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International Renewable Energy Agency

RENEWABLE POWER GENERATION COSTS IN 2024

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About IRENA

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

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FOREWORD

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Director-General

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The global energy system is undergoing a profound transformation, with renewables accounting for an increasing share of power generation. Global renewable power capacity additions in 2024 reached 582 GW – a 19.8% increase over additions in 2023 – marking the highest annual increase on record, driven by technological innovation, competitive supply chains, and economies of scale.

Cost competitiveness remains the defining characteristic of renewable energy sources. In 2024, 91% of all newly commissioned utility-scale renewable projects delivered electricity at a lower cost than the cheapest new fossil fuel-fired alternative. Onshore wind retained its position as the most affordable source of new power generation globally, with a global weighted average levelised cost of electricity (LCOE) of USD 0.034/kWh, closely followed by solar PV at USD 0.043/kWh and hydropower at USD 0.057/kWh.

After more than a decade of steep cost declines, solar and wind energy prices have begun to stabilise – a natural sign of market maturity. Technologies like solar PV and onshore wind are now widely deployed, with efficient and competitive supply chains. Meanwhile, emerging enabling technologies, such as battery energy storage systems, continue to see rapid cost reductions. In 2024, the cost of utility-scale battery storage fell to USD 192/kWh – a 93% decline since 2010 – driven by manufacturing scale-up, improved materials and production efficiencies.

In 2024 alone, renewables avoided an estimated USD 467 billion in fossil fuel costs, demonstrating not only their cost-efficiency but also their strategic value for energy security and economic stability. As battery storage and digital solutions evolve and scale up, their role in enabling grid integration, improved economics and larger deployment of renewables will only grow in importance.

Nevertheless, short-term risks remain. Geopolitical tensions, supply chain bottlenecks, and trade-related barriers threaten to disrupt further cost reductions. Access to financing is challenging in capital-constrained markets. In some regions, permitting delays and grid infrastructure constraints are already slowing deployment. Urgent action is needed to address these barriers, and to both speed up and scale up the energy transition.

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ABBREVIATIONS

AC	alternating current
AGS	advanced geothermal system
AI	artificial intelligence
AU	African Union
BECCS	bioenergy with carbon capture and storage
BESS	battery energy storage system
BNEF	Bloomberg New Energy Finance
BoP	balance of plant
BoS	balance of system
CAES	compressed air energy storage
CAPEX	capital expenditure
CBG	compressed biogas
CCGT	combined-cycle gas turbine
CHP	combined heat and power
CIS	Capacity Investment Scheme (of Australia)
CLGS	closed-loop geothermal system
CO_2	carbon dioxide
CSP	concentrated solar power
DC	direct current
DCF	discounted cash flow
DNI	direct normal irradiation
ECF	effective capacity factor
EIA	Energy Information Administration (of the United States)
EGS	enhanced geothermal system
EPC	engineering, procurement and construction
ERP	equity risk premium
EU	European Union
FOB	free onboard
g	gramme
G20	Group of 20
GDP	gross domestic product
GHG	greenhouse gas
GLOBSEC	Global Security
GW	gigawatt
GWEC	Global Wind Energy Council
GWh	gigawatt hour
h	hour
HJT	heterojunction
IBC	interdigitated back contact
IEA	International Energy Agency
IEC	International Electrical Commission
IPP	independent power producer
IRA	Inflation Reduction Act (of the United States)
IRENA	International Renewable Energy Agency
ISA	International Solar Alliance
kg	kilogramme
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LACE	levelised avoided cost of electricity
LCOE	levelised cost of electricity
LCOS	levelised cost of storage
LDES	long duration energy storage
LFP	lithium iron phosphate
m^2	square metre
MENA	Middle East and North Africa
mg	milligrams
mm	millimetre
MW	megawatt
MWh	megawatt hour
Na-ion	Sodium-ion
NCA	nickel cobalt aluminium
NID	nature-inclusive design
NMC	nickel manganese cobalt
NO_x	nitrogen oxides
NPV	net present value
O&M	operations and maintenance
OECD	Organisation of Economic Co-operation and Development
OEM	original equipment manufacturer
OPEX	operational expenses
PDC	polycrystalline diamond compact
PERC	passivated emitter and rear cell
PHS	pumped hydro storage
PPA	power purchase agreement
PPP	public private partnership
PTC	parabolic trough collector
PV	photovoltaic
Q	quarter (of the year)
R&D	research and development
RoR	run-of-river
SATAT	Sustainable Alternative Towards Affordable Transportation (of India)
SCADA	supervisory control and data acquisition
sCO_2	supercritical carbon dioxide
SHJ	silicon heterojunction
SO2	sulphur dioxide
SOV	service operation vessel
ST	solar tower
T&D	transmission and distribution
TIC	total installed costs
TopCon	tunnel oxide passivated contact
TW	terawatt
TWh	terawatt hour
USD	US dollars
WACC	weighted average cost of capital
W	watt

EXECUTIVE SUMMARY

HIGHLIGHTS

- On a levelised cost of electricity (LCOE) basis, renewables remained the most cost-competitive option for new electricity generation in 2024, with 91% of newly commissioned utility-scale capacity delivering power at a lower cost than the cheapest, newly installed fossil fuel-based alternative.
- In 2024, new utility-scale onshore wind projects remained the cheapest source of renewable electricity, with a global weighted average LCOE of USD 0.034/per kilowatt hour (kWh),[1] followed by new solar photovoltaic (PV) (USD 0.043/kWh) and new hydropower (USD 0.057/kWh).
- Between 2010 and 2024, total installed costs (TIC) declined sharply across major renewable technologies. By 2024, TIC fell to USD 691/kW for solar PV, USD 1 041/kW for onshore wind, and USD 2 852/kW for offshore wind.
- LCOE increased slightly for some technologies over 2023: solar PV by 0.6%, onshore wind by 3%, offshore wind by 4%, and bioenergy by 13%. Meanwhile, costs declined for CSP (-46%), geothermal (-16%), and hydropower (-2%).
- Battery storage costs declined by 93% from 2010 to 2024, falling from USD 2 571/kWh to USD 192/kWh.
- For onshore wind, China (USD 0.029/kWh) and Brazil (USD 0.030/kWh) recorded LCOEs below the global average, reflecting the maturity of these top markets. For solar PV, China and India reported below-average LCOEs, at USD 0.033/kWh and USD 0.038/kWh, respectively. For offshore wind, Asia's average (USD 0.078/kWh) was slightly below Europe's (USD 0.080/kWh).
- Over the next five years, global total installed costs are expected to reach approximately USD 388/kW for solar PV, USD 861/kW for onshore wind, and USD 2 316/kW for offshore wind.
- While long-term cost reductions are expected from continued technological learning and supply chain maturity, emerging geopolitical risks – notably trade tariffs on renewable components and materials and Chinese manufacturing sector dynamics – could raise costs in the short term.
- Financing costs remain a key determinant of renewable project viability, with capital costs shaped by factors such as revenue certainty, capital structure and macroeconomic conditions.
- Integrating more variable renewables into the grid may lead to higher short-term costs; but a growing number of projects are combining solar, wind, storage, and digitalisation - enhancing economic performance and facilitating integration.
- In 2024, renewables helped avoid USD 467 billion in fossil fuel costs, reinforcing their role not only as the lowest-cost source of new power but also as a key driver of energy security, economic stability, and resilience in a volatile global energy landscape.

[1] *All total installed cost (TIC) and levelised cost of electricity (LCOE) values presented in this report are expressed in 2024 USD.*

[2] *Excluding African Union (AU) countries.*

Table S1 Total installed cost, capacity factor and LCOE trends by technology, 2010 and 2024

	Total installed costs (2024 USD/kW)			Capacity factor (%)			Levelised cost of electricity (2024 USD/kWh)		
	2010	2024	Percent change	2010	2024	Percent change	2010	2024	Percent change
Bioenergy	3 082	3 242	5%	72	73	1%	0.086	0.087	1%
Geothermal	3 083	4 015	30%	87	88	1%	0.055	0.060	9%
Hydropower	1 494	2 267	52%	44	48	9%	0.044	0.057	30%
Solar PV	5 283	691	-87%	15	17	13%	0.417	0.043	-90%
CSP	10 703	3 677	-66%	30	41	37%	0.402	0.092	-77%
Onshore wind	2 324	1 041	-55%	27	34	26%	0.113	0.034	-70%
Offshore wind	5 518	2 852	-48%	38	42	11%	0.208	0.079	-62%

Notes: CSP = concentrated solar power; kW = kilowatt; kWh = kilowatt hour; USD= United States dollars.

ANNUAL RENEWABLE POWER CAPACITY ADDITIONS SET A NEW RECORD IN 2024, WITH TOTAL INSTALLED CAPACITY INCREASING 15% YEAR-ON-YEAR[3]

In 2024, global renewable power capacity[4] additions reached an unprecedented 582 gigawatts (GW), representing a 19.8% increase compared to the capacity additions delivered in 2023 and marking the highest annual expansion since records began in 2000. Solar photovoltaics (PV) led this surge, accounting for 452.1 GW (77.8%) of the total, followed by wind, with 114.3 GW. These additions brought the total global installed renewable capacity to 4 443 GW by the end of the year.

Capacity additions for other technologies - concentrated solar power (CSP), geothermal, bioenergy and hydropower - remained modest in 2024, collectively adding approximately 15.4 GW, up from 13.7 GW in 2023. Hydropower alone accounted for 9.3 GW. Additions for CSP and geothermal continued to stagnate, while bioenergy saw a slight increase compared to 2023.

In 2024, Asia added 413.2 GW of renewable capacity – a 24.9% increase that brought the region's total to 2 374 GW. China alone accounted for 61.2% of global PV additions (276.8 GW) and 69.4% of new wind installations (79.4 GW). Other notable contributors included the United States, India, Brazil and Germany, all of which added substantial volumes of new renewable capacity, highlighting the continued global diversification of renewable investment.

The growth in renewable power capacity additions reflects the accelerating global momentum to increase the share of renewables in electricity generation. However, current deployment levels fall short of that required to triple renewable energy capacity by 2030 – the goal set out in the First Global Stocktake, known as the "UAE Consensus", at COP28. Although installed capacity reached 4 443 GW in 2024, achieving the 11 000+ GW target by 2030 requires annual additions well over 1 000 GW in the latter half of the decade. Meeting this goal will require not only a rapid scale-up in deployment but also substantial investment in enabling infrastructure – particularly grid expansion and energy storage.

[3] This section reflects the latest capacity data presented in: (IRENA, 2025d).

[4] In this report, "renewable power capacity" is expressed in AC and refers to the net generating capacity of power plants and other installations utilising renewable energy sources to produce electricity, commissioned within the respective year.

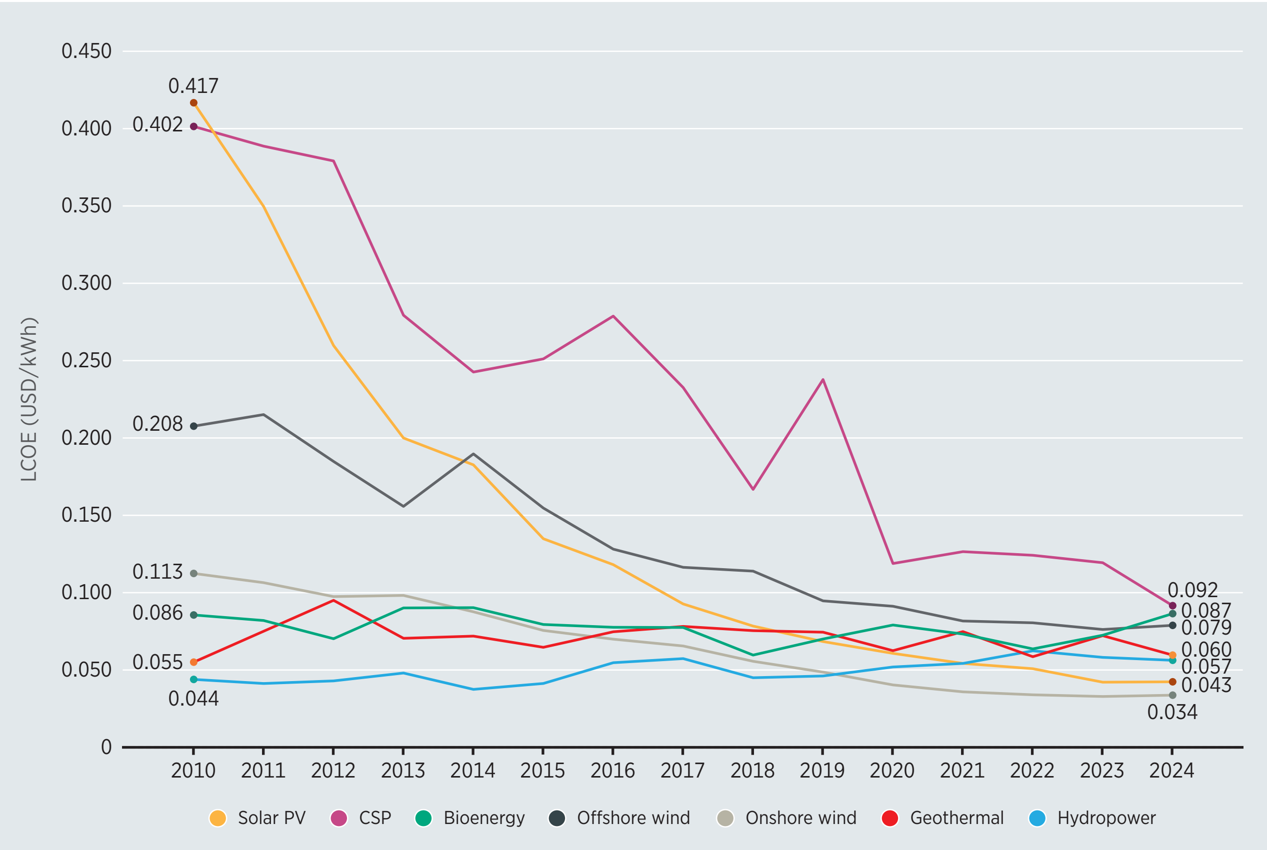
Data from IRENA's renewable cost database, paired with an analysis of recent power sector trends, nevertheless reaffirm renewables' central role in achieving climate objectives while underscoring their growing cost-competitiveness relative to all fossil fuel alternatives.

The rapid deployment of renewables is beginning to reshape the electricity mix in key economies. In the European Union, solar generation surpassed coal for the first time in 2024, while clean sources overall accounted for more than two-thirds of total generation. In the United States, solar and wind generation combined grew at an average compound rate of 12.3% per year in 2018-2023, while coal and peat generation declined by an average of 10.2% each year, compounded over the same period. These trends point to a structural decoupling from fossil fuel-based power generation, enabled by supportive policies, falling technology costs and rising electrification.

LCOE FROM RENEWABLES: A RISING COST ADVANTAGE

Renewable energy technologies have experienced spectacular cost declines since 2010, driven by technology improvement, competitive supply chains and economies of scale (Figure S1). Notably, 91% of new renewable power projects commissioned in 2024 were more cost-effective than any fossil fuel-fired alternative.

Figure S1 Renewable energy LCOE decline, 2010-2024

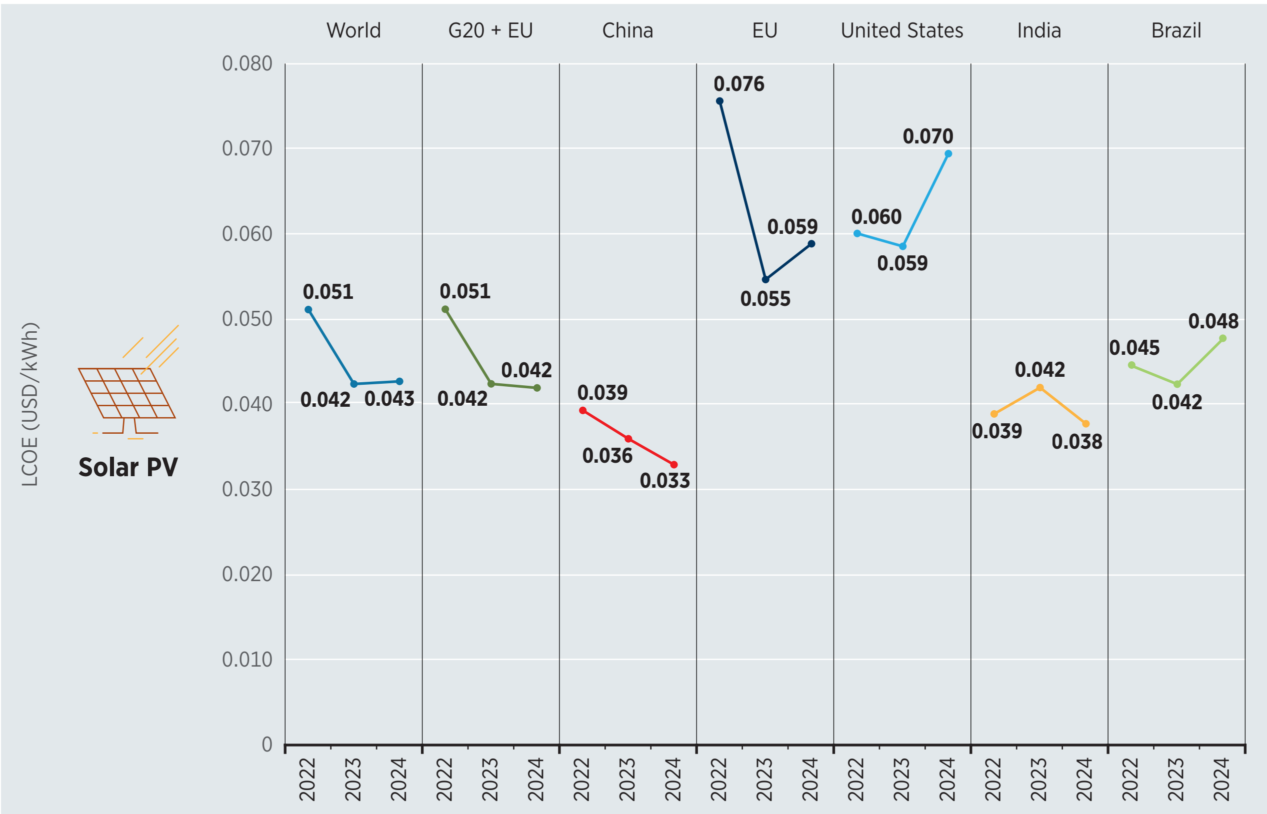


Notes: CSP = concentrated solar power; kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; USD = United States dollar.

Solar PV LCOE has dropped further in China and stabilised on a global level

By 2024, the global weighted average LCOE for utility-scale solar PV stabilised at USD 0.043/kWh, making it 41% cheaper than the least-cost fossil fuel-fired alternative (Figure S2).[5] In China, where vertically integrated supply chains and abundant domestic manufacturing capacity continue to exert downward pressure on costs, LCOE fell to USD 0.033/kWh. India also reported competitive values at around USD 0.038/kWh. In contrast, PV LCOE increased in the United States and the European Union, where permitting delays, interconnection bottlenecks and higher balance-of-system costs limited further cost reductions.

Figure S2 Solar PV weighted average LCOE: Global, G20, EU and selected countries, 2022–2024



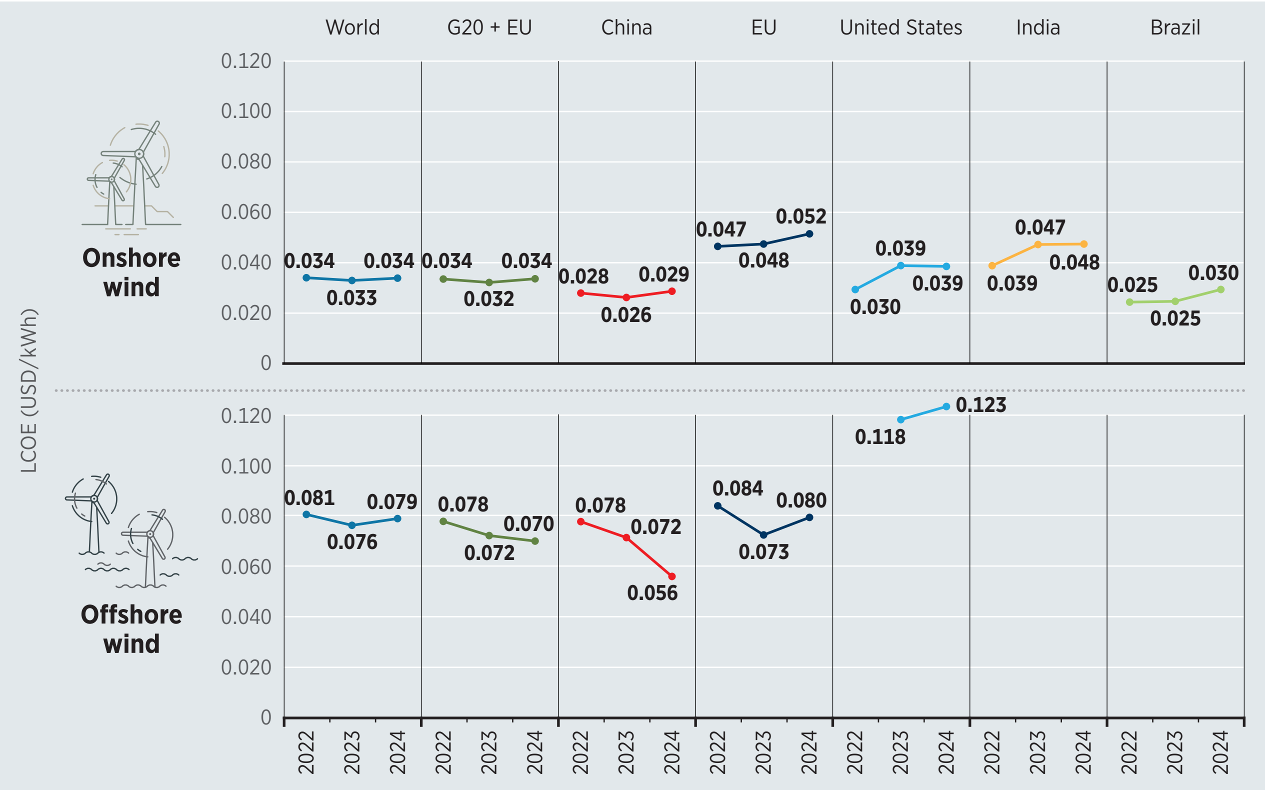
Notes: EU = European Union; G20 = Group of 20; kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; USD = United States dollar.

[5] *The global average LCOE of coal power was USD 0.073/kWh, and for CCGT was USD 0.085/kWh.*

Wind has become cheaper than fossil fuels in all major markets

Onshore wind continued reinforcing its cost advantage (Figure S3), with a global average LCOE of USD 0.034/kWh in 2024 – 53% lower than fossil fuel-based generation. China (USD 0.029/kWh) and Brazil (USD 0.030/kWh) recorded the lowest costs, benefitting from strong resource availability, domestic manufacturing and streamlined project execution. Offshore wind costs slightly increased from their 2023 levels (Figure S3), driven by a greater presence of projects in emerging markets with higher costs. Offshore wind global weighted average LCOE reached USD 0.079/kWh. In China, the LCOE fell to USD 0.056/kWh, significantly below levels in the EU and North America, where offshore wind remained substantially more expensive, exceeding USD 0.123/kWh in the United States.

Figure S3 Wind power weighted average LCOE: Global, G20, EU and selected countries, 2022–2024

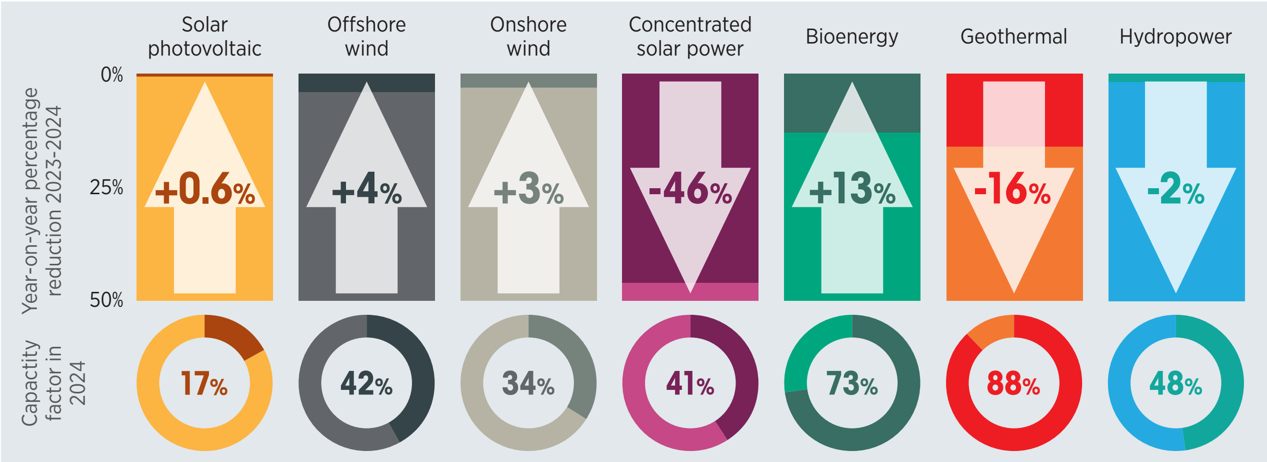


Notes: EU = European Union; G20 = Group of 20; kWh = kilowatt hour; LCOE = levelised cost of electricity; USD = United States dollar.

The economics of most dispatchable renewables are improving

The economics of new dispatchable hydropower, geothermal and CSP technologies improved in 2024. Hydropower achieved a global weighted average LCOE of USD 0.057/kWh, supported by better hydrological conditions and higher energy yields in China and Latin America. Geothermal power averaged USD 0.060/kWh, with particularly favourable outcomes in New Zealand and Indonesia. CSP saw its global LCOE fall by 77% since 2010, reaching USD 0.092/kWh, driven by longer thermal storage durations, reduced operation and maintenance (O&M) costs, and improved capacity utilisation in regions of high direct normal irradiance (DNI), such as in China and South Africa. By contrast, however, bioenergy faced upward pressure, with LCOE rising to USD 0.087/kWh due to volatile feedstock and logistics costs (Figure S4).

Figure S4 Global weighted-average LCOE reduction and capacity factor from newly commissioned utility-scale renewable power technologies, 2024

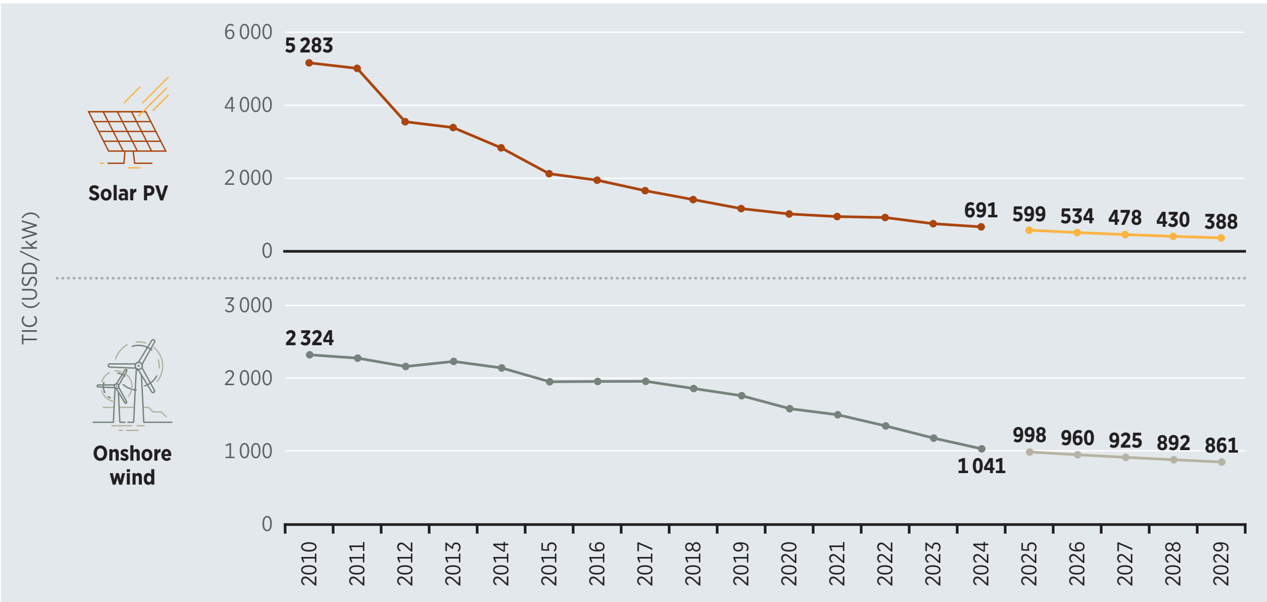


Note: The colour shading indicates the year-on-year percentage LCOE reduction (increase or decrease), starting from top (0%) to bottom (50%).

Future cost declines will slow but remain significant in high-growth regions

Looking ahead, total installed costs are projected to decline further – although at a slower pace – as learning rates and economies of scale continue to drive efficiency gains. Globally, solar PV is expected to fall below USD 600/kW by 2026, while onshore wind TICs are projected to stabilise at between USD 850 and 1 000/kW (Figure S5). For both technologies, Asia is set to retain a distinct cost advantage, with solar PV projected at around USD 500/kW and onshore wind, USD 850/kW. However, higher costs are likely to persist in Europe and North America, reflecting structural factors such as permitting delays and higher balance-of-system costs. Strong learning rates and high deployment sensitivity to costs – especially in Asia, Africa and South America – suggest that accelerated market growth could amplify cost reductions.

Figure S5 Global short-term TIC projections for solar PV and onshore wind



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; TIC = total installed cost; USD = United States dollar.

ENABLING TECHNOLOGIES ARE IMPROVING THE ECONOMICS OF RENEWABLES

Battery storage, hybrid systems and digitalisation are all critical enablers of the energy transition and the integration of variable renewables (solar PV and wind). Battery deployment must expand significantly to support a renewables-based power system, with storage technologies expected to provide the majority of short-duration flexibility needs (IRENA, 2024a). Batteries also play a central role in enabling sector coupling and electrification, contributing to emissions reductions both directly and indirectly. China dominates supply, producing over 75% of global batteries at costs 20–30% lower than in European and North American markets (IEA, 2025a), driven by scale and vertical integration. AI-enabled digital tools are improving asset performance and grid responsiveness, yet digitalisation and grid-readiness gaps remain acute in many emerging markets.

Battery storage costs have fallen 93% since 2010

From 2010 to 2024, the total installed cost of utility-scale battery energy storage systems (BESS) dropped by 93%, falling from USD 2 571/kWh to USD 192/kWh. This sharp decline has been driven by manufacturing scale-up, improved materials efficiency and optimised production processes. Lithium-ion batteries – particularly lithium iron phosphate (LFP) chemistries – dominate utility-scale deployment. BESS installations are increasingly co-located with variable renewable energy sources, especially solar PV, to provide peak shaving, frequency regulation and grid balancing. In 2024, the United States and China led global BESS growth, supported by national policy incentives and grid integration mandates.

Hybridisation is enhancing grid integration

Hybrid systems,[6] combining solar PV or wind with battery storage, are becoming standard in many markets, offering firmer output profiles, improved capacity factors (Figure S6) and enhanced grid reliability. In China, solar-plus-storage systems have helped mitigate curtailment risks in provinces with high renewable penetration. In the United States, the integration of BESS with new solar capacity has accelerated, enabling dispatch during peak demand and deferring investments in peaking gas plants. Hybridisation is also being explored with geothermal and CSP, particularly for long-duration storage applications.

Figure S6 illustrates the relationship between storage capacity and capacity factor improvement for a sample of hybrid wind and solar projects. Using a linear optimisation approach (described in Box 1.7), gains in terms of capacity factor increase are estimated from adding storage. As expected, the larger the battery (measured by the storage-to-generation capacity ratio), the greater the improvement. However, this comes at a cost (investing in a BESS) and must be weighed against the increased revenue or reliability benefits storage may provide.

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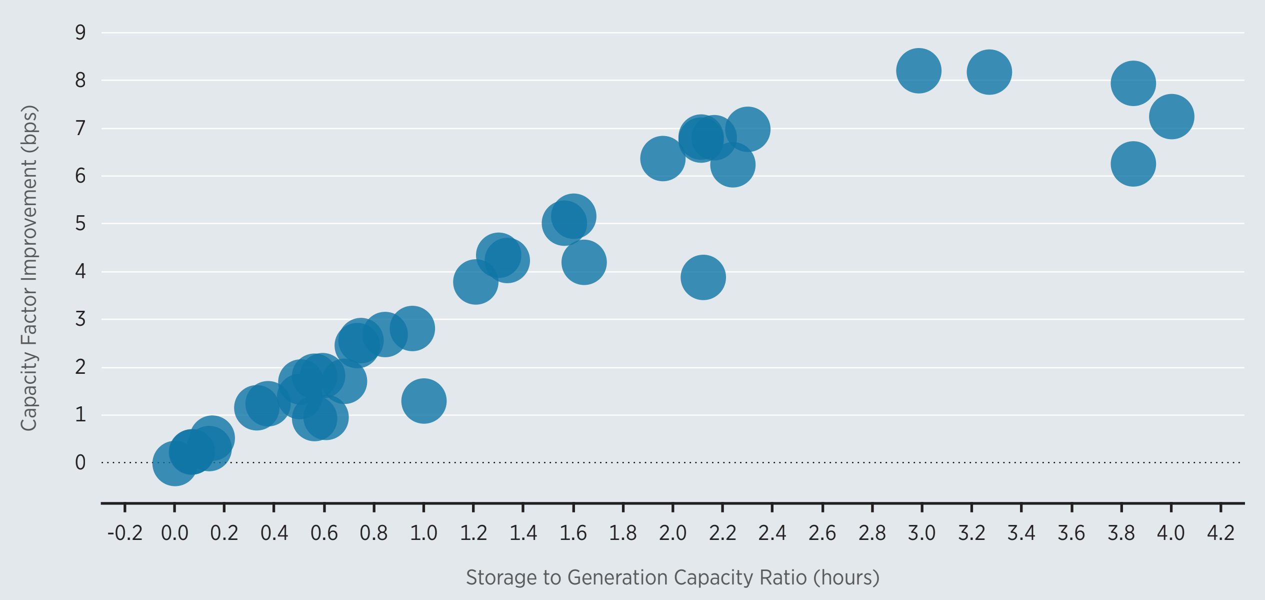
[6] *This report refers to "hybrid systems" as configurations that combine renewable generation (e.g. solar PV or wind) with battery storage to improve dispatchability, reliability or grid alignment. We acknowledge that international work – notably under the IEA Wind Task 50 – is underway to develop a standardised taxonomy distinguishing between hybrid systems and hybrid power plants. In this framework, hybrid systems encompass broader energy conversion applications (e.g. power-to-hydrogen), whereas hybrid power plants are defined as co-located and/or integrated generation and storage resources connected at a single grid interconnection point.*

Figure S6 Impact of adding storage capacity on the capacity factor for selected wind and solar projects



Note: bps = basis points.

Although comprehensive LCOE estimates for hybrid systems remain scarce, available data indicates that renewables coupled with battery storage are increasingly approaching cost parity with fossil fuel-based generation in key markets. In the United States, IRENA data for 2024 show that 17 operational hybrid projects (combining 4 486 MW of solar PV and 7 677 MWh of battery storage) achieved a weighted average LCOE of USD 0.079/kWh, which is aligned with the midpoint of the LCOE range for combined-cycle gas turbines (USD 0.077/kWh) and below that of coal (USD 0.119/kWh). In Australia, eight hybrid projects combining solar, wind and battery storage (totalling 412.2 MW of generation and 188.4 MWh of storage) report a significantly lower weighted average LCOE of USD 0.051/kWh.

Digitalisation is driving operational efficiency

Digital technologies – predictive maintenance, real-time performance monitoring, AI-enabled asset management, *etc.* – are improving operational efficiency across renewable assets, allowing for lower O&M costs and extended asset lifetimes. For solar PV and onshore wind, in particular, digitalisation enables granular optimisation of performance, enhancing competitiveness in merchant and auction-based markets. Innovations in digital platforms are also supporting advanced forecasting and grid services, helping to align variable generation with system needs.

Beyond the asset level, digitalisation is increasingly being deployed across power systems to improve forecasting, grid operation and demand-side participation. Smart meters, dynamic pricing systems and Internet of Things (IoT) enabled appliances support demand response programmes, allowing consumers to shift or reduce their electricity use in response to price signals. At the power system level, such capabilities can help smooth out peaks, reduce system stress and facilitate the integration of renewable energy sources. Advanced grid management systems also use digital twins and AI algorithms to forecast congestion, co-ordinate distributed energy resources and optimise dispatch in near real-time.

Integration costs must be recognised and addressed

While the plant-level solar and wind costs continue to fall, grid constraints are increasingly limiting their deployment. A substantial volume of wind and solar projects worldwide are facing delays due to grid connection bottlenecks, while long procurement lead times for key components such as transformers and high-voltage cables are further affecting project timelines. These delays contribute to rising integration costs, including expenditures associated with storage, curtailment and transmission infrastructure. Although often triggered by renewable expansion, investments in such assets enhance grid flexibility and benefit the entire power system – including non-renewable generators. Recognising and addressing these costs is essential, particularly in emerging markets, where grid investment must keep pace with rising demand. In Australia, for example, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) estimates that integration costs can add USD 0.028–0.032/kWh to the cost of variable renewables at high penetration levels.[7] These integration costs vary significantly depending on project location, grid distance and infrastructure availability, and are often higher for projects requiring long-distance transmission or that are located in remote areas.

STRUCTURAL COST DRIVERS AND MARKET CONDITIONS

Supply chain integration keeps Chinese costs low

China's vertically integrated supply chains continue to deliver structural cost advantages across solar PV components, wind turbines and batteries. This integration reduces procurement delays, compresses margins and enables efficient scaling of gigawatt-scale projects. In 2024, Chinese manufacturers remained dominant across global supply chains for solar PV, wind and battery technologies, supplying a substantial share of key components.[8] However, this concentration also introduces vulnerabilities, including exposure to geopolitical tensions and emissions intensity. Although renewable capacity additions in China have grown rapidly in recent years, a significant share of PV manufacturing in China is still powered by coal, raising concerns about lifecycle carbon footprints.

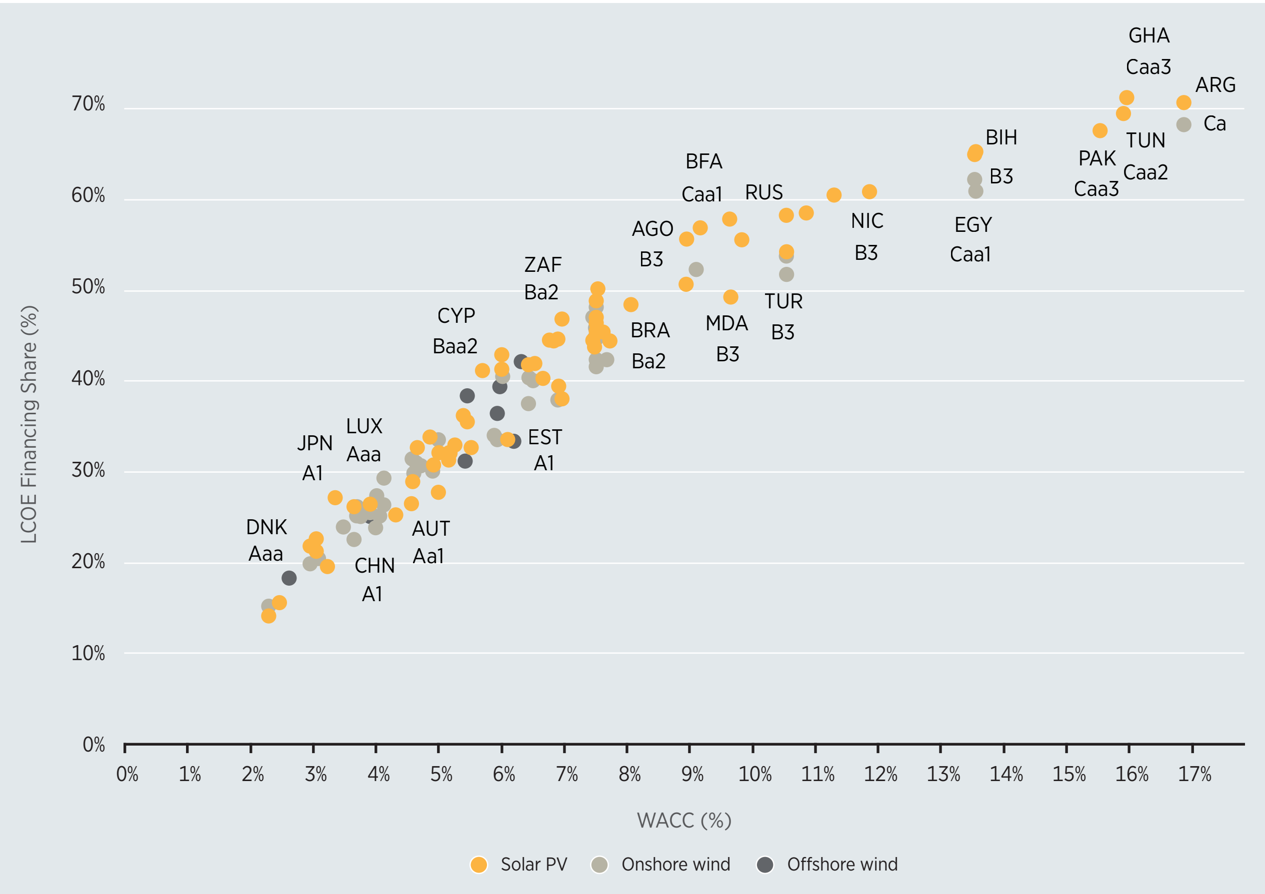
[7] *These figures are based on system modelling, not direct project-level adders. The cost range reflects total integration costs - including storage, transmission, and curtailment - under scenarios with 60-90% shares of variable renewable energy (VRE).*

[8] *China accounted for 79% of global polysilicon production, 97% of wafer production, 85% of cell production, and 75% of module production in 2021 (IEA, 2022). China also holds nearly 85% of global battery cell production capacity and a leading share of anode and cathode active material production (IEA, 2024a). On the other hand, the 2025 edition of the GWEC Global Wind Report indicates that China accounted for 70% of global onshore wind installations in 2024, supported by domestic original equipment manufacturers that are increasingly expanding their presence in international markets (GWEC, 2025a).*

Cost of capital remains a key barrier in high-risk markets

Renewable energy projects are capital-intensive, with most costs incurred up front and recovered over long operating lifetimes. As a result, the LCOE is highly sensitive to financing conditions. In 2024, financing costs[9] represented an important share of LCOE, particularly in markets with elevated risk premiums, as indicated by sovereign credit ratings (*e.g.* Moody's) and illustrated in Figure S7. For example, while the average LCOE for onshore wind was similar in Africa and Europe – USD 0.051/kWh and USD 0.052/kWh, respectively – the underlying cost structures differed markedly. In Europe, LCOE were driven primarily by capital expenditure, whereas in Africa, financing costs accounted for the majority share. In 2024, IRENA's weighted average costs of capital (WACC) assumptions ranged from 3.8% in Europe to 12% in Africa, reflecting country risk and macroeconomic conditions prevailing in 2023.[10]

Figure S7 Share of financing in LCOE vs. cost of capital (WACC) for selected countries (with Moody's ratings), 2024



Notes: AGO = Angola; ARG = Argentina; AUT = Austria; BFA = Burkina Faso; BIH = Bosnia and Herzegovina; BRA = Brazil; CHN = China; CYP = Cyprus; DNK = Denmark; EGY = Egypt; EST = Estonia; JPN = Japan; LCOE= levelised cost of electricity; LUX = Luxembourg; MDA = Moldova; NIC = Nicaragua; PAK = Pakistan; PV = photovoltaic; RUS = Russia; TUN = Tunisia; TUR = Türkiye; WACC = weighted average cost of capital; ZAF = South Africa.

[9] *Financing costs are estimated as the difference between the LCOE at a given weighted average cost of capital (WACC) and the LCOE under a zero-discount rate scenario. For example, at a WACC of 5%, financing costs are calculated as LCOE(WACC=5%) minus LCOE(WACC=0%). Their share is then expressed as a proportion of the full LCOE. This approach isolates the effect of time on money from undiscounted cost components. WACC values account for country-specific parameters (e.g. sovereign credit ratings, risk premiums and tax rates).*

[10] *According to IRENA's methodology, the WACC for a given year (y) is based on macroeconomic data from the preceding year (y-1), reflecting the typical lag between shifts in financing conditions and investment decisions.*

Policy stability and market design influence competitiveness

Stable revenue frameworks are essential to lowering risk and attracting profit-driven investment. Revenue-securing instruments such as power purchase agreements (PPAs) and contracts-for-difference (CfDs) are key to accessing low-cost capital. Conversely, retroactive policy shifts and unclear procurement processes erode investor confidence. Strategic industrial policies – such as the United States (U.S.) Inflation Reduction Act and the EU's Green Deal Industrial Plan – have increased domestic investment and localisation despite introducing modest cost premiums for domestically manufactured technologies. However, effective implementation remains uneven, with many regions still grappling with permitting delays, grid bottlenecks and costlier local supply chains.

BEYOND COSTS: THE BROADER BENEFITS OF RENEWABLE ENERGY

Increased renewable energy integration is shifting fossil fuel generation to peak or residual demand, reducing thermal plant use and exposure to volatile fuel markets. By 2024, solar and wind comprised 46.4% of global installed electricity generation capacity, significantly displacing coal and gas in key markets like China, the United States and the EU, and reducing associated greenhouse gas emissions.

Renewables not only offer some of the lowest generation costs in LCOE terms but are also structurally advantageous. Their deployment can drastically reduce the need for costly infrastructure related to fossil fuel extraction, transport and backup generation while limiting dependence on international fuel markets and improving energy system resilience. As such, the full value of renewables extends far beyond the LCOE, encompassing long-term energy security as well as public health and environmental sustainability.

Crucially, renewable electricity displaces emissions of carbon dioxide (CO_2) and harmful air pollutants – including sulphur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter ($PM_{2.5}$) – that are closely linked to respiratory and cardiovascular illnesses. These co-benefits, while not captured by the LCOE metric, are critical for public health and environmental integrity.

In 2024, the United States generated 1 057 terawatt hours (TWh) of electricity from renewables. Based on conservative assumptions about displaced fossil generation (30% coal; 70% gas), the estimated benefits include:

- USD 24.1 billion in avoided fossil fuel costs[11]
- USD 21.5 billion in avoided air pollution damages[12]

[11] Based on avoided fossil fuel costs calculated using 2024 average U.S. fuel prices of USD 3.25/metric million British thermal unit (MBtu) for coal and USD 2.76/MBtu for gas, thermal efficiency assumptions (35% for coal, 48% for gas), and generation displacement shares (30% coal, 70% gas). Price data sourced from U.S. Energy Information Administration. These estimates are based on typical, average fossil fuel prices under long-term supply contracts, not temporary market spikes.

[12] Monetised air pollution damages estimated using flat damage rates of USD 50/megawatt hour (MWh) for coal and USD 10/MWh for gas, consistent with the World Health Organization (WHO) estimates and applied to the fossil generation displaced by renewable deployment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This yields a total estimated benefit of USD 45.6 billion in a single year,[13] reinforcing the broader value proposition of renewables beyond their LCOE.

Table S2 complements this analysis by presenting comparable estimates for avoided fossil fuel costs and air pollution damages across several major economies.

Table S2 Estimated annual benefits from renewable power generation in selected countries, 2024

	China	Germany	Brazil	Australia
Avoided fossil fuel costs (USD billion)	179.8	16.4	28.3	5.0
Avoided air pollution damages (USD billion)	261.1	6.0	3.9	1.9
Total (USD billion)	**440.9**	**22.4**	**32.2**	**6.9**

While this example reflects the benefits in a specific national context, scaling such outcomes globally depends very much on the development of enabling infrastructure – including advanced grids, storage systems, critical material supply chains, *etc.* As deployment accelerates, it becomes increasingly important to move beyond plant-level metrics and fully assess renewables' system-wide impacts and co-benefits.

[13] This assessment does not include avoided carbon dioxide (CO_2) emissions in the total benefit calculation. However, applying a carbon price of USD 190 per tonne of CO_2, as recommended by the High-Level Commission on Carbon Prices, the estimated 597 $MtCO_2$ avoided in 2024 would translate to an additional USD 113.5 billion in monetised climate benefits.

01 LATEST COST TRENDS

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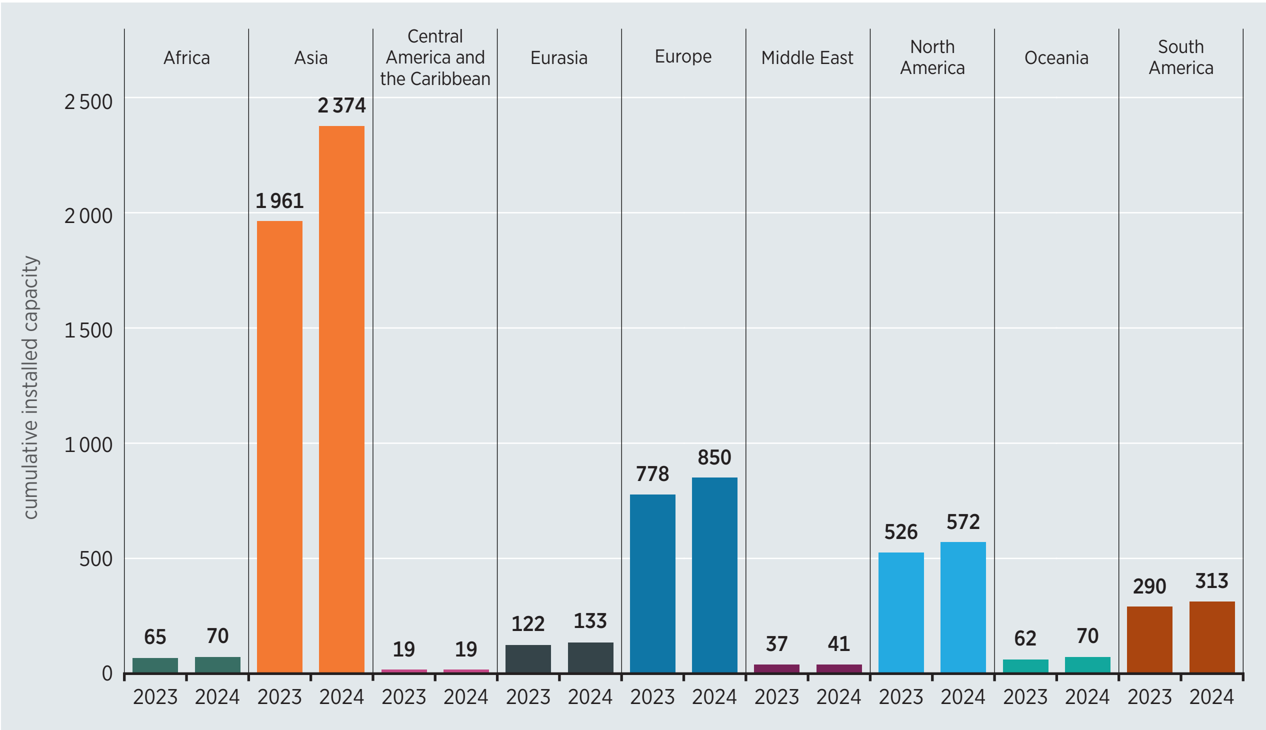
INTRODUCTION

A record year for renewable energy deployment

The global renewable energy sector achieved a historic milestone in 2024, with capacity additions reaching 582 gigawatts (GW). This was a 19.8% increase on the capacity additions delivered in 2023 and the most significant annual expansion on record (IRENA, 2025d).

Solar photovoltaic (PV) dominated this capacity increase, contributing 452.1 GW, or 77.8%, of the total. This was followed by wind, with 114.3 GW (19.6%), then hydropower, with 9.3 GW (1.6%). Together with small quantities of bioenergy, geothermal and marine energy, these additions brought global renewable energy capacity to 4 443 GW (IRENA, 2025d).

Figure 1.1 Renewable power cumulative installed capacity by region, 2023-2024



Note: GW = gigawatt.

As shown in Figure 1.1, this growth was largely driven by Asia, which added 413.2 GW of renewable capacity in 2024. This was a 21.1% annual increase on 2023 and brought the region's cumulative capacity to 2 374 GW. All other regions also recorded year-on-year growth, albeit with significant variation in scale. China alone accounted for 61.2% of new solar PV, for example, and 69.4% of new wind installations.[14] Growth was also notable in the United States, India, Brazil and Germany, reflecting a broader global momentum (IRENA, 2025d).

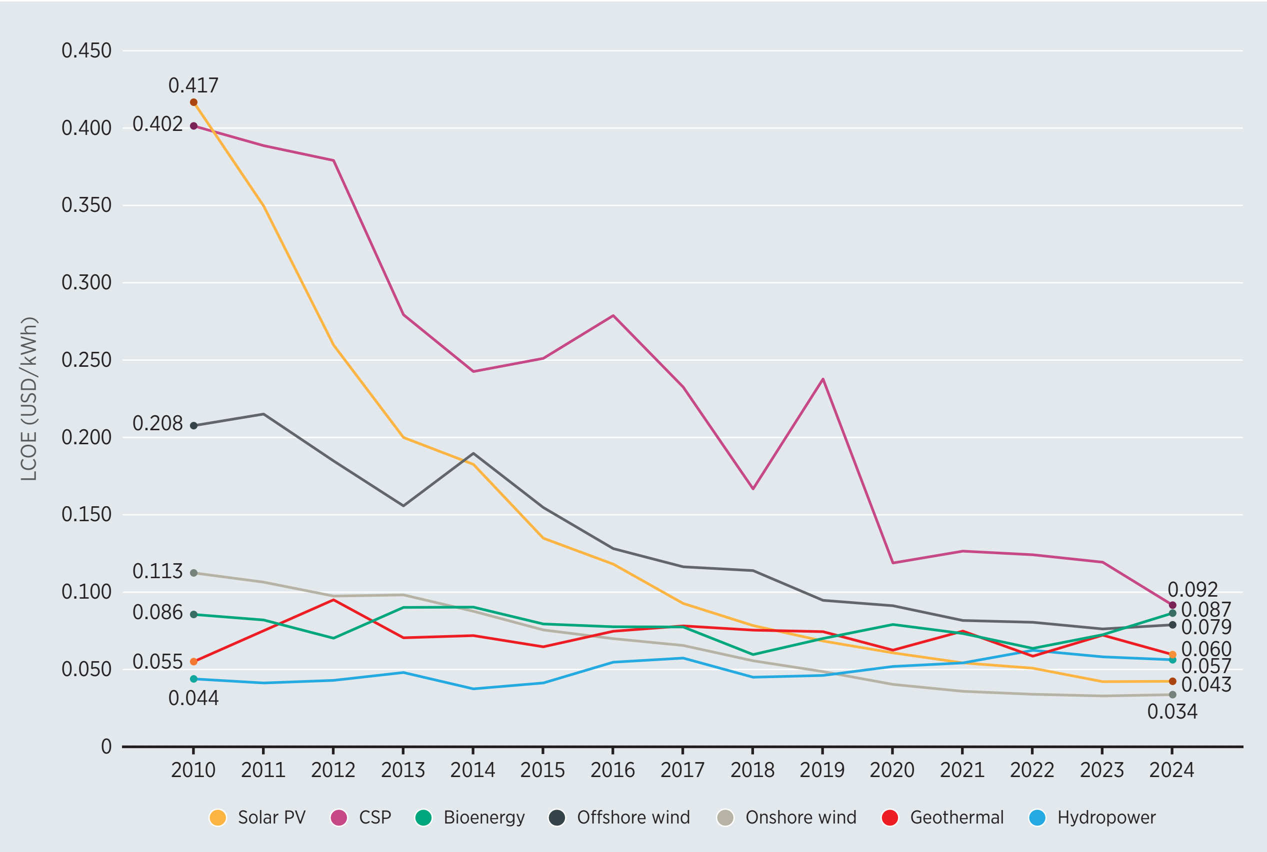
[14] *Excluding Special Administrative Regions.*

Renewables maintain cost leadership in global power markets

Renewable energy technologies have experienced spectacular cost declines since 2010. This has been driven by improvements in technology, competitive supply chains and economies of scale (Figure 1.2). In 2010, the global weighted-average levelised cost of electricity (LCOE) for new utility-scale solar PV was over four times higher than the cost of the least-expensive fossil fuel-fired generation. By 2024, solar PV had become 41% cheaper, with an average global LCOE, in US dollar (USD) terms, of USD 0.043 per kilowatt hour (kWh).

Onshore wind costs also declined at an impressive rate. In 2010, onshore wind was 23% more expensive than fossil fuels; by 2024, it was 53% cheaper, averaging USD 0.034/kWh. The cost reduction dynamics extended to offshore wind as well. Its global LCOE was USD 0.079/kWh in 2024, which was 62% lower than in 2010. In China, strong domestic supply chains pushed the average LCOE down to just USD 0.056/kWh.

Figure 1.2 Global weighted-average LCOE from newly commissioned utility-scale renewable power technologies, 2010-2024



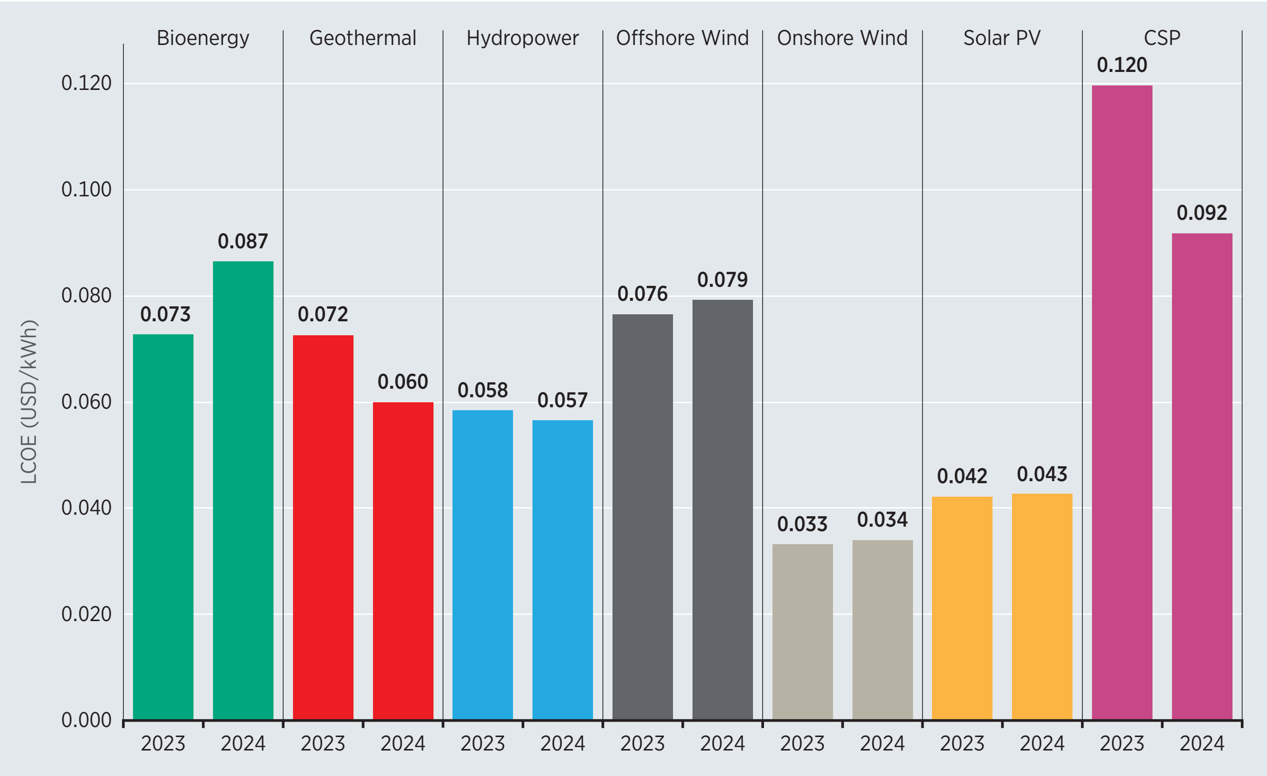
Notes: CSP = concentrating solar power; kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; USD = United States dollar.

Hydropower, a fully dispatchable, mature technology, saw its LCOE decrease by 7% between 2023 and 2024, reaching a global weighted-average of USD 0.057/kWh. This performance was driven by decreasing capital expenditure (CAPEX), particularly in China. While hydropower's LCOE did not decline as rapidly as solar or wind, this technology continues to provide competitively priced baseload electricity and flexibility services, especially in Latin America, Southeast Asia and China.

Among other dispatchable technologies, geothermal power achieved a global average LCOE of USD 0.060/kWh in 2024. A few projects in geologically favourable regions within Indonesia, the United States and East Africa also delivered electricity at below global fossil fuel benchmarks.

Bioenergy, on the other hand, saw upward pressure on costs in 2024, with its global average LCOE rising to USD 0.087/kWh. This was due to feedstock price volatility and logistics costs.

Figure 1.3 Global weighted-average LCOE, 2023-2024



Notes: CSP = concentrating solar power; kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; USD = United States dollar.

Between 2010 and 2024, the global weighted-average LCOE for concentrated solar power (CSP) fell by 77%, to USD 0.092/kWh. This reduction was driven by a combination of declining total installed costs, higher average capacity factors, lower operation and maintenance (O&M) costs, and longer thermal energy storage durations.

Cost reductions also extended to enabling technologies, such as battery energy storage systems (BESS). Between 2010 and 2024, the total installed cost of utility-scale BESS declined by 93%, from USD 2 571/kWh to USD 192/kWh. This was driven by manufacturing scale-up, improved materials efficiency and optimised production processes.

Figure 1.3 shows the year-on-year changes in LCOE across renewable technologies from 2023 to 2024. These values were derived from a comprehensive dataset that underpins a decade-long renewable cost and performance tracking effort by the International Renewable Energy Agency (IRENA), the IRENA renewable costs database (Box 1.1).

Box 1.1 The role of IRENA in tracking renewable energy costs

In 2012, IRENA began one of the most comprehensive programmes for tracking the cost and performance of renewable power generation technologies ever launched. As of 2024, that programme, the IRENA renewable costs database, included more than 25 000 projects across all major utility-scale power generation and storage systems. This expansive dataset continues to provide unique insights into cost trends and performance evolution, both globally and regionally.

This cost analysis is based on project-level data IRENA has collected and while efforts are made to ensure broad and representative coverage, the dataset is not exhaustive. As with any statistical exercise of this kind, discrepancies may arise between IRENA's estimates and figures reported by national authorities or third-party research bodies, especially in situations where different data sources or methodological assumptions are used.

The IRENA renewable costs database covers major renewable energy technologies, including solar PV, onshore and offshore wind, CSP, hydropower, geothermal energy, bioenergy and battery storage. For each technology, the database provides access to detailed data on CAPEX, operational expenditure (OPEX), capacity factors and the LCOE, enabling a year-by-year assessment of renewables' cost and performance across markets and technologies.

This ongoing effort enables IRENA to report aggregate weighted-average LCOE figures and disaggregate the underlying cost and performance factors that shape project economics. In recent years, IRENA has expanded its coverage to include equipment-level cost breakdowns, solar module efficiency trends and country-specific factors impacting costs. This development allows a thorough analysis of cost drivers, such as technological learning rates, supply chain shifts, and inflationary pressures on equipment and materials.

This 2024 update builds on more than a decade of renewable cost and performance data analysis. The technical-economic information made available through this publication aims to support informed investment decisions by governments and industry, while also supplying key inputs to the global energy modelling community as it assesses decarbonisation pathways and the broader implications of the energy transition.

As in previous editions, this report uses the LCOE as the primary metric for comparing technologies across time and regions. All weighted average figures are based on the capacities reported in the March 2025 edition of the IRENA *Renewable capacity statistics* report (IRENA, 2025b). A detailed explanation of the methodology, cost metrics and calculation assumptions supporting this work can be found in the annexes of this report.

While LCOE remains a widely accepted benchmark for generation costs, its well-recognised limitations should be kept in mind when interpreting the results:

- It assumes the generation asset to be operated at its maximum load factor.
- It condenses expenditures incurred at different points in time into a single figure and blurs the distinction between different cost categories.
- It captures generation costs at the plant level. As such, it ignores the expenditures incurred beyond the limits of the plant (the "busbar"), such as transmission and distribution costs.

LCOE is also often criticised for its inability to reflect the economic value of generation assets - the value of an unconstrained dispatchable power plant, for example. To overcome these limitations, alternative metrics were introduced. These include the *Levelised Avoided Cost of Electricity* (LACE), suggested by the Energy Information Administration (EIA) of the United States, and the *Value-Adjusted LCOE* (VALCOE), proposed by the International Energy Agency (IEA). LACE and VALCOE are suitable for evaluating and comparing the economic performance of power generation technologies. Unlike LCOE, however, their calculation requires a substantial modelling effort to represent and simulate the operation of the asset being evaluated within the power system of a country or region.

Another key metric used in this report to compare the performance of different technologies is the capacity factor. This describes the degree of utilisation of a generation asset. It is calculated as the ratio of expected annual electricity generation (typically based on projections assessing the project's electricity generation potential) to the maximum possible generation (plant operating at full capacity year-round). However, the actual electricity delivered to the grid can be significantly lower than this theoretical output. The difference is often due to curtailment, which can result from grid constraints, regulatory limits, system imbalances, or market dispatch rules. These factors are particularly influential in markets with less developed or flexible infrastructure.

Key technical-economic indicators: Capacity factors, total installed costs and the LCOE

Between 2022 and 2024, new geothermal power generators maintained the highest and most stable capacity factors of all renewable energy technology types. With weighted-average capacity factors of over 80%, this confirmed the role of geothermal as a reliable baseload source. At the same time, offshore wind performed strongly in the EU and the United States, with capacity factors up to 48%, while China maintained a capacity factor of 37%. Onshore wind showed a modest global decline, however, with sharper drops in India and China. Solar PV remained stable, at around 17%–19% in the United States and India and 14%-15% in the EU, reflecting differences in solar resource quality.[15] Hydropower proved highly climate-sensitive; in the United States, the capacity factor halved in 2023, contrasting with relative stability in China and the EU. Bioenergy operated consistently at around 70%, reaffirming its dispatchable character. CSP exhibited variable output, with a brief global peak in 2023. These patterns reflect the combined impact of resource availability, technology maturity and grid integration on renewable energy performance.

Recent assessments have confirmed these regional trends, with grid congestion and variable permitting environments increasingly cited as performance constraints in high-penetration markets such as the EU and the United States (BNEF, 2025a; Lazard, 2024). Global Security (GLOBSEC, 2024a) adds that underinvestment in grid infrastructure and limited deployment of demand response and storage technologies may further constrain future utilisation rates. In response, innovation in system design and operational strategies – including hybrid configurations, battery integration and digital asset management – is becoming an increasingly important factor shaping real-world performance, particularly for solar and wind assets.

From 2022 to 2024, total installed costs (TICs) for renewables declined globally, though with marked regional disparities. Solar PV saw the most uniform reductions, with India achieving the lowest cost in 2024, at USD 525/kW. This was followed by China, while the EU and the United States remained costlier due to structural and regulatory factors. Onshore wind costs dropped steadily in China and India, but remained at higher levels in Western markets. Offshore wind costs fell sharply in China, reaching USD 1520/kW, contrasting with persistently high costs in the EU and the United States. Hydropower remained highly site-dependent; costs in India and China were relatively low, while the United States recorded a spike in 2023, when costs reached USD 7460/kW. Bioenergy costs were broadly stable, with the EU at the higher end. Geothermal remained capital-intensive, especially in the EU, where costs reached over USD 12 000/kW, while China and the United States maintained lower values. CSP recorded the steepest drop, notably in China, where costs halved from 2022 levels to stand at USD 2 252/kW.

[15] *The increasing use of high direct current (DC) to alternating current (AC) ratios in solar-saturated grids (in which modules are oversized relative to inverters) can depress observed AC-side capacity factors. This effect is not currently accounted for in the capacity factor metrics reported here.*

According to the BloombergNEF (BNEF), the persistent cost gap between China and higher-income regions such as Europe and the United States reflects both surplus manufacturing capacity and vertically integrated value chains. These compress margins and streamline procurement (BNEF, 2025a). Lazard, on the other hand, underscores the impact of rising balance-of-system (BoS) and interconnection costs in the United States (Lazard, 2024), partially offsetting technological cost declines. The IEA notes that cost reductions in emerging markets are increasingly linked to innovation diffusion and mass manufacturing, rather than to frontier research and development (R&D) (IEA, 2025b). This reinforces a growing narrative that cost efficiency is very much about deployment scale and supply chain maturity.

From 2022 to 2024, the LCOE for renewables declined globally, though regional disparities remain stark. China and India consistently recorded the lowest costs across technologies. In China, solar PV costs fell to USD 0.033/kWh, while in India, they fell to USD 0.038/kWh. Meanwhile, onshore wind reached USD 0.029/kWh in China. In contrast, the EU and the United States maintained higher LCOEs due to structural differences. Offshore wind remained expensive in the United States, at USD 0.123/kWh, while China achieved the far lower level of USD 0.056/kWh. Hydropower costs were highly volatile, with spikes in the United States and India likely linked to site constraints. Bioenergy and geothermal showed wide cost spreads, with the EU consistently at the upper cost end. CSP costs in China almost halved between 2022 and 2024, falling to USD 0.069/kWh, signalling improved economics and increased competitiveness.

Several independent studies confirm these findings. Lazard points out a widening LCOE range for the same technologies across geographies, driven by factors such as permitting lead times, grid curtailment risks and financing costs (Lazard, 2024). BNEF estimate that global clean energy LCOEs could fall by between 22% and 49% by 2035, depending on technology and region (BNEF, 2025a). Wood Mackenzie, however, warns that trade-related costs and local content requirements – particularly in the United States – could temporarily inflate LCOEs despite declining TICs (Wood Mackenzie, 2025a).

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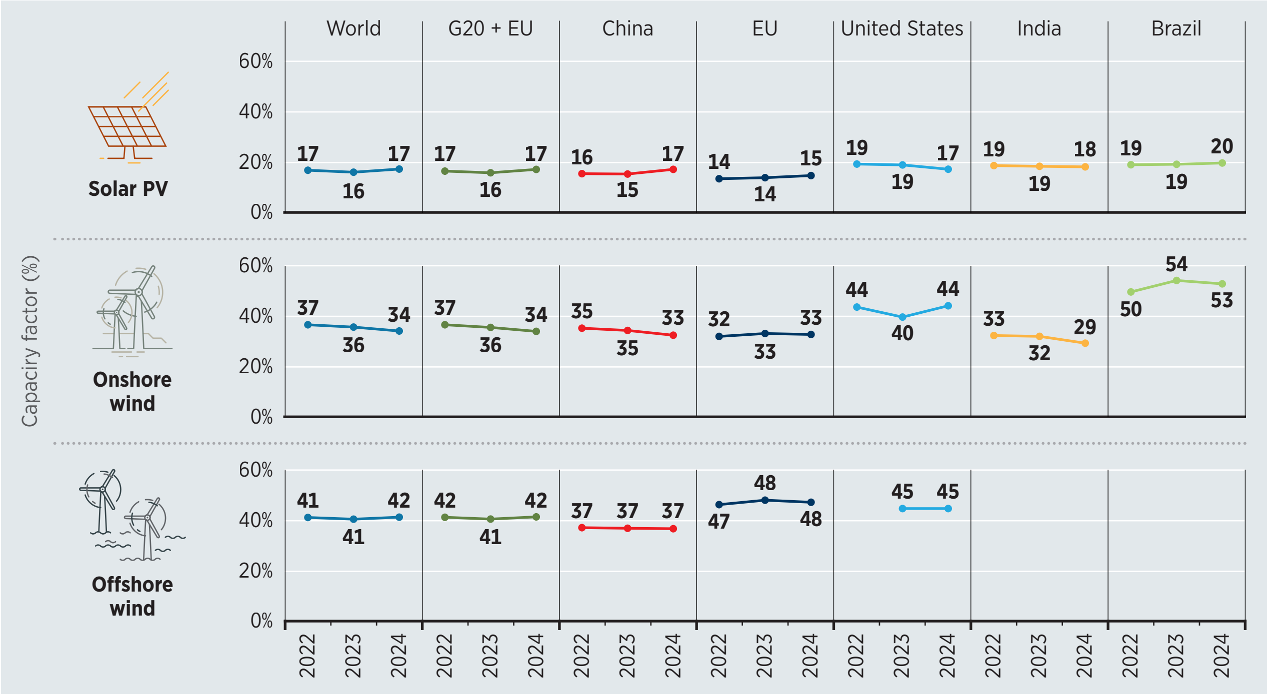
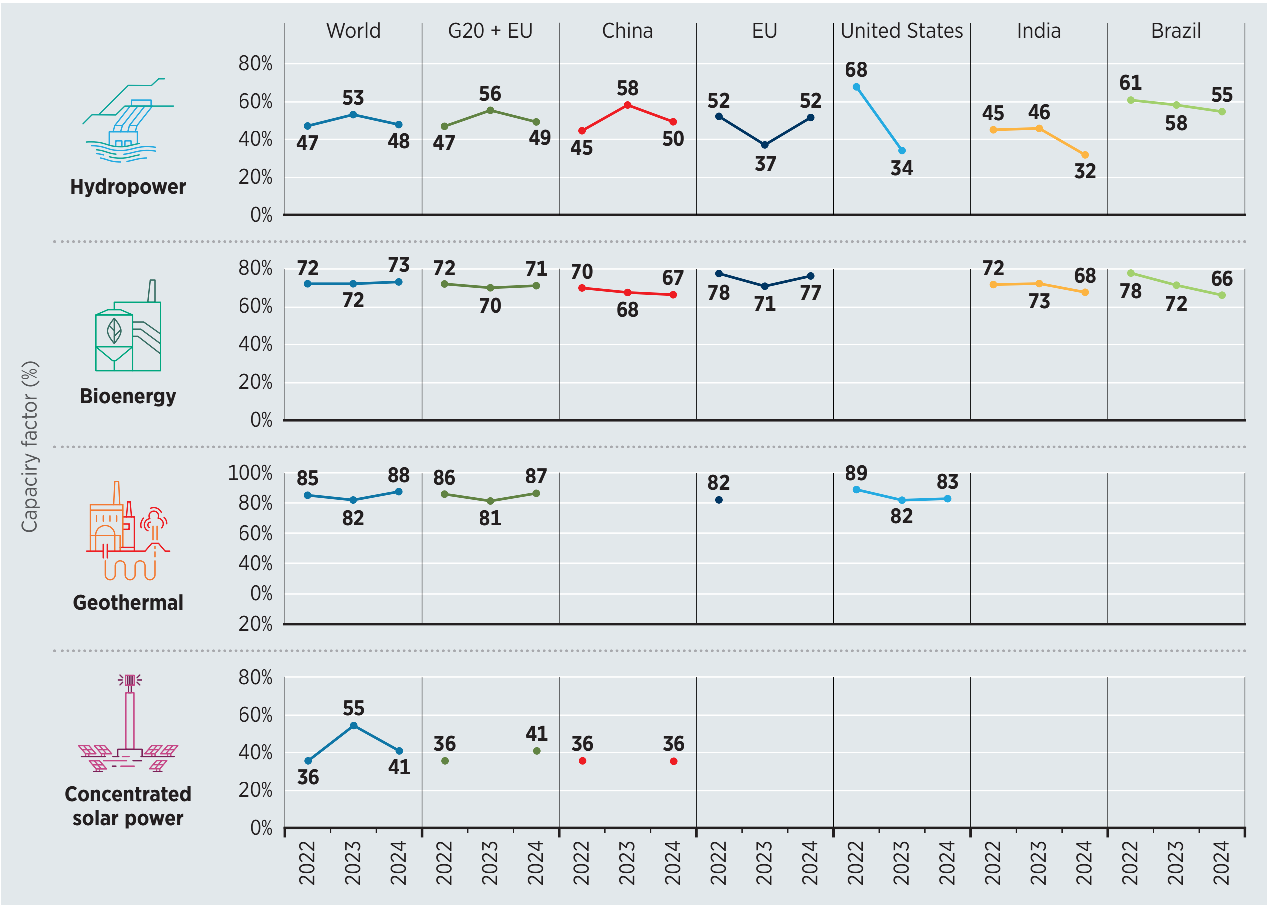
Figure 1.4 Capacity factor trajectories of variable technologies in selected regions, 2022-2024



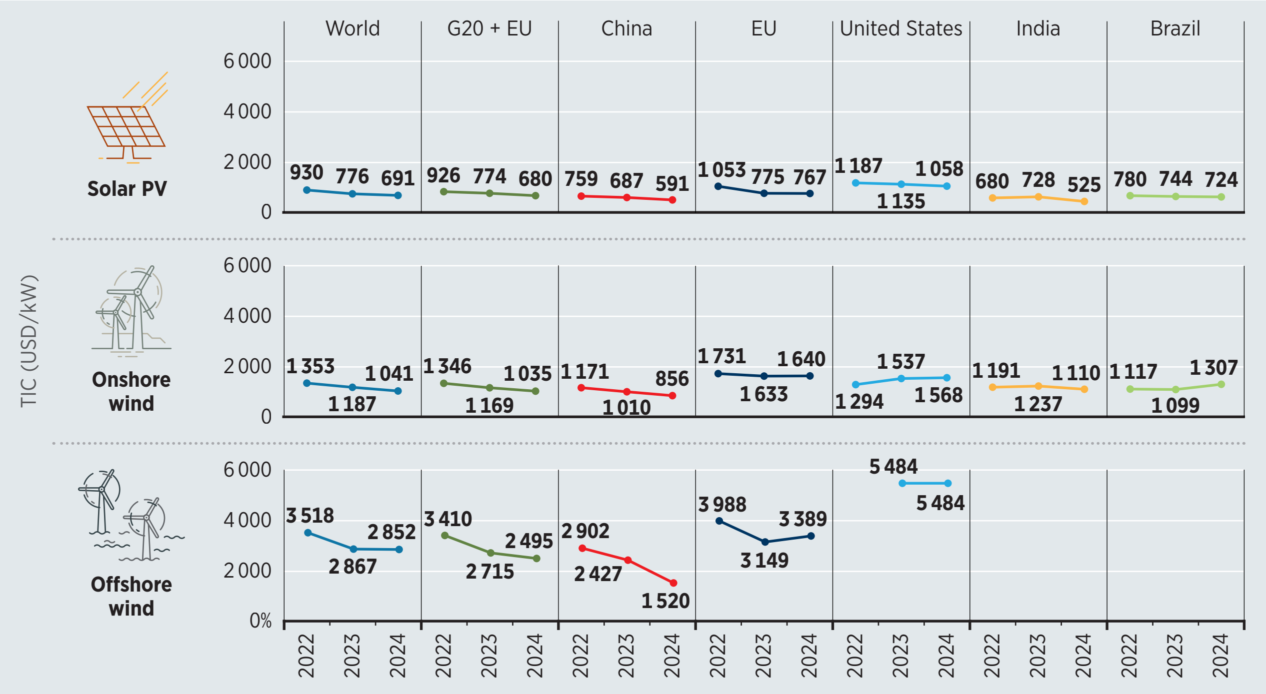
Notes: EU = European Union; G20 = Group of 20; PV = photovoltaic.

Figure 1.5 Capacity factor trajectories of dispatchable technologies in selected regions, 2022-2024



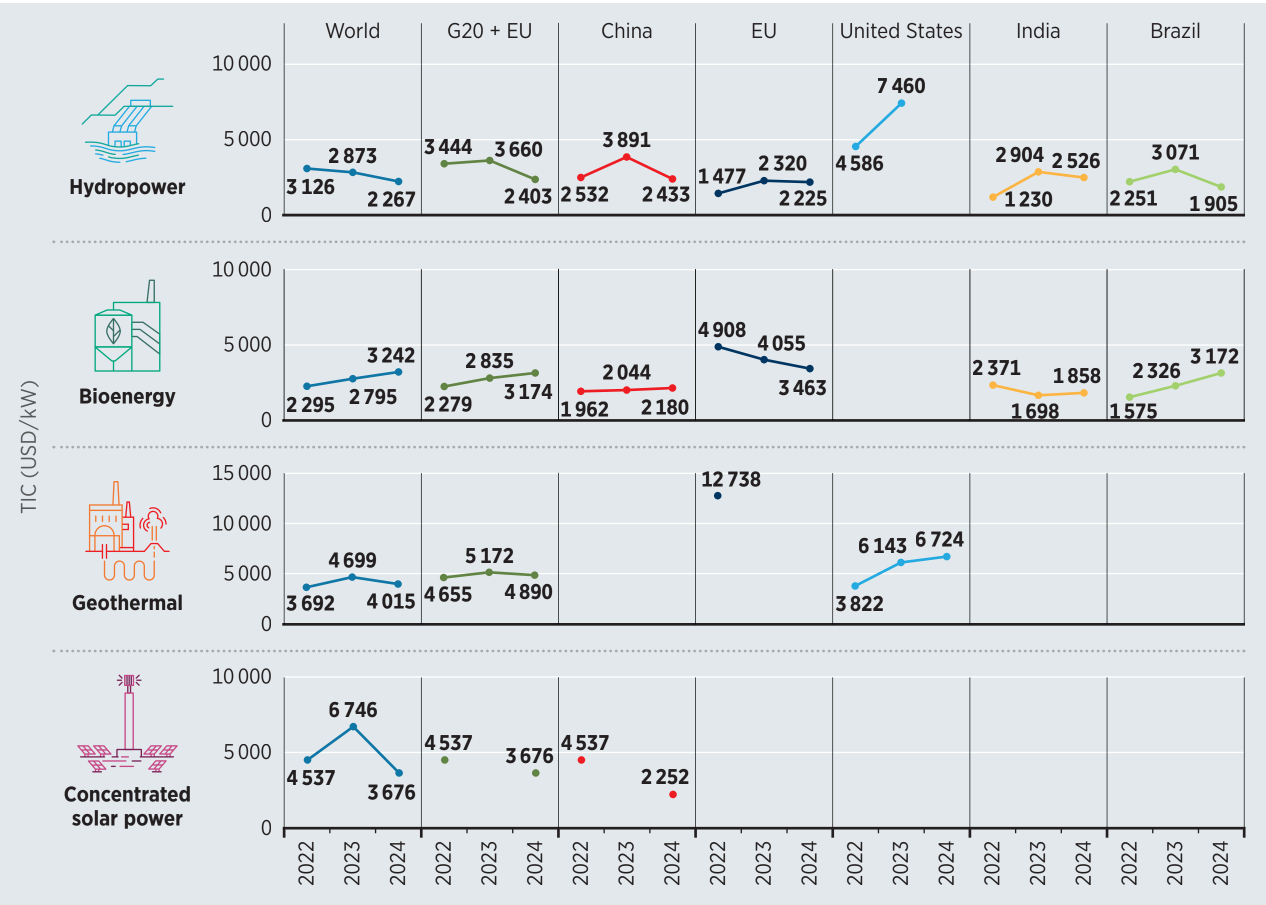
Notes: EU = European Union; G20 = Group of 20.

Figure 1.6 TIC trajectories of variable technologies in selected regions, 2022-2024



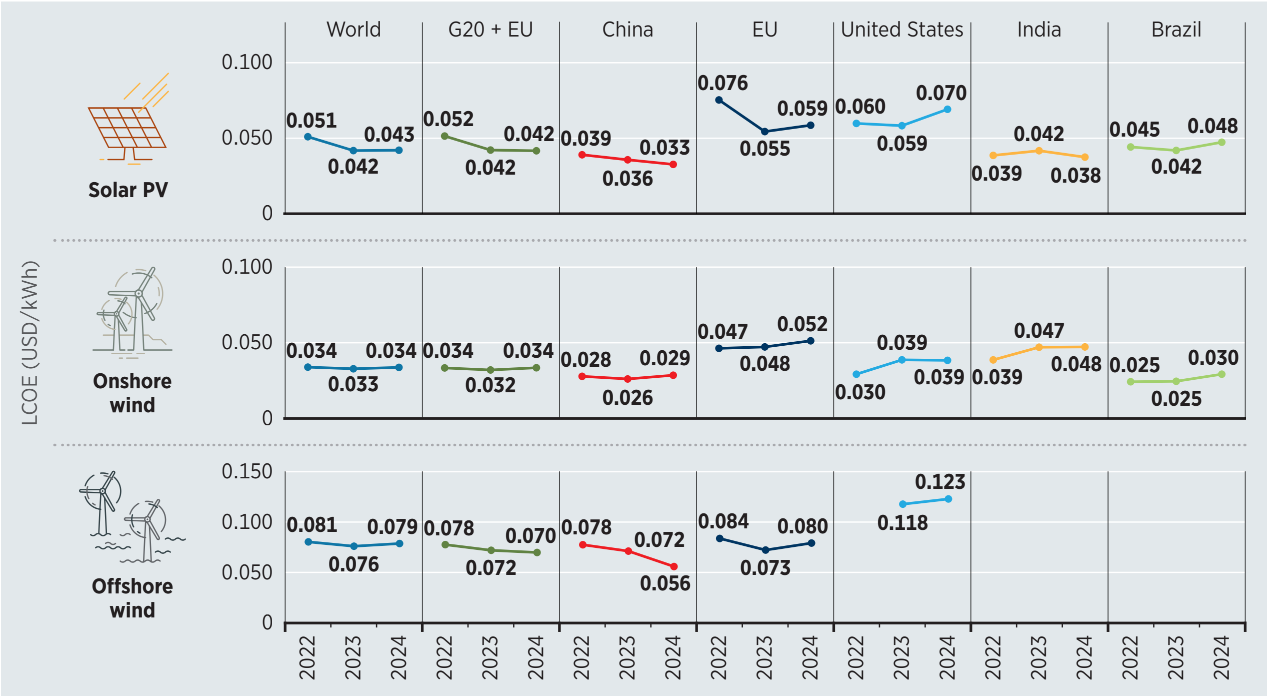
Notes: EU = European Union; G20 = Group of 20; kW = kilowatt; PV = photovoltaic; TIC = total installed costs; USD = United States dollar.

Figure 1.7 TIC trajectories of dispatchable technologies in selected regions, 2022-2024



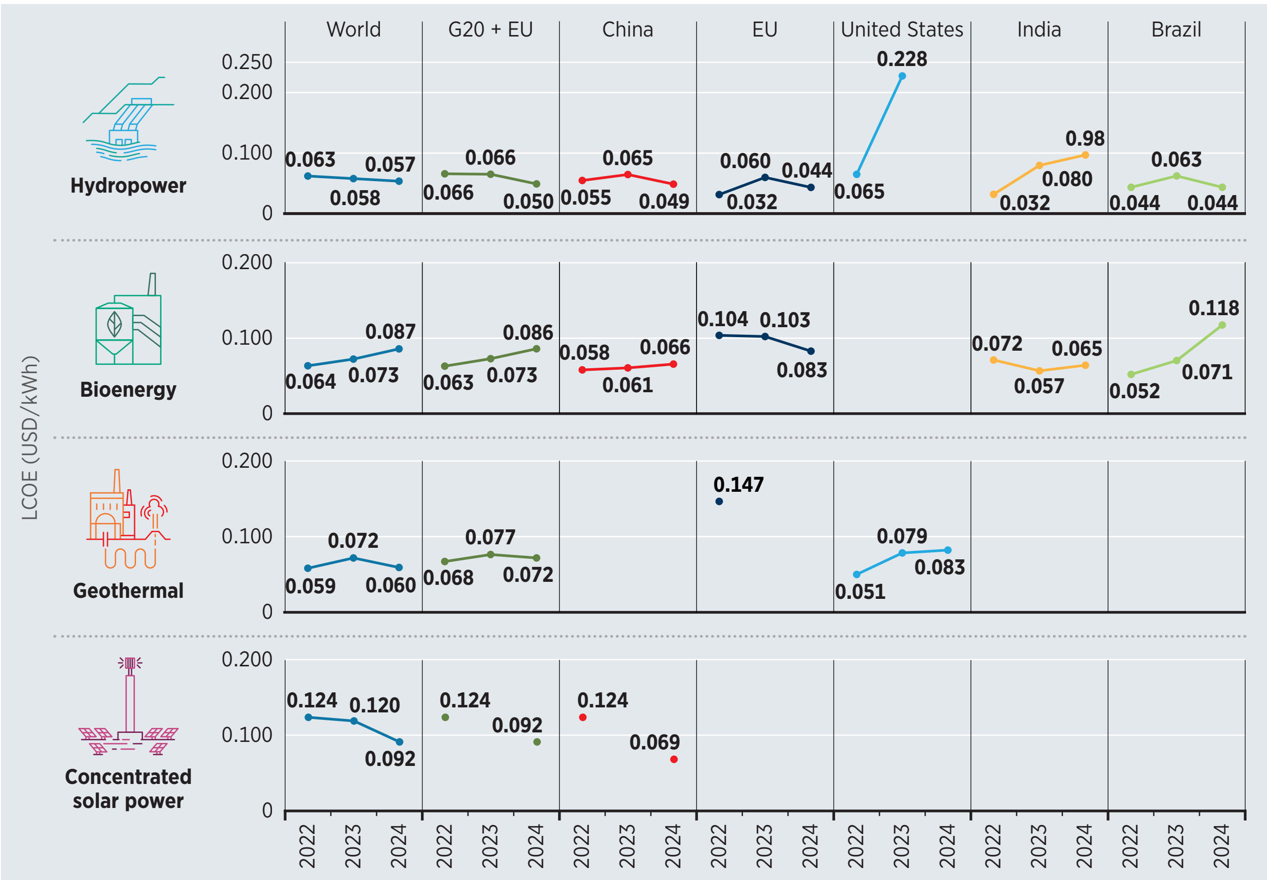
Notes: EU = European Union; G20 = Group of 20; kW = kilowatt; TIC = total installed costs; USD = United States dollar.

Figure 1.8 LCOE trajectories of variable technologies in selected regions, 2022-2024



Notes: EU = European Union; G20 = Group of 20; kWh = kilowatt hour; PV = photovoltaic; LCOE = levelised cost of electricity; USD = United States dollar.

Figure 1.9 LCOE trajectories of dispatchable technologies in selected regions, 2022-2024



Notes: EU = European Union; G20 = Group of 20; kWh = kilowatt hour; LCOE = levelised cost of electricity; USD = United States dollar.

Beyond costs: Renewable energy benefits in terms of avoided fossil fuel use

In 2024, a record-breaking 582 GW of renewable energy capacity was added, displacing significant volumes of coal and gas generation in key markets such as China, the United States, and the EU.

Indeed, as the penetration of renewable energy increases, fossil fuel generation is being increasingly relegated to residual, or peak demand. This is lowering overall thermal plant utilisation and the exposure of energy systems to fuel market volatility.

This structural shift has also improved the overall resilience of electricity systems. During periods of extreme weather or rapid demand growth – such as heatwaves, cold snaps, or the post-pandemic rebound – renewables have helped to buffer against fuel price spikes and physical supply constraints by reducing reliance on gas and coal-fired generation. IEA analysis confirms that rising shares of variable renewables significantly curtail the marginal demand for gas-fired power, especially during peak periods, thereby limiting market volatility, lowering system balancing costs and enhancing long-term energy security through reduced exposure to international fuel markets (IEA, 2024a).

Renewables also displace emissions from fossil fuel combustion, resulting in far-reaching environmental and public health benefits. These benefits include direct reductions in carbon dioxide (CO_2) emissions and substantial declines in harmful air pollutants, such as sulphur dioxide (SO_2), nitrogen oxides (NO_x) and fine particulate matter ($PM_{2.5}$), all of which are linked to respiratory and cardiovascular illnesses.

In addition, renewables also reduce the need for fossil fuel infrastructure, such as fuel pipelines, storage terminals and thermal backup. Renewables do, however, increase the need for infrastructure throughout the renewable supply chain, as well as grid, storage and related infrastructure. Hybrid solar-plus-storage systems are increasingly replacing gas peakers in China and the United States, avoiding associated capital and operational costs (Ember, 2025c; IEA, 2024a; Lazard, 2024). Grid-edge solutions, including demand response and distributed energy resources, further mitigate peak load requirements, thereby deferring expensive system upgrades and reducing inefficient ramping of thermal assets (IEA, 2024a, 2025b). These system-level gains illustrate how renewables can reduce infrastructure and system-level expenditures, especially when paired with storage and demand-side measures, complementing renewables' declining generation costs.

IRENA research covering multiple countries illustrates the benefits associated with renewable power deployment. An analysis was made that quantified the avoided costs of fossil fuels, CO_2 emissions and the damage of air pollution by comparing actual renewable generation in 2024 with a counterfactual scenario in which the same electricity would have been produced using coal- and gas-fired power plants.[16]

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[16] The model used in this case study applied standard assumptions across countries, including: fixed displacement shares between coal and gas; fuel prices based on typical long-term contract values (rather than temporary market spikes); and assumptions for thermal efficiency, emissions intensity and damage factors. The model estimated the benefits by comparing actual renewable electricity generation in 2024 with a counterfactual scenario in which fossil fuel plants would have generated the same electricity. The resulting avoided fossil fuel use, CO_2 emissions and damage from air pollution was then monetised using average fuel prices and per-megawatt hour (MWh) damage cost factors.

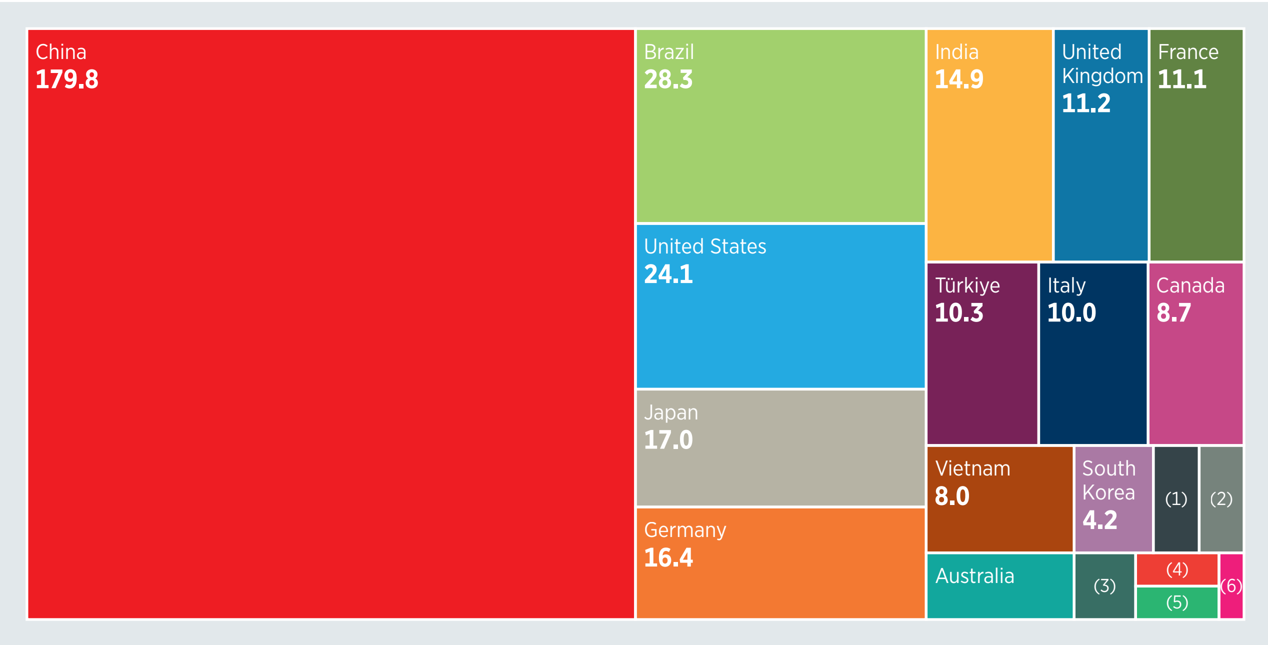
While this provides a useful benchmark for gauging the benefits of renewables, the model does not constitute a full cost-benefit analysis. It does not account for the costs incurred by renewable deployment (such as investment or integration costs), nor does it include indirect or induced effects through broader economic linkages.

The results revealed that countries with the highest levels of renewable electricity production captured the largest absolute benefits. In particular, the research revealed that:

- China avoided fossil fuel costs of USD 179.8 billion and reduced CO_2 emissions by 2.89 billion tonnes, with an additional USD 261.1 billion in air pollution-related health benefits.
- The United States avoided USD 24.1 billion in fossil fuel costs, 597 million tonnes of CO_2 emissions, and gained USD 21.5 billion in air pollution benefits.
- Brazil avoided USD 28.3 billion in fossil fuel costs and 372.6 million tonnes of CO_2 emissions, with USD 3.9 billion in air pollution benefits.
- India avoided USD 14.9 billion in fossil fuel costs and 410.9 million tonnes of CO_2 emissions, with USD 31.7 billion in air pollution-related benefits.

Considering the total renewable capacity currently in operation worldwide, avoided fossil fuel costs in 2024 totalled USD 467 billion (Figure 1.10). In 2024 alone, the addition of 585 GW of new renewable power capacity avoided fossil fuel use worth USD 57 billion – the equivalent to the entire gross domestic product (GDP) of a country such as Armenia or Mongolia.

Figure 1.10 Avoided fossil fuel costs from renewable electricity generation in 2024 (USD billion)



Notes: (1) Indonesia 2.5; (2) Mexico 2.4; (3) Malaysia 2.0; (4) Argentina 1.4; (5) Philippines 1.4; (6) South Africa 0.9.

This case study supports the broader narrative established throughout the chapter: that renewables consistently outperform fossil fuels not only in terms of LCOE, but also on avoided environmental damage and health outcomes. These co-benefits provide a compelling justification for accelerating clean energy deployment, particularly in fossil-reliant and cost-sensitive regions.

STRUCTURAL COST DRIVERS AND MARKET DYNAMICS

Supply chains: Efficiency, concentration and risk

The global supply chains supporting the development and expansion of renewable technologies are key drivers in cost reduction, yet also a source of systemic vulnerability. China, for instance, is a large – and cost-effective – supplier across the solar PV, battery and wind turbine manufacturing sectors, covering a wide variety of key components (*e.g.* wafers, cells, modules).[17]

Several structural factors explain China's cost advantage. According to Wood Mackenzie, China's vertically integrated supply chains help lower total system costs by streamlining production, transport and distribution processes (Wood Mackenzie, 2025a). This structural integration also supports lower financing risk and tighter cost control in megaprojects. BNEF also stresses the effect on global prices of China's expanded production capacity, especially in solar PV modules, batteries and – to a lesser extent – on wind turbines (BNEF, 2025a).

This concentration exposes the renewable industry to trade frictions, logistical bottlenecks and lifecycle emissions concerns.[18] Several countries have launched initiatives to reduce exposure to geopolitical risks by promoting the development of local procurement strategies and domestic supply chains. Local manufacturing, however, typically carries a cost premium[19] and requires substantial upfront capital investment.

Financing conditions and the cost of capital

While fossil fuel-based system costs tend to be dominated by variable fuel expenditures, renewable energy projects are characterised by relatively high upfront CAPEX requirements. These are typically incurred at the pre-project, construction and commissioning phases, and are recovered at a later stage over the operational lifetime of the plant. The LCOE of such systems is highly dependent on the time value of project cashflows, which are driven by the cost of capital.

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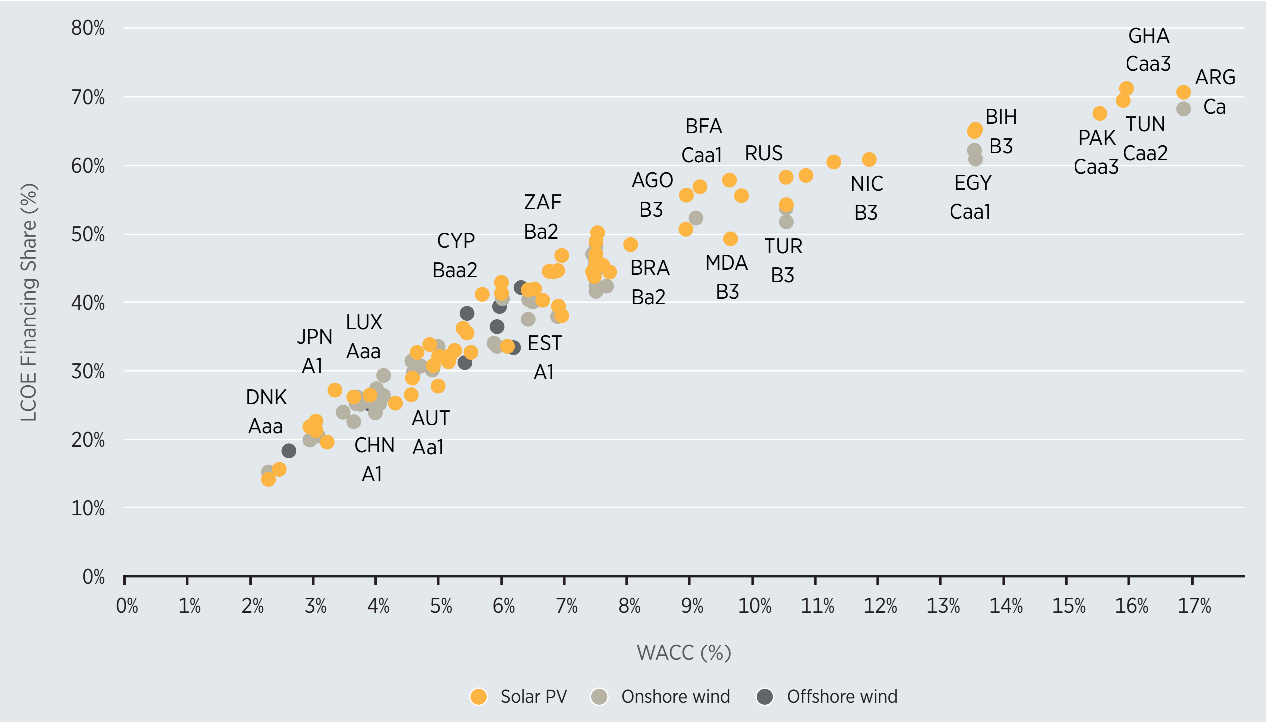
[17] China accounted for 79% of global polysilicon production, 97% of wafer production, 85% of cell production and 75% of module production in 2021 (IEA, 2022). China also holds nearly 85% of global battery cell production capacity and a leading share of anode and cathode active material production (IEA, 2024a). On the other hand, the 2025 edition of the Global Wind Energy Council (GWEC) Global Wind Report indicates that China accounted for 70% of global onshore wind installations in 2024, supported by domestic original equipment manufacturers (OEMs) that are increasingly expanding their presence in international markets (GWEC, 2025a).

[18] While the manufacturing carbon intensity is often linked to China's use of coal as a power source, many energy-intensive facilities are located in western provinces where hydropower, solar and wind contribute a significantly higher share of electricity generation than the national average.

[19] The International Solar Alliance (ISA) notes that while modules produced in China and Southeast Asia are 25%-37% more cost-competitive than those from the United States or Europe, this gap can be partly offset by transportation costs and end-user willingness to pay a premium for locally manufactured, or low-carbon modules (ISA, 2023).

Figure 1.11 illustrates this relationship. The share of financing costs[20] in the LCOE increases with the WACC across countries. Those jurisdictions with elevated perceived risk (as proxied by Moody's credit ratings) are associated with higher WACC values. This translates into a higher share of LCOE being taken by financing costs.

Figure 1.11 Share of financing in LCOE in comparison with WACC for selected countries, 2024

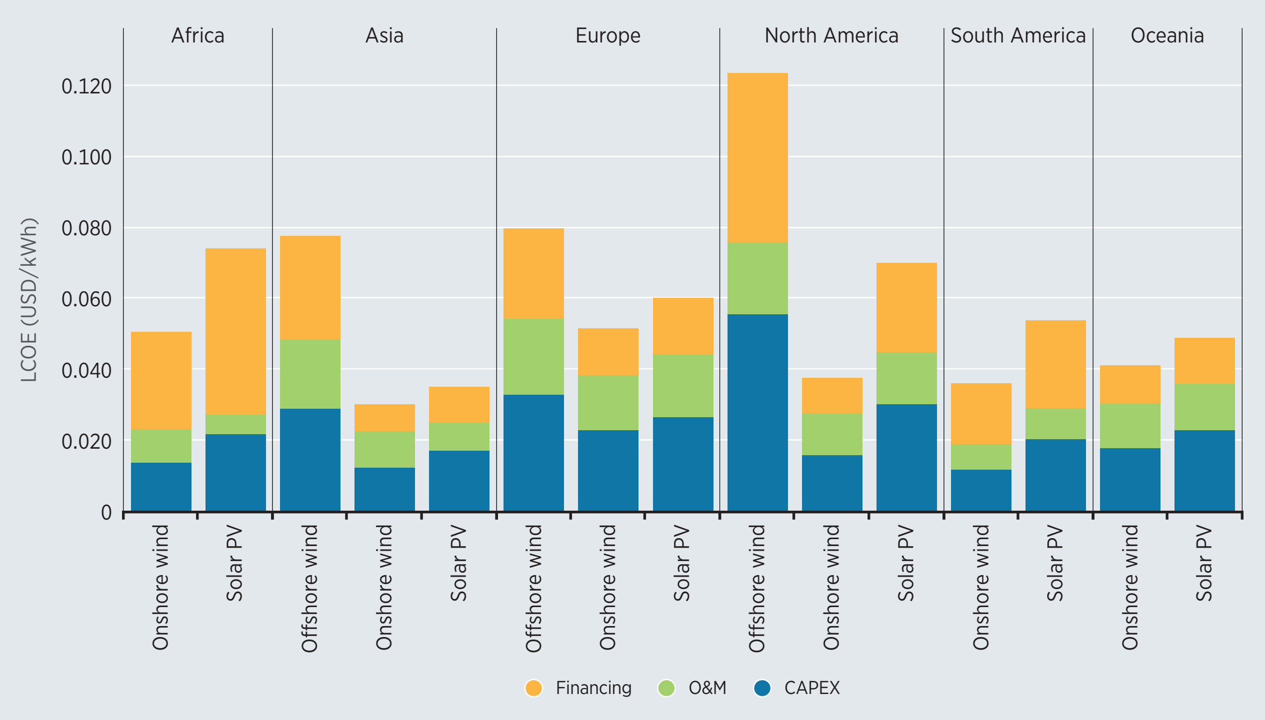


Notes: AGO = Angola; ARG = Argentina; AUT = Austria; BFA = Burkina Faso; BIH = Bosnia and Herzegovina; BRA = Brazil; CHN = China; CYP = Cyprus; DNK = Denmark; EGY = Egypt; EST = Estonia; JPN = Japan; LCOE= levelised cost of electricity; LUX = Luxembourg; MDA = Moldova; NIC = Nicaragua; PAK = Pakistan; PV = photovoltaic; RUS = Russia; TUN = Tunisia; TUR = Türkiye; WACC = weighted average cost of capital; ZAF = South Africa.

Figure 1.12 illustrates this effect. The weighted average LCOE of onshore wind in Africa and Europe is comparable (USD 0.051 and 0.052/kWh, respectively). However, the cost structure differs significantly: in Europe, LCOE is driven more by CAPEX, while in most African countries, financing costs dominate. This example stresses the importance of reducing the cost of capital, especially in high-risk contexts, in order to unlock investment and bring down LCOEs in emerging markets.

[20] *Financing costs are estimated as the difference between the LCOE at a given WACC and the LCOE under a zero-discount rate scenario. For example, at a WACC of 5%, financing costs are calculated as LCOE(WACC=5%) minus LCOE(WACC=0%). Their share is then expressed as a proportion of the full LCOE. This approach isolates the effect of time on money from undiscounted cost components. WACC values account for country-specific parameters (e.g. sovereign credit ratings, risk premiums, and tax rates).*

Figure 1.12 LCOE breakdown in selected regions, 2024



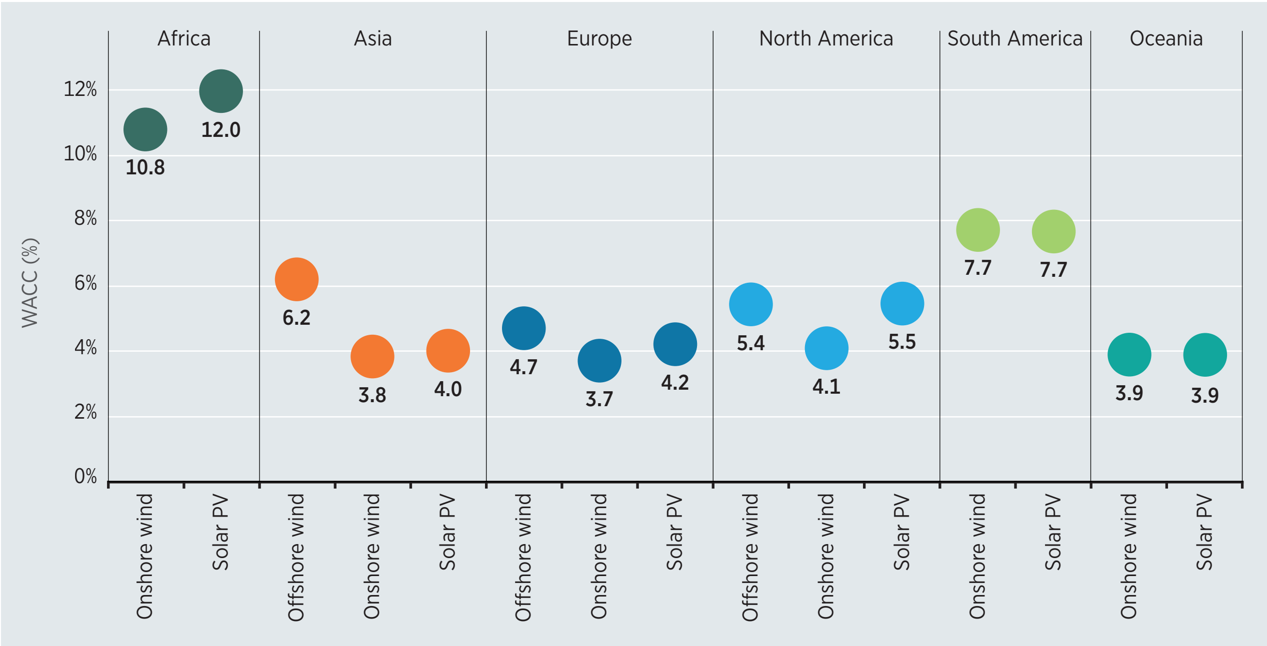
Notes: CAPEX = capital expenditure; kWh = kilowatt hour; LCOE = levelised cost of electricity; O&M = operation and maintenance; PV = photovoltaic; USD = United States dollar.

Beyond country risk, several structural factors influence financing costs. These include revenue certainty, capital structure and broader macroeconomic conditions, such as inflation and interest rate trends. In particular, these factors can have the following effects:

- **Revenue certainty:** Stable offtake structures significantly reduce risk premiums. Power purchase agreements (PPAs), regulated tariffs and state-backed contracts enhance creditworthiness and lower financing costs (IRENA, 2023a; Lazard, 2024).
- **Macroeconomic conditions:** Inflation and rising central bank rates have increased the cost of debt globally. Higher risk-free rates and equity risk premiums (ERPs) are reflected in the WACC across countries and regions (Damodaran, 2023; IRENA, 2023a).
- **Policy and regulatory environment:** Comprehensive fiscal support, such as the Inflation Reduction Act (IRA) in the United States, can increase investor confidence by lowering financial risk. Conversely, regulatory uncertainty or retroactive policy changes can undermine the viability of financing (Europe Economics, 2018; GLOBSEC, 2024a).
- **Technology risk:** Established technologies such as solar PV and onshore wind attract lower cost of capital due to high maturity and performance data. Conversely, offshore wind, geothermal and biomass face higher hurdle rates owing to longer construction cycles and perceived operational risks (IRENA, 2023a; Europe Economics, 2018).
- **Market risk exposure:** Projects selling into merchant markets bear greater volatility, resulting in higher equity return expectations. For instance, merchant solar PV and wind projects are associated with higher WACC levels than their contract-for-difference backed counterparts (Europe Economics, 2018).

In 2023, IRENA published a robust methodology combining expert elicitation, semi-structured interviews and a benchmark modelling tool to estimate the WACC for solar PV, onshore wind and offshore wind across major global markets (IRENA, 2023a). The benchmark tool accounts for macroeconomic factors, such as base interest rates, country risk premia and technology-specific premiums, to produce cost of capital estimates where empirical data are unavailable. This model was applied to derive WACC values for 2023, which in turn informed the discounted cash flow analysis supporting the 2024 LCOE estimates. According to IRENA's methodology, the WACC for a given year (y) is based on macroeconomic data from the preceding year (y-1), reflecting the typical lag between shifts in financing conditions and investment decisions. Figure 1.13 summarises the weighted average cost of capital for key regions in 2024.

Figure 1.13 Weighted average cost of capital (WACC) for key regions, 2024



Notes: PV = photovoltaic; WACC = weighted average cost of capital.

IRENA's cost of capital assumptions are relatively conservative. In 2024, the weighted average cost of capital for renewable energy projects declined compared to 2023, primarily due to the global monetary policy easing cycle, which reduced inflation and improved financing conditions. This trend is particularly pronounced in China, where WACC has fallen sharply as state-owned developers benefit from access to low-cost debt. Looking ahead, further interest rate cuts anticipated in 2025 by central banks in the United States, the Eurozone and the United Kingdom are expected to support continued reductions in financing costs, particularly for capital-intensive clean energy technologies.

Policy incentives and industrial strategy

Governments in key markets have increasingly turned to industrial policy to shape the trajectory of renewable energy deployment in their countries and beyond. Strategic policy frameworks such as the IRA in the United States and the EU's Green Deal Industrial Plan have played key roles in encouraging domestic manufacturing, reducing dependency on imports and supporting the creation of resilient clean energy ecosystems.

These initiatives were designed to accelerate the deployment of low-carbon generation and storage technologies while building domestic supply chains for key components. The IRA, for example, included tax credits for clean energy production, investment and domestic content, which have helped strengthen the competitiveness of clean energy projects based in the United States. Despite higher capital costs, these incentives enabled record deployments in 2024 (Ember, 2025b). Similarly, the EU's policy push has enabled wind and solar additions to reduce the bloc's fossil fuel import bill. In euro (EUR) terms, this fell by an estimated EUR 59 billion (USD 64 billion) between 2019 and 2024 (Ember, 2025a).

Implementation remains uneven, however. In many countries, local manufacturing remains cost-disadvantaged compared to imports, particularly when those come from Asia. This is due to higher energy, labour and overhead costs, limited economies of scale, and insufficient upstream integration. Moreover, effective localisation strategies need to be aligned with grid readiness, workforce development and consistent permitting frameworks – an integration that is rarely achieved in practice. To address these challenges, several countries are integrating broader industrial strategies that go beyond simple subsidies. These include innovation grants, de-risking mechanisms for first-of-a-kind projects and support for vertical integration across the supply chain (GLOBSEC, 2024a; Mazzucatoa and Semieniuk, 2018).

Macroeconomic pressures and trade-related costs

As for the broader energy sector, renewable power technologies remain vulnerable to macroeconomic and trade-related factors. In 2024, financing conditions for new power projects improved slightly, as central banks began to reduce interest rates. This brought the cost of capital back to levels last seen in 2022. Further rate cuts are expected in 2025, with these projected to benefit capital-intensive technologies such as renewables and storage, improving project economics globally.

Trade-related measures are also emerging as a critical structural cost driver. Ongoing tariff disputes, notably between the United States and China, could increase LCOEs for solar PV by up to 18%, or 20% for grid-scale storage. This would effectively threaten clean energy targets in tariff-affected markets (Wood Mackenzie, 2025a).

Looking ahead, cost trajectories will depend not only on technology learning rates and innovation, but also on how governments and markets navigate macroeconomic volatility and global trade realignment.

TECHNOLOGY SPOTLIGHT: SOLAR

Deployment leaders and global trends

In 2024, utility-scale solar photovoltaics (PV) dominated global renewable capacity additions. Some 452 GW of this technology was added globally,[21] representing 78% of total renewable additions. China remained the pre-eminent market, adding 277 GW of new PV capacity, followed by the United States, India and Brazil. Emerging markets in Southeast Asia and Africa began to scale up deployment, albeit from a lower baseline (Ember, 2025c; IRENA, 2025d).

[21] *Utility-scale systems represent about 58% according to IRENA estimates.*

While the rapid growth of utility-scale solar continues to be primarily driven by cost competitiveness and climate policies, emerging demand-side factors are beginning to shape the load profile and influence system planning. Such factors include electrification, digitalisation and the shift toward cleaner industrial processes. In 2024, electricity demand rose sharply in countries such as the United States, which saw an increase of 128 terawatt hours (TWh). India and China also saw rising demand, with clean electricity playing an increasing role in meeting this. In the EU, solar generation reached 251.7 TWh (IRENA, 2025d).

In parallel, solar PV continues to be the leading utility-scale technology. This is due to its modularity, declining costs and rapid scalability. Fixed-tilt and single-axis tracking systems remain standard, with bifacial panels and high-efficiency monocrystalline silicon cells widely adopted. In contrast, CSP saw limited new capacity in 2024 and remains niche, with most recent projects concentrated in China and the Middle East and North Africa (MENA) region. CSP's role is increasingly associated with hybridisation and long-duration storage support.

On the technology front, innovation remains concentrated in mass-manufactured technologies, such as PV modules, inverters and BESS. This is especially the case in China and the United States. Early-stage activity includes perovskites, tandem cells and artificial intelligence (AI)-integrated O&M platforms. Hybridisation is also a key trend. BESS are now integral to solar deployment, particularly in the United States and China. In 2024, the United States saw accelerated battery additions to complement rapid solar growth, enabling peak-shaving and grid stability (Ember, 2025d).

Box 1.2 Spotlight: China's record solar expansion in 2024

In 2024, China installed a record 277 GW of solar PV capacity, reinforcing its position as the world's largest and most cost-competitive solar market (IRENA, 2025d). This unprecedented expansion was enabled by substantial cost advantages arising from vertical integration, economies of scale and China's extensive involvement across all stages of the solar PV supply chain. Consequently, the average LCOE for utility-scale solar PV in China fell to USD 0.033/kWh, compared to the global average of USD 0.043/kWh.

Building on its manufacturing strength, China has become a leading force for solar PV development and deployment. The country produces most of the world's wafers, cells and modules, and offers module prices well below those in Europe and the United States. The country accounted for 79% of global polysilicon production, 97% of wafer production, 85% of cell production and 75% of module production in 2021 (IEA, 2022).

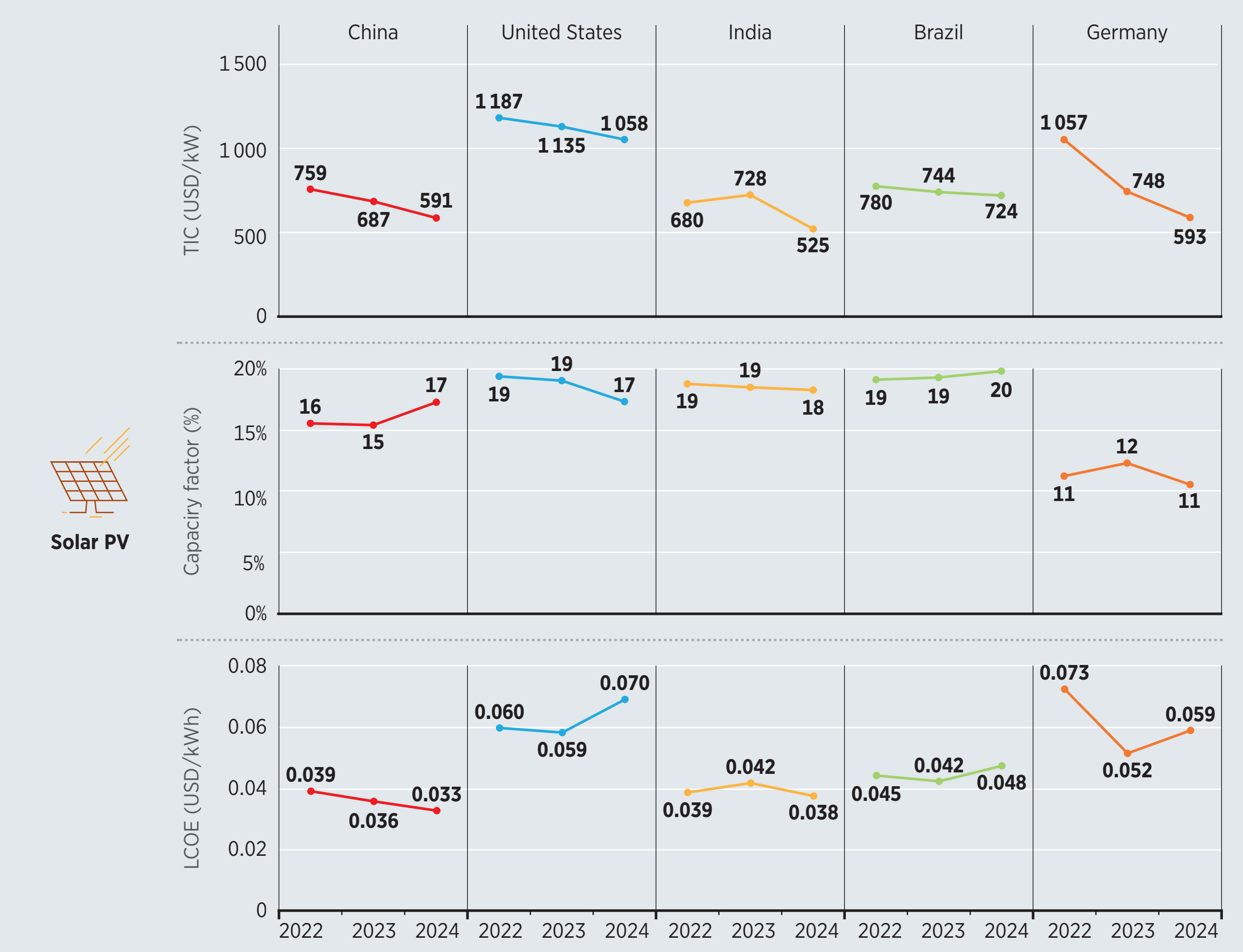
The rapid growth in China's solar deployment in 2024 was accompanied by a parallel acceleration in BESS, which enhanced grid integration and provided greater flexibility during peak demand periods, especially in provinces facing high curtailment risk.

China's large-scale solar rollout illustrates both the opportunities and the challenges of the global energy transition. While it demonstrates the value of vertically-integrated supply chains in reducing procurement delays, compressing margins and enabling the efficient scaling of GW-scale projects, it also highlights the supply chain and broader geopolitical risks associated with concentrated manufacturing, stressing the need for diversification.

Cost trajectories

In 2024, the weighted average LCOE for utility-scale solar PV ranged from USD 0.033/kWh in China to USD 0.070/kWh in the United States (Figure 1.14). The global weighted-average LCOE was approximately USD 0.043/kWh, reflecting a continued cost decline driven by scale, improvements in technology and competitive procurement. Costs remained lowest in China, supported by domestic manufacturing capacity and vertically integrated supply chains.

Figure 1.14 Solar PV cost and performance trajectories in selected countries, 2022-2024



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; PV = photovoltaic; TIC = total installed cost; USD = United States dollar.

Drivers of competitiveness

The global competitiveness of solar PV technology is driven by a convergence of technological, structural and geopolitical factors, as detailed below:

- **Technology:** There have been efficiency gains in modules, such as TOPCon, HJT and bifacial. There have also been increased economies of scale in BESS and more streamlined balance-of-system components.
- **Market structure:** Competitive auctions, merchant projects and corporate PPAs all influence pricing. Markets with stable offtake schemes, such as India and Brazil, attract lower financing costs.
- **Deployment scale:** China is able to leverage GW-scale installations with vertical integration, minimising per-unit costs.
- **Learning curve:** Estimated learning rates for solar PV are close to 33%, supporting rapid cost compression in maturing markets.
- **Policy support:** Measures such as the IRA in the United States and EU initiatives to streamline permitting have accelerated solar deployment by improving the investment environment and reducing administrative barriers.

TECHNOLOGY SPOTLIGHT: WIND

Deployment leaders and global trends

In 2024, global wind power capacity additions reached 114.3 GW, when onshore and offshore are combined. China accounted for 79.4 GW of this, or around 69.4% of the total. The United States added 5.1 GW, while Brazil, India, Canada, Türkiye and multiple EU member states also posted additional wind capacity (IRENA, 2025d).

In the EU, offshore and onshore wind generation combined reached 477.8 TWh in 2023. This accounted for over 17.4% of the EU's total power generation. In the United States, wind power's share of electricity generation reached 9.6%, maintaining its role as the leading renewable technology after hydropower (IRENA, 2025d).

Onshore wind remains the dominant utility-scale wind technology due to its cost competitiveness, maturity and favourable siting. Key technology trends include taller towers, longer blades and modular nacelles for logistics and maintenance optimisation. Offshore wind continues to scale up as well, particularly in China, the United Kingdom and parts of Northern Europe. Fixed-bottom installations remain the norm, but floating wind is emerging, with early commercial deployments expected in the latter half of the decade.

Similar to solar PV, the integration of BESS with wind projects is gaining momentum, worldwide, though at a lower deployment scale. This is so particularly in the United States and certain European countries, driven by the need to manage generation variability and alleviate grid congestion.

Box 1.3 Spotlight: EU wind surpasses coal in 2024 electricity generation

In the European Union, wind power generated 475 TWh in 2024. For the second consecutive year, it overtook coal, which generated 269 TWh, and became the second-largest source of electricity after nuclear (Ember, 2025a). Wind accounted for over 27% of EU electricity generation, highlighting the continent's continued leadership in clean energy deployment.

The wind sector's growth was driven by both onshore repowering and offshore expansion, particularly in Germany, the Netherlands and Denmark. Notably, offshore wind projects in the North Sea benefitted from cross-border grid investments and floating foundation trials, positioning the region as a future hub for inter-regional clean power exchange (GWEC, 2025a).

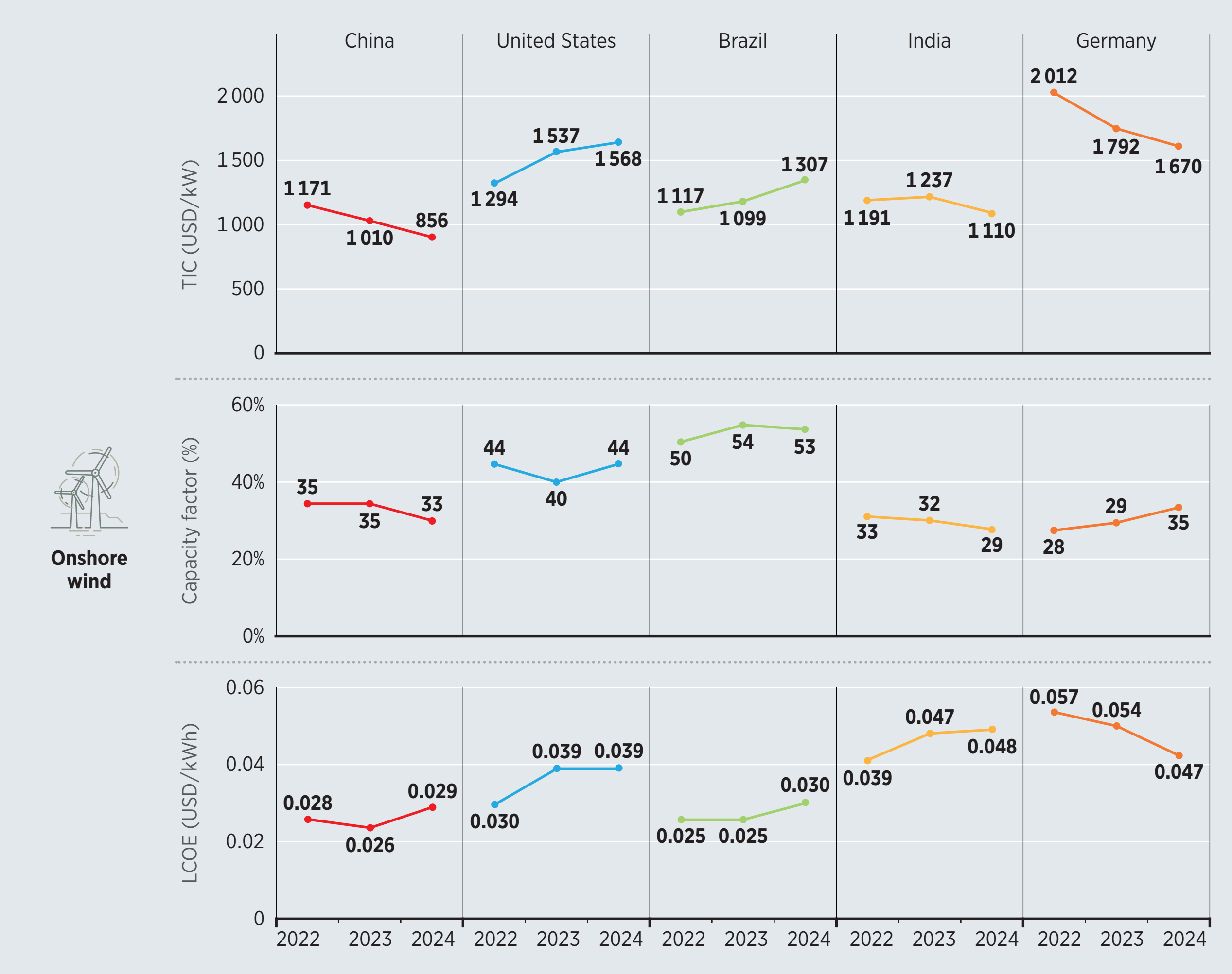
Wind and solar also contributed to a 9% reduction in EU power sector CO_2 emissions in 2024. They have also enabled the EU to avoid EUR 59 billion (USD 64 billion) in fossil fuel import costs since 2019 (Ember, 2025a). Battery storage capacity, although still limited, began playing a larger role in mitigating the intermittency of wind generation in 2024, particularly in hybrid wind-plus-storage deployments in Spain and Ireland.

The EU's experience highlights the key role played by investment in transmission and distribution (T&D) and cross-border co-ordination in accelerating the clean energy transition. It also demonstrates the broader system benefits - climatic, economic and geopolitical - of scaling up wind energy in tandem with enabling technologies.

Cost trajectories

Between 2022 and 2024, onshore wind LCOEs remained relatively stable or rose slightly across key markets, with 2024 values ranging from USD 0.029 to USD 0.048/kWh. China and Brazil maintained the lowest costs, at USD 0.029/kWh and USD 0.030/kWh, respectively. India and Germany saw higher LCOEs, however, at USD 0.048/kWh and USD 0.047/kWh, respectively.

Figure 1.15 Onshore wind cost and performance trajectories in selected countries, 2022-2024



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; TIC = total installed costs; USD = United States dollar.

In 2024, offshore wind LCOEs varied significantly across regions, with China achieving the lowest costs, at USD 0.056/kWh. This was supported by economies of scale, state-backed procurement and domestic manufacturing advantages. In contrast, the United States recorded one of the highest LCOEs, at USD 0.123/kWh, reflecting elevated financing costs, supply chain constraints and delayed project timelines. The EU averaged USD 0.080/kWh, profiting from more established infrastructure and permitting frameworks, though inflation and auction design continued to influence costs.

Drivers of competitiveness

The competitiveness of the wind industry depends on a variety of factors, including:

- **Technology:** The deployment of larger turbines – from 14 megawatts (MW) to 18 MW offshore and more than 6 MW onshore – boosts competitiveness. Modular components and the scaling of floating foundations – in offshore wind in particular – also achieve this goal.
- **Market design:** Auctions, contracts-for-difference and PPAs influence capital costs and revenue predictability.
- **Deployment scale:** Gigawatt-scale projects in China and the United Kingdom have spread development and grid integration expenses across larger project portfolios.
- **Learning effects:** Continued reductions in CAPEX and O&M are supported by growing standardisation and digitalisation.
- **Supply chain:** Rising commodity prices and inflationary pressures in the 2023–2024 period impacted turbine and foundation costs, though stabilisation is expected from 2025 onwards.
- **Regulation and policy:** Large-scale industrial policies, such as the IRA in the United States and the EU's Green Deal Industrial Plan, are expanding support through tax credits and infrastructure investment.
- **Grid infrastructure:** Investment in transmission and interconnection helps ease congestion and better integrate new wind capacity.
- **Permitting:** Streamlining permitting processes allows for reduced lead times for project development.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TECHNOLOGY SPOTLIGHT: HYDROPOWER

Deployment leaders and global trends

In 2024, global hydropower (excluding pumped storage) capacity additions totalled 9.3 GW. This was a notable rebound from the 11.3 GW added in 2023, although the pace remains slower than with solar and wind technologies. China accounted for 96% of the hydropower increase, with notable contributions also coming from Pakistan, Ethiopia, Vietnam, Tanzania, Indonesia and Nepal. Cumulative global hydropower capacity excluding pumped storage reached 1 277 GW in 2024, or 1 427 GW when pumped storage is included (IRENA, 2025d).

Despite the record expansion of solar and wind, hydropower remains the largest source of renewable electricity worldwide, generating around 4 270.2 TWh in 2023, accounting for 47.8% of all renewable electricity generation (IRENA, 2025d). In China and Brazil, hydro continues to play a foundational role in grid stability and baseload supply.

Hydropower technologies are broadly categorised into conventional dam-based reservoirs, run-of-river (RoR), and pumped storage hydropower (PSH). In 2024, most new capacity consisted of RoR and small-scale reservoir systems, particularly in emerging markets where rapid deployment and lower capital requirements are prioritised. Pumped storage is regaining strategic importance as a long-duration storage solution to support variable renewables. While precise commissioning figures vary, the year saw increased momentum supported by policy reforms, new investment commitments and co-ordinated global action, such as the launch of the Global Alliance for Pumped Storage. Innovation in variable-speed turbines, digital control systems and hybrid hydro-solar installations also advanced.

Box 1.4 Spotlight: France's hydropower resilience and export leadership in 2024

In 2024, low-carbon electricity sources accounted for 95% of France's total electricity production. This was the highest share on record and reflected a year of strong hydropower performance and overall system recovery. Hydropower output reached 75.1 TWh, its highest level since 2013, contributing to a record 150 TWh of renewable generation, or 27.8% of total output.

France's extensive hydropower fleet, including large-scale dams and pumped storage facilities in the Alps and Pyrenees, enabled the country to act as a net exporter of 89 TWh of electricity in 2024, reinforcing its position as a regional energy anchor. The electricity system was further supported by time-of-use tariffs and demand response pilots, which encouraged consumption during periods of surplus renewable generation and reinforced hydropower's essential role in grid balancing.

This case highlights the strategic value of maintaining and upgrading legacy hydropower infrastructure. Beyond electricity generation, these assets play a crucial role in ensuring grid flexibility, regional energy security, and climate resilience - especially in the face of increasingly volatile weather patterns across Europe.

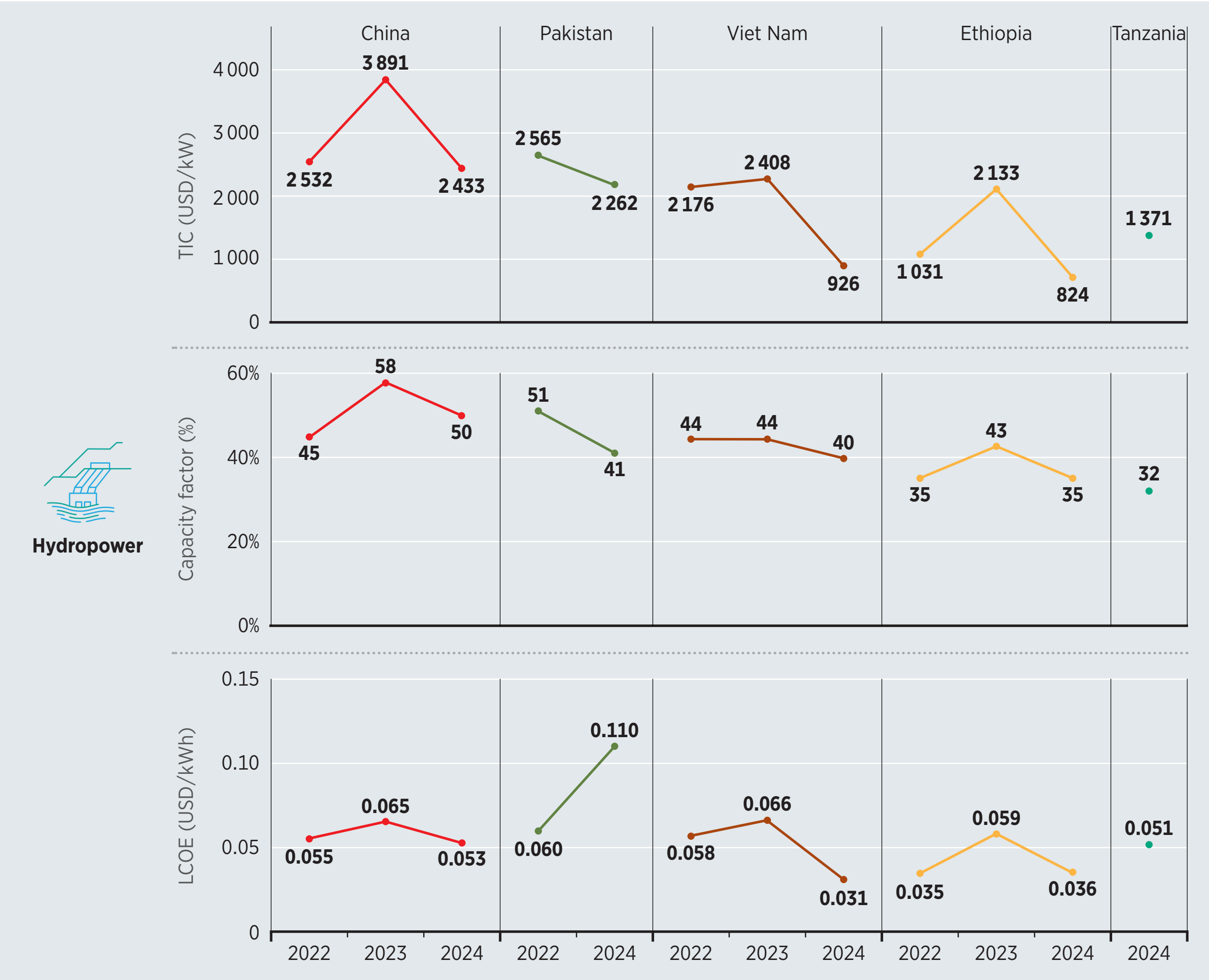
Cost trajectories

Pumped storage has higher upfront capital costs than other hydro power systems, with these typically ranging from USD 1000 to USD 3000/kW. LCOEs vary widely, depending on usage cycles and market structure.

In 2024, hydropower costs declined across most countries, with significant drops in LCOE and installed costs in Viet Nam, China and Ethiopia. In the latter, the LCOE fell as low as USD 0.036/kWh and the TIC fell below USD 1000/kW. Relatively high-capacity factors allowed for these cost reductions, though a slight decline in utilisation was observed in several countries. In contrast, Pakistan saw sharp cost increases, with the LCOE rising to USD 0.110/kWh.

Projections out to 2030 suggest limited cost decline potential in hydro compared to variable renewables. Instead, cost improvements are expected through operational optimisation, digitalisation and extended asset lifetimes.

Figure 1.16 Hydropower cost and performance trajectories in selected countries, 2022-2024



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; TIC = total installed costs; USD = United States dollar.

Drivers of competitiveness

The competitiveness of hydropower depends on a combination of technological, geographical and local context-related factors. These include:

- **Technology type:** RoR projects offer lower LCOEs due to smaller civil works, but face seasonal variability. PSH incurs high capex, but provides critical grid services such as inertia and frequency regulation.
- **Geographical and site conditions:** Topography, hydrology and proximity to load centres strongly influence feasibility and cost.
- **Regulatory certainty:** Environmental and social permitting remains a key determinant of timelines and costs. Fast-track approval is rare, particularly in the Organisation of Economic Co-operation and Development (OECD) markets.
- **Market structure:** Hydropower performs well in capacity or ancillary services markets, in addition to energy-only markets.
- **Financing environment:** Hydropower requires long-term debt with stable policy support; rising interest rates have increased capital cost burdens, especially for PSH.
- **Climate variability:** Increased droughts and extreme weather events have made hydropower output more volatile - reducing reliability and complicating investment planning.
- **Infrastructure age:** Much of the global hydropower fleet is over 30 years old, requiring significant upgrades to maintain competitiveness.
- **Geopolitical and transboundary risks:** In river basins such as the Mekong and Nile, tensions over shared water use increase project risk and regulatory complexity.
- **Social and environmental safeguards:** Large-scale projects face scrutiny over biodiversity impacts, displacement and indigenous rights, potentially slowing development and increasing costs.

TECHNOLOGY SPOTLIGHT: GEOTHERMAL POWER

Deployment leaders and global trends

In 2024, global installed geothermal power capacity reached 15 GW, following an annual increase of 0.3 GW (IRENA, 2025d). Most of this growth occurred in New Zealand, which added 0.2 GW, followed by smaller additions in Indonesia, Japan, Türkiye and the United States. These countries, along with the Philippines and Kenya, remain among the largest holders of geothermal capacity globally.

Conventional geothermal, which consists of hydrothermal flash, dry steam and binary technologies, remains the dominant form. Utilisation rates exceed 75%, often surpassing 90% in mature markets such as Iceland and Italy (IEA, 2024b).

Emerging technologies include:

- **Enhanced geothermal systems (EGS):** Unlocks geothermal in non-traditional geologies via hydraulic stimulation.
- **Closed-loop geothermal systems (CLGS):** Circulate fluid through sealed wells, avoiding reservoir dependency.
- **Supercritical geothermal:** Still at the research-stage, but targets ultra-deep, high-temperature resources.

Drilling and well construction remain the most capital-intensive components of geothermal development. Innovations adopted from the oil and gas industry are helping to reduce costs and improve reliability (IEA, 2024b; U.S. DoE, 2019). These innovations include directional drilling, polycrystalline diamond compact (PDC) bits and slim-hole exploratory drilling.

Geothermal is also evolving beyond its traditional role. Hybrid applications are expanding the strategic relevance of the technology in decarbonised energy systems. These applications include emerging pathways such as the co-production of lithium from geothermal brines and their use in subsurface energy storage, and in pairing geothermal with solar PV.

Box 1.5 Spotlight: The case for scaling deep geothermal in Germany

According to the 2022 Fraunhofer *Roadmap for Deep Geothermal Energy for Germany*, Germany's deep geothermal potential is substantial (Fraunhofer IEG, 2022). Indeed, estimates exceed 300 TWh of annual heat output, an amount equivalent to 25% of the country's total heat demand. This potential is concentrated in areas suitable for hydrothermal technologies, either for direct use or in combination with high-temperature heat pumps. Additional opportunities lie in petro-thermal resources, seasonal underground thermal storage and surface geothermal systems for building heating and cooling.

To unlock this potential, the Fraunhofer roadmap outlines the investment and governance structures required to scale up geothermal energy nationwide. If deployed effectively, geothermal systems could deliver competitive heat at costs below EUR 30/megawatt hour (USD 32/MWh). Municipalities play a central role in this strategy, as deployment depends heavily on integrating geothermal plants with district heating infrastructure. The roadmap calls for enhanced co-ordination between industry, science, and government, alongside new support instruments tailored for cities to enable project development and overcome implementation bottlenecks.

Cost trajectories

In 2024, geothermal's LCOE ranged from USD 0.033/kWh in Türkiye to USD 0.090/kWh in Indonesia. The Philippines and Japan recorded intermediate values of USD 0.081/kWh and USD 0.065/kWh, respectively. New Zealand also achieved a low LCOE, at USD 0.042/kWh. This was supported by a high capacity factor – 91% – and a relatively low TIC of USD 2 987/kW. In contrast, Indonesia saw a sharp rise in TIC, with this reaching over USD 6 000/kW in 2024. At the same time, the country maintained strong utilisation rates that went above 85%. Türkiye's TIC fell dramatically, meanwhile, from USD 4 076/kW in 2022 to USD 1 217/kW in 2024, while the capacity factor increased to 91%.

Figure 1.17 Geothermal power cost and performance trajectories in selected countries, 2022-2024

Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; TIC = total installed costs; USD = United States dollar.

These trends illustrate the sensitivity of geothermal project economics to site-specific conditions, with capital costs remaining high (up to USD 6 042/kW in Indonesia) due to exploration and drilling uncertainties, which can account for up to 50% of total project expenditure (IEA, 2024b; US DoE, 2019). Once operational, however, geothermal systems benefit from relatively low O&M costs, supported by high capacity factors and stable output.

Drivers of competitiveness

The economics of geothermal power generation are affected by a variety of factors. These include:

- **Resource risk:** Exploration uncertainty drives insurance, drilling contingencies and permitting costs.
- **Technology maturity:** Conventional plants are proven; EGS and CLGS face steep learning curves, but promise large cost declines.

- **Drilling costs:** These are dependent on rig availability, depth and geological conditions. The use of oil and gas technologies can mitigate costs.
- **Market design:** Dispatchability allows geothermal to capture capacity and revenues from ancillary services in mature markets.
- **Policy incentives:** Risk mitigation – such as drilling insurance – feed-in tariffs and tax credits – such as in the IRA – are critical to viability.
- **Supply chain and skills:** Geothermal relies on a shrinking pool of skilled oil and gas professionals and bespoke equipment.
- **Permitting and regulatory complexity:** Long lead times of often 7 to 10 years, along with complex mineral rights frameworks significantly slow project development, particularly in OECD markets.
- **Social acceptance and environmental risk:** Although typically low-impact, some projects face community resistance due to concerns about induced seismicity and local siting.

TECHNOLOGY SPOTLIGHT: BIOENERGY

Deployment leaders and global trends

In 2024, global bioenergy capacity increased by 5.1 GW, bringing the total installed capacity to 151 GW. The leading markets included China, Brazil, India, Japan and several EU member states. China and France added 2.3 GW, reflecting continued investment in biomass and waste-to-energy projects (IRENA, 2025d).

Bioenergy demand is closely linked to the agricultural and waste management sectors. In Brazil and the United States, biofuels (particularly ethanol and biodiesel) constitute a significant share of liquid fuel supply. In Europe, bioenergy is being increasingly integrated into district heating, industrial combined heat and power (CHP) and gas grid injection through the rising deployment of biomethane.

A wide range of technologies support this expansion. Utility-scale bioenergy technologies encompass biomass combustion (using solid fuels), anaerobic digestion (producing biogas) and advanced biofuels (such as lignocellulosic ethanol, biodiesel and synthetic biofuels). In 2024, the most mature and deployed technologies remained direct combustion and digestion-based biogas plants.

At the same time, new trends are emerging. These involve co-firing in coal plants, in Asia in particular, integration of bioenergy with carbon capture and storage (BECCS), and gasification pathways for syngas and biohydrogen production. Pilot-scale BECCS and biogenic CO_2-capture initiatives are underway in the United Kingdom, Scandinavia and California.

Looking ahead, innovation is driving the next phase of deployment. The sector is shifting toward modular, decentralised systems and waste valorisation. Biomass hybridisation with solar or geothermal is being explored to improve dispatchability and reduce emissions intensity.

Box 1.6 Spotlight: India's SATAT programme accelerates biogas market development

India's Sustainable Alternative Towards Affordable Transportation (SATAT) initiative continues to play a strategic role in scaling the production of compressed biogas (CBG) from waste and biomass sources, including agricultural residues, cattle dung, municipal solid waste, sugarcane press mud and sewage. Launched in 2018, the initiative aims to produce 15 million tonnes of CBG from 5 000 plants.

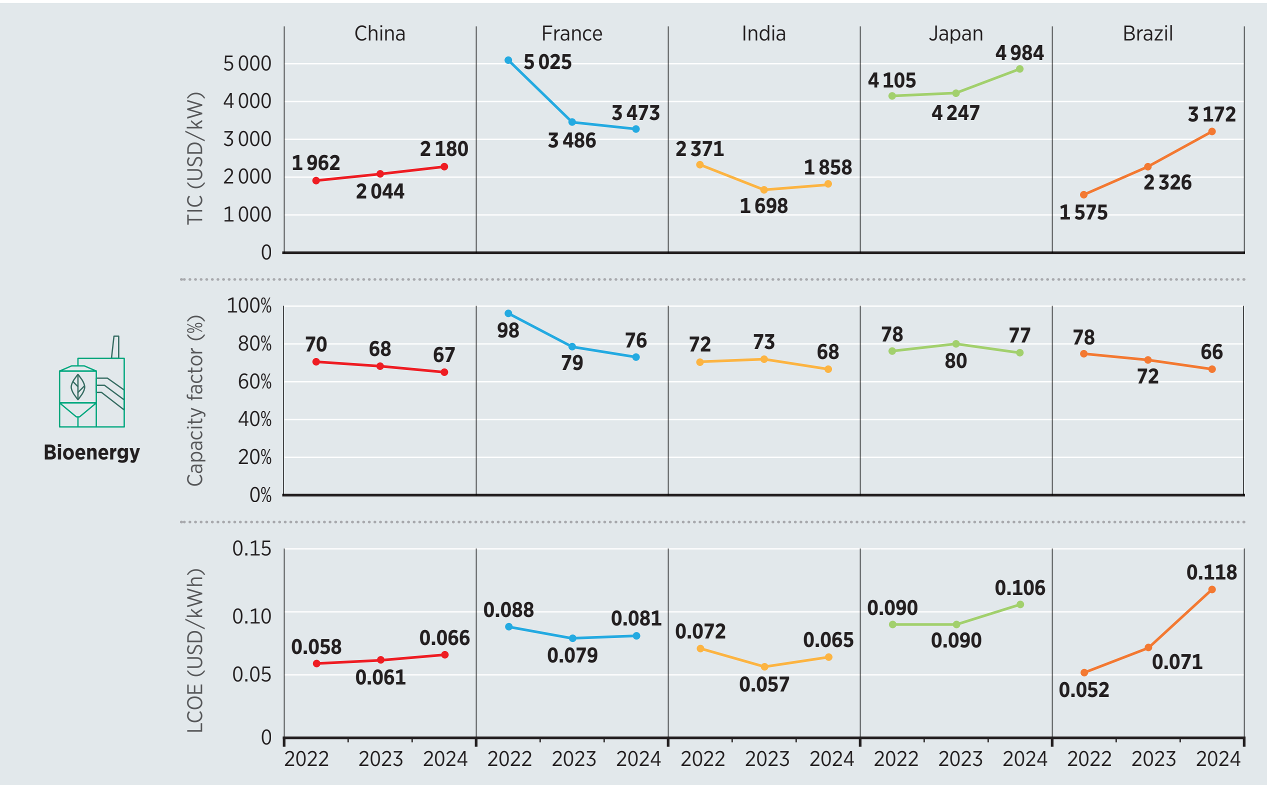
These decentralised systems are designed and operated by entrepreneurs who supply CBG to public sector oil marketing companies for use as automotive and industrial fuel. The model converts waste into clean fuel, providing additional revenue streams for farmers and waste collectors while supporting rural economies and promoting job creation.

SATAT also contributes to energy security by reducing dependency on imported natural gas and buffering against global fuel price volatility. The programme demonstrates the potential of policy-driven bioenergy development in emerging markets, combining public-private partnerships (PPPs), decentralised infrastructure and integration into existing city gas networks, extending clean fuel access to underserved areas.

Cost trajectories

Bioenergy's LCOE ranged from USD 0.065/kWh in India to USD 0.118/kWh in Brazil. India achieved the lowest TIC, at USD 1 858/kW, while Brazil's sharp rise to USD 3 172/kW and declining capacity factor (from 72% to 66%) contributed to its cost escalation. In contrast, France saw a substantial reduction in TIC, from USD 5 025/kW in 2022 to USD 3 473/kW in 2024, despite a decline in utilisation. China remained highly cost-competitive, with a 2024 LCOE of USD 0.066/kWh and a TIC of USD 2 180/kW, supported by stable operating conditions.

Figure 1.18 Bioenergy cost and performance trajectories in selected countries, 2022-2024



Notes: kWh = kilowatt hour; LCOE = levelised cost of electricity; TIC = total installed costs; USD = United States dollar.

Persistent structural barriers shape bioenergy cost trends. Feedstock costs remain volatile and regionally uneven. Prices are generally more predictable and less volatile for bioenergy derived from industrial and municipal waste, particularly in countries with established waste management systems, such as Germany, Denmark and Japan. Financing conditions remain less favourable than for solar or wind, reflecting smaller project sizes and higher technology premiums.

Drivers of competitiveness

The drivers of competitiveness of bioenergy projects include:

- **Choice of technology:** Anaerobic digestion and direct combustion are more cost-effective at scale than gasification or advanced biofuels, which remain commercially limited.
- **Feedstock availability:** Costs vary significantly depending on local biomass markets, logistics and competition with other sectors, such as fertilisers, animal feed and heating.
- **Regulatory environment:** Feed-in tariffs, renewable fuel standards and waste management regulations heavily influence project economics.
- **Market design:** Dispatchable attributes of biomass can command premiums in capacity or ancillary services markets, particularly in Europe and Japan.
- **Supply chain maturity:** Transport, storage and pre-processing infrastructure are often underdeveloped outside of leading markets, adding to the LCOE.
- **Geopolitics and trade:** The biomass trade, such as in wood pellets, is affected by international tariffs, sustainability certification and greenhouse gas (GHG) accounting frameworks.
- **Environmental and social risks:** Social acceptance issues - especially regarding land use and emissions - persist in both developed and developing economies.
- **GHG accounting and climate policy integration:** Fragmented GHG accounting frameworks complicate bioenergy's positioning in climate policy portfolios.
- **Innovation and investment gap:** Relative to solar and wind, bioenergy attracts lower levels of research and development (R&D) funding and venture capital. This results in slower innovation and commercialisation of emerging pathways, such as advanced biofuels and biomass gasification.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ENABLING SYSTEMS: BATTERIES, HYBRIDISATION AND DIGITALISATION

Deployment leaders and global trends

In 2024, global additions of utility-scale energy storage - primarily BESS - surpassed 40 GW. This was a year-on-year increase of over 60%, led by the United States, China and Europe. The United States alone added approximately 10 GW, primarily co-located with solar PV, while China accounted for more than half of global BESS installations. This was supported by national mandates for storage alongside new renewable capacity.

Lithium-ion batteries dominate utility-scale deployments. This is due to declining costs, scalability and availability. Proven technologies include lithium iron phosphate (LFP) and nickel manganese cobalt (NMC) chemistries, with LFP preferred for its thermal stability and lower cost.

PSH remains the dominant form of long-duration energy storage (LDES) globally, offering multi-hour to multi-day flexibility, along with essential grid services such as frequency regulation and inertia. While lithium-ion batteries dominate recent additions, PSH continues to provide the vast majority of installed LDES capacity, worldwide.

Emerging technologies in the LDES segment include: flow batteries, such as vanadium redox, for multi-hour storage; sodium-ion and zinc-based batteries as alternatives to lithium; and thermal storage, compressed air and gravity-based systems under demonstration.

These innovations remain pre-commercial in most contexts, but are being trialled in grid applications requiring discharge durations beyond four hours.

Hybrid configurations – solar-plus-storage and wind-plus-storage – are becoming standard in procurement frameworks in the United States, India and parts of the EU. Although these systems help enhance dispatchability and grid stability, their deployment faces several obstacles. Regulatory frameworks often treat each component (generation, storage) separately, resulting in complex permitting processes and misaligned market signals. Revenue stacking across energy, capacity and ancillary services are rather underdeveloped, limiting commercial viability. The absence of a standard metric that captures hybrid system performance and cost further complicates investment and planning decisions.

Digital technologies are increasingly important for making power systems more flexible, efficient and responsive - especially as more renewable and distributed energy sources come online. The rollout of digital solutions remains uneven, however. In many emerging markets, progress is slowed by limited use of smart meters, weak investment in digital infrastructure and unclear rules for how energy data should be managed and shared. Regulatory frameworks have not kept pace with innovation, making it difficult for technologies such as virtual power plants and behind-the-meter systems to participate in energy markets or provide grid services. At the same time, the lack of common technical standards and growing cybersecurity risks create barriers to widespread adoption. Closing these gaps will be crucial to ensuring that digitalisation can support a secure, reliable and decentralised energy transition.

Cost trajectories

Between 2010 and 2024, utility-scale BESS experienced a cost decline of approximately 93%, with global installed project costs falling from USD 2 571/kWh to USD 192/kWh (BNEF, 2024a). Improvements in battery chemistry, materials efficiency, manufacturing scale-up and increased market competition drove this reduction. During the same period, annual gross BESS deployment increased from 0.1 gigawatt hours (GWh) to 169 GWh, reflecting the growing role of storage in enhancing system flexibility and facilitating renewable integration.

In 2024, the global LCOE for BESS averaged USD 104/MWh, with leading projects in the United States and China achieving values of around USD 90/MWh for 1-4 hour configurations (BNEF, 2024b). BNEF projects that LCOEs will fall below USD 100/MWh in 2025, with a further reduction of up to 50% possible by 2030, depending on chemistry, market maturity and application.

Although comprehensive LCOE estimates for hybrid systems remain scarce, available data indicates that in key markets renewables coupled with battery storage are increasingly approaching cost parity with fossil fuel-based generation.

In the United States, IRENA 2024 data show that 17 operational hybrid projects – combining 4 486 MW of solar PV and 7 677 MWh of battery storage – achieved a weighted average LCOE of USD 0.079/kWh, which was aligned with the midpoint of the LCOE range for combined-cycle gas turbines (USD 0.077/kWh) and below that of coal (USD 0.119/kWh). In Australia, eight hybrid projects combining solar, wind and battery storage (totalling 412.2 MW of generation and 188.4 MWh of storage) reported a significantly lower weighted average LCOE of USD 0.051/kWh.

Box 1.7 A simple, linear optimisation approach to estimating the effective capacity factor (ECF) for hybrid systems

Batteries add value to renewable energy systems by shifting electricity from times of high generation to periods of high demand or market value. This enhances grid reliability, reduces curtailment and enables key functions, such as energy arbitrage, frequency regulation and other ancillary services.

The full benefit of a battery depends on how it is operated within a specific electricity market. Capturing this accurately requires detailed modelling of the broader energy system. Such modelling should include demand and supply conditions, grid constraints, market rules and the battery's operational profile. This typically involves simulating battery dispatch based on hourly price signals, system balancing needs and the full range of services provided.

Such detailed system-level modelling is beyond the scope of this report. Instead, a simplified linear optimisation approach is suggested to capture some of the key benefits delivered by battery storage in hybrid systems. The resulting metric – the ECF – is used as the basis for calculating the LCOE of hybrid systems.

The ECF is calculated by solving a simple linear optimisation problem for two system configurations:

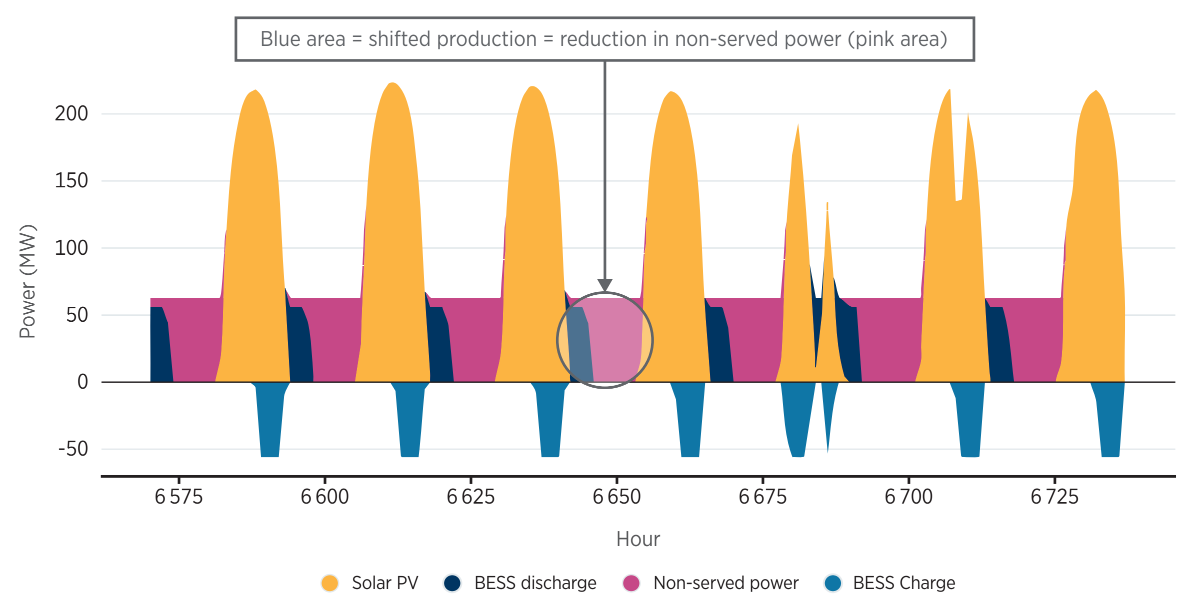
- A "without" scenario, featuring a stand-alone renewable energy generator with no storage.
- A "with" scenario, featuring the same generator combined with a battery.

In both cases, the system is tested against a flat, constant electricity demand. This is set as equal to the average hourly output of the variable renewable energy (VRE) generator over the year.

In the "without" scenario, the generator may meet demand during daylight or windy hours, but fail to do so during others. This results in non-served power.

In the "with" scenario, a battery can store excess generation and discharge it later, reducing these shortfalls. However, storage also introduces efficiency losses. Both the benefits – reduced non-served energy and the losses are captured in the model.

Figure B1.7 Hourly output profiles of solar and batteries (illustrative calculation)



Notes: BESS = battery energy storage systems; MW = megawatt; PV = photovoltaic.

The effective capacity factor (ECF) is then calculated as:

ECF = CF + (reduction in non-served power − battery losses) ÷ (8 760 hours × installed capacity)

CF is the capacity factor of the VRE generator in the "without" scenario.

Drivers of competitiveness

- The competitiveness of battery storage systems depends on a combination of factors. These include:
- **Technology and chemistry:** LFP offers cost and safety advantages, while NMC remains preferred for high-energy-density applications.
- **Supply chains:** China dominates lithium-ion battery production, influencing cost and availability. Tariffs and local content rules are reshaping sourcing strategies in the United States and the EU.
- **Market design:** Capacity markets, ancillary service payments and time-of-use arbitrage influence project bankability. Regulatory clarity remains uneven.
- **Policy and subsidies:** The IRA in the United States introduced standalone storage tax credits. India and the EU are following with national incentives and procurement mandates.
- **Geopolitics:** Trade disputes and dependencies on critical minerals such as lithium, cobalt and nickel present medium-term risks to cost stability.

- **Permitting and siting:** Urban fire safety codes, land-use constraints and public opposition present growing barriers, particularly in dense population areas.
- **Revenue stacking complexity:** Many BESS projects rely on multiple income streams, such as arbitrage, capacity and ancillary services. This complicates project finance and risk management.
- **Performance degradation and end-of-life risks:** Battery lifespan and recycling infrastructure remain underdeveloped, raising both cost and environmental concerns.

COMPARATIVE COST TRENDS AND LEARNING EFFECTS

Regional learning rates and economies of scale

Using a bottom-up model calibrated with historical deployment and cost data based on project-level information from the IRENA renewable costs database, IRENA has estimated technology- and region-specific learning rates and cost elasticities.

The learning rate reflects the reduction in unit costs with each doubling of cumulative capacity. The cost elasticity of deployment, meanwhile, captures the responsiveness of annual renewable energy deployment to changes in generation costs. Table 1.1 compiles the learning rates and cost elasticities for selected regions and technologies. The methodology underlying these estimates is detailed in Box 1.8.

Table 1.1 Learning rates and cost elasticities associated with variable technologies in key regions

Solar PV	Learning rate (%)	Cost elasticity
Africa	21.9	1.70
Asia	26.0	1.91
Europe	49.1	0.50
North America	28.8	1.43
Oceania	35.3	1.14
OECD	37.5	0.95
South America	18.9	3.20
World	33.8	1.34
Onshore wind	**Learning rate (%)**	**Cost elasticity**
Africa	9.6	2.04
Asia	14.4	2.31
Eurasia	14.9	1.61
Europe	32.4	0.52
North America	32.7	0.68
Oceania	32.4	1.58
OECD	31.9	0.78
South America	16.2	2.30
World	25.0	1.52
Offshore wind	**Learning rate (%)**	**Cost elasticity**
OECD	16.0	0.83
World	15.7	2.56

Note: OECD = Organisation for Economic Co-operation and Development.

Solar PV has the highest global learning rate among utility-scale technologies, at 33.8%, while regional rates in Europe reach an impressive 49.1%. The responsiveness of deployment to cost reductions, which is captured by the price elasticity of demand, is particularly high in South America, Asia and Africa, suggesting a strong potential for further cost reductions as markets expand.

Onshore wind also has a strong learning profile, with a global learning rate close to 25%. In the OECD countries, the value is even higher, at 31.9%. This reflects technological advancements and improving supply chain efficiencies. On the other hand, offshore wind has a lower global learning rate, at 15.7%, due to limited deployment scale and supply chain constraints. This technology has one of the highest global cost elasticities, at 2.56, highlighting the sensitivity of deployment dynamics to cost fluctuations and inflationary pressures.

Box 1.8 IRENA's approach to estimating learning rates and projecting cost trends

Assessing short-term cost dynamics is based on a learning curve framework that estimates learning rates that are specific to different technologies and regions.

The model is fully endogenous: it captures the feedback loop where lower costs lead to higher deployment, which then drives further cost reductions. This framework enables short-term projections – up to five years – based on IRENA's rich set of historical data, with the flexibility to apply the model by technology, region, or even country.

The projections are based on a two-step econometric approach, using historical data covering TICs and annual deployment across technologies and regions. The model includes the following components:

- the learning rate (LR): the percentage reduction in TIC for each doubling of cumulative capacity; and
- the cost elasticity of demand (ε): the sensitivity of annual capacity additions to changes in TIC.

The projections aim to provide trend-consistent insights into possible short-term cost trajectories. The model cannot account for unexpected policy shifts, supply chain disruptions, or exogenous macroeconomic shocks. Therefore, the results should be interpreted as indicative, rather than predictive.

Short-term CAPEX projections, 2025–2029

Assuming stable macroeconomic and deployment conditions, projections based on learning rates and cost elasticities suggest continued declines in total installed costs (TIC) – although with diminishing reduction rates, compared to the 2010s.

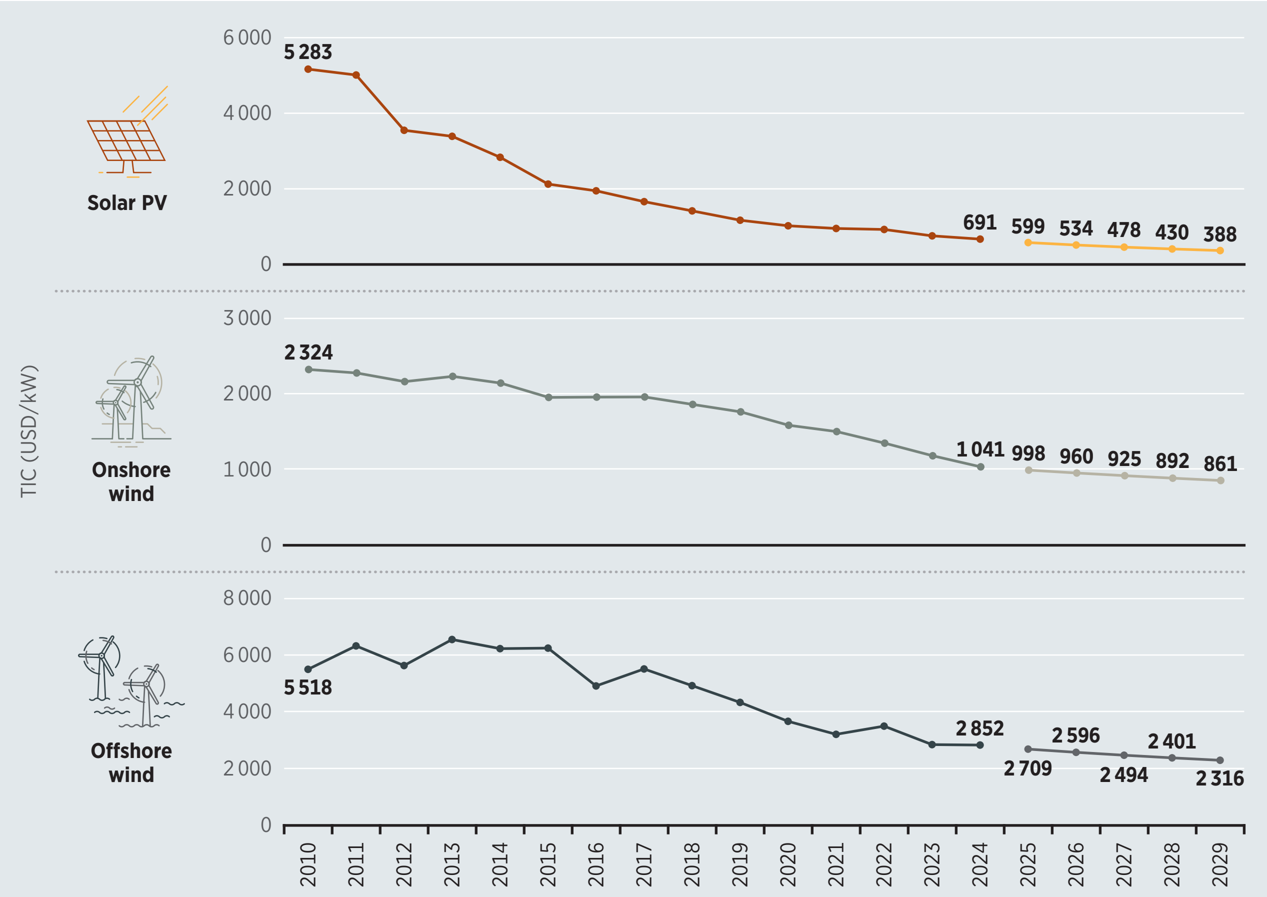
Over the next five years, global total installed costs are expected to reach approximately USD 388/kW for solar PV, USD 861/kW for onshore wind, and USD 2 316/kW for offshore wind (Figure 1.19).

Between 2024 and 2029, the TIC of solar PV is expected to fall below USD 400/kW in Europe and Asia, while remaining higher than USD 600/kW in the rest of the world. Onshore wind costs are projected to decline at a slower pace, with most regions converging toward the USD 1 100/kW to USD 1 300/kW range by 2029, except for Asia. There, TIC values between USD 750/kW and USD 850/kW are foreseen.

Offshore wind will see more modest reductions, particularly in Europe, where costs are expected to get close to USD 3 000/kW by 2029.

These estimates broadly align with independent market analyses. BNEF projects global solar LCOEs to fall by an additional 31% by 2030, while onshore wind should decline by 26%, driven by technological learning, policy support and growing scale (BNEF, 2025a). Lazard's 2024 update similarly points to continued cost competitiveness for solar and wind, though it emphasises widening regional spreads due to permitting, interconnection and policy delays (Lazard, 2024).

Figure 1.19 Historical and projected global TIC values



Notes: TIC = total installed cost; USD = United States dollar; kW = kilowatt.

Recent independent projections foresee global LCOE declines of between 22% and 49% by 2035 across clean energy technologies. This includes a 31% drop for fixed-axis PV and 50% for battery storage systems (BNEF, 2025a). These trajectories are driven by reductions in TIC and supply capacity (particularly in China), favourable capital market trends, and efficiency gains across maturing supply chains. For instance, process-level innovations in wafer production have drastically reduced polysilicon use per watt since 2010, contributing to steep module cost declines. Moreover, central bank easing is expected to lower financing costs, further enhancing the cost competitiveness of capital-intensive renewables such as solar PV and storage.

Trade barriers and material bottlenecks can disrupt this learning trajectory, however. Wood Mackenzie highlights, for example, that under full-scale trade war scenarios, LCOEs for solar PV and battery storage could rise by up to 20% in the context of the United States. This underscores the role of global geopolitics in shaping future cost paths (Wood Mackenzie, 2025a).

02 ONSHORE WIND

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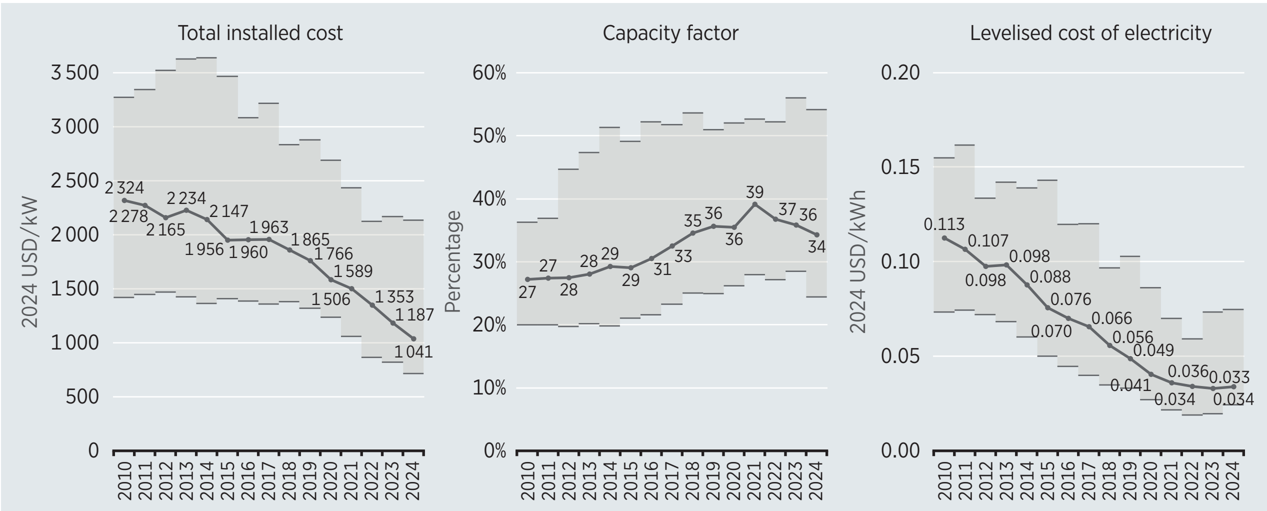
HIGHLIGHTS

- Between 2010 and 2024, the global weighted average LCOE of onshore wind fell 70%, from USD 0.113/kWh to USD 0.034/kWh. In 2024, however, the LCOE increased by 3% year-on-year, driven by a combination of financing costs and lower capacity factors in key markets.
- The global cumulative capacity of onshore wind increased more than five times during the 2010–2024 period, from 178 GW to 1 049 GW.
- The global weighted average total installed cost of onshore wind fell 55% between 2010 and 2024, from USD 2 324/kW to USD 1 041/kW. There was a 12% decline between 2023 and 2024, matching the reduction observed between 2022 and 2023.
- In 2024, the weighted average total installed cost ranged from USD 727/kW at the 5th percentile to USD 2 110/kW at the 95th percentile. China continued its strong performance, maintaining a weighted average total installed cost below USD 1 000/kW for the second consecutive year.
- Technological progress resulted in an improvement in the global weighted average capacity factor of new onshore wind projects, with this rising from 27% in 2010 to 34% in 2024.
- In 2024, prices for new wind turbines remained relatively stable, owing to supply chain bottlenecks, inflation and geopolitical uncertainties. Outside China, the average price was USD 998/kW, while inside China, the average price was USD 195/kW. The average price inside China was 80% lower than elsewhere.
- In 2024, original equipment manufacturers from China accounted for 82% of all wind turbine orders, driven largely by domestic demand, with Chinese OEMs capturing 100% of orders within China. When that country is excluded, however, the distribution of orders becomes more balanced, with OEMs from Europe holding the largest share, at 48%. European OEMs also had a strong position in other regions, including Africa, Central America and the Caribbean, Oceania and North America.
- The growing integration of hybrid systems and green hydrogen production is expanding the value proposition of onshore wind, enabling more flexible, dispatchable energy solutions. Grid constraints, however, remain critical challenges that must be addressed in order to scale onshore wind development.

Figure 2.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for onshore wind, 2010-2024



Notes: kW = kilowatt; kWh = kilowatt hours; USD = United States dollar.

INTRODUCTION

Onshore wind has developed significantly in recent decades, becoming a widely deployed renewable energy technology. In 2024, around 105.7 GW of onshore wind capacity additions were installed globally, marking the second consecutive year in which annual installations surpassed 100 GW. Between 2023 and 2024, there was an increase of 1% in capacity additions, with the extent of onshore wind deployment second only to that of solar PV. China remained the largest market, accounting for 75 GW, or 71% of the total capacity added in 2024. This was an increase of 9% compared to the 69 GW added in 2023. In the second and third largest markets – the United States and Brazil – capacity additions decreased by 17% and 22%, respectively, year-on-year. In the United States, this was partly because several projects were delayed to 2025 (Wood Mackenzie and ACP, 2025).

While the year marked another global record for new wind installations, it was also a challenging year. Finance, macroeconomic headwinds, inflation, supply chain pressures and regulatory inertia continued to impact markets. Growth was particularly strong – and even record-breaking – in Asia, Oceania and Eurasia. Other established markets, however, such as Europe, South America and North America, saw a decline in onshore wind additions compared to the previous year, along with increasing or stagnant prices, year-on-year.

The expansion of the onshore wind sector has been largely driven by a combination of technological advancement and market maturity. The deployment of larger and more reliable turbines, higher hub heights and larger rotor diameters have all significantly enhanced capacity factors. Furthermore, in addition to technological improvements, economies of scale, heightened competitiveness and the growing maturity of the sector have also contributed. In a rapidly evolving market environment, continued technological acceleration is crucial, as is the development of supportive policies, optimisation of project pipelines and adaptation of strategies.

Looking ahead, considerable further growth in global installations is expected, with these including new builds and the upgrading of existing projects. This anticipated surge is largely driven by continued strength in China and the completion of projects in other parts of the world that have previously faced delays. In addition, the repowering of aging wind farms is projected to increase, contributing both to system efficiency and new capacity additions. The growing integration of hybrid systems – particularly those combining wind with battery storage – is also set to accelerate. These hybrid configurations enhance the dispatchability of wind energy, enabling its deeper integration into modern, flexible power systems.

TECHNOLOGICAL TRENDS

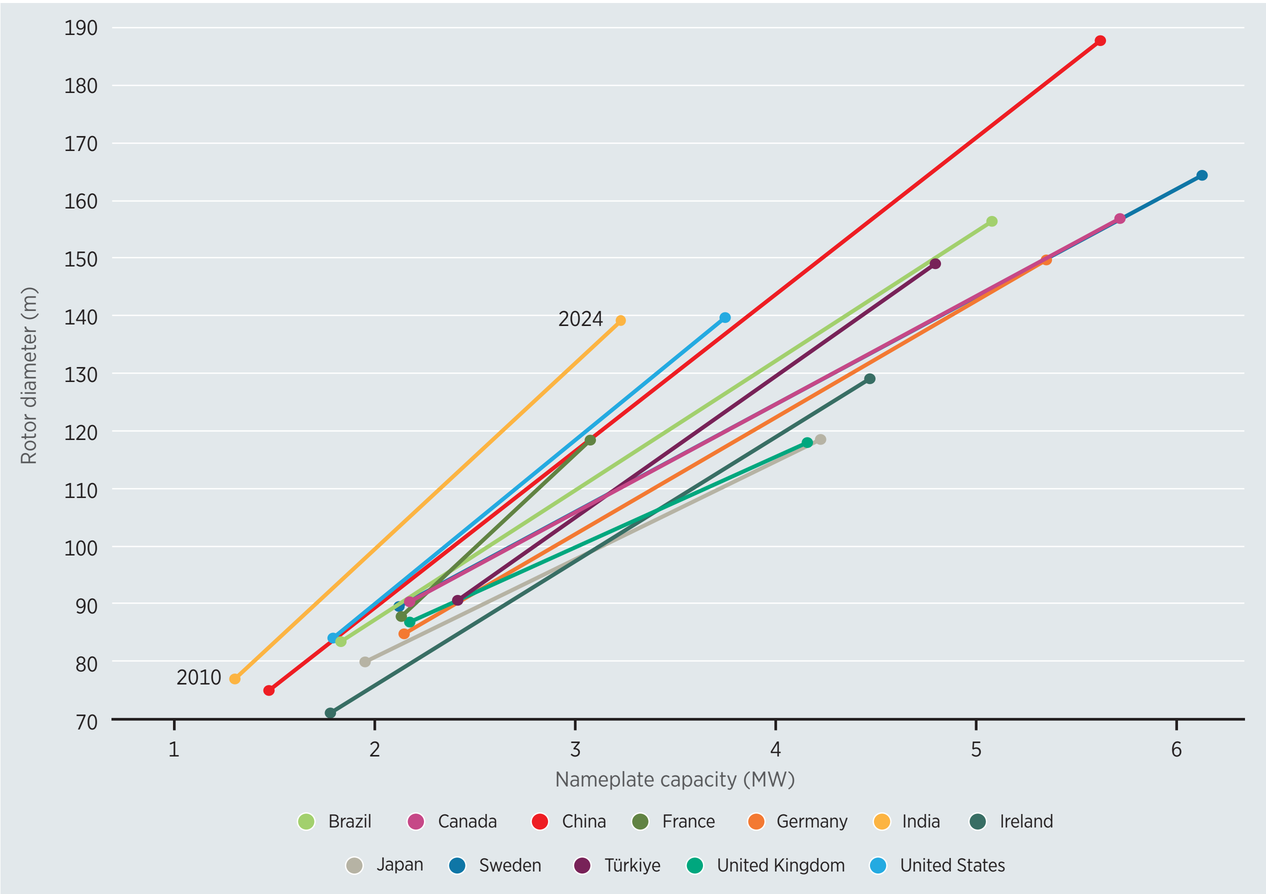
Technological innovation is a driving force behind the evolution and competitiveness of onshore wind. As markets mature and project developers seek to optimise returns in increasingly diverse environments, new advances in turbine design, manufacturing and project planning are reshaping the industry landscape.

Continued improvements in digital technologies, including AI-driven predictive maintenance and autonomous inspections, are expected to optimise O&M. As the sector matures, increased competition in O&M services and more efficient project development processes are also likely to place further downward pressure on costs. At the same time, improvements in wind resource assessment, digital modelling and project design software have further enhanced the ability to configure wind farms that minimise wake losses and turbulence, maximising performance at the site level. Additionally, advances in materials science, such as lighter, more durable composite materials, could reduce manufacturing and transportation costs, contributing to lower total installed costs (Firoozi *et al.*, 2024).

Larger turbine sizes and swept areas have led to significantly higher energy outputs[22] and improved onshore wind project economics. These advances have also expanded repowering options, allowing an increase in wind capacity at sites where the spots identified by previous technology as optimal for wind energy were already occupied.

Figure 2.2 illustrates the evolution in weighted average turbine rating and rotor diameter between 2010 and 2024 in some major onshore wind markets.

Figure 2.2 Weighted average onshore wind rotor diameter and nameplate capacity evolution, 2010–2024



Notes: m = metre; MW = megawatt.

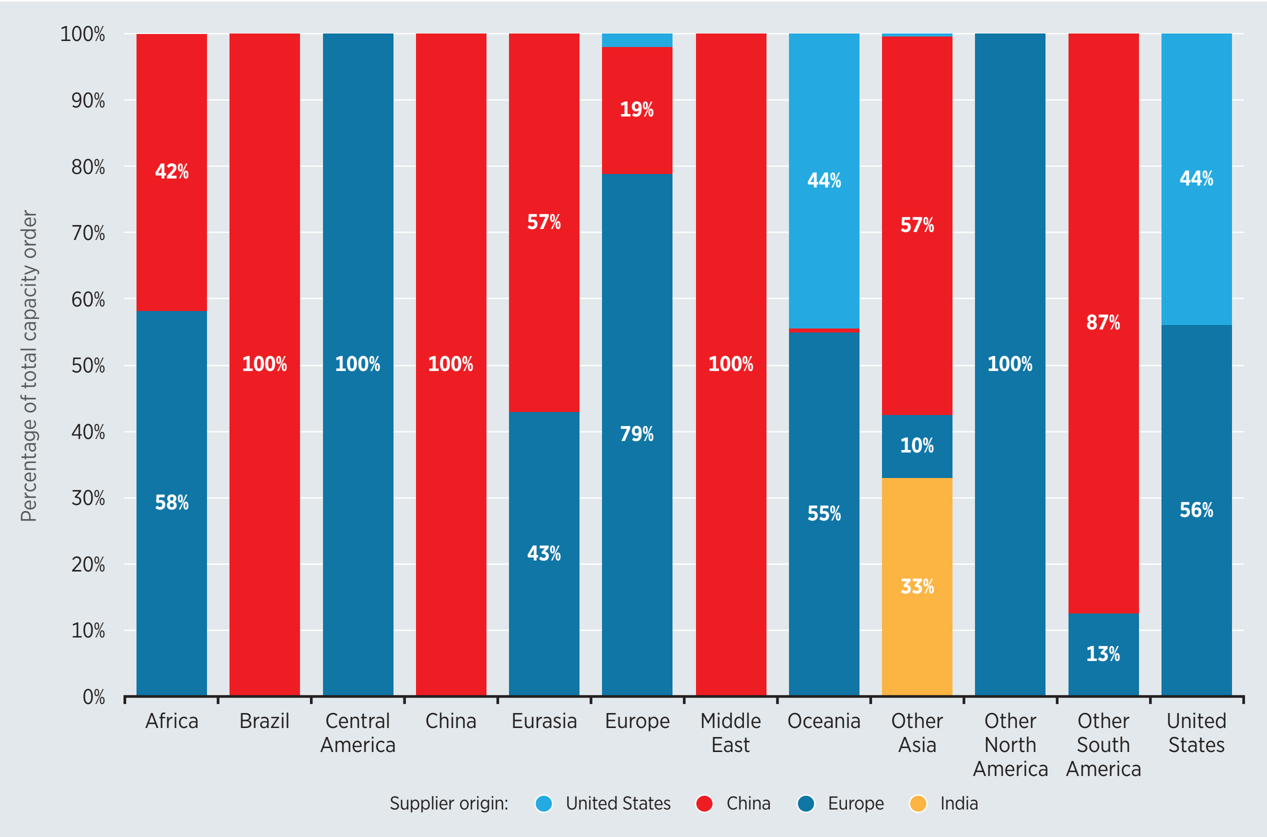
[22] *Energy output increases as a function of wind speed, air density, power coefficient and the swept area of the blades, with these being key variables in the power output of a wind turbine.*

Over the 2010–2024 period, the largest increases in rotor diameter were observed in China (151%), followed by Brazil (87%) and Sweden (84%). In terms of turbine capacity, the largest increases occurred in China (282%), Sweden (189%) and Brazil (178%). Based on data from the IRENA renewable costs database, for projects commissioned in 2024, Sweden had the largest weighted average turbine rating, at 6.2 MW, while China had the largest turbine rotor diameters, at 188 metres.

Wind turbine OEMs have responded to evolving needs by offering an increasingly diverse portfolio of turbine models. These have been tailored to specific market conditions, regulatory environments and grid integration requirements. Increasing competition, driven by differences in design, pricing, local content policies and tariffs, has significantly shaped the geographical distribution of turbine suppliers across global markets.

For 2024, Figure 2.3 illustrates the distribution of wind turbine orders according to the origin of the supplier and across different regions and selected countries. That year, OEMs from Europe held a strong position in their domestic markets, along with several global markets. These included Africa, Central America and the Caribbean, Oceania, and North America. OEMs from the United States held an important position in the United States and Oceania, with more limited participation in Europe and Other Asia. In most other regions, turbine supply is shared between OEMs from China and Europe, while Other Asia stands out with a diversified supplier base that includes a share of OEMs from India.

Figure 2.3 Share of wind turbine orders by origin of supplier across regions and countries, 2024



Source: (Wood Mackenzie, 2025a).

In recent years, manufacturers from China have significantly expanded their global footprint, especially in emerging markets. They have been able to do this by capitalising on economies of scale and cost competitiveness.

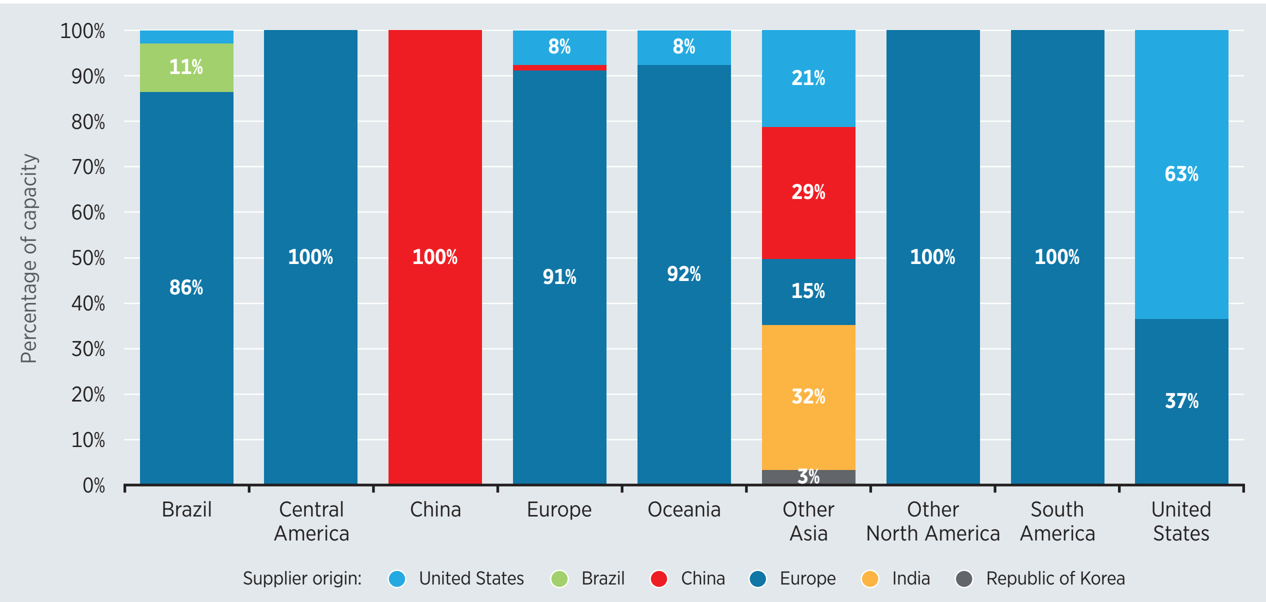
In 2024, turbine OEMs from China secured a record 26.7 GW of orders across 33 international markets, underscoring their rapidly expanding global market share (Wood Mackenzie, 2025b). Notably, Envision and Goldwind accounted for more than half of these overseas orders, reinforcing their leadership among exporters from China (Wood Mackenzie, 2025a).

In 2024, OEMs from China accounted for 82% of all wind turbine orders, driven largely by domestic demand, in which they captured 100% of orders within China (Wood Mackenzie, 2025a). When excluding China, the distribution of orders becomes more balanced. When this is done, OEMs from Europe held the largest share in 2024, at 48%, followed by OEMs from China, at 36%, India, at 9%, and the United States, at 7%. Notably, three manufacturers – Vestas (31%), Nordex (15%) and Envision (14%) – together accounted for over half of the global wind turbine orders placed outside China that year.

For 2024, Figure 2.4 illustrates the distribution of wind turbine installations by origin of supplier across selected countries and regions where data from the IRENA renewable costs database was available.[23]

While in some regions the pattern resembles the distribution of turbine orders, several key differences emerge. In Brazil, domestic manufacturers captured a notable share, accounting for 11% of installations in a market dominated by OEMs from Europe. In Other Asia, the market showed the highest supplier diversity. The United States exhibited a strong presence of domestic manufacturers, with a larger market share than OEMs from Europe. In Europe, domestic OEMs dominated installations within the region, with 91%, while China was entirely supplied by domestic manufacturers.

Figure 2.4 Share of wind turbine installation by origin of supplier across regions and countries, 2024



[23] *The data presented in this figure does not represent onshore wind total installed capacity in each region or country. It reflects only installations for which supplier origin information was available in 2024.*

Increased competition has also led to a trend of production moving to other countries. For example, Envision – an OEM from China – will develop a wind turbine manufacturing factory in Saudi Arabia. This will have an estimated annual capacity of 4 GW and is expected to supply neighbouring markets such as Egypt, Jordan, Iran and Oman (Wood Mackenzie, 2024a). Similarly, Goldwind established its first overseas factory in 2024, in Brazil. This will produce models ranging from 5.3 MW to 7.5 MW (GWEC, 2025a).

China has a presence in approximately 70% of the global wind supply chain, a figure that has drawn attention to global dependency (Wood Mackenzie, 2024b). For most key components, China holds the largest production share, followed by either the Asia Pacific region or Europe. In 2024, China accounted for 70% of global blade manufacturing capacity, with Asia Pacific holding 12%. For tower production, China led with 53%, followed by Europe, with 19%. Nacelle production was even more concentrated, with China at 74% and Asia Pacific at 12%. Gearbox manufacturing also followed this trend, with China accounting for 73%.

Beyond diversifying the supply chain, one of the main challenges facing the continued growth of onshore wind is grid infrastructure. Rising levels of grid curtailment are creating operational delays and threatening revenue stability for project developers. In China for example, despite significant increases in capacity additions, large-scale projects in the northern and northwest regions, along with the desert/Gobi region, have been experiencing setbacks due to transmission bottlenecks (Wood Mackenzie, 2024c). This is a widespread issue affecting many countries and highlights the urgent need for increased investment in transmission infrastructure. This is because the successful deployment of wind resources is heavily dependent on the timely construction and effective utilisation of grid connections to transport electricity.

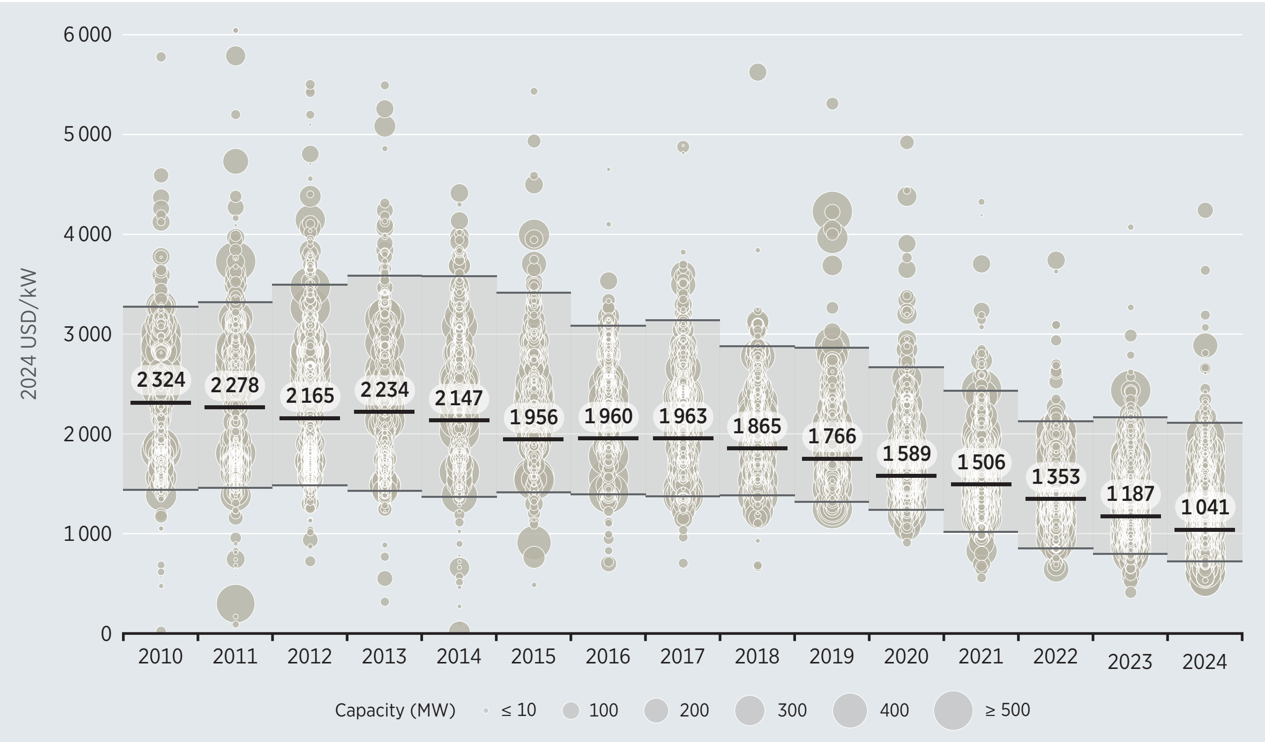
In parallel, the integration of emerging technologies – most notably green hydrogen – is expanding the strategic role of onshore wind within broader energy systems. In regions such as Asia and Oceania, investments in wind energy paired with electrolysis to produce green hydrogen have increased. Australia, for example, is planning to utilise surplus renewable energy for green hydrogen production, instead of curtailing excess renewable generation. It plans to do this by expanding transmission infrastructure and deploying storage. Following this approach, Australia is supporting the development of 6 GW of dispatchable capacity through tenders under the Capacity Investment Scheme (CIS) (DCCEEW, 2025; Wood Mackenzie, 2025c). This approach not only diversifies revenue streams for wind projects, but also enables decarbonisation in sectors that are otherwise difficult to electrify, such as heavy industry, long-haul transport and chemicals.

TOTAL INSTALLED COST

The energy transition has placed onshore wind energy at the forefront of global energy strategies. This is due to the technology's maturity, scalability and steadily declining costs. Additionally, the wind energy sector has responded with significant advances that have helped lower costs and expand capacity worldwide.

According to data from the IRENA renewable costs database, between 2010 and 2024 the global weighted average total installed cost of onshore wind projects fell by 55%, from USD 2 324/kW to USD 1 041/kW (Figure 2.5). Notably, there was a consistent 12% year-on-year decline. This matched the reduction observed between 2022 and 2023 and highlighted a sustained momentum in cost efficiency. For projects commissioned in 2024, the global weighted average total installed cost ranged from USD 727/kW to USD 2 110/kW, between the 5th and 95th percentiles.

Figure 2.5 Total installed costs of onshore wind projects and global weighted average, 2010–2024

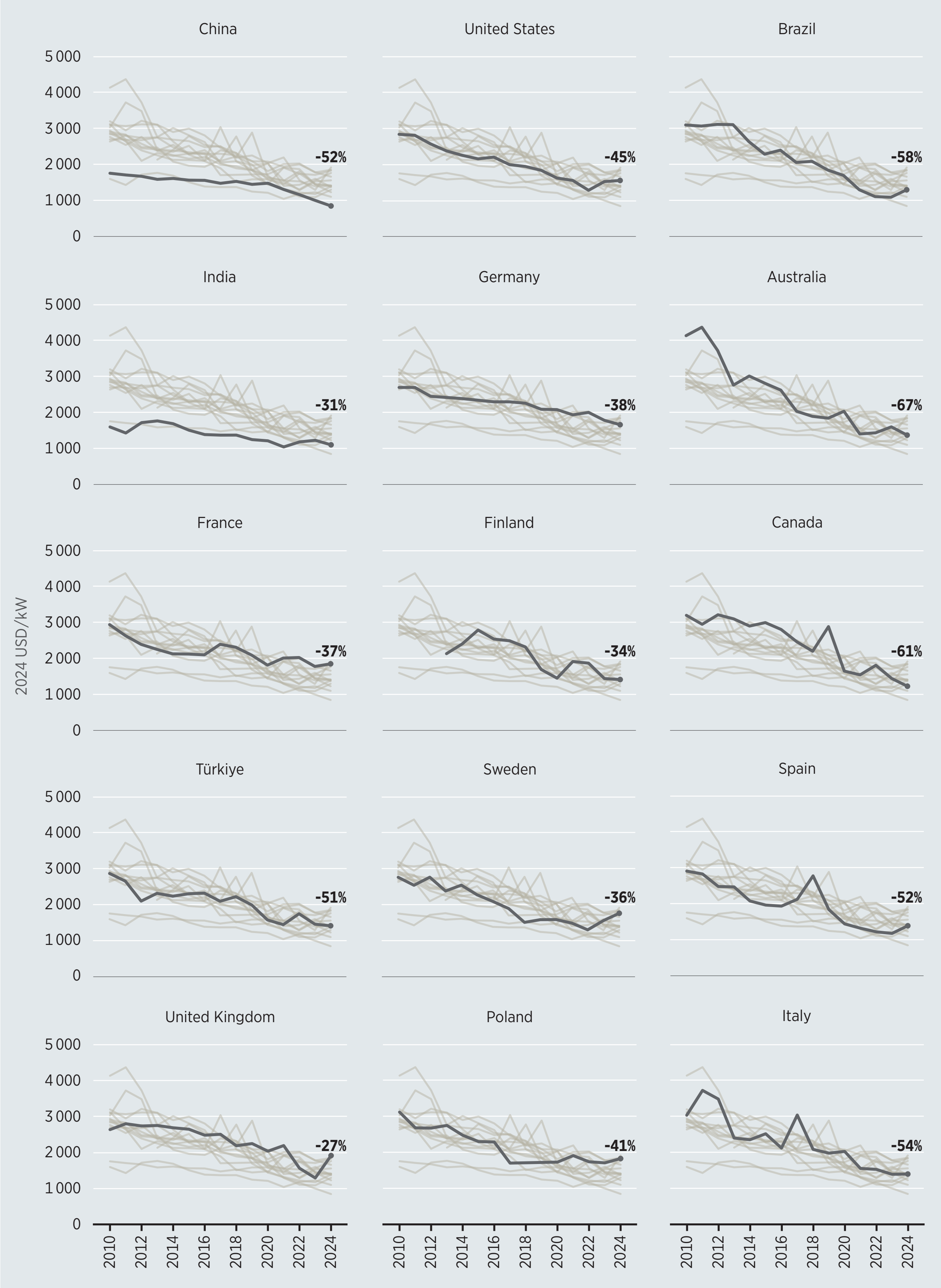


Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

For 2024, Figure 2.6 shows the trend in country-specific, weighted average total installed costs for the top 15 countries in onshore wind. The range of cost reductions varies significantly across countries, from a 67% decrease in Australia to a 27% reduction in the United Kingdom.

Among the top three markets, China has consistently demonstrated cost declines, with a total reduction of 52% over the period. The downward trend has been particularly pronounced since 2020, indicating a steep and sustained drop in costs. The United States and Brazil recorded overall decreases of 45% and 58%, respectively, with Brazil's performance reflecting notable improvements in its domestic supply chain. However, on a year-on-year basis, both countries experienced increases in costs. In the case of the United States, this uptick is linked to inflation, supply chain constraints and policy uncertainty, which has led to shifts in investment strategy and project timelines.

Figure 2.6 Onshore wind weighted average total installed costs in top markets, 2010–2024



Notes: Lines represent all 15 markets, with the bold line corresponding to the market identified at the top of each graph. The number in bold represents the total investment cost decrease between 2010 and 2024; kW = kilowatt; USD = United States dollar.

Table 2.1 presents the weighted average total installed cost of onshore wind projects at regional and country levels. For newly-commissioned projects, all the countries and regions in the table saw a decrease in their weighted average total installed cost.

In 2024, the regions with the highest weighted average total installed costs were (in descending order): Central America and the Caribbean, Other Asia, Europe, Other South America, Eurasia, Oceania, Africa and Other North America. Significant convergence was also observed in the weighted average installed costs across regions, with this ranging from USD 856/kW to USD 2 108/kW.

Table 2.1 Total installed cost ranges and weighted averages for onshore wind projects by country/region, 2010 and 2024

	2010			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kW)					
Africa	1 834	**1 834**	1 834	1 238	**1 333**	1 435
Central America and the Caribbean*	3 153	**3 153**	3 153	2 108	**2 108**	2 108
Eurasia	2 878	**2 878**	2 878	960	**1 425**	1 977
Europe	2 080	**2 859**	4 170	1 211	**1 659**	2 232
Oceania	3 608	**4 143**	4 555	1 143	**1 363**	1 704
Other Asia	2 181	**2 960**	3 249	1 277	**1 912**	3 764
Other North America	2 464	**3 245**	3 781	1 012	**1 238**	1 544
Other South America*	1 698	**2 521**	3 945	1 088	**1 492**	1 960
Brazil	3 106	**3 106**	3 106	1 015	**1 307**	1 628
China	1 489	**1 765**	2 066	626	**856**	1 315
India	1 053	**1 607**	1 900	984	**1 110**	1 270
Unitad States	2 201	**2 850**	3 863	950	**1 568**	1 902

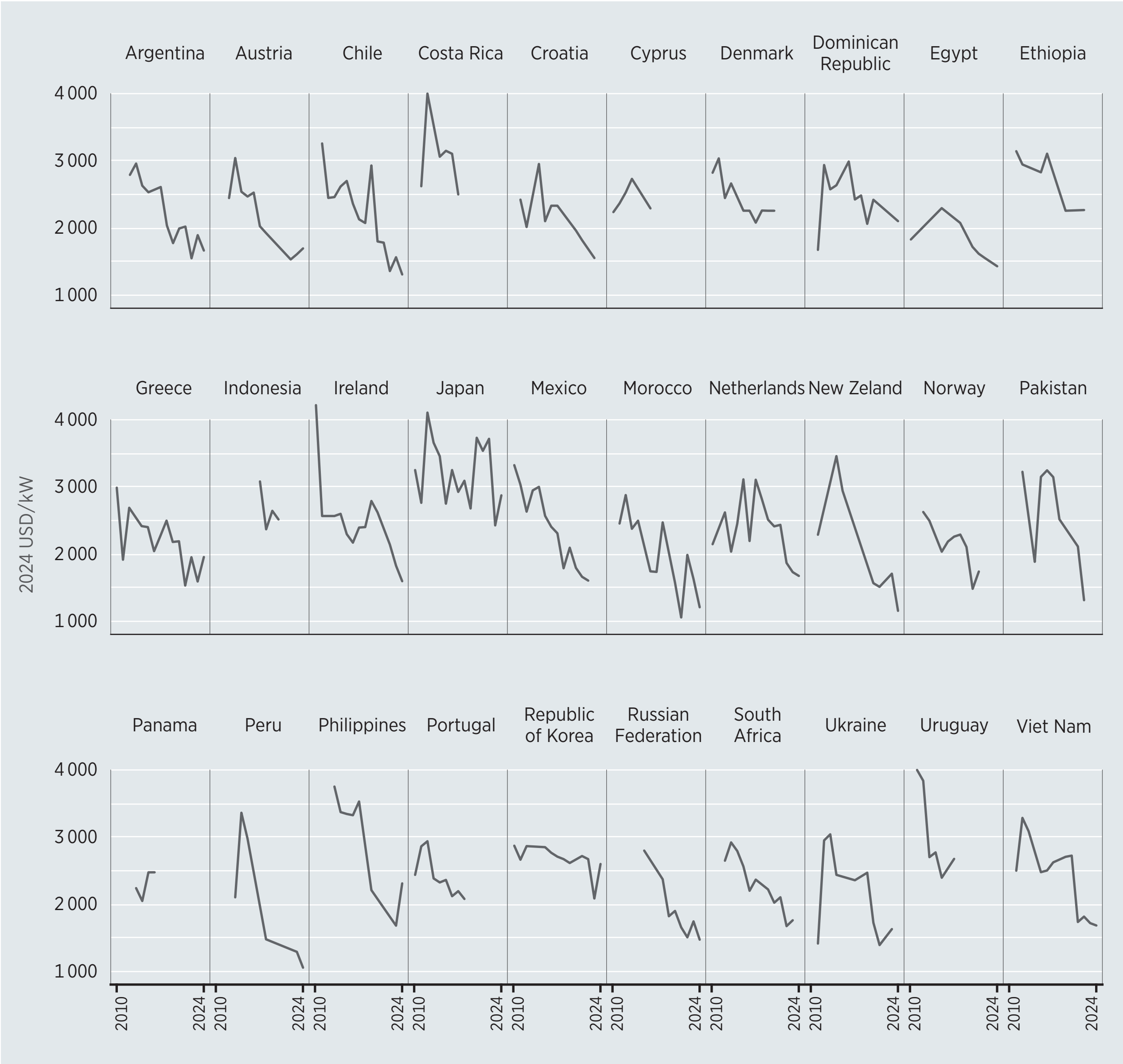
Notes: * Regions where data was only available for projects commissioned in 2012, not 2010; See Annex III for regional country groupings.

As mature markets, Brazil, China, India and the United States typically have lower cost structures than other countries. In 2024, China continued its strong performance, maintaining a weighted average total installed cost below USD 1 000/kW for the second consecutive year.[24] This reflected a 15% year-on-year decrease and continued cost competitiveness. India also reported a notably low weighted average installed cost, falling below all regional benchmarks, while both the United States and Brazil recorded values exceeding those of other regions and the global weighted average.

[24] *Based on nominal values in 2023 and 2024.*

Figure 2.7 shows the weighted average total installed costs trend in smaller markets. In 2024, among the countries with deployment and available data in the IRENA renewable costs database, Argentina, Chile, Egypt, Ireland, Morocco, New Zealand, Peru and Vietnam all experienced a decline in their weighted average total installed costs.

Figure 2.7 Onshore wind weighted average total installed costs in smaller markets, 2010–2024

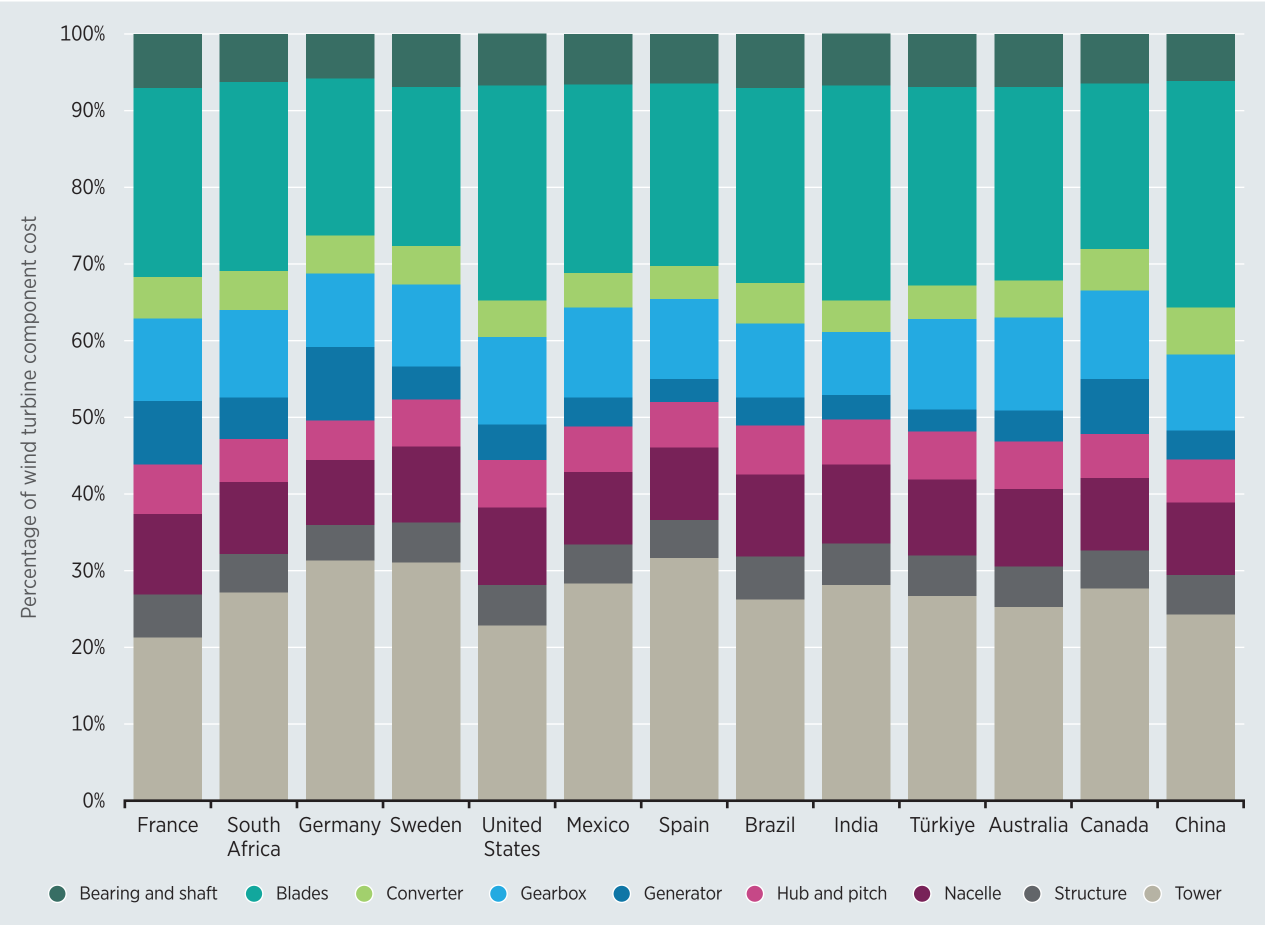


Notes: kW = kilowatt; USD = United States dollar.

The total installed costs of wind energy projects can vary significantly within and across countries. This is due to a range of factors, including transportation logistics, local content requirements, labour costs, permitting timelines and site-specific characteristics.

At an aggregated level, wind turbines are the largest cost driver. On average, they account for approximately 75% of total installed costs (IEA Wind, 2011). Figure 2.8 presents the cost breakdown of wind turbine components for 13 countries. While the exact percentages may vary from country to country, the overall structure remains comparable. Among wind turbine components, towers and blades consistently represent the largest share of costs. Other components, such as the nacelle, gearbox, generator and hub and pitch system, contribute smaller – though still notable – portions.

Figure 2.8 Breakdown of wind turbine cost by component in selected countries, 2024



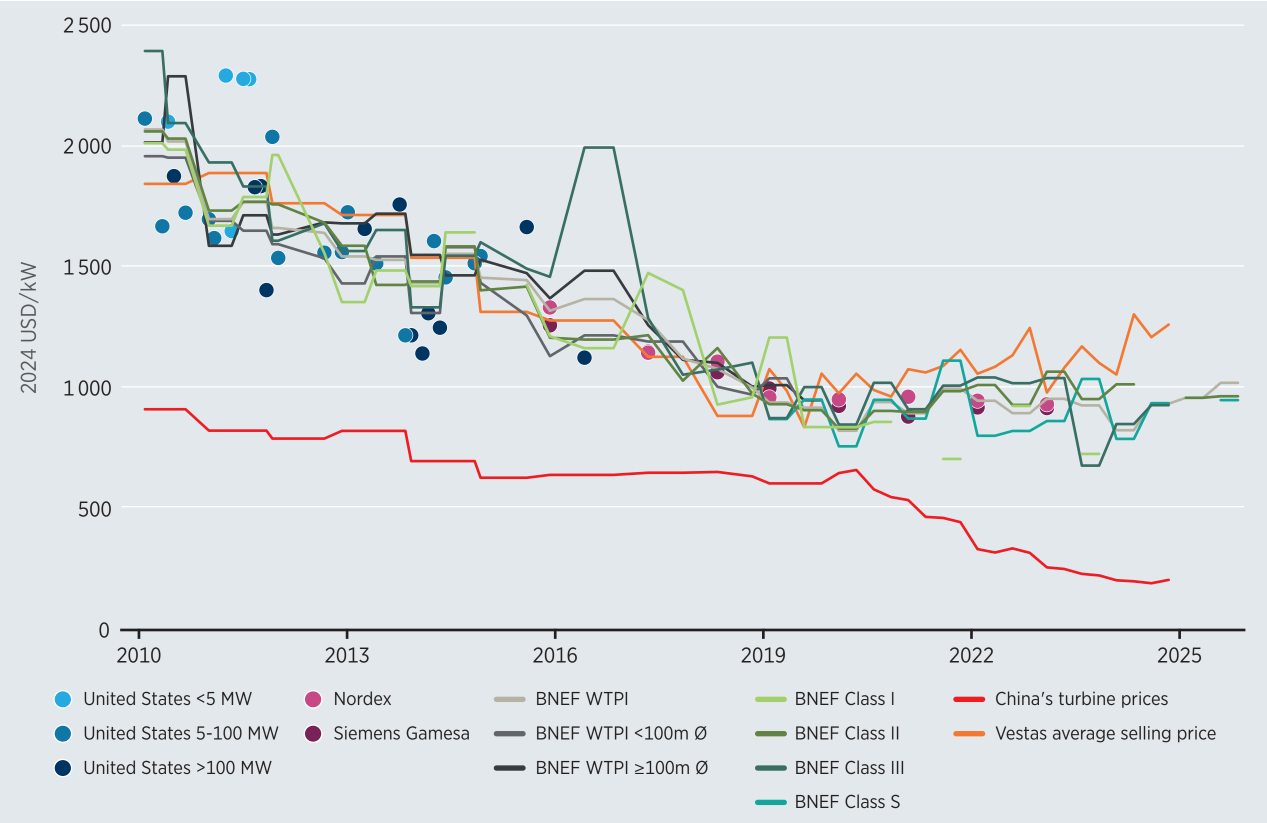
Based on: GWEC inputs and (Wood Mackenzie, 2021).

As wind turbines account for the largest share of total installed costs in onshore wind projects, turbine pricing is a key indicator for understanding cost dynamics across different markets. Figure 2.9 presents wind turbine price indices and trends for the period 2010–2024.

Between 2010 and 2024, average turbine prices (excluding China) declined, on average, by 51%. This reflected significant cost reductions over the period. In China, prices dropped even further – by 78% – although precise comparisons are difficult due to differences in contract scope. In 2024, quarterly prices were in the range of USD 786/kW to USD 1 303/kW in most major markets, excluding China. Outside China, the average 2024 price was USD 998/kW, while in China the average 2024 price was USD 195/kW. In 2024, the average price in China was 80% lower than the average price outside China.

During 2024, China's wind turbine prices remained largely flat, with a decline of only 1%, year-on-year, between the fourth quarter (Q4) of that year and Q4 2023. This was largely due to a reduction in price competition among original OEMs after they experienced significant profit reductions (Wood Mackenzie, 2024b).[25]

Figure 2.9 Wind turbine price indices and price trends, 2010–2024



Source: (BNEF, 2024a; Vestas, 2024; Wiser *et al.*, 2025).
Notes: kW = kilowatt; USD = United States dollar.

Globally, wind turbine platform prices remained relatively stable throughout 2024. Outside China, the slight decline in average prices stemmed from manufacturers executing previously signed, lower-priced orders while negotiating newer contracts at higher rates in an effort to restore profit margins (BNEF, 2024b). Global competition among OEMs has continued to put pressure on margins. This was compounded by rising commodity prices in the 2021–2022 period, along with inflation and supply chain disruptions linked to geopolitical tensions, and elevated interest rates (BNEF, 2024c; S&P Global, 2022).

In 2023, turbine prices fluctuated, with Vestas experiencing a dip in early-year pricing, followed by a mid-year rise and a subsequent decline toward year-end. This pattern continued into 2024, with prices decreasing from Q4 2023, rebounding mid-year, then falling again before rising slightly in the final quarter. By contrast, manufacturers like Nordex and Siemens maintained more stable pricing, with only marginal decreases of 1.5% and 0.3%, respectively, from 2022 to 2023.

[25] *In China, turbine contracts often exclude delivery, installation and towers, making comparisons with international markets difficult. This highlights the influence of turbine contracts, local infrastructure and regulatory context on overall costs, underscoring the need for caution when benchmarking turbine prices across regions.*

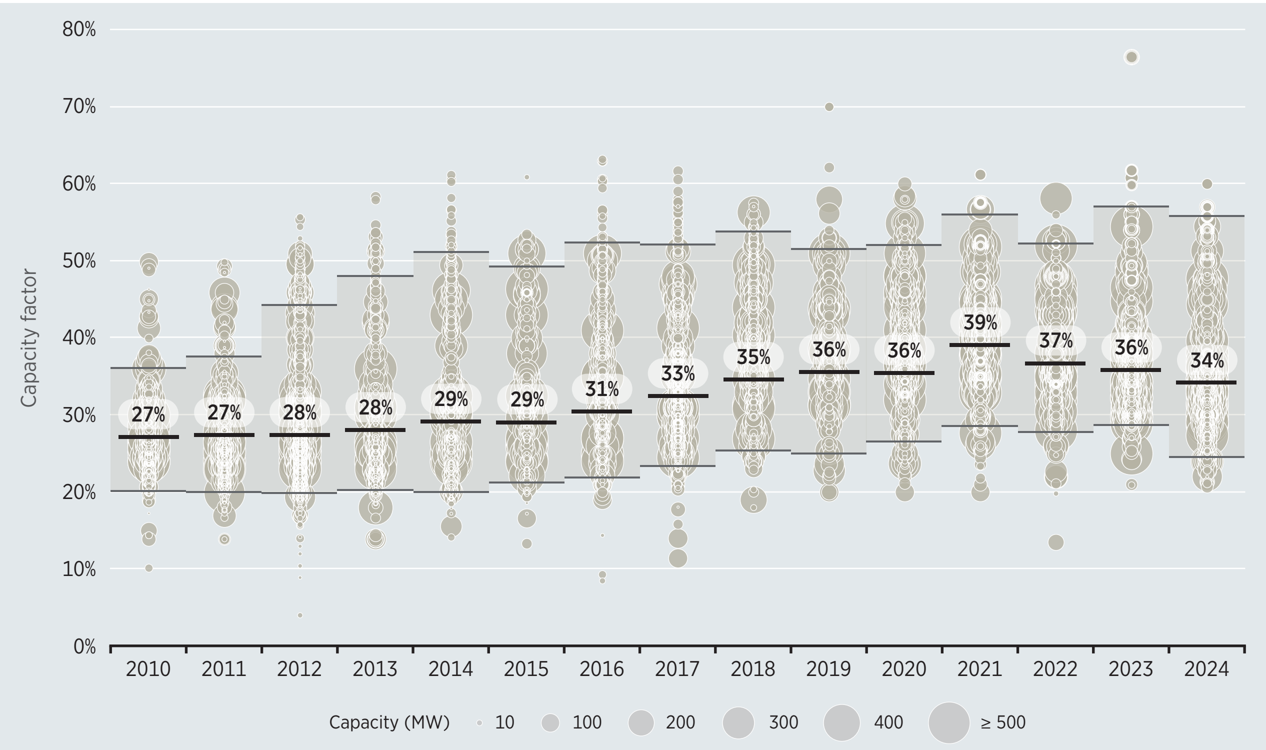
Overall, 2024 proved to be a challenging year, marked by price stability rather than continued reductions. Nevertheless, over the past decade, wind turbine prices have declined substantially, even as rotor diameters, hub heights and nameplate capacities have increased. By the end of 2024, price differentials among turbines with varying rotor diameters had narrowed considerably, with turbines in Classes II, III and S[26] converging around an average price of USD 920/kW.

CAPACITY FACTORS

In assessing wind energy performance, the capacity factor serves as a key indicator of both technological progress and site quality. Over the last decade, there have been many improvements in turbine design. These include larger rotor diameters, higher hub heights, improved aerodynamic profiles and more sophisticated control systems. These have all enhanced the ability of wind turbines to capture energy more efficiently, particularly at lower wind speeds. These advances, combined with better siting practices and digital optimisation tools, have led to notable improvements in capacity factors across many markets.

Between 2010 and 2024, the global weighted average capacity factor for onshore wind rose from 27% to 34%, driven by technological improvements (Figure 2.10). For projects commissioned in 2024, the global weighted average capacity factor ranged between 24% and 56% between the 5th and 95th percentiles.

Figure 2.10 Capacity factor of onshore wind projects and global weighted average, 2010–2024



Notes: MW = megawatt; USD = United States dollar.

[26] *This refers to the International Electrical Commission (IEC) wind turbine classification. Broadly speaking, Class I wind turbines are designed for the best wind speed sites and typically have shorter rotors, while Class III turbines are designed for poorer wind conditions where larger rotor diameters and lower specific power (watts/swept square metre) are used to harvest the maximum energy. Class S wind turbines are designed to meet specific site conditions and requirements that fall outside the standard classification.*

In 2024, the global weighted average capacity factor for newly commissioned onshore wind projects declined, year-on-year, from 36% to 34%. This trend was influenced by lower capacity factors across several key markets. Notably, in China – which had the largest share of new installations and was a major driver of the global average – the capacity factor fell from 35% to 33%. Data from the IRENA renewable costs database indicates that this decline was largely due to a shift in project location. Fewer installations occurred in Inner Mongolia, a region of China known for its exceptional wind resources. This broader geographical distribution had a moderating effect on national and global capacity factor averages.

For 2024, Figure 2.11 shows the trend in country-specific, weighted average capacity factors for the top 15 countries, in terms of added onshore wind capacity. Complementing this, Table 2.2 provides capacity factor values for projects commissioned in these countries in 2010, 2023 and 2024.

All 15 countries with complete data over the 2010–2024 period recorded increases in their weighted average capacity factors. This reflected ongoing improvements. Poland and Brazil experienced the most substantial gains, with increases of 56% and 48%, respectively. In 2024, Brazil also achieved the highest reported capacity factor, at 56%, followed by the United States at 44%, and the United Kingdom at 41%. In contrast, China has seen a decline in recent years; however, it saw a 28% increase in capacity factor over the 2010–2024 period.

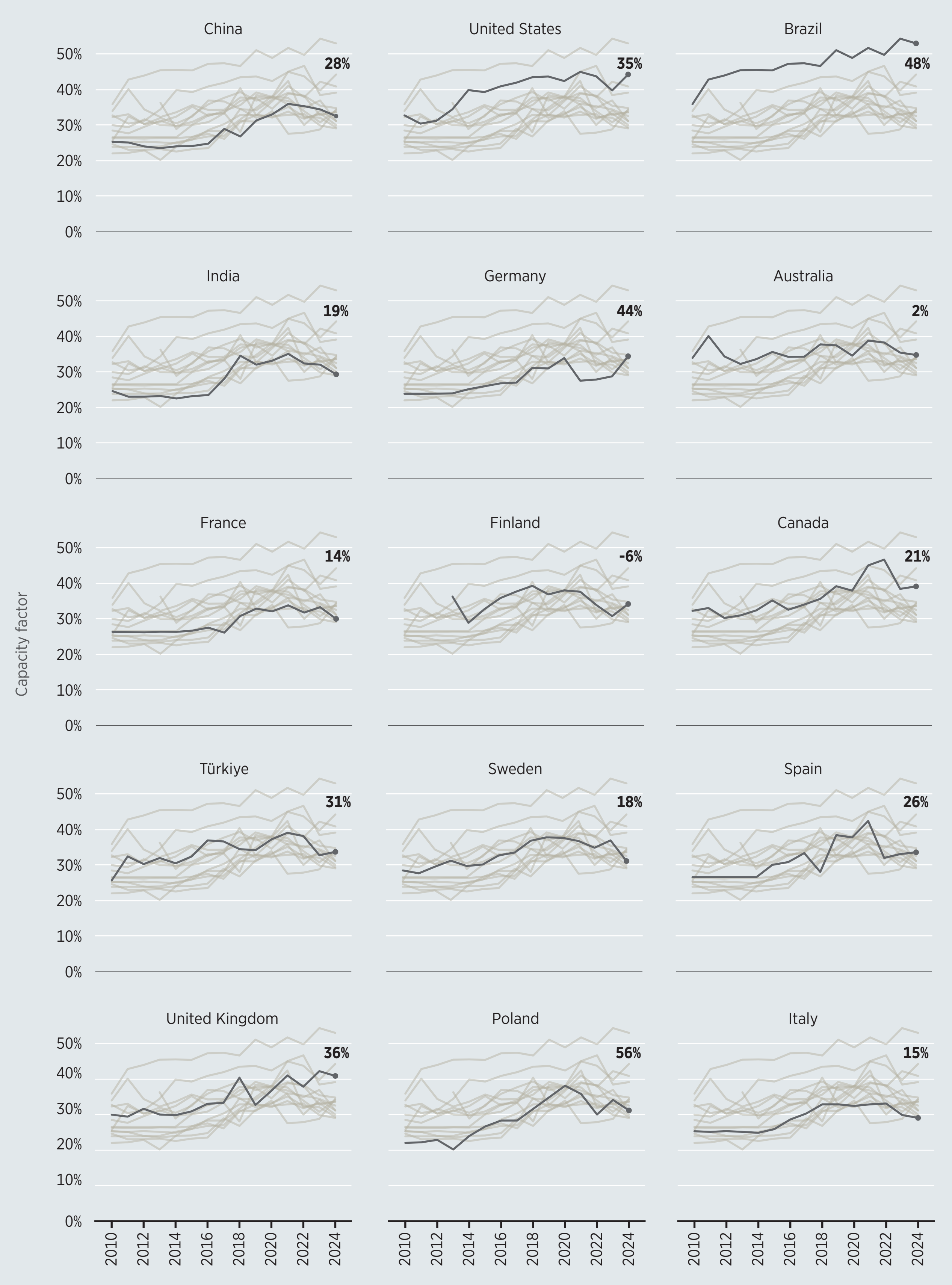
The extent of improvement between 2010 and 2024 varied across markets. Out of the 15 countries examined, four saw capacity factor gains greater than 35%. An additional five saw increases between 20% and 35%, while six countries achieved improvements of less than 20%.

Table 2.2 Weighted average capacity factor ranges for onshore wind projects by country, 2010, 2023 and 2024

	2010	2023	2024
	%		
China	25	35	33
United States	33	40	44
Brazil	36	54	56
India	25	32	39
Germany	24	29	35
Australia	34	36	35
France	26	33	30
Finland*	36	31	34
Canada	32	39	39
Türkiye	26	33	34
Sweden	29	37	34
Spain	37	33	34
United Kingdom	30	42	41
Poland	22	34	35
Italy	25	30	29

* Countries where data was only available for projects commissioned in 2013, not 2010.

Figure 2.11 Onshore wind weighted average capacity factors in top markets, 2010–2024



Notes: Lines represent all 15 markets, with the bold line corresponding to the market identified at the top of each graph. The number in bold represents the capacity factor increase/decrease between 2010 and 2024.

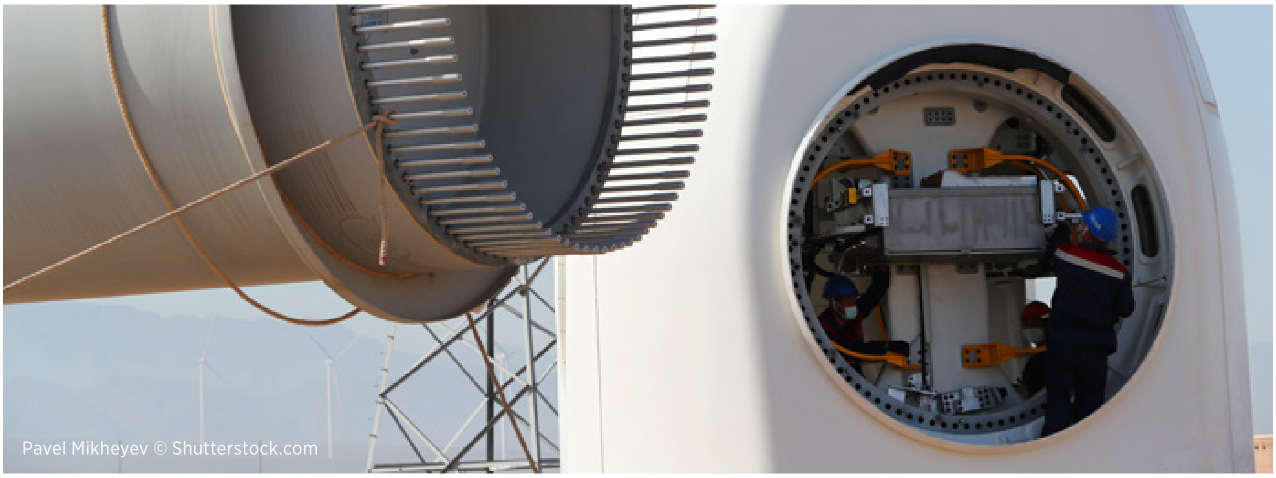


Table 2.3 presents the weighted average total installed cost of onshore wind projects at the regional level. Between 2010 and 2024, all regions experienced an increase in the weighted average capacity factor of newly commissioned projects. In 2024, the region with the highest weighted average capacity factor was Other South America, driven by Argentina and Peru.

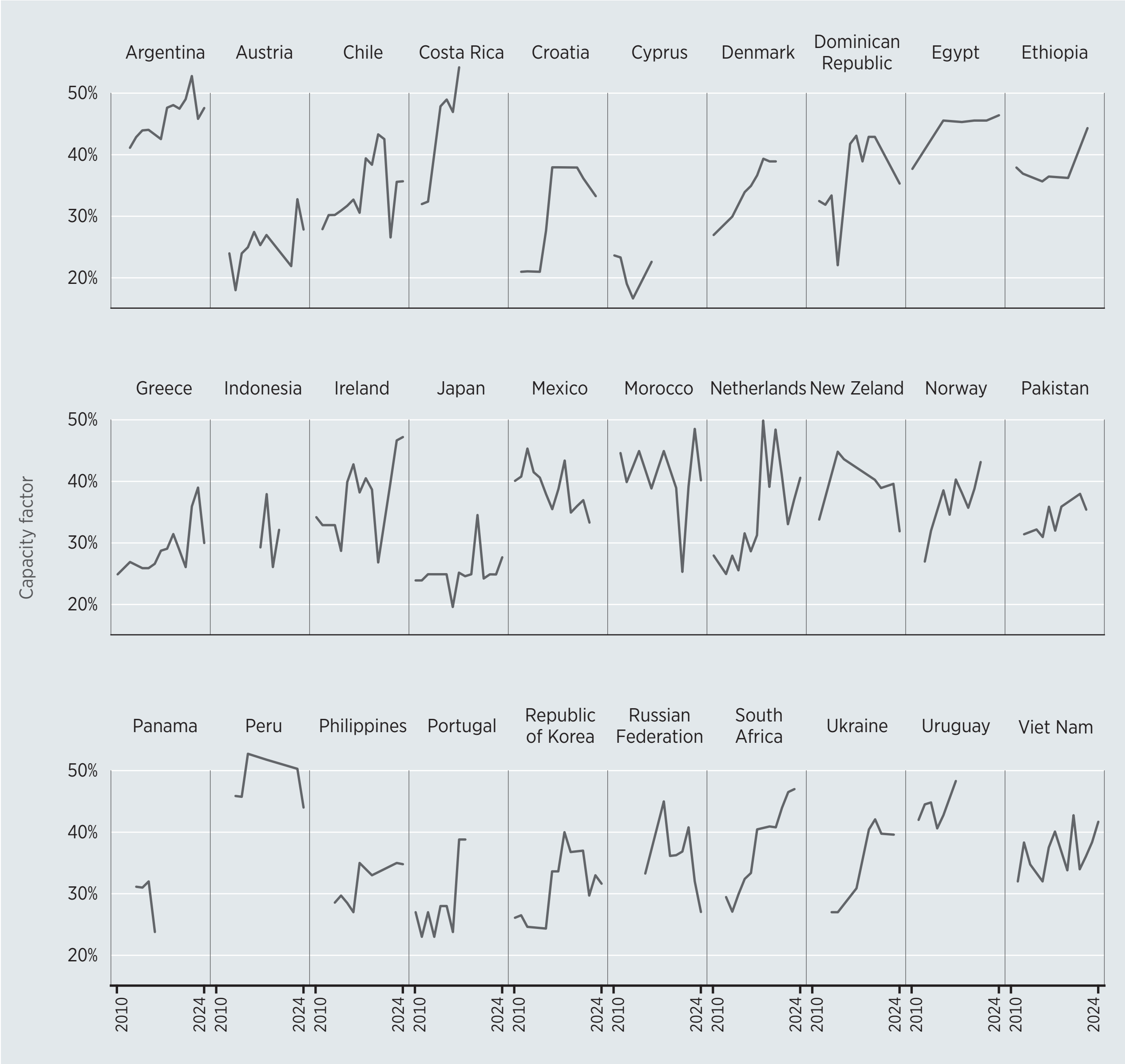
Table 2.3 Weighted average capacity factor ranges for onshore wind projects by region, 2010 and 2024

	2010			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	Capacity factor (%)					
Africa	38	**38**	38	41	**44**	47
Central America and the Caribbean	45	**45**	45	35	**35**	35
Eurasia	26	**26**	26	28	**34**	37
Europe	18	**26**	33	25	**34**	43
Oceania	34	**34**	34	32	**35**	43
Other Asia	22	**26**	32	24	**39**	47
Other North America	29	**34**	49	35	**39**	42
Other South America*	19	**32**	46	36	**45**	51

Notes: * Regions where data was only available for projects commissioned in 2012, not 2010; see Annex III for regional country groupings.

Figure 2.12 illustrates the trend in weighted average capacity factors for newly commissioned onshore wind projects in smaller markets, where deployment volumes are typically lower. In most of the countries with reasonably robust time series data presented, capacity factors demonstrated an upward trend over the 2010–2024 period. However, some exceptions remain, such as Cyprus, Mexico, New Zealand, Panama and Peru, all of which exhibited either stagnating or declining trends.

Figure 2.12 Onshore wind weighted average capacity factors in smaller markets, 2010–2024



O&M COSTS

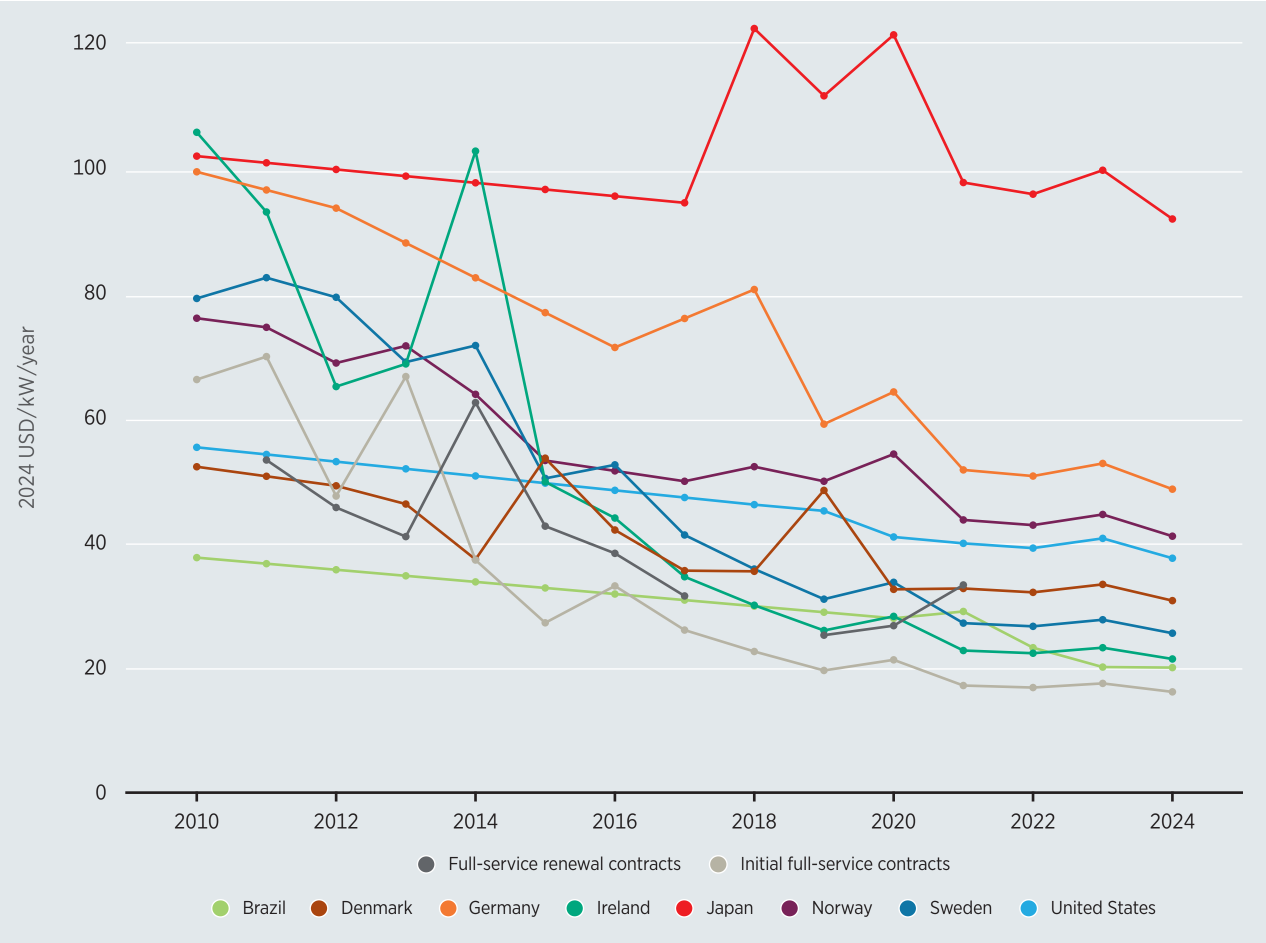
O&M costs play a critical role in the long-term performance, reliability and cost-effectiveness of onshore wind energy projects. As wind power deployment expands globally and turbine fleets age, O&M strategies have become increasingly sophisticated, data-driven and cost-optimised.

Economies of scale have played a particularly important role by enabling cost reductions through larger turbines, bigger project sizes and consolidated service agreements. These larger installations also contribute to lowering O&M fixed costs. For instance, between 2023 and 2024, average O&M contract prices for wind turbines of 6 MW or more were 21% cheaper than those for turbines between 4 MW and 4.99 MW, dropping from USD 18/kW/year to USD 14.4/kW/year (BNEF, 2025).

Figure 2.13 presents country-level O&M costs alongside BNEF's O&M price indexes. The latter distinguish between initial full-service contracts and contracts for aging fleets. Older fleet contracts are typically more expensive, as aging turbines are more prone to breakdowns. To manage these rising costs, many operators are transitioning from long-term, full-wrap service agreements to more flexible partial-wrap contracts. This shift creates opportunities for third-party service providers to offer tailored, cost-effective solutions (BNEF, 2024d). In addition, more players have been entering the O&M servicing sector for onshore wind, which is increasing competition and driving down costs (BNEF, 2019, 2020).

Over the 2010–2024 period, there has been an observable downward trend in O&M costs. This reflects the maturity and competitiveness of the market (Figure 2.13). Initial full-service contracts fell 76% between 2010 and 2024. At the country level, in 2024, O&M costs for onshore wind ranged from USD 20/kW/year in Brazil to USD 93/kW/year in Japan, with Germany at around USD 49/kW/year. The latter country is known for having onshore wind O&M costs that are higher than the European average. The gap between contract prices and actual O&M costs reflects additional expenses not covered by service contracts, such as insurance, land leases and local taxes.

Figure 2.13 Full-service (initial and renewal) O&M pricing indexes and weighted average O&M costs in selected countries, 2010–2024



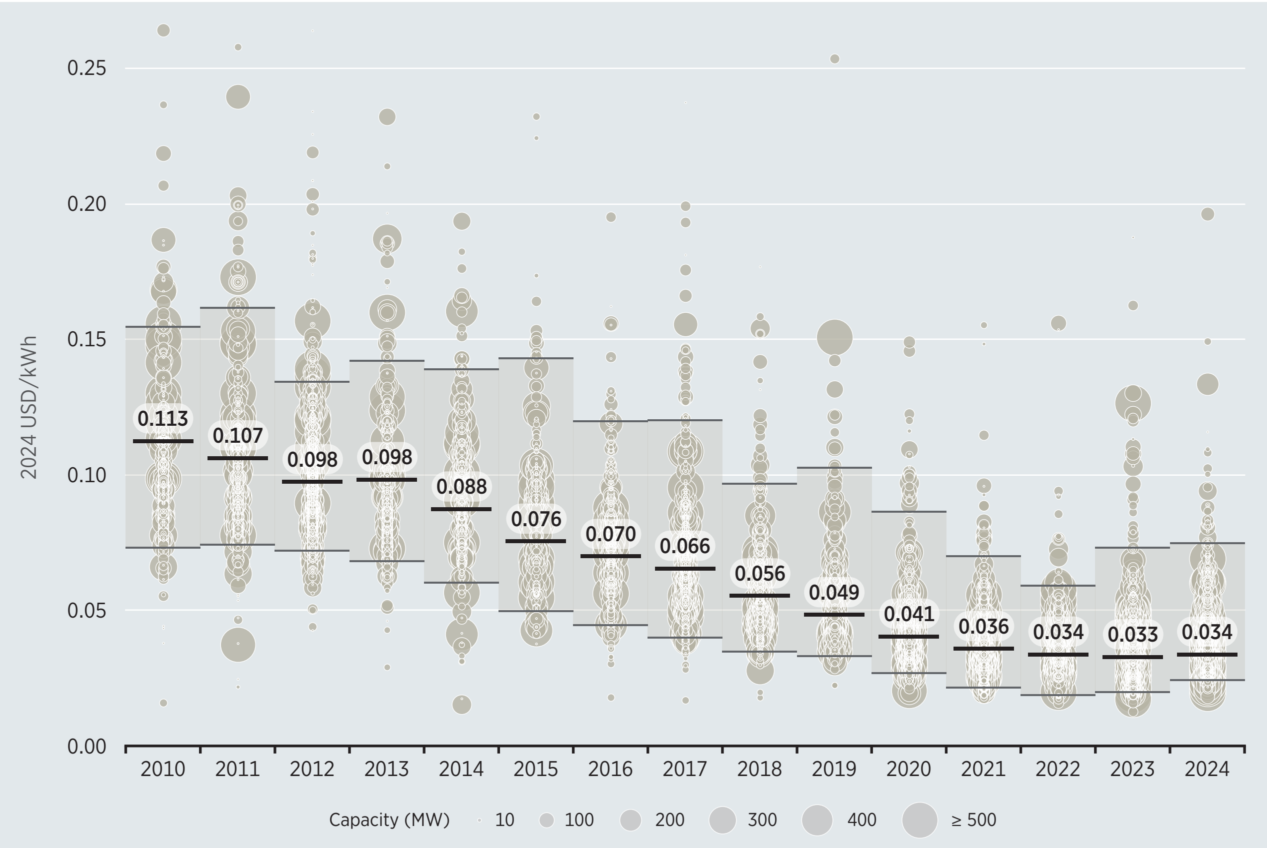
Source: (BNEF, 2025; IEA Wind, 2023; Wood Mackenzie, 2025d).
Notes: kW = kilowatt; USD = United States dollar.

LCOE

The LCOE of an onshore wind project is determined by the following factors: the total installed costs; capacity factor; O&M costs; the economic lifetime of the project; and the cost of capital. Among these, certain elements – such as the total installed costs – carry greater weight in determining economic viability. Meanwhile, with no fuel expenses, the efficiency of electricity generation (capacity factor) and the cost of financing (cost of capital) become critical levers in driving the LCOE down.

Figure 2.14 presents the evolution of the global weighted average LCOE of onshore wind between 2010 and 2024. Over that period, the global weighted average LCOE declined by 70%, from USD 0.113/kWh to USD 0.034/kWh. For projects commissioned in 2024, the global weighted average LCOE ranged between USD 0.024/kWh at the 5th percentile and USD 0.075/kWh at the 95th percentile. In 2024, the global weighted average LCOE for newly commissioned onshore wind projects increased by 3% year-on-year. This was driven by a combination of financing costs and lower capacity factors in key markets.

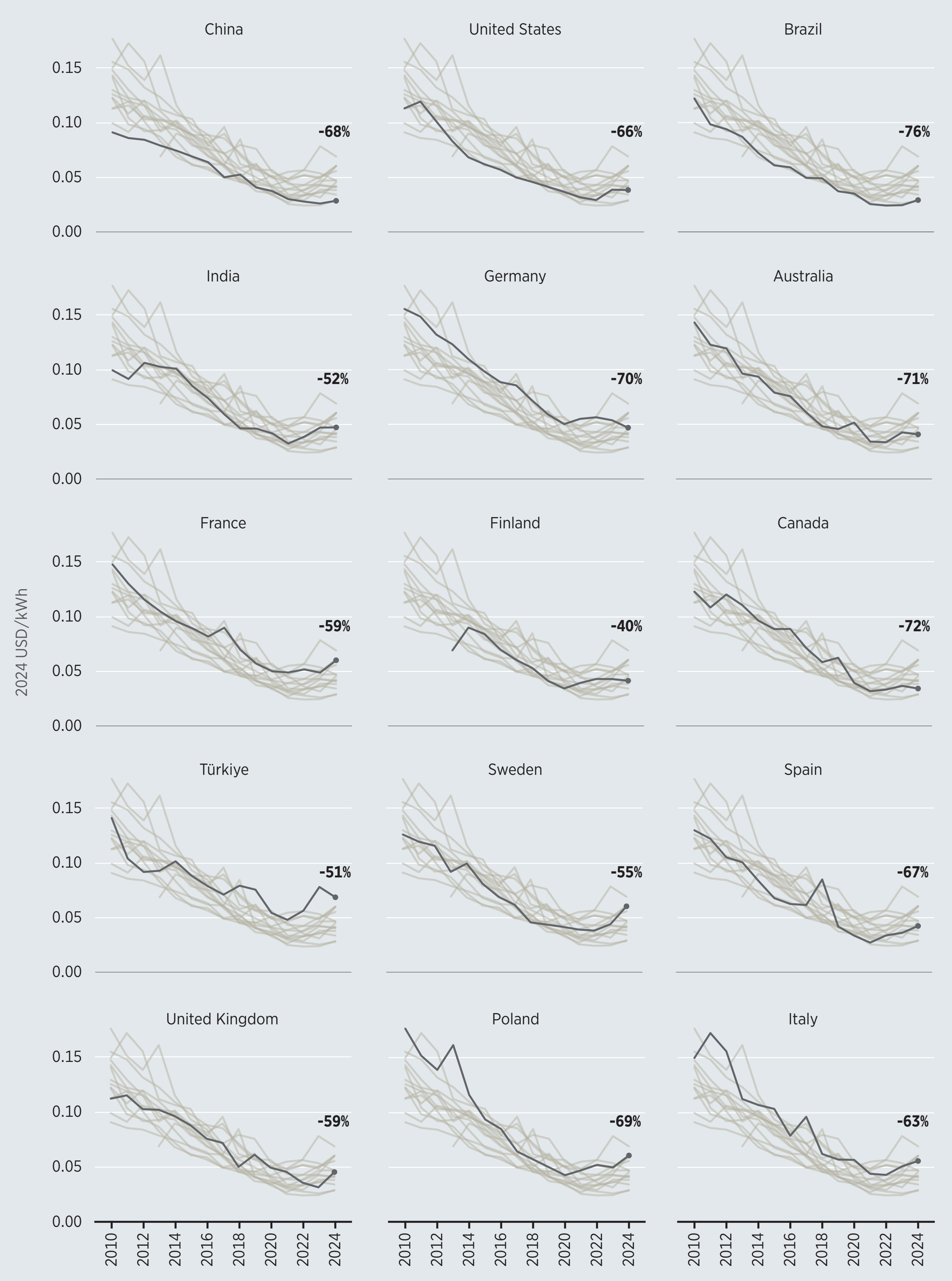
Figure 2.14 LCOE of onshore wind projects and global weighted average, 2010–2024



Notes: kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

For 2024, Figure 2.15 shows the trends in the country-specific weighted average capacity factors for the top 15 countries, in terms of added capacity in onshore wind. The 15 countries also represent major onshore wind energy markets with robust time series data over the period analysed (except for Finland).

Figure 2.15 Weighted average LCOE of onshore wind in top markets, 2010–2024



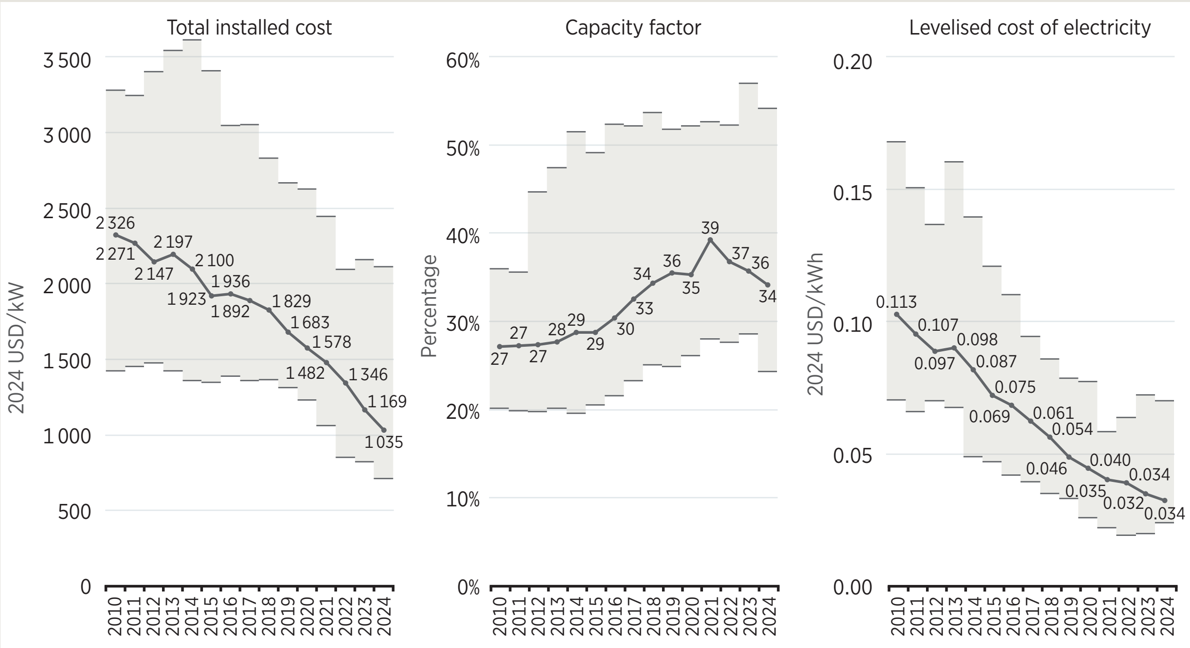
Notes: Lines represent all 15 markets, with the bold line corresponding to the market identified at the top of each graph. The number in bold represents the LCOE decrease between 2010 and 2024; kWh = kilowatt hour; USD = United States dollar.

All 15 countries with complete data over the 2010–2024 period recorded a decline of more than 50% in their weighted average LCOE. For the top three markets in 2024 – China, the United States and Brazil – each saw a decrease of over 65%, with Brazil achieving the most significant reduction, at 76%. Between 2023 and 2024, however, most countries exhibited either stagnant or slightly increasing LCOE trends, highlighting short-term challenges despite long-term gains. Notably, in 2024, only China and Brazil reported an LCOE below the global weighted average of USD 0.034/kWh.

Box 2.1 G20 onshore wind trends, 2010–2024

In recent decades, the Group of 20 (G20) has been central to the scale-up of onshore wind power. Over the period 2010–2024, G20 countries accounted for 96% of global cumulative onshore wind installed capacity, while in 2024, they accounted for 98% of new capacity additions. Between 2010 and 2024, the weighted average total installed cost across G20 members fell by 55%, reaching USD 1 035/kW by the end of 2024. Over the same period, average capacity factors increased from 27% to 34%, peaking at 39% in 2021. These improvements were driven by larger turbines, better siting and operational efficiencies. They also contributed to a substantial drop in the LCOE, which declined by 70%, from USD 0.113/kWh in 2010 to USD 0.024/kWh in 2024.

Figure B2.1 G20 weighted average and range of total installed costs, capacity factors and LCOEs for onshore wind, 2010–2024



Notes: See Annex III for the G20 country grouping, which includes all G20 member countries except for African Union; kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

Table 2.4 shows the country/region weighted average LCOE and 5th and 95th percentile ranges by region in 2010 and 2024. In 2024, the region with the highest weighted average LCOE for newly commissioned projects was Central America and the Caribbean, at USD 0.081/kWh. In contrast, the lowest was observed in Other North America, at USD 0.035/kWh.

Table 2.4 Weighted average LCOE and ranges for onshore wind by country/region, 2010 and 2024

	2010			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kWh)					
Africa	0.077	**0.077**	0.077	0.043	**0.051**	0.058
Central America and the Caribbean	0.101	**0.101**	0.101	0.081	**0.081**	0.081
Eurasia	0.142	**0.142**	0.142	0.050	**0.070**	0.101
Europe	0.094	**0.144**	0.216	0.034	**0.051**	0.075
Oceania	0.127	**0.144**	0.156	0.037	**0.041**	0.044
Other Asia	0.118	**0.162**	0.177	0.037	**0.072**	0.159
Other North America	0.088	**0.120**	0.145	0.032	**0.035**	0.037
Other South America*	0.071	**0.107**	0.344	0.038	**0.064**	0.100
Brazil	0.122	**0.122**	0.122	0.024	**0.030**	0.037
China	0.074	**0.092**	0.115	0.023	**0.029**	0.048
India	0.061	**0.100**	0.125	0.043	**0.048**	0.053
United States	0.071	**0.114**	0.157	0.026	**0.039**	0.052

Notes: * Regions where data was only available for projects commissioned in 2012, not 2010; see Annex III for regional country groupings.

Box 2.2 China's influence on weighted average LCOE

In 2024, onshore wind power capacity additions in China reached 78 GW – 71% of the global total. The weighted average total installed cost and capacity factor in China declined compared to 2023, and the financing cost increased. Given China's share in new installations, this significantly impacted the global weighted average LCOE. In 2024, China's weighted average LCOE was USD 0.029/kWh, contributing 57% to the global weighted average LCOE.

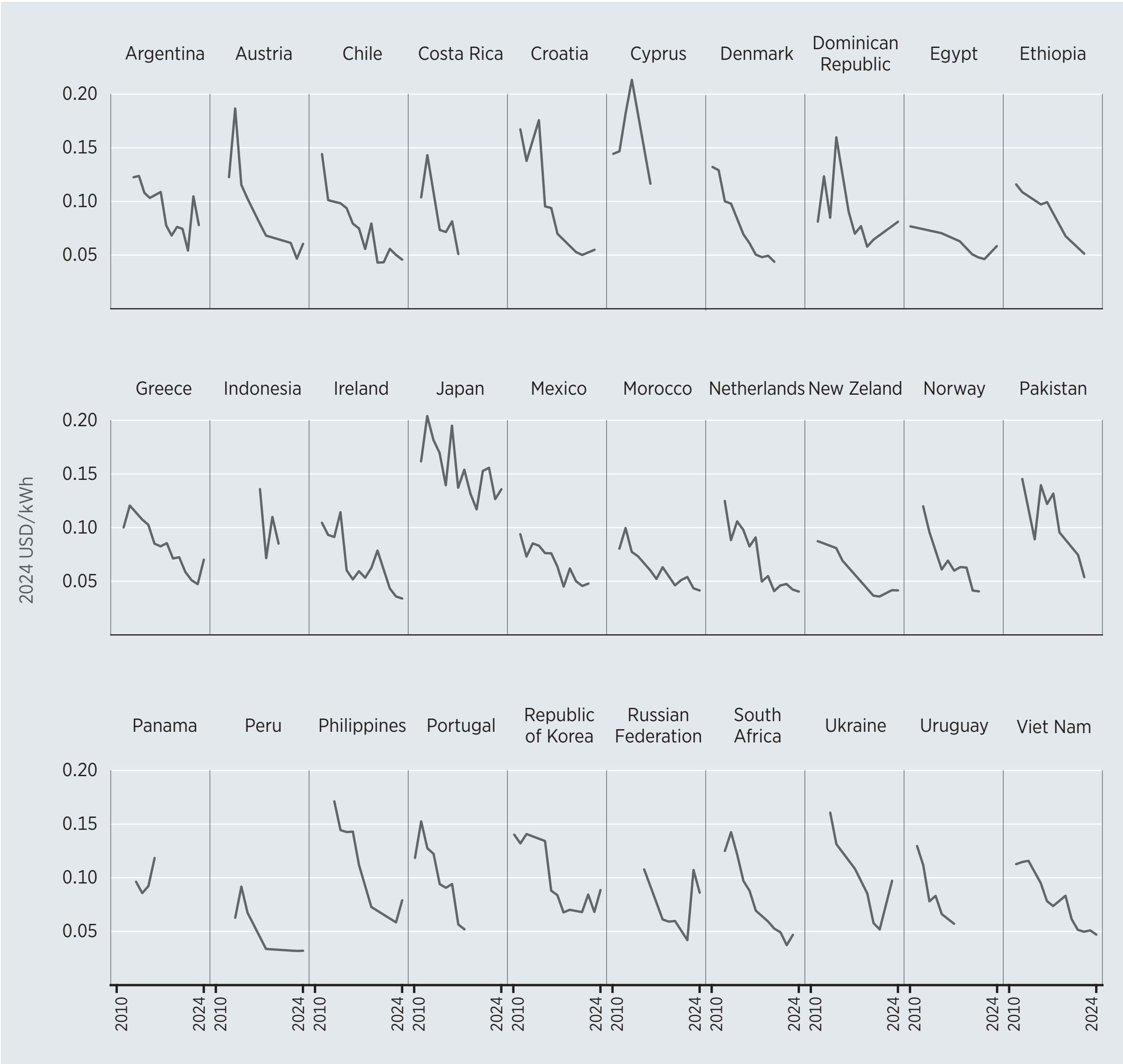
To illustrate the sensitivity of LCOE to the capacity factor and financing costs, two scenarios have been analysed:

- In the first scenario, the same financing and cost conditions for China have been assumed, while the capacity factor is changed to the value reported in 2023. China's weighted average LCOE thus falls to USD 0.027/kWh. As a result, the global weighted average LCOE in 2024 was USD 0.033/kWh.
- In the second scenario, the same cost and capacity factor conditions are assumed, with the financing condition changed to the same as 2023. Under this scenario, China's weighted average LCOE decreases to USD 0.026/kWh, while the global weighted average becomes USD 0.032/kWh.

These scenarios underscore the critical influence on the LCOE of not only total installed capital costs, but also operational performance and financing conditions. China's role is particularly significant due to its scale, highlighting how changes in domestic conditions can materially affect global averages.

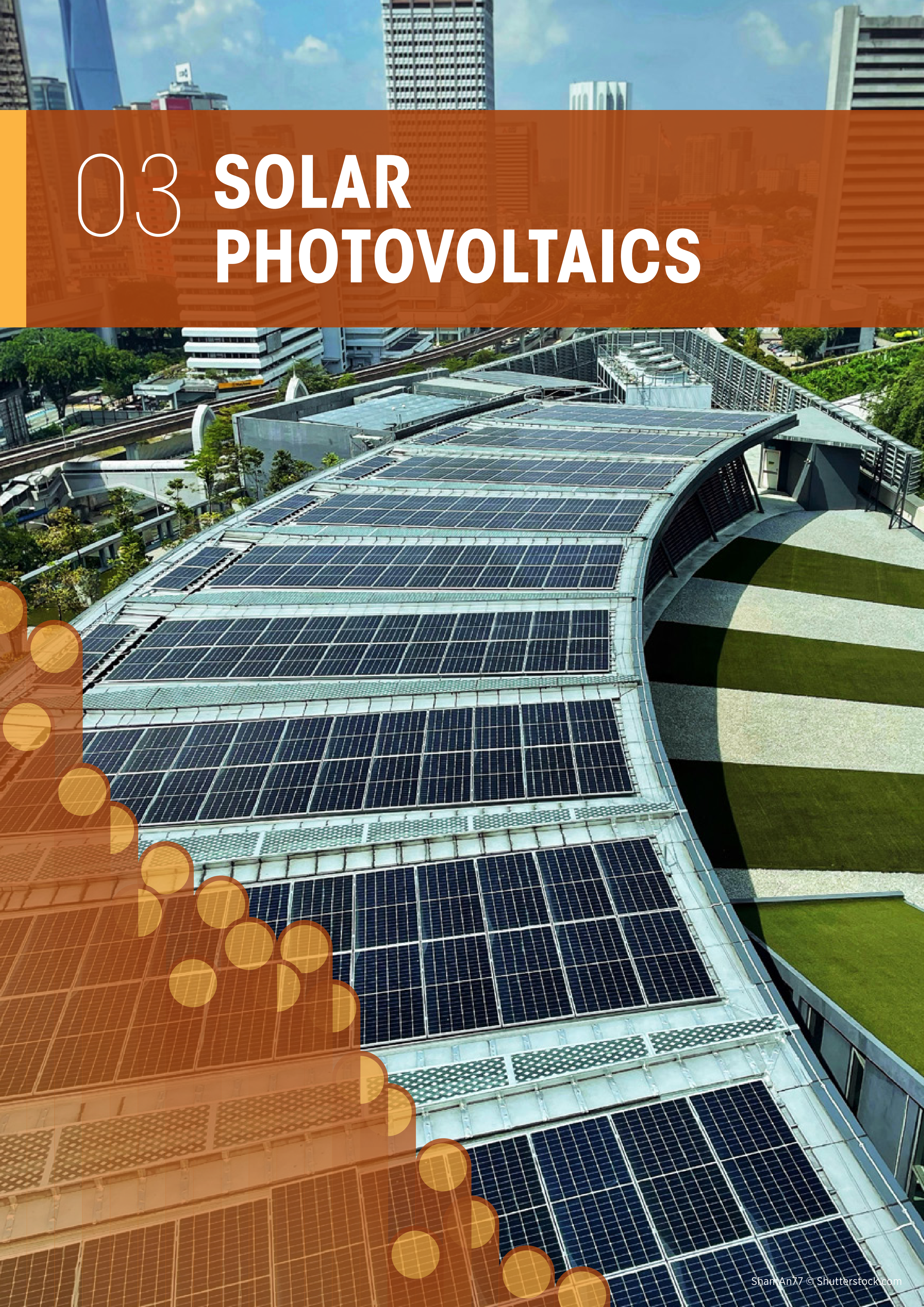
Figure 2.16 shows the weighted average LCOE for newly commissioned onshore wind projects in smaller markets. Among these, Ireland and Peru reported values below the global average, signalling growing competitiveness even in less mature markets.

Figure 2.16 Onshore wind weighted average LCOE in smaller markets, 2010–2024



Notes: kWh = kilowatt hour; USD = United States dollar.

03 SOLAR PHOTOVOLTAICS



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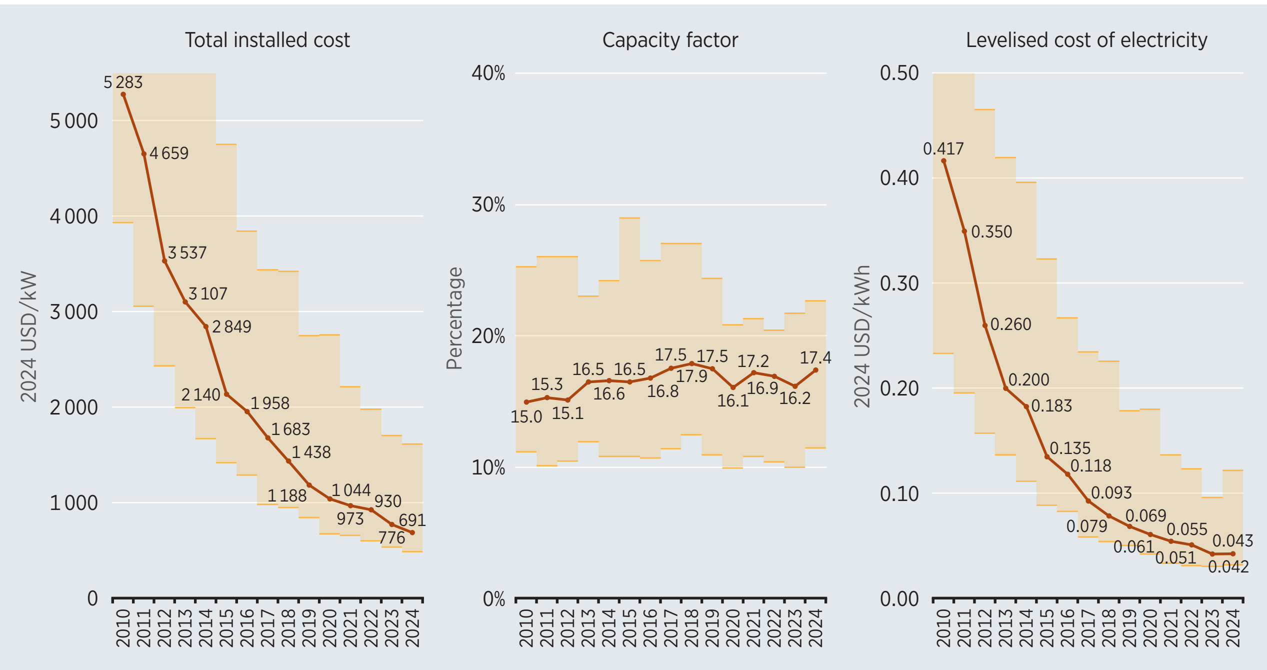
HIGHLIGHTS

- Between 2010 and 2024, the global weighted average LCOE of utility-scale solar PV plants declined by 90%, from USD 0.417/kWh to USD 0.043/kWh. The 2024 value, however, remained almost flat in comparison to 2023, registering a slight increase of around 0.6%, year-on-year. This trend reflects changing financial conditions across markets.
- The global weighted average total installed cost of projects commissioned in 2024 was USD 691/kW. This was 87% lower than in 2010 and 11% lower than in 2023.
- Between 2010 and 2024, the global weighted average capacity factor for new, utility-scale solar PV increased from 15% to 17.4%.
- The increase in capacity factors occurred for a combination of reasons, including evolving inverter load ratios, overpaneling ratios, and a shift in average market irradiance. The expanded use of trackers, driven largely by increased adoption of bifacial technologies, was a third. These trends produced trade-offs in capacity factors, unlocking more solar PV deployment in latitudes that have less solar resources.
- In 2024, average balance-of-system (BoS) costs (excluding modules and inverters) made up around 65% of the total installed costs (TICs) of utility-scale PV plants.
- Global crystalline silicon module costs registered a 97% decline between January 2010 and December 2024.
- Utility-scale solar PV installations are increasingly paired with battery storage, effectively creating hybrid systems that enhance grid reliability and flexibility.

Figure 3.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for utility-scale solar PV, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

INTRODUCTION

By the end of 2024, over 1 859 GW of solar PV systems had been installed globally, with 452 GW of newly-installed systems being commissioned in 2024 alone (IRENA, 2025d). This was 26.7% more than in 2023. Solar PV also had the highest capacity additions worldwide among all renewable energy technologies. Indeed, in recent times, solar PV has been breaking installation records, year after year.

In 2024, 262 GW of the capacity installed was in the form of utility-scale projects. This was around 58% of total, new global solar PV deployment. The top three markets for new additions were China, the United States and India. China led in new additions, accounting for approximately 64% of global utility-scale installations.

Utility-scale solar PV installations are also increasingly being paired with battery storage. This effectively creates hybrid systems that enhance grid reliability and flexibility. This is also becoming more important as the penetration of solar PV in the energy system continues to grow. In 2024, this trend was particularly evident in the United States: for every 3 GW of solar capacity added there that year, approximately 1 GW of battery storage was installed as part of co-located PV-battery hybrid projects (Ember, 2025). This growing synergy reflects a broader move toward hybrid energy systems that can better manage variability and improve energy dispatch.

Historically, the downward trend in solar PV module costs has been an important driver in improving competitiveness. Solar PV has also shown the highest learning rates of all renewable energy technologies, achieving a level of 33.8% in 2024. Various factors are expected to continue to increase solar PV technology's competitiveness in the long term. These factors include: continued improvement in the efficiency of manufacturing equipment; production optimisation by the implementation of lean processes; more efficient use of materials; standardisation of PV module sizes; and further design innovation.

These factors are expected to more than offset recent temporary cost increases. An example of this is the further adoption of bifacial technologies. These are being built from increasingly efficient cells – devices that have become standard today in both monofacial and bifacial modules. In 2024, module efficiencies ranged from 21.7% for P-type passive emitter and rear cell (p-PERC) to 23.8% for N-type interdigitated back contact (n-IBC) cells (ITRPV, 2025). The efficiency of p-PERC modules, however, is expected to reach 24.7% in the next few years, approaching this variety's limits. Meanwhile, back contact concepts, combined with passivated contacts, have been undergoing further development. Higher efficiencies are therefore expected for back-contact cells, with the N-type reaching 25.4% for TOPCon-based and 26% for SHJ-based within the next 10 years (ITRPV, 2025).

At the module design level – independent from the cell – recent developments in technology have also contributed to increasing module power outputs. Half-cut cells, zero busbar technology and high-density cell packing pathways – such as shingling – are clear examples of this. In the future, these technologies are expected to be increasingly utilised.

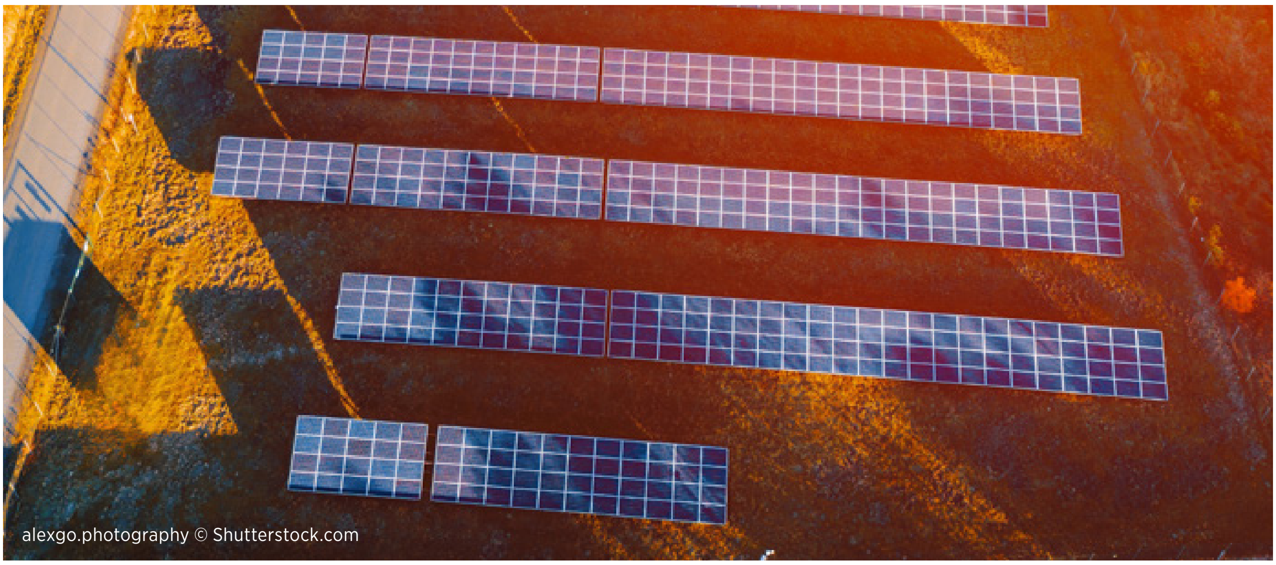
In addition, increased adoption of bifacial technology is an important driver in solar PV competitiveness, given its potential to provide higher yields per watt than monofacial technologies. Bifacial cells allow light to enter from the rear of the cell, as well as the front. The rear-side of bifacial cells features metallisation in a grid, in common with traditional, front-side cell metallisation. Bifacial cells are now dominant, accounting for 90% of the market (ITRPV, 2025).

TECHNOLOGICAL TRENDS

As the global solar PV market continues to expand, factors such as the sustainability of materials, resource efficiency and higher recycling rates are becoming increasingly critical.

Reduced material consumption decreases overall production costs, which in turn lowers balance-of-system (BoS) expenditure. In this context, the industry has been putting a strong emphasis on technological innovations that reduce material consumption. Notable progress has been made through advances in wafer thinning, kerf loss reduction and overall process optimisation, resulting in significant material savings. This focus is especially important given high volatility in the prices of raw materials such as polysilicon and silver, which heavily influence the cost of solar modules. Polysilicon consumption currently varies between 1.7 grammes/watt (g/W) and 1.9 g/W, depending on the size of the wafer, with this projected to drop below 1.4 g/W by 2030. Meanwhile, silver consumption currently stands at a median of 13.5 milligrammes/Watt (mg/W) for TOPCon cells, with the industry aiming to reduce this figure to approximately 8 mg/W over the next decade (ITRPV, 2025).

In terms of innovation, tandem technologies incorporating perovskite are also a major focus of solar PV industry R&D. When combined with silicon, perovskite cells have efficiency rates of up to 29.15% (HZB, 2025). However, to achieve commercial viability, further technological improvements are required. Current efforts with this technology are being focused on improving long-term stability, enabling scalable manufacturing and incorporating novel materials. These steps should help unlock the full potential of these high-efficiency tandem cells (Aydin *et al.*, 2024).

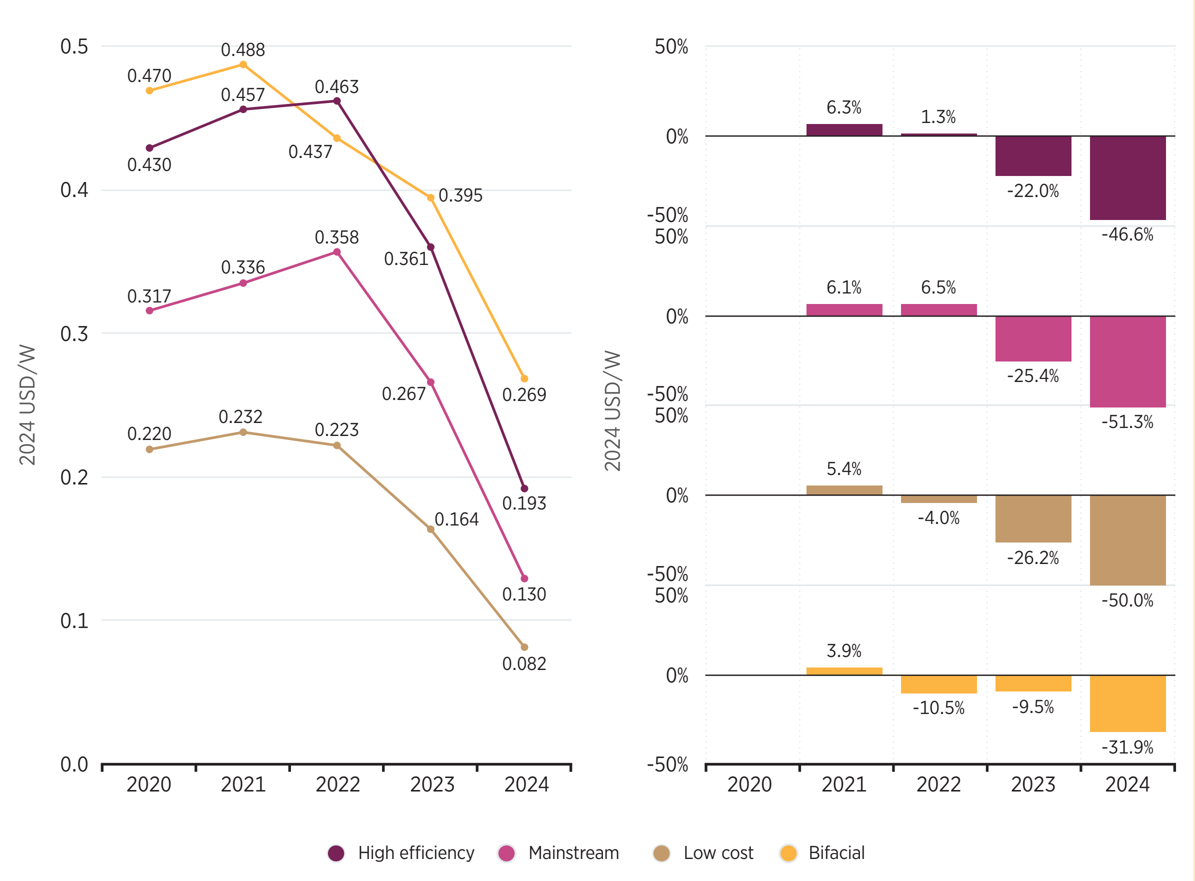

alexgo.photography © Shutterstock.com

Box 3.1 Solar PV module prices in Europe

In the 2020–2024 period, module costs decreased significantly since 2023. Indeed, by the end of 2024, all the module technologies sold in Europe were at their lowest levels yet (see Figure B3.1a). The "mainstream" category had the highest five-year decline, at 51.3%, followed by low-cost modules, with 50%, and high efficiency modules, with 47%. The smallest decrease was for bifacial modules, which registered a price of USD 0.27/W. This value was 32% lower compared to 2023.

This sharp decline in prices, overall, was primarily driven by overproduction from China, which led to a large volume of unsold inventory. Low prices impacted small suppliers, some of whom faced insolvency and were forced to liquidate their stocks.

Figure B3.1a Average yearly solar PV module prices by technology sold in Europe, 2010 to 2023 and Q1 2024; average (left) and percentage increase (right)

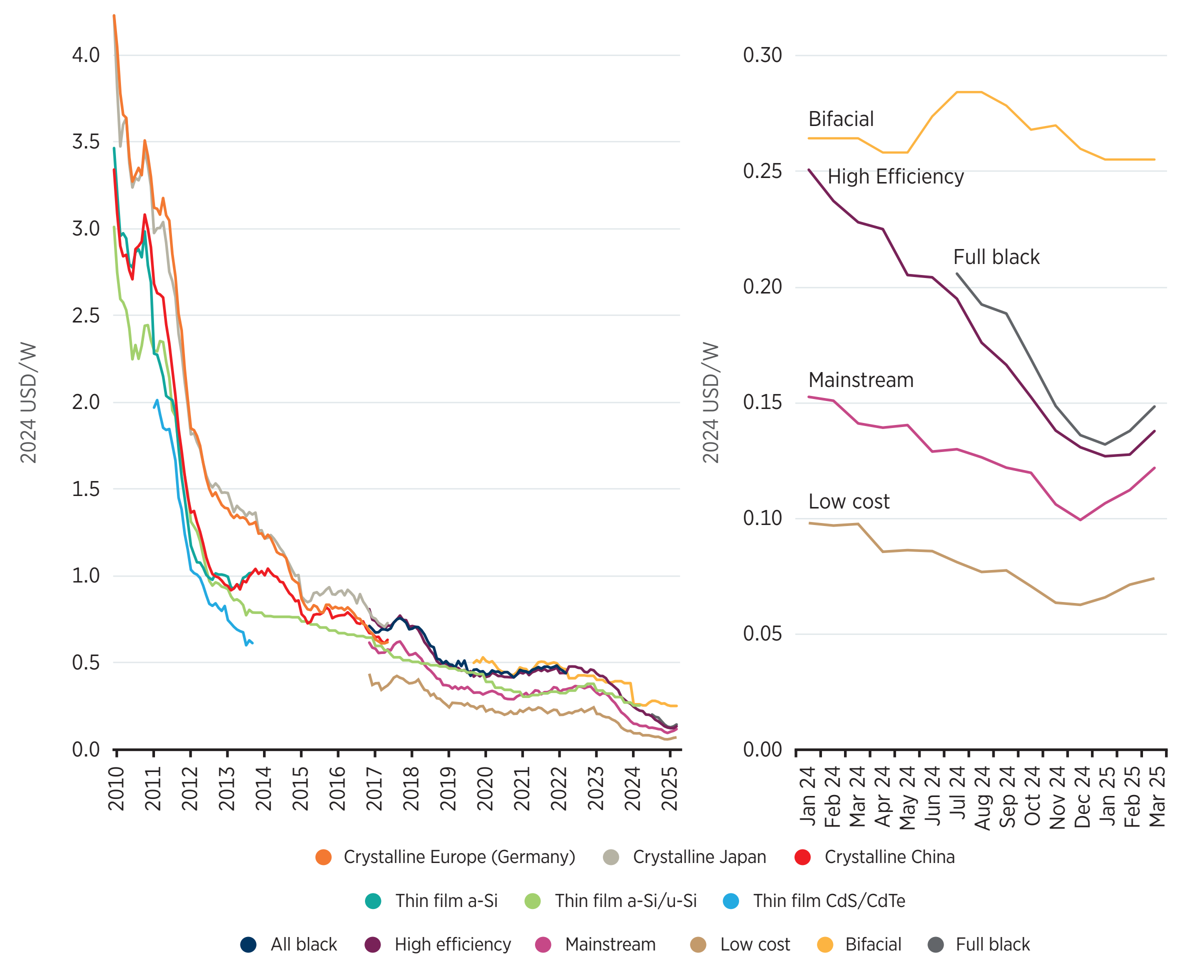


Source: (pvXchange, 2025).
Notes: W = watt; USD = United States dollar.

Between January 2010 and January 2024, the cost of modules sold in Europe registered an average 97% decline. During December 2024, mainstream modules sold for USD 0.11/W, a value 22% lower than in December 2023. The period also saw significant cost variation between the different types of module technology. In Europe, module costs varied from as low as USD 0.08/W for the lower-cost category to as high as USD 0.27/W for bifacial modules, the market leaders. Bifacial modules registered continuous growth in their market share, rising from 50% in 2023 (ITRPV, 2024) to 64% in 2024 (ITRPV, 2025).

Preliminary European market data for Q1 2025 shows price increases in both February and March. These increases ranged from 4% to 9% across all module categories except bifacial, which saw its prices remain stable during the quarter (see Figure B3.1b). It is still unclear whether this overall increase in prices will continue throughout 2025. Prices are expected to rise rapidly, however, as demand continues to grow. Current production cuts have created an inventory shortage and manufacturers are experiencing delivery delays, prompting customers to increasingly turn to the spot market to meet their needs (pvXchange, 2025).

Figure B3.1b Average monthly solar PV module prices, 2010 to 2024 (left) and monthly solar PV module prices, 2024 to Q1 2025 (right), by technology and manufacturing sold in Europe

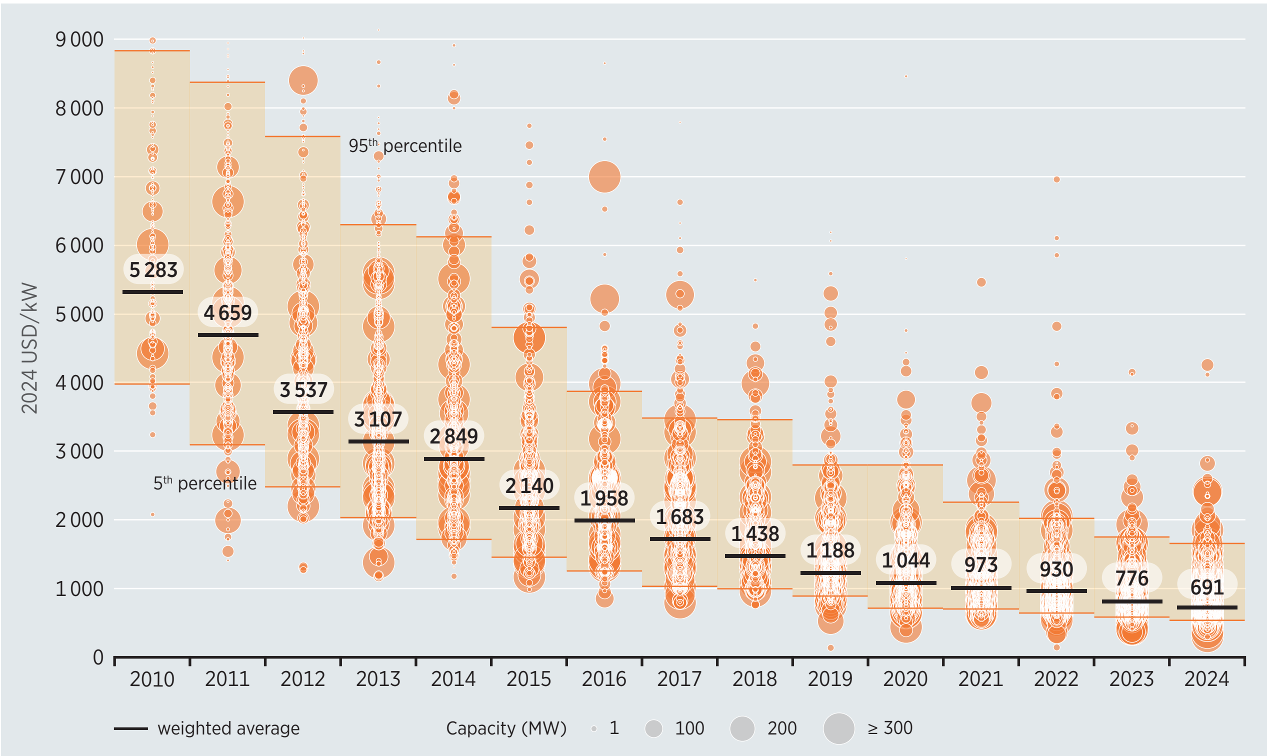


Source: (pvXchange, 2025; Wood Mackenzie, 2025e).
Notes: W = watt; USD = United States dollar.

TOTAL INSTALLED COSTS

The global weighted average total installed cost (TIC)[27] of utility-scale projects has continued to decrease in recent times. For projects commissioned in 2024, this figure fell 11%, year-on-year, to USD 691/kW. This value was also 87% lower than in 2010. During 2024, the 5th and 95th percentile range for all newly-commissioned projects fell within a range of USD 489/kW to USD 1 610/kW. The 95th percentile value was 5% lower than in 2023, while the 5th percentile value declined by 9% between 2023 and 2024. The long-term reduction trend in this cost range points towards continued cost structure improvements in an increasing number of markets. Compared to 2010, the 5th and 95th percentile values were 88% and 82% lower, respectively (Figure 3.2).

Figure 3.2 Total installed cost of utility-scale solar PV, by project and weighted average, 2010–2024



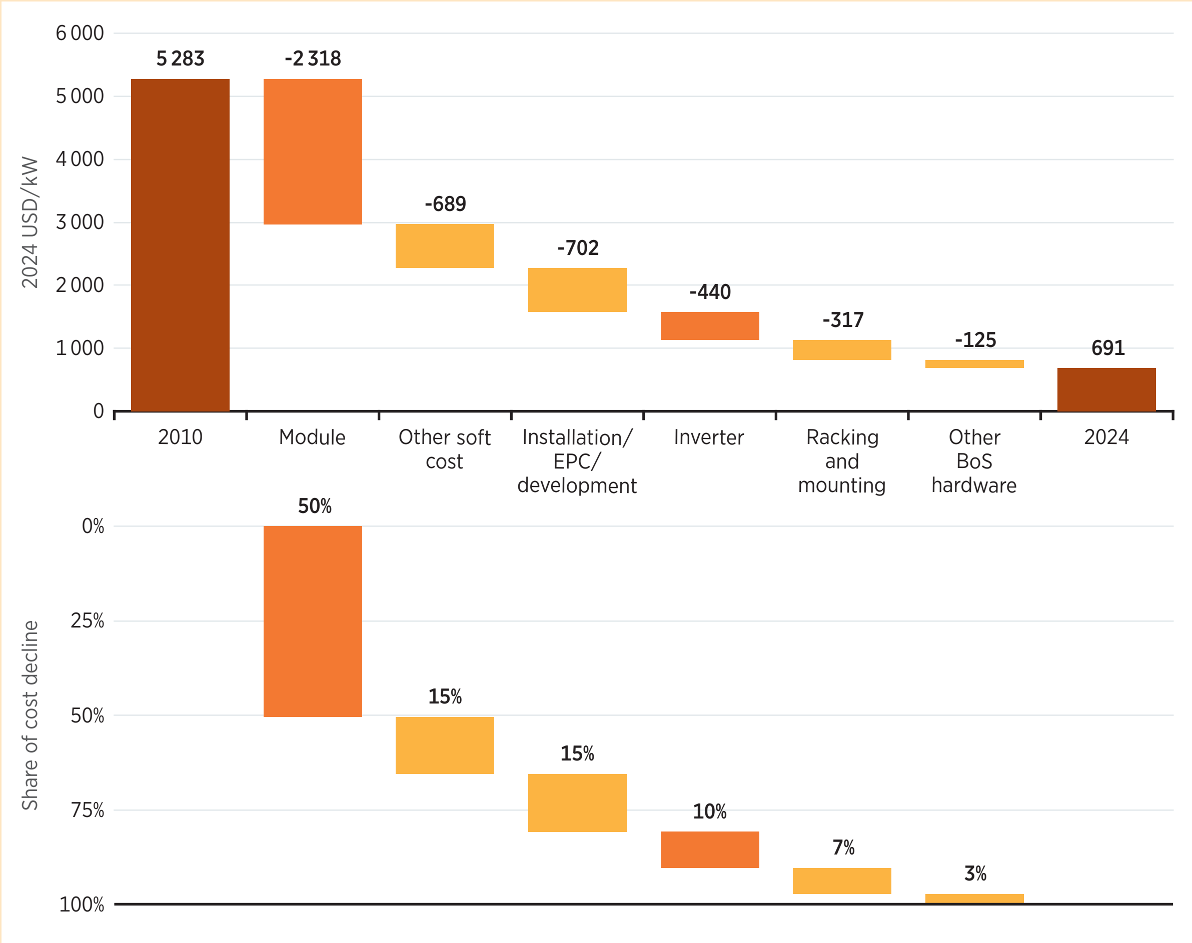
Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

[27] *TIC data in this report are expressed as per kW of direct current (DC) for solar PV only.*

Box 3.2 Drivers of declining total installed costs in utility-scale solar PV

Although reductions in the TICs of utility-scale solar PV are due to a variety of factors, module costs and inverters are a major driver, with these accounting for 60% of the TIC reduction between 2010 and 2024 (Figure B3.2).

Figure B3.2 Global weighted average TICs of utility-scale solar PV systems and cost reductions by source, 2010–2024



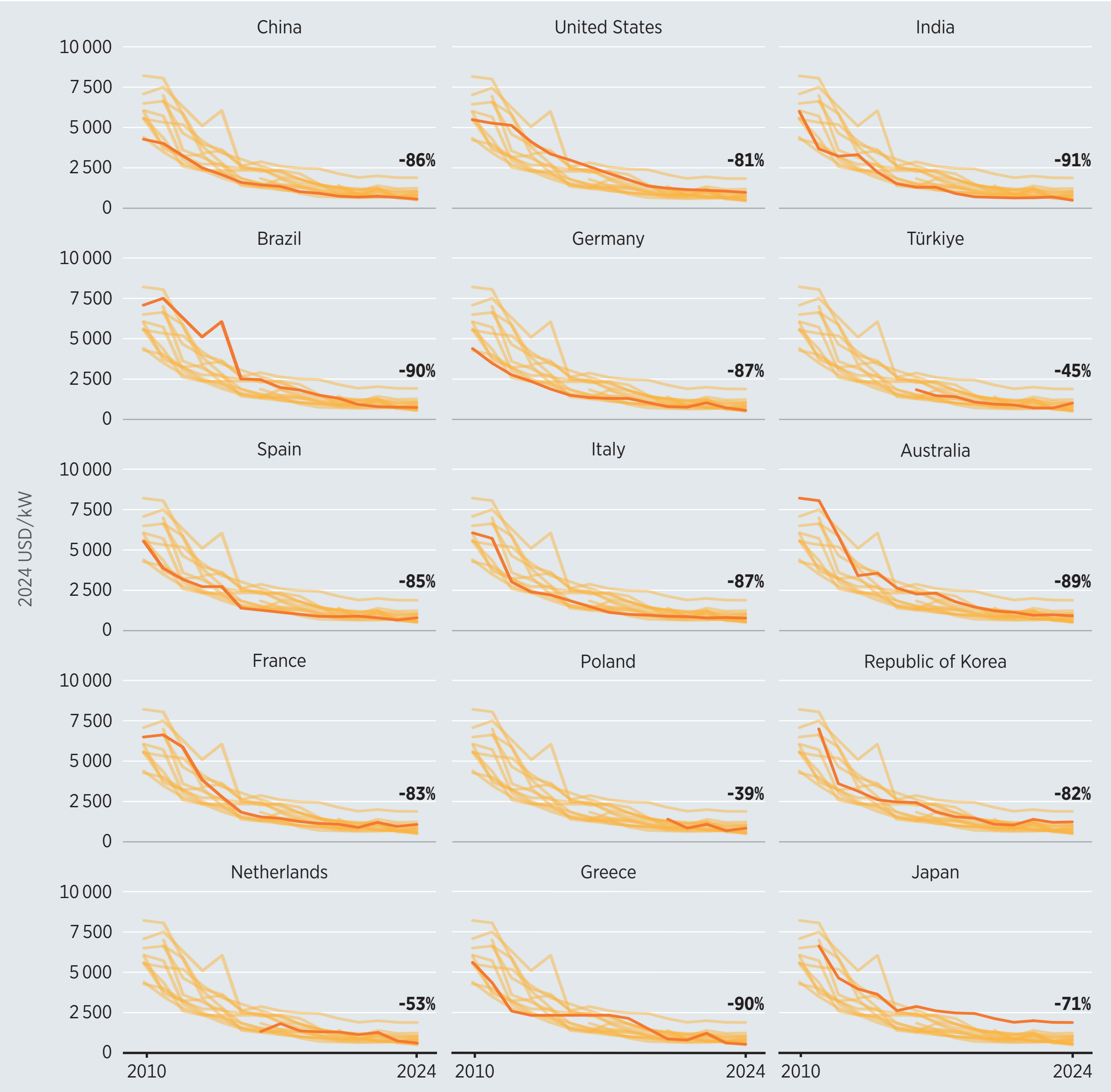
Notes: Percentage figures may not total 100 due to rounding up. BoS = balance-of-system; EPC = engineering, procurement and construction; kW = kilowatt; USD = United States dollar.

BoS[28] categories such as installation/EPC and development, along with other soft costs, accounted for 30% of the cost reductions over the period. This decline was driven by improved supply chain structures and increased experience among project developers in a variety of markets. This led to an increasing number of jurisdictions in which PV systems began to achieve competitive cost structures, with falling global weighted average total installed costs. Together, the rest of the categories contributed 10% to the reduction between 2010 and 2024. This highlights the increasing relevance of BoS costs in the competitiveness of solar PV utility-scale projects.

[28] *See Annex I for a description of all the BoS categories that are tracked by IRENA.*

For 2024, Figure 3.3 shows the top 15 countries for solar added-capacity recorded that year. For those countries in the figure with data for the whole 2010–2024 period, cost reductions ranged between 81% in the United States and 91% in India.

Figure 3.3 Utility-scale solar PV total installed cost trends in the top 15 markets, 2010-2024



Note: Lines represent all 15 markets, with the orange line in bold corresponding with the market identified at the top of each graph. kW = kilowatt; USD = United States dollar.

Between 2023 and 2024, TICs fell in 10 out of the top 15 markets surveyed. The reduction ranged from a 28% drop in India, year-on-year, to 3% in Brazil. Costs were up 41% in Türkiye, however, which registered the highest year-on-year increase, to USD 1 033/kW. European countries such as Poland, Spain and France had increases of 14%, 22% and 20%, respectively.

Table 3.1 shows the weighted average TICs and 5th and 95th percentile ranges for 8 regions of the globe and for the top 4 countries by region for 2015 and 2024.

In 2024, the highest weighted average TIC for commissioned projects by region was USD 1 375/kW, which occurred in the Central America and the Caribbean region. Projects commissioned in India and China saw the lowest weighted average TICs, at USD 525/kW and USD 591/kW, respectively. Among the top four country markets, the United States had the highest TIC in 2024, at USD 1 058/kW – although this was 7% lower than in 2023.

Among the regions, Eurasia had the highest TIC reduction between 2015 and 2024, at 70%. Africa registered the second highest decrease – 68% – for the same period. The continent saw TICs fall from USD 3 437/kW to USD 1 093/kW.

At country level, the highest TIC reduction was in Brazil, which saw a fall of 71% – from USD 2 498/kW to USD 724/kW. India, the United States and China had reductions of 66%, 65% and 64%, respectively, over the same period.

Regional differences in TICs are driven by disparities in the maturity of local supply chains, permitting requirements and labour costs. Understanding these differences can help policy makers develop more targeted and effective system cost reduction strategies.

Table 3.1 Utility-scale solar PV costs by region and in the top four major utility-scale markets, 2015 and 2024

	2015			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kW)					
Africa	1 591	**3 437**	5 091	861	**1 093**	1 630
Central America and the Caribbean	2 042	**2 612**	3 956	939	**1 375**	2 288
Eurasia	2 481	**3 438**	4 509	671	**1 030**	2 861
Europe	1 339	**1 759**	3 552	524	**779**	1 312
Oceania	2 160	**2 663**	2 787	598	**944**	1 385
Other Asia	1 819	**2 652**	4 929	502	**1 133**	2 585
Other North America	1 986	**2 642**	6 007	807	**1 206**	1 689
Other South America	2 234	**3 202**	5 440	596	**1 048**	1 634
Brazil	2 088	**2 498**	2 633	503	**724**	1 152
China	1 523	**1 623**	2 767	438	**591**	867
India	1 090	**1 548**	2 515	415	**525**	831
United States	1 932	**3 062**	4 835	771	**1 058**	2 308

Notes: Costs are total installed costs (TIC); see Annex III for regional country groupings.

While solar PV has become a mature technology, regional cost variations persist. These differences remain not only for the module and inverter cost components, but also for the BoS.[29] The reasons for BoS cost reductions relate to competitive pressures and increased installer experience. This has led to improved installation processes and lower soft development costs. BoS costs that decline proportionally with the area of the plant have also declined as module efficiencies have increased.

A better understanding of cost component differences in individual markets is crucial to understanding how to unlock further cost reduction potential. Obtaining comparable cost breakdown data, however, is often challenging. The difficulties relate to differences in the scale, activity and data availability of markets. Despite this, IRENA has expanded its coverage of this type of data, collecting primary cost breakdown information for additional utility-scale markets.

Adopting policies[30] that can bring down BoS and soft costs in particular provides an opportunity to move 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 cost differences among them will tend to decline. To track these developments – and to allow targeted policy changes that address outstanding issues properly – a detailed understanding of individual cost components remains essential.

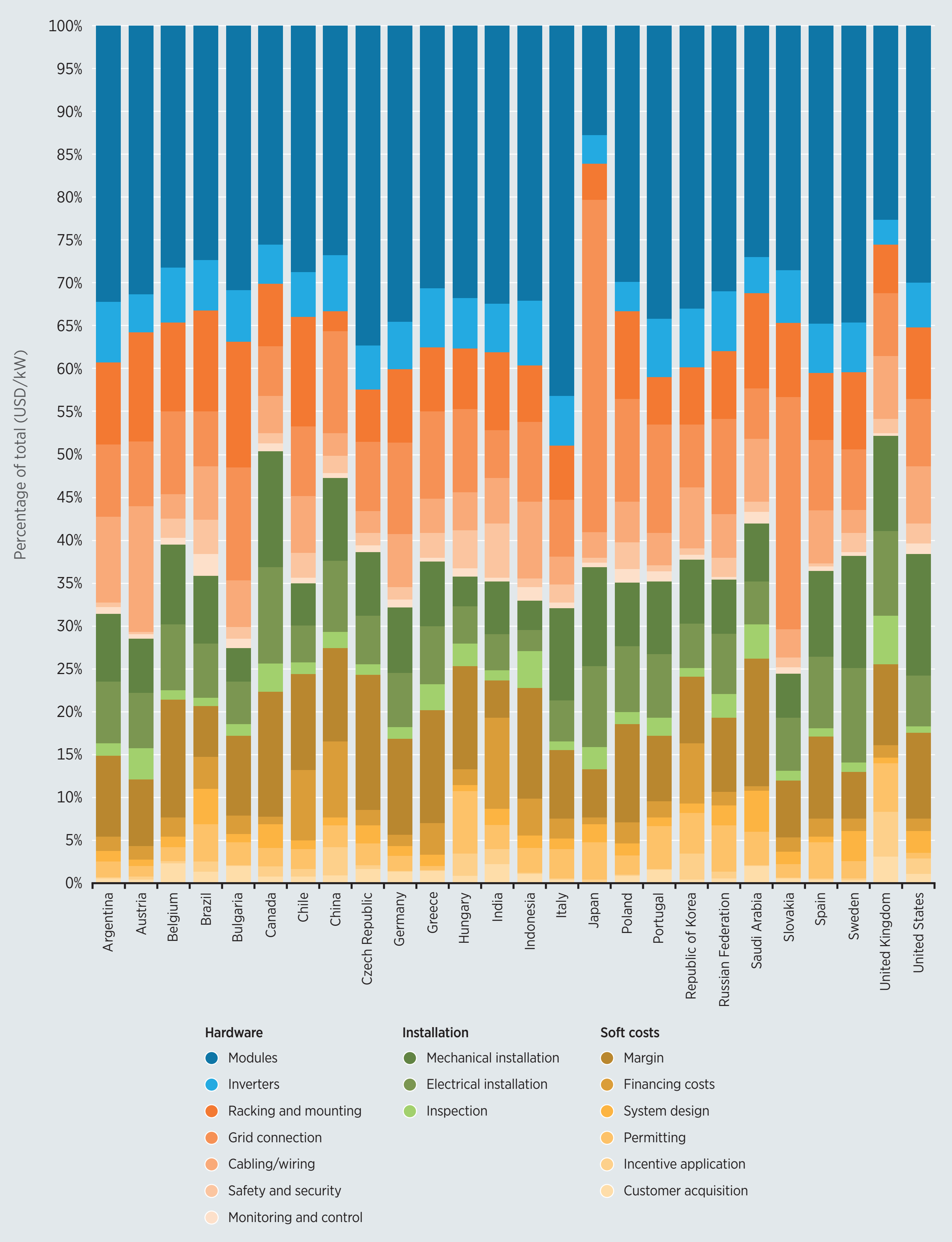
In the markets assessed in Figure 3.4, 2024 saw – on average – the BoS share (excluding inverters) make up around 65% of TICs. This percentage ranged from a low of 54% in Italy to a high of 87% in Japan. Overall, soft cost categories for the countries evaluated made up 30% of total BoS costs and, on average, 20% of TICs during 2024. Modules and inverters together (non-BoS costs) ranged from USD 197/kW to USD 504/kW, with their share ranging from 16% to 49%. The average share for that category was 35%.

BoS hardware components made up between 22% and 50% of TICs during 2024, with an average share of 33% (equivalent to USD 239/kW). Installation costs ranged between 10% and 28% of TICs, giving an average of 18%, or USD 151/kW.

[29] BoS costs in this chapter do not include inverter costs, which are treated separately.

[30] Specific policy measures, such as import tariffs on PV supply chain components, could lead to a contrary effect and contribute to higher overall system costs.

Figure 3.4 Total installed costs by component in selected countries, 2024[31]



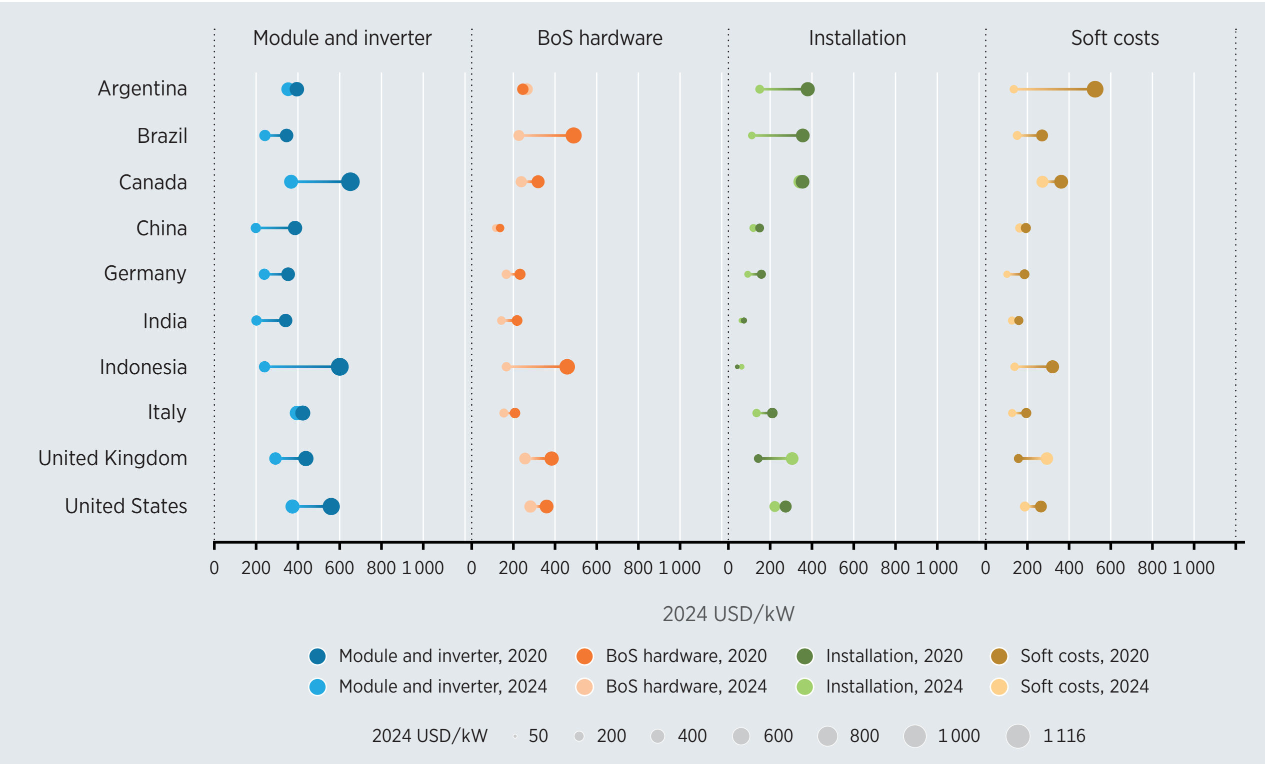
Notes: kW = kilowatt; USD = United States dollar.

[31] *A detailed description of the breakdown of TICs is provided in Annex I.*

An analysis of the time series for historical markets highlights the BoS cost trend by category between 2020 and 2024.

The 10 countries presented in Figure 3.5 experienced an average reduction of 34% in the module and inverter category. This decline shifted from between USD 339/kW and USD 649/kW to between USD 197/kW and USD 394/kW over the period. This was the highest decline across all total installed cost component categories.

Figure 3.5 Breakdown of utility-scale solar PV total installed cost by country, 2020 and 2024



Notes: BoS = balance-of-system; kW = kilowatt; USD = United States dollar.

BoS hardware costs declined 29% on average during the 2020–2024 period. The range of costs declined from between USD 135/kW and USD 487/kW in 2020 to between USD 114/kW and USD 280/kW in 2024. China was the most competitive market in both years, registering a cost decrease of 15%.

At the same time, installation costs declined by an average of 10% in 2024 compared to 2020. The cost range was between USD 41/kW and USD 378/kW in 2020, with this falling to between USD 61/kW and USD 342/kW in 2024. Although the lower cost increased, the difference between the lower and upper costs decreased. It was observed that a major contributor to the disparity between markets was the difference in labour costs.

Over the period, soft costs saw an average reduction of 26%. The range of soft costs fell from between USD 155/kW and USD 523/kW in 2020 to between USD 100/kW and USD 291/kW in 2024.

CAPACITY FACTORS

Referencing the year of commissioning, the global weighted average capacity factor[32] for new utility-scale solar PV increased from 15% in 2010 to 17.4% in 2024. The 2023–2024 increase was 8%. The highest value recorded – 17.9% – was in 2018.

This increasing trend is a result of various concurrent factors that have also often been competing. These drivers include the increased use of tracking and better project location, along with better solar resources and the increased market presence of bifacial modules. Factors have also included developments in the evolution of the inverter loading ratio. These concurring drivers, however, often develop differently by market and can therefore have a varying impact on the weighted average capacity factor.

In 2024, the 5th and 95th percentiles for all projects were 11.5% and 22.6%, respectively. The 95th percentile value was 4% higher than in 2023, while the 5th percentile value had increased 15% year-on-year (see Table 3.2). The increase in the average and the 95th and 5th percentiles indicates that projects deployed in 2024 have a better energy output than in 2023.

Table 3.2 Global weighted average capacity factors for utility-scale solar PV systems by year of commissioning, 2010–2024

Year	5th percentile	Weighted average	95th percentile
2010	11.1%	15.0%	25.2%
2011	10.1%	15.3%	26.0%
2012	10.5%	15.1%	25.9%
2013	11.9%	16.5%	23.0%
2014	10.8%	16.6%	24.4%
2015	10.8%	16.5%	29.0%
2016	10.7%	16.8%	25.7%
2017	11.4%	17.5%	27.0%
2018	12.5%	17.9%	27.0%
2019	10.9%	17.5%	24.3%
2020	9.9%	16.1%	20.8%
2021	10.8%	17.2%	21.3%
2022	10.4%	16.9%	20.4%
2023	10.0%	16.2%	21.7%
2024	11.5%	17.4%	22.6%

[32] *The capacity factor for PV in this chapter is reported as an alternating current (AC)-DC value, given that installed cost data in this report are expressed as per kW DC for solar PV only. This reflects the capacity of the solar modules. 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.*

O&M COSTS

Over the last decade, the O&M costs of utility-scale solar PV plants have declined. This has been driven by module efficiency improvements that have reduced the surface area required for every MW of capacity.

At the same time, competitive pressures and improvements in the reliability of the technology have resulted in system designs that are optimised to reduce O&M costs. In addition, improved strategies that take advantage of a range of innovations have also driven down these costs and reduced downtime. Such innovations stretch from robotic cleaning to big data analysis of performance to identifying issues and initiate preventative interventions ahead of failures.

In the United States, median O&M costs for utility scale plants declined 73% between 2012 and 2023, from USD 39.9kW/year to USD 11.3kW/year. The scope of these costs includes rents, maintenance, supervision and engineering, and the training of a sample of 146 projects, which totalled 7.4 GW of AC. For the period from 2021 to 2023, O&M cost estimates remined flat (Seel *et al.*, 2024). Recent costs in the United States have been dominated by preventive maintenance and insurance, with these making up between 59% and 62% of the total, depending on the system type and configuration (Bolinger *et al.*, 2023).

At the global level, average utility-scale O&M costs were reported at USD 6.2/kW per year in 2023. This was a 2% decrease compared to 2022 and 28% lower than in 2012 (BNEF, 2024e).

For 2024, data from projects in the IRENA renewable costs database showed that the weighted average utility-scale O&M cost was USD 13.1/kW per year at the global level.[33] This was a decline of 51% compared to 2010. The cost figures obtained were the estimated, total all-in O&M costs. These include items such as insurance and asset management, which are sometimes not reported in all O&M surveys.

It is important to note that the scope of O&M contracts varies according to regulatory frameworks and market conditions, which influence system reliability, operational efficiency, risk mitigation and compliance requirements across different countries. As a result, O&M contributes to the overall competitiveness of solar PV beyond the absolute cost figures. It does this by enhancing the attractiveness of a project to the investor and its long-term profitability.

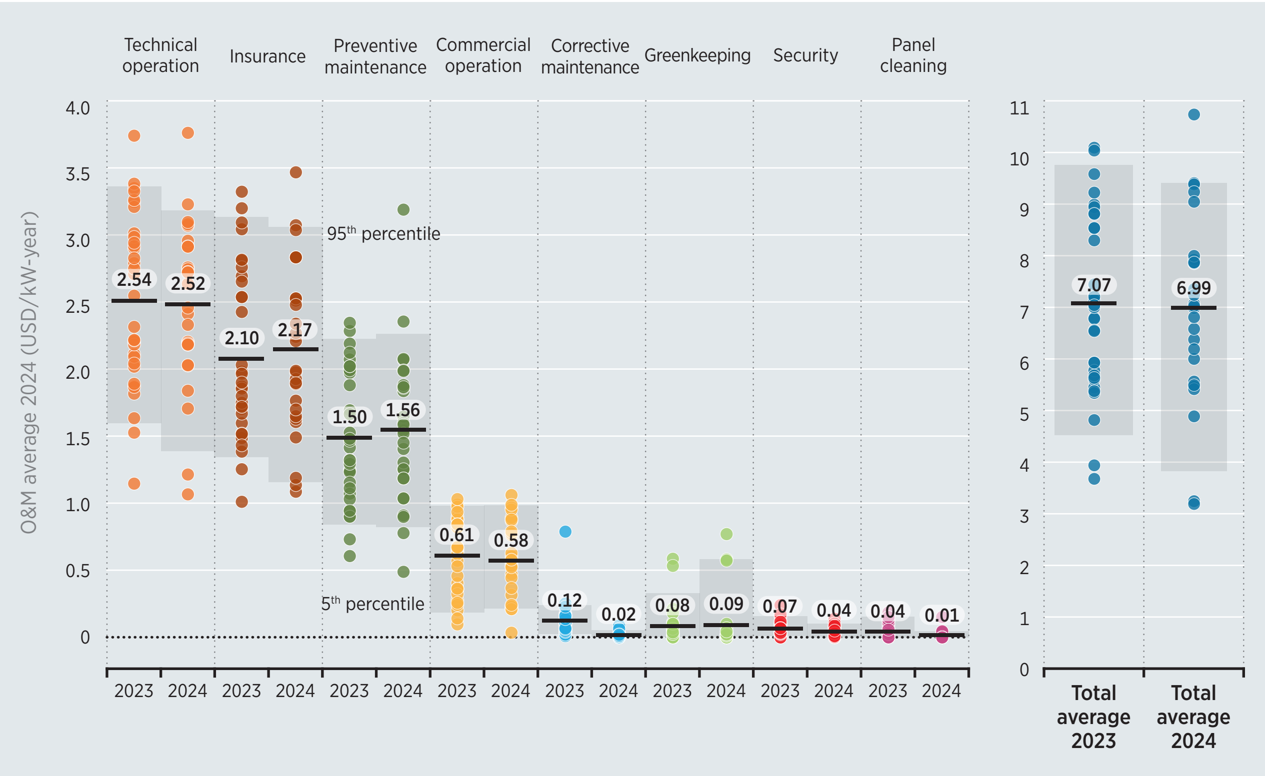
As total installed costs continue to decline, the importance of identifying and analysing the key drivers of O&M costs has become more significant. Increasing the country-granularity of these metrics in the calculation of the LCOE[34] could thus be beneficial in providing more timely and precise market information.

[33] *See Annex I for more detail on O&M cost assumptions.*

[34] *In this report, as an input for the LCOE calculation of projects commissioned in 2024, IRENA has assumed USD 20.73/kW per year for Organisation of Economic Co-operation and Development (OECD) countries and USD 10.95/kW per year for non-OECD countries.*

Challenges in obtaining comprehensive all-in O&M cost data, including detailed breakdowns by main cost categories, remain prevalent, however. Given these challenges, IRENA has a database that specifically includes a smaller subset of such data. These cover 253 utility-scale projects, totalling approximately 35 GW of capacity, that were commissioned between 2020 and 2024 across specific markets. The analysis below focuses on the projects surveyed from 2023 and 2024 in selected markets. The results by category, country and region are presented in Figures 3.6 and 3.7.

Figure 3.6 Survey results for the average, all-in O&M costs for utility-scale solar PV by cost category and country, 2023–2024



Notes: kW = kilowatt; O&M = operation and maintenance; USD = United States dollar.

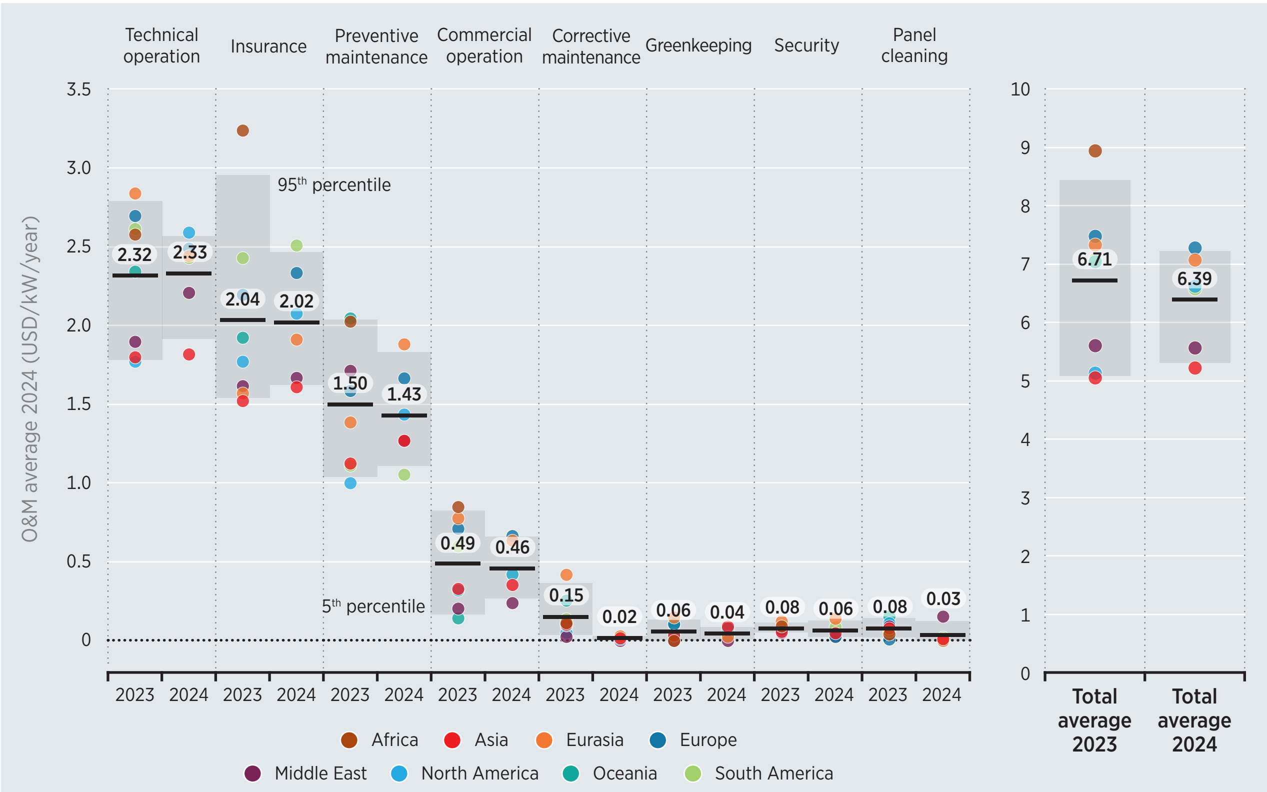
Average total O&M[35] costs show a wide divergence across markets. Considering the projects surveyed in 2024, this range spans from USD 3.2/kW per year in China to USD 10.7/kW per year in Japan. Aggregating all countries, the average for the sample was USD 6.99/kW, a value 1% lower than in 2023.

Looking at the individual cost categories, three of these – technical operation, insurance and preventive maintenance – make up about 89% of total O&M costs. Between 2023 and 2024, costs slightly decreased – by 1% – for technical operations, while they increased for insurance and preventive maintenance by 3% and 4%, respectively. This trend of increasing prices had already been observed between 2022 and 2023.

[35] *A description of O&M cost components for the projects surveyed is available in Annex I.*

A regional perspective reveals that the lowest O&M costs could be found in Asia. In 2024, the surveyed average results were USD 5.2/kW per year in that region, with this 3% higher than the value recorded in 2023 (Figure 3.7).

Figure 3.7 Survey results for the average, all-in O&M costs for utility-scale solar PV by cost category and region, 2023–2024



Notes: See Annex III for regional country groupings; kW = kilowatt; O&M = operation and maintenance; USD = United States dollar.

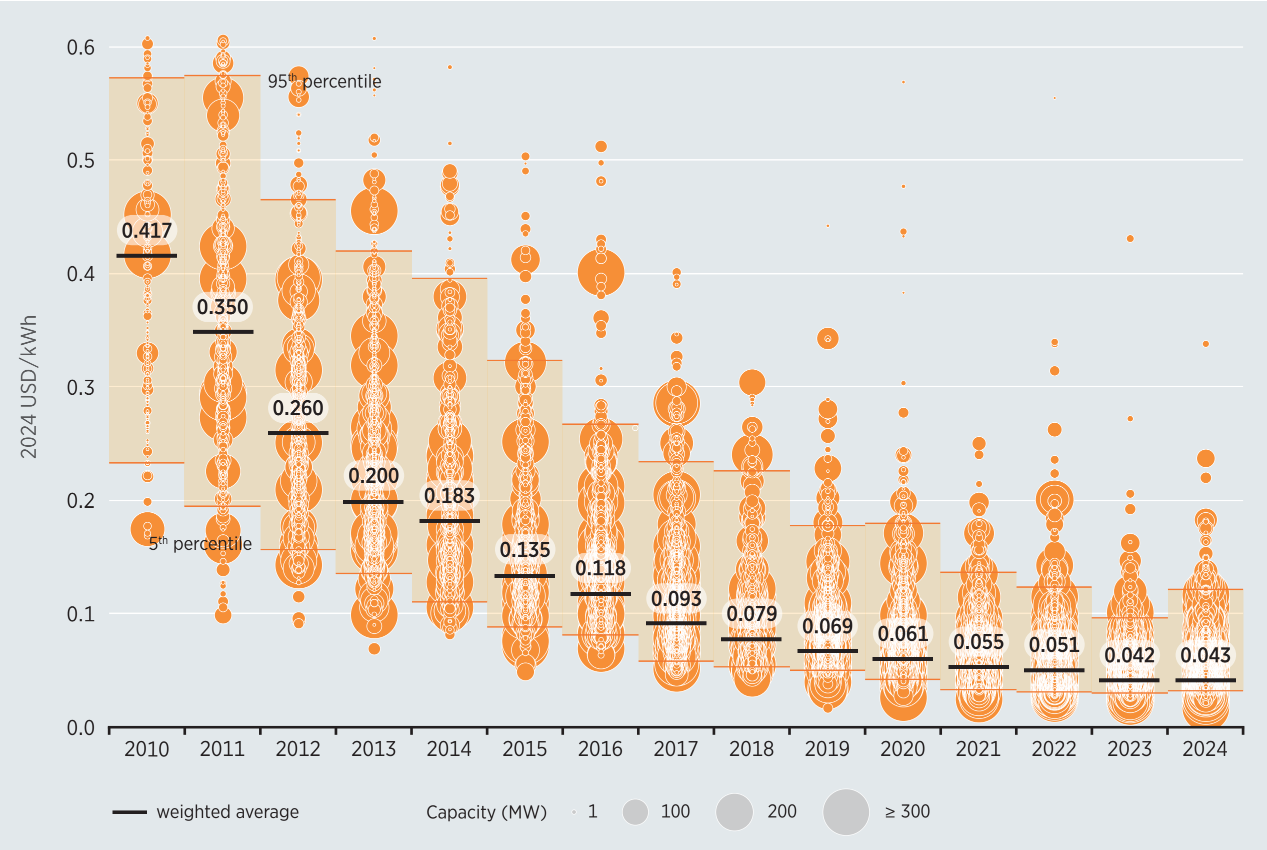
In 2024, Europe showed the highest total O&M costs in the survey, at USD 7.3/kW per year. This compared to USD 7.5/kW per year in 2023, illustrating a decline of 3%. Average values for Eurasia were USD 7.1/kW per year, representing a decrease of 4%, which was the second highest average O&M among all regions in 2024. Costs in North America and South America were the same, at USD 6.6/kW per year. In North America, O&M costs increased 29%, while South America registered the highest decline – 7%, year-on-year. Survey results for the Middle East were USD 5.6/kW per year. This meant O&M costs in the region remained flat, showing no change on their 2023 value.

LCOE

The global weighted average LCOE of utility-scale solar PV remained flat in 2024, registering a value of USD 0.043/kWh for projects commissioned that year. This value was 0.6% higher than in 2023 and 90% lower than in 2010.

During 2024, the 5th and 95th percentile range for all the projects surveyed fell within a range of USD 0.032/kWh to USD 0.122/kWh. The 95th percentile value was 26% higher than in 2023, while the 5th percentile saw a 4% increase, year-on-year. This trend shows the impact of financing costs, which have recently risen due to inflation and high interest rates in a considerable number of markets. Compared to 2010, the 5th and 95th percentile values were 86% and 79% lower, respectively (Figure 3.8).

Figure 3.8 Global utility-scale solar PV project LCOE and range, 2010–2024



Notes: kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

Box 3.3 Unpacking the decline in utility-scale solar PV LCOE from 2010 to 2024

Over the past decade, the remarkable decline in the cost of electricity from utility-scale solar PV is one of the power generation sector's most compelling stories.

Since 2010, the solar PV industry has seen a variety of technological developments that have contributed to improvements in the competitiveness of the technology. These have occurred along the whole solar PV value chain. They range from increased deployment of larger polysilicon factories to improved ingot growth methods and the ascendancy of diamond wafering methods. With the solar PV industry also seeing the emergence and dominance of newer cell architectures and larger wafer sizes, the sector is constantly seeing innovations that unlock LCOE reductions.

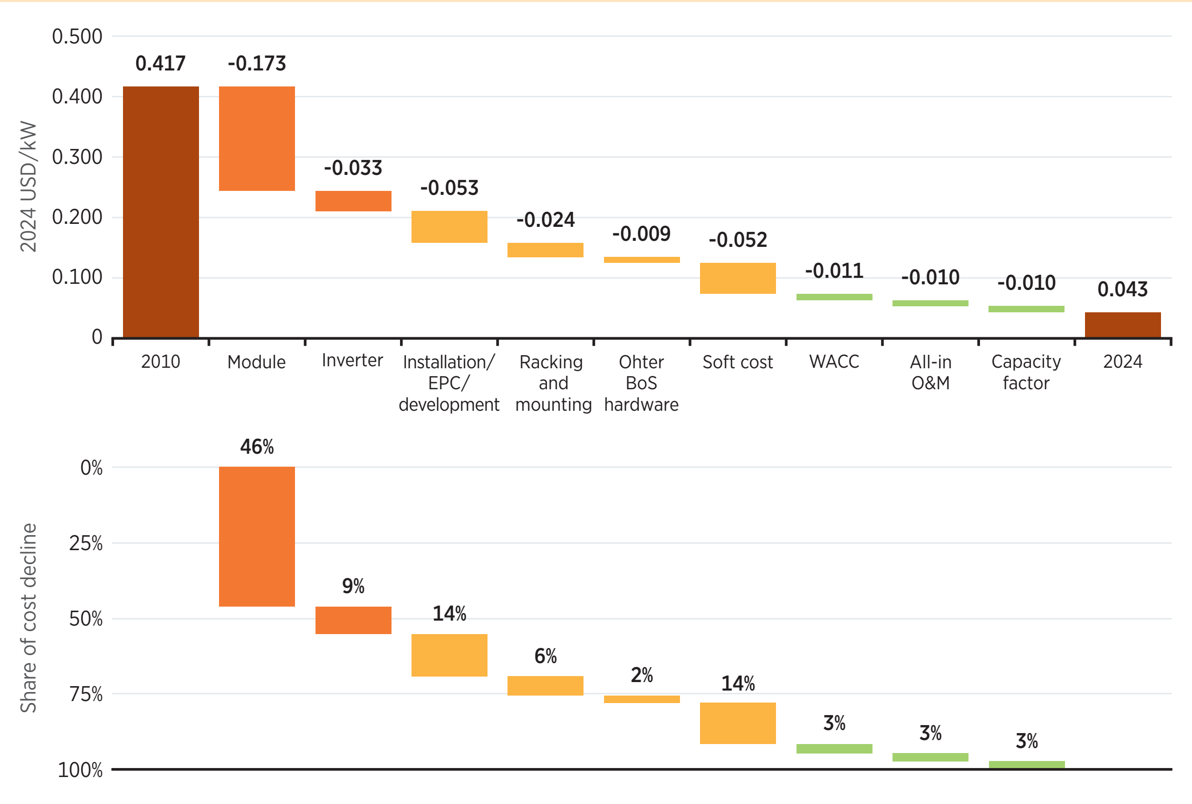
The rapid decline in solar PV module costs has also led to the emergence of new PV markets around the globe. This fall was driven heavily by module and inverter costs, which together were responsible for 55% of this decline (see Figure B3.3).

As solar PV technology has matured, the relevance of BoS costs has also increased. This is because module and inverter costs have historically decreased at a higher rate than non-module costs, increasing the share of TICs taken by BoS.

The costs of other hardware components declined between 2010 and 2024. Indeed, taken together, racking and mounting and other BoS hardware contributed another 8% to the LCOE reduction in that period. EPC, installation and development costs, when combined with other soft costs, were responsible for 28% of the LCOE decline over the 2010 to 2024 period.

The rest of the decline came from factors such as better financing conditions, as the technology risk perception started to decline in major markets. Other factors have included more competitive O&M costs and improved global-weighted capacity factors.

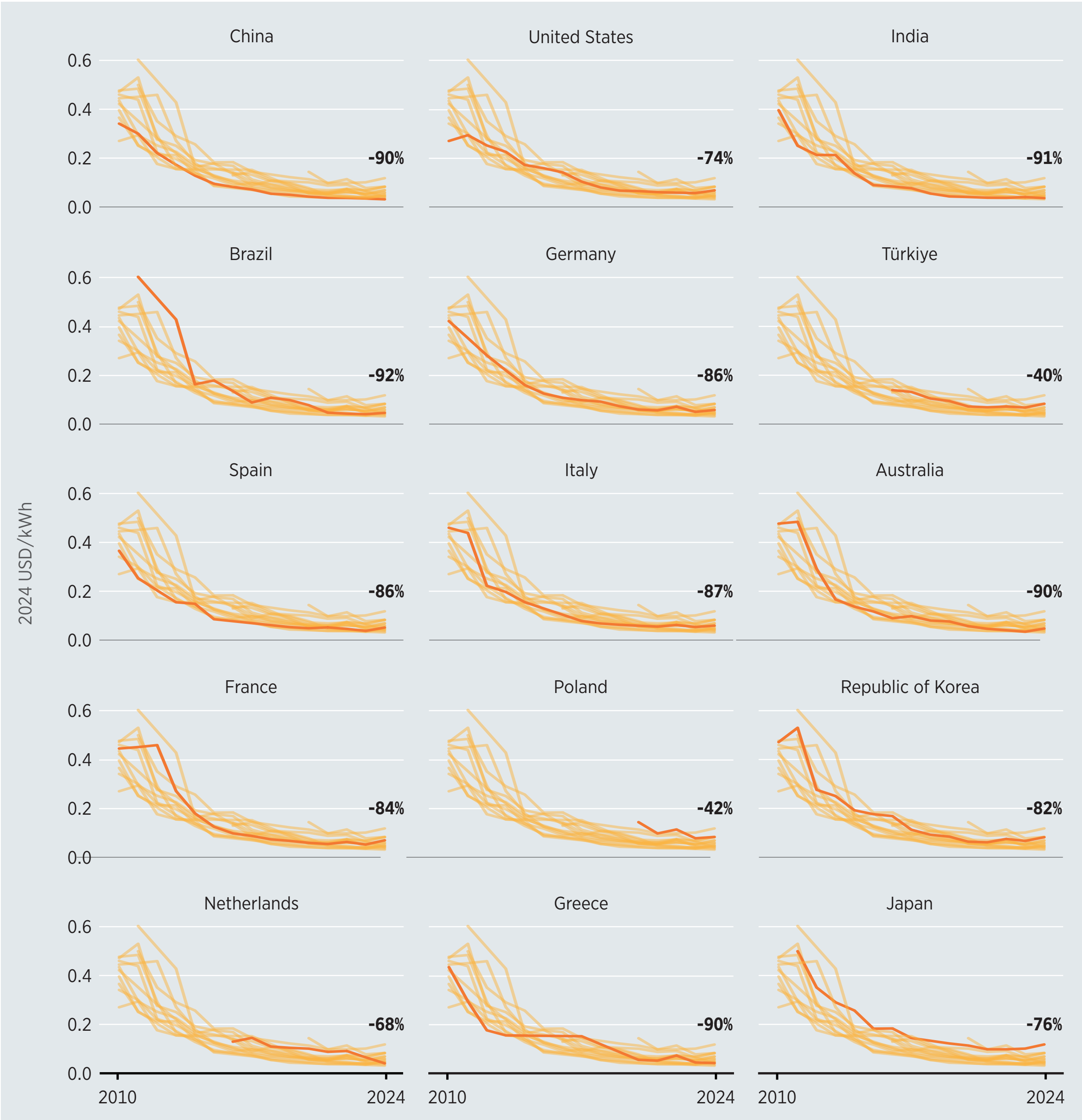
Figure B3.3 Drivers of the decline of the global weighted average LCOE of utility-scale solar PV, 2010–2024



Notes: Percentage figures may not total 100, due to rounding; BoS = balance-of-system; EPC = engineering, procurement and construction; kWh = kilowatt hour; O&M = operation and maintenance; USD = United States dollar; WACC = weighted average cost of capital.

The cost trend in the LCOE of utility-scale solar PV in the largest 15 markets is presented in Figure 3.9. This shows that in markets where historical data have been available since 2010, the weighted average LCOE of utility-scale solar PV declined by between 74% (in the United States) and 91% (in India) between 2010 and 2024.

Figure 3.9 Utility-scale solar PV weighted average cost of electricity in the top 15 markets, 2010–2024



Notes: Lines represent all 15 markets. The orange line in bold corresponds to the market identified at the top of each graph; kWh = kilowatt hour; USD = United States dollar.

Between 2023 and 2024, the weighted average LCOE increased in 13 out of the 15 markets shown in Figure 3.9. This increase ranged from 7% in Poland to 36% in Australia. In 2024, among these 15, the LCOE ranged from USD 0.033/kWh (in China) to USD 0.120/kWh (in Japan).

In 2024, India had the second most competitive LCOE, at USD 0.038/kWh. This represented a 10% year-on-year decline and a 91% decrease between 2010 and 2024. Elsewhere, costs in Greece decreased 5%, to USD 0.044/kWh.

Table 3.3 shows the weighted average LCOE and 5th and 95th percentile ranges for the regional and top four regional markets in 2015 and 2024.

In 2024, the highest weighted average LCOE for commissioned projects by region was USD 0.094/kW. This occurred in the Other North America region. Oceania, meanwhile, registered the lowest regional LCOE, at USD 0.049/kWh. Projects commissioned in China and India saw the lowest weighted average LCOEs, at USD 0.033/kWh and USD 0.038/kWh, respectively. Among the top four markets, the United States had the highest LCOE in 2024, at USD 0.070/kW, although this was 57% lower than in 2015.

Eurasia had the highest regional LCOE reduction between 2015 and 2024, at 74%. This was followed by Africa, with 67%, signifying a drop from USD 0.225/kWh to USD 0.074/kWh. At the country level, the highest total installed cost reduction was in Brazil, which saw a fall of 74%, from USD 0.0180/kWh to USD 0.048/kWh. Between 2015 and 2024, China and India had reductions of 66% and 59%, respectively.

Table 3.3 Utility-scale solar PV's LCOE by region and in the top four major utility-scale markets, 2015 and 2024

	2015			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kWh)					
Africa	0.100	**0.225**	0.356	0.049	**0.074**	0.186
Central America and the Caribbean	0.117	**0.154**	0.258	0.070	**0.091**	0.152
Eurasia	0.247	**0.338**	0.439	0.068	**0.087**	0.256
Europe	0.081	**0.150**	0.182	0.041	**0.060**	0.103
Oceania	0.106	**0.119**	0.122	0.033	**0.049**	0.065
Other Asia	0.101	**0.181**	0.378	0.035	**0.070**	0.146
Other North America	0.091	**0.163**	0.425	0.062	**0.094**	0.147
Other South America	0.091	**0.122**	0.192	0.040	**0.063**	0.126
Brazil	0.144	**0.180**	0.193	0.036	**0.048**	0.077
China	0.104	**0.097**	0.186	0.028	**0.033**	0.052
India	0.073	**0.091**	0.178	0.032	**0.038**	0.059
United States	0.093	**0.160**	0.302	0.049	**0.070**	0.141

Note: See Annex III for regional country groupings.

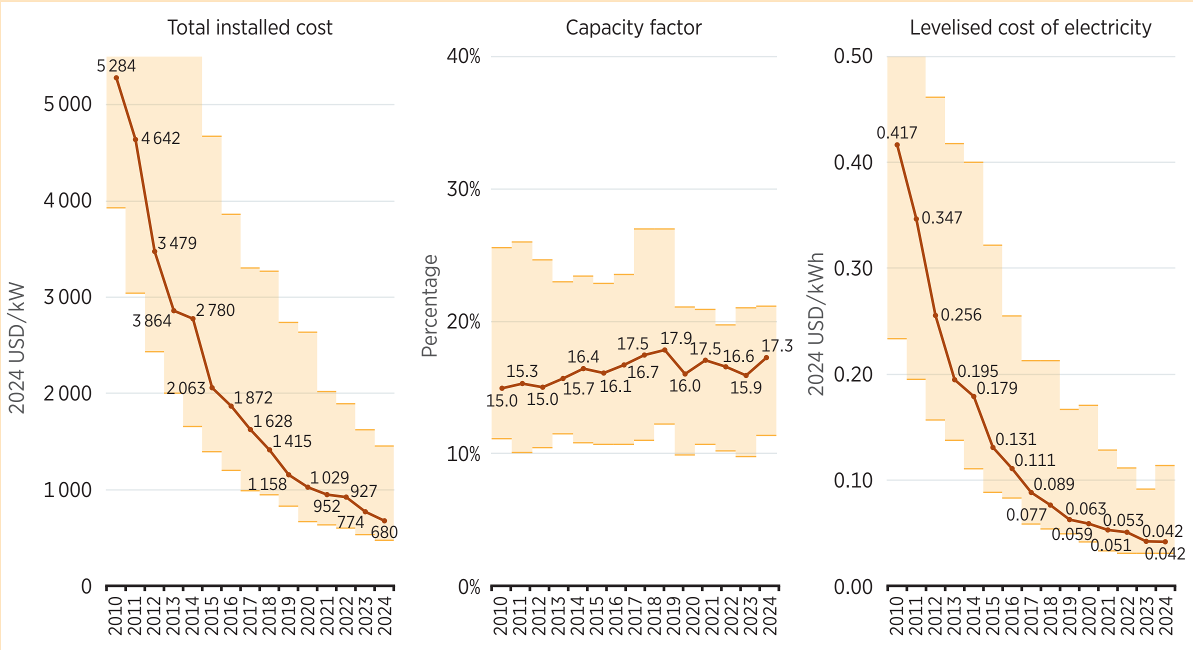
Box 3.4 G20 solar PV trends, 2010–2024

In recent decades, the G20 group has been central to the scale-up of solar PV. Over the 2010–2024 period, G20 countries accounted for 92% of global cumulative solar PV installed capacity. In 2024, they were responsible for 97% of the new capacity additions (IRENA, 2025).

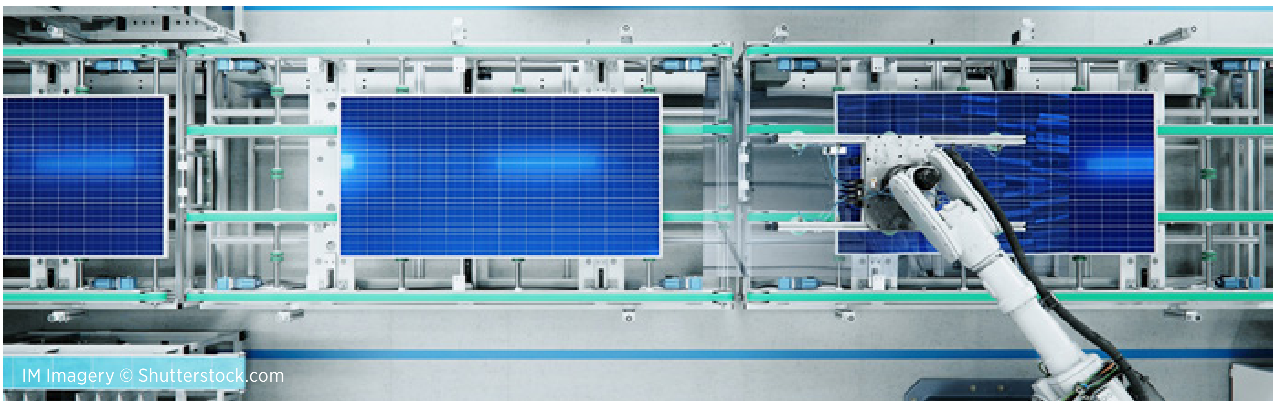
Between 2010 and 2024, the weighted average total installed cost of solar PV across the G20 fell by 87%, reaching USD 680/kW by the end of that period. This value was 2% lower than the global weighted average. Over the same period, average capacity factors increased from 15% to 17.3%, with the highest value recorded in 2018, when it was 17.9%.

Between 2010 and 2024, the G20 LCOE declined by 90%, from USD 0.417/kWh to USD 0.042/kWh. The 2024 value was 1% lower than the global weighted average and remained flat in real terms, showing no change from the 2023 value.

Figure B3.4 G20 weighted average and range of total installed costs, capacity factors and LCOEs for solar PV, 2010–2024



Notes: See Annex III for the member states of the G20 grouping, which includes all G20 member countries except for the African Union; kWh = kilowatt hour; USD = United States dollar.



04 OFFSHORE WIND

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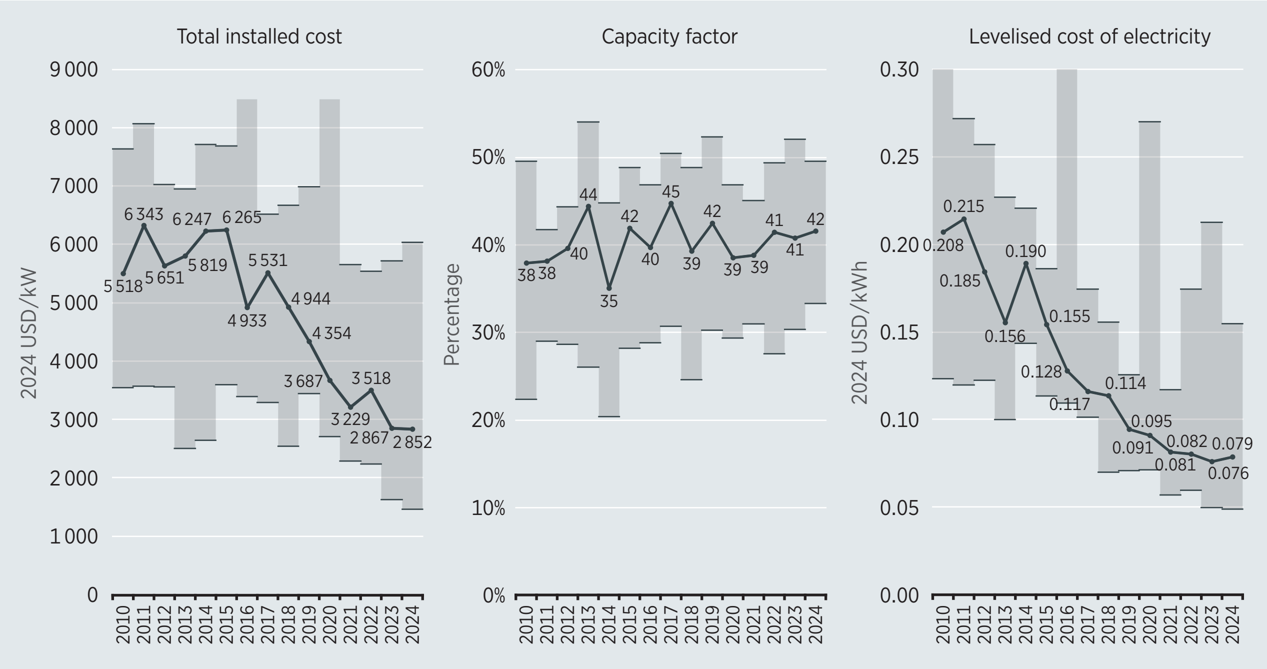
HIGHLIGHTS[36]

- Between 2010 and 2024, the global weighted average LCOE of offshore wind declined by 62%, from USD 0.208/kWh to USD 0.079/kWh. In 2024, the global weighted average LCOE increased by 4%, year-on-year, after a record low of USD 0.076/kWh in 2023. This increase was driven in part by shifts in market share.
- Between 2010 and 2024, the global cumulative installed capacity of offshore wind rose from 3.1 GW to 82.9 GW, a more than twenty-five-fold increase. In 2024, the global cumulative installed capacity of offshore wind increased by 8.6 GW, year-on-year.
- The global weighted average capacity factor of offshore wind increased from 38% in 2010 to 42% in 2024. Driving this were improvements in technology – such as larger turbines with longer blades and higher hub heights – and access to better wind resources.
- Between 2010 and 2024, global weighted average total installed costs fell 48%, from USD 5 518/kW to USD 2 852/kW. Notably, between 2023 and 2024, installed costs remained largely stable.
- In Europe, between 2023 and 2024, the weighted average LCOE of newly-commissioned projects increased 23%, from USD 0.065/kWh to USD 0.080/kWh. In 2024, total installed costs increased 12%, year-on-year, while the weighted average capacity factor of new projects decreased from 49% to 48%.
- In China, between 2023 and 2024, the weighted average LCOE of newly-commissioned projects dropped from USD 0.072/kWh to USD 0.056/kWh – a decline of 22%. In 2024, total installed costs fell 37%, year-on-year, while the weighted average capacity factor of new projects stayed at 37%.

Figure 4.1 Global weighted average and range of total installed costs, capacity factors and LCOE for offshore wind, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

[36] *Given the limited number of operational floating projects to date, this chapter has focused on fixed-bottom offshore wind developments.*

INTRODUCTION

Offshore wind technology has matured rapidly since 2010, achieving significant progress in innovation, cost reduction and geographical diversification. At the end of 2024, total global offshore wind capacity was 82.9 GW[37] (IRENA, 2025d), although new capacity additions were down 26%, year-on-year, to 8.6 GW. With 11.6 GW of new capacity commissioned in 2023, however, that year had been the second-highest on record for new offshore wind installations. The slowdown likely reflects a temporary dip influenced by macroeconomic and logistical challenges, rather than a reversal of long-term growth momentum.

In 2024, China spent another consecutive year as the global leader in annual offshore wind additions, contributing to Asia's continued lead in global growth, followed by Europe.

Recently, offshore wind has faced challenges due to inflation, interest rate volatility and persistent supply chain disruptions. These factors contributed to delays and cancellations in several key markets – including, in particular, the United States and parts of Europe (IEA, 2024c). Despite these challenges, however, offshore wind is now entering a new phase of global expansion. Beyond the established markets in Europe, China and the United States, a new wave of countries – particularly in Other Asia, Oceania, emerging Europe, Africa and South America – is beginning to adopt offshore wind as a key solution for clean energy generation and sustainable economic development (GWEC, 2025a).

Offshore wind auctions reached an all-time high in 2024, with 56.3 GW of capacity awarded worldwide (GWEC, 2025a). Of this total, 38.9 GW were allocated through competitive auctions and 17.4 GW granted in China under its grid-parity mechanism. Europe led global activity in auctions in 2024, with seven countries of the region offering support to at least 23.3 GW of offshore wind and awarding 85% of that capacity (WindEurope, 2025). The United States awarded 8.4 GW and South Korea 3.3 GW. Japan is also advancing in the sector, having selected 1.8 GW. Floating offshore wind gained momentum too, with a total of 1.9 GW awarded globally (GWEC, 2025a).

As offshore wind markets evolve, auction mechanisms are being reformed to address emerging challenges. These include rising capital costs, inflation, permitting delays and supply chain constraints. At the same time, established markets are beginning to show reduced levels of tender oversubscription, in contrast to newer entrants. This underscores the importance of well-designed auction frameworks, effective risk-sharing mechanisms and the availability of long-term contracts. A notable shift is also underway toward incorporating non-price criteria, such as local content and sustainability factors, into auction evaluations (Gasperin and Emden, 2024). Policy responses include higher price ceilings in the United Kingdom (GOVUK, 2023), along with auction design reviews in Denmark, Norway and Lithuania. These reviews followed recent tender failures. In Denmark, the auction redesign includes a stronger exposure to market signals through a capability-based, contract-for-difference model. This reflects potential production as a reference volume (ENTSO-E, 2024; KEFM, 2025).

[37] The cumulative installed capacity is largely bottom-fixed technology. At the end of 2024, a total of around 278 MW net floating wind was installed globally (GWEC, 2025b).

While recent challenges have tested the industry's resilience, they have also accelerated innovation, policy reform and strategic planning. With momentum building across emerging and established markets, technology will be the driving force behind unlocking new frontiers and delivering offshore wind's full potential.

TECHNOLOGICAL TRENDS

Technological advances continue to underpin the growth and competitiveness of the offshore wind sector. Original Equipment Manufacturers (OEMs) are rapidly scaling up turbine capacities, enabling greater energy yields and improved cost-efficiencies. In parallel, the development of next-generation installation vessels and the adoption of more efficient construction and maintenance practices are also enhancing deployment.

Floating offshore wind is progressing toward commercialisation by the end of this decade, unlocking access to deeper waters and expanding the geographical potential of the technology (GWEC, 2024). In 2024, Europe awarded 1.2 GW of capacity for floating offshore wind energy projects – 750 MW in France and 400 MW in the United Kingdom. This represented the technology's first large scale developments, with these expected to be online in the early 2030s (WindEurope, 2025).

The trend towards higher capacity turbines with taller hub heights and longer, more efficient and durable blades is evident across global markets. In China, OEMs have accelerated innovation, with 16 MW offshore turbines deployed. Notably, in 2024, Dongfang Electric unveiled a 26 MW offshore turbine – the world's largest to date (Dongfang Electric, 2024). In Europe, the first 20 MW+ prototypes are currently being tested.

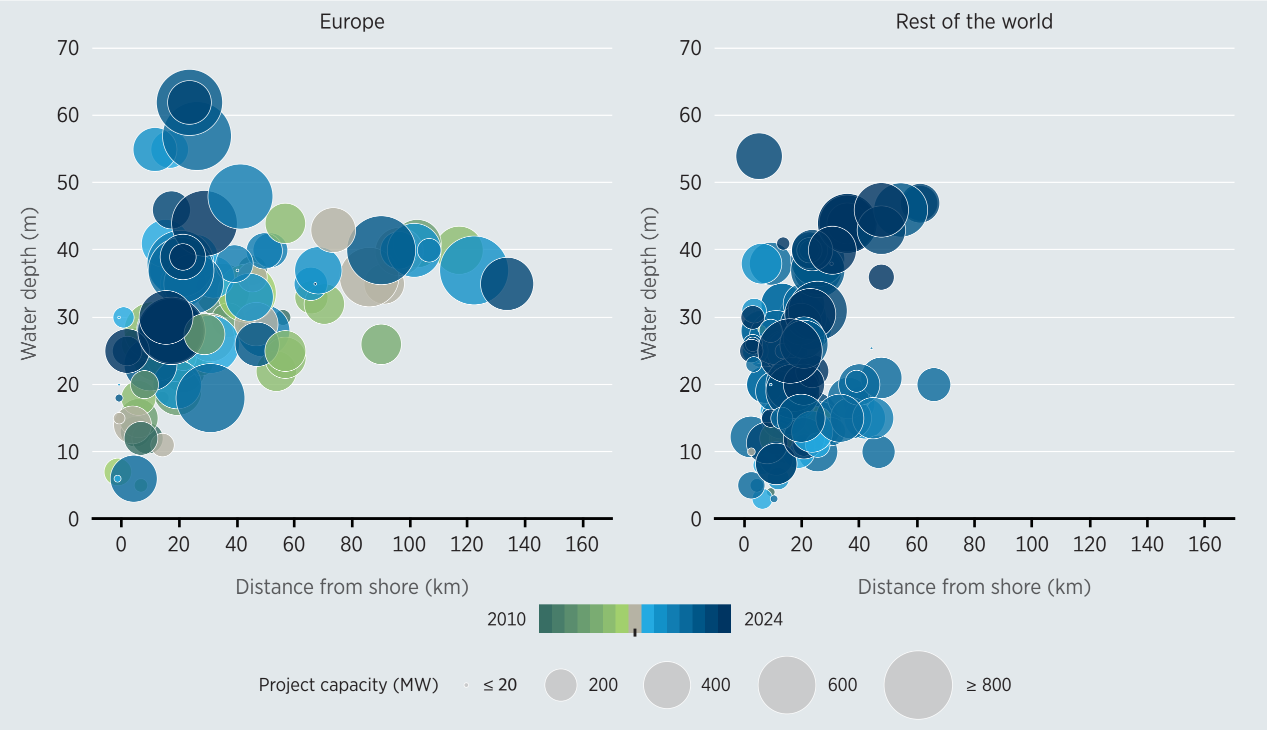
This trend of scaling up requires systemic upgrades across the supply chain. Increases in the size of components require new generations of installation vessels, larger foundations and enhanced port infrastructure. In 2024, several new factories were commissioned with this in mind, while existing ones were expanded to accommodate larger-sized production. One of the most critical developments was the ramp-up in delivery of next-generation jack-up vessels, nine of which are scheduled for completion in 2025 (Wood Mackenzie, 2025i).

There has also been widespread adoption of other cost optimisation strategies. These include the standardisation of turbine and foundation designs, the industrialisation of component manufacturing in regional supply hubs, and continuous improvements in installation practices. Operational performance has improved using dedicated service operation vessels (SOVs) that can manage multiple wind farms simultaneously, creating significant economies of scale.

Offshore wind project costs are shaped by logistical challenges, particularly water depth and the distance from shore. Greater distances extend transit times for installing turbines and foundations, while deeper waters require more complex foundations, depending on site conditions. These factors also impact long-term operations, vessel needs and decommissioning strategies, making efficient logistics critical throughout the project lifecycle.

Figure 4.2 presents trends in distance-to-port and water depth between 2010 and 2024 in Europe and the rest of the world. The trend towards deeper waters and sites farther from shore is most pronounced in Europe – the most mature market for offshore wind. Projects in this region are typically located in waters 18 metres (m) to 57 m in depth, with an increasing proportion sited between 65 kilometres (km) and 130 km from shore. Most projects in the rest of the world remain within 25 km of shore, however, with some located between 30 km and 67 km out. Almost all are located in waters shallower than 50 m. Efforts are underway in China to develop larger wind farms, however, with these located 50 km to 100 km offshore. Yet, along China's coast, more distant locations have deeper ocean floors, presenting new challenges and opportunities for foundation research and design in harsher marine environments (Zhang and Wang, 2022).

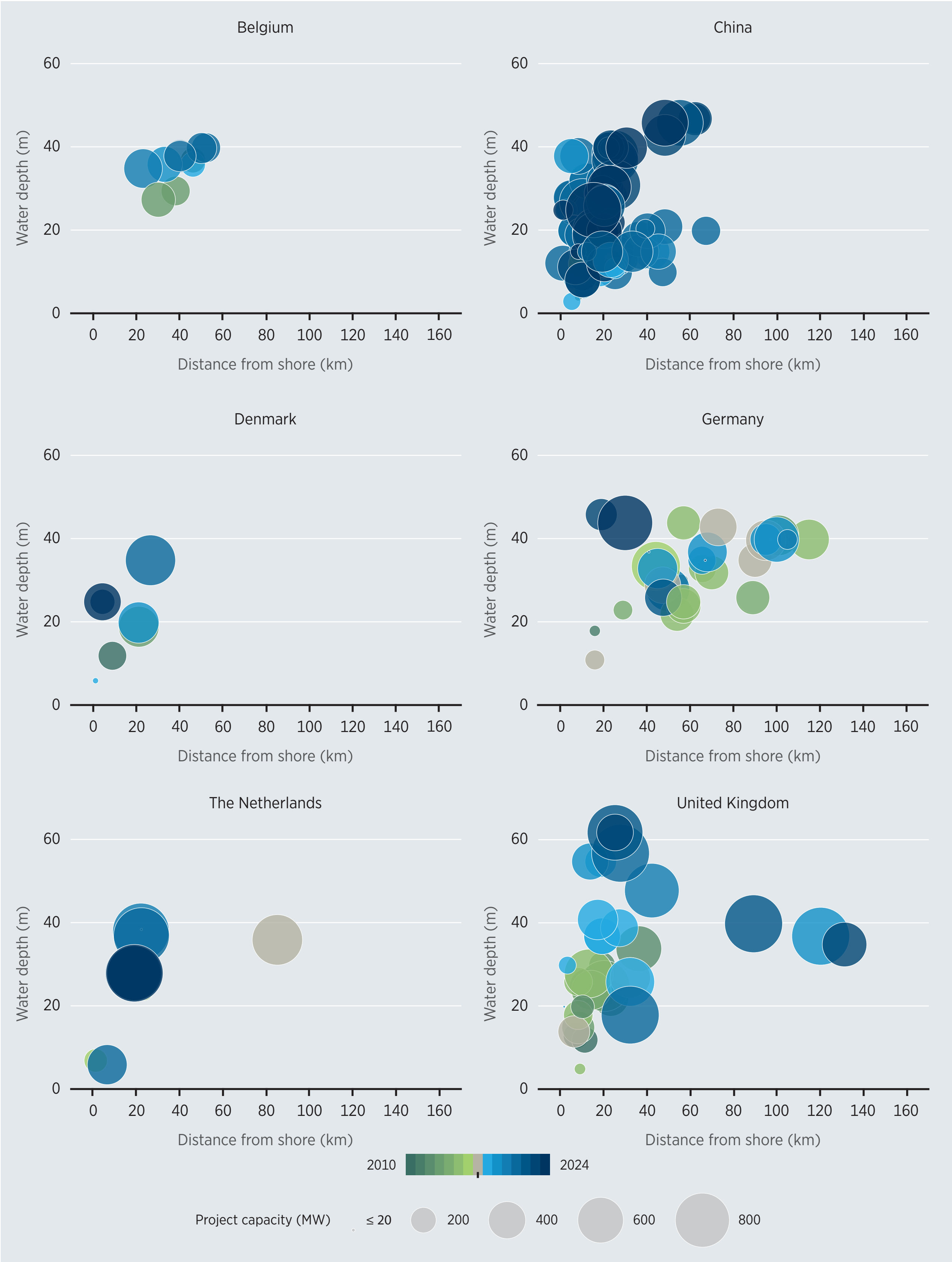
Figure 4.2 Average distance from shore and water depth for offshore wind in Europe and the rest of the world, 2010–2024



Source: (Wood Mackenzie, 2025j).
Notes: km = kilometre; m = metre; MW = megawatt.

Figure 4.3 highlights at the country level the varying trends in water depth and distance from shore for China, Belgium, the Netherlands, Germany, Denmark and the United Kingdom. In addition, the bubble sizes indicate increasing project capacities over time. This illustrates a noticeable shift toward larger-scale installations in most countries by 2024, particularly in China. Meanwhile, Germany and the United Kingdom have developed projects located more than 100 km from shore. In contrast, China, Belgium, the Netherlands and Denmark have concentrated their offshore wind development closer to shore, generally within 80 km. Compared to other countries, the United Kingdom has a higher number of offshore wind projects deployed at water depths greater than 40 m. Germany and Belgium tend to concentrate their projects at depths of between 20 m and 40 m, while China, Denmark and the Netherlands show a broader distribution across depth ranges.

Figure 4.3 Distance from shore and water depth for offshore wind projects by country, 2010–2024



Source: (Wood Mackenzie, 2025j).

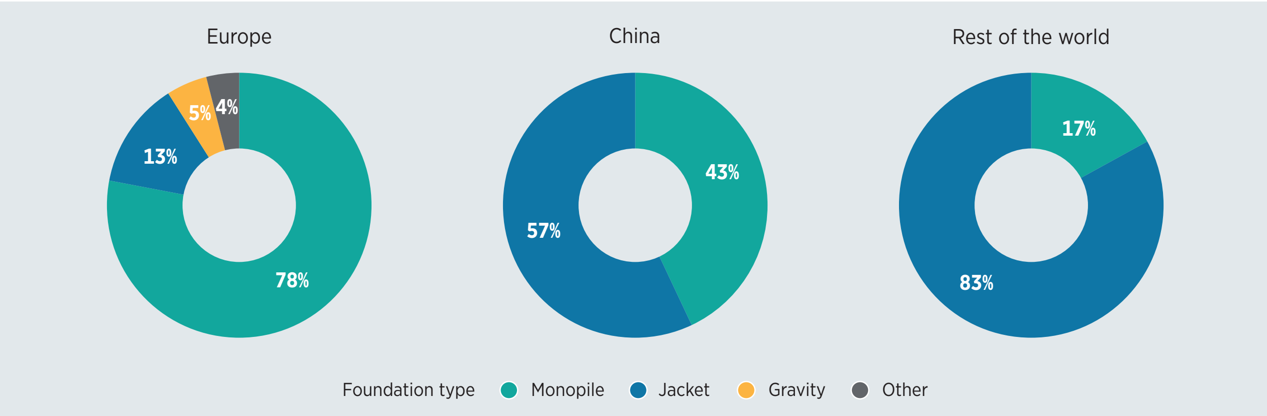
Notes: km = kilometre; m = metre; MW = megawatt.

Water depth and distance from shore are determined by a range of site-specific factors. These characteristics are influenced not only by resource potential and technical feasibility, but also by seabed conditions, maritime jurisdictional boundaries, environmental restrictions (including protected areas), and spatial competition with other marine activities, such as commercial shipping and fisheries.

For 2024, Figure 4.4 illustrates the distribution of bottom-fixed offshore wind foundation types across China, Europe and other global markets, based on installed capacity. The figure uses data for the projects where the IRENA renewable costs database has this information.[38] The choice of foundation is primarily influenced by factors such as water depth, seabed conditions and dynamic environmental loads.

In China, jacket foundations accounted for 57% of installed capacity, reflecting their suitability for deeper waters and complex seabed conditions (Du *et al.*, 2023). In Europe, monopiles represented 78% of installed capacity, jackets accounted for 13% and gravity-based foundations made up 5%, primarily in France. In other markets, jackets dominated, representing 83% of installed capacity. These regional differences highlight the importance of adapting foundation solutions to local marine environments.

Figure 4.4 Offshore wind foundation types in Europe, China and the rest of the world, 2024



Based on: (Wood Mackenzie, 2025j) and inputs from WindEurope.

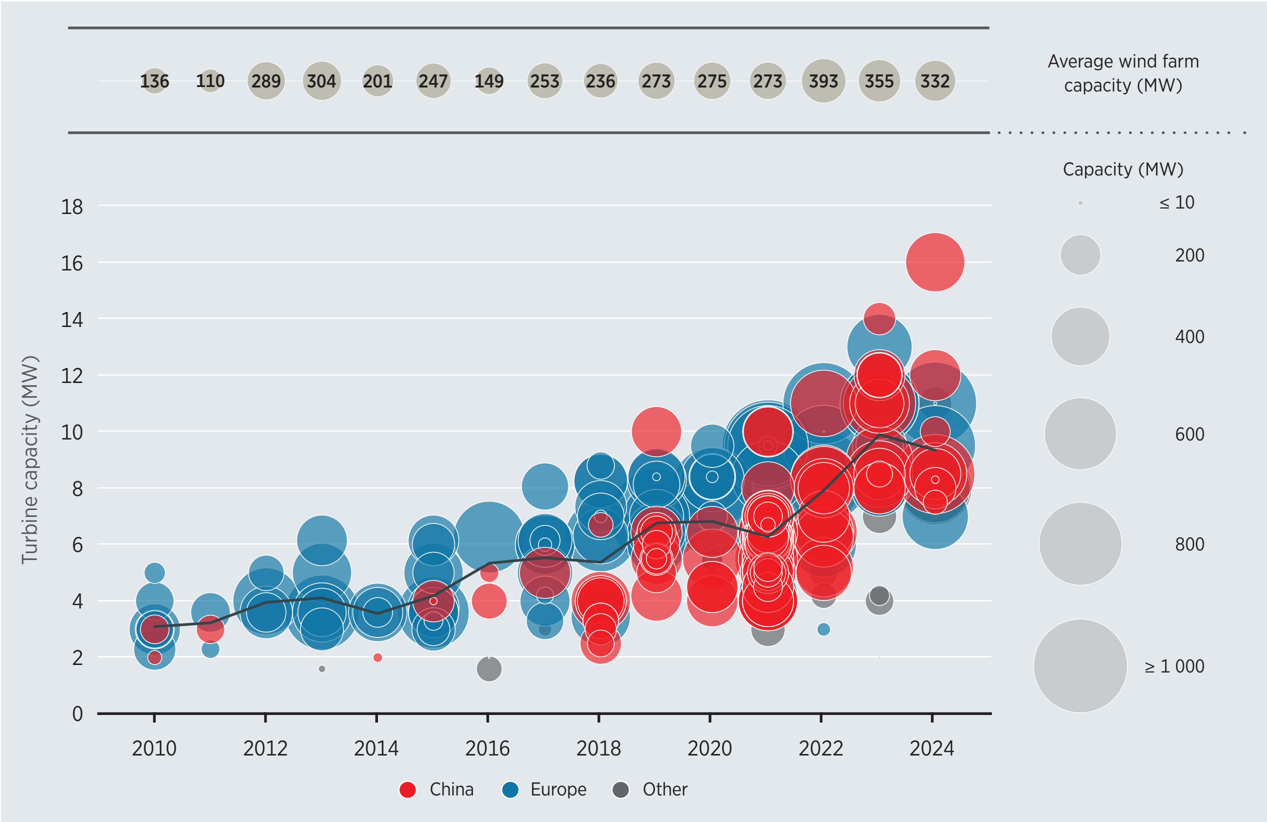
Offshore wind's potential is evident in the significant progress achieved in recent years through the scaling up of turbine sizes (Figure 4.5). The global weighted average turbine size rose from 3 MW in 2010 to 9.3 MW in 2024. In 2024, the average slightly decreased due to the deployment of several large-scale projects in Asia that utilise turbines in the 8 MW to 10 MW range. Nevertheless, technological progress continued, marked by the installation of the world's largest turbine to date – the 16 MW unit in China.

Between 2010 and 2024, the average offshore wind project size increased by 144%, from 136 MW to 332 MW (Figure 4.5). Although, with some exceptions, the average project size remained relatively stable between 2010 and 2021, since 2022 the average project size has consistently exceeded 300 MW, while several projects have reached capacities surpassing 1 GW.

[38] *The data presented in this figure does not represent offshore wind total installed capacity in each region or country. It reflects only installations for which foundation type information was available in 2024.*

In 2024, each of the regions analysed deployed at least one offshore wind project larger than 700 MW. This highlighted how a single development can contribute substantially to national wind capacity additions. Germany, for example, commissioned 742 MW of offshore wind capacity from a single project in 2024, with this representing nearly one-third of its total onshore wind deployment that year.

Figure 4.5 Project and global weighted average total installed costs for offshore wind, 2010-2024.



Source: (Wood Mackenzie, 2025j).
Note: MW = megawatt.

Table 4.1 presents the average characteristics of offshore wind farms in China and Europe in 2010 and 2024, based on the IRENA renewable costs database. The values refer specifically to those two years and do not necessarily represent the highest levels recorded during the period. As can be seen in Figure 4.5, for example, average turbine size was higher in 2023.

Offshore wind farms have evolved notably in terms of scale and site characteristics. In Europe, projects commissioned in 2010 had an average capacity of 155 MW, compared to 415 MW in 2024. Average water depth increased from 21 m to 38 m over the same period, while the average distance to shore remained around 20 km. In China, the average project size grew from 67 MW in 2010 to 339 MW in 2024. Over the same period, average water depth increased from 9 m to 29 m, while distance to shore doubled from 12 km to 24 km.

Turbine design has also advanced significantly, particularly in rotor diameters. Globally, the weighted average rotor diameter of turbines installed in offshore projects increased from 112 m in 2010 to 201 m in 2024, representing 79% growth. In 2024, the average rotor diameter reached 177 m in Europe and 235 m in China, reflecting a growing emphasis on high-capacity turbine designs.

Table 4.1 Project characteristics in China and Europe in 2010 and 2024

The average offshore wind farm in China and Europe		2010	2024
Project size (MW)	China	67	339
	Europe	155	415
Distance from shore (km)	China	12	24
	Europe	18	20
Water depth (m)	China	9	29
	Europe	21	38
Hub height (m)	China	80	138
	Europe	83	114
Rotor diameter (m)	China	90	235
	Europe	112	177
Nameplate capacity (MW)	China	2.8	10.1
	Europe	3.1	9.2

Based on: (Wood Mackenzie, 2025j; and inputs from WindEurope and GWEC).

The difference in rotor diameter between China and Europe is primarily attributed to the variance in wind speeds. This distinction arises from the fact that the weighted average wind speed of projects in the IRENA renewable costs database for China is lower than that for Europe.

Regarding other technological trends, digitisation is playing an increasingly central role in offshore wind development and operations. Advanced data analytics and AI are improving asset management, from predictive maintenance to supply chain optimisation. In Germany, AI-driven drone systems are being piloted to autonomously inspect turbine blades, reducing reliance on crewed vessels. This lowers maintenance costs and minimises turbine downtime (Vattenfall, 2025). In the Netherlands, the deployment of real-time wave prediction systems is helping vessel crews optimise schedules and safely navigate challenging sea conditions (Next Ocean, 2025; TRIMIS, 2018).

Environmental integration measures are also emerging as a critical technological consideration. The inclusion of nature-inclusive design (NID) features is intended to support marine biodiversity around offshore wind installations, reduce ecological impact and co-benefit local ecosystems. NID includes items such as fish shelters, reef structures and seabed restoration zones (Ørsted, 2024).

Collectively, these innovations demonstrate how technology is driving the next phase of offshore wind by enhancing system performance, reducing costs and promoting greater environmental stewardship.

TOTAL INSTALLED COSTS

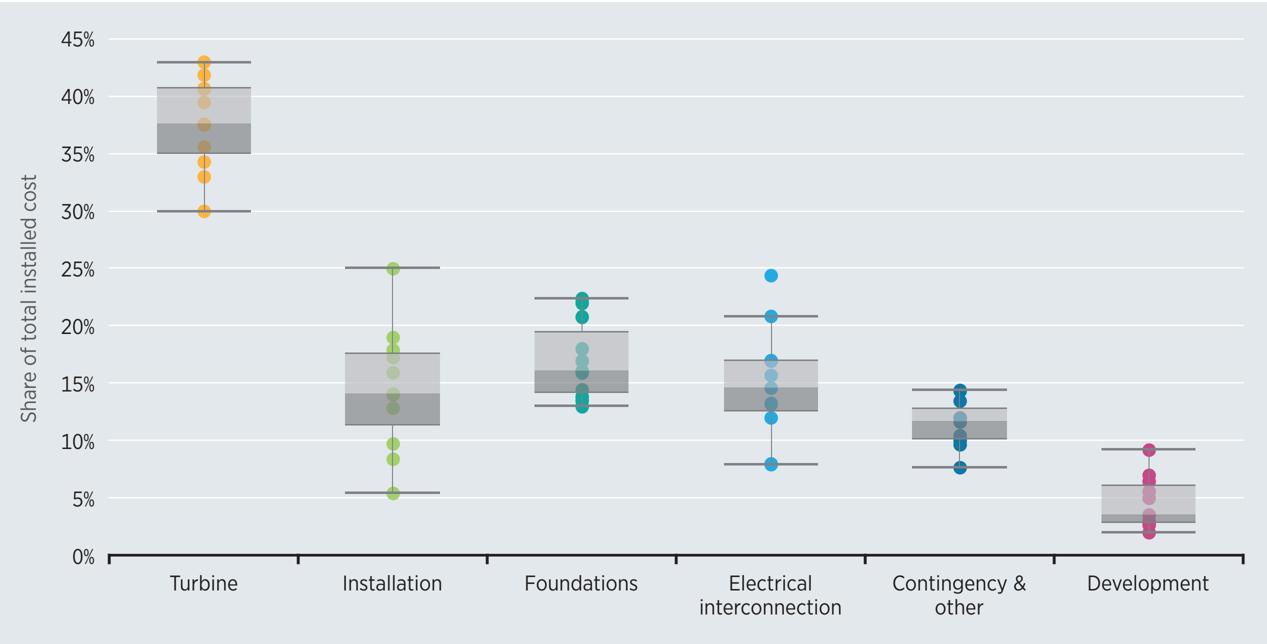
Offshore wind's expanding role in power generation has brought greater focus on its total installed costs. Typically higher than for onshore wind, these reflect the unique requirements of building in a harsher environment. Site assessments must account for complex seabed conditions and weather patterns, while permitting processes can be more extensive. Logistical considerations, such as distance from ports and water depth, add complexity to construction, grid connection, commissioning and ongoing operations and maintenance (O&M), all of which contribute to higher planning and development costs.

Yet despite these factors, offshore wind delivers substantial benefits. Larger turbines, higher capacity factors and economies of scale help reduce the cost per unit of energy over time. Technological advances, standardisation and more efficient construction and maintenance strategies are also steadily driving down costs.

As the offshore wind sector continues to scale up, understanding its cost structure becomes increasingly important. Project-level total installed cost breakdowns are challenging to obtain, however, due to confidentiality constraints; yet numerous studies do provide estimates for specific markets. These are often derived from consultations with project developers, although it is sometimes unclear exactly how comparable the data are.

Figure 4.6 presents an analysis of total installed cost in six categories: turbine, electrical interconnection, foundation, installation, contingency/other and development. These are based on a sample of studies across different markets.

Figure 4.6 Comparative breakdown of offshore wind total installed cost from selected market studies



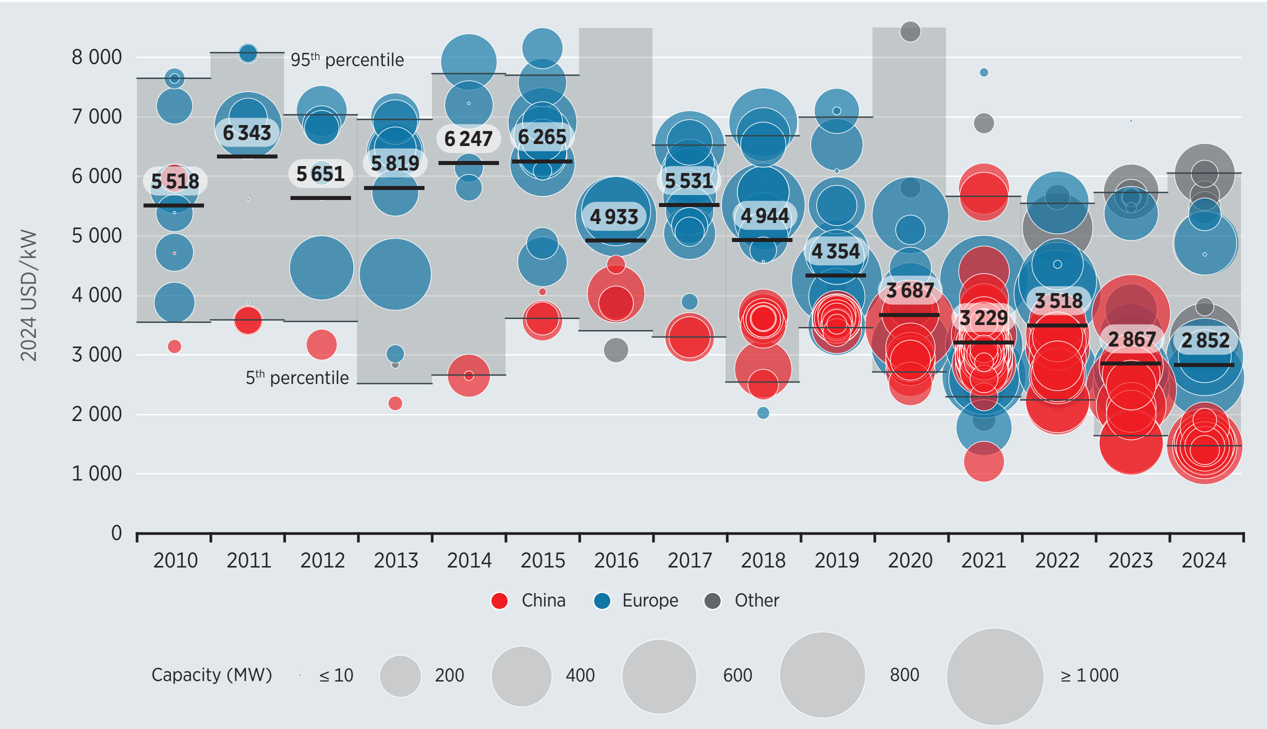
Sources: (Alsubal *et al.*, 2021; IRENA, 2016; Lacal-Arántegui *et al.*, 2018; MAKE Consulting, 2016; Musial, 2018; Noonan *et al.*, 2018; ORE Catapult, 2019; Smart *et al.*, 2016; Stehly *et al.*, 2020).

Offshore wind turbines (including towers) generally account for between 30% and 43% of the total installed cost (Figure 4.6). Electrical interconnection accounts for between 8% and 24% and foundation costs range between 13% and 22%. Installation costs range from 5% to 25% of total installed costs, while contingency/other costs range between 8% and 14%. Development costs – which include planning, project management, insurance during construction (when data is available) and other administrative costs – comprise between 2% and 9% of total installed costs.

Another factor influencing the total installed costs is the nature of the party responsible for the wind farm-to-shore transmission asset. This responsibility varies by country. In some cases, transmission assets are owned by the national or regional transmission network operator, while in other cases, they are owned by the wind farm developer. Grid connection assets in China, for example, are developed by project owners or the transmission network owner, while in Denmark and the Netherlands they are developed and owned by the network operator. It is therefore important to look at total installed cost trends on a country-by-country basis in order to understand how cost structures are evolving.

For 2010–2024, Figure 4.7 illustrates trends in global weighted average total installed cost for offshore wind projects. These costs decreased significantly over the period, from USD 5 518/kW to USD 2 852/kW. Between 2023 and 2024, costs remained relatively stable, however. This was partly because many of the projects commissioned in 2024 were continuations of projects developed in 2023 and were implemented at similar price levels. Additionally, the global average reflects a balance between lower-cost installations in China and higher-cost projects in emerging offshore wind markets. The differences between countries reflect market maturity and the scale of the local or regional supply chain. Each year's deployment is also distributed slightly differently across markets, adding to the annual volatility.

Figure 4.7 Project and global weighted average total installed costs for offshore wind, 2010–2024



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

All regions and countries listed in Table 4.2 experienced a decrease in their weighted average total installed costs between 2010 and 2024. Germany had the highest percentage decrease – 61% – with costs falling from USD 7 655/kW to USD 3 000/kW. Some emerging markets reported relatively higher costs than those, however. In France, for example, the weighted average for 2024 was USD 4 991/kW. These elevated figures may decline as supply chains strengthen, however.

Asia's regional average, largely influenced by China's extensive and competitive offshore wind sector, remains lower than Europe's, underscoring the cost advantages gained through larger project pipelines and growing industrial capacity.

Table 4.2 Regional and country weighted average total installed costs and ranges for offshore wind, 2010 and 2024

	2010			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kW)					
Asia	3 386	**5 316**	5 952	1 449	**2 467**	6 052
China	3 307	**5 268**	5 852	1 434	**1 520**	1 869
Japan	5 808	**5 808**	5 808	5 684	**5 684**	5 684
Europe	4 183	**5 547**	7 655	2 713	**3 389**	5 250
Denmark	3 888	**3 888**	3 888	2 987	**2 987**	2 987
France	n.a.	**n.a.**	n.a.	4 911	**4 991**	5 347
Germany	7 655	**7 655**	7 655	3 061	**3 000**	4 611
The Netherlands*	4 883	**4 883**	4 883	2 626	**2 626**	2 626
United Kingdom**	4 799	**5 399**	5 761	3 362	**3 514**	3 743

Notes: * Countries where data were only available for projects commissioned in 2015, not 2010; ** countries where data were only available for projects commissioned in 2023, not 2024; see Annex III for regional country groupings; n.a. = not available.

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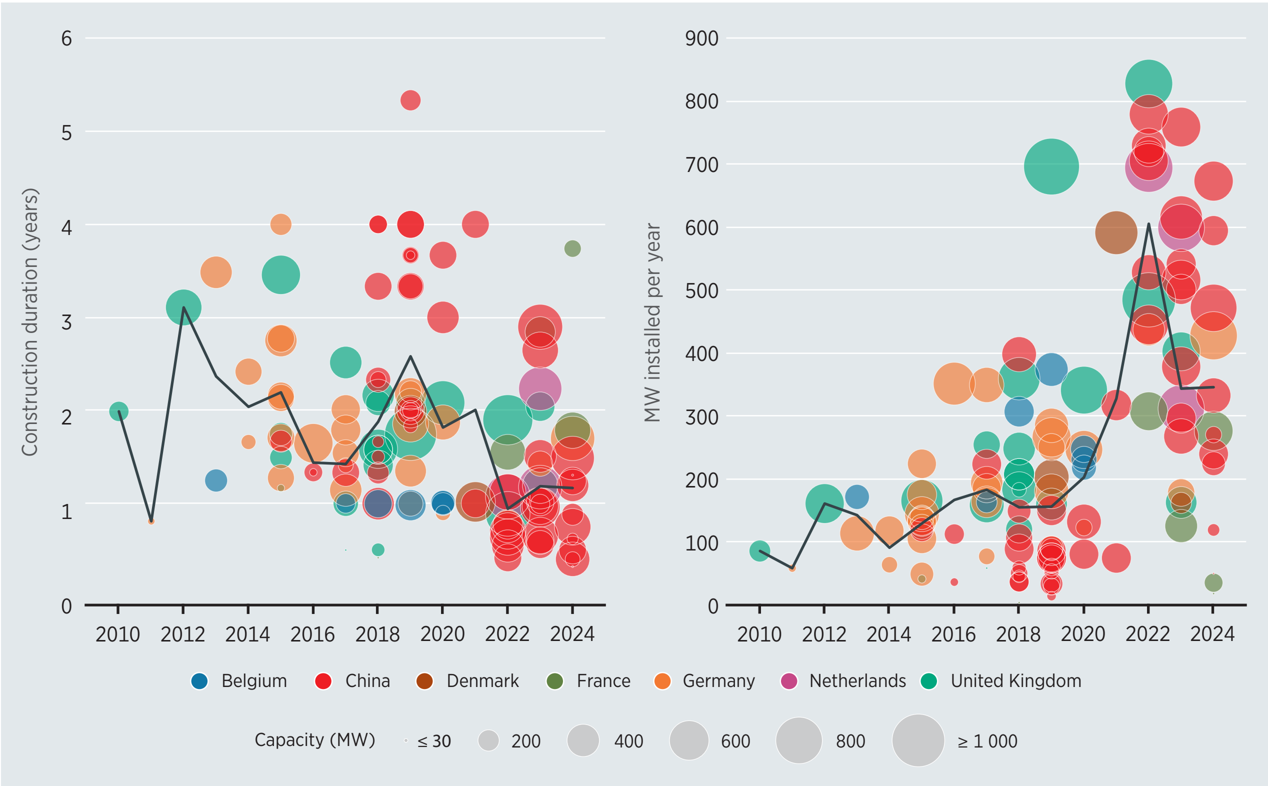
For offshore wind projects commissioned between 2010 and 2024, Figure 4.8 illustrates the duration of construction and annual installation rates. The figure is based on project-level data. This dual perspective offers insights into how project timelines and installation efficiency have evolved over time across different markets.

Over the period, installation times for projects have fallen. This is because of the wider availability of larger, dedicated installation vessels, the employment of larger turbines and the experience gained. From an average of two or more years per wind farm between 2010 and 2015, by 2020, the installation time had fallen to less than 18 months. In 2024, the average duration of construction was around 16 months. Projects in China tend to have shorter construction periods, reflecting the maturity and efficiency of the domestic supply chain.

From 2010 to 2020, the MW installed per year by project increased from 100 MW to 200 MW. A significant development has therefore occurred since 2020, with projects now routinely exceeding 300 MW per year.

Figure 4.8 Installation time and MW installed per year by offshore wind projects in Europe and Asia, 2010–2024



Note: MW = megawatt.

CAPACITY FACTORS

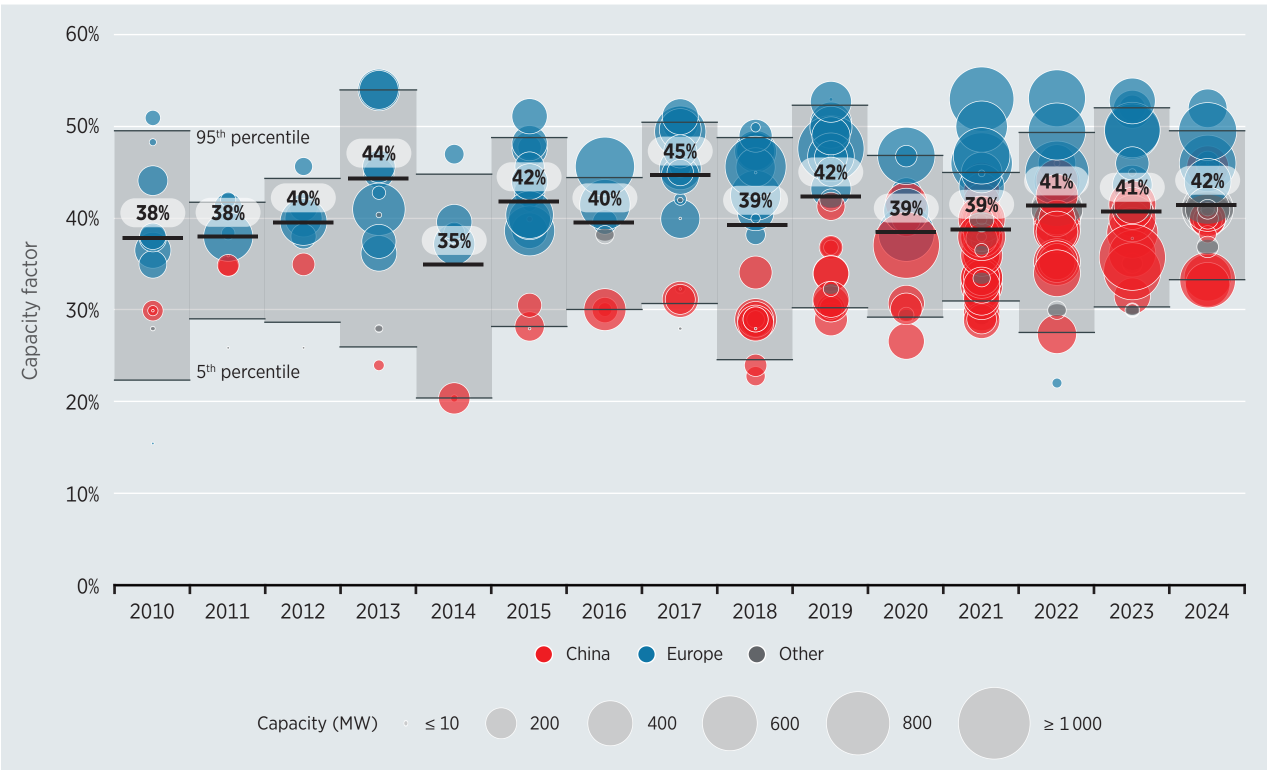
Offshore wind farms exhibit a wide range of capacity factors, influenced by several key elements. These include: atmospheric boundary layer conditions; local meteorology patters; the technology deployed; and the wind farm's configuration. The latter point describes the optimal turbine spacing to minimise wake losses and increase energy yields.

In addition, the optimisation of the O&M strategy over the life of the project is an important element in achieving higher capacity factors. Furthermore, offshore sites typically experience more stable wind conditions than onshore wind, with this characterised by higher average wind speeds and reduced wind shear and turbulence. This also leads to increased capacity factors for offshore. Indeed, as turbine technology continues to advance and project designs become more refined, offshore wind is positioned to deliver increasingly consistent and competitive energy output.

Between 2010 and 2024, the global weighted average capacity factor of newly commissioned offshore wind farms increased from 38% to 42% (Figure 4.9). In 2024, the capacity factor range – the 5th and 95th percentiles – for newly installed projects was between 33% and 50%.

Declines in the global weighted average capacity factor since 2017 have primarily been the result of shifts in the regional composition of offshore wind deployment. Most notably, they have resulted from the growing contribution made by markets with comparatively low wind yields, such as China. Indeed, over the past five years, China has accounted for more than a third of annual offshore capacity additions.

Figure 4.9 Project and global weighted average capacity factors for offshore wind, 2010–2024

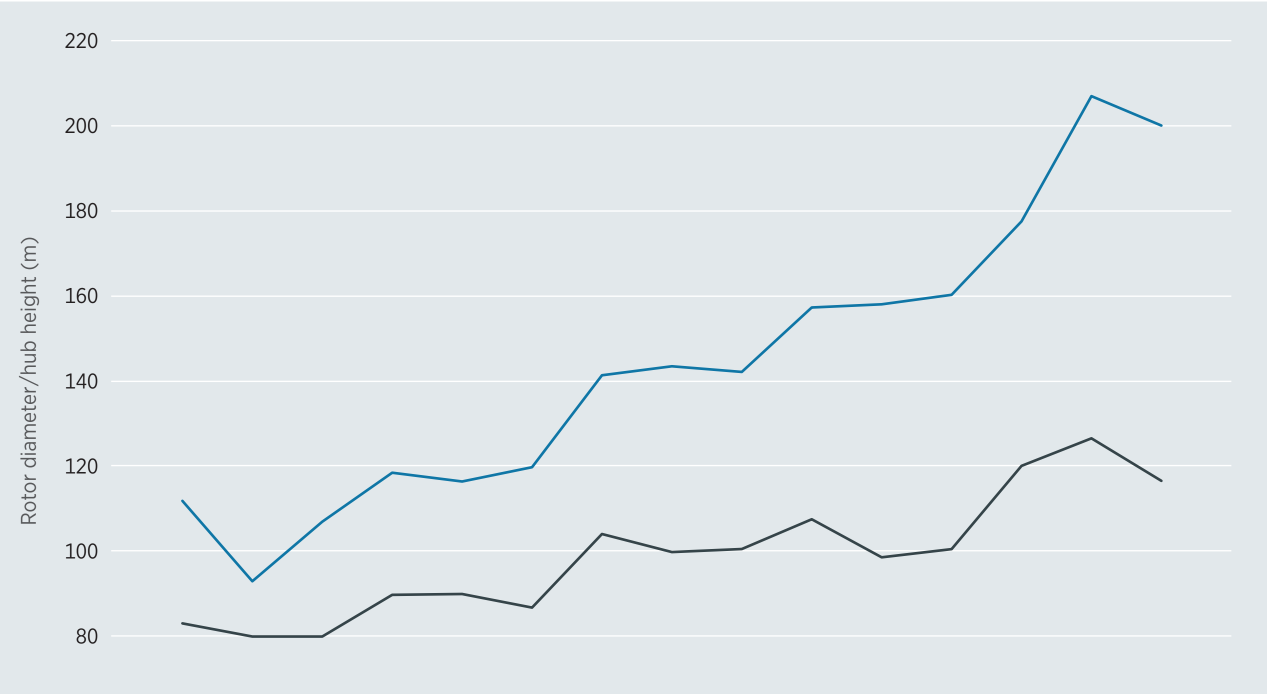


Note: MW = megawatt.

Between 2010 and 2024, the weighted average capacity factor for projects commissioned in Europe increased from 39% to 48%. In 2024, capacity factors in Europe ranged from 45% at the 5th percentile to 53% at the 95th percentile. In comparison, projects commissioned in China that year had a weighted average capacity factor of 37%, along with a lower range – stretching from 33% at the 5th percentile to 43% at the 95th percentile.

For the period 2010 to 2024, Figure 4.10 shows that offshore wind rotor diameters and hub heights followed a similar increasing trend. Over that time, the turbine rotor diameter experienced a 79% increase, growing from a weighted average value of 112 m to 200 m. Over the same period, turbine hub height grew by 41%, from a weighted average of 83 m to 117 m.

Figure 4.10 Global weighted average offshore wind turbine rotor diameter and hub height, 2010–2024



Source: (Wood Mackenzie, 2025j).
Note: m = metre.

Table 4.3 provides the weighted average capacity factor for offshore wind projects in selected countries, where data is available. For emerging markets, only the 2024 figures are included. Despite higher total installed costs in these markets than in more mature jurisdictions (as shown in Table 4.2), the capacity factors of these countries still fall within the upper range, highlighting the significant potential for low-cost electricity once these markets gain further expertise.

For all the countries presented in Table 4.3, except for Germany, there was an increase in the capacity factor. The greatest improvement in the period was in the United Kingdom, where there was a 44% increase. Germany trend during this period can be attributed to the already relatively high-capacity factor it had achieved in 2010, which was significantly above the country's peers. A similar trend is also evident in the Netherlands.

Table 4.3 Weighted average capacity factors for offshore wind projects in selected countries, 2010 and 2024

	2010	2024	Percentage change 2010-2024
	%		
China	30	37	↑ 23%
Denmark	44	52	↑ 18%
France	n.a	44	n.a.
Germany	50	46	↓ 8%
Japan	28	37	↑ 32%
The Netherlands*	48	49	↑ 2%
United Kingdom**	36	52	↑ 44%

Notes: * Countries where data were only available for projects commissioned in 2015, not 2010; ** countries where data were only available for projects commissioned in 2023, not 2024; see Annex III for regional country groupings; n.a. = not available.

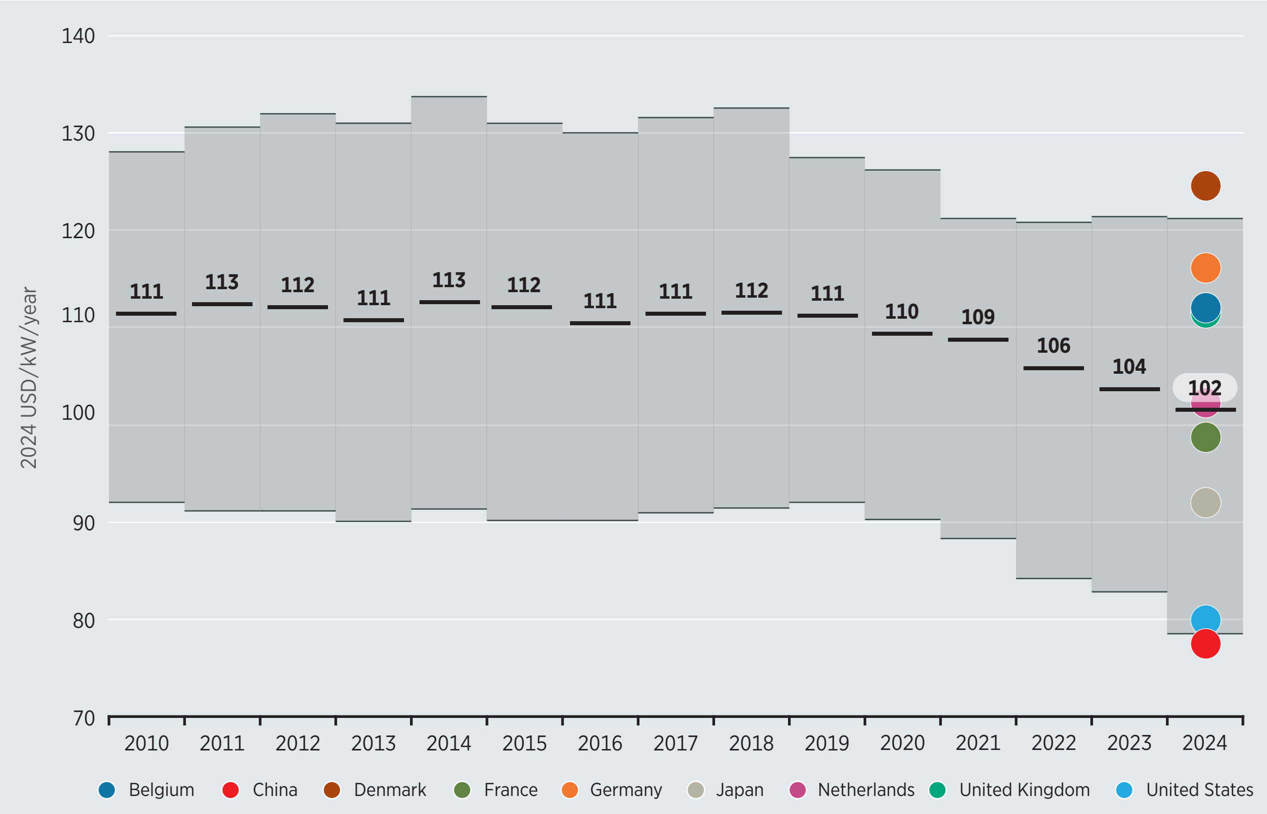
O&M COSTS

O&M costs play a critical role in determining the overall cost-effectiveness of offshore wind power. Compared to onshore wind, O&M costs per kW are higher in offshore projects, largely due to the challenges associated with cabling and accessing turbines in marine environments. Adverse weather conditions, the limited availability of skilled personnel and the need for specialised vessels and equipment are among the factors that compound these challenges.

As with onshore wind, reliable data on offshore wind O&M costs remain limited. Uncertainties persist, especially regarding long-term costs for projects located far from shore, where industry experience is still evolving. Nevertheless, O&M practices are continuously improving, contributing to downwards pressure on costs. Notably, O&M costs per kW have declined due to increased competition among service providers and improved project efficiency. In addition, the shift to higher turbine ratings has contributed to lower unit O&M costs by reducing the number of turbines needed per project (Lema *et al.*, 2024). An example of the O&M cost reduction impact from these factors comes from Ørsted. The company was able to reduce O&M costs by over 43% between 2015 and 2018. It achieved this through process optimisation and improved logistical solutions (Ørsted, 2018).

Figure 4.11 presents the average fixed O&M cost between 2010 and 2024 for selected countries, based on cumulative installed capacity data. Due to varying levels of deployment and data availability, only 2024 values are shown for each country. Over the period, the global weighted average fixed O&M cost declined from USD 111/kW per year in 2010 to USD 102/kW per year in 2024, reflecting increased operational experience and efficiency in the sector. In 2024, the 5th and 95th percentiles for fixed O&M costs across all countries were USD 76/kW per year and USD 121/kW per year, respectively. This wide range highlighted the influence of several market-specific factors. These included: the level of local optimisation in O&M practices; synergies gained from clustering offshore wind farms; and the chosen operational strategy following the expiration of the turbine OEM warranty.

Figure 4.11 Average fixed O&M costs for offshore wind in selected countries, 2010–2024



Source: (Wood Mackenzie, 2024c).
Notes: kW = kilowatt

O&M costs for offshore wind farms encompass a variety of activities, each contributing to total expenditure. Among these, turbine maintenance typically represents the largest share, accounting for around 60% of total O&M costs. This reflects the need to ensure optimal turbine performance over the project lifetime by regular servicing, repair work and component replacement. Operational support is the second largest cost, accounting for 19% of the total, while insurance costs contribute a further 11%. Balance of plant (BoP) maintenance – which includes marine operations, labour, spare parts, consumables, proactive and reactive O&M and offshore substation O&M – represents around 7%. The remaining 3% falls under “other costs”, which relate to contingencies and expenses associated with wind farm operation (Wood Mackenzie, 2024c). These proportions provide an insight into where cost-reduction strategies and technological improvements could be most impactful.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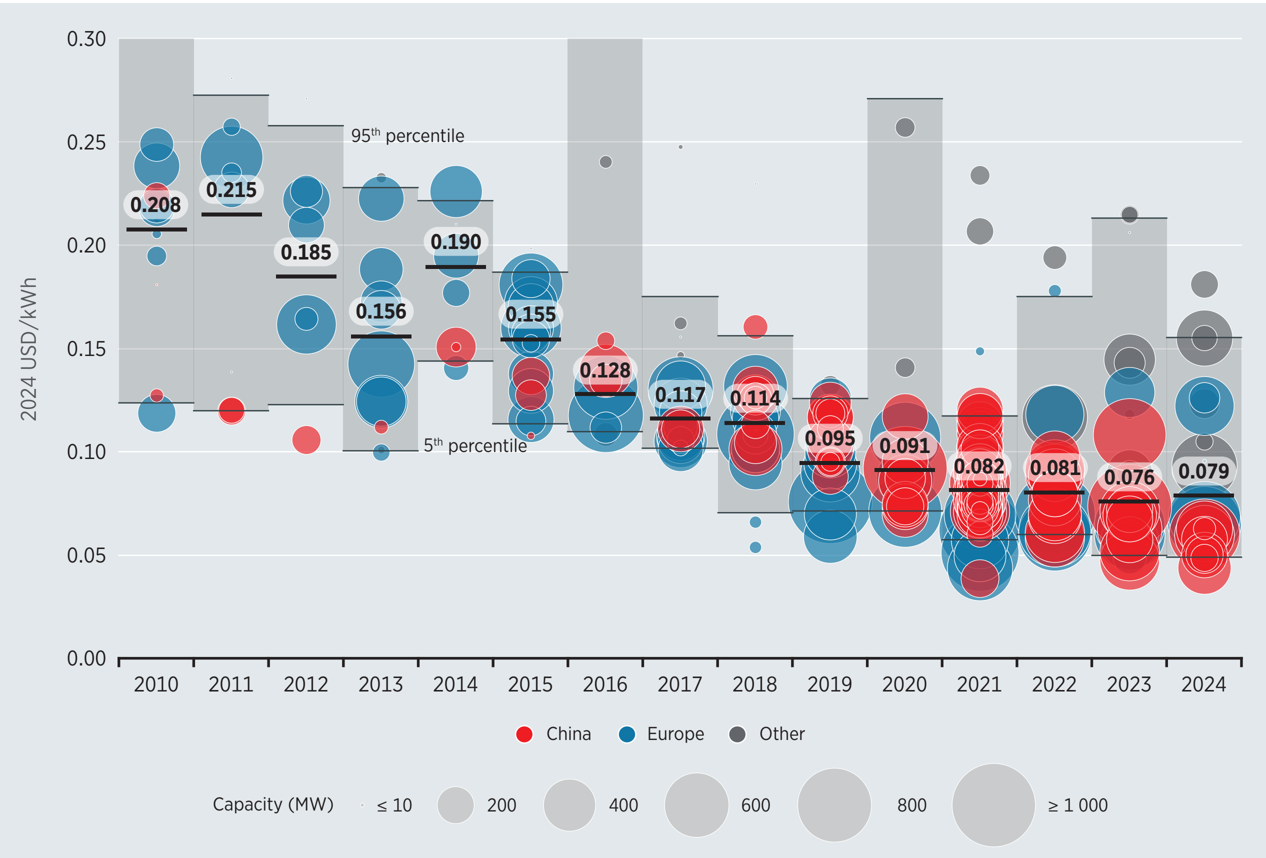
LCOE

Between 2010 and 2024, the global weighted average LCOE of offshore wind fell by 62%, from USD 0.208/kWh to USD 0.079/kWh (Figure 4.12). While this reflects substantial long-term progress, the 2024 figure marks a slight increase (4%) compared to the record low of USD 0.076/kWh achieved in 2023. For projects commissioned in 2024, the LCOE ranged between USD 0.049/kWh and USD 0.155/kWh (5th to 95th percentiles).

Market share plays a significant role in influencing the global weighted average LCOE, as the distribution of offshore wind deployments across different regions can impact overall costs. Between 2023 and 2024, Asia experienced a slight decrease in its weighted average LCOE. This fell by approximately 1.3%, from USD 0.079/kWh to USD 0.078/kWh. This was driven by continued cost reductions in China, although these were partially offset by the growing share of deployments taken by higher-cost markets. In contrast, Europe saw a pronounced increase in LCOE. In 2024, the LCOE in Europe rose by around 16%, year-on-year, from USD 0.069/kWh to USD 0.080/kWh.

Another driver influencing LCOE dynamics is the cost of capital. This is a critical factor for capital-intensive technologies like offshore wind. Even when total installed costs remain stable and capacity factors continued to improve, tighter financing conditions can significantly impact project economics. These changes highlight the outsized influence of financial variables on LCOE, underscoring the importance of stable and favourable investment environments in maintaining the downward trajectory of offshore wind costs.

Figure 4.12 Offshore wind project and global weighted average LCOE, 2010–2024



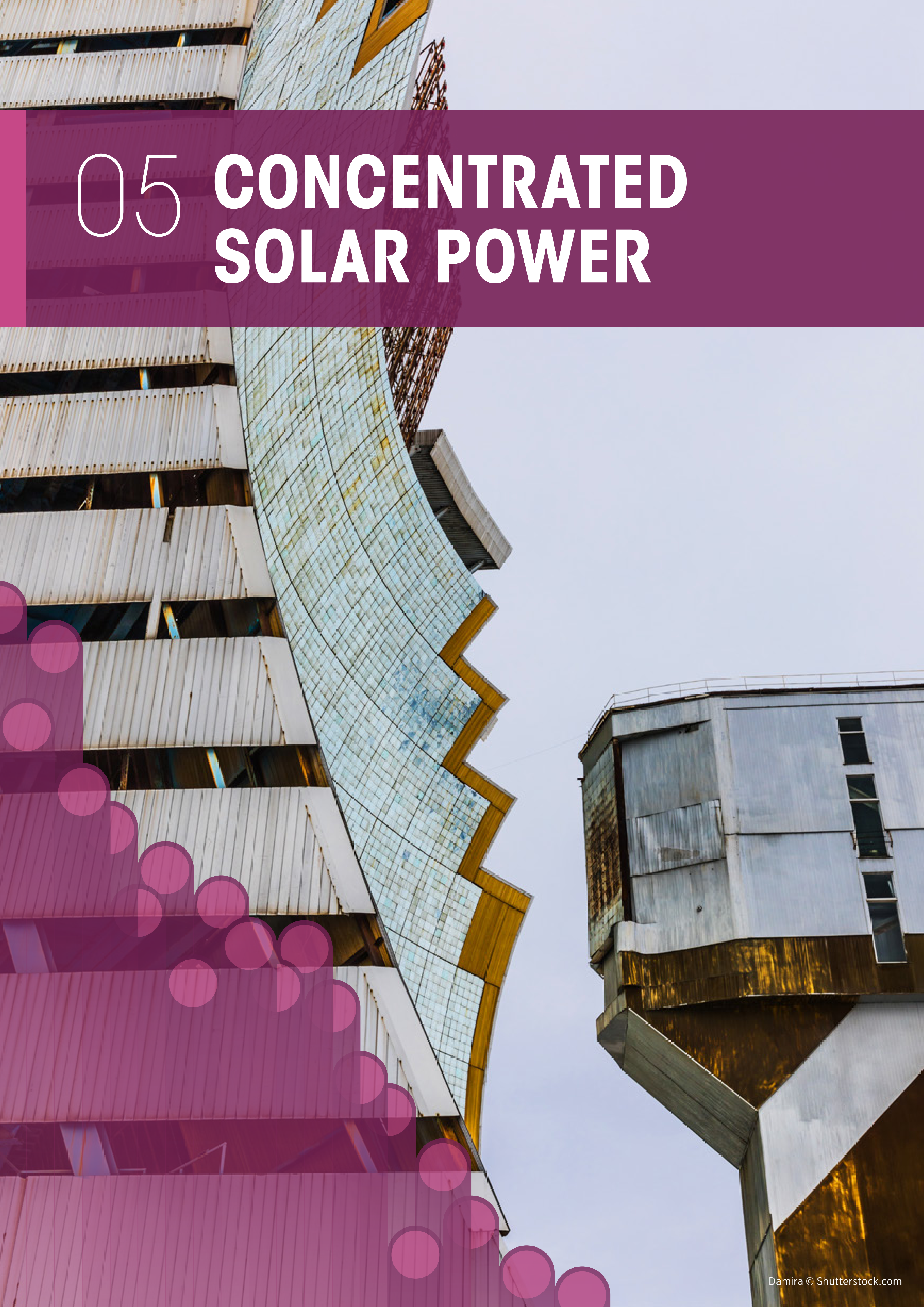
Notes: kWh = kilowatt; MW = megawatt; USD = United States dollar.

Table 4.4 presents the regional and country weighted average LCOE of offshore wind farms in Europe and Asia. Overall, Asia had a slightly lower weighted average LCOE, at USD 0.078/kWh, compared to Europe's USD 0.080/kWh. Within markets across regions, LCOE outcomes show notable contrasts. For example, in Europe, Denmark recorded the lowest weighed-average LCOE among countries for projects commissioned in 2024, at USD 0.053/kWh, while in France the weighted average LCOE was significantly higher, reaching USD 0.123/kWh

Table 4.4 Regional and country weighted-average LCOE for offshore wind, 2010 and 2024

	2010			2024		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2024 USD/kWh)					
Asia	0.135	**0.201**	0.222	0.047	**0.078**	0.164
China	0.133	**0.200**	0.220	0.046	**0.056**	0.063
Japan	0.212	**0.212**	0.212	0.181	**0.181**	0.181
Europe	0.142	**0.208**	0.246	0.056	**0.080**	0.125
Denmark	0.119	**0.119**	0.119	0.053	**0.053**	0.053
France	n.a.	**n.a.**	n.a.	0.123	**0.123**	0.126
Germany	0.195	**0.198**	0.205	0.070	**0.069**	0.094
The Netherlands*	0.115	**0.115**	0.115	0.066	**0.066**	0.066
United Kingdom**	0.218	**0.228**	0.237	0.057	**0.059**	0.063

Notes: * Countries where data were only available for projects commissioned in 2015, not 2010; ** countries where data were only available for projects commissioned in 2023, not 2024; see Annex III for regional country groupings; n.a. = not available.



05 CONCENTRATED SOLAR POWER

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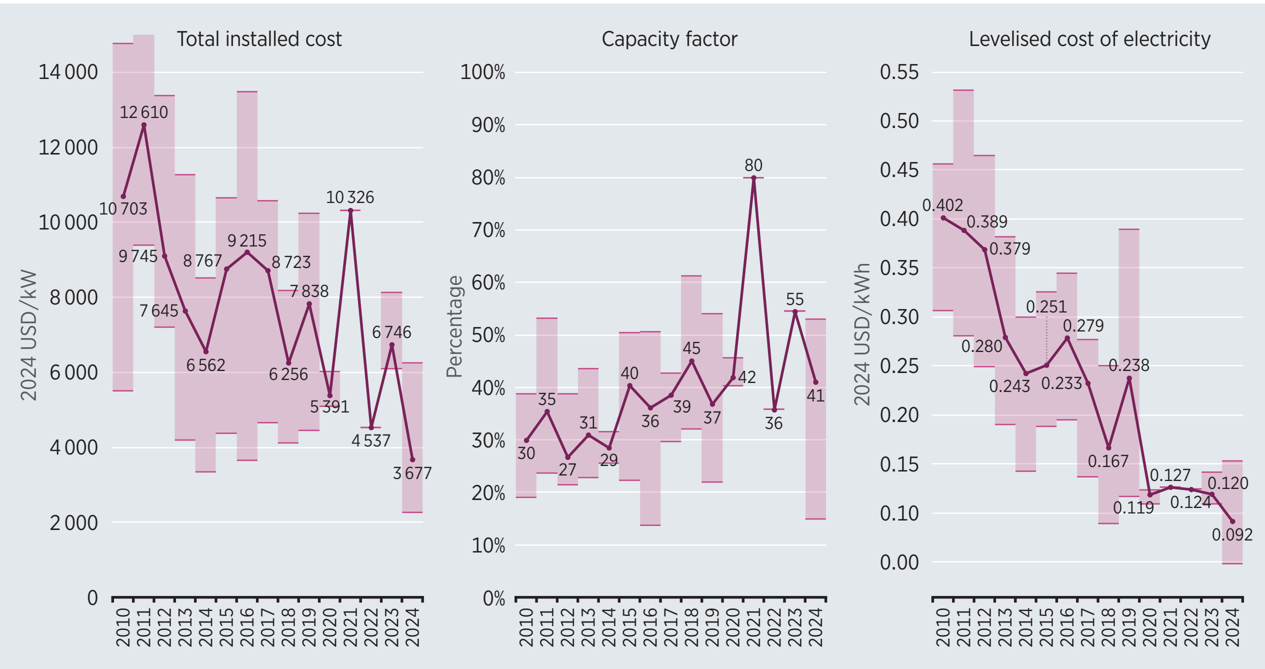
HIGHLIGHTS

- Between 2010 and 2024, the global weighted average LCOE of CSP plants fell by 77%, from USD 0.402/kWh to USD 0.092/kWh. Between 2021 and 2023, however, the figures show only one plant commissioned per year, indicating the limited deployment of CSP during this period.
- Between 2010 and 2024, the decline in the global weighted average LCOE was primarily driven by reductions in total installed costs (down 66%), higher capacity factors (up 37%) and lower O&M costs (down 62%).
- Between 2010 and 2024, the global weighted average total installed costs for CSP declined by 66%, to USD 3 677/kW. During 2024, total installed costs decreased 46% compared to 2023. This reflected the cost of projects deployed in China.
- The global weighted average capacity factor of newly commissioned CSP plants was 41% in 2024. This reflected the five projects deployed. This value was lower than the 55% reached the year before. This was because in 2023 only one project – in the United Arab Emirates – was deployed.
- In 2024, the average storage capacity of projects commissioned was 8.5 hours.

Figure 5.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for CSP, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

INTRODUCTION

Concentrated solar power (CSP) systems use heliostats or mirrors to reflect and concentrate solar radiation onto a central receiver. There, the radiation is captured as heat, also known as thermal energy. Electricity is then generated through a thermodynamic cycle. This uses the heat transfer fluid to create steam and then generate electricity, as in conventional Rankine-cycle thermal power plants.

There are four primary types of CSP technologies: solar tower (STs) systems; parabolic trough collectors (PTCs); linear Fresnel; and dish systems.

STs can achieve higher solar concentration factors and therefore operate at higher temperatures than PTCs. In ST systems, numerous heliostats are arranged in a circular, or polar field pattern around a large central receiver tower, redirecting the sun's rays towards it. This can give ST systems an advantage, as higher operating temperatures result in greater efficiencies within the steam-cycle and power block. Higher receiver temperatures also unlock greater storage densities within the molten salt tanks, driven by a larger temperature difference between the cold and hot storage tanks. Both factors cut generation costs and allow for higher capacity factors.

Single PTCs consist of a holding structure with an individual line focusing curved mirrors, a heat receiver tube and a foundation with pylons. The collectors concentrate the solar radiation along the heat receiver tube (also known as an absorber), which is a thermally efficient component placed in the collector's focal line. Many PTCs are traditionally connected in "loops" through which the heat transfer medium circulates and which help to achieve scale.

Linear-focusing CSP plants using linear Fresnel collectors are less common. This type of plant relies on an array of almost flat mirrors placed at different angles that concentrate the sun's rays onto an elevated linear receiver 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 meters above the primary mirror field.

CSP can be hybridised with other technologies, including solar PV, wind, combined-cycle natural gas plants, geothermal systems, or biomass power stations. It can also supplement existing fossil fuel plants by using gas-fired heaters to maintain output during low solar input.

Globally, CSP deployment has been modest over the last 3 years, reaching a total of almost 7.6 GW by the end of 2024. This figure includes five newly deployed projects, totalling 350 MW, of which four were in China and one in South Africa. Furthermore, in 2024, a significant milestone was achieved in the development of fourth-generation CSP technology. For the first time globally, a supercritical carbon dioxide (sCO_2) solar power system started electricity generation. Launched in China, this utilises solid particles as the heat transfer fluid (CSTA, 2025).

In the future, more CSP projects are expected to come online. Indeed, the Chinese CSP project pipeline includes 37 future and ongoing projects, with a total capacity of 4.8 GW (CSTA, 2025).

TECHNOLOGICAL TRENDS

Continued innovation in heat transfer fluids and materials has enabled CSP systems to reduce the size of their components, reach higher operating temperatures and improve overall efficiency (Molière *et al.*, 2024). Research into third and fourth generation technologies aims to enhance thermal storage and direct industrial heat applications, including solar thermochemistry processes for fuel production.

In China, regulatory changes now require CSP projects to incorporate thermal energy storage, further reinforcing the importance of dispatchability in clean energy systems. Additionally, revenues generated from solar PV projects have been strategically allocated to subsidise CSP developments. In such a system configuration, CSP facilities provide critical on-grid load support during periods when solar radiation is insufficient for PV generation. This reciprocal relationship not only enhances energy reliability, but also contributes to strengthening and optimising the CSP industry supply chain. Building on these advances, integrated CSP-wind-PV hybrid projects have been deployed in China to capitalise on CSP's capabilities for baseload generation, peak shaving and reduction in overall costs (CSTA, 2025).

In the future, further hybridisation of CSP technology with solar PV and wind is expected to enable additional cost reductions in China. For 1 GW ST plants equipped with 10-hour molten salt thermal energy storage, the investment per unit of capacity is projected to be around USD 1520/kW, with an expected electricity price in 2030 of around USD 0.048/kWh (CSTA, 2025).

Demonstration projects for 50 MW sCO_2 power systems are also set to be launched in China, creating opportunities for further reducing electricity costs (CSTA, 2025). The United States and Europe are also advancing this technology, as it has better cycle efficiency, leading to lower powerbock and O&M costs. It is expected that fourth-generation CSP technology in the United States will have an LCOE of USD 0.043/kWh by 2030 (NREL, 2025).

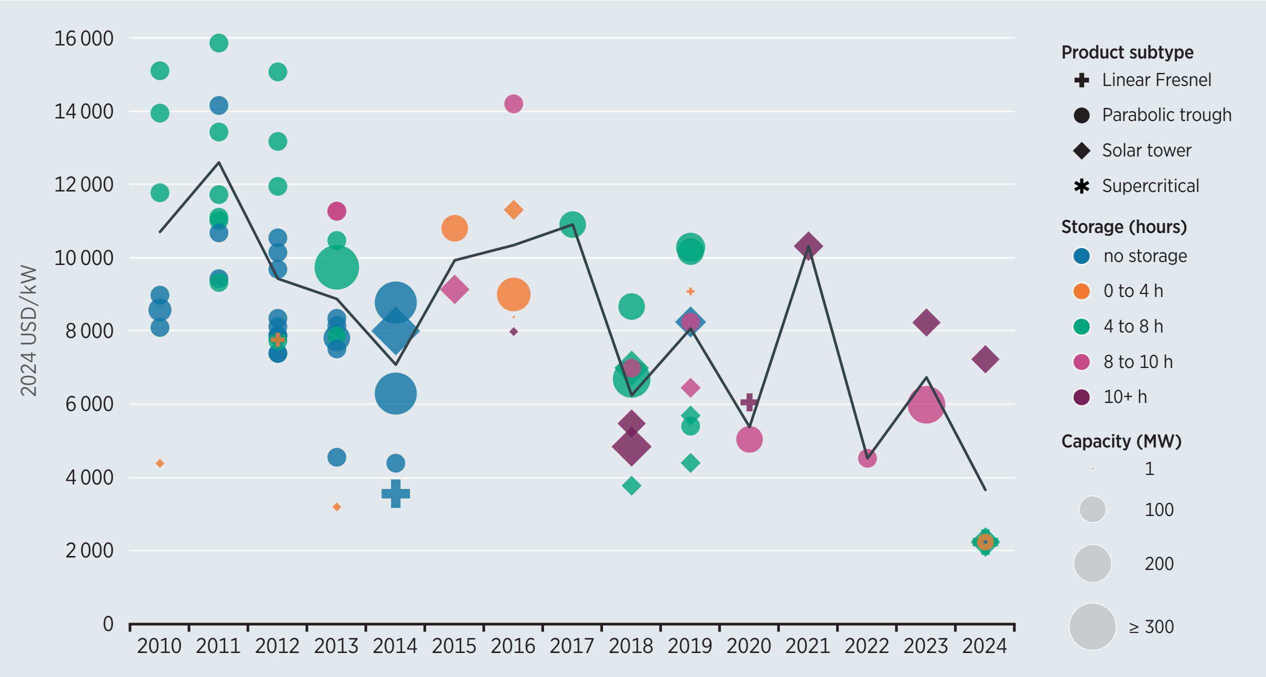
TOTAL INSTALLED COSTS

CSP facilities now commonly include low-cost and long-duration thermal energy storage, typically using molten salts. This gives CSP greater flexibility in dispatch and the ability to target output to periods of high cost in the electricity market. Indeed, this is also usually the route to lowest-cost and highest-value electricity, because thermal energy storage is now a cost-effective way to raise CSP capacity factors.

Yet, while thermal storage typically contributes up to 12% of the TICs of a CSP project, the primary cost component is the solar field, which can account for up to 58%. Second, in terms of costs, is the power block, which can account for up to 30% (NREL, 2025).

Figure 5.2 shows the year-on-year fluctuation in the total installed costs[39] for CSP between 2010 and 2024. Over that period, the weighted average TIC for CSP plants in the IRENA renewable costs database fell by 66%, reaching a period low of USD 3 676/kW in 2024.

Figure 5.2 Total installed costs for CSP by project size, collector type and amount of storage, 2010–2024



Notes: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset; h = hour; kW = kilowatt; MW = megawatt; USD = United States dollar.

In 2021, global TICs increased to USD 10 326/kW before falling back to USD 4 537/kW the following year. This fluctuation should be interpreted with care, however, as the 2021 value corresponds to that of the first solar power plant developed in Latin America, while in 2022, deployment shifted to China, where the cost structure is lower. Likewise, during 2023, global average TICs increased to USD 6 746/kW thanks to the deployment of the Noor Energy 1/DEWA IV project in the United Arab Emirates.

Overall, data from the IRENA renewable costs database show that total installed costs for CSP plants declined 66% between 2010 and 2024, reaching a global weighted average of USD 3 676/kW by the end of that period. This was despite the fact that the size of these projects' thermal energy storage systems had increased.

[39] *TICs for CSP projects do not refer to storage costs and capacity. The term is only related to specific costs of commissioned plants in USD/kW of nominal power.*

CAPACITY FACTORS

For CSP, the determinants of the achievable capacity factor for a given location and technology are the quality of the solar resource and the technological configuration. CSP is distinctive in that the potential to incorporate low-cost thermal energy storage can increase the capacity factor[40] and reduce the LCOE.

This is, however, a complex design optimisation issue that is driven by the desire to minimise the LCOE and/or meet the operational requirements of grid operators or shareholders in capturing the highest wholesale price. The optimisation of a CSP plant's design also requires detailed simulations. These are often aided by techno-economic optimisation software tools that rely increasingly on advanced algorithms. With the deployment of AI-based tools, the complexity of optimising CSP power plants can now be more effectively addressed.

Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments in improving the economics of CSP. The latter also lower the cost of storage, as higher heat transfer fluid temperatures reduce storage costs. For a given direct normal irradiance (DNI) level and plant configuration conditions, higher heat transfer fluid temperatures allow for a larger temperature differential between the "hot" and "cold" storage tanks. This means greater energy (and hence storage duration) can be extracted for a given physical storage size, or alternatively, less storage medium volume is needed to achieve a given number of storage hours. Since 2010, these combined factors have increased the optimal level of storage at a given location, as a consequence of the increased capacity factor helping minimise LCOE.

These drivers have contributed to the global weighted average capacity factor of newly commissioned plants rising from 30% in 2010 to 41% in 2024 – an increase of 37% over the decade. The highest capacity factor was registered in 2021, when it reached 80%. This was due to the excellent solar resource in Chile's Atacama Desert, the location of the Cerro Dominador CSP project. In 2022, a project located in China with 9 hours of storage drove the capacity factor to 36%, while in 2023, the global capacity factor increased to 55%. This was due to the Noor 1/DEWA IV CSP project – a solar tower and parabolic trough – deployed in the United Arab Emirates.

[40] *This is so up to a certain level, given that there are diminishing marginal returns.*

The increasing capacity factors of CSP plants, driven by increased storage capacity, can clearly be seen in Figure 5.3. Over time, CSP projects have been commissioned with longer storage durations.

Figure 5.3 Capacity factor trends for CSP plants by DNI and storage duration, 2010–2024

Source: (CSP.guru, 2025; World Bank Group *et al.*, 2025).

Notes: DNI = direct normal irradiance; h = hour; kW = kilowatt; kWh = kilowatt hour; MW = megawatt; m^2 = square metre; USD = United States dollar.

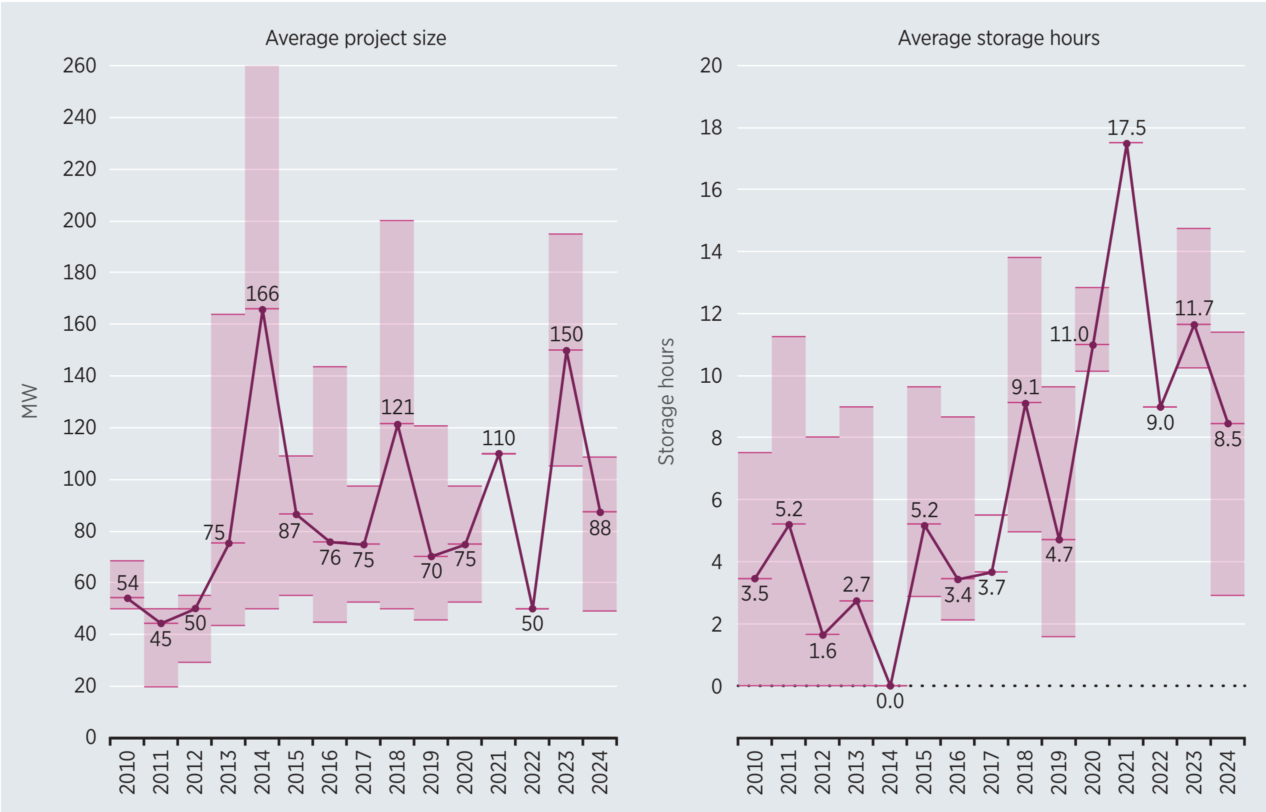
Higher DNI leads to an increase in the capacity factor, but the correlation between capacity factors and storage hours is much stronger. This is, however, only one part of the economics of plants at higher DNI locations. Higher DNIs also reduce the field size needed for a given project capacity and hence the size of the investment.

Yet, improvements in technology and cost reductions for thermal energy storage also mean that higher capacity factors can be achieved even in areas without world-class DNI. The 2020 data show the impact of higher storage levels, with newly-commissioned plants recording a weighted average capacity factor of 42% that year. This was despite the fact that the average DNI in 2020 was 1 792 kWh/m^2 per year, a lower value than the DNI average of 2 442 kWh/m^2 per year for plants commissioned between 2010 and 2017, inclusive. During that earlier period, the weighted average capacity factor was between 27% and 39% for newly commissioned plants. In 2024, the average DNI was 2 316 kWh/m^2 per year and the weighted average capacity factor was 41%.

CSP plants are also now routinely being designed to meet evening peaks and overnight demand. CSP with low-cost thermal energy storage has shown it can play an important role in integrating higher shares of variable renewables in areas with good DNI.

The recent increase in storage capacity has also been driven by the declining costs of thermal energy storage that have occurred as the market has matured. This is the result of both declining capital costs and higher operating temperatures, which allow larger temperature differentials in the molten salt storage systems, increasing the energy stored for the same volume. The result has been an increase in the weighted average number of storage hours through time. The average thermal storage capacity for solar thermal plants in the IRENA renewable costs database increased from 3.5 hours to 8.5 hours between 2010 and 2024, reaching its highest capacity – 17.5 hours – in 2021, when the Cerro Dominador 110 MW ST project, located in Chile's Atacama Desert, was commissioned. In 2024, the storage duration ranged between 2.9 hours and 11.4 hours.

Figure 5.4 Average project size and average storage hours of CSP projects, 2010–2024



Note: MW = megawatt.

O&M COSTS

For CSP plants, all-in O&M costs – which include insurance and other asset management items – are substantial compared to solar PV and onshore wind. They also vary from location to location, depending on differences in irradiation, plant design, technology, labour costs and individual market component pricing, which is in turn linked to local cost differences.

Historically, the largest individual O&M cost for CSP plants has been expenditure on receiver and mirror replacements. As the market has matured, however, experience – as well as new designs and improved technology – have helped reduce failure rates for receivers and mirrors, driving down these costs.

In addition, personnel costs represent a significant component of O&M for CSP. This is a result of the mechanical and electrical complexity of CSP plants relative to solar PV, in particular. Insurance charges also continue to be an important further contributor to O&M costs. These typically range between 0.5% and 1% of the initial capital outlay (a figure that is lower than the total installed cost).

With some exceptions, typical O&M costs for early CSP plants still in operation today range from USD 0.02/kWh to USD 0.04/kWh. These are high in absolute terms, compared to solar PV and many onshore wind farms.

Taking this into account, the LCOE calculations in the following section reflect O&M costs in the IRENA renewable costs database. These declined from a weighted average of USD 0.037/kWh in 2010 to USD 0.014/kWh in 2024 (a figure 62% lower than in 2010 and 27% lower than 2023).

The O&M costs per kWh for CSP projects are also high in absolute terms for major markets, compared to solar PV and many onshore wind farms. Table 5.2 presents the O&M estimates per technology for countries in which CSP projects have been deployed in the last five years, as well as OECD and non-OECD countries.

Table 5.1 All-in O&M cost estimates for CSP plants in selected markets, 2024

	Parabolic trough collectors	Solar tower
	(2024 USD/kWh)	(2024 USD/kWh)
Argentina	0.029	0.027
China	0.025	0.021
South Africa	0.015	0.014
OECD countries	0.028	0.025
Non-OECD countries	0.021	0.020

Note: OECD = Organisation for Economic Co-operation and Development.

LCOE

Between 2010 and 2024, as TICs, O&M costs and financing costs all fell while capacity factors rose, the LCOE for CSP also fell significantly. Indeed, over this period, the global weighted average LCOE of newly-commissioned CSP plants fell by 77%, from USD 0.402/kWh to USD 0.092/kWh.

Despite this decrease, however, financial costs continue to remain a significant factor contributing to the LCOE. This is largely due to the conservative assumptions made by lenders and investors, a factor requiring further attention from policy makers. For CSP projects in particular, higher perceived risks and elevated debt interest rates make financing more challenging. This contributes to delays in project development, thus slowing a commercial projects' deployment.

Figure 5.5 LCOE for CSP projects by technology and storage duration, 2010–2024

Notes: kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

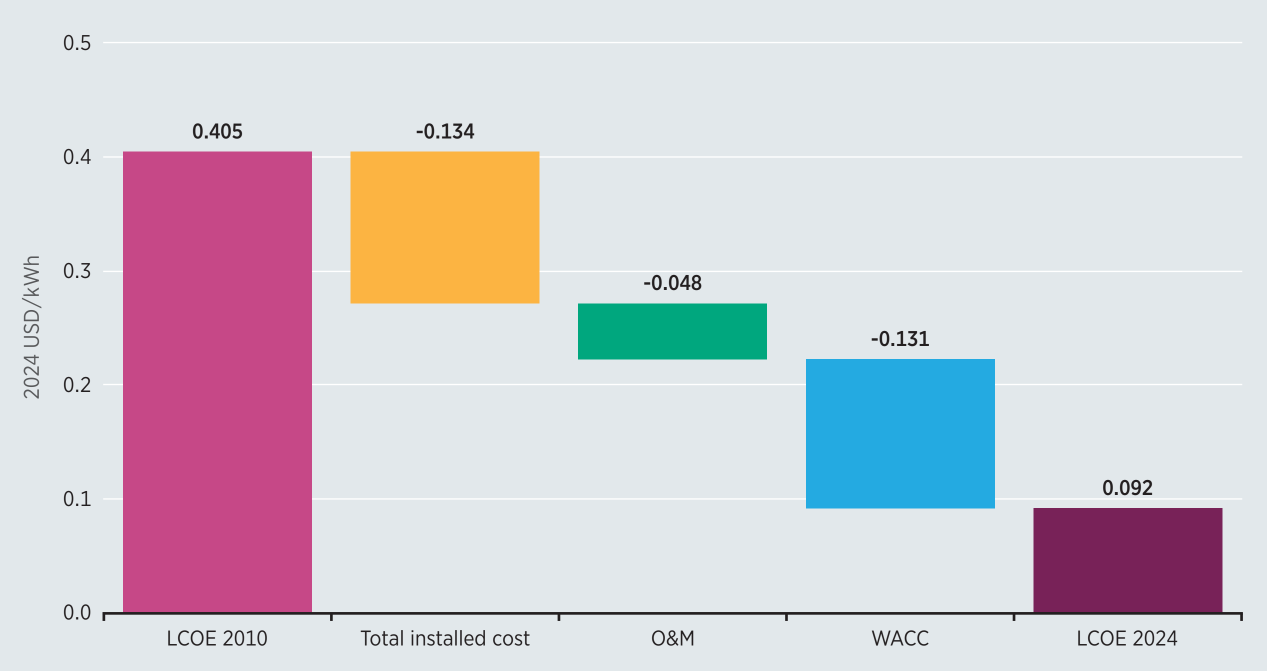
Between 2020 and 2023, the LCOE for CSP ranged between USD 0.127/kWh and USD 0.119/kWh. These values were based on a very thin market, however, as there was only one project commissioned each year over the period with a capacity between 50 MW and 200 MW.

In 2024, global deployment reached 350 MW – the highest level since 2020. In 2024, the low capital costs of projects occurring in China pushed down the weighted average LCOE to USD 0.092/kWh. This value was the lowest achieved since 2010, while it was also a 23% decrease compared to 2023.

For the period 2010 to 2024, Figure 5.6 illustrates[41] the 77% decline in the global weighted average LCOE of CSP, showing the breakdown of all the main cost components. The largest share of the decline was taken by the fall in TICs. Improvements in technology and cost reductions in thermal energy storage led to projects with longer storage duration being commissioned, while there were also improved capacity factors. This, in turn, accounted for a reduction in the LCOE from USD 0.405/kWh to USD 0.092/kWh. The role of increasingly experienced developers in reducing costs at every step of the development, construction and commissioning process also needs to be acknowledged.

[41] *The figure is the result of a simple decomposition analysis. In this, one variable is changed while holding all others constant. Values are then apportioned as shares of the actual total reduction in LCOE over the period. The results are indicative only and should be treated with caution.*

Figure 5.6 Reduction in LCOE for CSP projects by source, 2010–2024



Notes: LCOE = levelised cost of electricity; O&M = operation and maintenance; kWh = kilowatt hour; USD = United States dollar ; WACC = weighted average cost of cpaital.

Although there has been significant success in reducing costs since 2010, the CSP market remains small, with a limited number of new projects in the pipeline. As of the end of 2024, there were projects under construction in China and Europe which totalled 3.4 GW. These are expected to come online in the near future (SolarPaces, 2025).

A key advantage of CSP is its ability to provide dispatchable and renewable power to the grid. Research shows that for storage durations exceeding four hours, CSP with thermal energy storage can be more competitive than PV combined with batteries. However, in many countries, current regulations and market structures do not adequately reward the value of dispatchable generation. To enable CSP to compete on a level playing field, electricity markets must evolve to recognise and incentivise this technology's unique capabilities (Schöniger *et al.*, 2021).

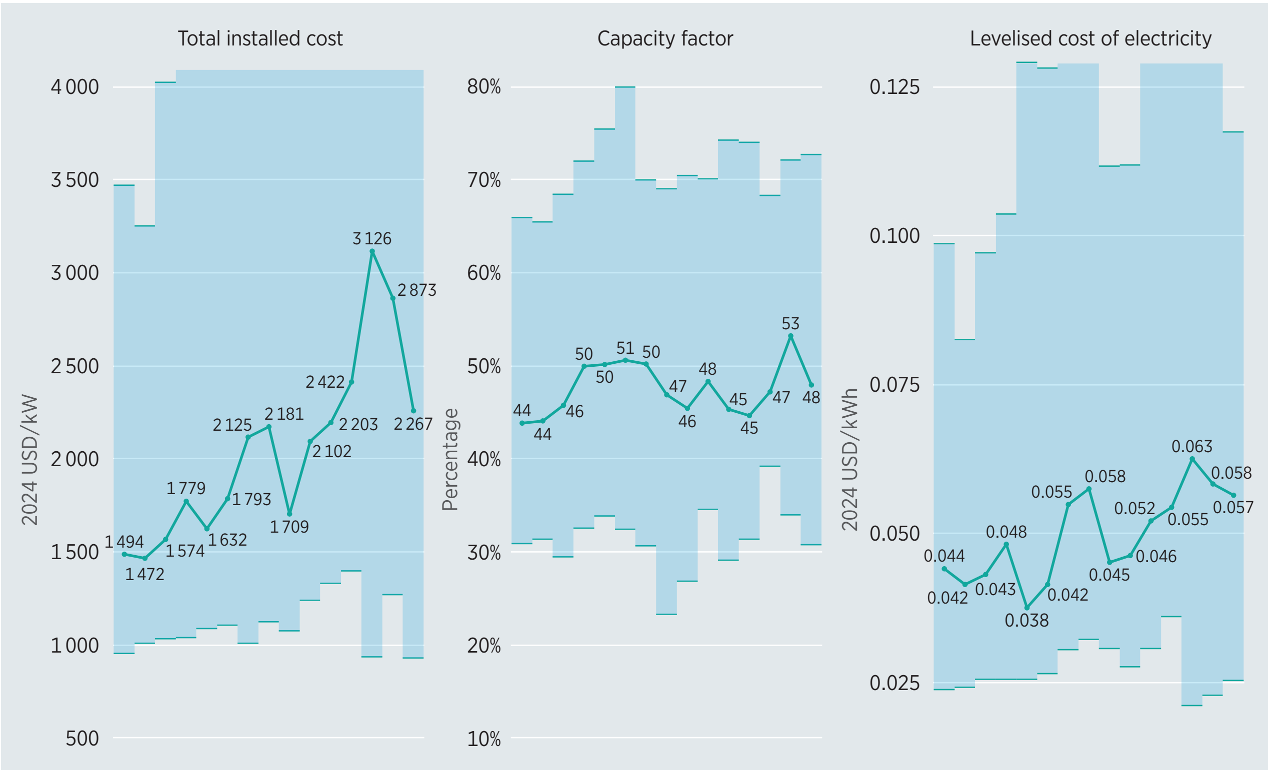
06 HYDROPOWER

Harry Beugelink © Shutterstock.com

HIGHLIGHTS[42]

- The global weighted average LCOE of newly-commissioned hydropower projects was USD 0.057/kWh in 2024 – 2% lower than the USD 0.058/kWh recorded in 2023 and 30% higher than the projects commissioned in 2010 (see Figure 6.1).
- In 2024, the global weighted average total installed costs of newly-commissioned hydro projects decreased 21%, year-on-year, to USD 2 267/kW. This was primarily due to cost decreases in regions with the highest deployment, such as Asia and South America. Additionally, unlike in 2023, when several over-costly projects were commissioned in North America, 2024 did not see similar high-cost projects in the region.
- Between 2010 and 2024, the global weighted average capacity factor for hydropower projects commissioned varied considerably. In 2024, the global weighted average capacity factor was 48%.
- Hydropower is a multi-purpose asset. It offers power generation along with system flexibility, energy storage and water management capabilities. Its role as a provider of flexibility is set to become increasingly important in supporting grid stability and balancing variable renewable energy sources.

Figure 6.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for hydropower, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

[42] *This chapter focuses on reservoir and run-of-river systems, excluding pumped storage, which primarily functions as an energy storage solution, rather than an electricity generator.*

INTRODUCTION

Hydropower is a mature and reliable renewable energy technology. With 1277 GW of installed capacity worldwide (excluding pumped storage) in 2024, it is also the world's second most deployed renewable energy technology, after solar PV. In 2024, newly-installed capacity (excluding pumped storage) for this technology was 9.3 GW (IRENA, 2025d). Worldwide, the top five markets, were all in Africa and Asia. China alone accounted for 72% of new installations.

Hydropower can be a key enabler of higher variable renewable energy shares in power systems. Its ability to provide flexible, dispatchable power – especially when the plant includes reservoir storage[43] – makes it an essential technology for balancing the variability of other renewable generation technologies. As countries accelerate the integration of these variable sources, hydropower plays a growing strategic role in grid stability. It does this by offering ancillary services, such as frequency regulation, spinning reserves and black start capability.

Hydropower provides affordable and reliable renewable electricity, water supply services, local jobs and socio-economic benefits. Its deployment must be approached carefully, however, due to potential environmental and social impacts, such as community displacement and ecological damage. The need for regulatory reforms and targeted funding is crucial to overcome existing environmental and permitting hurdles, attracting the investments required for modernisation and capacity additions.

TECHNOLOGICAL TRENDS

Hydropower has undergone a number of technological advances and strategic shifts in order to adapt to the evolving needs of modern power systems. In Europe, for example, efforts have recently been concentrated on modernising and expanding existing plants to enhance grid flexibility and resilience (Ember, 2025a; GLOBSEC, 2024). Generally, when assessing electro-mechanical equipment, life extension costs can be assumed to be 60% of the costs associated with greenfield projects, while upgrade expenses can be considered to be 90% of the greenfield costs (Quaranta *et al.*, 2021). However, hydropower total installed costs are highly site-specific, particularly in remote locations where specific civil engineering requirements, logistical and grid connection challenges can significantly increase overall cost.

In recent years, the application of AI techniques in hydropower has made notable advances. Digital technologies, such as AI-driven water management systems, are increasingly being integrated into hydropower operations (Ember, 2025a). Machine learning supports planning in the short, medium and long term – primarily in scheduling, optimisation and forecasting. These models are commonly used to predict water inflows and electricity generation. They consider market prices, operational costs – such as maintenance – and revenue optimisation. They also aim to maximise economic returns while ensuring reliable system performance (Chang *et al.*, 2023; Villeneuve *et al.*, 2023).

[43] *By holding water until it is needed by grid operators or for multipurpose benefits, hydropower can store energy over extended periods, ranging from weeks to years, depending on the size of the reservoir.*

The use of digital twins is another example of innovation. Digital twins are mathematical replicas of a physical plant which allow for the simulation of different operating conditions and the monitoring of various parameters. They can facilitate decision making and improve the resolution and capabilities of plant controls (IRENA, 2023b).

TOTAL INSTALLED COSTS

Hydropower project construction is influenced by various factors, including project size, location and technical specifications. The latter can include water head, reservoir dimension and inflow patterns. These characteristics directly determine the type and capacity of the turbine selected for the project. The plant type – whether reservoir, run-of-river or pumped storage – further shapes the technical requirements and the cost structures.

This chapter focuses on reservoir and run-of-river systems, excluding pumped storage. This is because the latter primarily functions as an energy storage solution, rather than an electricity generator. Projects have also been categorised by size. Small hydropower refers to installations below or equal to 10 MW, while large hydropower includes those with a capacity above 10 MW.

Table 6.1 provides a description of the hydropower projects covered by this chapter. Using a sample of European hydropower projects active in 2021, it also gives an overview of the estimated shares taken by civil, mechanical and electrical cost components, according to type of hydropower.

Table 6.1 Hydropower plant type description and total installed costs breakdown by component and weighted averages for a sample of hydropower projects in Europe, 2021

Europe 2021				
Hydropower type	Description	Share of total installed costs (%)		
		Civil	Mechanical	Electrical
Large-scale reservoir storage (high head)	Uses dams to store water, decoupling generation time from the inflow. Offers flexibility in timing and output.	70	10	20
Large-scale run of river (low head)	Limited storage capacity, generation depends on river flow, but may allow for moderate flow regulation. Offers moderate flexibility.	50	30	20
Small-scale run of river	Hydro inflows mainly determine generation output. This is because there is little or no storage to provide a buffer for the timing and size of inflows.	50	30	20

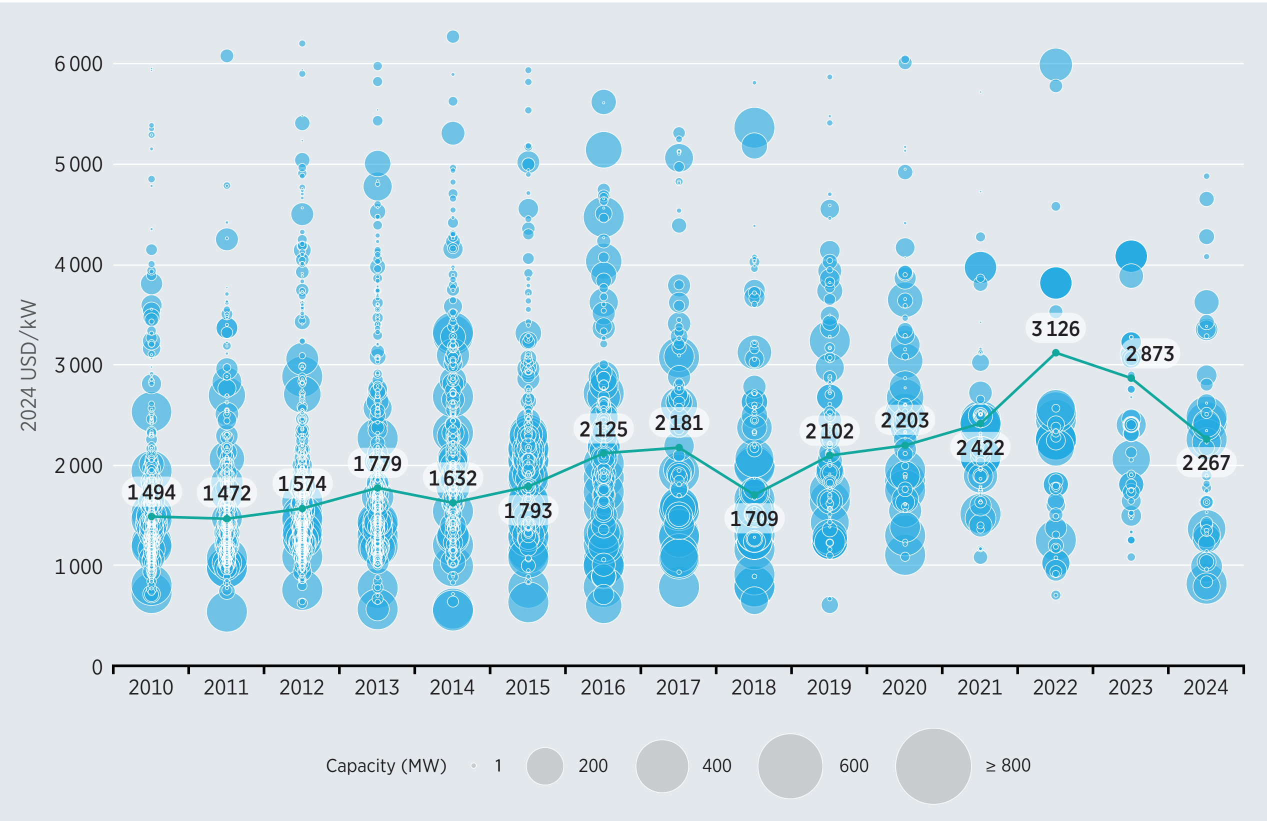
Source: Data from International Hydropower Association (IHA).

Hydropower is a capital-intensive technology with long lead times. It also requires substantial upfront investment. The main cost components typically include civil works, electro-mechanical equipment, supporting infrastructure and grid connection (see Table 6.1). In large-scale projects, civil works – such as dams, tunnels, canals and powerhouses – usually represent the largest share of capital expenditure. These are followed by mechanical and electrical components, including turbines, generators and control systems. However, this distribution can vary, particularly in projects that leverage or expand existing infrastructure. This can reduce civil construction costs, while increasing the share of electro-mechanical components.

Additional costs may arise from feasibility studies, stakeholder engagement, environmental measures and land acquisition. The long lead times of large-scale hydropower projects – which can be 7–9 years or more – mean that owner costs (which include project development costs) can also be a significant portion of the overall costs. This is due to the need for working capital and interest during construction.

Data from the IRENA renewable costs database show that the global weighted average total installed costs of new hydropower increased from USD 1 494/kW in 2010 to USD 2 267/kW in 2024 (see Figure 6.2). After rising relatively steadily between 2010 and 2017, in 2018 the global weighted average total installed costs dropped to USD 1 709/kW. Costs then resumed their upward trajectory, peaking in 2022 due to several large-scale projects with significant cost overruns. These projects were notably those in Canada and the Lao People's Democratic Republic. Fewer overruns were observed in 2023 and 2024, contributing to a cost reduction, year-on-year; nonetheless, the long-term increase in average costs reflects not only regional deployment shifts, but also a persistent rise in project-specific costs.

Figure 6.2 Total installed costs by project and global weighted average for hydropower, 2010–2024



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Table 6.2 shows the total installed costs for hydropower projects commissioned between 2010 and 2024, according to capacity range. The full dataset of hydropower projects in the IRENA renewable costs database for the years 2010 to 2024 does not suggest that there are strong economies of scale in hydropower projects that are below 450 MW. While there are some capacity ranges where the weighted average installed costs appear slightly lower – such as the 351 MW-400 MW range, where they are USD 1 804/kW – this pattern is not uniform across all categories. Moreover, the number of projects is unevenly distributed, with the services they provide varying significantly. This makes it difficult to draw definitive global conclusions and suggests that different regional contexts could lead to varying interpretations. In contrast, there is some evidence of economies of scale in projects above 700 MW, where the weighted average installed costs tend to be lower. For the 701 MW-750 MW range, for example, the cost is USD 1 792/kW, while for the 901 MW-950 MW range, it is USD 1 295/kW.

Table 6.2 Total installed costs for hydropower by weighted average and capacity range, 2010–2024

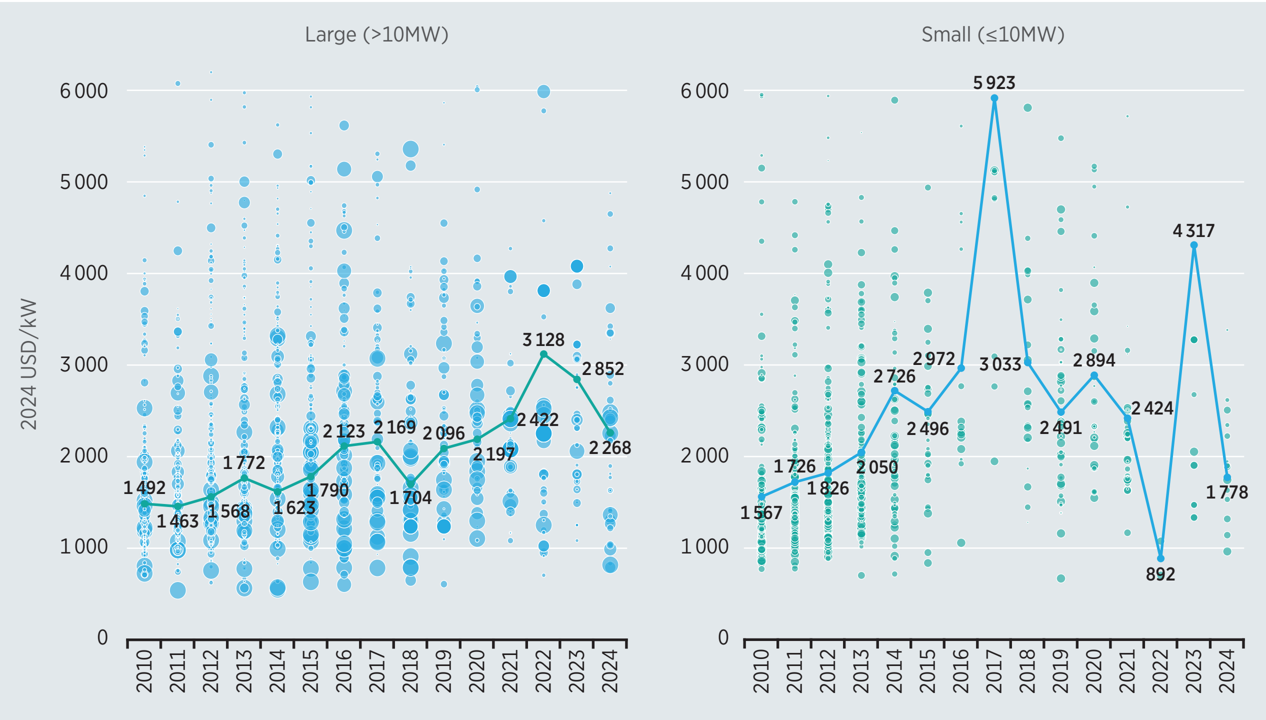
2010-2024			
Capacity (MW)	**5th percentile (2024 USD/kW)**	**Weighted average (2024 USD/kW)**	**95th percentile (2024 USD/kW)**
0-50	1 011	**2 067**	4 407
51-100	1 038	**2 261**	4 998
101-150	1 097	**2 117**	4 276
151-200	1 049	**2 089**	3 616
201-250	1 161	**2 376**	4 130
251-300	1 050	**2 478**	4 457
301-350	1 056	**2 318**	5 100
351-400	782	**1 804**	3 083
401-450	1 361	**2 288**	3 459
451-500	1 166	**1 773**	2 804
501-550	1 294	**3 036**	5 138
551-600	1 540	**2 084**	2 945
601-650	1 203	**1 686**	3 885
651-700	2 265	**2 577**	2 710
701-750	1 103	**1 792**	2 454
751-800	1 217	**1 789**	2 523
801-850	992	**3 801**	12 048
851-900	1 373	**1 947**	2 198
901-950	810	**1 295**	1 521
951-1000	2 533	**2 533**	2 533

Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Figure 6.3 presents the distribution of total installed costs by capacity for small and large hydropower projects in the IRENA renewable costs database. The global weighted average demonstrates an increasing trend from 2018 to 2022, primarily driven by large hydropower projects. In 2024, the weighted average total installed costs decreased for both small and large hydropower.

With moderate fluctuations, large hydropower projects display a relatively stable cost trajectory over time and have a clearer long-term trend. In contrast, small hydropower projects exhibit significant year-to-year variability. Average installed costs for small hydro peaked sharply in 2016, at USD 5 923/kW, but declined substantially in subsequent years, reaching a low of USD 892/kW in 2023. Costs rebounded slightly in 2024, to USD 1 778/kW, which remains below most previous years in the dataset. This volatility suggests that small hydro costs are heavily influenced by a limited number of projects. Additionally, data coverage for small hydro is notably thinner for the years 2015 to 2018. This may affect the robustness of these observed trends. As such, the long-term trend for small hydro remains to be confirmed.

Figure 6.3 Total installed costs for small and large hydropower projects and global weighted average, 2010–2024



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

As indicated earlier, two upward trends in the global weighted average total installed costs for hydropower can be identified between 2010 and 2024. The first occurred from 2010 to 2017, followed by a notable decrease in 2018. A second period of rising costs then began after 2019 and continued through 2022, before declining again in 2023 and 2024. Given these shifts, this analysis has been made using these two periods, 2010–2017 and 2018–2024, to better understand the underlying cost dynamics at the global and regional levels. This approach allows for a more detailed examination of the regional drivers behind the observed cost changes and helps identify whether similar patterns are reflected across different markets.

Figure 6.4 illustrates the differences in the distribution of total installed costs by capacity for large and small hydropower projects between the two periods. Across both periods, there was a noticeable shift in distribution cost over time. In 2010–2017, for large and small hydropower, most projects were concentrated in the lower-cost range from USD 600/kW to USD 1 800/kW, while in 2018–2024 the majority of newly commissioned projects ranged from USD 1 800/kW to USD 2 600/kW. At the same time, there was a marked increase in the proportion of projects falling into higher cost ranges – such as those above USD 2 800/kW. The shift in the distribution indicates greater cost variability, along with the increased presence of higher-cost projects.

Figure 6.4 Distribution of total installed costs of large and small hydropower projects by capacity, 2010–2017 and 2018–2024

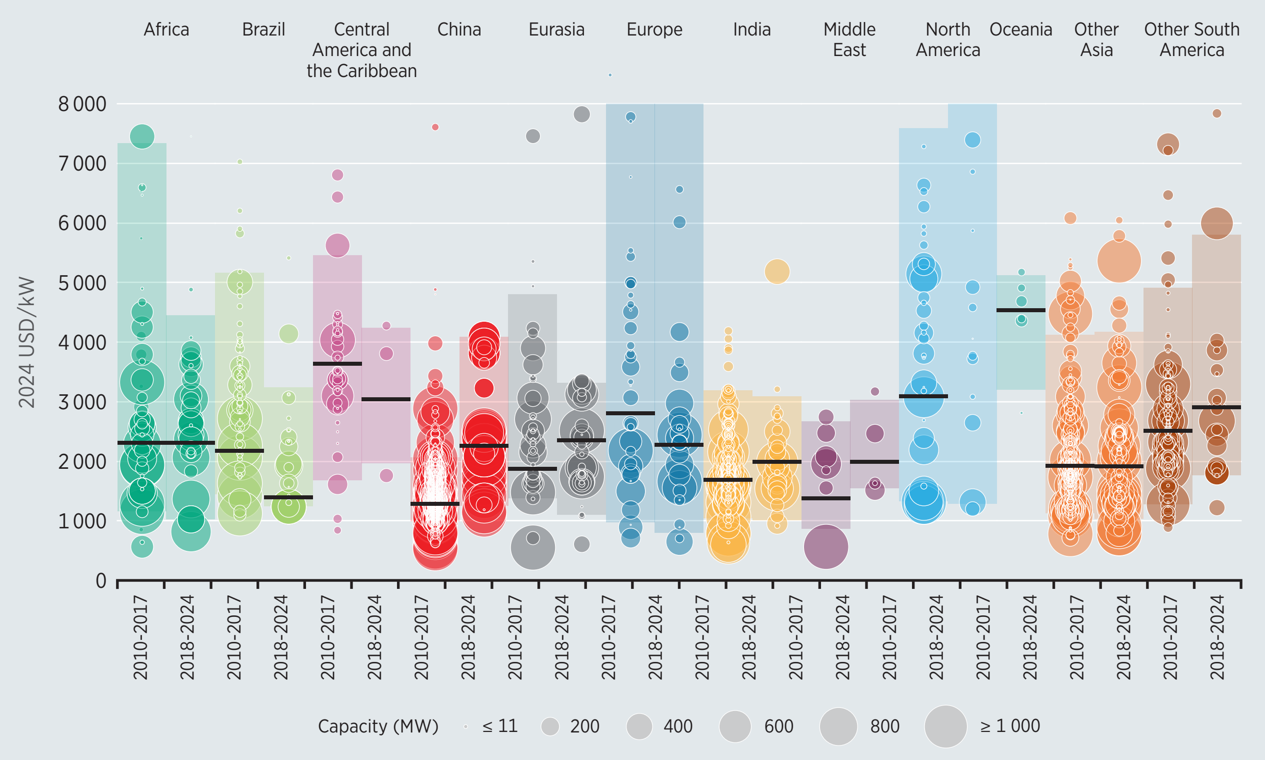
Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

Figures 6.5 and 6.6 and Table 6.3 present the total installed costs and weighted average total installed costs of large and small hydropower projects by region and selected countries across the same two periods.

In Oceania, data for large and small hydropower projects is sparse, however. This is also the case for small hydropower projects commissioned in the period 2018–2024 in Central America and the Caribbean, and the Other South America region. Results for these are therefore only presented for total installed costs during the 2010–2017 period.

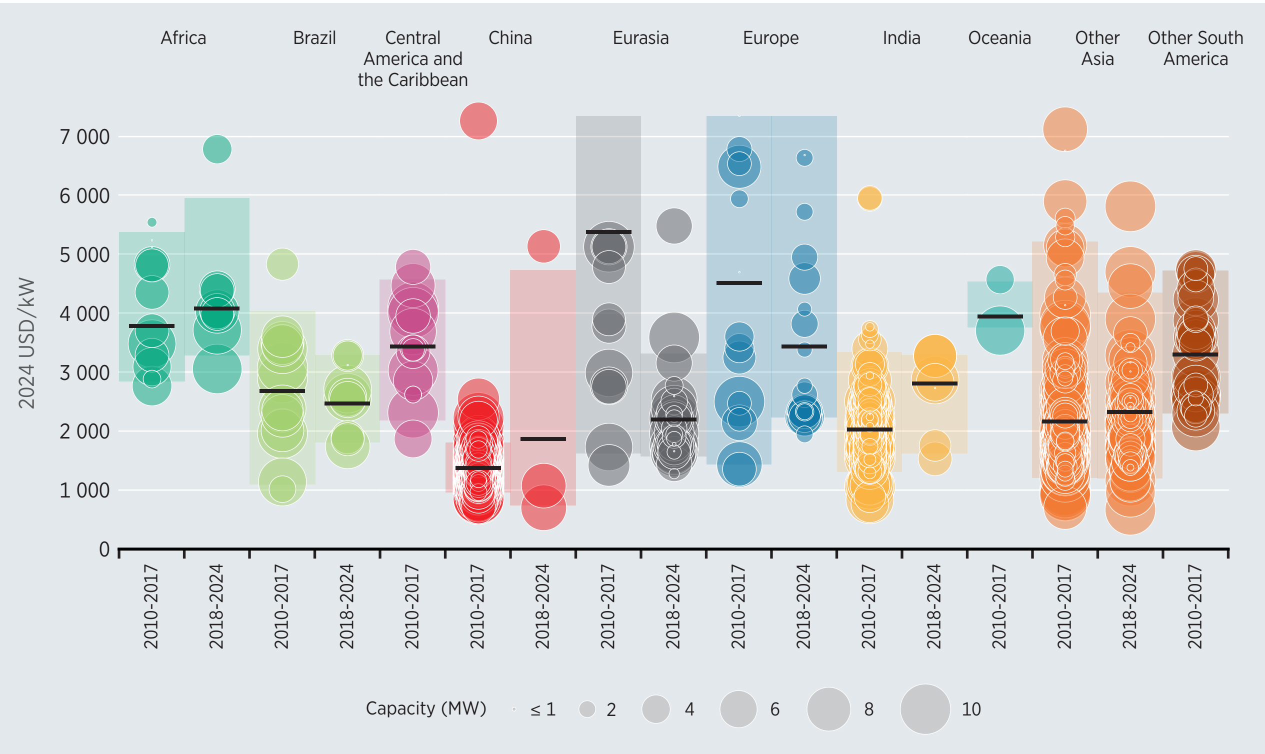
For large hydropower, the comparison between the two periods shows that more than half of the regions and selected countries presented experienced an increase in their weighted average total installed costs. These places included Africa, China, Eurasia, India, the Middle East, North America and Other South America. The most significant increase occurred in North America, which was also the region with the highest weighted average total installed costs in the 2018–2024 period, at USD 11 658/kW. This was driven by a few projects with substantial over-expensed costs. In four of the regions and selected countries presented, the weighted average total installed costs decreased. These included Brazil, Central America and the Caribbean, Europe and Other Asia. For the 2010–2017 period, the highest weighted average total installed costs was in Oceania, at USD 4 551/kW, while China recorded the lowest, at USD 1 301/kW. In the 2018–2024 period, Brazil reported the lowest weighted average total installed costs, at USD 1 405/kW.

Figure 6.5 Total installed cost by project and weighted averages for large hydropower projects by country/region, 2010–2024



Notes: See Annex III for regional country groupings; kW = kilowatt; MW = megawatt; USD = United States dollar.

Figure 6.6 Total installed costs by project and weighted averages for small hydropower projects by country/region, 2010–2024



Notes: See Annex III for regional country groupings; kW = kilowatt; MW = megawatt; USD = United States dollar.

For small hydropower, between 2018 and 2024, four out of the seven regions and selected countries with data available for both periods – Africa, China, India and Other Asia – experienced an increase in their weighted average total installed costs. In contrast, Brazil, Eurasia and Europe recorded decreases. The most significant increase was in India, where average cost rose by 45%, from USD 2 042/kW in 2010–2017 to USD 2 963/kW in 2018-2024. The most significant decline occurred in Eurasia, where the weighted average fell by 59%, from USD 5 386/kW during 2010–2017 (the highest value among all regions, due to some high-cost projects) to USD 2 228/kW in the 2018–2024 period. For the 2018-2024 period, Africa reported the highest weighted average total installed costs at USD 4 084/kW. Across both periods, China maintained the lowest weighted average total installed costs for small hydropower, at USD 1 378/kW and USD 1 873/kW, respectively.

Table 6.3 Hydropower weighted average total installed costs for large and small hydropower projects by country/region, 2010–2024

	Large hydropower		Small hydropower	
	2010-2017	2018-2024	2010-2017	2018-2024
	(2024 USD/kW)			
Africa	2 330	**2 515**	3 795	**4 084**
Central America	3 652	**3 058**	3 444	**n.a.**
Eurasia	1 884	**2 369**	5 386	**2 228**
Europe	2 815	**2 282**	5 080	**3 677**
Middle East	1 385	**2 092**	n.a.	**n.a.**
North America	3 097	**11 658**	n.a.	**n.a.**
Oceania	4 551	**n.a.**	3 959	**n.a.**
Other Asia	1 934	**1 914**	2 175	**2 414**
Other South America	2 519	**2 913**	3 307	**n.a.**
Brazil	2 188	**1 405**	2 698	**2 534**
China	1 301	**2 216**	1 378	**1 873**
India	1 700	**1 991**	2 042	**2 963**

Notes: See Annex III for regional country groupings; n.a. = not available.

CAPACITY FACTORS

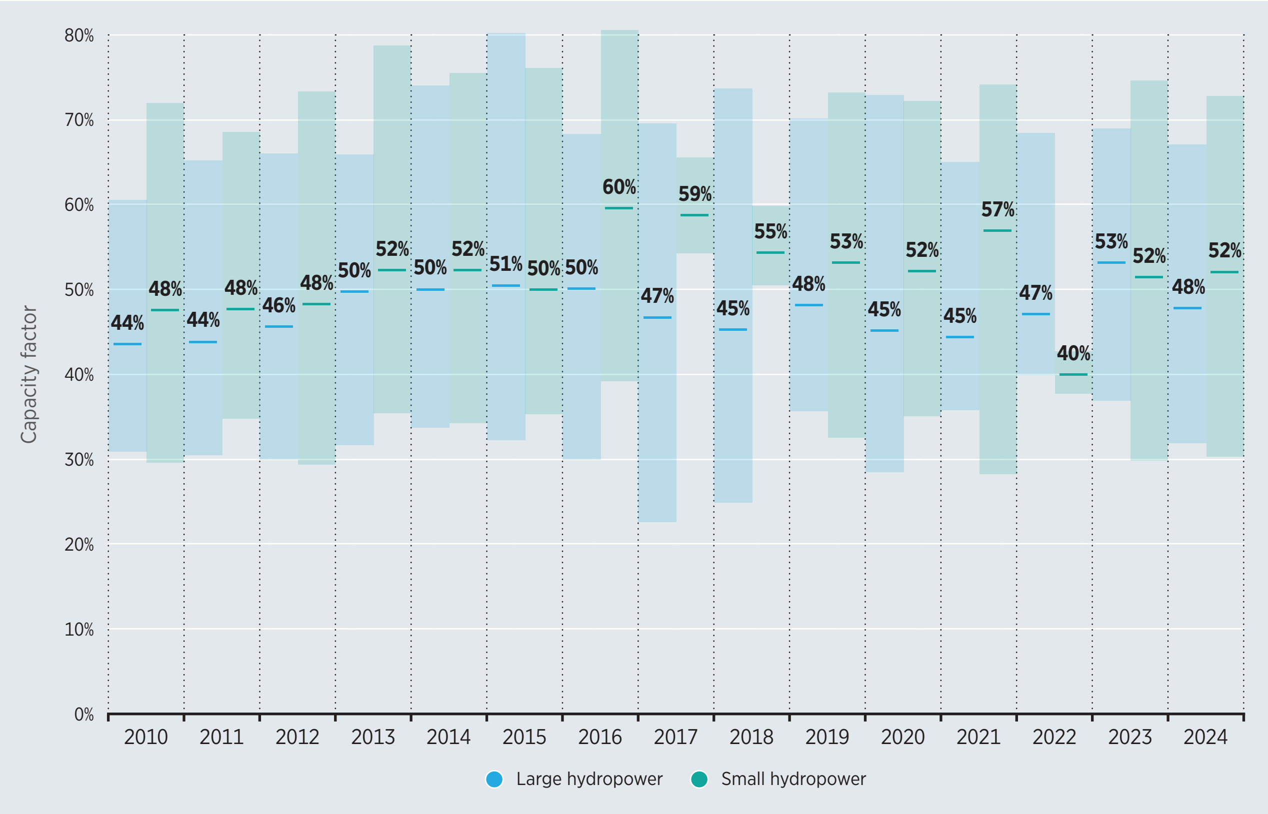
Between 2010 and 2024, the global weighted average capacity factor of newly commissioned hydropower projects of all sizes increased from 44% to 48%, with a peak value of 53% in 2023. The 5th and 95th percentiles of projects over the period were also within a range stretching from 23% to 80%. This wide range is to be expected, however, given the diverse site characteristics and operational strategies of hydropower projects.

Small hydropower projects from the IRENA renewable costs database for the years 2010–2024 have a higher weighted average capacity factor than large hydropower projects (Figure 6.7). In many cases, low-capacity factors are a design choice. For instance, a plant with low installed electrical capacity could run continuously to achieve high average capacity factors, but may struggle to ramp up production to meet peak demand loads. Alternatively, a plant with a high installed electrical capacity and low-capacity factor might be designed for peak demand and ancillary grid services.

Between 2010 and 2024, the annual global weighted average capacity factor of newly commissioned large hydropower projects increased from 44% to 48% (Figure 6.7). The 5th percentile of large hydropower projects ranged from a low of 23% in 2017 to a high of 40% in 2022. For the 95th percentile, the figure ranged from a low of 66% in 2010 to a high of 80% in 2015. The 5th and 95th percentile figures for 2024 were 32% and 67%.

Between 2010 and 2024, the annual global weighted average capacity factor of newly commissioned small hydropower projects increased from 48% to 52% (Figure 6.7). Excluding the years 2017, 2018 and 2022 – for which there is a lack of data – the annual 5th percentile of small hydropower projects ranged from a high of 39% in 2016 to a low of 28% in 2021. For the 95th percentile, these capacity factors ranged from a low of 69% in 2011 to a high of 81% in 2016. The 5th and 95th percentile figures for 2024 were 30% and 73%, respectively.

Figure 6.7 Global weighted average capacity factor, 5th and 95th percentiles for small and large hydropower, 2010–2024



In the IRENA renewable costs database there is often a significant regional variation in the weighted average capacity factor. Tables 6.4 and 6.5 represent hydropower project weighted average capacity factors and ranges for large and small hydropower projects by country and region.

For the 2018–2024 period, there was a limited number of newly-commissioned small hydropower projects in the database for Central America and Other South America. At the same time, for this period and for the 2010–2017 period, there was a limited number of newly-commissioned large and small hydropower projects in the database for Oceania. As a result, the weighted average capacity factors for these regions are not considered representative.

Between 2010 and 2017, average capacity factors for newly-commissioned large hydropower projects were highest in Brazil and Other South America, with both regions recording a level of 61%. Between 2018 and 2024, North America had the highest average capacity factor, at 64%, followed by Other South America, with 60%. Meanwhile, in both periods, Europe recorded the lowest average capacity factor for newly commissioned large hydropower projects. The respective figures were 36% in 2010–2017 and 38% between 2018 and 2024.

For small hydropower, the lowest country-level average was 45%, recorded for Oceania for the 2010–2017 period. For the 2018–2024 period, the lowest was India, with 37%. Similarly, weighted average capacity factors for newly-commissioned small hydropower projects between 2010 and 2017 were highest in Other South America and Brazil, at 65% and 62%, respectively. Between 2018 and 2024, Other Asia showed the highest weighted average capacity factor for this period, at 59%, followed by Eurasia, with a factor of 57%.

Table 6.4 Weighted average capacity factors and ranges for large hydropower projects by country/region, 2010–2024

	2010-2017			2018-2024		
	5th percentile (%)	Weighted average (%)	95th percentile (%)	5th percentile (%)	Weighted average (%)	95th percentile (%)
Africa	29	**51**	68	33	**48**	81
Central America	27	**50**	62	37	**46**	53
Eurasia	28	**44**	64	29	**41**	68
Europe	16	**36**	68	23	**38**	66
North America	24	**44**	78	39	**64**	73
Oceania	25	**38**	47	n.a.	**n.a.**	n.a.
Other Asia	37	**47**	68	37	**48**	69
Other South America	46	**61**	84	45	**60**	70
Brazil	51	**61**	80	39	**41**	61
China	31	**46**	57	37	**47**	63
India	27	**44**	62	29	**50**	63

Notes: See Annex III for regional country groupings; n.a. = not available.

Table 6.5 Weighted average capacity factors and ranges for small hydropower projects by country/region, 2010–2024

	2010-2017			2018-2024		
	5th percentile (%)	Weighted average (%)	95th percentile (%)	5th percentile (%)	Weighted average (%)	95th percentile (%)
Africa	38	**56**	68	50	**55**	66
Central America	45	**59**	75	n.a.	**n.a.**	n.a.
Eurasia	45	**60**	75	38	**57**	69
Europe	24	**48**	70	28	**41**	64
Oceania	45	**45**	45	n.a.	**n.a.**	n.a.
Other Asia	37	**50**	78	37	**59**	79
Other South America	43	**65**	82	n.a.	**n.a.**	n.a.
Brazil	43	**62**	88	49	**54**	59
China	33	**46**	60	38	**40**	43
India	28	**51**	70	34	**37**	45

Notes: See Annex III for regional country groupings; n.a. = not available.

O&M COSTS

Annual O&M costs are often quoted as a percentage of the investment cost per kW per year, with typical values ranging from 1% to 4%. IRENA had previously collected O&M data on 25 projects commissioned between 2010–2016 (IRENA, 2018) and found average O&M costs varied between 1% and 3% of total installed costs per year, with an average that was slightly less than 2%. Larger projects have O&M costs below the 2% average, while smaller projects approach the higher end of the range, or have above average O&M costs.

Table 6.6 presents the cost distribution of individual O&M items in the sample. As can be seen, operations and salaries take up the largest slices of the O&M budget. Operational costs vary from 20% to 61% of total O&M costs, while salaries vary from 13% to 74%. Materials are estimated to account for around 4%, while the “other” category accounts for 15%.

Table 6.6 Hydropower O&M costs by category from a sample of 25 projects

Project component	Share of total O&M costs (%)		
	Minimum	Weighted average	Maximum
Operational costs	20	**46**	61
Salary	13	**35**	74
Other	5	**15**	28
Material	3	**4**	4

Other sources, however, quote lower or higher values. For a conventional, 100 MW hydropower plant commissioned in 2020, the EIA, for example, assumes 0.6% of total installed costs as fixed annual O&M costs, along with USD 0.003/kWh as variable O&M costs (EIA, 2020). Other studies (Greenpeace, 2015) indicate that fixed O&M costs represent 4% of the total capital cost; however, this figure may represent small-scale hydropower, with large hydropower plants having significantly lower O&M costs as a percentage of their overall total cost. An average value for O&M costs of 2% to 2.5% of the capital cost is widely considered the norm for large-scale projects (IPCC, 2011).

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. However, O&M costs generally exclude major refurbishments of the electro-mechanical equipment, penstocks, tailraces and other durable items. Replacement of these is infrequent due to their long design lives. These are typically 40 years or more for electro-mechanical equipment and over 50 years for penstocks and tailraces. Civil components, which represent about 45% of the installed cost, tend to have even longer economic life, commonly between 50 and 100 years.

LCOE

Hydropower investment costs vary depending on location and site conditions. This results in a wide range of installed costs and differences in the LCOE between projects. In addition, hydropower projects can be designed to perform very differently from one another in order to meet particular energy requirements. These could be in order to meet peak demand, for example, or provide other ancillary grid services and non-energy services. This functional diversity adds complexity to LCOE assessments, as projects are not always directly comparable in terms of energy output alone.

The LCOE assessment presented in this chapter includes certain exclusions. It assumes a conservative economic life of 30 years[44] for hydropower plants, meaning that the original investment is fully amortised by the time any significant reinvestment is needed. Consequently, reinvestment cost is not considered. In addition to electricity generation, many hydropower projects provide other services, such as potable water, flood control, irrigation and navigation. While the costs of these services are included in the hydropower project costs, they are typically not remunerated and are therefore not included in the LCOE calculations in this chapter.

In 2024, the global weighted average cost of electricity from hydropower was USD 0.057/kWh, up 30% from the USD 0.044/kWh recorded in 2010. The global weighted average cost of electricity from hydropower projects commissioned in the years 2010 to 2017 averaged USD 0.045/kWh. This increased to an average of USD 0.053/kWh for projects commissioned over the years 2018–2024.

[44] Hydropower plants usually have longer lifetimes, which – depending on the components – are in the range 30 to 80 years (IRENA, 2012).

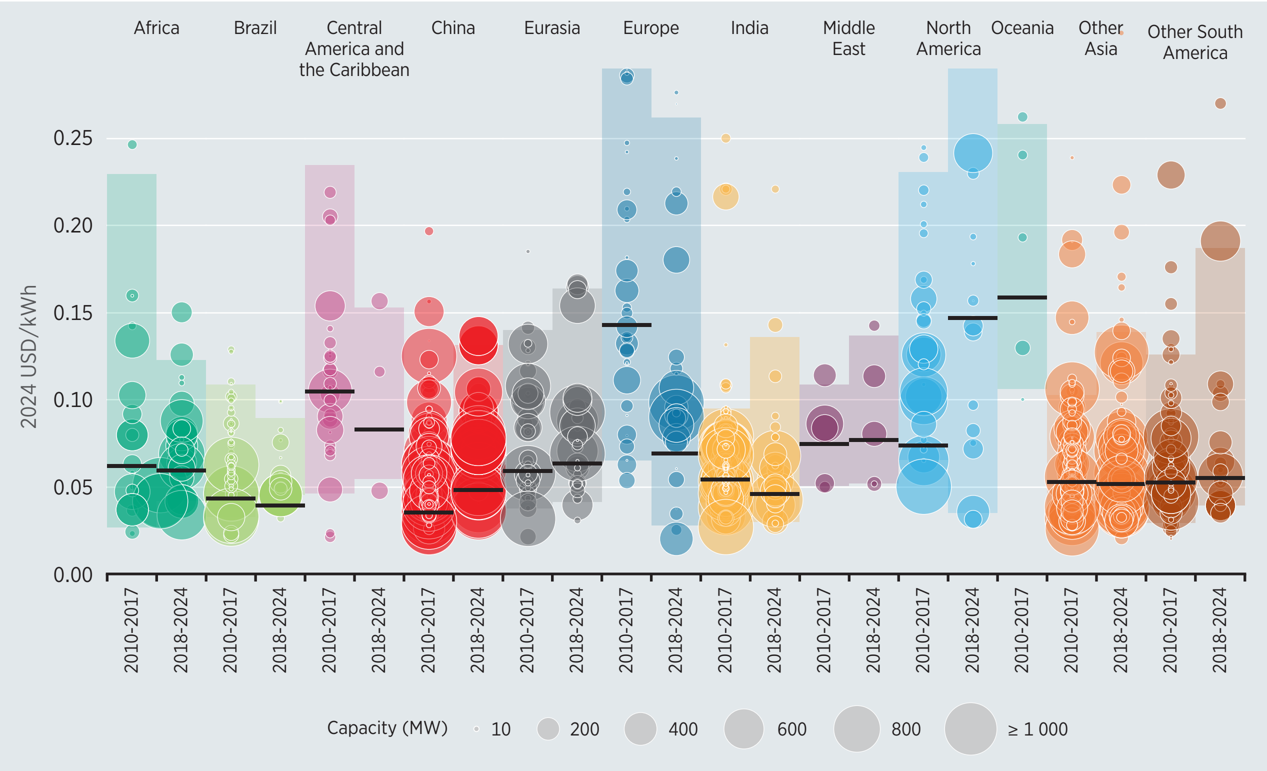
The weighted average country/regional LCOE of hydropower projects, large and small, in the IRENA renewable costs database reflects the variation in site-specific and country-specific project installed costs and capacity factors. Figures 7.8 and 7.9 present the LCOEs of large and small hydropower projects and the weighted averages by country/region.

For large hydropower projects, five of the regions and selected countries presented saw an increase in the weighted average LCOE between the periods 2010–2017 and 2018-2024. The five were: China, Eurasia, the Middle East, North America and Other South America. At the same time, in Africa, Brazil, Central America and the Caribbean, Europe, India and Other Asia the weighted average LCOE decreased. In the period 2018–2024, the highest weighted average LCOE corresponded with the highest total installed costs, which was recorded in North America, at USD 0.147/kWh. In contrast, Brazil had the lowest weighted average LCOE during the same period, at USD 0.040/kWh.

Between the periods 2010–2017 and 2018-2024, small hydropower projects showed a decrease in the weighted average LCOE in Africa, Brazil, Eurasia, Europe and Other Asia. There was, however, a different trend in China and India, where the weighted average LCOE increased. Between 2018-2024, India reported the highest weighted average LCOE, at USD 0.102/kWh, while Other Asia recorded the lowest, at USD 0.051/kWh.

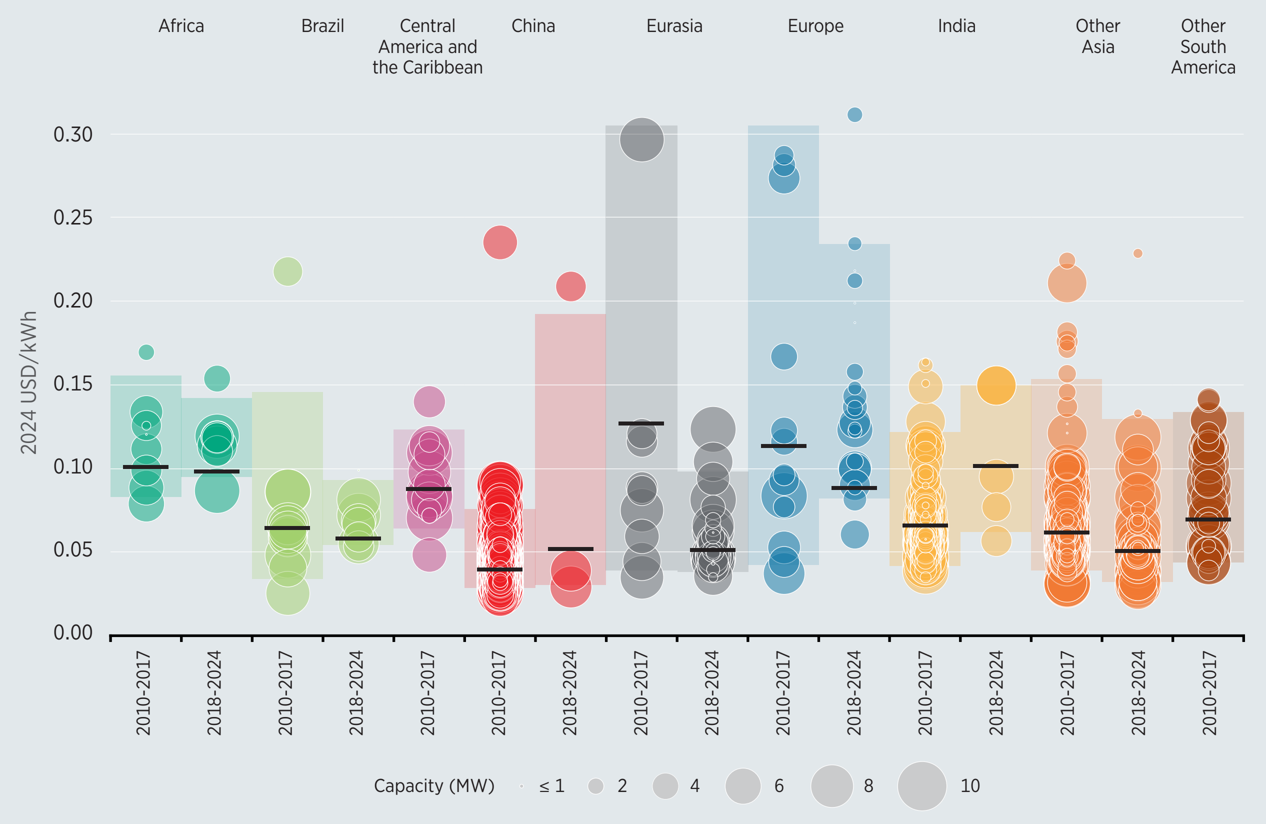
For small hydro, the available data was insufficient for Central America and the Caribbean and Oceania, and non-representative for Other South America. This meant that the trend for weighted average LCOE for small hydro projects in those regions could not be calculated accurately.

Figure 6.8 Large hydropower project LCOE and weighted averages by country/region, 2010–2024



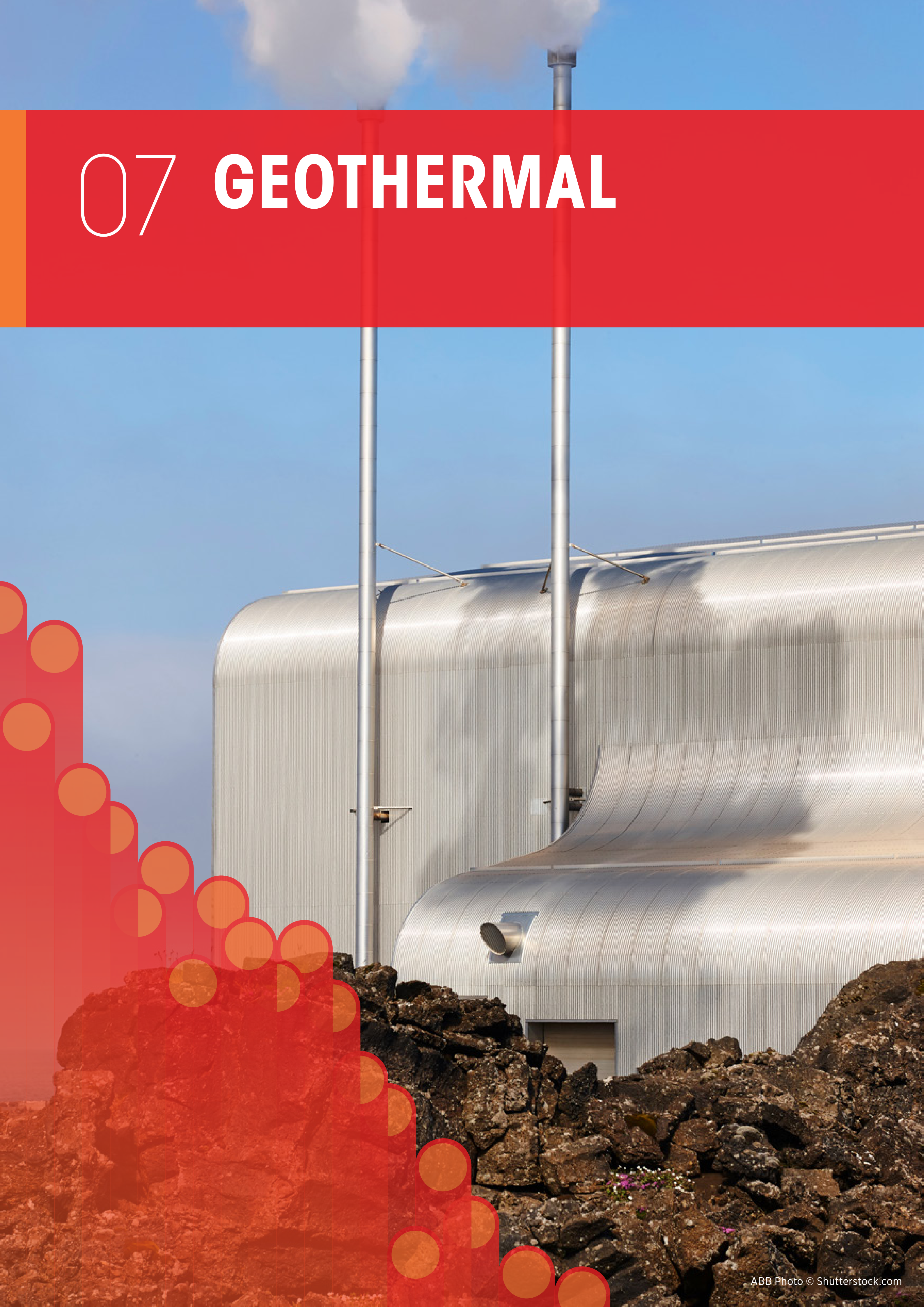
Notes: See Annex III for regional country groupings; kW = kilowatt; MW = megawatt; USD = United States dollar.

Figure 6.9 Small hydropower project LCOE and weighted averages by country/region, 2010–2024



Notes: See Annex III for regional country groupings; kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

07 GEOTHERMAL



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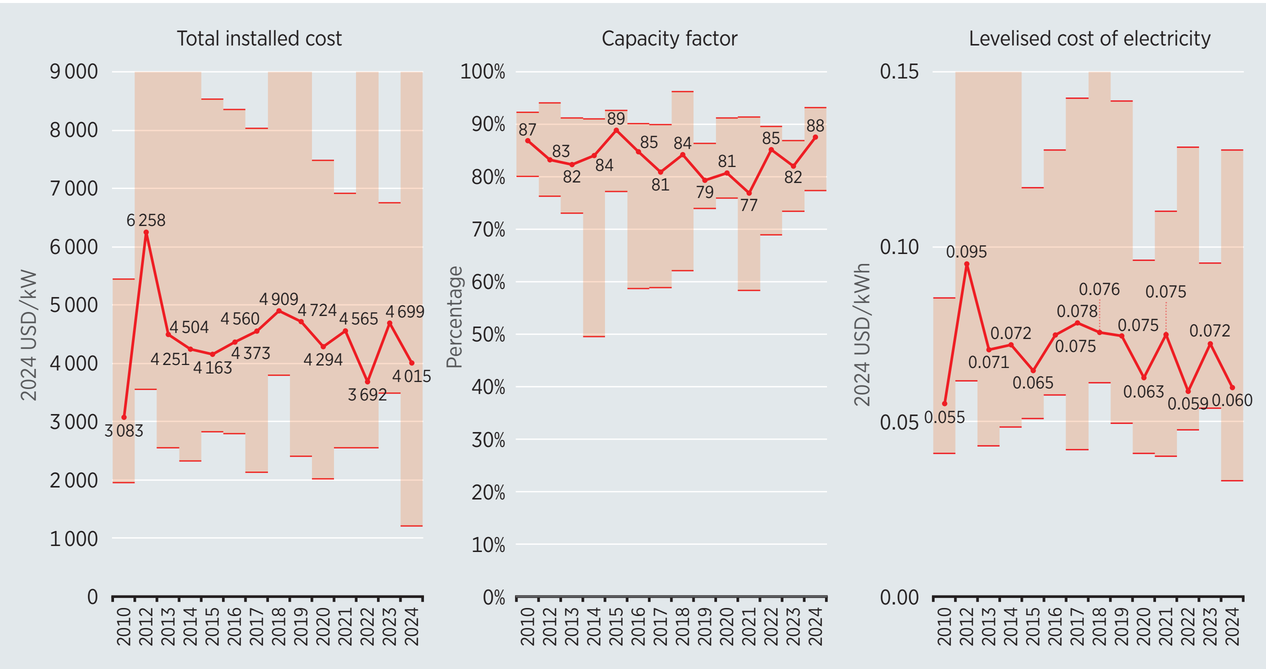
HIGHLIGHTS

- Worldwide, around 320 MW of new geothermal power generation capacity was commissioned in 2024. This brought global total installed capacity to almost 15.4 GW.
- The global weighted average LCOE of projects commissioned in 2024 was USD 0.060/kWh, representing a 16% decline from 2023.
- In recent years, the weighted average costs and performance of this technology have been determined by only a handful of plants. A low deployment rate for geothermal also explains the year-on-year fluctuation in costs.
- In 2024, the global weighted average total installed costs of the eight plants in IRENA's database was USD 4 015/kW, compared to the USD 4 699/kW recorded in 2023.
- Geothermal plants are typically designed to run as often as possible. This is in order to maintain constant flows from the reservoir and provide power around the clock. In 2024, the global weighted average capacity factor for newly commissioned plants was 88%.

Figure 7.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for geothermal, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

INTRODUCTION

At the end of 2024, geothermal power generation stations accounted for 0.35% of total installed renewable power generation capacity worldwide, with a total installed capacity of around 15.4 GW. Cumulative installed capacity at the end of 2024 was 56% higher than in 2010. This capacity was mostly located in active geothermal areas. The top five countries with the largest cumulative installed capacities were the United States, the Philippines, Indonesia, Mexico and New Zealand.

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 at a relatively low cost. These areas, with high-temperature water or steam at or near the surface, are commonly referred to as "active" geothermal areas. Where this is not the case, geothermal energy can still be extracted, however. This can be done by drilling to deeper depths and injecting water into the hot area through wells. In this way, the heat found in otherwise dry rocks can be harnessed.

Given the somewhat unique nature of geothermal resources, geothermal power generation is very different from other renewable power generation technologies. Indeed, developing a geothermal project presents a unique challenge when assessing the resource and how the reservoir will react once production starts. Subsurface resource assessments and reservoir mapping are expensive to conduct. Once completed, they must be confirmed by test wells. These allow developers to build models of the reservoir's extent and flow and how it will react to water and steam extraction for power generation. Much, however, will remain unknown about how the reservoir will perform and how best to manage it over the operational life of the project until actual operational experience is gained.

In addition to increasing development costs, these issues give geothermal projects very different risk profiles than other renewable power generation technologies. This is the case both in terms of project development and operation.

One of the most critical challenges faced when developing a geothermal power generation project lies in the availability of comprehensive geothermal resource mapping. Where it is available, this reduces the uncertainties that developers face during the field exploration period, which in turn also potentially reduces the development cost. This is because poorer-than-expected results during the exploration phase – such as lower than projected flow rates or reservoir permeability – might require additional drilling, or the deployment of wells over a much larger area, to generate the expected electricity. There is potential for governments to undertake some resource mapping and make this available to project developers in order to reduce project development risks and costs to consumers.

Once geothermal plants are commissioned, the management of the plant and its reservoir becomes a dynamic and evolving process. Unlike wind or solar PV, geothermal operations require ongoing adjustment as reservoir fluid is extracted and reinjected throughout the life of the project. The performance of individual production wells is then influenced by the natural change in fluid migration patterns. As operational experience grows, however, operators' understanding of a reservoir's behaviour improves, enabling more effective management of the plant over time.

Another important consideration for geothermal power plants is that once productivity at existing wells declines, there will often be a need for replacement wells to make up for this loss. As a result, lifetime O&M costs are, on average, higher in fixed terms than for other renewable technologies. Yet, with higher capacity factors, they can be similar on a per kWh basis.

TECHNOLOGICAL TRENDS

Next-generation geothermal energy is an emerging technology offering reliable and flexible electricity requiring small land areas. Enhanced geothermal systems (EGS) create artificial permeability by fracturing hot and dry rock, while advanced geothermal systems (AGS) employ a closed-loop system drilled into the rock. This makes AGS especially suitable for repurposing decommissioned oil and gas wells for energy production. These advanced systems can potentially double energy output per well, compared to conventional methods (Latham, 2024).

Traditionally run at full capacity, geothermal plants are now exploring flexible operations. In these, energy is stored underground during periods of low demand and released during peak demand. This makes geothermal plants a valuable complement to variable renewables, such as wind and solar. They are also suitable for long-duration energy storage, with efficiency rates between 59% and 93%. This flexibility suits large energy consumers, such as data centres and industrial facilities. Indeed, private and public entities are increasingly investing in geothermal through long-term PPAs. Google and Microsoft, for example, have recently signed PPAs for the development of geothermal powered data centres in the United States (Adie *et al.*, 2025).

Recent advances have also significantly cut drilling costs. EGS projects have shown improvements in drilling speed, reducing costs by up to 50%. These cost reductions are driven by better subsurface engineering, fewer wells needed for exploration, and design optimisation. Larger well diameters and improved stimulation methods also contribute (El-Sadi *et al.*, 2024).

With global interest resurging, the growth of next-generation geothermal depends on attracting new investors and overcoming regulatory hurdles. Continued innovation and government support are key to realising this technology's full potential.

TOTAL INSTALLED COSTS

In general, geothermal power generation projects require substantially higher capital investment than solar PV, hydropower and both onshore and offshore wind. Geothermal installed costs are more aligned with CSP. Like hydropower, geothermal plant costs are also highly site-sensitive, a key difference from the more standardised cost structures of solar PV and onshore wind.

Project development, field preparation, production and reinjection wells, the power plant, and associated civil engineering entail significant upfront costs for geothermal projects. These are also subject to variations in drilling costs, which have a direct impact on engineering, procurement, and construction (EPC) costs and are in turn often influenced by the business cycle in the oil and gas industry.

In particular, geothermal power project costs are heavily influenced by reservoir quality – that is to say, temperature, flow rates and permeability. This is because reservoir quality influences both the type of power plant and the number of wells required for a given capacity. The nature and extent of the reservoir, its thermal properties and its fluids (and at what depths they lie) will all have an impact on project costs.

In addition, the quality of the geothermal resource and its geographical distribution will determine the power plant type. This can be a flash, direct steam, binary, enhanced or a hybrid approach to providing the steam that will drive a turbine and create electricity. Typically, costs for binary plants designed to exploit lower temperature resources tend to be higher than those for direct steam and flash plants. This is because extracting the electricity from lower temperature resources is more capital intensive.

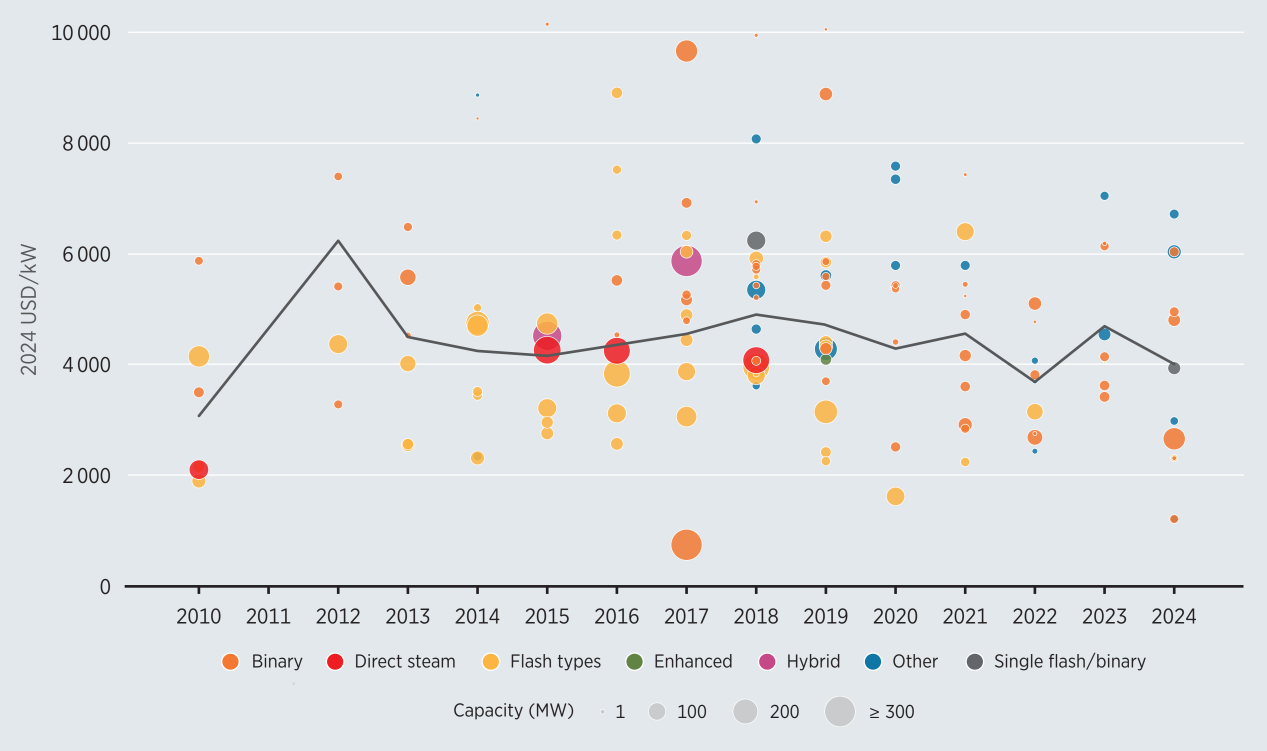
The total installed costs of geothermal power plants also include the cost of exploration and resource assessment. This includes seismic surveys and test wells. This cost category also applies to solar and wind resources, but resource assessment with weather stations costs much less than that for geothermal power plants.

For geothermal technology, drilling is one of the primary cost drivers, accounting for between 30% and 57% of the installation cost of a plant (Akindipe and Witter, 2025). As a result, improving drilling efficiency is critical. Recently, major gains have been achieved in this area by developers, cutting drilling times by over 60% across horizontal development wells. This has occurred in both pilot and commercial-scale projects (Latham, 2024).

Furthermore, if a large geothermal field needs to be exploited, the costs for field infrastructure, geothermal fluid collection, disposal systems and other surface installations can also be significant.

Based on the data available in the IRENA renewable costs database, total installed costs in 2024 ranged from a high of USD 6 724/kW to a low of USD 1 217/kW. Total installed costs reflect the specific costs of the geothermal generation plant, which includes factors such as the cost of exploration, plant equipment and construction. Then, there are BoS and financial costs. In 2024, the global weighted average total installed cost was USD 4 015/kW, which was 15% less than in 2023. Since 2010, the global weighted average has fluctuated annually. This has been due to the limited number of new geothermal plants, with cost trends largely influenced by the specific locations where projects are commissioned.

Figure 7.2 Geothermal power, total installed costs by project, technology and capacity, 2010–2024



Notes: kW = kilowatt; MW = megawatt; USD = United States dollar.

CAPACITY FACTORS

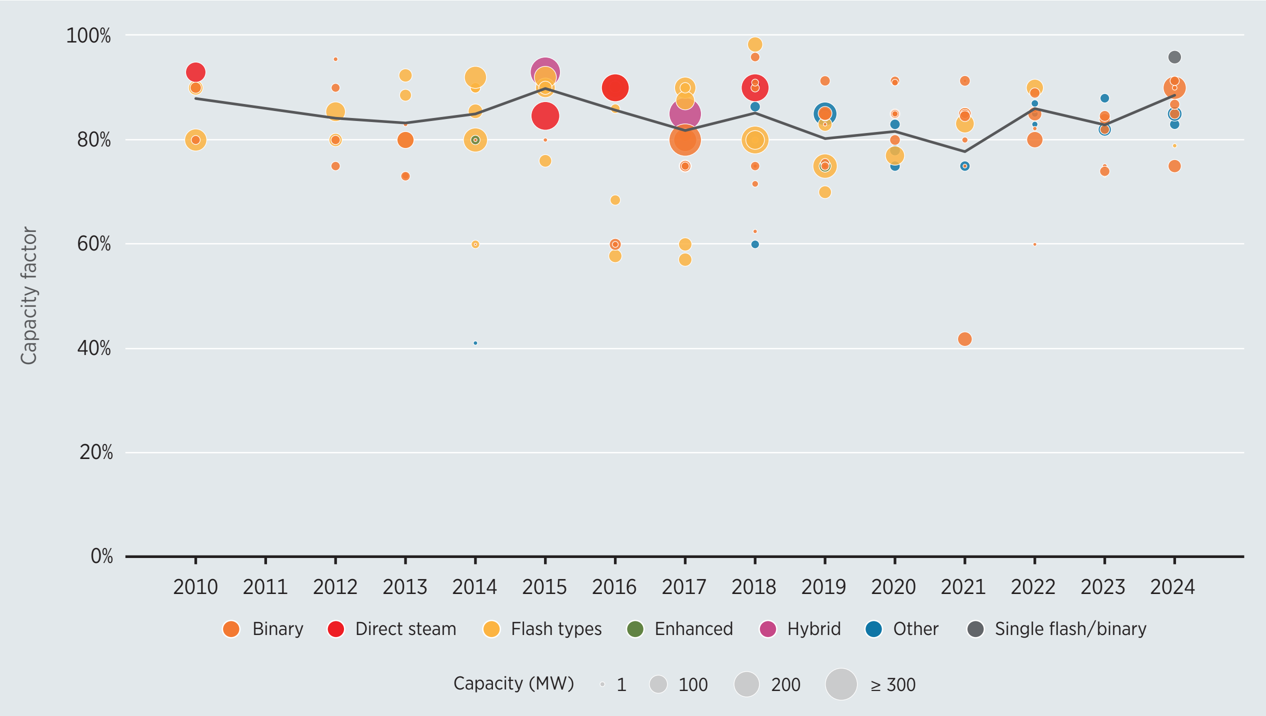
By accessing steam or heated water near the Earth's surface, geothermal plants have a continuous source of energy and tend to operate during most times of the year.

Data from the IRENA renewable costs database indicate that between 2010 and 2024, geothermal power plants typically had capacity factors that ranged from 50% to 96%, with some exceptions. There were, however, significant variations by project and – to a lesser extent – between countries. To name just three of the most important drivers, these variations were impacted by: the quality of the resource; the reservoir dynamics; and economic factors.

For the 2010–2024 period, Figure 7.3 presents the capacity factors of geothermal power plant projects in the IRENA renewable costs database by year, project size and technology.

In 2024, the global weighted average capacity factor for newly-commissioned geothermal projects was 88% – seven percentage points up on 2023. Looking at the different technologies, flash type plants had a capacity factor of 87% during the period, while the average for single flash/binary plants was 96%.

Figure 7.3 Capacity factors of geothermal power plants by technology and project size, 2010–2024



Note: MW = megawatt.

O&M COSTS

O&M costs for geothermal projects are high relative to onshore wind and solar PV. In particular, this is because over time the reservoir pressure around the production well declines, leading to poorer flow rates. The productivity of the well therefore deteriorates over time. Eventually, power generation production also falls, if remedial measures are not taken.

To maintain production at the designed capacity factor, the reservoir and production profile of the geothermal power plant therefore require agile management. This will also typically include the need to incorporate additional production wells over the lifetime of the plant.

The O&M cost assumption applied for projects commissioned in 2024 was USD 125/kW per year and USD 110/kW per year for projects deployed between 2010 and 2023. Those values include two sets of wells for makeup and reinjection – necessary to maintain performance over the 25-year life of the project.

LCOE

The total installed costs, WACC, economic lifetime and O&M costs of a geothermal plant determine its LCOE. Geothermal power plants tend to have higher installed costs, O&M costs and capacity factors than hydropower, some bioenergy plants, solar PV and onshore wind projects. The higher capacity factors help to offset the higher capital and operating costs, while also indicating that the plant runs during most hours of the day.

Where available, the capacity factors used here were taken from project data, while national averages were used if no specific project information was available.

Even more so than with solar and wind technologies, geothermal power projects require continuous optimisation throughout their lifetime. The sophisticated reservoir and production well management required to ensure output meets expectations does, however, also lead to higher O&M costs.

Figure 7.4 presents the LCOE of geothermal power projects by technology and size for the period 2010–2024. During 2024, the LCOE varied from as low as USD 0.033/kWh to as high as USD 0.090/kWh.

The LCOE of geothermal power projects tends to follow the trends in total installed costs, with typically little variation in capacity factors, considering the diversity of geothermal technologies.

The data available suggest the LCOE was relatively stable between 2013 and 2023, with a global weighted average ranging between USD 0.059/kWh and USD 0.078/kWh. In 2024, the global weighted average LCOE decreased 16%, year-on-year, to USD 0.060/kWh. This was a value close to the global weighted average LCOE for geothermal registered in 2022. The cost trend was driven by the largest project deployed in 2024, which was in New Zealand.

Figure 7.4 LCOE of geothermal power projects by technology and project size, 2010–2024

Notes: kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

08 BIOENERGY

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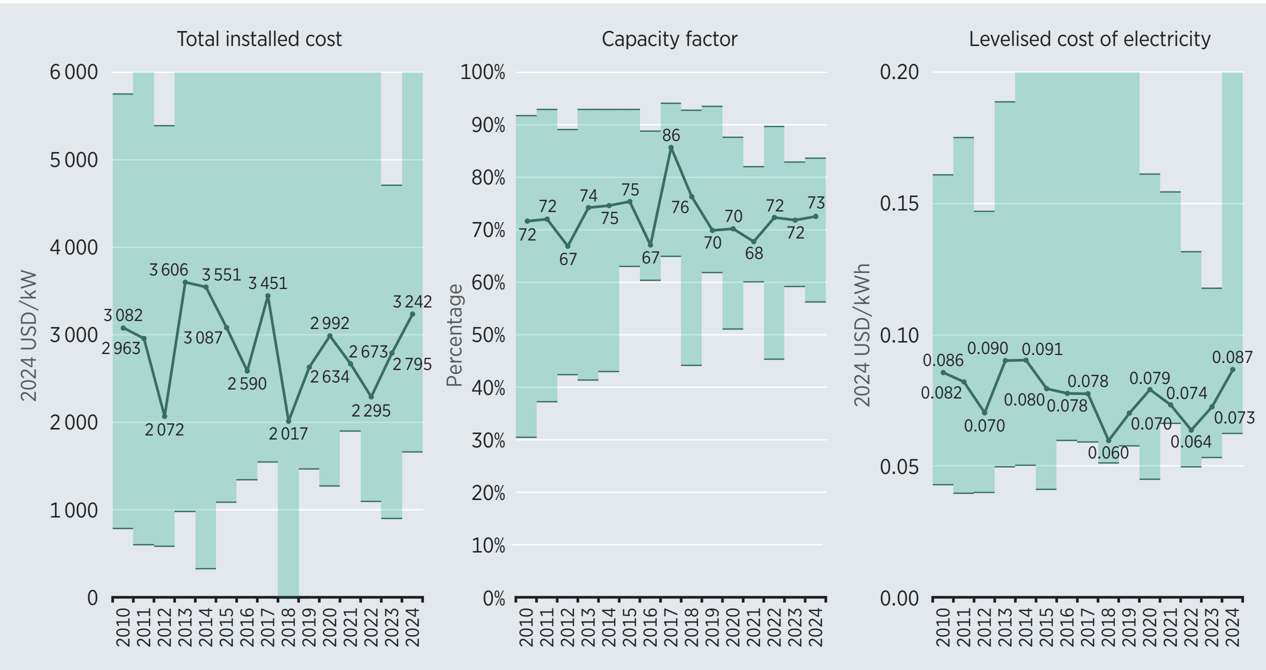
HIGHLIGHTS

- Between 2010 and 2024, the global weighted average LCOE of bioenergy for power projects did not follow a specific upward or downward trend. In 2024, the LCOE was 0.087/kWh. This value was 1% higher than in 2010 and 19% higher than the 2023 value of USD 0.073/kWh. Nonetheless, in 2024, the LCOE remained below the peak levels observed during the 2010–2024 period.
- Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available, it can provide highly competitive, dispatchable electricity. It also provides a flexible, dispatchable power source essential for grids integrating more variable renewables.
- For bioenergy projects newly commissioned in 2024, the global weighted average total installed cost was USD 3 242/kW (see Figure 8.1). This represented a 16% increase on the 2023 weighted average of USD 2 795/kW.
- Capacity factors for bioenergy plants are heterogeneous, depending on technology and feedstock availability. Between 2010 and 2024, the global weighted average capacity factor for bioenergy projects varied between 67%, recorded in 2012 and 2016, and 86%, recorded in 2017. The 2024 global weighted-capacity factor was 73%.
- In 2024, the weighted average LCOE ranged from lows of USD 0.062/kWh and USD 0.065/kWh in India and in China, respectively, to highs of USD 0.096/kWh in Europe and USD 0.106/kWh in North America.

Figure 8.1 Global weighted average and range of total installed costs, capacity factors and LCOEs for bioenergy, 2010–2024



Notes: kW = kilowatt; kWh = kilowatt hour; USD = United States dollar.

INTRODUCTION

Since 2010, bioenergy capacity has grown steadily worldwide, with annual additions ranging from a low of 2.6 GW in 2023 to 9.4 GW in 2020 (IRENA, 2025d). In 2024, bioenergy contributed around 1% of the global total of renewable power capacity additions, with 5.1 GW of new bioenergy projects installed. France, China, Japan, India and the United Kingdom have the largest shares of installed capacity, accounting for more than three-quarters of the global total.

Electricity generation from bioenergy is shaped by three fundamental factors: the type and availability of feedstock; the conversion and transportation processes; and the power generation technologies employed. These elements collectively determine the performance, cost-effectiveness and sustainability of bioenergy systems.

Bioenergy electricity production relies on a diverse array of feedstocks. In 2024, the most dominant was solid biofuels, such as woodchips, pellets and bagasse. Together, these represented around 84% of total installed capacity. This was followed by renewable municipal waste, which accounted for 15% of additions (IRENA, 2025d).

Feedstocks vary widely in composition, moisture content and energy density (Mutlu and Tuncer, 2024). Between on-site processing residues and dedicated energy crops, their cost also varies significantly. Feedstocks such as sugar cane bagasse, rice husks, black liquor, other pulp and paper processing residues, sawmill offcuts and sawdust, and renewable municipal waste streams offer low-cost, sustainable inputs. On the other hand, dedicated energy crops require more investment in land use, harvesting, logistics and storage, thus affecting the economics of biomass power generation.

The conversion and transportation processes are critical to system cost and efficiency. Feedstock heterogeneity and its physical properties – such as ash content, density, particle size and moisture – also impact storage, pre-treatment and the suitability of specific conversion technologies. Some systems, such as direct combustion boilers, can handle a broad range of inputs, while others, like advanced gasifiers, require more uniform material properties. Additionally, transport logistics significantly affect project feasibility. The greater the distance between the feedstock source and the plant, the higher the costs, so in practice, bioenergy plants tend to be most cost-effective when supplied by feedstocks sourced within a limited radius.

In addition, bioenergy power generation spans a spectrum of technologies. These range from mature, commercially proven systems to innovative, emerging technologies. The latter category includes atmospheric biomass gasification and pyrolysis – technologies that are still in the developmental stage, but are now being tested 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 (CHP).

TECHNOLOGICAL TRENDS

Bioenergy offers unique opportunities to support the energy transition. The technology can serve as dispatchable power, providing flexibility to grids with growing shares of variable renewables. Biomass co-firing also offers a transitional pathway in the phase-out of coal, while CHP applications can efficiently serve industrial users and district heating networks. Moreover, bioenergy combined with carbon capture and storage (BECCS), can deliver net-negative emissions, positioning it as a strategic option for achieving long-term climate goals (IRENA, 2022).

TOTAL INSTALLED COSTS

Different regions have differing costs for biomass power generation, with both a technological and local cost component. The total installed costs (TICs) of bioenergy power generation projects typically include planning, engineering and construction costs, along with machinery for fuel handling and preparation. They also include costs for key equipment, such as the prime mover and fuel conversion system. Additional expenses are derived from grid connection and infrastructure, such as civil works and roads.

Yet, while equipment often accounts for the largest share of total costs, some projects face elevated infrastructure or logistics related expenses, especially in remote or off-grid locations. CHP biomass installations have higher capital costs, but their overall efficiency – which ranges from 80% to 85% – and their ability to produce heat and/or steam for industrial processes or district heating networks, can significantly enhance their economic viability.

For the 2000–2024 period, Figure 8.2 presents the total installed cost of bioenergy-fired power generation projects for different feedstocks, where IRENA has sufficient data to provide meaningful cost ranges.

Although the pattern of deployment by feedstock varies by country and region, TICs across feedstocks tend to be higher in Europe and North America. Between 2000 and 2024, costs in these two regions ranged across the 5th and 95th percentiles, stretching in North America from a low of USD 745/kW for landfill gas projects[45] to a high of USD 7 384/kW for wood waste. In Europe, costs ranged from a low of USD 858/kW for other vegetal and agricultural waste, to a high of USD 7 848/kW for wood waste.

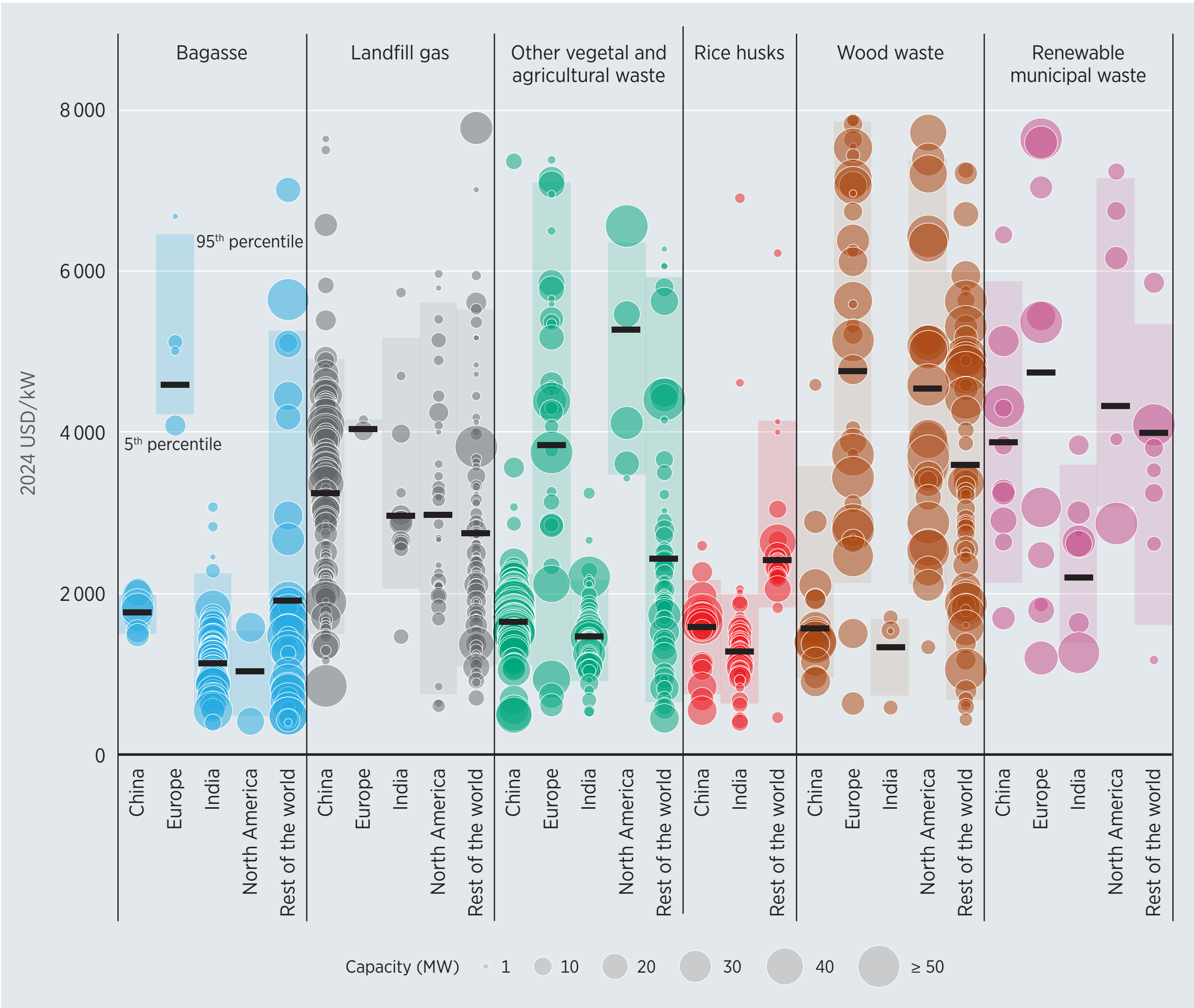
In China, for the 2000-2024 period, the 5th and 95th percentiles of projects across all feedstocks saw TICs range from a low of USD 746/kW for rice husk projects to a high of USD 5 864/kW for renewable municipal waste projects. In India, the range was from a low of USD 603/kW for bagasse projects to a high of USD 5 171/kW for landfill gas projects.

[45] *These figures exclude the TICs for bagasse, which are not representative given that there are only two projects in the database.*

The data available by feedstock for the rest of the world was more limited, but the 5th and 95th percentile TIC range for other vegetal and agricultural waste was the widest. In this category, the data stretched from USD 657/kW to USD 5 911/kW.[46] For the period covered, the weighted average total installed cost for projects in the rest of the world typically ranged between the lower values seen in China and India and the higher values prevalent in Europe and North America.

Across all countries and regions, landfill gas and rice husks stand out as the most consistent feedstocks in terms of weighted average total installed costs, showing minimal variation across geographies. The sample standard deviation of capital costs was USD 504/kW for landfill gas and USD 588/kW for rice husks. For comparison, more heterogeneous feedstocks, such as other vegetal and agricultural waste or wood forest residues, were observed to be exhibiting standard deviations sometimes exceeding USD 1 000/kW.

Figure 8.2 Total installed costs of bioenergy power generation projects by selected feedstocks and country/region, 2000–2024



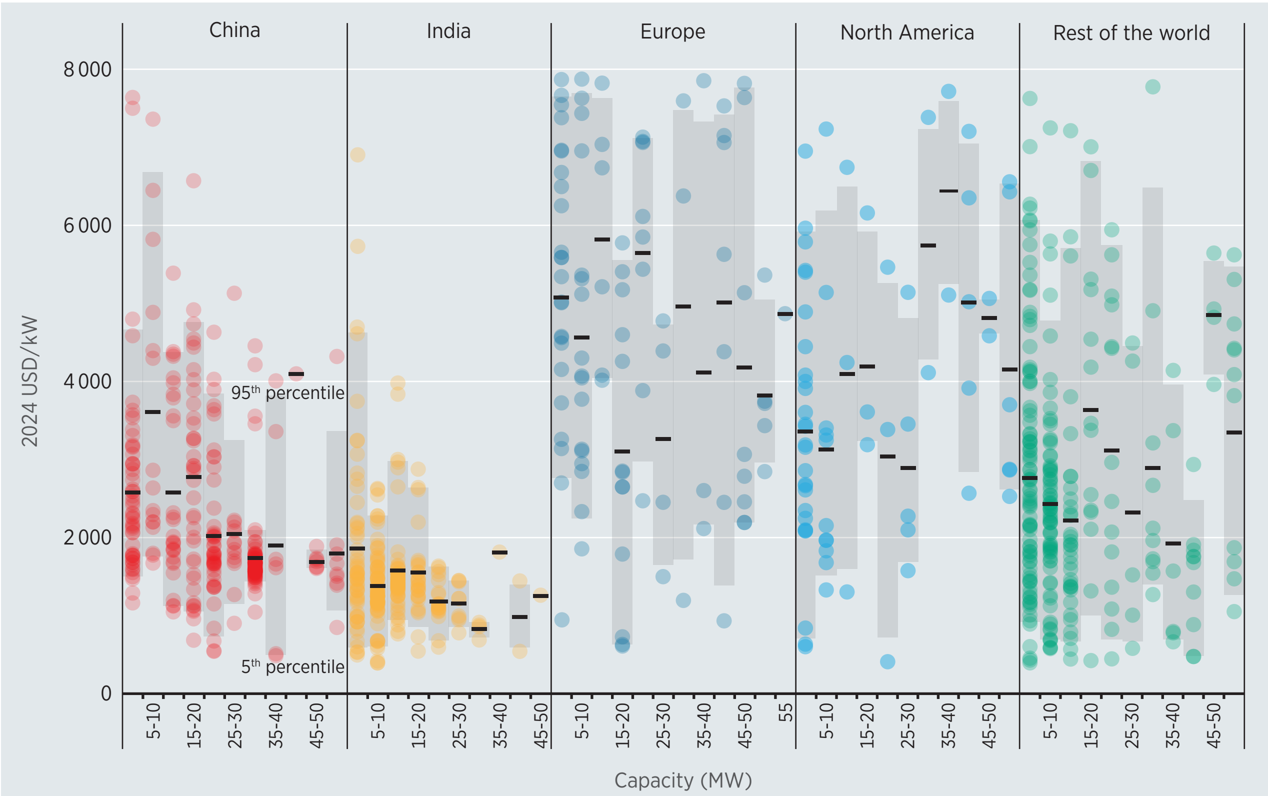
Notes: See Annex III for regional country groupings; kW = kilowatt; MW = megawatt; USD = United States dollar.

[46] *These figures exclude the TICs for renewable municipal waste, which are not representative given that there are only three projects in the database.*

Figure 8.3 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 under 25 MW in capacity. There are, however, clear economies of scale evident for plants roughly above 25 MW – at least in the data for China and India.

The relatively small plant size of bioenergy for electricity 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 the LCOE of a project, in this context, is a trade-off between the cost benefits of economies of scale and the higher feedstock costs. The latter grow as the average distance from the sourced feedstocks to the plant expands.

Figure 8.3 Total installed costs of bioenergy power generation projects for different capacity ranges by country/region, 2000–2024



Note: See Annex III for regional country groupings; kW = kilowatt; MW = megawatt; USD = United States dollar.

CAPACITY FACTORS

Bioenergy electricity plants can usually reach capacity factors as high as 85% to 95% when the supply of feedstock is consistent throughout the year. If feedstock availability relies on seasonal agricultural harvests, however, the capacity factor is often diminished. An emerging concern for bioenergy power plants is the potential impact of climate change on feedstock availability. This factor may alter the total annual volume and its distribution across the year. This underscores the ongoing need for research as climate patterns evolve.

Figure 8.4 shows that biomass plants that rely on bagasse tend to have lower average capacity factors. For the period in question, these were typically around 50% to 60%, with a lower end of 39% in North America and a higher end of 82% in Europe. Plants relying on other vegetal and agricultural waste and wood waste have weighted average capacity factors by region that range from 63% to 93%. Among these, wood waste stands out as the most stable feedstock, with weighted average capacity factors across the regions that are tightly clustered between 68% and 78%.

Figure 8.4 Capacity factors and weighted averages of selected feedstocks for bioenergy power generation projects by country and region, 2000–2024

Note: See Annex III for regional country groupings; MW = megawatt.

Table 8.1 presents the weighted average capacity factors of bioenergy-fired power generation projects for the period 2000–2024. According to the IRENA renewable costs database, North America showed the highest weighted average capacity factor for the period, at 85%, followed by Europe, with 81%. India and the rest of the world showed lower weighted average capacity factors – 68% each – while China recorded 66%.

Table 8.1 Weighted average capacity factors of bioenergy fired power generation projects, 2000–2024

	2000-2024		
	5th percentile (%)	Weighted average (%)	95th percentile (%)
China	44	**66**	81
Europe	57	**81**	91
India	35	**68**	90
North America	50	**85**	93
Rest of the world	39	**68**	91

Note: See Annex III for regional country groupings.

O&M COSTS

Fixed O&M costs include expenses related to labour, insurance and scheduled maintenance. They also include routine replacement of plant components, such as boilers and gasifiers, feedstock handling equipment and other associated costs. Generally, these costs constitute between 2% and 6% of the TICs per year. Larger bioenergy power plants typically have lower fixed O&M costs per kW, due to economies of scale.

Variable O&M costs for bioenergy power plants are generally lower than fixed O&M costs, averaging around USD 0.004/kWh. The primary components of variable O&M costs are replacement parts and incremental servicing costs, including non-biomass fuel expenses such as ash disposal. Due to project specific variations and limited available data, this report combines variable O&M and fixed O&M costs.[47]

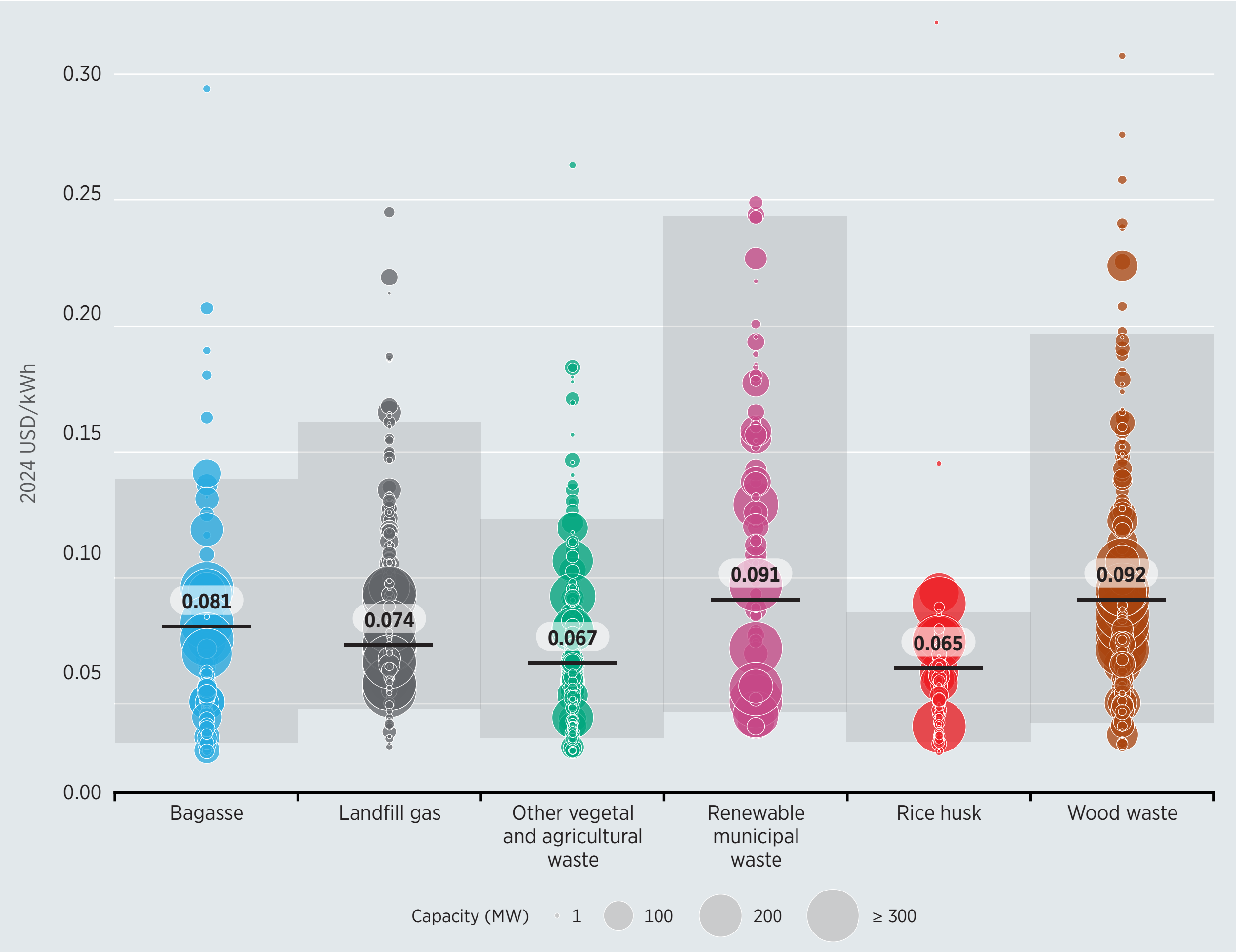
LCOE

The wide range of bioenergy-fired power generation technologies, installed costs, capacity factors and feedstock costs results in a variety of observed LCOEs for bioenergy-fired electricity. Where capital costs are relatively low and low-cost feedstocks are available, bioenergy can provide very competitive electricity. 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.

[47] *These assumptions have remained unchanged since IRENA's Renewable Power Generation Costs, 2017 (IRENA, 2018). However, in 2024, values were adjusted using a GDP deflator to account for the effects of inflation.*

Using figures from the IRENA renewable costs database, where sufficient data is available, Figure 8.5 presents the LCOE of bioenergy projects by feedstock over the 2000–2024 period. Among all feedstocks, rice husk-based projects had the lowest weighted average LCOE, at USD 0.065/kWh. This was consistent with their relatively low TICs. Wood waste projects experienced the highest LCOE, recording a weighted average of USD 0.092/kWh. Although wood waste benefits from stable capacity factors across regions, variability in installed costs between countries results in a broader LCOE range.

Figure 8.5 LCOE and weighted averages of bioenergy power generation projects by feedstock, 2000–2024



Notes: kW = kilowatt; kWh = kilowatt hour; MW = megawatt; USD = United States dollar.

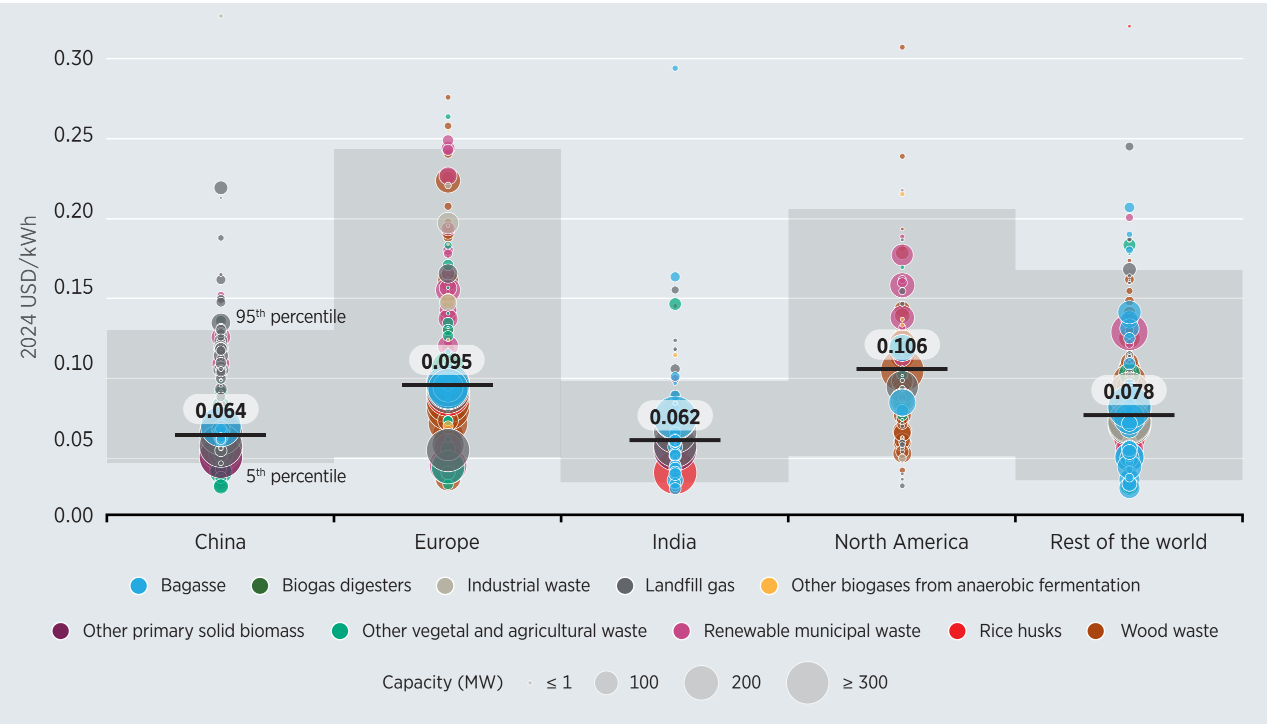
Figure 8.6 summarises the estimated LCOE range for biomass power generation technologies by feedstock and country/region, where the IRENA renewable costs database has sufficient data to provide meaningful insights.

Looking at the full dataset for the period from 2000 to 2024, the lowest weighted average LCOE of biomass-fired electricity generation was found in India, where it stood at USD 0.062/kWh. In addition, India's 5th and 95th percentile values were USD 0.035/kWh and USD 0.096/kWh, respectively (see Figure 8.6). The highest weighted average for this period was USD 0.106/kWh, which was recorded in North America. There, the 5th and 95th percentiles of projects fell between USD 0.052/kWh and USD 0.206/kWh.

Over the same period, the weighted average LCOE of bioenergy projects in China was USD 0.064/kWh, with the 5th and 95th percentiles of projects falling between USD 0.048/kWh and USD 0.130/kWh. The weighted average in Europe over this period was USD 0.095/kWh, while in the rest of the world it was USD 0.078/kWh.

Municipal waste used for bioenergy often results in high capacity factors and serves as an economically viable source of electricity. The LCOE for such projects in North America, however, is notably higher than the average in other regions. Projects there have been developed primarily to address waste management issues, rather than to maximise competitiveness in electricity production. This means that a higher LCOE may not necessarily compromise their feasibility. In contrast, similar projects in Europe frequently supply heat to local industrial users or district heating networks. This generates additional revenue that brings down the LCOE below the values presented here. Additionally, many of the higher-cost projects in Europe and North America use municipal solid waste as a feedstock and rely on technologies with higher capital costs. These more expensive technologies are used in order for plants to meet emissions regulations.

Figure 8.6 LCOE and weighted averages of bioenergy power generation projects by feedstock and country/region, 2000–2024

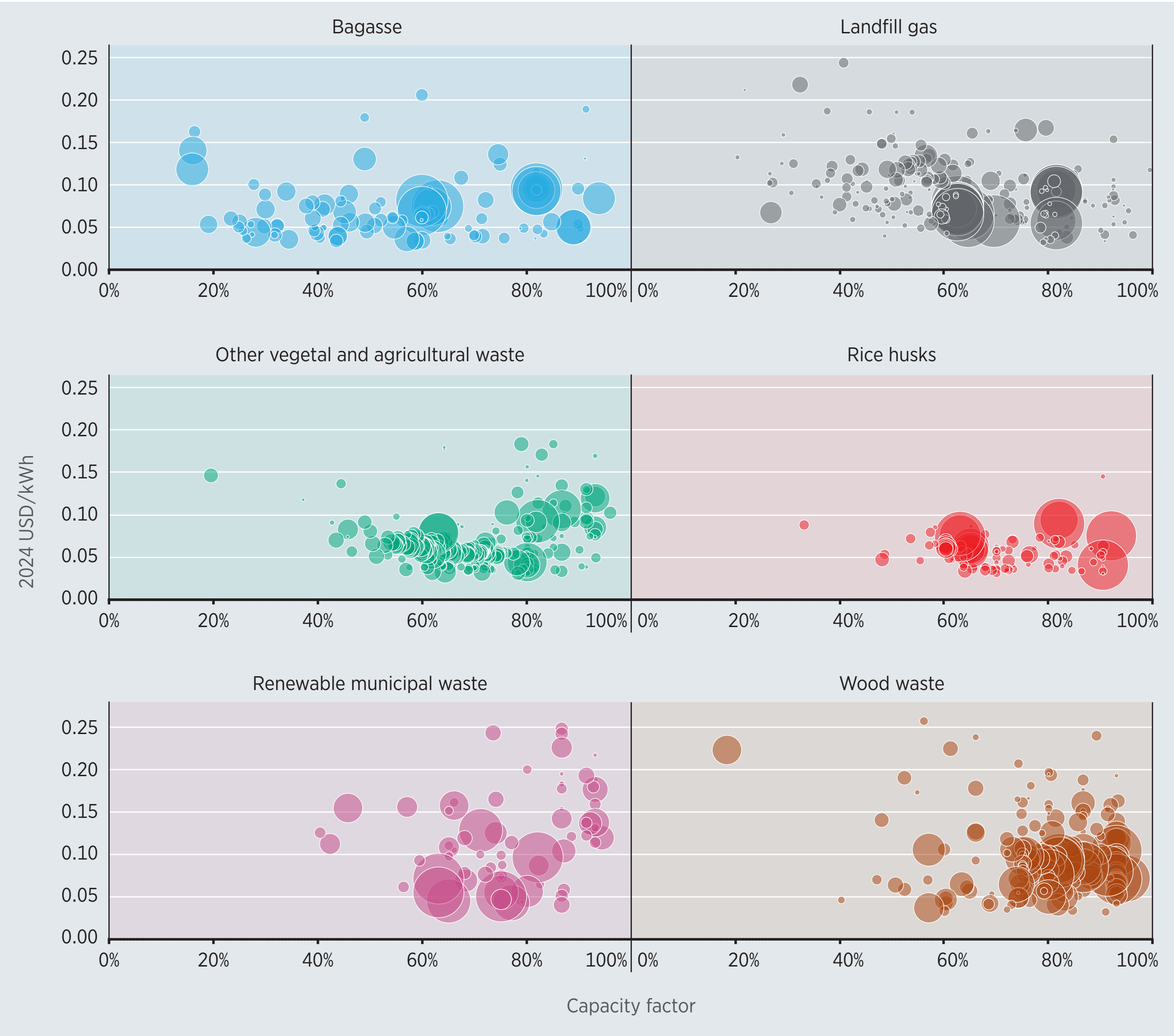


Notes: See Annex III for regional country groupings.; kWh = kilowatt hour; MW = megawatt.

Figure 8.7 presents the LCOE and capacity factor by project and weighted average for bagasse, landfill gas, other vegetal and agricultural waste, rice husks, renewable municipal waste, and wood waste. The data underscores how the availability, seasonality and characteristics of each feedstock affect a project's economic viability. For instance, in bagasse plants with a capacity factor above 30%, there is no strong relation between the capacity factor and the LCOE of the project. This suggests that while a continuous feedstock supply can enable higher capacity factors, this may not necessarily be more cost-effective – especially if it requires supplementing low-cost seasonal agricultural residues with expensive feedstocks.

For landfill gas-based projects, a clearer trend emerges – higher capacity factors are generally associated with lower LCOEs. This reflects the advantage of on-site, steady feedstock availability, which in turn supports continuous operation and improved cost efficiency. Ultimately, the figure demonstrates that optimising feedstock sourcing is just as important as technological efficiency in determining the economic performance of bioenergy projects.

Figure 8.7 LCOE and capacity factor of selected feedstocks for bioenergy power generation projects, 2000–2024



Note: kWh = kilowatt hour; USD = United States dollar.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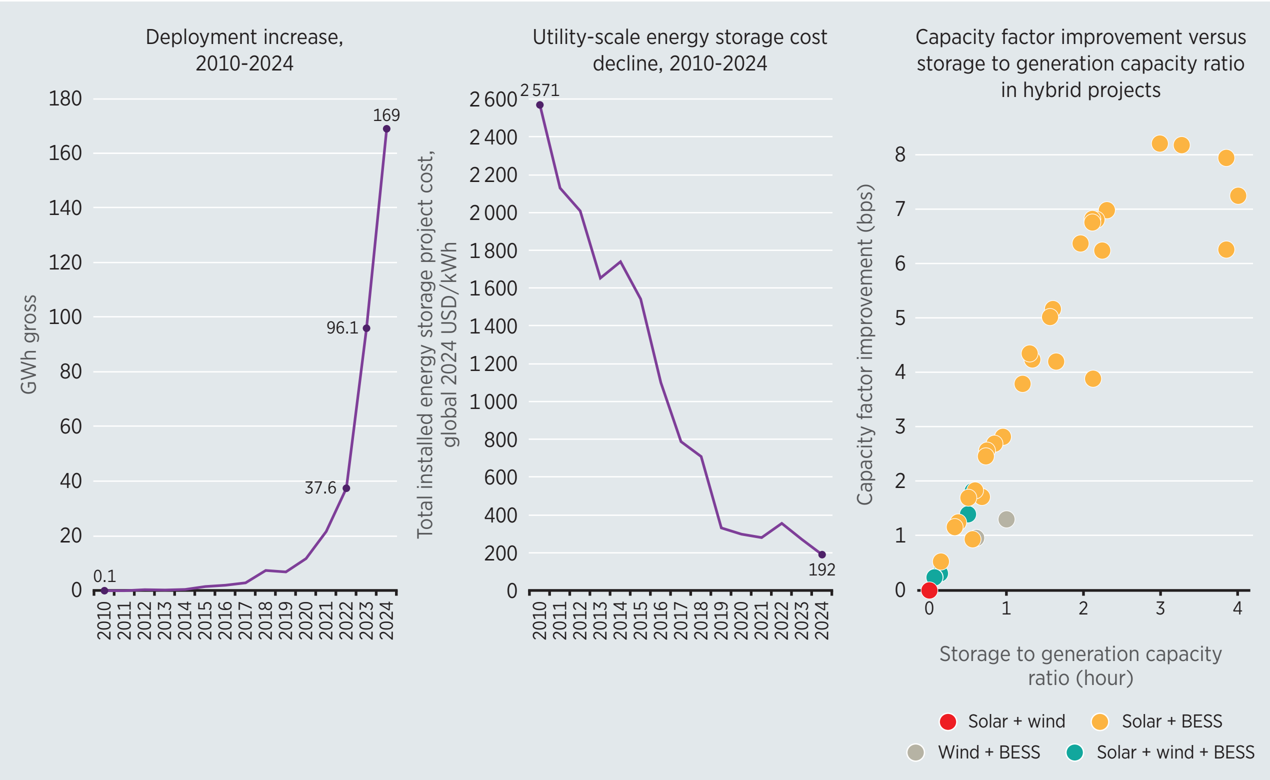
09 ENABLING TECHNOLOGIES

HIGHLIGHTS

- Between 2010 and 2024, the costs of battery storage projects declined 93%, from USD 2 571/kWh to USD 192/kWh. This cost reduction was driven by technological advancements in battery chemistries, materials efficiency improvements, manufacturing scale-up and optimisation, as well as increased market competition.
- Annual capacity additions for chemical battery storage increased from 0.1 GWh gross capacity in 2010 to 169 GWh gross capacity in 2024.
- China led in terms of new additions, installing 84 GWh in 2024 and accounting for half of total global additions.
- The United States was the second largest market, adding 41 GWh of BESS and representing almost a quarter of the total new added capacity.
- Energy shifting is the main application of electricity storage, accounting for 68% of the total added capacity in 2024. Energy shifting balances the power system by storing renewable energy production at times of low market prices (leading to low/null revenue), or low demand (leading to curtailments).
- The commissioning of renewable energy projects coupled with of battery energy storage systems (BESS) has increased over the past two years, and more of these projects are expected to come online in the near future, ensuring greater grid flexibility.
- In hybrid wind and solar projects, increasing the storage-to-generation capacity ratio generally leads to greater improvements in capacity factor. However, these gains must be balanced against the upfront costs of BESS.

Figure 9.1 Global deployment increase and utility-scale energy cost decline, 2010–2024 (left) and capacity factor improvement in hybrid systems (right)



Notes: bps = basis points; BESS = battery energy storage system; GWh = gigawatt hour; kWh = kilowatt hour; USD = United States dollar.

INTRODUCTION

The energy transition requires urgent and substantial acceleration across the energy supply and end-use sectors, as well as the leveraging of technologies to achieve global climate goals. Currently, the rising competitiveness of renewables in comparison to fossil fuels is driving extensive deployment of the former, and the goal to triple renewable energy capacity by 2030 agreed at COP28 sets an ambitious and significant target. In the next few years of this decade, extensive deployment of renewable power generation in more countries and regions is expected. As the electricity system evolves, enabling technologies are also being introduced to facilitate the transition from a fossil fuel-based system to one based on renewables (IRENA, 2024).

Today, a wide variety of energy storage solutions are available, including: electrochemical storage (notably lithium-ion batteries, but also flow batteries and those using other chemistries); thermal energy storage (which employs rocks, bricks or molten salts to store heat); mechanical technologies (using compressed air, liquid air or gravitational potential such as in conventional and novel pumped hydro); and chemical storage (storing energy in chemical bonds, such as hydrogen or its derivatives).

With a growing share of variable renewable power generation, energy storage will play a crucial role in ensuring the successful delivery of a reliable electricity system. By capturing surplus electricity and releasing it when needed, batteries enhance system flexibility, cut transmission losses and relieve grid congestion. Energy storage technologies, such as chemical batteries or pumped hydro storage, have fast-response capabilities and can stabilise frequency, bolster resilience during outages and provide backup power, thereby safeguarding grid security. At the same time, storage underpins the clean energy transition by reducing dependence on fossil-fuels and lowering overall emissions. Finally, by deferring costly transmission and distribution upgrades, and enabling market arbitrage opportunities, battery systems deliver significant economic value to both grid operators and end users.

Electricity storage is already an important tool in minimising overall electricity system costs – mainly using pumped hydropower storage systems. It can also provide ancillary services to the electricity market and offer energy arbitrage. Ancillary services provide stability and reliability to the grid, while energy arbitrage often involves storing electricity at times of relative surplus, such as overnight, for release when wholesale prices or generating costs are higher. However, it is noteworthy that electricity flexibility needs encompass time scales that range from seconds to entire seasons. Electricity storage, particularly in the form of batteries, is entirely relevant, but only up to daily time scales. It cannot solve, for example, the mismatch between PV production in summer and maximum energy demand in winter for space heating in many northern countries. Unlike short-duration batteries, long-duration energy storage (LDES) can support a broader range of grid services — from supplying short-term reserves to addressing extended energy shortfalls. It also helps minimise reliance on coal and gas power plants, enables continuous use of renewable energy, and can delay the need for major grid infrastructure upgrades (BNEF, 2021).

Storage can be coupled directly with solar PV or wind (as with hybrid generation assets), or function as a standalone asset, optimising distribution and transmission systems. Other hybrid system configurations exist and a growing number of hydropower and pumped hydro storage projects are being co-located with wind, ground-mounted solar PV systems as well as floating solar installations. Hybrid systems deliver more predictable, dispatchable power profiles, helping to mitigate the impacts of grid connection delays, curtailment risks, and network congestion, by absorbing excess generation and smoothing demand peaks. As grid modernisation efforts advance, co-locating storage with renewables is proving to be a key enabler for accelerating renewable deployment. Battery storage is increasingly being deployed in hybrid configurations, with renewable technologies, enhancing their value and grid compatibility.

LONG DURATION ENERGY STORAGE

As the energy transition accelerates to 2030, the system will need long-duration energy storage (LDES), as well as a combination of other flexibility measures (bioenergy for power, geothermal, reservoir storage hydropower, demand-side management, interconnectors, *etc.*). LDES technologies are well adapted to ensure the resilience of the electricity system thanks to their capacity to discharge over long periods of time, especially in a system relying on more variable renewable sources. LDES offers durations of at least six hours and can complement short duration applications, such as lithium-ion batteries.

A variety of LDES technologies are emerging, including chemical, electro-chemical, thermal and mechanical. The global total installed capacity of long duration energy storage reached 1 GW in 2024, representing an energy capacity of 4.6 GWh (Zhou, 2024). Currently, the electricity storage landscape is dominated by conventional pumped hydroelectricity storage (PHS), with around 150 GW of cumulative power capacity in 2024 (IRENA, 2025d). While first used to support nuclear fleets, many countries are expanding and increasingly utilising their pumped storage hydropower capacity to enhance electricity storage and grid flexibility for variable renewable integration. Pumped storage hydropower (PSH), is increasingly utilised in Europe (Germany, Switzerland and Spain) and in Asia (China and India), expanding national capacities to enhance grid flexibility (Ember, 2025a; GLOBSEC, 2024).

While LDES technologies often remain costlier than lithium-ion batteries, continued innovation and supportive policies are key to reducing costs and unlocking broader deployment potential. Costs depend on the technology, project size, storage duration and location. Conventional pumped storage is still the most competitive technology, with a global average installed cost of USD 156/kWh; thermal storage, such as molten salt and solid state, has a global average installed cost of USD 238/kWh. For emerging technologies, costs range from USD 300/kWh for compressed air energy storage (CAES) to USD 658/kWh for gravity energy storage (BNEF, 2024a). The viability and performance of LDES for extended storage needs are expected to improve as technology advances and practical experience grows. Early adoption and faster commercialisation may also depend heavily on favourable regulatory and policy frameworks.

An increasing number of markets – particularly those with high renewable energy penetration – are expected to implement policies, market mechanisms and financial incentives to promote LDES deployment. Targets for long-duration energy storage have been established at the local level in Australia, Canada and China (Zhou, 2024).

UTILITY-SCALE BATTERY STORAGE DEPLOYMENT COST TRENDS

Stationary storage complements and facilitates the rapid rise of installed electricity generation capacity in solar PV and wind. By balancing supply and demand, as well as providing ancillary electricity market services, storage technologies enhance system stability and flexibility (IRENA, 2023). This strategic role is reflected in the sharp growth of global deployment in recent years.

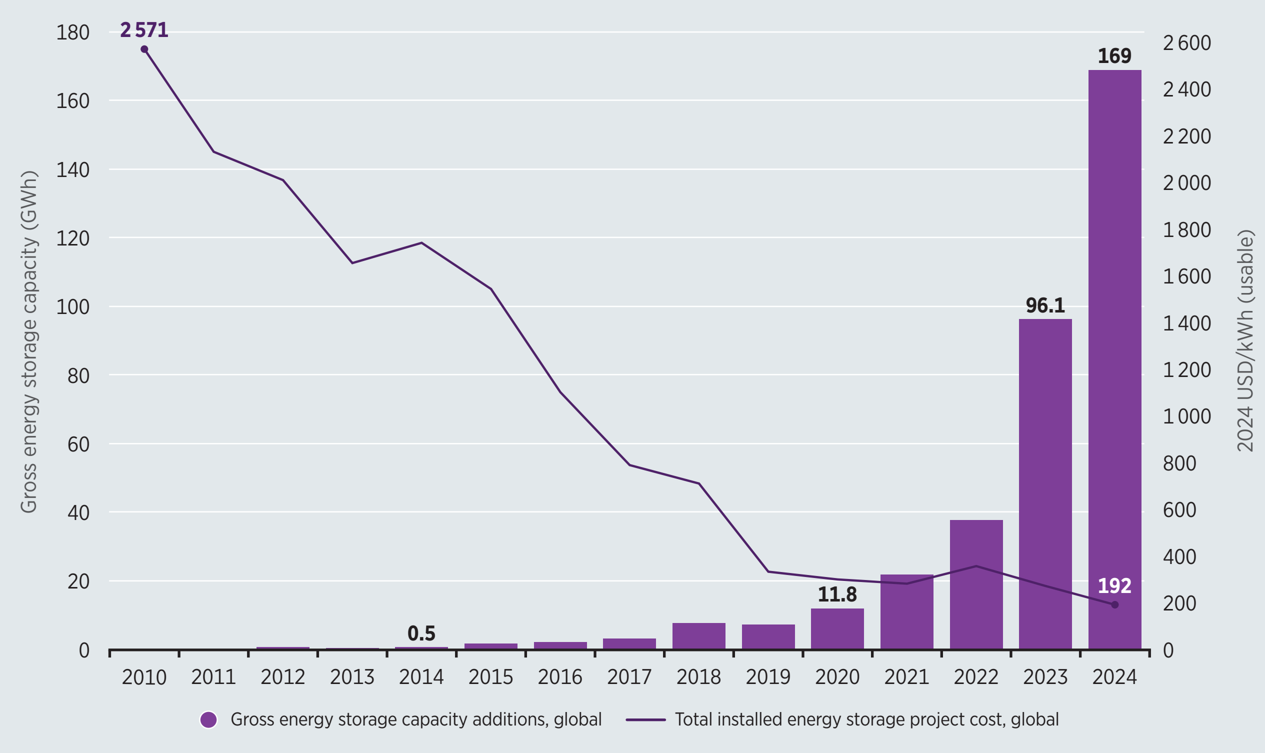
Between 2010 and 2024, new annual capacity additions of battery energy storage increased from 0.1 GWh of gross capacity in 2010 to 169 GWh of gross capacity in 2024 – a year that witnessed a record annual increase (Figure 6.2). China and United States remained the markets leaders in 2024. China installed the most capacity, at 84 GWh (36 GW) – representing an increase of 80% compared to the annual additions in 2023 and accounting for half of total global additions. The United States was the second largest market, adding 41 GWh (13 GW), which was almost a quarter of total new added capacity.

In China and the United States, the rapid increase in capacity was mainly driven by regional and local energy storage mandates and targets. These will continue to foster deployment in the period ahead. The commissioning of renewable energy projects coupled with battery energy storage systems (BESS) has been increasing over the past two years, and more are expected to come online in the coming years ensuring greater grid flexibility.

In other regions, such as Europe, the United Kingdom, Germany and Italy lead the annual utility-scale storage deployment, accounting for 62% of total capacity additions in 2024 (BNEF, 2024b). This includes a mix of pumped hydro storage, grid-scale batteries and behind-the-meter systems (Petrovich and Fox, 2024).

Meanwhile, in the Middle East and North Africa, countries such as Saudi Arabia, the United Arab Emirates and Egypt are leading investments in giga-scale energy storage projects; these recent additions are entirely electrochemical, reflecting a strong shift toward BESS (Aruffo and Matthes, 2025). Across both regions, local supply chain development has been a crucial strategy to reduce costs and enhance the resilience of energy storage deployment.

Figure 9.2 Global gross battery storage capacity additions by year and total installed electricity storage project costs per kWh, 2010–2024



Source: (BNEF, 2024; Schmidt and Staffell, 2023).

Notes: Cost data from 2010 to 2015 was calculated based on the capacity, price and experience curve regression data for electrical energy storage technologies model developed by Oliver Schmidt and Iain Staffell; GWh = gigawatt hour; kWh = kilowatt hour; USD = United States dollar.

Globally, the costs of a fully installed and commissioned battery storage project declined by 93% between 2010 and 2024, from USD 2 571/kWh to USD 192/kWh (Figure 9.2) (BNEF, 2024c). In recent years, this cost reduction has been driven by technological developments that have improved materials efficiency and manufacturing processes, leading to economies of scale. From a manufacturing perspective, the market has been growing, creating competition between suppliers across the entire value chain. Production has rapidly expanded, especially in China, where the supply chain had already established a robust scale of production that was capable of delivering in a short period of time. In 2024, abundant supply capacity and competition are the main drivers of cost declines in energy storage systems (BNEF, 2024d).

Figure 9.3 presents turnkey[48] battery storage system prices by market and duration between 2021 and 2024. Supply chain disruptions and volatility of raw material costs pushed up prices in 2022 but turnkey energy storage costs have fallen rapidly in recent years, reaching USD 165/kWh in 2024 – this value is 40% lower compared to 2023. One of the main drivers of the cost reduction is the increase of global manufacturing, leading first to technological improvements and higher performances in energy density and specific energy, and thereafter to economies of scale with increasing factory size and throughput.

[48] *Turnkey battery storage system costs include project equipment based on usable capacity, excluding EPC and grid connection costs*

Figure 9.3 Turnkey battery storage system prices by market and duration, 2021–2024

Based on: (BNEF, 2024d).

Notes: In the lower half of the chart, the reference line represents the cost ratio compared to the global average; kWh = kilowatt hour; USD = United States dollar.

Turnkey energy storage system costs are available for major markets, with these providing a sense of the cost variation between regions. These costs include the price of battery providers and system integrators and exclude EPC, grid connection and development costs. In 2024, global weighted average turnkey energy storage costs ranged between USD 165/kWh and USD 148/kWh, according to system duration. As the duration of the system increases from two to four hours, the cost decreases by 11%. Battery storage costs decreased 38% for a 2-hour system and 32% for a 4-hour system compared to 2023.

Battery cell prices, which are closely linked to the cost of key raw materials such as lithium, nickel and cobalt, remained relatively low in 2024. This trend was partly driven by the stabilisation or decline in battery metal prices as new mining and refining capacity came online, softening demand expectations (BNEF, 2024e). The future evolution of battery cell costs remains uncertain, as it will be dominated by these material costs, the volatility of which is increasing with demand.

China maintains the lowest battery storage costs due to its robust manufacturing scale and supply chain efficiencies, while Europe and the United States continue to experience higher costs due to import reliance (BNEF, 2023).

In China – the most competitive market – prices are around 40% less expensive than the global average. In 2024, electricity storage in China saw a cost decrease ranging from 48% (for a 4-hour system) to 47% (for a 2-hour system). Lower prices in China are mainly due to its well-established supply chain and large manufacturing capacity, which creates strong domestic market competition, maintaining downward pricing pressure that will endure in the years ahead.

Europe had the highest cost ratio compared to global prices, and the lowest cost decrease between 2023 and 2024, ranging from 16% (for a 2-hour system) to 20% (for a 4-hour system) for all storage systems. Battery economics have improved in European countries due to the growth of renewables. The United Kingdom is the biggest market in grid-scale BESS deployment, and also leads in hybrid solar PV plus BESS installations, which account for 62% of the total installed capacity in the country. This leadership is driven by strong policy support, favourable market conditions, and the development of some of the largest hybrid energy parks in Europe (SolarPower Europe, 2025).

In 2024, the United States registered a cost ratio compared to global prices of 1.50 for a 2-hour and 1.58 for a 4-hour battery system. Prices decreased 34% and 27%, respectively, compared to 2023, and developers willing to pay more for products made in the United States have become more common in recent years, driven by efforts to diversify away from Chinese supply chains to avoid policy uncertainties such as the threat of rising tariffs, or in response to utility requirements to avoid Chinese suppliers (BNEF, 2024f).

UTILITY-SCALE BATTERY STORAGE TECHNOLOGY MARKET SHARE

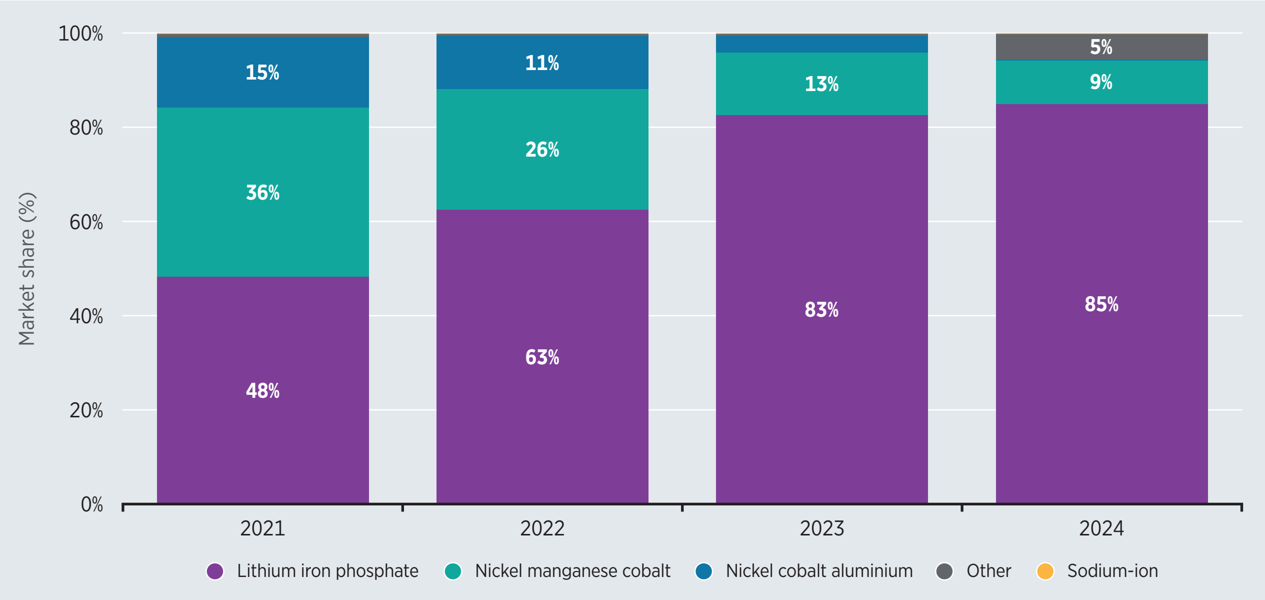
A wide range of battery technologies has emerged to meet various performance, cost and sustainability requirements. Key chemistries include: lithium iron phosphate (LFP), nickel manganese cobalt (NMC), nickel cobalt aluminium (NCA), and sodium-ion (Na-ion) batteries, among others.

Figure 9.4 illustrates the evolving market share of utility-scale battery storage technologies from 2021 to 2024. Overall, lithium-ion batteries have dominated the market due to their high energy density, efficiency, proven scalability and lifecycle advantages (IEA, 2024).

A clear trend toward the increasing dominance of LFP batteries is seen. LFP batteries grew from 48% in 2021 to an estimated 85% by 2024, thanks to their relatively lower cost, higher cycle of life and better security. Meanwhile, NMC batteries declined from 36% to 9% over the same period and NCA batteries dropped from 15% to less than 1% by 2024, as these chemistries have higher energy density than LFP. A small but growing share of other batteries[49] emerged in 2024 at 5%, reflecting the early stages of market entry for this alternative chemistry. The Na-ion category remained minimal throughout the years.

[49] *'Other' refers to technologies for long-duration energy storage, the commercialisation of which remains uncertain.*

Figure 9.4 Global market share trends of utility-scale battery technologies, 2021–2024



Based on: (BNEF, 2024c).

Advances in alternative battery technologies are progressing rapidly. China is leading in the development of sodium-ion and solid-state batteries for large-scale storage, thanks to significant investments in research and development (IEA, 2024).

UTILITY-SCALE BATTERY STORAGE APPLICATIONS

Since 2018, the primary use of electricity storage has been energy shifting (Figure 9.5), which accounts for 67% of the total capacity energy storage additions in 2024. Energy shifting balances the power system by storing renewable energy production at times of low market prices (leading to low/null revenue), or low demand (leading to curtailments). These circumstances encourage the storing of this energy for its later use at times of peak electricity demand or prices, resulting in improved system efficiency.

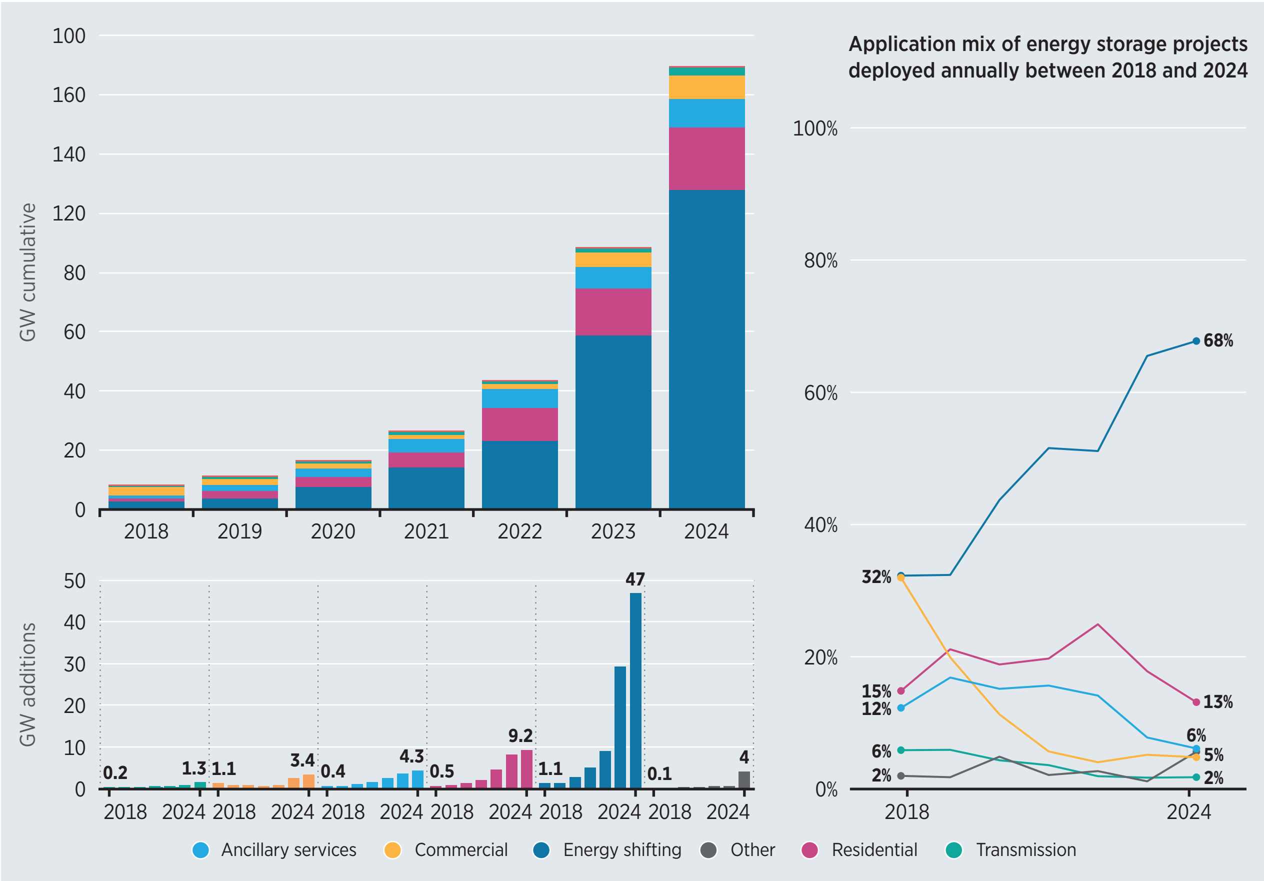
The increase in the use of BESS for energy shifting shows that falling electricity storage costs have led to economic opportunities for time shifting, especially as solar PV penetration has risen in certain markets. In the United States, solar PV with storage dominates the year-on-year growth of renewable hybrid projects, with this arrangement having the highest number of plants (Bolinger *et al.*, 2023), which are concentrated in California and Texas (Ember, 2025b). Additionally, hybrid power plants represent 55% of current installed solar capacity in the country (Gorman *et al.*, 2024).

BESS capacity for energy shifting added in 2024 was almost 47 GW; this value is 60% higher than the added capacity in 2023 and almost 70% of the total new BESS capacity additions in 2024. In both China and the United States, the large deployment of commissioned, utility-scale solar PV and wind projects – paired with energy storage – was the main driver of this increase in the share of capacity taken by energy shifting applications.[50]

[50] *These refer to the use of energy storage for renewable integration, price arbitrage and capacity services (BNEF, 2024a).*

In the residential segment, the capacity added reached 9 GW, but its share of the energy storage application mix fell from 18% in 2023 to 13% in 2024, as deployment in the utility-scale sector accelerated. Ancillary services also saw their share of the application mix decrease to 5% of all energy storage projects deployed annually in 2024. The new capacity added in that year accounted for 4.3 GW, compared to 3.5 GW in 2023. Transmission and distribution were marginal applications, despite the increase in year-on-year added capacity.

Figure 9.5 Battery storage deployment by application in GW



Based on: (BNEF, 2024c).
Note: GW = gigawatt.

HYBRID POWER SYSTEMS: INTEGRATING GENERATION AND STORAGE

Hybrid power plants combine different renewable generation technologies and/or integrate storage systems, creating flexible configurations that enhance energy reliability and system performance. By leveraging the complementary generation profiles of different technologies, these systems help align electricity supply with demand more effectively, mitigating issues such as intermittency and oversupply during peak generation periods. In addition, hybrid systems offer an effective response by maximising the use of available energy while alleviating constraints posed by limited grid connection points. The integration of battery storage, guided by system needs and supported by its inherent operational flexibility, makes these solutions increasingly vital for grid stability and the efficient integration of renewable energy sources (Intersolar, 2024).

With the growing deployment of hybrid systems, IRENA has been collecting data on these technologies to gain deeper insights into their cost optimisation. The Agency's database includes four different hybrid systems (solar[51] + BESS; wind + BESS; solar + wind; and solar + wind + BESS) with a combined total capacity of 10 GW (Figure 9.6) of projects with available cost data. Projects considered in this analysis were deployed in 2023 and 2024 across different countries, with the top markets in hybrid installations being the United States, China, India and Australia.

Figure 9.6 shows that solar + wind systems tend to have lower LCOE, as they do not include the additional cost of batteries. Their weighted average LCOE was USD 0.021/kWh, calculated based on a sample of ten projects deployed in 2023 and 2024 across different regions.

Figure 9.6 Characteristics of hybrid projects plants deployed in 2023 and 2024 by country

Notes: This analysis is based on a sample of projects with available cost data and does not represent the entire hybrid market; BESS = battery energy storage system; kWh = kilowatt hour; LCOE = levelised cost of electricity; USD = United States dollar.

Figure 9.7 shows hybrid project capacities, LCOE and capacity factors from the IRENA renewable costs database. The methodology applied for the LCOE calculation is described in Annex 1.

[51] *In all four hybrid systems, solar refers to solar photovoltaic.*

From the sample analysed, solar + BESS systems typically have the highest LCOE, with capacity factors generally ranging between 18% and 30%. The capacity factor of solar + wind + BESS systems varies widely, which largely depends on the specific mix and share of each technology. For wind + BESS systems, the available data is limited, making it difficult to draw any definitive conclusions.

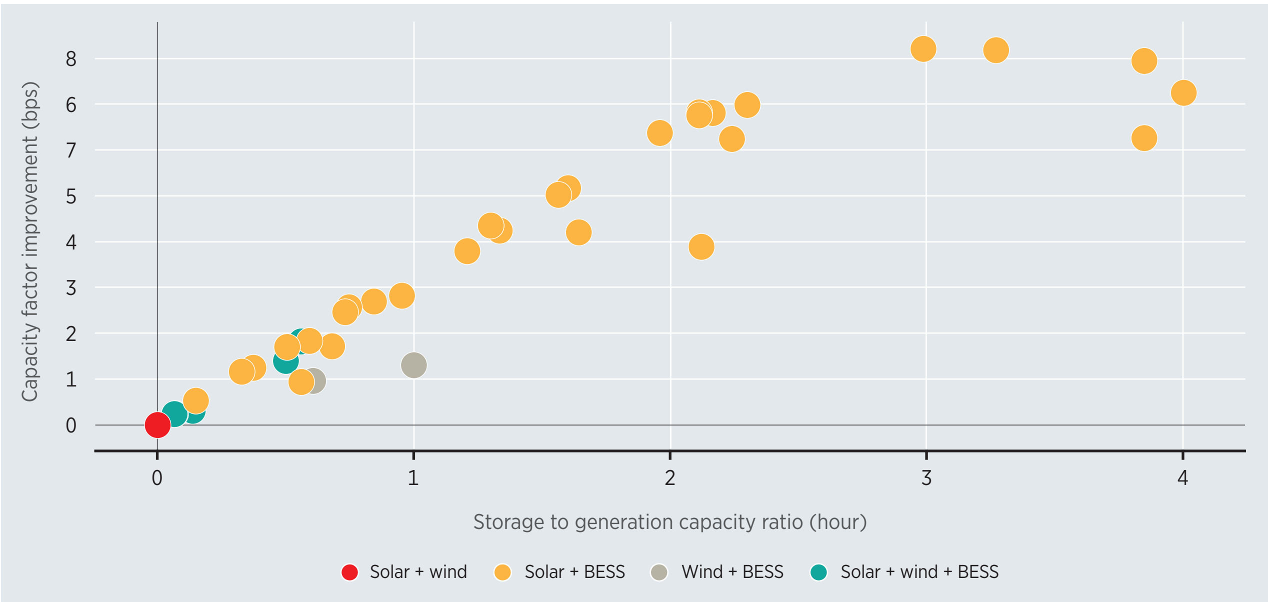
Hybrid systems typically achieve higher capacity factors than standalone solar or wind plants. This performance advantage is gained by leveraging complementary generation profiles and storage capabilities to deliver more consistent, efficient and higher capacity energy output.

When combining renewable technologies, hybrid systems can generate power more consistently, minimising periods of low or zero output and making better use of existing grid infrastructure. Storage adds another layer of flexibility, allowing excess energy to be saved and dispatched during times of high demand or low generation. This reduces curtailment and enhances the plant's ability to provide steady and dispatchable power (Murphy *et al.*, 2023).

Figure 9.7 shows the improvement in capacity factor of hybrid systems when compared to the storage and generation capacity ratio. Hybrid projects with a higher storage-to-generation capacity ratio have higher capacity factors.

Hybrid systems provide cost-saving advantages, including lower expenses for grid connections, land use, project development (such as feasibility studies), and operations and maintenance (O&M). They can also help reduce overall project financing costs by streamlining infrastructure and improving project efficiency. In hybrid systems, the LCOE for each renewable component is reduced due to shared investment and operational costs – particularly those related to grid interconnection and infrastructure. This cost efficiency makes hybrid projects more financially attractive compared to standalone systems (SolarPower Europe, 2025).

Figure 9.7 Capacity factor improvement vs. storage-to-generation capacity ratio



Notes: BESS = battery energy storage system; bps = basis points.

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ANNEX I
COST METRIC METHODOLOGY

Cost can be measured in different ways, with different cost metrics bringing their own insights. TICs, fixed and variable O&M costs, fuel costs, LCOEs, equipment costs for solar PV modules or wind turbines, financing costs – are just some examples of the types of costs that can be examined.

That examination and analysis can be very detailed. For purposes of comparison and transparency, however, the approach used here is a simplified one, focussing on the core cost metrics for which sound data are readily available. This allows greater scrutiny of the underlying data and its assumptions, while improving transparency and confidence in the analysis. This approach also facilitates 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; and
- LCOE.

Throughout the report, these indicators are predominantly represented using the 5th and 95th percentiles, along with the weighted average. The weighted average is calculated according to the following formula, where the total installed capacity is considered based on the level of analysis.

$$Weighted\ average = \frac{\sum_{i=1}^{n} X_i * Cap_i}{\sum_{i=1}^{n} Cap_i}$$

In this:

X_i = the indicator value of each project (the total installed project cost [in USD/kW]; the capacity factor [%] or LCOE [in USD/kWh]);

Cap_i = the installed capacity of each project (in MW);

i = the project in the IRENA renewable costs database

One of the key advantages of using a weighted average is that it accounts for the scale of individual projects, ensuring that the larger ones have a proportionate influence on the final result. This method prevents distortion caused by smaller or outlier projects with unusually high costs. It thus provides a more robust and reliable reflection of overall trends.

The analysis in this paper focuses on estimating the costs of renewables from the perspective of private investors. Such entities may be state-owned electricity generation utilities, or independent power producers (IPPs). They may also be an individual or community looking to invest in small-scale renewables. At the same time, this analysis excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect. Furthermore, the analysis does not take into account any CO_2 pricing, or the benefits of renewables in reducing other externalities – such as reduced local air pollution, or contamination of the natural environment. Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important, but are covered by other IRENA work streams.

Clear definitions of the categories of technology have also been provided, where they are relevant, to ensure that cost comparisons are robust and provide useful insights. Similarly, functionality must be distinguished from other qualities of the renewable power generation technologies being investigated. An example of this would be CSP, with and without thermal energy storage. This distinction is important in order 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, or grid connection costs.

The data used for the comparisons in this paper come from a variety of sources. These include 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 also been compiled into a single repository – the IRENA renewable costs 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. These are also sometimes not even true market average prices, but price indicators – surveyed estimates of average module selling prices in different markets, for example.

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.

A further point here is that 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. In times of excess supply, however, 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.

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

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) technique. 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 WACC used to evaluate the project – often also referred to as the discount rate – has a critical impact on the LCOE.

To more accurately assess the competitiveness of renewable power, IRENA has created a database of fossil fuel price indices and of the capital costs, efficiency and O&M costs of fossil fuel power plants.

When developing an LCOE modelling approach, there are many potential trade-offs to be considered. 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 the assumptions required. This can give the impression of greater accuracy, but when the model cannot be robustly populated with assumptions – and if those assumptions are not differentiated based on real-world data – then the accuracy of the approach can be misleading.

The framework used for estimating the LCOE of renewable energy technologies is described in Box 1.7 of Chapter 1.

Unless otherwise stated, all costs presented in this report are denominated in real, 2024 US dollars – that is to say, after inflation has been taken into account.

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 project-specific TICs and capacity factors, as well as the O&M costs. The data for project specific-TICs for the most recent years are a mix of *ex ante* and *ex post* data. The data for project-specific capacity factors, in virtually all cases, are *ex ante* data and subject to change.

Although the terms "O&M" and "OPEX" (operational expenses) are often used interchangeably, the LCOE calculations in this report are based on "all-in-OPEX". This is a metric that accounts for all the 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; while every effort is made to ensure the data is directly comparable, it is often not possible to verify this with certainty. Indeed, 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 data to compute LCOE calculations.

Levelised costs of energy storage and hybrid systems

The LCOE does not apply to stand-alone energy storage systems, as these do not generate electricity, but instead shift energy in time through charging and discharging. For such technologies, a commonly used metric is the levelised cost of storage (LCOS).

For several reasons, estimating the LCOS for stand-alone energy storage projects is challenging. The economic viability of energy storage systems depends on: their operational profile within a specific electricity market; their response to price signals; and their performance of functions such as energy arbitrage, frequency regulation and other ancillary services. Each application affects the battery's charge-discharge cycles, degradation rates and revenue streams, making it difficult to derive a universal cost metric.

Given this complexity, the revenue requirement framework described earlier is used to estimate lifetime revenue requirements per MWh of installed capacity and per year. The resulting figure is distinct from upfront or “overnight” costs, as it fully accounts for capital expenditures, O&M costs and their timing. By abstracting from specific applications and decoupling cost estimation from market behaviour, the framework provides a transparent and comparable baseline for assessing storage costs.

Hybrid systems, which combine solar PV (or wind) with battery storage, are increasingly being deployed to enhance grid flexibility and reduce curtailment. Batteries in these systems allow electricity to be shifted to periods of higher demand or market value, improving system reliability by reducing curtailment and helping to balance supply and demand more effectively.

The key challenge in estimating the LCOE of hybrid systems lies in capturing the interaction between renewable output and storage, and its impact on the effective utilisation of the power generation asset. When a battery is added, energy is charged at one point in time and later discharged – incurring efficiency losses in the process (the round-trip efficiency of battery storage systems is typically around 90%). However, the ability to shift energy does increase the usable share of renewable output, especially during periods of low generation or high demand.

To reflect these gains – particularly from peak shaving and load shifting – an effective capacity factor (ECF) is estimated based on the methodology described in Box 1.7.

Box A.1 Estimating the effective capacity factor (ECF) for hybrid systems

Batteries add value to renewable energy systems by shifting electricity from times of high generation to periods of high demand or market value. They also enhance grid reliability, reduce curtailment and enable key functions – such as energy arbitrage, frequency regulation and other ancillary services – to take place.

The full benefit of a battery depends on how it is operated within a specific electricity market. Capturing this accurately requires detailed modelling of the broader energy system. This includes modelling the demand and supply conditions, grid constraints, market rules, and the battery’s operational profile. This typically involves simulating battery dispatch based on hourly price signals, system balancing needs and the full range of services provided.

Such detailed, system-level modelling is beyond the scope of this report. Instead, a simplified linear optimisation approach is suggested in order to capture some of the key benefits delivered by battery storage in hybrid systems. The resulting metric – the ECF – is used as the basis for calculating the LCOE of hybrid systems.

The ECF is calculated by solving a simple linear optimisation problem for two system configurations:

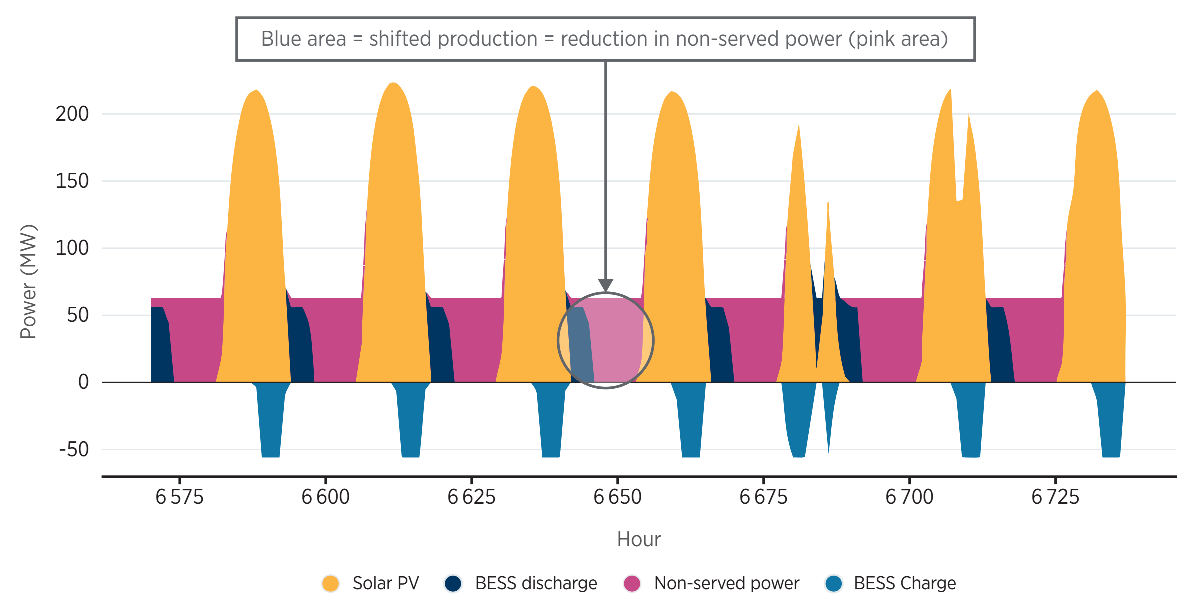
- the “without” scenario: a stand-alone renewable energy generator with no storage; and
- the “with” scenario: the same generator, combined with a battery.

In both cases, the system is tested against a flat, constant electricity demand set equal to the average hourly output of the variable renewable energy generator over the year.

In the “without” scenario, the generator may meet demand during daylight or windy hours, but fail to do so during other periods, resulting in non-served power.

In the “with” scenario, a battery can store excess generation and discharge it later, reducing these shortfalls. However, storage also introduces efficiency losses. Both the benefits (reduced non-served energy) and the losses are captured in the model.

Figure B.1 Hourly output profiles of solar and batteries (illustrative calculation)



Notes: BESS = battery energy storage systems; MW = megawatt; PV = photovoltaic.

The ECF is then calculated as:

ECF = CF + (reduction in non-served power − battery losses) ÷ (8760 hours × installed capacity)

CF is the capacity factor of the variable renewable energy generator in the "without" scenario.

LCOE short-term projections

To explore short-term cost trends, regional LCOE projections have been developed using a learning curve approach. This method assumes that capital costs decline as cumulative deployment increases, which is often referred to as "learning by doing". Based on historical data for cumulative installed capacity and unit costs, a learning rate is derived and used to project costs up to the year 2030 for different technologies across regio ns.

The method implemented here follows a simplified log–log linear regression to estimate the learning index and learning rate, allowing cost projections based on future deployment scenarios. While this approach offers a practical and transparent means of extending current cost trends, it does not capture the full spectrum of factors that will shape future technology adoption. Integrated modelling frameworks (such as GALLM-E) provide a more comprehensive treatment of endogenous learning, regional constraints and market interactions.

WACC

The analysis in IRENA cost reports up to and including the year 2020 assumes the real WACC for a project to be 7.5% in OECD countries and China, and 10% in the rest of the world. The former figure is lower because in these regions borrowing costs are relatively low and stable regulatory and economic policies tend to reduce the perceived risk of renewable energy projects.

In the 2021 edition of the IRENA report, the WACC assumptions were reduced to reflect more recent market conditions. Consequently, the previous edition of this report assumed that the WACC of 7.5% used in 2010 for the OECD and China declined to 5% in 2020. For the rest of world, the previous edition assumed that the WACC of 10% in 2010 fell to 7.5% in 2020.

Since 2022, IRENA's WACC benchmark tool (IRENA, 2023) has been used to give WACC benchmark values for 100 countries that are specific both to those countries and to a range of technologies. These values have been calibrated with the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey. That exercise resulted in technology-specific WACC data for onshore wind, offshore wind and solar PV technologies for those 100 countries. These data can be found in the dataset accompanying this report.[52] For countries not included in the benchmark tool and for bioenergy, geothermal and hydropower, simpler assumptions on the real cost of capital have been made for the OECD countries and China, and for the rest of the world (see Table A1).

Table A1 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% in 2010 falling to 5% in 2020 **Minimum WACC floor applied (see Box A2)**	10% in 2010 falling to 7.5% in 2020 **Minimum WACC floor applied (see Box A2)**
Solar PV	25		
CSP	25		
Hydropower	30		
Biomass for power	20		
Geothermal	25		

Notes: CSP = concentrated solar power; OECD = Organisation for Economic Co-operation and Development; PV = photovoltaic; WACC = Weighted average cost of capital.

[52] *Visit irena.org for more details.*

Box A.2 Minimum WACC adjustments

The default WACC assumptions for countries and technologies not covered by the benchmark tool – 5% for the OECD and China, and 7.5% for the rest of the world – may, in certain cases, underestimate the cost of capital when compared to more conservative estimates. Argentina's default WACC of 7.5%, for example, is much lower than the 12% minimum suggested by economist Aswath Damodaran for 2024 – a figure which reflects an elevated country-specific risk. To address such discrepancies, a minimum WACC floor has been introduced. This was calculated as follows:

Cost of debt =
(global risk-free rate + country default spread + lender margin) × (1 - tax rate)

Cost of equity =
global risk-free rate + equity risk premium + country premium

Minimum WACC Floor =
80% × Cost of Debt + 20% × Cost of Equity

The minimum WACC floor assumes an 80% debt share and excludes all technology-specific premiums, in order to derive a lower limit for the cost of capital grounded in market fundamentals. Inputs include global risk-free rates, country default spreads, lender margins and equity risk premia, primarily sourced from Damodaran and other financial market data. This adjustment ensures that default values do not underestimate capital costs in higher-risk contexts, maintaining internal consistency and improving the accuracy of LCOE estimates.

IRENA has substantially improved the granularity and/or representation of the WACC and O&M costs that are utilised in the LCOE calculation. The changes are designed to improve the accuracy of the LCOE estimates by technology. Challenges remain in obtaining accurate and up-to-date WACC assumptions, however, given 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 of reducing the LCOE by lowering the WACC.

CHANGING FINANCING CONDITIONS FOR RENEWABLES AND THE WACC

This section discusses the background to the WACC benchmark model in more detail, as well as the process behind the IRENA, IEA Wind and ETH Zurich survey of financing conditions for solar and wind technologies.

Having more accurate WACC assumptions not only improves the advice IRENA can give its member countries, but also fills a gap for the broader energy modelling community. This is in critical need of improved renewable energy cost of capital data (Egli, Steffen and Schmidt, 2018). Changes in the cost of capital that are not properly accounted for over time – between countries or technologies – can result in significant misrepresentations of the LCOE, leading to distorted policy recommendations.

Today, however, reliable data that comprehensively cover, through time, individual renewable technologies across a representative number of countries and/or regions remain remarkably sparse (Donovan and Nuñez, 2012). This is typically due to the extreme difficulty in obtaining project-level financial information due its proprietary nature (Steffen *et al.*, 2019). While there is extensive evidence of lower and declining WACCs than in the assumptions previously used (Steffen *et al.*, 2019), it can be challenging to extract meaningful insights from the data contained in today's literature. This is because the majority of studies to date use inconsistent methodologies and may refer to different years, countries and technologies. A key challenge is the small number of countries for which data are available for each technology, as well as the relatively narrow 'snapshot' of financing conditions many studies provide.

Typically, existing studies have assessed only a single country, with just a few studies extending their analysis to five or more states. Most studies have also focused on onshore wind and solar PV only and limited their assessment to historical data, as opposed to developing a method and data basis for projections and associated scenarios. A broader coverage of countries/regions and technologies and the capability to develop scenarios that include the future cost of capital is critical for IRENA and other stakeholders, if a proper assessment of the LCOE across different world regions, technologies and over time is to be made.

In November 2019, IRENA conducted a workshop with experts in the field to discuss these issues and current WACC assumptions, in order to identify a way to improve data availability. In 2020, this resulted in IRENA, IEA Wind and ETH Zurich working together to benchmark WACC values by country. These organisations also worked on formulating a survey on the cost of finance for renewable energy projects that could be implemented online, but would also be supported by a number of semi-structured interviews with key stakeholders. This would be done in order to understand the drivers behind financing costs and conditions. The initiative also had the long-term goal of developing a survey methodology which could be periodically repeated.

The first goal of this work – namely, to arrive at detailed country and technology-specific WACC data for solar PV, onshore and offshore wind – has already been implemented in this edition of the report. This was achieved via a three-pronged approach to data collection. The basis for this was the following:

- **Desktop analysis**: This combined two analytical methods to better understand WACCs. The first matched projects in the IRENA renewable costs database and *IRENA Auctions and PPA Database*. It took the adjusted PPA and/or auction price as the benchmark to vary the WACC in the LCOE calculation. The other components of that calculation at the project level, such as economic life, capacity factors, O&M costs and TICs, remained fixed. This allowed IRENA to reverse engineer a WACC indicator.
- The second analytical method took financial market data on risk-free lending rates, country risk premiums, lender's margins and equity risk premiums and used them to develop country-specific WACC benchmarks for renewables. The "benchmark tool" was designed to generate annual WACC data for this report that were specific to countries and technologies, while also based on updated input assumptions made on an annual basis.

- **An online expert elicitation survey**: This was undertaken by IRENA, IEA Wind Task 26 and ETH Zurich in Q2 2021 and Q3 2021. The survey was distributed widely to knowledgeable finance professionals with a detailed understanding of the financing conditions. It asked stakeholders with experience of financing renewable projects about the individual components that contribute to the WACC.
- **In-depth, semi-structured interviews**: These targeted a small number of finance professionals involved in the financing of renewable projects. They aimed to collect data about the cost of debt and equity and the share of debt in the total. In addition, they aimed to uncover the contextual factors that have been driving these financing costs – or differences in costs – across markets and technologies. These interviews were conducted in Q3 2021 and Q4 2021.

The desktop analysis, which aimed at deriving benchmark WACC components such as debt cost, equity cost and the debt- to-equity ratio, served as a precursor to the online survey and the semi-structured interviews. The benchmarking process was also a part of developing an enhanced understanding of the constituents of WACC and their key drivers, while also serving two goals. The first of these was to provide insights into the underlying drivers of the WACC components; the second was the creation of a benchmarking cost of capital tool that could be used to fill in gaps in the survey analysis.[53] In addition to using the benchmark values created in this process to seed the online survey, the survey process itself helped refine the benchmarking tool, therefore improving its robustness.

For the first part of the benchmarking work, IRENA and ETH Zurich worked together to match utility-scale solar PV projects in the IRENA renewable costs database and *IRENA Auctions and PPA Database* with project-level total installed costs and capacity factors, country O&M values and standardised economic lifetimes. We then arrived at a WACC that yielded an LCOE that matched the adjusted PPA/auction price.

IRENA, IEA Wind and ETH Zurich have also developed a benchmark cost-of-capital tool. The benchmark approach uses the following method to calculate the WACC for renewable power generation projects:

$$WACC = c_e \frac{E}{D+E} + c_d * (1-T) * \frac{D}{D+E}$$

Where:

Ce = cost of equity

Cd = cost of debt

D = market value of debt

E = market value of equity

T = corporate tax rate

$WACC$ = weighted average cost of capital.

[53] *It is not feasible for survey stakeholders' project partners to provide real-world WACC components for solar PV, onshore and offshore wind in even a majority of the countries of the world. Therefore, the benchmark cost of capital tool will be essential in fleshing out gaps in the survey results to provide climate and energy modellers with data for all the countries/regions in their models.*

The benchmark also takes the cost of debt as calculated by taking the global risk-free rate, provided by current US government 10-year bonds at 3.96%, and combining this with a country risk premium for debt. The latter premium was based on credit default swap values[54] and lenders' margins, using a standardised assumption of 2% as a global baseline for lending margins for large, private infrastructure debt. The cost of equity is the sum of the US long-run equity rate of return of 8.56% (or a premium of 4.60% over risk-free rate), plus any country equity premium, plus any technology equity risk premium, plus the US risk-free rate. Debt-to-equity ratios and the technology-risk premium are varied by technology, based on local market maturity.

Market maturity levels are based on the share of penetration of each technology. These have been arbitrarily defined as "new", "intermediate" and "mature", depending on thresholds of 0%-5%, 5%-10% and 10%+ of cumulative installed capacity, respectively. They have also used fixed values of 60%, 70% and 80% for the debt-to-equity ratio, along with equity technology risk premiums of 1.5%, 2.4% and 3.25%, depending on market maturity.

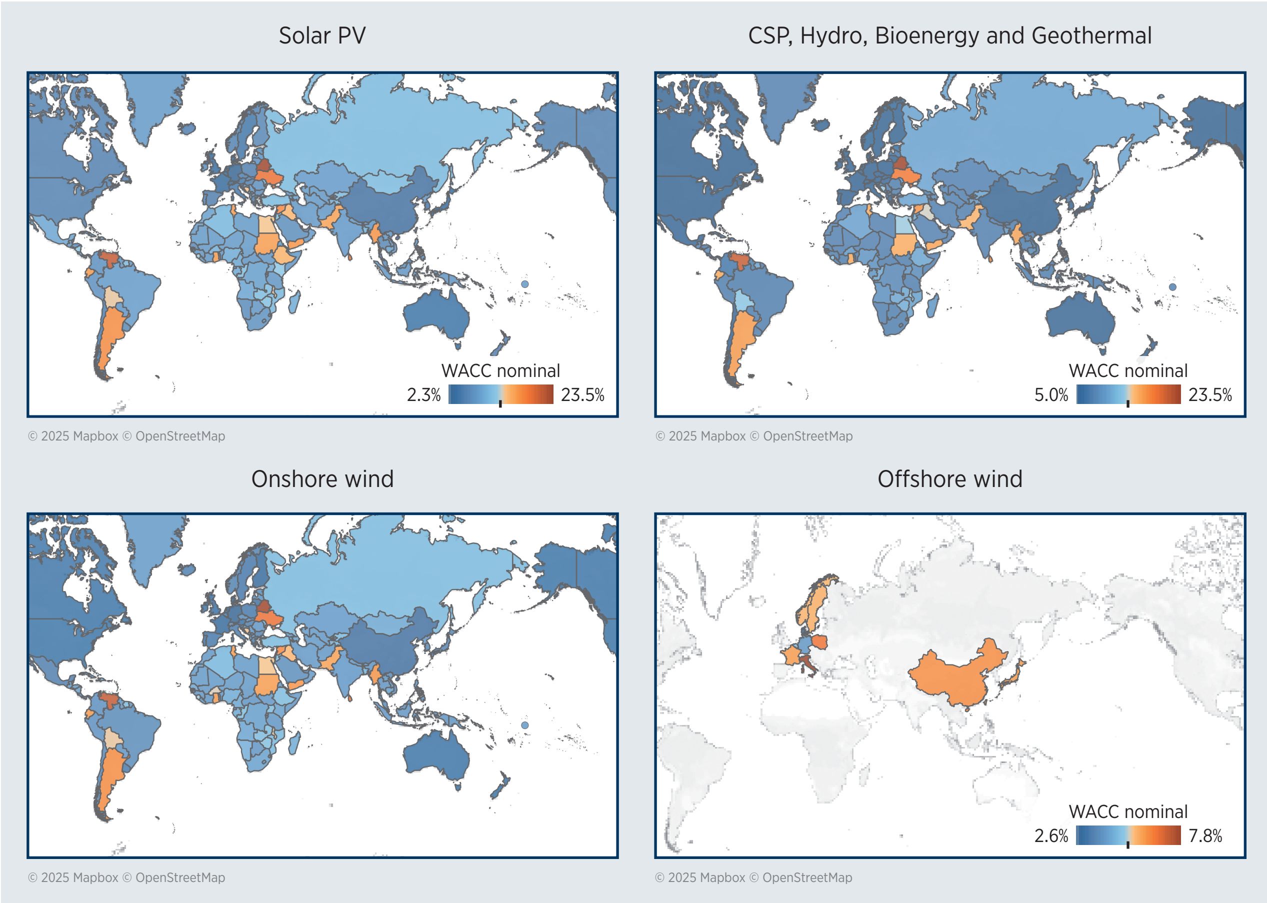
The benchmark tool creates nominal values for each WACC parameter, but by assuming 2.39% inflation (roughly the value in the United States over the last decade), we can transform the results into real values.

The project team developed and refined the benchmark tool in the second half of 2021 and Q1 2022. IRENA took the survey results and then used these to refine the benchmark model. This was done so that margins for different financing cost components for individual countries and technologies were as close as possible to the surveyed results. More detail on the process and the summarised results of the survey can be found in IRENA's cost of financing for renewable power report (IRENA, 2023).

[54] *This is based on Country Risk: Determinants, Measures and Implications: The 2020 Edition, (Damodaran, 2020).*

Figure A1 presents the results of the calibrated benchmark tool for the real after-tax WACC values by country and technology. The values used for the LCOE calculations for deployment in 2024 are those in Figure A1, with values in 2010 of 7.5% for the OECD and China, and 10% elsewhere. Values between these two dates are linearly interpolated. For those countries not covered by the benchmark, as already noted, the real after-tax WACC values decline linearly from 2010, reaching 5% for the OECD and China and 7.5% for elsewhere in 2024.

Figure A1 Country and technology-specific real after-tax WACC assumptions for 2024



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The WACC values surveyed in 2021 were generally representative of financing conditions in 2020 and 2021. Given most onshore wind and solar PV projects are financed in the year prior to commissioning, the WACC values used for 2022 are unchanged from the benchmark values for 2021. However, with inflation and interest rates rising rapidly in 2022, the 2023 benchmark WACC values were updated. The lagged impact of rising interest rates on LCOEs will be significant in the coming years, given the low cost of finance for renewables that has characterised recent times. Overall, these more realistic WACC changes have improved the representativeness of the LCOE calculations at a country level. In the case of the WACC assumptions, they have also brought our assumptions into line with the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey. The resulting changes provide yet another step forward in ensuring the most accurate estimation possible of the lifetime cost of renewable power generation costs by country. There is still room for improvement, however, and IRENA is always working to improve its data.

TOTAL INSTALLED COST BREAKDOWN: DETAILED CATEGORIES FOR SOLAR PV

For some years, IRENA has collected cost data on a consistent basis and at a detailed level for a selection of solar PV markets. In addition to tracking average module and inverter costs, the BoS cost has been 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 that can give greater understanding of the drivers of solar PV BoS costs and are the basis for such analysis in this report.

Table A2 BoS cost breakdown categories for solar PV

Category	Description
Non-module hardware	
Cabling	· All 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 ramming 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)
Soft costs	
Inspection (construction supervision)	· Construction supervision · Health and safety inspections
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 solar PV system. This includes profit, wages, finance, customer service, legal, human resources, rent, office supplies, purchased corporate professional services and vehicle fees.

Notes: AC = alternating current; DC = direct current; EPC = engineering, procurement and construction; PV = photovoltaic.

O&M COSTS

Onshore wind

In the absence of project-specific cost data, IRENA has used secondary sources for its O&M cost assumptions for onshore wind. In many cases, all that was available were costs per kWh, while the year of collection or applicability was often not clear. With rising capacity factors for onshore wind, making the assumption that there was a fixed per kWh figure would have likely been to overstate the actual contribution of O&M to overall LCOE costs, in some cases.

Consistent with last year's report, all O&M assumptions are on a USD/kW basis (see Table A3). Data comes from the IRENA renewable costs database, IEA Wind Task 26, regulatory filings, investor presentations and country-specific research. Where country data is not available through these primary sources, assumptions from secondary sources are used. If no robust country-specific data can be found, regional averages are used.

Table A3 O&M cost assumptions for the LCOE calculation of onshore wind projects

	2024 USD/kW/year
Sweden	45
Ireland	38
Germany	53
Denmark	40
United States	45
Norway	45
Japan	100
Brazil	29
Canada	39
Mexico	49
Spain	29
United Kingdom	41
France	53
China	29
India	23
Australia	38
Other OECD	45
Other non-OECD	38

Notes: kW = kilowatt; OECD = Organisation for Economic Co-operation and Development; USD = United States dollar.

Solar PV

Depending on the commissioning year, a different O&M cost assumption is used for the calculation of the solar PV LCOE estimates used 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 (see Table A4).

Table A4 O&M cost assumptions for the LCOE calculation of solar PV projects

Year	OECD 2024 USD/kW/year	Non-OECD 2024 USD/kW/year
2010	27.1	25.6
2011	24.0	23.5
2012	23.4	18.2
2013	22.9	15.3
2014	22.4	13.7
2015	21.7	12.4
2016	21.1	11.3
2017	21.5	10.9
2018	20.1	10.4
2019	19.2	9.9
2020	18.2	9.6
2021	18.2	9.6
2022	18.2	9.6
2023	18.2	9.6
2024	20.7	11

Notes: kW = kilowatt; OECD = Organisation for Economic Co-operation and Development; USD = United States dollar.


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For some years, IRENA has collected O&M cost data for a selection of PV markets. The O&M cost is broken into different categories, with these composed of the cost items listed in Table A5.

Table A5 O&M cost breakdown categories for solar PV

Category	Cost items considered
Preventive maintenance	· Scheduled visual inspections · Tool calibration · Preventive maintenance of transformer stations · Protection system maintenance · Medium voltage cable testing · Communication system maintenance · Electroluminescence sampling, if contracted · Drone thermography, if contracted · Preventive vehicle maintenance · Sensor cleaning and meteorological station calibration
Corrective maintenance	· Corrective maintenance on transformers · Corrective maintenance on inverters · Transformer spare parts, not under warranty · Repair and maintenance of recurring equipment, not under warranty · Unscheduled vehicle maintenance and repair · Unscheduled maintenance of park roads · Inverter spare parts, not under warranty · Panel spare parts, not under warranty · Other spare parts, not under warranty and unscheduled repair works not covered by insurances or warranty
Greenkeeping	· Mowing or other activities that limit the growth of vegetation
Panel cleaning	· Regular panel cleaning activities including water and consumables
Security	· Professional guards and security patrols for control of physical barriers · Access and gate control · CCTV supervision · Emergency response · Observation of cybersecurity measures
Insurance	· General liability insurance · Property and equipment insurance · Business interruption insurance · Solar performance guarantee Insurance · Natural disaster and weather-related insurance · Supervisory control and data acquisition and cyberattack coverage · Environmental liability insurance
Technical operation	· Real-time monitoring · Supervisory control and data acquisition system operation · Fault detection and diagnosis · Performance ratio calculation · Loss analysis · Land lease and periodic real estate payments · Grid Code Compliance

Technical operation	· Reactive power control · Curtailment and dispatch control · Weather monitoring and impact assessment · Health and safety management · Fire detection and prevention · Technical reporting and documentation
Commercial operation	· Commercial evaluation of performance analysis and optimisation · Management of real estate and lease obligations · PPA compliance · Revenue and billing management · Tax reporting and management · Incentive and regulatory compliance · Insurance management and warranty claims · Investor and lender reporting · Contractor and vendor management · Long-term asset strategy · Environmental monitoring · Regulatory reporting · Health, safety and environmental regulation compliance
Other	· Examples include third-party services and quality audits, performance audits, legal opinions and audits

Notes: CCTV = closed-circuit television; PPA = power purchase agreement.

Offshore wind

The O&M cost assumptions with this technology have also been aligned with a single USD/kW per year metric.

Table A6 O&M cost assumptions for the LCOE calculation of offshore wind projects

	2024 USD/kW/year
Belgium	87
Denmark	79
Netherlands	91
Germany	88
United Kingdom	84
France	91
China	59
United States	80
Japan	144
Other OECD	86
Other non-OECD	70

Notes: kW = kilowatt; OECD = Organisation for Economic Co-operation and Development; USD = United States dollar.

ANNEX II

The composition of the IRENA renewable costs database largely reflects the deployment of renewable energy technologies over the last 10–15 years. In terms of GW, most projects in the database are in China (1 460 GW), the United States (303 GW), India (202 GW) and Brazil (116 GW).

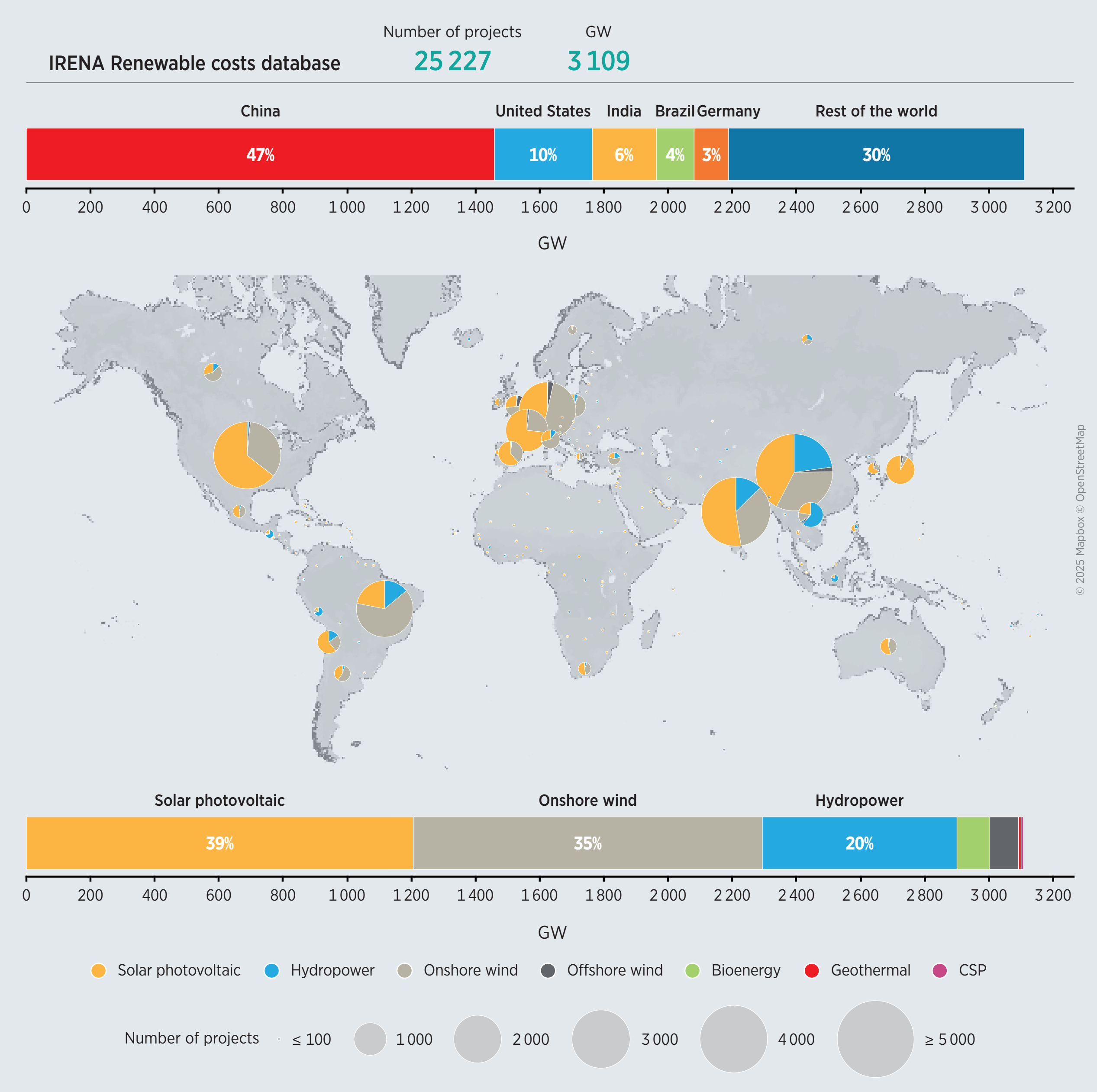
After these four major countries, Germany's project deployment totals 109 GW, Spain, 60 GW, the United Kingdom, 50 GW, Viet Nam, 43 GW, Türkiye, 39 GW, Australia and Italy, 39 GW each, France 38 GW and Canada, 37 GW.

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 made available.

Solar PV is the largest single renewable energy technology represented in the IRENA renewable costs database, with 1 207 GW of project data available from 2001 onwards. Onshore wind is the second largest technology in the database, with 1 087 GW of projects since 1983, followed by hydropower, with 607 GW of projects. Around 90% of those hydro projects were commissioned in the year 2000 or later. Cost data are available for 102 GW of biomass for power projects, 87 GW of commissioned offshore wind projects, 9 GW of geothermal projects and around 8 GW of CSP projects.

The coverage of the IRENA renewable costs database is roughly complete for offshore wind and CSP – technologies in which the relatively small number of projects deployed 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 20 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 have only become available more recently, however, making the database representative from around 2011 onwards and comprehensive from around 2013 onwards.

Figure A2 Distribution of projects by technology and country in the IRENA renewable costs database



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Note: GW = gigawatts.

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, the Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, São Tomé and Príncipe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, South Sudan, Sudan, Togo, Tunisia, Uganda, the 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, Türkiye.

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, the Netherlands, Norway, Poland, Portugal, Republic of Moldova, Romania, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, the United Kingdom.

The Middle East

Bahrain, Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, the United Arab Emirates, Yemen.

North America

Canada, Mexico, the United States.

South America

Argentina, Plurinational State of Bolivia, Brazil, Chile, Colombia, Ecuador, Guyana, Paraguay, Peru, Suriname, Uruguay, Bolivarian Republic of Venezuela.

Oceania

Australia, Fiji, Kiribati, Marshall Islands, Federated States of Micronesia, Nauru, New Zealand, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga, Tuvalu, Vanuatu.

G20

Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russian Federation, Saudi Arabia, South Africa, South Korea, Türkiye, the United Kingdom, the United States, the European Union.

IRENA

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