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Acknowledgement

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Consultation process

This report is provided for the purposes of stakeholder review. Feedback received will be used to improve content and produce a final GenCost 2024-25 report mid-2025. Feedback can be provided at: https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr

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 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.

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 consultation draft.

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. 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 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 around 45 years from now, significantly reducing their value to consumers compared to other options which can be deployed now.

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 fact is that the 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 coal plants operate at close to 90% capacity factor but the average for black 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) had a 12 year lead time. Both estimates are in relation to building nuclear for the first time. This consultation draft provides additional analysis of nuclear lead times to examine this issue more closely. We examine recent construction times and their relationship with the level of democracy in that country.

In the last 5 years, median construction time has increased to 8.2 years compared to 6 years when the IAEA made their estimate in 2015. 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.

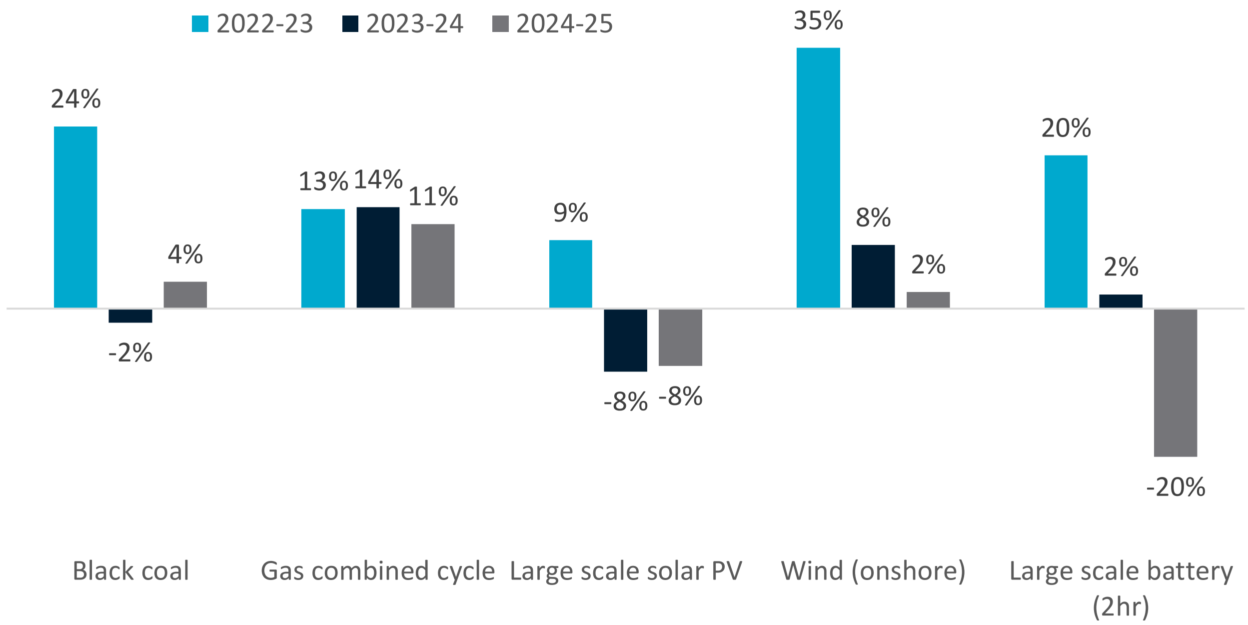
Another factor which is correlated with shorter construction times is the existence of an ongoing building program rather than long intervals between projects.

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 in 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 2% in 2024-25 while large-scale solar PV has fallen by 8% in consecutive years (ES Figure 0-1). Large-scale battery costs improved the most in 2024-25 falling by 20% in 2024-25. Gas turbine technologies are still increasing but this is because GenCost is now including hydrogen fuel readiness as a standard feature. This has increased gas technology capital costs but recognises the reality that gas generation is more likely to be deployed with multiple fuel options.



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

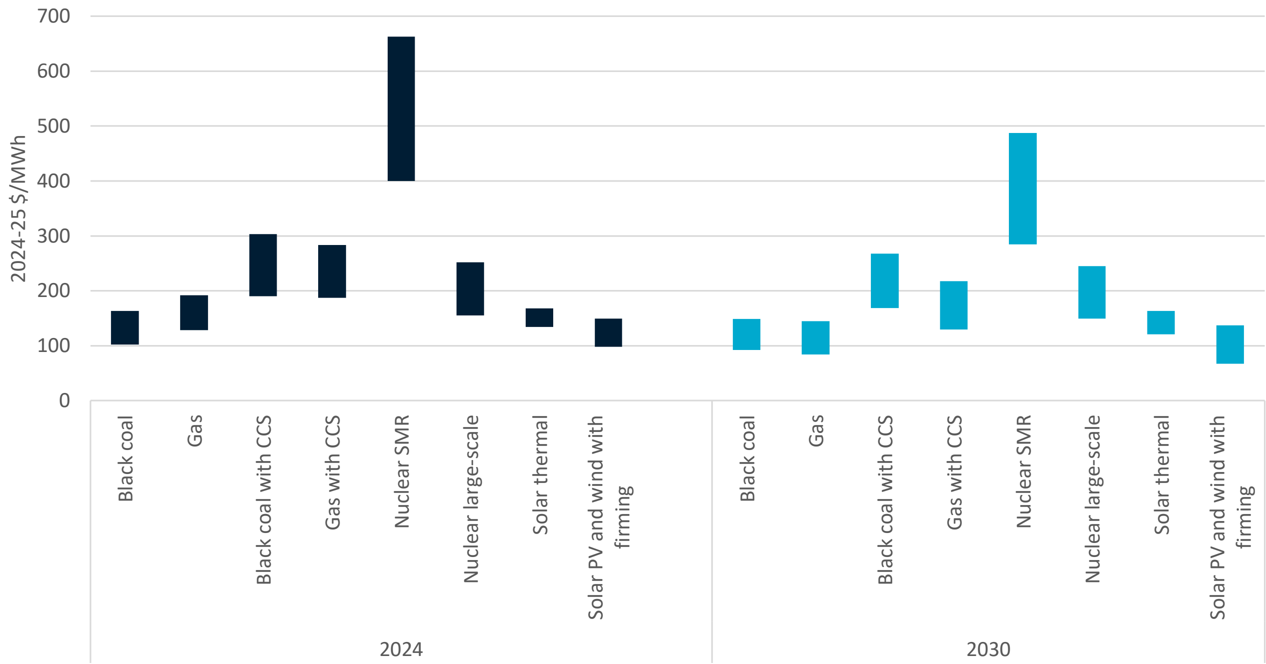
The cost of electricity technologies compared

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 2024 and 2030. The cost range overlaps with the lower end of the cost range for coal and gas generation. These are high emission technologies which, if used to deliver the majority of Australia's power supply, are not consistent with Australia's current climate change policies[1].

If we exclude high emission 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.

[1] Although 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 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/consultations/current-and-closed-consultations/draft-2024-isp-consultation



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. At least 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 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.

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 (2024b) 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[2]. 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

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

of electricity generation, storage and hydrogen technologies (Aurecon, 2024b). 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.

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.

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 Consultation

This report is provided for the purposes of stakeholder review. Feedback received will be used to improve content and produce a final GenCost 2024-25 report in the second quarter of 2025. While the release of the consultation draft represents our main annual consultation process, CSIRO also participates in various additional consultations throughout the year.

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.

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

The role of GenCost is to make fair comparisons of technologies on a common costing basis. Governments can and do subsidise technologies and our consistent approach since project inception is to exclude any subsidies in our analysis. However, stakeholders have raised direct government ownership as a serious proposal. Consequently, it is difficult to avoid the consideration of subsidies which are irrevocably intertwined with any government ownership. Governments have access to several financing abilities which are not available to the private sector and whether these are made available to all technologies or selectively to some technologies, they represent a subsidy.

The first advantage of government ownership is that it could apply the lower interest rates which are available to governments to the investment. This is a clear subsidy which would benefit any technology it is applied to[3]. If access to lower interest rates were the only intent of government ownership of nuclear then this would simply represent a subsidy and require no further investigation by GenCost. However, based on feedback received throughout the course of the GenCost project[4], it is assumed the primary intent of government ownership is not low interest rates but rather to unlock the potential benefits of nuclear technology's long operational life with a longer capital recovery period. We therefore ignore the lower interest rate aspect of government ownership and focus on the issue of financing and long operational life.

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[3] Lower interest rates provide the most benefit to technologies with a higher proportion of capital costs in total costs. If low interest rates were offered to all technologies as a technology neutral government subsidy, renewables and nuclear would achieve close to the same proportional cost reduction since they both have around a 90% share of capital in their total cost of generation. Technologies with higher fuel costs such as gas generation would receive a lower proportional benefit but would still experience reduced costs.

[4] The Liberal-National Coalition has not yet specifically stated exactly why and how government ownership is justified or will benefit nuclear generation. However, GenCost has received many submissions requesting we ignore the standard 30-year financing period and apply capital recovery over the whole operational life of nuclear, which could be achieved under government ownership. Financing projects for longer than 30 years it not generally available to the private sector without government guarantees, even for technologies with operational lives longer than 30 years.

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 9% 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 7% 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 130% 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 11-16% 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 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	13%	13%	13%	13%	12%	13%	12%	13%
60	Nuclear large-scale	11%	11%	11%	11%	11%	11%	11%	11%
100	Nuclear SMR	15%	16%	15%	15%	14%	15%	14%	15%
100	Nuclear large-scale	12%	13%	13%	13%	13%	13%	13%	13%

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.

[5] The exact amount of interest depends on the detailed schedule of payments and addition of interest. This estimate is based on a simple annual model. Fixed and variable interest rates are also a source of uncertainty.

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 $150-245/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 $2765/kW or $43-80/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 go offline for a longer than normal maintenance period to complete the installations associated with the life extension.

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 $133-217/MWh which is an 11% 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 $136-222/MWh which is a 9% reduction in costs relative the costs for a single 30-year generation project.

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[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.

[7] This aligns perfectly with the costs 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.

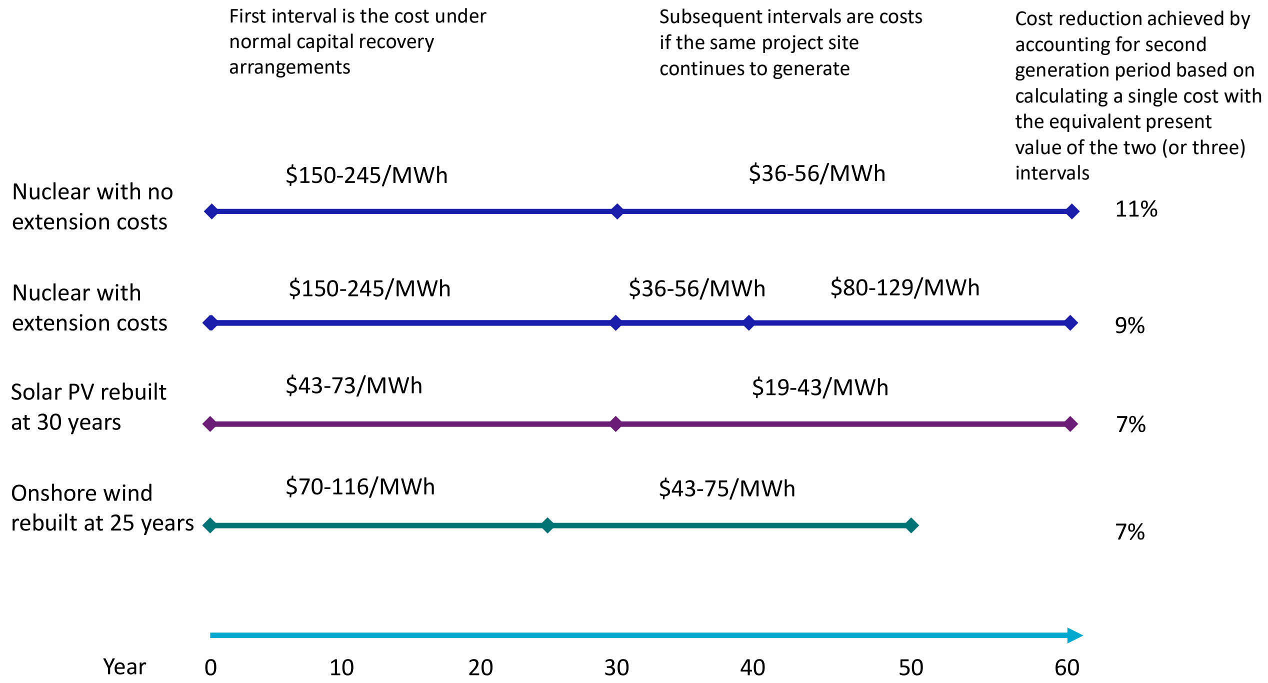

Figure 2-1 Costs for long-lived multi-stage projects and the subsequent cost reduction achieved for electricity consumers.

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 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

[8] Aurecon (2024b) suggest a possible 40-year technical life for solar and 30 to 35 years for onshore wind.

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 which is of benefit to consumers.

To calculate the benefit of the second period of lower costs, in the same way that we did for nuclear generation, we convert the costs in the full 50- and 60-year lifetimes to a common 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 $40-68/MWh which is a 7% 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 $65-108/MWh which is also a 7% 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 $44 if you have to wait 15 years to receive it (using the same annual real discount rate as the analysis above). As such, the 9% savings associated with a 60-year nuclear project are worth less than half their value when delayed 15 years before generation can commence.

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 9% 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 US 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 coal generation in the same baseload power role. GenCost uses a range of 53% to 89%. 89% represents the best performance of black coal in a recent ten-year period (2011 to 2021). 53% is 10% below the average capacity factor of black 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).

[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.

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), 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.

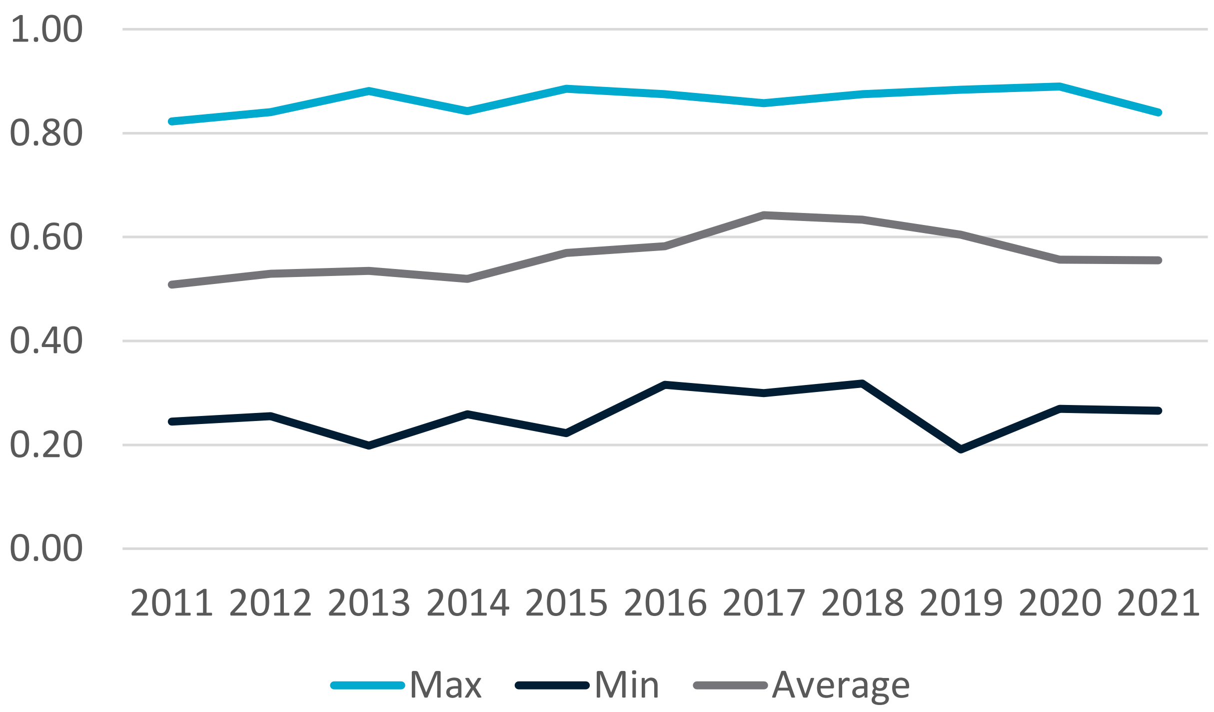

Figure 2-2 Historical capacity factors for black coal in Australian electricity generation (NEM states)

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 2040s). While AEMO's Integrated System Plan 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 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 2015).

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 report was released in 2015 it could be inferred that the timeline was at least based on recent construction times at the time of writing. 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 report 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.

[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

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.

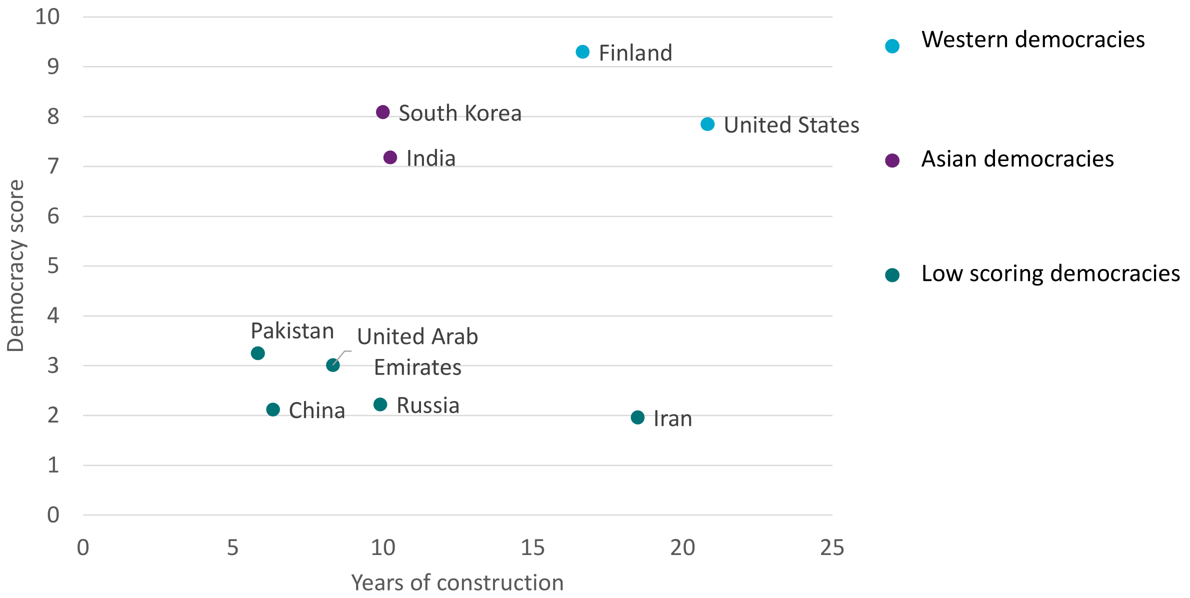

Figure 2-3 Relationship between the level of democracy, regions and construction times since 2011

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 democratic consultation and construction experience both play into achievable construction times.

Given the direction of construction data available after the report's release, 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 (2024b). Aurecon (2024b) 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 (2024b) 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. As such, while special circumstances occurred in each case, we cannot rule out FOAK premiums of 100% applying to other 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.

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, and unique site conditions.

It is likely that 2023 nuclear SMR costs include some FOAK costs. The extent of that FOAK component will not be completely transparent until further projects proceed. The first commercial project did not proceed, and the next may be some years ahead. Further complicating matters, the first commercial project to almost proceed coincided with a large global inflationary event. We can remove all the identifiable inflationary impacts based on a costing that was available before the pandemic, but cannot reliably identify the FOAK share of the cost increase.

3.2 Capital cost source

AEMO commissioned Aurecon (2024b) 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 (2024b) 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°C to determine $/kW costs. Aurecon states that the uncertainty range of their data is +/- 30%.

Technologies not included in Aurecon (2024b) 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.

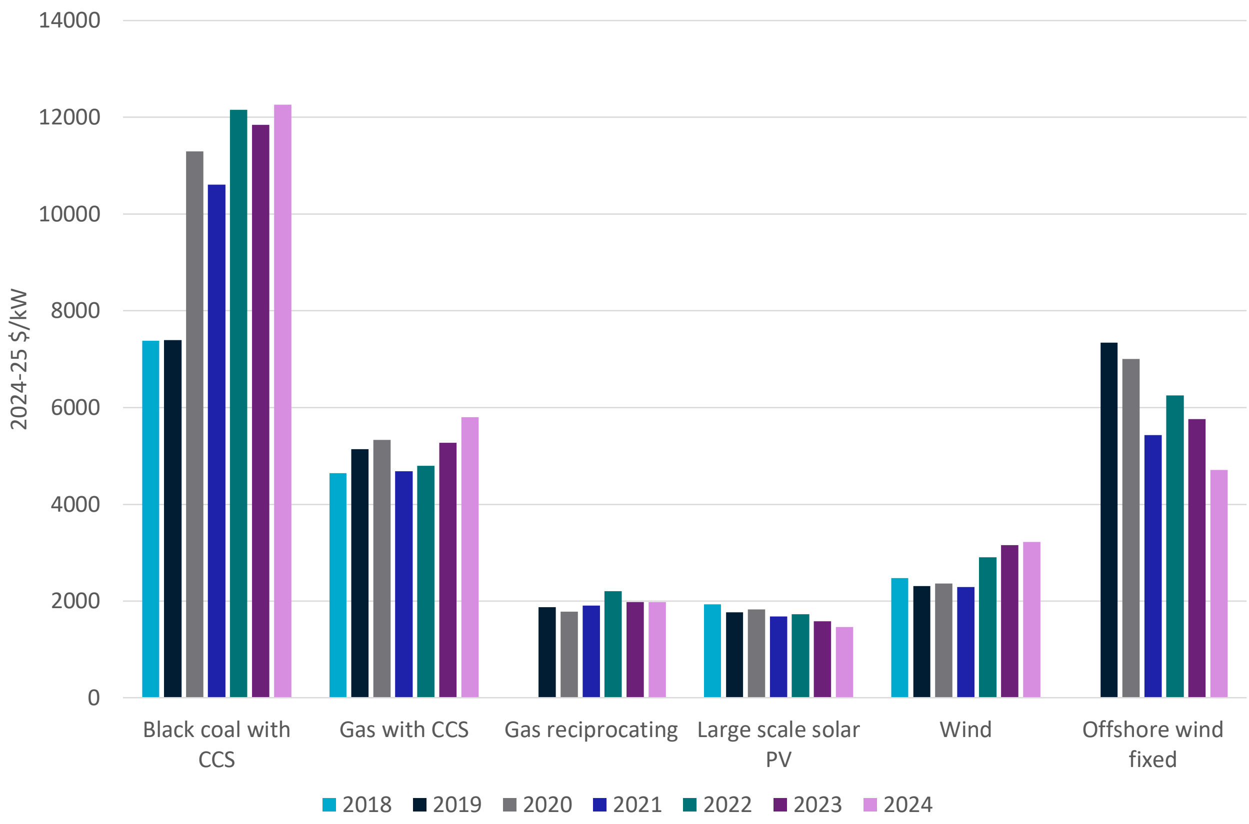

Figure 3-1 Comparison of current capital cost estimates with previous reports (FYB)

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 two 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 all 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 mostly still experiencing real cost increases but at a reduced rate compared to the previous two years.

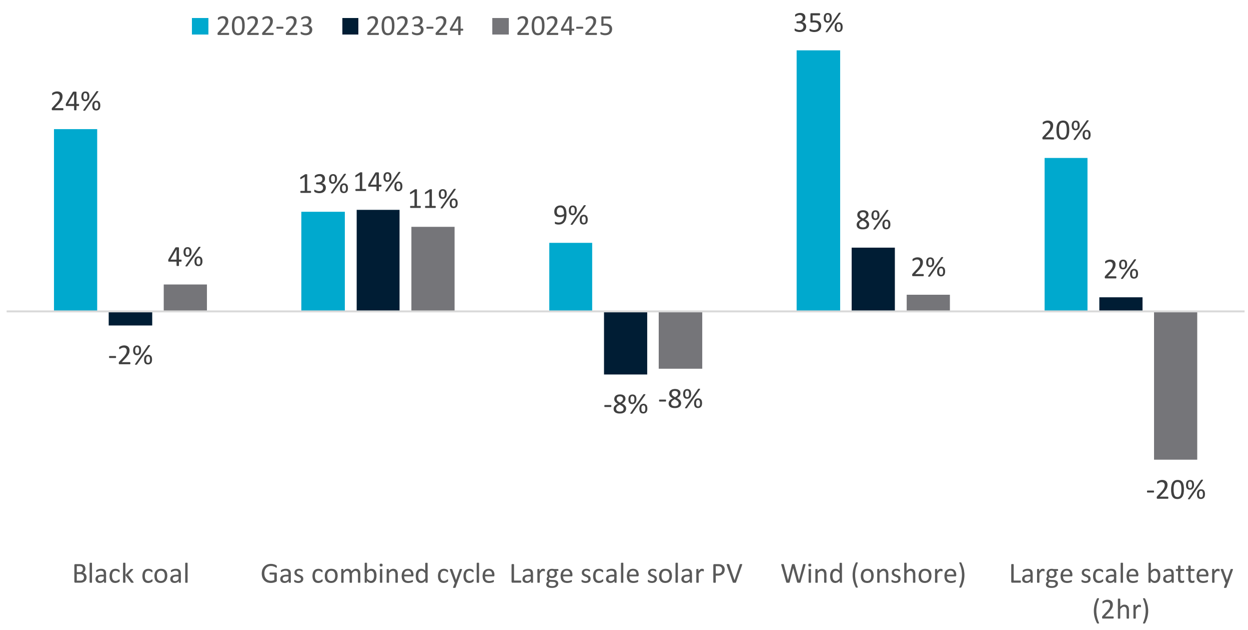

Figure 3-2 Year on year change in current capital costs of selected technologies in the past 3 years (in real terms)

3.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[12] of batteries, adiabatic compressed air energy storage (A-CAES) and pumped hydro energy storage (PHES) in $/kW and $/kWh. Battery durations of 24 hours and 48 hours have been added for the first time. 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), 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[13]. 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.

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[12] 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

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

Note that these $/kWh costs are not for energy delivered but rather a capacity of storage. GenCost does not present levelised costs of storage. However, these are available from the CSIRO (2023) *Renewable Energy Storage 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 depending on the operation of other generation in the system, particularly the scale of variable renewable generation and peaking plant (see Section 5).

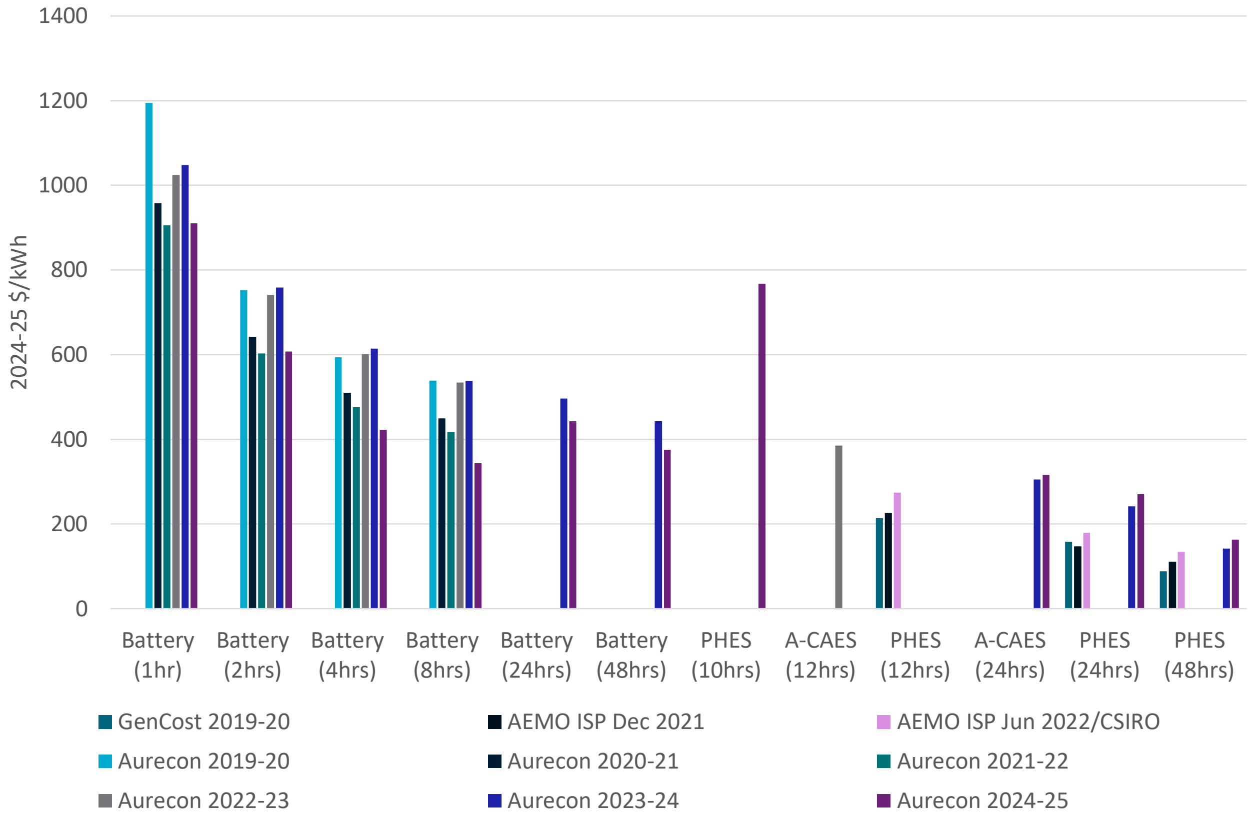

Figure 3-3 Capital costs of storage technologies in $/kWh (total cost basis)

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%[14]. Aurecon (2024b) 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%

[14] 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%.

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.

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

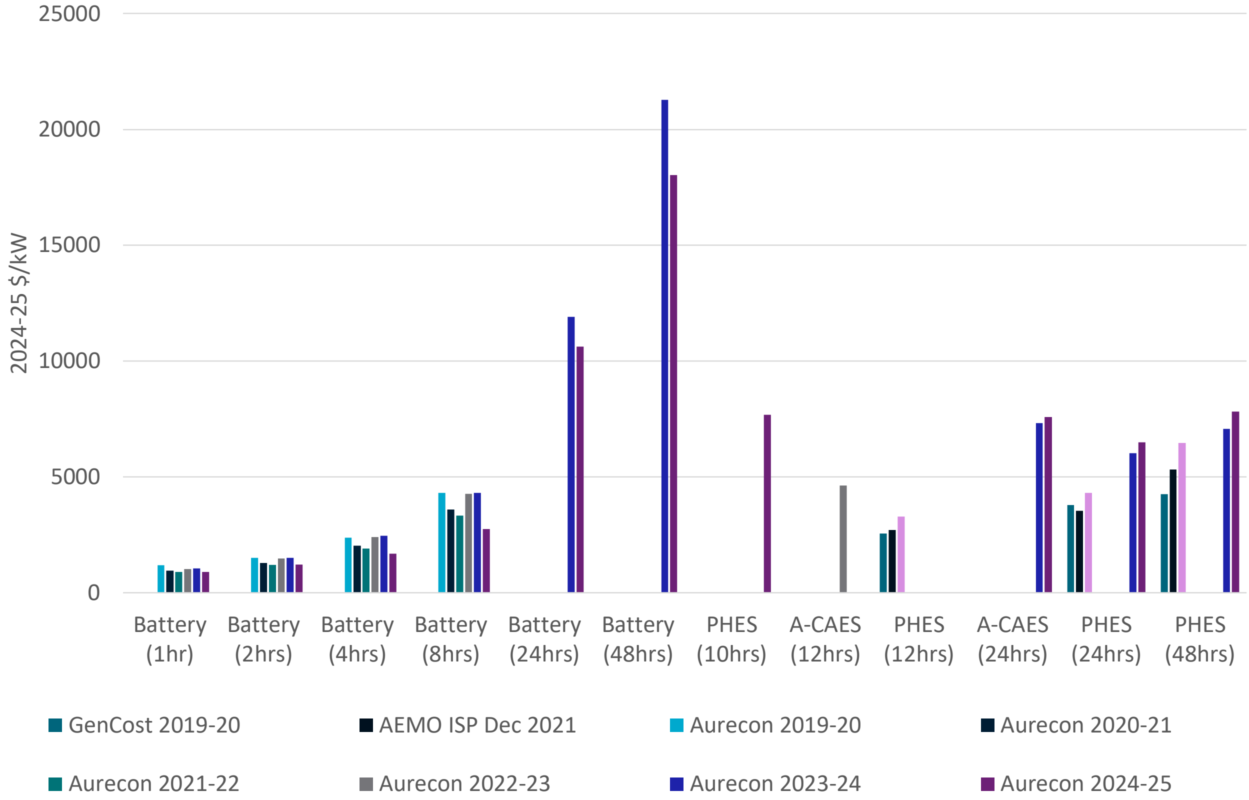

Figure 3-4 Capital costs of storage technologies in $/kW (total cost basis)

PHES current cost estimates have increased by 12% for 24-hour duration projects and by 15% for 48-hour duration projects[15]. 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 (2024b) 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

[15] The PHES capital costs used in this report are based on taking the mid-point of the range provided by Aurecon (2024b). Percentage differences will be higher or lower for projects at different ends of that range.

comparison with the other electricity storage technologies is complicated by the fact that a CST system also collects its own solar energy. Direct comparison with other storage technologies via calculation of the Levelised Cost of Storage (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 2023 *World Energy Outlook* (IEA, 2023) 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.

The final GenCost 2024-25 report will update the scenario data to align with the IEA's 2024 *World Energy Outlook*. However, the timing of its release does not allow for inclusion in the Consultation draft.

4.1.1 Current policies

The *Current policies* scenario includes existing climate policies as at mid-2023 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[16]. 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*.

[16] 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.

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 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

5.1 Short-term inflationary pressures

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 those projected by 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 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[17]). The current cost update indicates 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

[17] 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.

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 costs resume their pre-pandemic modelled pathway.

In response to feedback, this report includes an exception which is that onshore wind costs do not return to their normal path until 2035. Of all the technologies that are currently in high demand, onshore wind capital costs were impacted the most and have demonstrated to be the slowest to recover. It is therefore appropriate to give onshore wind a separate pathway.

A consequence of this modelling approach is that all of the cost reductions to either 2027 or 2030 (or 2035 for onshore wind) 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.

An exception to the resumption of a modelled cost path after 2027, 2030 or 2035 is that the projection has been adjusted to recognise that land may be a source of ongoing input scarcity. 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 (2024b) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[18]. 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 is a recent feature, first included in *GenCost 2022-23: Final report*.

All projections start from a current cost and the primary source of 2024 costs is Aurecon (2024b) 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.

5.2 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.

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

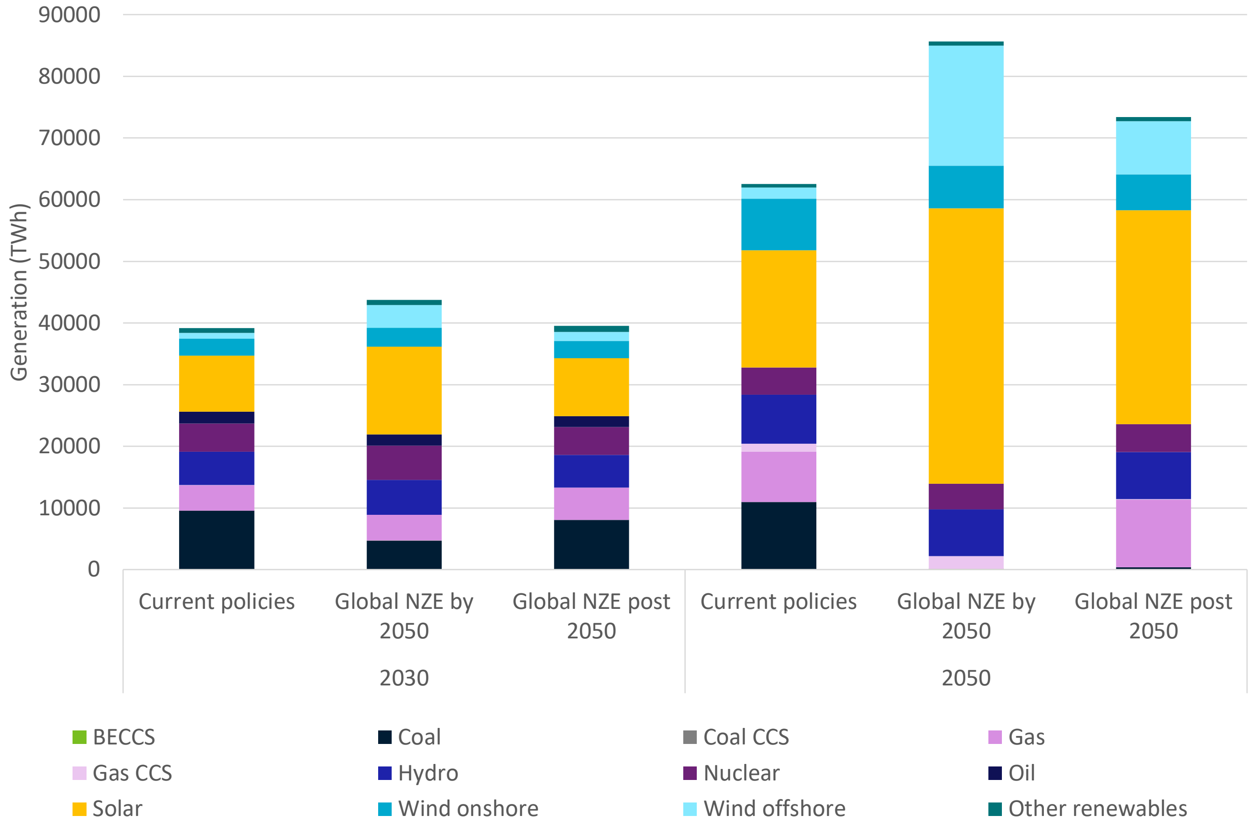

Figure 5-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Current policies has the lowest electrification because it is a slower decarbonisation pathway than the other scenarios considered. However, it has the least energy efficiency and industry transformation[19]. 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.

Current policies has the lowest non-hydro renewable share at 48% 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 2050.

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 3% of generation by 2050. Offshore wind features strongly in this scenario at 23% of generation by 2050. Renewables other than

[19] 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.

hydro, biomass, wind and solar are 1% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs.

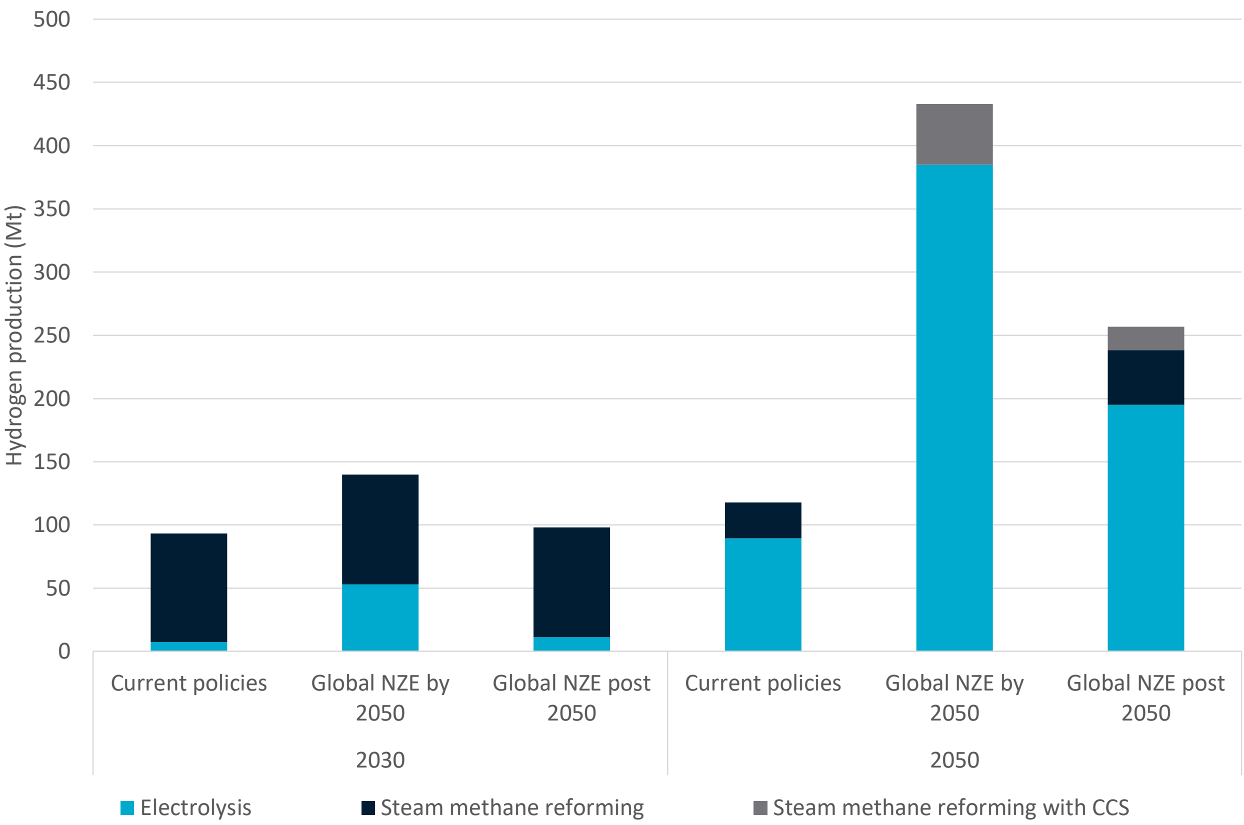

Figure 5-2 Global hydrogen production by technology and scenario, Mt

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, where the current costs have not changed and the assumed improvement rate after 2027 or 2030 (depending on the scenario) is very similar, their projection pathways often overlap. The land cost inflator results in a 56% increase in land costs by 2050 but this is only a small portion of capital costs. Before the land cost inflation is added, the assumed annual rate of cost reduction for mature technologies post-2027 or 2030 (depending on the scenario) is 0.35% (the same as previous reports given the rate is based on a long-term historical trend). The method for calculating the reduction rate for mature technologies is outlined in Appendix A. Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[20].

5.3.1 Black coal ultra-supercritical

The updated cost of black coal ultra-supercritical plant in 2024 has been sourced from Aurecon (2024b). Prior to 2023-24, the black coal capital cost had previously been based on a supercritical

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

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 to the *Current policies* scenario and the learning rate is low. The outlook for costs in all scenarios is flat, with a slight increase due to increasing land costs.

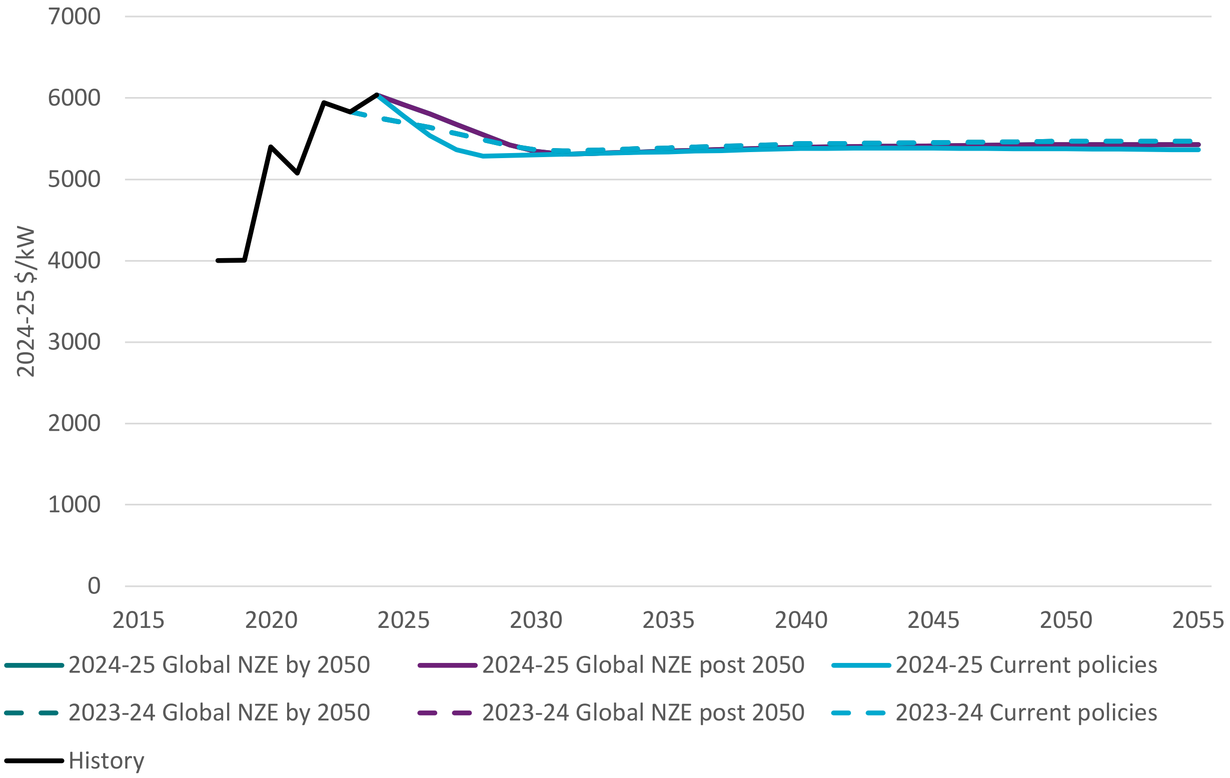

Figure 5-3 Projected capital costs for black coal ultra-supercritical by scenario compared to 2023-24 projections

5.3.2 Coal with CCS

The current 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 in a similar manner as mature technologies, but with differences to take account of its unique set of inputs. Thereafter, the capital cost of the mature parts of the plant improves at the mature technology cost improvement rate. For the CCS components, the cost reductions 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 current inflationary pressures.

Current policies has no uptake of steam methane reforming with CCS in hydrogen production. Consequently, cost reduction from the late 2030s is 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.

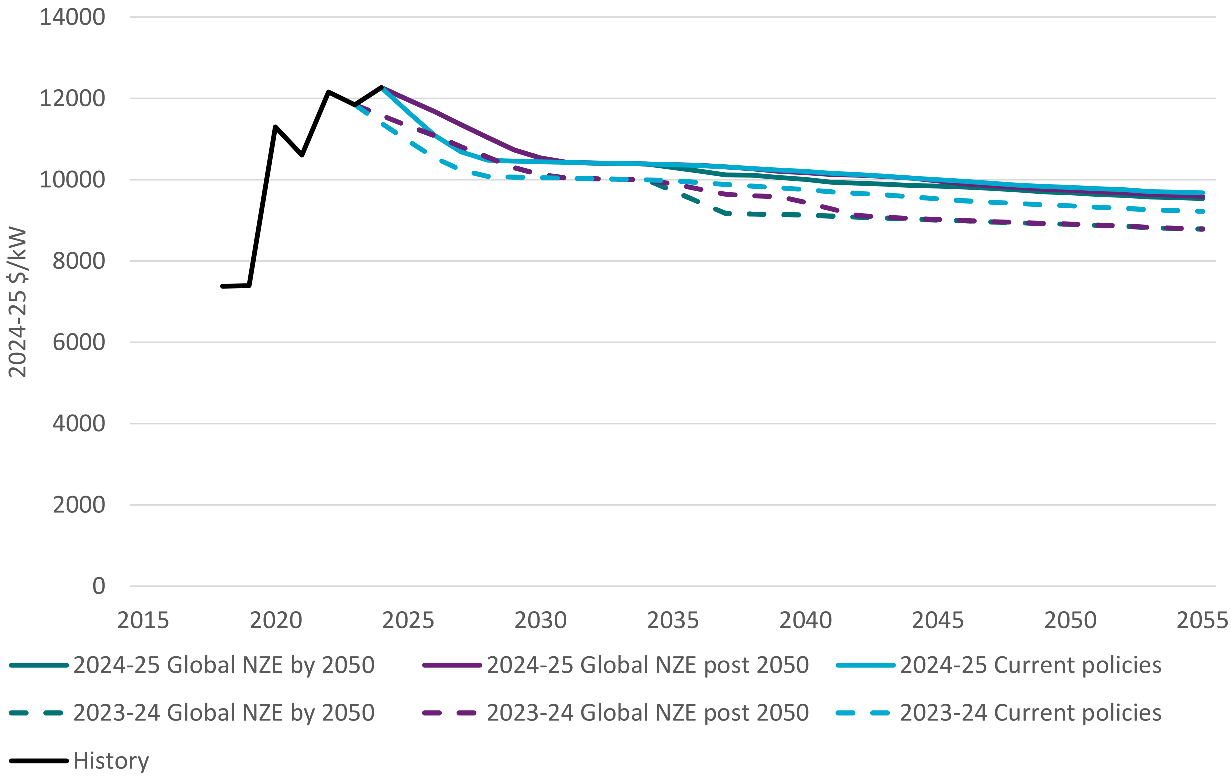

Figure 5-4 Projected capital costs for black coal with CCS by scenario compared to 2023-24 projections

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 learning and cost reduction by 2050 but with differences in the timing of reductions.

5.3.3 Gas combined cycle

Aurecon (2024b) have included an increase in gas combined cycle costs for 2024 but this needs to be interpreted with caution because the 2024 capital cost update includes a premium for hydrogen readiness that was not included in previous data. CSIRO has imposed an assumed return to previous costs levels by 2027 in *Current policies* and 2030 in the *Global NZE* scenarios while still maintaining the premium for hydrogen readiness. 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 by our assumed cost improvement rate for mature technologies together with a land cost increase for all scenarios. Consequently, the rate of improvement is constant across the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios.

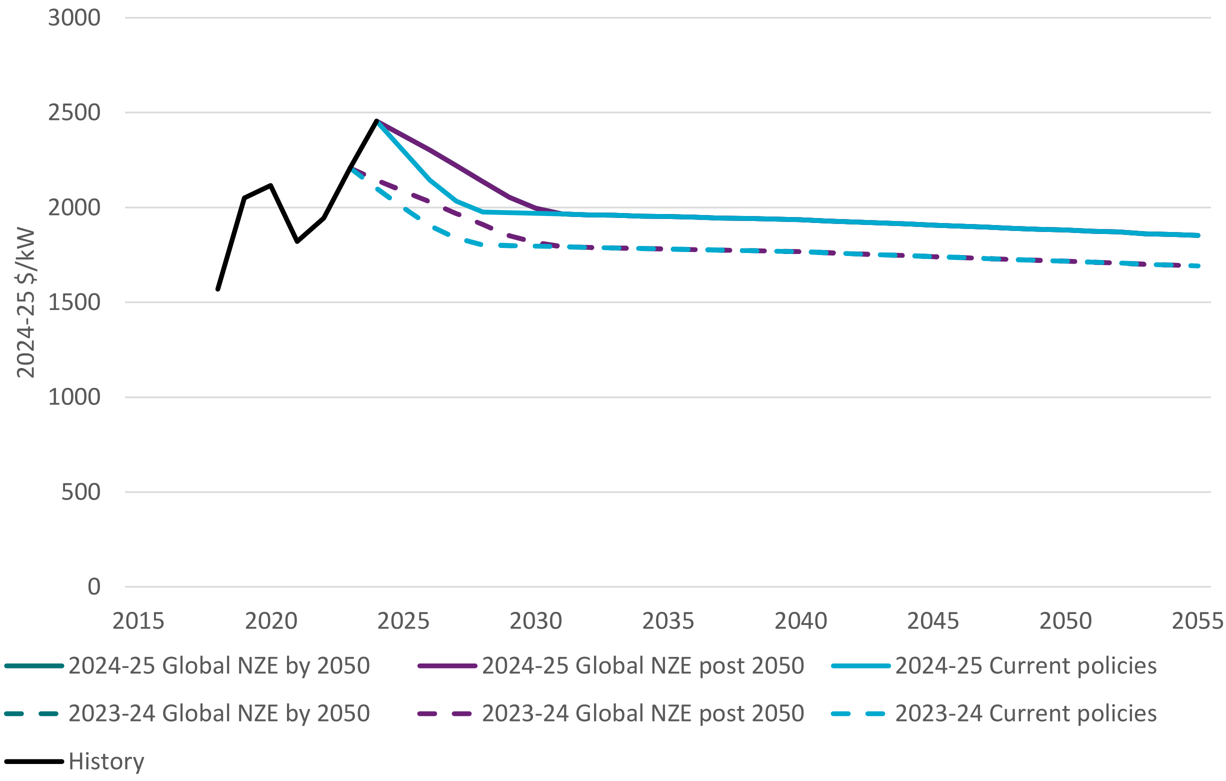

Figure 5-5 Projected capital costs for gas combined cycle by scenario compared to 2023-24 projections

5.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2023-24 projections reflecting the increase in gas combined cycle capital costs. The relativities between the scenarios reflect the 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, gas with CCS is lower by 2050 in those scenarios. Conversely, CCS has the highest cost in *Current policies* where CCS deployment is lowest. The projection reductions in the cost of CCS are much less than in the 2023-24 projections because the low cost of solar PV while other technology costs have increased has meant a greater share of solar and lower share of CCS. Less deployment limits the amount of cost reduction that can be achieved.

The IEA CCS database[21] indicates there are over 100 planned electricity related projects which are yet to make a financial investment decision, six under construction and five completed. The advanced projects are for smaller volumes and/or low capture rates. Given the current state of the pipeline of projects, significant global deployment of CCS is not expected until after 2030.

[21] CCUS Projects Database - Data product - IEA

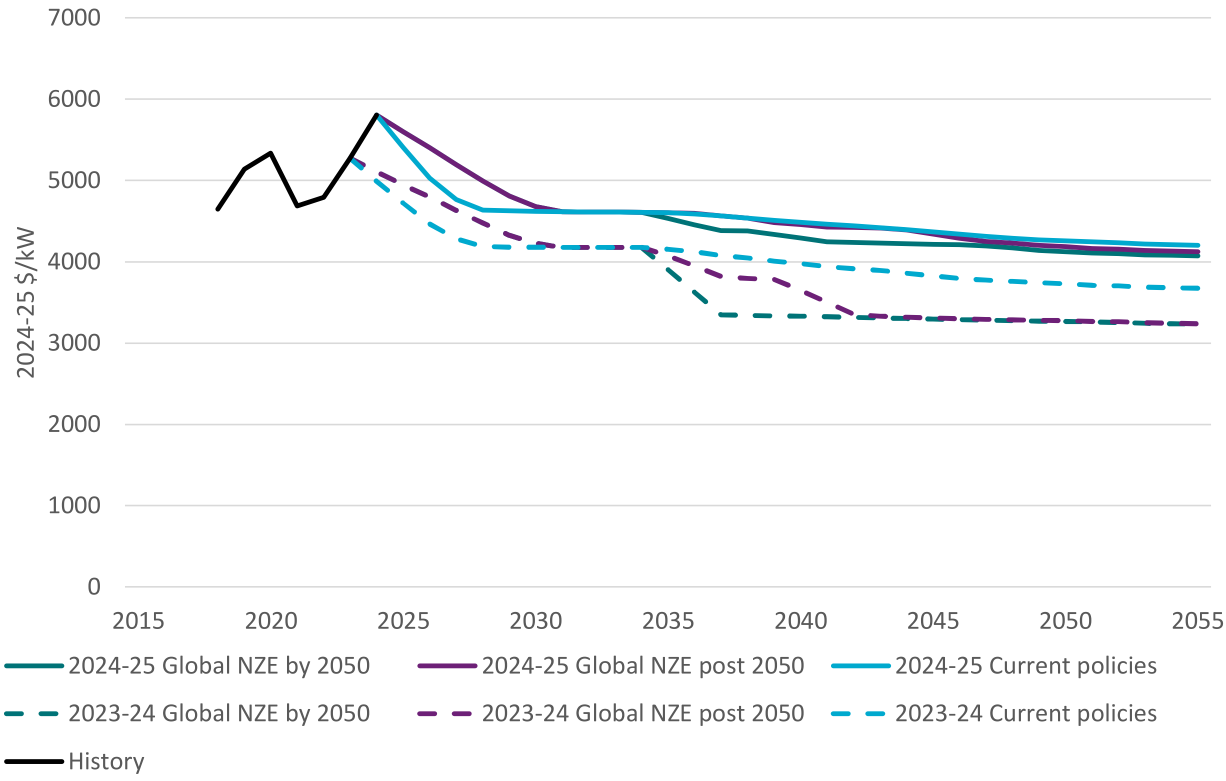

Figure 5-6 Projected capital costs for gas with CCS by scenario compared to 2023-24 projections

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. Detail of previous costs are not included because the technology design has changed, impacting the costs. That is, 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. This is in addition to the existing ability to use liquid fuels such as diesel or renewable diesel. The small open cycle gas technology is designed with a maximum 35% hydrogen blend. The large size is designed for 10%.

Aurecon (2024b) provides additional details for the unit sizes and total plant capacity that defines the small and large sizes. Given this is a new technology type with no historical series, no provision is made for reverting back to previous costs over time. Aside from assumed increasing land costs, open cycle gas is classed as a mature technology for projection purposes and as a result its change in capital costs is also governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the scenarios.

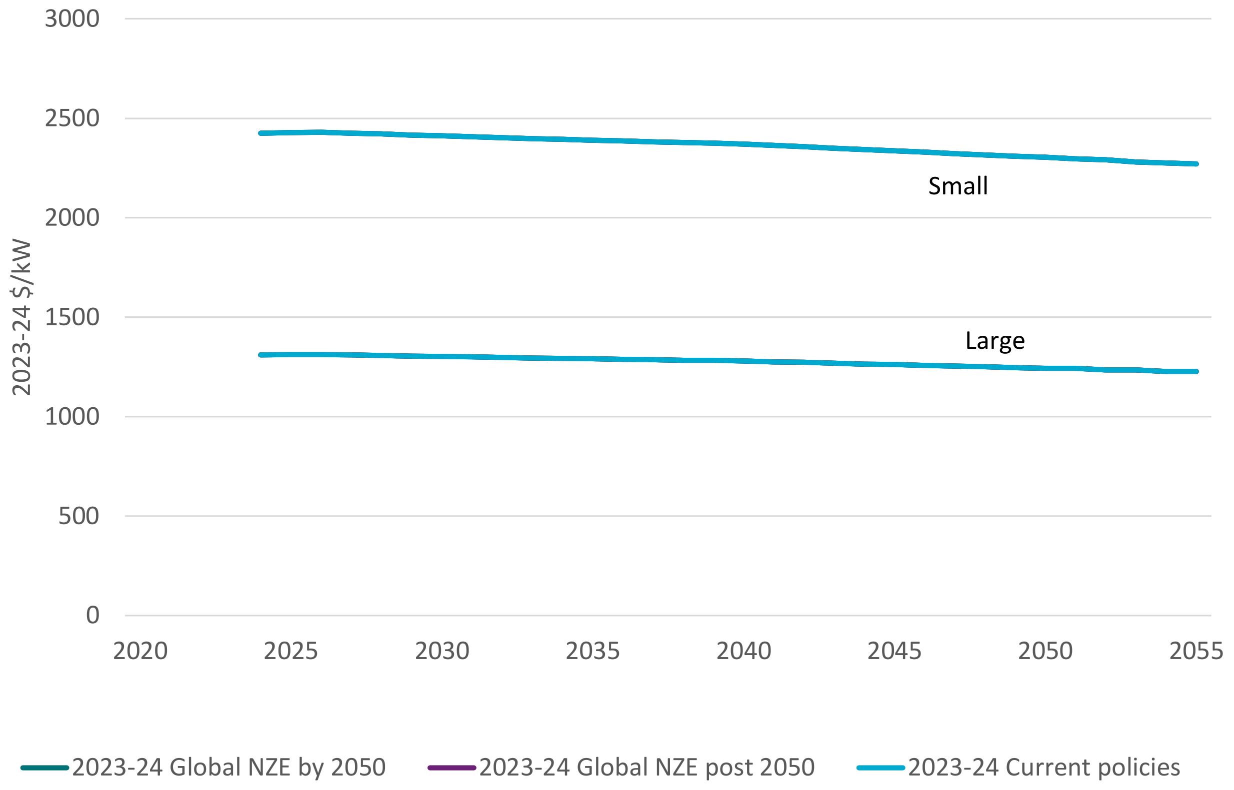

Figure 5-7 Projected capital costs for gas open cycle (small) by scenario compared to 2023-24 projections

5.3.6 Nuclear SMR

The projections start at the updated 2024 capital cost of around $29,600/kW. Cost reductions to 2027 in *Current policies* and to 2030 in the *Global NZE* scenarios are an assumed unwinding of global inflationary premiums following the COVID-19 pandemic. Cost reductions after those times are due to learning. The nuclear SMR capital cost results are higher for longer in the updated projections compared to 2023-24 because updates have been made to the expected dates of deployment for projects, which have been pushed further into the future, beyond the 2020s (Global Energy Monitor, 2024a). Later deployment of nuclear SMR means it takes longer for capital cost reductions due to learning-by-doing and economies of scale to materialize.

Capital costs only improve slightly for the *Current policies* scenario due to a low deployment of projects in the 2030s followed by a later stage of deployment in the 2040s. *Global NZE by 2050* achieves a similar level of deployment as *Current policies* but with deployment commencing 10 years earlier due to a stronger commitment to addressing climate change.

In *Global NZE post 2050*, the less competitive renewables means that nuclear SMR can deploy a little further into the late 2030s than under *Global NZE by 2050*. As a result, this scenario has the largest deployment of nuclear SMR with subsequently lower cost reductions through the learning rate assumptions which may be partly driven by modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. Capital costs are between approximately $12,000/kW and $16,000/kW across the scenarios by the 2040s.

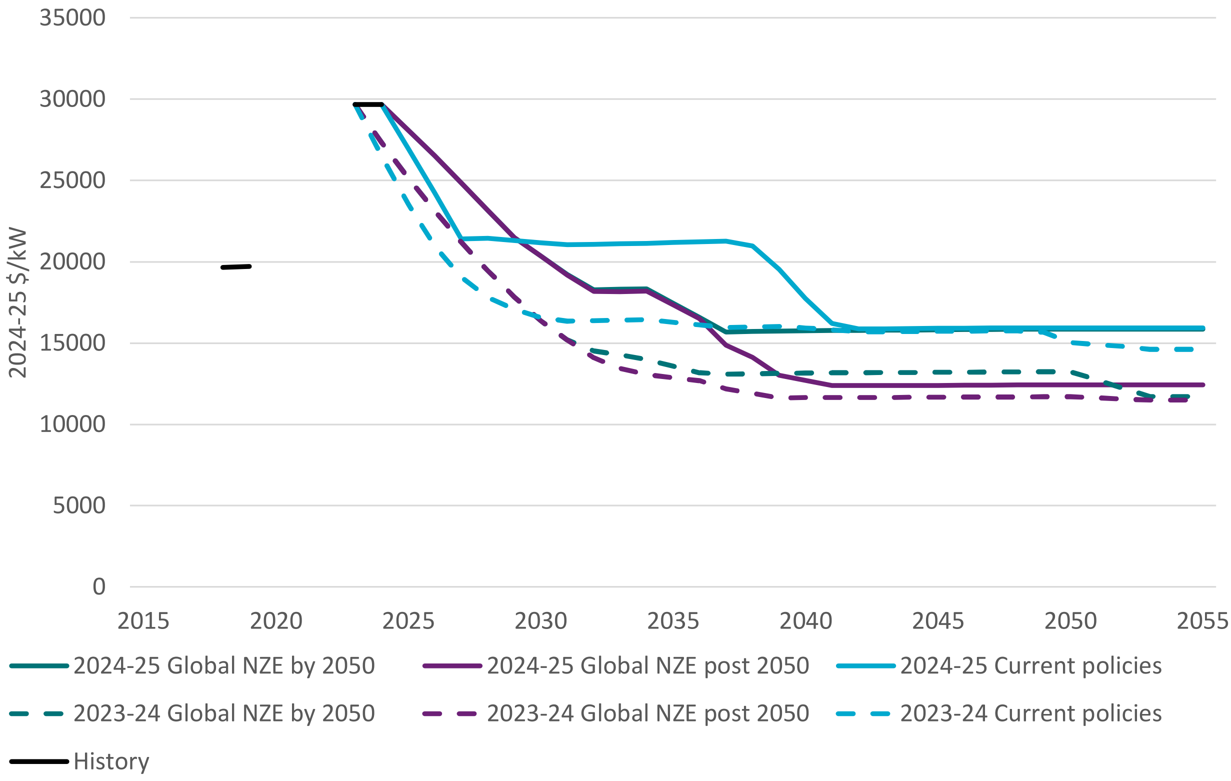

Figure 5-8 Projected capital costs for nuclear SMR by scenario compared to 2023-24 projections

5.3.7 Large-scale nuclear

Like other technologies, large-scale nuclear capital costs are assumed to return 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 decline after 2027 or 2030 at the pre-determined annual cost reduction rate assigned to all mature 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 around proven designs.

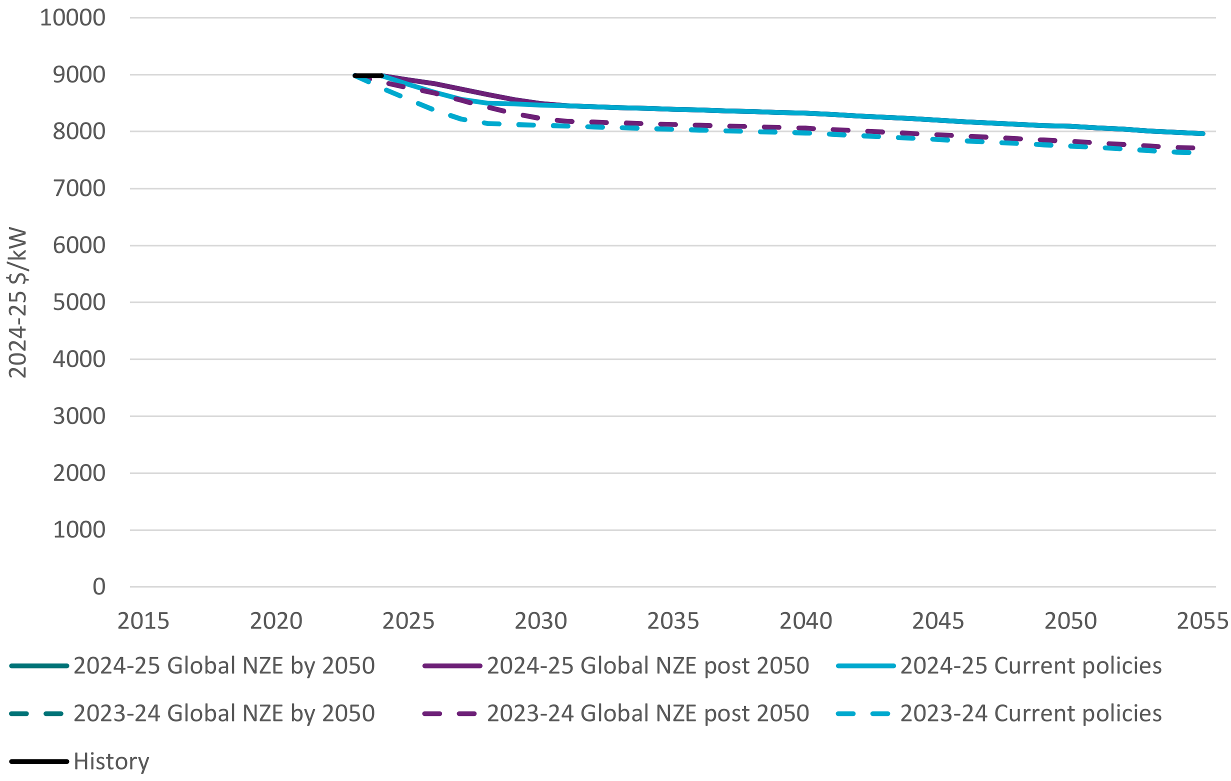

Figure 5-9 Projected capital costs for large-scale nuclear by scenario compared to 2023-24 projections

5.3.8 Solar thermal

The starting cost for solar thermal has been updated by Aurecon (2024b) drawing on Fichtner Engineering (2023) which includes a change to the baseline configuration, with a storage duration of 16 hours. The small increase in current year costs is the main cause for changes in the projection compared to 2023-24. Otherwise, the 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.

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.

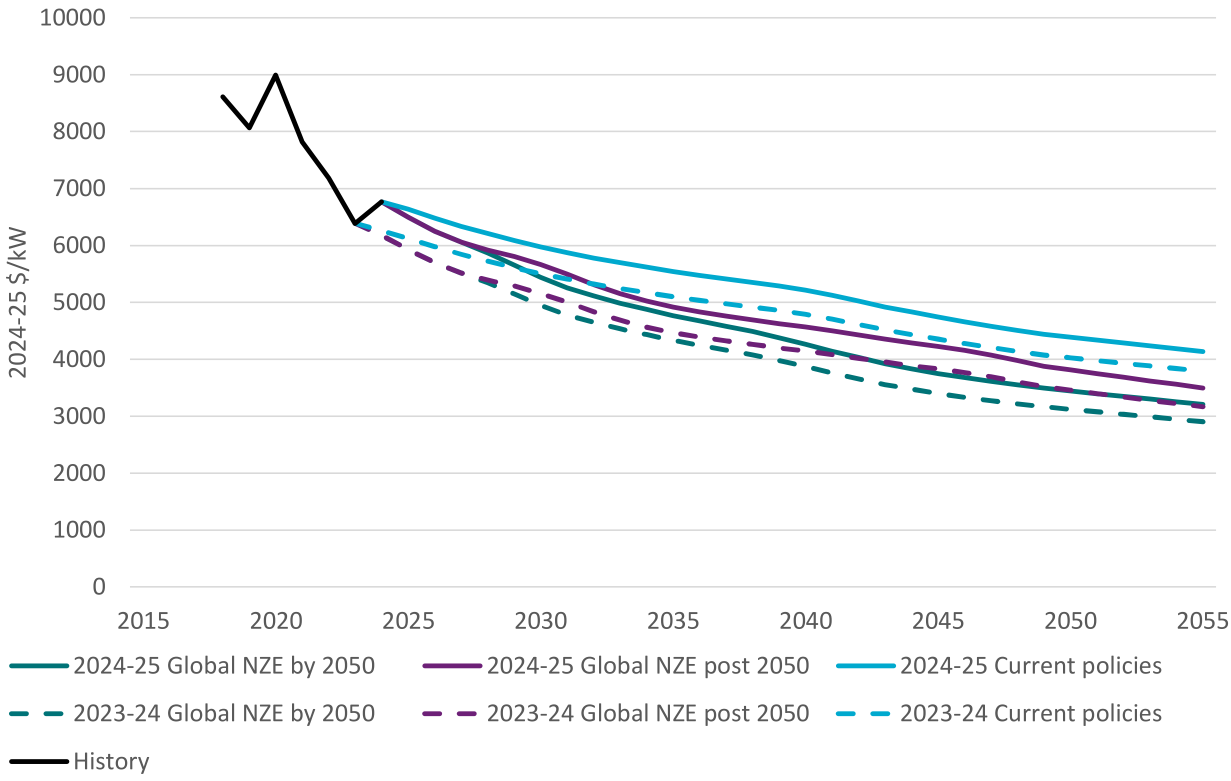

Figure 5-10 Projected capital costs for solar thermal with 14 hours storage compared to 2023-24 projections

5.3.9 Large-scale solar PV

Large-scale solar PV costs have been revised downwards for 2024-25 based on Aurecon (2024b) indicating solar PV production costs are recovering more rapidly than projected from global inflationary pressures. As a result of the ongoing cost reductions for this technology, we do not impose any additional cost reduction related to recovery from the global inflationary pressures. All cost reduction in the projection is due to learning through deployment. The *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. The differences are most prominent in the mid-2030s whereas deployment in the next few years is less divergent across the scenarios.

Cost outcomes across the three scenarios project a capital cost range of $550/kW to $800/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 slowed. The modular nature of solar PV appears to be the main point of difference in explaining this characteristic.

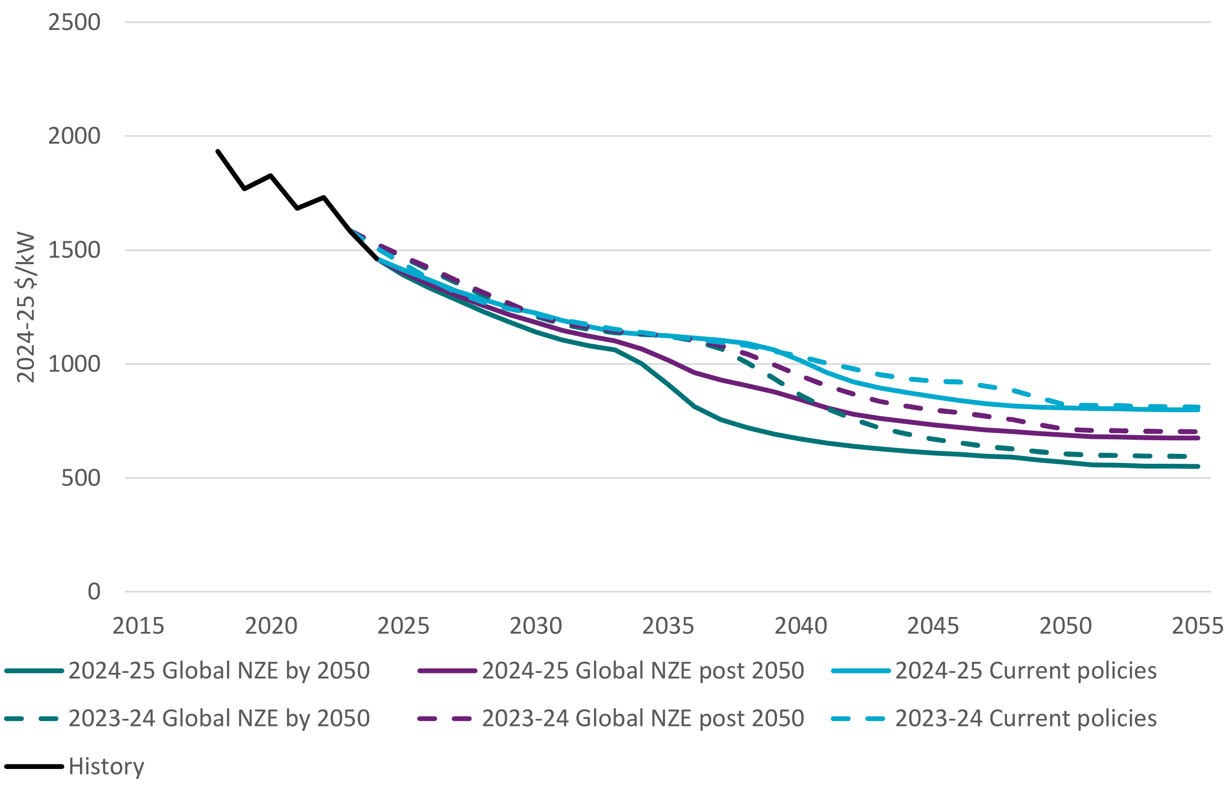

Figure 5-11 Projected capital costs for large-scale solar PV by scenario compared to 2023-24 projections

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[22]. This data is best interpreted as a mean and may not align with the lowest cost systems available.

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. As a result, we can observe similar trends in the rate of capital cost reduction in each scenario as for large-scale solar PV.

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

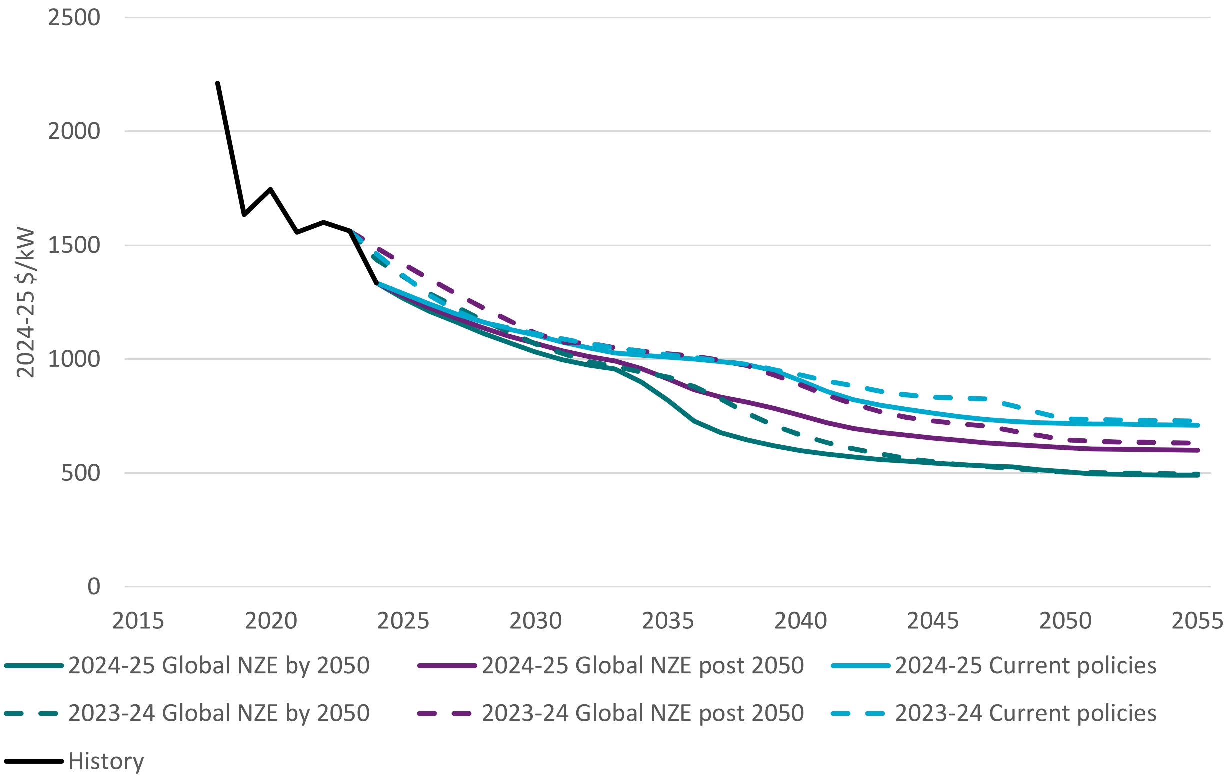

Figure 5-12 Projected capital costs for rooftop solar PV by scenario compared to 2023-24 projections

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. Costs have risen around 36% since the beginning of the pandemic. Equipment costs appear to account for around 40% of that increase with the remainder reflecting other factors such as local installation[23]. The updated Aurecon (2024b) data indicates that the rate of increase is slowing. 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 be reduced with greater global climate policy ambition and subsequent deployment. Land cost increases are assumed which will partially offset these reductions. Cost reductions are strongest under *Global NZE by 2050* resulting in a range of around $1830/kW to $1910/kW by 2055.

[23] Based on analysis of Vestas average selling price adjusted for Australian dollars.

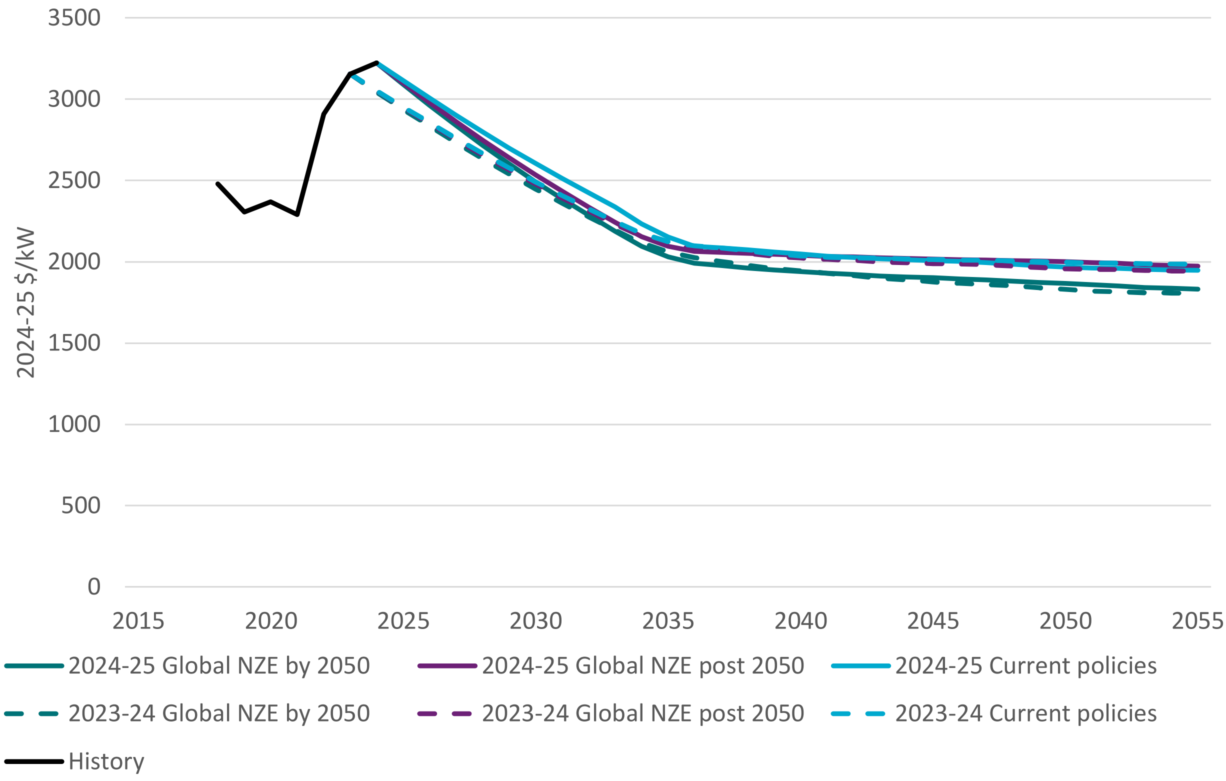

Figure 5-13 Projected capital costs for onshore wind by scenario compared to 2023-24 projections

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 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 (2024b). The updated 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 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 so

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

GenCost will continue to be required to rely on global sources of offshore wind cost data until then.

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 constraints 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 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.

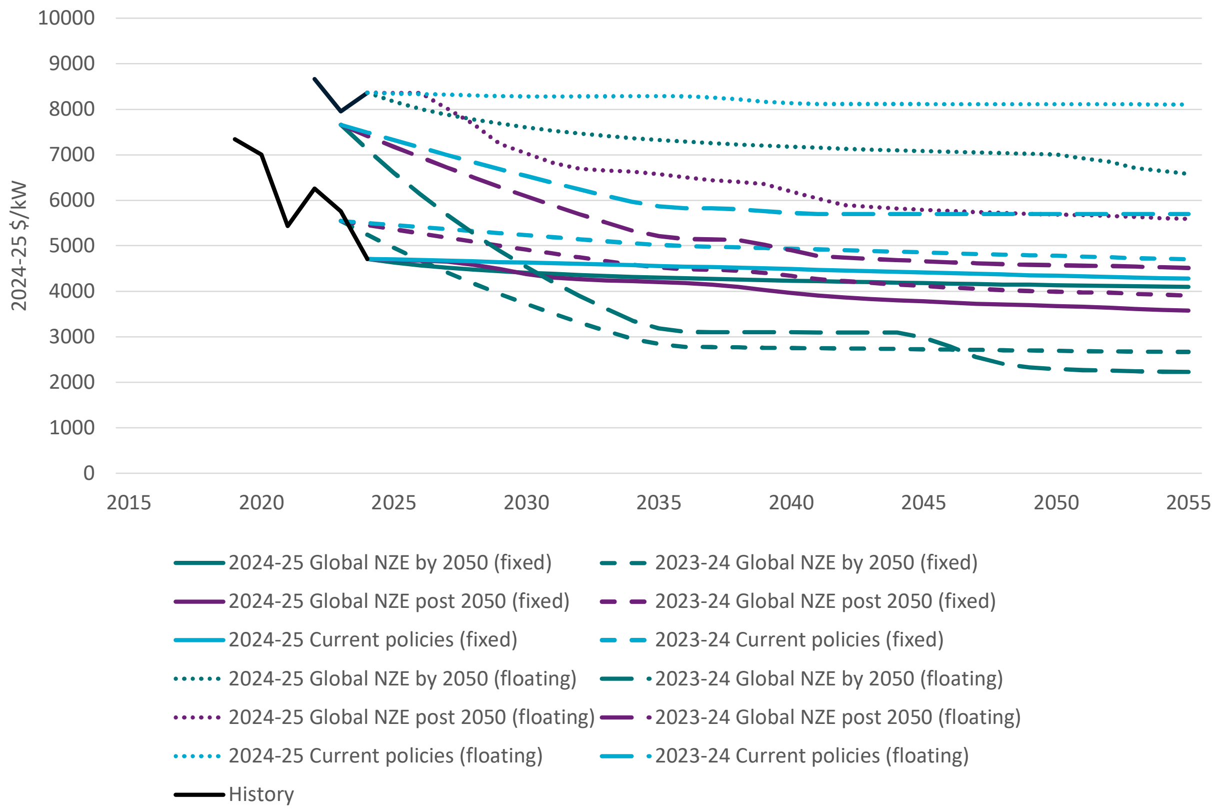

Figure 5-14 Projected capital costs for fixed and floating offshore wind by scenario compared to 2023-24 projections

5.3.13 Battery storage

The projections for batteries include a 11% to 36% decrease in total costs (depending on the duration) which is faster than the 2023-24 projections. 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.

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. However, 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. The projected future change in the total cost of battery projects is shown in Figure 5-15.

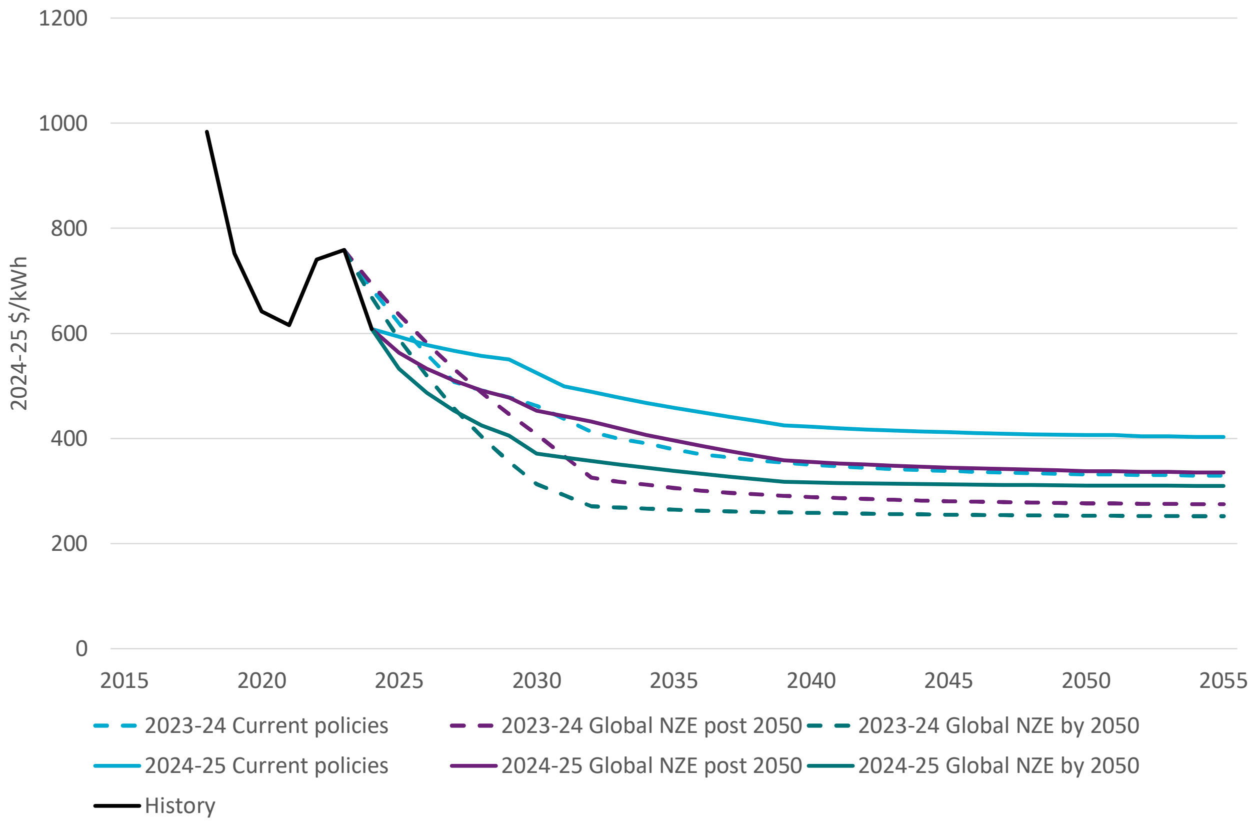

Figure 5-15 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

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

Aurecon (2024b) 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 is assumed to be a mature technology and receives the same assumed improvement rate as other mature technologies. 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 the level of global climate ambition will result in different cost trajectories before 2030. Site variability is more likely a greater source of variation in costs.

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).

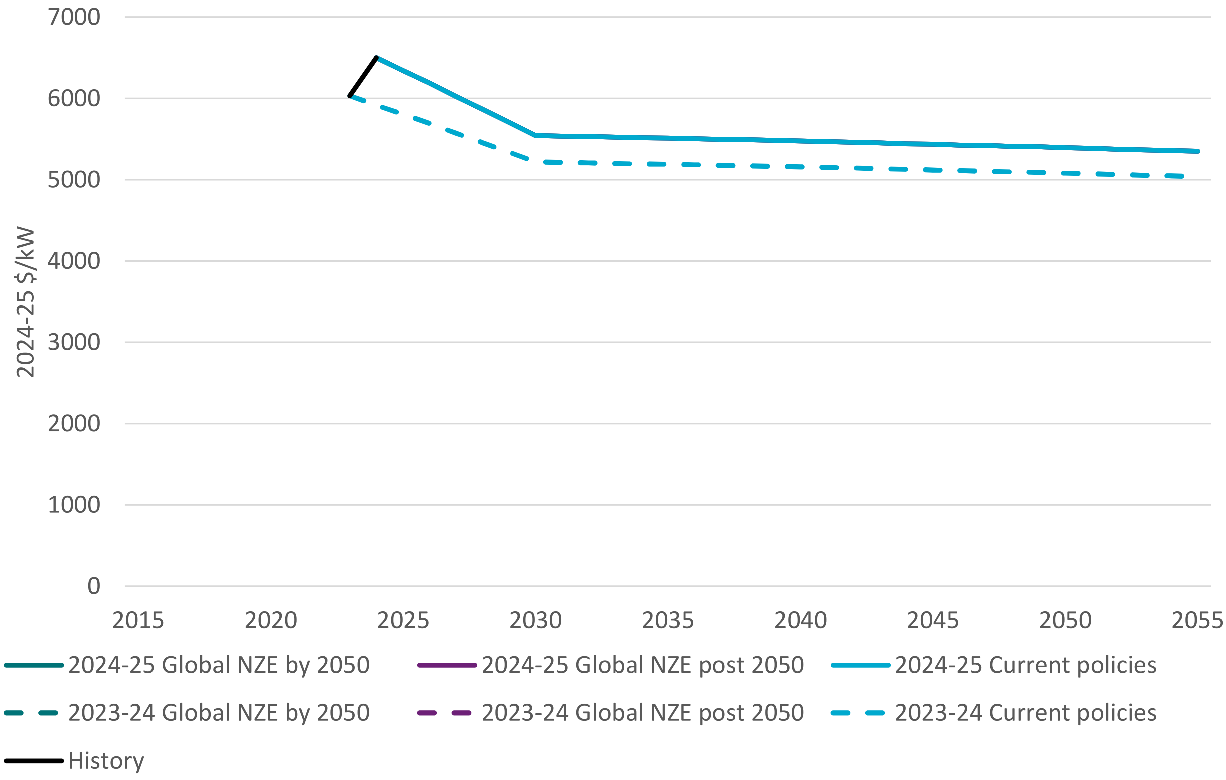

Figure 5-16 Projected capital costs for pumped hydro energy storage (24-hour) by scenario

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 costs.

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.

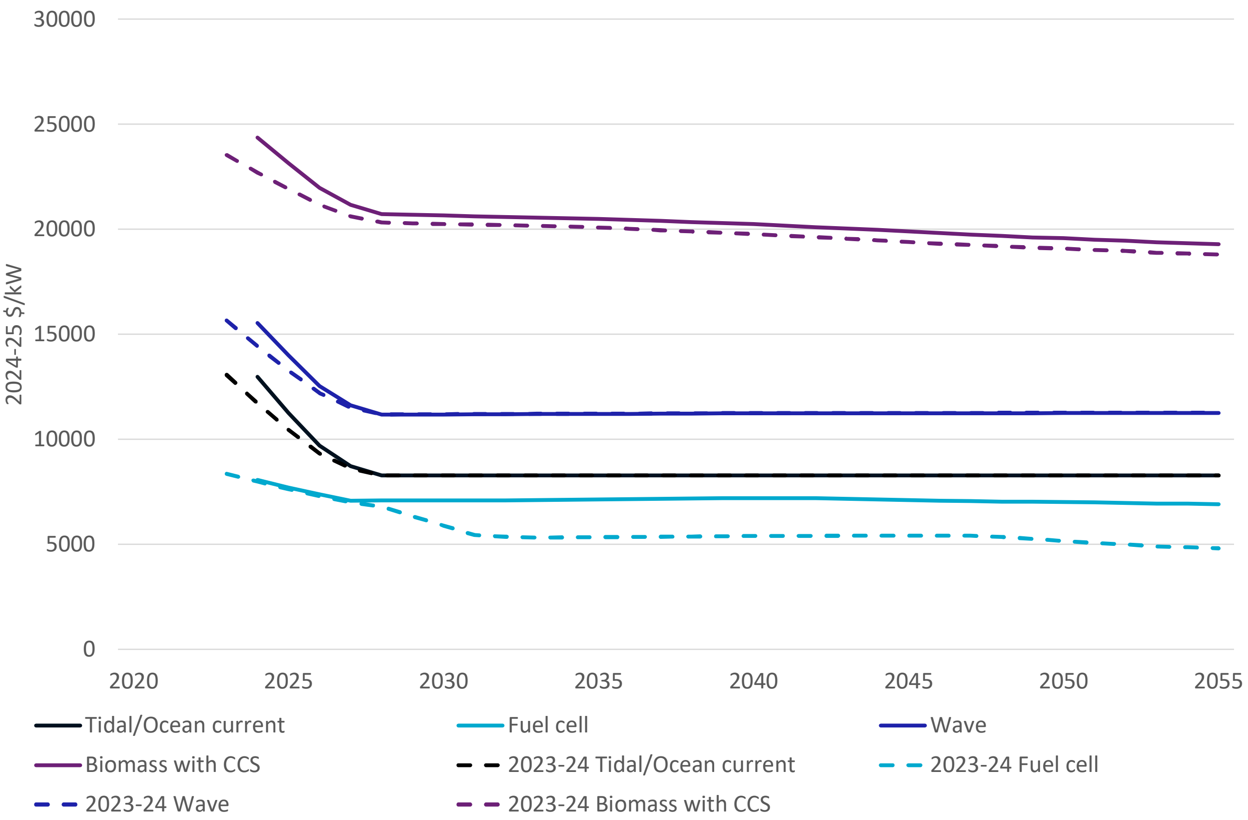

Figure 5-17 Projected technology capital costs under the *Current policies* scenario compared to 2023-24 projections

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. Fuel cells and tidal/ocean current generation are not deployed. The higher costs (reflecting lower deployment) relative to 2023-24 are the result of ongoing cost increases for these technologies relative to more mature technologies such as solar PV whose costs have decreased.

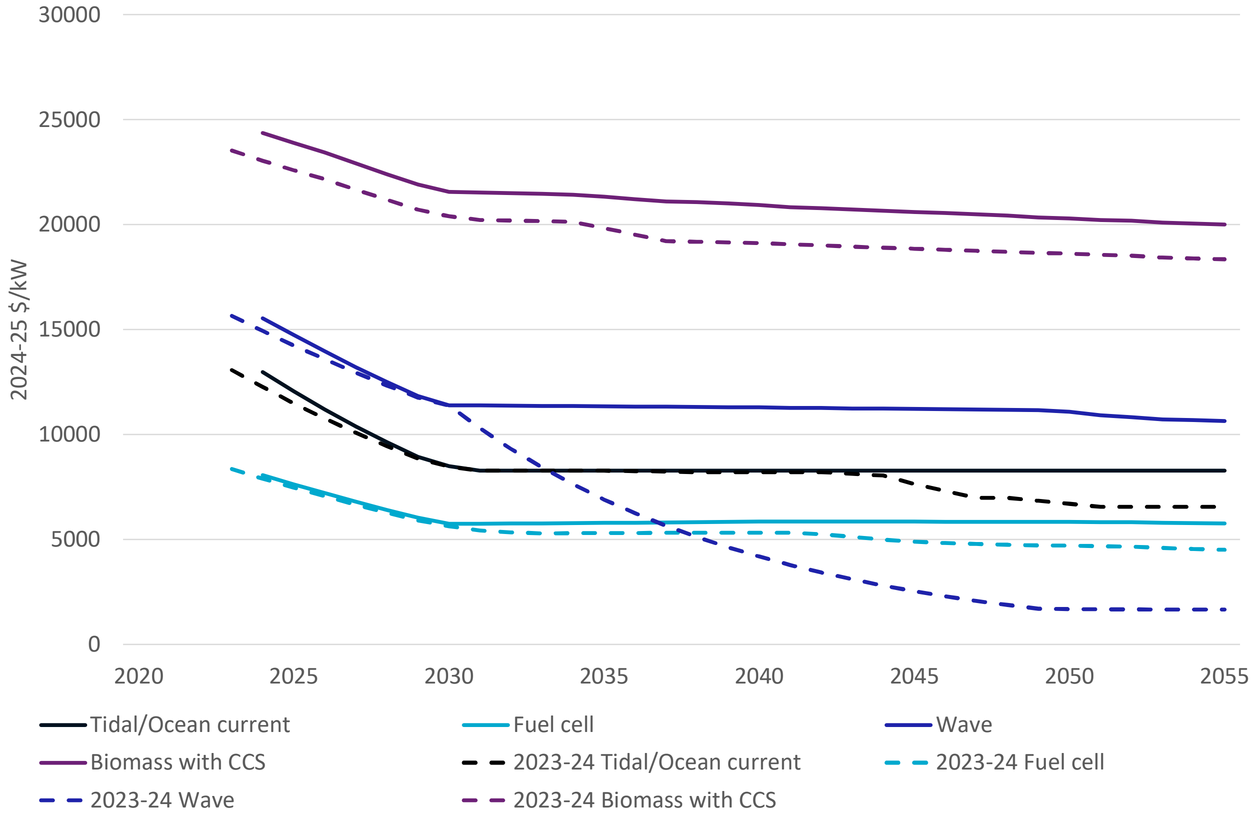

Figure 5-18 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2023-24 projections

Global NZE post 2050

Biomass with CCS is deployed at only 10% of the level of *Global NZE by 2050* but achieves similar 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 gas with CCS generation and steam methane reforming with CCS which brings down the cost of all CCS technologies sooner compared to *Current policies*.

Tida/ocean current energy is deployed at a minor level in the 2050s. Fuel cells are deployed in the 2040s but wave energy is not. Higher costs relative to 2023-24 reflect the increasing gap between costs of these technologies and more mature renewables.

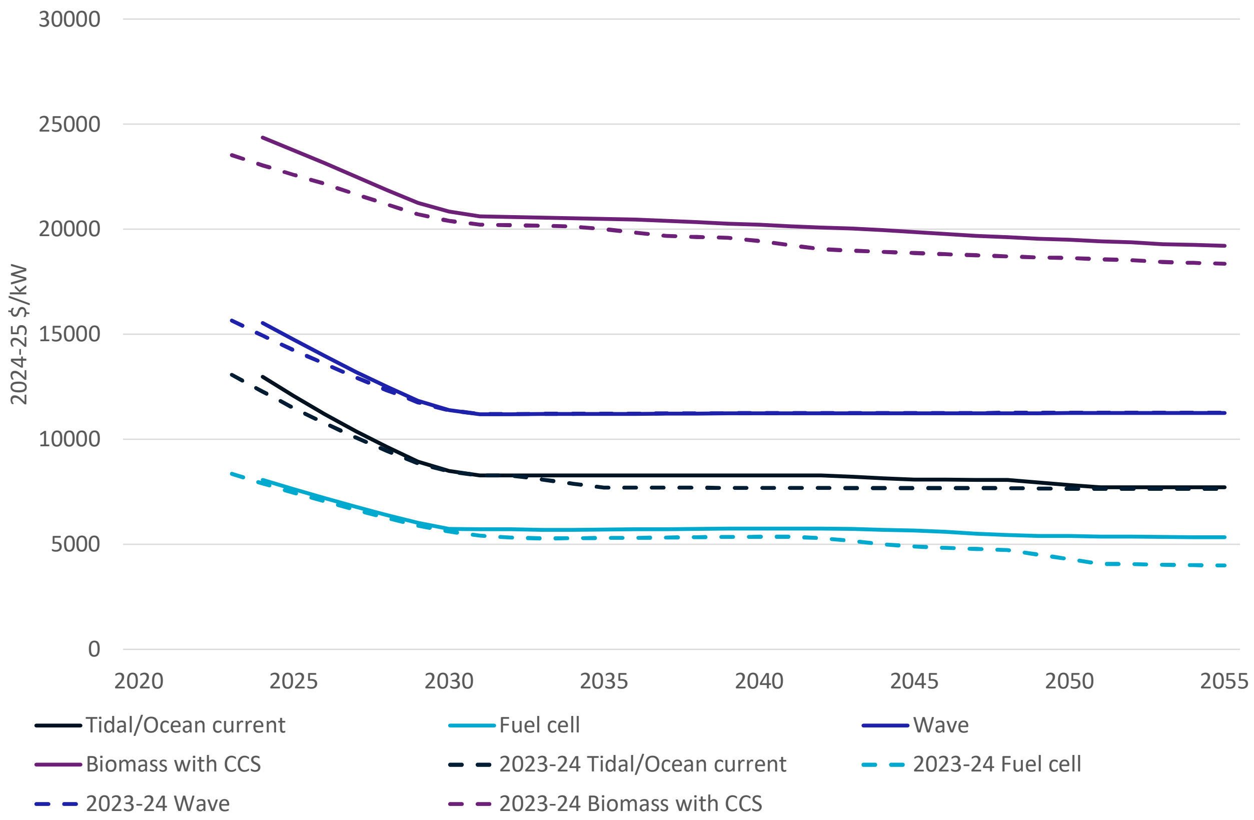

Figure 5-19 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2023-24 projections

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 (2024b). 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 sperate 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 reflect future uncertainty.

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 manufacturing which supports cost reductions through economies of scale.

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 $816/kW to $1613/kW. The range of alkaline electrolysers is $435/kW to $1138/kW.

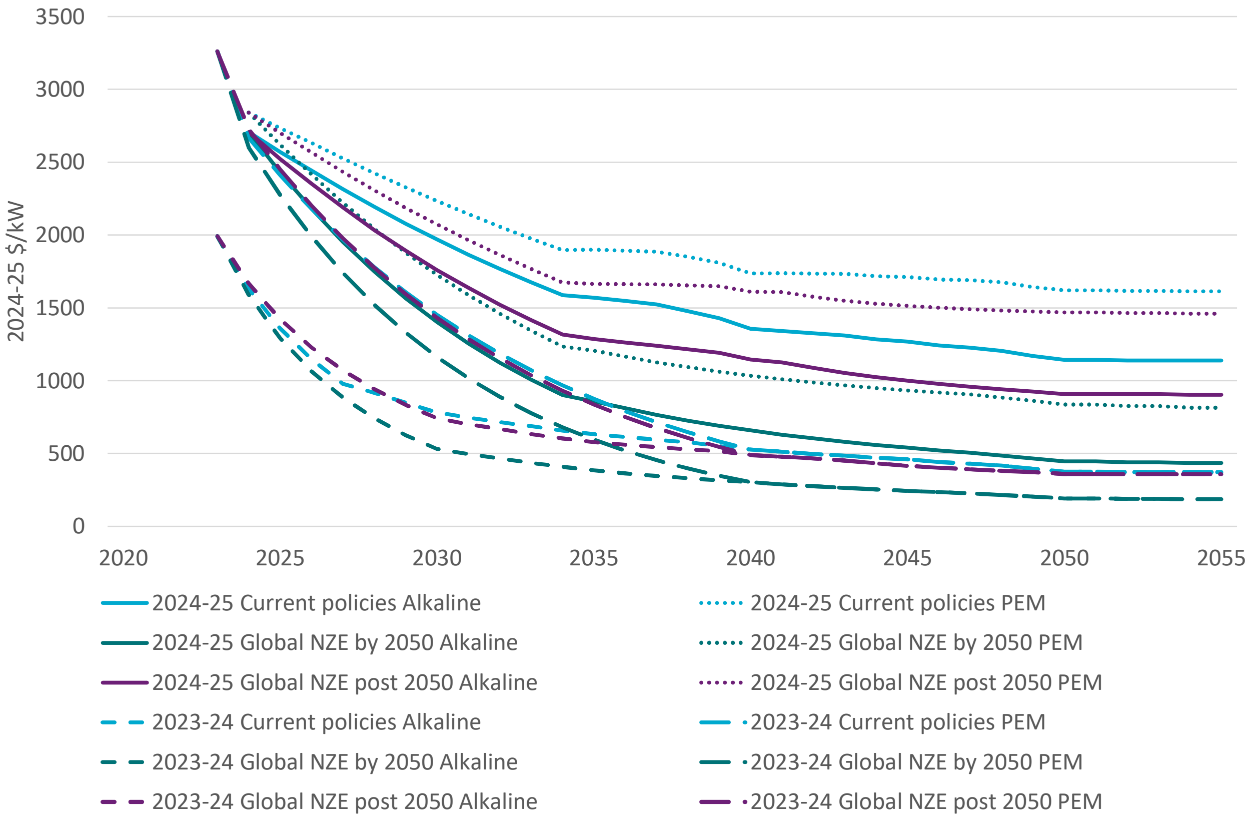

Figure 5-20 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2023-24

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 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, we proposed a new method for addressing the first dot point – inclusion of integration costs unique to variable renewables. That new method was implemented in the 2020-21 GenCost report and we update results from that method 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.

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[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 2023 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 are 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.

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. 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 65% renewable share and 57% variable renewable share in Australia ex-NT[31] (both excluding rooftop PV). The share fluctuates a few percent

[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. Also 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 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 states 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 ($3.3 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 June 2022 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 AEMO inputs and assumptions workbook (AEMO, 2023a). 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 2023 cost of integrating variable renewables

Category	$billion
Transmission	15.9
Storage	22.9
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).

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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 4.8GW, solar PV capacity by 3.9GW and large-scale batteries (VPP capacity is fixed) by 1.4GW. The capacities shown have been compared with the AEMO ISP 2030 capacity projections. The NEM coal retirements to 2030 are aligned with Step Change (June 2022 release) but the overall demand and renewable generation is lower. Wind capacity is preferred over solar PV by 2030. However, this preference is stronger in the ISP[35]. The NEM and WA total variable renewable shares are 57% and 52% on average across the weather years.

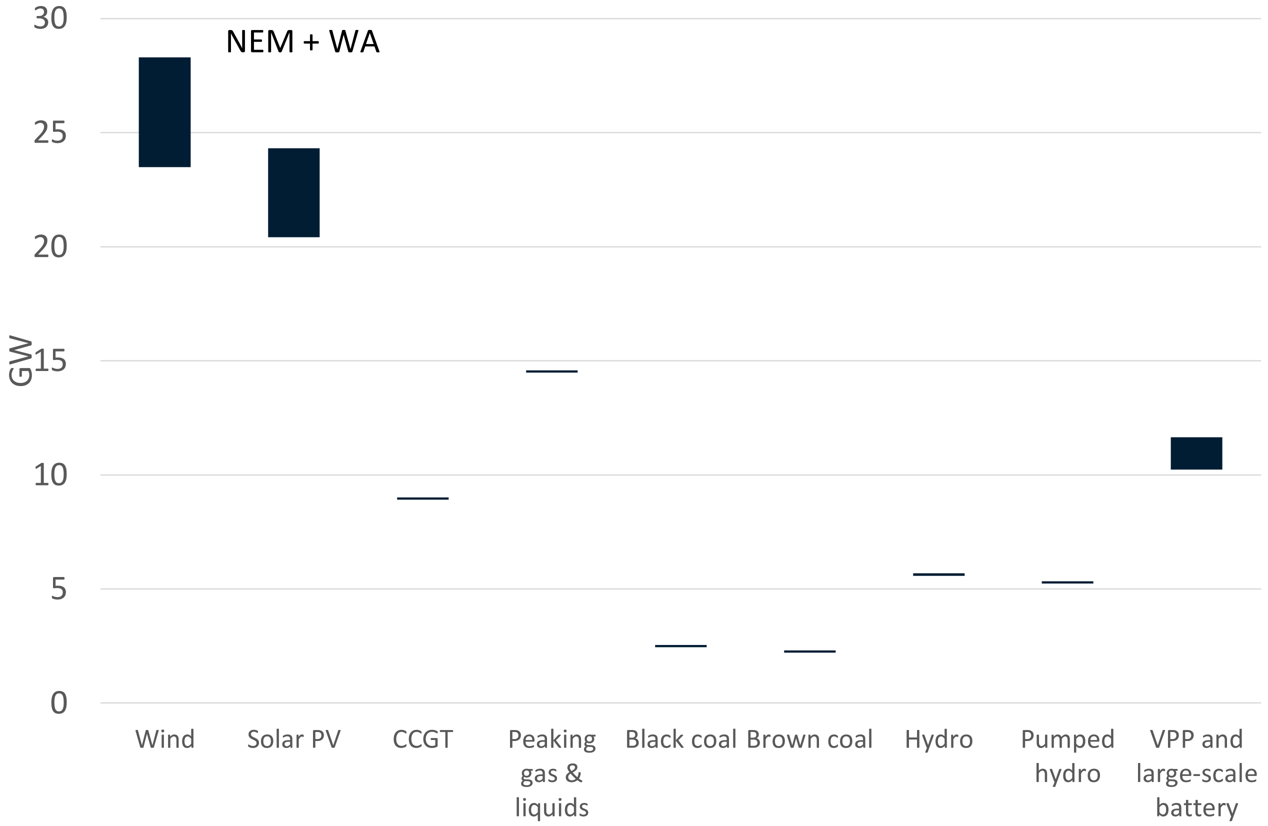

Figure 6-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia

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] This outcome only relates to 2030 and large-scale generation. When rooftop solar PV is included and as solar PV costs fall faster in the projections, a closer share of wind and solar PV is likely to emerge in the long run as reflected in the global generation mix in Figure 5-1

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 $125/MWh on average in the NEM. This is 58% higher than average costs in 2030 for 60% VRE, but only 18% 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).

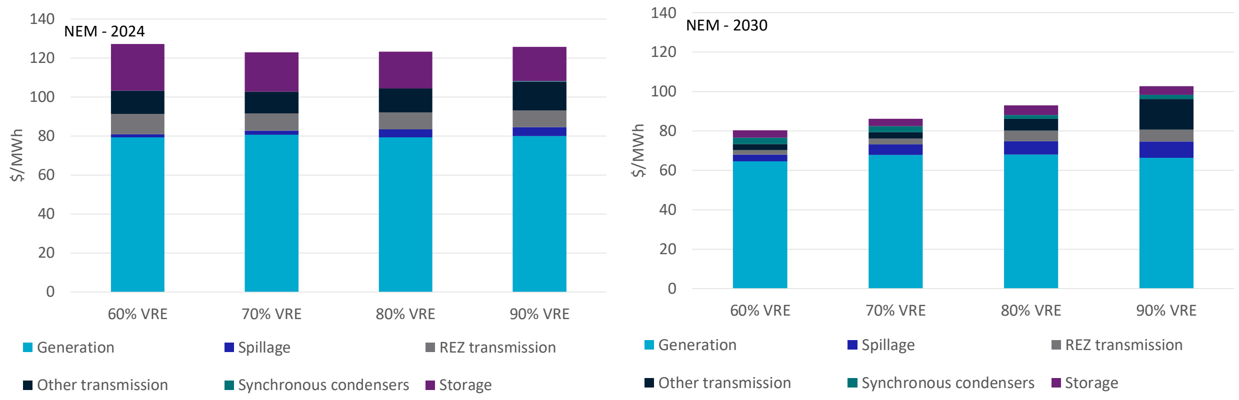

Figure 6-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in the NEM in 2024 and 2030

Variable renewable integration costs in 2023 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.

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, this 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 given the limited ability to connect, via transmission, the various isolated systems in that state. Higher or lower costs in different states or regions are averaged out at the aggregate level for the NEM and WA. The cost of REZ transmission expansions adds an average $8.20/MWh in 2024 and $5.30/MWh in 2030, as the VRE share increases from 60% to 90%. Other transmission costs add $10.00/MWh in 2024 and $4.20/MWh in 2030. Storage costs add an average $19.20/MWh in 2024 and $10.70/MWh in 2030. Spillage costs peak at the 90% VRE share at $8.70/MWh in 2024 and $15.10/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 $42/MWh to $48/MWh in 2024 and $20/MWh to $50/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 and its higher capacity factor could result in lower storage costs. Integration costs have only been calculated for onshore wind in this report given it remains the lowest cost form of wind generation.

The cost range for variable renewables with integration costs is the lowest of all new-build technology capable of supplying reliable electricity in 2024 and 2030. The cost range overlaps slightly with the lower end of the cost range for high emission coal and gas generation. However, the lower end of the range for coal and gas is only achievable if they can deliver a high capacity factor and source low cost fuel. Their deployment is also not consistent with Australia’s net zero by 2050 target. If we exclude high emission generation options, the next most competitive generation technologies are solar thermal, gas with carbon capture and storage (CCS) and large-scale nuclear.

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[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).

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.

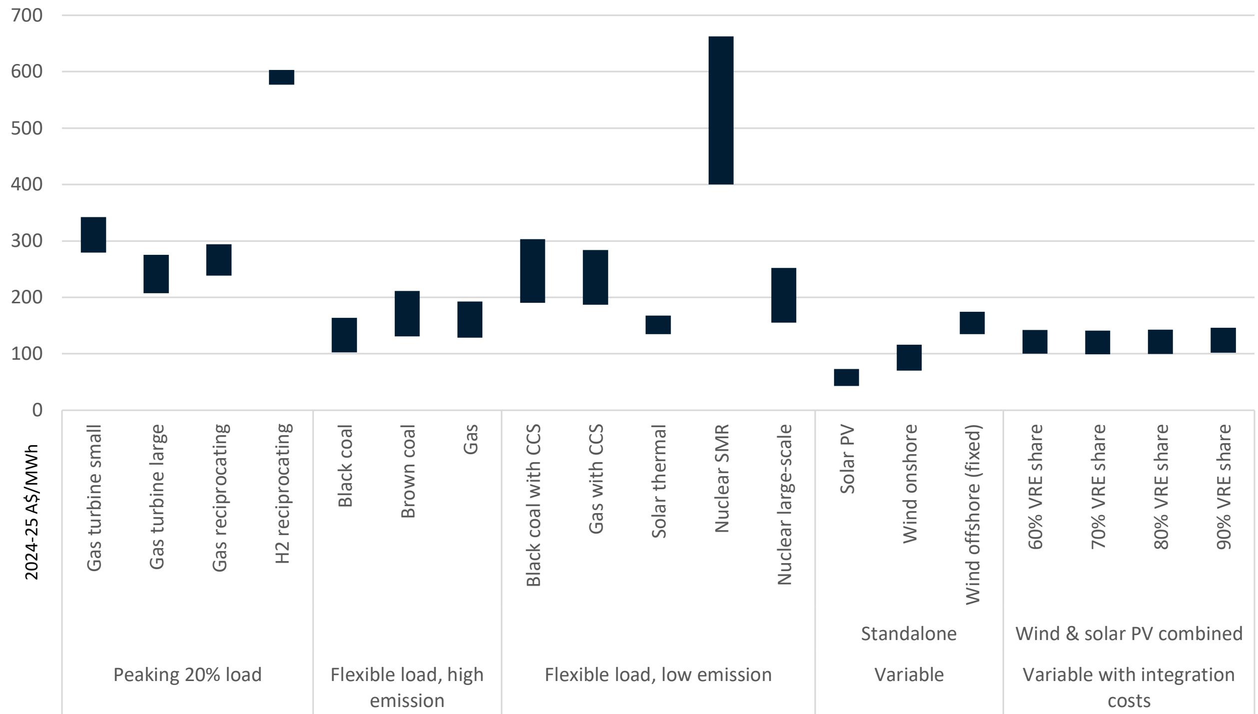

Figure 6-3 Calculated LCOE by technology and category for 2024

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 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.

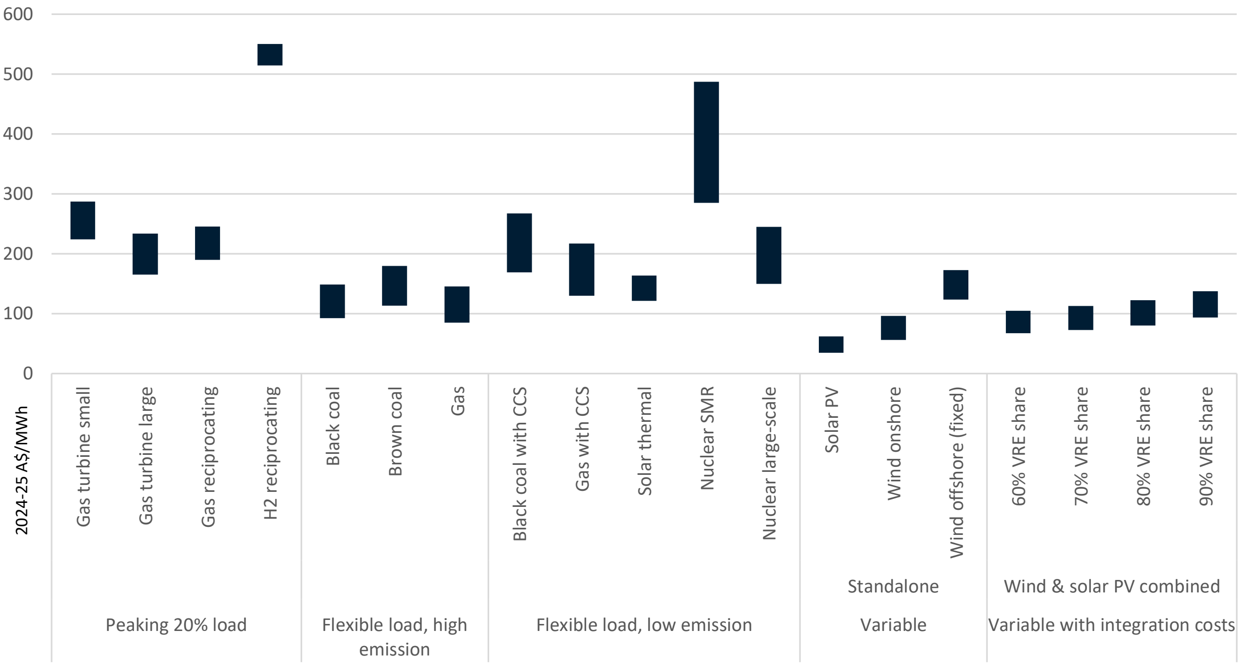

Figure 6-4 Calculated LCOE by technology and category for 2030

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. 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%.

[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.

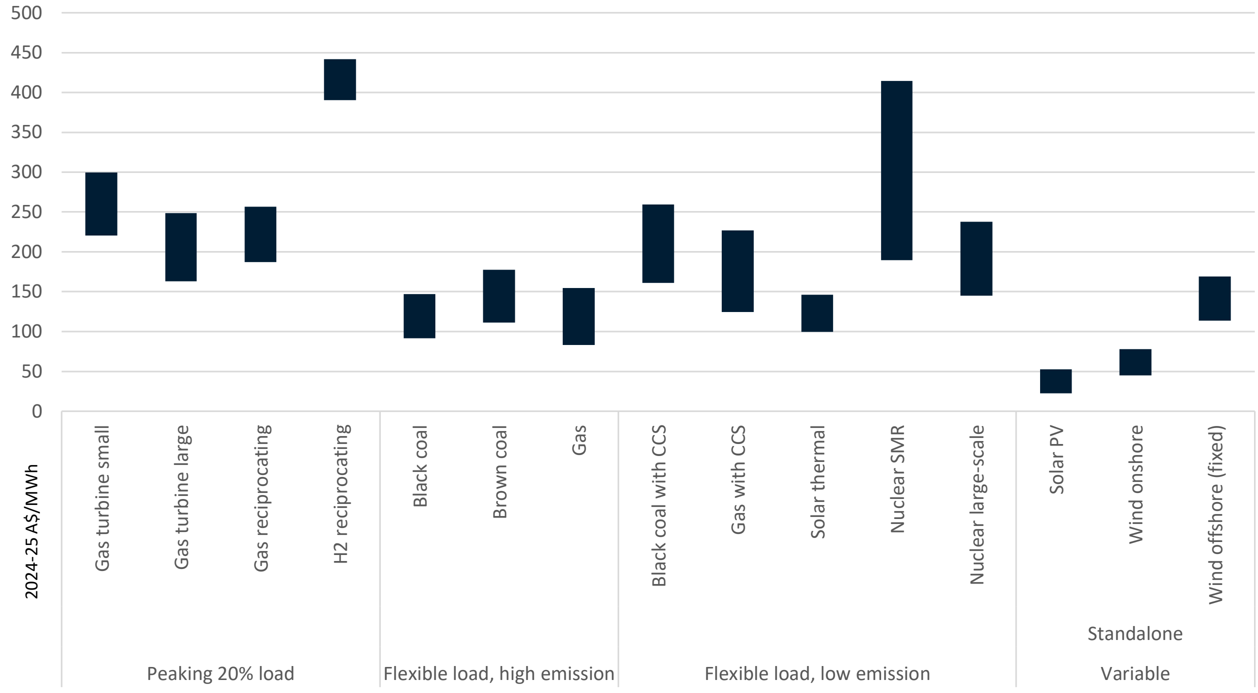

Figure 6-5 Calculated LCOE by technology and category for 2040

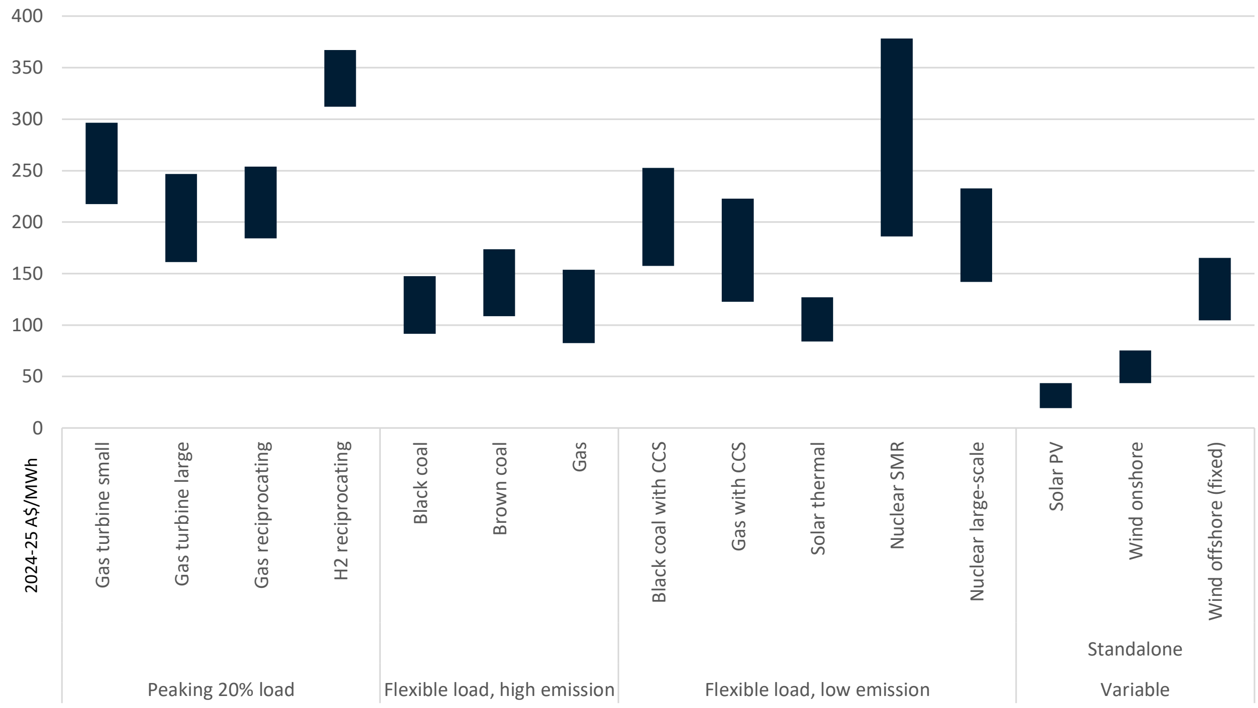

Figure 6-6 Calculated LCOE by technology and category for 2050

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 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 low demand level on these low renewable generation days is a more important benchmark in setting the amount of additional back-up capacity required.

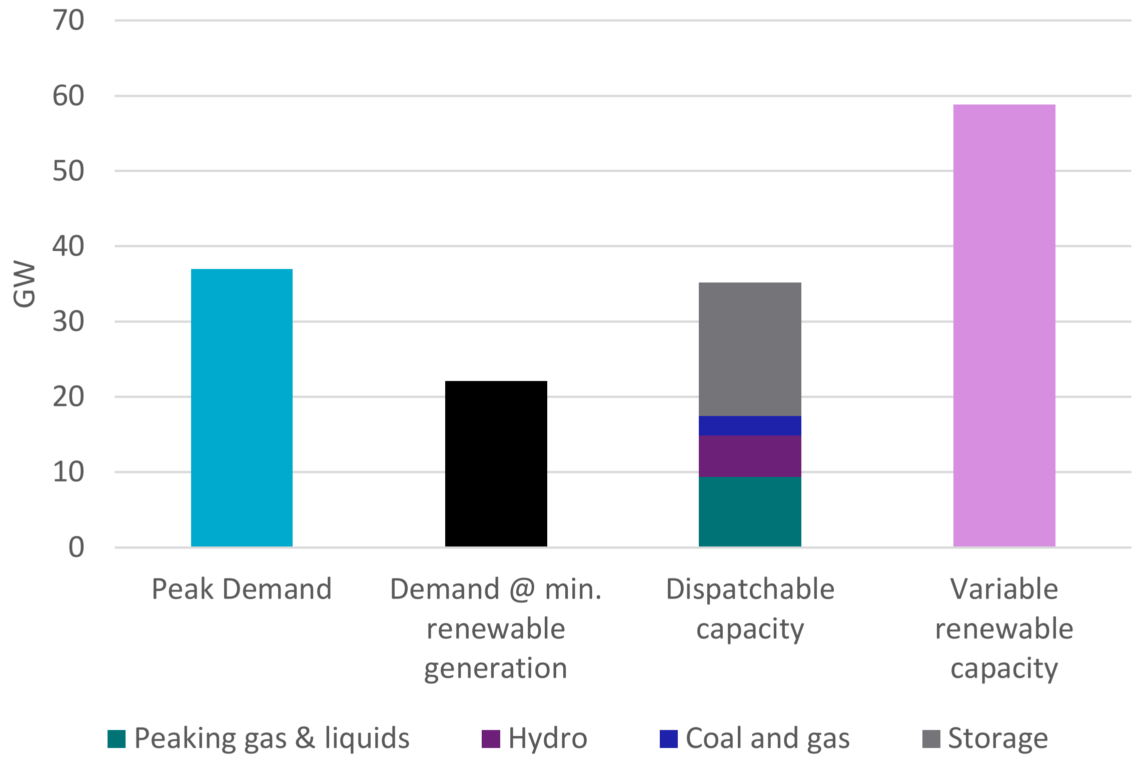

Figure 6-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

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 0.28kW to 0.41kW 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 slightly lower than maximum demand. This indicates that there is some variable renewable generation available at peak demand events in at least one state of the NEM (mostly likely 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.

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[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:

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

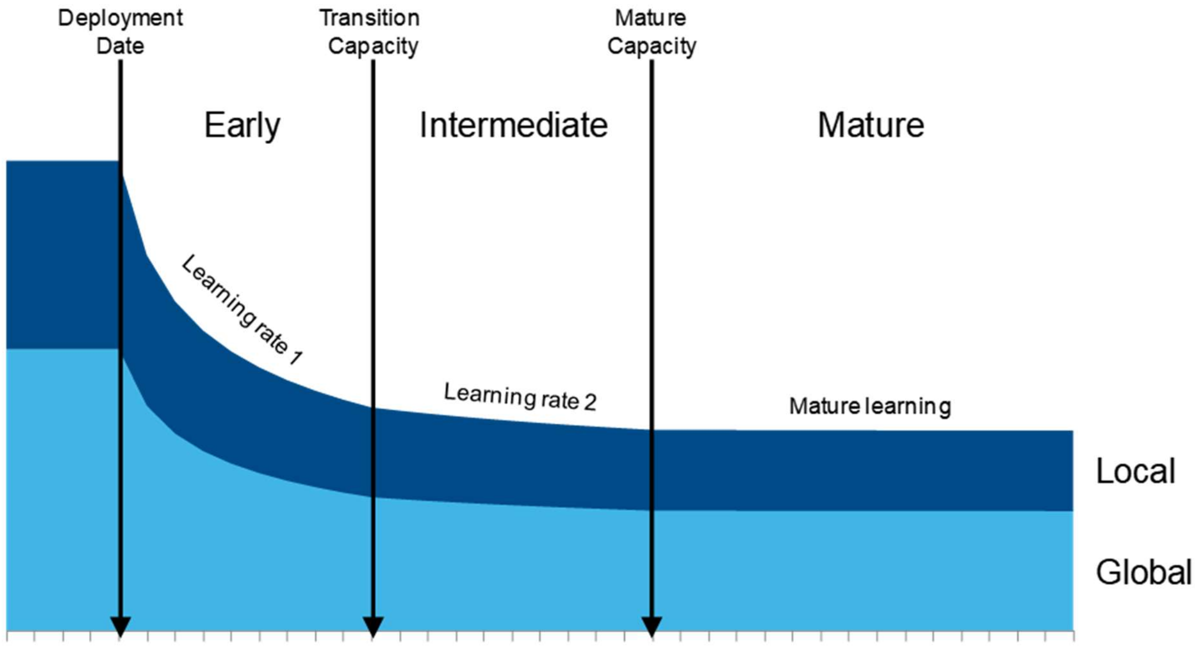
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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 Mature technologies and the "basket of costs"

There are three main drivers of mature technology costs: imported materials and equipment, domestic materials and equipment, and labour. The indices of these drivers over the last 20 years (ABS data) combined with the split in capital cost of mature technologies between imported equipment, domestic equipment and labour (BREE, 2012) was used to calculate an average rate of change in technology costs: - 0.35%. This value has been applied as an annual capital cost reduction factor to mature technologies and to operating and maintenance costs.

A.1.4 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 (2024b) 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 (2024b) 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.

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.

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	3223	4710	8362	15547	29667	12979	8067	8984
2025	5781	11667	8782	2300	2428	1311	5404	1982	2073	8954	23149	1414	1287	6633	3113	4699	8345	13986	26958	11257	7710	8834
2026	5533	11091	8264	2144	2431	1312	5025	1984	2075	8995	21975	1369	1242	6482	3006	4687	8335	12531	24231	9690	7371	8687
2027	5363	10684	7907	2034	2426	1310	4765	1980	2071	9009	21152	1322	1198	6337	2900	4673	8323	11610	21414	8725	7075	8567
2028	5284	10474	7727	1977	2421	1307	4634	1976	2067	9023	20729	1284	1163	6209	2797	4658	8306	11177	21436	8279	7085	8500
2029	5292	10452	7712	1973	2416	1305	4624	1972	2063	9037	20688	1250	1131	6084	2698	4643	8291	11181	21301	8279	7087	8483
2030	5301	10435	7698	1969	2412	1302	4617	1968	2059	9052	20651	1224	1106	5973	2603	4629	8282	11186	21168	8279	7087	8467
2031	5309	10421	7684	1966	2407	1300	4614	1965	2055	9067	20618	1191	1075	5872	2511	4615	8279	11190	21035	8279	7086	8452
2032	5316	10408	7670	1962	2403	1297	4611	1961	2051	9082	20586	1164	1050	5780	2423	4600	8282	11195	21071	8279	7096	8436
2033	5323	10397	7656	1959	2399	1295	4610	1957	2047	9097	20556	1140	1027	5696	2338	4586	8286	11199	21107	8279	7107	8421
2034	5330	10382	7642	1955	2394	1293	4605	1954	2044	9113	20524	1131	1017	5618	2231	4572	8289	11204	21144	8279	7121	8406
2035	5338	10368	7629	1952	2390	1291	4601	1951	2040	9129	20492	1123	1009	5545	2152	4558	8291	11209	21181	8279	7134	8392
2036	5346	10342	7616	1948	2386	1288	4586	1947	2037	9146	20449	1115	1000	5476	2094	4544	8286	11214	21219	8279	7148	8377
2037	5354	10312	7603	1945	2382	1286	4565	1944	2033	9162	20402	1104	989	5411	2085	4530	8262	11219	21257	8279	7162	8363
2038	5362	10273	7590	1942	2378	1284	4537	1941	2030	9179	20347	1090	975	5350	2074	4516	8219	11224	20979	8279	7176	8349
2039	5370	10236	7578	1939	2374	1282	4510	1938	2027	9196	20294	1062	949	5291	2061	4503	8167	11229	19538	8279	7190	8336
2040	5378	10202	7566	1935	2371	1280	4486	1934	2023	9214	20244	1016	907	5217	2047	4489	8134	11234	17735	8279	7205	8322
2041	5380	10159	7544	1930	2364	1276	4460	1929	2017	9219	20171	962	859	5125	2034	4474	8117	11236	16222	8279	7207	8298
2042	5382	10122	7522	1924	2357	1272	4440	1923	2012	9224	20105	921	821	5020	2025	4459	8117	11238	15874	8279	7194	8273
2043	5383	10084	7499	1918	2350	1269	4419	1917	2006	9230	20038	895	798	4922	2018	4444	8117	11239	15883	8279	7166	8249
2044	5383	10043	7477	1913	2343	1265	4395	1912	2000	9235	19968	875	780	4830	2013	4429	8115	11241	15892	8279	7131	8225
2045	5382	9998	7456	1907	2336	1261	4367	1906	1994	9240	19894	857	763	4743	2007	4414	8113	11242	15901	8279	7100	8201
2046	5380	9953	7434	1902	2329	1258	4340	1901	1988	9245	19821	840	748	4661	2001	4399	8112	11244	15911	8279	7077	8177
2047	5379	9909	7412	1896	2322	1254	4312	1895	1982	9251	19748	825	735	4583	1993	4385	8111	11246	15920	8279	7057	8153
2048	5378	9868	7390	1891	2316	1250	4289	1890	1976	9256	19679	816	726	4510	1985	4370	8111	11247	15929	8279	7039	8129
2049	5377	9832	7369	1885	2309	1247	4268	1884	1971	9262	19614	810	720	4439	1974	4355	8111	11249	15938	8279	7021	8105
2050	5376	9810	7356	1882	2305	1243	4257	1881	1967	9267	19575	807	718	4388	1967	4346	8112	11250	15948	8279	7012	8091
2051	5372	9776	7330	1875	2297	1243	4242	1874	1960	9267	19506	804	715	4337	1961	4330	8110	11250	15948	8279	6990	8063
2052	5370	9754	7313	1871	2291	1234	4233	1870	1956	9267	19462	803	714	4287	1958	4320	8110	11250	15948	8279	6976	8044
2053	5366	9712	7279	1862	2281	1234	4216	1861	1947	9267	19374	801	712	4237	1953	4300	8108	11250	15948	8279	6947	8007
2054	5364	9691	7262	1858	2275	1226	4208	1857	1942	9267	19331	800	711	4187	1950	4290	8107	11250	15948	8279	6932	7988
2055	5362	9670	7245	1853	2270	1226	4200	1852	1938	9267	19287	798	710	4139	1947	4280	8106	11250	15948	8279	6917	7969

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	3223	4710	8362	15547	29667	12979	8067	8984
2025	5919	11962	9048	2380	2428	1311	5599	1982	2073	8954	23891	1391	1266	6499	3091	4633	8168	14738	28093	12065	7626	8912
2026	5804	11669	8782	2304	2431	1312	5401	1984	2075	8995	23431	1332	1209	6251	2962	4569	8006	13958	26510	11194	7212	8842
2027	5674	11348	8498	2220	2426	1310	5194	1980	2071	9009	22909	1283	1163	6056	2837	4519	7884	13210	24838	10386	6796	8746
2028	5547	11036	8223	2137	2421	1307	4996	1976	2067	9023	22399	1231	1115	5868	2716	4476	7777	12501	23162	9636	6405	8652
2029	5423	10734	7958	2053	2416	1305	4805	1972	2063	9037	21902	1184	1071	5653	2601	4441	7686	11831	21481	8940	6037	8559
2030	5344	10529	7779	1996	2412	1302	4678	1968	2059	9052	21563	1141	1031	5437	2491	4409	7601	11398	20359	8494	5753	8493
2031	5310	10421	7684	1966	2407	1300	4614	1965	2055	9067	21529	1105	997	5251	2386	4382	7529	11387	19233	8279	5754	8452
2032	5319	10408	7670	1962	2403	1297	4611	1961	2051	9082	21495	1080	974	5115	2285	4358	7467	11376	18273	8279	5762	8436
2033	5328	10397	7656	1959	2399	1295	4610	1957	2047	9097	21464	1062	956	4986	2188	4337	7413	11365	18304	8279	5772	8421
2034	5337	10382	7642	1955	2394	1293	4605	1954	2044	9113	21430	1000	900	4878	2095	4318	7366	11354	18336	8279	5782	8406
2035	5347	10294	7629	1952	2390	1291	4530	1951	2040	9129	21321	911	818	4767	2030	4301	7325	11343	17453	8279	5794	8392
2036	5356	10206	7616	1948	2386	1288	4455	1947	2037	9146	21212	812	729	4674	1990	4286	7288	11332	16567	8279	5805	8377
2037	5366	10120	7603	1945	2382	1286	4381	1944	2033	9162	21106	756	677	4579	1975	4271	7256	11321	15678	8279	5816	8363
2038	5376	10109	7590	1942	2378	1284	4379	1941	2030	9179	21077	720	645	4491	1962	4258	7227	11311	15707	8279	5827	8349
2039	5386	10054	7578	1939	2374	1282	4335	1938	2027	9196	21003	693	619	4380	1950	4246	7201	11300	15737	8279	5839	8336
2040	5396	10001	7566	1935	2371	1280	4292	1934	2023	9214	20931	671	599	4269	1940	4235	7178	11290	15767	8279	5851	8322
2041	5399	9934	7544	1930	2364	1276	4243	1929	2017	9219	20831	653	583	4142	1929	4223	7154	11276	15775	8279	5854	8298
2042	5402	9911	7522	1924	2357	1272	4237	1923	2012	9224	20776	639	570	4034	1920	4211	7133	11262	15784	8279	5855	8273
2043	5405	9886	7499	1918	2350	1269	4229	1917	2006	9230	20720	628	560	3921	1913	4200	7114	11248	15793	8279	5854	8249
2044	5408	9862	7477	1913	2343	1265	4221	1912	2000	9235	20664	619	551	3831	1907	4190	7096	11234	15802	8279	5850	8225
2045	5411	9837	7456	1907	2336	1261	4213	1906	1994	9240	20608	610	543	3747	1901	4180	7080	11220	15811	8279	5847	8201
2046	5415	9815	7434	1902	2329	1258	4206	1901	1988	9245	20554	603	537	3678	1895	4170	7065	11206	15821	8279	5846	8177
2047	5418	9786	7412	1896	2322	1254	4194	1895	1982	9251	20493	596	530	3613	1888	4161	7051	11192	15830	8279	5844	8153
2048	5421	9745	7390	1891	2316	1250	4169	1890	1976	9256	20421	591	526	3552	1881	4151	7037	11178	15839	8279	5844	8129
2049	5424	9699	7369	1885	2309	1247	4141	1884	1971	9262	20344	578	514	3493	1873	4142	7020	11164	15848	8279	5843	8105
2050	5427	9670	7356	1882	2305	1243	4122	1881	1967	9267	20296	569	505	3444	1868	4136	7008	11080	15857	8279	5844	8091
2051	5427	9636	7330	1875	2297	1243	4107	1874	1960	9267	20224	557	496	3395	1858	4126	6925	10916	15857	8279	5833	8063
2052	5427	9615	7313	1871	2291	1234	4100	1870	1956	9267	20179	556	494	3347	1852	4120	6849	10837	15857	8279	5823	8044
2053	5427	9575	7279	1862	2281	1234	4085	1861	1947	9267	20090	553	492	3300	1841	4108	6710	10720	15857	8279	5799	8007
2054	5427	9555	7262	1858	2275	1226	4078	1857	1942	9267	20045	552	491	3253	1837	4103	6645	10681	15857	8279	5785	7988
2055	5427	9536	7245	1853	2270	1226	4071	1852	1938	9267	20001	551	490	3207	1833	4097	6581	10643	15857	8279	5771	7969

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	3223	4710	8362	15547	29667	12979	8067	8984
2025	5919	11962	9048	2380	2428	1311	5599	1982	2073	8954	23753	1403	1277	6499	3099	4691	8358	14738	28093	12065	7622	8834
2026	5804	11669	8782	2304	2431	1312	5401	1984	2075	8994	23154	1351	1226	6251	2978	4673	8356	13958	26510	11194	7203	8687
2027	5674	11348	8498	2220	2426	1310	5194	1980	2071	9007	22502	1302	1181	6056	2860	4649	8023	13210	24838	10386	6784	8567
2028	5547	11036	8223	2137	2421	1307	4996	1976	2067	9021	21869	1258	1139	5919	2746	4581	7679	12501	23162	9636	6390	8500
2029	5423	10734	7958	2053	2416	1305	4805	1972	2063	9035	21255	1217	1101	5807	2637	4485	7239	11831	21481	8940	6019	8483
2030	5344	10529	7779	1996	2412	1302	4678	1968	2059	9049	20840	1183	1069	5666	2533	4379	7033	11398	20359	8494	5736	8467
2031	5310	10421	7684	1966	2407	1300	4614	1965	2055	9064	20618	1148	1036	5497	2432	4305	6821	11190	19183	8279	5724	8452
2032	5319	10408	7670	1962	2403	1297	4611	1961	2051	9079	20586	1122	1012	5314	2336	4265	6694	11195	18173	8279	5707	8436
2033	5328	10397	7656	1959	2399	1295	4610	1957	2047	9094	20556	1101	992	5154	2243	4239	6654	11199	18154	8279	5692	8421
2034	5337	10382	7642	1955	2394	1293	4605	1954	2044	9110	20524	1066	958	5021	2154	4226	6630	11204	18186	8279	5690	8406
2035	5347	10368	7629	1952	2390	1291	4601	1951	2040	9126	20492	1017	914	4913	2094	4202	6573	11209	17344	8279	5701	8392
2036	5356	10354	7616	1948	2386	1288	4597	1947	2037	9142	20461	963	864	4832	2063	4185	6504	11214	16500	8279	5711	8377
2037	5366	10311	7603	1945	2382	1286	4565	1944	2033	9159	20401	930	833	4758	2057	4146	6443	11219	14878	8279	5722	8363
2038	5376	10269	7590	1942	2378	1284	4533	1941	2030	9175	20343	905	810	4694	2052	4097	6404	11224	14128	8279	5732	8349
2039	5386	10204	7578	1939	2374	1282	4479	1938	2027	9193	20262	877	784	4625	2045	4023	6355	11229	13031	8279	5743	8336
2040	5396	10172	7566	1935	2371	1280	4457	1934	2023	9210	20214	843	753	4570	2039	3961	6190	11234	12710	8279	5754	8322
2041	5399	10127	7544	1930	2364	1276	4429	1929	2017	9215	20140	808	721	4501	2033	3908	6036	11236	12372	8279	5756	8298
2042	5402	10104	7522	1924	2357	1272	4423	1923	2012	9220	20087	780	696	4431	2029	3868	5892	11238	12379	8279	5749	8273
2043	5405	10081	7499	1918	2350	1269	4416	1917	2006	9225	20035	761	679	4357	2024	3833	5852	11239	12386	8215	5734	8249
2044	5408	10038	7477	1913	2343	1265	4390	1912	2000	9230	19963	747	666	4288	2020	3803	5818	11241	12393	8151	5695	8225
2045	5411	9969	7456	1907	2336	1261	4340	1906	1994	9235	19866	733	653	4227	2017	3775	5788	11242	12400	8080	5660	8201
2046	5415	9901	7434	1902	2329	1258	4289	1901	1988	9240	19769	721	642	4155	2013	3751	5762	11244	12407	8073	5596	8177
2047	5418	9844	7412	1896	2322	1254	4250	1895	1982	9246	19684	711	632	4073	2009	3729	5739	11246	12414	8065	5516	8153
2048	5421	9807	7390	1891	2316	1250	4230	1890	1976	9251	19619	703	626	3975	2006	3709	5719	11247	12421	8065	5438	8129
2049	5424	9762	7369	1885	2309	1247	4201	1884	1971	9256	19545	694	617	3881	2003	3691	5700	11249	12428	7947	5393	8105
2050	5427	9734	7356	1882	2305	1243	4184	1881	1967	9261	19500	688	612	3814	2001	3679	5684	11250	12436	7829	5387	8091
2051	5427	9695	7330	1875	2297	1243	4164	1874	1960	9261	19427	681	605	3748	1995	3658	5673	11250	12436	7711	5374	8063
2052	5427	9673	7313	1871	2291	1234	4155	1870	1956	9261	19382	680	604	3684	1990	3642	5653	11250	12436	7711	5366	8044
2053	5427	9630	7279	1862	2281	1234	4138	1861	1947	9261	19294	677	602	3620	1981	3610	5637	11250	12436	7711	5349	8007
2054	5427	9610	7262	1858	2275	1226	4131	1857	1942	9261	19251	676	601	3558	1977	3595	5608	11250	12436	7711	5341	7988
2055	5427	9590	7245	1853	2270	1226	4123	1852	1938	9261	19209	675	600	3497	1973	3580	5593	11250	12436	7711	5333	7969

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	889	836	784	319	310	302	570	526	482	593	563	533	307	299	290	287	265	243
2026	864	788	713	313	296	280	551	492	433	577	532	487	301	285	269	277	247	217
2027	848	755	663	307	284	262	541	471	401	567	510	453	295	273	252	272	237	201
2028	833	728	622	302	274	246	531	454	376	557	491	425	290	263	236	267	228	189
2029	824	708	592	298	266	234	525	442	358	550	478	405	286	256	225	264	222	180
2030	780	667	531	290	257	228	490	410	302	525	453	371	279	247	219	246	206	152
2031	737	654	522	282	249	223	455	406	299	499	442	364	271	239	214	228	204	150
2032	724	641	513	274	240	217	450	401	296	489	432	357	263	231	209	226	201	148
2033	709	623	505	266	232	212	443	391	293	478	419	350	255	223	203	222	196	147
2034	696	606	498	259	224	207	437	382	291	467	407	344	248	215	198	219	191	146
2035	685	592	491	251	217	202	433	375	289	458	396	338	241	208	193	217	188	145
2036	674	579	484	244	210	197	430	369	288	449	386	333	234	201	188	215	185	144
2037	664	566	478	237	203	192	426	363	286	441	376	327	228	194	184	213	182	143
2038	654	554	473	231	196	187	423	358	286	433	367	322	221	188	179	212	179	143
2039	644	543	467	224	189	182	420	354	285	425	358	317	214	181	175	210	177	142
2040	640	539	466	223	188	182	418	350	284	422	355	316	213	180	174	209	175	142
2041	636	534	465	221	187	182	415	346	283	419	353	315	212	179	174	208	173	142
2042	633	530	464	220	187	181	413	343	282	417	350	315	211	179	173	207	172	141
2043	630	526	463	219	186	181	411	340	282	415	348	314	209	178	173	206	170	141
2044	628	523	462	218	185	181	410	338	281	413	346	313	209	177	173	205	169	141
2045	625	520	461	217	185	180	408	335	280	412	344	313	208	177	172	204	168	140
2046	623	518	460	217	184	180	406	333	280	410	343	312	207	176	172	203	167	140
2047	621	515	459	216	184	180	405	332	279	409	341	312	207	176	172	202	166	140
2048	619	513	458	215	183	180	404	330	279	408	340	311	206	175	172	202	165	139
2049	618	512	458	215	183	180	403	328	278	407	339	311	206	175	172	201	164	139
2050	617	509	457	215	183	180	402	326	278	406	338	311	205	175	172	201	163	139
2051	617	509	457	215	183	180	402	326	278	406	338	311	205	175	172	201	163	139
2052	613	506	457	214	182	179	399	324	277	404	336	310	205	174	171	200	162	139
2053	613	506	457	214	182	179	399	324	277	404	336	310	205	174	171	200	162	139
2054	611	504	456	213	182	179	397	323	277	402	335	310	204	174	171	199	161	138
2055	611	504	456	213	182	179	397	323	277	402	335	310	204	174	171	199	161	138

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	413	394	376	268	260	253	145	134	123	336	323	310	260	253	246	76	70	64
2026	402	373	345	262	248	235	140	125	110	327	306	285	254	241	228	73	65	58
2027	395	358	321	257	238	219	138	120	102	321	293	266	249	231	212	72	63	53
2028	388	344	301	253	229	206	135	115	95	315	282	249	245	222	199	71	60	50
2029	383	335	287	249	223	196	133	112	91	311	274	237	242	216	190	70	59	47
2030	367	319	268	242	215	191	124	104	77	300	263	225	235	208	185	65	54	40
2031	351	311	262	235	208	186	115	103	76	288	255	220	228	201	180	60	54	40
2032	343	302	256	229	201	181	114	102	75	281	247	215	222	194	176	60	53	39
2033	334	293	251	222	194	177	112	99	74	274	239	210	215	188	171	59	52	39
2034	326	284	246	216	187	172	111	97	74	267	232	205	209	181	167	58	50	38
2035	319	276	241	209	181	168	110	95	73	260	224	201	203	175	163	57	50	38
2036	312	268	236	203	175	164	109	93	73	254	218	196	197	169	158	57	49	38
2037	305	260	232	198	169	160	108	92	72	247	211	192	191	163	154	56	48	38
2038	299	253	228	192	163	155	107	90	72	241	205	188	186	158	150	56	47	38
2039	292	247	223	186	157	152	106	89	72	235	199	184	180	152	147	55	47	37
2040	290	245	223	185	156	151	105	88	72	234	197	183	179	151	146	55	46	37
2041	288	243	222	184	156	151	105	87	71	232	196	183	177	150	146	55	46	37
2042	287	241	221	183	155	150	104	86	71	231	195	182	177	150	145	54	45	37
2043	285	240	221	182	154	150	104	86	71	230	194	182	176	149	145	54	45	37
2044	284	239	221	181	154	150	103	85	71	229	193	182	175	149	145	54	44	37
2045	283	238	220	180	153	150	103	84	71	228	192	181	174	148	145	54	44	37
2046	282	237	220	180	153	149	102	84	70	227	191	181	174	148	144	53	44	37
2047	281	236	219	179	152	149	102	83	70	226	191	181	173	147	144	53	43	37
2048	280	235	219	179	152	149	102	83	70	225	190	181	173	147	144	53	43	37
2049	279	234	219	178	152	149	101	83	70	225	190	180	172	147	144	53	43	36
2050	279	233	219	178	151	149	101	82	70	225	189	180	172	146	144	53	43	36
2051	279	233	219	178	151	149	101	82	70	225	189	180	172	146	144	53	43	36
2052	278	233	218	177	151	149	100	82	70	224	188	180	171	146	144	52	42	36
2053	278	233	218	177	151	149	100	82	70	224	188	180	171	146	144	52	42	36
2054	277	232	218	177	151	148	100	81	70	223	188	180	171	146	143	52	42	36
2055	277	232	218	177	151	148	100	81	70	223	188	180	171	146	143	52	42	36

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	310	299	288	260	252	245	51	47	43	285	276	267	260	252	245	25	23	21
2026	302	284	266	254	241	227	49	44	38	278	262	247	254	241	227	24	22	19
2027	297	272	248	249	230	212	48	42	35	273	251	230	249	230	212	24	21	18
2028	291	262	232	244	222	199	47	40	33	268	242	216	244	222	199	23	20	17
2029	288	254	221	241	215	189	46	39	32	264	235	205	241	215	189	23	20	16
2030	278	244	211	234	208	185	43	36	27	256	226	198	234	208	185	22	18	13
2031	268	236	206	228	201	180	40	36	26	248	219	193	228	201	180	20	18	13
2032	261	229	201	221	194	175	40	35	26	241	211	188	221	194	175	20	18	13
2033	253	221	196	214	187	171	39	34	26	234	204	184	214	187	171	19	17	13
2034	247	214	192	208	181	166	38	34	26	227	197	179	208	181	166	19	17	13
2035	240	207	187	202	174	162	38	33	25	221	191	175	202	174	162	19	16	13
2036	234	201	183	196	168	158	38	32	25	215	184	170	196	168	158	19	16	13
2037	228	194	179	190	162	154	37	32	25	209	178	166	190	162	154	19	16	13
2038	222	188	175	185	157	150	37	31	25	203	172	162	185	157	150	18	16	12
2039	216	182	171	179	151	146	37	31	25	197	167	158	179	151	146	18	15	12
2040	214	181	170	178	150	145	36	31	25	196	166	158	178	150	145	18	15	12
2041	213	180	170	177	150	145	36	30	25	195	165	157	177	150	145	18	15	12
2042	212	179	169	176	149	145	36	30	25	194	164	157	176	149	145	18	15	12
2043	210	178	169	175	148	144	36	30	25	193	163	157	175	148	144	18	15	12
2044	210	177	168	174	148	144	36	29	24	192	162	156	174	148	144	18	15	12
2045	209	176	168	173	147	144	35	29	24	191	162	156	173	147	144	18	15	12
2046	208	176	168	173	147	144	35	29	24	190	161	156	173	147	144	18	15	12
2047	207	175	168	172	146	143	35	29	24	190	161	155	172	146	143	18	14	12
2048	207	175	167	172	146	143	35	29	24	189	160	155	172	146	143	18	14	12
2049	206	174	167	171	146	143	35	29	24	189	160	155	171	146	143	17	14	12
2050	206	174	167	171	145	143	35	28	24	188	160	155	171	145	143	17	14	12
2051	206	174	167	171	145	143	35	28	24	188	160	155	171	145	143	17	14	12
2052	205	173	167	170	145	143	35	28	24	188	159	155	170	145	143	17	14	12
2053	205	173	167	170	145	143	35	28	24	188	159	155	170	145	143	17	14	12
2054	204	173	167	170	145	142	35	28	24	187	159	155	170	145	142	17	14	12
2055	204	173	167	170	145	142	35	28	24	187	159	155	170	145	142	17	14	12

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

	$/kW			$/kWh		
	10hrs	24hrs	48hrs	10hrs	24hrs	48hrs
2024	7677	6496	7822	768	271	163
2025	7493	6341	7635	749	264	159
2026	7310	6186	7448	731	258	155
2027	7119	6024	7254	712	251	151
2028	6929	5863	7060	693	244	147
2029	6739	5702	6866	674	238	143
2030	6548	5541	6672	655	231	139
2031	6540	5534	6664	654	231	139
2032	6532	5527	6656	653	230	139
2033	6524	5521	6647	652	230	138
2034	6516	5514	6640	652	230	138
2035	6509	5508	6632	651	229	138
2036	6501	5501	6624	650	229	138
2037	6493	5495	6616	649	229	138
2038	6486	5488	6608	649	229	138
2039	6478	5482	6601	648	228	138
2040	6471	5476	6593	647	228	137
2041	6461	5467	6583	646	228	137
2042	6451	5459	6573	645	227	137
2043	6441	5451	6563	644	227	137
2044	6431	5442	6553	643	227	137
2045	6421	5434	6543	642	226	136
2046	6412	5426	6533	641	226	136
2047	6402	5417	6523	640	226	136
2048	6392	5409	6513	639	225	136
2049	6382	5401	6503	638	225	135
2050	6372	5392	6493	637	225	135
2051	6362	5383	6482	636	224	135
2052	6351	5374	6471	635	224	135
2053	6340	5365	6460	634	224	135
2054	6329	5356	6449	633	223	134
2055	6318	5347	6438	632	223	134

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 (24hrs)	-	-	-	-	496	442	-	-	-	-	-	-	-	11910	10617	-	-	-
Battery (48hrs)	-	-	-	-	443	376	-	-	-	-	-	-	-	21272	18032	-	-	-
PHES (10hrs)	-	-	-	-	-	768	-	-	-	-	-	-	-	-	7677	-	-	-
A-CAES (12hrs)	-	-	-	386	-	-	-	-	-	-	-	-	4626	-	-	-	-	-
PHES (12hrs)	-	-	-	-	-	-	213	226	275	-	-	-	-	-	-	2561	2711	3295
A-CAES (24hrs)	-	-	-	-	305	316	-	-	-	-	-	-	-	7326	7585	-	-	-
PHES (24hrs)	-	-	-	-	242	271	158	147	179	-	-	-	-	6030	6496	3796	3537	4307
PHES (48hrs)	-	-	-	-	142	163	89	111	135	-	-	-	-	7078	7822	4252	5313	6470

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1350/kWh (Aurecon, 2024b).

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	1.5	44%	22.5	8.0	1.9	5802	13.5	89%	5802	19.8	53%
Gas combined cycle	25	1.5	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	1.3	33%	14.1	8.1	0.0	943	13.5	20%	943	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	40.9	20%	2071	43.2	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	4.1	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	8655	1.1	89%	8655	1.3	53%
Solar thermal	25	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	3223	0.0	48%	3223	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	1.5	44%	22.5	8.0	1.9	4678	8.0	89%	4617	14.4	53%
Gas combined cycle	25	1.5	51%	15.0	4.1	0.0	1996	8.0	89%	1969	14.4	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2412	8.0	20%	2412	14.4	20%
Gas open cycle (large)	25	1.3	33%	14.1	8.1	0.0	1302	8.0	20%	1302	14.4	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	1968	8.0	20%	1968	14.4	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2059	35.4	20%	2059	38.6	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	4.1	10529	2.8	89%	10435	4.3	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5301	2.8	89%	5344	4.3	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7779	0.7	89%	7698	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	20359	0.8	89%	21168	1.0	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	8467	0.8	89%	8493	1.0	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	7315	0.0	71%	7939	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	1141	0.0	32%	1224	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	2491	0.0	48%	2603	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	4409	0.0	54%	4629	0.0	40%

2040												
Gas with CCS	25	1.5	44%	22.5	8.0	1.9	4292	7.9	89%	4486	15.8	53%
Gas combined cycle	25	1.5	51%	15.0	4.1	0.0	1935	7.9	89%	1935	15.8	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2371	7.9	20%	2371	15.8	20%
Gas open cycle (large)	25	1.3	33%	14.1	8.1	0.0	1280	7.9	20%	1280	15.8	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	1934	7.9	20%	1934	15.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2023	24.5	20%	2023	29.1	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	4.1	10001	2.6	89%	10202	3.9	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5378	2.6	89%	5396	3.9	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7566	0.7	89%	7566	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	12710	0.5	89%	17735	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	8322	0.5	89%	8322	0.7	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	5743	0.0	71%	6935	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	671	0.0	32%	1016	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	1940	0.0	48%	2047	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	4235	0.0	57%	4489	0.0	40%
2050												
Gas with CCS	25	1.5	44%	22.5	8.0	1.9	4122	7.9	89%	4257	15.8	53%
Gas combined cycle	25	1.5	51%	15.0	4.1	0.0	1882	7.9	89%	1882	15.8	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2305	7.9	20%	2305	15.8	20%
Gas open cycle (large)	25	1.3	33%	14.1	8.1	0.0	1243	7.9	20%	1243	15.8	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	1881	7.9	20%	1881	15.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	1967	17.8	20%	1967	22.7	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	4.1	9670	2.6	89%	9810	3.9	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5376	2.6	89%	5427	3.9	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7356	0.7	89%	7356	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	12436	0.5	89%	15948	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	8091	0.5	89%	8091	0.7	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	4633	0.0	71%	5833	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	569	0.0	32%	807	0.0	19%
Wind onshore	25	1.0	100%	28.0	0.0	0.0	1868	0.0	48%	1967	0.0	29%
Wind offshore (fixed)	25	3.0	100%	174.6	0.0	0.0	4136	0.0	61%	4346	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 discount rate for all technologies is 5.99%.

Apx Table B.10 Electricity generation technology LCOE projections data, 2023-24 $/MWh

Category	Assumption	Technology	2024		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas open cycle (small)	279	342	224	287	221	300	217	297
		Gas open cycle (large)	207	275	165	234	163	248	161	247
		Gas reciprocating	238	294	190	245	187	257	184	254
		H_2 reciprocating	577	603	514	550	390	442	312	367
Flexible load, high emission		Black coal	102	164	92	149	91	147	91	147
		Brown coal	131	211	113	180	111	178	109	174
		Gas	128	192	85	145	83	155	82	154
Flexible load, low emission		Black coal with CCS	190	303	169	268	161	260	157	253
		Gas with CCS	187	284	130	217	125	227	123	223
		Nuclear SMR	400	663	285	487	189	414	186	378
		Nuclear large-scale	155	252	150	245	145	238	142	233
		Solar thermal	134	168	121	164	99	146	84	127
Variable	Standalone	Solar photovoltaic	43	73	35	62	22	53	19	43
		Wind onshore	70	116	56	96	45	78	43	75
		Wind offshore (fixed)	135	175	124	173	114	169	105	165
Variable with integration costs	Wind & solar PV combined	60% VRE share	101	142	67	105				
		70% VRE share	98	141	72	113				
		80% VRE share	100	143	80	122				
		90% VRE share	106	150	94	137				

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	2571	2734	2429	2619	2523	2700
2026	2443	2632	2182	2415	2353	2567
2027	2314	2526	1953	2221	2188	2433
2028	2193	2424	1749	2042	2035	2307
2029	2078	2327	1566	1878	1892	2187
2030	1968	2233	1402	1727	1760	2073
2031	1865	2144	1256	1588	1636	1965
2032	1767	2058	1124	1460	1522	1863
2033	1675	1975	1007	1343	1415	1766
2034	1587	1896	902	1235	1316	1675
2035	1571	1900	859	1206	1285	1664
2036	1547	1893	811	1166	1262	1662
2037	1523	1885	765	1125	1240	1661
2038	1478	1851	726	1093	1215	1654
2039	1429	1809	690	1061	1191	1648
2040	1356	1737	658	1034	1146	1611
2041	1342	1738	629	1009	1126	1608
2042	1325	1734	603	987	1088	1577
2043	1310	1733	580	968	1053	1549
2044	1285	1717	559	950	1024	1529
2045	1268	1713	540	934	1000	1513
2046	1243	1695	522	919	978	1501
2047	1227	1690	506	905	959	1491
2048	1205	1676	486	884	941	1483
2049	1169	1642	467	862	924	1475
2050	1144	1621	446	837	909	1469
2051	1144	1621	446	837	909	1469
2052	1140	1616	441	826	907	1465
2053	1140	1616	441	826	907	1465
2054	1138	1613	435	815	904	1461
2055	1138	1613	435	815	904	1461

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 (%)	References
Photovoltaics	Current policies	G	30	13	(IEA 2021, IRENA, 2022, Fraunhofer ISE, 2015)
		L	-	17	
Photovoltaics	Global NZE by 2050	G	30	23	
		L	-	17	
Photovoltaics	Global NZE post 2050	G	30	23	
		L	-	17	
Electrolysis	Current policies	G	10	5	(Schmidt et al., 2017, IEA 2024)
		L	-	8	
Electrolysis	Global NZE by 2050	G	18	9	
		L	-	8	
Electrolysis	Global NZE post 2050	G	10	5	
		L	-	8	
Ocean	Current policies	G	10	5	(IEA, 2021)
	Global NZE by 2050	G	20	10	

	Global NZE post 2050	G	14	7	
Fixed offshore wind	Current policies	G	10	5	(Samadi, 2018; Zwaan, et al. 2012; Voormolen et al. 2016; IEA, 2021)
Fixed offshore wind	Global NZE by 2050	G	20	10	
Fixed offshore wind	Global NZE post 2050	G	15	8	
Floating offshore wind	Current policies	G	10	5	
		G	10	5	
Floating offshore wind	Global NZE by 2050	G	20	10	
		G	20	10	
Floating offshore wind	Global NZE post 2050	G	15	8	
		G	15	7.5	
Utility scale energy storage – Li-ion	Current policies	G	-	7.5	(Grübler et al., 1999; McDonald and Schrattenholzer, 2001)
		L	-	7.5	
Utility scale energy storage – Li-ion	Global NZE post 2050	G	-	10	
		L	-	10	
Utility scale energy storage – Li-ion	Global NZE by 2050	G	-	15	
		L	-	15	

Solar photovoltaics is listed as one technology with global and local components however there are two separate PV plant technologies in GALLME. Rooftop PV includes solar photovoltaic modules, and the local learning component is the balance of plant (BOP). Large-scale PV also include modules and BOP. However, a discount of 25% is given to the BOP to take into account economies of scale in building a large-scale versus rooftop PV plant. Inverters are not 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 (2024b) 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 (%)	References
Coal, supercritical	-	-	-	
Coal, ultra-supercritical	G	-	2	(IEA, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	20	10	(EPRI 2010; Rubin et al., 2007)
	L	20	10	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	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Diesel/oil-based generation	-	-	-	
Reciprocating engines	-	-	-	
Hydro and pumped hydro	-	-	-	
Biomass	G	-	5	(IEA, 2008; Neij, 2008)
Concentrating solar thermal (CST)	G	14.6	7	(Hayward & Graham, 2013)
Onshore wind	G	-	4.3	(IEA, 2021; Hayward & Graham, 2013)
	L	-	9.8	As above
CHP	-	-	-	
Conventional geothermal	G	-	8	(Hayward & Graham, 2013)
	L	20	20	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Fuel cells	G	20	10	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Steam methane reforming with CCS	G	20	10	(EPRI, 2010; Rubin et al., 2007)
	L	20	10	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	117
Global NZE post 2050	251
Global NZE by 2050	428

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
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

[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.

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, 2024b)(Aurecon, 2023a) (Aurecon, 2022) (Aurecon, 2021) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2022) (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) (US Energy Information Administration, 2017a) (US 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 judgement 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

D.3.3 Why did you use the capital cost of a single failed project in the United States for your representative nuclear SMR cost (the UAMPS Carbon Free Power Project)?

While there are several currently existing and proposed SMR projects, only the UAMPS project has been willing to provide an open and reliable costing for their project. Costings for projects not built often turn out to be optimistic or marketing pieces and for those reasons are not considered reliable. The UAMPS project is deemed to be reliable because the developers were prepared to financially commit and there would have been financial consequences if they had provided lower than achievable estimates and then tried to proceed at a higher cost. Their subscription model for power produced meant they had to agree to a cost up front. If they underestimated costs, they would be liable for the shortfall. In contrast, there are no financial consequences for manufacturers who supply unrealistically low estimates for technologies they are not committed to both build and sell the power from themselves. While many submissions have in the past requested GenCost use different data, no evidence was provided for an alternative project with data quality equal to or better than the UAMPS project. All other suggested costs were vendor estimates for projects the vendor has not committed to directly build or own which we regard as low quality data.

D.3.4 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].

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.3.5 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

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

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 (2024b) 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.

D.3.6 Why is the uncertainty in the data not emphasised more?

Aurecon (2024b) 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 (2024b) also provide factors to convert the general costs to specific locations in the National Electricity Market. 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.3.7 Why include an advanced ultra-supercritical pulverised coal instead of cheaper, less efficient plant designs?

Some stakeholders take a view that although Australia has bipartisan commitment for net zero emissions by 2050, the highest greenhouse gas emitting options should remain on the table. The deployment of new coal has low plausibility given its high emission intensity. A high efficiency design brings it closer to being plausible. 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 (2024b) 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 typically brown coal plants which have a significant 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 coal generators. At the low end of the range a capacity factor of 53% is assumed for new black coal or nuclear generators which is equivalent to achieving 10% below the average capacity factor for black coal. Around 10% of nuclear generators globally run at less than 60% capacity factor and have run at over 90%. 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. 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. 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 avoid such projects in preference for more 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 none of the topics presented in the feedback have a large enough impact on LCOE to warrant a change in the boundary or formula (and no quantitative evidence of their significance was provided). That is, it would add complexity and cost to the project without significantly changing the outcome of the comparisons.

One exception is 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. 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 (2024b) 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*
- *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[42]. 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 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).

[42] 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

- 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. No gas peaking plants are allowed creating an artificially high cost scenario. Baik (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 would have been cheaper had the gas peaking plant been allowed. Thereafter, it is unlikely that adding any of the other resources – nuclear, CCS, hydrogen and biofuels would have reduced costs. 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[43] 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.

[43] 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 (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 2023 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[44], (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

[44] 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 judgement 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 greenfield 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 (greenfield) projects which are different to coal prices that are received by existing projects. 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 greenfield and existing coal generators. Reflecting the issues discussed above, average greenfield 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 greenfield coal prices.

After June 2022, AEMO has no longer published greenfield 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 greenfield coal prices, GenCost 2023-24 had to apply a new methodology based on the only available data which was coal prices for existing generators. Knowing that greenfield coal prices are at least as high as that for existing generators, for the maximum, GenCost 2023-24 simply takes the maximum of existing generator prices.

However, for the minimum greenfield 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 greenfield 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 will not go ahead if their capacity factor is too low. 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[45] 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. While additional renewable supply has, in some regions, lowered wholesale electricity prices, customers may not immediately feel the impact due to existing higher priced supply contracts. There is no guarantee that renewables or any other new

[45] 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.

entrant technology will maintain downward pressure on prices. If 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 economics have meant there is no current domestic interest in this technology
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 5 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
ABS	Australian Bureau of Statistics
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
ATSE	Academy of Technological Sciences and Engineering
BAU	Business as usual
BOP	Balance of plant
CCGT	Combined cycle gas turbine
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

Abbreviation	Meaning
IEA	International Energy Agency
ISP	Integrated System plan
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
LCOS	Levelised cost of storage
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
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
USC	Ultra-supercritical
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEO	World Energy Outlook

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