Australia's National
Science Agency

Small-scale solar PV and battery projections 2024

Commissioned for AEMO's draft 2025 Input, Assumptions and Scenarios Report

Paul Graham and Chathurika Mediwaththe
December 2024

Contact

Paul Graham

paul.graham@csiro.au

02 4960 6061

Citation

Graham, P. and Mediwaththe, C. 2024, *Small-scale solar PV and battery projections 2024*. CSIRO, Australia.

Copyright

Important disclaimer

Contents

Figures

Tables

Acknowledgments

This report was improved by input from participants in AEMO's Forecasting Reference Group and from AEMO staff.

Executive summary

This report updates CSIRO's projections of small-scale solar PV and battery uptake. The report was completed in 2024 but has been commissioned as an input to AEMO's draft 2025 Input, Assumptions and Scenarios Report. This update is the first since CSIRO's last projection report completed in 2022 and so represents two extra years of historical data. The key trends since 2022 are:

1. Steady growth in both solar PV and batteries with no slowdown in capacity additions or any early evidence of market saturation
2. Strong growth in residential solar PV system sizes in contrast to a lower outlook for business system sizes
3. Changes in the trajectory of solar PV and battery but overall continued cost reductions

These trends mean that the updated outlook is generally stronger than the 2022 projections for both solar PV and batteries. The main exception is business solar PV which is lower due to assumed smaller system sizes. Prior to 2022, business solar PV system sizes had indicted a mostly growing trend. However, they have been consistently falling in the past three years. Consequently, the previous assumptions about future business system sizes could no longer be supported.

Despite the reduced growth in business solar PV, business batteries are likely to increase in the short term owing to government investment in community batteries which is expected to add 281MWh of storage capacity. This will assist in shifting generation from solar PV to meet consumption needs into the evening for all customers.

1 Introduction

This report provides projections for three scenarios of small-scale solar PV and battery storage adoption. The analysis also includes simulations of the operation of small-scale batteries by residential and business customers under different tariffs.

The scope includes all the National Electricity Market (NEM) states of New South Wales, Victoria, Queensland, South Australia and Tasmania. This area excludes some postcodes in those five states that are not connected to the NEM. Only areas of Western Australia that are a part of the South West Interconnected System (SWIS) are included.

Projections for small-scale solar include residential and commercial systems below 100kW and separate projections for larger solar PV systems in the following ranges: above 100kW to 1MW, above 1MW to 5MW, above 5MW to 10MW and above 10MW to 30MW. For batteries, projections include residential systems and a small and large category for commercial systems.

The three scenarios are *Progressive Change, Step Change* and *Green Energy Exports*. These are described further in the body of this report.

The report is set out in five sections. Section 2 provides a description of the projection methodology. Section 3 describes the scenarios and their broad settings. Section 4 describes the scenario assumptions in detail. Finally, the projection results are presented in Section 5.

2 Methodology

2.1 Overview

The projections undertaken are for periods of months, years and decades. Consequently, our projection approach aims to be robust over both shorter- and longer-term projection periods.

Longer term projection approaches tend to be based on a theoretical model of the relevant drivers including human behaviour and physical drivers and constraints. These models can overlook short term variations from the theoretical model of behaviour because of imperfect information, unexpected shifts in key drivers and delays in observing the current state of the market.

Shorter term projection approaches tend to be based on extrapolation of recent activity without an underlying theory of the drivers. These include regression analysis and other types of trend extrapolation. While trend analysis will generally perform the best in the short term, extrapolating a trend indefinitely will lead to poor results since eventually a fundamental driver or constraint on the activity will assert itself, changing the activity away from past trends.

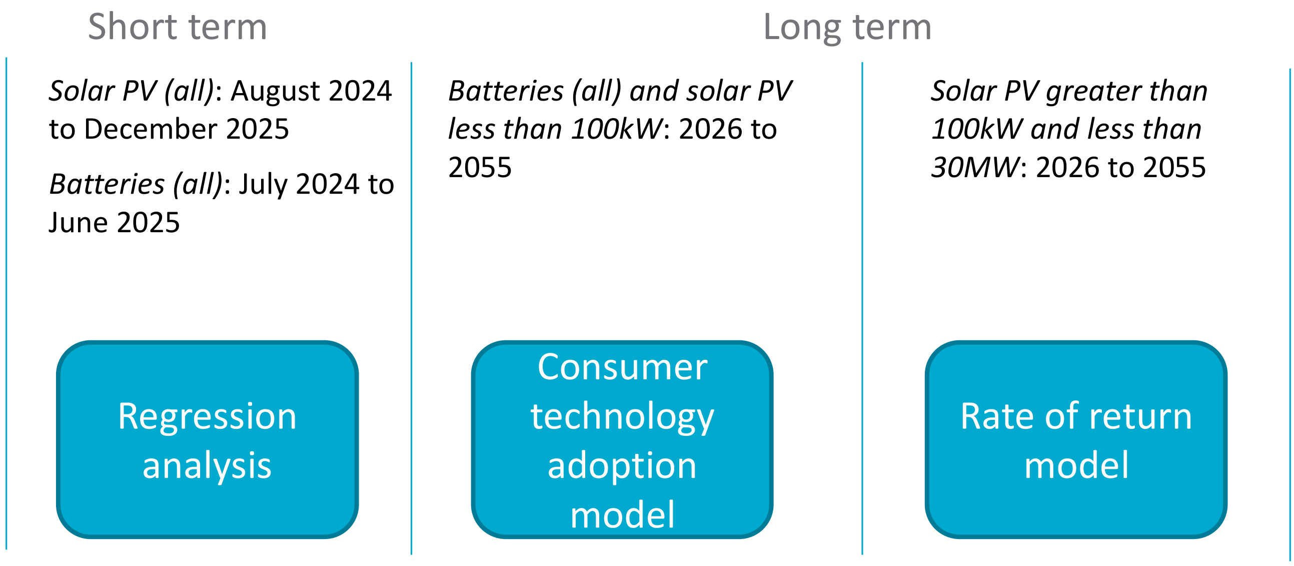


Figure 2-1 Short- and long-term projection approaches applied to the technology groups

Based on these observations about the performance of short- and long-term projection approaches, and our need to deliver both long and short projections, this report applies a combination of short-term trend models and two types of long-term projection models depending on the size of the technology (Figure 2-1).

2.1.1 Short-term trend model

From the point where historical data ends[1], trend analysis is applied to produce projections of installations[2] to December 2023. The trend analysis for batteries is conducted on financial year data going back several years[3] as monthly data sources for that technology are incomplete. For solar PV, the trend is estimated as a linear regression against 5 years of monthly data with dummy variables against each month to account for trends in monthly sales. A non-linear relationship was explored but was not preferred because the scenarios themselves can be used to impose additional downside or upside risk against the linear trend and as a result explore non-linear outcomes (this is explained further below). The solar PV regression takes the following form:

$$X_{m=f(month\ in\ sequence, mont\quad of\ year\ dummy\ variable)}$$

Where X is the (m) monthly activity of either solar PV installations and generation capacity by residential and commercial segments. This requires around 10,000 regressions – two activity types by two customer types by around 2,500 postcodes across the National Electricity Market and the South West Interconnected System. Information from both installations and capacity is also used to observe and project the trends in average system size.

For solar PV systems less than 100kW, regressions are calculated at the postcode level, while the regressions for larger systems are calculated at the state level[4]. For larger non-scheduled solar PV, we also use the monthly data but unlike systems less than 100kW, there will often be several months without a deployment.

The regression results for residential (Figure 2-2) and commercial (Figure 2-3) rooftop solar installations indicate a mostly linear growth trend. As discussed, we only use data back to the beginning of 2019 to emphasise recent trends in creating the forecast but show earlier data for context. NSW growth has been stronger than other states in recent years. This is consistent with being at a lower point on the consumer technology adoption curve (which we discuss further in the next section).

[1] Around August 2024 for solar and end of 2023 for batteries when this report was being developed. The historical solar PV data is supplied by AEMO but is originally from the Clean Energy Regulator (CER). CER data in 2023-24 is aligned to the CER's estimate of full financial year data adjusted for delays in applying for small-scale technology certificates. AEMO has supplied historical battery data including an extrapolation to June 2024.

[2] We separately make an assumption about solar PV system sizes. As such the projections for the capacity of solar PV is the multiple of the new installations projections and the assumed new system sizes over time added to historical capacity. The system size assumptions are outlined in Section 4.2. Battery sizes have been relatively stable and are listed in Appendix A.

[3] We do not have a strict number of years used in the trend analysis. We select based on what period looks representative. For example, we may go back an extra year if there is an outlier year dominating an otherwise clear trend.

[4] Postcode level installations of larger scale systems are too infrequent to support trend analysis at that level.

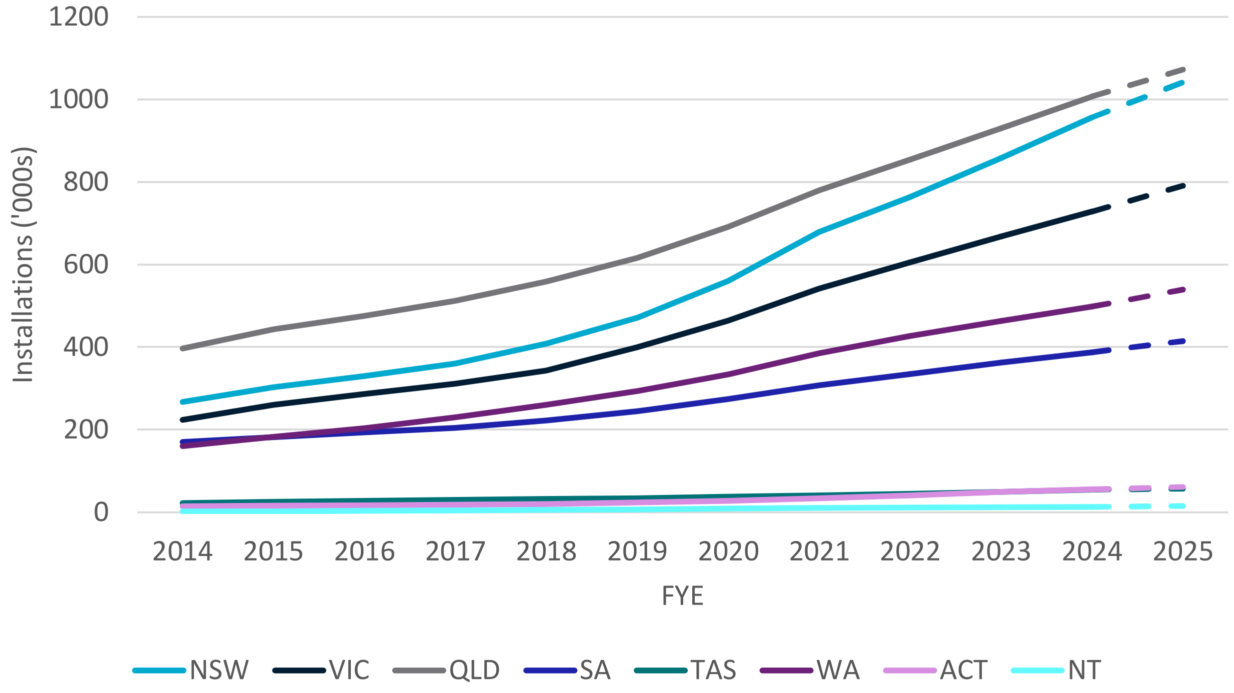


Figure 2-2 Regression results for residential rooftop solar installations by region

Commercial systems have not followed residential systems in terms of state rankings. NSW has the highest number of commercial installations whereas Queensland is the leading state for residential installation. South Australia also has relatively higher ranking for commercial installations than in residential installations.

These trends are applied differently to each scenario by applying differing scale factors of +/- 0.5% to the December 2025 projection and linearly interpolating that factor back to August 2024. This approach allows for the possibility that some scenarios will grow faster or slower than a linear trend and creates a short-term uncertainty range. The scale factors for each scenario applying to both residential and commercial systems are: *Progressive Change* -0.5%, *Step Change* 0% and *Green Energy Exports* 0.5% (the scenarios are outlined in more detail in Section 3).

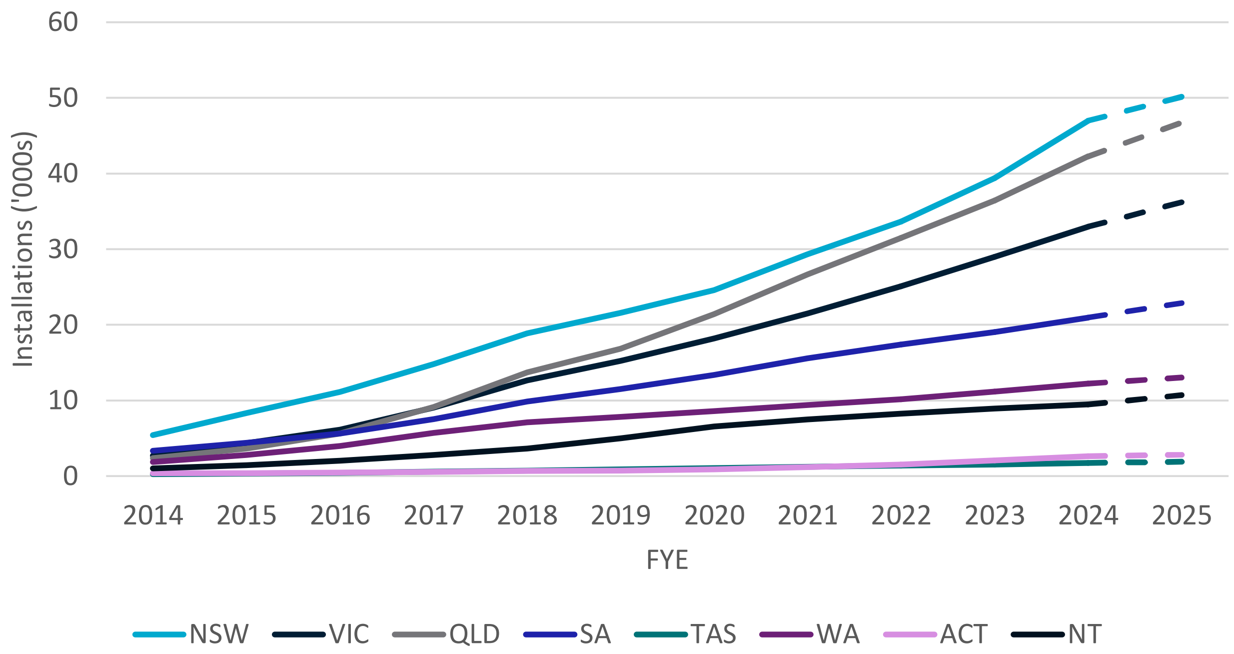


Figure 2-3 Regression results for commercial (<100kw) rooftop solar installations by region

2.1.2 Consumer technology adoption model

The consumer technology adoption curve is a whole of market scale property that we can exploit for the purposes of projecting adoption, particularly in markets for new products. The theory posits that technology adoption will be led by an early adopter group who, despite high payback periods, are driven to invest by other motivations such as values, autonomy and enthusiasm for new technologies. As time passes, fast followers or the early majority take over and create the most rapid period of adoption. In the latter stages, the late majority or late followers may still be holding back due to constraints they may not be able to nor wish to overcome, even if the product is attractively priced. These early concepts were developed by authors such as Rogers (1962) and Bass (1969).

In the last 50 years, a range of market analysts seeking to use the concept as a projection tool have experimented with a combination of price and non-price drivers to calibrate the shape of the adoption curve for any given context. Price can be included directly or as a payback period or return on investment. Payback periods are relatively straightforward to calculate and compared to price also capture the opportunity cost of staying with the existing technology substitute. A more difficult task is to identity the set of non-price demographic or other factors that are necessary to capture other reasons which might motivate a population to slow or speed up their rate of adoption. CSIRO has previously studied the important non-price factors and validated how the approach of combining payback periods and non-price factors can provide good locational predictive power for rooftop solar and electric vehicles (Higgins et al 2014; Higgins et al 2012).

In Figure 2-4 we highlight the general projection approach including some examples of the demographic or other factors that could be considered for inclusion. We also indicate an important interim step, which is to calibrate the adoption curve at appropriate spatial scales (due to differing demographic characteristics and electricity prices) and across different customer segments (due to differences between customers' electricity load profiles which are discussed in Appendix A).

Once the adoption curve is calibrated for all the relevant factors, we can evolve the rate of adoption over time by altering the inputs according to the scenario assumptions. For example, differences in technology costs and prices between scenarios alter the payback period and lead to a different position on the adoption curve. Non-price scenario assumptions such as available roof space in a region result in different adoption curve shapes (particularly the height at saturation). Data on existing market shares (after it has been extrapolated forward by the trend analysis) determines the starting point on the adoption curve.

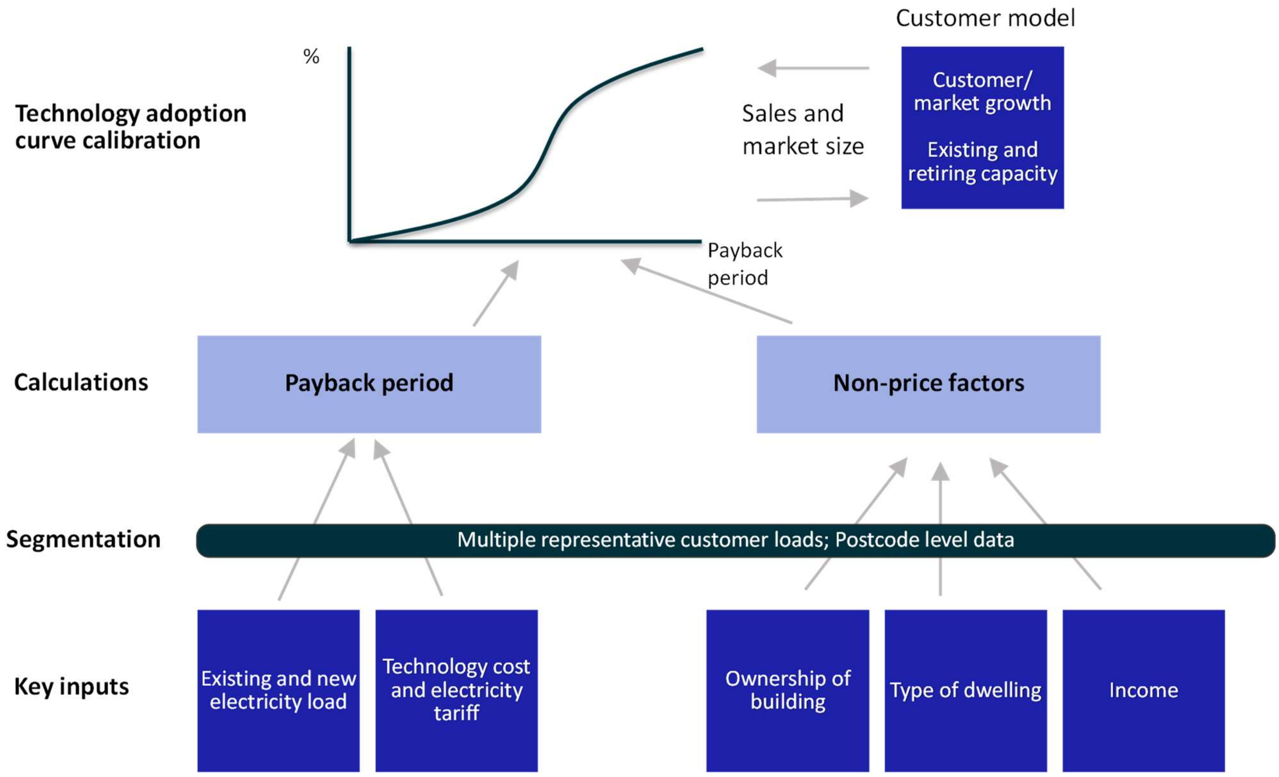


Figure 2-4 Adoption model methodology overview

The methodology also considers the total available market size, which can differ between scenarios. While we may set a maximum market share for the adoption curve based on various non-financial constraints, maximum market share is only reached if the payback period falls. Maximum market share assumptions are outlined in the Data Assumptions section (Table 4-5 and Table 4-6).

All calculations are carried out at the postcode level, but results are presented here at the state or NEM level for brevity by aggregating the appropriate postcodes.

The above technology adoption curve model is used for storage and all solar installations below 100kW. We regard these technology markets as "consumer" markets in the sense that investment decisions are driven by a combination of financial and non-financial drivers so that adoption will broadly follow the consumer technology adoption curve. For larger solar installations, we take the view that such decisions should be regarded as more purely financial investment decisions, therefore we apply the more financially driven "rate-of-return" model as described in the following section.

2.1.3 Rate of return model (larger-scale installations)

For projecting solar panel installations and capacity above 100kW and up to 30MW, we employ a different approach. The difference in approach is justified on the basis that larger projects require special purpose financing and, as such, are less influenced by non-financial factors in terms of the decision to proceed with a project. In other words, financiers will be primarily concerned with the project achieving its required return on investment when determining whether the project will receive financing. Commercial customer equity financing is of course possible, but it is more common that businesses have a wide range of important demands on available equity, so this is only a very limited source of funding (as compared to being the main source of small-scale solar investment).

The projected uptake of solar panels between 100kW and 30MW is based on determining whether the return on investment for different size systems meets a required rate of return threshold. If they do, investment proceeds in that year and region. For less than 5MW capacity generation, we assume investment proceeds if revenue is 10% higher than that which would have been required to break even. For plants with generation capacity larger than 5MW, we assume that revenue must be sustained at this rate of return for more than five years (does not need to be consecutive)[5]. Solar generation costs, electricity prices and any additional available renewable energy credits are the strongest drivers of the rate of return. Where investment can proceed, we impose a build limit rate based on an assessment of past construction rates and typical land/building stock cycles.

2.2 Demographic factors and weights

The projection methodology includes three non-price factors (see Table 2-1) drawn from accessible demographic data to calibrate the consumer technology adoption curve. Our methodology assigns different weights to each factor to reflect their relative importance. The multiple of the weights by the postcode level demographic data is used to create a demographic score for that postcode. The demographic score is used as part of the calibration of the local maximum market share.

Higgins et al (2014) validated prediction of historical sales for rooftop solar by combining a weighted combination of factors such as income, dwelling density and share of Greens voters. While these factors performed well when the model was calibrated for 2010, given the time that has passed and 2010 being very much an early adopter phase of the market we recalibrated a new set of factors and weights as shown in Table 2-1.

Reliable battery storage sales data is not available below the state or territory level. Consequently, it is not possible to calculate a set of historically validated combination of weights and factors. In

[5] These factors represent CSIRO's own judgement. They are essentially trying to capture the premium that might be required to overcome two concepts in investment theory – risk and competing investment options. More revenue upside sustained over a longer period of time can help to offset downside risks in an expected net present value analysis. Furthermore, higher and sustained revenue upside makes a project more likely to be selected for investment when there are several competing investment opportunities which is often the case for any business venture.

the absence of such data, we assume the same weights apply to battery storage as for rooftop solar.

Table 2-1 Weights and factors for residential rooftop solar and battery storage

Factor	Weight
Average income	0.25
Share of separate dwelling households	1
Share of owned or mortgaged households	0.25

For commercial systems less than 100kW we do not apply any demographic weights since none were found to be highly explanatory. However, the existing location of commercial systems tends to be a strong indicator of future deployment in a postcode region. This indicates a network effect whereby awareness of deployment of solar neighbours inspires adoption.

3 Scenario definitions

The three scenarios defined in this section are *Progressive Change*, *Step Change* and *Green Energy Exports*. The AEMO scenario definitions are described in narrative form and then by their key drivers in Table 3-1. Further detail is available in AEMO (2024). To implement the solar and battery projections, CSIRO has developed an additional set of extended scenario definitions based on more detailed road transport sector drivers that are covered in the broader scenario design process.

3.1.1 AEMO's scenario narratives and definitions

Progressive Change

Meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios

Step Change

Achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C by 2100 compared to pre-industrial levels. The electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy utilises the electricity sector's low emissions footprint to decarbonise through electrification. The electricity sector's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the electricity sector's transition. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in coordinated consumer energy resources (CER), including electrification of the transportation sector.

Green Energy Exports

Reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C by 2100, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The electricity sector plays a very significant role in decarbonisation

Table 3-1 AEMO scenario definitions (current at time of modelling)

	Progressive Change	Step Change	Green Energy Exports
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination

National decarbonisation target	At least 43% emissions reduction by 2030.	At least 43% emissions reduction by 2030.	At least 43% emissions reduction by 2030.
National decarbonisation target	Net zero by 2050	Net zero by 2050	Net zero by 2050
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower	Moderate economic growth, with near-term economic growth impacted by current economic challenges	Higher, with near-term economic growth impacted somewhat by current economic challenges
Electrification	Electrification is tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption
Emerging commercial loads	Emerging sectors such as data centres experience lower growth as weaker economic circumstances limit technology uptake	Emerging sectors such as data centres match opportunities associated with moderate domestic economic drivers	Emerging sectors such as data centres match opportunities associated with higher domestic economic drivers
Industrial Load Closures	Weak economic conditions provide challenging commercial conditions, resulting in load closures across key commercial and industrial facilities	No specific load closures	No specific load closures
Consumer energy resource investments (batteries, PV and EVs)	Lower	High	Higher
Coordination of CER (VPP and V2G)	Low long-term coordination, with gradual acceptance of coordination	Moderate long-term coordination, with gradual acceptance of coordination	High long-term coordination, with faster acceptance of coordination
Energy efficiency	Lower	Moderate	Higher
Hydrogen use and availability	Low production for domestic use, with no export hydrogen.	Medium-Low production for domestic use, with minimal export hydrogen.	High production for domestic industries, with moderate exports in the short term, and

			high exports in the longer term
Hydrogen blending in gas distribution network	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases
Biomethane/ synthetic methane	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it
Supply chain strength influencing demand forecasts	Low	Moderate	High
Global/domestic temperature settings and outcomes	Applies Representative Concentration Pathway (RCP) 4.5 where relevant, consistent with a global temperature rise of ~ 2.6°C by 2100	Applies RCP 2.6 where relevant, consistent with a global temperature rise of ~ 1.8°C by 2100	Applies RCP 1.9 where relevant (~ 1.5°C), consistent with a global temperature rise of ~ 1.4°C by 2100
IEA 2021 World Energy Outlook scenario	Stated Policies Scenario (STEPS)	Sustainable Development Scenario (SDS)	Net Zero Emissions (NZE)

3.1.2 Extended scenario definitions

The AEMO scenario definitions have been extended by CSIRO in Table 3-2 by adding additional detail on the economic, infrastructure and business model drivers. The purpose is to fill out more detail about how the scenarios are implemented whilst remaining consistent with the higher level AEMO scenario definitions. The extended table remains a summary and does not include all scenario assumptions. We discuss what has been considered and included for each driver in more detail below.

Table 3-2 Extended scenario definitions

Driver	Progressive Change	Step Change	Green Energy Exports
Commonwealth SRES subsidy	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down
NSG solar subsidies available in addition to LGCs	ACCU and VEEC subsidies available and increasing 2% p.a.	ACCU and VEEC subsidies available and increasing 3% p.a.	ACCU and VEEC subsidies available and increasing 5% p.a.
State rooftop solar and battery storage subsidies or support schemes (detailed in Section 3.2.5)[1]	Current state policies	Current state policies.	Current state policies.

Driver	Progressive Change	Step Change	Green Energy Exports
Growth in apartment share of dwellings	Medium-low	Medium	Medium-high
Decline in home ownership	High	Medium	Low
Tariff and CER incentive arrangements[1]	Slow change	Stronger energy management incentives	Stronger energy management incentives
System architecture changes support greater incentives to CER participation	Low	Medium-high	High
Feasibility of participation of apartment dwellers and renters in DER	Low	Medium-high	High

1. The assumed shares of TOU tariffs and more direct control measures such as Virtual Power Plant are outlined in Table 4-2 .

The scenario definitions are in some cases described here in general terms such as “high” or “Low”. More specific scenario data assumptions are outlined in the next section and in Section 4.

3.2 Financial and non-financial scenario drivers

3.2.1 Direct economic drivers

Whilst the general buoyancy of the economy is a factor in projecting adoption of small-scale technologies, here we are concerned with the direct financial costs and returns. The key economic drivers which alter the outlook for rooftop solar and battery storage adoption scenarios are shown in Table 3-3.

Table 3-3 Economic drivers of rooftop solar and batteries and approach to including them in scenarios

Driver	Approach to including in scenarios
Any available subsidies or low interest loans	Varied by scenario and outlined in Section 3.2.4 and 3.2.6
Installed cost of rooftop solar and battery storage systems and any additional components such as advanced metering	Varied by scenario and outlined in Section 4.1.1 and 4.1.3
Current and perceived future level of retail electricity prices	Varied by scenario and outlined in Section 4.3.1
The level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity	FiTs varied over time to converge towards the wholesale market price which is varied by scenario and outlined in Section 4.3.1. A

and wholesale (generation) prices which may influence the future level of FiTs	further adjustment is made to account for the impact of congestion and increased large scale solar production on wholesale electricity prices (see Table 4-1)
The shape of the customer's load curve	Not varied by scenario but a range of representative customers are included. See Appendix A

3.2.2 Infrastructure drivers

One of the key reasons for the already significant adoption of rooftop solar has been its ease of integrating with existing building infrastructure. Battery storage has also been designed to be relatively easily incorporated into existing spaces. However, there are some infrastructure limitations which are relevant over the longer term.

Table 3-4 Infrastructure drivers for rooftop solar and battery systems and approach to including them in scenarios

Driver	Approach to including in scenarios
The quantity of residential or commercial roof space or vacant adjacent land, of varying orientation, ideally free of shading relative to the customer's energy needs (rooftop solar)	Varied by scenario and expressed as maximum market share constraints in Section 4.6
Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)	Varied by scenario and expressed as maximum market share constraints in Section 4.6
The quantity of buildings with appropriate roof and indoor space that are owned or mortgaged by the occupant, with an intention to stay at that location (and who therefore would be able to enjoy the benefits of any longer-term payback from solar or integrated solar and storage systems)	Varied by scenario and expressed as maximum market share constraints in Section 4.6
Distribution network constraints imposed on small-scale systems as a result of hosting capacity constraints (e.g., several distribution networks have set rules that new rooftop system sizes may be no larger than 5kW per phase)	Varied by scenario and expressed as maximum rooftop system sizes outlined in Section 4.6
Distribution network constraints relating to connection of solar photovoltaic projects in the 1MW to 30MW range	Not included or varied by scenario due to lack of data

The degree to which the NEM and WEM management of security and reliability begins to place limits on the amount of large- and small-scale variable renewables that can be accepted during peak supply and low demand periods (e.g., to maintain a minimum amount of dispatchable or FCAS serving plant)	AEMO has commissioned a relatively unconstrained projection from CSIRO with the aim of managing this issue downstream of forecasting, within the ISP process.
The degree to which solar can be integrated into building structures (flat plate is widely applicable but alternative materials, such as thin film solar, could extend the amount of usable roof space)	Varied by scenario and expressed as maximum market share constraints in Section 4.5

3.2.3 Disruptive business model drivers

New business models can disrupt economic and infrastructure constraints by changing the conditions under which a customer might consider adopting a technology. Table 3-5 explores some emerging and potential business models which could drive higher adoption. The degree to which these potential business model developments apply by scenario is expressed primarily through their ability to change the maximum saturation levels for rooftop solar PV and batteries as outlined in Section 4.5.

Virtual power plants are an example of an existing business model that incentivises further uptake of batteries by providing greater value from the battery than simply shifting local solar generation.

Table 3-5 Emerging or potential disruptive business models to support solar and battery adoption

Name	Description	Constraint reduced
Building as retailer	Apartment, car park or shopping centre building body corporate as retailer	Rooftop solar is more suitable for deployment in dwellings which have a separate roof
Peer-to-peer	Peer-to-peer selling as an alternative to selling to a retailer	Owners may generate more from solar if they could trade directly with a related entity (e.g., landlords and renters, corporation with multiple buildings, families and neighbours) without a retailer distorting price reconciliation
Landlord-tenant intermediary	An intermediary (such as the government) sets up an	Neither the landlord nor tenant are adequately

Name	Description	Constraint reduced
	agreement for cost and benefit sharing	incentivised to adopt solar because neither party can be assured of accessing the full benefits.
Virtual power plant	Retailers, aggregators, networks or an independent market operator reward demand management through direct payments, alternative tariff structures or direct ownership and operation of battery to reduce costs elsewhere in the system	Given the predominance of volume-based tariffs, the main value for customers of battery storage is in reducing rooftop solar exports. The appetite for demand management participation could be more directly targeted than current incentives.
Going off-grid	Standalone power system is delivered at lower cost than new distribution level connections greater than 1km from existing grid and decreasing over time (e.g., WA[6])	Except for remote area power systems and edge of grid, it is cost effective to connect all other customers to the grid
Solar/battery new housing packages	New housing developments include integrated solar and batteries on new housing either as a branding tool and to reduce distribution network connection costs or due to building code mandates	Integrated solar and battery systems represent a discretionary and high upfront cost
Vehicle battery second life	Electric vehicle batteries are sold as low-cost home batteries as a second life application	Battery storage represents a high upfront cost and discretionary investment.

[6] https://www.westernpower.com.au/our-energy-evolution/grid-technology/stand-alone-power-system/

3.2.4 Existing Commonwealth policy drivers

There are a variety of commonwealth policy drivers which impact solar and battery adoption. We outline how we have chosen to include them and describe them in further detail below.

Table 3-6 Summary of Commonwealth policies and their inclusion in scenarios

Policy	Approach to including in scenarios
Small-scale renewable energy scheme	Assumed to continue as planned to 2030 in all scenarios
Large scale renewable energy target	Certificate prices maintained at current levels
Australian Carbon Credit Unit (ACCU) Scheme	Price of ACCUs grows at 2% per annum in *Progressive Change*, 3 % in *Step Change* and 5% in *Green Energy Exports*.

Small-scale Renewable Energy Scheme and Large-scale Renewable Energy Target

Rooftop solar currently receives a subsidy under the Small-scale Renewable Energy Scheme whereby rooftop solar is credited with creating small scale technology certificates (STCs) which Renewable Energy Target (RET) liable entities have a legal obligation to buy. Rooftop solar purchases typically surrender their rights to these certificates in return for a lower upfront cost. The amount of STCs accredited is calculated using a formula that recognises location/climate, based on the renewable electricity generation that will occur over the life of the installation. The amount of STCs accredited to rooftop solar installation will decline over time to reflect the fact that the Renewable Energy Target policy closes in 2030 and therefore renewable electricity generated beyond that time is of no value in the scheme.

STCs can be sold to the Clean Energy Regulator (CER) through the STC Clearing House for $40 each. However, the CER makes no guarantees about how quickly a sale will occur. Consequently, most STCs are sold at a small discount directly to liable entities on the STC open market.

The Large-scale Renewable Energy Target (LRET) is a requirement on retailers to purchase large-scale generation certificates (LGCs). This represents a subsidy for large scale renewable generation but is relevant for any solar system above 100kW as they are not eligible for STCs. In this report we are interested in any solar system up to 30MW, hence the price of LGCs is a relevant driver for adoption. The requirements for the LRET are largely met within existing and under construction plant as the target currently plateaus from 2020 and remains at that level until 2030. However, the LGC price or an equivalent mechanism is expected to be maintained at least through to 2030 due to additional demand from voluntary corporate and other institutional renewable generation targets[7]. Beyond 2030 their value is expected to decline because the purpose of voluntary targets beyond 2030 will be less clear once the wider electricity system becomes less emission intensive.

Australian Carbon Credit Unit (ACCU) Scheme

Historically the government was the sole buyer of ACCUs under schemes such as The Emissions Reduction Fund (ERF) and Climate Solutions Fund. However, under voluntary schemes and a revised safeguards mechanism industry has now the largest buyer. The supply of ACCUs is developed on the basis of several methods for emission reduction under which projects may be eligible to claim emission reduction and make offers for ACCUs.

To earn ACCUs from solar generation, the relevant method in this case is the *Carbon Credits (Carbon Farming Initiative - Industrial Electricity and Fuel Efficiency) Methodology Determination 2015*. If the price of LGCs declines it may become more attractive to seek ACCUs under this method rather than LGC payments. However, this is a longer term prospect.

3.2.5 New customer financial support

Batteries have been identified as a technology that is likely to have only modest growth without additional support because they remain a high cost investment for households of around $10,000. New financial support to reduce costs for customers could come from different levels of government or the industry (e.g. retailers, DNSPs, aggregators). Financial support could be in the form of subsidies, low interest loans, rebates for participation in specific schemes (e.g. VPP) or some combination of all three. To align with the scenario narratives, it is assumed that new mechanisms are available, and their combined impact is equivalent to a 20% and 30% reduction in the upfront cost of batteries in *Step Change* and *Green Energy Exports* respectively.

3.2.6 State policy drivers

The policies discussed here are drawn from several state government websites[8]. While we summarise them all, we do not include each one specifically in the modelling where we think the broader modelling approach has already captured the driver. The approach to including them in the scenarios is outlined in Table 3-7. Feed-in tariffs are addressed separately (in the following section) since they are a mix of market forces and government regulation.

[7] Businesses buy LGCs as part of meeting their upstream 2030 corporate emission targets. These voluntary actions are in addition to electricity retailer obligations which end in 2030. Business demand for LGCs or another equivalent certificate not yet available may not end in 2030 because if it did than many businesses would need to report that their upstream emissions have increased post-2030 (unless they can find alternative offsets).

[8] https://www.energy.nsw.gov.au/households/rebates-grants-and-schemes/household-energy-saving-upgrades/sign-your-battery-virtual

https://www.energy.nsw.gov.au/households/rebates-grants-and-schemes/household-energy-saving-upgrades/install-battery

https://www.solar.vic.gov.au/solar-panel-rebate

https://www.solar.vic.gov.au/solar-battery-loan

https://www.recfit.tas.gov.au/what_is_recfit/climate_change/electric_vehicles/support

https://www.climatechoices.act.gov.au/policy-programs/home-energy-support-rebates-for-homeowners

https://www.climatechoices.act.gov.au/policy-programs/sustainable-household-scheme

https://nt.gov.au/industry/business-grants-funding/home-and-business-battery-scheme

NSW

Under NSW's new Consumer Energy Strategy: Powering our People and communities, there are subsidies available for installation of batteries. The incentive is proportional to the usable capacity of the battery in kilowatt-hours (kWh). Larger batteries will receive a larger incentive of between

- $770 and $1150 when you install a new 6.5 kWh battery
- $1600 and $2400 when you install a new 13.5 kWh battery

For existing batteries or once the battery is installed there are additional incentives to participate in a VPP scheme of between:

- $120 and $190 when you sign up a 6.5 kWh battery
- $250 to $400 when you sign up a 13.5 kWh battery

The incentive can be claimed twice, with at least 3 years in-between claims.

NSW also has a Peak Demand Reduction Scheme which awards Peak Reduction Certificates (PRCs) for each 0.1kW of demand reduction during summer peak periods. Depending on the system size and value of PRCs this could contribute a subsidy of around $1500.

Victoria

The Victorian government is providing a subsidy for solar systems of $1400 for households, $3500 for businesses and means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access the scheme. For batteries, the Victoria offers means-tested interest free loans of up to $8,800.

Large Victorian solar projects are also eligible for Victorian Energy Efficiency Certificates (VEECs). These are administratively less complex than applying for ACCUs. As with the emissions reduction fund, this potential subsidy source will become attractive only once LGC prices have declined.

Tasmania

The Energy Saver Loan scheme offers interest free loans for up to $10,000 that must be repaid in 1 to 3 years. These could apply to batteries and solar PV or any household energy saving investment.

Northern Territory

The Home and Business Battery Scheme is the key incentive available in Northern Territory. The scheme offer a $400/kWh on the cost of usable battery capacity up to a maximum of $5000 for households and businesses.

Australian Capital Territory

Under the Home Energy Support scheme eligible households (Australian Government Pensioner Concession Card, Department of Veterans' Affairs Gold Card, and Australian Government Health Care Card holders) can apply for a rebate of up to 50% (capped at $2,500) on a rooftop solar system, plus an interest-free loan to cover the remainder.

Under the sustainable Households Scheme Zero interest free loans for energy-efficient upgrades including solar and battery are available. Loans can be for $2,000 up to $15,000, to be repaid over a maximum of 10 years.

Other regions

There are currently no significant state based incentives in Queensland and South Australia. There are local council based schemes in Adelaide (20% discount on solar PV) and Randwick local councils (10% of solar PV or batteries).

Table 3-7 Summary of state policies supporting solar and batteries and their inclusion in scenarios

	Policy	Approach to including across all scenarios
NSW	Consumer Energy Strategy: Power our people	Included as a subsidy on battery costs and additional revenue from VPP participation.
NSW	The Peak Demand Reduction Scheme	Included as a subsidy on battery costs
VIC	700,000 home solar systems over ten years. Policies include a subsidy (up to a value of $1,400) including means-tested interest free loans (also available for batteries). Another feature is a landlord-tenant agreement whereby renters can also access an additional 50,000 systems.	Minimum addition of 70,000 residential solar systems per year to 2028-29 with some allowance for variation between scenarios in to reflect uncertainty and updated scheme subsidy availability (the exact subsidies available is announced annually and can vary year to year). Impact of interest free loans not included.
VIC	In the Victorian Energy Saver Incentive Scheme, embedded solar systems not claiming large- or small-scale technology certificates are eligible to create Victorian Energy Efficiency Certificates.	The value of certificates is assumed to increase 2% per annum in *Progressive Change*, 3% in *Step Change* and 5% in *Green Energy Exports*
TAS	Energy Saver Loan scheme	Impact of interest free loans not included.
ACT	Pensioners who own their home are eligible for up to 50% (with a cap of $2500) of a home solar system.	Minimum addition of 5000 systems over five years
All	State feed-in tariffs	Varied over time to converge towards generation price which is varied by scenario and outlined in Section 4.3.1

Feed-in tariffs

Feed-in tariffs (FiTs) were historically provided by most state governments to support rooftop solar adoption but have largely been replaced by voluntary retailer set FiTs for new solar customers. These legacy government FiTs are in some cases still being received by those customers who took them up when they were available.

The current FiTs set by retailers recognise some combination of the value of the exported solar electricity to the retailer and the value to the retailer of retaining a rooftop solar customer. Retailer designed FiTs vary mostly in the range of 5-10 c/kWh across most states but there are some large outliers.

The exceptions, where state government policy or state-owned retailers set the FiT, are as follows:

- Northern Territory: 9.13c/kWh for both residential and commercial customers[9].
- Queensland: Recognising lower competition, regional Queensland FiTs are set by the state government and were 12.377c/kWh from July 2024[10].
- Western Australia: From 31 August 2020, residential, non-profit and educational premises who were eligible for the Renewable Energy Buyback Scheme' for new residential solar power systems installed in Western Australia will no longer receive the Fit of 7.135 cents per kilowatt-hour. Instead, they will receive the DEBS or 'Distributed Energy Buyback Scheme' that will instead pay[11]:
    - 2 cents for each kilowatt-hour of solar electricity fed into the grid for most of the day, and
    - 10 cents for each kilowatt-hour exported from 3:00 pm in the afternoon until 9:00 in the evening.
- Victoria: The current minimum feed-in tariff of 3.3c/kWh is set by the government[12]. It applies to retailers with more than 5000 customers and generation from any renewable energy less than 100kW. A time varying feed-in rate is also available from July 2024 with prices of between 2.1 and 8.4c/kWh depending on the time of day.
- Tasmania: The feed-in tariff for residential and commercial customers is 8.935c/kWh from July 2024[13].

While not binding on retailers, the NSW government has called on NSW energy retailers to offer solar customers feed-in tariffs that meet a benchmark set by the Independent Pricing and Regulatory Tribunal (IPART). The benchmark range for the 2024-25 financial year is 4.9 to 6.3c/kWh [14]. It also advises on time of day rates ranging from 4.7 to 22c/kWh.

3.2.7 Regulations, standards and curtailment

The Australian Energy Market Commission (AEMC) can make changes to regulations which are consistent with the goals set out in relevant electricity law. In general, the electricity market rules were written at a time that did not envisage such a large and competitive role for distributed energy resources. The current customer obligations placed on networks are focussed on reliability of supply and power quality. There is no explicit statement to ensure that customers with rooftop solar can export their excess generation, although this does intersect with power quality requirements. If too many embedded solar systems try to export generation relative to local

[9] Solar Update | Jacana Energy

[10] Regulated electricity prices for regional Queensland 2023–24

[11] Energy Buyback Schemes (www.wa.gov.au)

[12] Minimum feed-in tariff review 2024–25 | Essential Services Commission

[13] Feed-in Tariffs (economicregulator.tas.gov.au)

[14] All day solar feed-in tariffs | IPART (nsw.gov.au)

demand, then voltage rises. Inverters are set to trip off solar generation once voltage exceeds the set point, which then reduces the returns to customers from owning rooftop solar.

The technical specification of many older installed inverters was not as high as they could have been to address the issue of voltage rise. Improved inverter standards, if appropriately set when installed, will contribute to reducing the occurrence of voltage issues associated with high rooftop solar exports onto the local distribution network. They provide reactive power which limits the impact of exports on voltage. However, if rooftop solar penetration is very high (the exact limit depends on the feeder), improved inverters will be unable to continually prevent voltage changes that result in inverter trip off. Also, reactive power uses 20% of the available real power and so still represents an impact on rooftop solar customer returns from a lack of distribution network capacity.

Previous projections of operational demand have identified that some states may experience negative load in the 2020s and 2030s if forecasts of rooftop and non-scheduled solar generation projections are realised. This raises the prospect that the electricity system will need to prepare contingencies for some combination of curtailment, demand management and standby generation to maintain system stability.

It is difficult to predict the electricity system reform process and subsequent impacts on customers, regarding the degree of lost solar production and exports as a result of distribution network congestion or efforts to manage state loads for stability. AEMO has indicated that, in response to feedback on this topic, they intend to manage the process of estimating optimal levels of curtailment of the system relative to the net benefits of increase penetration of consumer energy resources downstream in the ISP process. We therefore avoid double accounting of this issue and make no judgements on physical curtailment in the assumptions or projections herein.

However, we do impose a financial penalty of declining export revenues which impact the overall payback period from installing solar PV (if without storage). The declining export revenue assumption is designed to capture declining feed-in tariffs and potential export fees.

4 Data assumptions

This section outlines the key data assumptions applied to implement the scenarios. Some additional data assumptions which are used in all scenarios are described in Appendix A.

4.1 Technology costs

4.1.1 Solar photovoltaic panels and installation

The costs of installed rooftop or small-scale solar installations for each scenario is shown in Figure 4-1 and compared to previous assumptions CSIRO's 2022 projections. The updated costs are sourced from the GenCost 2023-24 final report by Graham et al. (2024)[15]. The GenCost report contains three global cost projection scenarios called Current policies, Global NZE post 2050 and Global NZE by 2050. *Progressive Change* is assigned the Current policies cost projections and *Step Change* is assigned Global NZE post 2050 cost projections. *Green Energy Exports* is assigned the fastest cost reduction projection which is Global NZE by 2050.

The 2024 costs shown imply that a 6.6kW system ought to be advertised for approximately $6,070 (6.6 × (1280-360)[16]) on average. However, we also see 6.6kW systems advertised in the range of $4000 installed (or $970/kW before subsidies) reflecting significant differences in the quality of products and the scale of installation businesses (that is, economies of scale may support discounting). However, we include the average cost estimate on the basis that the cost trajectory applied is steep enough to allow for a greater prevalence of the lower observed prices over time.

It is also evident that locations that are further from capital cities pay a remoteness premium for installations, and we have factored this in as a one third premium in low population density regions[17]. A full survey of regional market prices was not in scope.

[15] Some minor adjustments have been made to the GenCost data series. Values in the next five years are fitted to the historical series from Solar Choice and a moving average has been applied to the whole timeframe. Costs have a big impact on the shape of the projections. Moving averages are applied to cost data on the basis of removing unnecessary volatility in the projection.

[16] $1280/kW for the solar capital cost before subsidies and $360/kW for the small-scale technology certificates.

[17] Based on other CSIRO projects a premium of one third is used in more remote areas such as the Northern Territory

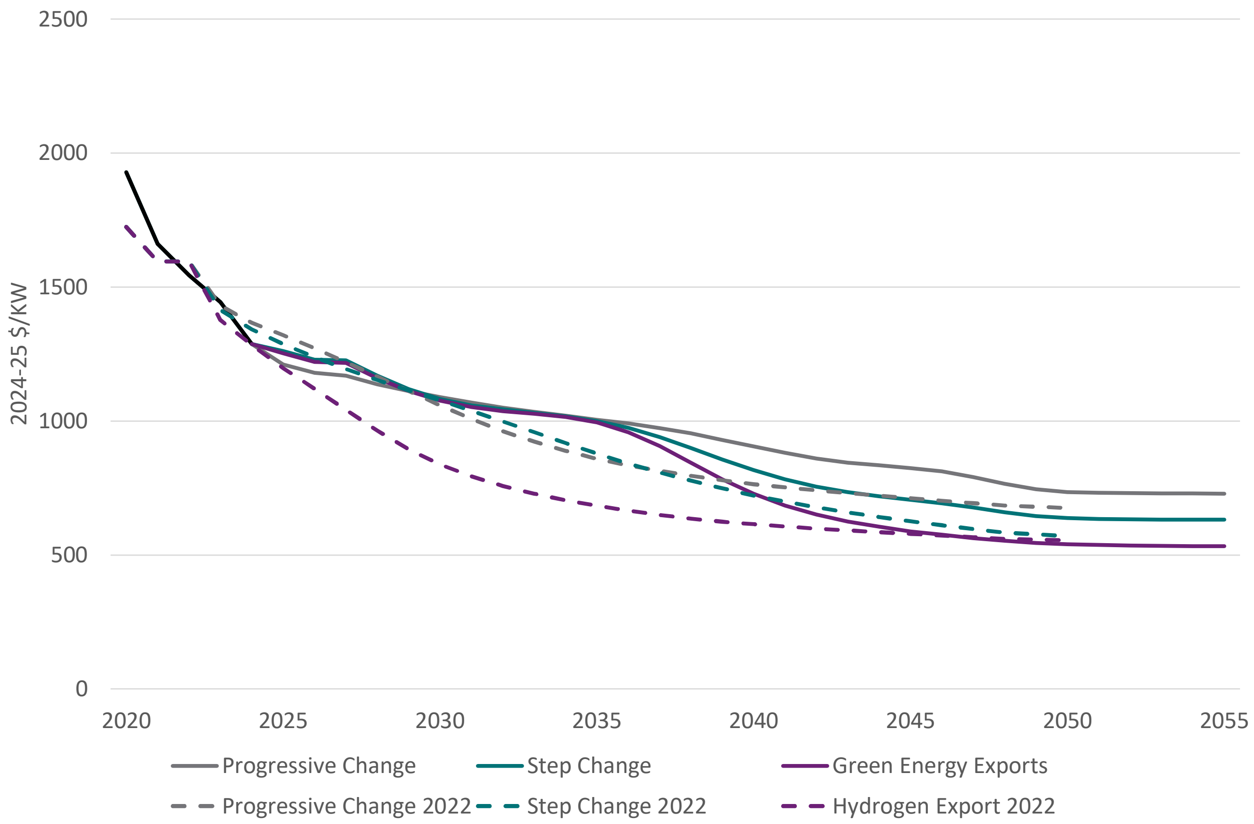


Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

4.1.2 Small-scale technology certificates (STCs)

STCs reduce the upfront cost of rooftop solar systems beyond that shown in Figure 4-1. While there is the option to sell to the STC Clearing House for $40/MWh, the value of STCs is largely determined on the open market and vary according to demand and supply for certificates. The number of certificates generated depends roughly on the solar capacity factor in different states although this calculation is not spatially detailed (i.e., involves some significant averaging across large areas). Solar generation is calculated over the lifetime, but any life beyond 2030 is not counted as it is beyond the scheme period. Over time the eligible solar generation is declining. Multiplying the eligible rooftop solar generation by the STC price gives the projected STC subsidy by state shown in Figure 4-2. These STC subsidies are assumed to prevail across all scenarios.

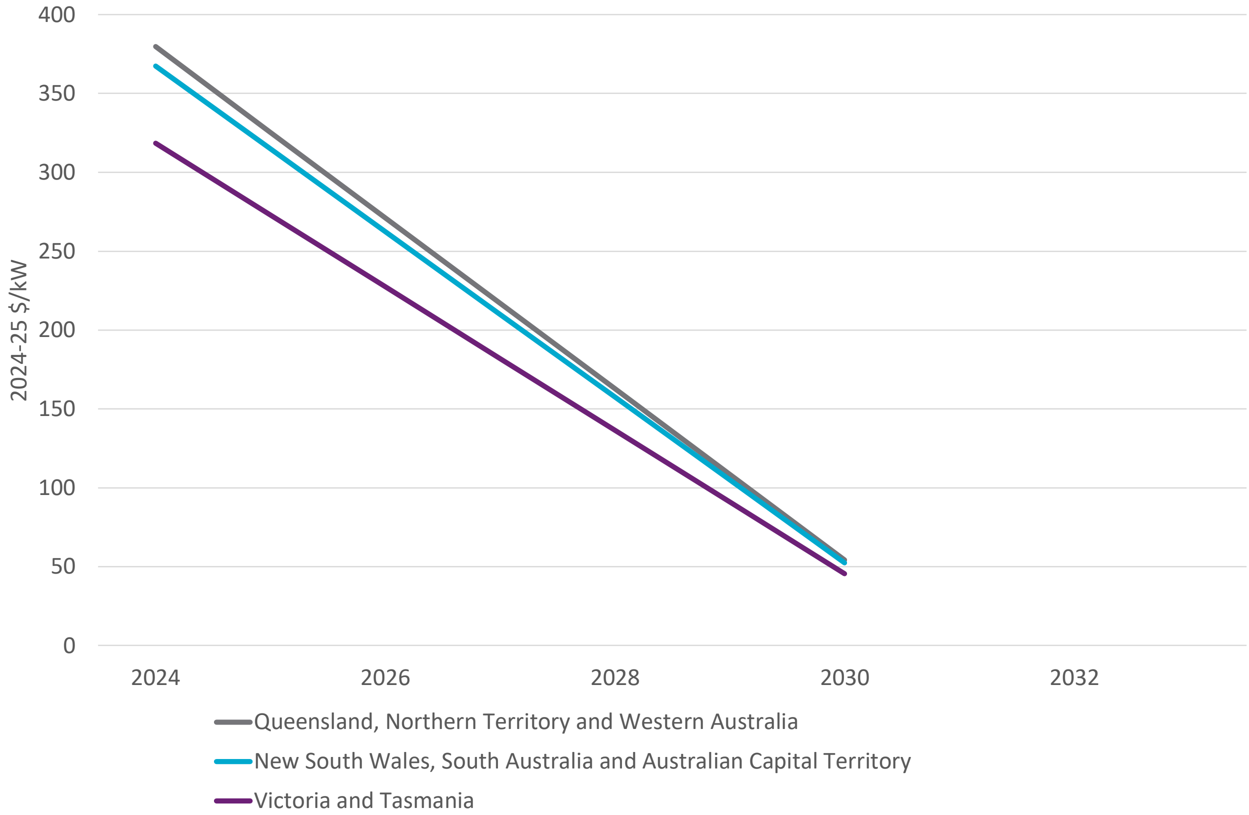


Figure 4-2 Assumed STC subsidy available to rooftop solar and small-scale solar systems by state

4.1.3 Batteries and installation

The current capital cost of small-scale batteries is sourced from Solar Choice and the projection is partially based on the trajectory of large-scale batteries in GenCost 2023-24 (Graham et al. 2024). Small-scale systems have a significant premium over large scale systems that is not as evident in the relationship between small-scale solar and large-scale solar. If this premium were too narrow over time, the cost reduction for small-scale batteries would be faster than the large-scale solar cost reduction rate. However, so far there is no sign of this potential phenomenon, and it is not included in the assumptions[18].

The large-scale battery trajectory includes a more rapid reduction in costs in the first decade of the projection and flatter thereafter. However, given the uncertainty in the relationship to large scale batteries, a more linear trajectory has been imposed for small-scale batteries, converging to a common flatter trajectory by 2050. This makes for a slightly higher trajectory than in the 2022 projections. However, small-scale battery costs are similar or lower by 2050 in the updated cost projections.

The scenarios are assigned to the corresponding GenCost cost projection scenarios in the same way as solar - *Progressive Change* to current polices, *Step Change* to Global NZE post 2050 and *Green Energy Exports* to Global NZE by 2050. *Progressive Change* costs are initially lower than *Step Change*. This reflects the assumption in GenCost that *Step Change* will face stronger supply chain

[18] That is, we calculate the premium for small-scale batterie and maintain that premium when drawing on the large-scale battery projection.

constraints due to faster deployment of low emission generation and storage technology. *Green Energy Exports* also has similar supply chain constraints but in that scenario cost reductions due to learning by deployment outweigh that factor.

These are upfront battery capital costs and do not take account of degradation or cost of disposal at end of life. Asset life and degradation assumptions are included in the modelling and are outlined in Appendix A. Currently most batteries can be sent to battery collection points at end of life free of charge. Lithium-ion battery recycling facilities have emerged in countries that have more mature battery deployment (e.g. Norway which has a large electric vehicle fleet as the feedstock source). The lithium recycling industry in Australia will not be able to reach scale until there are more end of life batteries to recycle therefore it is difficult to say whether there will be any new charges associated with their recycling. Consequently, at this point it is not appropriate to add any battery disposal costs.

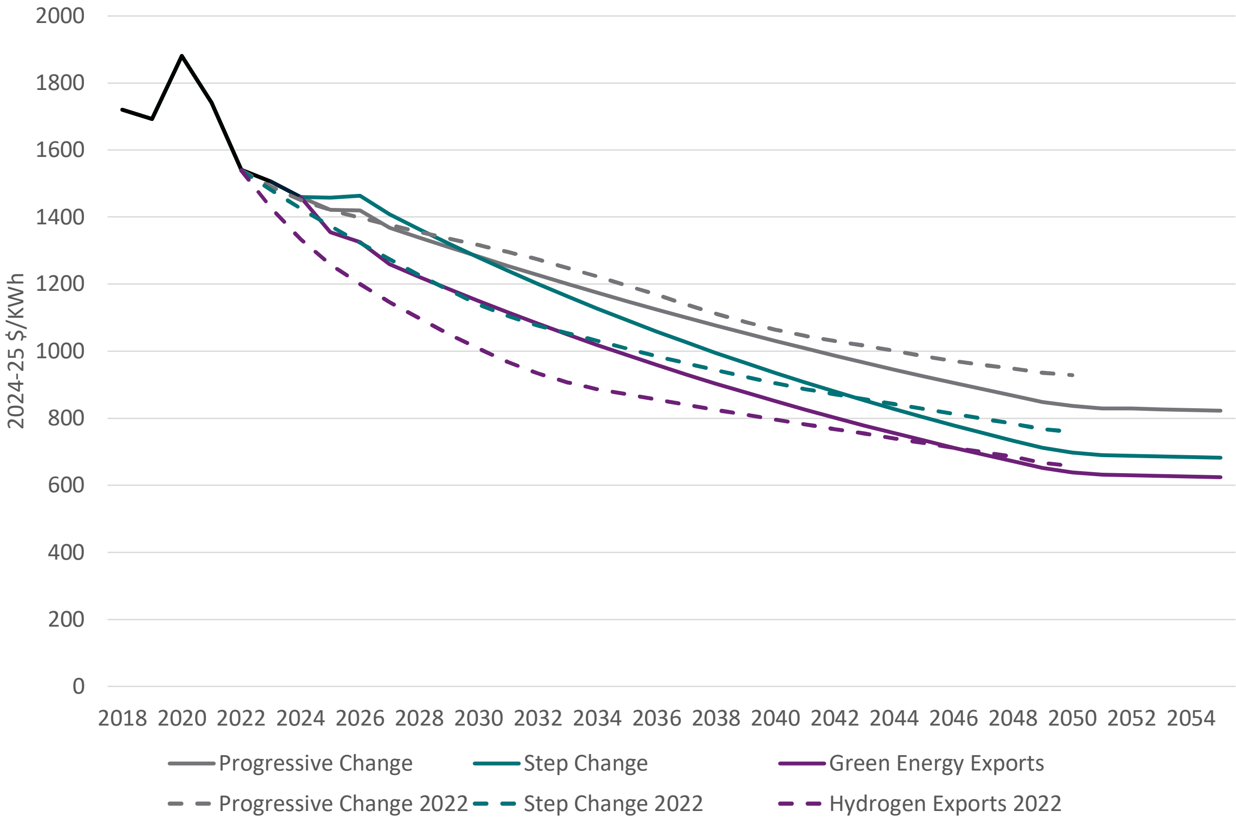


Figure 4-3 Assumed capital costs for battery storage installations by scenario

4.2 New solar system sizes (less than 100kW)

Assumed new residential and commercial new solar system sizes as shown in Figure 4-4 and Figure 4-6 and compared to the 2022 projections. These are the size of the panels, while inverters are the same size or smaller. We impose a trend in 2025 and then impose different assumptions by scenario from 2026 to 2050.

Residential rooftop solar systems are advertised with panel to inverter capacity ratios greater than 1. This likely reflects the fact that subsidies are available on rooftop solar capacity. Licensing conditions for installers require that the inverter is no less than 75% capacity of the solar panels. For example, a 6.6kW solar panel with a 5kW inverter meets this criteria. The average for new residential systems has been above 6.6kW and sits at 8.6kW in 2024[19] (averaged over those systems deployed in that year). This continued increase in residential system sizes supports an assumed increasing trend in the next 5 to ten years. However, over the longer term we assume system sizes will plateau and there are a number of considerations supporting that (Figure 4-5).

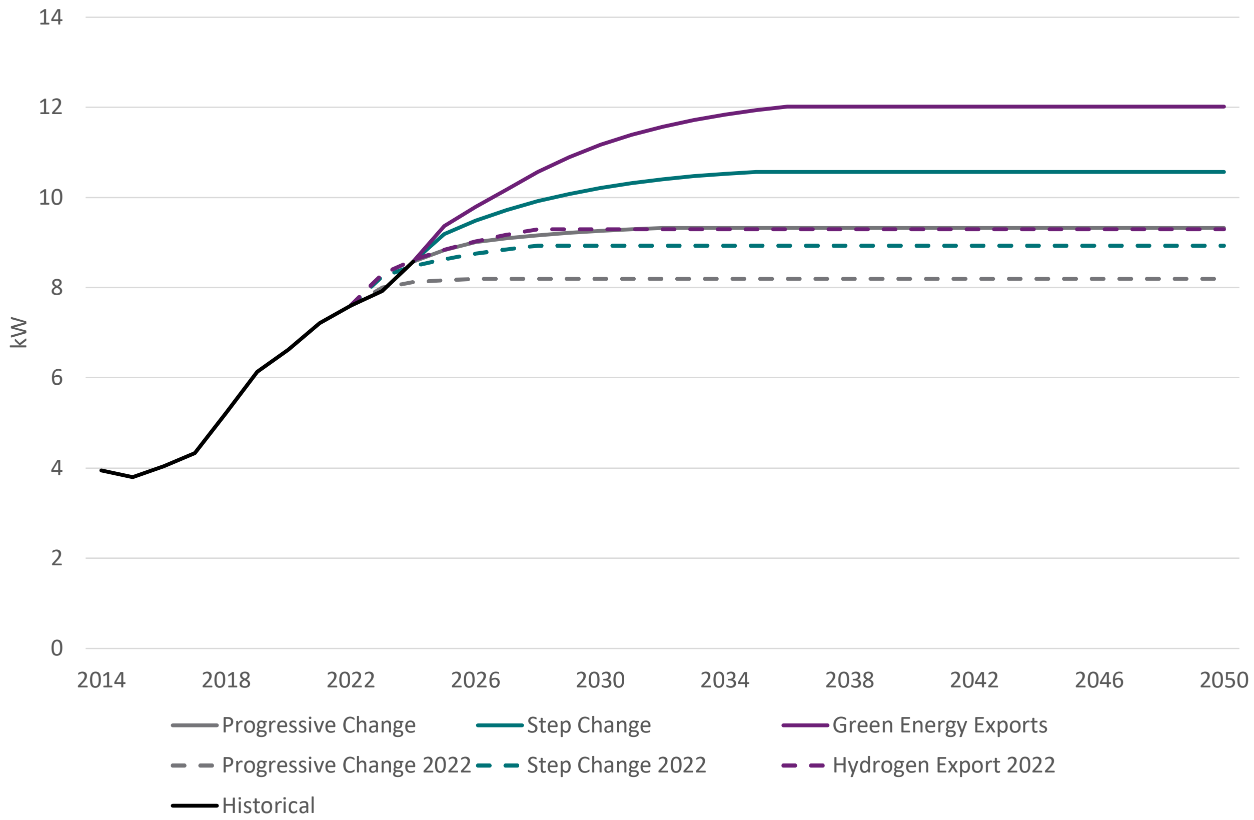


Figure 4-4 Historical and assumed future size of new residential solar systems

Many networks impose a connection limit of 5kW per phase and these may tighten in the future as hosting capacity (the ability of the system to support more distribution connected solar generation without crossing desired power quality thresholds) declines. Dynamic connection levels are also being explored as an alternative, but these also represent a message to consumers that they cannot always use their full capacity for export. A maximum of three phase indicates a ceiling of 15kW. But given some houses will have fewer phases the maximum is probably closer to 12kW[20]. Physical roof size is of course another limit to maximum average system size. However, we expect that with lower solar panel costs and improving panel efficiency, acceptance of the use of non-north facing roof areas will continue to grow.

Government subsidies per watt of solar power capacity are declining (see also discussion of STCs in the body of the report) and being replaced with fewer rebates or low interest loans. A 10kW system would provide around 13,000kWh per annum which is more than an average household

[19] Noting that the public CER data does not differentiate between residential and commercial systems and so the 6.6 threshold was crossed around 2017 from a combined residential and commercial systems perspective

[20] Unless all houses upgrade to three phase or run the solar systems with a panel to inverter ratio higher than 1. A ratio higher than 1 makes sense for smaller systems which will have lower output in winter. However, it makes less sense at 15kW given this is significantly more than household needs, even with electric vehicles.

can use per annum, even considering an expected 50% increase in electricity consumption due to adoption of electric vehicles (average household consumption is currently around 6000kWh). Storage will be more prevalent in the long run and can assist in increasing own consumption but does not create significant new demand as storage losses are low. It is also limited in how much solar energy it can shift (typically 2 hours) without significantly more expense. Larger systems therefore imply significantly more exports at a time when the value of exports are expected to decline owing to congestion and possible export fees.

Based on these drivers, we assume the recent increasing system size trend will continue for 5 to 10 years but ultimately saturate in the long run. For residential customers, *Green Energy Exports* saturates at 12kW, *Step Change* at 10.6kW and *Progressive Change* at 9.3kW. These saturation levels are significantly higher than those assumed in the 2022 projections. The higher outlook for system sizes is justified on the basis that while the historical trend was showing signs of slowing by 2022, additional data to 2024 indicates a stronger growth trend.

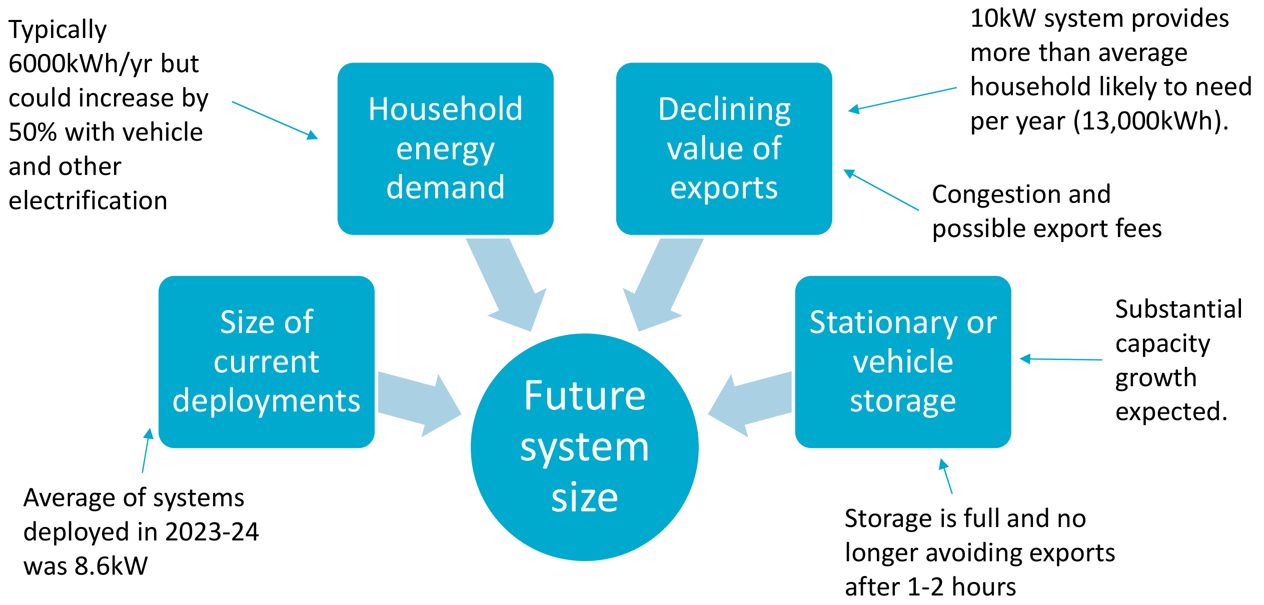


Figure 4-5 Summary of drivers of future solar PV system size

For business customers, while we impose an average trend across all customers, we assume that individual customers will continue to match their solar systems to meet local needs such as supplying their average daily peak-period load. That is, they may be less focussed on earning export revenue, but rather reducing their peak-period time of use charges which are more prevalent in business retail tariffs. For these reasons commercial solar system sizes are assumed to plateau from the beginning rather as part of slowing trend over time in residential systems.

Setting the level of business solar PV systems has been difficult due to the volatility of the historical system sizes. A growing trend was evident until 2019 but that has been reversed with falling system sizes in the remaining historical years[21]. For the 2022 projections the preceding

[21] This higher volatility in commercial system size trends likely reflects the relatively unconstrainted nature of commercial solar PV relative to household solar PV where land and roof space is available at a greater premium.

growth trend was given more weight. However, with an additional two years of data, both with lower average system sizes, the updated projections are set at a significantly lower level.

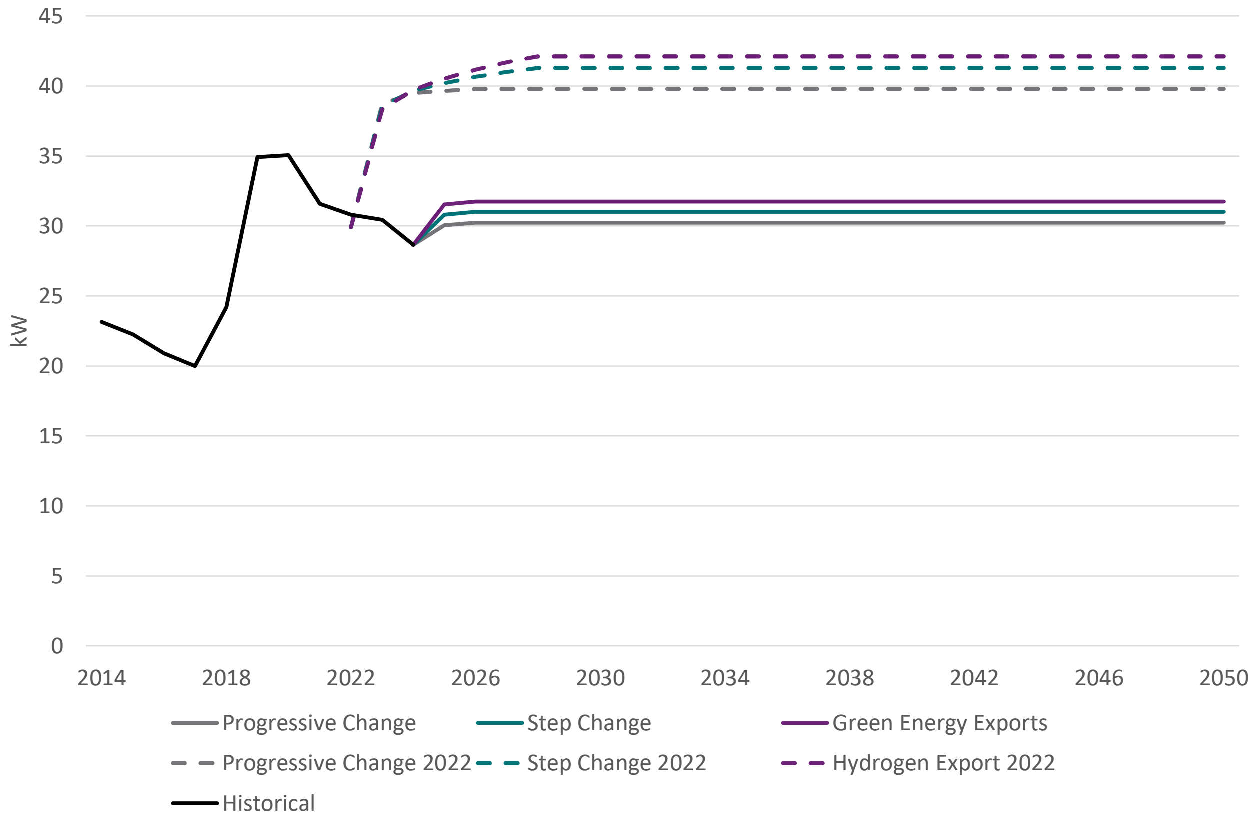


Figure 4-6 Historical and assumed future size of new commercial solar systems

4.3 Electricity tariffs, battery management and virtual power plants

4.3.1 Assumed trends in retail and generation prices

Retail electricity prices increased significantly in 2022 to 2024 reflecting the impact of the Ukraine War on global fossil fuel prices which flowed through to domestic generation costs. Other factors such as generator outages also played a part. Global fossil fuel prices have declined but it will take some time to unwind their impact into forward electricity prices and hedging positions. Some modest increases in generation and retail prices are assumed later in the projection period as higher electricity generation prices are required to support investment necessary for replacement of retiring generation capacity and to meet new demand growth. The non-generation components of the retail price are expected to be more stable. Transmission costs may increase due to higher investment in that sector to connect renewable energy zones and strengthen the system overall. However, transmission is a small proportion of current retail bill and costs are amortised over 50 years such that current costs mostly reflect past expenditure. Therefore, there will be no sudden increase from this bill component.

Retail electricity prices in Western Australia are set by government and are therefore less volatile. Commercial retail prices are assumed to follow residential retail price trends for all scenarios, although under different tariff structures.

Day time generation prices and feed-in prices

Day time generation prices are important as a long-term anchor point for feed-in tariffs. Feed-in tariffs do not have to reflect daytime generation prices as retailers will have their own pricing strategies for recruiting and retaining customers. This can mean export prices are higher than their wholesale value. Other issues like changes in tariff structures (e.g., export fees) and curtailment also impact the export revenue. Based on unpublished CSIRO electricity modelling of similar scenarios, we have made assumptions about the long-term trajectory of rooftop solar PV production weighted generation electricity prices, and we use the financial impact of this assumption to capture all of the broad range of factors that are likely to reduce the value of exports.

We assume that feed-in prices will converge towards their state rooftop solar PV production weighted price which, by 2050, on average, will fall by the amounts shown in Table 4-1. *Progressive Change* has the greatest impact because it has low system demand growth. The decrease in daytime prices is the least in *Green Energy Exports* because it has a large hydrogen industry which is expected to match some of its load to supply countering the dampening effect of coincident large- and small-scale solar output on prices. *Step Change* has high solar PV deployment, but stronger demand is also assumed to partially offset this factor.

Table 4-1 Assumed reduction in rooftop solar production weighted wholesale market prices by 2050

Scenario	Reduction
Progressive Change	50%
Step Change	40%
Green Energy Exports	33%

4.3.2 Current electricity tariff status

Electricity tariff structures are important in determining the return on investment from customer adoption of EVs and, perhaps importantly for the electricity system, how they operate those technologies. One type of tariff structure that residential and business customers have is 'flat' tariff structure which consists of a daily charge of $0.80 to $1.20 per day and a fee of approximately 20 to 30c for each kWh of electricity consumed regardless of the time of day or season of the year. Customers with rooftop solar will have an additional element which is the feed-in tariff rate for solar exports. Customers in some states have an additional discounted 'controlled load' rate which is typically connected to hot water systems.

The second group of tariffs are 'time-of-use' (TOU) or 'demand' tariffs with TOU being more common. In addition to a daily charge, TOU tariffs specify different per-kWh rates for different times of day. Demand tariffs impose a capacity charge in $/kW per day in addition to kWh rates (with the kWh rates usually discounted relative to other tariff structures). Demand tariffs are more common for larger businesses. TOU and demand tariffs may also be combined. Both types of tariff structures seek to provide signal that there are times when it is more expensive to supply electricity. These tariff structures are not perfectly aligned with daily wholesale market price fluctuations but are a better approximation of wholesale price than a flat tariff. In that sense, TOU and demand tariffs are also described as being more 'cost reflective' or 'smart' tariffs.

Some consumer advocates have argued, however, that TOU tariffs are not cost reflective of network costs which make up a similar proportion to wholesale costs in retail bills. Network costs do not vary by the time of day like wholesale prices. In some cases, reducing customer demand at peak times is not beneficial to networks where the customer is located in an area that has significant capacity above peak demand. It may only have some value in the long run if demand eventually rises in that network zone.

Distribution networks have led a growing trend of assigning customers to TOU tariffs. Network tariffs are the tariffs that networks charge retailers for use of their system. In most cases networks are increasingly charging retailers a TOU tariff for residential customers and the share of customers assigned to cost reflective tariffs has risen sharply in recent years (Figure 4-7). Retailers are not obliged to pass this network tariff structure through in their retail tariffs and there are no publicly available statistics on TOU share of residential customer retail tariffs.

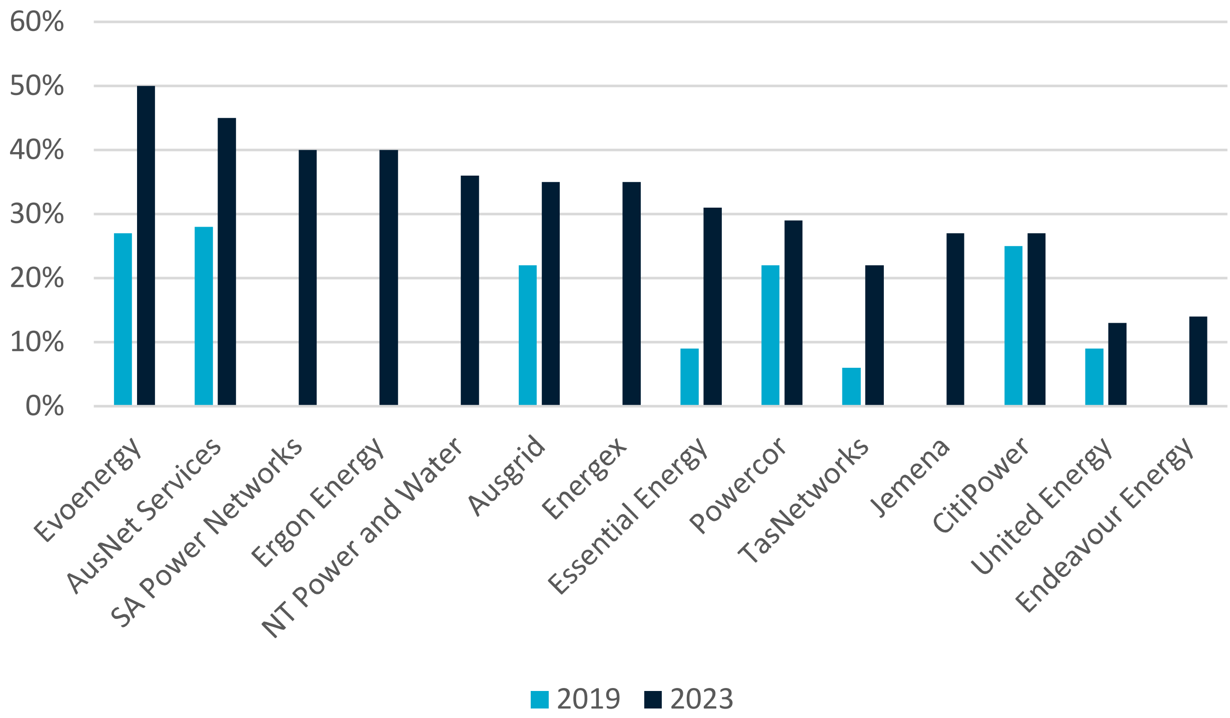


Figure 4-7 Change in the share of residential consumers assigned to cost reflective tariffs by electricity distribution networks, AER (2024)

Access to smart meters are a technical limit on the full roll out of TOU tariffs since older meters are not capable of recording daily electricity usage patterns[22]. However, smart meters have also been increasing rapidly in recent years outside Victoria (Figure 4-8). Victoria already has complete coverage of smart meters due to an earlier statewide change over. It is therefore interesting that Victoria has some of the lowest cost reflective network tariff assignment. This reflects the fact that, under the rules of the statewide change over, Victorian customers had to opt-in to TOU

[22] Instead they accumulate electricity consumption and are read manually once a quarter.

tariffs. However, in other jurisdictions, customers are assigned cost reflective tariffs when they have a smart meter and have to opt-out.

Figure 4-8 Change in the share of residential consumers with smart meters in non-Victorian states and territories

Some customers with home batteries have also participated in virtual power plant (VPP) trials where battery owners are rewarded for system controlled battery charging and discharging. AEMO (2021) reported that around a quarter of all registered battery owners had participated in trials. With some trials ending, this share is now estimated at 14%[23]. While there is a decrease in participation after the trials, these behaviours indicate that battery ownership is a facilitator for customer adoption of more complex tariffs. This likely reflects that customers are less invested in how their batteries operate (of all home appliances, their daily operation does not impact directly on household amenity and comfort).

4.3.3 Future developments in battery owner incentives and management

Changes to customer connections and network charges to retailers are the main policy arrangements in place for changing the tariff structures that battery owners face. Historical research has shown that customers do not necessarily want more complicated tariffs[24] but there are clearly cases, such as in the recent VPP trials, where customers are willing to adopt new approaches. Retailers have already demonstrated success in offering cost savings for battery owners to charge and discharge at times that are lower cost for the system and reward owners.

There are long term issues with relying too heavily on TOU tariffs as the main incentive and control mechanism. Once batteries reach a greater critical mass, TOU tariffs will result in new peak

---

[23] SunWiz

[24] Stenner et al (2015) provide further insights on customer's responses to alternative tariffs.

charging behaviours during the transition from peak to off-peak pricing. Consequently, this report also considers the eventual increasing use of more direct control measures such as VPP arrangements.

This report does not outline the operation of VPPs under direct control schemes – this is estimated by AEMO in their market modelling. CSIRO only estimates the number of batteries participating in such schemes and their participation, in turn, influences battery uptake as it can represent improved payback from battery ownership.

Simulations by CSIRO indicate that, in order to have no increase in their electricity bill, battery owners would need to be compensated an average $15 per year to participate in 10 half hour calls which discharge all available capacity (mainly in the period 6pm to 10pm). This indicates the minimum battery owners would need to be compensated but not what they would accept. Also, this calculation only values their energy, but they could provide other services to the system. AEMO (2020) found in one trial that an energy services company operating a VPP for the purposes of participating in the FCAS market could earn an average $78.52 per month per participating household in South Australia[25]. In a fully commercial project, the proportion of this revenue that might be shared with the owner of the batteries is unknown.

In reviewing various VPP contracts the terms vary considerably. Some offer rebates on battery purchases, others offer an upfront joining fee and ongoing monthly or event based credits. Others offer generous feed-in tariffs for energy from the battery of around 40c/kWh. Some have a combination of feed-in tariffs and credits.

For the purposes of projecting uptake of batteries, our simplified assumption is that, an incentive equivalent to around $250 per year in all scenarios is available to residential customers (i.e., implemented as a rebate) and a higher amount for commercial customers proportional to their battery size.

For those customers on flat tariffs, customers will set their battery to solar shifting mode which has two key principles:

- If solar exports are detected and the battery is not full, charge
- If electricity imports are detected and the battery is not empty, discharge.

This is a relatively simple onsite algorithm to implement and generally comes as part of the battery manufacturer's standard available settings. Those on a TOU tariff will add more complicated rules which are designed to minimise their exposure to peak price periods, discharging the battery during peak pricing periods and occasionally charging the battery from the grid during off-peak times (not just from solar generation) to ensure the battery is full prior to peak pricing periods.

The assumed proportion of customers on each tariff contract type and the subsequent battery storage operating mode by scenario is shown in Table 4-2. The tariff assignments are CSIRO's judgement of the combined impacts of the payback available from participating in each tariff type,

[25] This period did include some significant market events and so may be the higher end of the possible range.

the outcome of increasing assignment of cost reflective network tariffs and smart meter uptake and the long term needs of the electricity system[26].

Relative to the 2022 projections the flat tariff or solar shift share of battery operating modes has been decreased to recognise the strong growth in allocation of network cost reflective network tariffs (predominantly TOU). However, we assume there is not a perfect pass through of these tariff types by retailers. Furthermore, with more customers participating on TOU tariffs, this increases the need to eventually shift them to VPP contracts to avoid growing coincident charging behaviour. This gradual transition was already accounted for in the 2022 projections but is slightly increased in the updated shares.

Table 4-2 Assumed proportions of tariffs and subsequent battery storage operating modes by scenario

		Flat tariff (Solar shift mode)		Time-of-use tariff		VPP contract (Aggregated mode)	
		Residential	Commercial	Residential	Commercial	Residential	Commercial
2030	Progressive Change	31%	34%	54%	51%	15%	15%
	Step Change	23%	27%	54%	51%	23%	23%
	Hydrogen Export	17%	20%	55%	52%	28%	28%
2050	Progressive Change	10%	11%	64%	64%	25%	25%
	Step Change	6%	7%	48%	48%	45%	45%
	Hydrogen Export	6%	6%	39%	38%	55%	55%

4.3.4 Community batteries

Community batteries are an emerging type of battery that can complement household and utility-scale batteries. A community battery is a shared battery system located in a neighbourhood and enables customers to store excess electricity generated by rooftop PV which the community can use later (e.g., in the evenings) to reduce the need to import electricity from large coal generators. Additionally, a community battery can be used to support the operation of the local distribution grid. Network support services include demand management and reducing adverse effects on the local grid due to surges of rooftop solar PV, therefore reducing the need for network upgrades.

Community batteries have been included in the projections for the first time as commercial battery systems. In Appendix B of CSIRO's 2022 projections (Graham and Mediwaththe, 2022) we outlined a number of community battery projects that were completed or planned. These are now in the historical data for large commercial batteries. Going forward the key growth in community batteries is from the commonwealth government. In the October 2022 Federal Budget, the government provided $200 million for the Community Batteries for Household Solar Budget Measure to deploy 420 community batteries across Australia for a total of up to 281MWh of storage capacity. Of this, $171 million was allocated to ARENA to deliver at least 342 batteries,

[26] This is not to suggest investors in batteries are not obliged to consider the electricity systems needs. However, whatever outcome most supports the electricity system needs is likely to offer the greatest rewards to consumers.

with the remainder being delivered by the Department of Climate Change, Energy, the Environment and Water (DCCEEW). Only a fraction of this funding has been allocated but it is assumed most of these batteries will be deployed in the next two years.

Challenges for implementing community batteries

Although there are widely accepted socio-techno-economic benefits of community batteries, deploying this type of battery system faces challenges. The key challenges for community batteries are:

- Management of service contracts to multiple parties, e.g., retailers, DNSPs and/or other third parties (e.g., a local council, a community group, a private investor). This is particularly challenging in the disaggregated NEM. For instance, operating the battery for network support services by a DNSP and operating the battery for market/customer retail services by a retailer at the same time.
- Balancing the provision of services among multiple parties to benefit all stakeholders (customers, DNSPs, retailers, and other third parties like local governments or community energy groups etc) and ensuring the benefits are distributed fairly among all stakeholders
- How best can DNSPs procure the services that storage can provide from non-distributor-owned storage within the current framework
- Social acceptance challenges are also potential due to the lack of community confidence in transparency, fairness and trust in the energy sector business models

In addition, ownership-related challenges include:

- DNSPs in the NEM can own a battery system to provide distribution network services (voltage management and/or electricity demand management), but cannot use a battery to provide contestable services (electricity retail services, customer side generation solutions such as batteries and solar, energy consultancy services) mainly due to the *ring-fencing guideline*
- Retailer-owned models face challenges in social acceptance due to the lack of community trust and transparency of existing retail market models including pricing
- Local council or community groups do not have the resources and expertise to manage the storage asset (the possible workaround would be to contract a third party such as a DNSP or a retailer)

Battery ownership and business models

Primarily, three community-battery ownership models have been identified and are being trialled by the industry:

- DNSP-owned model
  - DNSP incurs the capital investment, battery maintenance and operational costs
  - Priorities of the battery operation would be to achieve network support, including network capacity and power reliability
  - The DNSP can lease the battery capacity to a retailer where the retail partner can provide customer offerings and the market services incl. FCAS or wholesale spot market energy trading

    – Customers may buy any product related to the battery via the retailer
- Third-party owned model
    – A third party can include either a community-based organisation or a local government or a not-for-profit entity. A third party owns and operate the battery and incurs all the capital investment, maintenance and operational cost of the battery
    – A third party may operate the battery in response to the requests for network support services
    – Also, the capacity can be leased to a retailer or market services incl. FCAS and wholesale arbitrage
    – To offer customer-related products, the third party can partner with a retailer
- Retailer or DER aggregator-owned model
    – A retailer or a DER aggregator is the owner and operator of the battery and incurs battery capital investment, maintenance and operational costs
    – The battery can be operated to respond to the requests of network support services
    – Also, the battery can be used to trade energy in the wholesale electricity market
    – The retailer or the aggregator can provide a *virtual battery service* directly to customers

Although ownership models have been identified, the lack of viable business models for operating a community battery is a significant barrier to wider commercial uptake of community batteries.

4.4 Income and customer growth

4.4.1 Gross state product

Gross state product (GSP) assumptions by scenario are presented in Table 4-3 and these are provided by AEMO and their economic consultant. These assumptions have been applied to project income growth which is relevant for calibrating adoption functions where income is part of the adoption readiness score. However, in our projection methodology, movement along the adoption curve is largely driven by factors other than economic growth. As such, economic growth assumptions have only a marginal impact on projections (for more discussion see Section **Error! Reference source not found.**). Economic growth is generally weaker than the 2022 projections.

Table 4-3 Average annual percentage growth in GSP to 2050 by state and scenario, source: AEMO and economic consultant

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory
Progressive Change	1.4%	1.5%	1.5%	1.0%	1.2%	1.0%	1.4%
Step Change	1.8%	2.0%	1.9%	1.5%	1.6%	1.4%	1.8%
Green Energy Exports	2.6%	2.8%	2.6%	2.2%	2.3%	2.1%	2.5%

4.4.2 Customer connections

Customer connections growth assumptions by scenario are shown in Table 4-4. These assumptions are relevant for establishing the current market share of solar and batteries per customer connection and converting projected adoption shares back to number of installations. Customer connections is slightly higher than the 2022 projections owing to stronger population growth assumptions.

Table 4-4 Average annual percentage rate of growth in customers to 2050 by state and scenario, source: AEMO and economic consultant

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory
Progressive Change	1.1%	1.5%	1.5%	0.7%	1.6%	0.5%	1.4%
Step Change	1.4%	1.7%	1.6%	0.9%	1.7%	0.6%	1.6%
Green Energy Exports	1.5%	1.8%	1.7%	1.0%	2.0%	0.7%	1.7%

4.5 Separate dwellings and home ownership

Owing to rising land costs in large cities where most residential customers reside, there is a trend towards building of apartments or town houses, compared to detached houses (also referred to as separate dwellings in housing statistics). As a result, it is expected that the share of separate dwellings will fall over time in all scenarios (Figure 4-9). This assumption does not preclude periods of volatility in the housing market where there may be over and undersupply of apartments relative to demand. The assumptions have been provided by AEMO and their economic consultant.

AEMO’s economic consultant does not provide home ownership projections. Home ownership projections are shown in Figure 4-10 with home ownership assumed to be higher the stronger the economic growth and climate policy ambition on the basis that these outcomes are more likely the more affordable the level of housing costs. If housing is less affordable then it will be more difficult to attract labour to the required locations and there will be less political support for higher order concerns such the health of the environment.

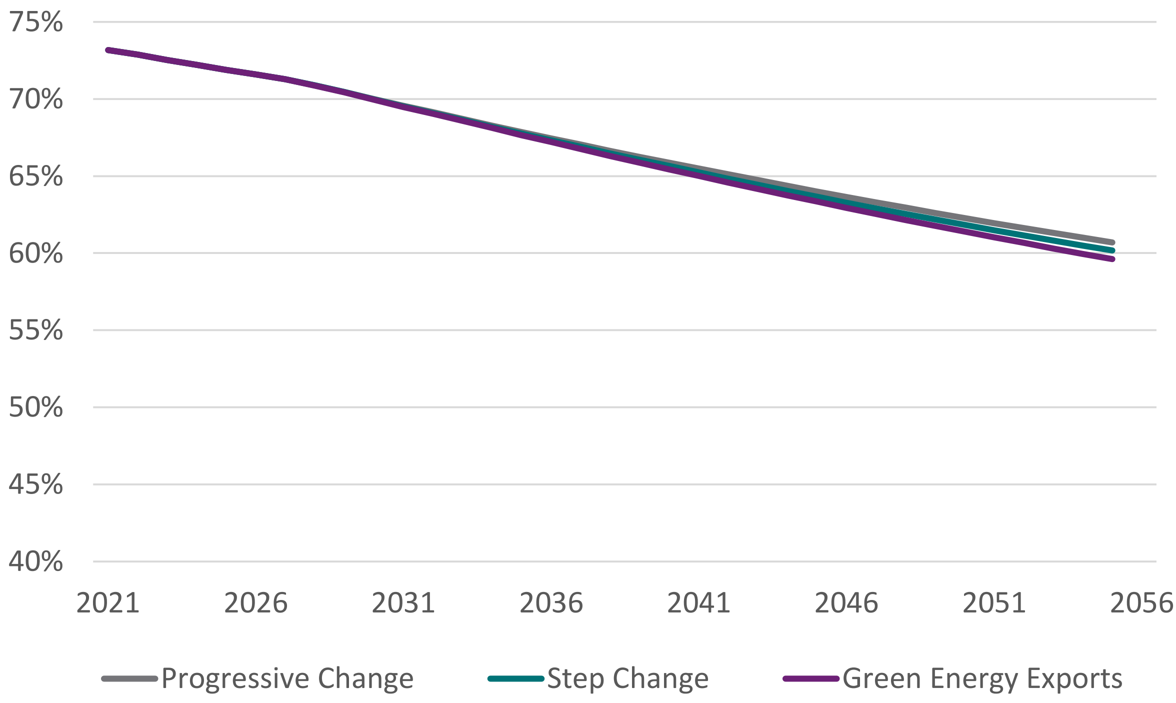


Figure 4-9 Assumed share of separate dwellings in total dwelling stock by scenario

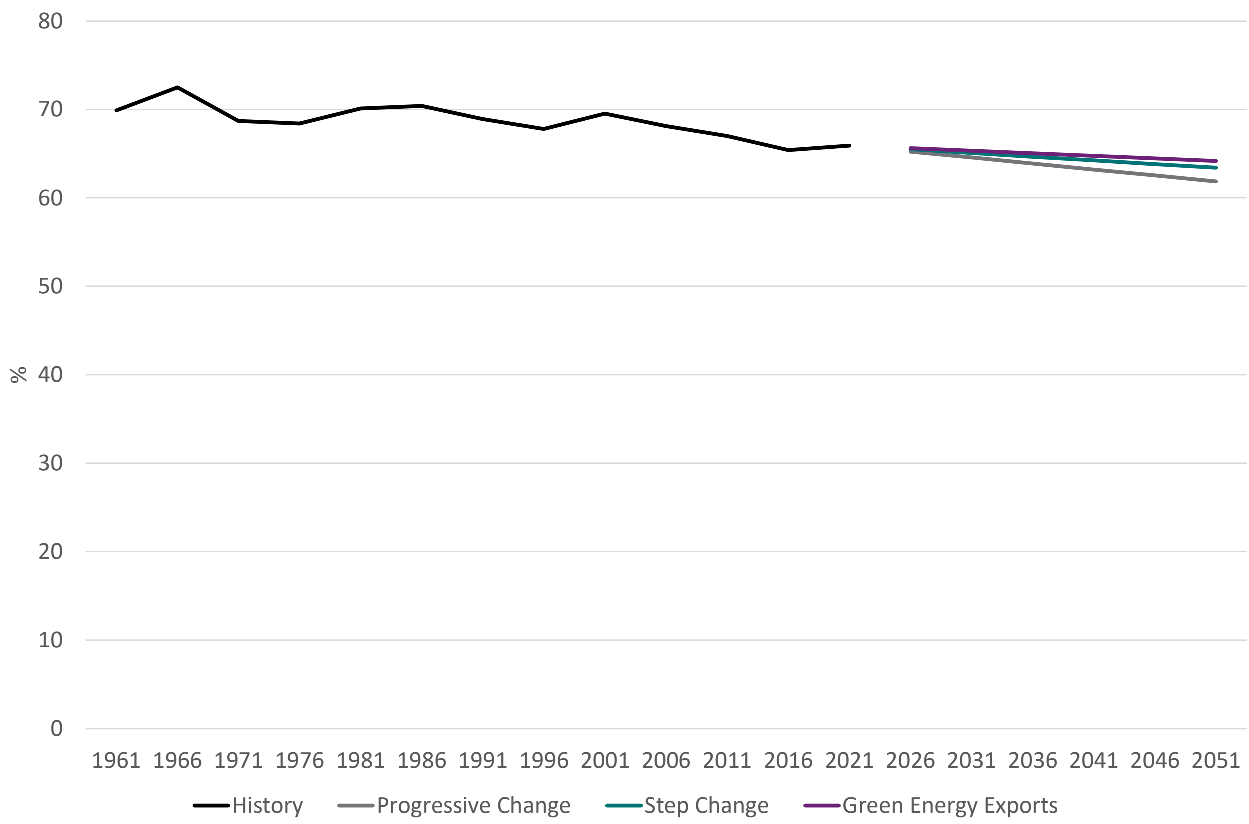


Figure 4-10 Projected home ownership rates by scenario

4.6 Rooftop solar and battery storage market segmentation

For both residential and commercial customers, the market that can most easily adopt rooftop solar are those with a separate owner-occupied building. Multi-occupant buildings or those that are not owner-occupied require more complex arrangements (business models) to extract and share the value of rooftop solar. This latter group is therefore a smaller market segment. Table 4-5 and Table 4-6 outline the size of each market segment by scenario and their implications for the overall size of the rooftop solar market. The assumptions are based on housing and ownership data discussed elsewhere in this report. The availability of commercial building data is not as good as residential, and consequently there is greater uncertainty in those assumptions.

The market share limits are imposed on average. However, the modelling allows individual locations (modelled at the postcode level) to vary significantly from the average according to their demographic characteristics.

The battery storage market is assumed to be a subset of the rooftop solar market since the main motivation for storage is improving the utilisation and financial returns from rooftop solar. In reality, there may be a small residential and commercial battery only market. For example, commercial customers may use storage to minimise capacity costs, particularly in the South West Interconnected System (SWIS) where capacity market costs are shared out according to customer contribution to demand peaks.

We impose the rooftop solar maximum market shares on the batteries' adoption curves. However, since the payback period for solar with integrated batteries lags behind the level of solar alone, in practice, batteries only reach a fraction (between a third to three quarters depending on the scenario and period) of the total addressable market (all solar owners) in the projections[27].

[27] In some states the payback period for a solar and battery system can eventually match that of a solar only system, however, it would still take many years beyond the projection period to fully saturate the solar owner's market.

Table 4-5 Non-financial limiting factors and maximum market share for residential rooftop solar

		Progressive Change	Step Change	Green Energy Exports	Rationale/formula
Limiting factors					
Separate dwelling share of households	A	62%	62%	61%	AEMO and consultant
Share of homeowners	B	62%	63%	64%	Based on historical trends
Multi-occupant buildings able to set up internal retailing of solar	C	10%	15%	18%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	5%	6%	9%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		54%	60%	66%	Formula=(A*B)+C+D

Table 4-6 Non-financial limiting factors and maximum market share for commercial rooftop solar

		Progressive Change	Step Change	Green Energy Exports	Rationale/formula
Limiting factors					
Separate dwelling share of businesses	A	38%	40%	43%	Data limited. Scenario assumption
Share of business building owners	B	27%	28%	29%	Data limited. Scenario assumption
Multi-occupant buildings able to set up internal retailing of solar	C	5%	10%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	5%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		18%	26%	35%	Formula=(A*B)+C+D

5 Projections results

The projection results are presented in terms of megawatts (MWs) or megawatt hours (MWhs) after taking account of capacity degradation. While historical data is commonly reported in terms of non-degraded or nameplate capacity, only the capacity after degradation matters for forecasting and planning of electricity system generation and demand.

CSIRO's projections are one of two sources of solar PV and battery projections commissioned by AEMO. AEMO will also occasionally rebase commissioned projections when new historical data becomes available. As such, none of the current or previous projections presented will necessarily align directly with the final projections published by AEMO. In its published work, AEMO will usually provide a table that indicates which projection source it has used, whether it has used it directly or some other alternative method (for example, an average of the two sources).

With this context, our approach in this section is to use the CSIRO 2022 projections (Graham and Mediwaththe, 2022) as the key source of comparison to the current projections rather than an AEMO source document. CSIRO's previous projections use the same modelling approach. The 2022 CSIRO projections provide the best basis for understanding how changes in the scenario assumptions have impacted the projection.

The projections include all solar capacity from residential and business systems up to 100kW as well as non-scheduled generation greater than 100kW to 30MW. In some figures and text, we group up all sizes less than 30MW. In others we may only include residential or business roof mounted systems 100kW and below. In others we may focus on greater than 100kW to 30MW systems which are more likely to be ground mounted.

5.1 Small-scale solar PV

5.1.1 Year ahead projection

As discussed in the methodology section, we use trend extrapolation to project to the end of 2025. To create diversity between the projections we also overlay an assumed uncertainty range across the scenarios. In the 2022 projections we added mostly upside uncertainty to the trend. However, in these updated projections we allow more even potential for upside and downside annual change to reflect that the last time capacity additions were this high they decreased. This approach applies to all system sizes up to 30MW (Figure 5-1).

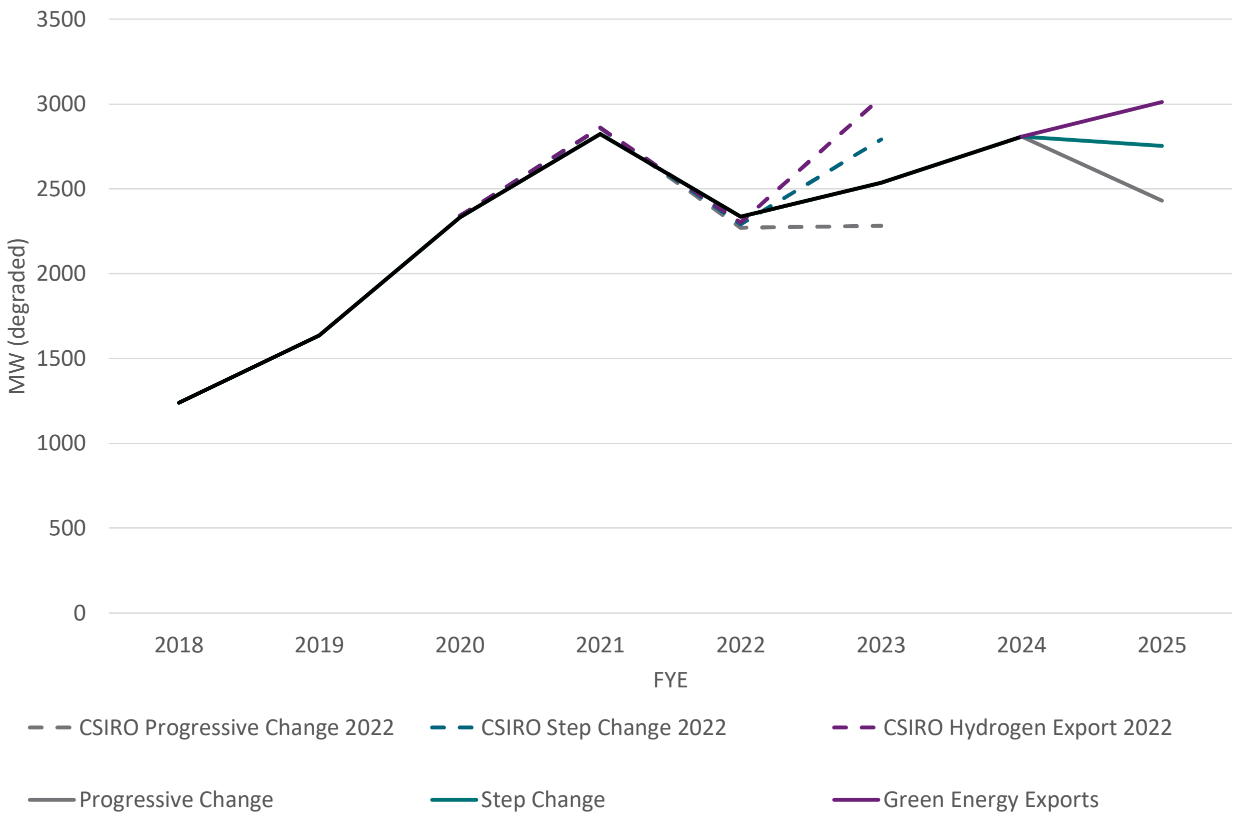


Figure 5-1 Year ahead projection of solar PV (<30MW) capacity additions

5.1.2 Key long term drivers

The projected capacity of small-scale solar PV for residential and business customer segments in the NEM and SWIS for the whole projection period is shown in Figure 5-2 and Figure 5-3 respectively. To generate these projections, after 2025, our second projection methodology is implemented which takes account of various financial and non-financial drivers that inform an adoption curve (see Section 2 for more details). The key positive financial drivers are, historically high retail and wholesale electricity prices since the second quarter of 2022, low payback period and ongoing reductions in solar PV costs. On the negative side, subsidies are expected to fall over time[28] and there are various market developments that could reduce the value of solar PV exports. Some networks are considering the possible introduction of export charges to tariff structures or dynamic export constraints. Greater uptake of rooftop solar PV could also increase the incidence of curtailment in various forms including voltage-based curtailment due to increased local solar PV generation and directed curtailment for system security.

[28] All the 100kW or smaller residential and commercial systems are eligible for small-scale technology certificates under the national renewable energy target. This subsidy is slowly declining to zero by 2030. The greater than 100kW systems remain eligible for large-scale renewable energy generation certificates (LGCs). The value of large-scale certificates has varied over time. They were initially expected to decline with the maturation of the government targets for large-scale renewables but have been sustained by corporate or voluntary demand for LGCs. However, the value of LGCs to the voluntary community is less certain in the long run as the average emission intensity of the grid declines. As such both commonwealth schemes are in the process of reducing their financial incentives. State subsidies are also less common with Victoria being the main exception.

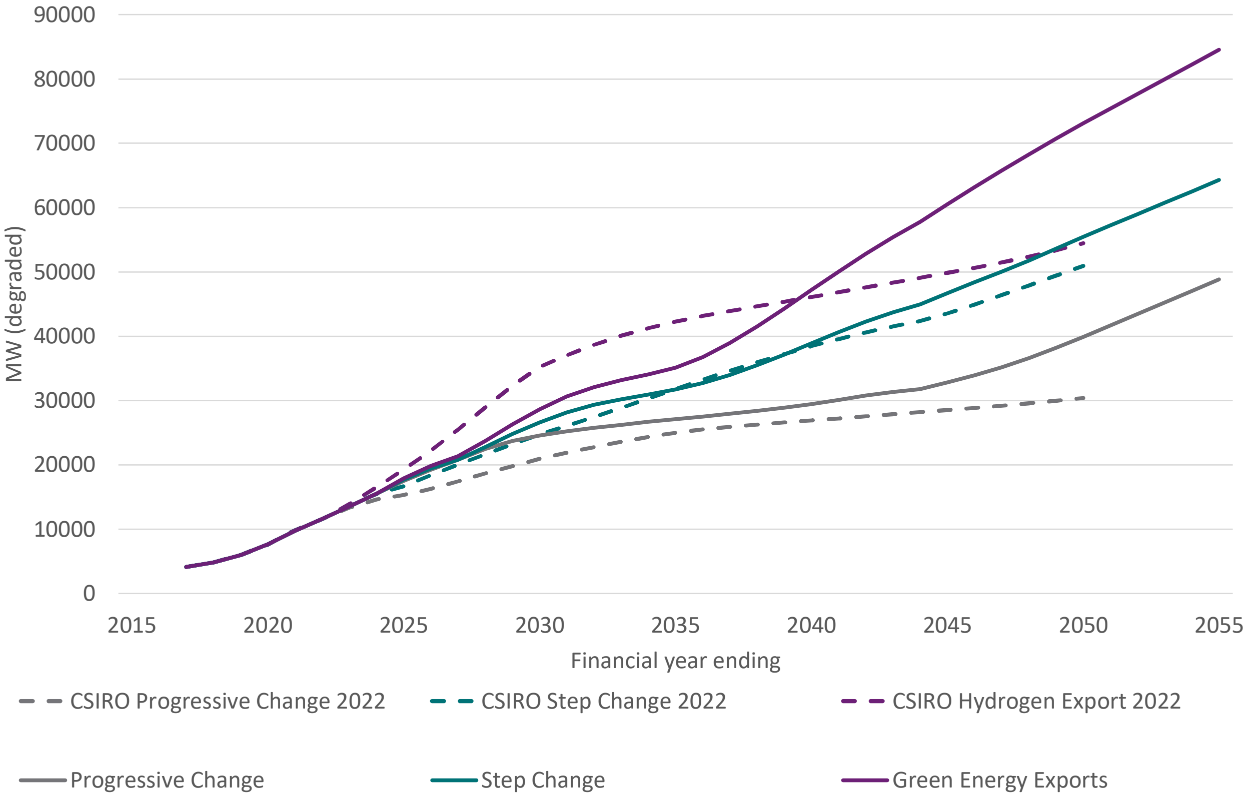


Figure 5-2 Projected capacity of residential small-scale (<100kW) solar PV in the NEM and SWIS

Besides the negative financial factors, the projections are also limited by non-financial factors which are mostly infrastructure related. Solar PV is installed easiest on owner occupied separate dwellings which represent about 45% of households (decreasing to around 38% by 2050), and even fewer of commercial buildings (Table 4-5 and Table 4-6). This means that wherever a projection increases installations beyond 38% by 2050, those installations must occur in either a rental property or multi-occupancy building.

The problem of split incentives arises if the dwelling or place of business is rented. The tenant is not incentivised (and may not be authorised) to upgrade the home to solar because they are unlikely to be staying long enough to gain the product lifetime benefits. Likewise, the landlord receives no benefit other than potentially recovering costs through higher rent (except in some cases where the landlord pays for utilities). For *Step Change* and *Green Energy Exports* we allow for this problem to be partially overcome through either business model innovation or some previously owned buildings entering the rental market through changed circumstances. For *Progressive Change,* these factors are assumed to be less successful, and fewer renters can access solar. Some governments (e.g., Victoria) are providing incentives for landlords and renters to reach a benefit sharing agreement.

Table 5-1 shows the projected outcomes from the scenarios of the share of households with rooftop solar PV. *Green Energy Exports* represents the maximum household share for all states and *Progressive Change* represents the minimum share.

Besides housing and business infrastructure, states will reach different saturation levels reflecting the historical legacy of the support of solar PV in each state and their climate conditions. Queensland, South Australia, and Western Australia have been leading rooftop solar adoption for a long period. As premises change hands, there is an increasing chance they will already have solar installed which helps to bring some systems into the rental market or drive adoption amongst those who were not otherwise in the mainstream adoption group. As a result, their projected minimum and maximum adoption levels across the scenarios are higher than other regions. The ACT has good average income, but its share of separate dwellings home ownership are below the national average inhibiting solar PV adoption.

Table 5-1 Share of households with rooftop solar PV in 2050

	Progressive Change	Step Change	Green Energy Exports
New South Wales	37%	42%	47%
Victoria	36%	42%	47%
Queensland	49%	51%	55%
South Australia	55%	57%	62%
Western Australia	45%	48%	50%
Tasmania	34%	46%	51%
Australian Capital Territory	39%	31%	47%
NEM	39%	44%	49%

While these physical limits are mainly discussed in terms of limiting factors, other physical factors have a positive impact. Both rooftop system sizes and growth in household and business connections help to boost installed solar PV capacity over time. Residential system sizes grow throughout but at a declining rate. System size growth is strongest for *Green Energy Exports* and weakest for *Progressive Change*. Business systems sizes do not grow, however.

5.1.3 Comparison with 2022 projections

The result of the combination of all these drivers is that there is continuing growth. The change in the shape of the growth paths for *Progressive Change*, *Step Change* and *Green Energy Exports* compared to the 2022 projections mostly reflects the change in solar PV cost projections. The range of the new cost projections is narrower in the decade bringing the three scenarios closer together than they were in 2022. As the range of costs widens the projected capacities across the scenarios also widens. Furthermore, in the 2022 cost projections *Step Change* and the then *Hydrogen Export* scenario costs converged. However, in the new cost projections *Step Change* and *Green Energy Exports* costs are more divergent by the 2050s with *Step Change* costs sitting higher in the long run compared to the 2022 cost projections.

For the residential sector (Figure 5-2), the scenario projections are higher in the long run than in 2022. This primarily reflects the increase in assumed average system size over time. In 2022 the highest average system size was assumed to be just over 9kW. In the updated projections this previous assumption represents the lowest assumed outcome for system size with the highest average system size being 12kW (noting that this average allows for much larger individual system sizes). *Step Change* gets the least additional growth from larger system sizes because it has higher technology costs relative to the 2022 projections

For the business sector (Figure 5-3) the opposite is true. The scenario projections are lower in the long run than in 2022. This reflects the decrease in assumed average system size relative to 2022 projections. Business system sizes have been reduced by around 10kW. *Progressive Change* is least impacted by the new assumptions because for the first five years solar PV costs are lower than they were in the 2022 projections which supports stronger growth during that period.

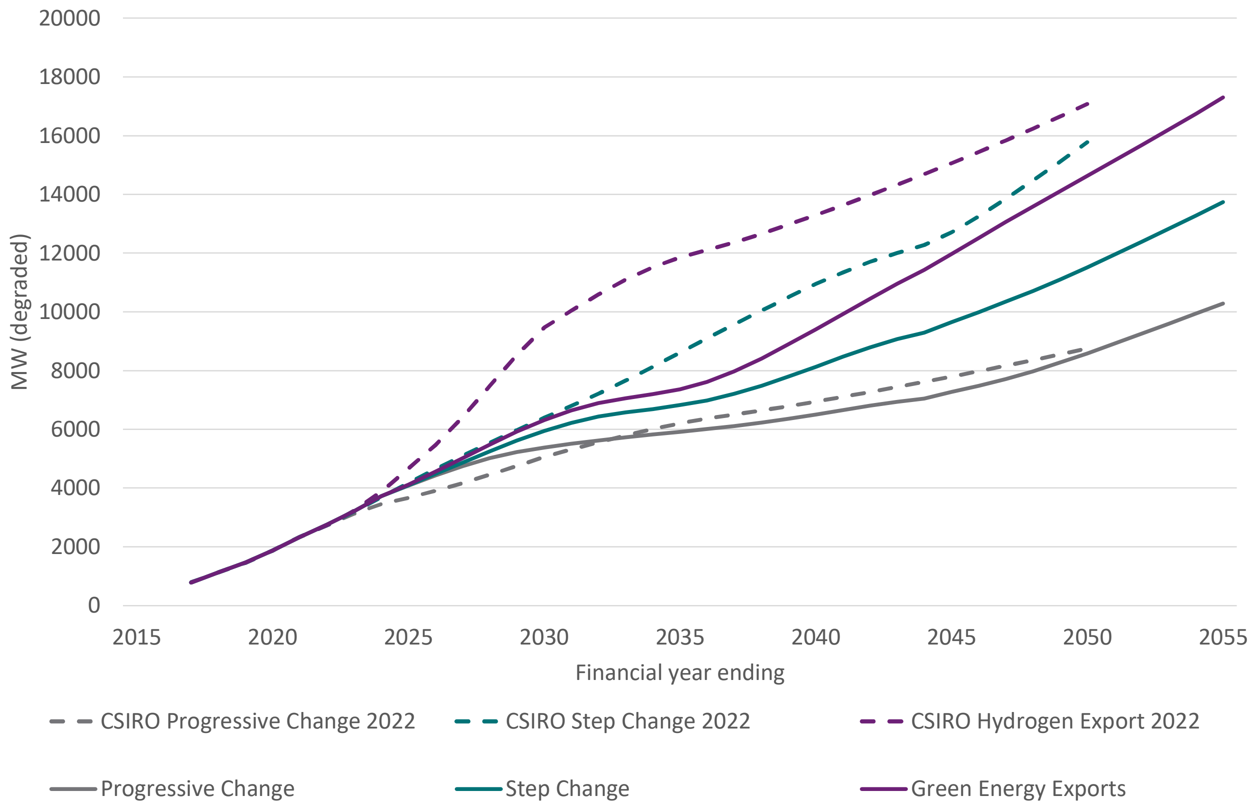


Figure 5-3 Projected capacity of business small-scale (<100kW) solar PV in the NEM and SWIS

Larger-scale solar PV (100kW to 3MW)

Investment in larger scale solar PV in the range of 100kW to 30MW (also called non-scheduled generation) is less driven by infrastructure and more by the potential financial rate of return. The projected capacity of non-scheduled solar PV generation for the NEM and SWIS are shown in Figure 5-4. The projections exhibit some discontinuity which reflects the intermittent installation of projects at the larger end of the spectrum. These tend to occur in a narrower set of regions and make for larger steps in capacity additions.

With the large-scale technology certificates decreasing in value over time, a potential new source of subsidy for these projects is state and commonwealth offset schemes such as the Australian Carbon Credit Unit scheme, state energy efficiency schemes and corporate or voluntary emission reduction targets. The potential incentives under these other incentive schemes are not likely to be as strong as that previously available from large-scale technology certificates. However, we allow for the offset certificate prices of these schemes to increase over time consistent with the greenhouse gas ambitions of each scenario. This is the main driver of the spread of the projected capacity across the scenarios.

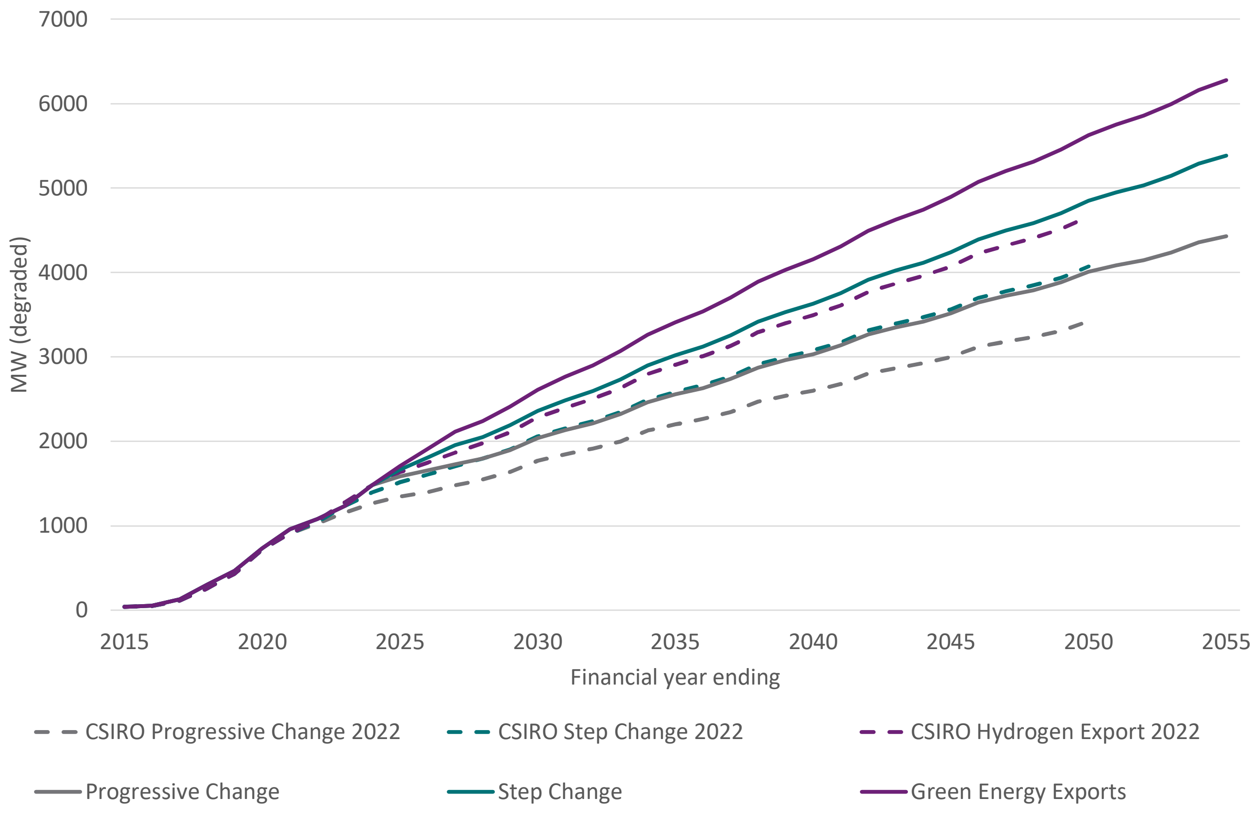


Figure 5-4 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the NEM and SWIS

The increase in the projections relative to the 2022 projections largely reflects the development of some larger deployments in the historical series. Our projection approach uses historical build rates to inform future build rates. As a consequence, once a state has deployed a large (>5MW) project, they are more likely to experience similar growth again. Despite this increase relative to the 2022 projections, the overall trend for non-scheduled solar PV generation is slightly slower than linear growth. This reflects the uncertainty in the future value of incentives from the various policies under which subsidies are available.

5.2 Batteries

Small-scale battery projections are developed in the same way as solar PV with most of the same information and constraints applied. In the year ahead we apply a combination of regression analysis and an uncertainty range across the scenarios (Figure 5-5). An uncertainty range with equal upside and downside risk is applied on the basis that additions have been fairly constant, and the historical series indicates upward and downward movements of around the same magnitude. During the next year or two, there is a reasonably significant commonwealth government funded deployment of 281MWh of community batteries. These are included in the business deployment projection in 2025 and 2026. This capacity has been excluded from the year ahead projection so that the underlying trend prior to their inclusion is clearer.

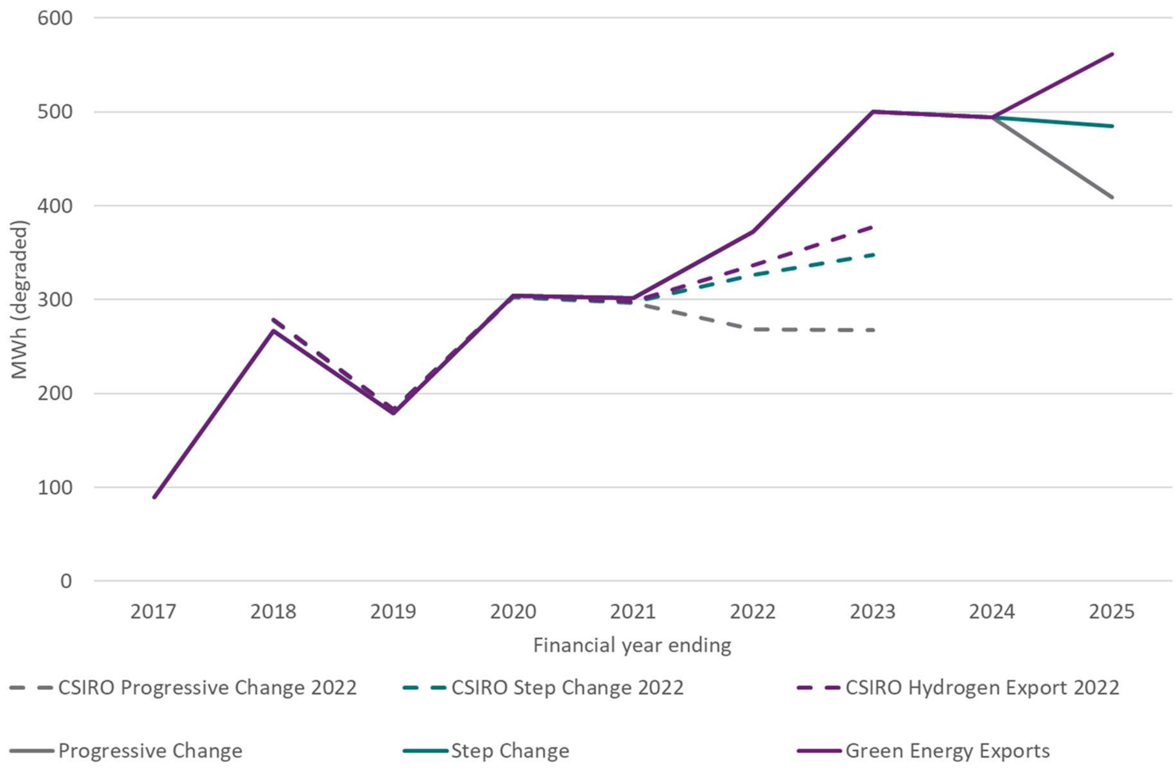


Figure 5-5 Year ahead projection for total small-scale battery additions (excluding community batteries)

The short-term outlook for batteries has improved since the 2022 projections with two new subsidies schemes in NSW (see Section 3.2.6). Furthermore, we assume a national scheme that results in a 20% and 30% reduction in capital costs in *Step Change* and *Green Energy Exports* respectively. *Progressive Change* only gets the benefit of the NSW scheme. The impact of stronger subsidies is evident in the first few years of residential uptake in Figure 5-6.

From a technology cost perspective *Step Change* and *Green Energy Exports* have mostly higher costs compared to the 2022 projections until the 2040s so that after the national subsidies are assumed to be phased out, the projected capacity temporarily falls lower than the 2022 projections. However, for *Progressive Change*, costs are generally lower than the 2022 projections resulting in stronger growth throughout the whole projection period. Residential batteries are assumed to increase proportionally in size with growing solar PV system sizes and so this allows stronger growth in all scenarios by the end of the projection period. In the 2022 projections residential battery sizes were held constant throughout.

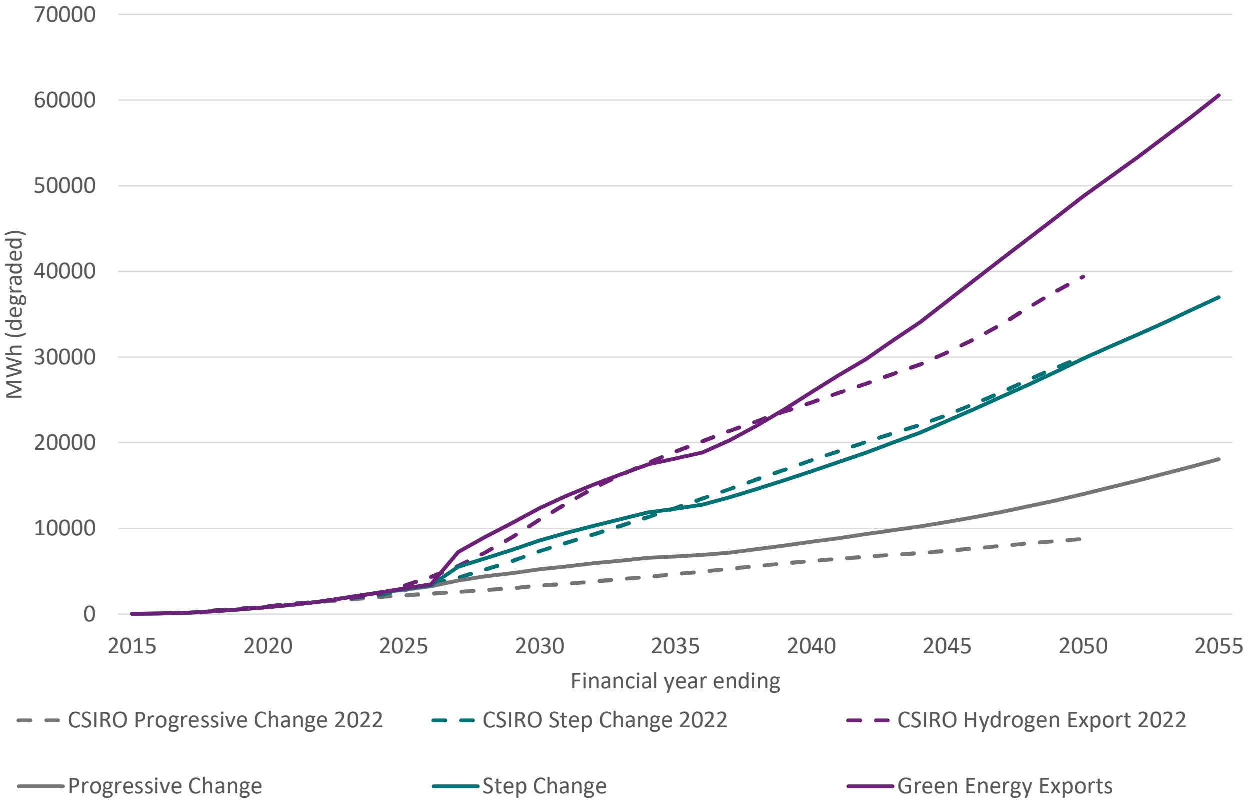


Figure 5-6 Projected capacity of small-scale residential batteries in the NEM and SWIS

For the business sector, the projected outlook is significantly impacted by the assumed deployment of 281MWh of community batteries in 2025 and 2026 (Figure 5-7). This lifts the capacity significantly above that which was projected in 2022 when the policy was known but was less certain. It is assumed these community battery deployments are replaced at the end of life and so that there is a permanent upward shift in the projection from 2026.

Leaving aside the community batteries, the key underlying drivers are falling technology costs and subsidies and battery sizes. Business battery sizes have increased because updated historical data has resulted in a larger market share for larger battery deployments. Apart from community batteries, this is the main reasons for higher projections than 2022. Absent these two factors, business battery projections might have been expected to track slightly lower and then converge back to the 2022 projections due to projected battery cost changes. Battery costs are higher than the 2022 projections in *Step Change* and *Green Energy Exports* until the last ten years of the projection period. However, for *Progressive Change*, costs are generally lower than the 2022 projections.

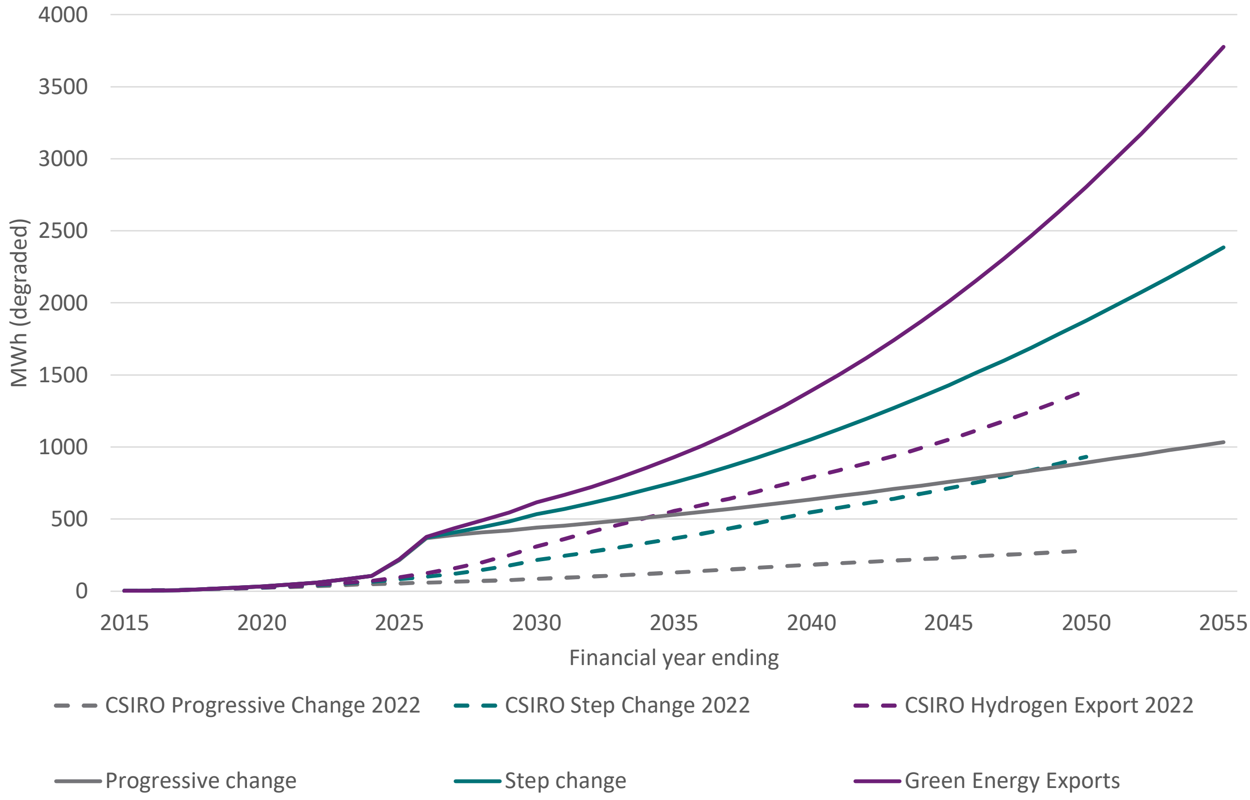


Figure 5-7 Projected capacity of small-scale business batteries in the NEM and SWIS

The current and projected share of residential solar PV owners who also own batteries is presented in Figure 5-8. The battery share for residential customers with solar is expected to increase over time for all scenarios. The share of residential customers with batteries increases at an equivalent rate for all scenarios in the next four years, before becoming increasingly divergent in the 2030s, maintaining those differences for the remainder of the projection period. This largely reflects the trend in solar PV and battery costs which are relatively narrow and then evenly divergent over time. In the 2022 projections, technology costs for *Step Change* and the then named *Hydrogen export* scenario were closer together leading to less divergence between those two scenarios.

The long term range for battery ownership is projected to be 29% to 56%. This high rate of battery uptake does not necessarily conflict with the potential future use of electric vehicles for home energy storage. Up to just over one sixth of electric vehicles are assumed to be used as household batteries by 2050 (Graham at al., 2024).

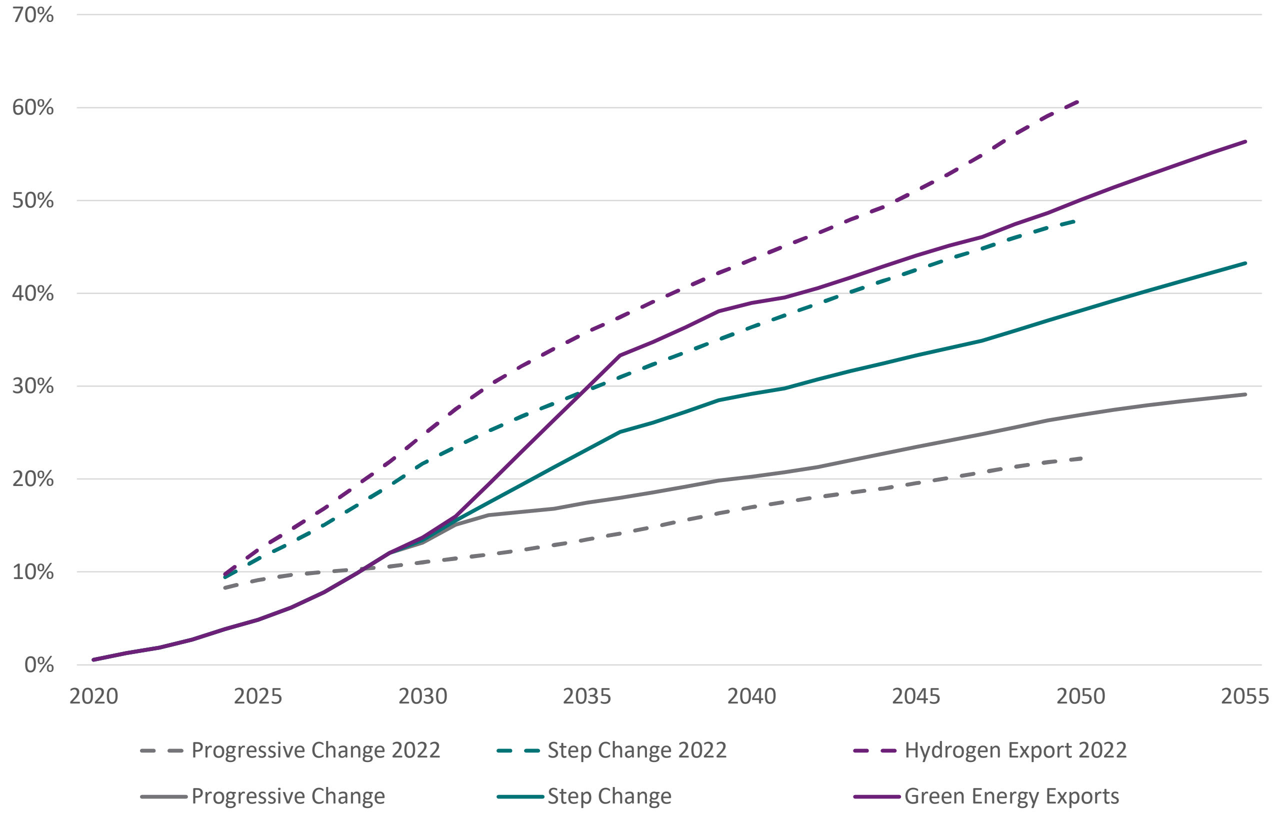


Figure 5-8 Projected share of residential solar-PV systems with a battery

5.3 Battery operation profiles

The operation of batteries was simulated for different weather years and customer and tariff types. A flat tariff was simulated which results in a solar shifting operational profile. In this profile, the battery tends to charge to avoid exports since the most financially advantageous use of any solar generation is on site once a battery is installed. The battery will also discharge to avoid imports as much as the battery capacity will allow. The battery capacity was not optimised but rather fixed at observed current average battery sizes (detailed in Appendix A).

The results for the solar shifting profile are presented in Figure 5-9. In summer the charging profile is wider and flatter indicating less coincident behaviour because longer daylight hours allow a longer period over which to charge the battery. With the exception of Western Australia[29], the residential customer loads we use have higher electricity consumption in the summer months (see Apx Figure A.2). The lower winter electricity demand reflects the use of electrical cooling in summer but, on average, lower use of electricity as a heating source in winter. As a result, there is less peak charge available to go into the battery in summer. This higher demand is partially offset by longer hours in which to charge the battery. In winter, lower electricity demand and narrower daylight period means that charging is more coincident, resulting in a peakier shape.

[29] Some southern states have a higher share of gas combined with coolers for summer (which cannot provide heating in winter. Western Australia has reverse cycle heats pumps closer to shares observed in northern states but with cooler winters resulting in a different average residential load curve.

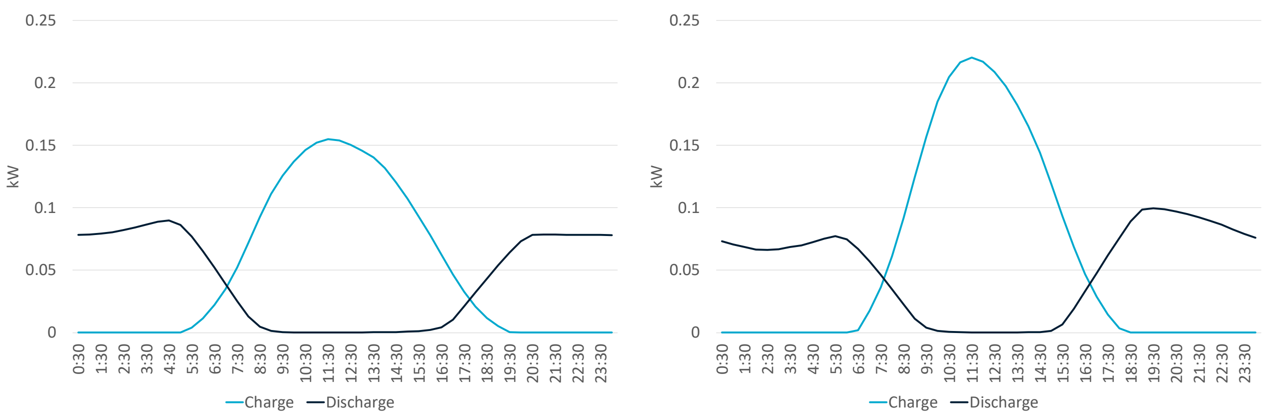


Figure 5-9 Summer (left) and winter (right) solar shift residential battery operation profiles

A peak avoidance profile was simulated based on typical time of use incentives which impose a higher retail price from around 7:00am (local time), a further step up in prices between 6pm and 10pm and low prices 10pm until 7:00am (these times and their individual rates vary slightly between jurisdictions, and these have been included in the detailed modelling). From a charging perspective the shape of the daily curve is similar during solar production times. However, there is additional charging (from the grid rather than onsite solar PV) as soon as off-peak pricing commences at night. This behaviour is to ensure the battery has sufficient charge to be ready to discharge during the commencement of increasing prices in the morning. The behaviour is stronger in winter because the battery has a poorer charge during the day and solar production will likely be lower and later in the morning and so it can be less relied on to assist with reducing imports from the grid. Some off-peak charging from the grid may continue until early morning.

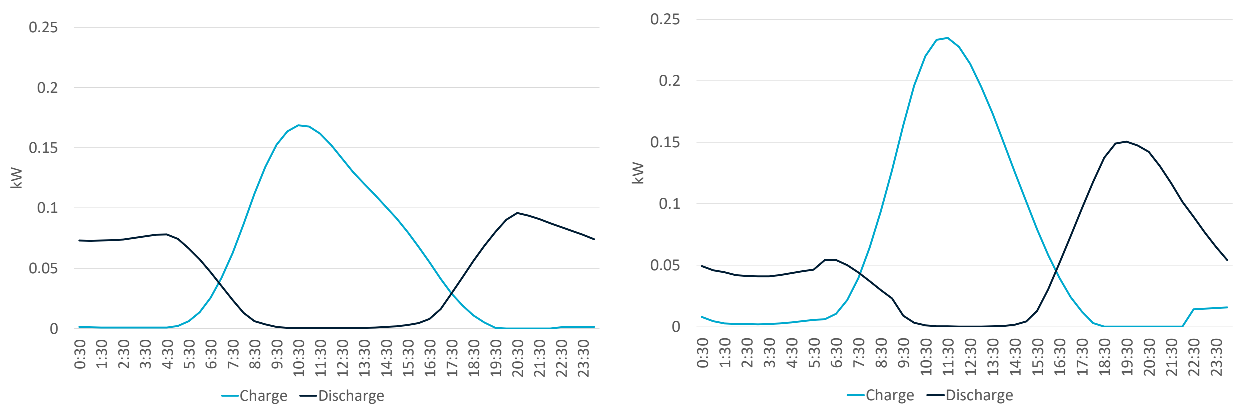


Figure 5-10 Summer (left) and winter (right) peak avoidance residential battery operation profiles

The discharge profile for the peak avoidance profile is also different from the solar shift profile. Not surprisingly, there is a more pronounced discharging peak during the peak pricing period of 6:00pm to 10:00pm. There can also be a second peak discharge around 7:00am on days with low solar output at this time. These discharges are more prominent in winter when the state of charge is lower due to lower solar input, and the need to preserve the battery charge for the peak period rather than just overnight. In summer the amount of charge is more able to cover residential demand in the peak periods and overnight to reduce imports from the grid.

For commercial customers, given better alignment of load with solar production and shorter duration batteries, discharge focusses mostly on the early evening period in the solar shift profile without the sustained discharge through the night. Under the peak avoidance profile, the same off-peak charging and peak discharging occurs but again with even lower emphasis on night or off-peak discharge.

Appendix A Additional data assumptions

In this appendix we outline some key additional assumptions that were used to develop the adoption projections in addition to the scenario specific assumptions discussed in the body.

A.1 Technology performance data

Each technology can be described by a small number of performance characteristics with energy efficiency being a common one whilst others are specific to the technology. The following tables outline key performance data for rooftop solar and battery storage.

A.1.1 Rooftop solar

Rooftop solar generation profiles were sourced from AEMO. Table A.1 shows the average capacity factors from these production profiles.

Apx Table A.1 Rooftop solar average annual capacity factor by region

	Capacity factor
New South Wales	0.146
Victoria	0.134
Queensland	0.152
South Australia	0.148
Tasmania	0.129
Western Australia (SWIS)	0.155
Northern Territory	0.148

The share of installed rooftop solar with a north orientation appears to be around 90%, with mostly West followed by east being the remainder. We assume the ratio of north-facing in new installs falls to 70% by 2050 (with the other orientations proportionally gaining) owing to those buildings with less favourable orientations being in the late follower group and larger systems potentially requiring to be laid at on more than one aspect. There is also expected to be a greater incentive for west orientation due to more customers responding to incentives to reduce demand during peak times.

Rooftop solar capacity degradation is assumed to be 0.5% per annum based on Jordan and Kurtz (2012). Warranties imply closer to 1% annual degradation but include a margin to be conservative.

This is a stock wide assumption and does not preclude better or worse performing product variations.

Rooftop solar capacity is also lost to breakdown of equipment before scheduled end of life due to quality or misadventure (e.g., hail). This data is not available. Our assumption is that the survival rate of 1 to 10 years old systems is very high at 99.5% and 10 to 20 years old systems is 97% per year. However, the total replacement rate can be significantly higher in any given year owing to a high number of historical deployments becoming due for replacement.

While replacements do not add to the total number of installations, they can impact installed capacity. This is because replacement systems may be larger than existing capacity, particularly during periods where system size is rising such as over the next few years. This means that for the next few years replacements are adding to capacity. In our system size trend assumptions, as the trend flattens over time, the impact of replacements on total installed capacity begins to wane significantly.

A.1.2 Battery storage

For the battery storage capacity projections, we assume one average battery size for each of the three segments: residential, small commercial and large commercial. However, when we are developing the battery operational profiles, we allow the model to optimise the residential battery size for each customer.

While residential battery sizes are around 11kWh, there is some evidence of modest growth in size over time. Growth has likely been inhibited by high costs. However, as costs decrease, our expectation is that larger batteries will be deployed proportional to ongoing increases in solar PV system sizes (mainly for residential customers). Business battery sizes have been assigned based on historical data provided by AEMO and do not grow owing to the assumption that business solar PV sizes are not growing.

The degradation rate is a function of many factors including temperature, depth of discharge and battery design. There are a wide variety of models for understanding how degradation occurs (Reniers at al., 2019) which can give diverse predictions about degradation rates. We have chosen a rate consistent with loss of 30% battery capacity by the end of a 5000-cycle life which assumes moderate temperatures, the battery is not fully charged or discharged and there is only one cycle per day.

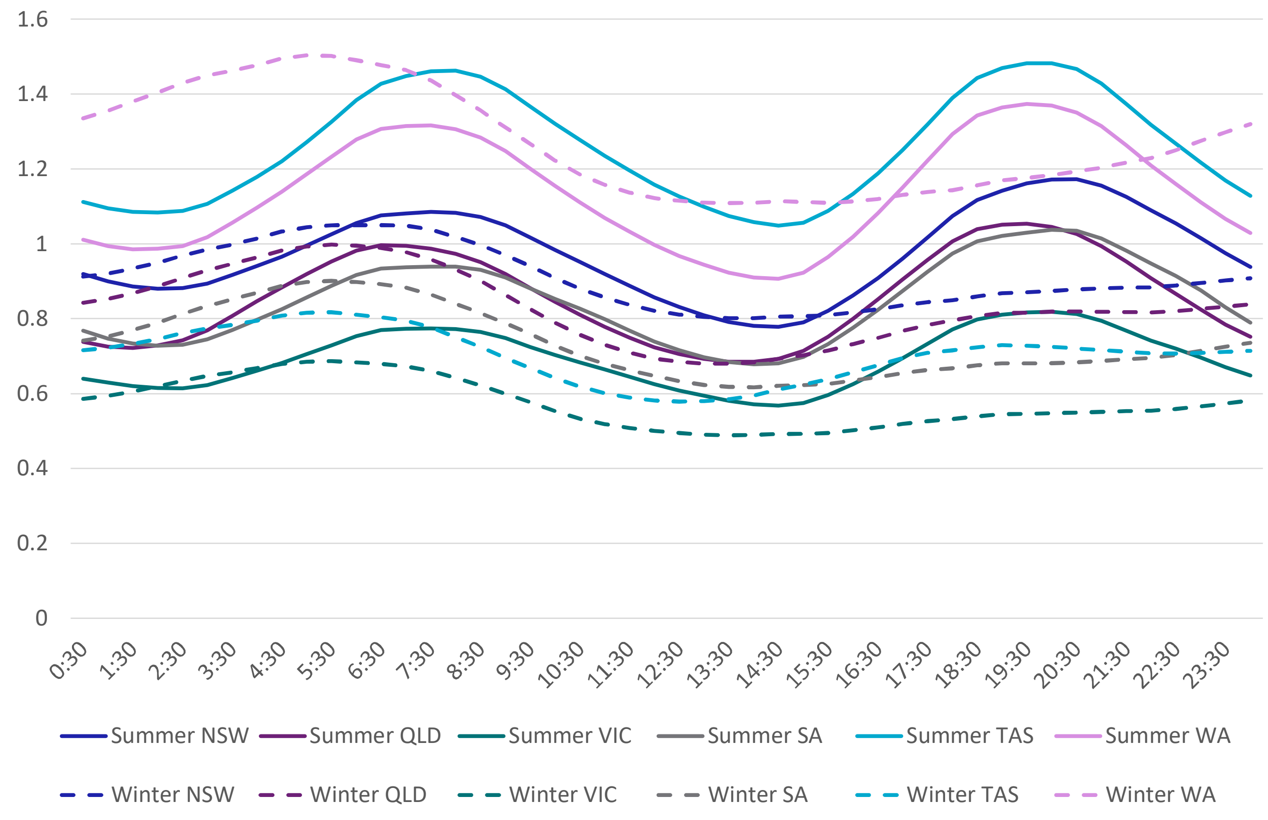
Apx Table A.2 Battery storage performance assumptions

Characteristic	Assumption
Round trip efficiency	85%
Maximum charge or discharge of rated capacity	85%
Rated capacity projections	Residential: 11kWh increasing proportional to change in average solar PV system sizes
	Small commercial: 20kWh Large commercial: 516kWh
Maximum power in kW	Residential: Rated capacity divided by 2.1 Commercial: Rated capacity divided by 1.3
Degradation rate	1.8% per annum on kWh capacity
Life	Financing period: 10 years, Asset life: 5000 cycles

A.2 Customer load profiles

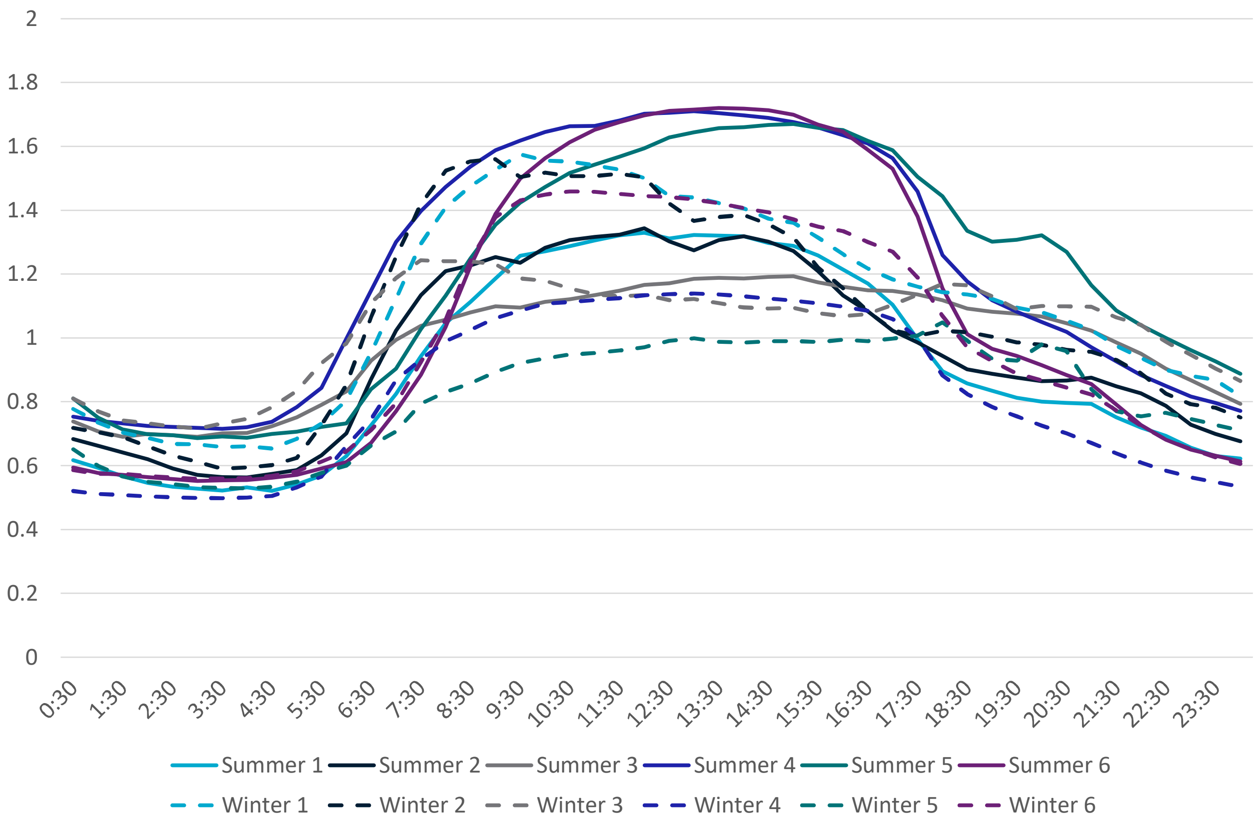
Australia still faces difficulty in accessing public load profiles due to privacy considerations. For that reason, we use a mixture of synthetic and real customer load profiles. For residential data we started with around 5000 New South Wales Ausgrid profiles from the Smart Grid Smart Cities program and found the 5 most representative profiles and their nine nearest neighbours using clustering analysis. We then synthetically created profiles for each other distribution network area by subtracting the difference between the most residential zone substation in each network relative to Ausgrid's most residential zone substation. This process should adjust for differences in timing (daytime hours) and climate but is probably insufficient to account for all differences in gas versus electricity use, for example, between different states. The SGSC data set did include people with and without gas and with and without hot water control, but the proportions will not match other states. The average summer and winter profile for each region is shown in Figure A.2.

These loads are electricity only and therefore do not reflect the use of natural gas, LPG and wood for space heating, water heating and cooking. For this reason, summer loads (with the exception of Western Australia) are higher with electricity being the dominant as a cooling technology.



Apx Figure A.1 Index of average half hourly residential summer and winter loads by region, normalised to average load

For commercial load profiles we use a small number from previous work and do not adjust them by region. In using a smaller set our assumption is that commercial profiles vary less than residential between customers and regions (Figure A.3). The commercial data has a stronger summer load, biased towards the evening. The winter load is biased towards the morning. This indicates a greater reliance on electrical space heating and cooling in both seasons than the residential data.



Apx Figure A.2 Index of average half hourly summer and winter loads for six commercial customers

Shortened forms

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
ACCU	Australian Carbon Credit Unit
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APVI	Australian Photovoltaic Institute
BOP	Balance of plant
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DNSP	Distribution network service provider
EE	Energy Efficiency
ERF	Emissions Reduction Fund
FCAS	Frequency Control Ancillary Services
FiT	Feed-in Tariff
GDP	Gross Domestic Product
GSP	Gross State Product
hrs	Hours
IPART	Independent Pricing and Regulatory Tribunal
ISP	Integrated System Plan
kW	Kilowatt

kWh	Kilowatt hour
LGC	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSG	Non-Scheduled Generation
PV	Photovoltaic
QRET	Queensland Renewable Energy Target
RET	Renewable Energy Target
SA2	Statistical Area Level 2
SGSC	Smart Grid Smart Cities
STC	Small-scale Technology Certificates
SWIS	South-West Interconnected System
TOU	time-of-use
UNFCCC	United Nations Framework Convention on Climate Change
VEEC	Victorian Energy Efficiency Certificate
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WEM	Wholesale Electricity Market (WA)

References

Australian Energy Market Operator (AEMO) 2024, *2025 IASR scenarios: Consultation paper*, AEMO.

Australian Energy Market Operator (AEMO) 2021, *AEMO virtual power plant demonstrations: Knowledge sharing report #4*, AEMO.

Australian Energy Market Operator (AEMO) 2020, *AEMO virtual power plant demonstration: Knowledge sharing report #1*, AEMO.

Australian Energy Market regulator (AER) 2024, *State of the energy market 2024*, AER.

Bass, F.M., 1969. A New Product Growth for Model Consumer Durables. *Management Science*, vol. 15, pp 215-227.

Graham, P., Hayward, J. and Foster, J. 2024, *GenCost 2023-24: Final report,* CSIRO, Australia.

Graham, P. and Mediwaththe, C. 2022, *Small-scale solar and battery projections 2022*. CSIRO, Australia.

Graham, P., Mediwaththe, C. and Green, D. 2024, *Electric vehicle projections 2024*. CSIRO, Australia.

Higgins, A., McNamara, C. and Foliente, G. 2014, Modelling future uptake of solar photo-voltaics and water heaters under different government incentives, *Technology forecasting and social change*, vol. 83, pp 142-155.

Higgins, A., Paevere, P., Gardner, J., Quezada G. 2012, Combining choice modelling and multi-criteria analysis for technology diffusion: An application to the uptake of electric vehicles, *Technological Forecasting & Social Change*, vol. 79, pp 1399–1412

Jordan, D.C. and Kurtz, S.R. 2012, *Photovoltaic degradation rates – An analytical review*, NREL/JA-5200-51664.

Rogers E., 1962. *Diffusion of Innovations*. Glencoe: Free Press

Stenner, K., Frederiks, E., Hobman, E. V., and Meikle, S. 2015, *Australian consumers' likely response to cost-reflective electricity pricing*. CSIRO, Australia

As Australia's national science agency and innovation catalyst, CSIRO is solving the greatest challenges through innovative science and technology.

CSIRO. Unlocking a better future for everyone.

Contact us

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

For further information

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