Australia's National
Science Agency

GenCost 2023-24

Consultation draft

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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 2023-24 report in the second quarter of 2024. Feedback can be provided at: https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation

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, in broad terms, world leaders continue to provide their support for collective action limiting global average temperatures. 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

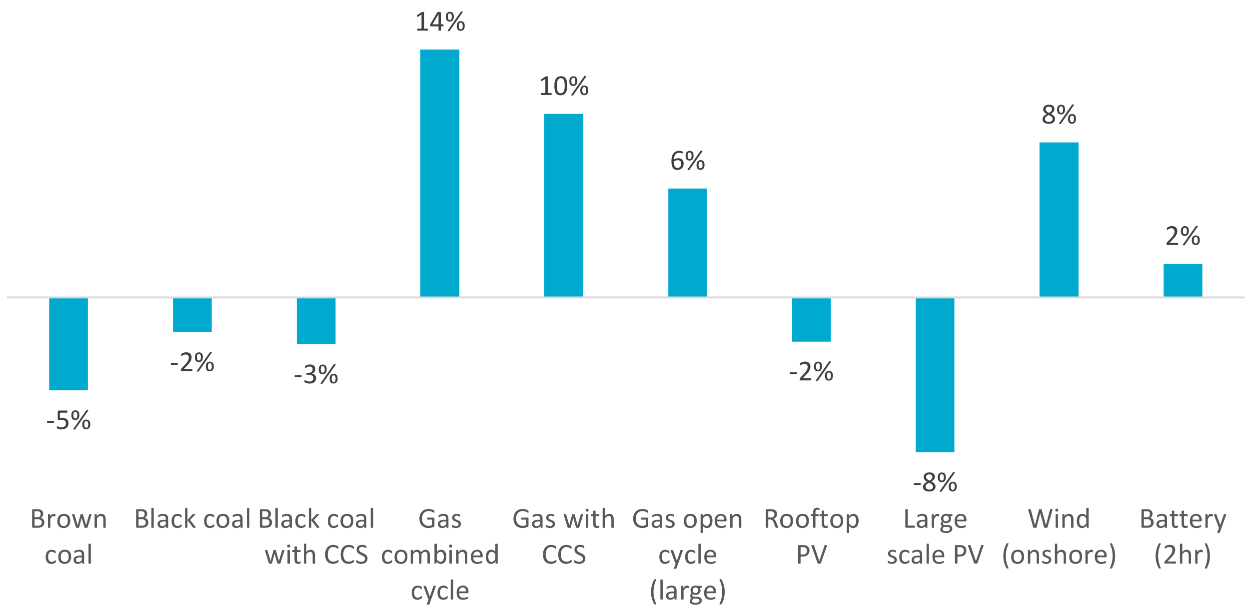
GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating the costs of electricity generation, energy storage and hydrogen production with a strong emphasis on stakeholder engagement. GenCost represents Australia's most comprehensive electricity generation cost projection 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 electricity costs change significantly each year. This is the sixth 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.

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. One year on, the inflationary pressures have considerably eased but the results are mixed. The capital costs of onshore wind generation technology increased by a further 8% while large-scale solar PV has fallen by the same proportion. Gas turbine technologies were the other main group to experience cost increases of up to 14% (ES Figure 0-1). The capital costs of other technologies were relatively steady. Technologies are affected differently because they each have a unique set of material inputs and supply chains.



ES Figure 0-1 Change in current capital costs of selected technologies relative to GenCost 2022-23 (in real terms)

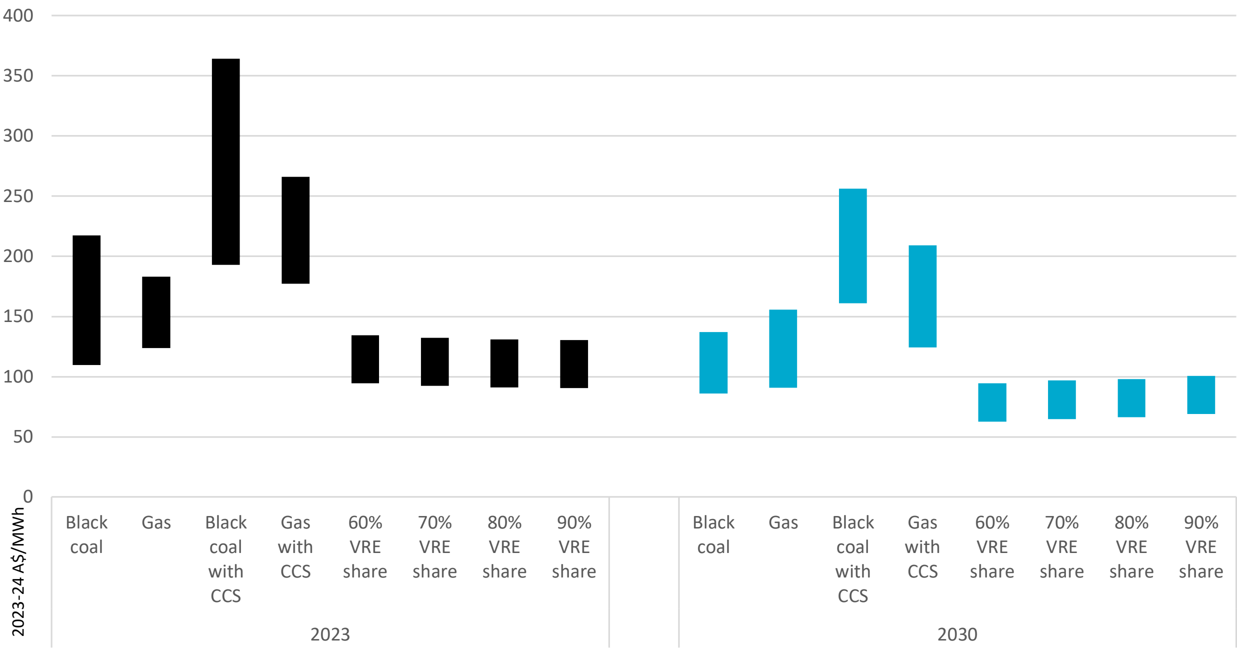
Levelised cost of electricity

Levelised cost of electricity (LCOE) data is an electricity generation technology cost comparison metric. It is the total unit costs a generator must recover 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 is estimated on a common basis for all technologies. Most new-build technologies can enter an electricity system and provide reliable power by relying on existing capacity already deployed. Existing capacity can provide generation at times when the new plant is not available or when demand is rising but the new-build technology is already at full production. This includes new-build variable renewables such as solar PV and wind when they are in the minority. However, as their share increases, forcing the retirement of existing flexible capacity, the system will find it increasingly difficult to provide reliable supply without additional investment.

To address this issue, GenCost calculates the additional cost of making variable renewables reliable at shares of 60%, 70%, 80% and 90%[1]. We call these additional costs the integration costs of variable renewables and they consist mainly of additional storage and transmission costs. Feedback from the 2022-23 GenCost report requested that integration costs be presented that account for storage and transmission projects that will be delivered before 2030 since they have been sponsored by government or approved by the relevant regulator on the basis that they will be needed to support variable renewables. To accommodate that request, we present variable renewable integration costs for 2023 which include committed and under construction pre-2030 storage and transmission projects. 2030 LCOE results are also included but continue to exclude these pre-2030 costs since by 2030 they will represent existing capacity already deployed.

[1] 90% is about as high as variable renewable deployment is likely to need to go as increasing it further would result in the undesirable outcome of shutting down existing non-variable renewable generation from biomass and hydroelectric sources.



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

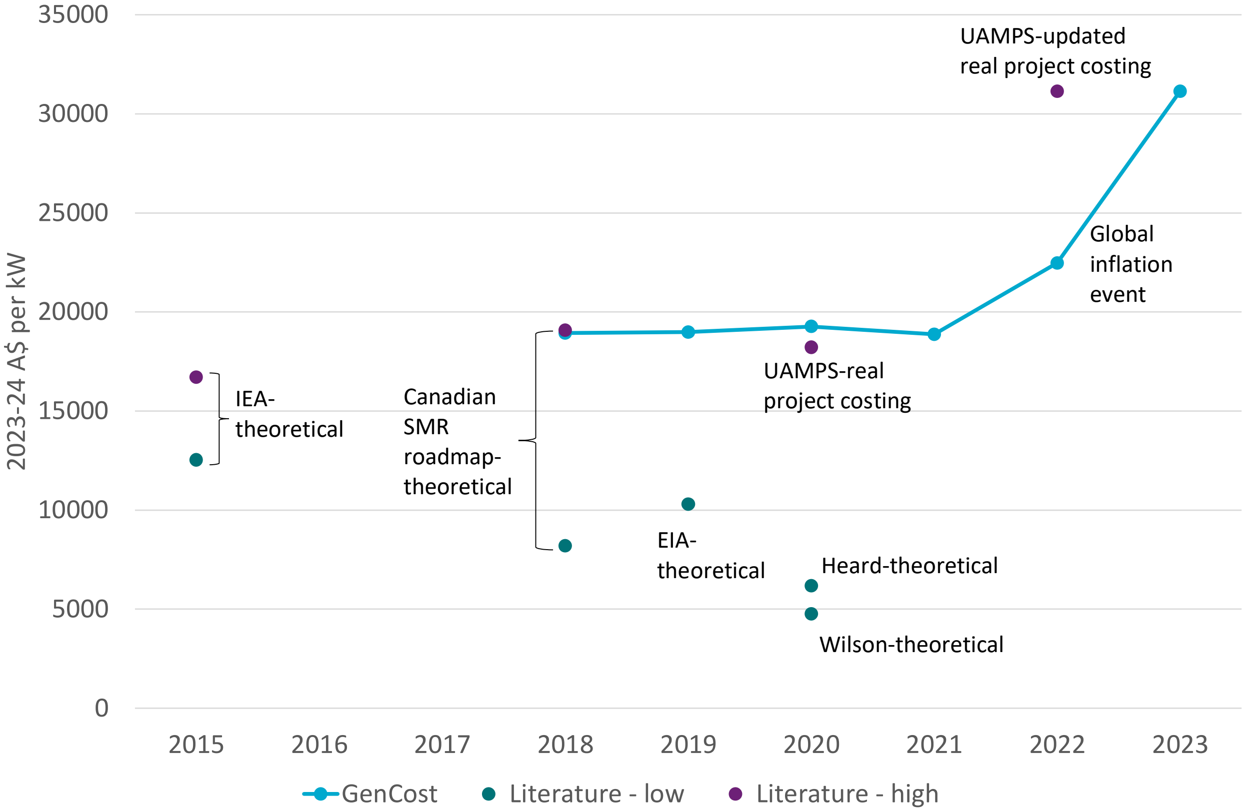
The results indicate that the cost of deploying high VRE shares is 40% to 60% higher in 2023 than in 2030. Around a half to three quarters of the higher costs (depending on the VRE share) are due to investors having to pay 2023 instead of 2030 technology costs. Technology costs are falling over time. The remainder of the difference is due to the cost of the pre-2030 committed and under construction storage and transmission projects. Total integration costs to make high shares of variable renewables reliable are estimated at $34/MWh to $41/MWh in 2023 and $25 to $34/MWh in 2030 depending on the VRE share.

The LCOE cost range for variable renewables with integration costs is the lowest of all new-build technologies in 2023 and 2030. The cost range overlaps slightly with the lower end of the cost range for 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, source low cost fuel and be financed at a rate that does not include climate policy risk despite their high emissions. If we exclude high emission generation options, the next most competitive generation technology is gas with carbon capture and storage.

Significant increase in nuclear small modular reactor costs

The cost of nuclear small modular reactors (SMR) has been a contentious issue in GenCost for many years with conflicting data published by other groups proposing lower costs than those assumed in GenCost (ES Figure 0-3). UAMPS (Utah Associated Municipal Power Systems) is a US regional coalition that develops local government owned electricity generation projects. Up until the project’s cancellation in November 2023, UAMP was the developer of a nuclear SMR project called the Carbon Free Power Project (CFPP) with a gross capacity of 462MW. It was planned to be fully operational by 2030. After conversion to 2023 Australian dollars, project costs were estimated in 2020 to be $18,200/kW which is only slightly below the level that GenCost had been applying ($19,000kW).

In late 2022 UAMPS updated their capital cost to $31,100/kW citing the global inflationary pressures that have increased the cost of all electricity generation technologies. The UAMPS estimate implies nuclear SMR has been hit by a 70% cost increase which is much larger than the average 20% observed in other technologies. This data was not previously incorporated in GenCost. Consequently, current capital costs for nuclear SMR in this report have been significantly increased to bring them into line with this more recent estimate. The significant increase in costs likely explains the cancellation of the project. The cancellation of this project is significant because it was the only SMR project in the US that had received design certification from the Nuclear Regulatory Commission which is an essential step before construction can commence.



ES Figure 0-3 Timeline of nuclear SMR cost estimates (calendar year) and current costs included in each GenCost report (financial year beginning)

1 Introduction

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

The report provides an overview of updates to current costs in Section 2. This section draws significantly on updates to current costs provided in Aurecon (2023a) and further information can be found in their report. The global scenario narratives and data assumptions for the projection modelling are outlined in Section 3. Capital cost projection results are reported in Section 4 and LCOE results in Section 5. 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. GenCost does not seek to describe the set of electricity generation and storage technologies included in detail.

1.2 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 current electricity generation and storage cost and performance characteristics (Aurecon, 2023a). This report focusses on capital costs, but the Aurecon report provides a wider variety of data such as operating and maintenance costs and

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

energy efficiency. Some of these other data types are used in levelised cost of electricity calculations in Section 5.

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

1.3 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 added an extra reporting year, 2023, for renewable integration costs reflecting strong interest in pre-2030 integration costs. The report also includes a longer discussion on nuclear SMR costs in Section 2 given the significant new data that has become available on that topic.

1.4 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.

1.5 Overview of feedback received

GenCost receives unsolicited feedback throughout the year and also specifically during a December/January consultation period. The greatest feedback since the previous report was on the method for calculating variable renewable integration costs. Changes to the report to accommodate this feedback are discussed in Section 5.

2 Current technology costs

2.1 Current cost definition

Our definition of current capital costs are 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[3]. 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 (2023a). Aurecon (2023a) also provide more detail on specific definitions of the scope of cost categories included. Aurecon cost estimates are provided for Australia in Australian dollars. CSIRO adjusts the data when used in global modelling to take account of regional differences in costs.

2.2 Capital cost source

AEMO commissioned Aurecon (2023a) 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 (2023a) which is consistent with either the beginning of financial year 2023-24 or middle of 2023. Aurecon provides several measures of project capacity (e.g., rated, seasonal). We use the capacity at 25ºC to determine $/kW costs. Aurecon state that the uncertainty range of their data is +/- 30%.

Technologies not included in Aurecon (2023a) 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

[3] 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.

consumer price indices applied to knowledge of the relative mix of imported and local content for each technology. Pumped hydro has been updated by Aurecon (2023a) whereas previously this was sourced from AEMO.

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2022-23) cost estimates (drawing primarily on the Aurecon (2023a) update) for electricity generation technologies with those from previous years: GenCost 2018 to GenCost 2022-23 (which are a combination of Aurecon (2021, 2022, 2023b), GHD and CSIRO data), Hayward and Graham (2017) (also CSIRO) and CO2CRC (2015) which we refer to as APGT (short for Australian Power Generation Technology report).

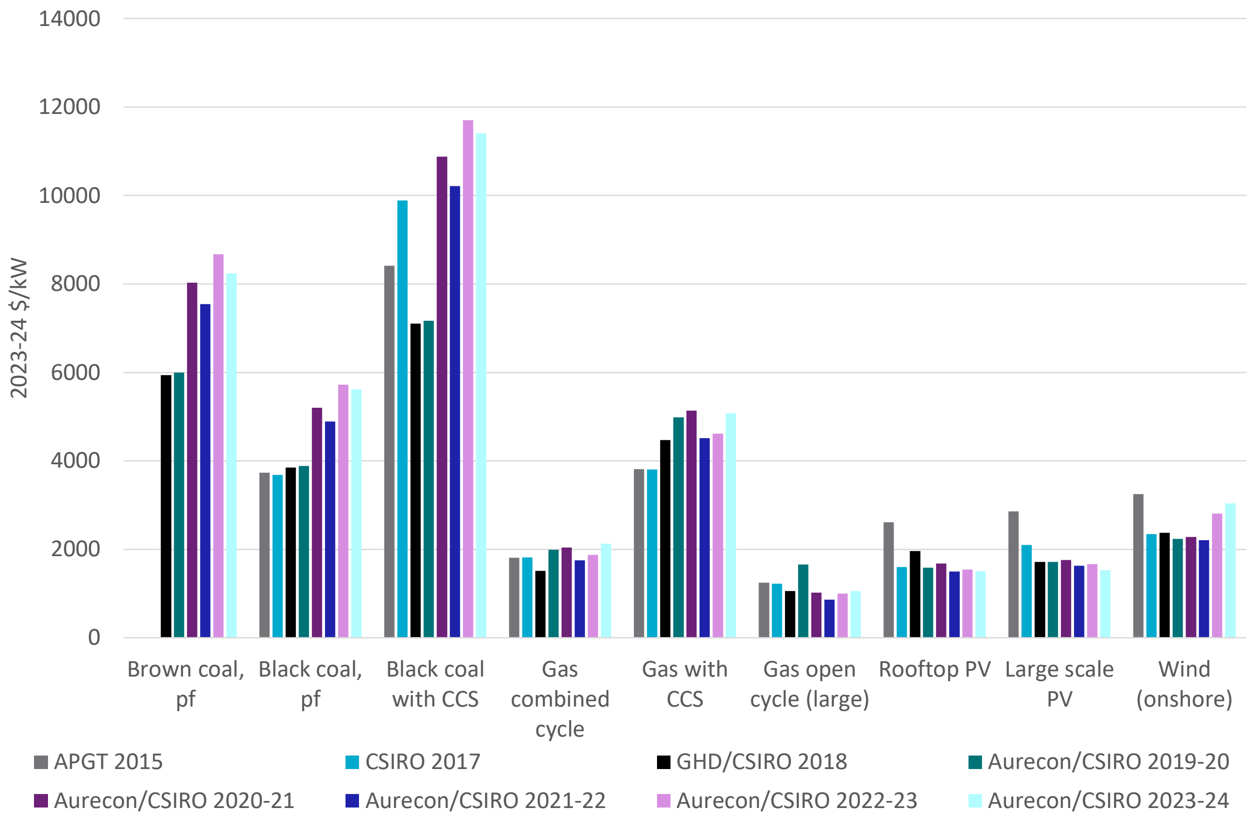

Figure 2-1 Comparison of current capital cost estimates with previous reports

All costs are expressed in real 2023-24 Australian dollars and represent overnight costs. Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme.

Whilst there had been some steady declines over the years for technologies such as solar PV and wind, for 2022-23, there was a universal increase in capital costs (20% on average). In 2023-24, the result was more mixed with solar PV reducing in costs while gas and onshore wind technology costs increasing (Figure 2-2). The source of the 2022-23 increase was 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. However, overall, it can be said that the impacts are less in 2023-24 than the previous year.

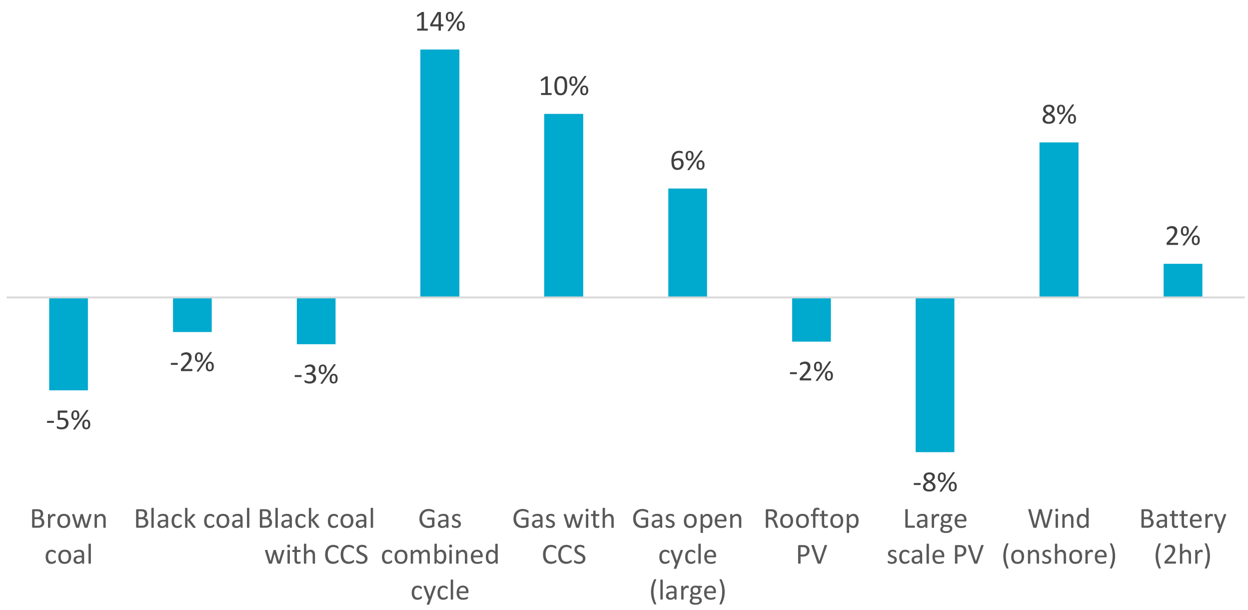

Figure 2-2 Change in current capital costs of selected technologies relative to GenCost 2022-23 (in real terms)

2.4 Update on current costs and timing of nuclear SMR

2.4.1 Challenges in determining capital costs of nuclear SMR

An ongoing issue for the estimation of the capital costs for nuclear SMR has been the lack of data from completed commercial projects. Completed commercial projects or signed contracts for completion are the preferred data source for all capital cost estimates in GenCost. While there are completed projects in Russia and China these were 100% government funded rather than commercial projects which makes it difficult to ascertain what their costs would be in a market setting.

Cost estimates can also be in two forms: first-of-a-kind and nth-of-a-kind. First-of-a-kind refers to the first commercial project costs and, for emerging technologies, these costs are expected to be high reflecting the lack of experience in applying the technology to commercial production. Nth-of-a-kind costs refer to the cost after several commercial plants have been deployed and developers have gained more experience with the technology. For estimating nuclear SMR current costs, GenCost requires first-of-a-kind cost estimates given the first commercial project is yet to be completed. Nth-of-a-kind cost data could be relevant for projecting costs after the first commercial project is deployed. However, learning through deployment is already an in-built feature of our cost projection approach and not something that needs to be imposed from external data.

CSIRO has been monitoring the broader literature to try to firm up the current costs of nuclear SMR in the absence of our preferred data source. Such literature has tended to represent theoretical projects. More recently costs have become available for real projects, however, not at the stage yet of signed contracts for completion (consequently, costs for such projects could still change up to that point).

2.4.2 Early estimates for theoretical projects

Early estimates for theoretical projects have tended to be presented as a range representing the high degree of uncertainty in emerging technologies. In its *2015 Projected Cost of Generating Electricity*, the IEA (2015) stated that first-of-a-kind nuclear SMR project costs were expected to be 50% to 100% higher than the current cost of large scale nuclear. Based on large-scale nuclear costs in that report, this results in a range of $12,500/kW to $16,700/kW (all data in this report from all sources is adjusted to Australian dollars and inflated to 2023-24 dollars unless otherwise stated[4]). In 2018 the Canadian SMR Roadmap provided a list of first-of-a-kind project costs collected from the literature (EFWG, 2018). The range was wider still, from $8,200/kW to $19,100/kW.

In 2019 the US Energy Information Administration published its *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (EIA, 2019). It claimed that a theoretical first-of-a-kind nuclear SMR project could be constructed for $10,300/kW. This appeared to align with the lower end of the range of previous literature.

Two in-depth Australian publications that provided costs for nuclear SMR in Australia are Wilson (2021) and Heard (2022). They estimated capital costs of $4800/kW and $6200/kW respectively. Both studies relied on theoretical costs provided by technology vendors which were a mix of first-of-a-kind and nth-of-a-kind data for 2020.

GenCost reports which begin from 2018 (Figure 1), chose to adopt the high end of the range of costs from these theoretical cost estimates, particularly relying on the Canadian SMR Roadmap. The reason for using the high end of the range was because the estimates were from countries that already had nuclear electricity generation and it was assumed that, because Australia has no experience in nuclear electricity generation, it would be more likely to experience higher costs. Another consideration was that historically vendors are over-optimistic about their own technologies before they have practical experience in deploying it commercially.

2.4.3 Recent estimates from a leading US project[5]

UAMPS (Utah Associated Municipal Power Systems) is a US regional coalition that develops local government owned electricity generation projects. Up until the projects cancellation in November 2023, it was the developer of a nuclear SMR project called the Carbon Free Power Project (CFPP) with a gross capacity of 462MW[6]. It was planned to be fully operational by 2030. After conversion to 2023 Australian dollars, project costs were estimated in 2020 to be $18,200/kW (DOE, 2023) which is only slightly below the level that GenCost had been applying ($19,000kW).

In late 2022 UAMPS updated their capital cost to $31,100/kW citing the global inflationary pressures that have increased the cost of all electricity generation technologies (UAMPS, 2023).

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[4] An exchange rate of 0.7 US dollars per Australian dollar was applied. Prices were adjusted to today's dollars using the Australian Bureau of Statistics Consumer Price Index.

Note that IEA (2015) was the original source for information provided to GenCost by GHD in 2018. However, they recommended a cost of $19,000/kW (adjusted for today's prices) which later aligned well with the high end of the Canadian SMR Roadmap data.

[5] Another SMR project we are monitoring is the Darlington project in Canada. However, they have stated they will not provide costs to the public until end of 2024. https://www.opg.com/projects-services/projects/nuclear/smr/darlington-smr/

[6] https://www.uamps.com/Carbon-Free

GenCost 2022-23 found that most technology capital costs had increased in 2022 by 20%, up to a maximum of 35% for onshore wind. Accordingly, we had increased our own cost estimate of nuclear SMR by 20% to $22,400/kW. However, the UAMPS estimate implies nuclear SMR has been hit by a much larger 70% cost increase. Consequently, GenCost 2023-24 current capital costs for nuclear SMR have been modified to bring them into line with this more recent estimate. The cancellation of this project is significant because it was the only SMR project in the US that had received design certification from the Nuclear Regulatory Commission which is an essential step before construction can commence.

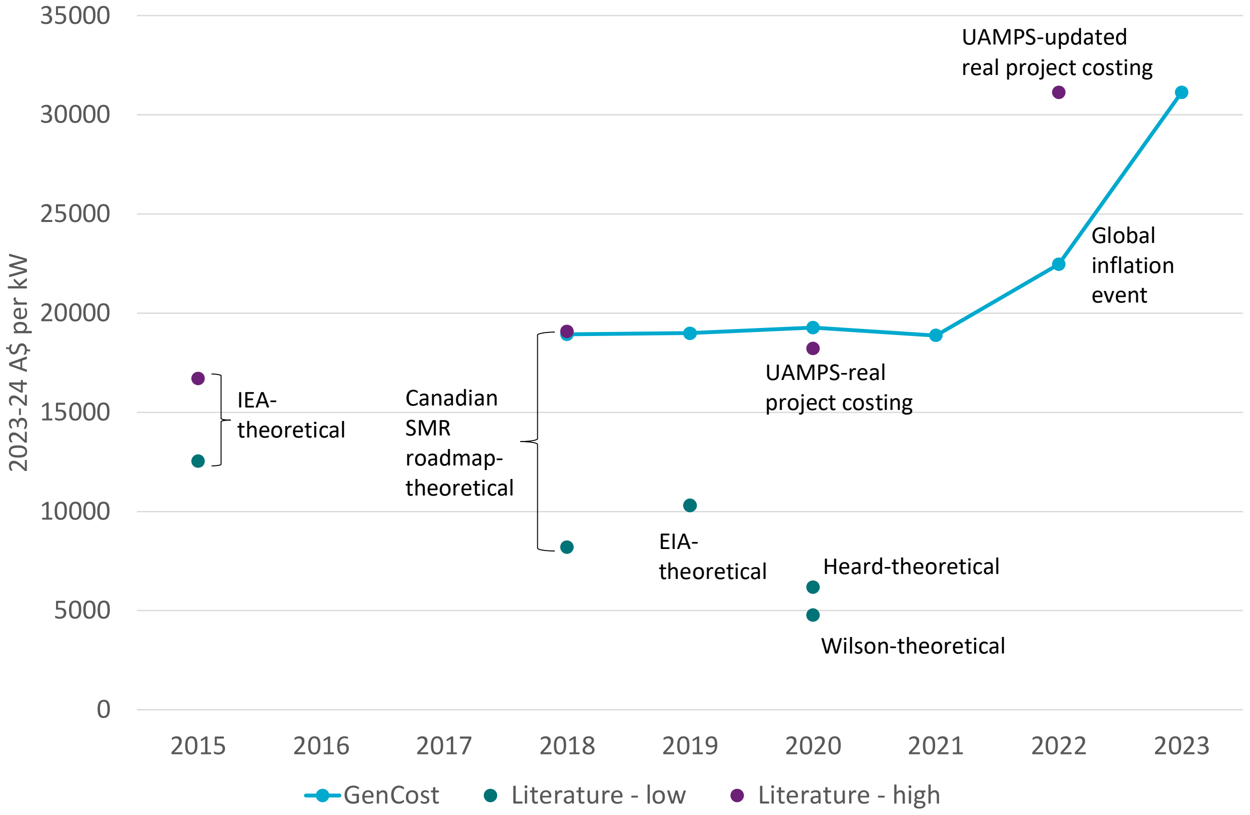

Figure 2-3 Timeline of nuclear SMR cost estimates (calendar year) and current costs included in each GenCost report (financial year beginning)

2.4.4 Perceived inconsistency between high nuclear SMR capital costs and low-cost nuclear electricity overseas

Based on information to date, current nuclear SMR capital costs are significantly higher than any other technology included in GenCost. This result appears out of step with overseas experience where some countries enjoy low cost nuclear generation. There are two reasons for this seemingly inconsistent result.

GenCost has been advised by stakeholders that small modular reactors are the appropriate size nuclear technology for Australia. Australia's state electricity grids are relatively small compared to the rest of the world and planned maintenance or unplanned outages of large scale nuclear generation would create a large contingent event of a gigawatt or more that other plant would find challenging to address. In the present system, it would take two or more generation units to provide that role. As such, large-scale nuclear plants which are currently lower cost than nuclear

SMR, may not be an option for Australia, unless rolled out as a fleet that supports each other - which represents a much larger investment proposition.

The second issue is that observations of low cost nuclear overseas may in some cases be referring to projects which were either originally funded by governments or whose capital costs have already been recovered. 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 will not be available to countries that do not have existing nuclear generation such as Australia.

In summary, given overseas nuclear electricity costs may be referring to technology that is not appropriate for Australia, or 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 to Australia's circumstances which is the focus of GenCost.

2.4.5 Timing of deployment in Australia

Commencing from the GenCost 2020-21 report, nuclear SMR capital costs were only reported from 2030. This was due to advice from stakeholders that nuclear SMR costs before 2030 were irrelevant for Australia because before that date there is no prospect of an Australian project (allowing 10 years from the time of that discussion). This date has not been revised for several years. However, in 2023 a senate committee for the Environment and Other Legislation Amendment (Removing Nuclear Energy Prohibitions) Bill 2022 heard evidence about nuclear SMR development completion times. The view from regulators was that it would be around 15 years to first production from a decision to build nuclear SMR in Australia, emphasising the time taken to revise regulations[7]. Even though legislation in the US is more developed, it is interesting to note that had the CFPP proceeded in the US it would have taken 15 years from its formal launch[8] to complete full operation in 2030 as planned.

This new information on deployment timing suggests that if a decision to pursue a nuclear SMR project in Australia were taken today, with political support for the required legislative changes, then the first full operation would be in 2038. Regardless of whether this date is accurate, and there remains a high degree of uncertainty, continuing to apply the 2030 date to the presentation of GenCost nuclear SMR cost data is no longer appropriate – that is, Australia is very unlikely to see a project that early. However, rather than extending our previous approach to exclude data before 2038, this report has reverted to showing the full timeline of nuclear SMR capital costs but with this added commentary on timing.

[7] https://www.aph.gov.au/Parliamentary_Business/Hansard/Hansard_Display?bid=committees/commsen/26831/&sid=0009

[8] https://inl.gov/trending-topics/carbon-free-power-project/

2.5 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[9] of battery, concentrating solar thermal (CST) with 14 hours storage[10], adiabatic compressed air energy storage (A-CAES) and pumped hydro energy storage (PHES) in $/kW and $/kWh. Solar thermal includes the cost of the solar field which provides thermal energy input to the storage device. 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[11]. As the storage duration of a project increases then more batteries or larger reservoirs need to be included in the project, but the power components of the storage technology remain constant. As a result, $/kWh costs tend to fall with increasing storage duration (Figure 2-4). The downward trend flattens somewhat with batteries since its power component, mostly inverters, is relatively small but adding more batteries increases capital cost. However, the hydroelectric turbine in a PHES project is a large capital expense while adding more reservoir is less costly. As a result, PHES capital costs fall steeply with more storage duration. Note that these $/kWh costs are not for energy delivered but rather a capacity of storage. GenCost does not present levelised costs of storage. However, these are available from the CSIRO (2023) *Renewable Energy Storage Roadmap*. While A-CAES and CST appear relatively higher capital cost at present, they are 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 2-5). 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).

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[9] 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

[10] The previous year's data (from Fitchner Engineering) was based on 15 hours storage.

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

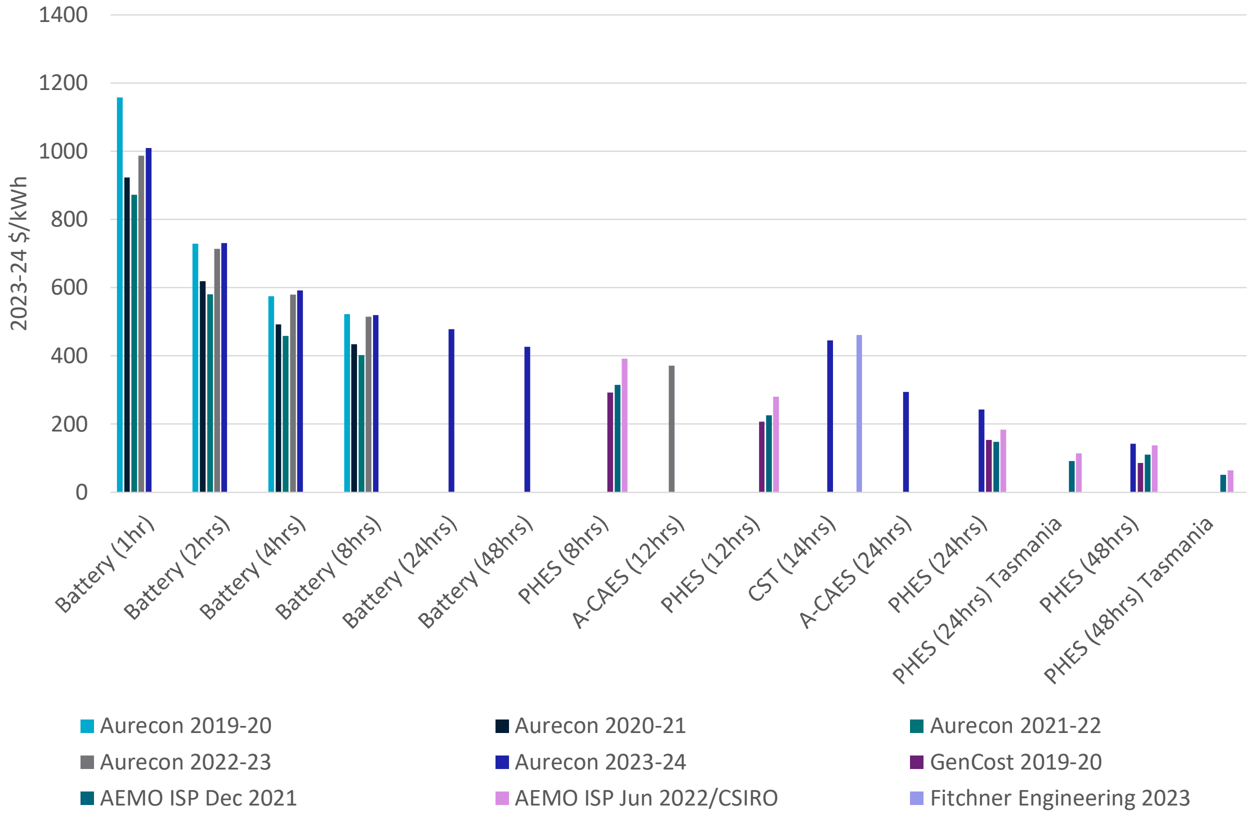

Figure 2-4 Capital costs of storage technologies in $/kWh (total cost basis)

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 depth of discharge is 100%[12]. Aurecon (2023a) also includes estimates of battery costs when they are integrated within an existing power plant and can share some of the power conversion technology. This results in a 5% lower battery cost for a 1-hour duration battery, scaling down to a 1% cost reduction for 8 hours duration and negligible for longer durations. PHES is more difficult to co-locate.

The current capital costs of the storage technologies have increased in 2023-24. Battery costs (battery and balance of plant in total) have increased slightly by only 1-2% depending on the duration.

PHES current cost estimates have increased by 32% for 24 hour duration projects and by only 3% for 48 hour duration projects indicating the increase is more so in the power equipment and installation than the reservoir[13]. These increases cannot be all assigned to global inflationary pressures because this is the first new capital cost estimates for pumped hydro since the Entura (2018) study which has been the basis of previous AEMO data used in this report. The increase likely represents a fresh perspective informed by additional information since 2018 on pumped hydro projects.

[12] 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%.

[13] The PHES capital costs used in this report are based on taking the mid-point of the range provided by Aurecon (2023a). Percentage differences will be higher or lower for projects at different ends of that range.

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. As an indicator of the influence of site costs, we have included the cost of Tasmania pumped hydro for 24 and 48 hours duration. AEMO provides state and regional cost adjustment factors for PHES and other technologies as part of the *Inputs and Assumptions Workbook* publication.

A-CAES is not yet integrated into our projection methodology and so its future costs are not presented here. While some components are mature, its deployment is not widespread relative to other options. Aurecon (2023a) 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.

CST is also relatively less commonly deployed than other technologies, but projections are available in Section 4.

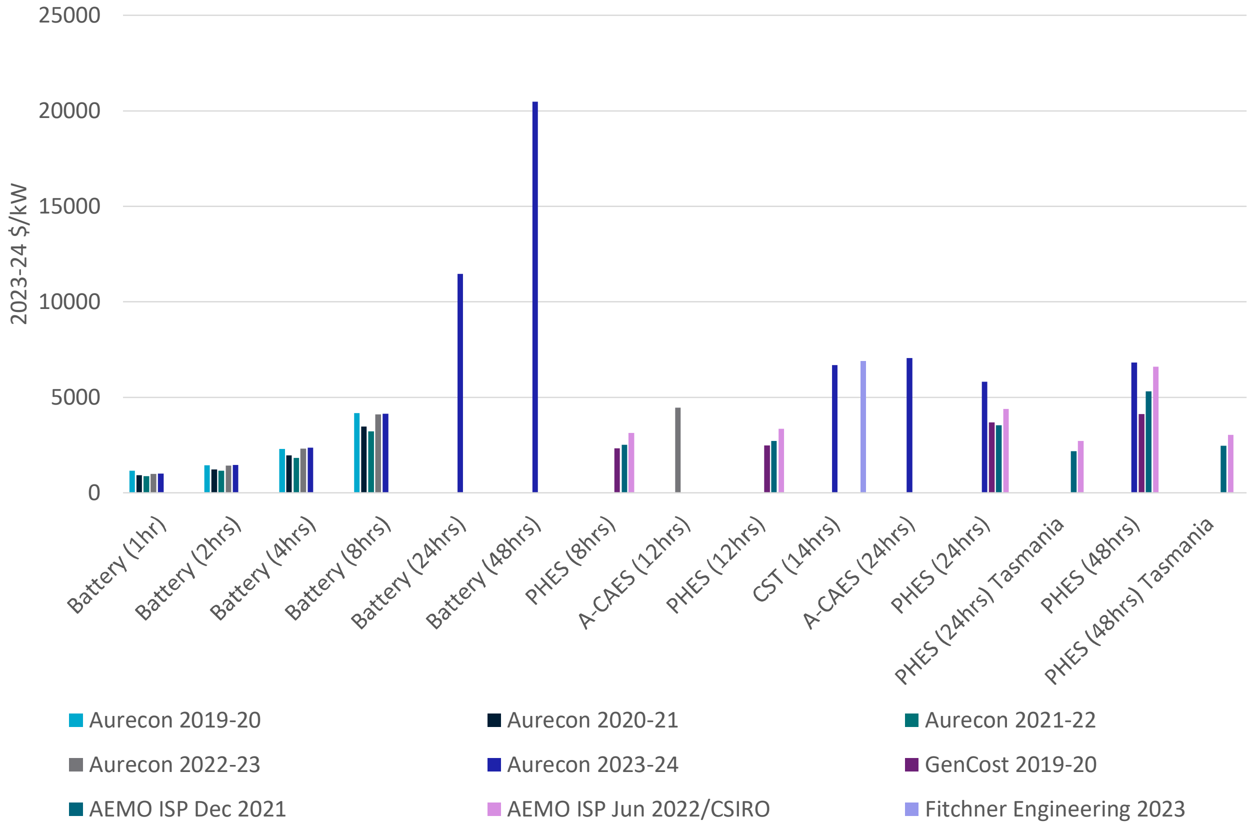

Figure 2-5 Capital costs of storage technologies in $/kW (total cost basis)

3 Scenario narratives and data assumptions

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

3.1 Scenario narratives

The global climate policy ambitions for the *Current policies*, *Global NZE post 2050* and *Global NZE by 2050* scenarios have been adopted from the International Energy Agency's 2022 World Energy Outlook (IEA, 2022) 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.

New data from the 2023 World Energy Outlook will be incorporated into the final GenCost report in 2024.

3.1.1 Current policies

The *Current policies* scenario applies a 2.5 degrees of global warming consistent climate policy (using a combination of carbon prices and other climate policies[14]). This represents mid- 2022 climate and renewable energy policy commitments with no extension beyond targets existing at that time. This implies that the 2030 Paris Nationally Determined Contributions (NDCs) are met but that the planned ramping up of ambition to prevent a greater than 2 degrees increase in temperature is limited to only those countries that had committed to further action. This scenario has the strongest constraints applied with respect to global variable renewable energy resources and the slowest technology learning rates. Subsequently, electricity sector greenhouse gas abatement costs are higher. 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.

3.1.2 Global NZE post 2050

The *Global NZE post 2050* has moderate renewable energy constraints and middle of the range learning rates. It has a carbon price and other policies consistent with a 1.7 degrees of warming climate change ambition which provides the investment signal necessary to deploy these technologies. The scenario covers all announced climate-related commitments, even those that are not backed by policy, including net zero emissions by 2050 targets, NDCs and energy access

[14] 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.

commitments. Hydrogen trade (based on a combination of gas with CCS and electrolysis) and transport and industry electrification are higher than in *Current policies*.

3.1.3 Global NZE by 2050

Under the *Global NZE by 2050* scenario there is 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 3-1 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	Consistent with 1.7 degrees world	Consistent with 2.5 degrees world
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 the next section for assumed learning rates.
2 Existing large-scale and rooftop solar PV renewable generation constraints are as shown in Table 3-5.

3.1.4 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 Table 3-2 and Table 3-3 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.

Table 3-2 Assumed technology learning rates that vary by scenario

Technology	Scenario	Component	LR 1 (%)	LR 2 (%)	References
Photovoltaics	Current policies	G	35	13	(IEA 2021, IRENA, 2022, Fraunhofer ISE, 2015)
		L	-	17	
Photovoltaics	Global NZE by 2050	G	35	23	
		L	-	17	
Photovoltaics	Global NZE post 2050	G	35	23	
		L	-	17	
Electrolysis	Current policies	G	10	5	(Schmidt et al., 2017)
		L	10	5	
Electrolysis	Global NZE by 2050	G	18	9	
		L	18	9	
Electrolysis	Global NZE post 2050	G	10	5	
		L	10	5	
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. 2021; 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	7.5	
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	7.5	
		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 (2023a) 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.

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. Table 3-2 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 Table 3-3.

Table 3-3 Assumed technology learning rates that are the same under all scenarios

Technology	Component	LR 1 (%)	LR 2 (%)	References
Coal, pf	-	-	-	
Coal, IGCC	G	-	2	(IEA, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	10	5	(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	-	3	(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	-	11.3	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	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Steam methane reforming with CCS	G	10	5	(EPRI, 2010; Rubin et al., 2007)
	L	20	10	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)

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.

3.1.5 Electricity demand and electrification

Various elements of underlying electricity demand are sourced from the World Energy Outlook (IEA, 2021; IEA 2022). 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.

Global vehicle electrification

Global adoption of electric vehicles (EVs) by scenario is projected using an adoption curve calibrated to a different shape to correspond to the matching IEA World Energy Outlook scenario sales shares to ensure consistency in electricity demand. The rate of adoption is highest in the *Global NZE by 2050* scenario, medium in the *Global NZE post 2050* scenario and low in the *Current policies* scenario consistent with climate policy ambitions. The shape of the adoption curve varies by vehicle type and by region, where countries that have significant EV uptake already, such as China, Western Europe, India, Japan, North America and rest of OECD Pacific, are leaders and the remaining regions are followers. Cars and light commercial vehicles (LCV) have faster rates of adoption, followed by medium commercial vehicles (MCV) and buses. The EV adoption curves for the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios are shown in Figure 3-1, Figure 3-2 and Figure 3-3 respectively. The adoption rate is applied to new vehicle sales shares.

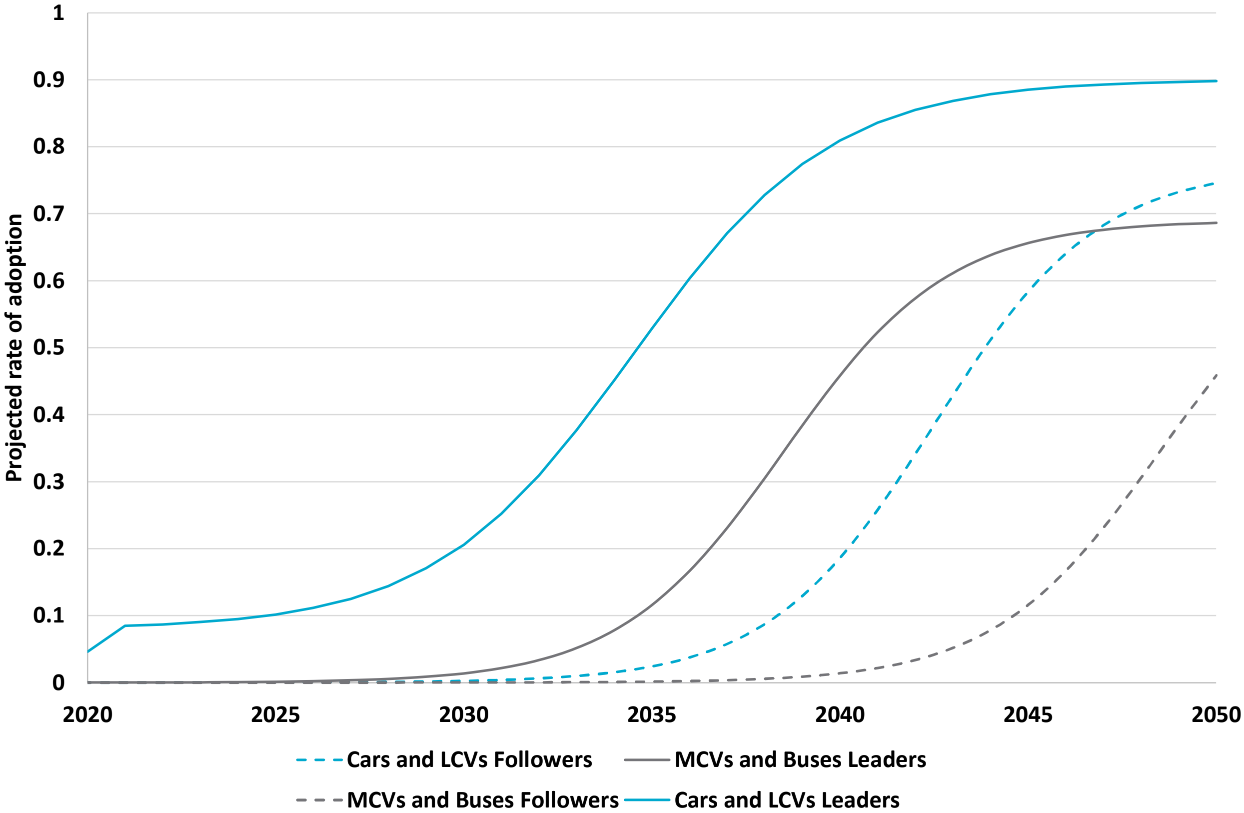

Figure 3-1 Projected EV sales share under the *Current policies* scenario

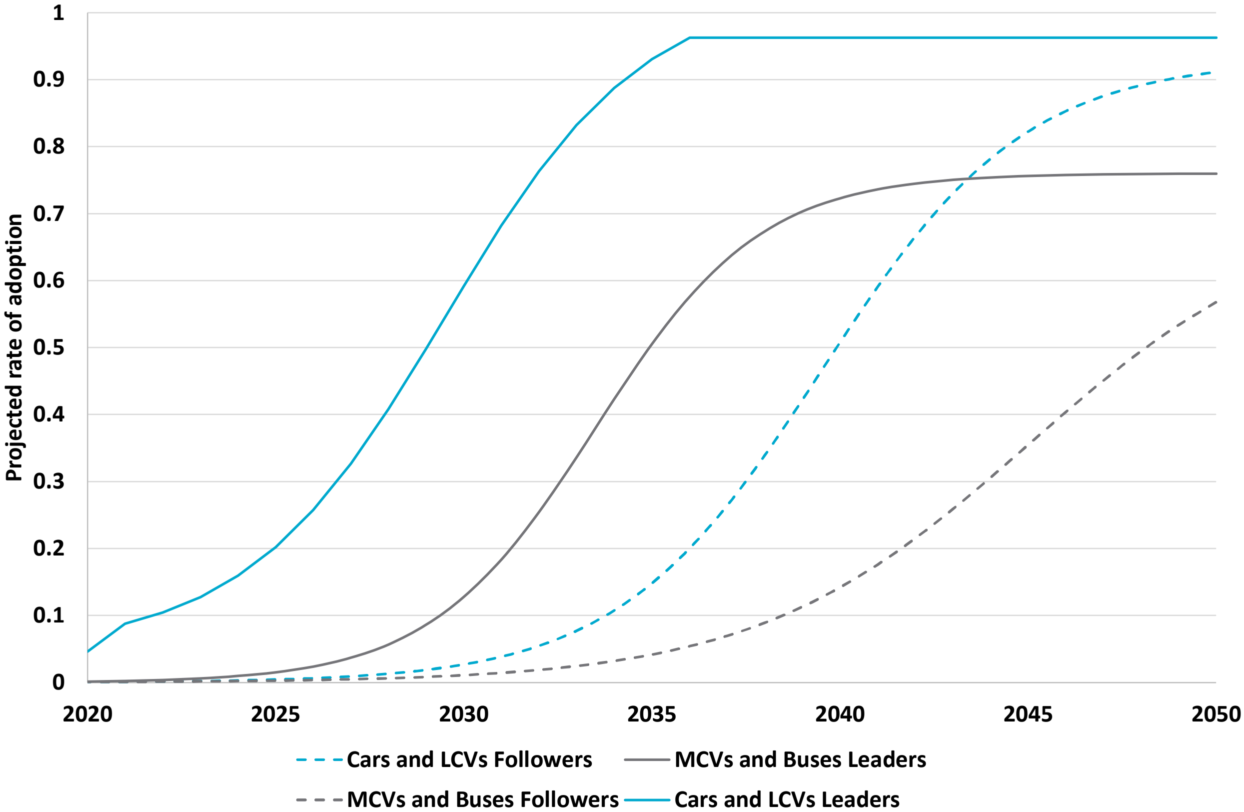

Figure 3-2 Projected EV adoption curve (vehicle sales share) under the *Global NZE by 2050* scenario

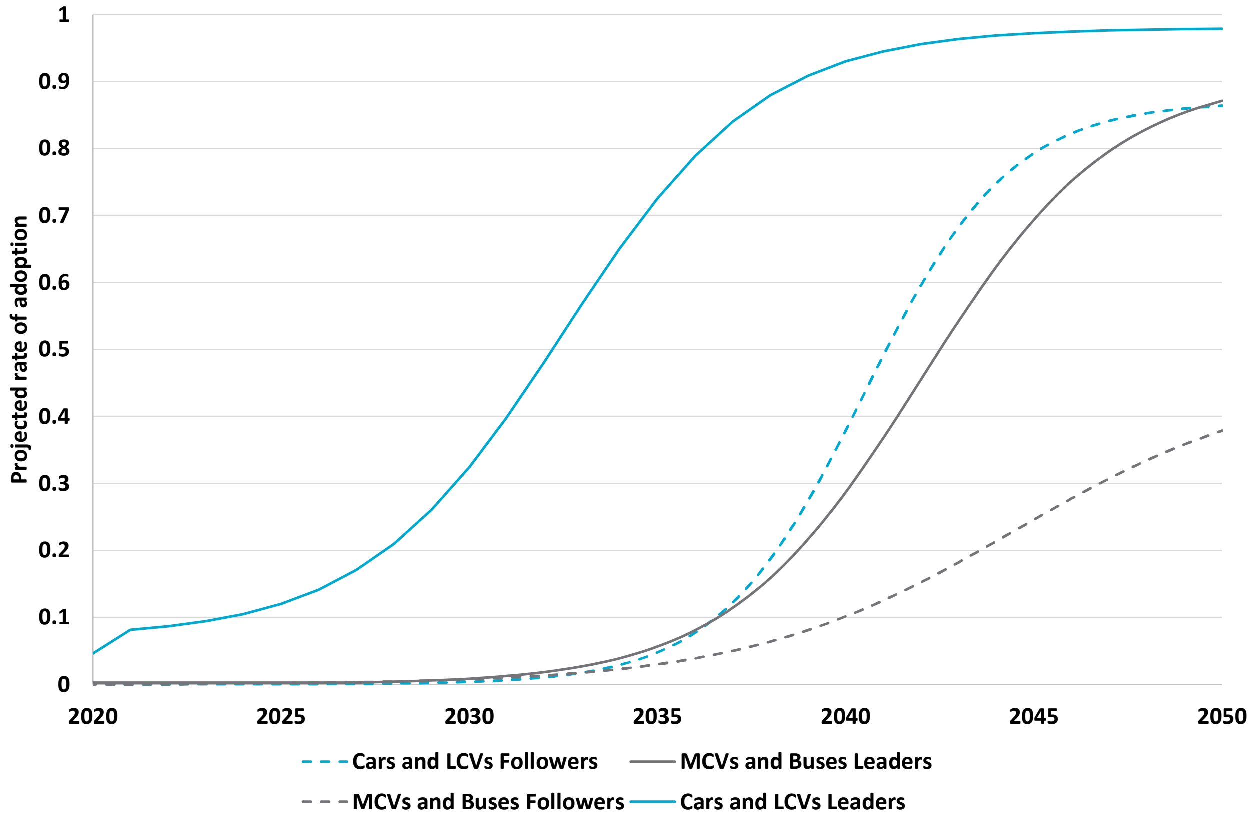

Figure 3-3 Projected EV sales share under the *Global NZE post 2050* scenario

3.1.6 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 Table 3-4 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.

Table 3-4 Hydrogen demand assumptions by scenario in 2050

Scenario	Total hydrogen demand (Mt)
Current policies	118
Global NZE post 2050	243
Global NZE by 2050	475

3.1.7 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.

3.1.8 Resource constraints

The availability of suitable sites for renewable energy farms, available rooftop space for rooftop 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 (Table 3-5) (see Government of India, 2016, Edmonds, et al., 2013 and Hayward & Graham, 2017 for more information on sources). With the exception of rooftop 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.

3.1.9 Other data assumptions

GALLME international black coal and gas prices are based on (IEA, 2022) 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[15]. 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.

Table 3-5 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

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, 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,

[15] 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.

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).

4 Projection results

4.1 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 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 four to seven years. It is not appropriate to project long term future costs directly from the top of a price bubble, otherwise all future costs will contain the current temporary market conditions.

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 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[16]). The 2023-24 update to current costs has mixed information with some technology costs declining, some flat and some increasing. However, as a group it indicates inflationary pressures are weakening.

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

[16] 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 costs resume their pre-pandemic modelled pathway.

The exception to the resumption of a modelled cost path after 2027 or 2030 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 (2023a) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[17]. 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 first and primary source of 2023 costs is Aurecon (2023a). Aurecon (2023a) provides an update on the current costs of contracting the deployment of most of the technologies included in GenCost (biomass with CCS and brown coal are two exceptions).

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 2023 are in addition to the general level of inflation.

4.2 Global generation mix

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

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

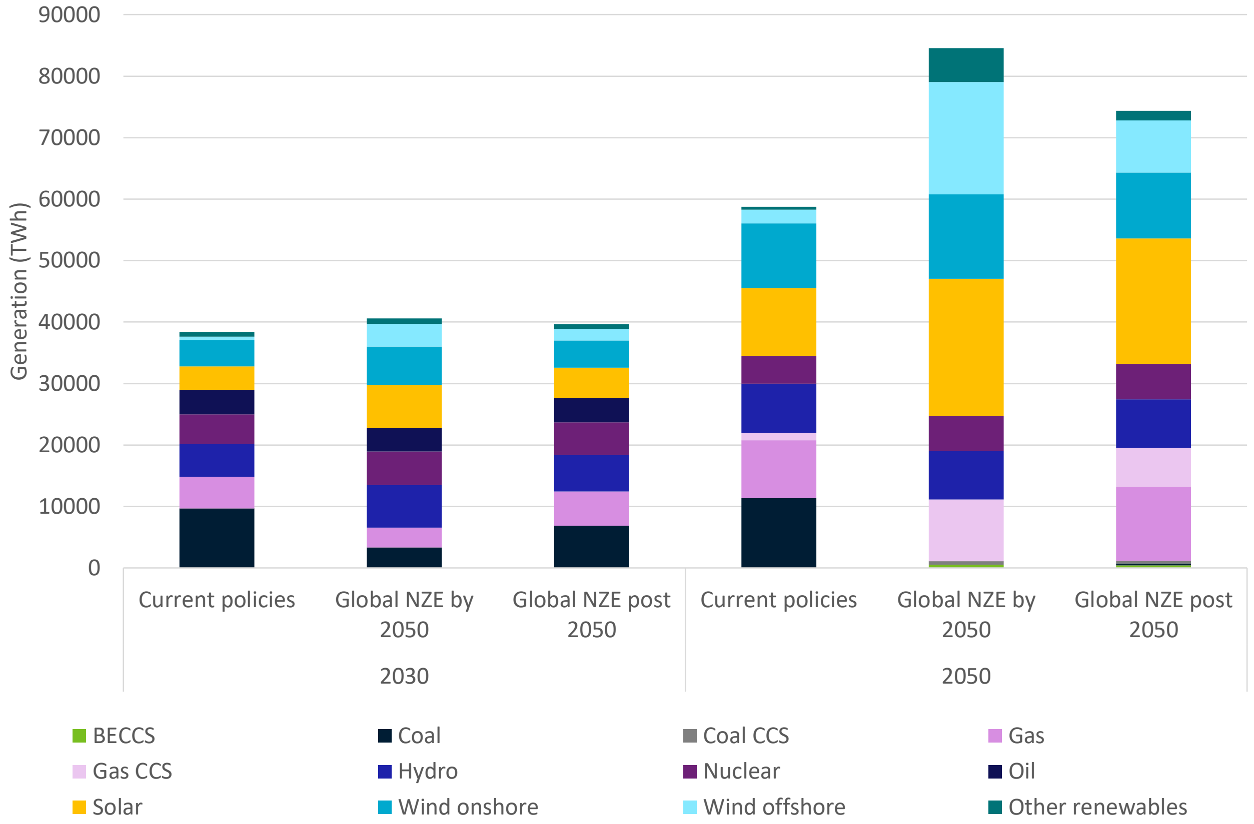

Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Current policies 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[18]. 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 4-2 shows the contribution of each hydrogen production technology in each scenario.

Current policies has the lowest non-hydro renewable share at 41% 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, but is around 8% in all scenarios by 2050.

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. 99% of generation from fossil fuel sources is with CCS accounting for 13% of generation by 2050. Offshore wind features strongly in this scenario at 22% of generation by 2050. Renewables other than

[18] 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 6% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs.

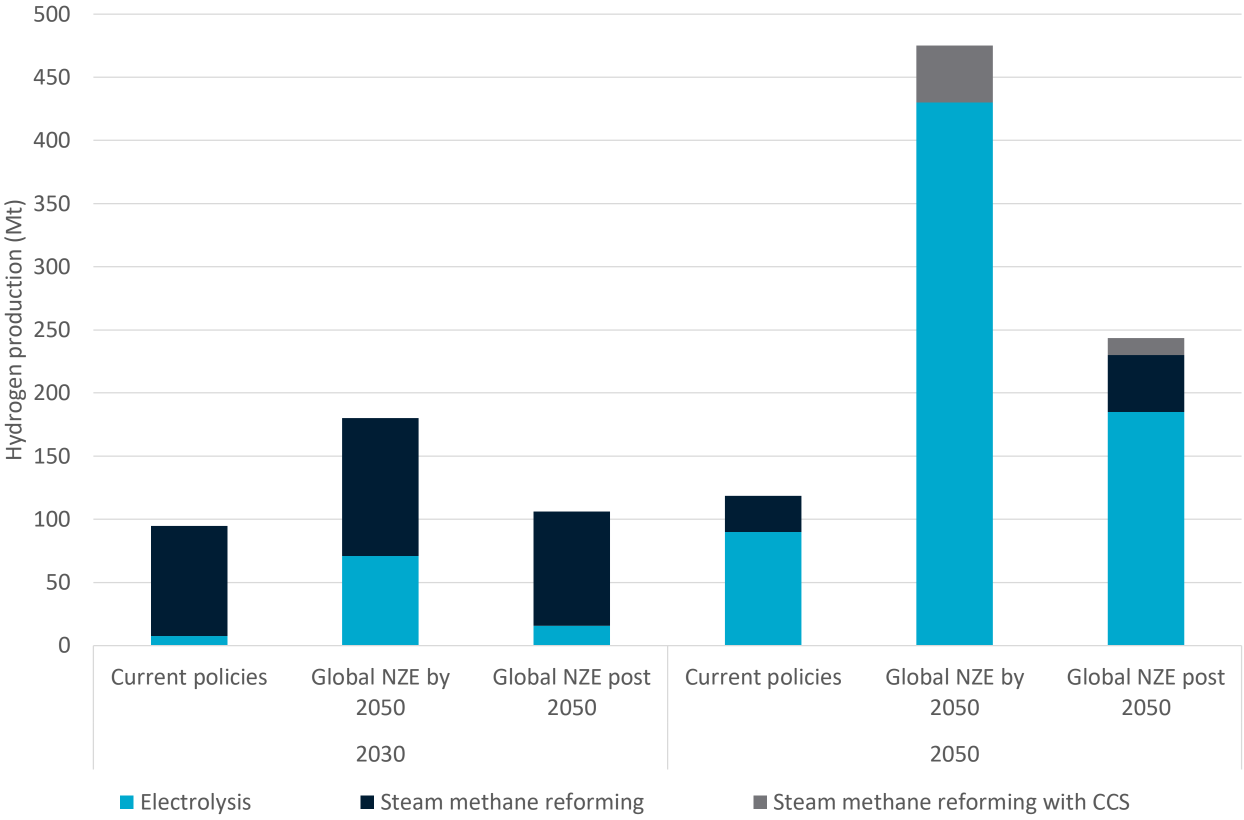

Figure 4-2 Global hydrogen production by technology and scenario, Mt

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2022-23 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. 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[19].

4.3.1 Black coal supercritical

The cost of black coal supercritical plant in 2023 has been updated by Aurecon (2023a) whereas in the previous year it had been inflated from older data. From 2023 the capital cost is assumed to

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

return to levels 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 for mature technologies outlined at the beginning of this section. The updated trajectory includes a more even progression over time. The assumed long term rate of improvement in costs for mature technologies over time and the land cost inflator are the same as in the 2022-23 projections.

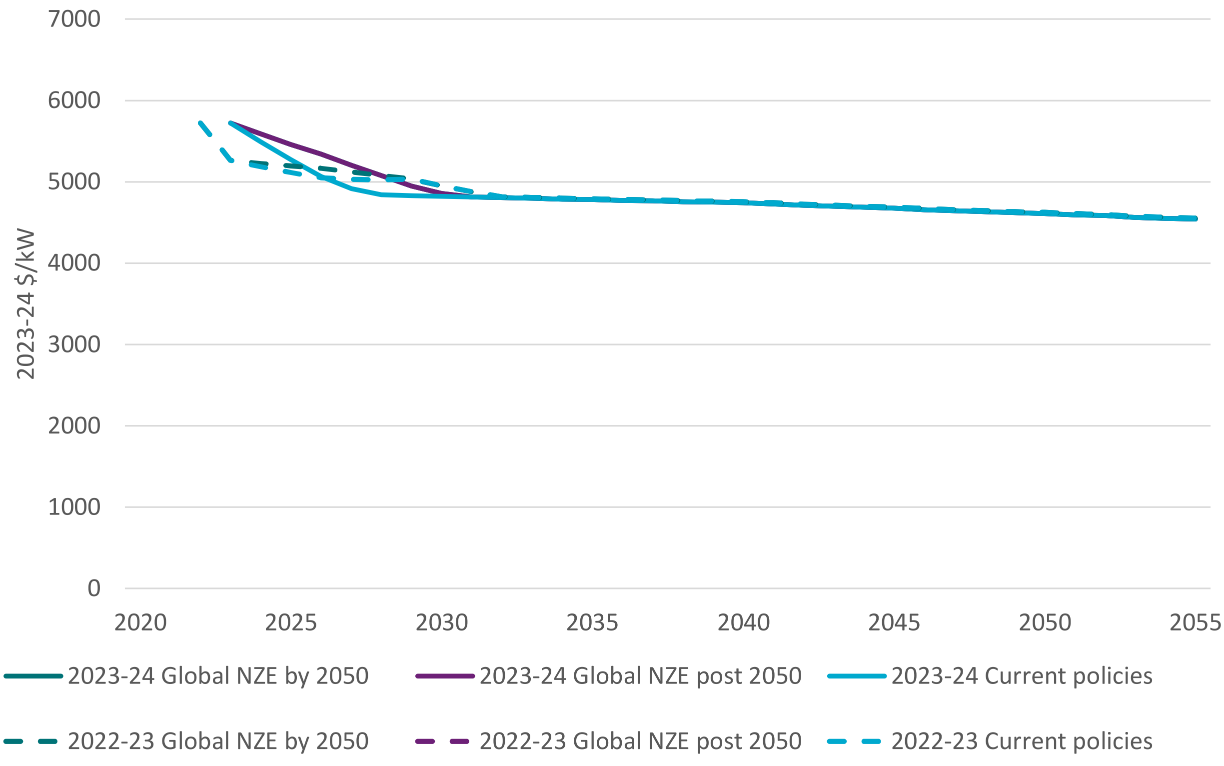

Figure 4-3 Projected capital costs for black coal supercritical by scenario compared to 2022-23 projections

4.3.2 Coal with CCS

The current cost of black coal with CCS from 2023 to 2027 in *Current policies* or 2023 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. 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 are mainly driven by the deployment of CCS in other industries. While black coal with CCS benefits from co-learning from deployment of CCS in non-electricity industries, there is only a negligible amount of generation from black coal with CCS throughout the projection period.

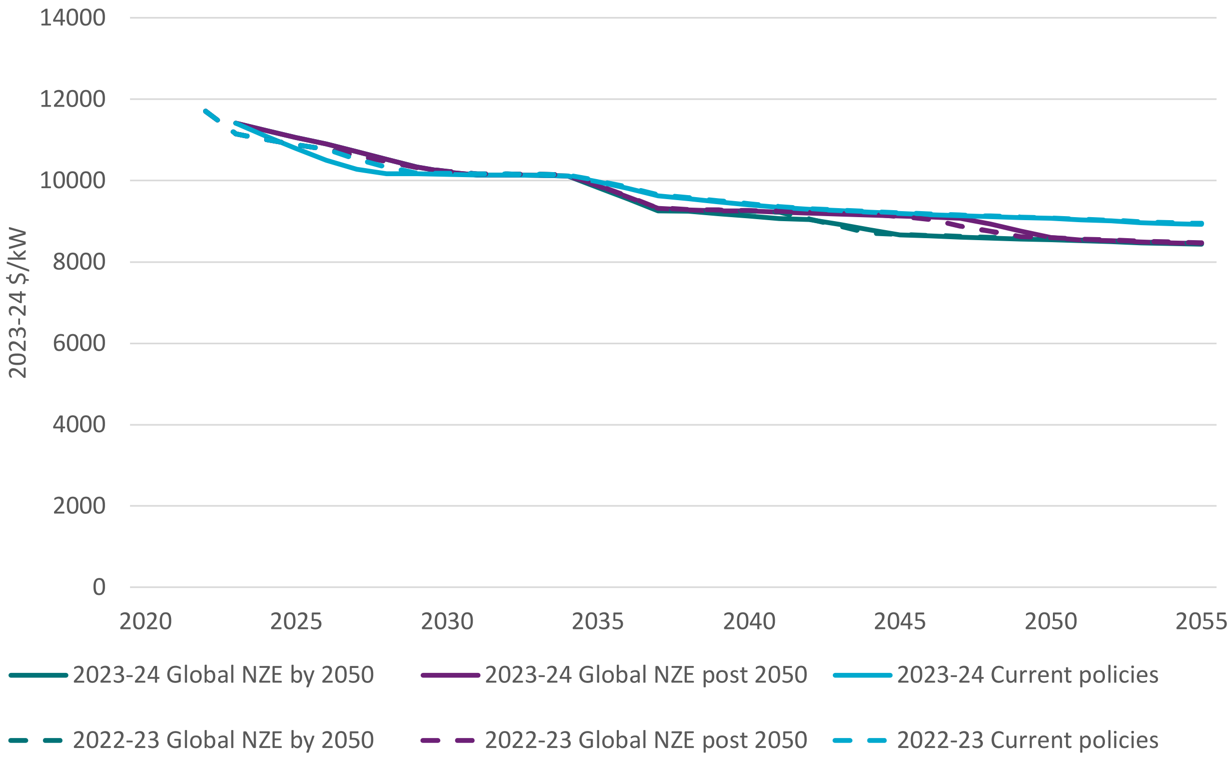

Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2022-23 projections

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). Given the scale of generation and hydrogen production required in those scenarios, together with assumed high other industry use of CCS, the total deployment of CCS technologies across all applications is high. The total CSS 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.

4.3.3 Gas combined cycle

Aurecon (2023a) have included an increase in gas combined cycle costs for 2023 and CSIRO has imposed an assumed return to previous costs levels by 2027 in *Current policies* and 2030 in the *Global NZE* scenarios. After the return to normal period, because gas combined cycle is classed as a mature technology for projection purposes, its change in capital cost is governed 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.

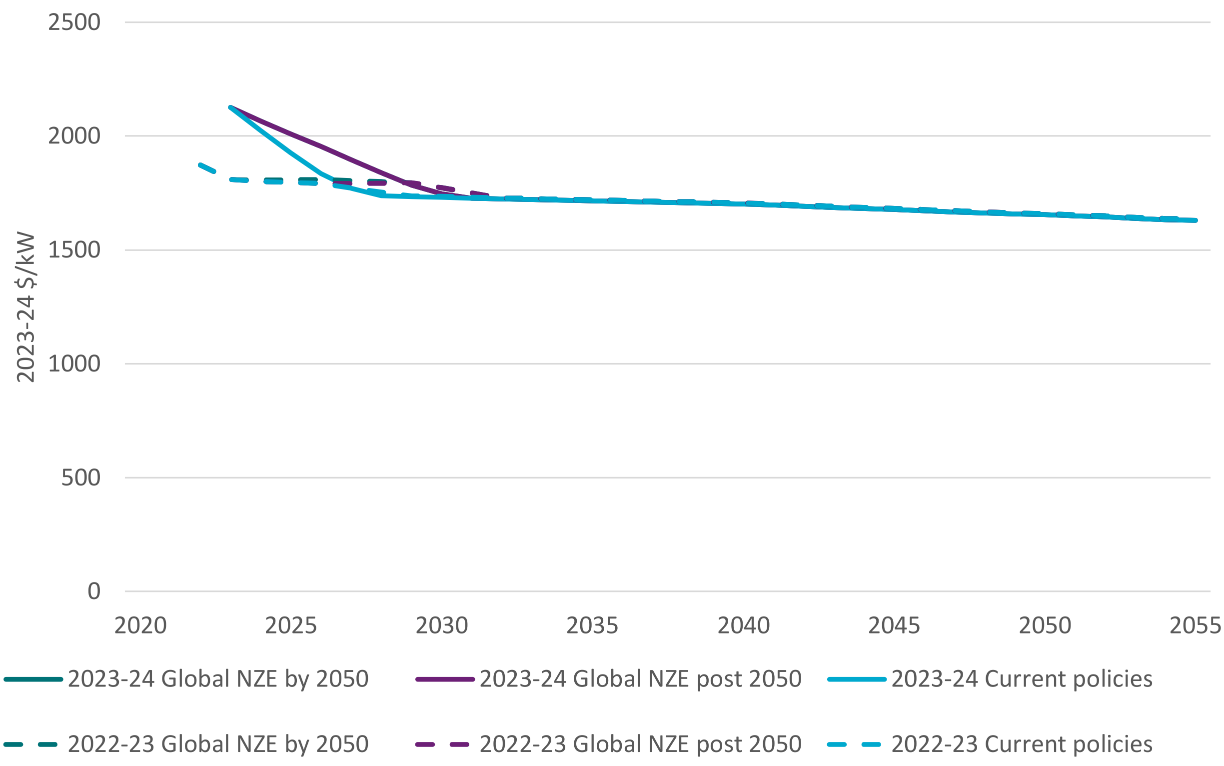

Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2022-23 projections

4.3.4 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 lowest by 2050 in those scenarios. Conversely, CCS is highest cost in *Current policies* where CCS deployment is lowest.

The IEA CCS database[20] indicates there are around 30 planned electricity related projects which are yet to make a financial investment decision, two under construction and one completed. The advanced projects are for smaller volumes and/or low capture rates. Given the current state of the pipeline of projects, the earliest date for commercial, high capture rate, electricity CCS projects has been set at 2035.

[20] CCUS Projects Database - Data product - IEA

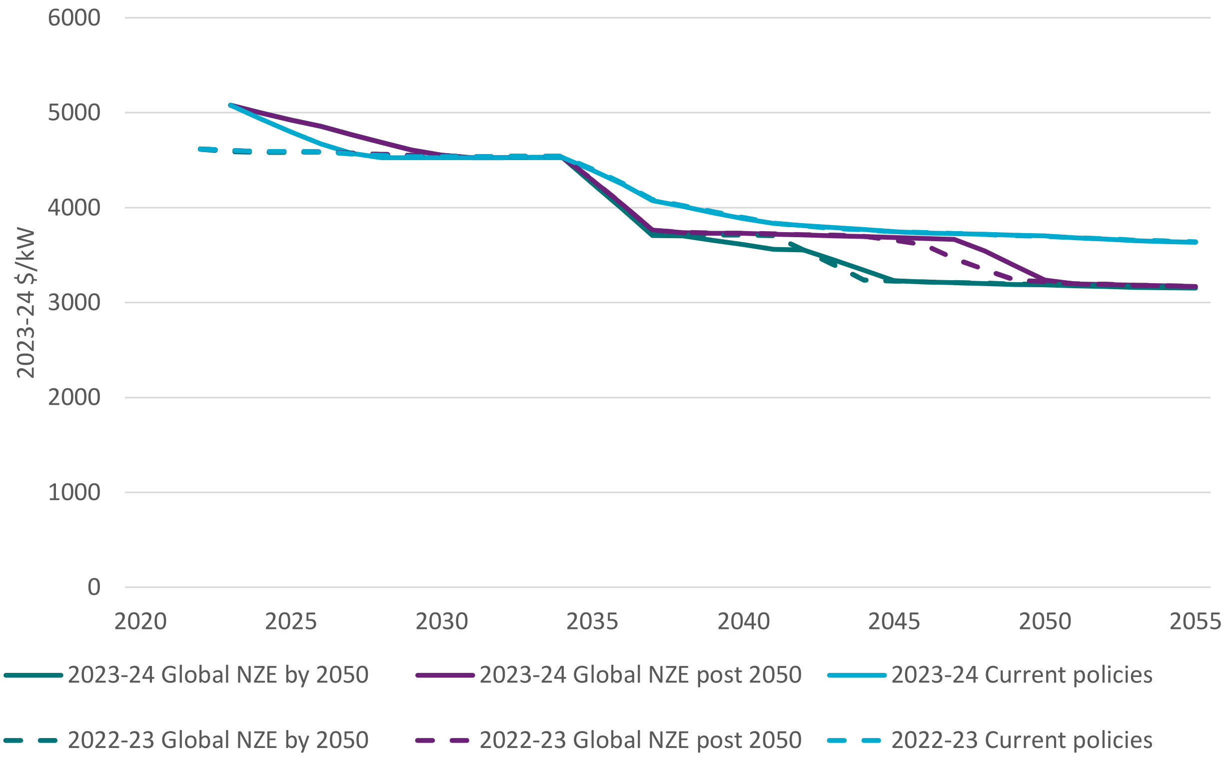

Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2022-23 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2022-23 and updated 2023-24 cost projections for small and large open cycle gas turbines. Aurecon (2023a) provides the details for the unit sizes and total plant capacity that defines the small and large sizes. Current costs are higher for both sizes based on the updated 2023 data. However, a further cost increase was anticipated for 2023 in the previous projections and aligns well with the updated cost. Capital costs are assumed to converge towards their previous projected levels by 2027 or 2030. 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.

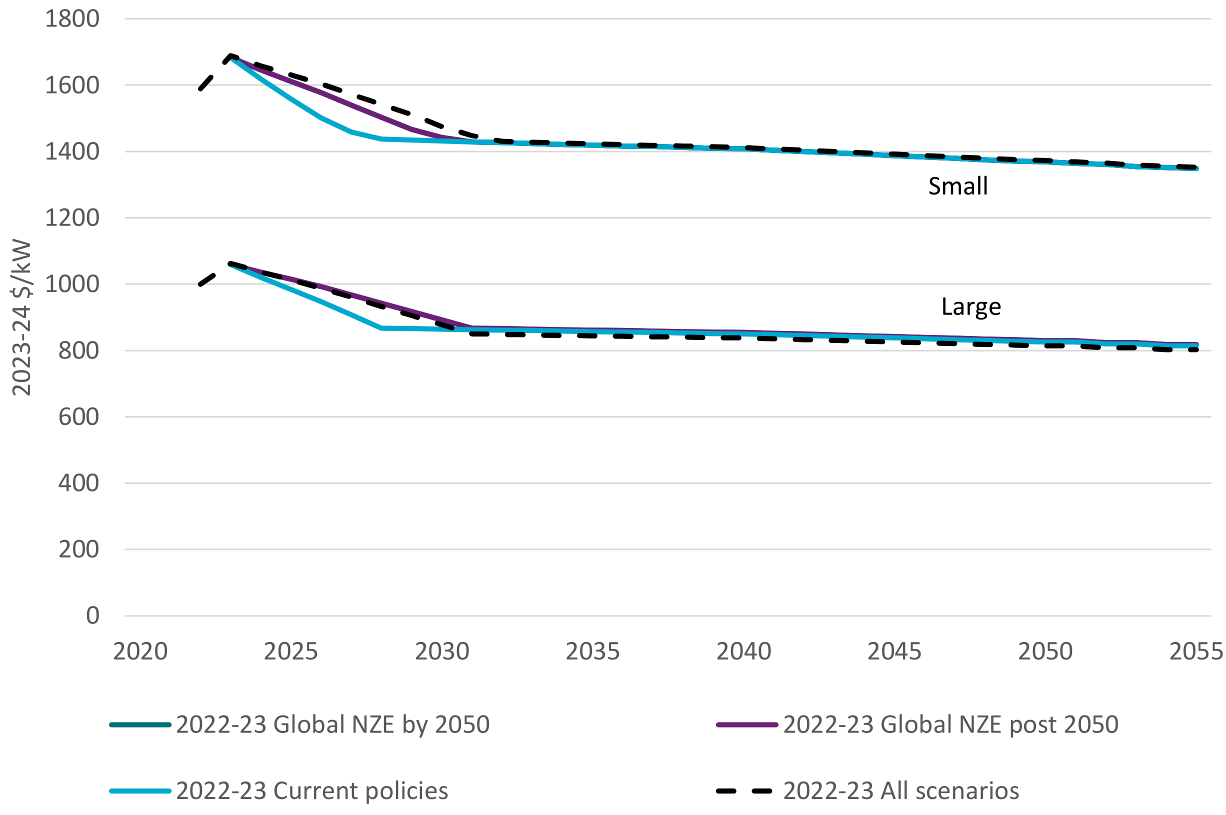

Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2022-23 projections

4.3.6 Nuclear SMR

Given the lack of global commercial deployment and very low expectation of deployment in Australia, GenCost previously did not report cost data before 2030 for nuclear SMR. However, as discussed in Section 2.4, more information has become available on the current cost of nuclear SMR, and it is now reported from 2023.

New information has meant that the scenarios are less divergent than previous projections but higher on average. The projections start at the updated 2023 capital cost of around $31,000/kW. Like all other technologies, we assume costs converge back to a level that does not include the current short term inflationary impacts. The new published information discussed in Section 2.4 has been useful in determining the pre-inflationary cost level. There is also some learning within the period to 2030 assuming projects at advanced planning stages proceed. Beyond 2030 further deployment of less developed projects needs to proceed to achieve further cost reductions. 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 2050s.

In the Global NZE scenarios, the scale of abatement and growth in demand means that existing commercial technologies are not sufficient to achieve the electricity sector emissions reduction. As a result, significant deployment of nuclear SMR proceeds with subsequent cost reductions achieved during the 2030s 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. There is some variation in the timing and depth of cost changes with *Global*

NZE by 2050 around $200/kW lower on average. Capital costs are between approximately $11,000/kW and $15,000/kW across the scenarios.

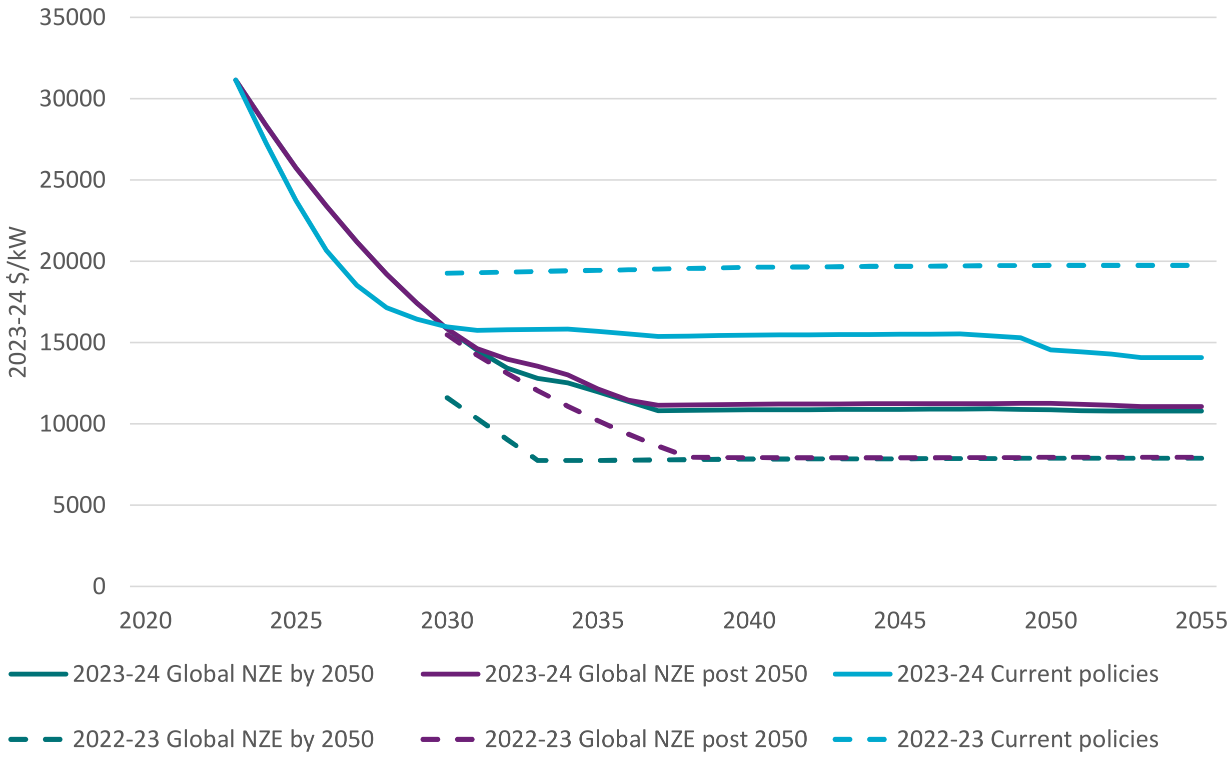

Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2022-23 projections

4.3.7 Solar thermal

The starting cost for solar thermal has been updated by Aurecon (2023a) drawing on Fichtner Engineering (2023) which also includes an adjustment for inflationary pressures in 2022. Due to lack of projects, it is unknown whether solar thermal would have been subject to further cost inflation in 2023 and so the apparent cost reduction compared to the previous year's data should be viewed with caution. This cost reduction is the main cause for changes in the projection compared to 2022-23. 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.

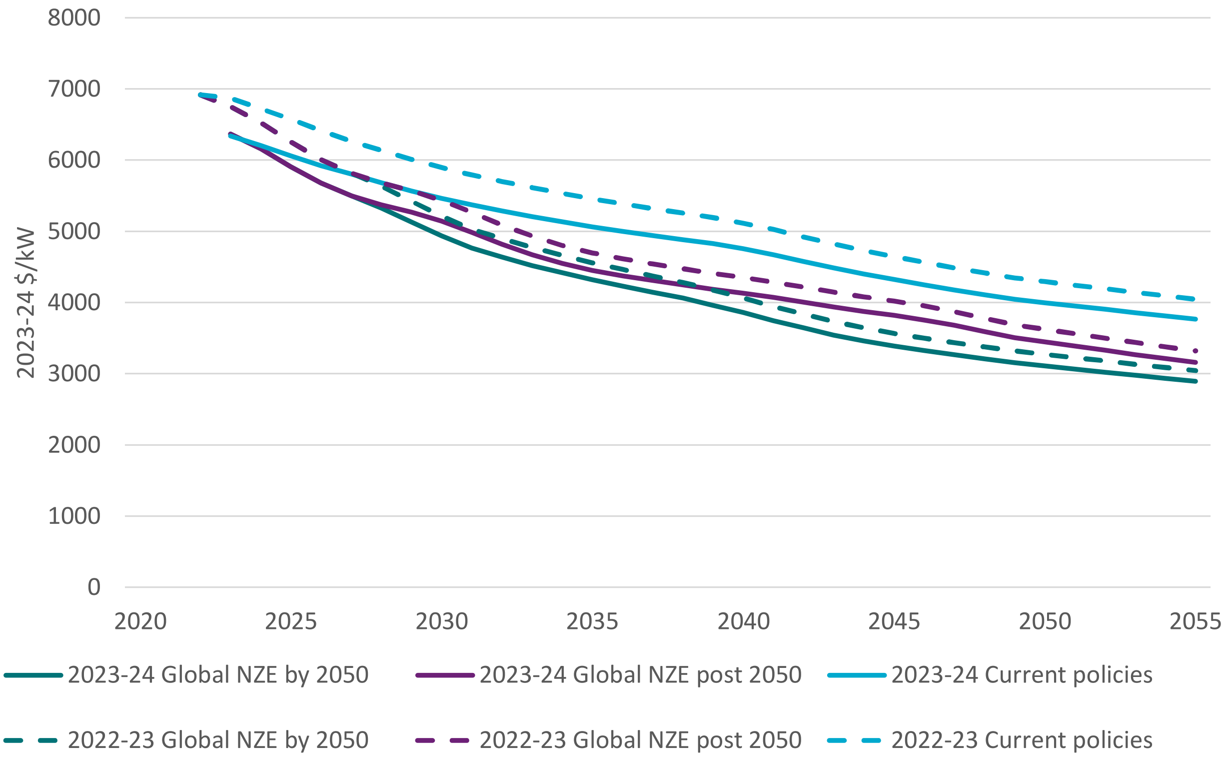

Figure 4-9 Projected capital costs for solar thermal with 14 hours storage compared to 2022-23 projections (which was based on 15 hours storage)

4.3.8 Large scale solar PV

Large-scale solar PV costs have been revised downwards for 2023-24 based on Aurecon (2023a) indicating solar PV production costs are recovering more rapidly than projected from global inflationary pressures. Under the *Current policies* scenario, costs fully return to their normal cost pathway by 2027. In the Global NZE scenarios, inflationary pressures remain higher for longer due to faster technology deployment to meet stronger climate policies, but after 2030 experience the strongest cost reductions with *Global NZE by 2050* being the lowest cost overall.

By 2050 the three scenarios project a capital cost range of $540/kW to $740/kW. The final minimum cost level for solar PV is one of the most difficult to predict because, unlike other technologies, and notwithstanding current extreme 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.

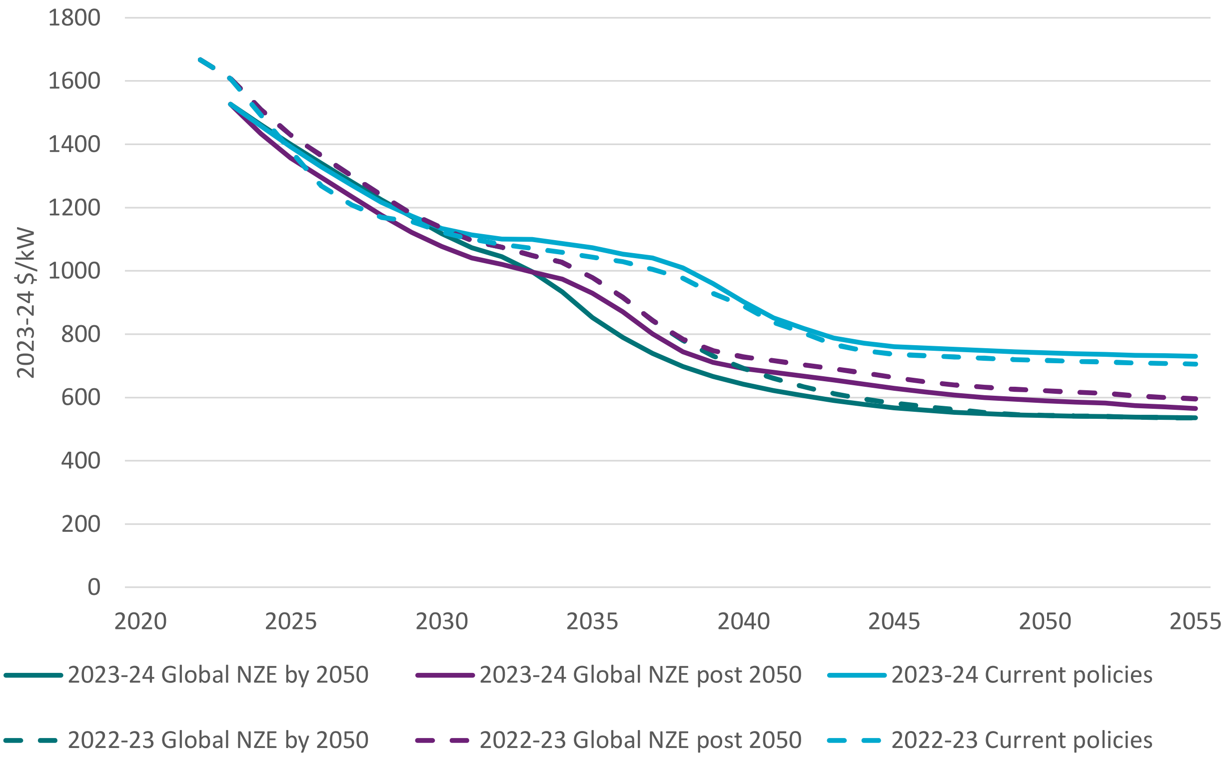

Figure 4-10 Projected capital costs for large scale solar PV by scenario compared to 2022-23 projections

4.3.9 Rooftop solar PV

The current costs for rooftop solar PV systems are lower and well aligned to the level projected for 2023 in the previous 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[21]. 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.

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

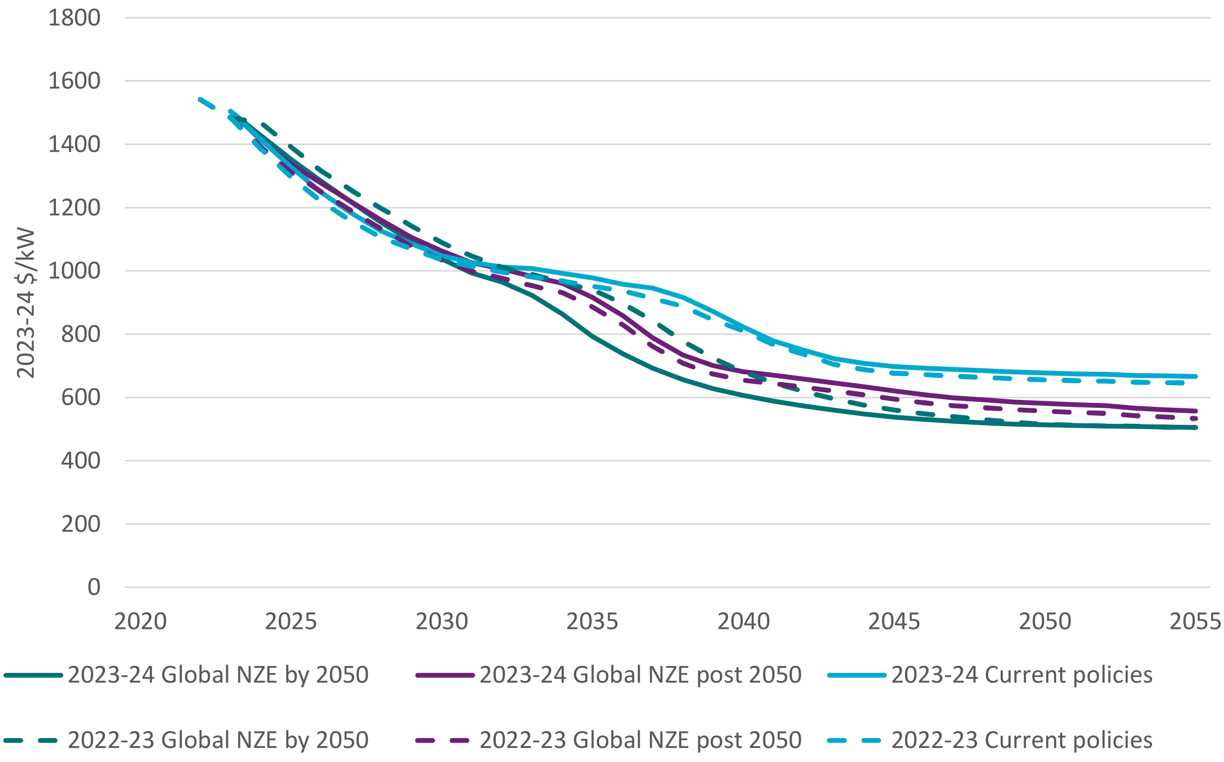

Figure 4-11 Projected capital costs for rooftop solar PV by scenario compared to 2022-23 projections

4.3.10 Onshore wind

The updated Aurecon (2023a) data indicates that onshore wind has experienced an 8% increase in capital costs in 2023 (down from a 35% increase the previous year). Like all technologies, our assumption is that capital costs of onshore wind will return to its normal cost path by 2027 in *Current policies* and by 2030 in the Global NZE scenarios. From the 2030s, wind costs will 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 stronger with stronger global climate policy ambition resulting a range of around $1700/kW to $2000/kW by 2050.

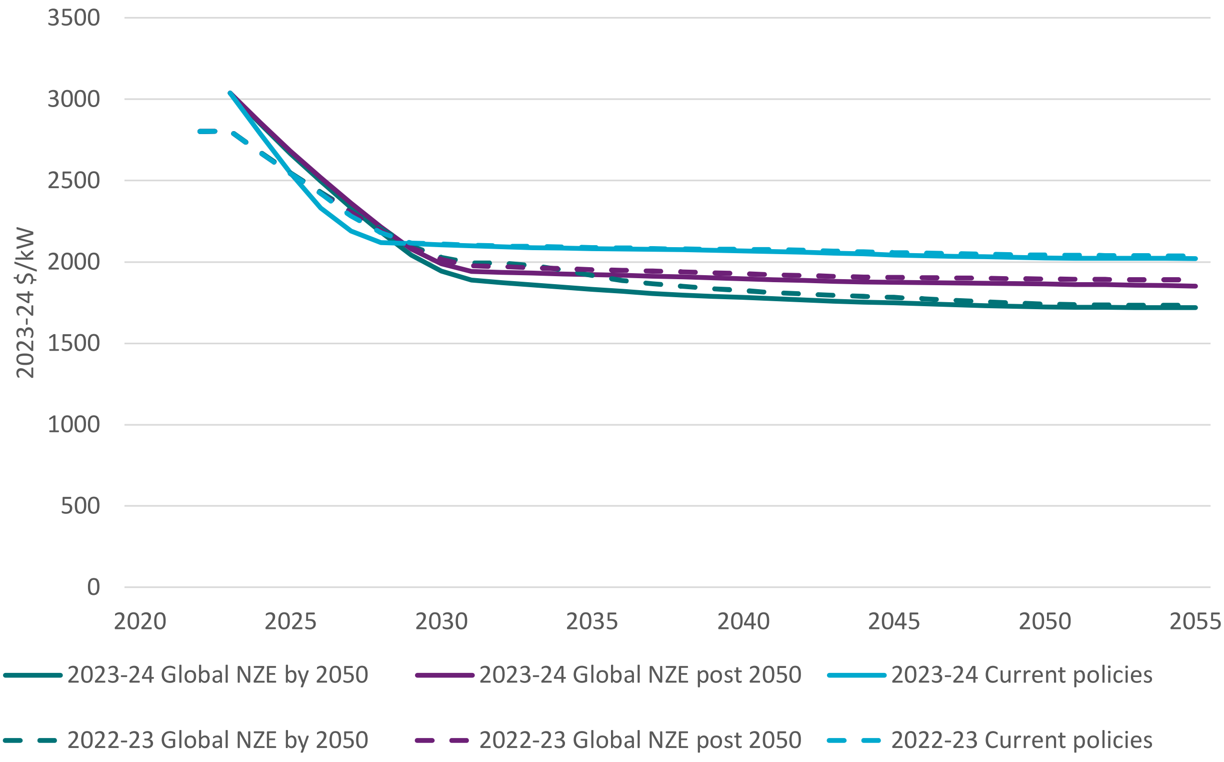

Figure 4-12 Projected capital costs for onshore wind by scenario compared to 2022-23 projections

4.3.11 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 least cost offshore technology, but its maximum deployment is limited by access to seas of a maximum depth of around 50-60 metres[22] and any navigation or marine conservation issues within those zones. Floating offshore wind can be deployed at much greater depths increasing its potential global deployment and providing a unique reason to select the technology.

Figure 4-13 presents projections for both fixed and floating compared to 2022-23. The current costs for both types of offshore wind are provided in Aurecon (2023a). The updated capital costs align well with the cost reductions projected in 2022-23. Post 2023 the offshore wind capital costs are assumed to reconnect with underlying costs prior to the global inflationary pressures in 2027 for *Current policies* and in 2030 for the Global NZE scenarios. In some scenarios they are slightly higher reflecting some competition from floating offshore wind.

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

In *Current policies*, floating offshore wind deployment is low. As such, cost reductions after 2027 are low. Cost reductions are deeper in the Global NZE scenarios where the demand for low emission electricity is higher and climate policy ambitions are stronger. Just before 2050, the cost of floating offshore wind falls below that of fixed offshore wind. This result could be plausible if we consider that, in this scenario and time period, most readily accessible fixed offshore wind sites adjacent to the highest demand countries may already be claimed shifting the focus of global manufacturing to supplying floating offshore wind technology.

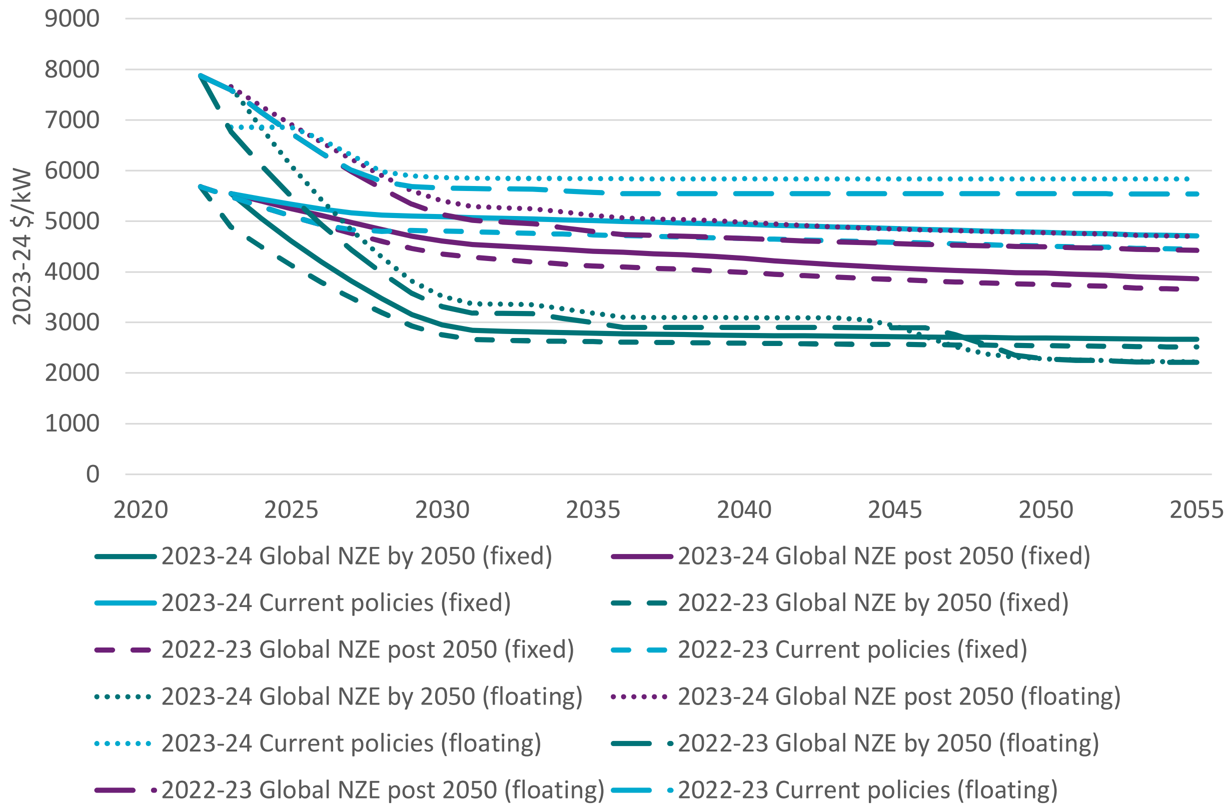

Figure 4-13 Projected capital costs for fixed and floating offshore wind by scenario compared to 2022-23 projections

4.3.12 Battery storage

The projections for batteries include a 2% increase in total costs which is reasonably well aligned with the previous projections. It is assumed that costs converge back to their underlying level pathway by 2027 in *Current policies* and by 2030 in the Global NZE scenarios.

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. 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 supporting variable renewables alongside other storage and flexible generation options and in growing electric vehicle deployment. The projected future change in total cost of battery projects is shown in Figure 4-14 (battery and balance of plant).

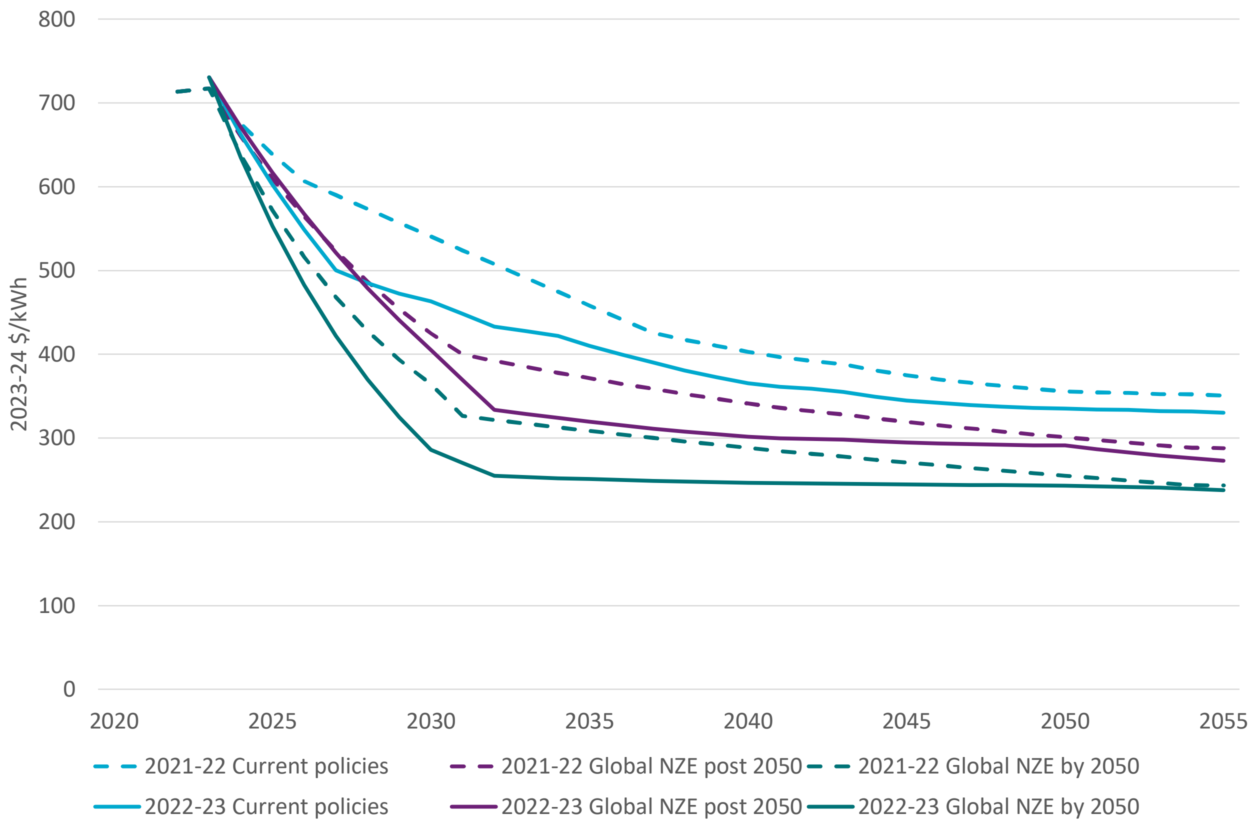

Figure 4-14 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

Battery deployment is strongest in the *Global NZE by 2050* scenario reflecting stronger deployment of variable renewables, which increases electricity sector storage requirements, and stronger uptake of electric vehicles to support achieving net zero emissions by 2050. Together with an assumed high learning rate this leads to the fastest cost reduction. The remaining scenarios have more moderate cost reductions reflecting slower uptake of electric vehicles and 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 (2023a) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $14,400 for a 5kW/10kWh system or $1455/kWh, including installation. This is around twice the cost of large-scale battery projects.

4.3.13 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. The previous source of current cost data was the 2020-21 and 2021-22 is the AEMO Integrated System Plan (ISP) input and assumptions workbooks – December 2020 and June 2022 respectively. These were informed by the Entura (2018) report and adjusted for inflation. Aurecon (2023a) has provided the first update in some time and capital costs have risen as a result of new information since that time. The increase in current costs is the main feature of the new projections.

Appendix B includes the costs of pumped hydro energy storage at different durations. We also assume that the costs for Tasmania 24 and 48 hour pumped hydro storage are 62% and 46%, respectively, of mainland costs. This approach is consistent with the AEMO ISP and reflects greater confidence in Tasmanian project cost estimates. The AEMO data also includes some other state differences that are not included in the national figures presented here.

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.

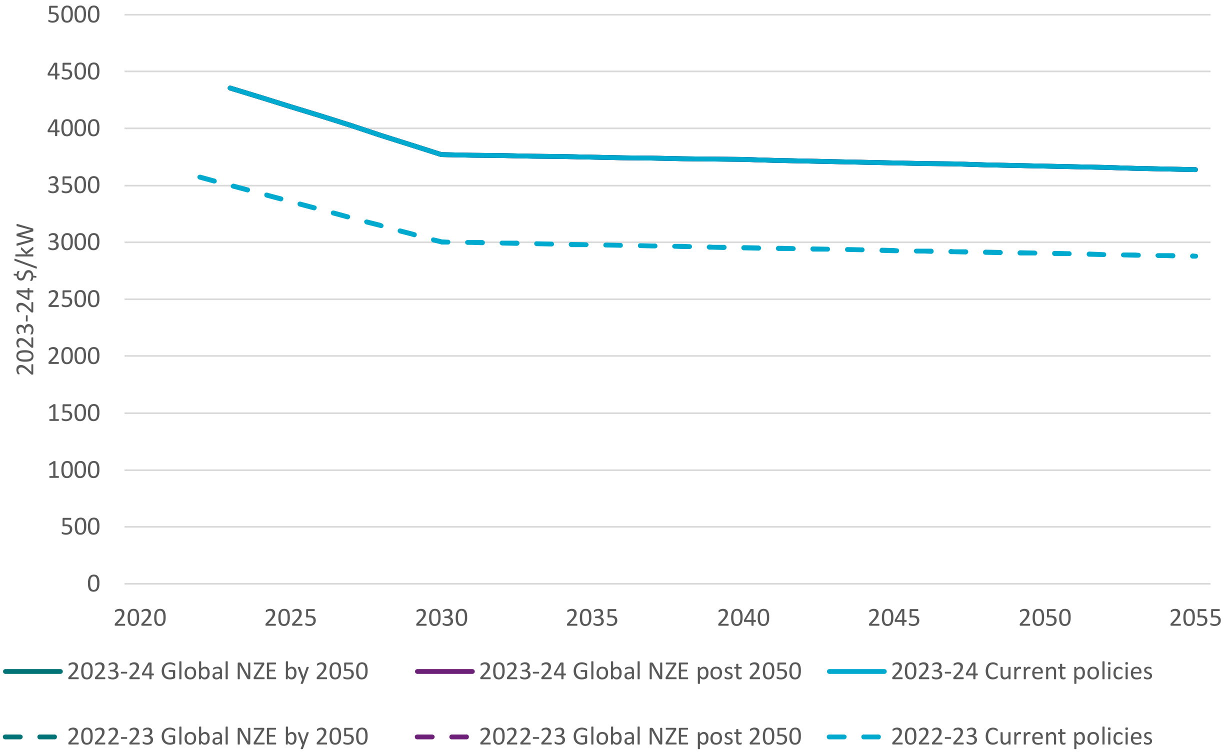

Figure 4-15 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

4.3.14 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 with most technologies other than fuel cells increasing in capital costs. Like PHES, wave and tidal energy had not been updated for some time and so increases reflect the recent update by Aurecon (2023a) rather than current inflationary pressures. Fuel cells have been updated more regularly and are well aligned with previous projections. The downward trend to either 2027 or 2030 have been included using the same methodology for other technologies. Projections also include increasing land costs.

Current policies

Biomass with CCS is not deployed in the *Current policies* scenario because the climate policy ambition is not strong enough to incentivise deployment. Cost reductions after 2027 reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors. Fuel cell cost improvements are mainly a function of deployment and co-learning in the vehicle sector rather than in electricity generation. Neither wave nor tidal/ocean current are deployed to any significant level mainly reflecting the lack of climate policy ambition needed to drive investment in these relatively higher cost renewable generation technologies. The current costs for wave and tidal/ocean current technologies have changed significantly reflecting that the data provided by Aurecon (2023a) is more up to date than previous sources.

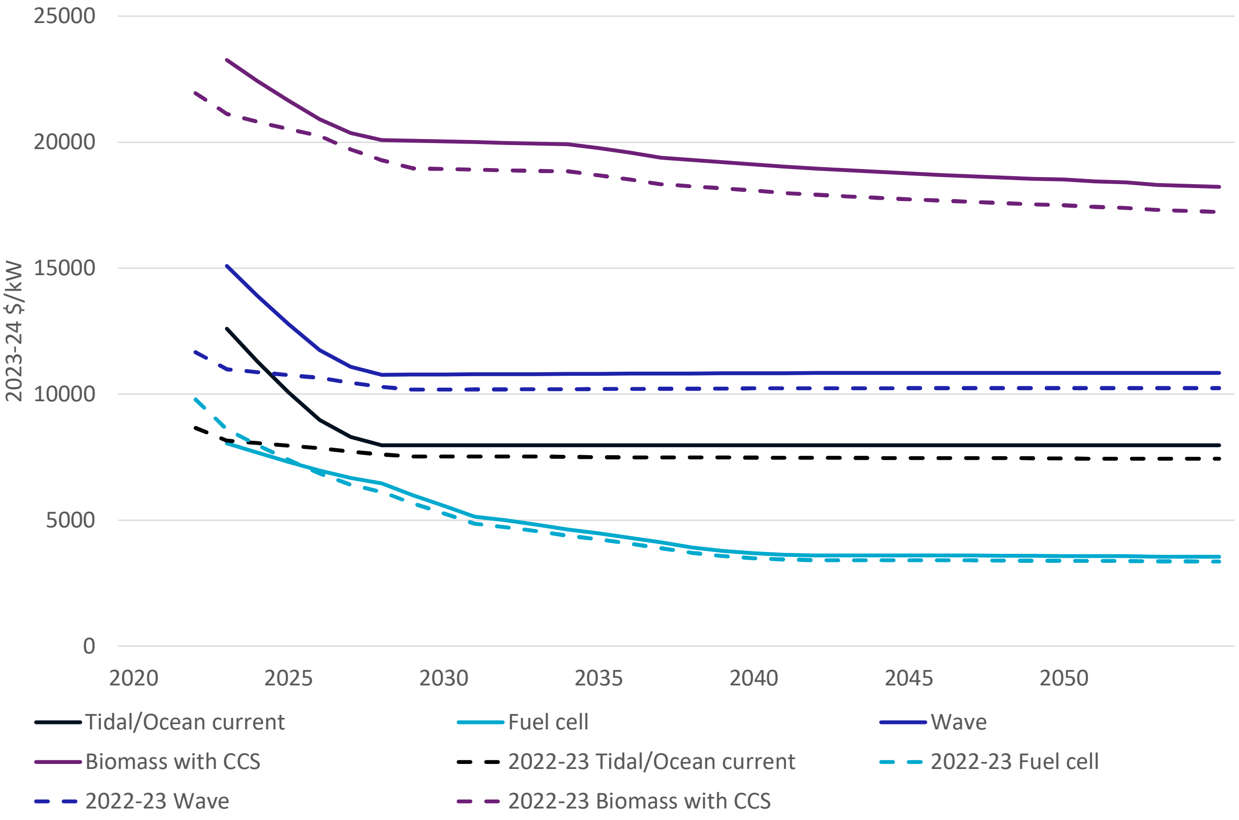

Figure 4-16 Projected technology capital costs under the *Current policies* scenario compared to 2022-23 projections

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.

Fuel cells and wave energy are deployed although the early reduction in fuel cells reflects their use in the transport sector. Tidal/ocean current generation has minor deployment from the mid-2040s.

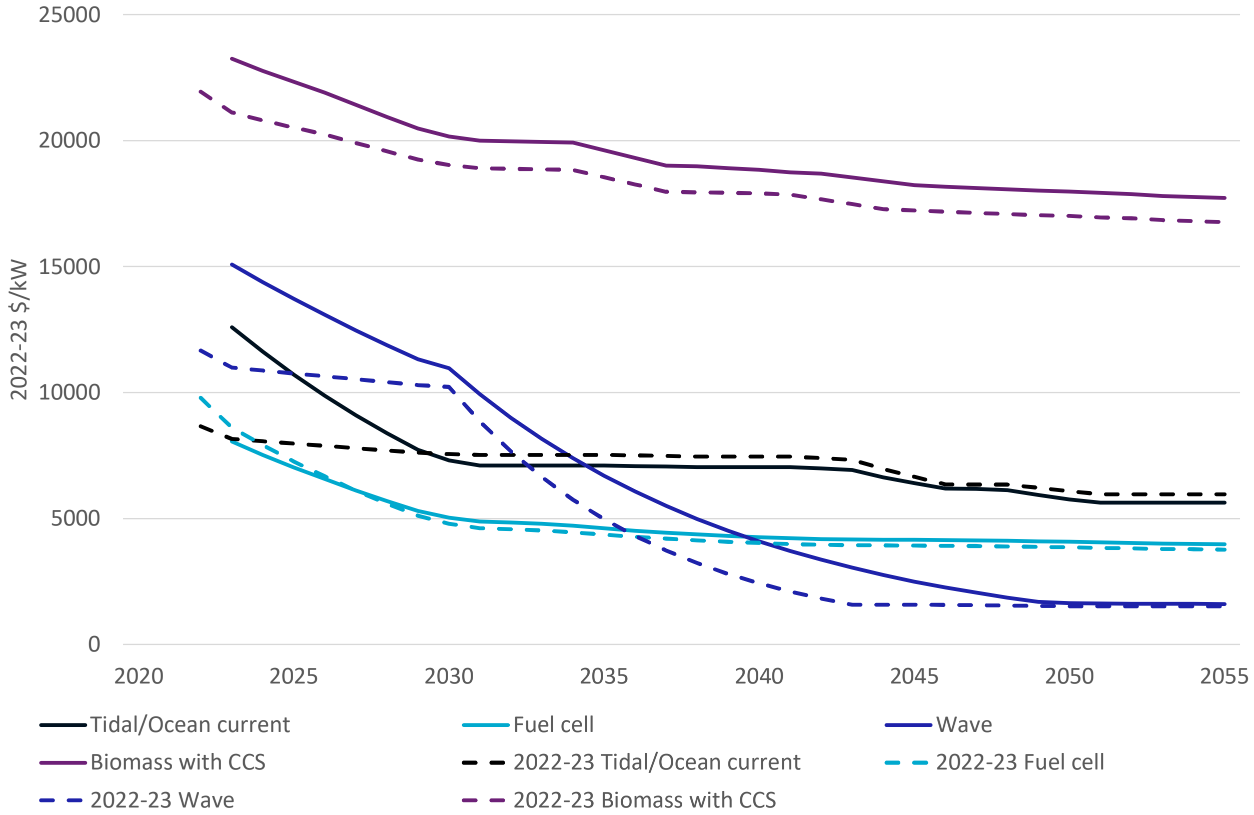

Figure 4-17 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2022-23 projections

Global NZE post 2050

Biomass with CCS is deployed at about 80% the level of *Global NZE by 2050*. However, the cost reductions achieved are similar to that scenario because 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*. Similar to *Current policies* wave and tidal/ocean energy is not deployed.

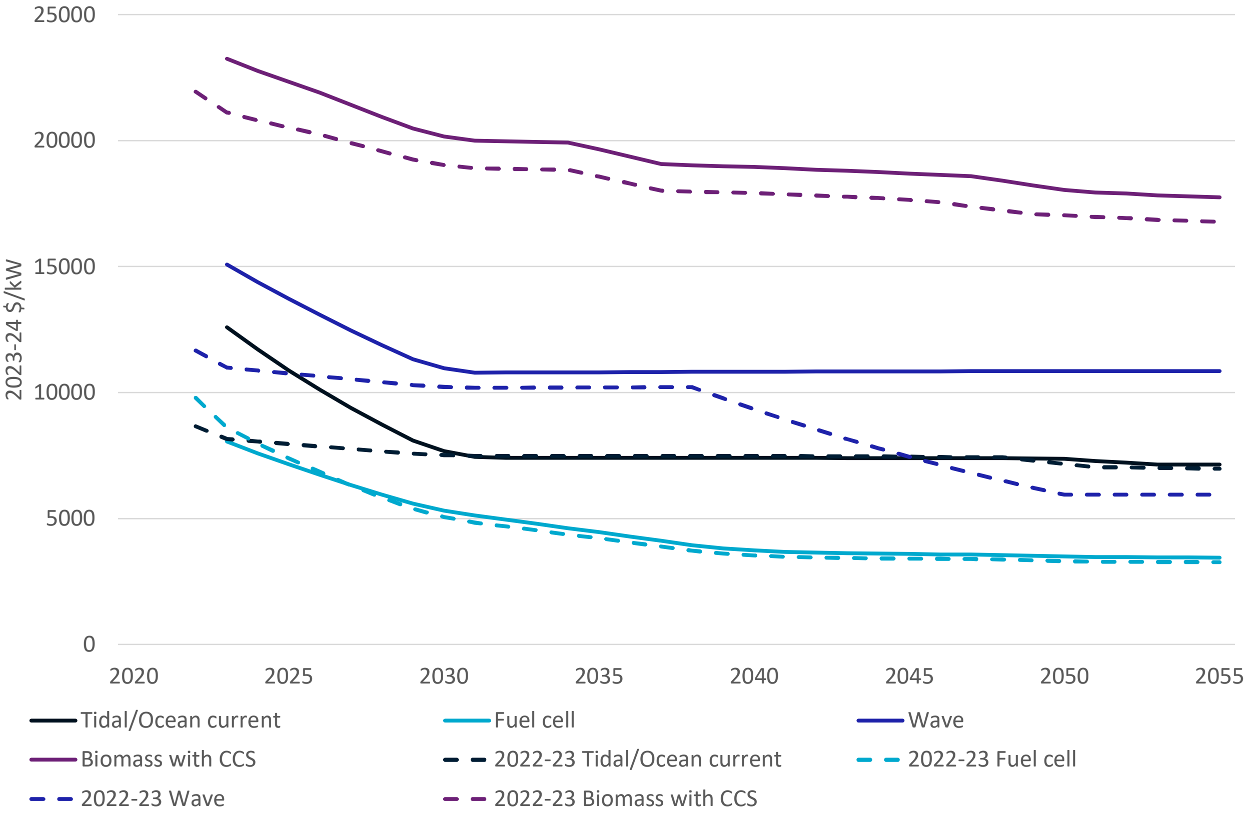

Figure 4-18 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2022-23 projections

4.4 Hydrogen electrolysers

Hydrogen electrolyser costs have decreased in 2023 and the decrease is sourced from Aurecon (2023a). Alkaline electrolysers are lower cost than proton-exchange membrane (PEM) electrolysers at present. However, PEM electrolysers have a wider operating range which gives them a potential advantage in matching their production to low-cost variable renewable energy generation. PEM costs fell slightly faster than Alkaline electrolyser capital costs. 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.

GALLME does not directly model the competition between PEM and alkaline technologies since it does not have the temporal resolution to evaluate the trade-off between capital utilisation and the cost of electricity. We model a single electrolyser technology, with current cost based on alkaline electrolyser costs and we assume PEM costs converge to alkaline costs by 2040.

The current costs applied at the starting point of the projection are for 10MW electrolysers. This scale is far smaller than we would expect to see deployed over the long term where multi-gigawatt renewable zones are being considered to supply hydrogen production hubs. No other technology in this report is presented at trial scale. We therefore adjust the scale over time in the projection to recognise electrolysers moving out of the trial stage and into full scale production. We assume full scale is 100MW and after that size they are deployed in 100MW modular units. Applying typical engineering cost scaling factors this movement to full scale accounts for around an 80% reduction in costs. The electrolyser capital cost reduction rate would be significantly slower without this scale effect.

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. Very low costs of electrolysers, at the bottom end of the projections here, have been reported in China. However, differences in engineering standards and operating and maintenance costs mean these are not able to be immediately replicated in other regions. They do indicate, however, a potentially achievable level of costs for other regions over the longer term.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario. Consistent with their lower global climate policy ambition, hydrogen electrolyser production is 57% lower by 2050 in *Global NZE post 2050* and 79% lower in *Current policies*.

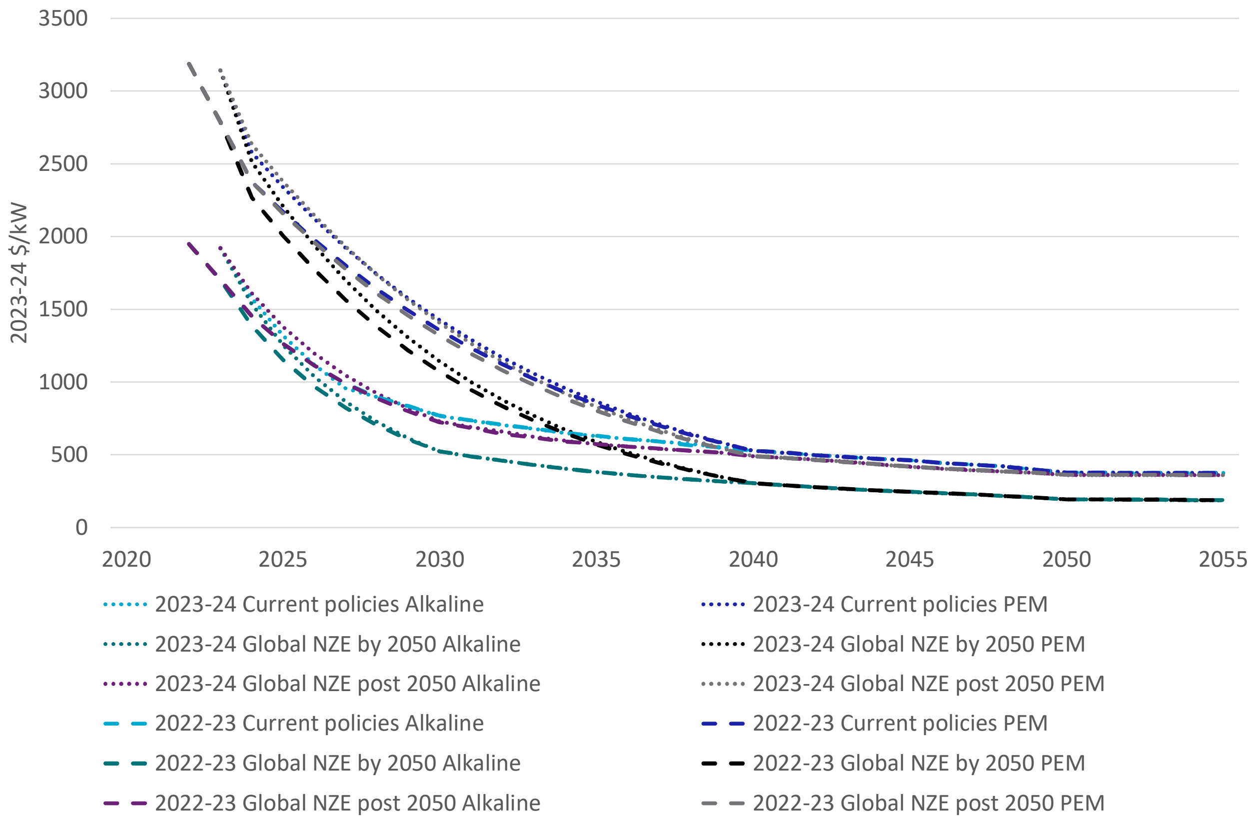

Figure 4-19 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2022-23

5 Levelised cost of electricity analysis

5.1 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. Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data[23]. 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:

- LCOE does not take account of the additional costs associated with each technology and in particular the significant integration costs of variable renewable electricity generation technologies
- 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.
- 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
- Include additional LCOE data on fossil fuel technologies which includes an additional risk premium of 5% based on Jacobs (2017).

[23] 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.

5.2 LCOE estimates

5.2.1 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[24]). 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.

In previous GenCost reports 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 has 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 2023 in addition to 2030.

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 2023, there are only negligible amounts of home battery systems and electric vehicles which must be considered when looking at future points in time. The large scale system can only use storage that it builds for itself in 2023.

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

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[24] Interest lost during construction is added so that the advantage given by projects that take shorter to is recognised.

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 5-1 defines the question that is answered by the 2023 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.

Table 5-1 Questions the LCOE data are designed to answer

LCOE data	Question answered
2023 variable renewables LCOE with integration costs	Assuming any existing capacity available in 2023 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 2023 from a combination of variable renewable generation, transmission, storage and other resources, including the cost of currently committed or under construction projects?
2023 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 2023?
2030 variable renewables LCOE with interrogation 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?

5.2.2 Key assumptions

We calculate the integration costs of renewables in 2023 and 2030 imposing variable renewable energy (VRE) shares of 60% to 90%[25] 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

[25] 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.

wind and large-scale solar PV are the only variable renewables deployed in the modelling due to their cost competitiveness[26].

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 2023. 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 a range[27]. 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.

2023 represents the current electricity system. In 2030, we project forward including all existing state renewable energy targets resulting in a 64% renewable share and 56% variable renewable share in Australia ex-NT[28]. The share fluctuates a few percent 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 2023 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 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.

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[26] This does not preclude other types of projects proceeding in reality but is a reflection of modelling inputs in 2023 and 2030.

[27] The capacity factor range assigned to new build technologies are designed to be higher than the historical range. This is based on the view that new build technologies may include some technical advancements on their historical predecessors which mean they do not enter at the low range. Consequently, their low range capacity factor assumption is closer to the average capacity factor rather than the worst case. Specifically, we assume the low range value is 5% below the average. The high range assumption is that it equals the historical high range. Appendix D of the *GenCost 202-23: Final report* provided a discussion of historical capacity factors upon which the data in this report is based.

[28] At the time of modelling the government had not announced the Capacity Investment Scheme which is a policy for achieving 82% renewables by 2030. In the June ISP the 82% renewables policy was consistent with 65% VRE share with the remainder of renewable share made up of hydro, biomass and rooftop solar PV. However, we had not implemented the same outcome in GenCost because there was no policy that ensured the goal was achieved. In light of the strengthened policy mechanism we may need to implement a new baseline consistent with it and potentially remove the 60% VRE case in 2030.

As we implement higher variable renewable energy shares, we must forcibly retire coal plant as meeting the variable renewable share and the minimum load requirements on coal plant would otherwise eventually become infeasible[29]. Snowy 2.0 and battery of the nation 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. 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[30]. For the 2023 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[31]. These costs are included regardless of the VRE share. Pumped hydro and battery costs are sourced either directly from the projects or (AEMO 2023a). Transmission costs are from AEMO (2023b). For the 2030 investor, all of these projects are considered free capacity.

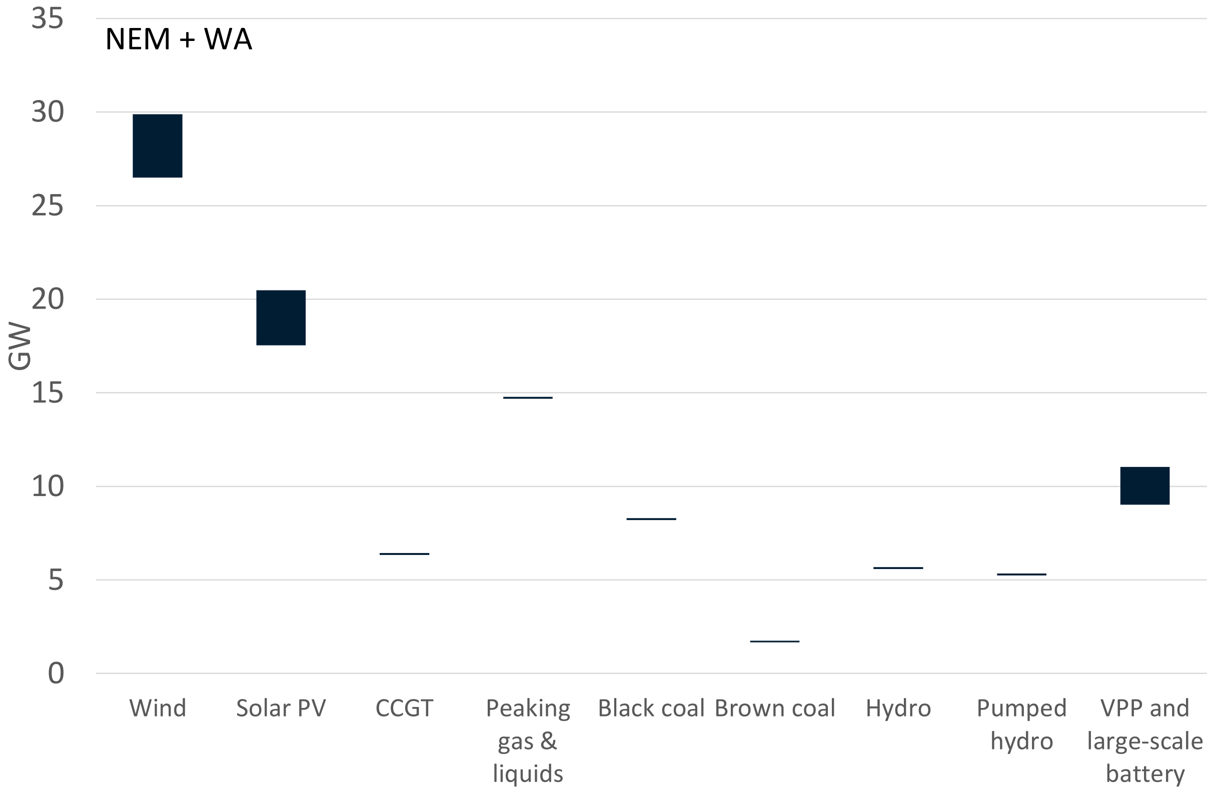

Figure 5-1 Range of generation and storage capacity deployed in 2023 (left) and 2030 (right) across the 9 weather year counterfactuals in NEM plus Western Australia

For 2023, the initial generation capacity is as it is today with the pumped hydro projects in New South Wales and Tasmania and the New South Wales 8 hour battery target added to that capacity.

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[29] 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.

[30] Two gas-fired power plants were also due to be added to capacity this summer in NSW and are therefore treated as existing capacity in both 2023 and 2030 LCOE calculations given that is their likely status for the final version of this report which will be released in mid-2024. As projects become operational, they are transformed from committed into existing capacity. Victoria also intends legislate for storage capacity. If enacted, this could be updated in the final report.

[31] 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.

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 5-1). 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 3.4GW, solar PV capacity by 2.9GW and large-scale batteries (VPP capacity is fixed) by 2.0GW. 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[32]. The NEM and WA total variable renewable shares are 56% and 58% on average across the weather years. The announced closure of the Muja and Collie coal-fired generators by 2029 and 2027 respectively has increased the BAU variable renewable share in WA.

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 5-2, include storage, transmission and synchronous condenser costs where applicable. The integration costs fall with increasing variable renewable share in the 2023 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.

Across the different VRE shares the cost of variable renewable generation in 2023 is $118/MWh on average in the NEM. This is 40% to 57% higher than in 2030. Around a half to three quarters of the higher costs (depending on the VRE share) are due to investors having to pay 2023 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 2023 analysis, but are considered free existing capacity for investors in 2030 (in the same way that anything built pre-2023 is free existing capacity for 2023 investors).

The use of 2023 technology costs for all VRE shares in the 2023 results means these results represent the highest cost for achieving these outcomes. In reality, the transition to these VRE shares would occur over several years and there would be access to lower costs as technologies improve over time (see the projections in the previous section).

[32] 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 4-1

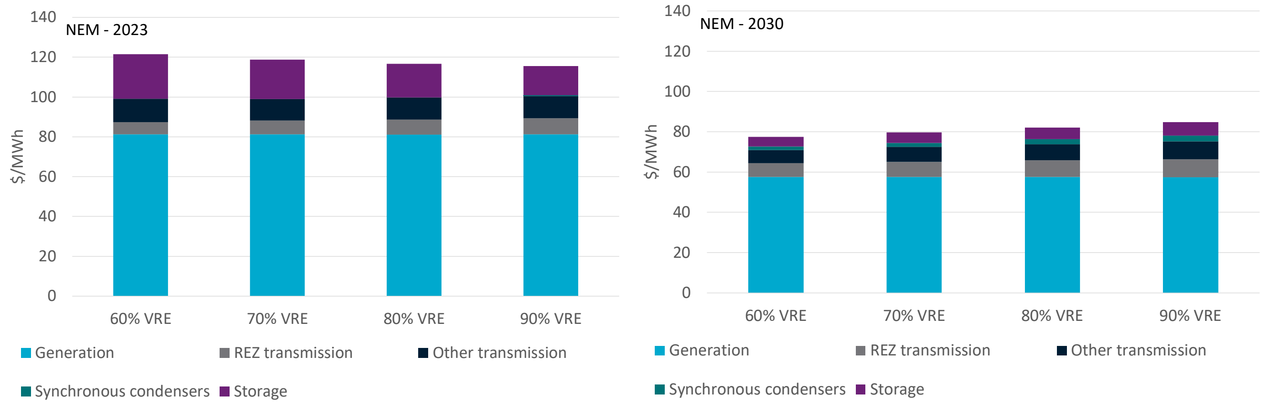


Figure 5-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in the NEM in 2023 and in 2030

Variable renewable integration costs in 2023 are dominated by storage and transmission. Synchronous condenser costs are relatively minor reflecting that less synchronous generation has retired in 2023. In 2030, after greater retirement, synchronous condenser 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. As transmission and storage 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 and 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 $6.40/MWh in 2023 and $7.50/MWh in 2030, as the VRE share increases from 60% to 90%. Other transmission costs add $8.90/MWh in 2023 and $5.80/MWh in 2030. Storage costs add an average $15.80/MWh in 2023 and $8.70/MWh in 2030.

5.2.3 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 2023 and 2030 to include a combined wind and solar PV category for different VRE shares. Integration costs to support renewables are estimated at $34/MWh to $41/MWh in 2023 and $25/MWh to $34/MWh in 2030 depending on the VRE share (Figure 5-3 and Figure 5-4).

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 2023 and 2030. The cost range overlaps slightly with the lower end of the cost range for coal and gas generation. However, the lower end of the range for coal and gas is only achievable only if they can deliver a high capacity factor, source low cost fuel and be financed at a rate that does not include climate policy risk despite their high emission intensity. If we exclude high emission generation options, the next most competitive generation technology is gas with carbon capture and storage.

5.2.4 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.

Hydrogen peaking plant are higher cost at present. However, their costs are expected to fall over time. Providing the hydrogen is made from low emission sources, this technology is either a zero or low emission option for providing peaking services, depending on how the hydrogen is produced.

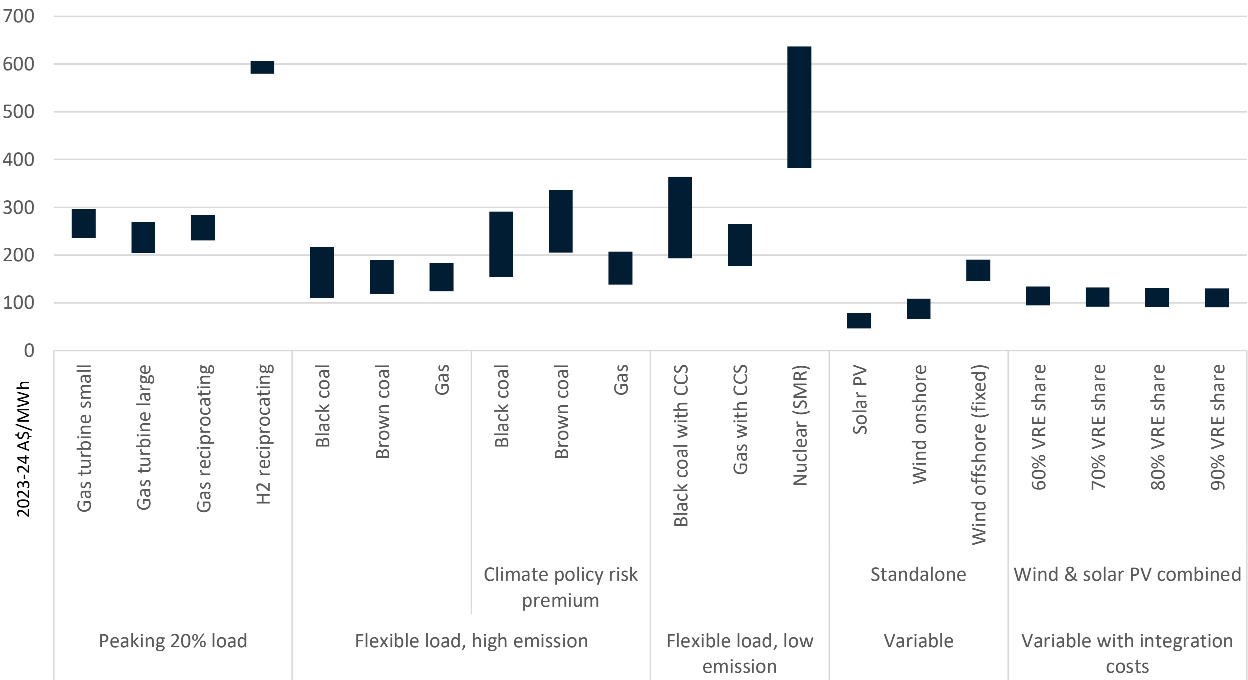


Figure 5-3 Calculated LCOE by technology and category for 2023

5.2.5 Flexible technologies

Nuclear SMR, 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). They are the next most competitive generation technologies after variable renewables (with or without integration costs). The reduction in fossil fuel generation costs between 2023 and 2030 is not as a result of technological improvement. It represents a reduction in fuel prices which have fallen from their high in 2022 and are assumed to fall a little further over time.

Of the fossil fuel technologies, it is difficult to say which is more competitive as it depends very much on the price outcome achieved in contracts for long term fuel supply and the investor's perception of climate policy risk.

New fossil fuel generation faces the risk of higher financing costs over time because all states and the commonwealth have either legislated or have aspirational net zero emission by 2050 targets. We address these risks in the cost estimations by including a separate estimate which assumes a 5% risk premium on borrowing costs[33]. Natural gas-based generation is less impacted by the risk premium because of its lower emissions fuel, higher thermal efficiency (in combined cycle configuration only) and lower capital cost.

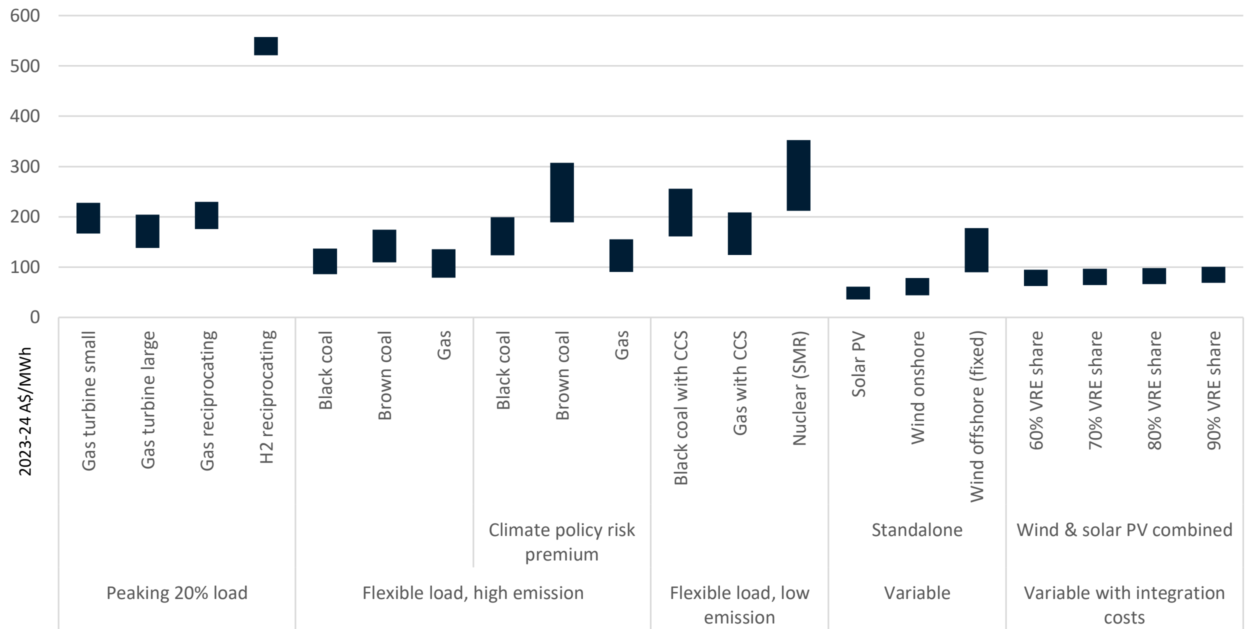


Figure 5-4 Calculated LCOE by technology and category for 2030

We do not include a risk premium for low emission flexible technologies. Gas with CCS is the next most competitive after the high emission technologies. The LCOE for nuclear small modular reactors (SMRs) has increased compared to the GenCost 2022-23 report due to new information (see Section 2.4). Achieving the lower end of the nuclear SMR range requires that SMR is deployed

[33] This risk premium has been applied in previous studies (e.g., the 2017 Finkel review modelling) but may not adequately represent the present difficulty in obtaining finance for fossil fuel projects.

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). Both technologies would also have to be successful in operating at 89% capacity factor to achieve the lower end of the cost range.

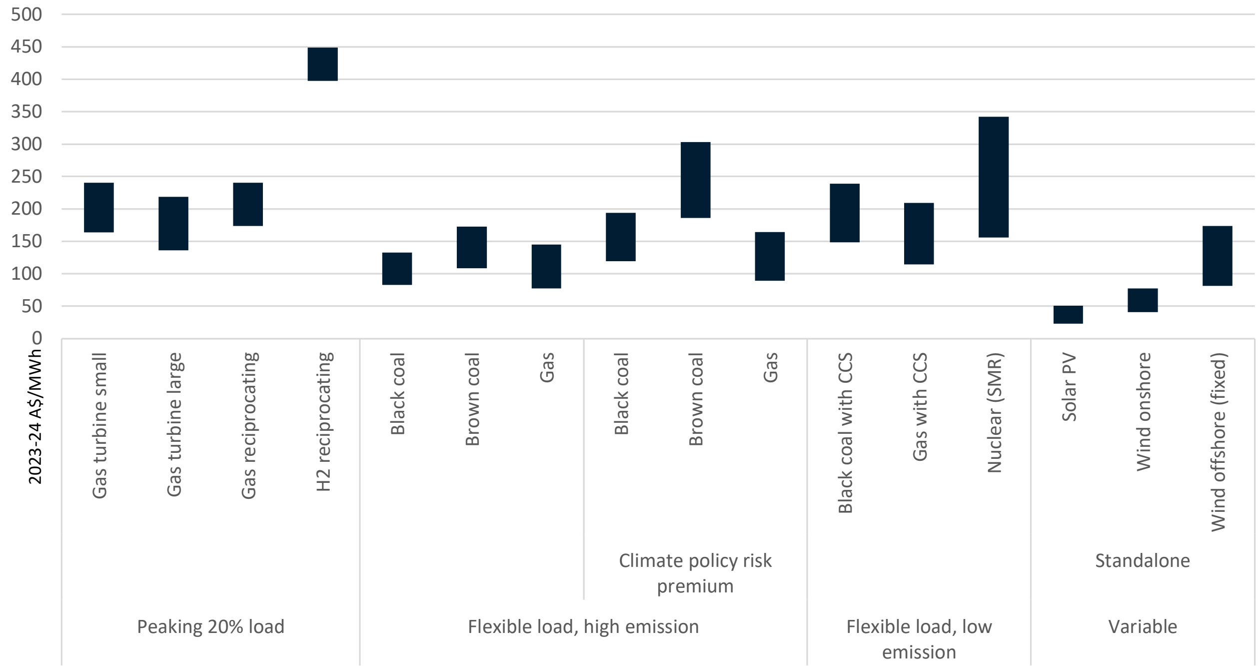


Figure 5-5 Calculated LCOE by technology and category for 2040

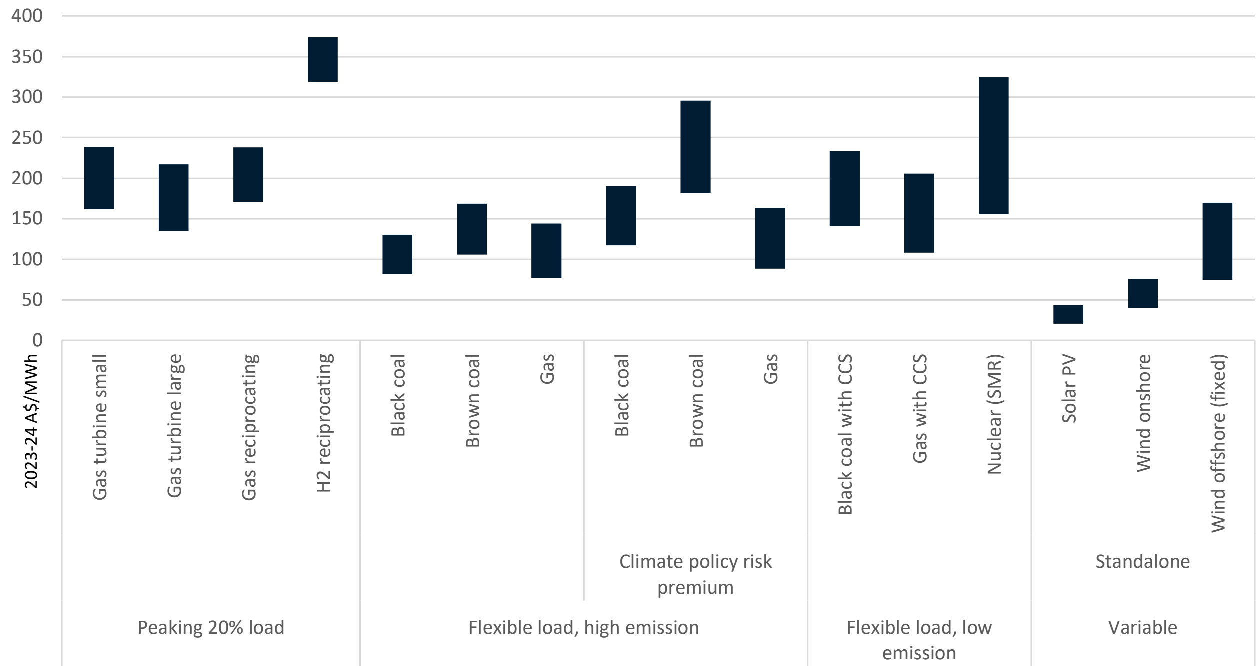


Figure 5-6 Calculated LCOE by technology and category for 2050

5.3 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 SMR which can provide 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%). As a result, to deliver the equivalent energy of a coal-fired generator, the system needs to install two to three times the variable renewable capacity. If the system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has four to six times the capacity needed when coal is deployed. For a number of reasons, this scale of capacity development is not necessary.

The most important factor to remember 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. It 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. So 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 new 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.

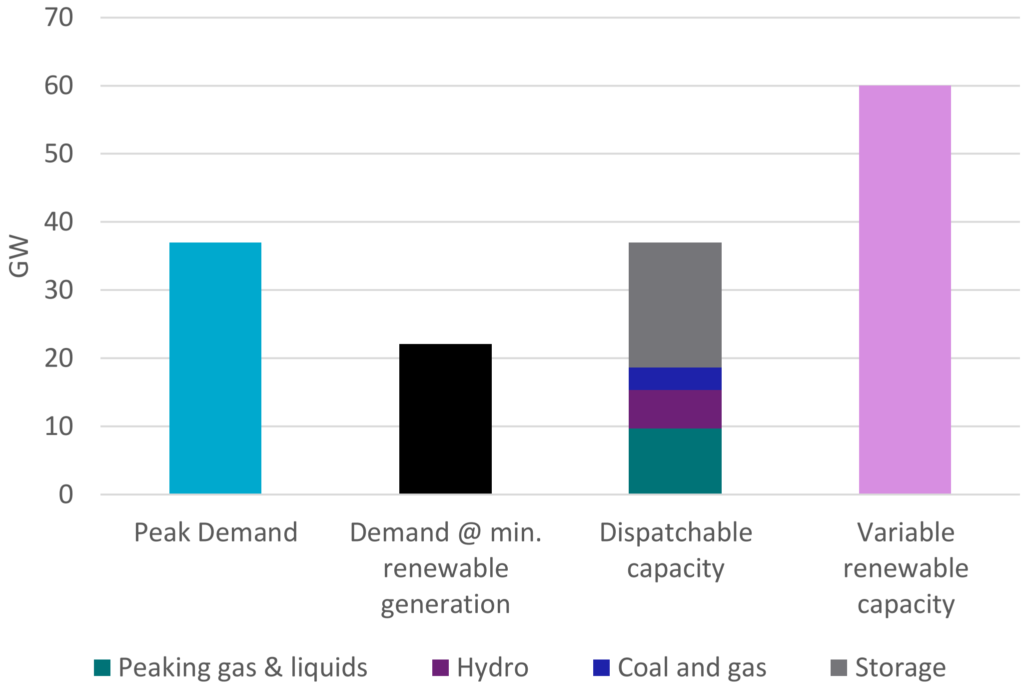


Figure 5-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

The modelling approach applied accounts for all of these factors across nine historical weather years. The result we find is that, in 2030, the NEM needs to have 0.28kW to 0.4kW storage capacity for each kW of variable renewable generation installed[34]. Showing the most extreme case of 90% variable renewable share for the NEM, Figure 5-7 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[35] 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.

[34] 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.

[35] 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 & Graham, 2017) (Hayward & Graham, 2013) (Hayward, Foster, Graham, & 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 & Schrattenholzer, 2001). Cost reductions due to this phenomenon are normally shown via the equation:

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

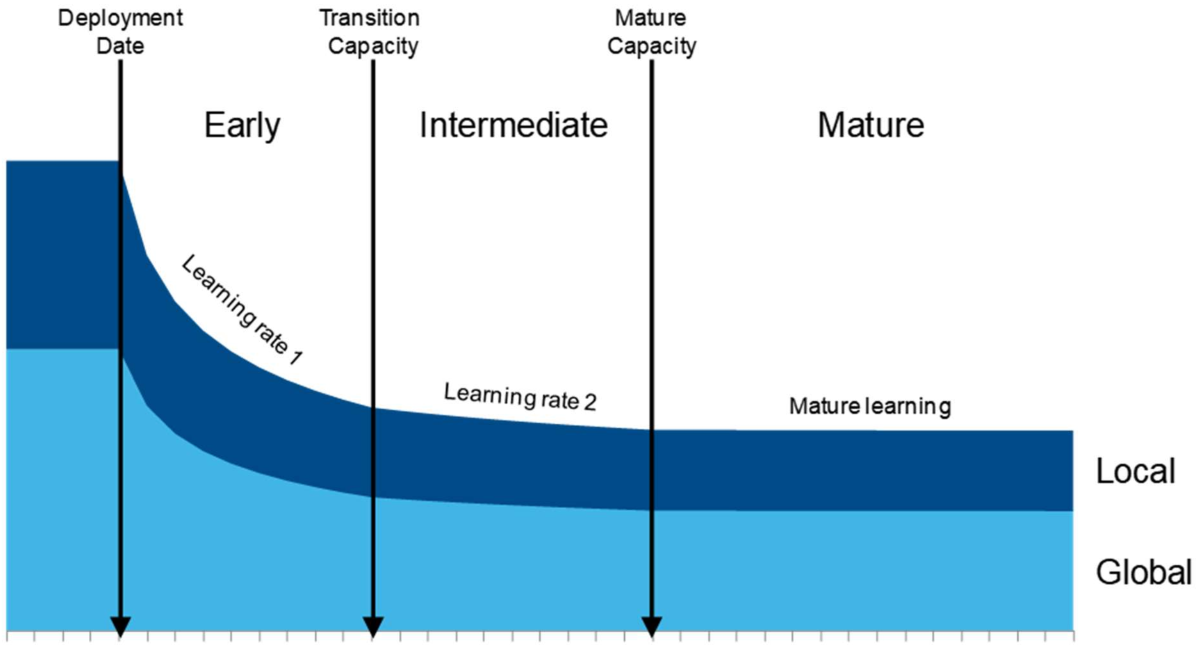
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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 on the cost reductions as each region will have a different level of demand for a technology and this will affect its uptake.

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 & Graham, 2013) and (Hayward, Foster, Graham, & Reedman, 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 (2022) and Stehly & 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 (2023a) 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 2023 is mostly sourced from Aurecon (2023a) and is aligned to the middle of that calendar year or the beginning of the 2023-24 financial year.

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

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear (SMR)	Tidal /ocean current	Fuel cell
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2023	5722	11407	8236	2126	1684	1059	5079	1908	2134	8294	23251	1526	1505	6339	3038	5545	6856	15081	31138	12590	8052
2024	5491	11086	8039	2023	1619	1021	4934	1886	2155	8194	22424	1457	1415	6205	2785	5440	6856	13896	27253	11281	7671
2025	5273	10787	7856	1926	1559	985	4799	1867	2178	8106	21648	1392	1329	6058	2548	5338	6857	12778	23727	10064	7313
2026	5066	10498	7680	1835	1501	948	4669	1849	2203	8022	20905	1329	1249	5924	2331	5239	6610	11751	20662	8979	6974
2027	4917	10283	7543	1770	1459	908	4573	1832	2213	7953	20363	1272	1183	5803	2189	5165	6303	11090	18513	8297	6673
2028	4839	10171	7469	1737	1437	868	4526	1822	2216	7926	20083	1217	1126	5684	2118	5121	5980	10776	17140	7976	6454
2029	4830	10160	7455	1734	1435	866	4526	1818	2212	7939	20054	1174	1085	5568	2112	5105	5893	10781	16442	7976	5998
2030	4821	10150	7441	1731	1432	865	4526	1815	2208	7952	20026	1134	1048	5465	2105	5089	5863	10785	15959	7976	5574
2031	4812	10140	7428	1727	1429	863	4526	1812	2204	7966	19999	1113	1027	5371	2099	5073	5849	10789	15748	7976	5143
2032	4804	10131	7415	1724	1427	861	4526	1808	2200	7979	19972	1101	1013	5286	2093	5058	5847	10794	15776	7976	4992
2033	4796	10122	7402	1721	1424	860	4527	1805	2196	7993	19945	1100	1007	5207	2088	5042	5846	10799	15803	7976	4827
2034	4787	10113	7389	1718	1422	858	4527	1802	2192	8008	19920	1086	992	5134	2085	5027	5844	10803	15832	7976	4637
2035	4779	9969	7376	1715	1419	857	4395	1799	2189	8022	19759	1073	978	5066	2081	5011	5839	10808	15677	7976	4485
2036	4771	9807	7364	1713	1417	856	4244	1796	2185	8037	19579	1053	958	5001	2079	4996	5837	10813	15521	7976	4298
2037	4764	9624	7352	1710	1415	854	4072	1793	2181	8052	19379	1041	945	4940	2077	4981	5835	10818	15366	7976	4116
2038	4756	9553	7340	1707	1413	853	4012	1790	2178	8068	19293	1010	916	4883	2075	4966	5836	10823	15395	7976	3923
2039	4748	9477	7329	1704	1410	851	3945	1787	2175	8083	19201	960	873	4827	2072	4951	5835	10828	15425	7976	3780
2040	4741	9406	7318	1702	1408	850	3883	1785	2171	8099	19114	903	823	4758	2069	4936	5837	10834	15455	7976	3690
2041	4727	9340	7296	1697	1404	848	3834	1780	2165	8104	19020	851	779	4673	2063	4919	5836	10835	15464	7976	3633
2042	4713	9298	7275	1692	1400	845	3809	1774	2158	8108	18950	819	750	4577	2058	4903	5836	10837	15473	7976	3609
2043	4700	9264	7254	1687	1396	843	3790	1769	2152	8113	18887	788	723	4487	2053	4886	5836	10838	15482	7976	3599
2044	4686	9227	7233	1682	1392	840	3770	1764	2146	8118	18823	771	708	4403	2048	4870	5836	10840	15491	7976	3601
2045	4672	9189	7211	1677	1388	838	3748	1759	2140	8123	18757	760	698	4323	2042	4853	5834	10842	15501	7976	3604
2046	4659	9160	7190	1672	1384	835	3734	1754	2133	8128	18699	756	694	4248	2038	4837	5834	10843	15510	7976	3603
2047	4645	9136	7170	1667	1380	833	3726	1749	2127	8132	18648	752	689	4177	2034	4821	5833	10845	15519	7976	3599
2048	4632	9115	7149	1663	1376	831	3721	1744	2121	8137	18599	748	685	4109	2031	4805	5834	10846	15403	7976	3593
2049	4618	9089	7128	1658	1372	828	3710	1739	2115	8142	18545	744	680	4045	2027	4789	5834	10848	15287	7976	3587
2050	4610	9071	7116	1655	1369	826	3702	1735	2111	8147	18511	741	678	3998	2025	4778	5835	10850	14544	7976	3584
2051	4594	9033	7091	1649	1365	826	3682	1729	2104	8147	18440	738	675	3951	2023	4762	5834	10850	14439	7976	3576
2052	4583	9008	7074	1645	1361	820	3671	1725	2099	8147	18393	737	673	3904	2023	4750	5834	10850	14293	7976	3571
2053	4562	8963	7041	1638	1355	820	3651	1717	2089	8147	18305	734	670	3859	2021	4728	5833	10850	14074	7976	3560
2054	4551	8942	7025	1634	1352	814	3642	1713	2084	8147	18262	732	669	3813	2020	4717	5832	10850	14074	7976	3555
2055	4541	8922	7008	1630	1349	814	3634	1709	2079	8147	18219	730	667	3768	2020	4706	5832	10850	14074	7976	3550

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

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear (SMR)	Tidal /ocean current	Fuel cell
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2023	5722	11407	8236	2126	1684	1059	5079	1908	2134	8294	23251	1526	1505	6368	3038	5545	7658	15081	31138	12590	8052
2024	5587	11223	8120	2065	1646	1036	4998	1895	2145	8243	22771	1461	1428	6159	2847	5060	6845	14388	28344	11628	7523
2025	5461	11057	8017	2009	1611	1014	4925	1884	2160	8205	22330	1400	1353	5909	2665	4606	6093	13721	25753	10715	7028
2026	5340	10896	7918	1955	1577	993	4854	1875	2174	8169	21903	1341	1283	5679	2495	4193	5424	13085	23405	9874	6567
2027	5205	10704	7796	1896	1540	968	4770	1860	2183	8108	21418	1282	1216	5500	2334	3814	4825	12470	21205	9099	6116
2028	5074	10516	7676	1839	1503	943	4687	1845	2191	8048	20944	1225	1153	5328	2183	3469	4292	11884	19213	8385	5696
2029	4947	10332	7558	1784	1467	918	4606	1830	2199	7988	20481	1171	1093	5131	2042	3156	3817	11326	17409	7727	5305
2030	4860	10207	7475	1747	1443	893	4552	1819	2204	7938	20167	1118	1038	4934	1944	2950	3516	10964	15844	7306	5036
2031	4812	10140	7428	1727	1429	867	4526	1812	2204	7912	19999	1073	993	4763	1888	2843	3370	9935	14510	7105	4883
2032	4804	10131	7415	1724	1427	866	4526	1808	2200	7867	19972	1045	965	4638	1872	2826	3360	9003	13437	7105	4839
2033	4796	10122	7402	1721	1424	864	4527	1805	2196	7796	19945	998	922	4520	1858	2811	3353	8159	12793	7105	4787
2034	4787	10113	7389	1718	1422	863	4527	1802	2192	7694	19920	933	864	4421	1845	2798	3268	7394	12526	7104	4710
2035	4779	9828	7376	1715	1419	861	4256	1799	2189	7604	19617	853	793	4319	1832	2786	3184	6700	11955	7104	4612
2036	4771	9542	7364	1713	1417	860	3983	1796	2185	7554	19312	790	738	4233	1819	2776	3101	6072	11381	7086	4516
2037	4764	9253	7352	1710	1415	859	3708	1793	2181	7531	19007	740	694	4146	1807	2767	3098	5503	10805	7064	4439
2038	4756	9241	7340	1707	1413	857	3704	1790	2178	7539	18979	698	657	4065	1796	2759	3096	4987	10824	7042	4371
2039	4748	9185	7329	1704	1410	856	3658	1787	2175	7545	18907	667	629	3963	1788	2753	3094	4519	10845	7039	4310
2040	4741	9130	7318	1702	1408	855	3611	1785	2171	7534	18837	643	607	3861	1781	2748	3094	4095	10866	7039	4259
2041	4727	9062	7296	1697	1404	852	3561	1780	2165	7491	18741	622	588	3746	1774	2742	3093	3710	10872	7039	4214
2042	4713	9041	7275	1692	1400	850	3555	1774	2158	7452	18691	606	574	3648	1767	2736	3092	3361	10879	6986	4187
2043	4700	8917	7254	1687	1396	847	3449	1769	2152	7432	18539	591	560	3545	1759	2731	3091	3045	10885	6919	4169
2044	4686	8790	7233	1682	1392	845	3339	1764	2146	7437	18383	579	549	3464	1753	2725	3054	2759	10891	6643	4158
2045	4672	8663	7211	1677	1388	842	3229	1759	2140	7441	18227	568	538	3387	1747	2719	2932	2499	10898	6409	4148
2046	4659	8636	7190	1672	1384	840	3219	1754	2133	7446	18173	560	531	3325	1742	2713	2725	2264	10904	6189	4138
2047	4645	8611	7170	1667	1380	837	3209	1749	2127	7450	18120	554	525	3265	1737	2707	2519	2051	10911	6179	4129
2048	4632	8586	7149	1663	1376	835	3199	1744	2121	7455	18067	549	520	3210	1731	2700	2378	1858	10917	6118	4113
2049	4618	8560	7128	1658	1372	832	3189	1739	2115	7459	18013	545	516	3157	1726	2694	2311	1684	10889	5934	4092
2050	4610	8546	7116	1655	1369	830	3184	1735	2111	7464	17983	543	513	3112	1723	2689	2279	1642	10862	5750	4075
2051	4594	8519	7091	1649	1365	830	3176	1729	2104	7464	17923	541	511	3067	1721	2683	2258	1627	10813	5627	4050
2052	4583	8501	7074	1645	1361	824	3171	1725	2099	7464	17884	540	510	3023	1721	2679	2249	1622	10799	5627	4035
2053	4562	8467	7041	1638	1355	824	3161	1717	2089	7464	17805	538	508	2980	1719	2672	2234	1613	10785	5627	4008
2054	4551	8449	7025	1634	1352	818	3156	1713	2084	7464	17766	537	507	2938	1719	2669	2227	1610	10785	5627	3995
2055	4541	8432	7008	1630	1349	818	3151	1709	2079	7464	17727	536	506	2896	1718	2665	2220	1607	10785	5627	3982

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

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (14hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear (SMR)	Tidal /ocean current	Fuel cell
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2023	5722	11407	8236	2126	1684	1059	5079	1908	2134	8294	23251	1526	1505	6368	3038	5545	7658	15081	31138	12590	8052
2024	5587	11223	8120	2065	1646	1036	4998	1895	2145	8246	22771	1434	1413	6159	2855	5396	7275	14388	28344	11716	7586
2025	5461	11057	8017	2009	1611	1014	4925	1884	2160	8211	22330	1357	1338	5909	2681	5252	6908	13721	25753	10884	7149
2026	5340	10896	7918	1955	1577	993	4854	1875	2174	8178	21903	1296	1278	5679	2518	5112	6560	13085	23405	10110	6739
2027	5205	10704	7796	1896	1540	968	4770	1860	2183	8120	21418	1235	1218	5500	2362	4972	6224	12470	21205	9391	6331
2028	5074	10516	7676	1839	1503	943	4687	1845	2191	8062	20944	1177	1161	5375	2216	4836	5906	11884	19213	8724	5948
2029	4947	10332	7558	1784	1467	918	4606	1830	2199	8005	20481	1122	1106	5271	2079	4704	5604	11326	17409	8104	5588
2030	4860	10207	7475	1747	1443	893	4552	1819	2204	7972	20167	1078	1063	5141	1989	4604	5399	10964	15844	7671	5315
2031	4812	10140	7428	1727	1429	867	4526	1812	2204	7962	19999	1041	1027	4986	1942	4539	5288	10789	14636	7444	5116
2032	4804	10131	7415	1724	1427	866	4526	1808	2200	7976	19972	1021	1006	4819	1936	4510	5268	10794	13978	7409	4957
2033	4796	10122	7402	1721	1424	864	4527	1805	2196	7990	19945	996	982	4673	1931	4475	5243	10799	13551	7409	4794
2034	4787	10113	7389	1718	1422	863	4527	1802	2192	8004	19920	975	961	4551	1926	4445	5184	10803	13003	7409	4610
2035	4779	9863	7376	1715	1419	861	4290	1799	2189	8019	19652	929	916	4451	1922	4404	5117	10808	12130	7409	4463
2036	4771	9591	7364	1713	1417	860	4031	1796	2185	8033	19362	871	859	4377	1918	4381	5064	10813	11455	7409	4285
2037	4764	9312	7352	1710	1415	859	3765	1793	2181	8048	19066	800	789	4308	1913	4355	5045	10818	11150	7409	4116
2038	4756	9275	7340	1707	1413	857	3737	1790	2178	8044	19013	745	734	4248	1908	4338	5035	10823	11169	7409	3941
2039	4748	9259	7329	1704	1410	856	3730	1787	2175	8015	18981	710	701	4185	1902	4303	5010	10828	11186	7408	3815
2040	4741	9248	7318	1702	1408	855	3727	1785	2171	7976	18955	691	682	4133	1897	4264	4982	10834	11204	7407	3734
2041	4727	9224	7296	1697	1404	852	3720	1780	2165	7946	18903	680	671	4071	1891	4217	4947	10835	11207	7405	3678
2042	4713	9200	7275	1692	1400	850	3711	1774	2158	7941	18850	668	659	4006	1885	4177	4917	10837	11213	7405	3647
2043	4700	9176	7254	1687	1396	847	3703	1769	2152	7945	18798	656	647	3939	1880	4139	4889	10838	11220	7402	3627
2044	4686	9150	7233	1682	1392	845	3694	1764	2146	7950	18745	643	634	3877	1876	4106	4866	10840	11226	7398	3608
2045	4672	9125	7211	1677	1388	842	3685	1759	2140	7954	18692	629	621	3822	1874	4077	4845	10842	11233	7393	3592
2046	4659	9100	7190	1672	1384	840	3675	1754	2133	7959	18639	617	609	3755	1872	4050	4826	10843	11240	7392	3578
2047	4645	9075	7170	1667	1380	837	3666	1749	2127	7963	18586	608	599	3681	1871	4027	4810	10845	11246	7391	3565
2048	4632	8934	7149	1663	1376	835	3542	1744	2121	7968	18417	600	592	3592	1869	4005	4795	10846	11253	7391	3549
2049	4618	8761	7128	1658	1372	832	3388	1739	2115	7972	18216	594	586	3507	1866	3985	4782	10848	11260	7380	3516
2050	4610	8599	7116	1655	1369	830	3237	1735	2111	7977	18036	590	582	3446	1864	3973	4774	10850	11266	7368	3490
2051	4594	8540	7091	1649	1365	830	3197	1729	2104	7977	17944	585	577	3386	1862	3950	4758	10850	11196	7285	3466
2052	4583	8522	7074	1645	1361	824	3191	1725	2099	7977	17904	582	574	3328	1860	3932	4745	10850	11126	7213	3464
2053	4562	8487	7041	1638	1355	824	3181	1717	2089	7977	17825	575	567	3270	1857	3899	4721	10850	11056	7141	3458
2054	4551	8469	7025	1634	1352	818	3176	1713	2084	7977	17786	570	562	3213	1854	3882	4710	10850	11056	7141	3455
2055	4541	8451	7008	1630	1349	818	3170	1709	2079	7977	17746	565	558	3158	1851	3866	4698	10850	11056	7141	3452

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
2023	1009	1009	1009	467	467	467	542	542	542	731	731	731	450	450	450	281	281	281
2024	928	933	890	408	423	390	520	510	500	662	671	635	393	407	376	269	264	259
2025	857	863	788	357	383	327	500	480	461	602	617	553	344	369	314	258	248	238
2026	793	799	699	313	347	273	480	452	426	549	567	483	301	334	263	248	234	220
2027	734	739	621	273	314	228	460	425	392	500	521	422	263	302	219	238	220	203
2028	711	684	552	265	284	191	446	400	361	485	479	370	255	273	183	230	206	187
2029	693	632	492	258	257	159	435	376	333	472	440	325	248	247	153	225	194	172
2030	679	585	440	254	232	133	426	353	307	463	405	286	244	223	128	220	182	158
2031	660	546	423	243	197	117	417	349	306	448	369	270	233	189	113	215	180	158
2032	640	508	407	232	162	101	407	346	306	433	334	255	223	155	97	210	178	158
2033	630	501	405	232	159	100	398	342	305	428	329	253	223	152	96	205	176	157
2034	621	495	404	230	156	99	391	340	305	422	324	252	220	149	95	201	175	157
2035	603	489	403	225	153	98	377	336	304	410	320	251	216	147	94	194	173	157
2036	588	483	402	220	150	97	368	333	304	400	315	250	210	144	93	190	172	157
2037	573	478	400	215	148	97	358	330	304	390	311	249	206	141	92	184	170	156
2038	560	473	400	209	145	96	351	328	304	381	308	248	200	139	92	181	169	156
2039	548	469	399	205	143	95	344	326	304	373	304	247	196	137	91	177	167	156
2040	539	465	398	200	141	95	339	324	303	366	302	247	191	135	91	174	167	156
2041	534	463	398	196	139	94	338	324	303	361	300	246	187	133	90	174	166	156
2042	531	462	397	194	139	94	337	323	303	359	299	246	186	133	90	173	166	156
2043	526	460	397	192	138	94	333	322	303	355	298	246	184	132	90	171	165	156
2044	518	458	396	188	137	93	330	321	303	349	296	245	179	131	89	170	165	156
2045	513	456	396	184	136	93	329	320	303	345	295	245	176	130	89	169	165	156
2046	509	455	396	182	135	93	327	320	303	342	294	244	174	129	89	168	164	156
2047	506	454	395	180	135	92	326	319	303	339	293	244	172	129	88	168	164	156
2048	504	453	395	178	134	92	326	319	303	338	292	244	170	128	88	167	164	156
2049	502	453	395	177	134	92	325	319	303	336	292	243	169	128	88	167	164	156
2050	501	452	395	176	133	92	325	319	303	335	291	243	168	128	88	167	164	156
2051	499	444	393	175	133	92	324	311	302	334	287	242	168	127	88	166	159	155
2052	499	436	392	175	133	91	323	303	300	334	283	242	168	127	87	166	156	154
2053	497	429	390	174	133	91	323	297	299	332	279	241	166	127	87	166	152	153
2054	496	424	387	174	133	91	322	291	296	332	276	239	166	127	87	165	149	152
2055	494	418	385	173	132	91	321	286	294	330	273	238	165	126	87	165	147	151

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
2023	592	592	592	441	441	441	151	151	151	519	519	519	431	431	431	88	88	88
2024	530	540	507	385	399	368	145	142	139	460	472	441	376	390	360	84	82	81
2025	475	494	436	337	361	308	139	133	128	409	430	375	329	352	300	81	77	74
2026	427	452	375	294	326	257	133	125	118	364	391	319	287	318	251	77	73	68
2027	384	413	323	257	295	214	127	118	109	325	356	272	251	288	209	74	68	63
2028	372	377	279	249	267	179	123	111	100	314	324	233	243	260	175	72	64	58
2029	363	345	242	242	241	149	120	104	92	306	295	199	236	235	146	70	60	53
2030	356	315	210	238	218	125	118	98	85	300	269	171	232	212	122	68	57	49
2031	343	281	194	228	185	110	115	96	85	289	236	156	222	180	107	67	56	49
2032	330	247	179	218	151	95	112	96	84	277	203	142	212	148	93	65	55	49
2033	327	243	178	217	149	94	110	94	84	275	200	140	212	145	91	64	55	49
2034	323	239	177	215	146	93	108	94	84	272	196	139	209	142	90	62	54	49
2035	314	235	176	210	143	92	104	93	84	265	193	138	205	139	89	60	54	49
2036	306	232	175	205	140	91	101	92	84	258	190	137	200	136	89	59	53	49
2037	299	229	174	201	138	90	98	91	84	252	187	136	195	134	88	57	53	48
2038	292	225	173	195	135	89	97	90	83	246	184	135	190	132	87	56	52	48
2039	285	223	172	191	133	89	94	89	83	240	182	135	186	130	86	55	52	48
2040	279	220	171	186	131	88	93	89	83	235	179	134	181	128	86	54	52	48
2041	275	219	171	182	130	88	93	89	83	231	178	134	178	126	85	54	51	48
2042	273	218	171	181	129	88	92	89	83	229	177	133	176	126	85	54	51	48
2043	270	217	171	179	129	87	91	88	83	227	176	133	174	125	85	53	51	48
2044	265	216	170	175	128	87	91	88	83	222	175	133	170	124	85	52	51	48
2045	261	215	170	171	127	87	90	88	83	219	174	132	167	123	84	52	51	48
2046	259	214	169	169	126	86	90	88	83	216	173	132	164	122	84	52	51	48
2047	257	213	169	167	125	86	89	87	83	214	173	132	162	122	84	52	51	48
2048	255	212	169	166	125	86	89	87	83	213	172	131	161	121	83	52	51	48
2049	254	212	168	165	124	85	89	87	83	212	171	131	160	121	83	52	51	48
2050	253	211	168	164	124	85	89	87	83	211	171	131	159	121	83	51	50	48
2051	252	209	168	163	124	85	89	85	83	210	169	131	158	120	83	51	49	48
2052	251	207	167	163	124	85	89	83	82	210	168	130	158	120	83	51	48	48
2053	250	204	167	162	123	85	88	81	82	208	167	130	157	120	82	51	47	47
2054	250	203	166	162	123	85	88	80	81	208	166	129	157	120	82	51	46	47
2055	249	201	165	161	123	85	88	78	80	207	165	129	156	119	82	51	45	47

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
2023	478	478	478	353	353	353	125	125	125	427	427	427	353	353	353	74	74	74
2024	428	436	410	308	319	295	120	117	115	379	388	363	308	319	295	71	69	68
2025	384	398	352	269	288	246	115	110	106	337	353	308	269	288	246	68	65	63
2026	345	364	302	235	260	205	110	104	97	300	321	263	235	260	205	65	61	58
2027	310	332	261	205	235	171	105	97	90	267	293	224	205	235	171	62	57	53
2028	300	304	225	198	212	143	102	91	83	259	266	191	198	212	143	60	54	49
2029	292	278	195	193	192	119	99	86	76	252	243	164	193	192	119	59	51	45
2030	286	254	169	189	173	99	97	80	70	247	221	141	189	173	99	57	48	41
2031	276	226	157	181	147	87	95	79	70	237	194	129	181	147	87	56	47	41
2032	266	199	145	173	121	76	93	79	70	228	167	117	173	121	76	55	47	41
2033	263	196	144	173	118	75	90	78	69	226	164	116	173	118	75	53	46	41
2034	260	193	143	171	116	74	89	77	69	223	161	115	171	116	74	52	46	41
2035	253	190	142	167	114	73	86	76	69	218	159	114	167	114	73	51	45	41
2036	246	187	141	163	111	72	83	75	69	212	156	113	163	111	72	49	45	41
2037	240	184	140	159	109	72	81	75	69	207	153	112	159	109	72	48	44	41
2038	234	181	139	155	107	71	79	74	69	202	151	111	155	107	71	47	44	41
2039	229	179	139	151	106	70	78	73	68	197	149	111	151	106	70	46	43	40
2040	224	177	138	147	104	70	76	73	68	193	147	110	147	104	70	45	43	40
2041	221	176	138	145	103	69	76	73	68	190	146	110	145	103	69	45	43	40
2042	219	175	138	143	102	69	76	73	68	188	145	110	143	102	69	45	43	40
2043	217	174	137	142	102	69	75	72	68	186	145	109	142	102	69	44	43	40
2044	212	173	137	138	101	69	74	72	68	182	144	109	138	101	69	44	43	40
2045	210	172	137	136	100	69	74	72	68	179	143	109	136	100	69	44	43	40
2046	207	172	136	134	100	68	74	72	68	177	142	108	134	100	68	43	42	40
2047	206	171	136	132	99	68	73	72	68	176	142	108	132	99	68	43	42	40
2048	204	170	136	131	99	68	73	72	68	174	141	108	131	99	68	43	42	40
2049	203	170	136	130	98	68	73	72	68	173	141	108	130	98	68	43	42	40
2050	202	170	135	129	98	67	73	71	68	172	140	108	129	98	67	43	42	40
2051	202	167	135	129	98	67	73	70	68	172	139	107	129	98	67	43	41	40
2052	201	166	135	129	98	67	73	68	67	172	138	107	129	98	67	43	40	40
2053	200	164	134	128	97	67	72	67	67	171	137	107	128	97	67	43	39	40
2054	200	163	133	128	97	67	72	65	66	171	136	106	128	97	67	43	39	39
2055	199	161	133	127	97	67	72	64	66	170	135	106	127	97	67	43	38	39

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

	$/kW							$/kWh						
	6hrs	8hrs	12hrs	24hrs	24hrs Tas	48hrs	48hrs Tas	6hrs	8hrs	12hrs	24hrs	24hrs Tas	48hrs	48hrs Tas
2023	3809	4139	4356	5808	3601	6818	3136	635	517	363	242	150	142	66
2024	3736	4060	4273	5697	3532	6688	3077	623	507	356	237	147	139	65
2025	3665	3983	4192	5589	3465	6561	3018	611	498	349	233	144	137	63
2026	3594	3905	4111	5481	3398	6434	2960	599	488	343	228	142	134	62
2027	3519	3825	4025	5367	3328	6300	2898	587	478	335	224	139	131	61
2028	3445	3744	3940	5254	3257	6167	2837	574	468	328	219	136	128	60
2029	3370	3663	3855	5140	3187	6034	2776	562	458	321	214	133	126	58
2030	3296	3582	3770	5026	3116	5901	2714	549	448	314	209	130	123	57
2031	3292	3577	3765	5020	3113	5893	2711	549	447	314	209	130	123	57
2032	3288	3573	3761	5014	3109	5886	2708	548	447	313	209	130	123	57
2033	3284	3569	3756	5008	3105	5879	2704	547	446	313	209	129	122	57
2034	3280	3565	3752	5002	3101	5872	2701	547	446	313	208	129	122	57
2035	3276	3561	3748	4997	3098	5866	2698	546	445	312	208	129	122	57
2036	3273	3556	3743	4991	3094	5859	2695	545	445	312	208	129	122	57
2037	3269	3552	3739	4985	3091	5852	2692	545	444	312	208	129	122	57
2038	3265	3548	3735	4979	3087	5845	2689	544	444	311	207	129	122	57
2039	3261	3544	3730	4974	3084	5839	2686	544	443	311	207	128	122	57
2040	3258	3540	3726	4968	3080	5832	2683	543	443	311	207	128	122	56
2041	3253	3535	3720	4960	3075	5823	2679	542	442	310	207	128	121	56
2042	3248	3529	3715	4953	3071	5814	2675	541	441	310	206	128	121	56
2043	3243	3524	3709	4945	3066	5805	2670	540	440	309	206	128	121	56
2044	3238	3519	3703	4938	3061	5796	2666	540	440	309	206	128	121	56
2045	3233	3513	3698	4930	3057	5788	2662	539	439	308	205	127	121	56
2046	3228	3508	3692	4923	3052	5779	2658	538	438	308	205	127	120	56
2047	3223	3503	3687	4915	3047	5770	2654	537	438	307	205	127	120	56
2048	3218	3497	3681	4908	3043	5761	2650	536	437	307	204	127	120	56
2049	3213	3492	3675	4900	3038	5752	2646	536	436	306	204	127	120	56
2050	3208	3487	3670	4893	3034	5744	2642	535	436	306	204	126	120	56
2051	3203	3481	3663	4884	3028	5734	2638	534	435	305	204	126	119	55
2052	3197	3475	3657	4876	3023	5724	2633	533	434	305	203	126	119	55
2053	3192	3469	3651	4868	3018	5714	2629	532	434	304	203	126	119	55
2054	3187	3463	3645	4859	3013	5705	2624	531	433	304	202	126	119	55
2055	3181	3457	3638	4851	3008	5695	2620	530	432	303	202	125	119	55

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	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Fitchner Engineering 2023	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	Aurecon 2023-24	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Fitchner Engineering 2023
Battery (1hr)	1158	923	873	987	1009	-	-	-	-	1158	923	873	987	1009	-	-	-	-
Battery (2hrs)	729	618	580	713	731	-	-	-	-	1458	1236	1161	1427	1461	-	-	-	-
Battery (4hrs)	575	491	458	579	592	-	-	-	-	2301	1966	1833	2317	2367	-	-	-	-
Battery (8hrs)	522	434	402	515	519	-	-	-	-	4176	3468	3218	4116	4149	-	-	-	-
Battery (24hrs)	-	-	-	-	478	-	-	-	-	-	-	-	-	11472	-	-	-	-
Battery (48hrs)	-	-	-	-	427	-	-	-	-	-	-	-	-	20491	-	-	-	-
PHES (8hrs)	-	-	-	-	-	292	315	392	-	-	-	-	-	-	2336	2520	3135	-
A-CAES (12hrs)	-	-	-	371	-	-	-	-	-	-	-	-	4456	-	-	-	-	-
PHES (12hrs)	-	-	-	-	-	207	226	280		-	-	-	-	-	2482	2711	3365	-
CST (15hrs)	-	-	-	-	445	-	-	-	461	-	-	-	-	6682	-	-	-	6918
A-CAES (24hrs)	-	-	-	-	294	-	-	-	-	-	-	-	-	7057	-	-	-	-
PHES (24hrs)	-	-	-	-	242	153	147	183	-	-	-	-	-	5808	3678	3537	4399	-
PHES (24hrs) Tasmania	-	-	-	-	-	-	91	114	-	-	-	-	-	-	-	2185	2727	-
PHES (48hrs)	-	-	-	-	142	86	111	138	-	-	-	-	-	6818	4121	5313	6608	-
PHES (48hrs) Tasmania	-	-	-	-	-	-	51	64	-	-	-	-	-	-	-	2468	3040	-

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1455/kWh or $2910/kW (Aurecon, 2023a).

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
2023	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	5079	13.5	89%	5079	19.5	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	2126	13.5	89%	2126	19.5	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1684	13.5	20%	1684	19.5	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	943	13.5	20%	943	19.5	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1908	13.5	20%	1908	19.5	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2134	40.9	20%	2134	43.2	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	11407	4.3	89%	11407	11.3	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	5722	4.3	89%	5722	11.3	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8236	0.6	89%	8236	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	8294	0.6	89%	8294	1.9	53%
Nuclear (SMR)	30	3.0	30%	200	5.3	0.0	31138	0.5	89%	31138	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1526	0.0	32%	1526	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	3038	0.0	48%	3038	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	5545	0.0	52%	5545	0.0	40%
2030												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4552	7.7	89%	4526	13.8	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1747	7.7	89%	1731	13.8	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1443	7.7	20%	1432	13.8	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	865	7.7	20%	865	13.8	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1819	7.7	20%	1815	13.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2204	35.4	20%	2208	38.6	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	10207	2.7	89%	10150	4.1	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4860	2.7	89%	4821	4.1	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7475	0.7	89%	7441	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7938	0.6	89%	7952	1.9	53%
Nuclear (SMR)	30	3.0	35%	200.0	5.3	0.0	15844	0.5	89%	15959	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1118	0.0	32%	1134	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1944	0.0	48%	2105	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2950	0.0	54%	5089	0.0	40%

2040												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3727	7.6	89%	3883	15.2	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1702	7.6	89%	1702	15.2	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1408	7.6	20%	1408	15.2	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	850	7.6	20%	850	15.2	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1785	7.6	20%	1785	15.2	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2171	24.5	20%	2171	29.1	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	9248	2.5	89%	9406	3.8	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4741	2.5	89%	4741	3.8	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7318	0.7	89%	7318	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7534	0.6	89%	8099	1.9	53%
Nuclear (SMR)	30	3.0	40%	200.0	5.3	0.0	10866	0.5	89%	15455	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	643	0.0	32%	903	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1781	0.0	48%	2069	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2748	0.0	57%	4936	0.0	40%
2050												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3184	7.6	89%	3702	15.2	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1655	7.6	89%	1655	15.2	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1369	7.6	20%	1369	15.2	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	826	7.6	20%	826	15.2	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1735	7.6	20%	1735	15.2	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2111	17.8	20%	2111	22.7	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8546	2.5	89%	9071	3.8	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4610	2.5	89%	4610	3.8	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7116	0.7	89%	7116	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7464	0.6	89%	8147	1.9	53%
Nuclear (SMR)	30	3.0	45%	200.0	5.3	0.0	10862	0.5	89%	14544	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	543	0.0	32%	741	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1723	0.0	48%	2025	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2689	0.0	61%	4778	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% unless a climate policy risk premium of 5% is added.

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

Category	Assumption	Technology	2023		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas turbine small	236	296	167	228	164	240	162	238
		Gas turbine large	204	269	138	204	136	219	135	217
		Gas reciprocating	231	284	176	230	173	240	171	238
		H_2 reciprocating	580	606	521	557	397	449	319	374
Flexible 60-80% load, high emission		Black coal	110	217	86	137	83	133	82	131
		Brown coal	118	190	110	175	108	173	106	169
		Gas	124	183	79	136	78	145	77	144
	Climate policy risk premium	Black coal	154	291	123	199	120	194	117	190
		Brown coal	206	337	189	307	186	303	181	296
		Gas	138	207	91	156	89	165	88	163
Flexible 60-80% load, low emission		Black coal with CCS	193	364	161	256	149	239	141	233
		Gas with CCS	177	266	124	209	114	209	108	206
		Nuclear (SMR)	382	636	212	353	156	342	155	325
		Biomass (small scale)	116	200	113	194	109	196	108	197
Variable	Standalone	Solar PV	47	79	36	61	23	51	21	43
		Wind onshore	66	109	44	78	41	77	40	76
		Wind offshore	146	190	90	178	81	174	75	170
Variable with integration costs	Wind & solar PV combined	60% share	94	134	63	95				
		70% share	92	132	65	97				
		80% share	91	131	66	98				
		90% share	91	130	69	101				

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
2023	1919	3141	1919	3141	1919	3141
2024	1575	2577	1536	2513	1611	2636
2025	1318	2339	1253	2207	1379	2378
2026	1118	2123	1037	1939	1196	2146
2027	955	1921	864	1698	1046	1930
2028	897	1739	726	1487	921	1736
2029	833	1574	613	1303	817	1562
2030	767	1425	521	1141	728	1405
2031	734	1290	489	999	689	1264
2032	704	1167	459	875	658	1138
2033	678	1057	430	767	623	1023
2034	649	957	404	672	597	921
2035	627	866	381	589	572	829
2036	608	784	362	516	556	746
2037	591	710	345	452	540	671
2038	576	643	329	396	527	604
2039	550	582	316	347	514	543
2040	527	527	304	304	489	489
2041	513	513	289	289	478	478
2042	497	497	276	276	467	467
2043	486	486	265	265	452	452
2044	472	472	254	254	434	434
2045	462	462	244	244	417	417
2046	443	443	235	235	404	404
2047	432	432	227	227	393	393
2048	420	420	216	216	383	383
2049	398	398	206	206	375	375
2050	377	377	193	193	361	361
2051	377	377	193	193	361	361
2052	375	375	190	190	360	360
2053	375	375	190	190	360	360
2054	374	374	188	188	360	360
2055	374	374	188	188	360	360

Appendix C 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.

C.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.

C.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.

C.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 C.1 Examples of considering global or domestic signficance

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 **Large scale nuclear**: scale is unsuitable
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**)

C.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, they cannot be validated by stakeholders. However, confidential sources could provide some guidance to interpreting public sources.

C.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 or 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 is similar.

Shortened forms

Abbreviation	Meaning
A-CAES	Adiabatic Compressed Air Energy Storage
ABS	Australian Bureau of Statistics
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
APGT	Australian Power Generation Technology
BAU	Business as usual
BECCS	Bioenergy carbon capture and storage
BOP	Balance of plant
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated solar thermal
EV	Electric vehicle
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
IEA	International Energy Agency
ISP	Integrated System plan
kW	Kilowatt
kWh	Kilowatt hour

Abbreviation	Meaning
LCOE	Levelised Cost of Electricity
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
NSW	New South Wales
NZE	Net zero emissions
O&M	Operations and Maintenance
OECD	Organisation for Economic Cooperation and Development
PEM	Proton-exchange membrane
pf	Pulverised fuel
PHES	Pumped hydro energy storage
PV	Photovoltaic
REZ	Renewable Energy Zone
SDS	Sustainable Development Scenario
SMR	Small modular reactor
STEPS	Stated Policies Scenario
SWIS	South-West Interconnected System
TWh	Terawatt hour
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEO	World Energy Outlook

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