

RENEWABLE POWER GENERATION COSTS IN 2019



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FOREWORD

The world changed drastically in the opening months of 2020, with the COVID-19 pandemic forcing much of the world into lockdown. Now, as we move towards the new, post-COVID normality, renewable power generation must form a key part of global economic stimulus measures.

Installing new renewables increasingly costs less than the cheapest fossil fuels. With or without the health and economic crisis, dirty coal plants were overdue to be consigned to the past. But the cost data presented in this report – compiled from 17 000 real-world projects – confirms how decisively the tables have turned.

More than half of the renewable capacity added in 2019 achieved lower electricity costs than new coal, while new solar and wind projects are also undercutting the cheapest and least sustainable of existing coal-fired plants. Auction results show these favourable cost trends accelerating, reinforcing the case to phase-out coal entirely.

Next year, up to 1200 gigawatts of existing coal-fired capacity could cost more to operate than new utility-scale solar photovoltaic (PV) costs to install, the report shows. Replacing the costliest 500 gigawatts of coal capacity with solar and wind would cut annual system costs by as much as USD 23 billion per year and reduce annual carbon dioxide (CO₂) emissions by around 1.8 gigatonnes, or 5% of last year's global total. It would also yield a stimulus worth USD 940 billion, or around 1% of global GDP.

Generation costs for onshore wind and solar PV have fallen between 3% and 16% yearly since 2010 – far faster than anything in our shopping baskets or household budgets. Renewables have outpaced fossil fuels in new power capacity additions overall since 2012. They are emerging as the default choice for new projects everywhere. Now, crucially, their continued cost decline means the world can afford to be ambitious amid the crisis.

Post-pandemic stimulus packages would be greatly enhanced by these clean, easily scalable, cost-effective energy solutions. Scaling up renewables can boost struggling economies. It can save money for consumers, pique the appetites of investors and create numerous high-quality new jobs.

Renewables, meanwhile, align recovery measures with climate resilience, sustainable development and other medium- and long-term policy goals. Cutting carbon dioxide (CO₂) emissions in line with the Paris Agreement remains as crucial as ever in the wake of COVID-19, while also offering tremendous potential to put millions of people back to work.

The same energy infrastructure needed to meet today's needs can also pave the way for a far better future. Investment in renewables equates with investing in health, sustainability and inclusive prosperity. Moreover, as the report underscores, the more we deploy these technologies, the more their costs will fall.



Francesco La Camera

Director-General
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Energy Agency

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ABBREVIATIONS

ACP	Alternative Compliance Payment	IPP	independent power producer
BoS	Balance of System	IRENA	International Renewable Energy Agency
CAD	Canadian dollar	IRP	integrated resource plan
CARICOM	Caribbean Community	kW	kilowatt
CCS	carbon capture and storage	kWh	kilowatt-hour
CEER	Council of European Energy Regulators	LSE	load-serving entities
CfD	Contract for Difference	MDG	Millennium Development Goal
CO₂	carbon dioxide	MEMEE	Ministry of Energy, Mines, Water and Environment (Morocco)
CPI	Consumer Price Index	MENA	Middle East and North Africa
CSP	concentrated solar power	Mtoe	million tonnes of oil equivalent
EC	European Council	MW	megawatt
ECOWAS	Economic Community of West African States	MWh	megawatt-hour
EJ	exajoule	NDRC	National Development and Reform Commission
EU	European Union	NREL	National Renewable Energy Laboratory (US)
EUR	euro	O&M	Operation and Maintenance
FIT	feed-in tariff	OECD	OECD Organisation of Economic Co-operation and Development
GBP	British pound	OEM	Original Equipment Manufacturer
GDP	gross domestic product	PPA	Power Purchase Agreement
GSR	Global Status Report	SDG	Sustainable Development Goal
GW	gigawatt	TWh	Terawatt-hour
GWh	gigawatt-hour	VRE	Variable Renewable Energy
GWth	gigawatt-thermal	WACC	Weighted Average Cost of Capital
ILR	Inverter Load Ratio		
ILUC	indirect land-use change		
INR	Indian rupee		

HIGHLIGHTS

- Renewable power generation costs have fallen sharply over the past decade, driven by steadily improving technologies, economies of scale, competitive supply chains and growing developer experience.
- Costs for electricity from utility-scale solar photovoltaics (PV) fell 82% between 2010 and 2019.
- New solar and wind projects are undercutting the cheapest and least sustainable of existing coal-fired power plants. Auction results show these favourable cost trends continuing in 2020 and beyond.
- Replacing the 500 gigawatts of existing coal capacity with the highest operating costs with new solar PV and onshore wind would:
 - » cut annual system costs by up to USD 23 billion per year;
 - » reduce annual CO₂ emissions by around 1.8 gigatonnes, or 5% of last year's global total;
 - » yield a stimulus worth USD 940 billion, or around 1% of global GDP.
- This comprehensive cost study, drawing on cost and auction price data from projects around the world, highlights the latest trends for each of the main renewable power technologies.
- Continuing cost declines confirm that competitive renewables are a low-cost climate and decarbonisation solution, that align short-term economic needs with medium- and long-term sustainable development goals.
- Renewable power installations could form a key component of economic stimulus packages in the wake of the COVID-19 pandemic.

EXECUTIVE SUMMARY

RENEWABLE POWER GENERATION COST TRENDS, 2010-2019

Electricity costs from renewables have fallen sharply over the past decade, driven by improving technologies, economies of scale, increasingly competitive supply chains and growing developer experience. As a result, renewable power generation technologies have become the least-cost option for new capacity in almost all parts of the world. This new reality has been increasingly reflected in deployment, with 2019 seeing renewables account for 72% of all new capacity additions worldwide.

According to the latest cost data from the International Renewable Energy Agency (IRENA), the global weighted-average levelised cost of electricity (LCOE)¹ of utility-scale solar photovoltaics (PV) fell 82% between 2010 and 2019,² while that of concentrating solar power (CSP) fell 47%, onshore wind by 39% and offshore wind at 29% (Figure ES.1), the IRENA Renewable Cost Database shows.³

Costs for solar and wind power continued to fall in 2019, as equipment costs and balance of plant costs declined and, in the case of wind power, improvements in technology yielded higher capacity factors. Electricity costs from utility-scale solar PV fell 13% year-on-year in 2019, reaching

USD 0.068 per kilowatt-hour (kWh). For projects commissioned in 2019, the global weighted-average LCOE of onshore and offshore wind both declined about 9% year-on-year, reaching USD 0.053/kWh and USD 0.115/kWh, respectively. Costs for CSP – still the least-developed among solar and wind technologies – fell 1% to USD 0.182/kWh.

The trend in the global weighted-average LCOE for the mature technologies of bioenergy for power, geothermal and hydropower has been more varied. These technologies represent competitive, firm power with already low costs in many cases. Between 2010 and 2019, the global weighted-average LCOE of bioenergy for power projects fell from USD 0.076/kWh to USD 0.066/kWh – a figure at the lower end of the cost range for new fossil fuel-fired projects.⁴

Power generation costs in 2019 were around USD 0.073/kWh for newly commissioned geothermal power projects. The global weighted-average LCOE of newly commissioned hydropower projects increased from USD 0.037/kWh in 2010 to USD 0.047/kWh in 2019. Despite this, hydropower remains very competitive, with nine-tenths of all capacity commissioned in 2019 producing power for less than the cheapest new fossil fuel-fired cost project.

¹ The LCOE 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 financial values are in real 2019 USD (that is to say, taking into account inflation). LCOEs are calculated assuming a real cost of capital of 7.5% in OECD countries and China, and 10% in the rest of the world, for all technologies unless explicitly mentioned. All LCOE calculations exclude the impact of any financial support.

² All data presented in this report are for the year of commissioning, unless explicitly stated otherwise.

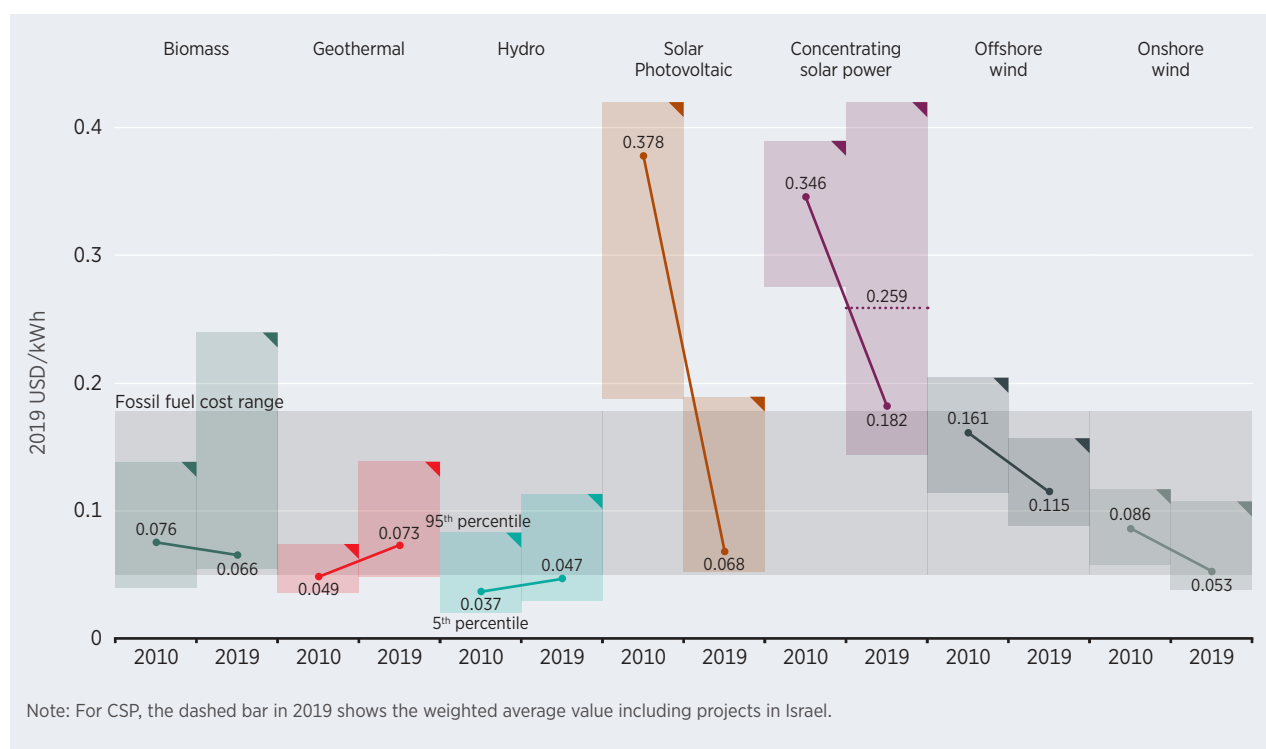
³ The IRENA Renewable Cost Database contains cost and performance data for around 17 000 renewable power generation projects with a total capacity of more than 1 770 GW that is installed or in the pipeline for commissioning.

⁴ The fossil fuel-fired power generation cost range by country and fuel is estimated to be between USD 0.05/kWh and USD 0.177/kWh. The lower bound represents new, coal-fired plants in coal-producing regions in China.

Renewable power generation continues to grow in 2020, despite the COVID-19 pandemic. New capacity additions in 2020, however, will be lower than the new record previously anticipated. Nonetheless, renewables steadily increasing competitiveness, along with their modularity, rapid scalability and job creation potential, make them highly attractive as countries and communities evaluate economic stimulus options.

Crucially, boosting investment in renewables can align short-term recovery measures with medium- and long-term energy and climate sustainability goals. Solar PV and onshore wind offer easy, rapid roll-out possibilities, while offshore wind, hydropower, bioenergy and geothermal technologies provide complementary and cost-effective medium-term investment options.

Figure ES.1 Global weighted average levelised cost of electricity from utility-scale renewable power generation technologies, 2010 and 2019



Note: This data is for the year of commissioning. The thick lines are the global weighted-average LCOE value derived from the individual plants commissioned in each year. The project-level LCOE is calculated with a real weighted average cost of capital (WACC) is 7.5% for OECD countries and China and 10% for the rest of the world. The single band represents the fossil fuel-fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

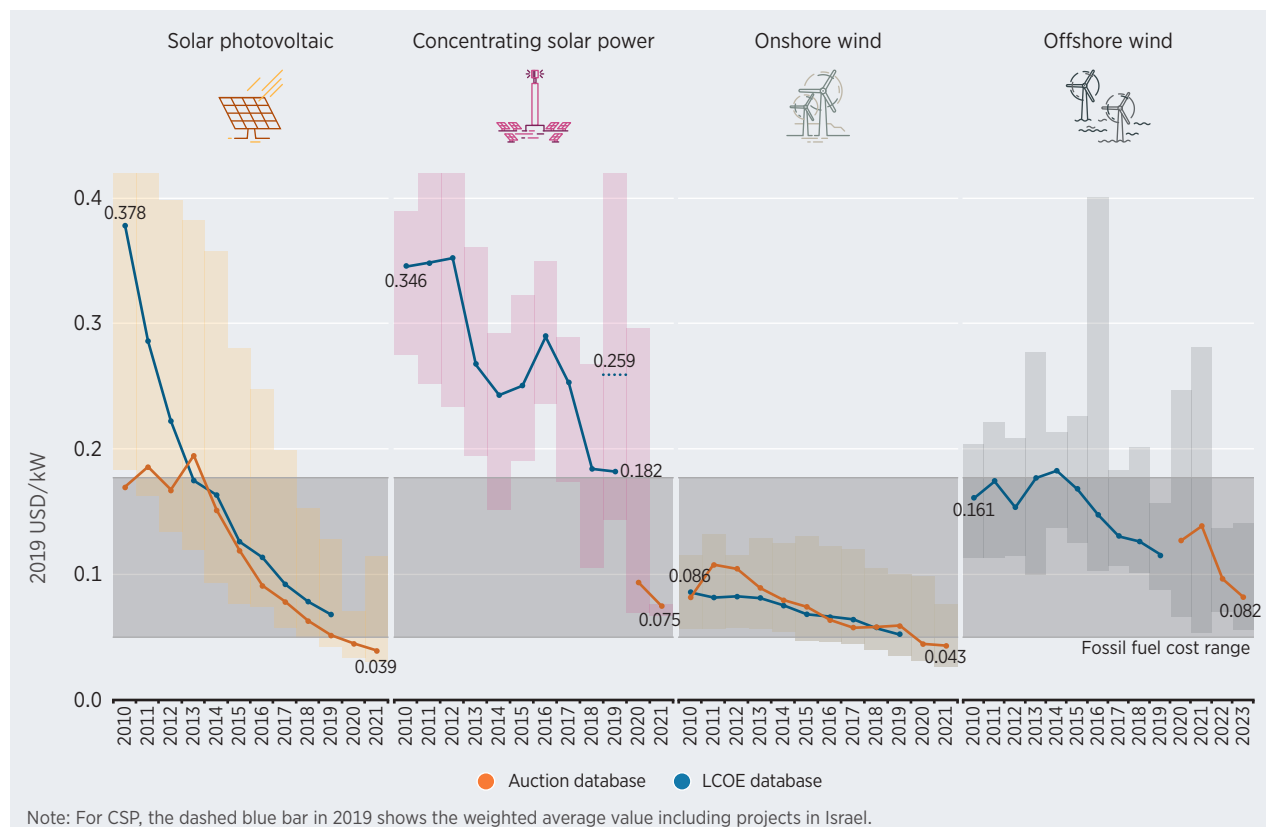
RENEWABLE POWER GENERATION INCREASINGLY OUT-COMPETES FOSSIL FUELS

Not only do costs continue to decline for solar and wind power technologies, but new projects are increasingly being commissioned at very low absolute cost levels. In 2019, 56% of all newly commissioned utility-scale renewable power generation capacity provided electricity at a lower cost than the cheapest new fossil fuel-fired option. Nine-tenths of the newly commissioned hydropower capacity in 2019 cost less than the cheapest new fossil fuel-fired option, as did three-quarters of onshore wind capacity and two-fifths of utility-scale solar PV. The latter value is remarkable considering that in 2010, solar PV electricity cost 7.6 times the cheapest fossil fuel-fired option. Overall, these projects will save consumers in non-OECD countries alone, USD 1 billion per year.

Solar and wind cost reductions show no sign of abating, either. Data in the IRENA Auction and PPA Database indicate that solar PV projects that have won recent auction and power purchase agreements (PPAs) processes – and that will be commissioned in 2021 – could have an average price of just USD 0.039/kWh. This represents a 42% reduction compared to the global weighted-average LCOE of solar PV in 2019 and is more than one-fifth less than the cheapest fossil-fuel competitor, namely coal-fired plants.

The auction and PPA data indicate the price of electricity from onshore wind could fall to USD 0.043/kWh by 2021, down 18% from 2019. Offshore wind and CSP projects, meanwhile, are set for a step change, with their global average auction prices set to fall 29% and 59% from 2019 values, respectively. With its longer lead times, offshore wind will fall to USD 0.082/kWh in 2023, while CSP will fall to USD 0.075/kWh in 2021.

Figure ES.2 Global weighted average LCOE and Auction/PPA prices for CSP, onshore and offshore wind, and solar PV, 2010 to 2023



Note: The thick lines are the global weighted average LCOE, or auction values, by year. The grey bands that vary by year are cost/price range for the 5th and 95th percentiles of projects. 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 that crosses the entire chart represents the fossil fuel-fired power generation cost range.

With the global weighted-average LCOE of utility-scale solar PV and onshore wind potentially set to fall to USD 0.039/kWh and USD 0.043/kWh in 2021, new renewable power projects are cheaper than the marginal operating costs of an increasing number of existing coal-fired power plants, raising the risk of a growing number of stranded assets. Comparing these electricity costs to analysis by Carbon Tracker (Carbon Tracker, 2018) of the operating costs of over 2000 GW of coal-fired power plants suggests 1200 GW of coal-fired power plants may have higher operating costs than the average price of new utility-scale solar PV in 2021, while for the slightly higher average electricity price for onshore wind, it would be 850 GW of coal capacity.

Retiring the least competitive 500 GW of existing coal-fired plants and replacing them with solar PV and onshore wind would reduce system generation costs – and potentially also the costs passed on to consumers – by between USD 12 billion and USD 23 billion per year, depending on the evolution of coal prices and coal-fired power capacity factors in 2021. Retiring 500 GW of the least competitive existing coal-fired power plants would reduce coal generation by around 2170 terawatt hours (TWh), reducing carbon dioxide emissions by 1.8 gigatonnes (Gt) of carbon dioxide (CO₂) (5% of global CO₂ emissions in 2019). The 500 GW coal replacement would yield a stimulus worth USD 940 billion over and above the past year's solar PV and onshore wind deployment, or around 1% of global GDP.⁵

Solar and wind power have achieved impressive “learning rates” since 2010. Steadily rising deployment, technological refinements and growing developer and country experience have seen higher capacity factors and lower total installed costs over time.⁶ For the period 2010 to 2019, the LCOE learning rate was 36% for solar PV, 23% for CSP and onshore wind, and 10% for offshore wind. Extending the period examined for CSP, onshore wind and utility-scale solar PV out to 2021, by including the global weighted-average electricity prices from the IRENA Auction and PPA Database, sees the learning rate for utility-scale solar PV increase to 40% for the period 2010-2021.

Over the same period, the CSP learning rate increases significantly to 38% and that of onshore wind to 29%. These learning rates represent quite remarkable rates of deflation for wind and solar power technologies, unrivalled by anything in our household budgets.

The same amount of money invested in renewable power today produces far more new capacity than it would have a decade ago. Renewable power generation capacity commissioned in 2010 – totalling 88 GW for the year worldwide – represented combined investments worth USD 210 billion in 2019 US dollars. Twice as much was commissioned in 2019 for USD 253 billion – only around one-fifth more in terms of investment value.

COST TRENDS BY TECHNOLOGY

Utility-scale solar PV's global weighted-average LCOE fell by a precipitous 82% between 2010 and 2019, from a value of USD 0.378/kWh in 2010 to USD 0.068/kWh in 2019. This decline in LCOE was driven by the 90% reduction in module prices between 2010 and 2019, which with declining balance-of-system (BoS) costs saw the global weighted-average total installed cost fall by 79% over the same period.

The global weighted-average total installed cost of projects commissioned in 2019 fell below the USD 1000/kW mark for the first time, to just USD 995/kW, 18% lower than in 2018. India leads the world, in having the lowest weighted-average total installed costs of USD 618/kW in 2019. Competitive cost structures are not confined to established markets anymore, however. Market growth in Ukraine and Viet Nam, for example, shows how PV continues to become a cost competitive technology choice in a growing number of settings. The weighted-average total installed cost in Ukraine in 2019 was USD 874/kW, while it was USD 1054/kW in Viet Nam. Significant country cost differences persist, however, and many markets could create significant cost reduction opportunities by moving to best practice cost structures.

⁵ The calculation includes USD 0.005/kWh for integrating this additional variable power generation. The GDP stimulus is based on a contraction of global GDP in 2020 limited to 5%.

⁶ The “learning rate” is the percentage reduction in costs that is achieved for every doubling of cumulative installed capacity.

By year commissioned, the global weighted-average capacity factor⁷ for new utility-scale solar PV increased from 13.8% in 2010 to 18.0% in 2019. This was predominantly driven by the increased share of deployment in sunnier locations. After increasing steadily every year between 2010 and 2018, the capacity factor seems to be stabilising around the 18% mark.

The largest reduction in country-level weighted-average LCOE between 2010 and 2019 occurred in India, where costs declined by 85%, to reach USD 0.045/kWh in 2019 – a value 34% lower than the global weighted average for that year. China and Spain achieved the next most competitive LCOEs in 2019, with weighted-average values of USD 0.054/kWh and USD 0.056/kWh respectively for 2019.

Residential and commercial sector rooftop solar PV typically have higher cost structures than utility-scale projects within a country. The LCOE of residential PV systems has, however, also experienced a steep reduction. Assuming a 5% weighted average cost of capital (WACC) to allow for cheaper finance for homeowners, the LCOE of residential PV systems by country and market declined from between USD 0.301/kWh and USD 0.455/kWh in 2010 to between USD 0.063/kWh and USD 0.265/kWh in 2019 – a decline of between 42% and 79% by country/market. In 2019, the lowest country/market average LCOEs for commercial PV up to 500 kW could be found in India and China, at USD 0.062/kWh and USD 0.064/kWh, respectively (Table 3.3). Between 2017 and 2019, the LCOEs in these markets fell 12% and 26%, respectively.

For **onshore wind** and renewable power generally, continuous technological innovation remains a constant. The global weighted-average LCOE of onshore wind projects commissioned in 2019 fell to USD 0.053/kWh, 9% lower than in 2018 and 39% lower than in 2010, when it was USD 0.086/kWh.

Onshore wind now consistently outcompetes even the cheapest fossil fuel-fired source of new electricity, as installed costs have fallen and capacity factors increased, while costs continue to edge lower.

In 2019, the country-level weighted-average LCOE for new projects was lower than the cheapest fossil fuel-fired option in Argentina, Brazil, China, Egypt, Finland, India, Sweden and the United States.

Falling prices for onshore wind turbines – down 55-60% since 2010 – have reduced installed costs, while expanding hub heights and swept areas have boosted capacity factors at the same time as operation and maintenance (O&M) costs have fallen. The global weighted-average total installed cost of onshore wind farms thus declined by 5% in 2019, year-on-year, falling from USD 1549/kW in 2018 to USD 1473/kW in 2019.

Improvements in wind turbine technology have resulted in larger rotor diameters, swept blade areas, name plate capacities and hub-heights. This has driven an improvement in capacity factors that means today's turbines harvest more electricity from the same resource than their predecessors. Between 2010 and 2019, the global weighted-average capacity factor for onshore wind increased by almost one-third, from just over 27% in 2010 to 36% in 2019.

Offshore wind's installed costs fell 18% in 2010-2019, while its capacity factor improved by nearly one-fifth over the last decade (from 37% in 2010 to 44% in 2019). Operation and maintenance costs similarly fell with larger turbine sizes, expanded service capacities, and the emergence of cost synergies across growing maritime wind-farm zones. In 2019, the global weighted-average LCOE of offshore wind had fallen to USD 0.115/kWh, from USD 0.161/kWh in 2010. Recent auction results, including subsidy-free bids, however, herald a step-change in competitiveness for offshore wind in the 2020s, with electricity prices of between USD 0.05 and USD 0.10/kWh about to become the norm.

⁷ For solar PV only, capacity factors are the AC/DC value, given costs for solar PV are quoted in DC terms.

Concentrating solar power's installed costs have fallen in recent years with ongoing technological improvements and increased supply-chain competitiveness. The global weighted-average capacity factor improved from 30% to 45% between 2010 and 2019, with new CSP plants being built with improved technology, at better sites and in countries with more sunshine. The global weighted-average LCOE of CSP plants was around USD 0.35/kWh between 2010 and 2012, but fell 47% between 2010 and 2019. Recent auction and PPA results suggest the cost of electricity from CSP will fall into the USD 0.07/kWh to USD 0.08/kWh range. With its ability to provide dispatchable renewable power, CSP could therefore play an increasingly important role in facilitating ever-higher shares of variable solar PV and wind in areas with the direct solar resources to support CSP plants.

Hydropower is a mature, commercially attractive renewable power generation technology. Hydropower is also uniquely placed to provide not only low-cost electricity, but also cheap electricity storage and large-scale flexibility services to the grid. Between 2018 and 2019, the global weighted-average total installed cost of hydropower projects rose from USD 1435/kW to USD 1704/kW. The global weighted-average LCOE of hydropower in 2019 was USD 0.047/kWh – 6% higher than in 2018 and 27% higher than in 2010. Despite the increase in global weighted-average LCOE since 2010, hydropower remains a competitive, low-cost source of electricity, with its global weighted-average LCOE still comfortably below the cheapest fossil fuel-fired source of new electricity generation.

Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available – such as by-products from agricultural or forestry processes onsite – they can provide highly competitive, dispatchable electricity.

For bioenergy projects newly commissioned in 2019, the global weighted-average total installed cost was USD 2141/kW, an increase on the 2018 weighted-average of USD 1693/kW. Capacity factors for bioenergy plants are driven by the availability of low-cost feedstocks. Between 2010 and 2019, the global weighted-average capacity factor for bioenergy projects varied between a low of 64% in 2012 to a high of 86% in 2017. Due to the heterogeneity of bioenergy feedstock and technology costs – and the typically higher technology costs in OECD countries – annual global weighted-averages are strongly influenced by the technology mix and geographical location of commissioned plants. Between 2010 and 2019, the global weighted-average LCOE of newly commissioned bioenergy plants has therefore ranged between a low of USD 0.055/kWh in 2011 to a high of USD 0.082/kWh in 2014, ending at USD 0.066/kWh in 2019.

Newly commissioned **geothermal plants** had a global weighted-average LCOE of USD 0.073/kWh in 2019, up only slightly from the previous year and still broadly in line with costs since 2013. From then until 2019, the global weighted-average LCOE ranged between USD 0.06/kWh and USD 0.07/kWh for this mature technology which provides firm renewable electricity in areas with active geothermal resources. New capacity additions for this technology remain modest. The year 2019 saw record new capacity additions, but they totalled just 680 megawatts.



01



LATEST COST TRENDS

The growth in deployment of renewable power generation technologies continued in 2019, as costs continued to fall and renewable power generation increasingly became the default source of least-cost new power generation. Since the year 2000, renewable power generation capacity worldwide has increased 3.4-fold, from 754 gigawatts (GW) to 2 537 GW by the end of 2019 (IRENA, 2020a).

In 2019, 176 GW of new renewable power generation was added, with solar photovoltaic (PV) capacity increasing by 97 GW, onshore wind power by 54 GW, hydropower by 12 GW, bioenergy by 6 GW and offshore wind by 5 GW. At the same time, geothermal capacity increased by just under 700 megawatts (MW) and concentrating solar power (CSP) by 600 MW. New capacity additions by renewables represented 72% of the net capacity expansion of all power generation sources in 2019. Indeed, renewables have consistently accounted for more than half of all new, net capacity additions since 2015, while accounting for 49% to 53% of the total during the period 2012-2014, inclusive (IRENA, 2020a).

Since 2012, IRENAs cost analysis programme has been collecting and reporting the cost and performance data of renewable energy technologies. Having, 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. Indeed, in the case of solar PV, in some markets, even data six months old can significantly overstate the costs.

The key sources of data for the cost metrics contained in this report are the IRENA Renewable Cost and the IRENA Auctions and PPA databases. The IRENA Renewable Cost Database has grown to include project-level cost and performance data for over 17 000 projects, representing over 1 700 GW of capacity, either installed or in the pipeline for commissioning in the coming years. The IRENA Auctions and PPA Database contains data on 10 700 projects or programme results, where pricing data is not disclosed for individual winners, totalling around 496 GW of capacity. These databases contain significant overlap, which opens up the possibility of directly comparing projects; an area IRENA will explore in greater detail in future work.

In recent years, IRENA has expanded the range of cost and performance metrics it tracks and regularly reports, from average onshore wind turbine sizes and rotor diameters by country, to detailed cost reduction breakdowns for utility-scale solar PV. Since 2018 (IRENA, 2018a), IRENA has been publishing detailed data not only on the levelised cost of electricity (LCOE)¹ at the project level, but also on the results of auctions and power purchase agreements (PPAs).

¹ Note that “weighted-average LCOE” and “weighted-average cost of electricity” are used interchangeably in this report.

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 in real, 2019 USD (that is to say, taking into account inflation). They are also calculated excluding any financial support and using a fixed assumption of a real cost of capital of 7.5% in Organisation of Economic Co-operation and Development (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.

All data presented here is for the year of commissioning. Planning, development and construction can take 2-3 years for solar PV and onshore wind, but can take five years or more for CSP, fossil fuels, hydropower and offshore wind.

These varied metrics allow us not only to follow the evolution of the costs of renewable power generation technologies, but also analyse what the underlying drivers are, at a global level and in individual countries. These layers of data and the granularity available provide deeper insights for policy makers and other stakeholders.

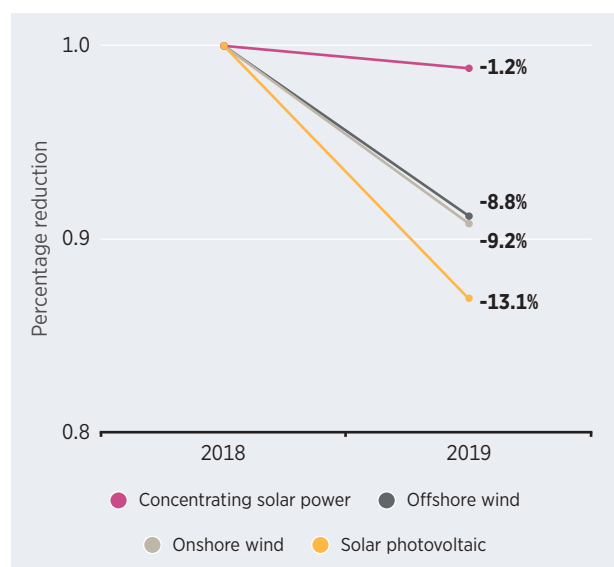


RENEWABLE POWER GENERATION COST TRENDS: 2010 TO 2019

In 2019, data from the IRENA Renewable Cost Database demonstrated the ongoing competitiveness of the mature renewable power generation technologies – hydropower, bioenergy and geothermal. This data also showed a continued improvement in the competitiveness of solar and wind power technologies. The global weighted-average LCOE of solar PV fell by 13% year-on-year in 2019 – slightly lower than the 15% reduction experienced in 2018 – driven by declines in module prices and balance of system costs (Figure 1.1).

Onshore and offshore wind both experienced a year-on-year decline of around 9%. For onshore wind, this was similar to the experience in 2018, but for offshore, it was a significant increase on the 3% recorded in 2018. Cost reductions for onshore wind were driven by falls in turbine prices and balance of plant costs.

Figure 1.1 Global LCOE from newly commissioned utility-scale renewable power



Source: IRENA Renewable Cost Database.

These saw the global weighted-average total installed cost of onshore wind fall below USD 1500/kW. Another factor in reducing costs was the continued improvement in technology, leading to an increase in average capacity factors.

Between 2010 and 2019, the global weighted-average LCOE of bioenergy projects commissioned fell 13%, while that of offshore wind by 29%. For onshore wind, the figure fell by 39%, that of CSP by 47% and that of solar PV by a precipitous 82%. The global weighted-average LCOE of geothermal projects, where the market is very thin², increased by 50% between 2010 and 2019, to USD 0.073/kWh³ in 2019.

For newly commissioned projects, the global weighted-average LCOE of utility-scale solar PV fell by 82% between 2010 and 2019, from USD 0.378/kWh to USD 0.068/kWh (Figure 1.2), as global cumulative installed capacity of all solar PV (utility-scale and rooftop) increased from 40 GW to 580 GW. This reduction has been primarily driven by declines in module prices – which have fallen by around 90% since 2010 – and balance of system costs. Together, these factors led to total installed costs of utility-scale solar PV to fall by almost four-fifths between 2010 and 2019. Capacity factors have also risen, but predominantly due to a shift in the share of deployment to regions with better solar resources. The global weighted-average LCOE in 2019 of USD 0.068/kWh is at the lower end of the range for new fossil fuel-fired electricity projects, while utility-scale solar PV projects are increasingly undercutting even the cheapest new fossil fuel-fired option.⁴

Over the period 2010 to 2019, the global weighted-average cost of electricity from CSP fell from USD 0.346/kWh to USD 0.182/kWh when two Israeli projects that were much delayed and came online in 2019 are excluded.⁵ That decline is even more remarkable when taking into account that global cumulative installed capacity at the end of 2019 was just 6.3 GW.

² New capacity additions for geothermal in 2010 were 225 MW and in 2011, just 89 MW. As a result, these years are not particularly representative of recent geothermal cost trends.

³ All cost data in this report is expressed in real, 2019 United States dollars (USD), that is to say, taking into account inflation.

⁴ The fossil fuel-fired power generation cost range by country and fuel is estimated to be between USD 0.05/kWh and USD 0.177/kWh. The lower bound represents new, mine-mouth coal-fired plants in China.

⁵ These two utility-scale projects in Israel were much delayed and as a result were contracted while CSP costs were significantly higher than today. They also use what is now considered an uneconomic configuration. Given the thin market for CSP, these two projects have an outsized impact on the global weighted average. Figure 1.2 includes both the weighted-average value without these plants, to track the underlying trend in CSP costs, as well as with the plants included, to show their impact on 2019 numbers.

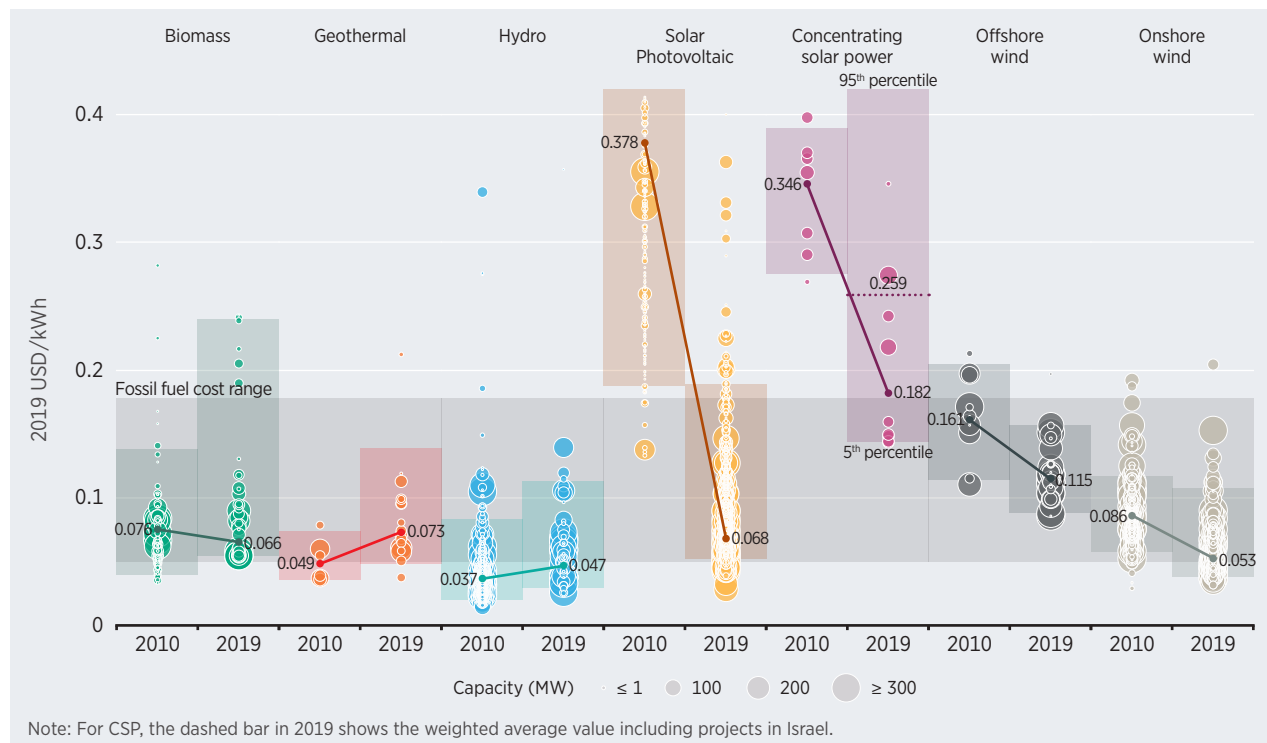
Similarly to solar PV, the cost of electricity decline for CSP has been driven by reductions in total installed costs. Yet, improvements in technology have also played a significant role in increasing capacity factors, aided by a shift in deployment to areas with better solar resources.

Onshore wind power represents an increasingly competitive source of new generation. Between 2010 and 2019, the global weighted-average cost of electricity from onshore wind projects fell by 39%, from USD 0.086/kWh to USD 0.053/kWh, as cumulative installed capacity grew from 178 GW to 594 GW. The decline in the cost of electricity from onshore wind has been driven by reductions in total installed costs and improvements in the technology of wind turbines, which have increased capacity factors and lowered operations and maintenance (O&M) costs. Wind turbine prices have fallen by around 55-60% since 2010, with the global weighted-average total installed cost falling more slowly, by 24%.

For onshore wind, the key impact on reducing costs that improvements in technology have been having is through the deployment of larger turbines, with higher hub-heights and swept areas. These can collect more electricity than older turbines from the same resource. As a result, the global weighted-average capacity factor of newly commissioned onshore wind projects increased by almost a third between 2010 and 2019.

For offshore wind, over this period, the global weighted-average LCOE of newly commissioned facilities fell from USD 0.161/kWh to USD 0.115/kWh, as cumulative installed capacity at the end of 2019 reached 28 GW. With a relatively volatile trend in weighted-average values, given the relatively small number of projects added in some years, there is somewhat more “noise” in the data for any one year-on-year comparison. From 2010 to 2019, however, total installed costs fell by around 18%, as capacity factors increased by around one-fifth, from 37% in 2010 to 44% in 2019.

Figure 1.2 Global LCOEs from newly commissioned utility-scale renewable power generation technologies, 2010-2019



Source: IRENA Renewable Cost Database.

Note: This data is for the year of commissioning. 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 (WACC) is 7.5% for OECD countries and China and 10% for the rest of the world. The single band represents the fossil fuel-fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

Over half of newly commissioned utility-scale renewable power generation capacity in 2019 produced electricity at lower costs than the cheapest new source of fossil fuel-fired power.

The installed costs and capacity factors of bioenergy for power, geothermal and hydropower are highly project-specific. As a result, there can be significant year-to-year variability in global weighted-average values when deployment is relatively thin and the share of different countries/regions in new deployment varies significantly year-to-year. Between 2010 and 2019, the global weighted-average LCOE of bioenergy for power projects fell from USD 0.076/kWh to USD 0.066/kWh – a figure at the lower end of the cost of electricity from new fossil fuel-fired projects. For hydropower, the global weighted-average LCOE for this period rose by 27%, from USD 0.037/kWh to USD 0.047/kWh. This was still lower than the cheapest new fossil fuel-fired electricity option, despite the fact that costs increased by 6% in 2019, year-on-year.

For hydropower, the commissioning in 2019 of a number of delayed projects that had experienced some cost overruns was a contributing factor that may not be repeated in 2020. The global weighted-average LCOE of geothermal has been around USD 0.07/kWh since 2016.

Costs not only continue to decline for solar and wind power, but these, along with the more mature technologies, are increasingly being built at very low absolute cost levels. Indeed, in many cases renewables are not just competing, but out-competing fossil fuels. The data shows that renewables – without financial support – are undercutting fossil fuels by a substantial margin in an increasing number of cases. In 2019, 41 GW of the onshore wind projects commissioned in 2019 (around 75% of the total) had electricity costs that were lower than the cheapest fossil fuel-fired option.

For hydropower, 10.7 GW of the projects commissioned (around 89% of the total) had costs that were less than the lowest cost fossil fuel-fired power generation option.⁶ With the dramatic decline in the costs of solar PV, 2019 saw 28 GW (40% of utility-scale deployment) of utility-scale solar PV projects commissioned having lower costs than the cheapest fossil fuel-fired option. Overall, 56% of all newly commissioned utility-scale renewable power generation projects by capacity had an LCOE lower than the cheapest new source of fossil fuel-fired power.

In 2020, in non-OECD countries, where demand for electricity is growing over the medium- and long-term, renewable power generation projects will, in their first full year of operations, reduce costs in the electricity sector by just over USD 1 billion, relative to adding the same amount of fossil fuel-fired generation. The majority (52%) of these savings are attributable to hydropower (USD 554 million/year), due to the large capacity added at significant discounts to the cheapest fossil fuel-fired cost option, along with hydropower's higher capacity factor. Onshore wind contributes USD 354 million/year. This is because although four times as much onshore wind capacity as hydropower is being added at an LCOE lower than fossil fuels, the discount is, on average, smaller, while onshore wind also has a lower capacity factor. Solar PV accounts for USD 148 million/year of the savings.

The cumulative savings of the above projects, over their economic lives, will reach around USD 28 billion. In addition to these direct cost savings, the substantial economic benefits of reduced carbon-dioxide emissions and local air pollutants also need to be factored in.

⁶ Overall, since 2010, almost 250 GW of hydropower capacity has been added that has a lower cost than even the cheapest fossil fuel-fired option.

AUCTION AND POWER PURCHASE AGREEMENT DATA: A CRYSTAL BALL INTO THE NEAR FUTURE

The continued cost reductions for solar and wind power technologies have by no means run their course. Data from IRENA's Auction and PPA Database⁷ and forthcoming analysis of the techno-economic potential for continued cost reductions for solar and wind power technologies⁸ indicates that the costs of solar and wind power will continue to fall in the short-term and out to 2030 and beyond. These reductions are being driven by ongoing improvements in technology, reduced manufacturing costs, greater economies of scale, competition in supply chains and ongoing competitive pressures.

IRENA's Auction and PPA Database contains data on around 10 700 individual winning auction or tender bids, as well as PPA contracts, covering 496 GW of capacity. The data is predominantly at the project level, but where the details of individual winning bids are not disclosed, the entries represent the total capacity of that particular auction. This database provides a complementary view to the IRENA Renewable Cost Database, with its project installed cost, capacity factor and LCOE data.

While the Auction and PPA prices conceal all the assumptions that are necessary to calculate an LCOE, the pricing provides unique insights into where market prices for renewable electricity are trending. These prices can also be benchmarked against LCOE trends to improve our understanding of cost trends in different markets.

Direct comparisons between the LCOE and PPA/Auction data are not always possible, however. This is because in many instances the terms and conditions of tenders, auctions and PPAs mean that the boundary conditions (e.g., the auction price is a "premium" over spot prices), or underlying contract length or terms diverge from LCOE assumptions.

This occurs, for example, when contract periods for the winning bids do not match the economic lifetime of a project, or there are prices that are not indexed to inflation.⁹ Some of these differences can be accurately corrected for. Others, however, require additional assumptions that may differ from the asset owners assumptions (e.g., likely revenues after the end of the awarded contract, out to the end of the economic life of the asset) – and therefore may not accurately reflect what the project LCOE is likely to be.

Despite these caveats, the volume of data available makes it possible to draw some compelling insights from the global dataset about trends in renewable electricity costs over the next few years. Competitive procurement has grown in importance in recent years, with significant volumes of awards from around 2016, allowing more robust comparisons with the LCOE database.

Figure 1.3 overlays the Auction and PPA Database data and project LCOE data. In this figure, auction or PPA prices that are clearly not comparable to an LCOE have been removed or corrected to the extent possible. For instance, the impact of the Investment Tax Credit (ITC) on solar PV and Production Tax Credit (PTC) on onshore wind auction and PPA prices in the United States have been corrected for. Additionally, all projects where it is known that no indexing of award prices occurs, have been deflated to a real price.

The differences in the global weighted-average trend lines from the LCOE and Auction and PPA databases in the earlier years can be largely attributed to the fact that data in the Auction and PPA database was thin and the projects in those years were not representative of the global deployment of each technology. In recent years, however, competitive procurement processes have become the dominant source of new utility-scale deployment in an increasing number of countries, especially for utility-scale solar PV. Some variation

⁷ This database contains data on successful and unsuccessful bids and awards in tender and auction processes to competitively procure renewable power. Only data on winning bids is presented here, however. The database includes data on the winning bid prices, duration of the contracts and information on whether and how the award price is indexed over the contract period.

⁸ In 2020, IRENA will release an update of the 2016 report, "The power to change: Solar and wind cost reduction potential to 2025" (IRENA, 2016), with updated cost reduction potentials for solar and wind power technologies, updated to 2030 and extended to provide country-level analysis.

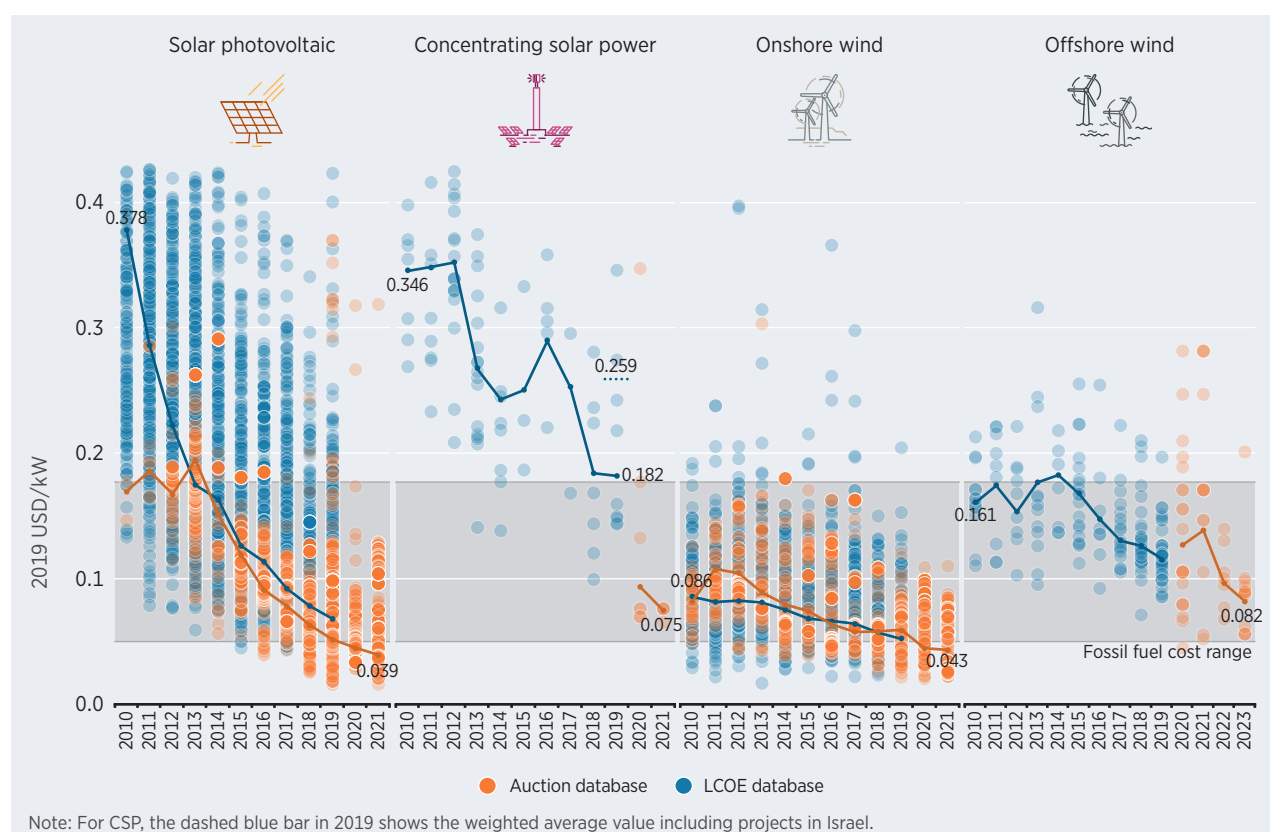
⁹ As discussed, care must be taken in interpreting the Auction and PPA data results. IRENA has already discussed these issues in previous editions of its power generation cost update series. See IRENA, 2018 for more details.

naturally exists, given the different coverage of each dataset and the fact that the O&M and weighted average cost of capital assumptions in the LCOE database may diverge from what's implied by the Auction and PPA data.

Bearing in mind these caveats, the data shows that for onshore wind, the global weighted-average price for electricity from the 27 GW of utility-scale onshore wind projects in the Auction and PPA Database expected to be commissioned in 2020 will decline to USD 0.045/kWh, and to USD 0.043/kWh in 2021 for the 25 GW of capacity in the database expected to be commissioned in that year (Figure 1.3).

Given the potential slippage in commissioning of some of the projects in the database due to the impact of efforts to control the outbreak of COVID-19 in 2020, it is possible that a small number of onshore wind projects commissioning dates may slip into 2021, but what impact this will have on the global weighted-average electricity cost for onshore wind for 2020 and 2021 is not yet clear. It is therefore likely that, compared to 2019, the cost of electricity from onshore wind will fall by a further 18% between 2019 and 2021. Of the projects in the Auctions and PPA database that are expected to be commissioned in 2021, 62% (15 GW) have electricity costs lower than the cheapest fossil fuel-fired new capacity option, which stands at USD 0.05/kWh.

Figure 1.3 The LCOE and PPA/Auction prices by project for solar PV, onshore wind, offshore wind and CSP, 2010-2023



Source: IRENA Renewable Cost Database.

Note: Each circle represents an individual project LCOE (blue dots), or an auction result (orange dots), where there was a single clearing price at auction, for the actual or estimated year of commissioning respectively. 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.

For utility-scale solar PV, the IRENA Auction and PPA Database suggests that the global weighted-average price for solar PV will fall to USD 0.045/kWh in 2020 and USD 0.039/kWh in 2021, which is a 42% reduction in electricity cost implied in 2021 compared to the 2019 global weighted-average LCOE. This is for a total of 37 GW of capacity in the database expected to be commissioned in 2020, while 18 GW has currently been procured that is expected to be online in 2021. Of the projects in the Auction and PPA database that are expected to be commissioned in 2021, four-fifths will have an award price that is lower than the cheapest fossil fuel-fired power generation option.

Indeed, with the right regulatory and institutional frameworks in place, well-designed contract terms and appropriate risk sharing, the recent record low auction prices for solar PV in Dubai, Ethiopia, Mexico, Peru, Chile, Abu Dhabi and Saudi Arabia and elsewhere have shown that an LCOE of USD 0.03/kWh is possible in a wide variety of national contexts. Expectations are that values as low as USD 0.02/kWh are potentially feasible in the coming years.

Such very low values are possible when all the factors driving the cost of electricity reach their lowest or best values. These factors include installed and O&M costs being low, the solar resource being excellent and low financing costs. What is remarkable for solar PV is that very competitive total installed costs for this technology are now possible around the world, even in markets with little previous deployment experience with solar PV. This is because international project developers are now bringing their experience in project development to new markets, partnering with local stakeholders to take advantage of low – and falling – equipment costs, while also tapping into international finance markets to secure low-cost financing for their solar PV projects. They are thus able to deliver very low-cost electricity to consumers.

The low-cost of finance has, indeed, been an important driver of the very low-cost solar PV seen in recent years. It is also likely to be one of the reasons why the Auction and PPA data started to diverge from the global weighted-average

value in the LCOE database after 2015.¹⁰ There is also the possibility that there is a growing divergence in the O&M and economic lifetime assumptions in the LCOE calculations from what is becoming the norm in the PV market. However, the most significant area where assumptions could be diverging sufficiently to induce the current gap is in the weighted average cost of capital (WACC). There is significant anecdotal evidence that WACC expectations have fallen significantly for solar PV in recent years, as the extremely low-risk nature of developing solar PV projects is increasingly being correctly priced into cost-of-capital rates for both debt and equity. This issue will be examined in more detail later in this chapter.

For CSP and offshore wind, deployment is thinner and the annual global weighted-average more volatile in both the LCOE and Auction and PPA databases. The global market for CSP revived somewhat in 2018 and 2019, as a variety of projects around the world have come online, from Morocco to South Africa and China. Yet, new capacity additions remain relatively low, at between 500 MW and 650 MW per year. The Chinese market shows potential to scale, but very aggressive timelines for the first batch of pilot projects have proved challenging and, in hindsight, perhaps overly ambitious. With special dispensation for some projects to be completed later than originally envisioned, however, the CSP industry is gaining valuable experience. There is, therefore, the potential for increased Chinese deployment and investment in supply chains to be a future game-changer for the industry.

There are only a handful of CSP projects in the IRENA Auction and PPA database to be commissioned in 2020 and 2021, but with a price of electricity of around USD 0.075/kWh, this represents a reduction of 59% compared to the global weighted-average project LCOE in 2019.

For offshore wind, the years 2018 and 2019 marked the revelation in auction and tender results of a step change in pricing. Subsidy-free bids in the Netherlands and Germany highlighted the fact that in the right conditions, offshore wind can compete in the wholesale electricity market.

¹⁰ This divergence is more pronounced in this edition of IRENA's cost update as a result of the revisions made to the database over the past year, including adding additional auction and PPA results and more detail on the contract conditions that have allowed an increased number of "corrected" auction values that more closely align with LCOE values.

Meanwhile, record low bids (in 2019 USD) of USD 0.051/kWh in France and between USD 0.056-0.059/kWh in the United Kingdom undercut new capacity from fossil fuel options in those countries. In the case of the United Kingdom, they were also lower than expected long-run wholesale prices.

This step-change in competitiveness has been driven by the industry achieving critical mass, along with innovations in wind turbine technology, installation and logistics; economies of scale in O&M (from larger turbines and offshore wind farm clustering); and improved capacity factors from higher hub heights, better wind resources (despite increasing costs in deeper waters offshore), and larger rotor diameters.

With longer lead times than onshore wind and solar PV for project commissioning, these cost reductions will take time to appear in annual, newly commissioned cost data. By 2023, however, the majority of projects being commissioned are likely to have costs in the USD 0.05/kWh to USD 0.10/kWh range. With just 28 GW of total installed capacity globally at the end of 2019, this represents a remarkable achievement in driving down costs to competitive levels, all in the space of a decade.

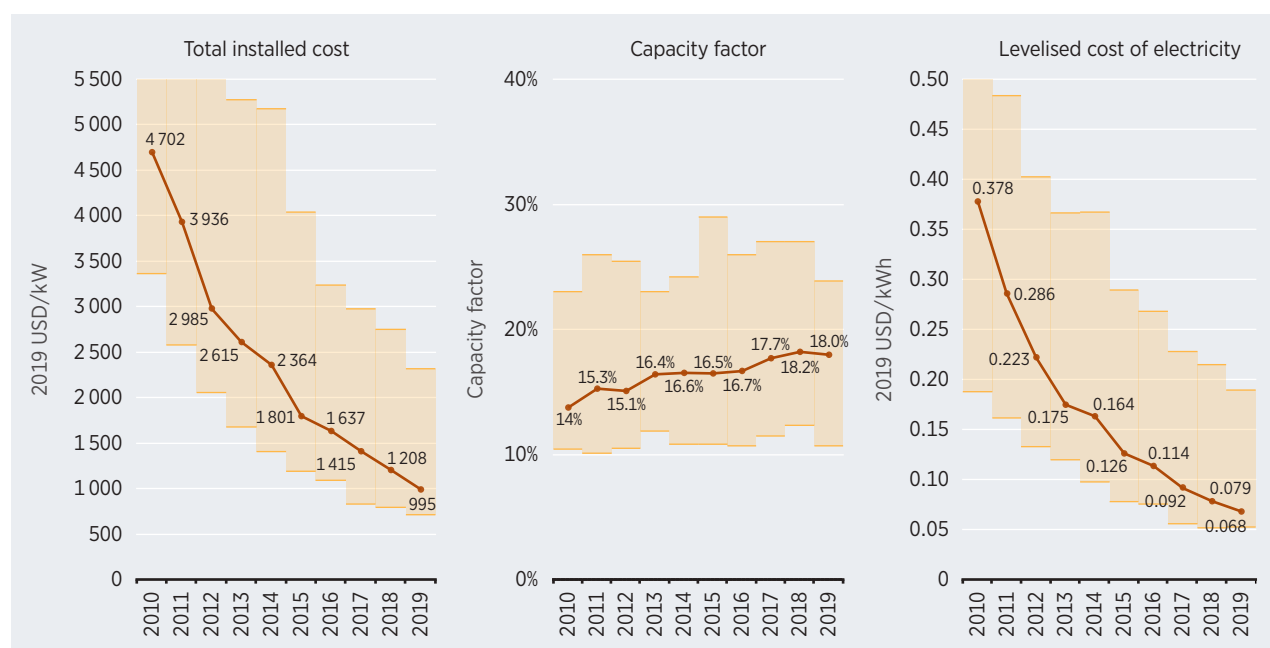
COSTS TRENDS BY TECHNOLOGY: 2010 TO 2019

Solar photovoltaics

The remarkable, continued decline in the cost of electricity from solar PV has been driven by reductions in the total installed costs for utility-scale projects (Figure 1.4)¹¹, with these declining by 79% between 2010 and 2019. In 2019, the global weighted-average total installed cost for utility-scale solar PV fell below USD 1000/kW for the first time, to just USD 995/kW, down from USD 4702/kW in 2010. In 2019, the 5th and 95th percentile of projects ranged from USD 714/kW to USD 2320/kW. The year-on-year reduction in total installed costs in 2019 reached 13%.

There has not only been a significant reduction in average costs, however. There has also been a shift in the distribution of projects around the weighted average, as the global weighted-average for utility-scale projects has shifted to the lower end of the 5th and 95th percentile ranges. As will be discussed in Chapter 3, there has also been a convergence in country-level installed costs, as increasingly competitive local markets have seen a range of countries move towards best practice project development and cost structures. Given the highly

Figure 1.4 Global weighted average total installed costs, capacity factors and LCOE for solar PV, 2010-2019



Source: IRENA Renewable Cost Database.

¹¹ For Figures 1.4 to 1.9, please see the individual technology chapters and Annex One for all of the important assumptions required for the LCOE calculations.

replicable and modular nature of solar PV project development — and a narrowing of country-level price differentials for solar PV modules (although there are exceptions, such as the United States and Japan), this means that the most competitive cost structures for solar PV are increasingly less affected by individual project characteristics than for other renewable power generation technologies. Variation remains, both within and between countries, but those with competitive markets can expect to see convergence of installed costs with best practice levels, as local supply chains become more competitive and developers gain more experience.

The reduction in solar PV installed costs has been driven by cost reductions in PV modules. Between December 2009 and December 2019, module prices fell by between 87% and 92% for crystalline silicon modules, depending on the type. These module price reductions have been driven by a number of factors. First, by the continued improvement in module efficiency. This acts by reducing the surface area required for the same power output, driving down materials costs and some balance of system costs directly influenced by surface area. Second, by improvements in manufacturing that have reduced materials costs (e.g., diamond-wire sawing); third, by reduced labour costs through improved productivity and increased factory automation; fourth, by economies of scale in manufacturing, along with vertical integration of the manufacturing process from polysilicon production to module manufacture; and finally, by increased competition among suppliers.

Between December 2018 and December 2019, the decrease in installed costs for crystalline silicon module-based projects was driven by module price declines of between 4% (for “low-cost” modules) and 12% (for “high-efficiency” modules). In December 2019, benchmark prices for modules in Europe ranged from USD 211/kW for low-cost manufacturers’ products, to USD 267/kW for mainstream manufacturers’ products (pvXchange, 2020). At the same time, benchmark prices for high-efficiency modules stood at USD 367/kW.

The year 2019 also saw the emergence of the widespread deployment of bifacial modules, which boost output by allowing reflected light onto the back of a panel to be captured. Currently, these retain a cost premium in Europe, averaging around USD 445/kW in December 2019, but the premium is often lower elsewhere.

Balance-of-system (BoS) costs¹² have fallen slightly less rapidly than module costs. This is in part due to very different levels of domestic market maturity (as, for example, evidenced in the degree of project developers’ experience), as well as structural differences in local labour and manufacturing costs. Different support policy structures also end up influencing competitiveness. Having said that, there are now a number of examples where, with the right regulatory and policy settings, new markets have emerged that have been able to take advantage of international developer experience and local civil engineering expertise to rapidly scale local supply chains and achieve very competitive cost structures in 1-2 years. This ability to rapidly achieve competitive cost structures in a very short time frame, sets today’s solar PV market apart from that of five years ago. It is also behind the growing number of very competitive solar PV auction and Power Purchase Agreement (PPA) results in new markets.

The growth of these new markets for solar PV has also seen an increasing proportion of the market located in areas with excellent solar resources. This has led to the global weighted-average capacity factor increasing from 14% in 2010 to around 18% today. In addition to the shift to deployment in areas with better solar resources, there have been some improvements in the overall efficiency (e.g., in reducing inverter losses) of utility-scale solar PV systems. These have been dwarfed by the resource quality impact in the period of IRENA’s data, but the emergence of bifacial modules as the new electricity cost-minimising choice in some markets already for projects achieving financial close — and likely in a growing number over time — could provide another boost to capacity factors.

¹² BoS costs for solar PV include cable and wiring, grid connection, racking and mounting, safety and security, electrical and mechanical installation, customer acquisition, financing costs, permitting, system design and profit margin.

Between 2010 and 2019, the dramatic fall in solar PV module prices, along with continuing reductions in BoS costs (albeit at a slower rate) and the increase in capacity factors saw the global weighted-average LCOE of newly commissioned utility-scale solar PV fall 82%, to USD 0.068/kWh in 2019. As a result, around 40% of the capacity deployed that year had costs (excluding any financial support) that were lower than the cheapest, new, fossil fuel-fired capacity option.

The country-level weighted-average cost of electricity from utility-scale solar PV between 2010 and 2019 fell by 85% in India, 82% in China, Italy and the Republic of Korea; 81% in Spain, 78% in Australia, 73% in Germany and 66% in the United States. Emerging PV markets have also seen rapid declines, with Viet Nam, for example, seeing the cost of electricity from solar PV falling 55% since 2016.

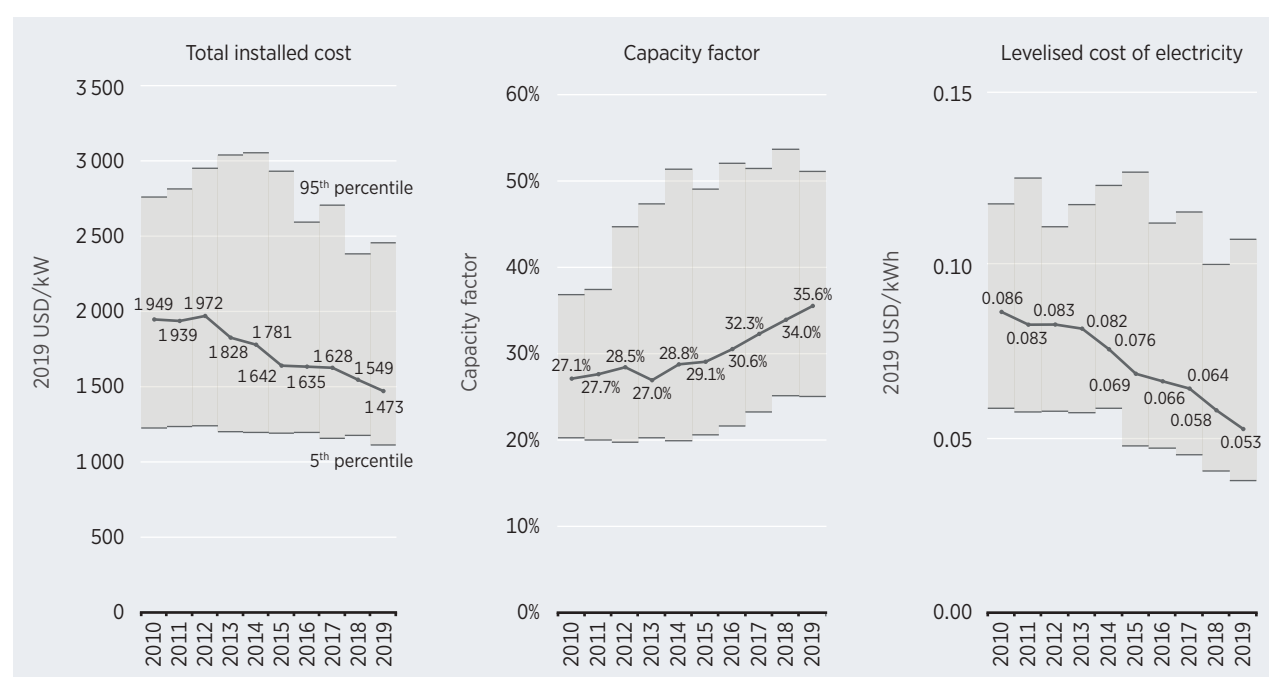
Onshore wind

Continuous technological innovation remains a constant in the renewable power generation market, with onshore wind no exception.

The global weighted-average LCOE of projects using this technology and commissioned in 2019 was USD 0.053/kWh – 9% lower than in 2018 and 39% lower than in 2010, when it was USD 0.086/kWh. Onshore wind now consistently outcompetes even the cheapest fossil fuel-fired source of new electricity, while costs continue to edge lower.

The lower cost of electricity for onshore wind in 2019 was driven by continued reductions in total installed costs, as wind turbine prices continued their downward trend. Just as importantly, the LCOE reduction was also driven by improvements in the average capacity factor (Figure 1.5). After 40 years of commercial development, wind turbine technology continues to improve, with improvements in turbine design and manufacturing. In addition, more competitive global supply chains and an expanding suite of turbines designed to minimise LCOE in a range of operating conditions have contributed to reducing the cost of electricity from onshore wind, either by reducing capital costs (e.g., the material and labour costs of manufacturing) and/or by increasing energy yields for a given resource (e.g., higher hub-heights with larger swept blade areas).

Figure 1.5 Global weighted average total installed costs, capacity factors and LCOE for onshore wind power, 2010-2019



Source: IRENA Renewable Cost Database.

The global weighted-average total installed cost of onshore wind farms thus declined by 5% in 2019, year-on-year, falling from USD 1549/kW in 2018 to USD 1473/kW in 2019, as wind turbine prices continued to decline, while ongoing reductions in BoS costs also occurred. Indeed, the cost declines experienced over the year appear to have come more or less evenly from both factors. Initial data suggests turbine prices declined by between 5-6% in 2019. Total installed costs declined year-on-year in 2019 by 9% in India, 5% in the United States and China, and 34% in Spain, with the United Kingdom experiencing a 2% increase. The figure for Spain is somewhat exaggerated, as the market has only just revived. A comparison to the more presentative 2017 total installed costs yields a reduction of 13%.

Improvements in wind turbine technology have resulted in larger rotor diameters, swept blade areas, name plate capacities and hub-heights. This has driven an improvement in capacity factors that means today's turbines harvest more electricity from the same resource than their predecessors. As a result, overall energy output has been on the rise, leading to a consistent trend towards higher capacity factors, globally. Between 2010 and 2019, the global weighted-average capacity factor for onshore wind increased by almost a third, from just over 27% in 2010 to 36% in 2019. The year 2019 saw an increase of around 5%, from 34% in 2018 to 36%.

There has also been wide variation between countries in capacity factor growth and average capacity factor levels. Between 2010 and 2019, Brazil, Denmark and Spain experienced increases in weighted-average capacity factors in excess of 40%, while Canada saw an increase of 21%, China, 24% and France, 25%. In absolute terms, in 2019, the weighted-average capacity factor of new projects added in Brazil hit 51%, while the weighted-average was 44% in the United States, 39% in Spain, and 32% in both China and India.

In 2019, the global weighted-average LCOE of onshore wind, at USD 0.053/kWh, was just 6% higher than the cheapest new source of fossil fuel-fired electricity (coal, which had an LCOE of around USD 0.05/kWh). The country-level weighted average LCOE for new projects commissioned in 2019 was lower than the cheapest fossil fuel-fired option in Argentina, where the weighted-average

LCOE was USD 0.049/kWh, as well as in Brazil (USD 0.048/kWh), China (USD 0.047/kWh), Egypt (USD 0.049/kWh), India (USD 0.049/kWh), Finland (USD 0.039/kWh), Sweden and the United States (both at USD 0.046/kWh). Onshore wind is now consistently undercutting fossil fuels in a growing number of markets, often by a substantial amount.

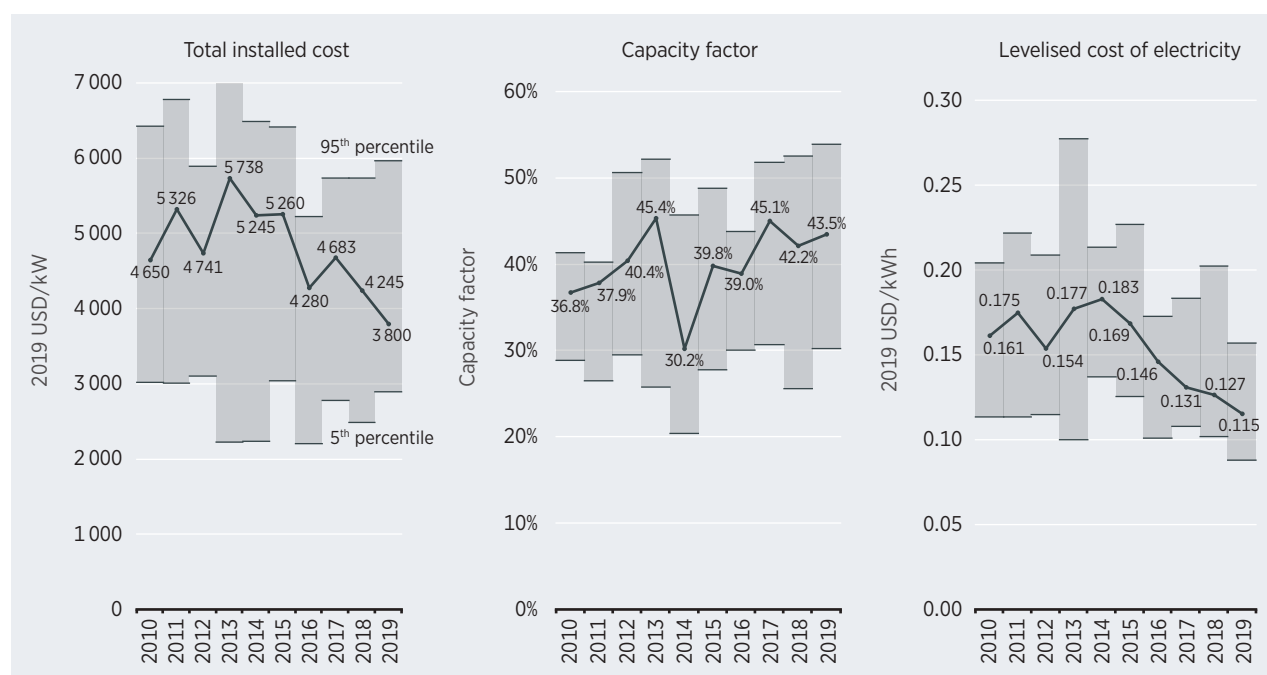
Offshore wind

Total installed costs of offshore wind farms declined by 18% between 2010 and 2019. Given that some years saw a relatively thin market for offshore wind, however, with deployment being dominated in different years by markets in different stages of maturity, there is a significant degree of year-on-year volatility in the total installed costs of newly commissioned offshore wind farms.

The global weighted-average installed costs for offshore wind declined from USD 4650/kW to USD 3800/kW between 2010 and 2019 (Figure 1.6). A range of factors are behind this, with the overall evolution in installed costs being driven by efforts to reduce the overall cost of electricity from a project. As a result, there are some factors that push up individual cost components, while at the same time reducing others.

The trend to larger turbines is one example of this. Per kW, these tend to be slightly more expensive, but they create savings when it comes to installation – and in some cases, foundations – as well as helping reduce Operation and Maintenance (O&M) costs, while increasing capacity factors (with higher hub-heights and swept areas). In Europe up to around 2013, the shift to deployment farther offshore and in deeper waters, as well as the fact that supply chains were only just beginning to scale meant that in some cases upward pressure on installed costs occurred due to increasing installation, foundation and grid connection expenses. More recently, however, most of these factors have either plateaued (e.g., distance from shore) or are starting to now generate cost reductions. These have occurred most notably via the achievement of economies of scale and greater competition in supply chains, with optimised logistic hubs for multiple-GW wind farm zones and increased developer experience.

Figure 1.6 Global weighted average total installed costs, capacity factors and LCOE for offshore wind power, 2010-2019



Source: IRENA Renewable Cost Database.

At the same time, the continuing innovation in turbine technology, larger turbine ratings, and greater experience with project development, saw average capacity factors rise from 37% in 2010 to 44% in 2019.

In 2019, in comparison with 2018, there was a slight decline (-1%) in the global weighted-average LCOE of offshore wind projects commissioned. This takes the decline in the LCOE of offshore wind between 2010 and 2019 to 29%, from USD 0.162/kWh to USD 0.115/kWh.

In country-specific terms, there has been a wide variation in LCOE declines since 2010. In Europe, which has the largest deployment of offshore wind, projects commissioned between 2010 and 2019 recorded a 27% fall in LCOE, from USD 0.159/kWh to USD 0.117/kWh. The largest drop occurred in Belgium, where LCOE fell 40% between 2010 and 2019, from USD 0.198/kWh to USD 0.119/kWh. In Germany and the United Kingdom, which were the biggest markets for commissioned projects in Europe, between 2010 and 2019 there were 33% and 26% drops respectively, with the LCOEs in both countries falling to around USD 0.12/kWh for projects commissioned in 2019.

In Asia, the LCOE reduction between 2010 and 2019 reached 39% (from USD 0.180/kWh to USD 0.112/kWh). This was driven by China, which has over 95% of offshore wind installations in Asia.

Concentrating solar power

In 2019, projects totalling around 600 MW were commissioned, worldwide, but, with only a handful of these occurring annually since 2015, cost trends have been volatile.

In addition, while projects were completed in Israel, Kuwait, South Africa and China in 2019, cost trends for that year require even more explanation than usual. The reason for this that two much delayed Israeli projects, one parabolic trough and one tower, finally came online. These projects were tendered in 2012, since when technology costs and performance have changed significantly. Notably, one of the plants does not include any thermal energy storage, which is the norm in reducing LCOE to more competitive levels. To allow for these two plants' impact, we have reported weighted-average values for CSP that both include and exclude them, with the latter providing a better view of CSP industry trends.

The global weighted average LCOE for CSP in 2019, excluding the two Israeli projects, was USD 0.182/kWh – slightly lower than in 2018 and 47% lower than in 2010 (Figure 1.7). The global weighted-average total installed cost of CSP in 2019 was USD 5 774/kW, excluding the two Israeli projects, which is a fall of 36% from the global weighted-average for projects commissioned in 2010 (USD 8 987/kW). If the two delayed Israeli projects are included, this raises the global weighted-average for projects commissioned in 2019 to USD 6 474/kW.

The 5th and 95th percentile range for individual projects commissioned in 2019 ranged from around USD 3 740/kW to USD 8 595/kW. With a number of Chinese project start dates delayed into early 2020, total installed costs for 2020 are likely to fall again to around the USD 5 200/kW level.

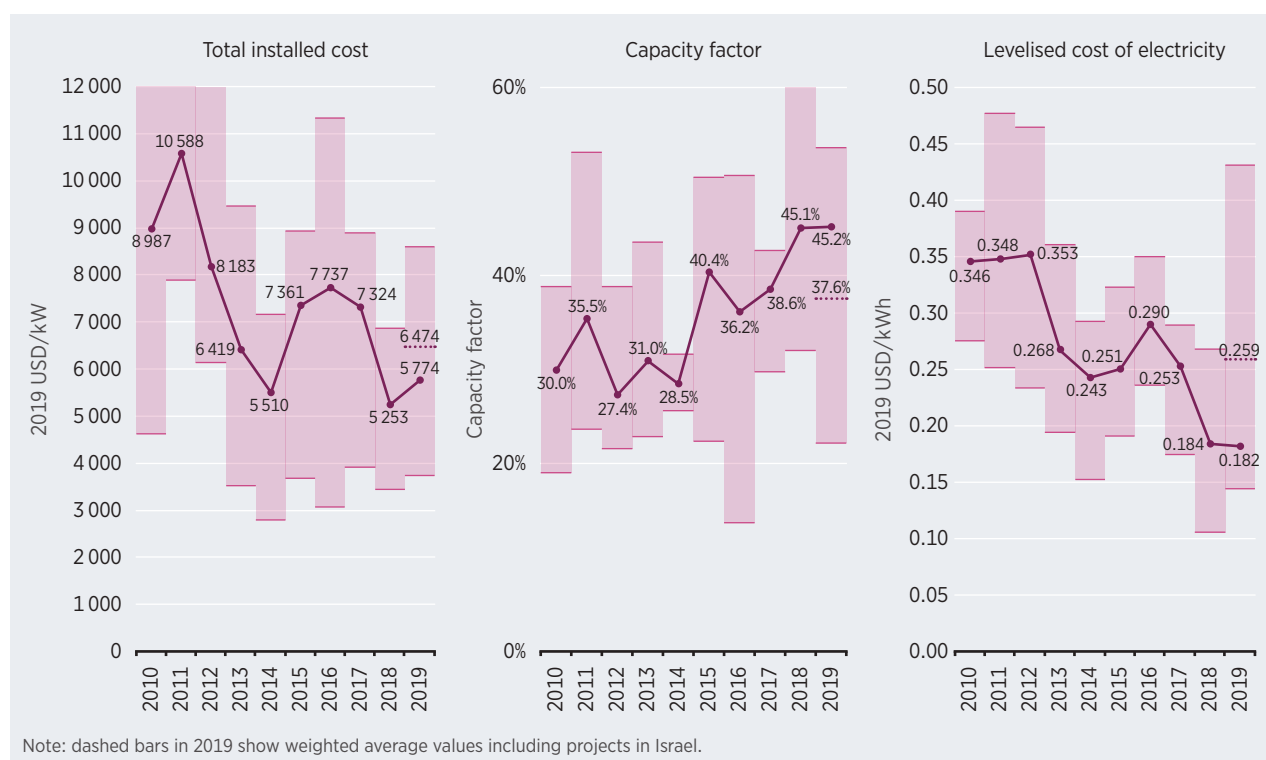
A key driver of lower electricity costs from CSP has been the shift of deployment to locations which are, on average, sunnier. Better solar resources directly reduce the installed costs of projects by reducing the area of solar field collector necessary for a given level of power output, and by improving the performance and the economics of the plant. An important

additional consideration is that CSP projects can achieve the lowest LCOE by including storage to improve the overall utilisation of the project's power block and associated investments. This has been reflected to some extent in trends in deployment, as the average storage of projects commissioned in 2018 (8.3 hours) was more than twice the level observed in 2010 (3.6 hours). The optimal level of storage varies depending on the solar resource and the storage and collector costs, but is typically in the range of 7-10 hours.

These drivers combined to increase the global weighted-average capacity factor by half between 2010 and 2019 – from 30% to 45%, if the two Israeli projects are excluded. Including those projects sees the weighted average regress to the technology specifications prevalent in the period 2011 to 2014, with a correspondingly lower weighted-average capacity factor.

The global weighted-average LCOE of CSP plants was around USD 0.35/kWh between 2010 and 2012. In the latter year, virtually all new capacity-added was in Spain (around 850 MW). In 2013, the market changed, however, with new capacity added by Spain that year only accounting for about 28% of the market.

Figure 1.7 Global weighted average total installed costs, capacity factors and LCOE for CSP, 2010-2019



Source: IRENA Renewable Cost Database.

As the market expanded beyond Spain, the LCOE started to fall, with a downward trend being clear, despite volatility in annual numbers. As mentioned above, this decrease in LCOE was driven in part by the geographical shift away from Spain to newer markets with better solar resources and, increasingly, lower installed costs and improved technology (e.g., higher operating temperatures).

Continued modest growth in the market – and the growing role of Chinese companies – has seen a broadening of supply chains. This, when combined with the emergence of a number of internationally competitive, experienced project developers, has seen electricity costs fall.

As will be discussed later in this report, the results of recent auction and PPA programmes suggest that a step-change in CSP competitiveness will occur in the next few years, as the cost of electricity from CSP will potentially fall into the USD 0.07/kWh to USD 0.08/kWh range, with potential for this to fall even further. With its ability to provide dispatchable renewable power, CSP could therefore play an increasingly important role in facilitating ever-higher shares of variable solar PV and wind in areas with good direct solar resources that can support CSP plants.

Hydropower

Hydropower is a mature, commercially attractive renewable power generation technology. It produces low-cost electricity and, where reservoir storage is available, it can also play an important role in providing grid flexibility and ancillary services.

Indeed, hydropower is uniquely placed to provide not only low-cost electricity, but also cheap electricity storage and large-scale flexibility in services to the grid, such as frequency or voltage regulation, fast reserve, black start capability, etc. This can not only reduce the cost of running the grid, but also contribute to integrating higher shares of Variable Renewable Electricity (VRE) and adds substantially to the value hydropower brings to the grid. It has the ability to meet load fluctuations minute-by-minute, as spinning turbines can be ramped up more rapidly than any other generation source, providing additional

generation or voltage regulation to ensure that the electricity system operates within its quality limits. In addition, hydropower's ability to operate efficiently at partial loads – which is not the case for many thermal plants – should also not be overlooked.

Hydropower plants can be constructed in a variety of sizes and with different properties, with a range of technical characteristics affecting the choices of turbine type and size, as well as the generation profile. These characteristics 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. As a result, the project-specific variation in total installed costs around hydropower's weighted average can be more significant than for other technologies. Part of the reason for this is also due to the fact that hydropower has long been the bedrock of remote area electrification in many countries around the world. These remote hydropower projects are the cheapest source of electricity, but typically have significantly higher total installed costs.

Between 2018 and 2019, the global weighted-average total installed cost of hydropower projects rose from USD 1435/kW (Figure 1.8) to USD 1704/kW. The global weighted-average total installed cost therefore increased by 36% between 2010 and 2019. Most of this increase happened in the period 2010 to 2016, however, when the global weighted-average total installed cost increased from USD 1254/kW to USD 1784/kW – albeit not linearly. The figure has been in the approximate range of USD 1700/kW to USD 1825/kW since, with the exception of the decline in 2018.

Despite the recent volatility, the new higher average cost level seems to be driven by a shift towards the exploitation of sites with more challenging civil engineering conditions, resulting in higher costs. This is, to a large extent, the story of what is happening in China and the rest of Asia, given that they have been responsible for 63% of the capacity additions since 2010. For example, the weighted-average total installed cost of hydropower in China in the period 2010 to 2014 was USD 1062/kW, while for the period 2015 to 2019 (inclusive) it had risen to the albeit still low level of USD 1264/kW.

In the rest of Asia, this figure rose 10%, from USD 1488/kW to USD 1630/kW, over the same two periods. Yet, it is not just a question of costs rising within countries/regions, but also of a slowdown in deployment in China, notably in 2019. Given China still has the lowest installed costs, any decline in that country's share raises the weighted average. Thus, part of the growth in the global weighted average in recent years is due to the fact that in 2019, China accounted for 31% of new hydropower capacity additions, down from 48% in 2010.

The full dataset of hydropower projects in the IRENA Renewable Cost Database for the years 2000 to 2019 suggests that the total installed costs of smaller projects spans a wider range than larger projects, but in terms of deployment, the weighted-average installed cost is not materially lower for large projects, except for sizes beyond around 700 MW.

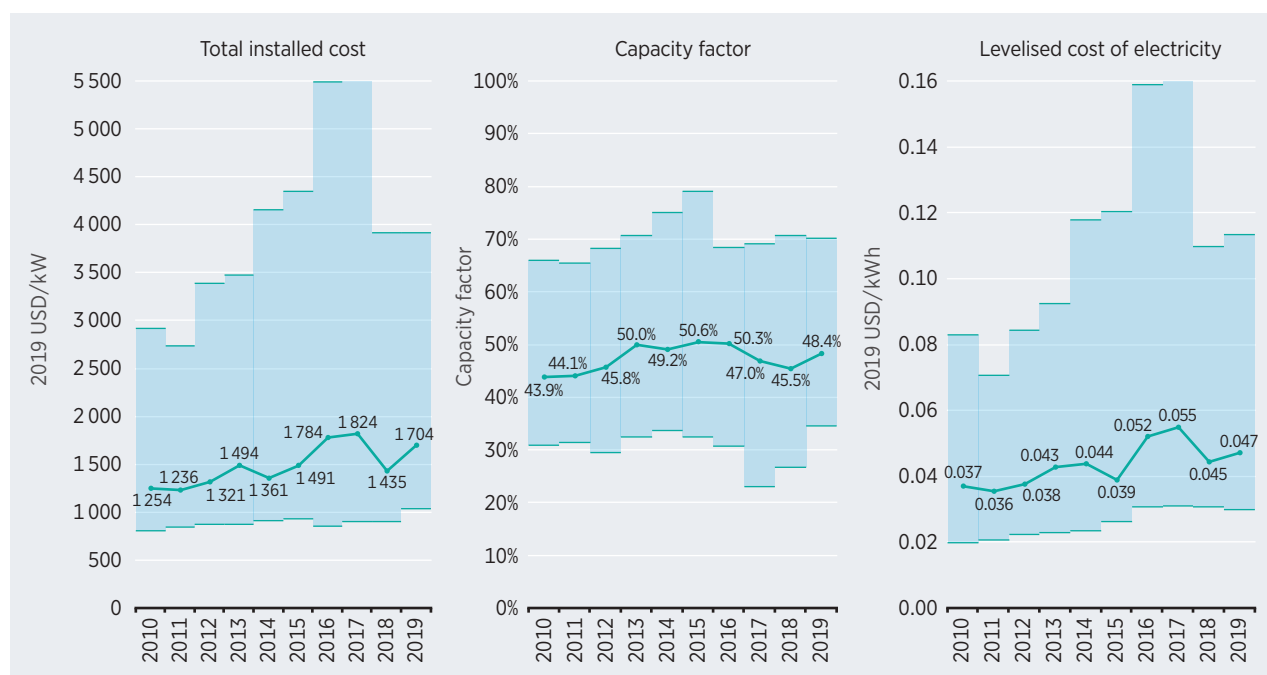
At the same time that total installed costs were trending upwards, so too were capacity factors. Between 2010 and 2013, the global weighted-average capacity factor of newly commissioned hydropower projects rose from 44% to 50%, while between 2014 and 2019 it varied between 46% and 51%. In 2019, the global weighted-average capacity factor was 48%, one-tenth higher than in 2010.

Hydropower is somewhat unique, in that depending on the site characteristics and the ability to store water behind the dam, a project can take a flexible approach to designing for different capacity factors. So for instance, systems can be designed with relatively high capacities relative to inflows, resulting in lower average capacity factors, but with the ability to generate large volumes when that is most valuable. Alternatively, generation could be more constant and result in higher capacity factors for a smaller electrical capacity. This diversity is evident in the data for the 5th and 95th percentiles of project-level capacity factors, which have ranged from around 23% to 71% for the last four years.

In 2019, the global weighted-average LCOE of hydropower was USD 0.047/kWh – 6% higher than in 2018 and 27% higher than in 2010. The increase in LCOE since 2010 is lower than the 38% increase in global weighted-average total installed costs due to the moderating influence of O&M costs, as well as the one-tenth increase in average capacity factors.

Despite the increase in global weighted-average LCOE since 2010, hydropower remains a competitive, low-cost source of the electricity, with its global weighted-average LCOE still comfortably below the cheapest fossil fuel-fired source of new electricity generation.

Figure 1.8 Global weighted average total installed costs, capacity factors and LCOE for hydropower, 2010-2019



Source: IRENA Renewable Cost Database.

Bioenergy

Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available – such as by-products from agricultural or forestry processes onsite – they can provide highly competitive, dispatchable electricity.

For bioenergy projects newly commissioned in 2019, the global weighted-average total installed cost was USD 2141/kW (Figure 1.9). This represented an increase on the 2018 weighted-average of USD 1693/kW, which is itself a revised figure, substantially lower than the USD 2150/kW published in 2019.

Due to the heterogeneity of bioenergy feedstock and technology costs – and the typically higher technology costs in OECD countries – annual global weighted-averages are strongly influenced by the technology mix and geographical location of where plants are commissioned.

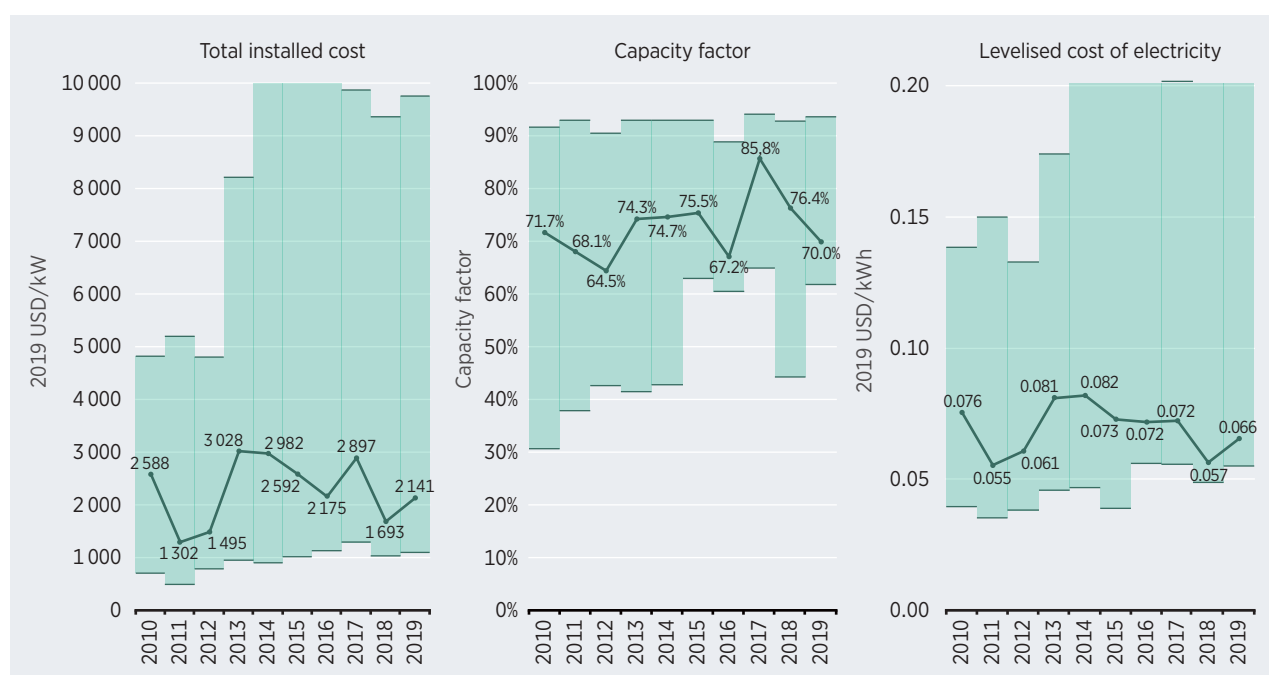
Outside the OECD countries, the combustion of sugar cane bagasse wood waste and other vegetal or agricultural wastes uses proven, low-cost technologies. As a result, non-OECD countries typically have lower average installed costs.

For instance, the weighted-average total installed cost of bioenergy projects in the IRENA Renewable Cost Database is USD 1578/kW for China and USD 1368/kW for India, while it is USD 3179/kW for Europe and USD 4 329/kW in North America.

Capacity factors for bioenergy plants are very heterogeneous and are typically driven by the availability of low-cost feedstocks. Between 2010 and 2019, the global weighted-average capacity factor for bioenergy projects varied between a low of 64% in 2012 to a high of 86% in 2017. The widest variation in capacity factors is observed where feedstocks are agricultural or forestry wastes or residues, with the variation for bagasse being notable for ranging from 24% (5th percentile of projects) to 89% (95th percentile). With a greater share of projects commissioned in non-OECD countries utilizing waste streams, where availability is often low outside certain seasons, weighted-average capacity factors in Europe and North America (81% and 84% respectively) are higher than in China (64%), India (68%) and the rest of the world (66%).

The wide range of bioenergy-fired power generation technologies, feedstock costs and their availability results in a broad range of observed LCOEs for bioenergy electricity generation projects.

Figure 1.9 Global weighted average total installed costs, capacity factors and LCOE for bioenergy power, 2010-2019



Source: IRENA Renewable Cost Database.

The weighted-average LCOE of biomass-fired electricity generation projects commissioned in 2019 was USD 0.066/kWh – a figure up on the 2018 value, but otherwise lower than all but three years over the period 2010 to 2019, inclusive.

Looking at all the data in the IRENA Renewable Cost Database, so as to smooth out annual variations in technology deployment by country and region, the weighted-average LCOE ranged from a low of USD 0.057/kWh in India and USD 0.059/kWh in China, to highs of USD 0.08/kWh in Europe and USD 0.099/kWh in North America. The higher electricity costs in Europe and North America reflect the more advanced technology choices, but also the more stringent emissions controls and higher feedstock costs. Having said this, 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 USD 0.03/kWh, even in OECD countries, particularly when they are combined heat and power plants.

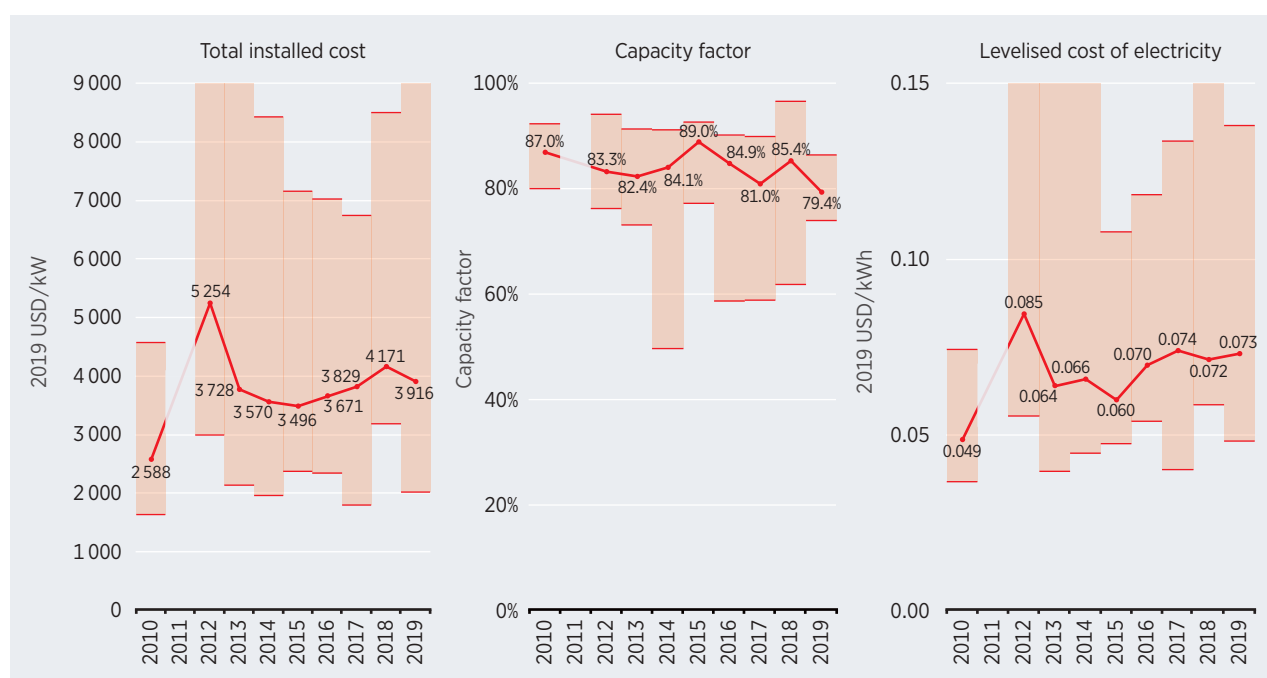
Geothermal

Geothermal is a mature, commercially available technology that can provide low-cost baseload capacity in areas with very good high-temperature geothermal resources, close to the Earth's surface.

Around 680 MW of new geothermal power generation capacity was commissioned in 2019, making it the best year for new capacity additions since the 655 MW added in 2015. Yet, additions remain modest compared to other technologies, except CSP.

On average, relative to solar PV and onshore wind, geothermal power is more capital intensive, but can be comparable or have lower installed costs than offshore wind and CSP. The global weighted-average LCOE of newly commissioned geothermal plants was USD 0.049/kWh in 2010, with this rising to USD 0.085/kWh in 2012, while between 2013 and 2018, the average was between USD 0.06/kWh and USD 0.07/kWh (Figure 1.10).

Figure 1.10 Global weighted average total installed costs, capacity factors and LCOE for geothermal power, 2010-2019



Source: IRENA Renewable Cost Database.

The total installed costs of geothermal power plant can be as low as USD 560/kW for brownfield projects where capacity is being added to a geothermal reservoir which is already well mapped and understood, and where existing infrastructure can be used. Such cases are, however, somewhat rare. Data for recent projects shows that total installed costs for most projects have largely fallen in the range of USD 2 000/kW to USD 5 000/kW, although smaller projects in new markets have experienced higher costs.

The swings in new capacity additions between 2010 and 2013 saw volatile weighted average total installed costs for geothermal. Since 2014, new capacity additions have been more stable, though (in the range of 440 MW to 680 MW per year), while global weighted-average total installed costs have been between USD 3 496/kW and USD 4 171/kW.

Capacity factors for geothermal are typically high, with projects utilising low-temperature resources that require binary power production technologies typically delivering capacity factors of 60% to 80%. Geothermal plants using high-temperature resources and “flash” technologies consistently deliver capacity factors higher than 80%, with few outliers below that value. Plants using direct-steam technologies also see capacity factors around 80%.

A factor crucial to maintaining these capacity factors over the life of the plant is an active management plan for the reservoir, which will often necessitate additional production wells over the life of the project. This is one of the reasons why O&M costs for geothermal, at an assumed USD 110/kW/year, are much higher than all but offshore wind and CSP plants.

Yet, geothermal power generation still offers a competitive source of new electricity generation. In 2019, the global weighted-average LCOE of newly commissioned geothermal plants was USD 0.073/kWh and, with some small inter-year variations, has been around USD 0.07/kWh since 2016.

NEW SOLAR PV AND ONSHORE WIND: INCREASINGLY CHEAPER THAN THE MARGINAL COSTS OF EXISTING COAL-FIRED CAPACITY

Data from the IRENA Auction and PPA Database suggests that for utility-scale solar PV and onshore wind, the new capacity that has been procured competitively and will be commissioned in 2021 will have significantly lower costs than the global weighted-average for 2019. Indeed, the average price of projects awarded through auction/tender or via a PPA, will fall to USD 0.043/kWh for onshore wind and USD 0.039/kWh for utility-scale solar PV. These values are cheaper than the marginal operating costs of an increasing number of existing coal-fired power plants, raising the risk that there are an increasing number of stranded assets.

Carbon Tracker’s assessment of short-run marginal costs (Carbon Tracker, 2018) for over 2 000 GW of global coal-fired capacity suggests that for 2021, around 1200 GW of coal-fired capacity could have operating costs higher than the average price of electricity from auctions for solar PV, which are estimated to average USD 0.039/kWh in that year. Around 850 GW of this existing coal would also higher operating costs than the estimated average



cost of electricity in 2021 from new onshore wind capacity. Some of these plants will be exposed to international market prices, which have fallen since the Carbon Tracker analysis, but this has likely been offset to some extent by the continued decline in the average capacity factors of coal-fired plants, especially the less competitive ones, in this higher-cost sample. This report assumes that by 2021, in line with expectations for a recovery in economic growth, that coal prices return to prices around 10-20% lower than in 2018, but that capacity factors are also lower. The net result is marginal operating cost situation for most coal plants of around the same values as the original analysis (some plants will be slightly higher or lower depending on efficiency and capacity factor values).

Notably, the analysis here is based on the global averages for the solar PV and onshore wind costs, while individual countries' competitive balances will look different and would need to be confirmed by a country-level analysis. The calculations presented here should therefore be treated with caution and considered indicative of the order of magnitude of the opportunity, due to the need to do a more in-depth country-level analysis and the uncertainty surrounding traded coal prices in 2021.

This economic opportunity, is indeed significant. Closing the least-competitive 500 GW of coal-fired capacity would save consumers between USD 12 billion and USD 23 billion per year, taking into account USD 0.005/kWh for grid integration costs, the extent to which coal prices recover or not from their 2018 values and how fast capacity factors for coal continue to fall. Over 20 years, this would represent cumulative savings to consumers, worldwide, of USD 244-463 billion. This would reduce coal-fired power generation by around 2170 terawatt hours (TWh), or about 22% of the total 10100 TWh global coal-fired generation in 2018 (BP, 2019). Assuming one-third of this coal-fired generation reduction was made up by building new solar PV and two-thirds by building onshore wind, this would require around 860 GW of new capacity. This may seem like a very large increase in capacity for solar PV and wind. Yet, for solar PV, this would represent less than two years of the average annual additions level to 2030 required for compliance with the Paris Agreement (IRENA, 2020b) and three years of onshore wind's.

Even unlocking a fraction of this economic opportunity could provide an important, clean stimulus, as the additional investment represents a total of around USD 1.1 trillion, with USD 274 billion for the utility-scale solar PV capacity and USD 813 billion for the onshore wind capacity. Compared to investment in solar PV and onshore wind in 2019, this would represent a net stimulus of around USD 940 billion.

LEARNING CURVES FOR SOLAR AND WIND POWER TECHNOLOGIES

The cost declines experienced from 2010 to 2019 and signalled for 2020 to 2023 in the IRENA Auctions and PPA database represent a remarkable rate of change. They also have enormous implications for the competitiveness of renewable power generation technologies over the medium term. In addition, they provide some lessons that might be applicable to the myriad technologies that need to be scaled up over the coming decade, in order to ensure decarbonisation of end-use sectors – from electrolyzers to electric vehicles and heat pumps to stationary battery storage.

Figure 1.11 shows the global weighted-average LCOE and Auction/PPA price trends for utility-scale solar PV, CSP, onshore and offshore wind from 2010 to 2021 (or 2023, in the case of offshore wind) plotted against deployment. By placing both these variables on a logarithmic scale (log-log), the line on the charts represents the learning rate for these technologies. The learning rate is the average cost reduction experienced for every doubling of cumulative installed capacity.

The LCOE learning rate for offshore wind (*i.e.* the LCOE reduction for every doubling in global cumulative installed capacity) is expected to reach 10% over the period 2010 to 2023, with new capacity additions over this period estimated to be 95% of the cumulative, installed offshore wind capacity that would be deployed out to 2023.

For onshore wind, the LCOE learning rate for the period 2010 to 2019 was 23%. Extending the period to 2021 with the data from Auction and PPA data in this report, however, implies a learning rate for the period 2010 to 2021 of 29%.

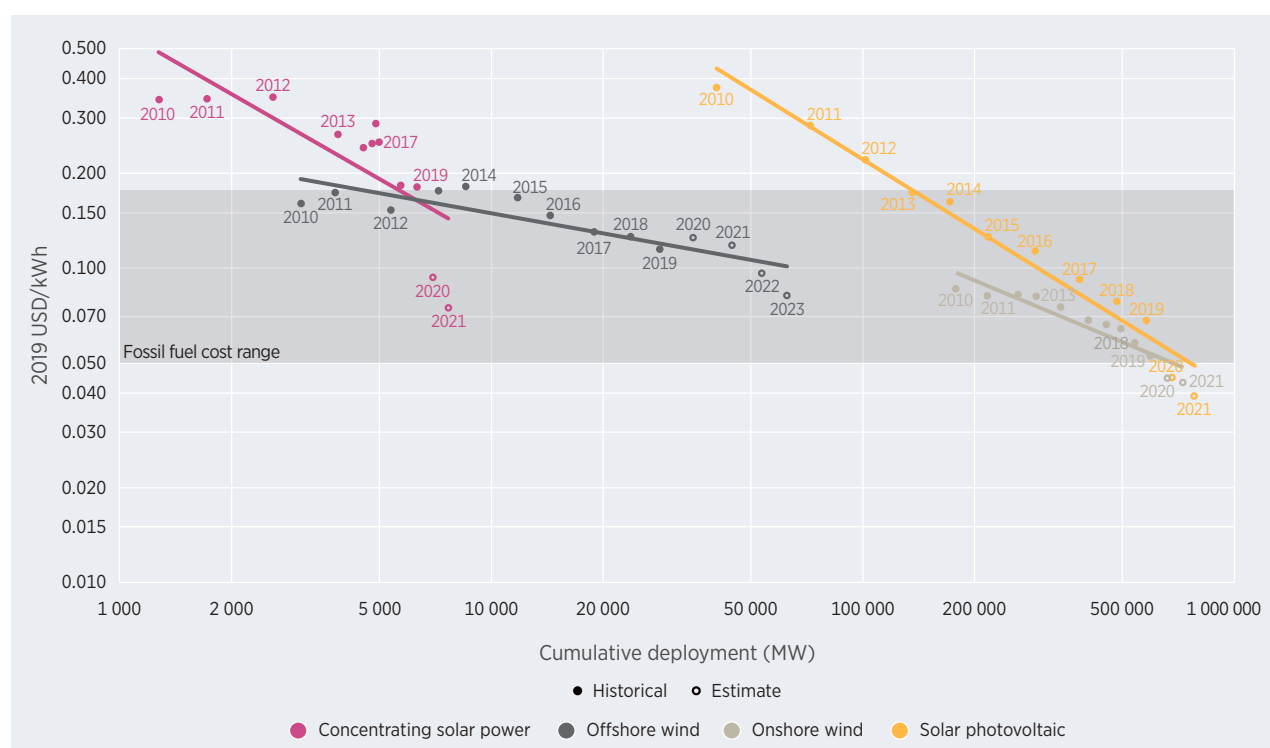
New capacity added over this period covers an estimated 76% of cumulative installed capacity out to 2021. In both cases, this is materially higher than the estimated LCOE learning rate calculated by IRENA in 2018, which was 21%, and represents the more rapid fall in the cost of electricity than was implied by the data available two years ago, although part of the reduction to 2021 comes from a more detailed treatment of the non-indexed price contracts in the Auctions and PPA Database.

Utility-scale solar PV has the highest estimated learning rate for the cost of electricity over the period 2010 to 2019, of 36%. The learning rate rises to 40% when the Auction and PPA data are used to extend the time series out to 2021, a period over which 95% of cumulative installed capacity for this technology will have been added. The learning rate for CSP for the period 2010 to 2019 is 23%.

It rises to 38% for the period 2010 to 2021 using the PPA and Auction prices in this report for 2020 and 2021, when an estimated 83% of cumulative installed capacity for this technology will have been deployed.

These learning rates represent quite remarkable rates of deflation for wind and, in particular, solar power technologies. Just quite how remarkable can be seen by comparing solar and wind power cost declines to Consumer Price Index (CPI) data for individual unit costs. For instance, of the price quotes for 531 individual items that are used to compile the United Kingdom's CPI index, only five items¹³ (all of relatively little weight in a household's annual consumption) saw price declines of 23% to 32% (nominal) between January 2010 and August 2019. At the same time, however, the global nominal LCOE decline of solar PV was over 70%, that of CSP over 40%, that of onshore wind 35%, and that of offshore wind 24%.

Figure 1.11 The global weighted-average LCOE and Auction/PPA price learning curve trends for solar PV, CSP, onshore and offshore wind, 2010 – 2021/23



Source: IRENA.

Note: The LCOE and auction price data are for utility-scale projects.

¹³ These were: strawberries, fruit smoothies, internet computer games, household cleaner and underground/metro fares outside London.

INVESTMENT TRENDS

With falling costs, investment trends in renewables need to be examined with a critical eye, as trends in absolute currency values mask the dramatically improved value for money that renewables investments now represent.

To illustrate, Figure 1.12 shows the trends in the value of investment of new renewable capacity added by year.¹⁴ In 2010, when new capacity additions of renewables totalled 88 GW, the investment value of all the renewable capacity newly commissioned in that year was USD 210 billion. In 2019, twice that level of new renewable power generation capacity was commissioned, but cumulative investment had increased by only one-fifth, to USD 253 billion.

For utility-scale and distributed solar PV, in 2010, the 17.5 GW of capacity added required USD 87 billion, or 42%, of total renewable investment. Approximately three-quarters of that (or 31% of the total) derived from distributed, typically rooftop, solar PV. By 2019, new capacity additions had risen to 97 GW, while investment needs rose to USD 115 billion, or 45% of the total. In 2019, utility-scale solar PV dominated deployment capacity (70 GW) and accounted for 60% of total solar PV investment (USD 69 billion).

For newly commissioned wind power, in 2010, the numbers were 31 GW of capacity added, with an investment of USD 62 billion, or 30% of the total, with nine-tenths of that investment going to onshore wind. By 2019, new wind power capacity additions had almost doubled, to 59 GW, and required investment of USD 98 billion, which was 39% of total renewable power generation investment. Over the same period, offshore wind investment grew more than four-fold, from USD 4.3 billion to USD 17.8 billion, while new capacity additions grew from 900 MW in 2010 to 4 680 MW in 2019 – accounting for 7% of all renewable investment in the latter year.

Hydropower, CSP and bioenergy for power all saw their investment peak in 2013. For hydropower, the peak was in terms of new capacity deployed (46 GW), investment (USD 70 billion) and share of total investment in renewable power generation (26%).

In 2010, new hydropower capacity additions of 22 GW supported investment of USD 43 billion (20% of the total), while this fell to 12 GW of new capacity, requiring investment of USD 22 billion in 2019 – some 9% of the total.

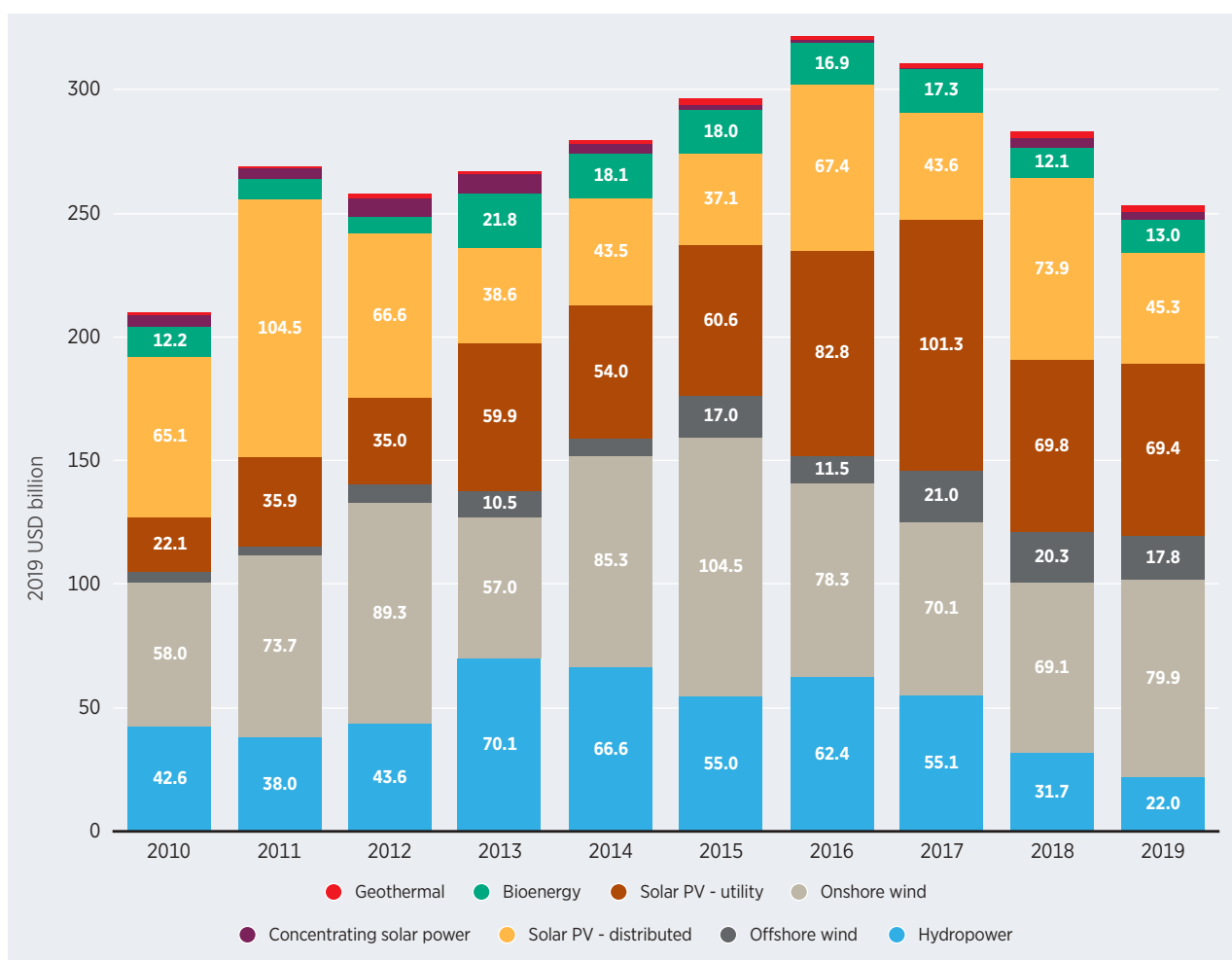
CSP capacity additions and investments peaked in 2013, at 1.3 GW and USD 8 billion, while investment in 2019 was USD 3.5 billion. Investment in bioenergy also peaked in 2013, at around USD 22 billion, up from USD 12 billion in 2010. In 2019, investments in bioenergy for power were around USD 13 billion, or 5% of the total. Driven by modest new capacity additions, investment in geothermal ranged from a low of around USD 0.5 billion in 2011 to a high of USD 2.7 billion in 2019, which saw the largest new capacity commissioned in a single year this decade.

Taking into account the global mix of new capacity additions, USD 1 million invested in renewable energy in 2010 yielded around 420 kW of capacity, but by 2019, on average, for every USD 1 million invested, 693 kW of renewable capacity was added, or around 70% more than in 2010. Examining the global average across all technologies is somewhat misleading, however, as this hides the shift in share of deployment away from low-cost hydropower. Looking at individual technologies reveals more about how investment needs have changed over time.

Figure 1.13 shows the trends in investment by technology (bars) and the associated annual new capacity deployment (lines). This makes obvious the dramatic increase in utility-scale solar PV deployment relative to the total investment needed. The trend is a little less evident for distributed solar PV, but is significant nonetheless. For instance, USD 1 million invested in utility-scale solar PV in 2010 yielded 213 kW of capacity, while by 2019, this had more than quadrupled, to 1005 kW. The same comparison for distributed solar PV saw a tripling in capacity yielded for the same USD 1 million invested, from 196 kW in 2010 to 603 kW in 2019.

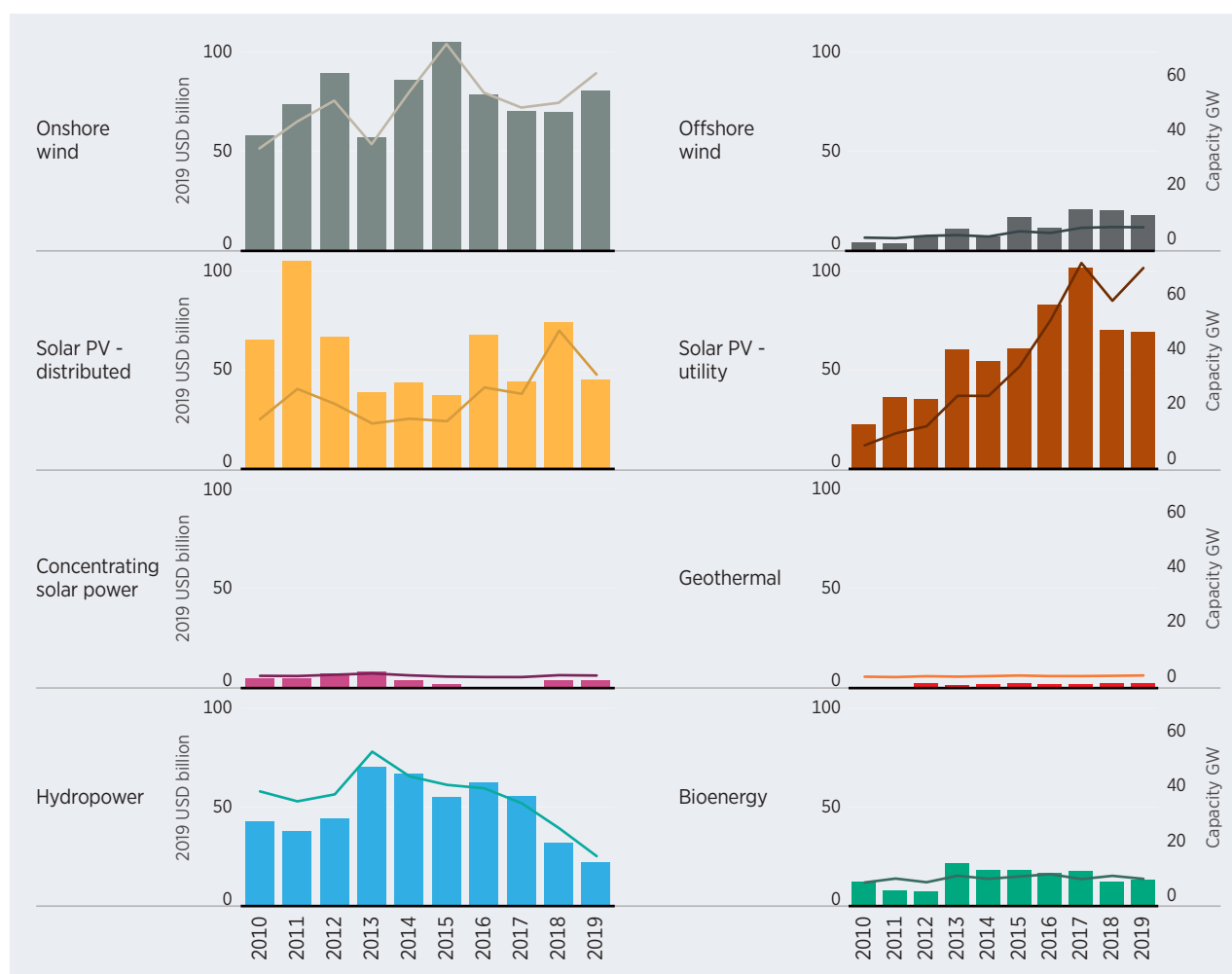
The trend for onshore wind and offshore wind is more modest, with USD 1 million invested in 2010 yielding 215 kW of offshore capacity and 514 kW of onshore capacity, while by 2019 these figures had risen to 263 kW and 679 kW respectively.

¹⁴ This is simply the weighted average installed cost from this report for the specific technology and year multiplied by the new capacity commissioned in that year taken from IRENA statistics (IRENA, 2020a).

Figure 1.12 Investment value of new renewable capacity added by year, 2010-2019

Source: This report for total installed costs and IRENA, 2020a for deployment statistics.



Figure 1.13 Investment value and new capacity added by renewable power technology, 2010-2019

Source: IRENA Renewable Cost Database and IRENA, 2020a.

Note: Investment value is represented by bars and new capacity additions by lines.

SENSITIVITY TO COST OF CAPITAL

With either no, or trivial, fuel costs for renewable power generation technologies – except for bioenergy – and typically low O&M costs,¹⁵ the level of total installed costs, capacity factor and the cost of capital become key determinants of the cost of electricity from renewable power generation projects.

Yet, while the IRENA Renewable Cost Database provides insights into the total installed cost at the project level, the data for cost of capital is almost always unavailable.

Unfortunately, even the availability of this information from secondary sources for timely, up-to-date data on the average cost of capital for individual renewable technologies in different markets in different years is seriously lacking. Indeed, the data available provides only a very partial view of the cost of capital in some markets, for some technologies and for some years. There is not nearly enough data available for IRENA to include a technology, country and year-specific WACC assumption that can be based on robust empirical data. This remains a key gap in our understanding of the global trends in the cost of electricity from renewable power generation projects.

¹⁵ There are some exceptions to this, notably for geothermal (where make-up wells can be considered an O&M expense) and certain bioenergy technologies (notably the gasification of woody biomass). These do not, however, broadly undermine the argument that the cost of capital has an important impact on the cost of electricity.

As a result of the lack of data on the key determinants of project-level WACC – that is to say the cost of debt and equity, as well as the debt tenure and debt-to-equity ratio – for different technologies in different years, IRENA and others (e.g., the International Energy Agency)¹⁶ rely on broad WACC assumptions. By necessity, however, these miss the granularity inherent in project-level WACC's and their differentiation by market, technology and year. While an average assumption for the project-level WACC is not necessarily a critical failing, it does mask what would otherwise be useful insights. Yet, the lack of data for even differentiated country-level technology WACC's over the period 2010 to 2019 means there is a significant risk that at any given point, the simplistic WACC assumptions used become a poor indicator of real world conditions and hence bias the results.

By way of example, Figure 1.14 presents the LCOE for offshore wind from the IRENA Renewable Cost Database of projects, plotted against the adjusted Auction/PPA price for the same project. The data is therefore a subset of the database where we have data for both these metrics.

The Auction/PPA price has been adjusted to ensure that it conforms as closely as possible with the IRENA LCOE methodology. This requires an estimate of the value of the “merchant tail” of projects which have contracts that are shorter than their economic life. It also necessitates putting all values into real currency terms, for those whose strike prices are not indexed to inflation, or only partially indexed. When plotting the results, the implication is that for those projects which are significantly above or below the 45 degree line, the actual WACC experienced by the project has deviated significantly from the assumption made by IRENA of a real value of 7.5%.¹⁷

The data tends to suggest that in the early years of offshore wind deployment, more projects were around the 45 degree line or above, implying a WACC value exceeding the IRENA assumption of 7.5% for all years. This is perhaps to be expected, given that project developers had less experience

in both developing and proving the ongoing performance of offshore wind projects.

Banks would have taken this into account when pricing debt, while shareholders would have factored it in to hurdle rates for equity. Similarly, the relative lack of experience of financing institutions with offshore wind projects and their relative lack of understanding of the technology specific risks in operating wind farms offshore would likely have resulted in higher risk premiums to cover this uncertainty. In contrast, recent projects and those to be commissioned out to 2025 are clustered more tightly around the 45 degree line, implying that the WACC assumption of 7.5% is more reasonable today than it was for projects being commissioned between 2010 and 2016.

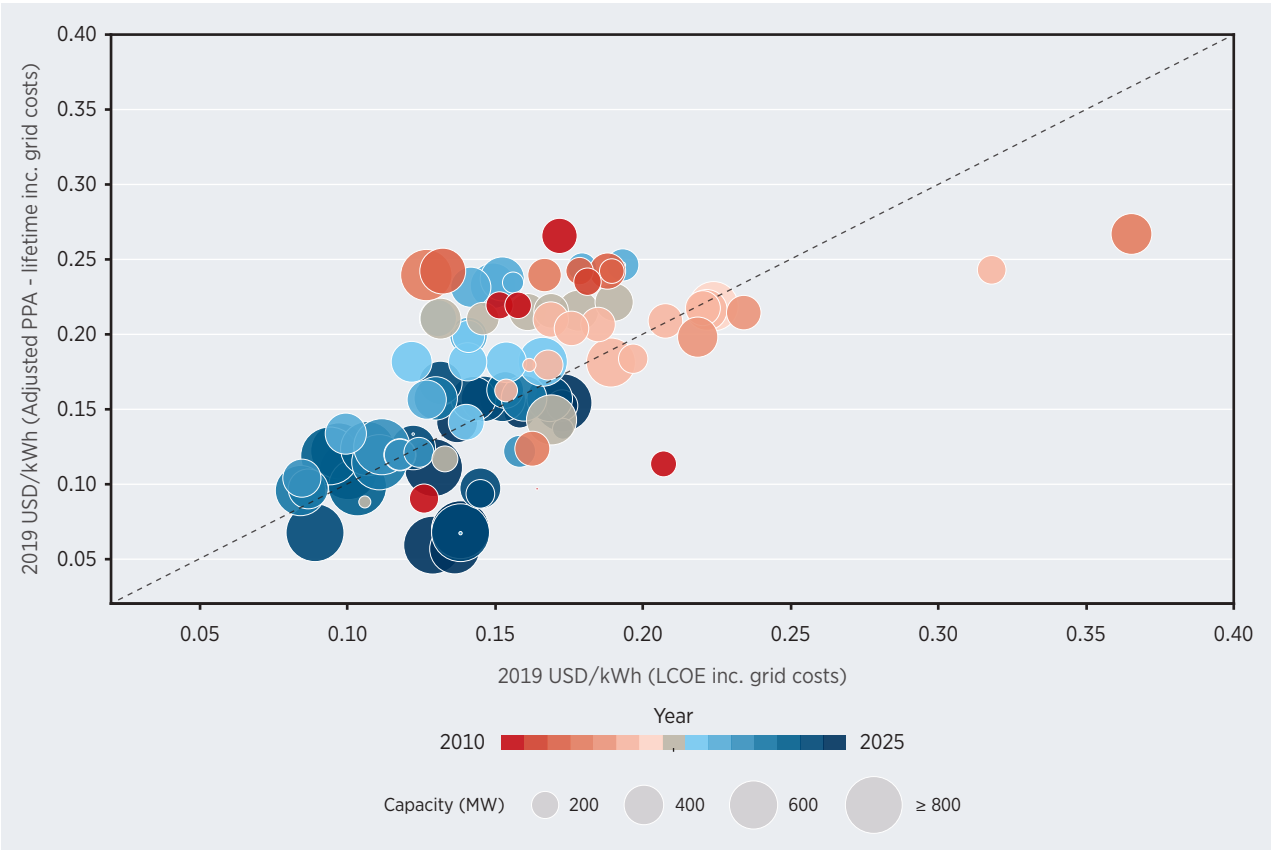
Depending on market maturity, the situation for each technology and even country will differ, while the ability to collect sufficient data to extract meaningful trends would be a very resource-intensive task. This is the case for solar PV. The LCOE and PPA data in Figure 1.3 for utility-scale solar PV diverge materially from around 2016 onwards. This can, in part, be explained by selection bias, given that competitive procurement processes are by their nature likely to lead to lower prices. The order of magnitude of the difference, especially in 2018 and 2019, however, tends to imply that the anecdotal evidence supporting lower WACC's for solar PV than assumed in the LCOE calculations is having a material impact.

To fill this significant data gap, IRENA proposes conducting a global survey of financial sector professionals on costs of capital for solar and wind technologies, in order to establish a reliable, replicable and well-documented database. The data collected through this survey effort will potentially add a new level of insight to IRENA Renewable Cost Database and analysis. It will also benefit IRENA's member states and other stakeholders who need accurate cost of capital assumptions (e.g., regulators, researchers, energy system and climate modellers, etc.). The initial results of this exercise will be seen in *Renewable Power Generation Costs in 2020*, to be released in 2021.

¹⁶ IRENA assumes a real WACC of 7.5% in OECD countries and China, and 10% elsewhere for all technologies. While the IEA, in contrast, assumes 8% in developed countries and 7% in developing countries (IEA, 2019).

¹⁷ It is also possible that the IRENA O&M assumptions might differ materially from project-specific values, but these will have a proportionately lower impact on LCOE values, meaning the majority of variation should be due to the WACC assumption. It does, however, imply that the comparison of individual projects may be of limited value and that a large body of data is needed to draw robust inferences about overall trends in WACC.

Figure 1.14 Offshore wind project LCOE compared to adjusted Auction/PPA pricing, 2010-2025



Source: IRENA Renewable Cost Database.



Box 1.1 Energy subsidies: Evolution in the global energy transformation to 2050

New IRENA estimates suggest that while fossil fuel subsidies have been widely underestimated, renewables subsidies have been overestimated. The new analysis also dispels the myth that the energy transition would entail a massive growth in subsidies. Indeed, the reality is quite the opposite: the energy transition can reduce total subsidies in the energy sector (Taylor, 2020).

IRENA estimates that in 2017, the world's total, direct energy sector subsidies – including those to fossil fuels, renewables and nuclear power – amounted to at least USD 634 billion. Subsidies to fossil fuels accounted for around 70% (USD 447 billion) of this total. Meanwhile, the same year, subsidies for renewable power generation technologies accounted for around 20% of total energy sector subsidies (USD 128 billion), biofuels for about 6% (USD 38 billion) and nuclear for at least 3% (USD 21 billion).

Amongst fossil fuels, subsidies for petroleum products dominated the total, at USD 220 billion, followed by electricity-based support for fossil fuels, at USD 128 billion. Subsidies for natural gas and coal in 2017 were estimated at USD 82 billion and USD 17 billion, respectively.

Supply-side support for renewables amounted to USD 166 billion in 2017. This broke down into USD 128 billion in support for renewable power generation, while transport sector biofuel support added a further USD 38 billion. The European Union (EU) accounted for around 54% (USD 90 billion) of total estimated renewable subsidies in 2017, the United States 14% (USD 23 billion), Japan 11% (USD 19 billion), China 9% (USD 16 billion), India 2% (USD 4 billion), and the rest of the world slightly less than 9% (USD 15 billion). Subsidies for renewable power generation were dominant in Japan (99%), China (97%), the EU (87%) and India (76%). Subsidies for biofuels dominated in the United States (61%) and the rest of the world (71%).

In 2017, globally, solar PV is estimated to have received the largest share of renewable power generation support, at 48%, or USD 60.8 billion. The next largest recipient was onshore wind, which received USD 31.6 billion (25%), followed by biomass, with USD 21.9 billion (17%), while offshore wind received USD 6.6 billion (5%).

In the REmap Case consistent with a pathway to meet the Paris Agreement goals (IRENA, 2020b), between 2017 and 2050, total energy subsidies decline from 0.8% of global Gross Domestic Product (GDP) to 0.2%. Total energy sector subsidies in the REmap scenario could decline from USD 634 billion in 2017 to USD 475 billion per year in 2050, which would be around 25% lower than in 2017 and 45% (USD 390 billion) lower than they would be based on current plans and policies.

This development is a net result of falling fossil fuel subsidies and rising efficiency and renewables subsidies. In the REmap Case, support for renewables is expected to increase from USD 166 billion/year in 2017 to USD 192 billion/year in 2030 and USD 209 billion/year in 2050. However, with falling costs, support for renewable power generation falls to USD 53 billion in 2030 – a 60% decline between 2017 and 2030 – and to just USD 5 billion in 2050.

At the same time, a broader definition of subsidies reveals a staggering gap: in 2017, the costs of unpriced externalities and direct subsidies for fossil fuels (USD 3.1 trillion) exceeded subsidies for renewable energy by a factor of 19.

In conclusion, an accelerated energy transition will reduce energy subsidy needs in the long term and can yield benefits that substantially exceed costs. Governments should use this knowledge in their design of future stimulus packages.

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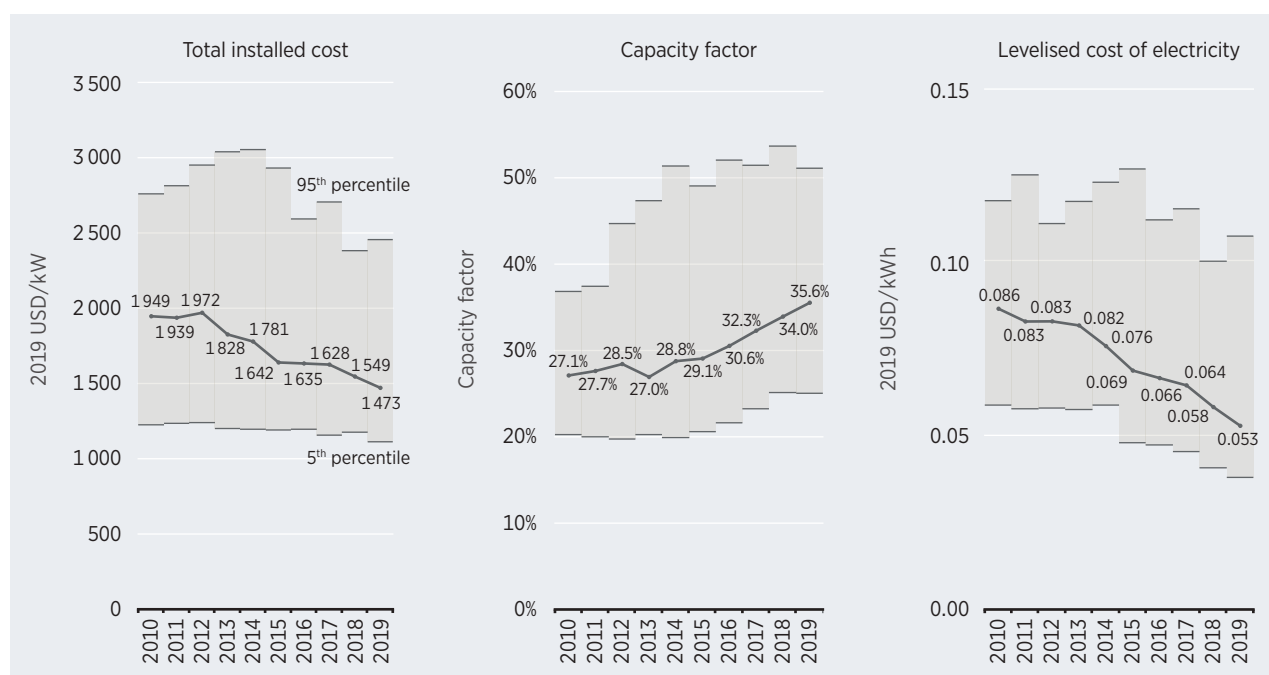


ONSHORE WIND

HIGHLIGHTS

- The global weighted-average LCOE of onshore wind fell 39% between 2010 and 2019 from USD 0.086/kWh in 2010 to USD 0.053/kWh in 2019. There was an 9% year-on-year reduction in 2019.
- In 2019, 41 GW (75%) of the new onshore wind projects commissioned had an LCOE lower than the cheapest new source of fossil fuel-fired power generation.
- The cumulative capacity of onshore wind has increased more than threefold during the past decade, from 178 GW in 2010 to 594 GW in 2019.
- The global weighted-average total installed cost has fallen by 24%, from USD 1949/kW in 2010 to USD 1473/kW in 2019, when it was down 5% on the 2018 value of USD 1549/kW.
- The country/region weighted-average total installed cost for onshore wind in 2019 ranged from around USD 1055 to USD 2 368/kW. China and India have weighted-average total installed costs between 21% to 55% lower than other regions.
- Average turbine prices fell below USD 850/kW in 2019. Prices in most regions, excluding China, have fallen by between 55% and 65% from their peaks in 2008 and 2009. Chinese wind turbine prices have fallen 78% since their peak of USD 2 480/kW in 1998, to USD 550/kW.
- Technology improvements have resulted in an almost one-third improvement in the global weighted-average capacity factor, from 27% in 2010 to 36% in 2019.

Figure 2.1 Global weighted average total installed costs, capacity factors and LCOE for onshore wind, 2010-2019



Source: IRENA Renewable Cost Database.

INTRODUCTION

Onshore wind turbine technology has made significant advances over the past decade. Larger and more reliable turbines, along with higher hub heights and larger rotor diameters, have combined to increase capacity factors. In addition to these technology improvements, total installed costs, O&M costs and LCOEs have been falling as a result of economies of scale, increased competitiveness and maturity of the sector. In 2019, onshore wind deployment was second only to solar PV.

Today, virtually all onshore wind turbines are horizontal axis turbines, predominantly using three blades and with the blades “upwind”. 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. Wind turbines now make up between 64% and 84% of the total installed costs of an onshore wind project (IRENA, 2018a). Indeed, with declining installation costs, the contribution turbines make to the overall share of total installed costs is now trending towards the higher end of the range. The other major cost categories include the installation costs, grid connection costs, and development costs. The latter includes environmental impact assessment and other planning requirement costs, project costs, and land costs – with these representing the smallest share of total installed cost.

WIND TURBINE CHARACTERISTICS AND COSTS

Wind turbine original equipment manufacturers (OEMs) offer a wide range of designs, catering for different site characteristics,¹⁴ different grid accessibility and different policy requirements in different locations. These variations may also include different land-use and transportation requirements, and the different technical and commercial requirements of the developer.

Turbines with larger rotor diameters increase energy capture¹⁵ at sites with the same wind speed and this is especially useful in exploiting marginal locations. In addition, the higher hub heights that have become common enable higher wind speeds to be accessed at the same location. This can yield materially higher capacity factors, given that power output increases as a cubic function of wind speed. The higher turbine capacity also enables larger projects to be deployed and reduces the total installed cost per unit for some cost components (expressed in MW).¹⁶

Figure 2.2 illustrates the evolution in average turbine rating and rotor diameter between 2010 and 2018 in some major onshore wind markets. Sweden, Germany, China and Canada stand out, with increases of greater than 40% in both the average rotor diameter and turbine capacity of their commissioned projects, between 2010 and 2018. In percentage terms, the largest increase in turbine capacity was observed in Ireland (104%) followed by Denmark (71%). The largest increase in rotor diameter occurred in Canada (78%) followed by China (60%). Of the countries considered, on average for 2018, Denmark and Sweden have the largest turbine rating and rotor diameters, respectively, while India had the lowest turbine rating and the United Kingdom had the lowest rotor diameter. Overall, in 2018 the country-level average capacity ranged from 1.96 MW to 3.59 MW, and rotor diameter from 100 metres (m) to 126 m.

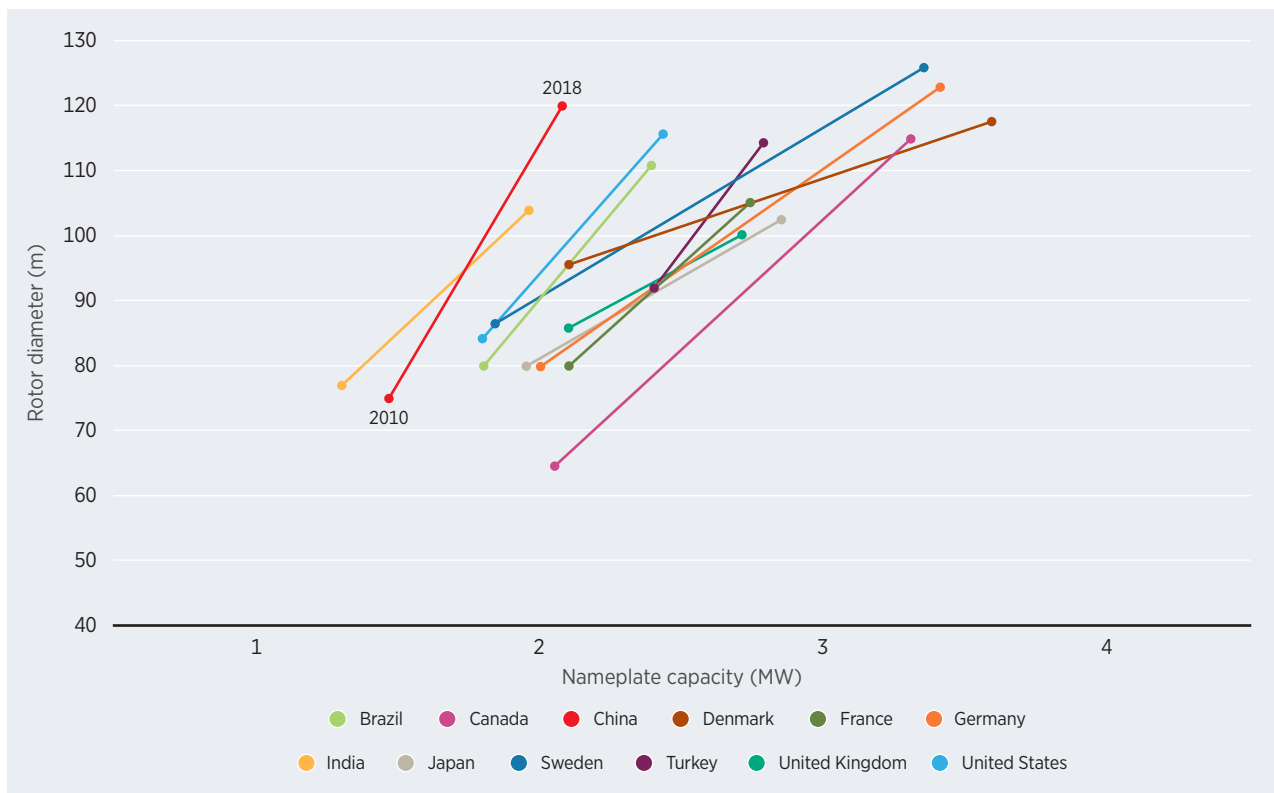
Wind turbine prices reached their previous low between 2000-2002, with this followed by a sharp increase in prices. This was attributed to increases in commodity prices (particularly cement, copper, iron and steel); supply chain bottlenecks; and improvements in turbine design, with larger and more efficient models introduced into the market. However, due to increased government renewable energy policy support for wind deployment, this period also coincided with a significant mismatch between high demand and tight supply, which enabled significantly higher margins for OEMs during this period.

¹⁴ Wind speeds, area for adequate spacing to reduce wake turbulence, and turbulence inducing terrain features.

¹⁵ Energy output increases as a squared function of the surface area, which is a key variable in the power output of a wind turbine.

¹⁶ Increasing turbine size does not lead to a proportional increase in the cost of other turbine components, e.g. towers, bearings, nacelle, etc. Thus, the increase in cost on a per unit basis is not as significant as might be expected.

Figure 2.2 Weighted average rotor diameter and name plate capacity evolution, 2010-2018



Source: Based on CanWEA, 2016; GlobalData (2020a); IEA Wind, 2020; Wiser and Bollinger, 2019; Danish Energy Agency, 2020; and Wood MacKenzie, 2020a.



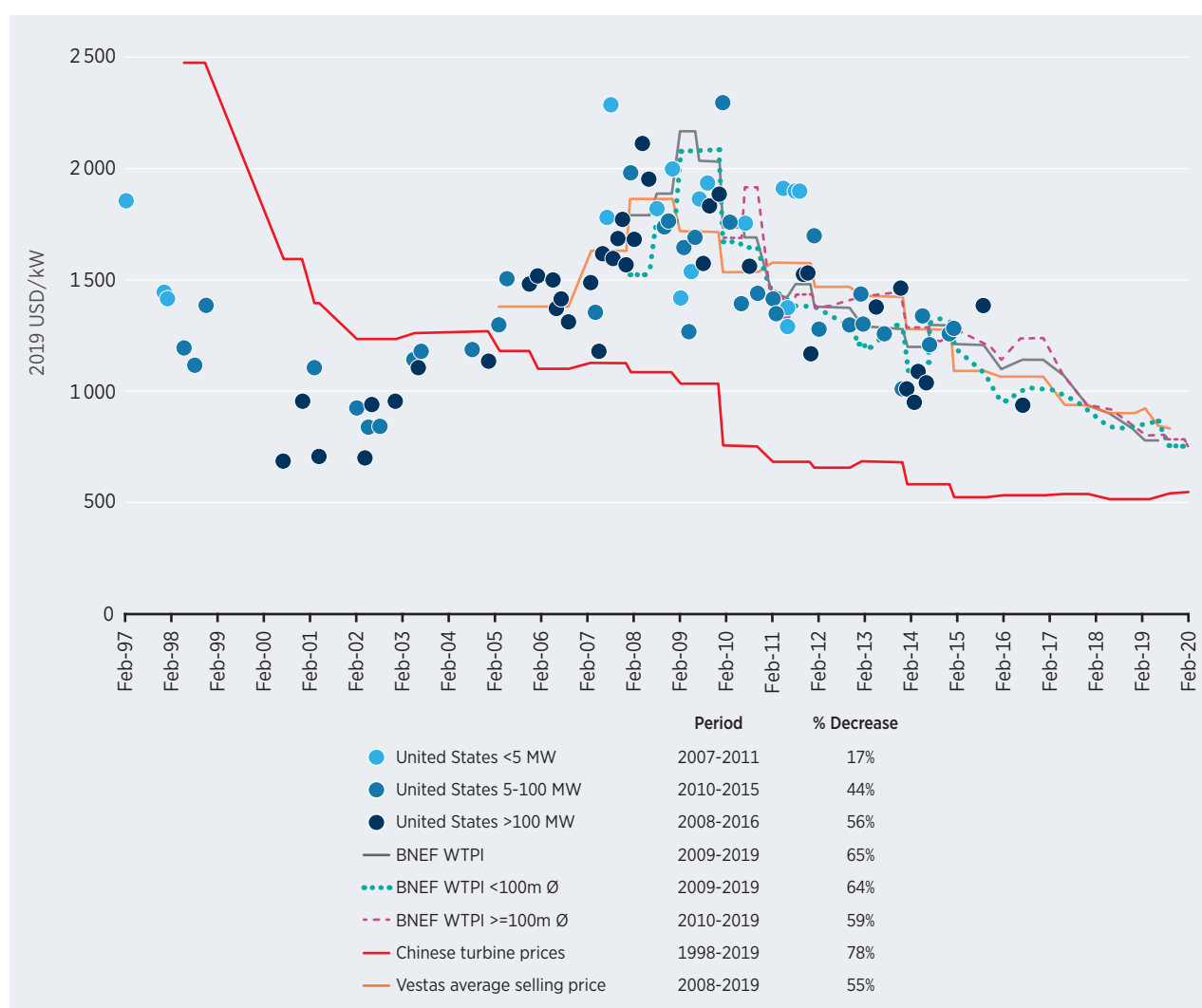
As supply chains grew and production capacity ramped up, wind turbine prices then peaked between 2007 and 2010, depending on the market, but have since fallen, by between 44% and 78% by the end of 2019, with the latest prices ranging between USD 560/kW and USD 830/kW (Figure 2.3). The experience in China was one of a dramatic price fall from 1998 - when the wind turbine price was around USD 2 480/kW - to the year 2002, then declining steadily to the point where the 2019 price was around an average of USD 530/kW.

With greater competition among manufacturers, margins have come under increasing pressure, to the benefit of consumers. For instance, Vestas saw its turbine sales margins drop below 10% in 2019 (BNEF, 2020). This competition is being reinforced

by the increased use of competitive procurement processes by a growing number of countries for the procurement of renewable energy. Increased competition has also led to acquisitions in the turbine and balance-of-plant sectors, and a trend of production moving to countries with lower manufacturing costs (Wood MacKenzie, 2020b).

The decline in turbine prices globally has occurred despite the increase in rotor diameters, hub heights, and nameplate capacities. In addition, price differences between turbines with differing rotor diameters has narrowed. In 2019, this could be seen in the minimal percentage difference - 4% - between the prices of turbines with a rotor diameter above 100 m (USD 785/kW) and those with a rotor diameter of less than 100 m (USD 752/kW).

Figure 2.3 Wind turbine price indices and price trends, 1997–2019



Source: Based on Wiser & Bollinger, 2019; BNEF, 2019a; Vestas Wind Systems, 2005–2020; and the IRENA Renewable Cost Database.

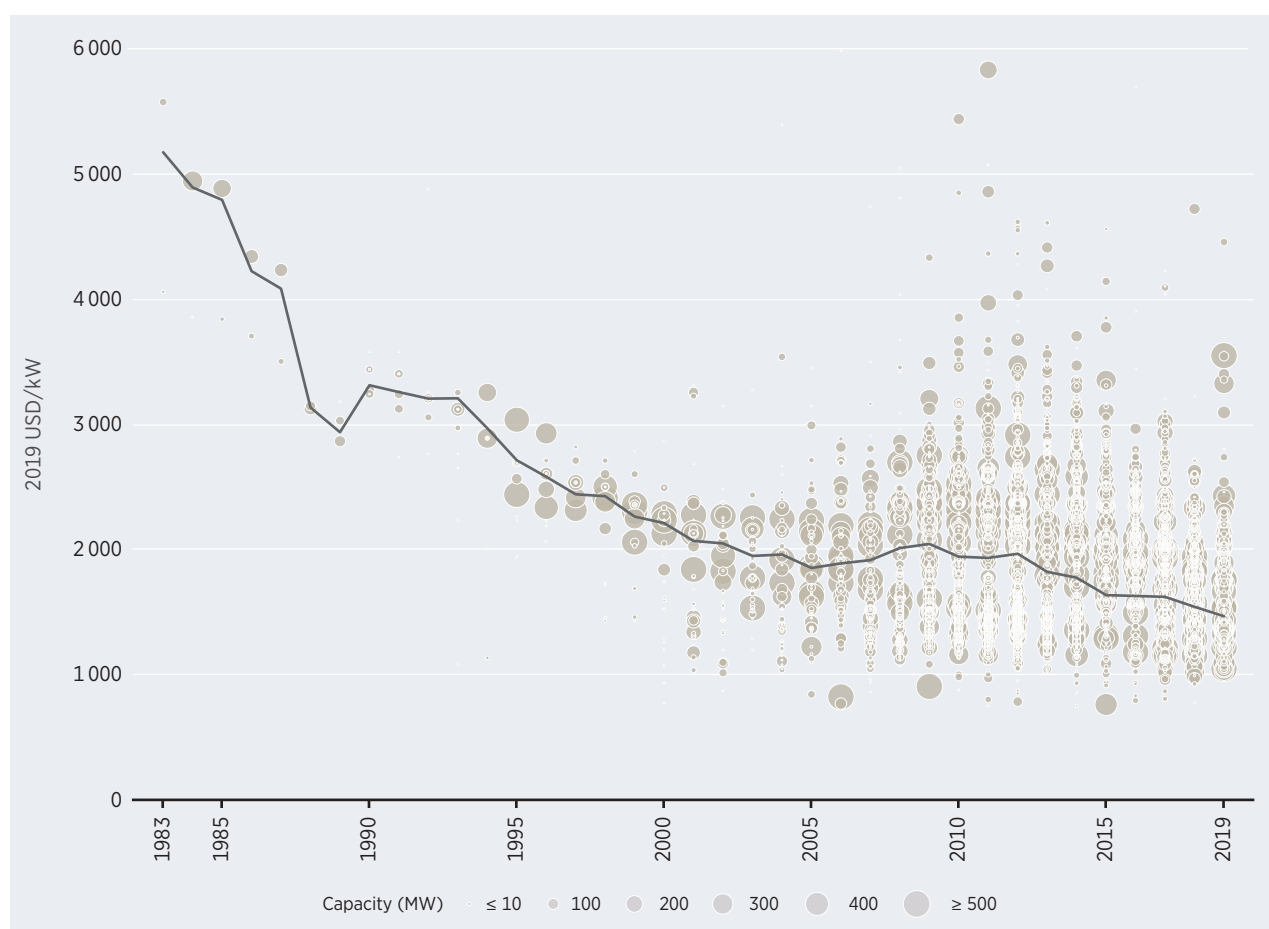
ONSHORE WIND TOTAL INSTALLED COSTS

The global weighted-average total installed cost of onshore wind projects fell by 72% between 1983 and 2019, from USD 5179 to USD 1473/kW, based on data from the IRENA Renewable Cost Database (Figure 2.4). Global average total installed costs have fallen by up to 9% for every doubling in cumulative onshore wind capacity deployed globally. This has been driven by wind turbine price and balance-of-plant cost reductions. The global weighted-average total installed cost of onshore wind fell by 24% between 2010 and 2019, from USD 1949/kW to USD 1473/kW, with a 5% decline year-on-year in 2019.

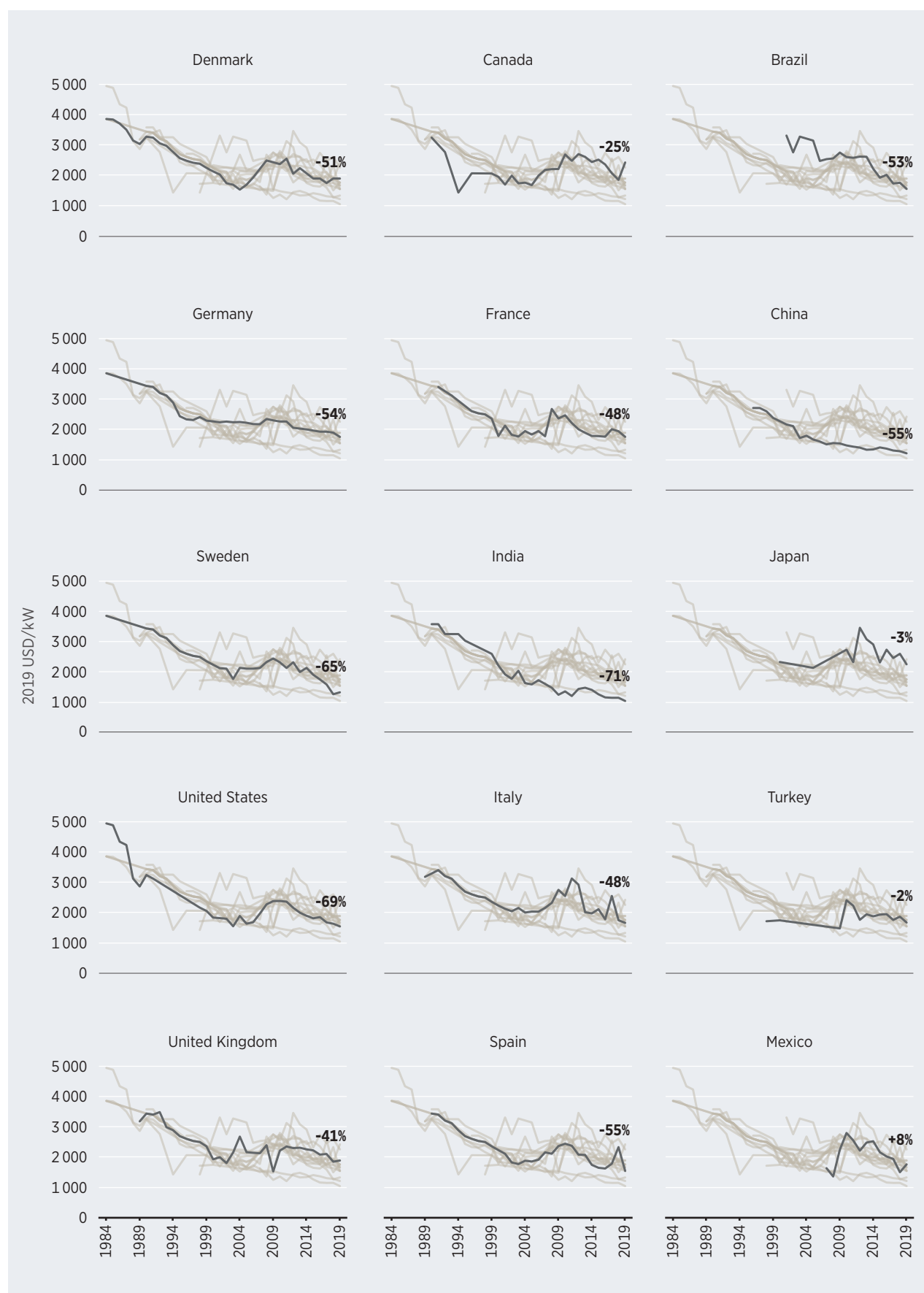
The trend in country-specific weighted-average total installed cost for 15 countries that are major wind markets and have significant time series data,

are shown in Figure 2.5. Individual countries saw a range of cost reductions from 71% in India to just 2% in Turkey – but these comparisons need to be treated with caution, given the differing start dates for the first available data. Mexico saw an 8% increase over the period shown, with the first cost data point in 2007, when there was a low weighted-average total installed cost of USD 1644/kW. This cost then increased, before falling in the period 2010-2019 as deployment accelerated. The more competitive, established markets show larger reductions in total installed costs over longer time periods than newer markets. There is, however, a wide range of individual project installed costs within a country and region. This is due to the different country and site-specific requirements, e.g. logistics limitations for transportation, local content policies, land-use limitations, labour costs, etc.

Figure 2.4 Total installed costs of onshore wind projects and global weighted average, 1983-2019



Source: IRENA Renewable Cost Database.

Figure 2.5 Onshore wind weighted average total installed costs in 15 countries, 1984–2019

Source: IRENA Renewable Cost Database.

Looking at the data at a regional level (Table 2.1), shows that the regions with the highest weighted average total installed costs in 2019 were (in descending order): “Other Asia” (that is to say, excluding China and India), Middle East and Africa, Europe, Central America and the Caribbean, and South America (excluding Brazil) and Oceania. Brazil, China and India have more mature markets and lower cost structures than their neighbours. This can be seen in their lower average installed costs for onshore wind in 2019. India and China had the most competitive weighted average total installed costs in 2019 – USD 1055/kW and USD 1223/kW respectively – with installed costs falling by 23% in India and 10% in China, since 2010.

CAPACITY FACTORS

The capacity factor represents the energy output from a wind farm on an annual basis as a percentage of the farms maximum output and is predominantly determined by two factors: the quality of the wind resources where the wind farm is sited; and the turbine and balance-of-plant technology used.

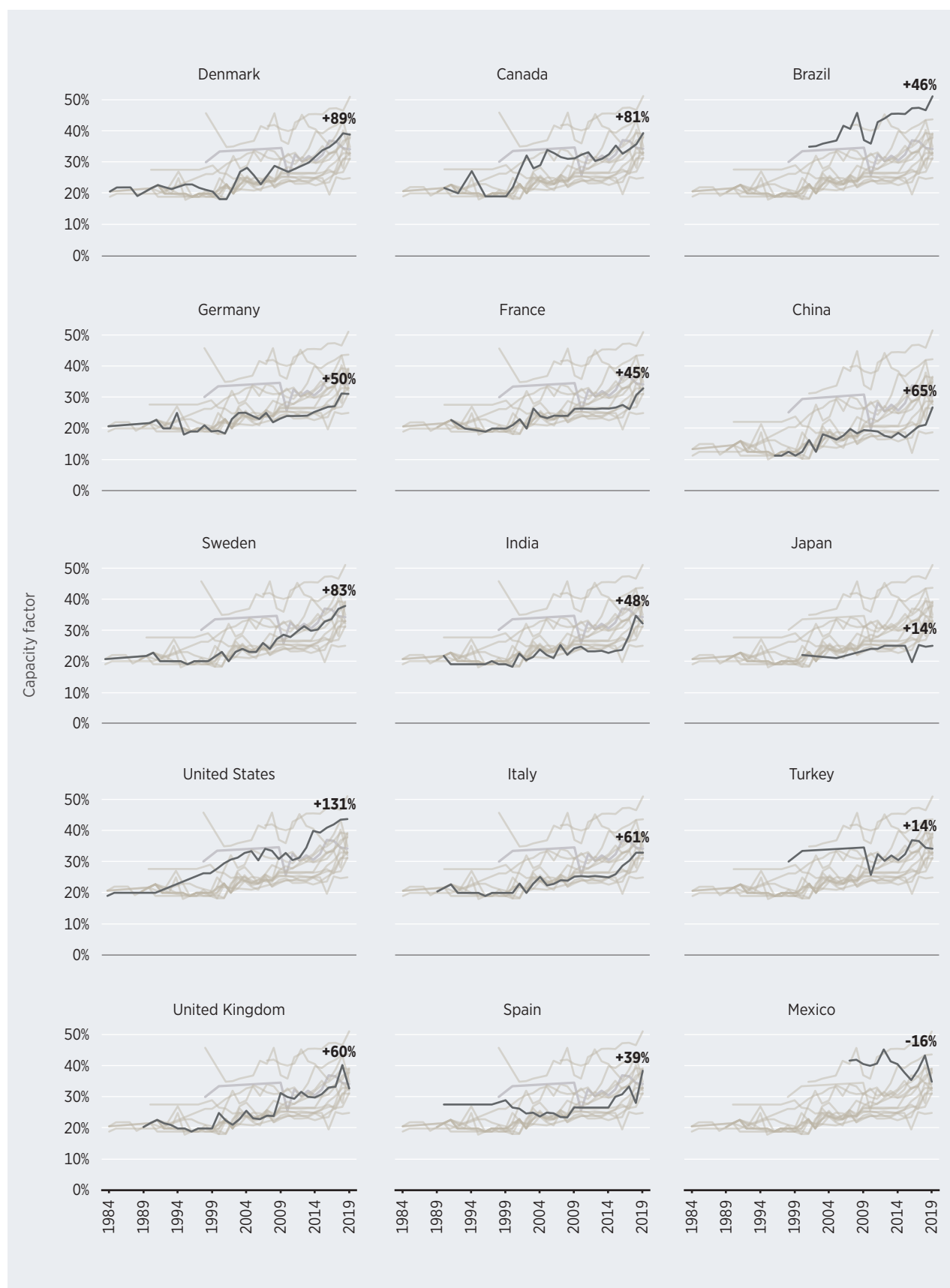
The trend towards more advanced and more efficient turbine technologies with larger rotor diameters and hub-heights, has seen energy outputs and capacity factors rise in most markets over the last ten years. The global weighted-average capacity factor for onshore wind increased by 81% between 1983 and 2019, from around 20% in the former year to 36% in the latter. This upward trend has also been observed during the past decade (2010-2019). During this period, there has been an almost one-third increase in the capacity factor, from just over 27% in 2010 to 36% in 2019. Between 2018 and 2019, the capacity factor went up 5%, from around 34% to 36%.

Resource quality has a significant impact on capacity factors, even as technology improvements have raised outputs across the board. There is, therefore, still wide variation across markets predominantly due to differing wind resource qualities, but also, to a lesser extent, the different technologies used and site configurations. It’s worth noting that not all capacity factor improvements are the result of turbine technology improvements, as owing to advancements in remote sensing and computing, there have been improvements in wind resource characterisation and layout methods. This has enabled the selection of better wind sites and better wind turbine layouts for optimal energy output.

Table 2.1 Total Installed cost ranges and weighted averages for onshore wind projects by country/region, 2010 and 2019

	2010			2019		
	5 th percentile	Weighted average	95 th percentile	5 th percentile	Weighted average	95 th percentile
	(2019 USD/kW)					
Africa	2 226	2 291	3 196	1 448	1 952	2 189
Other Asia	1 829	2 501	2 762	1 392	2 368	3 709
Central America and the Caribbean	2 497	2 664	2 787	1 737	1 737	1 737
Eurasia	2 284	2 432	2 501	1 277	1 633	2 035
Europe	1 575	2 405	3 602	1 071	1 800	2 233
North America	1 594	2 407	3 696	1 099	1 636	2 162
Oceania	2 993	3 501	3 882	1 157	1 555	1 788
Other South America	2 399	2 644	2 729	1 123	1 718	2 270
Brazil	2 252	2 539	2 603	1 224	1 559	2 061
China	1 173	1 491	2 038	1 115	1 223	1 340
India	1 013	1 412	1 941	1 039	1 055	1 082

Source: IRENA Renewable Cost Database.

Figure 2.6 Historical onshore wind weighted average capacity factors in 15 countries, 1984–2019

Source: IRENA Renewable Cost Database.

Figure 2.6 depicts the historical evolution of onshore wind capacity factors for commissioned projects in each year across the 15 markets where IRENA has the longest time series data. Average capacity factors increased by just over half for the 15 countries examined in Figure 2.6. Granted, there are varying start dates for commercially deployed projects, but nonetheless, this shows the scale of capacity factor improvements. Indeed, compared to the earliest commissioned project in 1984 in the United States, capacity factors in 2019 increased by over 130%, while capacity factors in Denmark, Sweden and Canada have increased by more than 80% between their earliest deployment and 2019. Brazil, like the United States, has excellent onshore wind resources and in 2019, newly commissioned projects had a weighted average capacity factor of 51%.

Table 2.2 shows the more recent change in capacity factors for projects commissioned in the same 15 countries for the 2010-2019 period. Except for Mexico, all the countries experienced improvements in the weighted average capacity factor, with an increase of between 9% in the United Kingdom and 44% in Denmark and Spain.

OPERATION AND MAINTENANCE COSTS

Operation and maintenance costs for onshore wind often make up a significant part (up to 30%) of the LCOE for this technology (IRENA, 2018a). Technology improvements, greater competition among service providers, and increased operator and service provider experience are, however, driving down O&M prices. This trend is being supported by increased efforts by turbine OEMs to secure service contracts given the potentially higher profit margins available than in turbine supply (BNEF, 2020 and Wood MacKenzie, 2019a). Nonetheless, the share of the O&M market covered by turbine OEMs continues to shrink, with asset owners increasingly internalising major parts of O&M services or using independent service providers in order to reduce costs. This share fell from 70% in 2016 to 64% in 2017 and it is expected to fall a further ten percentage points in 2027, to 54% (Make Consulting, 2017).

Table 2.2 Country-specific average capacity factors for new onshore wind projects, 2010 and 2019

	2010	2019	Percentage change 2010-2019
	%		
Denmark	27	39	↑ 44%
Spain	27	39	↑ 44%
Brazil	36	51	↑ 42%
United States	33	44	↑ 33%
Turkey	26	34	↑ 33%
Sweden	29	38	↑ 33%
India	25	32	↑ 30%
Italy	26	33	↑ 30%
Germany	24	31	↑ 30%
France	27	33	↑ 25%
China	26	32	↑ 24%
Canada	32	39	↑ 21%
United Kingdom	30	33	↑ 9%
Japan	24	25	↑ 4%
Mexico	40	35	↓ 13%

Source: IRENA Renewable Cost Database.

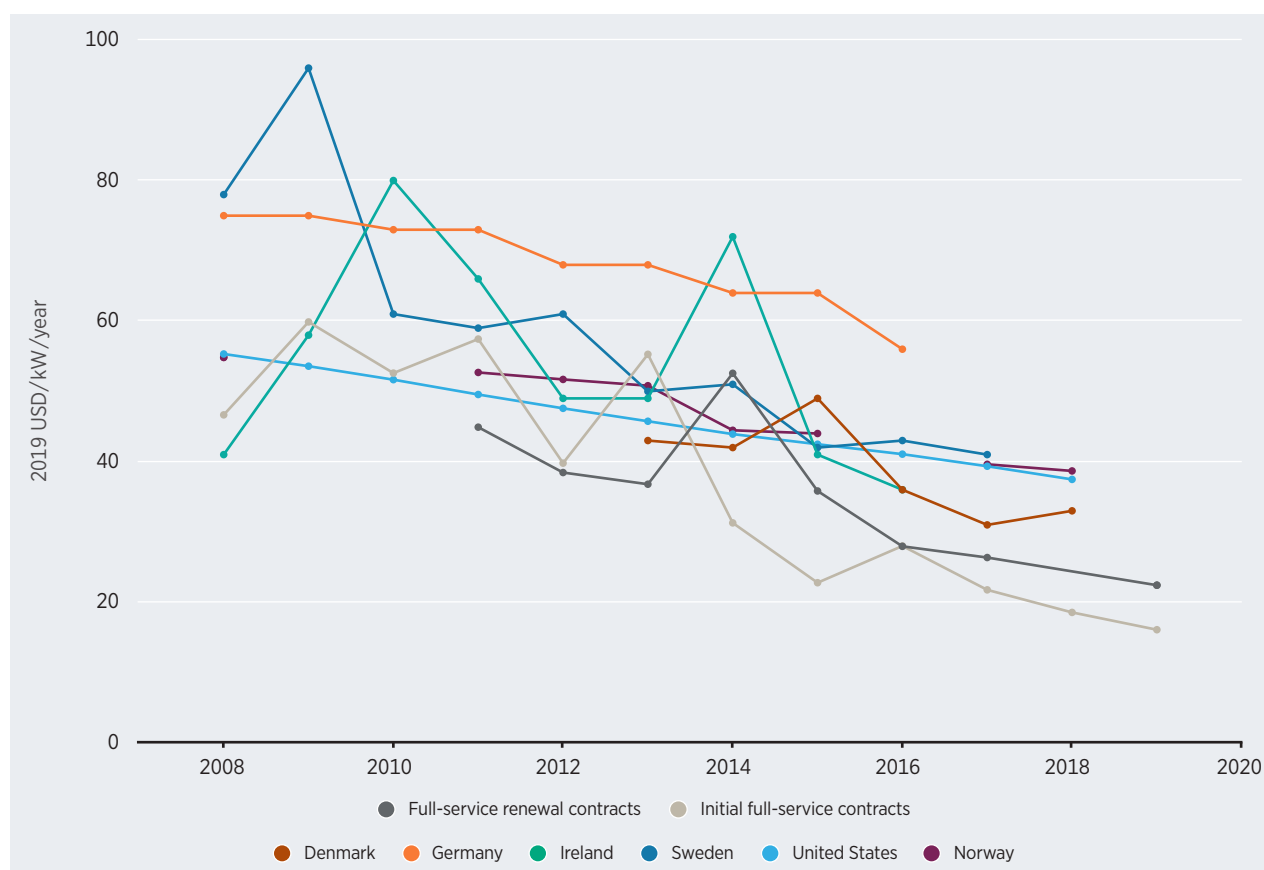
Figure 2.7 shows O&M costs in selected countries, along with BNEF O&M price indexes. The latter are represented as either initial full-service contracts, or full-service contracts for already established wind farms – which are more expensive, as they factor in the ageing of turbines. The data shows an observable downward trend in O&M costs – which reflects the maturity and competitiveness of the market. Initial full-service contracts fell 66% between 2008 and 2019 while full-service renewal contracts declined by 50% between 2011 and 2019. At the country level, between 2016 and 2018, O&M costs for onshore wind have ranged from USD 33/kW per year (in Denmark) to USD 56 USD/kW per year (in Germany) – which is known for having higher than average onshore wind O&M costs. The difference between the contract prices and observed country O&M costs is explained by the additional, predominantly operational expenses, not covered by service contracts (e.g., insurance, land lease payments, local taxes, etc.).

LEVELISED COST OF ELECTRICITY

The LCOE of an onshore wind farm is determined by: the total installed costs; lifetime capacity factor; the O&M costs; the economic lifetime of the project; and the cost of capital. While all of these factors are important in determining the LCOE of a project, some components have a larger impact. For instance, the cost of the turbine (including the towers) makes up the most significant component of total installed costs in an onshore wind power project and with no fuel costs, the capacity factor and cost of capital also have a significant impact on LCOE.

The O&M costs, made up of fixed and variable components, make up from 10 to 30% of the LCOE in 2019 in the IRENA Renewable Cost Database. Reductions in these costs are becoming increasingly important in driving down LCOEs, as turbine price reductions – which are now around USD 850/kW or less across most markets – are contributing less in absolute terms to cost reductions.

Figure 2.7 Full-service (initial and renewal) O&M pricing indexes and weighted average O&M costs in Denmark, Germany, Ireland, Norway, Sweden, United States and Norway, 2008–2019



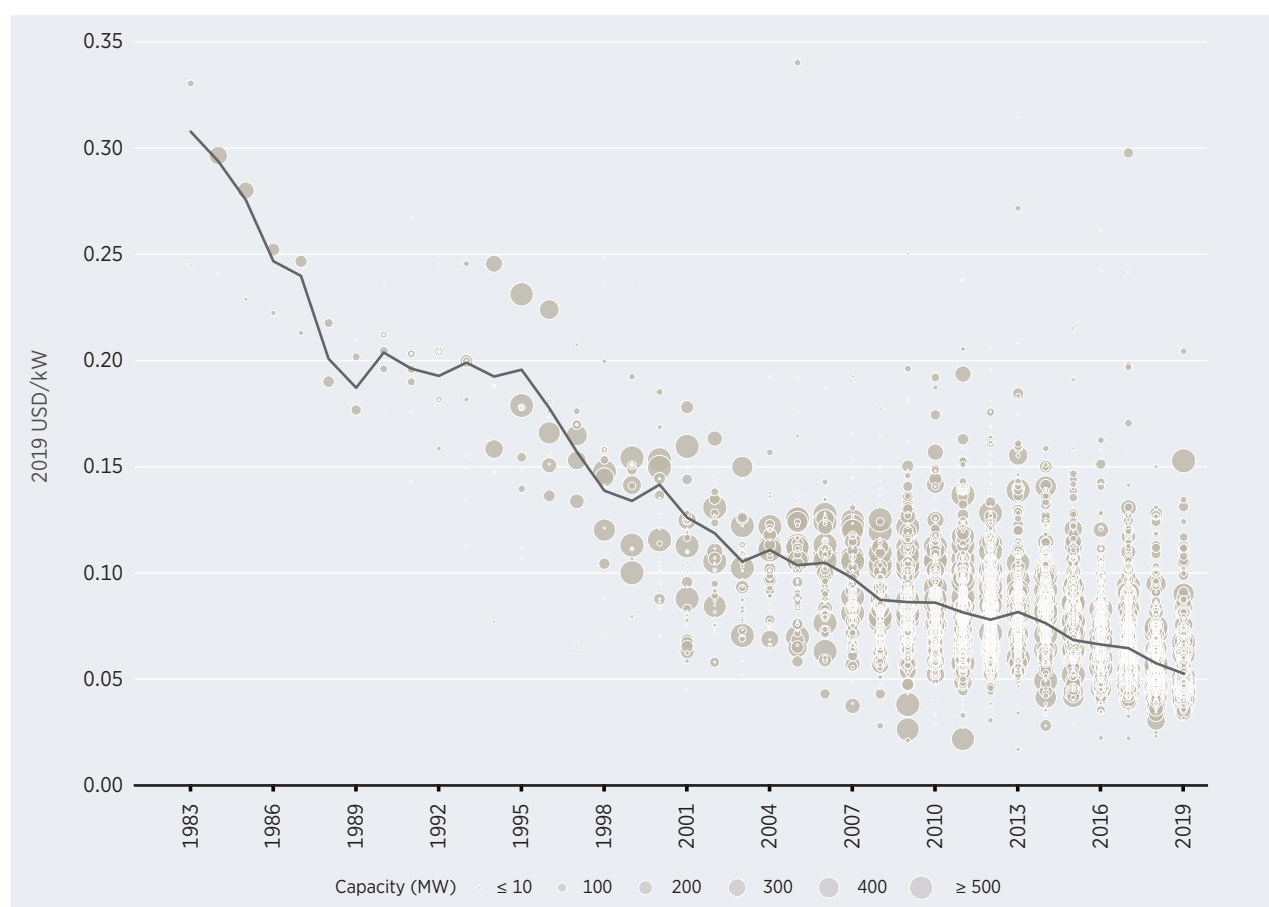
Source: BNEF, 2019b and IEA Wind, 2020.

Figure 2.8 presents the evolution of the LCOE (global weighted average and project level) of onshore wind between 1983 and 2019. Over that period, the global weighted-average LCOE declined by 83%, from USD 0.308/kWh to USD 0.053/kWh. In 2010, the LCOE was USD 0.086/kWh, meaning a 39% decline over the decade to 2019. Consequently, onshore wind now increasingly competes with hydropower as the most competitive renewable technology, without financial support.

Factors behind the decline the in the global weighted-average LCOE include:

- Turbine technology improvements: With the increase in turbine sizes and swept areas, the process of optimising the rotor diameter and turbine ratings, *i.e.* the specific power, has led to increased energy yield and thus project viability for the asset owner, depending on site characteristics. In addition, optimising the site configuration to better exploit wind resources and reduce output losses due to turbulence has
- Economies of scale: Impacting costs of manufacturing, installation (with the reduction in the number of turbines required for a project due to the higher turbine ratings), and O&M costs.
- O&M costs: The combination of digital technologies – that has allowed for improved data analytics – and autonomous inspections. This has been joined by improvements in the reliability and durability of new turbines, while larger turbines have reduced the number of turbines for a given capacity. Improved O&M practices have also contributed to lower O&M costs. In addition, more players are entering the O&M servicing sector for onshore wind, which is increasing competition and driving down costs (BNEF, 2019c and BNEF, 2020).

Figure 2.8 LCOE of onshore wind projects and global weighted average, 1983–2019

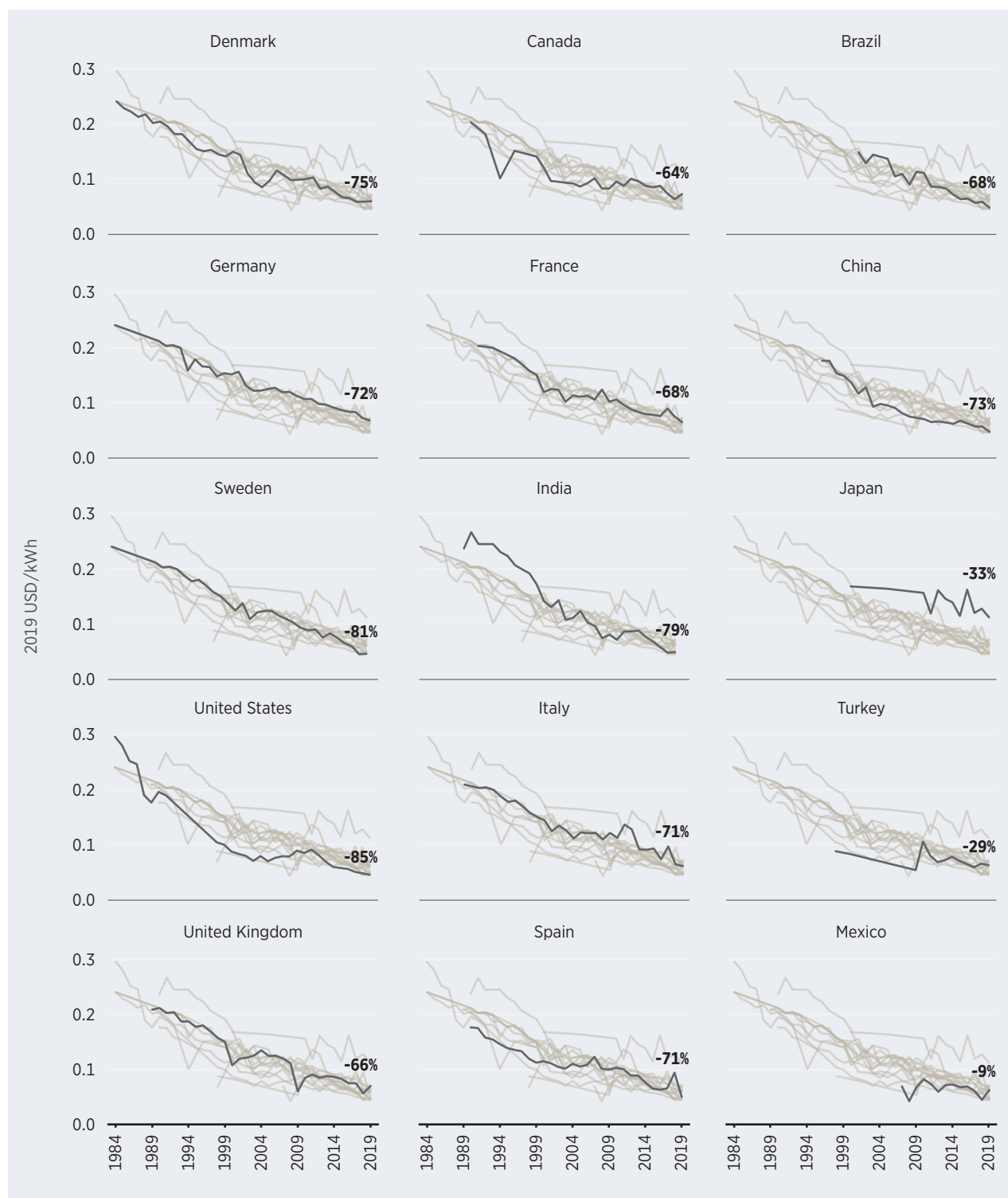


Source: IRENA Renewable Cost Database.

- Competitive procurement: The shift from feed-in-tariff support schemes to competitive auctions is leading to further cost reductions, as it drives competitiveness across the supply chain, from development to O&M,

both at a local and global scale. For turbine manufacturers, the supply chain has also moved to support regional hubs and countries to minimise labour and delivery costs, further improving competitiveness.

Figure 2.9 The weighted average LCOE of commissioned onshore wind projects in 15 countries, 1984–2019



Source: IRENA Renewable Cost Database.

The growing maturity of the market (cumulative deployment grew by 578 GW between 2000-2019) should also not be overlooked. Increased operational experience and favourable government regulations and policies, have reduced project development and operation risks for onshore wind, especially in established markets. Development, installation and operational risks are now better understood, with adequate mitigation measures in place, all driving down project risk.

Figure 2.9 presents the historical evolution of the LCOE of onshore wind in 15 countries where IRENA has the longest time series data. The data should be interpreted with care, and cross-country comparisons are problematic, because of the variation in base years for each country in the data available to IRENA. Having said this, the biggest LCOE reduction – 85% – was in the United States, which had the second largest reduction in average total installed costs and largest improvement in average capacity factor, among the 15 countries analysed. Sweden and India both had the second and third largest weighted average LCOE reductions, at 81% and 79% respectively. In 2019, the United States, Sweden, India, China, and Brazil all have weighted average LCOEs below

USD 0.050/kWh – the lower range for fossil fuel-fired power generation.

Table 2.4 shows the country/region weighted average LCOE and 5th and 95th percentile ranges by region in 2010 and 2019. In 2019, the highest weighted average LCOE for commissioned projects by region was USD 0.099/kWh in “Other Asia” (e.g., excluding China and India), while projects commissioned in North America saw the lowest weighted average LCOE, at USD 0.051/kWh. The highest LCOE reductions between 2010 and 2019 were in Oceania and South America, with a 54% (USD 0.117/kWh to USD 0.054/kWh) and 44% (USD 0.101/kWh to USD 0.057/kWh) reduction respectively. Wind power projects are increasingly achieving LCOEs of under USD 0.040/kWh, and in some cases, as low as USD 0.030/kWh. The most competitive weighted average LCOEs below USD 0.050/kWh were observed across different regions: in Asia (India and China), Europe (Finland and Sweden), Africa (Egypt), North America (the United States), and South America (Argentina and Brazil). Considering LCOE ranges regionally, in 2019, the 5th and 95th percentile range for the global weighted-average LCOE was between USD 0.035 in North America and USD 0.131/kWh in Other Asia.

Table 2.3 Regional weighted average LCOE and ranges for onshore wind in 2010 and 2019

	2010			2019		
	5 th percentile	Weighted average	95 th percentile	5 th percentile	Weighted average	95 th percentile
	(2019 USD/kWh)					
Africa	0.061	0.100	0.119	0.050	0.067	0.072
Other Asia	0.090	0.117	0.129	0.057	0.099	0.131
Central America and the Caribbean	0.080	0.086	0.131	0.061	0.061	0.061
Eurasia	0.089	0.108	0.123	0.048	0.064	0.093
Europe	0.067	0.107	0.143	0.037	0.067	0.096
North America	0.051	0.089	0.144	0.035	0.051	0.082
Oceania	0.101	0.117	0.155	0.043	0.054	0.071
Other South America	0.087	0.101	0.131	0.039	0.057	0.092
Brazil	0.080	0.095	0.120	0.032	0.048	0.056
China	0.051	0.072	0.101	0.037	0.046	0.064
India	0.050	0.083	0.120	0.036	0.049	0.070

Source: IRENA Renewable Cost Database.

03

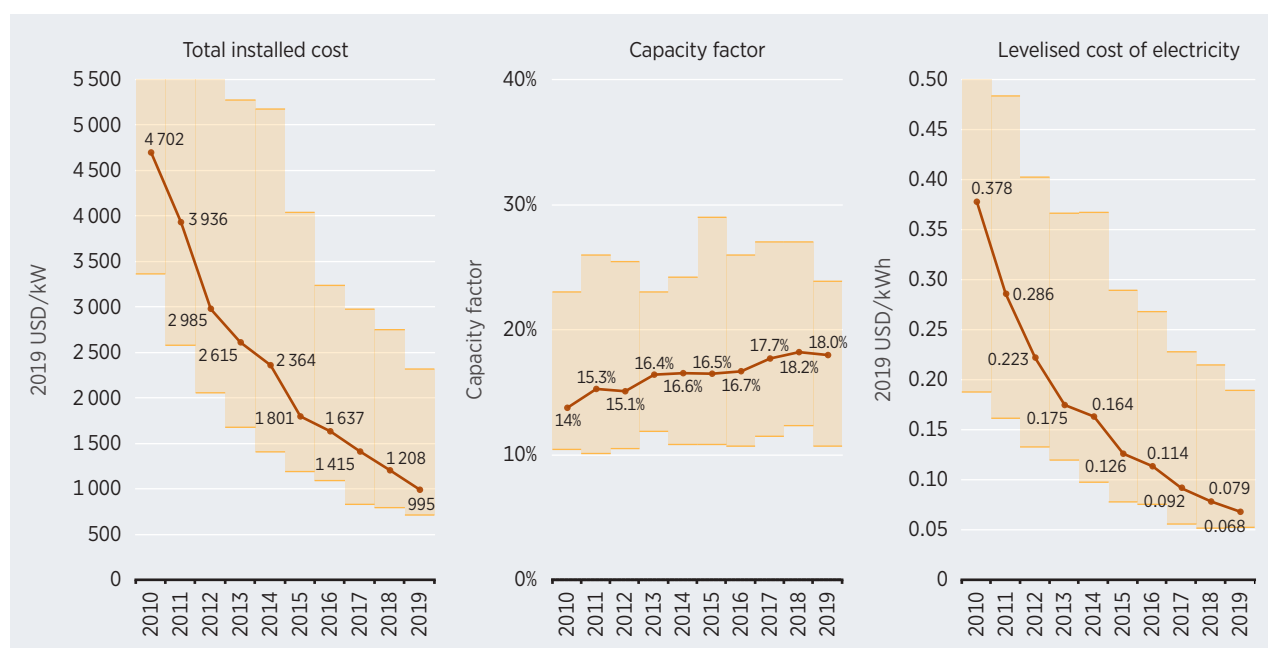


SOLAR PHOTOVOLTAICS

HIGHLIGHTS

- The global weighted-average LCOE of utility-scale PV plants declined by 82% between 2010 and 2019, from around USD 0.378/kWh to USD 0.068/kWh in 2019, with a 13% reduction year-on-year in 2019.
- At an individual country level, the weighted average LCOE of utility-scale solar PV declined by between 66% and 85% between 2010 and 2019.
- The cost of crystalline solar PV modules sold in Europe declined by around 90% between December 2009 and December 2019.
- The global capacity weighted-average total installed cost of projects commissioned in 2019 was USD 995/kW, 79% lower than in 2010 and 18% lower than in 2018.
- Solar PV capacity grew 14-fold between 2010 and 2019, with 580 GW installed at the end of 2019.
- The total installed costs in the residential rooftop PV market are higher than utility-scale due to their small size, but decreased by between 47% and 80% between 2010 and 2019 depending on the market.
- Total installed system costs in the commercial rooftop markets where data is available decreased by between 64% and 86% between 2010 and 2019.
- On average, in 2019, balance of system costs (excluding the module and inverter) made up about 64% of total installed costs.
- The global weighted-average capacity factor for new, utility-scale solar PV, increased from 13.8% in 2010 to 18.0% in 2019. This was predominantly driven by the increased share of deployment in sunnier locations.

Figure 3.1 Global weighted average total installed costs, capacity factors and LCOE for PV, 2010–2019



Source: IRENA Renewable Cost Database.

RECENT MARKET TRENDS

By the end of 2019, over 580 GW of solar PV systems had been installed, worldwide. This represents a 14-fold growth for the technology since 2010. About 98 GW of newly installed systems was commissioned just during 2019. These new capacity additions were the highest among all renewable energy technologies for the year.

Growth in 2019 was driven by continued new capacity additions in Asia, with the region contributing about 60% of the new installations during the year. Developments in that region were driven by China, India, Japan and the Republic of Korea, which together installed 47.5 GW of new PV capacity during 2019. Viet Nam has emerged as a new, important PV market in the region, after installing about 5.6 GW last year in another example of newer markets gaining maturity.

Meanwhile, historical markets outside Asia continued to gain scale. The United States, Australia and Germany together installed another 17.5 GW, while both Spain (4.0 GW) and Ukraine (3.9 GW) both stood out after experiencing notable growth compared to 2018 (IRENA, 2020a).

TOTAL INSTALLED COSTS

Solar PV module cost trends

An important driver of improved competitiveness historically, the downward trend in solar PV module costs continued during 2019. Between December 2009 and December 2019, crystalline silicon module prices declined between 87% and 92% for modules sold in Europe, depending on the type. The weighted average cost reduction could be in the order of 90% during that period. More recently the cost of mainstream module technology declined 14% between December 2018 and December 2019, reaching USD 0.27/Watt (W). A wide range of costs exists, however, depending on the type of module considered, with costs for December 2019 varying from as low as USD 0.21/W for the lower cost modules to as high as USD 0.38/W for all black modules. The cost of high efficiency crystalline modules at USD 0.37/W was slightly above thin film offerings, which sold for USD 0.36/W during that period.

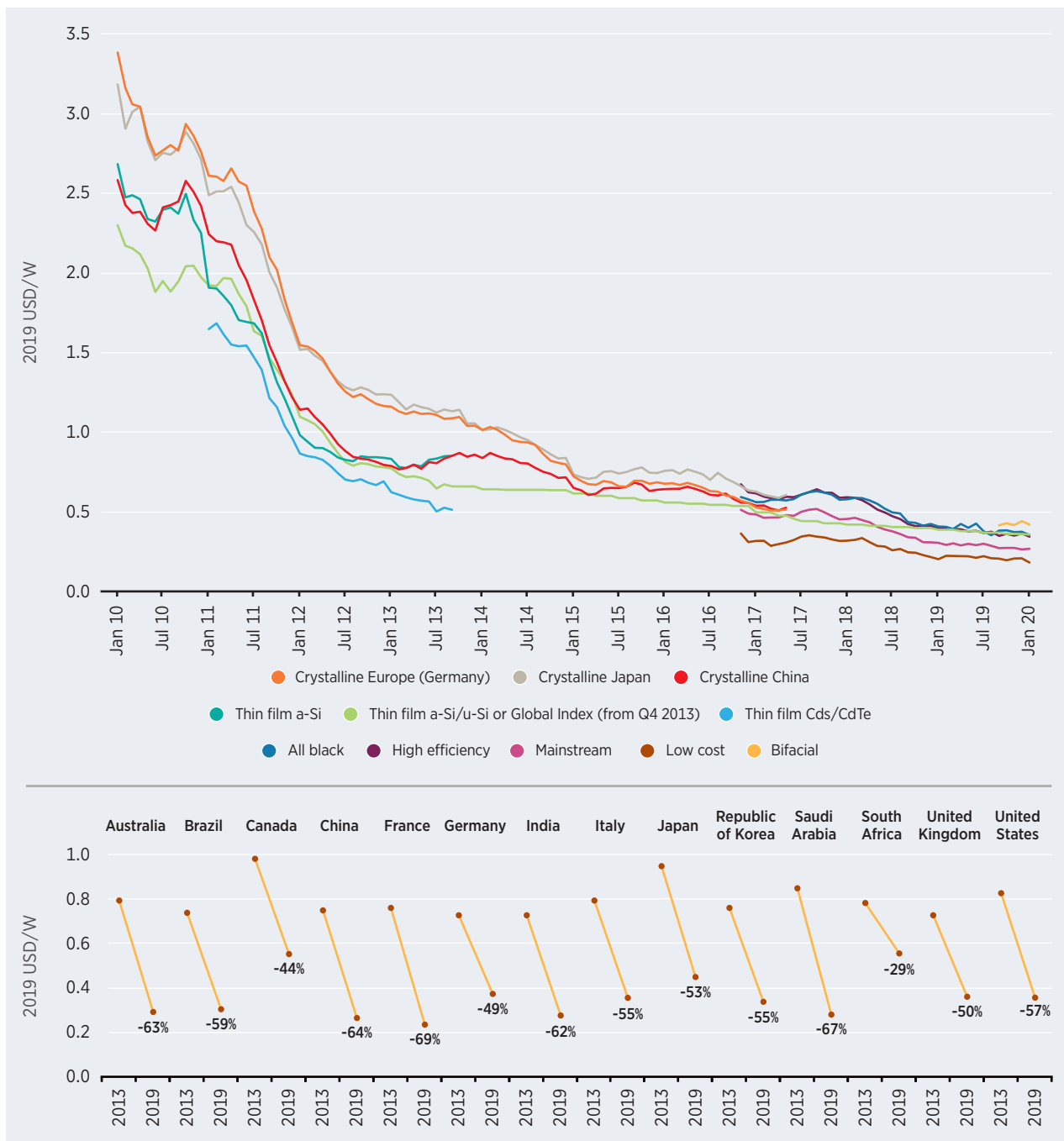
Data for bifacial modules has also started to become available. During December 2019, bifacial module

costs were 56% higher than the 'mainstream' category and 18% higher than the more expensive, mono-facial option. While there is still insufficient historical data to more consistently assess bifacial module costs trends, this technology's costs per Watt have been within a close range of the higher performing mono-facial options in recent months. This may support expectations of increased bifacial technology adoption in the market, given its potential for increased yield per Watt, compared to mono-facial technologies.

Between 2013 and 2019, market-level module costs declined between 29% (South Africa) and 69% (France) for the markets for which historical data is available. Data for 2019 shows that a wide range of module costs still exists among the evaluated markets. Compared to 2018, however, the range has narrowed both in USD/W terms (from USD 0.52/W to USD 0.32/W), as well as in the ratio of the highest to lowest costs in the assessed markets (from 2.89 times to 2.35 times). At the same time, module cost reductions of between 4% and 30% occurred in all assessed markets between 2018 and 2019, pointing to the increasing cost maturity of a growing number of markets (Figure 3.2).

Even though manufacturing scale and experience still play an important role in achieving low module costs, recent module cost reductions are closely related to module manufacturing process optimisation and to efficiency gains associated with increased adoption of newer cell architecture types. The market shift towards higher utilisation of both multi- and mono passivated emitter rear cell (PERC) architectures is an example of this. Solar PV modules based on these and other similar cell architecture types (often referred to as double-sided contact cell concepts) already make up 60% of the market in 2019 and are expected to gain further dominance in the next years. The average module efficiency of crystalline modules has increased from 14.7% in 2010 to 19.2% in 2019 (ITRPV, 2020). In solar PV modules, higher efficiencies translate in to smaller areas required for a given wattage. Higher module efficiencies therefore directly reduce module costs per watt and those balance of system costs related to the area of the solar installation (e.g., racking and mounting structures, cabling, etc.). Cost reductions have also been achieved in the solar PV module manufacturing value chain (e.g., reduced materials usage from diamond wire sawing, higher throughput in factories, automation and reduced labour costs). These, then reflect in lower achievable costs per Watt (IRENA, 2018).

Figure 3.2 Average monthly solar PV module prices by technology and manufacturing country sold in Europe, 2010 to 2020 (top) and average yearly module prices by market in 2013 and 2019 (bottom)



Source: GlobalData (2019); pvXchange (2020); Photon Consulting (2017).



Total installed costs

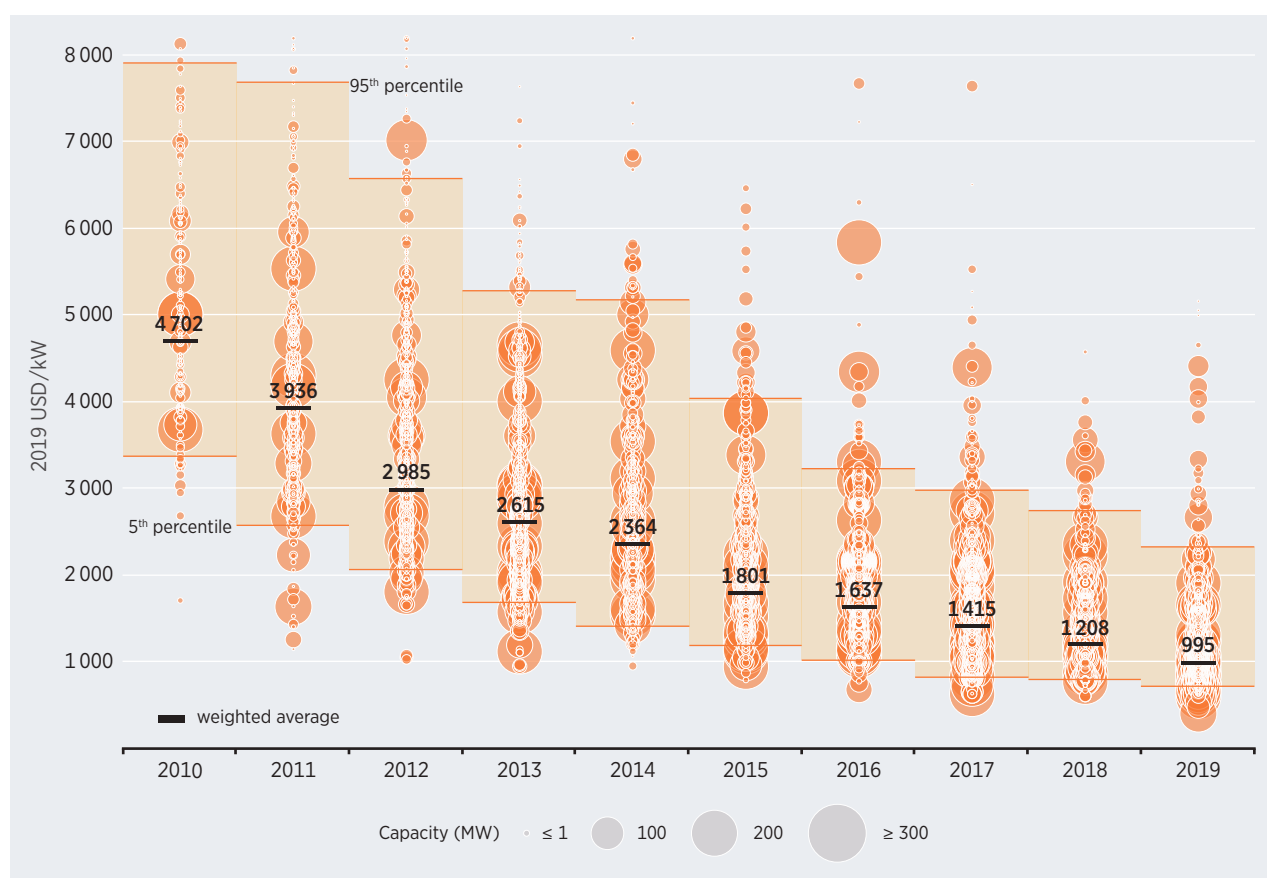
The global capacity weighted-average total installed cost of projects commissioned in 2019 was USD 995/kW (18% lower than in 2018 and 79% lower than in 2010). During 2019, the 5th and 95th percentile range for all projects fell to a range between USD 714/kW and USD 2 320/kW – numbers 10% and 16% lower than in 2018, respectively. With time, cost structures have continued to mature in an increasing number of markets and compared to 2010, the 5th and 95th percentile values were 79% and 71% lower, respectively (Figure 3.3).

The total installed cost reductions are related to various factors. Improved manufacturing processes, reduced labour costs and enhanced module efficiency (new technologies) are the key drivers of lower module costs. In addition, as project developers gain more experience and supply chain structures continue to develop in more and more markets, declining BoS¹⁷ costs have followed.

This has led to an increased number of markets where PV systems are achieving competitive cost structures and resulted in falling global weighted-average total installed costs. In 2019, significant total installed cost reductions have occurred across all the major markets such as China, India, Japan, Republic of Korea and the United States.

An increasing number of cost competitive projects in India led to weighted average total installed costs of USD 618/kW in 2019, around a fifth lower than in China. However, competitive costs structures are not confined to established markets anymore. For example, market growth in Ukraine and Viet Nam shows how PV continues to become a cost competitive technology choice in a growing number of settings. The weighted-average total installed cost in the Ukraine in 2019 was USD 874/kW and USD 1054/kW in Viet Nam. These values are increasingly at par – and sometimes even cheaper than the averages in a number of cost-mature markets. Furthermore,

Figure 3.3 Total installed PV system cost and weighted averages for utility-scale systems, 2010-2019



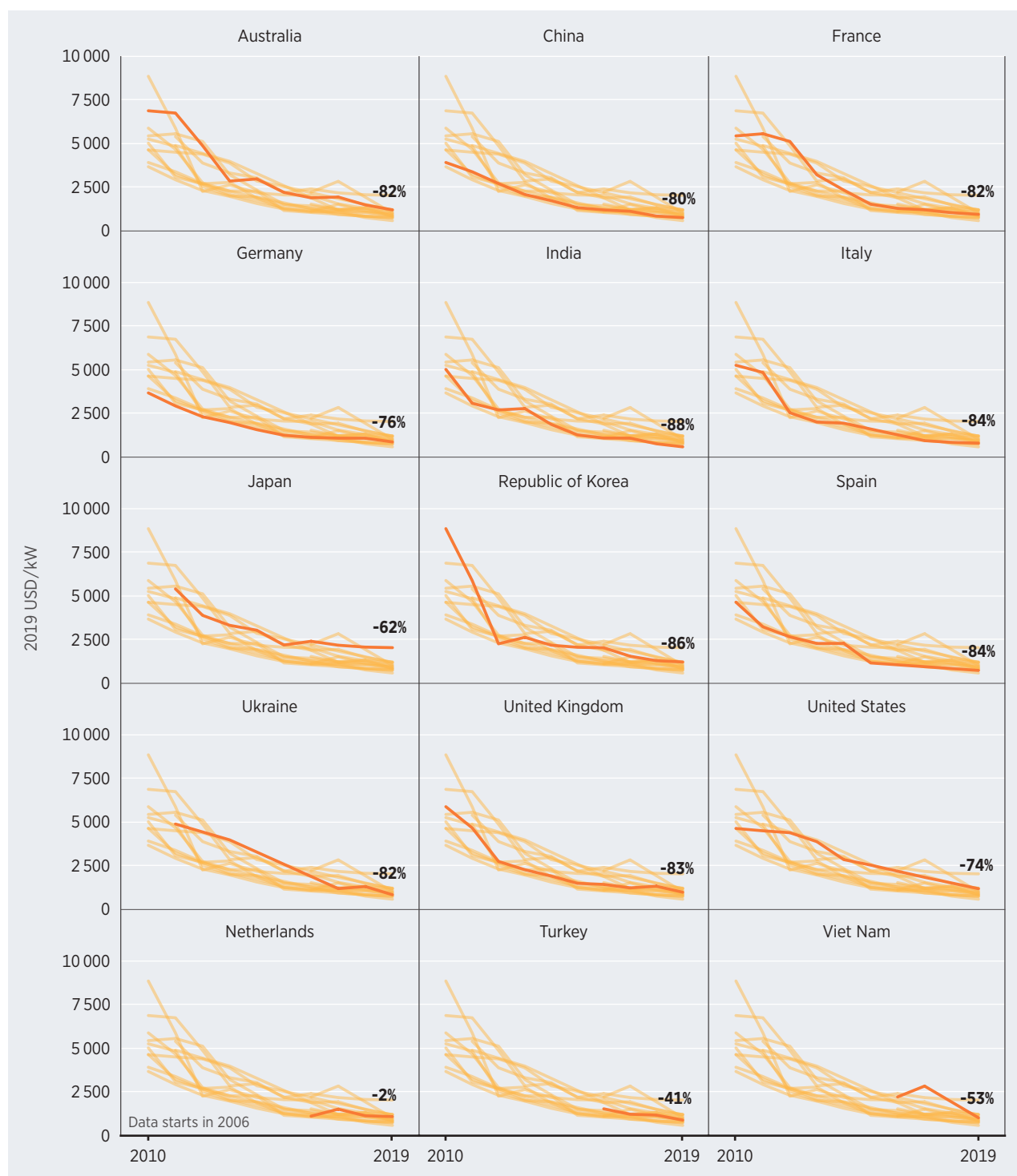
Source: IRENA Renewable Cost Database.

¹⁷ See Annex I for a description of all the BoS categories that are tracked by IRENA.

recent subsidy-free developments in Spain – a market that surged in 2019 after very modest activity in recent years – and elsewhere also highlight the improved competitiveness landscape for PV, globally. Between 2010 and 2019, total

installed costs have declined between 74% and 88% in markets where historical data is available back to 2010. Meanwhile, between 2016 and 2019, total installed costs in Viet Nam more than halved (Figure 3.4).

Figure 3.4 Utility-scale solar PV total installed cost trends in selected countries, 2010-2019



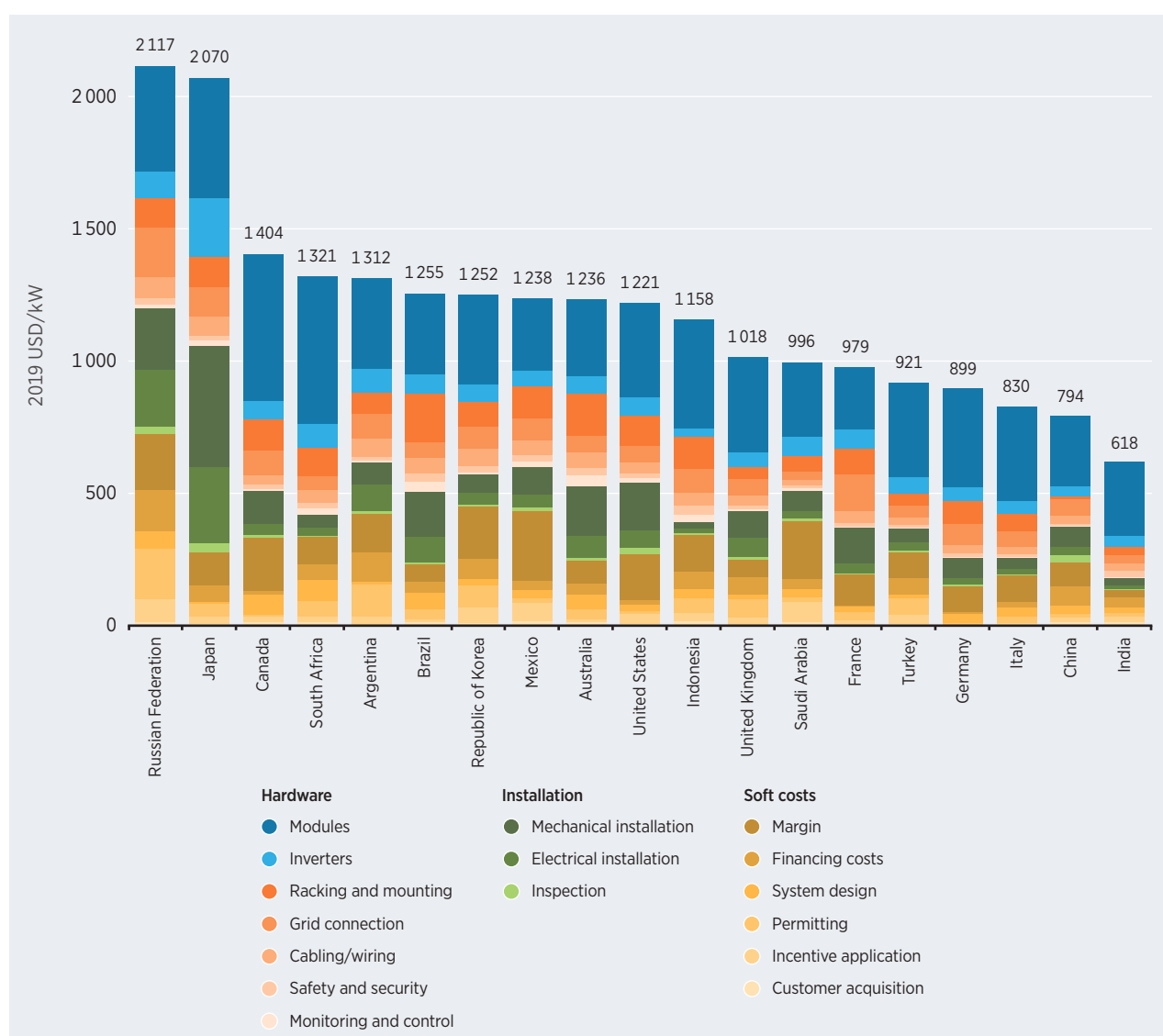
Source: IRENA Renewable Cost Database.

Though solar PV technology continues to mature, regional cost differences persist (Figure 3.5). This is true for the module and inverter costs components, but also for the BoS (the rest of the system components). At a global level, cost reductions for modules and inverters accounted for 62% of the global weighted-average total installed cost decline between 2010 and 2019. BoS¹⁸ costs are therefore also an important contributor to the declining global weighted-average total installed costs, with 13% of the global reduction coming from lower installation costs, 7% from racking, 3% from other BoS hardware (e.g., cables, junction boxes, etc.) and 15% from a range of smaller categories. This has been driven by

competitive pressures, greater installer experience, the spread of best practice installation and soft costs, and module efficiency improvements that reduce some area related BoS costs.

Understanding differences in the individual cost components of PV systems in the individual markets, however, remains key to understanding how to unlock further cost reduction potential. This is because there are a range of markets where competitive module and inverter costs are offset by BoS costs significantly above best practice levels. Therefore, adopting policies that can bring down BoS, and soft costs in particular, provides the

Figure 3.5 Detailed breakdown of utility-scale solar PV total installed costs by country, 2019



Source: IRENA Renewable Cost Database.

¹⁸ BoS costs in this chapter do not include inverter costs, which are treated separately.

opportunity of improving cost structures towards best practice levels. Reducing the administrative hurdles associated with the permit or connection application process is a good example of a policy that can unlock cost reduction opportunities.

As markets continue to mature, it is expected that some of the remaining cost differences among them will tend to decline. To track their development and be able to devise targeted policy changes that address remaining issues properly, a detailed understanding of individual cost components remains essential, however.

The country average for the total installed costs of utility scale solar PV in these countries ranged from a low of USD 618/kW in India to a high of USD 2 117/kW in the Russian Federation in 2019. The highest cost average was about three-and-a-half times more than the lowest, despite the convergence of installed costs in major markets in recent years.

On average, in 2019, BoS costs (excluding inverters) make up about 64% of total system costs in the countries in Figure 3.5. During 2016, they made up about half of the total system cost. This increased share highlights the increasing importance of BoS costs as module and inverter costs together continue to come down. In 2019, total BoS costs ranged from a low of 48% in India to a high of 76% in the Russian federation. Overall, soft cost categories for the evaluated countries made up around 40% of total BoS costs and about a quarter, on average, of the total installed costs. In 2016, these values were a third and 17% respectively.

In the residential PV sector, since 2010, the declining cost trend in installed costs has also been visible in a wide range of countries.

The residential, rooftop solar PV market has generally higher costs than utility-scale system due to their small-scale. Depending on the market, the total installed system costs (Table 3.1) decreased from between USD 4 277/kW and USD 7 756/kW in 2010 to between USD 840/kW and USD 4 096/kW in 2019 – a decline of between 47% and 80%. Since 2013, data for more markets beyond the early-adopter markets has also become available.

Compared to Germany, long the benchmark in terms of competitive small-scale systems, residential system costs since 2013 have generally remained within twice the German cost level (except for France in 2013 and the US markets). Since 2013, however, India has become the new benchmark for the lowest cost residential systems, although it has been joined by China in 2019. Costs since 2013 in the reported markets have been between two-and-a-half times and three times those of India, except in the US markets. There, they have been between three and five times higher.

The total installed system costs in the commercial markets shown in Table 3.1 decreased from between USD 5 405/kW and USD 8 534/kW in 2010 to between USD 760/kW and USD 3 081/kW in 2019 (a decline of between 64% and 86%). Since 2017, more data has become available, as new markets have emerged. Between 2017 and 2019 commercial costs in the markets evaluated fell between 62% in China and 95% in the United Kingdom. Except for the American markets, during that period costs have not exceeded two-and-a-half times those in India in any other commercial market.

CAPACITY FACTORS

By year commissioned, the global weighted-average capacity factor¹⁹ for new utility-scale solar PV increased from 13.8% in 2010 to 18.0% in 2019. This was predominantly driven by the increased share of deployment in sunnier locations. After increasing steadily every year between 2010 and 2018, the capacity factor seems to be stabilising around the 18% mark (Table 3.2).

The development of the global weighted-average capacity factor is a result of multiple elements working at the same time. Higher capacity factors in recent years have been driven by the shift in deployment to regions with higher irradiation, the increased use of tracking devices in the utility-scale segment in large markets and a range of other factors that have made a smaller contribution (e.g., reduction in system losses). Available data for the United States, especially, documents the increased use of trackers and their impact

¹⁹ 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 of this can be found in: Bolinger and Weaver, 2014; Bolinger et al., 2015.

Table 3.1 Residential and commercial sector solar PV total installed cost by country or state, 2010-2019

Sector	Market	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
		2019 USD/kW									
Residential	Australia	7 715	6 126	4 301	3 670	3 424	2 198	1 988	1 738	1 557	1 380
	Brazil				3 947	3 657	3 458	2 664	2 126	1 604	1 350
	China			2 823	2 432	2 330	1 672	1 591	1 436	1 079	840
	France		9 797	6 950	5 773	4 231	2 359	2 174	1 967	1 771	1 600
	Germany	4 277	3 634	2 712	2 414	2 229	1 750	1 704	1 645	1 746	1 646
	India				2 374	2 276	1 501	1 326	1 093	916	840
	Italy	6 949	6 106	4 031	3 660	2 438	1 983	1 803	1 676	1 527	1 460
	Japan	7 314	7 228	6 237	4 601	3 771	3 313	2 927	2 685	2 361	2 250
	Malaysia				2 871	2 861	2 423	2 227	1 792	1 466	1 191
	Republic of Korea				3 036	3 056	2 166	2 079	1 707	1 527	1 440
	South Africa				4 140	3 684	3 109	2 916	2 602	2 231	1 843
	Spain				2 871	2 438	1 758	1 633	1 509	1 445	1 410
	Switzerland				3 864	3 440	3 216	3 022	2 716	2 421	2 173
	Thailand				4 019	3 121	2 798	2 726	2 362	1 944	1 388
	United Kingdom				3 300	3 475	3 007	2 668	2 692	2 597	2 566
	California	7 756	7 325	6 323	5 475	5 155	5 231	5 053	4 529	4 294	4 096
	Other US states	7 705	7 049	5 697	4 921	4 954	4 925	4 280	3 844	3 702	3 652
Commercial	Australia					2 846	2 222	1 957	1 674	1 562	1 464
	Brazil							2 126	1 565	1 228	1 040
	China		3 193	2 495	2 118	1 661	1 403	1 285	1 226	936	760
	France	8 534	4 145	2 889	2 932	2 880	2 262	1 854	2 138	1 999	1 678
	Germany		3 496	2 259	1 927	1 691	1 267	1 354	1 290	1 260	1 130
	India								1 010	901	817
	Italy	5 405	4 611	2 600	2 053	2 016	1 571	1 442	1 311	1 181	1 140
	Japan			5 238	4 212	3 122	2 421	2 356	2 269	2 076	1 980
	Malaysia					2 650	1 885	1 818	1 271	1 053	0 921
	Republic of Korea								1 644	1 445	1 290
	Spain		4 305	3 756	3 519	3 168	1 437	1 421	1 249	1 140	1 080
	United Kingdom							1 884	1 730	1 662	1 647
	Arizona	7 032	6 218	5 480	4 341	3 574	3 834	3 437	3 107	2 687	2 480
	California	6 491	6 267	4 970	4 634	3 668	3 569	3 697	3 505	3 197	3 081
	Massachusetts	6 935	6 315	4 973	4 229	4 004	3 706	3 620	3 065	3 007	2 652
	New York	7 305	6 550	5 475	4 247	3 786	3 500	3 253	2 827	2 679	2 508

Source: IRENA Renewable Cost Database.

Table 3.2 Global weighted average capacity factors for utility-scale PV systems by year of commissioning, 2010–2019

Year	5 th percentile	Weighted average	95 th percentile
2010	10.5%	13.8%	23.0%
2011	10.1%	15.3%	26.0%
2012	10.5%	15.1%	25.4%
2013	11.9%	16.4%	23.0%
2014	10.8%	16.6%	24.4%
2015	10.8%	16.5%	29.0%
2016	10.7%	16.7%	25.9%
2017	11.5%	17.7%	27.0%
2018	12.3%	18.2%	27.0%
2019	10.7%	18.0%	23.9%

Source: IRENA Renewable Cost Database.

Note: These capacity factors are the AC-to-DC capacity factors, given that installed cost data in this report for solar PV (only) are expressed as per kilowatt direct current.

on capacity factors. It has been reported that tracking made up 69% of the capacity installed in United States in 2018, up from 26% in 2010 (Bolinger *et al.*, 2019).

A trend towards higher Inverter Load Ratios (ILR) is, however, complicating comparisons in some cases. In the United States, for example, the median ILR reached 1.33 in 2018 – its highest value reported so far and about a tenth higher than in 2010. Depending on the context, increasing the Direct Current (DC) array relative to the Alternating Current (AC) inverter capacity to achieve a higher ILR (also known as the DC/AC ratio) can be beneficial in reducing yield variability and enhancing revenue, depending on the context (Good and Johnson, 2016). The choice of the ILR is a system design consideration and is often influenced by the type of tracking used in projects, since fixed-tilt projects can benefit more from increased ILR values than systems with tracking devices. In the United States, fixed-tilt projects recorded a median ILR of 1.41. The corresponding value for tracked systems was 7% lower (Bolinger *et al.*, 2019).

All things being equal, increasing ILR would result in a reduction of the AC/DC capacity factor. The combination of increased deployment in areas with favourable solar resource conditions and the

increased use of tracking seem to have outweighed the effect of increasing ILR in the weighted-average values for the capacity factor in recent years. These factors seem to be balancing out and the weighted average capacity factor value in 2019 stayed almost flat from 2018 levels. However, better data is needed on ILR ratios globally to better assess these trends.

OPERATION AND MAINTENANCE COSTS

The O&M costs of utility-scale solar PV plants have declined in recent years. However, in certain markets, the share of O&M costs in total LCOE has risen, as capital costs have fallen faster than O&M costs. O&M cost declines have been driven by module efficiency improvements, that have reduced the surface area require per MW of capacity. At the same time, competitive pressures and improvements in the reliability of the technology have resulted in system designs optimised to reduce O&M costs and improved O&M strategies that take advantage of a range of innovations – from robotic cleaning to “big data” analysis of performance data to identify issues and preventative interventions ahead of failures – to drive down O&M costs and reduce downtime.

For the period 2018-2019, O&M cost estimates for utility-scale plants in the United States have been reported at between USD 10/kW and USD 18/kW per year (Bolinger *et al.*, 2019; EIA, 2020; NREL, 2018). If a central estimate of USD 14/kW is assumed, utility-scale O&M costs in the United States have halved since 2011. Recent costs there seem to be dominated by preventive maintenance and module cleaning, with these making up as much as 75% and 90% of the total, depending on the system type and configuration. The rest of the O&M costs can be attributed to unscheduled maintenance, land lease costs and other component replacement costs.

Average utility-scale O&M costs in Europe have been recently reported at USD 10/kW per year, with historical data for Germany suggesting O&M costs came down 85% between 2005 and 2017, to USD 9/kW per year. This result suggests there has been a reduction of between 15.7% and 18.2% with every doubling of the solar PV cumulative installed capacity (Steffen *et al.*, 2020; Vartiainen *et al.*, 2019).

For 2019, the solar PV LCOE calculations in this report assume utility-scale O&M costs of USD 18.3/kW per year for projects commissioned in the OECD. For projects commissioned in non-OECD countries during that year, USD 9.5/kW per year is assumed.²⁰ These are the estimated total “all-in” O&M costs, so include costs such as insurance and asset management costs that are sometimes not reported in all O&M surveys.

LEVELISED COST OF ELECTRICITY

The rapid decline in total installed costs, increasing capacity factors and falling O&M costs, have contributed to the remarkable reduction in the cost of electricity from solar PV and the improvement of its economic competitiveness.

The global weighted-average LCOE of utility-scale PV plants declined by 82% between 2010 and 2019, from around USD 0.378/kWh to just USD 0.068/kWh. This 2019 estimate also represents a 13% year-on-year decline from 2018. Globally, too, the range of LCOE costs continues to narrow.

The 5th and 95th percentile of projects in 2019 ranged from USD 0.052/kWh to USD 0.190/kWh. Which is a 72% and 63% decline in the 5th and 95th percentile values, respectively, compared with 2010. The 5th percentile value remained flat between 2018 and 2019, while the 95th percentile value declined 12%, during that period (Figure 3.6).

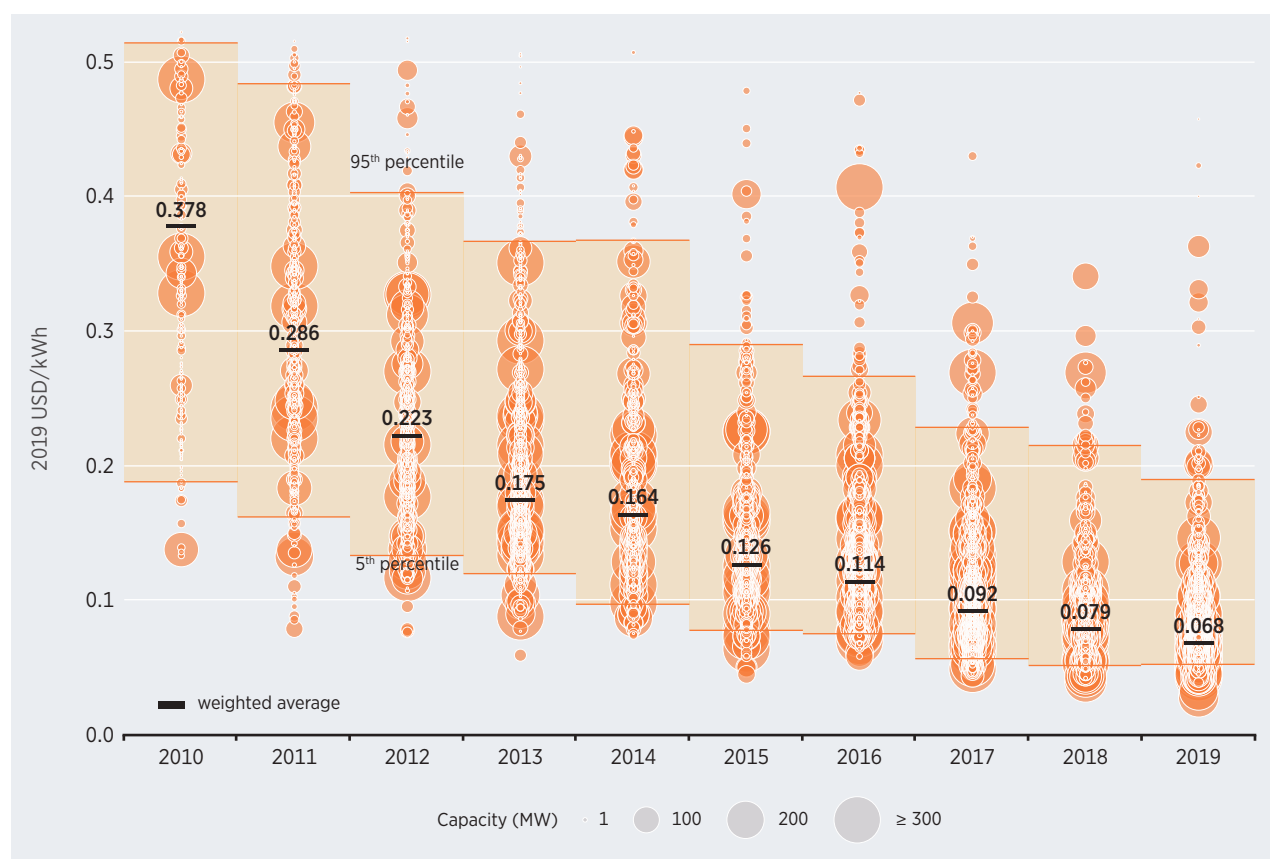
The downward trend in the LCOE of utility-scale solar PV by country is presented in Figure 3.7. Analysis of the markets where historical data is available back to 2010, shows that between 2010 and 2019, the weighted-average LCOE of utility-scale solar PV declined by between 66% and 85%, depending on the country.

The largest reduction in the utility-scale sector could be seen in India, where between 2010 and 2019, costs declined by 85%, to reach USD 0.045/kWh – a value 34% lower than the global weighted average for that year as reported in Figure 3.6. After India, China and Spain achieved the most competitive LCOEs, with values of USD 0.054/kWh and USD 0.056/kWh respectively for 2019 (a fifth and a quarter higher than in India). The LCOE of utility-scale PV in both the United States and Italy was USD 0.068/kWh, with a 14% year-on-year reduction between 2018 and 2019 in the former and a 5% reduction in the latter. In the United States, a market where BoS costs have remained stubbornly high in the past, this LCOE reduction was likely driven by BoS costs there falling by about a quarter during that period, showing a reversing trend in this respect.

Elsewhere, the LCOE of utility-scale PV in Japan was about two times higher than in India, given the LCOE in Japan declined only 4% (the lowest among markets evaluated). This was after the large-scale segment in Japan had shown little participation in recent solar auctions.

As discussed in Chapter 1, for OECD countries at least, the recent auction and tender results tend to suggest that the WACC assumptions used by IRENA (7.5% real, before tax) have started to diverge from what the average project can achieve. The LCOE values for countries with low interest rates in recent years, should therefore be

²⁰ See Annex I for a more details on O&M costs assumptions.

Figure 3.6 Global utility-scale solar PV project levelised cost of electricity and range, 2010-2019

Source: IRENA Renewable Cost Database.

treated with caution. Reducing the WACC to 5% in OECD countries would reduce the weighted average LCOE by around one-fifth from the values reported here. Future work by IRENA will collect financing data to develop more accurate, country-specific WACC data.

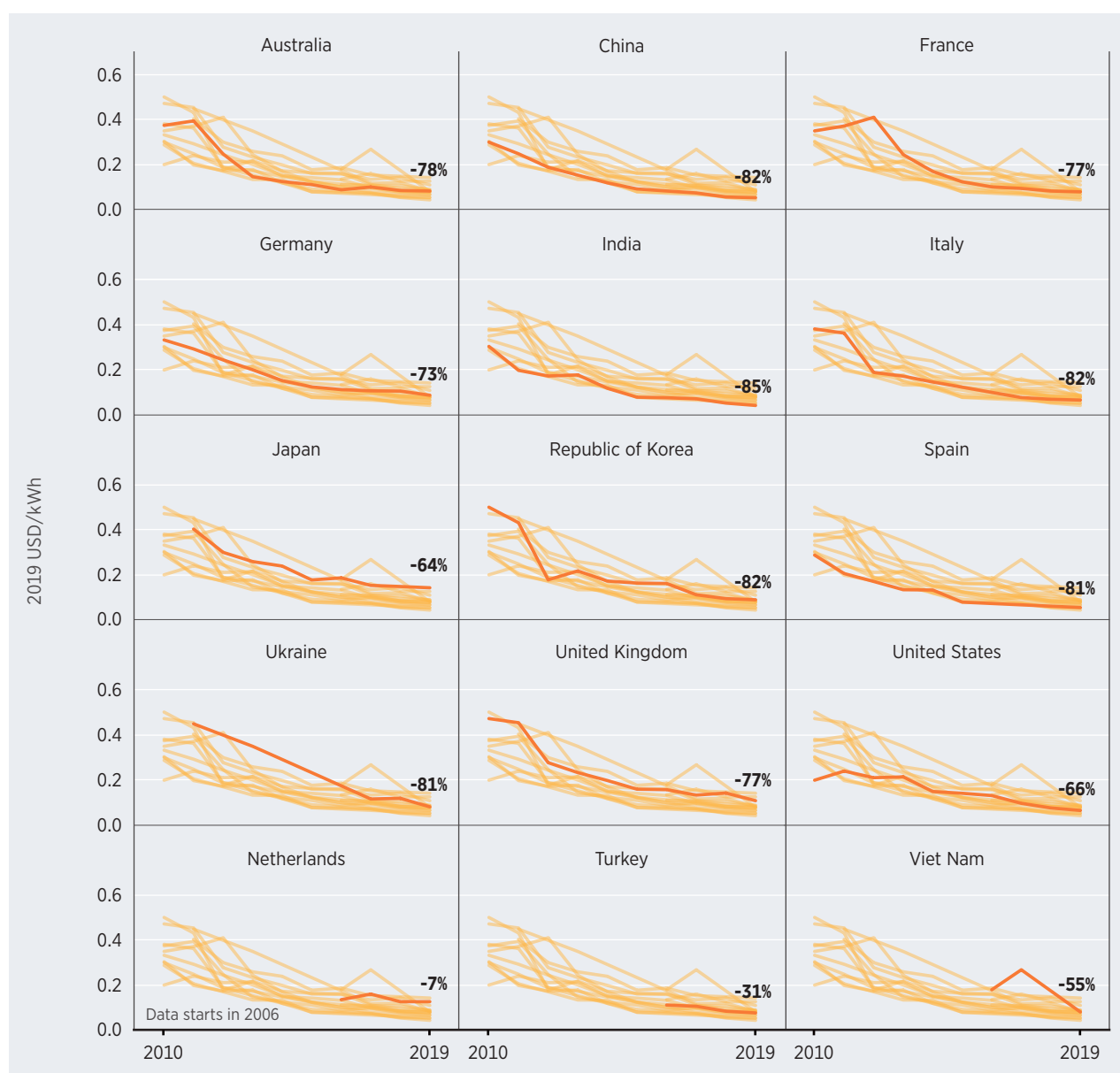
The LCOE of residential PV systems has also experienced a steep reduction. Assuming a 5% WACC,²¹ the LCOE of residential PV systems in the markets shown in Table 3.3 declined from between USD 0.301/kWh and USD 0.455/kWh in 2010 to between USD 0.063/kWh and USD 0.265/kWh in 2019 – a decline of between 42% and 79%.

Germany, a market that has been a major growth driver in residential solar PV over the last ten years, has very competitive total installed costs, yet relatively poor solar resources. The LCOE of German

residential systems more than halved between 2010 and 2019. The LCOE of residential costs in Japan declined 64% during the same period, during which, steeper LCOE reductions (by about three-quarters) occurred in other historical markets with better resources, such as Italy and Australia.

Available data since 2013 from India, China, Australia, Spain, and Malaysia shows that in these locations, which have good irradiation conditions and have experienced increasingly competitive total installed costs, very low LCOEs can be achieved. In these low-cost markets, the LCOE range declined between 2013 and 2019, from between USD 0.156/kWh and USD 0.220/kWh to between USD 0.071/kWh and USD 0.121/kWh – a decline of between 46% and 57%. The LCOE of residential PV systems in India, China and Australia

²¹ This is lower than the 7.5% for the OECD and China and 10% elsewhere assumed for utility-scale projects in all the other LCOE calculations in this report. This is based on the lower expected returns required by the owners of the assets in these sectors where self-consumption is often a major driver.

Figure 3.7 Utility-scale solar PV weighted average cost of electricity in selected countries, 2010-2019

Source: IRENA Renewable Cost Database.

has stayed below USD 0.096/kWh since 2017. During 2019, the most competitive residential PV LCOE costs occurred in India, at USD 0.063/kWh, with Chinese costs just 7% higher (Table 3.3).

In 2019, the lowest average LCOE for commercial PV up to 500 kW could be found in India and China, at USD 0.062 and USD 0.064/kWh, respectively (Table 3.3). Between 2017 and 2019, the LCOEs in these markets have fallen 12% and 26%, respectively. Since 2017, these two markets have been more competitive in terms of the LCOE

of commercial systems, after having undercut what was by then the reference LCOE benchmark for commercial systems – Australia. This is despite a 20% LCOE reduction in the Australian market between 2017 and 2019. The markets with the highest LCOE in 2019 were the United Kingdom and Massachusetts, at USD 0.187/kWh and USD 0.186/kWh, respectively. The overall commercial PV LCOE range by markets declined from between USD 0.259 and USD 0.625/kWh in 2010 to USD 0.062 and USD 0.187/kWh in 2019 – a reduction of between 70% and 76%.

Table 3.3 Residential and commercial sector solar PV levelised cost of electricity by country or state, 2010-2019

Sector	Market	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
		2019 USD/kWh									
Residential	Australia	0.319	0.258	0.187	0.163	0.154	0.106	0.098	0.089	0.082	0.075
	Brazil				0.261	0.244	0.232	0.187	0.155	0.125	0.111
	China			0.162	0.144	0.139	0.107	0.103	0.096	0.079	0.067
	France		0.712	0.516	0.435	0.330	0.201	0.188	0.174	0.161	0.149
	Germany	0.301	0.261	0.204	0.185	0.174	0.144	0.141	0.138	0.144	0.138
	India				0.132	0.128	0.093	0.085	0.074	0.067	0.063
	Italy	0.405	0.360	0.248	0.228	0.162	0.137	0.128	0.121	0.113	0.109
	Japan	0.455	0.450	0.393	0.298	0.250	0.224	0.202	0.188	0.169	0.163
	Malaysia				0.185	0.185	0.161	0.151	0.127	0.109	0.095
	Republic of Korea				0.224	0.225	0.170	0.164	0.141	0.130	0.125
	South Africa				0.200	0.180	0.156	0.148	0.134	0.119	0.102
	Spain				0.181	0.158	0.122	0.116	0.109	0.106	0.104
	Switzerland				0.304	0.274	0.259	0.246	0.225	0.205	0.188
	Thailand				0.250	0.201	0.183	0.179	0.159	0.137	0.106
	United Kingdom				0.327	0.342	0.302	0.274	0.276	0.268	0.265
	California	0.306	0.290	0.253	0.222	0.210	0.213	0.207	0.187	0.179	0.171
	Other US states	0.304	0.280	0.230	0.202	0.203	0.202	0.178	0.162	0.157	0.155
Commercial	Australia					0.131	0.107	0.097	0.086	0.082	0.078
	Brazil							0.155	0.123	0.104	0.093
	China		0.180	0.147	0.129	0.107	0.094	0.089	0.086	0.072	0.064
	France	0.625	0.324	0.237	0.240	0.237	0.194	0.166	0.186	0.176	0.154
	Germany		0.253	0.176	0.155	0.140	0.114	0.119	0.115	0.114	0.105
	India								0.071	0.066	0.062
	Italy	0.322	0.279	0.171	0.141	0.139	0.115	0.108	0.101	0.094	0.092
	Japan			0.335	0.276	0.213	0.172	0.169	0.164	0.153	0.147
	Malaysia					0.173	0.132	0.128	0.099	0.087	0.080
	Republic of Korea								0.137	0.125	0.115
	Spain		0.257	0.228	0.215	0.197	0.105	0.105	0.096	0.090	0.087
	United Kingdom							0.207	0.194	0.189	0.187
	Arizona	0.279	0.249	0.222	0.180	0.152	0.162	0.147	0.135	0.120	0.112
	California	0.259	0.251	0.203	0.191	0.156	0.152	0.157	0.150	0.138	0.134
	Massachusetts	0.433	0.397	0.320	0.277	0.264	0.247	0.242	0.210	0.206	0.186
	New York	0.439	0.397	0.337	0.268	0.243	0.227	0.213	0.189	0.181	0.171

Source: IRENA Renewable Cost Database.

Note: Unlike all other LCOE data presented in this report, the LCOE data in this table is calculated using a 5% WACC.

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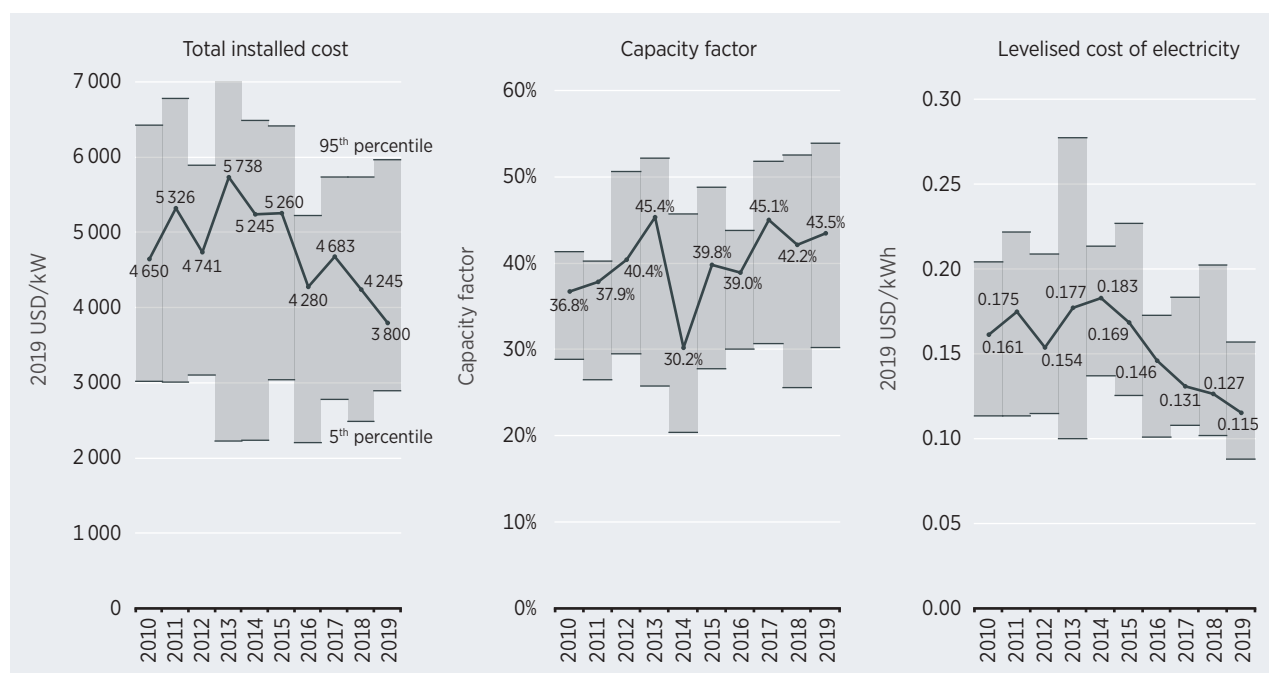


OFFSHORE WIND

HIGHLIGHTS

- The global weighted-average LCOE of offshore wind declined by 29% between 2010 and 2019, from USD 0.161 to USD 0.115/kWh, with a 9% reduction year-on-year in 2019. Auction and tender results suggest that from 2023, the cost of electricity will fall to between USD 0.05/kWh and USD 0.10/kWh and can be achieved even in relatively new markets.
- Between 2010 and 2019, global weighted-average total installed costs fell 18%, from USD 4 650 to USD 3 800/kW. The global weighted-average total installed cost peaked at USD 5 740/kW in 2013, representing a 33% drop to its 2019 value.
- Global cumulative installed capacity of offshore wind increased by over ninefold between 2010 and 2019, from 3.1 GW to 28.3 GW. This was largely driven by installations in Europe, which accounted for 78% of cumulative global deployment by the end of 2019.
- Technology improvements, including larger turbines and longer blades, with higher hub heights, and access to better wind resources – as offshore wind farms moved farther offshore – have resulted in the global weighted-average capacity factor increasing from 37% in 2010 to 44% in 2019.
- Total installed cost and LCOE reductions have been driven by both technology improvements and the growing maturity of the industry. A range of factors, including developer experience, greater product standardisation, manufacturing industrialisation, regional manufacturing and service hubs, and economies of scale have all contributed to cost declines. This has been facilitated by clear deployment and, in many cases, manufacturing policies that have supported this growth and the benefits of scale evident in the industry today.

Figure 4.1 Global weighted average and range of total installed costs, capacity factors and LCOE for offshore wind, 2010-2019



Source: IRENA Renewable Cost Database.

OFFSHORE WIND INDUSTRY TRENDS

While offshore wind was a relatively new and developing technology in 2010, this has since changed, with the technology maturing rapidly. Indeed, there was a ninefold increase in cumulative deployed capacity between 2010 and 2019, from 3 GW to 28 GW. Europe accounted for over 78% of this cumulative installed capacity (IRENA, 2020a).

Currently, offshore wind makes up just under 5% of global wind (onshore and offshore) deployment. Yet, plans and targets for future deployment have been expanding, as costs decrease and the technology heads towards maturity. Annual capacity additions have averaged over 4.5 GW between 2017 and 2019 inclusive.

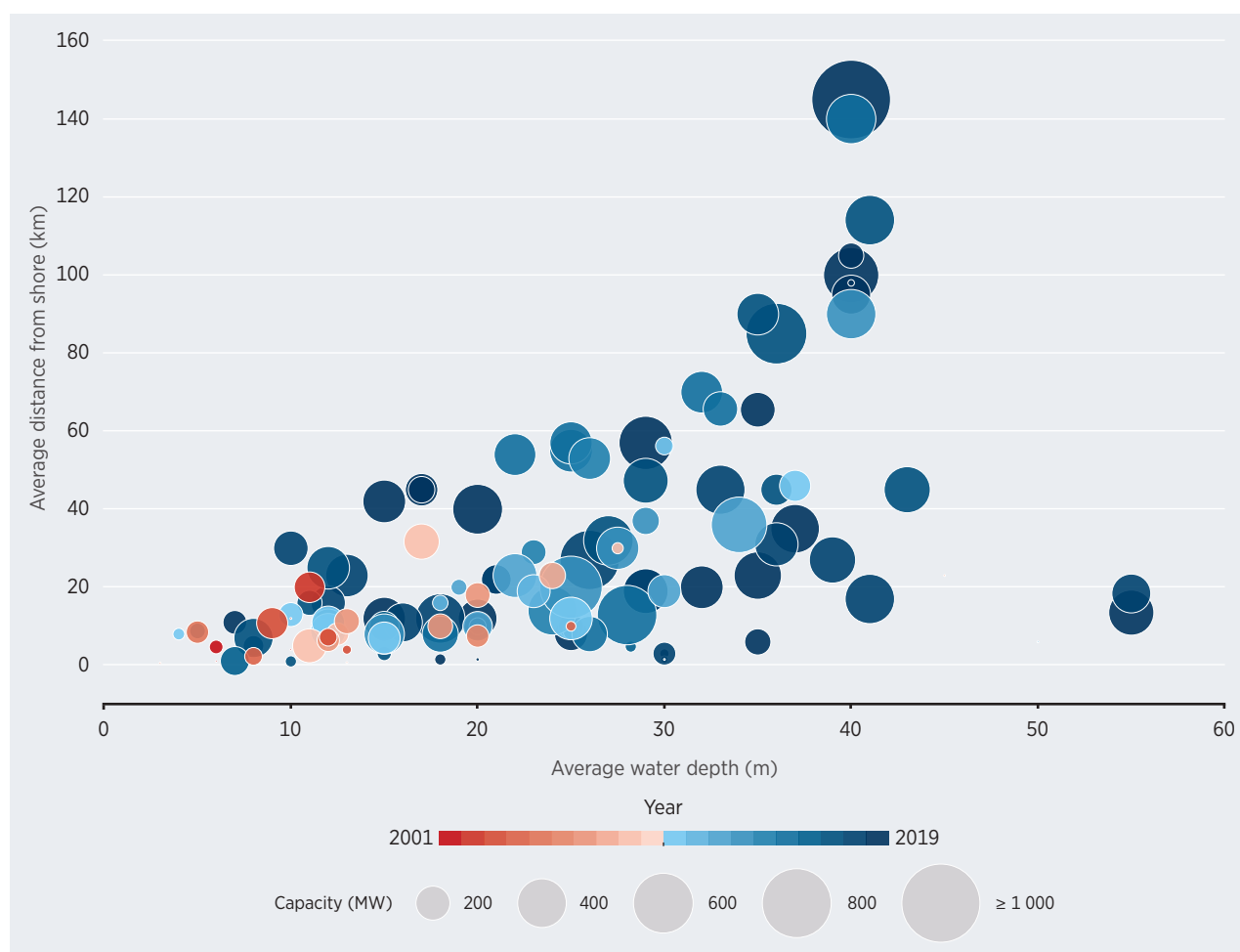
In comparison to onshore wind projects, offshore wind farms must contend with installation, operation and maintenance in harsh marine environments. This tends to increase costs and offshore wind projects have significantly higher lead times. The planning and project development required for offshore wind farms is more complex and construction even more so, with the latter, in particular, increasing total installed costs. Given their offshore location, they also have higher grid connection and construction costs. Offshore wind project installed costs peaked around the period of 2012-13, as projects were sited farther from shore, in deeper waters, and have been using more advanced technology.

With the recent increase in deployments, cost reductions have been unlocked. This has been driven by technology improvements, economies of scale and increase in developer and turbine manufacturer experience. However, the increasing maturity of the industry is also reflected in cost saving programmes such as the standardisation of turbine and foundation designs, the industrialisation of manufacturing for offshore wind components in regional hubs, and the increasing sophistication and speed of installation practices. Installation times and costs per unit of capacity are falling with developer experience, the use of specialised ships designed for offshore wind work and increases in turbine size that amortise installation efforts for one turbine over ever larger capacities.

The introduction of specialised ships for maintenance has also helped lower O&M costs. However, the scale and optimisation benefits of providing O&M to large offshore wind farms zones is also playing a role, as is the increased wind turbine availability as manufacturers are constantly learning from experience and improving their products. Increasingly sophisticated data mining of turbine performance data and predictive maintenance programmes that are designed to intervene before costly failures are also contributing to lower O&M costs. The latter is evident in everything from larger, higher rated offshore wind turbines to improved foundations.

Figure 4.2 presents the trend between 2001 and 2019 of offshore wind farms in deeper waters and farther from shore. In 2001, the weighted-average characteristics of the commissioned offshore wind farms in that year were a 25 MW windfarm in a water depth of 7 m, roughly 5 km from shore. These figures have significantly increased since, with the weighted-average distance to shore and water depth in 2019 standing at 60 km and 32 m, respectively, based on project data in the IRENA renewable cost database. Distance from a shore/port suitable for installation and water depth both impact total installed costs, given the return trips to port for foundations and turbines during installation, and size of the foundations. The distance to port also has an impact on O&M costs and decommissioning costs. In European waters, the trend to site wind farms farther from shore has also been correlated with harsher weather conditions making installation more difficult, this has added time and cost to the already high logistical costs when projects are farther from ports (EEA, 2009).

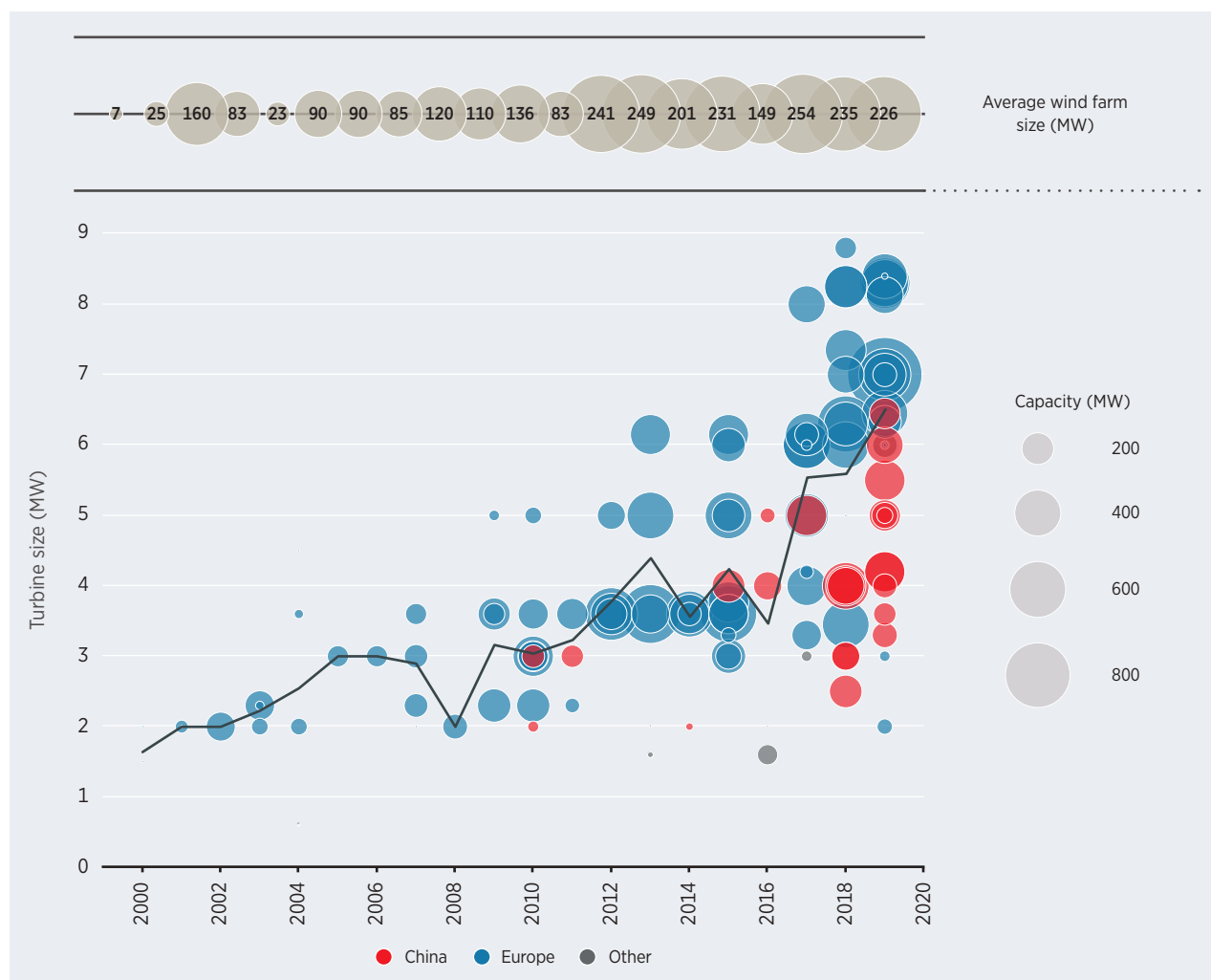
In addition to offshore wind farm installations increasingly being located farther from ports and anchored in deeper waters, there has also been a trend towards higher capacity turbines, with higher hub heights and longer, more efficient and durable blades. These are now specially designed for the offshore sector and to increase energy capture. This is crucial in reducing the LCOE of offshore projects. The larger turbines also provide economies of scale, with a reduction in installation costs and an amortisation of project development and O&M costs (Figure 4.3).

Figure 4.2 Average distance from shore and water depth for offshore wind, 2000-2019

Source: IRENA Renewable Cost Database.



Figure 4.3 Project turbine size and global weighted average turbine size and wind farm capacity for offshore wind, 2000-2019



Source: IRENA Renewable Cost Database.

Between 2010 and 2019, the weighted-average turbine capacity increased 114%, from 3 MW to 6.5 MW. Projects commissioned in 2019 had a turbine rating 16% higher than the average for 2018 of 5.6 MW. While less significant than the higher turbine rating, the increase in rotor diameter is also important, as this allows for higher energy capture from the turbines and smoother energy output. This makes offshore wind particularly useful in reducing overall intermittency, if wind deployment displaces more conventional baseload generation. Between 2010 and 2019, the weighted-average rotor diameter for deployments grew by 52%, from 99 m to 151 m, based on available data for active projects.

TOTAL INSTALLED COSTS

Compared to onshore wind, offshore wind farms have higher total installed costs. Having to install and operate wind turbines in the harsh marine environment offshore increases costs. Planning and project development costs are higher and lead times longer as a result. Data must be collected on seabed characteristics and the site locations offshore wind resource, while permitting and environmental consents are often more complex and time consuming. Logistical costs are higher the farther the project is from a suitable port, while greater water depths require more expensive foundations.

Offshore wind, however, has the advantage of economies of scale, meaning that many of these costs are not disproportionately that much higher than for onshore wind. At the same time, the higher capacity factors offshore, more stable wind output (due to higher average wind speeds and reduced wind shear and turbulence), that also coincides with winter demand peaks in Europe ensures offshore wind output is of higher value to the electricity system than onshore wind. The promise of offshore wind has always been evident and in the last few years, it has started to realise its potential from scaling. Between 2010 and 2019, the average offshore wind project size increased by 67%, from 136 MW to 226 MW. There are currently projects being deployed in 2020 and beyond that have capacities exceeding 1 GW.

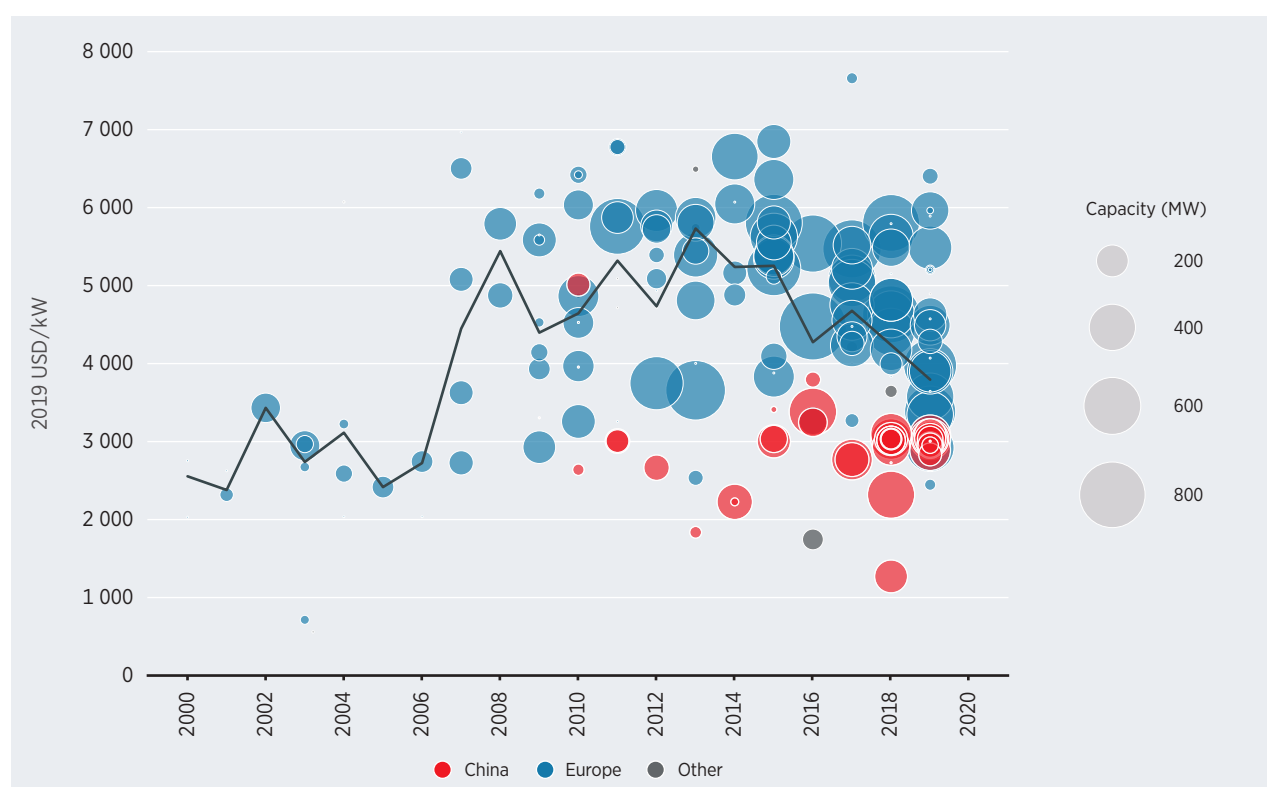
The global weighted-average total installed cost of offshore wind farms increased from an average of around USD 2 600/kW in 2000 to an average of over USD 5 000/kW between 2011 and 2014, as projects moved farther from shore and into deeper waters (Figure 4.4). The global weighted-average total installed cost peaked in 2013, when

it reached USD 5 740/kW, and has since fallen to USD 3 800/kW in 2019.

A number of factors explain the increase that occurred after 2008, including:

- The shift to projects in deeper waters and farther from shore/ports increased logistical costs, installation costs and foundation costs.
- the increasing scale and complexity of projects required a proportional increase in project development costs (surveys, licensing, etc.)
- The industry was still in its infancy and the specialised installation vessels of today were not available, resulting in less efficient installation processes. Additionally, supply chains were not yet optimised, operating at scale and with widespread competition.
- Rising commodity prices in this period also had a direct impact on the cost of transportation and on the offshore wind materials used in turbines, their foundations, transmission cabling and other components (IRENA, 2019a)

Figure 4.4 Project and weighted average total installed costs for offshore wind, 2000-2019



Source: IRENA Renewable Cost Database.

Some of the contributing factors to cost increase, such as supply chain bottlenecks for turbines and cables and logistics issues, were transient (Green, R., 2011; Anzinger, N., 2015). Consequently, the weighted-average total installed costs have since followed a downward cost reduction trend, falling by around a third from their peak in 2013 to a global weighted-average of USD 3 800/kW for projects commissioned in 2019. Major support came from lower commodity prices; lower risks from stable government policies and support schemes; improved turbine designs; standardisation of design and industrialised manufacturing; improvements in logistics – especially with specialised installation vessels and larger turbines for offshore wind; and economies of scale from clustered projects in Europe. Yet, due to the relatively thin market compared to onshore wind and solar PV, the global weighted-average total installed cost by year remains volatile.

The yearly volatility in total installed costs is due to site-specific nature of offshore wind projects and the differences in market maturity and the scale of local or regional supply chain. As deployment in each year is distributed slightly differently across markets this can drive yearly volatility. For instance, total installed costs observed in China are lower than in Europe due to lower commodity prices and labour costs, but also because most Chinese deployments so far are in shallow waters, nearshore. But there are drivers for differences in

total installed costs by country. The most notable is who is responsible for the wind farm-to-shore transmission assets. In some countries the transmission assets are owned by the national or regional transmission network, in some cases they are owned by the wind farm developer.

Looking at the total installed cost trends by country is therefore important to understand how cost structures are evolving. Germany, which has the second largest cumulative wind deployment globally (roughly 7.5 GW), experienced a decline in weighted-average total installed cost between 2010 and 2019 of 37% – from USD 6 428/kW to USD 4 077/kW (Table 4.1). In Denmark and China, the grid connection assets are developed and owned by public entities or the transmission network owner, lowering the project-specific installed costs. As a result, the project-specific weighted-average total installed costs in 2019 were USD 2 928/kW in Denmark and USD 3 012/kW in China. There was up to a 1% increase in the weighed-average total installed costs in the UK and Japan. In the UK, the higher total installed costs could be attributed to, among other factors, the fact that the projects deployed in 2019 have the highest weighted-average distance to shore and water depths of 113 km and 43m, which is 87% and 35% respectively, above the average distance from shore (60 km) and water depth (32m) in 2019. In Japan, the market remains in the pre-commercial deployment phase.

Table 4.1 Regional and country weighted-average total installed costs and ranges for offshore wind, 2010 and 2019

	2010			2019		
	5 th percentile	Weighted average	95 th percentile	5 th percentile	Weighted average	95 th percentile
	(2019 USD/kW)					
Asia	4 801	4 464	2 646	3 784	3 014	2 842
China	4 782	4 424	2 646	3 059	3 012	2 842
Europe	6 179	4 658	3 265	5 992	4 094	2 928
Belgium	6 041	6 041	6 041	3 907	3 907	3 907
Denmark	3 265	3 265	3 265	2 928	2 928	2 928
Germany	6 428	6 428	6 428	5 958	4 077	3 352
Japan	4 877	4 877	4 877	4 900	4 900	4 900
United Kingdom	4 782	4 534	3 975	5 677	4 580	3 583

Source: IRENA Renewable Cost Database.



The cost breakdown for offshore wind farms differs from onshore wind farms. Offshore, turbines (including towers) generally account for between 34% and 54% of the total installed cost (IEA *et al.*, 2018; Tyler Stehly, 2018; Crown Estate; and BVG Associates, 2019). Other costs, however – including installation, foundation, and electrical interconnection – are significant, and take up a sizeable share of the total installed costs. Globally, installation costs can account for up to 19% of total installed costs, while contingency/other costs, electrical interconnection²² and foundation costs can account for over 22%. Development costs, which includes planning, project management and other administrative costs, comprises up to 5% of total installed costs. Offshore wind site characteristics and country policies can also cause differences in the cost breakdown. In the Netherlands, Denmark and China, for example, developers are not responsible for electrical interconnection costs (besides the cost of electrical arrays for connecting the turbines).

CAPACITY FACTORS

The range of capacity factors for offshore wind farms is very wide. This is due, first of all, to differences in the meteorology of the different locations where the wind farms are deployed. Second, it is influenced by the technology used and the configuration of the wind farm, *i.e.* the optimal turbine spacing to minimise wake losses and increase energy yields. Optimisation of the O&M strategy over the life of the project is also an important determinant of the realised lifetime capacity factor.

Between 2010 and 2019, the global weighted-average capacity factor of newly commissioned offshore wind farms grew from 37% to 44%. In 2019, the capacity factor range (5th and 95th percentile) for newly installed projects was between 30% and 55%. The weighted-average capacity factor for projects commissioned in Europe increased by one-fifth (or 8 percentage points) from 39% in 2010 to 47% in 2019. Capacity factors are lower in China than Europe, given that Chinese projects tend to be located closer to shore and are sited in lower

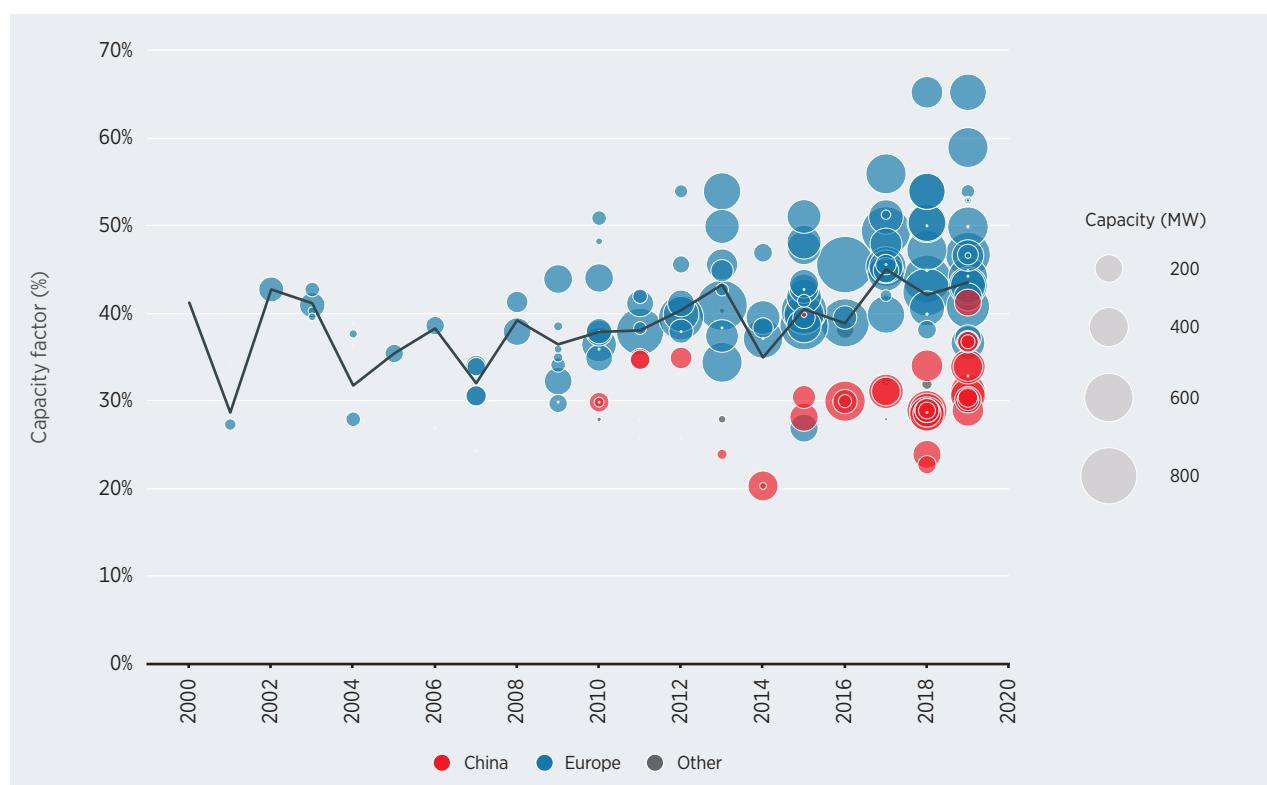
wind speed locations, than Europe. China also lags Europe in terms of turbine technology, typically using cheaper, smaller turbines that harvest less wind from available wind resources than today's latest turbines. As a result, the weighted-average capacity factor for projects commissioned in China in 2019 was 33% and in Europe it was 47%. In Europe, the 5th and 95th percentile capacity factor for projects commissioned in 2019 was 37% and 58%, compared to 30% and 39% in China.

Capacity factors have been rising due to larger wind turbines, with higher hub heights and larger swept areas that harvest more electricity from the same resource than older machines. There has also been a contribution from reduced downtime as manufacturers have integrated experience from operating wind farm models into more reliable new designs. It is also worth noting the experience in optimising O&M practices to reduce unscheduled maintenance that has been

unlocked by improvements in data collection and analytics, allowing for predictive maintenance and production output optimisation. In addition, improvements in the development stage, due to greater experience, have led to better methods for wind resource characterisation when it comes to identifying the best sites, and improved wind farm designs that optimise operational output.

For the period 2010 to 2019, an examination of weighted-average capacity factor improvements in countries with offshore wind installations shows that the greatest improvement was in the United Kingdom, where there was a 46% increase over the period (Table 4.2). Germany was the exception to generally increasing capacity factors over the period. This can be attributed to the already relatively high capacity factor achieved in 2010, significantly above its peers, and the impact of projects in Baltic Sea that experience lower wind speeds (Wehrmann, B., 2020).

Figure 4.5 Project and weighted average capacity factors for offshore wind, 2000-2019



Source: IRENA Renewable Cost Database.

22 This includes substations (offshore and onshore), electrical array cabling and export cabling

Table 4.2 Weighted average capacity factors for offshore wind projects in six countries, 2010 and 2019

	2010	2019	Percentage change 2010-2019
	%		
United Kingdom	36	52	↑ 46%
Belgium	38	43	↑ 14%
Denmark	44	50	↑ 13%
China	30	33	↑ 10%
Japan	28	30	↑ 7%
Germany	46	44	↓ 3%

Source: IRENA Renewable Cost Database.

OPERATION AND MAINTENANCE COSTS

O&M costs for offshore wind farms are higher than those for onshore wind. This is mainly due to the harsher, marine environment and higher costs for access to the wind site for performing maintenance on turbines and cabling. The latter is heavily influenced by weather conditions and the availability of skilled personnel and specialised vessels.

As with onshore wind, however, there is limited data available for offshore wind O&M costs. There is also general uncertainty around lifetime O&M costs for offshore wind, owing to limited operational experience, especially in sites farther offshore. As mentioned in the capacity factor discussion, O&M practices are being continuously refined to reduce costs and improve availability. As a result of improved capacity factors, and due to increased competition in O&M provision, O&M costs per kWh have been falling through time.

For 2018, representative ranges for current projects fell between USD 70/kW per year to USD 129/kW per year (IEA *et al.*, 2018; Ørsted, 2019;

Stehly, T. *et al.*, 2018). The lower range was observed for projects in established European markets and in China, usually with sites closer to shore. The range is broad because the O&M costs vary depending on local O&M optimisation, synergies from offshore wind farm zone clustering, as well as on the approach taken by the offshore wind farm owners after the initial turbine OEM warranty period. As the sector has grown, increased competition in O&M provision has emerged and has resulted in a variety of strategies to minimise O&M costs (e.g., the use of independent service providers, turbine OEMs service arms, in-house O&M, marine contractors, or a combination thereof). Besides the impact of experience and competition on O&M cost reduction, higher turbine ratings have reduced the unit O&M costs. An example of the O&M cost reduction impact from these factors comes from Ørsted – a major offshore wind developer with a portfolio of up to 9.9 GW of offshore wind farms in operation or under construction globally – who have been able to reduce O&M costs from 2015 to 2018 by over 43%, from USD 118 /kW/year to USD 67/kW/year (Ørsted, 2019).

The global weighted-average total installed cost of offshore wind projects peaked in 2013, when it reached USD 5 740/kW, and has since fallen to USD 3 800/kW in 2019.

LEVELISED COST OF ELECTRICITY

In recent years, increasing experience, advances in wind turbine technology, the establishment of optimised local and regional supply chains, increasing competition, and strong policy and regulatory support have resulted in a steady pipeline of projects, that have been increasingly competitive.

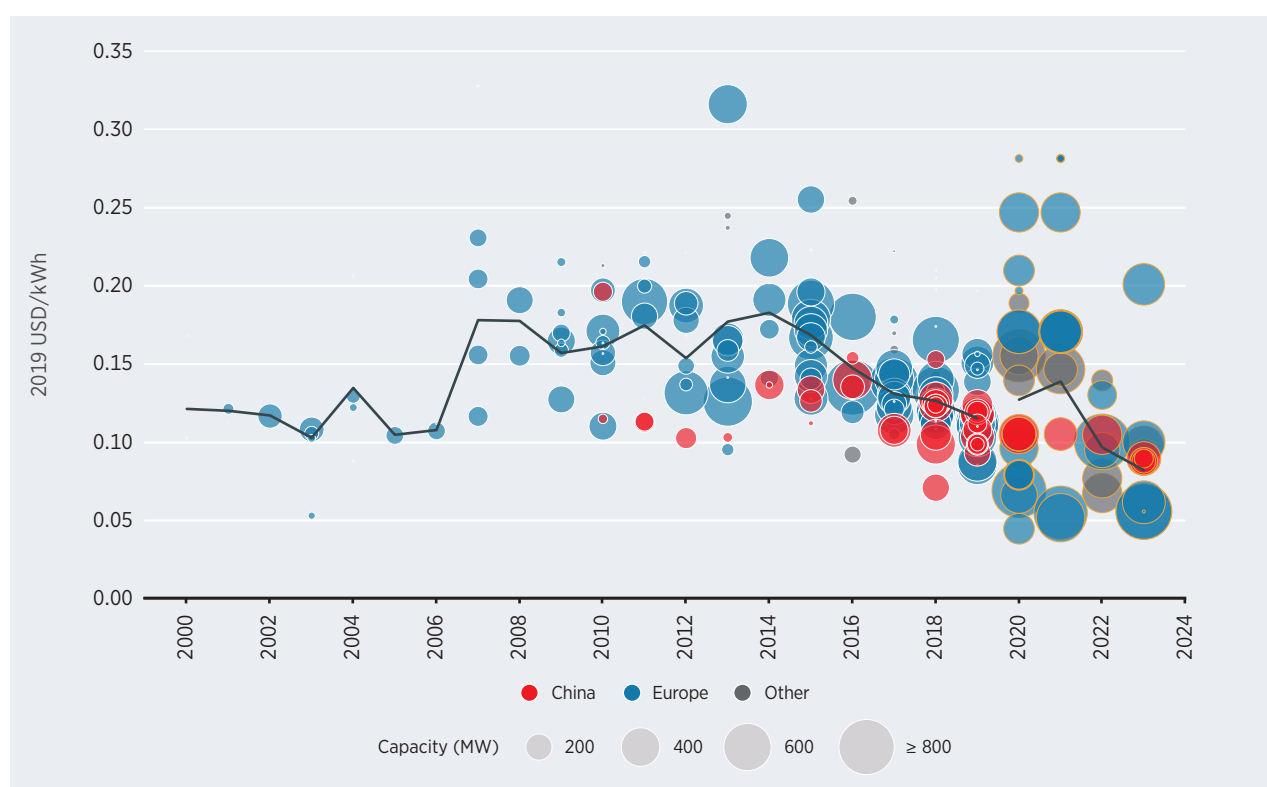
Between 2010 and 2019, the global weighted-average LCOE of offshore wind fell 29%, from USD 0.161/kWh to USD 0.115/kWh (Figure 4.6). Year-on-year, in 2019, weighted-average LCOE fell 9% from its 2018 value of USD 0.127/kWh. From its peak in 2014, the global weighted-average LCOE of offshore wind fell by 37%.

Denmark had the lowest weighted-average LCOE for projects commissioned in 2019, at USD 0.087/kWh (Table 4.3). The country was the first to pioneer offshore wind at a commercial-scale, with the commissioning of the the Vindeby wind project in 1991. Denmark's low LCOE is driven by experience, projects that are located

close to shore and in shallower waters than many of its neighbours and the fact that wind farm-to-shore transmission assets are not the responsibility of the project developer. Of the countries for which data is available since 2010 in Europe, Belgium saw the highest percentage reduction (40%) in country weighted-average LCOE values between 2010 and 2019. But it also had the highest starting point.

As Figure 4.6 shows, the recent auction and PPA results for projects expected to be commissioned in 2023 represent a step change in competitiveness, with prices falling into the USD 0.050 to USD 0.10/kWh range. The decline to a weighted-average price of USD 0.082/kWh in 2023 for the data available in the IRENA Auction and PPA database implies an additional 29% reduction over the 2019 global weighted-average LCOE. This shows that larger LCOE reductions are expected in the 2020s. Care should be taken in interpreting the Auction and PPA results, as discussed in Chapter 1, however, they provide a clear indication of where project LCOEs are moving.

Figure 4.6 Offshore wind project and global weighted average LCOEs and auction/PPA prices, 2000-2023



Source: IRENA Renewable Cost Database.

Table 4.3 Regional and country weighted average LCOE of offshore wind, 2010 and 2019

	2010			2019		
	5 th percentile	Weighted average	95 th percentile	5 th percentile	Weighted average	95 th percentile
	(2019 USD/kW)					
Asia	0.214	0.214	0.214	0.115	0.117	0.189
China	0.116	0.177	0.189	0.094	0.112	0.119
Europe	0.111	0.159	0.178	0.087	0.117	0.157
Belgium	0.198	0.198	0.198	0.119	0.119	0.119
Denmark	0.111	0.111	0.111	0.087	0.087	0.087
Germany	0.178	0.179	0.181	0.104	0.120	0.155
Japan	0.214	0.214	0.214	0.198	0.198	0.198
United Kingdom	0.152	0.163	0.17	0.089	0.121	0.142

Source: IRENA Renewable Cost Database

Box 4.1 Floating offshore wind

The development of the offshore wind sector has exceeded expectations. With zero subsidy projects in Germany and the Netherlands, and auction prices in the UK coming in at lower than the expected wholesale electricity price, offshore wind has announced its arrival as a competitive source of renewable electricity at scale.

However, these projects are typically in relatively shallow waters. There is still a huge technical potential that can be unlocked in waters deeper than 60 metres. Installations in these water depths would enable countries such as Japan, where the seabed drops away rapidly as distance from the coast increases, to install significant volumes of offshore wind. However, the use of fixed-bottom foundations presents not only a technical challenge, but an economic one.

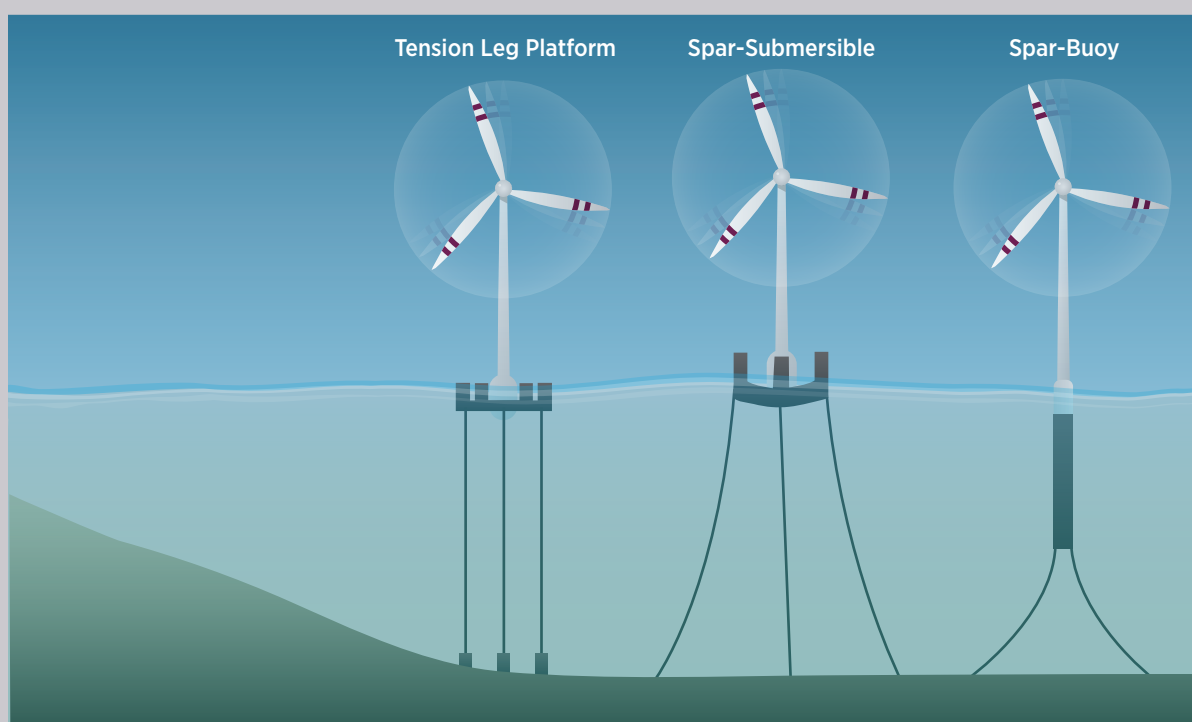
The most promising solution to the economic challenge of offshore wind in deep waters is the use of floating foundations. From a technical and economic perspective, floating foundations offer an attractive solution, because they can build on the oil and gas industries deepwater experience with floating production platforms. This could allow floating wind to complement fixed-bottom developments by allowing greater deployment in deepwater locations, potentially closer to load centres, but also where seabed conditions mean fixed-bottom foundations are impractical even in shallow waters.

The potential scale of resources that could be unlocked by floating wind is impressive. For example, the potential resource in Europe in water depths of 60 m or more is 4 TW, almost twice the potential in shallower waters. In the United States, the offshore wind potential in deep waters is estimated at 2.45 TW and in Japan at 0.5 TW – representing 60% and 80% of total potential offshore wind resources in those countries respectively (Carbon Trust, 2015). In both the United States and Japan, floating wind could play a very important role, given the close proximity of good deepwater offshore wind resources to major cities, which are usually high electricity demand centres. In China, where a large share of installations has been near-shore, there is potential for over 2.2 TW of offshore wind in depths between 50-100m (IRENA, 2019b). IRENA's analysis of a sustainable pathway that is consistent with meeting the Paris Agreement goals projects that floating offshore wind installed capacity might grow to 5-30 GW by 2030 and 50-150 GW by 2050 (IRENA, 2019b and IRENA, 2020b).

Besides opening new markets for offshore wind, floating offshore wind reduces significantly any disturbance to the sea bed during installation and reduces installation time as the installation can be largely assembled in port and towed to its final location. Floating offshore wind turbines may also have lower overall O&M costs, as some major O&M operations (e.g., blade or generator replacements) can be carried out in port. These potential O&M savings will be highly project specific, however, as it depends on the distance to an appropriate deepwater port.

Although there are multiple floating foundation types with different anchoring and mooring systems, there is no clear indication of which design will be successful commercially at this stage. It is possible that multiple solutions will co-exist within or between different markets, depending on local sea and seabed conditions, deepwater port availability and developer experience. The three most prevalent designs that have been used for demonstration projects are the spar-buoy, spar-submersible or semi-submersible, and the tension-leg platform, illustrated in Figure B4.1.

Figure B4.1 Floating offshore wind foundation types



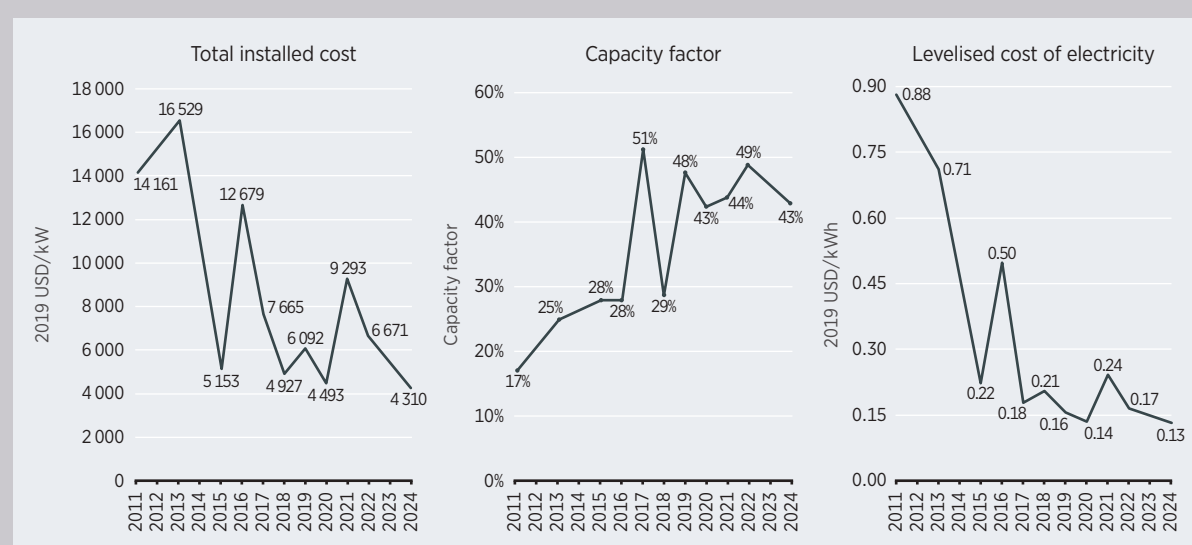
Source: IRENA, 2018b

Most of the floating projects thus far are pre-commercial projects (with some in test centres). These projects are vital in enabling development, especially the standardisation of fabrication processes of floating foundations, gaining operational data and in understanding how to drive cost reductions. Floating offshore wind has been proven to be technically feasible with up to 19 prototype and demonstration projects installed as of 2019, with a capacity of 55.6 MW (42.5 MW which is operational) – with 54% of capacity in the UK²³ and 30% of capacity in Japan (Wood Mackenzie, 2019b). Development is, however, picking up pace and by the end of 2020 up to five designs are expected to have been demonstrated at full-scale, with their commercialisation expected to start in the following five years between 2020 and 2025.

²³ The Hywind project is the first commercial floating offshore wind project, deployed in Scotland in 2017 at rated at 30 MW (with five 6 MW wind turbines) using a spar buoy foundation. It is estimated to have an annual net capacity factor of 65%.

IRENA's available data for demonstration and commercial projects that have been installed or are expected to be installed by 2024 shows projects in water depths with between 50 – 515 m²⁴. The available cost and performance data for pre-commercial and planned commercial projects (with the projects varying in size from 2 MW – 400 MW)²⁵ is modest, but provides some insight into the cost evolution of floating offshore wind (Figure B5.2). Given this data is for demonstration and pre-commercial projects, the data needs to be treated with caution, as it is not representative of what commercial floating offshore wind costs might be. The data indicates that for these projects, total installed costs could fall by 70% between 2010 and 2024, from USD 14 161/kW to USD 4 310/kW. By 2024, the projects being built have an implied LCOE of around USD 0.13/kWh. If confirmed by more projects, these values must be considered very encouraging given the industry is expected to be commissioning mostly relatively small commercial projects from 2022 onwards.

Figure B4.2 Global weighted average total installed costs, capacity factors and LCOE for floating offshore wind, 2010–2022²⁶



Source: IRENA Renewable Cost Database

Developments to support the commercialisation of floating offshore wind are accelerating. For example, there is ongoing work by the International Electrotechnical Commission (IEC) to develop international standards that would contribute to mitigating some of the technical risks associated with the technology. The IEC sub-committee TC 88/PT 61400-3-2 includes representatives from China, Denmark, France, Germany, Japan, the Netherlands, Norway, the Republic of Korea, South Africa, Spain, the United Kingdom; is working on standards for the 'Design requirements for floating offshore wind turbines.' (IRENA, 2018b).

²⁴ Based on the 5th and 95th percentile water depth of projects deployed between 2010 - 2022.

²⁵ Includes installations that are operational, have been decommissioned, are permitting, or have been announced.

²⁶ Mostly pre-commercial projects.

05

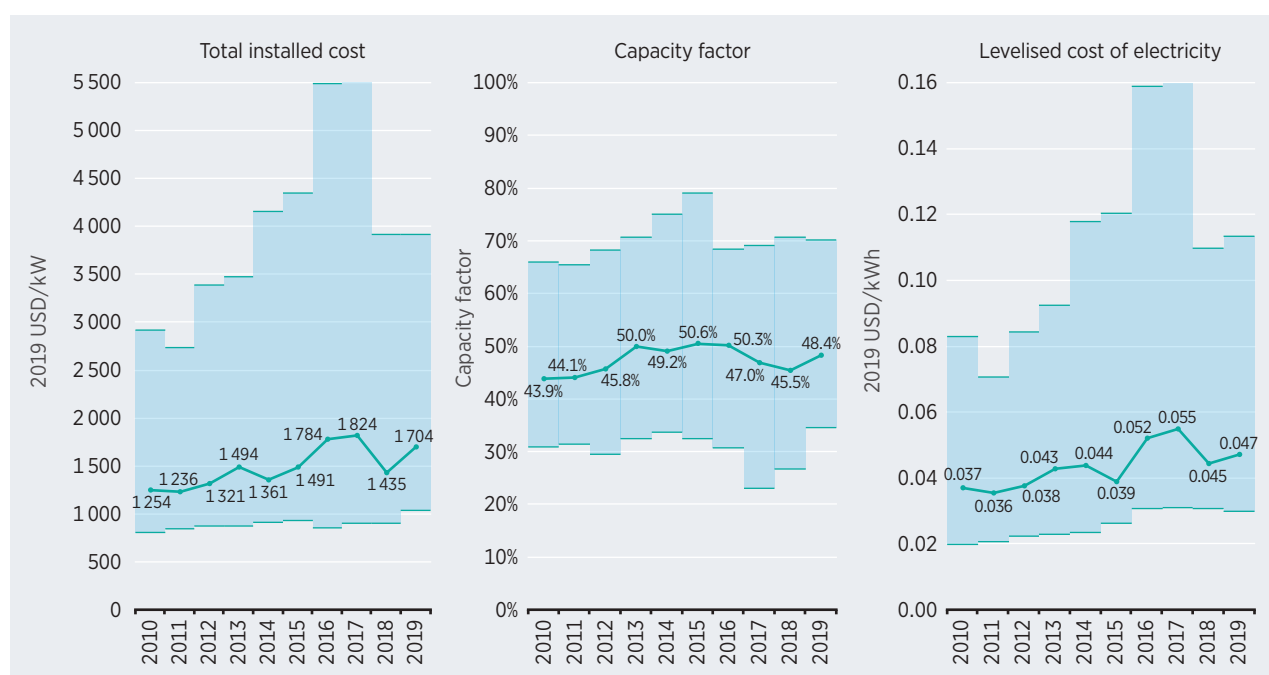


HYDROPOWER

HIGHLIGHTS

- The global weighted-average LCOE of newly commissioned hydropower projects in 2019 was USD 0.047/kWh, 6% higher than the USD 0.045/kWh recorded in 2018 and 27% higher than the projects commissioned in 2010 (Figure 5.1).
- Despite this increase in the LCOE, nearly nine-tenths of the capacity commissioned in 2019 had an LCOE lower than the cheapest new fossil fuel-fired cost option.
- The increase in LCOE since 2010 has been driven by rising installed costs, notably in Asia, which have been driven by the increased number of projects with more expensive development conditions compared to earlier projects. This is likely due to an increase in projects in locations with more challenging site conditions.
- In 2019, the global weighted-average total installed cost of newly commissioned hydropower projects increased to USD 1704/kW, 17% higher than in 2018. This increase is explained by the lower share of deployment occurring in China (3.8 GW in 2019) and the higher share of installed capacity deployment in other countries/regions with higher average installed costs. In Brazil, for example, 4.6 GW was added in 2019, while there was also a higher share of deployment in Africa and Other Asia in 2019 compared to 2018 – all locations with higher than average installed costs.
- Between 2010 and 2019, the global weighted-average capacity factor for hydropower projects commissioned varied between 44% – in 2010 – and a high of 51% in 2015. For projects commissioned in 2019, it was 48%.

Figure 5.1 Global weighted average total installed costs, capacity factors and LCOE for hydropower, 2010–2019



Source: IRENA Renewable Cost Database.

Hydropower is both mature and reliable and is also the most widely deployed renewable generation technology – even though its share of global renewable energy capacity has been slowly declining. Indeed, its share fell from 76% (925 GW) in 2010 to just under 47% in 2019. Global installed hydropower capacity (excluding pumped hydro) was 1189 GW at the end of 2019.

Hydropower provides a low-cost source of electricity and, if the plant includes reservoir storage, also provides a source of flexibility. This enables the plant to provide flexibility services, such as frequency response, black start capability and spinning reserves. This, in turn, increases plant viability by increasing asset owner revenue streams, while enabling better integration of VRE sources to meet decarbonisation targets. In addition to the grid flexibility services hydropower can provide, it can also store energy over weeks, months, seasons or even years, depending on the size of the reservoir.

In addition, hydropower projects combine energy and water supply services. These can include irrigation schemes, municipal water supply, drought management, navigation and recreation, and flood control – all of which provide local socioeconomic benefits. Indeed, in some cases the hydropower capability is developed because of an existing need to manage the river flows and hydropower can be incorporated into the design.

While these additional services increase the viability of hydropower projects, the LCOE analysis carried out in this report, however, does not calculate the value of any services, outside of electricity generation, which are not site and power market specific.

TOTAL INSTALLED COSTS

The construction of hydropower projects varies in size and properties, influenced by the location of the project. There are also key technical characteristics which determine the type and size of turbine used. These key parameters include, among other factors, the “head” (which is the water drop to the turbine determined by the location and design); the reservoir size; the minimum downstream flow rate; and seasonal inflows.

Hydropower plants fall under three categories:

- Reservoir, or storage hydropower, which provide a decoupling of hydro inflows from the turbines, with the water storage serving as a buffer that dams can use to store or regulate hydro inflows decoupling the time of generation from inflows.
- Run-of-river hydropower, in which hydro inflows mainly determine generation output, because there is little or no storage to provide a buffer for the timing and size of inflows.
- Pumped storage hydropower, in which there are upper and lower storage reservoirs and electricity is used to pump water from the lower to the upper reservoir in times of low demand (mostly during off-peak periods²⁷) to be released in periods of high electricity demand. Pumped hydro is mostly used for peak generation, grid stability and ancillary services. It can also be used to integrate more variable renewables by storing abundant renewable generation that is not needed during periods of low electricity demand.

²⁷ Periods of low electricity demand and consequently low electricity prices.

²⁸ Large hydropower projects for this analysis are deemed to be projects greater than 10 MW in capacity.

Hydropower is a capital-intensive technology, often requiring long lead times, with this especially true for large capacity projects. The lead time involves development, permitting, site development, construction and commissioning. Hydropower projects are large, complex civil engineering projects and extensive site surveys, collection of inflow data (if not already available), environmental assessments and permitting all take time and extra often have to be completed before site access and preparation can be undertaken.

There are two major costs components for hydropower projects:

- The civil works for the hydropower plant construction, which include any infrastructure development required to access the site, grid connection, any works associated with mitigating identified environmental issues and the project development costs.
- The procurement costs related to electro-mechanical equipment.

Civil construction work (which includes the dam, tunnels, canal and construction of the powerhouse) usually make up the largest share of total installed costs for large hydropower plants (Table 5.1).²⁸ Following this, costs for fitting out the powerhouse (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) means that owner costs (including 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.

However, in certain circumstances cost shares can vary widely. This is especially true if a project is adding capacity to an existing hydropower dam or river schemes or where hydropower is being added to an existing dam that was developed without electricity generation in mind.

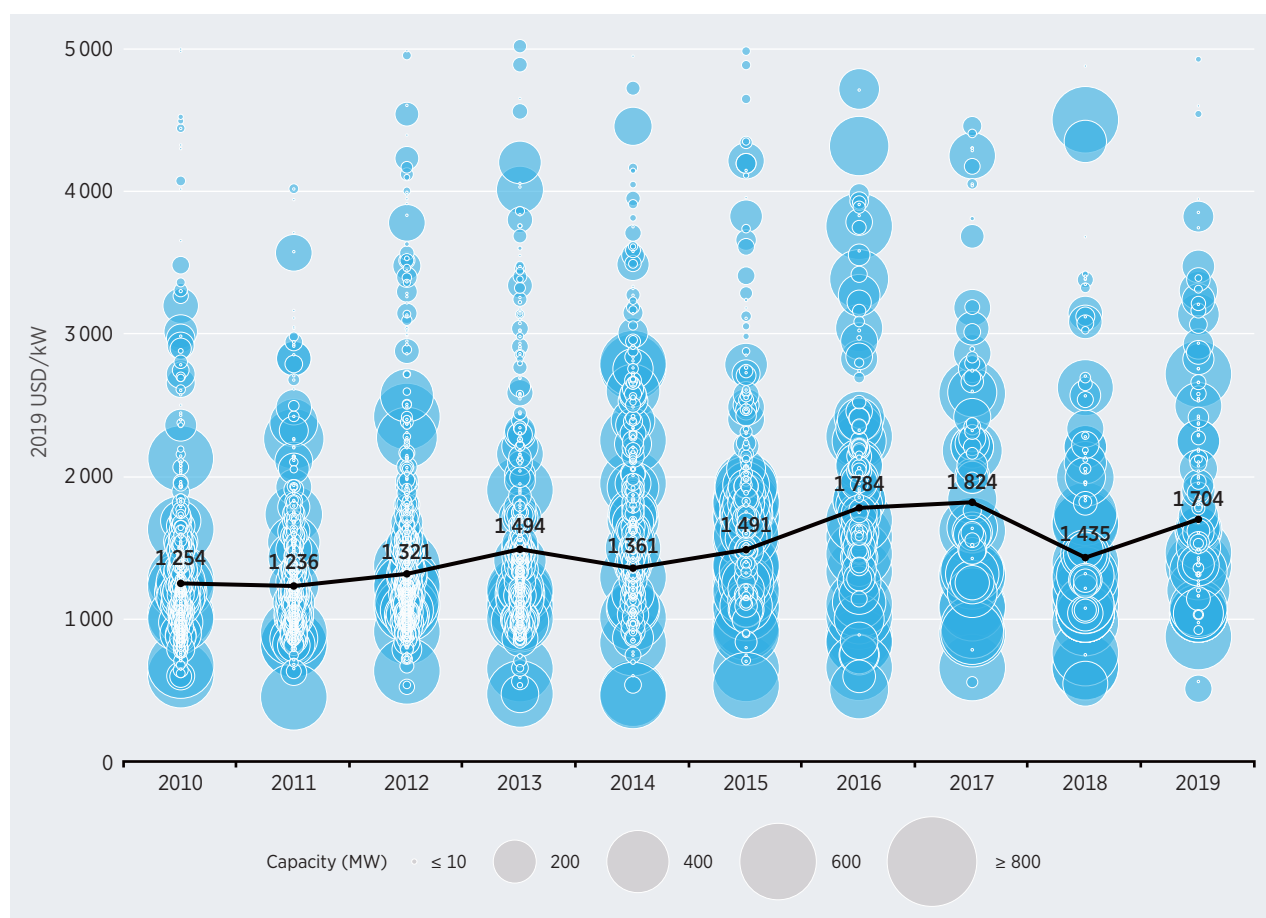
The total installed costs for the majority of hydropower projects commissioned between 2010 and 2019, range from a low of around USD 600/kW to a high of around USD 4 500/kW (Figure 5.2). It is not unusual, however, to find projects outside this range. For instance, adding hydropower capacity to an existing dam that was built for other purposes may have costs as low as USD 450/kW, while remote sites, with poor infrastructure and located far from existing transmission networks, can cost significantly more than USD 4 500/kW, due to higher logistical, civil engineering and grid connection costs.

Between 2010 and 2019, the global weighted-average total installed cost of new hydropower rose from USD 1 254/kW to USD 1 704/kW. There was some volatility, year-on-year, with increases driven by the share of deployment in different regions and changes in project-specific costs.

Table 5.1 Total installed cost breakdown by component and capacity weighted averages for 25 hydropower projects in China, India and Sri Lanka, 2010-2016

Project Component	Share of total installed costs (%)		
	Minimum	Weighted average	Maximum
Civil works	17	45	65
Mechanical equipment	18	33	66
Planning and other	6	16	29
Grid connection	1	6	17
Cost of land	1	3	8

Source: IRENA Renewable Cost Database.

Figure 5.2 Total installed costs by project and global weighted average for hydropower, 2010-2019

Source: IRENA Renewable Cost Database.

The increase has been driven by rising installed costs for projects in Asia, Africa and South America. The data appears to suggest that many countries in these regions are now developing hydropower projects at less ideal sites, where such projects are located further from existing infrastructure, or the transmission network, resulting in higher logistical costs, as well as boosting grid connection costs. This results, overall, in higher installation costs.

Looking at the global weighted-average total installed cost trends for large hydro (greater than 10 MW in capacity) and small hydro (10 MW or less) suggests that average installed costs for small-hydro have increased at a faster rate than for large hydropower projects (Figure 5.3). However, this trend remains to be confirmed, given that data in the IRENA Renewable Cost Database for small hydropower projects is noticeably thinner for the years 2016-2018.

The full dataset of hydropower projects in the IRENA Renewable Cost Database for the years 2000 to 2019 (Table 5.2) does not suggest that there are strong economies of scale in hydropower projects below around 450 MW in size. The number of projects is not evenly distributed, however, and could likely support different hypotheses. There are clearly economies of scale for projects above 700 MW, but these only represent about 6% of the data capacity for hydropower for the period of commissioning between 2000 and 2019.

Figure 5.4 presents the distribution of total installed costs by capacity for small and large hydropower projects in the IRENA Renewable Cost Database. As the global weighted-average has risen over the two periods, it is possible to see the reason for this in the large hydropower data.

Figure 5.3 Total installed costs for small and large hydropower projects and the global weighted average, 2010-2019



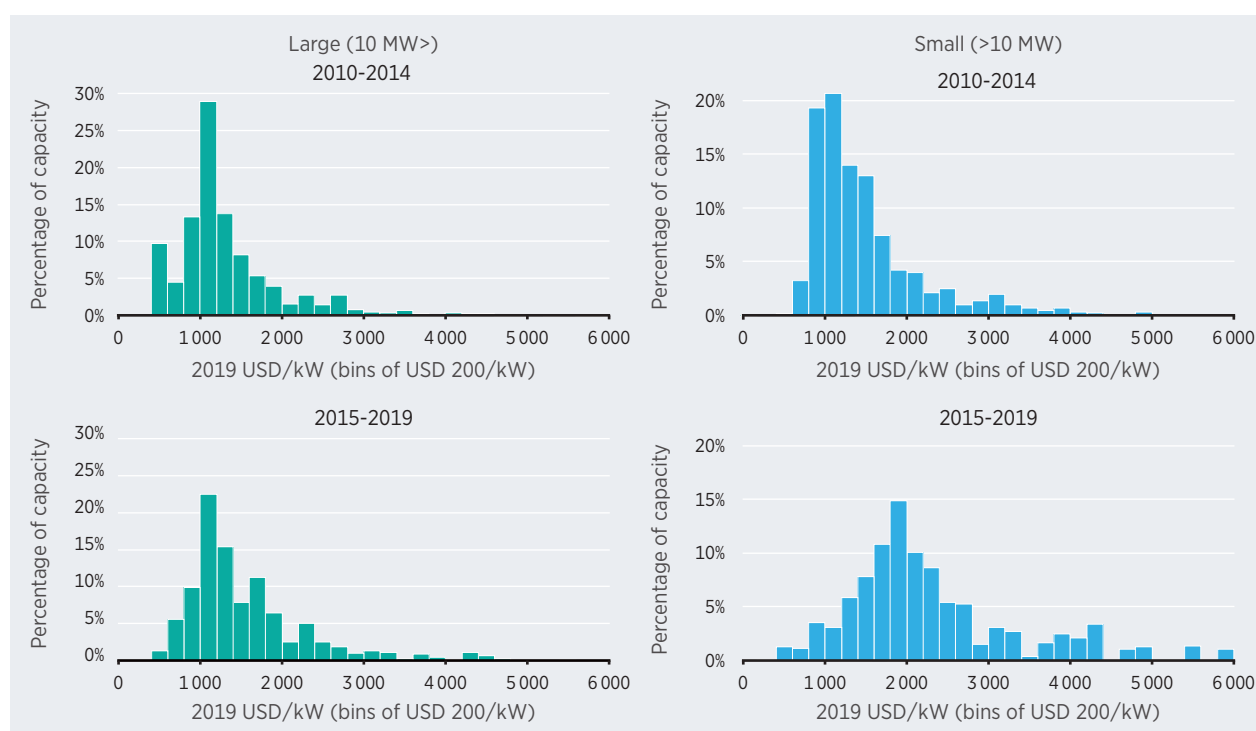
Source: IRENA Renewable Cost Database.



Table 5.2 Total installed costs for hydropower by project and weighted average by capacity range, 2000-2019

2000-2019			
Capacity (MW)	5 th percentile (2019 USD/kW)	weighted-average (2019 USD/kW)	95 th percentile (2019 USD/kW)
0-50	845	1 641	3 619
51-100	872	1 832	3 881
101-150	916	1 697	3 481
151-200	882	1 713	3 011
201-250	976	1 819	3 397
251-300	837	2 082	3 886
301-350	874	1 994	4 349
351-400	808	1 655	3 144
401-450	1 138	1 905	2 979
451-500	1 029	1 508	2 102
501-550	1 077	1 585	2 580
551-600	1 280	1 795	2 515
601-650	1 007	1 309	2 903
651-700	2 194	2 244	2 277
701-750	919	1 431	1 941
751-800	1 019	1 384	2 022
801-850	1 244	1 879	2 521
851-900	1 063	1 455	1 787
901-950	680	1 086	1 277

Source: IRENA Renewable Cost Database.

Figure 5.4 Distribution of total installed costs of large and small hydropower projects by capacity, 2010-2014 and 2015-2019

Source: IRENA Renewable Cost Database.

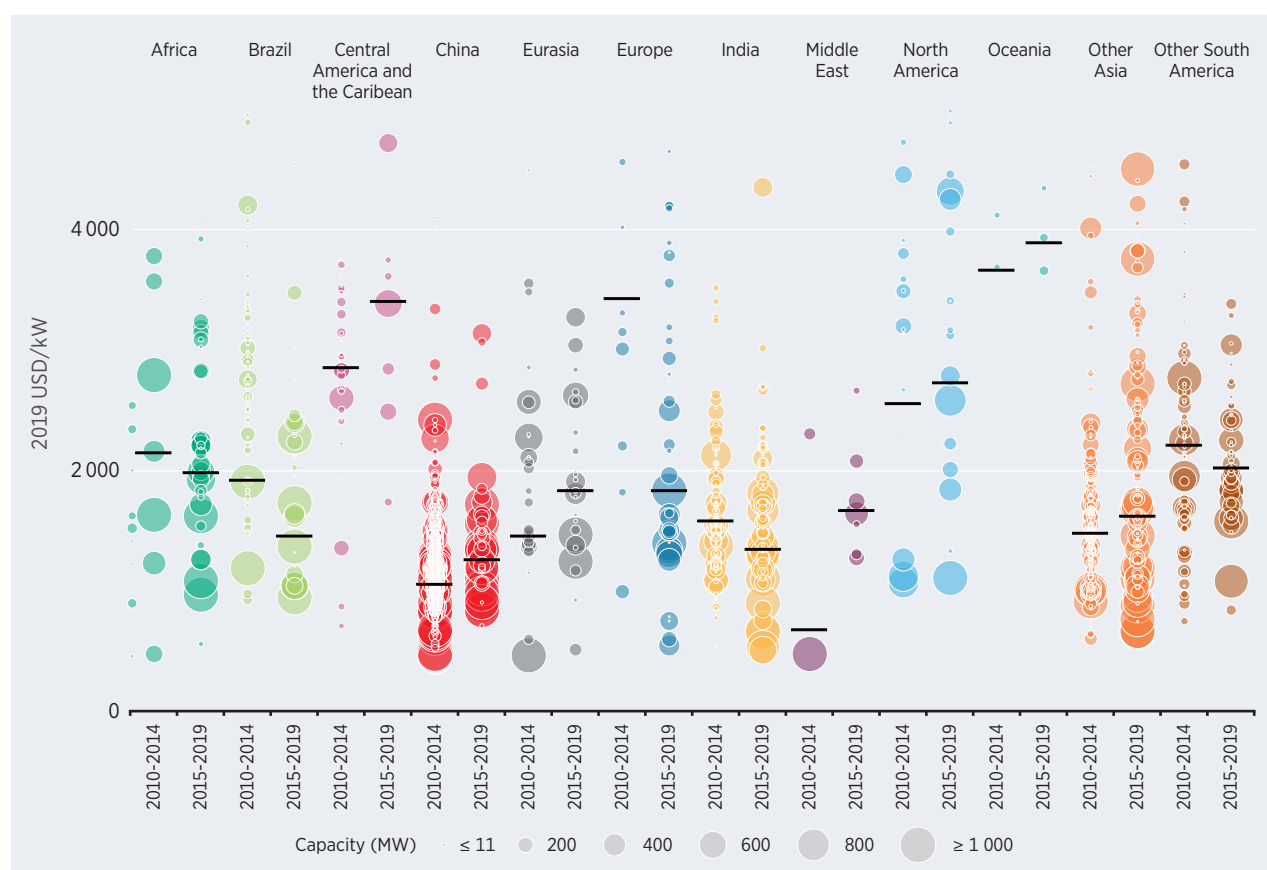
Compared to the period 2010-2014, the data for 2015-2019 shows a reduction in the share of newly commissioned projects in the USD 600 to USD 1200/kW range and an increase in the capacity of projects above that. The shift in the distribution of small hydropower projects is more pronounced, but has also been accompanied by a reduction in the skew of the distribution of projects, although there has also been growth in the tail of more expensive projects, compared to 2010-2014.

Total installed costs for large hydropower (more than 10 MW) are highest in Oceania and Central America and the Caribbean, while lowest in China and India (Figure 5.5). For the period 2015-2019, the weighted-average installed cost in China was USD 1264/kW, while in Brazil it was USD 1460/kW and in India it was USD 1349/kW. In Other Asia, it was USD 1630/kW and in Other South America it was USD 2 029/kW. Not surprisingly, regions with higher costs tend to have lower deployment rates.

Due to the very site-specific development costs of hydropower projects, the range in installed costs for hydropower tends to be wide. Part of this variation is due to the variation in development costs, civil engineering, logistics and grid connection costs. Some variation may also be driven by the non-energy requirements integrated into different projects – for example, to provide other services, such as potable water, flood control, irrigation and navigation. These services are included in the hydropower project costs, but are typically not remunerated. It is therefore worth noting that these benefits are not included in the LCOE calculations in this chapter.

A comparison between installed costs for large and small hydro plants shows that small hydro plants generally have between 20% and 80% higher installed costs when compared to large hydro plants. The exception is in the Central America and the Caribbean, and Oceania regions, where installed costs are higher for large

Figure 5.5 Total installed costs ranges and capacity weighted averages for large hydropower projects by country/region, 2010-2019



Source: IRENA Renewable Cost Database.

hydropower plants as a result of the relatively small number of large projects developed in those regions (Figure 5.6). Total installed costs for small hydropower projects between 2015 and 2019 in Brazil were USD 2 364/kW, somewhat higher than in the period 2010-2014. The total installed costs of small hydropower in India averaged USD 1 777/kW in the period 2015-2019, a figure 3% higher than in the period 2010-2014.

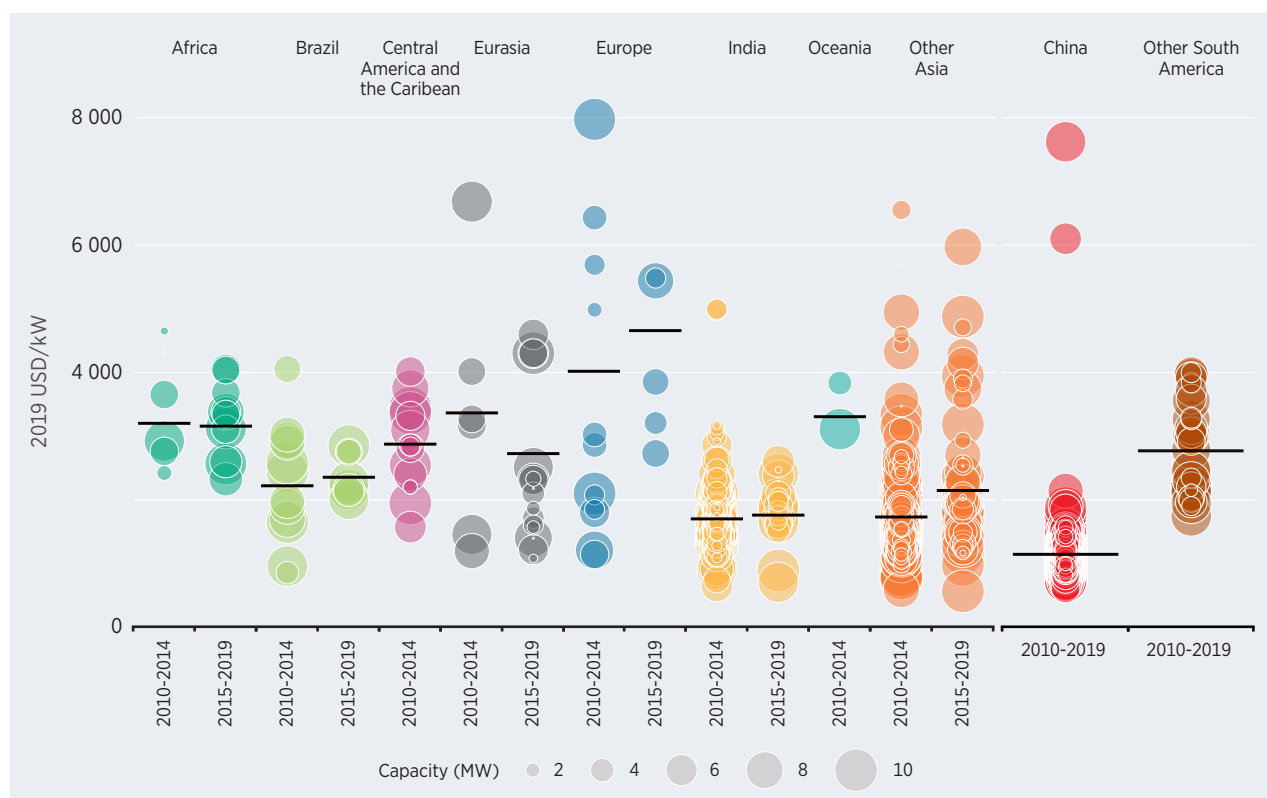
The data for small hydropower projects commissioned in the period 2015-2019 is sparse in China and the Other South America region. Results are therefore only presented for total installed costs for the period 2010 to 2019. The weighted-average installed cost for small hydropower in China was USD 1 157/kW over the period 2010-2019 and USD 2 278/kW in Other South America.

CAPACITY FACTORS

Between 2010 and 2019, the global weighted-average capacity factor of newly commissioned hydropower projects of all sizes increased from 44% to 48%, with an average of 47% in the period 2010 to 2014 and 49% in the period 2015 to 2019. The 5th and 95th percentiles of projects over this period staying within the range 23% to 79%. The wide range overall is to be expected, given that each hydropower project has very different site characteristics and that low capacity factors are sometimes a design choice, with turbines sized to help meet peak demand and provide other ancillary grid services.

The average capacity factor for projects commissioned between 2010 and 2019 was 49% for small and 48% for large hydropower projects, respectively, with most projects in the range of 25% to 84% (Tables 5.3 and 5.4). Europe was a notable exception, having a range of projects with capacity factors lower than 20%.

Figure 5.6 Total installed costs ranges and capacity weighted averages for small hydropower projects by country/region, 2010-2019



Source: IRENA Renewable Cost Database.

Between 2010 and 2019, the annual global weighted-average capacity factors of the 5th percentile of large hydropower projects ranged from a low of 23%, in 2017, to a high of 38% in 2019, while for the 95th percentile, the figure ranged from a low of 60%, in 2010, to a high of 78%, in 2015.

Between 2010 and 2019, the global weighted-average capacity factor of newly-commissioned small hydropower projects was 49%. Excluding the years 2017 and 2018, where there is a paucity of data, between 2010 and 2019, the annual, global weighted-average capacity factors of the 5th percentile of small hydropower projects ranged from a low of 29%, in 2012, to a high of 39%, in 2016. For the 95th percentile, these capacity factors ranged from a low of 66%, in 2016, to a high of 76%, in 2015.

In the IRENA database, there is often a significant variation in the weighted-average capacity factor by region. Tables 5.3 and 5.4 represent hydropower project capacity factors and capacity weighted-averages for large and small hydropower projects by country and region.

Between 2010 and 2014, average capacity factors for newly-commissioned large hydropower projects were highest in Brazil and South America, with 65% and 61%, respectively, while between 2015 and 2019, South America maintained its average capacity factor at 61%, followed by 55% for Eurasia. Meanwhile, Oceania and Europe recorded the lowest average capacity factors for newly-commissioned large hydropower projects, with 29% between 2010 and 2014 and 35% between 2015 and 2019.

Small hydropower projects (less than 10 MW) showed a smaller range of country-level weighted-average variation (Table 5.4). For these, there was a country-level average low of 46% in China in the period 2010 to 2014. Similarly, weighted-average capacity factors for newly-commissioned small hydropower projects between 2010 and 2014 were highest in Other South America and Brazil, with 65% and 64% respectively, while between 2015 and 2019, due to the limited number of newly commissioned small hydropower projects in the database for Other South America, its weighted average capacity factor was considered not representative. Eurasia showed the highest weighted average capacity factor for this period, with 58%, while Brazil's dropped to 57%.

Table 5.3 Hydropower project capacity factors and capacity weighted averages for large hydropower projects by country/region, 2010–2019

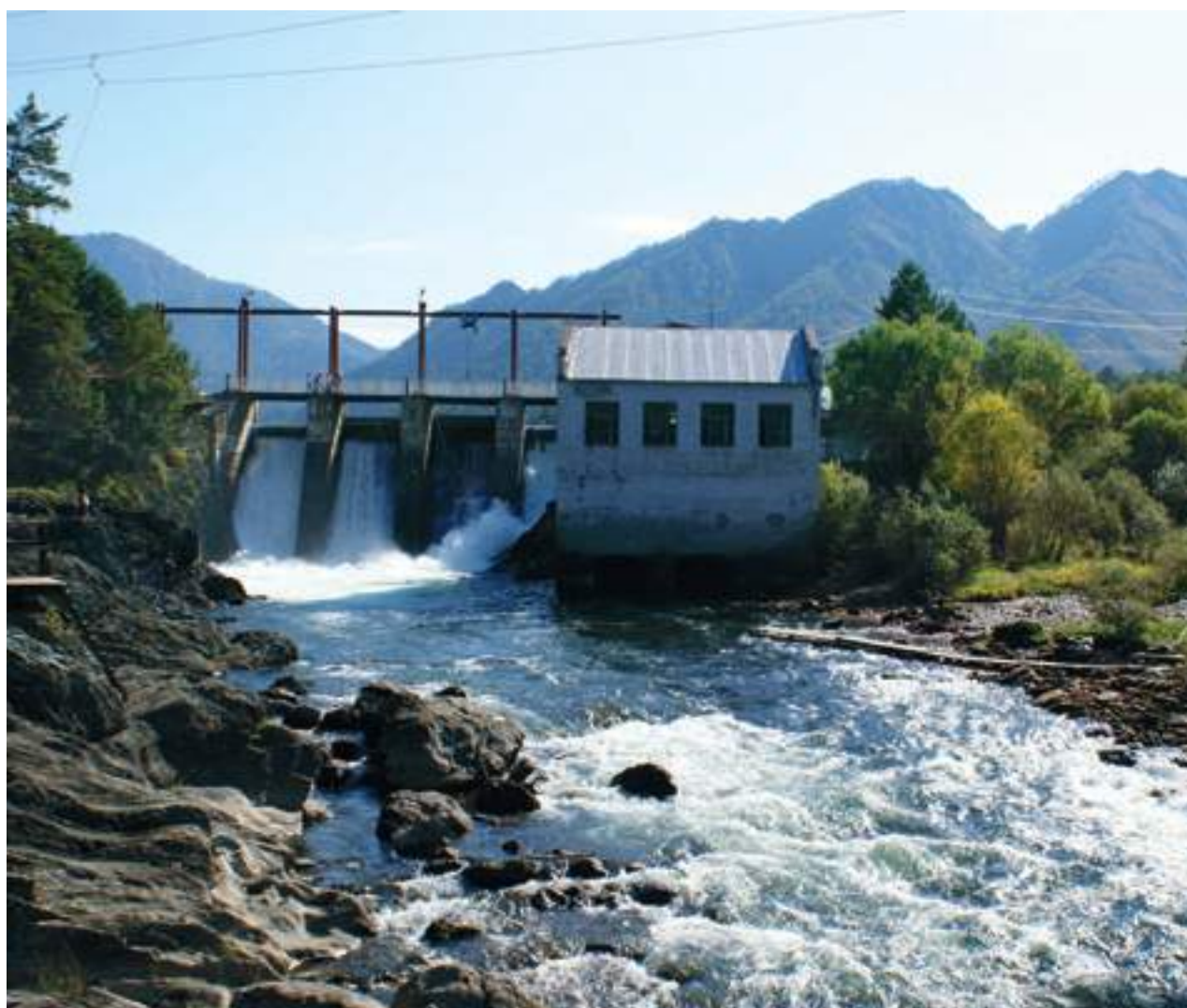
	2010–2014			2015–2019		
	5 th percentile (%)	Weighted-average (%)	95 th percentile (%)	5 th percentile (%)	Weighted-average (%)	95 th percentile (%)
Africa	28	50	72	35	52	82
Brazil	51	65	80	39	47	59
Central America	27	48	64	36	53	56
China	31	45	57	35	50	57
Eurasia	27	31	58	31	55	67
Europe	14	33	69	16	35	62
India	30	47	62	22	42	65
North America	18	31	80	34	52	75
Oceania	25	29	42	39	45	48
Other Asia	36	48	66	37	47	73
Other South America	45	61	83	49	61	85

Source: IRENA Renewable Cost Database.

Table 5.4 Hydropower project capacity factors and capacity weighted averages for small hydropower projects by country/region, 2010–2019

	2010-2014			2015-2019		
	5 th percentile (%)	Weighted- average (%)	95 th percentile (%)	5 th percentile (%)	Weighted- average (%)	95 th percentile (%)
Africa	32	55	68	50	55	61
Brazil	41	64	88	53	57	61
Central America	45	59	75	n.a.	n.a.	n.a.
China	33	46	60	53	54	54
Eurasia	44	58	75	50	58	69
Europe	23	48	70	45	51	55
India	28	50	69	37	56	68
Other Asia	37	51	80	34	45	56
Other South America	43	65	82	n.a.	n.a.	n.a.

Source: IRENA Renewable Cost Database.



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% to 4%. IRENA has previously collected O&M data on 25 projects (IRENA, 2018) and found an average O&M cost that was slightly less than 2% of total installed costs per year, with a variation of between 1% and 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 cost.

Table 5.5 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% to 61% of O&M costs, salaries from 13% to 74%, while materials are estimated to account for around 4% (Table 5.5).

The International Energy Agency (IEA) assumes O&M costs of 2.2% for large hydropower projects and 2.2% to 3% for smaller projects, with a global average of around 2.5% (IEA, 2010). This would put large-scale hydropower plants in a similar range of O&M 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 also reduce O&M costs to much lower levels.

Other sources, however, quote lower or higher values. The Energy Information Agency (EIA) assumes 0.06% of total installed costs as fixed annual O&M and USD 0.003/kWh as variable O&M costs for a conventional hydropower plant of 500 MW 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% to 2.5% is considered the norm for large-scale projects (IPCC, 2011), which is equivalent to average costs of between USD 20/kW/year and USD 60/kW/year for the average project, by region, in the IRENA Renewable Cost Database.

O&M costs 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 of the electro-mechanical equipment, or the refurbishment of penstocks, tailraces, etc. 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.

Table 5.5 Hydropower project O&M costs by category from a sample of 25 projects

Project Component	Share of total O&M costs (%)		
	Minimum	Weighted average	Maximum
Operation costs	20	51	61
Salary	13	39	74
Other	5	16	28
Material	3	4	4

Source: IRENA Renewable Cost Database.

LEVELISED COST OF ELECTRICITY

Hydropower has historically provided the backbone of low-cost electricity in a significant number of countries around the world. These range from Norway to Canada, New Zealand to China, and Paraguay to Brazil and Angola – to name just a few countries. Investment costs are highly dependent on location and site conditions, however, which explains the wide range of plant installed costs, and also much of the variation in LCOE between projects. It is also important to note that hydropower projects can be designed to perform very differently from each other, which complicates a simple LCOE assessment.

As an example, a plant with a low installed electrical 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 demand and provide spinning reserve and 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. The strategy pursued in each case will depend on the characteristics of the site inflows and the needs of the local market. This is before taking into account the increasing value of hydropower systems with significant reservoir storage, which can provide very low cost and long-term electricity storage to help facilitate a growing share of VRE.

In 2019, the global weighted-average cost of electricity from hydropower was USD 0.047/kWh, up 27% from the USD 0.037/kWh recorded in 2010. The global weighted-average cost of electricity

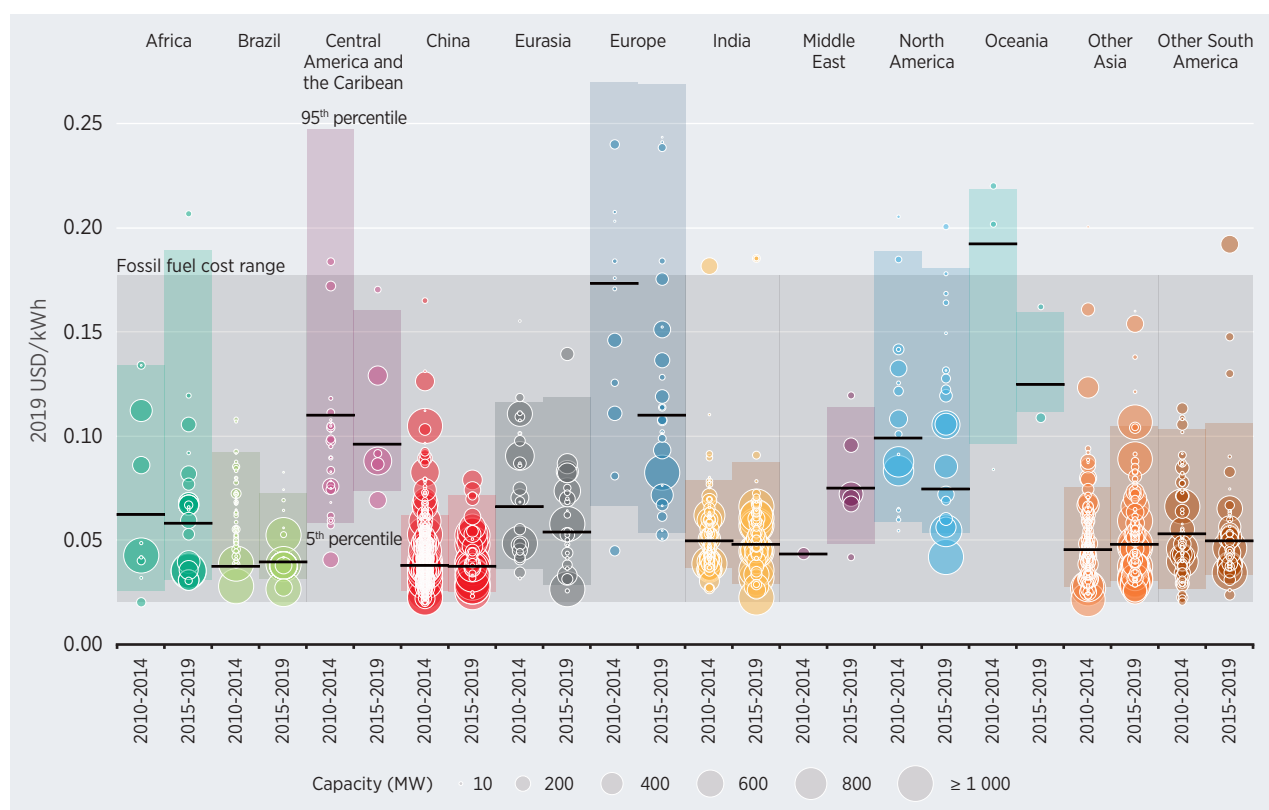
from hydropower projects commissioned in years 2010 to 2014 averaged USD 0.044/kWh. This increased to an average of USD 0.049/kWh for projects commissioned over the years 2015 to 2019.

Despite these increases through time, however, 89% of the capacity added in 2019 had costs lower than the cheapest new source of fossil fuel-fired electricity generation. This was before considering that a significant proportion of those projects with costs above the lowest fossil fuel cost may have been deployed in remote areas, where it was still the cheapest source of new electricity, given the extensive use of small hydropower, in particular, in providing low-cost electricity in remote locations, and for overall electrification.

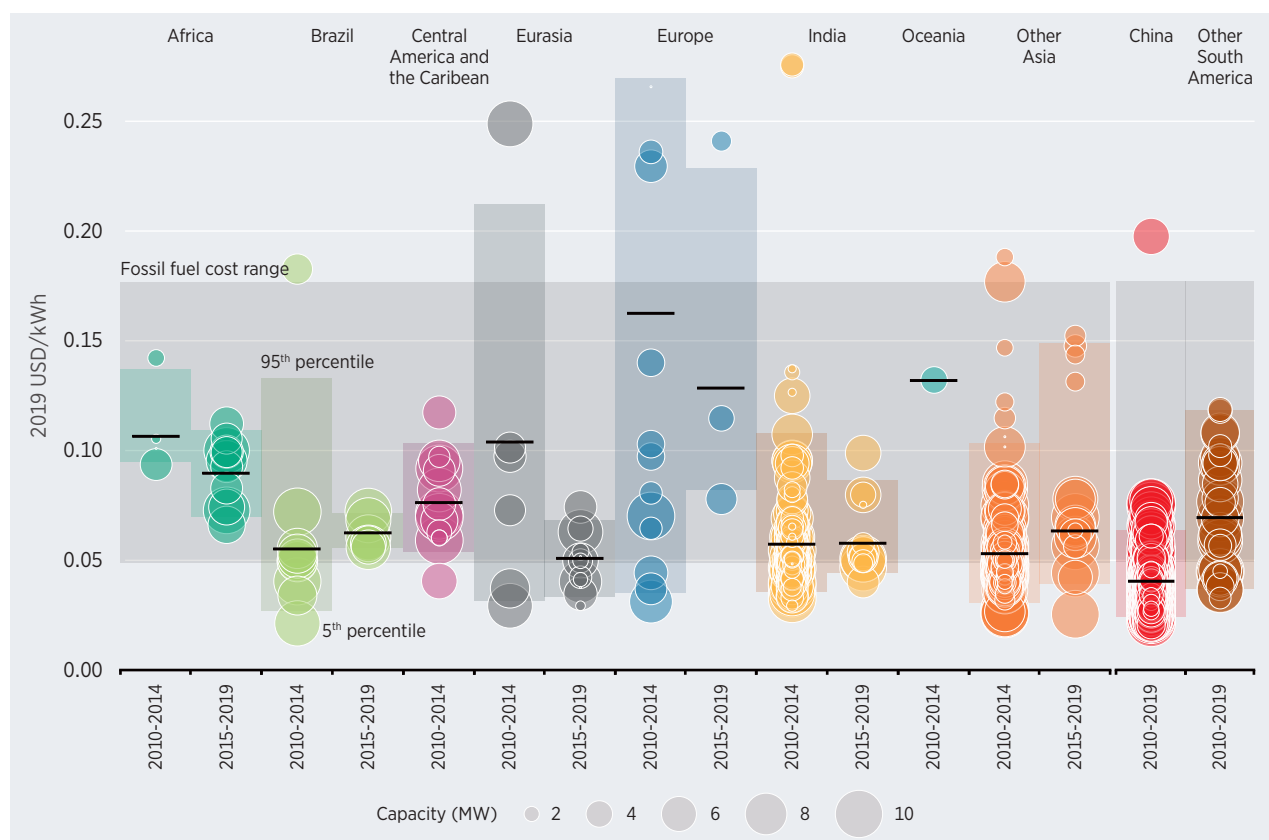
The weighted-average country/regional LCOE of hydropower projects, large and small, in the IRENA Renewable Cost Database reflects the variation in site- and country-specific project installed costs and capacity factors. The figures for projects commissioned in 2019 range from a country low of USD 0.038/kWh in Brazil to a high of USD 0.13/kWh in North America, where very little new capacity was added in 2019.

Figure 5.7 and Figure 5.8 present the LCOEs of large and small hydropower projects and the capacity weighted averages by country/region. For large hydropower projects, most countries/regions demonstrated a decrease in the weighted-average LCOE between the periods 2010 to 2014 and 2015 to 2019. The exceptions were Brazil and Other Asia, where the weighted-average LCOE increased, while China maintained relatively the same weighted-average LCOE. Small hydropower projects showed similar trends, with China having the lowest weighted-average LCOE – USD 0.041/kWh – for the 2015 to 2019 time period.

In 2019, the global weighted-average LCOE of hydropower was USD 0.047/kWh. Around nine-tenths of the capacity commissioned had costs lower than the cheapest new source of fossil fuel-fired electricity.

Figure 5.7 Large hydropower project LCOE and capacity weighted averages by country/region, 2010-2019

Source: IRENA Renewable Cost Database.

Figure 5.8 Small hydropower project LCOE and capacity weighted averages by country/region, 2010-2019

Source: IRENA Renewable Cost Database.

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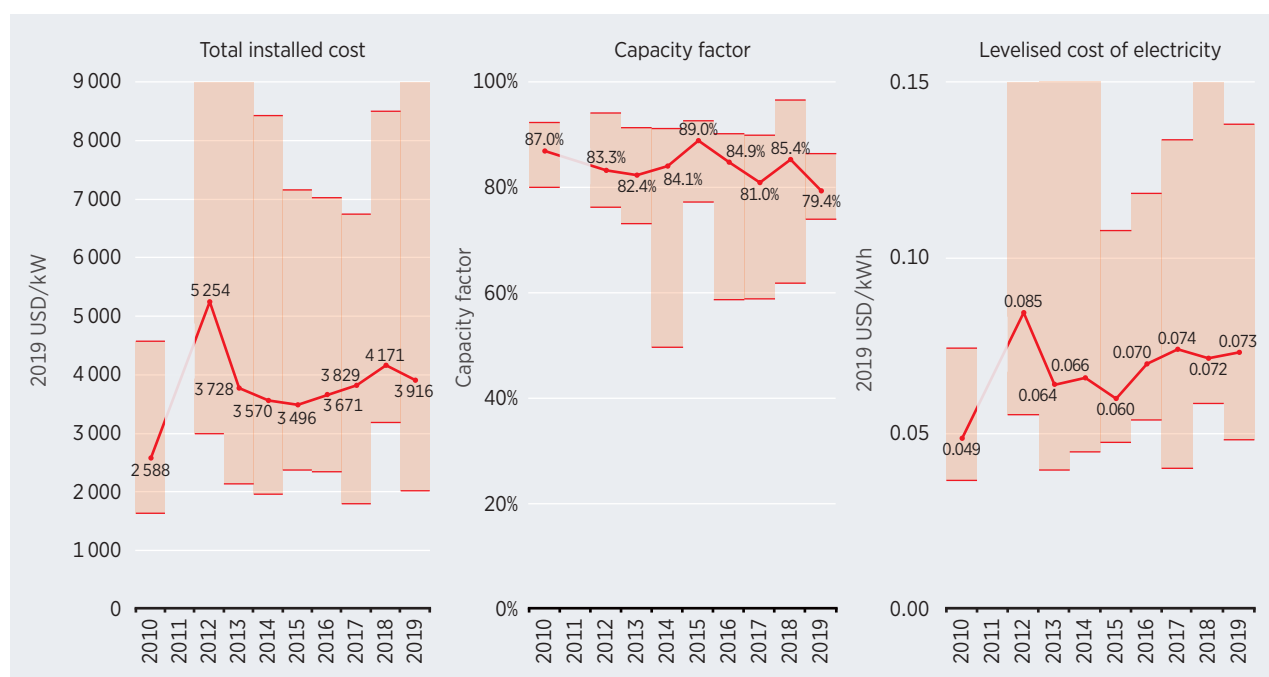


GEO THERMAL

HIGHLIGHTS:

- The deployment of geothermal power plants remains modest, with the 682 MW added in 2019 – a new record. The global weighted-average LCOE of the projects commissioned in 2019 was USD 0.073/kWh, broadly in line with values seen over the last four years.
- Annual new capacity additions for geothermal were 225 MW in 2010, 89 MW in 2011, 400 MW in 2012 and 237 MW in 2013. As a result, just a handful of projects often determined the weighted-average costs in these years. However, since 2014 new additions have been at least 440 MW per year and trends have been more stable.
- Between 2014 and 2019, total installed costs increased from USD 3 570/kW to USD 3 916/kW. In 2019, the total installed costs of the majority of newly commissioned plants spanned the range USD 2 000 to USD 5 000/kW.
- In 2019, the global weighted-average capacity factor for newly commissioned plants was 79%.
- For the years 2007-2021, the data from the IRENA Renewable Cost Database suggests that over the next couple of years, the global weighted-average LCOE could fall to just over USD 0.05/kWh in 2021. However, this will depend on whether projects meet their commissioning goals.

Figure 6.1 Global weighted average total installed costs, capacity factors and LCOE for geothermal, 2010-2019



Source: IRENA Renewable Cost Database.

INTRODUCTION

Geothermal resources are found in active geothermal areas on or near the surface of the Earth's crust, as well as at deeper depths. By drilling into the earth's surface, this naturally occurring steam or hot water can be used to generate electricity in steam turbines. As a result, geothermal power generation is very different in nature to the other renewable power generation technologies. Sub-surface resource assessments are expensive to conduct and need to be confirmed by test wells that will allow developers to build models of the reservoir's extent and flows. Much, however, remains unknown about how the reservoir will perform and how best to manage it over the operational life of the project. This means geothermal projects have very different risk profiles compared to other renewable power generation technologies in both project development and operation.

Geothermal resources consist of thermal energy, stored as heat in the rocks of the Earth's crust and interior. At shallow depths, fissures to deeper depths in areas saturated with water will produce hot water and/or steam that can be tapped for electricity generation with relatively low cost. Where this is not the case, geothermal energy can still be extracted, by drilling to deeper depths and injecting water into the hot area through wells to harness the heat found in otherwise dry rocks.

At the end of 2019, geothermal deployment accounted for 0.5% of the total installed capacity of renewable energy, worldwide, with a total installed capacity of 13.9 GW. This was mostly deployed in active geothermal areas and cumulative installed capacity at the end of 2019 was 39% higher than in 2010.

Geothermal is a mature and commercially available technology that can provide low-cost "always-on" capacity in geographies with very good to excellent high-temperature conventional geothermal resources, close to the Earth's surface. The development of unconventional geothermal resources, however, using the so called "enhanced geothermal" or "hot dry rocks" approach, is much less mature. In this instance, projects come with costs that are typically significantly higher, due to the deep drilling required, rendering the economics

of such initiatives much less attractive, today. Research and development into more innovative, low-cost drilling techniques and advanced reservoir stimulation methodologies is needed in order to lower development costs and realize the full potential of enhanced geothermal resources, by making them more economically viable.

One of the most important challenges faced when developing geothermal power generation projects lies in the availability of comprehensive geothermal resource mapping. Where it is available, this reduces the uncertainties that developers face during the exploration period, potentially reducing the development cost. This is because 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. Resource mapping is, however, an expensive and time-consuming process.

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 – although greater experience in each region has also played a part. A key point is that adherence to global best practices significantly reduces exploration risks (IFC, 2013).

In addition, geothermal plants are very individual in terms of the quality of their resources and management needs. As a result, experience with one project may not yield specific lessons that can be applied to new developments. 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. Intervention in the reservoir creates a dynamic situation, with more information becoming available from operational experience, operators' understanding of how to best manage the reservoir will be constantly evolving over time. Once productivity at existing wells declines, there might also be a need for replacement wells to make up for the loss in productivity.

TOTAL INSTALLED COSTS

As a capital-intensive technology with drilling requirements, cost trends in geothermal power plant development are highly influenced by the commodity and oil markets. These have a direct impact on drilling costs and thus the costs of engineering, procurement and construction (EPC).

Geothermal power plant installed costs are highly site sensitive. In this respect, they have more in common with hydropower projects than the more standardised, solar PV and onshore wind facilities. Geothermal plants depend largely on the reservoir quality, the type of power plant and number of wells. The nature and extent of the reservoir, the thermal properties of the reservoir and at what depths it lies will all have an impact on project costs. The quality of the geothermal resource and its geographical distribution will determine the power plant type, ranging from flash, direct steam, binary, enhanced or a hybrid approach to provide the steam that will drive a turbine and create electricity. Typically, costs for binary plants tend to be higher than those for direct steam and flash plants, as extracting the electricity from lower temperature resources is more capital intensive.

The total installed costs of geothermal power plants consist of the project development costs, the costs of exploration and resource assessment (including seismic surveys and test wells), and the drilling costs for the production and injection wells. Total installed costs also include field infrastructure, geothermal fluid collection and disposal systems, along with other surface installations. These are in addition to the cost of the power plant and grid connection costs.

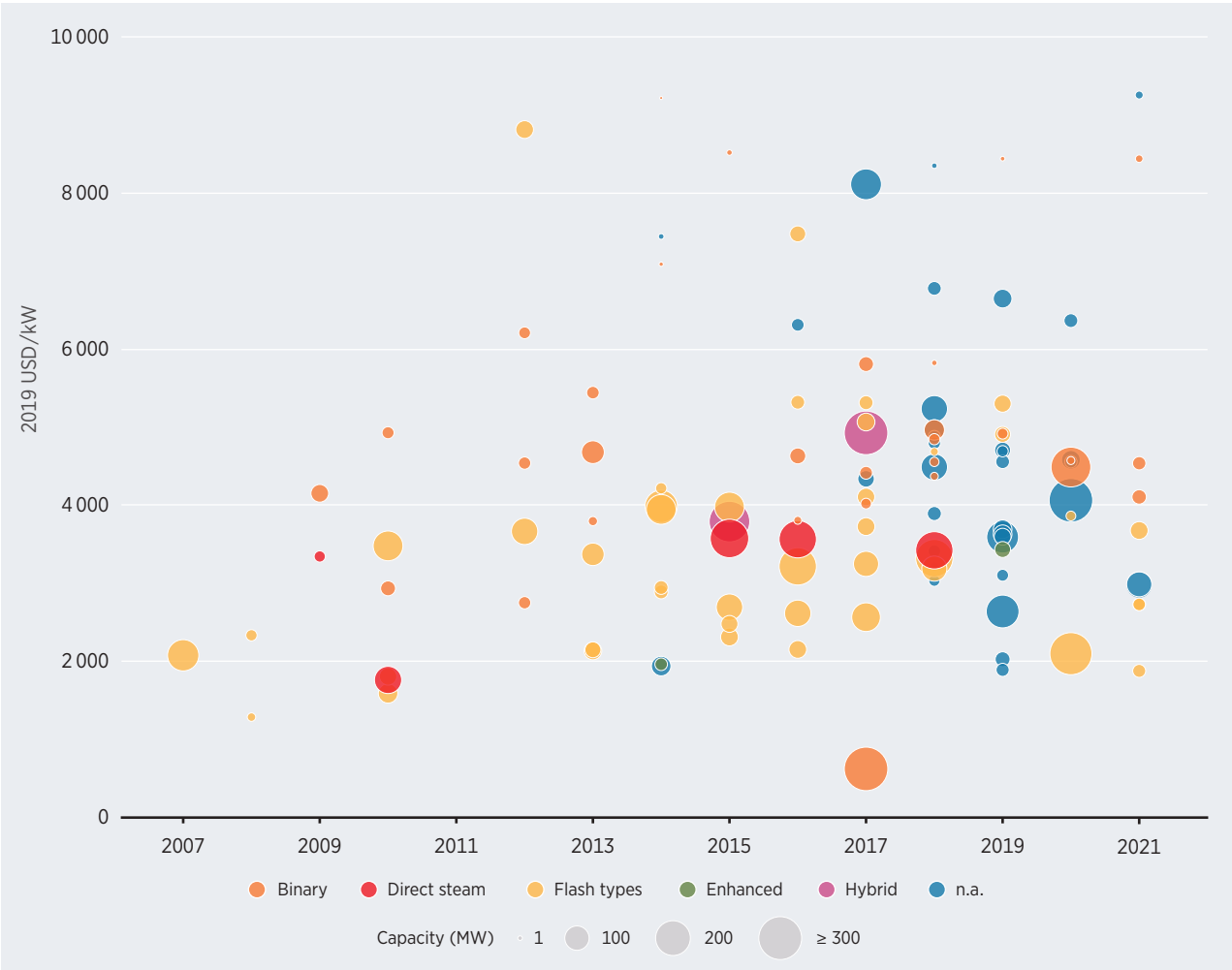
In line with rising commodity prices and drilling costs, between 2000 and 2009, the total installed costs for geothermal plants increased by between 60% and 70% (IPCC, 2011). Project development costs followed general increases in civil engineering and EPC costs during that period, with cost increases in drilling associated with surging oil and gas markets. Costs appear to have stabilized in recent years, however. In 2009, the total installed costs of conventional condensing “flash” geothermal power generation projects were between around USD 2 020/kW and USD 4 030/kW. Binary power plants were more expensive and installed costs for typical projects were between USD 2 390 and USD 5 840/kW that same year (IPCC, 2011).

Figure 6.2 presents the geothermal power total installed costs by project, technology and capacity, from 2007 to 2021. Based on the data available in the IRENA Renewable Cost Database, installed costs from 2010 onwards generally fell within the range of around USD 2 000/kW to USD 7 000/kW, although there were a number of project outliers.²⁹ Up to 2014, installation costs showed an increasing trend, with this stopping in 2015, when installed costs stabilized. In 2019, the global weighted average of installed cost was USD 3 916/kW, down from the USD 4 171/kW recorded in 2018 but up from the USD 2 588/kW reported in 2010. In the more exceptional case of projects where capacity is being added to an existing geothermal power project, the IRENA Renewable Cost Database suggests the cost of a geothermal power plant can be as low as USD 560/kW.

Geothermal power plants provide firm, 'always on' power, with capacity factors typically ranging between 60% to more than 90% depending on site conditions and plant design.

²⁹ These outliers are typically either small projects in remote areas, or are not representative of typical costs for a variety of other reasons.

Figure 6.2 Geothermal power total installed costs by project, technology and capacity, 2007-2021



Source: IRENA Renewable Cost Database.



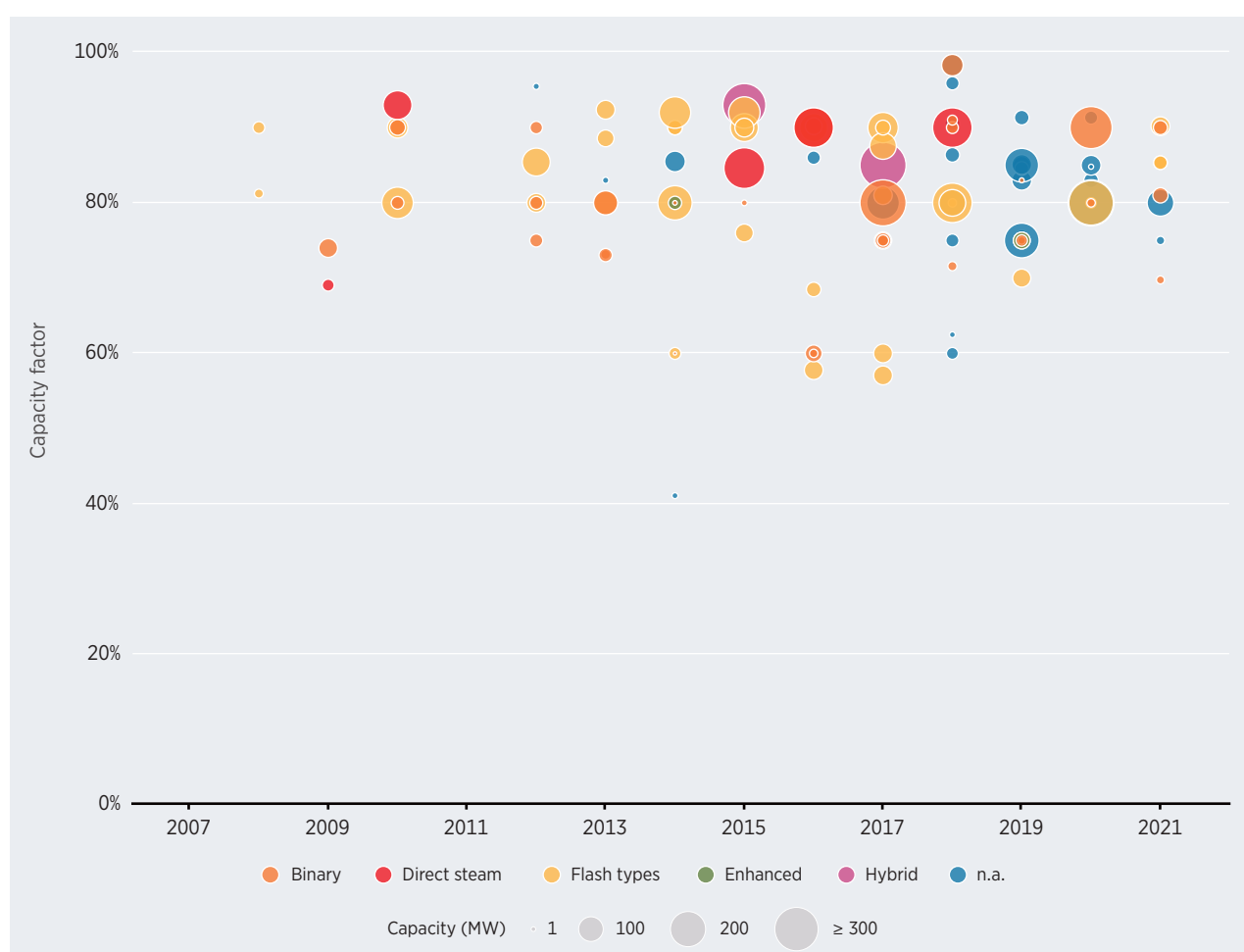
CAPACITY FACTORS

For the years 2007-2021, the data from the IRENA Renewable Cost Database shows that the capacity factors of geothermal power plants typically range between 60% to more than 90%. Figure 6.3 shows the capacity factors of geothermal power plants by technology and project size. For the data in the IRENA Renewable Cost Database, the average capacity factor of geothermal plants using direct steam is around 85%, while the average for flash technologies is 82%. Binary geothermal power plants that harness lower temperature resources are expected to achieve an average capacity factor of 78%.³⁰

LEVELISED COST OF ELECTRICITY

The total installed costs, weighted-average cost of capital, economic lifetime and O&M costs of a geothermal plant determine its LCOE. Even more so than solar and wind technologies, geothermal power projects require continuous optimisation throughout the lifetime of the project, with sophisticated management of the reservoir and production wells to ensure output meets expectations.

Figure 6.3 Capacity factors of geothermal power plants by technology and project size, 2007-2021



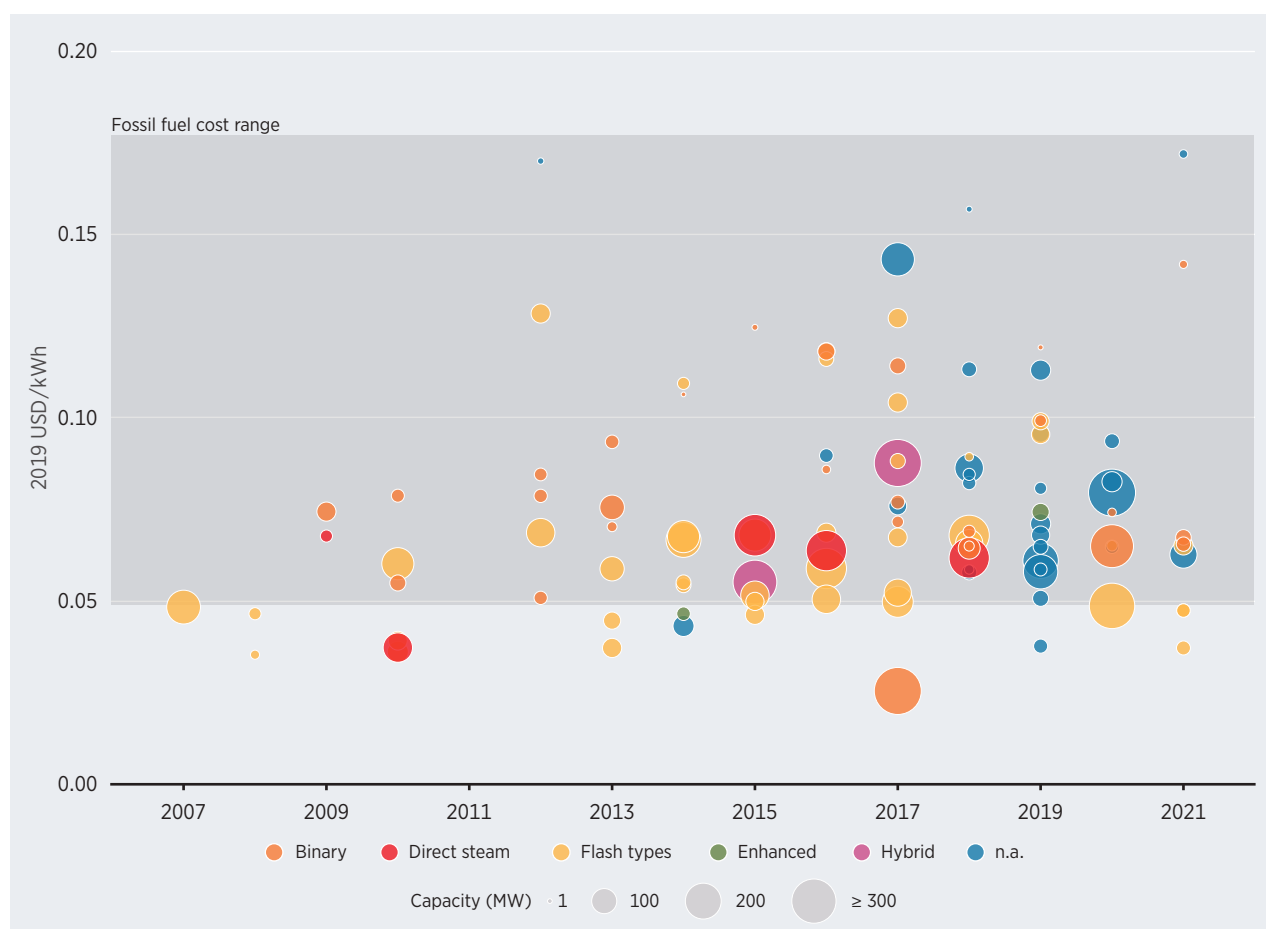
Source: IRENA Renewable Cost Database.

³⁰ In terms of the efficiency of conversion of the primary energy content (heat) to electricity, geothermal power plants report a worldwide average of 12% efficiency, while the upper range is situated at 21% for a vapour dominated plant (Zarrouk, S.J. and H. Moon, 2014).

Figure 6.4 presents the LCOEs of geothermal power projects by technology and size for the period 2007 to 2021. 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 0.17/kWh for greenfield developments in remote areas. The global weighted-average LCOE increased from around USD 0.05/kWh for projects commissioned in 2010 to around USD 0.07/kWh in 2019. With relatively little variation in project capacity factors, the LCOE of geothermal power projects tends to follow the trends in total installed costs. For the period 2019 to 2021, the data available suggests the LCOE could fall. However, this will depend on whether projects meet their commissioning goals and if not, whether cost overruns are incurred.

For this study, a project economic life of 25 years was assumed, along with O&M costs of USD 115/kW/year. Capacity factors were based on project data, if available; if not, national averages were used. O&M costs for geothermal projects are high relative to onshore wind and solar PV, in particular, because over time the reservoir pressure around the production well declines. This reduces well productivity and eventually power generation production, if remedial measures are not taken. In order to maintain production at the designed capacity factor, the reservoir and production profile of the geothermal power plants requires agile management, which will also typically mean the need to incorporate additional production wells over the lifetime of the plant. O&M costs of USD 115/kW/year therefore also include two sets of wells for makeup and re-injection over the 25-year life of the project, in order to maintain performance.

Figure 6.4 LCOE of geothermal power projects by technology and project size, 2007-2021



Source: IRENA Renewable Cost Database.



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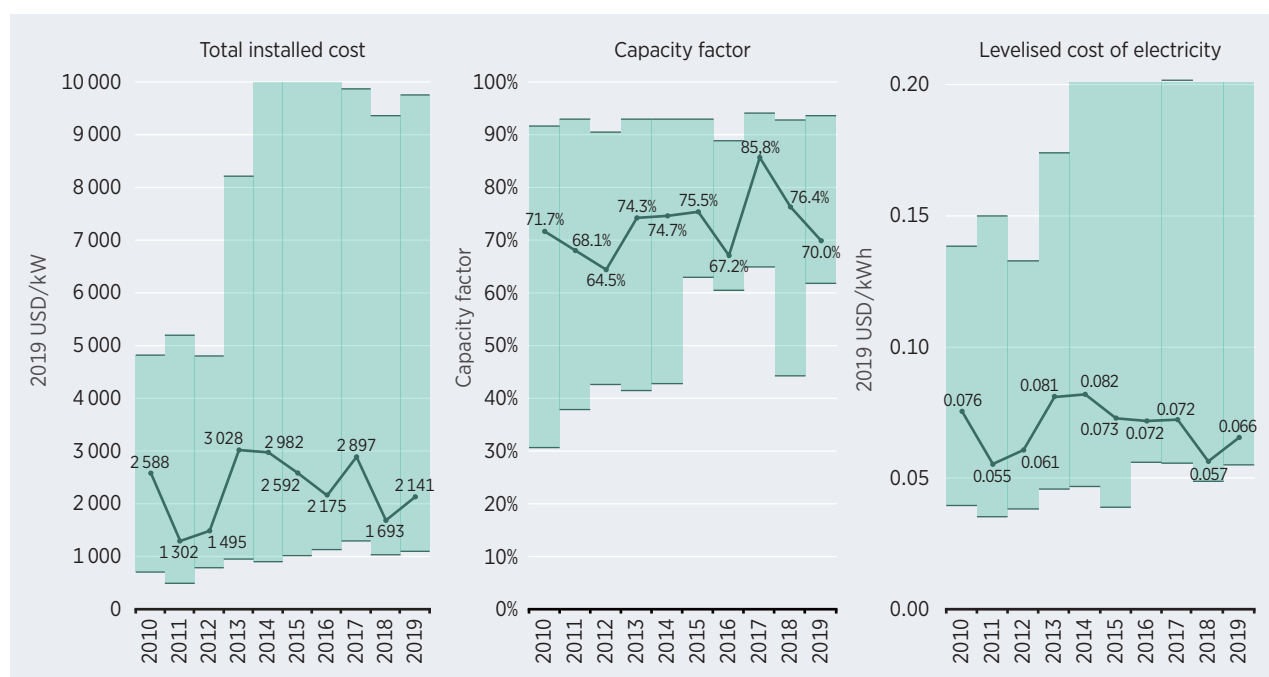


BIOENERGY

HIGHLIGHTS

- Between 2010 and 2019, the global weighted-average LCOE of bioenergy for power projects fell from USD 0.076/kWh to USD 0.066/kWh – a figure at the lower end of the cost of electricity from new fossil fuel-fired projects.
- Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available – such as by-products from agricultural or forestry processes onsite – they can provide highly competitive, dispatchable electricity.
- For bioenergy projects newly commissioned in 2019, the global weighted-average total installed cost was USD 2 141/kW (Figure 7.1). This represented an increase on the 2018 weighted-average of USD 1 693/kW.
- Capacity factors for bioenergy plants are very heterogeneous, depending on technology and feedstock availability. Between 2010 and 2019, the global weighted-average capacity factor for bioenergy projects varied between a low of 65% in 2012 to a high of 86% in 2017.
- In 2019, the weighted-average LCOE ranged from a low of USD 0.057/kWh in India and USD 0.059/kWh in China, to highs of USD 0.08/kWh in Europe and USD 0.099/kWh in North America.

Figure 7.1 Global weighted average total installed costs, capacity factors and LCOE for bioenergy, 2010-2019



Source: IRENA Renewable Cost Database.

Power generation from bioenergy can come from a wide range of feedstocks and use a variety of different combustion technologies. These run from mature, commercially available varieties with a long track record and a wide range of suppliers, to less mature and innovative technologies. The latter includes atmospheric biomass gasification and pyrolysis – technologies that are still largely at the development stage, but are now being tried out on a commercial scale. Mature technologies include: direct combustion in stoker boilers; low-percentage co-firing; anaerobic digestion; municipal solid waste incineration; landfill gas; and combined heat and power.

In order to analyse the use of biomass power generation, it is important to consider three main factors: feedstock type and supply; the conversion process; and the power generation technology. Although the availability of feedstock is one of the main elements for the economic success of biomass projects, this report's analysis focuses on the costs of power generation technologies and their economics, while briefly discussing delivered feedstock costs.

BIOMASS FEEDSTOCKS

The economics of biomass power generation are different to those of wind, solar and hydro, as biomass is dependent upon the availability of a feedstock supply that is predictable, sustainably sourced, low-cost and adequate over the long term. An added complication is that there are a range of cases where electricity generation is not the primary activity of the site operations, but is tied to forestry or agricultural processing activities that may impact when and why electricity generation happens. For instance, electricity generation at pulp and paper plants a significant proportion of the generated electricity will be used to run their operations.

Biomass is the organic material of recently living plants, such as trees, grasses and agricultural crops. Biomass feedstocks are thus very heterogeneous, with the chemical composition highly dependent on the plant species.

The cost of feedstock per unit of energy is highly variable, too, ranging from onsite processing residues that would otherwise cost money to dispose of, through to dedicated energy crops that must pay for the land used, harvesting and logistics of delivery, as well as storage on-site at a dedicated bioenergy power plant. Examples of low-cost residues that are combusted for electricity and heat generation are sugarcane bagasse, rice husks, black liquor and other pulp and paper processing residues, sawmill offcuts and sawdust, and renewable municipal waste streams.

In addition to cost, the physical properties of the feedstocks matter, as they will differ in ash content, density, particle size and moisture, with heterogeneity in quality. These factors also have an impact on the transportation, pre-treatment and storage costs, as well as the appropriateness of different conversion technologies. Some technologies are relatively robust and can cope with heterogeneous feedstocks, while others require more uniformity (e.g., some gasification processes).

A key cost consideration for bioenergy is that most forms have relatively low energy density. Collection and transport costs often therefore dominate the costs of feedstocks derived from forest residues and dedicated energy crops. A consequence of this is that logistical costs start to increase significantly the further from the power plant the feedstocks need to be sourced. In practical terms, this tends to limit the economic size of bioenergy powerplants, as the lowest cost of electricity is achieved once feedstock delivery reaches a certain radius around the plant.

For biomass technologies, the typical share of the feedstock cost in the total LCOE ranges from between 20% and 50%. However, prices for biomass sourced and consumed locally are difficult to obtain, meaning whatever market indicators are available for feedstock costs must be used as proxies. Alternatively, estimates of feedstock costs from techno-economic analyses that may not necessarily be representative or up-to-date can be used (see IRENA, 2015, for a more detailed discussion of feedstock costs).

TOTAL INSTALLED COSTS

Different regions have varying costs in biomass power generation, with both a technology component and a local cost component to the total. Projects in emerging economies tend to have lower investment costs when compared to projects in the OECD countries, as emerging economies often benefit from lower labour and commodity costs, but often also benefit from less stringent environmental regulations, thus allowing lower cost technologies with reduced emission control investments, albeit in some cases with higher local pollutant emissions.

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). Equipment costs tend to dominate, but specific projects can have high costs for infrastructure and logistics, or for grid connection when located in remote areas. Combined heat and power (CHP) biomass installations have higher capital costs, but the higher overall efficiency (around 80% to 85%) and the ability to produce heat and/or steam for industrial processes, or for space and water heating through district heating networks, can significantly improve the economics.

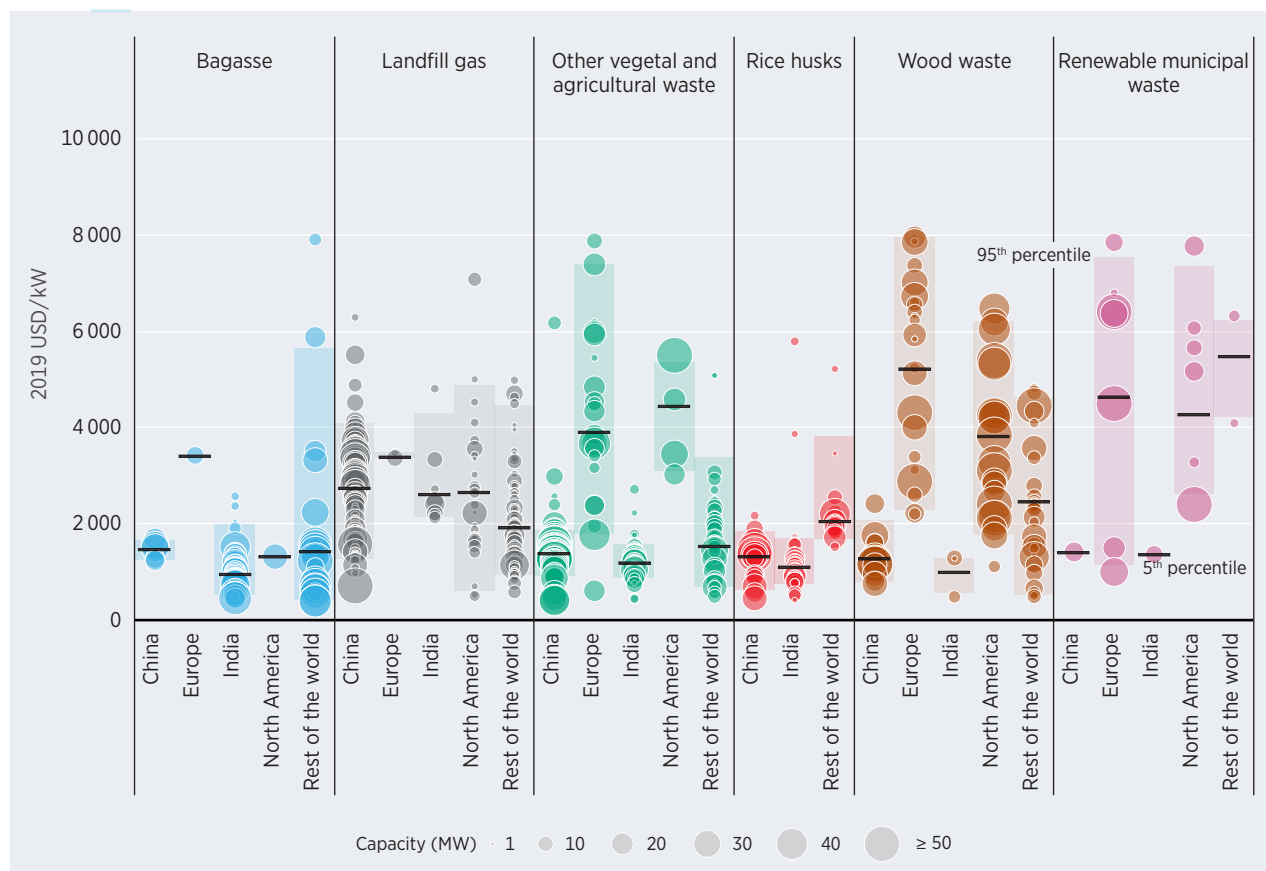
Figure 7.2 presents the total installed cost of bioenergy-fired power generation projects for different feedstocks for the years 2000–2019 where IRENA has sufficient data to provide meaningful cost ranges. Although the pattern of deployment by feedstock varies by country and region, it is clear that total installed costs across feedstocks tend to be higher in Europe and North America and lower in Asia and South America. This often reflects the fact that bioenergy projects in OECD countries are often based on wood, or are combusting renewable municipal or industrial waste, where the main activity may be waste management, with energy generation (potentially heat and electricity) a byproduct of CHP being the cheapest way to manage the waste.

In China, the 5th and 95th percentile of projects across all feedstocks ranged from a low of USD 620/kW for rice husk projects to a high of USD 4 094/kW for landfill gas projects, while in India, the range was from a low of USD 508/kW for bagasse projects to a high of 4 305/kW for landfill gas projects. The range is higher for projects in Europe and North America, with costs there ranging from USD 591/kW for landfill gas projects in North America to a high of USD 7 960/kW for wood waste projects in Europe, since the technological options used to develop projects are more heterogeneous and on average more expensive in these regions. The data available by feedstock for the rest of the world is more limited, but the 5th and 95th percentile total installed cost range for bagasse projects was the widest, from USD 422 to USD 5 654/kW.³¹ The weighted average total installed cost for projects in the rest of the world typically lay between the lower values seen in China and India and the higher values prevalent in Europe and North America for the time period covered.

Figure 7.3 presents the total installed cost by project, based on capacity ranges. It shows that in the power sector, bioenergy projects are predominantly small scale, with the majority of projects under 25 MW in capacity. There are, however, clear economies of scale evident for plants above around 25 MW, at least in the data for China and India. The relatively small size of bioenergy for electricity plants is the result of the low-energy density of bioenergy feedstocks and the increasing logistical costs involved in enlarging the collection area to provide a greater volume of feedstock to support large-scale plants. The optimal size of a plant to minimise LCOE of the project, in this context, is a trade-off between the cost benefits of economies of scale and the higher feedstock costs as the average distance to the plant of the feedstocks sourced grows.

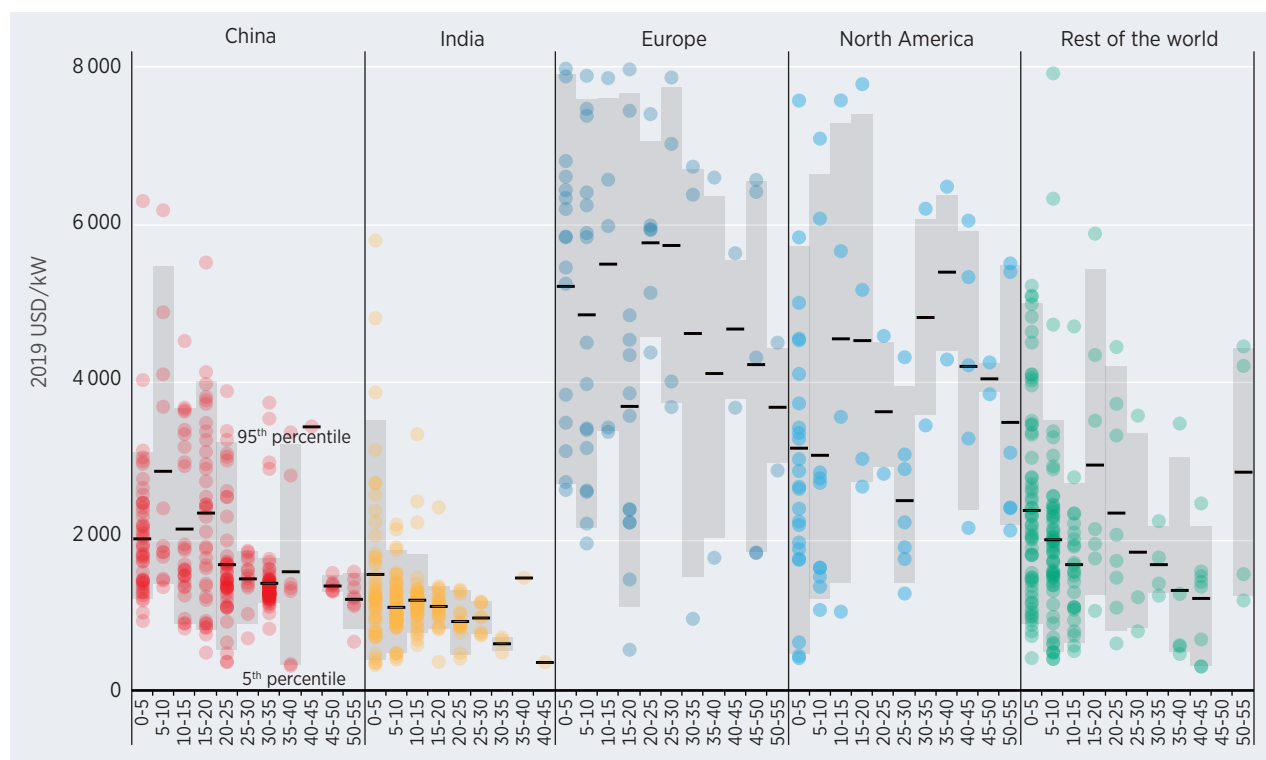
³¹ Excluding the total installed costs for renewable municipal waste, which are not representative given that there are only two projects in the database.

Figure 7.2 Total installed costs of bioenergy power generation projects by selected feedstocks and country/region, 2000-2019



Source: IRENA Renewable Cost Database.

Figure 7.3 Total installed costs of bioenergy power generation projects for different capacity ranges by country/region, 2000-2019



Source: IRENA Renewable Cost Database.

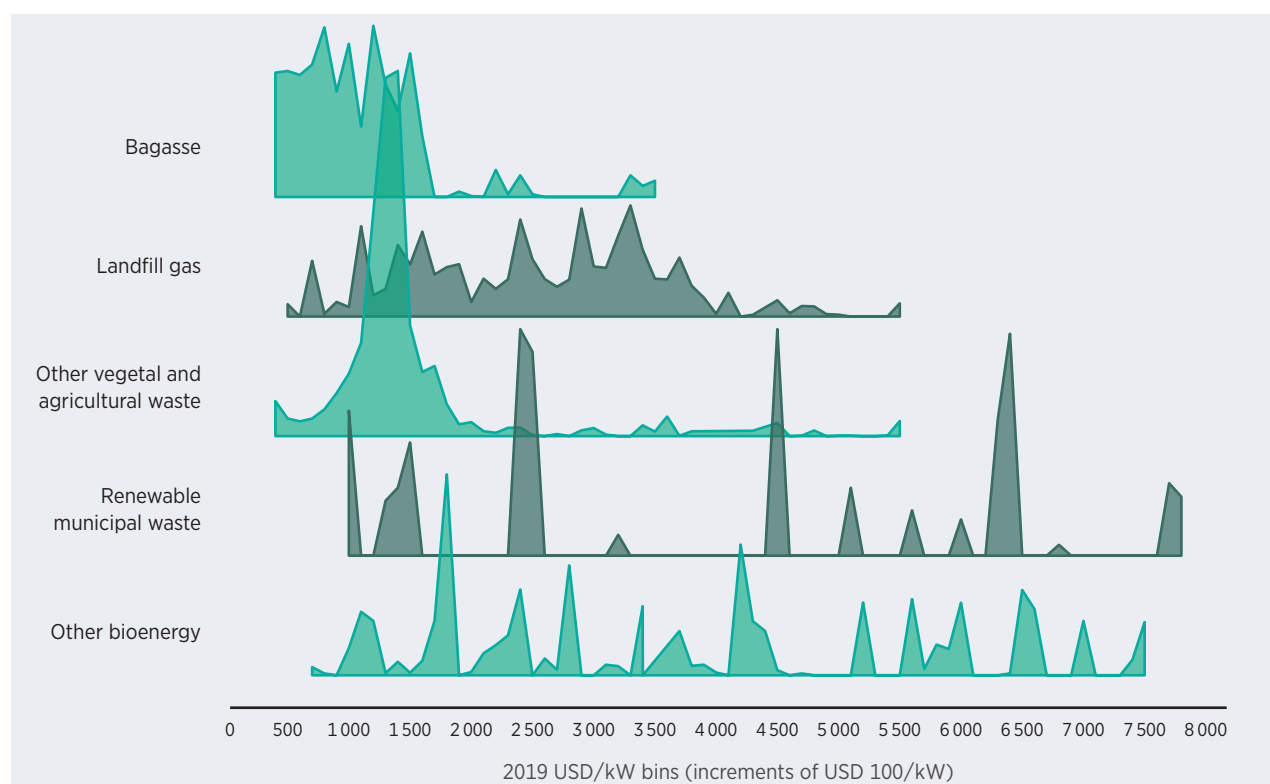
Figure 7.4 highlights that, the heterogeneous technology options available for bioenergy-fired power generation – from simple stoker boilers to advanced gasification technologies – and the location of their deployment result in a very heterogeneous distribution of total installed costs by feedstock. The exception is for projects using other vegetal and agricultural waste feedstocks, where deployment is concentrated in non-OECD countries and stoker boilers dominate. This results in much lower variation in total installed costs, although there remains a significant tail of high-cost projects, predominantly related to the use of more advanced technologies with much lower emissions profiles in OECD countries.

CAPACITY FACTORS AND EFFICIENCY

Bioenergy-fired electricity plants can have very high capacity factors – ranging between 85% and 95% – where feedstock availability is uniform over the entire year. Where the availability of feedstock is based on seasonal agricultural harvests, however, capacity factors are typically lower. An emerging issue for bioenergy power plants is the impact climate change may have on feedstock availability and how this might impact the total annual volume available, as well as its distribution throughout the year. This is an area where the need for research will be ongoing as the climate changes.

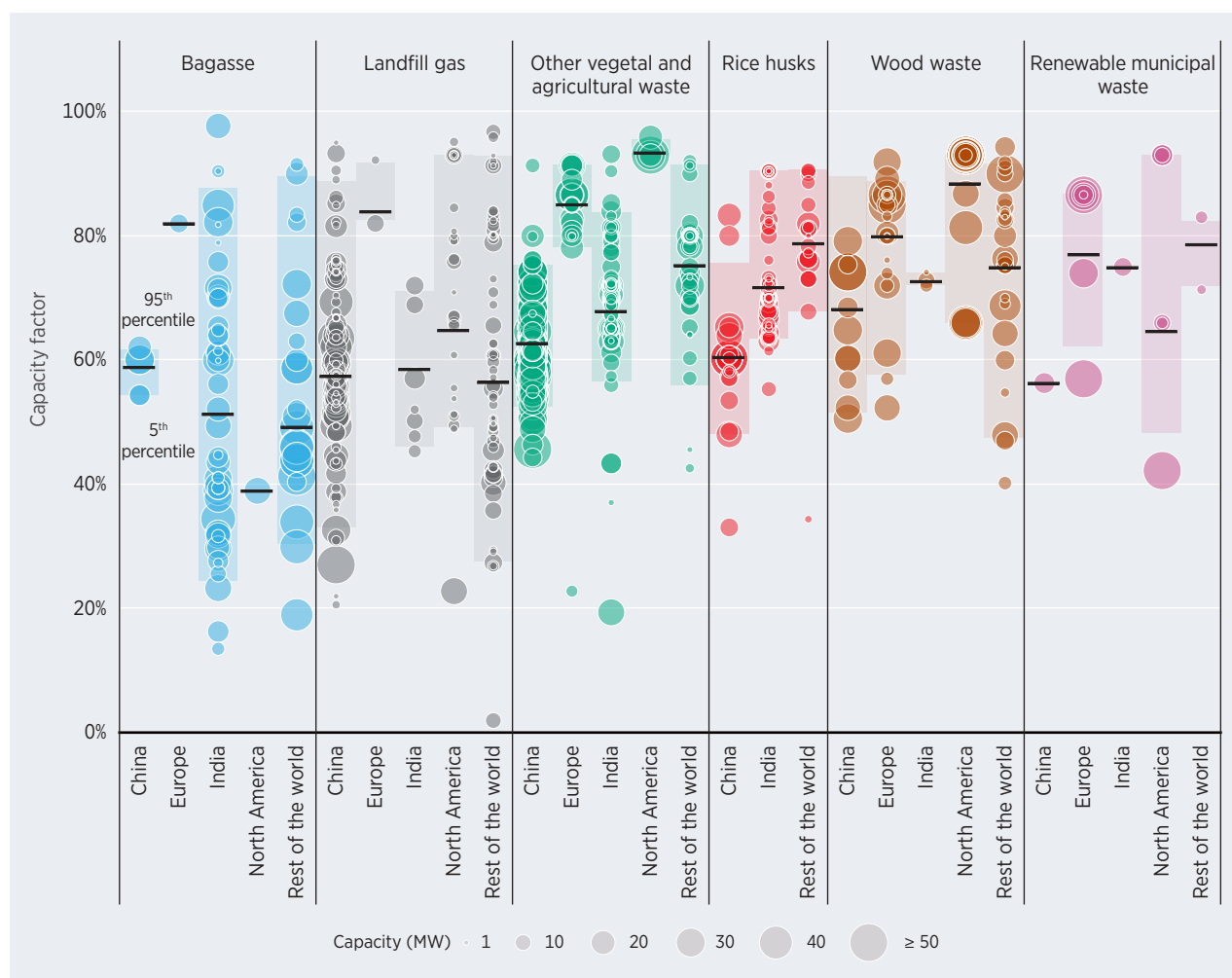
Figure 7.5 shows that biomass plants that rely on bagasse and landfill gas and other biogases tend to have lower capacity factors (around 50% to 60%), while plants relying on wood, fuel wood, rice husks and industrial and renewable municipal waste tend to have weighted-average capacity factors by region in the range of 60% to 85%.

Figure 7.4 Distribution of bioenergy for power total installed costs by technology, 2000-2019



Source: IRENA Renewable Cost Database.

Figure 7.5 Project capacity factors and weighted averages of selected feedstocks for bioenergy power generation projects by country and region, 2000-2019



Source: IRENA Renewable Cost Database.

After accounting for feedstock handling, the assumed net electrical efficiency of the prime mover (generator) averages around 30%, but varies from a low of 25% to a high of around 36%. CHP plants that produce heat and electricity, achieve higher efficiencies, with an overall efficiency of 80% to 85% not uncommon. In developing countries, less advanced technologies – and sometimes suboptimal maintenance when revenues are less than anticipated – 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 a modern, well-maintained stoker,

circulating fluidised bed (CFB), bubbling fluidised bed (BFB) and anaerobic digestion systems (Mott MacDonald, 2011). These assumptions are unchanged from the last two IRENA cost reports (IRENA, 2018a and 2019a).

Table 7.1 presents data for project weighted-average capacity factors of bioenergy-fired power generation projects for the period 2000-2019. Europe showed the highest weighted-average capacity factor– 81% – followed by North America, with 78%. India and China showed the lowest weighted-average capacity factors, of 67% and 64%, respectively.

Table 7.1 Project capacity factors and weighted averages of bioenergy power generation projects by country/region, 2000-2019

	2000-2019		
	5 th percentile (%)	Weighted average (%)	95 th percentile (%)
China	39	64	83
Europe	46	81	92
India	30	67	85
North America	37	78	94
Rest of the world	30	65	91

Source: IRENA Renewable Cost Database.

OPERATION AND MAINTENANCE COSTS

Fixed O&M costs include labour, insurance, scheduled maintenance and routine replacement of plant components, such as boilers, gasifiers, feedstock handling equipment and other items. In total, these O&M costs account for between 2% and 6% of the total installed costs per year. Large bioenergy power plants tend to have lower per kW fixed O&M costs, due to economies of scale.

Variable O&M costs, at an average of USD 0.005/kWh, are usually low for bioenergy power plants, when compared to fixed O&M costs. Replacement parts and incremental servicing costs are the main components of variable O&M costs, although these also include non-biomass fuel costs, such as ash disposal. Due to its project-specific nature and the limited availability of data, variable O&M costs have been merged in this report with fixed O&M costs.

LEVELISED COST OF ELECTRICITY

The wide range of bioenergy-fired power generation technologies, installed costs, capacity factors and feedstock costs result in a wide range of observed LCOEs for bioenergy-fired electricity. Figure 7.6 summarises the estimated LCOE range for biomass power generation technologies by feedstock and country/region where the IRENA Renewable Cost Database has sufficient data to provide meaningful insights.

Assuming a cost of capital of between 7.5% and 10% and feedstock costs between USD 1/Gigajoule (GJ) and USD 9/GJ (the LCOE calculations in this report are based on an average of USD 1.5/GJ), the global weighted-average LCOE of biomass-fired electricity generation for projects commissioned in 2019 was USD 0.066/kWh, down from USD 0.076/kWh in 2010.

Looking at the full dataset for the period from 2000 to 2019, the lowest weighted-average LCOE of biomass-fired electricity generation was found in India at USD 0.057/kWh, while the 5th and 95th percentile values were USD 0.040/kWh and USD 0.097/kWh (Figure 7.6). The highest weighted-average for this period was USD 0.099/kWh in North America, where the 5th and 95th percentiles of projects fell between USD 0.048/kWh and USD 0.180/kWh. The weighted average LCOE of bioenergy projects in China was USD 0.059/kWh, where the 5th and 95th percentiles of projects fell between USD 0.044/kWh and USD 0.116/kWh. The weighted average in Europe over this period was USD 0.08/kWh, and USD 0.069/kWh in the rest of the world.

Bioenergy can provide very competitive electricity where capital costs are relatively low and low-cost feedstocks are available. Indeed, this technology can provide 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

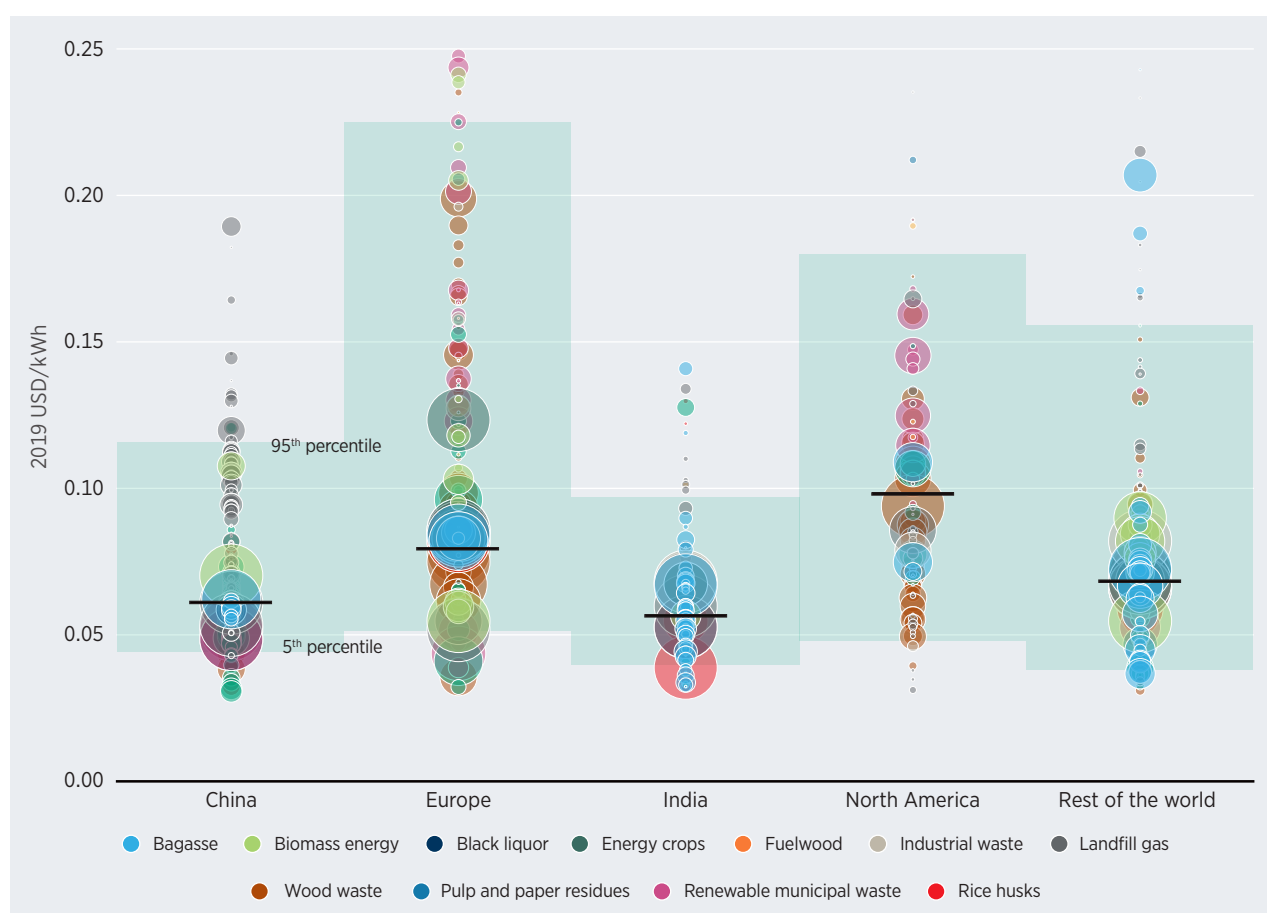
feedstock costs are minimal, or even zero. Where onsite industrial process steam or heat loads are required, bioenergy CHP systems can reduce the LCOE for electricity to as little as USD 0.03/kWh, depending on the alternative costs for heat or steam available to the site.³² Even higher-cost projects in certain developing countries can be attractive, however, because they provide security of supply in conditions where brownouts and blackouts can be particularly problematic for the efficiency of industrial processes.

Projects using low-cost feedstocks such as agricultural or forestry residues, or the residues from processing agricultural or forestry products, tend to have the lowest LCOE's. For projects in the IRENA Renewable Cost Database, the weighted average project LCOE by feedstock is USD 0.06/kWh or less for projects using black

liquor, primary solid bioenergy (typically wood or wood chips), renewable municipal solid waste and other vegetal and agricultural waste. Projects relying on municipal waste come with high capacity factors and are generally an economic source of electricity, however, the LCOE for projects in North America is significantly higher than the average. 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, such projects also sometimes supply heat either to local industrial users, or district heating networks, with the revenues from these sales bringing the LCOE below what is presented here. Many of the higher cost projects in Europe and North America using municipal solid waste as a

Figure 7.6 LCOE by project and weighted averages of bioenergy power generation projects by feedstock and country/region, 2000-2019



Source: IRENA Renewable Cost Database.

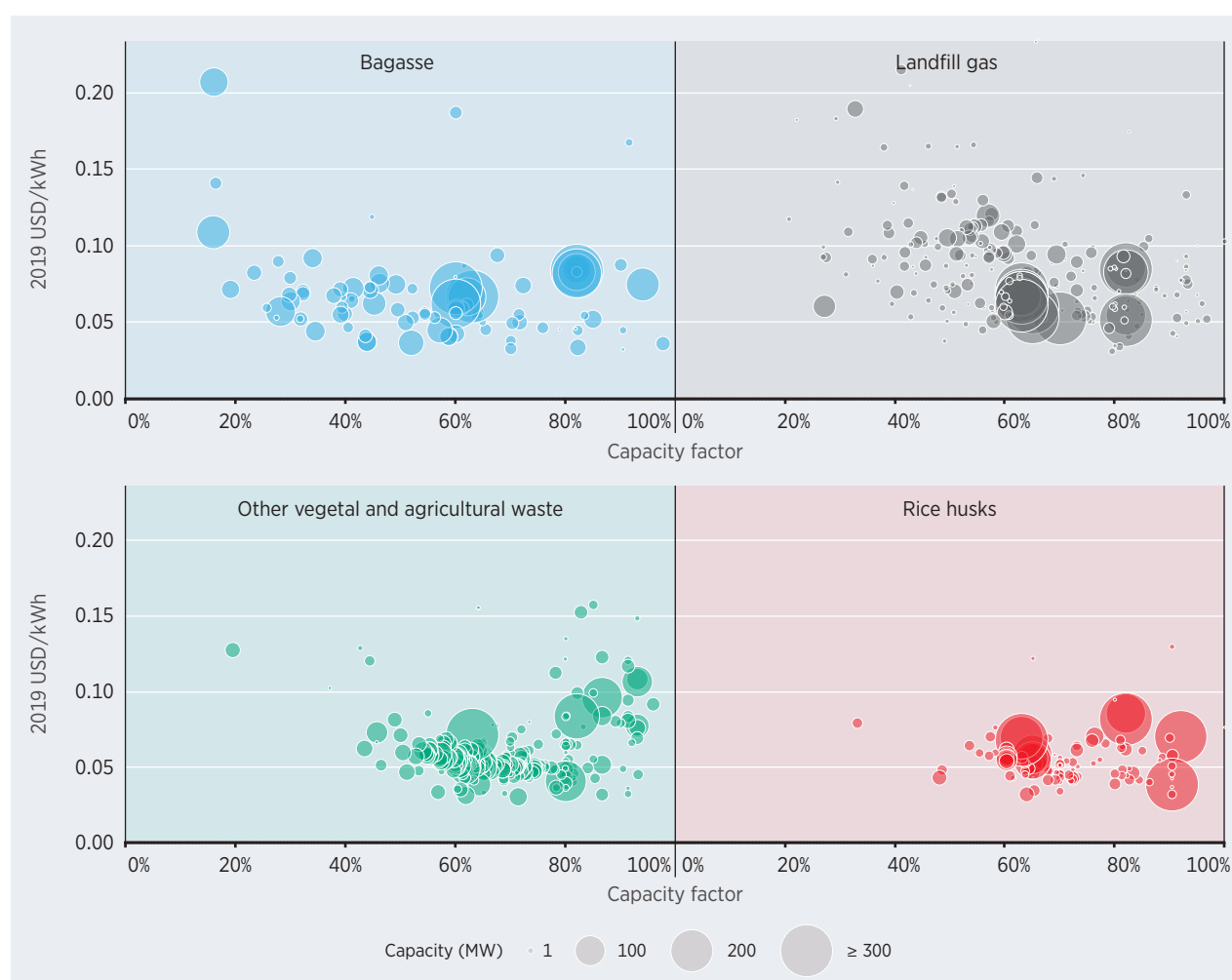
³² This is an area of weakness of the data available to IRENA, as in many cases the details of any onsite heat use or sales is not readily available. Future work by IRENA will focus on research that will try and collect this information for a greater number of projects. Until that time, these LCOE values should be considered upper ranges, as an increased heat credit would materially reduce weighted-average LCOE values.

feedstock rely on technologies with higher capital costs, as more 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.

Figure 7.7 presents the LCOE and capacity factor by project and weighted averages for bagasse, landfill gas, rice husks and other vegetal and agricultural waste used as feedstock for bioenergy-fired power generation projects. It shows how the dynamic relationship between feedstock availability influences the economic optimum for a project. This shows through clearly in the data for bagasse plants. Over a capacity factor of 30%, there is no strong relation between capacity factors and the

LCOE of projects. This indicates that the availability of a continuous stream of feedstock allows for higher capacity factors, but is not necessarily more economic, if it means that low-cost seasonal agricultural residues need to be supplemented by more expensive feedstocks. Importantly, the LCOE of these projects is comparable to projects relying on more generic, woody biomass feedstocks, such as wood pellets and chips, that can be more readily purchased year-round. Thus, access to low-cost feedstock offsets the impact on LCOE of lower capacity factors. For projects using other vegetal and agricultural wastes as the primary feedstock, the data tends to suggest that there is correlation between higher capacity factors and lower LCOE's in developing countries, given that the higher cost projects with capacity factors above 80% are located in OECD countries.

Figure 7.7 LCOE and capacity factor by project of selected feedstocks for bioenergy power generation projects, 2000-2019



Source: IRENA Renewable Cost Database.

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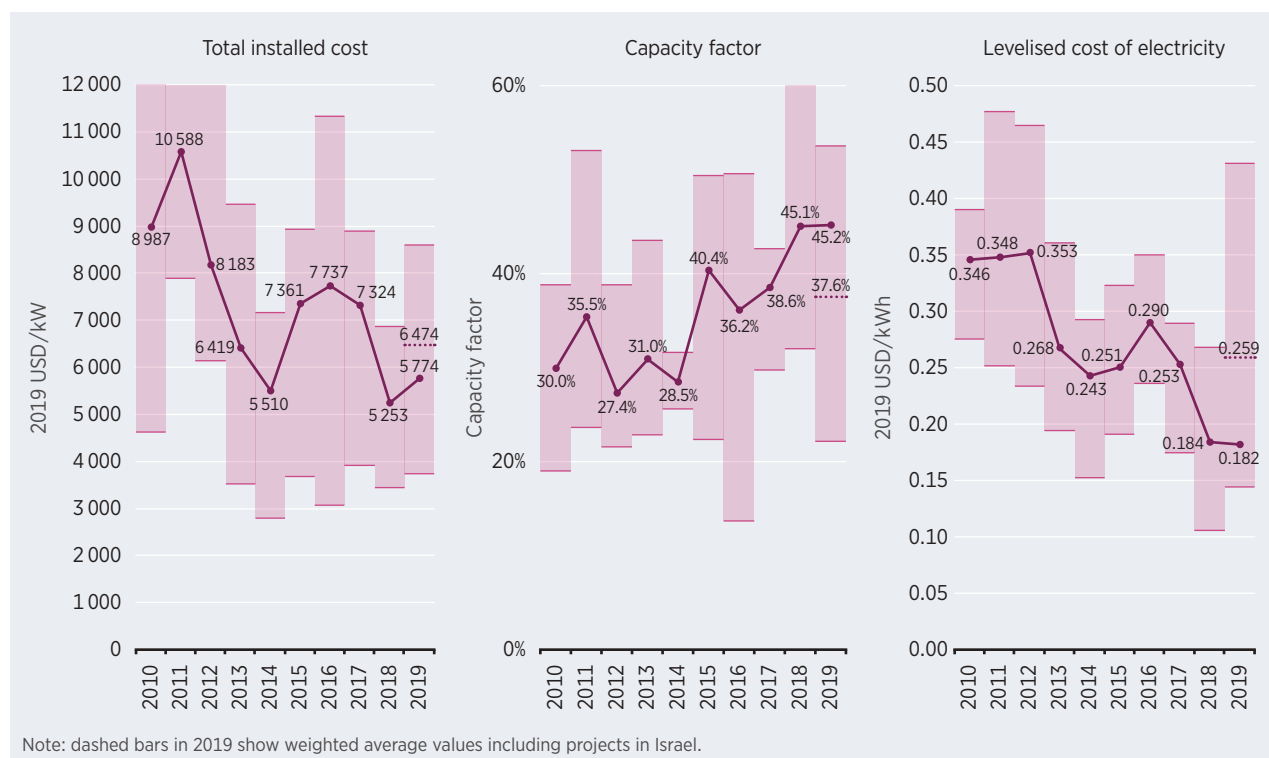


CONCENTRATING SOLAR POWER

HIGHLIGHTS

- The weighted average LCOE of CSP plants fell by 47% between 2010 and 2019, from USD 0.346/kWh to USD 0.182/kWh, excluding two much delayed projects that are not representative of today's optimised technology configuration that were commissioned in 2019.
 - The global weighted-average total installed costs of CSP plants commissioned in 2019 were USD 5 774/kW – one-tenth higher than in 2018, but 36% lower than in 2010.
 - The IRENA data shows that during 2018 and 2019, total installed costs ranged between USD 3 183 and USD 8 645/kW for CSP projects with storage capacities from 4-8 hours.
- Projects with eight hours or more of thermal storage capacity evidenced a narrower range, of between USD 4 077/kW and USD 5 874/kW.
- The capacity factor of CSP plants increased from 30% in 2010 to 45% in 2019, as the technology improved, deployment occurred in areas with better solar resources and the average number of hours of storage increased.
 - Data in the IRENA Auction and PPA Database shows a weighted-average price of electricity of USD 0.075/kWh for CSP projects to be commissioned in 2021. This represents a reduction of 59% when compared to the global weighted-average project LCOE in 2019.

Figure 8.1 Global weighted average total installed costs, capacity factors and LCOE for CSP, 2010-2019



Source: IRENA Renewable Cost Database.

Concentrating solar power (CSP) systems work by concentrating the sun's rays using mirrors to create heat. In most systems today, the heat created from the sun's energy is transferred to a heat transfer fluid. Electricity is then generated in a steam cycle, using the heat transfer fluid to create steam and generate as in conventional thermal power plants. CSP plants today typically also include low-cost thermal storage systems to decouple generation from the sun. Most commonly, a two-tank molten salt storage system is used, but designs vary.

With reference to the mechanism by which solar collectors concentrate solar irradiation, it is possible to classify CSP systems into 'line concentrating' and 'focal concentrating' varieties. This refers to the arrangement of the concentrating mirrors.

The most widely deployed linear concentrating systems are parabolic trough collectors (PTCs). These systems are made up of parabolic trough shaped mirrors, that are connected together in 'loops'. The parabolic trough mirrors are also known as collectors and concentrate the solar radiation along a heat receiver tube (absorber). This is a thermally efficient component placed in the collector's focal line. Single-axis tracking systems are traditionally used to increase energy absorption across the day and ensure the highest temperature feasible for the heat transfer fluid (often thermal oil) is reached given the intensity of the solar irradiation and the technical characteristics of the concentrators and heat transfer fluid. These transfer the heat through a heat exchange system to produce superheated steam, which drives a turbine to generate electricity.

Another type of linear-focusing CSP plant, though much less deployed, uses Fresnel collectors. This type of plant relies on an array of almost flat mirrors that concentrate the sun's rays onto elevated linear receivers above the mirror array. Unlike parabolic trough systems, in Fresnel collector systems, the receivers are not attached to the collectors, but situated in a fixed position several metres above the primary mirror field Fresnel systems.

Solar towers (STs), sometimes also known as power towers, are the most widely deployed focal point CSP technology. In these systems, the mirrors are called heliostats (a ground-based array of mirrors). The heliostat field is arranged in a circular or semi-circular pattern around a large central receiver tower. Each heliostat is individually programmed to track the sun, orientating constantly in two axes to concentrate solar irradiation onto the receiver located at the top of a tower. The central receiver absorbs the heat through a heat transfer medium,³³ which turns it into electricity – typically through a water-steam thermodynamic cycle. Solar towers can achieve the highest solar concentration factors (above 1000 suns) and therefore the highest operating temperatures. This gives them an advantage in terms of greater steam cycle generating efficiency and in reducing the cost of thermal energy storage, reducing generating costs and resulting in higher capacity factors.

Cumulative CSP installed capacity grew five-fold, globally, between 2010 and 2019, to reach around 6.3 GW. However, compared with other renewable energy technologies, CSP can still be considered in its infancy, in terms of deployment. After very modest activity in 2016 and 2017 – with annual additions hovering around 100 MW per year – the global market for CSP grew in 2018 and 2019. In those years, an increasing number of projects came online in China, Morocco and South Africa. Yet, new capacity additions overall remained relatively low, at 660 MW per year on average, during that period.

The sector was optimistic China's plans to scale up the technology domestically would provide a boost to the industry and take deployment to new levels. China's policy to support the build-out of 20 commercial-scale plants to scale up a variety of technology solutions, develop supply chains and gain operating experience included an ambitious timeline for completion. A number of developers were able to meet the required commissioning dates, but many have struggled for a variety of reasons from land acquisition issues to EPC contractor delays. Despite these delays, a further three projects are likely to be commissioned in 2020. The industry

³³ Some solar tower designs that have been developed, however, aim to avoid the use of the heat transfer medium and instead directly produce steam.

experience gained from these early projects is likely to be beneficial to future deployment plans and to the further development of the supply chains. If this does turn out to be the case, the global industry may benefit from this, as Chinese suppliers and EPC contractors will put increasing downward pressure on cost structures in projects around the world.

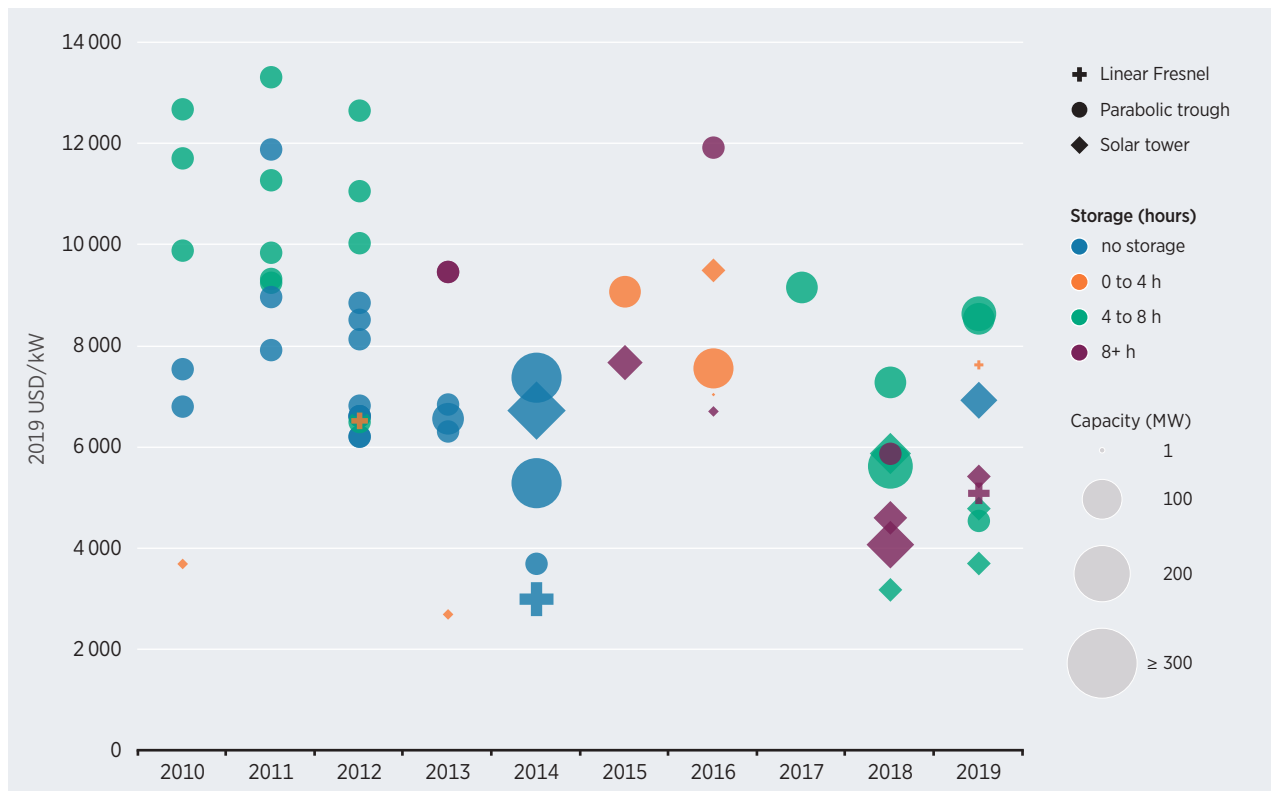
TOTAL INSTALLED COSTS

In the early years of CSP plant development, adding thermal energy storage was often uneconomic and its use was limited. Since 2015, hardly any projects have been built or planned without thermal energy storage, as adding thermal energy storage is now a cost-effective way to raise capacity factors and contributes to a lower LCOE and greater flexibility in dispatch over the day. The average thermal storage capacity for PTC plants in the IRENA Renewable Cost Database increased from 3.3 hours between 2010 and 2014 to 5.7 hours between 2015 and 2019 (an increase of almost three-quarters). For STs, that value increases from 5 hours in the 2010-2014 period to 7.7 hours in the 2015-2019 period (a 54% increase).

Total installed costs for CSP plants have fallen between 2010 and 2019. This has been true even as the projects developed have increased the size of their thermal energy storage systems. During 2018 and 2019, the installed costs of CSP plants with storage were at par or lower – sometimes dramatically so – than the capital costs of plants without storage commissioned in the 2010-2014 period. The projects commissioned in 2018 and 2019 contained in the IRENA Renewable Cost Database had an average of 7.2 hours of storage. This is 2.2 times larger than the average value for projects commissioned between 2010 and 2014, and is expected to continue to grow. For instance, the average storage level for projects in the ‘under construction’ or ‘under development’ categories of the SolarPACES database is 11.7 hours (63% higher than those of 2018-2019) for projects expected to be operational in 2020 and 2021 (SolarPACES, 2020).

The capital costs for CSP for projects for which cost data is available in the IRENA Renewable Cost Database and that were commissioned in 2019 ranged between USD 3 704/kW and USD 8 645/kW (Figure 8.2).

Figure 8.2 CSP total installed costs by project size, collector type and amount of storage, 2010-2019



Source: IRENA Renewable Cost Database.

Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.

The range of installed costs in 2019 is between 16% and 19% higher than in 2018. The data for 2019 include two Israeli projects that were much delayed (one ST and one PTC project). One of these projects was first announced in 2008, with the winning bid succeeding in 2012. These projects continued between 2014 and 2017, using technology and capital cost structures of that time (Power Technology, 2016; SolarPACES/NREL, 2020). Excluding these projects results in capacity weighted-average installed costs of USD 5 774/kW in 2019 – a value 10% higher than in 2018, but 36% lower than in 2010. Year-on-year variability in average capital costs remains high, however, given the small number of projects commissioned in each year.

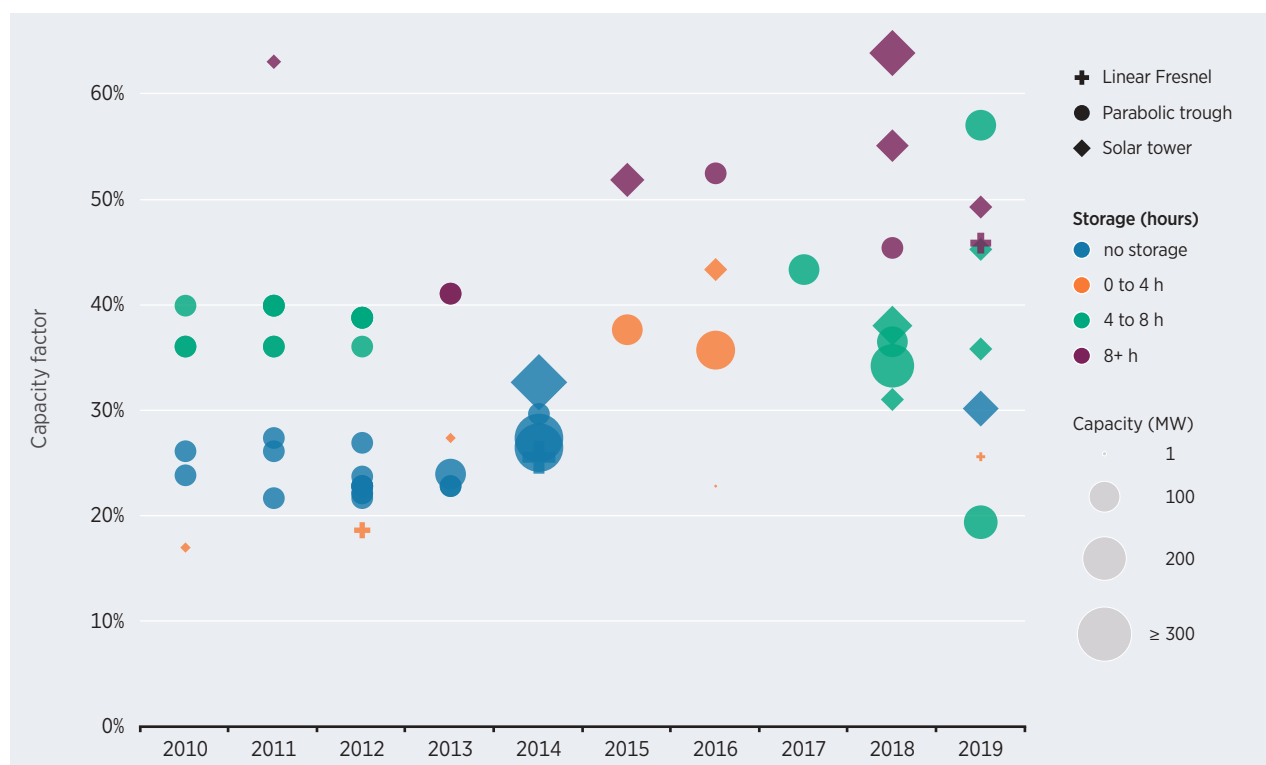
During 2018 and 2019, the IRENA's Renewable Cost Database shows a capital cost range of between USD 3 183/kW and USD 8 645/kW for CSP projects with storage capacities of between 4 and 8 hours. In the same period, the cost range of projects with 8 hours or more of thermal storage capacities was narrower – between USD 4 077/kW and USD 5 874/kW – and had a lower maximum value due to the fact these projects were in China.

CAPACITY FACTORS

The quality of the solar resource is the determining factor, along with the technology configuration, of the achievable capacity factor for a given location and technology. Adding storage capacity can increase the capacity factor, up to a certain level, given there are diminishing marginal returns. However, this is a complex design optimisation that is driven by the desire to minimise the LCOE. The LCOE is being optimised, given the site solar resource, across the storage capacity and the necessary solar field size to minimise LCOE and ensure optimal utilisation of the heat generated. This is a delicate balance, as smaller than optimal solar field sizes result in under utilisation of the thermal energy storage system and the selected power block. A larger than optimal solar field size would add additional capital costs, but with the potential heat generation being curtailed at times due to lack of storage and generation capacity.

The fact that costs for thermal energy storage have fallen and operating temperatures increased, has lowered the cost of storage and has increased the optimal level of storage to minimise LCOE

Figure 8.3 Capacity factor trends for CSP plants, 2010-2019



Source: IRENA Renewable Cost Database.

Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.

in a given location. This has been an important contributor in unlocking increased capacity factor values for CSP plants, in recent years. The capacity factor values for projects in IRENA's Renewable Cost Database during 2018 and 2019 ranged from 19% to 57% (Figure 8.3).

The CSP market has experienced a shift from areas with lower solar resources in its early years, towards project development in areas with higher irradiation – a level typically referenced by the annual Direct Normal Irradiance (DNI) metric. Projects with higher DNI levels than the early facilities developed in Spain have come online in a wide range of high-resource locations, such as Morocco, Chile and South Africa. Besides the

increased storage capacity trend – which has sometimes made up for lower DNI availability (e.g. in the case of China) – the shift towards high DNI locations has been an important driver of increased CSP capacity factors (Figure 8.4).

High heat transfer fluid (HTF) temperatures can also contribute to lower storage costs. For a given DNI level and fixed plant configuration conditions, higher HTF temperatures allow for a larger temperature differential between the 'hot' and 'cold' storage tanks that means greater energy (and hence storage duration) can be extracted for a given physical storage size, or less storage medium volume is needed to achieve a given number of storage hours.

Figure 8.4 Capacity factor trends for CSP plants by direct normal irradiance, 2010-2019



Source: IRENA Renewable Cost Database.

Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.

OPERATION AND MAINTENANCE COSTS

All-in O&M costs that include insurance and other asset management costs for CSP plants are substantial compared to solar PV and onshore wind. The typical range of O&M costs for CSP plants in operation today, with some exceptions, is in the range USD 0.02/kWh to USD 0.04/kWh. This is likely a good approximation for the range of O&M in relevant markets, globally today, even if based on an analysis relying on a mix of bottom-up engineering estimates and best-available reported project data (Fichtner, 2010; IRENA, 2018; Li *et al.*, 2015; Turchi, 2017; Turchi *et al.*, 2010; Zhou, Xu and Wang, 2019). However, IRENA analysis for a range of markets (Table 8.1) suggests for projects which achieved financial close in 2019, more competitive O&M costs are possible in some markets.

Although the O&M costs in absolute terms are high compared to solar PV and many onshore wind farms per kWh, the higher LCOEs of CSP plants today mean that the overall share of O&M is not as high as might be expected. Analysis conducted by IRENA in collaboration with DLR, found that in 2019, O&M costs averaged about 18% of the LCOE for projects in G20 countries.

Historically, the largest individual O&M costs for CSP plants were the expenditures for receiver and mirror replacements. As the market has evolved, new designs and improved technology have helped reduce failure rates for receivers and mirror breakage, driving down these costs. Insurance costs also remain an important contributor to O&M costs. Though partly dependant on how secure the project location may be, these typically range between 0.5% and 1% of the initial capital outlay (a figure that is lower than the total installed cost).

O&M costs vary from location to location, however, given differences in irradiation, plant design, technology, labour costs and individual market component pricing, linked to local costs differences. Upcoming analysis for G20 countries provides estimates for a wider range of markets than the data reported historically. This has the advantage of indicating possibilities in deploying CSP in previously undeveloped markets. The results indicate that in those markets presented, the overall range of insurance-included O&M costs is likely to be within

the USD 0.011/kWh to USD 0.032/kWh range. Most markets evaluated in the analysis seem to be able to achieve costs closer to the lower bound of that range, however, in a sign of improved competitiveness in total running costs (Table 8.1).

LEVELISED COST OF ELECTRICITY

Lower total installed costs and higher capacity factors are driving the decline in the cost of electricity from CSP. The LCOE of CSP between 2010 and 2012 stayed relatively stable, at a global weighted average of between USD 0.346/kWh and USD 0.353/kWh (Figure 8.1). With the additional deployment of about 800 MW in Spain and a few projects in the United States and other markets, in 2012, the LCOE increased over that of 2010 and the range widened (Figure 8.5).

From 2013 onwards, however, a downward trend in the LCOE of projects become clearly visible. Data from IRENA's Renewable Cost Database shows weighed-average LCOE estimates by project during 2013-2015 about one third lower than observed in the 2010-2012 period. After 2012, the CSP market also shifted away from Spain to newer markets with higher solar resources. Rather than technology learning effects alone, it is more likely, then, that that these higher DNIs offer a more predominant explanation of the lower LCOEs during that second period (Lilliestam *et al.*, 2017).

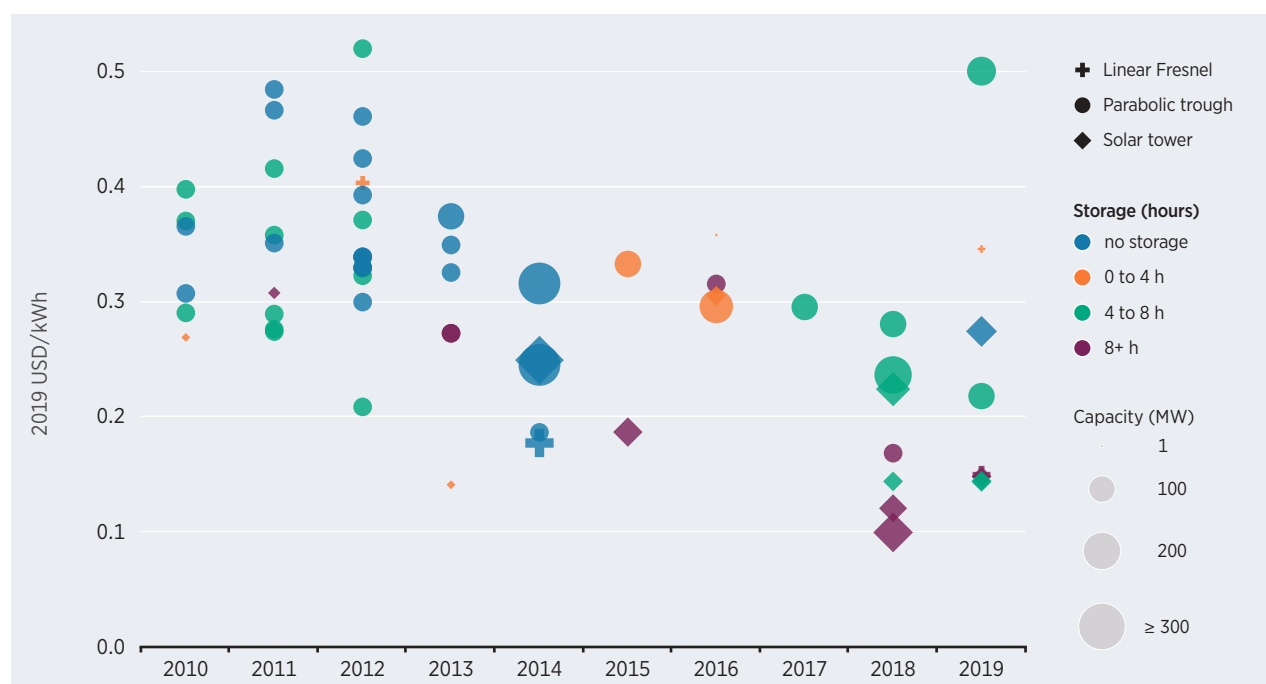
Yet, while a shift towards project locations with higher DNIs was a major contributor to the increased capacity factors (and therefore lower LCOE values) seen after 2012, the increasing capacity factor trend is also related to a move towards plant configurations with higher storage capacities and the ability to be more freely dispatched over the day.

In 2016 and 2017, only a handful of plants were completed, with around 100 MW added in each year. The results for these two years are therefore volatile and driven by the specific plant costs. The increase in LCOE in 2016 was driven by the higher costs of the early projects in South Africa and Morocco commissioned in that year. In 2017, the global weighted-average LCOE returned to levels more consistent with those experienced in

Table 8.1 Insurance included O&M costs estimates in selected markets, 2019

Country	Parabolic trough collectors (2019 USD/kWh)	Solar tower (2019 USD/kWh)
Argentina	0.025	0.023
Australia	0.027	0.026
Brazil	0.020	0.020
China	0.021	0.018
France	0.032	0.027
India	0.015	0.015
Italy	0.025	0.023
Mexico	0.016	0.015
Morocco	0.013	0.012
Russian Federation	0.024	0.022
Saudi Arabia	0.012	0.011
South Africa	0.013	0.012
Spain	0.024	0.022
Turkey	0.018	0.016
United Arab Emirates	0.018	0.020
United States of America	0.024	0.021

Source: IRENA Renewable Cost Database.

Figure 8.5 The levelised cost of electricity for CSP projects, 2010-2019

Source: IRENA Renewable Cost Database.

Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.

the 2013 to 2015 period. This was driven newer South African CSP projects with lower costs than the first plants, while there was also deployment in China – which has lower cost structures.

The clear downward trend in the cost of electricity from CSP was reinforced in 2018 and 2019, as market deployment regained its 2014 level and yearly installations again exceeding the 600 MW mark. Coinciding with this market uptake, IRENA's Renewable Cost Database shows that – excluding the two discussed Israeli projects – the LCOE of PTC and ST projects commissioned in 2018 and 2019 ranged between USD 0.100/kWh and USD 0.243/kWh (consistently below the 2017 value).³⁴

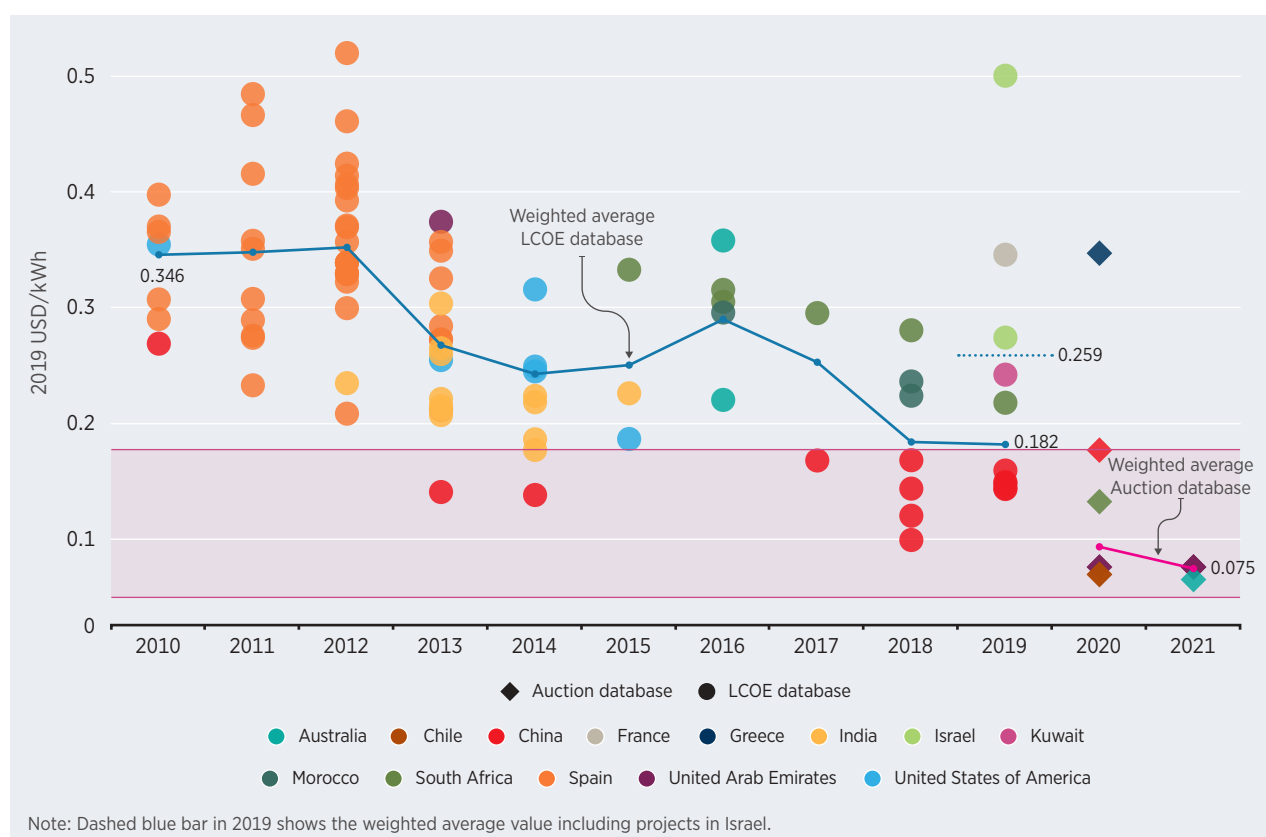
In 2019, the global weighted-average LCOE of CSP plants declined 1% from its value in 2018 and 47% from its value in 2010, when the influence of the two Israeli projects coming online during 2019 is excluded.

Despite relatively thin deployment compared to other technologies, the CSP market is likely to

continue experiencing a downward trend in the cost of electricity, as indicated by the evolution of PPA announcements for CSP projects, due to come online in 2020 and 2021. These are also increasingly within the lower end of the fossil fuel range (Figure 8.6). Data in the IRENA Auction and PPA Database shows a weighted-average price of electricity of between USD 0.075/kWh and USD 0.094/kWh for CSP projects to be commissioned in 2020 and 2021. This represents a reduction of 48% to 59%, compared to the global weighted-average project LCOE in 2019. These figures should be interpreted with care, however, since they are not directly comparable with the LCOE metric discussed here. Yet, these announcements do point towards the increased competitiveness of CSP projects, compared to fossil fuel alternatives.

With CSP costs likely to continue to decline, the technology can play an important role in a transition towards higher shares of VRE in electricity markets

Figure 8.6 Levelised cost of electricity and auction price trends for CSP, 2010-2021



Source: IRENA Renewable Cost Database and IRENA Auction and PPA Database.

³⁴ Including the the most expensive Israeli project would push the range out to an upper value of USD 0.501/kWh, but as already discussed this is clearly an outlier in terms of technology configuration and costs due to the delays the project encountered. It is also not representative of the planned pipeline.

with excellent solar resource. CSP, with its low-cost, long-duration thermal energy storage and the technology's ability to be dispatched when

required, make it a complementary technology to solar PV and onshore wind (Lunz *et al.*, 2016; Mehos *et al.*, 2015).

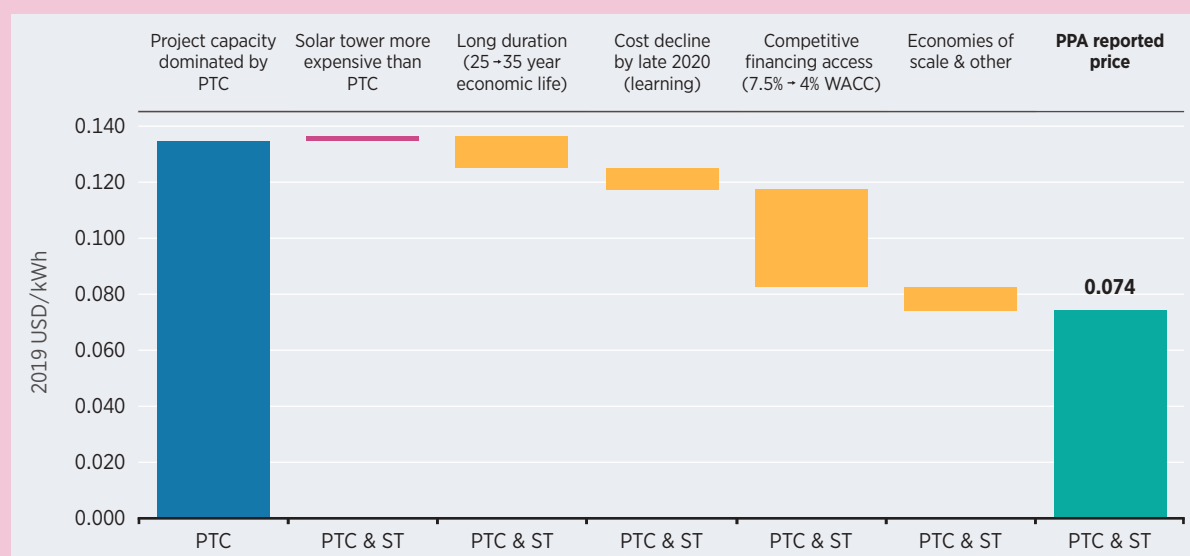
Box 8.1 The LCOE of CSP, considering recently published PPA prices

Although PPA details, including the agreed price, have been made available for some projects, comparing LCOE and PPA and auction data can be challenging. Yet, discussing their differences can also shed light on trends in competitiveness for a given technology. A notable example of such announced PPA details is Phase 4 of the Mohammed bin Rashid Al Maktoum Solar Park, located in Dubai. This project, which was tendered by the Dubai Electricity and Water Authority (DEWA), represents a step-change in CSP project competitiveness.

The project consists of 600 MW of PTC and 100 MW of ST capacity.³⁵ This is to be commissioned in stages, starting from the fourth quarter of 2020. The PPA price has been announced as USD 0.074/kWh for a duration of 35 years. Both these numbers are exceptional. They are also different from the benchmark conditions used for the LCOE calculation in this study, which assume 7.5% WACC and 25 years of economic life.

In order to understand this PPA price and how it was achieved, an analysis of the different factors that see it deviate from the estimated LCOE of a benchmark CSP plant are given in Figure 8.7. The analysis takes as a starting point a reference plant in Dubai, based on a plant configuration for the PTC elements similar to the latest Moroccan Noor³⁶ design, a 25 year economic life and a WACC of 7.5%. The chart then examines how the DEWA project then deviates from these parameters in order to achieve such a competitive auction price.

Figure B8.1 Reconciling the LCOE of a benchmark CSP project to the PPA price for the Mohammed bin Rashid Al Maktoum Solar Park, Phase 4



Source: IRENA.

The project consists of 86% PTC technology, while a single ST will provide the remaining CSP. This will slightly increase costs compared to using PTC exclusively in Dubai, but not materially. The calculations for the economic life, learning rates and access to competitive financing are robust and based on publicly available information. The access to very competitive financing for the project is the largest contributor to the cost difference, followed by the long economic life and the learning effects that reduce costs. The remaining contribution to the very low PPA price is likely to be the result economies of scale this exceptionally large project has, from benefits from building the plant in stages with the same work force on the same site, through to better prices for procuring equipment, favourable production guarantee conditions, etc.

³⁵ A later amendment has added 250 MW of solar PV capacity to the project plan, potentially complicating an analysis of the CSP component of the PPA given not all data is in the public domain.

³⁶ For additional details on the Noor projects in the Moroccan Ouarzazate region see: <https://solarpaces.nrel.gov/by-country/MA>



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ANNEX I

Cost can be measured in different ways, with different cost metrics bringing their own insights. The costs that can be examined include equipment costs (e.g., photovoltaic modules or wind turbines), financing costs, total installed costs, fixed and variable operating and maintenance costs (O&M), fuel costs (if any), and the levelised cost of electricity (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 are readily available. This allows greater scrutiny of the underlying data and assumptions, improves transparency and confidence in the analysis, while facilitating the comparison of costs by country or region for the same technologies, enabling the identification of the key drivers in any cost differences.

The five key indicators that have been selected are:

- equipment cost (factory gate, free onboard [FOB], and delivered at site)
- total installed project cost, including fixed financing costs
- capacity factor by project
- the LCOE.

The analysis in this paper focuses on estimating the costs of renewables from the perspective of private investors, whether they are a state-owned electricity generation utility, an independent power producer (IPP), 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 CO₂ pricing or 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., small hydropower vs. large hydropower). Similarly, functionality has to be distinguished from other qualities of the renewable power generation technologies being investigated (e.g., concentrating solar power [CSP] 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. These data have 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 examines costs, strictly speaking, the data points available are actually prices – which 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 not 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 where they might be expected to be in their long-term trend, every effort has been made to identify the causes.

Although every effort has been 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 conducted a number of analyses focusing on individual technologies and markets in an effort to fill this gap (IRENA, 2016a and 2016b).

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) used to evaluate the project – often also referred to as the discount rate – 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. This has the advantage, however, of producing a transparent and easy-to-understand analysis. In addition, more detailed LCOE analyses result in a significantly higher overhead in terms of the granularity of assumptions required. This can give the impression of greater accuracy, but when the model cannot be robustly populated with assumptions, and if assumptions are not differentiated based on real-world data, then the accuracy of the approach can be misleading.

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

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

Where:

LCOE = the average lifetime levelised cost of electricity generation

I_t = investment expenditures in the year t

M_t = operations and maintenance expenditures in the year t

F_t = investment expenditures in the year t

E_t = electricity generation in the year t

r = discount rate

n = life of the system.

All costs presented in this report are denominated in real, 2019 US dollars; 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 yield 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 projectspecific total installed costs and capacity factors, as well as the O&M costs. Though the terms “O&M” and “OPEX” (operational expenses) are often used interchangeably. The LCOE calculations in this report are based on “allin OPEX”, a metric that accounts for all operational expenses of the project including some that are often excluded from quoted O&M price indices, such as insurance and asset management costs. Operational expense data for renewable energy projects are often available with diverse scope and boundary conditions. These data can be difficult to interpret and harmonise depending on how transparent and clear the source is around the boundary conditions for the O&M costs quoted. However, every effort has been made to ensure comparability before using it to compute LCOE calculations. 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.

A WACC of 10% is assumed for 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.

The increasing importance of Power Purchase Agreements (PPAs), auctions and tenders in the competitive procurement landscape of renewable energy has led to important differences among their designs between markets. Data available from these sources often reflect these differences. Where they are important, they have been corrected for a fair comparison between markets before their inclusion in IRENA's Auction and PPA Database and its analysis in this report. Examples of this include: harmonising indexed vs. non-indexed auction or PPA data, correcting for tax-credits influenced cost data (e.g., US Investment or Production Tax Credit schemes), and excluding outliers. In these and other similar corrections, care has been taken to maintain the integrity of the data, while enabling the possibility of a more robust comparison that presents ‘like-for-like’ data.

Table A1.1 Standardised assumptions for LCOE calculations

Technology	Economic life (years)	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		

O&M COSTS

Solar PV

Depending on the commissioning year, a different O&M cost assumption is used for the calculation of the solar PV LCOE estimates calculated in this report. An additional distinction is made depending on whether the project has been commissioned in a country belonging to the OECD or not (Table A1.2).

Onshore wind

Based on the annual range of O&M onshore wind costs in China, India and the rest of the world for the 448 project subset with O&M data in the IRENA Renewable Cost Database, 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% (IRENA, 2018a). Based on IRENA's O&M data and new project- and country-level data IRENA has gathered, the average O&M cost assumptions used for onshore wind LCOE calculations falls between USD 0.006/kWh and USD 0.02/kWh.

Offshore wind

The O&M cost assumptions used are based on estimates that fall between USD 0.017/kWh and USD 0.030/kWh, when converted from average costs in USD/kW/year (IEA *et al.*, 2018; Ørsted, 2019; Stehly *et al.*, 2018). The lower range is seen in projects in China and established European markets with sites closer to shore, while the latter, higher cost range is seen in less-established offshore wind markets or markets with harsher metocean conditions, like Japan.

TOTAL INSTALLED COST BREAKDOWN: DETAILED CATEGORIES FOR SOLAR PV

IRENA has for some years collected cost data on a consistent basis at a detailed level for a selection of PV markets. In addition to tracking average module and inverter costs, the balance of system costs are broken down into three broad categories: non-module and inverter hardware, installation costs, and soft costs. These three categories are composed of more detailed sub-categories which can greater understanding of the drivers of solar PV balance of system (BoS) costs and are the basis for such analysis in this report (Table A1.3).

Table A1.2 O&M cost assumptions for the LCOE calculation of PV projects

Year	OECD 2019 USD/kW/year	Non-OECD 2019 USD/kW/year
2010	25.9	24.4
2011	22.9	22.4
2012	22.3	17.4
2013	21.8	14.6
2014	21.3	13.0
2015	20.7	11.9
2016	20.2	10.8
2017	20.6	10.4
2018	19.2	9.9
2019	18.3	9.5

Source: IRENA Renewable Cost Database

Table A1.3 BoS cost breakdown categories for solar PV

Category	Description
Non-module hardware	
Cabling	· All direct current (DC) components, such as DC cables, connectors and DC combiner boxes · All AC low voltage components, such as cables, connectors and AC combiner boxes
Racking and mounting	· Complete mounting system including racking profiles, foundations and all material for assembling · All material necessary for mounting the inverter and all type of combiner boxes
Safety and security	· Fences · Camera and security system · All equipment fixed installed as theft and/or fire protection
Grid connection	· All medium voltage cables and connectors · Switch gears and control boards · Transformers and/or transformer stations · Substation and housing · Meter(s)
Monitoring and control	· Monitoring system · Meteorological system (e.g., irradiation and temperature sensor) · Supervisory control and data system
Installation	
Mechanical installation (construction)	· Access and internal roads · Preparation for cable routing (e.g., cable trench, cable trunking system) · Installation of mounting/racking system · Installation of solar modules and inverters · Installation of grid connection components · Uploading and transport of components/equipment
Electrical installation	· DC installation (module interconnection and DC cabling) · AC medium voltage installation · Installation of monitoring and control system · Electrical tests (e.g., DC string measurement)
Inspection (construction supervision)	· Construction supervision · Health and safety inspections
Soft costs	
Incentive application	· All costs related to compliance in order to benefit from support policies
Permitting	· All costs for permits necessary for developing, construction and operation · All costs related to environmental regulations
System design	· Costs for geological surveys or structural analysis · Costs for surveyors · Costs for conceptual and detailed design · Costs for preparation of documentation
Customer acquisition	· Costs for project rights, if any · Any type of provision paid to get project and/or off-take agreements in place
Financing costs	· All financing costs necessary for development and construction of PV system, such as costs for construction finance
Margin	· Margin for EPC company and/or for project developer for development and construction of PV system includes profit, wages, finance, customer service, legal, human resources, rent, office supplies, purchased corporate professional services and vehicle fees

Source: IRENA.

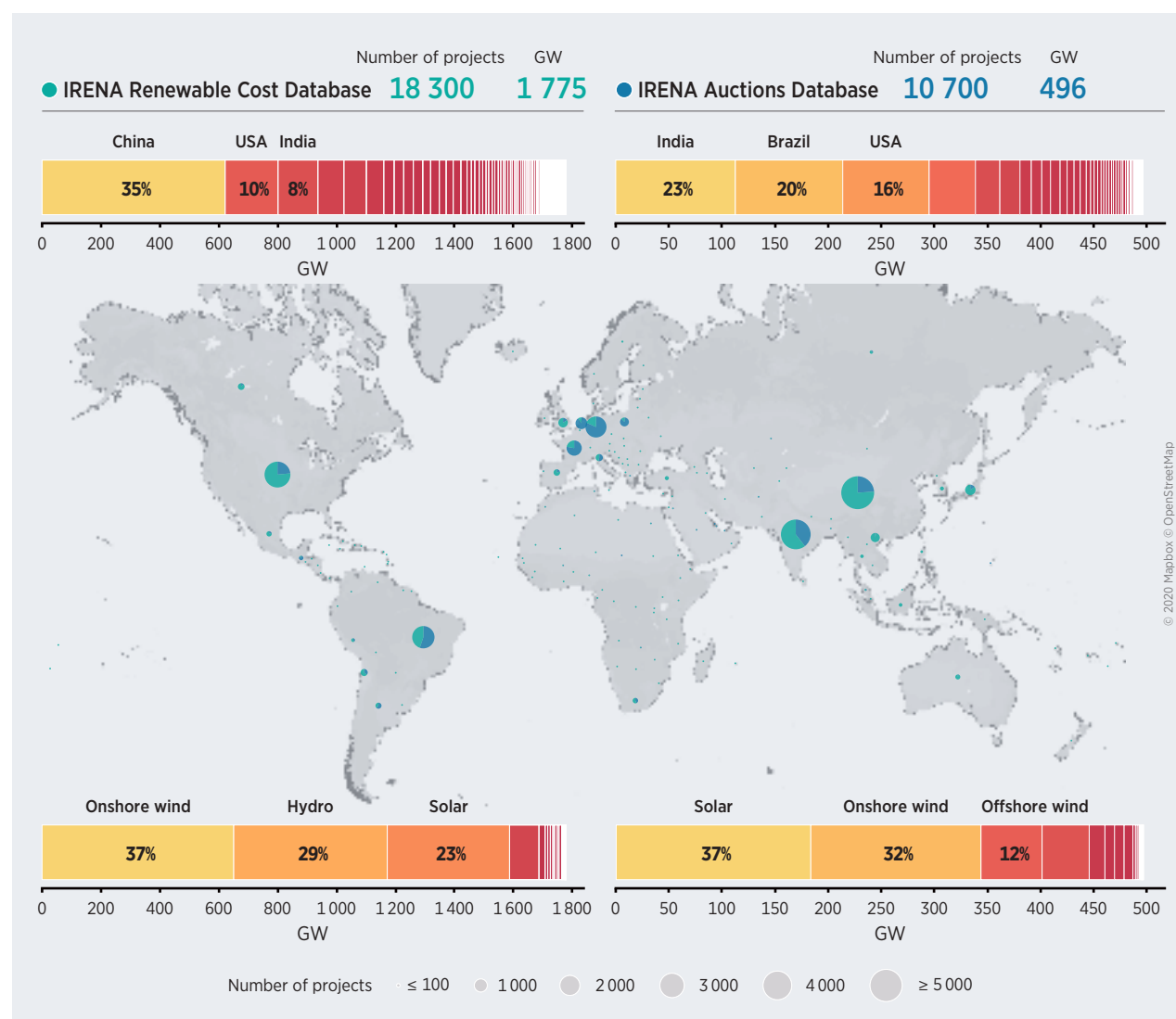
ANNEX II

THE IRENA RENEWABLE COST DATABASE

The composition of the IRENA Renewable Cost Database largely reflects the deployment of renewable energy technologies over the last ten to fifteen years. Most projects in the database are in China (620 GW), the United States (181 GW), India (136 GW), and Germany (87 GW).

Collecting cost data from OECD countries, however, is significantly more difficult due to greater sensitivities around confidentiality issues. The exception is the United States, where the nature of support policies leads to greater quantities of project data being available.

Figure A2.1 Distribution of projects by technology and country in IRENA's Renewable Cost Database and Auction and PPA Database



Disclaimer: Boundaries and names shown on this map do not imply any official endorsement or acceptance by IRENA.

After these four major countries, Brazil is represented by 78 GW of projects, the United Kingdom by 58 GW, Spain by 35 GW, Italy and Viet Nam are represented by 33 GW of projects, Japan by 31 GW, Australia and Canada by 28 GW of projects.

Onshore wind is the largest single renewable energy technology represented in the IRENA Renewable Cost Database, with 650 GW of project data available from 1983 onwards. Hydropower is the second largest technology represented in the database with 523 GW of projects since 1961, with around 90% of those projects commissioned in the year 2000 or later. Cost data is available for 415 GW of solar PV projects, 100 GW of commissioned and proposed offshore wind projects, 71 GW of biomass for power projects, 9 GW of geothermal projects and around 8 GW of 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 be more easily tracked. The database for onshore wind and hydropower is representative from around 2007, with comprehensive data from around 2009 onwards. Gaps in some years for some countries that are in the top ten for deployment in a given year require recourse to secondary sources, however, 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.



ANNEX III

REGIONAL GROUPINGS

Asia: Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, People's Republic of 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, Eswatini, 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, 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, Kingdom of the Netherlands, Norway, Poland, Portugal, Republic of Moldova, Romania, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland.

Middle East: Bahrain, Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Kingdom of 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).

RENEWABLE POWER GENERATION COSTS IN 2019