Australia's National
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GenCost 2025-26

Final report

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Acknowledgement

CSIRO acknowledges the Traditional Owners of the lands that we live and work on across Australia and pays its respect to Elders past and present

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Foreword

Assumptions about the cost of electricity generation and storage technologies are a key input to any electricity system planning exercise in Australia or around the world. The primary role of GenCost is to provide capital cost data for the electricity modelling and planning community. The project delivers the capital cost data with an emphasis on stakeholder consultation, recognising that no single organisation can be completely across the changing circumstances of all relevant technologies.

A secondary goal of the project is to provide an indicator of what the capital cost data means for the cost of delivered electricity and the relative competitiveness of generation technologies. This function is delivered by calculating a metric called the levelised cost of electricity (LCOE) which is the minimum per unit price that a project requires to pay back its investment and running costs over its life. LCOE typically only consider a small number of core project details with the more minor or unique costs of each project ignored so that costs are calculated on a simple and common basis.

GenCost also provides a system levelised cost of electricity (SLCOE) which is the average cost of electricity from a bundle of electricity generation and storage technologies that together meet all the requirements of the electricity system. Electricity systems will always require a diversity of resources to deliver all their functions and so no single technology will meet all the system’s needs regardless of its relative cost position.

Acknowledgements

This report has benefited from feedback provided by electricity sector stakeholders in February 2026 on a Consultation Draft version of this report that was made available in December 2025. The authors greatly appreciate the time stakeholders have given to support the project. Submissions received can be viewed at https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-forecasting-assumptions-update.

Executive summary

Technological change in electricity generation is a global effort that is strongly linked to global climate change policy ambitions. While the rate of change remains uncertain and the level of commitment of each country varies over time, in broad terms, there is continued support for collective action limiting global average temperature increases. At a domestic level, the Commonwealth government, together with Australian states and territories aspire to or have legislated net zero emissions (NZE) by 2050 targets.

Globally, renewables (led by wind and solar PV) are the fastest growing energy source, and the role of electricity is expected to increase materially over the next 30 years with electricity technologies presenting some of the lowest cost abatement opportunities.

Purpose and scope

GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating the capital costs of electricity generation, energy storage and hydrogen production technologies with a strong emphasis on stakeholder engagement. GenCost represents Australia's most comprehensive electricity generation cost projection report. It uses the best available information each cycle to provide an objective annual benchmark on cost projections and updates forecasts accordingly to guide decision making, given technology costs change each year. This is the eighth update following the inaugural report in 2018.

Technology costs are one piece of the puzzle. They are an important input to electricity sector analysis which is why we have made consultation an important part of the process of updating data and projections.

The report encompasses updated current capital cost estimates commissioned by AEMO and delivered by GHD. Based on these updated current capital costs, the report provides projections of future changes in costs consistent with updated global electricity scenarios which incorporate different levels of achievement of global climate policy ambition. Levelised costs of electricity (LCOEs) are also included and provide a summary of the relative competitiveness of generation technologies.

Responses to stakeholder feedback

The GenCost consultation draft introduced a major new feature which was the system levelised cost of electricity (SLCOE) which provides a more transparent way of capturing all of the system wide costs that are needed to support the increasing share of renewables that are being deployed in Australia's electricity system. These broader costs are unable to be captured in the standard levelised cost of electricity (LCOE) which is applied on a single technology basis. The new SLCOE method also included the publication of a new open source electricity system model and input data set.

Stakeholders generally supported the new method but were less convinced of the value of the SLCOE in measuring cost in 2030 than in 2050. In 2030, cost estimates are strongly influenced by existing capacity and there is no consistent rule or readily available data for capturing the amount of unrecovered costs associated with that capacity. In response to this feedback, for 2030 SLCOE estimates have been replaced with electricity futures prices as an alternative indicator of generation prices in the period to 2030. These rely on market expectations rather than modelling and are publicly available.

Stakeholders also requested more detail on SLCOE modelling results. A detailed set of results for the 2050 SLCOE modelling is now included in the GenCost data file that accompanies this report. Other minor points of feedback and responses are summarised in the body of the report and submissions can be viewed at AEMO's consultation website.

Response to the 2026 Iran War

The Iran war began on 28 February 2026 constricting global oil products supply. The depth and direction of its broader impacts for energy technologies is unpredictable. It is inflationary in the sense of oil being a fundamental input to almost all global supply chains. It may also increase demand for energy technologies in general that reduce a region's reliance on imported oil. It is also deflationary because it could reduce global economic growth and demand for energy. In light of this development, for 2026, we have assumed no improvement in costs for the majority of technologies.

Data centre impacts on gas turbine costs

New electricity generation capacity required to meet demand from data centres is growing strongly and is impacting gas turbine costs. The IEA (2026) reported that:

"if data centres were a country, they would be the second-largest destination for gas turbines ordered from Q1 2025 to Q1 2026".

Gas turbine costs have already increased for the last four consecutive years. As a result of this ongoing demand from data centres, the projections assume that the cost of gas turbine technologies will continue to increase in the next two years after which manufacturers are expected to be in a better position to meet demand, allowing costs to stabilise.

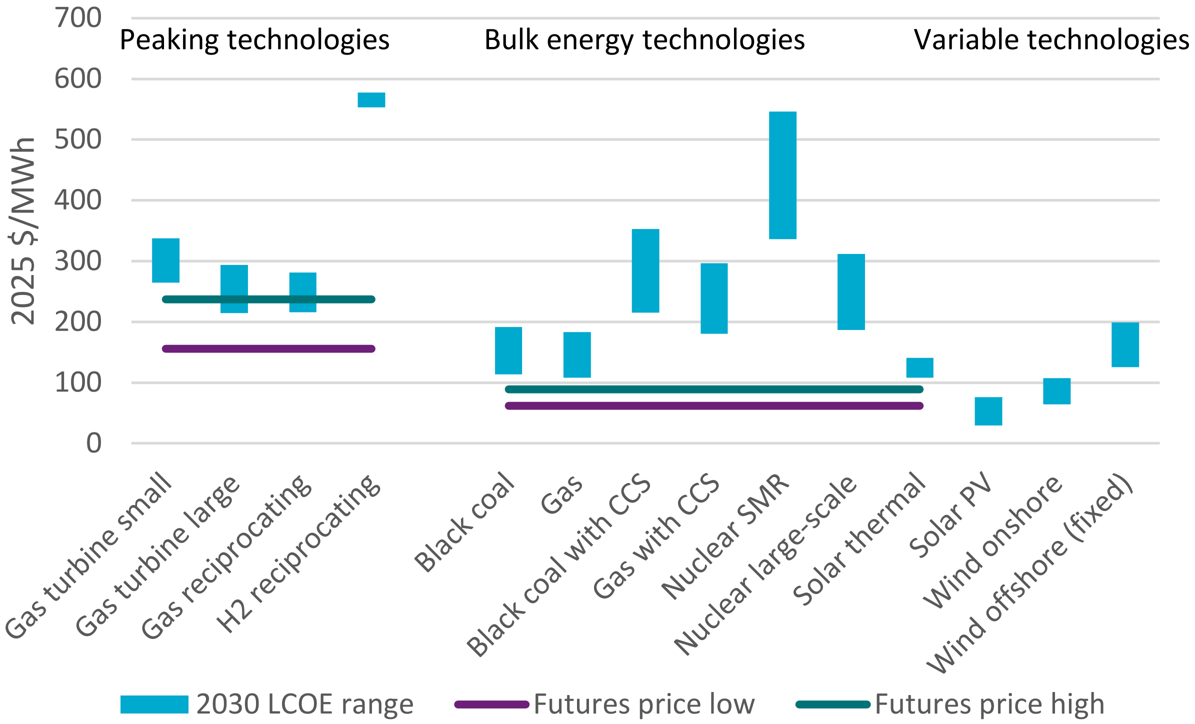
2030 costs

Baseload electricity futures prices are in the range of \$68/MWh to \$92/MWh for the next 3 years with a flat or rising trend, depending on the state. Peak evening futures prices range from \$152/MWh to \$220/MWh.

Peaking generation technologies are currently sitting at the high end of Peak evening futures prices. This is consistent with observations that batteries have started to compete with traditional gas generation in this category, with lower battery costs and significant new capacity added resulting in reduced peak evening prices.

Similarly, most bulk energy generation technologies are higher cost than the Baseload electricity futures price. This is an academic observation because most of these technologies could not be deployed within the next 4 years due to their required development and construction times.

Solar PV and onshore wind are almost exclusively the only generation technologies sufficiently advanced in the development pipeline to be deployed before 2030. Their deployment is being supported by existing flexible gas and coal together with new battery, pumped hydro and transmission capacity. Given the Baseload electricity futures price is an all-day, all-year price it represents the expected total annual generation cost of this combination of technologies. Transmission costs, which are recovered outside of the electricity system increase to 2030 but from a low base (AEMC 2025).



LCOE does not include renewable integration costs.

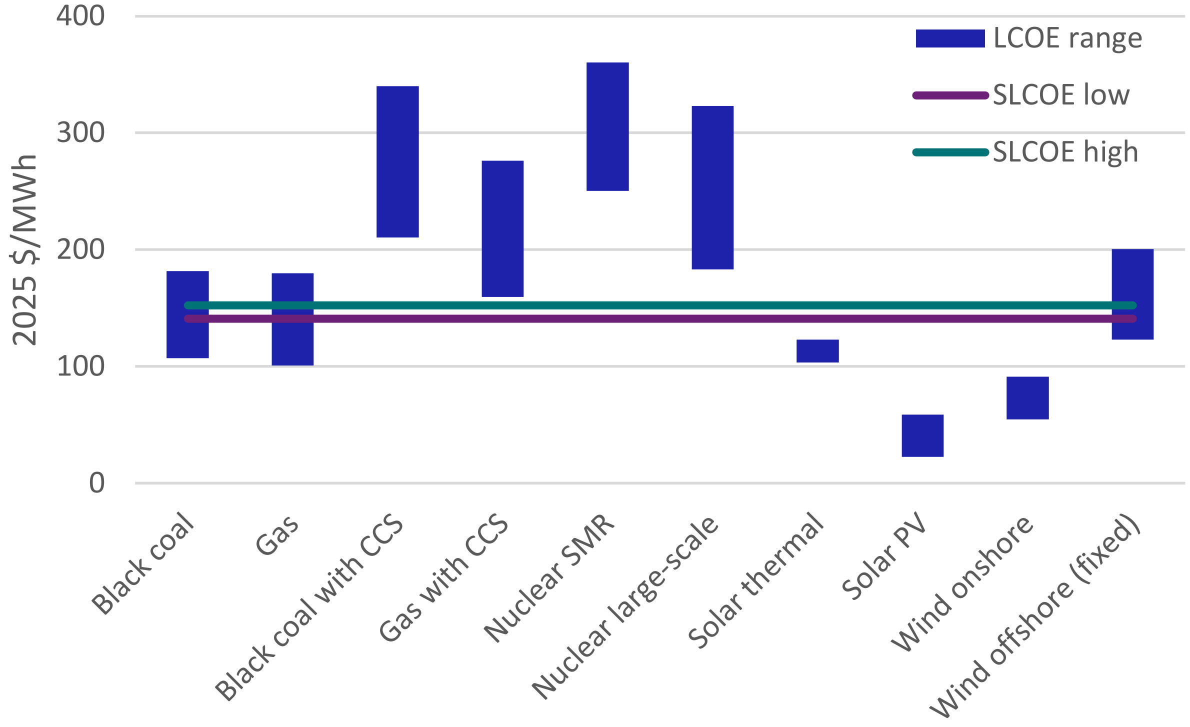
ES Figure 0-1 Levelised cost of electricity (LCOE) in 2030 by technology category and corresponding electricity futures price

2050 generation technology competitiveness

The key findings from the 2050 analysis are:

- For the electricity sector to efficiently support achieving net zero by 2050 across the economy, solar PV and onshore wind will deliver the majority of electricity supply (93%) supported by hydro, storage, transmission and either gas or hydrogen or a combination of both.
- New black coal, while competitive at this SLCOE range is not suitable for deployment if the goal is to efficiently achieve net zero (coal would increase the cost of achieving net zero across the economy). Unlike coal, the SLCOE analysis indicates gas will play a role in achieving net zero emissions contributing a 3% to 7% share of generation.
- Solar thermal is competitive relative to other technologies and inside the SLCOE range. However, given the need to access better solar resources which are further from load centres, solar thermal will be subject to additional transmission costs of up to $20/MWh.
- Some offshore wind is also in the competitive range however the modelling used the average cost of offshore wind. Lower range offshore wind costs appear to be competitive but were not explored in the modelling and so need more analysis.

- Gas with CCS is the next most competitive after solar thermal and offshore wind. Large-scale nuclear is slightly higher in cost than gas with CCS. Black coal with CCS occupies a similar cost range to large-scale nuclear. Nuclear small modular reactors (SMRs) are the highest cost.



LCOE does not include renewable integration costs. SLCOE does.
ES Figure 0-2 Levelised cost of electricity (LCOE) in 2050 by technology and system levelised cost of electricity (SLCOE) for efficiently achieving net zero by 2050

Implications for electricity prices

In 2025 calendar year the average NEM volume weighted generation price was estimated to be $104/MWh, down from the recent peak in 2022 of $189/MWh caused predominantly by high gas prices. Based on NEM electricity futures prices in the next three years (and supported by AEMC (2025) modelling), generation costs to 2030 are expected to fall further relative to 2025, down to $80-$90/MWh.

By 2050, most generation capacity that exists today will be retired. The LCOE and SLCOE analysis in this report indicates that there are no new build technology options, fossil or non-fossil with firming costs, that cost less than $100/MWh. By 2050, new build coal generation costs are in the range of $107/MWh to $182/MWh. As such, even without net zero by 2050 policies, generation prices are expected to increase above $100/MWh in the post-2030 period.

The cost of generation if the electricity sector makes an efficient contribution to achieving net zero by 2050 is $141/MWh to $152/MWh based on solar PV and wind generation inclusive of all firming costs. Excluding transmission costs which are not recovered through the generation market, the net zero consistent generation cost is $120/MWh to $130/MWh or an average of $125/MWh.

These cost estimates do not guarantee future generation prices. Changes in generation prices are also subject to:

- Supply-demand imbalance as a result of too much or too little deployment relative to demand growth and retirements.
- Fuel price and weather volatility.
- The level of competition amongst suppliers.

These additional drivers of generation price formation can lead to prices significantly lower or higher than the underlying cost of the system and can take many years to correct due to the long lead times for capacity deployment. Generation prices are currently around 33% of retail prices. Transmission is around 7%, distribution around 34% with the remainder made up of metering, retail services and government programs.

1 Introduction

Current and projected electricity generation, storage and hydrogen technology costs are a necessary and highly impactful input into electricity market modelling studies. Modelling studies are conducted by the Australian Energy Market Operator (AEMO) for planning and forecasting purposes. They are also widely used by electricity market actors to support the case for investment in new projects or to manage future electricity costs. Governments and regulators require modelling studies to assess alternative policies and regulations. There are substantial coordination benefits if all parties are using similar cost data sets for these activities or at least have a common reference point for differences.

The report provides an overview of updates to current costs in Section 2. This section draws significantly on updates to current costs provided in GHD (2026) and further information can be found in their report. The global scenario narratives are outlined in Section 3. Capital cost projection results are reported in Section 4 and LCOE and SLCOE results in Section 5. CSIRO's cost projection methodology is discussed in Appendix A including key global data assumptions. Appendix B provides data tables and this data can also be downloaded from CSIRO's Data Access Portal[1]. A set of technology selection and data quality principles has been included in Appendix E. Feedback on these principles is always welcome.

1.1 Scope of the GenCost project and reporting

The GenCost project is a joint initiative of the CSIRO and AEMO to provide an annual process for updating electricity generation, storage and hydrogen technology cost data for Australia. The project is committed to a high degree of stakeholder engagement as a means of supporting the quality and relevancy of outputs. Each year a consultation draft is released in December for feedback before the final report is completed towards the end of the financial year.

The project is flexible about including new technologies of interest or, in some cases, not updating information about some technologies where there is no reason to expect any change, or if their applicability is limited. Appendix E discusses some technology inclusion principles. GenCost does not seek to describe the set of electricity generation and storage technologies included in detail. The report provided by GHD (2026) does include more detailed technology specifications and commentary.

1.1.1 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own resources. AEMO commissioned GHD to provide an update of the current cost and performance characteristics of electricity generation, storage and hydrogen technologies (GHD, 2025). This report focusses on

[1] Search GenCost at https://data.csiro.au/collections

capital costs, but the GHD report provides a wider variety of data such as operating and maintenance costs and energy efficiency. Some of these other data types are used in levelised cost of electricity calculations in Section 5.

Project management, capital cost projections (presented in Section 4), LCOE estimates (Section 5) and development of this report are primarily the responsibility of CSIRO.

1.1.2 Incremental improvement and focus areas

There are many assumptions, scope and methodological considerations underlying electricity generation and storage technology cost data. In any given year, we are readily able to change assumptions in response to stakeholder input. However, the scope and methods may take more time to change, and input of this nature may only be addressed incrementally over several years, depending on the priority.

In this report, the main innovation is an update of the method for calculating technology integration costs. The method used up until now was designed in 2018 and its revision and new results are discussed in Section 5. The new method accounts for feedback we received about the previous method and the development of the new method has been separately published in Graham et al. (2025).

1.2 The GenCost mailing list

The GenCost project would not be possible without the input of stakeholders. No single person or organisation can follow the evolution of all technologies in detail. We rely on the collective deep expertise of the energy community to review our work before publication to improve its quality. To that end the project maintains a mailing list to share draft outputs with interested parties. The mailing list is open to all. To join, use the contact details on the back of this report to request your inclusion. Some draft GenCost outputs are also circulated via AEMO’s Forecasting Reference Group mailing list which is also open to join via their website.

1.3 Summary of feedback received and changes to the consultation draft

1.3.1 Technology specific items

Solar thermal

A new report on the economics of Australian solar thermal by Fichtner (2026) became available after the release of the consultation draft. Consequently, several of the cost and performance factors for solar thermal have been updated to be consistent with this new information.

Pumped hydro energy storage (PHES)

PHES current capital costs have increased relative to the draft report in recognition of additional data becoming available regarding the costs of a current PHES development. The current development provides evidence of higher costs and has been incorporated into the new estimates by GHD (2026).

Offshore wind

The economic life of offshore wind has been increased from 25 to 30 years to be consistent with international approaches. In the LCOE calculations, the maximum capacity factor for off-shore wind in 2050 has been reduced from 61% to 55%. This change makes the capacity factor assumption more consistent with fixed off-shore wind projects. Higher capacity factors could be achieved with floating offshore wind but that technology is not currently included in the LCOE analysis. These changes do not impact the SLCOE analysis which directly uses renewable production profiles for each relevant NEM renewable energy zone (rather than simple average capacity factors) and includes both fixed and floating offshore wind options.

Nuclear

Current capital costs for nuclear SMR continue to be based on the Darlington project in Canada. The Australian interpretation of this capital cost data has been revised downwards to recognise that the published cost for that project includes interest during construction. Capital costs in GenCost do not include that factor but rather are expressed as an 'overnight' costs. For all technologies, interest during construction is added back in when converting capital costs to levelised costs of electricity (LCOE).

In the system levelised cost of electricity analysis, the 2050 least cost generation mix is calculated on the basis of an average emissions intensity level consistent with the electricity sector cost-effectively contributing to a national net zero target. Nuclear generation was a assigned a zero emission intensity in the draft report. However, it now has a small positive emissions intensity associated with its scope 3 emissions associated with nuclear fuel processing, extraction and transport. This change was to be consistent with coal and gas whose emissions factors also include these scope 3 emissions associated with fuel supply.

Electrolysis

There continue to be diverse views on the current capital cost of electrolysis projects. These arise mainly from differences in emphasis on available project examples and different definitions of project boundaries. The approach in the GHD (2026) report remains unchanged and includes detail on project boundaries applied.

This final GenCost report updated to the 2025 IEA *World Energy Outlook*. This included a significant reduction in long term hydrogen demand under the *Global NZE post 2050* scenario compared to 2024. There was a smaller decrease in hydrogen demand under the *Current Policies* and *Global NZE by 2050* scenarios. Constraints were also placed on the maximum build out of electrolysers in Australia based on market constraints and are consistent with AEMO scenarios. Given costs are reduced through deployment, a direct consequence of lower hydrogen demand is that electrolyser cost reductions are more limited in the updated projection.

Solar PV

Differences in solar PV learning rates between scenarios which are used to project future changes in capital costs have been simplified for greater consistency.

1.3.2 General items

Consistency of approach to land and development costs

There was a request for consistency to be applied across some technologies in the approach to calculating the land and development costs in current capital costs. This request was not supported on the basis that there are important differences between technologies that warrant a technology specific approach.

Treatment of historical investments in 2030 SLCOE

The primary goal of providing LCOE information is so that anyone can quickly compare the cost of different technologies. As many have noted, this approach is not directly possible with renewable generation technologies because they require a portfolio of technologies to provide reliable power. Hence, for renewables GenCost calculates the cost of a full system dominated by renewable energy but including additional costs such as transmission, storage and peaking generation. With this approach the average cost of such a new system can be compared to the cost of new builds of technologies such as gas, coal and nuclear. This information tells us two useful things:

- - Whether renewables can compete with other new technologies and vice versa
- - The likely cost of electricity generation for renewable dominated systems in the future

This system costing approach is well-accepted when examining a far-off year such as 2050 when we can assume most existing capacity has retired and is therefore not included as either a resource or a cost. However, many stakeholders remain uncomfortable in using this approach for near term analysis such as calculating 2030 system costs. The issue that arises is what should be done with costing existing capacity? There will be existing capacity in the system which cannot be ignored. Some of the cost of existing capacity has already been recovered, some will be recovered in the future (particularly transmission costs which are recovered through regulatory arrangements) and some costs may either never be recovered or could be more than recovered (i.e. producing profits above planned rates of return) depending on future market conditions and individual contracting and hedging arrangements.

In the 2025-26 consultation draft, GenCost assigned no cost to existing or under construction capacity in 2030 which is a fairly typical approach in economic modelling. However, despite this deliberate omission, the 2030 cost of generation projected by the system cost modelling, if applied as the average generation price, would likely allow for reasonable recovery of past generation investment costs as well. This is perhaps surprising given no cost was assigned to existing capacity. However, so long as new build costs are not too different from past costs then the cost of new build can be similar to the market price needed for existing market participants to recover their costs.

Whilst our approach to calculating 2030 generation costs is indicative of an electricity price that would allow for both existing and new generation capacity to recover costs, some stakeholders will likely remain uncomfortable with the approach as it does not specifically explore the costs of those recent historical investments. For this reason, we have decided to find an alternative measure of 2030 generation costs.

The new source of generation costs to 2030 is the NEM electricity futures prices (volume weighted across the NEM states excluding Tasmania). Futures prices provide buyers with a hedge against higher prices at the potential cost of not benefiting from lower price outcomes should they occur. For sellers, a futures contract can be used to protect them against lower price outcomes at the cost of not gaining from higher priced outcomes, should they occur. With this context, a supplier is only motivated to contract if the futures contract price already covers all of their costs since they will not receive any additional revenue on the contracted volume. Therefore, the futures price is a good indicator of expected generation costs of suppliers in that future year. The futures price we use to compare to bulk energy technologies is the Baseload price for all hours of a full year and so has the same time scope as the average system price previously calculated through SLCOE modelling. There is also a peak evening futures price that is relevant for peaking technologies.

The change in method for costing the system in 2030 has not led to a significant change in results. For now, the Baseload futures prices is reasonably well aligned with the consultation draft 2030 SLCOE estimate.

SLCOE model

The following improvements and upgrades were made to the Simple Electricity Model:

- All input data has been updated to be consistent with either
  - Draft 2026 ISP Input and Assumptions Workbook, or
  - Draft 2026 Forecasting Assumptions Update Workbook, and
  - This version of GenCost

Data from the Final 2026 ISP could not be included as its release date did not allow enough time for it to be considered for this publication.

- The updated data resulted in two additional weather years being available, however, after testing, 2011 remains the highest cost weather year among those available and so is the year use in the SLCOE modelling.
- Nuclear now has an emissions factor to be consistent with the gas and coal technologies which recognise upstream emissions from fuel supply. As a consequence, the previous *Zero Emission* scenario included in the consultation draft that had a target of $0tCO_2e/MWh$ has been replaced with a scenario called *VeryStrongNetZero* with an emission target of $0.005tCO_2e/MWh$. While not zero, it only allows for about 1 million tonnes of CO_2e in 2050.

Cost year

For greater clarity all costs charts now refer to the calendar year rather than financial year. See the beginning of Appendix B for a longer discussion of the cost year basis.

2 Current technology costs

2.1 Current cost definition

Our definition of current capital costs is current contracting costs or costs that have been demonstrated to have been incurred for projects completed in the current financial year (or within a reasonable period before). We do not include in our definition of current costs, costs that represent quotes for potential projects or project announcements.

While all data is useful in its own context, our approach reflects the objective that the data must be suitable for input into electricity models. The way most electricity models work is that investment costs are incurred either before (depending on construction time assumptions) or in the same year as a project is available to be counted as a new addition to installed capacity[2]. Hence, current costs and costs in any given year must reflect the costs of projects completed or contracted in that year. Quotes received now for projects without a contracted delivery date are only relevant for future years. This point is particularly relevant for technologies with fast-reducing costs. In these cases, lower cost quotes will become known in advance of those costs being reflected in recently completed deployments – such quotes should not be compared with current costs in this report but with future projections.

For technologies that are not frequently being constructed, our approach is to look overseas at the most recent projects constructed. This introduces several issues in terms of different construction standards and engineering labour costs which have been addressed by GHD (2026). GHD (2026) also provide more detail on specific definitions of the scope of cost categories included. GHD cost estimates are provided for Australia in Australian dollars. They represent the capital costs for a location not greater than 200km from the Victorian metropolitan area. GHD provide adjustments for costs for different regions of the NEM. Site conditions will also impact costs to varying degrees, depending on the technology. CSIRO adjusts the data when used in global modelling to take account of differences in costs in different global regions.

GHD (2026) also provides detailed information on the boundary of capital costs such as what development costs are included, ambient temperature, distance to fuel source and many other considerations.

2.1.1 First-of-a-kind cost premiums

When building a technology that has a degree of novelty, capital cost estimates typically underestimate the realised cost of installation. This is sometimes called an optimism factor or first-of-a-kind (FOAK) costs. These costs are reduced with more installations. The industry term for the point when costs are no longer impacted by the immaturity of the development supply chain is

[2] This is not strictly true of all models but is most true of long-term investment models. In other models, investment costs are converted to an annuity (adjusted for different economic lifetimes), or additional capital costs may be added later in a project timeline for replacement of key components.

nth-of-a-kind (NOAK). The cost estimates in GenCost are mostly on a NOAK basis. This is not because all technologies have mature supply chains but rather because it is too difficult to objectively estimate the FOAK premium that should be applied. It is only observable after a proponent fails to deliver the first project for the cost they had planned. Even then it is difficult to separate optimism from ordinary changes in circumstances, particularly for projects that have long total development times. These cost increases will sometimes be found through the process of more detailed engineering and feasibility studies prior to final investment decisions but may not be shared publicly.

EIA (2023) applies FOAK premiums of up to 25% to their technology costs. AACE (1991) recommends applying different levels of contingency based on the Technology Readiness Level ranging from 10% to up to 70%. In practice, we can find examples of projects that have cost around 100% more than planned such as the Vogtle large-scale nuclear plant in the US and the Snowy 2.0 pumped hydro project in Australia. Flyvbjerg and Gardner (2023) report that the global average cost overrun for nuclear, hydro, wind and solar are 120%, 75%, 13% and 1%, respectively. As such, while special circumstances may have occurred in specific cases, generally, FOAK premiums should be part of normal expectations for estimating the cost of deploying less mature or large technology projects in the future.

The technologies most at risk of FOAK cost premiums in Australia are:

- Offshore wind
- Large-scale nuclear
- Small modular reactor (SMR) nuclear
- Solar thermal
- Coal, gas or biomass with carbon capture and storage
- Wave, tidal and ocean current technologies.

Given the size and unique site conditions of most pumped hydro projects they may also continue to be at risk of cost overruns. However, given these projects are relatively rare, in practice there is not as much difference between a FOAK and NOAK costing.

Technologies that are currently being regularly deployed in Australia such as onshore wind, solar PV, batteries and gas generation are least likely to be impacted. Technologies that have been deployed before and are globally commercially mature may still be subject to FOAK premiums due to large intervals since the last deployment leading to loss of skills, new designs which create uncertainty or new licensing requirements, project size and unique site conditions.

It is likely that 2024 nuclear SMR costs included some FOAK costs given it was based on a FOAK in the US project. However, the first commercial project is proceeding in Canada at Darlington and costs are reduced from the 2024 level to match that project's costings which include the assumption that they will build each of the four proposed units at lower cost than the previous unit. Regardless of how successful Canada is in reducing costs for each unit build, Australia would still experience a FOAK premium if that technology were to be built for the first time here.

FOAK premiums are very difficult to forecast. However, given stakeholder interest in the technologies listed above, there is a need for an estimate of the FOAK premium (Table 2-1). To develop the premium the value of 120% has been applied to large scale nuclear based on Flyvbjerg and Gardner (2023). The remaining premiums are based on observing the ratio between this large scale nuclear premium and its construction time and applying that ratio to the other technology's construction times. Effectively we are proposing that technologies that take longer to build will face higher FOAK premiums as they are more complex to plan. We then halve the premium for the second project and assume the third and subsequent projects are not impacted by a FOAK premium.

Table 2-1 Suggested FOAK premium by technology

	Construction time	Premium	
Technology	Years	First project	Second project
Gas with CCS	2.0	42%	21%
Black coal with CCS	2.0	42%	21%
Nuclear SMR	4.4	92%	46%
Nuclear large-scale	5.8	120%	60%
Solar thermal	1.8	37%	18%
Wind offshore	3.0	63%	31%

2.2 Capital cost source

AEMO commissioned GHD (2026) to provide an update of current cost and performance data for existing and selected new electricity generation, storage and hydrogen production technologies. We have used data supplied by GHD (2026) which represents a July estimate and so it is consistent with either the beginning of the financial year 2025-26 or the middle of 2025.

Nuclear technologies are not included in GHD (2026). These are sourced separately by CSIRO.

2.3 Current generation technology capital costs

Figure 2-1 provides capital costs for selected technologies since the project's inception in 2018. All costs are expressed in real 2025-26 Australian dollars, represent overnight costs and do not include any available subsidies.

Costs increased for many technologies from 2022 owing to the global supply chain constraints following the COVID-19 pandemic which also increased freight and raw material costs. Technologies were impacted differently given different input materials and manufacturing regions and are recovering from this development at different rates. The change in current costs over the past four years indicates an easing of inflationary pressures for solar PV, wind and batteries while coal and gas technology costs have recently increased significantly (Figure 2-2). Coal and gas costs are not developed from project data but rather using standard industry software since there are insufficient projects in Australia. In particular, existing coal projects are very old and therefore unreliable for estimating current costs. The latest updates to industry software included a large upwards revision in gas turbine and steam turbine costs.

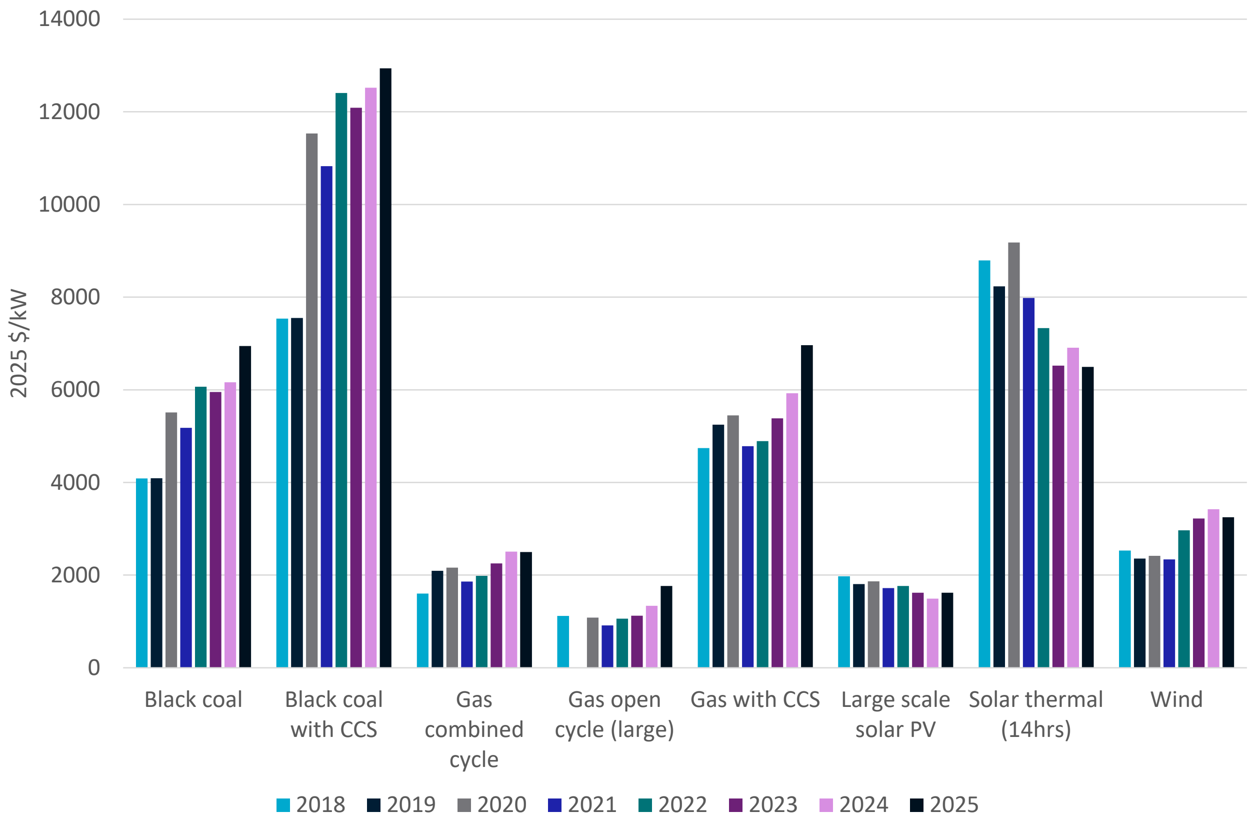


Figure 2-1 Comparison of current capital cost estimates with previous reports (in real terms)

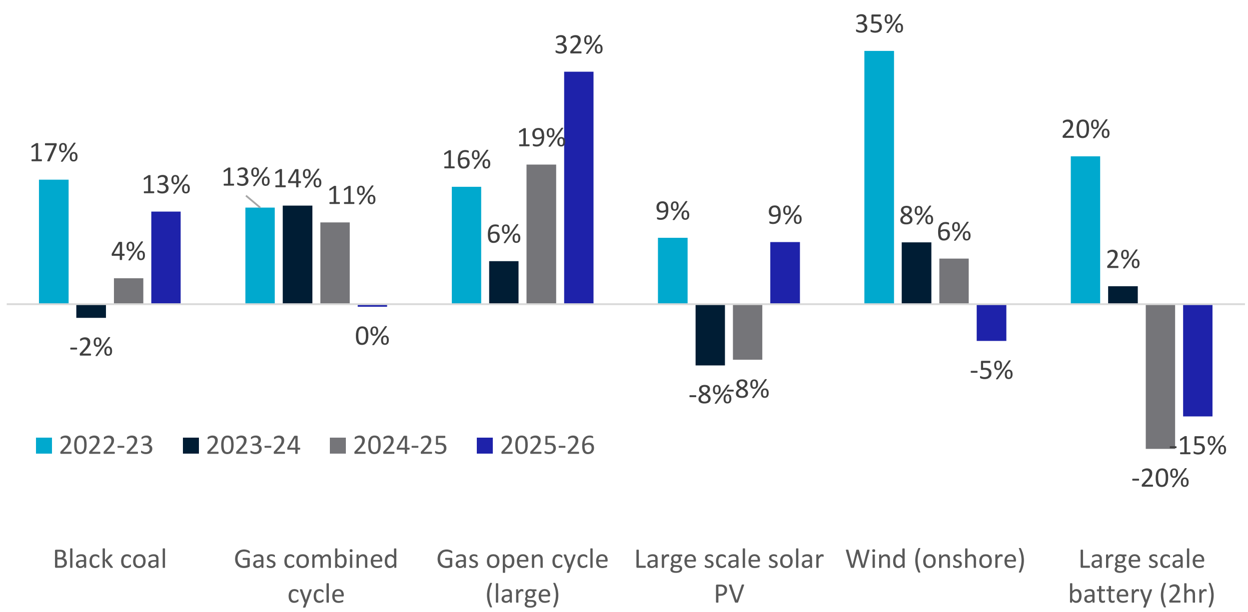


Figure 2-2 Year on year change in current capital costs of selected technologies in the past four years (in real terms)

2.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[3] of batteries and pumped hydro energy storage (PHES) in $/kW and $/kWh. GenCost only provides projections for batteries and PHES. Current costs of compressed air energy storage are included in GHD (2026).

None of these capital costs provide enough information to be able to say one technology is more competitive than the other. Capital costs are only one factor. Additional cost factors include energy input costs (where not already included), utilisation rate, round trip efficiency, operating costs and design life.

Total cost basis means that the costs are calculated by taking the total project costs divided by the capacity in kW or kWh[4]. As the storage duration of a project increases then more batteries or larger reservoirs need to be included in the project, but the power components of the storage technology remain constant. As a result, $/kWh costs tend to fall with increasing storage duration (Figure 2-3).

Note that these $/kWh costs are not for energy delivered but rather a capacity of storage. GenCost does not present levelised costs of storage (LCOS) which are on an energy delivered basis. However, LCOS estimates are available from the CSIRO (2023) *Renewable Energy Storage Roadmap*.

Storage capital costs in $/kW increase as storage duration increases because additional storage duration adds costs without adding any additional power capacity to the project (Figure 2-4). Additional storage duration is most costly for batteries. These trends are one of the reasons why batteries tend to be deployed in low storage duration applications, while PHES is deployed in high duration applications. A combination of durations may be required by the system depending on the operation of other generation in the system, particularly the scale of variable renewable generation and peaking plant (see Section 5).

Depth of discharge in batteries can be an important constraint on use. However, all GHD battery costs are presented on a usable capacity basis such that the depth of discharge is 100%[5]. GHD (2026) also includes estimates of battery costs when they are integrated within an existing power plant and can share some of the power conversion technology. This results in around a 5% lower battery cost for a 1-hour duration battery, scaling down to a 2% cost reduction for 8 hours duration. PHES is more difficult to co-locate.

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[3] The storage duration used throughout this report refers to the maximum duration for which the storage technology can discharge at maximum rated power. However, it is important to note that every storage technology can discharge for longer by doing so at a rate lower than their maximum rated power

[4] Component costs basis is when the power and storage components are separately costed and must be added together to calculate the total project cost.

[5] The batteries in this publication have additional capacity which is not usable (e.g., there is typically a minimum 20% state of charge). This unusable capacity is not counted in the capacity of the battery or in any expression of its costs. When other publications include this unusable capacity the depth of discharge is less than 100%.

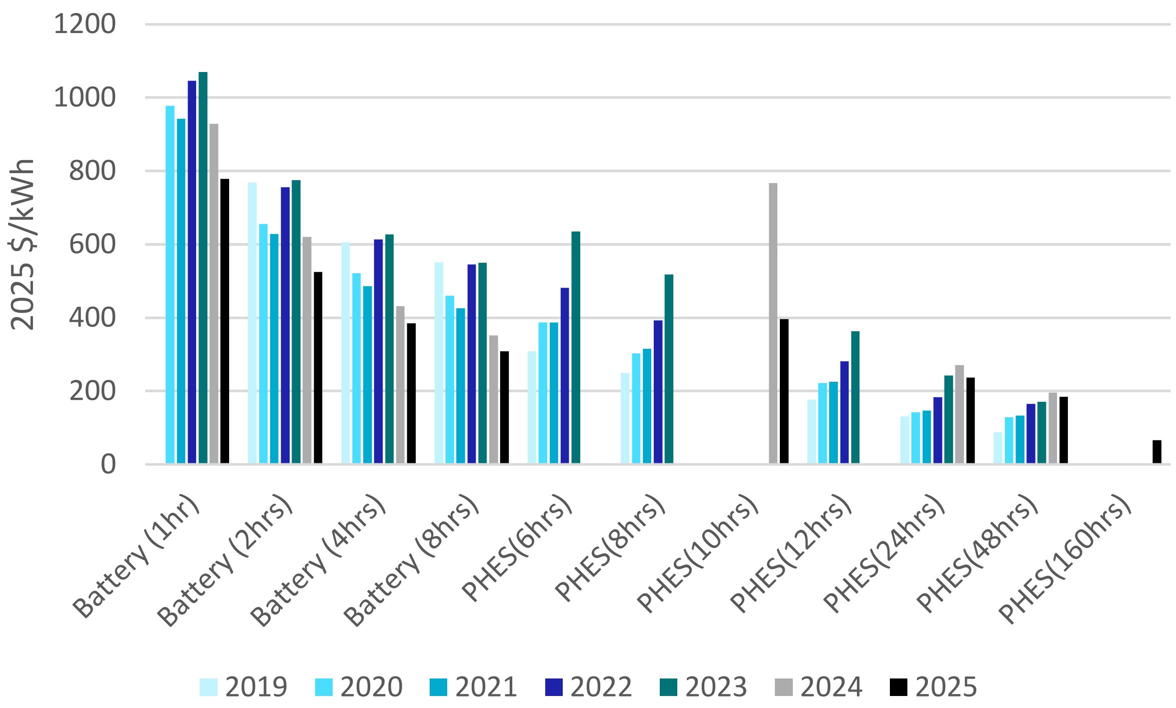

Figure 2-3 Capital costs of storage technologies in $/kWh (total cost basis)

Battery costs (battery and balance of plant in total) have decreased significantly by 11% to 16% depending on the duration.PHES current cost estimates have decreased in 2025. See GHD (2026) for details on how the costs were prepared. It is important to note that PHES has a wider range of uncertainty owing to the greater influence of site-specific issues. Batteries are more modular and as such costs are relatively independent of the site.

Concentrating solar thermal (CST) is another technology incorporating storage but it is reported as a generation technology in Section 5. It incorporates built-in long-duration energy storage. Direct comparison with the other electricity storage technologies is complicated by the fact that a CST system also collects its own solar energy. Direct comparison with other storage technologies via calculation of the LCOS can be found in CSIRO's *Renewable Energy Storage Roadmap* (CSIRO, 2023), but is outside the scope of GenCost.

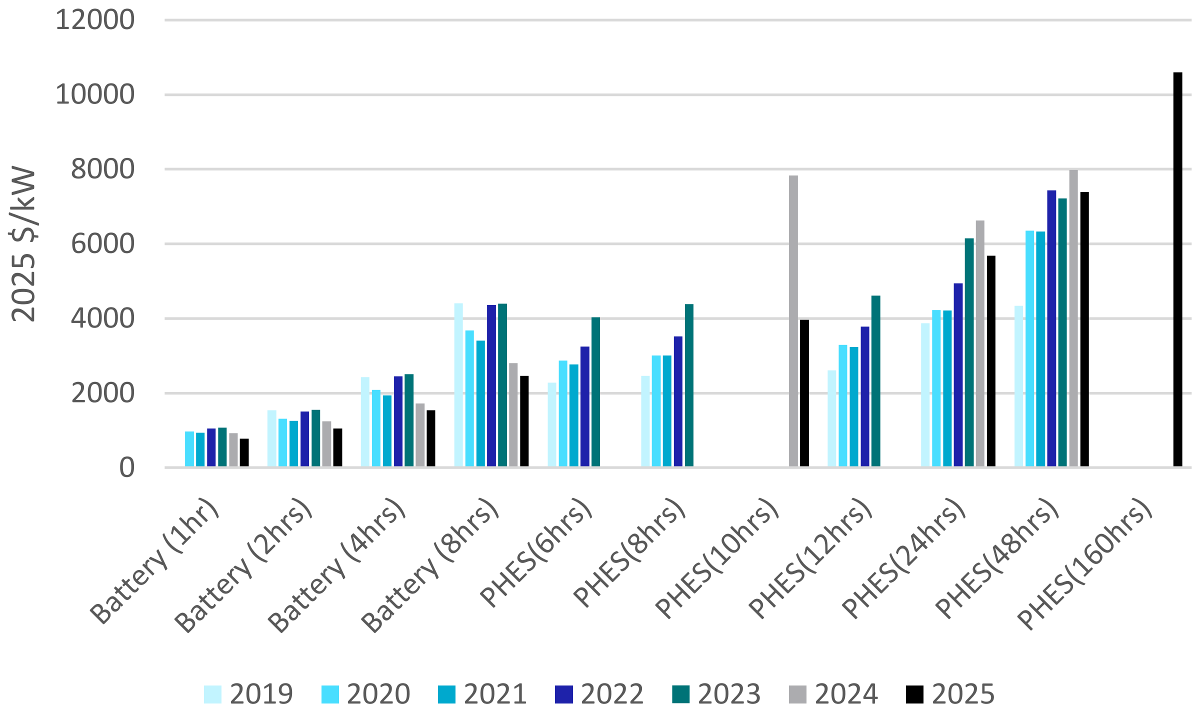

Figure 2-4 Capital costs of storage technologies in $/kW (total cost basis)

3 Scenario narratives and data assumptions

The global scenario narratives for *Current Policies* and *Global NZE by 2050* included in GenCost have not changed since GenCost 2022-23 but there have been some updates to data assumptions. The narrative of *Global NZE post 2050* has changed slightly to reflect changes in the matching IEA scenario.

3.1 Scenario narratives

The global climate policy ambitions for the *Current policies*, *Global NZE post 2050* and *Global NZE by 2050* scenarios have been adopted from the International Energy Agency's (IEA) 2025 *World Energy Outlook* (IEA, 2025) scenario matching to the Current Policies scenario, Stated Policies (STEPS) scenario, and Net Zero Emissions by 2050. Previous versions of the World Energy Outlook included an Announced Pledges Scenario, which was matched to GenCost's *Global NZE post 2050* scenario and the STEPS scenario to GenCost's *Current policies* scenario. The IEA has adjusted its scenario definitions to be less ambitious, except for the Net Zero Emissions by 2050 scenario.

Various elements, such as the degree of vehicle electrification and hydrogen production, are also consistent with the matching IEA scenarios.

3.1.1 Current policies

The *Current policies* scenario includes existing climate policies as at mid-2025 and does not assume that all government targets will be met. The implementation of climate policies in the modelling includes a combination of carbon prices and other climate policies[6]. This scenario has the strongest constraints applied with respect to global variable renewable energy resources and the slowest technology learning rates. This is consistent with a lack of any further progress on emissions abatement beyond recent commitments. Demand growth is moderate with moderate electrification of transport and limited hydrogen production and utilisation. Total greenhouse gas emissions lead to a global average surface temperature rise of around 2 °C in 2050 and 2.9 °C in 2100.

3.1.2 Global NZE post 2050

The *Global NZE post 2050* has moderate renewable energy constraints and middle-of-the-range learning rates. It includes existing policies, a carbon price and policy announcements that are consistent with the broad direction the energy sector is travelling in. It does not assume that

[6] The application of a combination of carbon prices and other non-carbon price policies is consistent with the approach applied by the IEA. While we directly apply the IEAs published carbon prices, we design our own implementation of non-carbon price policies to ensure we match the emissions outcomes in the relevant IEA scenario. Structural differences between GALLM and the IEA's models means that we cannot implement the exact same non-carbon price policies. Even if our models were the same, the IEA's description of non-carbon price policies is insufficiently detailed to apply directly.

governments will meet their Nationally Determined Contributions (NDCs) and longer-term net zero emission targets. Hydrogen trade and transport and industry electrification are similar to *Current policies*. By 2100, the global temperature is projected to rise by 2.5 °C

3.1.3 Global NZE by 2050

Under the *Global NZE by 2050* scenario there is a strong climate policy consistent with achieving net zero emissions by 2050 worldwide. The achievement of these abatement outcomes is supported by the strongest technology learning rates and the least constrained (physically and socially) access to variable renewable energy resources. Reflecting the low emission intensity of the predominantly renewable electricity supply, there is an emphasis on high electrification across sectors such as transport, hydrogen-based industries and buildings leading to the highest electricity demand across the scenarios. This scenario reflects the fact that exceeding 1.5 °C is now inevitable. However, by targeting net zero by 2050 and with further actions beyond 2050, the global average temperature increase falls back below 1.5 °C by 2100.

Table 3-1 Summary of scenarios and their key assumptions

Key drivers	Current policies	Global NZE post 2050	Global NZE by 2050
IEA WEO scenario alignment	Current policies scenario	Stated policies scenario	Net zero emission by 2050
CO_2 pricing / climate policy	Based on current policies only	Based on current policies and policies consistent with the direction of travel of the energy sector	Consistent with 1.5 degrees world in 2100.
Renewable energy targets and forced builds / accelerated retirement	Current renewable energy policies	Renewable energy policies extended as needed	High reflecting confidence in renewable energy
Demand / Electrification	Medium	Medium	High
Learning rates[1]	Weaker	Normal maturity path	Stronger
Renewable resource & other renewable constraints[2]	More constrained than existing assumptions	Existing constraint assumptions	Less constrained

1 The learning rate is the potential change in costs for each doubling of cumulative deployment, not the rate of change in costs over time. See Appendix C for assumed learning rates.
2 Existing large-scale and rooftop solar PV renewable generation constraints are as shown in Apx Table C.4.

4 Projection results

All projections start from a current cost observed in 2025. The primary source of 2025 costs is GHD (2026) with data gathered from other sources where otherwise not available in that report. All projections are in real terms. That is, all projected cost changes after 2025 are in addition to the general level of inflation.

4.1 Short-term and long-term inflationary pressures

4.1.1 Short term equipment costs

In recent years, the cost of a range of technologies including electricity generation, storage and hydrogen technologies has increased rapidly driven by two key factors: increased freight and raw materials costs. The most recent period where similar large electricity generation technology cost increases occurred was 2006 to 2009 with wind turbines and solar PV modules being most impacted. The cost drivers at that period of time were policies favouring renewable energy in Europe, which led to a large increase in demand for wind and solar. This coincided with a lack of supply due to insufficient manufacturing facilities of equipment and polysilicon in the case of PV and profiteering by wind turbine manufacturers (Hayward and Graham, 2011). Once supply caught up with demand, the costs returned to a trajectory consistent with learning-by-doing and economies of scale.

CSIRO has explored a number of resources to understand cost increases already embedded in technology costs and to project how this recent increase in costs will resolve. We normally use our model GALLM to project all costs from the current year onwards. While GALLM takes into account price bubbles caused by excessive demand for a technology (as happened in 2006-2009), the drivers of the current situation are different and thus we have decided to take a different approach, at least for projecting costs over the next decade. It is not appropriate to project long-term future costs directly from the top of a price bubble, otherwise all future costs will permanently embed what may be temporary market features.

It is acknowledged that some stakeholders believe the price bubble is not temporary but rather a permanent feature of future costs. However, to sustain real price increases, supply needs to be either constrained by a cartel (or other persistent market power) or resource scarcity or technology demand needs to grow faster than supply (which implies strong non-linear demand growth since, once established, a given supply capacity can meet linear growth at the rate of that existing capacity[7]). The current cost update indicates inflationary pressures are weakening for at least some technologies.

[7] If the world ramps up to X GW per year technology manufacturing capacity by a certain date, then, without expanding manufacturing capacity any further, it can meet any future capacity target after that date up to the value of bX (where b is the years since the manufacturing capacity was established). The future capacity target would need to include all capacity needed to meet growth as well as replace retiring plant.

Historical experience and the projections available for global clean energy technology deployment do not provide confidence that the required market circumstances for sustained real price increases will prevail for the entire projection period (see Appendix D of the *GenCost 2022-23: Final report* for more discussion on this topic). However, it is considered that the period to 2030 will likely experience extra strong technology deployment. This is partly because of the low global clean technology base (from which non-linear growth is more feasible) but also because governments and industry often use the turning of a decade as a target date for achieving energy targets.

Our current view is that it may take longer than 2030 for technologies to return to a more normal level of costs. This report assumes that if a technology has not already started to show strong signs of recovery it will not return to their normal cost path until 2035. This includes technologies such as onshore wind, coal, gas and nuclear. Note that to achieve a recovery in technology costs they need only stay constant in nominal prices. This delivers real cost reduction of around 2-3% per year.

A consequence of this modelling approach is that the near-term cost reductions that are shown in the following pages mostly do not reflect learning. Rather, they are predominantly the slow unwinding of inflationary pressures that have temporarily placed costs above the underlying cost curve. Solar PV, batteries, fuel cells and offshore wind have already passed through the global inflationary event and their costs now follow the underlying learning curve cost trajectory.

Response to the 2026 Iran war

The Iran war began on 28 February 2026 constricting global oil products supply. The depth and direction of the broader impacts for energy technologies is unpredictable. It is inflationary in the sense of oil being a fundamental input to almost all global supply chains. It may also increase demand for energy technologies in general that reduce a region’s reliance on imported oil. It is also deflationary because it could reduce global economic growth and demand for energy. In light of this development, for 2026, we have assumed no improvement in costs for the majority of technologies. Solar PV and batteries are excluded as they have previously demonstrated greater resilience against global inflationary pressures.

Data centre impacts on gas turbine costs

New electricity generation capacity required to meet demand from data centres is growing strongly and is impacting gas turbine costs. The IEA (2026) reported that:

“if data centres were a country, they would be the second-largest destination for gas turbines ordered from Q1 2025 to Q1 2026”.

Gas turbine costs have already increased for the last four consecutive years. As a result of this ongoing demand from data centres, the projections assume that the cost of gas turbine technologies will continue to increase in the next two years after which manufacturers are expected to be in a better position to meet demand, allowing costs to stabilise.

4.1.2 Long term land and construction costs

Two exceptions where scarcity is a factor and is expected to lead to ongoing real increases in costs is land and construction costs. Land costs generally make up 2% to 9% of generation, storage and electrolyser capital costs. The projections take the land share of capital costs provided in GHD (2026) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[8]. This common land cost index provides some consistency between the treatment of land costs between transmission, generation and storage assets in AEMO's modelling. The inclusion of a specific land cost inflator was first included in the *GenCost 2022-23: Final report*.

Information on future real construction costs become available in a February 2025 report from Oxford Economics Australia (2025), commissioned by AEMO. The data indicates that while construction costs are expected to ease in the short term, a longer-term trend of rising real construction costs is projected owing primarily to above inflation growth in construction workers' wages and, to a lesser extent, constrained supply of quarry and cement materials. The construction cost escalation factors estimated by Oxford Economics Australia are applied to the installation cost proportion of capital costs which is sourced from GHD (2026). Note that, this escalation factor is applied after learning. That is, it is still possible for developers to be more productive or innovative at installing some technologies while at the same time facing increases in real costs for some installation components (such as labour). Consequently, mature technologies, which have limited prospect of installation cost reductions, are the most impacted by this new escalation factor (e.g., gas and coal technologies).

4.2 Global generation mix

The rate of global technology deployment is the key driver for the rate of reduction in technology costs for all non-mature technologies. However, the generation mix is determined by technology costs. Recognising this, the projection modelling approach simultaneously determines the global generation mix and the capital costs. The projected generation mix consistent with the capital cost projections described in the next section is shown in Figure 4-1.

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[8] It is referred to as an easement cost index in that document.

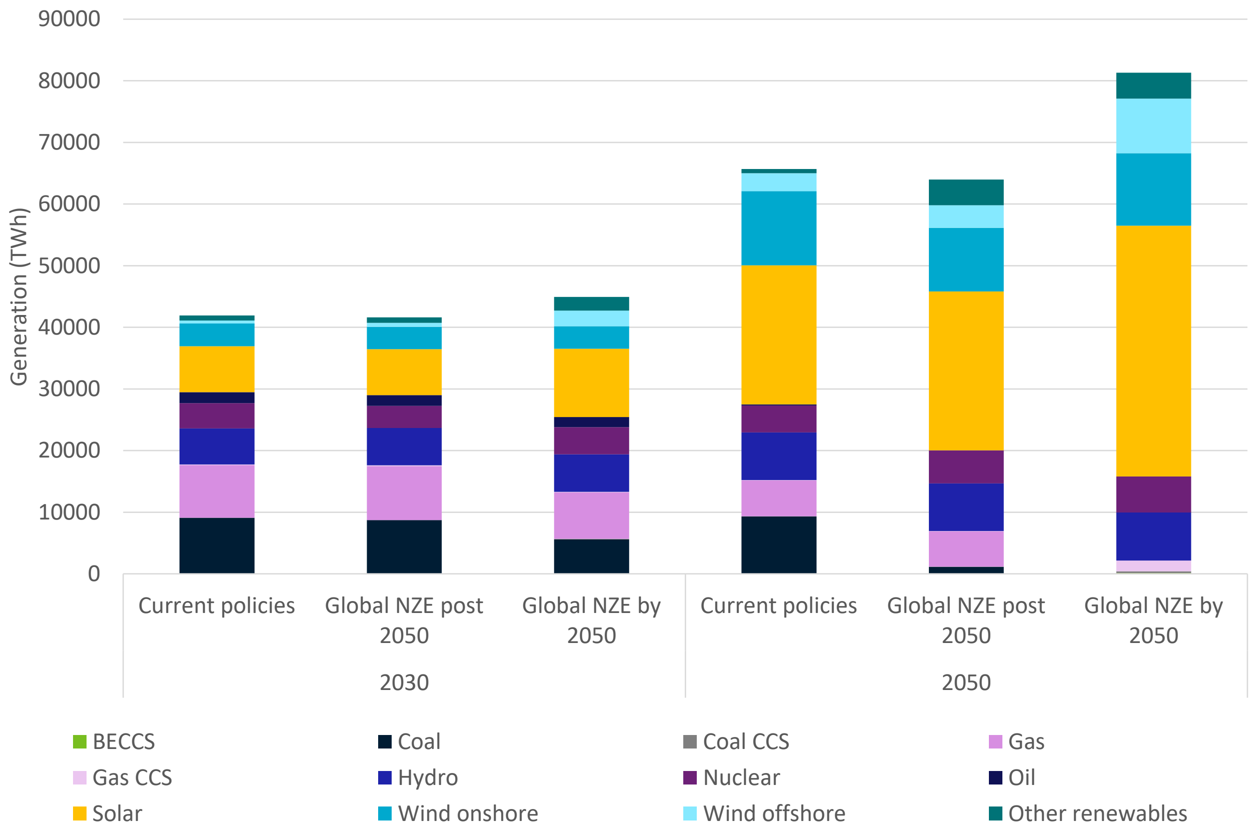

Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Current policies and *Global NZE post 2050* have the lowest electrification because they are a slower decarbonisation pathway. However, they have the least energy efficiency and industry transformation which supports electricity demand growth[9]. *Global NZE by 2050* has high vehicle electrification and high electrification of other industries including hydrogen. However, it also has high energy efficiency and industry transformation which partially offsets these sources of new electricity demand growth. *Current policies* and *Global NZE post 2050* have similar demand in both 2030 and 2050 indicating these opposing drivers are somewhat in balance in those scenarios over time with a slight dip in 2050 for *Global NZE post 2050* due to stronger energy efficiency improvements. However, *Global NZE by 2050* has the highest electricity demand in both 2030 and 2050 indicating electrification is the stronger driver throughout the projection period.

Figure 4-2 shows the contribution of each hydrogen production technology in each scenario indicating the *Global NZE by 2050* scenario is assumed to experience a significant growth in electrolysis hydrogen production and modest growth in the other two scenarios. Note that the IEA's 2025 estimates of hydrogen demand which are used to guide GenCost global assumptions, have decreased relative to previous outlooks across all scenarios, but most notably in the *Global NZE post 2050* scenario.

[9] Economies can reduce their emissions by reducing the activity of emission intensive sectors and increasing the activity of low emission sectors. This is not the same as improving the energy efficiency of an emissions intensive sector. Industry transformation can also be driven by changes in consumer preferences away from emissions intensive products.

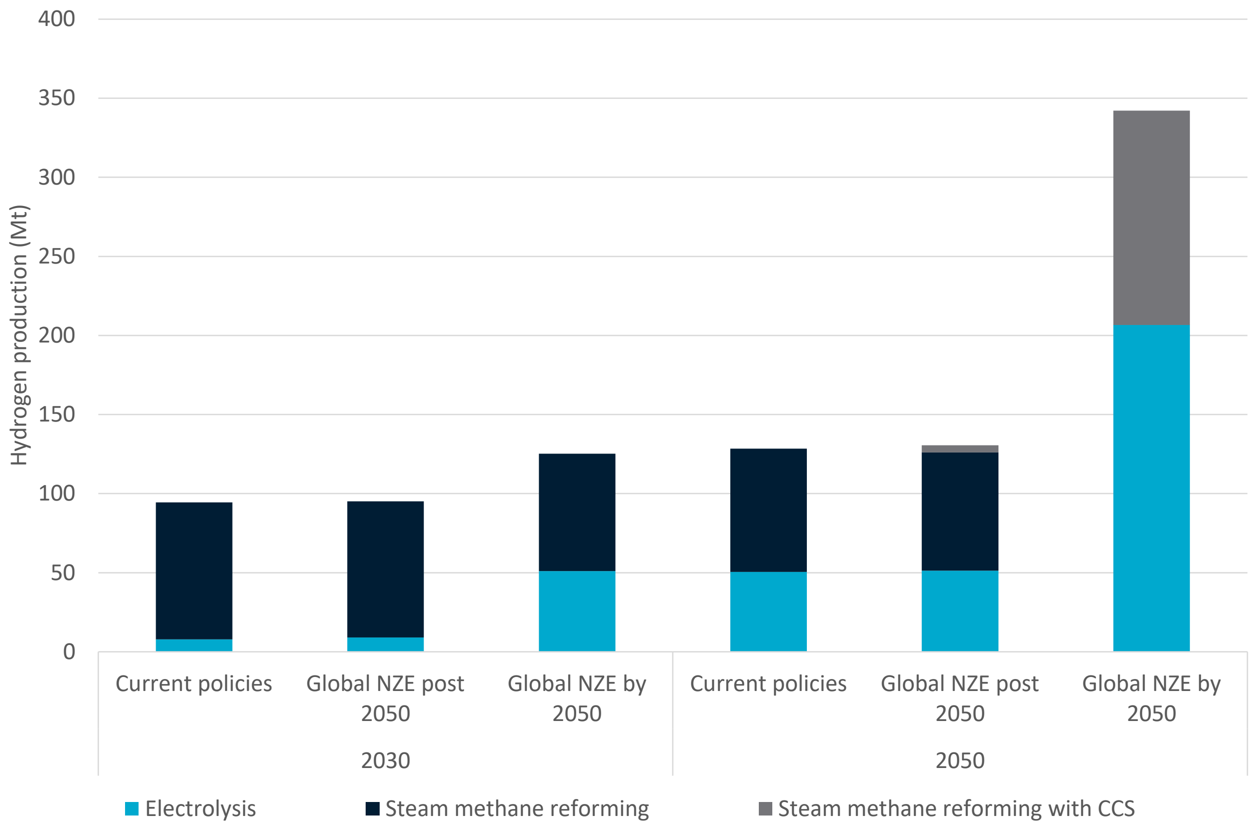

Figure 4-2 Global hydrogen production by technology and scenario, Mt

Current policies and *Global NZE post 2050* have the lowest non-hydro renewable share but still relatively high at 58 and 69% of generation respectively by 2050 compared to 81% in *Global NZE by 2050*. Growth in hydro generation is constrained by land use competition and coal by emissions constraints. Consequently, gas with and without CCS and nuclear make up most of the remaining new generation by 2050. Gas with CCS is preferred to coal with CCS given the relatively lower capital cost and lower emissions intensity of that technology. Nuclear is around 9% of generation in 2030 and is steady or, in the worst case, declining to 6.7% generation share by 2050 reflecting its relatively slower development and installation rate while electrification causes global demand to grow rapidly in the next three decades.

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. All generation from fossil fuel sources is with CCS accounting for 2% of generation by 2050. Offshore wind features strongly in this scenario at 11% of generation by 2050. Renewables other than hydro, biomass, wind and solar are 5% of generation in 2050. The greater deployment of renewables and CCS in this scenario leads to lower renewable and CCS costs. CCS costs are also impacted by the use of CCS in hydrogen production and other industries.

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2055 compared to the 2024-25 projections. For mature technologies, differences mainly reflect any changes in current costs, an assumed return to normal costs by 2035 and land and construction costs increases thereafter.

Less mature technologies include learning components in addition to the land and construction cost escalators. For technologies with high learning potential, the cost reduction from learning more than offsets the escalation factors for most of the projection period. For those with lower learning potential, the cost changes may cancel one another out or the escalation factors may dominate the trend.

Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[10].

4.3.1 Black coal ultra-supercritical

The updated cost of black coal ultra-supercritical plant in 2025 has been sourced from GHD (2026). This included a substantial increase based on updates to standard software used to model coal generation capital costs. From 2025, the capital cost is assumed to be constant in real terms in 2026 (increasing in nominal terms) and return to levels consistent with ultra-supercritical prior to the COVID-19 pandemic by 2035 adjusted for changes in construction costs. Black coal ultra-supercritical is treated in the projections as a learning technology. However, global new building of ultra-supercritical coal is limited due to climate change policies and consequently the cost reduction achieved from deployment via the learning rate is low.

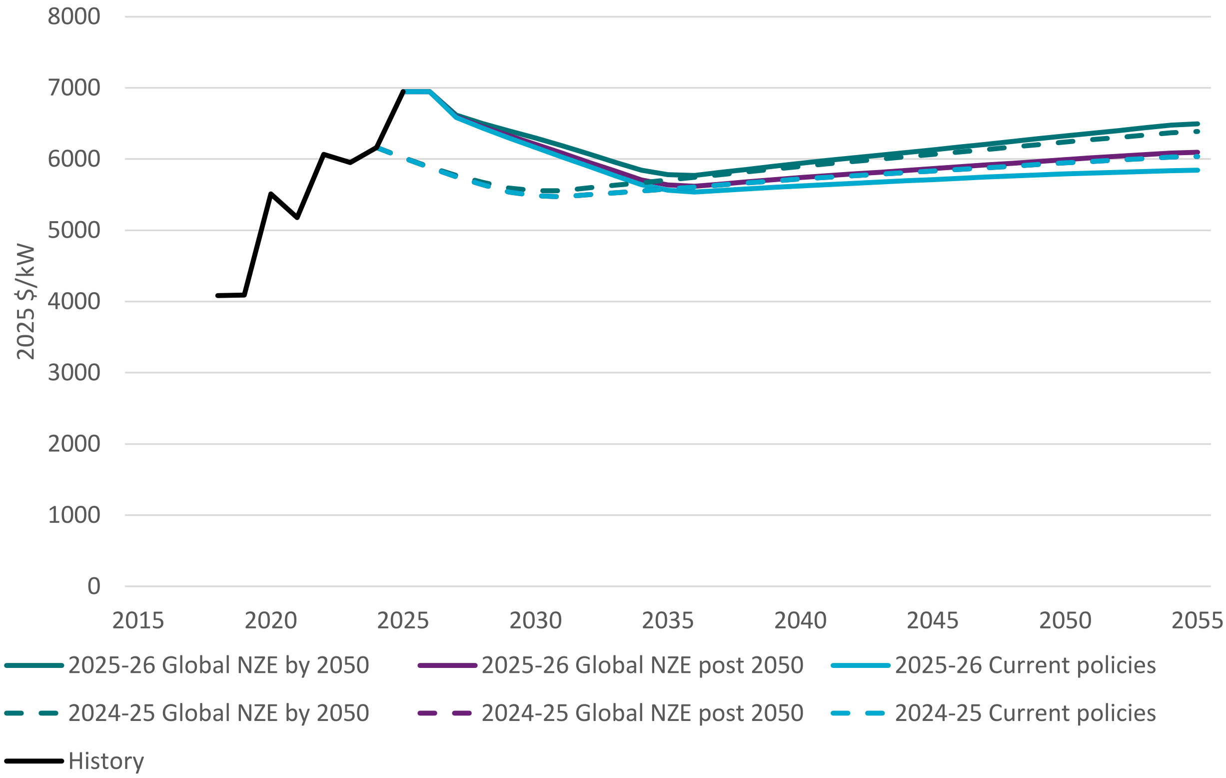

Figure 4-3 Projected capital costs for black coal ultra-supercritical by scenario compared to 2024-25 projections

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[10] Search GenCost at https://data.csiro.au/collections

The outlook for costs in all scenarios is increasing due to increasing land and installation costs. Installation costs are rising faster the stronger the climate policy ambition of the scenario reflecting a stronger rate of electricity sector construction activity.

4.3.2 Coal with CCS

The capital cost of black coal with CCS from 2025 to 2035 has been updated according to the approach outlined in the beginning of this section. Thereafter, the capital cost of the mature parts of the plant reflects assumed land and installation cost increases. For the CCS components, in addition to these changes in land and installation costs, changes in equipment costs are a function of global deployment of gas and coal with CCS, steam methane reforming with CCS and other industry applications of CCS. Compared to the 2024-25 projections, global CCS deployment has not significantly changed.

Current policies has no uptake of steam methane reforming with CCS in hydrogen production. Consequently, any equipment cost reductions from the late 2030s are mainly driven by the deployment of CCS in other industries. While black coal with CCS benefits from co-learning from deployment of CCS in non-electricity industries, there is only a negligible amount of generation from black coal with CCS throughout the projection period.

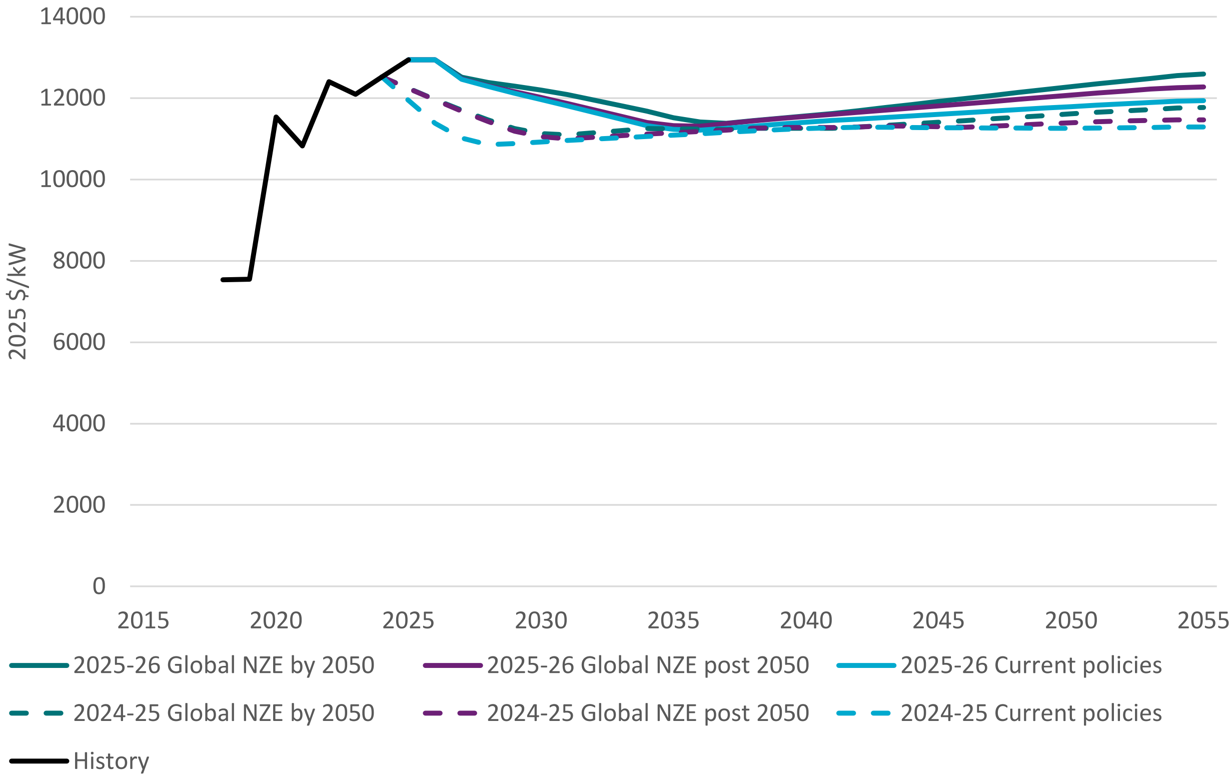


Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2024-25 projections

Global NZE by 2050 and *Global NZE post 2050* take up CCS in hydrogen production and both gas and coal electricity generation (although gas generation with CCS is significantly more preferred and the amount is much lower in *Global NZE post 2050*). The total CCS deployment in electricity generation and hydrogen production is higher in *Global NZE by 2050.* However, CCS deployment in other industries is higher in *Global NZE post 2050*. Subsequently, those scenarios experience a similar amount of equipment cost reduction by 2050 but with stronger local construction cost increases in *Global NZE by 2050*. In *Current policies*, equipment cost reductions are not significant, but installation cost increases are lower than the *Global NZE* scenarios.

A first of a kind premium, in addition to the costs shown, will likely apply when coal with CCS is deployed in Australia for the first time.

4.3.3 Gas combined cycle

GHD (2026) have included negligible real change in gas combined cycle costs for 2025 which is a change compared to real increases the previous two years. In the next two years costs are expected to increase due to the impacts of data centre demand on gas turbine prices and then slowly return to normal by 2035. After the return to normal period, because gas combined cycle is classed as a mature technology for projection purposes, its change in capital cost is governed only by assumed increases in land and installation costs for all scenarios. Consistent with the need for greater construction activity the stronger the climate policy ambition, combined cycle gas costs are highest in *Global NZE by 2050.*

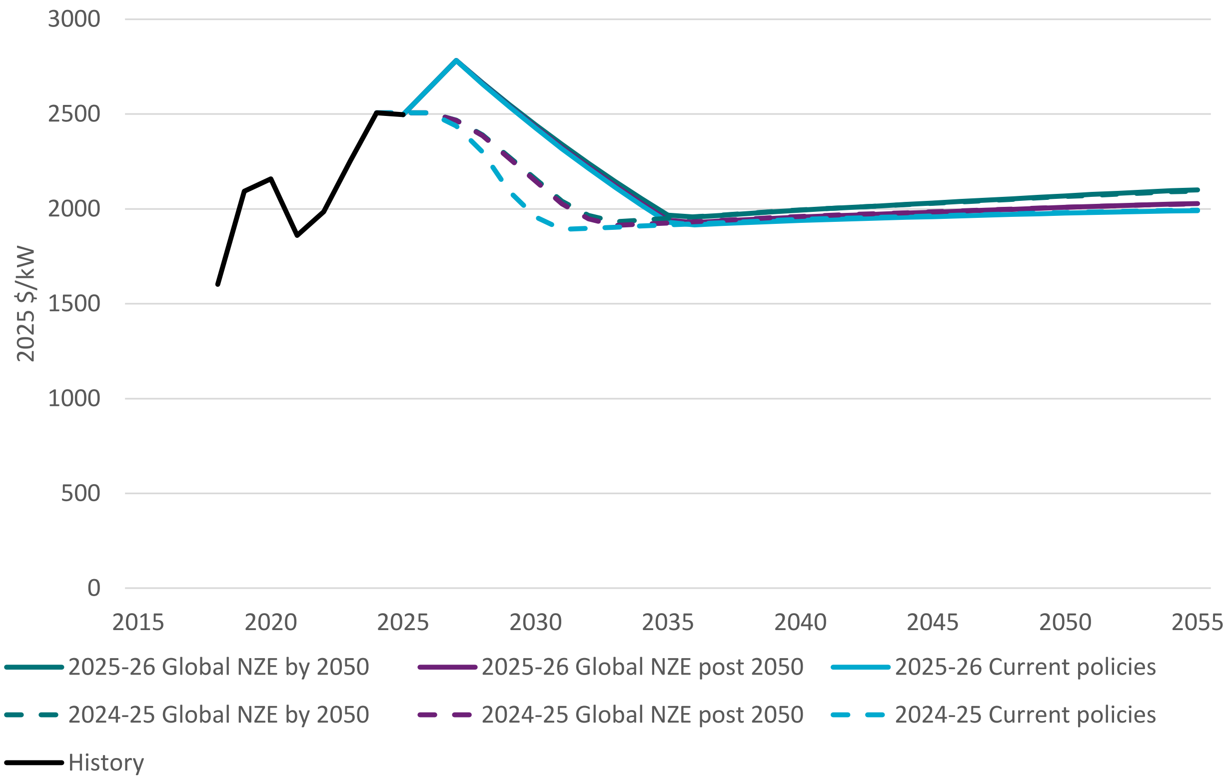


Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2024-25 projections

4.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2025-26 projections and is assumed to increase further in the next two years due to the impact of data centre demand on gas turbine prices. From 2028, costs decline to 2035 based on our return to normal assumptions during this period. The relativities between the scenarios reflect the changes in land and installation costs increases and differences in global deployment in electricity generation, hydrogen production and other industry uses of CCS. *Global NZE by 2050* has the highest total deployment of all CCS technologies. Subsequently, the equipment component of gas with CCS is lower by 2050 in that scenario and this results in total costs being lower from the late 2030s. CCS equipment costs are highest cost where CCS deployment is lowest in *Current policies* and *Global NZE post 2050*. While these two scenarios are assumed to experience lower construction costs increases, they remain highest cost overall by 2050.

The IEA CCS database[11] indicates there are over 100 planned electricity related projects which are yet to make a financial investment decision and around 8 under construction. One is operational. Given the current state of the pipeline of projects, significant global deployment of CCS is not expected until after 2030.

A first of a kind premium, in addition to the costs shown, will likely apply when gas with CCS is deployed in Australia for the first time.

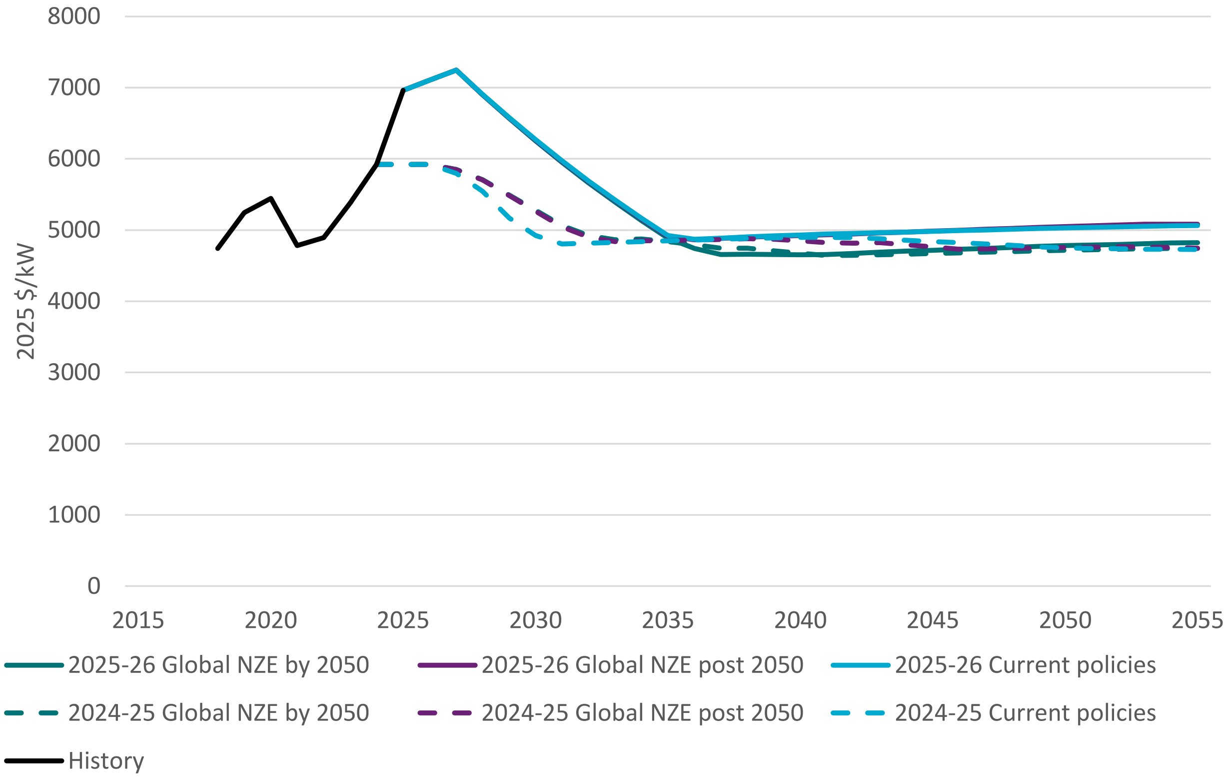


Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2024-25 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2025-26 cost projections for small and large open cycle gas turbines. All new gas turbine projects are expected to include the capability for hydrogen blending and eventual conversion to hydrogen firing when hydrogen supply becomes more readily available and lower cost. This is in addition to the existing ability to use liquid fuels such as diesel or renewable diesel. However, it is possible that some plants will only ever use natural gas during their life. It depends on the market conditions and climate policy during their operation. The small open cycle gas

[11] CCUS Projects Database - Data product - IEA, including only those projects that include storage

technology is designed with a maximum 35% hydrogen blend. The large size is designed for 10%. However, GHD (2026) also provides costs for higher and lower blends at both sizes. This assumption of hydrogen readiness adds a negligible premium to gas open cycle capital costs.

The GHD (2026) report provides additional details for the unit sizes and total plant capacity that defines the small and large sizes. Gas open cycle costs are increasing rapidly due to strong growth in data centre demand outpacing manufacturing supply capability. Costs are expected to increase further in the next two years as manufacturing capacity remains below demand. Costs are not projected to return to normal until 2035. For the remainder of the projection period, there are no improvements in equipment costs because of the maturity of the technology, and so the assumed land and installation cost increases result in a rising trend in costs post-2035. Capital costs are highest under the *Global NZE* scenarios reflecting the higher installation costs associated with the greater construction activity of those scenarios

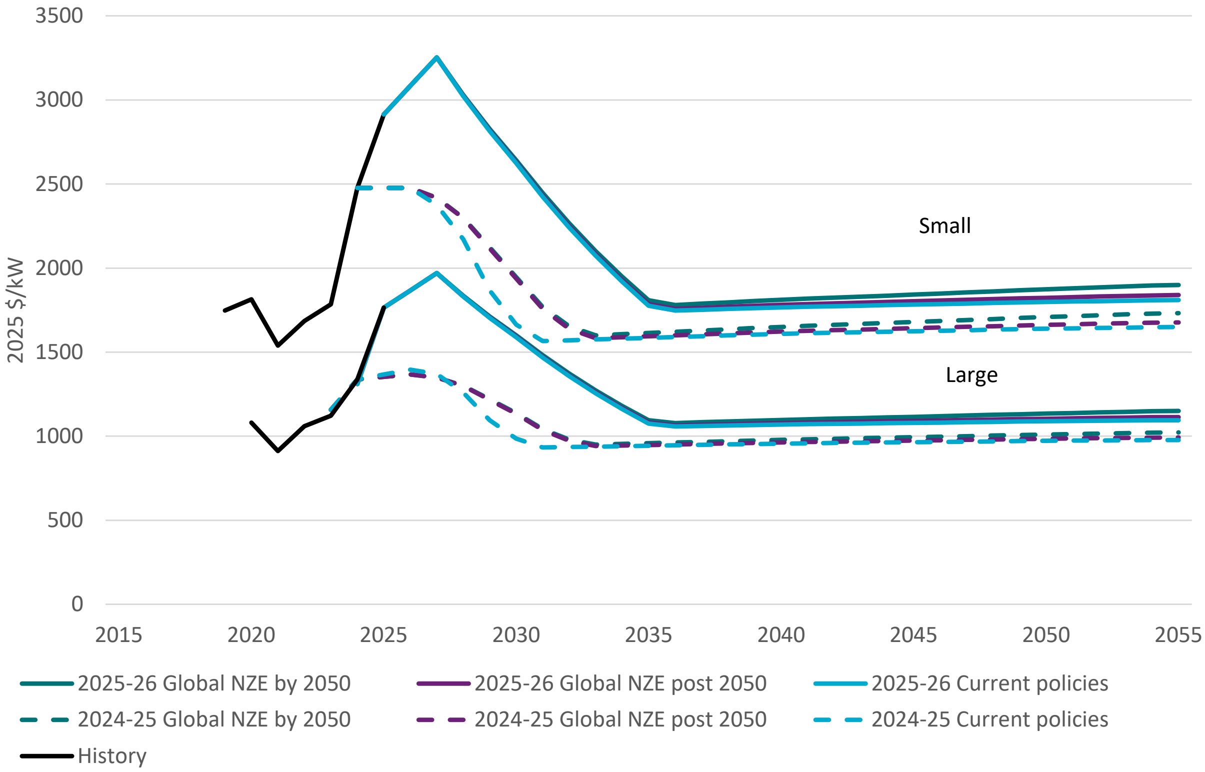


Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2024-25 projections

4.3.6 Nuclear SMR

For the next five years, costs are based on the planned Darlington SMR project in Canada which consists of four 300MW units for a total cost of C$20.9b. Costs are expected to be highest for the first unit but lower for each subsequent unit and this is captured in the cost trajectory. Unlike large-scale nuclear, to convert Darlington nuclear SMR costs to Australian dollars the method only included an exchange rate conversion. That is, no allowance has been made for differences in construction costs between Canada and Australia. The difference in approach is justified based on the high level of commercial immaturity of nuclear SMR outweighing any other uncertainties in the cost estimate. The Darlington project cost conversion also includes removal of interest during construction in the capital cost compared with the 2024-25 projections.

The rate of cost reductions after the Darlington project is calculated as function of deployment of other global nuclear SMR projects, to a greater or lesser degree depending on the global scenario and some known projects. Capital costs only improve in the 2040s for the *Current policies* scenario due to a lack of additional deployment of projects in the 2030s. The *Global NZE* scenarios achieve a greater level of deployment of nuclear SMR in the 2030s owing to a stronger commitment to addressing climate change.

Nuclear SMR equipment cost reductions may be partly driven by modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. Assumed increases in land and installation costs are responsible for increases in Australian nuclear SMR costs in the 2040s and 2050s.

A first of a kind premium, in addition to the costs shown, will likely apply when nuclear SMR is deployed in Australia for the first time.

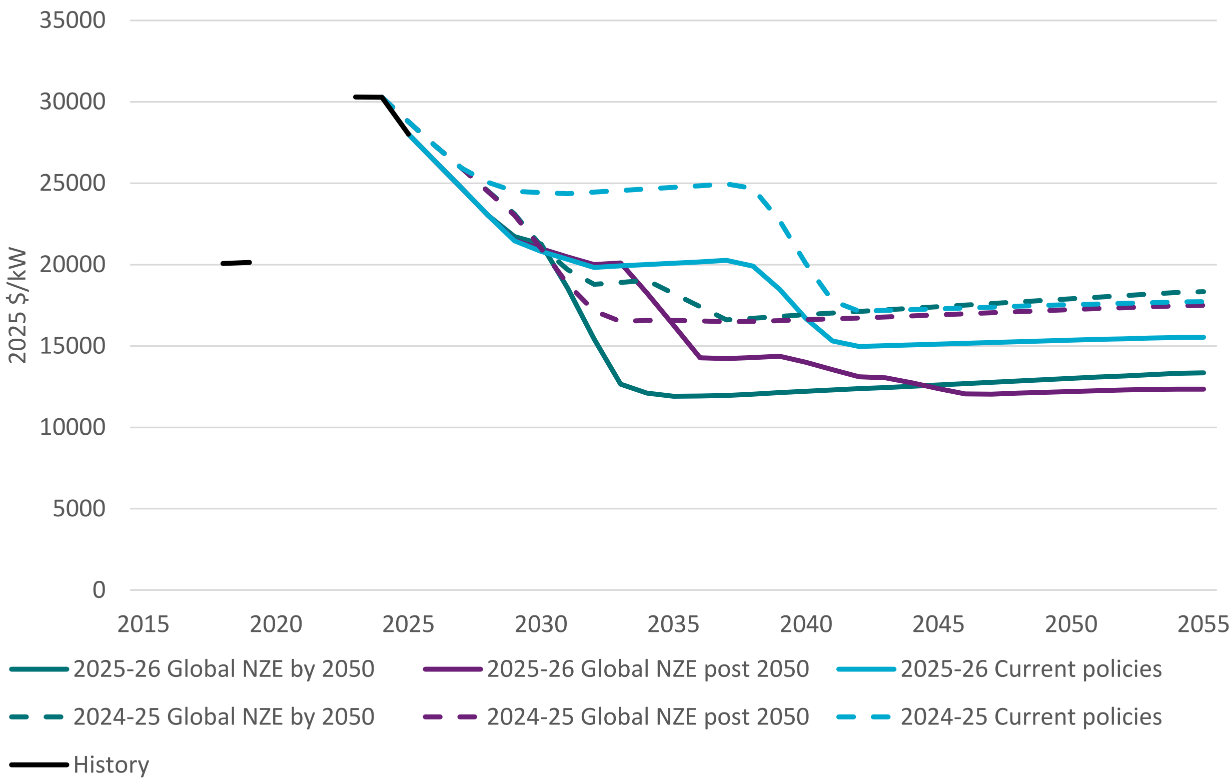


Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2024-25 projections

4.3.7 Large-scale nuclear

Given Australia has no experience building large scale nuclear, we base costs on South Korean nuclear building costs adjusted for the relative costs of building ultra-supercritical coal in each country. Given the cost of building ultra-supercritical coal in Australia has increased, nuclear costs are also revised upwards. From a more direct perspective, given all steam turbine costs have gone up, then nuclear costs are also impacted. However, like other technologies, large-scale nuclear capital costs are assumed to return to their underlying costs by 2035 after constant real costs in 2026 (rising in nominal terms).

Large-scale nuclear is treated as a mature technology and therefore is not assigned any learning rate whereby cost reductions are achieved as a function of deployment. Instead, large-scale nuclear costs increase after 2035 due to the assumed increases in land and installation costs that impact all technologies.

There is some uncertainty in the literature about whether large-scale nuclear is a learning technology or not. There are many new designs for nuclear generation and so it is not a settled technology in the way we might consider steam turbines. Even settled technologies still incrementally change. However, our reluctance to assign a learning rate to large-scale nuclear reflects two issues. First, an assigned learning rate would have little impact because it is difficult for any mature technology to double its global capacity which is the required trigger to receive the benefit of an assigned learning rate (see Appendix A for an explanation of the learning rate function). Second, new designs for large-scale nuclear have not always delivered cost reductions. Therefore, our projection reflects a nuclear industry that mostly consolidates construction around proven designs.

A first of a kind premium, in addition to the costs shown, will likely apply when large-scale nuclear is deployed in Australia for the first time.

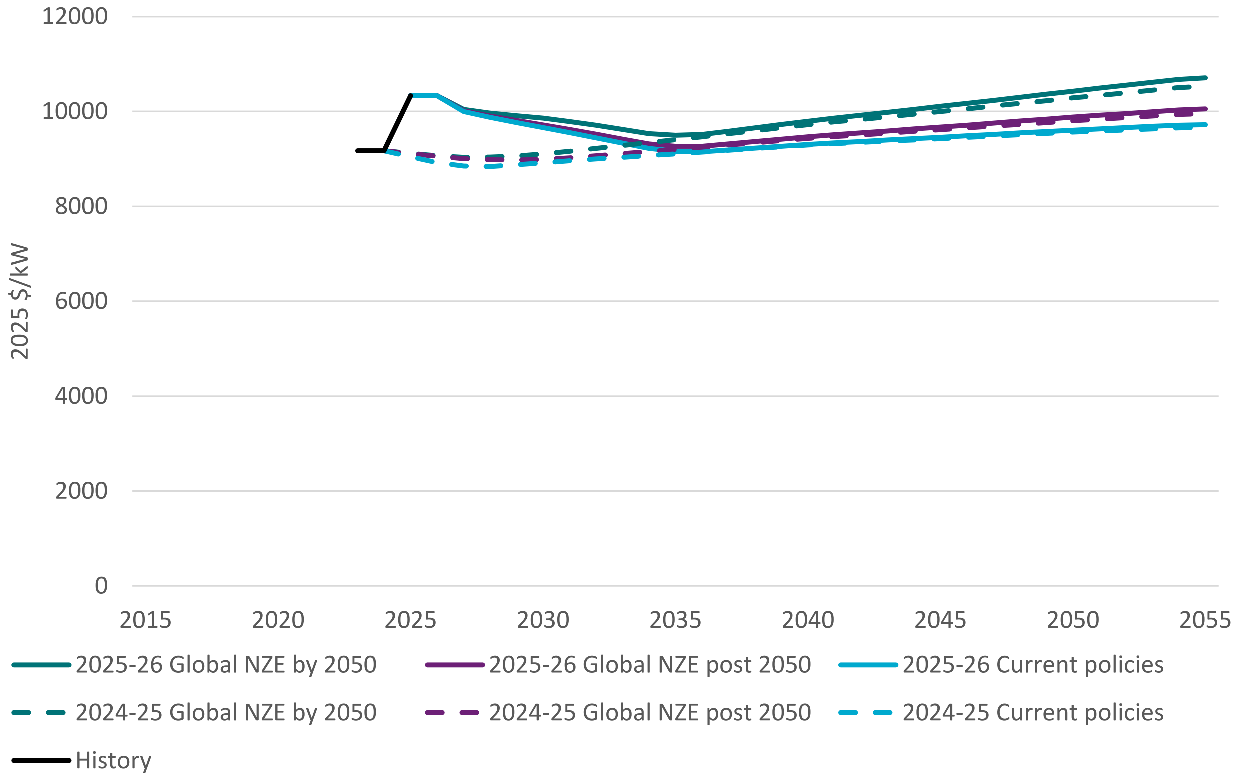


Figure 4-9 Projected capital costs for large-scale nuclear by scenario compared to 2024-25 projections

4.3.8 Solar thermal

The starting cost for solar thermal has decreased in GHD (2026) and this results in lower costs by 2055 relative to 2024-25 in some scenarios. While greater deployment and equipment cost reduction is generally aligned to the stronger abatement scenarios, local construction costs increase with stronger abatement. These higher construction costs are the stronger factor over time for this technology. Consequently, long term costs are higher under the *Global NZE* scenarios and lowest under *Current policies*.

Solar thermal systems consist of the combination of solar mirror field, thermal storage and power blocks that are sized in varying ratios according to the location and market signals that prevail. Each such configuration will have a different capital cost. As a consequence, the baseline configuration represented in the capital cost projection data is not the same as the configurations used to calculate the LCOEs in Section 5.

A first of a kind premium, in addition to the costs shown, will likely apply when solar thermal is deployed in Australia for the first time.

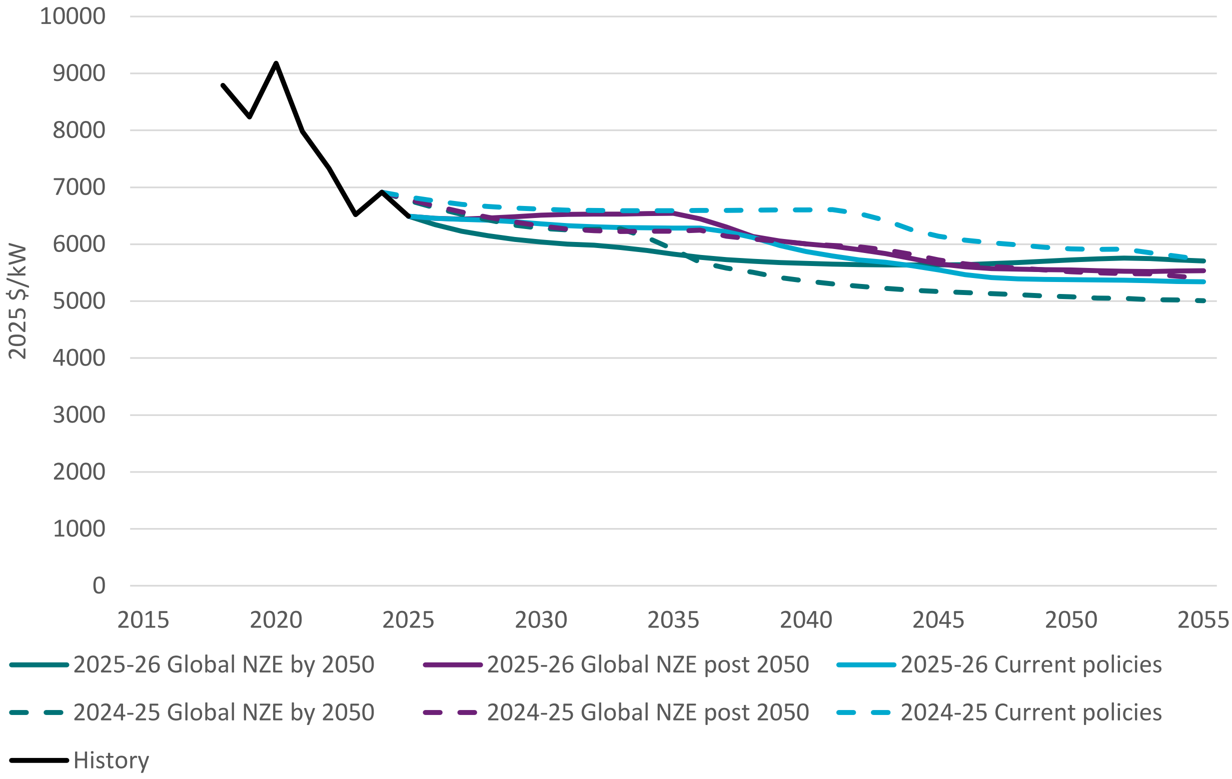


Figure 4-10 Projected capital costs for solar thermal with 14 hours storage compared to 2024-25 projections Historical data includes costs for some 15 and 16 hour project designs

4.3.9 Large-scale solar PV

Large-scale solar PV costs have been revised upwards for 2025 based on GHD (2026). This represents a reversal of the last two historical years of cost reductions but likely reflects cost volatility rather than a new trend. As a result of past cost reductions for this technology, unlike other technologies, we do not impose any additional cost reduction related to recovery from the global inflationary pressures. All cost reductions in the projection are due to learning through deployment. Weaker abatement policies and lower electricity generation in *Current policies* and *Global Net Zero Post 2050* result in less solar PV deployment and less cost reduction. *Global Net Zero by 2050* has the largest deployment with costs declining to around $600/kW.

The final minimum cost level for solar PV is difficult to predict because, unlike other technologies, and notwithstanding recent inflationary pressures, the historical learning rate for solar PV has not significantly slowed. The modular nature of solar PV appears to be the main point of difference in explaining this characteristic. High global manufacturing capacity that has kept up with or exceeded demand has also been a significant feature of this technology.

All scenarios include increases in installation costs in Australia and this also contributes to the narrowing of the differences between the scenarios over time. Installation costs are assumed to grow faster the stronger the global climate policy ambition due to stronger construction activity.

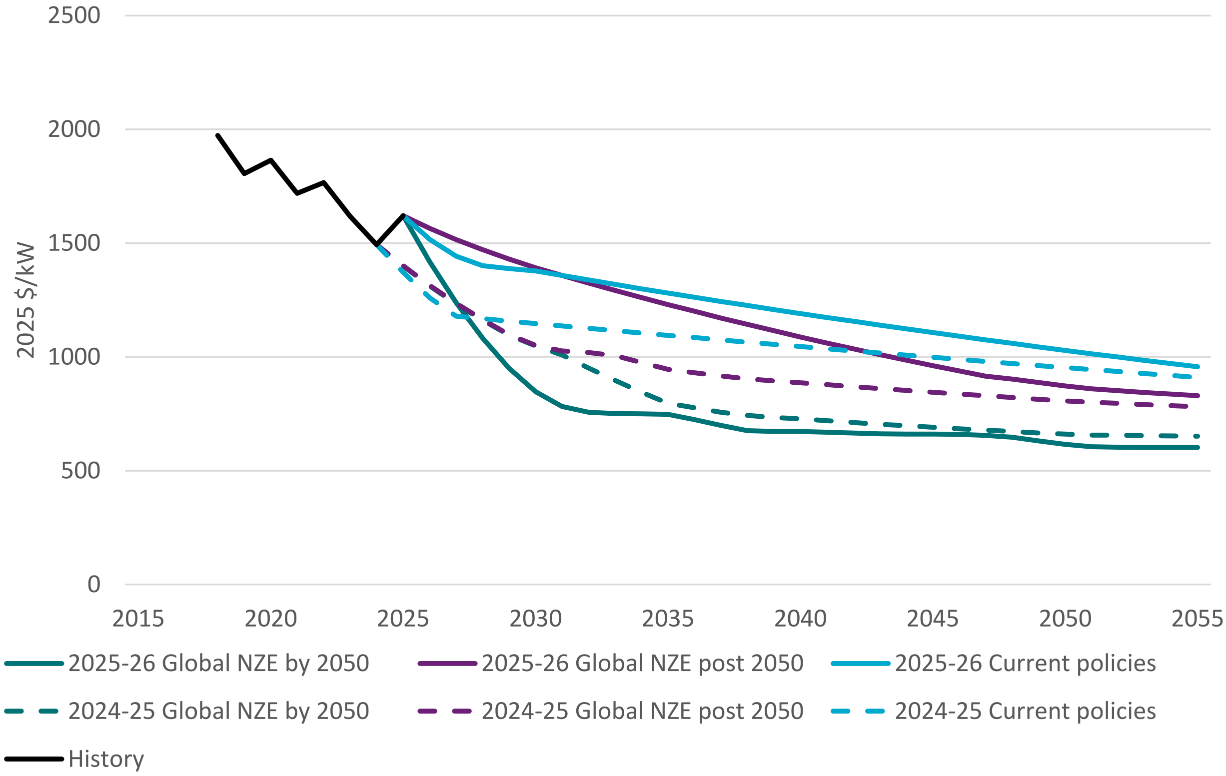


Figure 4-11 Projected capital costs for large-scale solar PV by scenario compared to 2024-25 projections

4.3.10 Rooftop solar PV

The current costs for rooftop solar PV systems are lower than was projected for 2025 in the 2024-25 GenCost report. Rooftop solar PV is sold across a broad range of prices[12] and consequently this data is best interpreted as a mean and may not align with the lowest cost systems available. The cost is before available subsidies and on the basis of the direct current power rating of the system whereas large-scale solar PV and all other generation technologies are on an alternating current power rating basis.

Rooftop solar PV benefits from co-learning with the components in common with large scale PV generation and is also impacted by the same drivers for variable renewable generation deployment across scenarios. However, the rate of capital cost reduction in each scenario is slower than large-scale solar PV because we have assumed a low learning rate on the installation or local learning component for rooftop solar. This reflects that Australia already has a very high degree of experience in installing rooftop solar so there are less opportunities to reduce the cost

[12] The Cost of Solar Panels - Solar Panel Price | Solar Choice

of installation compared to large-scale solar PV. The *Global NZE by 2050* scenario has a higher learning rate on installation than the other scenarios and this allows for a stronger cost reduction trend.

Rooftop solar PV installation costs are also impacted by the general increase in installation costs that apply to all technologies.

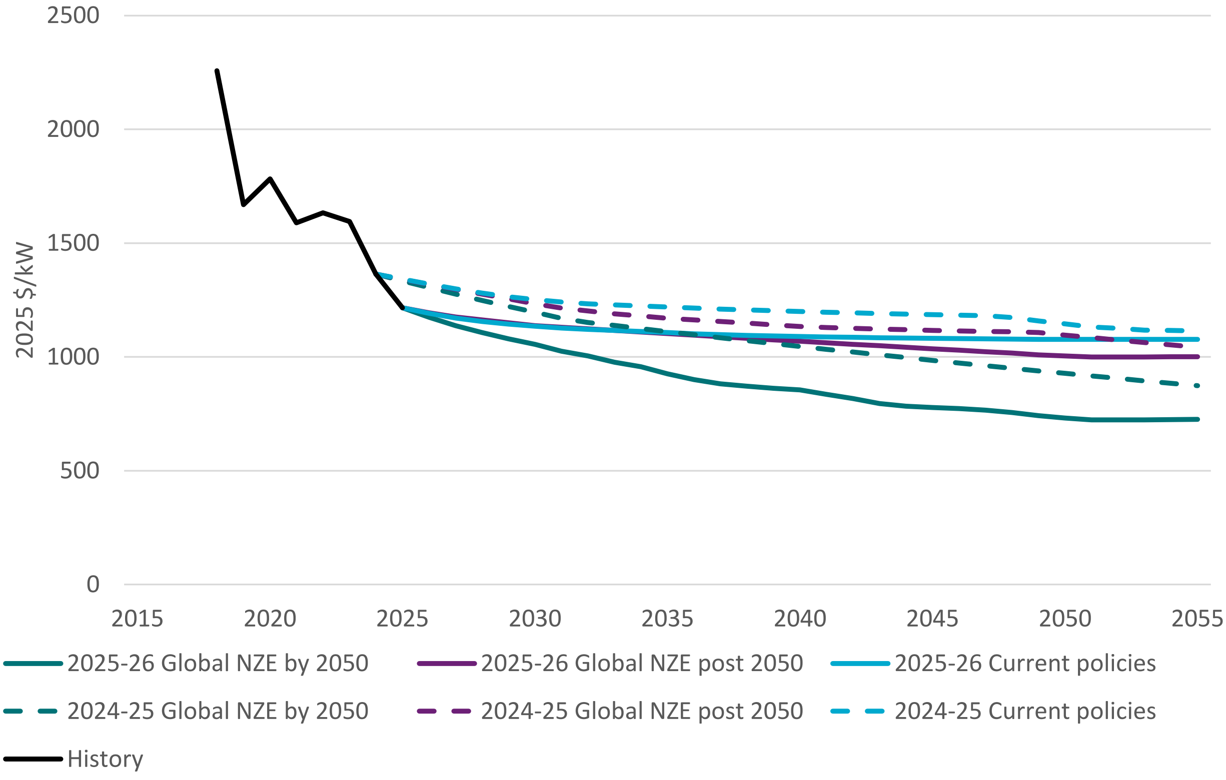


Figure 4-12 Projected capital costs for rooftop solar PV by scenario compared to 2024-25 projections

4.3.11 Onshore wind

As the historical data indicates onshore wind is one of the technologies which has been most impacted by recent global inflationary pressures. The updated GHD (2026) data indicates that the costs pressures are stabilising. However, due to the Iran war, no further improvement in costs is expected in 2026.

To recognise the more difficult circumstances for the onshore wind industry locally and globally, our assumption is that capital costs of onshore wind will not return to its normal cost path until 2035 in all scenarios. After 2035, wind costs are projected to decline only a modest amount. Global equipment cost reductions from learning are offset by local increases in land and installation costs. While equipment costs fall the most in stronger climate policy ambition scenarios, these scenarios also experience the strongest increase in installation costs due to greater construction activity. Consequently, these global and local changes in costs tend to offset one another resulting in little difference between the three scenarios by 2055.

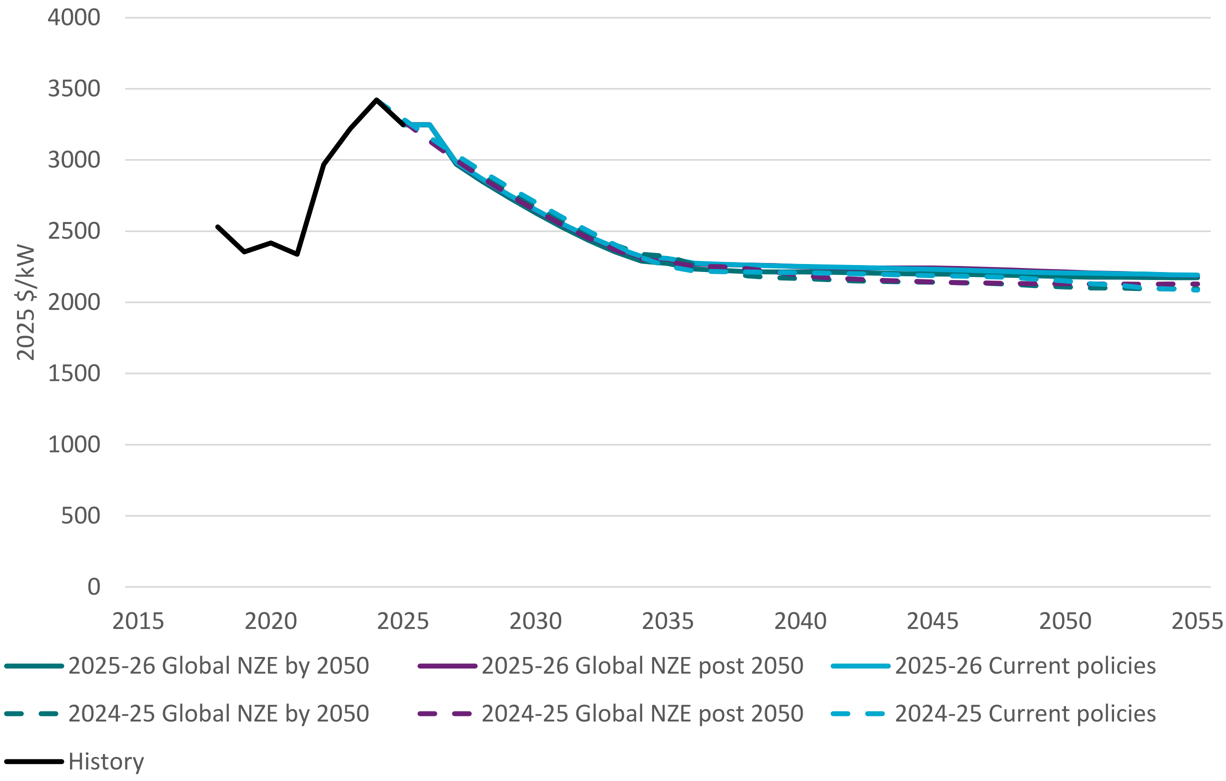


Figure 4-13 Projected capital costs for onshore wind by scenario compared to 2024-25 projections

4.3.12 Fixed and floating offshore wind

Fixed and floating offshore wind are represented separately in the projections. Our general approach is not to include similar technologies because of model size limits and because the model will usually choose only one of two similar technologies to deploy, therefore adding no new insights. However, while the two offshore technologies have a lot of common technology, floating wind is less constrained in terms of the locations in which it can be deployed. As the global effort to reduce greenhouse gas emissions looks increasingly to electricity as an energy source, many countries will be seeking to use technologies that have fewer onshore siting conflicts. Fixed offshore wind is the lowest cost offshore technology, but its maximum deployment is limited by access to seas of a maximum depth of around 50-60 metres[13] and any navigation, marine conservation or aesthetic issues within those zones. Floating offshore wind can be deployed at much greater depths increasing its potential global deployment and providing a unique reason to select the technology.

Figure 4-14 presents projections for both fixed and floating compared to the 2024-25 projection. The current costs for both types of offshore wind are provided in GHD (2026). The updated current capital costs are lower than projected in 2024-25 for floating offshore wind and higher than projected for fixed offshore wind. Post 2025, offshore wind capital costs are not adjusted for inflationary pressures in the same way as other technologies because fixed offshore wind has already recovered based on the average global data which informs the historical series. However,

[13] This is more an economic than absolute technical limit.

it is likely that technology prices are higher for some regions and manufacturers. Australia is not likely to deploy offshore wind before 2030 and therefore GenCost will continue to be required to rely on global sources of offshore wind cost data until then. A first of a kind premium, in addition to the costs shown, will likely apply when offshore wind is deployed in Australia for the first time.

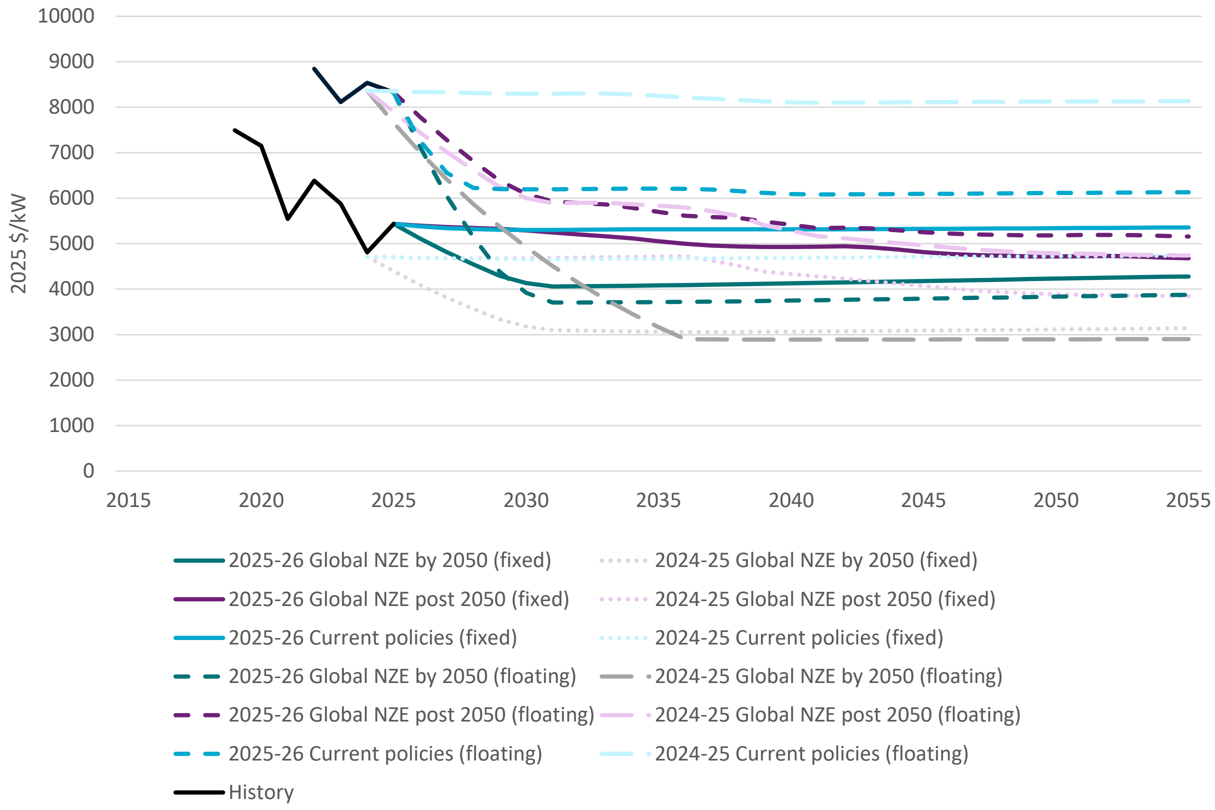


Figure 4-14 Projected capital costs for fixed and floating offshore wind by scenario compared to 2024-25 projections

Fixed offshore wind costs are higher than projected in 2024-25 but this mostly reflects the higher current cost rather than a change in global deployment. Floating offshore wind projections have a greater range of cost reduction pathways, and this reflects their relative immaturity and greater potential global deployment.

Offshore wind is not as impacted as other technologies on land costs but does require some onshore land to connect to the grid. Offshore wind costs are impacted by the new assumptions with regards to increasing installation costs.

4.3.13 Battery storage

Current 2025 costs of battery storage fell in line with the fastest cost reduction projected in 2024-25 and the updated cost projections continue to allow for a modest range of cost reductions after 2025 but slower than the most recent year. The costs shown in Figure 4-15 are for a 2-hour duration battery (total battery cost including battery and balance of plant). Given the 2025 cost reduction takes batteries back to below their pre-pandemic levels we do not impose any additional reduction beyond the learning projected by the modelling.

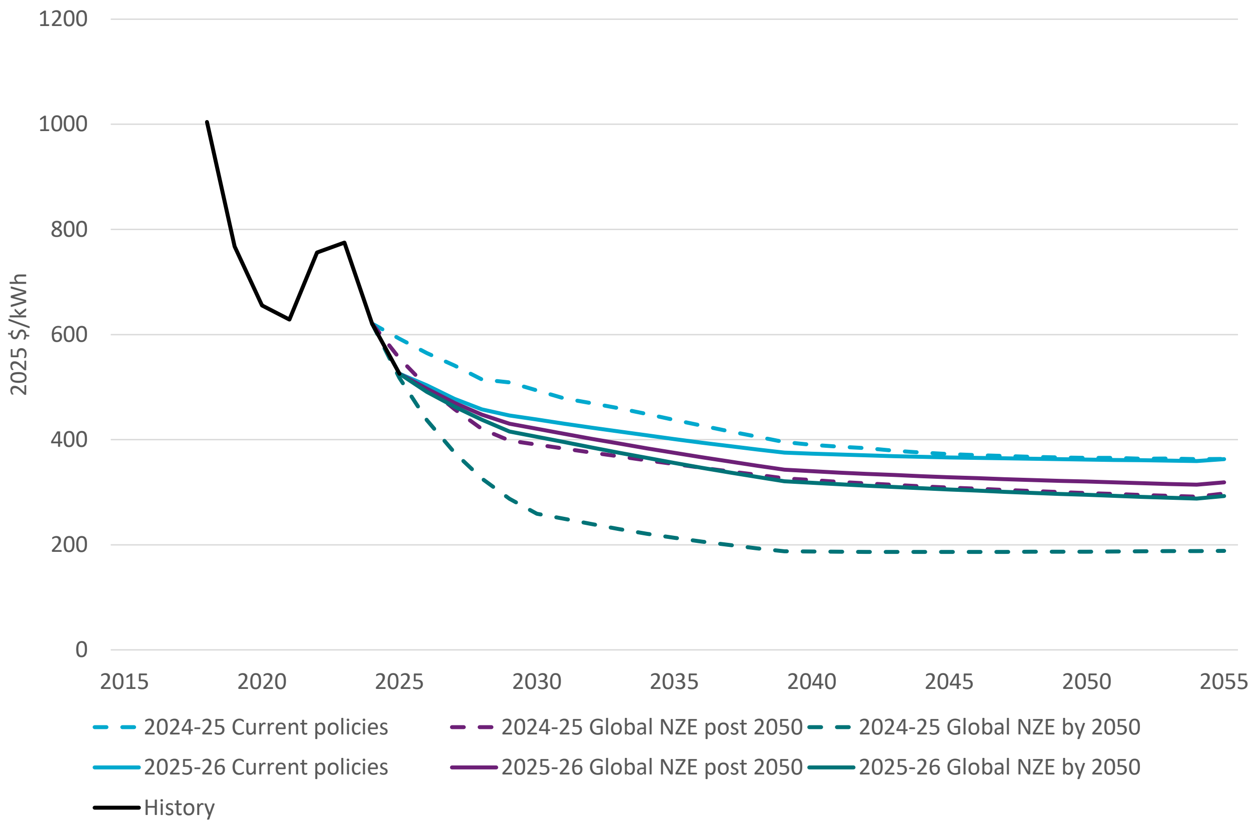


Figure 4-15 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

The projections use different learning rates by scenario to reflect the uncertainty as to whether they will be able to continue to achieve their high historical cost reduction rates (notwithstanding the pandemic period). Historical cost reductions have mainly been achieved through deployment in industries other than electricity such as in consumer electronics and electric vehicles. Global electric vehicle uptake has been updated with inputs from IEA (2025). While these other uses are important, small- and large-scale stationary electricity system applications are growing globally. Under the three global scenarios, batteries have a large future role to play in supporting variable renewables alongside other storage and flexible generation options and in growing electric vehicle deployment.

Battery deployment is strongest in the *Global NZE by 2050* scenario reflecting stronger deployment of variable renewables, which increases electricity sector storage requirements. Together with an assumed high learning rate this leads to the fastest cost reduction. The remaining scenarios have more moderate cost reductions reflecting a reduced requirement for stationary storage and assumed lower learning rates. All projections are impacted by assumed increases in installation costs. However, for batteries, the learning effects more than offset this factor leading to declining cost trajectories.

A breakdown of battery pack and balance of plant costs for various storage durations are provided in Appendix B.

GHD (2026) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $11,000 for a 5kW/10kWh system or $1100/kWh, including installation but excluding subsidies. This is around twice the cost of large-scale battery projects per kWh.

However, larger household batteries are achieving lower per kWh costs more consistent with large-scale costs.

4.3.14 Pumped hydro energy storage

GHD (2026) has provided a reassessment of pumped hydro energy storage (PHES) costs and this is the main driver of differences in the cost outlook compared to 2024-25. See GHD (2026) for more discussion. PHES is a mature technology and receives the same increase in installation costs as other technologies which is the main driver for the increasing cost trend post 2030. Unlike the other technologies, all three scenarios assume costs return to normal by 2030 (rather than in 2035). This reflects the already large downgrade in costs in 2025. Site variability is also a great source of variation in PHES costs and is separately addressed by GHD (2026) and AEMO external to GenCost.

The cost trajectory shown in Figure 4-16 is for a 24-hour duration storage design. Costs for 10-hour, 48-hour and 160-hour durations are also included in this report (Appendix B).

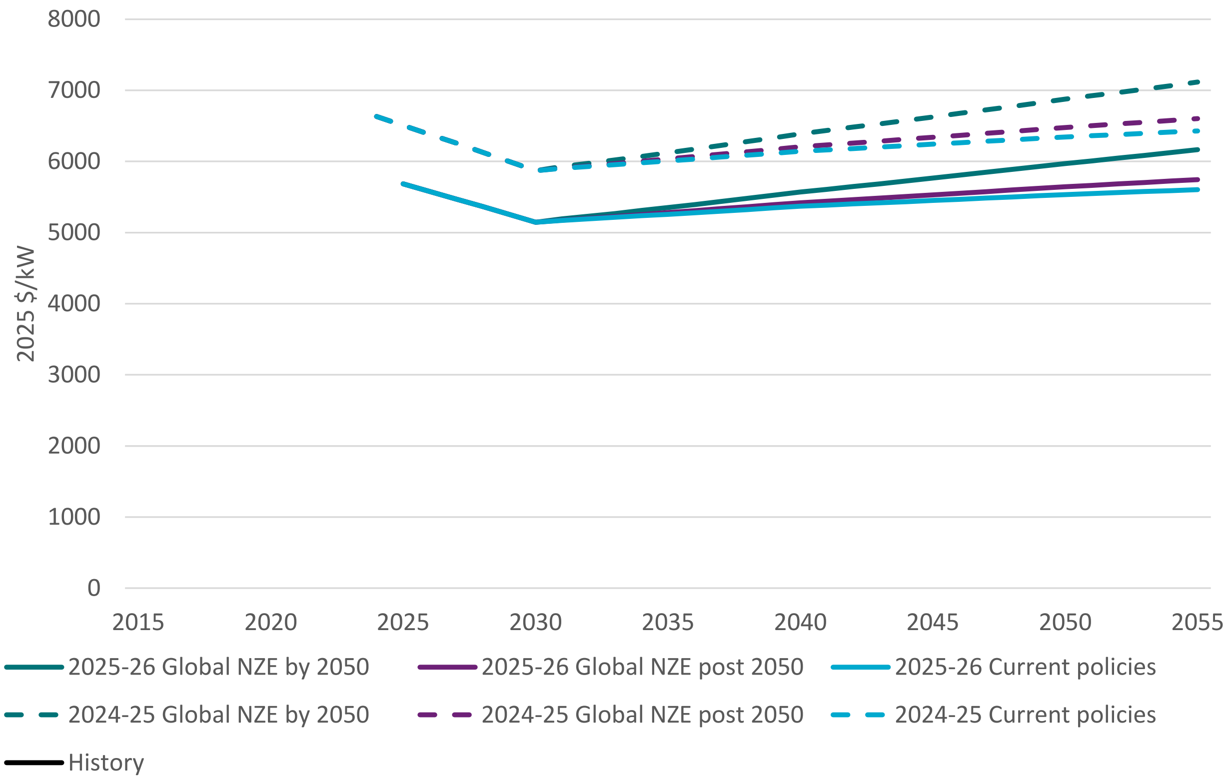


Figure 4-16 Projected capital costs for pumped hydro energy storage (24-hour) by scenario

4.3.15 Other generation technologies

There are several technologies that are not commonly deployed in Australia but may be important from a global energy resources perspective or as emerging technologies. These additional technologies are included in the projections for completeness and discussed below. They are each influenced by revisions to current costs which have generally experienced an increase in capital costs for 2025 with the exception of fuel cells. Reflecting the infrequency with which these technologies are built, the increases for some technologies mostly represent theoretical increases in costs if they had been built based on the general increase in infrastructure building costs. The flat trend in 2026 followed by a downward trend to 2035 has been included using the same methodology for the technologies above. The projections also include increasing land and installation costs for biomass with CCS and fuel cells (wave and tidal/ocean current are excluded due to insufficient data).

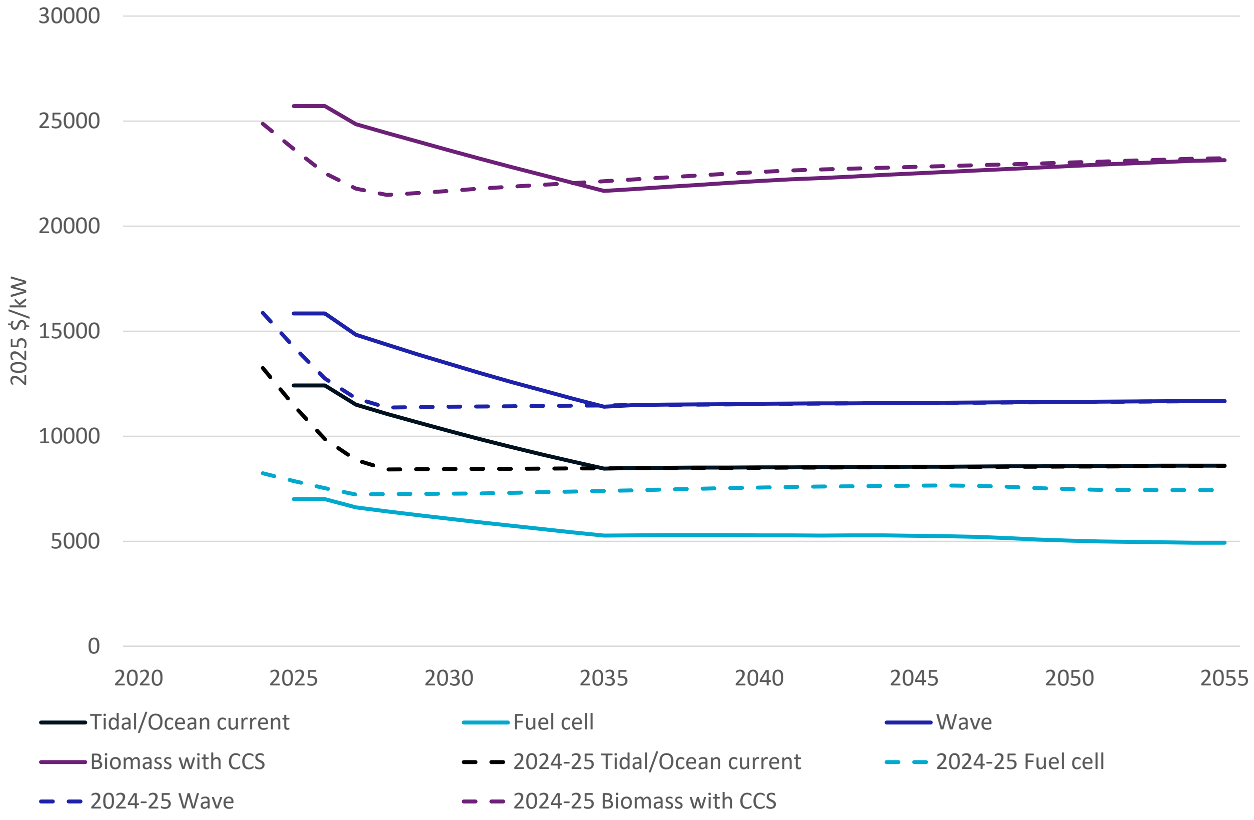


Figure 4-17 Projected technology capital costs under the *Current policies* scenario compared to 2024-25 projections

Current policies

Biomass with CCS is deployed at a negligible level in the *Current policies* scenario because the climate policy ambition is not strong enough to incentivise significant deployment. Cost changes after 2035 reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors but these are more than offset by increasing installation costs. There is also no significant deployment of tidal or wave technology reflecting the lack of climate policy ambition. Fuel cells are lower owing to updated current costs and minor deployment in the late 2040s.

Global NZE by 2050

Biomass with CCS has the highest deployment in *Global NZE by 2050* scenario but this scenario also has the strongest increase in installation costs. Biomass with CCS is an important technology in some global climate abatement scenarios if the electricity sector is required to produce negative abatement for other sectors. However, we are not able to model that scenario with GALLME. GALLME only considers the value of this technology to the electricity sector's own abatement task and from that perspective alone, biomass with CCS is a relatively high-cost generation technology.

Wave energy is deployed at a modest level in the 2040s leading to some costs reductions during those periods. Fuel cells are lower owing to updated current costs.

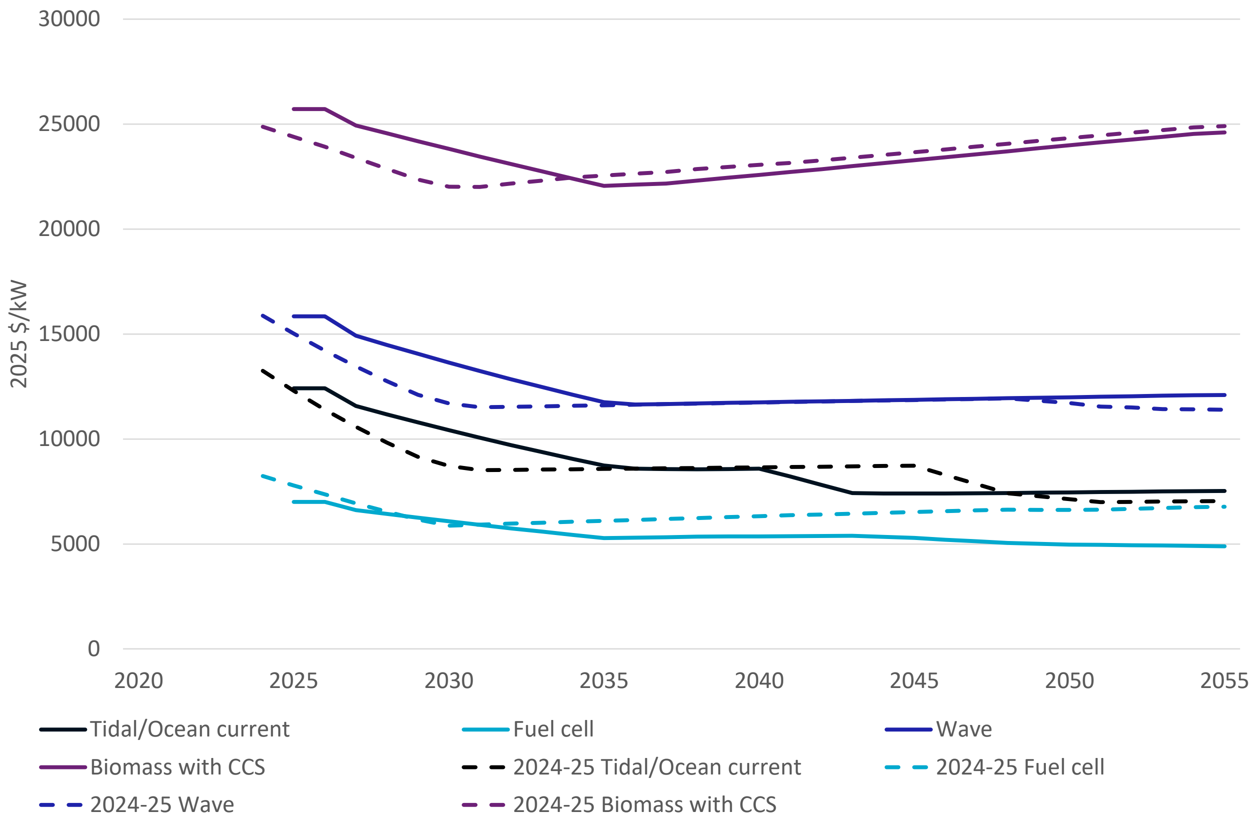


Figure 4-18 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2024-25 projections

Global NZE post 2050

Biomass with CCS, wave and tidal energy are not deployed at significant scale in this scenario. However, fuel cell technologies are favoured in this scenario with modest but steady deployment through to 2055. This result is similar to the *Current policies* scenarios but with a stronger reduction in fuel cell costs. This reflects the weaker abatement policy leading to stronger reliance on more mature abatement technologies.

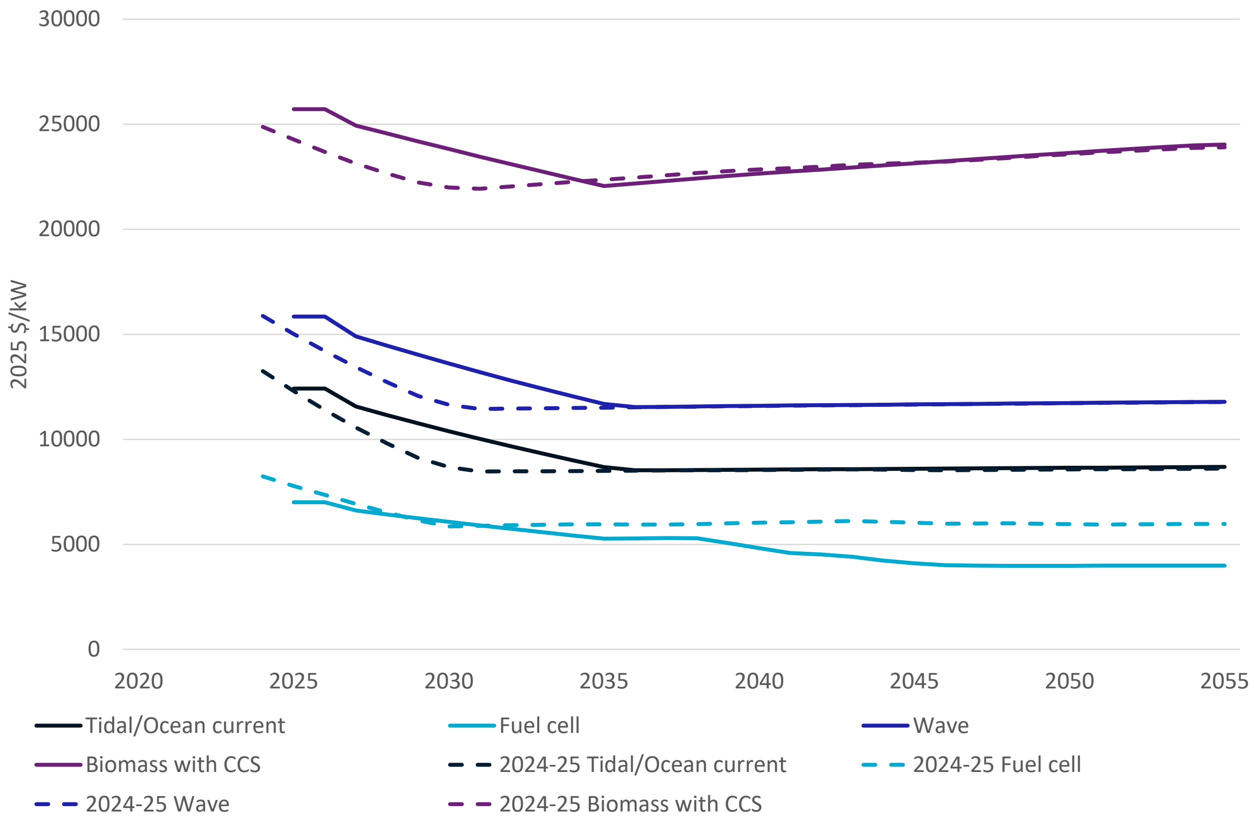


Figure 4-19 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2024-25 projections

4.3.16 Hydrogen electrolysers

Hydrogen electrolyser costs have decreased in 2025 for both proton-exchange membrane (PEM) and alkaline electrolysers based on GHD (2026). Alkaline electrolysers remain lower cost than PEM electrolysers but their costs are becoming closer together.

The key advantage of PEM electrolysers is their wider operating range which gives them a potential advantage in matching their production to low-cost variable renewable energy generation. If the costs of electrolysers fall sufficiently, capital costs would become less significant in total costs of hydrogen production. This development could make it attractive to sacrifice some electrolyser capacity utilisation for lower energy costs (by reducing the need to deploy storage in order to keep up a minimum supply of generation). Under these circumstances, the more flexible PEM electrolysers could be preferred if their costs are low enough.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario with a lesser and similar amount of change expected in *Current policies* and *Global NZE post 2050.* However, given stronger assumed increases in installation costs, *Global NZE post 2050* is the higher cost of the two scenarios.

The 2025-26 electrolyser cost projections are significantly higher than in 2024-25. This reflects the significantly reduced outlook for hydrogen production from electrolysers that has occurred due to updating the global hydrogen demand projections from IEA (2025). Lower deployment means lower cost reductions under the learning based projection approach used in GALLM (see appendix A).

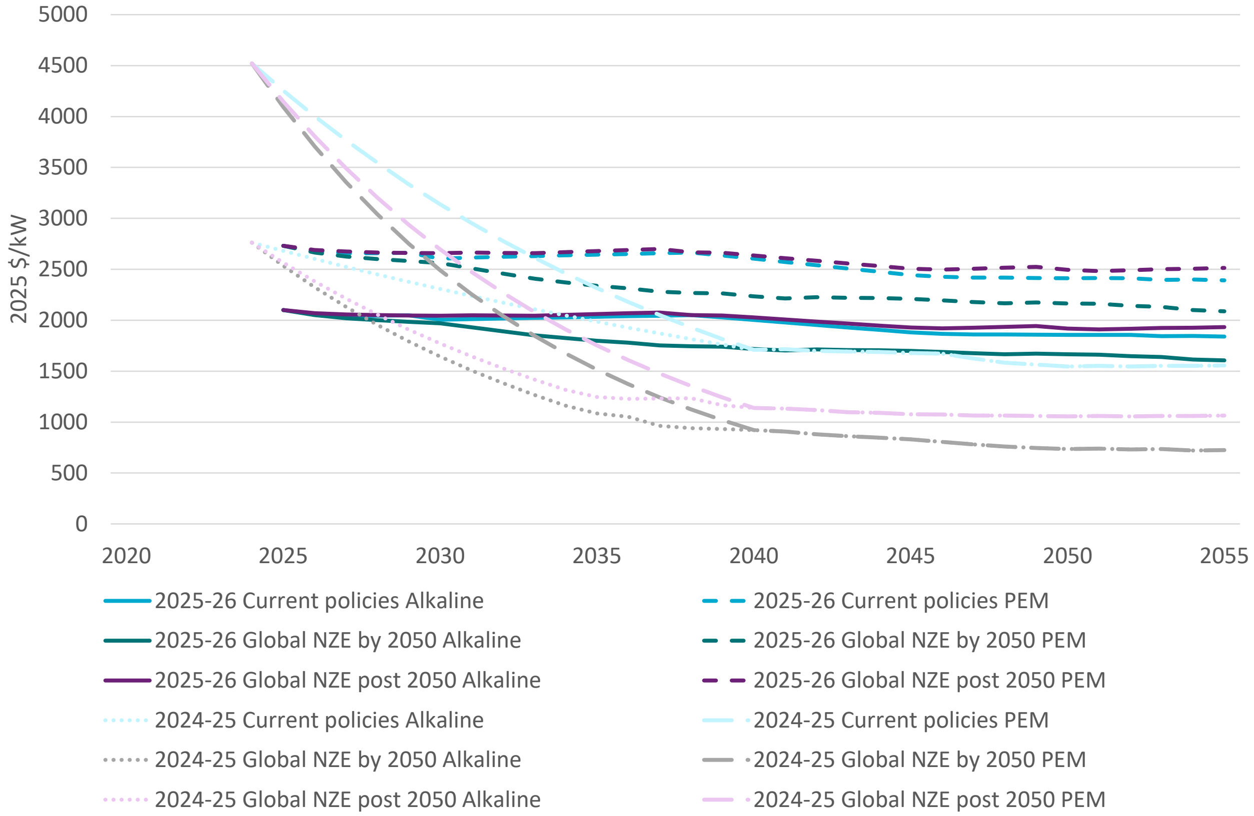


Figure 4-20 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2024-25

5 Levelised cost of electricity analysis

5.1 LCOE definition

Levelised cost of electricity (LCOE) data is an electricity generation technology comparison metric. It is the total unit costs a generator must recover to meet all its costs including a return on investment[14]. Modelling studies such as AEMO's Integrated System Plan (AEMO, 2024) do not require or use LCOE data[15]. LCOE is a simple screening tool for quickly determining the relative competitiveness of electricity generation technologies. It is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance.

The standard method of calculating LCOE does not include all of the additional costs required to deliver reliable electricity supply from variable renewable energy (VRE) generation, particularly when the share of VRE generation is high. The two key VRE technologies are wind and solar photovoltaics (PV). To address this issue of additional VRE costs, since 2019, GenCost has deployed a two-step methodology which separately calculates the VRE integration costs in an electricity system model and then adds them back into the standard LCOE for wind and solar photovoltaics. This method was devised after a thorough literature review in Graham (2018) but has received an update in this 2025-26 report.

5.2 Change in method for estimating the cost of reliable high VRE share generation

This 2025-26 GenCost report revises the methodology for estimating the cost of high VRE electricity systems in response to stakeholder feedback. Through various submissions over several years, stakeholders requested that the methodology be revised in two ways:

1. Use a System Levelised Cost of Electricity (SLCOE) approach. A SLCOE takes the cost of electricity directly from an electricity system model by dividing the system costs associated with existing and new technology deployments by the total useful electricity supply in a given year. This concept is also equivalent to the average annual unit cost of electricity for a given electricity system boundary[16]. Calculation of SLCOE is more direct than the previous approach which required setting up a baseline and identifying additional integration costs by calculating differences in costs for alternative levels of VRE generation share. Another advantage is that SLCOE also provides a system perspective which inherently requires a

[14] For a description the LCOE formula and the application of the formula go to CSIRO's Data Access Portal and download the latest Excel file that accompanies this report. CSIRO Data Access Portal

[15] LCOE is a measure of the long run marginal cost of generation which could partly inform generator bidding behaviour in a model of the electricity dispatch system. However, in such cases, it would be expected that the LCOE calculation would be internal to the modelling framework to ensure consistency with other model inputs rather than drawn from separate source material.

[16] In this case we are concerned with generation and transmission

bundle of technologies. This is a more useful perspective than comparing single technologies against one another using LCOE since very few systems use a single technology (the exception being remote power systems but even these are increasingly combining multiple technologies.)

2. Provide greater transparency with regard to the data inputs and the modelling system used.

Separate from these two key items of stakeholder feedback, it was also observed over several years that while public interest in the future generation mix remains high, and the GenCost project's primary goal is to support electricity system modelling by providing cost data, the amount of published electricity system modelling had not increased. It is hypothesised that the high complexity and cost of creating and applying commercial electricity system modelling tools may have been a significant contributor to this outcome. With this context, and to address all three issues simultaneously, a new open source electricity system model was created to calculate SLCOE, replacing the previous method for estimating the integration costs for solar PV and wind.

The new electricity system model is a simplified version of the larger commercial models used by CSIRO and other organisations. With the needs of other potential users in mind, the model was designed to be as short and fast solving as possible whilst not significantly reducing accuracy regarding the estimation of electricity costs and the generation mix. The final model design and the simplifications considered in the development phase are described in Graham et al. (2025). The model is of the National Electricity Market (NEM), excluding Western Australia and Northern Territory. The exclusion of these regions is a simplification in itself but also reflects the fact that these jurisdictions do not provide enough publicly available information about their electricity systems to easily construct an open source model.

Additional model details, software code and all input data can be downloaded at https://data.csiro.au/collection/csiro:71289. The model has been named Simple Electricity Model or SEM. Despite the goal of simplification, the model still requires access to and knowledge of specialised software and solvers and is targeted at users with a university level of knowledge who will likely have most success in following the equations and code. This is because universities typically provide education on linear programming across a wide variety of degree courses as well as access to free software and solver licences. Simpler spreadsheet type models or calculations were considered as an alternative but ultimately are not accurate enough to be relied on to estimate system costs due to their inability to consider and optimise all of the available system configurations.

5.3 The 2030 SLCOE, existing capacity and electricity futures prices

The main feedback that the new SLCOE method received on the consultation draft of this report was that some stakeholders are uncomfortable with or uncertain about how existing capacity should be treated in an SLCOE calculation that is focussed on a near term year such as 2030. Applying SLCOE to 2050 is less complicated because most existing capacity will be retired and to some extent can be ignored (and this is the approach taken in academic articles such as Idel (2022)). However, in a 2030 SLCOE existing capacity cannot be ignored. The model must recognise the availability of existing capacity if it is to realistically represent the 2030 electricity system.

Views differ on how much of the historical cost of each item of existing capacity should contribute to system costs. Aside from transmission which has a specified regulatory system, there is no public record of how much of the original investment plus reasonable return has already been received by the owner of generation and storage assets before 2030. As such, any attempt to include the cost of existing capacity will be based on low quality data. Stakeholders offered suggestions for costs of existing projects that should be included in the system cost but no general consistent approach for how to cost existing capacity.

As the GenCost report is intended to be updated each year including 2030, this implementation issue in regard to SLCOE can only grow larger as existing capacity will become an increasing share of total capacity. This has led to the conclusion that with the practical limitations of data, SLCOE is not appropriate for 2030 or short term system costing in general.

There are alterative modelling approaches that could project the cost of electricity in 2030 by forecasting electricity spot market prices. However, these are large, commercial models and consequently they would not meet the goals of simplicity and transparency. An alternative approach that does meet these goals is to look to electricity futures prices. These are a hedging product for market participants and as such they provide reasonable indicator of the market participants' expectation of electricity prices. Electricity futures prices are available for around 3-4 years ahead from https://www.asxenergy.com.au/. The baseload contract includes all hours of the year and so is equivalent in scope to an SLCOE cost for a specific year. Electricity futures contracts also include a daily evening peak product. This will be useful as a comparison point for peaking technologies included in GenCost whereas SLCOE results were only relevant as a comparison point for bulk energy technologies.

5.4 2050 SLCOE scenarios

The 2050 LCOE focusses on an emissions intensity target range in 2050 that supports achieving the policy of net zero emissions by 2050. This is the most common type of 2050 policy in place at the national, state and corporate level. However, stakeholders interested in other scenarios can explore them with the open source model provided.

The 2050 SLCOE considers either mature firmed renewables *only* or mature firm renewables *plus* any of three groups of technologies: floating and fixed offshore wind, coal and gas with carbon capture and storage and large-scale and small modular reactor nuclear. Each additional technology group is modelled separately because they each are assumed to require two first-of-a-kind (FOAK) projects to be built before they can access the standard technology costs. As such each technology group represents a unique scenario creating three renewable *plus* scenarios. It would not be advisable to design a scenario where all technologies are built as it would be prohibitively expensive to build FOAK projects for all technologies. After building the two FOAK projects in each of the technology group scenarios the model determines whether to build any more of that technology at the standard cost based on whether additional capacity of that technology contributes to achieving a least cost electricity system.

The 2050 scenarios must meet emission intensity targets of 0.0025tCO_2e/MWh up to 0.20tCO_2e/MWh. On their own these numbers mean little and so Table 5-1 provides more context and scenario names. It is appropriate to explore a range of electricity sector emissions intensity targets because there is no strict policy on the degree to which any sector must decarbonise in a net zero emissions policy world. To minimise greenhouse gas emissions abatement costs, ideally emission reduction takes place in each sector up to the point where no less expensive abatement may be found in any other sectors, including offset sectors such as land use, land use change and forestry. The value of 0.02tCO_2e/MWh is most closely aligned with AEMO's Step Change scenario in the 2024 and draft 2026 Integrated System Plan (ISP) modelling results, after adjusting for the ISP only reporting direct emissions and GenCost modelling being on a full fuel cycle basis (that is, inclusive of fugitive emissions in fuel supply). Other emissions intensity scenarios serve as minimum and maximum costs, helping to define the range of possible electricity systems costs in 2050.

Table 5-1 2050 full fuel cycle greenhouse gas emissions intensity target scenarios and their meaning

2050 emissions intensity target scenario	Scenario name	Meaning
0.20tCO_2e/MWh	NoProgressToNetZero	Consistent with achieving the 2030 82% renewables target policy target and holding the emissions intensity constant to 2050. This is not consistent with achieving net zero by 2050 but serves as a reference case cost against which reducing the emissions intensity beyond 2030 can be measured.
0.10tCO_2e/MWh	WeakNetZero	A halving of the 2030 emissions intensity by 2050. Only weakly consistent with the Australia's net zero by 2050 policy, requiring significantly more abatement in non-electricity sectors.
0.05tCO_2e/MWh	ModerateNetZero	A 75% reduction in the 2030 emissions intensity by 2050. In the range of what is required for the electricity sector to meet Australia's net zero by 2050 policy
0.02tCO_2e/MWh	StrongNetZero	The emissions intensity consistent with AEMO's 2024 and draft 2026 Integrated System Plan Step Change scenario. Likely to be what is required to meet Australia's net zero by 2050 policy
0.0025tCO_2e/MWh	VeryStrongNetZero	Almost eliminating emissions from the electricity sector (just under a million tonnes remain). This likely exceeds what is required to meet Australia's net zero by 2050 policy but serves to define the maximum cost of electricity associated with emissions abatement.

A zero emission scenario is not included because, on a full fuel cycle basis only the mature firm renewables technology mix on its own or plus-offshore wind can achieve this outcome. The plus-nuclear and plus-CCS options have upstream emissions in their fuel supply chain and plus-CCS downstream in the CO_2 released that is not captured.

AEMO currently makes available 15 historical weather years of demand and renewable production data. It is possible to simulate all of these. However, for the sake of brevity and because for reliability purposes sufficient renewables and other supporting technologies must be deployed to deal with the worst weather conditions, all scenarios only use the single most costly weather year which is 2011. Graham et al. (2025) provides more detail on the distribution of costs across weather years.

5.5 SLCOE estimates

5.5.1 Data alignment

The results below are based on the capital cost projections of generation and storage technologies in this final GenCost report and on transmission costs and other electricity sector inputs available in AEMO's 2026 Draft Forecasting Assumption Update Inputs and Assumptions Workbook.

5.5.2 Interpretation of costs from SLCOE and LCOE

Neither SLCOE or LCOE estimates guarantee a future wholesale electricity generation price outcome. They indicate the breakeven price required for investors to make a return on their portfolio or individual investments respectively. SLCOE is the more accurate indicator of the two because it includes the integration costs and operational requirements of the entire system whereas LCOE does not with the much simpler calculation only including a limited set of standard cost and technical inputs

Neither of these cost estimates guarantee future electricity prices. Changes in electricity prices are also subject to[17]:

- Supply-demand imbalance as a result of too much or too little deployment relative to demand growth and retirements.
- Fuel price and weather volatility.
- The level of competition amongst suppliers.

These additional drivers of price formation can lead to prices significantly lower or higher than the underlying cost of the system and can take many years to correct due to the long lead times for capacity deployment.

[17] Retailers also have hedging costs, market fees and ancillary services costs associated with their purchase of wholesale electricity. However, we do not go into those topics here as we are focussed with the main underlying drivers of generation price changes.

Lead times are impacted by many factors such as the maturity of technology, approval and development processes, general uncertainty, contract markets and confidence in government policy directions. Construction times also vary significantly between technologies.

Given this background the SLCOE and LCOE data in GenCost are an indicator of the minimum price needed for investors to enter the market of their own accord ignoring any other uncertainties or external influences. However, should current or future electricity prices be much lower or higher than the indicated breakeven SLCOE, this outcome is likely to have been caused by excess or insufficient new capacity in the market whose root causes may span several years.

5.5.3 SLCOE results and the ISP

The SLCOE results will cover some similar ground to the Integrated System Plan (ISP) in that they present a future generation mix for the NEM. Where results differ, GenCost advises that the ISP should be given greater weight. The SLCOE results are based on a simplified electricity model. The results are designed to be reasonably accurate but, by design, are substantially less sophisticated than the multi-model state-of-the-art framework deployed in the ISP.

5.5.4 2030 LCOE results and future prices

Electricity futures prices for baseload and peak evening energy in New South Wales (NSW), Victoria (VIC), Queensland (QLD) and South Australia (SA) are shown Figure 5-1.

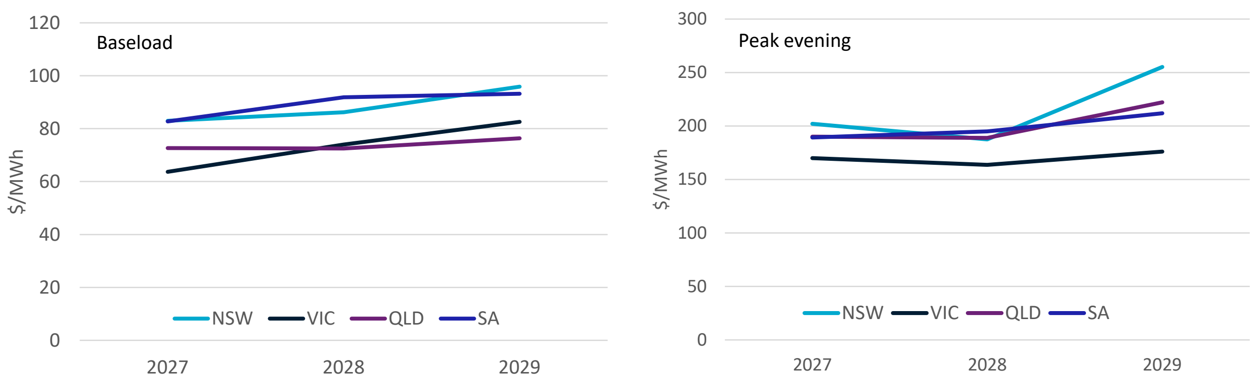


Figure 5-1 Baseload and Peak evening electricity futures prices by state, nominal $/MWh

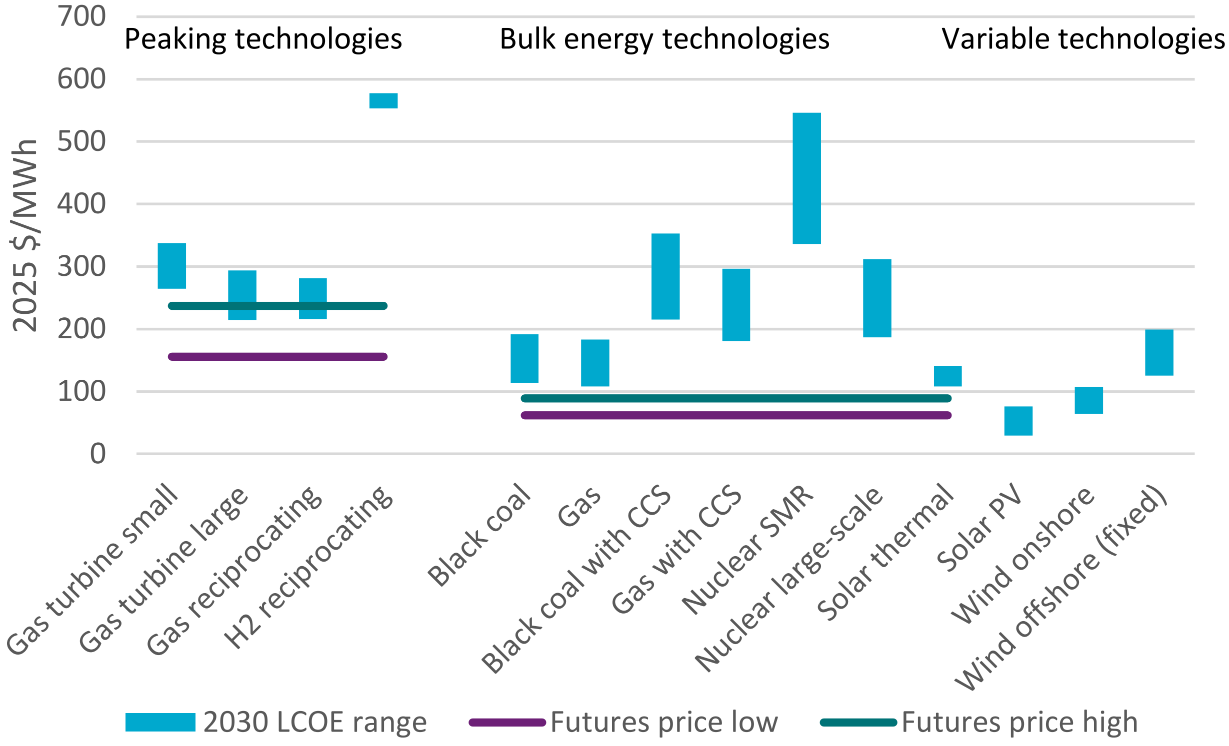
Baseload electricity futures prices are around $79/MWh on average for the next 3 years with a rising trend, towards an average $85/MWh by 2029. For context, the AEMC (2025) projected wholesale generation costs of just over $90/MWh in 2030 indicating reasonable alignment between the futures market and available modelling results.

In Figure 5-2, technologies are grouped into peaking technologies and bulk energy technologies. Peaking technologies have a capacity factor of 20% and this aligns well with the Peak evening contract which applies 16:00 hours to 21:00 hours (AEST) Monday – Sunday[18] representing a load

[18] australian-electricity-fact-sheet.pdf

factor of 21% of the year. Trades in Peak evening futures contracts are much lower and so there is a lower level of confidence in this futures price.

Bulk energy technologies might have an availability of up to just over 90% but often have much lower capacity factors in practice due to the lack of market loads requiring a 90% load factor. The Baseload electricity futures price is for a 100% or constant load factor throughout the year and so is not a perfect match but is the closest of available futures prices. The futures prices shown in Figure 5-2 are the lowest and highest of all states over the next three years. They have also been adjusted for inflation to make them consistent with the LCOE data which is in real terms.



LCOE excludes integration costs. See footnote previous page for futures price definitions

Figure 5-2 Calculated 2030 LCOE of peaking and bulk energy technologies compared to Baseload and Peak evening electricity futures price ranges

The comparison in Figure 5-2 indicates that peaking generation technologies are currently sitting at the high end of the Peak evening futures prices. This is consistent with observations that batteries have started to compete with traditional gas generation in this category, with the significant new capacity added resulting in reduced peak evening prices[19]. A four hour duration battery currently has a lower cost than a large open cycle gas turbine and this competitive advantage is expected to widen in the next two years (Figure 5-3).

Most bulk energy generation technologies are higher cost than the Baseload electricity futures price. This is an academic observation because most of these technologies could not be deployed within the next 4 years due to their required development and construction times.

[19] https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed

Solar PV and onshore wind are almost exclusively the only generation technologies sufficiently advanced in the development pipeline to be deployed before 2030. Their deployment is being supported by existing flexible gas and coal together with new battery, pumped hydro and transmission capacity. Given the Baseload electricity futures price is an all-day, all-year price it represents the expected total annual generation cost of this combination of technologies. Transmission costs, which are recovered outside of the electricity system increase to 2030 but from a low base (AEMC 2025).

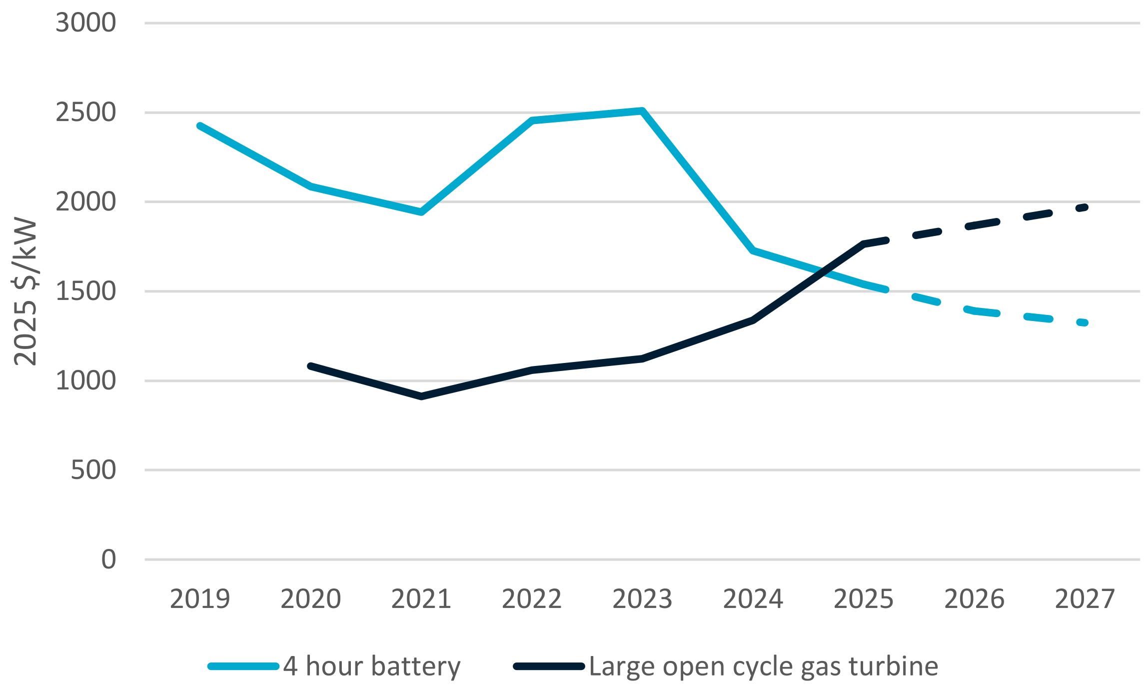


Figure 5-3 Historical and two year projection of capital cost of 4 hour duration battery and large open cycle gas turbine

5.5.5 2050 SLCOE results

Generation mix

By 2050, we assume all current generation is retired and only currently existing or committed hydro, pumped hydro and transmission remains. The existence of any rooftop solar PV, home batteries and vehicle-to-grid batteries are aligned to AEMO's Step Change scenario assumptions.

The three technology groups considered in the analysis, in addition to mature renewables, are floating and fixed offshore wind, carbon capture and storage (CCS) applied to either coal or gas generation and large-scale and small modular reactor nuclear. However, to be eligible to deploy these technologies at the costs published in Appendix B of this report, each of these three technologies must first build a minimum of two projects at a cost premium consistent with the discussion of first-of-a-kind premiums in Section 2 of this report. The premiums applied are consistent with those presented in Table 2-1. In other words, there is an initial additional cost which must be paid to establish the required workforce, skills and supply chains when commencing a program of building technologies that Australia has not previously deployed.

Mature renewables includes solar PV, onshore wind and hydro. FOAK – first of a kind. CCS – carbon capture and storage.

Figure 5-4 The projected generation mix in 2050 by emissions intensity target and allowed technology.

The least cost generation mix in 2050 by emission intensity target for either mature technologies only or mature technologies plus one of three technology groups not previously deployed in Australia are shown in Figure 5-4. In *NoProgressToNetZero*, with an emissions intensity 0.20tCO_2e/MWh, the 2050 technology mix would include 70% renewables or slightly lower in those scenarios where the FOAK technologies are included. The remaining generation is from unabated fossil fuels which, in the past, GenCost has found are only slightly higher cost or similar cost to firmed renewables depending on prevailing fossil fuel prices. As such, it is not surprising that, where emission reduction targets are only mild, some fossil fuels will be deployed, even as a minority of generation.

There is an inconsistency in fossil assumptions for the *NoProgressToNetZero* emission intensity scenario. The fossil fuel prices are sourced from AEMO's Input and Assumptions workbook where the scenarios assume that both Australia and the world are targeting substantial emissions reduction. In those scenarios, global and local fossil fuel demand is declining, keeping fossil fuel prices stable or in some cases falling. The *NoProgressToNetZero* emission intensity scenario is not consistent with those scenarios. The *NoProgressToNetZero* emission intensity scenario might be more consistent with increasing demand for fossil fuels which could mean increasing fossil fuel prices. With this context, the competitiveness of fossil fuels in this scenario should be interpreted with some caution. Projections of fossil fuel prices for a non-decarbonising world are not readily available.

While the model is free to do so, the least cost solution excludes any additional offshore wind, CCS or nuclear beyond the required initial FOAK projects in the *NoProgressToNetZero* emission intensity scenario.

In *WeakNetZero* (at 0.10tCO_2e/MWh) the gas share of generation is decreased and there is no expansion of offshore wind, CCS or nuclear beyond the FOAK projects. Solar PV and onshore wind gain all of the market share lost by gas and coal relative to *NoProgressToNetZero*. In *ModerateNetZero* (at 0.05tCO_2e/MWh), the same trend occurs with solar PV and onshore wind replacing natural gas with no competition from other generation sources.

In *StrongNetZero* (at 0.02tCO_2e/MWh) the trend changes. Gas is too emission intensive to continue providing 7% of generation that it did under *ModerateNetZero*. However, gas cannot be cost effectively replaced with only solar PV and onshore wind because this would increase storage costs. Instead, the model deploys an alternative flexible generation technology in the form of hydrogen generation. The model does not deploy additional FOAK capacity beyond the required initial projects.

When the emission intensity target is set to zero in *VeryStrongNetZero*, the hydrogen share is increased from around 4% to 7% and natural gas decreases to less than 1% (this scenario allows for less than a million tonnes of residual emissions). Again, the model does not deploy additional FOAK capacity beyond the required initial projects.

Cost

The SLCOE results for all scenarios are shown in Figure 5-5. The SLCOE results for 2050 only allows for existing long-lived transmission and hydro technology, assuming all other large scale generation technology that exists today has retired[20]. For this reason, the 2050 estimates overstate the average cost of generation in 2050 by assuming there will be no significant existing generation capacity, but the estimates can be considered an upper bound on average costs[21].

The SLCOE results show that deploying mature technology only (solar PV, wind, gas and storage) is the least cost generation mix in 2050 for all emission intensity levels modelled. For the FOAK technologies, the CCS and offshore wind scenarios have very similar costs with CCS being only slightly higher cost than offshore wind. Nuclear is consistently the highest cost. These outcomes are based on average costs. Offshore wind has a much wider cost uncertainty range and so could perform better under alternative cost scenarios not explored.

[20] This is not strictly true because most solar PV built now or in the last few years will remain operating in 2050 due to their 30 year life.

[21] In practice, the partial existing capacity that would normally be available to meet 2050 demand will be developed and paid for through generation in the decades leading up to 2050 and building out this investment pathway is how a more commercial grade electricity system model would estimate electricity costs over time. However, in this simplified modelling approach we only include selected long-lived existing resources and other resources needed to meet demand in 2050 are built in 2050 and paid for in the decades that follow (through amortisation).

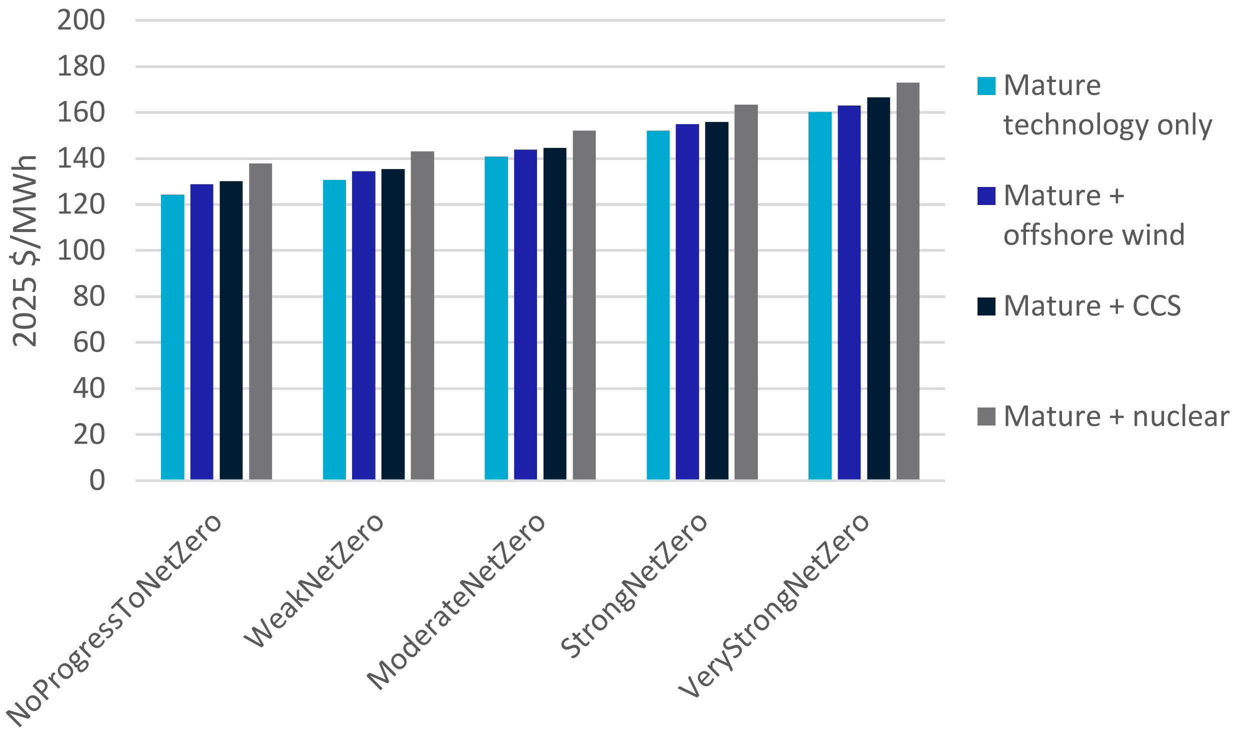
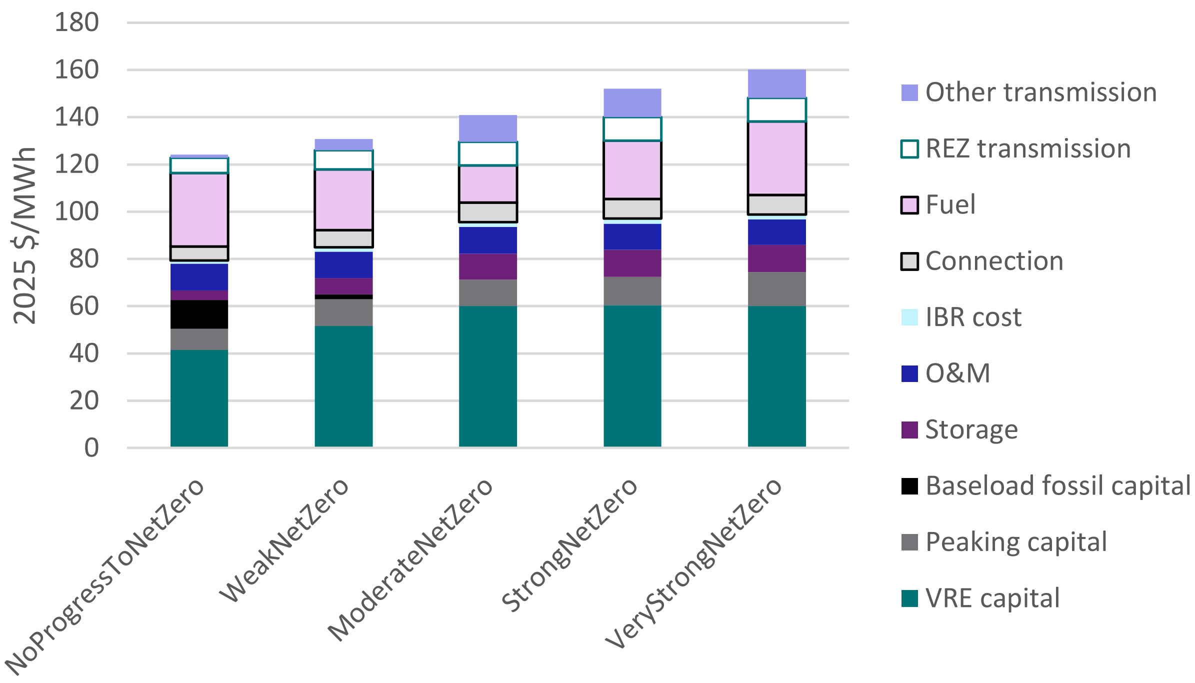


Figure 5-5 The projected SLCOE in 2050 in the NEM by emission intensity target and technology allowed

There is a clear trend that decreasing emissions increases 2050 electricity costs but lower cost emission intensity scenarios may increase costs elsewhere in the economy and so should be interpreted with caution. We identify the efficient level of emissions to reach net zero further below. The rising trend reflects that as the emissions intensity declines, more zero emissions technology must be deployed, supported by more storage and more transmission as well as more expensive fuels (such as hydrogen) in some cases (*StrongNetZero* and *VeryStrongNetZero*).

The breakdown of costs for each mature technology emissions intensity scenario is shown in Figure 5-6. The fuel cost falls as the gas share of generation declines but increases for the last two scenarios as hydrogen enters the generation mix with hydrogen fuel being higher cost than gas on an energy unit basis. Baseload fossil fuel costs also fall as they are removed from the generation mix as the emission intensity declines. Almost all other cost categories increase as the emissions intensity falls. However, the increase in connection costs, inverter-based resource costs and operating and maintenance costs are relatively minor. The biggest increases are in storage and transmission costs.



VRE-– variable renewable generation; IBR - Inverter-based resources cost such as deployment of synchronous condensers and grid-forming batteries; REZ – renewable energy zone. O&M – operating and maintenance costs
Figure 5-6 The breakdown of SLCOE in 2050 in the NEM by cost component for mature technology only scenario

As discussed in the scenario descriptions, in theory the highest of the projected costs in 2050 need only be experienced if lower cost abatement is not available elsewhere in the economy outside of the electricity sector since there is no specific requirement for the electricity sector to eliminate all emissions. To find the efficient level of electricity sector abatement, the marginal (incremental) cost of abatement of each emissions intensity level was calculated relative to the next highest emission intensity scenario (Figure 5-7). The cost of abatement in the electricity sector can be compared to the expected cost of abatement across the whole economy to reach net zero which is published by Infrastructure Australia[22]. They publish a cost of abatement range in 2050 of $304 to $497/t$CO_2$e (adjusted to 2025 dollars).

The analysis shows that it is not efficient for the electricity sector to implement the *VeryStrongNetZero* emission intensity scenario which almost eliminates emissions from the sector (with less than a million tonnes remaining) because it is expected that there will be lower cost abatement in other sectors of the economy. If the whole of economy cost of abatement is in the high end of the range, then it would be efficient for the electricity sector to implement *StrongNetZero*. On the other hand, if the whole of economy cost of abatement is at the lower end of the expected range then the *StrongNetZero* emission intensity scenario is not efficient as it would incur costs that are higher than abatement options in other sectors of the economy.

At the lowest end of the whole of economy cost range, it would be efficient for the electricity sector to target an emissions intensity of 0.05tCO_2e/MWh in the *ModerateNetZero* scenario or slightly lower that given its marginal cost of abatement is below the whole of economy range.

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[22] https://www.infrastructureaustralia.gov.au/publications/valuing-emissions-economic-analysis

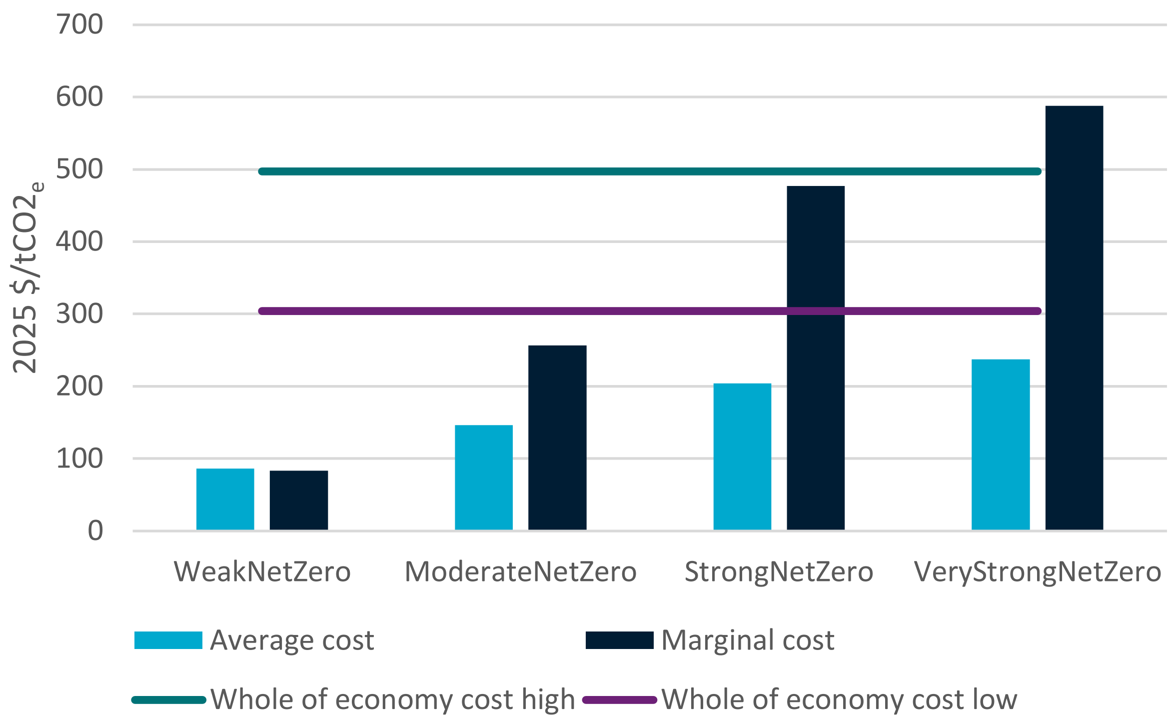


Figure 5-7 Average and marginal cost of abatement to achieve lower emissions intensity targets in 2050 compared to whole of economy abatement costs

In summary, examining the cost of abatement indicates that:

- In a whole of economy effort to reach net zero by 2050, efficient level of emission abatement in the electricity sector is uncertain given the cost of abatement in the rest of the economy has a wide uncertainty range.
- Based on the range of whole of economy abatement costs, the efficient range of emissions intensity of the electricity sector is 0.05tCO_2e/MWh to 0.02tCO_2e/MWh.
- Achieving the electricity sector's efficient role in whole of economy net zero abatement is projected to result in electricity costs $141/MWh to $152/MWh or an average of $146/MWh in the NEM inclusive of new transmission costs or $120/MWh to $130/MWh or an average of $125/MWh measured as wholesale generation costs only.
- The average cost of implementing the efficient level of abatement in the electricity sector of 0.02tCO_2e/MWh is $175/t$CO_2$e. Achieving weak or no progress in reducing electricity sector emissions is not efficient for achieving net zero because electricity sector emissions reduction is a third to a half the cost of emissions reduction elsewhere in the economy.

5.5.6 Alternative results for cost of high renewable systems in the literature

There is a surprising range of estimates of the cost of electricity from systems with a high share of weather dependent renewable generation. These studies have been separately reviewed in Graham (2025) where costs have been estimated in the range of below $70/MWh to over $1000/MWh. The review finds that, in each case where system average costs were reported to be high, the published modelling had excluded key resources required to keep costs low. Typical exclusions included: only one type of storage technology allowed, only one duration of storage technology allowed, peaking technology not allowed and a narrow set or single type of renewable generation allowed. When resources are made available, renewable generation is lowest cost when sourced from both solar PV and wind in different locations and combined with multiple storage technologies and gas or hydrogen peaking plant. Graham (2025) concludes that the observed exclusions in other studies do not appear to be valid for the NEM which has all of these resources available.

5.5.7 2050 LCOE estimates

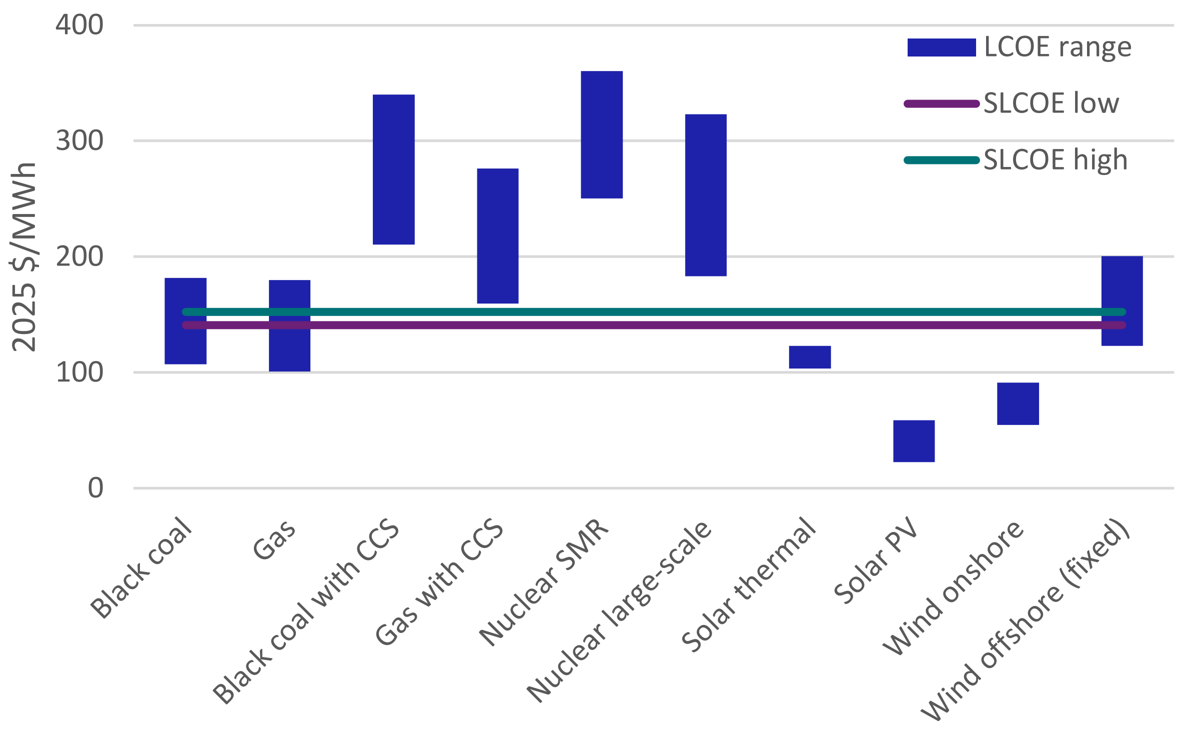
In addition to the SLCOE estimates provided in the previous section, the LCOE for individual technologies is also calculated and represents the breakeven price needed for each technology to achieve a reasonable return on investment. Appendix B includes the LCOE for additional years and technologies, however in this section we focus on a selected set of technologies for consistency with the SLCOE modelling.

Figure 5-8 shows the LCOE results for 2050. Here they have been compared to the electricity system cost range identified in the SLCOE analysis as being the potential efficient range for electricity sector abatement from *ModerateNetZero* to *VeryStrongNetZero*. By 2050, the costs of most technologies other than coal and gas have fallen compared to 2025. Solar PV and onshore wind (without integration costs) are lowest cost relative to the SLCOE estimates. The SLCOE analysis, which does include the renewable integration costs, indicates that solar PV and wind will deliver the majority of electricity supply (93%) supported by hydro, storage, transmission and either gas or hydrogen or a combination of both.

New black coal, while competitive at this SLCOE range is not relevant for deployment if the goal is to efficiently achieve net zero (that is, it would increase the cost of achieving net zero across the economy). New gas is also in the competitive range and unlike coal, the SLCOE analysis indicates it will play a role in achieving net zero emissions contributing a 3% to 7% share of generation.

Solar thermal is competitive relative to other technologies and inside the SLCOE range. However, given the need to access better solar resources which are further from load centres, solar thermal will be subject to additional transmission costs compared to coal, gas and nuclear which have not been directly accounted for. Based on Figure 5-6, additional transmission costs could add around $20/MWh. Some offshore wind is also in the competitive range however the modelling used the average cost of offshore wind. Lower range offshore wind costs appear to be competitive but were not explored in the modelling and so need more analysis.

Gas with CCS is the next most competitive after solar thermal and offshore wind. Large-scale nuclear is slightly higher in cost than gas with CCS. Black coal with CCS occupies a similar cost range to nuclear. Nuclear small modular reactors (SMRs) are the highest cost. Achieving the lower end of the nuclear SMR range requires that SMR is deployed globally in large enough capacity to bring down costs available to Australia. Lowest cost gas with CCS is subject to accessing gas supply at the lower end of the range assumed (see Appendix B for fuel cost assumptions). Coal, gas and nuclear technologies would all have to be successful in operating at 89% capacity factor to achieve the lower end of the cost range when historically coal, which has been the main baseload energy source in Australia's largest states, has only achieved an average of around 60%.



LCOE excludes integration costs. SLCOE includes integration costs of the least cost technology mix which includes a combined solar PV and onshore wind share of 87% to 89%.

Figure 5-8 Calculated LCOE range by technology and SLCOE range for 2050

5.6 Overall implications for long term electricity generation cost trends

In 2025 calendar year the average NEM volume weighted generation price was estimated to be $104/MWh, down from the recent peak in 2022 of $189/MWh caused predominantly by high gas prices. Based on NEM electricity futures prices in the next three years (and supported by AEMC (2025) modelling), generation costs to 2030 are expected to fall further compared to 2025 to around $80-$90/MWh.

In the post-2030 period, net zero by 2050 is the most common type of climate change policy adopted globally and at the national, state and corporate level in Australia. By 2050, most generation capacity that exists today will be retired. The LCOE and SLCOE analysis in this report indicates that there are no new build technology options, fossil or non-fossil including integration costs, that cost less than $100/MWh (Figure 5-8). By 2050, new build coal generation costs are in the range of $107/MWh to $182/MWh. As such, even without the net zero by 2050 policies, generation prices are expected to increase above $100/MWh in the post 2030 period.

The cost of generation if the electricity sector makes an efficient contribution to achieving net zero by 2050 is $141/MWh to $152/MWh inclusive of all firming costs (an average of $146/MWh). This is based on a 2050 generation mix of large-scale solar PV and onshore wind of around 93% in total. Excluding transmission costs which are not recovered through the generation market, the net zero consistent generation cost is $120/MWh to $130/MWh or an average of $125/MWh.

Appendix A Global and local learning model

A.1 GALLM

The Global and Local Learning Models (GALLMs) for electricity (GALLME) and transport (GALLMT) are described briefly here. More detail can be found in several publications (Hayward and Graham, 2017; Hayward and Graham, 2013; Hayward, Foster, Graham and Reedman, 2017).

A.1.1 Endogenous technology learning

Technology cost reductions due to 'learning-by-doing' were first observed in the 1930s for aeroplane construction (Wright, 1936) and have since been observed and measured for a wide range of technologies and processes (McDonald and Schrattenholzer, 2001). Cost reductions due to this phenomenon are normally shown via the equation:

$$IC = IC_0 \times \left(\frac{CC}{CC_0}\right)^{-b},$$

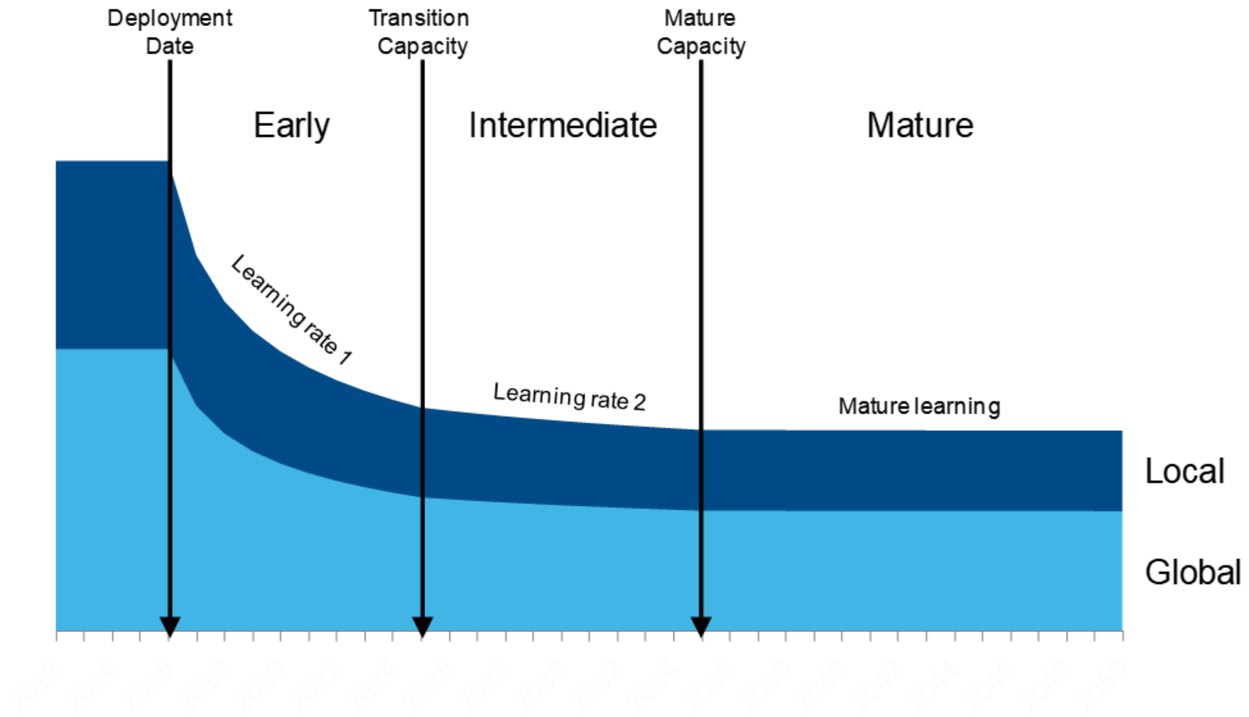
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

where IC is the unit investment cost at CC cumulative capacity and IC_0 is the cost of the first unit at CC_0 cumulative capacity. The learning index b satisfies $0 < b < 1$ and it determines the learning rate which is calculated as:

$$LR = 100 \times (1 - 2^{-b})$$

(typically quoted as a percentage ranging from 0 to 50%) and the progress ratio is given by PR=100-LR. All three quantities express a measure of the decline in unit cost with learning or experience. This relationship states that for each doubling in cumulative capacity of a technology, its investment cost will fall by the learning rate (Hayward & Graham, 2013). Learning rates can be measured by examining the change in unit cost with cumulative capacity of a technology over time.

Typically, emerging technologies have a higher learning rate (15–20%), which reduces once the technology has at least a 5% market share and is considered to be at the intermediate stage (to approximately 10%). Once a technology is considered mature, the learning rate tends to be 0–5% (McDonald and Schrattenholzer, 2001). The transition between learning rates based on technology uptake is illustrated in Apx Figure A.1.



Apx Figure A.1 Schematic of changes in the learning rate as a technology progresses through its development stages after commercialisation

However, technologies that are modular and as a result can be used in a variety of applications tend to have a higher learning rate for longer (Wilson, 2012). This is the case for solar photovoltaics, batteries and historically for gas turbines.

Technologies are made up of components and different components can be at different levels of maturity and thus have different learning rates. Different parts of a technology can be developed and sold in different markets (global vs. regional/local) which can impact the relative cost reductions given each region will have a different level of demand for a technology.

A.1.2 The modelling framework

To project the future cost of a technology using experience curves, the future level of cumulative capacity/uptake needs to be known. However, this is dependent on the costs. The GALLM models solve this problem by simultaneously projecting both the cost and uptake of the technologies. The optimisation problem includes constraints such as government policies, demand for electricity or transport, capacity of existing technologies, exogenous costs such as for fossil fuels and limits on resources (e.g., rooftops for solar photovoltaics). The models have been divided into 13 regions and each region has unique assumptions and data for the above listed constraints. The regions have been based on Organisation for Economic Co-operation Development (OECD) regions (with some variation to look more closely at some countries of interest) and are Africa, Australia, China, Eastern Europe, Western Europe, Former Soviet Union, India, Japan, Latin America, Middle East, North America, OECD Pacific, Rest of Asia and Pacific.

The objective of the model is to minimise the total system costs while meeting demand and all constraints. The model is solved as a mixed integer linear program. The experience curves are segmented into step functions and the location on the experience curves (i.e., cost vs. cumulative capacity) is determined at each time step. See Hayward and Graham (2013) and Hayward et al. (2017) for more information. Both models run from the year 2006 to 2100. However, results are only reported from the present year to 2055.

A.1.3 Offshore wind

Offshore wind has been divided into fixed and floating foundation technologies. IRENA (2024) and Stehly and Duffy (2021) provided a breakdown of the cost of all components of both fixed and floating offshore wind, which allowed us to separate out the cost of the foundations from the remainder of the cost components. This division in costs was then applied to the current Australian costs from GHD (2026) resulting in the values as shown in Apx Table A.1.

Apx Table A.1 Cost breakdown of offshore wind

Cost component	Fixed offshore wind ($/kW)	Floating offshore wind ($/kW)
Foundation	597	2393
Remainder of cost	4065	4065
Total cost	4662	6459

The learning of all offshore wind components (i.e., “Remainder of cost” components) except for the foundations are shared among both offshore wind technologies. The floating foundations used in floating offshore wind have a learning rate, but the fixed foundations used in fixed offshore wind have no learning rate.

Appendix B Data tables

The following tables provide data behind the figures presented in this document.

The year 2025 is mostly sourced from GHD (2026) and is aligned to July which represents either the middle of that calendar year or the beginning of the 2025-26 financial year. All projections are in real 2025 dollars.

As discussed in Section 2, the data is not intended to include FOAK costs. Therefore, for technologies not recently constructed in Australia, the cost of the first and some subsequent deployments may be higher than shown in this appendix. Section 2 includes suggested FOAK premiums.

GHD provide data for adjusting costs for different locations in the NEM and this data is also published by AEMO. Site conditions will also impact costs to varying degrees, depending on the technology.

All capital costs are for the alternating current power rating of the equipment with the exception of rooftop solar which is on a direct current basis. Power is also on a net basis after auxiliary loads. Capital costs are before any subsidies that may be available.

Apx Table B.1 Current and projected generation technology capital costs under the *Current policies* scenario

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear SMR	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2914	1764	6962	2022	2648	9016	25712	1621	1216	6493	3248	5433	8325	15842	28009	12420	7000	10332
2026	6946	12941	10725	2640	3083	1867	7105	2022	2648	9016	25712	1516	1191	6453	3248	5380	7261	15842	26351	12420	7000	10332
2027	6584	12465	10108	2783	3253	1970	7248	2010	2594	8387	24850	1443	1171	6435	2984	5342	6559	14835	24692	11500	6613	10000
2028	6435	12284	9852	2658	3023	1831	6906	2009	2573	8287	24430	1401	1156	6424	2866	5320	6224	14356	23034	11066	6428	9877
2029	6296	12118	9613	2539	2814	1704	6580	2009	2554	8316	24017	1388	1145	6395	2755	5306	6202	13893	21452	10649	6248	9764
2030	6162	11961	9385	2426	2624	1589	6269	2010	2537	8349	23611	1378	1135	6358	2650	5300	6194	13444	20806	10247	6073	9658
2031	6031	11805	9161	2317	2425	1468	5973	2011	2519	8381	23211	1358	1127	6327	2553	5300	6195	13010	20325	9860	5903	9552
2032	5899	11644	8938	2213	2242	1357	5691	2011	2501	8411	22819	1338	1121	6308	2464	5307	6201	12590	19830	9488	5738	9442
2033	5769	11481	8717	2114	2073	1255	5422	2010	2482	8439	22433	1319	1117	6295	2386	5311	6206	12183	19915	9130	5577	9330
2034	5641	11320	8501	2020	1919	1162	5166	2010	2463	8466	22054	1300	1112	6287	2323	5314	6209	11790	20000	8786	5421	9220
2035	5564	11230	8371	1929	1776	1076	4922	2012	2454	8494	21681	1281	1107	6284	2309	5316	6211	11409	20085	8454	5269	9159
2036	5536	11210	8325	1916	1747	1058	4873	2017	2453	8522	21771	1262	1101	6284	2275	5317	6207	11489	20171	8493	5283	9149
2037	5558	11260	8362	1922	1752	1061	4888	2024	2462	8551	21865	1244	1098	6220	2268	5316	6189	11502	20258	8499	5291	9189
2038	5581	11310	8400	1928	1757	1064	4904	2031	2471	8581	21960	1226	1094	6115	2262	5316	6157	11515	19900	8504	5294	9229
2039	5603	11361	8437	1934	1762	1067	4919	2038	2480	8610	22056	1208	1092	5979	2257	5315	6118	11528	18488	8510	5295	9269
2040	5624	11408	8472	1939	1767	1070	4933	2045	2488	8637	22144	1191	1090	5873	2253	5315	6093	11539	16682	8516	5284	9306
2041	5642	11450	8503	1944	1770	1072	4944	2050	2494	8659	22222	1174	1088	5791	2249	5316	6082	11550	15308	8522	5276	9339
2042	5659	11487	8531	1948	1773	1074	4954	2055	2500	8679	22292	1157	1086	5726	2246	5317	6084	11560	14974	8528	5274	9368
2043	5677	11524	8558	1952	1776	1076	4963	2060	2506	8698	22362	1140	1084	5684	2242	5320	6088	11569	15021	8534	5280	9398
2044	5695	11562	8586	1955	1780	1078	4973	2065	2512	8717	22433	1123	1083	5622	2236	5322	6091	11579	15068	8540	5280	9428
2045	5713	11600	8615	1959	1783	1079	4982	2070	2518	8737	22504	1107	1082	5546	2232	5325	6095	11589	15116	8545	5265	9457
2046	5730	11638	8643	1963	1786	1081	4992	2075	2524	8757	22575	1091	1081	5465	2227	5328	6098	11598	15164	8551	5242	9487
2047	5747	11676	8671	1967	1789	1083	5002	2080	2530	8776	22647	1075	1080	5414	2222	5332	6102	11608	15212	8557	5207	9517
2048	5762	11715	8700	1971	1792	1085	5012	2085	2537	8796	22719	1060	1079	5390	2216	5335	6106	11618	15260	8563	5151	9548
2049	5777	11754	8729	1974	1795	1087	5022	2090	2543	8816	22792	1044	1077	5380	2210	5338	6110	11628	15309	8569	5082	9578
2050	5791	11790	8756	1978	1798	1089	5031	2095	2548	8835	22860	1029	1077	5376	2207	5342	6114	11637	15355	8576	5026	9607
2051	5804	11825	8782	1981	1801	1090	5039	2099	2554	8852	22925	1014	1077	5373	2204	5345	6117	11646	15399	8582	4992	9634
2052	5815	11858	8806	1984	1803	1092	5046	2103	2558	8867	22986	999	1077	5369	2201	5348	6121	11654	15439	8588	4975	9660
2053	5827	11890	8830	1987	1806	1093	5053	2107	2563	8882	23047	985	1077	5358	2198	5351	6124	11662	15480	8594	4953	9685
2054	5838	11923	8855	1990	1808	1095	5060	2111	2568	8898	23108	971	1077	5347	2194	5355	6129	11671	15522	8600	4935	9711
2055	5843	11940	8867	1991	1809	1095	5064	2113	2571	8906	23138	957	1077	5341	2192	5357	6131	11675	15542	8603	4928	9724

Apx Table B.2 Current and projected generation technology capital costs under the *Global NZE by 2050* scenario

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear SMR	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2914	1764	6962	2022	2648	9016	25712	1621	1216	6493	3248	5433	8325	15842	28009	12420	7000	10332
2026	6946	12941	10725	2640	3083	1867	7105	2022	2648	9016	25712	1419	1174	6345	3248	5115	7124	15842	26351	12420	7000	10332
2027	6617	12514	10156	2783	3253	1970	7248	2016	2602	8702	24937	1237	1137	6228	2971	4816	6049	14923	24692	11577	6616	10046
2028	6498	12387	9946	2665	3030	1835	6900	2022	2590	8578	24558	1083	1107	6148	2849	4544	5145	14484	23034	11177	6433	9967
2029	6396	12291	9765	2552	2827	1712	6568	2030	2581	8469	24184	950	1080	6084	2735	4293	4382	14057	21716	10791	6254	9912
2030	6296	12196	9588	2443	2642	1600	6252	2039	2574	8408	23817	847	1055	6037	2629	4133	3917	13643	21273	10418	6080	9858
2031	6188	12083	9399	2340	2447	1481	5951	2046	2563	8364	23455	783	1025	6002	2529	4059	3705	13242	18574	10058	5911	9790
2032	6074	11952	9200	2240	2267	1373	5665	2050	2550	8368	23098	757	1004	5981	2436	4064	3707	12852	15440	9711	5747	9708
2033	5957	11815	8999	2145	2101	1272	5393	2054	2536	8367	22747	751	977	5943	2355	4070	3709	12474	12661	9375	5587	9620
2034	5843	11680	8803	2054	1949	1180	5133	2058	2522	8365	22401	750	957	5892	2289	4076	3713	12106	12099	9052	5432	9533
2035	5782	11517	8695	1967	1808	1095	4886	2064	2517	8341	22061	747	926	5824	2273	4083	3717	11750	11903	8739	5281	9499
2036	5772	11416	8674	1957	1781	1078	4741	2073	2522	8327	22115	725	901	5770	2234	4090	3722	11643	11919	8583	5304	9516
2037	5814	11383	8739	1966	1788	1083	4658	2085	2536	8330	22168	699	881	5728	2225	4098	3727	11669	11955	8572	5323	9585
2038	5857	11446	8806	1975	1796	1088	4660	2097	2551	8348	22310	676	871	5700	2216	4107	3733	11695	12043	8561	5348	9656
2039	5900	11504	8873	1985	1804	1092	4657	2109	2566	8359	22448	673	862	5678	2214	4117	3740	11722	12131	8572	5360	9727
2040	5941	11561	8937	1994	1811	1097	4654	2120	2579	8385	22582	672	855	5662	2214	4126	3748	11747	12216	8588	5366	9795
2041	5981	11621	8998	2002	1818	1101	4657	2131	2592	8416	22714	669	836	5650	2213	4137	3757	11772	12297	8214	5376	9859
2042	6018	11694	9055	2009	1824	1104	4672	2141	2604	8451	22852	666	817	5642	2209	4146	3765	11795	12373	7819	5379	9920
2043	6055	11770	9114	2016	1830	1108	4689	2151	2616	8487	22994	663	795	5637	2205	4157	3773	11819	12450	7423	5386	9982
2044	6093	11843	9173	2023	1836	1112	4704	2160	2628	8524	23135	662	784	5635	2202	4167	3782	11843	12527	7410	5336	10044
2045	6131	11915	9232	2031	1842	1115	4717	2171	2640	8561	23276	661	778	5637	2199	4177	3791	11867	12606	7409	5290	10107
2046	6169	11987	9292	2038	1848	1119	4729	2181	2653	8598	23417	660	773	5643	2197	4188	3800	11891	12685	7408	5198	10171
2047	6208	12061	9353	2046	1855	1123	4743	2191	2665	8636	23560	656	767	5658	2194	4199	3809	11916	12765	7413	5133	10235
2048	6247	12136	9414	2054	1861	1127	4757	2201	2678	8674	23705	647	756	5676	2190	4210	3818	11940	12845	7428	5053	10299
2049	6287	12210	9476	2061	1867	1131	4771	2212	2691	8712	23851	631	742	5700	2185	4221	3826	11965	12927	7442	5007	10365
2050	6326	12282	9537	2069	1874	1134	4782	2222	2703	8749	23992	616	731	5723	2180	4231	3834	11990	13007	7457	4970	10429
2051	6364	12349	9597	2076	1879	1138	4791	2232	2715	8785	24128	606	723	5742	2177	4241	3843	12014	13085	7471	4956	10491
2052	6401	12416	9655	2083	1885	1141	4799	2241	2726	8819	24262	603	723	5755	2176	4252	3852	12038	13161	7486	4943	10553
2053	6439	12483	9714	2090	1891	1145	4808	2251	2738	8854	24396	602	723	5746	2176	4262	3860	12062	13239	7501	4934	10615
2054	6476	12553	9773	2096	1896	1148	4819	2260	2750	8889	24534	602	725	5724	2174	4273	3869	12087	13316	7516	4908	10677
2055	6495	12588	9803	2100	1899	1150	4824	2265	2756	8907	24603	602	726	5705	2173	4278	3873	12099	13355	7524	4894	10708

Apx Table B.3 Current and projected generation technology capital costs under the *Global NZE post 2050* scenario

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear (SMR)	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2914	1764	6962	2022	2648	9016	25712	1621	1216	6493	3248	5433	8325	15842	28009	12420	7000	10332
2026	6946	12941	10725	2640	3083	1867	7105	2022	2648	9016	25712	1566	1194	6454	3248	5396	7787	15842	26351	12420	7000	10332
2027	6596	12472	10121	2783	3253	1970	7248	2012	2596	8704	24937	1515	1176	6441	2981	5366	7281	14906	24692	11561	6613	10013
2028	6456	12303	9879	2660	3026	1832	6904	2012	2578	8572	24558	1471	1162	6458	2863	5344	6817	14460	23034	11155	6428	9902
2029	6329	12156	9658	2543	2818	1706	6576	2015	2562	8451	24184	1430	1151	6485	2751	5326	6386	14026	21487	10762	6248	9808
2030	6207	12015	9446	2431	2630	1592	6264	2019	2548	8379	23817	1392	1137	6511	2647	5292	6092	13606	20972	10384	6073	9718
2031	6084	11869	9233	2324	2432	1472	5967	2021	2532	8332	23455	1358	1130	6524	2549	5246	5927	13198	20477	10018	5903	9624
2032	5957	11713	9016	2222	2250	1362	5684	2022	2515	8327	23098	1325	1123	6530	2460	5202	5894	12802	19997	9666	5738	9522
2033	5832	11556	8802	2124	2082	1261	5414	2023	2498	8323	22747	1293	1116	6530	2381	5164	5865	12418	20101	9326	5577	9418
2034	5710	11402	8593	2030	1928	1167	5157	2024	2481	8342	22401	1261	1109	6538	2318	5116	5788	12046	18260	8998	5421	9315
2035	5639	11321	8471	1941	1786	1081	4912	2028	2473	8352	22061	1230	1103	6541	2303	5053	5698	11685	16275	8681	5269	9264
2036	5619	11312	8434	1929	1758	1064	4865	2034	2475	8362	22177	1200	1096	6447	2270	4996	5614	11532	14280	8524	5284	9264
2037	5650	11375	8481	1936	1764	1068	4882	2043	2485	8373	22297	1171	1089	6303	2266	4957	5584	11548	14222	8533	5300	9314
2038	5680	11439	8529	1943	1770	1071	4901	2052	2496	8392	22418	1143	1082	6134	2261	4937	5570	11564	14294	8541	5292	9365
2039	5711	11497	8577	1950	1776	1075	4914	2061	2507	8409	22535	1115	1075	6059	2258	4927	5487	11581	14366	8549	5061	9416
2040	5740	11552	8622	1957	1781	1078	4925	2069	2517	8428	22644	1088	1069	6007	2251	4929	5414	11596	13994	8558	4817	9464
2041	5767	11602	8663	1963	1786	1081	4934	2077	2526	8442	22744	1061	1062	5963	2246	4933	5341	11610	13553	8566	4587	9508
2042	5792	11653	8702	1968	1790	1084	4947	2083	2534	8458	22841	1036	1056	5905	2240	4941	5350	11623	13103	8574	4518	9548
2043	5816	11704	8740	1973	1794	1086	4959	2090	2542	8472	22938	1010	1049	5834	2241	4919	5333	11636	13047	8583	4412	9589
2044	5841	11756	8779	1978	1798	1089	4972	2096	2550	8455	23036	986	1043	5748	2242	4872	5297	11650	12741	8591	4229	9630
2045	5866	11808	8818	1983	1802	1091	4985	2103	2558	8422	23135	962	1036	5657	2241	4812	5249	11663	12375	8600	4096	9671
2046	5892	11861	8857	1988	1807	1094	4998	2110	2567	8376	23235	938	1030	5604	2238	4775	5221	11676	12052	8609	4005	9713
2047	5917	11914	8897	1993	1811	1096	5010	2117	2575	8341	23335	915	1023	5574	2232	4752	5204	11690	12045	8617	3985	9754
2048	5942	11967	8937	1998	1815	1099	5023	2124	2583	8299	23436	903	1017	5563	2227	4734	5191	11703	12097	8626	3981	9797
2049	5968	12021	8977	2003	1819	1102	5036	2130	2592	8274	23537	888	1010	5554	2219	4721	5182	11717	12149	8635	3978	9839
2050	5993	12073	9015	2008	1823	1104	5049	2137	2600	8272	23635	873	1004	5548	2213	4721	5183	11730	12200	8644	3982	9880
2051	6017	12123	9053	2013	1827	1106	5060	2143	2607	8294	23729	860	1000	5536	2207	4727	5189	11742	12248	8652	3988	9919
2052	6040	12171	9088	2017	1831	1108	5071	2149	2614	8315	23819	851	1000	5523	2203	4730	5194	11754	12295	8661	3992	9957
2053	6063	12219	9125	2021	1834	1110	5081	2155	2621	8336	23910	844	1000	5520	2198	4718	5186	11767	12326	8670	3993	9995
2054	6086	12257	9161	2025	1838	1113	5082	2161	2629	8357	23991	836	1001	5530	2191	4697	5170	11779	12345	8679	3988	10033
2055	6097	12276	9179	2027	1839	1114	5083	2164	2632	8367	24032	829	1001	5537	2188	4681	5158	11785	12347	8684	3984	10052

Apx Table B.4 One- and two-hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	Battery storage (1 hr)									Battery storage (2 hrs)								
	Total			Battery			BOP			Total			Battery			BOP		
	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
2025	778	778	778	310	310	311	467	467	467	525	525	525	290	290	290	235	235	235
2026	743	733	723	301	298	295	443	436	428	503	497	491	281	278	276	223	219	215
2027	707	692	678	285	284	283	422	408	395	478	470	463	266	265	265	212	205	198
2028	678	657	637	272	272	273	406	385	364	458	447	438	254	254	255	204	193	183
2029	661	631	601	264	264	264	397	367	337	446	430	416	247	246	246	199	184	169
2030	653	620	588	256	255	256	397	365	333	438	421	406	239	238	238	199	183	167
2031	645	608	575	248	246	248	396	362	327	430	411	395	232	230	231	199	182	164
2032	636	596	561	241	238	240	396	359	322	423	402	385	224	222	223	199	180	162
2033	628	585	548	233	229	232	395	356	316	415	392	375	217	214	216	198	179	159
2034	620	575	536	226	222	224	394	353	311	408	383	365	210	206	209	198	177	156
2035	613	564	523	219	214	217	394	350	306	401	375	356	204	199	202	197	176	153
2036	605	554	511	212	207	210	393	347	301	394	366	347	197	192	196	197	174	151
2037	598	544	499	205	199	204	393	345	296	388	358	338	191	186	190	197	173	148
2038	591	535	488	199	193	197	392	342	291	381	350	329	185	179	183	196	171	146
2039	584	525	477	193	186	191	392	339	286	375	343	321	179	173	178	196	170	143
2040	582	521	472	191	185	190	391	337	281	373	340	318	178	172	177	196	168	141
2041	580	517	467	190	183	190	390	334	277	372	337	315	176	170	177	195	167	138
2042	578	513	462	188	182	190	389	331	272	370	335	312	175	169	176	195	166	136
2043	576	509	457	187	181	190	389	328	267	369	333	310	174	169	176	194	164	134
2044	574	506	452	187	181	190	388	325	262	367	331	308	173	168	176	194	163	131
2045	573	502	447	186	180	190	387	322	258	366	329	305	173	167	176	193	161	129
2046	571	499	443	185	180	190	386	319	253	365	327	303	172	167	176	193	160	127
2047	570	496	439	185	179	190	385	317	249	364	325	301	172	167	176	193	158	125
2048	569	493	435	185	179	190	384	314	245	364	323	299	171	166	176	192	157	122
2049	568	490	431	184	179	190	383	311	240	363	322	297	171	166	177	192	156	120
2050	567	487	427	184	179	190	383	308	236	362	320	295	171	166	177	191	154	118
2051	565	484	423	184	179	190	382	306	232	361	319	293	171	166	177	191	153	116
2052	564	481	419	184	178	191	381	303	228	361	317	291	170	166	177	190	151	114
2053	563	478	415	183	178	191	380	300	224	360	316	289	170	166	177	190	150	112
2054	562	476	411	183	178	191	379	297	220	359	314	288	170	166	178	189	149	110
2055	569	485	421	183	178	191	386	306	230	363	319	293	170	166	178	193	153	115

Apx Table B.5 Four- and eight-hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	Battery storage (4 hrs)									Battery storage (8 hrs)								
	Total			Battery			BOP			Total			Battery			BOP		
	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
2025	385	385	385	265	265	265	120	120	120	308	308	308	245	245	245	63	63	63
2026	370	365	361	256	254	251	114	112	110	296	293	290	236	234	232	60	59	58
2027	350	346	342	242	242	241	108	105	101	280	278	276	224	223	223	57	55	53
2028	335	330	326	231	232	232	104	99	93	268	265	263	213	214	214	55	52	49
2029	326	318	311	225	224	224	102	94	86	261	256	252	208	207	207	53	49	45
2030	319	310	302	218	217	217	101	93	85	254	249	245	201	200	201	53	49	45
2031	312	302	294	211	209	210	101	92	84	248	241	238	195	193	194	53	48	44
2032	305	293	286	204	202	203	101	92	82	241	234	231	188	186	188	53	48	43
2033	299	286	278	198	195	197	101	91	81	235	227	224	182	180	182	53	48	42
2034	292	278	270	191	188	190	101	90	79	229	220	217	177	173	176	53	47	42
2035	286	271	262	185	181	184	100	89	78	223	214	211	171	167	170	53	47	41
2036	280	263	255	179	175	178	100	89	77	218	208	204	165	161	164	52	46	40
2037	274	257	248	174	169	172	100	88	75	212	202	198	160	156	159	52	46	39
2038	268	250	241	168	163	167	100	87	74	207	196	192	155	150	154	52	46	39
2039	262	243	234	163	157	161	100	86	73	202	190	187	150	145	149	52	45	38
2040	261	241	232	161	156	161	99	86	72	201	188	186	149	144	148	52	45	37
2041	259	240	231	160	155	161	99	85	70	199	187	185	147	143	148	52	44	37
2042	258	238	229	159	154	160	99	84	69	198	186	184	147	142	148	52	44	36
2043	257	236	228	158	153	160	99	83	68	197	185	183	146	141	147	52	44	35
2044	256	235	227	158	153	160	98	83	67	196	184	182	145	140	147	51	43	35
2045	255	234	225	157	152	160	98	82	65	196	183	182	144	140	147	51	43	34
2046	254	233	224	156	152	160	98	81	64	195	182	181	144	140	147	51	42	34
2047	254	232	223	156	151	160	98	80	63	195	181	180	144	139	147	51	42	33
2048	253	231	222	156	151	160	97	80	62	194	181	180	143	139	147	51	42	32
2049	253	230	221	155	151	160	97	79	61	194	180	180	143	139	148	51	41	32
2050	252	229	220	155	151	160	97	78	60	193	180	179	143	139	148	51	41	31
2051	252	228	220	155	151	161	97	78	59	193	179	179	143	139	148	51	41	31
2052	251	227	219	155	150	161	97	77	58	193	179	178	142	139	148	50	40	30
2053	251	227	218	155	150	161	96	76	57	193	178	178	142	138	148	50	40	30
2054	250	226	217	154	150	161	96	75	56	192	178	178	142	138	148	50	39	29
2055	252	228	220	154	150	161	98	78	58	193	179	179	142	138	149	51	41	30

Apx Table B.6 Twelve- and twenty-four hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	Battery storage (12 hrs)									Battery storage (24 hrs)								
	Total			Battery			BOP			Total			Battery			BOP		
	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050	Current policies	Global NZE post 2050	Global NZE by 2050
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
2025	287	287	287	245	245	245	42	42	42	266	266	266	245	245	245	21	21	21
2026	276	273	271	236	234	232	40	39	38	256	254	251	236	234	232	20	20	19
2027	261	260	258	224	223	223	38	37	35	243	242	241	224	223	223	19	18	18
2028	250	248	247	213	214	214	36	34	33	232	231	231	213	214	214	18	17	16
2029	243	240	237	208	207	207	35	33	30	225	224	222	208	207	207	18	16	15
2030	237	233	230	201	200	201	35	33	30	219	216	215	201	200	201	18	16	15
2031	230	225	223	195	193	194	35	32	29	212	209	209	195	193	194	18	16	15
2032	224	218	216	188	186	188	35	32	29	206	202	202	188	186	188	18	16	14
2033	218	211	210	182	180	182	35	32	28	200	195	196	182	180	182	18	16	14
2034	212	205	203	177	173	176	35	31	28	194	189	189	177	173	176	18	16	14
2035	206	198	197	171	167	170	35	31	27	188	183	183	171	167	170	18	16	14
2036	200	192	191	165	161	164	35	31	27	183	177	178	165	161	164	17	15	13
2037	195	186	185	160	156	159	35	31	26	178	171	172	160	156	159	17	15	13
2038	190	180	180	155	150	154	35	30	26	172	165	167	155	150	154	17	15	13
2039	185	175	174	150	145	149	35	30	25	167	160	161	150	145	149	17	15	13
2040	183	173	173	149	144	148	35	30	25	166	159	161	149	144	148	17	15	12
2041	182	172	172	147	143	148	35	30	25	165	157	160	147	143	148	17	15	12
2042	181	171	172	147	142	148	34	29	24	164	156	160	147	142	148	17	15	12
2043	180	170	171	146	141	147	34	29	24	163	156	159	146	141	147	17	15	12
2044	179	169	171	145	140	147	34	29	23	162	155	159	145	140	147	17	14	12
2045	179	168	170	144	140	147	34	29	23	162	154	159	144	140	147	17	14	11
2046	178	168	170	144	140	147	34	28	22	161	154	159	144	140	147	17	14	11
2047	178	167	169	144	139	147	34	28	22	161	153	158	144	139	147	17	14	11
2048	177	167	169	143	139	147	34	28	22	160	153	158	143	139	147	17	14	11
2049	177	166	169	143	139	148	34	28	21	160	153	158	143	139	148	17	14	11
2050	177	166	169	143	139	148	34	27	21	160	152	158	143	139	148	17	14	10
2051	176	166	168	143	139	148	34	27	21	159	152	158	143	139	148	17	14	10
2052	176	165	168	142	139	148	34	27	20	159	152	158	142	139	148	17	13	10
2053	176	165	168	142	138	148	34	27	20	159	152	158	142	138	148	17	13	10
2054	176	165	168	142	138	148	33	26	19	159	152	158	142	138	148	17	13	10
2055	176	165	169	142	138	149	34	27	20	159	152	159	142	138	149	17	14	10

Apx Table B.7 Pumped hydro storage cost data by duration, by scenario, total cost basis

	$/kW												$/kWh											
	Current policies				Global NZE post 2050				Global NZE by 2050				Current policies				Global NZE post 2050				Global NZE by 2050			
	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs
2025	3960	5687	7394	10601	3960	5687	7394	10601	3960	5687	7394	10601	396	237	154	66	396	237	154	66	396	237	154	66
2026	3884	5578	7253	10399	3884	5578	7253	10399	3884	5578	7253	10399	388	232	151	65	388	232	151	65	388	232	151	65
2027	3810	5472	7115	10201	3810	5472	7115	10201	3810	5472	7115	10201	381	228	148	64	381	228	148	64	381	228	148	64
2028	3736	5366	6977	10003	3736	5366	6977	10003	3736	5366	6977	10003	374	224	145	63	374	224	145	63	374	224	145	63
2029	3659	5255	6833	9796	3659	5255	6833	9796	3659	5255	6833	9796	366	219	142	61	366	219	142	61	366	219	142	61
2030	3582	5144	6688	9589	3582	5144	6688	9589	3582	5144	6688	8514	358	214	139	60	358	214	139	60	358	214	139	53
2031	3601	5171	6724	9640	3604	5176	6730	9649	3616	5193	6730	8595	360	215	140	60	360	216	140	60	362	216	140	54
2032	3615	5192	6751	9679	3621	5201	6762	9696	3642	5231	6762	8657	362	216	141	60	362	217	141	61	364	218	141	54
2033	3631	5215	6780	9721	3640	5227	6797	9744	3668	5269	6797	8720	363	217	141	61	364	218	142	61	367	220	142	55
2034	3646	5236	6808	9761	3658	5254	6831	9794	3697	5310	6831	8789	365	218	142	61	366	219	142	61	370	221	142	55
2035	3661	5258	6836	9802	3677	5281	6866	9845	3727	5352	6866	8859	366	219	142	61	368	220	143	62	373	223	143	55
2036	3676	5280	6865	9842	3696	5308	6902	9896	3756	5395	6902	8929	368	220	143	62	370	221	144	62	376	225	144	56
2037	3692	5302	6894	9884	3715	5336	6938	9947	3786	5438	6938	9001	369	221	144	62	372	222	145	62	379	227	145	56
2038	3707	5325	6923	9926	3735	5364	6974	9999	3817	5482	6974	9073	371	222	144	62	373	224	145	62	382	228	145	57
2039	3723	5347	6952	9968	3755	5392	7011	10052	3848	5526	7011	9147	372	223	145	62	375	225	146	63	385	230	146	57
2040	3739	5370	6982	10011	3774	5421	7048	10105	3879	5571	7048	9221	374	224	145	63	377	226	147	63	388	232	147	58
2041	3750	5386	7003	10041	3790	5443	7077	10146	3906	5609	7077	9284	375	224	146	63	379	227	147	63	391	234	147	58
2042	3762	5403	7024	10071	3805	5465	7105	10187	3933	5648	7105	9348	376	225	146	63	380	228	148	64	393	235	148	58
2043	3773	5419	7045	10101	3820	5487	7134	10228	3960	5687	7134	9413	377	226	147	63	382	229	149	64	396	237	149	59
2044	3784	5435	7067	10132	3836	5509	7163	10269	3987	5726	7163	9478	378	226	147	63	384	230	149	64	399	239	149	59
2045	3796	5452	7088	10163	3851	5531	7192	10311	4015	5766	7192	9543	380	227	148	64	385	230	150	64	401	240	150	60
2046	3807	5468	7110	10193	3867	5554	7221	10353	4043	5806	7221	9610	381	228	148	64	387	231	150	65	404	242	150	60
2047	3819	5485	7131	10224	3883	5576	7250	10395	4071	5846	7250	9677	382	229	149	64	388	232	151	65	407	244	151	60
2048	3831	5502	7153	10256	3898	5599	7280	10437	4099	5887	7280	9744	383	229	149	64	390	233	152	65	410	245	152	61
2049	3842	5518	7175	10287	3914	5622	7309	10480	4128	5928	7309	9812	384	230	149	64	391	234	152	65	413	247	152	61
2050	3854	5535	7197	10318	3930	5645	7339	10523	4157	5970	7339	9881	385	231	150	64	393	235	153	66	416	249	153	62
2051	3864	5549	7215	10344	3944	5665	7365	10560	4184	6009	7365	9945	386	231	150	65	394	236	153	66	418	250	153	62
2052	3873	5563	7233	10370	3958	5685	7391	10597	4211	6047	7391	10009	387	232	151	65	396	237	154	66	421	252	154	63
2053	3883	5577	7251	10396	3972	5705	7417	10635	4238	6087	7417	10074	388	232	151	65	397	238	155	66	424	254	155	63
2054	3893	5591	7269	10422	3986	5725	7444	10672	4266	6126	7444	10140	389	233	151	65	399	239	155	67	427	255	155	63
2055	3902	5605	7287	10448	4000	5745	7470	10710	4293	6166	7470	10206	390	234	152	65	400	239	156	67	429	257	156	64

Apx Table B.8 Historical storage cost data, total cost basis

	$/kW											$/kWh										
	Battery (1hr)	Battery (2hrs)	Battery (4hrs)	Battery (8hrs)	PHES (6hrs)	PHES (8hrs)	PHES (10hrs)	PHES (12hrs)	PHES (24hrs)	PHES (48hrs)	PHES 160hrs)	Battery (1hr)	Battery (2hrs)	Battery (4hrs)	Battery (8hrs)	PHES (6hrs)	PHES (8hrs)	PHES (10hrs)	PHES (12hrs)	PHES (24hrs)	PHES (48hrs)	PHES 160hrs)
2019		1535	2424	4404	2283	2461		2614	3875	4341			768	606	551	308	249		177	131	88	
2020	977	1310	2086	3676	2877	3004		3292	4232	6358		977	655	521	460	387	303		222	142	128	
2021	942	1257	1942	3407	2771	3006		3234	4219	6337		942	629	485	426	387	315		226	147	133	
2022	1046	1513	2454	4360	3245	3526		3786	4949	7434		1046	756	614	545	481	392		281	184	165	
2023	1069	1549	2510	4400	4037	4387		4617	6156	7226		1069	775	627	550	635	517		363	242	170	
2024	929	1241	1727	2809			7837		6632	7985		929	621	432	351			768		271	196	
2025	778	1050	1540	2464			3960		5687	7394	10601	778	525	385	308			396		237	185	66

Notes: Batteries are large scale. Small scale batteries of 10kWh for home use with 2-hour duration are estimated at $1100/kWh before subsidies (GHD, 2025). However, lower costs may be available for larger household battery sizes.

Apx Table B.9 Data assumptions for LCOE calculations

	Constant						Low assumption			High assumption		
	Economic life	Construction time	Efficiency	O&M fixed	O&M variable	CO_2 storage	Capital	Fuel	Capacity factor	Capital	Fuel	Capacity factor
2025	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	6962	12.7	89%	6962	17.9	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	2497	12.7	89%	2497	17.9	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2886	12.7	20%	2886	17.9	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	2886	12.7	20%	2886	17.9	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2022	12.7	20%	2022	17.9	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2648	41.9	20%	2648	41.9	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	12941	2.9	89%	12941	5.4	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	6946	2.9	89%	6946	5.4	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	10725	0.6	89%	10725	0.7	53%
Nuclear SMR	30	4.4	33%	200	5.3	0.0	28009	1.1	89%	28009	1.3	53%
Nuclear large-scale	30	5.8	33%	200	5.3	0.0	10332	1.1	89%	10332	1.3	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	6532	0.0	71%	6454	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	1621	0.0	32%	1621	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	3248	0.0	48%	3248	0.0	29%
Wind offshore (fixed)	30	3.0	100%	175.0	0.0	0.0	5433	0.0	52%	5433	0.0	40%
2030												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	6269	9.6	89%	6252	16.8	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	2426	9.6	89%	2443	16.8	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2624	9.6	20%	2642	16.8	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1589	9.6	20%	1600	16.8	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2010	9.6	20%	2039	16.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2537	35.7	20%	2574	37.7	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11961	3.2	89%	12196	5.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	6162	3.2	89%	6296	5.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	9385	0.7	89%	9588	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	21273	0.8	89%	20806	1.0	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9658	0.8	89%	9858	1.0	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	6074	0.0	71%	6320	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	847	0.0	32%	1378	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2629	0.0	48%	2650	0.0	29%
Wind offshore (fixed)	30	3.0	100%	175.0	0.0	0.0	4133	0.0	53%	5300	0.0	40%

2040												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	4654	9.4	89%	4933	16.4	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	1939	9.4	89%	1994	16.4	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1767	9.4	20%	1811	16.4	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1070	9.4	20%	1097	16.4	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2045	9.4	20%	2120	16.4	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2579	26.6	20%	2488	31.2	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11408	3.0	89%	11561	4.7	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5624	3.0	89%	5941	4.7	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8472	0.7	89%	8937	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	12216	0.5	89%	16682	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9306	0.5	89%	9795	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	5696	0.0	71%	5837	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	672	0.0	32%	1191	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2214	0.0	48%	2253	0.0	29%
Wind offshore (fixed)	30	3.0	100%	175.0	0.0	0.0	4126	0.0	54%	5315	0.0	40%
2050												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	4782	9.3	89%	5031	17.4	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	1978	9.3	89%	2069	17.4	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1798	9.3	20%	1874	17.4	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1089	9.3	20%	1134	17.4	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2095	9.3	20%	2222	17.4	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2703	24.9	20%	2548	29.6	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11790	3.0	89%	12282	4.4	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5791	3.0	89%	6326	4.4	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8756	0.7	89%	9537	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	15355	0.5	89%	13007	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9607	0.5	89%	10429	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	5757	0.0	71%	5344	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	616	0.0	32%	1029	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2180	0.0	48%	2207	0.0	29%
Wind offshore (fixed)	30	3.0	100%	175.0	0.0	0.0	4231	0.0	55%	5342	0.0	40%

Notes: Economic life is the design life or the period of financing. Total operational life, with refurbishment expenses, is not included in the LCOE calculation but is used in electricity system modelling to understand natural retirement dates. Large-scale solar PV is single axis tracking. The real discount rate for all technologies is 7%. The assumption of 100% efficiency for renewable generation is purely for the purpose avoiding division by zero in the standard LCOE formula. This assumption has no practical impact because fuel cost is zero for these technologies.

Apx Table B.10 Electricity generation technology LCOE projections data, $/MWh

Category	Technology	2025		2030		2040		2050	
		Low	High	Low	High	Low	High	Low	High
Peaking 20% load	Gas open cycle (small)	310	362	264	338	216	288	217	302
	Gas open cycle (large)	319	375	215	294	184	261	185	275
	Gas reciprocating	244	290	216	281	216	282	218	296
	H_2 reciprocating	628	628	553	578	453	500	441	486
Flexible load, high emission	Black coal	120	203	113	191	105	176	107	182
	Brown coal	167	272	149	246	137	232	141	245
	Gas	131	192	108	184	101	171	101	180
Flexible load, low emission	Black coal with CCS	224	365	215	353	206	329	211	340
	Gas with CCS	214	321	180	297	158	265	159	276
	Nuclear SMR	433	718	336	546	207	446	250	360
	Nuclear large-scale	200	328	187	312	178	307	183	323
	Solar thermal	115	143	108	141	102	132	103	123
Variable	Solar photovoltaic	52	88	29	76	24	67	23	59
	Wind onshore	78	129	64	107	55	93	55	91
	Wind offshore (fixed)	156	203	126	199	123	200	123	200

Apx Table B.11 Hydrogen electrolyser cost projections by scenario and technology, $/kW

	Current policies		Global NZE by 2050		Global NZE post 2050	
	Alkaline	PEM	Alkaline	PEM	Alkaline	PEM
2025	2100	2730	2100	2730	2100	2730
2026	2061	2680	2050	2665	2069	2690
2027	2043	2656	2020	2626	2058	2675
2028	2045	2658	2000	2600	2050	2665
2029	2049	2663	1985	2581	2047	2660
2030	2004	2605	1971	2562	2045	2658
2031	2011	2615	1931	2510	2049	2664
2032	2017	2622	1891	2459	2047	2661
2033	2023	2630	1852	2407	2045	2658
2034	2028	2637	1824	2371	2052	2668
2035	2034	2644	1798	2337	2060	2678
2036	2039	2651	1780	2314	2068	2689
2037	2045	2658	1753	2279	2076	2699
2038	2050	2665	1745	2268	2051	2667
2039	2028	2636	1741	2263	2047	2661
2040	2003	2604	1718	2234	2027	2635
2041	1979	2572	1703	2213	2007	2609
2042	1954	2540	1713	2226	1987	2583
2043	1929	2508	1708	2220	1967	2558
2044	1905	2476	1706	2218	1947	2532
2045	1880	2444	1700	2210	1927	2506
2046	1867	2428	1688	2194	1920	2496
2047	1860	2418	1676	2178	1927	2505
2048	1861	2419	1666	2166	1934	2515
2049	1858	2415	1673	2175	1942	2525
2050	1856	2413	1665	2165	1918	2494
2051	1856	2413	1663	2161	1910	2483
2052	1856	2413	1647	2141	1916	2491
2053	1843	2396	1639	2131	1923	2500
2054	1846	2400	1615	2099	1927	2505
2055	1840	2392	1605	2087	1933	2513

Appendix C Data assumptions

C.1 Technologies and learning rates

The technical approach to applying learning rates is explained in Appendix A and involves a specific mathematical formula. The projection approach uses two global and local learning models (GALLM) which contain applications of the learning formula. One model is of the electricity sector (GALLME) and the other of the transport sector (GALLMT). GALLME projects the future cost and installed capacity of 31 different electricity generation and energy storage technologies and now four hydrogen production technologies. Where appropriate, these have been split into their components of which there are 21 (noting that in total 52 items are modelled). Components have been shared between technologies; for example, there are two carbon capture and storage (CCS) components – CCS technology and CCS construction – which are shared among all CCS plant and hydrogen technologies.

Key technologies are listed in Apx Table C.1 and Apx. Table C.2 showing the relationship between generation technologies and their components and the assumed learning rates under the central scenario. Learning is either on a global (G) basis, local (L) to the region, or no learning (-). Up to two learning rates are assigned with LR1 representing the initial learning rate during the early phases of deployment and LR2, a lower learning rate, that occurs during the more mature phase of technology deployment.

Apx Table C.1 Assumed technology learning rates that vary by scenario

Technology	Scenario	Component	LR 1 (%)	LR 2 (%)	LR 3 (%)	References
Photovoltaics	Current policies	G	20	30	13	(IEA 2021, IRENA, 2023, Fraunhofer ISE, 2015)
Rooftop BOP		L	17.5	8.5	4.5	
Large scale BOP		L	17.5	17.5	17.5	
Photovoltaics	Global NZE by 2050	G	20	30	23	
Rooftop BOP		L	17.5	17.5	12.5	
Large scale BOP		L	17.5	17.5	17.5	
Photovoltaics	Global NZE post 2050	G	20	30	23	
Rooftop BOP		L	17.5	8.5	4.5	
Large scale BOP		L	17.5	17.5	17.5	
Electrolysis	Current policies	G	10	5	5	(Schmidt et al., 2017, IEA 2024b)
		L	8	8	8	

Electrolysis	Global NZE by 2050	G	18	18	9	
		L	8	8	8	
Electrolysis	Global NZE post 2050	G	10	5	5	
		L	8	8	8	
Ocean	Current policies	G	10	5	5	(IEA, 2021)
	Global NZE by 2050	G	20	10	10	
	Global NZE post 2050	G	14	7	7	
Fixed offshore wind	Current policies	G	10	5	5	(Samadi, 2018; Zwaan, et al. 2012; Voormolen et al. 2016; IEA, 2021)
Fixed offshore wind	Global NZE by 2050	G	20	10	10	
Fixed offshore wind	Global NZE post 2050	G	15	8	8	
Floating offshore wind	Current policies	G	10	5	5	
		G	10	5	5	
Floating offshore wind	Global NZE by 2050	G	20	10	10	
		G	20	10	10	
Floating offshore wind	Global NZE post 2050	G	15	8	8	
		G	15	7.5	7.5	
Utility scale energy storage – Li-ion	Current policies	G	7.5	7.5	7.5	(Grübler et al., 1999; McDonald and Schrattenholzer, 2001)
		L	7.5	7.5	7.5	
Utility scale energy storage – Li-ion	Global NZE post 2050	G	10	10	10	
		L	10	10	10	
Utility scale energy storage – Li-ion	Global NZE by 2050	G	15	15	15	
		L	15	15	15	
Onshore wind	Current policies	G	4.3	4.3	4.3	(IEA, 2021; Hayward & Graham, 2013)
		L	9.8	4.8	2.8	
	Global NZE post 2050	G	4.3	4.3	4.3	

		L	11.3	9.8	4.8
	Global NZE by 2050	G	4.3	4.3	4.3
		L	11.3	11.3	11.3

While solar photovoltaics are implemented with separate learning rates for large scale and rooftop balance of plant (BOP), inverters are not included in the BOP nor given a learning rate. Instead, they are given a constant cost reduction, which is based on historical data.

The potential for local learning means that technology costs are different in different regions in the same time period. This has been of particular note for technology costs in China, which can be substantially lower than other regions. GALLME uses inputs from GHD (2026) to ensure costs represent Australian project costs. For technologies not commonly deployed in Australia, these costs can be higher than other regions. However, the inclusion of local learning assumptions in GALLME means that they can quickly catch up to other regions if deployment occurs. However, they will not always fall to levels seen in China due to differences in production standards for some technologies. That is, to meet Australian standards, the technology product from China would increase in costs and align more with other regions. Regional labour construction and engineering costs also remain a source of differentiation.

Apx Table C.2 Assumed technology learning rates that are the same under all scenarios

Technology	Component	LR 1 (%)	LR 2 (%)	LR 3 (%)	References
Coal, supercritical	-	-	-		
Coal, ultra-supercritical	G	2	2	2	(IEA, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	20	10	5	(EPRI 2010; Rubin et al., 2007)
	L	20	10	5	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Gas peaking plant	-	-	-		
Gas combined cycle	-	-	-		
Nuclear	G	-	-		(IEA, 2008)
Nuclear SMR	G	20	10	5	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Diesel/oil-based generation	-	-	-		
Reciprocating engines	-	-	-		
Hydro and pumped hydro	-	-	-		
Biomass	G	5	5	5	(IEA, 2008; Neij, 2008)
Concentrating solar thermal (CST)	G	14.6	7	7	(Hayward & Graham, 2013)
	L	14.6	7	7	

CHP	-	-	-		
Conventional geothermal	G	8	8	8	(Hayward & Graham, 2013)
	L	20	20	20	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Fuel cells	G	20	10	10	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Steam methane reforming with CCS	G	20	10	5	(EPRI, 2010; Rubin et al., 2007)
	L	20	10	5	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)

To provide a range of capital cost projections for all technologies, we have varied learning rates for technologies where there is more uncertainty in their learning rate. We focus on variable renewable energy and storage given that these technologies tend to be lower cost and crowd out opportunities for competing low emission technologies. Apx. Figure C.1 shows the learning rates by scenario for solar PV, electrolysis, ocean energy (wave and tidal), offshore wind, batteries and pumped hydro. The remainder of learning rate assumptions, which do not vary by scenario are shown in Apx. Table C.2.

In addition to the offshore wind learning rate, we have included an exogenous increase in the capacity factor up to the year 2050 of 0.9% per year. This assumption extrapolates past global trends (see Appendix D). As discussed in Appendix D, Australia has had a flat onshore wind capacity factor trend and so these global assumptions do not apply to Australia. The capacity factor for floating offshore wind is assumed to be 5.6% higher than that of fixed offshore wind, based on an average of values (Wiser et al., 2021). Capacity factors for offshore wind are assumed to improve in Australia in line with the rest of the world.

C.2 Electricity demand and electrification

Various elements of underlying electricity demand are sourced from the World Energy Outlook (IEA, 2021; IEA, 2022; IEA, 2023; IEA, 2024; IEA, 2025). Demand data is provided for the Stated Policies scenario, which is used in our *Global NZE post 2050* scenario. The demand data from the Current Policies scenario is used in our Current policies scenario. *Global NZE by 2050* demand is sourced from the Net Zero Emissions by 2050 scenario. We also allow for some divergence from IEA demand data in all scenarios to accommodate differences in our modelling approaches and internal selection of the contribution of electrolysis to hydrogen production.

C.2.1 Global vehicle electrification

Global adoption of electric vehicles (EVs) is projected using an adoption curve calibrated to correspond the matching scenarios from the IEA World Energy Outlook. The shape of the adoption curve varies by vehicle type, where cars and light commercial vehicles (LCV) have faster rates of adoption, followed by medium commercial vehicles (MCV) and buses. The adoption rate is applied to new vehicle sales shares.

C.3 Hydrogen

In GenCost projections prior to 2022-23, hydrogen demand was imposed together with the type of production process used to supply hydrogen. In our current model, GALLME determines which process to use – steam methane reforming with or without CCS or electrolysers. This choice of deployment also allows the model to determine changes in capital cost of CCS and in electrolysers.

The model does not distinguish between alkaline (AE) or Proton Exchange Membrane (PEM) electrolysers. That is, we have a single electrolyser technology. The approach reflects the fact that GALLME is not temporally detailed enough to determine preferences between the two technologies which are mainly around their minimum operating load and ramp rate. There is currently a greater installed capacity of AE which has been commercially available since the 1950s, whereas PEM is a more recent technology.

The IEA have included demand for electricity from electrolysis in their scenarios. Since GALLM is endogenously determining which technologies are deployed to meet hydrogen demand, we have subtracted the IEA's demand for electricity from electrolysis from their overall electricity demand. The assumed hydrogen demand assumptions for the year 2050 are shown in Apx. Table C.3 and include existing demand, the majority of which is currently met by steam methane reforming. The reason for including existing demand is that in order to achieve emissions reductions the existing demand for hydrogen will also need to be replaced with low emissions sources of hydrogen production.

Apx Table C.3 Hydrogen demand assumptions by scenario in 2050

Scenario	Total hydrogen demand (Mt)
Current policies	128
Global NZE post 2050	130
Global NZE by 2050	342

C.4 Government climate policies

Carbon trading markets exist in major greenhouse gas emitting regions overseas at present and are a favoured approach to global climate policy modelling because they do not introduce any technological bias. We directly impose the IEA carbon prices. The IEA also includes a broad range of additional policies such as renewable energy targets and planned closure of fossil fuel-based generation. The GALLME modelling includes these non-carbon price policies as well but cannot completely match the IEA implementation because of model structural differences. The IEA have greater regional and country granularity and are better able to include individual country emissions reduction policies. Some policies are difficult to recreate in GALLME due to its regional aggregation. Where we cannot match the policy implementation directly, we align our implementation of non-carbon price policies so that we match the emission outcomes in the relevant IEA scenario.

We align our scenarios with the IEA and the IEA does not include more recent announcements or changes of government policy since the IEA report was complete. As such, the country policy commitments included are not completely up to date.

C.5 Resource constraints

The availability of suitable sites for renewable energy farms, available rooftop space for rooftop solar PV and sites for storage of CO_2 generated from using CCS have been included in GALLME as a constraint on the amount of electricity that can be generated from these technologies (Apx. Table C.4) (see Government of India, 2016, Edmonds, et al., 2013 and Hayward and Graham, 2017 for more information on sources). With the exception of rooftop solar PV these constraints are removed in the Global NZE by 2050. Floating offshore wind has some technical limitations in regions, but these limitations are greater than electricity demand.

C.6 Other data assumptions

GALLME international black coal and gas prices are based on (IEA, 2023) with prices for the Stated Policies scenario applied in all cases. The IEA tends to reduce its fossil fuel price assumptions in scenarios with stronger climate policy action. Whilst we agree that stronger climate policy action will lead to lower demand for fossil fuels, we do not think it follows that fossil fuel prices must fall[23]. This is one of the very few areas where we do not align with all IEA scenario assumptions. Brown coal is not globally traded and has a flat price of 0.6 $/GJ.

Apx Table C.4 Maximum renewable generation shares in the year 2050, except for offshore wind which is in GW of installed capacity.

Region	Rooftop PV %	Large scale PV %	CST %	Onshore wind %	Fixed offshore wind GW
AFR	21	NA	NA	NA	NA
AUS	35	NA	NA	NA	NA
CHI	14	NA	NA	NA	1073
EUE	21	NA	NA	NA	NA
EUW	21	2	23	22	NA
FSU	25	NA	NA	NA	NA

[23] In the long run, fossil fuel prices will fluctuate due to cycles of demand and supply imbalances. However, underlying these fluctuations, prices should track the cost of production given the competitive nature of commodity markets. This relationship holds whether demand is falling or rising over the long run.

Region	Rooftop PV %	Large scale PV %	CST %	Onshore wind %	Fixed offshore wind GW
IND	7	21	18	4	302
JPN	16	1	12	11	10
LAM	25	NA	NA	NA	NA
MEA	21	NA	NA	NA	NA
NAM	30	NA	NA	NA	NA
PAO	11	1	8	8	15.5
SEA	14	3	32	8	NA

NA means the resource is greater than projected electricity demand. The regions are Africa (AFR), Australia (AUS), China (CHI), Eastern Europe (EUE), Former Soviet Union (FSU), India (IND), Japan (JPN), Latin America (LAM), Middle East (MEA), North America (NAM), OECD Pacific (PAO), Rest of Asia (SEA), and Western Europe (EUW)

Power plant technology operating and maintenance (O&M) costs, plant efficiencies and fossil fuel emission factors were obtained from (GHD, 2025) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2023) (IEA, 2015) (CO2CRC, 2015) and historical technology installed capacities from (IEA, 2008) (Gas Turbine World, 2009) (Gas Turbine World, 2010) (Gas Turbine World, 2011) (Gas Turbine World, 2012) (Gas Turbine World, 2013) (UN, 2015a) (UN, 2015b) (Energy Information Administration, 2017a) (Energy Information Administration, 2017b) (GWEC) (IEA, 2016a) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015).

New capacity that was installed in 2023 was sourced from (IRENA, 2024) (Global Energy Monitor, 2024a) (Global Energy Monitor, 2024b) and (Global Energy Monitor, 2024c).

Appendix D Frequently asked questions

The following list of questions represents a summary of the most commonly asked questions in relation to methods and assumptions applied in GenCost.

D.1 Process

D.1.1 Why does GenCost not immediately change its report when provided with new advice from experts?

The GenCost report undertakes a significant stakeholder consultation process, but it is not a consensus process and the response to feedback is based on its quality, not who provided it. This process is consistent with the objectivity and scientific approach that stakeholders expect of CSIRO.

There have been suggestions from some stakeholders that because some information was provided by an expert or group of experts it should have been accepted and acted upon immediately. This is not sufficient grounds for making a change to the GenCost report. Changes to the GenCost report need to be based on public evidence and reason. They cannot be based on assertions alone, no matter the qualifications and experience of the individual or group of individuals providing input.

GenCost reserves the right to test the quality of any evidence provided. There are widely varying qualities of data and evidence provided in the consultation process. Stakeholders should consider the many issues that can impact the quality of evidence when providing it such as the appropriateness of methodologies used to develop the data, stated or unstated vested interests behind the data development, and the level of inherent proof the evidence represents (e.g., correlation versus causation, opinion versus verifiable data).

Finally, CSIRO reserves the right to prioritise the issues and evidence it chooses to investigate. Not every topic raised will be fully investigated in the year the feedback is received. We prioritise issues based on their relevance, the weight of feedback received, and the technical challenges associated with investigating the topic in a way that meets our own standards.

D.2 Scenarios

D.2.1 Why are disruptive events and bifurcations excluded from the scenarios?

It is acknowledged that the future evolution of major drivers of the global energy system will not be smooth, particularly considering the recent pandemic and Ukraine war impacts on the energy sector. GenCost provides relatively smooth projections of capital costs over time compared to what is likely to occur. This reflects our understanding that very few end-users of the capital cost projections would like to access results that include major discontinuities. More volatility in inputs will lead to more volatility in all model outputs. Such volatility can interfere with the interpretation of models which are often seeking to answer separate questions about the evolution of the system by reading into the changes in the modelling results. As such, our judgment is that adding more realism does not add value in this case.

D.2.2 Why is no sensitivity analysis conducted and presented?

The staff delivering GenCost have many decades of experience in energy and electricity system modelling. They understand which parameters in the model have the greatest impact on model outcomes. The scenarios have been designed to explore those parameters that are the most uncertain and impactful (within a plausible range) so that they provide a set of results that represent the likely range of outcomes. The possible range of outcomes is wider and could be calculated. However, our understanding of end-user needs is that they require outputs that align with globally accepted literature on the likely range of major drivers such as global climate policy, learning rates and resource constraints. Should our understanding of the likely range of any of these factors change, the scenarios will be updated.

D.3 Capital costs

D.3.1 What did you base your large-scale nuclear costs on?

The GenCost 2023-24 final report provides a detailed discussion of the method for estimating large-scale nuclear costs in Section 2.5

D.3.2 Why have the estimates for nuclear SMR capital costs increased so much since 2022?

The GenCost 2023-24 final report provides a detailed discussion of the history of estimating nuclear SMR costs in Section 2.4. This report has adopted the project cost for the Darlington nuclear SMR project as its primary source for current and near term costs.

D.3.3 Do you assume Australia continues to rely on overseas technology suppliers or are you assuming Australia develops its own original equipment manufacturing capability?

The context of this question is the concern that reliance on overseas manufacturers makes Australia vulnerable to non-competitive market pricing (e.g., the dominance of China), delayed access to technology because of competing buyers or represents a security of supply risk in the event of conflict in or with supplying countries. In this context, some government policies have provided international partnership support and direct grants for critical minerals projects[24].

[24] https://www.industry.gov.au/publications/critical-minerals-strategy-2023-2030/our-focus-areas/2-attracting-investment-and-building-international-partnerships

Whilst GenCost will continue to monitor these developments, the equipment component of capital cost estimates remains based on the best available representative technology cost deployment in Australia with equipment supplied from anywhere in the world that meets our standards.

D.3.4 Why does GenCost persist with the view that technology costs will fall over time when there are many factors that will keep technology costs high?

In the GenCost 2022-23 final report, research was outlined that indicated that there is no historical precedence for the real cost of commodities increasing indefinitely in real terms. Most periods of high prices resolve themselves within 4 years. Longer-term commodity price super cycles do occur but are shallower and are associated with changes in global economic growth. There is no suggestion from stakeholders that the world is in a major economic growth cycle. It was also argued in GenCost 2022-23 that global manufacturing will not need to be endlessly scaled up. Rather global technology capacity forecasts indicate that technology manufacturing capacity will need to grow to 2030, but after that point will be able to meet mostly linear demand for additional capacity without significant additional scale-up.

Stakeholders have raised the following additional points on this topic:

- That the energy sector may have a different inflationary path to the economy in general
- That GenCost needs to prove that the world is not in a new commodity super cycle
- That concentration of manufacturing in China will lead to non-competitive behaviour and high prices for those products, particularly solar
- That demand for energy technologies will remain non-linear for a long time because of delays in Australian deployment.

The current uncertainty in global manufacturing is acknowledged and makes forecasting at this time in history very challenging. The global inflationary event triggered by the pandemic is a significant structural break. Based on the evidence available of similar events, the approach taken has been to assume a reasonably quicker resolution of high technology prices with some lingering effects for 3 to 6 years, the length depending on the scenario. Recovery has started but has also been delayed by the 2026 Iran war.

The data on technology project costs from GHD and various commodities price inputs to those technologies indicates (so far) that the evidence is in alignment with our approach. Some costs have already fallen in real terms. Some are still rising but the rate of increase is significantly lower. The evidence from GHD (2026) points to cost pressures easing. Commodity price reporting also indicates cost pressures have eased in raw material markets such as lithium, not withstanding recent volatility associated with the Iran war.

Based on this data, it does not appear energy is on a different path to the rest of the economy. Solar panels produced predominantly by China are recovering better than others and their price increase was more modest to begin with.

Regarding the expected linear growth rates in technology deployment, this refers to the global technology deployment and the required global manufacturing capacity to meet this growth.

Australia's technology deployment rate, while important to us as Australians, has very little impact on the scale or cost of global technology manufacturing.

Notwithstanding these points, our projection methodology assumes increasing land and installation costs (in real terms). These exceptions are due to the scarcity of land and suitably qualified construction labour. This assumption means that the costs of some technologies (particularly mature technologies) increases for significant parts of the projection period.

D.3.5 Why is the uncertainty in the data not emphasised more?

GHD (2026) provide an uncertainty range of +/- 30% for their capital costs. To reduce this uncertainty, their analysis would have to be performed on a specific project. The GenCost project requires general data, not specific project data, that can be used in national level modelling studies. GHD (2026) also provide factors to convert the general costs to specific locations in the National Electricity Market (NEM). In that context, GenCost data can be converted to specific locations. An important aspect for GenCost is that all data is on a common basis.

Some stakeholders have requested that we emphasise this uncertainty in capital costs more in the text and diagrams. The main purpose of GenCost has always been to provide data which can be used in modelling studies. While there are stochastic modelling frameworks, the majority of electricity system models used in Australia are deterministic. In simple terms, this means they use single data points without any probability information attached to them. Therefore, GenCost capital cost outputs, which focus on providing scenarios to explore uncertainty rather than probability ranges, remain appropriate for the end-use they are created for.

LCOE data is specifically designed for the non-modelling community. In this case, we take a different approach. LCOE data is always presented as a range representing the plausible maximum and minimum costs. We also provide ranges for key inputs to the LCOE calculations such as capital costs, fuel costs and capacity factors.

D.3.6 Why include an advanced ultra-supercritical pulverised coal instead of cheaper, less efficient plant designs?

Some stakeholders take a view that although Australia has national and state net zero emissions policies by 2050, the highest greenhouse gas emitting options should remain on the table. The deployment of new coal has low plausibility given its high emissions intensity. A high efficiency design brings it closer to being plausible by reducing its emissions. Perhaps the most plausible scenario for building new coal consistent with meeting the net zero emissions by 2050 target would be to later retrofit coal generation with carbon capture and storage. Carbon capture and storage imposes a very significant fuel efficiency loss on the coal generator. In this context, it is even more important to start from a high efficiency coal generation technology.

D.4 LCOE

D.4.1 Why is the economic life used in LCOE calculations instead of the full operational life?

The LCOE calculation converts all upfront and ongoing costs to annual costs which is then divided by annual production. The capital cost component of a technology is converted to an annual repayment to the debt and equity providers. The annual repayment amount is determined using the economic life and the weighted average cost of capital. The economic life is shorter than the asset life for some technologies such as coal, nuclear and hydro. Some stakeholders have queried why this is so.

Debt and equity providers require a shorter payback period than the total asset life for some technologies to avoid the risk that part of the equipment might fail or might need new investment (sometimes called refurbishment or extension costs) to keep operating safely and reliably. To determine the economic life, debt and equity providers might look to the warranties provided with the equipment. They might also look at the typical timing of refurbishments or life extensions for that technology. The economic life is an input provided by the engineering firm that AEMO commissions each year as an input to GenCost.

Some stakeholders suggested that coal and nuclear could access special financing arrangements to move the economic life closer to the asset life. However, our preference is not to introduce special arrangements for technologies where there is limited Australian evidence. A common approach to the LCOE calculation is important to maintain comparability. The 2024-25 report does explore the impact of longer capital recovery periods in Section 2. It finds there is no significant benefit from the longer operational life of nuclear relative to shorter-lived technologies whose costs have been falling over time.

Determining the economic life of storage is more complex because the cycle life comes into play in determining the life of some components. The cycle life and intended use of the storage device might also be something debt and equity providers are also interested in to set the repayment date. Batteries in GenCost are costed for a project which has purchased a 20-year warranty on the battery (this warranty is costed as part of the ongoing operating and maintenance cost – see GHD (2026) for more information on this).

It should also be noted that cycle life is often calculated in the academic literature based on a full charge and discharge and is tested over a shorter period than would occur in practice. It is not clear how well deployed storage projects will match the lab tests. Their operation may be more prone to partial discharge, preferring to save some charge for higher priced periods. That is, they will bid parts of their storage capacity at different prices. Time will tell how this bidding behaviour will impact their cycle life, but it is a reasonable expectation that practical operation will be less damaging to batteries than the lab tests.

D.4.2 Coal and nuclear plants are capable of very high capacity factors, why do LCOE calculations not always reflect this?

Stakeholders are sometimes not aware of the difference between the availability factor, which is how often a plant will be technically available to generate electricity and the capacity factor which is how often they typically generate electricity after the effects of competition or other market constraints which limit generation.

In the last ten years in Australia, baseload generators have had an average capacity factor of 59% (see Appendix D GenCost 2022-23 final report). The simple reason for this outcome is that most baseload plants need to reduce production at night and in milder seasons when demand is lowest. There are individual generators that do achieve around 90%. These are a minority of plants which have a fuel cost advantage which allows them to keep running at full production during low demand periods by underbidding other generators for the right to keep generating at a high level.

GenCost LCOE calculations allow for the fact that a new baseload generator might achieve a capacity factor of up to 89% based on the maximum achieved by black and brown coal generators. At the low end of the range a capacity factor of 53% is assumed for new black coal, brown coal or nuclear generators which is equivalent to achieving 10% below the average capacity factor for black and brown coal. Around 10% of nuclear generators globally run at less than 60% capacity factor and many have run at over 90%[25]. However, we prefer to use Australian data for the plausible baseload plant operation data because it is consistent with our electricity load curve while other countries may have very different loads. For example, some equatorial and northern regions with hotter and colder climates have higher rates of air conditioning in buildings leading to flatter electricity loads (where either electricity or combined heat and power are the energy source).

Higher penetration of renewables, which have a zero fuel cost, could make it difficult for new baseload plant to achieve high capacity factors depending on the scale of demand overall. Ultimately, we do not know what new coal or nuclear will be competing with in the future. The key principle though is to acknowledge a plausible range rather than assume only the best outcome for new build capacity factors.

D.4.3 Why do LCOE calculations not use the lowest historical capacity factors for the low range assumptions?

For all existing technologies there are some generators that are performing poorly relative to what might be expected, and these represent the low range of historical capacity factors which were examined in Appendix D of the GenCost 2022-23 report. The data does not reveal why some projects are performing below expectations, but it could represent older technologies or, for renewables, sites that did not live up to expectations in terms of the renewable resource. GenCost LCOE capacity factor low range assumptions are developed on the basis that new entrant technologies will not be deployed if they cannot perform close to the current average capacity factor performance. Investors would prefer to avoid such projects in preference for more

[25] https://world-nuclear.org/our-association/publications/world-nuclear-performance-report/global-nuclear-industry-performance

attractive investment options. Accordingly, we apply a common rule across renewables, coal, nuclear and gas that the minimum capacity factor for new plant is 10% below the ten years average capacity factor for that technology or its nearest equivalent grouping (baseload technologies are treated as one group).

D.4.4 Why were all potential cost factors not included in the LCOE calculations?

While each technology has its own specific characteristics the goal of the LCOE calculation is to use a common formula to calculate costs so that that observed differences in costs are due to a small set of key differences in the technology, namely: capital costs, fuel costs, fuel efficiency, operating and maintenance costs, economic life and construction time. However, often stakeholders request that other special topics be included in the calculations. Items requested to be added to the LCOE analysis by stakeholders include:

- Plant decommissioning and recycling costs
- Deeper pre-development costs
- Technology degradation
- Whole-of-life emissions
- Savings from developing on a brownfield site
- Various environmental impacts
- Energy in manufacturing costs
- Public acceptance barriers
- National security impacts
- Extreme climate events
- Connection costs
- Marginal loss factors.

Adding these additional parameters would greatly expand the physical and time boundary of the generic generation projects assumed in GenCost and require more complicated formulas to implement. Our current understanding is that few of the topics presented in the feedback have a large enough impact on LCOE to warrant a change in the boundary or formula. That is, it would add complexity and cost to the project without significantly changing the outcome of the comparisons. Some factors, like marginal loss factors are significant but are too unpredictable at this stage of the energy transition.

We do acknowledge that taking account of brownfield project characteristics would make a difference in costs. This is because brownfield projects can avoid some development costs associated with site selection, grid connection and land. However, brownfield projects are outside our stated scope for GenCost of greenfield or new build projects. The study of brownfield projects is always site-specific and more resource intensive and for these reasons less generally comparable to other options. Their inclusion would essentially amount to bringing “one-off” projects into the analysis. This is inconsistent with our goal of providing a general comparison metric. Some brownfield project costs are included in AEMO’s publicly accessible forecasting input data.

There are two exceptions in the past where GenCost added new technology cost elements. These are CO_2 storage costs for carbon capture and storage technologies and integration costs for variable renewables. In both cases, the impact of these additional elements is significant and justifies modification of the standard approach to LCOE calculation.

Given that GenCost does not account for all potential additional project costs such as those captured in the list above, real projects are likely to cost more than indicated by the LCOE. Consequently, investors must do their own deeper studies to discover these. Likewise, investors who are interested in brownfield project development will need to source this information elsewhere (e.g., check AEMO publications) or do their own analysis.

Energy used in manufacturing costs are accounted for in capital costs. Notwithstanding the current difficulties in manufacturer profitability following the global supply chain crunch, to remain solvent, manufacturers must recover these costs (as with all other costs), in the long term, by building them into their technology prices. Also, the more that global economies track and potentially price greenhouse gas emissions, the greater the incidence of lifecycle greenhouse gas emissions of projects being built into technology prices. Planned carbon border adjustment mechanisms are an example of this.

D.4.5 What is the boundary of development costs? Is it only costs from the point of contracting a developer before commencing construction?

GHD's reports and data break down the capital cost into three components: equipment, land and development and installation costs. Development costs are captured in the land and development segment. GHD (2026) provides this definition of the land and development cost component:

"*The development and land costs for a generation or storage project typically include the following components:*

- *Legal and technical advisory costs*
- *Financing and insurance (no interest during construction considered)*
- *Project administration, grid connection studies, and agreements*
- *Permits and licences, approvals (development, environmental, etc)*
- *Land procurement and applications."*

D.4.6 How is interest lost during construction included in GenCost?

The type of capital cost data included in GenCost is called overnight capital costs. That is, it is the cost if you built it overnight. Consequently, to make the costs more realistic, interest lost during the construction period needs to be added when using this data.

Interest lost during construction is added differently depending on how the data is being used. When overnight capital cost data is being used in an energy system model, information is provided to the model about the construction time. The time discounting function within the system model accounts for the interest lost during construction in the time delay between investment expenditure and when the project is fully operational.

When overnight capital cost data is being used in an LCOE calculation a different approach is used. LCOE calculations must average all costs into a single year of electricity production and so the time during construction does not exist as a concept. However, there are several ways in which the interest lost can be added to an LCOE. GenCost uses the simplest way which is to increase the capital cost by the assumed discount rate raised to the power of the construction time[26]. There are more sophisticated ways to do this which account for developer plans for drawing down the financing during construction depending on the arrival time of different plant parts and payment for each component. These more detailed approaches are appropriate for real project planning but require tailored calculations for each technology and a cash flow model approach. The cashflow approach tracks payments over each year of construction plus economic life before averaging them into a single yearly cost (dividing total expenditure including the construction period by total production including periods of zero production during the construction period). The simpler approach is more efficient (requires just a few cells of calculations and fewer input data), but the latter is more accurate. The simpler approach tends to overestimate interest lost during construction as it assumes all funds need to be drawn down at the beginning of construction.

D.4.7 Why are the cost of government renewable subsidies not included in the LCOE calculations for variable renewables with integration costs?

The cost of government subsidies for variable renewables, in whatever form they take, are not included as a cost because all of the variable renewable costs applied in the modelling are without subsidy. In other words, because we do not subtract any subsidies from the cost of variable renewable generation, it is not necessary to add those subsidies back in as a cost to society. The GenCost estimates of the cost of integrating variable renewables are without any government subsidies.

D.4.8 Why is a value of 100% applied to the fuel efficiency of renewables in the LCOE formula?

For our purposes there is no practical limit to supply of solar and wind power and its cost as a fuel is free. Since the fuel price applied is zero, any value for renewable energy efficiency other than zero would work in the fuel cost formula (and avoid division by zero) where fuel cost equals FuelPrice÷FuelEfficiency. We choose 1 or 100% for simplicity. This is not to say that the energy conversion efficiency of renewable generation technologies is 100%, or irrelevant, or not accounted for. The conversion efficiency of solar irradiance and wind to electricity is accounted for in the capital cost. Manufacturers apply a nameplate plant capacity in watts to the equipment they sell based on exposure to representative wind speeds or solar irradiance and this reflects the energy conversion efficiency of the plant. Conversion efficiency is also partially captured in land costs which reflect the scarcity of sites with the required renewable resources to operate at nameplate capacity.

[26] GenCost readers who have downloaded the Appendix tables from CSIRO's Data Access Portal should be able to find this step in the cell formula under the Capital component of the LCOE calculation

D.4.9 Why do you apply only one discount rate or weighted average cost of capital to all technologies?

This question may arise in the context of stakeholder concerns that some projects might be government funded and receive a lower financing rate and that should be included. While GenCost recognises that governments have in the past and may choose in the future to provide lower cost financing to selected projects, GenCost makes no specific assumptions about who will invest in a technology project.

Another factor guiding our approach is that we wish to compare technologies on a common basis wherever that approach does not lead to an unwanted distortion. In most cases, that can be achieved but there are exceptions. In some cases, we need to apply a different formula or method to different technologies to capture important additional costs such as adding reliability costs for variable renewables or carbon dioxide storage costs for CCS technologies (see D.4.4 for a longer discussion of what additional costs we have chosen to include).

Previous versions of GenCost also applied a cost of capital premium to fossil fuel technologies due to their additional climate policy risk. However, our judgement was that although that risk is real and ongoing, we were no longer able to find a cost of capital premium that adequately captured that risk. Instead, wherever we present high emission fossil fuel technology costs we simply state that investment in these technologies may not be consistent with government emission targets.

In conclusion, our judgment is that, in the case of the cost of capital, applying the same rate to every technology is the most informative and least distortionary approach for levelised cost of electricity. Other modelling exercises may take an alternative approach. However, our LCOE data is not likely to be an input to any detailed electricity system modelling. Rather LCOE data is simply an indicator of the potential direction of the results from more detailed modelling.

D.4.10 Why did you take the maximum and average of existing generator prices to create the high and low range new build coal prices?

Our goal is to explore the high and low range for total coal generation costs in the LCOE calculations. To do this we include high and low ranges for the various inputs to coal generation costs such as capacity factors, capital costs and coal fuel costs.

We require coal prices for new-build projects which are different to coal prices that are received by existing generation sites. Some existing generators receive low coal prices because they may have captured an adjacent coal mine with no competing rail line to export markets. Alternatively, if they are competing with export markets, they are more likely to have developed a favourable long-term contract to manage high price risk. New-build projects will start their life by competing with export markets for supply of coal.

High and low coal prices are sourced from the AEMO Inputs and Assumptions workbook. The June 2022 Inputs and assumptions workbook provided coal prices for new build and existing coal generators. Reflecting the issues discussed above, average new build coal prices were two and half times higher than the minimum existing generator coal prices. For GenCost 2022-23, our methodology for selecting coal prices to use in GenCost was to take the minimum and maximum of only the new build coal prices.

After June 2022, AEMO has no longer published new build coal prices. AEMO continued to publish coal prices, but only for existing generators which remain in the system.

To create the high and low range for new build coal prices post-2022-23 GenCost had to apply a new methodology based on the only available data which was coal prices for existing generators. Knowing that new build coal prices are at least as high as that for existing generators, for the maximum, GenCost simply takes the maximum of existing generator prices.

However, for the minimum new build coal prices, taking the minimum of existing generator prices is not appropriate. CSIRO developed a new methodology, using the only available data from AEMO on coal prices for existing generators, to extrapolate the low-cost range. This methodology takes into account that new-build coal generation projects cannot achieve the same low prices as existing generators, hence why the low coal prices are averaged. The average of the lowest coal price trajectory for existing generators tends to be two to three times the minimum coal price for those generators, which maintains the previously observed relationship between existing generator and new build coal prices.

IEA coal prices are used in the global modelling which underpins the capital cost projections. A different source is justified on the basis that the global modelling requires a consistent set of global fuel prices by major global region which is not available from AEMO which only provides Australian data.

D.4.11 Why do you not include high and low ranges for economic life?

Economic life is in some cases set by a warranty. This is the case for batteries. In other cases, it represents long standing practice in the financing of utility assets which are unlikely to vary significantly between Australian projects. While many stakeholders have provided evidence for variation in asset lives, there has been little evidence provided on variation in economic life or warranties or loan periods. At this stage, there is not enough information to form a basis for a high and low range for economic life as an input to the LCOE calculations. See D.4.1 for a discussion on the differences between economic and asset life.

D.4.12 Why are your low range capacity factors for coal and renewables closer to the historical average capacity factor?

In the GenCost 2022-23, report capacity factors from the previous ten years were reviewed to inform our choices about capacity factors in the LCOE calculations. Stakeholders have noted that the low range capacity factor applied is close to the ten-year average capacity factor. In fact, the approach to set the low range value for new-build generators is to use a value 10% below the average capacity. Our reasoning is that new projects are less likely to proceed if their capacity factor is significantly lower than the market average. The same method is applied for renewables as for coal to develop the low range capacity factor assumption.

For the high capacity factor assumption, the highest capacity factor achieved over a ten year period is applied. Given these are new-build, it is appropriate to be less conservative on the high range assumption. Again, the approach is the same for coal and renewables.

D.4.13 If GenCost shows renewables are cheaper, why are electricity prices higher in Australia and in countries transitioning to renewables?

GenCost calculates the breakeven cost of electricity needed for investors to recover their capital, fuel and operating costs, including a reasonable return on investment. This is an indicator of the electricity price needed to encourage new investment, but it does not control the electricity price. Electricity prices are controlled by the balance of supply and demand. If supply is tight relative to demand, then prices go up. If supply is significantly more than demand, then prices go down. Changes in fossil fuel prices are another source of volatility. Price increases in recent years are a combination of lack of supply and fuel price volatility.

In 2022, global natural gas supply constraints, triggered by sanctions on Russia due to the Ukraine war, together with unplanned coal plant outages caused a price spike in Australia that is still reverberating through the electricity system. The prices of other electricity systems around the world were also impacted by the rising global fossil fuel prices and constrained supply of gas.

In Australia, retailers, experiencing these conditions, secured electricity supply contracts for the future which factored these higher prices in. A decrease in gas prices or growth in new supply capacity (net of retirements) can put downward pressure on market prices. However, there is no guarantee that either of these forces will maintain downward pressure on prices. If gas prices rise again or capacity is retired faster than it is rebuilt, then prices will increase again regardless of the cost of new entrant capacity.

The quality of both renewables and fossil fuel resources varies substantially around the world as do the pace of transition to lower emission sources, the degree of state ownership, subsidies, age of generation fleet and market incentives for building new capacity. As a result, due to the variety of differences in circumstances and the impact of supply and demand imbalances, there are no clear causal relationships that can be concluded from a simple correlation analysis of electricity prices and the energy source used by country or region.

D.4.14 If nuclear has such high capital costs why do they have such low-cost nuclear electricity overseas?

New large-scale nuclear costs are significantly lower than nuclear SMR but both represent moderate- to high-cost sources of electricity generation. This result could be perceived as out of step with overseas experience where some countries enjoy low-cost nuclear electricity. There are two reasons for this seemingly inconsistent result.

The first is that new generation technology electricity costs have only weak transferability between countries. While the technology can be identical, electricity generation costs vary widely between countries due to differences in installation, maintenance and fuel costs in each country. There are also unknown or known subsidies and different levels of state versus private ownership which impact the costs that ultimately get passed to electricity customers.

The second issue is that observations of low-cost nuclear electricity overseas are in most cases referring to historical rather than new projects which could have been funded by governments or whose capital costs have already been recovered by investors. Either of these circumstances could mean that those existing nuclear plants are charging lower than the electricity price that would be required to recover the costs of new commercial nuclear deployment. Such prices are not available to countries that do not have existing nuclear generation such as Australia.

In summary, given overseas new generation electricity costs are not easily transferable and may be referring to assets that are not seeking to recover costs equivalent to a commercial new-build nuclear plant, there may be no meaningful comparison that can be made between overseas nuclear electricity prices and the costs that Australia could be presented with in building new nuclear.

Appendix E Technology inclusion principles

GenCost is not designed to be a comprehensive source of technology information. To manage the cost and timeliness of the project, we reserve the right to target our efforts on only those technologies we expect to be material, or that are otherwise informative. However, the range of potential futures is broad and as a result there is uncertainty about what technologies we need to include.

The following principles have been established to provide the project with more guidance on considerations for including technology options.

E.1 Relevant to generation sector futures

The technology must have the potential to be deployed at significant scale now or in the future and is a generation technology, a supporting technology or otherwise could significantly impact the generation sector. The broad categories that are currently considered relevant are:

- Generation technologies
- Storage technologies
- Hydrogen technologies
- Consumer scale technologies (e.g., rooftop solar PV, batteries).

Auxiliary technologies such as synchronous condensers, statcoms and grid-forming inverters are also relevant and important but their inclusion in energy system models is not common or standardised due to the limited representation of power quality issues in most electricity models. Where they have been included, results indicate they may not be financially significant enough to warrant inclusion. Also, inverters, which are relevant for synthetic inertia, are not distinct from some generation technologies which creates another challenge.

E.2 Transparent Australian data outputs are not available from other sources

Examples of technologies for which Australian data is already available from other sources includes:

- Operating generation technologies (i.e., specific information on projects that have already been deployed)
- Retrofit generation projects
- New build transmission.

Most of these are provided through separate AEMO publications and processes.

Other organisations publish information for new build Australian technologies but not with an equivalent level of transparency and consultation. New build cost projections also require more complex methodologies than observing the characteristics of existing projects. There is a distinct lack of transparency around these projection methodologies. Hence, the focus of GenCost is on new build technologies.

E.3 Has the potential to be either globally or domestically significant

A technology is significant if it can find a competitive niche in a domestic or global electricity market, and therefore has the potential to reach a significant scale of development.

Technologies can fall into four possible categories. Any technology that is neither globally nor domestically significant will not be included anywhere. Any other combination should be included in the global modelling. However, we may only choose to include domestically significant technologies in the current cost update which is subcontracted to an engineering firm.

Apx Table E.1 Examples of considering global or domestic significance

Globally significant	Domestically significant	Examples
Yes	Yes	**Solar PV**, **onshore and offshore wind**
Yes	No	**New large-scale hydro**. No significant new sites expected to be developed in Australia **Conventional geothermal energy**: Australia is relatively geothermally inactive
No	Yes	None currently. A previous example was **enhanced geothermal,** but domestic interest in this technology declined
No	No	Emerging technologies that have yet to receive commercial interest (e.g., **fusion**) or have no commercial prospects due to changing circumstances (e.g., **new brown coal**)

E.4 Input data quality level is reasonable

Input data quality types generally fall into five categories in order of highest (A) to lowest (E) confidence in Australian costs:

A. Domestically observable projects (this might be through public data or data held by engineering and construction firms)

B. Extrapolations of domestic or global projects (e.g., observed 2-hour battery re-costed to a 4-hour battery, gas reciprocating engine extrapolated to a hydrogen reciprocating engine)

C. Globally observable projects

D. Broadly accepted costing software (e.g., ASPEN)

E. “Paper” studies (e.g., industry and academic reports and articles).

While paper studies are least preferred and would normally be rejected, if a technology is included because of its potential to be globally or domestically significant in the future, and that technology only has paper studies available as the highest quality available, then paper studies are used. Confidential data as a primary information source is not used since, by definition, it cannot be validated by stakeholders. However, confidential sources could provide some guidance in interpreting public sources.

E.5 Mindful of model size limits in technology specificity

Owing to model size limits, we are mindful of not getting too specific about technologies but achieving good predictive power (called model parsimony). We often choose:

- A single set of parameters to represent a broad class (e.g., selecting the most common size)
- A leading design where there are multiple available (e.g., solar thermal tower has been selected over dish or linear Fresnel and single axis tracking solar PV over flat).

The approach to a technology’s specificity may be reviewed (e.g., two sizes of gas turbines have been added over time and offshore wind turbines have been split into fixed and floating). For a technology like storage, it has been necessary to include multiple durations for each storage as this property is too important to generalise. As it becomes clearer what the competitive duration niche is for each type of storage technology, it will be desirable to remove some durations. It might also be possible to generalise across storage technologies if their costs at some durations are similar.

Shortened forms

Abbreviation	Meaning
AAS	Australian Academy of Science
A-CAES	Adiabatic Compressed Air Energy Storage
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
ATSE	Academy of Technological Sciences and Engineering
BAU	Business as usual
BOP	Balance of plant
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CIS	Capacity Investment Scheme
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated solar thermal
EV	Electric vehicle
FOAK	First-of-a-kind
GALLM	Global and Local Learning Model
GALLME	Global and Local Learning Model Electricity
GALLMT	Global and Local Learning Model Transport
GJ	Gigajoule
GW	Gigawatt
H2	Hydrogen
hrs	Hours
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
ISP	Integrated System plan

Abbreviation	Meaning
kW	Kilowatt
kWh	Kilowatt hour
LAES	Liquid Air Energy Storage
LCOE	Levelised Cost of Electricity
LCOS	Levelised cost of storage
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
MLF	Marginal Loss Factor
Li-ion	Lithium-ion
LR	Learning Rate
Mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NOAK	Nth-of-a-kind
NSW	New South Wales
NT	Northern Territory
NZE	Net zero emissions
O&M	Operations and Maintenance
OECD	Organisation for Economic Cooperation and Development
PEM	Proton-exchange membrane
PHES	Pumped hydro energy storage
PV	Photovoltaic
REZ	Renewable Energy Zone
SLCOE	System Levelised Cost of Electricity
SMR	Small modular reactor
STEPS	Stated Policies Scenario
SWIS	South-West Interconnected System

Abbreviation	Meaning
TWh	Terawatt hour
UAE	United Arab Emirates
USC	Ultra-supercritical
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEM	Western Electricity Market
WEO	World Energy Outlook

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