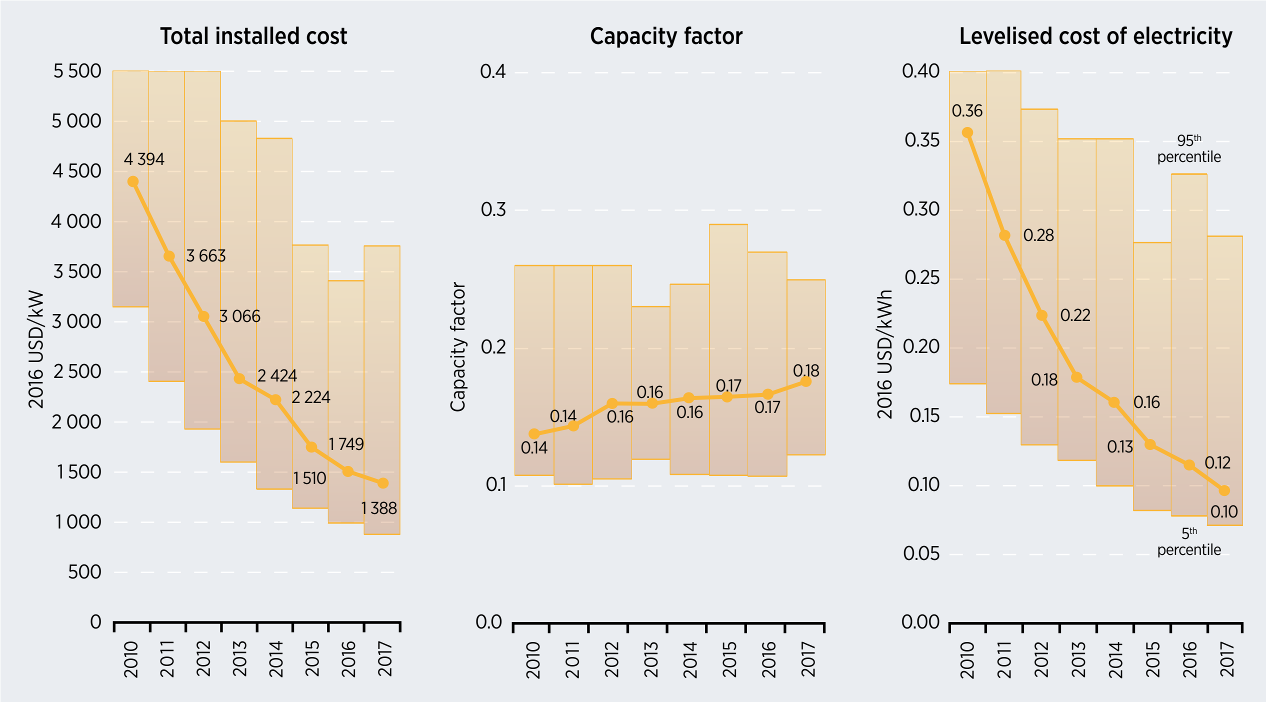
The global weighted average total installed cost for utility-scale solar PV fell from USD 4 394/kW in 2010 to USD 1 388/kW in 2017, with a 5th and 95th percentile of USD 898/kW and USD 3 754/kW. The distribution of project costs for solar PV remains wide and is skewed towards a long tail of more expensive projects. In part, this reflects the natural variation in project costs for renewable projects; however, there are two other significant drivers. The first is that there remain a number of markets with persistently higher costs than in other markets, with the United States and Japan being two notable examples. Historically, though, this has also been the case for new markets that have yet to establish mature and competitive local supply chains and developers. Secondly, solar PV is extremely modular and is often increasingly being deployed in remote locations (e.g., in the interior of African countries, islands, or other isolated locations), where logistical costs are significantly higher than in areas close to ports and with supporting infrastructure. Here, the higher costs are typically economically supportable, as the savings in diesel costs and, sometimes, improving electricity network reliability, make the projects economic.

Capacity factors for utility-scale solar PV projects have been edging higher through time, with a global weighted average increase of 28%, from 14% on average in 2010 to 18% in 2017. This is predominantly due to a shift in deployment to areas with better solar resources, rather than as a result of an increase in the use of tracking or other technology improvements. There have been some system performance improvements in this time as well, notably in terms of improving the overall efficiency of the array and inverters to reduce losses, but these are minor contributors to the overall improvement.

The overall result of the contribution of these two factors playing out at a project level was the dramatic fall in LCOE of utility-scale solar PV between 2010 and 2017. Within this, two distinct periods are visible: between 2010 and 2013, the global weighted average LCOE fell by around 20% each year. After 2014, when the decline was 10%, the fall was more variable, as 2015 saw a 20% decline, 2016 a 10% reduction, and 2017 a 17% decline. The compound annual rate of decline was 21% per year for 2010-2013 and 14% per year for 2013-2017.

Hydropower produces some of the lowest-cost electricity of any generation technology and is the largest source of renewable electricity generation today (3 996 TWh in 2015). The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, while average costs have risen in recent years and in 2016 the global weighted average reached USD 0.053/kWh. In 2017, it fell back to USD 0.047/kWh. Developments in Asia, where good untapped economic resources still remain, saw weighted average LCOEs of USD 0.04/kWh in 2016-2017, with South America having a weighted average of USD 0.05/kWh and North America USD 0.06/kWh. Africa, Eurasia and the Middle East averaged USD 0.07/kWh. Developments were somewhat more expensive in Central America and the Caribbean, at USD 0.10/kWh, and in Europe, at USD 0.12/kWh.

**Figure 2.4** Global weighted average total installed costs, capacity factors and LCOE for solar PV, 2010-2017




*Source: IRENA Renewable Cost Database.*

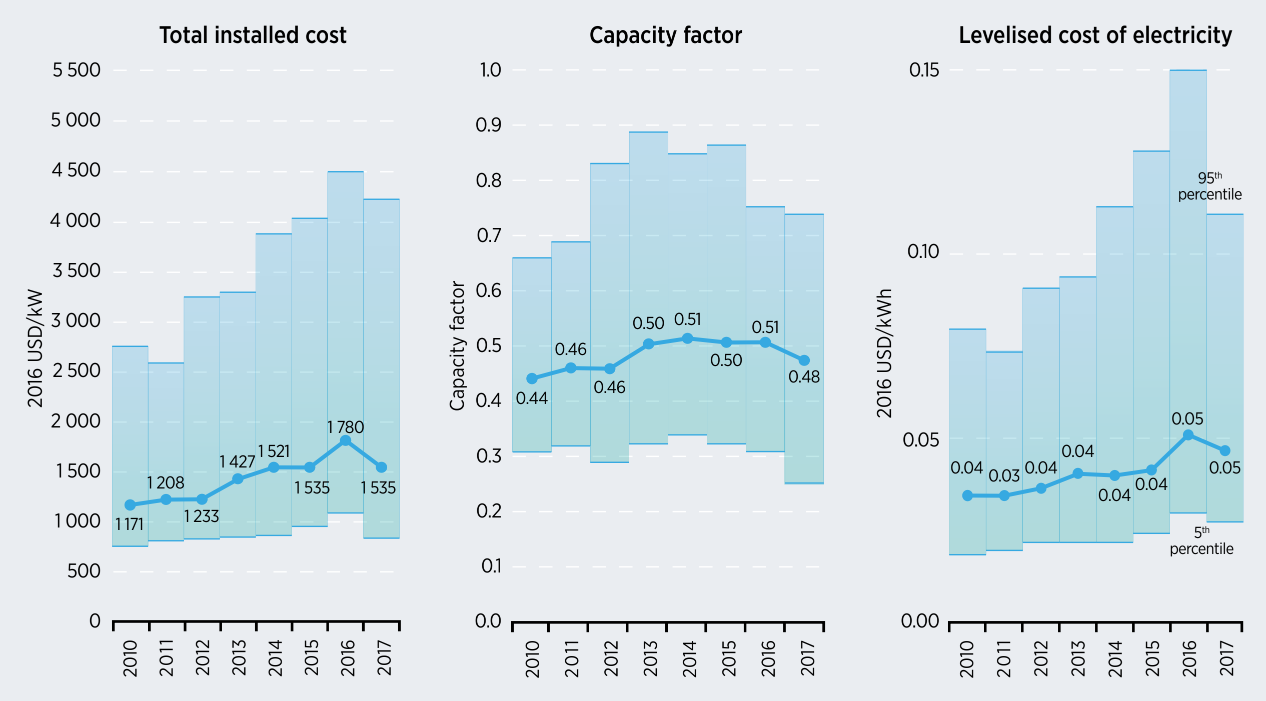
As deployment has accelerated in regions that have previously had significant untapped potential, notably in Asia and South America, recent development has had to start depending on projects at more challenging sites, with higher project development costs and civil engineering costs, either due to conditions at the dam location, or in terms of more expensive infrastructure and logistics for the project. This means that projects' total installed costs have started to rise (Figure 2.5). To some extent, this was offset by an increase in the weighted average project capacity factor, which went up from around 44% for projects in 2010 to 50-51% in 2014-2016, although in 2017 this fell back to 48%.

In terms of LCOE, projects in Asia and South America are clearly moving up the cost curve as deployment continues. Hydropower remains one of the most competitive sources of new electricity, however, and significant untapped potential still remains for sustainable hydropower development, notably in Africa, but also in Asia and the Americas. The global weighted average LCOE of hydropower projects increased from an average of around USD 0.04/kWh in 2010 to USD 0.05/kWh in 2016 and 2017, with a decline between 2016 and 2017 as the weighted average LCOE fell 14% in 2017 (to USD 0.046/kWh), compared to 2016.

Small-scale hydropower can also be very economic, although typically it has higher costs than large-scale projects. This is partly due to economies of scale, but is often because it is being deployed in remote areas, as it can provide low-cost electricity to isolated communities or locations.

Onshore wind now rivals hydropower, geothermal and biomass as a source of low-cost electricity, without financial support. Capacity factors have increased as performance has improved, installed costs have fallen and O&M costs have reduced all serving to drive down the LCOE. The global weighted average LCOE for onshore wind fell by 22% between 2010-2017 and is now around USD 0.06/kWh (Figure 2.6). The weighted average regional LCOE of onshore wind has also narrowed in recent years. In 2016/17 Asia, Eurasia, North America and South America all averaged around USD 0.06/kWh or less, while the weighted average was USD 0.08/kWh in Europe and Oceania, USD 0.09/kWh in the Middle East and Africa, and USD 0.10/kWh in Central America and the Caribbean. Where excellent resources and

**Figure 2.5** Global weighted average total installed costs, capacity factors and LCOE for hydropower, 2010-2017




*Source: IRENA Renewable Cost Database.*

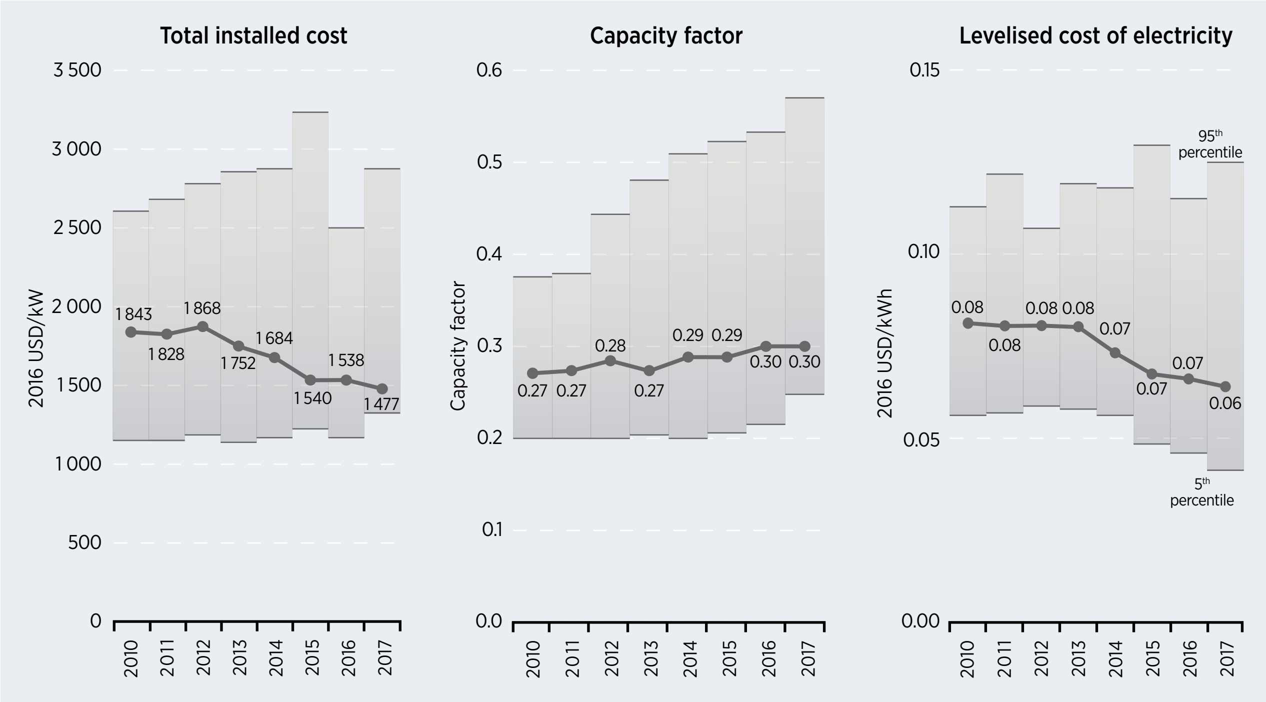
low-cost structures exist, wind power projects are now routinely achieving costs of just USD 0.04/kWh, without any financial support, and in some currently exceptional cases, USD 0.03/kWh. The 5th and 95th percentile range for the LCOE of newly commissioned onshore wind projects was between USD 0.04 and USD 0.12/kWh in 2017, which is wider than in 2010 as new markets have developed broadening the deployment of onshore wind from traditional markets.

Globally, onshore wind total installed costs fell by an average of 20% between 2010 and 2017, notably as deployment in China and India grew, given their relatively low-cost structures. The global weighted average capacity factor increased by around 11% over the same period, from 27% to 30%, conversely being slowed by the increased share of China and India, which have only average resources and are lagging somewhat in the deployment of the latest turbine technologies. Changes in the shares of deployment by country between 2010 and 2013, despite total installed costs in individual countries continuing to decline, combined to yield relatively modest global weighted average reduction in the LCOE of just 2%, before reductions of 19% between 2013 and 2017.

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 0.04 and USD 0.19/kWh, but can fall outside that range for some projects. The weighted average LCOE by region in 2016/17 varied from a low of around USD 0.05/kWh South America to USD 0.06/kWh in Asia, and to between USD 0.07 to USD 0.11/kWh in other regions.

Deployment of new bioenergy projects for power (and often heat generation at the same time) is smaller than for hydropower, solar PV and onshore wind and results in more year-to-year volatility in the characteristics of newly commissioned projects. With a shift to more sophisticated, bioenergy plants capable of performing with a range of heterogenous feedstocks, the global weighted average total installed cost increased between 2010 and 2014 before falling in 2015 and

**Figure 2.6** Global weighted average total installed costs, capacity factors and LCOE for onshore wind, 2010-2017




*Source: IRENA Renewable Cost Database.*

2016 (Figure 2.7). Data for 2017 is preliminary, but suggests more capital intensive plants took a larger share of deployment that year. With a corresponding increase in capacity factors, due to the anticipated wider range of feedstocks available at low cost, the impact on LCOE was muted, however.

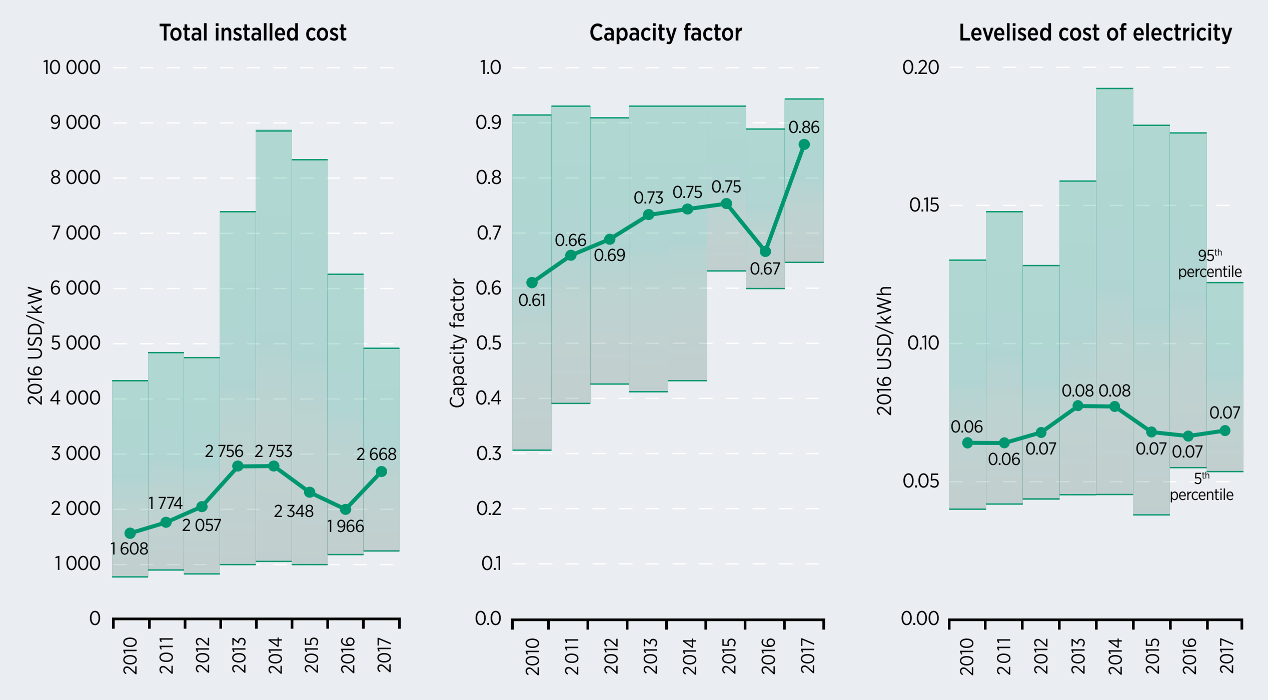
Geothermal electricity generation is a mature, baseload generation technology that can provide very competitive electricity where high-quality resources are well-defined. The LCOE of conventional geothermal power varies from USD 0.05 to USD 0.13/kWh for recent projects. Yet the LCOE can be as low as USD 0.04/kWh for the most competitive projects, such as those which utilise excellent, well-documented resources and are brownfield developments.

Many recent projects have been based on well surveyed fields, helping to reduce development risks and keep installed costs towards the lower end of the cost range. Brownfield projects can benefit from past experience with a geothermal reservoir and can not only reduce risks, but existing infrastructure in place can reduce engineering and grid-connection costs, as well as spread O&M maintenance costs over greater capacity. Significantly, geothermal projects carry a very different risk profile than other renewable technologies, given that the dynamics of managing geothermal reservoirs over the life of a project present some unique challenges.[3]

The two main CSP systems that have been deployed commercially are parabolic trough and solar towers. Deployment of these is still modest, however, and until recently was concentrated in Spain and the United States. Between 2009 and 2011, the LCOE of projects varied from around USD 0.30 to USD 0.47/kWh as generous support policies provided little incentive to drive down costs, with installed costs remaining high. Since 2012, these have been falling, as deployment has shifted away from the traditional markets of Spain and

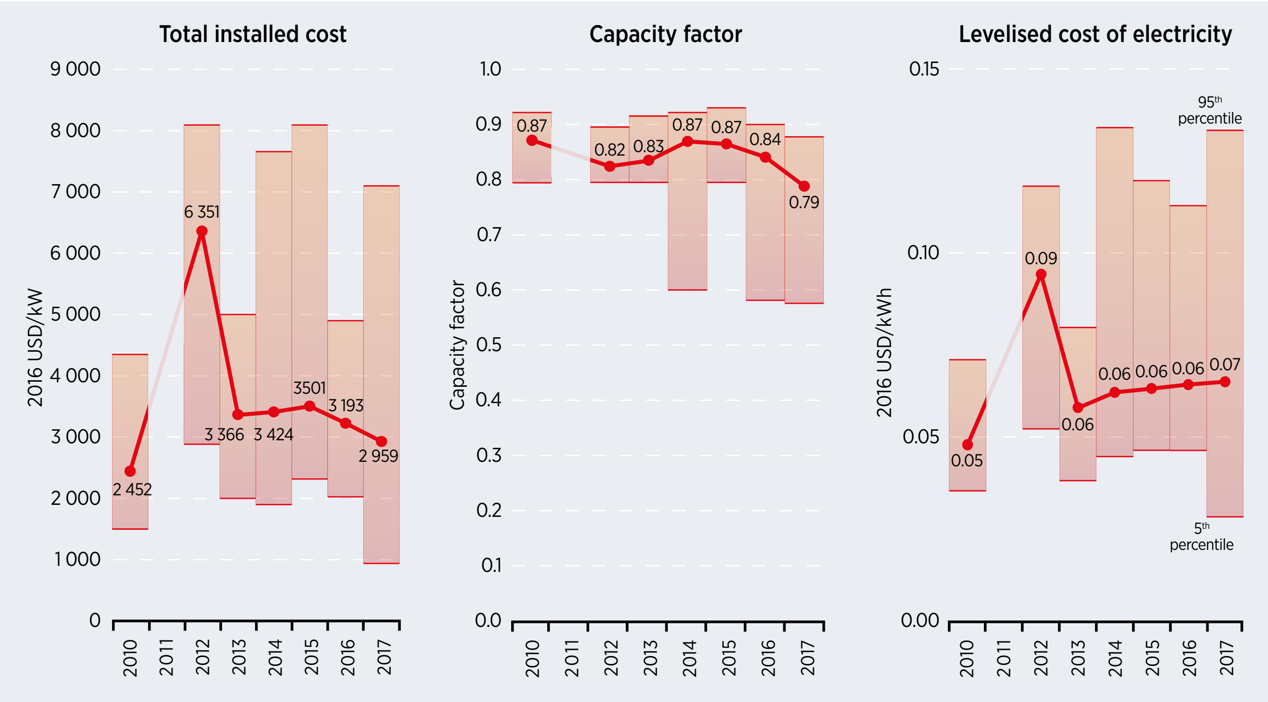
*3. Given field dynamics and uncertainty about how the reservoir will react to different operating regimes, operational experience is always adding to the base of knowledge that allows for optimal reservoir management.*

**Figure 2.7** Global weighted average total installed costs, capacity factors and LCOE for bioenergy for power, 2010-2017




*Source: IRENA Renewable Cost Database.*

**Figure 2.8** Global weighted average total installed costs, capacity factors and LCOE for geothermal power, 2010-2017



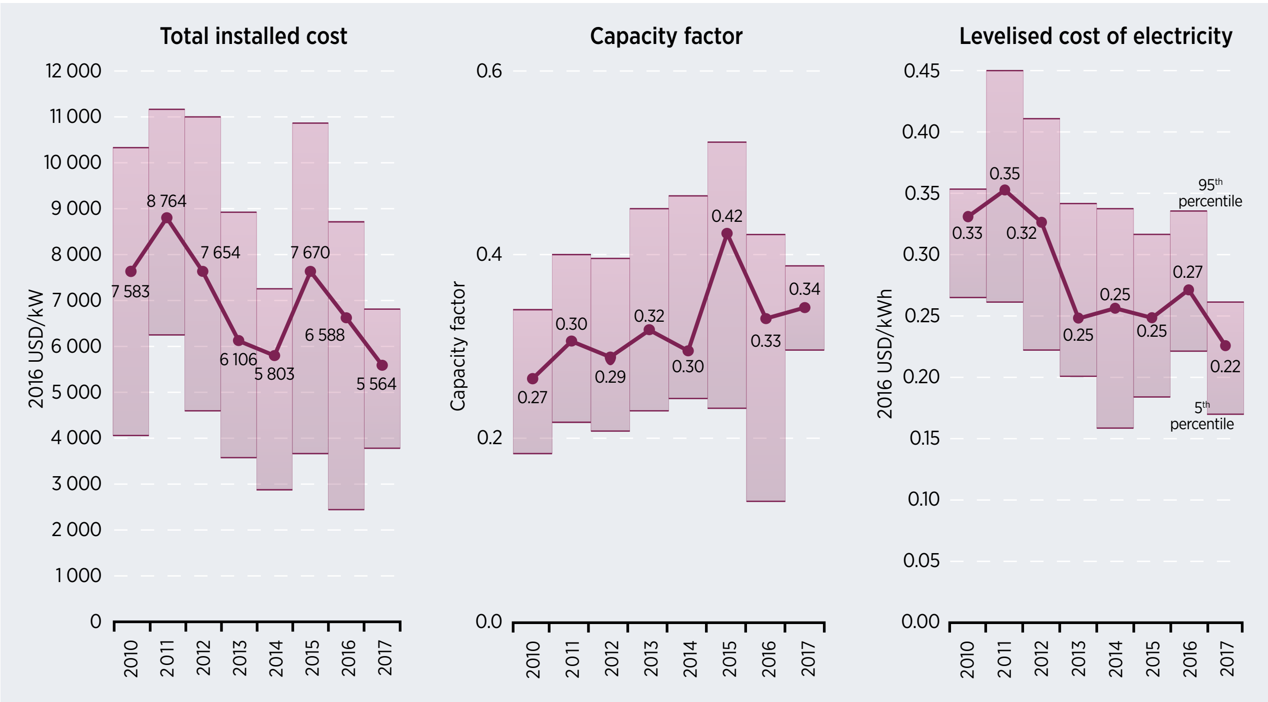

*Source: IRENA Renewable Cost Database.*

the United States. Greater competitive pressures have reduced installed costs, with projects also benefitting from higher solar resources in new markets like Chile, Morocco and the United Arab Emirates. LCOEs ranged between USD 0.16 and USD 0.29/kWh in 2016-2017. Recent auction results, however, have heralded an acceleration in cost reductions, as supply chains have become more competitive, a wider range of project developers have had experience developing multiple projects and projects have been more often sited in regions with excellent solar resources, but still with access to low-cost finance. These results remain to be confirmed by a broader set of auction results or project announcements beyond Australia and Dubai, but the initial indications are that the competitiveness of CSP will fundamentally change for plants commissioned beyond 2020.

Offshore wind, like CSP, has relatively modest levels of cumulative installed capacity with just 13 GW installed at the end of 2016. Deployment has been concentrated in Europe, notably in Belgium, Denmark, Germany, the Kingdom of the Netherlands and the United Kingdom. In addition, China has also built some inter-tidal projects and the United States is joining the ranks of offshore wind power producers.

Costs for offshore wind in the early 2000s climbed, as deployment accelerated and projects moved into deeper waters, further offshore – raising foundation and installation expenditure. Costs have since peaked, however, and have come down significantly in recent years. Nonetheless, the weighted average LCOE by region remains around USD 0.14 to USD 0.15/kWh. As with CSP, though, the recent auction results from 2016 and 2017 in Belgium, Denmark, the Kingdom of the Netherlands, Germany and the United Kingdom all show that offshore wind will be a very competitive source of new generation capacity in Europe for projects that will be commissioned in 2020 and beyond. Indeed, in Germany, 2 projects that will be commissioned in 2024 and 1 in 2025 won with bids that did not ask for a subsidy over market rates.[4]

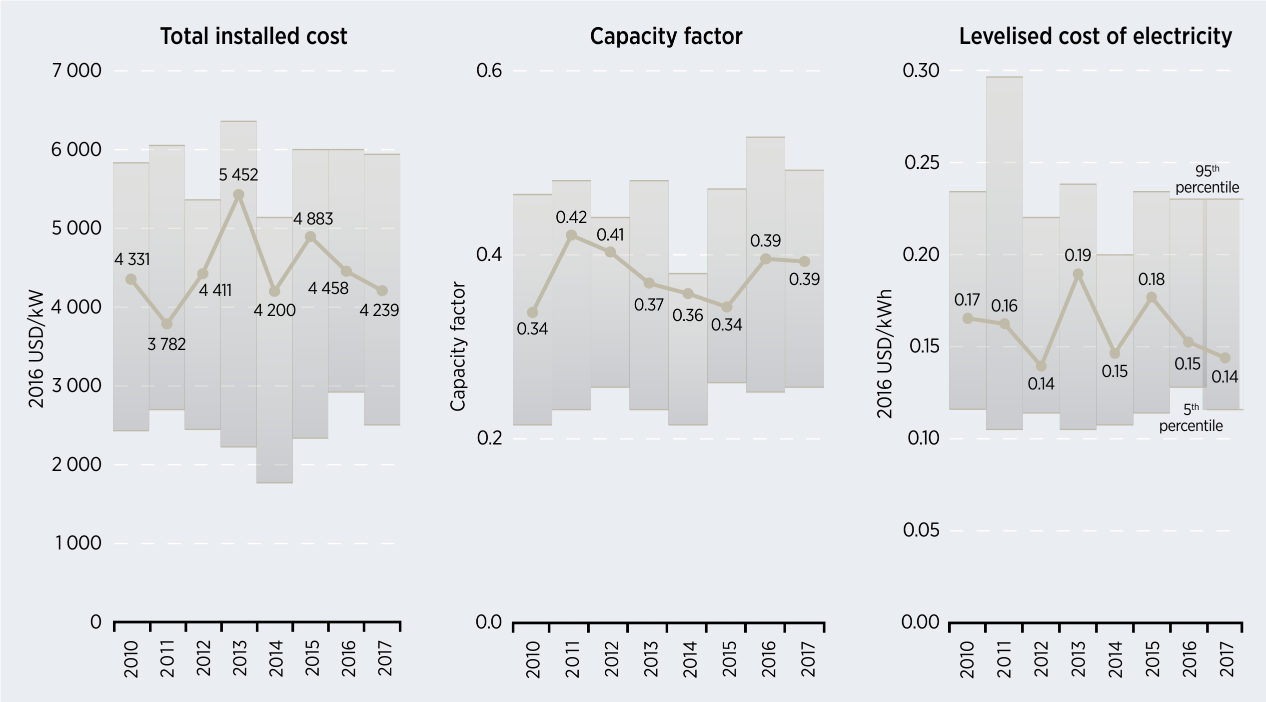
**Figure 2.9** Global weighted average total installed costs, capacity factors and LCOE for CSP, 2010-2017




*Source: IRENA Renewable Cost Database.*

*4. For more details see: https://ore.catapult.org.uk/download/subsidy-free-offshore-wind/*

**Figure 2.10** Global weighted average total installed costs, capacity factors and LCOE for offshore wind, 2010-2017




*Source: IRENA Renewable Cost Database.*

## 2.3 THE COST OF RENEWABLE ELECTRICITY TO 2020: INSIGHTS FROM PROJECT DATA AND AUCTIONS

The range of costs for renewable power generation technologies between regions is wide for a given technology – and even for a given technology within a particular region, due to site-specific cost drivers. It is striking, though, that virtually all renewable power generation technologies now not only include significant numbers of projects which offer very competitive electricity costs, but that renewable power generation technologies are also increasingly overlapping towards the low-end of the fossil fuel-fired electricity cost range. This is 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, in comparison with the figures presented here.[5] As already discussed, the variability of solar PV and wind power must also be taken into consideration in system modelling to arrive at the least-cost combination of technologies. However, as previous IRENA analysis has highlighted, the additional environmental costs of fossil fuels and estimates of the additional costs of variability of solar and wind may broadly offset each other (IRENA, 2015). However, estimates of both these cost groups is country specific and evolving over time as a better understanding of the various impacts of each is achieved through operational experience and additional research.

This section examines in more detail some of the high-level trends that are behind the convergence in LCOE, for commissioned projects up to 2017 and for proposed projects up to 2020. It will look at all the major contributors to new capacity – hydropower, onshore and offshore wind, solar photovoltaics and CSP – and outline five key messages from the data:

5. *For a more detailed discussion of the costs of local and global pollutants see IRENAs analysis in "Perspectives for the energy transition: Investment needs for a low-carbon energy system" (IRENA, 2017f).*

- In 2017, a significant number of newly commissioned bioenergy for power, hydropower, geothermal, onshore wind and, increasingly, solar PV projects competed head-to-head with fossil-fuels without financial support. Offshore wind and CSP projects to be commissioned in the period from 2020 onwards will also compete in this fashion.
- A remarkable convergence in the global weighted average cost of electricity from each technology has been signaled to 2020 by recent auction results. Installed cost differentials between countries persist for onshore wind and solar PV in particular, however, highlighting cost reduction opportunities.
- Cost reductions for solar and wind are continuing at a steady pace and between 2010 and 2020 represent remarkable rates of cost reduction, significantly beating long-term forecasts.
- Renewable power generation technologies are increasingly not just competitive without financial support, but out-compete fossil fuel-fired power.
- The cost of electricity from onshore wind and solar PV is reaching extremely low levels, only achieved in the past by the very best hydropower projects.

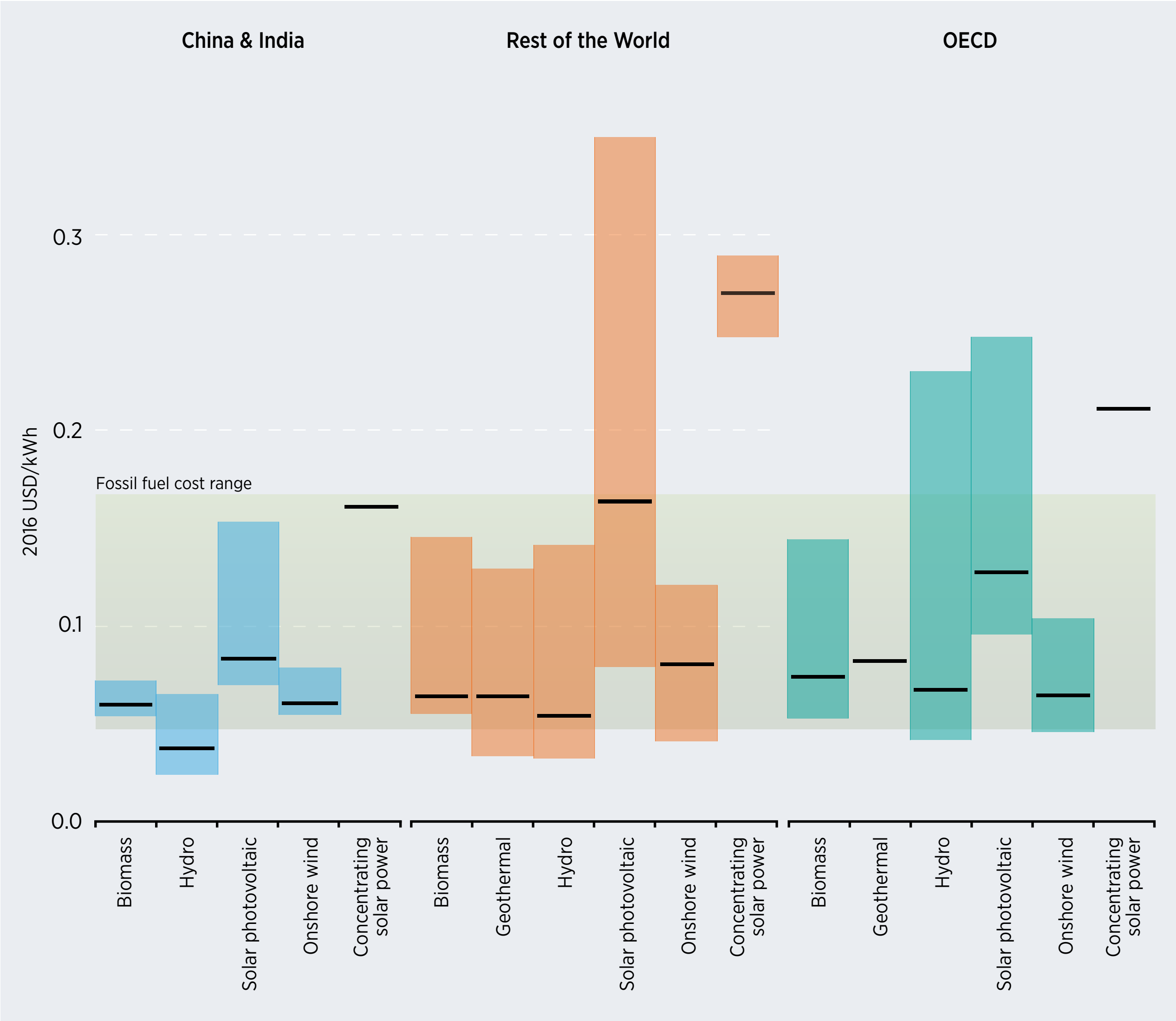
In 2017, weighted average electricity costs for bioenergy for power, geothermal, hydro, onshore wind and solar PV all fell within the range of fossil fuel-fired electricity and are often the cheapest source of new generation needs. The fossil fuel-fired electricity generation cost range for G20 countries spans the range USD 0.05 to USD 0.17/kWh (IRENA, forthcoming).[6]

Figure 2.11 shows the weighted average LCOE by technology and region/country grouping, as well as the 5th and 95th percentile ranges for projects commissioned in 2016 and 2017. In China and India, hydropower remains the most competitive source of electricity, on average coming in below the lowest fossil fuel-fired option. The weighted average LCOEs for bioenergy for power and onshore wind are only slightly higher than the lowest fossil fuel-fired cost option, while solar PV has fallen to around USD 0.08/kWh and is also increasingly competitive.

In 2016/2017, in the OECD countries, onshore wind was the cheapest renewable power generation option, with an average USD 0.065/kWh. Hydropower and bioenergy for power were on average only slightly more expensive, while solar PV was more expensive, but still well within the range of the LCOE of fossil fuel-fired electricity. In the rest of the world, a similar pattern exists,

6. *In 2017 IRENA collected project level cost data for fossil fuel-fired power stations in the G20 countries, as well as data on actual capacity factors, O&M costs, operational efficiency and fuel costs, this analysis is forthcoming and will be published in 2018.*

**Figure 2.11** Project LCOE ranges and weighted averages for China and India, OECD and rest of the world, 2016 and 2017

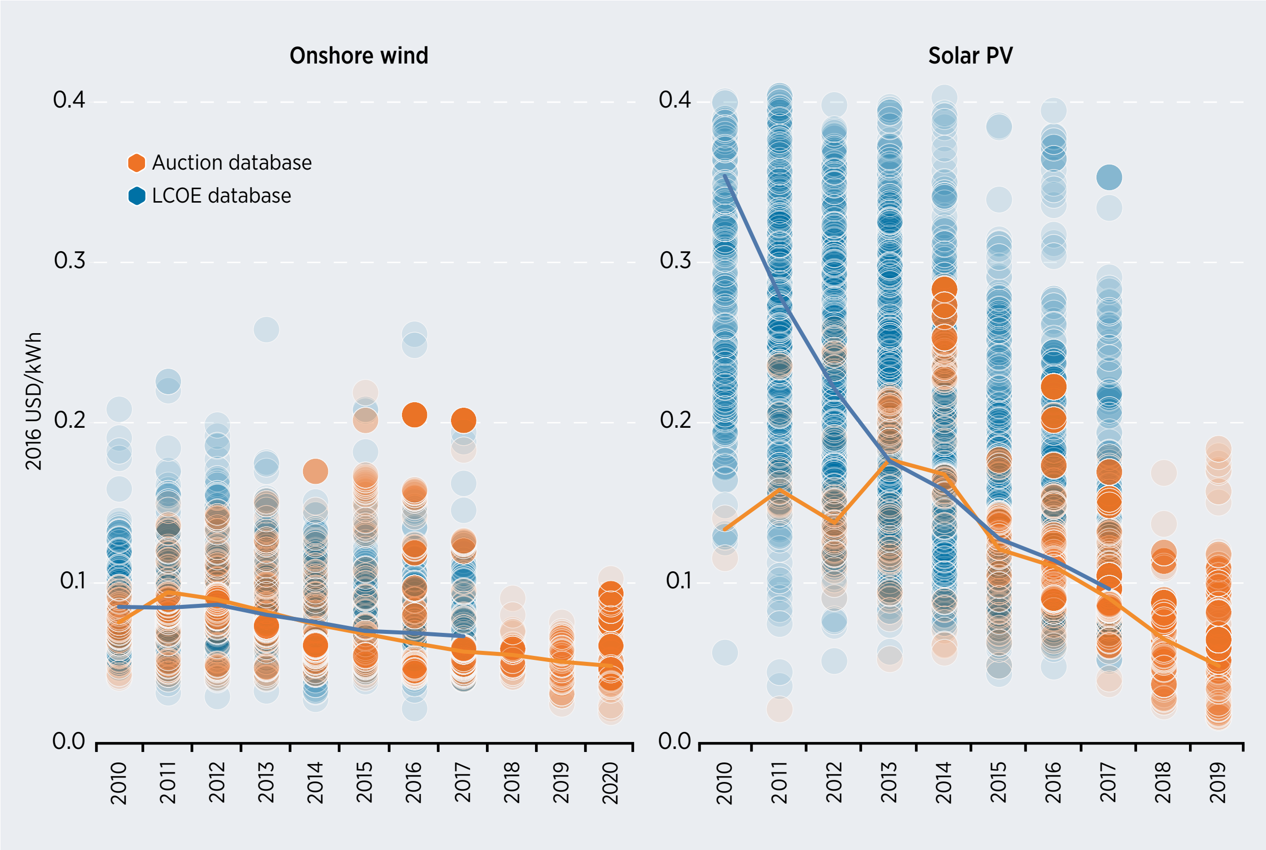



*Source: IRENA Renewable Cost Database.*

with very competitive weighted average LCOEs for bioenergy for power, geothermal, hydropower and, to a lesser extent, onshore wind. The weighted average solar PV LCOE remained close to the upper end of the fossil fuel-fired LCOE range.

Figure 2.12 highlights the continued cost reductions for onshore wind and solar PV that have been experienced. Since 2013, the weighted average LCOE trends from the IRENA Renewable Cost Database and Auctions Databases have followed a similar path and level. Given that competitive procurement represents a relatively small percentage (10-15%) of recently commissioned utility-scale onshore wind and solar PV (IEA PVPS, 2017), care should be taken in interpreting this close relationship. What is clear from the trend in auction results for projects that will be commissioned between 2018 and 2020 however, is that recent cost reductions identified from project-level data look set to continue at a steady pace. This presumes that the recent relationship between the two datasets is maintained over this period, although as can be seen, there are slight deviations in trends in individual years. Yet the direction of travel is clear. If current trends continue, in 2019 or 2020, the global weighted average LCOE for solar PV may fall to below USD 0.06/kWh, converging to slightly above that of onshore wind at USD 0.05/kWh.

**Figure 2.12** Global levelised cost of electricity and auction price trends for onshore wind and solar PV, 2010-2020




*Source: IRENA Renewable Cost Database and Auctions Database.*

*Note: Each circle represents an individual project or auction result, while the solid line is the capacity-weighted average from each database.*

There are a number of caveats to a comparison of LCOE results and auction prices, however. The two metrics are rarely equivalent and cannot necessarily be compared at an individual project level. The reasons for this are manifold. Firstly, it is rare that the auction or tender terms reflect the same assumptions for the calculation of an LCOE. The length of remuneration may not match the economic life of the asset. For instance, in the IRENA Auction Database, where contract length was disclosed, around 15% of the onshore wind and two-thirds of the solar PV projects had terms that matched the 25-year assumption IRENA uses for their economic life. Yet this is only a partial view, as 60% of the onshore wind projects in the Auction Database did not have their contract length disclosed with the announcement of the price (although this falls to 16% for solar PV projects). Another important issue is that the auction price may not be indexed to inflation, or may be partially indexed, meaning the price is not in real terms, as all IRENA LCOE calculations are. For 39% of the projects in the Auction Database, it was not clear from the announcements if the project was indexed or not. For onshore wind, where data was available, 80% of projects were fully indexed, but for solar PV, this dropped to 30%, with 70% appearing not to be indexed to inflation.

Other issues are that the remuneration may cover only a fraction of the project's output and the balance may be contracted bilaterally at an undisclosed value. The project may also benefit from free land under the auction and/or share O&M costs over a number of projects in a development zone. Another significant differentiator of prices can be if an existing (or to be built) grid connection is provided to the developer, or the developer is required to construct its own. This has a significant difference on the auction prices seen for offshore wind in Denmark and the Netherlands, where recent auctions included grid connections, while in the

United Kingdom, the project developer has to pay for this work. Although these issues are also present in project-level data from the IRENA Renewable Cost Database, they highlight the need to have large volumes of data to draw robust conclusions on trends and the dangers of comparing individual project without full knowledge of the terms and conditions under which it will be developed.

In addition, there are a number of auction design choices that can greatly affect the risk profile of a project. These can include whether the winners will be remunerated in local currency or USD, or if the offtake party has a government guarantee/ partial guarantee or not, amongst other factors. The final complication is that the LCOE calculation assumes a single value for WACC, effectively controlling for this variables impact on costs, while the auction price is explicitly dependent on the, unknown, WACC of the individual project and project developer.[7] This is an important point, as recent auction experience suggests that very low costs of capital are playing an important role in the most competitive auction results. Policies to reduce the perceived risks of project development are therefore an important part of the overall framework required to achieve very low costs.

Finally, there are other complications. In many instances, the full details of the auction or tender conditions are not publicly disclosed, making any judgement about the relative level of remuneration highly speculative. Sometimes "headline" prices announced do not represent the full remuneration to the project under the agreement. For instance, only the off-peak remuneration may be quoted, or additional capacity payments that are not remunerated by kWh may be left out.

There may also be additional sources of revenue available to the project that are not clear. In the recent Mexican auctions, for example, much has been made of the sub-USD 0.02/kWh results. Yet this excludes the value of the clean energy certificates that will be associated with the projects, with the value of these still unclear today.

Taking these limitations into account, though, it is clear that cost reductions will continue for onshore wind and solar PV out to 2020 and beyond. Even if the validity of comparing LCOE and auction prices for individual projects is often difficult or inadvisable, the volume of data available and the consistent trends between the two datasets suggest that its possible to feel some confidence in the overall trend.

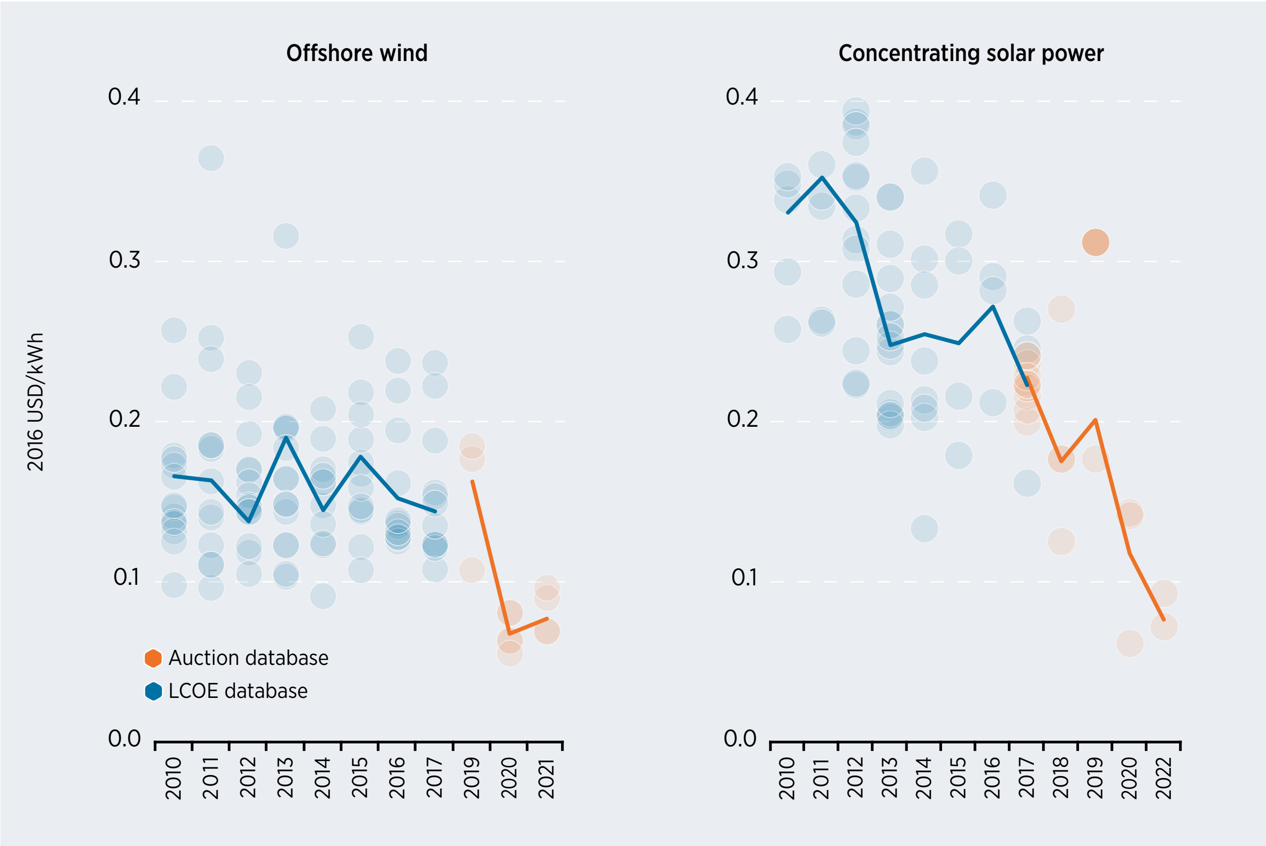
CSP and offshore wind had cumulative installed capacity of just 5 GW and 13 GW respectively at the end of 2016, while the cost of electricity from recently commissioned projects for these technologies is higher than for other renewable power generation technologies. Yet costs are coming down. For both technologies, 2016 and 2017 have been breakthrough years, as auction results around the world have confirmed that a step change in costs has been achieved. The estimated global weighted average offshore wind project LCOEs between 2010 and 2017 varied between USD 0.14 and USD 0.19/kWh (Figure 2.13). Auction results in 2016 and 2017 suggest, however, that projects commissioned from 2020 onwards will fall in the range USD 0.06 to USD 0.09/kWh, excluding grid connection costs, and USD 0.07 to USD 0.10/kWh, including grid connection costs.[8] The progression for CSP appears to be equally, if not more spectacular. Although the estimated weighted average LCOE of projects fell significantly between 2010 and 2017 for commissioned projects, they were still estimated to average USD 0.22/kWh in 2017 – albeit in a relatively thin year for deployment. The successful bidder for the recent Dubai auction heralded a new price paradigm, however, while Australia has also announced a highly competitive project in South Australia.[9] With slightly longer lead times for commissioning, notably for the 700 MW Dubai Electricity and Water Authority (DEWA) project, by 2022, CSP will be providing electricity in the USD 0.07/kWh range, while the South Australian Port Augusta project is expected to be online in 2020 and delivering electricity at a price of USD 0.06/kWh.

*7. This makes a project-by-project comparison of costs difficult, but also represents an opportunity. Future work by IRENA will look at trying to use auction data to identify WACC spreads in different markets based on auction results.*

*8. In some markets, offshore wind farm developments have been co-ordinated in zones, so as to share grid infrastructure which is provided by the grid operator. Such projects do not therefore include these costs in their bids. In other markets, however, notably the UK, this is not the case.*

*9. https://www.premier.sa.gov.au/index.php/jay-weatherill-news-releases/7896-port-augusta-solar-thermal-to-boost-competition-and-create-jobs*

**Figure 2.13** Global levelised cost of electricity and auction price trends for offshore wind and CSP from project and auction data, 2010-2020




*Source: IRENA Renewable Cost Database and Auctions Database.*

Thus, cost reductions for onshore wind, solar PV, offshore wind and CSP are continuing unabated. Despite the increasing maturity of the markets for onshore wind and solar PV, too, further cost reductions are being carved out. As a result, these technologies have significantly exceeded previous predictions for cost reduction. It is also worth highlighting just how wrong previous projections or assumptions have sometimes been. In 2017, the global weighted average installed cost of utility-scale solar PV was USD 1 388/kW. This was around 30% lower than the 2050 estimated value from the 2004 United States *Solar PV Industry Roadmap* and only slightly higher than the roadmap module only cost for 2030 (Moner-Girona, Kammen and Margolis, 2018). More recent estimates have also been exceeded, too, with the 2017 installed cost numbers already lower than the projected values for 2031-2035 made in the International Energy Agency's 2012 *World Energy Outlook* (IEA, 2012). This is not meant to denigrate the efforts of these publications, but to highlight just how much solar PV – and to a lesser extent onshore wind – have continuously exceeded expectations. Erring on the side of caution in terms of cost reduction potential can therefore be a major error.

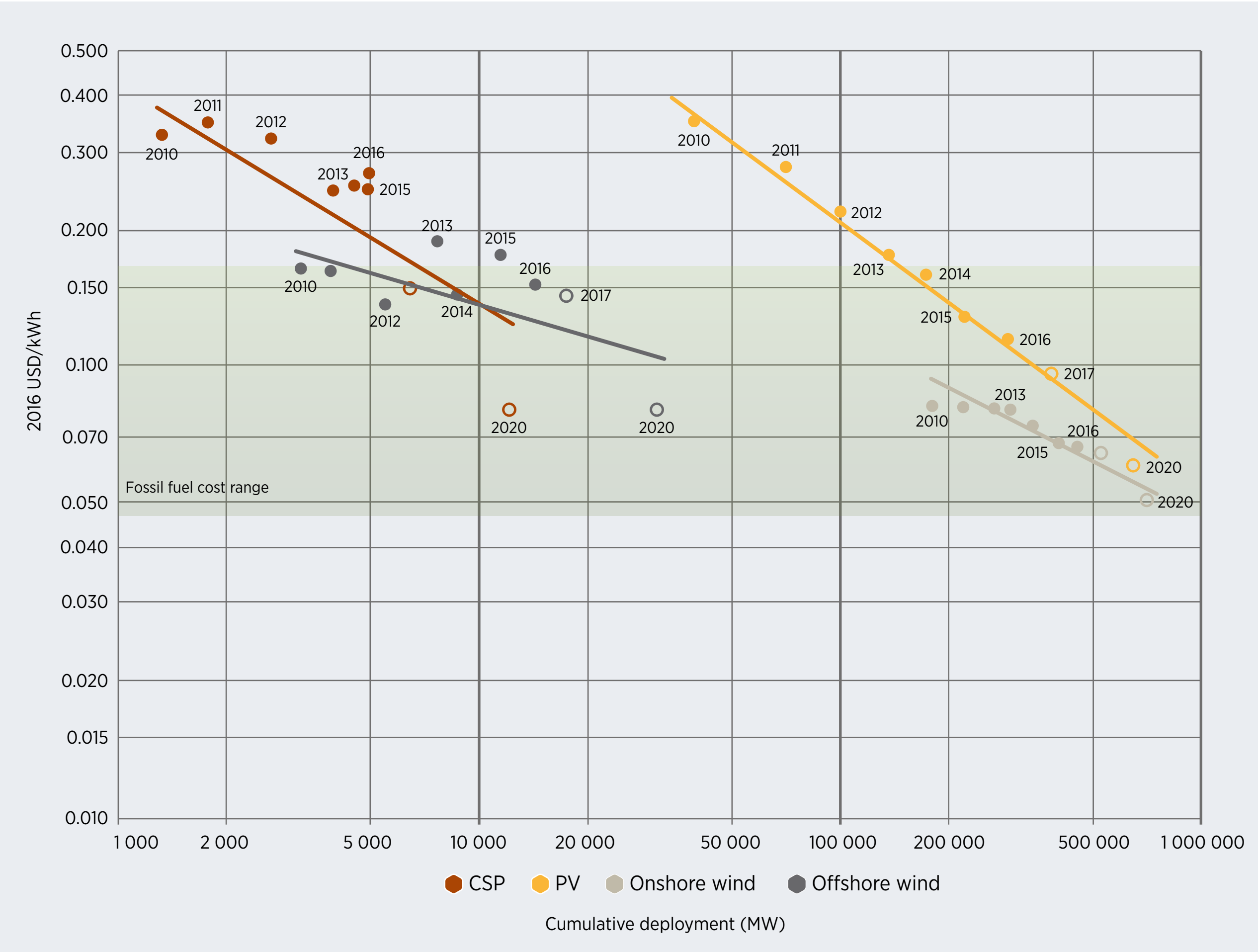
Indeed, solar and wind technologies highlight just how poor a guide conventional wisdom can be in estimating the continued capacity for technology improvement, industry efforts to improve manufacturing, the impact of competition on supply chains and the benefits of experienced project developers in driving down contingencies to wafer thin margins. This process is also beginning to play out in other areas of the energy transition – notably in electricity storage (IRENA, 2017c).

The cost declines experienced from 2010 to 2017 and signalled for 2020 thus represent a remarkable rate of change, and have enormous implications for the competitiveness of renewable power generation technologies.

Figure 2.14 plots the LCOE evolution of the four, main solar and wind technologies against cumulative installed capacity. A log-log scale is used to allow easy interpretation as learning curves. The learning rate for offshore wind (i.e. the LCOE reduction for every doubling in global cumulative installed capacity) is expected to reach 14% over the period 2010 to 2020, with new capacity additions over this period estimated to be 90% of the cumulative installed offshore wind capacity that would be deployed out to 2020.[10] For onshore wind, the learning rate for 2010-2020 is 21%, with new capacity added over this period covering an estimated 75% of cumulative installed capacity out to 2020. CSP has a higher learning rate of 30%, with deployment between 2010 and 2020 representing an estimated 89% of cumulative installed capacity in 2020.[11] Solar PV has the highest learning rate – 35% between 2010 and 2020 – with new capacity additions over this period that are estimated to be 94% of cumulative capacity in 2020.

Solar and wind power generation technologies have entered a phase of rapid scale up and increasing technological and industry maturity that in many ways mirrors the theory of industry lifecycles (Utterback and Abernathy, 1975). As

**Figure 2.14** Global weighted average CSP, solar PV, onshore and offshore wind project LCOE data to 2017 and auction price data to 2020, 2010-2020




*Based on IRENA Renewable Cost Database and Auctions Database; GWEC (2017), MAKE Consulting (2017a), SolarPower Europe (2017), and WindEurope (2017).*

*10. Global cumulative installed capacity of CSP is projected to be 12 GW by 2020, for offshore wind 31 GW, solar PV 650 GW and onshore wind 712 GW. This is based on IRENA (2017a), GWEC (2017), WindEurope (2017), SolarPower Europe (2017) and MAKE Consulting (2017a)*

*11. Extending the horizon to 2022 to take into account the likely commissioning of the DEWA project increases uncertainty over total deployment values, but would be unlikely to greatly alter the learning rate.*

such, rather than a focus on product differentiation, industry is increasingly having to focus on cost competitiveness. It is doing this by unlocking economies of scale and optimising manufacturing and delivery processes to ensure an optimised low-cost product that meets the full range of customer needs. It is also resulting a in a focus on improving the efficiency of the overall technology system (e.g., reducing PV module and inverter losses, wind availability focussing on MWh lost, not just downtime for O&M, etc.). This focus is facilitated by the highly modular and replicable nature of renewable power generation technologies.

This is not to imply that renewable energy technologies are simple or not continuing to evolve. The ongoing R&D efforts and sophistication of current solar PV panels, wind turbines, gearboxes, blade designs, control software etc. is undoubtable. The advantage comes from the completeness of the product as it leaves the factory, and the basic construction skills then required for installation. When combined with the volume of individual projects, renewable technologies represent technologies and processes that can benefit from standardisation, replicability and adaptability. The latter is important, once local technical specificities (e.g., cold or hot climate operation, typhoon strengthening, etc.), regulatory, legal and environmental processes are adapted to, then new markets can rapidly benefit from experienced project developers replicating projects.

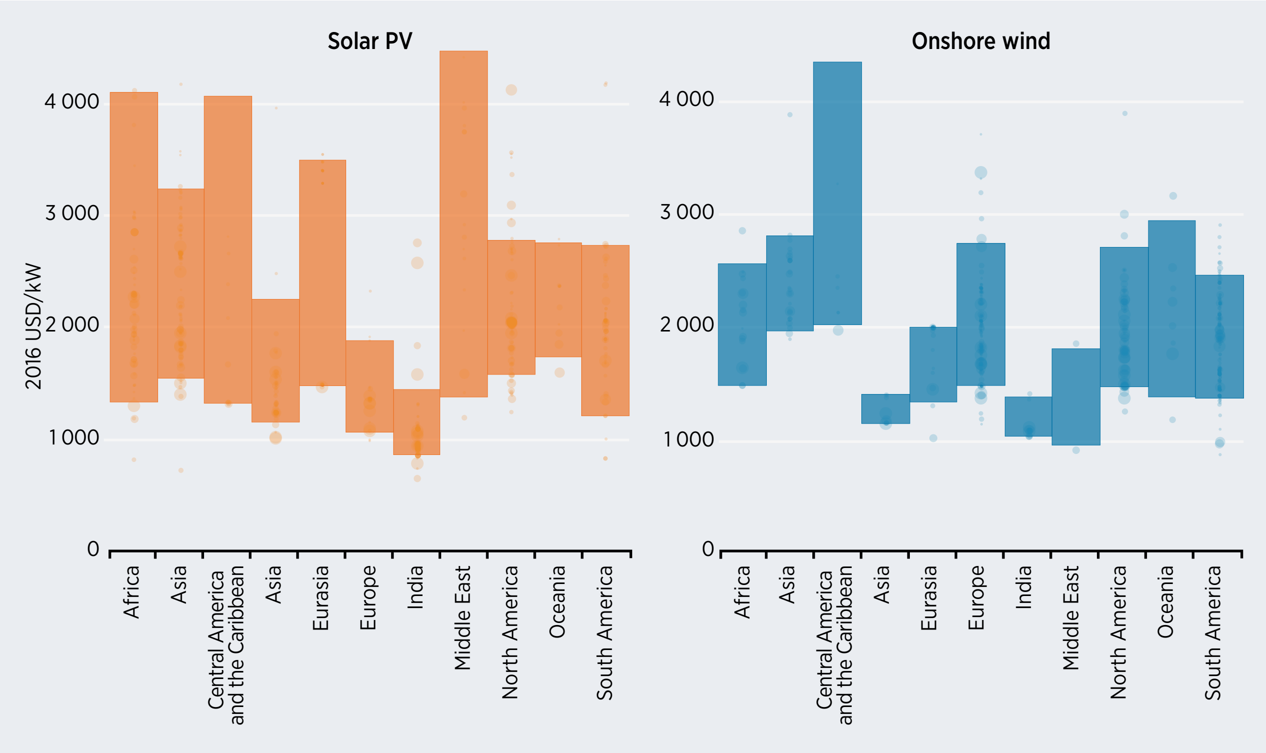
This has been evident in recent years, as solar and wind auctions in Mexico, Argentina, Saudi Arabia and elsewhere have seen very competitive results in countries without a significant history in deployment of solar or wind technologies. The open question is how long this period of rapid cost reduction will continue before the industry experiences a slowing in the rate of cost reductions. Given the relatively narrow deployment of the majority of solar and wind power capacity to date – relative to the global potential – there is no reason to think that there will be a slowing in the average rate of cost reduction at a global level in the short- to medium-term. There still remain important technology improvements that are already signalled by today's best-in-class projects and technologies, while ongoing R&D efforts will push those boundaries out even further. At the same time, for solar and wind, there still remain significant installed cost differences between countries. The convergence of installed costs towards best practice in many countries therefore still represents a significant cost reduction potential, in addition to the underlying competitive and technology drivers acting to drive down the costs of best-in-class projects.

Figure 2.15 highlights the 5th and 95th percentile ranges for the total installed costs of onshore wind and solar PV projects by region. There exist significant differences within regions, due to site specific factors, but also market maturity, while there are also significant differences between regions. For wind, China and India have different cost structures to the rest of the world. These are not easily replicable, given their lower labour, raw material and commodity costs and their access to cheap, local manufacturing hubs. However, that is not to say that individual projects in other regions can't achieve these installed costs, just that the average is likely to remain higher. For most of countries and regions, however, shifting towards best practice in terms of today's installed cost structures still represents one of the largest cost reduction opportunities available (IRENA, 2016a).

The trend of convergence towards best practice installed costs is already underway and is likely to continue in the period out to 2020 and beyond, given the current evidence from auctions and ongoing competitive pressures. What has been a remarkable trend in the successful bids from recent auctions has been the emergence of results in the USD 0.03 to USD 0.04/kWh range in Australia, Canada, Chile and Turkey and elsewhere, for both solar PV and onshore wind.

For onshore wind, recently commissioned projects havepreviously achieved these levels of LCOE and are part of the reason why the global weighed average has been declining. Yet these projects have typically been concentrated in locations with the best wind resources. What has been just as impressive, therefore, are the bids seen in more mature markets with significantly poorer wind

**Figure 2.15** Regional total installed cost ranges for onshore wind and solar PV, 2016/2017




*Source: IRENA Renewable Cost Database.*

resources. These include Germany and India, where projects have been bid in the range around USD 0.04 to USD 0.05/kWh.

Solar PV is not being left behind in trend towards very low electricity costs. For 2018 and 2019, the auction results announced in 2016 and 2017 suggest that cost reductions are set to continue apace, as deployment starts to accelerate in regions with excellent solar resources. The series of world record low successful bids in 2016 and 2017 for solar PV capacity in Abu Dhabi, Chile, Dubai, Peru, Mexico and Saudi Arabia has shown that very low solar PV costs are possible, particularly where there are excellent resources, strong local civil engineering sectors, a regulatory and policy structure that inspires confidence in the stability of a project's cashflows, and there is access to low cost finance.

This latter point is extremely important in achieving very competitive solar PV, even with low capital costs and excellent resources. Having the right regulatory and policy framework, low offtake risk, exchange rate risk and country risk are all essential to unlocking low cost finance. Governments can go a long way in ensuring these factors come together, but in some cases they will need the aid of development partners. One example of this is Zambia, where the clear benefits unlocked from the World Bank's "Scaling Solar" programme reduced country risk, offtake risk and exchange rate risk allowing a successful bid around half that of results in a neighbouring country.[12]

Elsewhere, the recent auction in Mexico has potentially seen values of around USD 0.02/kWh being locked in for solar PV and onshore wind, although these results are undoubtedly counting on additional revenue from the clean energy certificates that will accompany the project. Given current and likely near-term equipment costs, bids in the USD 0.02/kWh or lower range are extremely unlikely to represent an LCOE equivalent value, with additional revenue streams likely already factored in. This allows the headline price to be at

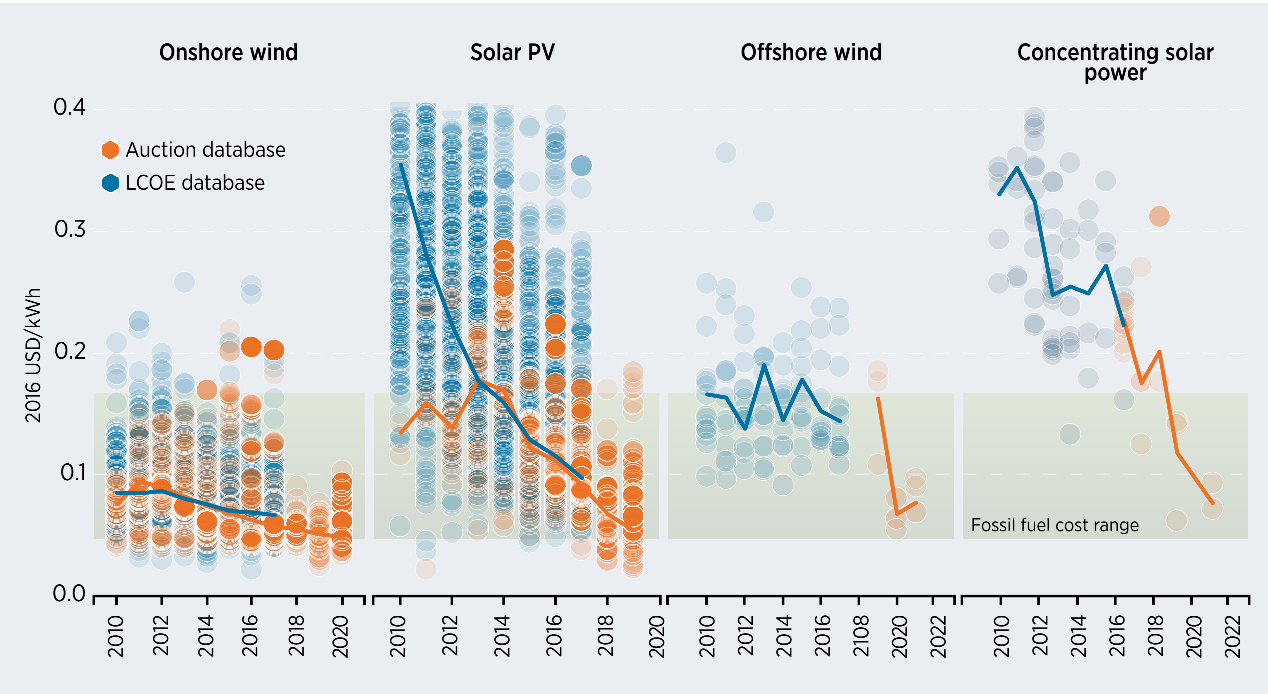
*12. For more details see: www.scalingsolar.org* a discount to what an LCOE, even with very low WACC, would look like.

Figure 2.16 presents the range of LCOE and auction price data from the IRENA Renewable Cost Database and Auction Database for onshore wind, solar PV, offshore wind and CSP for the period 2010-2021, as well as the weighted average trend for these sources and the fossil fuel-fired cost range. By 2019-2022, depending on the technology, solar and wind power generation technologies will not only be providing competitive electricity where new generation is needed, but individual projects will be increasingly providing some of the lowest cost electricity available, substantially undercutting fossil fuel-fired power generation LCOEs.

By 2019, the best onshore wind and solar PV projects that will be commissioned will be delivering electricity for an LCOE equivalent of USD 0.03/kWh or less, with CSP and offshore wind providing very competitive electricity from 2020 onwards. Today and increasingly in the future, many renewable power generation projects will be consistently undercutting fossil fuel-fired electricity generation, without financial support and despite the fact that fossil fuel projects do not pay for their full local and global environmental costs. The global average cost of electricity from onshore wind and solar PV will be flirting with the lowest cost value for fossil fuel-fired electricity, while CSP projects and offshore wind will be at the lower end of that cost range and offer competitive new generation capacity.

The outlook for solar and wind power electricity costs to 2020 presages historically low costs for new, renewable electricity. The overall average, but especially the very low electricity costs for the best solar PV and onshore wind projects represent a real paradigm shift in the competitiveness of renewables. Given these low costs, previously uneconomic strategies for the electricity and energy sector could become profitable. Curtailment – previously an unthinkable economic burden for renewables – may become a rational economic decision, maximising variable renewable penetration and minimising overall system costs.

**Figure 2.16** Global levelised cost of electricity and auction price trends for solar PV, CSP, onshore and offshore wind from project and auction data, 2010-2022



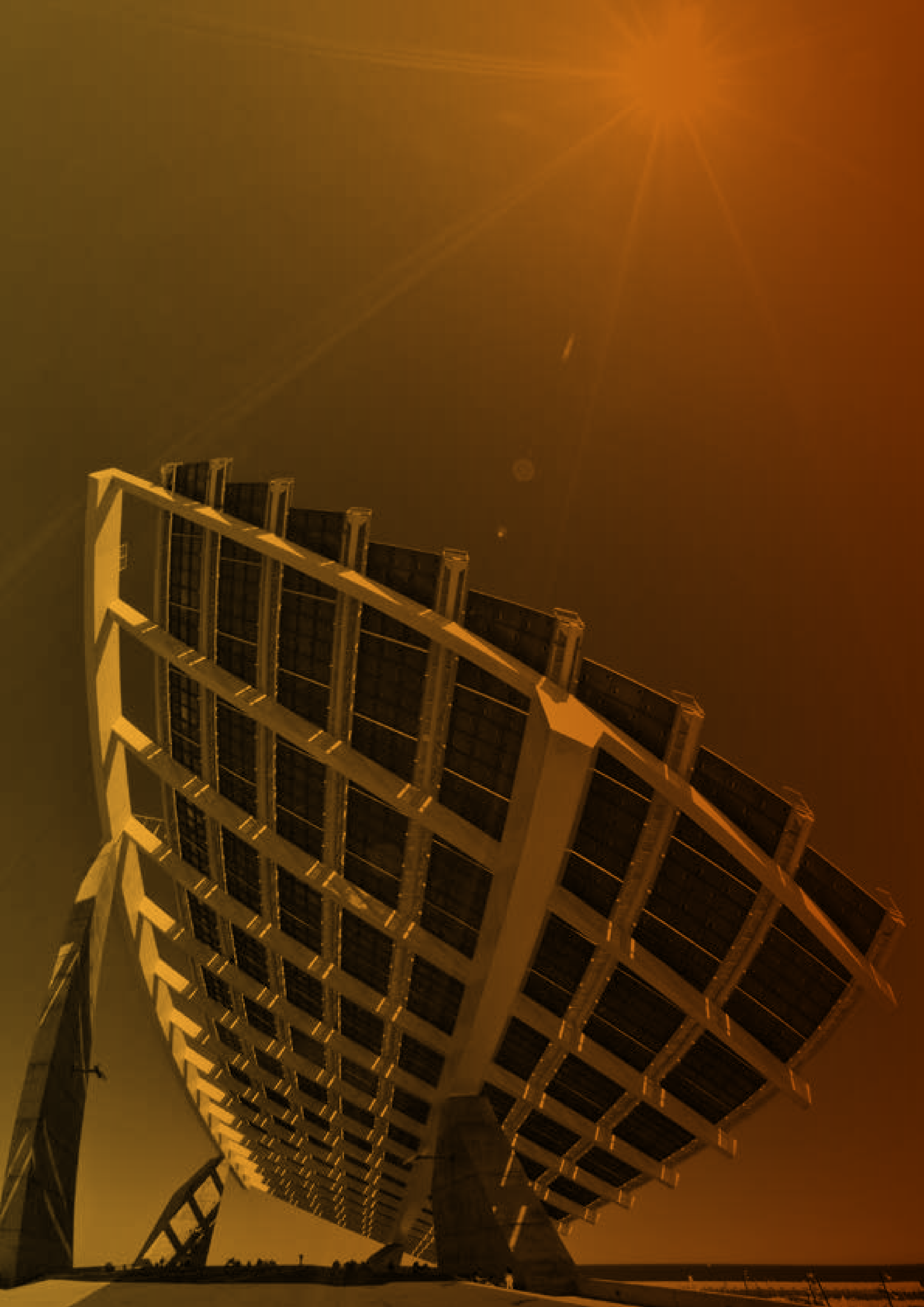

*Source: IRENA Renewable Cost Database and Auctions Database.*

Similarly, such low prices in areas with excellent solar and wind resources open up the economic potential of power-to-X technologies (e.g., power to hydrogen or ammonia, or other energy dense, storable mediums). At the same time, these low prices make the economics of electricity storage more favourable, potentially turning a drawback of electric vehicles (EVs) – their potentially high instantaneous power demand for recharging – into an asset, as EVs can take advantage of cheap renewable power when it is available and potentially feed electricity back into the grid if needed later on. This, however, has to be balanced by the increased costs of integrating variable renewables and the increased flexibility required to manage systems with high Variable Renewable Energy (VRE) – although noting that low costs help make that challenge less costly. To date, these integration costs have remained modest, but they will rise as very high shares of VRE are reached (IRENA, 2017f).

There is a clear pattern to the evolution of the cost of electricity from solar and wind power technologies. It is a template that has been driven by support policies that have unlocked technology improvements and cost reductions and has resulted in a virtuous cycle. As market deployment has grown, economies of scale have followed. More competitive supply chains and improvements in manufacturing processes have come as the markets for these technologies have been industrialised. Onshore wind and solar PV have both benefitted from this process of industrialisation, and now offshore wind and CSP are benefitting from the same development. Industrialisation has been facilitated, too, by the relative simplicity of the components, their modularity, scalability and the replicability of the construction and installation processes. This is in stark contrast with the norm for large civil engineering projects today, where cost overruns and time delays are common (Adam et.al; 2017).

As a result, the LCOE of electricity from onshore wind, offshore wind, solar PV and CSP are now converging on very competitive levels. By 2020-2022, the LCOE of electricity from solar and wind technologies will fall solidly within the range of USD 0.03 to USD 0.10/kWh. There will, however, be a range of projects that fall outside this range. Recent auction results have already signaled that there could be projects that, in future, fall below this range. At the same time, a range of projects in new markets or challenging development environments, such as in remote locations or on islands, will continue to fall above this range.

There is a lesson here for the rest of the energy sector's transformation, too. With the right policy and regulatory settings, renewable technologies can scale to provide cost-effective solutions to countries energy, environmental, economic and social goals. Crucially, once sufficient momentum in the sector is achieved, they will often exceed expectations as industrialisation and scale effects begin to take hold. Yesterday's insurmountable challenges, in terms of cost competitiveness, are falling by the wayside and there is a template in this for addressing tomorrow's challenges. The lesson of the last 10 years from solar and wind technologies is clear: a long-term vision, with the right support policies and regulatory frameworks, can allow industry to scale, competition to play its part and the right technology solutions to be brought to market faster and cheaper than conventional wisdom suggests is possible.



# 3. SOLAR PHOTOVOLTAICS

The global PV market has grown rapidly in the last decade. Cumulative global installed PV capacity grew from 6.1 GW at the end of 2006 to 291 GW at the end of 2016 (IRENA, 2017a). From 2010 to 2016, net additions grew about 28% annually on average and additions in the time period account for about 94% of the total capacity that was installed between 2006 and 2016 (Figure 3.1).

Recent growth in the Asian PV market has more than compensated for the decrease in new capacity additions in Europe in recent years, as growth in China and Japan has increased. These countries together installed about 88 GW between 2014 and 2016 alone. At the end of 2016, China was home to 27% of cumulative installed capacity globally. Growth in other regions has also continued. For example, through steady growth in recent years, the United States has become a large PV market with 11% of the global cumulative installed capacity at the end of 2016.

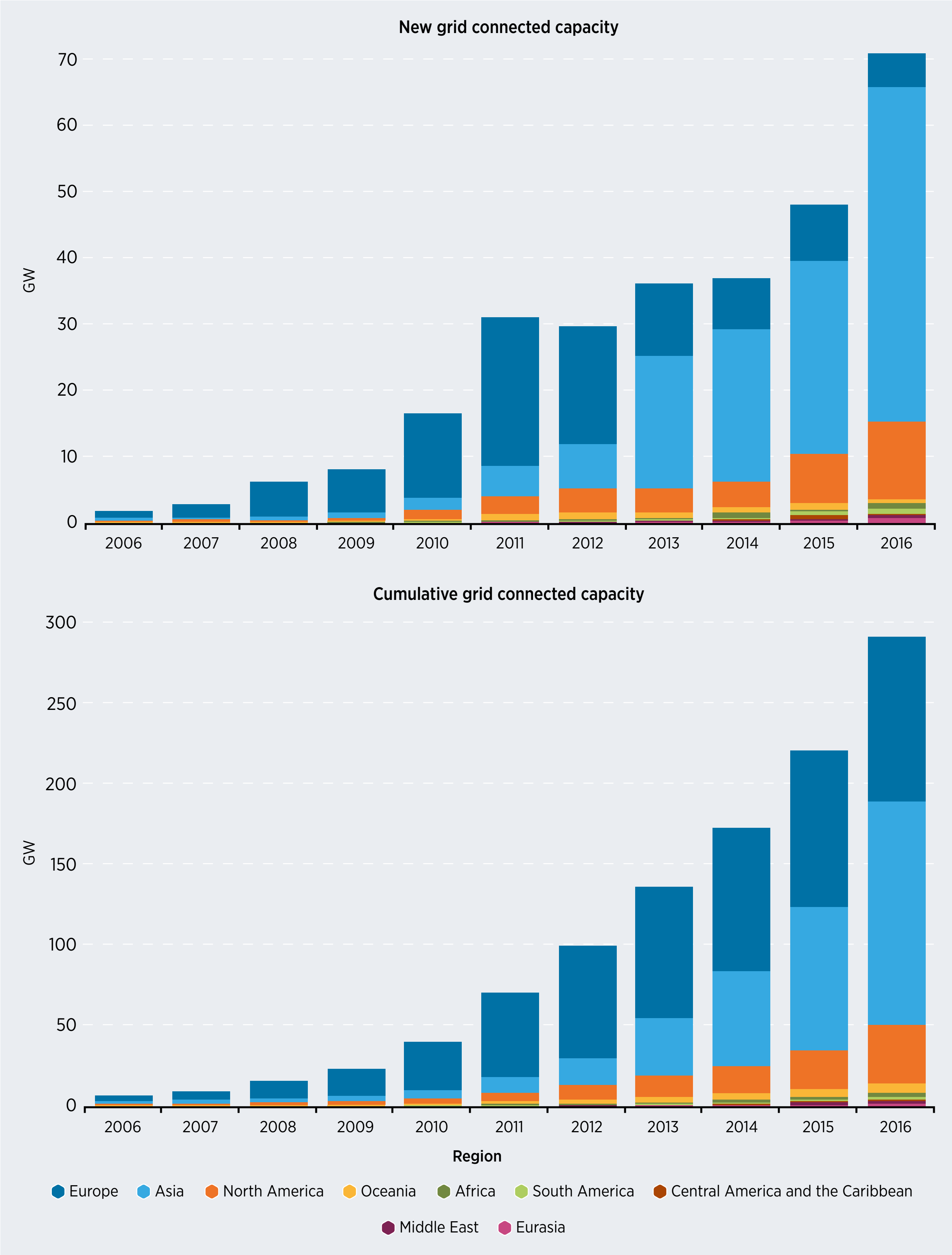
Yearly installations in Europe have declined since their highest historical value of 22 GW of new capacity additions in 2011. In both 2014 and 2015, new additions did not exceed 8 GW, and in 2016 5 GW were installed in the region. Europe's share of total global cumulative capacity declined from around three quarters over the period 2009 to 2011, to 44% in 2015. This was the last year when Europe held the leading position in respect to cumulative capacity. In 2016, this share decreased to 35%.

The bulk of PV production capacity continues to be situated in Asia, where China is the world leader in PV production. China and Japan together accounted for around 70% of global module production in both 2015 and 2016. Manufacturing capacity and production is also growing in other countries in the Asia-Pacific & Central Asia regions and countries in these regions accounted for about a tenth of the modules produced globally in 2016 (Fraunhofer ISE, 2016, 2017). First and second-generation technologies[1] account for virtually all production, while crystalline silicon-based photovoltaics currently continues to dominate the market (Figure 3.2). Crystalline silicon module production accounted for about 94% of production during 2016, up from 93% in 2015. (Fraunhofer ISE, 2016, 2017; GlobalData, 2017).

In the last decade, crystalline silicon wafer based commercial module average efficiencies have increased from about 12% to a range of 17% to 17.5%. Best performing modules in the laboratory can currently reach up to 24.4% efficiency. Current crystalline module efficiencies are typically at least 2% lower than efficiencies at the cell level due to losses caused by various factors such as: the module border, cell spacing, cover reflection and cell interconnection. However, cell and module efficiencies are intrinsically linked and current developments in best cell efficiency levels suggest that continued improvements in the average efficiency of modules will continue for the

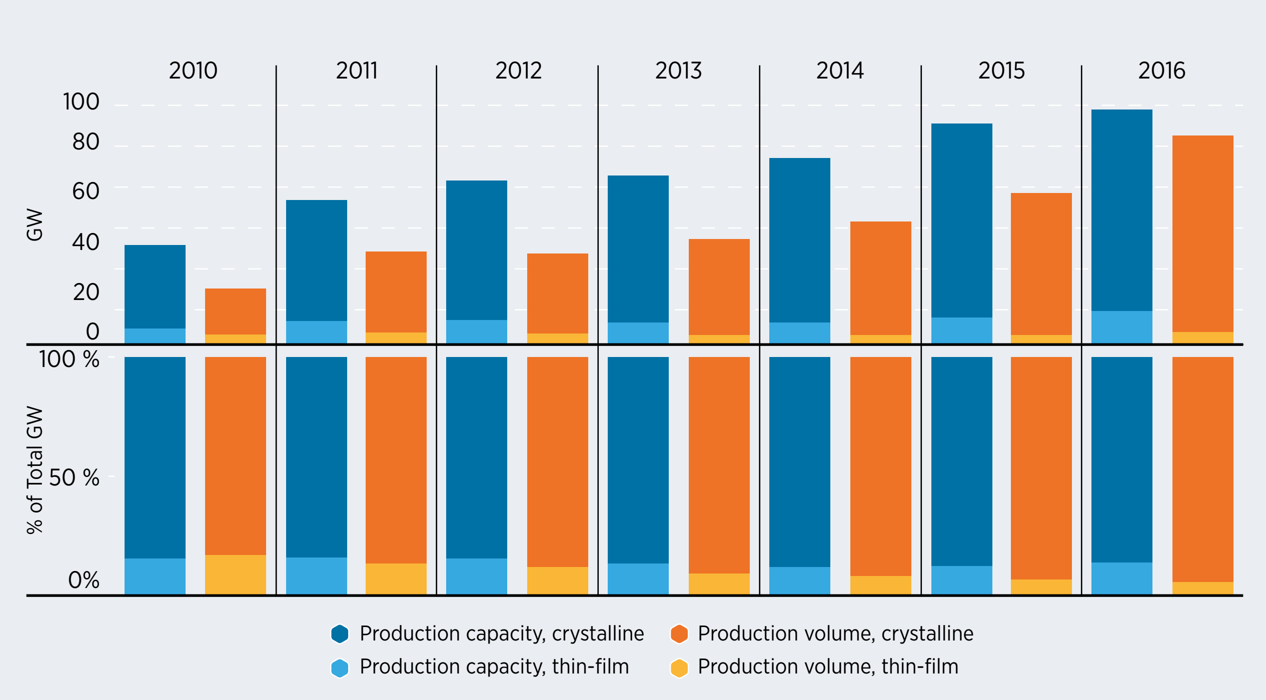
*1. A more detailed discussion of this solar PV technology categorisation can be found in IRENA, 2016a.*

**Figure 3.1** Yearly added and cumulative global PV capacity by region, 2006-2016




*Source: IRENA, 2017a.*

**Figure 3.2** Solar PV module production: Capacity and volume by technology, 2010-2016




*Based on GlobalData, 2017 and Fraunhofer ISE, 2016, 2017.*

foreseeable future. For instance, by 2024, industry expectations place the range of stabilised cell efficiency for mass production of crystalline silicon based cells at 19.8-25% depending on cell type and architecture up from a current range of 18.8-23.5% (ITRPV, 2017; Fraunhofer ISE, 2017).

The two most deployed thin-film technologies are Cadmium-Telluride (CdTe) and Copper-Indium-Gallium-Selenide (CIGS). First Solar (the largest CdTe manufacturer) reported fleet average efficiencies increasing from 12.9% in 2012 to 16.6% in 2016 for their CdTe modules (First Solar, 2017). For CdTe cells, module efficiency record for the moment is 18.6%. The best CIGS reported efficiencies so far were 17.5% for modules (Green et al., 2017). Solar Frontier reports current CIGS module efficiencies between 12.2%-13.8% for their CIGS modules (Solar Frontier, 2017).

## 3.1 INSTALLED COST TRENDS

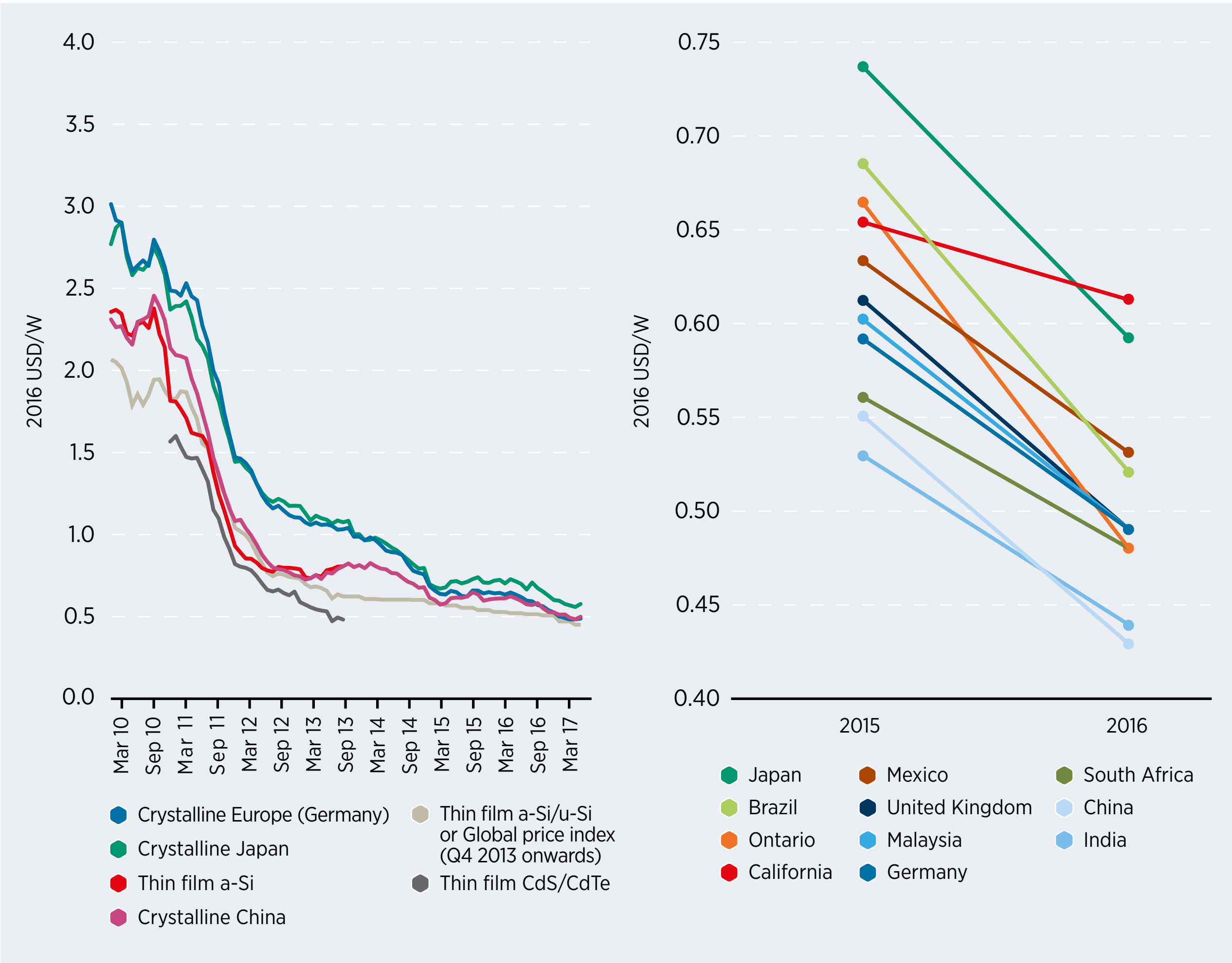
### Recent module costs trends

Solar PV module prices in Europe decreased by 83% from the end of Q1 2010 to the end of Q1 2017 (Figure 3.3). Module costs declined 80% between the end of 2010 and the end of 2016, a period over which 87% of the cumulative global PV capacity installed at the end of 2016 occurred. Solar PV module costs fell rapidly until 2013, but have experienced more modest cost reductions in recent years as PV module manufacturers made efforts to return profit margins to more sustainable levels and various trade disputes affected minimum prices in different markets. Average monthly solar PV module prices in Europe in 2016, were 13% lower than in 2015, while the decline in average prices across a range of markets (right side of Figure 3.3) was 18% between 2015 and 2016. As a result of import treatment and individual market preferences for particular module types, there are a wide range of module prices depending on the market. Figure 3.3 highlights that although PV modules are relatively homogeneous technologies, they are not entirely interchangeable commodities. In 2016, average selling prices in China were around USD 0.43/W, while California became one of the highest priced major markets with prices of USD 0.61/W, though all analysed markets experienced a decreasing cost trend between 2015-2016. These are average values and a range of prices around these values occur. In 2017, module prices have dipped as low as USD 0.3/W, but are somewhat higher for modules from Chinese majors and good quality modules can now be produced sustainably for USD 0.4/W or less (Exawatt, 2017).

Rather than being driven primarily by substantial capacity and deployment upsurge and their associated economies of scale, recent and near future module cost reductions relate more closely to improvements in the production processes and to efficiency gains associated with increased adoption of newer cell designs (although the growth in cumulative deployment and manufacturing scale still plays a role in achieving low costs).

On the processing side, previous IRENA work has reported on the growing market presence of the diamond wafer cutting method (IRENA, 2016a). Diamond wire sawing provides opportunities to reduce costs through reduction of material losses during slicing. During 2016, these costs were about a fifth lower than for the traditional method.[2] Since 2016, this wafer slicing technique is already prevalent in the monocrystalline segment, and by the end of 2017 90%+ of monocrystalline wafers worldwide will be being cut with this method and around half of multicrystalline (Exawatt, 2017). This occurred

**Figure 3.3** Average monthly European solar PV module prices by module technology and manufacturer, March 2010—May 2017 (left) and average yearly module prices by market in 2015 and 2016 (right)




*Source: GlobalData, 2017; pvXchange, 2017; Photon Consulting, 2017.*

*2. In the longer term, the advantage may be greater and by 2027, industry expects diamond slicing technology's kerf losses to decline to 60 µm, compared to 120 µm for slurry (ITRPV, 2017).*

as manufacturers transitioned from the traditional method involving abrasive powdered silicon carbide slurries. Industry announcements confirm a trend towards higher shares of diamond wafer slicing technology use in the multi-crystalline segment as well, as this has the potential to lower silicon consumption (ITRPV, 2017; Bernreuter Research, 2017; GCL-Poly, 2017; CanadianSolar, 2016).

At the same time, effective texturing processes are necessary for diamond wire sliced cells. This is in order to avoid issues with high surface texture reflectivity – which can affect cell performance – resulting from the slicing process. In this respect, there is a trend towards increased use of 'black silicon' in wafer texturing as an anti-reflection measure for solar cells and in combination with diamond wire slicing processes. The term 'black silicon' refers to a silicon surface which has been covered with a nanostructured surface layer in order to boost its light absorption properties (Liu et al., 2014).

Various approaches to black silicon fabrication are available. For example, metal assisted chemical etching methods are able to provide an efficient way of producing high efficiency 'black' multi-crystalline cells (Ying et al., 2016). Other etching methods, such as the reactive ion etching method (Shim et al., 2012), are also being researched and used for this purpose. While industry opinion seems divided regarding the most adequate etching method, several multi-crystalline industry players have placed their attention on black silicon technologies in an effort to improve the cost performance ratio of multi-crystalline wafers cut with diamond wires (EnergyTrend, 2017). Newer etching-texturing technologies are therefore expected to continue to gain market share over traditional, standard acidic etching methods.

In terms of the uptake of novel cell designs, there is a trend towards increased adoption of both multi- and mono-passivated emitter rear (PERC) cell architectures (IRENA, 2016a). Such a trend, alongside a shift towards a more widespread use of black silicon, is allowing multi-crystalline cells to move into the higher efficiency segment, has been confirmed. While the definitive technology path remains uncertain, wider adoption of diamond wire cut multi-crystalline wafers based on black silicon, as well as an increasing market share taken by PERC cells and their associated cost reductions are to be expected (pv magazine, 2017).

With the cell architecture shifting towards PERC cells, makers are also developing technologies to address the light-induced degradation (LID) problem which affects them. On the mono-crystalline side, LONGi Solar is developing a Light-Induced Regeneration (LIR) technology, jointly developed with the University of New South Wales. LONGi Solar claims that by controlling the degradation through the LIR technology, the energy yield at the PV plant level can be enhanced by 1%. The company has also announced that it is willing to open-up this technology to industry. (LONGi Solar, 2017). If realised, this step could have important implications for the race in cell architecture technology, given the leading market presence of the company. Though LID is a well-known issue for mono-crystalline wafer cells, it also affects multi-crystalline cells and PERC cells. Research and industry efforts are underway to better understand this phenomenon and to minimise the performance losses associated with this (Luka et al., 2016; Kraus et al., 2016; Padmanabhan et al., 2016).

With recent and expected cost and performance developments, a definitive PV module technology strategy remains difficult to predict. What is certain is that competitive pressures in the PV module market will remain intense, with technology innovations crucial to module manufacturers ability to remain profitable in a rapidly evolving market.

### Total installed costs

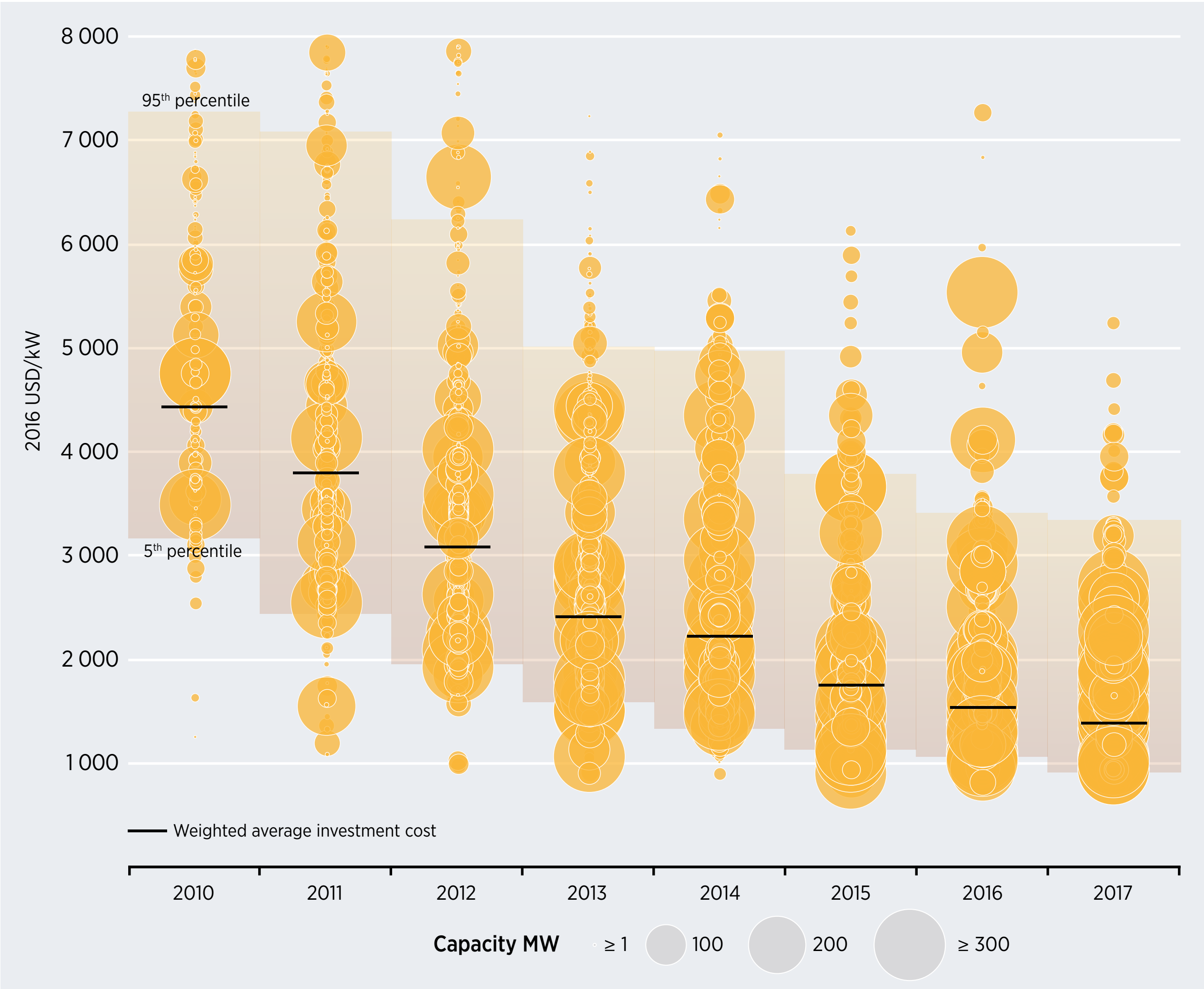
Though solar PV technology has matured and more and more countries are starting to deploy solar PV at scale, regional cost differences persist. Different domestic market maturity levels (as, for example, evidenced in project developer's experience), as well as differences in local labour and manufacturing costs and different support policy structures can all influence competitiveness. Some detailed research comparing individual markets has been published (Seel et al., 2014; Friedman et al., 2014; Kimura and Zissler, 2016; Strupeit, 2016), yet much more research of this nature would benefit the understanding of why cost differentials persist and how they might be most effectively reduced to best practice levels. In addition, on-going research on the topic is necessary, since gaining a deep understanding of the reasons behind the cost differences in the different markets can be extremely valuable in informing policy making for cost reduction targeting.

As balance of system (BoS)[3] costs, discussed in more detail in Annex I, contribute more and more to total system cost reductions, adopting policies that can bring down soft costs provides the opportunity to improve cost structures towards best practice levels. Examples of such policies include reducing the administrative hurdles associated with gaining permits or incentives, or those that slow connection application processes.

Between 2010 and 2017, the global capacity weighted average total installed cost of newly commissioned utility-scale PV projects decreased by 68%, with a 10% decrease in 2017 from 2016 levels (Figure 3.4). Projects in newer markets are being developed at costs that are increasingly at par, and sometimes even cheaper than the averages in more cost mature markets.

Rapid installed cost declines in China, Japan and the United States – and the rapid emergence of an increasing number of cost competitive projects in

**Figure 3.4** Total installed costs for utility-scale solar PV projects and the global weighted average, 2010-2017




*Source: IRENA Renewable Cost Database.*

*3. Balance of system costs in this chapter do not include inverter costs, which are treated separately.*

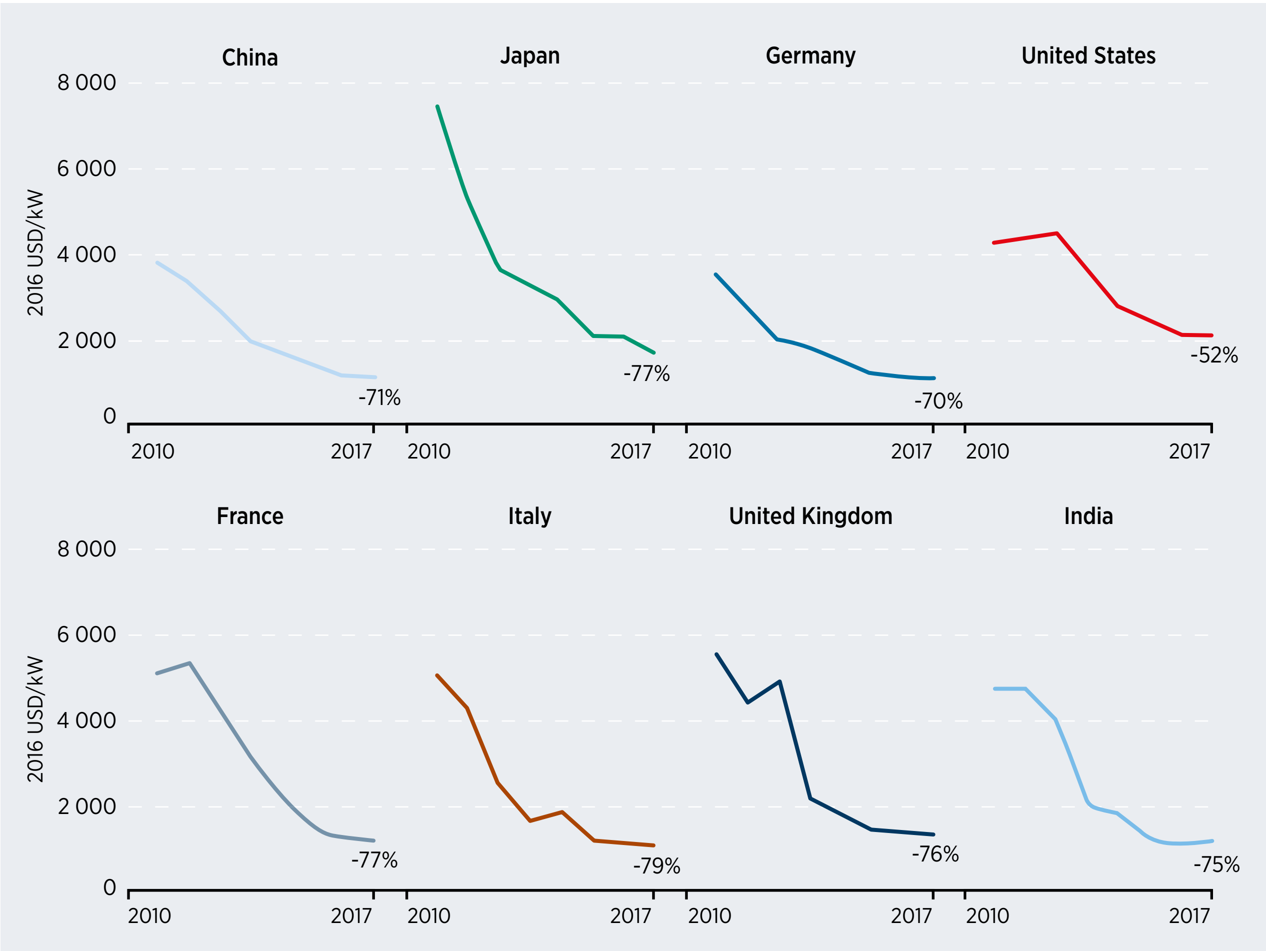
India (often at best-in-class cost levels), as well as in the newer markets – have been the main driver in the increasing competitiveness of utility-scale PV. During the period 2010 to 2017, utility-scale total installed cost reductions in many markets have exceeded 70% (Figure 3.5). Between 2010 and 2017, the United States saw utility-scale total installed costs reduce the least, at 52%, with Italy experiencing the largest reduction of 79%.

Despite the generalised reduction in installed costs across all markets, significant cost differentials between markets remain. Using China as a base for an index, Figure 3.6 shows that for a range of countries, the cost differentials compared to China have been declining. Cost differences among markets are expected to continue to decline, as the least mature markets gain more experience during their growth (IRENA, 2015). With greater competitive pressures, markets in Australia, Chile, France, Jordan and the United Kingdom have all seen rapid installed cost reductions that have reduced the differential from China in the period 2015 to 2016.

During 2016, the percentage difference of total installed costs for utility-scale systems compared to Chinese levels ranged between -6% and 77%. This is a significantly narrower span than in 2015, when they ranged between 10% and 136% above the Chinese level.

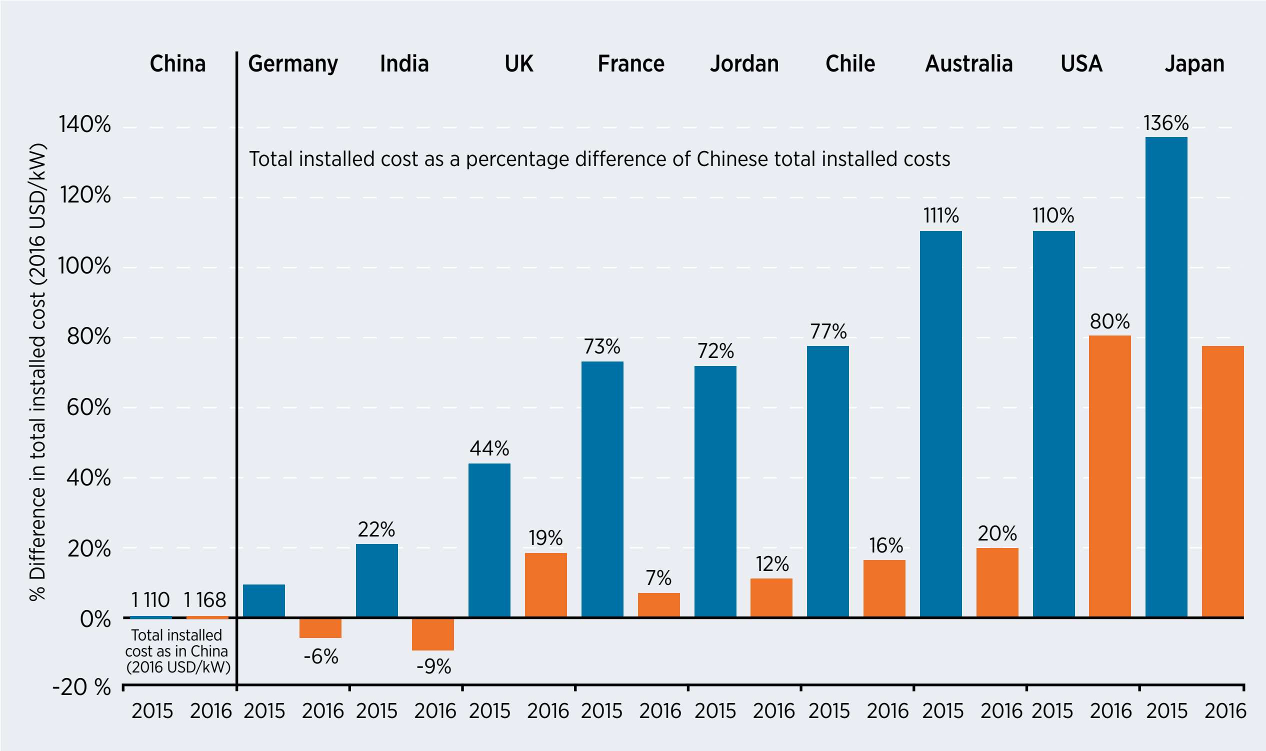
Figure 3.7 highlights the major reasons for these cost differentials by providing a detailed breakdown of utility-scale total installed costs by country in 2016. The markets that significantly reduced the differential over Chinese installed costs did so by driving down BoS costs towards more competitive

**Figure 3.5** Utility-scale solar PV total installed cost trends in selected countries, 2010-2017




*Source: IRENA Renewable Cost Database.*

**Figure 3.6** Estimated utility-scale solar PV system costs: China compared to other countries, 2015-2016




*Source: IRENA Renewable Cost Database.*

levels. Countries with competitive installed cost levels have, on average, balance of system costs (excluding the inverter) that make up about half of the total installed cost. Soft cost categories for the displayed countries make up a third of these BoS costs, and about 17%, on average, of the total installed costs.

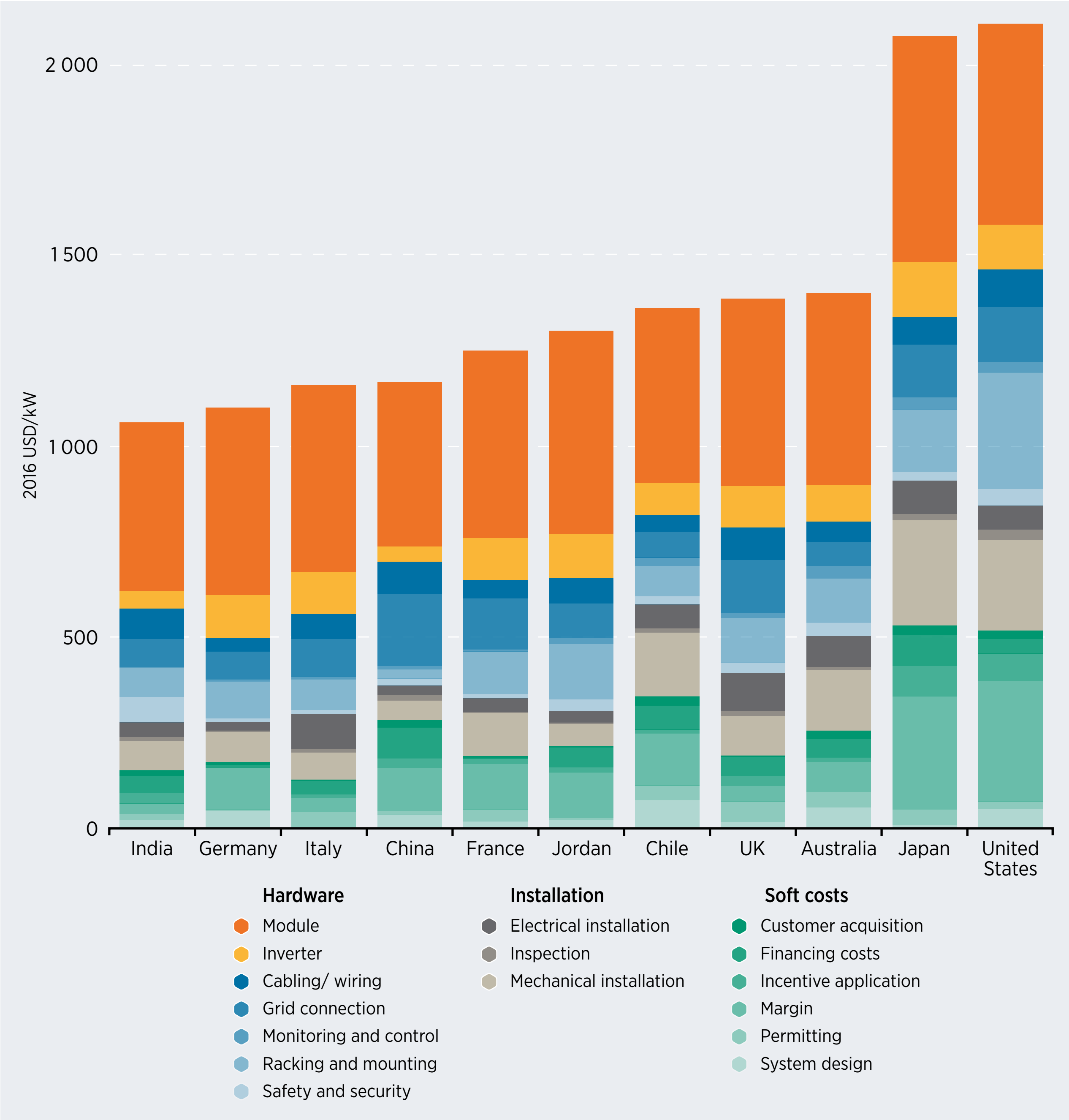
Residential PV system total installed costs have also declined sharply in a wide range of countries since 2010. The range of residential solar PV total system costs in the markets with the longest historical data shown in Figure 3.8 decreased from between USD 6 700 USD and USD 11 100/kW in Q2 2007 to between USD 1 050 and USD 4 550/kW in Q1 2017 (a decline of 47-78%). Since 2013, with the broadening of the residential solar PV market, more data has become available for a much wider selection of markets. For this wide range of emerging and OECD economy markets, the total installed costs of residential PV systems fell by between 18-66% between Q2 2013 and Q1 2017, but with a wide span of installed cost levels between markets. California has become the most expensive residential solar PV market for which IRENA has data, with total installed costs of USD 4 550/kW in Q1 2017, more than three times higher than India and double the costs in Germany.

## 3.2 CAPACITY FACTORS

The global weighted average capacity factor[4] of utility-scale PV systems increased by 28% between 2010 and 2017, from an average of 13.7% to 17.6%. This has been driven by three major factors, the trend towards greater deployment in regions with higher irradiation levels, the increased use of tracking and improvements in the performance of systems as losses have been reduced (e.g., though improvements in inverter efficiency). Data from the United States, for instance, highlights the increased use of trackers, with these making up 39% of new capacity additions in 2014, 70% in 2015 and 79% in 2016 (Bolinger and Seel, 2016 and Bolinger et al., 2017).

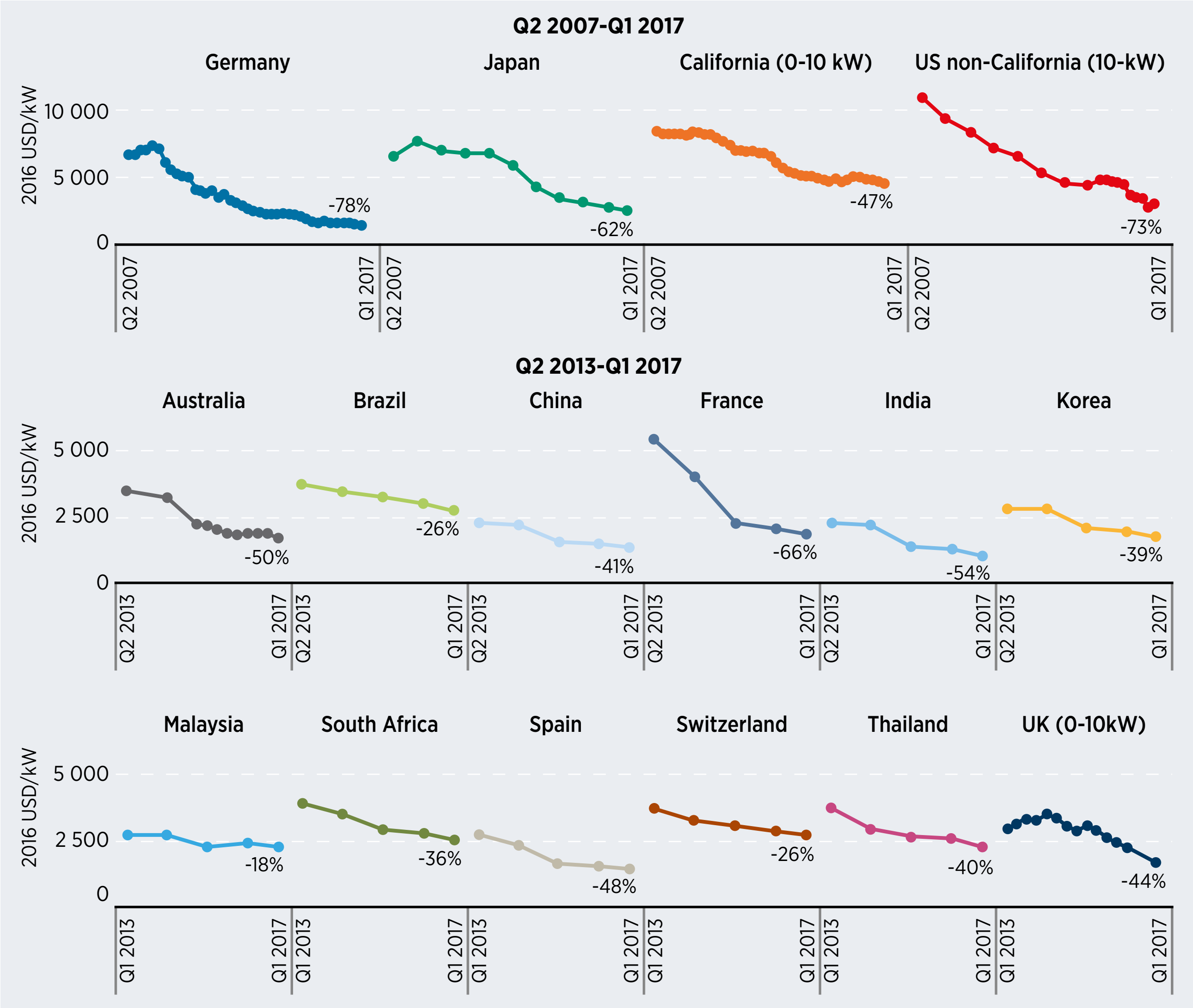
*4. The capacity factor for PV in this chapter is reported as an AC/DC value. For other technologies in this report, the capacity factors are expressed in AC-to-AC terms. More detailed explanations on this can be found in Bolinger and Weaver, 2014; Bolinger et al., 2015.*

**Figure 3.7** Detailed breakdown of utility-scale solar PV costs by country, 2016




*Source: IRENA Renewable Cost Database.*

**Figure 3.8** Average total installed costs of residential solar PV systems by country, Q2 2007-Q1 2017




*Source: IRENA Renewable Cost Database.*

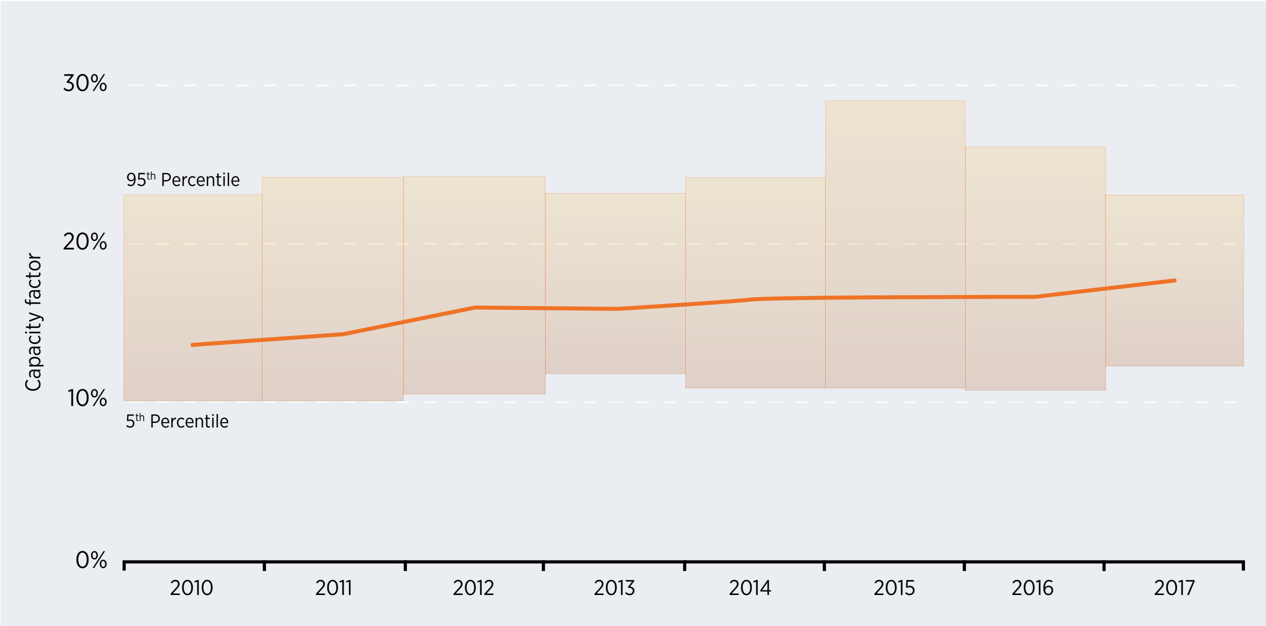
This increase in global weighted average utility-scale solar PV capacity factors is despite the trend in some markets towards higher inverter load ratios (ILR)[5]. This ratio of DC module capacity to AC inverter capacity (also known as DC/AC ratio) is a project design consideration and raising it can reduce the LCOE in some contexts (Good and Johnson, 2016). All things being equal, increasing the ILR reduces the AC/DC capacity factor. In the United States, for example, the capacity weighted average ILR of utility-scale projects increased 9% between 2010 and 2016 to a value of 1.31 (Bolinger et al., 2017; Fiorelli and Zuercher-Martinson, 2013). Globally, the trend towards more PV projects being developed in higher irradiation regions and the increased use of tracking seem to be driving increases in the global weighted average capacity factor, offsetting any reductions caused by increasing ILRs in recent years (Figure 3.9).

## 3.3 OPERATION AND MAINTENANCE COSTS

Historically, solar PVs O&M costs have not been considered a major challenge to their economics. Yet, with the rapid fall in solar PV module and installed costs over the last five years, the share of O&M costs in the LCOE of solar PV in some markets has climbed significantly.

5. *The Inverter Load Ratio (or DC/AC ratio) describes the ratio of a module array's DC rated output and the inverters size expressed in AC power terms.*

**Figure 3.9** Global weighted average capacity factors for utility-scale PV systems, 2010-2016




*Source: IRENA Renewable Cost Database.*

O&M costs in some OECD markets, such as Germany and the United Kingdom, now account for 20-25% of the LCOE (STA, 2014; deea, 2016). In terms of the breakdown of O&M costs, data for the United Kingdom in 2014 suggested maintenance costs accounted for 45% of total O&M costs, land lease for 18%, local rates/taxes for 15%, insurance for 7%, site security and administration costs for 4% each, and utilities (including purchased electricity) for 2% (STA, 2014). O&M costs for utility-scale plants in the United States have been reported to be between USD 10 and USD 18/kW per year (Bolinger and Seel, 2015; Fu, et al., 2015).

Land lease costs are very site- and market-specific. They can be extremely low where land values are minimal (e.g., in deserts or other uninhabited areas without other productive uses) or can even be zero when no land fees are charged as an incentive for the project developer to minimise costs.[6] This is in stark contrast to markets where land constraints are an important challenge, such as in densely populated locations, where land-use costs can be very significant.

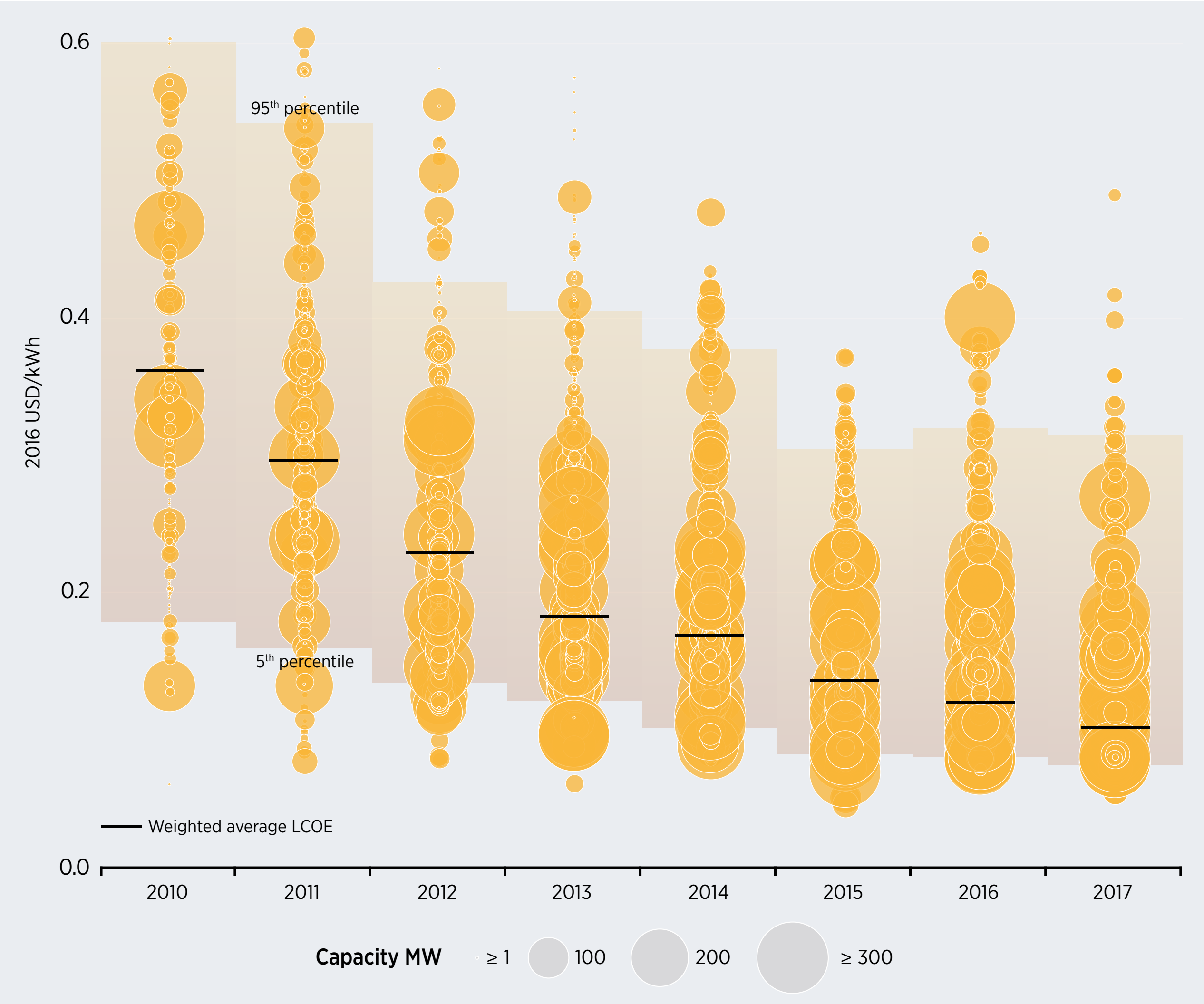
## 3.4 LEVELISED COST OF ELECTRICITY

Rapid declines in installed costs and increased capacity factors have improved the economic competitiveness of solar PV around the world. The global weighted average LCOE of utility-scale PV plants is estimated to have fallen by 73% between 2010 and 2017, from around USD 0.36 to USD 0.10/kWh. Between 2010 and 2013, the global weighted average LCOE declined by about 20% per year, although it experienced a more modest 8% decline between 2013 and 2014, as the market experienced a shift away from traditionally low cost markets towards higher cost markets, such as Japan and the United States (IRENA, 2015). Between 2014 and 2015 the LCOE declined again, by around a fifth, while the descent between 2015-2016 was 11%. The estimated decline between 2016 and 2017 was 15%

The 5th and 95th percentile range of the utility-scale LCOE declined from between USD 0.18 and USD 0.60/kWh in 2010 to between USD 0.07 and USD 0.31/kWh in 2017. The 5th and 95th percentile values declined by 58% and 48% respectively during the same period (Figure 3.10).

*6. This can be the case where regional or central governments have land in their possession that can be used for solar PV projects and can reduce the procurement costs for the electricity offered by project developers.*

**Figure 3.10** Levelised cost of electricity from utility-scale solar PV projects, global weighted average and range, 2010-2016



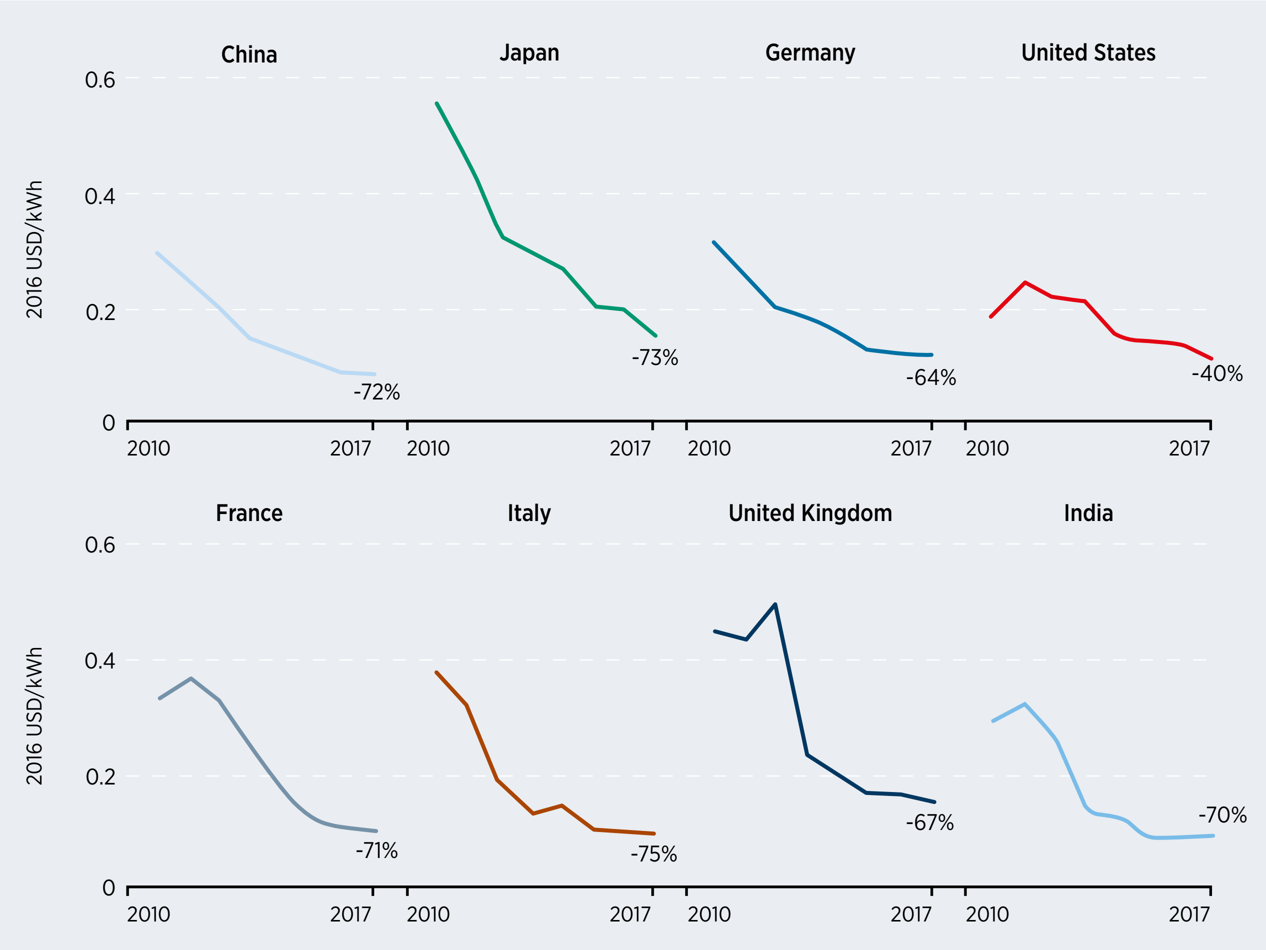

*Source: IRENA Renewable Cost Database.*

The downward trend in the LCOE of utility-scale solar PV by country is presented in Figure 3.11. Between 2010 and 2017, the weighted average LCOE of utility-scale solar PV declined by between 40-75% depending on the country. The Italian market experienced the largest percentage LCOE reduction between 2010 and 2017, driven by module price reductions, but also by significant reductions in BoS costs across the board. Italy has now reduced soft costs and other hardware costs to very low levels (Figure 3.7). In the United States, stubbornly high BoS costs across the board have resulted in slower cost reductions than in other markets. However, excellent solar resources mean that the LCOE of utility-scale projects in the United States is not significantly higher than in other markets.

The LCOE of residential systems has also declined at a very fast pace. For example, based on the assumption of a 7.5% cost of capital, the LCOE of residential PV systems in Germany declined 73% between Q2 2007 and Q1 2017 from USD 0.55 to USD 0.15/kWh (the decline from Q1 2010 to Q1 2017 was 58%[7]). Data since 2013 from India, China, Australia and Spain shows that in these countries, which have better irradiation conditions, and where installed costs have

*7. Assuming a weighted average cost of capital of 5% the LCOE decline in Germany between Q2 2007 and Q1 2017 would have been 72% (from USD 0.46 to USD 0.13/kWh). From Q1 2010-Q1 2017 it would have been 56% (from USD 0.30 to USD 0.13/kWh).*

**Figure 3.11** Utility-scale solar PV: Electricity cost trends in selected countries, 2010-2017



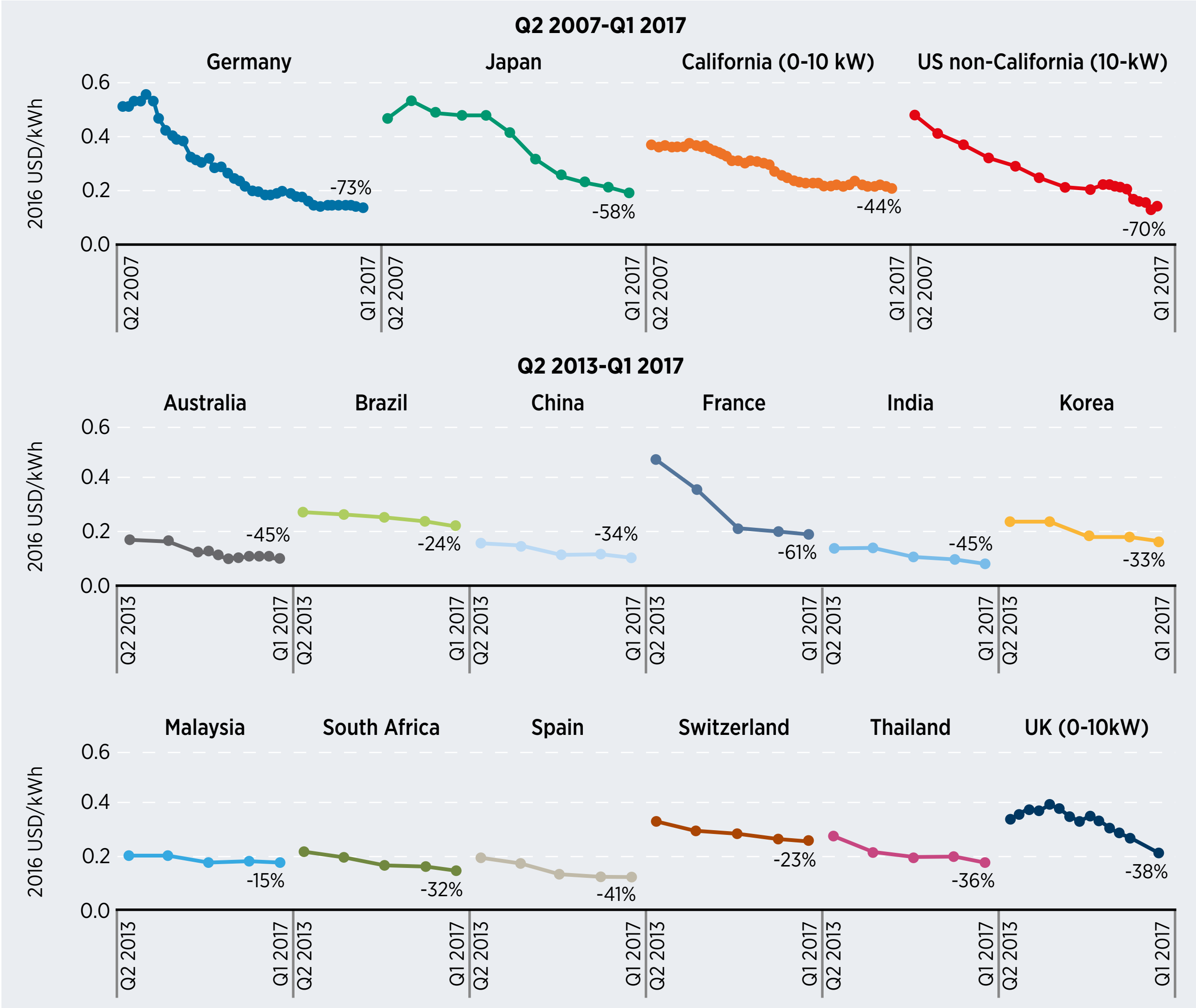

*Source: IRENA Renewable Cost Database.*

become increasingly competitive, lower LCOEs than the above German example can be achieved even if installed costs are sometimes higher. In these low-cost markets, the LCOE range was between USD 0.15 and USD 0.20/kWh in Q2 2013, falling to between USD 0.08 and USD 0.12/kWh in Q1 2017 (Figure 3.12), a decline of between 34% and 45% during the period.

In higher cost markets, reductions have continued as well. In France, for example, residential PV LCOEs declined 61% between Q2 2013 and Q1 2017, while in the United Kingdom, they declined 38% during the same period. The LCOE estimates in these three countries did not exceed USD 0.22/kWh during Q1 2017, however, this is still 46% higher than the costs in the more mature market of Germany.

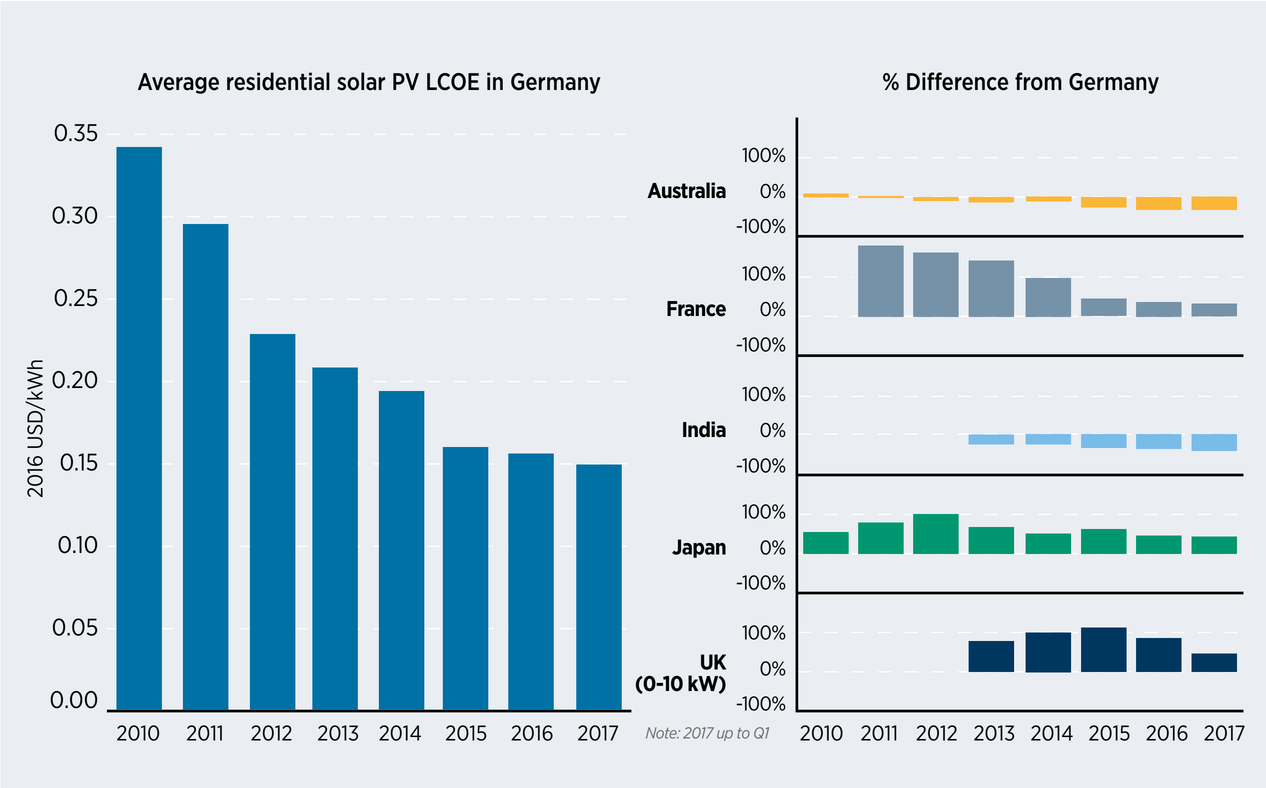
Historically, Germany was a major driver of the growth in residential solar PV over the last ten years and has highly competitive installed costs, but a poor solar resource. Figure 3.13 shows the average yearly LCOE estimates for residential PV in Germany, as well as the percentage difference of the LCOE in other markets to the German LCOE for a given year. From this point of view, it is noticeable that due to total installed cost reductions, traditionally high-cost markets have started to converge around the German level. At the same time, for markets with very competitive installed costs and good irradiation conditions, LCOE estimates have continued to fall and indeed have opened up a larger gap with Germany. Australia is a notable example, despite higher installed costs, the excellent solar resource meant that the estimated residential LCOE in 2010 in Australia was only 7% higher than in Germany and around the same in 2011. Since then, continued installed cost reductions in Australia saw the LCOE gap compared to Germany widen. In 2016 the LCOE estimate was 30% lower than in Germany and in 2017 it was 31% lower.

**Figure 3.12** Levelised cost of electricity from residential solar PV systems by country, Q2 2007-Q1 2017




*Source: IRENA Renewable Cost Database.*

**Figure 3.13** Levelised cost of electricity from residential PV: Average differentials between Germany and other countries, 2010-2017.

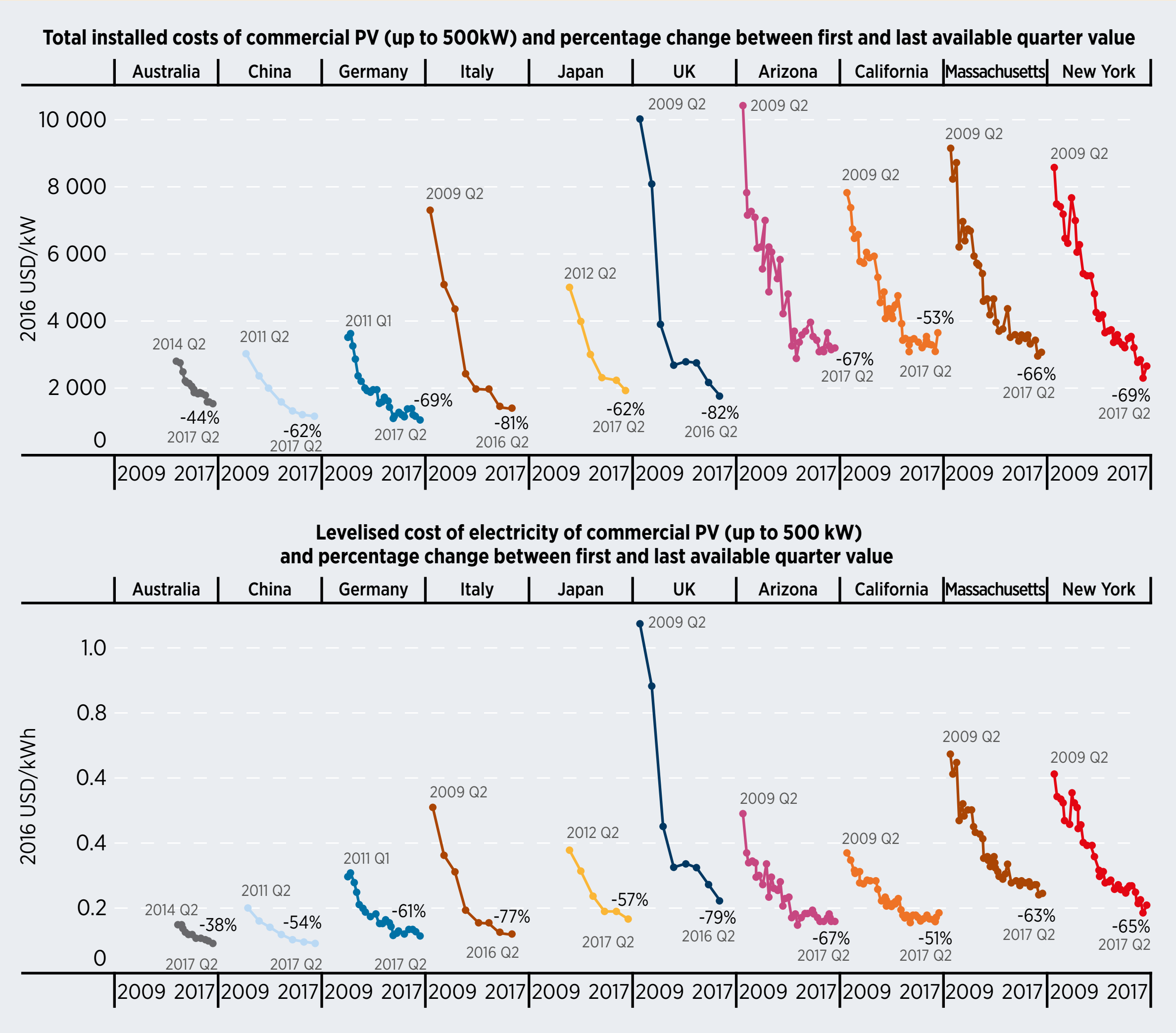



*Source: IRENA Renewable Cost Database.*

## Box 3 Solar PV cost trends in the commercial sector

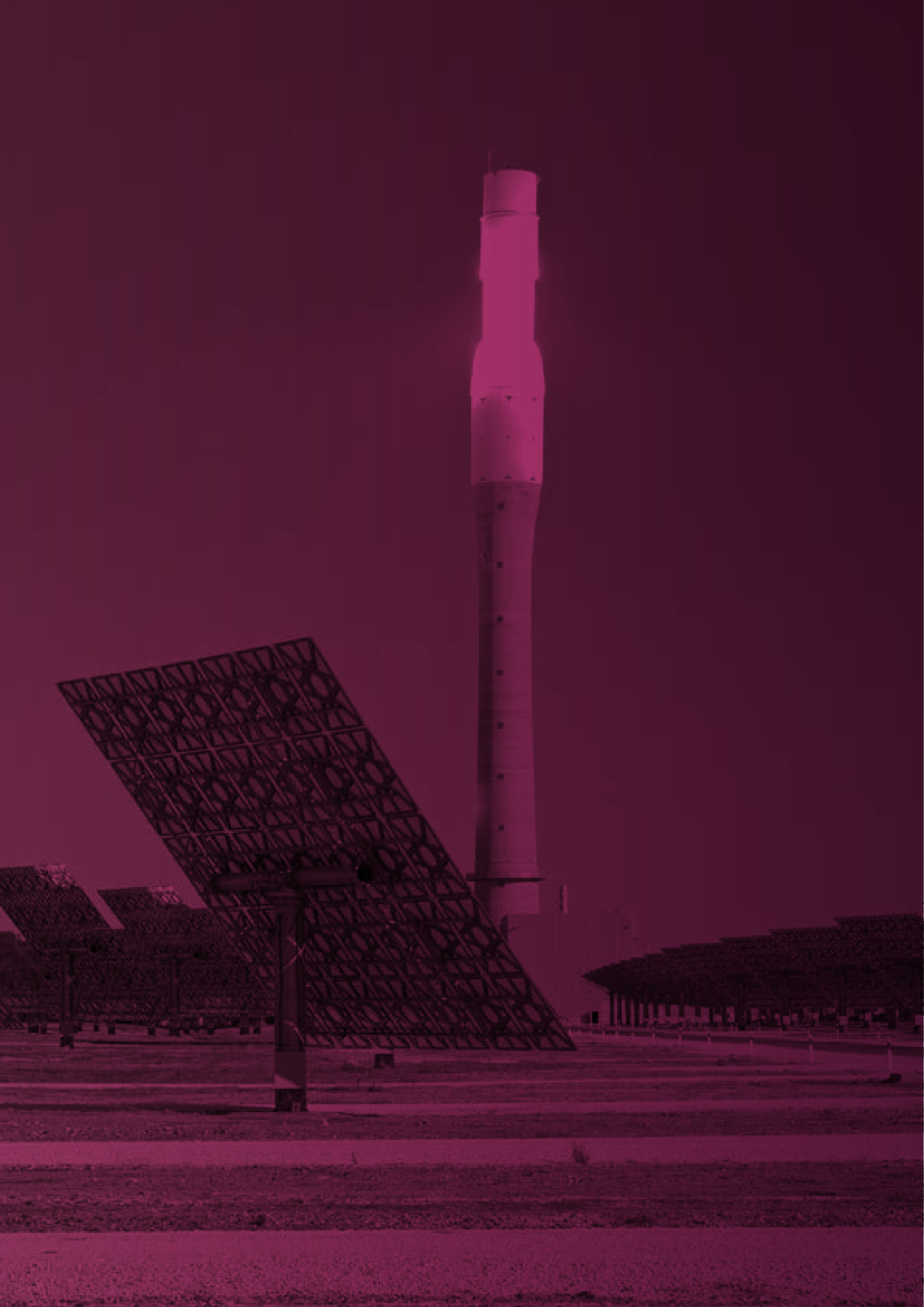
As more companies and businesses turn toward solar PV for electricity generation due to attractive economic returns under net metering or feed-in-tariff schemes, the commercial PV market has seen significant growth in recent years. The commercial segment is more heterogenous in class sizes among countries and economic sectors than the residential market. This and the diverse point in time at which the data has become available can make a comparison of cost trends between markets challenging. However, to shed more light into the global trends of this PV market segment, IRENA has compiled a dataset of commercial PV costs for systems up to 500 kW of capacity from markets for which data is readily available.

**Figure B3.1** Commercial solar PV total installed cost and levelised cost of electricity by country or state, 2009-2017




*Source: IRENA Renewable Cost Database.*

The total installed costs of commercial sector solar PV for system sizes up to 500 kW have often followed a similar downward trend as has been in evidence in the utility-scale solar PV sector. The lowest average total installed costs for commercial PV can be found in Germany and China, at USD 1 100/kW and 1 º150/kW, respectively. The highest cost market remains California with total installed costs of USD 3 650/kW. In terms of the LCOE of commercial solar PV, the lowest average LCOE was around USD 0.10/kWh in Australia Q2 2017, after having decreased 38% between Q2 2014 and Q2 2017.



# 4. CONCENTRATING SOLAR POWER

Concentrating solar power (CSP) relies on concentrating the sun's rays through the use of mirrors to create high temperature heat to drive a steam turbine. In the majority of today's systems, the sun's energy is transferred to a fluid, which in turn is passed through heat exchangers to run a traditional electricity steam cycle, similar to the one used in conventional thermal power plants. CSP plants can also have thermal storage systems. Often, a two-tank molten salt storage system is used, but designs vary. According to the way solar collectors concentrate the solar irradiation, CSP systems can be divided into line-concentrating and point focussing systems.

Parabolic trough collectors (PTC) are the more widely deployed linear concentrating technology. PTCs consist of parabolic trough shaped mirrors (collectors) that concentrate the solar radiation along a heat receiver tube (absorber). This tube is thermally efficient and placed in the collectors' focal line. Single axis sun tracking systems are typically used in PTC systems to orient the solar collectors, together with the receiver tubes, towards the sun and increase energy absorption. Through the use of a heat transfer fluid (often thermal oil) and a heat transfer fluid system these individual solar collectors are connected in a loop and deliver the heat to heat exchangers, where superheated steam is produced. The steam typically drives a steam turbine electricity generator. Though much less deployed, Fresnel collectors are another type of technology in linear focusing CSP plants. These are similar to PTCs, but they use an array of almost flat mirrors (reflectors) instead of parabolic trough-shaped mirrors – although they are designed to approximate the PTC's form. In Fresnel systems, mirrors concentrate the sun's rays onto elevated linear receivers that are not directly connected to them, but are located several metres above the primary mirror field. Solar towers are currently the most used point focal system currently deployed. Often also known as 'power towers', solar tower CSP systems use a ground based array of large mirrors that track the sun individually in two axes and which are commonly known as heliostats. In solar towers, the heliostats concentrate solar irradiation onto a receiver mounted at the top of a tower. The central receiver absorbs the heat through a heat transfer medium,[1] which is then used to generate electricity, typically through a water-steam thermodynamic cycle. Solar towers can achieve very high solar concentration factors (above 1000 suns) and reach higher operating temperatures than PTC plants, which can allow for low-cost thermal energy storage and higher capacity factors and efficiency levels compared to PTC plants.

CSP has the advantage that it can be equipped with low-cost thermal energy storage. This allows CSP to provide dispatchable renewable power. CSP therefore can offer advantages, such as allowing

*1. Some solar tower designs aim at avoiding the use of the heat transfer medium, however, and instead directly produce steam.*

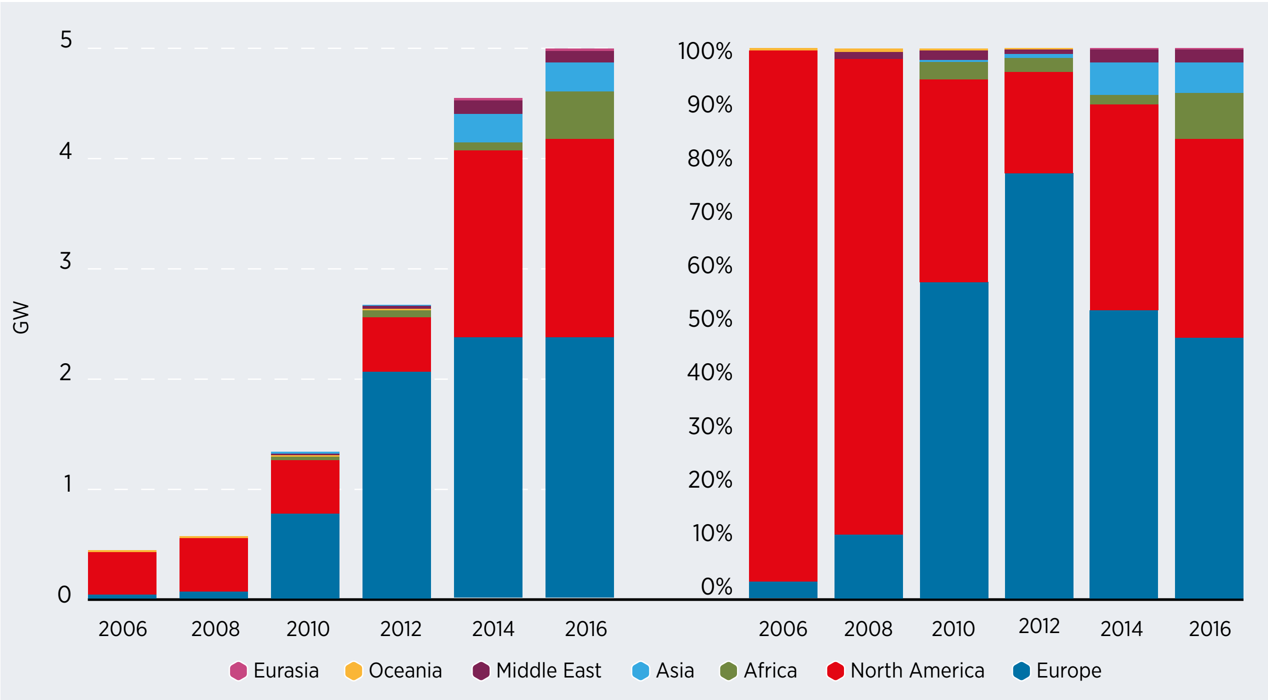
for generation to be shifted to times when the sun is not shining or to maximising generation at peak demand times. CSP with integrated storage can thus be a cost effective, flexible option in different locations, especially in the context of increasing shares of VRE. (Lunz et al., 2016; Mehos et al., 2015).

Cumulative CSP capacity grew tenfold worldwide between 2006 and 2016 (Figure 4.1). Growth rates have been linked in the past to incentive schemes in key markets. During the 2000s, support policies drove early CSP expansion, primarily in the United States and Spain, and these two countries account for more than 80% of the total cumulative installed CSP capacity between them. At about 5 GW of cumulative installed capacity, compared with other renewable energy technologies, CSP deployment remains modest.

Since 2013 in particular, new projects and plans have started to proliferate in new and emerging markets. Many of these have high irradiation levels, or major renewable energy adoption plans that include CSP, or both. These markets include India, South Africa, Morocco, the UAE, Australia, Chile and China. Compared to other technologies, China's share of CSP installations is quite modest – and ranked 10th in the world at the end of 2016 (IRENA, 2017a). The country has announced plans to increase CSP deployment, however, with the goal of installing 5 GW of CSP by 2020. This is half a previously released goal of 10 GW, though. In September 2016, China released information on a first group of CSP demonstration projects, some of which have already been implemented, albeit at slower pace than expected (SolarPV.TV, 2016; SolarPACES, 2016; Wang et al., 2017).

Globally, at the end of 2016, an estimated 4 GW of CSP projects were under construction or under development (SolarPACES, 2017a). This data should be treated with caution, as projects can be abandoned or delayed in the planning or project development stages for a variety of reasons. As an example, the subset of projects in the SolarPACES database for which the planning status has been recently revised (that is to say their status was revised in the period 2015-2017) is close to 3 GW.[2] Figure 4.2 shows the capacity of these more recent projects, broken down by technology and operational status.

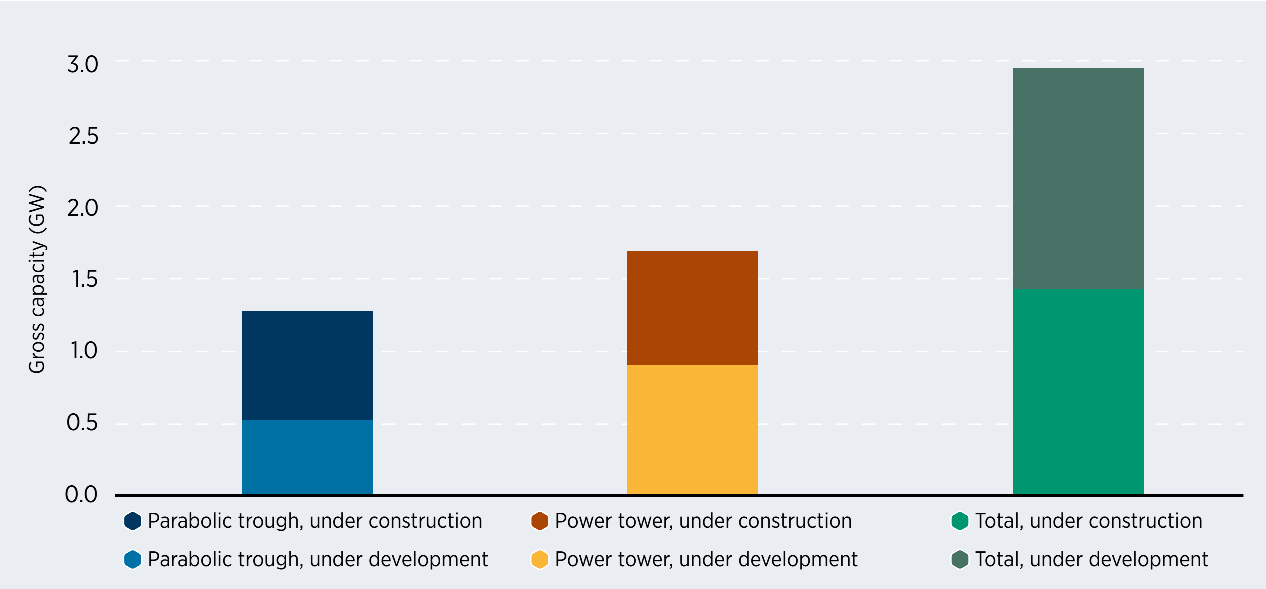
**Figure 4.1** Development of the cumulative installed CSP capacity by region, 2006-2016.




*Source: IRENA, 2017a.*

*2. At the time of writing, information as to whether some of the earlier projects categorised under these headings will be realised was unavailable.*

**Figure 4.2** Status of planned PTC and ST projects registered since 2015




*Source: IRENA analysis based on SolarPACES, 2017b.*

## 4.1 INSTALLED COST TRENDS

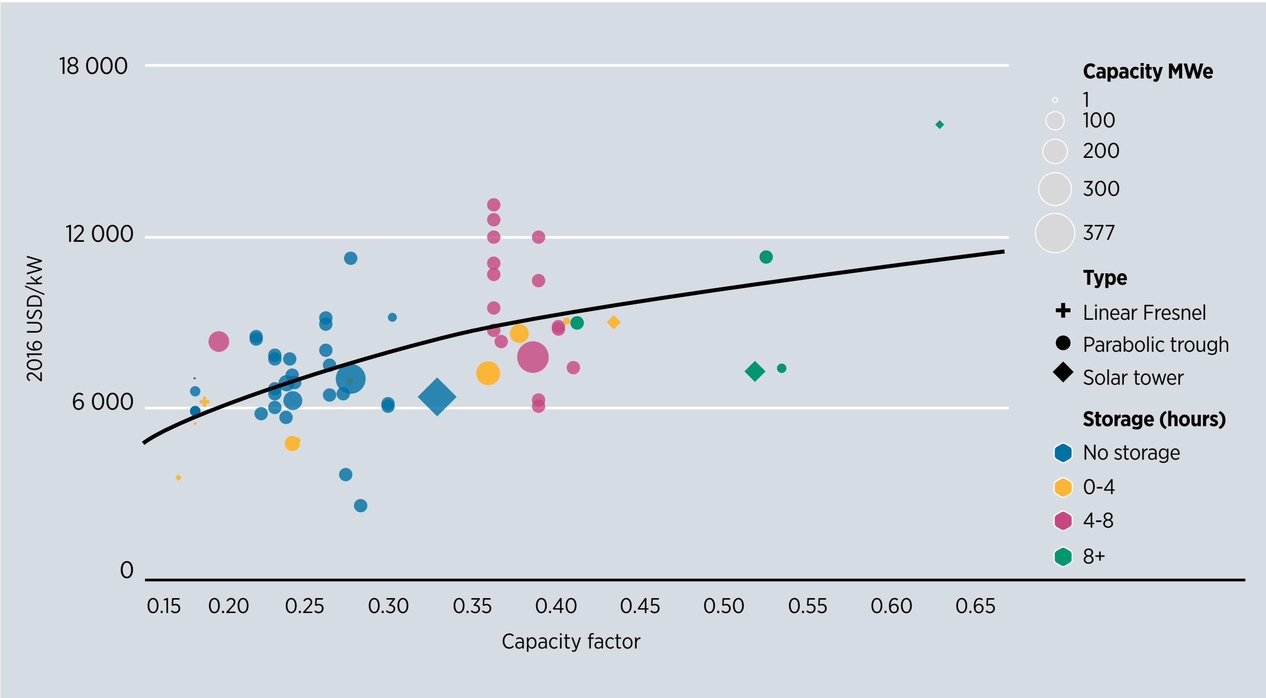
Total installed costs for CSP plants that include thermal energy storage tend to be higher than those without, but storage also allows for higher capacity factors. For example, for parabolic trough systems (the technology with the highest share of installed projects so far), total installed plant costs can range between USD 2 550 and USD 11 265/kW for systems with no storage. Adding four to eight hours of storage, however, can see this range increase to between USD 6 050 and USD 13 150/kW for projects for which cost data is available in IRENAs Renewable Cost Database for the period 1984-2016. (Figure 4.3).

A time series of such projects from 2009-2016 shows that PTC and ST CSP capital costs for systems with no storage displayed a wide range during the period, varying between USD 2 550 and USD 11 300/kW. The majority of these projects started operating between 2009 and 2013 in Spain and still benefitted from, or where conceived under, the generous Spanish FiT incentive of that time that kickstarted this second phase of CSP development. After a downward trend from the very early plants built in California in the 1980s, capital costs for PTC without storage started to increase as projects shifted to Spain. Projects from this era in the IRENA Renewable Cost Database, range in costs between USD 3 650 and 11 300/kW (Figure 4.4) for the period of 2009-2013.

There was also a strong capital cost increase for PTC without storage during the period 2008-2011. This increase could in part be explained by the comparatively lower solar resources in the project locations in Spain, but analysis allowing for Direct Normal Irradiance (DNI) suggests that at least 65% of the cost increase ought not to be attributed to the lower solar resources, but to fundamental cost increases in the configuration (Lilliestam et al., 2017). Figure 4.4 shows the narrower range of between USD 2 550 and USD 7 000/kW that can be observed for the 'no storage' configuration in the IRENA Renewable Cost Database for more recent PTC and ST plants, installed since 2014.

Parabolic trough and solar tower projects with up to four hours of storage show a range of total installed costs between USD 3 500 and USD 9 000/kW (though projects of this kind with

**Figure 4.3** Installed costs and capacity factors of CSP projects by their quantity of storage, 1984-2016.




*Source: IRENA Renewable Cost Database.*

**Figure 4.4** CSP installed costs by project size, collector type and amount of storage, 2009-2016


*Source: IRENA Renewable Cost Database.*

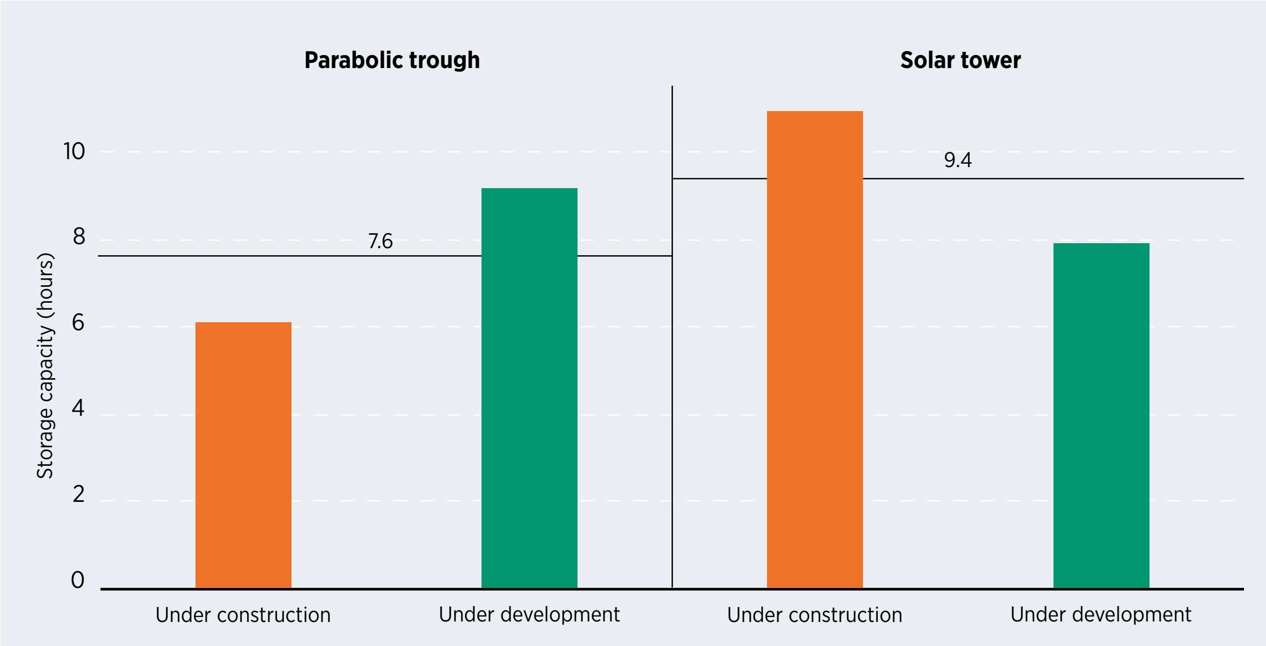
larger than 50 MW of capacity for which costs data is available were only installed from 2015 onwards). In the case of PTC and ST plants with four to eight hours of storage, capital costs ranged from USD 6 050 and 12 600/kW. Between 2013 and 2015, PTC and ST projects with storage capacities larger than eight hours were installed at a range of costs between USD 7 300 and 11 300/kW. Despite a somewhat irregular market growth, a trend towards plant designs with higher hours of storage can be inferred from the IRENA dataset. It can also be confirmed by analysing the storage design configuration for projects 'under construction' or 'under development' in the SolarPACES database.[3] For PTC projects, an average 7.6 hours of storage is planned, while for solar towers, project designs are for nine hours of storage or more (Figure 4.5).

The SolarPaces database also provides some insight into trends in heat transfer fluid usage for the two main CSP technologies. Data for planned projects with recently updated operational status in the database suggests a trend towards increased use of molten salt as the HTF, compared to the subset of projects in operation. Though data is not available for all projects, it seems that some ST plants are planned to operate with a water- or steam-based HTF configuration, these can provide efficiency gains, but are not suitable for use with large-scale storage. Most solar tower plants 'under construction' or 'under development', however, are poised to continue to use of molten salt as the HTF. The dataset also suggests that about 10% of PTC planned capacity is also going to use molten salt as its HTF with its associated benefits of higher operating temperatures (thermal oil is not suitable for operating temperatures in excess of 400°C) and hence higher steam cycle efficiencies compared to when mineral oils are used as the HTF (Figure 4.6).

Even though CSP deployment has been somewhat limited compared to other renewable power generation technologies, there exist significant opportunities for cost reductions as deployment grows (IRENA, 2016a). These cost reduction

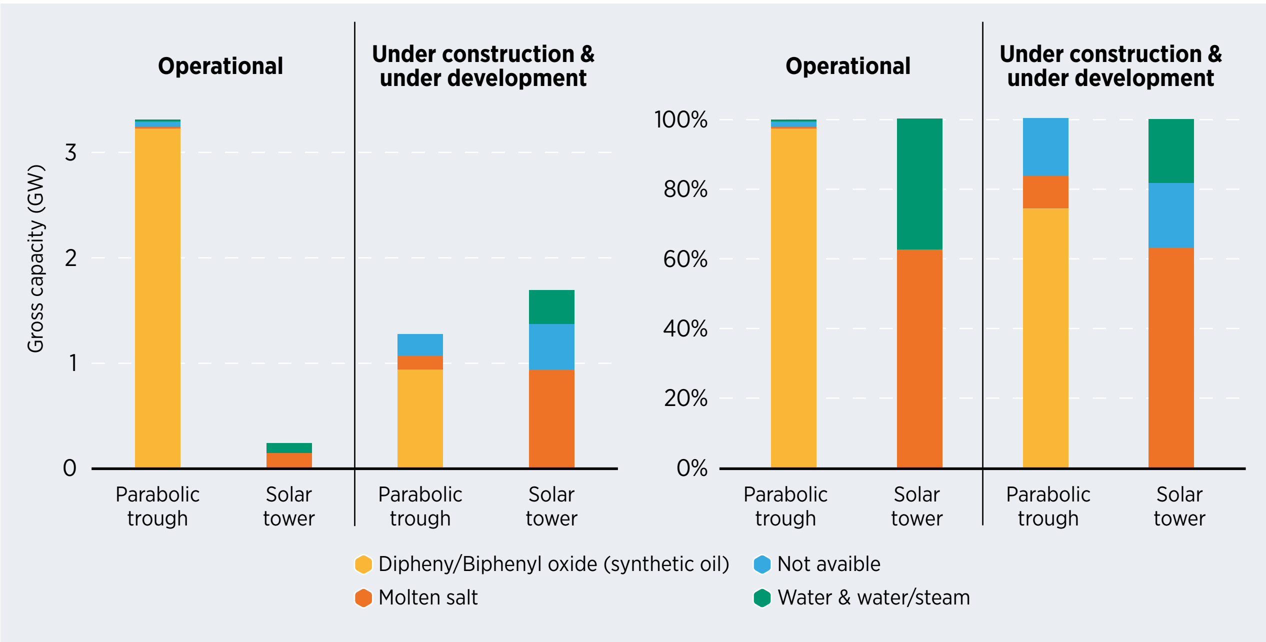
*3. That is to say, where the project status information was updated during the 2015-2017 period.*

**Figure 4.5** Storage hours of planned CSP projects with operational status updates in 2015-2017




*IRENA analysis based on SolarPACES, 2017b.*

**Figure 4.6** Heat-transfer fluid use in operational and planned projects with operational status updates in 2015-2017




*IRENA analysis based on SolarPACES, 2017b.*

potentials will enable CSPs market presence to grow and for this technology to contribute substantially to the global energy transition towards a low carbon future. Technological improvements in solar field elements, such as collectors and mirrors, reduced costs in installation and engineering, and cost reductions in specific components are expected for CSP. The technology is also expected to experience declines in its indirect costs and the owner's cost elements, with slightly higher cost reduction potential in these items for solar towers, compared to PTC. This can be explained with reference to the lower deployment of solar towers so far. With larger deployment, the risk margins of suppliers and EPC contractors would also fall, as developers and other players gain more experience (IRENA, 2016a).

Learning rates (the cost decrease with every doubling of cumulative capacity) for CSP have been previously estimated to be between 10% and 12% (Neij, 2008); (Haysom et al., 2015); (Fraunhofer ISE, 2013). However, recent analytical work suggests higher learning rates for CSP since 2013, with an estimated learning rate above 20% (Lilliestam et al., 2017; Pitz-Paal, 2017). If the auction results for Dubai and South Australia are factored in, then for the period 2010-2022 the learning rate could reach 30%.

## 4.2 CAPACITY FACTORS

The evolution of the capacity factors in the IRENA Renewable Cost Database is presented in Figure 4.7. Capacity factors have increased over time as a shift towards newer technologies, with larger thermal storage capacities has coincided with a trend towards the growth of markets in higher irradiation locations. The dominance of Spanish CSP projects, often with no storage capacity, has given way to projects with significant levels of storage, often in locations with higher DNI than in Spain, notably as projects in Morocco, Chile, South Africa and the United Arab Emirates have come online. The evolution of DNI of projects is presented in Figure 4.8. For CSP plants, the irradiation level at the plant location (typically referenced by the DNI metric) is inversely correlated to the LCOE (IRENA, 2015).

A clear trend towards higher Direct Normal Irradiance (DNI) values of commissioned CSP projects can be observed after 2012, albeit from relatively thin deployment data. For instance, the capacity weighted average DNI value for projects for which data is available increased 11% between 2012 and 2013 and exceeded 2 800 kWh/m$^2$/year in both 2014 and 2015. During 2016 it remained about one fifth higher than in 2012.

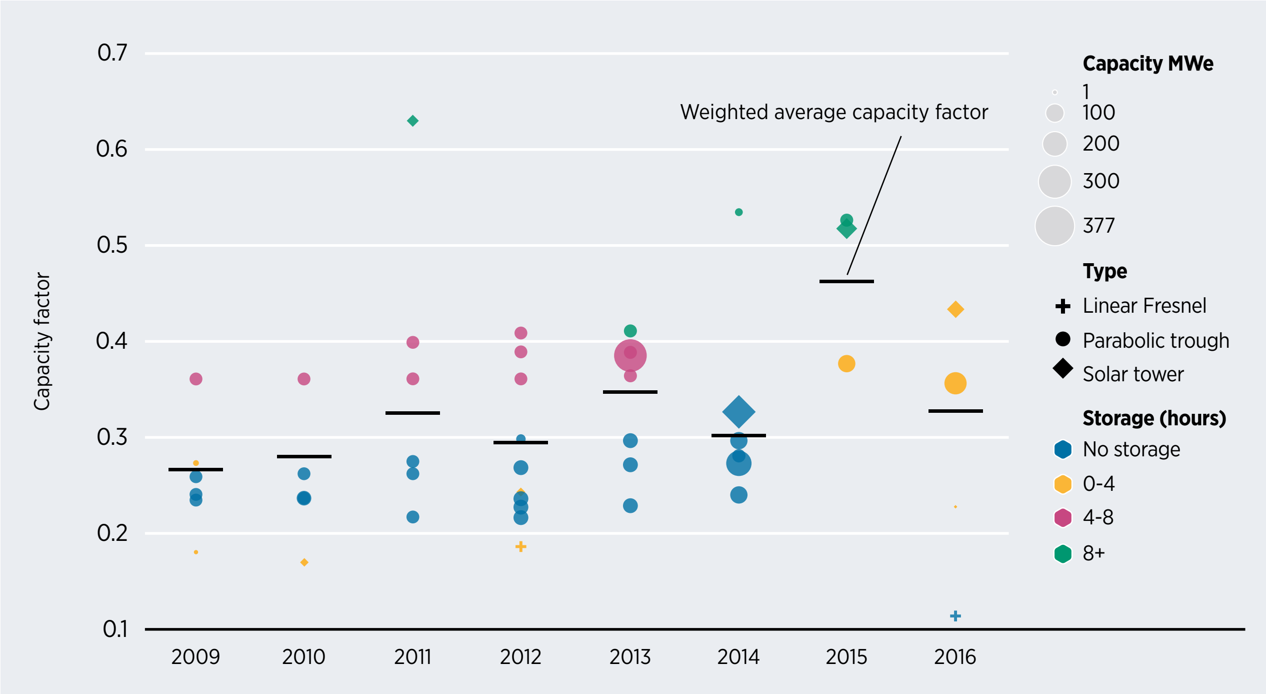
## 4.3 OPERATION AND MAINTENANCE COSTS

CSP O&M costs are a significant component of the overall LCOE of CSP projects (IRENA, 2016a). They have been falling through time and are significantly lower today than the original, pioneering Solar Electricity Generating System (SEGS) plants that were built between 1982 and 1990. The SEGS plants were estimated to have had O&M costs of around USD 0.04/kWh (Cohen, 1999), with expenditure for replacement receivers and mirrors being one of the largest cost components, as a result of glass breakage.

Advances in materials and new designs have helped to reduce the failure rate for receivers, to the point where mirror receiver breakage is no longer a large cost component. However, the cost of mirror washing, including water costs, is However, the significant. Plant insurance can also be an important expense, with its annual cost potentially between 0.5-1% of the initial capital outlay. Even higher costs are possible in particularly unsecure locations.

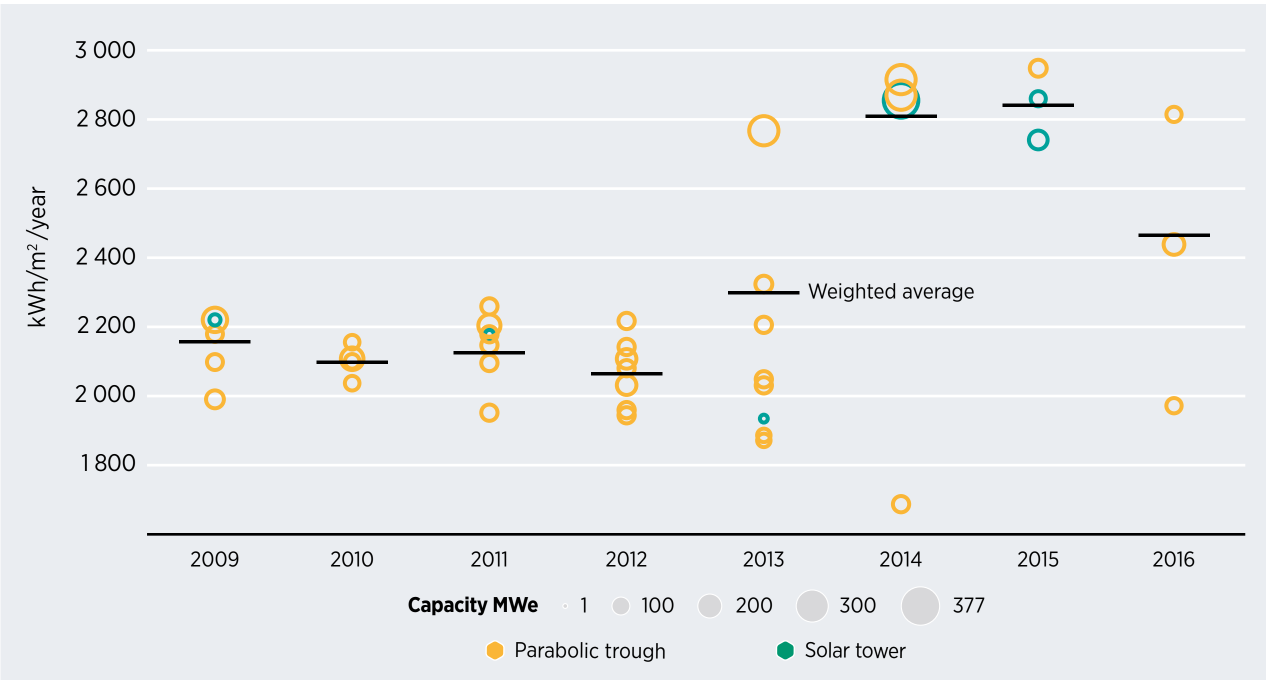
More recent projects built in Spain, the United States and elsewhere are estimated to have lower O&M costs than those of the SEGS plants, however. On the basis of available, bottom-up, engineering estimates (e.g., Turchi, 2010a and Turchi, 2010b) and recent proposed projects (Fichtner, 2010), O&M costs can be estimated to be in the range of USD 0.02 to USD 0.04/kWh (including insurance). The IRENA CSP cost analysis used in this report assumes an insurance-included average O&M cost range of USD 0.02 to USD 0.03/kWh for PTC and USD 0.03 to USD 0.04/kWh for ST (IRENA, 2016a).

**Figure 4.7** Capacity factor trends for CSP plants, 2009-2016




*Source: IRENA Renewable Cost Database.*

**Figure 4.8** Direct normal irradiance levels for CSP projects by year of commissioning and technology, 2009-2016




*Based on Lilliestam et al., 2017.*

## 4.4 LEVELISED COST OF ELECTRICITY

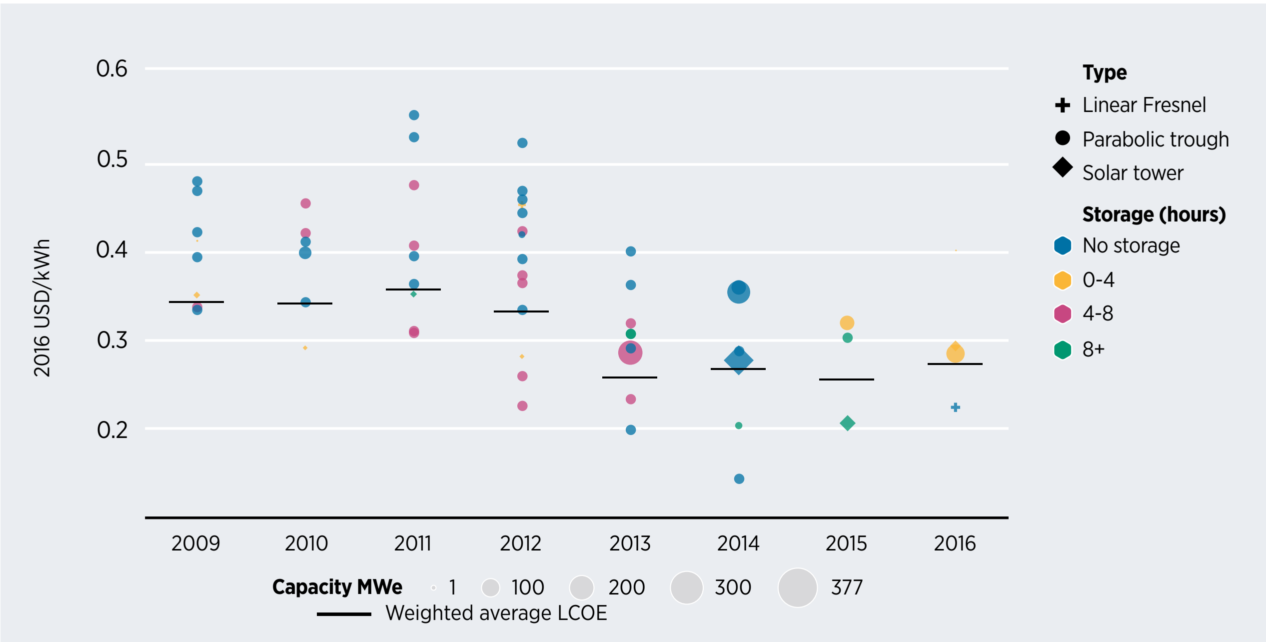
The LCOE of CSP plants stayed relatively stable between 2009 and 2012. Significant deployment during 2012, primarily in Spain (at least 800 MW), along with a couple of projects in the United States and in a few other countries, coincided, however, with a widening of the LCOE range in that year as more competitive plants were also commissioned (Figure 4.9). A downward trend in LCOE started in 2012. Indeed, during 2013 and 2014, the LCOE estimates were, on average, about one fifth lower than those of the 2009-2012 period. This decrease, coincided with a geographical shift away from Spain to newer markets with higher solar resources and sometimes, lower installed costs. Higher levels of Direct Normal Irradiance (DNI), were , however, likely the main factor behind lower levelised costs during that period (Lilliestam et al., 2017). Learning effects and technology improvements have not yet, therefore been the main driver of cost reductions, leaving significant cost reduction potentials to be unlocked as already highlighted (IRENA, 2016a).

*Higher levels of irradiance were likely the main factor behind lower levelised costs*

During 2016 the capacity weighted average LCOE of CSP plants was estimated to be USD 0.27/kWh (a fifth lower than in 2009) although IRENA data suggests that the LCOE, although about 18% during 2017 to USD 0.22/kWh.

The LCOE estimates discussed in this section assume a 25-year economic life and a WACC of 7.5% in OECD countries and China, and 10% elsewhere. Apart from increased DNIs at project locations between 2012 and 2014, the downward LCOE trend observed during 2012 and 2014 can be explained by a similar upward trend in the capacity factor of plants. The growth in the capacity factors of CSP during this period is not only related to higher solar resource availability, but also due to plant configurations with higher storage capacities and dispatching abilities.

**Figure 4.9** The levelised cost of electricity for CSP projects, 2009-2016




*Source: IRENA Renewable Cost Database.*

From 2014-2016, thin deployment makes it difficult to come to definitive conclusions regarding the LCOE trend, but a range between USD 0.14 and USD 0.35/kWh can be observed for projects for which cost data is available in the IRENA Renewable Cost Database. The LCOE of most projects in this period is below USD 0.30/kWh (Figure 4.9). Recent announcements and analysis of planned projects seems to predict a clear downward trend, too, starting in 2017 (Lilliestam et al., 2017). Indeed, recently, very low bids for CSP projects have been announced. Examples include the USD 0.073/kWh bid announced by the Dubai Electricity and Water Authority (DEWA) for a 700 MW plant at the Mohammed bin Rashid Al Maktoum Solar Park (DEWA, 2017) and the Port Augusta CSP project in Australia, at around USD 0.06/kWh.

These results should be treated with caution, as a direct comparison with project level LCOEs is complicated given PPA prices and LCOE often do not represent a like-for-like comparison due to auction prices being dependent on a set of obligations and terms in the contract that can be very market and project specific. The other important point to take into consideration is that these prices apply to projects that will be commissioned in the period 2020-2022 and beyond. However, these announcements do point towards the increased competitiveness of renewable energy projects compared to fossil fuel alternatives and that by 2020 commissioned CSP plants will increasingly be delivering electricity at a cost that is within the lower end of the fossil fuel-fired cost range (Figure 4.10).

**Figure 4.10** Levelised cost of electricity and auction price trends for CSP, 2010-2022


*Note: Each bubble represents a renewable energy project. The center of the bubble is the winning bid price in that year.*
*Source: IRENA Renewable Cost Database and Auctions Database.*

# 5. WIND POWER

In 1979, Danish and German manufacturers Vestas, Nordtank, Kuriant and Bonus ushered in wind power's modern era with the mass production of large wind turbines to produce electricity. These early wind turbines had small capacities by today's standards – 10-30 kW – but they have scaled up rapidly, as the modern wind power industry has grown and matured.

Wind power technologies have two main characteristics: the axis of the turbine and the location. The axis of the turbine can be vertical or horizontal and the location can be onshore or offshore. Virtually all onshore wind turbines are horizontal axis turbines, predominantly using three blades and with the blades "upwind". The utility-scale market for wind technologies uses almost exclusively horizontal axis turbines, both onshore and offshore.

The amount of electricity generated by a wind turbine is determined by nameplate capacity (in kW or MW), the quality of the wind resource, the height of the turbine tower, the diameter of the rotor and the quality of the O&M strategy. Wind turbines typically start generating electricity at a wind speed of 3-5 metres per second (m/s), reach maximum power at 11-12 m/s and generally cut out at a wind speed of around 25 m/s.

Wind power has experienced a somewhat unheralded revolution since 2008-09. Between 2008 and 2017, improved technologies – such as higher hub heights and larger areas swept by blades – have increased capacity factors for a given wind resource. At the same time, installed costs have fallen as wind turbine prices have declined from their peak in 2008-09. Balance of project costs have also declined, with these factors all driving down the LCOE of wind and spurring increased deployment. Yet there are significant cost differentials between countries. Comprehensive data on installed costs and market performance are crucial to understanding the current cost of electricity and opportunities for future cost reductions from performance improvements and installed cost reductions.

From 2000 to 2016, cumulative installed wind capacity increased at a compound annual rate of 15%, and by the end of 2016, total installed wind capacity had reached 467 GW, with 454 GW onshore (IRENA 2017b). China has the largest share of this – 32% at the end of 2016 – followed by United States (17%), Germany (11%), India (6%) and Spain (5%). China accounted for 38% of new annual capacity additions in 2016, followed by United States (17%), Germany (10%), India (7%), Brazil (4%) and France (3%). Net additions of wind power were 21% lower in 2016 than in 2015, a record year in which 65 GW was added to global capacity. This was mainly due to policy changes in China, which drove a rush of installation before the expiration of a policy support scheme at the end of 2015. China added 42% less capacity in 2016 compared to 2015, accounting for almost all the global difference between 2016 and 2015. The range of expected yearly additions in the next 3-5 years is 40-50 GW. China, the United States, Germany, India, and France are expected to account for the majority of new additions (MAKE, 2017).

## 5.1 WIND POWER TECHNOLOGY TRENDS

The largest share of the total installed cost of a wind project is related to the wind turbines. Contracts for these typically include the towers, installation, and delivery, except in China. The range of the share of wind turbines in total installed costs has historically varied from 64-84% for onshore wind and 30-50% for offshore wind (IRENA Renewable Cost Database; Blanco, 2009; EWEA, 2009; Douglas-Westwood, 2010; and MAKE Consulting, 2015a). In major markets, as costs have fallen, the share of wind turbines has tended towards the higher end of this range.

Five major cost categories drive the total installed costs of a wind project:

- Turbine cost: Rotor blades, gearbox, generator, nacelle, power converter, transformer and tower.
- Construction works for the preparation of the site and foundations for the towers
- Grid connection: Includes transformers and substations and connection to the local distribution or transmission network.
- Planning and project costs: Depending on project complexity, these can represent a significant share of the balance of project costs (i.e. the non-turbine costs).[1]
- Land: Cost of land represents one of the smallest shares of total costs. Land is usually leased through long-term contracts in order to diminish the high administrative costs associated with land ownership, but it is sometimes purchased outright.

One of the important trends in the wind market is the larger range of wind turbines offered by manufacturers to allow developers to choose designs that yield the lowest LCOE for the site constraints they are facing. General Electric, Siemens and Vestas have all roughly doubled the number of offerings in their portfolio since 2010, with each now offering over 20 models. This also helps to reduce costs below what they would otherwise be, as utilising the same structural components across a given platform can mean up to 50% of the turbine components are identical, significantly reducing development costs and unlocking supply chain efficiencies (MAKE Consulting, 2015b).

One of the key drivers of the increasing competitiveness of wind power has been continued innovation in wind turbine design and operation (IRENA, 2016a). There has been a continuous increase in the average capacity of turbines, hub-heights and swept areas as blade lengths have grown. These trends work together in synergy to reduce the cost of electricity from wind power. Higher hub-heights allow turbines to access higher wind speeds,[2] while larger swept areas from longer blades also increase the yield of a wind turbine. Higher turbine capacities allow larger projects, which can amortise project development costs over a larger output. The trade-off for these developments is that taller towers supporting greater weight typically cost more, so the impact in some markets may be cost-neutral for installed costs, but result in a lower LCOE due to the higher yields. The other challenge is that longer blade lengths come with additional engineering challenges, as loads on turbines increase significantly with longer blades, thus necessitating a different structural design. They also present a logistical challenge onshore, given their sheer length. Research into very long segmented blades is therefore ongoing, but for large projects road upgrades may prove a cheaper option than investing in segmented blades.

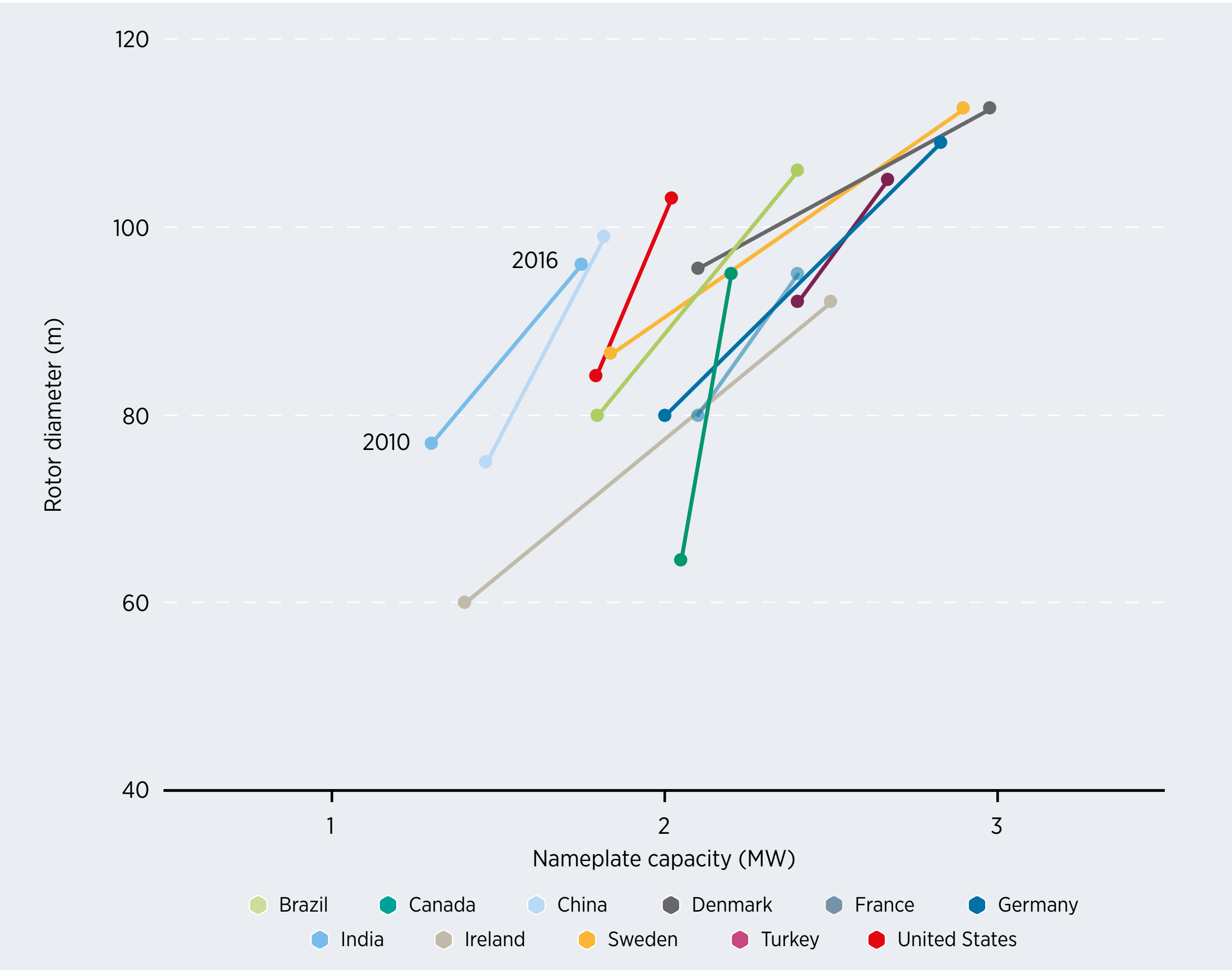
Demand for the latest turbine technologies is being driven by Europe, where space constraints and siting challenges mean that profitability rests heavily on using the highest performing technologies. Crucially, taller towers in European

1. *These include costs such as: development costs and fees, licenses, financial costs, development and feasibility studies, legal fees, right of way, insurance, debt service reserves, and construction management not associated with the engineering, procurement and construction contract.*
2. *Wind farm economics are significantly enhanced by accessing higher wind speeds given that the yield increases by a power of three as a function of wind speed.*

markets allow for the exploitation of marginal wind sites and existing forested land that is available for development (MAKE Consulting, 2013 & 2017b). The rapid development of wind turbine technologies has seen the most advanced turbine designs available change rapidly. In 1985, typical turbines had a capacity of 50 kW and a rotor diameter of 15 metres (UpWind, 2015). In 2016, offshore wind turbines of 8 MW capacity with a rotor diameter of 164 metres were in operation, while a 9.5 MW version of the same turbine is now available.

Figure 5.1 presents the evolution of wind turbine rotor diameter and nameplate capacity between 2010 and 2016 for countries where data is available. The ongoing trend towards larger turbines with greater swept areas is clear. Ireland stands out, having increased average nameplate capacity by 79% between 2010 and 2016 and rotor diameter by 53%. Canada, and to a lesser extent, the United States, are interesting examples of markets that have increased the rotor diameter faster than the nameplate capacity. Between 2010 and 2016, the rotor diameter of newly commissioned projects increased by 47% in Canada and 22% in the United States, while the growth in nameplate capacity was 7% and 13% respectively. Overall, the largest increases in rotor diameter occurred in Ireland (53%), Canada (47%) and Germany (36%). In percentage terms, the largest increase in nameplate capacity was observed in Ireland, followed by Germany (42%) and Denmark (42%).

**Figure 5.1** Weighted average rotor diameter and nameplate capacity evolution, 2010-2016




*Sources: Wiser and Bollinger, 2017; Global Data, 2016; Danish Energy Agency, 2017; IEA Wind, 2015; CanWEA, 2016.*

## 5.2 WIND TURBINE COSTS

Wind turbine prices fluctuate with demand and supply, as well as with economic cycles. The latter can affect the cost of the materials used in wind turbine manufacturing, as these have a significant exposure to commodity prices – notably those of copper, iron, steel and cement – given these account for a sizeable part of the final cost of a wind turbine.

Wind turbine prices reached a low in the period 2000-2002, but prices then increased, as commodity prices rose, turbine supply tightened and the growth in larger, higher performing turbines accelerated. During 2000-2002, the average turbine price in the United States was at its lowest, at around USD 800/kW and peaked at around USD 2 000 to 2 100/kW in 2008, (Wiser and Bollinger, 2017). In Europe, average prices peaked at around USD 1 900/kW for contracts signed in 2008/2009 (BNEF, 2017).

Depending on the market and technology segment, wind turbine prices peaked between 2007 and 2010 before starting to decline (Figure 5.2). The cost increase was driven by three factors. Firstly, the increase in construction costs, with materials (e.g. steel, copper, cement), labour and civil engineering costs all rising prior to the 2009 financial crisis. Secondly, for a few years, demand outstripped supply as many countries adopted policies favourable to wind deployment. This allowed manufacturers to operate with higher margins, as they struggled for a time to meet rising demand. Lastly, technology improved markedly; a trend that has continued ever since: wind turbine manufacturers introduced larger, more expensive turbines, with higher hub heights. As a result, more capital-intensive foundations and towers were needed, but helped deliver higher energy outputs, largely offsetting the higher installed costs and hence delivering a lower LCOE.

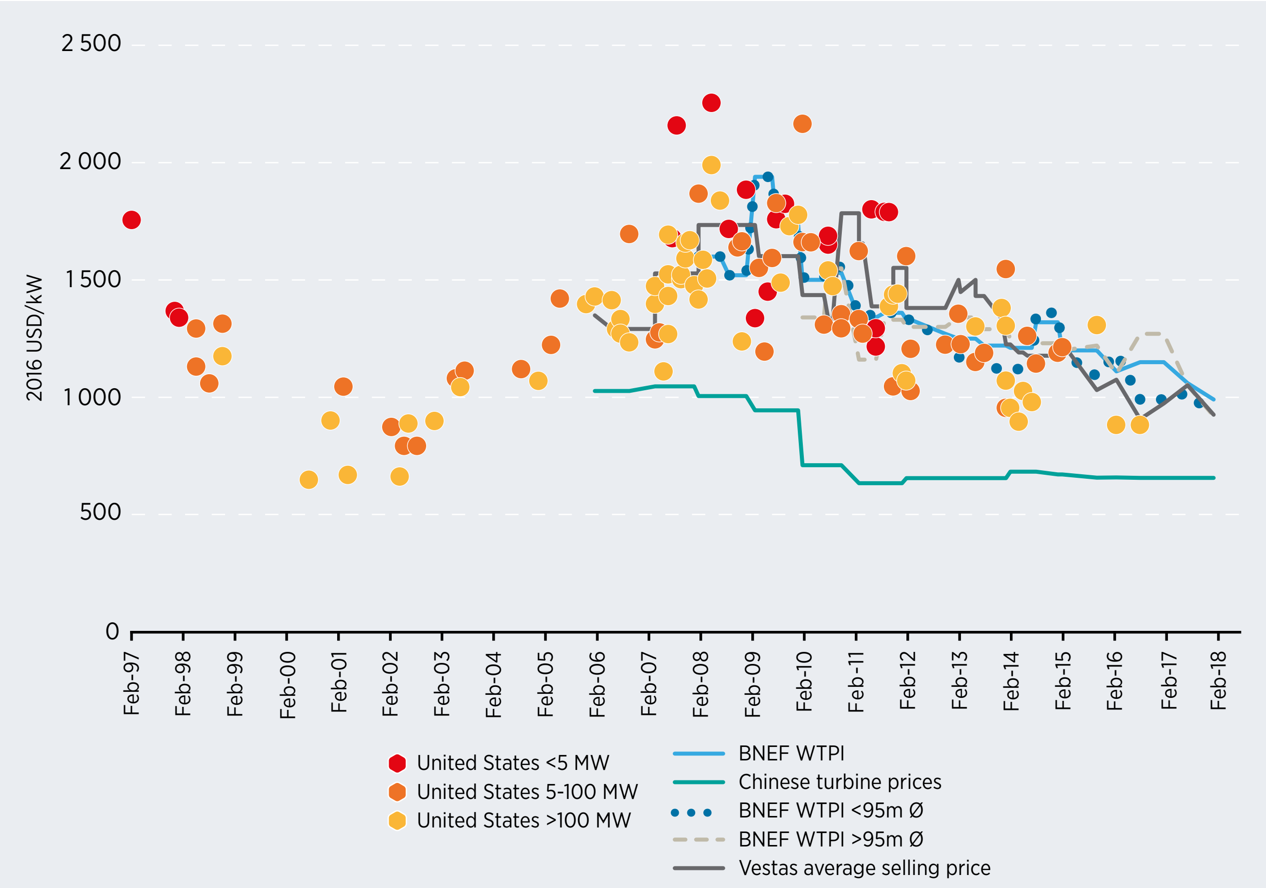
Bloomberg New Energy Finance's (BNEF) index for turbines with rotor diameters of less than 95 metres declined by 53% between 2009 and 2017, while the index for diameters greater than 95 metres declined by 41%. This value is in line with the decline observed in the average selling price for Vestas wind turbines over the period, at 48%, and close to values observed in the United States, for the vast majority of contracts. Chinese wind turbine prices peaked in 2007 and have fallen 37% between 2007 and 2016 – but started from lower levels, thus having slightly less room for cost declines.[3] The decline in turbine prices globally has occurred at the same time as improved wind turbine technology: rotor diameters, hub heights, and nameplate capacity have all increased markedly.

Provisional data for 2017 indicates that average wind turbine prices across most, if not all, markets were below USD 1 000/kW by the year's end. The last time this happened, in 2002, was when the most common installed turbine was in the 750-1 000 kW range. Contracts for onshore wind turbines signed in 2017 were for a weighted average turbine rating of 2 400-2 800 kW (BNEF, 2017;a;b;c). This is in addition to the fact that more favourable terms are now often being extracted from turbine manufacturers. These can include shorter delivery lead times, more generous initial O&M contracts, better performance guarantees and a reduced need for the order to be part of a larger framework agreement (Wiser and Bollinger, 2017).

The drivers of wind turbine price declines since 2007-2010 have been falling commodity prices, greater supply chain competition, manufacturing economies of scale and process improvements; transforming the global market into one more favourable for buyers. Competition has also increased in the wind turbine market. In 2016, the manufacturer with the largest share of global new capacity installed accounted for just 16.5% of total installations (BNEF, 2017). Indeed, competition has heightened to such an extent in the last few years that consolidation in the sector is gathering pace (Reuters, 2015, 2016 and Bloomberg, 2015).

*3. Chinese wind turbine prices are not directly comparable to the other indices, as they don't include towers or transportation, which are included in their engineering procurement and construction contracts.*

**Figure 5.2** Wind turbine price indices and price trends, 1997-2017




| | Period | % Decrease |
|---|---|---|
| BNEF WTPI | 2009-2017 | 49% |
| BNEF WTPI <95m Ø | 2009-2017 | 53% |
| BNEF WTPI >95m Ø | 2009-2017 | 41% |
| Chinese turbine prices | 2007-2016 | 37% |
| United States 5-100 MW | 2010-2015 | 44% |
| United States <5 MW | 2008-2011 | 21% |
| United States >100 MW | 2008-2016 | 56% |
| Vestas average selling price | 2008-2017 | 48% |

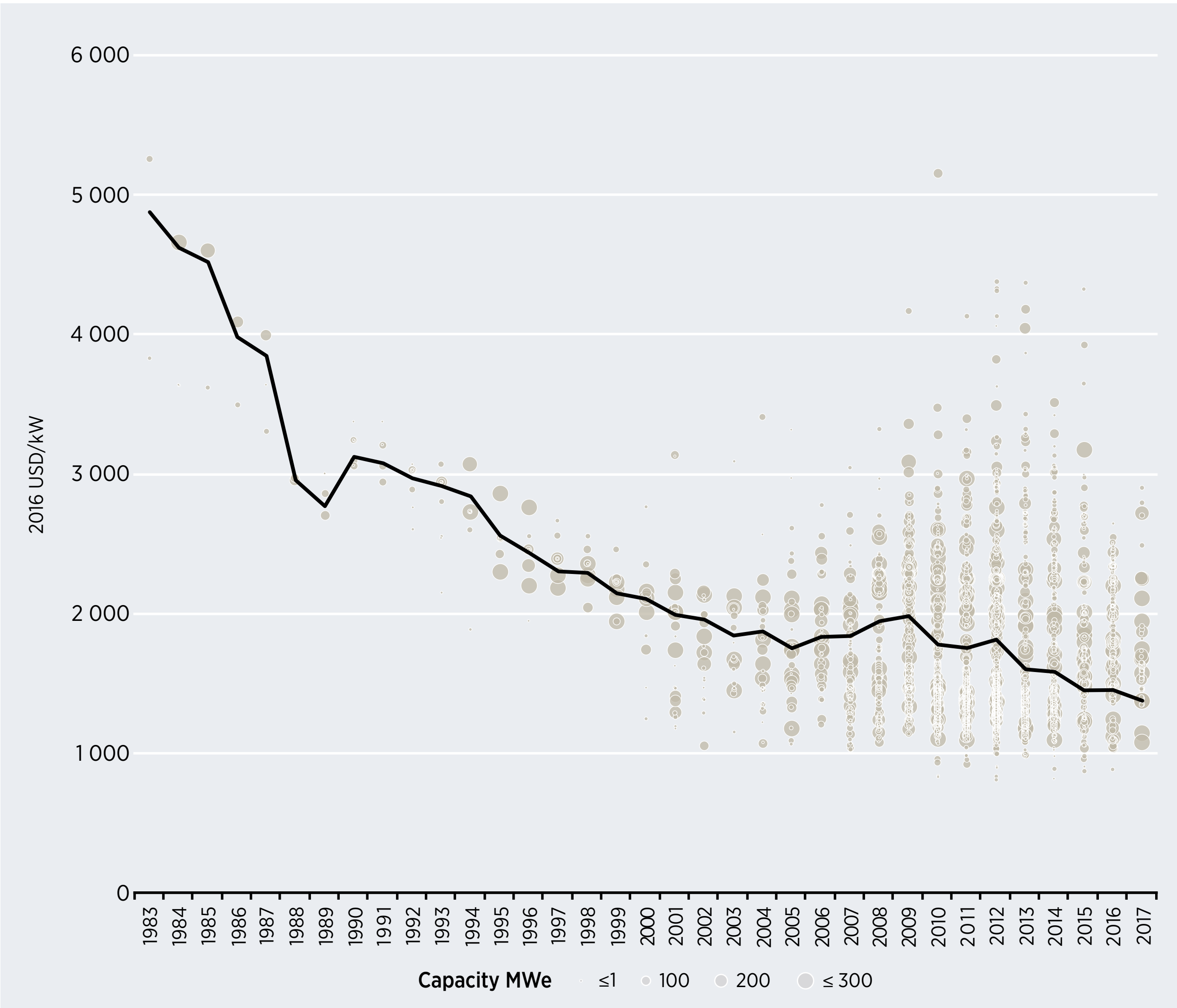
*Sources: Wiser and Bollinger, 2017; CWEA, 2013; BNEF, 2016; Global Data, 2014 and Vestas Wind Systems, 2005-2017.*

## 5.3 TOTAL INSTALLED COSTS ONSHORE

In the past 30 years, onshore wind installed costs have declined significantly, according to IRENAs database of onshore wind power project costs from 1983-2016.[4] The estimated global weighted average fall in total installed cost of wind farms between 1983 and 2017 was 70%, as costs fell from USD 4 880 to USD 1 477/kW. This represents a learning curve of 9% for total installed costs for every time installed capacity doubled, worldwide (Figure 5.3).

Depending on the country, the start date for first commercial deployment varies, complicating a simple comparative analysis. Nonetheless, the installed cost reductions of different countries show a range of declines, from 30-68%. As is clear from this comparison, on an installed cost basis, the shift in deployment to the most competitive countries has resulted in a larger global weighted average cost reduction than has been seen in any one country (Figure 5.4). For those countries with data available from 1983-2016, installed costs fell by the most (68%) in the United States and the least (53%) in Denmark. For the group of countries that started deployment at the end of the 1980s, the fall in installed costs for the period 1989-2016 ranged from a high of a 52% reduction in Spain to a low of a 30% reduction in the United Kingdom. For the group of countries where data is available for

**Figure 5.3** Total installed costs of onshore wind projects and global weighted average, 1983-2017



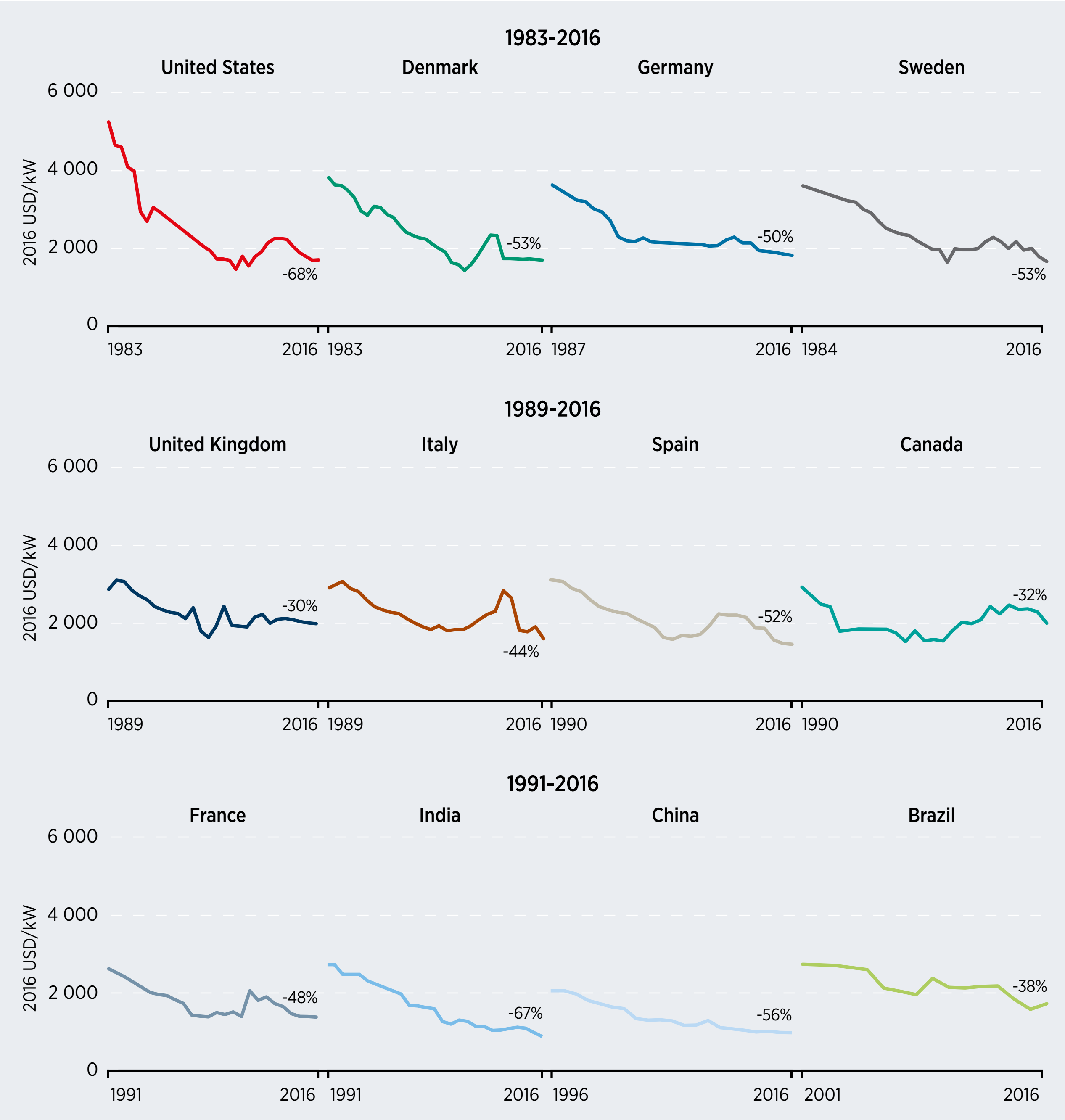

*Source: IRENA Renewable Cost Database.*

*4. This dataset covers more than 85% of all onshore wind capacity installed at the end of 2016.*

the period 1991-2016, total installed cost reductions ranged from a high of 67% in India to a low of a reduction of 38% in Brazil.

In terms of trends in total installed costs, there is still a wide range of individual project costs within a region. In some cases, this represents the differences between countries, where the maturity of local markets can be an important determinant of how efficient total installed cost structures are (e.g., due to logistics and installation, where a shortage of specialised equipment can raise costs). Cost ranges also represent the natural variation of renewable power projects, given the site-specific characteristics that can influence total installed costs. These characteristics include items such as the level of existing infrastructure to enable access to sites, the distance from ports

**Figure 5.4** Onshore wind weighted average total installed costs in 12 countries, 1983-2016



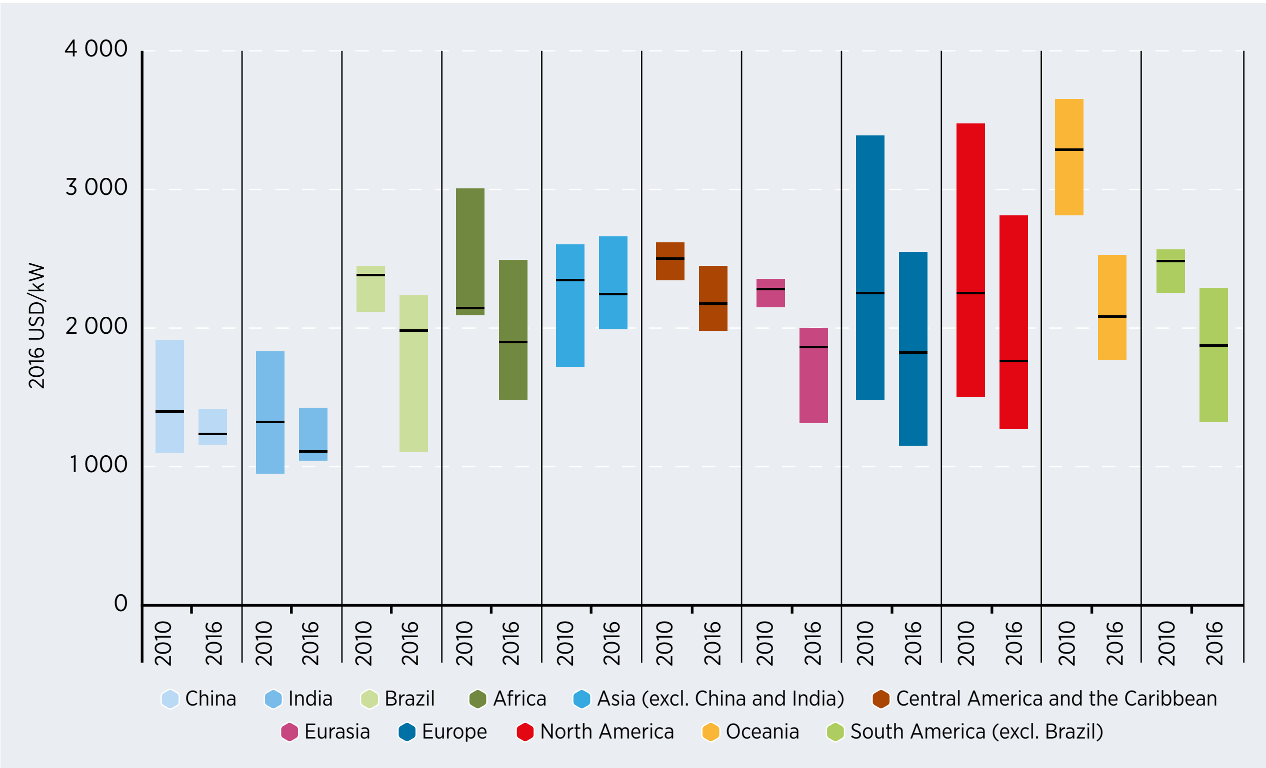

*Source: IRENA Renewable Cost Database.*

or manufacturing hubs, the distance from a major grid-interconnection point, labour costs, and many others. Overall, however, from 2010-2016, total installed costs decreased significantly across the nine geographical regions covered, while ranges also diminished across all regions.

The lowest installed costs for onshore wind projects are to be found in China and India, with weighted average total installed costs estimated to be USD 1 245/kW and USD 1 121/kW respectively in 2016 which translates into a decline of 11% and 16% respectively from 2010. Weighted average installed costs have declined in Brazil from USD 2 390/kW in 2010 to 1 994/kW in 2016. In terms of regions, Asia (excluding China and India), Oceania, Central America and the Caribbean and South America (excluding Brazil) are the most expensive regions, with weighted averages of between USD 1 884 and USD 2 256/kW in 2016. North America has competitive onshore wind installed costs, with a weighted average of USD 1 775/kW in 2016. Between 2010 and 2016, costs fell by 36% in Oceania, 22% in North America, 19% in Europe and between 13% and 19% in other regions (Figure 5.5).

In association with its Renewable Costing Alliance partners, IRENA conducted additional research in 2017 to collect cost breakdown data and O&M data for a range of projects in the IRENA Renewable Cost Database. This has yielded a subset of projects for onshore wind based on a consistent collection methodology. The subset includes data for 448 onshore wind projects commissioned between 2006 and 2017. These represented 17.2 GW of the capacity deployed in 15 countries, stretching from Asia to South America. The data collected should be treated with caution, as it may not be representative for all countries and regions in each year.

**Figure 5.5** Total installed costs ranges and weighted averages for onshore wind farms by country/region, 2010-2016




*Source: IRENA Renewable Cost Database.*

Figure 5.6 presents the evolution in cost breakdown for onshore wind projects in India, China, Germany and the rest of the world, but only for this subset of data. Wind turbines represent the highest share of costs in all regions, ranging from 66-84%, with this changing little over time, except in China. There, wind turbines accounted for 84% of costs in 2010, falling to 72% in 2014.[5] Civil works associated with the development of the wind farm, access and grid connection, represent the second highest share of costs in onshore wind projects. From 2010-2014, this share ranged from 5-23% in China, 8-12% in India and 8-10% in the rest of the world. Grid connection costs also accounted for a significant share of costs, with a maximum of 11% in the rest of the world and a minimum of 3% in China. The figures for Germany are presented using slightly different categories, as data was not available on the same basis as that of other countries and regions. In Germany, wind turbines ranged from 75-78% of costs, depending on the year, while the share of grid connection costs diminished over time, from 10% in 1998 to 5% in 2012.

**Figure 5.6** Cost breakdown of onshore wind farms by country and region, 1998-2016

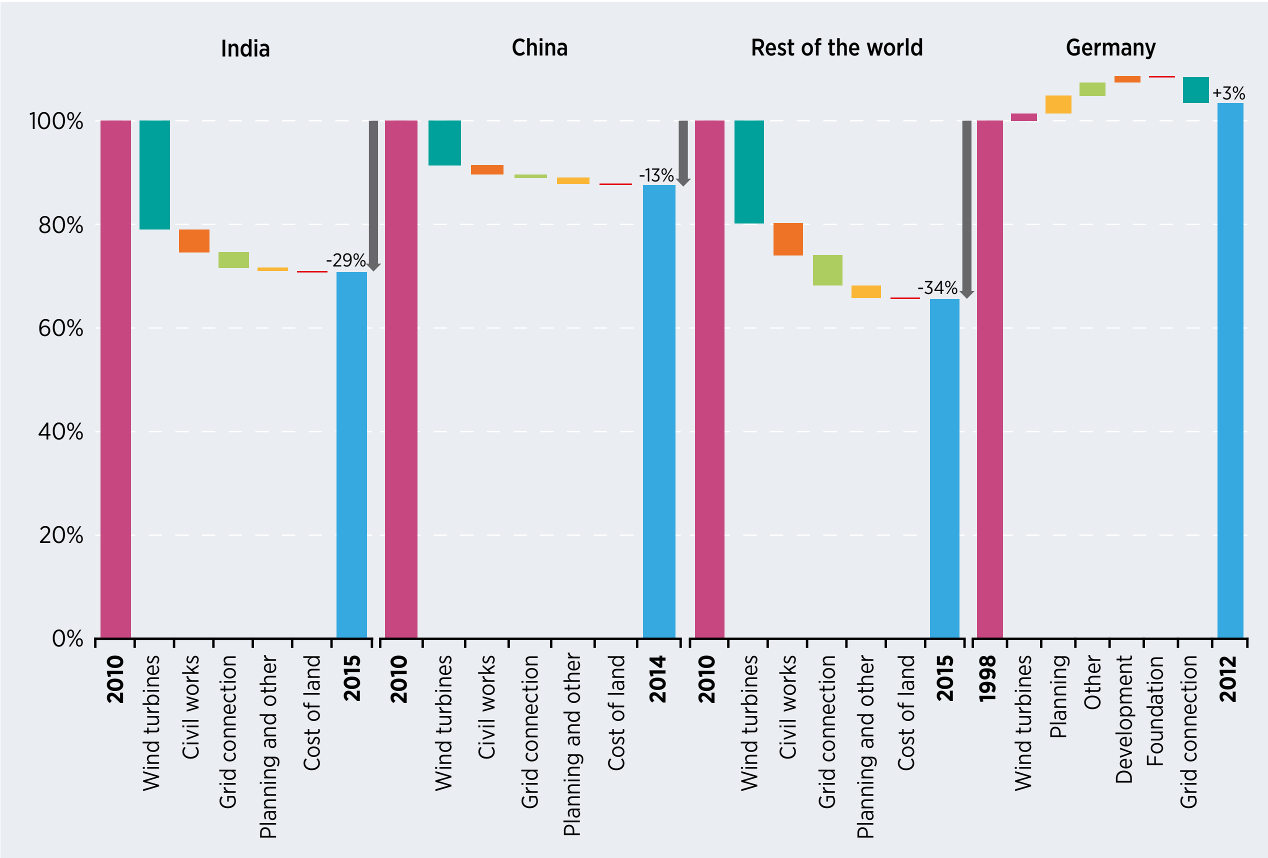

*Source: IRENA Renewable Cost Database and DWG, 2015.*

*5. This sharp change in the share in 2011 is unlikely to be statistically significant and maybe the result of a dataset for 2011 that is not representative of the overall market. IRENA will endeavour to identify additional data for 2011 to confirm or reject this hypothesis.*

Figure 5.7 uses the data available for cost breakdowns from Figure 5.6, with the overall weighted average change in the total installed cost of each of the markets from the complete set of country data in the IRENA Renewable Cost Database to examine what has been driving the reduction in total installed costs. For India and the rest of the world, this is for the period 2010-2015, while for China, it is for 2010-2014, and for Germany, from 1998-2012. Over these time periods, total onshore wind costs declined by 29% in India, 13% in China, and 34% in the rest of the world. In Germany, prices increased slightly, by 3%, due to higher prices for the more advanced turbines being used in Germany, when compared to the other markets, but also because this subset of data for Germany ends before the cost reductions seen in 2013 to 2016. The main drivers in China, India and the "Rest of the World" were declines in wind turbine costs, followed by declines in civil works, grid connection and planning and other project development costs.

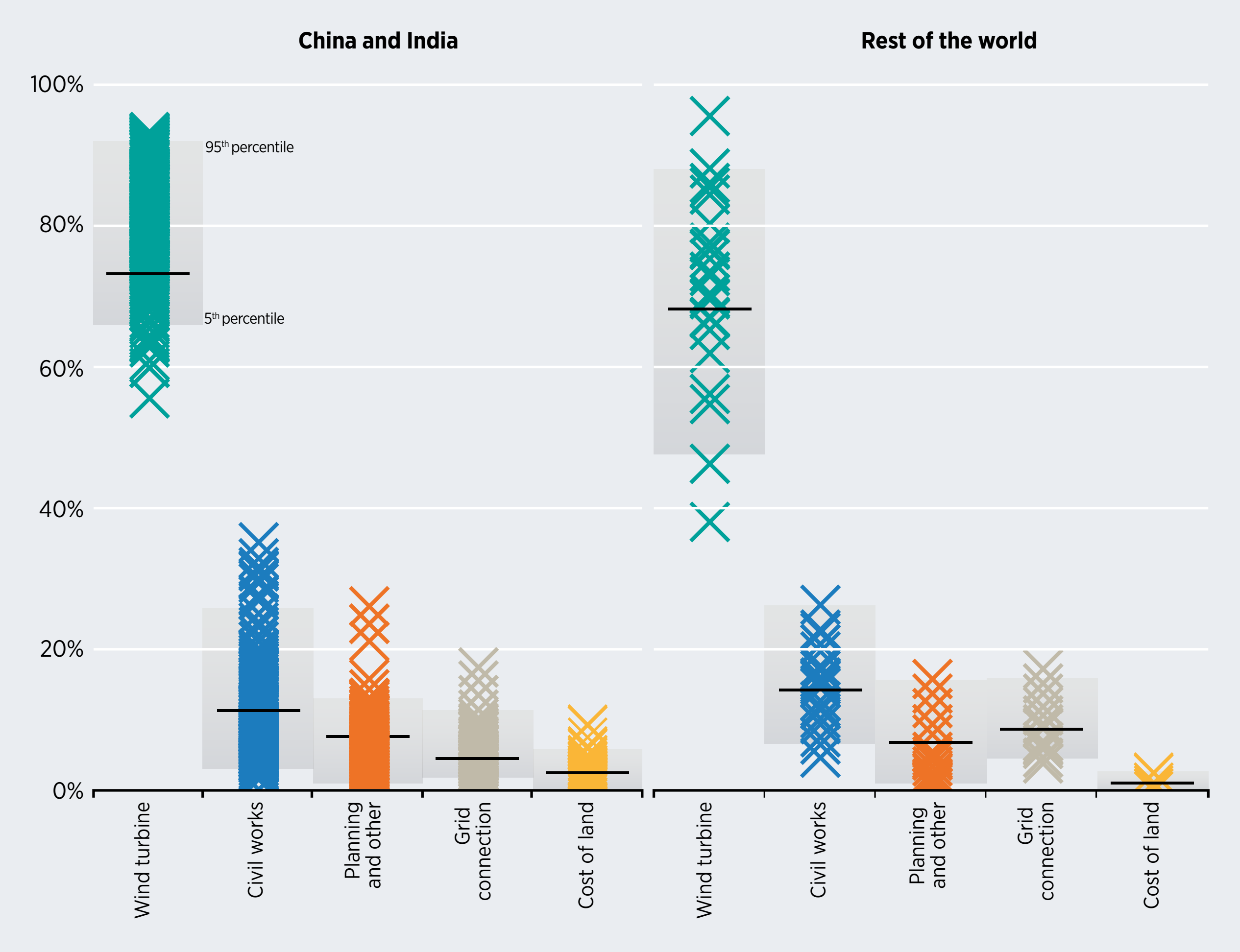
Figure 5.8 presents the distribution and weighted average of five main cost items in onshore wind projects in the subset of data covering 448 projects for which IRENA has been able to collect consistent data. This is stated as a share of the total installed costs for the project, where cost breakdown data was available. The weighted average share of wind turbine costs in China and India was around 73%, falling to 69% in the rest of the world data sub-set. The share of civil works in total installed costs was higher in the rest of the world (15%) than in China and India (12%). Most significantly, on average, the share of grid connection costs was almost twice as high in rest of the world at 9% than in China and India at 5%. The cost of land in China and India makes up a modest share of total installed costs at 3% in China and India and 1% in rest of the world.

**Figure 5.7** Average total installed cost reduction by source for onshore wind, 2010-2014/15 and 1998-2012




*Source: IRENA Renewable Cost Database, 2017.*

**Figure 5.8** Distribution and weighted average share of onshore wind total installed costs by source for China and India, and rest of the world, 2006-2016




*Source: IRENA Renewable Cost Database, 2017.*

## 5.4 TOTAL INSTALLED COSTS OFFSHORE

In comparison to onshore wind projects, offshore wind farms have significantly higher lead times. Planning for offshore wind farms is more complex and construction even more so, increasing total installed costs. Given their offshore location, they also have higher grid connection and construction costs. Offshore wind project installed costs rose in the period to around 2012-13, as projects were sited farther from shore and have been using more advanced technology.

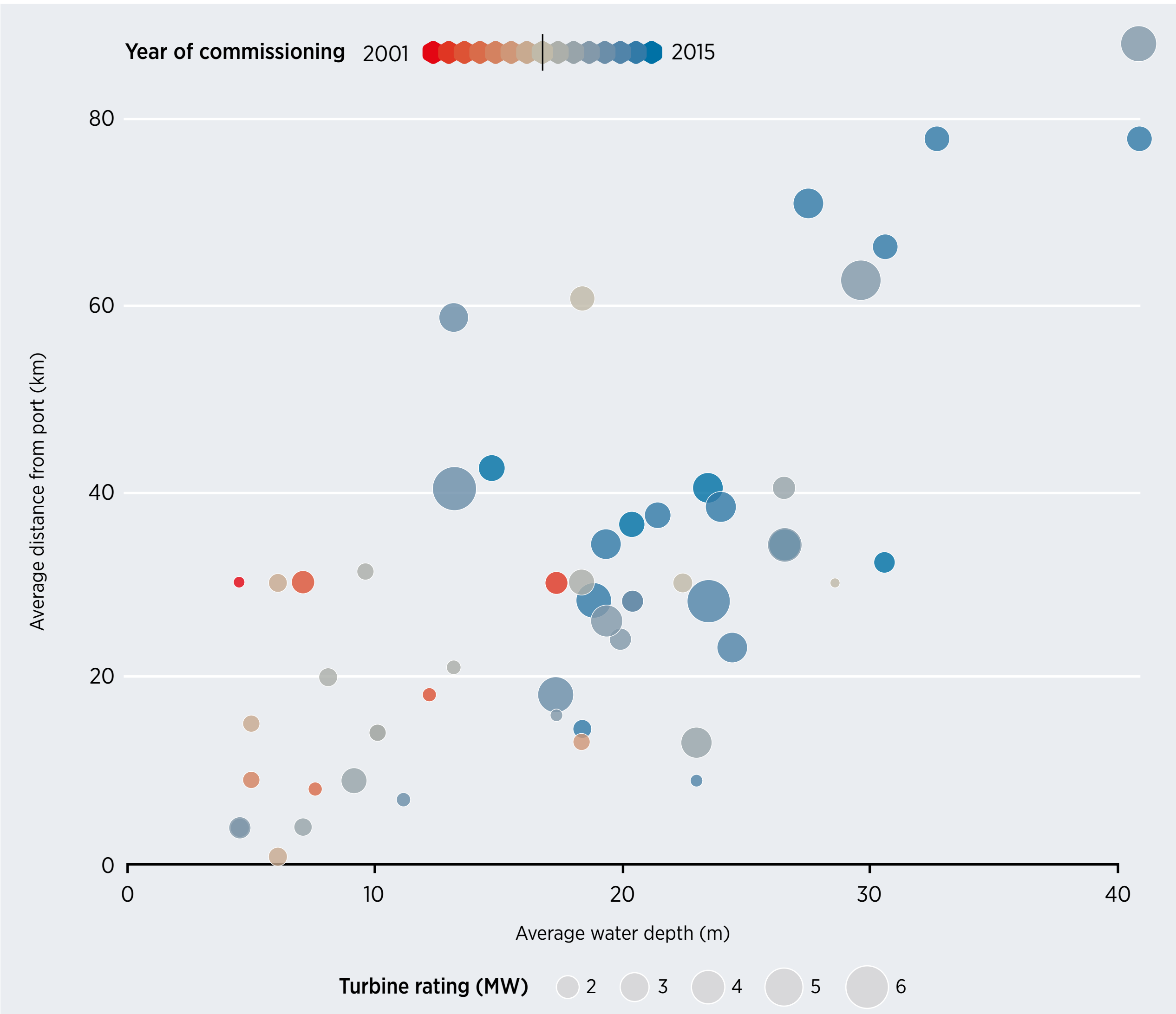
Wind turbines for offshore wind projects account for somewhere between 30% and 50% of total installed costs, while foundations are also a significant part of total installed costs (IRENA, 2016a). The specific location of offshore wind projects can also significantly increase the costs of construction, as well as grid connection due to the expense of deploying undersea cables and working further from a port on the installation. Increased costs to protect equipment and installations from the harsh marine environment also add to the final costs. These can be profitable incremental investments if they mitigate costly unplanned maintenance interventions. Operation and maintenance costs are higher for offshore wind than for onshore wind, because of the complexity of servicing offshore wind turbines and the more challenging environment at sea. Yet, on average, offshore wind projects harvest more energy than onshore wind projects, notably in Europe, due to the availability of better wind resources, less turbulence and steadier winds, overall.

The global cumulative installed capacity of offshore wind was 14 GW at the end of 2016, or 3% of total installed wind capacity. Over 2013 to 2016, the annual new capacity installed was above 2 GW, as the offshore market picked up a solid pace, predominantly in Europe.

As the industry matured after 2000, projects moved to deeper water and farther from shore (Figure 5.9). Since 2009, most projects have been sited in water depths greater than 15 metres and at a distance of 20-80 km from the nearest port. The average size of grid-connected offshore wind farms in Europe in 2016 was 380 MW, while the average water depth of completed, or partially completed, wind farms was 29 metres, with an average distance to the nearest port of 44 km (WindEurope, 2017). Developers also began using larger turbines during the period in question, with larger rotors and higher hub heights. These were increasingly specifically designed by manufacturers for the offshore market and the harsh marine environment in which they operate.

The reason for this trend towards larger turbines and longer blades designed for offshore operations was to increase capacity factors, as developers accessed better quality wind resources further offshore. Larger turbines can also help reduce installation costs and amortise project development costs over larger wind farm capacities for the same physical area. Cost reductions begun to be unlocked as the industry increasingly standardised new wind turbines and industrialised the manufacturing process. Installation methods and offshore construction vessels also became more sophisticated and more efficient, reducing the time, and hence costs, of installation.

**Figure 5.9** Offshore wind farm projects and distance from port, 2001-2017




*Source: IRENA Renewable Cost Database.*

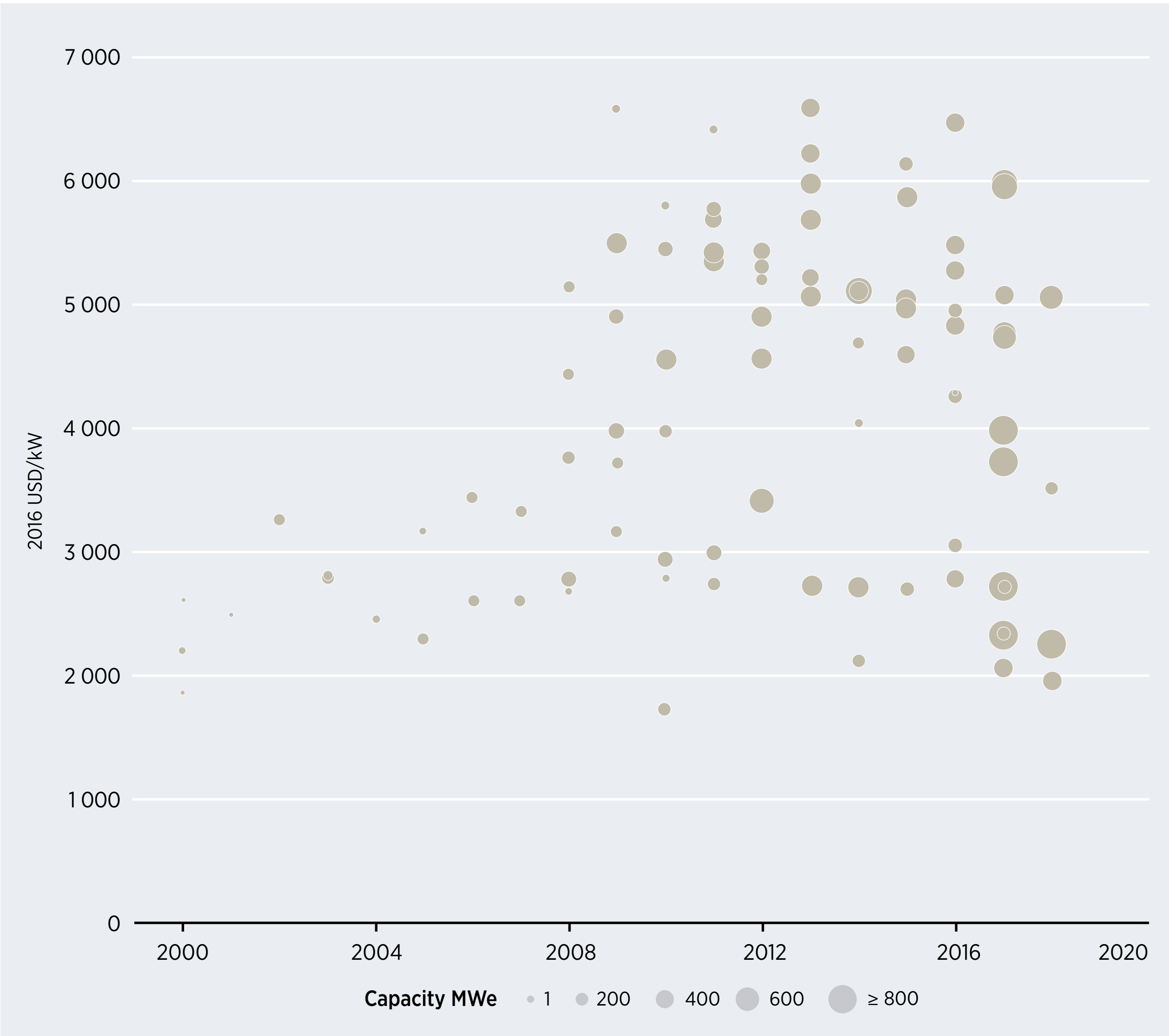
From 2001-2010, most of the wind turbines for offshore projects were in the 2-3.6 MW range. After 2011, due to improvements in technology, the range increased significantly, to 3.6-6.15 MW. Projects also became larger after 2011, thus allowing developers to benefit from economies of scale and to offset some the cost increases related to siting projects further ashore and in deeper waters. The average size of a European offshore wind farm was slightly below 200 MW in 2011 while in 2016 it had risen to 380 MW, a 90% increase over the entire period (EWEA, 2012; WindEurope, 2017). This trend has led to greater economies of scale, more competitive supply chains and O&M benefits that have been part of the drivers of recent cost reductions.

### Total installed costs of offshore wind

Figure 5.10 presents the evolution of total installed costs for offshore wind projects from 2000-2016. These rose in the period 2000-2010, as the shift towards deeper waters and locations farther from ports took place. Installed costs appear to have peaked around 2012-2013, although better wind resources accessed by better technologies moderated the impact of increasing installed costs between 2000 and 2012-2013 on LCOE. Between 2010 and 2016, global weighted average installed costs increased by 4%, up from USD 4 430 to USD 4 487/kW.

In 2016, average installed costs for a European offshore wind farm were slightly higher than the global weighted average, at USD 4 697/kW

**Figure 5.10** Total investment costs for commissioned and proposed offshore projects, 2000-2018



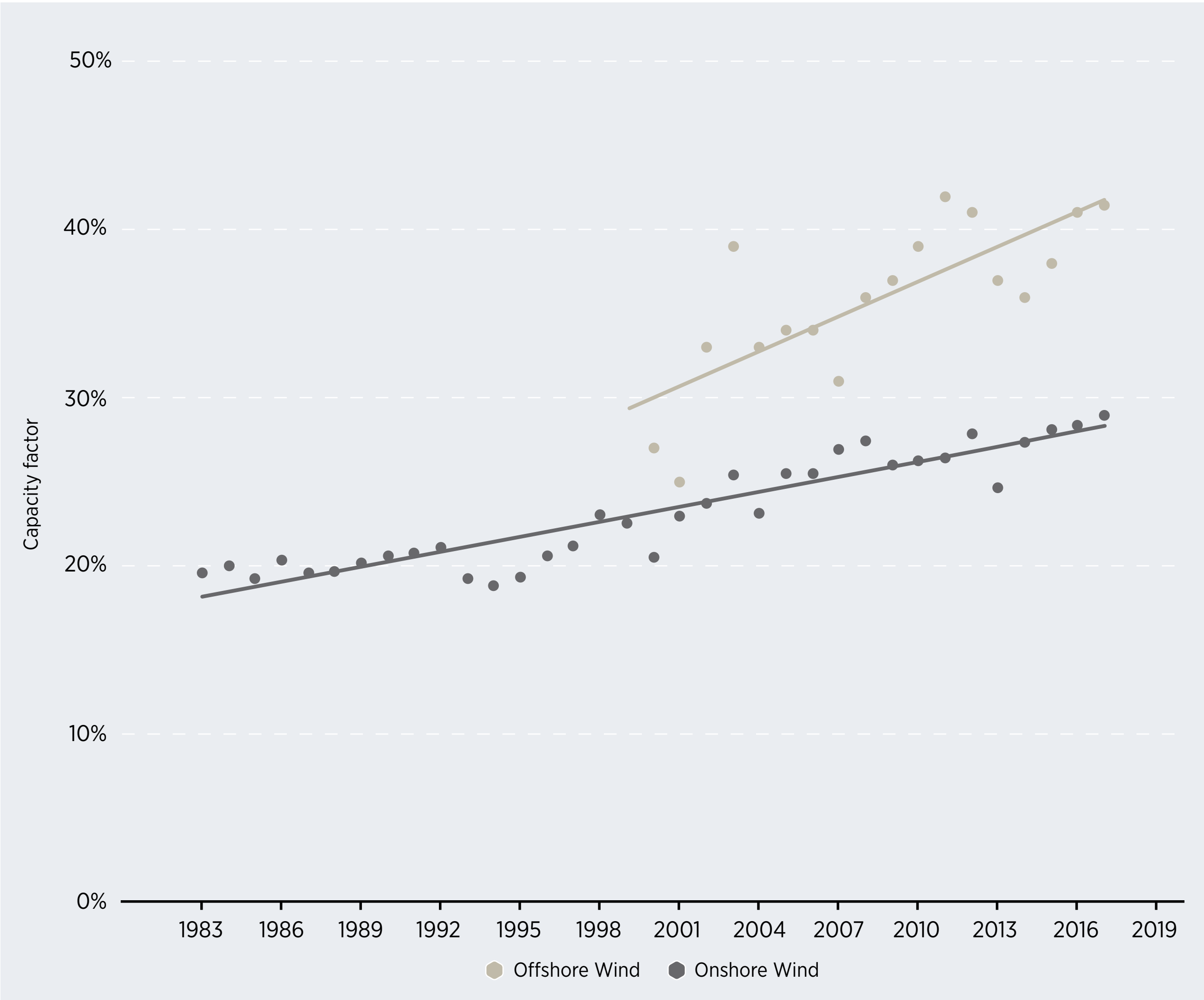

*Source: IRENA Renewable Cost Database.*

(IRENA, 2016a). The turbine rotor and nacelle was estimated to account for 38% of total installed costs, construction and installation for 19%, the support structure and foundations for 18%, grid connection/transmission for 13%, the turbine tower for 6% and project development and wind farms electrical array for 3% each. As is to be expected, foundations account for a significant percentage of total costs, due to the expense of operating offshore and designing for the harsh marine environment. On average, these therefore account for around 18% of installed costs (IRENA, 2016a). This share can vary, however, and is influenced by water depth, conditions on the seabed, turbine loading, rotor and nacelle weight and the speed of the rotor.

## 5.5 CAPACITY FACTORS

The capacity factors of wind projects are determined by the quality of the wind resource and the technology employed. There has been a trend towards the use of more advanced turbine technologies as previously discussed. As a result, there has been a consistent trend towards higher capacity factors globally, but with significant variations by market. This has been driven by the growth in the average hub height, turbine rating and rotor diameters of installed turbines, but also by the trends in resource quality at new projects in individual markets. The global weighted average capacity factor for onshore wind increased from around 20% in 1983 to around 29% in 2017 (Figure 5.11) – a rise of about 45%. The global

**Figure 5.11** Global weighted average capacity factors for new onshore and offshore wind power capacity additions by year of commissioning, 1983-2017

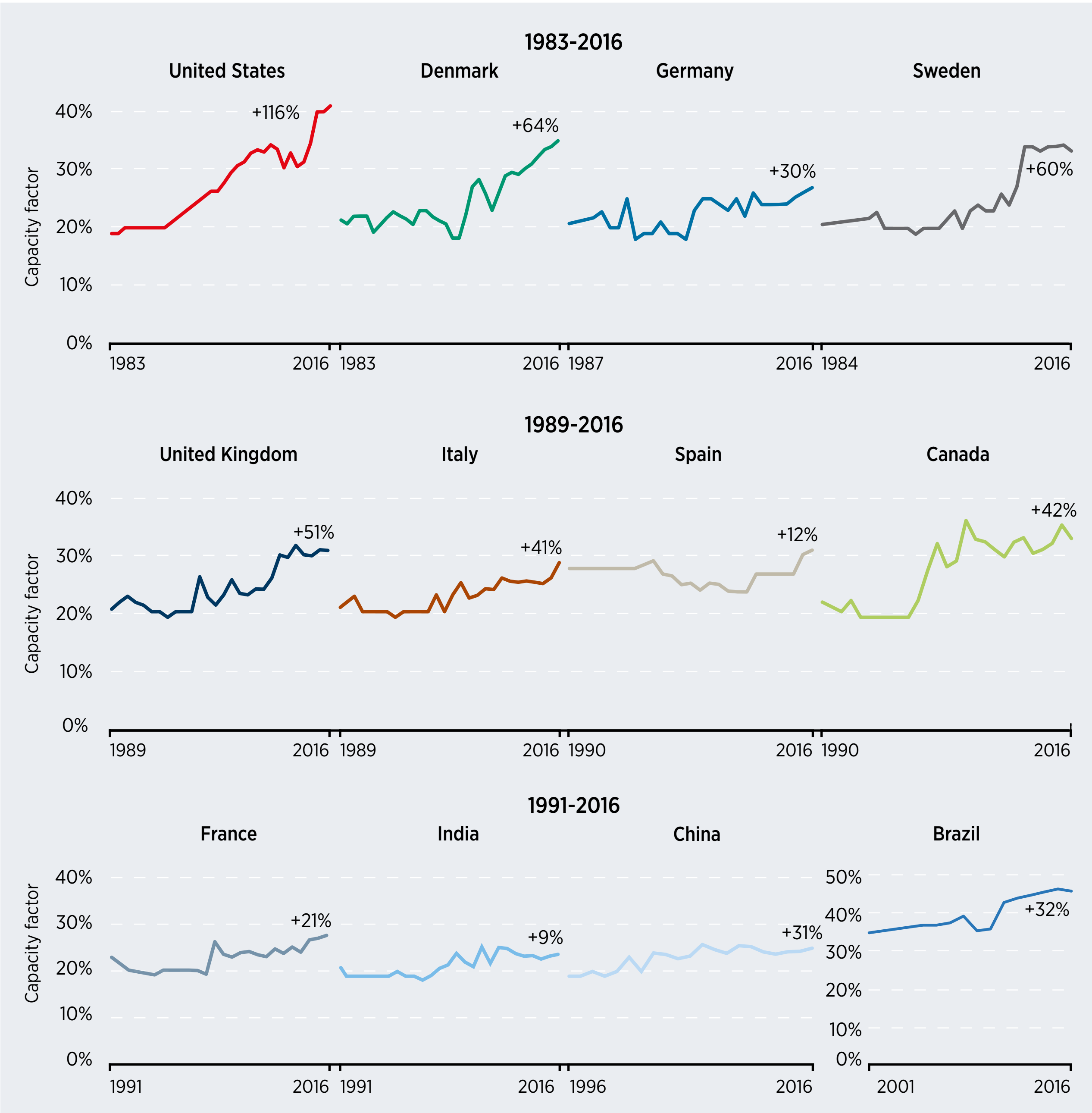



*Source: IRENA Renewable Cost Database.*

weighted average capacity factor for offshore wind also increased by 56%, but from a higher starting point. In 2017, the weighted average offshore capacity factor for newly commissioned plants reached around 42%, but given the relatively low volumes of projects being developed the newly commissioned average for a given year has been quite variable.

Figure 5.12 presents the historical evolution of onshore wind capacity factors for new capacity additions commissioned in each year for the 12 countries in IRENAs learning curve analysis. Capacity factors doubled in the United States and increased by more than 60% in Denmark and Sweden. The simple average increase in capacity factors for these 12 countries was around 43%. The United States stands out, however, as a market where the trend towards higher capacity factors has been driven not only by technology improvements, but also the trend towards the location of projects in areas with the best resources.

**Figure 5.12** Historical onshore wind capacity factors in a sample of 12 countries




*Source: IRENA Renewable Cost Database.*

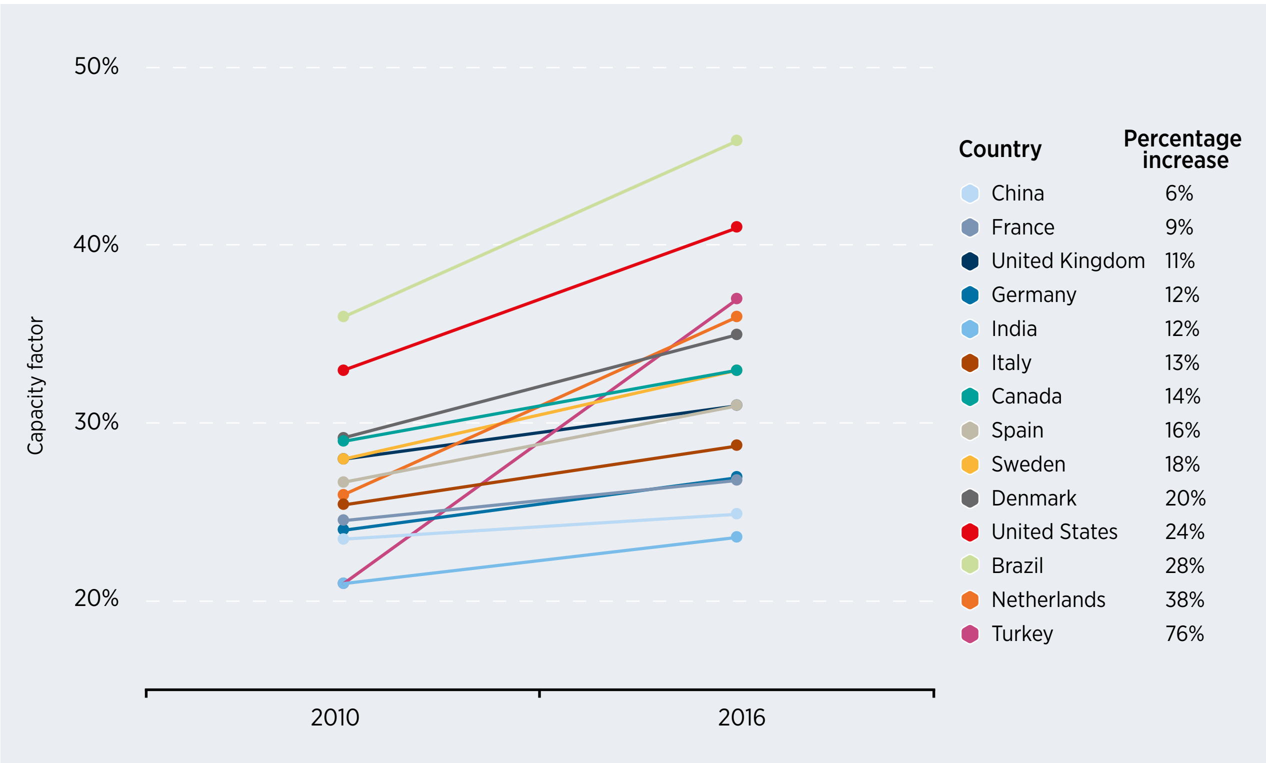
Figure 5.13 focuses on the change in the weighted average capacity factor of onshore wind projects that were commissioned in 2010 and 2016 in a range of countries. All countries for which data are available experienced a significant increase in the weighted average capacity factor of newly commissioned projects between 2010 and 2016, ranging from a low of a 11% increase in the United Kingdom to a high of 76% in Turkey.

Figure 5.14 presents the evolution of the global weighted average hub height, rotor diameter and capacity factor. Hub heights increased from around 20 metres in 1983 to more than 100 metres in 2016, while capacity factors increased from 23% in 1983 to 28% in 2016 – more than 25% over the entire period. This has been achieved as installed capacity of onshore wind has increased exponentially, growing from 0.2 GW in 1983 to more than 454 GW at the end of 2016.

## 5.6 OPERATION AND MAINTENANCE COSTS

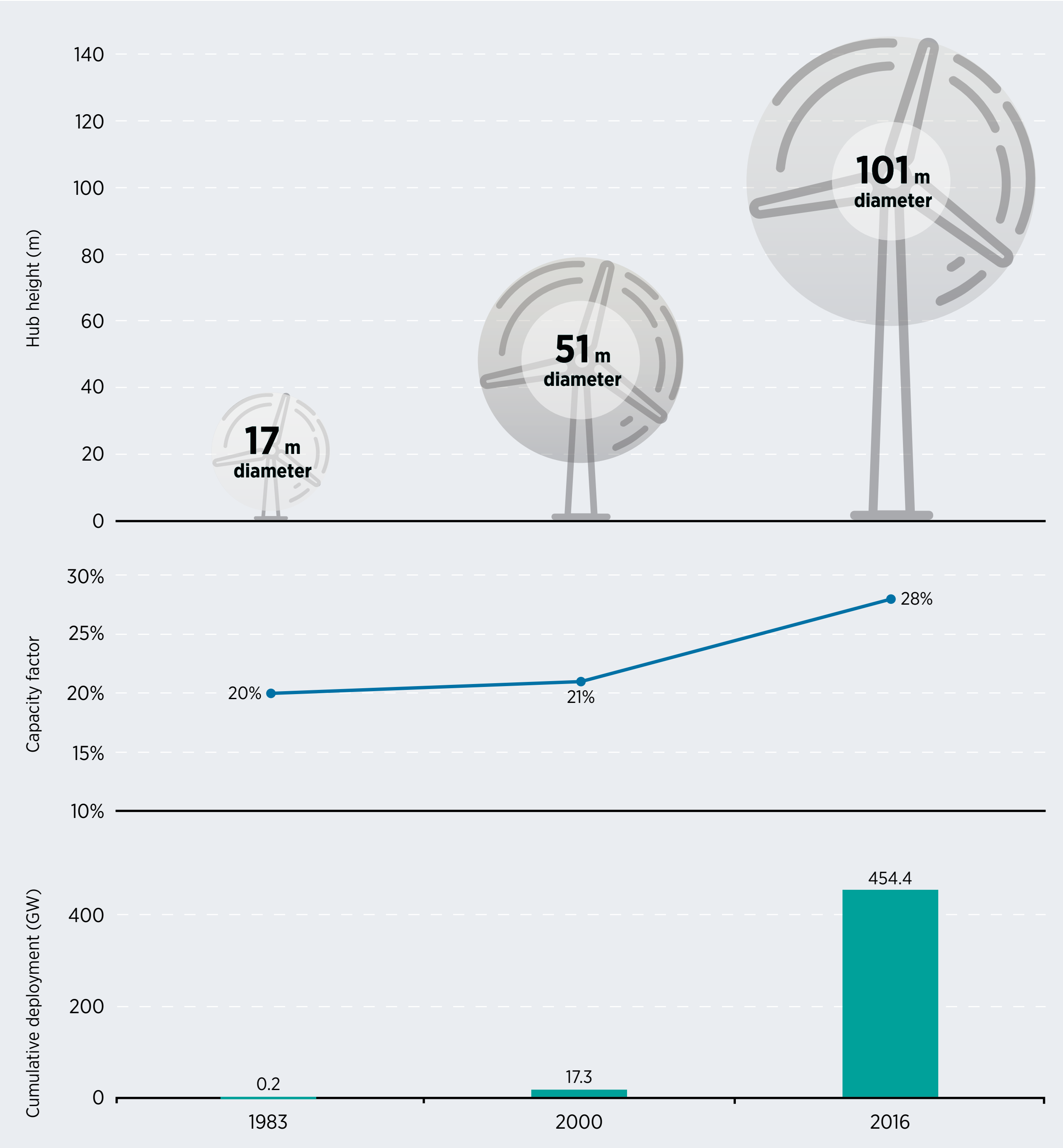
The global wind power O&M market is expected to grow from USD 12 billion in 2016 to more than USD 27 billion by 2026 (MAKE Consulting, 2017c). The biggest markets for O&M services are those countries with the greatest installed capacity – among which are China, the United States, Germany, India, Brazil and Spain. Operations and maintenance costs, both fixed and variable, are a significant part of the LCOE of wind power. Yet, data for the actual O&M costs of commissioned projects is not readily available. Where it is, care must be taken in extrapolating from historical O&M costs, as significant changes in wind turbine technology over the last decade must be taken into consideration. Though data for maintenance is often available, the cost data for operations is not systematically and uniformly collected (e.g. management costs, insurance, fees, land lease, taxes etc.).

**Figure 5.13** Country-specific weighted average capacity factors for new onshore wind projects, 2010 and 2016




*Source: IRENA Renewable Cost Database.*

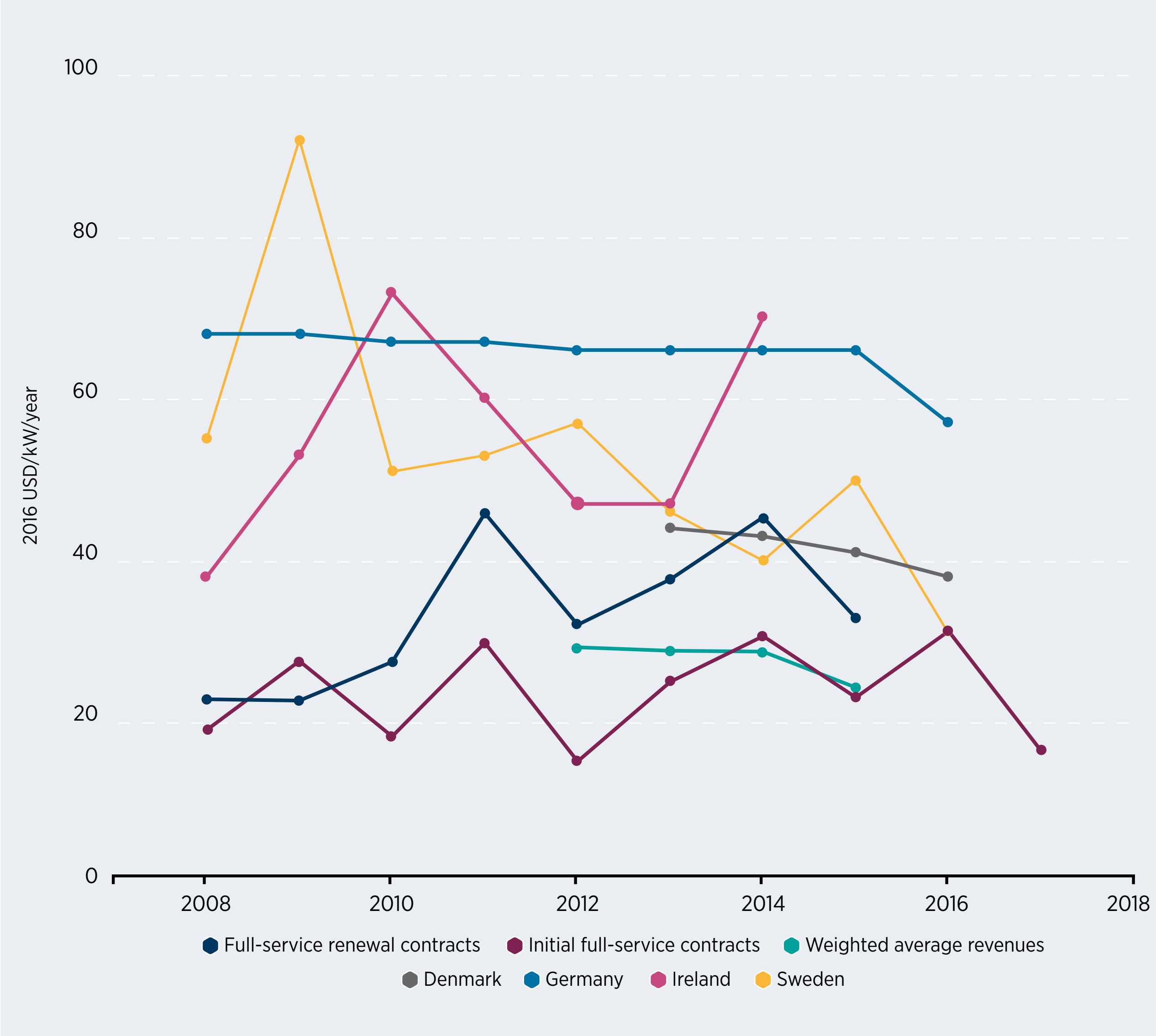
**Figure 5.14** Global weighted average hub height, rotor diameter and capacity factors, and cumulative capacity for onshore wind, 1983-2016




*Source: IRENA Renewable Cost Database.*

O&M costs measured as initial full-service contracts are less expensive than full-service renewal contracts (Figure 5.15). A clear trend cannot be extracted from the available data on these two categories, however, as these costs vary depending on the year. Initial full service contracts varied from USD 14 to USD 30/kW/year between 2008 and 2017, while full-service renewal contracts varied from USD 22 to USD 44/kW/year. In the United States, O&M costs ranged from USD 16 to USD 37/kW/year in 2016, while the weighted average was USD 27/kW/year (MAKE Consulting, 2017c). Data from IEA Wind for four countries shows

**Figure 5.15** Full-service (initial and renewal) O&M pricing indexes, weighted average O&M revenues of two manufacturers, and O&M costs in Denmark, Germany, Ireland and Sweden, 2008-2017




*Sources: BNEF, 2017; Global Data, 2017; IEA Wind, 2017.*

that O&M costs declined in three out of four markets, with high volatility in the Irish market in particular.

The premium identified in the BNEF full service renewal contract index over the initial contract offers represents the additional expected costs as turbines age. This will become an increasing consideration for wind farm asset owners as wind farms begin to age. Given the rapid growth in deployment, wind turbine fleets are still relatively young. In 2016, Germany had one of the oldest fleets in service, but was still just over 10 years old. In the United States the fleet was 8.5 years old, in China it was only around five years, while the global average for fleet is slightly over six years old. Original equipment manufacturers (OEM) had the largest share of the routine turbine O&M market in 2016, with around 70%. By 2026, however, OEM's market share is expected to decrease, as the trend towards self-operation increases (MAKE Consulting, 2017c).

Figure 5.16 presents the annual range of O&M costs in China, India and the rest of the world for the 448 project subset in the IRENA Renewable Cost Database. Reported O&M cost ranges are lower in India than in China, but in both countries there was a downward trend from 2010-2016. The bulk

**Figure 5.16** Project level O&M cost data by component from a subset of the IRENA database compared to the BNEF O&M index range, 2008-2016


*Source: IRENA Renewable Cost Database, BNEF 2017.*

of projects in China had O&M costs in the range of USD 22 to USD 47/kW/year during this period. The lower values for India are significant, but question marks over the comparability of reporting for all cost categories suggest that Indian data often excludes some operations costs and is composed mainly of maintenance costs. Further analysis is required to confirm or reject this hypothesis. A smaller number of projects reported O&M costs in other regions, and while this data spans a wide range, the quantity of data is not sufficient, when compared to the data for China and India, to suggest a definitive answer on where the bulk of project O&M costs range. The BNEF O&M index range has been included for comparison, but as already mentioned uncertainty about reporting of cost categories means that care should be taken in any comparison across the different cost metrics.

In China, converting the USD/kW/year O&M cost calculation to the USD/kWh range yields costs ranging from USD 0.008 to USD 0.028/kWh, while the average is USD 0.017/kWh. In India, weighted average O&M costs range from USD 0.005 to USD 0.027/kWh. The weighted average O&M costs in the database for Central and South America is USD 0.014/kWh, below that observed in China. Looking at the average share of O&M costs across all of the projects in the subset of data for which IRENA has detailed O&M data, the largest share of O&M costs is represented by maintenance operations, which have a weighted average of 67%, followed by salaries at 14% and materials at 7% (Figure 5.16).

Table 5.1 presents data for O&M costs reported for a range of OECD countries. The data is not consistently reported, however, making comparisons difficult. Averages of USD 0.02 to USD 0.03/kWh appear to be the norm, with certain exceptions.

**Table 5.1** O&M costs of onshore wind in selected OECD countries

| Country | Variable (2016 USD/kWh) | Fixed (2016 USD/kW/year) |
|---|---|---|
| Germany | 0.03 | 66 |
| Denmark | 0.02 | |
| Ireland | | 74 |
| Norway | 0.03 | |
| United States | 0.00 | 53 |
| Austria | 0.04 | |
| Finland | | 41 |
| Italy | | 50 |
| Japan | | 76 |
| The Netherlands | 0.01 | |
| Spain | 0.03 | |
| Sweden | 0.03 | |
| Switzerland | 0.05 | |

*Source: IEA Wind, 2011b; IEA Wind, 2015.*

O&M costs for offshore wind farms are higher than those for onshore wind, mainly due to the higher costs of access to the site and of performing maintenance on towers and cabling. The marine environment is harder to operate within than dry land, adding to the overall O&M costs. O&M costs for Europe are estimated to be between USD 109/kW/year and USD 140/kW/year today, but could fall to USD 79/kW/year by 2025 (IRENA, 2016a; IEA Wind, 2016).

### 5.7 LEVELISED COST OF ELECTRICITY

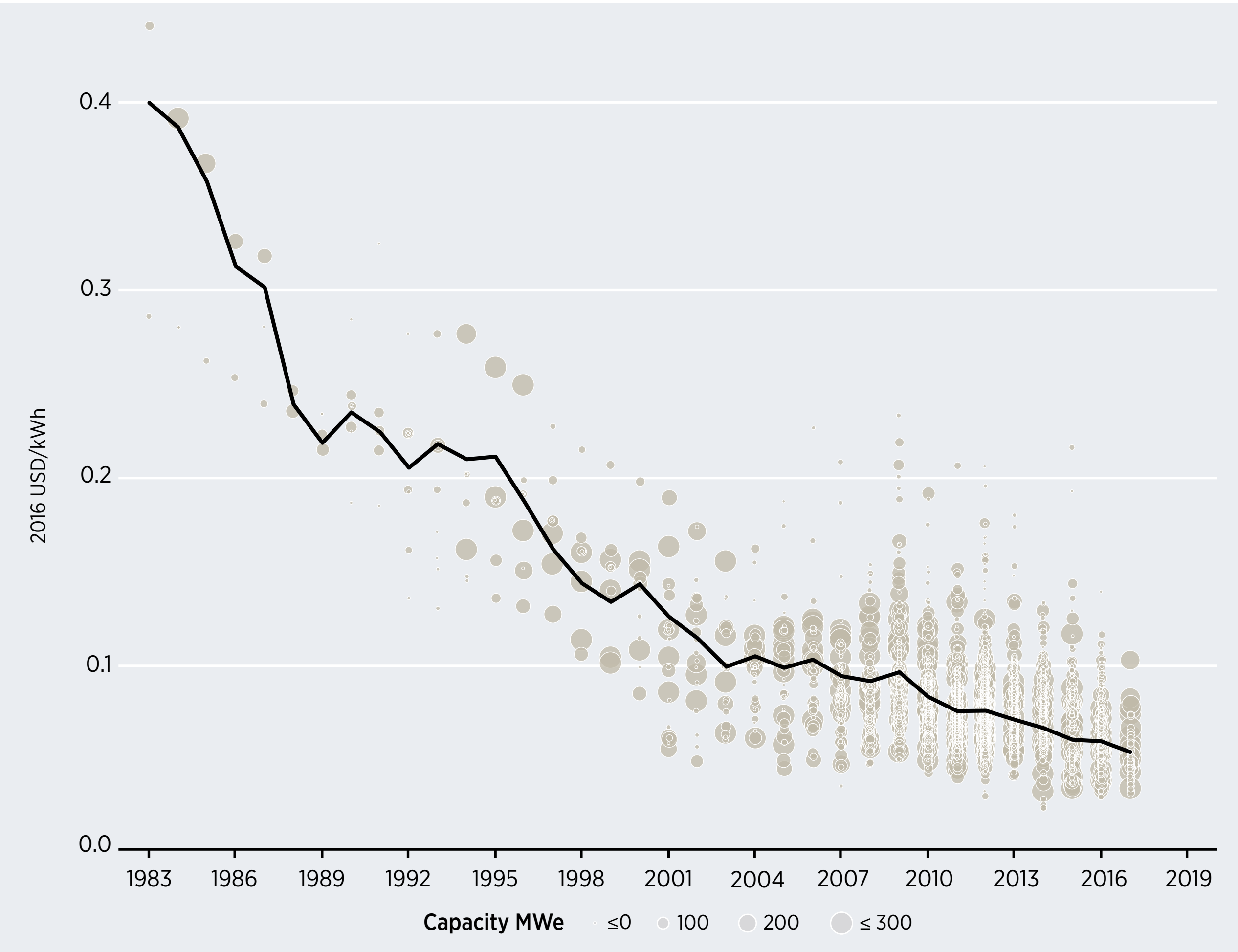
The LCOE of a wind power project is driven by total installed costs, wind resource quality, the technical characteristic of the wind turbines used, O&M costs, the cost of capital and the economic life of the project. Thus, the LCOE depends largely on four factors:

- Capacity factor: This is the result of an interplay of several variables, among which the most important is the nature and quality of the wind resource, followed by wind turbine design and operational availability – including potential curtailment.
- Total installed costs: The turbine cost is usually the single largest cost item in a wind project, though depending on the complexity of the project, its share can be less important. This is even more so for offshore wind projects.
- WACC: The cost of debt, the equity premium of the investors, and the share of debt and equity in a project all go towards the final value of the WACC.
- Operations and maintenance costs: Operational expenses consist of both fixed and variable costs and can represent up to 20%-25% of LCOE.

Figure 5.17 presents the evolution of the LCOE of onshore wind between 1983 and 2017. The global weighted average LCOE declined from USD 0.40/kWh in 1983 to USD 0.06/kWh in 2017, an 85% decline. The data suggests that every time cumulative installed capacity doubles, the LCOE of onshore wind drops by 15%. This trend includes the impact of lower O&M costs over time, but not the impact of a reduced cost of capital, as technology matures and financial markets become more comfortable with wind power development. The rate of 15% is therefore an underestimate of the total learning rate for onshore wind, but a lack of data means the exact value cannot be known with any certainty. However, the auction data for projects that will be commissioned out to 2020 yields a learning rate of 21% for the period 2010-2020, a figure more likely to represent the true learning curve value given the auction results include the impact of a lower WACC.

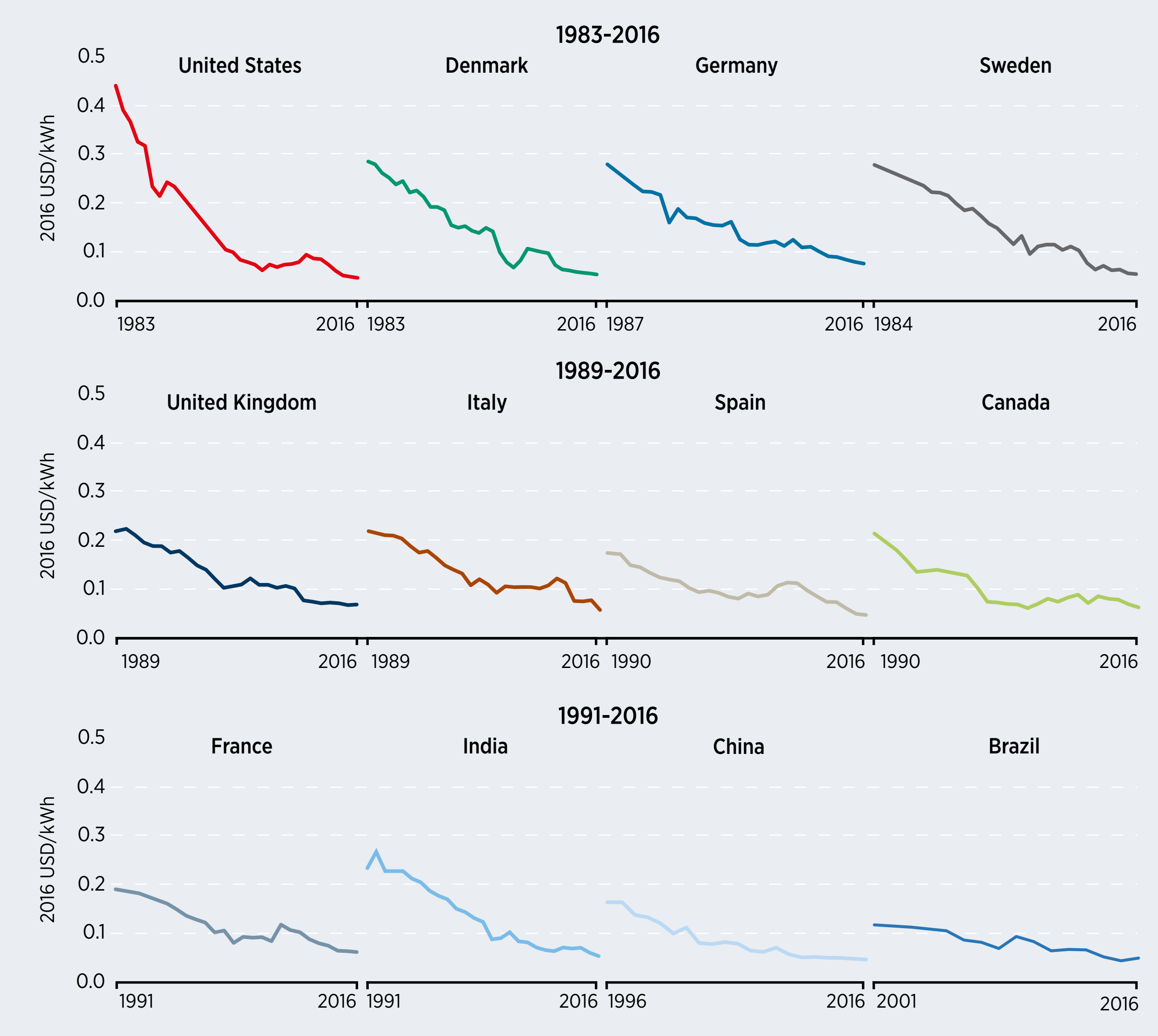
Figure 5.18 presents the historical evolution of the LCOE of onshore wind in 12 countries where IRENA has the longest time series data. The data needs to be interpreted with care, however, given that the first year for which IRENA has data for a country varies. From 2010 to 2016, the greatest decline in LCOE was in Spain, at 48%, followed by the United States, at 45%, and Italy with 43% (Figure 5.18, Table 5.2).

**Figure 5.17** The global weighted average levelised cost of electricity of onshore wind, 1983-2017




*Sources: IRENA Renewable Cost Database.*

**Figure 5.18** The weighted average LCOE of commissioned onshore wind projects in 12 countries, 1983-2016




*Source: IRENA Renewable Cost Database*

**Table 5.2** The weighted average LCOE reduction of commissioned onshore wind projects in 12 countries

| Country | Beginning to 2010 | 2010 - 2016 | Beginning - 2016 |
|---|---|---|---|
| United States | 80% | 45% | 89% |
| Denmark | 74% | 26% | 81% |
| Germany | 60% | 31% | 72% |
| Sweden | 71% | 28% | 79% |
| United Kingdom | 63% | 10% | 66% |
| Spain | 42% | 48% | 70% |
| Italy | 49% | 43% | 71% |
| Canada | 56% | 27% | 68% |
| France | 47% | 42% | 69% |
| India | 72% | 19% | 77% |
| China | 65% | 19% | 71% |
| Brazil | 29% | 39% | 57% |

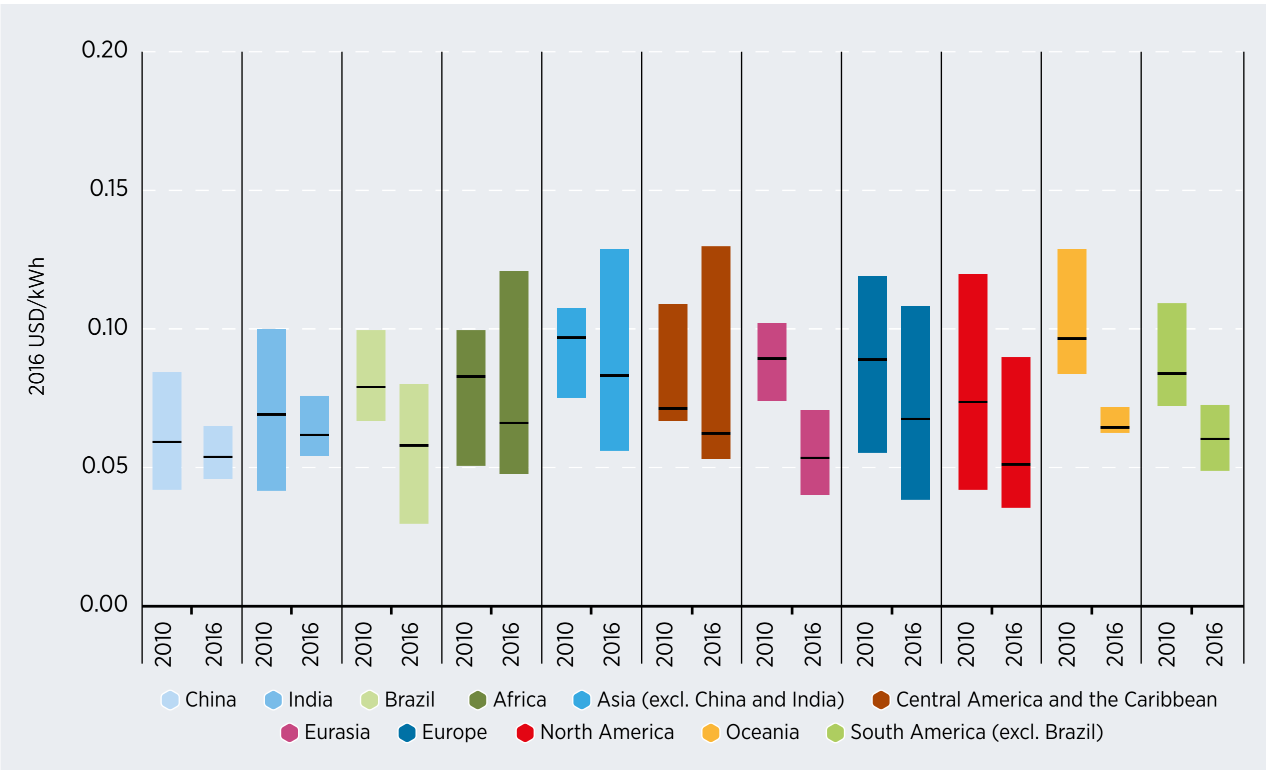
*Source: IRENA Renewable Cost Database*

Figure 5.19 presents regional and selected country weighted average LCOEs and ranges for onshore wind from 2010-2016. In 2016, the most competitive weighted average LCOEs were observed in China, India, Brazil, Eurasia and North America, at USD 0.06 to USD 0.07/kWh. These countries and regions are home to over half of global cumulative installed capacity. The highest weighted average LCOE in 2016 was observed in Europe, at USD 0.08/kWh, while in 2010 the highest LCOE was observed in Oceania and Asia (excluding China and India), at USD 0.11/kWh. The rate of LCOE decrease in North America between 2010 and 2016 was 30%. In 2010, Eurasia had one of the highest weighted averages, at USD 0.10/kWh, while in 2016 it came second, with an LCOE of USD 0.06/kWh, the highest regional LCOE decrease, at 40%. The second highest regional LCOE decline occurred in Oceania where the LCOE fell by 33% from 2010 to 2016, from USD 0.11 to USD 0.06/kWh. Europe saw its weighted average LCOE decrease by 24% over the period, from USD 0.10/kWh to USD 0.08/kWh.

*Improved technology has allowed higher capacity factors at the same site*

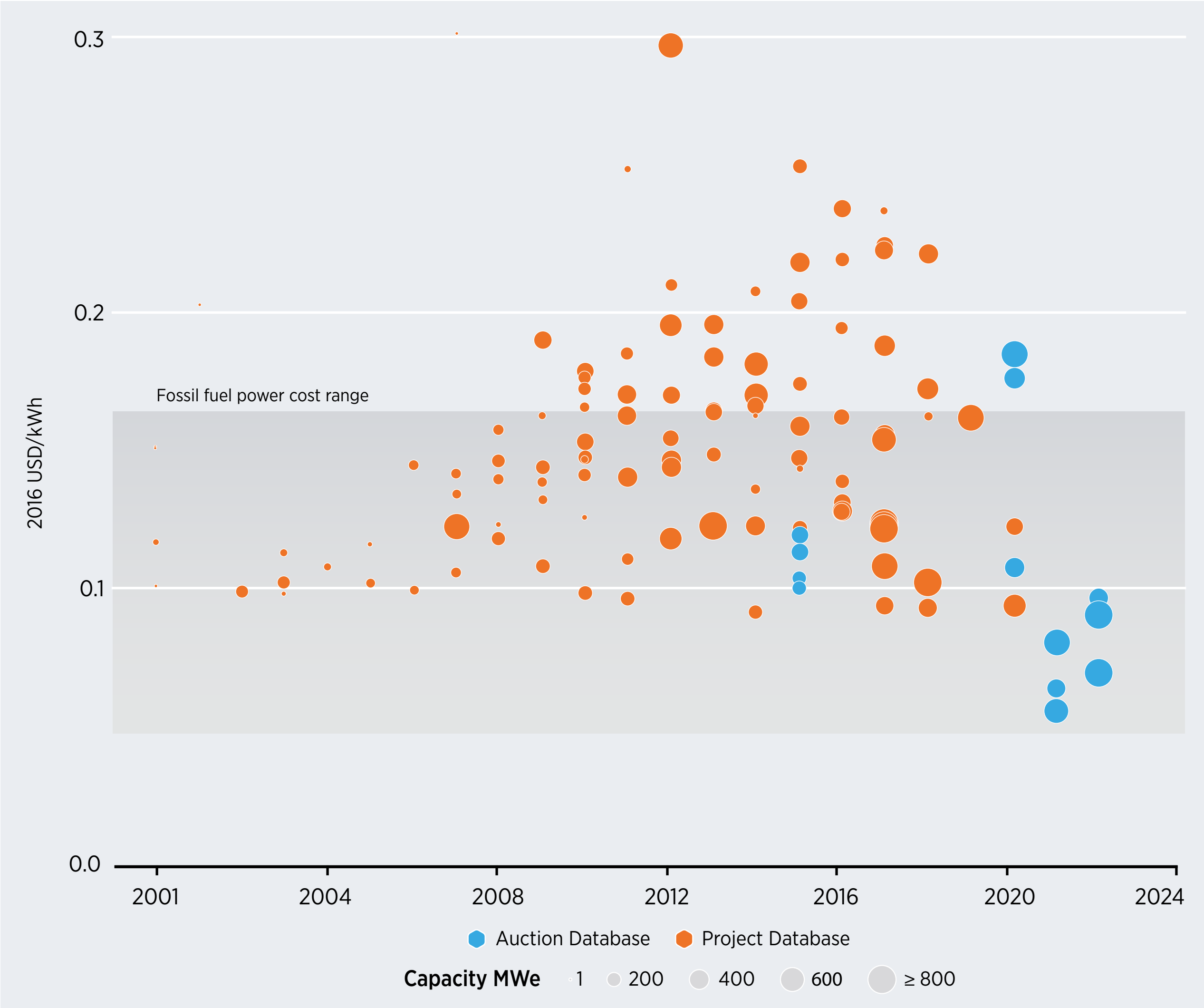
From 2010-2016, the global weighted average LCOE of offshore wind decreased from USD 0.17 to USD 0.14/kWh, despite total installed costs having increased by 8% during this period (Figure 5.20). This has been made possible by improved technology that has allowed higher capacity factors that have more than offset the increase in installed costs observed in this period. The prices awarded in auctions in 2016 and 2017 for projects that will come online by 2020-2022 range from USD 0.06 to USD 0.10/kWh.

**Figure 5.19** Regional weighted average LCOE and ranges of onshore wind in 2010 and 2016




*Source: IRENA Renewable Cost Database*

**Figure 5.20** The LCOE of commissioned and proposed offshore wind projects and auction results, 2000–2022




*Source: IRENA Renewable Cost Database and IRENA PPA Database*

# 6. HYDROPOWER

Hydropower is a mature and reliable technology, that still dominates total renewable electricity generation.[1] Worldwide, total installed hydropower capacity (excluding pumped hydro) was 1 121 GW at the end of 2016, although its share of global renewable capacity has been slowly declining. In 2010, it accounted for around 75% of this total, but by 2016, its share was approximately 50%. In terms of electricity production, hydropower accounted for 81% of electricity from renewable sources, but by 2016, its share had dropped to 70%.

Hydropower is an extremely attractive renewable technology due to the low-cost of the electricity it produces. Where reservoir storage is available hydropower is also uniquely placed to provide flexibility services to the grid that will, in addition to providing low cost electricity in its own right, contribute to integrating higher shares of VRE. Its usefulness is not restricted to the ability to absorb VRE when the sun is shining and wind is blowing, however, as it can also provide other grid services such as frequency or voltage regulation, fast reserve, etc. Its ability to meet load fluctuations minute by minute[2] and operate efficiently at partial loads, which is not the case for many thermal plants,[3] makes it a valuable part of any electricity system.

It is important, however, that hydropower developments respect the three pillars of sustainability: economic, environmental and social. Sustainable development of hydropower and early consultation with stakeholders are crucial in reducing project lead times and project development risks, and in accelerating the development 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. Hydropower can provide important grid stability services, as spinning turbines can be ramped up more rapidly than any other generation source to provide additional generation or voltage regulation to ensure that the electricity system operates within its quality limits. Hydropower projects are also unique in that they often combine both energy and water supply services. Hydropower projects can open up opportunities for irrigation schemes, drought management, municipal water supply, navigation and recreation; thus bringing local social and economic benefits. Similarly, hydropower projects can provide important flood control services. The LCOE analysis in this report does not include an estimate of the value of these services, however, as they are very site-specific.

*1. This section doesn't discuss the costs and performance of pumped hydro storage, as they are an electricity storage technology, not a generation source.*

*2. Some electricity storage devices, such as flywheels, can match this capability, but are more expensive and, in general, the more responsive they are, the less time they can be used before needing to be recharged.*

*3. Although many modern gas-fired plants can operate within one or two percentage points of their design efficiency over a relatively wide load range, this is usually not the case for older plants and coal-fired plants.*

Hydropower schemes often have significant flexibility in their design. This enables them to meet baseload demand 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. Hydropower can also store energy over weeks, months, seasons or even years, depending on the size of the reservoir.

Hydropower can therefore provide the full range of ancillary services required to allow high penetration of variable renewable energy sources, such as wind and solar PV. The importance of hydropower is therefore likely to grow over time as the shift to a sustainable electricity sector accelerates. Hydropower can therefore provide low-cost electricity and, in many cases, some of the flexibility required to integrate high levels of variable renewables at minimal costs.

## 6.1 INSTALLED COST TRENDS

Hydropower plants can be constructed in a variety of sizes and with different properties. There are a range of technical characteristics that affect the choices of turbine type and size, as well as the generation profile. These include the height of the water drop to the turbine – known as the "head" – seasonal inflows, potential reservoir size, minimum downstream flow rates, and many other factors. An important opportunity offered by hydropower is the possibility to add capacity at existing schemes, or install capacity at dams that do not yet have a hydropower plant.

Hydropower schemes can be broadly classified into the following categories:

- Run-of-river hydropower projects have no, or very little, storage capacity behind their dams, with generation almost completely dependent on the timing and size of river flows.
- Reservoir (storage) hydropower schemes can 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 a lower reservoir to a higher reservoir, so that the pumped storage water can be used for generation at peak times, provide grid stability, flexibility and other ancillary grid services. Pumped storage hydropower can also absorb renewable power generation during times of surplus, thus reducing potential curtailment.

Hydropower is a capital-intensive technology, however, with long lead times for development and construction. This is due to the requirement for significant feasibility assessments, planning, design and civil engineering work.

There are two major costs 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.
- The costs related to electro-mechanical equipment.

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 powerhouse). Following this, costs for fitting out the power house (including shafts and electro-mechanical equipment, in specific cases) are the next largest capital outlay, accounting for around 30% of the total costs. 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.

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 10 MW).

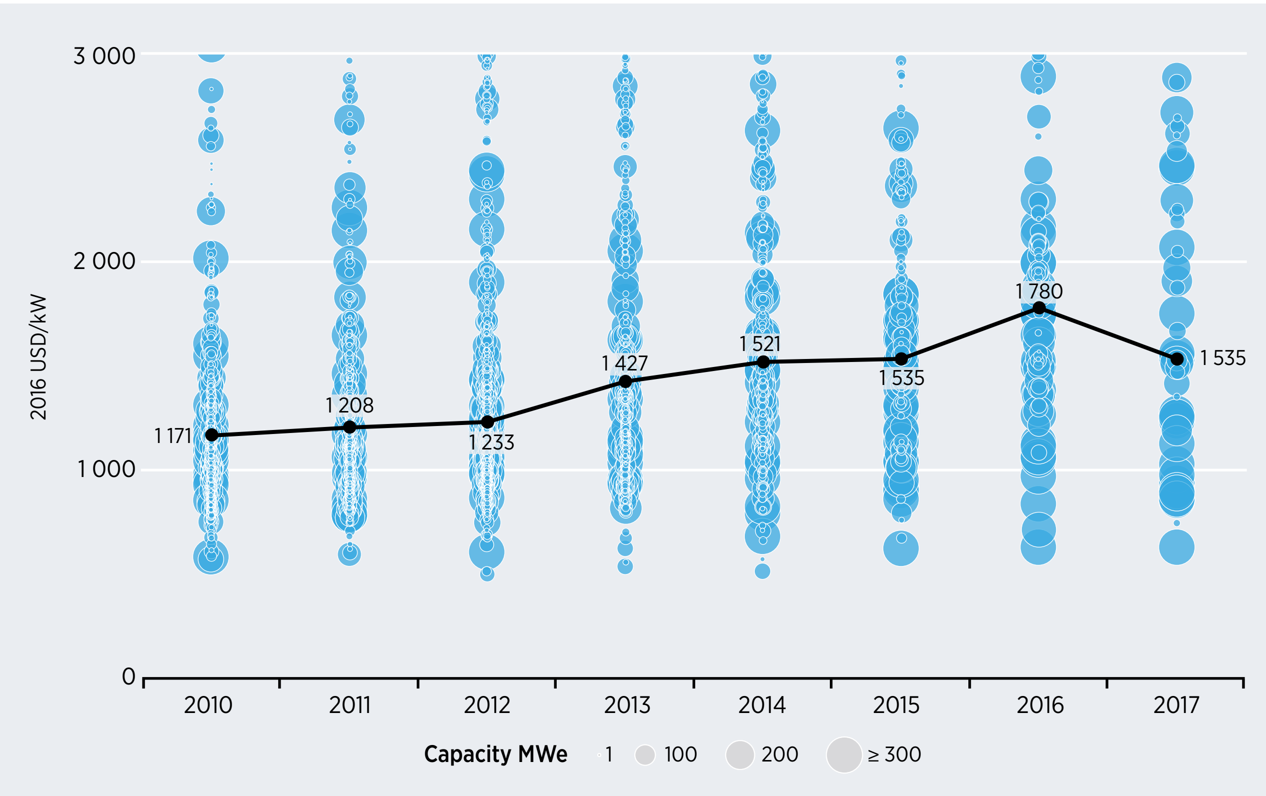
For small-scale projects, the electro-mechanical equipment costs can represent 50% or more of the total costs, due to the higher specific costs per kW of small-scale equipment.

The cost breakdown for small hydro projects in developing countries reflects the diversity of hydropower projects and their site-specific constraints and opportunities (IRENA, 2013a). It would require a large dataset to identify the specific reasons for the wide variation in project cost breakdowns and to identify "efficient" levels. 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.

The capital costs of large hydropower projects are dominated by the civil works and equipment costs, which can represent between 75% and as much 90% of the total investment costs (IRENA, 2015). 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, with each project designed for a particular location within a given river basin. This is so that it may 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 later (Ecofys et al., 2011).

The total installed costs for hydropower projects typically range from a low of USD 500/kW to around USD 4 500/kW (Figure 6.1). It is not unusual, however, to find projects outside this range. For instance, adding hydropower capacity to an existing dam that was built for other purposes 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

**Figure 6.1** Total installed costs by project and global weighted averages for hydropower, 2010-2017



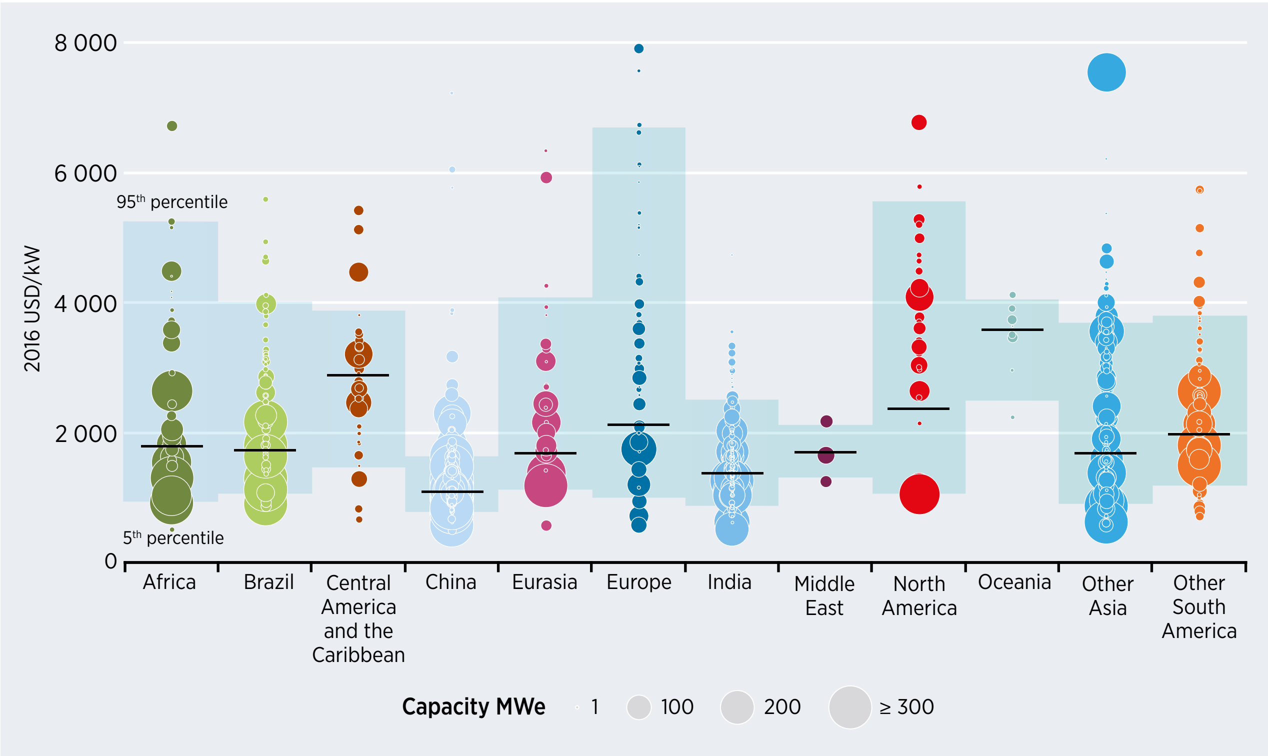

*Sources: IRENA Renewable Cost Database.*

than USD 4 500/kW due to higher logistical, civil engineering and grid connection costs.

The global weighted average for the total installed cost of a hydropower projects has increased in recent years from USD 1 171/kW in 2010 to USD 1 780/kW in 2016, before falling back to USD 1 558/kW in 2017. This trend has mainly been driven by increases in average total installed costs in Asia, Eurasia and North America, while other regions have experienced more volatile annual weighted averages. Although an analysis of the reasons behind these cost trends is not yet available, possible explanations include a shift towards hydropower projects in less ideal sites, with higher project development costs, projects further from existing infrastructure or the transmission network, thus requiring higher transport and logistical outlay, as well as boosting grid connection costs.

Total installed costs are lowest in China and India and highest in Oceania and Central America and the Caribbean (Figure 6.2). The range in installed costs for hydropower is wide, reflecting the very site-specific development costs of hydropower projects. Hydropower costs are typically lower in regions with significant remaining economic potential, like in Asia, as there are likely to be more ideal sites left to exploit. However, even in higher cost regions, the value of other services they can provide — such as potable water, flood control, irrigation and navigation — which are included in the hydropower project costs but are typically not remunerated, may mean benefits exceed costs. In addition, this 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.

**Figure 6.2** Total installed cost ranges and weighted averages for hydropower projects by country/region, 2010-2016



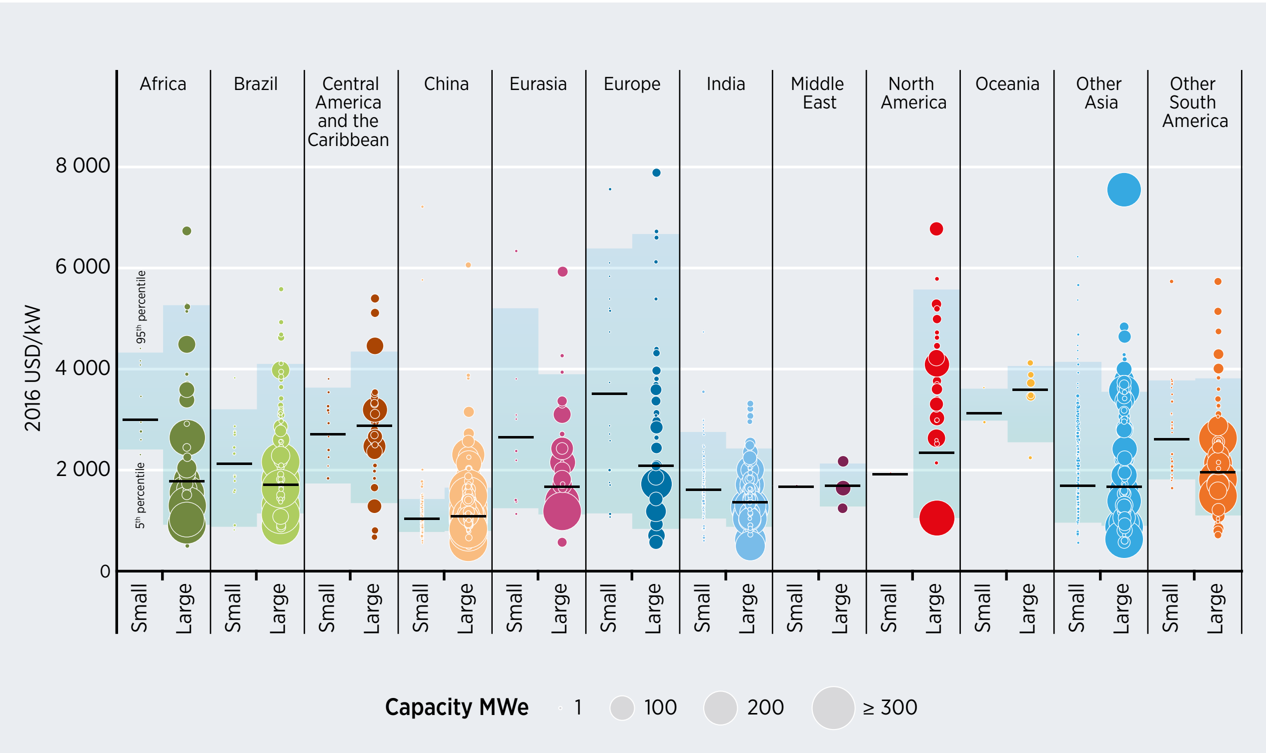

*Source: IRENA Renewable Cost Database.*

Figure 6.3 presents the installed costs for small (less than 10 MW) and large hydro plants by region. In almost every surveyed region, small hydro plants have higher installed costs compared to large hydro plants, with the exception being of Central America and the Caribbean and of Oceania. The small plants are 20-80% more expensive on average, outside of Central America and the Caribbean and Oceania. In the case of Central America and the Caribbean and Oceania, where installed costs are higher for large hydropower plants, the IRENA Renewable Cost Database contains a smaller subset of data than for many other regions and the results should be treated with caution.

To understand better the share of different cost components in the total installed costs of hydropower projects, IRENA collected cost data from a sample of 25 projects, totaling 337 MW, in China, India and Sri Lanka. These projects were commissioned between 2010-2016 and had installed costs of between USD 922 and USD 1 976/kW for all projects, while the installed costs for large projects having costs from USD 1 035 to USD 1 389/kW.

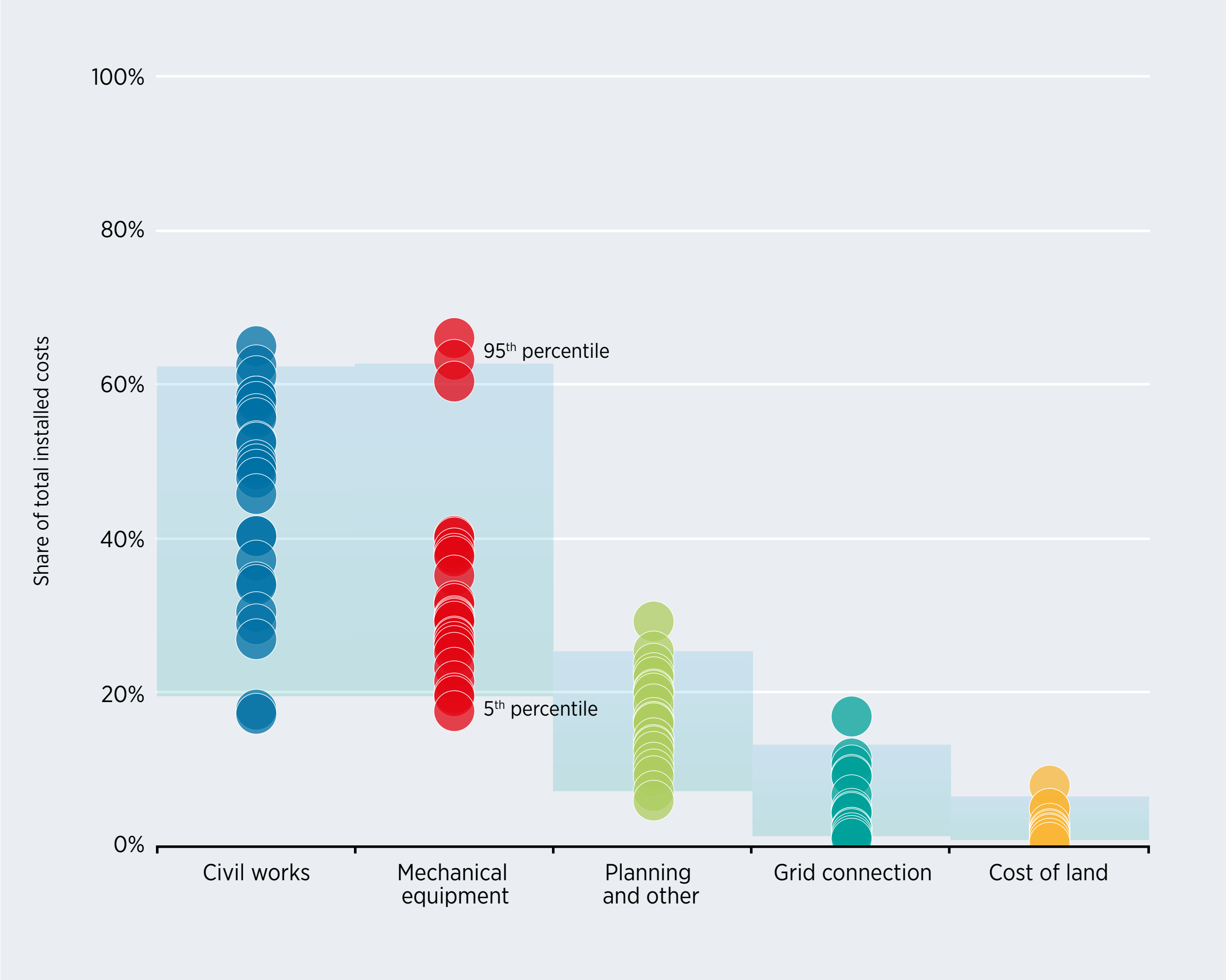
The data indicate that for this sample, civil works and mechanical equipment comprise the largest share of costs (Figure 6.4). The share of civil works in these projects varied from 17% to 65% in this particular sample. Mechanical equipment represented the second largest cost, on average, varying in the sample from a minimum of 18% to a maximum of 66%. Planning costs varied from 6-29% of total costs for these projects. Grid connection can represent a significant cost for the more remote hydropower projects, but are sometimes minimal if they represent an expansion of an existing scheme, with grid connection costs accounting for 1% for projects close to existing grid nodes to a high of 17% for projects in more remote areas. Lastly, land costs represent the smallest share of a hydropower project, varying from 1-8%. Care should be taken in interpreting these values given the relatively small sample size, but they do serve to illustrate the wide ranges of individual cost components that are driven by individual site characteristics.

**Figure 6.3** Total installed cost ranges and capacity weighted averages for small and large hydropower projects by country/region, 2010-2016




*Source: IRENA Renewable Cost Database.*

**Figure 6.4** Total installed cost breakdown by component and capacity weighted averages for 25 hydropower projects in China, India and Sri Lanka, 2010-2016

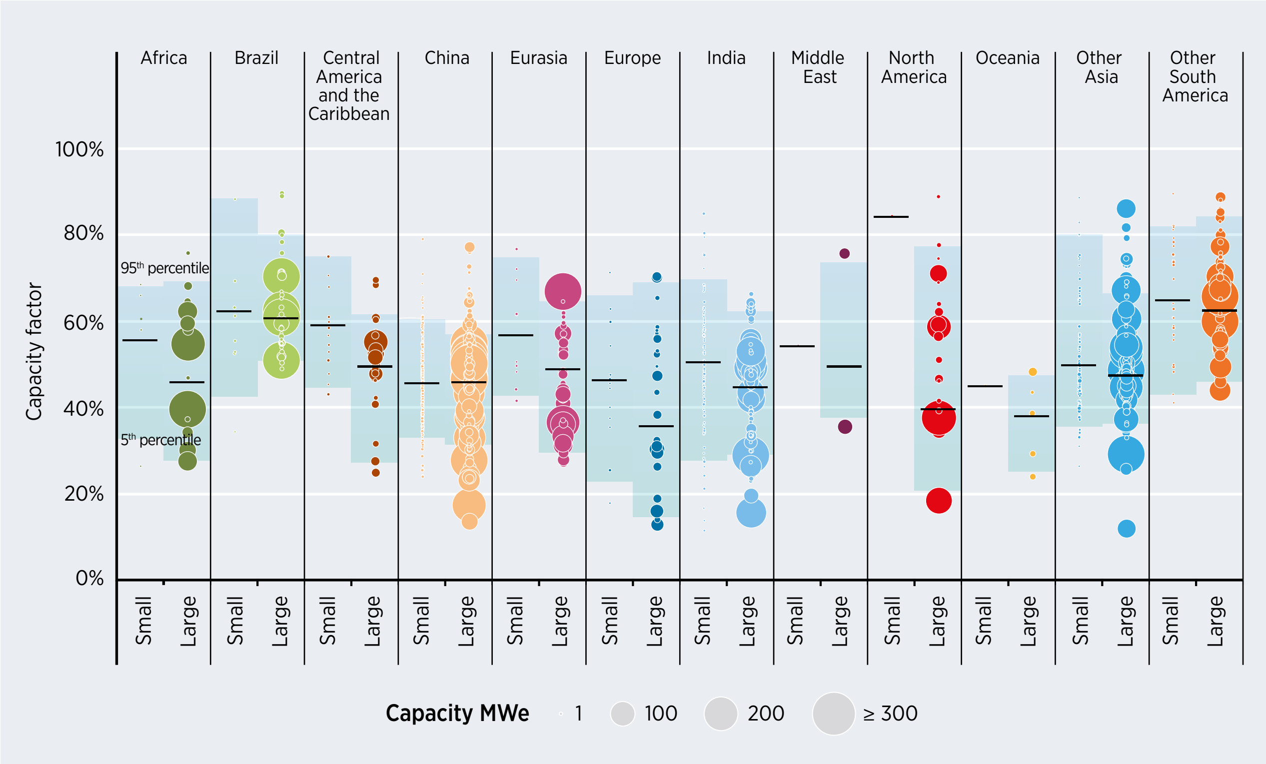



*Source: IRENA Renewable Cost Database.*

## 6.2 CAPACITY FACTORS

The global weighted average capacity factor of newly commissioned hydropower projects between 2010 and 2016 was 49% for small hydropower projects and 48% for large hydropower projects, with most projects in the range of 25-84% (Figure 6.5), Europe being a notable exception to this for having a range of projects with capacity factors lower than 20%. This wide range is to be expected, given that each hydropower project has very different site characteristics and that low capacity factors are sometimes a design choice to size the turbines to help meet peak demand and provide other ancillary grid services. Average capacity factors for newly commissioned large hydropower projects are highest in South America and Brazil, with 62% and 60%, respectively, while their average capacity factors for small hydropower projects are 66% and 58%, respectively.

**Figure 6.5** Hydropower project capacity factors and capacity weighted averages for large and small hydropower projects by country/region, 2010-2016




*Source: IRENA Renewable Cost Database.*
*Note: small refers to sub-10 MW plant and large to those above.*

## 6.3 OPERATION AND MAINTENANCE COSTS

Annual O&M costs are often quoted as a percentage of the investment cost per kW per year. Typical values range from 1-4%. The International Energy Agency (IEA) assumes 2.2% for large hydropower projects and 2.2-3% for smaller projects, with a global average around 2.5% (IEA, 2010). This would put large-scale hydropower plants in a similar range of costs as a percentage of total installed costs as those for wind, although not as low as the O&M costs 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 low levels.

Other sources, however quote lower or higher values. The Energy Information Agency assumes 0.06 % of total installed costs as fixed annual O&M and 0.003 USD/MWh as variable O&M costs for a conventional hydropower plant of 500 MW that would be commissioned in 2020 (EIA, 2017a). Other studies (EREC/Greenpeace,2010) indicate that fixed O&M costs represent 4% of the total capital cost. This figure may represent small-scale hydropower, but large hydropower plants will have significantly lower O&M costs. An average value for O&M costs of 2-2.5% 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 of mechanical and electrical equipment, such as turbine overhaul, generator rewinding and reinvestments in communication and control systems, but exclude major refurbishments.

The 25 projects that IRENA collected cost breakdown data for tend to confirm these results, as the average O&M cost was slightly less than 2% of total installed costs per year, with a variation between 1-3% of total installed costs per year. Larger projects have O&M costs below the 2% average, while smaller projects approach the maximum, or are higher than the average O&M costs. Figure 6.6 presents the cost distribution of individual O&M items in the sample. As can be seen, operations and salaries take the largest slices of the O&M budget. Maintenance varies from 20-61%, salaries from 13-74% of O&M costs, and materials are estimated to account for around 4%.

The O&M costs reported do not typically cover the replacement of major electro-mechanical equipment, or the refurbishment of penstocks, tailraces, etc[4]. Replacement of these is infrequent, with design lives of 30 years or more for electro-mechanical equipment, and 50 years or more for penstocks and tailraces. This means 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 analysis presented here. They may, however, represent an economic opportunity before the full amortisation of the hydropower project, in order to boost generation output.

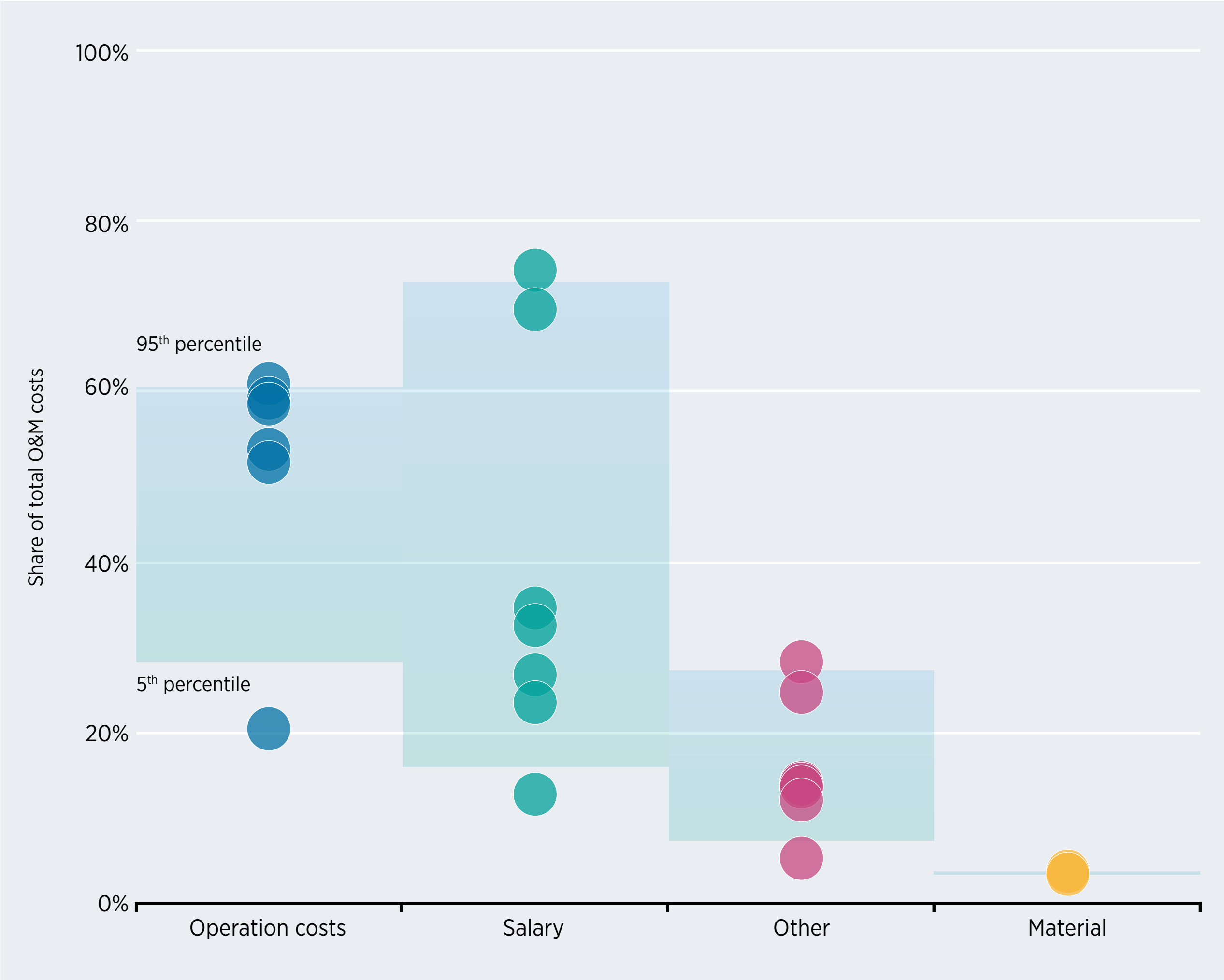
## 6.4 LEVELISED COST OF ELECTRICITY

Hydropower is a proven, mature, predictable technology and has historically been a low-cost source of electricity. Investment costs are highly dependent on location and site conditions, which explains the wide range of plant installed costs. However, the relatively high initial investment is balanced, by the long economic lifetime of the hydropower plant (with parts replacement) as well as by the low O&M costs. Thus, the average LCOE from hydropower is typically low, with excellent hydropower sites offering some of the lowest cost electricity of any generating option.

Hydropower projects can be designed to perform very differently from each other, however, which complicates a simple LCOE assessment. A plant with a low installed capacity could run continuously to ensure high average capacity factors, but at the expense of being able to ramp up production to meet peak demand loads. Alternatively, a plant with a high installed electrical capacity and low capacity factor would be designed to help meet peak demands and provide spinning reserve and

*4. 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 6.6** Hydropower O&M cost breakdown by project for a sample of 25 projects in China, India and Sri Lanka, 2010-2016




*Source: IRENA Renewable Cost Database.*

other ancillary grid services. The latter strategy would involve higher installed costs and lower capacity factors, but where the electricity system needs these services, hydropower can often be the cheapest and most effective solution to these needs.

Deciding which strategy to pursue for any given hydropower scheme is highly dependent on the local market, the structure of the power generation pool, grid capacity and constraints, the value of providing water management and grid services, etc. Perhaps more than with any other renewable energy, the true economics of a given hydropower scheme are driven by these factors, not just by the number of kWhs generated relative to the investment. The value of peak generation and the provision of ancillary grid services can thus have a significant impact on the economics of a hydropower project.[5]

The weighted average country/regional LCOE of all projects, large and small, in the IRENA Renewable Cost Database ranged from a low of USD 0.04/kWh in Brazil for all of the projects in the IRENA Renewable Cost Database to a high of USD 0.11/kWh in Europe. Focusing in on the global weighted average LCOE trend by year, in 2017, the global weighted average cost of electricity from hydropower projects commissioned in that

**Box 4 Pumped hydro storage**

Energy storage is becoming an increasingly flexible and cost-effective tool for grid operators to help manage instability on their networks. This is especially so, given with the growing amount of variable renewable energy generation being deployed in major markets worldwide, such as that from solar PV and wind.

Energy storage has gained prominence in recent years, and plays a key role in the design of modern electricity grids. According to the Global Energy Storage Database [DOE, 2017], the rated power of operational stationary energy storage reached a total of more than 170 GW, globally, by October 2016. More than 96% was provided by pumped hydro storage, followed by thermal storage (1.9%), electro-chemical batteries (1.0%) and electro-mechanical storage (0.9%). Three quarters of all energy storage was installed in the top 10 countries, led by China (18.8 %), Japan (16.7 %) and the United States (14.1 %).

Pumped hydro storage is a well-understood and proven technology, with decades of operating experience. Due to this maturity, only slight improvements in cost structure or transformation efficiency can be expected in the next few years. There are, however, many new ideas on how to expand worldwide pumped hydro storage capacities. These include the use of wind turbine structures as upper reservoirs [GE Reports, 2016], existing underground formations such as abandoned mines [ESA, n.d. – a], or added weight through rock formations [Heindl Energy, 2016]. These approaches may offer lower-cost pumped hydro storage and/or greatly expand their potential, but given the early stage of development of these approaches significant uncertainty remains as to their likely deployment.

Another type of unconventional Pumped Hydroelectric Storage (PHS) that has already been commercialised in a mid-sized storage asset is seawater storage [Fujihara, 1998]. This type of PHS utilises the sea as the lower water reservoir, instead of an artificial lake. These storage systems promise to offer comparably lower installation costs due to their single reservoir construction. Yet, the maintenance costs of these storage systems are significantly higher, due to the highly corrosive salt water environment and marine growth on hydraulic structures [ESA, n.d. – b], and suitable geological structures next to seas or lakes are not always available.

Promising developments in other energy storage technologies may one day challenge pumped hdyro storage's near monopoly on low-cost electricity storage (IRENA, 2017c), but for now, pumped hydro is still the only technology offering economically viable large-scale storage. The importance of pumped hydro storage, and indeed reservoir hydropower, is likely to grow over time as the shift to a truly sustainable electricity sector accelerates, not just for the low-cost storage it provides, but for the flexibility it brings to integrate high levels of variable renewables at minimal cost.

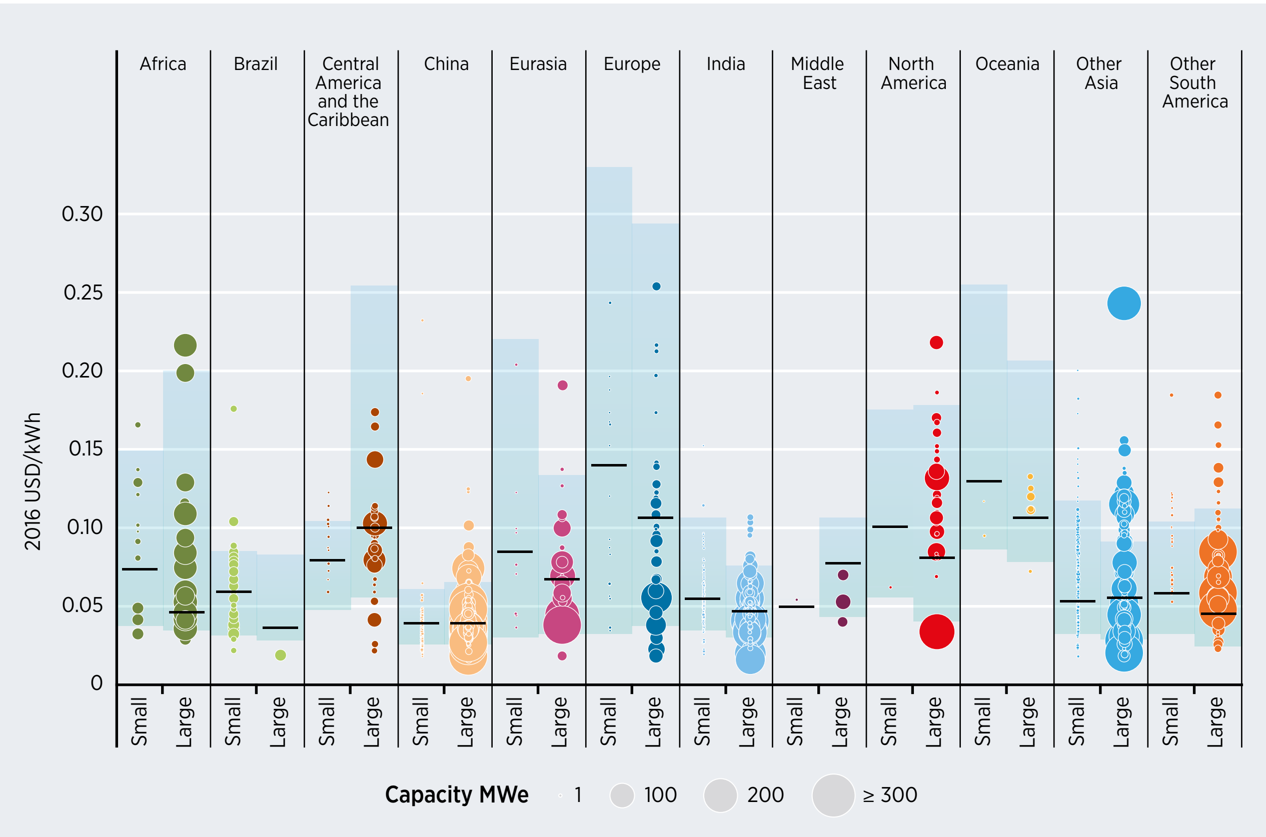
*5. This is without considering the other services being provided by the dam (e.g. flood control) that are not typically remunerated, but are an integral part of a project's purpose.*

year was USD 0.047/kWh. This was slightly lower than the weighted average of USD 0.053/kWh for projects commissioned in 2016, but substantially higher than in 2010, when the weighted average LCOE of newly commissioned projects was USD 0.036/kWh.

Figure 6.7 presents the LCOE of the 3 624 hydropower projects contained in the IRENA Renewable Cost Database. It shows that many new hydropower projects are expected to be highly competitive. LCOE data ranges from a low of around USD 0.02/kWh to a high of USD 0.30/kWh. Although the range is wide, for reasons already discussed, the weighted average LCOE is below USD 0.10/kWh for almost all regions and the weighted average remains low in most regions, typically ranging between USD 0.04 and 0.06/kWh. This is typically correlated with regions with significant remaining untapped economic resources. Europe is something of an exception, as most of the economic hydropower potential in this region has already been exploited. In Europe, new projects are relatively few in number, face long lead times to develop and have a higher weighted average LCOE, at USD 0.11/kWh.

In terms of the differences between small and large hydropower plants, the LCOE of small hydro plants is usually higher than the LCOE of large hydro plants, by 10%-40%, which is somewhat less than the difference in total installed costs for these different projects. Small hydropower projects can be attractive, despite higher LCOEs, either because they are the least costly supply solution in more remote areas, or because they provide valuable grid services.

**Figure 6.7** Levelised cost of electricity and weighted averages of small and large hydropower projects by country/region, 2010-2016




*Source: IRENA Renewable Cost Database.*

# 7. BIOENERGY FOR POWER

Power generation from bioenergy can come from a wide range of feedstocks and use a variety of different combustion technologies. Bioenergy power generation technologies range from commercially proven solutions, with a wide range of suppliers, through to those that are only just being deployed on a commercial scale.

The power generation technologies that are mature, commercially available and have a long track record include: direct combustion in stoker boilers; low-percentage co-firing; anaerobic digestion; municipal solid waste incineration; landfill gas and combined heat and power. Other less mature technologies, such as atmospheric biomass gasification and pyrolysis, are only at the beginning of their deployment. The potential for cost reductions from the technologies in use is therefore very heterogeneous. While only marginal cost reductions can be anticipated in the short term, there is good, long-term potential for cost reductions from those technologies that are not yet widely deployed.

To analyse the use of biomass power generation, the following three components must be examined:

- Biomass feedstocks: These come in a variety of forms and have different properties that impact their use in power generation.
- Biomass conversion: This is the process by which biomass feedstocks are transformed into the energy form that will be used to generate heat and/or electricity.
- Power generation technologies: A wide range of commercially proven power generation technologies are available that can use biomass as a fuel input, but technology risks remain for some of the newer, more innovative technologies.

The analysis in this report focuses on the costs of power generation technologies and their economics, while briefly discussing delivered feedstock costs. Indeed, 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. This area is the focus of increasing research by IRENA, given the uncertainty surrounding the global potential and supply of sustainably sourced bioenergy feedstocks (IRENA, 2017f and 2017g).

## 7.1 BIOMASS FEEDSTOCKS

Biomass is the organic material of recently living plants, such as trees, grasses and agricultural crops. Biomass feedstocks are very heterogeneous and the chemical composition is highly dependent on the plant species. Ash content, density, and particle size and moisture content are all critical issues for the biomass feedstock. These factors have an impact on the cost of this feedstock per unit of energy, its transportation, pre-treatment and storage costs, as well as the appropriateness of different conversion technologies. Moreover, heterogeneity in quality can also be a problem for the conversion process, since some combustion technologies require much more homogeneous feedstocks to operate. This can add complexity to the planning and economic viability of biomass-based power plants.

Thus, unlike wind, solar and hydro, the economics of biomass power generation are dependent upon the availability of a predictable, sustainably sourced, low-cost and long-term adequate feedstock supply. The range of costs for feedstocks is highly variable, too. Waste produced due to industrial processes can have a zero or even negative cost if it is waste that would otherwise have incurred disposal charges, such as black liquor at pulp and paper mills. Yet there can also be 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 density of the feedstock is lower and the distances become large. Transforming wet biomass into higher-density forms will help reduce transportation costs per unit of energy, but the transformation costs must also be taken into account. There is often a trade-off between the volume of low-cost feedstock available to a bioenergy power plant as collection radius grows, this can be offset if more cost-effective bulk freight deliveries can be made by rail or water.

Feedstocks typically account for between 20-50% of the final cost of electricity from biomass technologies. Agricultural residues, such as straw and sugarcane bagasse, tend to be the least expensive feedstocks, as they are a harvest or processing by-product. They are, however, correlated with the price of the primary commodity from which they are derived and have registered increased costs from 2000 to 2011 as indicated in the World Bank agricultural commodities index (World Bank, 2017). However, the cost of agricultural commodities has edged down, after the peak observed in 2011, with prices down by 28% in 2016 compared to 2011. Biomass power generation plants that are exposed to feedstocks that are derived from traded commodities are therefore exposed to volatile commodity prices, unless they have secure supplies or have acquired a long-term contract for their feedstock needs (see IRENA, 2015, for a more detailed discussion of feedstock costs).

## 7.2 INSTALLED COST TRENDS

Technology options largely determine the cost and efficiency of biomass power generation equipment, although equipment costs for individual technologies can vary significantly. Factors affecting this depend 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. the prime mover and fuel conversion system) represent the major categories of total investment costs of a biomass power plant. Additional costs are derived from grid connection and infrastructure (e.g. roads). Combined heat and power (CHP) biomass installations have higher capital costs, but the higher overall efficiency (around 80%-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.

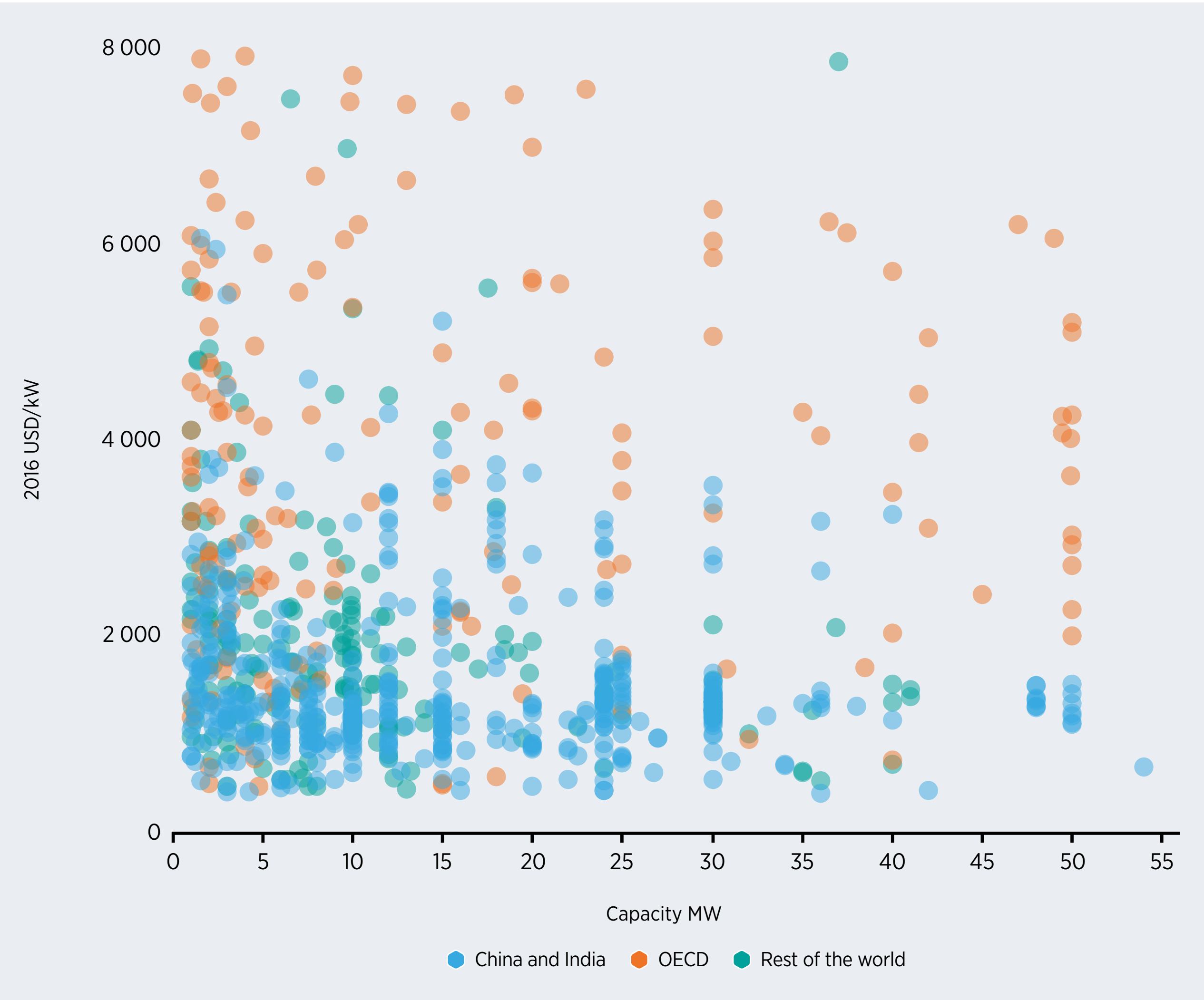
Biomass power plants in emerging economies can have significantly lower investment costs than the cost ranges for OECD-based projects, due to lower local content costs and the cheaper equipment allowed, in some cases, by less stringent environmental regulations.

*The wide range of bioenergy-fired power generation technologies translates into a broad range of observed installed costs*

Figure 7.1 and Figure 7.2 highlight the relatively low installed cost of biomass combustion technologies for projects in Asia and South America, while more expensive projects occur mostly in Europe and North America. Although small-scale projects can have higher capital costs, most large projects have total installed costs in the range of USD 450 to 2 500/kW. The lower range can be achieved when additional capacity is added to an existing project, as the economics of electricity generation improve. The data to which IRENA has access is dominated by steam cycle boiler systems, although in many cases the technology is not disclosed. Biomass projects using steam cycle boilers appear to have the lowest costs, clustering between USD 500 and USD 2 000/kW, while fixed bed gasifiers deployed in Europe and North America are between USD 2 000 and USD 7 000/kW. Most of the projects in the IRENA Renewable Cost Database have not, however, disclosed the technology, and tend to cluster between USD 500 and USD 8 000/kW. The less expensive projects are in Asia and South America, while the more expensive ones are in Europe.

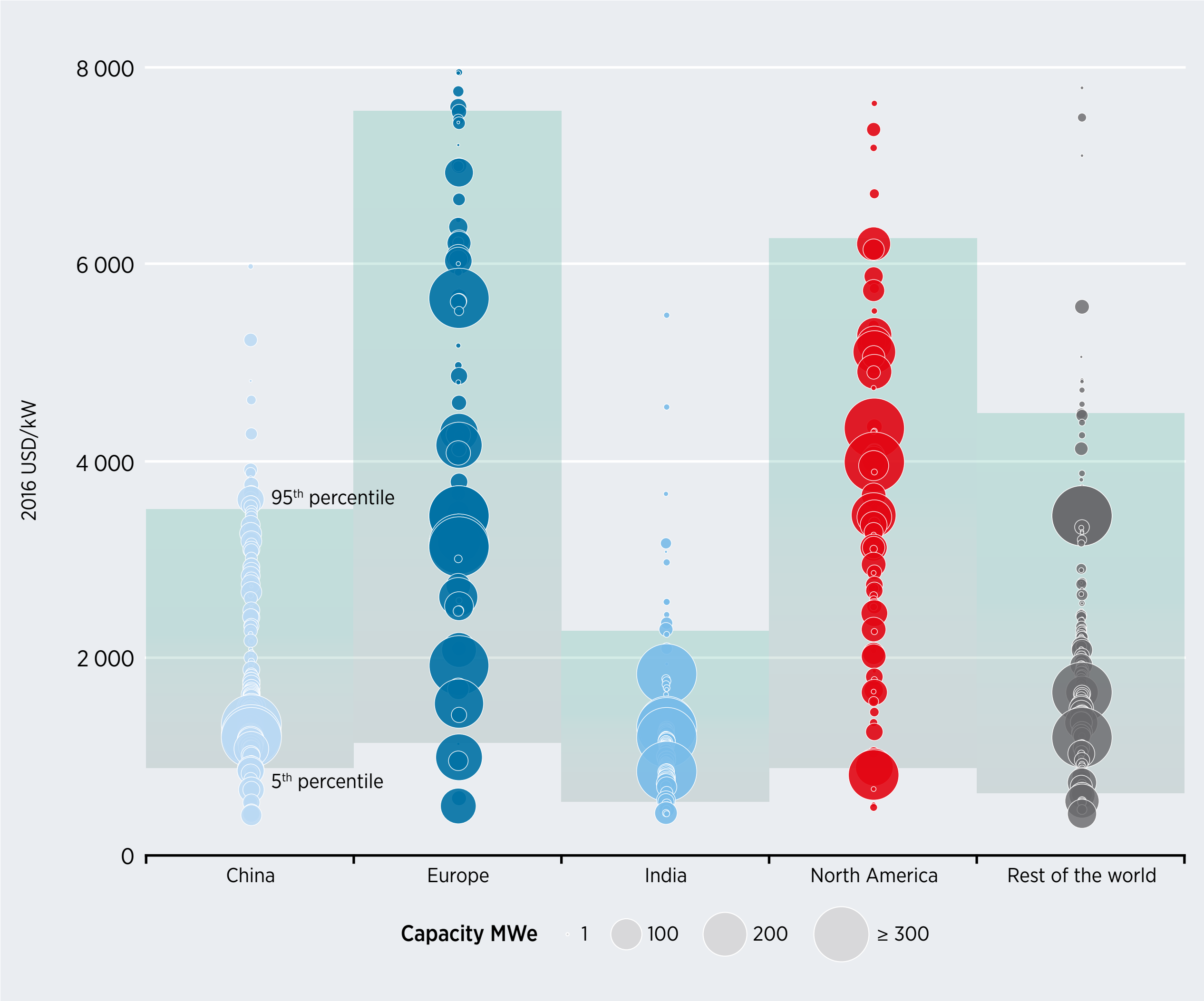
Figure 7.2 presents the total installed cost range of biomass fired power in several regional groupings. Biomass installed costs in India are the lowest, ranging from USD 450 to USD 2 600/kW, while in China they range from USD 450 USD 3 600/kW. Installed cost ranges are wider in Europe, North America and the rest of the world category, as the technological options used to develop projects are more heterogeneous and on average more expensive.

**Figure 7.1** Total installed costs of biomass-fired generation technologies by country/region and project capacity




*Source: IRENA Renewable Cost Database.*

**Figure 7.2** Total installed costs of biomass-fired generation technologies by country/region




*Source: IRENA Renewable Cost Database.*

## 7.3 OPERATION AND MAINTENANCE COSTS

Fixed operations and maintenance (O&M) costs for bioenergy power plants typically range from 2-6% of total installed costs per year, while variable O&M costs are typically relatively low, at around 0.005/KWh. 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 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 serving costs are the main components of variable O&M costs. Unfortunately, the available data often merges fixed and variable O&M costs into one number, thus rendering impossible a breakdown between fixed and variable O&M costs. Table 7.1 provides data for the fixed and variable O&M costs for selected bioenergy for power technologies.

## 7.4 CAPACITY FACTORS AND EFFICIENCY

Technically, bioenergy-fired electricity plants can achieve capacity factors of 85-95%. In practice, most plants do not regularly operate at these levels. Feedstocks may be a constraint on capacity factors, particularly in cases where systems relying

**Table 7.1** Fixed and variable O&M costs for bioenergy power

| | Fixed O&M *(% of CAPEX/YEAR)* | Variable O&M *(2016 USD/MWh)* |
|---|---|---|
| Stoker/BFB/CFB boilers | 3.2 | 4.08 - 5.03 |
| Gasifier | 3 - 6 | 4.08 |
| Anaerobic digester | 2.1 - 3.2 | 4.49 |
| | 2.3 - 7 | |
| Landfill gas | 11 - 20 | n.a |

*Source: IRENA, 2015.*

on agricultural residues may not have year-round access to low-cost feedstock, and where buying alternative feedstocks might make plant operation uneconomical. This is illustrated in Figure 7.3. In Figure 7.3, the lower capacity factors for projects in India represent the impact of the many bagasse-fired projects, which operate only during and after harvesting season 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 having invested in higher-cost technologies that can process a range of heterogeneous feedstocks, sourcing a steady supply of wood pellets and wood waste provided by a functional, buyer-driven international markets for such resources (Argus Biomass Markets, 2014), as well as waste-to-energy plants and those using forestry or pulp and paper residues available from their year-round operation.

Weighted average capacity factors are above 60% in China, India and the rest of the world, while in Europe and North America they are above 80% (Figure 7.3). Biomass plants relying on landfill gas and other biogases, wood and wood straws, fuel wood and industrial and renewable municipal waste tend to have higher capacity factors than the regional weighted average. Projects relying on agricultural inputs, such as bagasse, tend to have lower capacity factors, as they depend on seasonal harvesting.

**Figure 7.3** Project capacity factors and weighted averages of biomass-fired electricity generation systems by country and region


*Source: IRENA Renewable Cost Database.*

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, less advanced technologies – and sometimes suboptimal maintenance – result in lower overall efficiencies. These can be around 25%, but many technologies are available with higher efficiencies, ranging from 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).

## 7.5 LEVELISED COST OF ELECTRICITY

The wide range of bioenergy-fired power generation technologies and feedstock costs translates into a broad range of observed LCOEs for bioenergy-fired electricity. Figure 7.4 summarises the estimated range of costs for biomass power generation technologies in countries and regions where the IRENA Renewable Cost Database has good coverage. Assuming a cost of capital of 7.5%-10% and feedstock costs between USD 1/GJ and USD 9/GJ (the LCOE calculations in this report are based on an average of USD 1.5/GJ), the weighted average LCOE of biomass-fired electricity generation is around USD 0.05/kWh in India and USD 0.06/kWh in China.

The weighted average LCOE in Europe and North America is higher, at around USD 0.08/kWh-USD 0.09/kWh, reflecting more advanced technology choices, but also the more stringent emissions controls and higher feedstocks costs. 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. 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 for electricity to as little as USD 0.03/kWh.

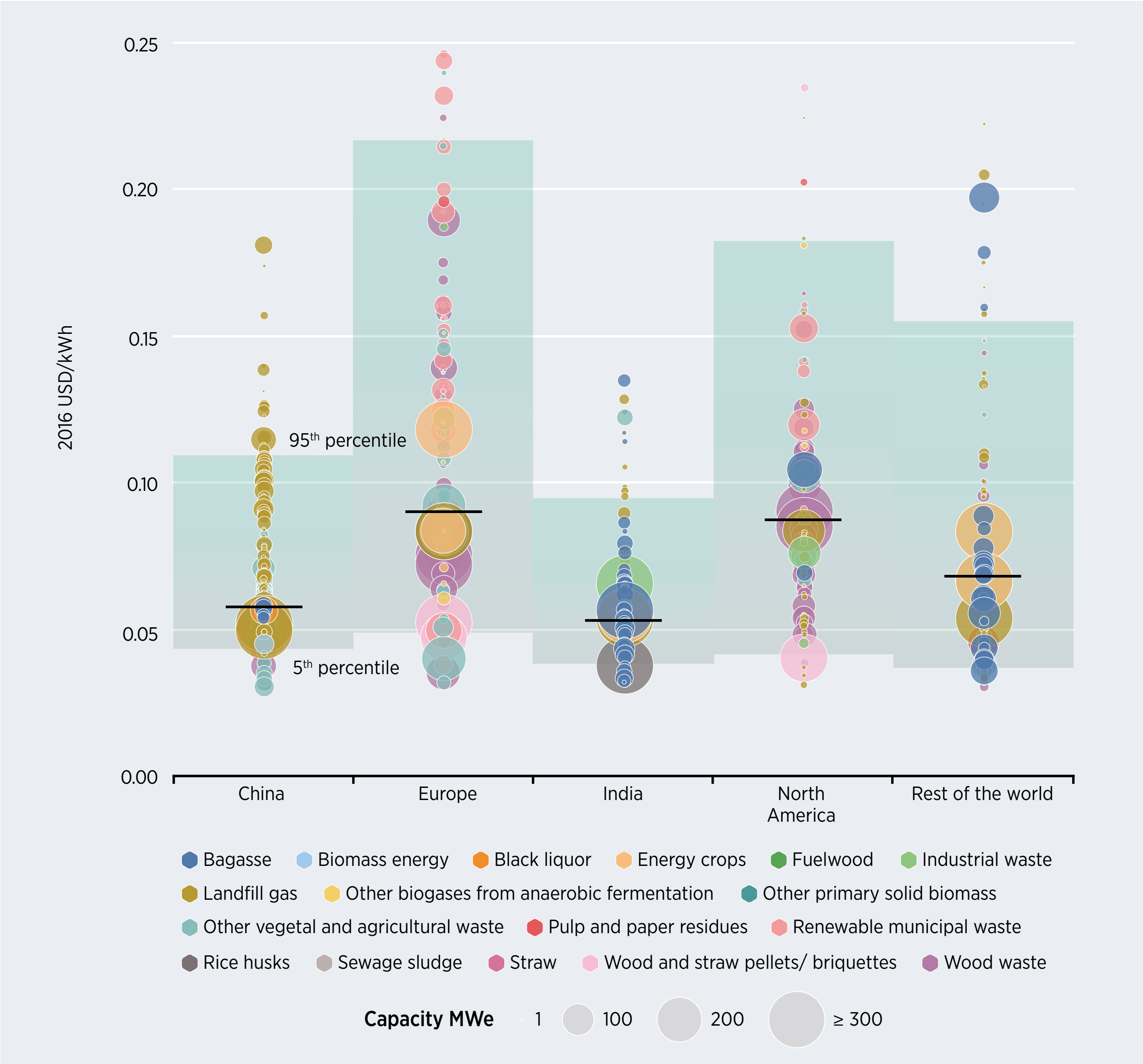
Low-cost opportunities to develop bioenergy-fired power plants present themselves at sites where low-cost feedstocks and handling facilities are available to keep feedstocks and capital costs low. Where this is not the case, or where these feedstocks need to be supplemented by additional feedstocks (e.g.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

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, too, 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 technologies, can have very competitive LCOEs (Figure 7.4). Even higher-cost projects in certain developing countries, however, can 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 in Europe and North America use municipal solid waste as a feedstock. It is therefore worth noting that the primary objective of these projects is not power generation, but waste disposal. Capital costs are often higher, as expensive technologies are used to ensure local pollutant emissions are reduced to acceptable levels. Excluding these projects – which are typically not the largest – 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.

Finally, the availability of a continuous and affordable stream of feedstock allows for higher capacity factors, but does not have a significant impact on LCOE. Projects based on bagasse and other agricultural residues come with lower capacity factors, due to the seasonality of the available feedstock. The LCOE of these projects, however, is comparable to projects relying on more generic woody biomass feedstocks, such as wood pellets and wood waste that can be more readily purchased year round. Thus, access to low cost feedstock offsets the impact of lower capacity factors on LCOE. Lastly, projects relying on municipal waste come with very high capacity factors, but also some of the highest LCOEs, above USD 0.15/kWh. Given that these projects have been developed mostly to solve waste management issues, though, and not primarily for the competitiveness of their electricity production, this is not necessarily an impediment to their viability. In Europe, they are also sometimes supplying heat either to local industrial users, or district heating networks, the revenues from these sales will reduce the LCOE below what is presented here.

**Figure 7.4** Levelised cost of electricity by project and weighted averages of bioenergy-fired electricity generation by feedstock and country/region, 2000-2016




*Source: IRENA Renewable Cost Database.*

**Figure 7.5** Levelised cost of electricity by capacity factors of bioenergy-fired projects, 2000-2016


*Source: IRENA Renewable Cost Database.*

# 8. GEOTHERMAL POWER GENERATION

Geothermal resources are found in the Earth's crust, in active geothermal areas on or near its surface and at deeper depths. These resources consist of thermal energy, stored as heat in rocks of the Earth's crust and interior, at shallow depths hot water or steam maybe be produced from subterranean water that has come in contact with the heated area. In other cases, water will need to be injected through wells to harness the the heat found in otherwise dry rocks.

Geothermal deployment reached a total installed capacity of 12.7 GW, globally, at the end of 2016. This was 26% up on the 2010 level. Most of this capacity is deployed in active geothermal areas. The new capacity added in 2016, 780 MW, was more than twice the capacity added in 2010.

Geothermal is a mature, commercially available technology that can provide low-cost baseload capacity in geographies with very good to excellent high-temperature resources that are close to the Earth's surface. The deployment of geothermal power outside such areas, however, using the so-called "enhanced geothermal" or "hot dry rocks" approach, is much less mature. In this instance, it comes with costs that are typically significantly higher, rendering the economics of such projects much less attractive today.

Readily available, extensive geothermal resource mapping can reduce the costs of development, by minimising the uncertainty about where initial exploration should be conducted. This is usually an expensive and time consuming process, however, and is one of most important barriers to the uptake of geothermal power generation. Poorer than expected results during the exploration phase might require additional drilling, or wells may need to be deployed over a much larger area to generate the expected electricity. Globally, around 78% of production wells drilled are successful, with the average success rate improving in recent decades. This is most likely due to better surveying technology, which is able to more accurately target the best prospects for siting productive wells. A key point is that adherence to global best practices significantly reduces exploration risks (IFC, 2013).

Geothermal plants are very individual in terms of the quality of their resources and management needs, and therefore specific lessons cannot be easily inferred. Nonetheless, adherence to best international practices for survey and management and thorough data analysis from the project site are the best risk mitigation tools available to developers (IFC, 2013).

Once commissioned the management of a geothermal plant and its reservoir evolves over time, as more information becomes available from operational experience. Once productivity at existing wells declines, there might also be a need for replacement wells to make up for the loss in productivity.

## 8.1 INSTALLED COST TRENDS

Geothermal power plants are, as with all other renewable technologies, relatively capital-intensive – yet they also come with low and predictable operating costs. The costs of engineering, procurement and construction (EPC) of a geothermal power plant follow trends in commodity prices and drilling costs. Thus, when commodity and oil markets are surging, the costs of developing geothermal power plants often also rise. The opposite happens when these markets are slowing.

The total installed costs of a geothermal power plant consist of:

- exploration and resource assessment costs
- drilling costs for production and re-injection costs, as well as additional working capital given that the success rate for well could vary between 60-90% (Hance, 2005; GTP, 2008)
- field infrastructure, the geothermal fluid collection and disposal system, and other surface installations;
- costs of the power plant
- project development and grid connection costs.

The characteristics of the geothermal field are key to what type of power plant (flash or binary) can be used for a given site. These field characteristics will determine well productivity, energy delivery,[1] and the economic capacity to provide steam, given the quality of the geothermal resource and its geographical distribution.

In line with rising commodity prices and drilling costs, the total installed costs for geothermal plants increased by between 60-70% (IPCC, 2011) between 2000 and 2009. Project development costs followed general increases in civil engineering and EPC costs during that period, and cost increases in drilling associated with surging oil and gas markets. The total installed costs of conventional condensing "flash" geothermal power generation projects were between USD 1 900/kW and USD 3 800/kW in 2009. Binary power plants were more expensive and installed costs for typical projects were between USD 2 250 and USD 5 500/kW that same year (IPCC, 2011).

Geothermal power plant costs can be as low as USD 560/kW, however, where capacity is being added to a geothermal reservoir which is already well mapped and understood, and where existing infrastructure can be used, but these cases are exceptional. Data for recent projects (Figure 8.1) fits within the range of USD 2 000 to USD 5 000/kW, but there have also been some small projects in new markets where costs are higher. Based on the data available in the IRENA Renewable Cost Database, the trend of increased installed costs up to 2014 seems to have ended in 2015, when, on average, costs began declining. Given the relatively thin market for geothermal power generation deployment, this trend, however, should be treated with caution.

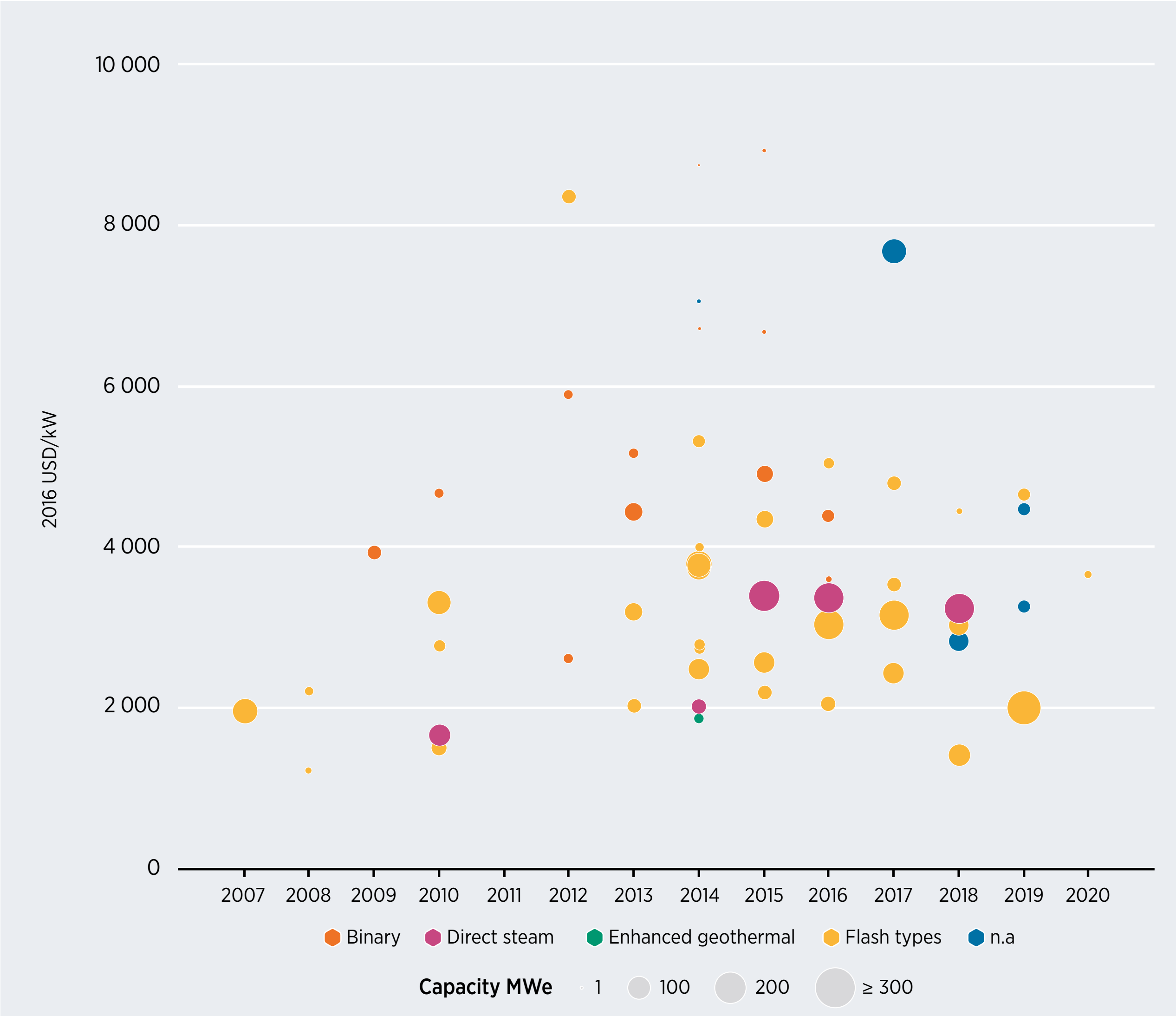
## 8.2 CAPACITY FACTORS

The capacity factors of geothermal power plants vary from around 60% to more than 85%. Using data from the IRENA Renewable Cost Database, Figure 8.2 shows that geothermal plants using direct steam deliver capacity factors higher than 80%, while projects utilising lower temperature resources that require binary plants deliver capacity factors of 60-80%. Geothermal plants using "flash" technologies consistently deliver capacity factors higher than 80%, with few outliers below that value. In terms of efficiency of conversion, geothermal power plants report a worldwide average of 12% efficiency, while the upper range is situated at 21% for a vapour dominated plant (Zarrouk, Moon, 2014).

It's important to note that geothermal power plants need active management of the reservoir and production profile to maintain production at the designed capacity factor. This will frequently require additional production wells, as over time, individual production wells become less productive as reservoir pressure around the production well drops. This tends to mean capacity factors would

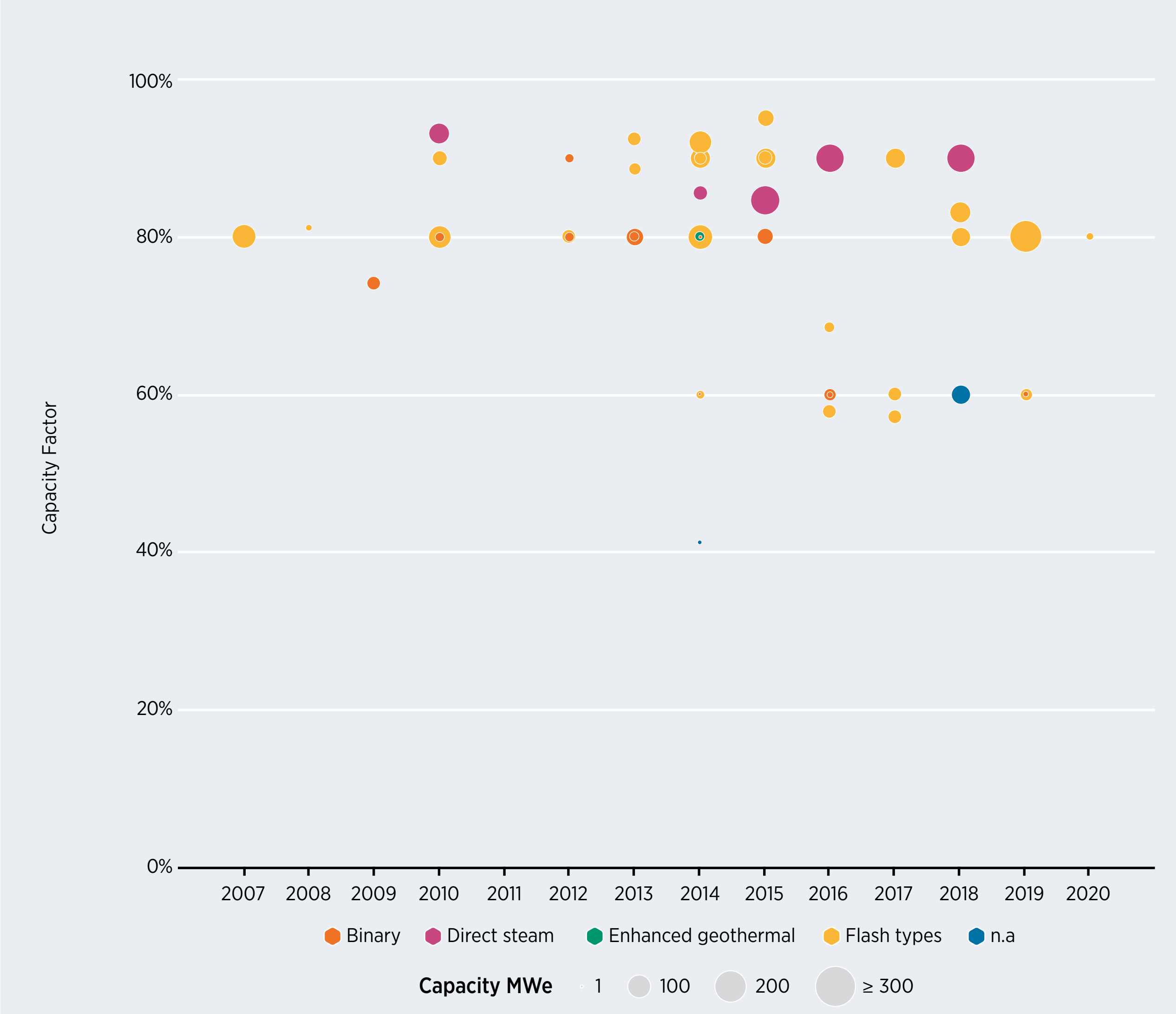
*1. The well productivity and energy delivery will determine the number of wells necessary for a given electrical capacity desired. These factors, and the geographical distribution of wells, will have a significant impact on overall development costs.*

**Figure 8.1** Geothermal power total installed costs by project, technology and capacity, 2007-2020




*Source: IRENA Renewable Cost Database and Global Data, 2016.*

**Figure 8.2** Capacity factors of new geothermal power plants by technology and project size, 2007-2020



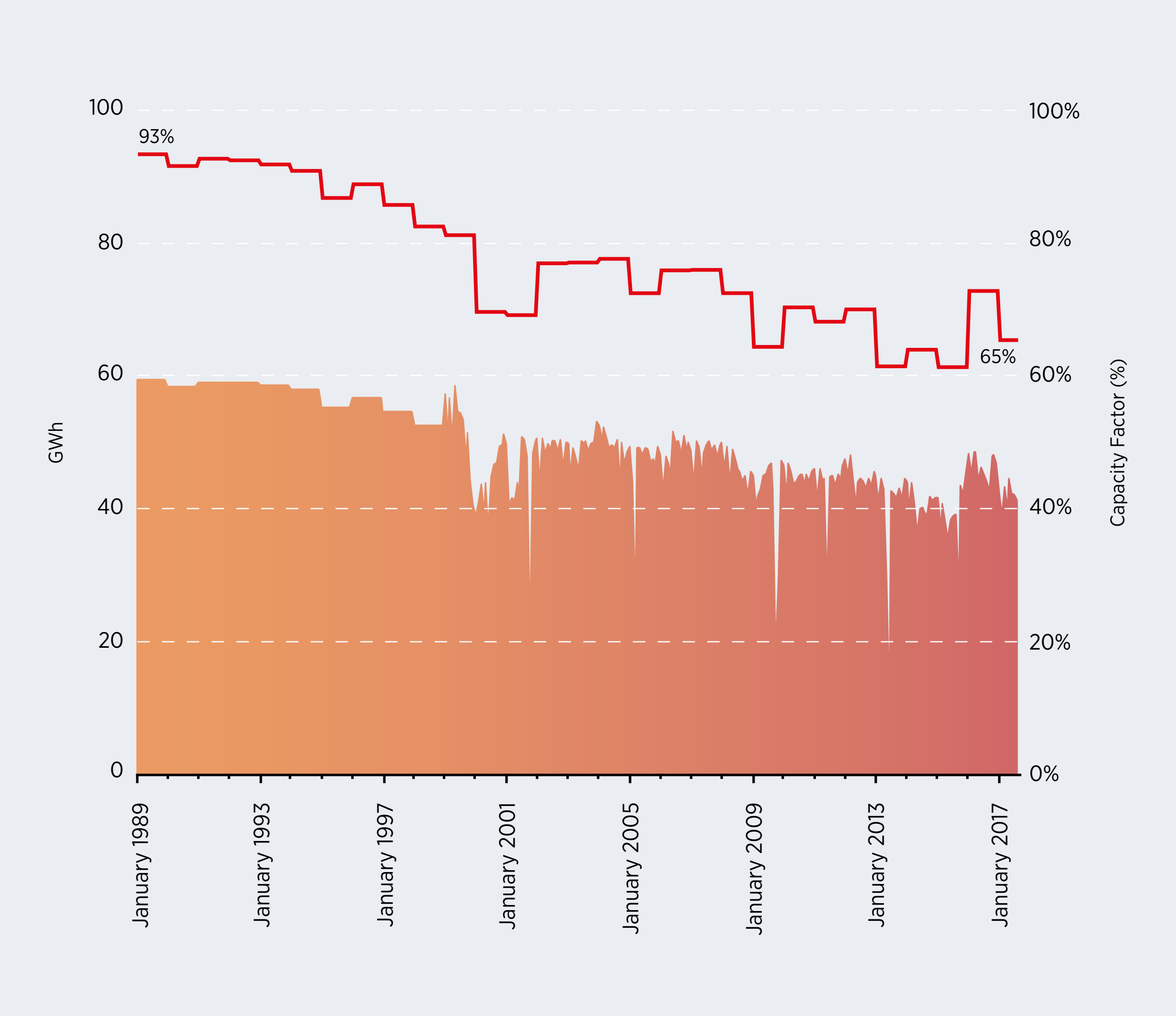

*Source: IRENA Renewable Cost Database.*

otherwise decrease over time and is why O&M costs are high, as provision for new production wells needs to be incorporated. Figure 8.3 presents a somewhat extreme example of the historical electricity generation of an 88.2 MW geothermal plant in California. For this plant, the capacity factor in the first 17 years of its life was 82%, while in the last 18 years, in was 70% – a 15% decrease.

## 8.3 LEVELISED COST OF ELECTRICITY

The LCOE of a geothermal plant is determined by its installed costs, O&M costs, economic lifetime and the weighted average cost of capital. Geothermal power projects need careful management, as geothermal resources require careful optimisation through time. Following best practice for field appraisal, project development, drilling and operation is therefore important to ensuring that projects match their anticipated economic performance.

**Figure 8.3** Electricity generation and capacity factor of an 88.2 MW geothermal plant in California, 1989-2017

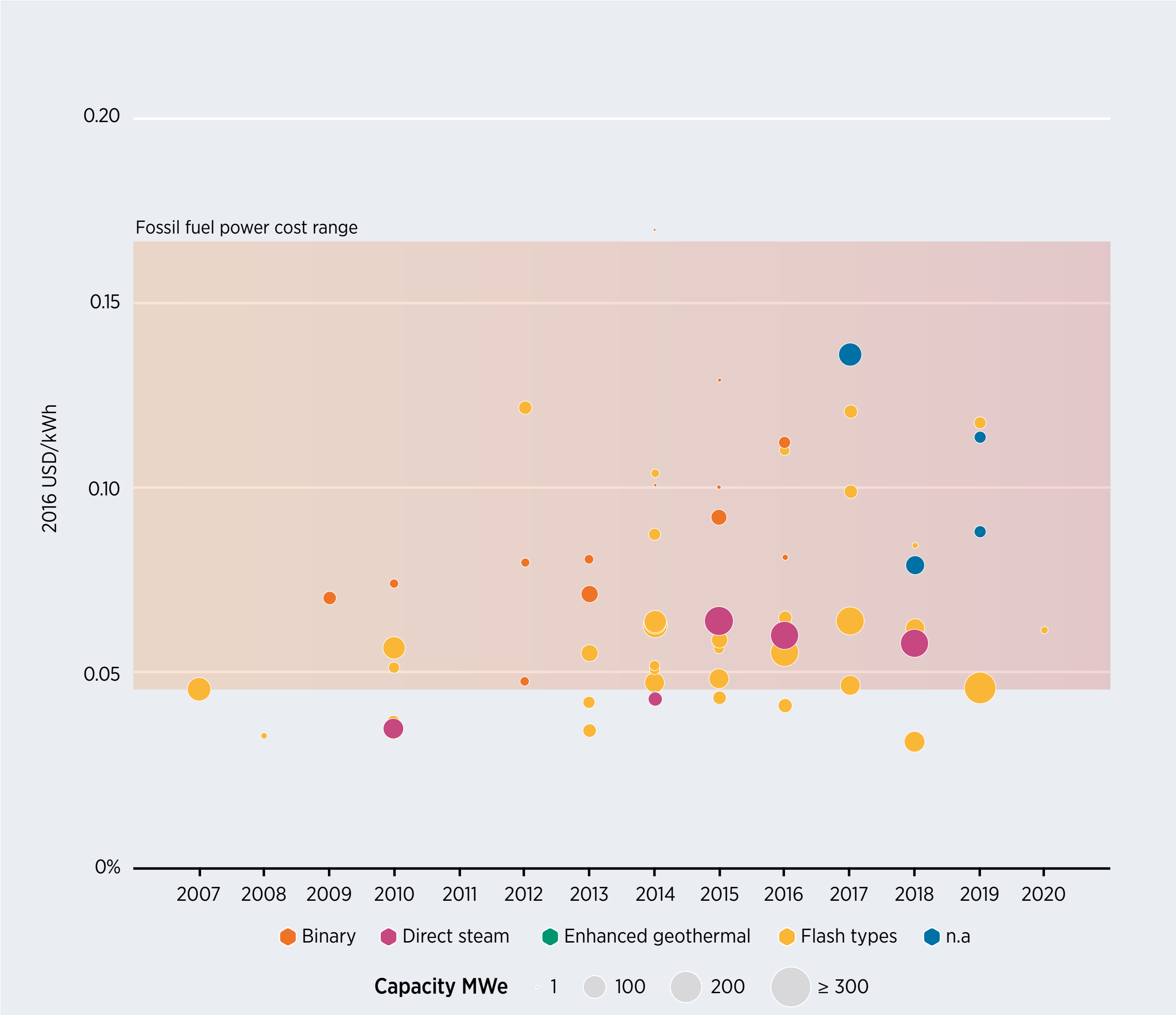



*Source: Energy Information Administration.*

Figure 8.4 presents the LCOE for geothermal projects under the following assumptions: a 25-year economic life; O&M costs of USD 110/kW/year; capacity factors based on project data (or national averages where project data is not available); two sets of wells for make-up and re-injection over the 25-year life of the project; and the capital costs outlined in Figure 8.1. Between 2007 and 2014, the trend in LCOE was increasingly in line with rises in capital costs. During this period, the LCOE varied from as low as USD 0.04/kWh for second-stage development of an existing field to as high as USD 0.14/kWh for greenfield developments.

For projects commissioned in 2014 and up to 2020, the LCOE of geothermal power plants appears to be trending downwards, in line with the general decrease in total installed costs observed. However, given the very thin deployment of geothermal and the very site-specific nature of geothermal developments, care needs to be taken in interpreting this trend. Additionally, this cost represents expectations about the lifetime costs of the project and may prove either overly pessimistic or optimistic for individual projects.

**Figure 8.4** Levelised cost of electricity of geothermal power projects by technology and size, 2007-2020




*Source: IRENA Renewable Cost Database.*

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# ANNEX I
# COST METRIC METHODOLOGY

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 or wind turbines), 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 that focusses on the core cost metrics for which good data is readily available. 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 five key indicators that have been selected are:
- Equipment cost (factory gate, FOB, and delivered at site);
- Total installed project cost, including fixed financing costs;
- Capacity factor by project; and

The levelised cost of electricity.

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. 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). 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, functionality has to be distinguished from other qualities of the renewable power generation technologies being investigated (e.g. concentrating solar power with and without thermal energy storage). This 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 IRENA Renewable Costing Alliance members, 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. This data has been compiled into a single repository – The IRENA Renewable Cost Database – that includes a mix of confidential and public domain data.

An important point is that, although this report tries to examine costs, strictly speaking, the data available are actually prices, and are sometimes not even true market average prices, but price indicators (e.g. surveyed estimates of average module selling prices in different markets). 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 sometimes no 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 can make analysing the cost of renewable power generation technologies challenging for some technologies in given markets at certain times. Where costs are significantly above or below what might be expected to be their long-term trend, every effort has been made to identify the causes.

Although every effort is made to identify the reasons why costs differ between markets for individual technologies, the absence of the detailed data required for this type of analysis often precludes a definitive answer. IRENA has conducted a number of analyses focussing on individual technologies and markets in an effort to fill this gap (IRENA, 2016a,b).

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:

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

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 report are real 2016 USD; that is to say, after inflation has been taken into account unless otherwise stated. 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 first order measure by which power generation technologies can be compared. 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, but are beyond the scope of this report.

The calculation of LCOE values in this report is based on project specific total installed costs and capacity factors, as well as the O&M costs detailed in the individual chapters. The standardised assumptions used for calculating the LCOE include the WACC, economic life and cost of bioenergy feedstocks.

The analysis in this report assumes a 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 regulatory and economic policies tend to reduce the perceived risk of renewable energy projects, and 10% in the rest of the world. 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.

| | 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 | | |

# ANNEX II
# IRENA RENEWABLE COST DATABASE

The composition of the IRENA Renewable Cost Database largely reflects the deployment of renewable energy technologies over the last 10-15 years. Most projects in the database are in China (388 GW), India (89 GW), the United States (88 GW), and Brazil (69 GW). It is significantly more difficult to collect cost data from OECD countries, however, due to greater difficulties with confidentiality issues. The exception is the United States, where the nature of support policies leads to greater quantities of project data being available. After these four major countries, Canada is represented by 26 GW of projects, the Russian Federation by 25 GW, Vietnam by 23 GW, Pakistan by 21 GW, Chile and the United Kingdom by 16 GW each, and Germany by 15 GW of projects.

With data for a small number of very large hydropower projects and the more extensive time series available, hydropower is the largest single technology represented in the IRENA Renewable Cost Database. This technology has provided cost data for 570 GW of projects since 1961, with around 90% of those projects commissioned in the year 2000 or later. The next largest technology represented in the database is onshore wind, with cost data for 268 GW of projects,worldwide. Cost data is available for 118 GW of solar PV projects, 31 GW of commissioned and proposed offshore wind projects, 20 GW of biomass for power projects and 5 GW each of geothermal and CSP projects.

The coverage of the IRENA Renewable Cost Database is more or less complete for offshore wind and CSP, where the relatively small number of projects can more easily be tracked. The database for onshore wind and hydropower is representative from around 2007, with comprehensive data from around 2009 onwards. Gaps for some countries (in the top 10 for deployment in a given year) in some years require recourse, however, to secondary sources in order to develop statistically representative averages. Data for solar PV at the utility-scale has only become available more recently and the database is representative from around 2011 onwards, and comprehensive from around 2013 onwards.

The data available so far for 2017 represents roughly 50-60% of what has become available to IRENA in previous years. At the time of release, for 2017, the total capacity of projects in the database totalled around 56 GW. The main technologies where data is yet to become available are onshore wind and, to a lesser extent, solar PV. As such, data for 2017 needs to be considered preliminary and subject to change. Typically, given previous experience with data collection, over the next one to two years, we would expect the volume of data available for solar PV (in GW) to double, given that data has become available for a significant number of projects already. For onshore wind power projects, the data in the database could grow up to five-fold, given that relatively little data has currently been finalised.

# ANNEX III
# 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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