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GenCost 2024-25

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. However, if these additional costs are significant, we make an exception. Two exceptions that this report includes are the additional system costs required to make solar PV and wind generation reliable and the carbon dioxide pipeline and storage costs of projects with carbon capture and storage.

The narrower and simpler scope of LCOE cost data means that readers should be cautious about drawing strong conclusions about the electricity system from such data. In particular, electricity systems will always require a diversity of resources to deliver all of 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 2025 on a Consultation Draft version of this report that was made available in December 2024. The authors greatly appreciate the time stakeholders have given to support the project.

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 all 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 seventh 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 Aurecon. 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.

'Firming' or integration costs of variable renewables

In this report, where we make a comparison between the costs of variable renewables such as solar PV and wind and the costs of other technologies we include the cost of firming those renewables which we call integration costs. These are the additional costs of ensuring supply is reliable when using intermittent energy sources. These integration costs are itemised in the report and include storage, transmission, system security and spilled energy.

Summary of feedback on the consultation draft

While feedback has been dominated by nuclear related topics in the past two GenCost cycles, the 2024-25 consultation draft feedback was more diverse with the majority of feedback covering pumped hydro, electrolysers, wind, solar PV and solar thermal. This indicates a shift in stakeholder focus towards technologies currently planned for investment or under construction. The most impactful changes to the report arising from feedback and the availability of new data are:

- Inclusion of an installation cost escalation factor to account for the impact of Australia's rising real construction costs on the electricity sector. This is supported by new Oxford Economics Australia analysis published by AEMO.
- A reduction in the rate of decline in rooftop solar PV costs recognising that the existing industry is already mature and so installation costs will be slower to fall for rooftop solar than in the large-scale solar sector.
- Inclusion of the cost of new work camps for construction workers in onshore wind generation capital costs.
- An assumed three year pause in gas technology cost reductions, reflecting a lack of gas generation manufacturing capacity relative to technology demand.
- Aligning nuclear SMR costs with the recently announced Canadian Darlington project. These new costs were within the range previously projected by GenCost but are significant as they will represent the first commercial scale western project to provide a cost evidence base.
- An increase in the average cost of capital financing from 6% to 7% to align with the rate used by AEMO and Infrastructure Australia. This impacts the levelised cost of electricity data provided in the report by increasing the cost of delivered energy from all technologies (because they now have higher loan or return to equity repayments).

Together, these changes have increased technology costs compared to previous GenCost reports but there has been no significant change to the relative competitive position of technologies.

Additional analysis on three key nuclear generation topics

Based on public discussion of GenCost's approach to nuclear generation since the 2023-24 final report release, the three most common areas of contention are:

- The capital recovery period should be calculated over the entire operational life (e.g. 60 years), and not the industry standard of 30 years used in GenCost
- Due to US experience, capacity factors of below 93% should not be considered (GenCost uses the range 53% to 89%)
- The nuclear development lead time should be 10 to 15 years, not 15 years or greater as proposed by GenCost.

Additional evidence and analysis of these topics has been provided in this report. There was no substantive feedback from the 2024-25 consultation to warrant changes in this analysis.

Nuclear technology's long operational life

Nuclear advocates have asked for greater recognition of the potential cost advantages of nuclear technology's long operational life and CSIRO has calculated those cost advantages for the first time in 2024-25. Our finding is that there are no unique cost advantages arising from nuclear technology's long operational life. Similar cost savings are achievable from shorter lived technologies, even accounting for the fact that shorter lived technologies need to be built twice to achieve the same operational life.

There are several reasons for the lack of an economic advantage from longer operational life. Substantial refurbishment costs are required, and without this new investment nuclear cannot achieve safe long operational life. When renewables are completely rebuilt to achieve a similar project life to nuclear, they are rebuilt at significantly lower cost due to ongoing technological improvements whereas large-scale nuclear technology costs are not improving to any significant extent owing to their maturity. Also, due to the long lead time in nuclear deployment, the limited cost reductions achieved in the second half of nuclear technology's operational life, when the original capital investment is no longer being repaid, are not available until more than 45 years from now, significantly reducing their value to consumers compared to other options which can and are being deployed in the present time.

Nuclear generation capacity factors

GenCost has always provided a capacity factor range for every generation technology rather than a single point estimate. However, nuclear advocates would prefer GenCost only consider a single value of 93% which is the average capacity factor achieved in the United States. To be clear GenCost agrees that high capacity factors of around 90% are achievable for nuclear generation. However, a prudent investor (government or private) must prepare for all plausible eventualities. The observed global average capacity factor for nuclear generation is 80% and 10% of nuclear generation is operating at below 60%. This is because circumstances vary widely between countries and even within a country there is a merit order for generation dispatch. On international data alone, the proposition of only considering a 93% capacity factor is not supported by the evidence.

However, our preference is to always use Australian data where it is available. In Australia, we have more than 100 years of experience with operating baseload generation, not nuclear but coal. Some black and brown coal plants operate at close to 90% capacity factor but the average for all coal in the past decade is 59%. On this basis a single point estimate of 93% does not adequately capture the plausible range achievable in Australia. GenCost bases its capacity factor assumptions for all baseload technologies – coal, gas, and nuclear – on the Australian evidence, applying a maximum of 89% and minimum of 53%. The minimum is based on the same formula that we apply to renewables (the minimum capacity factor for new build generation is assumed to be 10% below the average capacity factor of existing equivalent generation).

Nuclear development lead time

The development lead time includes the construction period plus all of the preconstruction activities such as planning, permitting and financing. Many stakeholders have agreed with the GenCost estimate of *at least* 15 years lead time for nuclear generation. Those stakeholders that are more optimistic cite two alternative sources, the International Atomic Energy Agency (IAEA) who have an estimate of 10 to 15 years and the recent completion of a nuclear project in the United Arab Emirates (UAE) which had a 12-year lead time. Both estimates are in relation to building nuclear for the first time. This report provides additional analysis of nuclear lead times to examine this issue more closely. Recent construction times and their relationship with the level of democracy in that country are examined.

In the last 5 years, median construction time has increased to 8.2 years compared to 6 years when the IAEA first made their estimate in 2015[1]. This increase in construction time cannot be explained by the pandemic because median construction times were longer in the two years preceding the pandemic (8.6 and 9.8 years). Note that most of the historical construction time data is dominated by countries with established nuclear industries and so may be optimistic for a first-time country.

There is some statistical evidence for the impact of the degree of democracy on nuclear lead times. Pakistan, China and the UAE have had the fastest construction times in the last decade with average construction times of 6 to 8 years, but their democracy index scores are low. Finland, South Korea, the United States (US) and India all had construction times 10 years or longer with high democracy scores. The two Western democracies in this list, Finland and the US had construction times of 17 and 21 years respectively which is significantly longer than the Asian democracies.

Another factor which is correlated with shorter construction times is the existence of an ongoing building program rather than long intervals between projects.

Given the direction of construction data available after the report's release, the IAEA range of 10-15 years should likely be reinterpreted as 12 to 17 years to allow for the extra 2 years median construction time which now prevails. The lower part of this new range, 12 years, would be consistent with the UAE experience. Australia is not likely to be able to repeat the UAE experience because our level of consultation will be consistent with our higher level of democracy and the experience of other Western democracies. As such, *at least* 15 years remains the most plausible lead time.

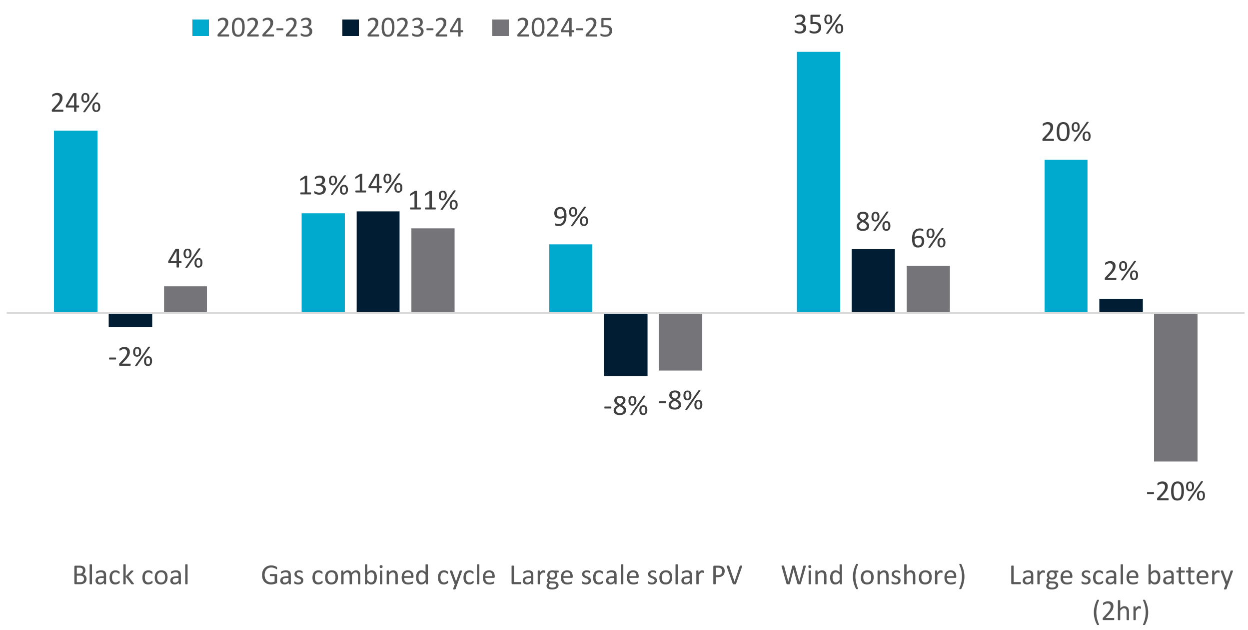
Key changes in capital costs in the past year

The COVID-19 pandemic led to global supply chain constraints which impacted the prices of raw materials needed in technology manufacturing and freight costs. Consequently, the 2022-23 GenCost report observed an average 20% increase in technology costs. For each of the two years following that observation, the inflationary pressures have progressively eased but the results remain mixed. Technologies have been affected differently because they each have a unique set of material inputs and supply chains.

The capital costs of onshore wind generation technology increased by a further 8% in 2023-24 and another 6% in 2024-25, while large-scale solar PV has fallen by 8% in consecutive years (ES Figure 0-1). The wind cost increase includes a one-off 4% increase to take account of work camp costs not previously included in wind capital cost estimates.

Large-scale battery costs improved the most in 2024-25, falling by 20% in 2024-25. The cost of gas turbine technologies is still increasing significantly. GenCost includes hydrogen fuel readiness as a standard feature in gas generation, but this only has a negligible impact on capital costs.

[1] They republished this estimate in 2024 but did not update it



ES Figure 0-1 Year on year change in current capital costs of selected technologies in the past 3 years (in real terms)

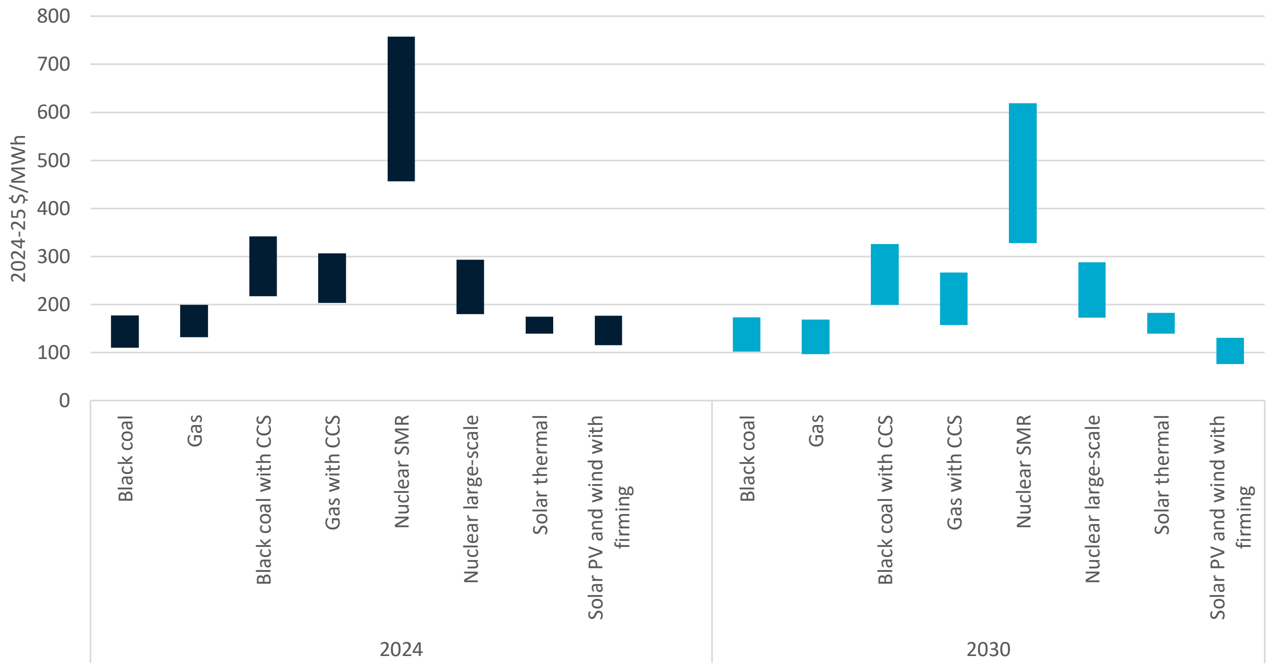
The cost of electricity technologies compared

LCOE is the total unit costs a generator must recover over its economic life to meet all its costs including a return on investment. Each input to the LCOE calculation has a high and low assumption to create an LCOE range for each technology (ES Figure 0-2).

The LCOE cost range for variable renewables (solar PV and wind) with integration costs is the lowest of all new-build technologies in 2030 and at a similar range with black coal in 2024. The lower end of the cost range of gas generation is also competitive. Black coal and gas are high emissions technologies which, if used to deliver the majority of Australia's power supply, are not consistent with Australia's current climate change policies[2].

If we exclude high emissions generation options, the next most competitive generation technologies are solar thermal, gas with carbon capture and storage, large-scale nuclear and coal with carbon capture and storage.

[2] Most modelling indicates that gas is likely to continue to be utilised and constructed for some time yet as a peaking technology which supports the grid but with a low contribution to total electricity produced. AEMO analysis of electricity systems consistent with net zero by 2050 can be accessed at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp



ES Figure 0-2 Calculated LCOE by technology and category for 2024 and 2030

While solar thermal costs are low, given the need to access better solar resources further from load centres, they will face additional transmission costs compared to coal, gas and nuclear. Directly calculating these costs was not in scope but could add around $14/MWh to solar thermal costs based on transmission costs that were calculated for solar PV and wind.

Nuclear SMR costs improve significantly by 2030 but remain significantly higher cost than these other alternatives (ES Figure 0-2). For clarity, neither type of nuclear generation can be operational by 2030. Developers will need to purchase the technology in the 2030s sometime after pre-construction tasks are completed. Around 8 years of construction would then follow before full operation can be achieved. As such, the inclusion of large-scale and SMR nuclear in the cost comparisons is only as a point where investment could be considered. A practical operation date would be the mid-2040s by which time the costs of other technologies will have fallen further. Renewable and storage technologies also have development lead times, but their deep development pipeline of projects means that there are new projects reaching the point of financial close each year.

While LCOE us useful for ranking technology costs, 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.

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.

Following the release of the 2023-24 final report there are still three key areas of disagreement with nuclear advocates. To address these topics, additional evidence and analysis are presented on nuclear capacity factors, lead times and the value of a long project life in Section 2.

The report provides an overview of updates to current costs in Section 3. This section draws significantly on updates to current costs provided in Aurecon (2025) and further information can be found in their report. The global scenario narratives and data assumptions for the projection modelling are outlined in Section 4. Capital cost projection results are reported in Section 5 and LCOE results in Section 6. CSIRO's cost projection methodology is discussed in Appendix A. Appendix B provides data tables for those projections which can also be downloaded from CSIRO's Data Access Portal[3]. A set of technology selection and data quality principles has been included in Appendix C. 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.

1.1.1 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own resources. AEMO commissioned Aurecon to provide an update of the current cost and performance characteristics

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

of electricity generation, storage and hydrogen technologies (Aurecon, 2025). This report focusses on capital costs, but the Aurecon 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 6.

For the 2024-25 report, AEMO also commissioned Oxford Economics Australia (2025) to provide installation cost escalation factors.

Project management, capital cost projections (presented in 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, we have included a longer discussion on some topics related to nuclear energy (Section 2). We have also added historical data to most of the capital cost projections to give readers a better sense of what cost trends existed prior to the projection period. Another small change is that open cycle gas generation technology now has an explicit hydrogen blending ratio and are the only type of open cycle gas technology included given current trends in investment in this technology. The installation cost escalation factors developed by Oxford Economics Australia (2025) are also a new feature applied to the capital cost projections.

1.2 The GenCost mailing list

The GenCost project would not be possible without the input of stakeholders. No single person or organisation is able to 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 on the Consultation draft

1.3.1 Technology specific items

Nuclear

Frontier economics report

Frontier Economics released a report on 13th December 2024 which was widely anticipated to provide some new information about the cost of nuclear generation in Australia’s electricity system. The report was reviewed to determine if it included any useful information on nuclear costs. Our conclusion is that the report is a valuable contribution to understanding the outcomes for the electricity sector from a combination of three factors: delayed emissions reduction, lower economic growth and increased nuclear generation. However, the report cannot be used to draw any conclusions about the cost of nuclear generation relative to other generation options. The reason it has limited applicability in determining the relative costs of generation options is that the scenario design employed in the analysis does not allow for this comparison to be made. By combining three factors together in a single scenario, it is not possible to determine whether the addition of nuclear generation increased or decreased system costs relative to the alternative scenario (AEMO's *Step Change*). There is no doubt that some of the three factors included did result in reduced system costs but, unless each factor is studied individually in their own scenario, their specific individual contributions cannot be determined from the data presented. The study only provides one other scenario, which clarifies the role of economic growth only, not the other two factors.

A second issue is that the report does not adequately consider first-of-a-kind (FOAK) costs which developers of nuclear in Australia would inevitably face due to our lack of experience in deploying the technology. The report initially considers a 10% premium but then removes that premium by the time nuclear is developed. Based on global experience, a premium of over 100% is more appropriate for the first plant. See section 3.1.1 for more discussion and sources of data on FOAK premiums.

Capacity factor assumption

In reaction to GenCost's use of historical coal capacity factors, as the basis for the potential future range of nuclear generation capacity factors in Australia, it was suggested that historical brown coal capacity factors would be most appropriate. The consultation draft had erroneously referred only to black coal capacity factors. However, the capacity factor range applied is in fact inclusive of brown coal. This clarification has been made in the body of the report. However, regarding the suggestion to only use brown coal capacity factors, this proposal was not accepted. Brown coal is confined to only one state in Australia and as such is regarded as too narrow a source of data for a national capacity factor range.

Near term nuclear SMR project

Credible costs for the Darlington nuclear SMR project became available with the announcement of its go ahead in May 2025. GenCost has chosen to align nuclear SMR costs with the $C20.9 billion 1200MW project. These new costs were within the range previously projected by GenCost for the late 2020s but nonetheless is a significant development as it will represent the first commercial scale western project to provide a cost evidence base for that technology.

Construction time

An individual stakeholder provided data which showed that democracies have been able to have fast nuclear construction times in the past. However, the point GenCost makes is that through environmental, industrial relations and safety regulations, countries with relatively high levels of democracy have increased their oversight of not just nuclear but all project development across the economy and consequently, can no longer build projects at the rate they did last century.

Additional consultation

The Australian Academy of Science (AAS) and the Academy of Technological Sciences and Engineering (ATSE) convened a Chatham House rules workshop in Canberra on Wednesday 17 July 2024, providing input to the GenCost team on nuclear energy in Australia.

Coal

Benchmark data

A stakeholder suggested GenCost use some specific historical benchmark data for ultra-supercritical coal generation technology capital costs. In the absence of any Australian coal-fired power plant projects for almost 20 years, Aurecon used commercially available reputable software "Thermoflow" for costing. The software is well recognised by industry for thermal power plant modelling and costing. The software includes the capability to normalise cost for the Australian context. It should be noted that construction of coal plants in the developed world is very limited and hence there remains supply chain issues along with limited availability of contractors to build them. Therefore, escalating costs of projects built many years ago may not be appropriate in the current market.

Land and development cost assumptions

A stakeholder had concerns about the land and development costs associated with coal. Coal generation projects require large land areas to accommodate ash dams, coal stockpile, evaporation ponds, water treatment and waste treatment. The development timeframe and approval process is also lengthy. A 20% share of capital for the cost of land and development is an estimate only and may vary depending upon location, type of land, coal delivery requirements, transport and logistics development and its proximity to the grid.

Gas

Capital costs

Stakeholders reported that gas generation technologies are in high demand relative to manufacturing capacity and as a result orders were taking longer than normal to fill. This observation was confirmed from other industry data sources. While this excess demand persists, it will be unlikely that gas generation technology costs fall. Consequently, the report introduces a three year pause before we see any real reductions in gas technology costs.

Renewables (general)

Spillage, storage and transmission costs

Some stakeholders found difficulty reconciling the ranges given for spillage, storage and transmission costs in the text with the relevant graph (Figure 6-2). The graphed costs are lower because they are for the National Electricity Market (NEM) whereas the text refers to the average of the NEM and south west Western Australian Wholesale Electricity Market (WEM). Due to the isolation of that grid transmission costs are lower since there are fewer opportunities to diversify renewable resources by connecting to other grids. However, the lack of diversity means that spillage costs and storage costs are higher in the WEM. This means that NEM+WEM average costs for spillage and storage are higher than shown in the charts. This has been clarified in the report body.

Capacity factor assumption

Some stakeholders observed a recent bad year for renewable capacity factors while also observing that they were within the range used by GenCost. Year on year variability is to be expected in renewable capacity factor performance and is not a basis for determining the plausible long-term range.

Rooftop and large-scale solar PV

Rate of decrease in installation costs

It was requested that the modelling approach be updated to separately model the installation costs of rooftop solar PV and large-scale solar PV with the view that rooftop solar PV installation costs were unlikely to continue to fall as fast as large-scale solar PV given the different levels of maturity of the two sectors. This was accepted and has been implemented for this report. The new learning rates for both types of solar PV are reported in Appendix C.

Wind

Work camp costs and a reminder about locational cost factor data

Stakeholders remain concerned about the cost of wind projects. Some of the variance in wind costs relate to differences between states and these are captured in the locational cost factors which are separately provided by Aurecon and used in AEMO modelling when applying the GenCost data. All costs in GenCost are for a Victorian project not more than 200km from Melbourne's port. The locational cost factors are required to adjust costs to be relevant to other states. However, in discussions with stakeholders it was identified that the increasing remoteness of wind projects and their workforce needed means that they typically need to construct a work camp as part of the project costs. This additional cost was added to current and future wind capital costs, increasing them by approximately 4%.

Solar thermal

Deeper analysis

Solar thermal stakeholders would like deeper analysis on solar thermal including more detail on its role globally, inclusion as a storage technology, inclusion in firmed renewables calculations and for multiple configurations (storage to power ratios) to be included. These are significant requests given the lack of real Australian project data and the difficulty of modelling solar thermal given it simultaneously intersects two technological categories without any standard configuration of those characteristics. Under current resources these actions are out of scope for GenCost.

Economic life assumption

At 25 years in the consultation draft, the economic life was inconsistent with the Aurecon (2025) report and has been updated to 30 years.

Consistency between Aurecon (2025) and Fichtner Engineering (2023) report

A number of consistency issues have been checked and actioned where appropriate.

Installation costs method

While not prompted by stakeholders, the broader consideration of installation costs in this report led to solar thermal technologies having their own learning rate for installation costs consistent with other technologies. Previously only one learning rate applied to the whole capital cost. This approach was implemented for the first time in this report.

Pumped hydro

Class of sites included

Some stakeholders felt that costs for pumped hydro energy storage should be based on a better class of sites. The GenCost project prefers sites that have stronger engineering and cost data over theoretical high quality sites with no commercial quality data associated with them. It is accepted that this limits the quality of sites included. It is noted that some high-quality sites may be difficult to develop due to the social, environmental or cultural values associated with them.

Land and development cost assumption

Aurecon's land and development costs includes the cost of environmental offsets. Stakeholders suggest that land is more likely to be leased. The Aurecon approach is to include this in the capital cost, but a leasing arrangement would mean the cost shifts to the operating and maintenance component.

Consistency of the cost and storage duration relationship

The costs presented in GenCost for the 10, 24 and 48 hour options do not follow the expected trend in dollar per kW costs with the 24 hour duration being lower cost than the 10 hour duration project (which would be expected to be lowest cost per unit of power output due to its smaller storage reservoir). The 10 hour project is however, based on the most recent relevant project of that duration under construction rather than a theoretical cost curve. It is accepted that using real project costs rather than a theoretical curve will at times result in unexpected trends. The unexpected trend reflects some economies of scale in pumped hydro due to relatively fixed costs such as water licencing, transmission connection and access roads.

Inclusion of additional 160 hour storage duration projects

Snowy 2.0 which has 160 hours storage duration is not included in GenCost because it is an existing project under construction. Stakeholders have requested additional new projects of this duration be included in GenCost. This will be considered for future GenCost publications but could not be actioned for 2024-25. Appendix E provides the principles applied in determining which technologies to include in GenCost.

A-CAES

Consistency with public international project data

Additional information has been added to the Aurecon report to ensure the basis of Australian A-CAES costs are understood. Natural cavern and vessel costs are very different. Some public costs cannot be relied upon because they lack detail about their scope (i.e. project boundaries, contingencies, subsidies and other assumptions). Finally, there are always significant differences in deployment costs between countries owing to different labour costs, productivity, equipment suppliers and experience.

LAES

Requested inclusion

It was requested that liquid air energy storage (LAES) be included in GenCost. It has not been included in this report but may be considered for future reports. Appendix E provides the principles applied in determining which technologies to include in GenCost.

Electrolysers

Consistency with Australian projects

There was a concern that current electrolyser costs in GenCost are below current Australian project costs. Aurecon cost estimates are based on selected Australian projects at various stages of development. A lower level of project development maturity will lead to a higher cost uncertainty (lower cost accuracy). Aurecon's cost estimates do not include contingency. Other infrastructure costs not included in Aurecon's cost estimate are hydrogen compression, storage, transportation, power generation, transmission, grid connection, bulk water source and supply to site and water treatment plant wastewater stream disposal and upgrade of port facilities.

Electricity price accuracy for electrolysers

There is a concern that simplified global models of electricity supply cannot capture the premium associated with using renewable electricity to supply electrolyser with energy that can be used to market their product as green hydrogen. It is accepted that GALLM, the electricity model employed in GenCost, is not sufficiently detailed to capture the cost of electricity to electrolysers at the accuracy that more temporally disaggregated national and precinct level electricity models can. This technical limitation diminishes as source of inaccuracy the further into the projection period. Electrolysers generally require less reliable (and consequently lower cost) electricity supply than the bulk of customers as their capital costs fall.

Electrolyser learning rate assumptions

Consistent with the view that electrolyser projects have not proceeded at the rate expected in the short term some stakeholders have suggested that electrolyser learning rates should be revised downwards, presenting literature which suggests technologies with high levels of complexity have lower learning potential. This report has not reduced learning rates on the basis that the range assumed across the scenarios (see Appendix C) already accommodates this view. However, in previous projections GenCost did assume cost reductions (in addition to the learning curve function) would be occur from the scaling up of electrolyser projects. This was implemented as a means of recognising the gigawatt scale of some proposed projects. However, cost reductions from large scale deployment so far have not significantly materialised. Consequently, this component of the projection approach has been removed.

Inclusion of solid oxide electrolysers

It was requested that solid oxide electrolysers be included in GenCost. They are higher cost but more energy efficient. It has not been included in this report but may be considered for future reports. Appendix E provides the principles applied in determining which technologies to include in GenCost.

1.3.2 General items

Capital cost projection method

Inclusion of installation cost escalation

A new methodology was implemented in this report which increases the installation cost component in line with expected real increases in construction costs (after any reduction in installation costs due to other learning and innovation related factors). This new methodology was not flagged in the consultation draft because the data on real construction cost changes did not become available until after the consultation draft was published. The method is based on data from Oxford Economics Australia (2025). A description of the new approach appears at the beginning of Section 5.

In this context, productivity improvements can offset rising labour costs. However, as some stakeholders have pointed out, many projects lack allowances for training and apprenticeships. This limits the both the number of qualified workers and the experience that can be carried from one project to another.

Mature technology cost reduction assumption

Since project inception, GenCost has included a general technology cost reduction rate for mature technologies which would otherwise not experience any cost reduction since they no longer experience learning by deployment effects that apply to newer or less mature technologies. The rationale for these cost reductions is primarily the fact that historically commodities fall in cost (in real terms) over time. Since the pandemic and subsequent global supply chain crisis the indices used to calculate the factor no longer indicate any ongoing cost reduction trend. As the global manufacturing sector works towards decarbonisation, some relevant commodities such as metals and minerals and other inputs such as cement are likely to increase in cost as they gradually adopt alternative low emissions production methods. As such, recent experience and expected developments in various material inputs no longer support the concept of falling costs for mature technologies. In acknowledgement of these developments which support a stakeholder request, the mature technology cost reduction factor has been removed from the projection method.

Scope

Definition of a new project

GenCost has limited its scope to only considering costs for new build generation, storage and electrolyser projects. Some stakeholders believe an extension of capacity at an existing site should be considered a new build. GenCost does not accept this. Extension of capacity at an existing site, even where the main structures are separate, must necessarily take advantage of some existing infrastructure and is therefore not a fair comparison with completely new build projects. Use of existing sites should be considered as part of Australia's electricity options. However, site specific cost estimates are outside of the scope of GenCost since it involves a different (higher) level of accuracy and engagement with existing owners of the site. Such studies are best led or commissioned by the site owner. AEMO publishes a range of cost information on existing sites in its regular *Inputs and Assumption Workbook* series (see AEMO, 2025 for latest workbook).

Capital cost projections

Inclusion of component detail

A request was made for capital cost projections to be provided broken down by equipment and installation cost components. This level of detail is not required by any modelling teams for which the data is targeted but rather would be for the purpose of interrogating the projections more deeply. This request is not supported as it would represent a scope increase which is to be avoided to maintain the sustainability of the project. GenCost is not designed to describe technologies in detail or represent a detailed bottom-up projection process. Where local installation costs are included in the modelling process, this is primarily for the purpose of recognising differences in technology deployment and subsequent cost reduction between countries rather than to be an accurate estimate of technology component shares. The current exception to that is batteries where we do describe the components in this report and this reflects the shared role of the battery equipment component across the electricity and transport sectors.

Levelised cost of electricity (LCOE)

Discount rate assumption

The discount rate or the weighted average cost of capital used in the LCOE formula has increased from 6% (used consistently since 2018) to 7%. This change is to align with AEMO and Infrastructure Australia. As a consequence of this change, the LCOE or delivered cost of energy for all technologies are higher than the consultation draft and all previous GenCost reports which used the lower value. This represents higher loan repayments or return to equity costs that must be recovered.

Data and method transparency for renewable integration costs

A request raised across several consultation cycles is for more detail and background information on the system modelling carried out to estimate variable renewable integration costs. The modelling tool used to carry out these calculations is not suitable for general release. It is also common that stakeholder submissions will attempt to calculate the cost of renewables integration using overly simplified 'back of the envelope' type approaches. The electricity system generation mix cannot be solved for a least cost outcome outside of a model (using a linear or mixed integer programming approach). There is only a relatively small number of researchers who are interested in the least cost generation mix but who also know how to and have the resource to build and operate appropriate electricity system models. To address both of these issues of transparency and lack of expertise and resources, work has commenced on a model and data set that could be more readily shared with other researchers and the results of this work will be discussed in the GenCost 2025-26 cycle.

Inclusion of technology degradation

A method was proposed by a stakeholder for incorporating technology degradation in the levelised cost of electricity formula. The method proposed averaging the initial and final capacity factors which is effectively a linearisation of the typical non-linear decline rate. This is accepted as a reasonable approximation at face value. One exception would be solar PV where the degradation occurs to the direct current panel capacity and would be ameliorated partially by the difference between the panel and inverter sizes. Wherever the topic of extending LCOE to include other factors has emerged the general philosophy of GenCost is to avoid adding additional factors in favour of simplicity if those factors they do not make a significant contribution to costs. However, the greatest concern is that capacity factors in GenCost already include degradation because they are based on ten years of data from the full range of projects in the NEM, many of which would already be significantly degraded. Consequently, the method has not been taken up.

Inclusion of marginal loss factors

It was requested that marginal loss factors (MLFs) be included in LCOE estimates driven by a concern that renewables are significantly impacted by this issue relative to other technologies due to their more distributed deployment away from strong parts of the existing transmission grid. MLFs are the electricity losses in the transmission network between a generator and the market's Regional Reference Node. MLFs are site specific by nature since they are based on location in the network. The LCOEs presented in GenCost are not site specific in the sense that they are for new build technologies but with no specific location. Furthermore, the grid will change over time to strengthen areas where new generation is being built but may also at other times weaken[4]. Therefore, while the issue is acknowledged as significant, it is neither practical nor desirable in the long run to include MLFs.

[4] The dynamic nature of this topic is acknowledged in this statement: “In recent years, supply and demand patterns in the NEM have been changing at an increasing rate, driven by new technology and a changing generation mix. This has led to large year-on-year changes in MLFs, particularly in areas of high renewable penetration that are electrically weak and remote from load centres”. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf?la=en

2 Nuclear: additional evidence and analysis on three topics

Based on public discussion of GenCost's approach to nuclear generation since the 2023-24 final report release, the three most common areas of contention with CSIRO analysis are that:

- The capital recovery period should be calculated over the entire operational life (e.g. 60 years), and not the industry standard of 30 years used in GenCost
- Due to US experience, capacity factors of below 93% should not be considered (GenCost uses the range 53% to 89%)
- The lead time should be 10 to 15 years, not 15 years or greater.

Additional evidence and analysis of these topics is provided in the following discussion.

2.1 Nuclear capital recovery period and long operational life

Stakeholders have raised direct government ownership as a serious proposal. Based on feedback received throughout the course of the GenCost project, it is assumed the primary intent of government ownership is to unlock the potential benefits of nuclear technology's long operational life with a longer capital recovery period than might be achievable with private ownership and funding.

In the following analysis we examine two potential ways in which government ownership might be able to unlock potential benefits of long operational life by:

- Accessing longer-term capital recovery periods not available to the private sector, and,
- Maintaining the same 30-year capital recovery period but acknowledging the lower generation costs in the remainder of the operational life in the assessment of levelised costs of electricity. With this knowledge, a government owner could choose to smooth out the average cost of electricity over time from nuclear generation. Alternatively, they might simply be able to weather the first 30 years of high-cost generation more sustainably than a private sector investor because governments can carry losses through debt for long periods of time.

Our analysis of these two financial strategies for using the longer operational life of nuclear to create cost savings from government ownership finds that:

- **Long-term operation of nuclear is not costless**. Extension costs are incurred and are significant.
- **Long operational life provides no major financial benefit to electricity customers relative to shorter-lived technologies**. Taking account of extension costs, long operational life confers an average cost reduction of 8% to nuclear power relative to the costs that are calculated when only considering the standard 30-year private sector financial arrangements. However, there are three important limitations to this benefit:
  - *Other technologies can achieve similar benefits*. Our analysis includes examples where onshore wind and solar PV are initially built and then completely rebuilt at the 25 to 30

year mark to achieve a total 50 to 60 year project life. Alternatively, we could build a nuclear project and incur normal extension costs at the 40-year mark. Both types of projects involve re-investment costs during their life, although for the renewable projects the reinvestment is more substantial than nuclear relative to the initial investment. However, overall, renewables achieve a similar cost reduction of 5% when considered over a 50 to 60 year life because their costs are falling over time making their second investment lower than the first.

– *Time erodes most of the benefit of long operational life*. The present value of the cost reduction that is available from lower costs in the second half of nuclear technology's long operational life fades to less than half when we consider the cost of the delay before first nuclear generation can commence.
– *It is unclear how customers would be awarded benefits of future lower cost operation*. The current electricity market design does not pass through the costs of the lowest cost generation – instead the benefits are captured as profits to owners.

The material below provides more detail on how these conclusions were reached.

2.1.1 Cost advantage of accessing longer-term capital recovery ignoring extension costs

In analysing the impact of longer-term capital recovery, for simplicity, we will initially ignore life extension costs. These are covered in the next section. The below analysis only changes one assumption about nuclear projects: the capital recovery period.

If the capital recovery period is changed from 30 years to a number that reflects the full operational life, then the annual cost of capital recovery will be lower. However, the scale of cost reduction is not proportional to the increase in capital recovery period. For example, doubling the capital recovery period from 30 years to 60 years does not halve the levelised cost of electricity (LCOE) from nuclear. The main reason is that a longer capital recovery period results in the payment of more interest. A 60-year loan will incur around 131% more interest than a 30-year loan and this increases the total amount (principle plus interest) that must be repaid[5]. Another reason is that while capital is the largest component of LCOE, nuclear generation has other non-capital costs which are not impacted by the longer capital recovery period.

As a result of these factors, a 60-year capital recovery period results in only an 9-12% reduction in LCOE compared to a 30-year period, depending on the technology type (Table 1). Stakeholders have proposed operational lives of nuclear plants of up to 100 years. To avoid any doubts about the benefits of longer capital recovery periods, Table 1 reports the cost savings for an operational life of 60 years and a more speculative 100 years to demonstrate that the benefits of very long capital recovery periods do not proportionally improve with length. The data shows that nuclear

[5] The exact amount of interest depends on the detailed schedule of payments, the interest rate and timing of addition of interest. This estimate is based on a simple annual payment and interest accrual model at 7% interest rate. Fixed and variable interest rate combinations are also a source of uncertainty.

SMR receives slightly more benefit. However, this is because its capital costs are higher and consequently capital recovery costs are a larger portion of total LCOE.

Table 2-1 The reduction in nuclear LCOE resulting from a 60- or 100-year capital recovery period compared to a 30-year capital recovery period, ignoring extension costs

New period	Type	2024	2024	2030	2030	2040	2040	2050	2050
		Low	High	Low	High	Low	High	Low	High
60	Nuclear SMR	11%	11%	10%	10%	10%	10%	10%	10%
60	Nuclear large-scale	9%	9%	9%	9%	9%	9%	9%	10%
100	Nuclear SMR	12%	12%	11%	12%	11%	12%	11%	11%
100	Nuclear large-scale	10%	10%	10%	10%	10%	11%	10%	11%

2.1.2 Impact of accessing lower costs after the 30-year capital recovery period

An alternative proposal for capturing the potential benefits of the longer operational life of nuclear is to go through the standard 30-year capital recovery period and reap the benefits of capital cost free operation thereafter. To go a step further, proponents have said that failure to recognise this opportunity for low-cost operation is a major flaw of LCOE analysis which is overly focussed on the investor’s perspective and not the long-term value to the consumer.

To address this viewpoint and work through this concept the following analysis will focus only on large-scale nuclear and a 60-year operation period.

Value to customers

To determine the value to customers we deconstruct the timeline of costs to consumers of large-scale nuclear generation over the entire 60-year period of operation. In the first 30 years, the cost to consumers including capital recovery is $173-288/MWh (based on a purchase in 2030). For the remaining 30 years (31 to 60), assuming the plant requires no life extension investment, there would be zero capital recovery costs, only the normal operating and maintenance (O&M) and fuel cost of $36-56/MWh, reflecting GenCost uranium fuel cost assumptions in 2050 (see the first line in Figure 2-1).

However, the assumption of no life extension costs is an oversimplification. Nuclear generation typically requires a major investment to extend life from 40 years to 60 years. Based on IEA (2019) these costs are estimated at A$2765/kW or $49-86/MWh when this refurbishment cost is recovered over the remaining 20 years of life[6]. For simplicity, these costs have been applied from year 41 to 60 in line two of Figure 2-1 assuming uninterrupted generation (together with the existing fuel and O&M costs). In practice, there might be a period where generation needs to be offline for a few years to complete the installations associated with the life extension.

[6] Similar to our approach to calculating original large-scale nuclear capital costs, the life extension costs for this technology were aligned with those in South Korea and scaled up to recognise the known differences in South Korean and Australian generation construction costs based on the cost of building a common coal technology type.

Taking these two nuclear cost examples with and without life extension costs, it is clear that lower costs are available in the years 31 to 60. However, on the downside the consumer must wait 31 years before this is available. This has less value to consumers than if it is available to consumers now. This delay in cost reduction makes the total value of the project to consumers unclear. To determine what value the whole timeline of costs has to consumers we need to convert the costs in all years to a common value. To do this, we have calculated the constant cost to consumers that would be equivalent (using a present value approach) to the uneven timeline of costs over the two or three different cost intervals.

From a present value point of view, the no life extension cost timeline which includes 30 years of no additional costs in years 31 to 60 is estimated to be equivalent to a constant cost to consumers of $157-261/MWh which is an 9% reduction in costs relative to a single 30-year generation project[7]. The with life extension cost timeline, which includes 10 years of no additional refurbishment costs and 20 years of life extension capital costs, is estimated to be equivalent to a constant cost to consumers of $160-265/MWh, which is an 8% reduction in costs relative the costs for a single 30-year generation project.

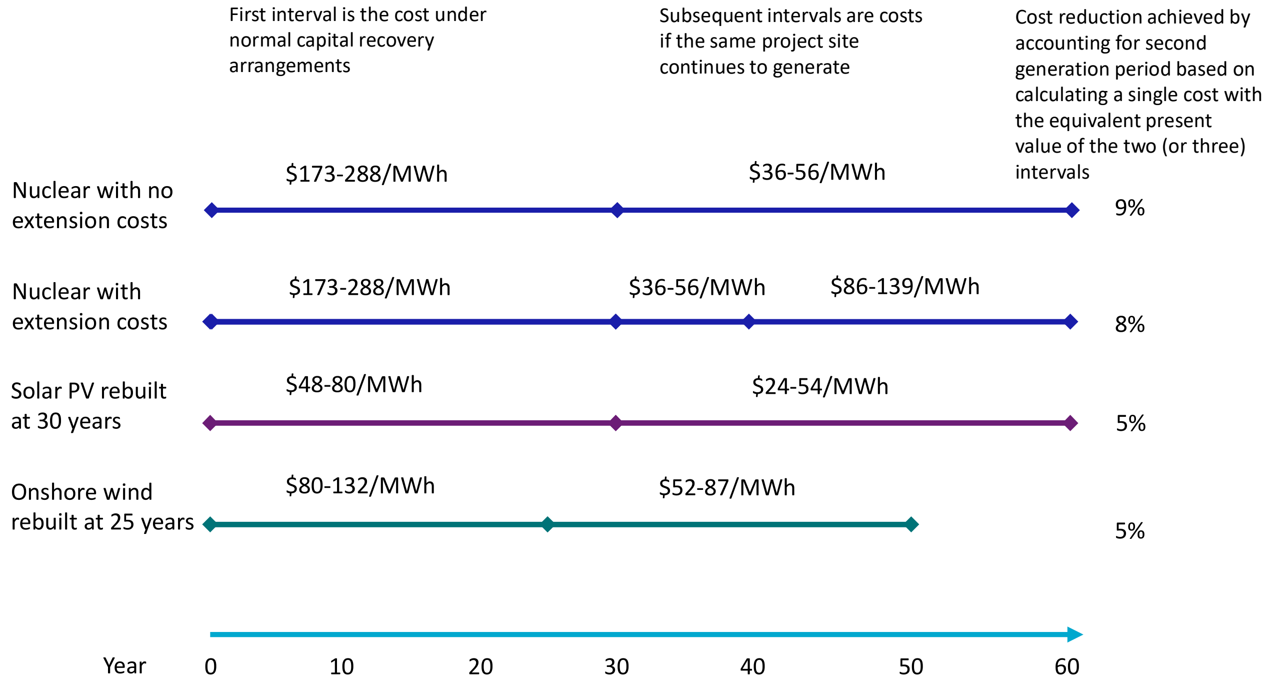


Figure 2-1 Costs for long-lived multi-stage projects and the subsequent cost reduction achieved for electricity consumers.

2.1.3 Allowing other technologies to benefit from multi-stage costing

While nuclear has an inherently longer operational life it is not without additional investment and not completely unique. Coal technologies have an operational life of around 50 years. However, it is too early to be able to say what the total operational life is of more recent technologies such as

[7] This aligns perfectly with the cost reductions that were calculated to be achievable from the 60-year capital recovery period in the previous section which also did not include life extension costs. The perfect alignment reflects that fact that interest cost on capital and the present value of future payments are based on the same central concept of the change in the time value of money.

solar PV and onshore wind. Solar PV panels will have degraded by year 30 but could go on generating for many more years at lower output. If it is advisable to replace panels due to degradation or damage, the underlying mounting system may still be viable beyond year 30. However, data for this will not be available until more projects reach the end of their capital recovery period[8]. Similarly, some parts of the mounting system or other groundwork for wind turbines may have some residual value but are yet unknown. Parts of the existing transmission connection are likely to be viable for at least 50 years.

Leaving aside the potential to re-use some elements of solar PV and onshore wind after their capital recovery period, since the data is not yet available, the analysis will focus on another major opportunity for second stage cost reduction which is to completely rebuild at a lower cost.

The complete rebuild costs are available from GenCost because it provides LCOEs for each decade to 2050. Solar PV has a capital recovery period of 30 years. Consequently, we have designed a 60-year project where the solar PV plant is completely rebuilt and operated for another 30 years (years 31 to 60). Onshore wind has a capital recovery period of 25 years. Consequently, we create a 50-year project where the technology is completely rebuilt and continues to operate for the years 26 to 50. The costs for both solar PV and onshore wind have a long history of declining. On global weighted average, the levelised cost of generation from solar PV reduced 90% and onshore wind by 71% in the 13 years to 2023. Therefore, the rebuild of both technologies can reasonably be expected to be lower cost than the initial project.

To calculate the benefit of the second period of lower costs, in the same way that we did for nuclear generation, we convert the two stages of costs in the full 50- and 60-year lifetimes to a constant value.

The full timeline costs of the 60-year solar PV project, including a complete rebuild in the second half, is estimated to be equivalent to a constant cost to consumers of $45-77/MWh which is a 5% reduction in costs relative to a single 30-year project. The full timeline costs of the 50-year onshore wind project including a complete rebuilt in the second half is estimated to be equivalent to a constant cost to consumers of $75-125/MWh which is also a 5% reduction in costs relative to a single 25-year project.

The solar PV and onshore wind 50– 60-year projects can be implemented immediately because of the existing pipeline of well-advanced projects. However, any Australian nuclear project would be at least 15 years away before first generation. It is therefore not a level playing field to measure the delayed present value benefits of generation from a nuclear project with that of a similar length solar PV or onshore wind project deployed now. The benefits of the nuclear project are devalued by the 15-year delay. For example, $100 today is only worth $39 if you have to wait 15 years to receive it (using the same annual real discount rate as the analysis above). As such, the 8% savings associated with a 60-year nuclear project are worth less than half their value when the 15 year delay before generation can commence is accounted for.

[8] Aurecon (2025) suggest a possible 40-year technical life for solar and 30 to 35 years for onshore wind.

2.1.4 Challenges in passing through lower costs in the post-capital recovery period

Whether it is nuclear or some other technology, passing on the lower costs associated with the second half of a long-lived multi-stage project will be challenging. Australia's current electricity generation system is designed so that the wholesale price reflects the balance between demand and supply. When in excess supply, prices may be below costs of production. When in tight supply, prices can be many times higher than costs of production. Furthermore, the same price is awarded to all generators - there is only one market clearing price. The clearing price is set by the bid price of the last generator required to be dispatched to meet demand. The fact that all generation before that was bid at a lower price is not factored into prices charged to consumers to recover costs of supply.

When an electricity system is growing, the expectation is that market prices will need to be at least as high as that needed for private investors to be sufficiently motivated to invest, otherwise the required new capacity will not be delivered. This is why the LCOE, which is a measure of the costs that investors need to recover to be economically viable, can be thought of as an indicator of future electricity prices. It remains only a partial indicator because other changes in supply and demand (such as capacity retirements, fuel price changes and strong weather changes) in any given year add noise to this underlying investment signal[9].

In this context, if the government owns nuclear and would like to pass on cost reductions estimated above (either as an average 8% lower cost for all 60 years or by waiting until year 31 and passing on lower generation cost from that point forward (see Figure 2-1)) it is not clear what mechanism it would use to do that. If the share of nuclear power is only minor (e.g. 20% or less) then it is unlikely second-stage nuclear generation costs will set the market price because many other sources of generation will be required on top of that to clear the market. The lower cost of nuclear generation will not be experienced by consumers in the market price. Rather, it will be experienced by the government owner as higher profits. A new mechanism would be required to pass on profits through the tax system.

Furthermore, if demand is growing, then to ensure sufficient new supply is invested in, the electricity price must reflect the cost of new investment. This is another barrier to consumers being able to access the lower costs of the second stage of nuclear generation.

2.2 Nuclear capacity factor range

Some stakeholders have posited that if nuclear generation can achieve high capacity factors of 93% in the United States then that is the sole capacity factor that GenCost should be using rather than a range. Australia has no history of nuclear electricity generation but has more than 100 years of experience in operating black and brown coal generation in the same baseload power role. GenCost uses a range of 53% to 89%. 89% represents the best performance of black and brown coal in a recent ten-year period (2011 to 2021). 53% is 10% below the average capacity

[9] There are also a number of other unique market features which enhance or mute market price signals to investors. The Reliability Obligation acts as a backstop mechanism if market prices are not expected to deliver the required capacity on time. Also, price caps prevent a full expression of market supply tightness.

factor of black and brown coal of 59% over the same period. We use the same approach to setting high and low values for all technologies based on the same ten-year sample.

The difference between large-scale nuclear costs at 93% and 89% capacity factor is an additional $5/MWh. This impact of the difference in assumptions for the high capacity factor range is negligible. In this context, the objection from stakeholders appears to be that GenCost is acknowledging that the capacity factor could be much lower than 90%. The sensitivity of some stakeholders to recognising this possibility is likely because, given the high capital cost of nuclear generation, the cost of generation could be very high if the capacity factor is low. Other technologies such as solar PV and wind have much lower capacity factors, but their capital costs are low and so the implications of low capacity factors are not as significant for them.

International data shows that nuclear generation did experience average capacity factors of 60% in the 1970s and 1980s. This has increased to 80% in more recent decades. However, even in 2023, some 10% of reactors were still operating at 60% capacity factor or below (World Nuclear Association, 2024).

Besides selected overseas experience, one reason for stakeholder insistence that capacity factors will be high could be confusion over the difference between the availability of a plant and the capacity factor. The availability factor is the percentage of the time over which a technology could generate electricity after accounting for required down time for maintenance or other outages. The capacity factor is the realised percentage of time generating at full capacity in a year which is influenced by the availability factor but also by market circumstances. Market circumstances include:

- Decreasing demand at night and all day during the milder seasons of spring and autumn means a large portion of generators must ramp down generation at these times. This combined with a traditionally high share of coal generation in Australia means a reasonable proportion of coal is subject to this ramp down (that is, decreasing output is not confined only to the traditional flexible plant types such as hydro and gas). In other countries there may be a higher share of these flexible plant or the ability to export which creates a protective buffer against this need to ramp down. Other countries may also have a less variable daily and seasonal load curve due to higher year-round heating or cooling loads.
- Since the mid-2010s, low-cost solar PV has reduced daytime and more broadly clear-weather-day demand. However, this does not appear to have substantially impacted average capacity factors (Figure 2-2). This is perhaps because coal retirements have allowed for less ramping down for the remaining coal fleet at other times of the day and year. Coal plants have also defended their minimum load by using negative price bids to stay operating during low demand periods. In states where wind generation is high, they can have a similar impact to solar by reducing other types of generation during periods of high wind availability.

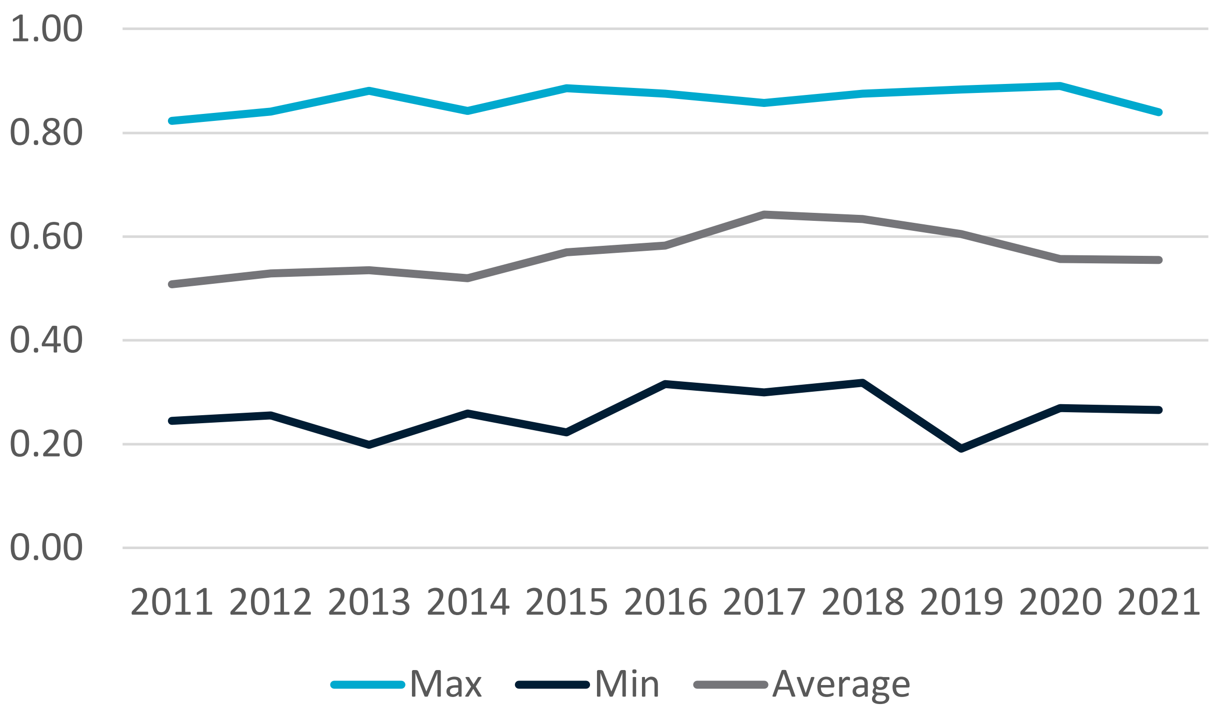


Figure 2-2 Historical capacity factors for black and brown coal in Australian electricity generation (NEM states)

The capacity factor that nuclear might be able to achieve due to market circumstances will depend on the types and scale of technologies already deployed in that market and the shape of the daily and seasonal load curves at the time that nuclear is deployed (from the mid-2040s). While AEMO's Integrated System Plan (AEMO, 2024) makes it clear this period will be dominated by solar PV and wind under current government policy, other generation mixes are possible under other policies, should they change. Rather than second guess this future generation mix, it is both appropriate and prudent to acknowledge that nuclear generation could face the same or other new market challenges resulting in a lower capacity factor consistent with the experience of Australian black and brown coal and some global regions with existing nuclear generation.

2.3 Nuclear development lead times

GenCost has estimated that nuclear generation in Australia will have a lead time of at least 15 years. While many stakeholders agree with this assessment the main criticism is that it is partially at odds with the International Atomic Energy Agency's *Milestones in the Development of a National Infrastructure for Nuclear Power* report (IAEA, 2024).

The *Milestones* report provides a step-by-step guide to how to set up a new nuclear industry for countries previously without nuclear generation. However, it does not provide any timeline for each individual step nor any working or past evidence for their proposed 10-15 year timeframe.

Given the estimate for lead time was originally published in 2015 (and the range not updated in 2024) it could be inferred that the timeline was at least based on recent construction times in the period leading up to 2015. Construction is the last stage of the lead time after other planning, safety licencing, financing and other approvals have been completed.

In the decade leading up to the release of the estimate in 2015 the median construction time was 6 years and fairly stable[10]. In the last 5 years median construction time has increased to 8.2 years. This increase cannot be explained by the pandemic because construction times were longer in the two years preceding the pandemic (8.6 and 9.8 years). Note that this historical construction time data is dominated by countries with established nuclear industries and so may be optimistic for a first-time country.

The IAEA do not explicitly state what characteristic of a country puts them at the high or low end of their range. The degree of community consultation is one obvious factor. High levels of consultation tend to occur in democracies. This could be in the form of standard guidelines for community consultation that an institution in charge of planning approvals is obliged to follow. It could also encompass electoral processes where governments in favour of or against a nuclear project face elections (if the project is partisan in that country).

There is some statistical evidence for the impact of the degree of democracy on nuclear lead times. A democracy index is published by The Economist Intelligence Unit. An index score of 8.01 to 10 (out of 10) indicates a full democracy, while countries that fall between 6.01 and 8.01 are considered flawed democracies. Countries that score lower on the index than 6.01 are not considered democracies. Australia's score in 2023 was 8.66.

We only have readily accessible data on construction times, not the total lead time. Considering the data since 2011, Pakistan and China have had the fastest construction times in the last decade with average construction times of 6 years, but their democracy index scores are 3.25 and 2.12 respectively (Figure 2-3). The United Arab Emirates (UAE) achieved 8 years construction with a democracy score of 3.01. Finland, South Korea, the United States (US) and India all had construction times 10 years or longer with democracy scores of 9.30, 8.09, 7.85 and 7.18 respectively. The two Western democracies in this list, Finland and the US had construction times of 17 and 21 years which is significantly longer than the Asian democracies. This matches with other analyses of the differences in Asian nuclear construction by authors such as Ingersoll et al. (2020) who noted that litigious responses to problems onsite are extremely rare in those cultures.

There are some exceptions in the data. Iran and Russia have low democracy scores but construction times longer than ten years. Also, Japan has a high democracy score and a low construction time but has not built any new projects in the last ten years. If they did, they may face longer delays for any new projects due to the ongoing political fallout of the Fukushima accident.

[10] This data is from the IAEA's own annual World Nuclear Performance Report. We include only the latest 2024 report in the reference list but studied the annual reports for 2015 and other nearby years to come to this conclusion

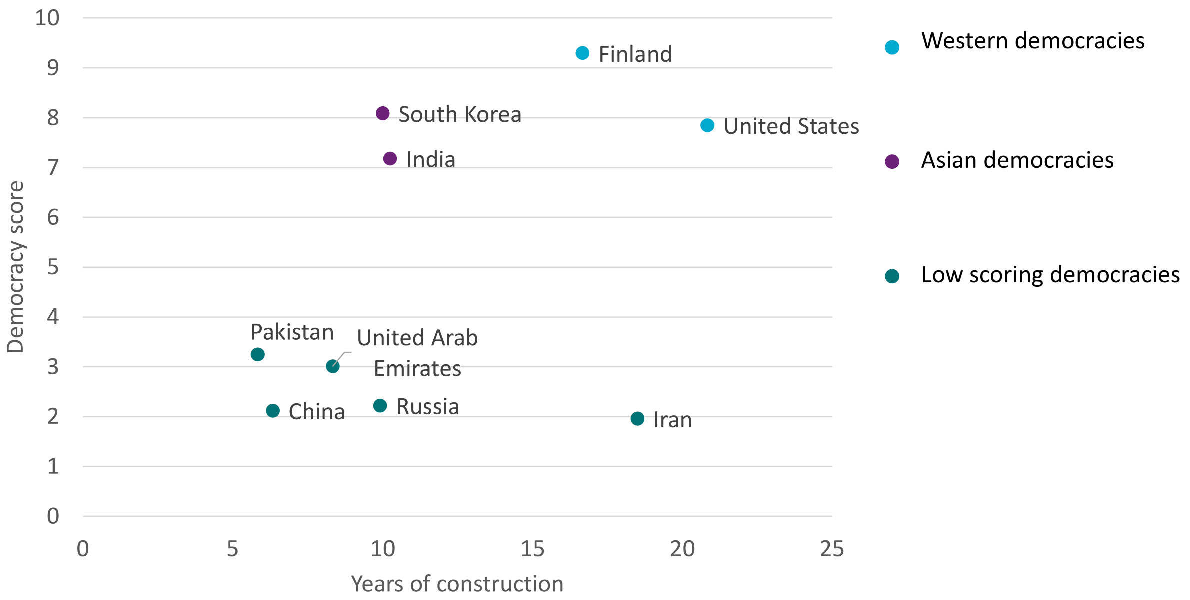


Figure 2-3 Relationship between the level of democracy, regions and construction times since 2011

Another factor associated with shorter construction times is ongoing building programs. Both China and Pakistan built multiple nuclear projects in the last decade. It is likely that democratic consultation and construction experience both play into achievable construction times.

Given the direction of construction data available after the report's initial estimate, the IAEA total lead time range of 10-15 years should likely be updated to 12 to 17 years to allow for the extra 2 years median construction time which now prevails. The lower part of this new range, 12 years, would be consistent with the UAE experience (completed in 2020) which is one of the highest profile first-time nuclear developer countries in recent years.

GenCost maintains that the UAE 12-year timeframe is unlikely to be achievable in Australia primarily because Australia is a democracy and therefore it will likely have processes that require greater consultation than in the UAE. Furthermore, the data indicates that Western democracies consistently take longer to complete nuclear projects than other regions. It is therefore appropriate to conclude that Australia is likely to have a lead time in the middle to top end of the (updated) IAEA range with significant risk it could be even longer.

Note that GenCost continues to use a six-year construction time in levelised cost of electricity calculations (based on Lazard (2023)). The reasons for this approach, despite the discussion above, is that GenCost only presents nth of a kind technology costs for all technologies. See Section 3.11 of this report for more discussion on the difference between first-of-a-kind and nth-of-a-kind technology costs.

3 Current technology costs

3.1 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[11]. 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 Aurecon (2025). Aurecon (2025) also provide more detail on specific definitions of the scope of cost categories included. Aurecon 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. Aurecon 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.

Aurecon (2025) also provides detailed information on the boundary of capital costs such as what development costs are included, ambient temperature, distance to fuel source, water availability and many other considerations.

3.1.1 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

[11] 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.

Therefore, we can only warn stakeholders that some projects will cost significantly more than projected in Section 5. 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
- 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 includes 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.

GenCost has previously declined to offer a suggested FOAK premium because they are very difficult to forecast. However, we also observed that some stakeholders have used CSIRO’s NOAK costs and not assigned an appropriate FOAK premium. It is judged that the lesser harm may be found in at least providing a suggested FOAK premium (Table 3-1). 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 3-1 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%

3.2 Capital cost source

AEMO commissioned Aurecon (2025) 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 Aurecon (2025) which represents a July estimate and so it is consistent with either the beginning of the financial year 2024-25 or the middle of 2024. Aurecon provides several measures of project capacity (e.g., rated, seasonal). We use the net capacity at 25^{o}C to determine $/kW costs. Aurecon states that the uncertainty range of their data is +/- 30%[12].

Technologies not included in Aurecon (2025) are typically those which are not being deployed in Australia but are otherwise of interest for modelling or policy purposes. For these other technologies we have applied an inflationary factor to last year's estimate based on a bundle of consumer price indices applied to knowledge of the relative mix of imported and local content for each technology. Where cost estimates are based on technologies not deployed recently and recent inflationary factors are not therefore observable, GenCost has added a cost factor which is then removed over time.

3.3 Current generation technology capital costs

Figure 3-1 provides capital costs for selected technologies since the project's inception in 2018. All costs are expressed in real 2024-25 Australian dollars, represent overnight costs and do not include any available subsidies.

[12] A significant portion of uncertainty is site related and Aurecon's report also provides adjustments for location.

Whilst there had been some steady declines over the years for technologies such as solar PV and offshore wind, costs increased for many technologies in the past three years 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 are also recovering from this development at different rates. The change in current costs over the past three years indicates a general easing of inflationary pressures across most technologies (Figure 3-2). We will discuss storage in more detail in the next section, but overall solar PV and battery storage have weathered the inflationary period the best of all technologies. Other technologies are still experiencing real cost increases but at a reduced rate compared to the previous two years.

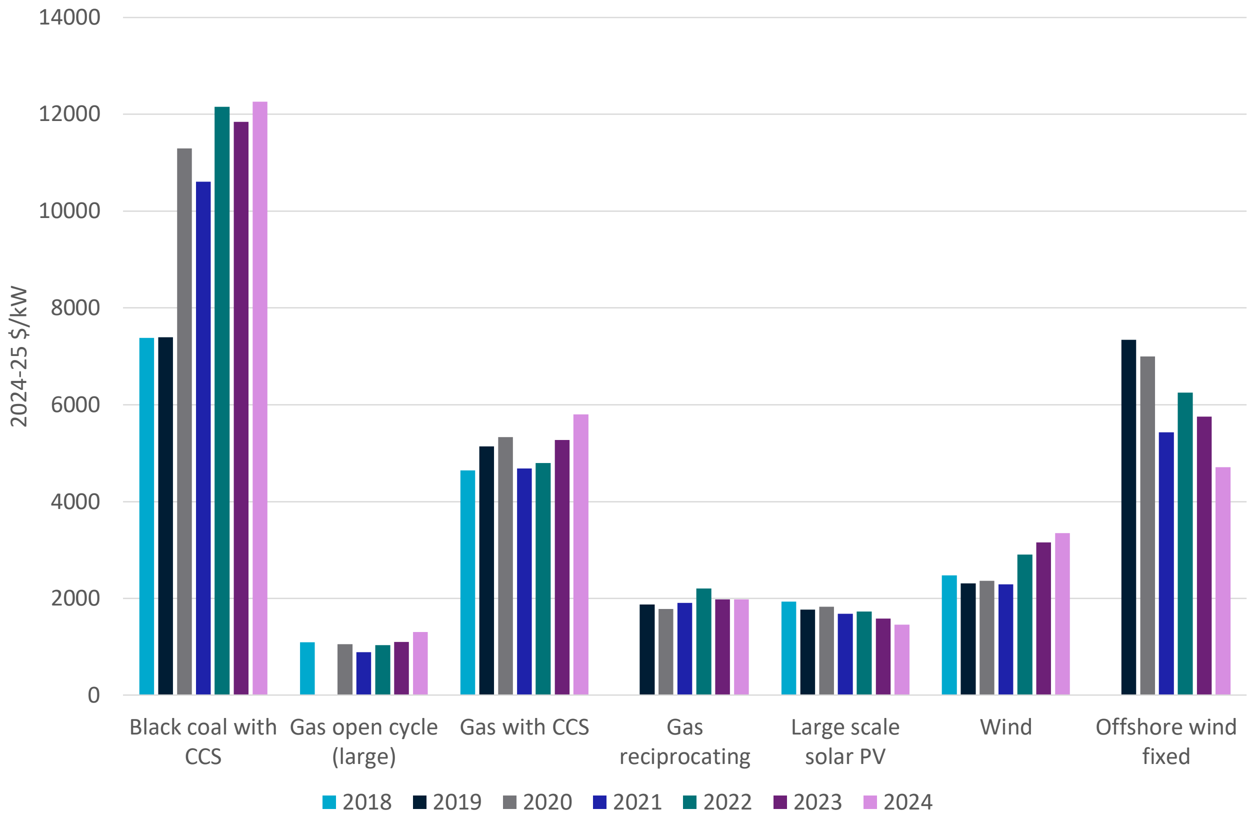


Figure 3-1 Comparison of current capital cost estimates with previous reports (FYB)

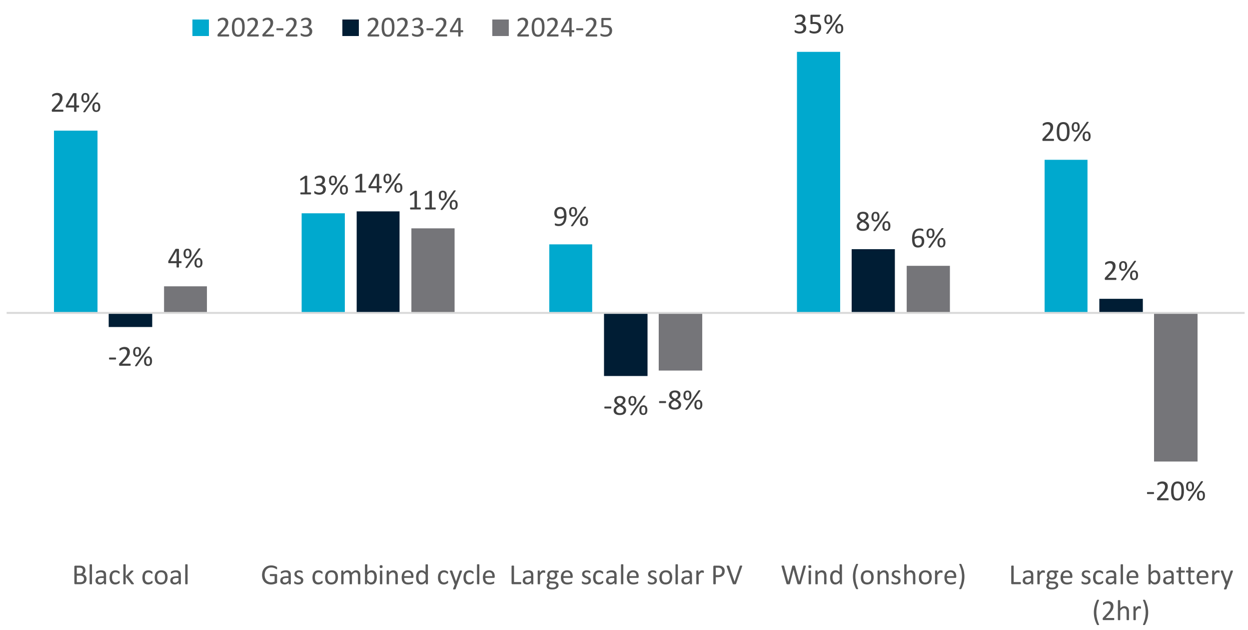


Figure 3-2 Year on year change in current capital costs of selected technologies in the past 3 years (in real terms)

3.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[13] of batteries, adiabatic compressed air energy storage (A-CAES) and pumped hydro energy storage (PHES) in $/kW and $/kWh. Battery durations of 12 hours and 24 hours have been added in 2024-25. 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[14]. 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 3-3). The downward trend flattens somewhat with batteries since its power component, mostly inverters, is relatively small but adding more batteries increases capital cost. However, the hydroelectric turbine in a PHES project is a large capital expense while adding more reservoir is less costly. As a result, PHES capital costs fall steeply with more storage duration.

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*

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[13] 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

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

Roadmap. While A-CAES appears to have a relatively higher capital cost at present, it is mainly competing with pumped hydro for longer duration storage applications. PHES is not expected to improve in costs and may be more distant to some locations.

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 3-4). 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 6).

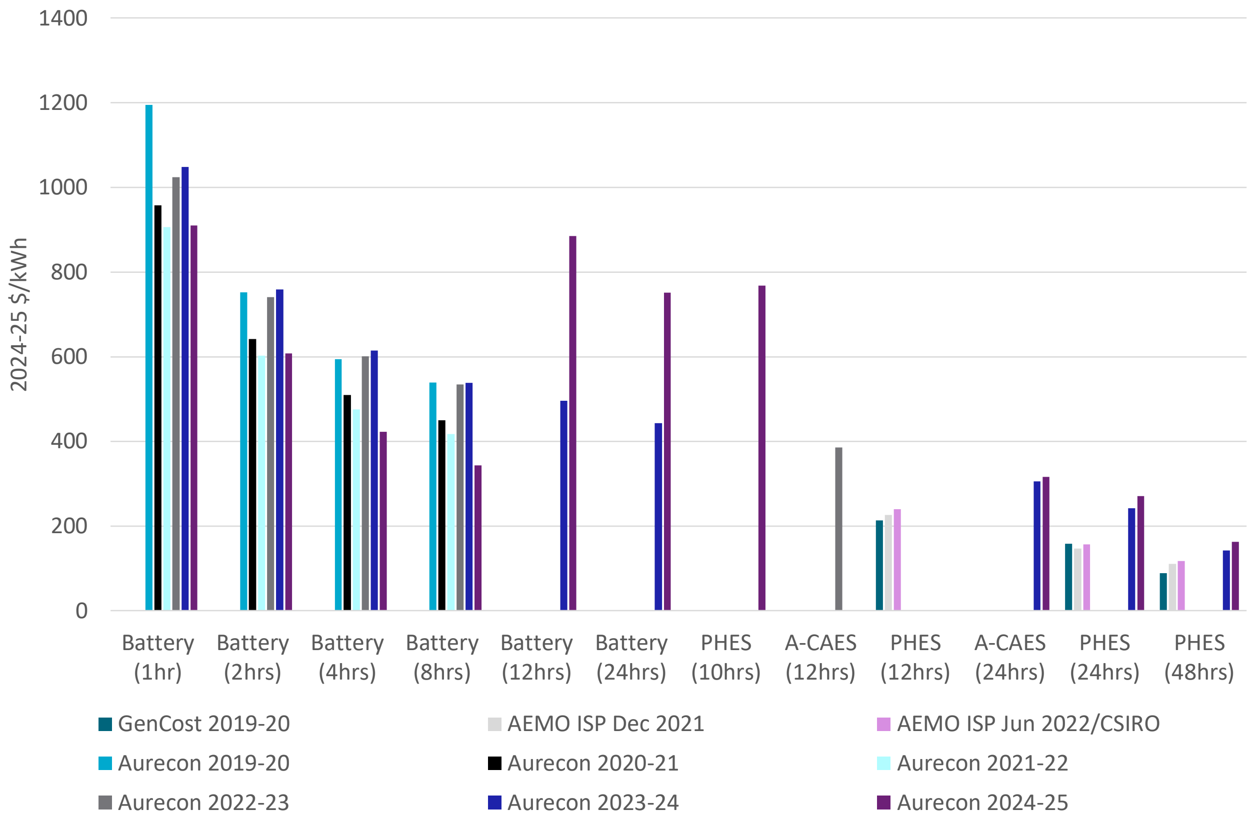

Figure 3-3 Capital costs of storage technologies in $/kWh (total cost basis)

Depth of discharge in batteries can be an important constraint on use. However, all Aurecon battery costs are presented on a usable capacity basis such that the depth of discharge is 100%[15]. Aurecon (2025) 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 a 5% lower battery cost for a 1-hour duration battery, scaling down to a 1% cost reduction for 8 hours duration and negligible for longer durations. PHES is more difficult to co-locate.

[15] 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%.

Battery costs (battery and balance of plant in total) have decreased significantly by 11% to 36% depending on the duration.

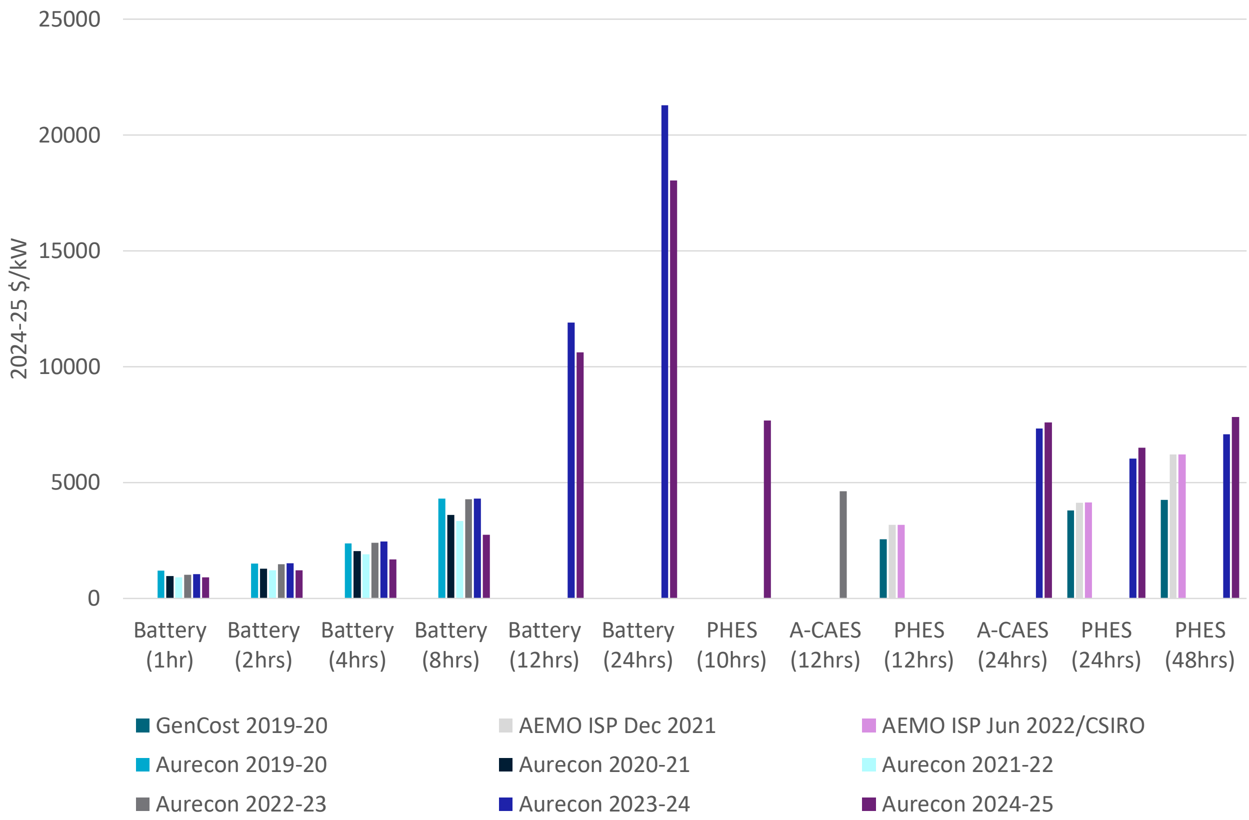

Figure 3-4 Capital costs of storage technologies in $/kW (total cost basis)

PHES current cost estimates have increased by 12% for 24-hour duration projects and by 15% for 48-hour duration projects[16]. The increases in PHES costs are partially due to higher construction costs associated with the global inflationary pressures but also increasing familiarity with PHES developments in Australia. 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.

A-CAES is not yet integrated into our projection methodology and so its future costs are not presented in this report. While some components are mature, their deployment is not widespread relative to other options. Aurecon (2025) has provided a 24-hour duration cavern storage A-CAES project cost. A cost for vessel storage is also provided by Aurecon for 12-hour duration but is not reported here given its high cost. It appears that cavern will be the preferred storage method where possible given the cost advantage.

Concentrating solar thermal (CST) is another technology incorporating storage but it is reported as a generation technology in Section 6. 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

[16] The PHES capital costs used in this report are based on taking the mid-point of the range provided by Aurecon (2025). Percentage differences will be higher or lower for projects at different ends of that range.

calculation of the LCOS can be found in CSIRO's *Renewable Energy Storage Roadmap* (CSIRO, 2023), but is outside the scope of GenCost.

4 Scenario narratives and data assumptions

The global scenario narratives included in GenCost have not changed since GenCost 2022-23 but there have been some minor updates to data assumptions.

4.1 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 2024 *World Energy Outlook* (IEA, 2024a) scenario matching to the Stated Policies scenario, Announced Pledges Scenario respectively and Net Zero Emissions by 2050. Various elements, such as the degree of vehicle electrification and hydrogen production, are also consistent with the IEA scenarios.

4.1.1 Current policies

The *Current policies* scenario includes existing climate policies as at mid-2024 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[17]. 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.

4.1.2 Global NZE post 2050

The *Global NZE post 2050* has moderate renewable energy constraints and middle-of-the-range learning rates. It has a carbon price and other policies consistent with governments meeting their Nationally Determined Contributions (NDCs) and longer-term net zero emission targets, which provides the investment signal necessary to deploy low emission technologies. Hydrogen trade (based on a combination of gas with CCS and electrolysis) and transport and industry electrification are higher than in *Current policies*.

4.1.3 Global NZE by 2050

Under the *Global NZE by 2050* scenario there is a strong climate policy consistent with maintaining temperature increases of 1.5 degrees of warming and achieving net zero emissions by 2050 worldwide. The achievement of these abatement outcomes is supported by the strongest

[17] 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.

technology learning rates and the least constrained (physically and socially) access to variable renewable energy resources. Balancing variable renewable electricity is less technically challenging. 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.

Table 4-1 Summary of scenarios and their key assumptions

Key drivers	Global NZE by 2050	Global NZE post 2050	Current policies
IEA WEO scenario alignment	Net zero emission by 2050	Announced pledges scenario	Stated policies scenario
CO_2 pricing / climate policy	Consistent with 1.5 degrees world	Based on NDCs and announced targets	Based on current policies only
Renewable energy targets and forced builds / accelerated retirement	High reflecting confidence in renewable energy	Renewable energy policies extended as needed	Current renewable energy policies
Demand / Electrification	High	Medium-high	Medium
Learning rates[1]	Stronger	Normal maturity path	Weaker
Renewable resource & other renewable constraints[2]	Less constrained	Existing constraint assumptions	More constrained than existing assumptions
Decentralisation	Less constrained rooftop solar photovoltaics (PV)[2]	Existing rooftop solar PV constraints[2]	More constrained rooftop solar PV constraints[2]

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.

5 Projection results

All projections start from a current cost and the primary source of 2024 costs is Aurecon (2025) with data gathered from other sources where otherwise not available in that report.

While we have used the trends in price indices of selected goods to inform our analysis, all projections remain in real terms. That is, all projected cost changes after 2024 are in addition to the general level of inflation.

5.1 Short-term and long-term inflationary pressures

5.1.1 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 current 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 three to ten years. 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 a price bubble but rather a permanent feature that will be built into all future costs. However, to sustain real price increases, supply needs to be either constrained by either 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[18]). The current cost update indicates

[18] 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.

inflationary pressures are weakening for most technologies and the cost of some technologies such as solar PV and batteries are falling again.

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, particularly for the *Global NZE by 2050* and *Global NZE post 2050* scenarios. 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. The *Current policies* scenario requires less growth in technology deployment and as such, for that scenario only, 2027 remains the date at which we assume most technology costs resume their pre-pandemic modelled pathway.

In response to feedback, this report includes two exceptions which is that onshore wind costs do not return to their normal path until 2035 and gas technologies experience a three year delay before their costs start falling in real terms in line with other technologies. Of all the technologies that are currently in high demand, onshore wind and gas technology capital costs were impacted the most and have demonstrated to be the slowest to recover. It is therefore appropriate to give them a separate pathway. The trajectory for wind reflects that cost increases are getting gradually smaller, while the trajectory for gas is different because there has been limited sign of slowing in their cost increases.

A consequence of this modelling approach is that the near term cost reductions to either 2027 or 2030 (or later for onshore wind and gas) mostly do not reflect learning. Rather, they are predominantly the slow unwinding of inflationary pressures that have temporarily placed costs above the underlying learning curve. Solar PV, batteries, fuel cells and offshore wind have already passed through the global inflationary event and their costs now follow the standard learning curve trajectory.

5.1.2 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 Aurecon (2025) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[19]. 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

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

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 Aurecon (2025). This report is the first time such assumptions have been applied to the projections and is responsible for higher technology costs than previous publications. 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).

5.2 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 5-1.

Current policies has the lowest electrification because it is a slower decarbonisation pathway than the other scenarios considered. However, it has the least energy efficiency and industry transformation[20]. For this reason, while it has the lowest demand by 2050 it is only slightly below *Global NZE post 2050* in 2030. Both Global NZE scenarios have high vehicle electrification and high electrification of other industries including hydrogen. However, they also have high energy efficiency and industry transformation which partially offsets these sources of new electricity demand growth in 2030. Figure 5-2 shows the contribution of each hydrogen production technology in each scenario indicating the *Global NZE* scenarios are assumed to experience a significant growth in electrolysis hydrogen production. Note that the IEA's estimates of hydrogen demand have deceased relative to the *2023 World Energy Outlook*.

[20] 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.

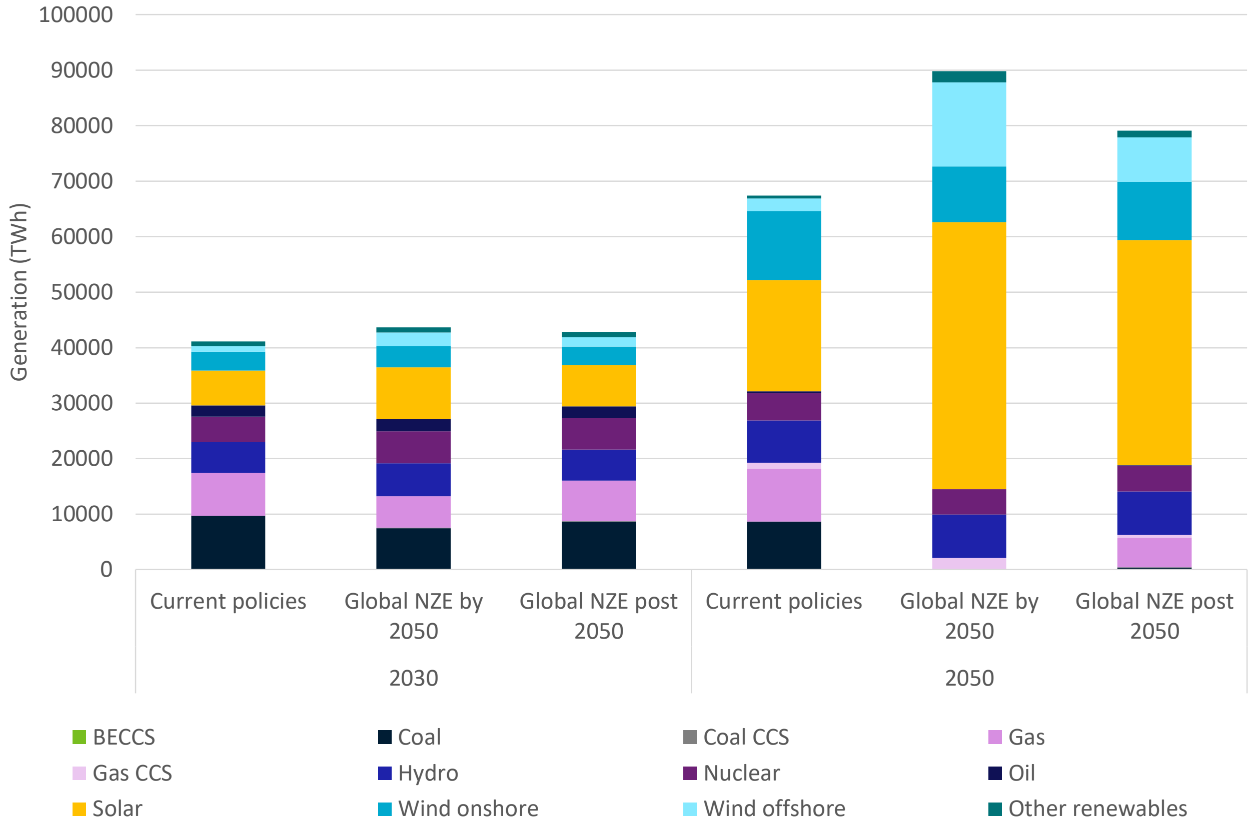

Figure 5-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Current policies has the lowest non-hydro renewable share at 52% of generation by 2050. Coal, gas, nuclear and gas with CCS are the main substitutes for lower renewables. Gas with CCS is preferred to coal with CCS given the lower capital cost and lower emissions intensity. In absolute capacity terms, nuclear increases the higher the climate policy ambition of the scenario with a range of 11% to 13% across the scenarios by 2030 but declines to 5% to 7% by 2050 reflecting its relatively slower installation rate as electrification causes demand to grow rapidly in the 2030s and 2040s.

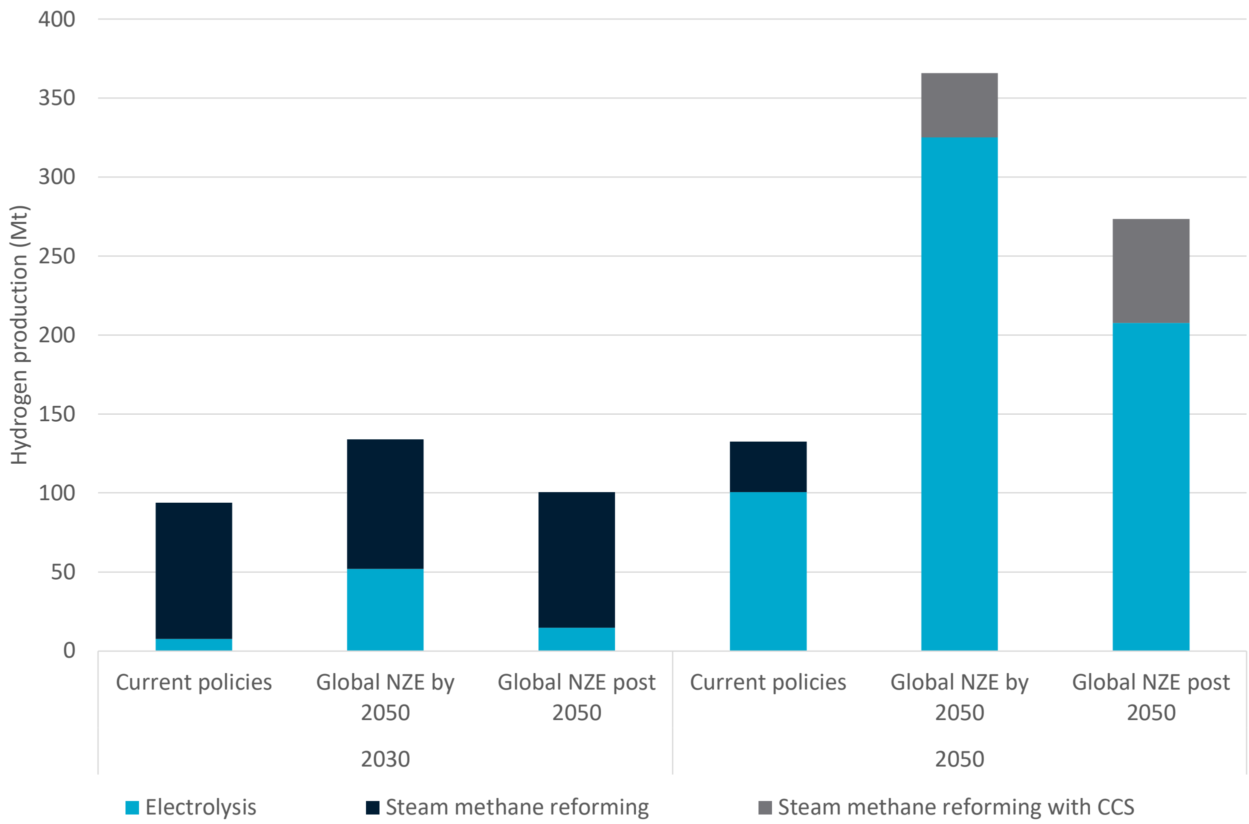

Figure 5-2 Global hydrogen production by technology and scenario, Mt

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 17% of generation by 2050. Renewables other than hydro, biomass, wind and solar are 2% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs. CCS costs are also impacted by the use of CCS in hydrogen production and other industries.

5.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2055 compared to the 2023-24 projections. For mature technologies, differences mainly reflect a change in current costs and the introduction into the projections of an installation cost escalator which was not included in the 2023-24 projections (Oxford Economics Australia, 2025). The 2023-24 projections for mature technologies also included an assumed annual rate of cost reduction for mature technologies post-2027 or 2030 (depending on the scenario) of 0.35%. This assumption has been discontinued as it is no longer supported by the historical data. Overall, the updated approach leads to higher capital costs in the long run relative to the 2023-24 projections.

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. Generally, capital costs for less mature technologies are higher than in 2023-24.

Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[21].

5.3.1 Black coal ultra-supercritical

The updated cost of black coal ultra-supercritical plant in 2024 has been sourced from Aurecon (2025). Prior to 2023-24, the black coal capital cost had previously been based on a supercritical plant. However, an ultra-supercritical technology is the most plausible type given Australia's net zero by 2050 target. From 2024, the capital cost is assumed to return to levels consistent with ultra-supercritical prior to the COVID-19 pandemic by 2027 in *Current policies* and by 2030 in the *Global NZE* scenarios, reflecting our approach for incorporating current inflationary pressures outlined at the beginning of this section. 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 the learning rate is low. 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.

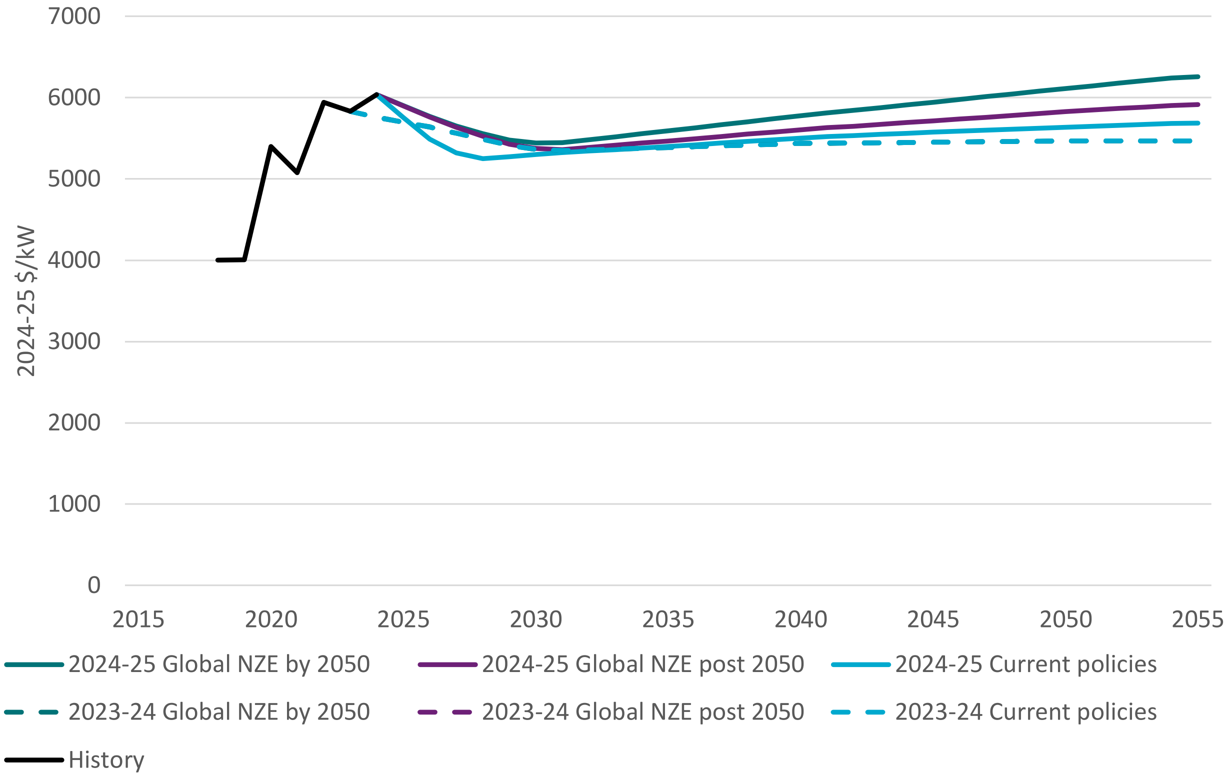

Figure 5-3 Projected capital costs for black coal ultra-supercritical by scenario compared to 2023-24 projections

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

5.3.2 Coal with CCS

The capital cost of black coal with CCS from 2024 to 2027 in *Current policies* or 2024 to 2030 in the *Global NZE* scenarios 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 2023-24 projections, significantly less CCS is deployed globally. This is mainly because the ongoing cost reductions achieved by solar PV have increased its share, reducing the share of CCS in electricity generation. Cost reductions up to 2027 or 2030 are not technology related but rather represent the weakening of short-term inflationary pressures.

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.

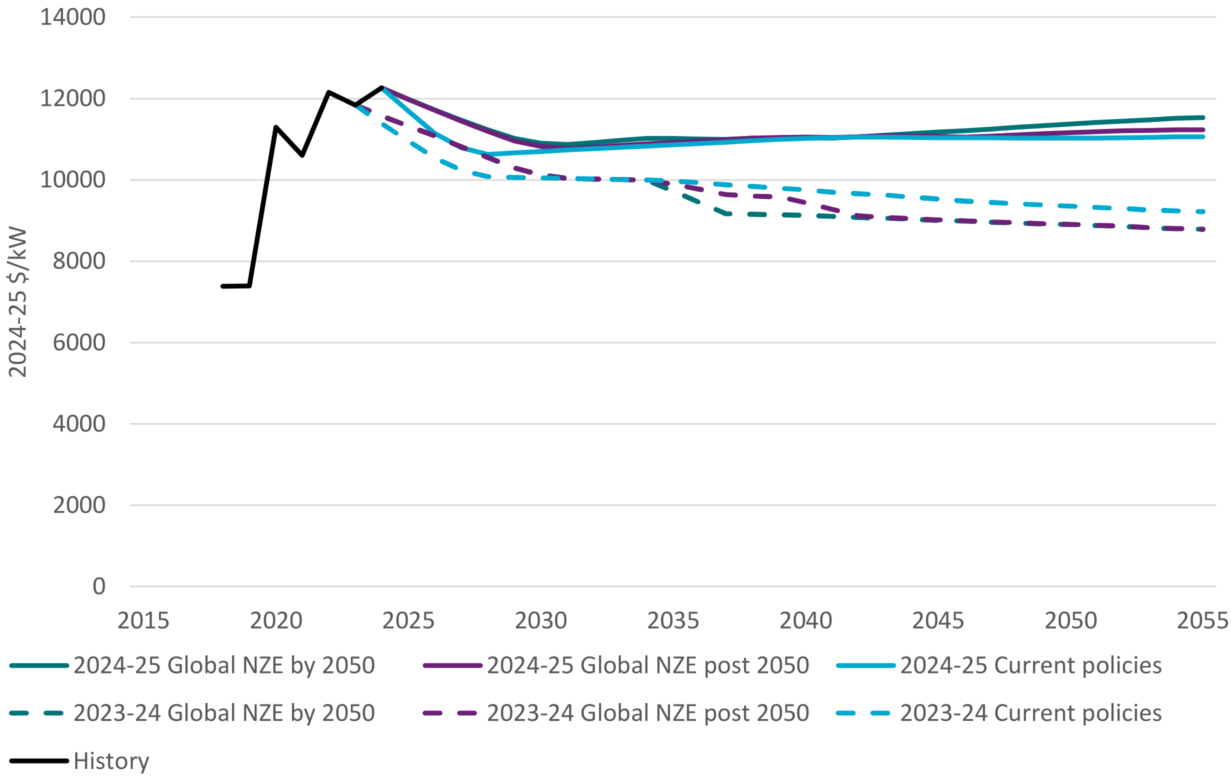

Figure 5-4 Projected capital costs for black coal with CCS by scenario compared to 2023-24 projections

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). 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 differences in the timing of reductions. As with *Current policies*, equipment cost reductions are not significant enough to offset and land and installation cost increases in the *Global NZE* scenarios.

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

5.3.3 Gas combined cycle

Aurecon (2025) have included an increase in gas combined cycle costs for 2024 which followed similar increases the previous two years. CSIRO has assumed no change in real costs for the next return three years and then a return to previous cost levels by 2030 in *Current policies* and 2033 in the *Global NZE* scenarios. 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.*

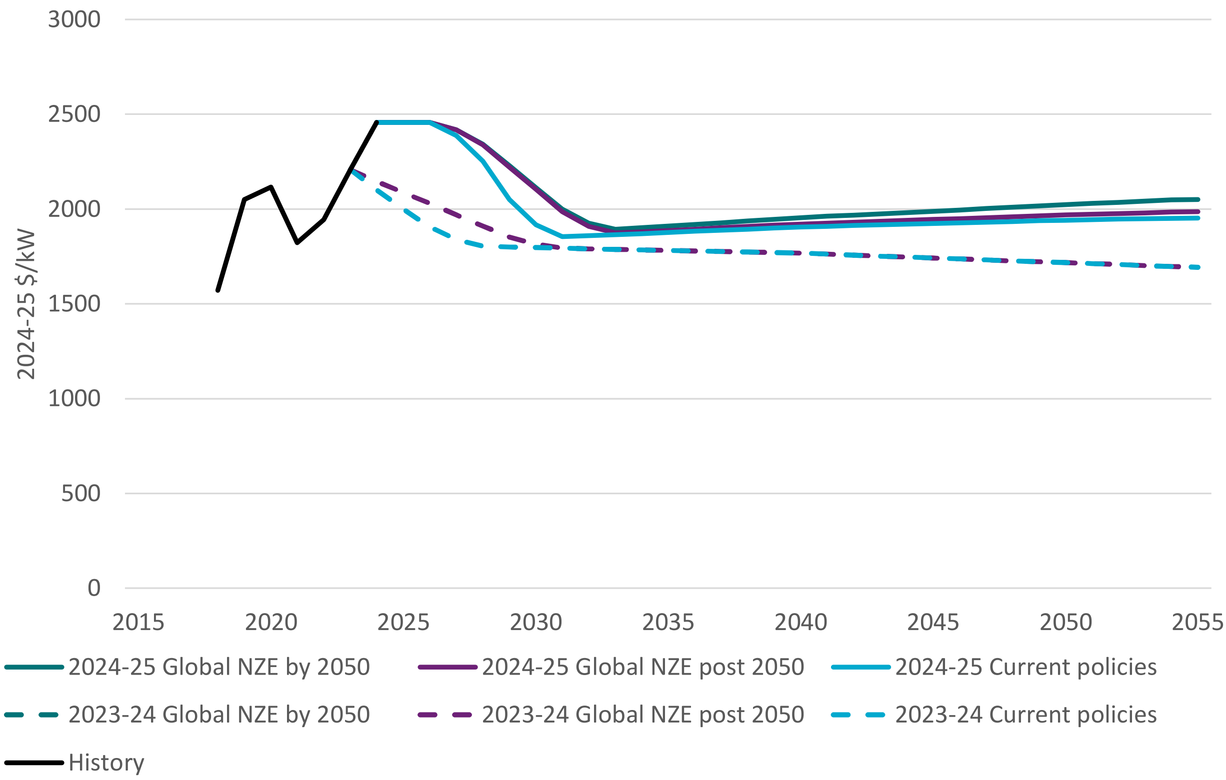

Figure 5-5 Projected capital costs for gas combined cycle by scenario compared to 2023-24 projections

5.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2024-25 projections reflecting the increase in gas combined cycle capital costs. 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* and *Global NZE post 2050* have the highest total deployment of all CCS technologies. Subsequently, the equipment component of gas with CCS is lower by 2050 in those scenarios and this results in total costs being lower in the late 2030s and early 2040s. In the same period, CCS equipment costs are highest cost in where CCS deployment is lowest. However, by 2050, installation costs have increased the most in *Global NZE by 2050* and the least in *Current policies*. The proportionally offsetting sources of cost changes result in similar total costs across all scenarios by 2050.

Apart from the introduction of increasing installation costs, the flatter outlook for CCS costs compared to the 2023-24 projections is because the lower costs of technologies such as solar PV and batteries has meant a lower share of CCS. Less deployment limits the amount of cost reduction that can be achieved.

The IEA CCS database[22] indicates there are over 100 planned electricity related projects which are yet to make a financial investment decision and two under construction. While there have been previously constructed plants in operation, none are currently 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.

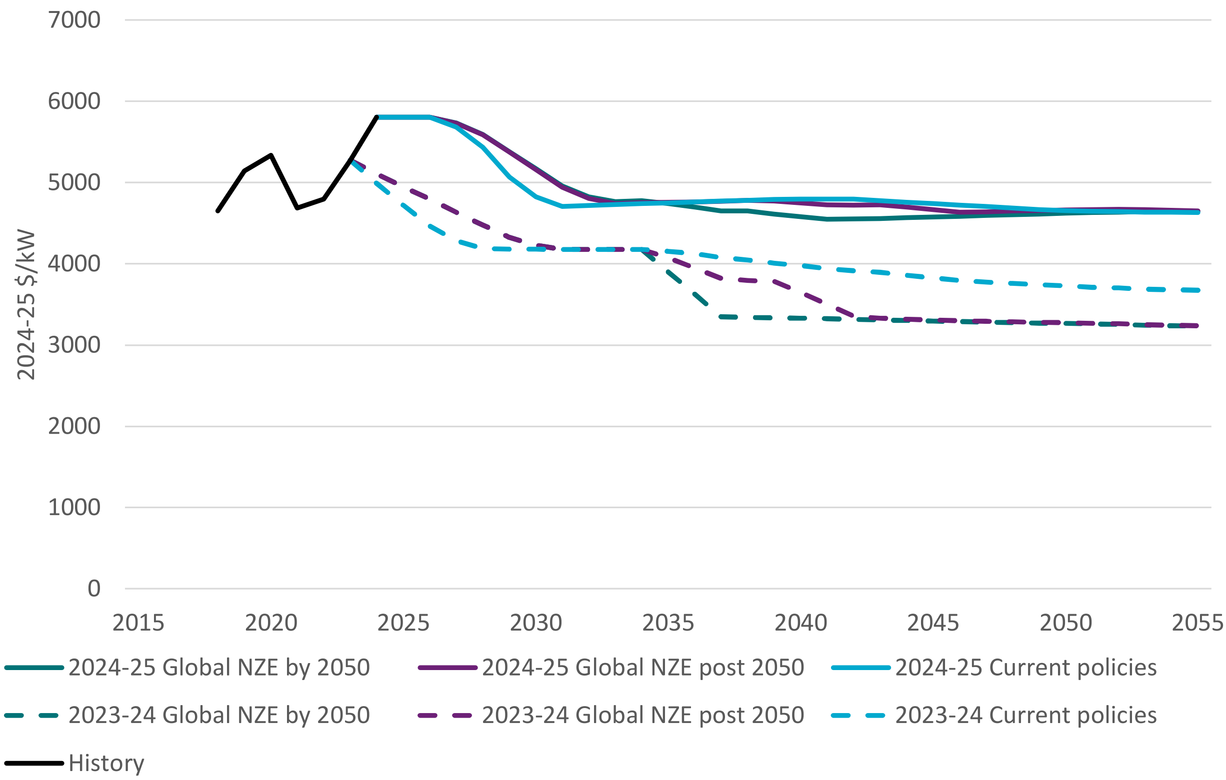

Figure 5-6 Projected capital costs for gas with CCS by scenario compared to 2023-24 projections

5.3.5 Gas open cycle (small and large)

Figure 5-7 shows the 2024-25 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

[22] CCUS Projects Database - Data product - IEA

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 technology is designed with a maximum 35% hydrogen blend. The large size is designed for 10%. This assumption of hydrogen readiness adds a negligible premium to gas open cycle capital costs.

The Aurecon (2025) report provides additional details for the unit sizes and total plant capacity that defines the small and large sizes. After a three year period where costs are flat or slightly increasing, capital costs are reverted back to previous costs in 2030 and 2033, depending on the scenario in line with the approach taken for other gas technologies. 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. Capital costs are highest under the *Global NZE* scenarios reflecting the higher installation costs associated with the greater construction activity of those scenarios

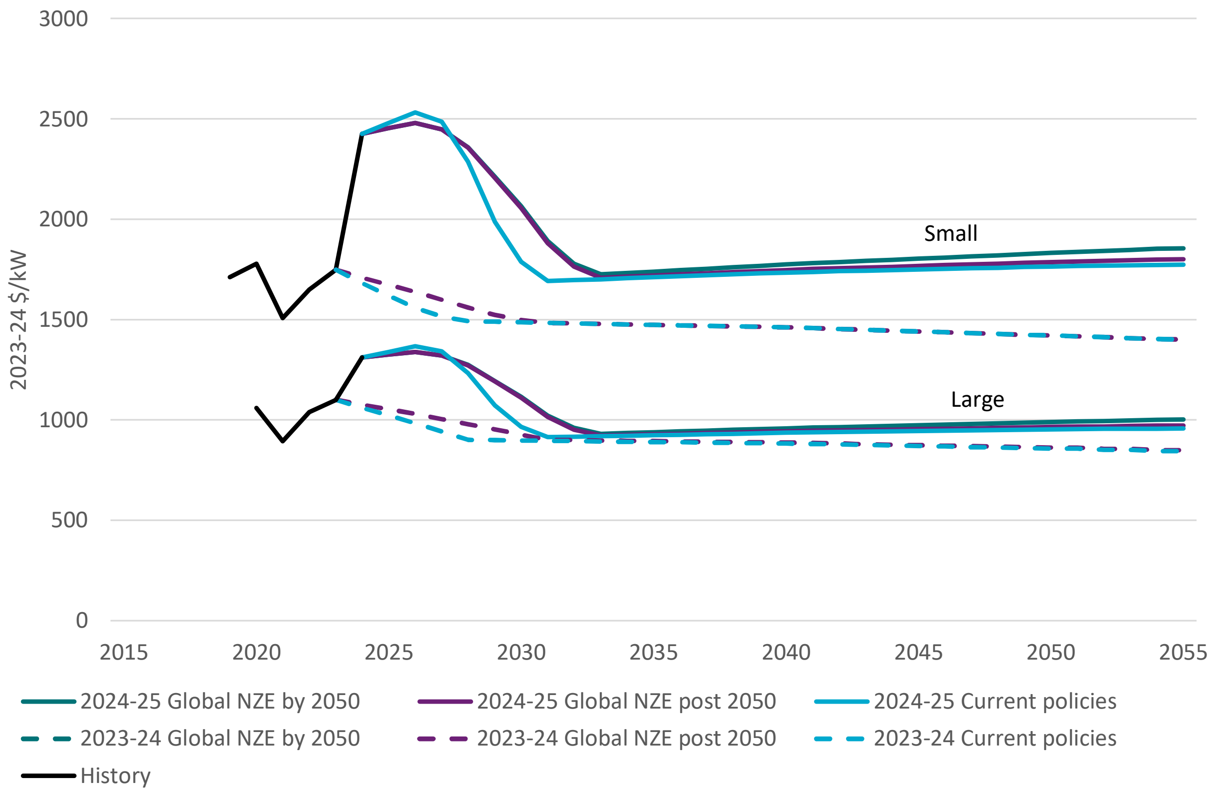

Figure 5-7 Projected capital costs for gas open cycle (small) by scenario compared to 2023-24 projections

5.3.6 Nuclear SMR

The projections start at the 2024 capital cost of around $29,600/kW which was based on a well-documented and costed project that did not go ahead in the United States. 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 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. Known projects have been pushed further into the future, beyond the 2020s (Global Energy Monitor, 2024a) relative to the 2023-24 projections. Later deployment of some nuclear SMR projects means it takes longer for capital cost reductions due to learning-by-doing and economies of scale to materialise.

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.

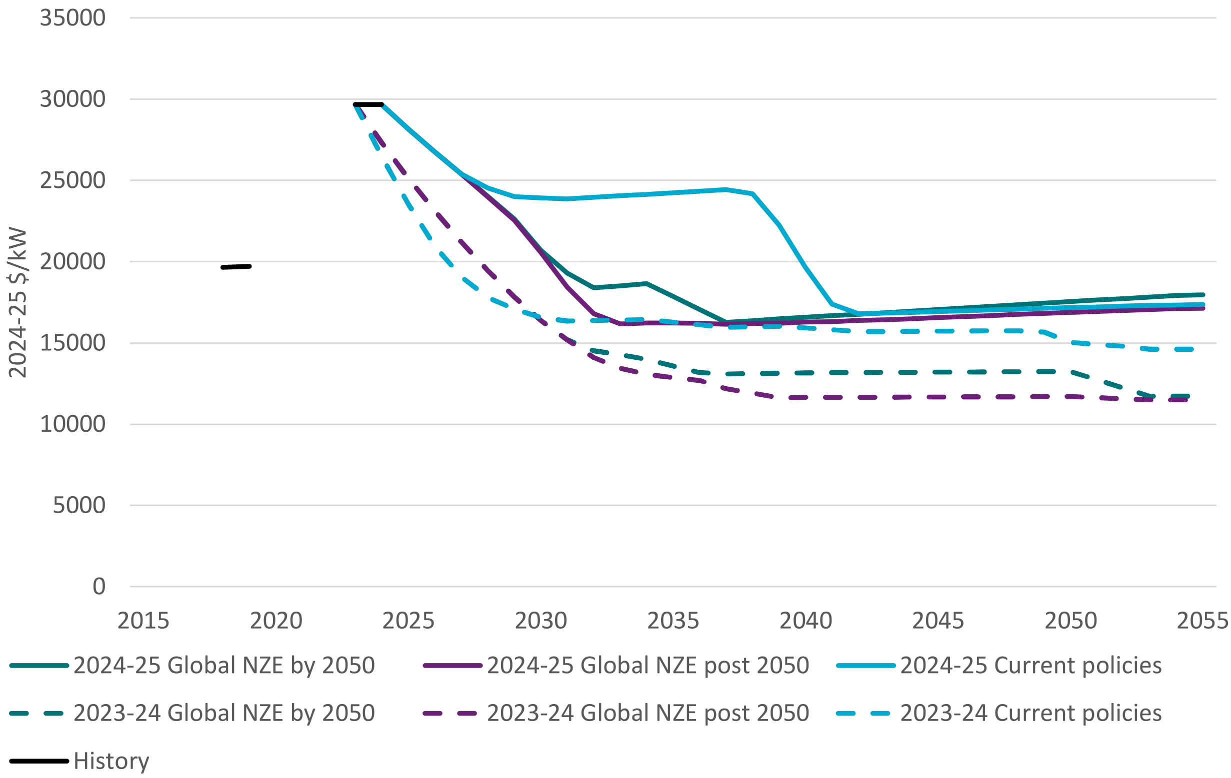

Figure 5-8 Projected capital costs for nuclear SMR by scenario compared to 2023-24 projections

5.3.7 Large-scale nuclear

Like other technologies, large-scale nuclear capital costs are assumed to return to their underlying costs, before the current global inflationary cycle, by 2027 in *Current Policies* and by 2030 in the *Global NZE* scenarios.

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 2027 or 2030 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 achieve 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.

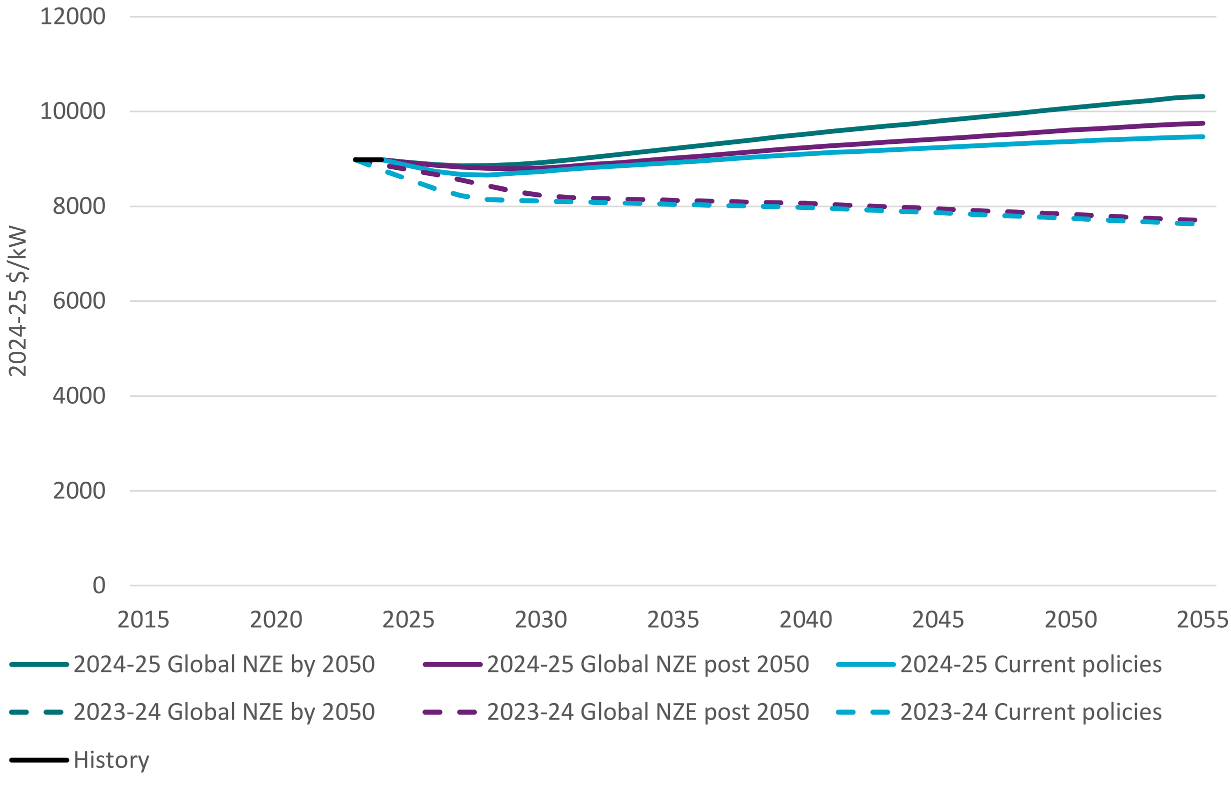

Figure 5-9 Projected capital costs for large-scale nuclear by scenario compared to 2023-24 projections

5.3.8 Solar thermal

The starting cost for solar thermal has been updated by Aurecon (2025) drawing on Fichtner Engineering (2023) which includes a change to the baseline configuration, with a storage duration of 16 hours. Changes relative to the projections since 2023-24 include a small increase in current year costs, inclusion of a local learning component for consistency with other learning technologies and increases in installation costs that apply to all technologies. The installation cost increases have had the largest impact. While higher than 2023-24, the capital cost projections diverge by a similar amount according to their scenario with the greatest cost reductions projected to be stronger the greater the global climate policy ambition. 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.

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 6.

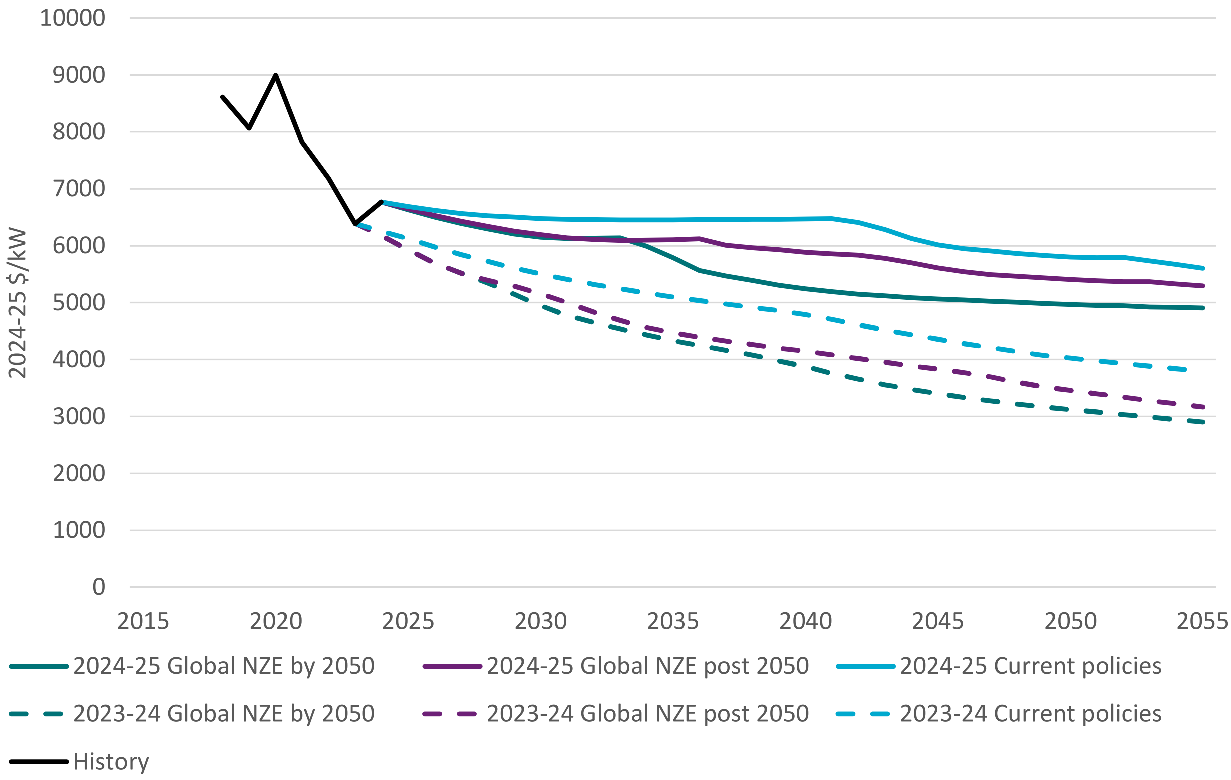

Figure 5-10 Projected capital costs for solar thermal with 14 hours storage compared to 2023-24 projections

5.3.9 Large-scale solar PV

Large-scale solar PV costs have been revised downwards for 2024-25 based on Aurecon (2025) indicating solar PV production costs are recovering more rapidly than previously projected from global inflationary pressures. As a result of the ongoing 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 is due to learning through deployment. *Current policies* has the lowest global share of solar PV generation and therefore the highest cost trajectory. In the *Global NZE* scenarios, there is faster technology deployment to meet stronger climate policies leading to proportionally higher cost reductions. All scenarios include increases in installation costs in Australia and this narrows the differences between the scenarios slightly over time. Installation costs are assumed to grow faster the stronger the global climate policy ambition due to stronger construction activity.

Cost outcomes across the three scenarios project a capital cost range of $640/kW to $890/kW. The final minimum cost level for solar PV is one of the most 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.

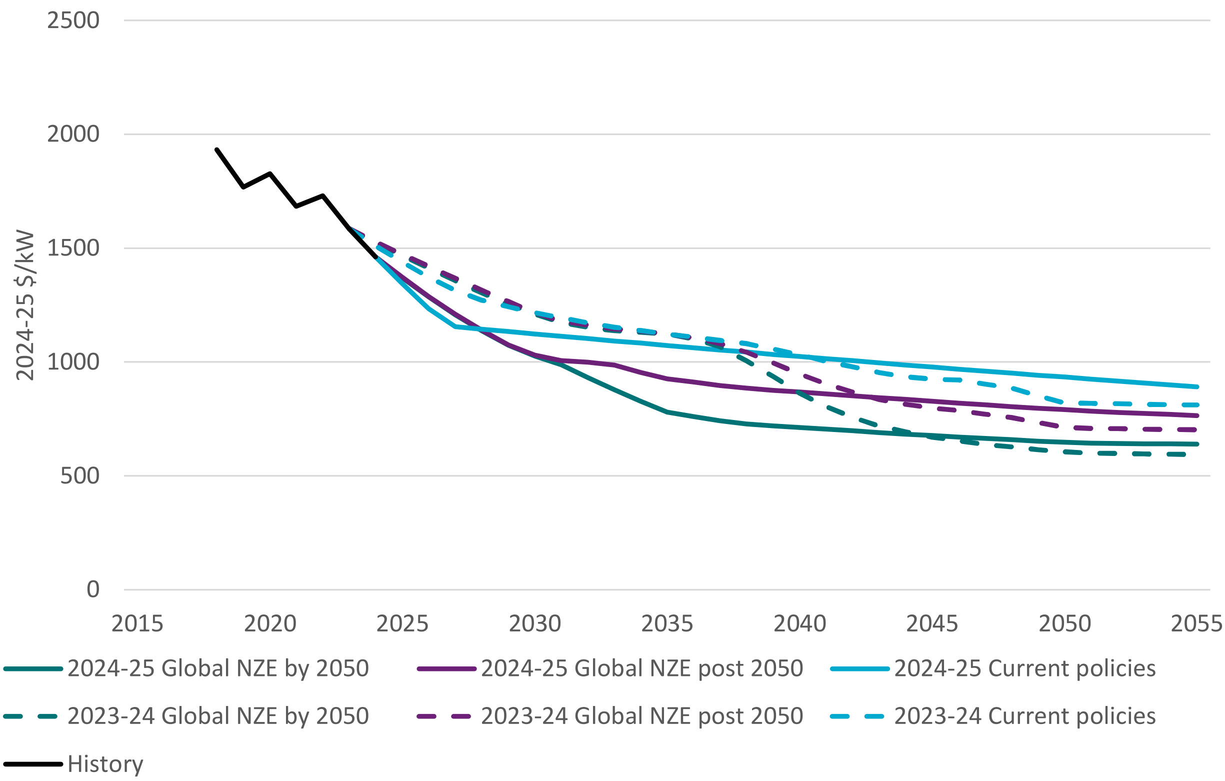

Figure 5-11 Projected capital costs for large-scale solar PV by scenario compared to 2023-24 projections

5.3.10 Rooftop solar PV

The current costs for rooftop solar PV systems are lower than was projected for 2024 in the 2023-24 GenCost report. The price aligns to a 7kW system, but it should be noted that rooftop solar PV is sold across a broad range of prices[23]. 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

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

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 of installation compared to large-scale solar PV. Installation costs are also impacted by the general increase in installation costs that apply to all technologies. Overall, this revised treatment of installation costs is the main point of difference with the 2023-24 projections which assumed a common installation learning rate and no general increase in installation costs.

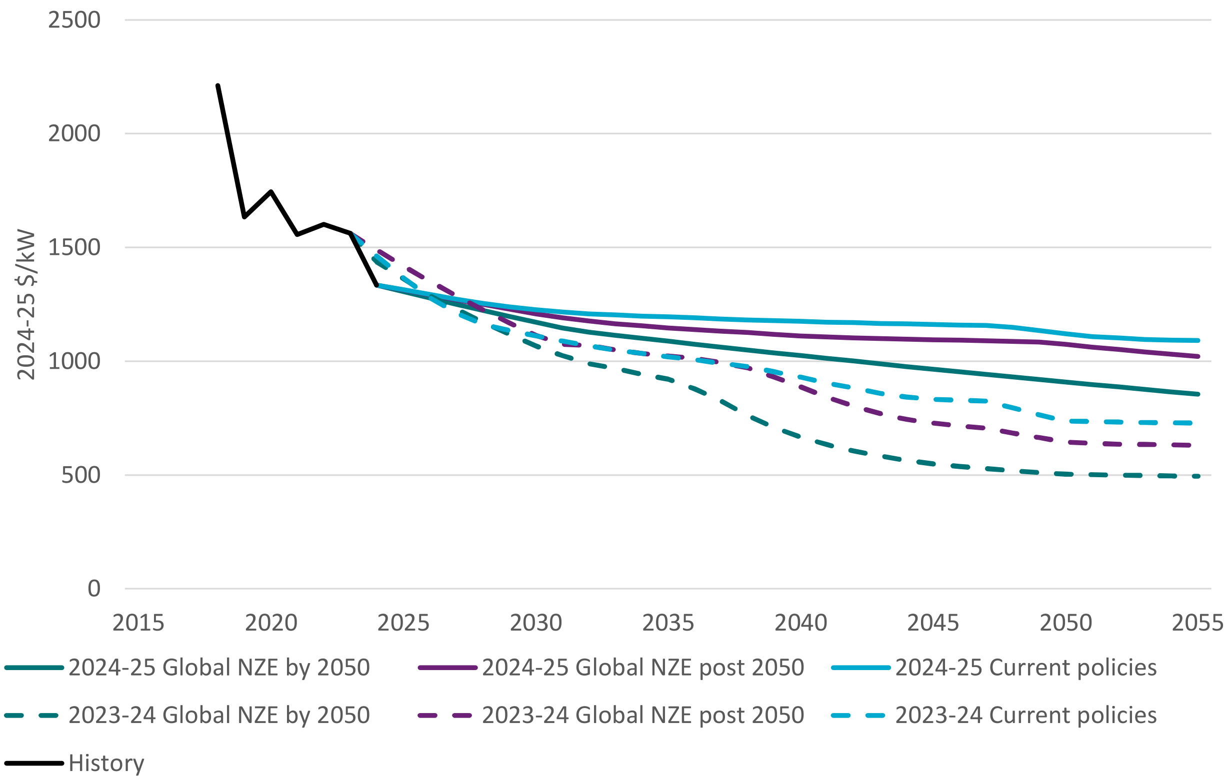

Figure 5-12 Projected capital costs for rooftop solar PV by scenario compared to 2023-24 projections

5.3.11 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 Aurecon (2025) data indicates that the rate of increase is slowing. However, the most recent 6% increase in current costs also includes the assumption that new wind generation projects will need to include the cost work camps. Without this new assumption the year-on-year cost increase would have been only 2%.

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 (five years later than other technologies). As such, wind costs are higher for longer throughout that period. 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.

The higher current costs, inclusion of increasing local installation costs and workcamp costs has meant that the 2024-25 projections are higher than all 2023-24 projections.

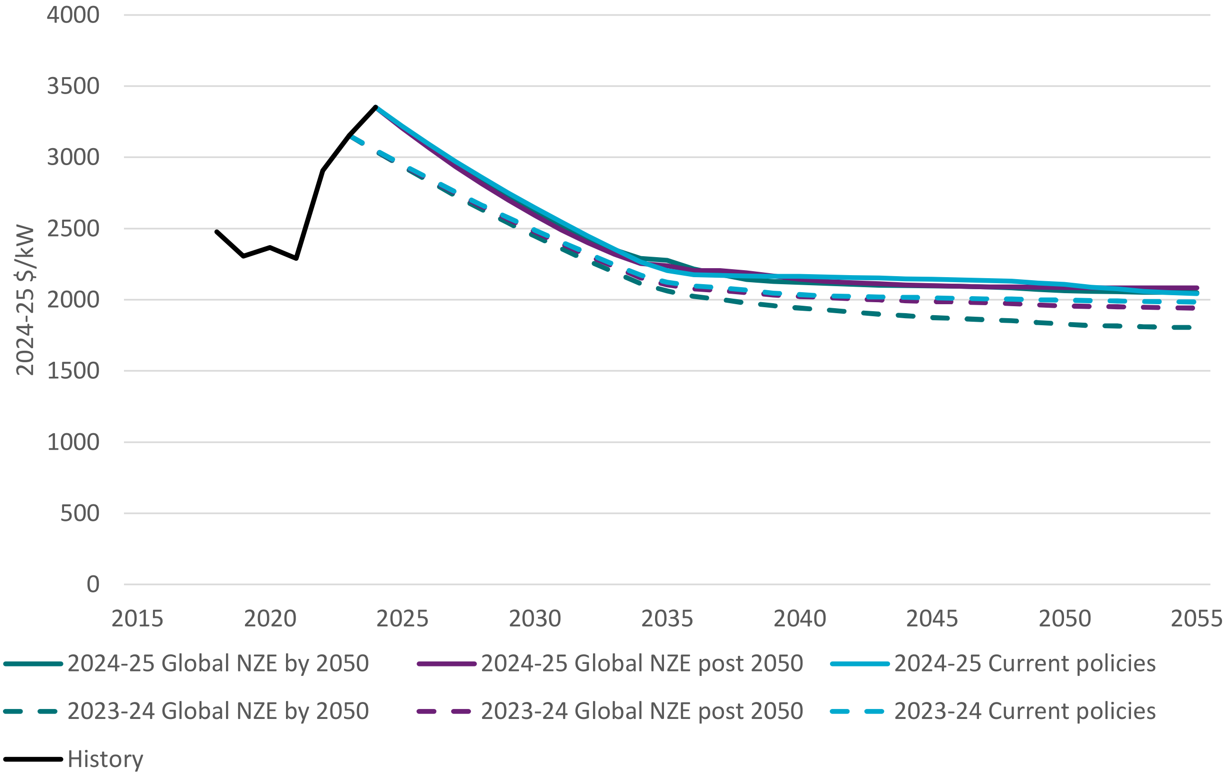

Figure 5-13 Projected capital costs for onshore wind by scenario compared to 2023-24 projections

5.3.12 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[24] 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 5-14 presents projections for both fixed and floating compared to 2023-24. The current costs for both types of offshore wind are provided in Aurecon (2025). The updated current capital costs are lower than projected in 2023-24 for fixed offshore wind and higher than projected for floating offshore wind. Post 2024, 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, 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.

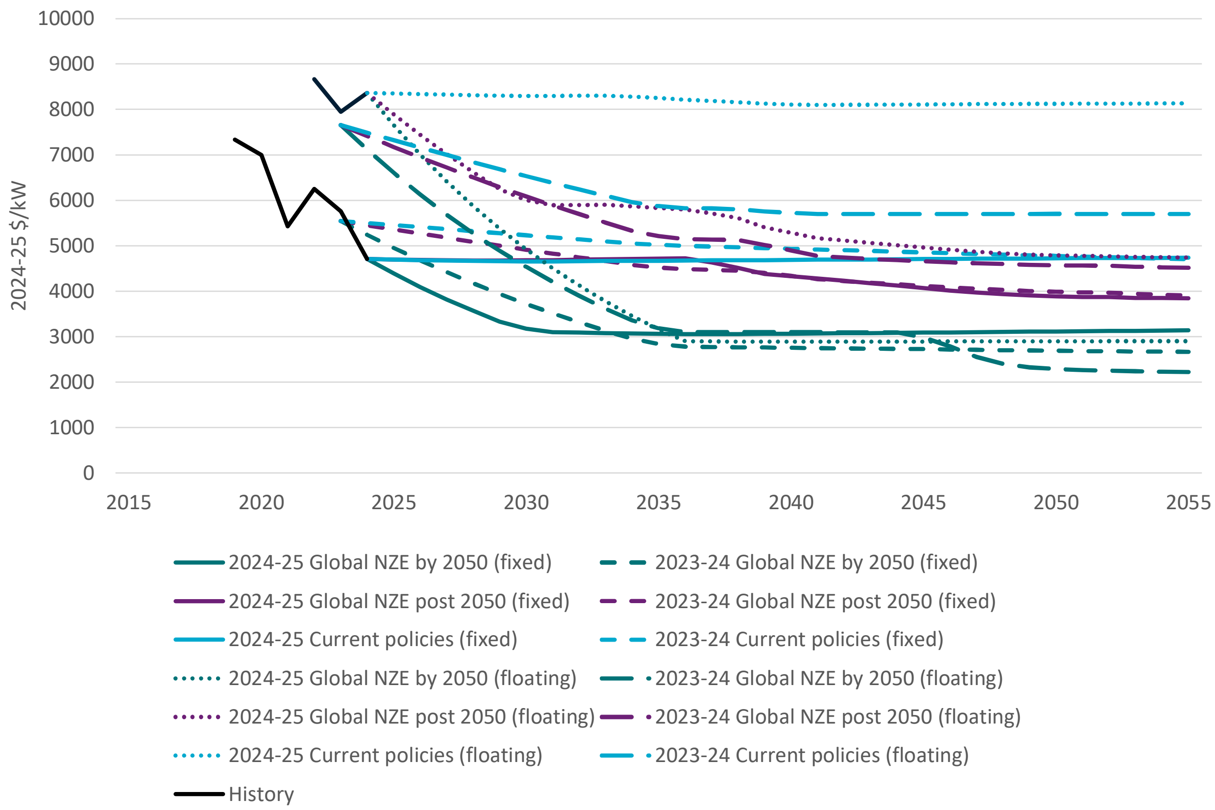

Figure 5-14 Projected capital costs for fixed and floating offshore wind by scenario compared to 2023-24 projections

A key feature of the updated projections is a lower rate of cost reduction over time, particularly for fixed offshore wind, relative to the 2023-24 projections. This reflects lower resource availability for floating offshore wind and the impact of continued reductions in solar PV technology costs. Floating offshore wind is deployed more widely than fixed offshore wind and therefore results in

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

proportionally higher cost reductions in the *Global NZE* scenarios. However, floating offshore wind has a low level of deployment in *Current policies* leading to a flat outlook for costs.

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.

5.3.13 Battery storage

Current costs of battery storage fell faster than projected in 2023-24 and the updated projections allow for a diversity of outcomes ranging from a continuation of the current rate of cost reduction to a slow rate of reduction. The costs shown in Figure 5-15 are for a 2-hour duration battery (total battery cost including battery and balance of plant). Given the 2024 cost reduction takes batteries back to their pre-pandemic levels we do not impose any additional reduction beyond the learning projected by the modelling.

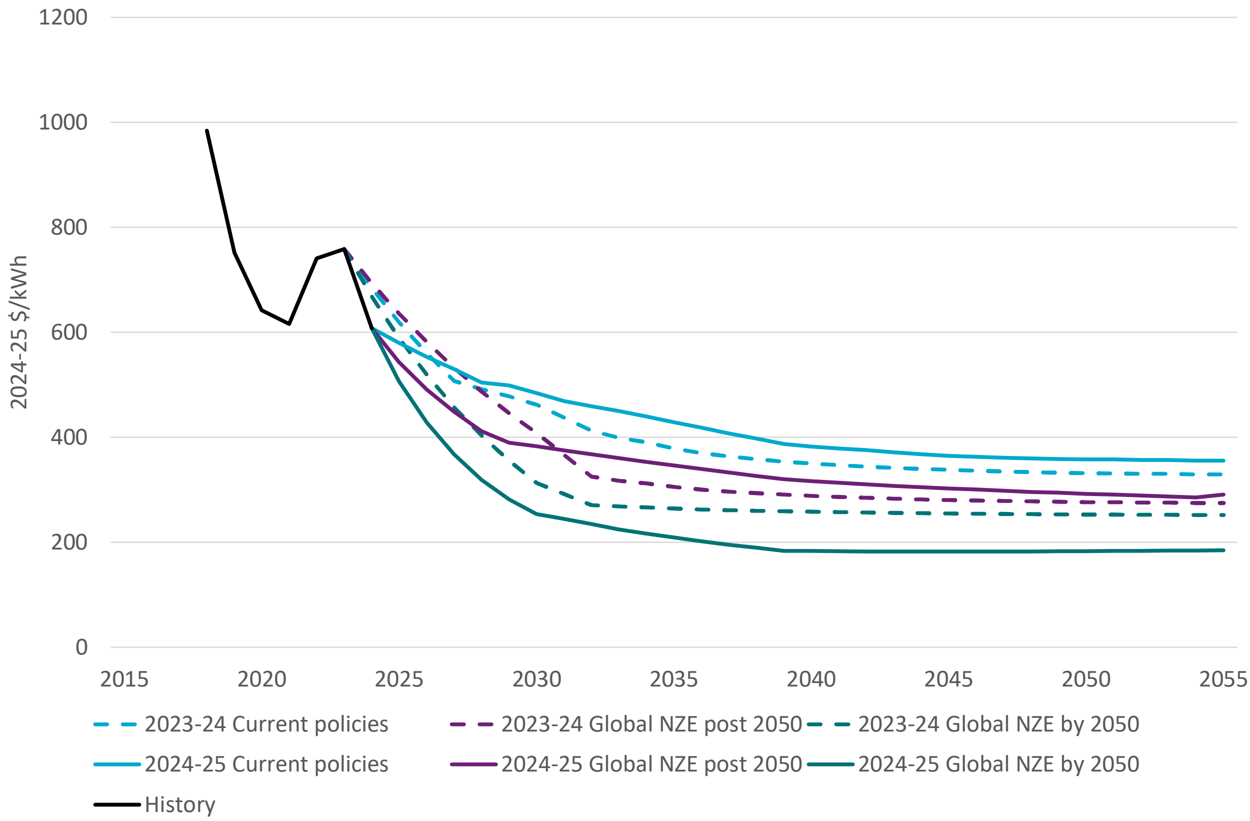

Figure 5-15 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

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 the 2024 IEA World Energy Outlook. 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.

Aurecon (2025) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $13,500 for a 5kW/10kWh system or $1350/kWh, including installation. This is more than twice the cost of large-scale battery projects per kWh.

5.3.14 Pumped hydro energy storage

Pumped hydro energy storage (PHES) is assumed to be a mature technology and receives the same increase in installation costs as other technologies which is the main driving for the increasing cost trend post 2030. Unlike the other technologies, all three scenarios assume costs return to normal by 2030 (rather than in 2027 for *Current policies*). This reflects the longer lead time for PHES projects which means it is unlikely that global inflationary trends will result in different cost trajectories before 2030. Site variability is also a great source of variation in PHES costs and is separately addressed by Aureon (2025) and AEMO external to GenCost

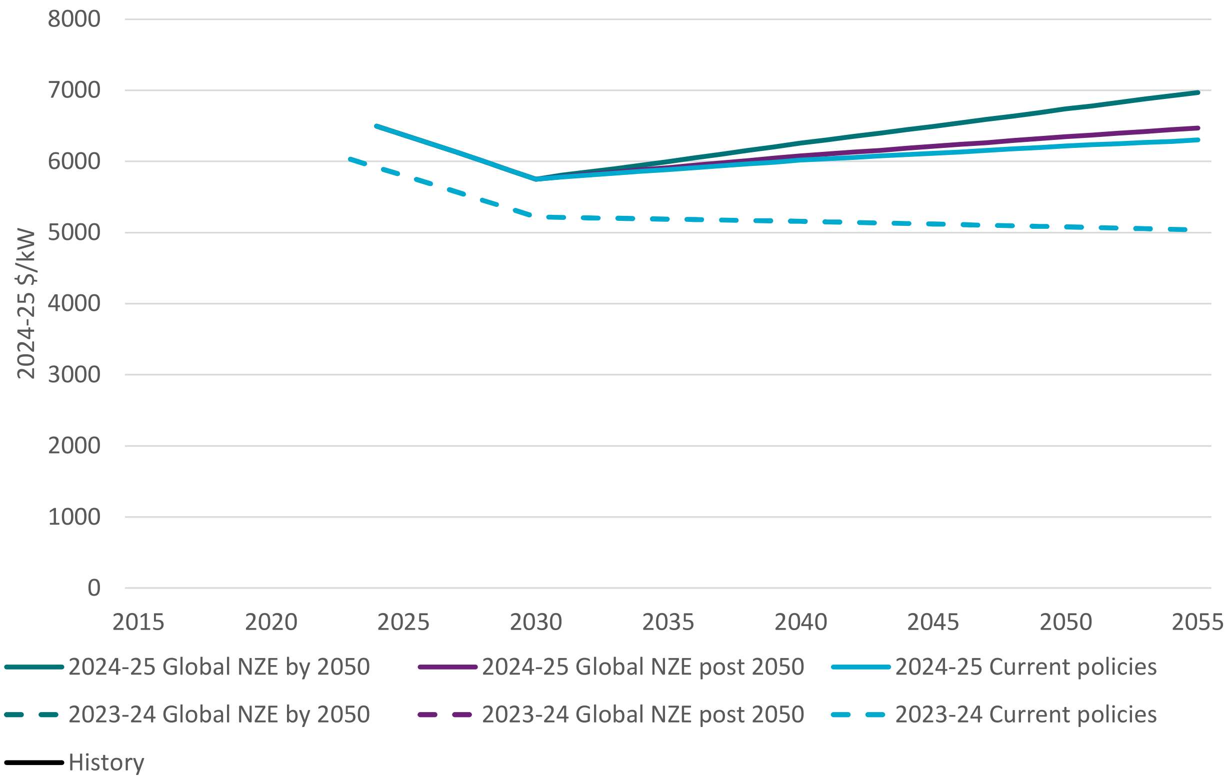

Figure 5-16 Projected capital costs for pumped hydro energy storage (24-hour) by scenario

The cost trajectory shown in Figure 5-16 is for a 24-hour duration storage design. Costs for 10-hour and 48-hour durations are also included in this report (Appendix B).

5.3.15 Other 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 2024 with the exception to 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 downward trend to either 2027 or 2030 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).

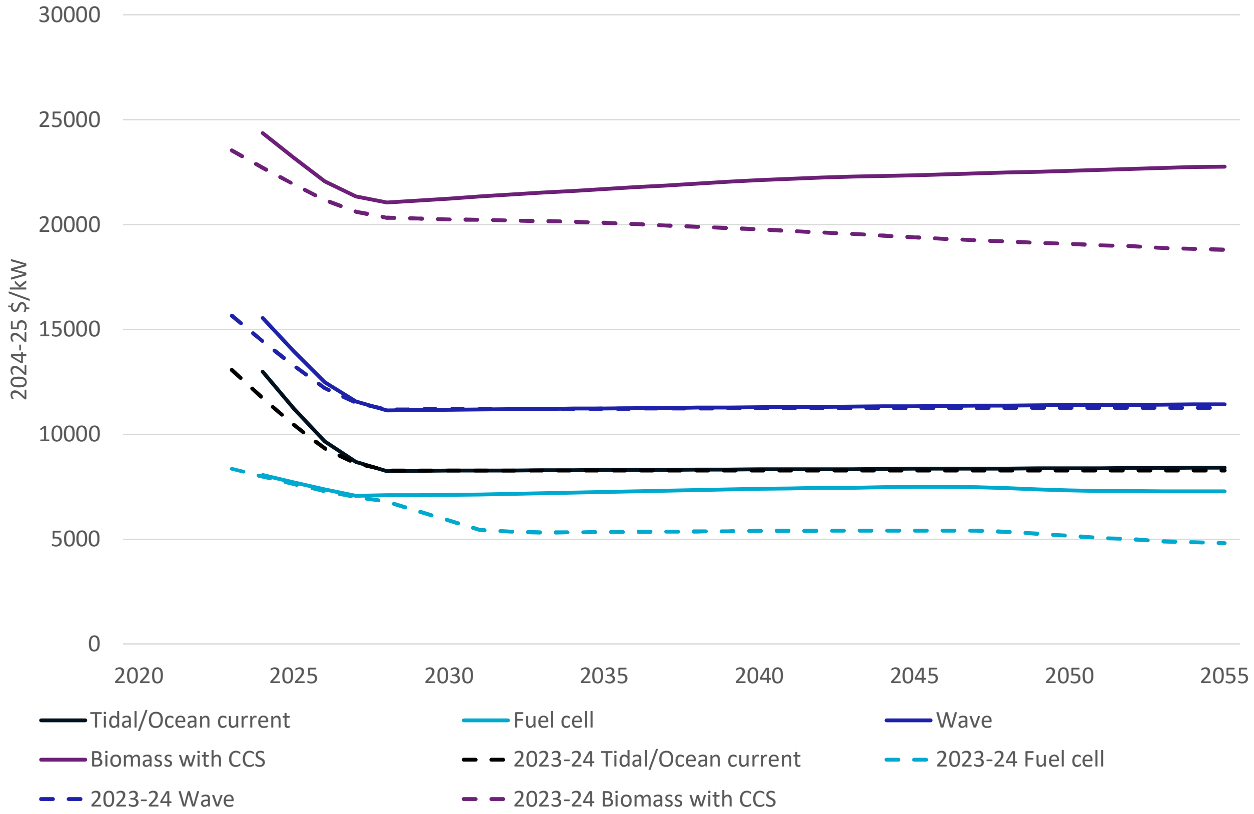

Figure 5-17 Projected technology capital costs under the *Current policies* scenario compared to 2023-24 projections

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 reductions after 2027 reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors. There is also no significant deployment of fuel cells, tidal or wave technology reflecting the lack of climate policy ambition. The major difference with the 2023-24 projections is that fuel cells were deployed in those projections. The continued cost increases in fuel cells together with cost decreases in other technologies such as solar PV and batteries is responsible for this change.

Global NZE by 2050

Biomass with CCS is adopted in the *Global NZE by 2050* scenario but can only achieve learning in the CCS component of the plant. Cost reductions reflect learning from its own deployment and co-learning from deployment of CCS in other electricity generation, hydrogen production and other industry sectors. 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 models the electricity sector and from that perspective alone, biomass with CCS is a relatively high-cost technology.

Wave energy is deployed at a minor level in the 2050s and tidal/ocean current in the late 2040s. Fuel cells are not deployed. The higher costs in most cases relative to 2023-24 are the result of higher installation costs for some technologies and a lack of deployment in favour of more mature technologies such as solar PV and wind.

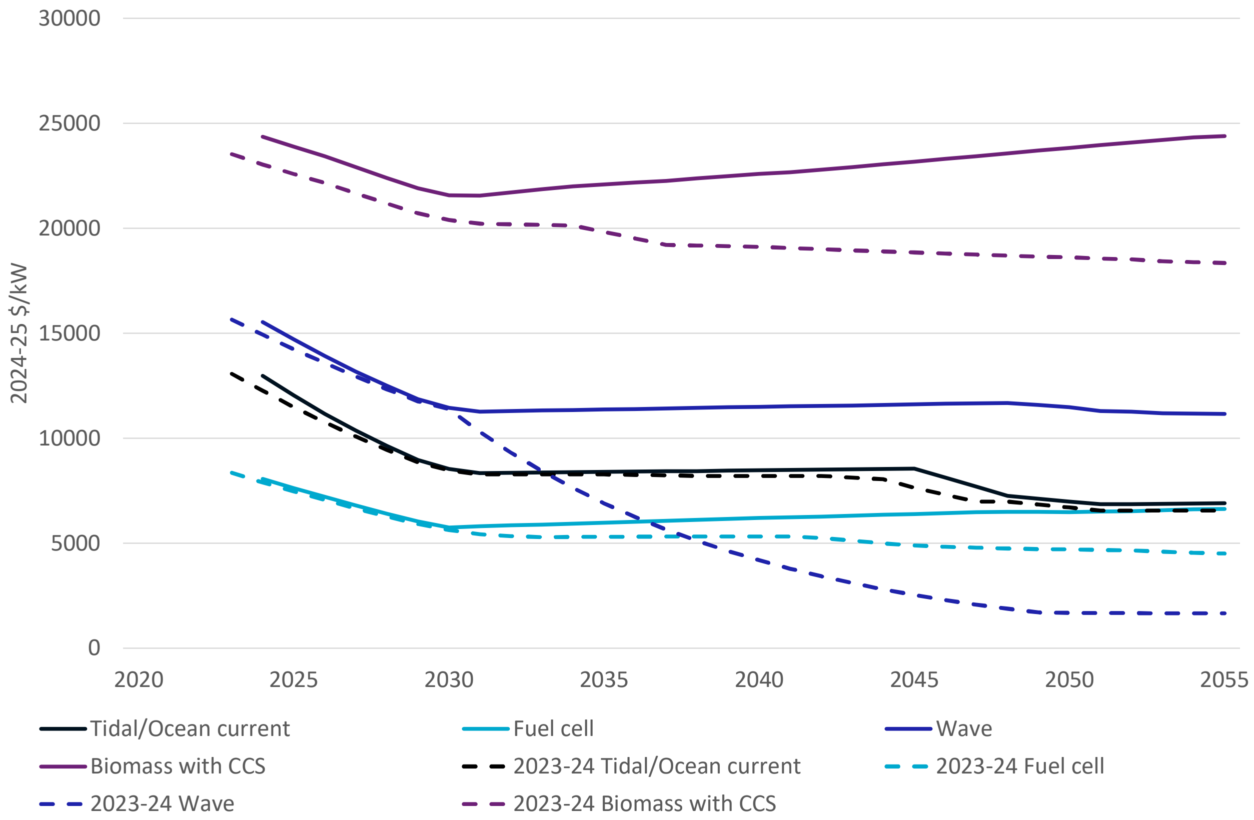

Figure 5-18 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2023-24 projections

Global NZE post 2050

Biomass with CCS is deployed at a slightly higher level than *Global NZE by 2050* resulting in slightly more cost reduction. Again, the majority of cost reductions reflect co-learning from deployment of other types of CCS generation or use of CCS in other applications. Both scenarios have significant deployment of steam methane reforming with CCS which brings down the cost of all CCS technologies sooner compared to *Current policies*.

Fuel cells are deployed in the 2040s but wave energy and tidal/ocean current not deployed. Higher costs relative to 2023-24 reflect lack of deployment due to the increasing gap between costs of these technologies and more mature renewables.

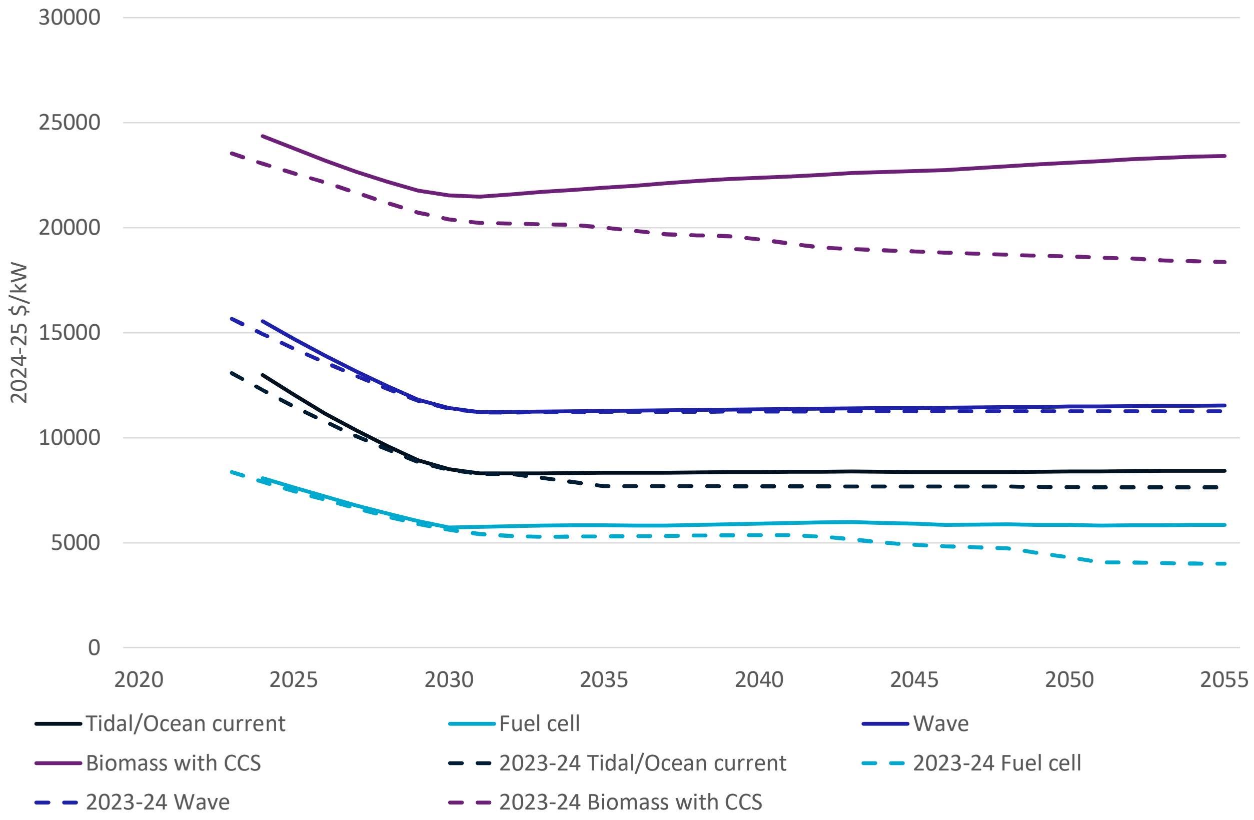

Figure 5-19 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2023-24 projections

5.3.16 Hydrogen electrolysers

Hydrogen electrolyser costs have decreased in 2024 for proton-exchange membrane (PEM) electrolysers but increased for alkaline electrolysers based on Aurecon (2025). Alkaline electrolysers remain lower cost than PEM electrolysers but their costs are now much 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. As the costs of both technologies fall, capital costs 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.

In 2023-24 and other previous GenCost reports we assumed that PEM and Alkaline cost would converge over time. However, the updated projections provide slightly more separated cost paths for the two technologies based on their differences in balance of plant. Updated analysis of balance of plant costs has also assisted in providing a more divergent cost range which better reflects future uncertainty.

Previous projections also made allowances for economies of scale to recognise the huge scale of electrolyser projects that were being proposed. However, while larger projects have been deployed there has been no significant decrease in costs associated with them. Consequently, this element of the projection approach has been removed.

Electrolyser deployment is being supported by a substantial number of hydrogen supply and end-use subsidised deployments globally and in Australia. Experience with other emerging technologies indicates that this type of globally coincident technology deployment activity can lead to a scale-up in technology manufacturing capacity which supports cost reductions.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario with the least change expected in *Current policies*. By 2055 the projected cost range for PEM electrolysers is \$746/kW to \$1601/kW. The range of alkaline electrolysers is \$710/kW to \$1525/kW.

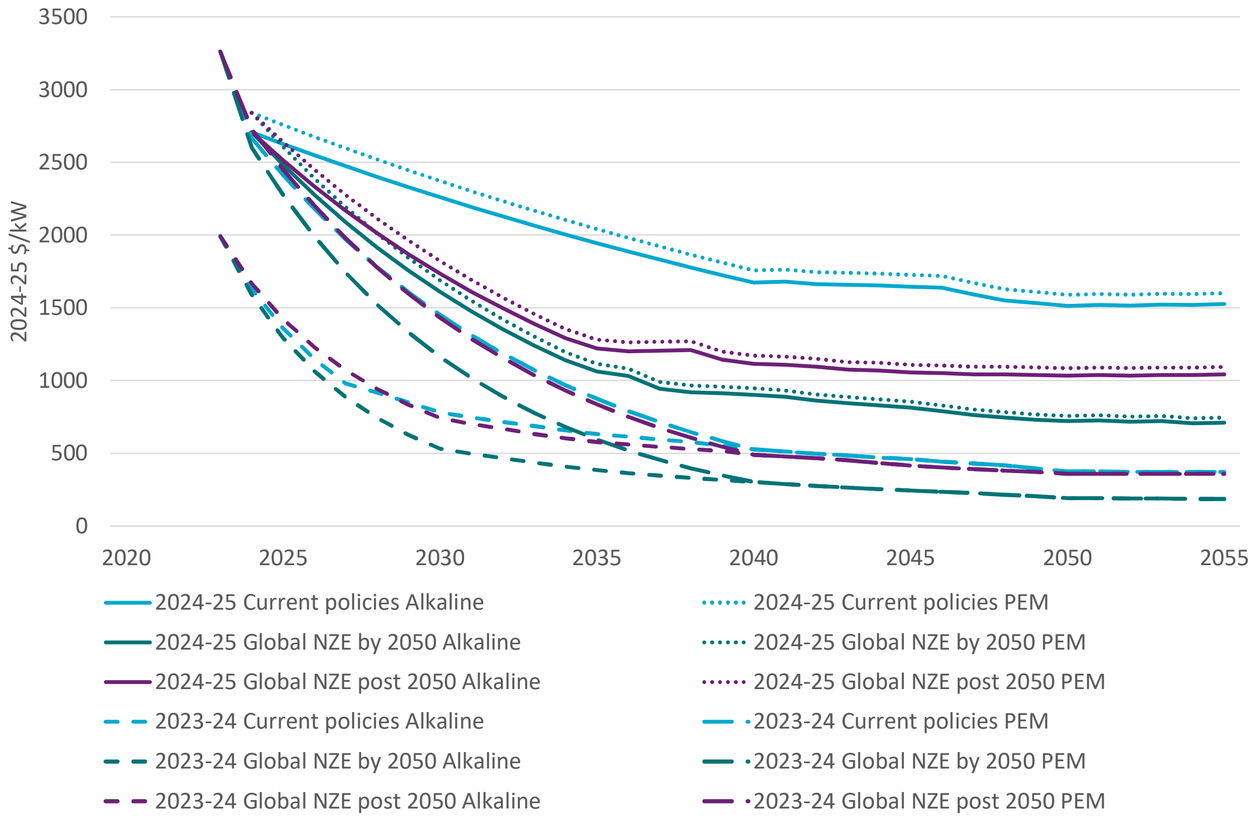

Figure 5-20 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2023-24

6 Levelised cost of electricity analysis

6.1 Purpose and limitations of LCOE

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[25]. Modelling studies such as AEMO's Integrated System Plan (AEMO, 2024) do not require or use LCOE data[26]. 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. Furthermore, in the GenCost 2018 report and a supplementary report on methods for calculating the additional costs of renewables (Graham, 2018), we described several issues and concerns in calculating and interpreting levelised cost of electricity. These include:

- The standard LCOE method does not take into account the additional costs associated with each technology and in particular the significant integration costs of variable renewable electricity generation technologies.
- The standard LCOE applies the same discount rate across all technologies even though fossil fuel technologies face a greater risk of being impacted by the introduction of current or new state or commonwealth climate change policies.
- The standard LCOE does not recognise that electricity generation technologies have different roles in the system. Some technologies are operated less frequently, increasing their LCOE, but are valued for their ability to quickly make their capacity available at peak times.

In Graham (2018), after reviewing several alternatives from the global literature, a new method for addressing the first dot point was proposed that calculated and added integration costs unique to variable renewables. That new method was implemented in the 2020-21 GenCost report and updated results from that method are included in this report. For an overview of the method see GenCost 2020-21 Section 5.1.

To address the issues not associated with additional cost of renewables, we:

- Separate and group together peaking technologies, flexible technologies and variable technologies

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[25]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

[26] 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.

- Included, up until the 2022-23 GenCost report, additional LCOE calculations for baseload fossil fuel technologies which added a climate policy risk premium of 5% based on Jacobs (2017). This information has been discontinued because the estimated risk premium is now considered inadequate to capture climate policy risk in a meaningful way.

6.2 LCOE estimates

6.2.1 Framework for calculating variable renewable integration costs

LCOE is typically used to compare the cost of one or more standalone projects on a common basis for a particular year (assuming they can all be built overnight, even if they have construction times varying from one to several years[27]). Technically, all electricity generation projects need other generation capacity to provide reliable electricity, even those that are dispatchable. Besides their inherent dispatchability, a key reason why the integration costs for dispatchable technologies are low is because they can rely on the flexibility of existing generation capacity to fill in at times when they are not generating or to add to generation during peak periods when they may already be at full production. The main difference with variable renewables is that existing capacity may not be enough to ensure reliable supply as the share of variable renewables grows. It may be enough when variable renewables are in the minority share of generation. However, it is not enough when they are in the majority because, to achieve their majority, significant existing flexible generation must be retired to make way for variable renewable generation.

To calculate the integration cost of variable renewables, we therefore start by allowing them free access to any existing flexible capacity (that has not retired). Next, we need to add the cost of any extra capacity the project needs to deliver reliable electricity.

Prior to the 2023-24 GenCost report, the focus was on calculating the integration costs for 2030 and the calculation allowed renewable projects to use any capacity that was expected to be built by that time at no cost. While this approach is strictly correct for answering the question of what integration costs are relevant for someone investing in a project in 2030, feedback from stakeholders indicated an appetite to consider the investor's perspective at an earlier point in time when the electricity system is less developed. Consequently, this report includes integration costs for renewables in 2024 in addition to 2030 (the 2023-24 report showed 2023).

Another concern of stakeholders is that the integration costs should include specific projects such as Snowy 2.0 and various committed or under construction transmission projects so that the community can understand how they are impacting the cost of electricity from variable renewables. Prior to 2030, there are many projects that are already committed by regulatory processes and government sponsored investments. After 2030, the investment landscape is less constrained.

In 2024, there are only negligible amounts of home battery systems and electric vehicles. Consequently, the high voltage system can only use storage that it builds for itself in 2024.

[27] Interest lost during construction is added so that the advantage given by projects that take less time to build is recognised.

The purpose of GenCost is to provide key input data, primarily capital costs, to the electricity modelling community so that they can investigate complex questions about the electricity sector up to the year 2055. LCOE data can only answer a narrow range of questions. It is provided for the purpose of giving stakeholders who may not have access to modelling resources an indication of the relative cost of different technologies on a common basis.

To avoid any confusion, Table 6-1 defines the question that is answered by the 2024 and 2030 LCOE data. Note that LCOE data for 2040 and 2050 is also provided, but without renewable integration costs. This reduces the computational burden for the GenCost project and recognises that, by the 2040s, if renewables are taken up, then most renewable integration resources will already be in place.

If the LCOE does not answer a stakeholder's question, then they may need to commission their own modelling study. Making data available that can be used in modelling studies is the primary goal of GenCost.

Table 6-1 Questions the LCOE data are designed to answer

LCOE data	Question answered
2024 variable renewables LCOE with integration costs	Assuming any existing capacity available in 2024 is free but insufficient to provide reliable supply, what is the total unit cost an investor must recover to deliver a project that provides reliable electricity supply in 2024 from a combination of variable renewable generation, transmission, storage and other resources, including the cost of currently committed or under construction projects?
2024 LCOE of all other generation technologies	Assuming any existing capacity available in 2024 is free and sufficient to support reliable integration, what is the total unit cost an investor must recover to deliver a project that provides electricity supply in 2024?
2030 variable renewables LCOE with integration costs	Assuming any existing capacity available in 2030 is free but insufficient to provide reliable supply, what is the total unit cost an investor must recover to deliver a project that provides reliable electricity supply in 2030 from a combination of variable renewable generation, transmission, storage and other resources?
2030 LCOE of all other generation technologies	Assuming any existing capacity available in 2030 is free and sufficient to support reliable integration, what is the total unit cost an investor must recover to deliver a project that provides electricity supply in 2030?

6.2.2 Key assumptions

We calculate the integration costs of renewables in 2024 and 2030 imposing large-scale variable renewable energy (VRE) shares of 60% to 90%[28] which will require additional capacity over and above that already existing in the electricity system to ensure reliable supply. An electricity system model is applied to determine the optimal investment to support each VRE share. In practice, although wave, tidal/current and offshore wind are available as variable renewable technologies, onshore wind and large-scale solar PV are the only variable renewables deployed in the modelling due to their cost competitiveness[29]. Victorian legislation creates a mandate for offshore wind generation, but this does not come into place until after 2030 and so is outside the scope of our analysis.

The VRE share does not include rooftop solar PV. The impact of rooftop solar PV is accounted for, however, in the demand load shape as is the impact of other customer energy resources. Virtual Power Plants (VPPs) and electric vehicles are negligible in 2024. However, in 2030, a portion of customer-owned battery resources are assumed to be available to support the wholesale generation sector consistent with the approach taken in the AEMO ISP (AEMO, 2024).

The standard LCOE formula requires an assumption of a capacity factor. Our approach in this report is to provide a high and low assumption for the capacity factor (which we report in Appendix B) in order to create an LCOE range[30]. Stakeholders have previously indicated they prefer a range rather than a single estimate of LCOE. However, it is important to note that these capacity factors are not used at all in the modelling of renewable integration costs. When modelling renewable integration costs, we use the variable renewable energy production traces published by AEMO for its Integrated System Plan (ISP). We incorporate the uncertainty in variable renewable production by modelling nine different weather years, 2011 to 2019, and the results represent the highest cost outcome from these alternate weather years.

The model covers the NEM, the South West Interconnected System (SWIS) in Western Australia (WA) and the remainder of WA. Northern Territory (NT) is not included in the results as it represents an outlier given its isolation and small size.

2024 represents the current electricity system. In 2030, we project forward including all existing state renewable energy targets resulting in a 54% renewable share and 47% variable renewable share in Australia ex-NT[31] (both excluding rooftop PV). The share fluctuates a few percent

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[28] Above 90% VRE share is of limited interest because it would mean forcibly retiring other non-variable renewables such as hydro and biomass which would not be optimal for the system. Furthermore, there is no current requirement for the electricity system to be emissions free. For example, a 95% emissions free electricity system could still be consistent with meeting Australia's 2050 net zero emission goal.

[29] This does not preclude other types of projects proceeding in reality but is a reflection of modelling inputs in 2024 and 2030.

[30] The capacity factor range assigned to new build technologies is based on a formula which uses the ten-year average capacity factors. For the high range, we use the high range of historically achieved capacity factors. However, the low range capacity factor assumption is closer to the average capacity factor rather than the lowest case. Specifically, we assume the low range value is 10% below the average on the basis that if a project cannot achieve a capacity factor at least that level it is unlikely to proceed as a new investment. Appendix D of the *GenCost 2022-23: Final report* provided a discussion of historical capacity factors upon which the data in this report is based.

[31] We do not include the impact of the Capacity Investment Scheme which is a national policy for achieving 82% renewables by 2030. In the June 2022 ISP, the 82% renewables policy was consistent with 65% large-scale VRE share with the remainder of renewable share made up of hydro, biomass and rooftop solar PV (which represents small-scale VRE). As such, most of the large-scale VRE shares explored in GenCost exceed government policy to 2030 except the 60% case. We exclude the Capacity Investment Scheme (CIS) policy so that the 60% case can remain and the trend in progression of costs from 60% to 90% can still be observed.

depending on the nine weather years. The counterfactual VRE share reflects the impact of existing state renewable targets, planned state retirements of coal capacity in the case of WA and an already existing high VRE share in South Australia.

In both 2024 and 2030, New South Wales, Queensland, Victoria and the SWIS are the main jurisdictions that are impacted by imposing the 60% to 90% VRE shares given that Tasmania and South Australia are already dominated by renewables such that the business as usual (BAU) already includes much of the necessary capacity to support high VRE shares. The NEM is an interconnected system, so we are also interested in how those states support each other and the overall costs for the NEM. The VRE share is applied in each state at the same time, but individual states can exceed the share if it is economic to do so.

As we implement higher variable renewable energy shares, we must forcibly retire coal plant (only as a modelling assumption) as meeting the variable renewable share and the minimum load requirements on coal plant would otherwise eventually become infeasible[32].

Snowy 2.0 ($12 billion) and battery of the nation ($1.7 billion) pumped hydro projects are assumed to be committed with construction complete before 2030 in the BAU, as well as various transmission expansion projects already flagged by the ISP process to be necessary before 2030 (Table 6-2). The NSW target for an additional 2 GW of at least 8 hours duration storage is also assumed to be committed and complete by 2030 together with the Kurri Kurri gas peaking plant[33]. For the 2024 calculations, we abstract from reality and assume these projects can be completed immediately so that the cost of these committed projects is included in the current cost of integrating variable renewables[34]. These costs are included regardless of the VRE share. Pumped hydro, battery and peaking plant costs are sourced either directly from the project source or estimated via GenCost capital costs. Transmission costs are from AEMO (2023b). For the 2030 investor, all of these projects are considered free capacity in the same way that existing capacity now is free for the 2024 analysis. This approach is consistent with the aim of the LCOE analysis (Table 6-1).

Table 6-2 Committed investments by category included in the 2024 cost of integrating variable renewables

Category	$billion
Transmission	15.9
Storage	19.2
Peaking gas	1.0

For 2024, the initial generation capacity is as it is today. For 2030, the capacity needs to be increased from today due to growing demand. In the nine weather year counterfactuals, the model does not choose to build any new fossil fuel-based generation capacity by 2030 (Figure 6-1).

32 The model would be unable to simultaneously meet the minimum VRE share and the minimum run requirements of coal plant which are around 30% to 50% of rated capacity. There have been experiments in Australia to determine whether some coal plant could switch off completely rather have a minimum run constraint. However, currently, not enough is known about this mode of operating coal generation to include it in the modelling.

33 The Tallawarra B gas-fired generation project is already in operation and is not included.

34 This is necessary because the LCOE methodology is designed to annualise all project costs into a single year. It is not well suited to costing a progression of projects over multiple years. Multi-year investment problems can be studied more appropriately in intertemporal electricity system models.

Pumped hydro storage is also the same. The main investment response to demand growth and the different weather years is to vary wind capacity by up to 2.6GW, solar PV capacity by 3.0GW and large-scale batteries (VPP capacity is fixed) by 0.7 GW. The capacities shown have been compared with the AEMO ISP 2030 capacity projections (AEMO, 2024). The NEM coal retirements to 2030 are slower than Step Change (2024 release) and the overall demand and renewable generation is lower. Reflecting the change in relative fortunes for solar PV, solar PV capacity is preferred over wind by 2030 but only slightly. Wind, was preferred in the ISP[35]. The NEM and WA total variable renewable shares are 49% and 38% on average across the weather years.

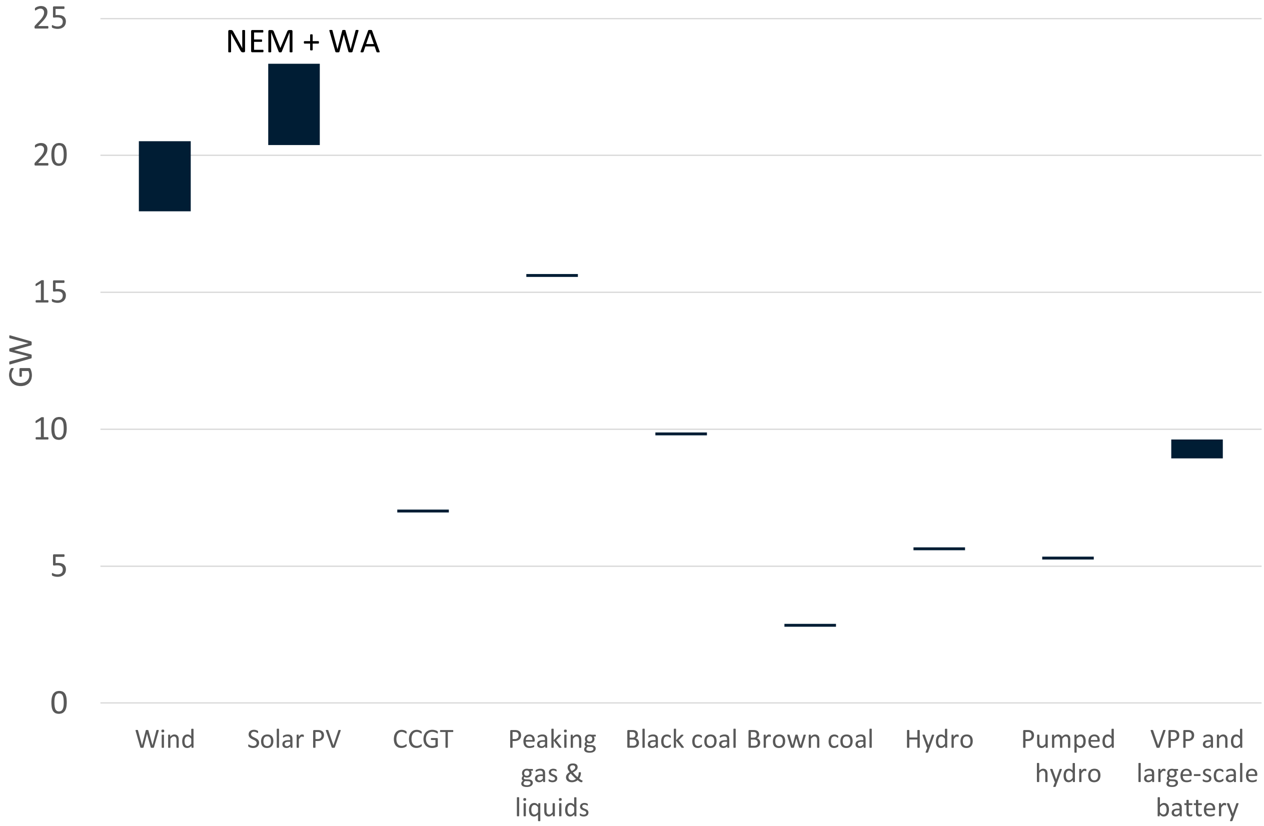


Figure 6-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia

The costs of VRE share scenarios were compared against the same counterfactual weather year to determine the additional integration costs of achieving higher VRE shares. We use the maximum cost across all weather years as the resulting integration cost on the basis that the maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation.

The results, shown in Figure 6-2, include storage, transmission, spillage and synchronous condenser costs where applicable. The integration costs are flat with increasing variable renewable share in the 2024 results. This is because the cost of the committed storage and transmission infrastructure can be spread over more of the additional renewable generation the greater the required variable renewable share. It is appreciated that this result is somewhat

[35] The 2024 ISP projections are based on older GenCost data where solar PV was relatively less competitive

counterintuitive as we normally understand that VRE integration costs increase with the VRE share. However, the result is valid and what can be learned from this result is that planned transmission and storage capacity is being built with higher electricity demand and subsequently higher volumes of variable renewable generation in mind. As the system reaches those higher VRE generation levels, the normal relationship between VRE share and costs (the higher the share the higher the costs) should resume.

Across the different VRE shares, the cost of variable renewable generation in 2024 is $149/MWh on average in the NEM. This is 57% higher than average costs in 2030 for 60% VRE, but only 36% higher than average costs for 2030 for 90% VRE. Around a third of the higher costs are due to investors having to pay 2024 instead of 2030 technology costs (technology costs are falling over time). The remainder is due to the cost of the pre-2030 committed projects which must be paid for in the 2024 analysis, but are considered free existing capacity for investors in 2030 (in the same way that anything built pre-2024 is free existing capacity for 2024 investors).

The use of 2024 technology costs in 2024, as well as applying committed project costs to lower VRE generation than these projects were intended to support, means these results represent the highest cost for achieving these VRE shares. In reality, the transition to these VRE shares would occur over several years at higher volumes and there would be access to lower costs as technologies improve over time (see the projections in Section 5).

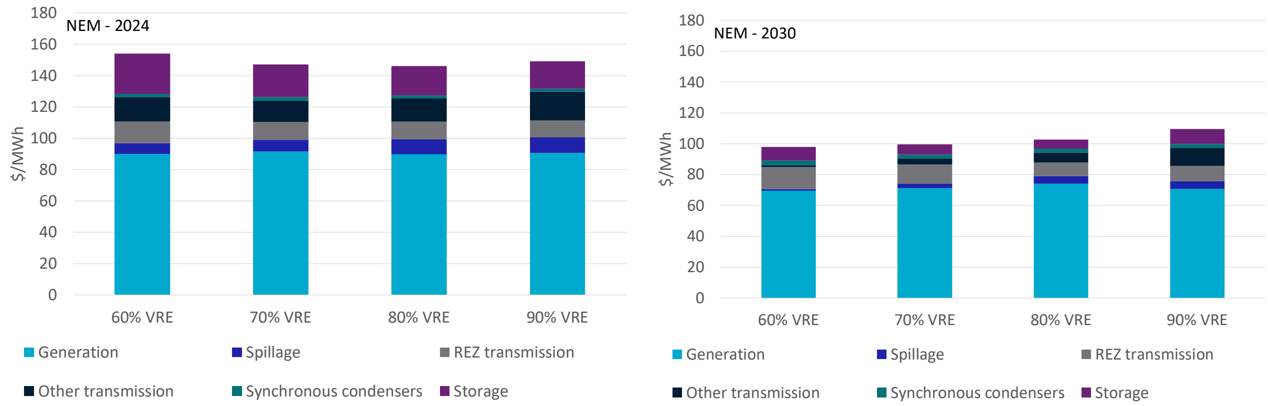


Figure 6-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in the NEM in 2024 and 2030

Variable renewable integration costs in 2024 are dominated by storage and transmission. Synchronous condenser costs are relatively minor reflecting that gas generation capacity remains high relative to 2024 demand and can mostly fulfill this role alongside other existing synchronous generation such as hydro (but less so coal which needs to increasingly be retired because coal's minimum run requirements make it incompatible with higher VRE shares). In 2030, with higher generation, synchronous condensers can play a larger role and expenditure is more significant. Storage is less significant by 2030 reflecting the value of investments made pre-2030 in the NEM.

In the 2030 results, the shares of the supporting technologies shifts with the VRE share but not necessarily in a predictable fashion. This reflects that at each VRE share, a different combination of resources are needed. For example, other (non-REZ) transmission is less important at low VRE shares but becomes increasingly important at higher shares.

Storage can shift variable renewable generation to a different time period. Transmission supports access to a greater diversity of variable renewable generation by accessing resources in other regions which can help smooth supply, reducing the need for storage. Spillage is a side-effect of over building VRE capacity to increase its minimum production levels[36]. Given the low cost of VRE capacity, deploying VRE capacity to a level where energy is spilled is a valid alternative to expenditure on storage and transmission. As transmission, storage and VRE capacity costs are updated, their share of integration costs will change as they are partially in competition with each other.

REZ expansion costs are required at similar levels for each additional 10% increase in VRE share in each state and across years. New South Wales and Victoria tend to attract the most transmission expenditure reflecting their central location in the NEM and access to pumped hydro storage.

Variable renewable integration costs are similar in WA but with a heavy reliance on storage and more spilled energy reflecting the limited ability to connect, via transmission, to more varied sources of renewable energy. Costs in different states or regions are averaged out at the aggregate level (NEM + WA) in calculating integration costs for comparison with other technologies (and so will differ from Figure 6-2 which is only the NEM result). The cost of REZ transmission expansions adds an average $10.3/MWh in 2024 and $10.2/MWh in 2030, as the VRE share increases from 60% to 90%. Other transmission costs add $12.6/MWh in 2024 and $4.2/MWh in 2030. Storage costs add an average $20.5/MWh in 2024 and $12.2/MWh in 2030. Spillage costs peak at the 90% VRE share at $14.0/MWh in 2024 and $9.7/MWh in 2030.

6.2.3 Variable renewables with and without integration costs

The results for the additional costs of increasing variable renewable shares are used to update and extend our LCOE comparison figures. We expand the results for 2024 and 2030 to include a combined wind and solar PV category for different VRE shares. Integration costs to support renewables are estimated at $48/MWh to $64/MWh in 2024 and $23/MWh to $40/MWh in 2030 depending on the VRE share (Figure 6-3 and Figure 6-4).

Onshore wind and solar PV without integration costs such as transmission and storage are the lowest cost generation technologies by a significant margin. These can only be added to the system in a minority share before integration costs become significant and must be added. Offshore wind is higher cost than onshore wind but competitive with other alternative low emission generation technologies. Its higher capacity factor could result in lower storage costs and it tends to have a higher potential contribution during peak demand times. Integration costs have only been calculated for onshore wind in this report given it remains the lowest cost form of wind generation.

The LCOE cost range for variable renewables (solar PV and wind) with integration costs is the lowest of all new-build technologies in 2030 and at a similar range with black coal in 2024. The lower end of the cost range of gas generation is also competitive. To achieve the lower end of the

[36] The spilled electricity cost is calculated as the LCOE of the variable renewable generation equipment when calculated via total additional generation minus the LCOE when calculated on the basis of useful generation only (defined as the minimum additional generation needed to meet the next 10% increment of VRE share).

range for coal and gas a high capacity factor must be achieved and low cost fuel sourced. Deploying coal and gas for delivery of the majority of Australia's electricity supply is not consistent with Australia's national and state climate policies. If we exclude these high emission generation options, the next most competitive generation technologies are solar thermal, gas with carbon capture and storage (CCS) and large-scale nuclear.

6.2.4 Peaking technologies

The peaking technology category includes two sizes for gas turbines, a gas reciprocating engine and a hydrogen reciprocating engine. Fuel comprises the majority of costs, but the lower capital costs of the larger gas turbine make it the most competitive. Reciprocating engines have higher efficiency and consequently, for applications with relatively higher capacity factors and where a smaller unit size is required, they can be the lower cost choice. All of the gas technologies include the ability to run on a mix of hydrogen and natural gas, but the costs shown are calculated for 100% natural gas.

Hydrogen peaking plant are higher cost at present and include the cost of 100% hydrogen fuel. However, their capital and fuel costs are expected to fall over time. This technology has zero direct greenhouse gas emissions, but may involve some upstream emissions, depending on the hydrogen production process.

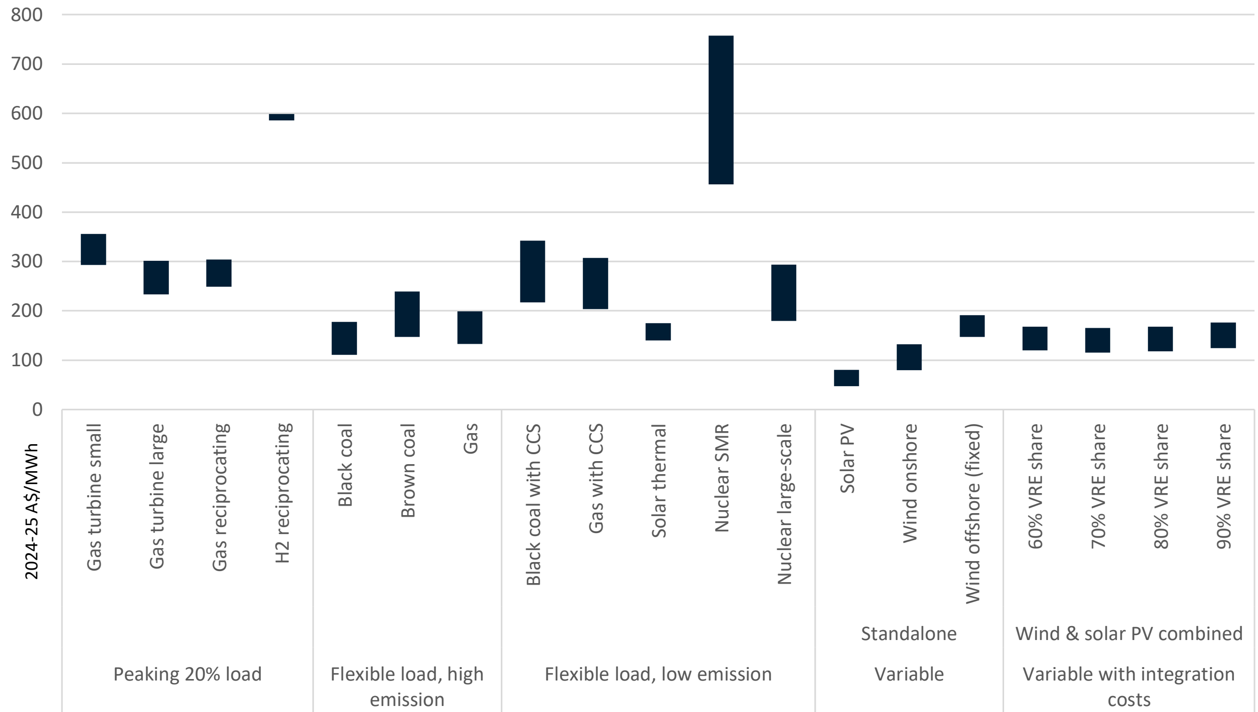


Figure 6-3 Calculated LCOE by technology and category for 2024

6.2.5 Flexible technologies

Large-scale nuclear, nuclear SMR, solar thermal, black coal, brown coal and gas-based generation technologies fall into the category of technologies that are designed to deliver energy for the majority of the year (specifically 53% to 89% in the capacity factor assumptions for most technologies and 57% to 71% for solar thermal based on ITP Thermal (2024) with this exception made because higher capacity factors to do not improve costs any further for this technology).

This technology category is the next most competitive technology group after variable renewables (with or without integration costs). The reduction in fossil fuel generation costs between 2024 and 2030, is not a result of technological improvement. It represents a reduction in fuel prices and capital costs which were impacted by global inflationary pressures that peaked in 2022.

Of the fossil fuel technologies, it is difficult to say which is more competitive as it depends on the price outcome achieved in contracts for long-term fuel supply. Also, using fossil fuels without carbon capture and storage makes them high emission technologies which makes them incompatible with national and state emission targets.

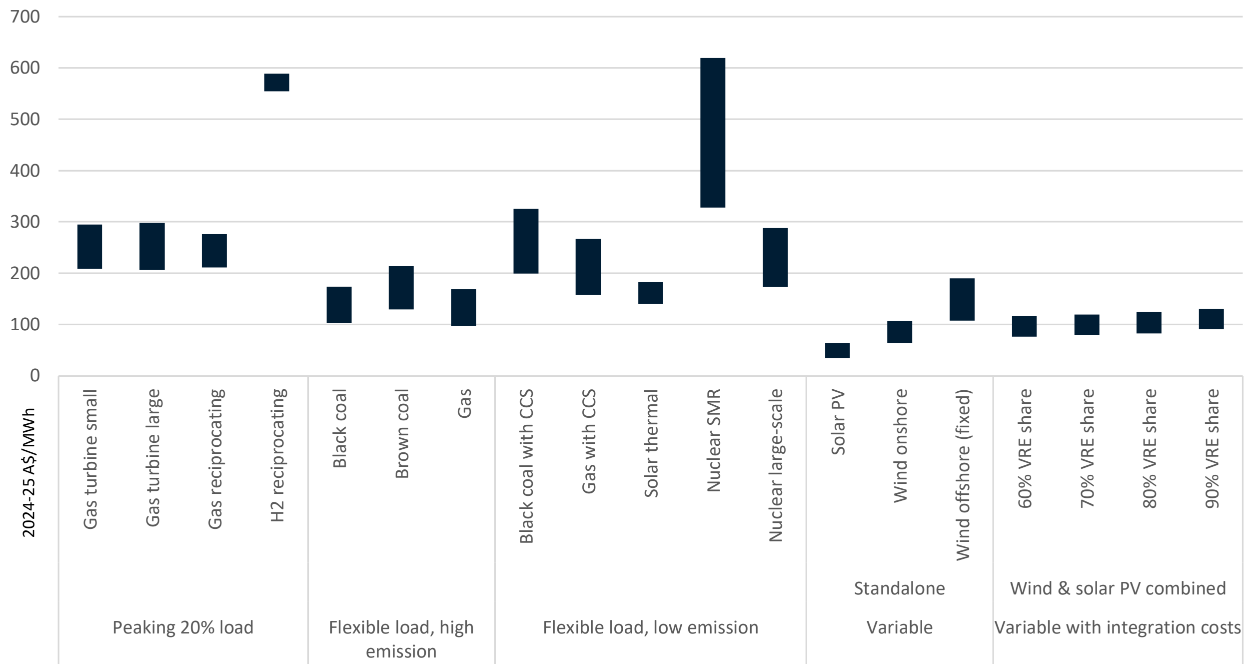


Figure 6-4 Calculated LCOE by technology and category for 2030

Low emission flexible technologies are more viable under current climate change policies. In this category, solar thermal is the most competitive technology. 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 the analysis for solar PV and wind, additional transmission costs could add around $14/MWh.

Gas with CCS is the next most competitive after solar thermal by 2030. Large-scale nuclear is only 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 in this category, but their cost range becomes more competitive over time. 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[37] 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%.

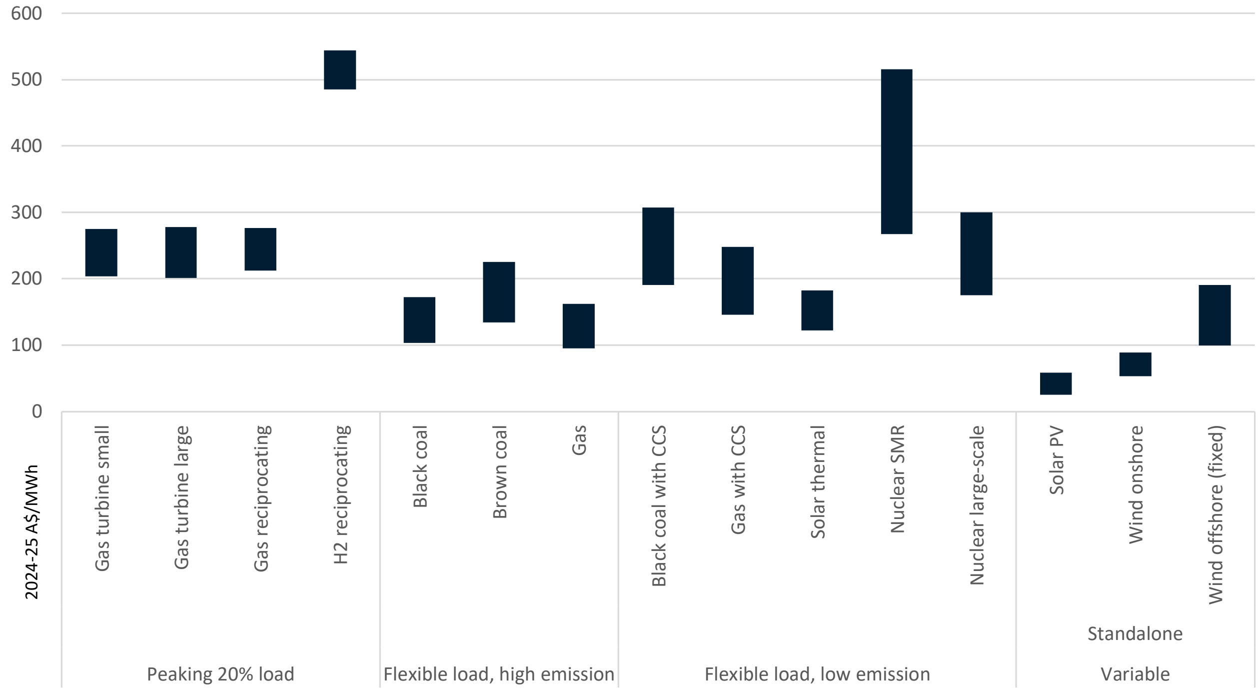


Figure 6-5 Calculated LCOE by technology and category for 2040

[37] The lowest cost flexible plant in the system will typically be able to operate at this high capacity factor. However, this will be challenging for new plant to achieve. Older existing plant, with their capital costs mostly paid down and access to existing low cost fuel sources, are typically the lowest cost generation units. New generation units entering the market must recover their capital costs and tend to have less favourable fuel contracts.

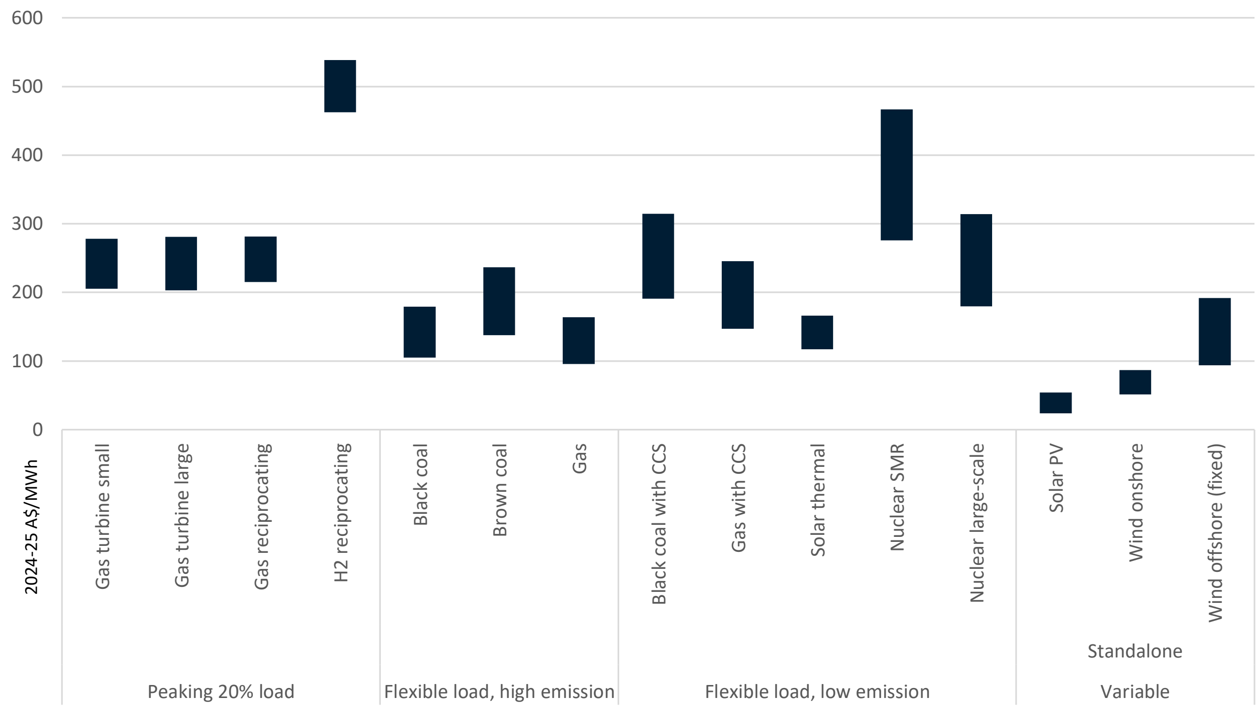


Figure 6-6 Calculated LCOE by technology and category for 2050

6.3 Storage requirements underpinning variable renewable costs

In both formal and informal feedback, a common concern is whether GenCost LCOE calculations have accounted for enough storage or other back-up generation capacity to deliver a steady supply from variable renewables. Ensuring all costs are accounted for is important when comparing costs with other low emission technologies such as nuclear which are capable of providing steady supply. Intuitively, high variable renewable systems will need other capacity to supply electricity for extended periods when variable renewable production is low. This observation might lead some to conclude that the system will need to build the equivalent capacity of long-duration storage or other flexible and peaking plant (in addition to the original variable renewable capacity). However, such a conclusion would substantially overestimate storage capacity requirements.

Variable renewables have a low capacity factor, which means their actual generation over the year expressed as a percentage of their potential generation as defined by their rated capacity, is low (e.g., 20% to 40%). The average capacity factor of coal dominated electricity supply in Australia is around 60%. As a result, to deliver the equivalent energy of current coal-fired generation, the system needs to install around two times the capacity of variable renewables. If the system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has around four times the capacity needed compared to a coal dominated system. For a number of reasons, this scale of capacity development is not necessary to replace coal.

The most important factor is that while we are changing the generation source, maximum demand has not changed. Maximum demand is the maximum load that the system has to meet in a given year. Maximum demand typically occurs during heat waves in warmer climates (which is most of Australia) and in winter during extended cold periods in cooler climates (e.g., Tasmania). The combined capacity of storage, peaking and other flexible generation only needs to be sufficient to meet maximum demand. In a high variable renewable system, maximum demand will be significantly lower than the capacity of variable renewables installed. Instead of installing storage on a kW for kW basis, to ensure maximum demand is met, we only need to install a fraction of a kW of storage for each kW of variable renewables. The exact ratio depends on two other factors as well.

First, we are very rarely building a completely new electricity system (except in greenfield off-grid areas). Existing electricity systems have existing peaking and flexible generation. This reduces the amount of new capacity that needs to be built. This is true for coal generation or any other new capacity as it is for variable renewable generation. All new capacity relies on being supported by existing generation capacity to meet demand.

Second, as the variable renewable generation share increases, summer or winter peaking events may not represent the most critical day for back-up generation. For example, during a summer peaking event day, solar PV generation will have been high earlier in the day and consequently storages are relatively full and available to deliver into the evening peak period. A more challenging period for variable renewable systems might be on a lower demand day when cloud cover is high and wind speed is low. These days with low renewable generation and low charge to storages could see the greatest demands on storage, peaking and other flexible capacity. As such, it may be that the demand level on these low renewable generation days is a more important benchmark in setting the amount of additional back-up capacity required.

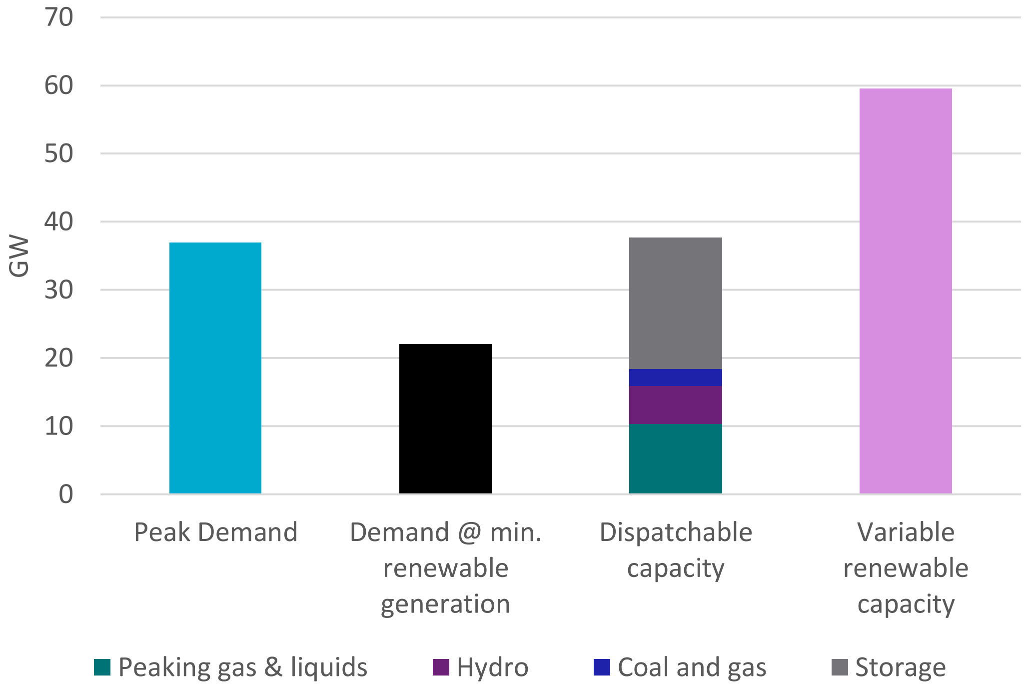


Figure 6-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

The modelling approach applied accounts for all of these factors across nine historical weather years. The result is that, in 2030, the NEM needs to have 0.3kW to 0.4kW storage capacity for each kW of variable renewable generation installed[38]. Showing the most extreme case of 90% variable renewable share for the NEM, Figure 6-7 shows maximum annual demand, demand when renewable generation is lowest, storage capacity, peaking capacity, other flexible capacity and total variable renewable generation capacity.

The data shows that:

- Demand at the point of lowest renewable generation[39] is substantially lower than maximum demand and can mostly be met by non-storage technologies (although in this example renewable generation is not zero and can still contribute).
- Existing and new flexible capacity is very similar to maximum demand and can meet demand mostly without renewable generation being available. However, there is often a small amount of variable renewable generation available at peak demand events somewhere in the NEM (typically wind generation if the peak occurs outside of daylight hours such as in the evening or early morning).
- Flexible capacity exceeds demand at minimum renewable generation.
- The required existing and new flexible capacity to support variable renewables is a fraction of total variable renewable capacity.

[38] This ratio may change as storage and transmission are partial competitors and as such the storage ratio could increase if transmission becomes relatively more expensive. There has been a drift upwards in the ratio projected over the past few years of analysis.

[39] Calculated as sum of coincident NEM state demand.

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:

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

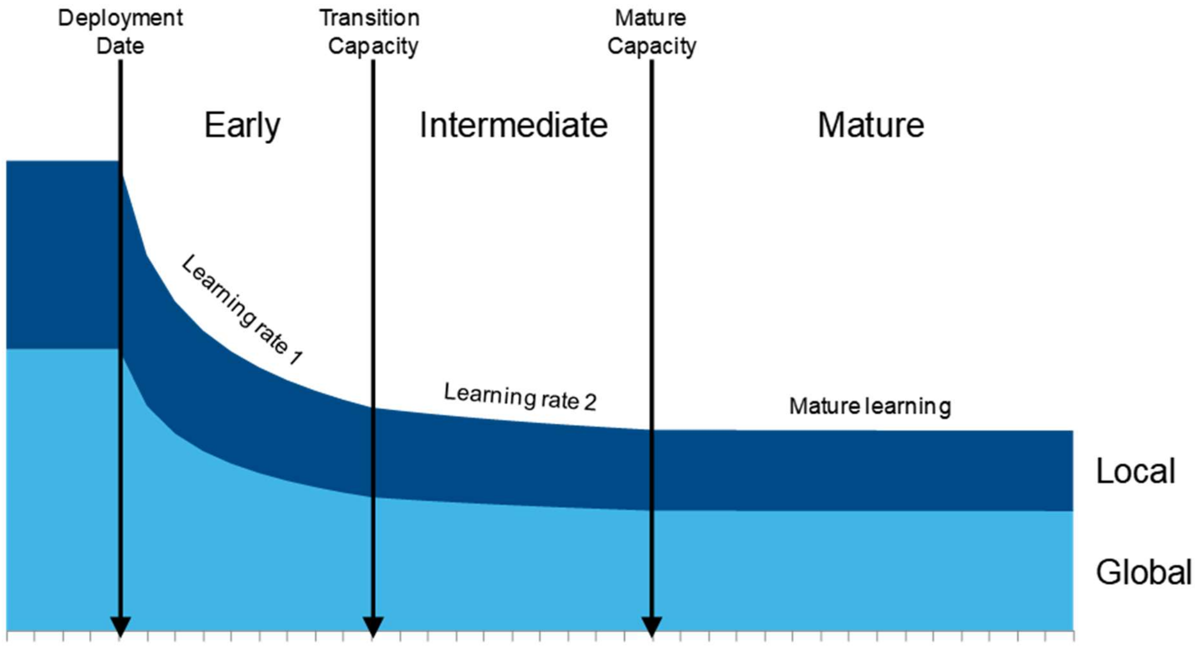
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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 do not have a standard unit size and 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 Aurecon (2025) 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 2024 is mostly sourced from Aurecon (2025) and is aligned to July which represents either the middle of that calendar year or the beginning of the 2024-25 financial year.

As discussed in Section 3, the data is not intended to include FOAK costs. Therefore, for technologies not recently constructed in Australia, the cost of the first plant may be higher than estimated here. Section 3 includes suggested FOAK premiums.

Furthermore, capital costs are for a location not greater than 200km from the Victorian metropolitan area. Aurecon provide data for adjusting costs for different locations in the NEM. 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 (16hrs)	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
2024	6037	12263	9321	2455	2426	1310	5802	1980	2071	8916	24366	1463	1336	6769	3351	4710	8362	15547	29667	12979	8067	8984
2025	5757	11696	8804	2455	2426	1305	5802	1980	2071	8641	23188	1344	1314	6692	3221	4697	8351	13956	28183	11234	7710	8858
2026	5489	11146	8311	2455	2426	1301	5802	1980	2071	8372	22060	1234	1293	6621	3094	4685	8339	12482	26749	9656	7371	8738
2027	5319	10790	7998	2388	2327	1296	5679	1975	2074	8202	21340	1155	1273	6564	2972	4673	8326	11560	25388	8688	7075	8667
2028	5251	10632	7869	2253	2127	1292	5433	1966	2081	8136	21048	1144	1255	6526	2859	4664	8314	11136	24539	8249	7096	8656
2029	5274	10660	7904	2050	1828	1287	5064	1952	2092	8166	21136	1134	1239	6500	2750	4658	8304	11150	23998	8256	7104	8694
2030	5299	10696	7942	1917	1630	1283	4822	1945	2102	8198	21237	1123	1227	6480	2646	4654	8299	11166	23925	8264	7115	8736
2031	5323	10733	7980	1854	1534	1278	4706	1945	2110	8230	21338	1113	1216	6465	2546	4656	8299	11181	23850	8272	7125	8778
2032	5343	10766	8014	1859	1538	1274	4717	1952	2118	8260	21429	1103	1208	6457	2449	4659	8302	11195	23952	8279	7154	8815
2033	5361	10799	8047	1865	1543	1269	4728	1959	2125	8288	21515	1093	1203	6453	2356	4663	8305	11207	24048	8285	7183	8851
2034	5380	10831	8079	1870	1548	1265	4738	1965	2132	8316	21600	1083	1199	6455	2266	4667	8285	11220	24145	8291	7215	8886
2035	5399	10863	8111	1876	1552	1260	4749	1972	2140	8345	21686	1073	1195	6454	2206	4670	8255	11232	24241	8296	7246	8922
2036	5419	10896	8144	1882	1557	1256	4760	1979	2147	8373	21773	1063	1190	6458	2175	4674	8215	11245	24339	8302	7279	8958
2037	5440	10930	8177	1887	1562	1252	4771	1986	2154	8402	21861	1053	1186	6460	2171	4678	8186	11257	24438	8307	7311	8994
2038	5461	10963	8210	1893	1567	1247	4782	1993	2162	8432	21950	1043	1182	6463	2168	4682	8157	11270	24170	8313	7344	9031
2039	5482	10995	8244	1899	1572	1243	4791	2000	2170	8462	22037	1034	1178	6466	2166	4686	8127	11283	22245	8319	7377	9068
2040	5500	11020	8275	1904	1576	1239	4796	2006	2176	8488	22114	1024	1175	6470	2163	4690	8108	11295	19646	8324	7406	9102
2041	5517	11040	8302	1909	1579	1234	4798	2011	2182	8511	22181	1015	1172	6473	2160	4694	8099	11305	17398	8330	7428	9132
2042	5533	11050	8325	1912	1582	1230	4793	2016	2187	8530	22233	1005	1169	6406	2157	4697	8102	11315	16791	8336	7446	9158
2043	5547	11050	8349	1916	1585	1226	4779	2020	2192	8549	22276	996	1166	6286	2152	4701	8105	11324	16838	8341	7460	9184
2044	5561	11043	8373	1919	1588	1221	4758	2025	2197	8568	22312	987	1164	6125	2147	4704	8108	11334	16886	8347	7477	9210
2045	5573	11038	8397	1923	1591	1217	4738	2029	2202	8588	22350	978	1161	6016	2143	4708	8111	11343	16934	8353	7494	9236
2046	5586	11039	8421	1926	1594	1213	4724	2034	2207	8607	22394	969	1159	5947	2139	4711	8114	11353	16983	8359	7499	9263
2047	5599	11036	8445	1930	1597	1208	4707	2039	2212	8627	22435	960	1157	5903	2136	4714	8117	11362	17032	8364	7482	9289
2048	5611	11031	8469	1934	1600	1204	4687	2043	2217	8647	22473	951	1149	5865	2131	4718	8119	11372	17081	8370	7436	9316
2049	5623	11024	8494	1937	1603	1200	4665	2048	2222	8667	22510	942	1135	5824	2119	4721	8122	11381	17130	8376	7373	9343
2050	5635	11026	8517	1940	1606	1196	4653	2052	2227	8685	22554	934	1122	5799	2108	4724	8125	11390	17176	8382	7332	9368
2051	5647	11030	8538	1943	1608	1196	4645	2056	2231	8701	22597	925	1109	5789	2088	4727	8127	11399	17219	8388	7297	9391
2052	5659	11040	8558	1946	1610	1187	4642	2060	2235	8716	22644	917	1103	5793	2078	4731	8129	11407	17259	8394	7296	9413
2053	5670	11045	8578	1948	1612	1187	4636	2063	2239	8731	22687	908	1095	5732	2058	4733	8131	11415	17299	8400	7281	9435
2054	5681	11056	8598	1951	1614	1179	4635	2067	2243	8746	22736	900	1093	5670	2051	4736	8133	11423	17340	8406	7286	9457
2055	5686	11059	8608	1952	1615	1179	4632	2069	2245	8754	22758	891	1092	5606	2043	4738	8134	11427	17360	8409	7282	9468

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 (16hrs)	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
2024	6037	12263	9321	2455	2426	1310	5802	1980	2071	8916	24366	1463	1336	6769	3351	4710	8362	15547	29667	12979	8067	8984
2025	5900	11988	9064	2455	2426	1305	5802	1980	2071	8787	23891	1371	1307	6633	3211	4395	7655	14712	28183	12044	7626	8929
2026	5768	11718	8819	2455	2426	1301	5802	1980	2071	8661	23431	1285	1278	6505	3075	4095	7008	13917	26749	11164	7212	8881
2027	5652	11462	8598	2417	2369	1296	5732	1980	2077	8548	22909	1207	1250	6391	2946	3818	6416	13179	25388	10362	6796	8851
2028	5558	11232	8413	2341	2253	1292	5591	1982	2088	8458	22399	1137	1223	6294	2829	3565	5874	12499	24014	9634	6405	8854
2029	5477	11019	8250	2227	2080	1287	5381	1983	2105	8381	21902	1074	1196	6206	2719	3333	5377	11861	22632	8962	6037	8876
2030	5441	10901	8169	2113	1906	1283	5170	1985	2122	8351	21563	1027	1172	6152	2616	3180	4923	11458	20700	8538	5753	8919
2031	5443	10869	8157	1999	1733	1278	4959	1986	2140	8360	21559	989	1146	6125	2520	3101	4507	11275	19298	8341	5806	8972
2032	5481	10920	8214	1926	1620	1274	4824	1991	2155	8407	21711	932	1128	6131	2431	3091	4126	11299	18397	8356	5851	9035
2033	5517	10969	8268	1893	1567	1269	4763	1998	2168	8451	21852	878	1115	6140	2353	3080	3777	11323	18517	8370	5893	9094
2034	5553	11018	8322	1902	1573	1265	4777	2009	2180	8468	21994	828	1102	5990	2289	3070	3458	11347	18638	8384	5935	9154
2035	5589	11015	8377	1910	1580	1260	4740	2019	2191	8447	22087	780	1088	5787	2276	3063	3166	11372	17848	8398	5978	9214
2036	5626	11006	8432	1919	1588	1256	4697	2030	2203	8427	22174	761	1075	5568	2217	3060	2898	11397	17055	8413	6021	9275
2037	5664	10992	8489	1927	1595	1252	4649	2041	2215	8436	22258	742	1062	5468	2179	3060	2895	11422	16257	8428	6065	9337
2038	5702	11028	8546	1936	1602	1247	4648	2053	2227	8482	22392	728	1050	5392	2141	3062	2893	11448	16366	8443	6110	9400
2039	5741	11028	8604	1945	1610	1243	4613	2064	2239	8529	22492	719	1037	5305	2129	3064	2891	11474	16477	8458	6156	9463
2040	5777	11028	8658	1953	1616	1239	4580	2074	2251	8573	22587	713	1025	5244	2123	3067	2891	11499	16582	8473	6199	9524
2041	5812	11026	8710	1961	1623	1234	4547	2084	2261	8613	22677	705	1013	5194	2115	3071	2891	11523	16680	8489	6239	9580
2042	5844	11059	8758	1968	1628	1230	4552	2093	2271	8650	22797	698	1001	5152	2108	3076	2892	11546	16773	8504	6277	9633
2043	5876	11096	8807	1974	1634	1226	4558	2102	2281	8687	22921	690	989	5117	2103	3080	2892	11569	16866	8520	6315	9687
2044	5909	11133	8856	1981	1639	1221	4566	2111	2291	8699	23047	683	977	5088	2100	3085	2893	11593	16960	8536	6353	9741
2045	5942	11172	8905	1988	1645	1217	4575	2120	2301	8712	23176	677	965	5064	2097	3089	2893	11616	17055	8552	6392	9795
2046	5975	11212	8955	1995	1651	1213	4584	2130	2311	8724	23306	671	954	5044	2095	3094	2894	11640	17150	8122	6432	9850
2047	6009	11253	9006	2002	1656	1208	4593	2139	2321	8763	23438	665	942	5027	2091	3098	2894	11664	17247	7692	6471	9906
2048	6043	11293	9057	2009	1662	1204	4602	2148	2331	8801	23570	659	931	5010	2084	3103	2895	11688	17345	7260	6493	9962
2049	6078	11334	9108	2016	1668	1200	4612	2158	2341	8840	23705	652	920	4986	2072	3107	2895	11581	17444	7125	6491	10019
2050	6111	11374	9159	2023	1674	1196	4621	2167	2351	8878	23835	647	909	4972	2065	3112	2896	11473	17540	6989	6488	10074
2051	6144	11411	9208	2029	1679	1196	4629	2176	2361	8893	23963	643	898	4951	2058	3117	2897	11305	17634	6853	6501	10128
2052	6176	11447	9255	2035	1684	1187	4636	2185	2370	8906	24087	643	887	4945	2057	3123	2898	11267	17725	6866	6538	10180
2053	6208	11480	9303	2041	1689	1187	4640	2193	2380	8919	24209	640	877	4923	2052	3128	2899	11194	17817	6880	6575	10233
2054	6240	11513	9352	2048	1694	1179	4645	2202	2389	8954	24332	640	866	4918	2052	3134	2901	11181	17910	6894	6612	10287
2055	6256	11529	9376	2051	1697	1179	4646	2206	2394	8972	24393	639	856	4907	2050	3137	2901	11157	17956	6900	6631	10313

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 (16hrs)	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
2024	6037	12263	9321	2455	2426	1310	5802	1980	2071	8916	24366	1463	1336	6769	3351	4710	8362	15547	29667	12979	8067	8984
2025	5896	11984	9060	2455	2426	1305	5802	1980	2071	8784	23770	1373	1314	6648	3208	4699	7894	14709	28183	12041	7622	8924
2026	5761	11709	8807	2455	2426	1301	5802	1980	2071	8654	23196	1288	1292	6534	3069	4688	7442	13909	26749	11157	7203	8869
2027	5634	11442	8571	2416	2368	1296	5730	1979	2075	8531	22659	1210	1271	6431	2936	4679	7017	13162	25388	10348	6784	8823
2028	5525	11194	8364	2338	2250	1292	5587	1977	2083	8423	22194	1140	1250	6341	2814	4676	6618	12469	23983	9611	6390	8801
2029	5425	10959	8172	2220	2074	1287	5372	1973	2094	8326	21768	1075	1229	6258	2700	4675	6243	11817	22550	8929	6019	8792
2030	5372	10822	8065	2102	1897	1283	5157	1970	2106	8276	21537	1030	1208	6191	2592	4679	6004	11403	20559	8497	5736	8806
2031	5360	10774	8034	1985	1721	1278	4942	1966	2118	8269	21480	1005	1190	6135	2492	4686	5890	11209	18438	8293	5762	8836
2032	5388	10812	8074	1908	1605	1274	4802	1966	2128	8303	21589	998	1177	6108	2400	4694	5896	11225	16799	8302	5787	8881
2033	5413	10850	8113	1873	1550	1269	4739	1970	2138	8336	21693	985	1165	6094	2320	4702	5902	11240	16175	8309	5812	8924
2034	5440	10888	8153	1880	1556	1265	4750	1978	2147	8369	21798	955	1156	6100	2255	4709	5867	11256	16228	8317	5830	8968
2035	5467	10920	8193	1887	1561	1260	4756	1987	2156	8404	21899	926	1145	6103	2239	4716	5832	11272	16228	8325	5829	9012
2036	5494	10952	8234	1893	1567	1256	4761	1995	2164	8438	22000	912	1139	6121	2207	4724	5798	11287	16201	8333	5818	9057
2037	5522	10986	8275	1900	1572	1252	4767	2003	2173	8474	22104	897	1132	6013	2204	4632	5713	11303	16148	8341	5821	9102
2038	5550	11026	8317	1907	1578	1247	4780	2012	2183	8509	22216	886	1125	5964	2190	4518	5608	11319	16176	8349	5843	9148
2039	5578	11045	8359	1914	1584	1243	4772	2020	2192	8546	22307	877	1118	5928	2168	4382	5408	11336	16220	8357	5876	9195
2040	5604	11047	8398	1920	1589	1239	4749	2028	2200	8578	22377	868	1111	5886	2144	4334	5288	11351	16273	8365	5906	9238
2041	5628	11044	8434	1926	1593	1234	4724	2035	2208	8607	22437	860	1106	5857	2129	4283	5165	11365	16320	8373	5933	9277
2042	5649	11059	8466	1930	1597	1230	4719	2041	2214	8632	22510	852	1103	5833	2120	4233	5118	11377	16371	8382	5958	9312
2043	5671	11086	8499	1935	1601	1226	4726	2047	2221	8658	22596	843	1100	5779	2111	4177	5065	11390	16433	8390	5983	9348
2044	5692	11076	8531	1939	1605	1221	4697	2053	2228	8684	22645	835	1097	5702	2105	4122	5013	11403	16496	8378	5947	9384
2045	5714	11064	8564	1944	1609	1217	4665	2059	2234	8710	22693	827	1094	5606	2099	4069	4964	11416	16560	8367	5904	9420
2046	5736	11052	8597	1949	1613	1213	4634	2065	2241	8736	22741	820	1092	5540	2095	4016	4913	11429	16624	8356	5857	9456
2047	5759	11078	8630	1954	1617	1208	4639	2072	2248	8762	22827	812	1090	5495	2092	3971	4871	11442	16688	8364	5866	9493
2048	5781	11106	8664	1958	1621	1204	4646	2078	2255	8789	22916	805	1088	5465	2089	3933	4835	11455	16753	8373	5877	9530
2049	5803	11134	8698	1963	1624	1200	4654	2084	2262	8815	23005	797	1084	5437	2088	3903	4806	11469	16818	8381	5857	9567
2050	5825	11160	8730	1968	1628	1196	4660	2090	2268	8840	23090	790	1073	5405	2087	3888	4791	11481	16880	8390	5840	9602
2051	5845	11184	8761	1972	1632	1196	4665	2096	2274	8864	23172	784	1063	5385	2085	3875	4777	11494	16940	8398	5819	9636
2052	5865	11206	8790	1976	1635	1187	4669	2101	2280	8886	23249	780	1052	5370	2085	3870	4771	11505	16997	8407	5832	9668
2053	5885	11218	8819	1979	1638	1187	4664	2107	2286	8908	23316	774	1042	5369	2084	3856	4756	11517	17053	8415	5836	9701
2054	5904	11230	8849	1983	1641	1179	4658	2112	2291	8931	23384	770	1031	5327	2085	3851	4750	11529	17111	8424	5849	9733
2055	5914	11230	8864	1985	1643	1179	4650	2114	2294	8942	23413	765	1021	5294	2084	3844	4742	11535	17139	8428	5851	9750

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
2024	910	910	910	326	326	326	584	584	584	608	608	608	314	314	314	294	294	294
2025	860	806	753	321	300	278	539	507	475	580	543	507	309	288	268	271	255	239
2026	812	721	629	316	280	244	497	441	385	553	491	428	304	269	235	250	222	194
2027	770	651	532	312	265	218	458	386	314	530	449	368	300	255	210	230	194	158
2028	722	588	455	309	254	198	413	335	256	504	412	319	297	244	191	207	168	129
2029	713	553	393	307	245	184	407	308	209	499	390	281	294	235	176	204	155	105
2030	691	544	346	298	239	175	393	305	171	484	383	254	287	230	168	197	153	86
2031	669	534	335	290	234	166	379	301	168	468	375	244	278	224	160	190	151	84
2032	659	525	323	282	228	158	377	296	164	460	368	235	270	219	152	189	149	82
2033	648	515	311	274	223	151	375	292	160	450	360	225	262	214	145	188	147	80
2034	634	506	301	266	218	143	368	288	157	440	353	217	255	209	138	185	145	79
2035	620	497	292	258	213	137	362	284	156	429	346	209	247	204	131	181	143	78
2036	605	488	284	251	208	130	355	280	154	418	339	202	240	199	125	178	141	77
2037	591	479	277	244	203	124	348	277	154	407	333	195	233	194	119	174	139	77
2038	578	471	271	237	198	118	341	273	153	398	326	189	227	190	113	171	137	77
2039	565	463	265	229	193	112	335	269	153	387	320	184	220	185	107	168	135	76
2040	557	457	264	227	192	112	331	266	153	382	317	183	217	184	107	165	133	76
2041	553	452	264	224	190	111	329	262	152	379	313	183	214	182	107	164	131	76
2042	549	447	264	222	189	111	326	258	152	376	310	183	213	181	107	163	129	76
2043	541	443	263	220	188	111	320	254	152	371	308	183	211	180	106	160	127	76
2044	535	438	263	219	188	111	316	251	152	368	305	182	210	180	106	158	125	76
2045	531	434	263	218	187	111	313	247	152	365	303	182	209	179	106	156	123	76
2046	528	430	263	217	187	111	310	243	152	363	300	183	208	179	106	155	122	76
2047	525	426	264	216	186	111	309	240	152	361	298	183	207	178	106	154	120	76
2048	523	422	264	216	186	111	307	236	153	360	296	183	206	178	106	153	118	76
2049	521	419	264	215	186	111	305	233	153	359	294	183	206	178	107	153	116	76
2050	519	415	264	215	186	111	304	230	153	358	292	183	206	178	107	152	115	76
2051	520	412	265	215	186	112	305	226	153	358	291	184	206	178	107	152	113	77
2052	517	408	265	214	185	112	303	223	153	356	289	184	205	177	107	151	111	77
2053	518	405	266	215	186	112	303	220	154	357	287	184	205	178	107	152	110	77
2054	516	402	266	214	185	112	302	216	154	356	285	184	205	177	107	151	108	77
2055	516	413	267	214	185	112	302	228	155	356	291	185	205	177	107	151	114	77

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
2024	423	423	423	274	274	274	149	149	149	344	344	344	266	266	266	78	78	78
2025	406	380	355	269	251	234	137	129	121	333	311	290	261	244	227	72	68	63
2026	391	346	302	264	234	204	126	112	98	322	286	249	256	227	198	66	59	51
2027	378	320	263	261	222	183	116	98	80	314	267	219	253	215	177	61	51	42
2028	363	297	231	258	212	166	105	85	65	305	250	195	251	206	161	55	44	34
2029	360	283	207	256	205	154	103	78	53	302	239	177	248	199	149	54	41	28
2030	349	277	190	249	200	146	100	77	43	294	234	164	242	194	142	52	40	23
2031	338	271	182	242	195	139	96	76	43	285	229	157	235	189	135	50	40	22
2032	331	266	174	235	191	132	96	75	42	278	224	150	228	185	128	50	39	22
2033	323	260	166	228	186	126	95	74	41	271	219	143	221	180	122	50	39	21
2034	315	254	159	222	181	120	93	73	40	263	214	137	214	176	116	49	38	21
2035	306	249	153	215	177	114	91	72	39	256	209	131	208	171	110	48	38	21
2036	298	244	147	209	173	108	90	71	39	249	204	125	202	167	105	47	37	20
2037	290	239	142	203	169	103	88	70	39	242	200	120	196	163	100	46	36	20
2038	283	234	137	197	165	98	86	69	39	235	195	115	190	159	95	45	36	20
2039	275	229	132	191	161	93	85	68	39	228	191	110	184	155	90	44	35	20
2040	271	226	131	188	159	93	83	67	38	225	189	110	182	154	90	43	35	20
2041	269	224	131	186	158	93	83	66	38	223	187	110	180	153	90	43	34	20
2042	267	222	131	184	157	92	82	65	38	221	186	109	178	152	89	43	34	20
2043	264	220	131	183	156	92	81	64	38	219	185	109	177	151	89	42	33	20
2044	261	219	131	182	156	92	80	63	38	217	184	109	176	151	89	41	33	20
2045	260	217	131	181	155	92	79	62	38	216	183	109	175	150	89	41	32	20
2046	258	216	131	180	155	92	78	61	38	215	182	109	174	150	89	41	32	20
2047	257	215	131	179	155	92	78	60	38	214	181	109	173	149	89	40	31	20
2048	256	214	131	179	154	92	77	60	38	213	180	109	173	149	89	40	31	20
2049	255	213	131	179	154	92	77	59	39	213	179	109	173	149	89	40	31	20
2050	255	212	131	178	154	92	77	58	38	212	179	109	172	149	89	40	30	20
2051	255	211	131	178	154	93	77	57	39	212	179	110	172	149	90	40	30	20
2052	254	210	131	178	154	93	76	56	39	211	178	110	172	149	90	40	29	20
2053	254	209	132	178	154	93	76	55	39	212	178	110	172	149	90	40	29	20
2054	253	208	132	177	154	93	76	54	39	211	177	110	171	148	90	40	28	20
2055	253	211	132	177	154	93	76	57	39	211	178	110	171	149	90	40	30	20

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
2024	318	318	318	266	266	266	52	52	52	292	292	292	266	266	266	26	26	26
2025	309	289	269	261	244	227	48	45	42	285	266	248	261	244	227	24	23	21
2026	300	266	232	256	227	198	44	39	34	278	247	215	256	227	198	22	20	17
2027	294	249	205	253	215	177	41	34	28	274	232	191	253	215	177	20	17	14
2028	287	235	184	251	206	161	37	30	23	269	220	172	251	206	161	18	15	11
2029	284	226	167	248	199	149	36	27	19	266	212	158	248	199	149	18	14	9
2030	276	221	157	242	194	142	35	27	15	259	207	149	242	194	142	17	13	8
2031	268	216	150	235	189	135	33	27	15	251	202	142	235	189	135	17	13	7
2032	261	211	143	228	185	128	33	26	15	244	198	135	228	185	128	17	13	7
2033	254	206	136	221	180	122	33	26	14	238	193	129	221	180	122	17	13	7
2034	247	201	130	214	176	116	32	25	14	231	188	123	214	176	116	16	13	7
2035	240	196	124	208	171	110	32	25	14	224	184	117	208	171	110	16	13	7
2036	233	192	118	202	167	105	31	25	14	218	180	112	202	167	105	16	12	7
2037	227	188	113	196	163	100	31	24	14	211	175	106	196	163	100	15	12	7
2038	220	183	108	190	159	95	30	24	13	205	171	101	190	159	95	15	12	7
2039	214	179	104	184	155	90	29	24	13	199	167	97	184	155	90	15	12	7
2040	211	177	103	182	154	90	29	23	13	196	166	96	182	154	90	14	12	7
2041	209	176	103	180	153	90	29	23	13	194	164	96	180	153	90	14	11	7
2042	207	175	103	178	152	89	29	23	13	193	163	96	178	152	89	14	11	7
2043	205	174	103	177	151	89	28	22	13	191	162	96	177	151	89	14	11	7
2044	203	173	103	176	151	89	28	22	13	190	162	96	176	151	89	14	11	7
2045	202	172	103	175	150	89	27	22	13	189	161	96	175	150	89	14	11	7
2046	201	171	103	174	150	89	27	21	13	188	160	96	174	150	89	14	11	7
2047	200	170	103	173	149	89	27	21	13	187	160	96	173	149	89	14	10	7
2048	200	170	103	173	149	89	27	21	13	186	159	96	173	149	89	13	10	7
2049	199	169	103	173	149	89	27	20	13	186	159	96	173	149	89	13	10	7
2050	199	169	103	172	149	89	27	20	13	185	159	96	172	149	89	13	10	7
2051	199	169	103	172	149	90	27	20	13	186	159	96	172	149	90	13	10	7
2052	198	168	103	172	149	90	26	19	13	185	158	96	172	149	90	13	10	7
2053	198	168	103	172	149	90	27	19	13	185	158	96	172	149	90	13	10	7
2054	198	167	103	171	148	90	26	19	13	185	158	97	171	148	90	13	9	7
2055	198	169	104	171	149	90	26	20	14	185	159	97	171	149	90	13	10	7

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	10hrs	24hrs	48hrs	10hrs	24hrs	48hrs	10hrs	24hrs	48hrs	10hrs	24hrs	48hrs	10hrs	24hrs	48hrs
2024	7677	6496	7822	7677	6496	7822	7677	6496	7822	768	271	163	768	271	163	768	271	163
2025	7530	6372	7673	7530	6372	7673	7530	6372	7673	753	266	160	753	266	160	753	266	160
2026	7387	6251	7527	7387	6251	7527	7387	6251	7527	739	260	157	739	260	157	739	260	157
2027	7244	6130	7381	7244	6130	7381	7244	6130	7381	724	255	154	724	255	154	724	255	154
2028	7094	6003	7228	7094	6003	7228	7094	6003	7228	709	250	151	709	250	151	709	250	151
2029	6944	5876	7075	6944	5876	7075	6944	5876	7075	694	245	147	694	245	147	694	245	147
2030	6794	5749	6922	6794	5749	6922	6794	5749	6922	679	240	144	679	240	144	679	240	144
2031	6833	5782	6962	6839	5787	6968	6863	5808	6968	683	241	145	684	241	145	686	242	145
2032	6862	5807	6992	6874	5817	7004	6916	5852	7004	686	242	146	687	242	146	692	244	146
2033	6893	5833	7024	6911	5848	7042	6969	5898	7042	689	243	146	691	244	147	697	246	147
2034	6924	5859	7055	6949	5880	7080	7028	5947	7080	692	244	147	695	245	148	703	248	148
2035	6954	5885	7086	6987	5912	7119	7087	5997	7119	695	245	148	699	246	148	709	250	148
2036	6985	5911	7117	7025	5945	7158	7147	6048	7158	698	246	148	703	248	149	715	252	149
2037	7016	5937	7149	7064	5978	7198	7208	6100	7198	702	247	149	706	249	150	721	254	150
2038	7047	5964	7181	7103	6011	7238	7270	6152	7238	705	248	150	710	250	151	727	256	151
2039	7079	5991	7213	7143	6045	7278	7332	6205	7278	708	250	150	714	252	152	733	259	152
2040	7111	6018	7246	7183	6079	7319	7396	6258	7319	711	251	151	718	253	152	740	261	152
2041	7134	6037	7269	7214	6105	7350	7450	6304	7350	713	252	151	721	254	153	745	263	153
2042	7157	6056	7292	7245	6131	7382	7504	6350	7382	716	252	152	724	255	154	750	265	154
2043	7180	6076	7316	7276	6157	7414	7559	6397	7414	718	253	152	728	257	154	756	267	154
2044	7203	6095	7339	7307	6184	7446	7615	6444	7446	720	254	153	731	258	155	761	268	155
2045	7226	6115	7363	7339	6210	7478	7671	6491	7478	723	255	153	734	259	156	767	270	156
2046	7250	6135	7387	7371	6237	7510	7727	6539	7510	725	256	154	737	260	156	773	272	156
2047	7273	6155	7411	7403	6264	7543	7785	6587	7543	727	256	154	740	261	157	778	274	157
2048	7297	6175	7435	7435	6291	7575	7842	6636	7575	730	257	155	743	262	158	784	277	158
2049	7320	6195	7459	7467	6319	7608	7900	6685	7608	732	258	155	747	263	159	790	279	159
2050	7344	6215	7483	7499	6346	7641	7959	6735	7641	734	259	156	750	264	159	796	281	159
2051	7364	6231	7503	7528	6370	7670	8014	6781	7670	736	260	156	753	265	160	801	283	160
2052	7383	6248	7523	7556	6394	7699	8069	6828	7699	738	260	157	756	266	160	807	285	160
2053	7403	6265	7543	7585	6418	7728	8124	6875	7728	740	261	157	758	267	161	812	286	161
2054	7423	6281	7563	7613	6442	7757	8180	6922	7757	742	262	158	761	268	162	818	288	162
2055	7443	6298	7584	7642	6467	7787	8237	6970	7787	744	262	158	764	269	162	824	290	162

Apx Table B.8 Storage current cost data by source, total cost basis

	$/kWh									$/kW								
	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	Aurecon 2023-24	Aurecon 2024-25	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	Aurecon 2023-24	Aurecon 2024-25	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO
Battery (1hr)	1195	958	906	1024	1048	910	-	-	-	1195	958	906	1024	1048	910	-	-	-
Battery (2hrs)	752	642	603	741	758	608	-	-	-	1504	1284	1205	1481	1517	1216	-	-	-
Battery (4hrs)	594	510	476	601	614	423	-	-	-	2375	2041	1903	2406	2457	1691	-	-	-
Battery (8hrs)	539	450	418	534	538	344	-	-	-	4309	3601	3340	4273	4308	2748	-	-	-
Battery (12hrs)	-	-	-	-	496	885	-	-	-	-	-	-	-	11910	10617	-	-	-
Battery (24hrs)	-	-	-	-	443	751	-	-	-	-	-	-	-	21272	18032	-	-	-
PHES (10hrs)	-	-	-	-	-	768	-	-	-	-	-	-	-	-	7677	-	-	-
A-CAES (12hrs)	-	-	-	386	-	-	-	-	-	-	-	-	4626	-	-	-	-	-
PHES (12hrs)	-	-	-	-	-	-	213	226	240	-	-	-	-	-	-	2561	3167	3167
A-CAES (24hrs)	-	-	-	-	305	316	-	-	-	-	-	-	-	7326	7585	-	-	-
PHES (24hrs)	-	-	-	-	242	271	158	147	157	-	-	-	-	6030	6496	3796	4132	4140
PHES (48hrs)	-	-	-	-	142	163	89	111	118	-	-	-	-	7078	7822	4252	6208	6219

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1350/kWh (Aurecon, 2025).

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
2024	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
Gas with CCS	25	2.0	44%	22.5	8.0	8.7	5802	13.5	89%	5802	19.8	53%
Gas combined cycle	25	2.0	51%	15.0	4.1	0.0	2455	13.5	89%	2455	19.8	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2426	13.5	20%	2426	19.8	20%
Gas open cycle (large)	25	1.5	33%	14.1	8.1	0.0	1310	13.5	20%	1310	19.8	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	1980	13.5	20%	1980	19.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2071	40.7	20%	2071	41.9	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.3	12263	3.1	89%	12263	4.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	6037	3.1	89%	6037	4.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	9321	0.6	89%	9321	0.7	53%
Nuclear SMR	30	4.4	33%	200	5.3	0.0	29667	1.1	89%	29667	1.3	53%
Nuclear large-scale	30	5.8	33%	200	5.3	0.0	8984	1.1	89%	8984	1.3	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	8278	0.0	71%	8179	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	1463	0.0	32%	1463	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	3351	0.0	48%	3351	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	4710	0.0	52%	4710	0.0	40%
2030												
Gas with CCS	25	2.0	44%	22.5	8.0	8.7	4822	9.4	89%	5170	16.5	53%
Gas combined cycle	25	2.0	51%	15.0	4.1	0.0	1917	9.4	89%	2113	16.5	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1630	9.4	20%	1906	16.5	20%
Gas open cycle (large)	25	1.5	33%	14.1	8.1	0.0	1630	9.4	20%	1906	16.5	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	1945	9.4	20%	1985	16.5	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2122	37.7	20%	2102	40.9	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.3	10696	3.1	89%	10901	5.5	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5299	3.1	89%	5441	5.5	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7942	0.7	89%	8169	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	20700	0.8	89%	23925	1.0	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	8736	0.8	89%	8919	1.0	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	8276	0.0	71%	8614	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	1027	0.0	32%	1123	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	2616	0.0	48%	2646	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	3180	0.0	54%	4654	0.0	40%

2040												
Gas with CCS	25	2.0	44%	22.5	8.0	8.7	4580	9.2	89%	4796	16.1	53%
Gas combined cycle	25	2.0	51%	15.0	4.1	0.0	1904	9.2	89%	1953	16.1	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1576	9.2	20%	1616	16.1	20%
Gas open cycle (large)	25	1.5	33%	14.1	8.1	0.0	1576	9.2	20%	1616	16.1	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2006	9.2	20%	2074	16.1	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2251	31.0	20%	2176	36.6	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.3	11020	2.9	89%	11028	4.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5500	2.9	89%	5777	4.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8275	0.7	89%	8658	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	16582	0.5	89%	19646	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9102	0.5	89%	9524	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	7055	0.0	71%	8600	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	713	0.0	32%	1024	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	2123	0.0	48%	2163	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	3067	0.0	57%	4690	0.0	40%
2050												
Gas with CCS	25	2.0	44%	22.5	8.0	8.7	4621	9.2	89%	4653	16.1	53%
Gas combined cycle	25	2.0	51%	15.0	4.1	0.0	1940	9.2	89%	2023	16.1	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1606	9.2	20%	1674	16.1	20%
Gas open cycle (large)	25	1.5	33%	14.1	8.1	0.0	1606	9.2	20%	1674	16.1	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2052	9.2	20%	2167	16.1	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2351	28.5	20%	2227	35.8	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.3	11026	2.9	89%	11374	4.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5635	2.9	89%	6111	4.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8517	0.7	89%	9159	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	17176	0.5	89%	17540	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9368	0.5	89%	10074	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	6688	0.0	71%	7709	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	647	0.0	32%	934	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	2065	0.0	48%	2108	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	3112	0.0	61%	4724	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%.

Apx Table B.10 Electricity generation technology LCOE projections data, 2024-25 $/MWh

Category	Assumption	Technology	2024		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas open cycle (small)	293	356	209	295	204	275	205	278
		Gas open cycle (large)	233	301	206	298	201	278	203	281
		Gas reciprocating	249	304	211	276	212	277	215	281
		H_2 reciprocating	586	599	554	589	485	544	462	538
Flexible load, high emission		Black coal	111	178	103	174	103	173	105	179
		Brown coal	148	240	129	214	134	225	138	237
		Gas	133	199	97	169	95	163	96	164
Flexible load, low emission		Black coal with CCS	217	342	200	326	201	317	201	324
		Gas with CCS	204	307	158	266	153	255	153	252
		Nuclear SMR	456	757	328	619	268	516	276	467
		Nuclear large-scale	180	293	173	288	175	300	179	314
		Solar thermal	140	175	140	183	122	182	117	166
Variable	Standalone	Solar photovoltaic	48	80	35	63	25	59	24	54
		Wind onshore	80	132	64	107	53	89	52	87
		Wind offshore (fixed)	147	191	108	189	100	191	94	192
Variable with integration costs	Wind & solar PV combined	60% VRE share	120	168	76	116				
		70% VRE share	116	165	80	119				
		80% VRE share	118	168	83	124				
		90% VRE share	125	176	90	131				

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
2024	2706	2840	2706	2840	2706	2840
2025	2626	2756	2482	2605	2513	2638
2026	2548	2675	2276	2389	2333	2449
2027	2473	2596	2087	2190	2167	2274
2028	2400	2519	1914	2009	2012	2112
2029	2329	2444	1755	1842	1868	1961
2030	2260	2372	1609	1689	1735	1821
2031	2193	2302	1476	1549	1611	1691
2032	2128	2234	1353	1421	1496	1570
2033	2065	2168	1241	1303	1389	1458
2034	2004	2103	1138	1195	1290	1354
2035	1945	2041	1063	1116	1221	1281
2036	1887	1981	1031	1082	1202	1262
2037	1831	1922	944	991	1207	1267
2038	1777	1865	921	966	1209	1269
2039	1724	1810	913	958	1143	1199
2040	1673	1757	903	948	1116	1171
2041	1680	1763	888	932	1110	1165
2042	1663	1746	862	905	1096	1150
2043	1658	1741	844	886	1074	1127
2044	1653	1736	830	871	1069	1122
2045	1644	1726	814	855	1055	1108
2046	1638	1720	790	829	1052	1104
2047	1592	1671	764	802	1043	1095
2048	1551	1628	745	782	1043	1095
2049	1533	1609	731	768	1039	1091
2050	1514	1589	721	756	1034	1085
2051	1519	1595	725	761	1038	1089
2052	1515	1590	716	752	1034	1086
2053	1521	1596	721	756	1038	1090
2054	1520	1595	706	741	1038	1090
2055	1525	1601	710	746	1042	1094

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	8.5	
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	20	10	10	
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	9.8	4.8	2.8
	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 Aurecon (2025) 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 6% in lower resource regions, and 7% in higher resource regions, up to a maximum of 55%, in capacity factor. 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). Demand data is provided for the Announced Pledges scenario, which is used in our *Global NZE post 2050* scenario. The demand data from the Stated Policies (STEPS) 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 to Global NZE by 2050 scenario 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	132
Global NZE post 2050	274
Global NZE by 2050	366

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[40]. 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 under the Current policies scenario, 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

[40] 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
EUW	21	2	23	22	NA
FSU	25	NA	NA	NA	NA
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 (Aurecon, 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 2024-25 report has adopted the project cost for the Darlington nuclear SMR project as its primary source 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[41].

[41] 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.

The data on technology project costs from Aurecon 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 Aurecon (2025) points to cost pressures easing. Commodity price reporting also indicates cost pressures have eased in raw material markets such as lithium.

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 who have market power 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?

Aurecon (2025) 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. Aurecon (2025) also provide factors to convert the general costs to specific locations in the National Electricity Market (NEM). In that context, GenCost data is based on transporting and installing equipment not more than 200km from Melbourne but can be converted to other 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 Aurecon (2025) 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%[42]. 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

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[42] 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 previous 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?

Aurecon'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. Aurecon (2025) 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.*
>
> *The costs for project and land procurement are highly variable and project specific. For the purposes of this report, and outlining development and land costs for a general project within each technology category, a simplified approach must be taken. Land and development costs are calculated as a percentage of capital equipment, and as a result, absolute values associated with these costs will change for those technologies whose equipment capital costs have changed. These costs do not include any applicable fees, such as fees paid to councils, local authorities, electrical connection fee etc. An indicative estimate has been determined based on a percentage of CAPEX estimate for each technology from recent projects, and experience with development processes.*"

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[43]. 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 do other studies find higher costs than GenCost for integrating variable renewables in the electricity system?

Stakeholders have forwarded research which they believe arrives at a different result to GenCost on the cost of integrating renewables and requested that GenCost adopt their methodology or justify why GenCost arrives at different results. In reviewing these studies, which in some cases appear in peer reviewed journals, it became evident that there were several common limiting factors which explain why they find higher variable renewable integration costs. These include:

- Requiring that the variable renewable share be 100% or that all electricity sector emissions be completely eliminated. There is no such requirement in Australia under our net zero emission policy. Furthermore, going to 100% variable renewables would require the non-sensical step of shutting down existing non-variable renewable generation such as the existing Snowy hydro scheme and biomass generation. This approach denies renewables access to peaking plant such

[43] 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

as open cycle gas turbines which are the most efficient technology for managing long periods of low renewable production but only result in residual emissions of a few percent compared to current electricity sector emissions.

- Limiting the types of storage technologies available to the system (e.g., only allowing batteries to participate rather than all storage options).
- Limiting the duration of storage technologies available to the system (e.g., only including one possible storage duration).
- Limiting access of the system to realistically diverse renewable profiles (e.g., using just one profile for solar and one for wind).
- Imposing inertia and system security constraints but only allowing a limited range of technologies to supply these services.
- Ignoring the availability of existing generation capacity in the system.

To be clear, none of the studies reviewed included all of these limiting factors but they all included at least one. The following table matches the common limiting factors to the published work. The table focuses on Idel (2022) because it was forwarded by more than one stakeholder and on Cross et al (2023) of Blueprint Institute because it is the most recent example specific to Australia. In September 2024, the DOE (2024) republished research by Baik et al (2021) which some stakeholders also brought to the attention of GenCost and so we include this as well.

It is our expectation that were these limiting factors not imposed, the results of their analysis of the cost of integrating variable renewables would be lower and likely similar to GenCost. For example, when Idel (2022) removes the requirement for a 100% variable renewable share, decreasing it to 95%, system cost estimates halve in the German and Texas case studies. In the case of Texas, the cost was $97/MWh which is inside the range of costs estimated by GenCost despite the higher VRE share and limits on storage technologies.

Like Idel (2022), the Baik et al (2021) research published in DOE (2024) initially sets up a scenario where solar and wind can only access battery storage to meet demand. No gas peaking plants are allowed creating an artificially high cost scenario. Baik et al (2021) then only allows nuclear, CCS, hydrogen or biofuels as additional firming options and finds the system cheaper under all of those combinations. The problem with this approach is that the initial system may have been cheaper had the gas peaking plant been allowed. Consequently, it is difficult to ascertain if adding any of the other resources – nuclear, CCS, hydrogen and biofuels would have reduced costs further. All of these other options for firming are more expensive than peaking gas. Baik et al (2021) also makes the error of including only one type of storage technology – batteries.

Gilmore et al (2023) published research which provided an estimate of the impact on the cost of electricity from a high VRE system of only including batteries in the storage options. They found a battery-only scenario increased costs by 35% compared to a system that also allowed pumped hydro storage. Gilmore et al (2023) also finds costs within the range estimated by GenCost.

One stakeholder submission argued that it is necessary to assume that renewables can provide baseload power sources like coal and gas. To be clear, GenCost is not targeting the production of baseload[44] power as the point of comparison. Australia's electricity system load is not flat. The cost of integrated VRE presented in GenCost is for delivery of reliable power to meet the system load.

[44] It is also worth noting that baseload generation which is taken to mean almost constant production except for periods of maintenance by this stakeholder, is something that happens at a very small minority of plants in Australia with the average historical capacity factor of coal plants being around 60%.

Apx Table D.1 Comparison of limiting factors applied in academic literature to the calculation of variable renewable integration costs and the GenCost approach

Limiting factor	Idel (2022)	Cross et al (2023) of Blueprint Institute	Baik et al (2021) reported in DOE (2024)	GenCost
Requiring 100% variable renewable share	The main analysis upon which conclusions are based assumes 100% VRE. A 95% VRE sensitivity that was included results in very different outcomes.	Focus on 90% and 99% calculated on the basis of VRE plus existing renewable share combined (VRE share not separately provided)	100% renewables with batteries or lesser shares of renewables with either nuclear, CCS, hydrogen or biofuel. Gas peaking plant disallowed	Considers 60%, 70%, 80% and 90% VRE shares
Limiting storage technologies	Only batteries are included	Only batteries are included	Only batteries are included	Lithium batteries, flow batteries, compressed air and pumped hydro storage included
Limiting the duration of storage technologies	Only 3-hour batteries are allowed	Only 4-hour batteries are allowed	Multiple battery durations allowed	lithium-ion batteries at 1, 2, 4, or 8 hours; flow batteries at 4, 8, 12 or 24; compressed air at 8, 12, 24 or 48; and pumped hydro at 6, 8 12, 24 or 48 hours. The 168-hour Snowy 2.0 pumped hydro project is also included
Limiting diversity of renewable profiles	Single profile each for solar and wind	Single profile for solar and wind per state	Range of Californian profiles	Profiles for a wide range of Australian Renewable Energy Zones included
Limiting technologies that can meet system security requirements	NA	Synchronous generators only, but pumped hydro excluded	NA	Synchronous condensers, grid forming batteries and synchronous generators all available to be deployed

However, CSIRO acknowledges that there will be circumstances where flat or baseload power is required such as in direct contracts to grid connected industrial facilities such as aluminium smelters or the industrial off-grid sector (e.g., mining). In these circumstances, it is likely that VRE will be more costly than it is when undertaking the task of supplying general residential and commercial customer demand. There is published research available on this topic based on CSIRO modelling (ClimateWorks and ClimateKic, 2023). The challenge and opportunity for Australia's industrial sector is whether it can access low emission industrial electricity supply at lower costs than our international competitors. This will depend not just on the generation technologies selected but on other factors such as relative labour and installation costs (Graham and Havas, 2023).

D.4.8 Why are integration costs not increasing with VRE share in 2024 but increase in the 2030 results?

Stakeholders requested that all of the currently committed transmission and storage projects in Australia be included in any assessment of current VRE integration costs. This request arises from some stakeholder views that the costs of integrating VRE may be high and none of the costs already committed should be left out when undertaking the assessment, regardless of the VRE share being targeted.

However, not all of those committed transmission and storage projects are strictly necessary to reach lower VRE shares at current demand. They are being built in anticipation of high renewable electricity supply and system demand. Consequently, the integration costs from these projects are high at low VRE shares because the investment is more than is necessary for a moderate increase in VRE share to meet 2024 demand. However, as we increase the VRE share these new investments are better utilised, decreasing the calculated costs of integration.

The same problem does not arise in 2030 because, following the same methodology we apply in 2024, existing capacity is not included in the LCOE, only committed projects and anything additional needed (as assessed by the modelling framework). Without the forced inclusion of a block of committed project expenditure in the 2024 calculation, the 2030 result conforms to expectations of higher integration costs as the VRE share increases.

In reality, the calculated 2024 VRE LCOE costs with integration will not be experienced by the electricity sector. Variable renewable generation will be deployed progressively (rather than in a single year) and likely at lower costs as cost reductions resume following recovery from recent global inflationary pressures. Electricity demand is expected to increase given the key role of electrification in decarbonising Australia's economy and this increase in volume will increase the volume of renewable generation to improve the utilisation of the planned integration assets. In this sense, the 2024 LCOE results could be considered an upper bound if variable renewable technology cost reductions never occur again and electricity demand is flat.

LCOE is not a tool that is designed to capture transitional costs. LCOE places all costs in a single year. Stakeholders who wish to explore system costs over multiple time periods will need to review existing multi-year modelling studies or commission new modelling that uses a multi-year framework. The information GenCost publishes on capital costs over time is targeted at providing the information needed for others to conduct multi-year modelling studies. It is not designed to provide those studies directly. LCOE data published by GenCost provides an indication of what those deeper modelling studies might find regarding technology competitiveness.

D.4.9 Why do other studies show the cost of storage increasing more rapidly with higher VRE share?

If storage is provided to an electricity system as the only technology available for variable renewables to meet electricity demand reliably, then the cost of storage increases exponentially as the VRE share increases. However, this is not a least cost system for integrating variable renewables. A least cost system uses a combination of storage of varying durations, peaking generation technology[45], (based on either natural gas, renewable gas or hydrogen) hydro if it is available and transmission (to source diverse renewables that complement each other). In particular, peaking generation technology is a more cost effective means to provide generation in so-called 'renewable droughts'. When peaking plants are made available to an electricity system with increasing VRE share, the power ratio of storage to renewable capacity tends to plateau at the 80-90% VRE share rather than continue to increase (as is otherwise found in studies where peaking generation technology are not made available). Transmission and spilling electricity also reduce the need for more storage. In summary, modelling studies that find an exponential increase in storage costs as the VRE share increases have artificially constrained the options available to support variable renewables.

D.4.10 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.4.11 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

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[45] Such as a gas turbine or reciprocating engine

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.

D.4.12 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.4.13 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. This reflects the bipartisan policies of net zero emissions by 2050 which make it unlikely that new coal can be developed in Australia. 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.4.14 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.4.15 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.4.16 Why does GenCost only conduct LCOE analysis instead of system cost to society analysis?

Some stakeholders believe GenCost is obligated to provide a system cost to society analysis. The stated purpose of GenCost is to provide essential capital cost information for the modelling community to use in their own system cost studies. There are several Australian researchers and consultants capable of delivering such studies.

CSIRO has significant experience in conducting whole of electricity system studies[46] and can therefore say with confidence that such a study would increase the annual budget of GenCost by around five- to ten-fold. It is therefore not a simple extension. Substantially expanding the scope of GenCost or creating a new separate project to accommodate stakeholder interest in whole-of-system studies is not planned at present. However, CSIRO does operate in this field and new separate research of this type is likely to be available in the future.

D.4.17 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 2023-24 and 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

[46] See for example these projects: https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/ and https://www.transgrid.com.au/about-us/network/network-planning/energy-vision.

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.4.18 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
SMR	Small modular reactor
STEPS	Stated Policies Scenario
SWIS	South-West Interconnected System
TWh	Terawatt hour

Abbreviation	Meaning
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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