Australia's National Science Agency

GenCost 2022–23

Final report

Paul Graham, Jenny Hayward, James Foster and Lisa Havas

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Contact

Paul Graham

+61 2 4960 6061

paul.graham@csiro.au

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Consultation and acknowledgments

A draft of this report was provided as one of several documents supporting AEMO's December 2022 to February 2023 consultation on its Draft 2023 Inputs, Assumptions and Scenarios Report (IASR). For details, go to AEMO | Current and closed consultations. Feedback received has been used to improve content. Parts of this report were also shared with stakeholders in an October 2022 webinar for initial feedback. The authors are grateful for all feedback received.

Executive summary

Technological change in electricity generation is a global effort that is strongly linked to global climate change policy ambitions. Following COP27 in Sharm el-Sheikh, world leaders reaffirmed their support for limiting global average temperature rise to 1.5 degrees Celsius. 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) 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.

Common to global scenarios presented here and by other leading international bodies is the implication that in order to limit emissions, the energy system must evolve and become more diverse. Chiefly: renewable energy is increasingly important, fossil fuels will remain in use (although increasingly challenged), and societies will redefine mobility. Also, Australia's efforts are characterised both by the value chains (and associated emissions) of our energy exports and our own consumption of energy.

GenCost update

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 help to guide decision making, given electricity costs change significantly each year. This is the fifth update following the inaugural report in 2018.

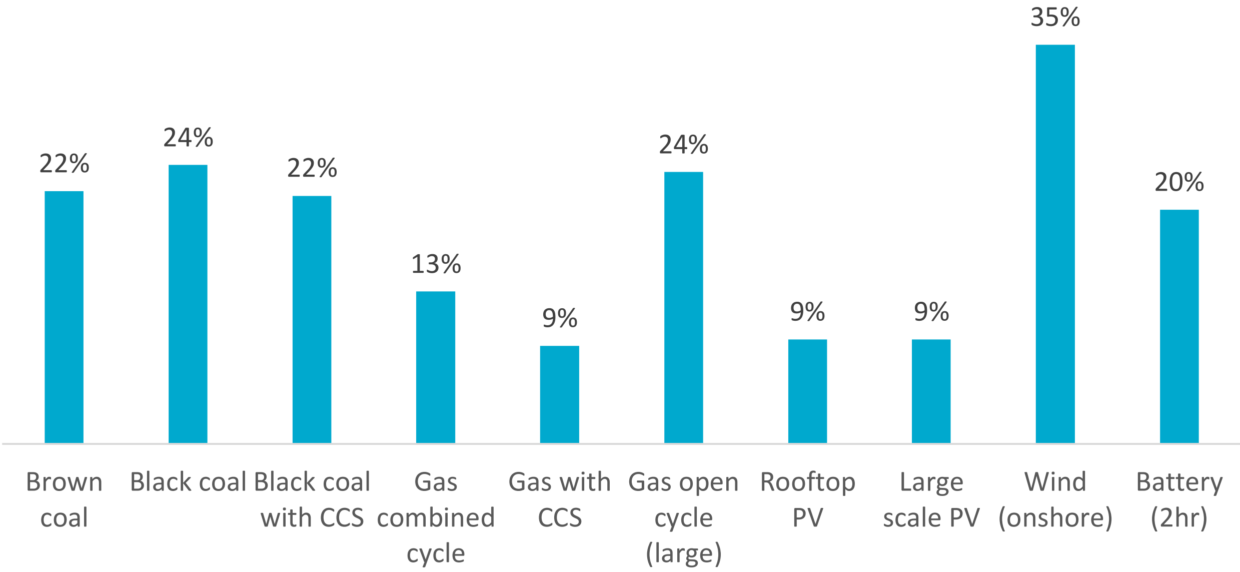
Technology costs are one piece of the puzzle. They are an important input to electricity sector analysis which is why we have made consultation an important part of the process of updating data and projections.

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.

Global inflationary pressures

The COVID-19 pandemic has resulted in global supply chain constraints which have impacted the prices of raw materials needed in technology manufacturing and in freight costs. As a result, the capital costs of all technologies which are currently being considered for construction have increased and Aurecon has provided data on the new cost levels. For technologies which are not currently being deployed, we assume their costs would also have increased had contracts for construction been entered into. We estimate the likely cost increase for these technologies based on increases in the costs of inputs they would require in their construction and installation. The data sourced for these calculations include price indices for consumer goods and services, imported equipment, domestic equipment and labour. We combine this information with data on their local content, imported content and installation share of costs.

The data indicates that compared to 2021-22 data, technology costs have increased 20% on average but with significant diversity. Cost increases are as low as 9% for solar PV and up to 35% for wind. The difference in cost increases mostly reflects differences in material inputs and exposure to freight costs. Some variation may also represent the extent to which cost increases had already flowed through to the previous year's estimate as we consider the beginning of this inflationary cycle to have started in 2020. Whilst prices had not risen in 2020, it appears cost reductions had started to slow from that time for some technologies.



ES Figure 0-1 Increase in current costs of selected technologies relative to GenCost 2021-22

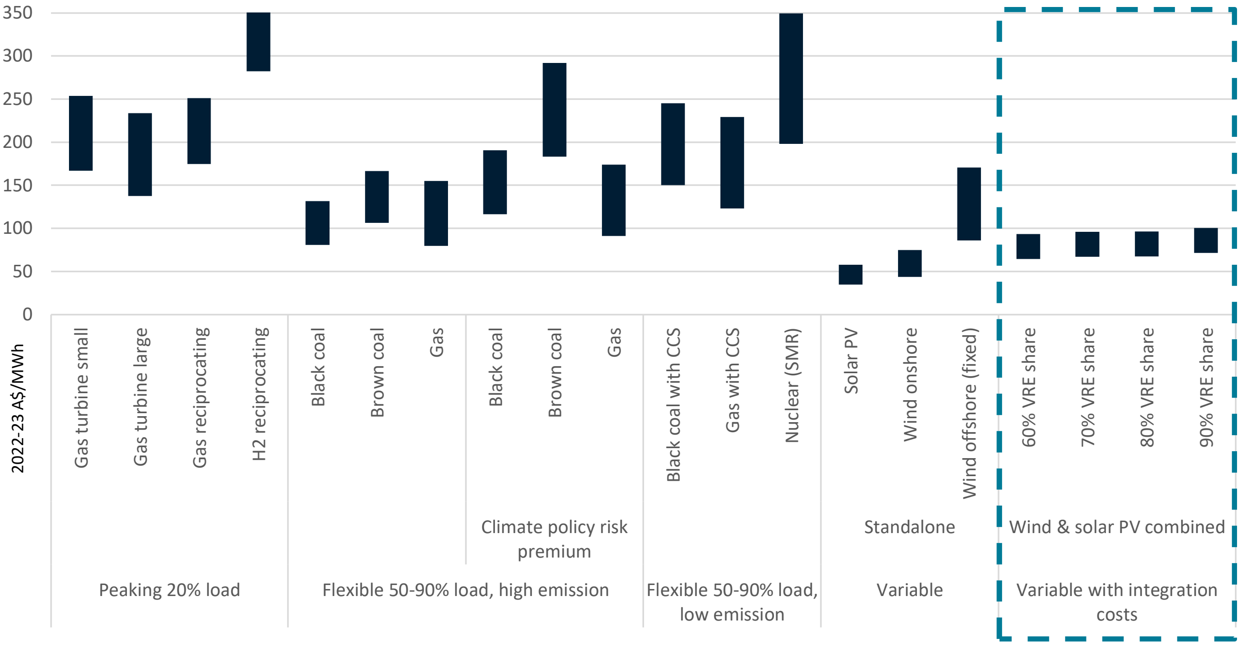
The inflationary cycle is assumed to be at its peak in 2022-23 and to take until 2027 to return to normal costs under current global climate policy commitments or to 2030 under if stronger global climate policy commitments are made which would require faster global technology deployment. After this adjustment period, our standard projection methodologies are resumed.

Levelised cost of electricity

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. 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 technology capacity factor is one input to the LCOE calculation and describes the percentage of year that the technology is generating to full capacity. As part of this update the capacity factors for both renewables and flexible technologies have been widened to recognise historical trends.

The LCOE is estimated on a common basis for all technologies. However, an additional process is undertaken to calculate the integration costs of variable renewables. The required amount of additional investment depends on the amount or share of variable renewable energy (VRE) generated. We calculated the additional costs of variable renewable generation for annual VRE shares from 60% to 90%[1] for the National Electricity Market (NEM) and Western Australia. We found that the additional costs to support a combination of solar PV and wind generation in 2030 is estimated at between $25 to $34/MWh depending on the VRE share. The key costs for supporting reliable supply of electricity under high shares of variable renewable electricity are additional transmission, storage and peaking gas capacity.

All estimates are based on a maximum of costs across nine weather years over which the costs were estimated. When added to variable renewable generation costs and compared to other technology options, these estimates indicate that onshore wind and solar PV remain the lowest cost new-build technologies.



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

[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. Approximately 55% will be achieved in 2030 without any new policies (excluding Northern Territory).

1 Introduction

Current and projected electricity generation and storage 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 (2023) 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].

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 and storage 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, 2023). This report focusses on capital costs, but the Aurecon report provides a wider variety of data such as operating and maintenance costs and energy efficiency. Some of these other data types are used in levelised cost of electricity calculations in Section 5.

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

Earlier drafts of Aurecon's capital cost data were initially shared with stakeholders during a webinar in October 2022. Project management, workshops, 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, our main priority has been to understand how inflationary pressures are impacting the short to medium-term outlook for technology costs. We have implemented a change to our methodology up to the year 2030 to capture this significant driver.

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 Technology selection principles

A set of technology selection principles has been included in Appendix C. Feedback on these principles is always welcome.

1.6 Overview of feedback received

GenCost receives unsolicited feedback throughout the year and also specifically as one of several documents supporting AEMO's December 2022 consultation on its most recent Inputs, Assumptions and Scenarios Report (IASR). For details, go to AEMO | Current and closed consultations. This report does not detail how all individual feedback was addressed. However, the overlapping feedback has been grouped into themes in Appendix D. We are grateful for all feedback.

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 (e.g., batteries). In these cases, lower cost quotes will become known well 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 (2023). Aurecon (2023) 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 makes adjustments to the data when used in global modelling to take account of regional differences in costs.

2.2 Capital cost source

AEMO commissioned Aurecon (2023) 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 (2023) which is consistent with either the beginning of financial year 2022-23 or middle of 2022. 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 (2023) 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 also not been updated by Aurecon (2023), but we have revised this data to be mostly consistent with AEMO's June 2022 ISP Input and Assumptions Workbook. CSIRO has modified AEMO's data for the years 2022 to 2027 to include the same inflationary effects as other mature technologies. Nuclear SMR current costs are not reported since there is no prospect of a plant being deployed in Australia before 2030. However, some improved data on nuclear SMR may be available in future reports[4] and projected capital costs for SMR have been included from 2030 onward.

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2022-23) cost estimates (drawing primarily on the Aurecon (2023) update) for electricity generation technologies with those from previous years: GenCost 2018 to GenCost 2021-22 (which are a combination of Aurecon (2021, 2022), 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).

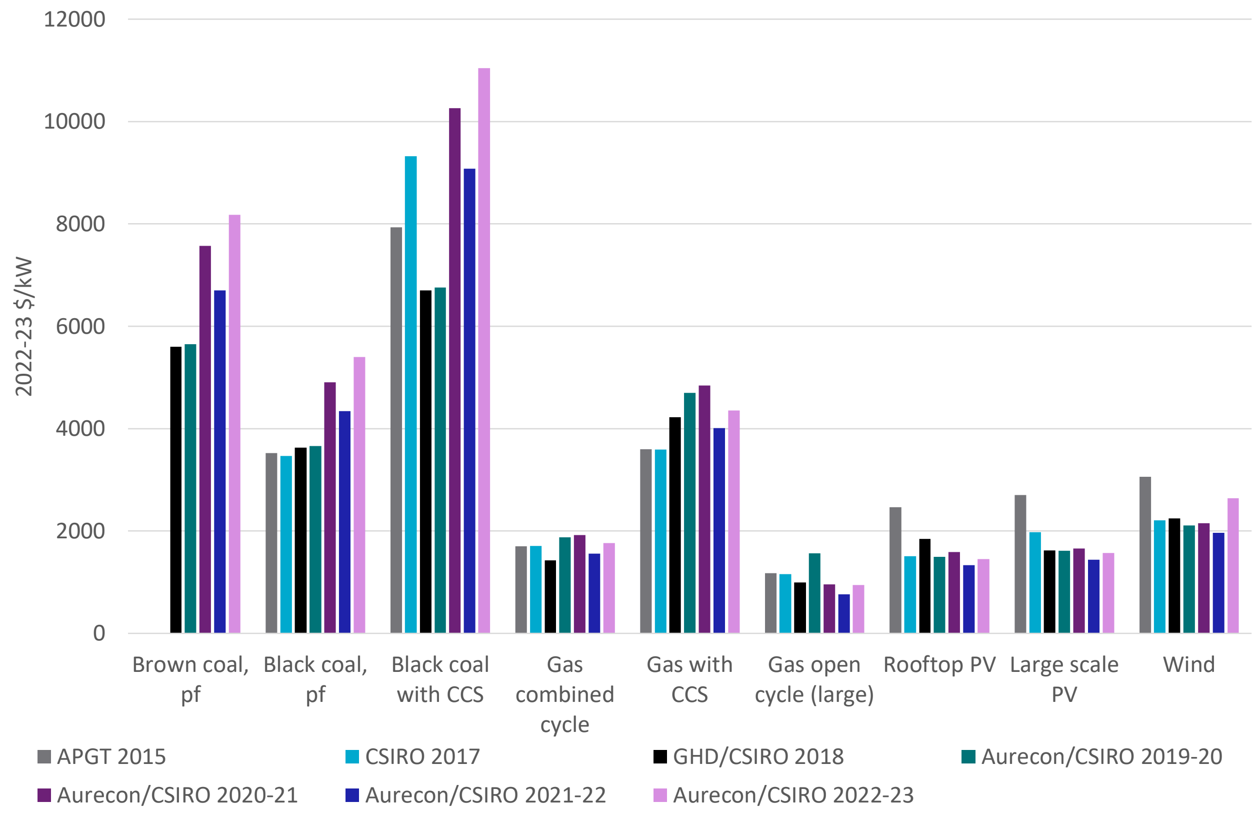

Figure 2-1 Comparison of current capital cost estimates with previous work

[4] The Australian Nuclear Science and Technology Organisation has joined an International Atomic Energy Agency project to appraise the costs of nuclear SMR. The project is due for completion in December 2024. Economic Appraisal of Small Modular Reactors Projects: Methodologies and Applications | IAEA. EFWG (2019) is the most recently available data source.

All costs are expressed in real 2022-23 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 has been an increase in capital costs impacting all technologies. The source of this increase is a combination of global supply chain constraints following the COVID-19 pandemic which has increased freight and raw material costs. The cost increase has not been uniform as shown in Figure 2-2 which is the percentage increase in capital costs by technology relative to 2021-22.

The increase in capital costs for gas technologies, onshore wind and solar PV are from observation by Aurecon (2023) of projects reaching financial close. The exception is Australian gas with CCS projects. Cost increases for this technology category are inferred from the gas technologies without CCS.

The increase in capital costs for black coal technologies has been calculated by CSIRO based on a bundle of consumer price indices applied to knowledge of the relative mix of imported and local content for each technology.

Overall, the differences in cost increases reflect different levels of exposure to increases in cost inputs. However, there is higher uncertainty about the impact of current inflationary pressure for those technologies not currently being deployed. Some variation may also represent the extent to which cost increases had already flowed through to the previous year's estimate as we consider the beginning of this inflationary cycle to have started in 2020. Whilst prices had not risen in 2020, it appears cost reductions had started to slow from that time for some technologies.

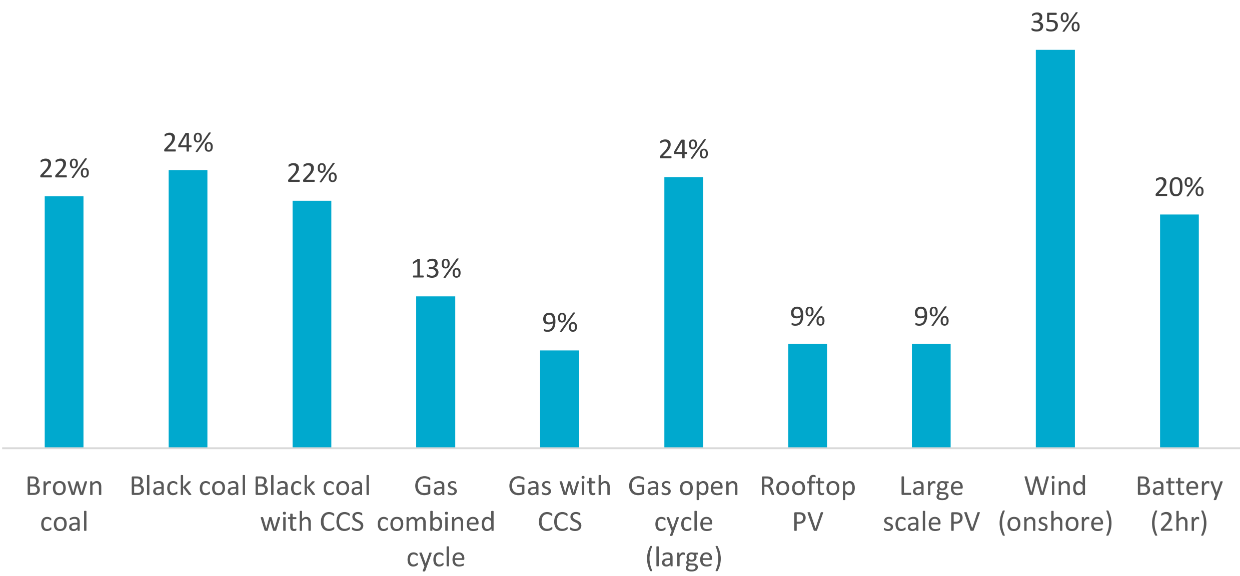

Figure 2-2 Annual increase in capital costs by technology

2.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[5] of battery and pumped hydro energy storage (PHES) in $/kW and $/kWh. Aurecon (2023) has also made available a cost for adiabatic compressed air energy storage (A-CAES) at 12 hours duration and a new capital cost estimate for concentrating solar thermal (CST) at 15 hours duration from Fichtner Engineering (2023) which became available to the GenCost project in April 2023[6].

Total cost basis means that the costs are calculated by taking the total project costs divided by the capacity in kW or kWh[7]. As the storage duration of a project increases then more batteries or larger reservoirs need to be included in the project, but the power components of the storage technology remain constant. As a result, $/kWh costs tend to fall with increasing storage duration (Figure 2-3). The downward trend flattens somewhat with batteries since its power component, mostly inverters, is relatively small but adding more batteries is costly. However, the hydroelectric turbine in a PHES project is a large capital expense while adding more reservoir is less costly. As a result, PHES 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 2-4). Additional storage duration is most costly for batteries. These trends are one of the reasons why batteries tend to be more competitive in low storage duration applications, while PHES is more competitive in high duration applications. A combination of durations may be required depending on the behaviour of other generation in the system, particularly the scale of variable renewable generation and peaking plant (see Section 5 and Appendix D).

[5] 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

[6] This data only became available after Aurecon had completed its analysis of solar thermal and so differs from their estimate of solar thermal capital costs which was presented in the consultation draft. Aurecon has therefore not been able to assess the Fichtner Engineering analysis. However, given the depth of the new analysis, the GenCost team has decided to use the new data as its current estimate of solar thermal capital costs.

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

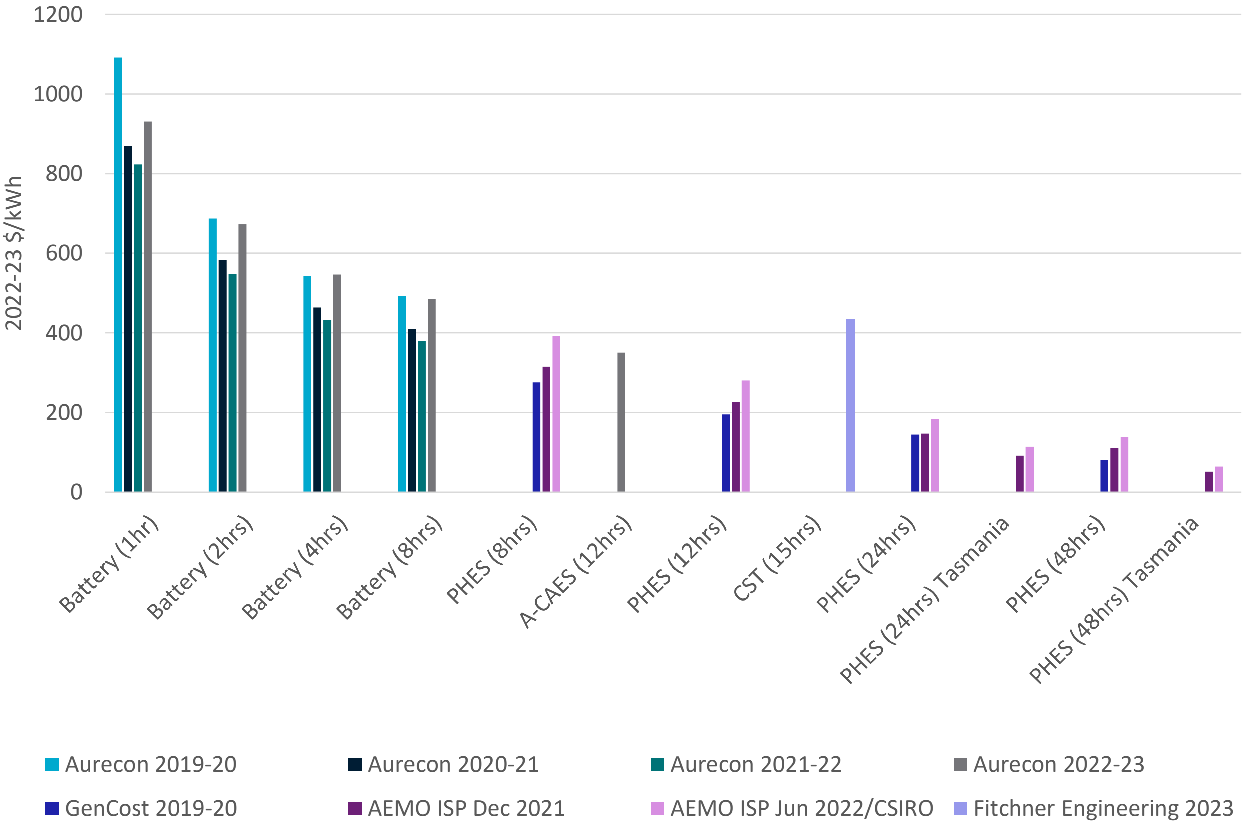

Figure 2-3 Capital costs of storage technologies in $/kWh (total cost basis)

Round trip efficiency, project design life and the potential for co-location all play a role in competitiveness of alternative storage technologies. Depth of discharge in batteries can be an important factor. However, all Aurecon battery costs are presented on a usable capacity basis such that depth of discharge is 100%[8]. Aurecon (2023) 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 6% lower battery cost for a 1-hour duration battery, scaling down to a 1% cost reduction for 8 hours duration. PHES is more difficult to co-locate.

Like the generation technologies the current capital costs of the storage technologies have both increased. Battery costs (battery and balance of plant in total) have increased by 13% for one hour duration batteries and up to 28% for eight hour duration batteries. The higher increase for longer duration batteries indicates that the cost of the battery pack has been the greater source of cost increases compared to the inverter and other balance of plant components.

PHES current cost estimates have increased by 17% and the rate of increase is not assumed to vary significantly by duration. These increases are based on a bundled consumer price increase approach and are therefore less certain. Ordinarily, besides inflationary pressures, PHES have 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

[8] 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%.

influence of site costs, we have included the cost of Tasmania pumped hydro for 24 and 48 hours duration. AEMO's IASR provides other state cost adjustment factors for PHES.

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

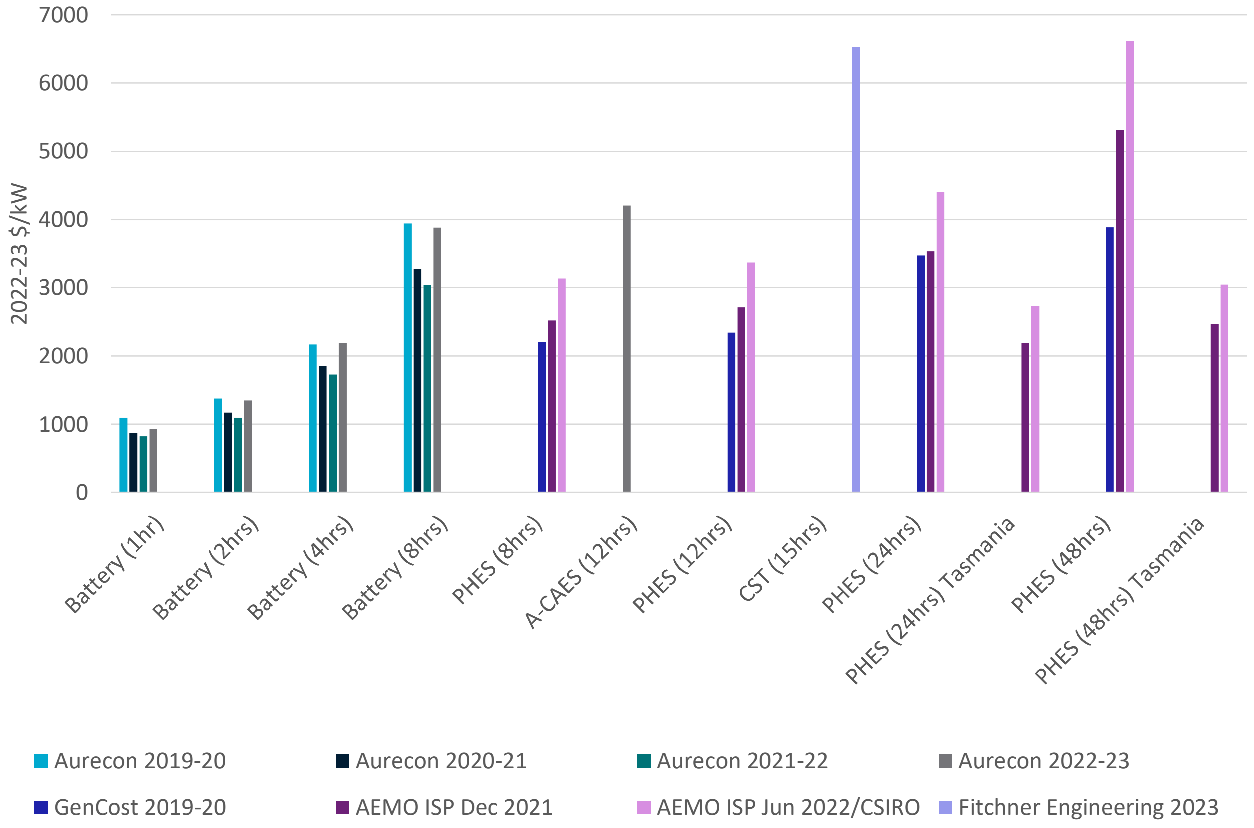

Figure 2-4 Capital costs of storage technologies in $/kW (total cost basis)

3 Scenario narratives and data assumptions

The scenarios were redesigned for GenCost 2021-22. For 2022-23 the scenario narratives have not changed 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.

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

[9] 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.

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, 2021, 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)
		G	-	-	
Fixed offshore wind	Global NZE by 2050	G	20	10	
		G	-	-	
Fixed offshore wind	Global NZE post 2050	G	15	7.5	
		G	-	-	
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	
Pumped hydro	Current policies	G	-	-	(Grübler et al., 1999; McDonald and Schrattenholzer, 2001)
		L	-	5	
Pumped hydro	Global NZE by 2050	G	-	-	
		L	-	20	
Pumped hydro	Global NZE post 2050	G	-	-	
		L		20	
Utility scale energy storage – Li-ion	Current policies	G	-	7.5	
		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 (2023) 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	-	-	-	
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.

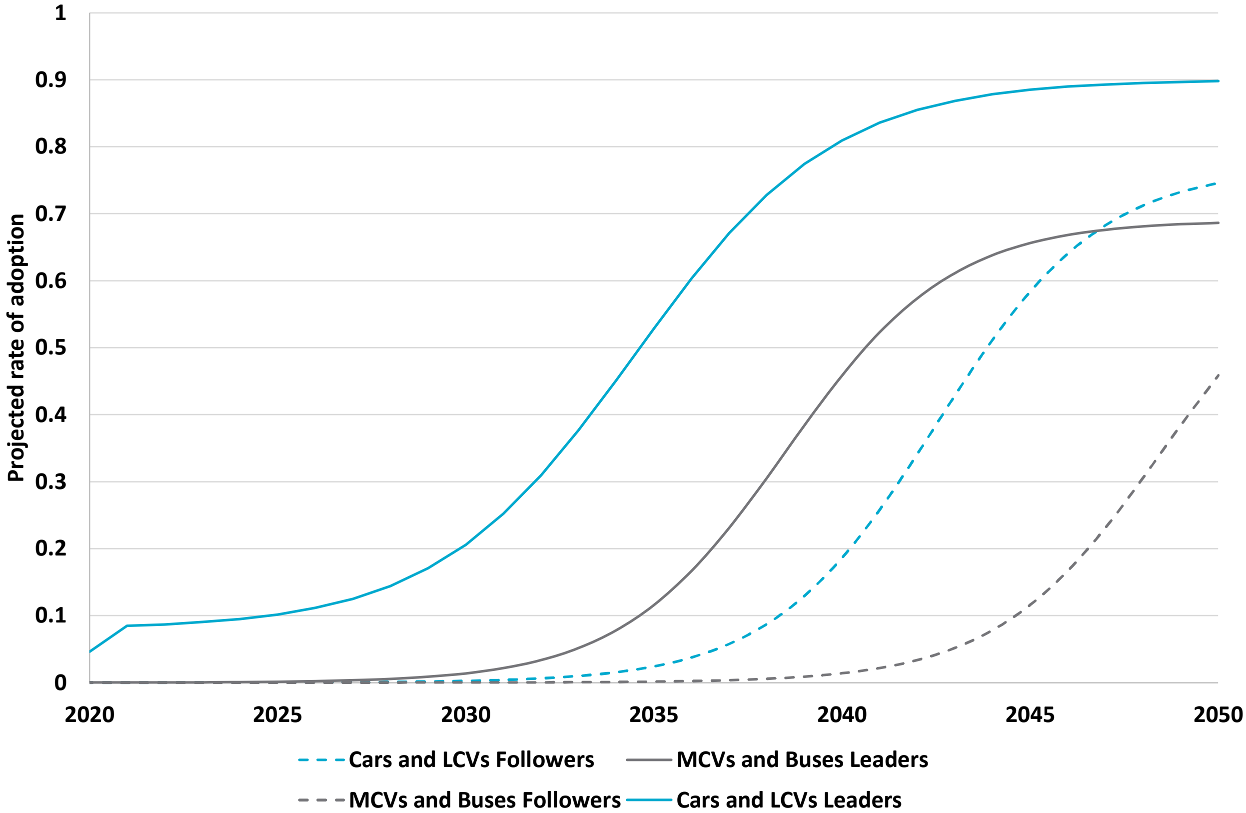

Figure 3-1 Projected EV sales share under the *Current policies* scenario

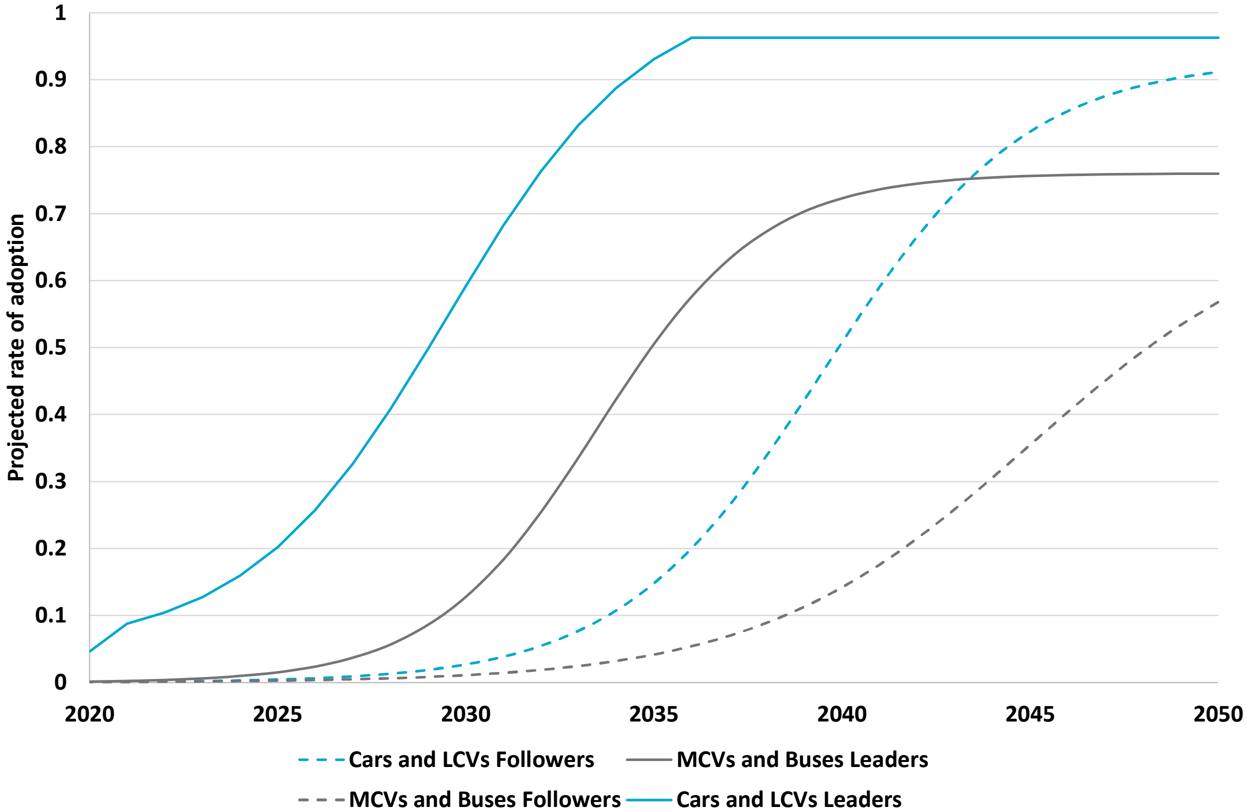

Figure 3-2 Projected EV adoption curve (vehicle sales share) under the *Global NZE by 2050* scenario

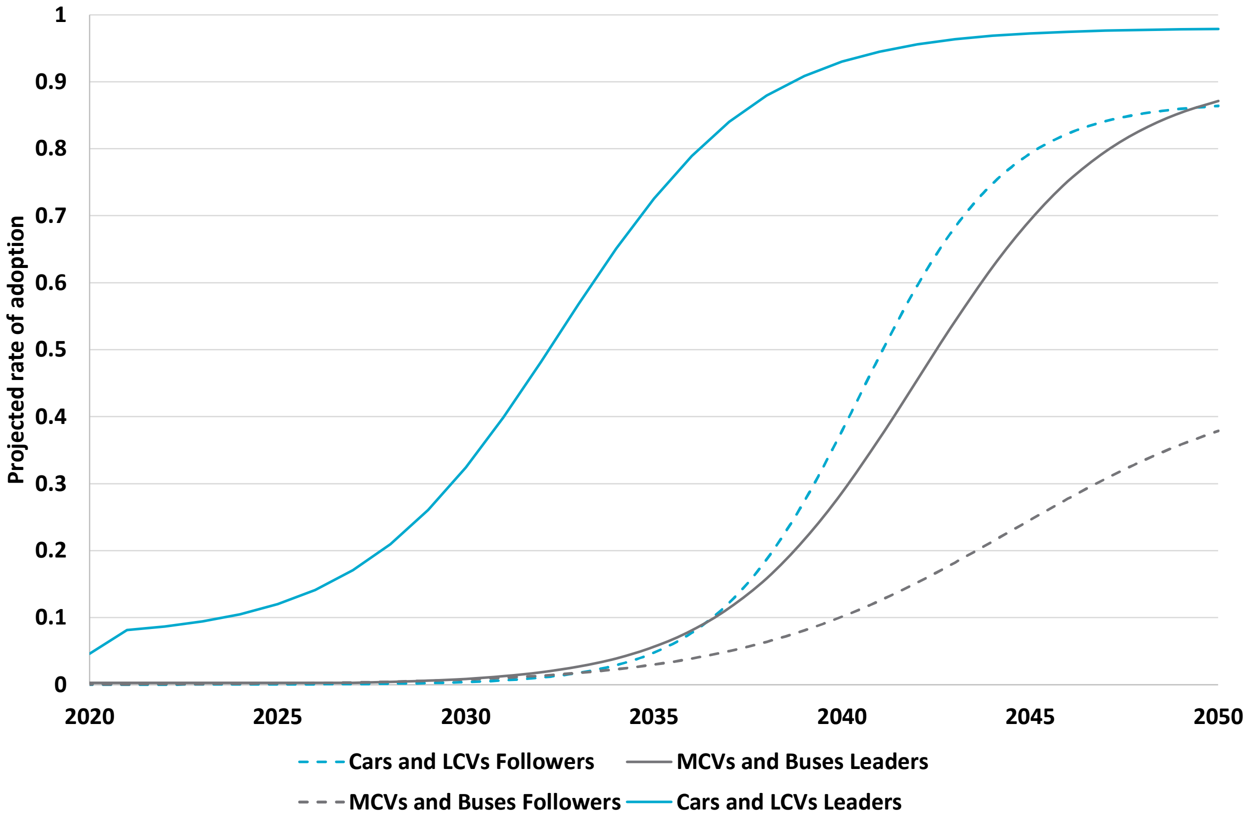

Figure 3-3 Projected EV sales share under the *Global NZE post 2050* scenario

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 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-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 prices must fall[10]. 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 %	CSP %	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, 2023) (Aurecon, 2022) (Aurecon, 2021) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2022) (IRENA, 2021) (IEA, 2015) (CO2CRC, 2015)

[10] 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.

and historical technology installed capacities from (IEA , 2008) (Gas Turbine World, 2009) (Gas Turbine World, 2010) (Gas Turbine World, 2011) (Gas Turbine World, 2012) (Gas Turbine World, 2013) (UN, 2015a) (UN, 2015b) (US Energy Information Administration, 2017a) (US Energy Information Administration, 2017b) (GWEC) (IEA, 2016a) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015).

4 Projection results

4.1 Incorporating short term inflationary pressures

Over the last two 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 five 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.

Some feedback received did suggest that some believe the price bubble is not a price bubble but rather a permanent feature that will strengthen. 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[11]).

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 for more discussion). However, it is considered that the period to 2030 will likely experience extra strong technology deployment, particularly for the *Global NZE by 2050* and *Global NZE post 2050* scenarios. This is partly because of the low global clean technology base (from which non-linear growth is more feasible) but also because governments and industry often use the turning of a decade as a target date for achieving energy targets. The *Current policies* scenario requires less growth in technology

[11] 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.

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 (2023) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[12]. 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 new feature of GenCost projections, not included in previous reports.

All projections start from a current cost and the first and primary source of 2022 costs is Aurecon (2023). Aurecon (2023) provides an update on the current costs of contracting the deployment of most of the technologies included in GenCost. The exceptions are some mature technologies such as coal and less commonly deployed and emerging technologies such as wave energy. Aurecon (2023) costs for 2022 were not used directly for offshore wind, hydrogen and natural gas reciprocating engines. These are cases where inflationary effects had not been included or they were lower than the 2021 costs which is contrary to recent cost increases seen in all other technologies.

The 2022 costs for technologies not included in Aurecon (2023) and both types of reciprocating engines and offshore wind have been calculated by multiplying the previous year's costs by a "basket of costs" factor to take into account the 2022 cost increases. To project the 2023 and 2024 costs the "basket of costs" calculation was extended out to those years and was applied to all technologies except for more commonly deployed renewable technologies where we were able to source more detailed information.

The approach used to determine this "basket of costs" factor is similar to that already taken for mature technologies (Appendix A 1.3) where we apply historical values of the CPI, imported equipment, domestic equipment and labour indices. However, for this approach we used projections of the CPI, continued the current trend in the labour index out to 2024 and estimated the domestic[13] and imported equipment indices based on materials and logistics cost projections (Mukherjee, 2022). These "basket of costs" factors have been calculated and applied to each technology on an annual basis, based on the share of local and imported equipment and installation costs.

For onshore wind, solar PV, batteries and electrolysers we were able to source projected costs to the year 2024 from S&P Global (Mukherjee 2022; Berg 2022; Jin & Zocco, 2022; Huntington 2022; Nikoleishvili & Klaesig, 2022; Davies & Nikoleishvili, 2022). However, these costs were not specifically designed for Australia but rather for the technologies on a global level. We thus used the Aurecon (2023) costs as a starting point and applied the trend in costs from S&P Global to the Aurecon (2023) 2022 cost.

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

[13] https://www.aer.gov.au/system/files/AGN%20-%20Attachment%207.8A%20-%20BIS%20Oxford%20Input%20Cost%20Escalation%20Forecasts%20to%202025-26%20-%2013%20January%202021.pdf

For all technologies, an interpolation is carried out between the 2024 projected cost and either the 2027 or 2030 modelled cost, depending on the scenario.

While we have used the trends in price indices of selected goods to inform our analysis of short-term changes in technology costs, all projections remain in real terms. That is, all projected price changes after 2022 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.

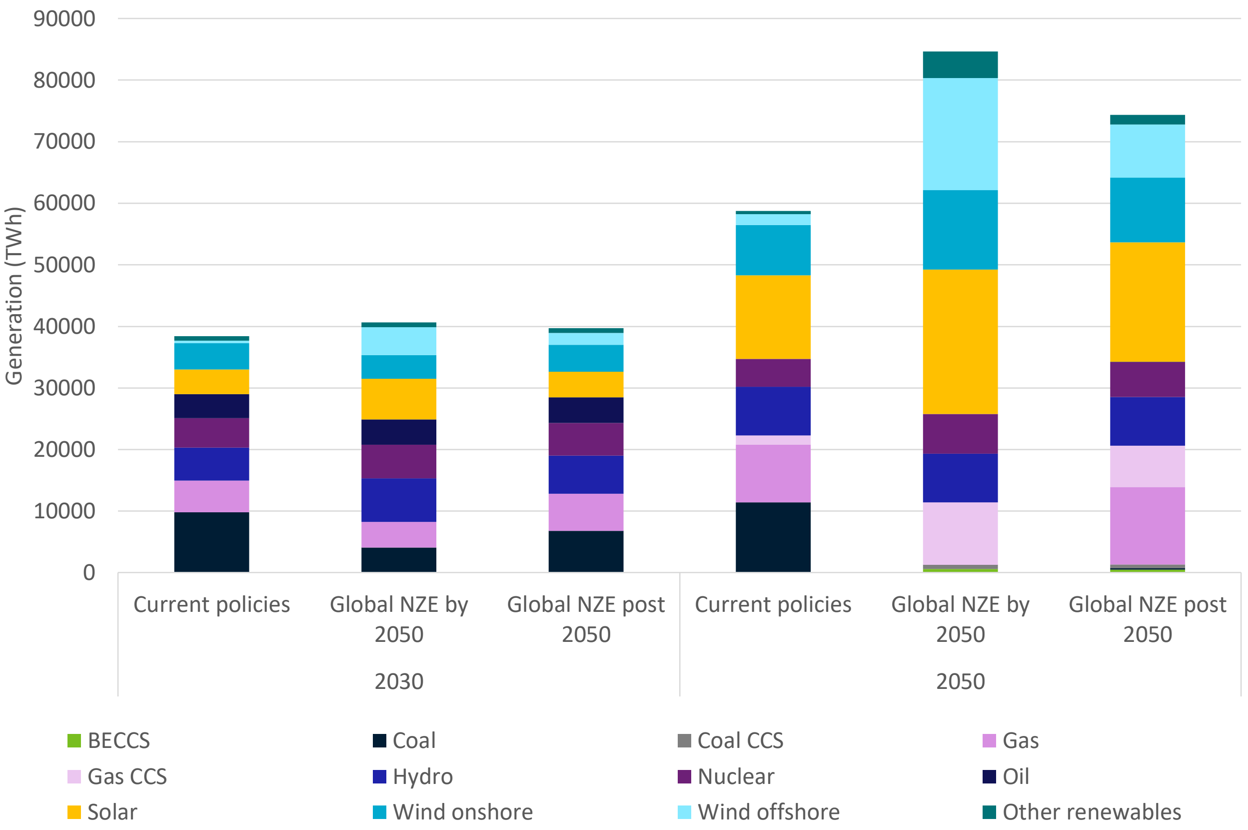

Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

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[14]. 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 technology to hydrogen production 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 emission 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 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 hydro, biomass, wind and solar are 5% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs.

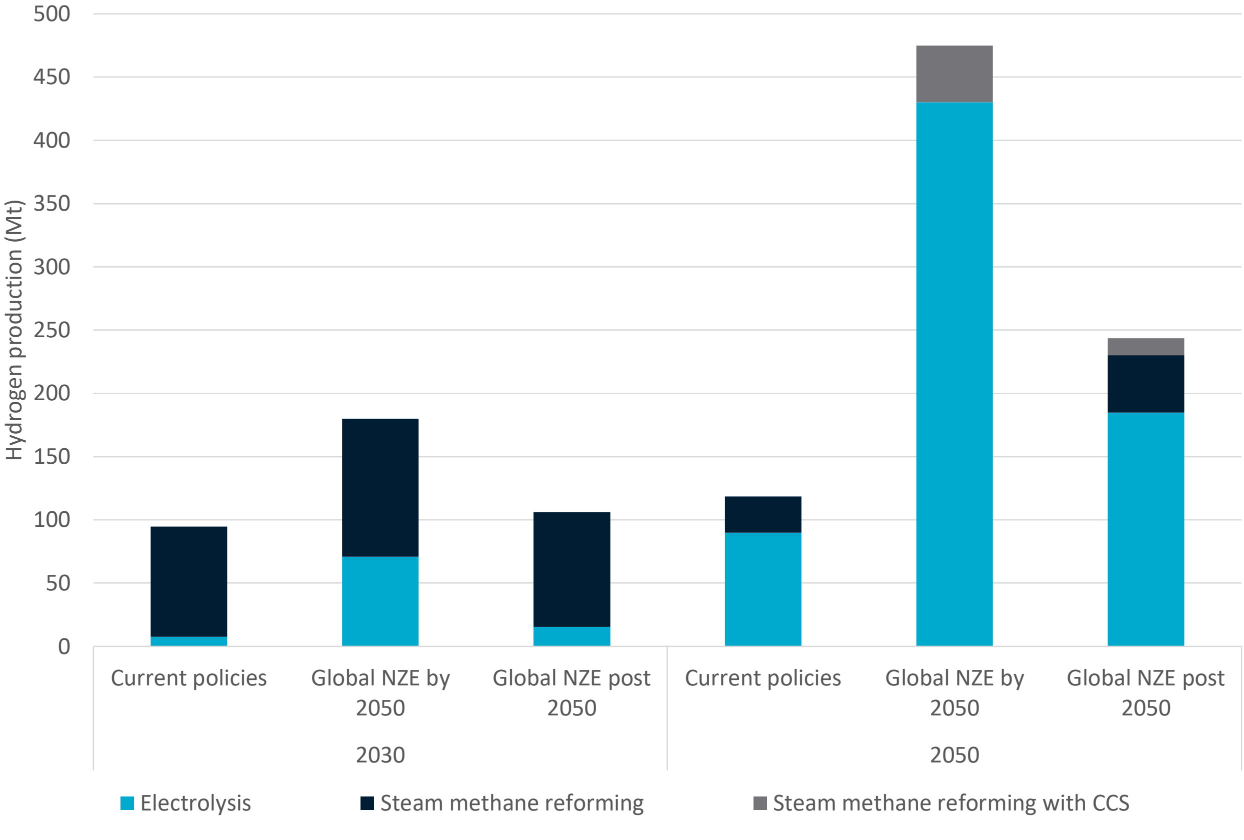

Figure 4-2 Global hydrogen production by technology and scenario, Mt

[14] 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.

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2021-22 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. In this final report, there is less overlap because, in addition to the assumed mature rate of technological improvement, a land cost inflator is also applied. The land cost inflator results in a 56% increase in land costs by 2050. The assumed annual rate of cost reduction for mature technologies post-2027 or 2030 (depending on the scenario) is 0.35% (the same as the 2021-22 report). 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[15].

4.3.1 Black coal supercritical

The cost of black coal supercritical plant in 2022 has been assumed to increase and then return to its previous level 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 assumed rate of improvement in costs for mature technologies over time is the same as in 2021-22, however the inclusion of a land cost escalator means that the 2022-23 projections are higher.

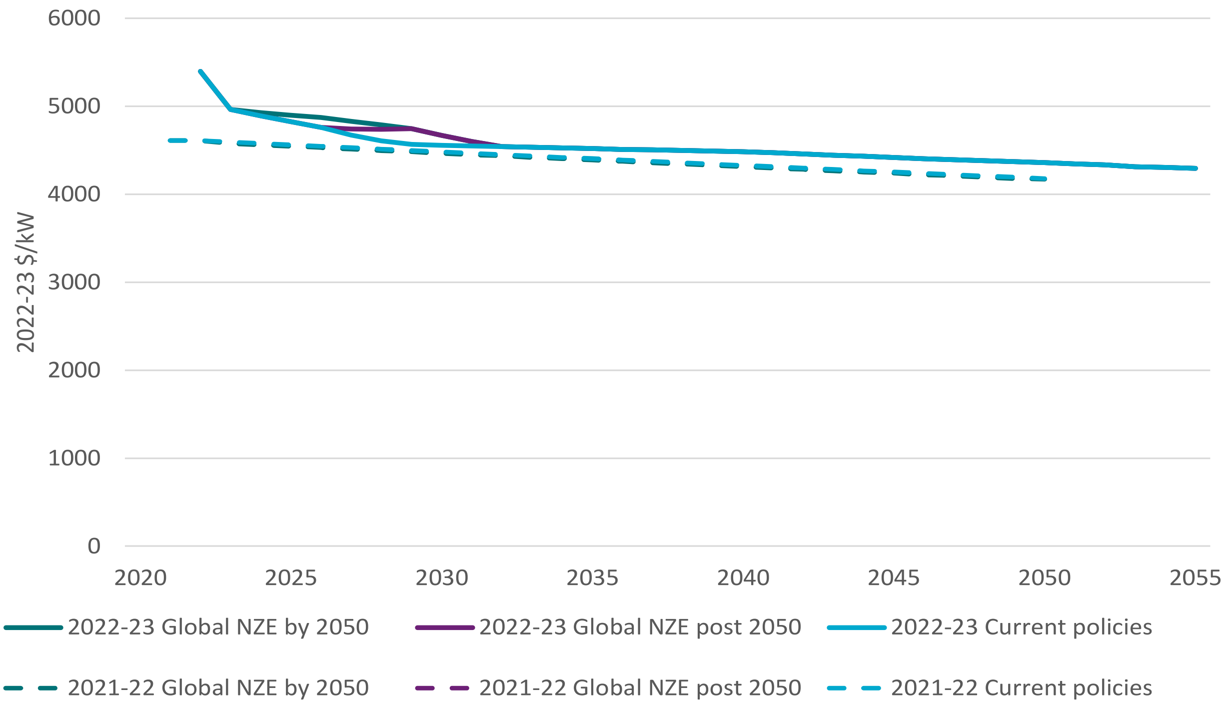

Figure 4-3 Projected capital costs for black coal supercritical by scenario compared to 2021-22 projections

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

4.3.2 Coal with CCS

The current cost of black coal with CCS from 2022 to 2027 in *Current policies* or 2022 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 improve 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 other industries, there is only a negligible amount of generation from black coal with CCS throughout the projection period.

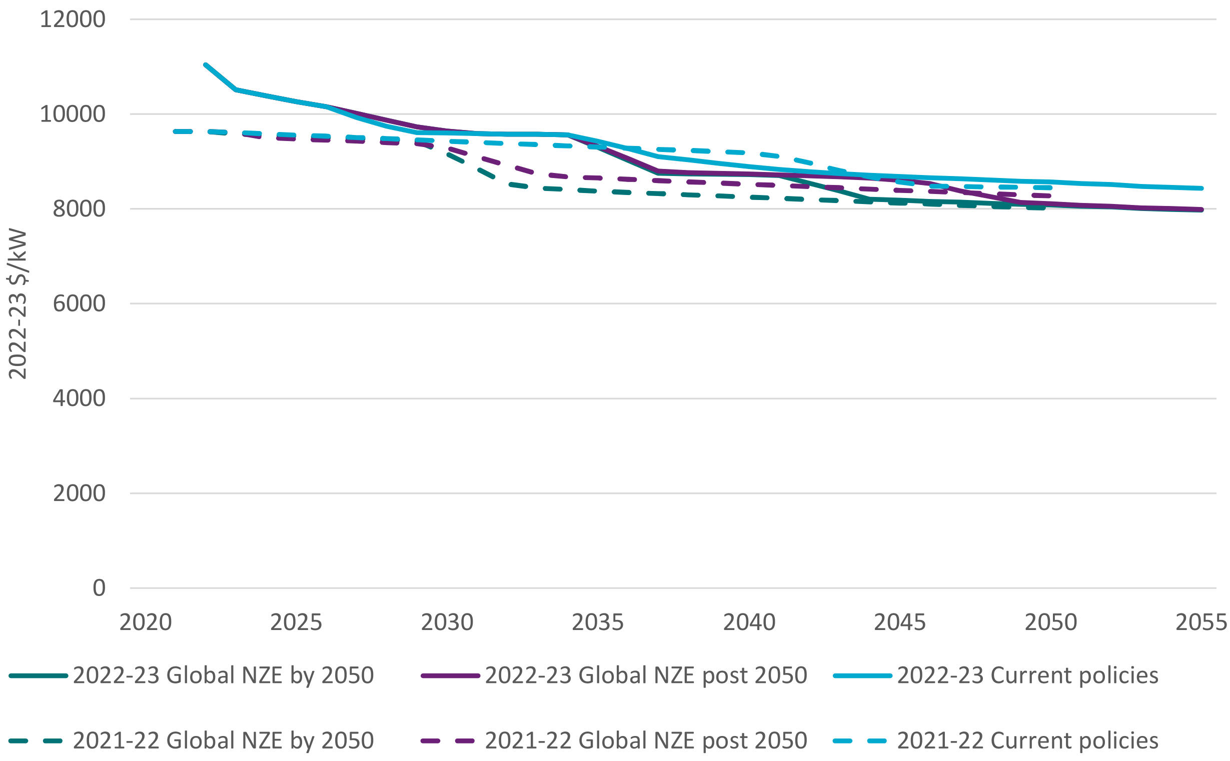

Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2021-22 projections

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. The assumed land cost increases has also been applied and may partially account for slightly higher long term costs than the 2021-22 projections

4.3.3 Gas combined cycle

Aurecon (2023) have included an increase in gas combined cycle costs for 2022 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.

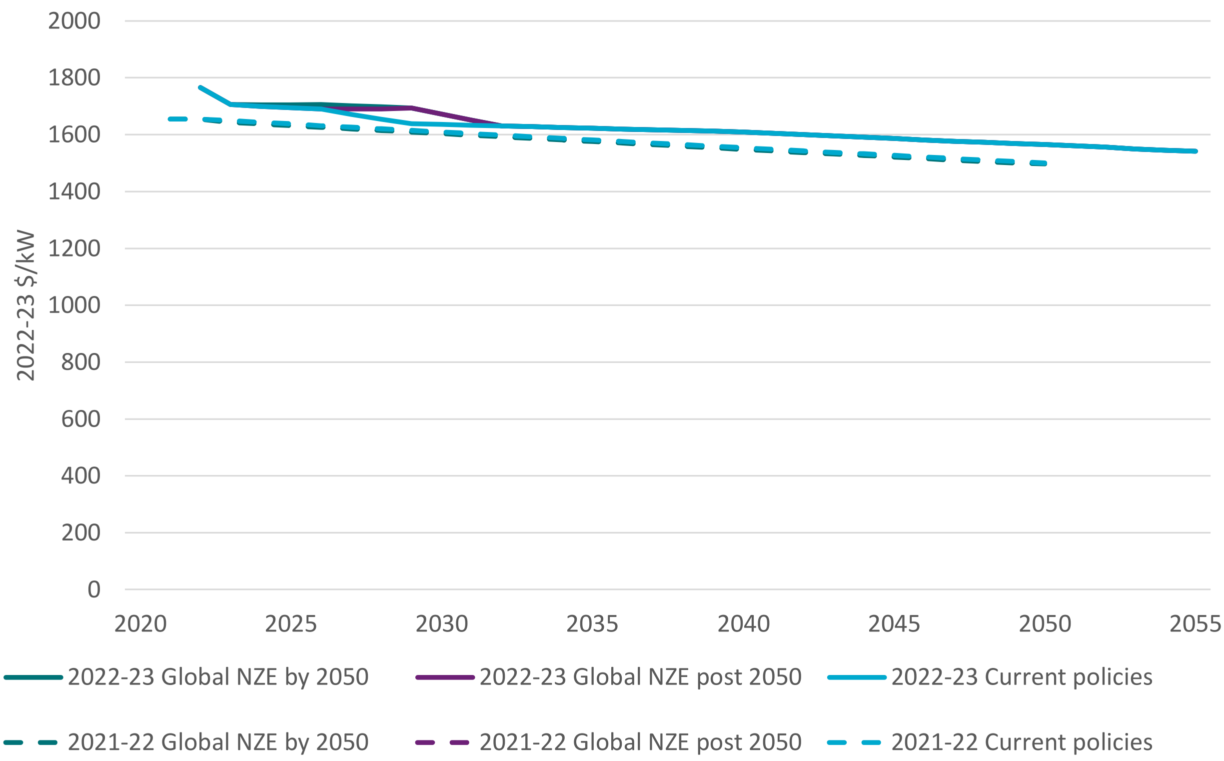

Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2021-22 projections

4.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2022-23 projections based on Aurecon (2023). 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. CCS deployment for electricity generation purposes has occurred around five years earlier than in the 2021-22 projections under *Current policies* and deployment is a little deeper overall in the *Global NZE* scenarios.

The IEA CCS database[16] 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. This has forced a delay in deployments and cost reductions until that date relative to the 2021-22 projections.

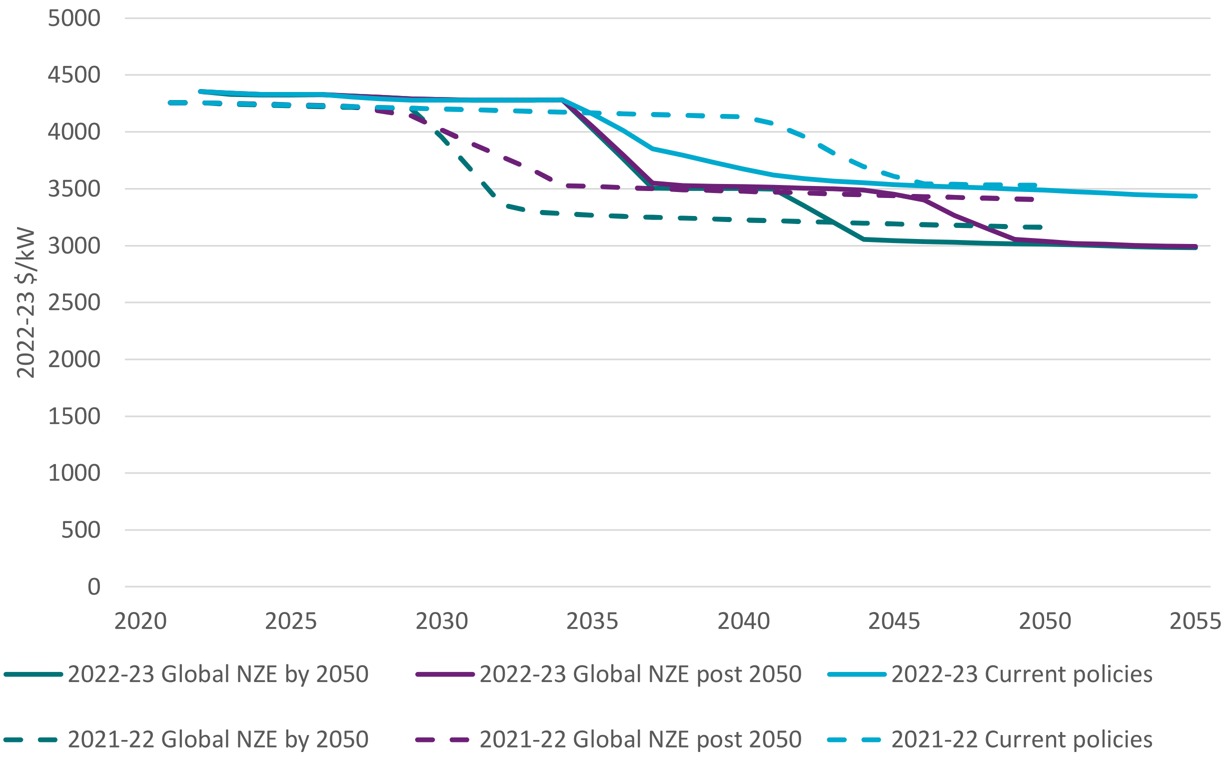

Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2021-22 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2021-22 and updated 2022-23 cost projections for small and large open cycle gas turbines. Aurecon (2023) 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 data but are assumed to converge towards their previous projected levels by 2027 or 2030. They do not return back to 2021-22 levels because the 2022-23 projections include increasing land costs over time. Aside from the land costs, open cycle gas is classed as a mature technology for projection purposes and as a result its change in capital costs is governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the scenarios.

[16] CCUS Projects Database - Data product - IEA

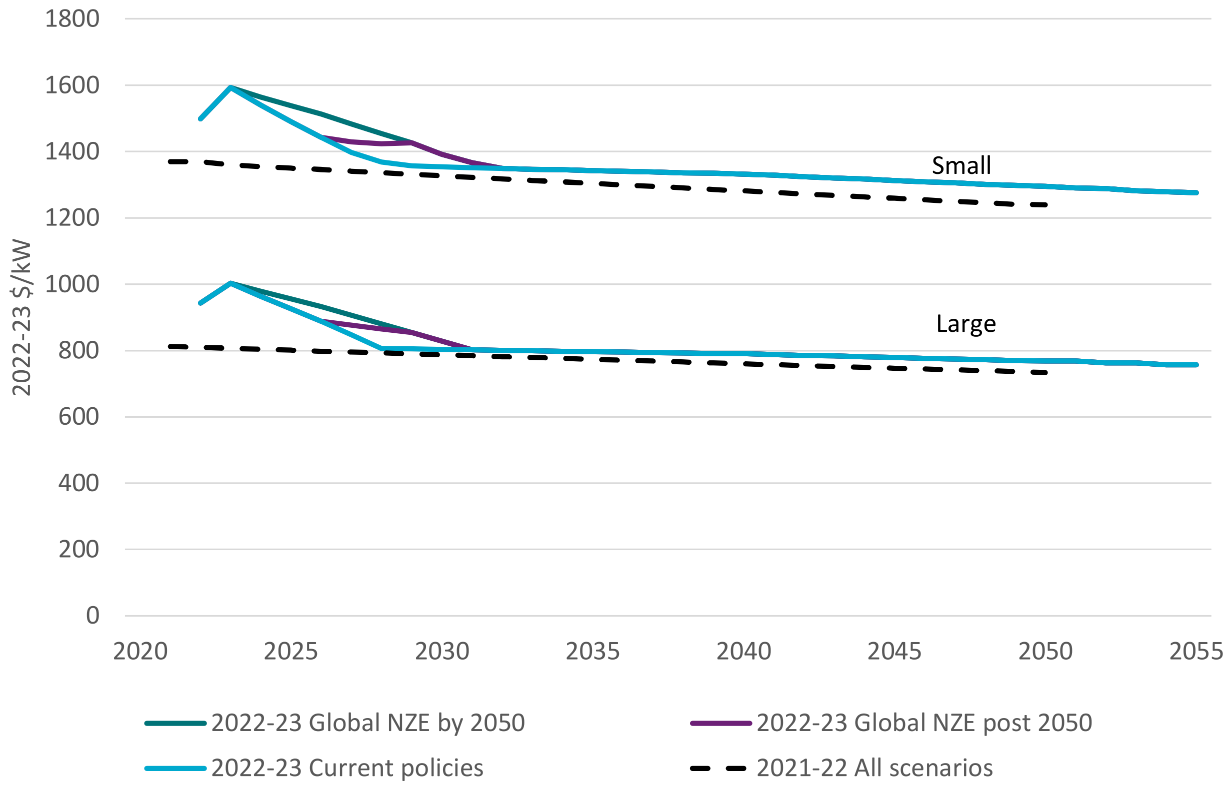

Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2021-22 projections

4.3.6 Nuclear SMR

Global commercial deployment of SMR is limited to a small number of projects and the Australian industry does not expect any deployment here before 2030. In this context, we do not report a current cost for Australian nuclear SMR. Instead, the projection begins from 2030.

The scenarios present a divergent set of possibilities for nuclear SMR. In the consultation draft of this report nuclear SMR was deployed globally in all scenarios. However, we have added a new technology to our model for this final report- floating offshore wind - and this has resulted in nuclear SMR deployment not growing in the *Current policies* scenario. *Current policies* has evolved towards being a higher abatement scenario since the 2021-22 report, with some countries increasing the ambition in their stated policies, which provides more incentive to grow nuclear SMR deployment particularly in regions with limited locations to deploy renewable generation. However, floating offshore wind provides an alternative source of renewable generation that does not require traditional locations for renewables. With nuclear SMR costs not improving due to deployment, their costs increase due to assumed increasing land costs (which impact all technologies). Assuming the world makes progress on climate policies, *Current policies* will converge towards the other scenarios over time and so this higher cost result in *Current policies* for 2022-23 may only be temporary.

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, deployment of nuclear SMR proceeds and significant cost reduction are delivered 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 reductions in the early 2030s. Capital costs are around $7500/kW in the Global NZE scenarios which is slightly lower than the low range of the 2021-22 projections (after adjusting for inflation).

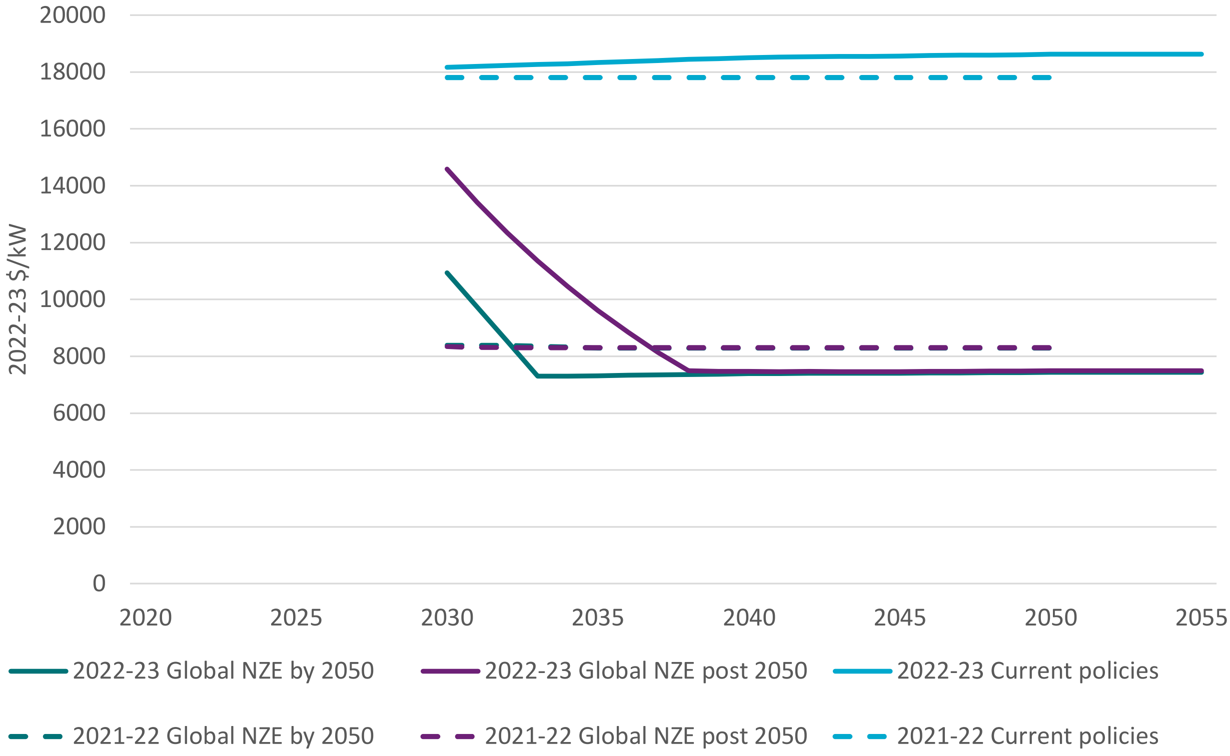

Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2021-22 projections

4.3.7 Solar thermal

The starting cost for solar thermal has been updated from Fichtner Engineering (2023) which also includes an adjustment for current inflationary pressures. Also, additional input from the solar thermal industry has indicated that the future preferred application of solar thermal has changed. Plans in Australia and elsewhere are not for standalone projects but rather for solar thermal to be integrated with other renewables such as solar PV and wind. In this case the role for solar thermal switches to provision of evening and nighttime generation. This role changes the configuration of the plant such as the ratio of the solar field to the power block. Therefore while we include the 2021-22 projections in Figure 4-9, they are not a like for like comparison.

We apply the same adjustments for inflationary pressure and land costs to solar thermal as other technologies. The projections diverge according to their scenario with the greatest cost reductions projected to be stronger the greater the global climate policy ambition.

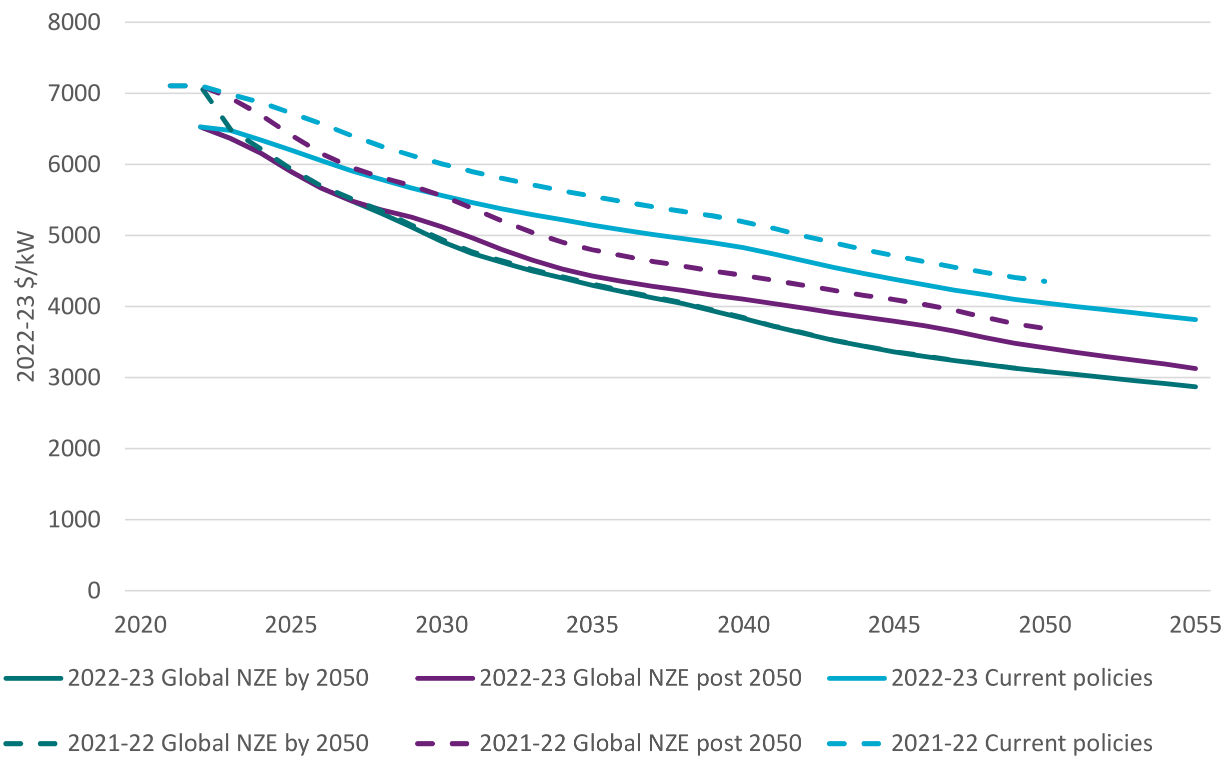

Figure 4-9 Projected capital costs for solar thermal with 15 hours storage compared to 2021-22 projections which were for 12 hours storage

4.3.8 Large scale solar PV

Large-scale solar PV costs have been revised upwards for 2022-23 based on Aurecon (2023) and reflecting current global inflationary pressures. Under the *Current policies* scenario, costs return to their normal cost pathway by 2027 and as a result this scenario has the lowest costs before 2030. In the Global NZE scenarios, inflationary pressures remain higher for longer due to faster technology deployment to meet stronger climate policies, but after 2030 these two scenarios become the lowest cost with *Global NZE by 2050* being the lowest cost overall from the 2040s.

By 2050 the three scenarios project a capital cost range of $500/kW to just under $700/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.

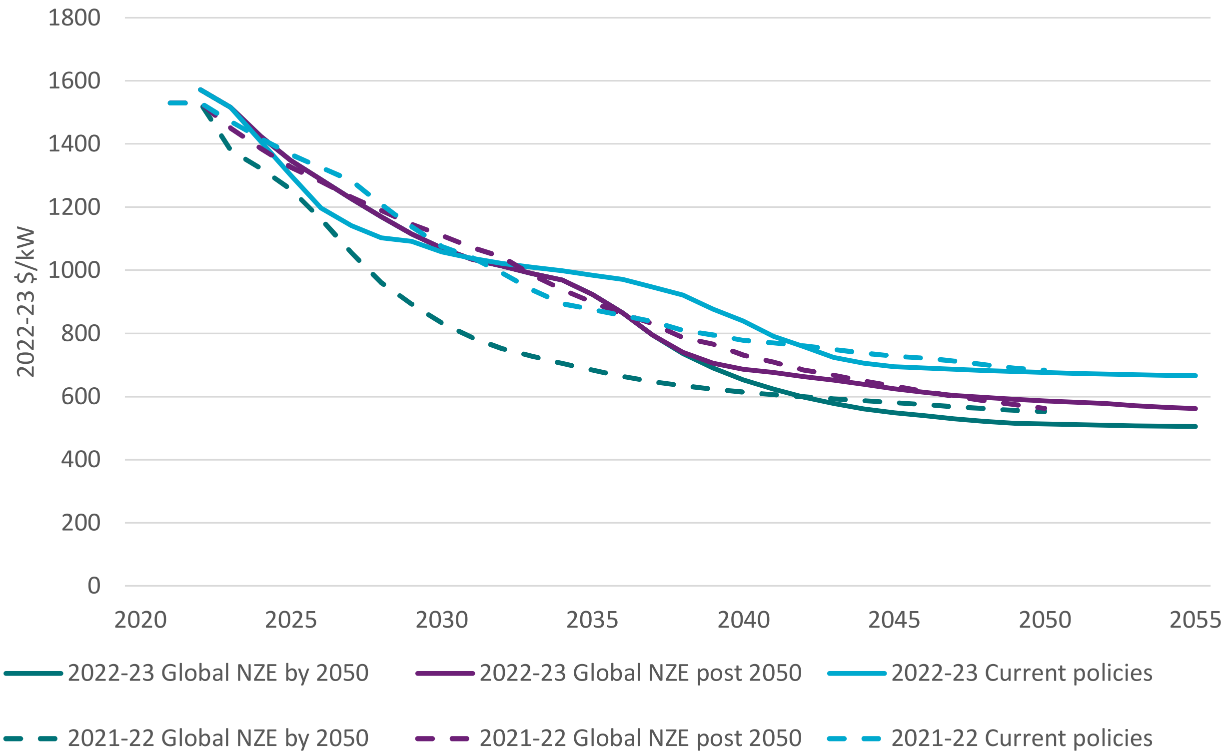

Figure 4-10 Projected capital costs for large scale solar PV by scenario compared to 2021-22 projections

4.3.9 Rooftop solar PV

The current costs for rooftop solar PV systems are higher and this increase has been aligned to that being experienced by large-scale solar PV. The price aligns to a 7kW system but it should be noted that rooftop solar PV is sold across a broad range of prices[17]. 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.

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

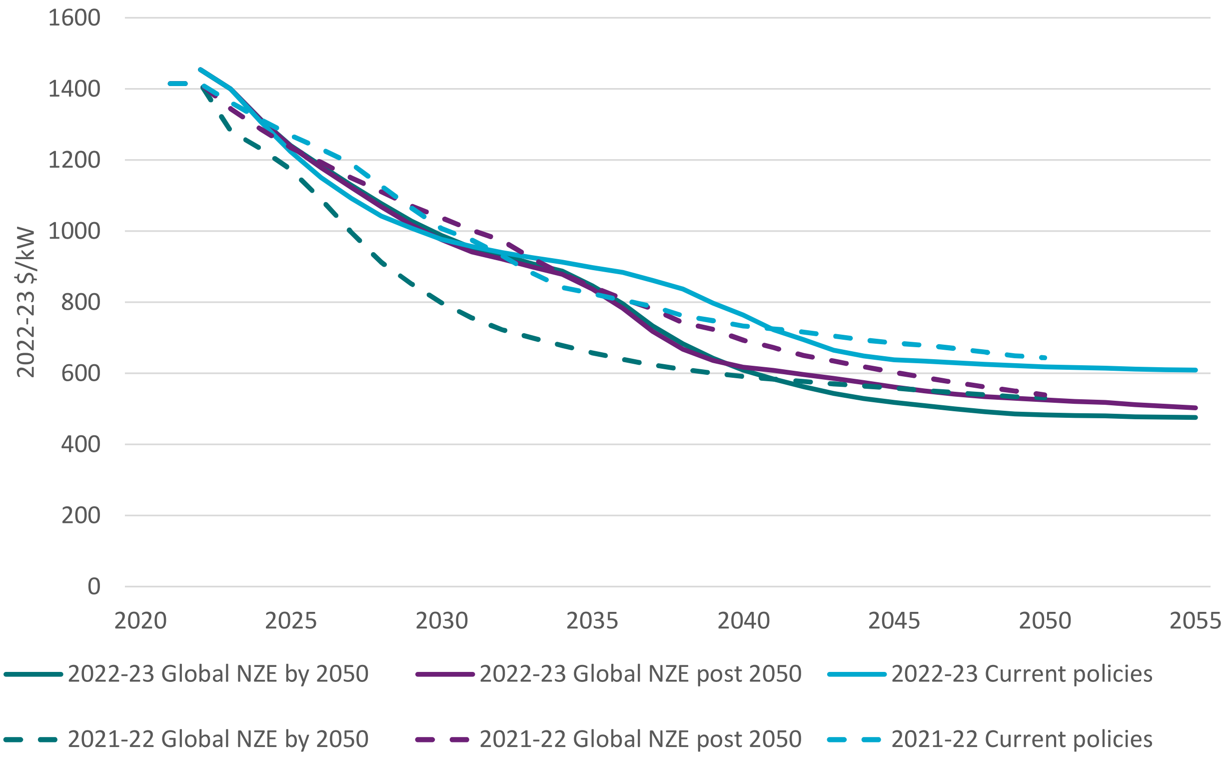

Figure 4-11 Projected capital costs for rooftop solar PV by scenario compared to 2021-22 projections

4.3.10 Onshore wind

The updated Aurecon (2023) data indicates that onshore wind has experienced one of the highest increases in costs in 2022 (around a 35% increase). Our assumption is that this cost does not reflect normal conditions and that wind will return to its normal cost path by 2027 in *Current policies* and by 2030 in the Global NZE scenarios. Like other technologies, wind costs will be reduced with greater global climate policy ambition and subsequent deployment and are also subject to land cost increases. Cost reductions are stronger with stronger global climate policy ambition resulting a range of around $1600/kW to $1900/kW by 2050.

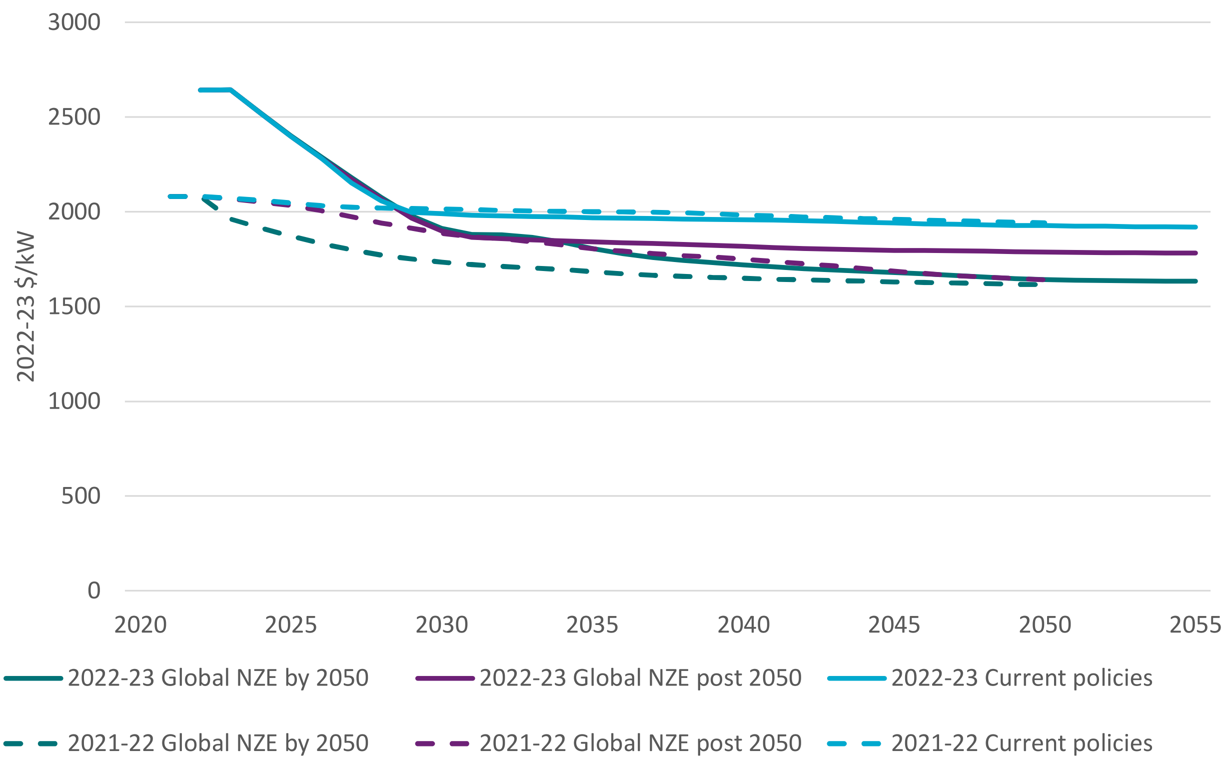

Figure 4-12 Projected capital costs for onshore wind by scenario compared to 2021-22 projections

4.3.11 Fixed and floating offshore wind

CSIRO decided that fixed and floating offshore wind should be represented separately in its 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 metres[18] 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 2021-22 (which only included fixed offshore wind). The current costs for both types of offshore wind are provided in Aurecon (2023), however we make some additional adjustments for inflationary pressure as discussed in Section 4.1. From 2023 we've allowed the offshore wind costs to resume cost reduction consistent with a stronger climate ambition as a result fixed offshore wind costs start to reconnect with the previous 2021-22 trajectory in 2027 for *Current policies* and in 2030 for the

[18] This is more an economic than absolute technical limit

Global NZE scenarios. In some scenarios they are slightly higher reflecting some competition from floating offshore wind.

In *Current policies*, floating offshore wind deployment is low. As such cost improve to 2027 reflecting an assumed reduction in inflationary pressures. However, costs reduction after that point are low. Cost reductions are deeper in the Global NZE scenarios where the demand of 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.

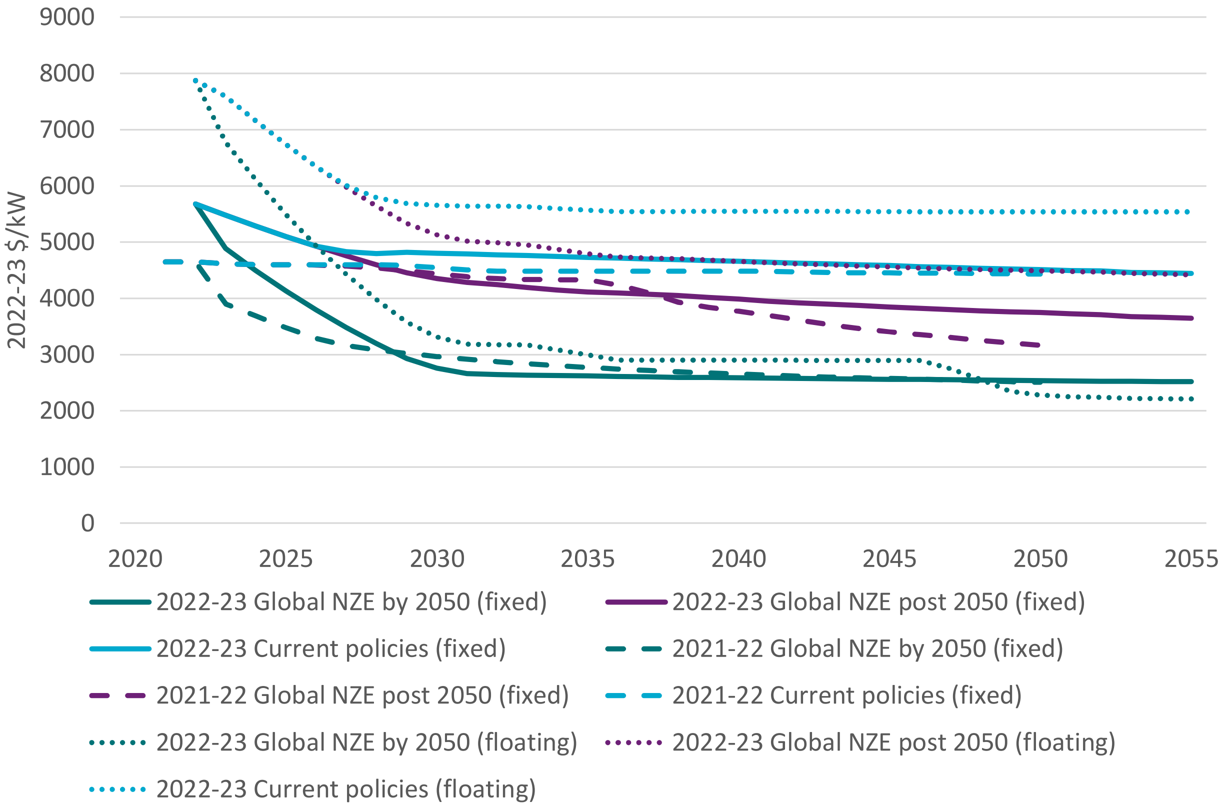

Figure 4-13 Projected capital costs for fixed and floating offshore wind by scenario compared to 2021-22 projections

4.3.12 Battery storage

The projections for batteries include a 20% increase in total costs and an underlying 37% increase in the battery component (excluding balance of plant). Consequently, batteries are one of the highest impacted technologies under the current global inflationary pressures. However, batteries have been able to sustain high rates of cost reduction over time and is it assumed that they are able to converge back to their underlying cost pathway by 2027 in *Current policies* and by 2030 in the Global NZE scenarios.

The projections use different learning rates by scenario in order to reflect the uncertainty as to whether they will be able to continue to achieve 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).

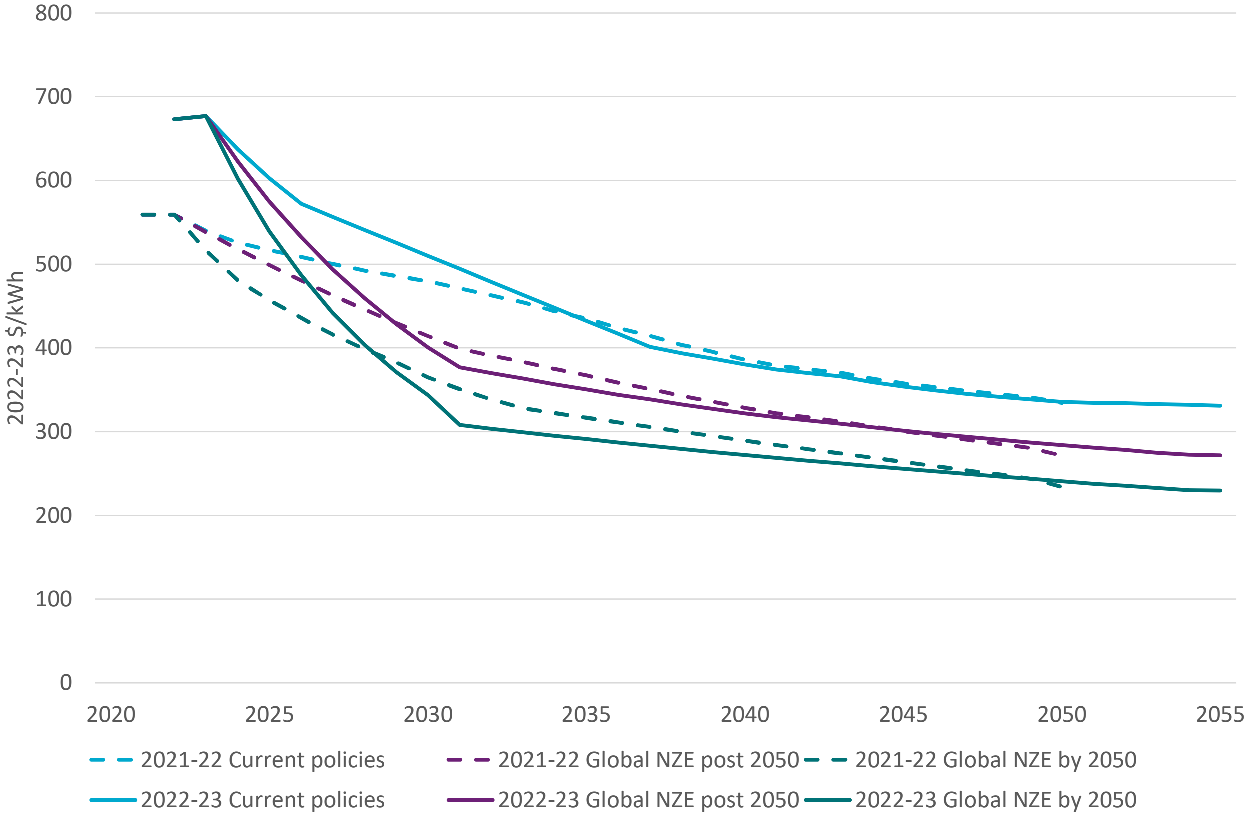

Figure 4-14 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

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 (2023) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $16000 for a 5kW/10kWh system or $1600/kWh, including installation. This is more than twice the cost of large-scale battery projects.

4.3.13 Pumped hydro energy storage

Pumped hydro energy storage is assumed to be a mostly mature technology with only a small proportion of site piping/drilling costs having the potential to improve with deployment[19]. Given the strong deployment of variable renewables in all scenarios and subsequent need for storage, this component of learning is maximised in all scenarios so that their cost trajectory is identical over time. The source of data is the 2020-21 and 2021-22 is the AEMO ISP input and assumptions workbooks – December 2020 and June 2022 respectively. These have been adjusted for ordinary inflation (being older estimates), for the current global inflationary pressures and for a continuing increase in land costs. 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.

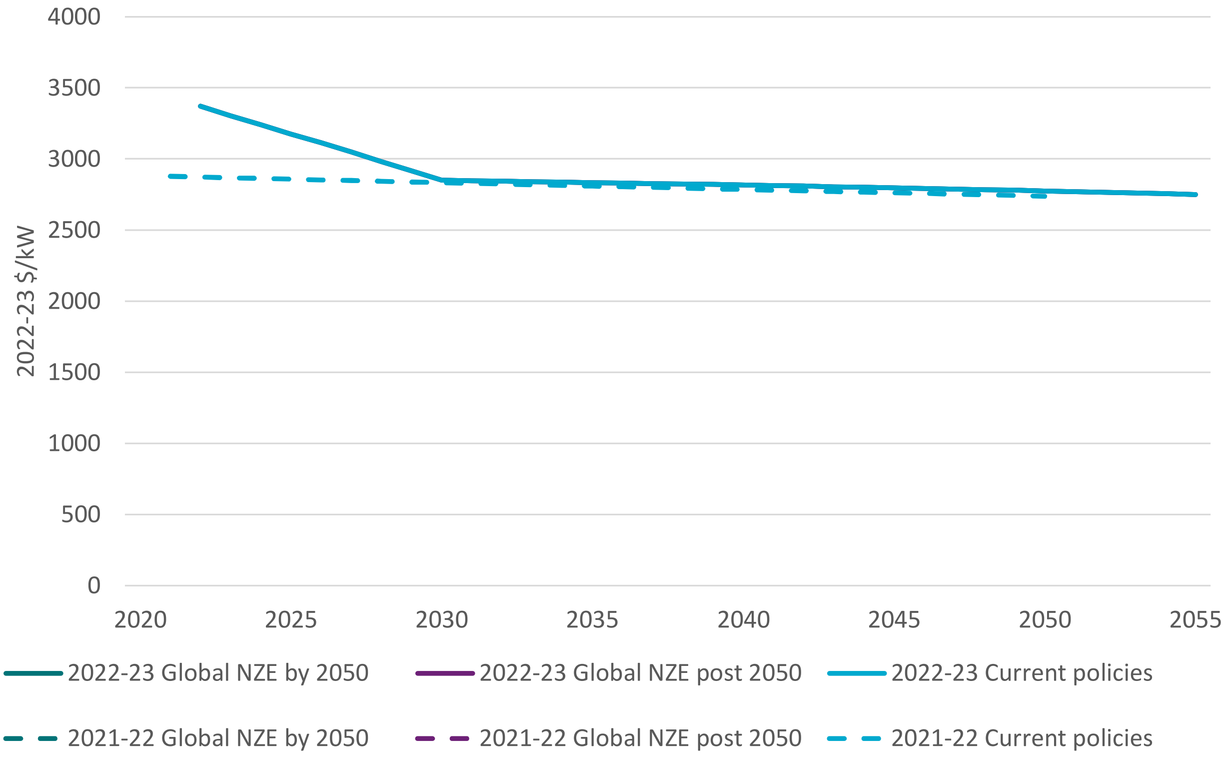

Figure 4-15 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

[19] This improvement occurs generically for the capital cost of pumped hydro energy storage. However, any capital cost estimate is a mean of projects that may have a wide distribution of costs due to site conditions. It is possible that poorer site conditions may offset cost savings from improved drilling productivity.

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. the increase in current costs and the downward trend to either 2027 or 2030 have been included using the same methodology for mature technologies. Updated projections include land costs which were not included in 2021-22 projections. The scale of increase in 2022 fuel cell costs was sourced from Aurecon (2023).

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.

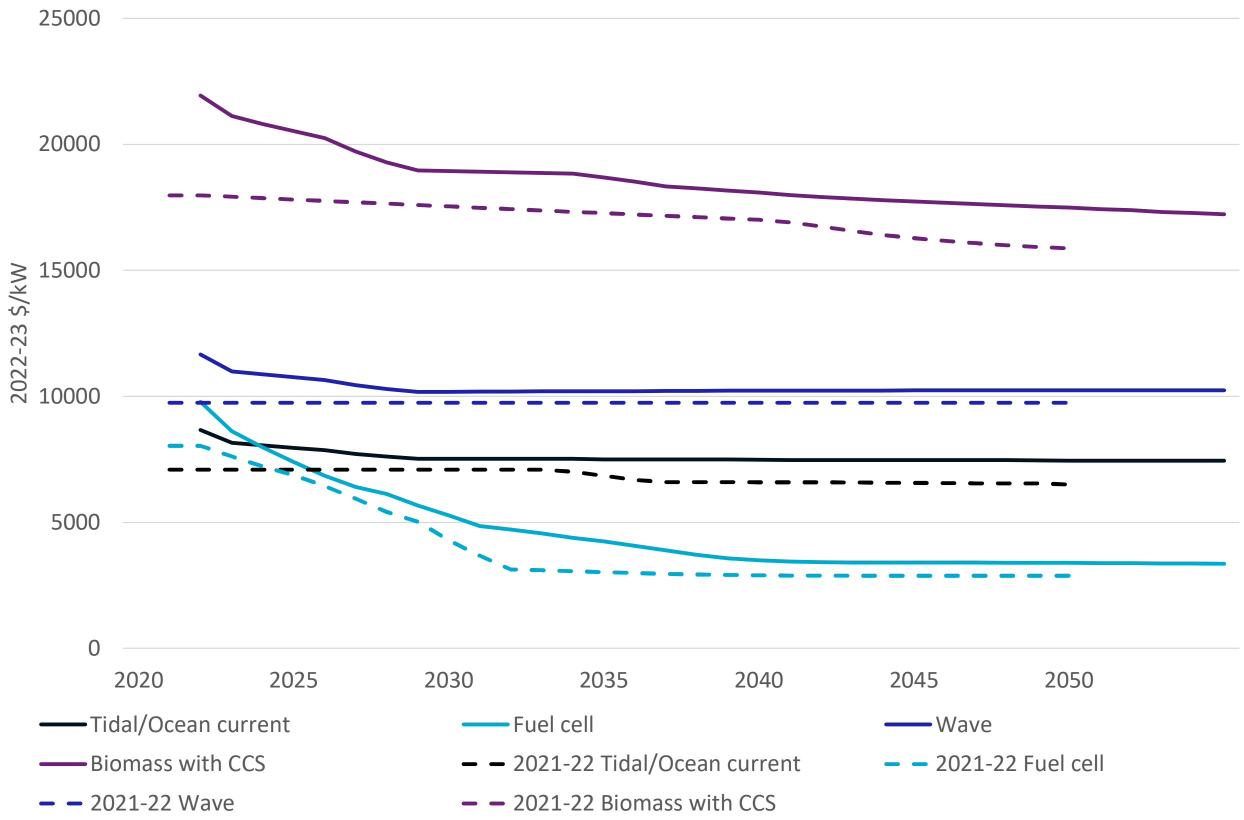

Figure 4-16 Projected technology capital costs under the *Current policies* scenario compared to 2021-22 projections

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 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 is not deployed to any significant level.

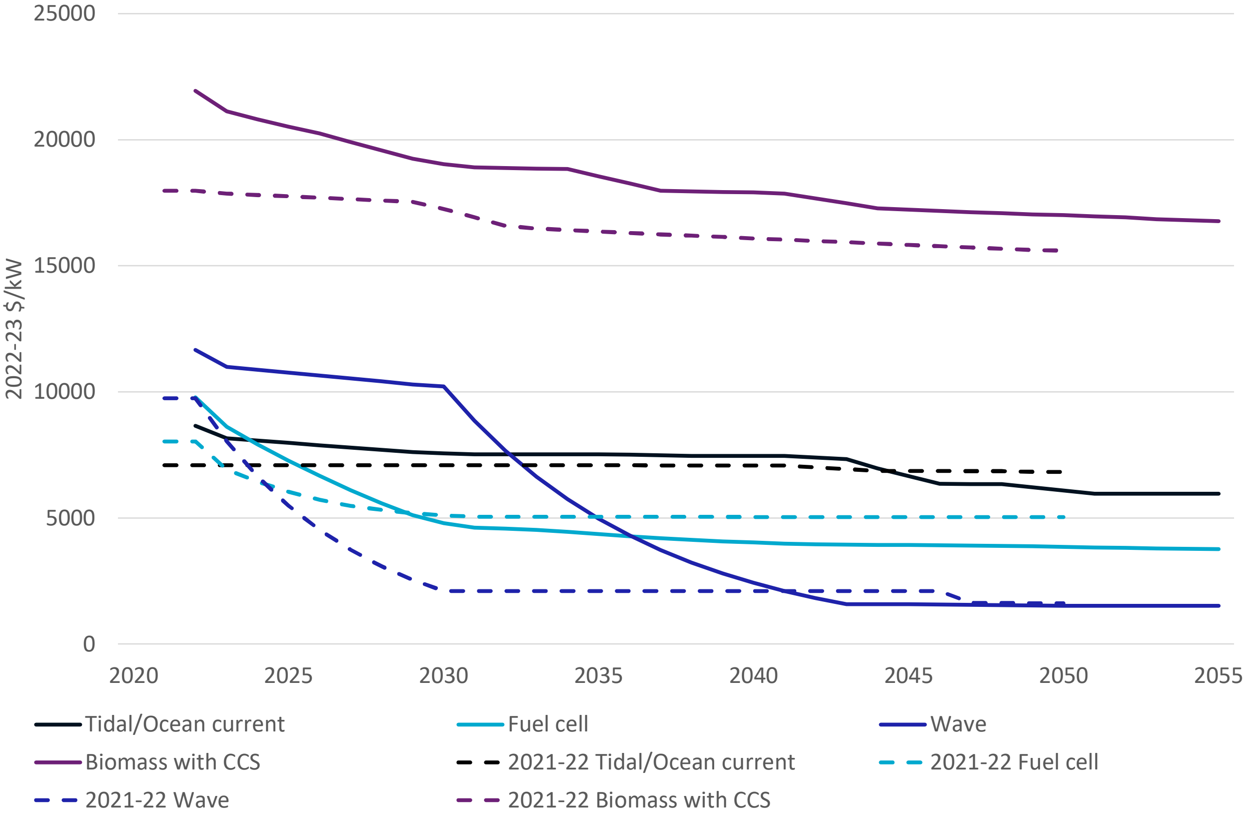

Figure 4-17 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2021-22 projections

Global NZE post 2050

Biomass with CCS is deployed at about 85% 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 *Global NZE by 2050*, wave and fuel cell generation are preferred to tidal/current generation.

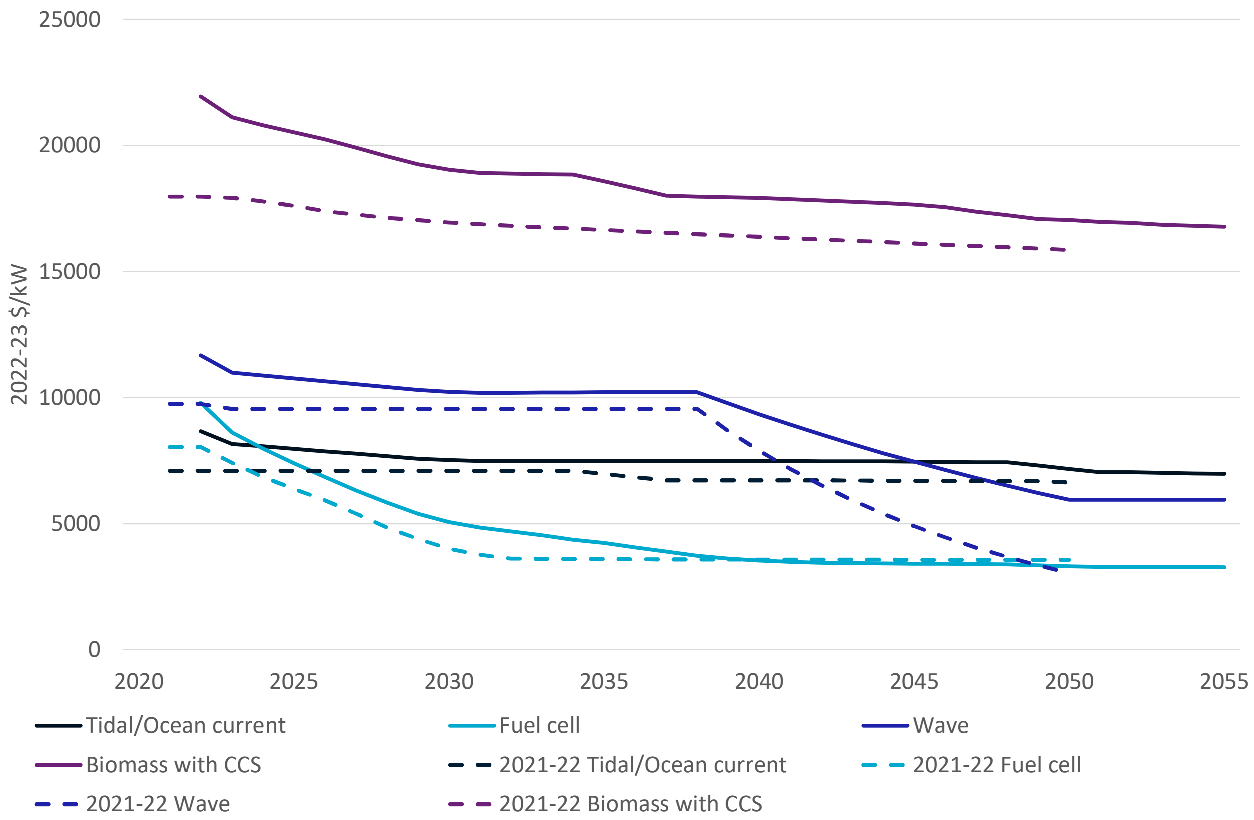

Figure 4-18 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2021-22 projections

4.4 Hydrogen electrolysers

Hydrogen electrolyser costs have increased in 2022 and the increase is sourced from Aurecon (2023). 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. 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 lower cost 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. Electrolysers costs would otherwise remain similar to 2022 levels in 2023 and the subsequent cost reduction rate thereafter significantly slower without this scale effect.

Electrolyser deployment is being supported by a substantial number of hydrogen supply and end-use trials 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*.

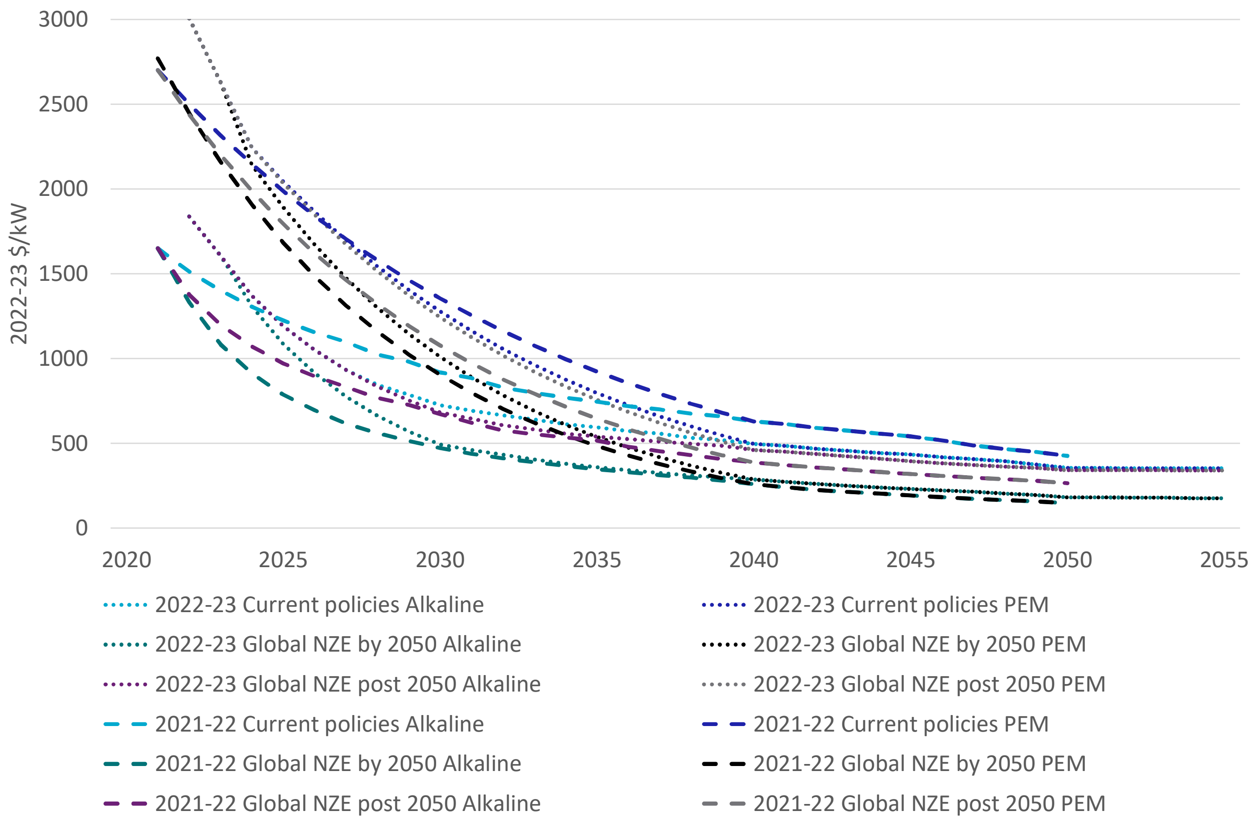

Figure 4-19 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2021-22

5 Levelised cost of electricity analysis

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[20]. 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 costs, 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 the present 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).

[20] 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.

5.1 LCOE estimates

5.1.1 Calculating additional costs of variable renewables

We calculate the integration costs of renewables for 2030[21], imposing a required variable renewable energy (VRE) share above the business as usual and running the model to determine the optimal additional investment to support the VRE share. In practice, although wave, tidal/current and offshore wind are available as variable renewable technologies, onshore wind and large-scale solar PV are the only variable renewables deployed in the modelling due to their cost competitiveness[22].

The VRE share does not include rooftop solar. The impact of rooftop solar is accounted for, however, in the demand load shape as is the impact of other customer energy resources. A portion of customer-owned battery resources are available to support the wholesale generation sector if designated as virtual power plans (VPPs) 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[23]. 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 yet included in the model.

In our counterfactual or business as usual (BAU) against which integration costs are calculated, we implement all existing state renewable energy targets resulting in a 64% renewable share and 56% variable renewable share in Australia ex-NT. 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.

[21] This year makes the most sense within the framework applied because there is enough time to plausibly reach high VRE shares but in the counterfactual or business as usual variable renewable shares are still expected to be below 60% in the larger states (although the total renewable share will be above that level). In the 2040s and 2050s, much of the existing flexible capacity in the system will retire due to end of asset life and be replaced with variable renewables (see AEMO ISP and other long-term modelling). As such, most of the additional costs will already be incurred in the counterfactual.

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

[23] 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 provides further discussion of historical capacity factors. Capacity factor ranges have been widened in this report compared to previous reports.

New South Wales, Queensland, Victoria and the SWIS are the main states that are impacted by the higher VRE shares imposed because Tasmania and South Australia are already dominated by renewables such that the BAU already includes all necessary investment to support very 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.

The BAU includes similar retirements of existing coal plants to previous AEMO ISP modelling. As we implement higher variable renewable energy shares, we must further forcibly retire coal plant as meeting the variable renewable share and the minimum load requirements on coal plant would otherwise eventually become infeasible[24]. Snowy 2.0 and battery of the nation pumped hydro projects are assumed to be constructed before 2030 in the BAU as well as various transmission expansion projects already flagged by the ISP process to be necessary before 2030. New South Wales (NSW) gas peaking plants at Kurri Kurri and Illawarra are assumed to have been constructed. The NSW target for an additional 2 GW of at least 8 hours duration storage is also assumed to be met by 2030.

Annual variable renewable energy shares (VREs) are explored in the range 60% to 90%. Below 60% is not of interest because the BAU already exceeds 50%. Above 90% VRE share is also not of interest because it would mean forcibly retiring other non-variable renewables such as hydro and biomass which would not be optimal for the system.

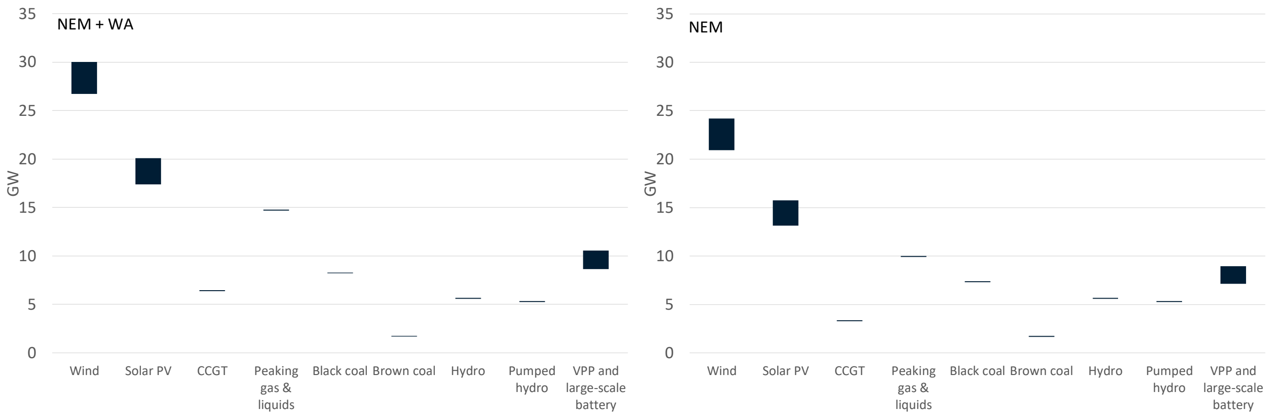

Figure 5-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia and NEM only

In the nine weather year counterfactuals, the model does not choose to build any new fossil fuel-based generation capacity (Figure 5-1). However, it also chooses a similar level of pumped hydro storage. The main investment response to the different weather is to vary wind capacity by up to 3.3GW, solar PV capacity by 2.7GW and large-scale batteries (VPP capacity is fixed) by 1.9GW. 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 more clearly preferred over solar PV by 2030.

[24] 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.

This preference is stronger in the ISP[25]. The NEM and WA total variable renewable shares are 56% and 57% on average across the weather years. The announced closure of the Muja and Collie coal 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. Synchronous condensers are one of several technologies that can be used replace lost inertia from mainly fossil fuel-based generation when it retires to make way for the higher VRE shares.

As expected, the results indicate that additional costs increase with higher VRE shares. Relative to the 2021-22 analysis, the NEM has a more even expenditure on storage and other transmission. Other transmission represents expenditure to strengthen the links between existing transmission zones (rather than connecting new renewable energy zones). Storage and transmission are somewhat in competition because they both help to manage variable renewable generation. Storage can shift variable renewable generation to a different time. Transmission supports access to a greater diversity of variable renewable generation by accessing resources in other regions which can help smooth supply. As transmission costs are updated, they have tended to increase in cost and this has likely led to a reduced reliance on transmission to balance supply in the modelling.

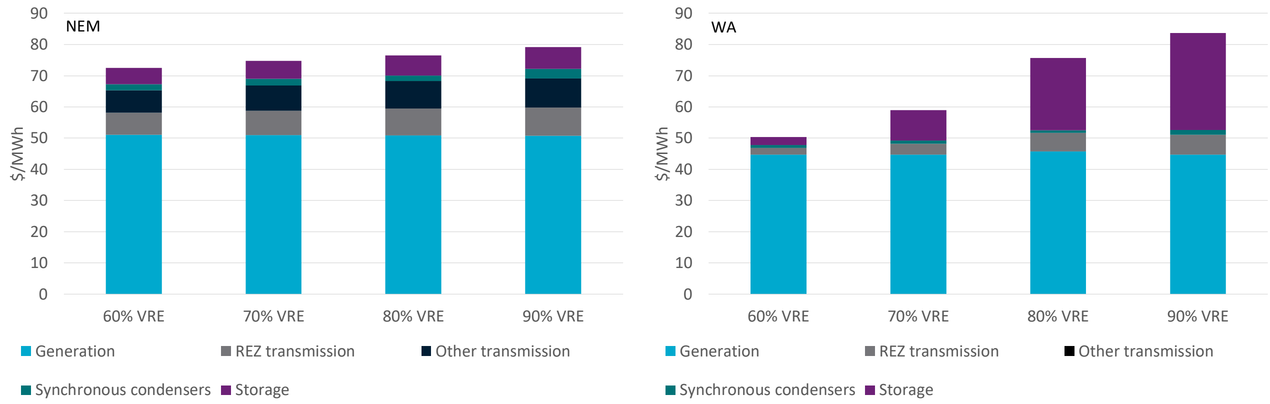

Figure 5-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in NEM and WA in 2030

REZ expansion costs appear to be required at similar levels for each additional 10% increase in VRE share and in each state. Other transmission costs have a rising trend in the NEM. The highest other transmission expenditure is in New South Wales and Victoria reflecting their central positions in the NEM and access to pumped hydro storage.

[25] 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

The SWIS and other WA systems are unable to use other transmission expenditure to significantly diversify renewable generation sources to reduce storage needs. WA therefore has relatively higher expenditure on storage offset by lower transmission costs. Queensland and Victoria have the next greatest storage needs reflecting less developed storage in the BAU compared to New South Wales. Queensland has recently announced some major pumped hydro projects to be completed by 2035[26], which is after the analysis period here.

Additional expenditure on synchronous condenser capacity is required in most states and increases moderately with VRE share. Higher VRE share leads to the retirement of fossil fuel-based capacity that otherwise supplies most of system inertia.

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 around $6/MWh to $8/MWh, as the VRE share increases from 60% to 90%. Synchronous condensers costs are low at between $1.7/MWh to $2.3/MWh increasing moderately with VRE share. Other transmission adds $5 to $6/MWh with costs accelerating with VRE share. Storage adds $9 to $14/MWh.

5.1.2 Variable renewables with and without integration costs

The results for the additional costs for increasing variable renewable shares are used to update and extend our LCOE estimates. We expand the results for 2030 to include a combined wind and solar PV category for different VRE shares. Integration costs to support renewables are estimated at $25 to $34/MWh depending on the VRE share (Figure 5-4).

Onshore wind and solar PV without transmission or storage costs are the lowest cost generation technology by a significant margin. Offshore wind is higher cost but competitive with other alternative low emission generation technologies and its higher capacity factor could result in lower integration costs. Integration costs have only been calculated for onshore wind in this report given it remains the lowest cost form of wind generation.

The additional integration costs associated with increasing variable renewable generation from onshore wind and solar PV are presented for 2030. The analysis confirms that when integration costs are included variable renewables remain the lowest cost new-build technology. The next lowest cost flexible technology in 2030 is gas generation but only if it could be financed at a rate that does not include climate policy risk. Of the low emissions flexible technologies, gas with carbon capture and storage is the next most competitive.

5.1.3 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.

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[26] https://media.epw.qld.gov.au/files/Queensland_Energy_and_Jobs_Plan.pdf

Hydrogen reciprocating engines 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 a low emission option for provide peaking services.

5.1.4 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 (around 50% to 90%) of the year. They are the next most competitive generation technologies after variable renewables (with or without integration costs). The large reduction in fossil fuel generation costs between 2022 and the remaining years is not as a result of technological improvement. It represents a reduction in fuel prices from their current historical highs.

Of the fossil fuel technologies, it 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.

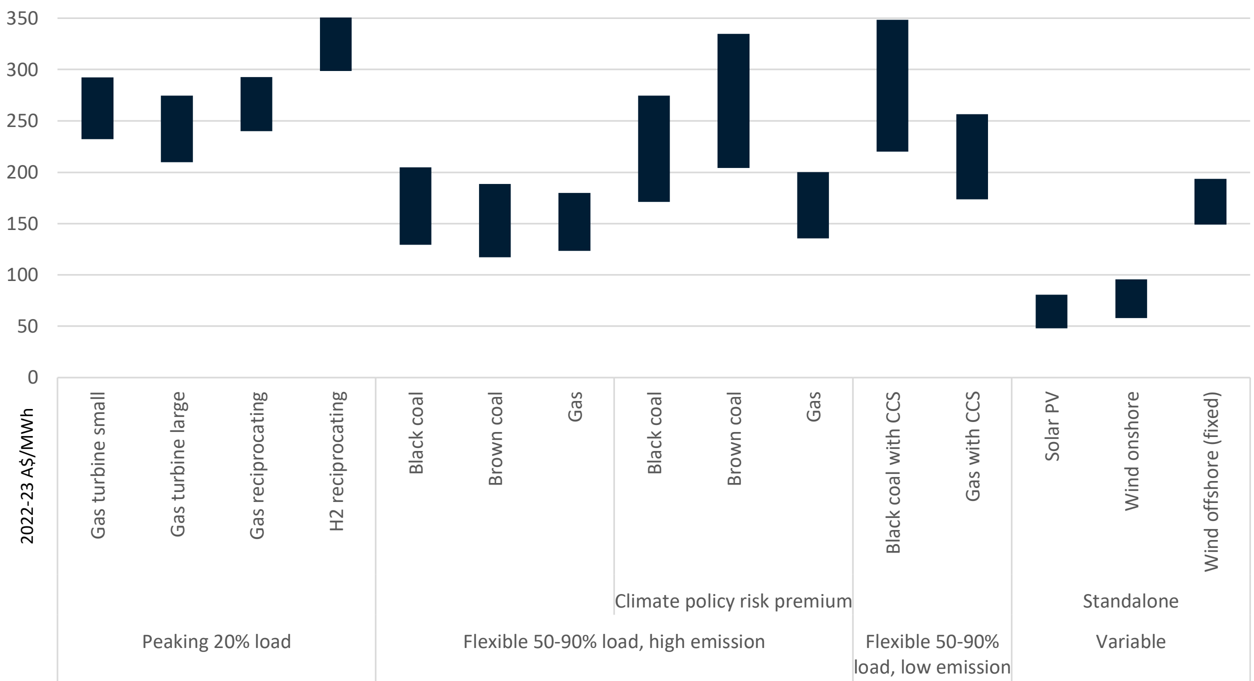


Figure 5-3 Calculated LCOE by technology and category for 2022

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[27]. Natural gas-based generation is less impacted by the risk premium because of its lower emission fuel, higher thermal efficiency (in combined cycle configuration only) and lower capital cost.

[27] 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.

We do not include a risk premium for low emission flexible technologies. Gas with CCS and small modular reactor (SMR) nuclear are the next most competitive. Achieving the lower end of the nuclear SMR range requires that SMR is deployed globally in large enough capacity to bring down costs available to Australia. Lowest cost gas with CCS is subject to accessing gas supply at the lower end of the range assumed (see Appendix B for assumptions). Both technology would also have to be successful in operating at 89% capacity factor to achieve the lower end of the cost range.

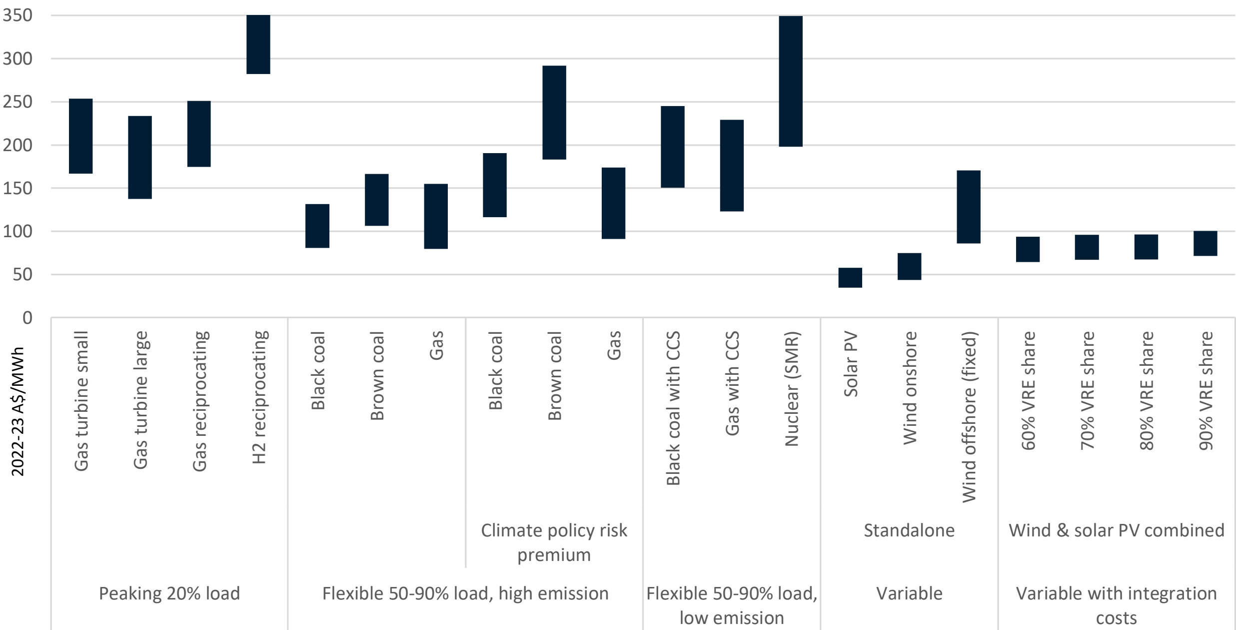


Figure 5-4 Calculated LCOE by technology and category for 2030

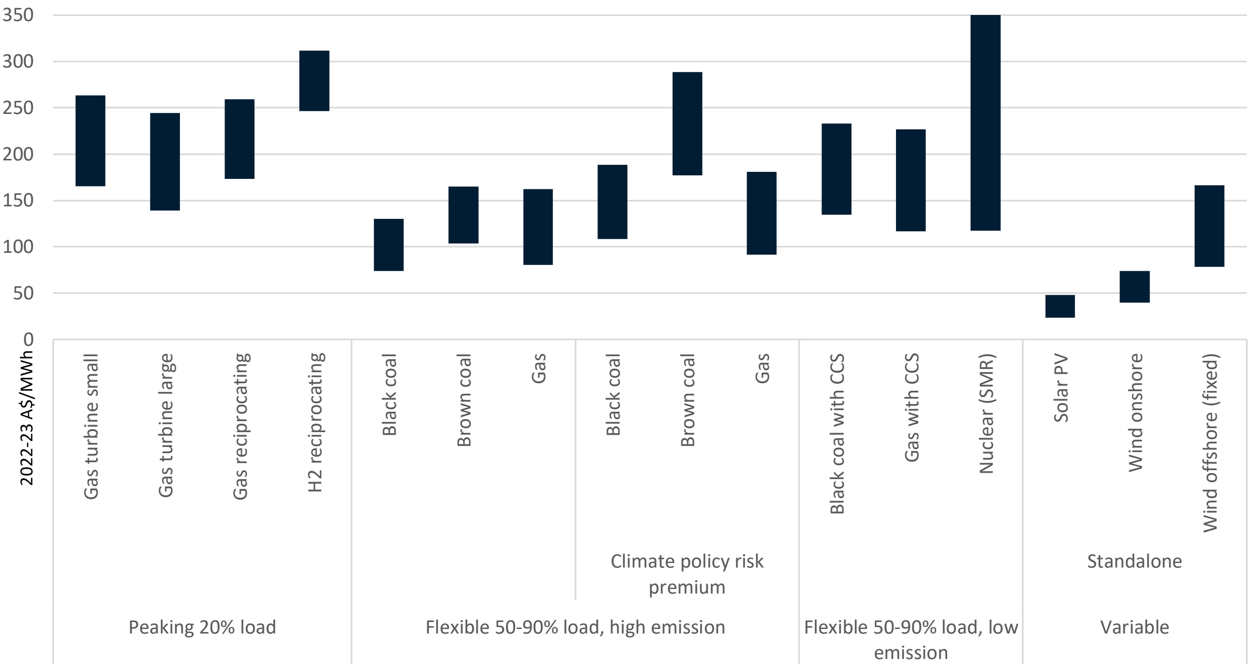


Figure 5-5 Calculated LCOE by technology and category for 2040

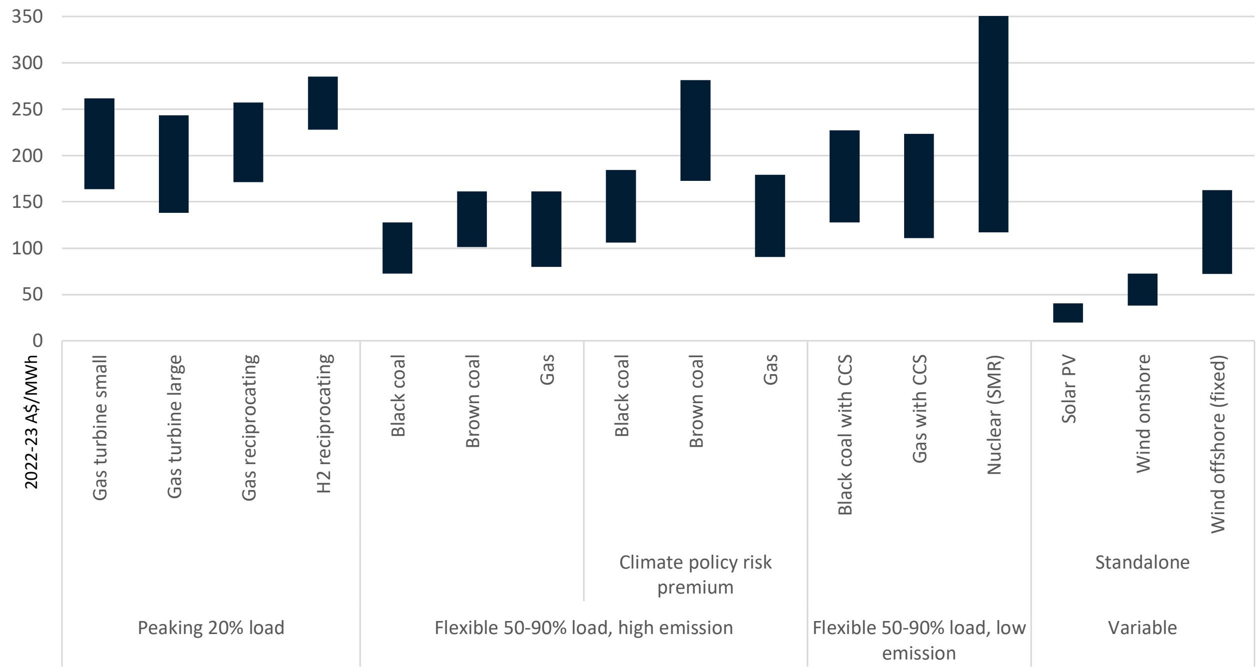


Figure 5-6 Calculated LCOE by technology and category for 2050

5.2 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 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 something else 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 generator, the system needs to install around 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 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 per 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.

The first is that we are very rarely building a completely new electricity system (except in new off grid areas). Existing electricity systems will have existing peaking and flexible generation. This reduces the amount of new capacity that needs to be built. This is as 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.

The second factor is that, 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 system 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.

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 0.26kW to 0.39kW storage capacity for each kW of variable renewable generation installed[28]. Showing the most extreme case of 90% variable renewable share for the NEM, Figure 5-7 show the 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[29] 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.

[28] This is higher than the ratio calculated in GenCost 2021-22. However, as discussed in Section 5.11, this likely reflects the updated modelling selecting a higher ratio of storage to avoid higher transmission costs since these two resource types are partially substitutable.

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

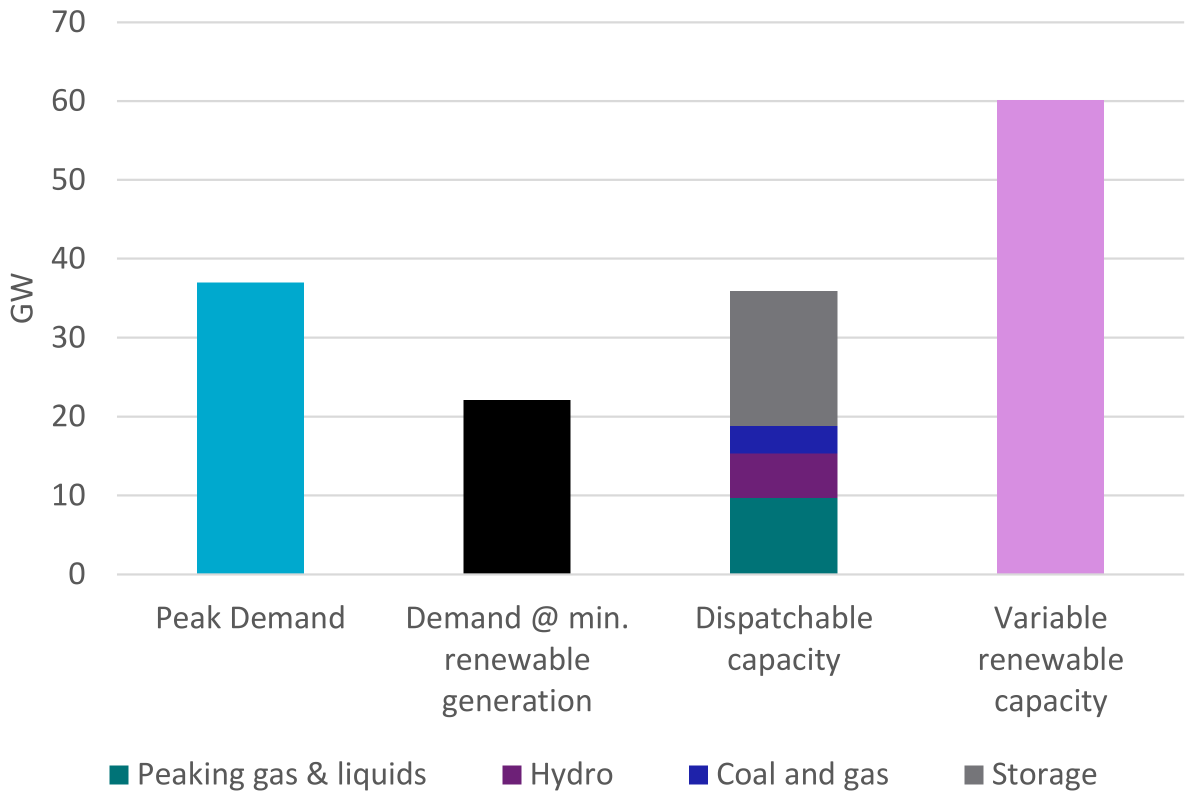


Figure 5-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

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 existing 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:

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

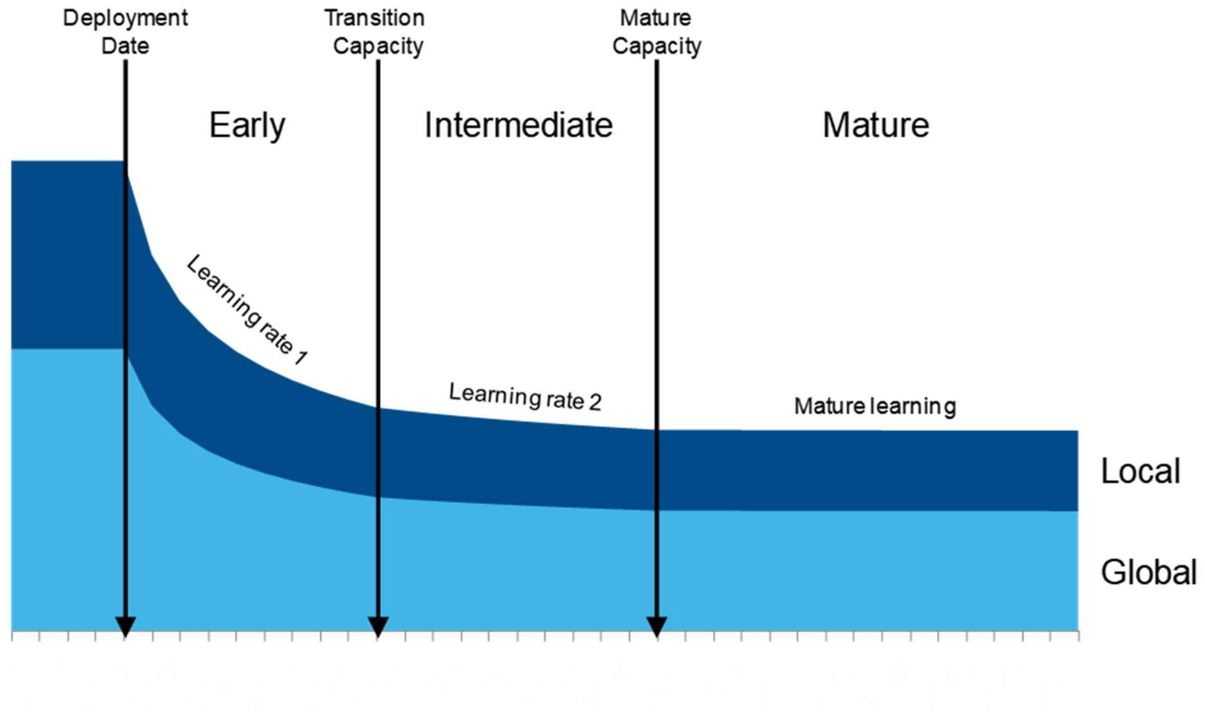
or equivalently $\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$

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 says 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% (Schrattenholzer and McDonald, 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 2050.

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 (Bureau of Resource and Energy Economics (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 (2023) 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 2022 is mostly sourced from Aurecon (2023) and is aligned to the middle of that calendar year or the beginning of the 2022-23 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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	6525	2642	5682	7872	11662	-	8663	9787
2023	4964	10513	7745	1706	1593	1002	4340	1759	2140	8666	21121	1516	1400	6478	2644	5480	7591	10987	-	8158	8612
2024	4890	10380	7609	1699	1540	963	4331	1759	2133	8496	20802	1407	1307	6339	2519	5288	7154	10869	-	8058	7979
2025	4825	10265	7487	1694	1490	926	4329	1762	2129	8340	20517	1301	1223	6202	2398	5103	6737	10756	-	7959	7389
2026	4761	10153	7368	1690	1442	888	4328	1765	2126	8189	20241	1197	1150	6050	2284	4924	6344	10645	-	7862	6844
2027	4673	9926	7219	1671	1397	847	4307	1750	2112	7898	19710	1141	1092	5911	2152	4834	6008	10447	-	7717	6404
2028	4608	9744	7112	1654	1369	806	4290	1735	2101	7671	19284	1103	1042	5789	2056	4799	5790	10291	-	7605	6117
2029	4566	9606	7048	1639	1356	805	4279	1719	2091	7506	18960	1091	1009	5669	1996	4818	5685	10176	-	7524	5672
2030	4558	9597	7035	1636	1354	803	4279	1716	2087	7519	18934	1058	977	5562	1989	4803	5657	10180	18167	7524	5271
2031	4550	9588	7023	1633	1351	802	4279	1713	2084	7532	18909	1038	956	5465	1983	4789	5643	10184	18199	7524	4864
2032	4542	9579	7011	1630	1349	800	4280	1710	2080	7545	18884	1022	939	5376	1978	4774	5641	10189	18231	7524	4721
2033	4535	9571	6999	1628	1347	799	4280	1707	2077	7558	18860	1010	926	5294	1974	4759	5631	10193	18264	7524	4565
2034	4527	9563	6987	1625	1345	798	4281	1704	2073	7572	18836	999	913	5218	1972	4745	5600	10198	18297	7514	4386
2035	4520	9428	6976	1622	1342	796	4156	1701	2070	7586	18685	984	897	5147	1969	4730	5567	10202	18331	7503	4242
2036	4512	9274	6964	1620	1340	795	4014	1699	2066	7601	18516	971	884	5080	1967	4716	5544	10207	18365	7492	4065
2037	4505	9101	6953	1617	1338	794	3851	1696	2063	7615	18327	947	861	5016	1964	4702	5543	10212	18401	7492	3894
2038	4498	9035	6942	1614	1336	793	3794	1693	2060	7630	18246	922	837	4956	1962	4688	5546	10217	18436	7492	3711
2039	4491	8963	6932	1612	1334	791	3731	1691	2057	7645	18160	876	797	4898	1960	4673	5548	10222	18473	7487	3576
2040	4484	8896	6921	1610	1332	790	3673	1688	2054	7660	18079	839	764	4826	1959	4659	5550	10227	18510	7482	3491
2041	4471	8827	6901	1605	1328	788	3620	1683	2048	7665	17983	791	723	4740	1956	4644	5549	10228	18520	7477	3437
2042	4458	8781	6881	1600	1324	786	3589	1678	2042	7669	17910	759	695	4642	1953	4628	5548	10230	18531	7477	3414
2043	4445	8744	6861	1596	1320	783	3567	1673	2036	7674	17846	724	665	4550	1949	4613	5547	10232	18543	7473	3405
2044	4432	8713	6841	1591	1316	781	3551	1669	2030	7679	17789	706	649	4464	1945	4597	5545	10233	18554	7469	3407
2045	4419	8682	6821	1586	1313	779	3535	1664	2024	7683	17731	695	639	4383	1940	4582	5543	10235	18565	7464	3409
2046	4407	8657	6801	1582	1309	776	3525	1659	2018	7688	17680	691	634	4306	1937	4566	5541	10236	18576	7464	3409
2047	4394	8633	6782	1577	1305	774	3516	1654	2012	7692	17630	687	630	4233	1933	4551	5540	10238	18587	7463	3405
2048	4381	8609	6762	1573	1301	772	3507	1649	2006	7697	17580	683	626	4164	1931	4536	5541	10239	18599	7463	3399
2049	4369	8582	6743	1568	1297	770	3495	1645	2001	7702	17527	679	622	4099	1928	4521	5541	10241	18610	7457	3394
2050	4361	8566	6731	1565	1295	768	3488	1642	1997	7707	17496	676	619	4051	1927	4511	5541	10242	18622	7451	3391
2051	4346	8534	6707	1560	1291	768	3473	1636	1990	7707	17432	674	616	4002	1925	4495	5540	10242	18622	7445	3383
2052	4336	8513	6692	1556	1288	762	3464	1632	1985	7707	17391	672	615	3955	1924	4485	5540	10242	18622	7444	3379
2053	4315	8474	6661	1549	1282	762	3448	1624	1976	7707	17310	669	612	3908	1922	4464	5538	10242	18622	7443	3369
2054	4305	8455	6645	1545	1279	757	3441	1621	1972	7707	17271	667	610	3862	1921	4453	5538	10242	18622	7443	3364
2055	4295	8436	6629	1542	1276	757	3434	1617	1967	7707	17231	666	609	3816	1920	4443	5537	10242	18622	7443	3359

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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	6525	2642	5682	7872	11662	-	8663	9787
2023	4964	10513	7745	1706	1593	1002	4329	1759	2140	8666	21121	1516	1400	6368	2644	4888	6771	10987	-	8158	8612
2024	4928	10380	7677	1704	1564	978	4323	1761	2133	8496	20802	1424	1313	6156	2521	4498	6107	10869	-	8065	7914
2025	4900	10265	7620	1705	1538	955	4324	1766	2129	8340	20517	1348	1241	5901	2403	4131	5488	10756	-	7972	7264
2026	4872	10153	7567	1706	1513	932	4325	1772	2126	8189	20241	1287	1184	5667	2290	3793	4933	10645	-	7881	6670
2027	4830	10011	7489	1702	1483	906	4314	1772	2116	8015	19905	1227	1129	5487	2181	3481	4430	10527	-	7790	6103
2028	4788	9871	7413	1697	1454	880	4302	1772	2107	7845	19576	1169	1077	5314	2077	3194	3979	10410	-	7701	5585
2029	4747	9733	7338	1693	1426	854	4290	1772	2097	7680	19253	1114	1028	5116	1978	2931	3574	10294	-	7612	5111
2030	4668	9639	7208	1672	1392	828	4283	1752	2089	7571	19031	1071	988	4917	1913	2755	3313	10219	10939	7554	4792
2031	4600	9588	7099	1651	1366	802	4279	1732	2084	7522	18909	1034	954	4746	1880	2662	3185	8850	9733	7524	4618
2032	4542	9579	7011	1630	1349	800	4280	1710	2080	7492	18884	1014	933	4620	1879	2646	3176	7665	8523	7524	4577
2033	4535	9571	6999	1628	1347	799	4280	1707	2077	7443	18860	989	908	4501	1866	2636	3172	6638	7309	7524	4528
2034	4527	9563	6987	1625	1345	798	4281	1704	2073	7352	18836	968	887	4401	1840	2627	3083	5749	7306	7524	4454
2035	4520	9294	6976	1622	1342	796	4025	1701	2070	7274	18551	923	846	4298	1807	2619	2993	4979	7317	7524	4362
2036	4512	9023	6964	1620	1340	795	3766	1699	2066	7219	18263	865	795	4211	1779	2611	2904	4312	7329	7504	4272
2037	4505	8750	6953	1617	1338	794	3506	1696	2063	7206	17974	795	734	4123	1759	2604	2903	3734	7342	7481	4199
2038	4498	8740	6942	1614	1336	793	3503	1693	2060	7220	17949	736	683	4041	1744	2598	2902	3234	7357	7458	4135
2039	4491	8731	6932	1612	1334	791	3502	1691	2057	7234	17926	690	642	3938	1731	2593	2901	2801	7371	7455	4077
2040	4484	8722	6921	1610	1332	790	3502	1688	2054	7248	17904	653	610	3835	1720	2589	2902	2426	7386	7455	4030
2041	4471	8702	6901	1605	1328	788	3496	1683	2048	7253	17857	623	584	3720	1709	2584	2901	2100	7390	7455	3987
2042	4458	8540	6881	1600	1324	786	3351	1678	2042	7257	17667	598	562	3622	1700	2579	2900	1819	7395	7399	3961
2043	4445	8376	6861	1596	1320	783	3204	1673	2036	7261	17476	578	544	3520	1693	2574	2900	1575	7399	7328	3944
2044	4432	8209	6841	1591	1316	781	3055	1669	2030	7266	17282	561	529	3439	1687	2569	2899	1575	7403	6968	3934
2045	4419	8183	6821	1586	1313	779	3044	1664	2024	7270	17229	549	518	3362	1680	2564	2899	1575	7408	6656	3924
2046	4407	8159	6801	1582	1309	776	3034	1659	2018	7274	17179	539	509	3300	1672	2560	2898	1572	7412	6359	3915
2047	4394	8137	6782	1577	1305	774	3027	1654	2012	7279	17131	530	500	3241	1664	2555	2753	1560	7417	6351	3906
2048	4381	8116	6762	1573	1301	772	3021	1649	2006	7283	17084	521	492	3186	1656	2549	2560	1544	7421	6351	3892
2049	4369	8095	6743	1568	1297	770	3015	1645	2001	7288	17038	515	486	3132	1648	2543	2348	1528	7426	6220	3872
2050	4361	8083	6731	1565	1295	768	3012	1642	1997	7292	17010	513	483	3087	1642	2539	2280	1521	7431	6090	3855
2051	4346	8058	6707	1560	1291	768	3004	1636	1990	7292	16954	511	481	3043	1638	2533	2250	1517	7431	5960	3832
2052	4336	8042	6692	1556	1288	762	3000	1632	1985	7292	16917	510	480	2999	1637	2530	2240	1515	7431	5960	3818
2053	4315	8009	6661	1549	1282	762	2990	1624	1976	7292	16842	507	478	2956	1635	2524	2223	1511	7431	5960	3792
2054	4305	7992	6645	1545	1279	757	2985	1621	1972	7292	16805	506	477	2913	1634	2520	2216	1510	7431	5960	3780
2055	4295	7976	6629	1542	1276	757	2981	1617	1967	7292	16768	505	475	2871	1633	2517	2209	1508	7431	5960	3768

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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	6525	2642	5682	7872	11662	-	8663	9787
2023	4964	10513	7745	1706	1593	1002	4340	1759	2140	8666	21121	1516	1400	6368	2644	5480	7591	10987	-	8158	8612
2024	4890	10380	7609	1699	1540	963	4331	1759	2133	8496	20802	1424	1312	6156	2519	5288	7154	10869	-	8058	7979
2025	4825	10265	7487	1694	1490	926	4329	1762	2129	8340	20517	1348	1238	5901	2398	5103	6737	10756	-	7959	7389
2026	4761	10153	7368	1690	1442	888	4328	1765	2126	8189	20241	1287	1179	5667	2284	4924	6344	10645	-	7862	6844
2027	4744	10011	7336	1690	1429	877	4315	1766	2116	8015	19905	1227	1122	5487	2173	4756	5979	10527	-	7765	6317
2028	4739	9871	7326	1691	1423	865	4302	1769	2107	7845	19576	1169	1068	5360	2067	4600	5643	10410	-	7670	5831
2029	4747	9733	7338	1693	1426	854	4290	1772	2097	7679	19253	1114	1017	5255	1967	4457	5336	10294	-	7576	5383
2030	4668	9639	7208	1672	1392	828	4283	1752	2089	7574	19031	1071	976	5124	1900	4352	5128	10219	14586	7513	5058
2031	4600	9588	7099	1651	1366	802	4279	1732	2084	7529	18909	1034	942	4968	1864	4284	5017	10184	13418	7482	4838
2032	4542	9579	7011	1630	1349	800	4280	1710	2080	7536	18884	1014	922	4800	1859	4243	4986	10189	12344	7482	4688
2033	4535	9571	6999	1628	1347	799	4280	1707	2077	7542	18860	989	899	4653	1852	4194	4950	10193	11356	7482	4534
2034	4527	9563	6987	1625	1345	798	4281	1704	2073	7528	18836	968	879	4529	1846	4150	4869	10198	10448	7482	4360
2035	4520	9318	6976	1622	1342	796	4049	1701	2070	7515	18575	923	836	4429	1841	4115	4795	10202	9612	7482	4222
2036	4512	9059	6964	1620	1340	795	3802	1699	2066	7504	18299	865	783	4353	1837	4099	4737	10207	8844	7481	4053
2037	4505	8793	6953	1617	1338	794	3548	1696	2063	7514	18017	795	718	4283	1833	4071	4717	10212	8137	7480	3894
2038	4498	8764	6942	1614	1336	793	3527	1693	2060	7529	17974	740	668	4223	1828	4051	4704	10217	7487	7479	3728
2039	4491	8749	6932	1612	1334	791	3521	1691	2057	7536	17945	706	636	4158	1822	4017	4680	9768	7474	7479	3609
2040	4484	8739	6921	1610	1332	790	3518	1688	2054	7532	17921	687	618	4105	1817	3988	4660	9340	7472	7479	3532
2041	4471	8717	6901	1605	1328	788	3511	1683	2048	7518	17872	676	608	4043	1812	3950	4631	8927	7465	7479	3479
2042	4458	8695	6881	1600	1324	786	3504	1678	2042	7512	17823	663	597	3979	1806	3922	4611	8532	7467	7476	3451
2043	4445	8673	6861	1596	1320	783	3497	1673	2036	7516	17775	652	586	3911	1802	3895	4592	8155	7464	7472	3431
2044	4432	8650	6841	1591	1316	781	3489	1669	2030	7521	17725	639	574	3849	1799	3872	4577	7794	7464	7468	3419
2045	4419	8598	6821	1586	1313	779	3453	1664	2024	7525	17647	625	562	3794	1796	3847	4558	7449	7463	7455	3408
2046	4407	8531	6801	1582	1309	776	3402	1659	2018	7530	17554	613	550	3728	1795	3824	4542	7120	7468	7443	3399
2047	4394	8379	6782	1577	1305	774	3266	1654	2012	7534	17375	604	542	3653	1793	3801	4527	6805	7472	7430	3389
2048	4381	8255	6762	1573	1301	772	3159	1649	2006	7538	17224	596	535	3565	1792	3781	4513	6504	7477	7430	3374
2049	4369	8134	6743	1568	1297	770	3053	1645	2001	7543	17077	591	529	3480	1789	3762	4501	6217	7481	7296	3339
2050	4361	8109	6731	1565	1295	768	3037	1642	1997	7547	17036	586	525	3419	1787	3751	4493	5942	7486	7163	3308
2051	4346	8071	6707	1560	1291	768	3017	1636	1990	7547	16966	581	521	3360	1785	3728	4477	5942	7486	7029	3283
2052	4336	8054	6692	1556	1288	762	3012	1632	1985	7547	16929	578	518	3301	1784	3711	4465	5942	7486	7029	3280
2053	4315	8021	6661	1549	1282	762	3002	1624	1976	7547	16854	571	512	3243	1783	3679	4442	5942	7486	7009	3275
2054	4305	8004	6645	1545	1279	757	2997	1621	1972	7547	16817	566	507	3187	1783	3664	4431	5942	7486	6989	3272
2055	4295	7987	6629	1542	1276	757	2992	1617	1967	7547	16780	562	503	3131	1782	3648	4420	5942	7486	6969	3269

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
2022	931	931	931	431	431	431	500	500	500	673	673	673	418	418	418	255	255	255
2023	936	936	936	440	440	440	496	496	496	677	677	677	427	427	427	250	250	250
2024	882	882	882	413	413	413	469	469	469	637	622	602	400	377	356	237	246	246
2025	835	835	835	388	388	388	447	447	447	602	575	539	376	333	297	227	242	242
2026	793	793	793	362	362	362	431	431	431	572	532	487	350	294	248	222	238	239
2027	799	743	726	373	319	302	426	424	425	556	494	442	337	260	207	219	234	235
2028	780	699	669	359	282	252	422	417	418	541	459	404	324	229	172	217	230	231
2029	761	659	621	344	249	210	417	410	411	525	428	371	311	202	144	214	226	228
2030	742	623	580	330	220	175	412	403	405	510	401	344	298	179	120	212	222	224
2031	723	592	526	316	196	128	407	396	399	494	377	308	285	159	87	209	218	220
2032	704	581	519	301	191	127	403	389	392	479	370	303	272	155	87	207	214	217
2033	685	571	512	287	188	126	398	383	386	463	363	299	259	153	86	204	211	213
2034	666	561	505	272	184	124	394	376	380	448	356	295	246	149	85	202	207	210
2035	647	551	498	258	181	124	389	370	374	432	350	291	232	147	84	200	204	207
2036	628	541	491	243	177	122	385	364	368	417	344	287	219	144	84	197	200	203
2037	610	533	484	229	175	122	381	358	363	401	338	283	206	142	83	195	197	200
2038	599	524	478	223	172	121	377	352	357	393	332	279	200	139	82	193	193	197
2039	590	515	471	218	169	120	372	346	352	387	327	276	196	137	82	191	190	194
2040	581	507	465	213	167	119	368	340	346	380	322	272	191	135	81	189	187	191
2041	572	499	459	209	165	118	364	334	340	374	317	268	188	133	81	186	183	188
2042	566	493	453	207	164	118	359	328	335	370	313	265	186	133	81	184	180	184
2043	560	486	448	205	164	118	355	323	329	366	310	262	184	132	81	182	177	181
2044	550	479	442	200	162	118	351	317	324	359	305	259	180	131	80	180	174	178
2045	543	473	436	196	161	117	347	311	319	354	301	255	176	130	80	177	171	176
2046	536	466	430	193	160	117	342	306	313	349	297	252	174	130	80	175	168	173
2047	530	460	425	191	159	117	338	301	308	345	294	249	172	129	79	173	165	170
2048	524	454	420	190	159	116	334	295	303	342	290	246	171	128	79	171	162	167
2049	519	448	415	188	158	116	330	290	298	338	287	243	169	128	79	169	159	164
2050	514	443	410	187	158	116	326	285	293	335	284	241	169	128	79	167	156	162
2051	512	437	405	187	157	116	326	280	289	334	281	238	168	127	79	167	153	159
2052	512	432	400	187	157	116	325	275	284	334	278	235	168	127	79	166	151	156
2053	510	427	395	185	157	116	324	270	279	332	275	232	167	127	79	166	148	154
2054	509	422	390	185	157	116	324	265	274	332	272	230	167	127	79	166	145	151
2055	507	421	390	184	156	116	323	265	274	331	272	230	166	126	79	165	145	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
2022	546	546	546	411	411	411	135	135	135	485	485	485	404	404	404	81	81	81
2023	549	549	549	419	419	419	130	130	130	488	488	488	412	412	412	75	75	75
2024	517	498	477	393	370	350	123	127	128	459	438	418	386	364	343	72	74	74
2025	488	452	417	369	327	292	120	125	126	433	394	359	362	321	286	71	73	73
2026	463	412	367	343	289	243	120	123	124	411	355	310	337	283	239	74	72	72
2027	449	376	324	330	255	203	118	121	122	403	320	269	330	250	199	73	70	71
2028	440	347	291	323	228	172	117	119	120	394	297	241	322	228	171	72	69	69
2029	426	318	261	310	202	143	116	117	118	380	269	211	309	201	143	71	68	68
2030	411	293	235	297	178	119	114	115	116	366	244	186	296	177	119	70	67	67
2031	397	271	201	284	158	87	113	113	114	352	223	153	283	158	87	69	65	66
2032	382	265	198	271	155	86	112	111	112	338	218	151	270	154	86	69	64	65
2033	368	261	196	257	152	85	110	109	110	324	214	149	257	151	85	68	63	64
2034	353	256	193	244	149	85	109	107	108	310	210	147	243	148	84	67	62	63
2035	339	251	191	231	146	84	108	105	107	296	206	145	230	145	84	66	61	62
2036	324	246	188	218	143	83	106	103	105	282	202	144	217	142	83	65	60	61
2037	310	242	186	205	141	83	105	102	103	269	199	142	204	140	82	65	59	60
2038	303	238	183	199	138	82	104	100	102	262	195	140	198	138	81	64	58	59
2039	297	234	181	195	136	81	103	98	100	257	192	139	194	136	81	63	57	58
2040	291	230	179	190	134	81	101	96	98	251	189	137	189	133	80	62	56	57
2041	287	227	177	186	132	80	100	95	97	247	187	136	185	132	80	61	55	56
2042	283	225	175	185	132	80	99	93	95	244	185	135	184	131	80	61	54	55
2043	281	223	173	183	131	80	98	91	94	242	184	134	182	131	80	60	53	54
2044	275	220	172	178	130	80	97	90	92	237	181	132	177	130	79	59	52	53
2045	270	217	170	175	129	79	95	88	90	233	180	131	174	129	79	59	51	52
2046	267	215	168	172	129	79	94	86	89	229	178	130	172	128	79	58	50	51
2047	264	213	166	171	128	79	93	85	87	227	176	129	170	127	78	57	49	51
2048	261	211	165	169	127	79	92	83	86	225	175	128	168	127	78	56	48	50
2049	259	209	163	168	127	79	91	82	85	223	174	127	167	126	78	56	47	49
2050	257	207	162	167	127	78	90	80	83	221	172	126	166	126	78	55	47	48
2051	256	205	160	166	126	78	89	79	82	220	171	125	165	126	78	55	46	47
2052	256	204	159	166	126	78	89	78	80	220	170	124	165	126	78	55	45	47
2053	254	202	157	165	126	78	89	76	79	219	169	124	164	125	78	55	44	46
2054	254	201	156	165	126	78	89	75	78	219	168	123	164	125	78	55	43	45
2055	253	200	156	164	125	78	89	75	78	218	168	123	163	125	78	54	43	45

Apx Table B.6 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
2022	2888	3138	3369	4404	2730	6616	3043	411	335	240	157	97	118	55
2023	2832	3077	3304	4319	2678	6488	2984	481	392	281	183	114	138	64
2024	2777	3018	3240	4235	2625	6361	2926	472	385	275	180	112	135	63
2025	2723	2959	3177	4152	2574	6238	2869	463	377	270	176	109	133	62
2026	2669	2900	3114	4070	2524	6114	2813	454	370	265	173	107	130	60
2027	2612	2839	3048	3984	2470	5985	2753	445	363	259	170	105	127	59
2028	2556	2778	2982	3898	2417	5856	2694	435	355	254	166	103	125	58
2029	2500	2716	2916	3812	2363	5726	2634	426	347	249	162	101	122	57
2030	2443	2655	2850	3726	2310	5597	2574	417	340	243	159	98	119	55
2031	2440	2652	2847	3721	2307	5590	2571	407	332	238	155	96	117	54
2032	2437	2648	2843	3717	2304	5583	2568	407	331	237	155	96	116	54
2033	2434	2645	2840	3712	2302	5577	2565	406	331	237	155	96	116	54
2034	2431	2642	2837	3708	2299	5570	2562	406	331	237	155	96	116	54
2035	2429	2639	2833	3704	2296	5564	2559	405	330	236	155	96	116	54
2036	2426	2636	2830	3699	2294	5557	2556	405	330	236	154	96	116	54
2037	2423	2633	2827	3695	2291	5551	2553	404	330	236	154	96	116	54
2038	2420	2630	2824	3691	2288	5545	2551	404	329	236	154	95	116	54
2039	2418	2627	2821	3687	2286	5539	2548	403	329	235	154	95	116	54
2040	2415	2624	2817	3683	2283	5532	2545	403	328	235	154	95	115	54
2041	2411	2620	2813	3677	2280	5524	2541	402	328	235	153	95	115	54
2042	2408	2616	2809	3672	2276	5516	2537	402	328	234	153	95	115	53
2043	2404	2612	2805	3666	2273	5507	2533	401	327	234	153	95	115	53
2044	2400	2608	2800	3660	2269	5499	2529	401	327	234	153	95	115	53
2045	2397	2604	2796	3655	2266	5490	2526	400	326	233	153	95	115	53
2046	2393	2600	2792	3649	2263	5482	2522	399	326	233	152	94	114	53
2047	2389	2596	2787	3644	2259	5474	2518	399	325	233	152	94	114	53
2048	2386	2592	2783	3638	2256	5465	2514	398	325	232	152	94	114	53
2049	2382	2589	2779	3633	2252	5457	2510	398	324	232	152	94	114	53
2050	2378	2585	2775	3627	2249	5449	2506	397	324	232	151	94	114	53
2051	2374	2580	2770	3621	2245	5440	2502	396	323	231	151	94	114	53
2052	2370	2576	2765	3615	2241	5430	2498	396	323	231	151	94	113	53
2053	2366	2571	2761	3609	2237	5421	2494	395	322	230	151	93	113	53
2054	2362	2567	2756	3602	2234	5412	2489	394	321	230	150	93	113	52
2055	2358	2563	2751	3596	2230	5402	2485	394	321	230	150	93	113	52

Apx Table B.7 Storage current cost data by source, total cost basis

	$/kWh								$/kW							
	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Fichtner Engineering 2023	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Fichtner Engineering 2023
Battery (1hr)	1092	870	823	931	-	-	-	-	1092	870	823	931	-	-	-	-
Battery (2hrs)	687	583	547	673	-	-	-	-	1375	1166	1095	1346	-	-	-	-
Battery (4hrs)	543	464	432	546	-	-	-	-	2171	1854	1729	2185	-	-	-	-
Battery (8hrs)	492	409	379	485	-	-	-	-	3939	3271	3035	3882	-	-	-	-
PHES (8hrs)	-	-	-	-	275	315	392	-	-	-	-	-	2203	2520	3138	-
A-CAES (12hrs)	-	-	-	350	-	-	-	-	-	-	-	4203	-	-	-	-
PHES (12hrs)	-	-	-	-	195	226	281	-	-	-	-	-	2341	2711	3369	-
CST (15hrs)	-	-	-	-	-	-	-	435	-	-	-	-	-	-	-	6525
PHES (24hrs)	-	-	-	-	145	147	183	-	-	-	-	-	3469	3537	4404	-
PHES (24hrs) Tasmania	-	-	-	-	-	91	114	-	-	-	-	-	-	2185	2730	-
PHES (48hrs)	-	-	-	-	81	111	138	-	-	-	-	-	3887	5313	6616	-
PHES (48hrs) Tasmania	-	-	-	-	-	51	64	-	-	-	-	-	-	2468	3043	-

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1600/kWh (Aurecon, 2023).

Apx Table B.8 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
	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
2022												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4354	14.0	89%	4354	20.0	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1766	14.0	89%	1766	20.0	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1499	14.0	20%	1499	20.0	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	943	14.0	20%	943	20.0	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	2004	14.0	20%	2004	20.0	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2438	14.6	20%	2438	21.9	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	11040	6.9	89%	11040	10.5	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	5398	6.9	89%	5398	10.5	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8180	0.6	89%	8180	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7825	0.5	89%	7825	2.0	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1572	0.0	32%	1572	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	2642	0.0	48%	2642	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	5682	0.0	52%	5682	0.0	40%
2030												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4283	8.0	89%	4279	16.8	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1672	8.0	89%	1636	16.8	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1392	8.0	20%	1354	16.8	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	803	8.0	20%	803	16.8	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1752	8.0	20%	1716	16.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2089	14.6	20%	2087	21.9	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	9639	2.3	89%	9597	4.0	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4668	2.3	89%	4558	4.0	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7208	0.7	89%	7035	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7571	0.5	89%	7519	2.0	53%
Nuclear (SMR)	30	3.0	35%	200.0	5.3	0.0	14586	0.5	89%	18167	0.7	60%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1071	0.0	32%	1058	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1913	0.0	48%	1989	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2755	0.0	54%	4803	0.0	40%

2040												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3518	8.2	89%	3673	17.9	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1610	8.2	89%	1610	17.9	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1332	8.2	20%	1332	17.9	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	790	8.2	20%	790	17.9	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1688	8.2	20%	1688	17.9	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2054	11.6	20%	2054	17.4	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8739	1.8	89%	8896	4.0	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4484	1.8	89%	4484	4.0	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6921	0.7	89%	6921	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7248	0.5	89%	7660	2.0	53%
Nuclear (SMR)	30	3.0	40%	200.0	5.3	0.0	7386	0.5	89%	18510	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	653	0.0	32%	839	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1720	0.0	48%	1959	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2589	0.0	57%	4659	0.0	40%
2050												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3012	8.2	89%	3488	17.9	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1565	8.2	89%	1565	17.9	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1295	8.2	20%	1295	17.9	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	768	8.2	20%	768	17.9	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1642	8.2	20%	1642	17.9	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	1997	10.2	20%	1997	15.3	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8083	1.8	89%	8566	4.0	53%
Black coal	30	2.0	40%	53.2	4.2	0.0	4361	1.8	89%	4361	4.0	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6731	0.7	89%	6731	0.7	53%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7292	0.5	89%	7707	2.0	53%
Nuclear (SMR)	30	3.0	45%	200.0	5.3	0.0	7431	0.5	89%	18622	0.7	53%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	513	0.0	32%	676	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1642	0.0	48%	1927	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2539	0.0	61%	4511	0.0	40%

Notes: Large-scale solar PV is single axis tracking. The discount rate used for all technologies is 5.99% unless a risk premium of 5% is added.

Apx Table B.9 Electricity generation technology LCOE projections data, 2022-23 $/MWh

Category	Assumption	Technology	2022		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas turbine small	232	292	167	254	166	263	164	262
		Gas turbine large	210	275	138	234	139	245	138	243
		Gas reciprocating	240	293	175	251	173	259	171	257
		H_2 reciprocating	298	381	282	364	246	312	228	285
Flexible 60-80% load, high emission		Black coal	129	205	81	132	74	130	73	128
		Brown coal	117	189	106	167	104	165	101	161
		Gas	123	180	80	155	80	162	80	161
	Climate policy risk premium	Black coal	171	275	116	191	108	188	106	185
		Brown coal	204	335	183	292	177	288	173	281
		Gas	136	200	91	174	91	181	91	179
Flexible 60-80% load, low emission		Black coal with CCS	220	348	150	245	135	233	128	227
		Gas with CCS	174	257	123	229	117	227	111	223
		Nuclear (SMR)			198	349	117	399	117	401
		Biomass (small scale)	110	193	107	188	104	191	105	191
Variable	Standalone	Solar PV	48	81	35	58	23	48	20	41
		Wind onshore	58	96	44	75	40	74	38	73
		Wind offshore	149	194	86	170	78	167	72	163
Variable with integration costs	Wind & solar PV combined	60% share			65	94				
		70% share			67	96				
		80% share			68	96				
		90% share			71	100				

Apx Table B.10 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
2022	1837	3006	1837	3006	1837	3006
2023	1606	2628	1606	2628	1606	2628
2024	1369	2241	1307	2139	1369	2241
2025	1191	2045	1086	1891	1191	2035
2026	1051	1866	914	1672	1051	1848
2027	933	1697	775	1474	933	1674
2028	846	1544	663	1300	836	1515
2029	787	1405	570	1146	753	1372
2030	725	1278	493	1010	682	1242
2031	693	1163	461	890	645	1125
2032	665	1058	433	785	607	1019
2033	641	962	405	692	582	923
2034	614	876	381	610	558	836
2035	595	797	360	538	541	757
2036	573	725	341	474	525	685
2037	557	660	325	418	511	621
2038	532	600	311	369	497	562
2039	519	546	299	325	486	509
2040	497	497	287	287	461	461
2041	486	486	273	273	451	451
2042	468	468	261	261	438	438
2043	456	456	250	250	423	423
2044	444	444	240	240	411	411
2045	435	435	231	231	395	395
2046	418	418	223	223	383	383
2047	407	407	215	215	372	372
2048	395	395	204	204	363	363
2049	375	375	195	195	355	355
2050	355	355	182	182	342	342
2051	355	355	182	182	342	342
2052	353	353	180	180	342	342
2053	353	353	180	180	342	342
2054	352	352	177	177	341	341
2055	352	352	177	177	341	341

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, 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, where we need to include a technology 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 we will use paper studies. We will not use confidential data as a primary information source 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.

Appendix D Responses to feedback

D.1 Input prior to the IASR 2023 consultation

D.1.1 Following up on feedback from GenCost 2021-22

We received feedback from the biomass and solar thermal industries that their technologies were not being represented in a way that reflected how those technologies were likely to be deployed. In regard to biomass, it was requested that the technology should include waste heat utilisation. For solar thermal, we were advised that this technology is likely to be configured with a greater emphasis on nighttime generation and 15 hours duration. These technologies have been adjusted in the Aurecon (2023) report and those changes flowed through to this GenCost report.

D.1.2 October 2022 webinar

At the October 2022 webinar it was noted that the impact of inflationary pressures on technologies that are not currently being built could not be observed but this needs to be addressed. As a result, CSIRO developed a method and there are more details on our approach in the body of this report

D.1.3 Energy Policy Institute of Australian policy paper 3/2022

On 23rd September 2022 the Energy Policy Institute of Australia (EPIA) publicly released a paper called *Future Australian Electricity Generation Costs – A review of CSIRO's GenCost 2021-22 Report*[30]*.* GenCost receives uninvited input and questions from stakeholders throughout the year outside of our planned stakeholder engagement processes. Stakeholders are encouraged to continue providing input - both invited and uninvited. We typically provide a summary of feedback received throughout the year and how it has been incorporated. However, the depth of input received in the EPIA paper is beyond what a summary could adequately address. Therefore, in this case, GenCost has provided a more detailed response in the form of a short report which is available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-5083.

D.2 Feedback from the IASR 2023 consultation

Given there are a number of overlapping areas of feedback included in submissions to the consultation, for efficiency, the discussion below addresses broad themes rather than each specific item of input. Two specific items which have been addressed in the body of the report are to include A-CAES in our storage technologies and to update our CST costs to account for more

[30] At the time of writing, the EPIA report was available at this link: https://www.energypolicyinstitute.com.au/_files/ugd/874c49_34b5379865264b12bec396e5ae8ebcfe.pdf

recently available analysis. A-CAES is now included in our comparison of current storage costs (Section 2.4) and CST costs have been updated based on Fichtner Engineering (2023).

D.2.1 Capacity factor range and trend in LCOE calculations

Some submissions requested CSIRO review the capacity factor assumptions it uses in its LCOE calculations. It is important to note that CSIRO's LCOE capacity factor assumptions are for the LCOE calculations only. They are not used by AEMO in any of their work[31]. The goal of the LCOE capacity factor assumptions is to help define the range of capacity factors and subsequent costs that might be experienced by a new build technology. The range should represent uncertainties regarding location, technology improvements and market operation. Location uncertainty is mostly relevant for variable renewables whose capacity factors are affected by local weather.

Technological uncertainty refers to changes in how a technology performs over time due to improvements which might mean for example, a longer operating time which improves the capacity factor. For example, if a wind turbine is better able to capture energy from low wind speeds or can access stronger winds by being built taller, it can operate for more hours per year. Finally, the market ultimately determines when and for how long a technology gets to operate and so this factor also cannot be ignored in determining a capacity factor range.

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 has been closer to the average capacity factor rather than the worst case. However, the high range assumption is closer to the historical high range with some exceptions and accounting for changes over time. Some additional text in the body of the report has been added to explain this approach as previous reports did not provide any significant discussion of this topic. The analysis below has led to changes in capacity factor assumptions which are incorporated in this report.

Review of data and proposed changes

The direction of feedback is that wind and solar capacity factors are too high and capacity factors for baseload generation such as coal too low. For large-scale solar PV the capacity factor range applied in the consultation draft for 2022 is 22% to 32% widening to 19% to 32% by 2050. For wind the range is 35% to 44% in 2022 and 35% to 50% in 2050. Apx Figure D.1 shows the historical range for existing solar PV and wind capacity in the NEM[32].

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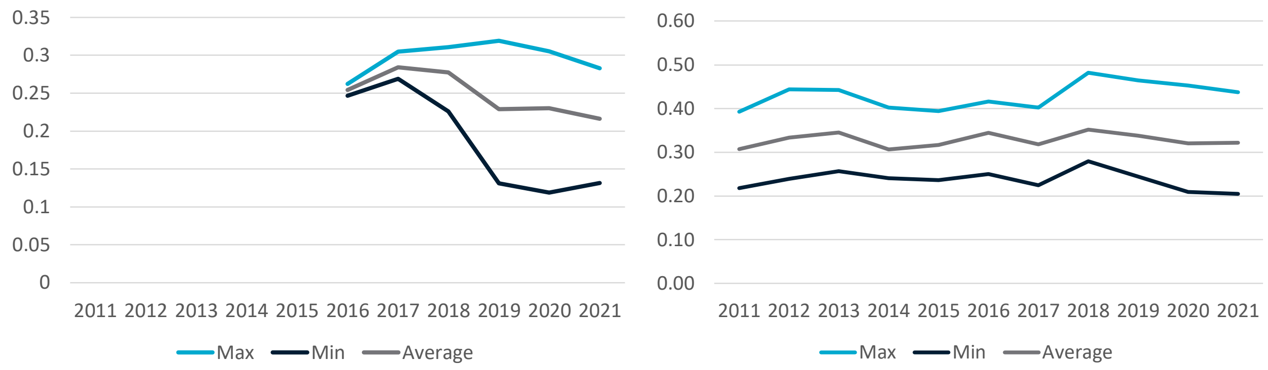
[31] AEMO capacity factors are determined within their models for dispatchable plant and through half hourly production profiles specifically related to each existing plant, and for new plant, each renewable energy zone and weather year included in their modelling.

[32] The data has removed projects that were built partway through the year such that the values represent only projects that operated for the whole year. Projects smaller than 30MW have also been excluded.



Apx Figure D.1 Historical maximum, minimum and average capacity factors for existing NEM solar PV (left) and onshore wind (right) generation

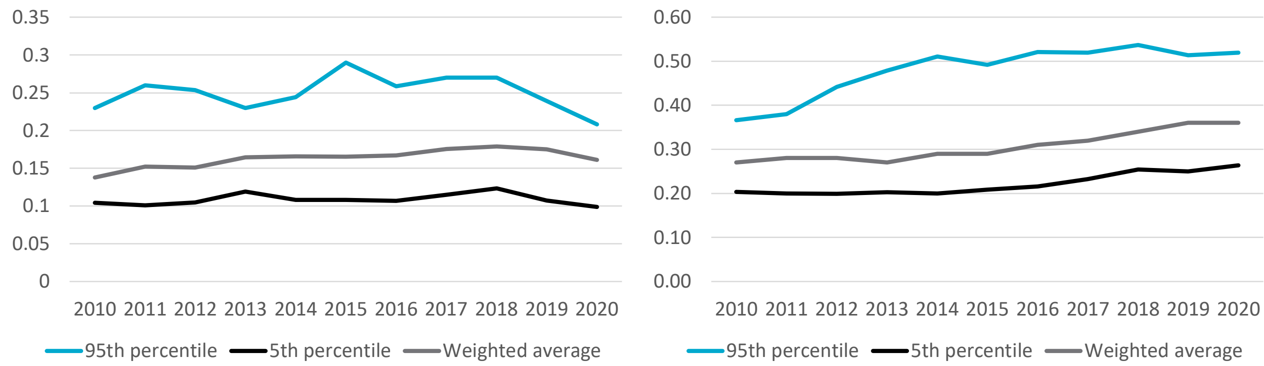
The capacity factor for wind has been relative steady, however there is a notable decline in the capacity factor for solar PV. This could represent several factors including curtailment due to transmission congestion, self-curtailment due to increased negative price periods during times of solar PV generation and increased rainfall and cloudiness due to the dominance of the La Nina weather pattern in recent years[33].

It is unclear if this declining capacity factor trend for solar PV will be temporary, stable or worsen. More solar PV capacity could worsen capacity factors through increased congestion. On the other hand, there are other factors which could improve capacity factors. There is a significant program of new transmission capacity planned to be built in Australia. There is also a significant pipeline of storage projects. The weather pattern is also forecast to shift back to El Nino in the short term which is less associated with rainfall on the east coast. Finally, coal fired power stations partly contribute to the prevalence of negative price periods because of their inability to reduce generation below their minimum run rate during periods of high renewable supply. Increased coal retirements might therefore potentially reduce those events depending on what they are replaced with.

The Australian NEM solar PV and wind capacity factor trends are somewhat at odds with global trends. IRENA (2022) published the capacity factor changes for the total global capacity (Apx Figure D.2). The global data shows a much flatter trend for solar PV and an increasing trend for onshore wind. Although Australia does have better than average solar resources, the range for solar PV indicates that the data may include smaller capacity solar PV systems which tend to have a lower capacity factor on average[34]. However, the range for wind is more comparable with the NEM.

[33] What is La Niña and how does it impact Australia? (bom.gov.au)

[34] Smaller systems are less likely to have any sort of built-in sun-tracking which improves the capacity factor



Apx Figure D.2 Historical high, low and weighted average capacity factors for existing global solar PV (left) and onshore wind (right) generation.

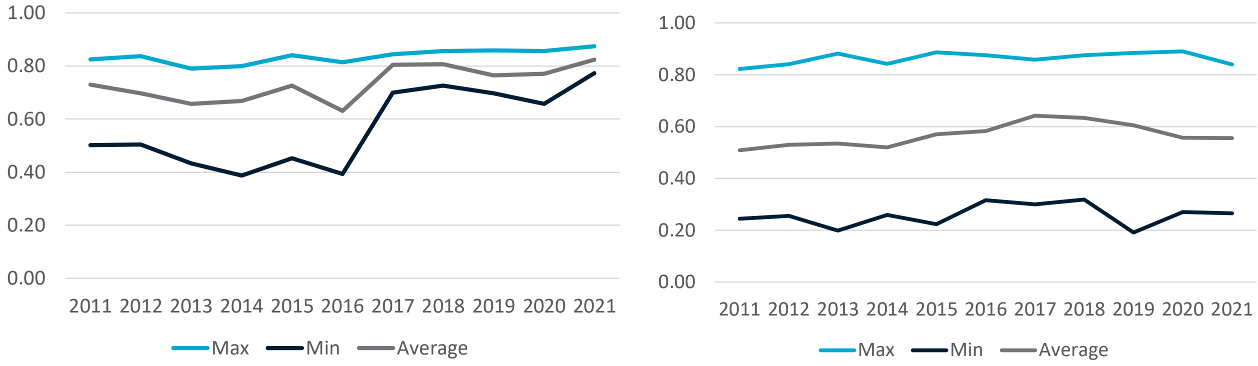
Based on the historical data, 32% remains a plausible maximum capacity factor for solar PV. The previously assumed low range capacity factor of 22% is equal to the most recent average. However, our updated approach is to apply a discount of 10% to the historical average which results in a value of 19%. The previous value was 22% declining to 19% by 2030 and flat thereafter. As such, this updated approach brings forward the previous 2030 value to 2022.

The previous values for onshore wind were a low range of 35% and a high range of 44% in 2022 (increasing to 50% by 2050). The historical wind data suggests an average of 33% and high of 48%. The updated values are therefore a low range of 29% (applying the 10% discount) and high of 48%. International data suggests the potential for an improving wind capacity factor could be justified. However, given this has not been the case in Australia for the last decade, this range will no longer be adjusted over time. These changes represent a broadening out of the wind capacity factor assumptions of 4% at the high end and 6% at the low end (in 2022).

The historical NEM capacity factors for brown and black coal generation are shown in Apx Figure D.3. Although there is a near zero probability of Australian deployment of new coal plant given existing government policy, these capacity factors are a guide to what could be achieved by alternative low emission baseload generation were they to emerge[35].

The data indicates that some coal plant are achieving up to 89% capacity factor. This is higher than the maximum of 80% applied in the consultation draft. The minimum capacity factor data is difficult to interpret because it includes plant which have been in the process of retiring and may not be operating under normal conditions. However, the average capacity factor for black coal is 57%. The average for brown coal is higher at 73%, reflecting their market bidding advantage associated with using a lower cost fuel. The average for all coal is 59% which is similar to the value of 60% used as the low range for flexible plant.

[35] Nuclear SMR and coal or gas with CCS are the main alternatives included in GenCost



Apx Figure D.3 Historical maximum, minimum and average capacity factors for existing NEM brown coal (left) and black coal (right) generation.

The average capacity factor of black coal has been declining from around the introduction of solar PV. This demonstrates the widely expected competitive tension arising from the near zero short run marginal cost variable renewables interacting with coal plant that are unable to reduce their generation below a minimum threshold. However, it is also interesting to note that low capacity factors for coal plant have been a feature of that technology group since before renewables were a significant share.

Brown coal's lower marginal cost appears to provide some protection relative to black coal to very low capacity factors. The competition faced by coal is expected to intensify as variable renewable capacity increases to meet state targets[36] but will at other times improve as coal retires[37] and more storage is deployed.

Based on the historical data, the maximum capacity factor for flexible plant is increased to 89% which is higher than the previous assumption of 80%. For the low range capacity factor assumption, if we average across brown and black coal average capacity factor and apply a 10% discount (the same as the approach for wind and solar PV) the new low range value is 53%. This widens the range from previous capacity factor values by 9% at the top and 7% at the bottom.

D.2.2 Long term materials and supply chain constraints and their impact on technology costs

While some submissions supported CSIRO's assumption that technology costs would return to their normal pathway by 2027 or even sooner, several submissions supported sustaining higher prices for longer reflecting unresolved or extended supply chain constraints. In some cases, it was suggested that the method could single out technologies that rely on rarer inputs. Whether universal or for selected technologies, the central idea is that technology costs will remain relatively high due to ongoing tight supply of materials relative to demand growth.

[36] Some submissions have requested that CSIRO ignore existing government policies that will accelerate deployment of variable renewable generation capacity, noting that the competitive impact of renewables on baseload generation is a dynamic that makes baseload generation more expensive and therefore difficult to examine as an alternative on a clean basis. While we acknowledge the point being made, CSIRO's role is to provide information consistent with government policy.

[37] Other coal retirements perhaps explains the improvement in the minimum brown coal capacity factor since 2017

CSIRO generally does not support this view. Sustained commodity prices would require some combination of:

- Strong global economic growth despite rising interest rates and slowing population growth in many countries or growth in demand for energy technologies that constantly outstrips supply
- A sustained war in the Ukraine and limited transition away from fossil fuels in affected regions. This would mean that fossil fuel supply from Russia continues to be low and its normal customers have failed to find significant opportunities to substitute alternative energy sources
- Insurmountable new entrant barriers in the mining sector such that, while product prices are highly profitable, companies are unable to commence new mining operations

Some of these factors are difficult to predict and none can be ruled out entirely. However, the historical evidence is that while there is significant volatility, commodity prices are flat to declining over the long run (measured over century scale data). The volatility is characterised by super cycles decades long as well as shorter term cycles lasting only 4 years on average. (Cashin and McDermott, 2002; Harvey et al, 2012).

When commodity price super cycles have occurred, they tended to be associated with periods of high global economic growth – that does not appear to be a feature of current and expected world conditions. As such, the central assumption of an end to inflationary pressures after a few years (i.e., a period of short cycle volatility) is reasonable in the context of historical experience. The argument for a longer cycle is based not around a period of high economic growth but growth specific to the clean energy technology sector. It is uncertain whether this would be enough to drive a super cycle as other parts of the economy may grow slower or decline, offsetting this source of faster demand growth.

The scale of deployment in clean energy technology relative to today is not grounds alone for sustained cost pressures. Linear growth, for example, is unlikely to support sustained price pressures. Once the relevant labour and materials markets have scale up to meet a strong period of growth, a linear period of growth implies it can meet all growth *without any further expansion of supply capacity*. Growth has to be non-linear to present an ongoing need to scale up supply capacity or a failure of supply to meet demand (triggering price rationing).

In the consultation draft we assumed that all scenarios experienced the same cost path until 2027, but we flagged that we would introduce more uncertainty in the final projections.

Having considered the feedback, the resolution of the price bubble has been extended to 2030 for Global NZE by 2050 and Global NZE post 2050. These two scenarios are about relatively stronger global climate policy ambition supported by large deployments of low emissions technologies. They will likely result in non-linear growth in demand for these technologies up until 2030. Globally, governments and industry have a tendency to set clean energy targets at the turning point of decades. As a result, 2030 is likely to result in a surge of activity to meet those targets. However, there are a number of projections, including those from the IEA, indicating the rate of deployment appears to be more linear and in some scenarios, slower than linear post-2030.

D.2.3 The appropriateness of treating past investment costs as sunk in 2030 LCOE calculations

A submission from Australian Resources Development (ARD) has indicated some stakeholder misunderstanding over how integration costs between different higher variable renewable energy shares relate to each other, and in addition, how calculation of those costs might be affected by the approach we apply whereby costs for all existing capacity in 2030 are treated as sunk. Putting these two issues together, ARD was concerned that the integration costs calculated for variable renewable shares failed to include the cost of moving from the current variable renewable share to the business as usual renewable share in 2030. To address this concern this explainer begins with the concept of sunk costs and then explores issues around the marginal cost of supply and how those costs change over time and with different variable renewable shares.

Sunk costs in the generation sector

Investment costs relate to the capital items of generation and storage infrastructure. These are considered to be sunk once they occur, by which we mean they are not immediately recoverable, for a variety of reasons:

- They cannot be returned to the seller unless there is a defect under warranty
- They can be sold to another party but that does not change their sunk status, it only changes the owner for which costs remain sunk
- The market does not owe the owner a reasonable return on investment

The sunk nature of the costs is in fact the reason why investors very carefully study the market before investing. If costs were not sunk then there would be no penalty for bad investments. Investors take the risk that future market prices will be high enough to provide a reasonable return on investment gradually over the economic life of the asset.

There are mechanisms external to the market which partially address investor risk. While all generation supply by units above 30MW is settled on the market, external contracts can buffet the market price volatility through long term contracts for supply. The AEMC provide an overview of the types of external contracts that are entered into, how they relate to the spot price and their relationship to the physical market[38]. An important point to remember is that while external contracts are a way of increasing the likelihood of achieving a reasonable return on investment, the average spot price and external contract prices should converge in the long run. That is, there is a limit on the premium buyers will pay for longer term supply if expectations about the future spot price are significantly lower than the contract market. Hence the general statement that the market does not owe the owner a reasonable return on investment remains true despite the existence of external contract markets.

It is also true that the market will at times over-reward investors, temporarily providing a greater than reasonable return on investment (if it were to continue). The NEM grid dispatch system sets the price each five minutes according to the last bid required to meet demand. All lower bids that were also accepted to meet demand receive the same price as the last bid accepted, regardless of

[38] https://www.aemc.gov.au/energy-system/electricity/electricity-market/spot-and-contract-markets.

their lower bid price or their actual costs of supply. However, these relatively high-priced periods do end for a number of reasons:

- Demand falls such that high bids are no longer needed
- New capacity enters the market which is able to compete with the higher bids
- Fuel or other input costs of existing generators decrease making it possible for them to lower their bids when sufficient competition encourages them to do so

Long term average prices and generation system costs

If, as we have discussed, the market does not have an inherent obligation to pay for current capacity, then what does the spot price represent? In the most immediate sense, the spot price represents the last bid required to clear the market – that is for demand to be only just met by total supply from all lower bids plus the last bid. However, the spot price also has an investment signalling function which plays out beyond the five-minute dispatch and governs its long-term average.

Investors observe the spot price over time and compare it to the costs of available generation or storage technologies. If the spot price is too low to provide confidence that a reasonable return on investment is achievable, then new investment does not proceed beyond those already committed. If this period of spot-prices-lower-than-new-investment-costs prevails over a long period, then no new capacity is entering while some existing capacity must eventually retire out of the current stock of capacity – either because a low spot price means they cannot recover short term costs (e.g., fuel, operating and maintenance) or because the plant's technical life has ended. Eventually, this loss of capacity reduces the number of low bids available to meet demand thereby forcing up the spot price since higher bids must be accepted to meet demand.

If supply were perfectly elastic, the spot price need only go high enough to encourage the level of capacity required to lower the market bids to the level of the cost of new entrants. However, in reality, investors face delays in bringing capacity to market because:

- Infrastructure takes years to plan and construct,
- Investors may need to see a sustained higher price to give them confidence that prices will remain higher on average rather than reflecting a more temporary phenomenon
- Investors may also need to consider the actions of other investors who may also bring new capacity to the market.

If spot prices overshoot the cost of new capacity for these reasons, prices should return to a lower level once the new capacity enters and conditions become more competitive.

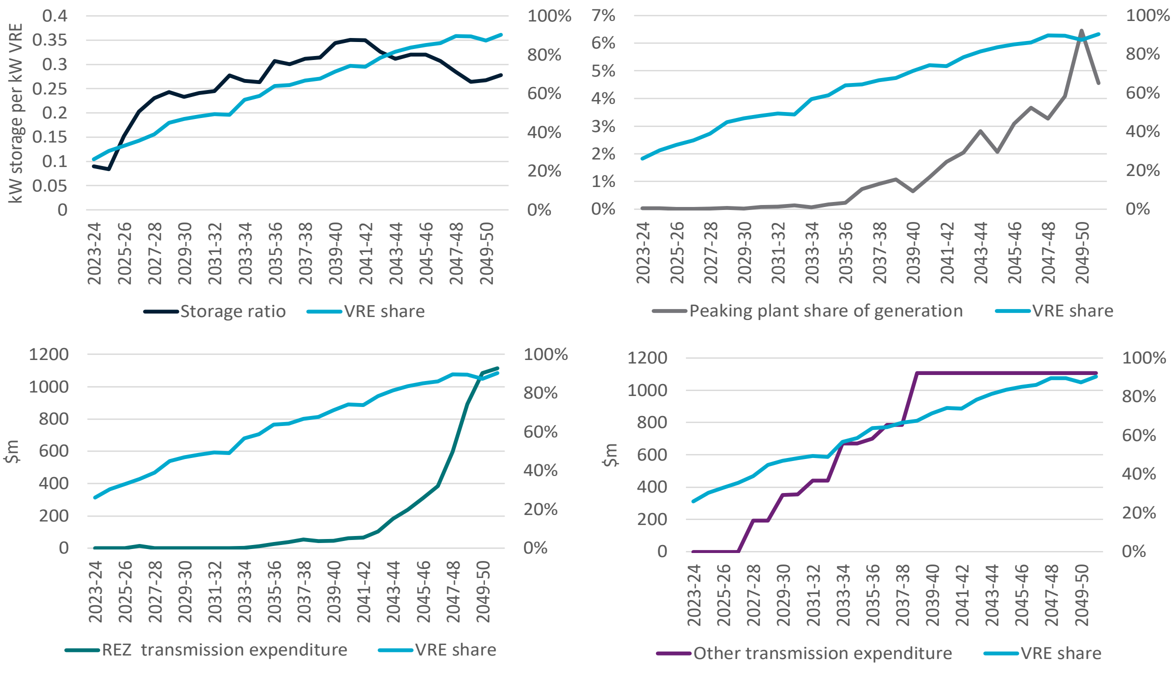
Overall, these dynamics mean that the spot price will under and overshoot the cost of new capacity, and these under and overshoot periods can last for years. However, in the long run, attrition of existing plant and competition between new entrants means that, on average, the spot price will ultimately reflect the cost of new capacity.

Implications for how to cost technology share scenarios

This market fundamentals discussion has explained why for any year that we wish the know the cost of achieving any given baseload or variable renewable generation share (as an indicator of the resulting average spot price trend), we only need to know the cost of the new entrants required to reliably deliver that generation technology mix.

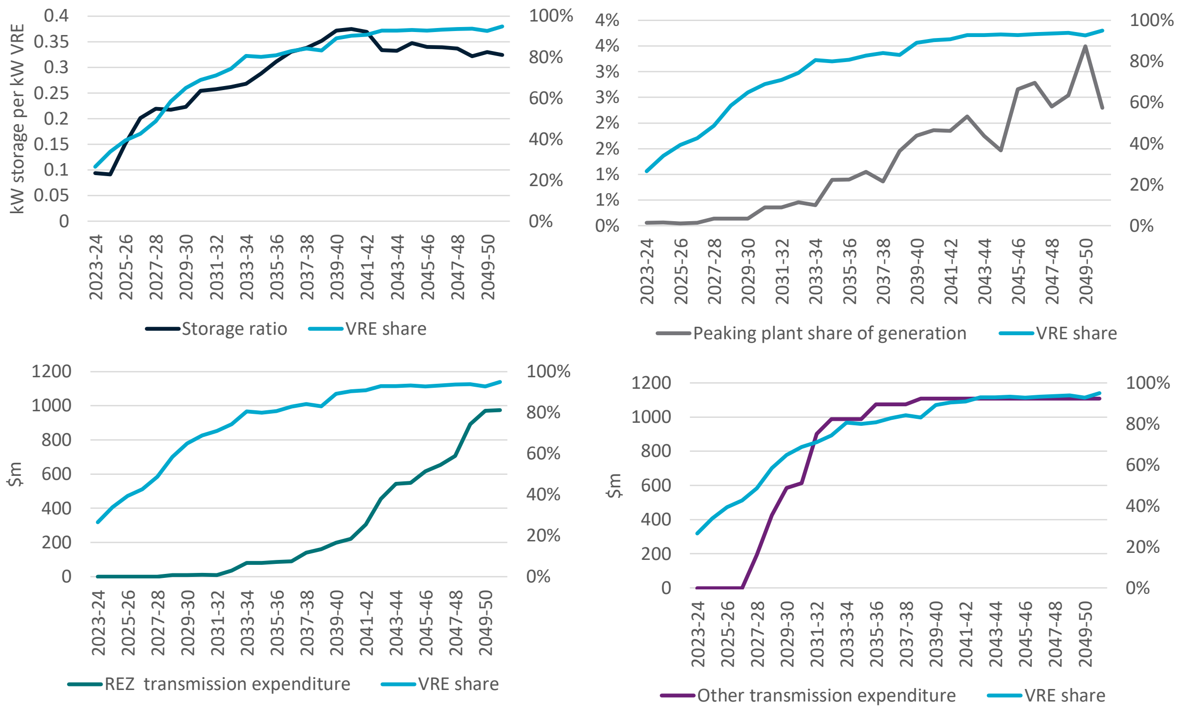
In GenCost we take the year 2030 and observe the combination of renewables and supporting technology that must be built for four levels of variable renewable energy (VRE) share – 60%, 70%, 80%, 90%. – starting form a system that has already exceeded 50% VRE. ADR's concern is that the costs to achieve 30%, 40% and 50% should also be added to those four VRE share costs. From the discussion above it should be clear that this is not the case. Each specific VRE share has its own cost which reflects the last new entrant needed to reach that share reliably, which will be a combination of renewable generation capacity, storage capacity, peaking capacity, renewable energy zone transmission and other additional transmission capacity. Some of these capacities increase proportionally with VRE share and some not. The results from the 2022 ISP modelling for the Progressive change and Step change scenarios provide useful indicators of the changing system needs with increasing VRE share of generation[39].

The ratio of storage capacity needed to meet a growing VRE share of generation increases fairly proportionally up to around a 70% VRE share but levels out thereafter with growth peaking capacity becoming more important after that point. Little to no new renewable energy zone transmission capacity is needed to move from 20% to 60% VRE share of generation. However, to move beyond that REZ transmission expenditure needs to increase with VRE share. Conversely, at higher levels of VRE share other transmission capacity is not needed. However, it does increase at low to medium VRE shares.



Apx Figure D.4 Changes in storage, peaking plant and transmission deployment with changes in VRE share, Progressive change scenario

[39] Small scale rooftop solar generation is excluded from the calculation of VRE share since from the perspective of the large scale grid and what it needs to build, it only sees the demand it needs to meet after the impact of rooftop solar on behind the meter demand.



Apx Figure D.5 Changes in storage, peaking plant and transmission deployment with changes in VRE share, Step change scenario

Based on these modelling results we can build a picture of the marginal cost of the last new entrant required to achieve each VRE share in 10% increments (Table 1):

- At low VRE shares the marginal new entrant is renewables with a low ratio of storage
- At low-medium VRE share the marginal new entrant is renewables with a medium ratio of storage and significant additional transmission.
- At medium-high VRE share the marginal new entrant is renewables with a high ratio of storage, new peaking plant and new REZ transmission and limited new transmission
- At a high VRE share the marginal new entrant is renewables with a high ratio storage (but potentially lower than previous entrants), new peaking plant and new REZ transmission

Apx Table D.1 Rate of new entrant investment required to increase VRE share reliably and efficiently

Change in VRE share	Storage	Peaking plant	REZ transmission	Other transmission
20% to 30%	Increase rate	None required	None required	None required
30% to 40%	Increase rate	None required	None required	May be required
40% to 50%	Increase rate	None required	May be required	Increase rate
50% to 60%	Increase rate	May be required	Increase rate	Increase rate
60% to 70%	Increase rate	Increase rate	Increase rate	Maintain rate
70% to 80%	Maintain rate	Increase rate	Increase rate	Maintain rate
80% to 90%	Decrease rate	Maintain rate	Maintain rate	Maintain rate

Whenever these VRE share transitions occur, the combined cost of these investments will be the main driver for electricity costs subject to any volatility at the time due to excess or tight capacity conditions. As discussed above, until the market corrects the price through attrition or new entrants, spot prices may under or overshoot the minimum cost of entry required for reliability for a period of time. A delay in making transmission available is one possible source of delay in new entrant competition. The cost of transmission is recovered separately from the generation spot market through regulated revenue recovery procedures. However, GenCost has included it as part of variable renewable integration costs given its importance to variable renewable deployment.

Shortened forms

Abbreviation	Meaning
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
CPI	Consumer price index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated solar power
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
IASR	Inputs, Assumptions and Scenarios Report
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
ISP	Integrated System plan

Abbreviation	Meaning
kW	Kilowatt
kWh	Kilowatt hour
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 electrolysis
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
SWIS	South-West Interconnected System
TWh	Terawatt hour
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia

Abbreviation	Meaning
WEO	World Energy Outlook

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Contact us

1300 363 400
+61 3 9545 2176
www.csiro.au/en/contact

For further information

E**nergy**
Paul Graham
+61 2 4960 6061
paul.graham@csiro.au
csiro.au/energy