Australia's National
Science Agency

GenCost 2020-21

Consultation draft

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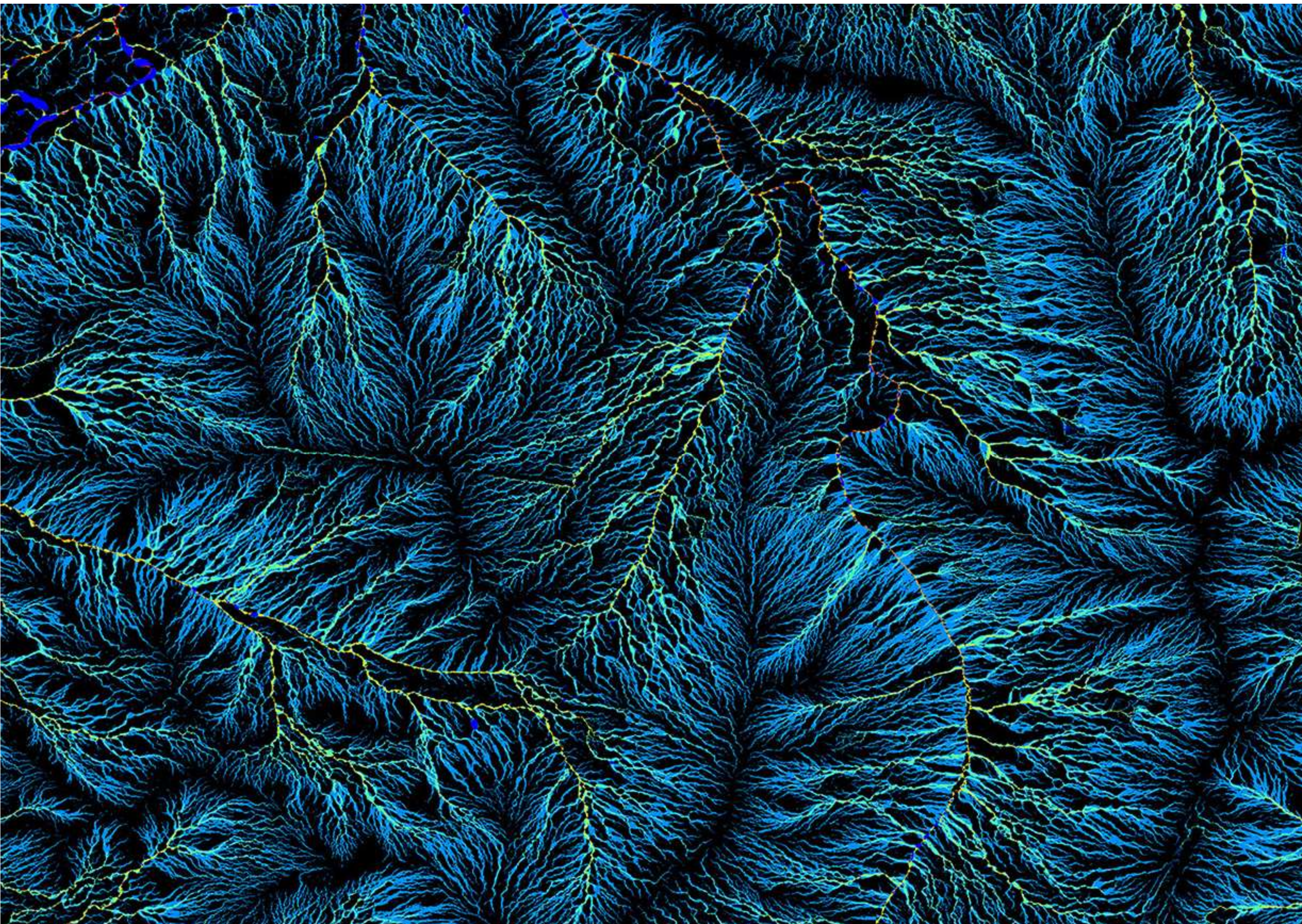

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This consultation report is provided with the purpose of seeking feedback. Stakeholders are requested to provide feedback on the GenCost scenarios, approach and results via formal submissions to AEMO's consultation on the Draft 2021 Inputs, Assumptions and Scenarios (IASR) Report. Submissions close 1 February. Further details are available at https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-scenarios-and-assumptions.

The consultation report has been improved by input from a stakeholder webinar in September 2020, comments provided in response to publication of draft scenario assumptions in October 2020 and the GenCost working group. Feedback received during the consultation phase will assist in finalising the report in early 2021.

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, projections of future changes in costs consistent with updated global electricity scenarios are also provided. Levelised costs of electricity (LCOEs) are also included and provide a simple 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 policy ambitions only, with the most likely assumptions for all other factors such as renewable resource constraints
- **High VRE**: A world that is driving towards net zero emission by 2050 and where technical, social and political support for variable renewable 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 generation and subsequently a greater role for other technologies.

Both the Central and High VRE scenarios reach high global renewable generation shares of 60% and 78% respectively by 2050. Wind and solar PV achieve the highest shares supported by battery and pumped hydro energy storage. Wind and solar PV are currently the lowest cost sources of low emission electricity generation for regions with good quality resources and this is projected to continue to be the case throughout the projection period to 2050

When access to wind and solar PV is assumed to be constrained in the Diverse technology scenario, generation from gas with carbon capture and storage fills the gap and is also used more commonly in hydrogen production. Nuclear small modular reactors could also play a role in the Diverse technology scenario so long as investors are willing to drive down costs through multiple deployments in the late 2020s and early 2030s.

The technology cost projections included in this report 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.

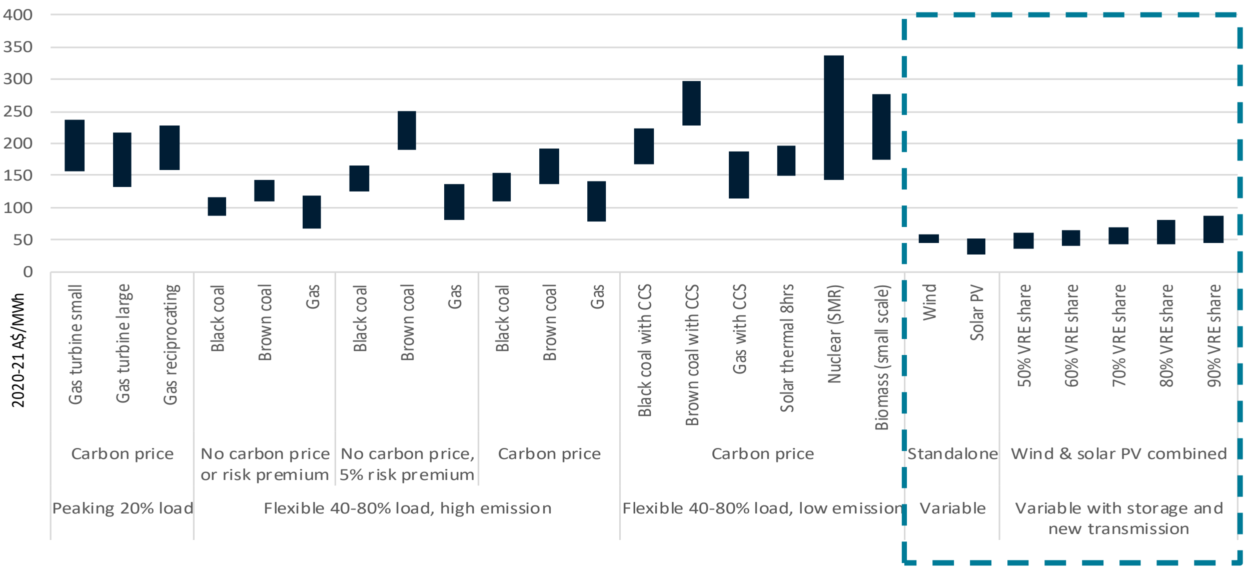
Levelised cost of electricity

There have been concerns for many years that it is difficult to quantify the additional costs associated with variable renewable 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
- Battery and pumped hydro storage to meet demand during low renewable generation periods.

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. We found that the additional costs to support a combination of solar PV and wind generation in 2030 is estimated at between $0 to $29/MWh depending on the VRE share and region of the NEM. When added to variable renewable generation costs and compared to other technology options, these new estimates indicate that wind and solar PV are the least cost generation technologies for the electricity system for any expected level of deployment.



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

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

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. 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.

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.

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 the 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, 2020). This update was initially shared with a wide range of stakeholders during a webinar in September 2020.

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

The report provides an overview of updates to current costs in Section 2. Further details on the Aurecon (2020) updates can be found in their report. The global scenarios 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 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[2]. 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 (2020).

2.2 Updates to current costs

AEMO commissioned Aurecon (2020) 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. Nuclear small modular reactor (SMR) costs have not been updated. Feedback from the 2019-20 report accepted that historical costs for completed SMR projects are high, that first of a kind plant in Australia would be high cost, but that future costs have the potential to be lower if there is significant global investment and the potential for modular construction is included (these future considerations are not part of our definition of current costs but are reflected in the projections). These views have not changed and there have been no major developments worldwide in SMR. Aurecon (2020) has included hydrogen electrolysers for the first time and these are separately reported.

[2] 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.

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

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2020-21) cost estimates (drawing primarily on the Aurecon (2020) update) for electricity generation technologies with the four most recent previous reports: GenCost 2012-20, 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 (2020). Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme. All data has been adjusted for inflation.

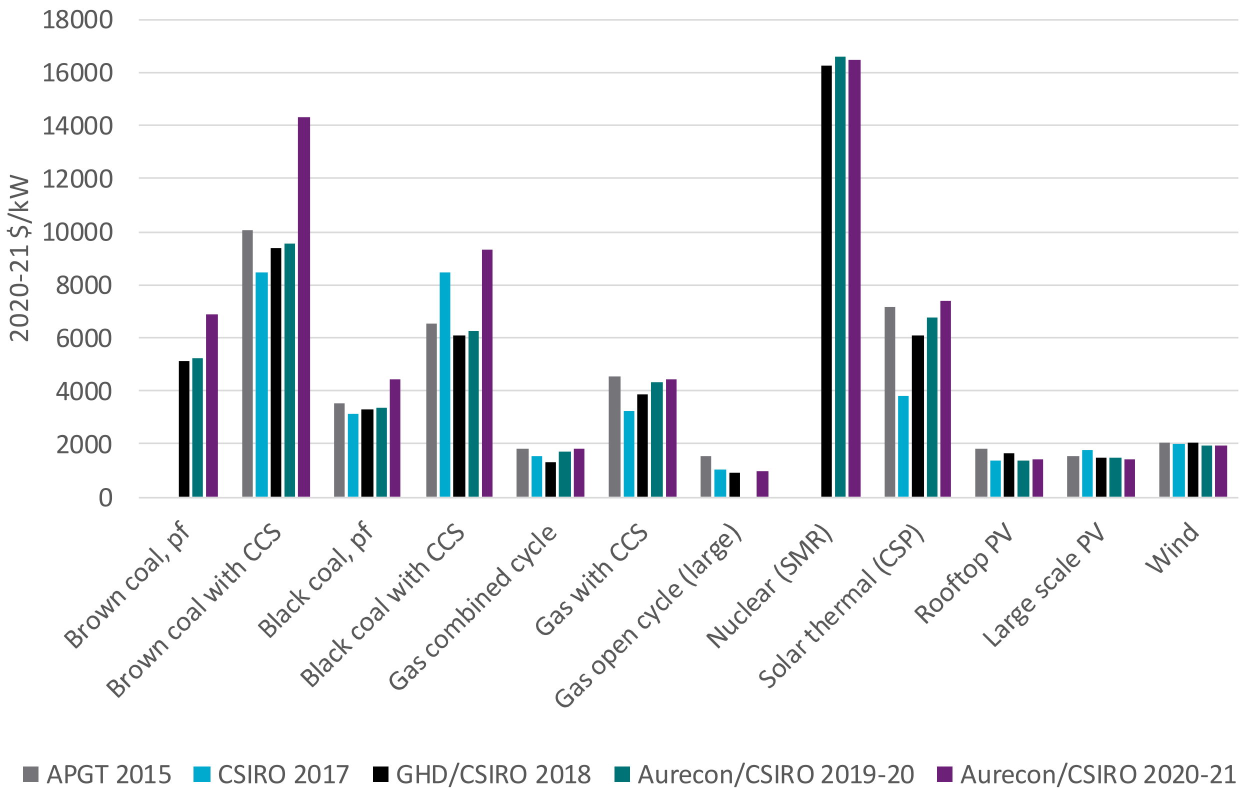


Figure 2-1 Comparison of current cost estimates with previous work

Coal generation capital costs have been revised upwards after not being significantly updated since the 2018 GHD 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 data 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[3]. 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 compared to the hydro turbine on PHES.

Conversely, the costs in $/kW increase as storage duration increase because additional storage duration adds costs without adding any power rating to the project (Figure 2-3). These relationships are the reasons why batteries tend to be more competitive in low storage duration applications, while PHES is more competitive in high duration applications.

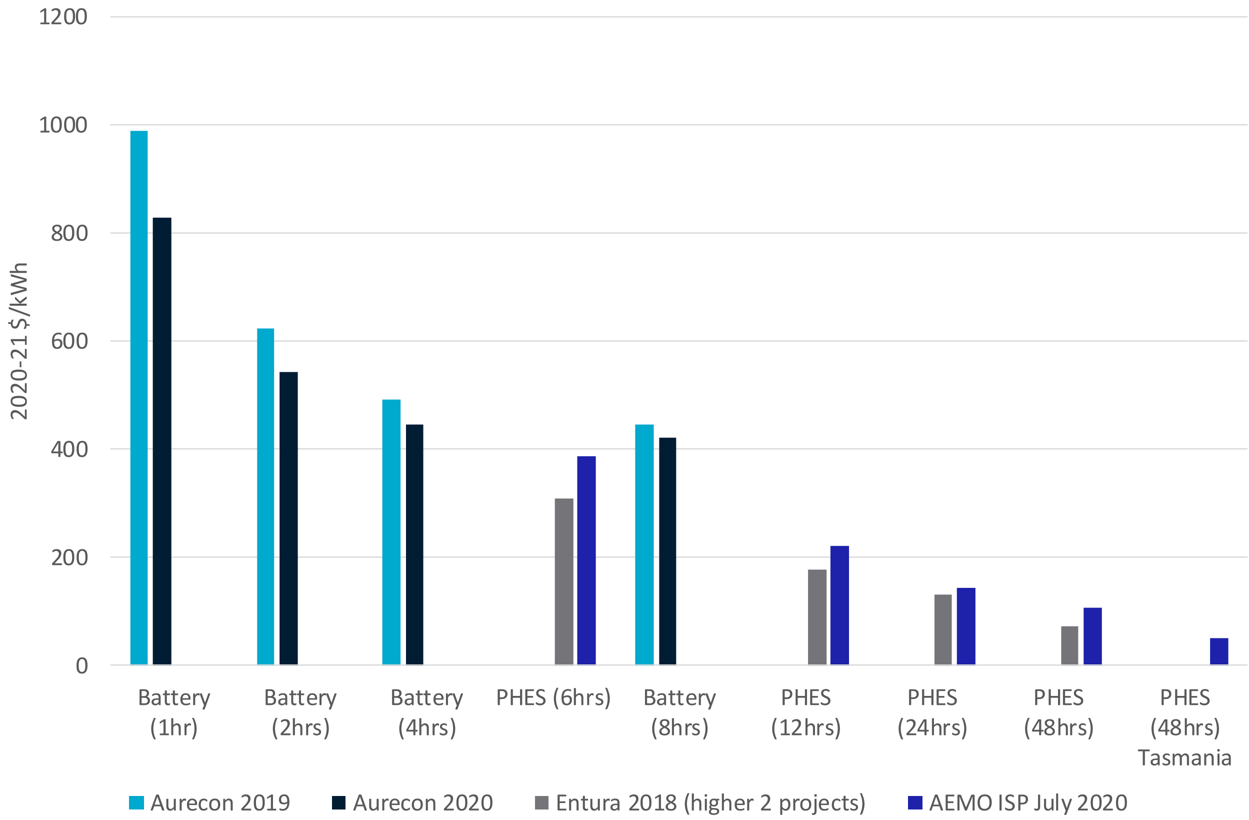


Figure 2-2 Capital costs of storage technologies in $/kWh (total cost basis)

Battery current costs have declined in Aurecon (2020) compared to their previous work. These are based on projects deployed. In contrast we have increased PHES costs by aligning with AEMO ISP July 2020 estimates. Feedback received during the ISP consultation indicated that PHES was under-estimated in previous assumptions. A new higher data point was included in the July 2020 ISP

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

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 consequently warrants greater certainty that it can achieve project cost estimates without the same level of escalation.

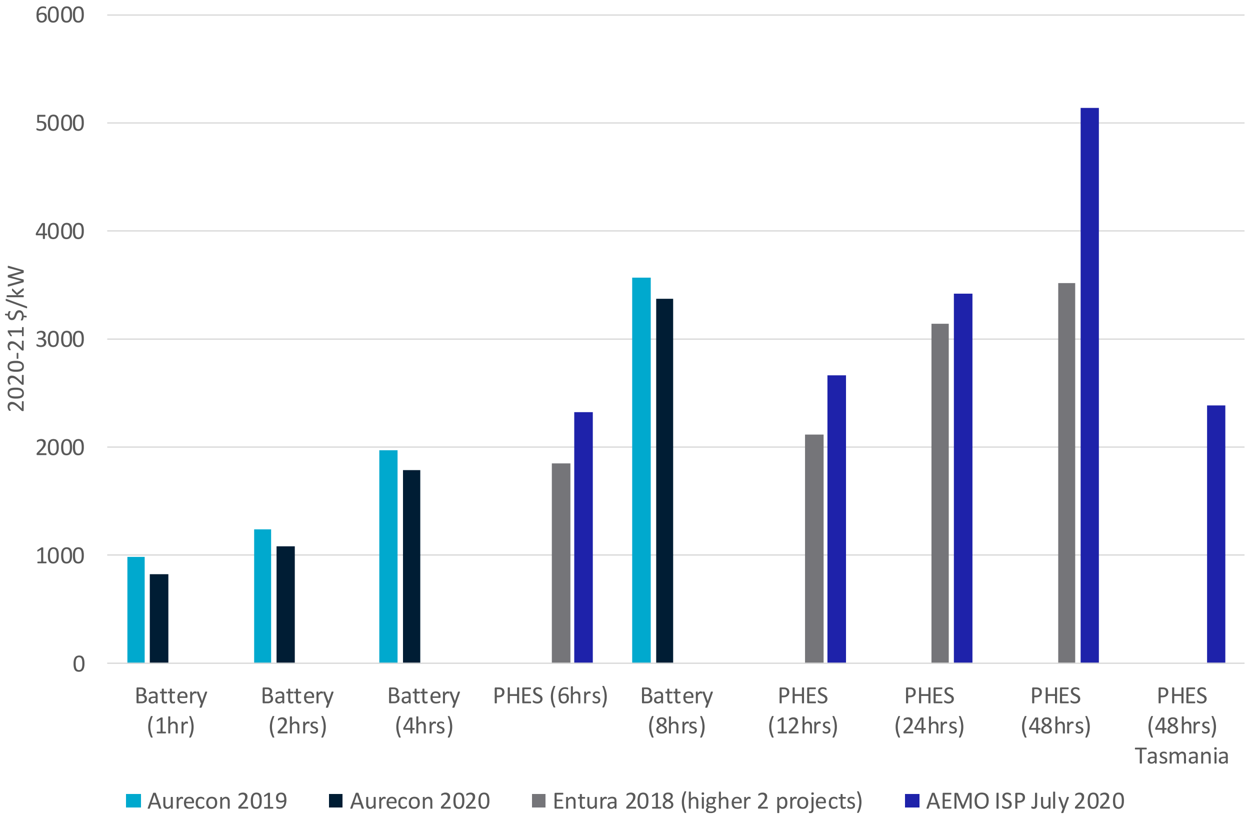


Figure 2-3 Capital costs of storage technologies in $/kW (total cost basis)

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 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 a carbon price[4]) and includes current renewable energy policies with no extension beyond current targets[5]. 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.

[4] The use of carbon prices does not mean that we expect this to be the favoured global policy tool. However, it is more efficient to use carbon prices in the modelling than to anticipate and implement all the potential future policy approaches. However, we have also included renewable energy targets because they are the exception to this rule.

[5] To be consistent with the IEA World Energy Outlook 2020, this does not include recent announcements or changes of government. For example, the WEO 2020 includes Chian'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 no 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.

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.

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 3-4

3.1.4 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 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 will use current costs from Aurecon 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 the Central and High VRE 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)

Technology	Component	LR 1 (%)	LR 2 (%)	References
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	-	3	(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)
	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)
Utility scale energy storage – Li-ion	G	-	15	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
	L	-	7.5	
Utility scale energy storage – flow batteries	G	-	15	(Brinsmead et al., 2015)
	L	-	7.5	
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.
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.
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.

The LR for PV BOP and li-ion batteries was adjusted for the Diverse technology scenario. Instead of continuing with a LR of 17.5% indefinitely, it was reduced to 10% for both technologies.

Compared to onshore wind, offshore wind has its own lower learning rate of 3%, based on findings in the literature (Samadi, 2018) (Voormolen, Junginger, Sark, & M, 2016) (van der Zwaan, Rivera-Tinoco, Lensink, & van den Oosterkamp, 2012). While this limits the potential for 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.

3.1.5 Electricity demand and electrification

In GenCost 2020-21 we are seeking to improve our approach to electrification assumptions. Previously we had been reliant on existing published global scenarios to capture all demand effects. We are looking 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.

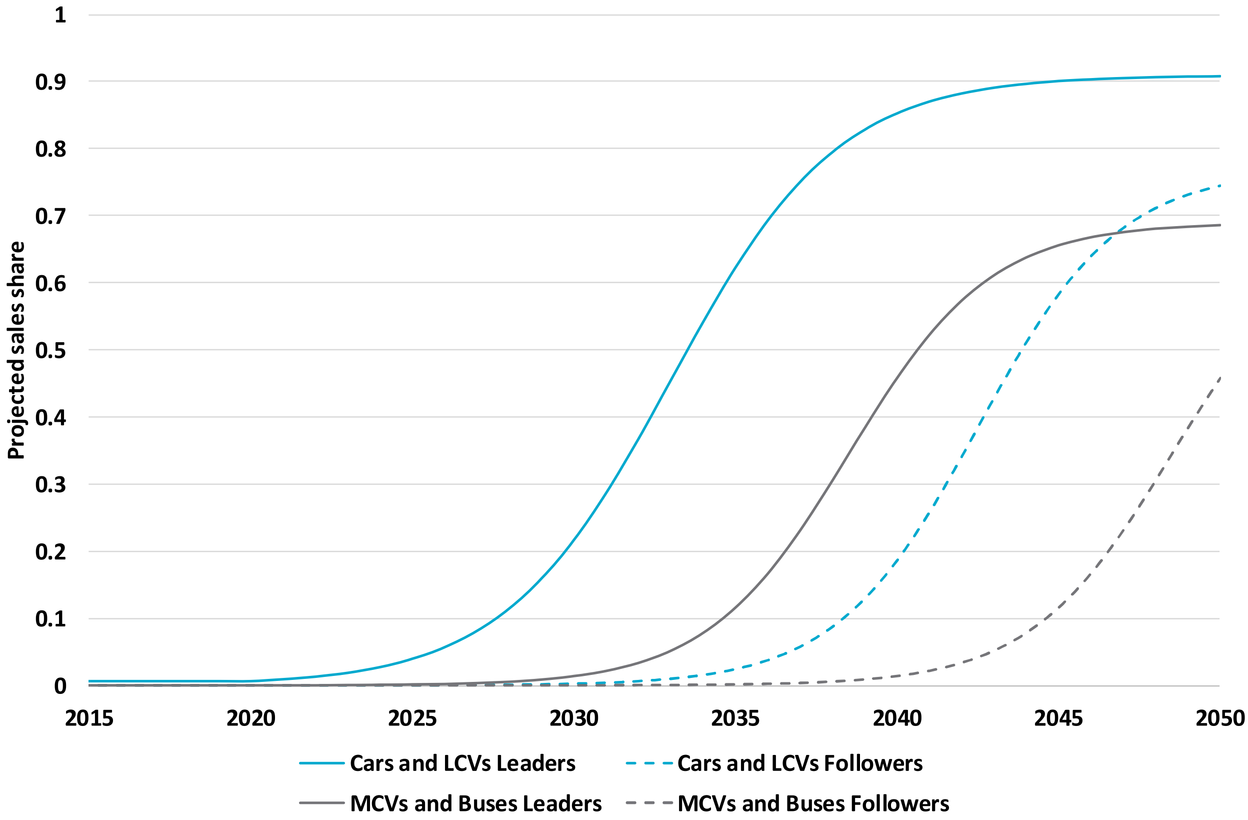


Figure 3-1 Projected EV sales share under the Central scenario

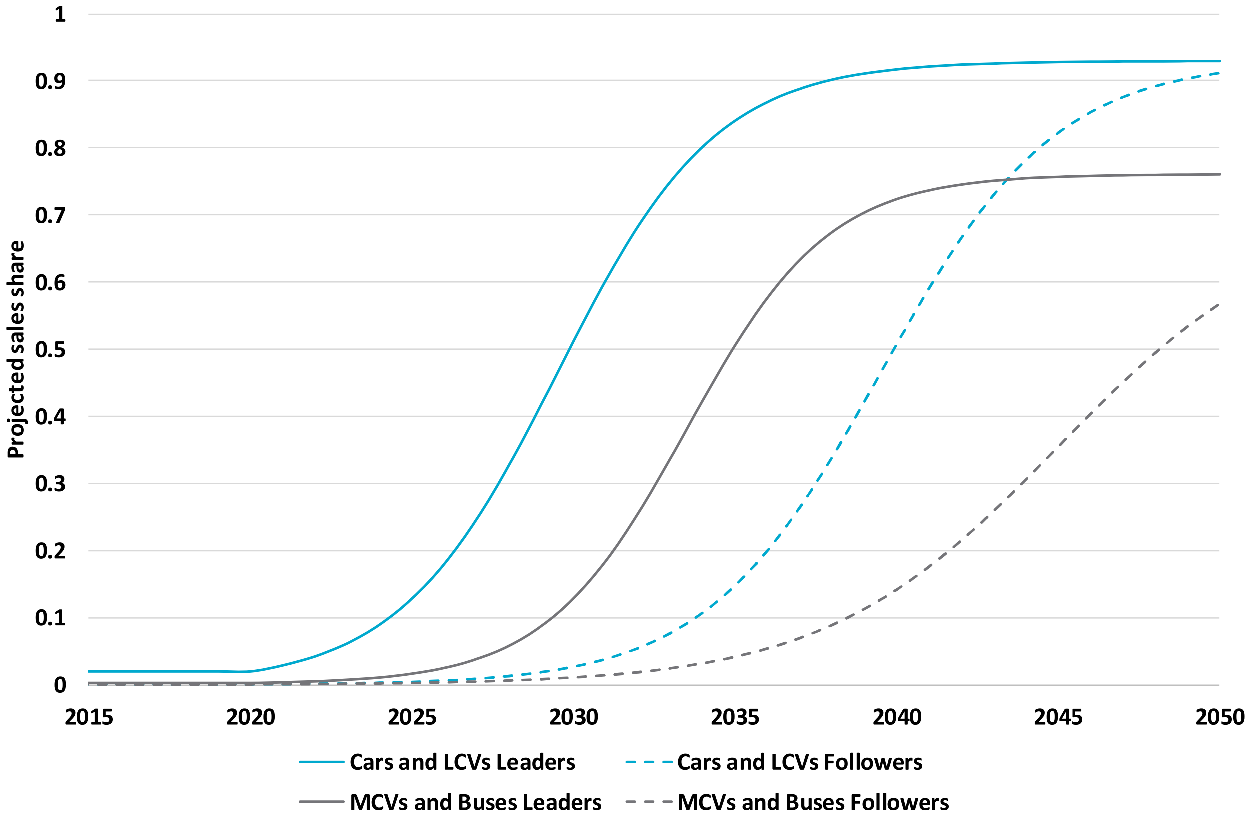


Figure 3-2 Projected EV adoption curve (vehicle sales share) under the High VRE scenario

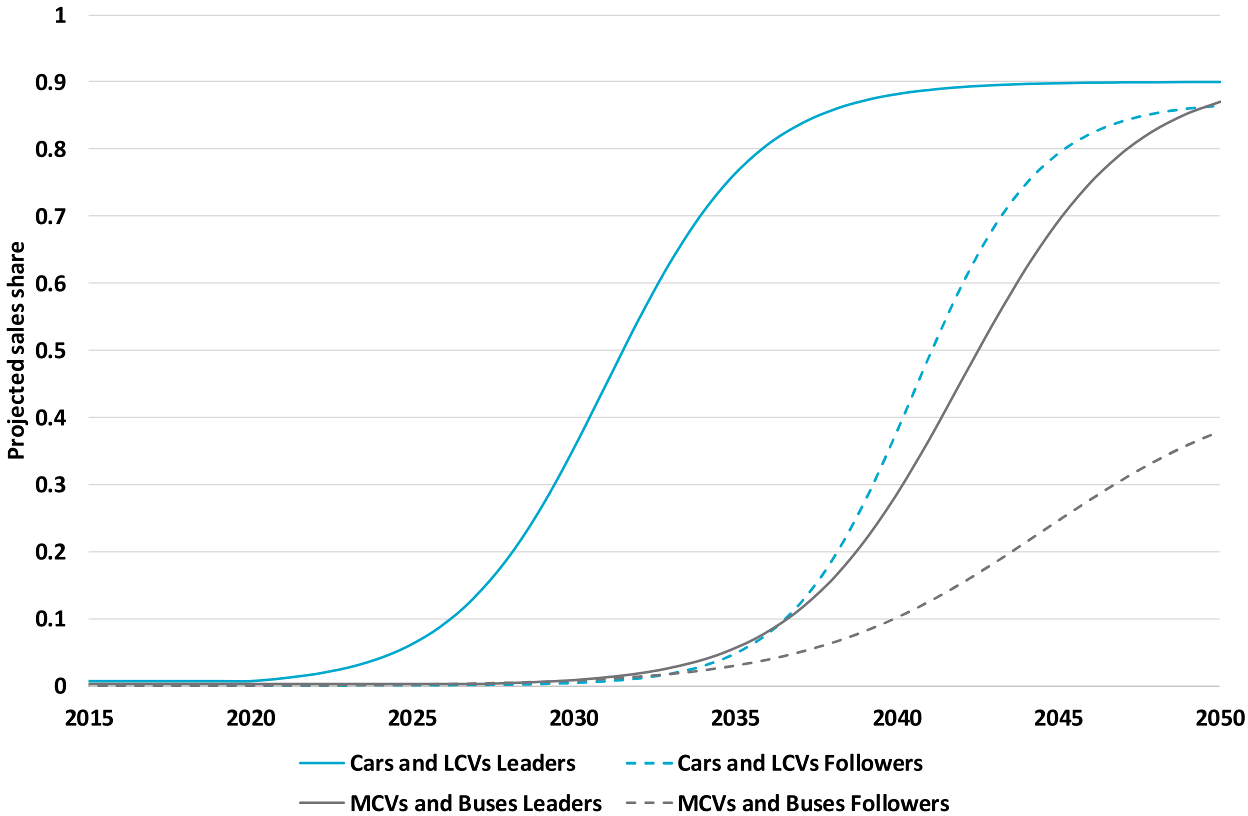


Figure 3-3 Projected EV sales share under the Diverse technology scenario

3.1.6 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 (SMR) with CCS dominates.

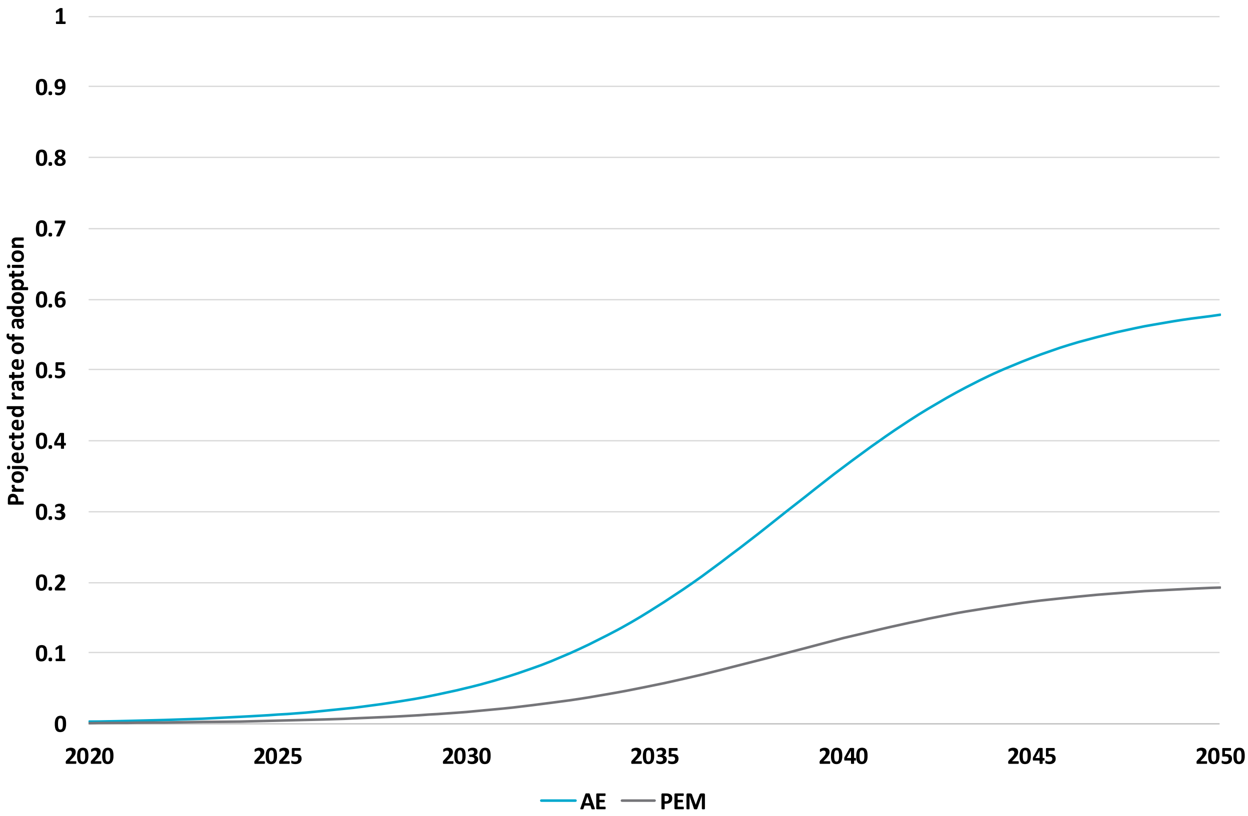


Figure 3-4 Adoption curves for hydrogen technologies under the Central scenario

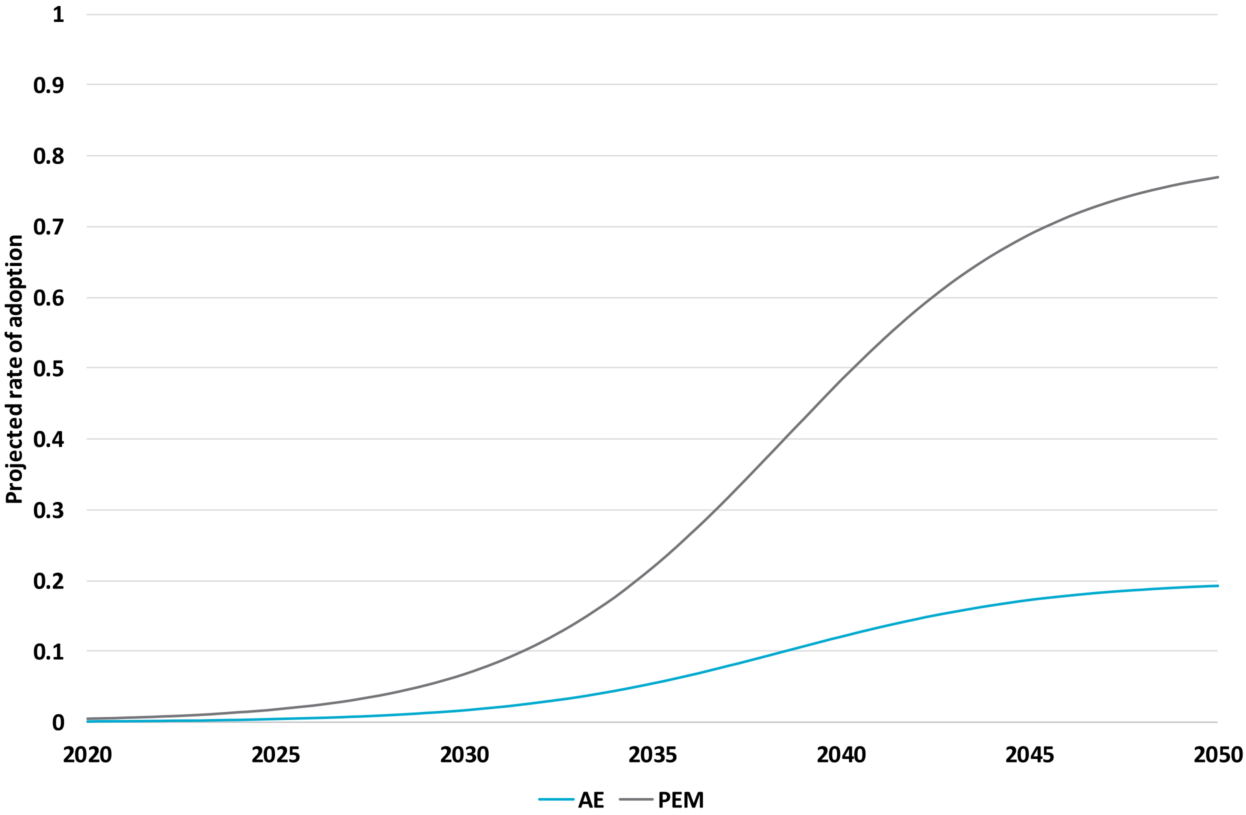


Figure 3-5 Adoption curves for hydrogen technologies under the High VRE scenario

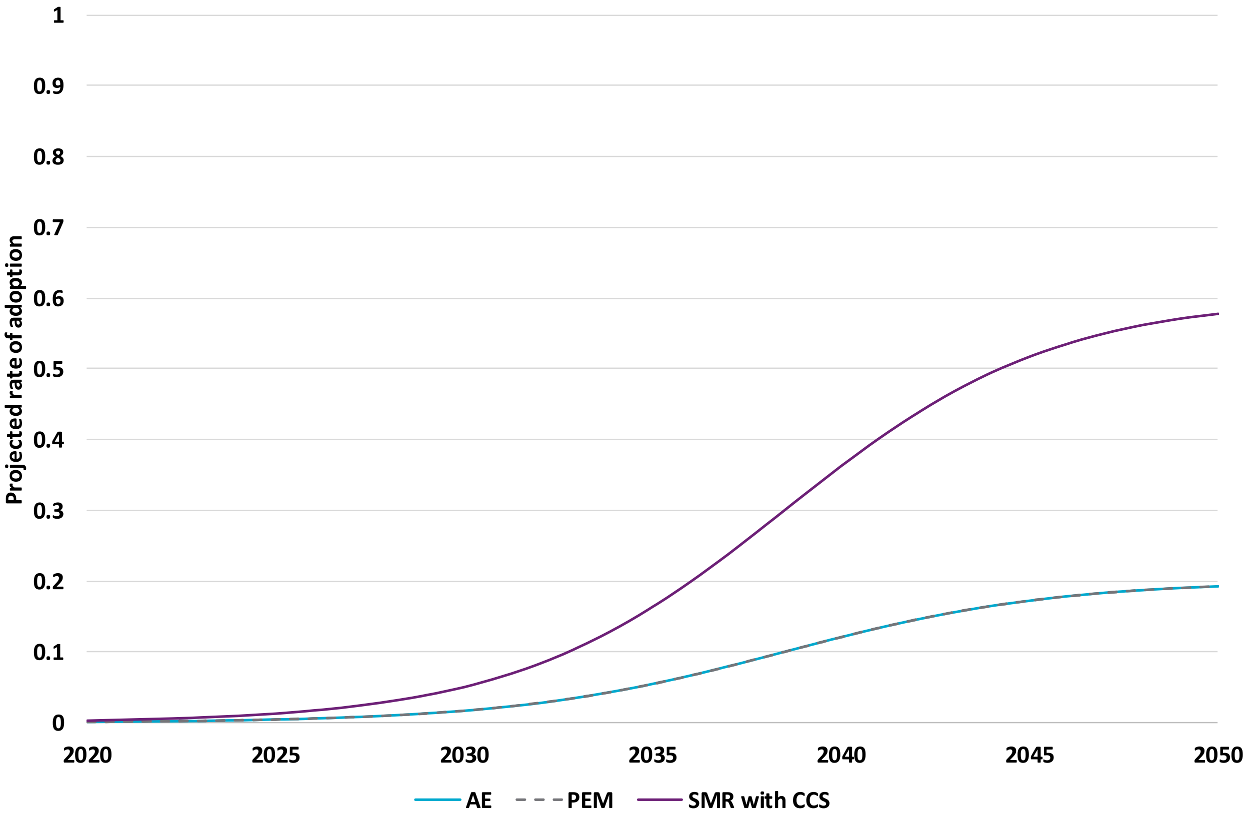


Figure 3-6 Adoption curves for hydrogen technologies under the Diverse technology scenario

There is currently a greater installed capacity of AE which has been commercially available since the 1950's, 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 into 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 3-3 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 3-3 Hydrogen demand assumptions by scenario

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

3.1.7 Government climate and renewable policies

GALLME contains government policies which act as incentives for technologies to reduce costs or limits their uptake. The key assumption about government policy that has an impact on results is a carbon price. The inclusion of carbon price should not be read to suggest this is the most likely global policy instrument[6]. It is the most efficient way of modelling a mix of climate policies. The carbon prices are based on those of Clarke et al. (2014).

The carbon price trajectory under the Diverse technology scenario has been designed to produce CO_2 emissions from electricity generation at the same level as those of the IEA Sustainable Development Scenario (SDS) (Figure 3-7). The High VRE scenario has a carbon price trajectory 40% higher than the Diverse technology scenario to try to achieve net zero emissions by 2050 These carbon price trajectories are in some cases higher than what the IEA use in their modelling. However, the IEA have greater regional and country granularity and are better able to include individual country emissions reduction policies, which is not possible in GALLME due to our regional aggregation. This means the IEA model reduces emissions through a greater variety of levers and not just a high carbon price. We do include some regional policies where possible, such

[6] However, it should be noted that China, the largest single country in greenhouse gas emissions, has indicated a preference to set up an emissions trading scheme.

as renewable energy targets and mandated construction of renewable technologies in countries like China.

The Central scenario uses a lower carbon price trajectory consistent with lower climate policy ambition as shown in Figure 3-8.

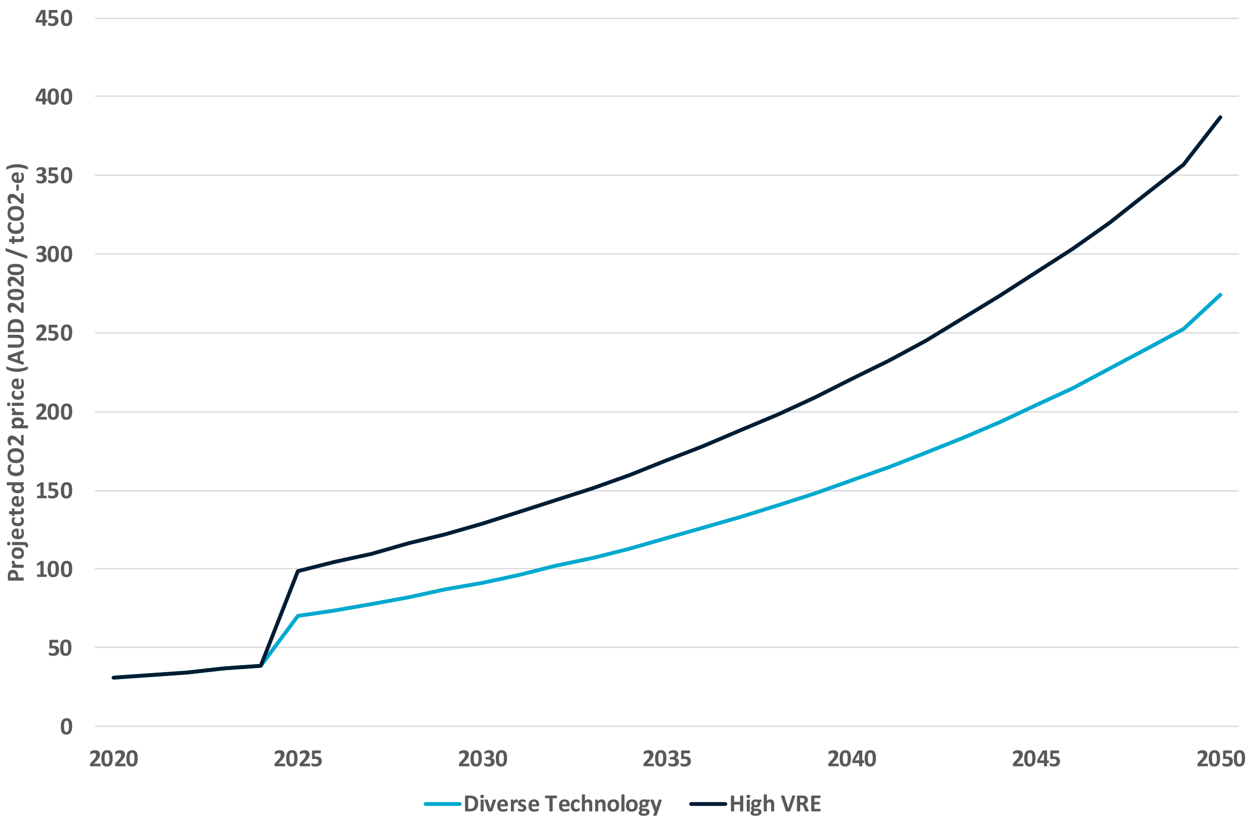


Figure 3-7 Projected carbon price trajectory under High VRE and Diverse technology scenarios, all regions

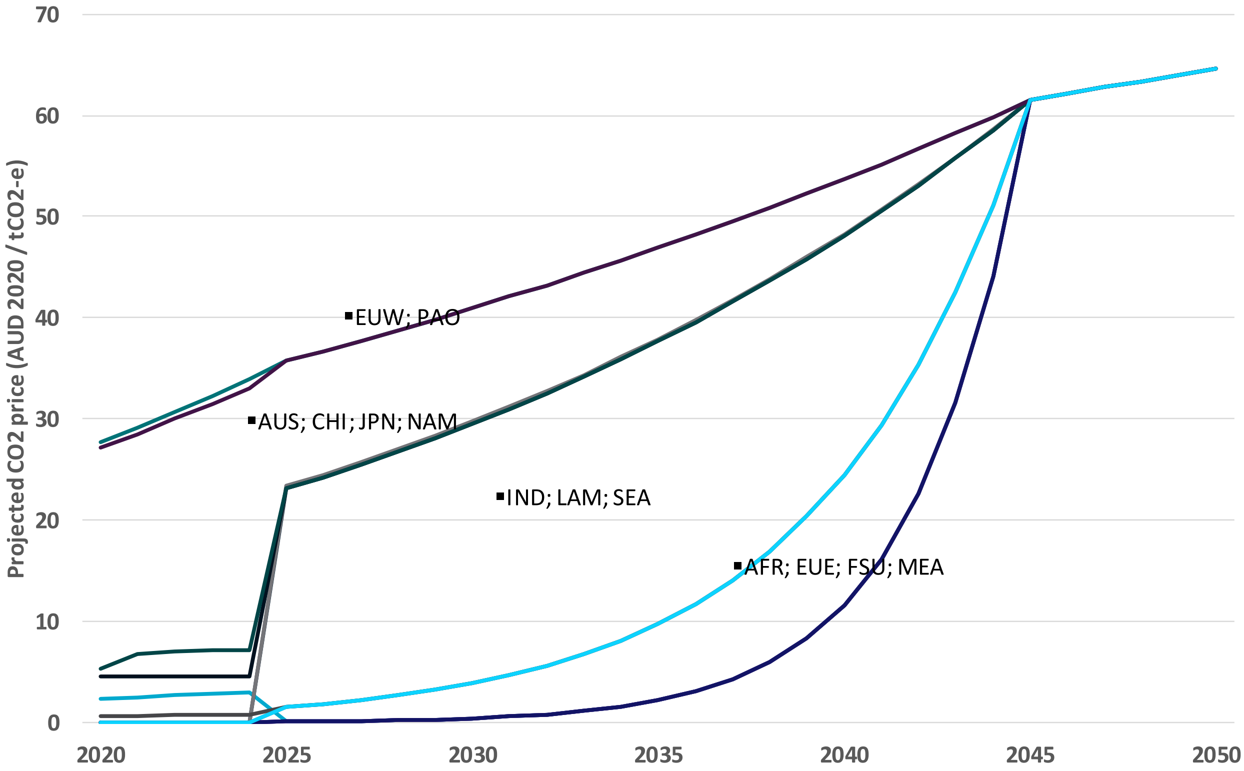


Figure 3-8 Projected carbon price trajectory under the Central scenario by region

3.1.8 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 3-4. 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 3-4 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	CST	Onshore wind
AFR	565	NA	NA	NA
AUS	113	NA	NA	NA
CHI	1913	NA	NA	NA
EUE	179	NA	NA	NA

Region	Rooftop PV	Large scale PV	CST	Onshore wind
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

3.1.9 Other data assumptions

GALLME international fossil fuel prices are based on (IEA, 2020) as shown in Table 3-5 for gas and Table 3-6 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 3-7.

Table 3-5 Assumed gas prices in $A/GJ

	2019	2025	2040	2050
AFR	12	13	16	18
AUS[7]	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

[7] It should be noted that Australian gas prices have no impact on model outcomes. These prices are consistent with moderate to strong climate policy ambition across the scenarios.

	2019	2025	2040	2050
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

Table 3-6 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 3-7 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, 2016) (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, 2015) (UN, 2015) (US Energy Information Administration, 2017) (US Energy Information Administration, 2017) (GWEC) (IEA) (IEA, 2016) (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 projection described in the next section is shown in Figure 4-1.

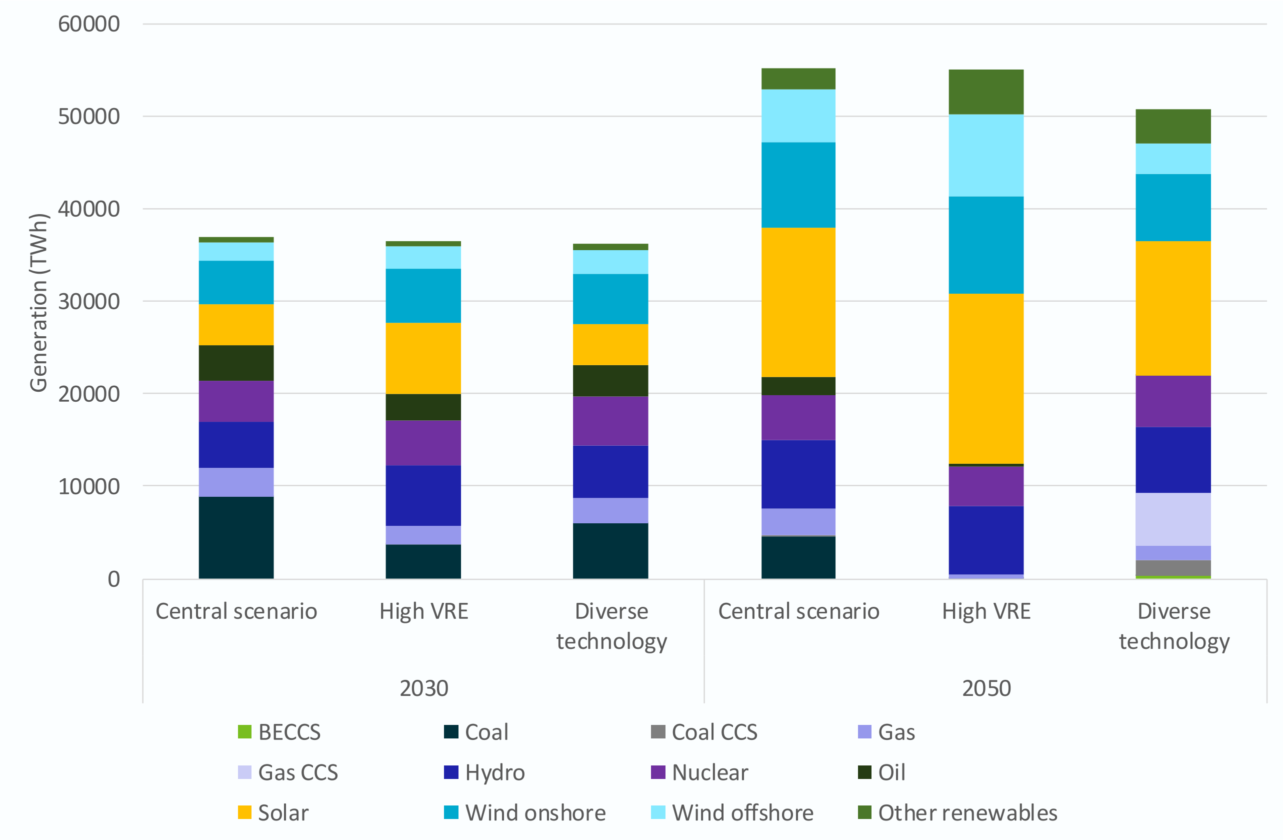


Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Central scenario has the lowest electrification because it has the least climate policy ambition. However, it has the least energy efficiency and industry transformation[8]. 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

[8] 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 the lowest renewable share. Variable renewables such as wind and solar PV are limited to a 40% share and as a result total non-hydro renewable generation accounts for 57% 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, although similar in magnitude to Central.

The Central scenario has the least climate policy ambition which we implement as a lower carbon price 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 60% by 2050 with a strong focus on solar and wind rather than other renewables which tend to require higher carbon prices to compete.

The High VRE scenario is near zero emission by 2050 with a non-hydro renewable share of 78% 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. Other renewables also feature strongly in this scenario, supported by high carbon prices. Nuclear generation is the lowest in High VRE consistent with the dominance of renewables 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.

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 (2020) 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.

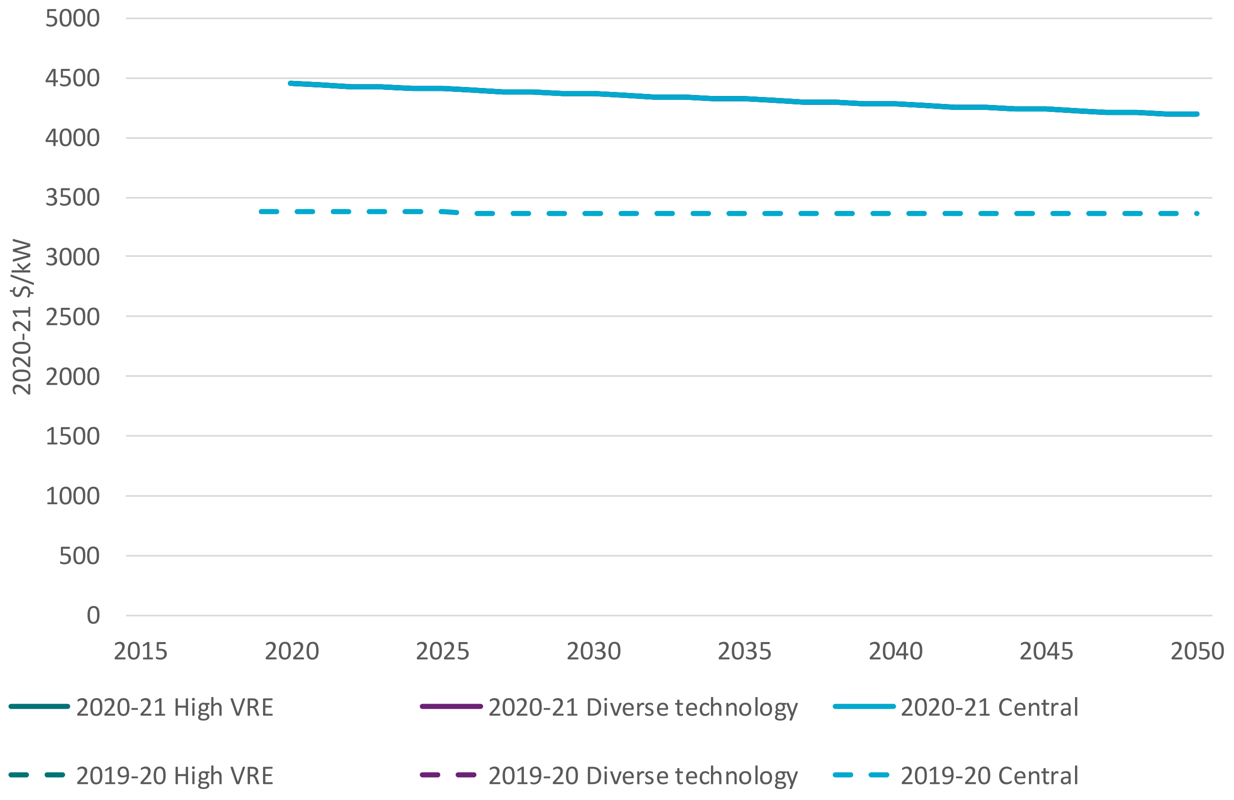


Figure 4-2 Projected capital costs for black coal supercritical by scenario compared to 2019-20 projections

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. This higher current cost estimate makes a minor contribution to more delayed deployment of CCS compared to the 2019-20 projections, particularly in the Central and High VRE scenarios. Overall black coal with CCS is not a large share of the generation mix in any scenario with cost reductions mainly reflecting co-learning from deployment of gas with CCS.

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 2030 which is around five years later than in the 2019-20 projections. In 2019-20, diverse technology and High VRE scenarios shared the same carbon price. However, in the 2020-21 projections High VRE has a much higher carbon price consistent with near zero net emissions by 2050 and consequently CCS technologies which have residual uncaptured emissions have only limited deployment.

Brown coal with CCS is included in the Appendix B data tables. It experiences a similar cost trajectory to black coal with CCS whereby cost reduction are due to co-learning from deployment of gas with CCS rather than any significant deployment of its own.

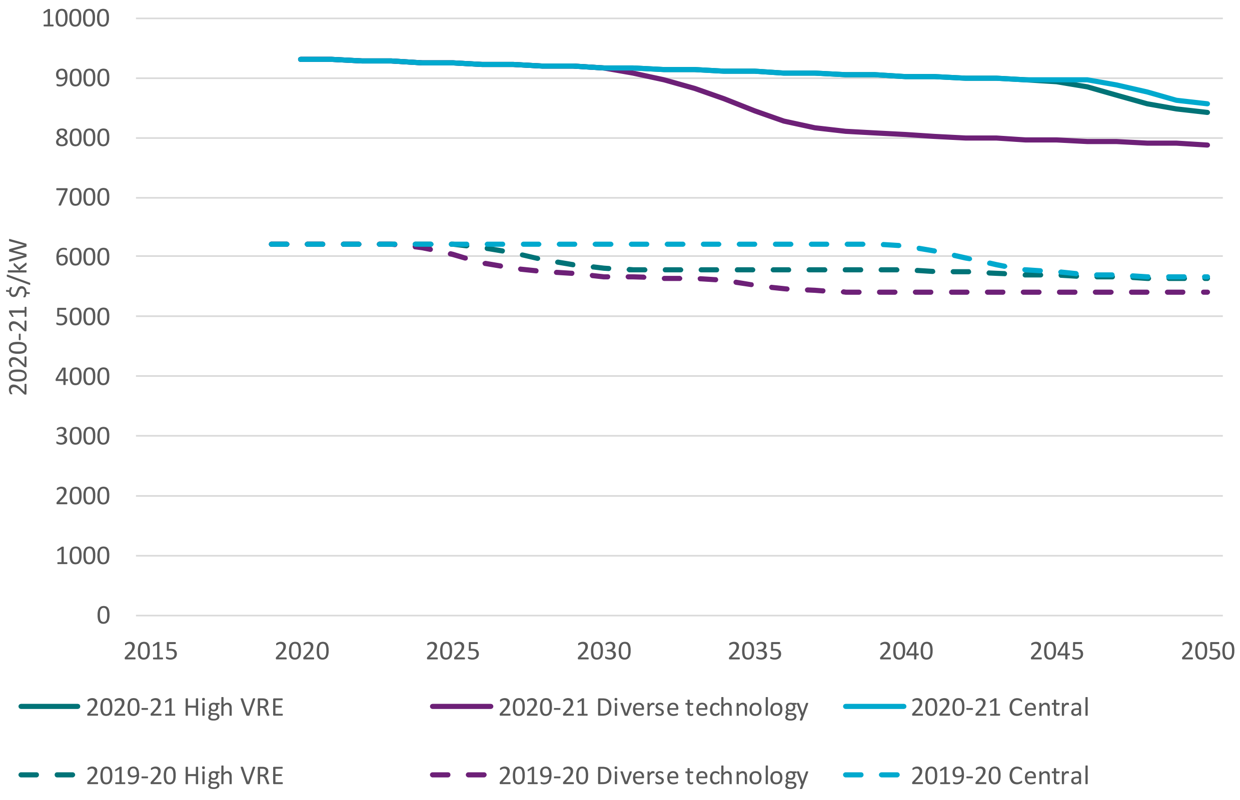


Figure 4-3 Projected capital costs for black coal with CCS by scenario compared to 2019-20 projections

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 (2020) 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 2040.

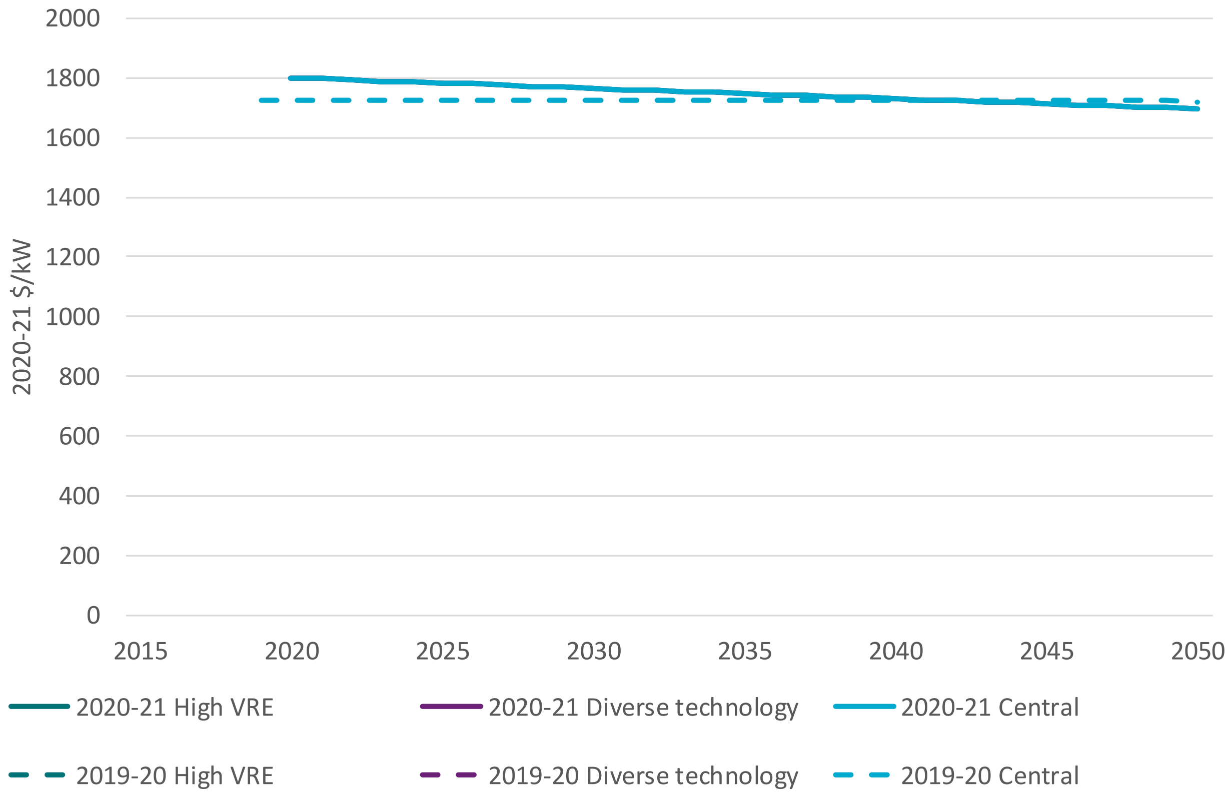


Figure 4-4 Projected capital costs for gas combined cycle by scenario compared to 2019-20 projections

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 (2020). 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 2030 which is around five years later than in the 2019-20 projections.

High VRE does not deploy CCS in the 2020-21 projections to the same degree as the 2019-20 projections. This is because a higher carbon price is used for High VRE in the 2020-21 projections consistent with achieving near zero global emissions by 2050. The residual emissions from fossil CCS plant are inconsistent with this change in the scenario design and are penalised more strongly by the higher carbon price to limit their uptake in the modelling. In 2019-20, High VRE had previously applied the same carbon price to diverse technology.

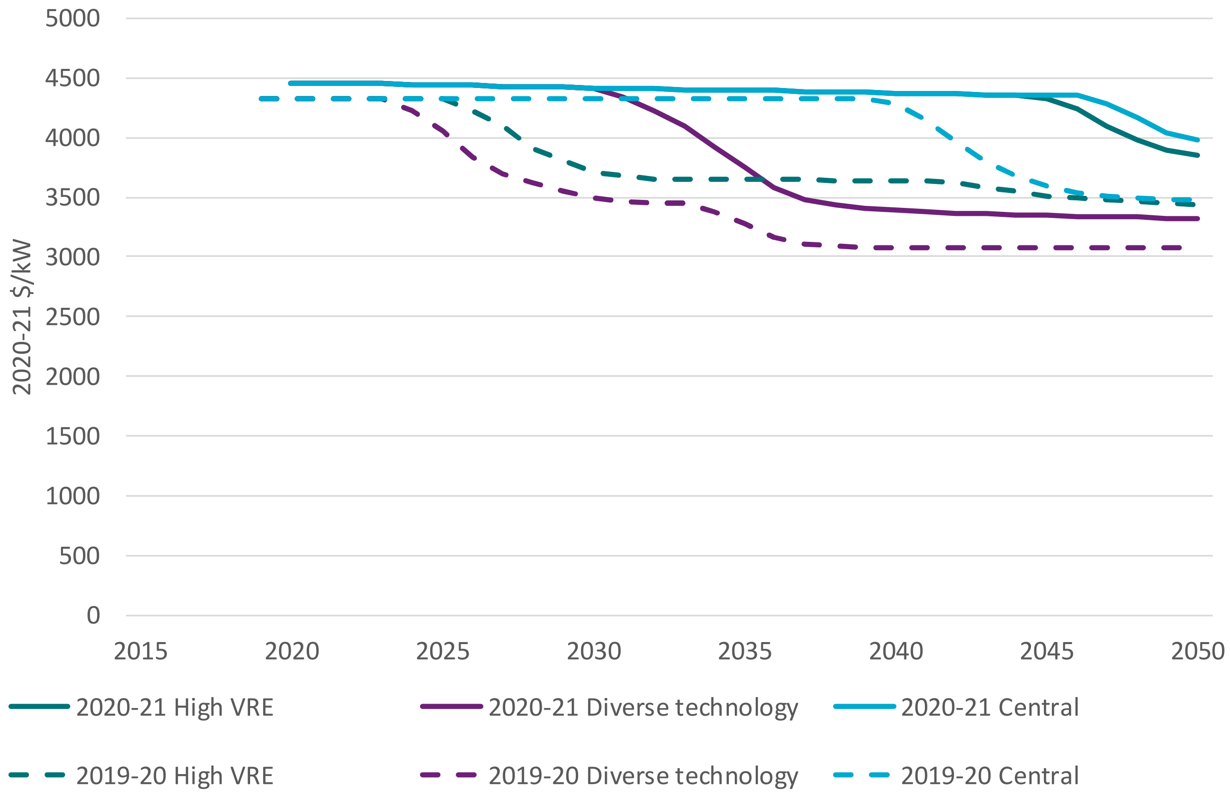


Figure 4-5 Projected capital costs for gas with CCS by scenario compared to 2019-20 projections

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 converges towards the 2019-20 projections by 2050.

Aurecon (2020) 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.

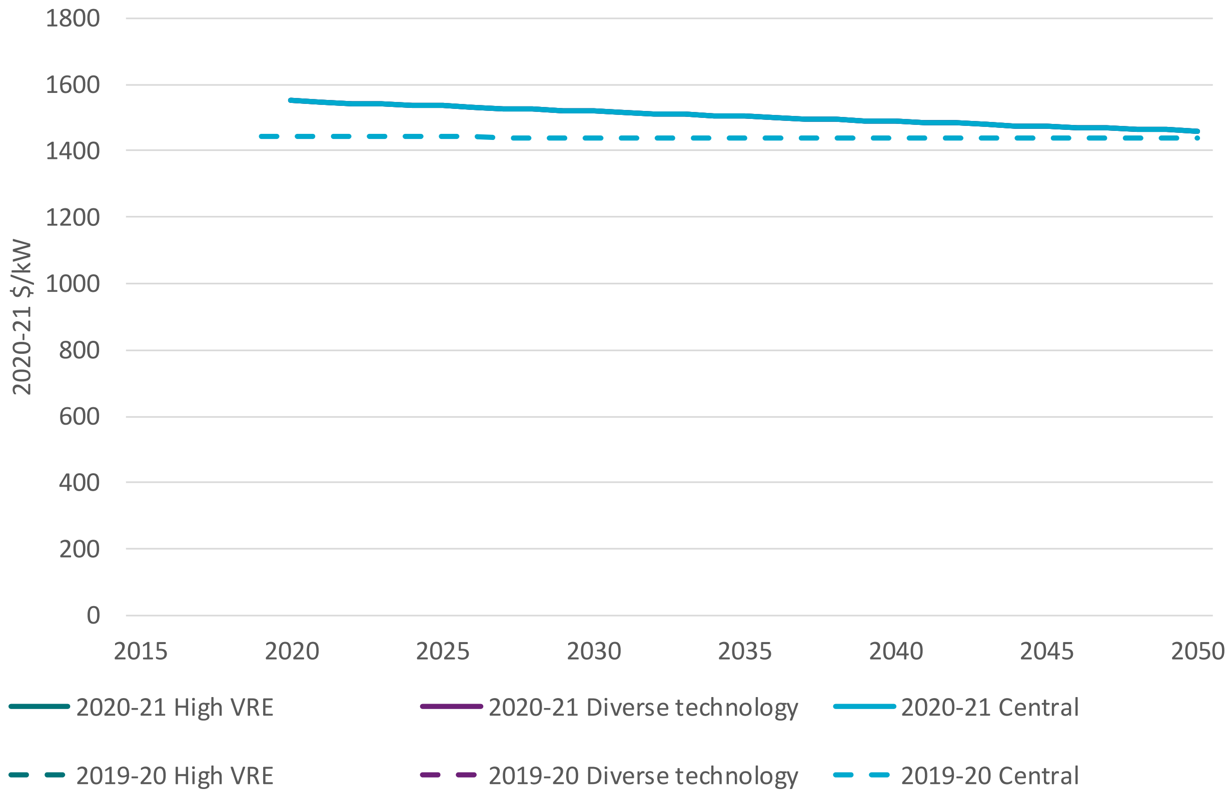


Figure 4-6 Projected capital costs for gas open cycle (small) by scenario compared to 2019-20 projections

4.2.6 Nuclear SMR

The current capital costs and assumed learning rates for nuclear SMR have not changed since the 2019-20 projections. The one major change is that the Central scenario has a higher carbon price consistent with current policies which will deliver 2.7 degrees temperature change whereas the previous Central scenario was based on a lower carbon price and 4 degrees. Consequently, nuclear SMR is deployed sooner in the Central scenario and is now aligned with deployment in the Diverse technology scenario. The high carbon price and limits on deployment of variable renewable generation make it an attractive scenario to deploy nuclear SMR.

In both scenarios, significant capital cost reductions occur over a five-year period. This is consistent with the sort of building program for a modular technology which manufacturers are hoping to achieve. Modular plants reduce the number of unique inputs that need to be manufactured. In Central and Diverse technology, capital costs fall to around $7000/kW.

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.

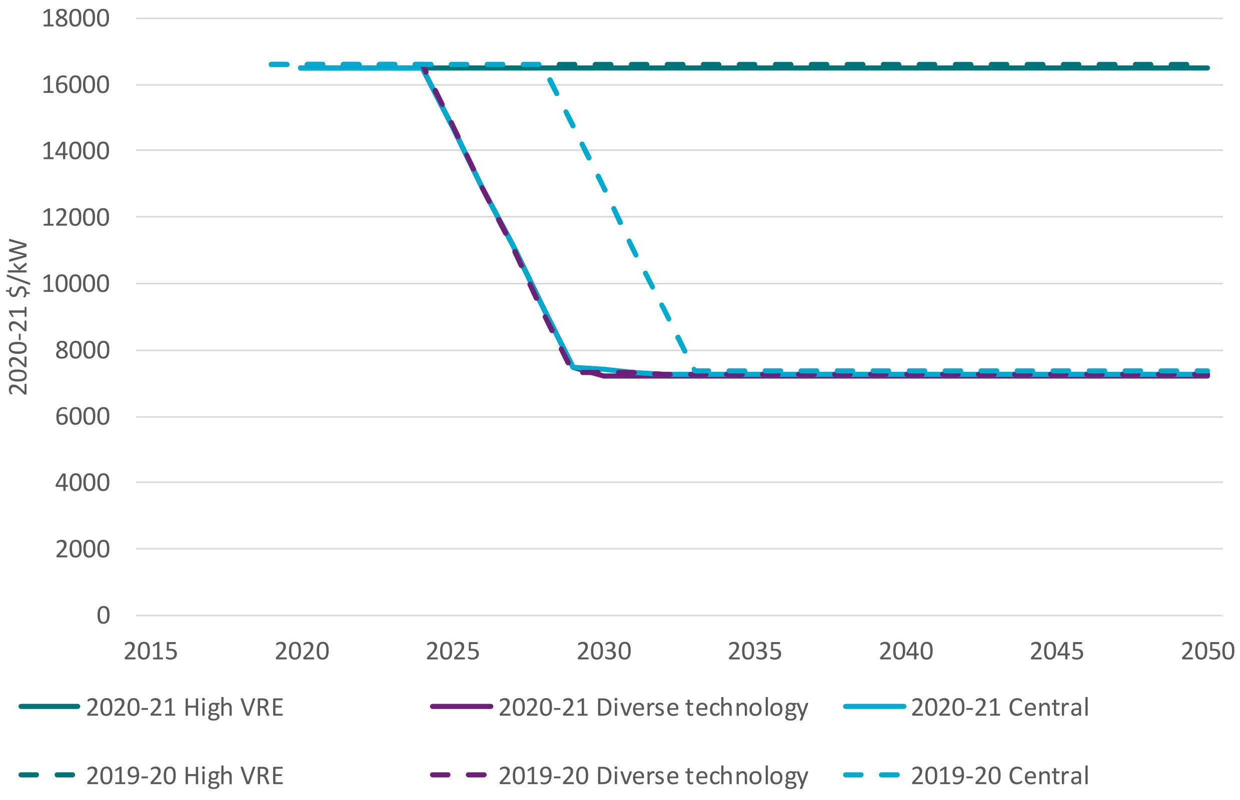


Figure 4-7 Projected capital costs for nuclear SMR by scenario compared to 2019-20 projections

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 generally higher climate policy ambitions – implemented as higher carbon prices sooner in the modelling. However, the overall scale of capital cost reduction, around $2000/kW, is less than previously projected. This reflects greater deployment of other renewables such as wind and solar PV whose current capital cost estimates continue to fall each year in contrast to solar thermal.

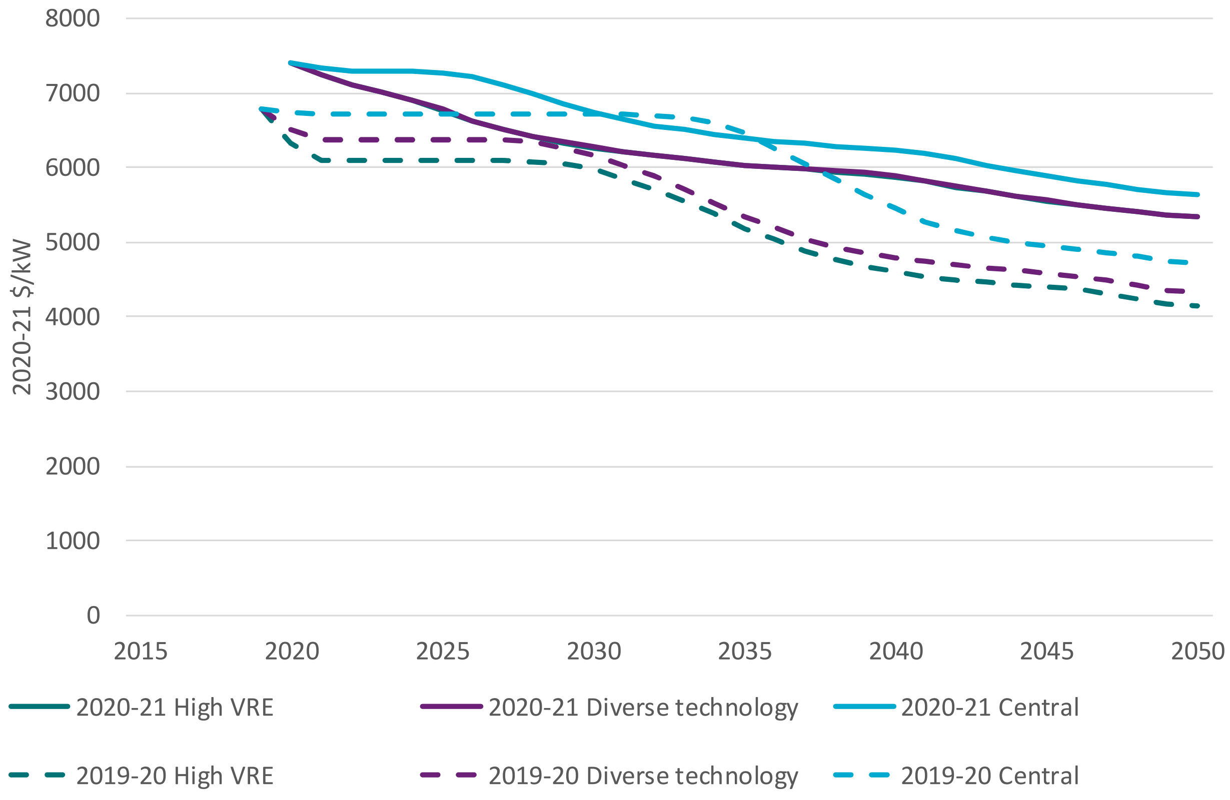


Figure 4-8 Projected capital costs for solar thermal with 8 hours storage by scenario compared to 2019-20 projections

4.2.8 Large scale solar PV

As was the case in the 2019-20 projections, the 2020-21 projections for large-scale solar continue to track their historical learning rate with current capital costs updated to a lower level of around $1400/kW. 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 with High VRE, as the name suggests, achieving the most deployment.

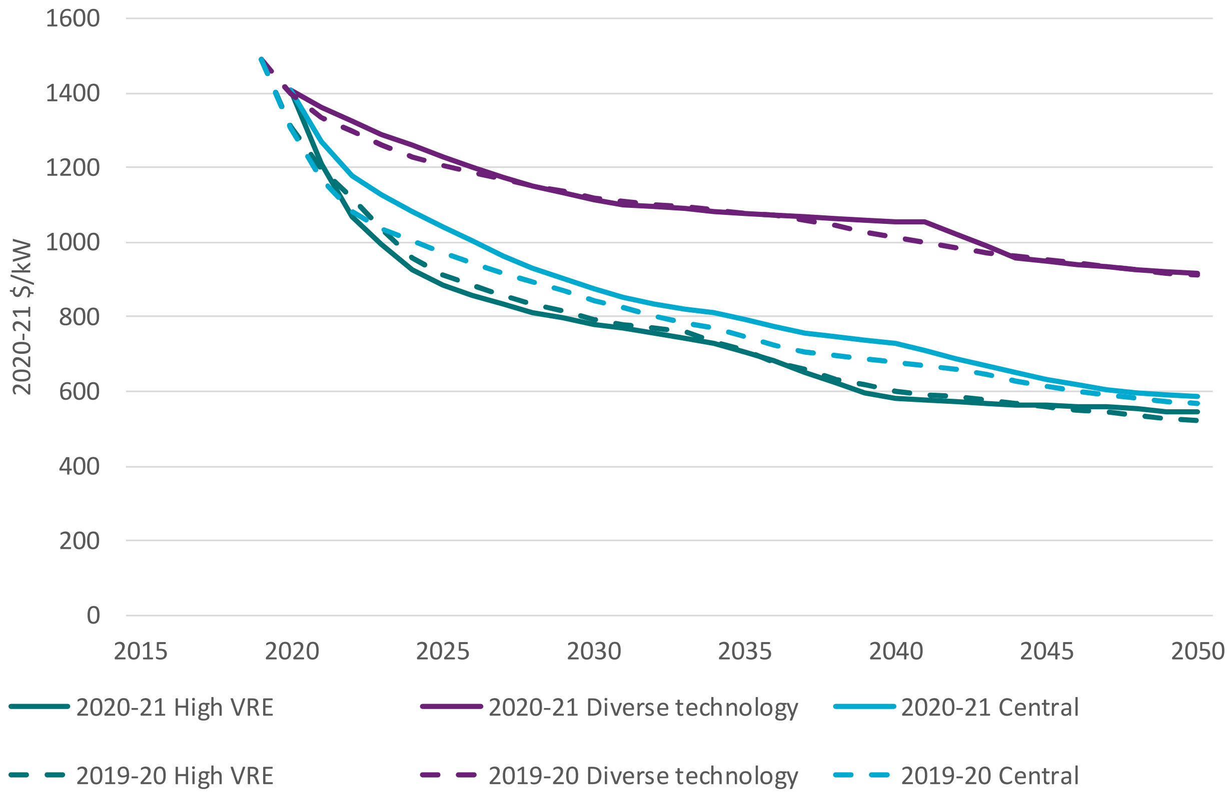


Figure 4-9 Projected capital costs for large scale solar PV by scenario compared to 2019-20 projections

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 system are sourced from historical data published by Solar Choice. However, they note that there are significantly discounted rooftop solar 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 in 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.

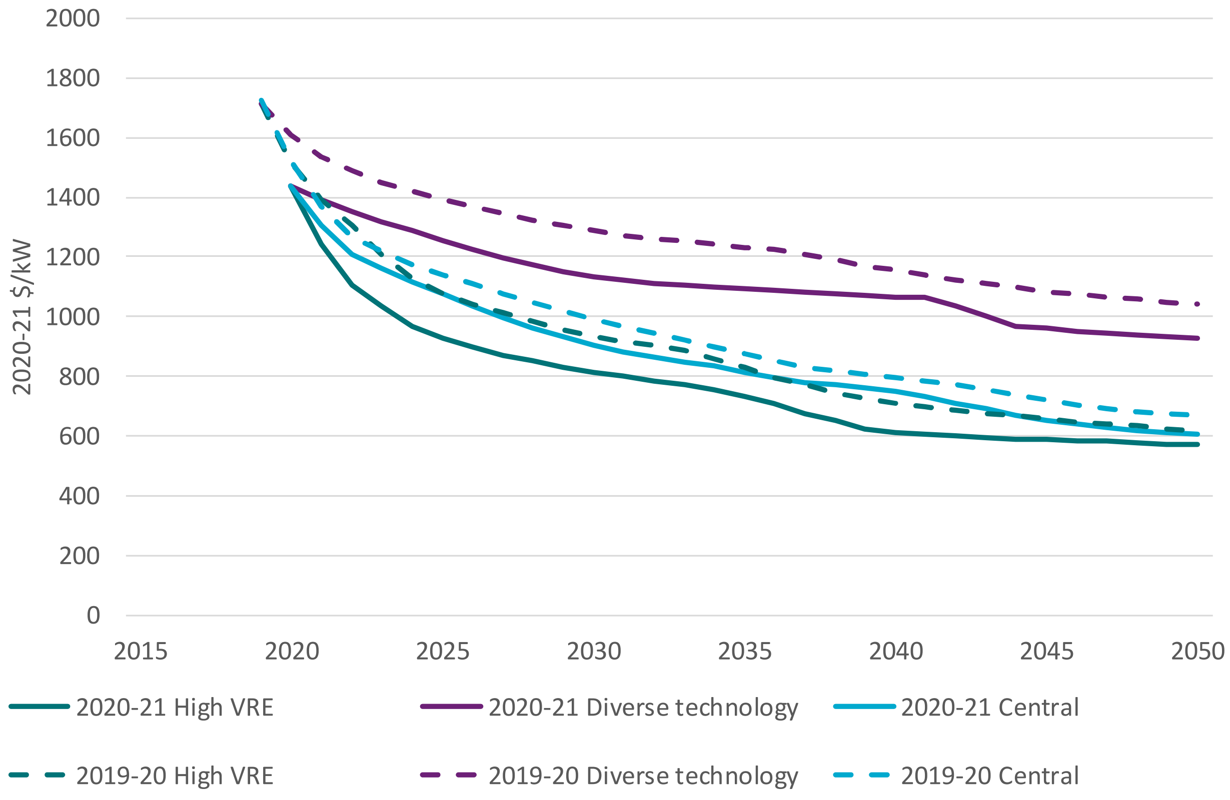


Figure 4-10 Projected capital costs for rooftop solar PV by scenario compared to 2019-20 projections

4.2.10 Onshore wind

The current capital cost for onshore wind remains similar to 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 Diverse technology reflecting limitations on variable renewable generation in that scenario. Central and High VRE achieve similar reductions in wind capital costs over time.

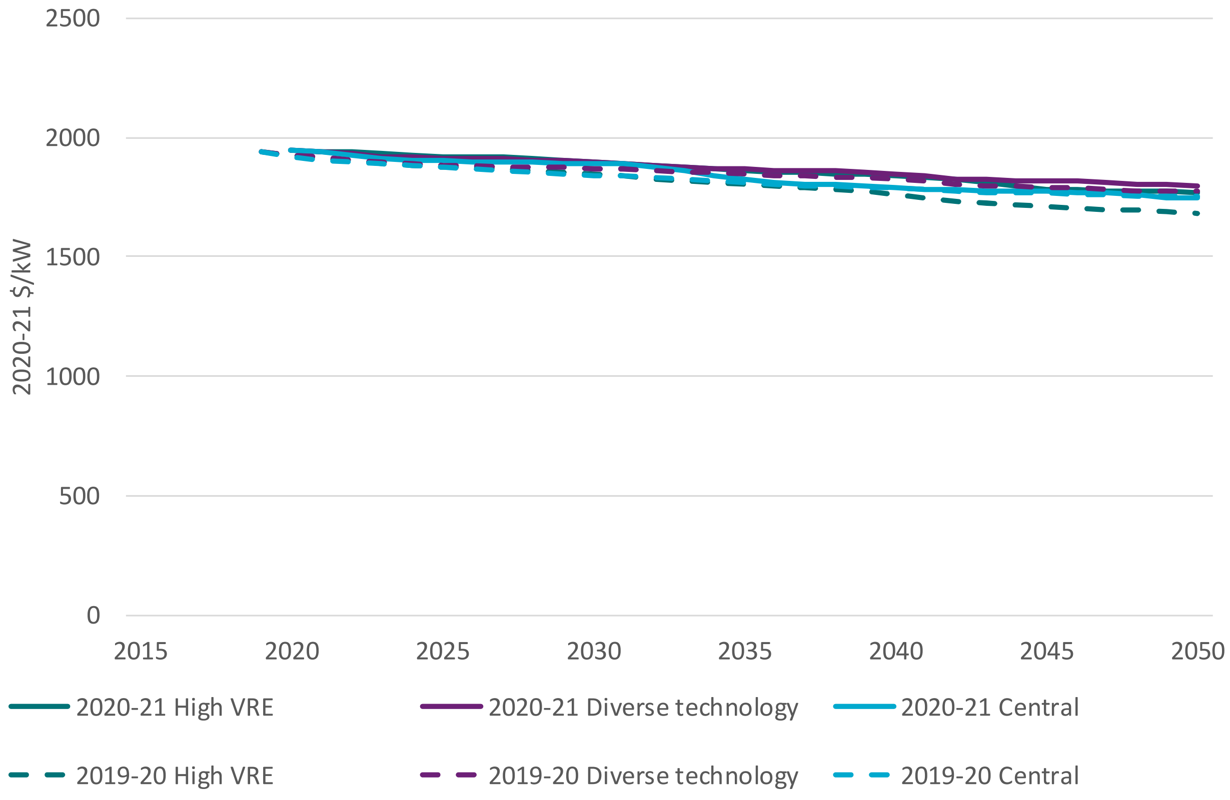


Figure 4-11 Projected capital costs for onshore wind by scenario compared to 2019-20 projections

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 (2020). Like onshore wind, the learning rate of offshore wind is low, at around 3% for each doubling of cumulative capacity. Consistent with this learning rate the capital cost reductions are low over time. However, 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.

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.

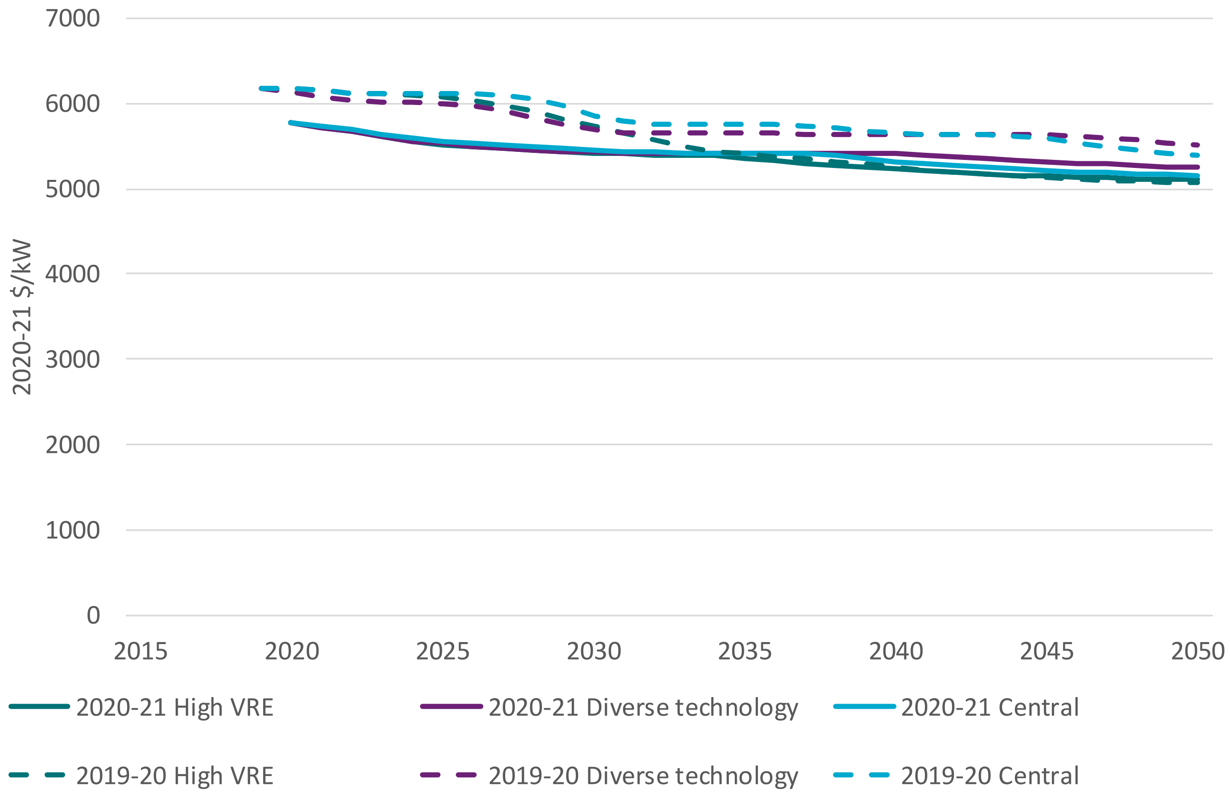


Figure 4-12 Projected capital costs for offshore wind by scenario compared to 2019-20 projections

4.2.12 Battery storage

Like solar PV, batteries are another technology which has been able to sustain high cost reduction rates over time which justifies the assumption of a 15% cost reduction for each doubling of cumulative capacity. The cost reductions have been achieved through deployment mainly 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 (2020) has revised the current capital cost of batteries downwards to around $300/kWh. Based on this current cost, the projected future change in battery pack costs is shown in Figure 4-13 (total costs are in Appendix B).

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. Diverse technology and Central have more delayed uptake of electric vehicles and stationary storage but after a period of around five years they begin to follow a parallel course of cost reduction. Diverse technology achieves stronger cost reduction from around the late 2020s reflecting the stronger climate policy ambition assumed in this scenario and it maintains higher deployment, mainly because of higher electric vehicle adoption rather than stationary energy as the lower deployment of variable renewables in this scenario means relatively lower stationary storage requirements. Central scenario battery costs remain relatively higher cost through to the end of the projection period, closing the gap slightly with the other scenarios as its variable renewable deployment and subsequent demand for stationary battery storage increases.

The complete costs for various storage durations including balance of plant are provided in Appendix B.

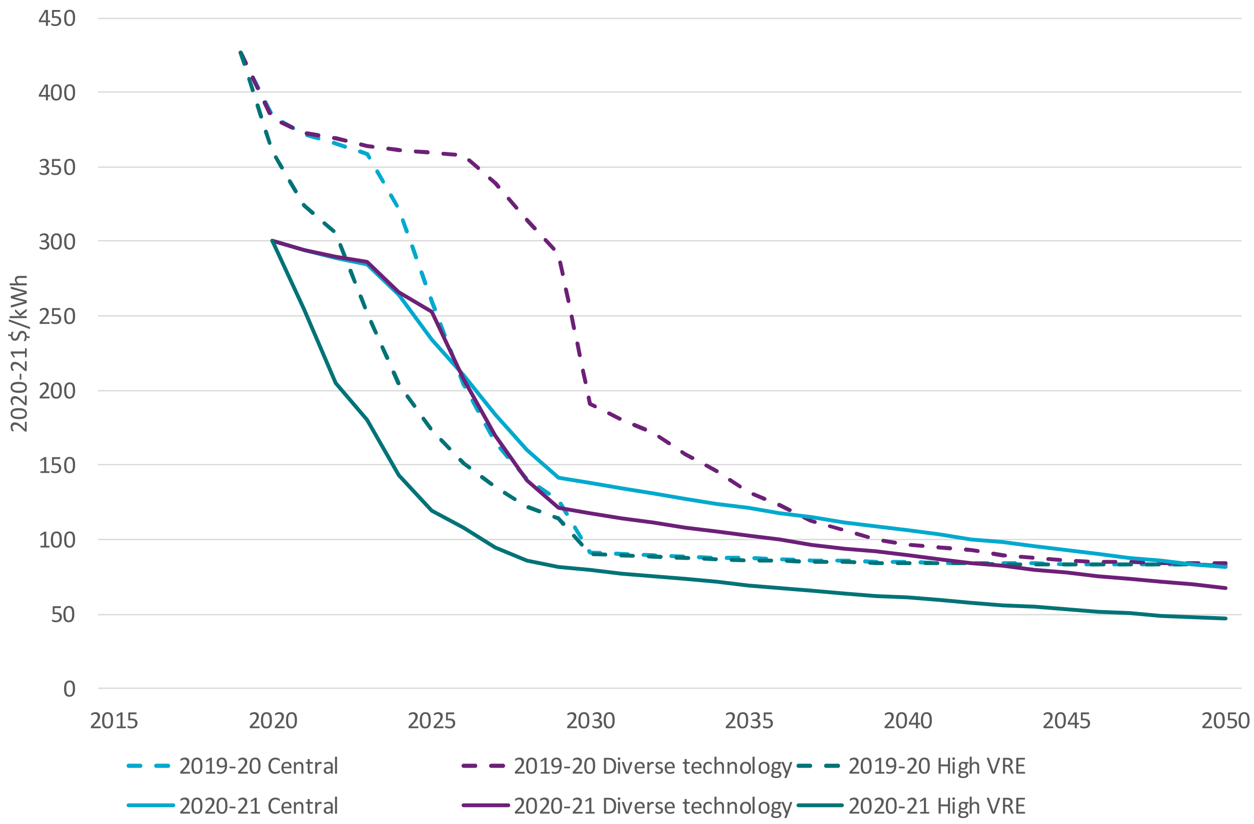


Figure 4-13 Projected capital costs for batteries by scenario (battery pack only)

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[9]. 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 from Entura (2018) to AEMO's July 2020 ISP assumptions. Appendix B includes the costs of pumped hydro energy storage at different durations. We also assume that Tasmania 24 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).

[9] 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.

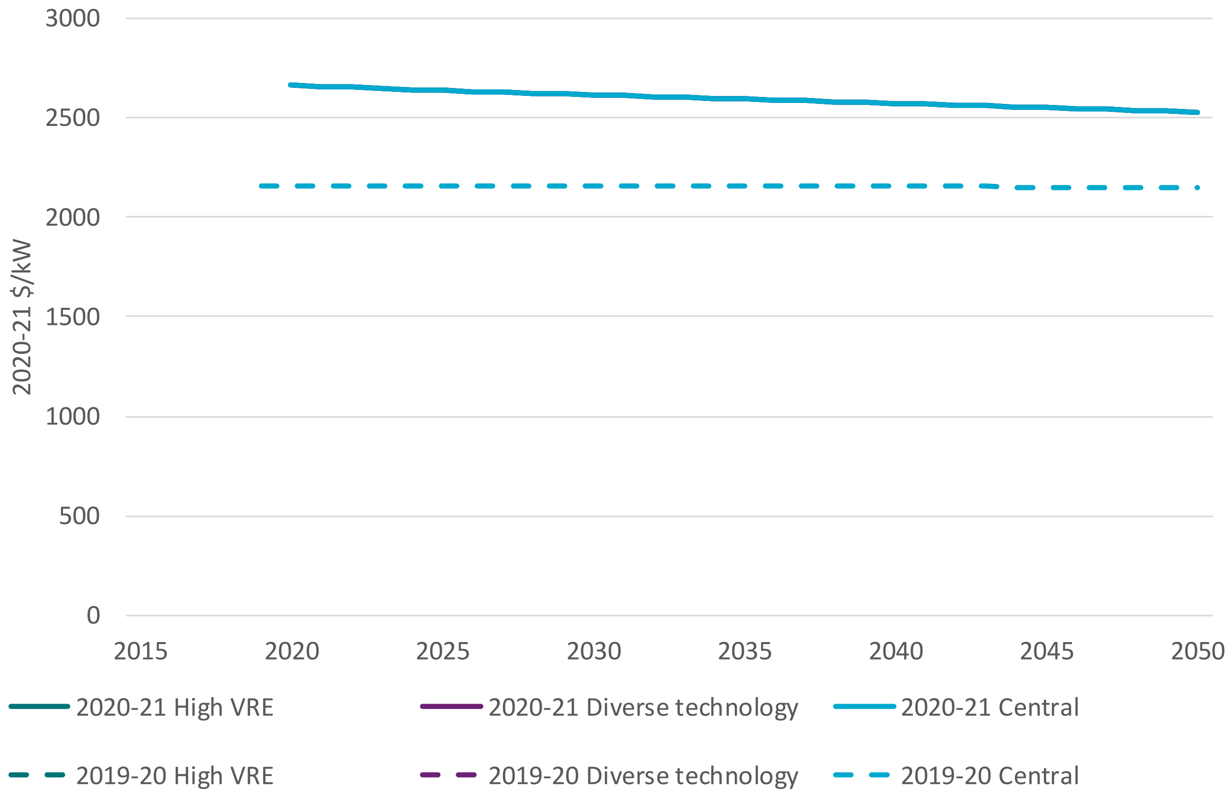


Figure 4-14 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

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 (2020) 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 (2020) 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 and subsequent carbon price 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.

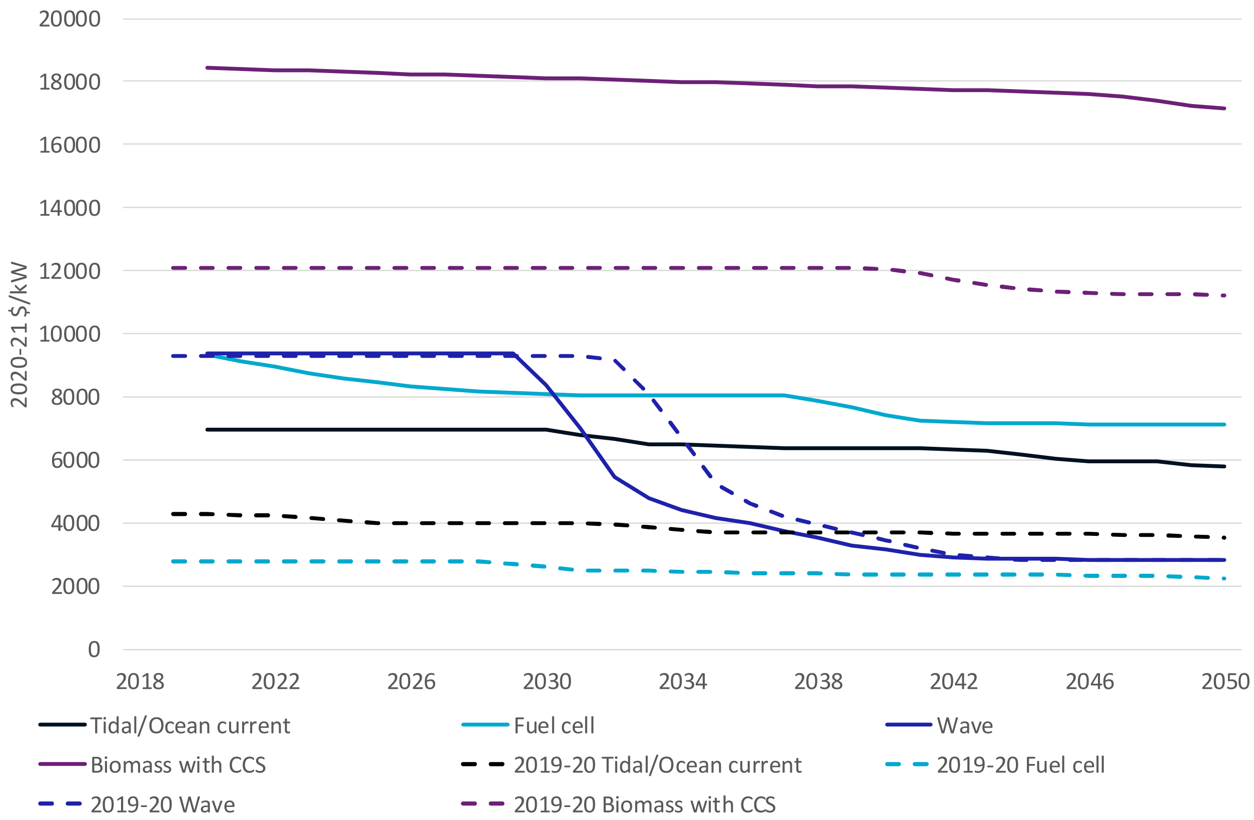


Figure 4-15 Projected technology capital costs under the Central scenario compared to 2019-20 projections

High VRE scenario

Biomass with CCS is not adopted in the High VRE scenario. Although this scenario has the highest climate policy ambition and subsequent carbon price, it is able to reach near zero emissions earlier using 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 also remains niche. Wave generation deploys earlier than in 2019-20 reflecting a strong carbon price and high assumed learning rate.

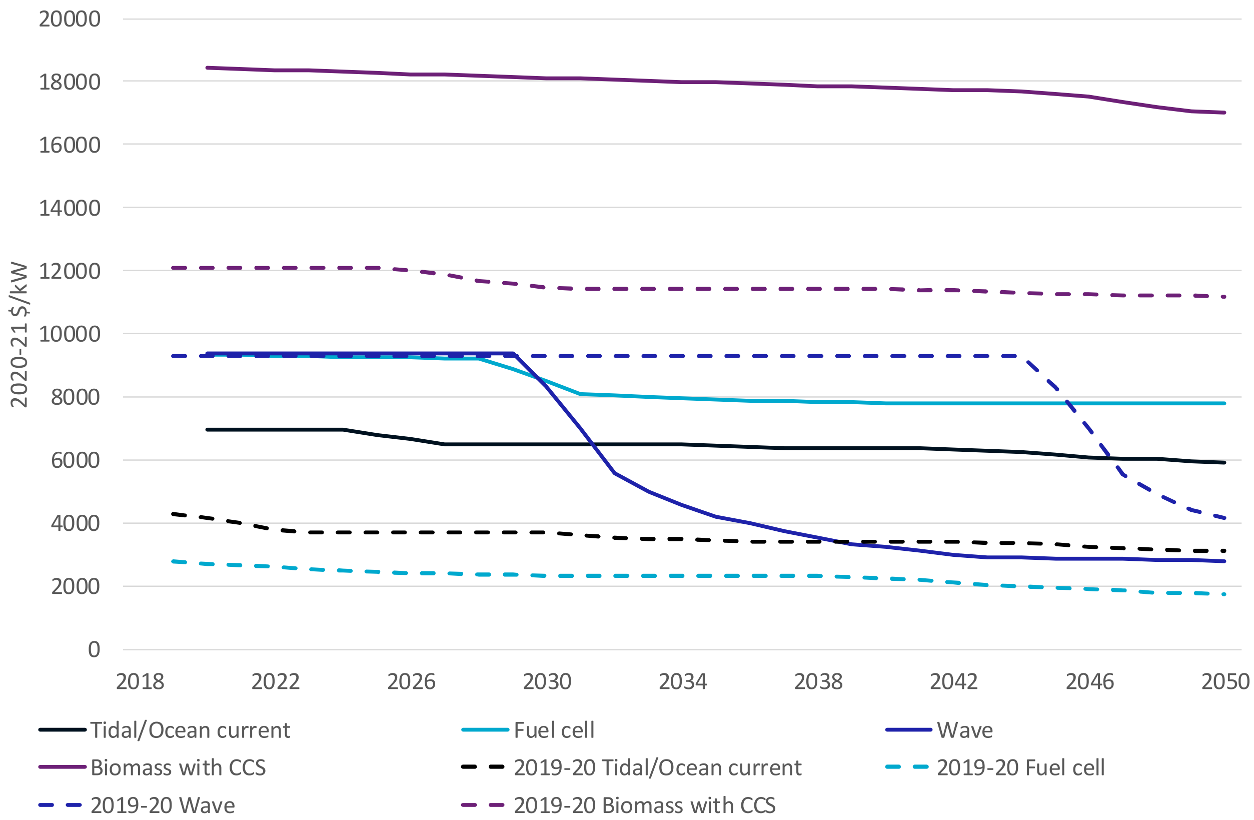


Figure 4-16 Projected technology capital costs under the High VRE scenario compared to 2019-20 projections

Diverse technology scenario

Biomass with CCS is deployed in the Diverse technology scenario reflecting the assumed limitations on variable renewable generation. This result is also consistent with the scenario climate policy ambition. Biomass with CCS benefits from co-learning from the significant deployment of gas and coal with CCS generation and 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. Tidal/current generation is deployed the fastest in this scenario reflecting the greater need for alternative energy sources. However, both tidal/current and fuel cell generation remains niche.

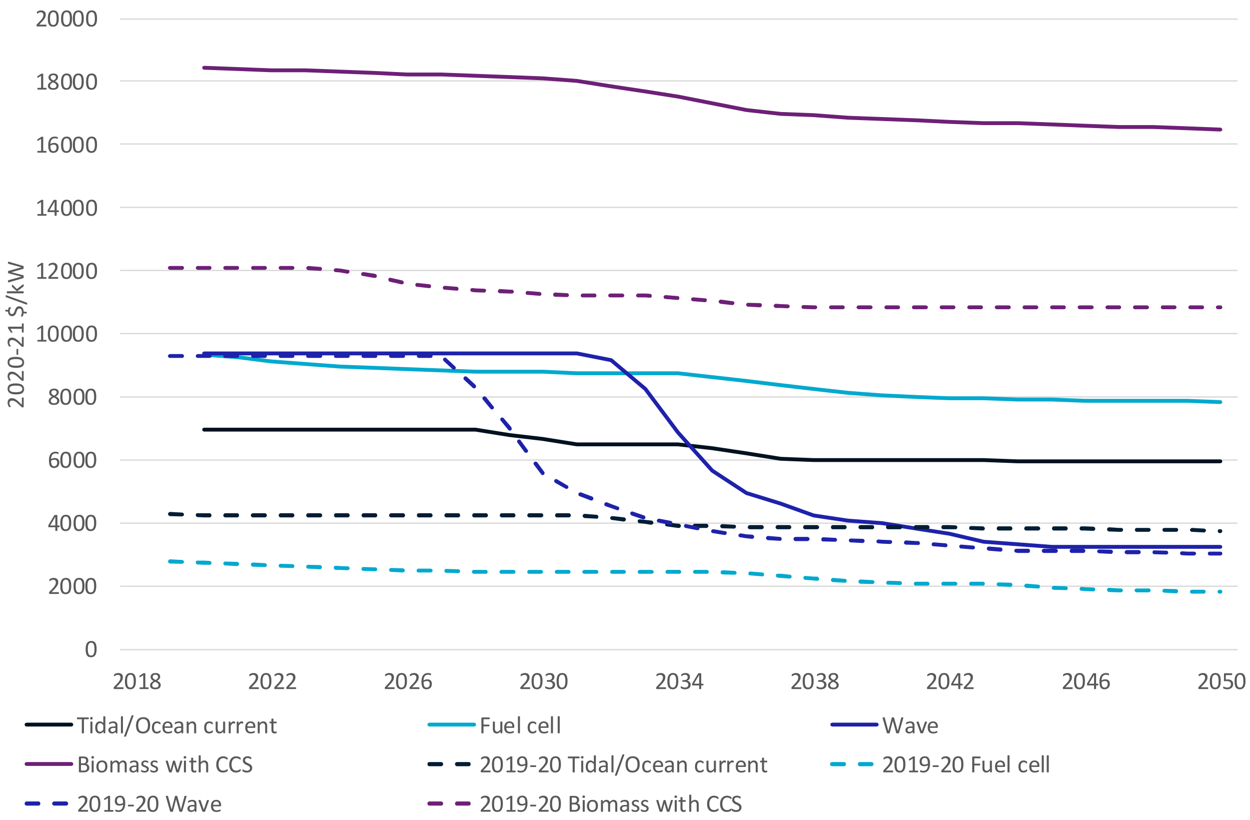


Figure 4-17 Projected technology capital costs under the Diverse technology scenario compared to 2019-20 projections

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 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 scaleup 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.

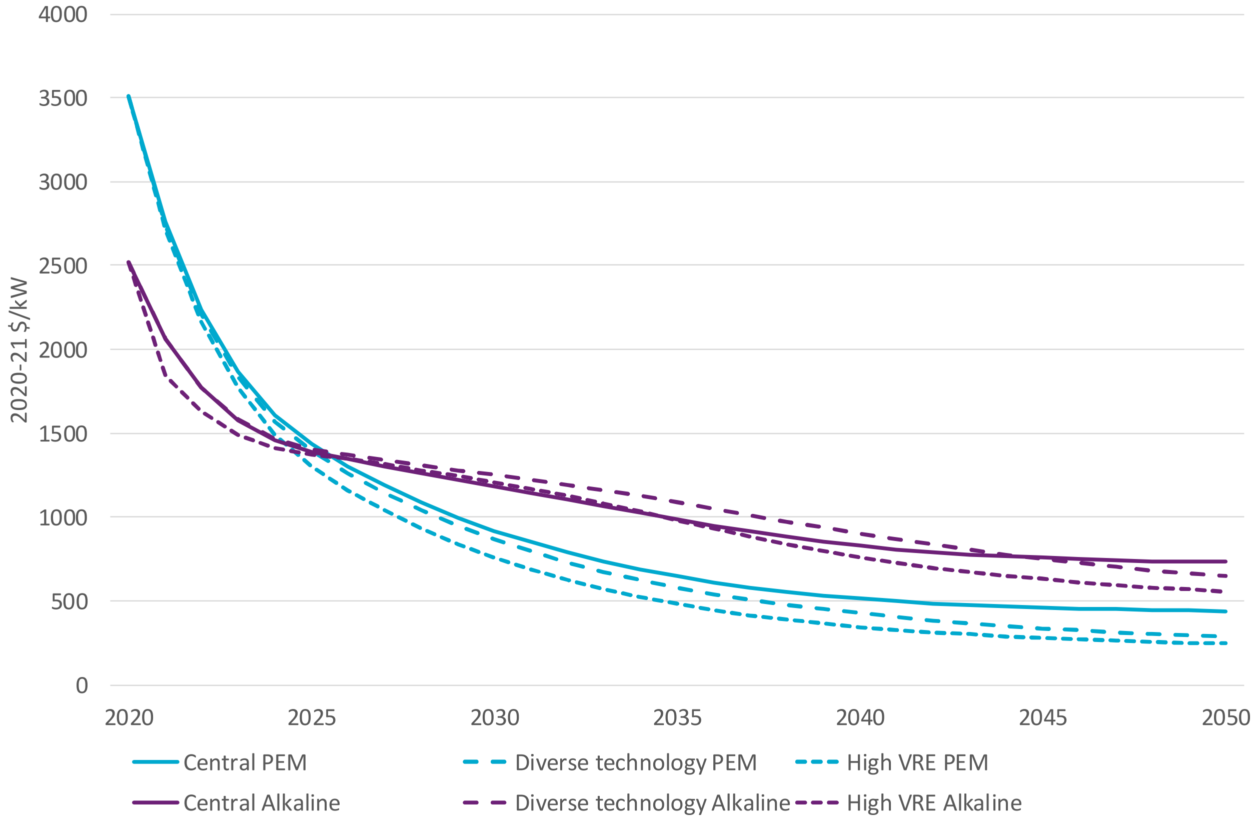


Figure 4-18 Projected technology capital costs for alkaline and PEM electrolysers by scenario

5 Levelised cost of electricity analysis

Levelised cost of electricity (LCOE) data is an electricity generation technology comparison metric. Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data. 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 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 new state or commonwealth climate change policies.
- LCOE does not recognise that electricity generation technologies have different roles in the system. In particular, 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 now 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 additional risk premiums or carbon prices[10] on fossil fuel technologies.

5.1 Overview of the new method

Options considered

Graham (2018) reviewed the methods of seven published studies which were relevant in developing a method for taking account of additional costs of variable renewables. Some of the

[10] A carbon price is used as a proxy for any policy which may be introduced to reduce high emission activities. This is not a statement of either likely or preferred policy mechanisms.

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 which 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 in 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 and other flexible generation. Two commonly applied system modelling frameworks are generation expansion models (intertemporal optimisation models) and dispatch models (half hourly optimisation models) (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.

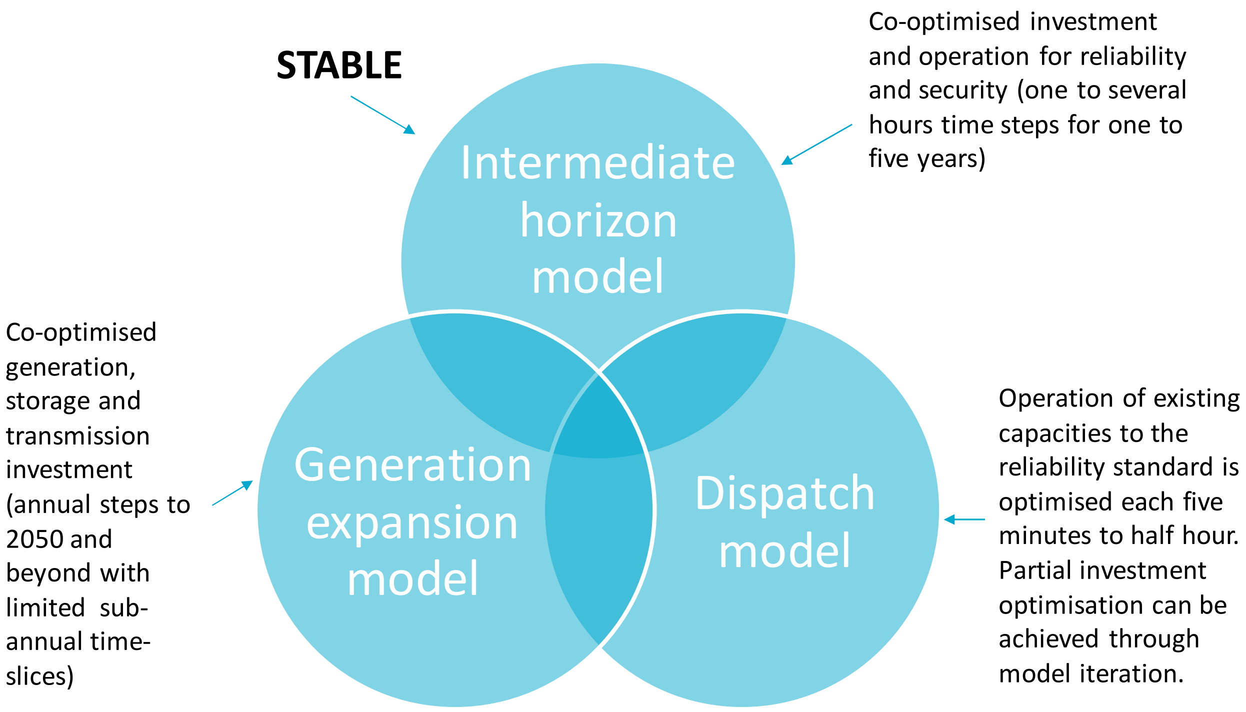


Figure 5-1 Three types of electricity system models

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 Planning process. Demand is solved at the transmission zone level and Renewable Energy Zones are the smallest spatial supply 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[11], imposing a required variable renewable energy (VRE) share and running the model to determine the optimal investment to 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[12].

[11] This year makes the most sense within the framework applied because there is enough time to plausibly reach high VRE shares but 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.

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

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 similar to 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 adoption, electric vehicle adoption and battery adoption with VPP participation are consistent with the more up to date ESOO 2020 Central projections rather than ISP 2020 Central. Customer non-VPP battery and electric charging patterns are also consistent with ESOO 2020.
- A single weather year, 2019, is applied to the demand profile
- No emission constraint is applied
- The 2030 Queensland renewable energy target of 50% is excluded.

We may be able to explore other future years other than 2030 and apply more weather years in future analysis. 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.

The Queensland renewable target was excluded because the existence of renewable targets in the BAU means that the system already builds resources to support renewables. We want to exclude those developments in order to see what those additional expenditures are. The Victorian target of 50% renewables was considered too far progressed to exclude. 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 100% renewables. 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 (except for Queensland which retain coal longer due to the absence of a renewable target). 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. 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.

Variable renewable energy shares (VREs) are explored in the range 50% to 90%. Below 50% is not of interest because the BAU already achieves 34% (43% if we include all renewables). 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.

As expected, the results, shown in Figure 5-2, 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. The other major cost category shown is transmission which includes transmission cost to connect Renewable Energy Zones to the grid and other transmission which includes state interconnectors and general expansion of existing lines. REZ expansion costs appear to be required at similar levels for each additional 10% increase. Other transmission expenditure, not already in the BAU, is only required in significant levels in NSW likely reflecting its position in the middle of the NEM.

Storage requirements are also highest in NSW. This reflects existing flexible resources and the quality of the variable renewable resources. Queensland 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. The reduced coincidence of wind and solar means less storage is necessary. Queensland also has around 430MW additional existing flexible gas and diesel than NSW in 2030.

The proximity to Tasmania's hydro resources means Victoria does not have to build as many storage resources locally. Also, in 2030 Victoria has 360MW of additional existing flexible gas and diesel compared to NSW. Without these existing assets more storage or other flexible generation would likely need to be built in Queensland and Victoria.

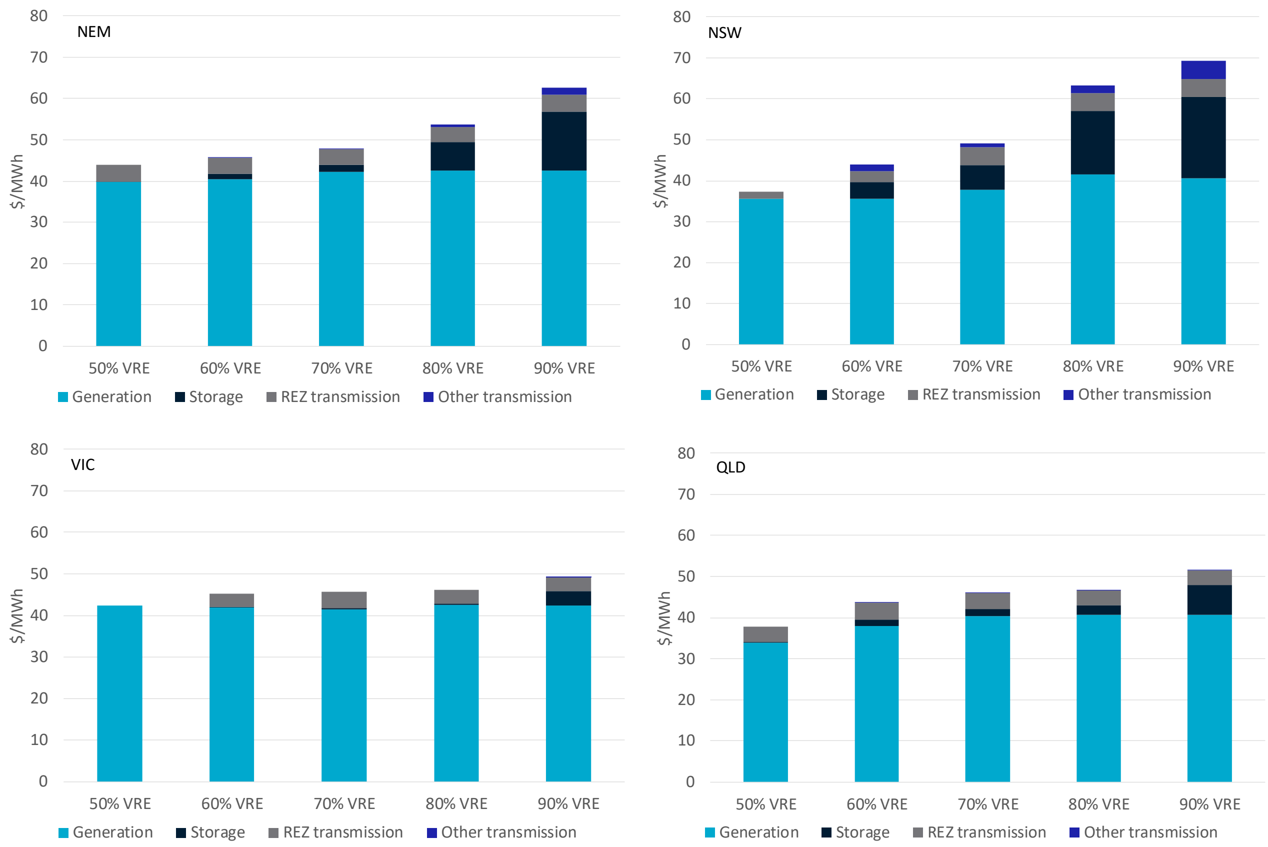


Figure 5-2 Levelised costs of achieving 50%, 60%, 70%, 80% and 90% variable renewable energy shares in the NEM, NSW, VIC and QLD

There are no additional costs of meeting a 50% VRE share in Victoria because all those costs are already in the BAU which includes a 50% target. Across the NEM, the cost of REZ transmission expansion adds around $4/MWh. Other transmission adds between $0.1 to $1.8/MWh. Storage adds between $0 to $14/MWh. For these latter two, the share of VRE targeted is crucial in determining the relevant point in that range. The region of the NEM is another key source of variation.

5.2.2 Variable renewables with and without storage and transmission

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 estimate 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 $0 to $29/MWh depending on the VRE share (Figure 5-4). As such, the previous approach was too conservative. While it did not consider transmission, which is an important additional cost, it over-estimated the need for storage and, in total, over-estimated the additional 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 and storage costs are included up to any relevant VRE share.

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 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 in two ways: directly adding a carbon price from our global scenario range and indirectly by imposing a 5% risk premium on borrowing costs. The results show that a carbon price would result in lower costs for black and brown coal over the next two decades than adding a 5% risk premium but this switches by 2050 reflecting the non-linear growth in the assumed carbon price range. Natural gas-based generation is less impacted by either a carbon price or risk premium because of its lower emission fuel, higher thermal efficiency and lower capital cost. However, it is at greater risk of facing high fuel prices.

We include a carbon price in calculating the costs of low emission flexible technologies because some of those technologies, such as those with carbon capture and storage, still have some emissions. However, their zero or low level of emissions means that their costs are not significantly impacted. Gas with CCS is the most competitive of this group however the lower end of the range is only achievable if it can source lower 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.

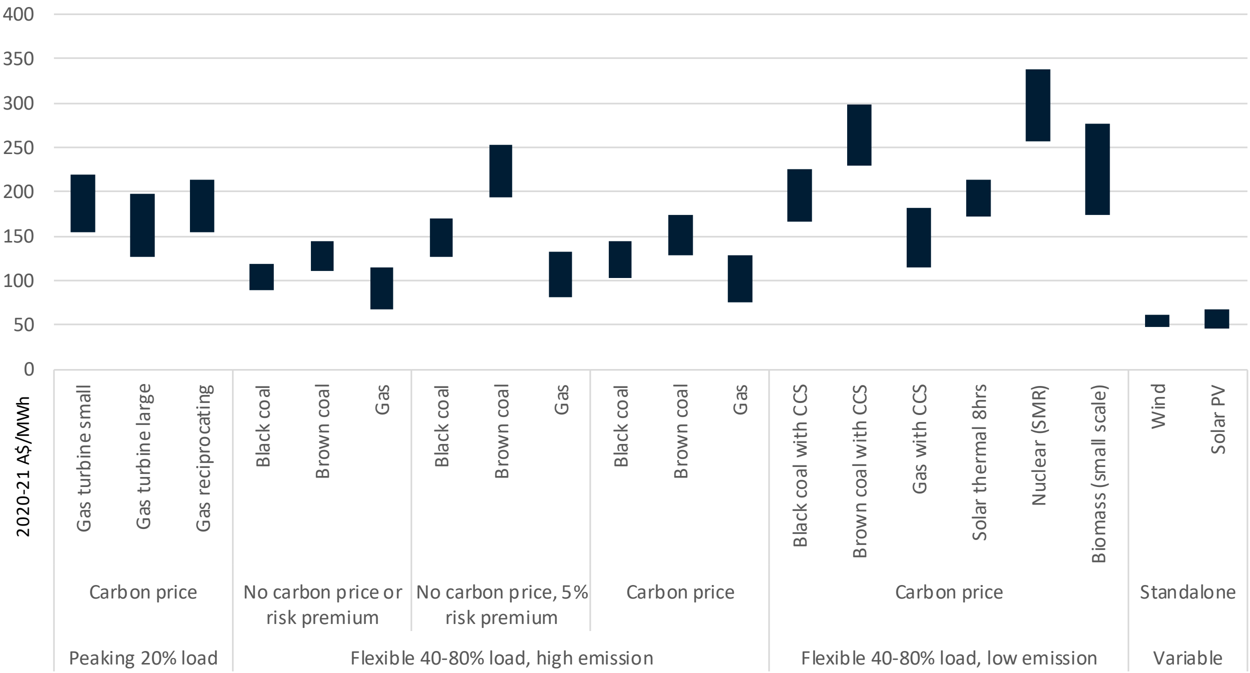


Figure 5-3 Calculated LCOE by technology and category for 2020

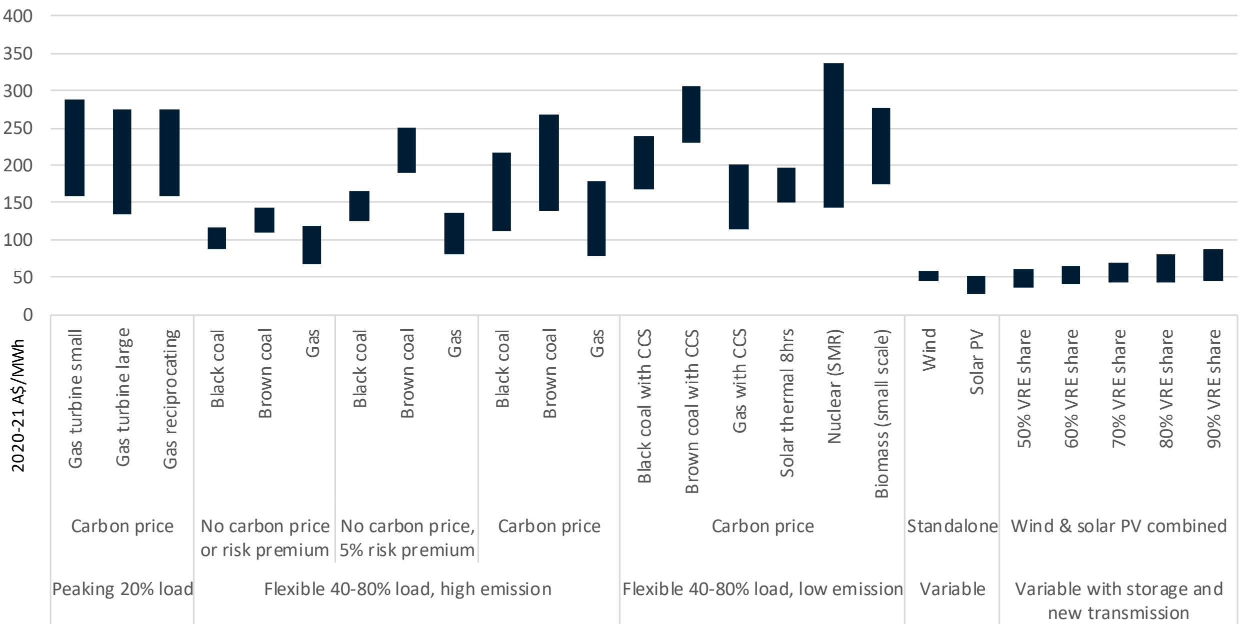


Figure 5-4 Calculated LCOE by technology and category for 2030

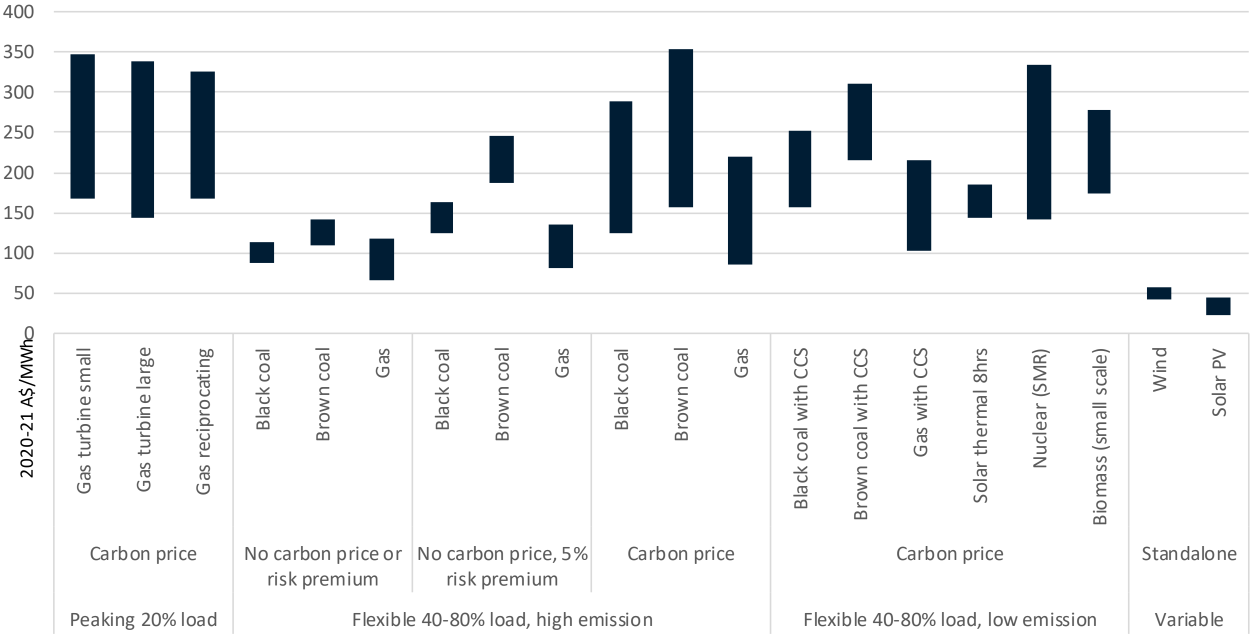


Figure 5-5 Calculated LCOE by technology and category for 2040

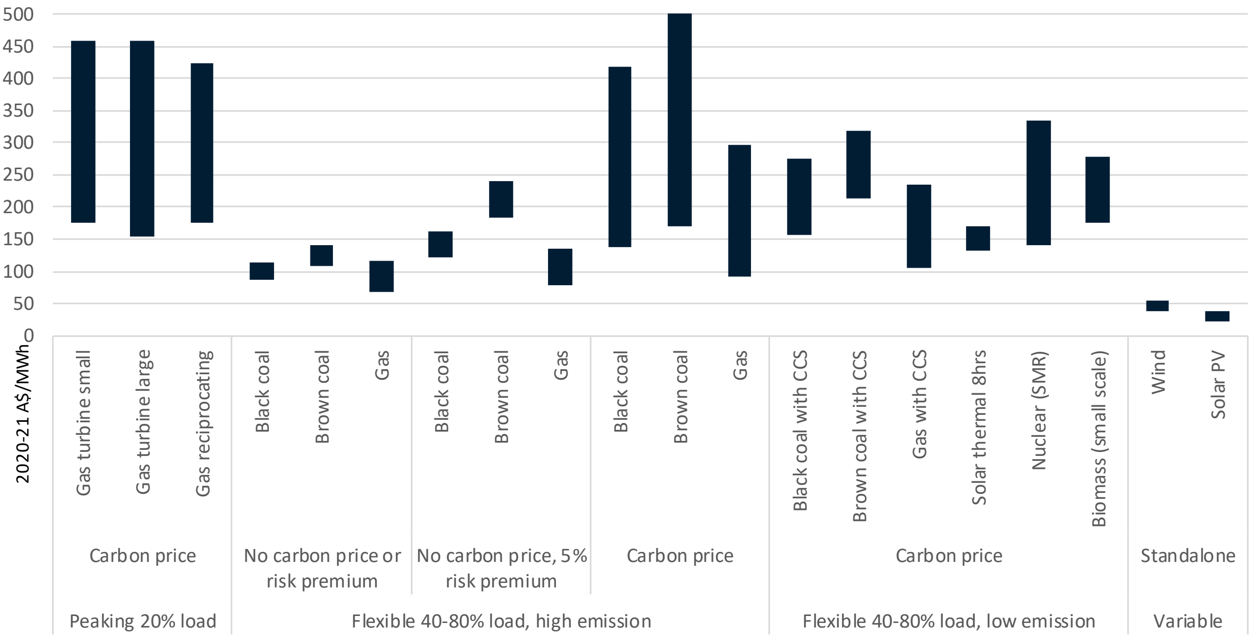


Figure 5-6 Calculated LCOE by technology and category for 2050

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:

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

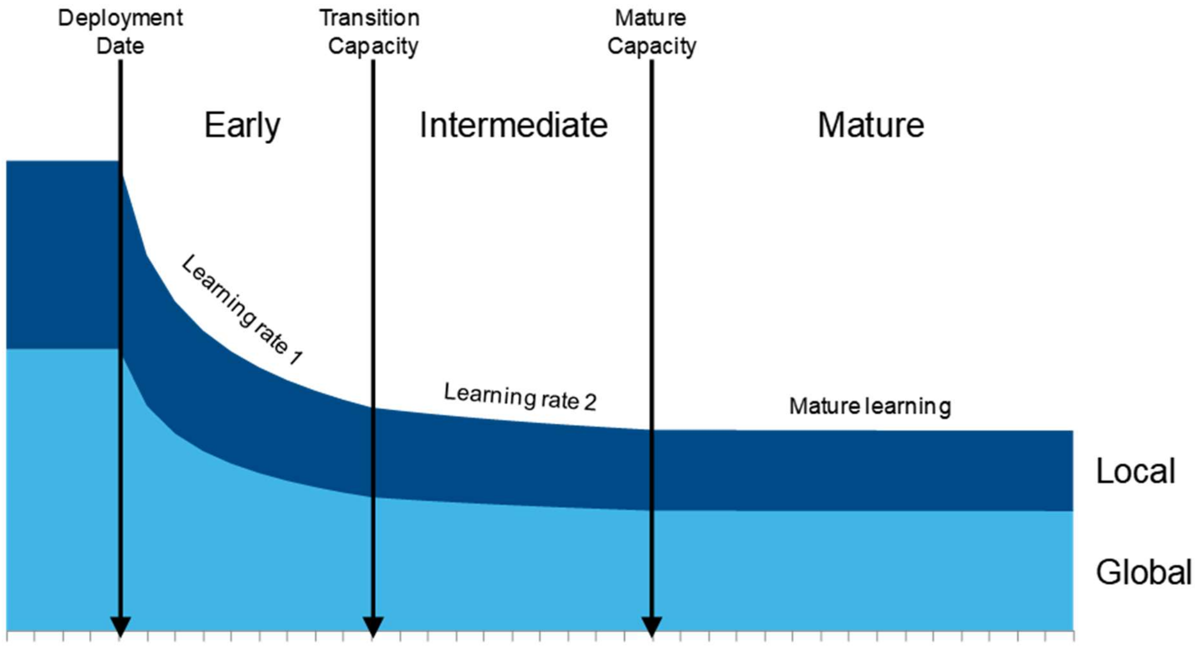
or equivalently $\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$

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

In order 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 GALLMs 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 function 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.

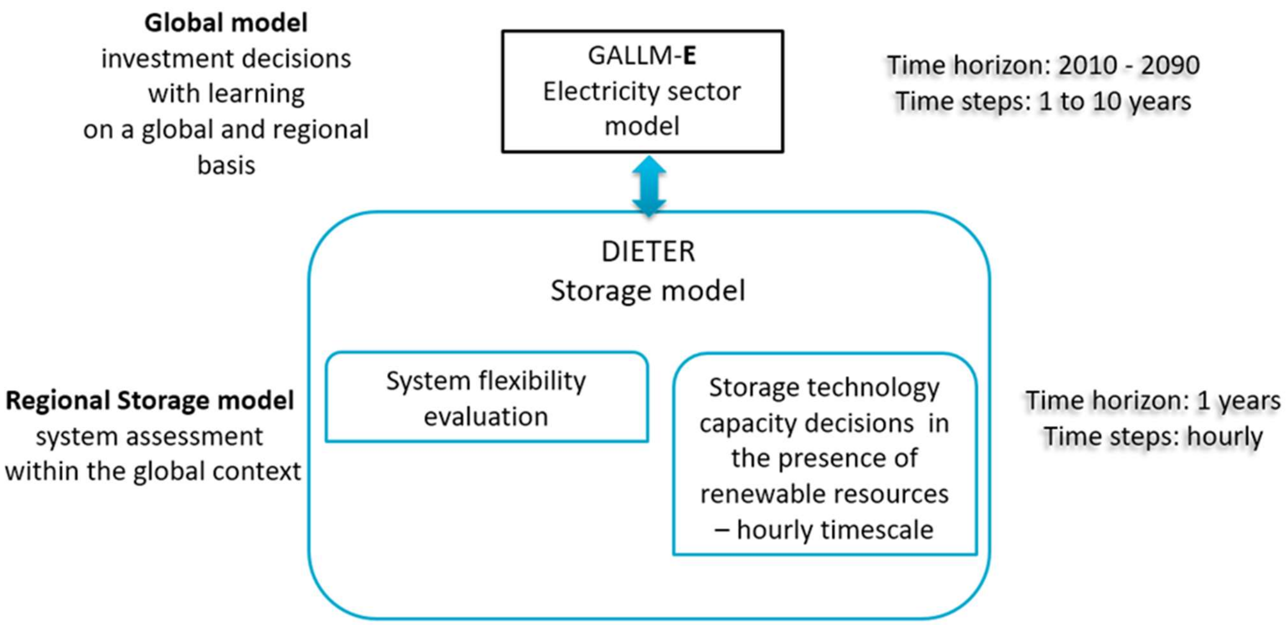
cumulative capacity) is determined at each time step. See (Hayward & Graham, 2013) and (Hayward, Foster, Graham, & Reedman, 2017) for more information. Both models run from the year 2006 to 2100. However, results are only reported from the present year to 2050.

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.

A.1.3 Variable Renewables and Energy Storage

The Dispatch and Investment Evaluation Tool with Endogenous Renewables (DIETER) is an open source model which has been designed to model the cost of electricity generation systems with high shares of variable renewables (PV, onshore and offshore wind and ocean renewables) and energy storage (http://www.diw.de/dieter). DIETER contains hourly renewable resource and load data for one calendar year, and because of this granularity, it is better able to optimise variable renewable and storage combinations than GALLME in any one year.



Apx Figure A.2 Schematic diagram of GALLM and DIETER modelling framework

DIETER has been used in this study to determine the new capacity of variable renewables and storage technologies in the years that DIETER is solved, and this data has then been included back in GALLME to update the cumulative capacity and thus the capital cost of these technologies. A schematic of the interaction between GALLME and DIETER is shown in Apx Figure A.2.

The model interactions are as follows:

1. GALLME is solved without DIETER to calculate cost and uptake of all technologies
2. GALLME cost data, installed capacity of non-variable renewable technologies and upper and lower bounds on demand for electricity satisfied by variable renewables are used as inputs into DIETER
3. DIETER is solved for each region in 5-yearly intervals, beginning in 2025.
4. The new installed capacity of variable renewables and storage is included in GALLME and GALLME is solved.

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	1801	1550	961	4461	1567	1750	8619	18438	1408	1439	7411	1951	5771	9384	16487	6971	9333	2139
2021	4441	9297	6854	14269	1797	1546	959	4457	1564	1746	8613	18406	1272	1304	7331	1937	5727	9384	16487	6954	9144	1990
2022	4432	9283	6841	14245	1793	1543	957	4453	1561	1743	8609	18373	1178	1211	7291	1925	5687	9384	16487	6945	8951	1885
2023	4423	9269	6827	14221	1790	1540	955	4448	1558	1739	8606	18341	1128	1162	7290	1915	5641	9384	16487	6945	8766	1814
2024	4414	9255	6813	14197	1786	1537	954	4444	1555	1736	8606	18309	1084	1118	7283	1908	5599	9384	16487	6945	8600	1730
2025	4406	9241	6800	14173	1783	1534	952	4439	1551	1732	8606	18277	1041	1076	7263	1904	5557	9384	14705	6945	8460	1637
2026	4397	9227	6786	14149	1779	1531	950	4435	1548	1729	8606	18245	1002	1036	7212	1901	5536	9384	12908	6945	8342	1543
2027	4388	9213	6773	14125	1775	1528	948	4430	1545	1725	8606	18213	964	998	7111	1899	5512	9384	11110	6945	8248	1455
2028	4379	9199	6759	14102	1772	1525	946	4426	1542	1722	8606	18181	931	964	6978	1896	5498	9384	9312	6945	8179	1374
2029	4370	9185	6746	14078	1768	1522	944	4422	1539	1718	8606	18149	901	933	6842	1894	5476	9384	7465	6945	8110	1273
2030	4362	9171	6732	14054	1765	1519	942	4417	1536	1715	8606	18117	874	905	6732	1892	5458	8365	7415	6945	8064	1189
2031	4353	9158	6719	14031	1761	1516	940	4413	1533	1711	8606	18086	852	882	6641	1889	5437	6976	7333	6798	8032	1123
2032	4344	9144	6705	14007	1758	1513	938	4408	1530	1708	8606	18054	835	863	6564	1878	5424	5443	7251	6652	8030	1099
2033	4336	9130	6692	13984	1754	1510	936	4404	1527	1705	8606	18022	822	849	6499	1864	5417	4794	7251	6506	8028	1079
2034	4327	9116	6678	13960	1751	1507	935	4400	1524	1701	8606	17991	810	835	6443	1841	5415	4428	7251	6506	8026	1060
2035	4318	9103	6665	13937	1747	1504	933	4395	1521	1698	8606	17959	790	815	6395	1826	5411	4152	7251	6467	8024	1035
2036	4310	9089	6652	13913	1744	1501	931	4391	1518	1694	8606	17928	773	797	6352	1812	5408	3978	7251	6419	8023	1012
2037	4301	9075	6638	13890	1740	1498	929	4387	1515	1691	8606	17896	756	779	6314	1807	5404	3734	7251	6369	8021	990
2038	4292	9061	6625	13867	1737	1495	927	4382	1512	1688	8606	17865	748	771	6281	1802	5389	3536	7251	6358	7891	977
2039	4284	9048	6612	13844	1733	1492	925	4378	1509	1684	8606	17834	739	761	6251	1797	5360	3282	7251	6357	7663	964
2040	4275	9034	6599	13820	1730	1489	923	4374	1505	1681	8606	17803	727	749	6224	1792	5323	3146	7248	6357	7406	949
2041	4267	9021	6585	13797	1726	1486	922	4370	1502	1678	8606	17772	710	732	6177	1786	5291	2983	7246	6357	7255	930
2042	4258	9007	6572	13774	1723	1483	920	4365	1499	1674	8606	17741	689	711	6112	1781	5269	2912	7244	6330	7199	907
2043	4250	8994	6559	13751	1720	1480	918	4361	1496	1671	8606	17710	669	691	6031	1778	5249	2867	7244	6296	7167	885
2044	4241	8980	6546	13728	1716	1477	916	4357	1493	1667	8606	17679	650	672	5956	1776	5231	2855	7244	6163	7155	864
2045	4233	8967	6533	13705	1713	1474	914	4353	1491	1664	8606	17648	632	654	5888	1774	5212	2843	7244	6049	7143	843
2046	4224	8953	6520	13682	1709	1471	912	4348	1488	1661	8606	17617	617	639	5825	1771	5197	2841	7244	5943	7132	827
2047	4216	8872	6507	13591	1706	1468	911	4276	1485	1657	8606	17518	606	628	5767	1766	5184	2837	7244	5938	7122	814
2048	4207	8755	6494	13464	1702	1465	909	4169	1482	1654	8606	17383	597	619	5714	1759	5176	2832	7244	5938	7114	804
2049	4199	8609	6481	13309	1699	1462	907	4034	1479	1651	8606	17220	589	611	5665	1750	5166	2826	7244	5846	7105	794
2050	4195	8553	6474	13248	1697	1461	905	3982	1477	1649	8606	17155	585	607	5641	1745	5162	2823	7244	5800	7101	789

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	1801	1550	961	4461	1567	1750	8619	18438	1408	1439	7411	1951	5771	9384	16487	6971	9333	2139
2021	4441	9297	6854	14269	1797	1546	959	4457	1564	1746	8613	18406	1209	1244	7243	1944	5723	9384	16487	6954	9314	1848
2022	4432	9283	6841	14245	1793	1543	957	4453	1561	1743	8609	18373	1067	1106	7108	1937	5668	9384	16487	6945	9294	1628
2023	4423	9269	6827	14221	1790	1540	955	4448	1558	1739	8606	18341	994	1034	7008	1931	5613	9384	16487	6945	9275	1480
2024	4414	9255	6813	14197	1786	1537	954	4444	1555	1736	8606	18309	927	968	6893	1926	5561	9384	16487	6945	9257	1355
2025	4406	9241	6800	14173	1783	1534	952	4439	1551	1732	8606	18277	885	926	6762	1923	5522	9384	16487	6798	9242	1262
2026	4397	9227	6786	14149	1779	1531	950	4435	1548	1729	8606	18245	857	898	6622	1920	5491	9384	16487	6652	9230	1200
2027	4388	9213	6773	14125	1775	1528	948	4430	1545	1725	8606	18213	833	873	6507	1918	5467	9384	16487	6506	9222	1150
2028	4379	9199	6759	14102	1772	1525	946	4426	1542	1722	8606	18181	813	851	6412	1914	5446	9384	16487	6506	9216	1109
2029	4370	9185	6746	14078	1768	1522	944	4422	1539	1718	8606	18149	796	833	6332	1907	5429	9384	16487	6506	8864	1060
2030	4362	9171	6732	14054	1765	1519	942	4417	1536	1715	8606	18117	780	816	6264	1899	5414	8349	16487	6506	8490	1030
2031	4353	9158	6719	14031	1761	1516	940	4413	1533	1711	8606	18086	770	803	6205	1891	5406	7015	16487	6506	8098	1008
2032	4344	9144	6705	14007	1758	1513	938	4408	1530	1708	8606	18054	754	786	6153	1884	5402	5584	16487	6506	8037	1001
2033	4336	9130	6692	13984	1754	1510	936	4404	1527	1705	8606	18022	742	773	6108	1877	5402	4978	16487	6506	7987	984
2034	4327	9116	6678	13960	1751	1507	935	4400	1524	1701	8606	17991	726	756	6068	1870	5388	4568	16487	6506	7945	965
2035	4318	9103	6665	13937	1747	1504	933	4395	1521	1698	8606	17959	703	732	6032	1863	5362	4189	16487	6467	7912	938
2036	4310	9089	6652	13913	1744	1501	931	4391	1518	1694	8606	17928	681	709	6000	1857	5327	3987	16487	6419	7885	913
2037	4301	9075	6638	13890	1740	1498	929	4387	1515	1691	8606	17896	649	678	5971	1852	5296	3731	16487	6369	7861	880
2038	4292	9061	6625	13867	1737	1495	927	4382	1512	1688	8606	17865	624	652	5945	1848	5269	3524	16487	6358	7839	852
2039	4284	9048	6612	13844	1733	1492	925	4378	1509	1684	8606	17834	597	626	5919	1844	5246	3331	16487	6357	7820	823
2040	4275	9034	6599	13820	1730	1489	923	4374	1505	1681	8606	17803	582	611	5874	1842	5225	3246	16487	6357	7806	807
2041	4267	9021	6585	13797	1726	1486	922	4370	1502	1678	8606	17772	576	604	5813	1835	5206	3124	16487	6357	7795	799
2042	4258	9007	6572	13774	1723	1483	920	4365	1499	1674	8606	17741	571	598	5740	1828	5190	3005	16487	6330	7790	791
2043	4250	8994	6559	13751	1720	1480	918	4361	1496	1671	8606	17710	567	593	5672	1811	5175	2917	16487	6296	7787	785
2044	4241	8980	6546	13728	1716	1477	916	4357	1493	1667	8606	17679	565	591	5610	1798	5162	2884	16487	6263	7787	781
2045	4233	8937	6533	13675	1713	1474	914	4323	1491	1664	8606	17618	563	588	5552	1785	5149	2864	16487	6176	7787	777
2046	4224	8838	6520	13566	1709	1471	912	4234	1488	1661	8606	17501	561	586	5499	1782	5138	2860	16487	6097	7787	773
2047	4216	8696	6507	13416	1706	1468	911	4103	1485	1657	8606	17342	556	581	5450	1779	5128	2849	16487	6018	7786	767
2048	4207	8563	6494	13272	1702	1465	909	3979	1482	1654	8606	17191	552	576	5404	1776	5119	2840	16487	6018	7786	761
2049	4199	8465	6481	13165	1699	1462	907	3891	1479	1651	8606	17076	547	571	5362	1773	5111	2809	16487	5939	7785	754
2050	4195	8426	6474	13121	1697	1461	905	3857	1477	1649	8606	17028	546	569	5341	1772	5106	2797	16487	5900	7784	752

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	1801	1550	961	4461	1567	1750	8619	18438	1408	1439	7411	1951	5771	9384	16487	6971	9333	2139
2021	4441	9297	6854	14269	1797	1546	959	4457	1564	1746	8613	18406	1363	1393	7247	1940	5723	9384	16487	6954	9235	2080
2022	4432	9283	6841	14245	1793	1543	957	4453	1561	1743	8609	18373	1323	1351	7115	1931	5669	9384	16487	6945	9136	2027
2023	4423	9269	6827	14221	1790	1540	955	4448	1558	1739	8606	18341	1290	1318	7021	1923	5613	9384	16487	6945	9046	1973
2024	4414	9255	6813	14197	1786	1537	954	4444	1555	1736	8606	18309	1260	1287	6907	1917	5563	9384	16487	6945	8970	1915
2025	4406	9241	6800	14173	1783	1534	952	4439	1551	1732	8606	18277	1229	1256	6778	1913	5525	9384	14705	6945	8912	1830
2026	4397	9227	6786	14149	1779	1531	950	4435	1548	1729	8606	18245	1199	1226	6634	1911	5495	9384	12908	6945	8865	1733
2027	4388	9213	6773	14125	1775	1528	948	4430	1545	1725	8606	18213	1172	1198	6517	1909	5471	9384	11110	6945	8832	1628
2028	4379	9199	6759	14102	1772	1525	946	4426	1542	1722	8606	18181	1150	1174	6420	1907	5450	9384	9312	6945	8809	1545
2029	4370	9185	6746	14078	1768	1522	944	4422	1539	1718	8606	18149	1130	1153	6338	1902	5434	9384	7465	6798	8790	1456
2030	4362	9171	6732	14054	1765	1519	942	4417	1536	1715	8605	18117	1114	1136	6269	1896	5425	9384	7237	6652	8778	1394
2031	4353	9083	6719	13956	1761	1516	940	4339	1533	1711	8604	18011	1102	1123	6209	1887	5418	9384	7223	6506	8770	1347
2032	4344	8960	6705	13823	1758	1513	938	4226	1530	1708	8603	17869	1094	1114	6156	1881	5415	9169	7219	6506	8770	1337
2033	4336	8814	6692	13667	1754	1510	936	4090	1527	1705	8603	17705	1089	1107	6111	1875	5411	8237	7218	6506	8769	1326
2034	4327	8644	6678	13486	1751	1507	935	3930	1524	1701	8603	17516	1083	1100	6070	1871	5410	6877	7217	6506	8730	1315
2035	4318	8456	6665	13289	1747	1504	933	3754	1521	1698	8603	17310	1077	1092	6034	1867	5409	5661	7213	6359	8645	1304
2036	4310	8273	6652	13096	1744	1501	931	3581	1518	1694	8603	17109	1071	1086	6003	1865	5409	4967	7210	6194	8511	1294
2037	4301	8169	6638	12982	1740	1498	929	3487	1515	1691	8603	16987	1067	1081	5975	1862	5409	4599	7206	6027	8378	1286
2038	4292	8112	6625	12915	1737	1495	927	3440	1512	1688	8592	16913	1063	1076	5949	1860	5409	4239	7206	6007	8245	1279
2039	4284	8069	6612	12863	1733	1492	925	3407	1509	1684	8553	16852	1060	1072	5925	1856	5408	4074	7206	6006	8127	1272
2040	4275	8043	6599	12827	1730	1489	923	3390	1505	1681	8487	16808	1056	1068	5883	1849	5408	3970	7205	6006	8041	1266
2041	4267	8020	6585	12795	1726	1486	922	3377	1502	1678	8427	16768	1053	1064	5823	1838	5398	3814	7205	6006	7994	1260
2042	4258	8000	6572	12765	1723	1483	920	3366	1499	1674	8394	16730	1023	1035	5749	1829	5376	3640	7205	5993	7973	1229
2043	4250	7983	6559	12738	1720	1480	918	3358	1496	1671	8388	16696	992	1004	5680	1824	5349	3423	7205	5976	7950	1196
2044	4241	7967	6546	12713	1716	1477	916	3351	1493	1667	8385	16663	958	970	5617	1821	5327	3321	7205	5959	7928	1161
2045	4233	7952	6533	12689	1713	1474	914	3346	1491	1664	8382	16630	948	960	5558	1819	5313	3237	7205	5949	7908	1149
2046	4224	7938	6520	12665	1709	1471	912	3341	1488	1661	8378	16599	939	951	5504	1816	5300	3237	7205	5943	7892	1139
2047	4216	7924	6507	12642	1706	1468	911	3336	1485	1657	8376	16568	932	944	5455	1812	5287	3237	7205	5938	7878	1130
2048	4207	7911	6494	12619	1702	1465	909	3332	1482	1654	8376	16537	927	938	5408	1807	5275	3236	7205	5938	7865	1123
2049	4199	7897	6481	12596	1699	1462	907	3327	1479	1651	8375	16506	921	932	5365	1802	5263	3233	7205	5938	7853	1115
2050	4195	7891	6474	12584	1697	1461	905	3325	1477	1649	8375	16491	919	929	5344	1800	5258	3231	7205	5938	7847	1112

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	827	827	827	300	300	300	527	527	527	542	542	542	300	300	300	242	242	242
2021	817	817	779	294	294	254	523	523	524	534	534	495	294	294	254	240	240	241
2022	809	810	727	289	290	205	520	520	522	528	529	445	289	290	205	239	239	240
2023	801	804	701	285	287	181	516	517	520	522	524	419	285	287	181	237	237	239
2024	777	780	661	264	266	143	513	514	518	499	502	381	264	266	143	235	236	238
2025	744	764	635	234	253	119	509	511	516	468	487	356	234	253	119	234	235	237
2026	716	715	621	210	207	108	506	508	514	442	441	343	210	207	108	232	233	236
2027	686	675	606	184	170	95	502	505	511	414	402	330	184	170	95	231	232	235
2028	659	642	596	160	140	86	499	502	509	389	370	320	160	140	86	229	230	234
2029	637	620	589	142	121	81	496	498	507	369	350	314	142	121	81	227	229	233
2030	630	613	584	138	117	79	492	495	505	364	345	311	138	117	79	226	227	232
2031	623	606	580	134	114	77	489	492	503	359	340	308	134	114	77	224	226	231
2032	616	600	576	131	111	75	485	489	501	354	336	305	131	111	75	223	224	230
2033	609	594	572	127	108	73	482	486	499	349	331	302	127	108	73	221	223	229
2034	602	588	568	124	105	71	478	483	496	344	327	299	124	105	71	220	222	228
2035	596	582	564	121	102	69	475	480	494	339	323	296	121	102	69	218	220	227
2036	589	576	560	118	100	68	471	477	492	334	318	293	118	100	68	216	219	226
2037	583	570	556	115	97	66	468	474	490	329	314	291	115	97	66	215	217	225
2038	576	565	552	112	94	64	464	470	488	325	310	288	112	94	64	213	216	224
2039	570	559	548	109	92	62	461	467	486	320	306	285	109	92	62	212	214	223
2040	563	553	544	106	89	61	458	464	484	316	302	283	106	89	61	210	213	222
2041	557	548	541	103	87	59	454	461	481	312	298	280	103	87	59	208	212	221
2042	551	542	537	100	84	58	451	458	479	307	295	278	100	84	58	207	210	220
2043	545	537	533	98	82	56	447	455	477	303	291	275	98	82	56	205	209	219
2044	539	532	530	95	80	55	444	452	475	299	287	273	95	80	55	204	207	218
2045	533	526	526	93	78	53	440	449	473	295	284	270	93	78	53	202	206	217
2046	527	521	522	90	76	52	437	445	471	291	280	268	90	76	52	201	204	216
2047	521	516	519	88	74	50	433	442	468	287	277	266	88	74	50	199	203	215
2048	516	511	516	86	72	49	430	439	466	283	273	263	86	72	49	197	202	214
2049	510	506	512	83	70	48	427	436	464	279	270	261	83	70	48	196	200	213
2050	504	501	509	81	68	47	423	433	462	275	266	259	81	68	47	194	199	212

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	446	446	446	300	300	300	146	146	146	421	421	421	300	300	300	121	121	121
2021	439	439	399	294	294	254	145	145	145	414	414	374	294	294	254	120	120	120
2022	433	434	350	289	290	205	144	144	144	408	409	325	289	290	205	119	119	120
2023	428	430	325	285	287	181	143	143	144	403	405	300	285	287	181	118	118	119
2024	406	409	287	264	266	143	142	142	143	381	384	262	264	266	143	117	118	119
2025	375	394	262	234	253	119	141	141	143	351	370	238	234	253	119	117	117	118
2026	350	348	250	210	207	108	140	140	142	326	324	225	210	207	108	116	116	118
2027	323	310	236	184	170	95	139	140	141	299	286	212	184	170	95	115	116	117
2028	298	279	227	160	140	86	138	139	141	274	255	203	160	140	86	114	115	117
2029	279	259	222	142	121	81	137	138	140	255	235	198	142	121	81	114	114	116
2030	274	254	219	138	117	79	136	137	140	251	231	195	138	117	79	113	113	116
2031	270	250	216	134	114	77	135	136	139	246	227	192	134	114	77	112	113	115
2032	265	246	214	131	111	75	134	135	139	242	223	190	131	111	75	111	112	115
2033	261	243	211	127	108	73	133	134	138	238	219	187	127	108	73	110	111	114
2034	256	239	209	124	105	71	132	134	137	234	216	185	124	105	71	110	111	114
2035	252	235	206	121	102	69	131	133	137	230	212	183	121	102	69	109	110	113
2036	248	231	204	118	100	68	130	132	136	226	209	180	118	100	68	108	109	113
2037	244	228	201	115	97	66	129	131	136	222	205	178	115	97	66	107	108	112
2038	240	224	199	112	94	64	128	130	135	218	202	176	112	94	64	106	108	112
2039	236	221	197	109	92	62	128	129	134	214	199	174	109	92	62	106	107	111
2040	232	218	195	106	89	61	127	128	134	211	195	172	106	89	61	105	106	111
2041	229	214	192	103	87	59	126	128	133	207	192	169	103	87	59	104	106	110
2042	225	211	190	100	84	58	125	127	133	204	189	167	100	84	58	103	105	110
2043	221	208	188	98	82	56	124	126	132	200	186	165	98	82	56	102	104	109
2044	218	205	186	95	80	55	123	125	131	197	183	163	95	80	55	102	103	109
2045	215	202	184	93	78	53	122	124	131	194	180	162	93	78	53	101	103	108
2046	211	199	182	90	76	52	121	123	130	190	178	160	90	76	52	100	102	108
2047	208	196	180	88	74	50	120	122	130	187	175	158	88	74	50	99	101	107
2048	205	193	178	86	72	49	119	121	129	184	172	156	86	72	49	99	101	107
2049	201	190	176	83	70	48	118	121	128	181	170	154	83	70	48	98	100	106
2050	198	187	174	81	68	47	117	120	128	178	167	152	81	68	47	97	99	106

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	1866	2325	2428	2661	3420	5139	2384	467	388	303	222	142	107	50
2021	1863	2321	2423	2656	3414	5130	2380	466	387	303	221	142	107	50
2022	1860	2318	2419	2652	3408	5121	2376	465	386	302	221	142	107	50
2023	1857	2314	2415	2647	3402	5112	2372	464	386	302	221	142	107	49
2024	1854	2310	2411	2643	3396	5103	2368	463	385	301	220	142	106	49
2025	1850	2306	2407	2638	3390	5095	2364	463	384	301	220	141	106	49
2026	1847	2302	2403	2634	3385	5086	2360	462	384	300	219	141	106	49
2027	1844	2298	2399	2629	3379	5077	2356	461	383	300	219	141	106	49
2028	1841	2294	2395	2625	3373	5069	2352	460	382	299	219	141	106	49
2029	1838	2290	2390	2620	3367	5060	2348	459	382	299	218	140	105	49
2030	1835	2286	2386	2616	3362	5051	2344	459	381	298	218	140	105	49
2031	1831	2282	2382	2611	3356	5043	2340	458	380	298	218	140	105	49
2032	1828	2278	2378	2607	3350	5034	2336	457	380	297	217	140	105	49
2033	1825	2274	2374	2602	3344	5025	2332	456	379	297	217	139	105	49
2034	1822	2270	2370	2598	3339	5017	2328	456	378	296	216	139	105	48
2035	1819	2267	2366	2593	3333	5008	2324	455	378	296	216	139	104	48
2036	1816	2263	2362	2589	3327	5000	2320	454	377	295	216	139	104	48
2037	1813	2259	2358	2584	3322	4991	2316	453	376	295	215	138	104	48
2038	1810	2255	2354	2580	3316	4983	2312	452	376	294	215	138	104	48
2039	1807	2251	2350	2576	3310	4974	2308	452	375	294	215	138	104	48
2040	1804	2247	2346	2571	3305	4966	2304	451	375	293	214	138	103	48
2041	1800	2243	2342	2567	3299	4957	2300	450	374	293	214	137	103	48
2042	1797	2240	2338	2563	3293	4949	2296	449	373	292	214	137	103	48
2043	1794	2236	2334	2558	3288	4940	2292	449	373	292	213	137	103	48
2044	1791	2232	2330	2554	3282	4932	2288	448	372	291	213	137	103	48
2045	1788	2228	2326	2549	3277	4924	2285	447	371	291	212	137	103	48
2046	1785	2224	2322	2545	3271	4915	2281	446	371	290	212	136	102	48
2047	1782	2221	2318	2541	3265	4907	2277	446	370	290	212	136	102	47
2048	1779	2217	2314	2536	3260	4899	2273	445	369	289	211	136	102	47
2049	1776	2213	2310	2532	3254	4890	2269	444	369	289	211	136	102	47
2050	1773	2209	2306	2528	3249	4882	2265	443	368	288	211	135	102	47

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

	$/kWh				$/kW			
	Aurecon 2019	Aurecon 2020	Entura 2018 (higher 2 projects)	AEMO ISP July 2020	Aurecon 2019	Aurecon 2020	Entura 2018 (higher 2 projects)	AEMO ISP July 2020
Battery (1hr)	988	827	-	-	988	827	-	-
Battery (2hrs)	622	542	-	-	1244	1083	-	-
Battery (4hrs)	491	446	-	-	1964	1783	-	-
PHES (6hrs)	-	-	308	388	-	-	1850	2325
Battery (8hrs)	446	421	-	-	3564	3365	-	-
PHES (12hrs)	-	-	177	222	-	-	2118	2661
PHES (24hrs)	-	-	131	142	-	-	3139	3420
PHES (48hrs)	-	-	73	107	-	-	3517	5139
PHES (48hrs) Tasmania	-	-	-	50	-	-	-	2384

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	Emission factor	Carbon price	Capital	Fuel	Capacity factor	Emission factor	Carbon price
	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$ktCO_2e$/PJ	$/$tCO_2e$	$/kW	$/GJ		$ktCO_2e$/PJ	$/$tCO_2e$
2020																
Gas with CCS	25	1.5	0.44	16.4	7.2	1.9	4461	5.8	0.80	10.3	18.1	4461	11.3	0.60	19.9	30.7
Gas combined cycle	25	1.5	0.51	10.9	3.7	0.0	1801	5.8	0.80	56.0	18.1	1801	11.3	0.60	65.6	30.7
Gas open cycle (small)	25	1.3	0.36	12.6	4.1	0.0	1550	5.8	0.20	57.0	18.1	1550	11.3	0.20	66.6	30.7
Gas open cycle (large)	25	1.1	0.33	10.2	2.4	0.0	961	5.8	0.20	57.0	18.1	961	11.3	0.20	66.6	30.7
Gas reciprocating	25	1.0	0.41	24.1	7.6	0.0	1567	5.8	0.20	57.4	18.1	1567	11.3	0.20	67.0	30.7
Black coal with CCS	30	2.0	0.30	77.8	8.0	4.1	9311	2.8	0.80	8.5	18.1	9311	4.1	0.60	15.4	30.7
Black coal	30	2.0	0.40	53.2	4.2	0.0	4450	2.8	0.80	88.0	18.1	4450	4.1	0.60	88.0	30.7
Brown coal with CCS	30	4.0	0.21	101.6	11.6	4.7	14293	0.6	0.80	5.8	18.1	14293	0.7	0.60	5.8	30.7
Brown coal	30	4.0	0.32	69.0	5.3	0.0	6868	0.6	0.80	85.0	18.1	6868	0.7	0.60	85.0	30.7
Biomass (small scale)	30	2.0	0.23	131.6	8.4	0.0	8619	0.5	0.60	0.0	18.1	8619	2.0	0.40	0.0	30.7
Nuclear (SMR)	30	3.0	0.30	200.0	20.0	0.0	16487	0.5	0.80	0.0	18.1	16487	0.7	0.60	0.0	30.7
Large scale solar PV	25	0.5	1.00	17.0	0.0	0.0	1408	0.0	0.32	0.0	18.1	1408	0.0	0.22	0.0	30.7
Solar thermal (8hrs)	25	1.8	1.00	142.5	0.0	0.0	7411	0.0	0.52	0.0	18.1	7411	0.0	0.42	0.0	30.7
Wind	25	1.0	1.00	25.0	0.0	0.0	1951	0.0	0.44	0.0	18.1	1951	0.0	0.35	0.0	30.7
2030																
Gas with CCS	25	1.5	0.44	16.4	7.2	1.9	4417	5.8	0.80	10.3	29.5	4417	11.8	0.60	19.9	129.0
Gas combined cycle	25	1.5	0.51	10.9	3.7	0.0	1765	5.8	0.80	56.0	29.5	1765	11.8	0.60	65.6	129.0
Gas open cycle (small)	25	1.3	0.36	12.6	4.1	0.0	1519	5.8	0.20	57.0	29.5	1519	11.8	0.20	66.6	129.0
Gas open cycle (large)	25	1.1	0.33	10.2	2.4	0.0	942	5.8	0.20	57.0	29.5	942	11.8	0.20	66.6	129.0
Gas reciprocating	25	1.0	0.41	24.1	7.6	0.0	1536	5.8	0.20	57.4	29.5	1536	11.8	0.20	67.0	129.0
Black coal with CCS	30	2.0	0.30	77.8	8.0	4.1	9171	2.9	0.80	8.5	29.5	9171	3.8	0.60	15.4	129.0
Black coal	30	2.0	0.40	53.2	4.2	0.0	4362	2.9	0.80	88.0	29.5	4362	3.8	0.60	88.0	129.0
Brown coal with CCS	30	4.0	0.21	101.6	11.6	4.7	14054	0.7	0.80	5.8	29.5	14054	0.7	0.60	5.8	129.0
Brown coal	30	4.0	0.32	69.0	5.3	0.0	6732	0.7	0.80	85.0	29.5	6732	0.7	0.60	85.0	129.0
Biomass (small scale)	30	2.0	0.23	131.6	8.4	0.0	8606	0.5	0.60	0.0	29.5	8606	2.0	0.40	0.0	129.0
Nuclear (SMR)	30	3.0	0.35	200.0	20.0	0.0	7237	0.5	0.80	0.0	29.5	16487	0.7	0.60	0.0	129.0
Large scale solar PV	25	0.5	1.00	17.0	0.0	0.0	780	0.0	0.32	0.0	29.5	874	0.0	0.19	0.0	129.0
Solar thermal (8hrs)	25	1.8	1.00	142.5	0.0	0.0	6264	0.0	0.52	0.0	29.5	6732	0.0	0.42	0.0	129.0
Wind	25	1.0	1.00	25.0	0.0	0.0	1899	0.0	0.46	0.0	29.5	1892	0.0	0.35	0.0	129.0

2040																
Gas with CCS	25	1.5	0.44	16.4	7.2	1.9	3390	5.8	0.80	10.3	48.1	4374	11.8	0.60	19.9	220.3
Gas combined cycle	25	1.5	0.51	10.9	3.7	0.0	1730	5.8	0.80	56.0	48.1	1730	11.8	0.60	65.6	220.3
Gas open cycle (small)	25	1.3	0.36	12.6	4.1	0.0	1489	5.8	0.20	57.0	48.1	1489	11.8	0.20	66.6	220.3
Gas open cycle (large)	25	1.1	0.33	10.2	2.4	0.0	923	5.8	0.20	57.0	48.1	923	11.8	0.20	66.6	220.3
Gas reciprocating	25	1.0	0.41	24.1	7.6	0.0	1505	5.8	0.20	57.4	48.1	1505	11.8	0.20	67.0	220.3
Black coal with CCS	30	2.0	0.30	77.8	8.0	4.1	8043	2.9	0.80	8.5	48.1	9034	3.8	0.60	15.4	220.3
Black coal	30	2.0	0.40	53.2	4.2	0.0	4275	2.9	0.80	88.0	48.1	4275	3.8	0.60	88.0	220.3
Brown coal with CCS	30	4.0	0.21	101.6	11.6	4.7	12827	0.7	0.80	5.8	48.1	13820	0.7	0.60	5.8	220.3
Brown coal	30	4.0	0.32	69.0	5.3	0.0	6599	0.7	0.80	85.0	48.1	6599	0.7	0.60	85.0	220.3
Biomass (small scale)	30	2.0	0.23	131.6	8.4	0.0	8606	0.5	0.60	0.0	48.1	8606	2.0	0.40	0.0	220.3
Nuclear (SMR)	30	3.0	0.40	200.0	20.0	0.0	7205	0.5	0.80	0.0	48.1	16487	0.7	0.60	0.0	220.3
Large scale solar PV	25	0.5	1.00	17.0	0.0	0.0	582	0.0	0.32	0.0	48.1	727	0.0	0.19	0.0	220.3
Solar thermal (8hrs)	25	1.8	1.00	142.5	0.0	0.0	5874	0.0	0.52	0.0	48.1	6224	0.0	0.42	0.0	220.3
Wind	25	1.0	1.00	25.0	0.0	0.0	1842	0.0	0.48	0.0	48.1	1792	0.0	0.35	0.0	220.3
2050																
Gas with CCS	25	1.5	0.44	16.4	7.2	1.9	3325	5.8	0.80	10.3	64.6	3982	11.8	0.60	19.9	386.7
Gas combined cycle	25	1.5	0.51	10.9	3.7	0.0	1697	5.8	0.80	56.0	64.6	1697	11.8	0.60	65.6	386.7
Gas open cycle (small)	25	1.3	0.36	12.6	4.1	0.0	1461	5.8	0.20	57.0	64.6	1461	11.8	0.20	66.6	386.7
Gas open cycle (large)	25	1.1	0.33	10.2	2.4	0.0	905	5.8	0.20	57.0	64.6	905	11.8	0.20	66.6	386.7
Gas reciprocating	25	1.0	0.41	24.1	7.6	0.0	1477	5.8	0.20	57.4	64.6	1477	11.8	0.20	67.0	386.7
Black coal with CCS	30	2.0	0.30	77.8	8.0	4.1	7891	2.9	0.80	8.5	64.6	8553	3.8	0.60	15.4	386.7
Black coal	30	2.0	0.40	53.2	4.2	0.0	4195	2.9	0.80	88.0	64.6	4195	3.8	0.60	88.0	386.7
Brown coal with CCS	30	4.0	0.21	101.6	11.6	4.7	12584	0.7	0.80	5.8	64.6	13248	0.7	0.60	5.8	386.7
Brown coal	30	4.0	0.32	69.0	5.3	0.0	6474	0.7	0.80	85.0	64.6	6474	0.7	0.60	85.0	386.7
Biomass (small scale)	30	2.0	0.23	131.6	8.4	0.0	8606	0.5	0.60	0.0	64.6	8606	2.0	0.40	0.0	386.7
Nuclear (SMR)	30	3.0	0.45	200.0	20.0	0.0	7205	0.5	0.80	0.0	64.6	16487	0.7	0.60	0.0	386.7
Large scale solar PV	25	0.5	1.00	17.0	0.0	0.0	546	0.0	0.32	0.0	64.6	585	0.0	0.19	0.0	386.7
Solar thermal (8hrs)	25	1.8	1.00	142.5	0.0	0.0	5341	0.0	0.52	0.0	64.6	5641	0.0	0.42	0.0	386.7
Wind	25	1.0	1.00	25.0	0.0	0.0	1772	0.0	0.50	0.0	64.6	1745	0.0	0.35	0.0	386.7

Notes: Wind is onshore. Large-scale solar PV is single axis tracking. Emission factors include fugitive emissions associated with the fuel. The low emission factor is from the lowest state average and the high from the highest emission state. The discount rate used for all technologies is 5.99%.

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	Carbon price	Gas open cycle (small)	154	219	159	289	168	348	176	458
		Gas open cycle (large)	127	198	133	274	144	339	153	458
		Gas reciprocating	155	213	159	274	167	327	174	423
Flexible 40-80% load, high emission	No carbon price or risk premium	Black coal	89	120	88	116	87	114	86	113
		Brown coal	112	145	111	143	110	142	108	139
		Gas	68	115	67	118	67	117	67	117
	No carbon price, 5% risk premium	Black coal	127	171	126	166	124	163	122	161
		Brown coal	193	254	190	249	188	246	184	242
		Gas	82	133	81	136	80	135	80	134
	Carbon price	Black coal	103	144	111	218	125	289	137	419
		Brown coal	129	175	139	268	156	354	170	512
		Gas	75	129	79	178	86	220	92	296
Flexible 40-80% load, low emission	Carbon price	Black coal with CCS	167	226	167	238	156	253	156	276
		Brown coal with CCS	230	299	229	305	216	311	214	318
		Gas with CCS	114	181	115	201	104	215	104	236
		Solar thermal 8hrs	172	213	150	197	143	185	133	171
		Nuclear (SMR)	258	338	143	336	142	335	141	335
		Biomass (small scale)	175	277	175	277	175	277	175	277
Variable	Standalone	Wind	48	61	45	59	42	57	39	55
		Solar photovoltaic	46	68	28	52	23	45	22	38

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
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
hrs	Hours
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
ISP	Integrated System plan
kW	Kilowatt
kWh	Kilowatt hour

Abbreviation	Meaning
LCOE	Levelised Cost of Electricity
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
Li-ion	Lithium-ion
LR	Learning Rate
MW	Megawatt
MWh	Megawatt hour
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
SDS	Sustainable Development Scenario
SMR	Small modular reactor
STABLE	Spatial Temporal Analysis of Balancing Levelised-cost of Energy
t	tonne
TWh	Terawatt hour
VRE	Variable Renewable Energy
WEO	World Energy Outlook

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