Australia's National
Science Agency

GenCost 2020-21

Final report

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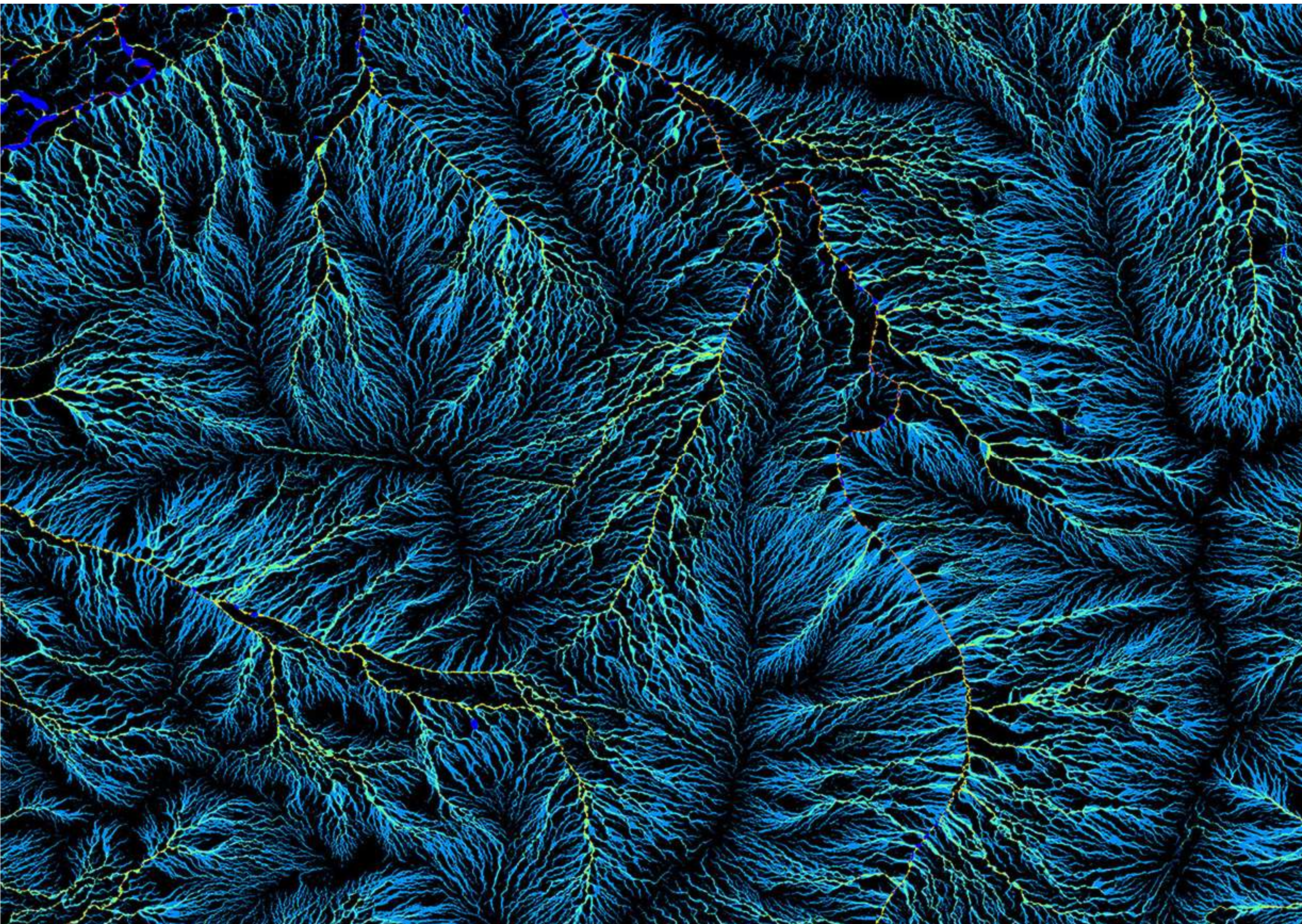

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Acknowledgements

This final report consolidates input received from stakeholders on the GenCost 2020-21 Consultation Draft which, in partnership with AEMO, was released for public consultation in December 2020. Submissions on the consultation draft were provided to AEMO and CSIRO in the period up to 1 February 2021. We are also grateful for feedback received via a webinar with stakeholders on 3 March 2021 and in various personal communications to the GenCost team.

Executive summary

GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating electricity generation and storage costs with a strong emphasis on stakeholder engagement. This is the third update following the inaugural report in 2018 and a second report in 2019-20. The 2020-21 report incorporates 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. Levelised costs of electricity (LCOEs) are also included and provide a summary of the relative competitiveness of generation technologies.

Capital cost projections

The projection methodology is grounded in a global electricity generation and capital cost projection model recognising that cost reductions experienced in Australia are largely a function of global technology deployment. Three scenarios are explored:

- **Central**: Current stated global climate polices (as of late 2020), with the most likely assumptions for all other factors such as renewable resource constraints
- **High VRE**: A world that is driving towards net zero emissions by 2050 and where technical, social and political support for variable renewable electricity generation is high
- **Diverse Technology**: A world where most developed countries are striving for net zero emissions by 2050 but others are lagging such that global net zero emissions is reached by 2070. Furthermore, there is lack of social, technical and political support for variable renewable electricity generation and subsequently a greater role for other technologies.

In the High VRE scenario, global non-hydro renewable generation reaches a share of 82% by 2050, with the majority sourced from solar photovoltaic (PV) and on- and off-shore wind. In the Diverse Technology and Central scenarios, global wind and solar PV shares are lower at around 50% in total. Access to wind and solar PV is assumed to be constrained in the Diverse Technology scenario. Consequently, generation from gas and coal with carbon capture and storage is deployed to meet the climate policy ambitions of that scenario. CCS is also used more commonly in hydrogen production. Nuclear small modular reactors could also play a role in the Diverse Technology scenario from 2030 so long as investors are willing to drive down costs through multiple deployments in the late 2020s.

Battery costs fell the most in 2020-21 compared to any other generation or storage technology and are projected to continue to fall. We have also adjusted assumptions to recognise that batteries are achieving longer lives. Falling battery storage costs underpin the long-term competitiveness of variable renewables. Pumped hydro is also an important storage technology and is more competitive than batteries when longer duration storage is required.

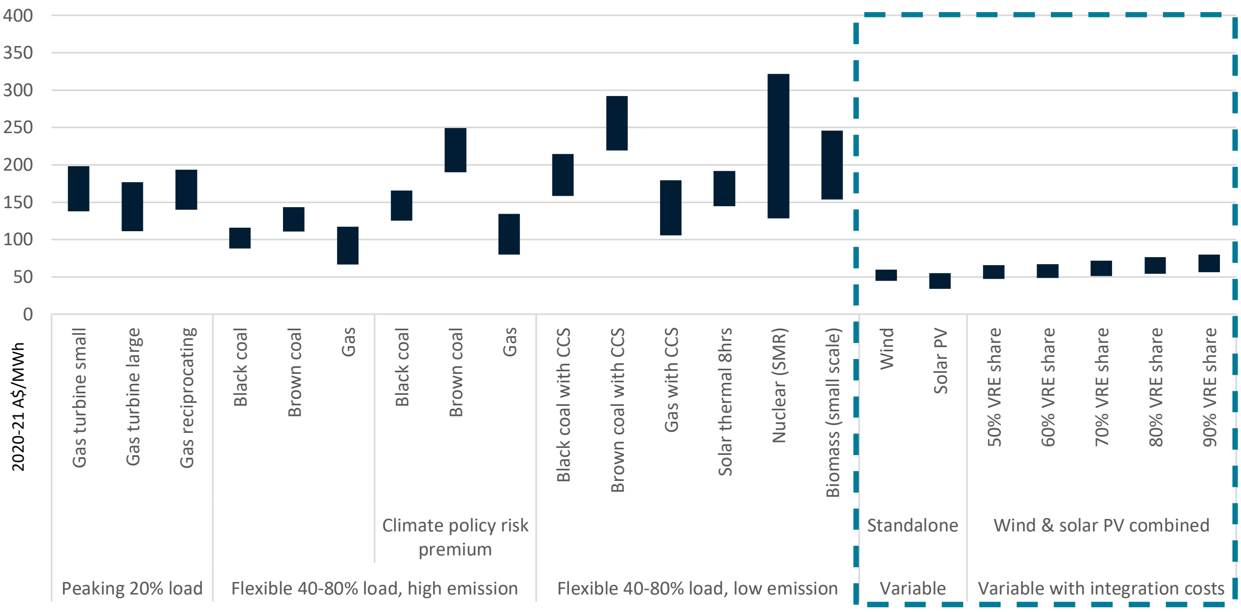
The technology cost projections have been extended to include hydrogen electrolysers reflecting strong interest in this technology that, combined with low cost renewable generation could potentially underpin a low emission hydrogen fuel industry for export or Australian domestic consumption. The results indicate that substantial cost reductions are expected over the next few decades, with many demonstration projects underway worldwide.

Levelised cost of electricity

There have been concerns for many years that it is difficult to quantify the additional costs associated with variable renewable electricity generation. Traditional approaches to calculating the levelised cost of electricity fail to include these additional costs, underestimating the full costs to the electricity system. The GenCost team has been seeking to address this issue since the first report in 2018 where we outlined this problem and reviewed a number of alternative solutions.

To calculate the additional costs CSIRO constructed an electricity system model that can calculate the required additional investment considering any existing resources in the system. The key additional investments required are in:

- New transmission to access Renewable Energy Zones
- Additional transmission to strengthen the grid so that dispersed renewable generation can reach key demand centres and expanded state interconnection so that connecting regions can provide more support for one another when renewable generation is low in one or more regions
- Synchronous condensers to support system security
- Battery and pumped hydro storage to meet demand during low renewable generation periods.



ES Figure 0-1 Calculated LCOE by technology and category for 2030

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 VRE shares from 50% to 90%[1] for the National Electricity Market (NEM). We found

[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.

that the additional costs to support a combination of solar PV and wind generation in 2030 is estimated at between \$6 to \$19/MWh depending on the VRE share and region of the NEM. These represent 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 new estimates indicate that wind and solar PV remain the lowest cost new-build technology up to a 60% VRE share.

The closest technology is the low range cost of a gas combined cycle generator which can match the costs of variable renewables with integration costs at a 70% or greater share. However, the low range 2030 gas combined cycle cost assumptions will be challenging to achieve. It requires no climate policy risk at the financing stage (despite the 25 year design life extending beyond the net zero emission targets of most states), a gas price just below \$6/GJ throughout that period and a capacity factor of 80% in a system with 70% or greater share of energy from near-zero marginal cost renewables.

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 (2020) 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 (Graham et al., 2020) is released for feedback before the final report is completed.

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 in-kind resources. AEMO commissioned Aurecon to provide an update of current electricity generation and storage cost and performance characteristics (Aurecon, 2021). Earlier drafts of Aurecon's report were initially shared with of stakeholders during a webinar in September 2020 and as part of the December 2020 to February 2021 public consultation.

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

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, we have improved our approach to calculating Levelised Costs of Electricity (LCOE) for renewables by employing a new modelling approach which is able to calculate additional costs to the system associated with variable renewable generation.

1.4 Overview of consultation draft feedback and responses

There was a strong level of interest and broad range of feedback provided on the December 2020 consultation draft. We summarise the feedback and how they have been addressed in the final report under the following themes.

1.4.1 Technology learning rates

Technology learning rates are an important input into the cost projections. They are based on historical data or on learning rates achieved by technologies at a similar stage of development. They determine the cost reduction for each doubling of cumulative capacity deployed. Stakeholders proposed that there was evidence for a higher learning rate for offshore wind and a wider range of learning rates for batteries. We also found that there was evidence to support a stronger offshore wind learning rate and increased it to 15%. We also agreed that the range of battery projections across the scenarios was too narrow. We modified the scenarios so that instead of using a single rate we use a range of 7.5 to 15% across the scenarios. We also extended these learning rates to the balance of plant. There were also suggestions for a stronger learning rate for hydrogen electrolysers and to consider including assumptions about improvements in the round-trip efficiency of batteries over time. While these suggestions might be plausible, we found no strong basis upon which to base any assumptions and so the approach is unchanged.

1.4.2 Scope of technologies included

It was requested that the GenCost project include two additional storage technologies: compressed air energy storage and non-lithium based batteries. At present, such projects have very limited deployment but are proposed. We are unable to accommodate new technologies in 2020-21 but will consider these for future inclusion. We will continue to trade off completeness against the cost to the project of updating a larger technology list.

1.4.3 Operating and maintenance costs

Stakeholders advised that operating and maintenance costs were too high for batteries and nuclear SMR. For batteries, an additional issue was the relationship between battery operating costs and storage size. These have been revised in Aurecon (2021) to take account of these issues. For nuclear SMR, it was found that prior variable operating and maintenance cost assumptions could not be supported and have been revised downwards to $5.3/MWh.

1.4.4 Capacity factors

There is a significant amount of confusion around capacity factors amongst stakeholders partly because they are used and reported in different ways by CSIRO and AEMO. In its various versions of the ISP input and assumptions workbooks, AEMO publishes medium and high average capacity factors as an indicator of the quality of wind and solar resources in Renewable Energy Zones. However, when conducting modelling they use a full half hourly production trace and vary the trace over future years by looping through “reference years”. For GenCost, the capacity factors we report are the range we use in our levelised cost of electricity (LCOE) calculations. The purpose of the LCOE calculations is to show the best and worst case for future new-build projects. Some stakeholders were disappointed that we had not included higher capacity factors for coal and nuclear technologies. However, historical evidence shows that coal generation is not achieving better than 80% capacity factor and most much lower. We therefore use 80% as a best case. 60% is the worst case because we assume a new plant, if built, will be more competitive than existing coal generators. Above 80% is not realistic in a system which is including more renewables (state renewable policies ensure this outcome will occur).

For renewable capacity factors the approach is similar but the outcome different. We again look to the historical range of capacity factors achieved but we consider that newer plant can increase their capacity factor due to improvements in the technology. This is particularly the case of wind where larger turbines are better at capturing wind energy throughout a greater proportion of the day. We have therefore not made any changes to our capacity factor assumptions but hope this background is useful in understanding the basis of their selection.

1.4.5 New entrant versus existing coal generation costs

Some stakeholders were concerned that our assumed coal costs were higher than what existing plant pay for coal. This is correct but consistent with our approach. GenCost is only concerned with the cost of new-build plant. New-build plant will have to compete with export markets to establish a coal supply and will therefore face higher prices. However, it should be noted that electricity modelling processes do include existing plant and lower coal costs for existing plant are considered in those processes. A breakdown of costs for existing plant are available in background documents to various AEMO planning processes and therefore there are no plans to duplicate that information in the GenCost project.

1.4.6 Externalities

There was a concern that generation technologies may impose external costs on the community that are not accounted for in the LCOE calculations or elsewhere. This is mostly correct by design. We wish to compare technologies on a common basis. Including each individual technology's set of externalities would make the comparability low and somewhat arbitrary. We therefore try to keep to costs inside the plant gate. There are two exceptions we have included: the cost of climate policy risk on financing and the integration costs of variable renewables. We made these exceptions because they are too large and direct to ignore. We have no plans to extend to other issues but will continue to review this topic as issues emerge.

1.4.7 Design and technical life

Design life is the period which tends to match the life of the initial financing and requires no additional capital costs or refurbishment (that is not already included in operating and maintenance costs). The operating life is longer and represents the full asset life inclusive of refurbishments. Stakeholders felt that the design life was too short for coal, pumped hydro and batteries. For coal, we acknowledge that a government might decide to finance a plant over a longer period, but we believe 30 years remains appropriate for design life for standard financing arrangements. The design life is used in LCOE calculations to determine the annualised cost of the capital. The operating life is of course longer (around 50 years if not retired for economic reasons), and operating lives are used in electricity system modelling. The two lifetime definitions are used for different purposes.

For batteries and pumped hydro, we found the proposal for a longer design life was supported. Batteries are being more commonly provided with 20-year warranties and we have shifted to this assumption based on Aurecon (2021). However, this comes with an additional 20-year warranty cost[3]. Note, the 2019-20 assumptions were a 20-year project design life but with batteries completely replaced every 10 years. That battery replacement is no longer necessary. For pumped hydro, we found local experience and international studies do tend to use a longer design life and so this has been changed to 40 years.

1.4.8 Battery cost basis relative to usable capacity

Stakeholders were understandably surprised that we had assumed a 100% depth of discharge and charge. Typically, batteries cannot be fully discharged or charged without degrading the battery. That remains true, however what we had failed to emphasise in the past is that Aurecon provides their current cost estimates for batteries on a usable-part-of-the-battery basis. To put it another way, the nameplate capacity of the plant is lower because it only represents the usable part of the battery. Therefore, when applying the battery costs in Aurecon (2021) and in GenCost, there is no need to apply further assumptions about maximum depth of discharge or charge.

[3] Not reported here, see Aurecon (2021).

1.4.9 Implementation of global emissions reduction policies

The global modelling requires the implementation of current and potential new policies to meet a range of global climate policy outcomes that are explored across the scenarios. Carbon prices are the most unbiased way in which to determine how meeting different emissions outcomes might impact global electricity generation technology choices. For this reason, we had tended to use stronger carbon prices than contemporary work which relies on a broader mix of policies. After further consideration we have decided to align our approaches more closely with the International Energy Agency, directly implementing their estimated carbon prices and using a mix of other policies (such as renewable energy targets) to match our electricity sector emissions outcomes to theirs.

Some stakeholders also considered that the inclusion of carbon prices in the LCOE calculations meant that the technology comparisons were invalid or biased towards low emission technologies. To be clear, wherever we had imposed a carbon price on a high emission technology we always included another measure of the cost without a carbon price and any conclusions were always based on the non-carbon price data. However, given some confusion has arisen and that the carbon price assumptions have minor impact on the relative competitiveness of technologies, we have removed carbon prices from the LCOE analysis.

1.4.10 Current costs – high rate of deployment

Tracking the costs for technologies that continue to be deployed while this report is in draft often leads to some stakeholders identifying differences in observed current costs. This is the case for solar and batteries. These two technologies have undergone minor revisions to reflect updated data. An additional issue raised around solar is that project sizes were being decreased closer to deployment to avoid extra costs associated with addressing system strength impacts. While we have not changed our standard size assumptions to reflect this it is a useful explanation for why some projects may not reflect the current costs reported here. The size fluctuation and its impact on costs will likely be an intermittent issue as renewable deployment sites both open up or become congested.

1.4.11 Current costs – low or no deployment

The current costs for immature technologies are often fraught because there is often no local deployment to provide a basis for cost estimates. Stakeholders were able to provide additional data on biomass generation projects and this has supported a 16% reduction in capital cost compared to the consultation draft.

We also have had a range of feedback into the assumed current costs for nuclear SMR over several years. Our current cost estimate is from GHD (2018). The basis of this estimate is the International Energy Agency and Nuclear Energy Association report *Projected costs of electricity generation 2015*. That report proposed that nuclear SMR typically costs 50% to 100% more than large scale nuclear. If we use the 100% value for Australia (because it has no experience in nuclear generation) and a 0.7 US$/A$ exchange rate the outcome matches the GHD (2018) estimate of $16,000/kW. If we update this number using more recent large-scale nuclear cost estimates and exchange rates, this estimate is not significantly different. It is also consistent with the higher end of more recent first of a kind estimate from EFWG (2019).

However, a major source of discomfort for stakeholders is that this high cost estimate is of theoretical value only. A nuclear SMR plant is not planned to be built in Australia anytime soon. It is more likely that Australia would only take up nuclear SMR, if at all, from around 2030, after other countries have brought down the cost. It is this future cost level that stakeholders would prefer to focus on. GenCost's projections of the after-learning future cost of nuclear SMR in the 2030s has not received significant feedback and is consistent with "nth of a kind" estimates such as EFWG (2019). On this basis, we will no longer be reporting nuclear SMR current costs before 2030.

1.4.12 Renewable integration costs

Stakeholders had two broad items of feedback on the new method for calculating the integration costs of variable renewables. One is that they would like to see more information presented on the existing generation, storage and transmission resources assumed to be in the system before higher variable renewable shares are imposed. The other is that they would like to see more weather years included to account for variability in renewable supply. Both items have been addressed and were included in the revised results included in Section 5.

2 Current technology costs

2.1 Current cost definition

Our preferred definition of current costs are the 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 wish to include in our definition of current costs, costs that represent quotes for delivery of projects in future financial years or project announcements.

While all data is useful in its own context, our preference 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[4]. Hence, current costs and costs in any given year must reflect the costs of projects completed in that year. Quotes received now for projects to be completed in future years are only relevant for future years.

For technologies that are not frequently being constructed, the preference 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 (2021). Aurecon (2021) also provide more detail on specific definitions of the scope of cost categories included.

2.2 Updates to current costs

AEMO commissioned Aurecon (2021) to provide an update of current cost and performance data for existing and selected new electricity generation and storage technologies. This data is used in this report as the starting point for projections of capital costs to 2050 and for calculations of the levelised cost of electricity.

Compared to 2019-20, Aurecon has reviewed coal generation and included two gas open cycle unit sizes. CSIRO has updated costs for technologies which are more rarely deployed such as tidal/current and wave energy. Aurecon (2021) has included hydrogen electrolysers for the first time and these are separately reported.

Pumped hydro has also not been updated by Aurecon (2021), but we have revised this data to be consistent with AEMO's ISP 2020 which received further input from stakeholders on this technology.

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[4] This is not strictly true of all models but is most true of long-term investment models. In other models, investments 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.

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2020-21) cost estimates (drawing primarily on the Aurecon (2021) update) for electricity generation technologies with the four most recent previous reports: GenCost 2019-20, GenCost 2018, Hayward and Graham (2017) (also CSIRO) and CO2CRC (2015) which we refer to as APGT (short for Australian Power Generation Technology report). All costs are expressed in real 2020-21 Australian dollars and represent overnight costs since it would not be possible to build and financially close projects before July 2021.

CSIRO's estimate for 2020-21 rooftop solar PV cost is included in the "Aurecon/CSIRO" data as that technology was not part of Aurecon (2021). Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme. All data has been adjusted for inflation.

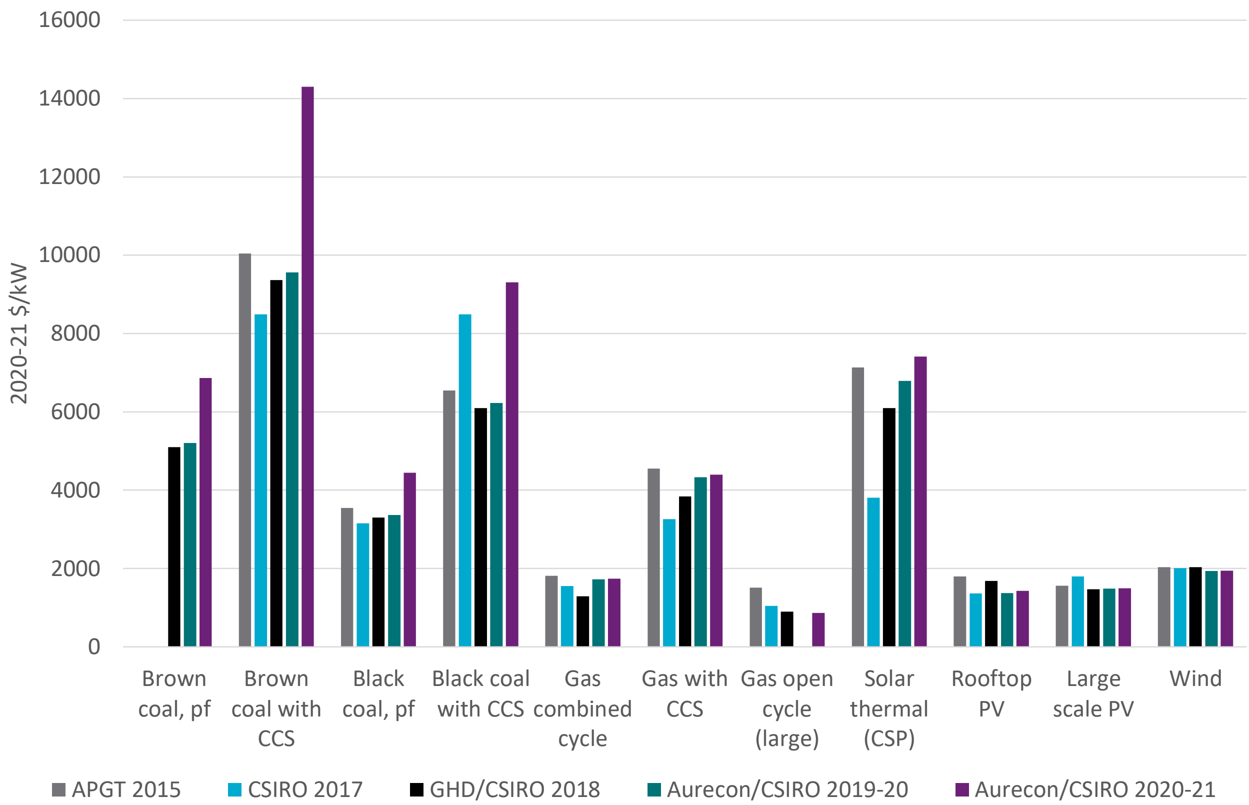

Figure 2-1 Comparison of current cost estimates with previous work

Coal generation capital costs have been revised upwards after not being significantly updated since the GHD (2018) analysis. The lack of Australian construction means there will always be a range of interpretations when converting overseas data to Australia. Solar thermal costs have increased on 2019-20 estimates reflecting inclusion of a first of a kind cost premium. Gas, wind and solar PV cost estimates have been relatively stable reflecting better data availability for Australian projects.

2.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations of battery and pumped hydro energy storage (PHES) in $/kW and $/kWh. Total cost basis means that the costs are calculated by taking the total project costs divided by the capacity in kW or kWh[5]. 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 2-2). The downward trend flattens somewhat with batteries since its power component, mostly inverters, is relatively small but adding more batteries is costly. However, the hydro 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.

Conversely, the costs in $/kW increase as storage duration increases because additional storage duration adds costs without adding any power rating to the project (Figure 2-3). 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 battery and pumped hydro with different durations may be required depending on the behaviour of other generation in the system, particularly the scale of variable renewable generation (see Section 5).

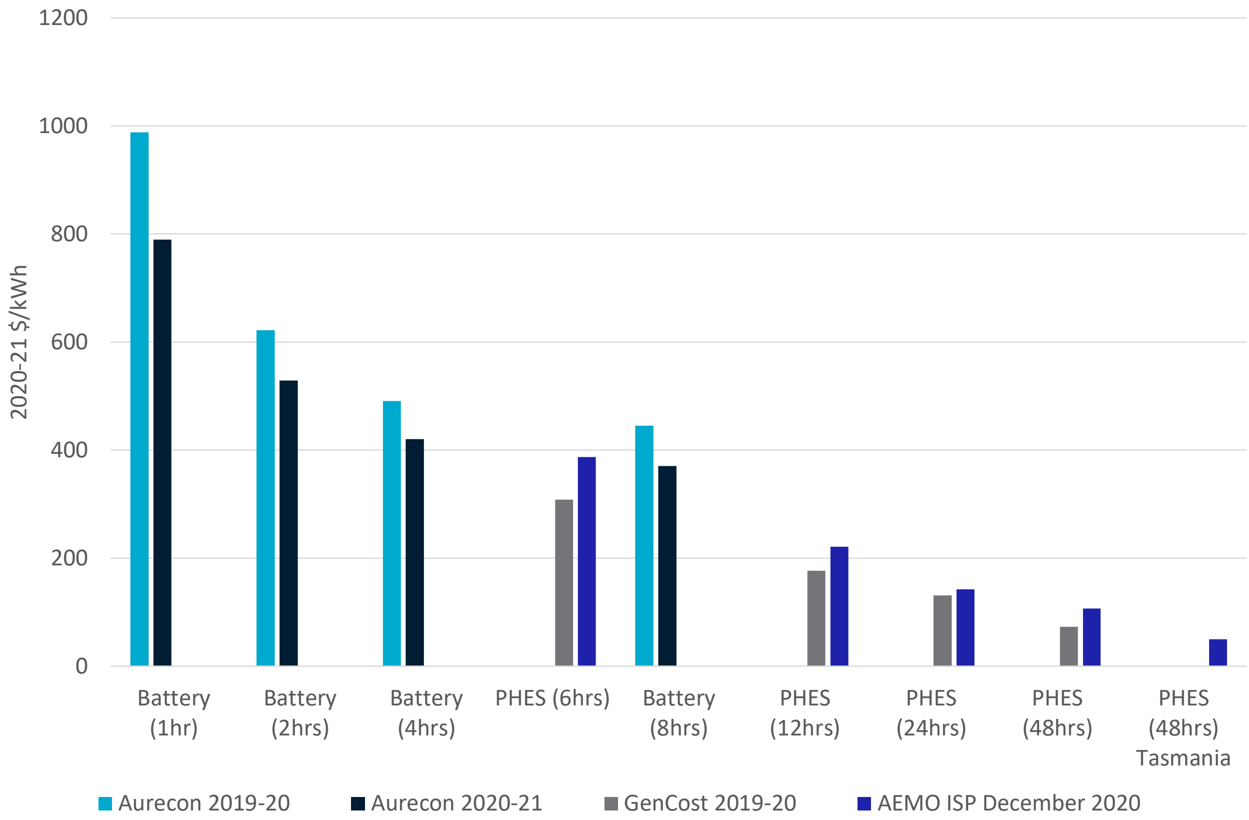

Figure 2-2 Capital costs of storage technologies in $/kWh (total cost basis)

Round trip efficiency, project design life and the potential for co-location also play a role in competitiveness of alternative storage technologies. Depth of discharge in batteries is also a relevant factor. However, all Aurecon battery costs are on a usable capacity basis such that depth

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

of discharge is 100%. Aurecon (2021) 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 9% lower battery cost for a 1-hour duration battery, scaling down to a 2.5% cost reduction for 8 hours duration. PHES is more difficult to co-locate.

Battery current costs have declined in Aurecon (2021) compared to their previous work. These are based on projects deployed. In contrast, we have increased PHES costs by aligning with AEMO ISP December 2020 estimates. Feedback received in 2020 indicated that PHES was under-estimated in GenCost 2019-20. A new higher data point was included in the December 2020 ISP inputs and assumptions workbook based on submissions and discussion with proponents and reputable consultants with experience in PHES deployments. Some escalation in costs is consistent with major infrastructure projects where cost increases occur after initial estimates. However, we have also added a separate category for Tasmania PHES with 48hrs duration. This area of Australia has had the most detailed analysis undertaken of its PHES costs and, consistent with ISP regional cost adjustments, warrants greater certainty that it can achieve lower project cost estimates.

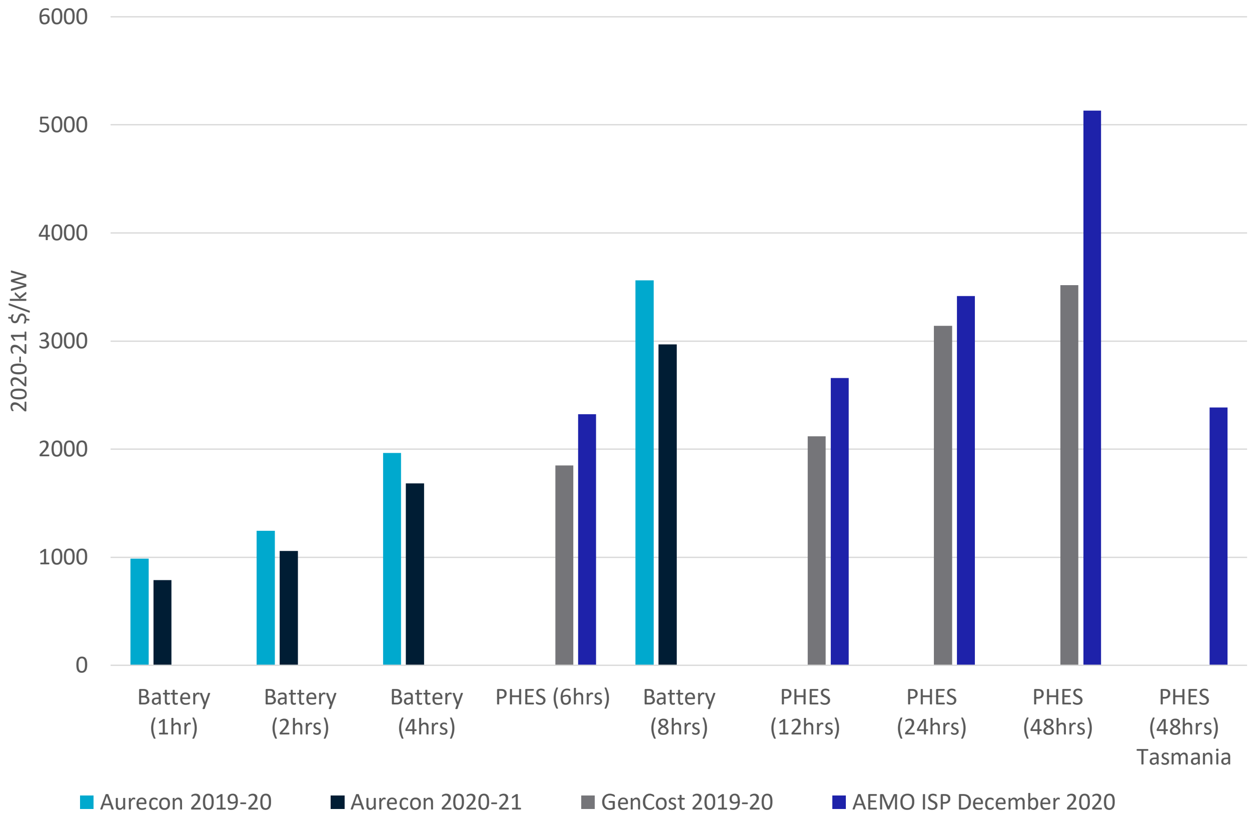

Figure 2-3 Capital costs of storage technologies in $/kW (total cost basis)

3 Scenario narratives and data assumptions

3.1 Scenario narratives

The global climate policy ambitions for the Central, High VRE and Diverse Technology scenarios have been adopted from the International Energy Agency's 2020 World Energy Outlook (IEA WEO 2020) scenarios matching to the Stated Policies scenario, Net Zero Emission by 2050 and Sustainable Development Scenario respectively. Other elements, such as the degree of vehicle electrification and hydrogen production, are also consistent with IEA WEO 2020. However, we also include other topics in our scenarios such as renewable resource constraints and the social and political acceptance and technical performance of renewables.

3.1.1 Central

The Central scenario applies a 2.7 degrees consistent climate policy (using the carbon prices and other climate policies implemented by the IEA[6]). This represents 2020 climate and renewable energy policy commitments with no extension beyond current targets[7]. This implies that current 2030 Paris Nationally Determined Commitments are met but that the planned ramping up of ambition to prevent a greater than 2 degrees increase in temperature does not occur. There are moderate constraints applied with respect to global renewable energy resources (based on currently available information). Technical approaches for managing balancing of variable renewable electricity are based on current technology. Demand growth is moderate with moderate electrification of transport.

3.1.2 High VRE

Under the High VRE scenario there is a strong climate policy consistent with maintaining temperature increases of 1.5 degrees and achieving net zero emissions by 2050 worldwide. Reflecting the low emission intensity of predominantly renewable electricity supply there is an emphasis on energy efficiency and high electrification across sectors such as transport, hydrogen-based industries and buildings leading to high electricity demand. Renewable energy resources are less constrained (both physically and socially) and balancing variable renewable electricity is less technically challenging.

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[6] 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. The IEA also includes a broad range of additional policies such as renewable energy targets and planned closure of fossil-based generation. We include these as well but cannot completely match the IEA implementation because of model structural differences. We align our own implementation of non-carbon price policies to ensure we match the emission outcomes in the relevant IEA scenario.

[7] To be consistent with the IEA World Energy Outlook 2020, this does not include more recent announcements or changes of government since the IEA report was complete. For example, the WEO 2020 includes China's 2060 net zero emissions pledge in its sustainable development scenario which we use for Diverse Technology but does not include recent announcements by Japan and South Korea, nor change of leadership in the United States. See Annex B of WEO 2020.

3.1.3 Diverse Technology

The Diverse Technology scenario assumes that physical and social constraints mean that access to variable renewable energy resources is more limited in most regions of the world. Governments subsequently limit their renewable targets below the threshold required for major deployment of balancing solutions. Consequently, there is a greater reliance on non-renewable technologies and a carbon price consistent with a 1.65 degrees climate policy ambition provides the investment signal necessary to deploy these technologies. Developed countries are still largely aiming for net zero emissions by 2050 but other countries are lagging such that worldwide net zero emissions are not achieved until 2070. Hydrogen trade (based mainly on gas with CCS and alkaline electrolysis) is relatively high allowing some regions with energy or CO_2 storage resource limitations to access a low emission imported fuel.

Table 3-1 Scenarios and their key drivers

Key drivers	High VRE	Diverse Technology	Central
IEA WEO 2020 scenario alignment	Net zero emission by 2050	Sustainable development scenario	Stated policies scenario
CO2 pricing / climate policy	Consistent with 1.5 degrees world, not requiring negative abatement technologies	Consistent with 1.65 degrees world (or 1.5 if negative abatement technologies deployed by 2070)	Consistent with 2.7 degrees world
Renewable energy targets and forced builds / accelerated retirement	High (reflecting confidence in VRE)	RE policies go to no more than 40%	Current RE policies
Demand / Electrification	High	Medium	Medium
Learning rates[1]	Higher for longer in solar and batteries	Normal maturity path	Higher for longer in solar and batteries
Renewable resource & other renewable constraints	Less constrained	More constrained than existing assumptions	Existing constraint assumptions[2]
Constraints around stability and reliability of variable renewables	New low-cost solutions	Conventional solutions but less demand for them	Conventional solutions
Decentralisation	Less constrained rooftop solar photovoltaics (PV)	More constrained rooftop solar PV constraints[2]	Existing 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. In a normal maturity path, learning rates fall over time as per Apx Figure A.1.
2 Existing large-scale and rooftop solar PV renewable generation constraints are as shown in Table 3-5.

3.1.4 Scenario design considerations

The GenCost scenarios are described in general in Table 3-1 and expanded on in the sub-sections below. The scenario drivers are based on the themes identified by stakeholders at a workshop in August 2019, together with insights from the modelling team on what would most likely deliver a broad range of technology cost outcomes.

We acknowledge that there are potential wild card events that are not included in the scenarios such as completely new technologies and inter-regional high voltage interconnection. However, we chose to exclude wild cards. We also considered the possibility of aligning scenarios with other globally recognised scenarios. However, we found that drivers for other scenarios were not well targeted at producing changes in technology outcomes. In particular, experience has shown that climate change policy drivers alone do not result in major differences in technology adoption.

3.1.5 Technologies and learning rates

As we explain further in Appendix A, we use two global and local learning models (GALLM). One 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. Where appropriate, these have been split into their components of which there are 48. 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 technologies. The 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 on a global (G) basis, local (L) to the region, or no learning (-) is associated).

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 current costs from Aurecon (2021) to calibrate 2020 Australian costs in GALLME. 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.

Table 3-2 Assumed technology learning rates under all scenarios

Technology	Component	LR 1 (%)	LR 2 (%)	References
Coal, pf	-	-	-	
Coal, IGCC	G	-	2	(International Energy Agency, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	10	5	(EPRI Palo Alto CA & Commonwealth of Australia, 2010; Rubin et al., 2007)
	L	20	10	As above + (Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001)
Gas peaking plant	-	-	-	
Gas combined cycle	-	-	-	
Nuclear	G	-	3	(International Energy Agency, 2008)
SMR	G	20	10	(Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001)
Diesel/oil-based generation	-	-	-	
Reciprocating engines	-	-	-	
Hydro	-	-	-	
Biomass	G	-	5	(International Energy Agency, 2008; Neij, 2008)
Concentrating solar thermal (CST)	G	14.6	7	(Hayward & Graham, 2013)
Photovoltaics	G	35	10	(Fraunhofer ISE, 2015; Hayward & Graham, 2013; Wilson, 2012)
	L	-	17.5	As above
Onshore wind	G	-	4.3	(Hayward & Graham, 2013)
	L	-	11.3	As above
Offshore wind	G	-	15	(Samadi, 2018) (van der Zwaan, Rivera-Tinoco, Lensink, & van den Oosterkamp, 2012) (Voormolen, Junginger, Sark, & M, 2016)
Wave	G	-	9	(Hayward & Graham, 2013)
CHP	-	-	-	
Conventional geothermal	G	-	8	(Hayward & Graham, 2013)

Technology	Component	LR 1 (%)	LR 2 (%)	References
	L	20	20	(Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001)
Fuel cells	G	-	20	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Pumped hydro	G	-		
	L	-	20	(Grübler et al., 1999; Schrattenholzer & McDonald, 2001)
Electrolysis	G	18	9	(Schmidt et al., 2017)
	L	18	9	
Steam methane reforming with CCS	G	10	5	(EPRI Palo Alto CA & Commonwealth of Australia, 2010; Rubin et al., 2007)
	L	20	10	As above + (Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001)

Pf=pulverised fuel, IGCC=integrated gasification combined cycle, CHP=combined heat and power, SMR=small modular reactor
Solar photovoltaics is listed as one technology with global and local components however there are three 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. PV with storage has all the components including batteries. Inverters are not given a learning rate instead they are given a constant cost reduction, which is based on historical data.
Geothermal BOP includes the power generation.
Shared technology components mean that when one of the technologies that uses that component is installed, the costs decrease not just for that technology but for all technologies that use that component.

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. The learning rates are applied uniformly across all scenarios except in the case of batteries. Table 3-3 provides the learning rate by scenario for batteries. Given batteries are deployed in such large numbers across all scenarios due to vehicle electrification and to support increases in variable renewable generation, without these assumed differences in learning rates the battery cost would converge to a common end point. Allowing for differences in the learning rate is useful in reflecting greater uncertainty in the long-term battery costs.

Table 3-3 Assumed utility scale energy storage learning rates by scenario

Technology	Scenario	Component	LR 1 (%)	LR 2(%)
Utility scale energy storage – Li-ion	Central	G	-	10
		L	-	10
Utility scale energy storage – flow batteries	Central	G	-	15
		L	-	10
Utility scale energy storage – Li-ion	High VRE	G	-	15
		L	-	15
Utility scale energy storage – flow batteries	High VRE	G	-	15
		L	-	15
Utility scale energy storage – Li-ion	Diverse Tech	G	-	7.5
		L	-	7.5
Utility scale energy storage – flow batteries	Diverse Tech	G	-	15
		L	-	7.5

Li-ion batteries are a component that is used in both PV with storage and utility scale Li-ion battery energy storage. Installation BOP is a component of utility scale battery storage that is shared between both types of utility scale battery storage. Source of High VRE learning rate and flow battery learning rate (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015). Central and Diverse Technology li-ion learning rates based on CSIRO estimates.

Offshore wind has a learning rate of 15% (IEA, 2020) which is significantly higher than that of onshore wind. In addition to capital cost reductions, offshore wind farms have seen significant increases in capacity factor as larger turbines are used, which reduce the LCOE (IRENA, 2019). We have included an exogenous increase 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.

Two types of reciprocating engines have been included in GALLME. The first type uses diesel as a fuel and the second, more expensive type uses hydrogen as fuel. They are considered to be mature technologies and therefore do not have a learning rate. They can be used as peaking or ‘baseload’ plant in the model.

3.1.6 Electricity demand and electrification

In GenCost 2020-21 we have sought to deepen our approach to electrification and hydrogen production assumptions. Previously we had been reliant on existing published global demand scenarios to capture all demand effects. Our goal is to provide more explicit road vehicle electrification assumptions whilst still using existing sources to set underlying global electricity demand. Underlying electricity demand is sourced from the IEA’s latest version of the World

Energy Outlook (IEA, 2020). Demand data is provided for the Sustainable Development Scenario (SDS), which is used in our Diverse Technology scenario. The demand data from the Stated Policies (STEPS) scenario is used in our Central scenario. Detailed demand data was not provided for the Net Zero Emissions scenario. However, the text indicates that it is higher than SDS and comparable with STEPS and thus we have applied the STEPS scenario demand assumptions to our Diverse Technology scenario. Added to this is the electric vehicle electricity consumption (net of existing electrification assumptions in the IEA scenarios). The IEA demand data also includes electricity used to make hydrogen by scenario. We have therefore assumed the same level of hydrogen demand per scenario as the IEA's World Energy Outlook.

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 across electricity and hydrogen demand. The rate of adoption is highest in the VRE scenario, medium in the Diverse Technology scenario and low in the Central 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 Central, High VRE, Diverse Technology 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.

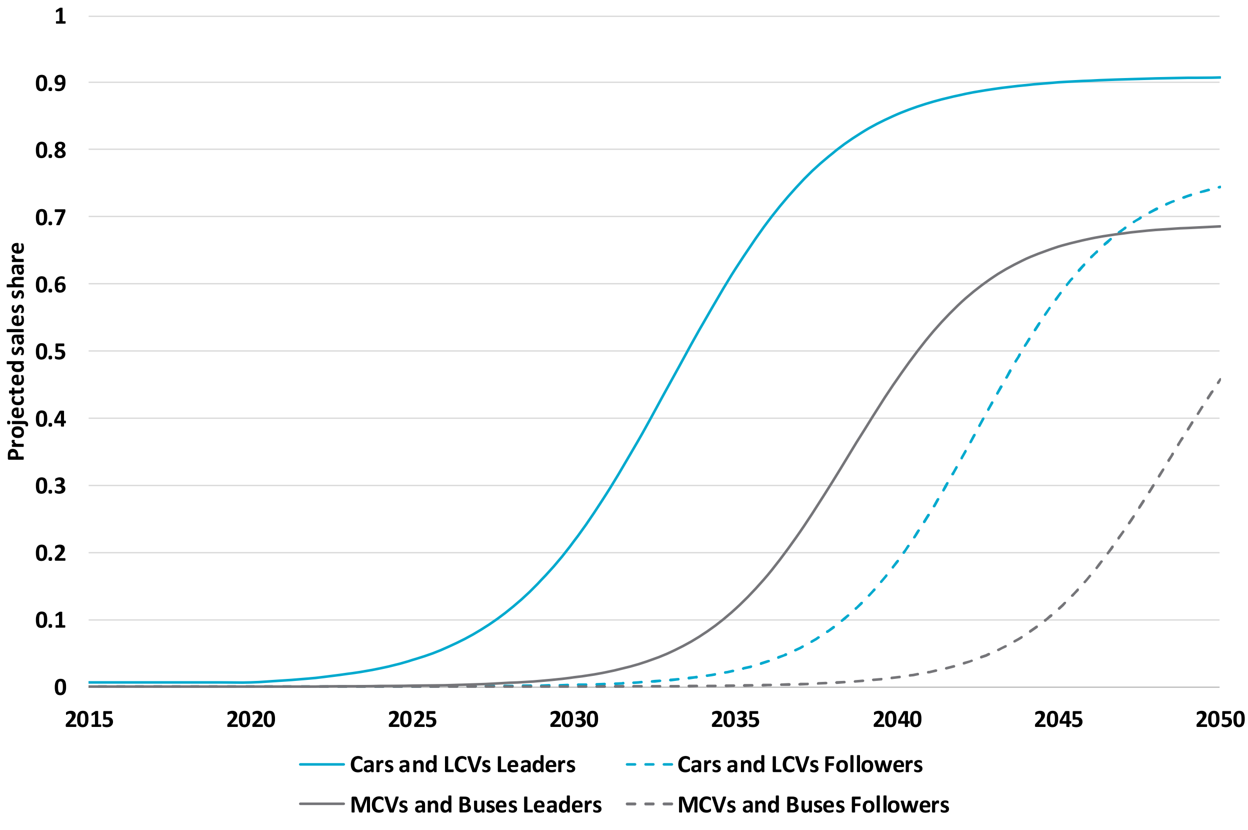

Figure 3-1 Projected EV sales share under the Central scenario

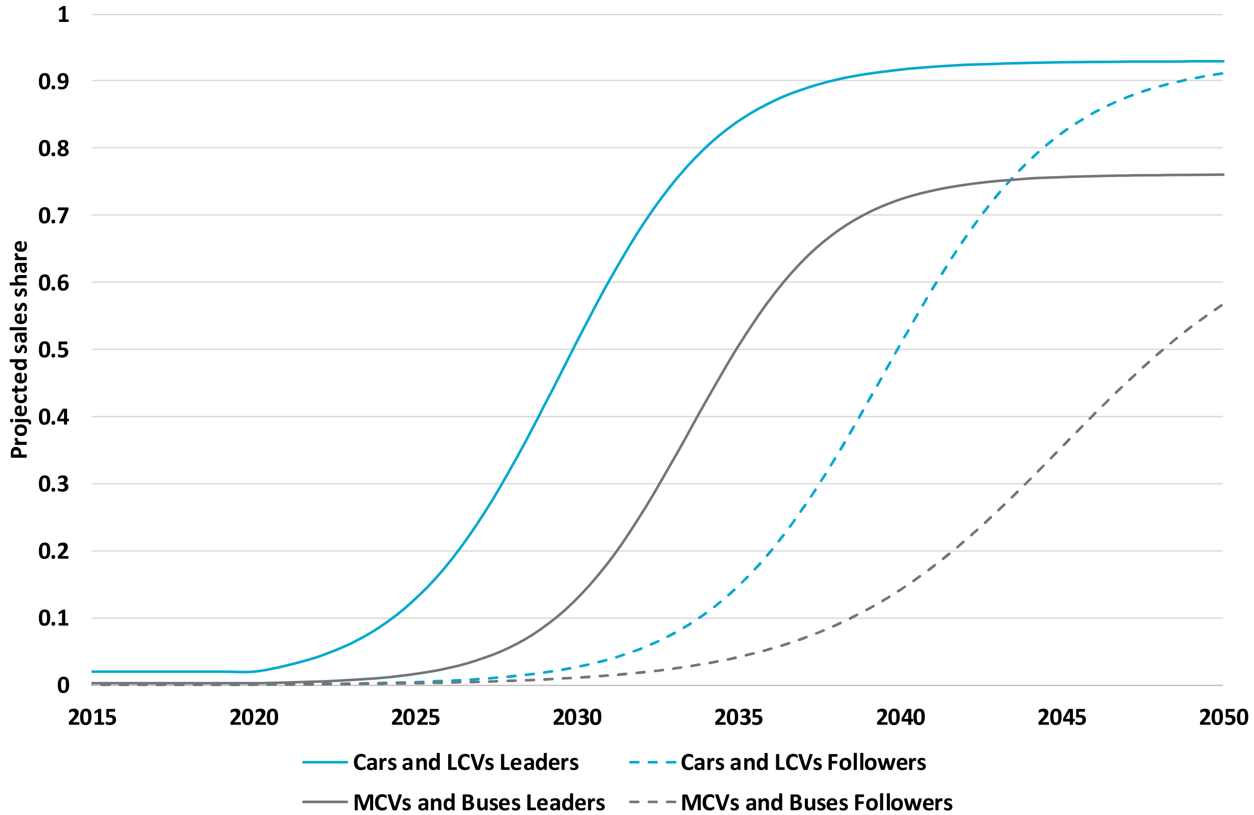

Figure 3-2 Projected EV adoption curve (vehicle sales share) under the High VRE scenario

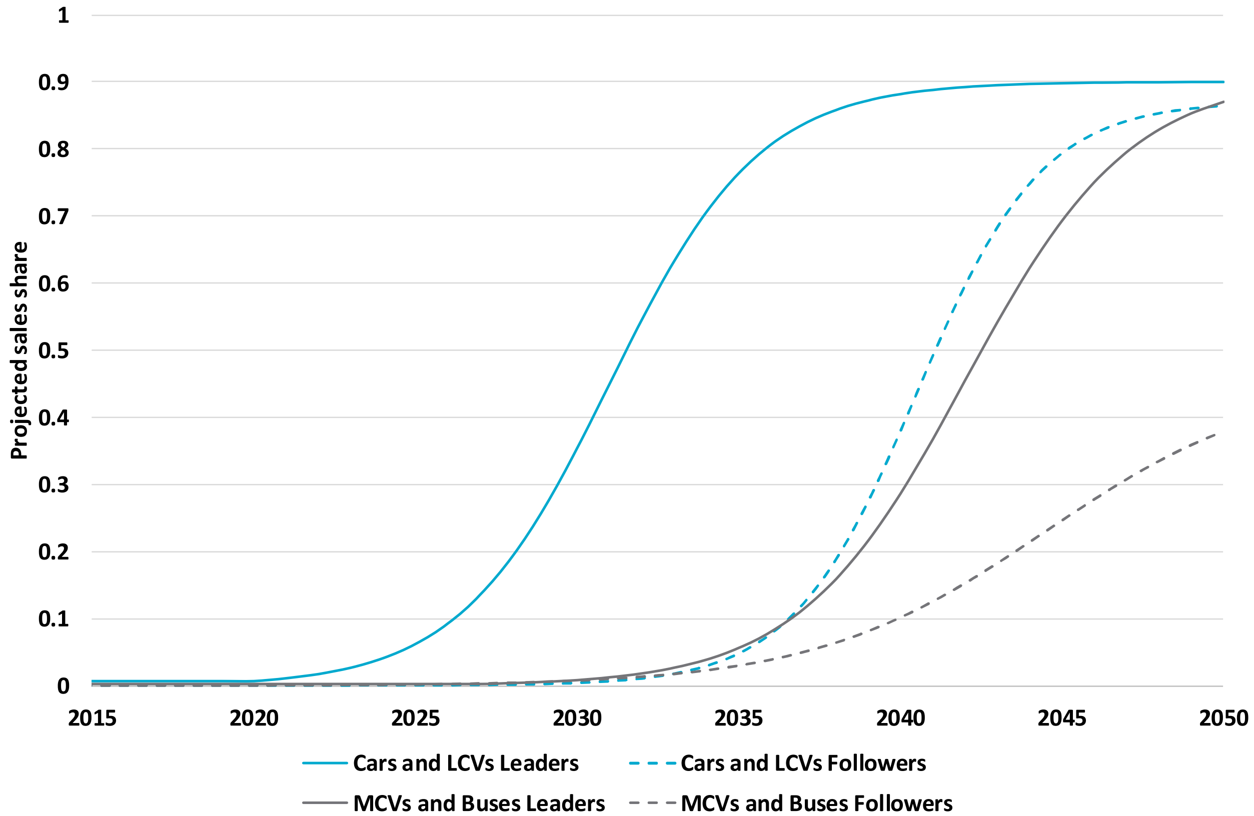

Figure 3-3 Projected EV sales share under the Diverse Technology scenario

3.1.7 Hydrogen

In previous GenCost projections, GALLME used an exogenous hydrogen price which varied by scenario. Given the large role hydrogen could potentially play in decarbonisation across the whole of the energy and industry sectors, hydrogen production technologies, namely electrolysis and steam methane reforming with CCS, now have learning rates applied and contribute to global electricity demand. Their capital costs have been projected based on deployment required to meet demand for hydrogen projected by the IEA and the technology contributions to meeting that demand have been based on adoption curves which vary by scenario. The learning rates used are shown in Table 3-2 and the adoption curves are shown in Figure 3-4 to Figure 3-6. The adoption curves have been designed to provide a range of future technology costs which match each scenario. In the High VRE scenario proton-exchange membrane electrolysis (PEM) is the dominant technology as this works best with VRE. In the Central scenario alkaline electrolysis (AE) is the dominant technology. In the Diverse Technology scenario steam methane reforming with CCS dominates.

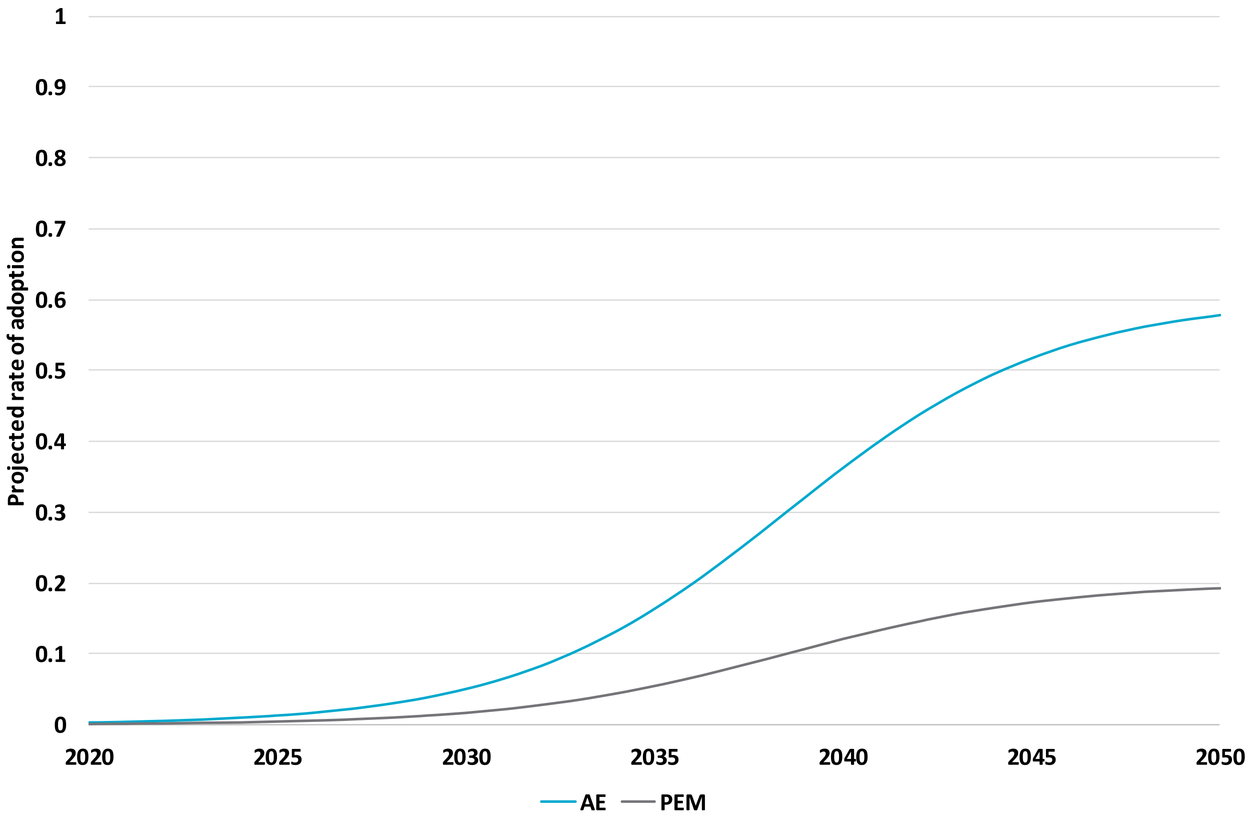

Figure 3-4 Adoption curves for hydrogen technologies under the Central scenario

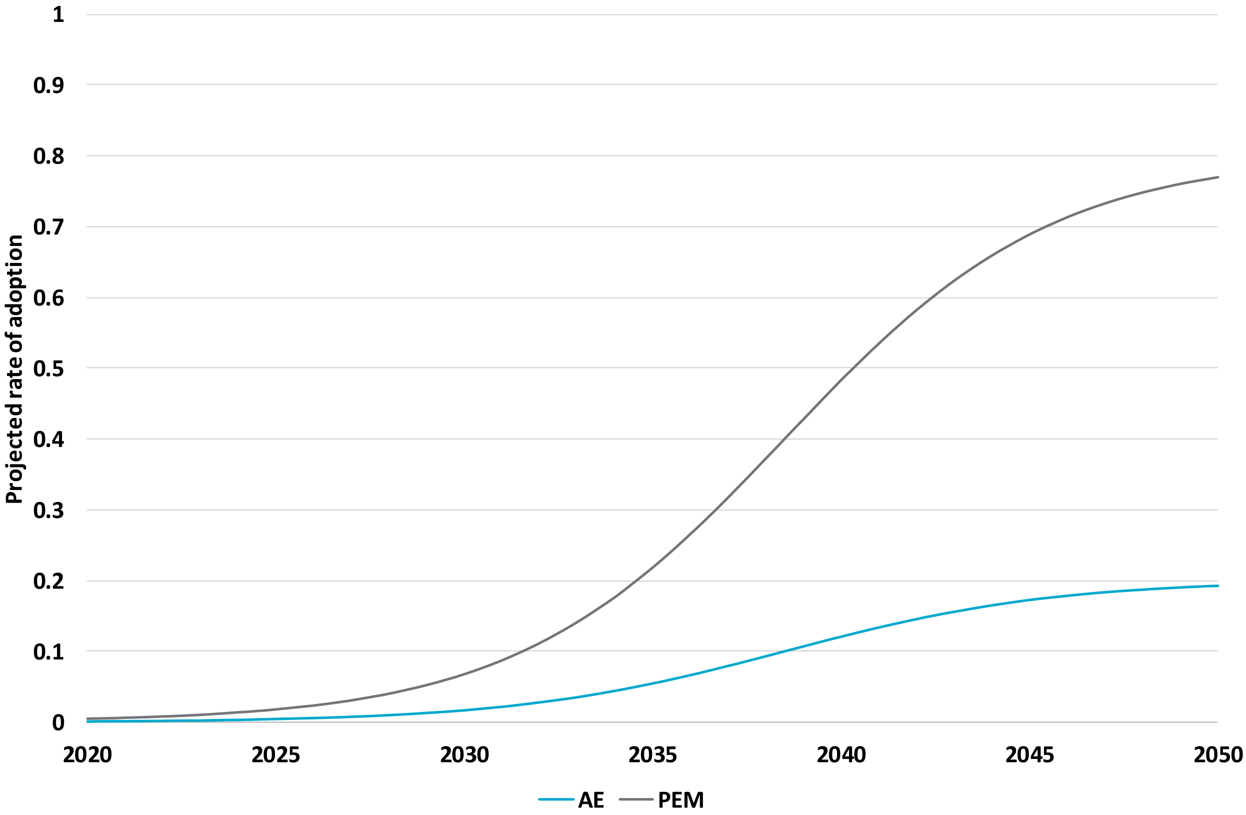

Figure 3-5 Adoption curves for hydrogen technologies under the High VRE scenario

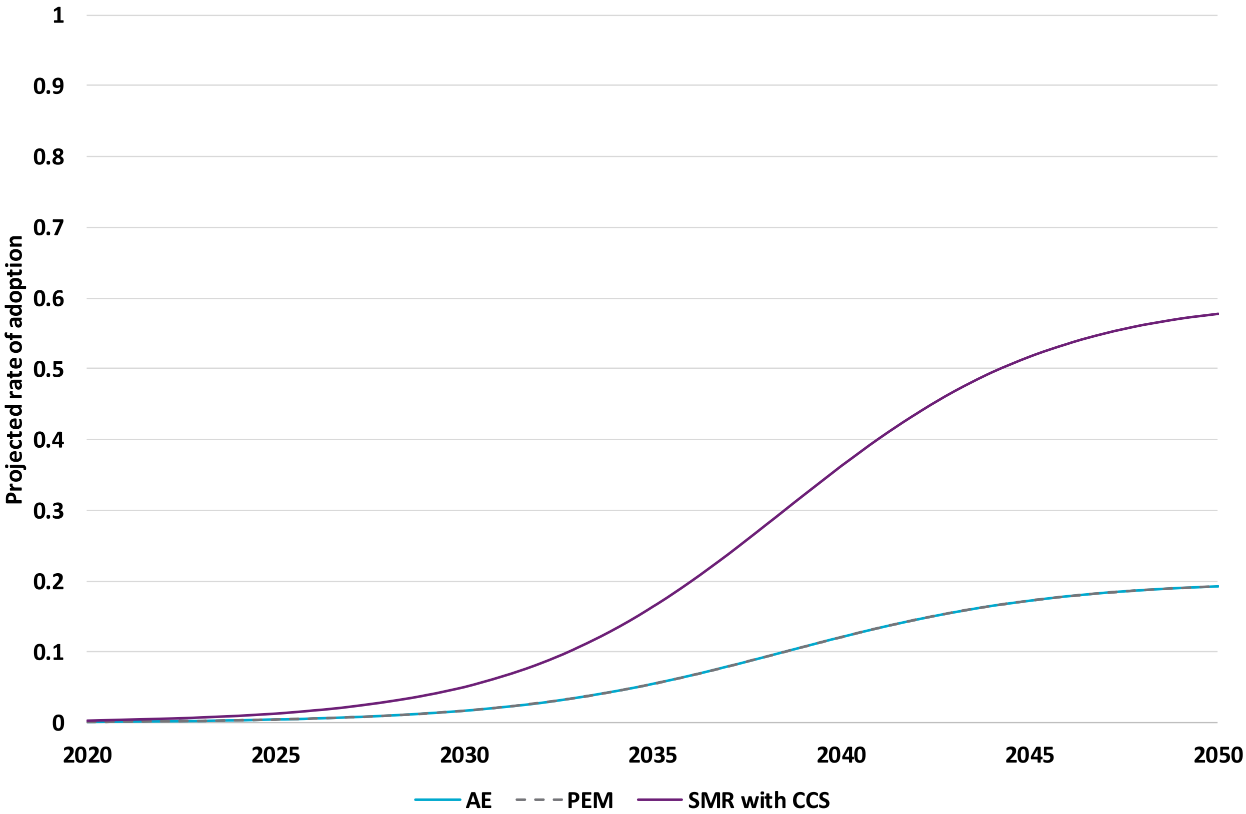

Figure 3-6 Adoption curves for hydrogen technologies under the Diverse Technology scenario

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 current generation of AE are better suited to a steady and continuous supply of electricity whereas PEM can work with variable renewable supply. However, that balance has been changing with recent developments focussed on improving the performance of AE and reducing the cost of PEM.

The IEA have included demand for electricity from electrolysis in their scenarios. Given that we are assuming the same rate of hydrogen demand per scenario as the IEA we have made no changes to electricity demand assumptions to take into account hydrogen production. The assumed hydrogen demand assumptions for the year 2040 are shown in Table 3-4 and include existing demand, the majority of which is 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

Scenario	2040 total hydrogen demand (Mt)
Central	80
High VRE	331
Diverse Technology	150

3.1.8 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 which are reported in IEA (2020). IEA (2020) 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.

The country policy commitments included are not completely up to date. To be consistent with the IEA World Energy Outlook 2020, the scenarios do not include more recent announcements or changes of government policy since the IEA report was complete. For example, the WEO 2020 includes China's 2060 net zero emissions pledge in its sustainable development scenario which we use for Diverse Technology but does not include recent announcements by Japan and South Korea, nor change of leadership in the United States. See Annex B of WEO 2020.

3.1.9 Resource constraints

Constraints around 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 (see Government of India, 2016, Edmonds, et al., 2013 and Hayward & Graham, 2017 for more information on sources). Constraints on key renewable technologies in the Central scenario are shown in Table 3-5. In the High VRE scenario, the resource constraint on renewables was removed. In the Diverse Technology scenario, variable renewables will be limited to 40% of generation below the year 2060. However, this will not limit all renewables i.e. all forms of biomass-fuelled and hydrogen-fuelled generation, hydro and geothermal are not limited.

Table 3-5 Renewable resource limits on generation in TWh in the year 2050. NA means the resource is greater than projected electricity demand.

Region	Rooftop PV	Large scale PV	CSP	Onshore wind
AFR	565	NA	NA	NA
AUS	113	NA	NA	NA
CHI	1913	NA	NA	NA
EUE	179	NA	NA	NA
EUW	776	112	1155	2125
FSU	300	NA	NA	NA
IND	416	1732	1465	550
JPN	165	17	174	247
LAM	587	NA	NA	NA
MEA	531	NA	NA	NA
NAM	1901	NA	NA	NA
PAO	157	47	480	682
SEA	647	249	2566	974

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)

3.1.10 Other data assumptions

GALLME international fossil fuel prices are based on (IEA, 2020) as shown in Table 3-6 for gas and Table 3-7 for black coal. Brown coal has a flat price of 0.6 $/GJ and there is one global oil price which is shown in Table 3-8.

Table 3-6 Assumed gas prices in $A/GJ

	2019	2025	2040	2050
AFR	12	13	16	18
AUS[8]	6	5	5	5
CHI	12	12	13	13
EUE	10	10	12	14
EUW	10	10	12	14
FSU	10	10	12	14
IND	15	13	13	13
JPN	15	13	13	13
LAM	12	12	13	13
MEA	4	5	6	7
NAM	4	5	6	7
PAO	15	13	13	13
SEA	10	10	12	14

[8] It should be noted that the IEA's Australian gas prices are more optimistic than we would normally expect. Given the strong climate policy ambition of the IEA scenarios, they are reflective of a system with low gas demand. Australian assumptions have very minor impact on the global modelling.

Table 3-7 Assumed black coal prices in $A/GJ

	2019	2025	2040	2050
AFR	5.1	4.7	4.7	4.7
AUS	2.9	2.7	2.7	2.7
CHI	5.6	5.0	4.8	4.6
EUE	3.7	4.0	4.2	4.3
EUW	3.7	4.0	4.2	4.3
FSU	2.8	3.2	3.0	2.9
IND	2.8	3.2	3.0	2.9
JPN	5.1	4.7	4.7	4.7
LAM	5.1	4.7	4.7	4.7
MEA	5.1	4.7	4.7	4.7
NAM	2.8	3.2	3.0	2.9
PAO	5.1	4.7	4.7	4.7
SEA	5.1	4.7	4.7	4.7

Table 3-8 Assumed global oil price in $A/bbl

	2019	2025	2040	2050
Global price	91	103	123	139

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

4 Projection results

4.1 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.

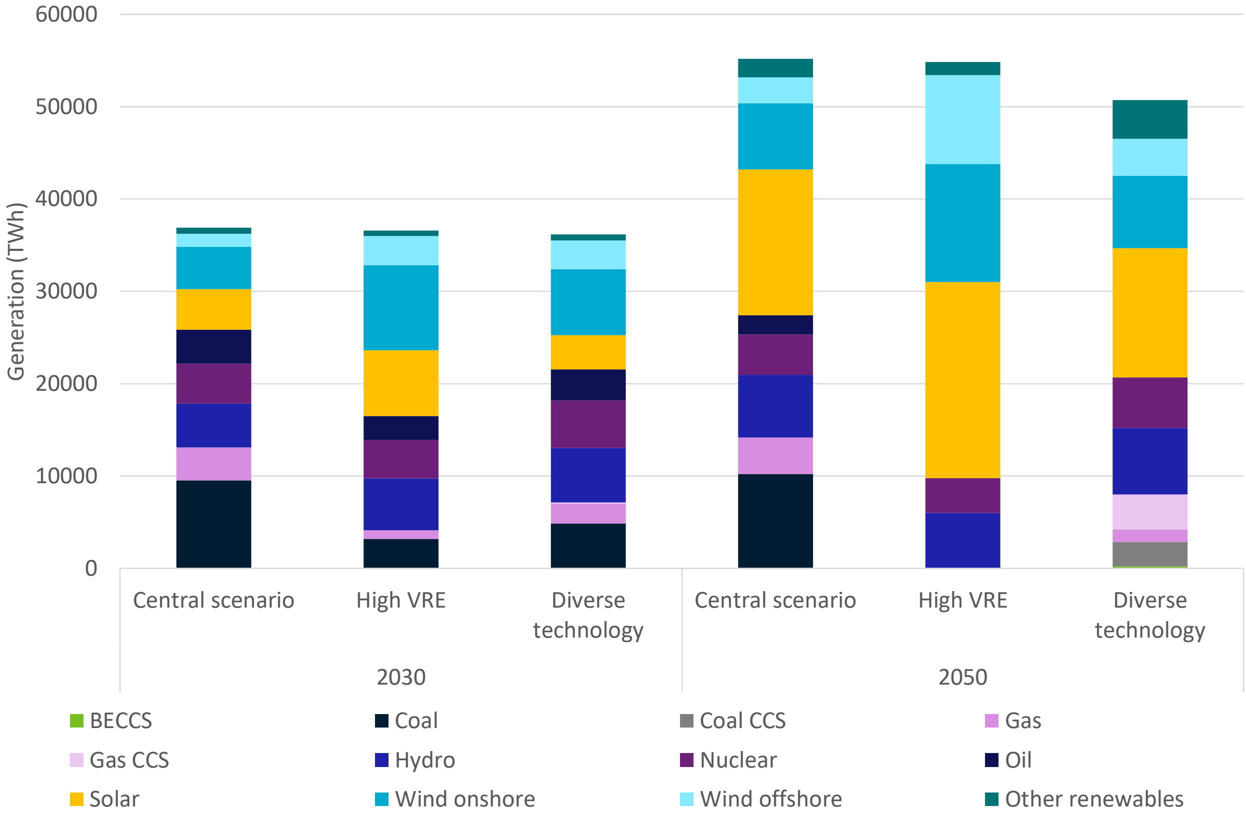

Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Central scenario has the lowest electrification because it has the least climate policy ambition. However, it has the least energy efficiency and industry transformation[9]. For this reason, it has similar overall electricity demand to High VRE which has the most climate policy ambition, high vehicle electrification and high hydrogen electrolysis but also high energy efficiency and industry transformation which offsets these sources of new electricity demand growth. Diverse Technology

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

also has stronger climate policy ambition than Central, but its hydrogen production is dominated by gas with CCS.

By design, Diverse Technology has a low renewable share for its level of climate policy ambition. Variable renewables such as wind and solar PV are limited to a 50% share and as a result total non-hydro renewable generation accounts for 59% of generation by 2050. Coal and gas with CCS are the main substitutes for lower renewables with gas being the most preferred CCS technology. A small amount of gas without CCS also remains in the mix. Nuclear has a proportionally higher role, 44% higher than in High VRE and 25% higher than Central.

The Central scenario has the least climate policy ambition and as a result it has the highest amount of coal, gas and oil-based generation in 2030 and 2050. The non-hydro renewable share of generation is 50% by 2050 with a strong focus on solar and wind.

The High VRE scenario is near zero emission by 2050 with a non-hydro renewable share of 82% by 2050. In 2030, it has the highest retirement of existing coal, gas and oil-based generation with earlier deployment of solar and wind generation. Offshore wind features strongly in this scenario, reflecting the strong need for renewable resources. Nuclear generation is the lowest in High VRE consistent with the dominance of lower cost renewables available at high volumes with high social, political and technical support.

4.2 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2019-20 projections. For mature technologies, where the current costs have not changed and the assumed improvement rate is very similar, their projection pathways often overlap. The assumed annual rate of cost reduction for mature technologies is 0.2% in this report. This is faster than the 0.01% calculated in GenCost 2019-20. 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 from CSIRO's Data Access Portal[10].

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

4.2.1 Black coal supercritical

The 2019-20 black coal generation capital costs were based on GHD (2018). For the 2020-21 projections, Aurecon (2021) has increased the current cost by around $1000/kW. However, the assumed rate of improvement in mature technologies is faster which leads to a modest amount of convergence in the projections over time.

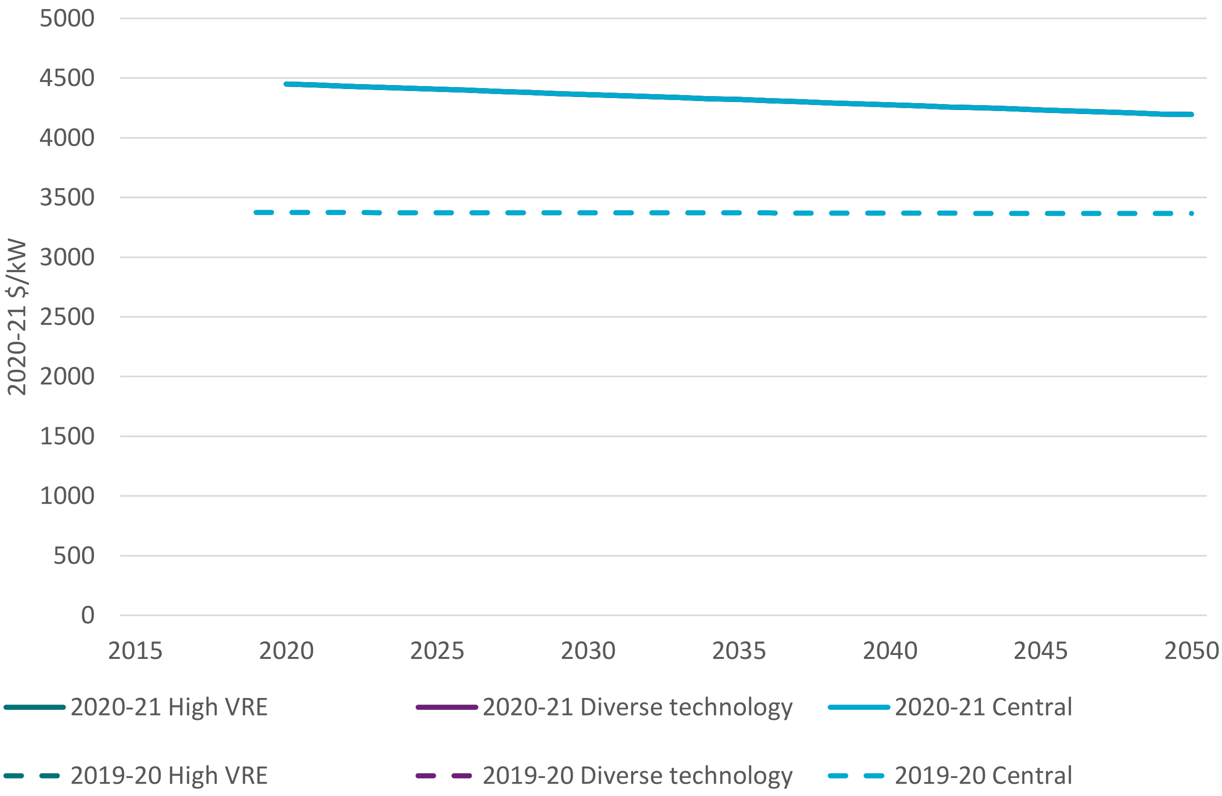

Figure 4-2 Projected capital costs for black coal supercritical by scenario compared to 2019-20 projections

4.2.2 Coal with CCS

The 2019-20 black coal with CCS current capital costs were based on GHD (2018) and have been updated by Aurecon (2020) for the 2020-21 projections. Consequently, these projections begin from a higher starting point of just over $9000/kW. CCS is not deployed in Central and high VRE and so it does not achieve any cost reduction. This is more negative than the 2019-20 results for those scenarios. The update to higher current costs is likely responsible.

Given assumed lower confidence in the deployment of variable renewables, the Diverse Technology scenario has the earliest and highest deployment of CCS in both the generation sector and in gas-based hydrogen production. Substantial deployment commences from around 2027 which is a four years later than in the 2019-20 projections. While the global generation share of coal with CCS is low at 5%, CCS cost reductions include co-learning from deployment of gas with CCS (global CCS generation share is 13%).

Brown coal with CCS is included in the Appendix B data tables. It experiences a similar cost trajectory to black coal with CCS due to co-learning.

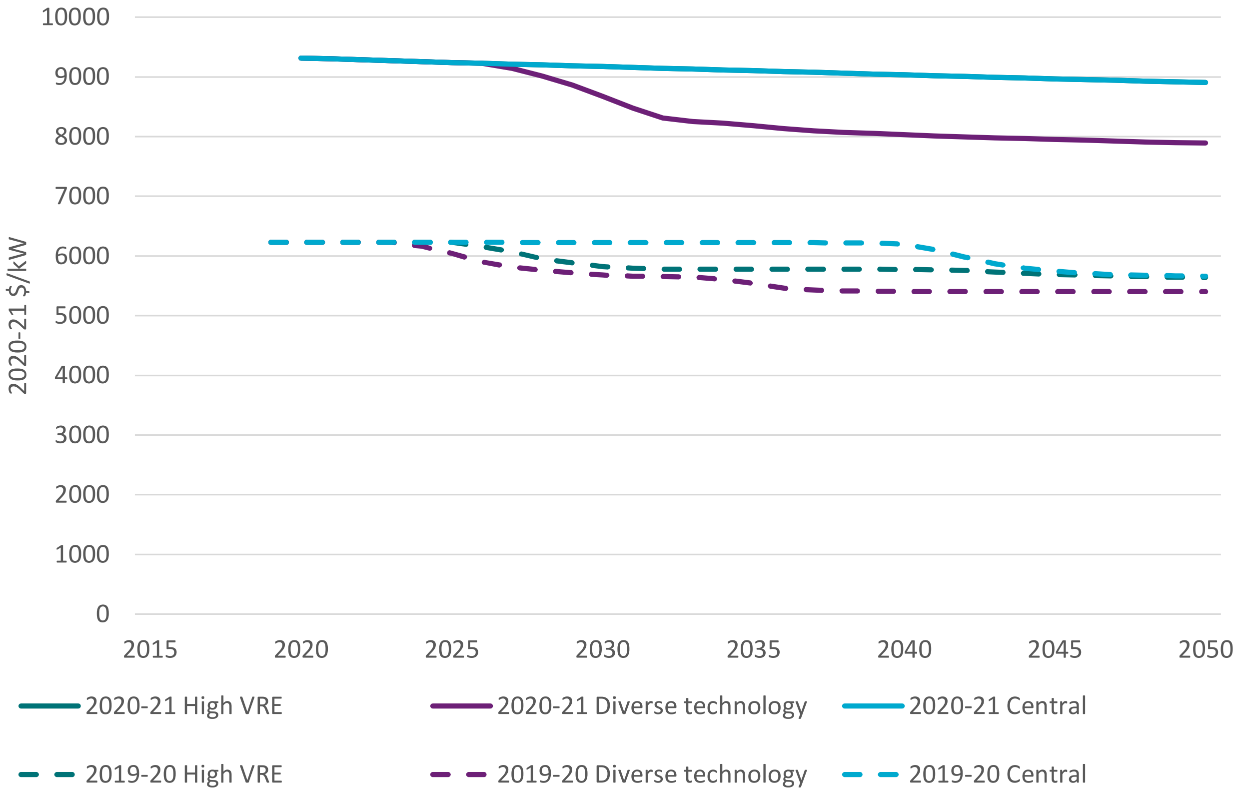

Figure 4-3 Projected capital costs for black coal with CCS by scenario compared to 2019-20 projections

4.2.3 Gas combined cycle

Gas combined cycle is classed as a mature technology for projection purposes and as a result its change in capital cost is governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the Central, High VRE and Diverse Technology scenarios. The current capital cost for gas combined cycle was updated by Aurecon (2021) and is only slightly higher than in 2019-20. The faster assumed reduction in mature technology costs in the 2020-21 projections results in a convergence with 2019-20 projections by 2025 and low costs in the long run.

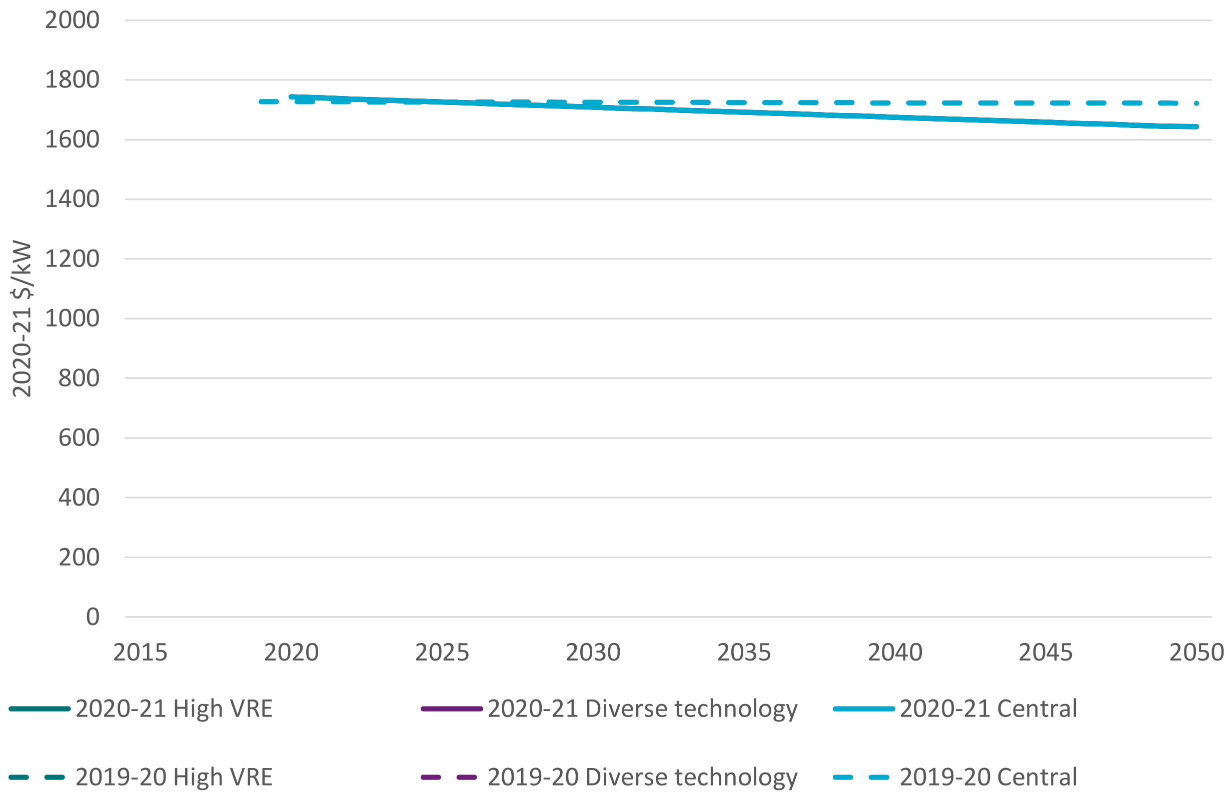

Figure 4-4 Projected capital costs for gas combined cycle by scenario compared to 2019-20 projections

4.2.4 Gas with CCS

The current cost for gas with CCS has been revised slightly upwards for the 2020-21 projections based on Aurecon (2021). Given assumed lower confidence in the deployment of variable renewables, the Diverse Technology scenario has the earliest and highest deployment of gas with CCS in both the generation sector and in gas-based hydrogen production. Coal with CCS, to a lesser extent, also contributes to co-learning between these three CCS technologies. Substantial deployment commences from around 2027 which is around four years later than in the 2019-20 projections.

The cost reduction by 2050 is not as great as that which was projected in the 2019-20 reflecting a lower scale of deployment. Deployment does not occur in any significant amount in Central and High VRE reflecting a preference for building lower cost renewables (plus the use of existing coal and gas without CCS in Central). As such there is no cost reduction achieved.

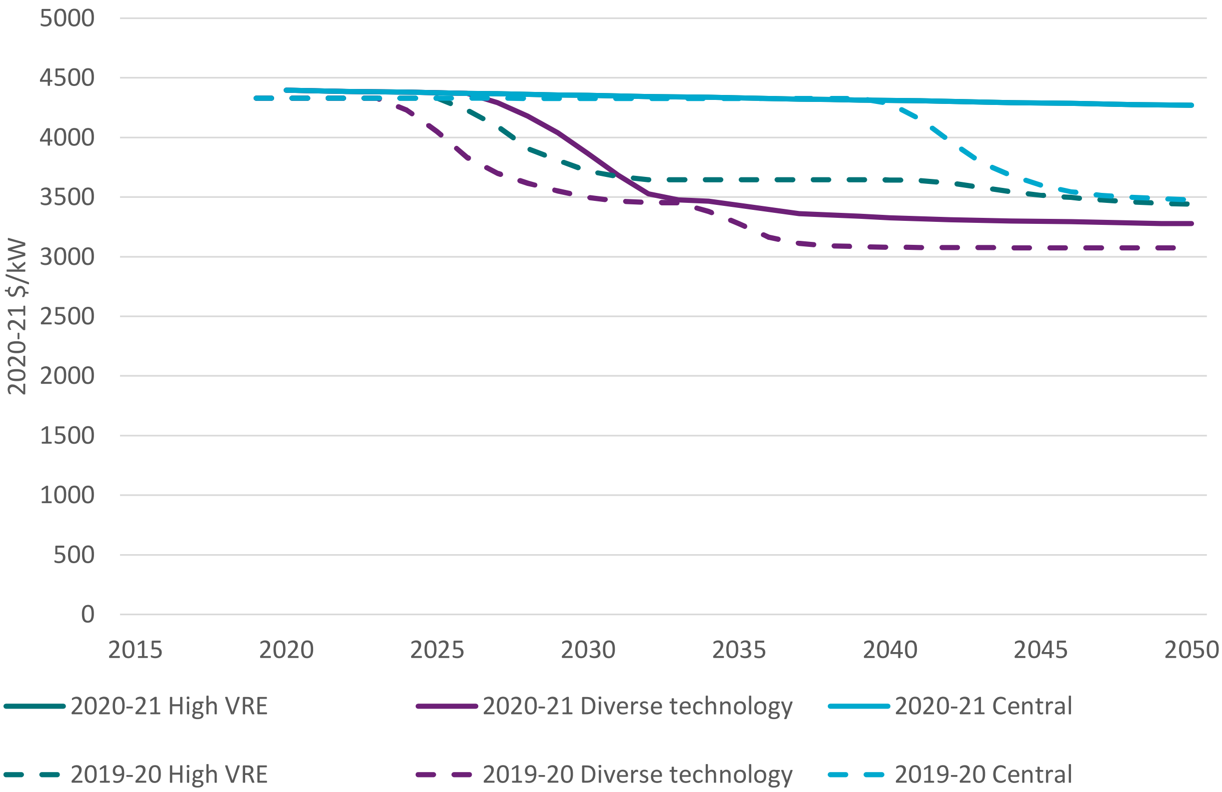

Figure 4-5 Projected capital costs for gas with CCS by scenario compared to 2019-20 projections

4.2.5 Gas open cycle (small)

The 2020-21 projections include results for both large- and small-scale gas open cycle generation. However, only small scale is shown in Figure 4-6 because only small was included in the 2019-20 projections. Both projections are provided in Appendix B with large open cycle starting at around $900/kW. 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. The faster rate of cost reduction for mature technologies assumed in the 2020-21 projections means that the projection exceeds cost reductions projected by 2050 in 2019-20.

Aurecon (2021) reports that current gas open cycle costs are impacted by global over supply and so there is some risk that costs will be adjusted upward if future conditions allow.

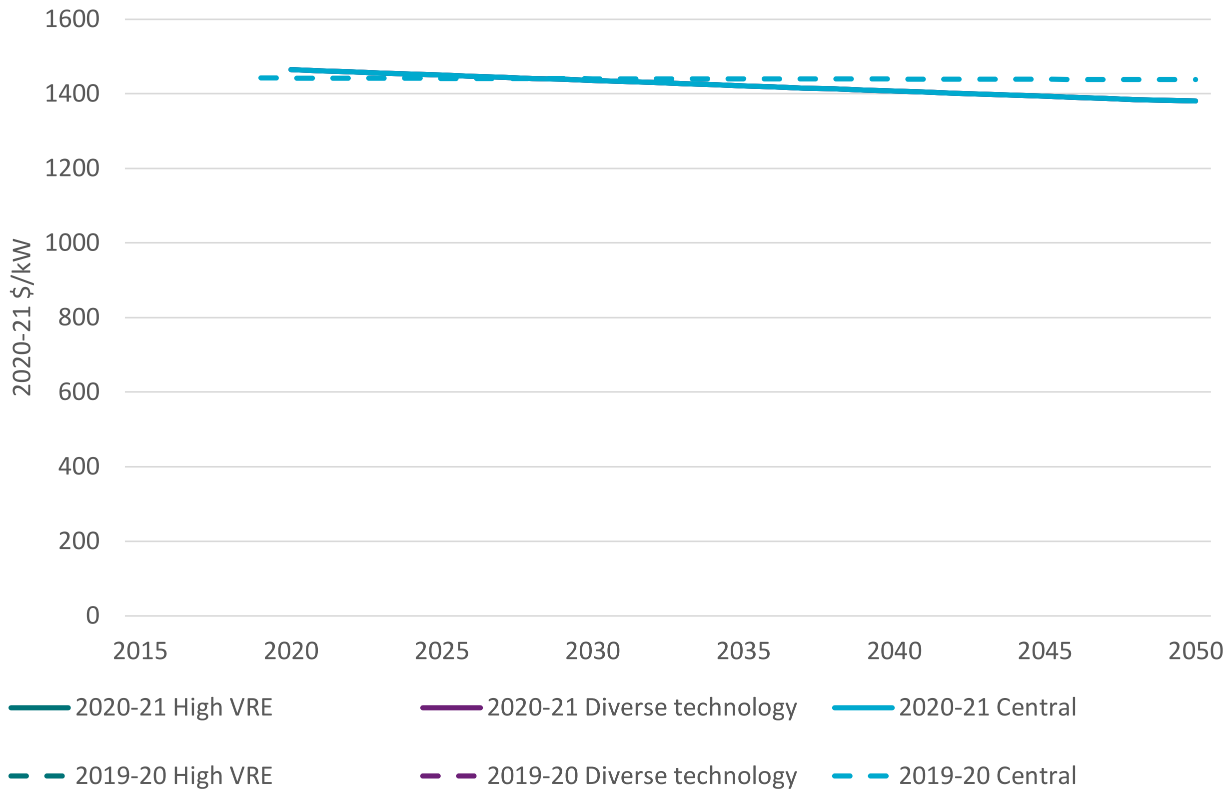

Figure 4-6 Projected capital costs for gas open cycle (small) by scenario compared to 2019-20 projections

4.2.6 Nuclear SMR

The 2020-21 projections start from 2030 consistent with feedback that if nuclear SMR is deployed in Australia, it will not be before 2030. Like the 2019-20 projections, the scenarios present a divergent set of possibilities for nuclear SMR. On the one hand, nuclear SMR does not make any significant cost reduction in the High VRE scenario because deployment of SMR does not proceed. The model has chosen instead to invest in reducing costs of renewables as the most efficient solution reflecting the already low cost of renewables and the scenario context of abundant renewable resources.

Alternatively, nuclear SMR is deployed in Central and Diverse Technology. In both scenarios, significant capital cost reductions occur in the period leading up to 2030 (this could be because of an industry development program in one of the leading nuclear energy nations). This resulting cost projection is consistent with the sort of building program for a modular technology which manufacturers are hoping to undertake. Modular plants reduce the number of unique inputs that need to be manufactured. In Central and Diverse Technology, capital costs are around $7000/kW.

These results are consistent with the 2019-20 projections except that nuclear SMR development is slightly delayed in the Central scenario.

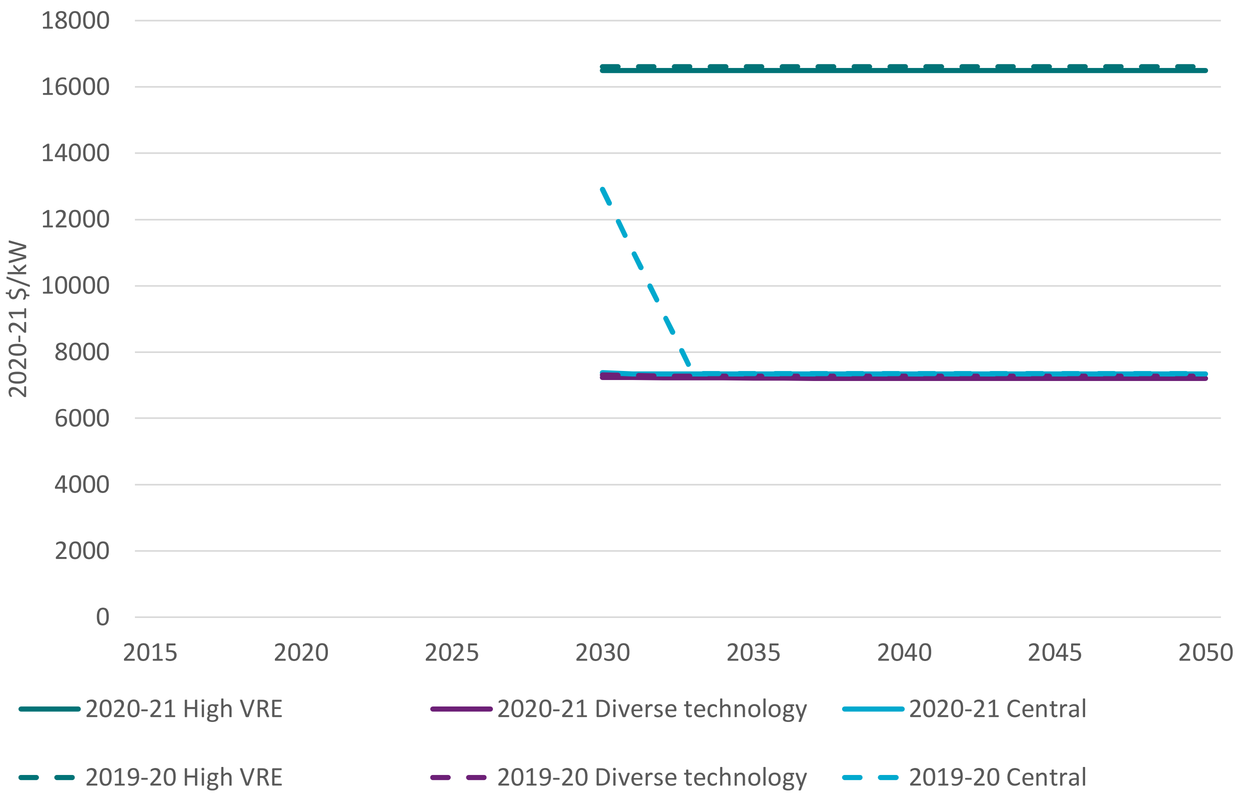

Figure 4-7 Projected capital costs for nuclear SMR by scenario compared to 2019-20 projections

4.2.7 Solar thermal with 8 hours storage

The current capital cost of solar thermal generation was revised upwards for the 2020-21 projections reflecting escalation in Australian project cost estimates. Cost reductions across the scenarios proceed at a faster and steady pace across the scenarios compared to the 2019-20 projections reflecting stronger alignment of the scenarios with the climate ambitions in the IEA 2020 World Energy Outlook. The overall scale of capital cost reduction, around $2500/kW, is similar in Diverse Technology and High VRE. However, the cost reduction in Central is lower. Central does not need to deploy as large a volume of renewables due to weaker climate policy ambitions and so concentrates on lower cost solar PV and wind.

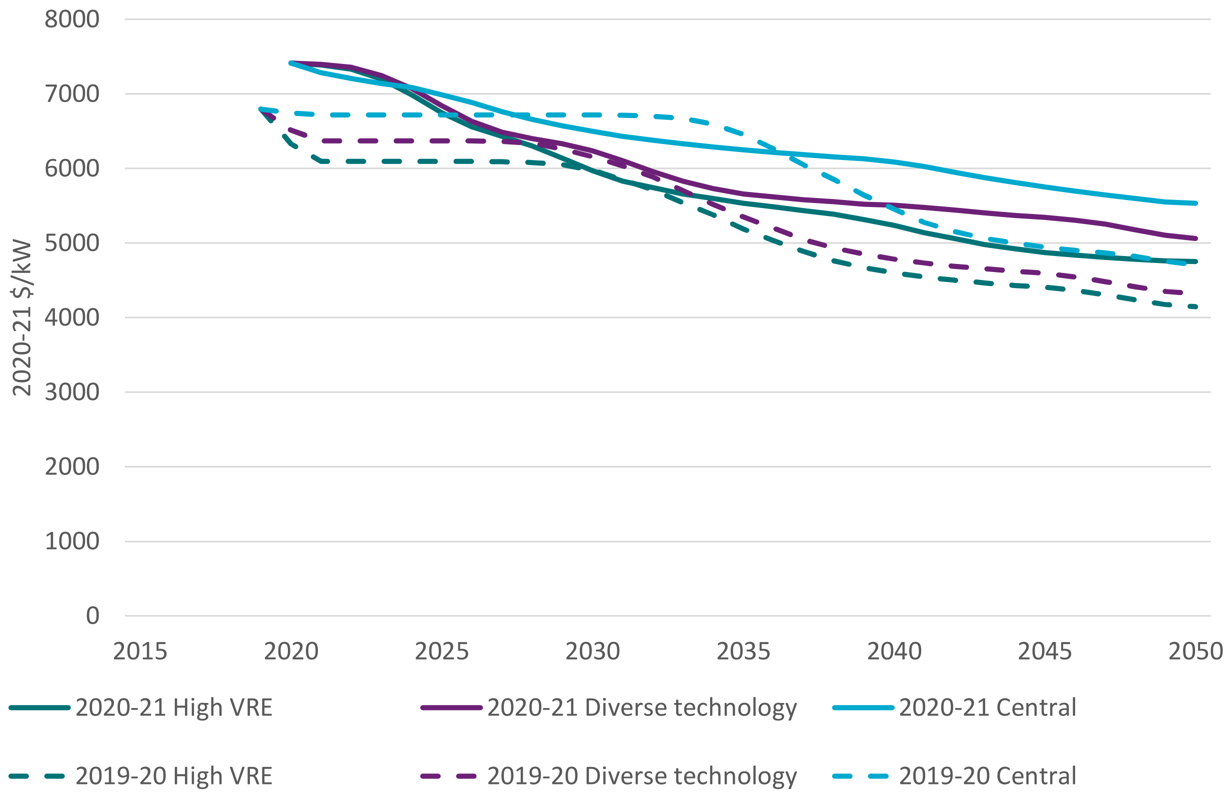

Figure 4-8 Projected capital costs for solar thermal with 8 hours storage by scenario compared to 2019-20 projections

4.2.8 Large scale solar PV

Large-scale solar PV was expected to continue to track their historical learning rate, however cost reductions have slowed in the 2020-21 current cost update. This reflects local challenges in the Australia industry whereby several solar developers went out of business. These developments have reduced competition and led to more conservative outcomes. The modelling has not built any further industry disruptions into the projection and so cost reductions resume in forward years. For future years, the capital cost projections are reasonably aligned with the 2019-20 projections. Under Diverse Technology, variable renewables are limited so that solar PV deployment is lower and as a result less learning occurs, and capital costs are at a higher level. Central and High VRE have greater deployment and subsequent learning. Higher levels of deployment result in High VRE having the lowest costs.

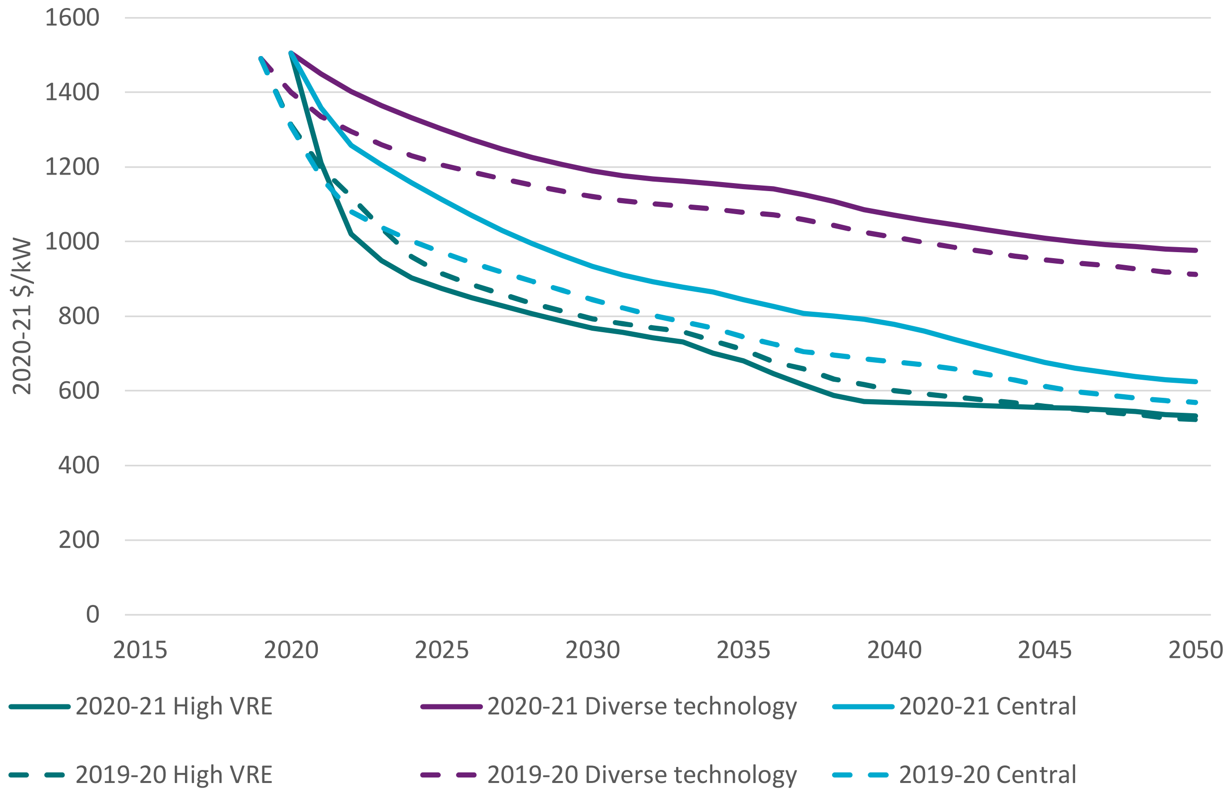

Figure 4-9 Projected capital costs for large scale solar PV by scenario compared to 2019-20 projections

4.2.9 Rooftop solar PV

Rooftop solar PV capital costs have been adjusted to align with a 6.6kW system size given the increasing popularity of this system size. The 2019-20 assumption was 5kW. This change to larger systems which have economies of scale in installation costs together with general cost reductions across all system sizes means that the projection starts with a significant reduction in capital costs.

The current costs for rooftop solar PV systems are sourced from historical data published by Solar Choice. However, they note that there are significantly discounted rooftop solar PV system prices available at any time and so their 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.

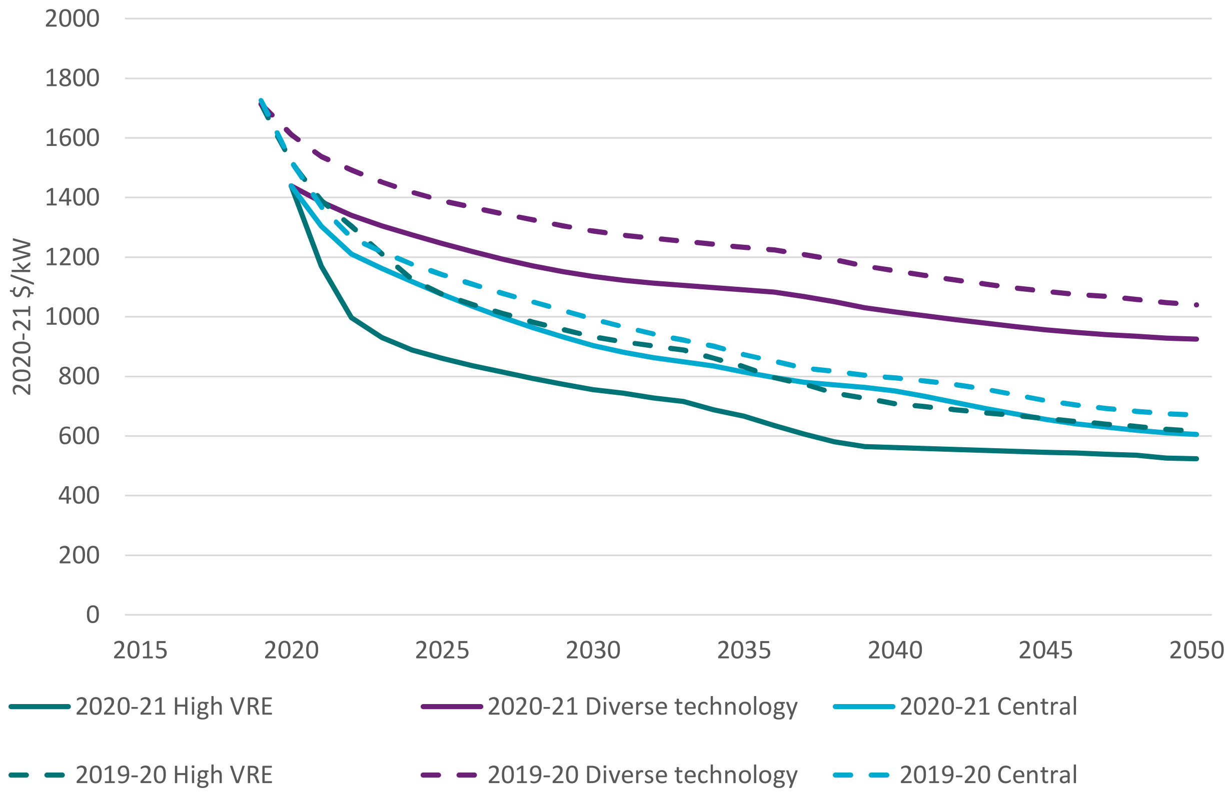

Figure 4-10 Projected capital costs for rooftop solar PV by scenario compared to 2019-20 projections

4.2.10 Onshore wind

The current capital cost for onshore wind remains like 2019-20 projections and this is consistent with observations that the capital cost learning rate of wind is slowing, at around 4% for each doubling of cumulative global capacity. However, while capital costs are falling slower for wind than solar PV, it is making improvements in its capacity factor which continue to make this technology one of the lowest cost available.

Capital costs fall the slowest in Central reflecting lower climate change policy ambition. Diverse Technology and High VRE achieve similar reductions in wind capital costs over time with High VRE just slightly lower.

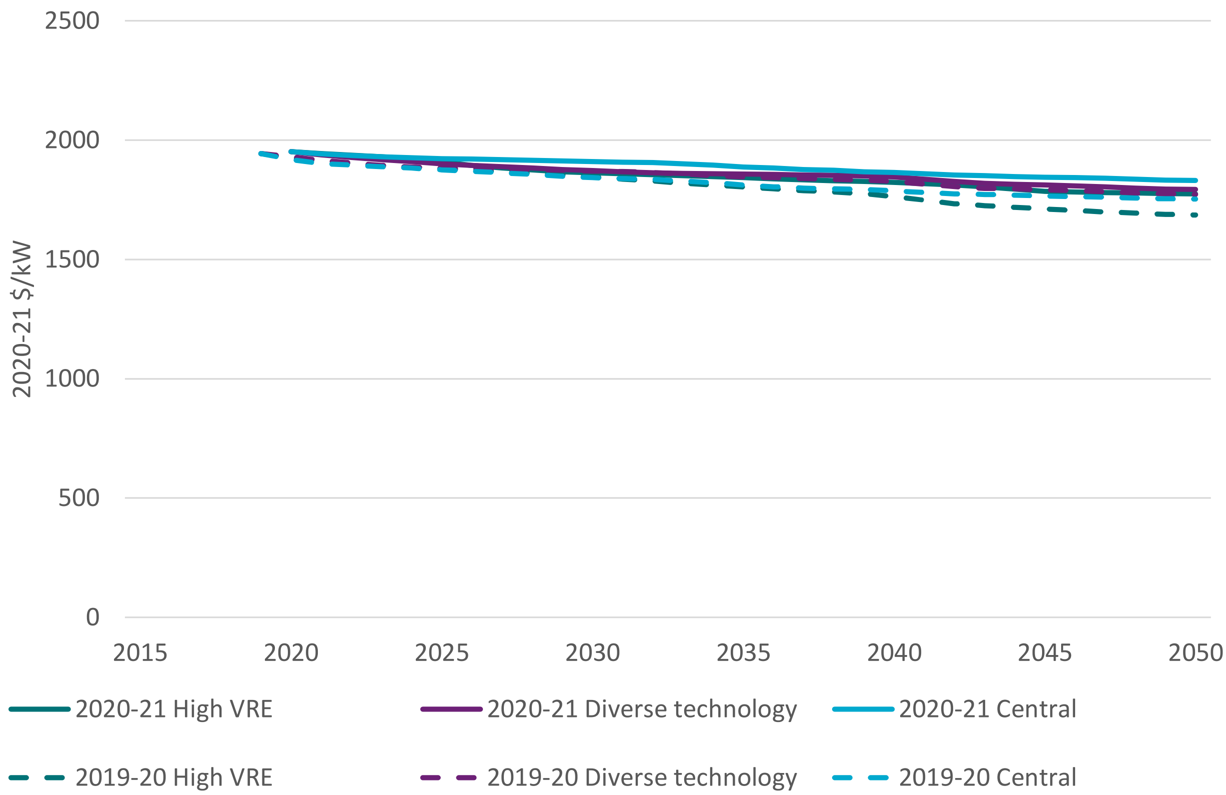

Figure 4-11 Projected capital costs for onshore wind by scenario compared to 2019-20 projections

4.2.11 Offshore wind

Offshore wind plays an important role globally in countries with good wind resources, relatively shallow coastal depths and strong competition for land use onshore. The current capital cost of offshore wind has been revised downwards based on Aurecon (2021). The learning rate has also been increased based on more evidence of improvement. Consistent with these changes the projected capital cost reductions are lower than all the 2019-20 projections. In addition to its capital cost, offshore wind has a high potential to improve its capacity factor since very large turbines can be built without impinging on the amenity of neighbouring land uses. These high capacity factors ensure offshore wind is a competitive technology globally, contributing just under 18% of electricity generation by 2050 in High VRE.

Capital cost reductions are highest in High VRE which has the greatest deployment as expected. Cost reduction are lowest in Diverse Technology where it is assumed variable renewable generation technologies are more limited in their deployment. Costs reduction are slow to develop in Central due to more limited climate policy ambition.

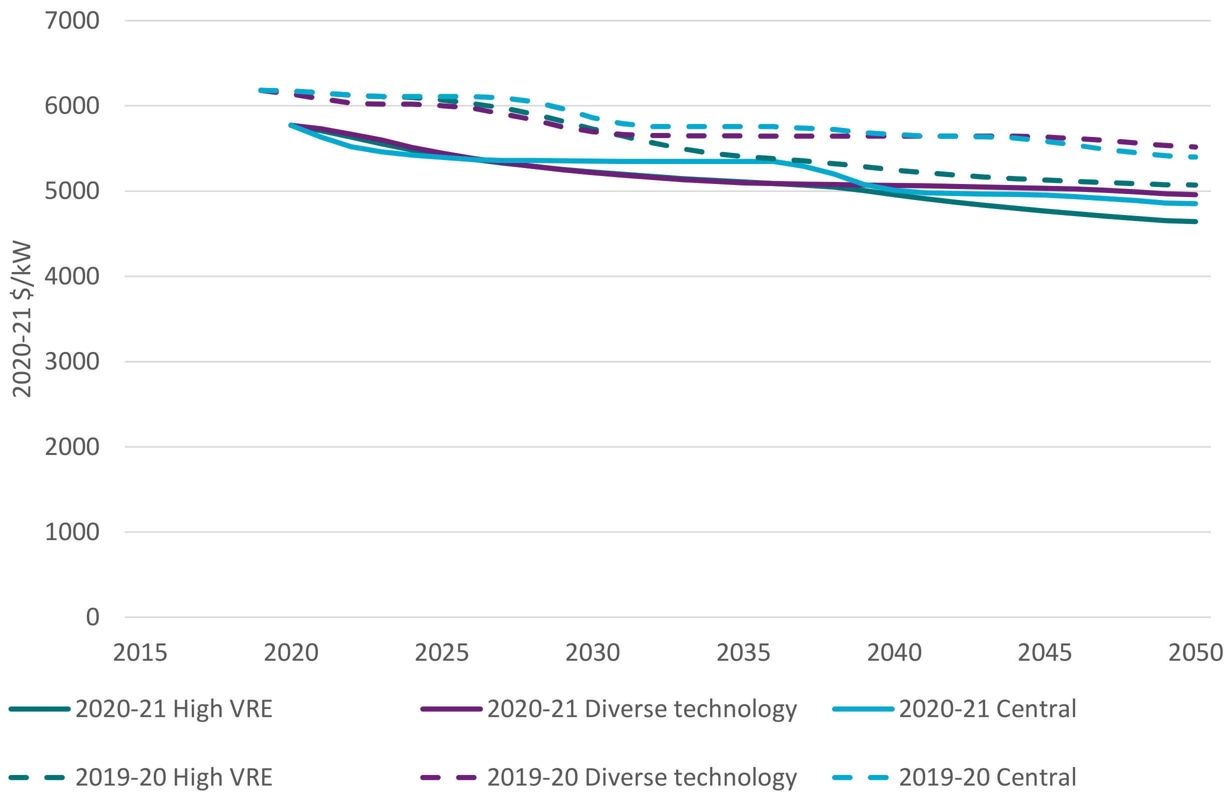

Figure 4-12 Projected capital costs for offshore wind by scenario compared to 2019-20 projections

4.2.12 Battery storage

Batteries have been able to sustain high cost reduction rates over time and the use of different learning rates by scenario has meant the projections can reflect some uncertainty as to how well they will be able to continue to achieve historical cost reduction trends. 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 from a small base. 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. Aurecon (2021) has revised the current capital cost of 2-hour duration batteries (including balance of plant) downwards from $622/kWh to around $529/kWh[11]. Based on this updated current cost, the projected future change in battery pack costs is shown in Figure 4-13 (total costs are in Appendix B).

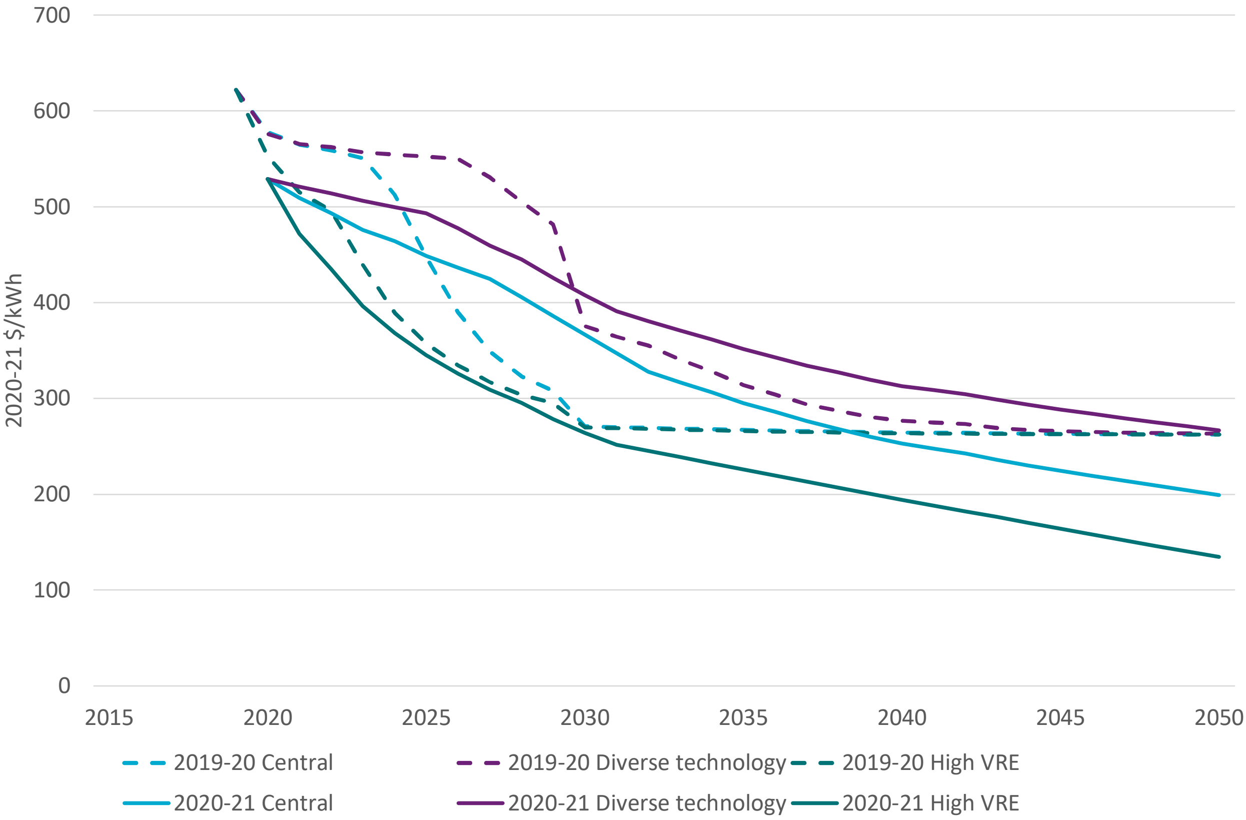

Figure 4-13 Projected total capital costs for 2 hour duration batteries by scenario (battery and balance of plant)

Battery deployment is strongest in the High VRE scenario reflecting stronger deployment of variable renewables increasing electricity sector storage requirements and stronger uptake of electric vehicles to support achieving near zero emission by 2050. Together with an assumed high learning rate this leads to the fastest cost reduction which is most consistent with recent trends. Diverse Technology and Central have slower rates of cost reduction reflecting slower uptake of electric vehicles and stationary storage and assumed lower learning rates. Consistent with the scenario narrative of a lack of confidence in variable renewable energy generation, the battery learning rate is assumed to be lowest in Diverse Technology. While Diverse Technology has strong climate policy ambition and strong deployment of electric vehicles to support transport sector greenhouse gas abatement, it has the slowest reduction in battery total project costs.

The Central scenario has low climate policy ambition and the slowest uptake of electric vehicles. However, its assumed higher learning rate of batteries means that battery costs fall faster than in Diverse Technology, particularly from the late 2020s.

[11] These are large scale batteries. Small scale batteries for home use with 2-hour duration cost around $1250/kWh (SunWiz, 2021)

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

4.2.13 Pumped hydro energy storage

Pumped hydro energy storage is assumed to be a mostly mature technology with only a small proportion of site drilling/piping having the potential to improve with deployment[12]. 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 increase in costs compared to the 2019-20 projections is due to the change in sources to AEMO's December 2020 ISP assumptions. Appendix B includes the costs of pumped hydro energy storage at different durations. We also assume that Tasmania 48 hour pumped hydro storage is 46% the cost of the mainland owing to greater confidence in Tasmanian project cost estimates (and consistent with the AEMO ISP).

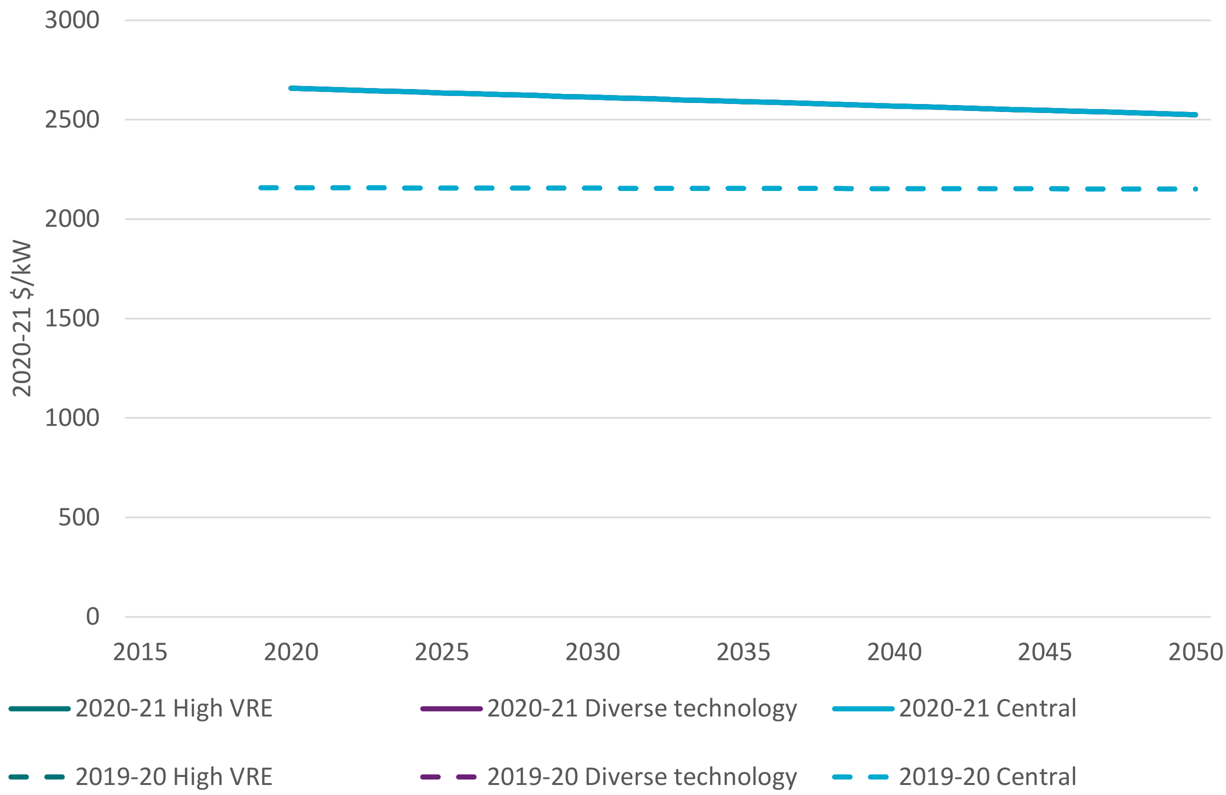

Figure 4-14 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

[12] 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.

4.2.14 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. While the estimate for wave electricity generation has not changed all other technologies have. Biomass with CCS has been revised upwards to be consistent with the proportional costs of CCS in coal generation (which increased due to Aurecon (2021) updates). Tidal/current technology updates to capital costs have been sourced from AUSTEn (2020) and reflect more in-depth analysis. Fuel cell updates were included in Aurecon (2021) and mainly reflect a smaller assumed average plant size.

Central scenario

Biomass with CCS is not adopted in the Central scenario because the climate policy ambition is not strong enough to incentivise deployment. Cost reductions reflect co-learning from other CCS technologies which are deployed. Fuel cell cost improvements are mainly a function of deployment and co-learning in the vehicle sector rather than electricity generation. There are modest cost reductions in tidal/current mainly reflecting a limited number of quality sites in various regions of world. Wave generation achieves the greatest cost reduction reflecting a higher assumed learning rate due to its relative immaturity. Earlier deployment compared to the 2019-20 projection reflects higher climate policy ambition in the 2020-21 Central scenario assumptions.

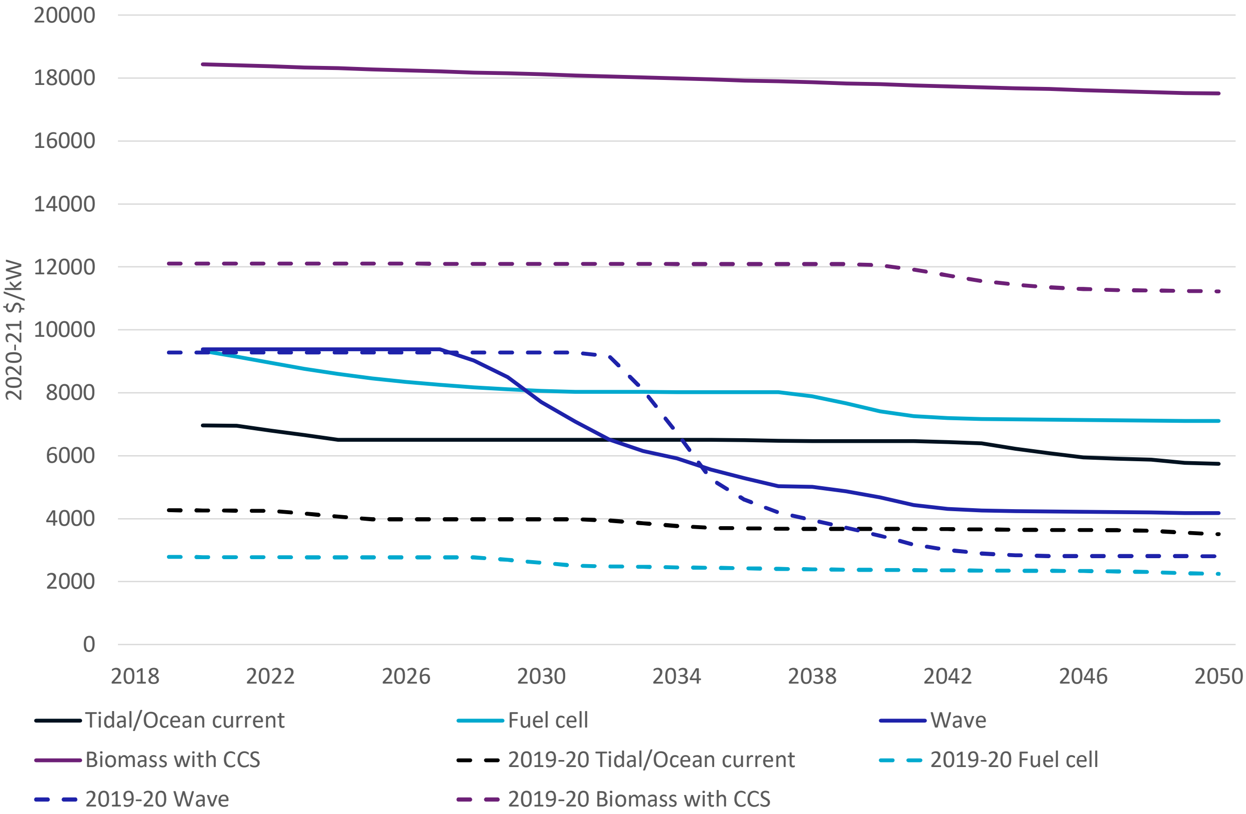

Figure 4-15 Projected technology capital costs under the Central scenario compared to 2019-20 projections

High VRE scenario

Biomass with CCS is not adopted in the High VRE scenario. Although this scenario has the highest climate policy ambition, it can reach near zero emissions earlier using various renewables so that a higher cost negative abatement technology is not required or competitive. Cost reductions reflect co-learning from other CCS technologies which are deployed.

Fuel cell generation does not achieve a significant share due to its high costs, but cost reductions are achieved through co-learning with fuel cell vehicles. Tidal/current generation is deployed the fastest in this scenario reflecting the greater need for alternative energy sources to reach net zero emissions. Wave generation deploys earlier than in 2019-20 also reflecting a stronger climate policy.

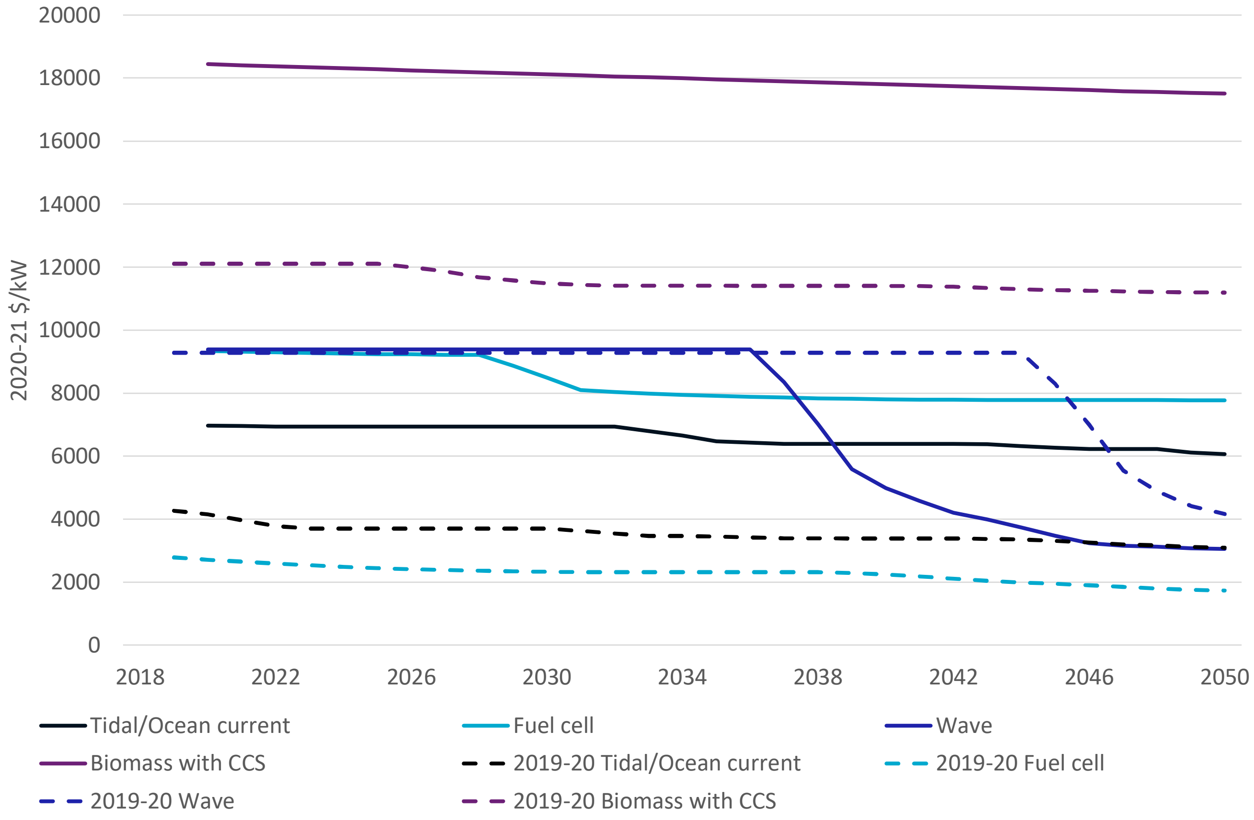

Figure 4-16 Projected technology capital costs under the High VRE scenario compared to 2019-20 projections

Diverse Technology scenario

Biomass with CCS is deployed early in the Diverse Technology scenario reflecting the assumed limitations on variable renewable energy generation. This result is also consistent with the climate policy ambition of this scenario. Biomass with CCS benefits from co-learning from the significant deployment of gas and coal with CCS generation and from hydrogen production from gas with CCS in this scenario.

Wave generation is relatively delayed in this scenario reflecting assumed limitations on variable renewables which are slightly tighter than that assumed in the 2019-20 assumptions. Both tidal/current and fuel cell generation remain niche.

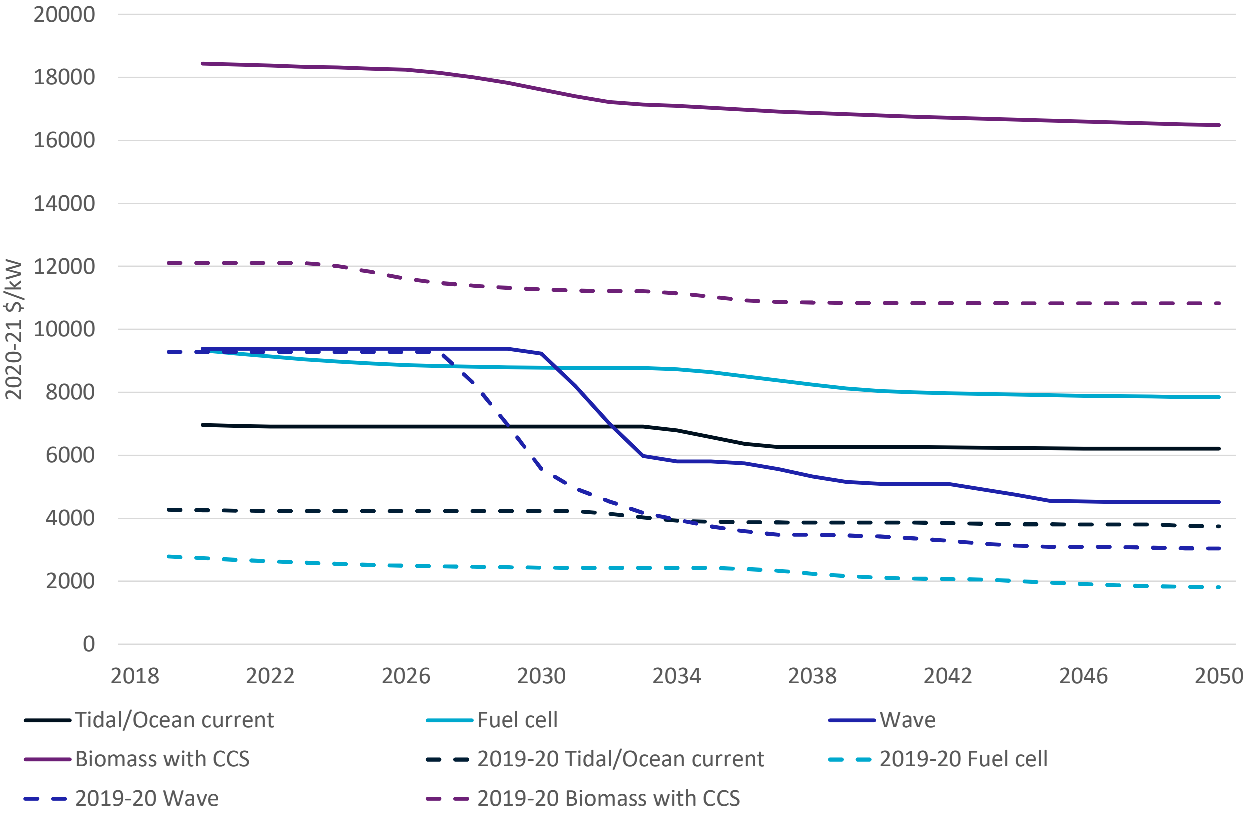

Figure 4-17 Projected technology capital costs under the Diverse Technology scenario compared to 2019-20 projections

4.3 Hydrogen electrolysers

Alkaline electrolysers are currently lower cost than proton-exchange membrane (PEM) electrolysers and they have a common learning rate applied in the modelling. However, we assume that PEM electrolysers are more suited to varying their daily output which makes them more suited to matching their production to low cost variable renewable energy generation. As the costs of both technologies fall, energy input costs increase in proportion making it increasingly more efficient to sacrifice electrolyser capacity utilisation for lower energy costs. Hence PEM electrolysers are projected to be lower cost over the long term.

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

Cost reductions are projected to be greatest in the High VRE scenario where global hydrogen production is assumed to be the largest. There is also substantial hydrogen production in Diverse Technology but gas with CCS takes a greater share of hydrogen production leading to lower deployment of electrolysers. The Central scenario achieves the least reduction in costs owing to lower global demand for hydrogen consistent with less climate policy ambition in this scenario.

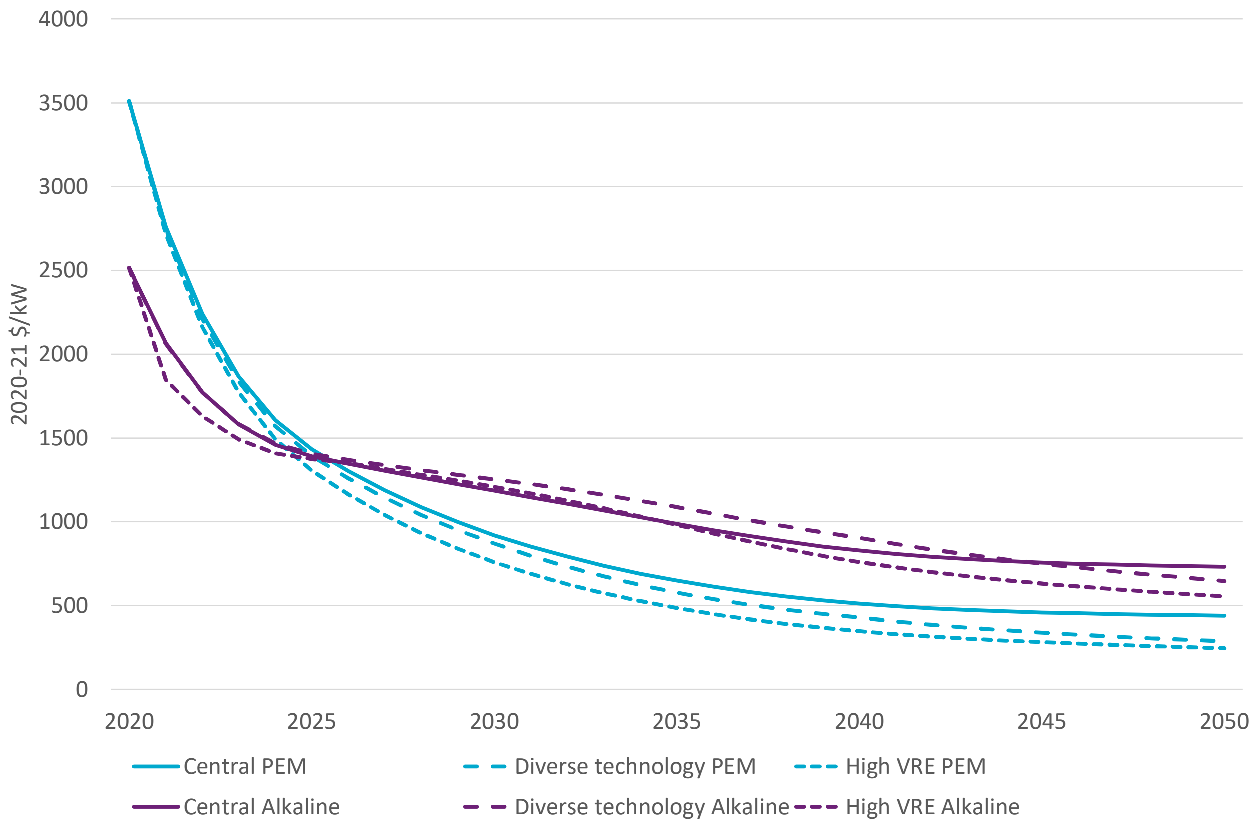

Figure 4-18 Projected technology capital costs for alkaline and PEM electrolysers by scenario

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 to investment. Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data[13]. 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 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 balancing and other costs unique to variable renewables costs. That new method has been implemented and we include those results in the projected LCOEs.

To address other issues not associated with additional cost of renewables, when we present LCOE information 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).

[13] 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 Overview of the new method

5.1.1 Options considered

Graham (2018) reviewed the methods of seven published studies which were relevant in developing a method for taking account of additional integration costs of variable renewables. Some of the reviews included the International Energy Agency's value adjusted levelised cost, the Energy Information Agency's levelised avoided cost of electricity and outputs from the MEGS model that has been applied in the Australian context.

In evaluating the different approaches, we developed an ideal set of criteria to compare methods. They are that the method should:

- Include the full breadth of renewable balancing solutions,
- Include the capacity to recognise the context in which the renewables are being deployed,
- Include the ability to draw conclusions about separate technologies as opposed to combinations, and
- Be transparent and repeatable.

No existing method was able to meet all these criteria and we concluded that it was unlikely that any new method would. Instead we must choose between simpler Excel implementable tools and complex system models. Simple Excel based tools can examine each technology separately and are highly transparent but can only focus on one balancing cost and are not able to say when these additional costs will be required. Complex system models can simultaneously examine the broadest range of additional costs of variable renewables and provide context on when these costs will need to be incurred but are only transparent and repeatable to the model or licence owner, not the audience.

It was concluded that the system modelling approach is preferred because, while transparency is lost, a greater weight is placed on the ability to study the broadest range of balancing solutions, at the right scale to meet a variety of relevant contexts.

None of the system modelling approaches reviewed included all the major relevant balancing solutions for variable renewables which include transmission, storage, other flexible generation and technologies for maintaining inertia and system strength. They also tended to emphasise reliable solutions or least cost investment but not both at the same time. Two commonly applied system modelling frameworks are generation expansion models (intertemporal optimisation models) and dispatch models (optimisation models at half-hour time-scales and below) (Figure 5-1). Dispatch models provide the highest confidence that the balancing solutions will be reliable in the context of the Australian National Electricity Market (NEM). However, on their own, dispatch models require a high number of iterations to optimise investment in the portfolio of solutions. Generation expansion models do optimise investment in solutions but their over-simplified time slicing (representing a year through a small number of representative time periods) means those solutions are not reliable.

A third option which we have concluded is the best compromise is an intermediate horizon model (which intertemporally optimises investments over a shorter horizon while also optimising operation of the assets during each day). Intermediate horizon models can automatically co-optimise investment in all balancing solutions while also simulating their operation to meet demand with a reasonable degree of reliability. They do this by simultaneously optimising most or all hours in a one to five-year timeframe.

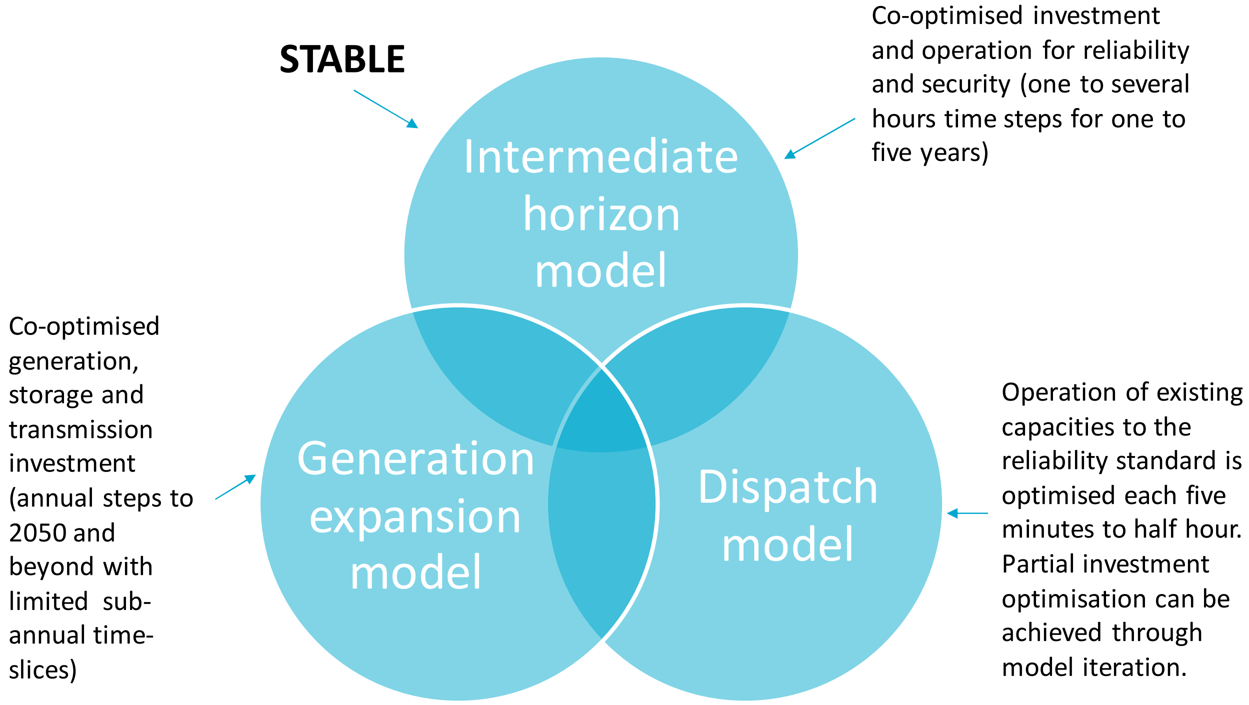

Figure 5-1 Three types of electricity system models

5.1.2 Development of STABLE

CSIRO has developed an intermediate horizon model called STABLE: Spatial Temporal Analysis of Balancing Levelised-cost of Energy. STABLE has drawn on the open source DIETER model for its basic design and been modified substantially to incorporate the details of the National Electricity Market. Time is represented hourly for one year. Most underlying data is based on the July 2020 AEMO ISP inputs and assumptions workbook and various other data (such as renewable energy production traces) published as part of the Integrated System Plan process. Demand is solved at the transmission zone level and Renewable Energy Zones are the smallest spatial supply sub-regions associated with each transmission zone.

5.2 LCOE estimates

5.2.1 Calculating additional costs of variable renewables

We implement STABLE by selecting a future year of interest, 2030[14], imposing a required variable renewable energy (VRE) share and running the model to determine the optimal investment to

[14] 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 at or below 50% in the larger states. 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.

support the VRE share. In practice, although wave, current, solar thermal 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[15].

We also implement a business as usual (BAU) optimisation of the same future year and use this as a counterfactual to determine which investments were additional to support the variable renewable shares imposed. STABLE's BAU is like AEMO's Central scenario with the following exceptions:

- GenCost cost data was used for all generation and storage costs
- Demand side participation is currently excluded from STABLE
- Rooftop solar PV adoption, electric vehicle adoption and battery adoption with Virtual Power Plant (VPP) participation are consistent with the ESOO 2020 Central projections rather than current ISP assumptions. Customer non-VPP battery and electric charging patterns are also consistent with ESOO 2020.
- Nine weather years, 2011 to 2019, are applied to the variable renewable supply traces and demand profiles
- No emissions constraint is applied
- The *New South Wales Electricity Infrastructure Roadmap* (which was not included in ISP 2020 modelling) is included.

We also apply 50% renewables targets in Victoria and Queensland and 100% in Tasmania. With South Australia already over 50% this means the NEM as a whole is just under 50% VRE share in 2030 before we impose 50% or higher VRE targets.

The exclusion of demand side participation (typically around 5% of peak demand) means that the model must deploy other resources to manage system balancing. This makes the result slightly more conservative in terms of investment required to meet demand.

New South Wales, Queensland and Victoria are the main states of interest 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. However, the NEM is an interconnected system so we are also interested in how the 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 the ISP. 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[16]. Snowy 2.0 is 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.

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

[16] The model would be unable to simultaneously meet the minimum VRE share and the minimum run requirements of coal plant which are around 25 to 40% of rated capacity.

Variable renewable energy shares (VREs) are explored in the range 50% to 90%. Below 50% is not of interest because the BAU already achieves 47% to 48% across the NEM (depending on the weather year). 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.

In the nine weather year counterfactuals, the model does not choose to build any new fossil fuel-based generation capacity (Figure 5-2). However, it also chooses the same level of battery and pumped hydro storage. The main investment response to the different weather is to build more or less of the wind and solar PV capacity with each varying by around 1 GW. The capacities shown are reasonably consistent with 2020 AEMO ISP 2030 capacity projections. This capacity mix is higher in renewables and storage mainly because the 2020 ISP modelling did not include the *New South Wales Electricity Infrastructure Roadmap*.

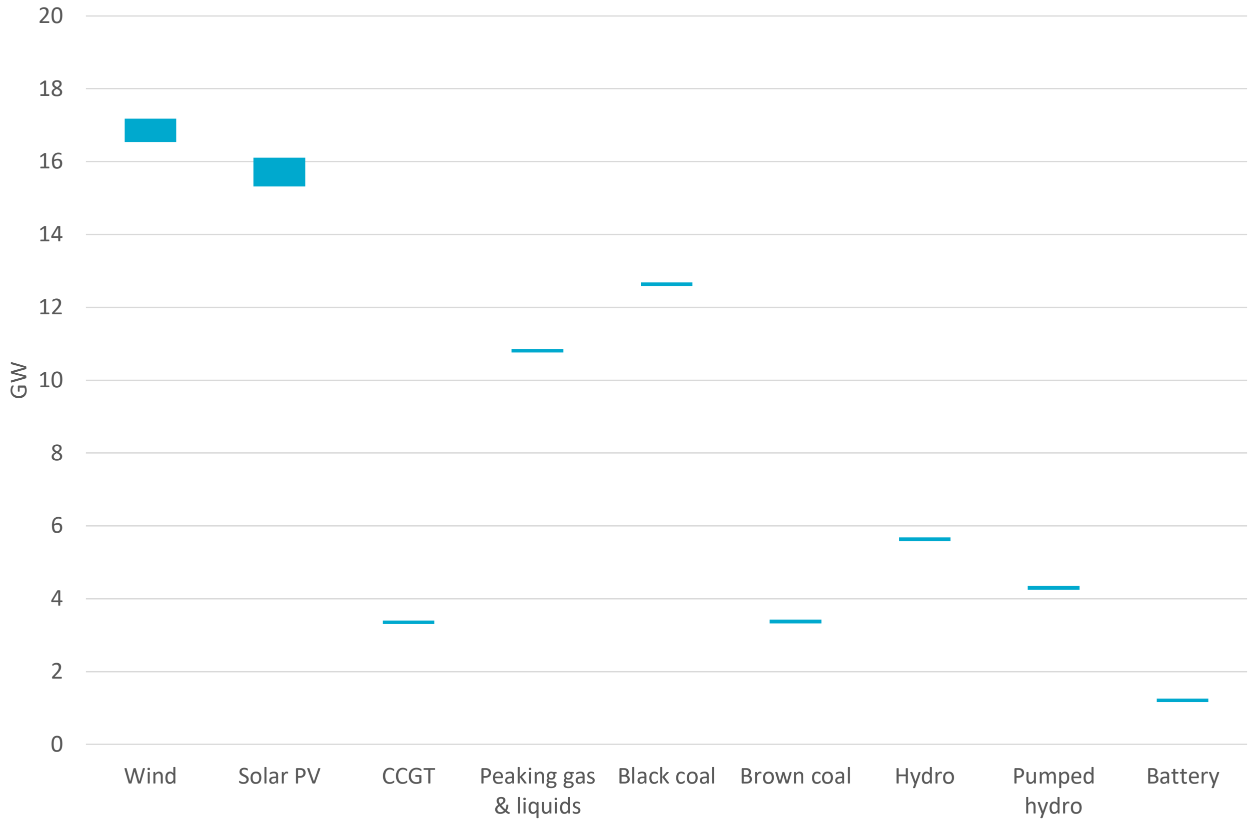


Figure 5-2 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals

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 5-3, include storage transmission and synchronous condenser costs. Synchronous condensers are required to 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. Previous analysis (see for example Campey et al. (2017)) has indicated that storage requirements increase non-linearly with VRE share, starting with little or no requirement at 50% VRE, and the results conform to that expectation.

Transmission costs include the transmission costs to connect Renewable Energy Zones (REZs) to the grid and other transmission which includes state interconnectors and general expansion of existing lines that connect transmission zones within states. REZ expansion costs appear to be required at similar levels for each additional 10% increase. Other transmission expenditure, not already in the BAU, is mainly required in significant levels in NSW and Victoria. The transmission investment in NSW reflects its central position in the NEM and both NSW and Victoria need strengthening of transmission between zones to get energy from the new REZs to demand centres. In Queensland the REZ transmission investment itself is sufficient.

Storage requirements are highest in NSW and Queensland. This reflects existing flexible resources and the quality of the variable renewable resources. Queensland storage requirements are significant but not as high as NSW because it has a wind resource which tends to be stronger at night which is therefore well suited to filling in the gaps left by solar PV. Queensland has 15% less peaking gas and liquids capacity than Victoria. NSW has 40% less peaking gas and liquids capacity than Victoria and more coincident wind and solar resource.

The greater peaking gas and liquids capacity in Victoria (around 3 GW) explains part of why it does not require significant additional storage. The other reason is that it has good proximity to hydro and pumped hydro capacity in Tasmania and New South Wales.

Figure 5-3 Levelised costs of achieving 50%, 60%, 70%, 80% and 90% variable renewable energy shares in the NEM, NSW, VIC and QLD in 2030

Additional expenditure on synchronous condenser capacity is required in all states and increasing moderately with variable renewable share. Higher VRE share leads to the retirement of fossil fuel-based capacity that otherwise supplies most of system inertia. The larger role of hydro generation in New South Wales means that it has a lower requirement for additional synchronous condensers.

The variation in state requirements is due to different resources and the system exploits the interconnectivity between state to reduce overall costs. As such higher or lower costs in different states are averaged out at the NEM level. At a 50% VRE share additional NEM level integration costs are generally very low, because they only include REZ transmission costs – the existing flexibility and inertia in the system is adequate to manage this VRE share without additional investment in storage or synchronous condensers. The cost of REZ transmission expansions adds around $5/MWh to $6/MWh, hardly changing at all as the VRE share increases. Synchronous condensers costs are low at between $1.0/MWh to $1.5/MWh increasing moderately with VRE share. Other transmission adds between $0 to $3.4/MWh at the NEM level with costs accelerating with VRE share. Storage adds between $0.1 to $9.6/MWh, also increasing non-linearly with VRE share.

5.2.2 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. We have also removed the wind plus storage and solar PV plus storage categories that were included in GenCost 2018 and GenCost 2019-20. These were always designed to be temporary estimates until a better approach was available. In GenCost 2019-20, for 2030, the simple approach of adding 2 or 6 hours storage added $19 to $106/MWh to the cost of variable renewables for an unspecified share of generation. With the new approach the additional costs to support renewables are estimated at $6 to $19/MWh depending on the VRE share (Figure 5-5). As such, the previous approach was too conservative. While it did not consider transmission and synchronous condensers, which are important additional costs, it over-estimated the need for storage[17] and, in total, over-estimated the additional integration costs that might be associated with variable renewable generation.

Variable renewables (wind and solar PV) without transmission or storage costs are the lowest cost generation technology by a significant margin. From 2030, the new estimates on additional costs associated with increasing variable renewable generation confirms that they are also competitive when transmission, synchronous condenser and storage costs are included. The closest technology is the low range cost of a gas combined cycle generator which can match the costs of variable renewables with integration costs at a 70% or greater share. The low range 2030 gas combined cycle cost assumptions require no climate policy risk at the financing stage (despite the 25 year design life extending beyond the net zero emission targets of most states), a gas price just below

[17] The previous approach assigned an equal capacity storage plant to every solar PV and wind project. In practice, the system modelling shows that it is not necessary to deploy storage at a one to one ratio. The previous approach fails to take account of existing flexible capacity in the system and non-coincident renewable supply (such that renewable generation would never be zero across the NEM).

$6/GJ throughout that period and a capacity factor of 80% in a system with 70% or greater share of energy from near zero marginal cost renewables.

5.2.3 Peaking technologies

The peaking technology category includes two sizes for gas turbines and a gas 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.

5.2.4 Flexible technologies

Evaluated purely on their energy costs, black coal, brown coal and gas-based generation technologies that are designed to deliver energy for 40 to 80% of the year are the next most competitive generation technologies after variable renewables (with or without transmission and storage). It is difficult to say which fossil fuel is more competitive as it depends very much on whether gas generation can secure gas supply at the lower end of the fuel cost range (just under $6/GJ).

New fossil fuel generation faces the risk of higher financing costs over time because all states in Australia have either legislated or aspirational net zero emission targets. There is also bipartisan commitment to the Paris agreement which is aiming for net zero emissions in the second half of the century. We address these risks in the cost estimations by including a separate estimate which assumes a 5% risk premium on borrowing costs. 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.

We do not include a risk premium for low emission flexible technologies. Gas with CCS is the most competitive of this group however the lower end of the range is only achievable if it can source low cost gas. Solar thermal and small modular reactor (SMR) nuclear are the next most competitive. Achieving the lower end of the SMR range requires that SMR is deployed globally in large enough numbers to bring down costs available to Australia.

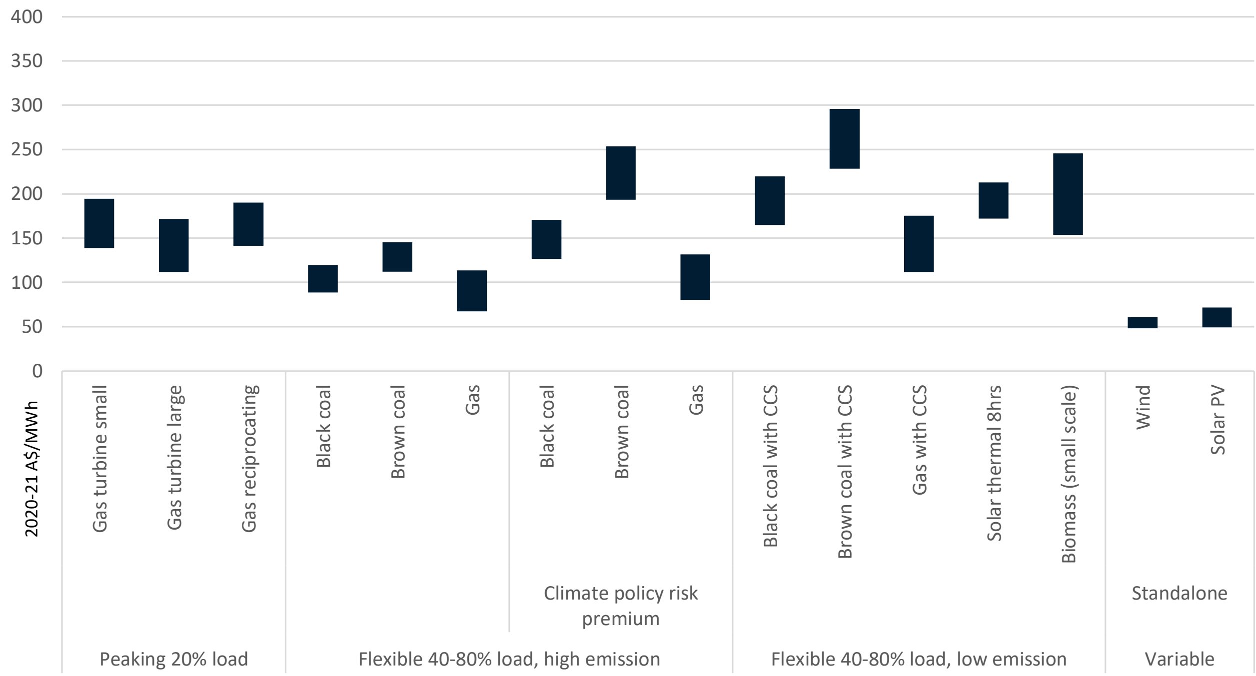


Figure 5-4 Calculated LCOE by technology and category for 2020

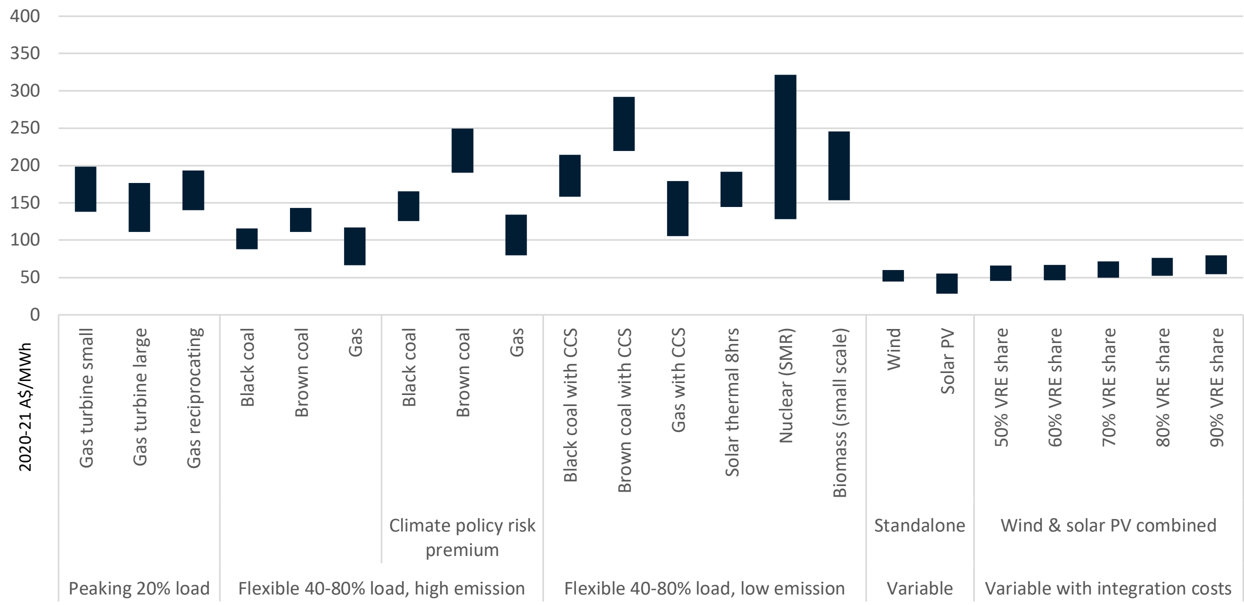


Figure 5-5 Calculated LCOE by technology and category for 2030

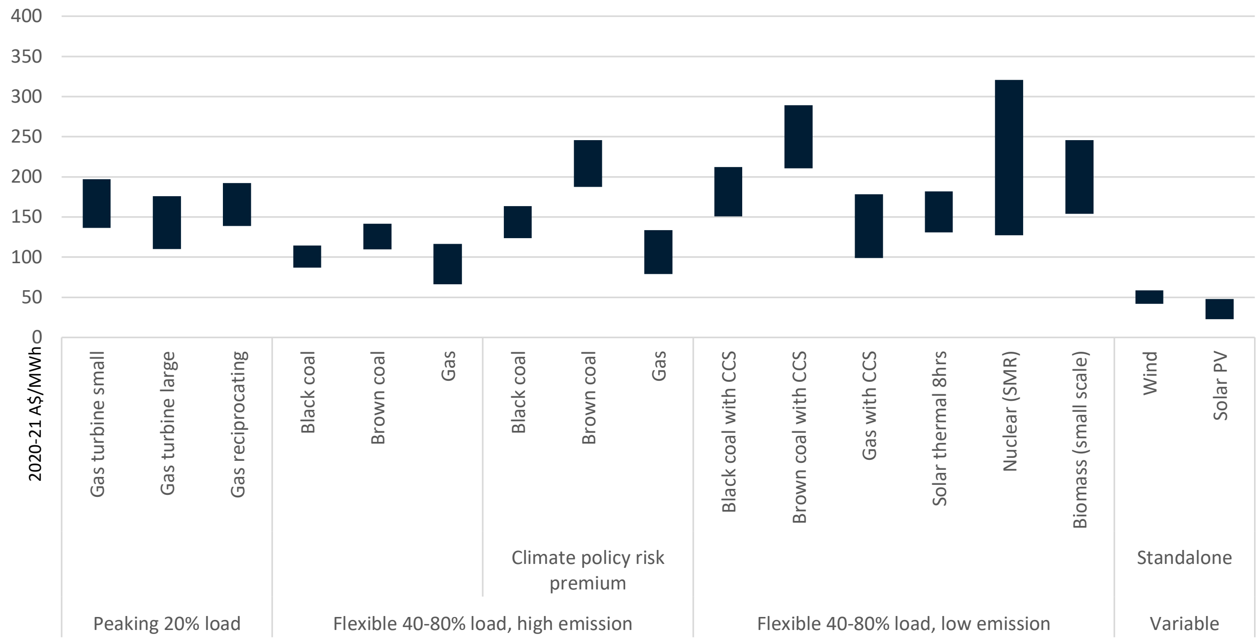


Figure 5-6 Calculated LCOE by technology and category for 2040

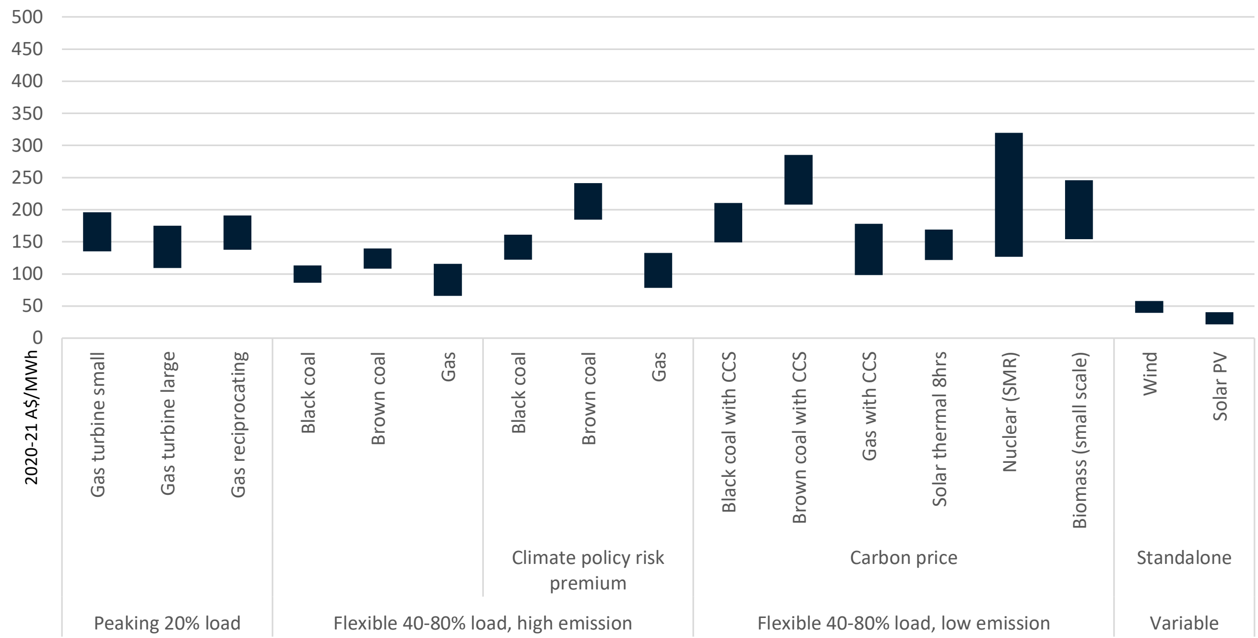


Figure 5-7 Calculated LCOE by technology and category for 2050

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:

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

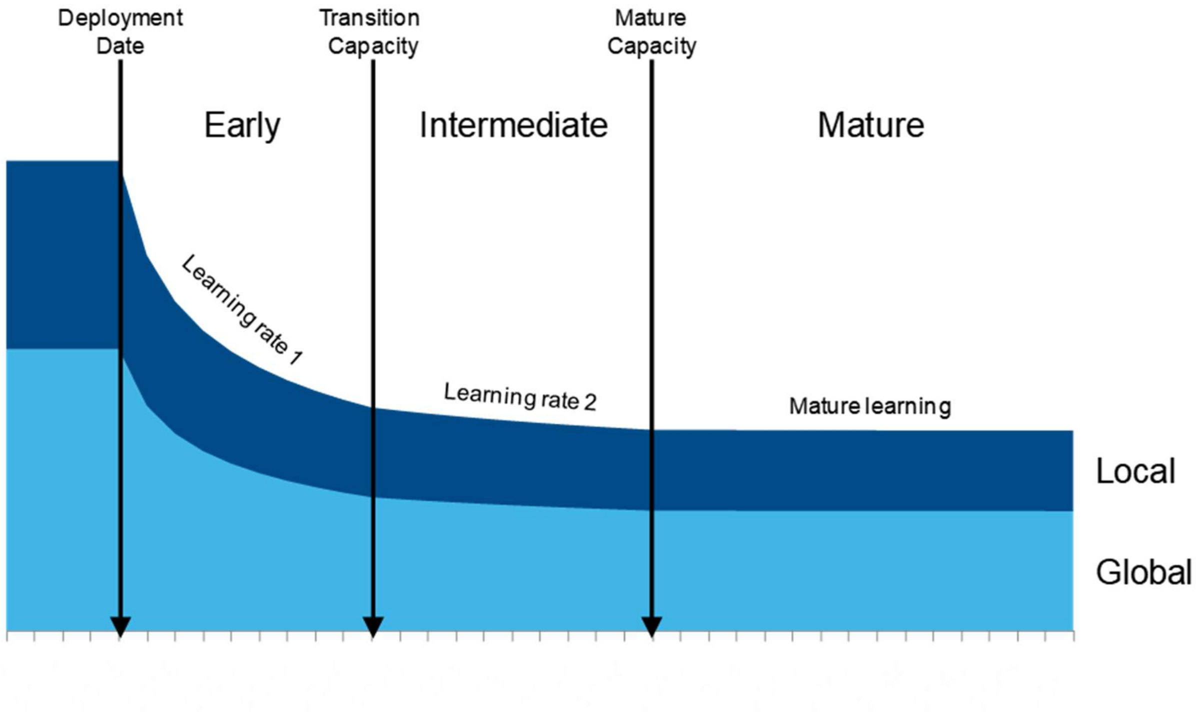
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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%. 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 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.

5.2.5 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.1.2 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: - 0.2%. This value has been applied as an annual capital cost reduction factor to mature technologies and to operating and maintenance costs.

Appendix B Data tables

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

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

	Black coal	Black coal with CCS	Brown coal	Brown coal with CCS	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 (8 hrs)	Wind	Offshore wind	Wave	Nuclear (SMR)	Tidal/ocean current	Fuel cell	Integrated solar and battery (2 hrs)
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2020	4450	9311	6868	14293	1743	1465	873	4396	1471	1750	7265	18438	1505	1439	7411	1951	5771	9384	-	6971	9333	2139
2021	4441	9297	6854	14269	1740	1462	871	4391	1469	1746	7260	18406	1358	1304	7281	1942	5632	9384	-	6954	9144	1974
2022	4432	9283	6841	14245	1736	1459	869	4387	1466	1743	7256	18373	1258	1211	7204	1934	5522	9384	-	6798	8951	1852
2023	4423	9269	6827	14221	1733	1456	868	4382	1463	1739	7254	18341	1205	1162	7140	1929	5460	9384	-	6652	8766	1780
2024	4414	9255	6813	14197	1729	1453	866	4378	1460	1736	7254	18309	1158	1117	7083	1926	5423	9384	-	6506	8600	1713
2025	4406	9241	6800	14173	1726	1450	864	4374	1457	1732	7254	18277	1113	1076	6983	1923	5395	9384	-	6506	8460	1652
2026	4397	9227	6786	14149	1722	1447	862	4369	1454	1729	7254	18245	1070	1036	6881	1920	5371	9384	-	6506	8342	1593
2027	4388	9213	6773	14125	1719	1444	861	4365	1451	1725	7254	18213	1030	998	6762	1918	5356	9384	-	6506	8248	1539
2028	4379	9199	6759	14102	1715	1441	859	4361	1448	1722	7254	18181	995	963	6657	1915	5356	9028	-	6506	8179	1490
2029	4370	9185	6746	14078	1712	1438	857	4356	1445	1718	7254	18149	963	933	6570	1912	5354	8495	-	6506	8110	1416
2030	4362	9171	6732	14054	1709	1436	856	4352	1442	1715	7254	18117	933	904	6496	1910	5351	7704	7375	6506	8064	1345
2031	4353	9158	6719	14031	1705	1433	854	4348	1439	1711	7253	18086	910	882	6432	1908	5348	7078	7346	6506	8032	1279
2032	4344	9144	6705	14007	1702	1430	852	4343	1437	1708	7253	18054	892	863	6377	1905	5347	6519	7345	6506	8030	1246
2033	4336	9130	6692	13984	1698	1427	850	4339	1434	1705	7253	18022	878	849	6328	1900	5347	6144	7345	6506	8028	1218
2034	4327	9116	6678	13960	1695	1424	849	4335	1431	1701	7253	17991	865	835	6286	1894	5347	5911	7345	6506	8026	1190
2035	4318	9103	6665	13937	1691	1421	847	4331	1428	1698	7253	17959	844	815	6248	1887	5347	5560	7345	6506	8024	1157
2036	4310	9089	6652	13913	1688	1418	845	4326	1425	1694	7253	17928	826	797	6214	1882	5347	5282	7345	6495	8023	1126
2037	4301	9075	6638	13890	1685	1416	844	4322	1422	1691	7253	17896	808	780	6183	1877	5292	5032	7345	6482	8021	1099
2038	4292	9061	6625	13867	1681	1413	842	4318	1419	1688	7253	17865	800	772	6156	1873	5198	5011	7345	6469	7891	1081
2039	4284	9048	6612	13844	1678	1410	840	4314	1417	1684	7253	17834	791	763	6131	1868	5077	4869	7345	6467	7663	1064
2040	4275	9034	6599	13820	1675	1407	839	4309	1414	1681	7253	17803	778	751	6087	1863	5010	4674	7345	6467	7406	1046
2041	4267	9021	6585	13797	1671	1404	837	4305	1411	1678	7253	17772	760	733	6026	1858	4980	4434	7345	6467	7255	1025
2042	4258	9007	6572	13774	1668	1401	835	4301	1408	1674	7253	17741	738	713	5948	1854	4972	4314	7345	6435	7199	1001
2043	4250	8994	6559	13751	1665	1399	834	4297	1405	1671	7253	17710	716	693	5877	1850	4966	4256	7345	6395	7167	977
2044	4241	8980	6546	13728	1661	1396	832	4292	1402	1667	7253	17679	696	674	5811	1847	4962	4243	7345	6225	7155	953
2045	4233	8967	6533	13705	1658	1393	830	4288	1400	1664	7253	17648	676	655	5751	1844	4953	4226	7345	6080	7143	932
2046	4224	8953	6520	13682	1655	1390	829	4284	1397	1661	7253	17617	661	641	5695	1842	4938	4218	7345	5943	7132	915
2047	4216	8940	6507	13659	1651	1387	827	4280	1394	1657	7253	17586	649	629	5644	1839	4909	4206	7345	5906	7122	901
2048	4207	8926	6494	13637	1648	1385	825	4276	1391	1654	7253	17556	638	619	5596	1836	4889	4194	7345	5875	7114	889
2049	4199	8913	6481	13614	1645	1382	824	4272	1388	1651	7253	17525	630	611	5552	1832	4861	4183	7345	5778	7105	879
2050	4195	8906	6474	13602	1643	1381	822	4270	1387	1649	7253	17510	624	606	5530	1830	4853	4178	7345	5745	7101	873

Apx Table B.2 Current and projected generation technology capital costs under the High VRE scenario

	Black coal	Black coal with CCS	Brown coal	Brown coal with CCS	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 (8 hrs)	Wind	Offshore wind	Wave	Nuclear (SMR)	Tidal/ocean current	Fuel cell	Integrated solar and battery (2 hrs)
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2020	4450	9311	6868	14293	1743	1465	873	4396	1471	1750	7265	18438	1505	1439	7411	1951	5771	9384	-	6971	9333	2139
2021	4441	9297	6854	14269	1740	1462	871	4391	1469	1746	7260	18406	1210	1170	7386	1942	5706	9384	-	6954	9314	1779
2022	4432	9283	6841	14245	1736	1459	869	4387	1466	1743	7256	18373	1020	997	7331	1936	5632	9384	-	6945	9294	1526
2023	4423	9269	6827	14221	1733	1456	868	4382	1463	1739	7254	18341	949	931	7198	1931	5552	9384	-	6945	9275	1401
2024	4414	9255	6813	14197	1729	1453	866	4378	1460	1736	7254	18309	903	888	6984	1921	5483	9384	-	6945	9257	1308
2025	4406	9241	6800	14173	1726	1450	864	4374	1457	1732	7254	18277	874	861	6746	1908	5424	9384	-	6945	9242	1243
2026	4397	9227	6786	14149	1722	1447	862	4369	1454	1729	7254	18245	849	837	6555	1894	5373	9384	-	6945	9230	1189
2027	4388	9213	6773	14125	1719	1444	861	4365	1451	1725	7254	18213	828	815	6427	1882	5329	9384	-	6945	9222	1144
2028	4379	9199	6759	14102	1715	1441	859	4361	1448	1722	7254	18181	806	793	6299	1874	5289	9384	-	6945	9216	1103
2029	4370	9185	6746	14078	1712	1438	857	4356	1445	1718	7254	18149	786	774	6136	1867	5254	9384	-	6945	8864	1059
2030	4362	9171	6732	14054	1709	1436	856	4352	1442	1715	7254	18117	768	755	5968	1863	5223	9384	16487	6945	8490	1021
2031	4353	9158	6719	14031	1705	1433	854	4348	1439	1711	7254	18086	757	744	5827	1858	5195	9384	16487	6945	8098	995
2032	4344	9144	6705	14007	1702	1430	852	4343	1437	1708	7254	18054	742	728	5740	1854	5169	9384	16487	6945	8037	977
2033	4336	9130	6692	13984	1698	1427	850	4339	1434	1705	7254	18022	730	716	5658	1850	5146	9384	16487	6798	7987	961
2034	4327	9116	6678	13960	1695	1424	849	4335	1431	1701	7254	17991	702	688	5597	1846	5125	9384	16487	6652	7945	930
2035	4318	9103	6665	13937	1691	1421	847	4331	1428	1698	7254	17959	680	667	5531	1842	5106	9384	16487	6467	7912	906
2036	4310	9089	6652	13913	1688	1418	845	4326	1425	1694	7254	17928	646	635	5483	1837	5089	9384	16487	6428	7885	872
2037	4301	9075	6638	13890	1685	1416	844	4322	1422	1691	7254	17896	616	607	5432	1833	5072	8349	16487	6389	7861	841
2038	4292	9061	6625	13867	1681	1413	842	4318	1419	1688	7254	17865	588	580	5386	1830	5045	7015	16487	6389	7839	812
2039	4284	9048	6612	13844	1678	1410	840	4314	1417	1684	7254	17834	571	565	5311	1827	5007	5584	16487	6389	7820	794
2040	4275	9034	6599	13820	1675	1407	839	4309	1414	1681	7254	17803	569	562	5234	1822	4959	4986	16487	6389	7805	789
2041	4267	9021	6585	13797	1671	1404	837	4305	1411	1678	7254	17772	566	558	5138	1817	4915	4579	16487	6389	7794	784
2042	4258	9007	6572	13774	1668	1401	835	4301	1408	1674	7254	17741	563	555	5063	1812	4873	4205	16487	6389	7788	779
2043	4250	8994	6559	13751	1665	1399	834	4297	1405	1671	7254	17710	560	552	4979	1803	4835	3995	16487	6377	7785	774
2044	4241	8980	6546	13728	1661	1396	832	4292	1402	1667	7254	17679	558	549	4923	1794	4800	3735	16487	6323	7784	769
2045	4233	8967	6533	13705	1658	1393	830	4288	1400	1664	7254	17648	555	546	4871	1785	4766	3472	16487	6270	7783	764
2046	4224	8953	6520	13682	1655	1390	829	4284	1397	1661	7254	17617	553	544	4838	1783	4735	3243	16487	6228	7782	761
2047	4216	8940	6507	13659	1651	1387	827	4280	1394	1657	7254	17586	549	539	4808	1780	4706	3158	16487	6228	7781	755
2048	4207	8926	6494	13637	1648	1385	825	4276	1391	1654	7254	17556	545	535	4783	1778	4679	3128	16487	6228	7780	749
2049	4199	8913	6481	13614	1645	1382	824	4272	1388	1651	7254	17525	536	527	4760	1775	4653	3081	16487	6118	7779	739
2050	4195	8906	6474	13602	1643	1381	822	4270	1387	1649	7254	17510	532	523	4748	1774	4640	3060	16487	6063	7779	735

Apx Table B.3 Current and projected generation technology capital costs under the Diverse Technology scenario

	Black coal	Black coal with CCS	Brown coal	Brown coal with CCS	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 (8 hrs)	Wind	Offshore wind	Wave	Nuclear (SMR)	Tidal/ocean current	Fuel cell	Integrated solar and battery (2 hrs)
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2020	4450	9311	6868	14293	1743	1465	873	4396	1471	1750	7265	18438	1505	1439	7411	1951	5771	9384	-	6971	9333	2139
2021	4441	9297	6854	14269	1740	1462	871	4391	1469	1746	7260	18406	1449	1386	7394	1937	5728	9384	-	6932	9235	2076
2022	4432	9283	6841	14245	1736	1459	869	4387	1466	1743	7256	18373	1402	1341	7354	1926	5669	9384	-	6913	9136	2020
2023	4423	9269	6827	14221	1733	1456	868	4382	1463	1739	7254	18341	1364	1305	7247	1918	5598	9384	-	6913	9046	1976
2024	4414	9255	6813	14197	1729	1453	866	4378	1460	1736	7254	18309	1332	1274	7073	1909	5515	9384	-	6913	8970	1937
2025	4406	9241	6800	14173	1726	1450	864	4374	1457	1732	7254	18277	1301	1246	6843	1901	5446	9384	-	6913	8912	1894
2026	4397	9227	6786	14149	1722	1447	862	4369	1454	1729	7254	18245	1273	1218	6632	1894	5386	9384	-	6913	8865	1845
2027	4388	9139	6773	14051	1719	1444	861	4292	1451	1725	7254	18138	1247	1193	6484	1888	5335	9384	-	6913	8832	1792
2028	4379	9015	6759	13917	1715	1441	859	4180	1448	1722	7254	17996	1225	1171	6396	1882	5290	9384	-	6913	8809	1745
2029	4370	8863	6746	13754	1712	1438	857	4041	1445	1718	7254	17825	1206	1152	6333	1877	5251	9384	-	6913	8790	1693
2030	4362	8674	6732	13556	1709	1436	856	3865	1442	1715	7251	17618	1189	1135	6235	1872	5217	9226	7239	6913	8778	1646
2031	4353	8477	6719	13348	1705	1433	854	3682	1439	1711	7248	17403	1177	1122	6104	1867	5187	8207	7229	6913	8770	1605
2032	4344	8308	6705	13170	1702	1430	852	3526	1437	1708	7245	17215	1168	1113	5955	1863	5160	7015	7218	6913	8770	1581
2033	4336	8248	6692	13099	1698	1427	850	3476	1434	1705	7245	17137	1162	1105	5829	1861	5135	5981	7217	6913	8769	1560
2034	4327	8227	6678	13069	1695	1424	849	3465	1431	1701	7245	17099	1155	1098	5730	1859	5112	5808	7217	6789	8730	1538
2035	4318	8182	6665	13014	1691	1421	847	3430	1428	1698	7245	17035	1148	1090	5658	1857	5095	5808	7213	6577	8645	1517
2036	4310	8136	6652	12959	1688	1418	845	3394	1425	1694	7221	16972	1141	1083	5615	1855	5087	5738	7210	6361	8511	1498
2037	4301	8092	6638	12905	1685	1416	844	3360	1422	1691	7193	16910	1126	1068	5578	1854	5080	5562	7207	6269	8378	1472
2038	4292	8070	6625	12873	1681	1413	842	3348	1419	1688	7137	16871	1108	1051	5553	1852	5076	5323	7207	6265	8245	1445
2039	4284	8050	6612	12843	1678	1410	840	3337	1417	1684	7098	16832	1086	1030	5522	1849	5069	5155	7207	6264	8127	1417
2040	4275	8030	6599	12813	1675	1407	839	3327	1414	1681	7043	16795	1071	1016	5505	1846	5066	5092	7207	6264	8041	1396
2041	4267	8011	6585	12785	1671	1404	837	3317	1411	1678	7005	16759	1057	1003	5475	1836	5063	5092	7207	6264	7994	1379
2042	4258	7994	6572	12759	1668	1401	835	3310	1408	1674	6973	16724	1044	990	5442	1828	5056	5092	7207	6253	7973	1363
2043	4250	7979	6559	12735	1665	1399	834	3305	1405	1671	6955	16692	1032	979	5403	1818	5048	4917	7207	6240	7950	1347
2044	4241	7966	6546	12711	1661	1396	832	3300	1402	1667	6948	16661	1020	967	5370	1815	5038	4742	7207	6226	7928	1331
2045	4233	7952	6533	12688	1658	1393	830	3296	1400	1664	6934	16630	1009	957	5346	1812	5033	4551	7207	6218	7908	1317
2046	4224	7938	6520	12665	1655	1390	829	3291	1397	1661	6925	16599	1000	948	5305	1808	5024	4535	7207	6214	7892	1305
2047	4216	7925	6507	12642	1651	1387	827	3287	1394	1657	6913	16568	992	940	5251	1803	5010	4518	7207	6209	7878	1294
2048	4207	7911	6494	12619	1648	1385	825	3283	1391	1654	6905	16537	987	935	5175	1798	4990	4518	7207	6209	7865	1287
2049	4199	7898	6481	12596	1645	1382	824	3278	1388	1651	6879	16506	980	928	5102	1794	4968	4518	7207	6209	7853	1278
2050	4195	7891	6474	12585	1643	1381	822	3276	1387	1649	6867	16491	977	925	5063	1793	4956	4518	7207	6209	7847	1274

Apx Table B.4 One and two hour battery cost data by storage duration, component and total costs

	Battery storage (1 hr)									Battery storage (2 hrs)								
	Total			Battery			BOP			Total			Battery			BOP		
	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
2020	789	789	789	340	340	340	449	449	449	529	529	529	300	300	300	229	229	229
2021	763	777	720	323	335	282	440	442	438	509	521	472	285	296	249	224	225	223
2022	741	766	673	310	331	246	431	435	427	493	514	435	273	292	217	220	222	217
2023	718	754	624	295	327	209	422	428	415	476	506	396	260	288	185	215	218	211
2024	701	744	588	287	323	184	413	420	404	464	500	368	254	285	163	211	214	206
2025	680	733	557	275	320	165	404	413	392	449	493	345	243	283	145	206	210	200
2026	662	713	530	266	307	149	395	406	381	436	477	326	235	271	132	201	207	194
2027	645	689	506	258	290	137	386	399	369	425	459	309	228	256	121	197	203	188
2028	619	670	486	242	278	128	377	391	358	406	445	295	213	245	113	192	199	182
2029	593	645	462	225	260	116	368	384	346	386	426	278	198	230	102	188	196	176
2030	567	621	441	208	245	106	359	377	335	367	408	264	184	216	93	183	192	171
2031	542	599	422	191	230	99	350	370	323	347	391	252	169	203	87	178	188	165
2032	516	585	410	174	222	98	341	362	312	328	381	245	154	196	86	174	185	159
2033	500	571	397	167	215	97	332	355	300	317	371	239	148	190	86	169	181	153
2034	484	557	385	161	209	96	323	348	289	306	361	232	142	184	85	165	177	147
2035	467	542	373	153	201	96	314	341	277	295	351	226	135	178	84	160	174	141
2036	453	529	361	148	196	95	305	333	266	286	343	219	130	173	84	156	170	135
2037	438	517	349	142	191	94	296	326	254	276	334	213	125	168	83	151	166	130
2038	425	505	337	138	187	94	287	319	243	268	327	207	122	165	83	146	162	124
2039	412	494	325	134	182	93	278	312	231	260	319	200	118	161	82	142	159	118
2040	400	483	313	131	179	93	269	304	220	253	313	194	116	158	82	137	155	112
2041	391	475	301	130	178	93	260	297	209	248	309	188	115	157	82	133	151	106
2042	381	467	290	130	178	93	251	290	197	242	304	182	114	157	82	128	148	100
2043	370	458	278	127	175	93	242	283	186	236	299	176	112	155	82	123	144	95
2044	359	449	266	126	173	92	233	275	174	230	293	170	111	153	81	119	140	89
2045	349	440	255	125	172	92	224	268	163	224	288	164	110	152	81	114	137	83
2046	339	432	243	124	171	92	215	261	151	219	284	158	110	151	81	110	133	77
2047	330	424	231	124	170	92	206	253	140	214	279	152	109	150	81	105	129	71
2048	320	416	220	123	170	92	197	246	128	209	275	146	109	150	81	100	125	65
2049	311	408	208	123	169	92	188	239	117	204	271	140	108	149	81	96	122	59
2050	301	400	197	122	169	92	179	232	105	199	267	134	108	149	81	91	118	54

Apx Table B.5 Four and eight hour battery cost data by storage duration, component and total costs

	Battery storage (4 hrs)									Battery storage (8 hrs)								
	Total			Battery			BOP			Total			Battery			BOP		
	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE	Central	Diverse Technology	High VRE
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
2020	421	421	421	300	300	300	121	121	121	371	371	371	300	300	300	71	71	71
2021	403	414	366	285	296	249	118	119	117	354	366	318	285	296	249	70	70	69
2022	389	409	332	273	292	217	116	117	114	341	361	285	273	292	217	68	69	67
2023	374	403	296	260	288	185	113	115	111	327	356	250	260	288	185	67	68	66
2024	365	398	271	254	285	163	111	113	108	319	352	226	254	285	163	65	66	64
2025	351	393	250	243	283	145	108	111	105	307	348	207	243	283	145	64	65	62
2026	341	379	234	235	271	132	106	109	102	297	335	192	235	271	132	62	64	60
2027	331	363	220	228	256	121	104	107	99	289	319	179	228	256	121	61	63	58
2028	315	350	209	213	245	113	101	105	96	273	307	170	213	245	113	60	62	56
2029	297	333	195	198	230	102	99	103	93	256	290	157	198	230	102	58	61	55
2030	280	317	183	184	216	93	96	101	90	240	275	146	184	216	93	57	59	53
2031	263	302	174	169	203	87	94	99	87	224	261	138	169	203	87	55	58	51
2032	245	293	170	154	196	86	92	97	84	208	253	135	154	196	86	54	57	49
2033	237	285	166	148	190	86	89	95	81	200	246	133	148	190	86	52	56	47
2034	228	278	163	142	184	85	87	93	77	193	239	131	142	184	85	51	55	46
2035	219	269	159	135	178	84	84	91	74	185	232	128	135	178	84	50	54	44
2036	212	262	155	130	173	84	82	89	71	179	226	126	130	173	84	48	53	42
2037	205	256	152	125	168	83	79	87	68	172	220	124	125	168	83	47	51	40
2038	199	250	148	122	165	83	77	85	65	167	215	121	122	165	83	45	50	38
2039	193	244	145	118	161	82	75	84	62	162	210	119	118	161	82	44	49	37
2040	188	240	141	116	158	82	72	82	59	158	206	117	116	158	82	43	48	35
2041	185	237	138	115	157	82	70	80	56	156	204	115	115	157	82	41	47	33
2042	182	234	135	114	157	82	67	78	53	154	202	113	114	157	82	40	46	31
2043	177	230	131	112	155	82	65	76	50	151	199	111	112	155	82	38	45	29
2044	174	227	128	111	153	81	63	74	47	148	197	109	111	153	81	37	43	27
2045	170	224	125	110	152	81	60	72	44	146	194	107	110	152	81	35	42	26
2046	167	221	122	110	151	81	58	70	41	143	192	105	110	151	81	34	41	24
2047	164	218	118	109	150	81	55	68	37	142	190	103	109	150	81	33	40	22
2048	161	216	115	109	150	81	53	66	34	140	189	101	109	150	81	31	39	20
2049	159	213	112	108	149	81	50	64	31	138	187	99	108	149	81	30	38	18
2050	156	211	109	108	149	81	48	62	28	136	185	97	108	149	81	28	37	17

Apx Table B.6 Pumped hydro storage cost data by duration, all scenarios, total cost basis

	$/kW							$/kWh						
	4hrs	6hrs	8hrs	12hrs	24hrs	48hrs	48hrs Tas	4hrs	6hrs	8hrs	12hrs	24hrs	48hrs	48hrs Tas
2020	1865	2323	2425	2658	3417	5133	2384	466	387	303	221	142	107	50
2021	1861	2319	2421	2653	3411	5124	2380	465	387	303	221	142	107	50
2022	1858	2315	2417	2648	3405	5115	2376	465	386	302	221	142	107	50
2023	1855	2312	2413	2644	3399	5106	2372	464	385	302	220	142	106	49
2024	1852	2308	2409	2639	3393	5098	2368	463	385	301	220	141	106	49
2025	1849	2304	2405	2635	3388	5089	2364	462	384	301	220	141	106	49
2026	1846	2300	2400	2630	3382	5080	2360	461	383	300	219	141	106	49
2027	1842	2296	2396	2626	3376	5072	2356	461	383	300	219	141	106	49
2028	1839	2292	2392	2621	3370	5063	2352	460	382	299	218	140	105	49
2029	1836	2288	2388	2617	3365	5054	2348	459	381	299	218	140	105	49
2030	1833	2284	2384	2612	3359	5046	2344	458	381	298	218	140	105	49
2031	1830	2280	2380	2608	3353	5037	2340	457	380	298	217	140	105	49
2032	1827	2276	2376	2603	3347	5028	2336	457	379	297	217	139	105	49
2033	1824	2272	2372	2599	3342	5020	2332	456	379	296	217	139	105	49
2034	1820	2268	2368	2595	3336	5011	2328	455	378	296	216	139	104	48
2035	1817	2265	2364	2590	3330	5003	2324	454	377	295	216	139	104	48
2036	1814	2261	2360	2586	3325	4994	2320	454	377	295	215	139	104	48
2037	1811	2257	2356	2581	3319	4986	2316	453	376	294	215	138	104	48
2038	1808	2253	2352	2577	3313	4977	2312	452	375	294	215	138	104	48
2039	1805	2249	2348	2573	3308	4969	2308	451	375	293	214	138	104	48
2040	1802	2245	2344	2568	3302	4960	2304	450	374	293	214	138	103	48
2041	1799	2241	2340	2564	3296	4952	2300	450	374	292	214	137	103	48
2042	1796	2238	2336	2559	3291	4943	2296	449	373	292	213	137	103	48
2043	1793	2234	2332	2555	3285	4935	2292	448	372	291	213	137	103	48
2044	1790	2230	2328	2551	3279	4927	2288	447	372	291	213	137	103	48
2045	1787	2226	2324	2546	3274	4918	2284	447	371	290	212	136	102	48
2046	1784	2222	2320	2542	3268	4910	2281	446	370	290	212	136	102	48
2047	1781	2219	2316	2538	3263	4901	2277	445	370	289	211	136	102	47
2048	1778	2215	2312	2533	3257	4893	2273	444	369	289	211	136	102	47
2049	1774	2211	2308	2529	3252	4885	2269	444	369	289	211	135	102	47
2050	1771	2207	2304	2525	3246	4876	2265	443	368	288	210	135	102	47

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

	$/kWh				$/kW			
	Aurecon 2019-20	Aurecon 2020-21	GenCost 2019-20	AEMO ISP December 2020	Aurecon 2019-20	Aurecon 2020-21	GenCost 2019-20	AEMO ISP December 2020
Battery (1hr)	988	789	-	-	988	789	-	-
Battery (2hrs)	622	529	-	-	1244	1058	-	-
Battery (4hrs)	491	421	-	-	1964	1682	-	-
PHES (6hrs)	-	-	308	387	-	-	1850	2323
Battery (8hrs)	446	371	-	-	3564	2968	-	-
PHES (12hrs)	-	-	177	221	-	-	2118	2658
PHES (24hrs)	-	-	131	142	-	-	3139	3417
PHES (48hrs)	-	-	73	107	-	-	3517	5133
PHES (48hrs) Tasmania	-	-	-	50	-	-	-	2384

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration cost around $1250/kWh (SunWiz, 2021).

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	
2020												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4396	5.8	80%	4396	11.3	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1743	5.8	80%	1743	11.3	60%
Gas open cycle (small)	25	1.3	36%	12.6	4.1	0.0	1465	5.8	20%	1465	11.3	20%
Gas open cycle (large)	25	1.1	33%	10.2	2.4	0.0	873	5.8	20%	873	11.3	20%
Gas reciprocating	25	1.0	41%	24.1	7.6	0.0	1471	5.8	20%	1471	11.3	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	9311	2.8	80%	9311	4.1	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4450	2.8	80%	4450	4.1	60%
Brown coal with CCS	30	4.0	21%	101.6	11.6	4.7	14293	0.6	80%	14293	0.7	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6868	0.6	80%	6868	0.7	60%
Biomass (small scale)	30	2.0	23%	131.6	8.4	0.0	7265	0.5	60%	7265	2.0	40%
Large scale solar PV	25	0.5	100%	17.0	0.0	0.0	1505	0.0	32%	1505	0.0	22%
Solar thermal (8hrs)	25	1.8	100%	142.5	0.0	0.0	7411	0.0	52%	7411	0.0	42%
Wind	25	1.0	100%	25.0	0.0	0.0	1951	0.0	44%	1951	0.0	35%
2030												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3865	5.8	80%	4352	11.8	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1709	5.8	80%	1709	11.8	60%
Gas open cycle (small)	25	1.3	36%	12.6	4.1	0.0	1436	5.8	20%	1436	11.8	20%
Gas open cycle (large)	25	1.1	33%	10.2	2.4	0.0	856	5.8	20%	856	11.8	20%
Gas reciprocating	25	1.0	41%	24.1	7.6	0.0	1442	5.8	20%	1442	11.8	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8674	2.9	80%	9171	3.8	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4362	2.9	80%	4362	3.8	60%
Brown coal with CCS	30	4.0	21%	101.6	11.6	4.7	13556	0.7	80%	14054	0.7	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6732	0.7	80%	6732	0.7	60%
Biomass (small scale)	30	2.0	23%	131.6	8.4	0.0	7254	0.5	60%	7254	2.0	40%
Nuclear (SMR)	30	3.0	35%	200.0	5.3	0.0	7239	0.5	80%	16487	0.7	60%
Large scale solar PV	25	0.5	100%	17.0	0.0	0.0	768	0.0	32%	933	0.0	19%
Solar thermal (8hrs)	25	1.8	100%	142.5	0.0	0.0	5968	0.0	52%	6496	0.0	42%
Wind	25	1.0	100%	25.0	0.0	0.0	1863	0.0	46%	1910	0.0	35%

2040												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3327	5.8	80%	4309	11.8	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1675	5.8	80%	1675	11.8	60%
Gas open cycle (small)	25	1.3	36%	12.6	4.1	0.0	1407	5.8	20%	1407	11.8	20%
Gas open cycle (large)	25	1.1	33%	10.2	2.4	0.0	839	5.8	20%	839	11.8	20%
Gas reciprocating	25	1.0	41%	24.1	7.6	0.0	1414	5.8	20%	1414	11.8	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8030	2.9	80%	9034	3.8	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4275	2.9	80%	4275	3.8	60%
Brown coal with CCS	30	4.0	21%	101.6	11.6	4.7	12813	0.7	80%	13820	0.7	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6599	0.7	80%	6599	0.7	60%
Biomass (small scale)	30	2.0	23%	131.6	8.4	0.0	7254	0.5	60%	7254	2.0	40%
Nuclear (SMR)	30	3.0	40%	200.0	5.3	0.0	7207	0.5	80%	16487	0.7	60%
Large scale solar PV	25	0.5	100%	17.0	0.0	0.0	569	0.0	32%	778	0.0	19%
Solar thermal (8hrs)	25	1.8	100%	142.5	0.0	0.0	5234	0.0	52%	6087	0.0	42%
Wind	25	1.0	100%	25.0	0.0	0.0	1822	0.0	48%	1863	0.0	35%
2050												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3276	5.8	80%	4270	11.8	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1643	5.8	80%	1643	11.8	60%
Gas open cycle (small)	25	1.3	36%	12.6	4.1	0.0	1381	5.8	20%	1381	11.8	20%
Gas open cycle (large)	25	1.1	33%	10.2	2.4	0.0	822	5.8	20%	822	11.8	20%
Gas reciprocating	25	1.0	41%	24.1	7.6	0.0	1387	5.8	20%	1387	11.8	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	7891	2.9	80%	8906	3.8	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4195	2.9	80%	4195	3.8	60%
Brown coal with CCS	30	4.0	21%	101.6	11.6	4.7	12585	0.7	80%	13602	0.7	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6474	0.7	80%	6474	0.7	60%
Biomass (small scale)	30	2.0	23%	131.6	8.4	0.0	7254	0.5	60%	7253	2.0	40%
Nuclear (SMR)	30	3.0	45%	200.0	5.3	0.0	7207	0.5	80%	16487	0.7	60%
Large scale solar PV	25	0.5	100%	17.0	0.0	0.0	532	0.0	32%	624	0.0	19%
Solar thermal (8hrs)	25	1.8	100%	142.5	0.0	0.0	4748	0.0	52%	5530	0.0	42%
Wind	25	1.0	100%	25.0	0.0	0.0	1774	0.0	50%	1830	0.0	35%

Notes: Wind is onshore. 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, 2020-21 $/MWh

Category	Assumption	Technology	2020		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas turbine small	139	195	138	199	136	197	135	196
		Gas turbine large	112	172	111	177	110	176	110	175
		Gas reciprocating	142	190	140	194	139	192	138	191
Flexible 40-80% load, high emission		Black coal	89	120	88	116	87	114	86	113
		Brown coal	112	145	111	143	110	142	108	139
		Gas	67	114	67	117	66	117	66	116
	Climate policy risk premium	Black coal	127	171	126	166	124	163	122	161
		Brown coal	193	254	190	249	188	246	184	242
		Gas	80	132	80	134	79	134	78	133
Flexible 40-80% load, low emission		Black coal with CCS	165	220	158	214	151	212	149	210
		Brown coal with CCS	229	296	220	292	211	289	208	285
		Gas with CCS	112	175	105	179	99	178	98	178
		Solar thermal 8hrs	172	213	145	192	131	182	121	169
		Nuclear (SMR)			128	322	127	321	127	320
		Biomass (small scale)	154	246	154	246	154	246	154	246
Variable	Standalone	Wind	48	61	44	60	42	58	39	58
		Solar PV	49	72	28	55	22	48	21	40
Variable with integration costs	Wind & solar PV combined	50% share			46	66				
		60% share			47	67				
		70% share			50	72				
		80% share			52	76				
		90% share			55	80				

Apx Table B.10 Hydrogen electrolyser cost projections by scenario and technology, 2020-21 $/kW

	Central		High VRE		Diverse Technology	
	Alkaline	PEM	Alkaline	PEM	Alkaline	PEM
2020	2516	3510	2516	3510	2516	3510
2021	2066	2760	1847	2716	2062	2743
2022	1773	2239	1631	2164	1771	2212
2023	1580	1868	1491	1771	1583	1836
2024	1458	1607	1409	1493	1467	1571
2025	1390	1432	1374	1305	1406	1393
2026	1346	1303	1350	1164	1370	1260
2027	1305	1188	1315	1041	1337	1143
2028	1264	1086	1280	932	1307	1039
2029	1225	998	1246	840	1280	950
2030	1185	919	1208	758	1253	870
2031	1147	852	1169	689	1224	796
2032	1108	792	1127	628	1194	731
2033	1068	738	1080	574	1161	674
2034	1028	691	1031	527	1125	622
2035	989	649	982	485	1088	577
2036	950	612	931	449	1048	538
2037	914	581	883	417	1009	504
2038	882	554	838	390	972	475
2039	853	531	797	367	937	450
2040	828	513	760	347	905	429
2041	808	497	728	330	868	405
2042	791	484	699	315	834	385
2043	777	474	674	302	804	367
2044	766	466	652	291	776	352
2045	757	459	632	282	750	338
2046	750	454	614	273	727	326
2047	744	449	598	265	705	315
2048	739	446	582	258	684	305
2049	735	443	568	251	665	295
2050	732	441	555	245	647	287

Shortened forms

Abbreviation	Meaning
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
BAU	Business as usual
bbl	Barrel
BOP	Balance of plant
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated solar power
DIETER	Dispatch and investment evaluation tool with endogenous renewables
EV	Electric vehicle
GALLME	Global and Local Learning Model Electricity
GALLMs	Global and Local Learning Models
GALLMT	Global and Local Learning Model Transport
GJ	Gigajoule
GW	Gigawatt
hrs	Hours
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle

Abbreviation	Meaning
ISP	Integrated System plan
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
MWh	Megawatt hour
NEM	National Electricity Market
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
STABLE	Spatial Temporal Analysis of Balancing Levelised-cost of Energy
STEPS	Stated Policies
t	tonne

Abbreviation	Meaning
TWh	Terawatt hour
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WEO	World Energy Outlook

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