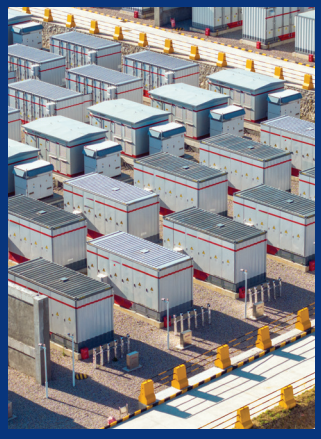
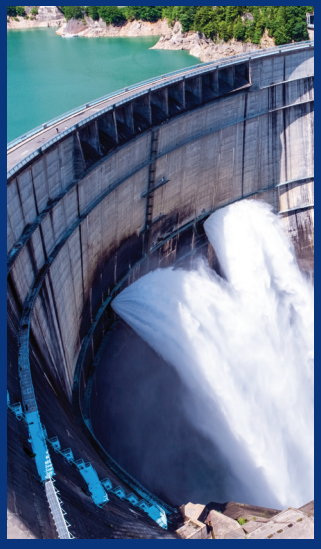
The Costs of Generating Electricity 2025





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The Costs of Generating Electricity

2025

ELECTRIC POWER RESEARCH INSTITUTE
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Foreword

In a fast-changing electricity and energy landscape, confronted by rising demand, price volatility and increasing capital intensity, decision making requires reliable data. To support policymakers, experts and modellers, *The Costs of Generating Electricity 2025* provides comprehensive plant-level generation costs for 23 different technologies in 21 industrialised countries. This report is the outcome of a collaboration between the OECD Nuclear Energy Agency (NEA) and the Electric Power Research Institute (EPRI). It is the 10th report on the costs of generating electricity published or co-published by the NEA since 1983, as part of the Projected Costs of Generating Electricity series. This 2025 Edition benefits from combining EPRI's extensive generation cost database, *Generation Technology Options 2024*, with the NEA's data on the comparative capital investment costs in its member countries.

An overview of the data reveals a few tendencies. First, electricity supply is becoming more diversified. The variability of wind and solar photovoltaics (PV), as well as the desire of many countries and stakeholders to reduce carbon emissions, has technologies that were once regarded as niche moving to the centre of interest in numerous countries. These include batteries, geothermal and biomass, but also coal and natural gas-fired plants with carbon capture usage and storage (CCUS), or hydrogen-fired gas turbines. All these options carry a premium over conventional fossil-powered technologies. Most of these low-carbon dispatchable technologies have plant-level costs of at least USD 100 per MWh.

Second, there is growing interest in nuclear generation technologies. This report provides systematic cost evaluations for large light-water reactors, small modular reactors (SMRs) and nuclear long-term operations (LTO). Given the long cycles of technology development, supply chain configuration and construction proficiency, the report contains data both for near-term deployment and Nth-of-a-kind reactors, when learning effects have played out.

Third, the plant-level costs for onshore wind and solar PV remain attractive at the level of the individual plant, although compared to past editions, no significant further cost decreases have been observed. The story changes if their system costs are included. Offshore wind remains an expensive option. If the estimates provided by numerous countries for geothermal generation can be realised, it could emerge as a competitive energy source that is both dispatchable and renewable, even if limited to specific locations. Dispatchable hydroelectricity, wherever available, remains an attractive option

Since 2010, the NEA and EPRI have undertaken considerable work showing how issues such as variability, dispatchability and flexibility, as well as transmission, distribution and connection determine the overall costs of electricity systems. The levelised cost of electricity (LCOE) figures in this report thus provide only a partial view of electricity generating costs, albeit an important one. First, plant-level costs constitute a substantial part of system-level costs. Second, LCOE remains uniquely transparent, comparable and intuitive. Experts and decision makers have an intuitive grasp of LCOE, even when fully aware that it requires complementing with additional analyses.

This report is intended to provide useful and reliable references for successful decision making in the years ahead.

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Acronyms and abbreviations

AI	Artificial intelligence
BESS	Battery energy storage system
CAPEX	Capital expenditure
CBA	Cost-benefit analysis
CCGT	Combined cycle gas turbine
CCUS	Carbon capture, utilisation and storage
CRF	Capital recovery factor
DAF	Degradation adjustment factor
DOC	Date of commissioning
EGC	Electricity generating costs
EPRI	Electric Power Research Institute
ESCA	Energy Systems and Climate Analysis Group (EPRI)
ETS	Emissions trading system
EU	European Union
FOAK	First-of-a-kind
GHG	Greenhouse gas
IDC	Interest during construction
HTGR	High-temperature gas-cooled reactor
ICE	Internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change (United Nations)
LCOE	Levelised cost of electricity
LCOS	Levelised cost of storage
LTO	Long-term operation
LWR	Light water reactor
LULUCF	Land-use, land-use change and forestry
MILP	Mixed-integer linear programming model
NEA	Nuclear Energy Agency
NOAK	Nth-of-a-kind
O&M	Operations and maintenance
OCC	Overnight construction cost

OCGT	Open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
SMR	Small modular reactor
PHWR	Pressurised heavy water reactor
Solar PV	Solar photovoltaic
tCO_2	Metric tonne of carbon dioxide
TCR	Total capital requirement
VRE	Variable renewable energy
WPNE	Working Party on Nuclear Energy Economics (NEA)
ALWR	Advanced light water reactor

Formulae definitions

c	Length of construction in years
Capital	Capital costs in year *t* (these are disbursed before commissioning)
Carbon	Carbon costs per MWh
$Carbon_t$	Carbon costs in year *t*
CF	Capacity factor (ratio of hours of generation to 8 760 hours)
DC	Annualised decommissioning costs
DC_t	Decommissioning costs in year *t*
FOM	Fixed annual operations and maintenance costs per kW
Fuel	Fuel costs per MWh
Fuelt	Fuel costs in year *t*
MWh	Amount of electricity produced annually
n	Operational lifetime
$O\&M_t$	Operation and maintenance costs in year *t*
PMWh	Constant price, or tariff, of electricity
r	Real discount rate corresponding to the cost of capital
s_t	Share of OCC spent in year *t*
VOM	Variable operations and maintenance costs per MWh

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Executive summary

A changing electricity landscape demands reliable data

The *Costs of Generating Electricity 2025* reports comprehensive cost generation data for 21 countries and 23 different technologies. This data is summarised in the levelised cost of electricity (LCOE). This report provides a comprehensive overview of current plant-level generation costs in the electricity systems of NEA Member countries and is the result of a collaboration between the OECD Nuclear Energy Agency (NEA) and the Electric Power Research Institute (EPRI).

Electricity systems are undergoing a period of stress due to several challenges, including a rise in demand linked to data centres, and electrification in transport and industry; price volatility of fossil fuels due to geopolitical events; and carbon emissions targets in a majority of NEA Member countries. The switch to low carbon generation also includes the challenge of financing an increasingly capital-intensive generation mix, often in liberalised markets with marginal cost pricing, as well as the need to accommodate the variability of wind and solar photovoltaic (PV).

Such systemic considerations can lead to questions about the relevance of discounted average lifecycle costs, such as LCOE as an indicator for the cost of electricity, and a call for more comprehensive metrics. However, LCOE can still provide useful insights. First, plant-level costs constitute a substantial part of system-level costs. A technology's overnight construction costs (OCC), variable, fuel and carbon costs all determine a technology's share in an integrated system. Second, LCOE remains uniquely transparent, comparable and intuitive. Experts and decision makers know what LCOE *means*. This holds true even when recognising that LCOE requires complementing with additional metrics in two crucial dimensions: the dimension of private investment with its financial, fiscal and portfolio considerations, and the dimension of public decision making, taking into account the system-level interactions of different technologies. Yet, each time LCOE remains a crucial element of the overall picture.

This joint report by the NEA and EPRI, is the 10th edition of the series of reports on the LCOE costs of generating electricity that the NEA has prepared since 1983 (several of which were published together with the International Energy Agency (IEA) under the title *Projected Costs of Generating Electricity*). This edition benefits from systematic input from EPRI's extensive technology-specific cost generation database, *Generation Technology Options 2024*, for the United States. This database is based on detailed technology-by-technology studies that are part of EPRI's research portfolio and compiles engineering-based cost estimates. The availability of this database has allowed a change in the methodology used in this report from previous reports which were based on data generated exclusively from national sources completing a blank questionnaire. This time, NEA and EPRI generated pre-filled data sheets for each individual participating country, which combined engineering-based bottom-up data from EPRI (2024) with locational adjustment factors based on data from the 2010, 2015 and 2020 Projected Costs reports. This allowed countries to verify, validate or modify the prefilled data, which facilitated participation and enhanced the completeness of the data. A uniquely large set with 309 datapoints was thus established. Table ES.1 provides an overview of the specific contributions by each participating country.

Table ES.1. Technology categories for which data was obtained for participating countries

Country	Total responses	Nuclear LLWR	Nuclear LTO	SMR	Onshore wind	Offshore wind	Solar PV	Solar PV + battery	Battery (4hr)	Hydro (pumped storage)	Hydro (reservoir)	Biomass	Biomass (CCUS)	Geothermal	Coal	Coal (CCUS)	CCGT	CCGT (CCUS)	OCGT	ICE	H_2 CCGT	H_2 OCGT
		16	6	11	20	15	20	14	15	11	13	15	8	13	12	10	15	13	13	13	15	15
Australia	19	X		X	X	X	X		X	X	X	X			X	X	X	X	X	X	X	X
Austria	14				X		X	X	X	X	X	X		X			X	X	X	X	X	X
Belgium	16	X	X	X	X	X	X	X	X			X	X				X	X	X	X	X	X
Bulgaria	22	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Canada	19	X		X	X	X	X	X	X		X	X		X	X	X	X	X	X	X	X	X
Czechia	18	X			X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Denmark	13				X	X	X	X	X			X		X	X		X		X	X	X	X
Finland	7	X		X	X		X		X													
France	21	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Germany	18				X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Italy	14			X	X	X	X	X	X	X	X	X		X			X	X			X	X
Japan	15	X			X	X	X	X			X	X		X	X	X	X	X			X	X
Korea	9	X	X	X	X	X	X								X		X					
Norway	4				X	X	X				X											
Poland	5	X			X	X	X					X										
Romania	1	X																				
Slovak Republic	21	X		X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Slovenia	22	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Sweden	16	X	X	X	X	X	X	X	X	X				X					X	X	X	X
Switzerland	5	X	X		X		X															
United States	23	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Note: The total number of technology datapoints obtained for participating by countries (309) is slightly greater than the number of entries reported in this overview table. See Chapter 3 for details.

NEA and EPRI are grateful for the participation of 21 NEA Member countries, a number that exceeds past participation in the Projected Cost series. Their help in establishing this overview of the current landscape of plant-level generation costs in NEA Member countries, has been essential.

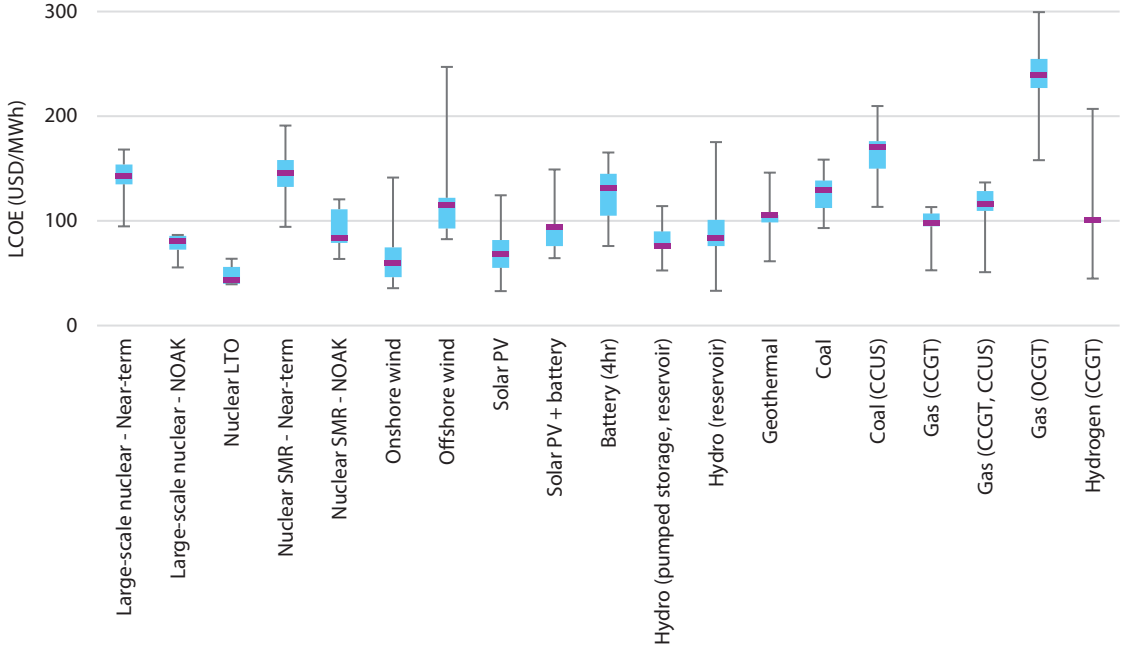
New technologies for new challenges

The nature of the data for NEA Member countries reflect technological developments, policy priorities and electricity system challenges. The overall picture that emerges from the cost data in this report is that new electricity generation is becoming increasingly low carbon and more diversified, but also relatively expensive. In most countries, electricity, in particular carbon-free electricity (the cost of unabated fossil fuel-generation is a function of the carbon price), currently costs USD 100 per MWh or more. Only the long-term operations (LTO) of existing nuclear power plants with already amortised initial investment costs, hydroelectricity where available, and, if their variability and related system-level costs are disregarded, onshore wind and solar PV, are capable of providing electricity for less than USD 100 (see Table ES.2 and Figure ES.1).

Table ES.2. Data overview of country submissions

Technology	Number of countries	Overnight costs (USD/kWe)				LCOE (USD/MWh)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Large-scale nuclear - Near-term	15	8 760	11 545	11 188	14 940	95	141	141	168
Large-scale nuclear - NOAK	10	2 487	5 477	5 502	6 791	56	78	81	87
Nuclear LTO	6	171	974	946	2 028	39	48	44	64
Nuclear SMR - Near-term	11	5 682	12 728	13 021	18 737	94	147	146	191
Nuclear SMR - NOAK	9	4 830	7 618	7 092	10 707	64	91	84	121
Onshore wind	20	1 323	1 874	1 792	3 089	36	63	59	141
Offshore wind	15	3 240	4 609	4 630	7 756	83	121	115	247
Solar PV	20	600	1 096	1 048	2 302	33	68	67	124
Solar PV + battery	14	1 337	2 061	1 986	3 907	64	95	94	149
Battery (4hr)	15	750	1 169	1 260	1 593	76	126	132	165
Hydro (pumped storage, reservoir)	11	1 067	1 911	1 904	2 620	53	81	77	114
Hydro (reservoir)	13	1 586	5 376	5 488	9 743	33	89	84	175
Biomass	15	3 263	4 831	5 050	7 291	86	159	135	397
Biomass (CCUS)	8	6 807	10 502	10 422	15 210	169	218	206	344
Geothermal	13	3 913	7 279	7 490	11 594	61	101	105	146
Coal	12	1 376	4 122	4 373	6 910	93	126	130	158
Coal (CCUS)	10	5 623	8 330	8 511	12 565	113	163	171	210
Gas (CCGT)	15	776	1 482	1 455	2 565	53	96	98	113
Gas (CCGT, CCUS)	13	1 613	3 144	3 070	4 984	51	110	116	137
Gas (OCGT)	13	659	1 300	1 270	2 062	158	237	240	299
ICE	13	708	2 250	2 357	2 755	211	317	329	371
Hydrogen (CCGT)	15	1 121	1 695	1 690	2 743	45	109	101	207
Hydrogen (OCGT)	15	1 242	2 304	2 480	4 026	146	392	406	523

Figure ES.1. Distribution of LCOE values



Note: Individual outliers have been eliminated to allow for re-scaling and better visibility. The full distribution of results including outliers is shown in Figure 3.1 in Chapter 3.

This may change. The dynamism of nuclear technologies translated into a large number of submissions from 15 countries for this report, including the new build of large-scale reactors, the LTO of existing reactors and the new build of small modular reactors (SMRs). As several countries are in the process of recreating the necessary infrastructure in terms of finance, supply chains, regulations and human capital for new nuclear builds, the temporal dimension becomes crucial. This report is thus providing cost data for both new nuclear builds now (near-term projects), as well as for new nuclear builds once the nuclear construction industry has again reached a level of maturity comparable to that of the 1970s and 80s, when learning effects and structural change had been fully realised (N^{th}-of-a-kind- NOAK projects). The differences are large. Near-term costs are roughly double those for NOAK large light-water reactors, and they are roughly 50% higher for SMRs, both of which remain more expensive overall. Should the NOAK promise be realised, however, nuclear energy will be able to provide round-the-clock carbon-free electricity at less than USD 100 per MWh. Reaching this level of deployment in NEA Member countries will require standardised designs and repeat construction, so that learning effects can be captured and supply chains can invest with confidence. It will also depend on stable policy frameworks, efficient and predictable regulation, access to competitive financing, and a renewed effort to develop the skilled workforce needed to deliver projects on time and at scale.

The dataset shows a strong prevalence of low carbon technologies. However, this does not imply the end of fossil fuels and, even less so, the end of gas turbines. For nearly as many countries data was obtained for coal- and gas-fired plants with carbon capture, utilisation and storage (CCUS) than for plants without CCUS. For combined cycle gas turbines (CCGT), every country that reported cost data for turbines fuelled by natural gas also reported data for turbines fuelled by hydrogen. For open cycle gas turbines (OCGT), the number of hydrogen-fired turbines even exceeded that for natural gas-fired ones. The large differences in the estimations of the costs of hydrogen should be noted. While the details – depending on relative prices, regional endowments and geopolitics, policy priorities and further technological developments – remain to be defined, some contours of a space for gas turbines, and even coal with CCUS, in the energy transition begin to emerge.

As far as the cost of renewable energies is concerned, this report suggests distinguishing more clearly than ever between variable renewable energies (VRE), and (in this category) onshore wind and solar PV on the one hand, and offshore wind on the other; and dispatchable renewable energies such as biomass, geothermal and hydroelectricity. For VRE, location truly matters. The higher load factors for solar PV in Australia or the United States, for instance, compared with those in Norway and Sweden, translate into significantly lower costs. On average, however, the LCOE for onshore wind and solar PV remain broadly attractive at the level

of the individual plant. Even if compared to past editions of this series, no further cost decreases have been observed. The clustering of VRE generation during a limited number of hours leads to decreasing prices for generators and to increasing costs at the system level, since large amounts of dispatchable capacity running at reduced capacity factors need to be retained.

Offshore wind remains an expensive option. While capacity factors of 50% and above look attractive, construction costs remain stubbornly high and their system costs, even if lower than those of onshore wind and solar PV, are not negligible. The estimates obtained for numerous countries for geothermal generation indicate a competitive energy source that is both dispatchable and renewable is emerging, even if limited to specific locations. This also holds for well-established hydroelectricity plants, whether in their form as reservoirs with only natural intake, or as pumped storage systems with both natural intake and pumped water resources. The competitiveness of biomass instead is restricted to rare exceptions. The LCOE of biomass remains high, even with unmitigated carbon emissions and, according to standard accounting conventions, no carbon costs added. When emissions are mitigated with CCUS, the costs are higher still, even if a carbon credit is then deducted. Even considering their dispatchability, biomass plants are thus not expected to play a major role in future electricity systems.

Battery energy storage systems (BESS) are becoming an important element in many modern energy systems, particularly those systems with significant shares of non-dispatchable renewables. Due to their intermittent use in widely varying system-contexts, their OCC with a median around USD 1 250 per installed kW for an energy charge of 4 hours, is possibly more indicative than their median LCOE. This report also includes, for the first time, combined systems of solar PV and BESS, which are becoming a reality in many electricity systems. The LCOE numbers of combined systems, higher than those for either standalone solar PV or standalone BESS capacity, must be contextualised. Even if costs are higher, the value of coupling solar PV with storage can increase profitability by enabling electricity to be stored during periods of low prices and sold during periods of high prices. Depending on market conditions, higher cost combined battery and solar PV systems can thus be more profitable than lower cost standalone solar PV.

The need for context and perspective

Battery systems are one area where the limits of the LCOE approach become apparent, and call for contextualisation and introduction of system considerations. The comparability of LCOE numbers for different technologies, or countries, requires a number of common assumptions. In reality, the input parameters will vary across countries. This publication thus provides sensitivity analyses for the discount rate, the capacity factor, the ratio of fixed to variable costs, lifetime, and fuel and carbon costs. This allows for better understanding of the sensitivity of the LCOE with respect to these drivers.

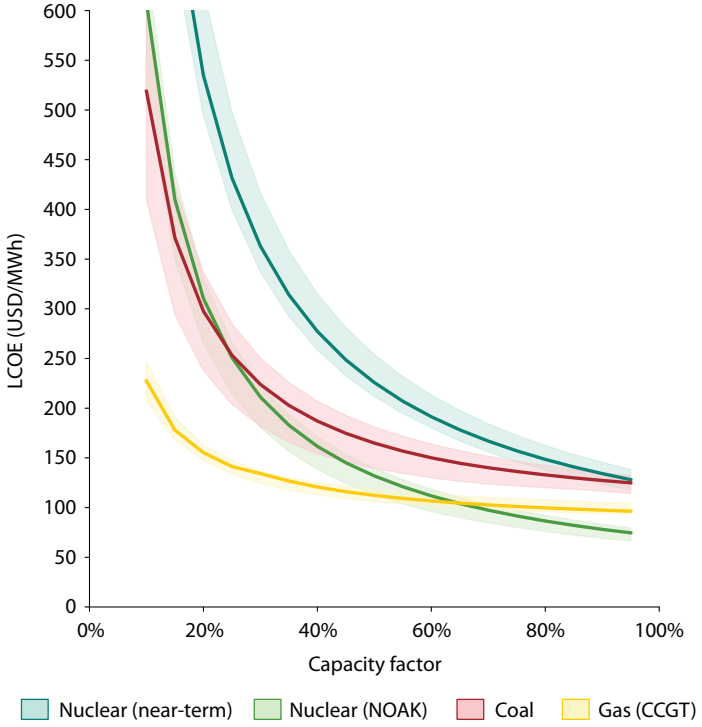
One of the most crucial parameters in an LCOE calculation is the capacity factor, which varies strongly in response to system conditions, such as the penetration of variable renewables. Varying the standard assumption of an 85% capacity factor for the baseload technologies of nuclear, coal and CCGT, the LCOE shows the impacts of deviating from the assumption of being operated at baseload. Figure ES.2 illustrates the impact on LCOE of varying the capacity factor. Driven by their high share of fixed compared to variable costs, nuclear power plants are the most affected technology when operated at lower capacity factors. In an environment in which they can be operated at maximum capacity, they benefit instead from their low variable costs.

Natural gas-fired CCGT plants are the least affected technology when the capacity factor is reduced. They benefit primarily from their relatively low investment costs and appear competitive in a wide range of use cases and market designs. Coal-fired power plants are in a challenging economic position given the underlying fuel and moderate CO_2-price assumptions. They typically require higher investment costs than gas-fired plants but lose the competitive advantage of lower variable costs to the CO_2-reduction measures in many countries. Even if hard to model in a simple graph, VRE such as wind and solar PV, are subject to system conditions and might not be operated at their technically possible number of hours. As their share in the energy generation mix increases, they will also increasingly have to be curtailed.

For further context, this publication also contains an overview of system cost analysis, which extends the assessment of electricity generation costs from the individual plant to the larger integrated electricity system. Its starting point is the total economic cost of continuously satisfying a given profile of electricity demand,

while respecting the continuous balance between production and consumption, the generation and network operating limits, emissions targets, security of supply requirements, reserve margins, interconnection capacities and other reliability criteria.

Figure ES.2. LCOE of coal, natural gas and nuclear technologies, as a function of the capacity factor



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

In practical terms, system cost analysis often relies on modelling optimal, least-cost system mixes, in which each technology assumes a particular role between generation, dispatchability and flexibility provision. Both the NEA and EPRI have been at the forefront of developing such system cost analysis and have developed a substantial body of work to assess the costs of alternative low-carbon electricity mixes. These studies constitute complements to the plant-level generation cost analysis performed in this report, by examining how different technologies affect the total cost of satisfying a given demand under technical and economic constraints.

For this purpose, the NEA has developed a family of open-access modelling tools. NOSY is thus a composable, component-based energy system modelling and optimisation platform, while POSY2 is an advanced power system model for system cost studies. As a mixed integer linear programming (MILP) model POSY2 combines least cost-optimisation with an array of technical and operational constraints. Country studies in Switzerland and Sweden have been published that allow policymakers to assess the overall costs of different strategic choices regarding the relative shares of different technologies, in particular nuclear and VRE. Additional work is ongoing. EPRI's work on system cost analysis has produced several publicly available studies on the decarbonisation of the US energy system and economy under different scenarios, as well as similar studies for members in regions including the Americas and East Asia.

The broader lesson from such system cost work is that the generation cost data summarised in LCOE remains valuable, but its interpretation changes in a system framework. Core inputs only gain meaning through their interaction with system operations. Mindful of the need for such contextualisation, the present report thus strives to provide, with the assembled LCOE data, one essential pillar for the assessment and the design of today's electricity systems.

Context, process, and summaries of submissions and results

1.1. Introduction

The global power sector is passing through a pivotal moment in the energy transition. Amidst challenging procurement conditions and the price volatility of fossil fuels due to geopolitical uncertainties and supply chain risks, the electrification of the building and transport sectors, the increased heating and cooling loads driven by extreme weather, and the rapid growth of artificial intelligence (AI) and data centres, are simultaneously driving up electricity demand. Policy objectives to improve the security of energy supply and decarbonise energy and electricity favour a switch towards more capital-intensive technologies such as VRE, nuclear energy and hydroelectricity. This makes the financing of energy supply projects a crucial issue; an increase in capital-intensity, for instance, can increase price volatility in deregulated electricity markets, with marginal cost pricing. Global inflation and the high-interest-rates that have persisted since the early 2020s have further increased the cost of capital, implying that the macroeconomic environment is exerting a stronger influence on the cost competitiveness of technologies than ever before.

Overall, the selection of generation technologies has evolved beyond a simple comparison of "generation costs per kWh" into a core strategic challenge, in which considerations of security of supply and system costs weigh heavily. Nevertheless, the plant-level costs of generation technologies, frequently expressed as the levelised cost of electricity (LCOE), remain a key decision parameter affecting the overall costs of procurement and industrial competitiveness.

This report, jointly published by the NEA and EPRI, is the 10th edition of the series of reports on the costs of generating electricity that the NEA has prepared since 1983 (several of which were published together with the IEA under the title of *Projected Costs of Generating Electricity*). Reflecting the new policy environment characterised by surging electricity demand and the need for 24/7/365 reliable carbon-free electricity, this edition focusses on providing comprehensive data in a framework that allows both international and inter-technology comparisons based on the (LCOE) framework with systematic input from EPRI's extensive technology-specific cost generation database, published in its *Generation Technology Options 2024*, for the United States. This database is based on detailed technology-by-technology studies that are part of EPRI's research portfolio and compile engineering-based cost estimates.

The availability of this database has allowed a change in the methodology from previous reports based on generating data exclusively from national sources completing a blank questionnaire. This time, NEA and EPRI generated pre-filled data sheets for each individual participating country that combined engineering-based bottom-up data from EPRI (2024) with locational adjustment factors based on data in previous Projected Costs reports. This allowed countries to review, validate or modify the prefilled data, which reduced the administrative burden. Many member countries broadened the scope of the technologies analysed and enhanced the completeness of the data. This resulted in a broader than ever coverage of countries, generation technologies and cost data as indicated in Tables 1.1 and 1.2 below.

The analysis covers 23 different generation technologies, spanning conventional fossil fuel plants (coal and natural gas), nuclear power (including large-scale reactors, small modular reactors, and long-term operation extensions), renewable energy sources (onshore and offshore wind, solar PV, hydroelectric, geothermal and biomass), and energy storage solutions (battery storage and pumped hydro). Carbon capture, utilisation and storage (CCUS) variants are also included for coal, gas and biomass technologies.

Table 1.1. Technologies for which data was obtained for participating countries

Country	Total responses	Nuclear LLWR	Nuclear LTO	SMR	Onshore wind	Offshore wind	Solar PV	Solar PV + battery	Battery (4hr)	Hydro (pumped storage)	Hydro (reservoir)	Biomass	Biomass (CCUS)	Geothermal	Coal	Coal (CCUS)	CCGT	CCGT (CCUS)	OCGT	ICE	H_2 CCGT	H_2 OCGT
		16	6	11	20	15	20	14	15	11	13	15	8	13	12	10	15	13	13	13	15	15
Australia	19	X		X	X	X	X		X	X	X	X			X	X	X	X	X	X	X	X
Austria	14				X		X	X	X	X	X	X		X			X	X	X	X	X	X
Belgium	16	X	X	X	X	X	X	X	X			X	X				X	X	X	X	X	X
Bulgaria	22	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Canada	19	X		X	X	X	X	X	X		X	X		X	X	X	X	X	X	X	X	X
Czechia	18	X			X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Denmark	13				X	X	X	X	X			X		X	X		X		X	X	X	X
Finland	7	X		X	X		X		X													
France	21	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Germany	18				X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Italy	14			X	X	X	X	X	X	X	X	X		X			X	X			X	X
Japan	15	X			X	X	X	X			X	X		X	X	X	X	X			X	X
Korea	9	X	X	X	X	X	X								X		X					
Norway	4				X	X	X				X											
Poland	5	X			X	X	X					X										
Romania	1	X																				
Slovak Republic	21	X		X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Slovenia	22	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Sweden	16	X	X	X	X	X	X	X	X	X				X					X	X	X	X
Switzerland	5	X	X		X		X															
United States	23	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Special care was taken to provide relevant values for the costs of nuclear energy, for which ranges can vary widely. Reflecting different stages of technology maturity and learning effects, cost data for early near-term deployment and for N^{th}-of-a-kind (NOAK) reactors were presented separately, for both large-scale Generation III+ nuclear power plants and small modular reactors (SMRs). However, it is recognised that achieving NOAK is possible only when essential boundary conditions are met, such as continuous construction, supply chain maturity, policy support and industrialisation, including factory-based production for SMRs (NEA, 2021). Furthermore, this report provides cost data for the long-term operations (LTO) of existing nuclear power plants over either 10, 20 or 40 years of additional operational lifetimes. While LTO investments are distinct from investing in nuclear new builds, their scale, cost and importance for dispatchable, carbon-free electricity generation matches that of most other capacity choices.

Table 1.2. Data overview of country submissions

Technology	Number of countries	Overnight costs (USD/kWe)				LCOE (USD/MWh)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Large-scale nuclear – Near-term	15	8 760	11 545	11 188	14 940	95	141	141	168
Large-scale nuclear – NOAK	10	2 487	5 477	5 502	6 791	56	78	81	87
Nuclear LTO	6	171	974	946	2 028	39	48	44	64
Nuclear SMR – Near-term	11	5 682	12 728	13 021	18 737	94	147	146	191
Nuclear SMR – NOAK	9	4 830	7 618	7 092	10 707	64	91	84	121
Onshore wind	20	1 323	1 874	1 792	3 089	36	63	59	141
Offshore wind	15	3 240	4 609	4 630	7 756	83	121	115	247
Solar PV	20	600	1 096	1 048	2 302	33	68	67	124
Solar PV + battery	14	1 337	2 061	1 986	3 907	64	95	94	149
Battery (4hr)	15	750	1 169	1 260	1 593	76	126	132	165
Hydro (pumped storage, reservoir)	11	1 067	1 911	1 904	2 620	53	81	77	114
Hydro (reservoir)	13	1 586	5 376	5 488	9 743	33	89	84	175
Biomass	15	3 263	4 831	5 050	7 291	86	159	135	397
Biomass (CCUS)	8	6 807	10 502	10 422	15 210	169	218	206	344
Geothermal	13	3 913	7 279	7 490	11 594	61	101	105	146
Coal	12	1 376	4 122	4 373	6 910	93	126	130	158
Coal (CCUS)	10	5 623	8 330	8 511	12 565	113	163	171	210
Gas (CCGT)	15	776	1 482	1 455	2 565	53	96	98	113
Gas (CCGT, CCUS)	13	1 613	3 144	3 070	4 984	51	110	116	137
Gas (OCGT)	13	659	1 300	1 270	2 062	158	237	240	299
ICE	13	708	2 250	2 357	2 755	211	317	329	371
Hydrogen (CCGT)	15	1 121	1 695	1 690	2 743	45	109	101	207
Hydrogen (OCGT)	15	1 242	2 304	2 480	4 026	146	392	406	523

The remainder of this chapter introduces the context, scope and key issues of this report, summarises the data collection and alignment process, and examines the characteristics of country submissions as well as major trends by technology group. The specific methodology and detailed assumptions are discussed further in Chapter 2, the technology-by-technology data and key results of this report are provided in Chapter 3, and sensitivity analysis over key parameters and system cost perspectives are included in Chapters 4 and 5, respectively.

1.2. The Context: Multiple new challenges for power systems

Simultaneous pressures of energy security and decarbonisation

Since 2025, electricity demand growth in the majority of NEA Member countries has accelerated and the volatility of electricity prices, driven by intermittent renewables and volatile gas prices, has increased. Demand growth is driven, in particular by the expansion of data centres driven by the needs of the AI industry, which demands large-scale, uninterrupted 24/7 supplies of electricity. More frequent extreme weather events (heatwaves, cold snaps, etc.) have also exposed the supply risks related to weather-dependent generation sources. Today's power systems thus face the unprecedented challenge of not merely producing more electricity but doing so while securing resilient and dispatchable low-carbon electricity sources.

The enduring usefulness and limitations of LCOE

LCOE is an intuitive and useful starting point for comparing costs across countries and generation technologies. However, levelised cost metrics are insufficient for evaluating the economic competitiveness of different power sector resources, as they do not evaluate how the market value and ancillary system costs of technologies vary as the state of the system evolves (EPRI, 2020). Additionally, LCOE is highly sensitive to prerequisites such as discount rates, construction times, capacity factors, regulatory environments and risk premiums. Depending on national conditions (grid connection, reserves, natural resources, etc.), the results can, in practice, vary significantly, even for the same technology. Thus, this report needs to tread a fine line between harmonising assumptions for purposes of comparison on the one hand and reflecting national particularities on the other hand. Chapter 2 spells out those trade-offs in more detail. A key parameter that has been harmonised over all countries and technologies is the cost of capital, which in the capital-intensive electricity sector can be of decisive importance.

This report adopted a universal real discount rate as the default assumption, thus enabling the comparison of the relative importance of other parameters and bringing out the inherent cost characteristics of each technology in a largely consistent manner. The LCOE of variable renewable energy (VRE) thus heavily depends on their local capacity factors, while the LCOE of fossil fuel generators is strongly dependent on fuel prices. The competitiveness of nuclear power is heavily dictated by capacity factors and overnight construction costs (OCC). As the Long-Term Operation (LTO) does not require the same significant capital costs of new nuclear construction, it emerges as a highly cost-effective alternative among various low-carbon options, in this dataset.

1.3. Process: Data collection, alignment and analysis procedures

Approach of this edition

Whereas previous editions considered estimates for the generation costs at a date of commissioning 5 years into the future, this 2025 edition focusses instead on current cost estimates. NEA Member

countries validated, corrected or supplemented data based on the shared EPRI dataset – adapted with individual locational adjustment factors and appropriate currency conversions – to reflect their national contexts and to add additional technologies, such as energy storage systems, where appropriate.

Common comparison standards and alignment principles

To ensure comparability across countries, core assumptions and calculation rules were applied as uniformly as possible, and the final LCOE was collectively calculated using the NEA's integrated lifecycle LCOE formula. Details of shared assumptions (discount rates, lifetimes, capacity factors, fuel and carbon costs, construction periods, expenditure profiles and decommissioning) and rules for harmonisation are presented in Chapter 2.

Data validation and clarification of technology definitions

NEA Member country validation focussed on the factuality of the input data and consistency with definitions, rather than the final LCOE figures themselves. To reduce confusion regarding terminology and scope at the level of the technologies themselves, key definitions were standardised. The key technology categories are the following:

- **Gas technologies**: Distinctions are made between combined cycle gas turbines (CCGT), open-cycle gas turbines (OCGT) without heat recovery and reciprocating internal combustion engines (ICE), using natural gas as fuel.
- **Hydroelectricity**: Distinctions are made between pumped storage with natural water intake and pumped water supplies, and reservoir storage with only natural water intake.
- **Nuclear long-term operations (LTO)**: These are not treated as a simple add-ons to the routine annual operating costs of existing nuclear power plants, but as free-standing new investment projects that, while making use of the existing plant, must consider new overnight construction investments that will need to be amortised over the additional lifetime of the plant.
- **Scale of renewables**: Solar and wind costs are based on grid-connected utility-scale large facilities, not distributed (residential/commercial) generation.

1.4. Summary of submissions and results

This section briefly outlines the characteristics of the data submitted by countries and the main cost trends for different technology groups. Specific figures and detailed results by country and by technology, are presented in Chapters 3 and 4.

Characteristics of country data

Countries were encouraged to focus their review on the factuality and definitional consistency of the individual input data points, rather than the resulting LCOE values. With these recommendations, one can distinguish between three major country groups:

- **Full-spectrum submissions**: Countries such as France, the United States, the Slovak Republic, Slovenia and Canada covered all or most of the 23 individual technologies.
- **Selective submissions**: Countries such as Korea, Finland and Norway provided data centred on specific market-leading technologies of high policy interest in their respective nations.
- **Targeted submissions**: There are also cases, such as Romania, that submitted data focussed on a specific single technology (primarily nuclear).

Therefore, when using the LCOE data in this report, one should carefully consider the context and assumptions of each country. This applies in particular in the following cases:

- **Poland and Romania**: For Poland, the values for overnight construction costs (OCC) and partial fixed operating costs were based on country-specific data, while the remaining operating costs were derived from EPRI estimates. For Romania, only data for operations and maintenance (O&M) were provided, and the OCC values were therefore taken from EPRI data.
- **Country-specific capacity factors**: As in previous editions, this report uses a common capacity factor of 85% for nuclear, coal and gas CCGT plants. This allows for a technology comparison of dispatchable baseload technologies. It does, however, imperfectly reflect the capacity factors achieved in the actual use in different countries, both due to technological and operational capabilities, and due to their use in the context of different generation systems. For example, nuclear plants in the United States routinely achieve capacity factors above 90%; conversely, CCGT plants in Australia often have capacity factors considerably below 85%, due to strong renewables penetration and their use as flexibility providers.
- **Specific national provisions**: LCOE figures correspond to what is referred to as "economic resource cost", i.e. the economic opportunity cost in terms of capital, labour and primary resources of building, maintaining and operating a given plant for electricity generation. This means that all cost figures in this report are net of taxes, subsidies, depreciation and other transfer payments or accounting conventions. They are also net of insurance costs, although the cost of capital is to some extent a measure of risk and contingency payments, and have been included in overnight construction costs.

Major trends in results by technology group

Aligning the submitted data with the help of shared assumptions, allows identification of some of the trends and drivers determining LCOE for each technology group (see also Figure 1.1). Furthermore, the country coverage of data submissions in itself provides an indication of the interest and policy context that each technology group receives:

- **Variable renewable energy technologies (onshore and offshore wind, solar PV)**: The LCOE of VRE is dictated by initial capital expenditures (CAPEX) and resource conditions based on location (wind speed or solar irradiance). Carbon or fuel costs do not apply. Connection and distribution costs are high but were not considered in this report. In terms of LCOE, VRE tend to be at the lower end of the costs of new generation sources in many countries. However, it is well established, partly due to the NEA's work on the issue, that their variability and intermittency require dispatchable back-up technologies that operate at higher capacities and at lower capacity factors than they would otherwise, which drives up the costs of the overall system. Negative prices and the risk of curtailment during low load hours can further increase those costs. Therefore, the cost competitiveness of VRE must be interpreted alongside the need for additional flexibility resources (dispatchable back-up, storage, demand response and transmission networks), in addition to the plant unit costs.
- **Hydroelectricity**: This report categorises hydropower into reservoir hydropower with only natural water intake and pumped storage systems, with both natural and pumped water recharge. Both are treated as storage system with costs expressed in LCOS. Reservoir hydropower, dependent on location and national endowments, shows a broad range of costs, whereas pumped storage exhibits not only lower OCCs but also a far narrower range of costs. Hydropower has low operating costs and offers high long-term cost stability. However, its LCOS is heavily dependent on location, hydrological conditions (flow rate and head), civil engineering difficulty, licensing (environmental and water resources), and construction timelines. New large dams tend to have very high CAPEX, but they hold significance at the system level beyond simple LCOS, as they can provide system flexibility with balancing services and load following, in the context of VRE expansion.
- **Geothermal**: The key drivers of geothermal generation costs are geological resource availability and risks in exploration, drilling, design, construction and corrosion, depending on geological conditions. This leads to a wide dispersion of costs across countries and projects. In some

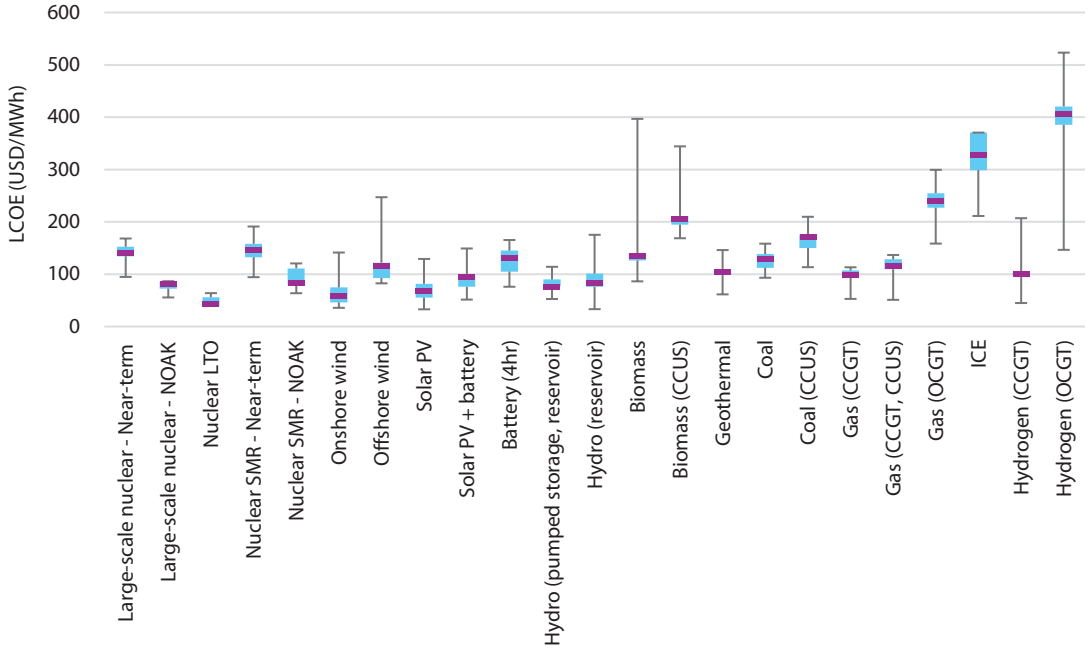
countries, geothermal energy can be combined with heat provision (district heating or industrial heat), meaning its value may be underestimated by considering electricity LCOE alone.[1]

- **Fossil fuels (coal and gas) without CCUS**: Fossil fuel-based power generation is the technology whose LCOE is most heavily dependent on variable costs. Even for similar technologies, the LCOE of fossil fuel sources can change drastically by region depending on region-specific fuel costs and carbon prices. Therefore, the comparative results in this report very much reflect national conditions in fuel and carbon markets. Shifts in fuel costs disproportionately affect their comparative LCOE.
- **Fossil fuels (coal and gas) with CCUS**: While CCUS greatly reduces the burden of carbon costs, it increases capital expenditure (CAPEX) and operating expenditure (OPEX) and imposes an additional penalty on the electric conversion efficiency from fossil fuel (coal or gas) to electricity. Consequently, a cost structure is observed where the overall LCOE rises, or the cost-saving margin is limited, compared to unabated counterparts.
- **Nuclear (Gen III, SMR and LTO)**: For new nuclear plants, CAPEX, which is heavily influenced by construction timelines and financing costs, dominate the LCOE. One of the points of most interest to readers of this report is likely to be the country-by-country cost estimates for new SMR models. While the absolute amounts of capital costs are considerably lower than those for Gen III reactors, the cost structure, i.e. the ratio of fixed costs (including capital recovery) to variable costs, is very similar. Conversely, LTO benefits from the availability of existing plants, and preparing a plant for additional operational lifetimes requires far lower CAPEX than nuclear new build. As indicated, LTO is treated as a separate technology rather than as an additional maintenance investment in a new nuclear plant.
- **Nuclear (near-term vs. NOAK)**: Given that in many NEA Member countries nuclear new build requires the reinitialisation of nuclear construction after a lengthy hiatus and a reconfiguration of supply chains, this report distinguishes between near-term construction and NOAK construction. Compared to near-term construction, NOAK construction demonstrates potential for cost improvements if boundary conditions such as continuous construction, supply chain maturity, policy support and industrialisation are met (NEA, 2021). The data in this report clearly show how LCOE is expected to improve considerably when the risks and costs of initial near-term construction of both large nuclear plants and SMRs are resolved through learning effects and repeated construction (NOAK).[2]
- **Storage systems and hydrogen generation**: Some of the newer technologies included in this report push the LCOE concept to its limits. Battery energy storage systems (BESS) and PV+BESS combinations thus *increase* the LCOE at the plant level; however, they *decrease* costs at the system level where they contribute to supply during periods of peak demand and then also earn particularly high prices for the individual owner. Similarly, hydrogen-fired generation currently exhibits high costs. Even if some long-term downward cost stabilisation is expected as the technology matures, the purposes and uses of hydrogen are more varied and more complex than can be captured in an LCOE per MWh of electricity metric.

1. This report does not include a heat credit for technologies capable of co-generation.

2. During the preparation of this report, NEA Member countries were informed that they could submit data for any generation technology where NOAK effects are anticipated, beyond just nuclear power. Reductions in overnight costs over time might, for instance, also accrue for geothermal, storage or the costs of hydrogen. Ultimately, however, the NOAK data provided by countries was limited to the nuclear sector. In addition, no data was collected for technologies other than nuclear for LTO, beyond the sensitivity analysis of LCOE costs with respect to lifetime in Chapter 4.

Figure 1.1. Range of LCOE per technology



Note: The purple lines indicate the median LCOE value, the light blue rectangles below and above the purple lines indicate LCOE values in the second and third quartiles, and the bars indicate LCOE values in the first and fourth quartiles of all submissions, ordered by magnitude.

Four typologies of countries in relation to nuclear energy

For some countries, nuclear energy is not only an important part of current and future low-carbon systems, but it is also a technology that strongly depends on the policy environment. It is therefore useful to briefly consider the main attitudes towards nuclear technology that NEA Member countries adopt today. The countries analysed in this report can be classified into the following four groups, based on their national nuclear policy directions and the continuity of their industrial ecosystems. This can provide some context, and partially explain why estimations for the LCOE and OCC of new nuclear power plants can vary across countries, even when adopting the same nuclear technology (reactor type).[3]

- **Countries with continuous new construction and standardisation (e.g. Korea and Canada)**: This group has achieved standardisation and serial construction by pursuing domestic and international projects without interruption. Benefitting from steady learning effects based on years of accumulated experience and solid supply chains, they are able to reduce costs and construction risks.[4]
- **Countries with strong operational bases resuming new construction (e.g. France, the Slovak Republic and the United States)**: Countries in this group have maintained high-level operation and maintenance capabilities for existing nuclear plants, but have experienced patchy and discontinuous construction schedules for new nuclear power plants since the 1990s. Recently, these countries have been resuming large-scale new projects for reasons of energy security and decarbonisation, but as they are in the process of rebuilding their supply chains, cost may exceed initial estimates for near-term projects.

3. This illustrates that ideally nuclear power construction is not merely a one-off investment but part of a continuous effort to optimise construction and maintenance, while maintaining a robust industrial ecosystem.

4. The phenomenon of relatively low overnight construction costs (OCC) calculated in OECD Asia is closely related to the macroeconomic industrial structures of those nations. As urban infrastructure and large-scale industrial/manufacturing facilities are actively being built nationwide (indicated by the high GDP share of the construction industry), an extensive, efficient construction ecosystem and a skilled labour pool are constantly maintained. Powerful economies of scale and positive spillovers are generated when this industrial context intersects with large, complex projects like nuclear power plants, accelerating construction times and reducing costs.

- **Countries with first-of-a-kind (FOAK) nuclear new build (e.g. Sweden, Poland and Czechia)**: These countries are either introducing nuclear power for the first time or are planning to expand existing capacities after a long hiatus. Due to the costs and risks associated with constructing FOAK new builds, including the establishment of licensing frameworks and the building of infrastructure, their initial LCOE estimates can be relatively high. However, supported by firm decarbonisation and energy security objectives, they are advancing nuclear development with determination.
- **Countries currently not considering nuclear new build (e.g. Denmark and Germany)**: This group of countries currently does not have concrete plans for nuclear new build and hence did not provide LCOE estimates for any of the different types of nuclear power generation in this report.

Link to the system cost discussion

While LCOE transparently shows costs at the plant level, it does not represent the entire cost of the power system. Additionally, it does not reflect the market value that a specific source contributes to the grid, based on supply and demand conditions at the time of generation. It also does not include the broader category of external effects (social costs) that accompany the introduction of a new power plant, such as air or water pollution, siting conflicts, connection or grid costs, or their impact on the security of energy supply.

As the share of VRE grows, additional system costs arise for the hourly balancing of demand and supply, guaranteeing technical grid stability, possible addition of energy storage devices, and the expansion of transmission and distribution networks (NEA, 2019). This is why, despite the significant drop in the standalone LCOE of VRE among various generation technologies recently, many countries are also pursuing the new construction and long-term operations (LTO) of nuclear power or the continued operation of a certain proportion of fossil fuel generation. In the face of extreme weather events and risks of intermittency, the security value of an uninterrupted power supply is more important than generation unit costs. Conversely, dispatchable generation provides system value to the grid by supplying firm capacity. Chapter 5 provides an in-depth discussion on how these generation cost data link to power system cost analyses.

1.5. Conclusion: Internationally validated LCOE data remain a vital piece of the energy puzzle

This report aims to provide a foundational evidence base and strategic insights for policymakers, industry stakeholders and researchers navigating an increasingly complex energy landscape, shaped by the ongoing evolution of the energy mix and the rapid deployment of AI. As global power systems simultaneously confront the dual imperatives of decarbonisation and energy security, alongside surging electricity demand driven by broader electrification and the expansion of AI data centres, robust, transparent and internationally comparable data are essential. Rigorously validated by NEA Member country delegations, such data enable decision makers to formulate sound, tailored energy policies that reflect their specific national contexts.

While LCOE remains a fundamental and established metric for assessing plant-level cost competitiveness, grasping the comprehensive economic realities of power generation requires looking beyond just LCOE. As discussed in preceding sections, holistic energy planning necessitates complementary analyses – incorporating system integration costs, the market value of dispatchability, grid infrastructure requirements and broader socio-environmental externalities.

Nevertheless, the plant-level cost data presented in this report continue to offer critical insights. By leveraging EPRI's extensive, engineering-based bottom-up database, alongside rigorous validation and the application of regional and national contextual adjustments by NEA Member countries, this 2025 edition provides a reliable and nuanced benchmark. Ultimately, while obtaining a full picture requires complementary system-level analysis, the robust LCOE data provided in this report remains a vital piece of the puzzle. It can serve as a quantitative bedrock upon which stakeholders can effectively design resilient energy policies capable of adapting to future systemic transitions.

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Methodology, conventions and key assumptions

This chapter presents the methodology to calculate the levelised costs of electricity (LCOE), as well as the methodological conventions and assumptions to ensure consistency and transparency among cost estimates across countries and technologies. The LCOE methodology has been carefully reviewed, and all assumptions have been discussed and agreed upon between the NEA and EPRI.

The LCOE methodology includes a limited set of cost parameters for establishing discounted average costs at the plant level. In doing so, it assumes a simplified representation of electricity output (constant, except for material changes such as the physical degradation of solar PV panels) over time and the absence of market risk. Such a stylised setting was reasonably close to reality when electricity was produced by baseload generators, typically nuclear, coal or gas, in regulated electricity systems with stable tariffs for each MWh generated at high and predictable capacity factors.

This stylised setting differs substantially from today's liberalised electricity markets with strongly fluctuating prices based on marginal rather than average costs, where irregular production profiles depend on generation from variable renewables, such as wind and solar PV. The risks in this new electricity world have impacts on the financial and economic costs of new generation. They are compounded by the fact that, in many markets, total revenues no longer consist only of hourly generation but on a "stack" of revenues resulting from contributions to forward, day-ahead, balancing and system services markets.

Most importantly, electricity generation costs depend not only on the fixed and variable costs of the individual plant but also on the shares of all other technologies in the generation mix. This is the reason why, since 2012, the NEA and others have engaged in the analysis of system cost rather than plant-level costs (see NEA, 2012; Hirth et al., 2013; and NEA, 2019). Chapter 5 of this report provides a succinct overview of the key determinants of cost formation in integrated low-carbon systems and the lessons learnt from almost 15 years of research in this area.[1]

Why then still engage in the calculation of plant-level LCOE today? First, plant-level costs remain an important part of system costs. While one can have meaningful discussions on whether LCOE is the most pertinent way of representing them, OCC, fuel, and fixed and variable O&M costs remain important for determining a technology's optimal share in an integrated system. Second, the LCOE metric remains uniquely useful, transparent, comparable and intuitive. General readers, experts and decision makers all know what LCOE *means*. This holds even when everybody is aware that quoted LCOE figures will only incidentally correspond to the financial costs of a given power plant in

1. Another factor that can drive a wedge between the conceptual representation and the reality of liberalised electricity markets is the existence of portfolio effects. When decisions are made by private investors according to financial criteria, portfolio considerations can steer the dispatch decisions by investors away from the variable costs of the marginal technology. For instance, investors might choose a more expensive technology because it hedges their risks in another market. Imagine an investor who is long on carbon credits (i.e. gains when the latter rise) and hedges the resulting price risk by letting a coal plant, rather than a gas or a biomass plant, generate, even if the latter should have slightly lower variable costs. However, such intricate financial considerations are also not captured by system cost analysis or any other economic analysis, striving for generality.

a specific market environment. The economic costs of different generation technologies thus need to be complemented with other metrics, such as their system effects. Notwithstanding, even without full contextualisation, LCOE data retains its fundamental usefulness as a widely used tool for modelling, policymaking and public debate.

2.1. The nature of the data in *The Costs of Generating Electricity 2025*

LCOE is a specific form of average costs. It corresponds to the total costs of building and operating an electricity generating plant over its lifetime (including decommissioning), divided by its total generation. Both costs and generation are discounted to the date of commissioning, the moment when the first MWh is produced.[2] This provides an indicator of the average cost of the electricity generated. In a regulated electricity system, where fixed tariffs aim to cover costs, LCOE thus also corresponds to the level of the tariff that would let a generator break even. One can consider LCOE calculation as a form of costs-benefit analysis (CBA) in which at the date of commissioning the net present value of the project is zero.

In this context, discounting costs is standard accounting procedure; however, discounting generation can seem unusual. Applying financial considerations, how can one discount a physical quantity measured in MWh? The conundrum is solved when considering that the physical output, the electricity generated, is just a proxy for the revenue generated by that output (compared to standard CBA, the break-even revenue is here an output, not an input). As electricity in far-away future years provides less financial value than electricity generated in years close to commissioning, it is necessary to discount it (see equations (1) and (2), below).

This standard methodological approach has been adopted since the 1st edition of the *Projected Costs of Generating Electricity* (1983), published by the OECD Nuclear Energy Agency (NEA) and has continuously been applied through the 9th edition, in 2020. From 1989 to 2020, NEA co-published the *Projected Cost* series approximately every five years, together with the International Energy Agency (IEA), leaving the methodology unchanged. The standard LCOE methodology has also been maintained in this edition with a minor computational adjustment (see below).

Nevertheless, compared to previous editions, this 10th edition presents a fundamental change in sourcing, vetting and validating the underlying cost data. In the past, the joint NEA/EPRI project team sent out blank templates to NEA Member countries for completion with national cost data for all relevant technologies. This data was then compiled, checked for consistency and used as input for computing LCOE figures. In the last three editions (2010, 2015 and 2020), the project team was assisted in vetting cost data supplied by participating countries by an Electricity Generating Costs (EGC) Expert Group composed of economists, engineers and representatives of international organisations with deep knowledge of electricity markets, generation technologies and cost accounting.

For this 2025 edition, the joint NEA/EPRI project team inversed this procedure. NEA Member countries no longer received a blank template to complete – a process that was handled in the past in widely different manners, often involving representatives from government, industry and academe, or independent experts. In this edition, NEA Member countries received templates for all chosen technologies which were prefilled with relevant cost data. Proceeding in this manner was only possible because the project was able to combine two unique data sources available at EPRI and at the NEA:

- First, the project was able to benefit from EPRI's extensive cost database under its *Generation Technology Options 2024*, for the United States. This database is based on detailed technology-by-technology studies that are part of EPRI's research portfolio and that compile engineering-based data. It results from a uniquely comprehensive effort, which is based on financial and institutional capabilities unavailable in most other countries.

2. Discounting to the date of commissioning (DOC) is a convention rather than a logical necessity. In principle, one could also choose the start of construction, which would result in slightly lower LCOE figures. In practice, however, most studies settle on the date of commissioning as a convenient and intuitive fixed point for comparisons between countries and technologies.

- Second, to adapt the cost data for generation technologies in the United States to comparable technologies in other countries, the NEA drew on a consistent set of generation costs compiled over the past 15 years. The 2010, 2015 and 2020 editions of the *Projected Costs of Generating Electricity* provide readily accessible cost ratios between the United States and other countries. These cost ratios reflect relatively stable structural differences between countries. Applying these locational adjustment factors to the overnight construction costs of technologies in the United States generated a crucial input into the country-specific datasets sent out by the joint NEA/EPRI project team.

Combining the two datasets – the larger set of EPRI bottom-up technology cost data and the smaller set of NEA locational adjustment factors – allowed the NEA/EPRI team to prefill the templates of NEA Member countries with individualised, relevant and reasonable cost data. However, proceeding in this manner yielded viable, trustworthy and useful results only because the project was able to draw on an additional, indispensable resource: the active involvement of participating countries themselves. Indeed, templates had been prefilled only provisionally and required validation, completion or correction by NEA Member countries before their data could be included in the present report. This process of validation took place throughout a long iterative process with the NEA/EPRI joint Secretariat.

There is a final difference between this edition, *The Costs of Generating Electricity 2025*, and previous editions of the *Projected Costs of Generating Electricity*. As the change in title indicates, this report contains the most relevant estimates of electricity generating costs today, (or more precisely, in 2025). In the past, countries were asked to provide estimates for electricity generating costs for projects that would be commissioned five years out in the future. The idea was to harmonise dates of commissioning for technologies with very different construction periods. If the construction of a nuclear power plant got underway today, it would not deliver electricity for five years, while the construction of a new solar PV plant would be a year.

These differences are reflected in LCOE values. However, the philosophy of previous editions of *Projected Costs of Generating Electricity* was that dates of commissioning also needed to be harmonised. All generating projects were thus supposed to start five years after the publication of the report. However, when regarding LCOE figures, the vast majority of readers considered these values as the relevant values at the date of publication, and most contributors to the reports worked under the same assumption, since the best estimate for cost data five years hence were today's costs.

The only instance when the difference between cost data for today, i.e. the date of publication, and cost data for five years hence came to bear was when presenting cost data for solar PV panels in the 2015 edition of *Projected Costs of Generating Electricity*. During a period of rapid cost and price declines in solar PV panels, it was agreed that a small annual cost degression factor was warranted for the five years between the date of publication and the date of the start of a hypothetical project. No other adjustment accounting for this five-year gap between reporting and a hypothetical start of operations was ever made. As such, even though the stated assumption for the date of commissioning has changed, the spirit of *The Costs of Generating Electricity 2025* is very much the same as that of Projected Costs of Generating Electricity.

Independent of the specific processes employed in obtaining data for the costs of 23 different electricity generation technologies, it should be noted that the firmness of the estimates provided by NEA countries can differ between technologies, as well as between specific cost categories. The capital costs of mature technologies such as gas turbines or solar PV panels have a large number of recent data points, even if these costs can change over time due to market conditions. Uncertainties are considerably greater for the costs of technologies that are still in development, such as SMRs or fossil fuel plants with CCUS. Finally, the uncertainty surrounding the cost estimates of yet another set of technologies, such as large-scale nuclear power plants, hydropower reservoirs or offshore wind turbines, falls somewhere in the middle of the first two groups. In all cases, participating countries and the NEA/EPRI project team have strived to provide the best cost information available.

2.2. Calculating LCOE: General methodology

LCOE values correspond to the constant electricity tariff, or price, that would equalise the present value of all revenues and the present value of all costs. In other words, if the tariff corresponds to the LCOE, this will ensure that an investor breaks even for capital and operating costs. Four important methodological assumptions need to be kept in mind:

(1) In this report, no difference is made between the cost of capital and the discount rate for the present value calculations. The methodology thus does not consider questions of debt/equity splits, taxes and depreciation.

(2) The cost of capital is the cost of risk. This report assumes an identical discount rate of 5% for all technologies and all countries. It is left to readers to decide whether it is warranted to contextualise the results in function of national circumstances or risk dimensions such as policy risk, construction risk or price risk, which may differ between technologies.[3]

(3) The rate of 5% assumed for the calculations in this report is a real discount rate, net of inflation. When making comparisons with real-world market rates for electricity generation investments, it needs to be kept in mind that the latter are nominal rates and do include inflation.

(4) The electricity tariff, or price, per MWh of electricity (P_{MWh}) that equalises the present values of revenues and costs is stable, and does not change during the lifetime of the project. All output is sold at this tariff.

With these assumptions the two basic equations for calculating the levelised costs of electricity (LCOE) corresponding to the stable price of electricity that equalise discounted revenues and costs, can be formulated.

Equation (1) establishes the equality between the present value of the sum of discounted revenues and the present value of the sum of discounted costs, including the cost of capital. The subscript t denotes the year in which the sale of production or the disbursement of cost takes place. Discounted costs and revenues are summed from the start of construction until the end of decommissioning, the costs of which are also included. For nuclear plants, while the physical costs of decommissioning are factored into the decommissioning costs, the costs for the management of spent nuclear fuel are included in the overall nuclear fuel cost.

The left-hand side of the equation indicates the discounted sum of revenues, constant annual production times the constant price of electricity, while the right-hand side indicates the discounted sum of costs:

$$\sum_{t=1}^{n} P_{MWh} * MWh_t * (1+r)^{-t} = \sum_{t=1}^{n} (Capital_t + O\&M_t + Fuel_t + Carbon_t + DC_t) * (1+r)^{-t} \qquad (1)$$

with

P_{MWh}	=	Constant price, or tariff, of electricity
MWh	=	Amount of electricity produced annually
r	=	Real discount rate corresponding to the cost of capital
n	=	Operational lifetime
t	=	Time in years
$Capital_t$	=	Capital costs in year *t* (these are disbursed before commissioning)
$O\&M_t$	=	Operation and maintenance costs in year *t*
Fuelt	=	Fuel costs in year *t*
$Carbon_t$	=	Carbon costs in year *t*
DC_t	=	Decommissioning costs in year *t*.

3. With a 5% real discount rate, *Electricity Generation Cost 2025* returns to the standard assumption of most previous editions of the Projected Costs of Generating Electricity. While some previous editions had included a 10% rate in complement to the 5% rate, only the 2020 edition had used discount rates of 3%, 7% and 10%. While there exist good economic arguments for differentiating values, in particular different electricity market designs implying different levels of price risk, reporting them in this manner made comparisons with previous results and other publications – a significant share of which also use 5% – more difficult. The sensitivity analysis in Chapter 4 provides results for key technologies over a range of discount rates.

Since P_{MWh} is a constant over time, it can be pulled out of the summation, and both sides can be divided by the remainder of the left side. The result is:

$$P_{MWh} = LCOE = \frac{\sum(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t)(1+r)^{-t}}{\sum MWh_t(1+r)^{-t}} \quad (2)$$

Equation (2) is the basic formula to calculate the levelised cost of electricity (LCOE) as the equivalent of the constant tariff, or price, that would equalise discounted lifetime revenues and costs and has been used in previous editions of the *Projected Costs of Generating Electricity* series.

Confusion occasionally arises when equation (2) is considered in isolation, since it seems to require discounting MWh – a measure of electric energy that is unaffected by risk or time. However, in the present context, the amount of MWh is a proxy for annual revenue, which corresponds to annual generation, measured in MWh, times the constant price. As revenues need to be discounted and the constant price is now an output rather than an input, discounting the annual MWh-values is the logical manner to maintain the required equality of discounted costs and revenues.

Working with capital recovery factors (CRF) and the LCOE formulas

Equations 1 and 2 were used in past editions of the *Projected Costs of Generating Electricity*. LCOE values were calculated from rather large Excel spreadsheets with line-by-line entries for each year of a generator's lifetime. In addition to requiring large spreadsheets, this procedure can be cumbersome and vulnerable to entry errors.

The alternative, which was employed in this edition, is to work with capital recovery factors (CRF) that allow transforming the total capital requirement (TCR), which is disbursed during the construction period, into annuities that can then be allocated to each unit of annual output. Once the respective formulas for TCR and CRF, as well as for the annuity of decommissioning costs, are correctly specified, they yield the same results as Equation 2, as long as two issues are appropriately dealt with. The key advantage is working with considerably leaner spreadsheets and avoiding errors of entry. The two methodological issues that need to be considered are:

(1) During the operational lifetime of a plant, there are no changes in either revenues (output) or costs. This is not a particularly restrictive assumption, as the freedom to introduce annual changes was never used in the previous methodology. Since the LTO of nuclear power plants are treated as a "new" technology, with the beginning of LTO being considered as a new date of commissioning, they can also be dealt with straightforwardly by the CRF-methodology.

(2) The precise date of commissioning (DOC), whether it takes place on 1 January, 31 December or the middle of the year, needs to be specified. Changes in the DOC affect the net present value of revenues and costs, and hence the LCOE. Such impacts arise both in the previously used methodology and in the methodology employed in this edition. However, they are less obvious in the CRF-based methodology and thus need to be considered attentively (see also the discussion about the appropriate formula for the CRF below).

With these two points considered, one can apply the alternative equation (3) for calculating LCOE values. Note that this equation does not include any summation signs for different years of operational lifetime; instead, it calculates the constant LCOE for a single year:

$$LCOE = \frac{TCR * 1000 * CRF + FOM * 1000 + (VOM + Fuel + Carbon) * 8760 * LF}{8760 * CF} + DC \quad (3)$$

with

TCR = Total capital requirement includes the cost of capital *r* and uprated to the DOC per kW

CRF = Capital recovery factor (see below)

FOM = Fixed annual operations and maintenance costs per kW[4]

VOM = Variable operations and maintenance costs per MWh[4]

Fuel = Fuel costs per MWh

Carbon = Carbon costs per MWh

DC = Annualised decommissioning costs

CF = Capacity factor (ratio of hours of generation to 8 760 hours).

Fully understanding equation (3) requires specifying the underlying calculation of the TCR and the capital recovery factor (CRF). The TCR sums the expenditures during the construction period adjusted by the annual share of expenditures and sums the annual expenditures that have been individually uprated to the date of commissioning by the interest rate (the cost of capital):

$$TCR = \sum_{t=1}^{c} OCC * s_t * (1+r)^t \qquad (4)$$

with

TCR = Total capital requirement including the cost of capital r and uprated to the DOC per kW

OCC = Overnight construction costs

c = Length of construction in years

st = Share of OCC spent in year *t*

r = Real discount rate corresponding to the cost of capital

t = Time in years.

The CRF calculates the annuity that is required to pay back the TCR over the lifetime of the project. What seems to be a straightforward concept become slightly more complicated when considering that it makes a difference whether the annuity is being paid at the beginning of the year, the end of the year or in between. In any case, the first annuity would be paid at the moment of the start of operations, the DOC. The standard formula is:

$$\text{CRF if first annuity is paid on 31 December of year 1} = \frac{r*(1+r)^n}{((1+r)^n-1)} \qquad (5)$$

with

r = Real discount rate corresponding to the cost of capital

n = Number of years over which the annuity is paid (operational lifetime).

Equation (5), however, assumes that the annuity is being paid at the end of each year and thus assumes also that commissioning would take place on 31 December. There would thus be a one-year hiatus between the last moment of construction and the first year of operations and repayment.

In the line-by-line calculations of LCOE in previous editions of the *Projected Cost* series, it was, however, assumed that generation and, hence, repayment would begin immediately after construction; in other words, on 1 January of the first year of operations. Translated into the CRF formula, this requires discounting the annuity calculated in equation (5) by another year, i.e. dividing it once more by *1+r*. This yields equation (6), which is the one that was retained for calculating the CRF in *The Costs of Generating Electricity 2025*.

$$\text{CRF if first annuity is paid on 1 January of year 1} = \frac{r*(1+r)^n}{(1+r)*((1+r)^n-1)} \qquad (6)$$

with

r = Real discount rate corresponding to the cost of capital

n = Number of years over which the annuity is paid (operational lifetime).

4. Fixed annual and variable costs for O&M cannot always be unequivocally allocated. Indeed, NEA Member countries have made slightly different trade-offs. In past editions of the Projected Costs of Generating Electricity, the distinction was not carried through very far and per MWh figures, including both fixed and variable O&M costs, were computed early on in the calculation process. In this edition, care has been given to identify and report them separately. However, as indicated, in the final allocation there remains some judgements of the participating countries involved.

This leaves one final component of the LCOE calculation in equation (3) to be clarified, which is the decommissioning costs. As usual, decommissioning costs accrue only far out in the future after the conclusion of the operating lifetime of the generating plant. Therefore, they affect LCOE calculations, which take the date of commissioning as their target date, only in a minor way. Discounting over the lifetime of the plant will greatly reduce their net present value. Nevertheless, given the importance of decommissioning costs in societal debates, it is important that any calculations are made correctly and transparently. This is most important for nuclear energy, where operating lifetimes are long, decommissioning costs are relatively high and the length of decommissioning (ten years) is the highest of all technologies. Equation (7) provides the annualised discounted decommissioning costs, taking into account the fact that costs in year one of the decommissioning period weigh more heavily on the discounted financial costs than in year ten.

$$\textbf{Annualised decomissioning costs} = \frac{(TDC*CAP*1000)/LDC}{CAP*8760*CF} * \frac{(\frac{1}{1+r})^n*(1-(\frac{1}{1+r})^{LDC})}{(1+r)*1-(\frac{1}{1+r})^n} \quad (7)$$

with

TDR	=	Total decommissioning costs per kW
CAP	=	Capacity in MW
LDC	=	Length of decommissioning
CF	=	Capacity factor
r	=	Real discount rate corresponding to the cost of capital
n	=	Operational lifetime in years.

Equations (4), (6) and (7) then specify equation (3) for the calculation of the LCOE values that are reported in Chapter 3.

2.3. Methodological conventions and key assumptions

Before specifying the methodological conventions and default assumptions that were adopted to harmonise the data received from different countries, one major underlying principle must be discussed: this report on the costs of generating electricity *is* concerned with the levelised cost of producing baseload electricity at the plant level. While this seems straightforward, it has implications that are frequently less evident.

First, the assumed capacity factors are reasonable consensus assumptions for comparing baseload technologies. They do not reflect the technical capabilities of different technologies. For example, nuclear power plants can typically operate at more than 90% capacity factors over many years, while CCGT often operate at less than 80% capacity factors when they are too expensive to compete in the baseload market in the presence of variable renewables. However, for this analysis, nuclear, coal and CCGT plants were assigned a common capacity factor of 85%. This is higher than the average observed capacity factors in practice, and particularly so for CCGT plants. The reason for this is that operators may choose to shut them down during baseload periods when prices are low, owing to their higher marginal costs (for example, due to high natural gas prices).

Second, the LCOE calculation does not consider overall system effects, i.e. the impact of a power plant on the electricity system as a whole. The system effects, however, can potentially have a significant impact on the actual economic feasibility of a project. For example, in the case of VRE, they might negatively impact expected revenues at higher shares of penetration. As such, LCOE should not be used to make financial decisions on its own.

Finally, in this report LCOE are considered social resource costs: the economic cost to society to build and operate a given plant, independent of all taxes, subsidies and transfers payments. For example, a tax credit or a faster amortisation schedule can reduce investor costs. However, such a cost reduction will be paid for by another party, frequently taxpayers. The social resource costs of building a given generating plant will remain unaffected.

Keeping in mind these points concerning the nature of the analysis, it is now possible to provide an overview of the more detailed methodological conventions and key numerical assumptions employed to calculate the LCOE for different technologies in different countries.

The purpose of these conventions and assumptions for calculating levelised average lifetime costs is to guarantee comparability of the data on the one hand, while preserving country-specific information on the other hand. Working with standard assumptions for all countries and technologies reduces descriptive realism, while working with individual assumptions for all parameters would lack transparency and relevance. This requires finding a careful balance between too much and too little homogenisation. In some cases, such as fuel prices, it also makes sense to use regional assumptions because intra-regional variations are considerably lower than inter-regional ones.

Decisions on methodological conventions and assumptions were made jointly by EPRI and the NEA Secretariat, according to precedent and best practice. The guiding principle at all times was to obtain the most relevant and transparent data on the costs of generating electricity to policymakers, stakeholders, modellers and experts in NEA Member countries. Harmonised assumptions have thus been used for:

- the discount rate;
- capacity factors of dispatchable plants (nuclear, coal, gas, biomass, geothermal and hydroelectric pumped storage);
- operating lifetimes (except for nuclear LTO, as lifetimes depend on national decisions);
- the carbon price;
- the timing and level of decommissioning costs, as a percentage of OCC.

Regionally or nationally differentiated values instead have been used for:

- fuel costs;
- construction duration and expense schedules;
- capacity factors of onshore and offshore wind, solar PV and reservoir hydroelectricity.

In addition to the central LCOE estimates reported in Chapter 3, Chapter 4 provides sensitivity analyses for the discount rate, capacity factors, operating lifetimes, fuel costs and carbon costs. The default assumptions and conventions used in this report are indicated below.

Discount rate

A real discount rate of 5% is used for all technologies in all countries.

Capacity

Wherever the distinction was made, net rather than gross capacity is used for LCOE calculations. No allowances or deductions are applied to the LCOE for plants with greater or smaller capacity levels. Equally, no allowances are made for multiple plants at a given site.

Capacity factors

A capacity factor of 85% is used for all CCGTs, coal-fired, geothermal and nuclear plants, assuming that they operate in baseload. It is understood that many CCGTs are frequently used in mid load or even peak load, rather than in baseload, and that coal-fired power plants habitually only achieve 50-60% capacity factors in major markets. Conversely nuclear power plants in several countries achieve capacity factors of 90% or above. Nevertheless, the 85% assumption is used as a generic assumption as it allows for the straightforward comparison of the costs of three technologies that *could* be used as baseload.

For biomass, a generic capacity factor of 75% is assumed.

For pumped storage hydroelectricity, a generic capacity factor of 25% is assumed.

For batteries, a generic capacity factor of 17% is assumed.

For OCGTs and internal combustion engines (ICE), a generic capacity factor of 10% is assumed.

For all other technologies, in particular variable renewables and reservoir hydro, country-specific capacity factors are applied.

Operating lifetimes

Operating lifetimes are assumed for all countries as below.

Battery storage:	20 years
Biomass plants:	30 years
Solar PV, wind onshore and offshore:	30 years
Gas- or H2-fired power plants:	30 years
Geothermal:	30 years
Coal-fired power plants:	40 years
Small modular reactors:	40 years
Nuclear power plants:	60 years
Hydropower plants and pumped storage:	60 years
Additional lifetimes following nuclear LTO:	10, 20 or 40 years, depending on national data.

Overnight construction costs (OCC)

OCC refers to the total capital expenditure required before the DOC in the absence of any cost of capital. The latter will be added to the final calculation of LCOE values in terms of the interest during construction (IDC). The OCC include:

1. direct construction and pre-construction costs, including licensing, site preparation and environmental evaluations;
2. indirect costs, such as engineering and administrative costs that cannot be associated with a specific direct construction cost category;
3. owner's costs including all expenses incurred by the owners associated with the plant and plant site, but excluding off-site, "beyond the busbar" transmission costs;[5]
4. contingency reserves for costs resulting from unforeseen technical or regulatory events.

Duration of construction and cost profiles

The LCOE calculations assume the following duration of construction and default construction profiles for different technologies. Most countries did not assume a difference in the duration of construction for fossil fuel-plants, with and without CCUS. Ranges indicate that responses between different countries varied.

5. The LCOE in this report only include costs before the busbar, i.e. before connection to the grid. While in some countries, project developers are obliged to pay for connection costs themselves, the latter are not part of the figures reported here.

Several countries assume construction profiles that differ slightly from those indicated. The percentage figures in parentheses indicate the share of OCC that is disbursed in a given year, based on the longest reported duration of construction.

Solar PV:	1 year (100%)
Battery storage:	1 year (100%)
Internal combustion engines (ICE):	1 year (100%)
OCGT (natural gas or hydrogen):	2 years (20%, 80%)
Onshore wind:	2 years (5%, 95%)
Nuclear (LTO):	2 years (50%, 50%)
Biomass-fired power plants:	1-3 years (10%, 60%, 30%)
CCGT (natural gas or hydrogen):	2-3 years (10%, 60%, 30%)
Hydroelectricity (reservoir):	3 years (80%, 10%, 10%)
Offshore wind:	3-4 years (5%, 10%, 45%, 40%)
Coal-fired power plants:	4 years (10%, 25%, 45%, 20%)
SMR (NOAK):	4 years (15%, 35%, 35%, 15%)
Geothermal plants:	3-5 years (31%, 19%, 25%, 10%, 15%)
SMR (near-term):	5 years (15%, 35%, 30%, 10%, 10%)
Large-scale nuclear (NOAK):	4-6 years (15%, 15%, 25%, 25%, 10%, 10%)
Large-scale nuclear (near-term):	6-8 years (10%, 10%,10%, 15%,15%, 20%, 10%, 10%)
Hydroelectricity (pumped storage):	8 years (12%, 12%,12%,12%,12%,12%,12%, 16%)

Total capital requirement (TCR)

TCR corresponds to the sum of overnight costs and financing costs, i.e. interest during construction.

Annual efficiency losses

Ageing power plants can experience lower electric conversion efficiencies and reduced output due to material degradation as their operational lifetime progresses. These losses are usually small and can be disregarded. The only technologies where efficiency losses have a non-negligible effect are solar PV and batteries. The values reported by countries vary between 0.3% and 0.5% per year, with a default value of 0.5% per year for solar PV, and between 1% and 2% per year with a default value of 2% per year for lithium-ion batteries.

Integrating annual degradation into the LCOE calculation in equation (3) requires adjusting the denominator consisting of annual hours of generation (8760 hours times the capacity factor) by a degradation adjustment factor (DAF). The DAF is calculated according to equation (8):

$$DAF = \frac{\sum_{t=1}^{n} \frac{(1-d)^{t-1}}{(1+r)^{t}}}{\sum_{t=1}^{n} \frac{1}{(1+r)^{t}}} \qquad (8)$$

with

d = Annual degradation
n = Operational lifetime
r = Real discount rate corresponding to the cost of capital
t = Time in years.

Operations and maintenance (O&M) costs

Fixed annual O&M and variable O&M costs are reported separately. Fixed annual O&M costs accrue each year the plant is operating independently of output, whereas variable O&M costs accrue with each unit of output.

Because in the LCOE methodology annual output does not vary over the years (except for efficiency losses due to material degradation), fixed and variable O&M could have been combined. It is, however, instructive to see the different allocations between the two cost categories made in different countries.

These allocations can have repercussions for market design issues such as the development of capacity remuneration mechanisms. Such mechanisms frequently aim to remunerate fixed annual O&M in order to keep existing plants in operation. Conversely, variable O&M must be added to fuel and carbon costs to establish the variable cost, which, in markets with marginal cost pricing, establish prices.

Fossil fuel costs

Costs for fossil fuels are either provided by countries individually or based on regional default values, as indicated below. The indicated values refer to final fuel cost per MWh of electricity accounting for energy efficiency losses during conversion. The differences in cost for the same fuel but different technologies are due to differences in the heat rate. The costs of coal refer to black coal, with an average value of 6 000 kilocalories per kilogramme. For a discussion on the impact of changes in fuel prices on LCOE calculations, see Chapter 4.

Table 2.1. Regional default values for fuel costs in absence of individual country responses (USD/MWh)*

Region	Coal	Coal (CCUS)	CCGT	CCGT (CCUS)	OCGT	ICE
OECD Asia	40.00	56.30	70.00	80.21	104.05	93.90
Australia	16.90	23.69	61.79	71.64	94.44	76.89
OECD Europe	30.00	42.22	60.00	68.75	89.19	80.49
OECD America	17.84	25.12	18.65	21.38	27.73	25.01

* Recent events have led to short-term increases in fuel prices. The indicated prices are intended as best current estimates of long-term averages.

Batteries and hydroelectric storage systems

The levelised cost of storage (LCOS) for batteries in this report refers to lithium-ion chemical batteries with an ability to store four hours of energy, and a roundtrip efficiency between charging and discharging of 85%. Annual efficiency losses due to chemical degradation loss vary between 1% and 2% per year, with a default value of 2%.

Both reservoir hydropower with only natural water intake, and pumped storage systems with natural and pumped water recharge, are considered as storage providers with costs expressed in LCOS.

The calculation of LCOS does not include charging costs, which vary widely and can be negative. Indicated LCOS values thus correspond to the spread between charging costs and discharging revenues required to cover the sum of investment, decommissioning and fixed O&M costs so that the net present value at the date of commissioning becomes zero. Including charging costs would require adding the average cost per MWh to the LCOS figure reported here.

Nuclear fuel costs

Values provided for nuclear fuel costs vary between countries and nuclear technologies, large-scale Gen III+ reactors or small modular reactors. In all cases, however, the indicated values comprise the full costs of the nuclear fuel cycle. At the front end of the cycle, this includes the costs for uranium

mining, enrichment and conditioning, and at the back end of the cycle, this includes the complete costs of nuclear waste management, including the costs for spent fuel removal, interim storage and disposal:

Large-scale Generation III+ reactors: USD 5.69 to USD 9.06 per MWh

Small modular reactors (SMRs): USD 7.25 to USD 12.43 per MWh

Nuclear fuels costs, just as costs for fossil fuel, can vary strongly in response to changing market conditions. Additional uncertainties are associated with the fuel costs for SMRs. Many SMR fuels are still in the research, development and testing stages, and more reliable estimates will only emerge in coming years.

Costs of carbon emission

For calculating LCOE, this report uses a harmonised carbon price of USD 50 per tonne of CO_2 for all technologies that emit end-of-pipe carbon emissions due to fuel combustion, in all countries. For countries that do not have an explicit carbon price, the indicated carbon price can be alternatively considered the shadow price of the implicit costs of regulations and mandates as well as local, regional and national objectives to reduce carbon emissions, or the social costs of a tonne of carbon emissions.

In the absence of specific country information, carbon emission factors for different fuels are based on Table 2.2, "Default emission factors for stationary combustion in the energy industries", in IPCC (2006). The calculation of the cost of carbon emissions per MWh is straightforward for unabated fossil fuel-based electricity generation. The application of CCUS strongly reduces carbon emissions per MWh but does not eliminate them. This report assumes a 90% capture rate of carbon emissions for coal plants with carbon capture and storage facilities, and a 95% capture rate for natural gas plants with carbon capture and storage facilities.

Unabated biomass is considered carbon neutral on the assumption that the carbon emissions generated by biomass combustion will be absorbed again by the regrowth of new biomass.[6] If instead carbon emissions from biomass are abated through CCUS, carbon credits corresponding to the avoided emissions are applied to the LCOE values. If the carbon costs of electricity generation with unabated biomass are zero, the regrowth of biomass must be credited for the net reduction of carbon emissions.

Decommissioning and residual values

At the end of a plant's lifetime, decommissioning costs are linearly spread over the decommissioning period. The durations below are assumed.

Nuclear power plants: 10 years

All other technologies: 2 years

The cost of decommissioning is defined as the total cost of dismantling an existing plant and related activities, minus any residual value. Based on the values used in previous editions of the *Costs of Generating Electricity* series, this report uses the values below for the sum of residual value and decommissioning costs.

Nuclear energy: 15% of overnight costs

All other technologies: 5% of overnight costs.

Because of the levelised cost methodology, decommissioning costs become small when discounted over 60 or 80 years, the lifetime of a nuclear plant or hydroelectric plant. In practice, the operator makes annual contributions to a Decommissioning Trust Fund during operations, the sum of which, plus accrued interest, will eventually correspond to the estimated total costs of decommissioning. While

6. This is, of course, an unproven assumption. In national greenhouse gas emission inventories, the different practices in this respect are captured in the entries for land use, land-use change and forestry (LULUCF). This report cannot engage in such detailed considerations.

the amount per MWh figure is small (see Chapter 3), the long lifetime and the accumulated return on the fund ensure full coverage of the estimated decommissioning costs. The accrued values can thus become quite sizeable, both through the contributions from large amounts of electricity and through compound interest at 5% over the lifetime of each plant.

Heat credit

No heat credit is applied to any technology discussed herein.

Transmission and grid connection costs

Transmission and grid connection costs were not included in any calculations herein, as the LCOE figures presented in this report exclusively consider plant-level production costs.

Exchange rates

Participating countries other than Australia already indicated their national cost figures in USD. For Australia, an exchange rate of AUD 1.52 per USD was used.

Conclusion

While individual assumptions adopted for calculating the levelised cost of electricity generation can be debated, their essential function is to allow comparing large amounts of heterogeneous data. In fact, only by rendering the data comparable can the specificity of each individual dataset be brought out and assessed. Readers are invited to form their own views. The sensitivity analyses in Chapter 4 will further help assess the impact of different assumptions and put each of them into perspective.

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The costs of generating electricity by technology and country

This chapter presents the results of the LCOE analysis for 23 electricity generation technologies across 21 participating countries. The methodology behind these calculations was described in Chapter 2, which detailed the assumptions for discount rates, plant lifetimes, capacity factors and the treatment of costs across the technology portfolio. Summary results are shown in Section 3.1. Since the number of responding countries changes across technologies, the reported results should not be interpreted as capacity-weighted averages across all countries.

The analysis covers 23 electricity generation technologies, spanning conventional fossil fuel plants (coal and natural gas), nuclear power (including large-scale reactors, small modular reactors, and long-term operation extensions), renewable energy sources (onshore and offshore wind, solar PV, hydroelectric, geothermal and biomass) and energy storage solutions (battery storage and pumped hydro). CCUS variants are also included for coal, gas and biomass technologies.

Within this set of technologies and participating countries, cost outcomes vary widely. Nuclear LTO emerges as the lowest-cost low-carbon option in countries where available, while onshore wind and solar PV rank among the most competitive. Much of the variation comes from differences in resource availability, labour costs, and fuel prices in different countries and regions. A further analysis of the sensitivity of these results to key assumptions is presented in Chapter 4.

3.1. Overview and summary statistics

Table 3.1 presents the summary of the statistics for the generating capacity and overnight cost for the various technologies included in this report. The analysis is based on data from the 21 participating countries, though coverage differs meaningfully across technologies. Renewables have the broadest country coverage, with 20 countries contributing data for both onshore wind and solar PV. Conventional thermal and nuclear new-build options are also relatively well represented: coal technologies are covered by 12 countries, gas CCGT by 15 countries, near-term large-scale nuclear by 15 countries and near-term SMR by 12 countries. By contrast, nuclear LTO is covered by only 6 countries, due to the smaller number of countries with operating nuclear fleets that have active life extension programs.

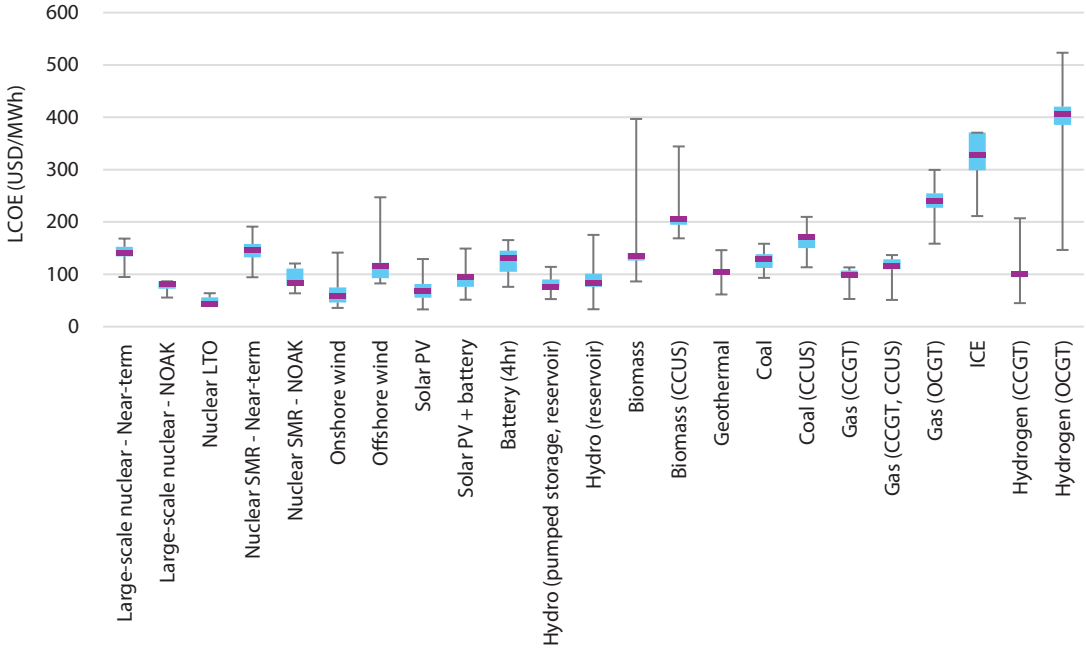
Table 3.1. Summary statistics for different generating technologies

Technology	Number of countries	Net capacity (MWe)				Overnight costs (USD/kWe)			
		Min	Mean	Median	Max	Min	Mean	Median	Max
Large-scale nuclear – Near-term	15	1 000	1 179	1 117	1 670	8 760	11 545	11 188	14 940
Large-scale nuclear – NOAK	10	1 000	1 189	1 117	1 670	2 487	5 477	5 502	6 791
Nuclear LTO	6	685	1 024	1 000	1 233	171	974	946	2 028
Nuclear SMR – Near-term	11	170	317	320	470	5 682	12 728	13 021	18 737
Nuclear SMR - NOAK	9	170	314	320	470	4 830	7 618	7 092	10 707
Onshore wind	20	10	179	200	601	1 323	1 874	1 792	3 089
Offshore wind	15	100	880	900	1 500	3 240	4 609	4 630	7 756
Solar PV	20	2	115	150	200	600	1 096	1 048	2 302
Solar PV + battery	14	20/10	150/100	150/100	150/150	1 337	2 061	1 986	3 907
Battery (4hr)	15	2	100	100	200	750	1 169	1 260	1 593
Hydro (pumped storage, reservoir)	11	500	955	1 000	1 000	1 067	1 911	1 904	2 620
Hydro (reservoir)	13	30	91	100	100	1 586	5 376	5 488	9 743
Biomass	15	28	142	150	250	3 263	4 831	5 050	7 291
Biomass (CCUS)	8	150	150	150	150	6 807	10 502	10 422	15 210
Geothermal	13	11	30	30	50	3 913	7 279	7 490	11 594
Coal	12	500	731	750	1 000	1 376	4 122	4 373	6 910
Coal (CCUS)	10	582	718	750	750	5 623	8 330	8 511	12 565
Gas (CCGT)	15	371	1 094	1 187	1 187	776	1 482	1 455	2 565
Gas (CCGT, CCUS)	13	319	1 028	1 136	1 136	1 613	3 144	3 070	4 984
Gas (OCGT)	13	100	320	358	358	659	1 300	1 270	2 062
ICE	13	18	104	110	209	708	2 250	2 357	2 755
Hydrogen (CCGT)	15	371	535	535	700	1 121	1 695	1 690	2 743
Hydrogen (OCGT)	15	39	63	39	240	1 242	2 304	2 480	4 026

Among the technologies analysed, nuclear LTO have the lowest median LCOE at USD 44 per MWh, largely reflecting the relatively low incremental investment required for life extension once original capital costs have been recovered.

Onshore wind and solar PV are also among the lower-cost options, with median LCOEs of USD 59 per MWh and USD 68 per MWh, respectively, where outcomes are primarily shaped by upfront capital expenditure, capacity factors and the absence of fuel costs. These costs, along with the LCOEs of all technologies analysed, are shown in Figure 3.1.

Figure 3.1. Distribution of LCOE values



Note: The purple lines indicate the median LCOE value, the light blue rectangles below and above the purple lines indicate LCOE values in the second and third quartiles, and the bars indicate LCOE values in the first and fourth quartiles of all submissions, ordered by magnitude.

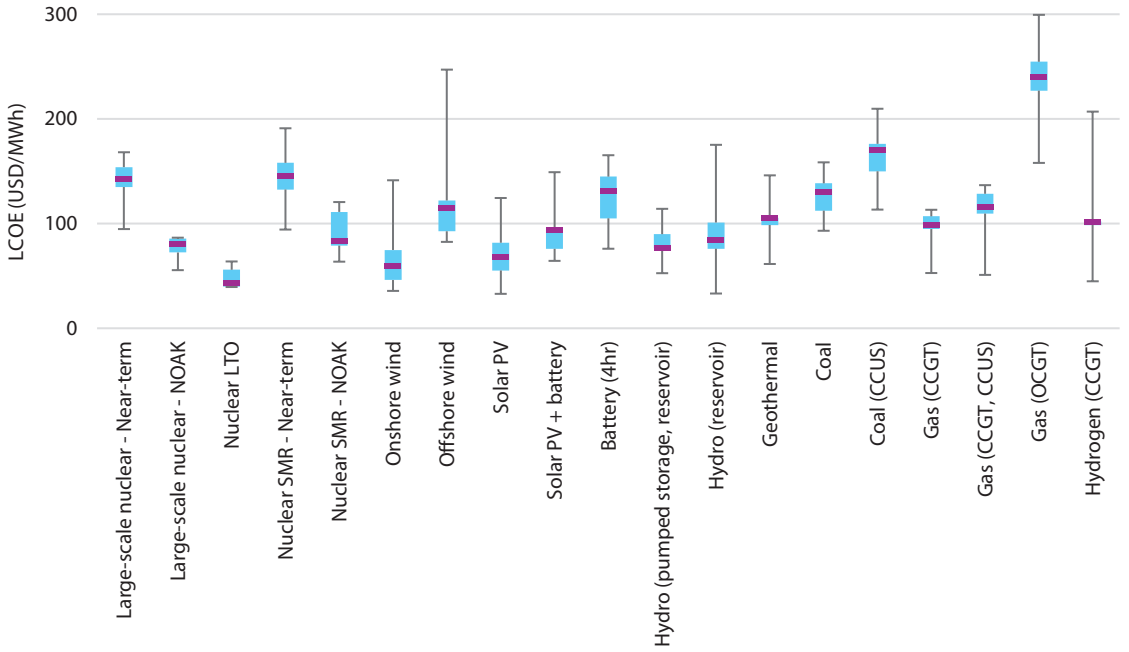
At the upper end of the distribution, hydrogen- and gas-based peaking technologies are markedly more expensive. Hydrogen-fired OCGT shows the highest median LCOE at USD 406 per MWh, followed by internal combustion engines (ICE) at USD 335 per MWh and gas OCGT at USD 247 per MWh. This is in line with their role as peaking and flexibility technologies rather than baseload generation, where costs are heavily influenced by fuel use and operating patterns. In particular, high fuel use and low utilisation mean that fixed costs are spread over relatively few operating hours.

Excluding the outliers (as shown in Figure 3.2), median LCOE values for the remaining technologies fall within a range of approximately USD 59 per MWh to USD 170 per MWh. At the lower end, onshore wind (USD 59 per MWh) and solar PV (USD 68 per MWh) are among the most cost-competitive new-build options. These mature renewable technologies benefit from low and declining capital costs and the absence of fuel costs. Hydropower (USD 79 to 84 per MWh) and nuclear under NOAK assumptions (USD 81 per MWh) also remain in the lower part of the range; hydro benefits from long asset lifetimes and minimal variable costs once constructed, while NOAK nuclear reflects the cost reductions achievable through standardised design and sequential deployment.

In the middle of the range, gas CCGT has a median LCOE of USD 98 per MWh, with technologies such as solar PV + battery (USD 95 per MWh), geothermal (USD 105 per MWh), gas CCGT with CCUS (USD 113 per MWh) and offshore wind (USD 115 per MWh) falling in a broadly similar band. For gas-fired generation, regional variation in natural gas prices is a key driver of cost differences across countries. Somewhat surprisingly, hydrogen-fired CCGT have median LCOE very similar to natural-gas fired ones. This masks large differences in regional prices for natural gas and national assumptions about the cost of hydrogen. The addition of battery storage to solar PV increases system costs but provides dispatchability, while offshore wind incurs higher capital and installation costs, compared to its onshore counterpart.

Near-term nuclear options – both large-scale (USD 140 per MWh) and SMR (USD 142 per MWh) – fall in a similar cost range to coal (USD 130 per MWh) and biomass (USD 135 per MWh), in the upper-middle part of the distribution. For nuclear options, high upfront capital costs and extended construction periods are the primary cost drivers, while coal and biomass are more sensitive to fuel prices and, in the case of coal, carbon costs. Regional differences in fuel availability and pricing contribute to the spread observed within these technologies.

Figure 3.2. LCOE values excluding outliers



Note: The purple lines indicate the median LCOE value, the light blue rectangles below and above the purple lines indicate LCOE values in the second and third quartiles, and the bars indicate LCOE values in the first and fourth quartiles of all submissions, ordered by magnitude.

At the higher end, 4-hour battery storage has a median LCOE of USD 136 per MWh, which does not include the cost of electricity to charge. Coal with CCUS has a median LCOE of USD 171 per MWh, reflecting the additional costs associated with carbon capture equipment. Biomass with CCUS is higher still at USD 205 per MWh and is excluded from the LCOE-without-outliers figure. CCUS technologies incur both higher capital expenditure and efficiency penalties, which increase the levelised cost relative to their unabated counterparts. Hydrogen-fired OCGT (USD 406 per MWh) and reciprocating ICE (USD 335 per MWh) which are modelled with low capacity factors and higher specific capital costs than natural gas-fired OCGT, are also excluded from the chart for clarity.

3.2. Detailed technology data

Tables 3.2 to 3.26 present the calculated LCOEs for technologies included in the EGC 2025 dataset, along with the relevant cost components, calculated at a 5% discount rate and constant capacity factors, except for renewable technologies, where capacity factors country-specific values were applied. Regional fuel costs were used for fossil fuels.

The LCOE calculations include capital costs, decommissioning costs, and fixed and variable O&M costs, alongside fuel and carbon-related costs where applicable. Charging costs for batteries are not included. Carbon costs are incorporated as an additional variable operating cost, based on a carbon price of USD 50 per tonne of CO_2 applied to all fossil fuel combustion emissions. For fossil fuel plants, a column indicating electrical conversion efficiency is included, and for solar and battery technologies, a column for annual degradation is added. Countries with identical locational adjustment factors that have validated and left unchanged the originally calculated estimates, can have identical cost figures.

Table 3.2. Large-scale nuclear (near-term) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Australia	ALWR	1 117	33%	14 940	120.16	0.63	7.84	17.65	3.48	149.76
Belgium	ALWR	1 117	32%	13 310	108.01	0.56	9.06	33.44	11.86	162.93
Bulgaria	ALWR	1 145	32%	11 188	90.79	0.47	9.06	33.44	11.86	145.62
Canada	AP1000/ CANDU	1 200	32%	8 760	66.94	0.37	7.35	17.18	2.94	94.77
Czechia	APR1000	1 000	32%	10 200	68.92	0.43	9.00	19.35	10.00	107.70
Finland	ALWR	1 117	32%	10 791	87.57	0.45	9.06	27.67	11.86	136.62
France	EPR2	1 670	32%	10 507	85.93	0.44	9.06	33.44	11.86	140.74
Poland	AP1000	1 170	32%	13 238	107.42	0.55	9.06	19.97	11.86	148.87
Romania	PHWR	1 400	32%	11 188	85.49	0.47	5.69	24.81	17.78	134.24
Slovak Republic	ALWR	1 117	32%	13 951	113.22	0.58	9.06	33.44	11.86	168.16
Slovenia	ALWR	1 117	32%	13 760	111.66	0.58	9.06	33.44	11.86	166.60
Sweden	ALWR	1 117	32%	12 380	100.46	0.52	9.06	33.44	11.86	155.35
Switzerland*	ALWR	1 160	32%	10 035	84.28	0.42	9.06	32.68	11.86	138.30
United States	AP1000	1 117	32%	9 810	79.61	0.41	9.06	33.44	11.86	134.38

* The data were reviewed by swissnuclear and, where necessary, adjusted based on available industry studies. They do not constitute official data of the Swiss Federal Office of Energy.

Table 3.3. Large-scale nuclear (NOAK) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Australia	ALWR	1 117	33%	6 791	54.62	0.28	7.84	17.65	3.48	83.88
Bulgaria	ALWR	1 000	32%	5 429	41.48	0.23	9.06	18.91	6.57	76.25
Finland	ALWR	1 117	32%	5 236	40.01	0.22	9.06	22.03	6.57	77.89
France	EPR2	1 670	32%	5 575	45.24	0.23	9.06	25.08	6.57	86.18
Japan	ALWR	1 117	32%	4 428	33.83	0.19	9.06	18.91	6.57	68.56
Korea	ALWR	1 400	32%	2 487	19.00	0.10	9.06	15.66	11.70	55.53
Slovak Republic	ALWR	1 117	32%	6 769	51.73	0.28	9.06	18.91	6.57	86.55
Slovenia	ALWR	1 117	32%	6 676	51.02	0.28	9.06	18.91	6.57	85.84
Sweden	ALWR	1 117	32%	6 622	50.60	0.28	9.06	18.91	6.57	85.42
United States	AP1000	1 117	32%	4 760	36.37	0.20	9.06	18.91	6.57	71.11

Table 3.4. Nuclear LTO – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom.[1] (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Belgium	LTO - 10 years	1 000	40%	1 165	20.76	0.00	9.33	11.42	8.57	50.08
France	LTO - 20 years	900	33%	848	9.37	0.00	10.32	17.60	6.53	43.82
Korea	LTO - 10 years	685	32%	171	3.05	0.00	9.06	14.09	13.70	39.90
Sweden	LTO - 20 years	1 000	33%	946	10.45	0.00	9.33	11.42	8.57	39.76
Switzerland	LTO - 20 years	1 233	33%	1 267	13.00	0.00	9.33	32.68	6.71	61.72
Switzerland[2]	LTO - 40 years	1 233	33%	2 028	15.11	0.00	9.33	32.68	6.71	63.83
United States	LTO - 20 years	1 117	33%	391	4.32	0.00	9.33	17.19	8.57	39.41

1. Decommissioning costs are assumed to have been funded during the initial plant lifetime.

2. The LTO 40-year case is indicative only.

Table 3.5. SMR (near-term, LWR) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Australia	LWR	320	33%	18 737	158.02	2.30	7.84	17.65	3.48	189.29
Belgium	LWR	320	40%	13 486	118.56	1.65	7.25	19.19	2.73	149.39
Bulgaria	LWR	320	40%	11 336	99.66	1.39	7.25	19.19	2.73	130.22
Canada	BWR	300	40%	18 737	162.07	2.30	7.35	17.57	1.79	191.07
Finland	LWR	300	31%	15 774	138.68	1.93	9.20	19.19	2.73	171.73
Italy	LWR	340	32%	5 682	49.95	0.70	12.43	70.29	0.00	133.37
Korea	LWR	170	33%	7 249	62.12	0.89	9.90	20.80	0.60	94.30
Slovak Republic	BWR	300	35%	12 557	110.39	1.54	8.00	17.16	5.00	142.10
Slovak Republic	PWR	470	35%	11 360	101.70	1.39	10.00	18.12	9.70	140.91
Sweden	LWR	320	40%	13 942	122.57	1.71	7.25	19.19	2.73	153.45

Table 3.6. SMR (near-term, Generation IV) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Slovenia	HTGR	320	40%	13 942	122.57	1.71	7.25	19.19	2.73	153.45
United States	HTGR	320	40%	9 940	87.39	1.22	7.25	19.19	2.73	117.78

Table 3.7. SMR (NOAK, LWR) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Australia	LWR	320	33%	10 707	90.30	1.31	7.84	17.65	3.48	120.58
Bulgaria	LWR	320	40%	5 508	46.43	0.68	7.25	12.34	2.73	69.43
Canada	BWR	300	40%	10 707	90.25	1.31	7.35	13.42	1.25	113.59
Finland	LWR	300	31%	7 409	62.45	0.91	9.20	12.34	2.73	87.63
Korea	LWR	170	33%	5 437	46.59	0.67	9.90	20.80	0.60	78.55
Slovak Republic	BWR	300	35%	9 254	78.01	1.13	8.00	12.59	5.00	104.73
Slovak Republic	PWR	470	35%	8 776	77.15	1.08	10.00	15.40	9.70	113.33
Sweden	LWR	320	40%	6 775	57.11	0.83	7.25	12.34	2.73	80.26

Table 3.8. SMR (NOAK, Generation IV) – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	LCOE (USD/MWh)
Slovenia	HTGR	320	40%	6 775	57.11	0.83	7.25	12.34	2.73	80.26
United States	HTGR	320	40%	4 830	40.71	0.59	7.25	12.34	2.73	63.63

Table 3.9. Onshore wind

Country	Net capacity (MWe)	Capacity factor (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Australia	601	40%	2 135	40.62	0.41	5.44	46.47
Austria	25	31%	1 836	44.10	0.45	13.62	58.17
Belgium	200	25%	1 782	53.06	0.54	20.19	73.80
Bulgaria	200	34%	1 754	38.41	0.39	14.85	53.65
Canada[1]	200	43%	1 633	26.86	0.00	8.84	35.70
Czechia	10	23%	1 834	58.35	0.60	19.03	77.97
Denmark	40	40%	1 637	30.47	0.31	9.78	40.56
Finland	170	34%	1 627	35.86	0.36	16.54	52.77
France	200	25%	1 759	52.38	0.54	20.19	73.10
Germany	200	26%	1 709	48.37	0.49	19.19	68.06
Italy	200	25%	2 132	63.49	0.65	13.70	77.83
Japan	200	30%	2 800	69.48	0.71	16.83	87.02
Korea	40	23%	1 977	63.99	0.65	19.16	83.80
Norway	90	40%	1 323	24.64	0.25	10.88	35.78
Poland	200	30%	1 801	44.69	0.46	15.60	60.75
Slovak Republic	200	30%	1 841	45.69	0.47	16.83	62.99
Slovenia	200	42%	1 841	32.64	0.33	12.02	44.99
Sweden	200	37%	1 326	26.68	0.27	13.64	40.60
Switzerland[2]	200	20%	3 089	114.97	1.17	25.24	141.39
United States	200	34%	1 640	35.70	0.36	14.76	50.82

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

2. Other than the capacity factor, the technology cost estimates based on EPRI data adjusted by the appropriate localisation factor were retained as reasonable.

Table 3.10. Offshore wind

Country	Net capacity (MWe)	Capacity factor (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Australia	1 152	50%	3 571	55.73	0.54	26.26	82.53
Belgium	900	37%	3 925	81.15	0.81	38.39	120.35
Bulgaria	900	43%	4 868	86.61	0.86	33.04	120.51
Canada[1]	1 000	55%	5 514	70.90	0.00	20.18	91.08
Denmark	1 000	43%	3 858	69.33	0.68	22.32	92.34
France	900	45%	5 365	91.20	0.91	31.57	123.68
Germany	900	40%	3 240	61.96	0.62	35.51	98.09
Italy	350	28%	3 696	100.98	1.00	53.00	154.98
Japan	900	30%	7 756	197.78	1.97	47.35	247.10
Korea	100	29%	4 345	114.61	1.14	37.47	153.23
Norway	1 500	51%	4 964	74.46	0.74	17.83	93.03
Poland	900	43%	3 662	65.15	0.65	19.11	84.91
Slovenia	900	45%	4 868	82.76	0.82	31.57	115.15
Sweden	900	45%	4 868	82.76	0.82	31.57	115.15
United States	900	43%	4 630	82.37	0.82	33.04	116.22

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.11. Solar PV

Country	Net capacity (MWe)	Capacity factor (%)	Annual degradation (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Australia	200	26%	0.4%	1 065	31.61	0.32	3.60	35.52
Austria	150	11%	0.5%	788	55.82	0.57	16.34	72.71
Belgium	150	11%	0.5%	1 048	74.29	0.76	20.94	95.95
Bulgaria	150	17%	0.5%	1 450	68.53	0.70	13.96	83.16
Canada[1]	150	19%	0.0%	1 430	53.21	0.00	32.96	86.17
Czechia	10	10%	0.5%	668	52.37	0.54	15.67	68.54
Denmark	40	17%	0.4%	763	35.67	0.37	11.21	47.23
Finland	80	15%	0.3%	770	38.88	0.39	18.27	57.54
France	150	15%	0.5%	1 149	59.71	0.61	15.36	75.65
Germany	150	13%	0.5%	1 049	62.90	0.64	17.72	81.24
Italy	2	24%	0.5%	810	25.79	0.26	6.85	32.89
Japan	150	17%	0.5%	2 302	109.36	1.12	14.04	124.46
Korea	3	15%	0.5%	998	52.16	0.53	15.42	68.09
Norway	6	11%	0.5%	644	44.21	0.45	13.59	58.23
Poland	150	17%	0.5%	960	45.37	0.46	9.44	55.25
Slovak Republic	150	17%	0.5%	1 206	56.99	0.58	13.96	71.51
Slovenia	150	24%	0.5%	1 206	38.40	0.39	9.41	48.18
Sweden	150	11%	0.5%	600	41.04	0.42	15.77	57.21
Switzerland[2]	150	14%	0.5%	1 598	89.00	0.91	16.45	106.32
United States	150	24%	0.5%	1 420	45.21	0.46	9.41	55.06

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

2. Other than the capacity factor, the technology cost estimates based on EPRI data adjusted by the appropriate localisation factor were retained as reasonable.

Table 3.12. Solar PV and lithium-ion battery energy storage systems (BESS)[1]

Country	Net capacity (MW PV, MW BESS/MWh BESS)	Capacity factor (%)	Annual degradation (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Austria	150, 100/400	25%	1.2%	1 337	45.73	0.47	25.93	72.07
Belgium	150, 100/400	25%	1.2%	1 973	67.52	0.69	25.93	94.05
Bulgaria	150, 100/400	25%	1.2%	2 461	84.21	0.86	25.93	110.90
Canada[2]	150, 100/400	25%	0.0%	1 902	53.82	0.00	17.40	71.22
Czechia	20, 10/20	25%	1.3%	1 450	49.18	0.50	15.64	65.27
Denmark	150, 100/400	25%	1.2%	1 998	68.02	0.70	25.80	94.44
France	150, 100/400	25%	1.2%	1 949	66.70	0.68	25.93	93.23
Germany	150, 100/400	25%	1.2%	1 780	60.90	0.62	25.93	87.37
Italy	2, 1/2	25%	0.5%	1 550	48.89	0.50	15.03	64.39
Japan	150, 100/400	25%	0.5%	3 907	123.88	1.27	24.03	149.12
Slovak Republic	150, 100/400	25%	1.2%	2 047	70.03	0.72	25.93	96.59
Slovenia	150, 100/400	25%	1.2%	2 047	70.03	0.72	25.93	96.59
Sweden	150, 100/400	25%	1.2%	2 047	70.03	0.72	25.93	96.59
United States	150, 100/400	25%	1.2%	2 410	82.46	0.84	25.93	109.13

1. The indicated values for the combined LCOE of battery and solar PV systems correspond to the spread between charging costs and discharging revenues required to cover the sum of capital costs, decommissioning costs, and fixed O&M costs and to achieve a net present value of zero. Additional charging costs are not included. In addition, for combined battery and solar PV systems, the reported values are not directly comparable to LCOE of standalone solar PV systems. Coupling PV with storage can increase system profitability by enabling electricity to be bought during periods of low prices and sold during periods of high prices. Depending on market conditions, higher cost combined battery and solar PV systems can thus be more profitable than lower cost standalone solar PV.

2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.13. Stand-alone lithium-ion battery energy storage system (BESS, 4 hour)[1]

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Annual efficiency loss (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOS (USD/MWh)
Australia	Lithium-ion	200	17%	1.4%	1 012	72.92	1.22	10.50	83.27
Austria	Lithium-ion	100	17%	2.0%	865	65.20	1.09	43.80	109.79
Belgium	Lithium-ion	100	17%	2.0%	1 514	114.09	1.90	43.80	159.28
Bulgaria	Lithium-ion	100	17%	2.0%	1 593	120.06	2.00	43.80	165.32
Canada[2]	Lithium-ion	100	17%	0.0%	905	55.74	0.00	26.71	82.45
Czechia	Lithium-ion	100	17%	2.0%	750	56.52	0.94	18.78	75.99
Denmark	Lithium-ion	2	17%	2.0%	805	58.49	1.01	41.08	100.31
Finland	Lithium-ion	100	17%	2.6%	885	67.55	1.13	58.37	126.71
France	Lithium-ion	100	17%	2.0%	1 262	95.09	1.59	43.80	140.05
Germany	Lithium-ion	100	17%	2.0%	1 152	86.82	1.45	43.80	131.68
Italy	Lithium-ion	100	17%	1.0%	1 260	88.07	1.47	30.48	119.70
Slovak Republic	Lithium-ion	100	17%	2.0%	1 325	99.84	1.67	43.80	144.86
Slovenia	Lithium-ion	100	17%	2.0%	1 325	99.84	1.67	43.80	144.86
Sweden	Lithium-ion	100	17%	2.0%	1 325	99.84	1.67	43.80	144.86
United States	Lithium-ion	100	17%	2.0%	1 560	117.55	1.96	43.80	162.79

1. For the LCOS, the indicated values correspond to the spread between charging costs and discharging revenues that is required to cover all costs, and to achieve a net present value of zero. Charging costs are not included.

2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.14. Hydropower (pumped storage)[1]

Country	Net capacity (MWe)	Capacity factor (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOS (USD/MWh)
Australia	500	25%	2 323	66.46	0.13	28.51	95.11
Austria	1 000	25%	1 258	35.99	0.07	22.04	58.09
Bulgaria	1 000	25%	1 067	30.52	0.06	22.04	52.62
Czechia	1 000	25%	1 904	54.48	0.11	22.04	76.62
France	1 000	25%	1 904	54.48	0.11	22.04	76.62
Germany	1 000	25%	2 184	62.49	0.12	22.04	84.65
Italy	1 000	25%	2 051	58.67	0.12	22.04	80.83
Slovak Republic	1 000	25%	1 904	54.48	0.11	22.04	76.62
Slovenia	1 000	25%	1 904	54.48	0.11	22.04	76.62
Sweden	1 000	25%	1 904	54.48	0.11	22.04	76.62
United States	1 000	25%	2 620	74.95	0.15	22.04	97.14

1. For the LCOS, the indicated values correspond to the spread between charging costs and discharging revenues that is required to cover all costs and achieve a net present value of zero. Charging costs for water supplies beyond natural intake are not included.

Table 3.15. Hydropower (reservoir)[1]

Country	Net capacity (MWe)	Capacity factor (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Australia	99	17%	3 451	128.63	0.29	46.34	175.26
Austria	100	66%	3 625	35.76	0.08	21.78	57.62
Bulgaria	100	66%	3 075	30.33	0.07	21.78	52.18
Canada[2]	50	50%	6 676	76.69	0.00	12.64	89.33
Czechia	100	50%	5 488	71.95	0.16	28.95	101.05
France	100	45%	5 488	79.94	0.17	32.17	112.28
Germany	100	66%	6 295	62.09	0.14	21.78	84.01
Italy	100	66%	5 933	58.52	0.13	21.78	80.43
Japan	100	66%	9 743	96.11	0.21	21.78	118.10
Norway	30	38%	1 586	27.36	0.06	5.78	33.20
Slovak Republic	100	66%	5 488	54.13	0.12	21.78	76.03
Slovenia	100	66%	5 488	54.13	0.12	21.78	76.03
United States	100	66%	7 550	74.47	0.16	21.78	96.42

1. Costs for natural water intake are assumed to be zero.

2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.16. Biomass[1] – *Capacity factor: 75%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	28	22%	5 376	53.23	0.55	7.05	18.42	7.06	0.00	86.31
Austria	150	25%	5 050	52.02	0.51	45.00	16.74	8.40	0.00	122.67
Belgium	150	30%	4 488	46.22	0.46	57.17	18.44	8.40	0.00	130.68
Bulgaria	150	30%	4 941	50.90	0.50	57.17	18.44	8.40	0.00	135.40
Canada[2]	50	26%	5 154	48.60	0.00	305.65	21.77	20.75	0.00	396.77
Czechia	150	30%	7 291	75.09	0.74	120.64	18.44	8.40	0.00	223.30
Denmark	250	28%	3 655	40.65	0.37	57.17	30.25	6.80	0.00	135.24
France	150	30%	5 050	52.02	0.51	57.17	18.44	8.40	0.00	136.53
Germany	150	30%	3 263	33.61	0.33	57.17	18.44	8.40	0.00	117.94
Italy	150	30%	5 050	52.02	0.51	130.00	45.66	4.00	0.00	232.19
Japan	150	30%	3 428	35.31	0.35	57.17	18.44	8.40	0.00	119.66
Poland	150	30%	4 478	46.12	0.45	57.17	24.35	8.40	0.00	136.50
Slovak Republic	150	30%	5 778	59.51	0.59	57.17	18.44	8.40	0.00	144.10
Slovenia	150	30%	5 050	52.02	0.51	57.17	18.44	8.40	0.00	136.53
United States	150	30%	4 410	45.42	0.45	57.17	18.44	8.40	0.00	129.87

1. Biomass generation costs vary significantly across countries due to differences in fuel type and feedstock costs. In this analysis, for instance, Canada thus accounts for the relatively high costs of wood pellets, while Australia accounts for lower-cost wood waste feedstocks.

2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.17. Biomass with CCUS[1] – *Capacity factor: 75%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Belgium	150	21%	9 363	96.43	0.95	79.44	36.63	15.90	-47.95	181.39
Bulgaria	150	21%	10 309	106.18	1.05	79.44	36.63	15.90	-47.95	191.23
Czechia	150	21%	15 210	156.66	1.54	167.63	36.63	15.90	-47.95	330.40
France	150	21%	10 536	108.52	1.07	79.44	36.63	15.90	-47.95	193.59
Germany	150	21%	6 807	70.11	0.69	79.44	36.63	15.90	-47.95	154.81
Slovak Republic	150	21%	12 054	124.16	1.22	79.44	36.63	15.90	-47.95	209.39
Slovenia	150	21%	10 536	108.52	1.07	79.44	36.63	15.90	-47.95	193.59
United States	150	21%	9 200	94.76	0.93	79.44	36.63	15.90	-47.95	179.70

1. Calculations assume a 90% capture rate for carbon emissions. Cost figures do not include transport and storage of carbon emissions.

Table 3.18. Geothermal[1] – *Capacity factor: 85%*

Country	Net capacity (MWe)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	O&M fixed (USD/MWh)	LCOE (USD/MWh)
Austria	30	7 502	73.89	0.67	30.86	105.42
Bulgaria	30	6 820	67.17	0.61	30.86	98.64
Canada[2]	50	6 104	50.79	0.00	18.03	68.82
Czechia	30	11 594	114.19	1.04	30.86	146.09
Denmark	11	3 913	37.69	0.35	23.37	61.41
France	30	7 490	73.77	0.67	30.86	105.30
Germany	30	7 490	73.77	0.67	30.86	105.30
Italy	30	7 597	74.82	0.68	30.86	106.36
Japan	30	6 820	67.17	0.61	30.86	98.64
Slovak Republic	30	7 502	73.89	0.67	30.86	105.42
Slovenia	30	7 490	73.77	0.67	30.86	105.30
Sweden	30	7 490	73.77	0.67	30.86	105.30
United States	30	6 820	67.17	0.61	30.86	98.64

1. The LCOE of geothermal power depends on site-specific geological conditions, which it is impossible to harmonise across locations.
2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.19. Coal – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost[1] (USD/MWh)	LCOE (USD/MWh)
Australia	Ultra-supercritical	671	42%	4 565	36.62	0.22	16.90	5.72	3.08	37.55	100.10
Bulgaria	Supercritical	750	38%	4 684	39.00	0.23	30.00	20.94	5.94	41.50	137.61
Canada[2]	Supercritical	600	41%	3 405	25.38	0.00	20.72	5.49	3.10	38.46	93.15
Czechia	Supercritical	750	38%	6 910	57.54	0.34	37.65	15.54	5.94	41.50	158.52
Denmark	Supercritical	500	50%	2 949	25.30	0.15	30.00	13.20	4.50	31.54	104.68
France	Supercritical	750	38%	4 787	39.86	0.24	30.00	20.94	5.94	41.50	138.48
Germany	Supercritical	750	38%	3 093	25.75	0.15	30.00	20.94	5.94	41.50	124.29
Japan	Supercritical	750	38%	3 250	27.06	0.16	40.00	20.94	5.94	41.50	135.60
Korea	Ultra-supercritical	1 000	43%	1 376	11.46	0.07	45.50	8.25	13.00	36.67	114.95
Slovak Republic	Supercritical	750	38%	5 477	45.60	0.27	30.00	20.94	5.94	41.50	144.26
Slovenia	Supercritical	750	38%	4 787	39.86	0.24	30.00	20.94	5.94	41.50	138.48
United States	Supercritical	750	38%	4 180	34.81	0.21	17.84	20.94	5.94	41.50	121.24

1. Carbon costs depend on the electrical conversion efficiency of the plant as well as on the quality of the coal, which can differ between countries.
2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.20. Coal with CCUS[1] – *Capacity factor: 85%*

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	Ultra-supercritical (CCUS)	582	30%	8 505	68.23	0.42	23.69	8.37	5.82	5.40	111.93
Bulgaria	Supercritical (CCUS)	750	27%	8 516	70.91	0.42	42.22	35.00	9.47	6.00	164.02
Canada[2]	Supercritical (CCUS)	600	30%	7 219	53.81	0.00	28.32	16.02	9.82	5.40	113.37
Czechia	Supercritical (CCUS)	750	27%	12 565	104.62	0.62	53.00	25.40	9.47	6.00	199.11
France	Supercritical (CCUS)	750	27%	8 704	72.47	0.43	42.22	35.00	9.47	6.00	165.59
Germany	Supercritical (CCUS)	750	27%	5 623	46.82	0.28	42.22	35.00	9.47	6.00	139.79
Japan	Supercritical (CCUS)	750	27%	5 908	49.20	0.29	56.30	35.00	9.47	6.00	156.26
Slovakia	Supercritical (CCUS)	750	27%	9 958	82.92	0.49	42.22	35.00	9.47	6.00	176.10
Slovenia	Supercritical (CCUS)	750	27%	8 704	72.47	0.43	42.22	35.00	9.47	6.00	165.59
United States	Supercritical (CCUS)	750	27%	7 600	63.28	0.37	25.12	35.00	9.47	6.00	139.25

1. Calculations assume a 90% capture rate for carbon emissions. Costs for the transport and storage of carbon emissions are not included.
2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.21. Natural gas (CCGT) – *Capacity factor: 85%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	371	51%	1 641	14.70	0.15	61.79	3.18	3.29	17.78	100.88
Austria	1 187	55%	1 700	15.45	0.15	60.00	4.15	2.22	16.49	98.46
Belgium	1 187	55%	1 223	11.11	0.11	60.00	4.15	2.22	16.49	94.08
Bulgaria	1 187	55%	1 247	11.34	0.11	60.00	4.15	2.22	16.49	94.31
Canada[1]	700	54%	1 307	10.87	0.00	17.19	4.36	3.56	16.80	52.78
Czechia	1 187	55%	2 565	23.31	0.23	64.50	4.15	2.22	16.49	110.90
Denmark	1 187	52%	1 262	11.36	0.11	60.00	8.22	6.30	17.44	103.43
France	1 187	55%	1 355	12.31	0.12	60.00	4.15	2.22	16.49	95.29
Germany	1 187	55%	1 455	13.22	0.13	60.00	4.15	2.22	16.49	96.21
Italy	1 187	60%	776	7.05	0.07	85.23	3.52	2.22	15.12	113.21
Japan	1 187	55%	1 915	17.41	0.17	70.00	4.15	2.22	16.49	110.44
Korea	1 100	55%	803	7.30	0.07	76.50	5.18	5.60	16.49	111.14
Slovak Republic	1 187	55%	1 700	15.45	0.15	60.00	4.15	2.22	16.49	98.46
Slovenia	1 187	55%	1 700	15.45	0.15	60.00	4.15	2.22	16.49	98.46
United States	1 187	55%	1 580	14.36	0.14	18.65	4.15	2.22	16.49	56.01

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.22. Natural gas (CCGT with CCUS)[1] – *Capacity factor: 85%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	319	44%	4 576	40.98	0.41	71.64	4.06	5.26	1.04	123.38
Austria	1 136	48%	3 304	30.03	0.30	68.75	8.32	4.24	0.95	112.59
Belgium	1 136	48%	2 586	23.50	0.23	68.75	8.32	4.24	0.95	106.00
Bulgaria	1 136	48%	2 424	22.03	0.22	68.75	8.32	4.24	0.95	104.51
Canada[2]	550	51%	2 532	21.07	0.00	18.20	2.28	4.98	0.89	47.42
Czechia	1 136	48%	4 984	45.29	0.45	73.89	8.32	4.24	0.95	133.15
France	1 136	48%	2 632	23.92	0.24	68.75	8.32	4.24	0.95	106.42
Germany	1 136	48%	2 827	25.69	0.25	68.75	8.32	4.24	0.95	108.21
Italy	1 136	52%	1 613	14.66	0.14	98.34	6.99	3.91	0.88	124.92
Japan	1 136	48%	3 722	33.82	0.33	80.21	8.32	4.24	0.95	127.88
Slovak Republic	1 136	48%	3 304	30.03	0.30	68.75	8.32	4.24	0.95	112.59
Slovenia	1 136	48%	3 304	30.03	0.30	68.75	8.32	4.24	0.95	112.59
United States	1 136	48%	3 070	27.90	0.27	21.37	8.32	4.24	0.95	63.06

1. Calculations assume a 95% capture rate for carbon emissions. Cost figures do not include transport and storage of carbon emissions.
2. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.23. Natural gas (OCGT) – *Capacity factor: 10%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	242	33%	1 897	144.38	1.44	94.44	19.51	6.57	27.42	293.77
Austria	358	37%	1 367	102.52	1.04	89.19	27.12	10.28	24.46	254.61
Belgium	358	37%	1 048	78.60	0.80	89.19	27.12	10.28	24.46	230.45
Bulgaria	358	37%	1 003	75.20	0.76	89.19	27.12	10.28	24.46	227.02
Canada[1]	240	37%	1 242	87.84	0.00	25.08	13.32	7.28	24.46	157.98
Czechia	358	42%	2 062	154.63	1.57	84.29	27.12	10.28	21.55	299.43
Denmark	100	42%	659	47.03	0.50	89.19	30.96	6.60	21.55	195.83
France	358	37%	1 089	81.67	0.83	89.19	27.12	10.28	24.46	233.55
Germany	358	37%	1 169	87.70	0.89	89.19	27.12	10.28	24.46	239.64
Slovak Republic	358	37%	1 367	102.52	1.04	89.19	27.12	10.28	24.46	254.61
Slovenia	358	37%	1 367	102.52	1.04	89.19	27.12	10.28	24.46	254.61
Sweden	358	37%	1 367	102.52	1.04	89.19	27.12	10.28	24.46	254.61
United States	358	37%	1 270	95.25	0.97	27.92	27.12	10.28	24.46	186.00

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.24. Natural gas (internal combustion engine) – *Capacity factor: 10%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	209	41%	1 329	98.69	1.01	76.89	22.06	5.59	22.09	226.33
Austria	110	41%	2 755	204.60	2.10	80.49	52.69	8.55	22.09	370.52
Belgium	110	41%	2 646	196.47	2.01	80.49	52.69	8.55	22.09	362.30
Bulgaria	110	41%	2 021	150.08	1.54	80.49	52.69	8.55	22.09	315.44
Canada[1]	21	43%	2 350	166.20	0.00	21.58	45.17	6.71	21.06	260.73
Czechia	110	41%	2 062	153.10	1.57	86.48	27.12	8.55	22.09	298.91
Denmark	18	37%	708	52.58	0.54	80.49	44.27	8.90	24.48	211.25
France	110	41%	2 195	162.99	1.67	80.49	52.69	8.55	22.09	328.49
Germany	110	41%	2 357	175.03	1.79	80.49	52.69	8.55	22.09	340.64
Slovak Republic	110	41%	2 755	204.60	2.10	80.49	52.69	8.55	22.09	370.52
Slovenia	110	41%	2 755	204.60	2.10	80.49	52.69	8.55	22.09	370.52
Sweden	110	41%	2 755	204.60	2.10	80.49	52.69	8.55	22.09	370.52
United States	110	41%	2 560	190.10	1.95	25.01	52.69	8.55	22.09	300.39

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category.

Table 3.25. Hydrogen (CCGT) – *Capacity factor: 85%*

Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	371	51%	1 551	13.89	0.14	188.94	1.33	2.69	0.00	206.99
Austria	535	52%	1 819	16.82	0.16	73.24	6.71	4.32	0.00	101.25
Belgium	535	52%	1 526	14.11	0.14	73.24	6.71	4.32	0.00	98.52
Bulgaria	535	52%	1 334	12.34	0.12	73.24	6.71	4.32	0.00	96.73
Canada[1]	700	54%	1 307	10.87	0.00	26.10	4.36	3.56	0.00	44.89
Czechia	535	52%	2 743	25.37	0.25	73.24	6.71	4.32	0.00	109.88
Denmark	535	52%	1 819	16.82	0.16	73.24	6.71	4.32	0.00	101.25
France	535	52%	1 449	13.40	0.13	73.24	6.71	4.32	0.00	97.80
Germany	535	52%	1 556	14.39	0.14	73.24	6.71	4.32	0.00	98.80
Italy	535	52%	1 121	10.36	0.10	141.73	8.73	5.50	0.00	166.43
Japan	535	52%	2 049	18.94	0.18	73.24	6.71	4.32	0.00	103.40
Slovak Republic	535	52%	1 819	16.82	0.16	73.24	6.71	4.32	0.00	101.25
Slovenia	535	52%	1 819	16.82	0.16	73.24	6.71	4.32	0.00	101.25
Sweden	535	52%	1 819	16.82	0.16	73.24	6.71	4.32	0.00	101.25
United States	535	52%	1 690	15.63	0.15	73.24	6.71	4.32	0.00	100.05

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category. Canada's fuel costs are considerably lower than those of other countries since data was provided for blended natural gas with a hydrogen share of 15%.

Table 3.26. Hydrogen (OCGT) – *Capacity factor: 10%*

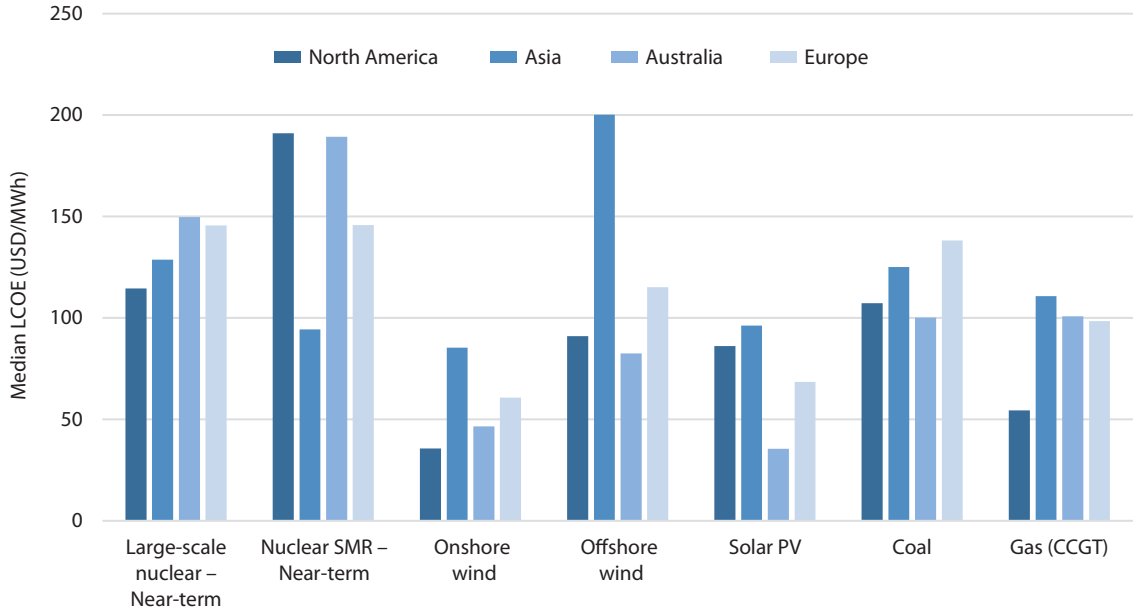
Country	Net capacity (MWe)	Electrical conversion efficiency (%)	OCC (USD/kW)	Investment (USD/MWh)	Decom. (USD/MWh)	Fuel (USD/MWh)	O&M fixed (USD/MWh)	O&M variable (USD/MWh)	Carbon cost (USD/MWh)	LCOE (USD/MWh)
Australia	194	36%	1 441	109.71	1.10	267.66	13.03	10.58	0.00	402.08
Austria	39	33%	2 669	200.19	2.03	116.33	97.00	4.98	0.00	420.52
Belgium	39	33%	1 316	98.70	1.00	116.33	97.00	4.98	0.00	318.01
Bulgaria	39	33%	1 958	146.85	1.49	116.33	97.00	4.98	0.00	366.64
Canada[1]	240	37%	1 242	87.84	0.00	38.09	13.32	7.25	0.00	146.50
Czechia	39	33%	4 026	301.95	3.06	116.33	97.00	4.98	0.00	523.31
Denmark	39	33%	2 669	200.19	2.03	116.33	97.00	4.98	0.00	420.52
France	39	33%	2 126	159.48	1.62	116.33	97.00	4.98	0.00	379.40
Germany	39	33%	2 283	171.25	1.74	116.33	97.00	4.98	0.00	391.29
Italy	39	40%	1 333	99.98	1.01	184.28	108.45	5.50	0.00	399.22
Slovak Republic	39	33%	2 669	200.19	2.03	116.33	97.00	4.98	0.00	420.52
Slovenia	39	33%	2 669	200.19	2.03	116.33	97.00	4.98	0.00	420.52
Sweden	39	33%	2 669	200.19	2.03	116.33	97.00	4.98	0.00	420.52
United States	39	33%	2 480	186.01	1.89	116.33	97.00	4.98	0.00	406.20

1. For this Canadian cost data, decommissioning costs are incorporated within the OCC and are not tracked as a standalone category. Canada's fuel costs are considerably lower than those of other countries since data was provided for blended natural gas with a hydrogen share of 15%.

3.3. Regional Variations

LCOE values vary significantly across participating countries because of differences in resource availability, fuel prices, labour costs, regulatory frameworks and technology maturity. This section highlights key regional patterns observed in the data.

Figure 3.3. Median LCOE by region for selected technologies



For fossil fuel technologies, regional gas prices are a primary driver of cost differences. Countries with access to lower-cost natural gas, such as the United States and Canada, thus report gas CCGT LCOEs towards the lower end of the distribution, while Asian countries with higher gas import costs tend to report higher values. Similarly, coal costs vary according to domestic availability and import dependency, with countries reliant on imported coal facing higher fuel cost components.

Table 3.27 presents the assumed fuel costs by region, used in the analysis where countries did not submit revised values. Asian fuel costs are notably higher than the OECD America values, with natural gas for CCGT plants assumed at USD 70 per MWh compared to USD 18.65 per MWh for the OECD America baseline. European fuel cost assumptions sit between these levels. These fuel price differences feed directly into the LCOE calculations and explain much of the variation in fossil fuel technology costs.

Among renewable technologies, onshore wind and solar PV costs depend primarily on available regional resources and capacity factors. For a given capital cost, countries with better wind or solar resources tend to have lower LCOEs. For example, solar PV capacity factors range from 10% to 26% across participating countries, with corresponding variations in levelised costs. Onshore wind shows a similar pattern, with capacity factors ranging from 23% to 43% and LCOE ranges from USD 36 per MWh to USD 141 per MWh.

Table 3.27. Fuel costs per region (USD/MWh)

Region	Coal	Coal (CCUS)	CCGT	CCGT (CCUS)	OCGT	ICE
OECD Asia	40.00	56.30	70.00	80.21	104.05	93.90
Australia	16.90	23.69	61.79	71.64	94.44	76.89
OECD Europe	30.00	42.22	60.00	68.75	89.19	80.49
OECD America	17.84	25.12	18.65	21.38	27.73	25.01

Offshore wind shares a similar pattern in capacity factor; however, it exhibits wider cost variation than its onshore counterpart, due to additional factors beyond resource quality. This includes higher overnight costs and maintenance costs, driven by more challenging installation conditions, and increased logistical complexity in operations and maintenance.

Figure 3.4. The capacity factors of wind and solar PV and LCOE

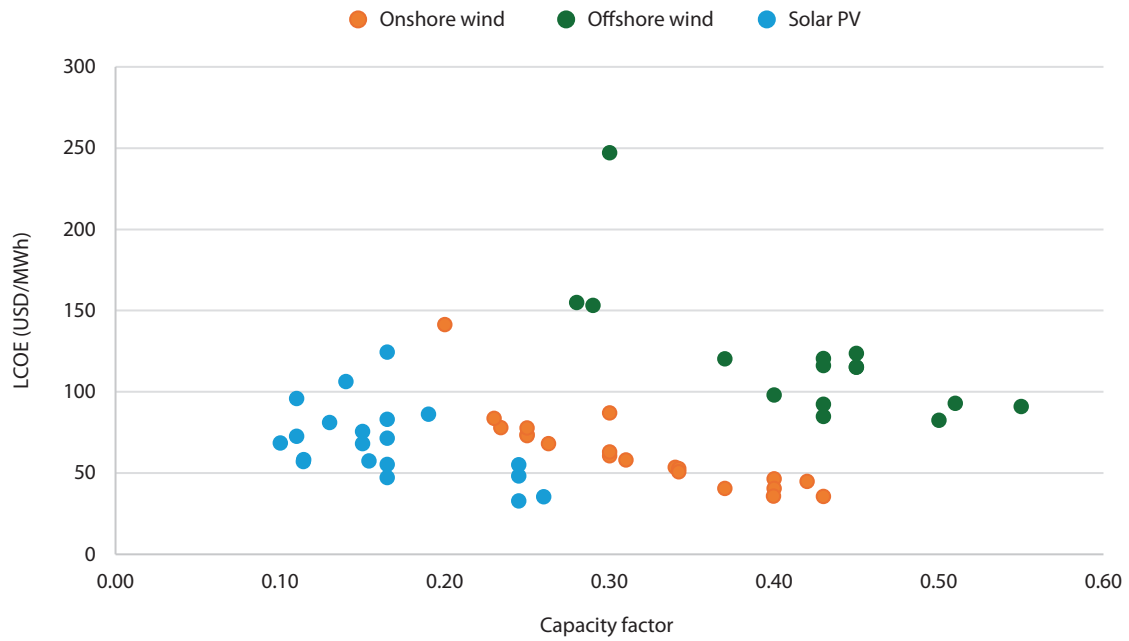
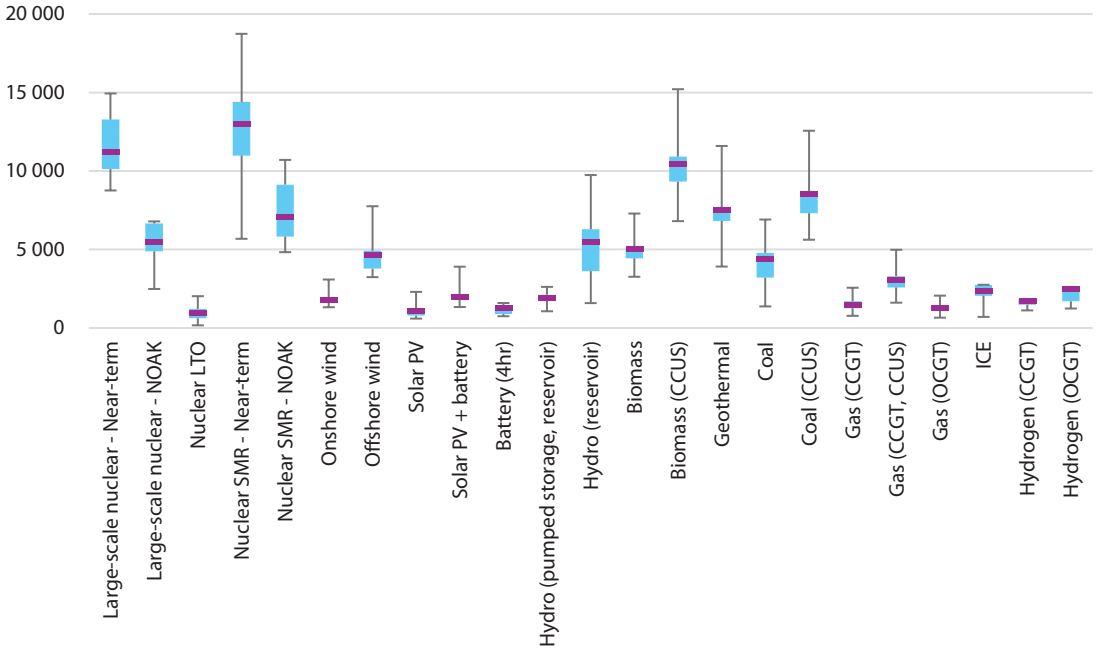


Figure 3.4 illustrates the relationship between capacity factor and LCOE for onshore wind, offshore wind and solar PV. All three show a roughly inverse relationship: countries with higher capacity factors tend to achieve lower LCOE. This is most pronounced for solar PV, where capacity factors range from 10% in Czechia to 26% in Australia. However, capacity factors do not explain everything and national differences in overnight construction costs, including labour costs, continue to weigh.

For nuclear technologies, regional variation in adjusted overnight capital costs is the dominant factor. In the final technology tables, near-term large-scale nuclear OCC ranges from USD 8 760 per kW in Canada to USD 14 940 per kW in Australia, with most country values falling between roughly USD 9 100 per kW and USD 14 000 per kW. This range reflects country-adjusted overnight construction costs rather than total capital required, and differences are likely driven by construction experience, regulatory requirements, labour productivity and local cost-adjustment factors. Nuclear LTO shows a narrower cost range because life extension projects are less affected by these factors once the original plant is already operating.

SMRs show higher cost variation than other nuclear technologies, with outcomes depending on the type of technology chosen and costs estimations made at different stages of maturity. In the near term, overnight capital costs range from USD 5 682 per kW to USD 18 737 per kW – the widest spread observed across the nuclear portfolio. Under NOAK assumptions, the range narrows, with a spread of around USD 6 214 per kW between the lowest and highest values. The percentage drop in OCC from near-term to NOAK is similar to what is seen for large-scale nuclear, although SMRs start from a higher level. As a result, even under optimistic NOAK assumptions, SMR capital costs stay above those of large-scale reactors in both stages.

Figure 3.5. Overnight capital costs



Note: The purple lines indicate the median LCOE value, the light blue rectangles below and above the purple lines indicate LCOE values in the second and third quartiles, and the bars indicate LCOE values in the first and fourth quartiles of all submissions, ordered by magnitude.

The LCOE of hydrogen-fired technology shows the widest regional variation, largely because of differences in assumed hydrogen fuel costs. Battery storage costs also vary significantly across countries, mainly because of overnight construction costs, likely due to supply chain and local market conditions for lithium-ion technology.

Sensitivity analysis

Simplifying assumptions must be made when performing the cost analysis of generation units to enable comparability of results; for example, by assuming a constant capacity factor or harmonised fuel price. In reality, the input parameters will vary across, or even within, countries. To better understand the sensitivity of the LCOE with respect to the most important drivers, a sensitivity analysis is performed for a particular set of generation types and parameters, comparing the relative sensitivity of the individual technologies.

As technology costs are subject to region-specific influences and individual plant characteristics, a single LCOE value would oversimplify the results; in many cases, there is not one single technology having lower costs than the rest. To account for this, the figures in this section show ranges of technology costs dependent on the variation of individual input parameters. As extreme values and outliers distort the illustration and aggravate the interpretation of the results, the figures are restricted to the median 50% of cases, i.e. the edges of the shaded region represent the 25th and the 75th percentiles. Solid lines for each technology category indicate the median costs.

If not stated otherwise, the sensitivities are performed with respect to the base-case 5% discount rate and with 85% capacity factor for baseload plants (renewable capacity factors are country-specific). The focus is on the widespread technologies for gas- and coal-fired generation, i.e. ultracritical coal plants and CCGTs without CCUS.

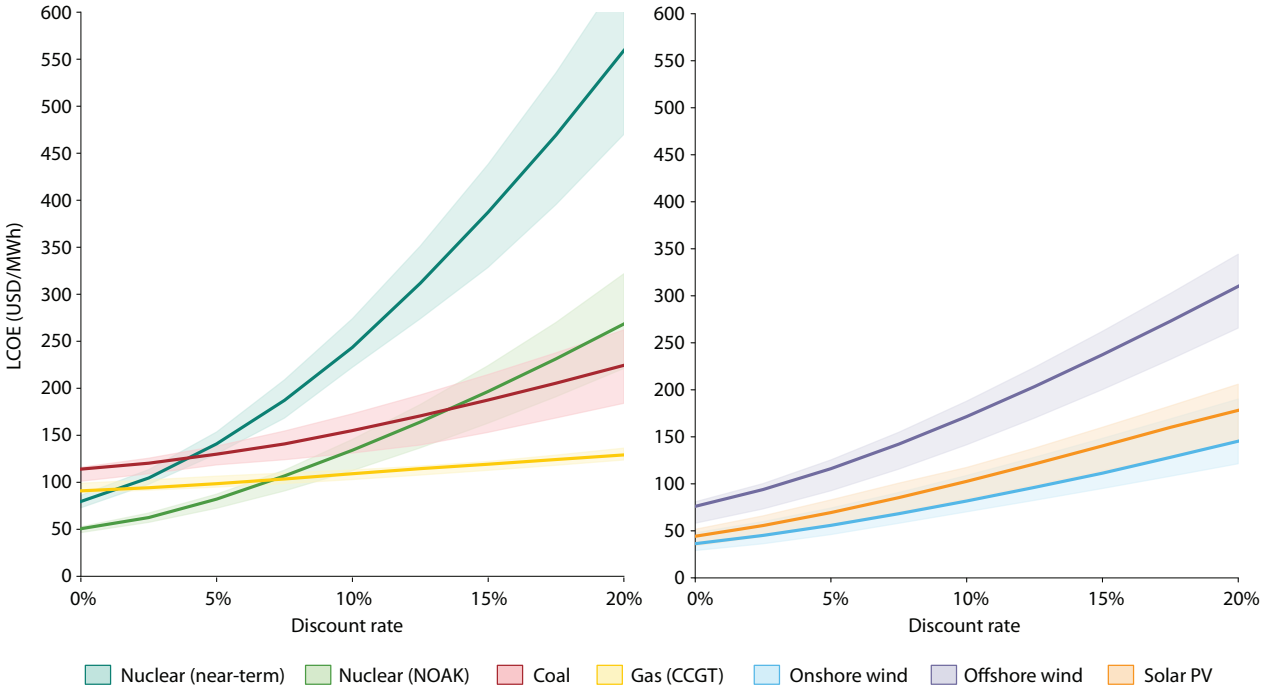
4.1. Discount rate sensitivity

The discount rate affects several aspects of LCOE costs, such as construction, refurbishment and decommissioning expenses. In general, the more capital-intensive a technology is, the more sensitive it is to changes in the discount rate. The discount rate itself might also be influenced by how capital-intensive a technology is: a technology with relatively high upfront costs might be more exposed to market risks, which increases financing costs. The impact of the discount rate is illustrated in Figure 4.1, with the discount rate varying between 0% and 20%.

Within the group of baseload plants, i.e. nuclear, coal and natural gas-fired CCGTs, the latter are the least susceptible to changes in the discount rate. The average costs of the median case increase by around 40% when comparing the 0% and 20% discount rate cases. Nuclear plants, due to their relatively high investment costs, are impacted the most: whereas they appear to have a cost advantage over coal- and gas-fired plants when assuming low (single digit) discount rates, they become relatively more costly when financing becomes more expensive, with NOAK median costs being more than five times higher at a 20% discount rate compared to the lower bound and with near-term construction even more than seven times higher.

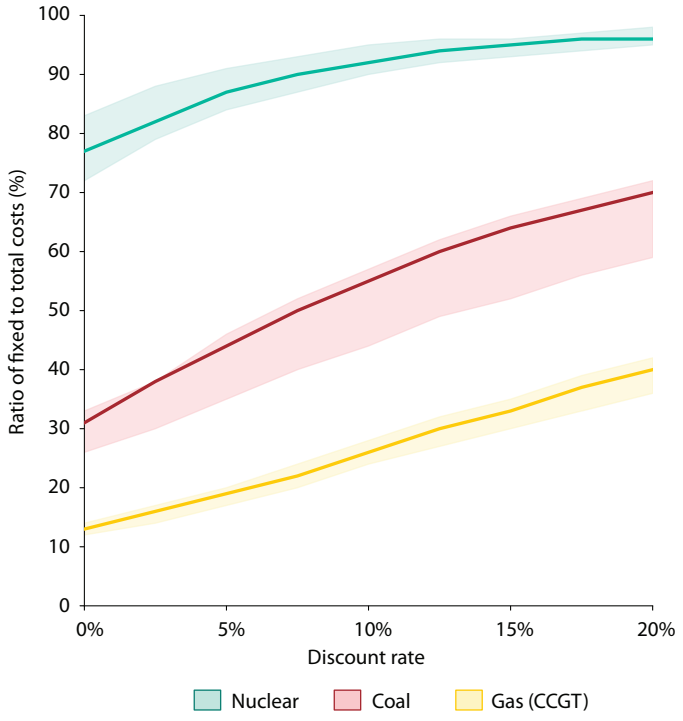
Coal, typically ranging between nuclear and gas-fired plants in terms of the ratio between fixed and variable costs, has the highest modelled LCOE at low discount rates, and is between nuclear and gas at high discount rates. The fixed cost share is illustrated in Figure 4.2, showing how the share of fixed costs on total costs is increasing with the discount rate and illustrating the relative position of the individual technologies.

Figure 4.1. LCOE as a function of the discount rate



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region. Left: non-renewables; Right: renewables.

Figure 4.2. Ratio of fixed costs (including capital recovery) to total levelised costs as a function of the discount rate



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

4.2. Capacity factor sensitivity

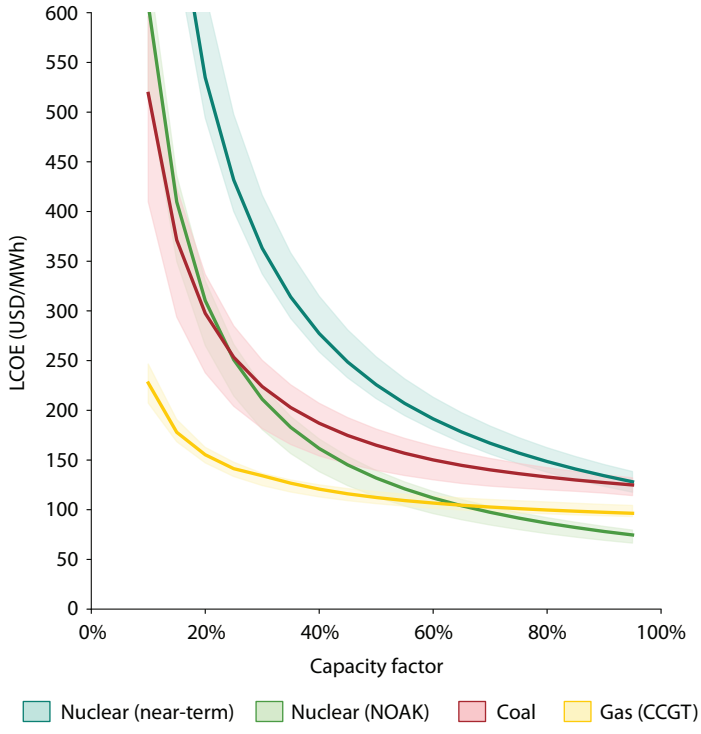
The levelised costs of generating electricity can be interpreted as the average market price a generation unit has to receive for its produced electricity over its lifetime, to recover total costs. For baseload technologies, reflected in the assumption of a capacity factor of 85% for nuclear, coal and CCGT, the LCOE reflects close to average wholesale energy prices.

When deviating from the assumption of being operated in baseload, the timing and, therefore, the value of generation – reflected in the time-varying market prices – becomes more important: mid- and peak-load plants only operate when market prices are high and thus receive, on average, higher revenues per produced unit of electricity. At the same time, average costs increase as investment and fixed costs are distributed over fewer operating hours. Profitability thus depends on the power plant's cost structure, as well as the prevalent market price structure, in individual markets.

Figure 4.3 illustrates the impact of varying the capacity factor on LCOE. Driven by its high share of fixed compared to variable costs, nuclear power plants are the most affected technology out of the three under consideration. Nuclear plants are, from an economical point of view, less suited to be operated at lower capacity factors. In an environment in which they can be operated at maximum capacity, they benefit from their low variable costs.

Natural gas-fired CCGT plants appear as the most versatile technology with respect to the economic impact of a varying number of operating hours: due to their relatively low investment costs and, depending on the region, their low to moderate variable costs, they appear competitive in a wide range of use cases and in different market designs.

Figure 4.3. LCOE of coal, natural gas and nuclear technologies, as a function of the capacity factor



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

Coal-fired power plants appear to be in a challenging economic position, given the underlying fuel and moderate CO_2-price assumptions. They typically come along with higher investment costs than gas-fired plants but lose their competitive advantage of significantly lower variable costs due to low gas prices and more frequently occurring CO_2-reduction mechanisms. Nonetheless, in particular markets, with access to low-cost coal (or expensive gas) or lower emission control costs, coal-fired plants can still be the most competitive option.

Also, variable renewables, such as wind and solar PV, are subject to system conditions and might not be operated at their theoretical maximum. As their share in the generation mix increases, they will also increasingly have to be curtailed. The greater the variability of a generation technology, the greater the need to complement LCOE values with a system-wide analysis of generating costs.

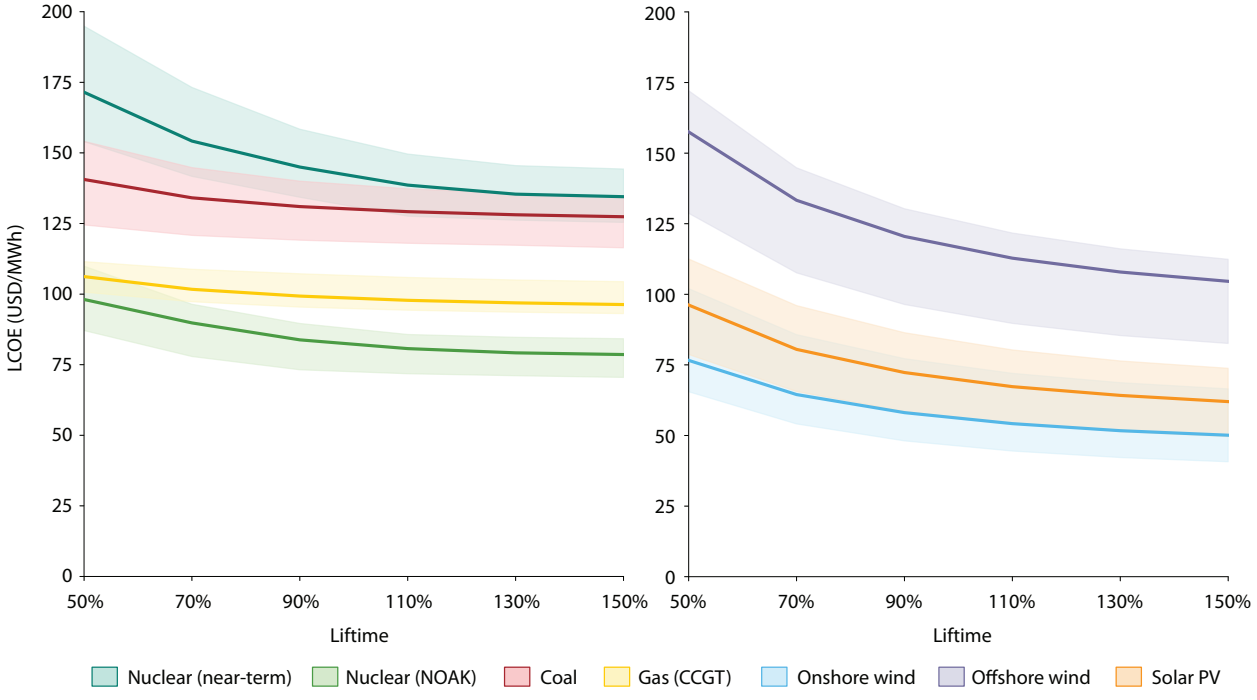
4.3. Lifetime sensitivity

To assess the impact of the technical lifetime assumption on average generation costs, this parameter was varied in the range of 50% (i.e. cutting the lifetime in half) to 150% (i.e. increasing the lifetime by 50%) of the original values. A decrease in lifetime is equivalent to an early retirement; an increase is equivalent to a no-cost lifetime extension.

A technology-specific lifetime was assumed for each technology. Large nuclear reactor plants are expected to last 60 years, SMR plants are expected to last 40 years, and coal and gas plants are also expected to last 40 years. Wind and solar PV installations have an expected lifetime of 30 years.

In general, decreasing the lifetime of an asset has a bigger impact on average costs than increasing it by the same amount. This is due to the discount rate, which renders costs and revenues in future periods less important; thus, taking away years with profits is more relevant than adding the same number of years in the distant future.

Figure 4.4. LCOE as a function of lifetime



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

For the same reason, changing the expected lifetime of an asset impacts those with a shorter expected lifespan more. For a nuclear plant with an assumed 60 years of operation, adding another year has virtually no effect. For a renewable technology with a relatively shorter lifetime, the effect could be different.

An additional driver is the ratio between investment and operating costs: if costs occur predominantly at the beginning, shortening the lifespan means having to recover high costs over fewer years. With relatively low investment costs, reallocating these costs is less severe.

For all dispatchable technologies, the impact of increasing the lifespan in the given range has little impact on average costs, and decreasing the lifespan has moderate impact as the decrease approaches halving. For all three, the LCOE difference between the lower value and the base case ranges between +7% and +22%, and the difference between the upper value and the base case ranges between -2% and -4%, showing that at 5% discount rate and 30 or more years of expected lifetime – in combination with a lower ratio of fixed to total costs for the shorter lived assets – changing the lifetime by a few years plays a small role for average costs.

For wind and solar units, which are more susceptible to lifetime changes due to their lower life expectancy and high share of investment costs, cutting the expected lifetime in half increases average costs between 36% and 39%. Extending it by 50%, on the other hand, reduces costs by around 10% to 11%.

4.4. Fuel cost sensitivity

To assess the impact of the fuel cost assumption on LCOE, this parameter was varied in the range of 50% (i.e. cutting the fuel cost in half) to 150% (i.e. increasing the fuel cost by 50%) of the original values. When analysing the fuel cost sensitivity of the average generation costs, it is important to keep several aspects in mind. Most importantly, fuel costs can vary significantly depending on the region. This is especially the case for the price of natural gas, where the price assumption in this analysis for North America is less than one-third of the price in other OECD regions.

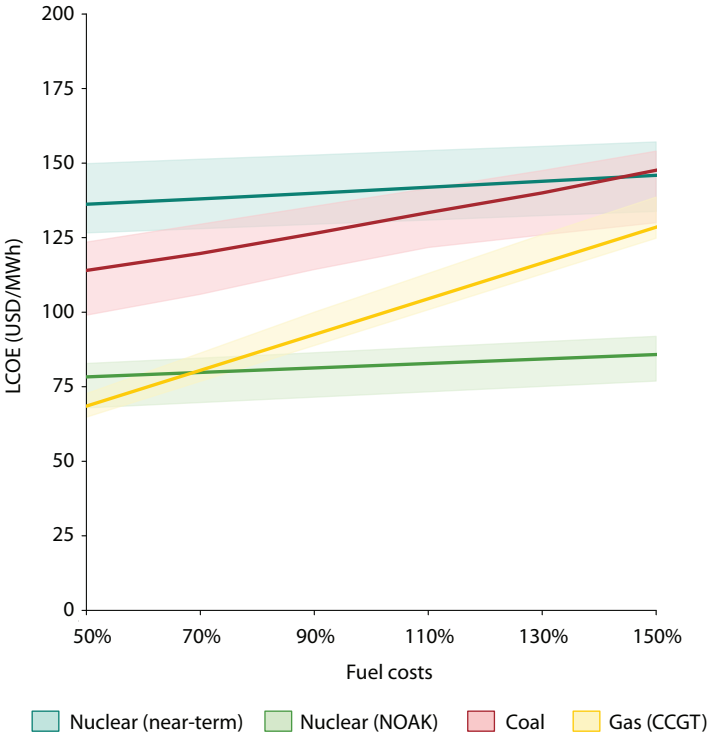
In most cases, fuel prices are not stable, but rather are being negotiated in international markets, and vary depending on the global economy and short- and long-term outlook of supply and demand. Additionally, prices may be subject to long-term supply contracts as well as seasonal fluctuations. This is true to different extents for different fuels: whereas coal and gas prices can vary significantly even within a year, nuclear fuel costs can be considered as relatively stable.

The share of fuel expenditures on total costs varies largely between technologies. Nuclear plants are characterised by high investment but relatively low fuel costs, while this ratio is typically reversed in the case of natural gas plants.

Also important to keep in mind for the interpretation of the results herein is that the technologies are, to different extents, exposed to competition (assuming the power plant dispatch is done according to least cost considerations). Whereas the variable costs of nuclear technologies are relatively low and even a significant increase would hardly affect its short-run competitive position, coal and natural gas plants – depending on the market – are frequently competing for market share on the basis of variable costs. Thus, an increasing or decreasing price for either coal or natural gas fuel can also affect their capacity factor, which additionally affects their average generation costs. Nevertheless, for this sensitivity analysis, a constant capacity factor of 85% is assumed. Depending on market design, the real-world impacts on relative generating costs resulting from fuel price increases can thus be even more significant than indicated in Figure 4.5.

Figure 4.5 illustrates that nuclear plants are only slightly affected by increasing or decreasing fuel costs by 50% in either direction. This is due to total nuclear costs being dominated by fixed costs. Average NOAK median costs change by 4.5% in either direction when reaching the end of the sensitivity range. Natural gas CCGT plants are the most susceptible among the analysed technologies, with LCOEs changing by about USD 6 with every 10% change in the fuel price. For coal, the impact is about half that of natural gas CCGT plants, with a USD 3 change in LCOE for every 10% change in fuel price. Natural gas prices, in particular, also vary widely from region to region. In this report, the costs for natural gas for a CCGT plant without CCUS vary from USD 18.65 per MWh in OECD North America to USD 60 per MWh in OECD Europe, and from USD 61.79 per MWh in Australia to USD 70 per MWh in OECD Asia.

Figure 4.5. LCOE as a function of fuel cost



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

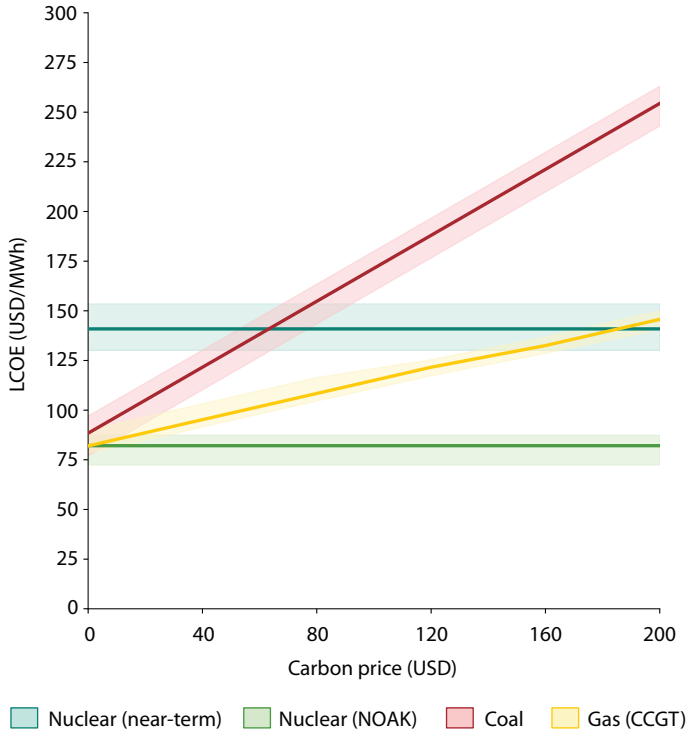
The fuel costs for a coal plant without CCUS vary from USD 17.84 per MWh in OECD North America to USD 16.90 per MWh in Australia, and from USD 30 per MWh in OECD Europe to USD 40 per MWh in OECD Asia. The costs for coal and natural gas do not include carbon costs, which are considered separately in the next section.

4.5. Carbon price sensitivity

A uniform carbon price of USD 50 per tonne of CO_2 is assumed throughout this report. As of 2026, direct carbon pricing covered 29% of global greenhouse gas (GHG) emissions through 87 implemented policies, including carbon taxes and emissions trading systems (ETS). The share of global GHG emissions covered by ETS' have tripled since 2016, rising from 8% to more than 24%, while the share covered by carbon taxes has remained stable at 4-5%. Globally, the average carbon price has more than doubled from 2016 to 2026, going from an average of USD 10/tCO_2e in 2010 to USD 21/tCO_2 in 2026 (World Bank, 2026). In the European Union (EU), the price of EU emissions allowances has exceeded EUR 60/tCO_2 (USD 70/tCO_2) since August of 2021 and was EUR 75/tCO_2 (USD 87/tCO_2) at the end of April 2026. To analyse the impact of these different prices on the competitiveness of baseload technologies, the carbon price was varied in the range of USD 0-200 per tonne CO_2.

Figure 4.6 illustrates the effects of different carbon prices. As nuclear plants do not emit CO_2, they are not affected by a carbon price but remain included as a reference. Coal, which generates approximately twice the CO_2 per unit of generated electricity than natural gas, is the most sensitive to varying carbon prices.

Figure 4.6. LCOE as a function of carbon price (in USD/tCO_2)



Note: Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region.

Increasing the carbon price by USD 10 changes the LCOE of the median coal technologies by around USD 8 – more than twice as much as the LCOE of a CCGT which increases about USD 3 for each carbon price increase of USD 10. Under the given fuel price assumptions, average coal technologies without carbon capture have a clear cost disadvantage compared with gas-fired CCGTs with any significant carbon price in place.

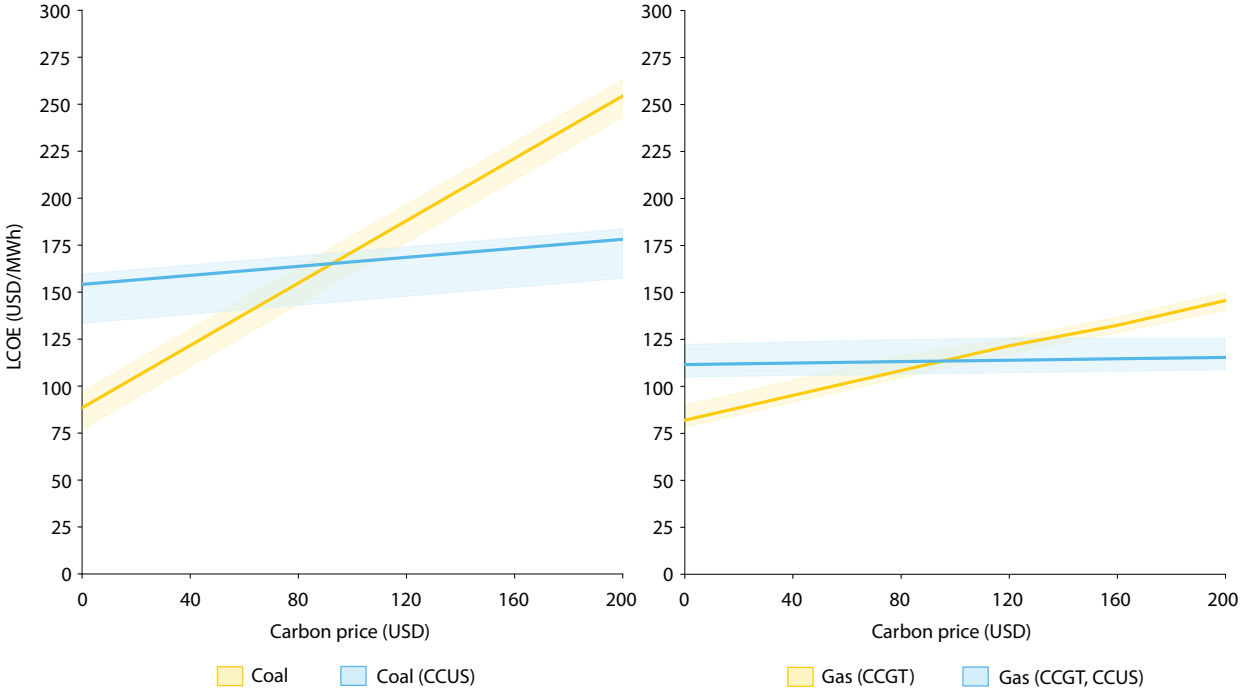
In the default case with carbon costs of USD 50/tCO2, equipping coal and gas plants with a CCUS unit remains more expensive than unmitigated fossil fuel-based electricity for the time being, due to the higher investment costs of CCUS equipment and their reduced thermal efficiency.

With higher emission costs, however, the picture could change. For coal power plants, due to the fuel's relatively high carbon content, CCUS units become competitive at around USD 90 per tCO_2, compared with around USD 95 per tCO_2 for gas-fired CCGTs. The apparent similarity of these thresholds reflects the differing capture rates assumed in the underlying plant designs (90% for coal, 95% for gas). On a like-for-like capture basis, the difference would be larger, reflecting coal's higher carbon intensity which delivers greater abatement value per MWh at any given carbon price.

However, LCOE is too simple to be a good indicator for assessing competitiveness under a carbon price because, as discussed in previous chapters, it does not capture all the value of the technology, including capacity factors, capacity value and hourly load.

Although the necessary regulatory carbon price levels required for triggering a cost advantage of CCUS plants exceed the average carbon prices around the world today, this price threshold already has been reached and exceeded several times since late 2022 in the EU-ETS.

Figure 4.7. LCOE with and without CCUS for various carbon prices (USD per tonne CO_2)



Note: Values at 5% discount rate. Lines indicate median values, while lighter coloured bands surrounding the lines indicate the 50% central region bands around lines.

The regulatory costs (or prices) of GHG abatement, and their uncertainty, will vary substantially between regions due to differences in resources, systems, opportunities and policy environments. Resource planning will also want to consider the range of potential regional GHGs costs (EPRI, 2025). Other economic issues can also play a role. For instance, portfolio strategies for managing GHG emissions, the use of direct air capture for CO_2 removal, carbon offsets as well as inter-regional clean power trading, may all affect investment decisions. Ultimately, the impacts of carbon pricing would require an analysis that is both broader and deeper than what is possible in the present context.

References

EPRI (2025), EPRI public comments in response to the Minnesota Public Utilities Commission request for comment on the regulatory cost of greenhouse gas emissions for gas integrated resource plans, Electric Power Research Institute, Palo Alto, 3002034797.

World Bank (2026), *State and Trends of Carbon Pricing 2026*, World Bank, Washington, DC. Doi: 10.1596/978-1-4648-2348-0. License: Creative Commons Attribution CC BY 3.0 IGO, pp. 2 and 5.

The role of electricity generation cost data in system costs analysis

5.1. Introduction: From plant costs to system costs

The LCOE remains a simple, transparent and widely used metric for comparing plant-level costs of electricity generation technologies. By expressing the discounted lifetime costs of a generating asset as a cost per unit of output, typically USD/MWh, LCOE provides a first-order estimate of the discounted average cost at which a technology can produce electricity.

Beyond providing a first intuitive indication of the costs of generating electricity at the plant level, one advantage of LCOE is to allow for comparisons. Within a country, LCOE can be used to compare the expected plant-level costs of technologies such as nuclear, coal, gas, hydro, wind and solar PV. For a given technology, it can also be used to compare costs across countries or regions, reflecting differences in resource quality, industrial maturity, construction costs, fuel prices, financing conditions and supply chains. It is in part due to these reasons that LCOE remains widely used by policymakers, modellers, industry experts and the wider public.

Historically, LCOE had been developed for regulated electricity systems to compare dispatchable baseload technologies such as coal-fired power plants, nuclear power plants or combined-cycle gas turbines. In such systems, remuneration could often be approximated by a stable tariff over the lifetime of the plant, and it therefore provided a useful indication of the electricity price required to recover investment, fuel, operation and maintenance, decommissioning and other plant-level costs. The LCOE methodology is thus closer to the cost accounting of regulated systems than to the revenue conditions of liberalised electricity markets, where generators face volatile prices and differentiated sources of value.

LCOE is a uniquely transparent and intuitive metric. It relies on a limited number of explicit assumptions, including capital costs, operating costs, fuel costs, plant lifetime, discount rates and assumed capacity factors. These assumptions can be harmonised across technologies and countries, making LCOE a useful screening tool. Such assumptions, however, are never neutral as the discount rates and capacity factors assumed can significantly affect results and rankings, especially for capital-intensive technologies.

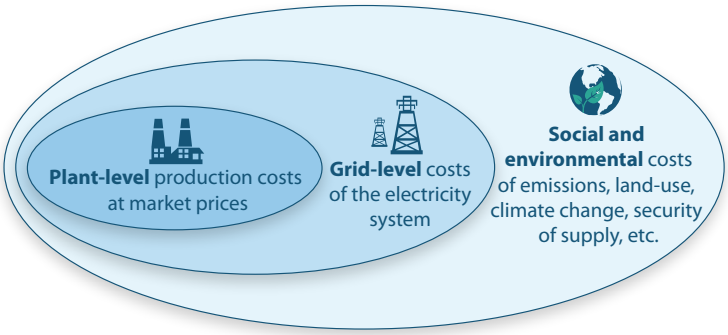
LCOE is a plant-level metric that captures average generation costs, but it does not reflect the value of electricity to the system at the time and location at which it is produced. It also does not capture the additional resources required to integrate a technology into an electricity system. This limitation has become more significant with the growth of VRE sources, such as wind and solar PV. Their output is variable, weather-dependent and often correlated across plants of the same technology. As their penetration increases, the value of their additional output declines, while the need for back-up capacity, storage, demand response, balancing services, grid reinforcement and interconnections, increases.

The most important aspect of these effects are the profile costs, which refer to the increase in the cost of satisfying a given demand profile due to the variability of VRE output. Wind and solar PV may, at times, produce less electricity than is needed, requiring dispatchable capacity or other flexibility resources to be engaged, and too much electricity during other periods, leading to curtailment or

lower market value. The autocorrelation of the production of different VRE plants leads to lower prices for all when meteorological conditions are good, which is sometimes referred to as self-cannibalisation. Typically, the marginal system value of an additional unit of VRE capacity decreases as its share in the generation mix rises. These profile effects are typically reflected in broader system cost analysis, which, in addition, incorporates balancing costs, connection costs and grid reinforcement needs.

The true economic value of a technology thus depends on its standalone electricity generation costs and on the services that it provides to a given system. Figure 5.1 illustrates the major cost categories in electricity systems: plant-level costs, grid-level costs and external costs such as unpriced social or environmental impacts.

Figure 5.1. Major cost categories in electricity systems



Adapted from NEA (2012).

System cost analysis focusses on costs arising within the electricity system itself, and, where relevant, on adjacent sectors such as hydrogen or heat when sector coupling is considered. Within this framework, the contribution of a technology to total system costs depends on a range of factors such as carbon prices, fuel price uncertainty, weather conditions, interconnection capacity, demand patterns, flexibility resources, operational reserves, inertia requirements, network outlays and the existing generation. Contrary to external effects, system costs accrue throughout the system in terms of higher overall costs satisfying a given level of demand.

The informational value of LCOE assessments is therefore bounded. Indeed, while they provide necessary information on plant-level generation costs, they provide only one building block of system analysis. Ultimately, technology choices must thus be assessed in terms of the additional resources they require, the flexibility they provide, and their contribution to the least-cost operation and expansion of the electricity system. Distinguishing between plant-level and system-level costs has therefore become increasingly important with the growing share of VRE.

5.2. System cost analysis – An overview

System cost analysis extends the assessment of electricity generation costs from the individual plant to the larger integrated electricity system. Its starting point is the total economic cost of continuously satisfying a given profile of electricity demand, while respecting the continuous balance between production and consumption, the generation and network operating limits, emissions targets, security of supply requirements, reserve margins, interconnection capacities and other reliability criteria.

In practical terms, system cost analysis often relies on modelling least-cost optimisation. The objective is to identify the combination of generation, storage, demand-side flexibility, grid infrastructure and electricity exchanges that minimises total system costs under defined assumptions. The result is a least-cost system mix, rather than a ranking of individual technologies by plant-level cost.

A typical system cost model combines two main components: capacity expansion and dispatch. Capacity expansion determines the type, location and scale of new investments, including generation capacity, storage, interconnections and other flexibility resources at the national, regional or bidding-zone level. Dispatch determines how the available system is operated over time, often at hourly resolution, ensuring that electricity supply meets demand in every period while accounting for storage use, demand response, curtailment and electricity exchanges with neighbouring systems.

The least-cost generation mix is an output of the modelling process, determined from the simultaneous optimisation of investment decisions and operational decisions. Plant-level electricity generation costs alone would not have been sufficient to determine outcomes: a technology with low plant-level costs may impose additional costs if its output is intermittent, weakly correlated with demand, or concentrated in a limited number of hours. Conversely, technologies with higher plant-level costs may reduce total system costs if they provide firm capacity, dispatchability, flexibility, inertia, seasonal availability, or other services that are valuable to the system.

This distinction is particularly important in low-carbon systems with high shares of wind and solar PV. As the share of variable renewable energy increases, the cost of integrating additional output depends increasingly on complementary resources such as storage, flexible hydro, dispatchable low-carbon generation, demand response and interconnections. The least-cost mix is therefore shaped by the interaction between plant-level costs, production profiles, demand profiles and flexibility options, and is not always dominated by the technology with the lowest plant-level cost.

System cost analysis can be applied both to existing electricity systems and to future scenarios. For existing systems, it can assess whether the current mix of generation storage, demand-side flexibility, interconnections and grid infrastructure is economically efficient under observed demand patters, fuel prices technology costs, policy constraints and reliability requirements. For example, it can help examine whether the current level of penetration of renewables energies in Europe is above or below the economically optimal level, once the full costs and benefits for the integrated power system are considered.

For future-oriented analysis, system costs analysis is typically scenario-based. Future technology costs, fuel prices, carbon prices, demand growth, electrification patterns, policy constraints, public acceptance, interconnection availability and climate conditions are uncertain. Scenarios and sensitivity analyses are therefore used to test how results change under different assumptions, and to identify which parameters have the largest effect on system costs, technology deployment, security of supply and the robustness of alternative strategic choices.

5.3. How electricity generation cost data is used in system modelling

System cost models do not use LCOE itself as an input. LCOE already embeds an assumed capacity factor, whereas in a system model the utilisation of each technology is an output of the optimisation. For example, dispatchable plants may operate at lower or higher capacity factors, depending on their position in the merit order, the availability of variable generation, fuel and carbon prices, and the need for flexibility. Variable renewables may also be curtailed when their output exceeds demand or when network and flexibility constraints prevent full integration.

System cost models thus use the underlying cost and performance parameters that also determine LCOE, including overnight capital costs, construction times, fixed and variable operation and maintenance costs, fuel costs, carbon costs, decommissioning and waste management costs, plant lifetime, efficiency, discount rate and availability. LCOE and system cost analysis therefore use closely related information for different purposes:

- LCOE summarises plant-level generation costs.
- System modelling places the same cost components in an integrated electricity system where output, curtailment, utilisation and, in market-based models, revenues are determined endogenously.

Plant-level generation costs thus remain one of the main determinants of system costs. Other key determinants include the correlation between variable renewable generation and demand, and the availability and cost of flexibility resources. System cost analysis complements LCOE by showing how technologies interact with one another and with the demand profile.

Unfortunately, there is no universally applicable metric equivalent to LCOE that can allocate system costs unambiguously to individual technologies across all systems. The system contribution of an individual technology depends on the structure of the electricity mix, the level of interconnection, the availability of flexibility, demand and weather patterns, network constraints and policy objectives. Complementary indicators, including value-adjusted LCOE (see IEA, 2018) and system LCOE (see NEA, 2019) approaches, can be useful, but their results remain system-specific.

System models can nevertheless quantify the cost implications of technology choices. One common approach is to determine the least-cost mix of a given electricity system under a triple constraint of carbon emissions, security of supply and cost minimisation. This reference case can then be compared with an alternative scenario that imposes an additional constraint, such as a minimum share of a given technology or a restriction on another. The cost difference between the two scenarios can be interpreted as the system-level cost of the imposed constraint and, where appropriate, allocated on a per-MWh basis.

All cost data used to establish the LCOE is therefore also used to evaluate the system costs. In addition to cost data, system models require detailed technical parameters. For variable renewables, this includes hourly or sub-hourly generation profiles based on geography, weather and resource quality. For dispatchable technologies, it includes ramping rates, minimum stable generation levels, start-up costs, minimum up- and down-times, outage assumptions and availability time series. For hydroelectricity, seasonal inflows and reservoir constraints are relevant. For nuclear plants, the planned outage relative to refuelling must be considered under different modes of fleet management.

Demand data – possibly with regional granularity, which would allow for inclusion of the modelling of network constraints – is just as important, since the value of a generation technology depends on when and where it provides electricity. Solar PV output may coincide well with air-conditioning demand in some systems but correlate poorly with evening peaks or winter heating demand in others. Wind output may have seasonal or daily patterns affecting the load of other generators. Industrial demand, transport electrification, heat pumps, hydrogen production, and demand response can all change the shape and flexibility of the demand curve.

Policy and hybrid parameters can also play important roles. These include emissions limits, technology-specific deployment constraints, renewable targets, nuclear phase-out assumptions, land-use limits, environmental restrictions, public acceptance constraints and limits on grid or interconnection expansion. Such parameters are not purely technical, but they set the boundaries of the model and can affect the resulting least-cost mix.

Finally, system models require information on infrastructure and possibilities for external electricity trade. Connection costs, transmission and distribution reinforcement costs, interconnection capacities, cross-border electricity prices, transaction costs and the cost of expanding either the grid or local generation capacity, can all affect outcomes. In systems with high shares of variable renewables, the relevant question is often which mix of additional dispatchable generation, storage, demand response, grid expansion, or imports provide the least-cost way to satisfy demand securely.

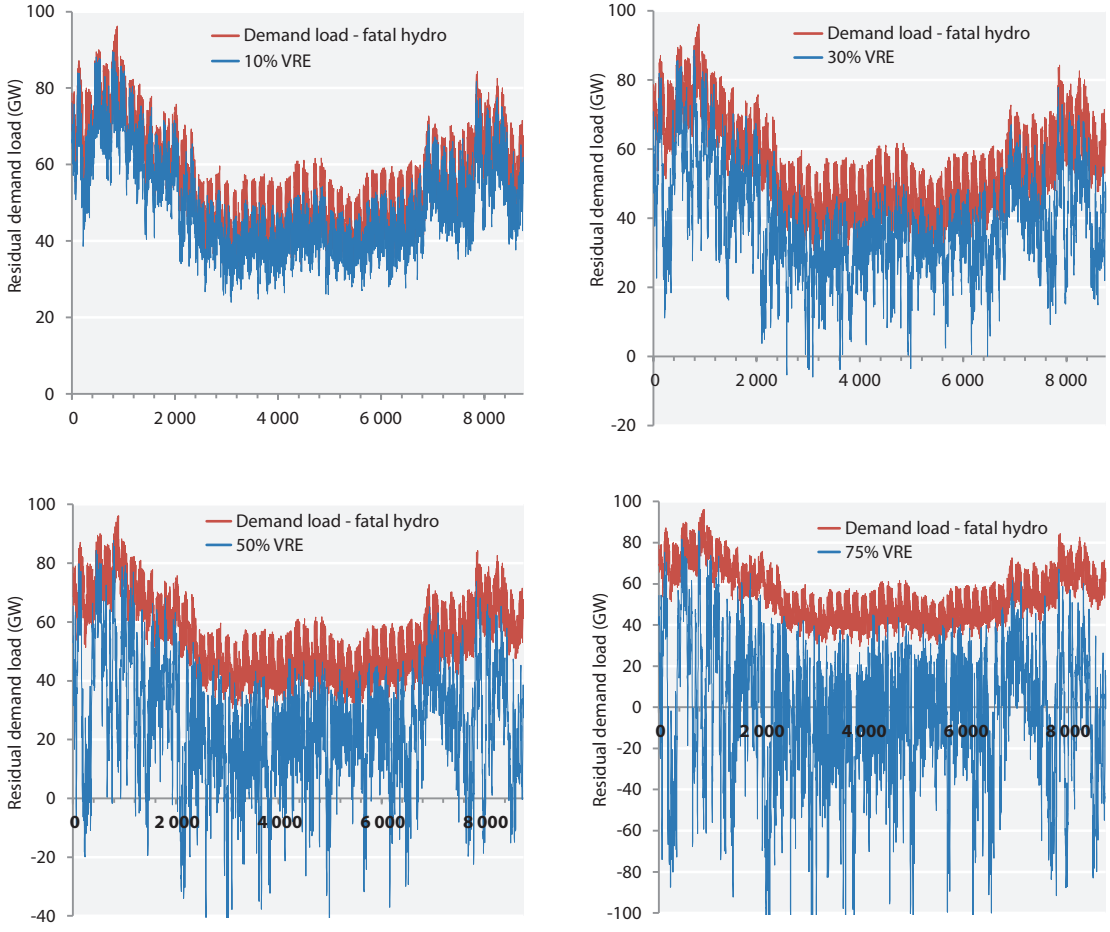
When modelling the future, uncertainty is an intrinsic feature of system cost assessments and concerns every input including: technology costs, construction schedules, financing conditions, fuel prices, carbon prices, electricity demand, climate conditions, public acceptance and policy choices. Fuel price uncertainty is particularly important for gas-fired generation, given its exposure to global and regional markets, infrastructure constraints and geopolitical developments. For capital-intensive low-carbon technologies, uncertainty over financing costs and construction performance are equally important. Analysts should therefore avoid single-point conclusions and use scenario analysis, sensitivity testing and transparent assumptions.

5.4. The roles of the generation mix, flexibility provision and infrastructure

In most NEA Member countries, the decarbonisation of electricity supply implies a progressive reduction of unabated fossil fuel generation, first coal-fired and then gas-fired generation. Low-carbon systems rely increasingly on VRE, complemented by dispatchable low-carbon generation, such as nuclear, hydroelectricity and low carbon fuels, as well as on flexibility providers. This transformation changes the cost structure of electricity generation and the operational requirements of the system.

One key systemic variable is residual load, defined as electricity demand net of non-dispatchable, variable generation. In systems with low shares of VRE, residual load remains close to the original demand profile and can be served by dispatchable generation with relatively predictable operating patterns. As the share of wind and solar PV increases, residual load becomes more volatile, with steeper ramps, lower minimum-load periods and, eventually, hours of negative residual load. This is illustrated in Figure 5.2. At 10% VRE, residual load remains broadly positive and follows the seasonal and daily structure of demand. At 50% and 75% VRE, residual load becomes far more irregular, with frequent deep troughs and negative values, indicating periods of curtailment.

Figure 5.2. Comparison of the residual load of different VRE generation shares



This increasing volatility has direct cost implications. Variable renewable technologies may have low plant-level LCOE, but they require complementary resources to maintain the balance between supply and demand at all times. These resources provide different forms of flexibility and operate over different time scales.

Short-duration storage, including batteries, can smooth intra-day mismatches between production and consumption. This is particularly useful for shifting solar PV output from midday to evening demand peaks, and for providing balancing and ancillary services. Most storage technologies, however, are less suited to multi-day, seasonal or inter-annual shortages of wind and solar generation. Even large hydro reservoirs are constrained by hydrology, geography and competing water uses.

Dispatchable generation provides a different service. Technologies capable of producing electricity continuously or on demand are required during periods of low wind and solar output, including extended weather-related shortfalls, e.g. *Dunkelflaute* events when wind and solar output are simultaneously low. In low-carbon systems, this role can be provided by nuclear energy, large hydro reservoirs (within limits of reservoir capacity), fossil generation equipped with carbon capture where available, or other dispatchable low-carbon technologies, including geothermal, hydrogen and biomass. Their value derives from their contribution to adequacy, system stability and reduced reliance on very large storage volumes.

Demand response can also contribute to flexibility by reducing or shifting consumption during scarcity periods. Its economic role is often concentrated in a limited number of high-stress hours. However, demand response is not costless, and its availability depends on consumer behaviour, industrial processes, digital infrastructure and the opportunity cost of foregone or delayed consumption.

Interconnections and regional electricity system integration also provide important sources of flexibility. They allow systems to import electricity during periods of domestic scarcity and to export electricity during periods of excess generation. They can reduce the need for domestic back-up capacity where neighbouring systems have complementary demand patterns, generation mixes or weather conditions. Their value depends on surplus capacity or added demand in neighbouring systems. Interconnection is less effective when adjacent regions experience correlated weather and demand patterns, or scarcity events. Transmission expansion within a country can play a similar role by reducing geographic mismatches between renewable resource locations and demand centres.

Due to their generally low investment cost, at low or moderate penetration, variable renewables can reduce total system costs, especially when output aligns well with demand or displaces high-cost generation. At high VRE penetration levels, however, simply adding more wind or solar capacity becomes decreasingly cost-effective. Indeed, higher VRE shares increasingly create periods of very low or negative residual load. Unless sufficient storage, demand response, exports or flexible demand are available, part of this output must be curtailed. Curtailment reduces the capacity factor of highly capital-intensive variable renewables and thus increases their average system cost.

The cost-effectiveness of generation technologies, therefore, depends strongly on the availability and cost of flexibility resources. A technology with a low standalone LCOE may be less attractive at the system level if it increases residual load volatility, curtailment or back-up requirements. A technology with higher plant-level costs may reduce total system costs if it provides firm capacity, dispatchability, seasonal availability or other system services. Ultimately, least-cost electricity mixes are determined by the interaction between generation technologies, demand profiles, network infrastructure and flexibility options.

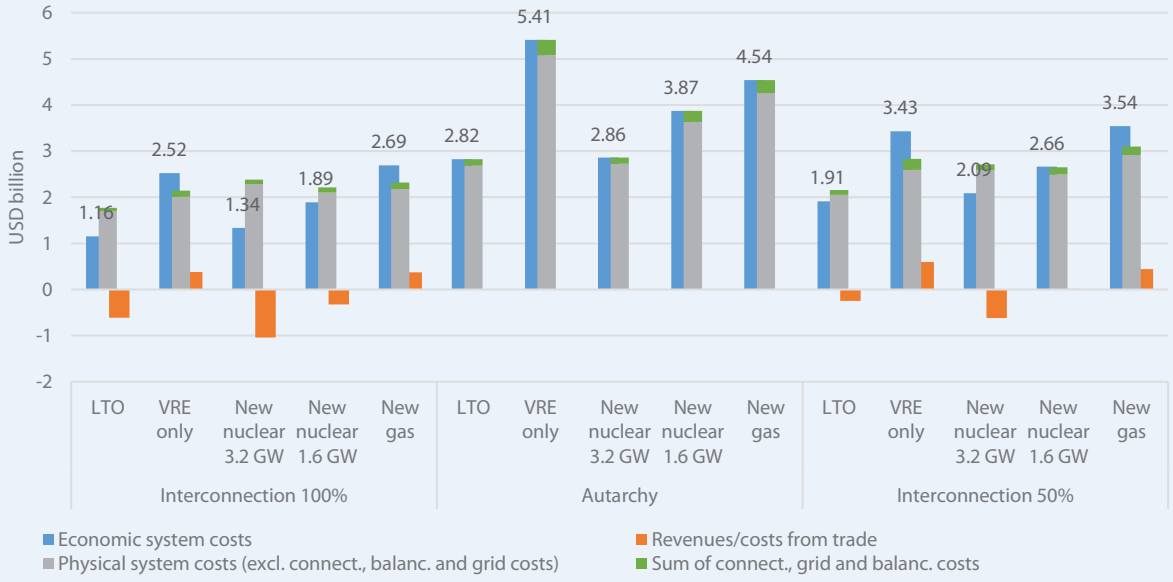
5.5. System cost analysis at the NEA and EPRI

The Nuclear Energy Agency has been at the forefront of developing system cost analysis and has developed a substantial body of work to assess the costs of alternative low-carbon electricity mixes. This work builds on several publications, including *Nuclear Energy and Renewables: System Effects in Low-Carbon Electricity Systems* (2012), *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables* (2019), and country-specific studies such as the analysis of net zero scenarios in Switzerland and Sweden (see NEA, 2022; and NEA, 2026; as well as Box 5.1 and 5.2 below). EPRI performs extensive system cost analysis in its Energy Systems and Climate Analysis (ESCA) group concentrating

on the reliability and affordability of power systems and their climate implications (EPRI, 2020 and 2026). EPRI's work on system cost analysis has produced several publicly available studies on decarbonisation of the US energy system and economy under different scenarios, as well as similar studies for members in other regions, including the Americas and East Asia (EPRI, 2024). These studies constitute necessary complements to the plant-level generation cost analysis performed in this report, by examining how different technologies affect the total cost of satisfying electricity demand under carbon, reliability and system constraints.

Box 5.1. Achieving Net Zero Carbon Emissions in Switzerland in 2050 – Low Carbon Scenarios and their System Costs

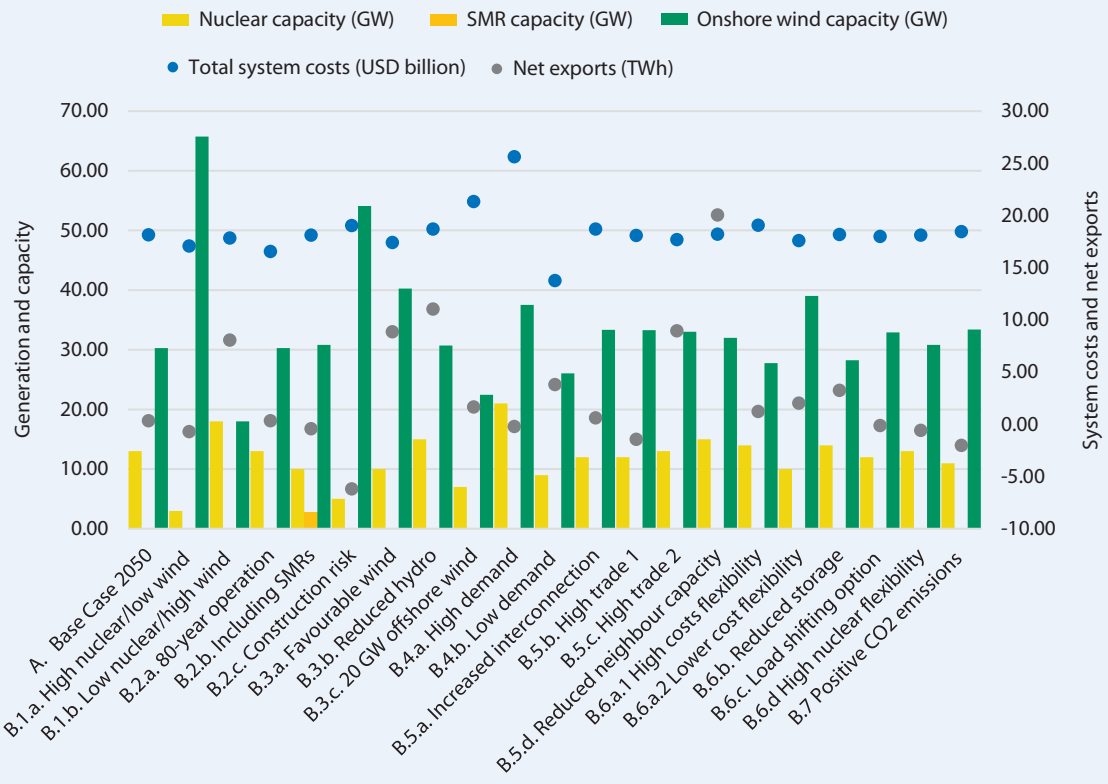
The NEA study on Switzerland (NEA, 2022; title as above) applies the system costs approach to the Swiss power system in 2050. It compares alternative pathways to net zero emissions under different assumptions on generation capacity and interconnection. Scenarios preserving the long-term operation of existing nuclear plants had the lowest annual system costs, followed by scenarios with new nuclear capacity. Scenarios relying only on variable renewables, hydroelectricity and other flexibility options were more costly – only exceeded in cost by the "Autarchy" scenarios evaluating the impact of not relying on interconnection. These results reflect the system value of firm, low-carbon generation in a country facing stringent carbon constraints and limited domestic flexibility options.



NEA system cost analysis relies on detailed electricity system modelling. The objective is to determine the least-cost combination of generation, storage, demand-side flexibility, transmission and interconnection resources capable of meeting demand at all times. Such models combine long-term investment decisions with short-term operational decisions, typically by linking capacity expansion and hourly dispatch. They capture the cost of individual technologies and the manner in which these technologies interact within the power system.

Box 5.2. A Least-cost Capacity Mix to Satisfy Growing Electricity Demand without Carbon Emissions in Sweden – Base Case 2050 and Sensitivity Scenarios

The NEA study on Sweden (NEA, 2026; title as above) examines a system with sharply increasing electricity demand, including large, new flexible demand from hydrogen production for the booming steel industry. The least-cost configurations include a combination of onshore wind, nuclear energy, hydroelectricity and interconnections. Variable renewables provide large volumes of low-carbon electricity, while hydroelectricity, interconnections and nuclear energy contribute to flexibility, adequacy and system stability. In total, 21 scenarios were modelled and analysed.



To support such work, the NEA, has developed a family of open modelling tools released under an MIT licence. NOSY is a composable, component-based energy system modelling and optimisation toolkit.[1] It provides a workflow to describe energy networks using linear programming and mixed-integer linear programming formulations, and is primarily intended for modellers who need a flexible framework for building and adapting energy system models.

Building on this modelling infrastructure, POSY2 is the NEA's own advanced power system model for system cost studies.[2] As a mixed integer linear programming (MILP) model it combines least cost-optimisation with an array of technical and operational constraints. It is designed for analysts and policy-oriented applications, using the modelling capabilities of NOSY to represent electricity systems, generation technologies, flexibility resources, interconnections and policy constraints. Its purpose is to assess the system-level consequences of alternative electricity mixes and policy choices. POSY2 replaces the earlier POSY model in the NEA modelling framework.

1. Available at https://github.com/oecd-nea/Nosy.jl.
2. Available at Posy2: https://github.com/oecd-nea/Posy2.jl.

The NEA has published two country scenario studies so far: Switzerland and Sweden, both at horizon 2050, the summaries and results of which are discussed above in Boxes 5.1 and 5.2. Additional work is ongoing. These findings should be read as scenario-specific results, rather than universal technology rankings. Outcomes depend on underlying assumptions and system conditions. The broader lesson from NEA system-cost studies is that generation cost data remain indispensable, but their interpretation changes in a system framework. Core inputs only gain meaning through their interaction with system operations.

5.6. Implications for policymakers and analysts

System cost analysis leads to several key conclusions regarding the role of generation costs in electricity system planning.

1. **Electricity generation cost data remains essential for electricity system analysis**. Reliable information on overnight capital costs, construction times, technical performance parameters, and financial assumptions is required to assess both plant-level generation costs and total system costs. Without such data, system models cannot provide meaningful estimates of least-cost capacity mixes, system operation, infrastructure needs, or the cost of meeting carbon constraints.
2. **Electricity generation costs must be interpreted in their system context**. Their value depends on how they interact with system conditions such as network structure, demand patterns, resource availability and operational requirements. A technology that is cost-effective in one system may be less so in another, depending on how these conditions shape its role and performance within the system.
3. **No technology has a universally optimal cost**. LCOE remains useful as a transparent plant-level metric, but it does not account for the timing, location, dispatchability, reliability or flexibility of a generation technology. It omits larger system-dependent effects such as profile costs, balancing requirements and costs associated with integrating a new generation into the grid. These effects can, however, become structurally important as the share of variable renewable generation increases, since overall system costs depend strongly on the misalignment of VRE generation patterns with demand, in addition to LCOE.

These findings have implications for the design and assessment of low-carbon electricity systems. In electricity systems that are subject to stringent CO_2 constraints, the reduction of fossil fuel generation means the double role of baseload and flexibility provision it has traditionally played must now be met by alternative technologies. As a result, cost-effective low-carbon systems generally require a portfolio of complementary resources, with different technologies contributing in different ways across time and operating conditions. In many cases, combinations of nuclear energy and renewables, supported by sources of flexibility like battery storage, hydroelectricity, low-carbon fuels, demand response, or interconnections, can provide lower-cost solutions than systems relying too heavily on a single technology alone. The precise optimal mix, however, remains system specific.

For policymakers, the main implication is that strategic planning cannot rely on LCOE rankings alone. Technology choices should be evaluated in terms of their contribution to total system costs, reliability and decarbonisation objectives. This requires models that represent all aspects of an electrical system. Such modelling provides a structured way to understand how different technology choices and policy decisions affect overall system outcomes.

For analysts, the corresponding implication is that cost databases should be transparent, regularly updated and internally consistent, with clearly stated assumptions. Results should be reported as total costs and broader system outcomes, providing a clear picture of how the system performs under different conditions. The purpose of system modelling is to clarify how different assumptions and policy choices affect the cost and feasibility of low-carbon electricity systems, rather than to produce a single definitive future.

Once these recommendations are respected, the analysis of plant-level electricity generation costs as performed in this report, and broader system cost analysis, are indispensable complements in the successful conception and management of low carbon electricity systems.

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The Costs of Generating Electricity 2025

In a fast-changing energy landscape, confronted by rising demand, price volatility and increasing capital intensity, providing reliable data on the costs of generating electricity to policymakers, experts and modellers is essential. Combining the deep techno-economic expertise of the OECD Nuclear Energy Agency (NEA) and the Electric Power Research Institute (EPRI), *The Costs of Generating Electricity 2025* provides plant-level data on the levelised costs of electricity (LCOE) for 23 technologies in 21 countries. It includes data on a broad range of low carbon technologies, including small modular reactors (SMRs) and hydrogen turbines, as well as a number of fossil-fuel based technologies, both with and without carbon capture and storage (CCUS). Based on this data, it seems electricity systems are becoming increasingly low carbon and more diversified, but also more expensive. Only the long-term operation (LTO) of existing nuclear power plants, hydroelectricity, and – as long as their system costs are excluded – onshore wind and solar photovoltaic (PV) can provide electricity for less than USD 100 per MWh. While LCOE remains a vital building block of the information infrastructure on electricity systems, the data on costs and capacity factors also signal that they need to be complemented by system cost analysis in a specific country context to provide a reliable guide for decision making.

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