Final 2021 Projections for distributed energy resources – solar PV and stationary energy battery systems

Report for AEMO

June 2021

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1 Executive Summary

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2051 of solar and stationary battery uptake for a sub-segment of this market that does not participate in AEMO's scheduled dispatch system.

Our results are divided into several system size brackets:

- Residential which are assumed to cover solar systems up to 15kW in size and their associated battery systems, which for modelling purposes were assumed to average 10kWh in size at the beginning of the projection and increase to a maximum of 15kWh.
- Small commercial which are assumed to be between 15kW and 100kW in scale and their associated battery systems, which for modelling purposes were assumed to also average 10kWh in size at the beginning of the projection and increase to a maximum of 15kWh[1].
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries, which for modelling purposes were assumed to be sized between 90kWh to 150kWh depending upon the state.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

Green Energy Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period - the years it takes for revenue to exceed the installation cost - which we can then compare against payback periods in the past. At a simplified level our approach is based on an assumption that installation levels in the past and associated paybacks provide a guide for likely levels of installs in the future. If

[1] Commercial battery systems are a similar size to residential systems because even though these premises have a larger load and are assumed to install a larger solar system than residential, the solar system is aligned more closely with daytime load and so has less generation surplus to load that would otherwise be exported to the grid. This substantially reduces the scale of arbitrage the battery can provide in taking power that would be otherwise be exported at a rate tied to wholesale energy costs and instead using it for self-consumption tied to retail rates.

paybacks deteriorate (get longer) then installations will decline and if paybacks improve (get shorter) then installations rise. This is then moderated by:

- the expected impact of market saturation in each state;
- the rate of new dwelling construction; and
- expected replacement cycles for systems.

In addition, we also account for the influence of non-financial factors such as changes in customer awareness and solar industry competitiveness and marketing which are informed by industry interviews.

In trying to evaluate financial attractiveness of project installations Green Energy Markets has segmented this into two core segments for the purposes of our analysis:

1. What are commonly referred to as “behind-the-meter” installations which are embedded within an end-consumer’s premises;
2. In front of the meter installations which are entirely focussed on exporting electricity to the grid and do not offset customer consumption from the grid.

For systems within segment 1 (behind-the-meter) we specifically analyse financial attractiveness and then subsequent uptake based upon Green Energy Market’s solar and battery system payback model.

For systems within segment 2 (small power stations) we have assumed that installs will be modest throughout the outlook. This is due to the fact that behind the meter installs are expected to effectively displace the market opportunity for these solar systems. These levels of installs though are adjusted depending on the scenario, with higher uptake in the scenarios intended to encapsulate greater levels of emission reduction policy ambition.

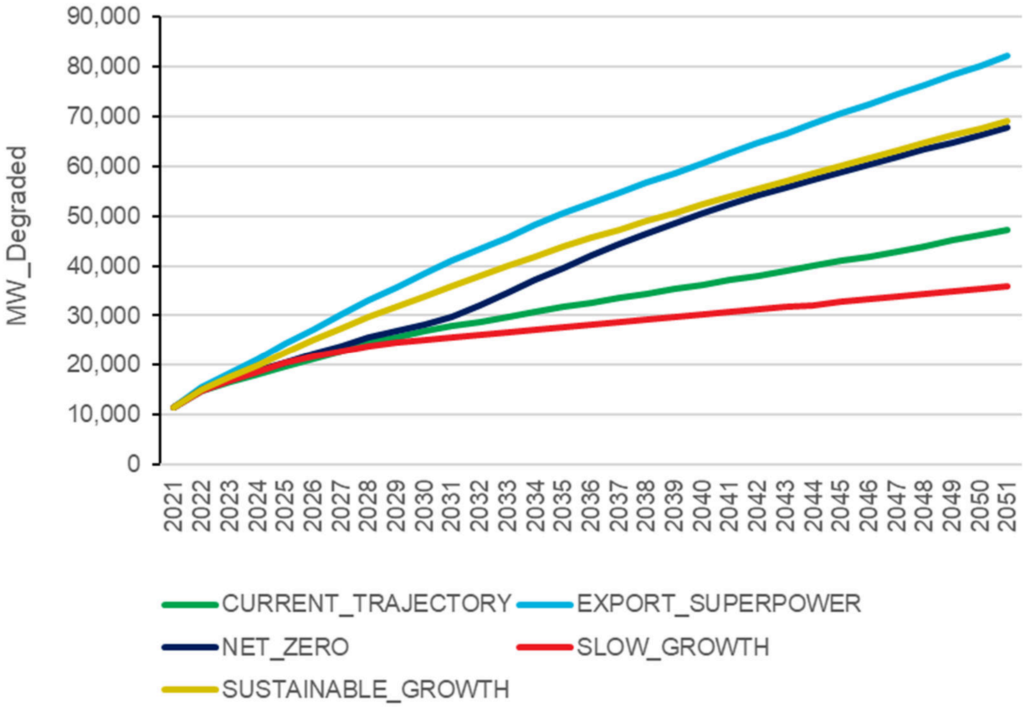
1.1 Results

1.1.1 Solar PV

National Electricity Market (NEM)

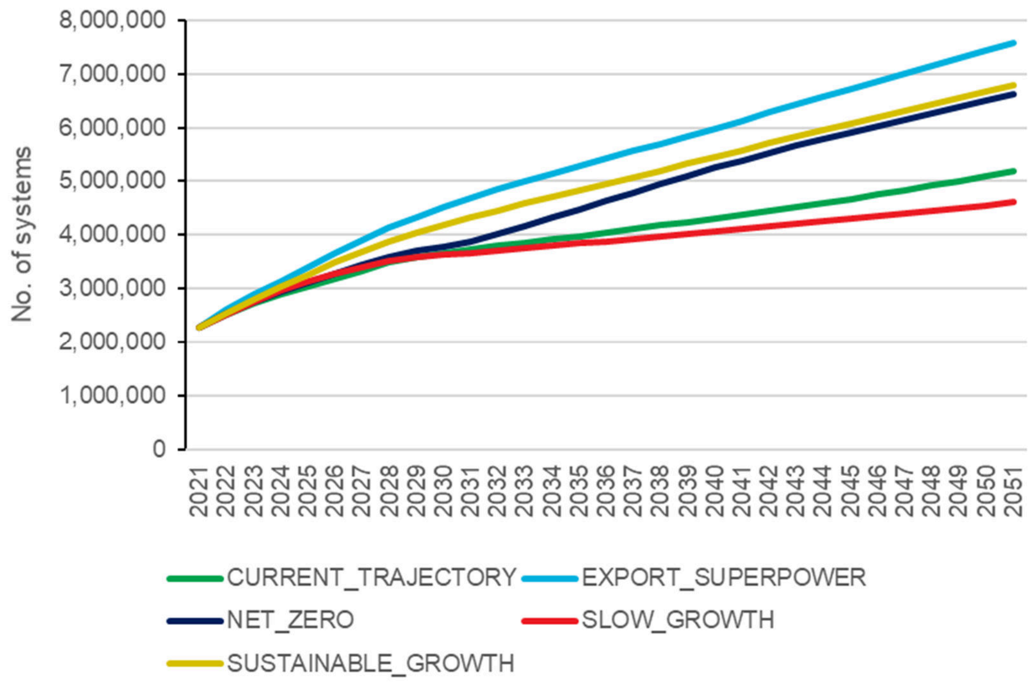
Figure 1-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time and adjusting for systems that are replaced. At the conclusion of the 2019-20 financial year cumulative installed degraded capacity stood at almost 9,900MW. Under Current Trajectory the cumulative degraded capacity reaches just over 47,000MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 82,000MW, while the lower bound represented by Slow Growth is close to 36,000MW.

Figure 1-1 NEM cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario within the NEM. At the conclusion of the 2019-20 financial year the cumulative number of systems stood at a little over 2 million. Under Current Trajectory the cumulative number of systems grows to just under 5.2 million by the end of the 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches almost 7.6 million, while the lower bound represented by Slow Growth is 4.6 million systems at the end of the 2050-51 financial year.

Figure 1-2 NEM cumulative number of PV systems by scenario

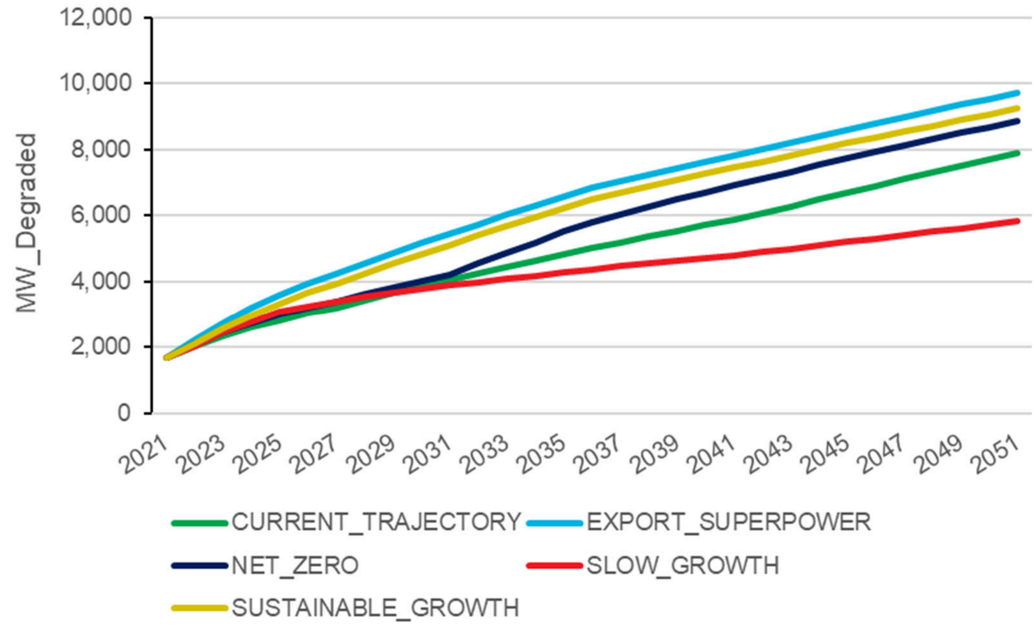


To put these system numbers in context the total number of NEM residential electricity connections (the vast bulk of solar systems by number are projected to be installed on residential premises) is expected to grow from 9.1m at the end of the 2019-20 financial year to just under 13.9m by 2051 under Current Trajectory, while under Export Superpower it grows to almost 14.5m. The number of systems under Current Trajectory equates to around 37% of all residential connections and in Export Superpower it is 52%.

Western Australian South-West Interconnected System

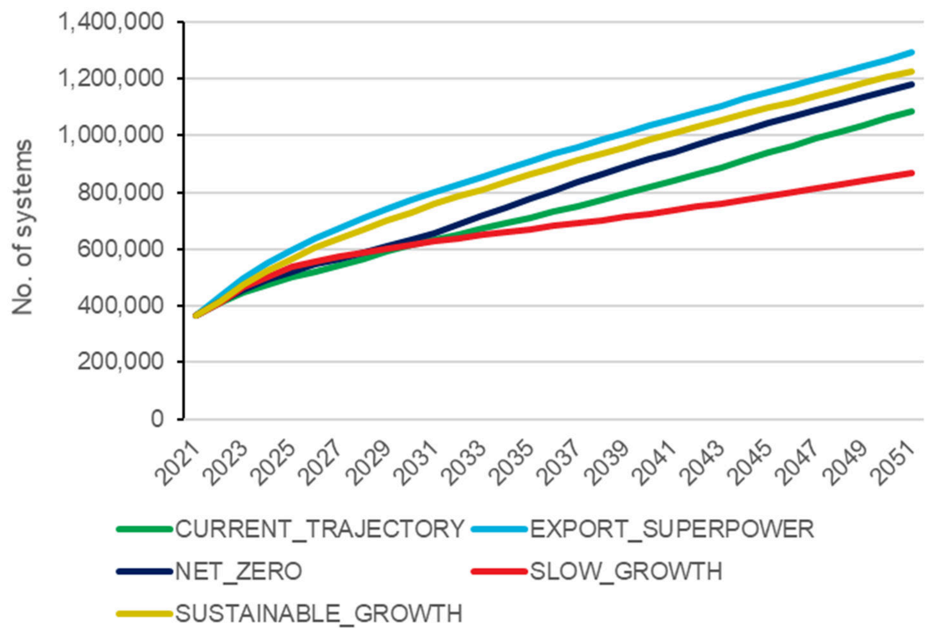
The figure below details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the WA South-West Interconnected System (SWIS), taking into account the degradation of solar panel output over time and replacement of existing systems. At the conclusion of the 2019-20 financial year cumulative installed degraded capacity stood at almost 1,400MW. Under Current Trajectory the cumulative degraded capacity reaches just over 7,900MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 9,700MW, while the lower bound represented by Slow Growth is slightly under 5,900MW.

Figure 1-3 WA SWIS cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario for the WA SWIS. At the conclusion of the 2019-20 financial year the cumulative number of systems stood at 325,000. Under Current Trajectory the cumulative number of systems grows to almost 1.1 million by the end of the 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches almost 1.3 million, while the lower bound represented by Slow Growth is 868,000 systems at the end of the 2050-51 financial year.

Figure 1-4 WA SWIS cumulative number of PV systems by scenario



The total number of residential electricity connections is expected to grow from 1.03m at the end of 2019-20 to 1.77m by 2050-2051 in Current Trajectory and 1.93m in Export

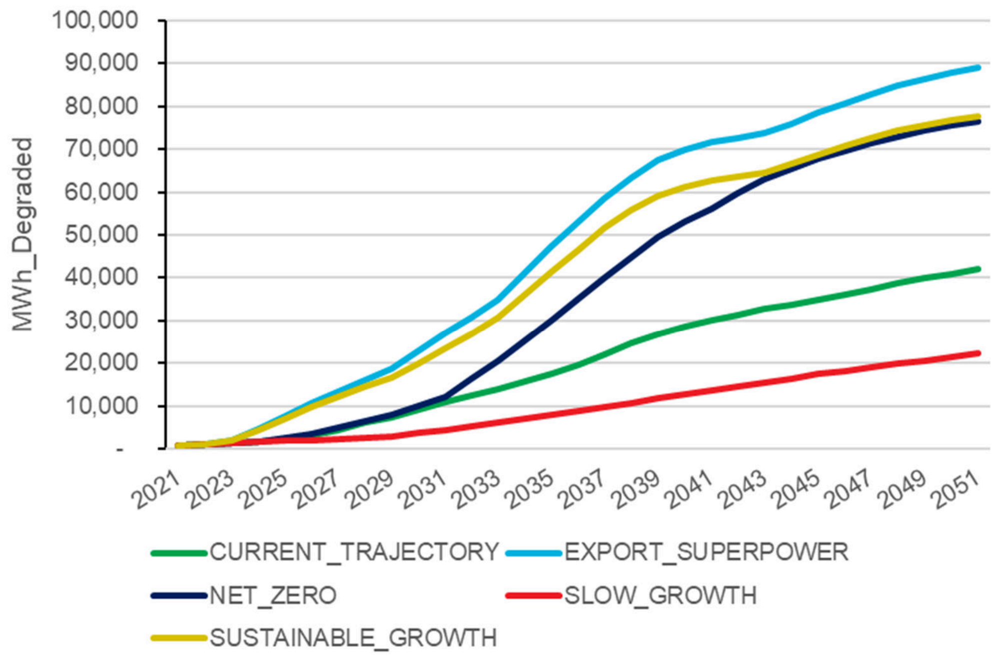
Superpower. As some perspective, the number of systems under Current Trajectory equates to around 62% of all residential connections and Export Superpower is slightly more than 67%.

1.1.2 Battery energy storage

National Electricity Market (NEM)

In terms of behind the meter stationary battery systems Figure 1-5 details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the National Electricity Market (NEM), taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2019-20 financial year) cumulative degraded battery capacity is estimated to stand at 667MWh[2]. Under Current Trajectory the cumulative degraded capacity reaches almost 42,000MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 89,000MWh, while the lower bound represented by Slow Growth is just above 22,200MWh by the end of the projection in 2050-51 financial year.

Figure 1-5 NEM cumulative degraded megawatt-hours of battery capacity by scenario



The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 287MW at the end of 2019-20 financial year. Under Current Trajectory this grows to 20,700MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 44,200MW, while the lower bound represented by Slow Growth is almost 11,000MW by the end of the projection in 2050-51 financial year. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

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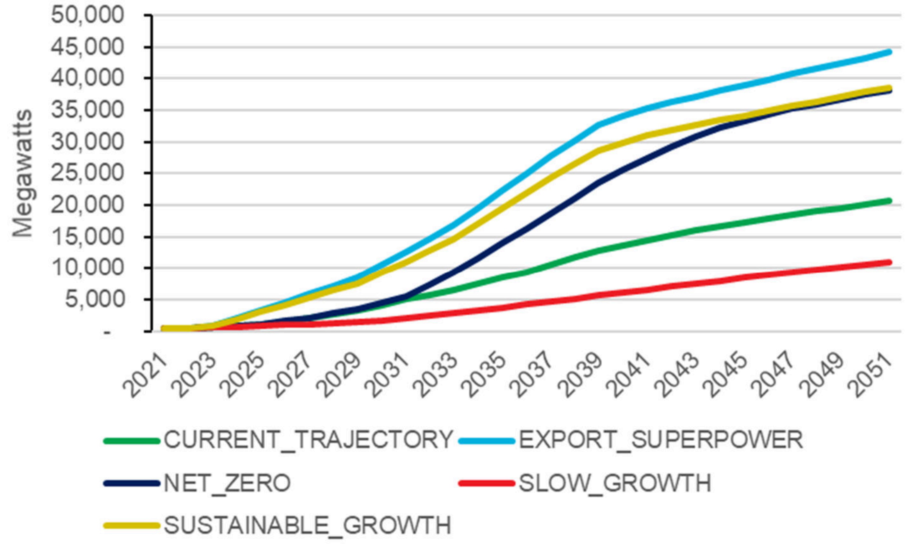
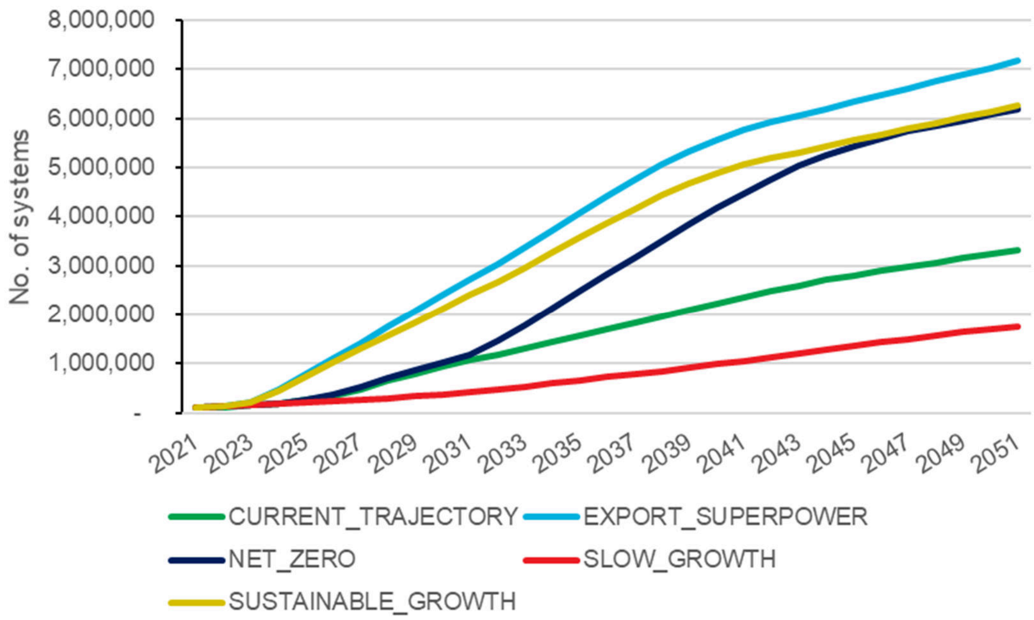
[2] Due to the fact the DER register is at an early stage of development we have developed estimates of battery capacity that are based on a combination of interviews with several battery suppliers and SunWiz (2020) Australian Battery Market Report -2020 (for media).

Figure 1-6 NEM cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the NEM. At the end of the 2019-20 financial year the cumulative number of grid-connected battery systems is slightly more than 71,000. Under Current Trajectory the cumulative number of systems grows to 3.3 million by the end of the projection in 2050-51 financial year. The upper bound represented by Export Superpower reaches almost 7.2 million, while the lower bound represented by Slow Growth is slightly less than 1.8 million systems by the end of the projection in 2050-51 financial year.

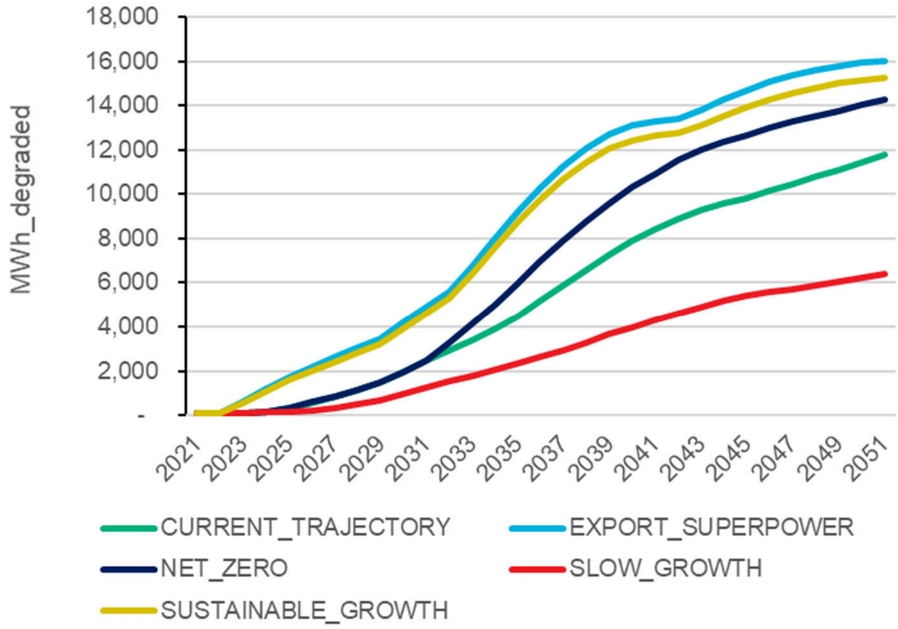
Figure 1-7 NEM cumulative number of battery systems by scenario



Western Australian South-West Interconnected System (SWIS)

The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2019-20 financial year) cumulative degraded battery capacity is estimated to stand at 44MWh[3]. Under Current Trajectory the cumulative degraded capacity reaches almost 11,800MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 16,000MWh, while the lower bound represented by Slow Growth is just above 6,400MWh by the end of the projection in 2050-51 financial year.

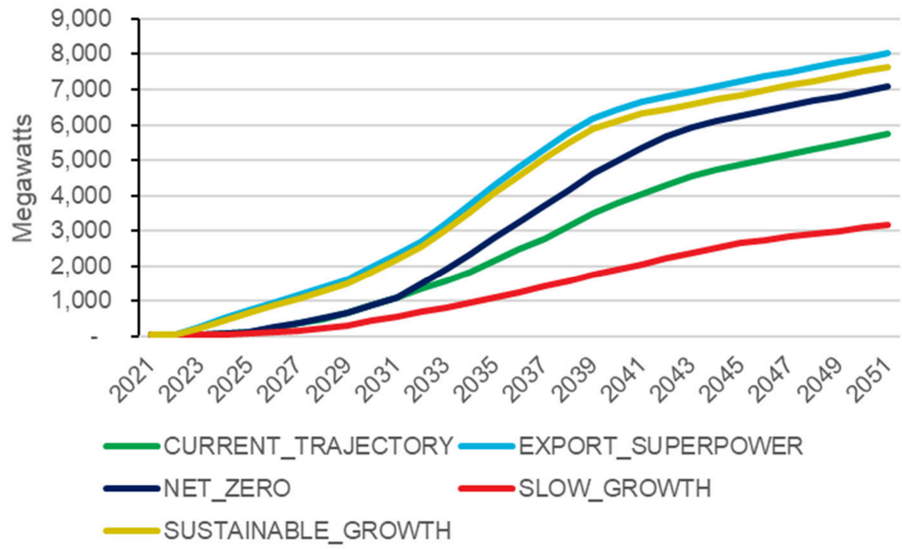
Figure 1-8 WA SWIS cumulative degraded megawatt-hours of battery capacity by scenario



The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 18MW at the end of 2019-20 financial year. Under Current Trajectory this grows to almost 5,800MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 8,000MW, while the lower bound represented by Slow Growth is just under 3,200MW by the end of the projection in 2050-51 financial year.

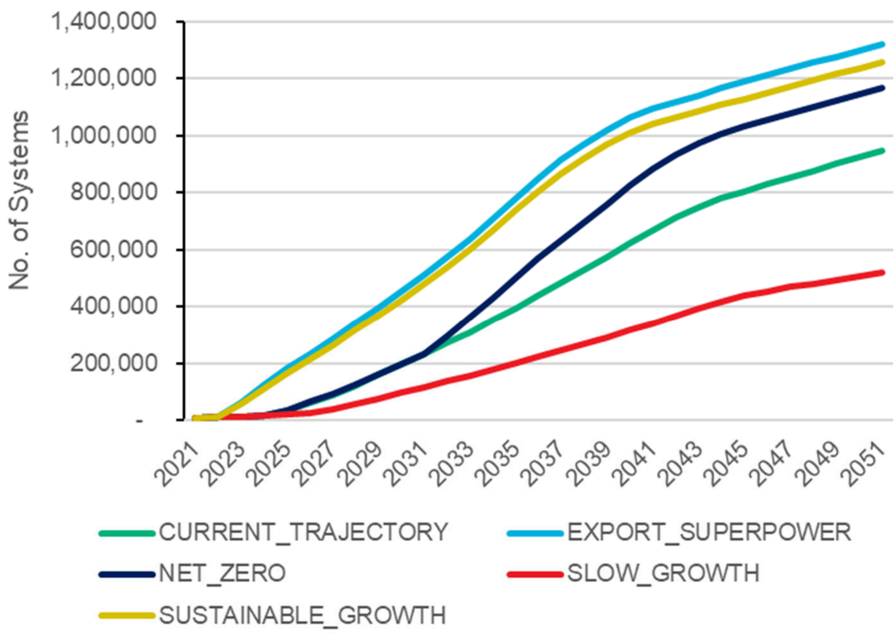
[3] *Due to the fact the DER register is at an early stage of development we have developed estimates of battery capacity that are based on a combination of interviews with several battery suppliers and SunWiz (2020) Australian Battery Market Report -2020 (for media).*

Figure 1-9 WA SWIS cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the WA SWIS. At the beginning of the projection (the end of the 2019-20 financial year) the cumulative number of grid-connected battery systems stands at 4,600. Under Current Trajectory the cumulative number of systems grows to almost 950,000 by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 1.3 million, while the lower bound represented by Slow Growth is 522,000 systems by the end of the projection in 2050-51 financial year.

Figure 1-10 WA SWIS cumulative number of battery systems by scenario



2 Introduction

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2051 of solar and battery uptake for a sub-segment of this market that does not participate in AEMO's scheduled dispatch system. It is optional for systems below 30MW in capacity to be scheduled[4] and so this report only considers systems below this size.

Our results are divided into several system size brackets:

- Residential which are assumed to cover solar systems up to 15kW in size and their associated battery systems, which for modelling purposes were assumed to average 10kWh in size at the beginning of the projection and increase to a maximum of 15kWh.
- Small commercial which are assumed to be between 15kW and 100kW in scale and their associated battery systems, which for modelling purposes were assumed to also average 10kWh in size at the beginning of the projection and increase to a maximum of 15kWh[5].
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries, which for modelling purposes were assumed to be sized between 90kWh to 150kWh depending upon the state.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

Section 3 of this report explains our approach for how we estimated solar and battery uptake.

Section 4 explains the scenarios we used for determining the potential range of solar and battery uptake and the underpinning assumptions of those scenarios.

Section 5 provides the results of our projections and seeks to explain with reference to the Central Scenario what are the underlying drivers or causes behind our results.

[4] Note that in the Western Australian Market the threshold is lower at 10MW.
[5] Commercial battery systems are a similar size to residential systems because even though these premises have a larger load and are assumed to install a larger solar system than residential, the solar system is aligned more closely with daytime load and so has less generation surplus to load that would otherwise be exported to the grid. This substantially reduces the scale of arbitrage the battery can provide in taking power that would be otherwise be exported at a rate tied to wholesale energy costs and instead using it for self-consumption tied to retail rates.

3 Methodology and Approach

3.1 Overview

This report seeks to project uptake for sub-segment of the total solar market which excludes AEMO-scheduled solar systems controlled by their dispatch system. In the NEM it is optional for systems below 30MW in capacity to be scheduled and so this report only considers systems below this size[6]. In addition, we also project uptake of stationary (non-transport) battery energy storage systems used by end-consumers of electricity.

Our results are divided into several system size brackets as noted earlier:

- Residential;
- Small commercial;
- Large commercial; and
- Small power stations.

Green Energy Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period (the years it takes for revenue to exceed the installation cost) which we can then compare against the payback periods in the past. At a simplified level our approach is based on an assumption that installation levels in the past and associated paybacks provide a guide for likely levels of installs in the future. If paybacks deteriorate (get longer) then installations will decline and if paybacks improve (get shorter) then installations rise. This is then moderated by:

- the expected impact of market saturation in each state;
- the rate of new dwelling construction; and
- expected replacement cycles for systems.

In addition, we also account for the influence of non-financial factors such as changes in customer awareness and solar industry competitiveness and marketing which are informed by industry interviews.

In trying to evaluate financial attractiveness of project installations Green Energy Markets has segmented this into two core segments for the purposes of our analysis:

1. What are commonly referred to as "behind-the-meter" installations which are embedded within an end-consumer's premises and can be used to avoid the need to purchase power from the grid at retail electricity rates; as well as potentially exporting electricity to the grid for other customers to consume;
2. In front of the meter installations which are entirely focussed on exporting electricity to the grid and do not offset customer consumption from the grid and so their predominant revenue is set by wholesale electricity market rates, not retail rates.

[6] In the Western Australian Market the threshold is 10MW.

For systems within segment 1 (behind-the meter) we specifically analyse financial attractiveness and then subsequent uptake based upon Green Energy Market's solar and battery system payback model.

For systems within segment 2 (small power stations) we take a different approach. In last year's modelling exercise we tied installation levels linked back to the level of scheduled large solar power station capacity installs projected within the draft Integrated System Plan. However, this year we do not have the benefit of draft results for the scenario's selected under this year's exercise. Given the very large scale of behind-the-meter solar installations that have been and are projected to unfold, and the highly depressed wholesale price conditions that have now materialised during daytime periods, economic conditions into the future are unlikely to be favourable for the deployment of small solar power stations. Consequently, we expect the scale of deployment will be relatively minor and have applied simple rules of thumb for future deployment under each scenario that are tied to development experience over the past 12 months and feedback from solar developers.

For solar and battery systems within segment 1, for the purposes of modelling convenience the solar systems are assumed to be no more than 1 megawatt in size. Meanwhile in front of the meter systems are assumed to be larger than 1 megawatt. In practice there are circumstances where a small number of behind the meter systems are larger than a megawatt and those in front of the meter are sometimes smaller than a megawatt. However better precision is not realistically achievable given the large uncertainties involved in forecasting this area. Given: the vast majority of capacity installed below 1 megawatt is behind the meter installations (and the size of most facilities constrains potential for systems much larger than this); while the vast majority of capacity installed above 1 megawatt is in front of the meter installations; this generalisation is likely to provide a reasonably good guide to capacity installed within the different system size brackets.

Further explanation of the components of the model are detailed in the headings below.

3.2 The payback model

The payback model evaluates the revenues and costs associated with a solar system and a coupled battery system based on three different customer types:

1. Residential – which cover solar systems up to 15kW in capacity and associated battery systems and which generally face electricity charges recovered on the basis of the amount of kilowatt-hours of electricity consumed plus a fixed daily charge;
2. Small commercial – which cover solar systems up to 100kW in capacity and who are assumed to face similar electricity tariff structures as residential consumers;
3. Large commercial – which cover solar systems above 100kW up to 1 MW and are assumed to face large consumer electricity tariffs. These typically involve network charges which involve some kind of demand-based tariff where costs are recovered based on a short 30 minute peak in demand over a month or year as well as the amount of overall kilowatt-hours of consumption.

3.2.1 Costs

Costs for solar systems and any discounts or other financial benefits associated with government policy support are detailed section 4.2 while those for batteries are in section 4.3.

As explained in further detail in section 4.2.1, the financial benefit flowing from government support policies is taken into account in the model as an upfront deduction on the purchase price of the solar or battery system rather than as revenue to simplify calculation processes.

3.2.2 Revenue estimations

In terms of revenues the model examines the degree to which generation from a solar system would:

- Reduce the need for electricity that would otherwise be imported from the grid to meet the customers' demand. This is then multiplied by the electricity price associated with those displaced imports;
- Be exported to the grid which is then multiplied by the expected feed-in tariff.

It then also calculates the degree to which a battery system could provide additional benefit to a consumer through:

- Taking electricity from the solar system that would otherwise be exported to the grid at the feed-in tariff rate and using it at a later period to displace electricity imported from the grid at a higher retail rate;
- On days where exported electricity is insufficient to charge the battery to full capacity, charge from the grid during a time when retail electricity prices were lower in order to avoid electricity imported from the grid when retail electricity prices were higher.

The formula that governs the charging of the battery operates in a manner that is able to perfectly predict the amount of solar exports in a day. If this is insufficient to charge the battery to its full capacity then it charges from the grid for the difference over 8am until 11am. While historically this has not been thought of as an off-peak period, with the increasingly high prevalence of solar in the generation mix this is likely to change.

The model does these calculations via an hour by hour breakdown across a 12 month period for:

- an archetype customer's load for the three customer types (residential/small commercial/large commercial);
- solar generation based on each state/territory's capital city generation profile; and
- different tariffs applying to each hour including whether the day is a weekday or a weekend with these being adjusted depending upon the state/territory and the customer type.

This 12 month period is then replicated out to 2051 but with changes across each year reflective of each year's assumptions for electricity prices.

This hourly breakdown allows for an estimate of how much of the solar generation is absorbed by the customer's load versus being exported and the degree to which the battery can be charged by the grid versus solar generation that would otherwise be exported, and also how much of the customer's imports from the grid can be offset by the battery. It also estimates the extent to which the customer's peak demand (which affects the network demand charge) is reduced by the solar and battery system.

Load profile

For residential consumers the load profile is derived from the smart meter consumption data made available from Ausgrid's Smart Grid, Smart City trial[7]. This provides consumption data for 300 residential sites which were separately metered from their solar generation allowing the impact of a solar system to be analysed independently. The model uses an averaged load profile of these 300 sites.

For both small and large commercial customers the load profile is based on the load for a substation that predominantly services non-residential customers – United Energy's Dandenong Substation[8]. The use of a single sub-station was in order to simplify and speed-up the calculation process. To ensure that this was a reasonable representation of commercial loads in other states it was cross checked against load data for substations serving mainly commercial customers in other states to ensure reasonable similarity in time profile of consumption across hours of the day, weekends versus weekdays and seasons.

The substation load profile was then scaled down to be representative of:

- a small commercial customer likely to use the average-sized commercial solar system claiming STCs, which is close to 20kW; and
- a large commercial customer using a 300kW solar system which is representative of a behind the meter solar system claiming LGCs.

This was guided by feedback from interviews with solar industry participants that they typically apply a rule of thumb in sizing solar systems that aims to keep exported generation (or spilled generation where the system is prevented from exporting) to around 20% or less of total annual solar generation. Industry feedback is that the financial attractiveness of a system to customers usually significantly deteriorates once exports exceed 20% of total annual generation.

3.2.3 Payback outputs

For each year of the projection period the model estimates a payback for a solar system alone and a solar system combined with a battery system. This uses the capital cost of the system for the year in question after deducting the value of government policy support mechanisms and then divides this by the estimated average annual revenue the system will deliver for the next three years.

The consideration of only the next three years' revenue rather than a longer period is based on information gathered from interviews from solar industry participants about customer purchasing behaviour. This suggests that customers do not typically use long-term forecasts about future electricity prices in evaluating the financial attractiveness of a solar or battery system. Instead they will tend to use their current electricity prices with potentially an adjustment to account for where electricity prices will go over the remaining duration of their electricity contract (in the case of large commercial customers); or some rule of thumb adjustment based on their expectation of electricity prices a small number of years into the future (e.g. inflation rate plus 3%).

[7] This dataset is available from Ausgrid's website here: https://www.ausgrid.com.au/Industry/Our-Research/Data-to-share/Solar-home-electricity-data

[8] This data is available from the website of Australia's National Energy Analytics Research Program here: https://near.csiro.au/assets/003fe785-401d-4871-a26d-742cb1776a2f

3.3 Residential demand

We have used detailed historical data for solar PV installations provided by the Clean Energy Regulator (CER). Residential and commercial installations have been segmented based on system size, with systems below 15kW deemed to be residential except in cases prior to 2015 where they are deemed residential if less than 10kW.

We forecast the level of new residential demand for each state with reference to the following four factors:

- Relative financial attractiveness - as represented by simple payback adjusted for changes in interest rates since 2015;
- Relative level of saturation – represented by scaling factor that reduces as saturation increases, we have calibrated this as being 1.0 (no discount) at saturation levels of 20% or less and then reduces to 0.5 (50% discount) at saturation levels of 80%. This is then also converted into an index with 2015 as the base. We have made a further enhancement to exclude the saturation impact with regard to the level of new homes built over the last 15 years;
- Relative customer awareness – heightened media concerns over high power prices has been demonstrated (through market interviews) to be a major contributing factor to customer preparedness to consider solar. We have developed a scaling factor that considers the impact in each year and then convert this into an index with 2015 as the base; and
- Relative solar industry competitiveness and marketing – the level of new market entrants (and exit), general industry competitive environment together with the level of marketing and promotion will also have an impact on solar PV uptake. We have developed a scaling factor that considers the impact in each year and then convert this into an index with 2015 as the base.

The last two factors (customer awareness and industry competitiveness and marketing) are extremely subjective but have clearly impacted on the level of demand particularly since 2017.

The six years from 2015 to 2020 provide a reasonable timeframe and cover new residential installations rising from 124,000 systems in 2015 to 316,000 systems in 2020. This now represents 6 years of reasonable data that is not complicated by solar credits multipliers or extremely attractive feed-in tariffs. The residential market sector can be seen to be mature and enables us to have confidence in this approach, albeit with some subjective factors. Interviews with industry participants have been a key component in gauging factors and issues that are actually working on the ground influencing customer purchasing decisions, beyond just financial attractiveness.

We have developed linear equations that represent the relationship between the level of installation and the adjusted payback in that year.

Our approach can be represented by the following formula:

Demand (year) = Systems derived from Payback equation (year) x Relative Level of Saturation (year) x Relative Customer Awareness Index (year) x Relative Solar Industry Competitive Index (year)

Average system size has increased dramatically over the last 5 years increasing from 4.1 kW per system in 2015 to 6.7 kW per system in 2020. We expect continued modest increases in system size rising to around 7.6 kW per system (although varying slightly by state) by 2030 and 8.2 kW per system by 2050 (varying slightly by state). We expect the benefit of the continued increase in the performance and efficiency of panels to be countered by electricity network constraint whereby it is a much easier process to connect systems where the inverter export capacity is 5kW or less (with oversizing of the panel capacity by a third of the inverter capacity). Yet in spite of this constraint we expect growth in system size will continue, albeit much slower than the past, because module price reductions will mean larger systems make financial sense even though they will be lose a greater portion of their output due to the inverter export constraint.

3.4 Commercial demand up to 100kW systems

The commercial or non-residential sector's demand for solar systems up to 100kW in size continues to be seen as an attractive market by the solar industry, now representing over 20% of installed capacity.

This market sector is not as mature as the residential market and we use 2019 installations as our base level of demand. Similar to our approach for the residential market we project the level of installations based on relative financial attractiveness (relative to the 2019 base year). We also incorporated a scaling factor to reflect the level of saturation and relative customer awareness and relative industry competitiveness and attractiveness similar to the process adopted for the residential sector.

We expect modest increases in average system size growing from around 22kW in 2020-21, to reach around to 29 kW per system by 2029-30 and then remain relatively steady at that level until 2050. The reason for modest growth in average system size is because systems in the commercial sector tend to be sized in accordance with the site load to minimise low value exports.

3.5 Modelling upgrades and replacements of residential and commercial systems up to 100kW

This market sector is increasing albeit from a very low base. Many small systems (less than 1.6 kW) were installed over the 2010 to 2013 period and a number of the customers are expanding their` systems in response to higher power prices and lower panel prices. While this market sector is still relatively small, we expect it to continue to grow and become a much more important feature of the industry in future years as saturation increases.

The commercial upgrade market at an estimated 80 MW in 2020 is currently not that material, however we believe it is worth separating as it has scope to grow in future and it is also important to exclude these systems when considering saturation levels.

We have developed a profile of projected future replacement systems based on (i) relative financial attractiveness and (ii) observed historical level of replacements. We expect that the solar industry will increasingly target this sector particularly as installed battery costs fall and larger new solar and battery packages become more attractive.

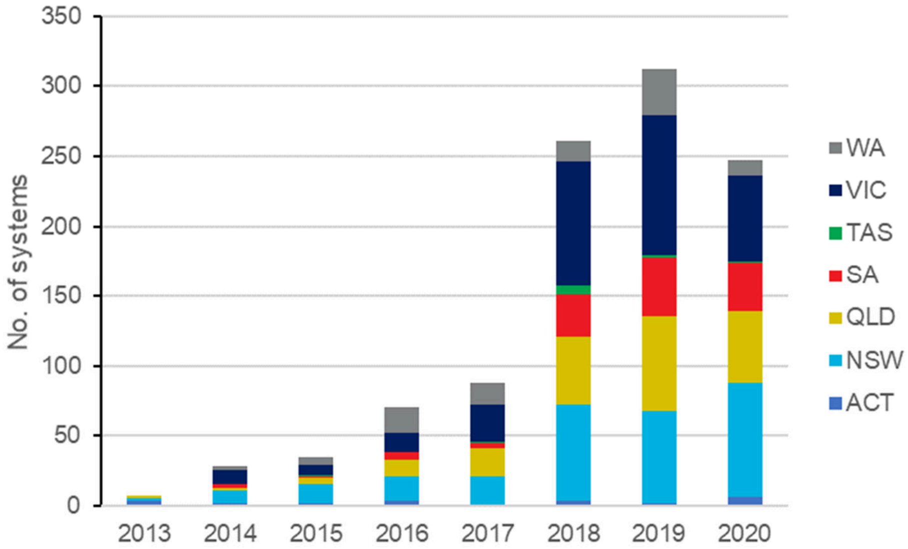
3.6 Large commercial behind the meter systems (above 100kW)

Projecting uptake within this narrow sub-sector of the solar market is subject to considerable uncertainty because the market is highly immature, highly complex and still undergoing rapid development and change.

The market has only really emerged at any noticeable level in the last three years as a result of significant reductions in system costs, and a dramatic increase in the wholesale price of electricity in the east-coast National Electricity Market.

Figure 3-1 illustrates that the number of systems being installed nationally per year only just broke through 300 last year and as recently as 2017 the annual number of systems still lay below 100. At a state level only Victoria has so far managed to record 100 systems in a year and in 2017 all states recorded less than 30 systems. Note that this includes systems that are larger than 1MW but which are known to be behind-the-meter systems.

Figure 3-1 Number of solar systems -behind-the-meter large commercial solar (by calendar year of accreditation)

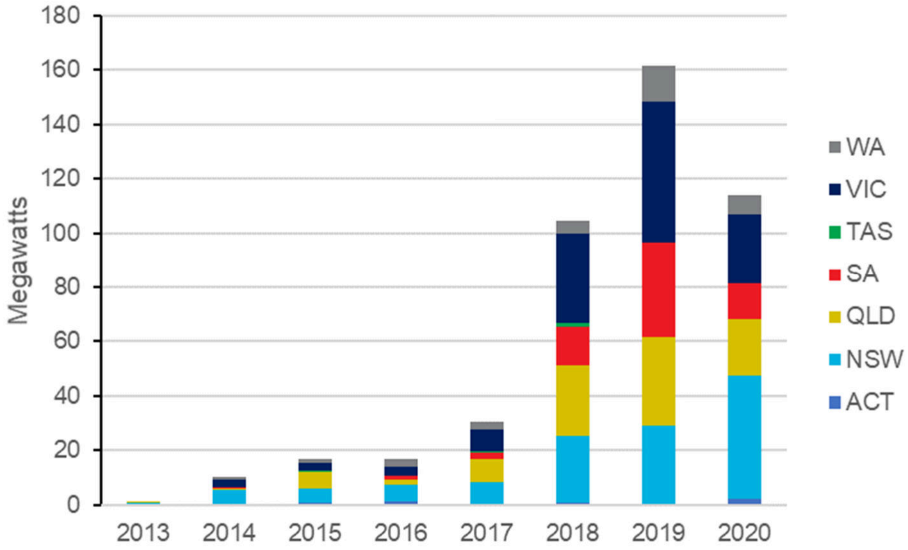


Note: Accreditation data is as at March 2021. There are lags in the awarding of accreditation to systems which means the numbers of systems receiving a 2020 year accreditation are likely to be slightly higher than indicated.

The lack of a suitably large and representative sample set of solar system installations, stretching back over several years and the rapid changes in this market, provide a less than ideal basis for assessing how uptake might change over time in response to different environmental variables. Nonetheless changes in payback periods provide a useful benchmark or guidepost to inform how future mid-scale solar uptake might unfold. The rapid rise in uptake that began in 2016 and has continued into 2019 was preceded by large rises in power prices faced by large commercial customers and rapid reductions in system costs and so uptake in this market is clearly tied to financial payback just as one might logically expect businesses to behave. Further reinforcing this observation is that the rapid growth in installations halted and system numbers fell last year as wholesale energy market costs declined both in terms of the spot market but also the forward contract market (as shown in ASX Energy futures contracts). While COVID-19 restrictions and the accompanying economic downturn cloud the picture somewhat in that they may have negatively influenced the sales environment for the commercial sector, it's clear that the rapid growth path evident after 2015 has now ended.

To guide our projections of uptake we have used 2019 and 2020 behind the meter capacity installs (inclusive of systems above 1MW) and likely customer evaluations of payback (which tend to be heavily biased towards market conditions in the recent past and what is expected only a year or two into the future) as a baseline to calibrate our model. To provide a lower bound guidepost as to how much capacity accredited could fall as paybacks deteriorate, we've used 2016 installation levels as a benchmark which we assume were a product of payback periods based on 2015 market prices. While it varies between states and customer-types, payback periods based on 2015 market conditions were roughly twice to three times as long as what they were in 2019. Figure 3-2 illustrates large commercial solar capacity by accreditation year illustrating that 2016 involved slightly more than 20MW of capacity while 2019 was close to 160MW.

Figure 3-2 Capacity of behind the meter large commercial solar PV (by calendar year of accreditation)



Note: Accreditation data is as at March. There are lags in the awarding of accreditation to systems which means the capacity receiving a 2020 year accreditation is likely to be slightly higher than indicated.

While these historical benchmarks provide a useful guide for how uptake might change if payback remains the same as it was around 2018 and 2019 or deteriorates, we lack a guide for how uptake might increase above 2019 levels if paybacks get shorter than recent levels. While it seems unlikely that power prices will increase substantially above the levels experienced in the last 3 years in the NEM (our projections assume they decline), it is very likely that system costs will decline. Also if governments seek to follow through on their ambitious long-term emission reduction commitments, then policy support could also increase (see section 4.2.1 and 4.3.1 for assumptions on government policy support for emission reductions by scenario). We have assumed that if paybacks were to halve from 2018-2019 levels then capacity installs would double but should acknowledge that this is subject to considerable uncertainty.

Paybacks and uptake are calibrated to installation levels in each state however with some adjustments to uptake in South Australia and NSW.

Figure 3-2 illustrates that in 2019 South Australia's share of solar PV installs in this segment are vastly greater than their share of total electricity consumption, population or GDP. They installed 10% more than NSW, yet NSW's business sector consumes over five times the electricity of South Australia's business sector. While one would expect that South Australia would have a higher rate of solar PV installs amongst businesses than other states given it has higher electricity prices, it seems unlikely such an out of proportion share would persist due to saturation effects. South Australia also has higher solar PV installation rates in the residential sector relative to other states but their share of the national residential market comes nothing close to what is seen for large commercial (SA represented 9% of Australian residential capacity additions but 20% of large-commercial behind the meter capacity in the 2019 calendar year). Our view is that

SA's large commercial solar market is more advanced and mature than the rest of the country because it has had high electricity prices for longer than other states. But as a consequence, SA will also approach challenges with market saturation sooner than other states which will slow sales. We therefore scale back SA uptake such that if paybacks were to replicate conditions in 2019, they would install 40% of the capacity that occurred in 2019. We also make one further modification to SA uptake in the 2021 and 2022 financial year to add in capacity from SA Water's roll-out of 154MW of solar (but remove those systems that will controlled via AEMO central dispatch). This single company's roll-out is equal to more than the entire national 2019 level of installs and so required a one-off external adjustment.

Another adjustment was deemed necessary to scale-up NSW uptake levels to a level of capacity greater than what was installed in 2019 which appears abnormally low relative to other states and relative to capacity installs in NSW in 2018 and 2020. Because the large commercial solar market still involves relatively small numbers of systems there is likely to be some volatility in figures from year to year that it is random rather than a function of long-term fundamentals. While all other mainland states recorded significant growth in annual capacity additions between 2018 and 2019, NSW annual capacity additions declined by 27% even though paybacks had not deteriorated. Then in 2020 NSW installed almost 60% more capacity than 2019 even though paybacks were relatively similar. Meanwhile all other states experienced capacity declines between 2019 and 2020.

Average system size for behind the meter in our modelling remains constant at 300kW per system across the outlook period. This is similar to what has been seen in the last few years, although with very wide variation. We maintain this constant assumption because systems in the large commercial sector are almost always sized in alignment with the load, unlike the residential sector where the industry seeks to sell as large a system as the customer can be persuaded to pay for (which is the profit maximising approach in the residential sector). Large commercial customers tend to apply more sophisticated financial evaluations to the solar purchase decision and minimising the level of exports is pivotal to maximising the financial attractiveness of a system. Furthermore, distribution network companies will require what can be quite costly and time-consuming grid studies for systems which export power and this also acts to constrain system sizes to something reasonably closely matched to daytime load on the site.

3.7 Battery uptake for behind the meter systems

Batteries are yet to reach levels of financial attractiveness (across all the behind the meter market segments analysed) that would support mass-market uptake. While the current very low levels of uptake and relatively poor paybacks give us a minimum baseline for uptake, they don't provide much usefulness in guiding how uptake might rise if paybacks improve materially.

Our model currently assumes that battery uptake only takes place once the paybacks on a battery plus solar system reach close to parity with the payback on a solar system alone. Battery uptake is assumed to follow similar rates of system uptake relative to payback as what we assess for solar systems in each of the customer segments analysed.

This approach however results in a gap in the first few years of the projection where the model projects zero battery uptake or battery uptake well below historical levels, because battery paybacks are so long (noticeably greater than warrantee period) in these years. For this interim period between historical actuals and when the model starts to estimate significant battery uptake we assume battery uptake follows a transition path of growth that is partly informed by how paybacks are estimated to improve over time in each scenario.

3.8 Power stations 1MW - 30MW

As mentioned earlier for solar systems larger than a megawatt in scale, these are assumed to be in front of the meter power station installations. This means their revenue is derived solely from wholesale electricity markets. They are not embedded within an electricity consumer's site and offsetting electricity that would otherwise need to be purchased from the grid at retail rates.

In last year's modelling exercise we tied installation levels back to the level of scheduled large solar power station capacity installs projected within the draft Integrated System Plan given solar power projects below 30MW will experience similar economics to those above 30MW. However, this year we do not have the benefit of draft results for the scenario's selected under this year's exercise. As noted previously, given the very large scale of behind-the-meter solar installations that have been and are projected to unfold, and the highly depressed wholesale price conditions that have already materialised during daytime periods, economic conditions into the future are unlikely to be favourable for the deployment of small solar power stations. Consequently, we expect the scale of deployment will be relatively minor. In the absence of market-wide supply-demand modelling we have applied simple rules of thumb for future deployment under each scenario that are tied to development experience over the past 12 months and feedback from solar developers.

Feedback from developers is that projects below 30MW in scale are not particularly attractive to pursue relative to those larger than 30MW with the one exception of those sized just below the 5MW threshold which are exempted from a range of regulatory requirements. This allows them to be built and commissioned faster and at less expense while also avoiding ongoing administrative costs that apply to projects above 5MW. Consequently, our modelling uses a simplifying assumption that power stations are all built to fit under this 5MW threshold.

Initially though, for 2021-22 and 2022-23 years we estimate installations based on bottom-up information on actual projects gathered from a range of solar developers and equipment providers. Then in 2023-24 we expect no projects at all will be installed due to highly depressed wholesale daytime prices over the preceding few years. We then expect a modest recovery in economic conditions for solar power stations as system costs decline and the market seeks to respond in anticipation of announced coal power plant closures.

Under Current Trajectory we assume project numbers for NSW, QLD and Victoria grow gradually to ten projects per annum per state from 2032 onwards. South Australia isn't anticipated to recover to its historical highs due to its now very high proportion of supply met by solar and relatively small overall electricity demand. It installs just 2 projects per annum of 5MW. Tasmania is expected to remain relatively unattractive to solar developers but given the lower levels of competing behind the meter solar in the state, it begins to deploy a project each year from 2028 onwards.

The level of build under other scenarios departs from Current Trajectory in accordance with expected emissions abatement ambition. Slow Growth sees no power station activity while Export Superpower sees around triple the capacity installed, and Sustainable Growth and Net Zero have about double the capacity of Current Trajectory.

3.9 Changes to the modelling approach relative to last year's estimates

3.9.1 The challenges of forecasting an immature market

The Australian market for distributed solar PV and battery energy storage is subject to considerable uncertainties and historical volatility that means any forecast, but particularly ones projecting outcomes over a 30 year period, are subject to a high degree of error.

The market for solar PV in Australia only emerged at a significant scale a little more than a decade ago. Meanwhile the market for grid-connected battery energy storage systems is still at what would be best described as an infant stage. This provides a relatively limited historical dataset to inform our understanding of the how capacity installs might respond to changes in environmental conditions. The size of the DER market has and continues to rapidly change, with the sub-100kW solar sector experiencing 20% to 30% growth so far this calendar year when comparing one month against the same month last year. What complicates matters for forecasting is that the Australian solar PV market since 2009 has experienced not just very rapid growth in many years, but also significant contractions in annual system sales and megawatts of capacity (there was a major contraction after 2012 until 2016). Over the past decade annual capacity installs have grown by as much as 400% year on year and contracted by as much as 20%. This is a level of volatility completely unlike that seen for overall electricity consumption in Australia that would change by at most a few percentage points each year.

Given this extreme volatility, the track record of forecasting the solar market at both an Australian and global level has, unsurprisingly, been patchy at best, with the International Energy Agency's forecasts notorious for systemically underestimating the market. In the case of Green Energy Markets' own forecasts however these have suffered from both overestimates and underestimates of annual capacity installations at different times over the past decade.

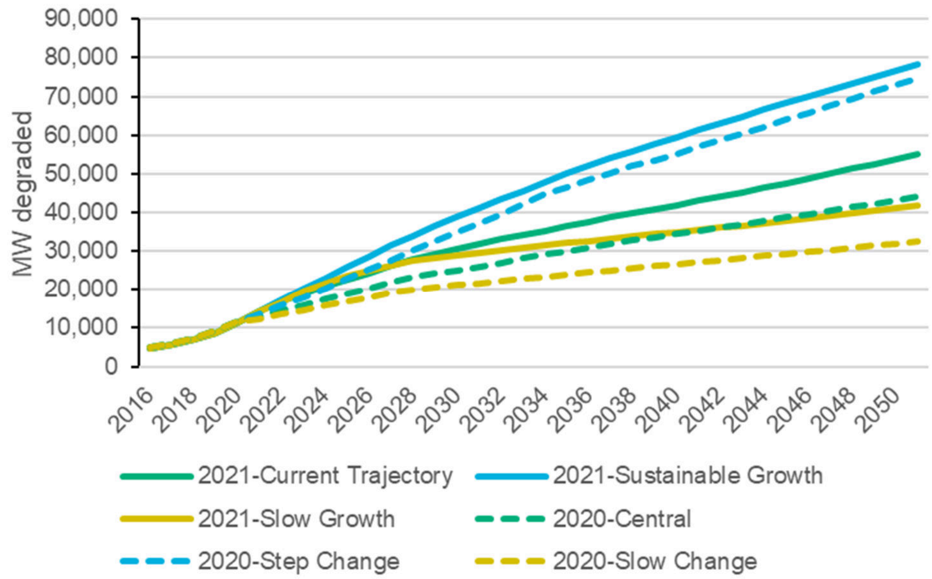
A further complication affecting these forecasts is that while the level of data around the solar PV market is comprehensive and highly accurate (due to the SRES scheme providing an incentive for installers to register systems with the Clean Energy Regulator), data on the market for batteries is poor. While the establishment of the DER Register should improve our understanding of the battery market over time, Green Energy Markets has found a wide divergence between system numbers within the DER Register and the number of system sales reported by battery suppliers (the size of the market is substantially larger according to battery suppliers than what is captured within the DER Register). While the DER Register provides quite a detailed, geographic record of battery systems it is probably not comprehensive. Meanwhile the information battery suppliers are willing to provide may be a more accurate picture of the overall size of the market but with minimal detail on the location and nature of systems being installed.

Given the volatility and uncertainty surrounding the future of the DER market, forecasts need to be treated as an approximate guide that needs to be regularly re-evaluated in light of new information and experience. This has certainly been the case for this year's edition of our forecasts where we have modified our modelling approach in an attempt to learn from new information as explained below.

3.9.2 Solar PV

We have substantially increased estimates of both solar and battery capacity installations this year relative to last year's modelling exercise, particularly in the short-term as shown in the chart below. The solid lines represent this year's (2021) forecasting results while the dashed lines represent last year's forecasts with colours assigned according to which scenarios are similar to last year's scenarios.

Figure 3-3 Degraded cumulative PV capacity- 2021 relative to 2020 forecasts



Installations in the 2020 calendar year proved to be a major surprise relative to what had been forecast at the beginning of that year, mainly in the residential segment of the market. The forecast developed for AEMO had annual megawatt additions to stock declining by over 20%, yet instead they grew significantly compared to 2019 calendar year levels. This was even though both feed-in tariffs and electricity retail charges declined in 2020 relative to 2019. Also, 2021 installs of capacity so far this year have been running at rates noticeably higher than the records set in 2020. This has necessitated a re-evaluation of our methods and assumptions for the residential sector.

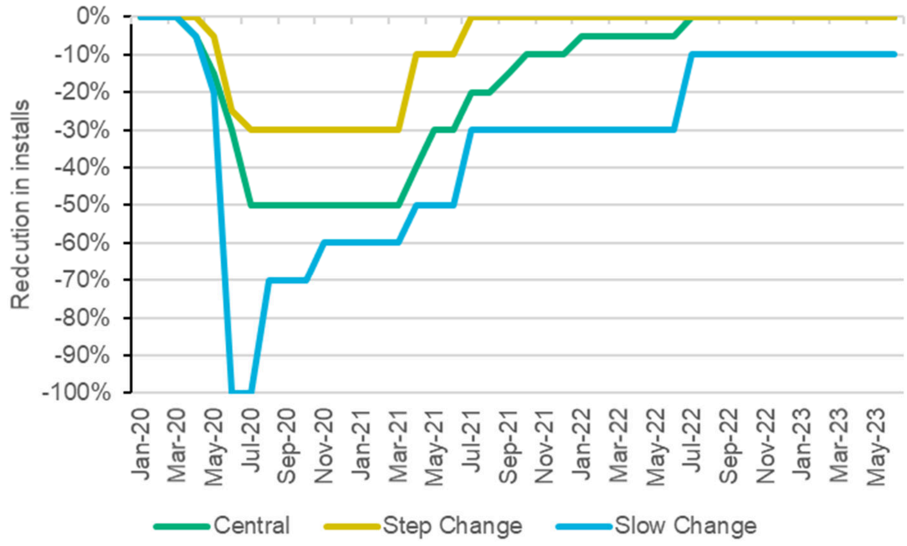
There were three key issues that have been modified in approach this year in light of the underestimates in the 2020 forecasts. These are explained in the headings below.

1- COVID 19 adjustment

The most important factor in explaining the underestimate is a misreading of the impact of COVID-19 restriction measures on the solar market. In March last year, part way through developing last years' projections Australian State and Federal Governments as well as governments overseas introduced a range of measures to contain the spread of the COVID-19 virus. These measures (and the health impact of COVID 19 itself in countries overseas) had a very rapid and significant impact in reducing economic activity and incomes including a significant increase in unemployment in Australia and the rest of the world.

As a result of the significant change in economic circumstances AEMO requested in late March that GEM make adjustments to projections to try to account for the potential impact of this economic downturn on solar PV and battery uptake. A survey via PV Magazine as well as interviews with several solar industry participants indicated that customer inquiries had fallen by around 50% over March relative to the preceding 6 to 12 months. This led us to make substantial manual downward adjustments to our initial model projections as detailed in the figure below for three of the scenarios.

Figure 3-4 Downward adjustment in solar system projections to account for COVID-19 impact



With the benefit of hindsight, we can now see that March was possibly the worst point for Australia in terms of the economic impact of COVID-19 and consumer confidence. While things looked extremely grave in March, several months on the country had managed to contain the spread of COVID 19 to very low or even non-existent levels (with the temporary exception of Victoria) such that governments could substantially relax restrictions on social interaction. Also the Federal Government provided significant fiscal stimulus that helped to alleviate some of the economic impacts.

Furthermore COVID-19 restrictions on travel and hospitality and greater confinement of people within their own homes also appear to have had the unanticipated effect of stimulating household expenditure on goods related to the home. Retailers selling household durable goods and home improvement hardware saw substantial increases in sales[9]. We suspect that solar suppliers were another beneficiary of this COVID19-induced home improvement expenditure effect, especially given increased incidence of working from home would have increased daytime electricity consumption.

So in the end COVID 19 had the very opposite effect to what was initially anticipated and this adjustment has been removed from our analysis.

2 - The feed-in tariff retailer premium

Our model has previously assumed that feed-in tariffs offered to residential customers would closely match the value of solar generation in the wholesale electricity market except where government policy specifically regulated an alternative rate. However, it has become apparent that in regions where the feed-in tariff is unregulated (QLD, SA and NSW) most of the major electricity retailers offer at least one product that provides a feed-in tariff noticeably higher than what a solar generation profile could expect to receive from the wholesale electricity market. Our understanding is that power retailers use the feed-in tariff rate as a marketing tool to attract some types of customers whose choice of retailer

[9] S. Mitchell (2020) *'Cocooning' boom could go on for years: Gerry Harvey*, Australian Financial Review, 25 November 2020, https://www.afr.com/companies/retail/harvey-norman-profits-rocket-as-consumers-cocoon-at-home-20201125-p56hpq; S. Marsh (2020) *Bunnings, Officeworks shine as Wesfarmers delivers $1.7 billion profit*, 9News.com.au, 20 August 2020, https://www.9news.com.au/national/wesfarmers-fy20-financial-results-bunnings-kmart-officeworks-giant-booms-during-covid19/0f370d5a-9bb1-4a64-a4d3-e7b69d9ab583

is predominantly driven by the feed-in tariff above other factors. In our research we find that while retailers will often also offer other products with lower energy import and fixed charges coupled with a lower feed-in tariff, the owner of a solar system sized at 6.6kW will usually be better off with the higher feed-in tariff product from a particular given retailer. This practice of offering a high feed-in tariff product is widespread across many electricity retailers and has remained commonplace even as the wholesale value of solar generation has dropped dramatically over the last two years.

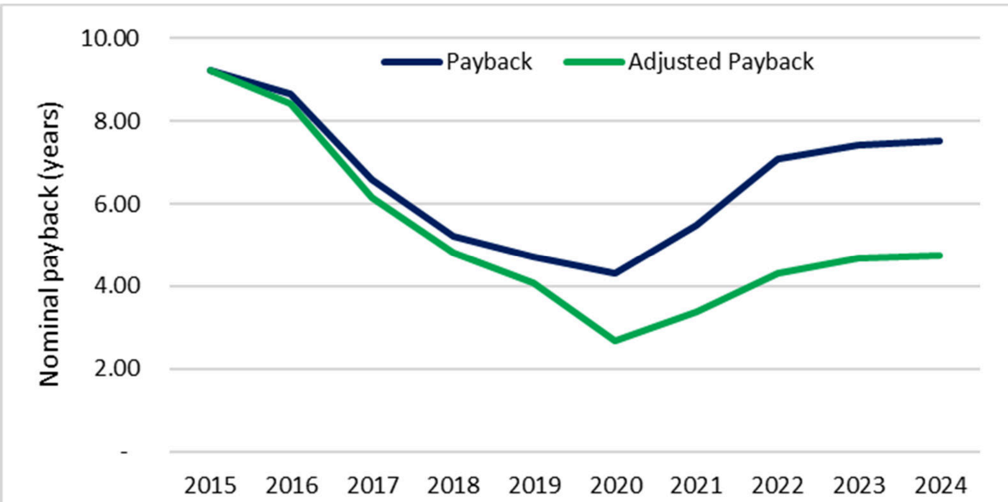
Due to the widespread nature of this practice, our model's estimate of feed-in tariffs for the residential sector now incorporates a 3 cent per kWh premium on top of the wholesale market energy rate. This premium is derived from a review of major retailers offers provided on the EnergyMadeEasy retailer comparison website across QLD, SA and NSW with an adjustment to partially account for the higher fixed and energy import charges.

3 - Falling borrowing costs

Over the last few years interest rates, particularly for home loans, but also other forms of household debt, other than credit cards, have fallen considerably. While industry feedback indicates that households tend not to rely on finance directly linked to the purchase of solar systems, it is rational that in evaluating whether to make a home improvement investment, households would at least roughly benchmark that investment against a home loan interest rate. Even if a household is not borrowing additional funds from the bank to specifically purchase a solar system, they may fund such a purchase by drawing down on funds within their home loan offset account. Alternatively, those that own their home outright, such as many retirees, could also be influence by low interest rates through benchmarking the solar investment relative to the interest paid on a bank deposit account.

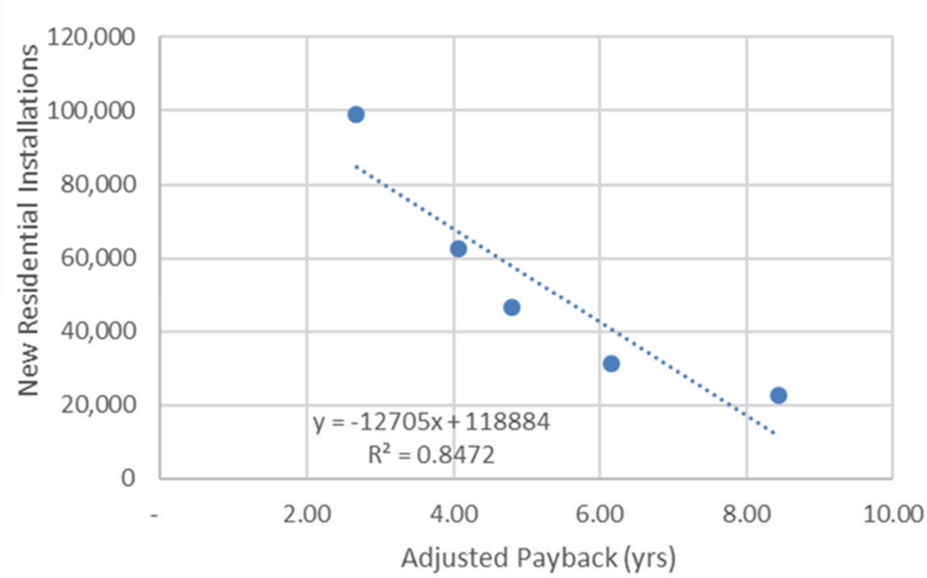
In our model we apply simple paybacks to evaluate solar financial attractiveness rather than for example IRR or NPV (which incorporate a rate of return) as it reduces model complexity and industry feedback suggests it more closely approximates how consumers actually make solar purchasing decisions. However, given borrowing costs have fallen so much we have sought to evaluate how this might have made consumer uptake more responsive (more inclined to purchase) to a given payback period over time as interest rates have declined. The impact of this adjustment on paybacks for NSW installations is shown in Figure 3-5

Figure 3-5 Nominal Payback adjusted for lower interest rates (NSW)



The adjusted payback each year for each state has been mapped against the level of installations each year to arrive at an equation that expresses the relationship between payback and the level of installations. The equation derived for NSW is shown in Figure 3-6

Figure 3-6 NSW system installations as a function of adjusted payback

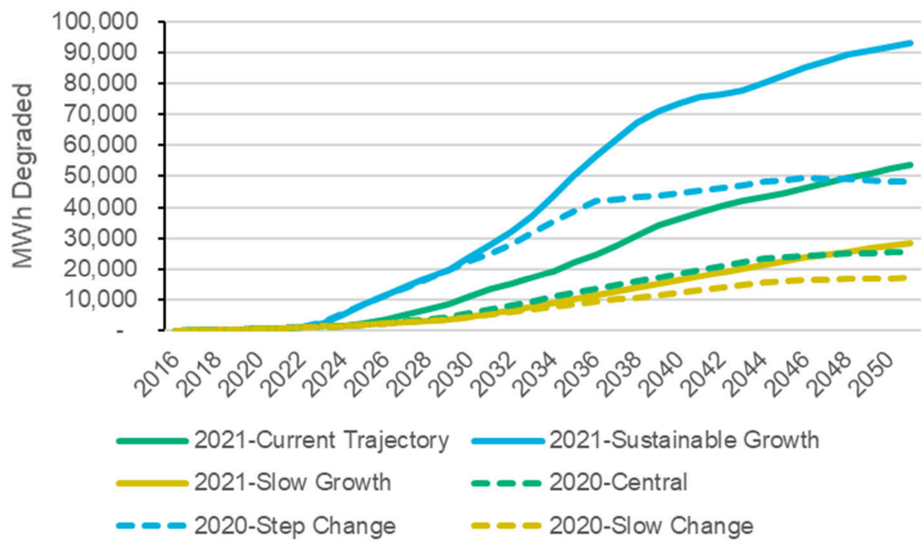


This adjustment to account for lower borrowing costs means that the level of uptake of solar is now greater for a given payback period on a solar system.

3.9.3 Batteries

Our forecasts of battery capacity this year have also been substantially increased relative to last year's forecast as shown in the figure below with the dashed lines representing last year's forecasts by scenario.

Figure 3-7 Degraded cumulative MWh battery capacity- 2021 relative to 2020 forecasts



There are two main reasons for the difference. The first is that battery uptake is tied to our model's expectations of solar uptake and solar uptake has been significantly increased in this year's forecasts. The second is that we now assume that the typical battery system capacity for households and small businesses will grow from 10kWh at present to 15 kWh by the end of this decade, whereas in last year's forecasts we held battery system size constant at 10kWh throughout the forecast period. The reason for increasing the battery size was based on observations of how the solar market has evolved over time and that similar patterns are likely to play out in batteries. In the solar market as the equipment costs per unit of capacity have declined, solar retailers have taken advantage of this change by upselling households to larger capacity systems which allow for greater profit margins given sales and installation costs are largely fixed irrespective of system size.

4 Scenarios and associated assumptions

4.1 About the scenarios

Projections for solar and battery uptake have been developed for five different scenarios that are intended to be consistent with AEMO's planning and assumptions for its overall electricity system planning process (note Rapid Decarbonisation is merged with Export Superpower for the purposes of our DER projections).

Table 4-1 provides a summary of the approach we have taken with the main modelling input assumptions or factors across each scenario. To assist with consistency, we have used the CSIRO's 2020-21 GenCost analysis[10] for guidance on the capital cost and LCOE of various power generation and storage technologies. However, in the case of distributed solar and batteries we have adapted these to a degree based on our own judgement about what cost reductions are likely to be achieved based on our own analysis of market data and interviews with solar industry participants.

[10] Graham, Hayward, Foster, Havas (2020) GenCost 2020-21 – Consultation Draft – December 2020

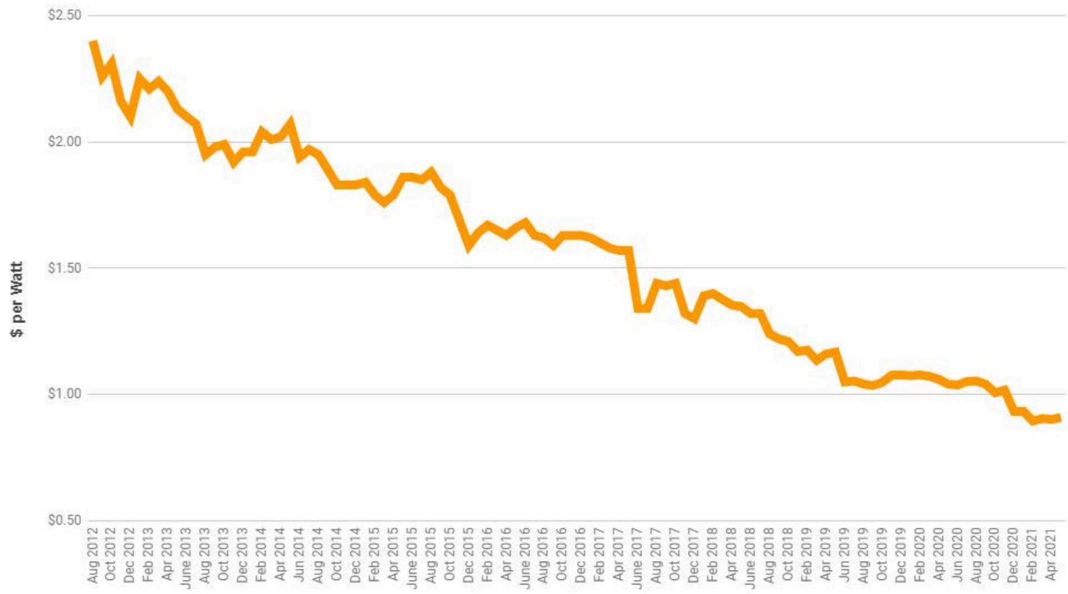
Table 4-1 Overview of modelling assumptions for each scenario

Modelling factor	Current Trajectory	Net Zero	Slow Growth	Export Superpower/ Rapid Decarbonisation	Sustainable Growth
Guiding themes	Continuation of existing technological trends. No new climate policies even though Paris commitment and states' 2050 net zero targets will not be met.	Continuation of existing technological trends but after 2030 major step up in policy effort to achieve net zero emissions by 2050.	Slowing in technological progress, regression in policy effort to reduce emissions. Subdued economy leading to lower power demand and lower conventional energy prices.	Rapid technological progress, major lift in demand for electricity to displace other energy fuels and production of hydrogen, policies target rapid emission reductions. High population growth.	Rapid technological progress combined with ambitious emission reduction policies but not as rapid emission reductions as Export Superpower/Rapid Decarbonisation. Increasing electrificiation but more modest growth in population and electricity consumption than Export Superpower.
Distributed solar and battery cost reductions	Steady cost reductions that align with CSIRO Gen-cost Central	Steady cost reductions that align with CSIRO Gen-cost Central	Slow cost reductions that align with CSIRO Gen-cost Diverse Technology	Rapid cost reductions that align with CSIRO Gen-cost High VRE	Rapid cost reductions that align with CSIRO Gen-cost High VRE
Centralised wholesale generation costs	Costs during solar period decline to very low levels but peak period remains persistently high.	Similar to Current Trajectory	Solar period costs higher than Current Trajectory but Peak period lower due to lower demand and fuel costs.	Lower that current trajectory over long term due to rapid technological progress	Lower over long term than Current Trajectory due to rapid technological progress
Government support for batteries	Just existing policies of SA and Vic household battery rebates and NSW Peak Demand Reduction Scheme.	After 2030 national policy to cover half capital cost of battery.	Support policies for batteries withdrawn.	National policy introduced in 2022 to cover half capital cost of battery	National policy introduced in 2022 to cover half capital cost of battery
Government support for solar	Just existing policies (SRES, LRET, Victorian Energy Upgrades, Victorian Solar Homes)	Existing policies to 2030 and then significant support provided via large expansion in Emission Reduction Fund or other demand for Australian Carbon Credit Units which exceeds that of Sustainable growth over 2030's to catch-up on lost time but with ultimate same emissions outcome by 2050.	Existing policies are withdrawn early and no new policies introduced except for a temporary rebate as part of economic stimulus in 2022-2024.	Existing policies overtaken by large expansion in Emission Reduction Fund and other demand for Australian Carbon Credit Units	Existing policies overtaken by large expansion in Emission Reduction Fund and other demand for Australian Carbon Credit Units but is less than Export Superpower/Rapid Decarbonisation.
Network charges and role of virtual power plants	Network charges remain stable but move to recovery via time of use tariffs. Growth of VPPs steady.	Network charges same as Current Trajectory. Growth of VPPs rapid after 2030.	Same as Current Trajectory but with higher fixed charge and lower variable (per kWh) charges.	Network charges same as Current Trajectory. Growth of VPPs rapid from 2020's.	Network charges same as Current Trajectory. Growth of VPPs rapid from 2020's.

4.2 Capital cost - PV

To help calibrate solar uptake to payback relative to historical levels we maintain records of system costs over time and use the Solar Choice Price Index as one of our inputs. As shown in Figure 4-1 illustrating solar system prices after the STC discount since August 2012, suppliers of solar have historically managed to achieve substantial and steady cost reductions over time. Critically, these cost reductions have managed to outpace the reductions that have been made to the value of the STC discount which stepped down substantially in 2013 and then further annual reductions after 2016 as the deeming period has been reduced.

Figure 4-1 Customer out of pocket installed system costs (after STCs) per watt of system capacity

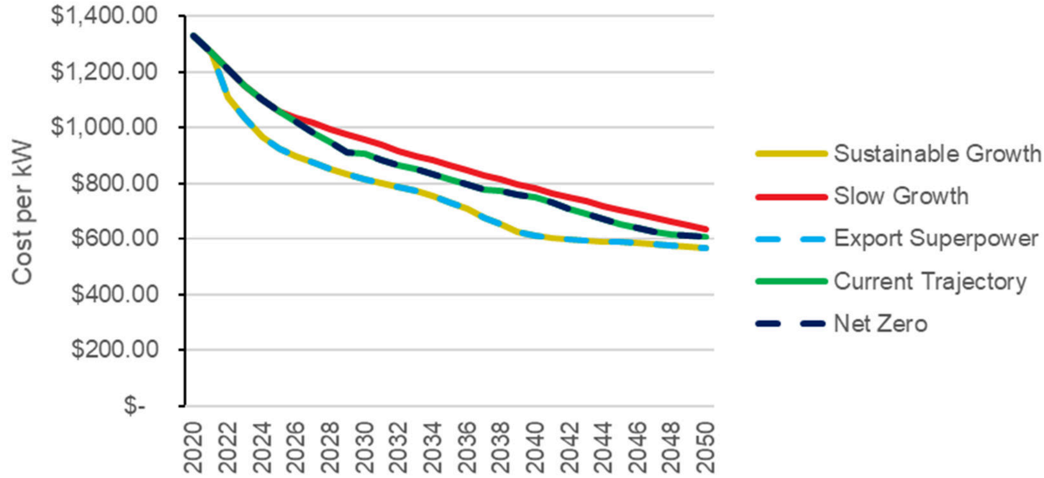


Source: https://www.solarchoice.net.au/blog/solar-power-system-prices

Cost reductions to date have been due to a combination of factors, including; declines in module prices, lower labour and balance of system equipment costs per watt installed through gains in solar module conversion efficiency and increasing system size.

In Figure 4-2 we detail assumed solar system costs per kW by scenario before the impact of any government financial support such as STCs or rebates.

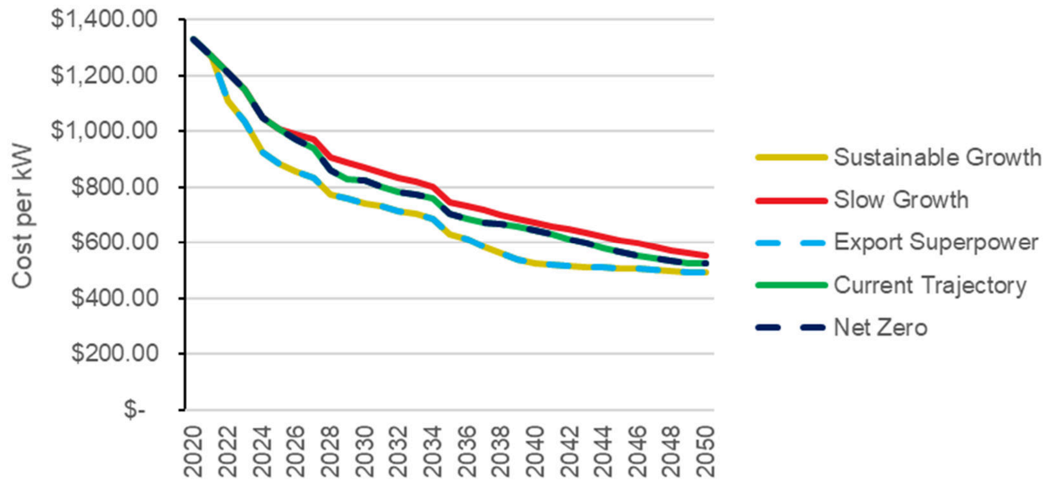
Figure 4-2 Fully installed residential solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



Sources: Current Trajectory based on Green Energy Markets' analysis of most likely cost trajectory until 2030 from which point it is aligned with CSIRO GenCost Central Scenario, Slow Change has same starting point as Current Trajectory and then follows a trajectory that aligns with CSIRO Gencost's Diverse Technology (higher cost) scenario by 2030. Sustainable Growth and Export Superpower follow CSIRO GenCost's High VRE (lower cost) scenario's capital cost from 2021-22. Note – includes GST.

Figure 4-3 below provides our capital cost assumptions for commercial-sized systems.

Figure 4-3 Fully installed commercial solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



Sources: Current Trajectory based on Green Energy Markets' analysis of most likely cost trajectory until 2030 from which point it is aligned with CSIRO GenCost Central Scenario, Slow Change has same starting point as Current Trajectory and then follows a trajectory that aligns with CSIRO Gencost's Diverse Technology (higher cost) scenario by 2030. Sustainable Growth and Export Superpower follow CSIRO GenCost's High VRE (lower cost) scenario's capital cost from 2021-22. Note – excludes GST.

4.2.1 Incorporating the impact of government support policies

To ease the calculation process the value of any government support policies to solar or batteries are estimated in the model as an upfront financial discount that is deducted from capital cost of the solar and/or battery system, rather than as an annual revenue flow. In terms of STCs this is what already occurs and is also the case for a range of solar and battery rebate programs offered at present to residential consumers. While such upfront discount offers are not yet common in terms of policy support delivered via abatement certificates such as LGCs or ACCUs, given customers will often estimate the discounted cash flow impact of such certificates in evaluating a purchase, our approach still provides an effective representation of how customers would evaluate such an investment.

STCs under the Small Scale Renewable Energy Scheme

For solar systems up to 100kW the model estimates the upfront discount the solar system would receive from STCs with the model valuing an STC at $38 fixed until the scheme ends in 2031. The number of STCs a solar system receives are determined by the deemed generation estimated by the Clean Energy Regulator based on each state and territory's capital city. The years of deemed generation steps down by a year until 2031 when the program ends.

LGCs under the Large Scale Renewable Energy Target

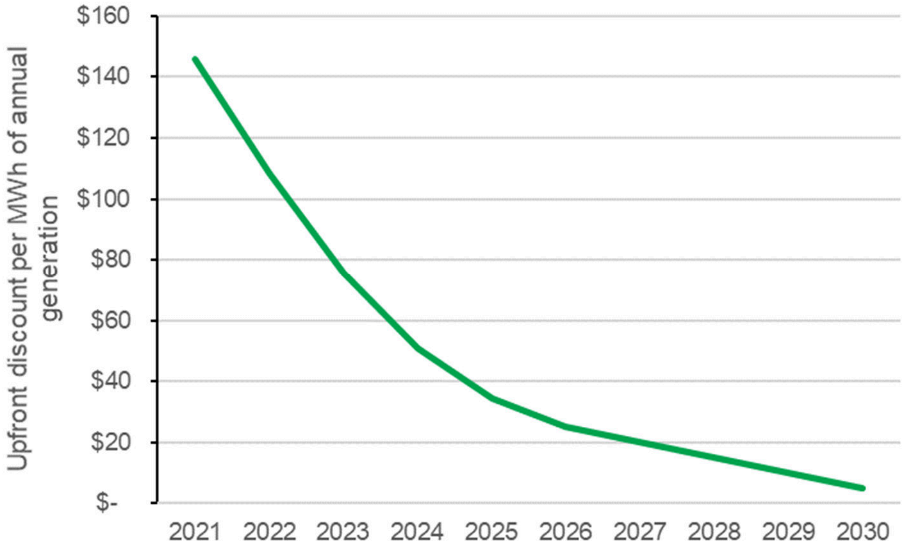
As an alternative to STCs, solar systems can instead claim Large-Generation Certificates or LGCs which electricity retailers and some other large electricity consumers are obligated to purchase in order to achieve the national Renewable Energy Target. LGCs are awarded to a solar system owner on the basis of one LGC per MWh of electricity generated by the system. There is no system capacity eligibility requirement for claiming LGCs, however a system that claims STCs is not eligible to also claim LGCs. In the model we assume that only solar systems greater than 100kW will claim LGCs with those 100kW or smaller all opting for STCs.

As touched upon earlier, while in practice an LGC is only awarded to a solar system after it generates a megawatt-hour of electricity, in the model we estimate the lifetime of megawatt-hours the system would generate that are eligible for LGCs and the real financial value of those LGCs. This is then deducted from the capital cost of the solar system, similar to what already occurs with the deeming of STCs.

The figure below illustrates the upfront, one-off capital cost discount or reduction the model applies based on the system's expected annual MWh of production. This declines over time because the LRET scheme ends in 2030 and so the amount of generation that will be eligible for LGCs gets shorter as we get closer to 2030. In addition, the price per LGC is expected to fall significantly over the next few years due to supply of LGCs growing beyond the level of mandated demand under the Renewable Energy Act. The upfront discount value applied from LGCs is the same across all scenarios.

Figure 4-4 Upfront discount to a solar system from LGCs

(Applies to all scenarios)



To explain how this works with an example, a 300 kilowatt solar system installed in Sydney can be expected to generate an average of 427MWh per year. The upfront reduction applied to the purchase price of such a solar system installed in 2020 in the model is 427 multiplied by $92, whereas a system installed 2025 receives 427 multiplied by $30.

Victorian Government Solar Homes Program

In 2018 the Victorian Government announced that it would seek to achieve an additional 650,000 solar systems on residential dwellings by 2028 via a Solar Homes Program. It then subsequently extended the program to also provide rebates to landlords installing solar on their rental properties and expanded the target to 700,000 solar systems. This program involved a rebate capped at a maximum of $2,225 per system (for a 4kW system) plus an interest-free four year loan to cover the remaining out of pocket costs, also up to a maximum of $2,225 per system. The Government has since indicated that the amount of the rebate will step down over time and it reduced it to a maximum of $1,888 per system on 1 January 2020 and reduced the loan to the same amount. It then made a further reduction in the rebate and loan to 1,850 from July 2020.

The model takes this into account through assuming that the Victorian government will more or less achieve its target of 70,000 systems per annum over the period of the program. So far the rebate for owner-occupied premises has overshot its 65,000 per annum target while the smaller program for rental properties has fallen short of 5,000 per annum. However, taking the two on balance as a package indicates the achievement of the 70,000 per annum target is credible.

Climate Solutions Fund and Safeguard Mechanism ACCUs

Under the Industrial Electricity and Fuel Efficiency Methodology solar systems located behind the meter are eligible to create Australian Carbon Credit Units (ACCUs) for the abatement they deliver in offsetting/avoiding the use of fossil fuels over a 7 year project crediting period. These ACCUs can then be sold to either:

- The Federal Government via the Emission Reduction Fund or Climate Solutions Fund;
- Entities that are short of sufficient ACCUs to honour their abatement delivery contracts with the Federal Government;
- Emitting facilities that are liable under the Federal Government's Safeguard Mechanism to keep their emissions below a regulated emission baseline
- Entities that are voluntarily seeking to reduce emissions.

To date solar systems have not created ACCUs because it has been administratively easier and more financially rewarding to create LGCs or STCs. However, with LGCs likely to fall in value and with the LRET coming to an end in 2030, it is conceivable that creating ACCUs may be preferable for systems above 100kW.

The value of these ACCUs based on 7 year's worth of self-consumption of generation is taken into account in the model for solar systems above 100kW on a national basis where these provide a higher value than claiming LGCs or, where applicable, state-based abatement certificate entitlements. It is assumed there will be a market for ACCUs out to 2050 under all scenarios except Slow Growth. Also under Export Superpower it is assumed the crediting period for abatement for solar systems is extended from 7 years to 10 years. It is also assumed that ACCUs are awarded for all generation, not just generation which displaces imports of power from the grid in Export Superpower and Sustainable Growth as well as Net Zero after 2030.

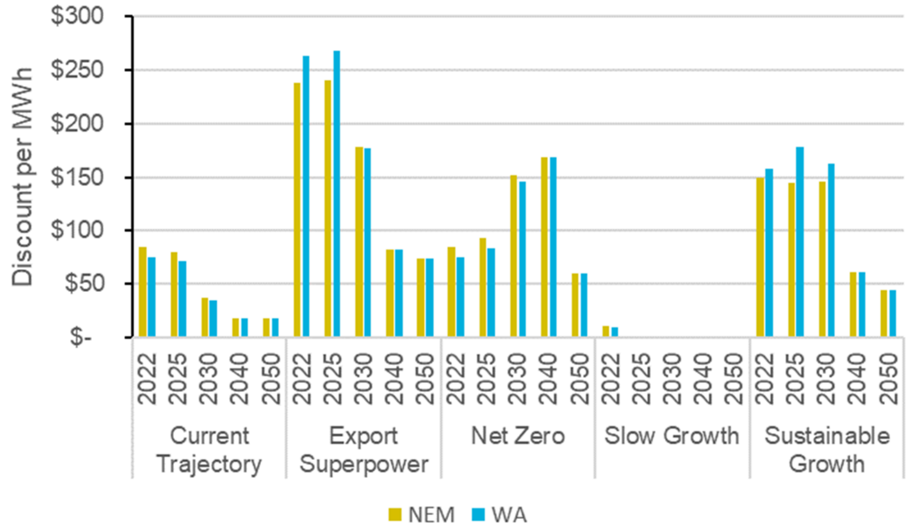
In the Net Zero, Sustainable Growth and Export Superpower scenarios it is assumed that changes are made to make it administratively easier to claim ACCUs such that systems below 100kW in size also claim ACCUs not just those above 100kW. For Net Zero this change occurs after 2030.

The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity assumed for the respective state in which the system is installed. In last year's modelling emissions intensity of electricity was derived from emissions data from the draft Integrated System Plan, however updated emissions data for the new scenarios has not yet been developed. In lieu of this data, emissions intensity for Current Trajectory was developed using the Australian Government's latest emissions projections to 2030. After 2030 emissions intensity is assumed to gradually fall to 0.25tCO2/MWh by 2041-42, in line with the Central Scenario from last year's ISP. It then holds constant at this level until the end of the projection. Slow Growth follows the same emissions intensity as the Slow Change scenario from last year's draft ISP results. Emissions intensity under Sustainable Growth has been derived from Step Change in last year's ISP which declines down to 0.08tCO2/MWh by 2041-42, while Export Superpower follows a slightly faster emission reduction trajectory that falls down to 0.05tCO2/MWh by 2037-38. Net Zero follows the same path as Current Trajectory before then aligning with Sustainable Growth's emissions intensity by the end of the projection period.

Figure 4-5 details the upfront discount applied according to the scenario and location the solar system is installed. Under Current Trajectory we are only able to incorporate demand for ACCUs based on existing legislated and funded initiatives and consequently demand for ACCUs falls precipitously from 2030 onwards as a result of the Climate Solutions Fund coming to an end and remaining demand being largely voluntary. Under Slow Growth the Climate Solutions Fund is assumed to be abandoned in 2022-23. The

Export Superpower and Sustainable Growth scenarios assume that abatement effort is substantially scaled up beyond the current settings for the Climate Solutions Fund and Safeguard Mechanism from 2021-22. This means the value of ACCUs in these two scenarios is bolstered relative to Current Trajectory across the entire outlook period to 2050. Net Zero meanwhile, is very similar to Current Trajectory until the 2030's. To make up for lost time over the first decade of the projection, policy support for decarbonisation in the 2030's and 2040's goes beyond that provided under Sustainable Growth which has a similar emissions end point. But by the end of the projection period emissions intensity has fallen to such low levels across Net Zero, Sustainable Growth and Export Superpower, that even relatively high ACCU prices provide relatively small financial benefit to a solar system because it earns only a small quantity of ACCUs.

Figure 4-5 Upfront discount to a solar system from ACCUs



As noted previously the way the discount is calculated is based on only the generation which is consumed on site (not exported) Current Trajectory. The same is the case for Net Zero up until 2030 after which it can create ACCUs for emissions displaced by all its generation including exports. While Sustainable Growth and Export Superpower can create ACCUs for emissions displaced by all generation not just that self-consumed.

State Governments' Energy Efficiency Schemes

At present the only state government energy efficiency certificate scheme that solar systems can claim abatement/energy saving certificates is the Victorian Energy Upgrades scheme. To date, solar systems are yet to claim certificates under the scheme, instead opting for either STCs or LGCs. However, LGC prices in the forward market fall substantially over the next few years and it appears likely that owners of solar systems larger than 100kW will be better off in the next year or so claiming Victorian Energy Efficiency Certificates (VEECs) instead for the grid imports a solar system displaces and the associated avoided emissions.

The value of these VEECs is taken into account in the model for solar systems above 100kW in Victoria in circumstances where these provide a higher value than claiming LGCs or Australian Carbon Credit Units. Under Current Trajectory and Net Zero the value is calculated based on generation up to the year 2030 whereas under Sustainable Growth and Export Superpower it is assumed the scheme continues throughout the outlook. Under Slow Change the value is assumed to be zero. Unlike last year's modelling we do not ascribe any benefit to solar systems from other state government energy efficiency schemes.

The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity for the NEM as a whole. This is based on electricity emissions taken from the Australian Government's emissions projections (issued in December 2020) in combination with emissions estimated in AEMO's draft ISP for scenarios similar to those in this year's exercise.

Over 2020 VEECs traded at an average value of around $30 but they have been above $40 since late 2020 and then between $45 and $50 over January and February when our modelling assumptions were determined. This large rise in VEEC prices was due to the Victorian Government announcing an increase in the target late last year. Like ACCUs VEECs are awarded on the basis of a tonne of CO2 estimated to have been abated by the activity or intervention.

For the Current Trajectory Scenario we assume the VEEC price ascends to $49.42 and holds at this level until 2030. This is the cost per certificate estimated by the Victorian Government for their enlarged target in their regulatory impact statement. After 2030 it is assumed the VEET scheme ends and the price of VEECs falls to zero. The same assumption is made for Net Zero as in this scenario it is assumed emissions abatement policy is largely driven by Federal Government policy via ACCUs. For Slow Growth it is assumed the VEEC scheme is closed early and solar systems never ultimately claim VEECs. Export Superpower and Sustainable Growth follow the same price path as Central to 2030 and then the price ascends by $2 per annum until 2050 under both scenarios.

Interaction between different government support options for solar systems

Solar system owners potentially have a choice of several government support programs that they can elect to take advantage of. However, in most cases owners can only choose one program and are not allowed to claim benefits from two programs simultaneously nor can they switch between programs from one year to the next. The exception to this rule is the Victorian Government Solar Rebate which can be claimed simultaneously with the STC program benefit, however this is only applicable to the residential sector.

To deal with the requirement that an owner must elect to choose only one program, in each year the model evaluates which government program is expected to deliver the greatest financial benefit over the lifetime of the system and uses that value to allocate an upfront discount to the capital cost of the system.

In the table below we've illustrated how the system lifetime financial benefit delivered by different government programs changes across the years within the model under the Net Zero scenario. It is important to note that some government programs award certificates based on all the power generated from the system such as with LGCs, but under other programs only generation that is self-consumed on site (not exported to the grid) is awarded certificates. This self-consumption restriction applies to VEECs and also applies for ACCUs in the case of the Industrial Electricity and Fuel Efficiency Methodology. Although as noted earlier in some scenarios we assume that ACCUs will be awarded for abatement from all of a solar system's generation, not just that which is consumed on-site. The lifetime value per annual MWh of generation is multiplied by the system's either total generation per annum or self-consumed generation to then derive the discount that the model applies to the system's capital cost.

Table 4-2 Financial benefit provided to a 100kW+ solar system from different government abatement programs over time (Net Zero scenario)

			LGCs		VEECs		ACCU		
Year	Total annual generation per kW (MWh)	Annual self consump'n per kW (MWh)	Lifetime value per MWh	All gen - discount per kW	Lifetime value per MWh	Self consump'n discount per KW	Lifetime value per MWh	Self consump'n discount per KW	All gen - discount per kW
2021	1.3	1.1	146	191	272	300	85	94	112
2025	1.3	1.1	34	45	154	170	93	103	122
2030	1.3	1.1	5	7	23	25	152	167	199
2035	1.3	1.1	0	0	0	0	202	223	265
2040	1.3	1.1	0	0	0	0	168	185	220
2050	1.3	1.1	0	0	0	0	60	66	79

What the table shows is that in the year 2021 VEECs provide the greatest financial benefit of all the programs even though they only award certificates for generation that is self-consumed. Therefore owners of large commercial systems based on Victoria are better off opting to create certificates under this program instead LGCs (this is the first year that this has occurred) or ACCUs. As we advance later in time the value of LGCs rapidly diminishes due to a combination of the declining price of an individual LGC as well as the fact that there are less years in which LGCs can be created (the scheme ends in 2030). The value of the VEEC financial benefit also declines due an assumption the program ends in 2030, but not due to declining certificate prices. Nonetheless in 2025 it remains the best option for a Victorian Solar System. Meanwhile because the ACCU program is assumed to last throughout the entire modelling period and is expected to be the predominant measure after 2030 for achieving the Net Zero emissions objective and so its certificates rise substantially in price, it overtakes the other programs to become the one delivering the greatest financial value to a solar system owner in the Net Zero scenario.

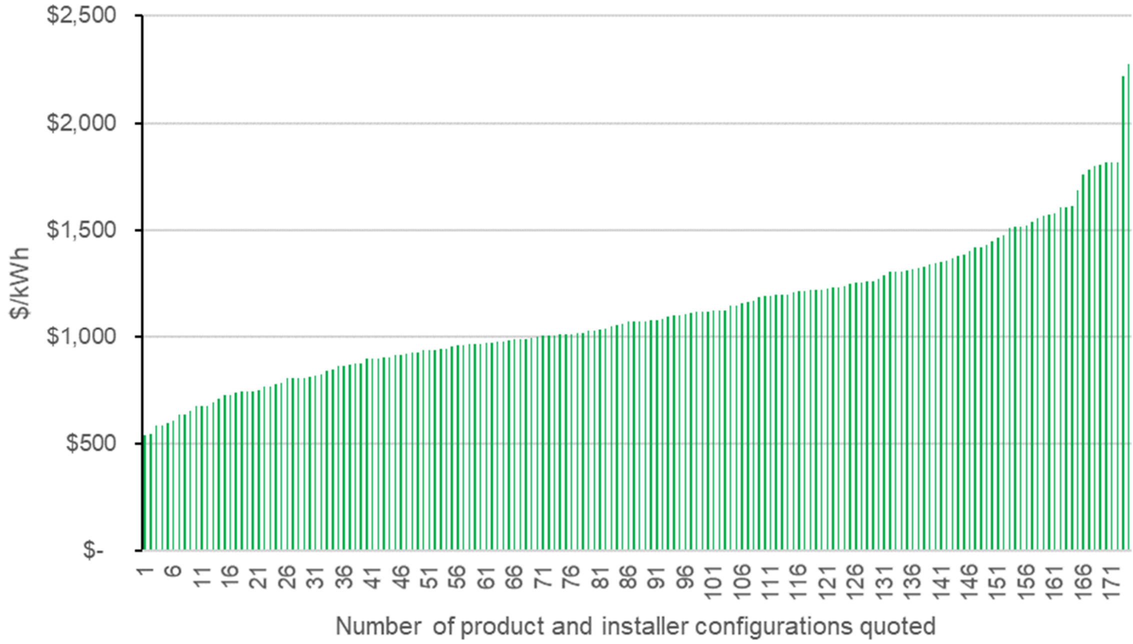
As an aside the reason that the ACCU Lifetime Value per MWh declines after 2035 is because the emissions intensity of the grid under Net Zero is assumed to have fallen to quite a low level. Therefore, the number of ACCUs a solar system can claim for its generation is greatly diminished.

4.3 Capital cost - Batteries

To inform our starting point of battery costs we have made use of the large dataset of battery system quotes provided by the South Australian Government's Home Battery Rebate Scheme complemented with interviews with several solar-battery industry participants.

Figure 4-6 illustrates the distribution of battery system quotes (excluding the rebate) that were available in January 2020, which range between $500 per kWh up to as much as $2,300 (excluding GST). Of course, not all of these quotes are ultimately accepted by end consumers, who will naturally tend towards accepting quotes at the lower end of the scale. We have since reviewed market offerings and quotes up to January 2021. This suggests prices have remained similar to what we had assessed last year with prices of around $1,000 per kWh (including GST) a reasonable rule of thumb for purchase prices of battery systems retrofitted to an existing solar system on a national basis.

Figure 4-6 Installed cost quotes per kWh for battery systems under SA rebate program (Excl. GST and rebate)

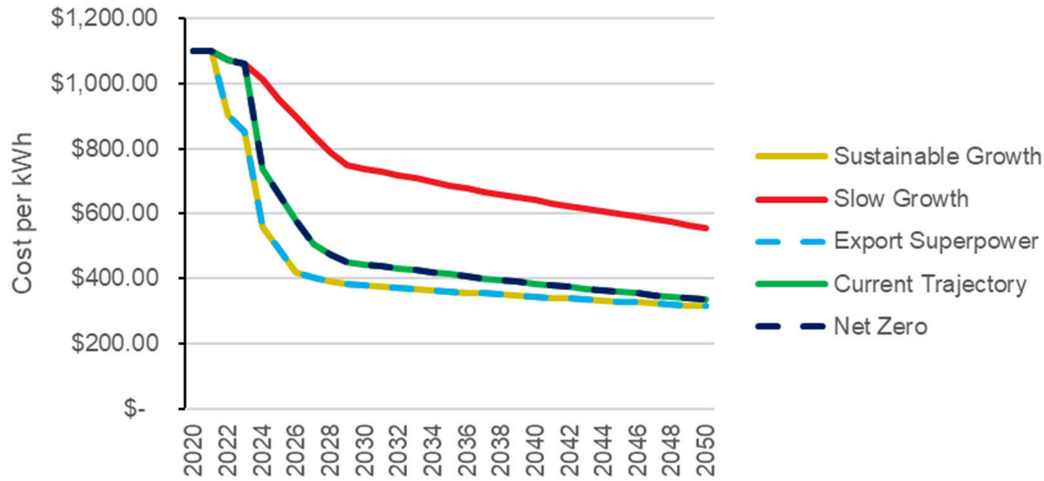


Source: : South Australian Government's Home Battery SchemeSystem Price Guide - https://homebatteryscheme.sa.gov.au/system/files/documents/System-Price-Guide.pdf

In many cases going forward batteries will be installed simultaneously with installation of a new solar system or an upgraded replacement solar system. This is likely to achieve savings in both install labour and the associated sales and back-office activities. We estimate this saving at $200 per kWh of battery capacity.

Figure 4-7 illustrates the assumed capital cost adopted for a battery system retrofitted to a residential solar system by scenario in the model. Please note that Net Zero follows the same path as Current Trajectory while Sustainable Growth follows the same path as Export Superpower. Costs for commercial systems are assumed to be the same as residential systems.

Figure 4-7 Assumed capital cost per kWh for residential battery system by scenario (Incl. GST)



Our own monitoring of the battery market suggests that prices for systems have been steady rather than falling for the past three years and the ITP Lithium-Ion Battery Test Centre's tracking of wholesale battery system prices shows stagnant rather than falling prices in its latest report published in September 2020. This continues a trend we have observed over the past few years of little to no reduction in home battery system prices in Australia. We expect that price reductions will remain modest for the next few years but will eventually be followed by quite rapid reductions in prices. A variety of information sources suggest that electric vehicle manufacturers have been able to attain quite significant reductions in battery pack purchase prices over the last few years which are reflective of lower battery cell production costs[11]. However, these have not flowed through to lower prices for customers purchasing stationary energy systems at behind-the-meter scale. We suspect that battery manufacturers are prioritising the far larger electric vehicle market over small scale stationary energy storage which is a much smaller market opportunity. But eventually prices will inevitably follow costs downward as new competitors enter the market and as its growing scale induces suppliers to compete more vigorously. Such a pattern occurred in the solar PV industry where price reductions pretty much stalled over 2003 to 2007 yet production costs were continuing to fall. However, the entry of a number of Chinese suppliers then led to solar module prices plummeting extremely rapidly.

In the latest edition of the GenCost publication, CSIRO did not publish an estimate of the capital cost of a distributed battery and solar system for us to utilise as a benchmark.

Instead we have used CSIRO's GenCost estimates for the cost of a utility-scale 2 hour duration battery to inform our assumptions of distributed battery price reductions over time. We assume that distributed batteries close the gap in cost per kWh with utility scale systems over time to approach a similar narrow differential as is currently achieved in Australia with distributed solar versus utility-scale solar. We believe that given battery

[11] For example see the results of Bloomberg New Energy Finance surveys of vehicle manufacturer's reported battery pack prices here: https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/ and https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/

technology is based on modular components (just like solar) that are simply replicated in larger numbers of units for utility scale relative to smaller behind the meter applications, there is good reason to believe small, mass produced, household battery units will achieve costs not that much greater than utility-scale systems once they are rolled out in large numbers. Also home battery storage systems are highly self-contained with simple plug and play architecture, so installation should be a straightforward and relatively quick process for electricians.

Just as we did last year for the purposes of the Central Scenario we assume price reductions are minimal over the next few years under the Current Trajectory and Net Zero scenarios before a competitive shake-out unfolds that then leads to dramatic falls in price as prices are reduced closer to underlying costs and as suppliers achieve a critical mass of volume that allows them to tolerate lower margins per sale.

Under Sustainable Growth and Export Superpower the fall in prices occurs without any lag while for Slow Growth price reductions tend to be more slow and steady.

Another factor that has delayed reductions in battery system prices in the Australian market has been the introduction of stricter installation standards to control fire risk that have added significant cost. These standards have gone beyond what is common internationally and we expect that as battery manufacturers demonstrate improved levels of safety, the standard will be adjusted to address costs.

While the timing for such a price shake-out are extremely uncertain, the history of Solar PV suggests a shake-out within the next five years is reasonably likely and we have timed it to begin in 2024 in Current Trajectory and Net Zero, while it begins in 2022 in Export Superpower and Sustainable Growth. In Slow Growth cost reductions are slower and more incremental which assumes no sudden competitive shake-out unfolds.

4.3.1 Incorporating impact of government support policies

SA Government Rebate

The South Australian Government has a target of rolling out 40,000 home battery energy storage systems over 2018 to 2022 which it has supported with $100m in funding for rebates.

The rebate initially began as a level of $500 per kWh of battery capacity up to a maximum of $5000, but then was subsequently reduced to $200 per kWh.

Victorian Government Rebate

A sub-component of the Victorian Government’s Solar Homes Program involves a rebate program targeting 10,000 battery systems by 2028 retrofitted to households that already have a solar system in place or 1000 systems per annum. While the uptake under the program had been running below target, a series of changes this year have significantly broadened eligibility. Feedback from Solar Victoria suggests that they are now on track to achieve the 1000 systems targeted. Our projections assume the target is met. But given it represents a minority of the total Victorian residential battery market based on historical data, it doesn’t fundamentally change projections of expected battery uptake.

NSW Energy Security Safeguard (Peak Demand Reduction Scheme)

In May 2020 the NSW Government legislated changes to the *Electricity Supply Act 1995* which reconstituted the Energy Savings Scheme as the Energy Security Safeguard. According to the NSW Government's Energy Security Target and Safeguard Consultation Paper[12], under this reconstituted program the Energy Savings Scheme element will continue but they will also establish a certificate scheme to reward the deployment of dependable peak demand reduction capacity. Like the Energy Savings Scheme, the scheme will place a peak demand reduction obligation on liable parties – mainly electricity retailers.

Under this scheme behind the meter batteries could qualify for peak demand reduction certificates by providing power to the premise where they are located at peak demand periods and reducing demand for power from the grid. Also importantlyif the scheme were to adopt similar parameters to the existing Energy Savings Scheme, then it would provide support for batteries not just in residential homes but also commercial premises (unlike the Victorian and South Australian rebate programs).

The intention of the scheme is to reduce the cost of electricity provision to customers by supporting activities that could act to reduce peak demand for electricity at a lower cost that adding new supply capacity in both generation and networks.

At the time of modelling the peak demand reduction scheme was yet to come into operation and the regulatory settings are yet to be determined in detail. This meant we don't yet have any market guide for the likely value of peak demand reduction certificates. For the purposes of modelling we adopted a simple assumption that the scheme would provide a financial benefit in between that currently provided by the Victorian and South Australian battery rebate programs that would be around half the capital cost of a battery per kWh of capacity. In 2022-23 this equates to a discount of $419/kWh which then declines to $156/kWh in 2029-30.

Other current battery support programs

Several other State and Territory governments have made rebates and/or low interest loans available to support battery uptake. However, in most cases these are relatively modest in scale or we suspect they will not be materially alter customers willingness to adopt batteries (particularly the provision of loans)[13]. Consequently, these are not explicitly part of the modelling process for battery uptake over the next decade.

[12] NSW Government Department of Planning, Industry and Environment (2020) Energy Security Target and Safeguard Consultation Paper - https://energy.nsw.gov.au/media/2031/download

[13] In the case of the Northern Territory battery rebate this was announced very recently and too late to be incorporated in our modelling.

Potential future battery support via energy-efficiency or demand management schemes

In the scenarios where there is a major step up in emission reduction policy efforts (Sustainable Growth, Net Zero and Export Superpower) we have assumed that the Federal Government introduces a national program to support battery uptake across both residential and commercial sectors. Like the NSW Peak Demand Reduction Scheme, we assume this provides a rebate value equal to half the capital cost of a battery.

4.3.2 The impact of Virtual Power Plant payments

Virtual power plants (VPPs) involve owners of battery systems handing over control to discharge or charge their battery system to a company which can then bid some or all of the battery's capacity into wholesale energy and frequency control markets operated by AEMO. There are now a number of companies which operate these virtual power plants and offer customers a variety of forms of compensation in return for being given at least partial control over the discharge/charging of the battery. Some of the offers on the market noticeably improve the financial attractiveness of a battery system[14].

However, this market is still very immature and it is highly uncertain how it might evolve over time and the amount of financial benefit battery owners might receive into the future. In addition, from a macro perspective, while consumers may receive a direct benefit from participating in Virtual Power Plants, as these become a significant source of supply they have the potential to lower power prices. This will then reduce revenue to solar and battery owners, partly offsetting the gain from the payment received from signing up to a Virtual Power Plant.

Given this uncertainty we have not explicitly accounted for the potential impact of VPP payments on battery paybacks. Although we would note that state governments have shown an interest in tying government support to customers participation in VPPs. Also, some VPPs structure their remuneration much like a rebate that reduces the effective upfront cost of a battery system (e.g. Tesla's VPP). Given these facts we suspect that scenarios such as Sustainable Growth and Export Superpower – which incorporate widespread and long-lived rebates for batteries – are reflective not just of environments where government support for batteries is forthcoming, but also where VPP payments/battery discounts remain significant.

4.4 Electricity prices

4.4.1 Overview

In estimating the revenue or bill savings behind-the-meter solar and battery systems deliver to consumers we need to consider two different electricity prices:

- Import replacement price: this is the variable electricity price that can be avoided by that level of solar generation that is consumed by the household or business. It is important to recognise that a large proportion of electricity charges are fixed

[14] See here for details on the VPP offers currently available to residential battery owners: https://www.solarquotes.com.au/battery-storage/vpp-comparison/

and can not be reduced through installation of solar or a battery unless the site completely disconnects from the grid; and

- Export price: this is the variable electricity price that is received through the export of electricity to the grid.

Our payback model time series incorporates the Australian Energy Market Commission's (AEMC) latest residential price trend projections[15] but are adjusted to exclude fixed standing charges utilising AEMC typical demand estimates.

For large commercial businesses we use a combination of a bottom-up estimate of the various bill components and advertised offers by electricity retailers.

For the purposes of forecasting ahead these prices we utilise the AEMC methodology of breaking down electricity costs into the following cost components:

- Wholesale energy
- Network charges
- Retail margin
- Environmental charges

We then add another component to this which is the feed-in tariff or export price. For the NEM states this is based on advertised feed-in tariffs offered by electricity retailers or, where applicable, the regulated rate for the year 2019-20, but after this it is tied to the wholesale energy market cost customers are assumed to pay. For Western Australia it is based on the buy-back price set by the government up until 2021-22. From 2022-23 until 2029-30 the feed-in tariff transitions steadily towards the wholesale energy market cost customers are assumed to pay and then remains tied to the wholesale energy market cost. On April 5 this year the Northern Territory Government announced that it would be significantly reducing the feed-in tariff new solar systems would be eligible to receive (reducing it from 23.68c/kWh to 8.3c/kWh GST exclusive). However, this was unable to be incorporated into this modelling exercise, which by that date was almost complete. Instead the modelling assumed that new solar systems would receive the prior regulated rate (now classified as the premium rate) until 2023-24. From 2024-25 until 2029-30 the feed-in tariff would then transition steadily towards the wholesale energy market cost customers are assumed to pay, and then remain tied to the wholesale energy market cost.

4.4.2 Tariff structure and network charges

Customers with sub-100kW systems

For both residential and small commercial customers the model applies a single uniform import price for electricity across all hours of the day up until 2021-22, which is derived from the AEMC's projections with adjustment to remove fixed charges.

This smeared uniform price then gradually unwinds over 2022-23 until 2029-30 towards a three part, time of day tariff network charging structure of the following:

- Peak – 3pm to 9pm

[15] Australian Energy Market Commission (2020) Final Report – Residential Electricity Price Trends 2020, December 2020

- Solar soak – 9am to 3pm
- Off-peak – all other times

Network charges applying during the peak period are set at 2.9 times the anytime smeared network charge in place in 2021-22. Meanwhile the solar soak and off-peak charge are both set at half the anytime smeared network charge in place in 2021-22. Network charges are assumed to remain constant in real terms across the period from 2021-22 until 2050.

In addition, wholesale energy costs are recovered based on a similar time structure but with the peak period only applying on weekdays and lasting until 10pm.

The model has adopted an assumption that tariff structures will change. This is because maintaining a single uniform smeared price is coming up against the challenge that solar capacity is reaching such large levels that it is substantially hollowing out demand and reducing costs in the middle of the day, but leaving the costs to service demand at other periods unchanged. This is seen by an increasing incidence of negative pricing events in some states' wholesale markets during daytime periods when demand is relatively low such as weekends and public holidays. To make better use of low cost solar there is a need to encourage greater electricity consumption in the middle of the day, while discouraging consumption during periods where more expensive supply options are required. Prices that reflect the lower cost of energy when solar power is plentiful while providing higher prices particularly during the demand peak (generally between 3pm to 9pm for residential areas) should help to do this.

In the NEM states the move towards tariffs with more differentiated pricing is reflected in AEMC rule changes requiring a shift towards more cost-reflective tariffs by network businesses, and also its requirement for the roll-out of interval or smart meters. The installation of such a meter is mandatory where a solar system is installed, and they should reach a large proportion of the other stock of buildings by 2030.

In Western Australia the government has also indicated in its Distributed Energy Resources Roadmap[16] that it will seek to restructure tariffs to be time differentiated as a result of increasingly high solar penetration. While the NT has not yet made such a statement, they have recently taken a step in this direction through substantially reducing the feed-in tariff offered to solar exports from the retail rate down to a rate closer to wholesale energy costs[17].

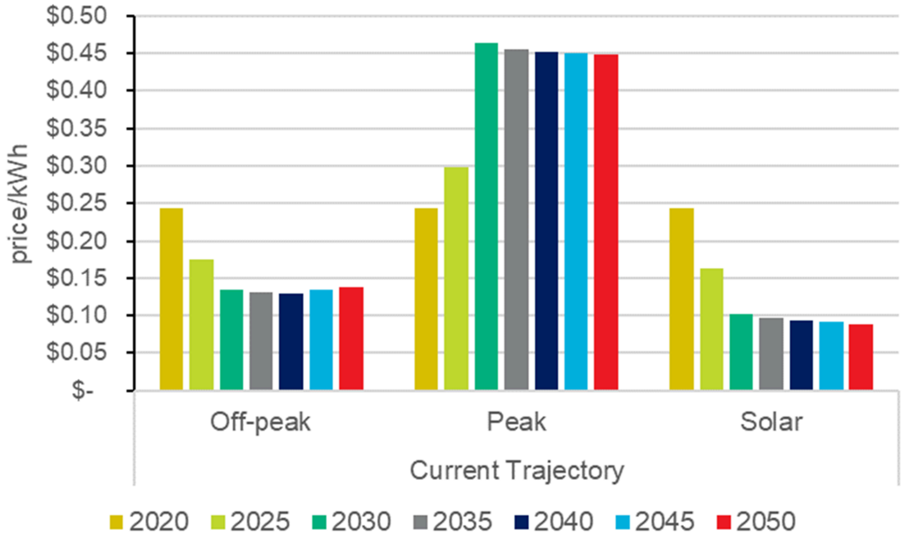
The time periods chosen for this tariff structure reflect a combination of our own analysis of residential substation load data and wholesale energy market data, as well as tariff structures proposed by some network businesses like Ausgrid and SA Power Networks to deliver more "cost-reflective" price signals.

To illustrate with an example how this change in tariff structure (as well as solar-induced reductions in wholesale prices) plays out, Figure 4-8 illustrates the import price per kWh a NSW residential consumer would pay for the 3 different time intervals in the Central

[16] Government of Western Australia – Energy Transformation Taskforce (2020) Distributed Energy Resources Roadmap, December 2019
[17] See Jacqueline Breen (2020) One-to-one solar feed-in tariff scrapped, battery subsidies announced in NT renewables changes, ABC News, 9 April 2020 available here: https://www.abc.net.au/news/2020-04-09/nt-scraps-one-to-one-solar-power-feed-in-tariff-renewables/11928988

Scenario over time. In 2020 they pay the same price irrespective of time interval but by 2030 there is a large difference between the peak period versus the solar and off-peak period. The other states and other scenarios see similar changes.

Figure 4-8 Assumed changes in NSW residential power price by time interval (Current Trajectory scenario, Incl. GST)



To also reflect potential alternative pathways for how electricity tariff reform might unfold we adjusted the Slow Growth scenario to reduce the network charges per kWh relative to Central by 3 cents per kWh for small consumers on the assumption that this scenario involves a situation where networks move to recover a greater proportion of their costs through fixed daily charges.

Large commercial customers installing systems larger than 100kW

For large commercial customers that install solar systems larger than 100kW, we generally assume they already face time differentiated tariffs for wholesale energy and also are on what are referred to as demand-based network tariffs. Under these network tariff structures, customers face much lower charges for the kilowatt-hours they consume relative to residential or small commercial customers. Although they face significant network charges based on their maximum demand for over a 30 minute interval across a monthly period or sometimes a yearly period.

For evaluating solar payback without a battery in place we assume that the solar system only delivers savings in the network's kWh charges, not the demand-based charge. Charges per kWh are derived from the network's current tariff charges although in states with multiple distribution businesses we have attempted to use an approximate composite.

Large commercial businesses tend to have co-incident peaks in demand earlier in the day than residential consumers. In addition, the proportion of load covered by distribution network embedded solar generation is much smaller than residential and is likely to remain that way for the foreseeable future. As a result we apply the following network charging time profile where the kWh charges are differentiated between peak and off-peak:

- Peak – 11am to 8pm

- Off-peak – all other times

In addition, when evaluating the battery payback we take into account the likely impact of the battery plus the solar system in reducing the customer's network peak demand charge. This is based on feedback from solar businesses that customers tend to be unwilling to incorporate a saving on their demand charge from a solar system due to concerns about solar output variability. But if a battery is being installed then customers have greater confidence in applying savings on the demand charge delivered by the solar system as well as the battery. We have assumed the peak demand charge is only assessed based on demand during the peak period (11am to 8pm). The demand charge is set at $110 per annum per kW of peak demand for all states except QLD where it is set at $190 (this is because QLD distributors set their cents per kWh charges especially low and recover most of their costs in the demand charge). Also for Tasmania we have used the commercial time of use tariff structure rather than the demand charge in payback calculations.

Wholesale energy costs are recovered on the same structure as for residential consumers.

4.4.3 Wholesale energy

Up until 2021-22 we use AEMC projections for wholesale energy by time of day except for WA and NT where prices reflect current retail pricing.

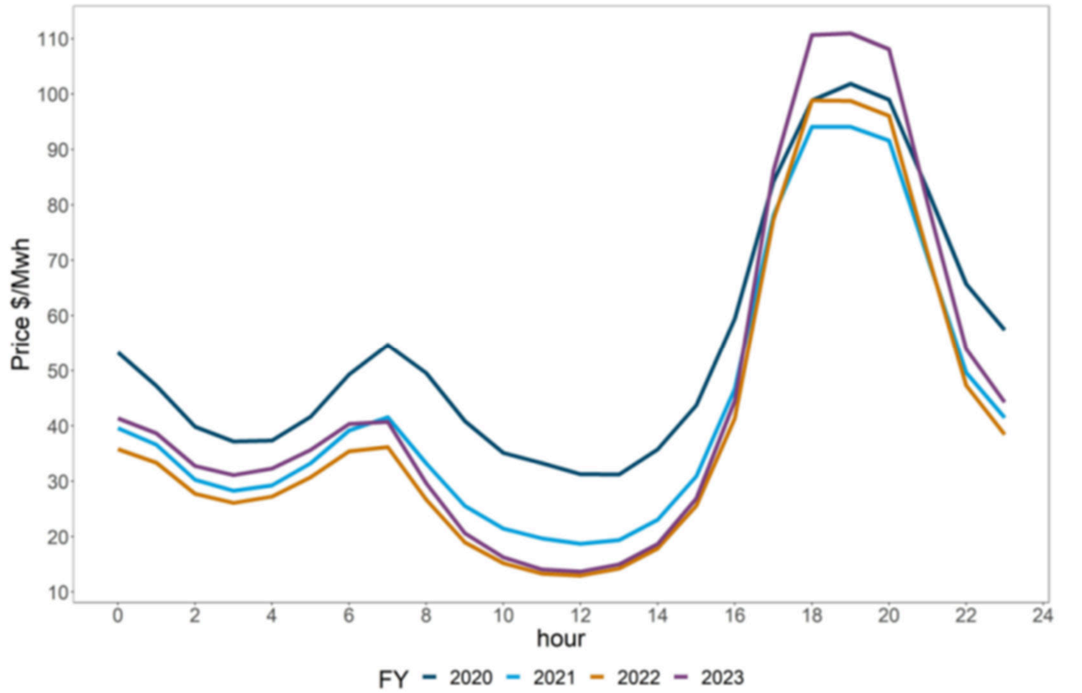
After 2021-22 wholesale energy prices then follow a linear path towards prices set from 2030 onwards based on CSIRO GenCost LCOE estimates and in Central and Slow Change scenarios also short-run marginal cost of existing coal. These are adjusted to suit themes within each scenario for differing levels of emission reductions and technological advancement.

For the first five to ten years of the projection wholesale price differences across time periods are smeared/averaged in final retail prices in line with current retail pricing practices. As explained in the prior section, the model assumes the smearing is gradually unwound to 2030 whereby wholesale energy costs are charged according to three time periods or intervals:

- Peak – 3pm to 10pm weekdays
- Solar soak – 9am to 3pm all days
- Off-peak – all other times

The reason for needing to distinguish wholesale costs by a solar period is because the scale of both rooftop and solar farm capacity being added to grids across the country is very large relative to overall supply. As a result, we expect that wholesale market prices (during sunlight hours) will drop considerably over the period to 2023. The AEMC in their 2019 Residential Price Trends report also recognised the expected drop in the wholesale price during daylight hours from the 2021 financial year. Figure 4-9, taken from the AEMC report illustrates the noticeable depression in prices in the middle of the day for Queensland, while prices during the peak period in the late afternoon and evening remain high. Such a development is likely to be replicated in other regions given they are also adding large amounts of solar capacity.

Figure 4-9 Average wholesale electricity prices by hour of day in QLD



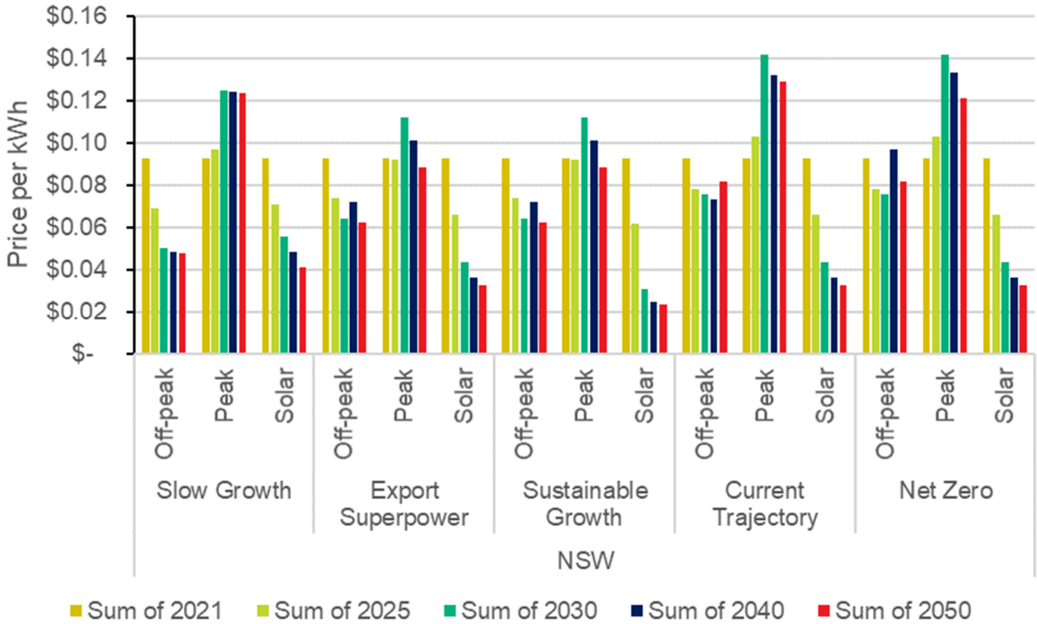
Source: AEMC (2020) Residential Electricity Price Trends 2020

In addition, even if demand in the middle of the day were to grow substantially we expect that any price increases will be constrained by the fact that the new entrant price required for solar farms is envisaged to fall to low levels under all the CSIRO GenCost scenarios.

For the off-peak and peak periods cost falls relative to 2020 levels are expected to be less significant because we envisage that they will continue to depend heavily on dispatchable sources of capacity such as gas, coal, pumped hydro or batteries.

Figure 4-10 details the assumed wholesale energy costs by time interval faced by a residential consumer in NSW for each scenario. Note that the model assumes a single NEM-wide price to apply from 2030 onwards for modelling simplicity and because the most recent AEMO ISP indicated that considerable interconnection capacity will be added over the next two decades. So this chart is also illustrative of expected costs across the other NEM states as well from 2030 onwards.

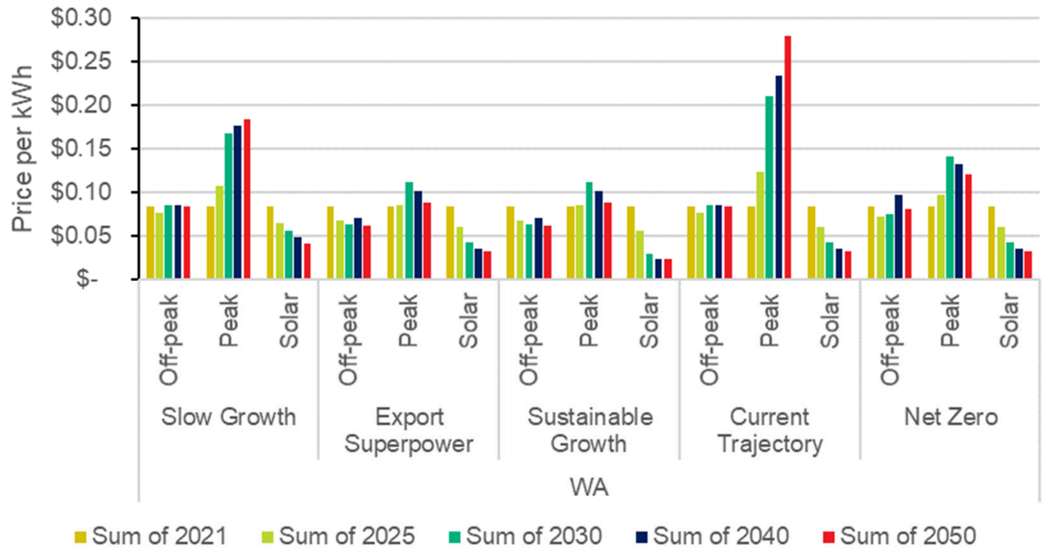
Figure 4-10 Assumed wholesale energy costs by time interval for NSW (and NEM from 2030) (excl GST)



Note: A large part of the change in prices between 2021 and 2030 of each time period is to do with the removal of smearing of costs in small consumer retail prices across time periods rather than underlying changes in wholesale energy costs during the hours covered by the Off-Peak, Solar and Peak periods.

The figure below details the assumed wholesale energy costs by time interval faced by a residential consumer in WA for each scenario.

Figure 4-11 Assumed wholesale energy costs by time interval for WA (excl GST)



Note: A large part of the change in prices between 2021 and 2030 of each time period is to do with the removal of smearing of costs in small consumer retail prices across time periods rather than underlying changes in wholesale energy costs during the hours covered by the Off-Peak, Solar and Peak periods.

Flow through of wholesale energy costs to prices paid for exported electricity from solar systems

As explained earlier, feed-in tariffs for exported generation for the 2019-20 year reflect an average of current offers from major retailers by state (or the regulated rate). But these are then assumed to adjust to align with our projected wholesale prices by time of day. This happens in 2020-21 for NEM states but for WA and NT feed-in tariffs transition from their current rates to wholesale prices gradually and it is not until 2029-30 that they fully reflect wholesale market rates.

4.4.4 Retail charges

For large commercial customers we assume a retail margin charge of 1 cent per kilowatt-hour.

Retail charges for residential and small commercial consumers are varied by region depending on differences between observed advertised retail offers to customers and underlying bottom-up estimates of network, environmental and wholesale energy costs per kWh of consumption. What this means in practice is that in some states the retail charge is zero or even negative in the model. For example, in Victoria retailers tend to shift a portion of the variable kWh costs they face into the daily fixed charge as well as recovering all their own costs in the fixed charge. So this led to the retail charge in the model being a negative value for residential consumers as the retailers effectively cross subsidise kWh consumption via increases in the fixed charge. In NT, as another example, the retail charge was also negative, but this was in part to reflect government subsidies for electricity rather than a cost shift of costs associated with consumption into the fixed charge.

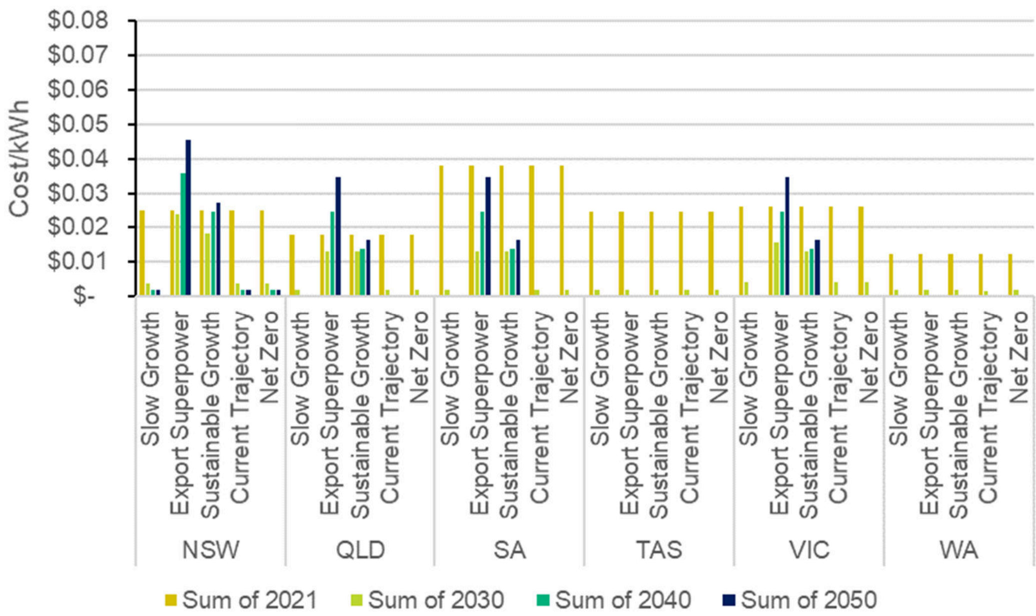
Retail charges are also held constant throughout the outlook.

4.4.5 Environmental charges

Figure 4-12 details assumptions used for environmental charges as applied to residential consumers by scenario and state. Small and Large commercial faces the same charges but with GST deducted. While large industrial energy consumers are typically exempt from a range of environmental charges – they represent such a small proportion of solar capacity being installed that their experience is not indicative of the typical large commercial solar market.

The level of environmental charges in each scenario are related to assumptions about the continuation or expansion of emission reduction programs currently funded via electricity charges such as the Renewable Energy Target, State-based energy efficiency schemes, and programs like premium feed-in tariffs and the NSW Climate Change Fund. Under Current Trajectory and Slow Change it is assumed emission reduction programs funded via electricity charges to a large degree cease after 2030 (with the exception of NSW's Energy Savings Scheme). However, under Sustainable Growth and Export Superpower scenarios state governments other than TAS and WA are assumed to extend and expand their emission reduction programs that are funded via charges on electricity consumption.

Figure 4-12 Environmental charges by state and scenario for residential consumers (incl. GST)



4.5 Technical characteristics of solar and battery systems

4.5.1 Solar systems

The amount of electricity per kilowatt of solar PV used in the payback model is based on daily average generation figures provided by the Clean Energy Council for each capital city of the respective state or territory being analysed[18]. These average figures are then converted into generation per hour across every day of the year based on Bureau of Meteorology historical measurements of irradiance between 1990 and 2015.

In developing the degraded capacity of the solar PV installed base we applied an annual degradation factor of 99.3%[19]. So a system that had an original capacity of 1kW would be multiplied by 0.993 after a year to give a degraded capacity of 0.993kW and then this degraded capacity would be multiplied again by 0.993 for its second year to give 0.986kW of degraded capacity and on and on for each consecutive year until the system was retired).

4.5.2 Battery systems

The following assumptions were adopted for the modelled battery stock:

- Conversion efficiency – both charging and discharging of the battery was assumed to be 95% efficient (round trip efficiency of 90.25%)[20]
- The maximum output/input of the battery in behind the meter applications was assumed to be 40% of the kilowatt-hour rated capacity of the battery. So a 10kWh battery system was assumed to have a maximum output and charge capability of 4 kilowatts.[21]
- Batteries kWh capacity was assumed to degrade to 60% of its original rated capacity after 10 years[22] and at this point would be retired and replaced by its owner.

[18] Clean Energy Council (2011) Consumer guide to buying household solar panels
[19] This level of degradation is in line with warranted performance of modules manufactured by Jinko - the world's largest producer. Some module suppliers provide warrantees for lower levels of degradation (SunPower, LG, Longi) but their share of the market is noticeably smaller. See here for further detail: https://www.solarquotes.com.au/blog/solar-panel-degradation/#:~:text=Solar%20panel%20performance%20warranties%20generally,in%20their%20first%20few%20hours. A literature review by The US National Renewable Energy Laboratory (see: https://www.nrel.gov/docs/fy12osti/51664.pdf) suggests median degradation for crystalline silicon panels in the realm of 0.5% per annum but with averages being higher which supports the use of Jinko's warranted performance as a conservative (lower_bound) value of likely future output of solar systems.
[20] This is based on a combination of stated performance provided by battery system vendors servicing the Australian market (available here: https://www.solarquotes.com.au/battery-storage/comparison-table/#) and field testing results from ITP's Battery Test Centre (see test result reports here: https://batterytestcentre.com.au/reports/)
[21] This is informed by a review of the kW to kWh ratios of a range of commercial battery systems offered into the Australian market based on SolarQuotes Battery Comparison table (available here: https://www.solarquotes.com.au/battery-storage/comparison-table/#). While there is wide variation a kW to kWh ratio of 0.4 is considered a reasonable approximation of what is being sold in the Australian market. This is heavily weighted by the fact the two most popular brands are LG Chem (whose batteries have a ratio of 0.5 to 0.6) and Tesla (with a ratio of 0.36 for the Powerwall 2).
[22] This is based on a combination of LG Chem's warranted performance and also informed by field testing results from ITP's Battery Test Centre (see test result reports here: https://batterytestcentre.com.au/reports/) .

5 Results

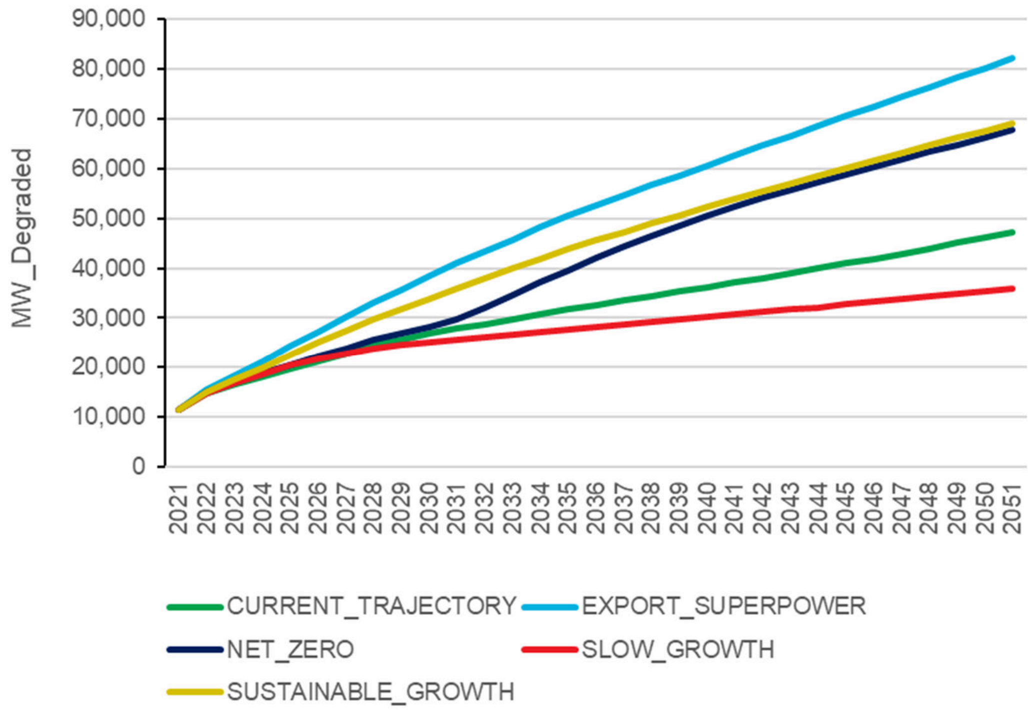
5.1 Overview

5.1.1 Solar PV

National Electricity Market

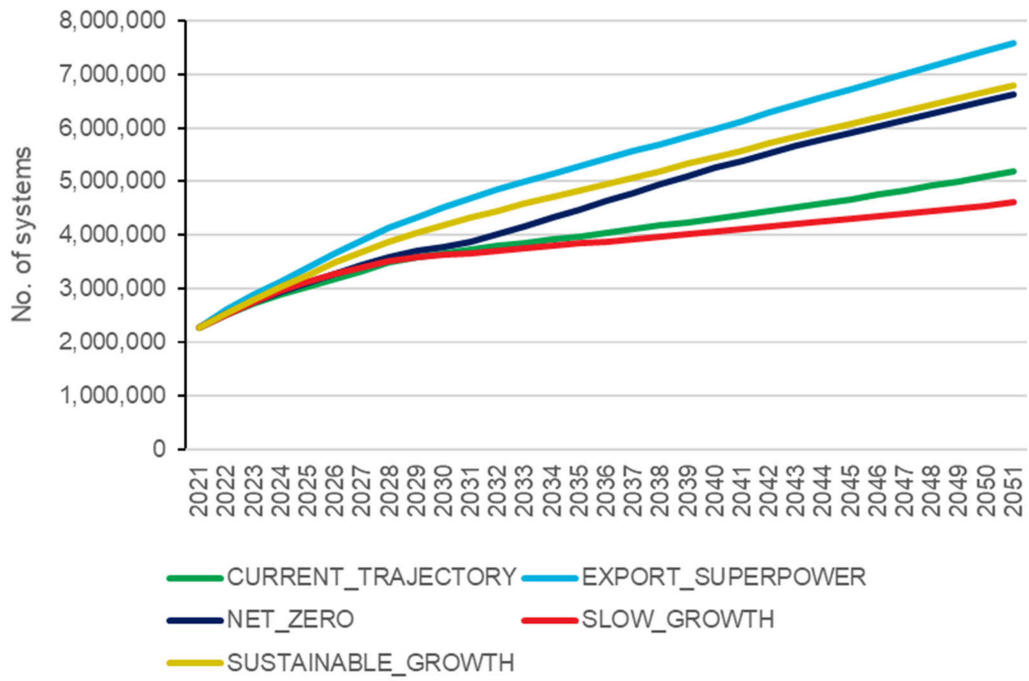
Figure 5-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2019-20 financial year) cumulative installed degraded capacity is expected to stand at almost 9,900MW. Under Current Trajectory the cumulative degraded capacity reaches just over 47,000MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 82,000MW, while the lower bound represented by Slow Growth is close to 36,000MW.

Figure 5-1 NEM cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario within the NEM. At the beginning of the projection (the conclusion of the 2019-20 financial year) the cumulative number of systems stands at a little over 2 million. Under Current Trajectory the cumulative number of systems grows to just under 5.2 million by the end of the 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches almost 7.6 million, while the lower bound represented by Slow Growth is 4.6 million systems at the end of the 2050-51 financial year.

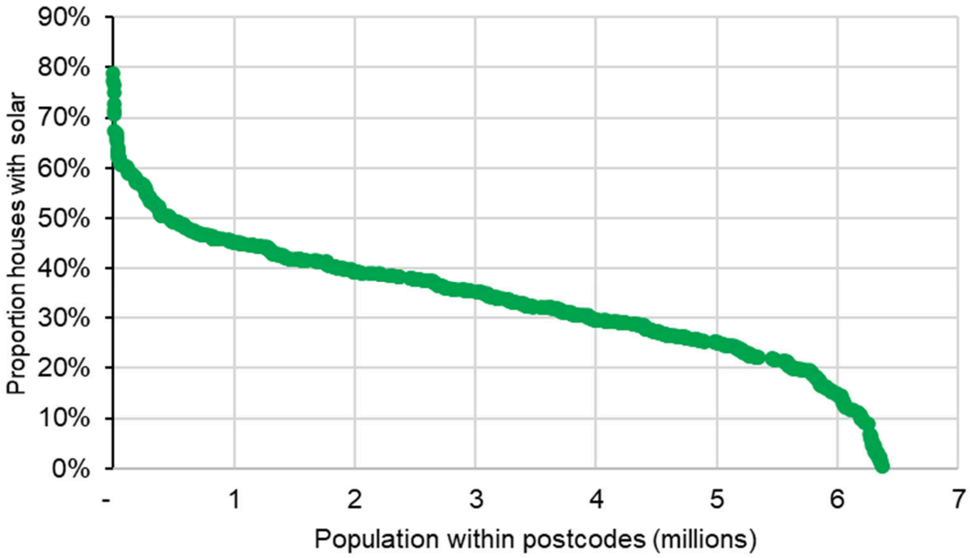
Figure 5-2 NEM cumulative number of solar PV systems by scenario



To put these system numbers in context the total number of NEM residential electricity connections (the vast bulk of solar systems by number are projected to be installed on residential premises) is expected to grow from 9.1m at the end of the 2019-20 financial year to just under 13.9m by 2051 under Current Trajectory, while under Export Superpower it grows to almost 14.5m. The number of systems under Current Trajectory equates to around 37% of all residential connections and in Export Superpower it is 52%.

In the states which have the highest solar penetration in Australia – Queensland and South Australia - such levels of penetration are already being realised across a number of postcodes. The figure below plots South Australian and Queensland postcodes in terms of the proportion of households within the postcode with a solar PV system and then on the horizontal axis we accumulate the amount of population residing within the postcodes. This shows that postcodes representing around 1m people within QLD and SA have already reached or exceeded 45% penetration of total dwellings with solar suggesting such penetration is achievable. 52% remains rare but examples do already exist, and this is in circumstances with almost no usage of batteries. Meanwhile our projections envisage that by the end of the projection period almost all solar systems will be coupled with batteries.

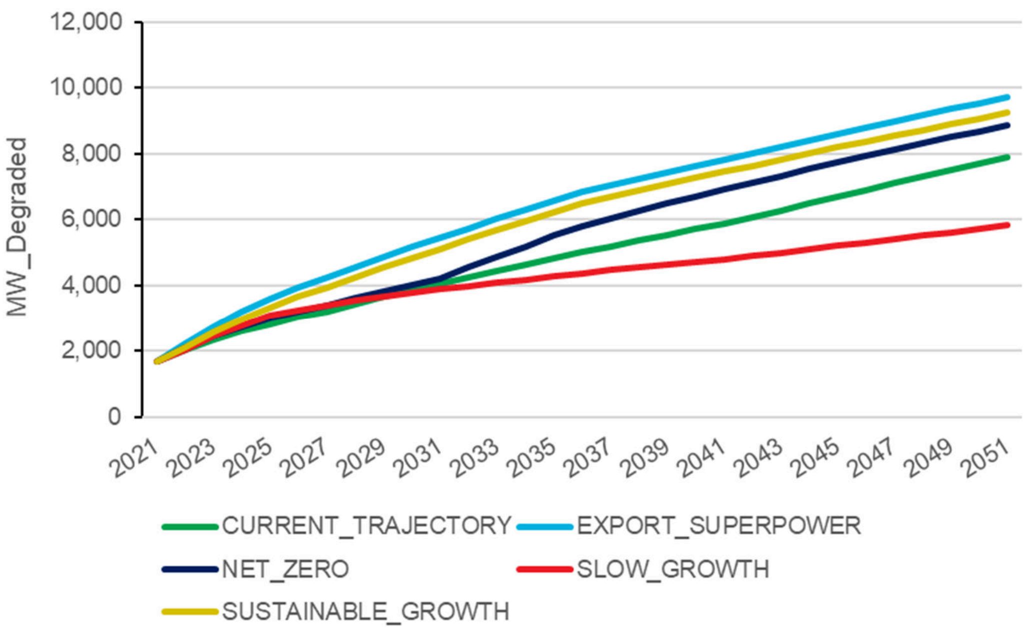
Figure 5-3 SA & QLD postcodes' solar penetration relative to population



Western Australian South-West Interconnected System

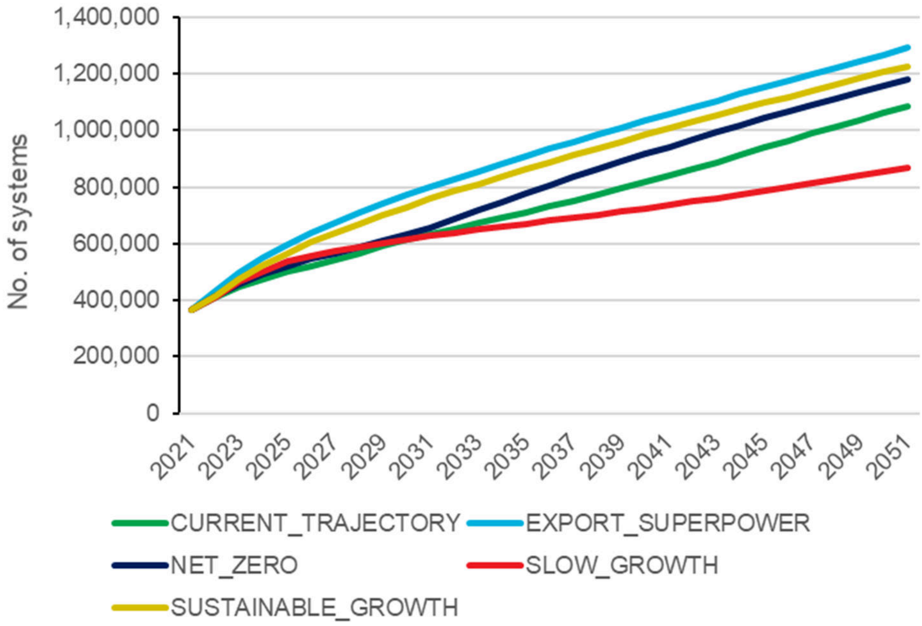
Figure 5-4 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the WA South-West Interconnected System (SWIS), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2019-20 financial year) cumulative installed degraded capacity is expected to stand at almost 1,400MW. Under Current Trajectory the cumulative degraded capacity reaches just over 7,900MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 9,700MW, while the lower bound represented by Slow Growth is slightly under 5,900MW.

Figure 5-4 WA SWIS cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario on a national basis. At the beginning of the projection (the conclusion of the 2019-20 financial year) the cumulative number of systems stands at 325,000. Under Current Trajectory the cumulative number of systems grows to almost 1.1 million by the end of the 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches almost 1.3 million, while the lower bound represented by Slow Growth is 868,000 systems at the end of the 2050-51 financial year.

Figure 5-5 WA SWIS cumulative number of PV systems by scenario

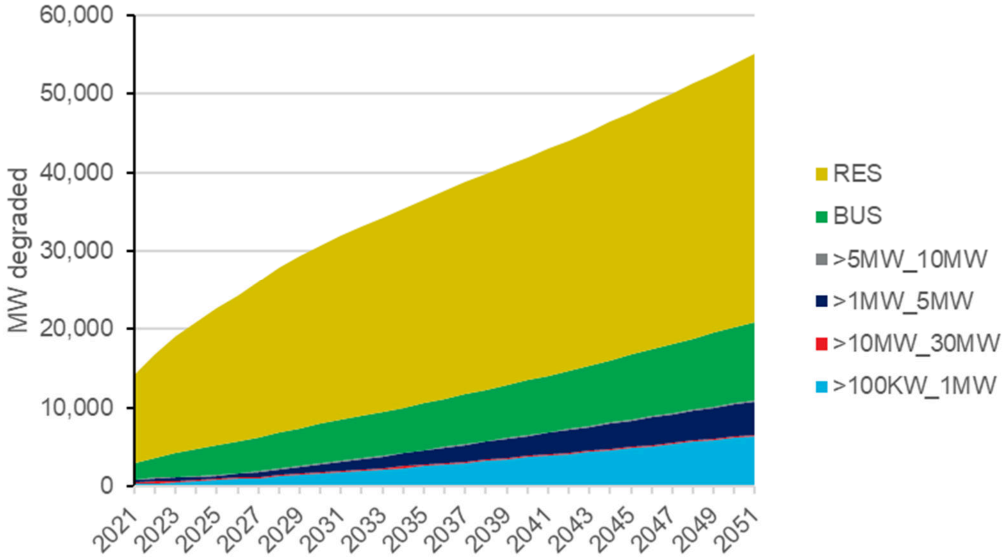


To put these system numbers in context the total number of residential electricity connections is expected to grow from 1.03m at the end of 2019-20 to 1.77m by 2050-2051 in Current Trajectory and 1.93m in Export Superpower. The number of systems under Current Trajectory equates to around 62% of all residential connections and Export Superpower is slightly more than 67%.

Break-down by end-customer type and state (both NEM & SWIS)

Figure 5-6 illustrates how the projected solar capacity is distributed across end-customer types under the Central Scenario. Residential (RES) remains by far away the dominant sector throughout the outlook period but behind the meter commercial systems at both the sub 100kW (denoted as BUS) and the 100kW to 1MW scale increasing in importance over time.

Figure 5-6 Cumulative degraded megawatts of national solar PV capacity by sector (Current Trajectory Scenario)

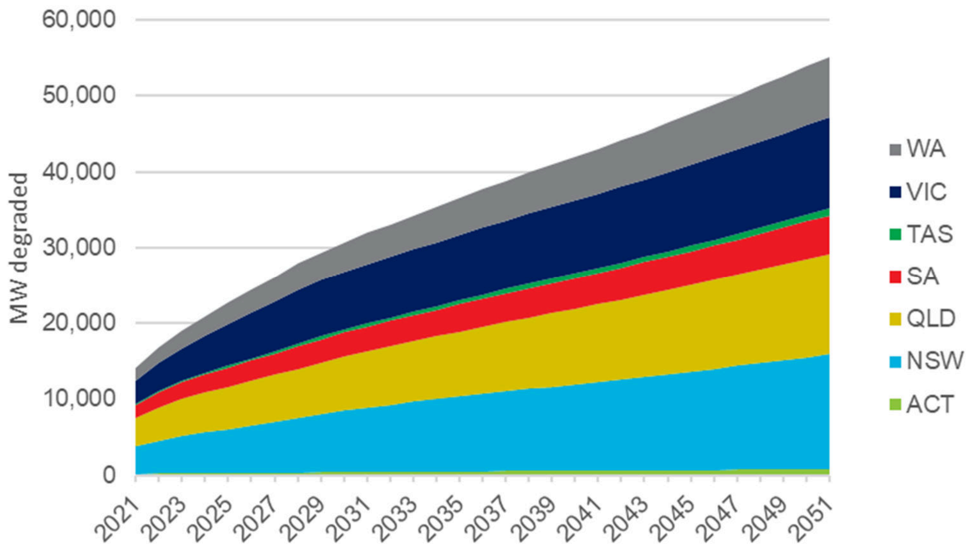


In front of the meter systems denoted by the segments greater than 1 megawatt in scale remain a relatively minor segment, with developers of solar power stations expected to favour much larger systems above 30MW in scale.

The sectoral breakdown is relatively similar across the other scenarios analysed.

Figure 5-7 illustrates how the projected solar capacity is distributed across states and territories under the Current Trajectory Scenario. The relative distribution across states is relatively similar across the other scenarios.

Figure 5-7 Cumulative degraded megawatts of solar PV capacity by state (Current Trajectory Scenario)

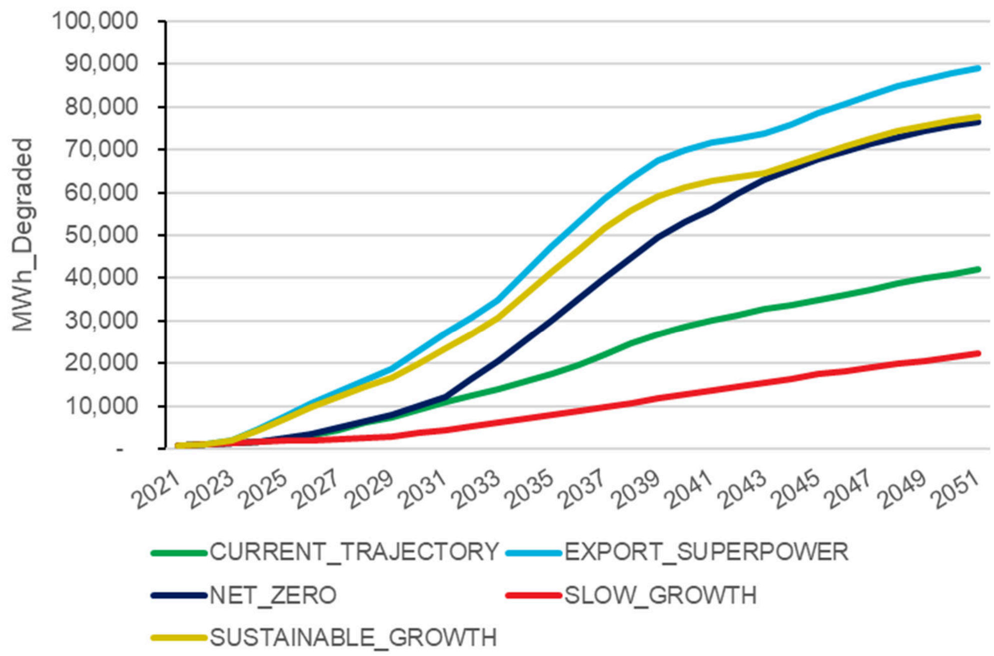


5.1.2 Battery energy storage

National Electricity Market

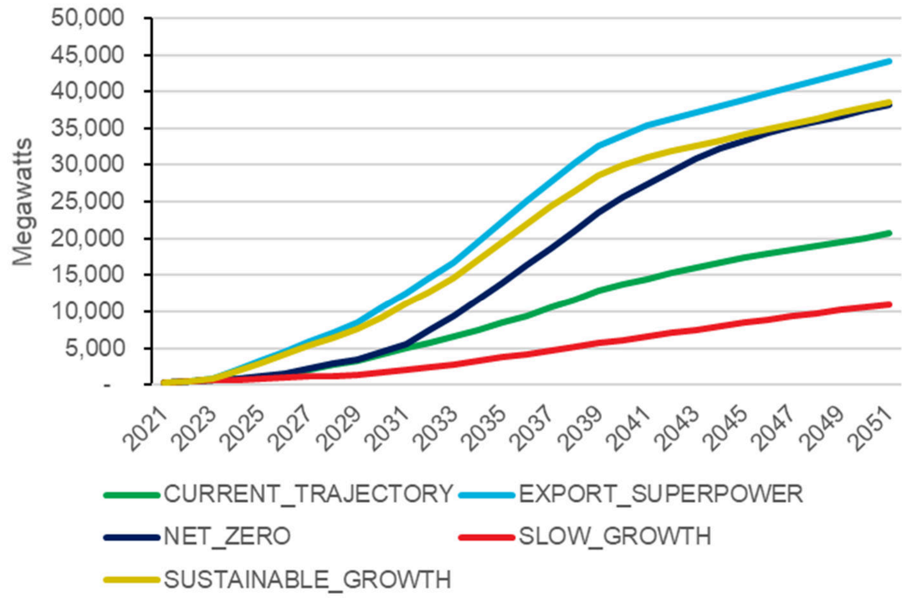
In terms of behind the meter stationary battery systems Figure 5-8 details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the National Electricity Market (NEM), taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2019-20 financial year) cumulative degraded battery capacity is estimated to stand at 667MWh. Under Current Trajectory the cumulative degraded capacity reaches almost 42,000MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 89,000MWh, while the lower bound represented by Slow Growth is just above 22,200MWh by the end of the projection in 2050-51 financial year.

Figure 5-8 NEM cumulative degraded megawatt-hours of battery capacity by scenario



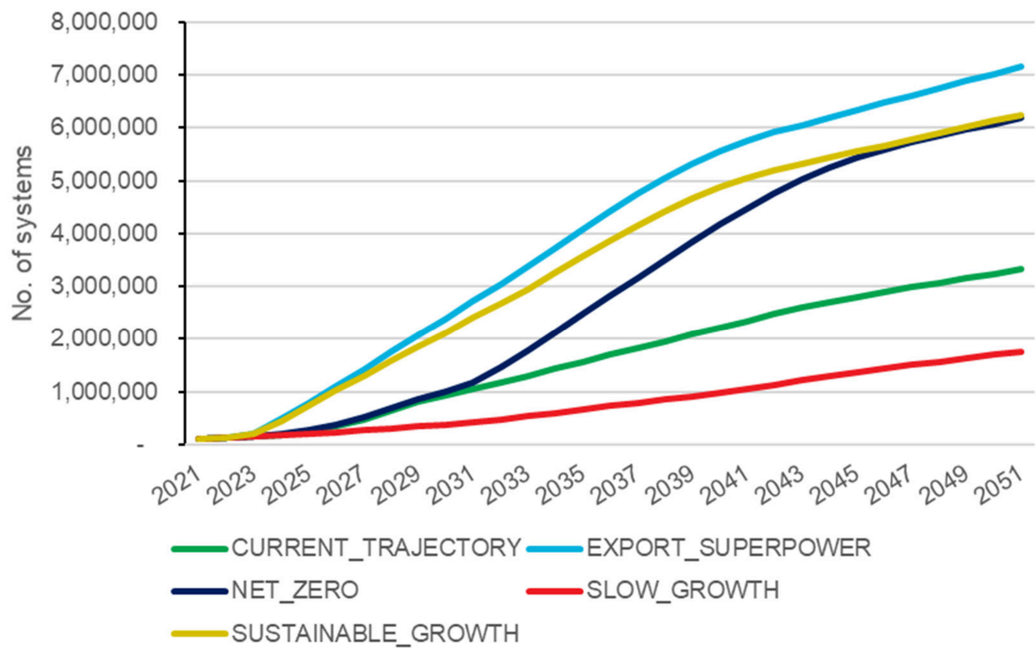
In Figure 5-9 is detailed the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 287MW at the end of 2019-20 financial year. Under Current Trajectory this grows to 20,700MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 44,200MW, while the lower bound represented by Slow Growth is almost 11,000MW by the end of the projection in 2050-51 financial year. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation (although the kilowatt-hours of storage is still subject to degradation) and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

Figure 5-9 NEM cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the NEM. At the end of the 2019-20 financial year the cumulative number of grid-connected battery systems is slightly more than 71,000. Under Current Trajectory the cumulative number of systems grows to 3.3 million by the end of the projection in 2050-51 financial year. The upper bound represented by Export Superpower reaches almost 7.2 million, while the lower bound represented by Slow Growth is slightly less than 1.8 million systems by the end of the projection in 2050-51 financial year.

Figure 5-10 NEM cumulative number of battery systems by scenario

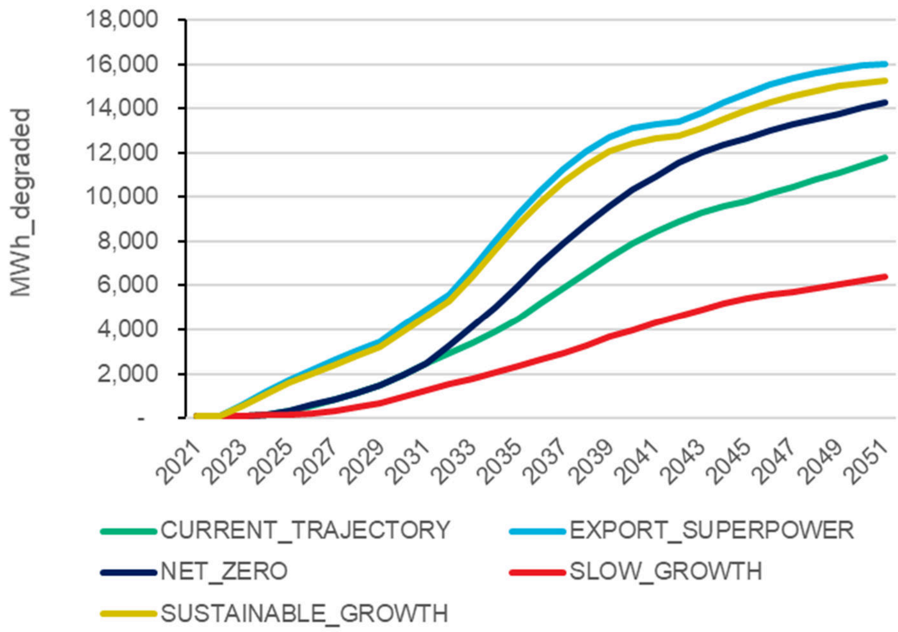


As some perspective, under Current Trajectory around 64% of solar systems in the NEM would be coupled with a battery, while almost 24% of residential connections in the NEM would have a battery system. At the very high end represented by Export Superpower, 95% of solar systems are coupled with a battery and 49% of residential connections host a battery system.

Western Australian South-West Interconnected System

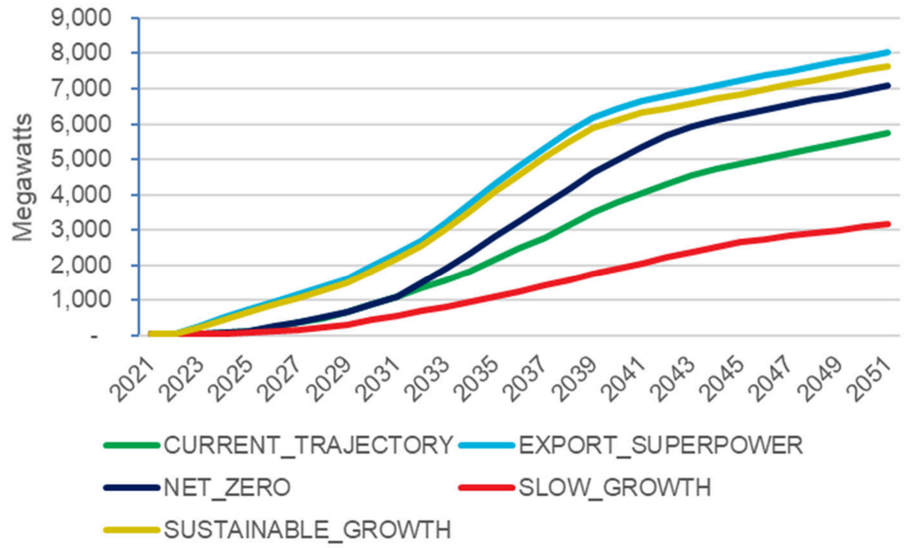
The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2019-20 financial year) cumulative degraded battery capacity is estimated to stand at 44MWh. Under Current Trajectory the cumulative degraded capacity reaches almost 11,800MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 16,000MWh, while the lower bound represented by Slow Growth is just above 6,400MWh by the end of the projection in 2050-51 financial year.

Figure 5-11 WA SWIS cumulative degraded megawatt-hours of battery capacity by scenario



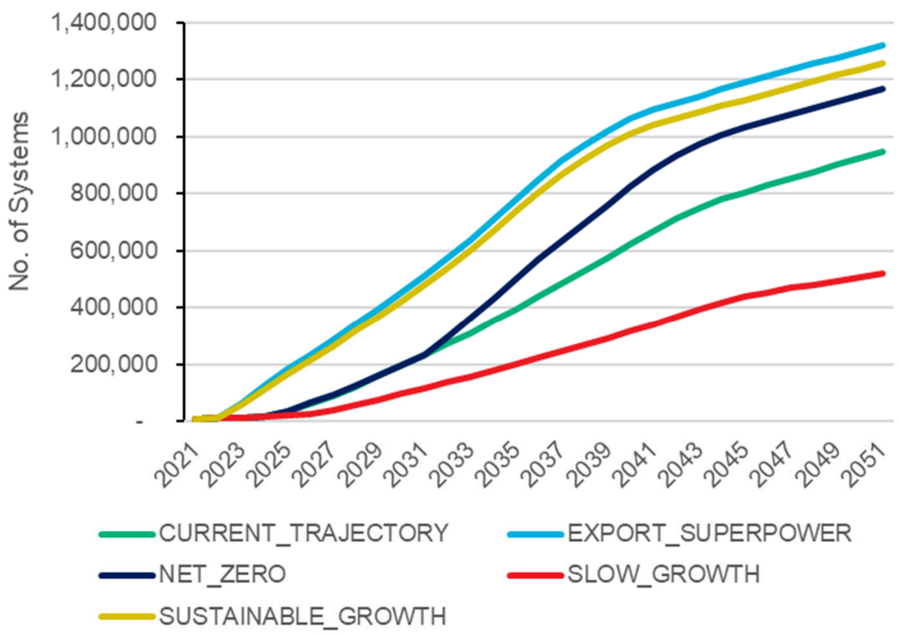
The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 18MW at the end of 2019-20 financial year. Under Current Trajectory this grows to almost 5,800MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 8,000MW, while the lower bound represented by Slow Growth is just under 3,200MW by the end of the projection in 2050-51 financial year.

Figure 5-12 WA SWIS cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the WA SWIS. At the end of the 2019-20 financial year the cumulative number of grid-connected battery systems stands at 4,600. Under Current Trajectory the cumulative number of systems grows to almost 950,000 by the end of the projection in 2050-51 financial year. The upper bound represented by the Export Superpower scenario reaches 1.3 million, while the lower bound represented by Slow Growth is 522,000 systems by the end of the projection in 2050-51 financial year.

Figure 5-13 WA SWIS cumulative number of battery systems by scenario

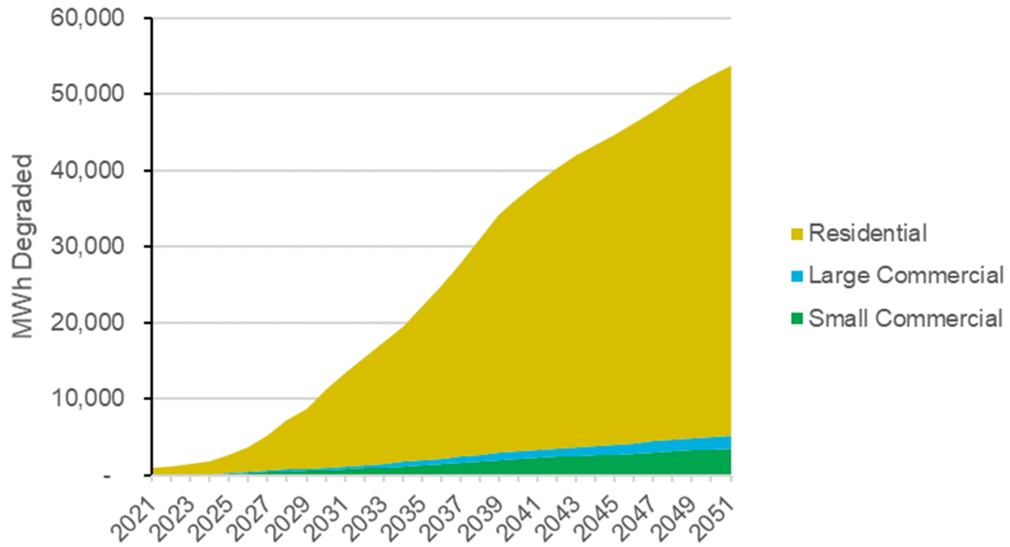


As some perspective, under Current Trajectory around 87% of solar systems in the SWIS would be coupled with a battery, while almost 54% of residential connections in the SWIS would have a battery system. At the very high end represented by Export Superpower, all solar systems are coupled with a battery and around 67% of residential connections host a battery system.

Break-down by end-customer type and state

The figure below illustrates how the projected battery capacity is distributed across end-customer types under the Current Trajectory Scenario. Just as in solar, Residential (RES) remains by far away the dominant sector throughout the outlook period.

Figure 5-14 Cumulative degraded megawatt-hours of battery capacity by sector (Current Trajectory Scenario)

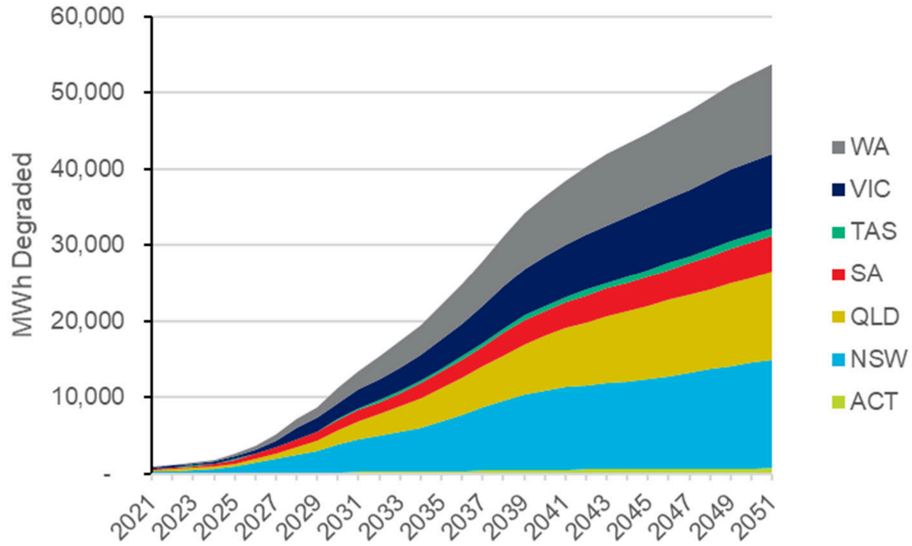


Note: Residential (RES) batteries are assumed to have average size of 10kWh as are small commercial (BUS) at the beginning of the projection period which then grows to 15kWh towards the end of the 2020's, while large commercial customers' (LGE_COM) batteries are assumed to have sizes averaging between 90kWh to 150kWh depending upon state. In practice though battery sizes will probably vary quite widely within these segments which are intended to be average archetypes for customers installing solar systems of: below 15kW – Residential; 15kW-100kW – small commercial; greater than 100kW but behind the meter – Large commercial.

The sectoral breakdown is relatively similar across the other scenarios analysed.

Figure 5-15 illustrates how the projected battery capacity is distributed across states and territories under the Current Trajectory Scenario. The relative distribution across states is relatively similar across the other scenarios.

Figure 5-15 Cumulative degraded megawatt-hours of battery capacity by state (Current Trajectory Scenario)

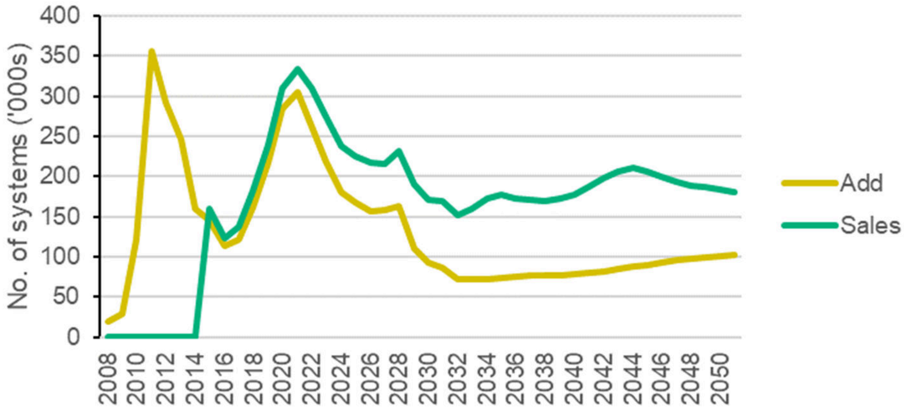


5.2 Residential solar and battery systems

As detailed in the prior section, systems installed in residential premises make up the vast bulk of both solar and battery capacity in our projections.

To more clearly illustrate and explain how solar uptake changes over time Figure 5-16 details the number of solar systems that are sold in each individual year (not cumulative) across both the NEM and SWIS. To provide some context, this chart details historical numbers stretching back to 2008, as well as projections from 2021 onwards for the Current Trajectory Scenario. The chart also details the number of these system sales which are new solar systems, as opposed to systems replacing a pre-existing solar system. The difference between total sales versus new incremental systems is only tracked from 2015 onwards because prior to this almost all solar systems sold were new additions rather than replacements.

Figure 5-16 Number of solar systems installed per annum (Historical and Current Trajectory Scenario)



5.2.1 Historical context

Prior to 2008 solar installations were very small, but then grew dramatically from 2009. This was as a result of plunging system costs combined with high feed-in tariff rates in the realm of $0.44 to $0.60 per kilowatt-hour, and a high STC rebate for the first 1.5kW of a system. By 2009-10 more than 121,000 systems were installed across the NEM and SWIS, compared to just 19,000 in 2007-08. In 2010-11 they peaked at almost 356,000 and remained high for the next two years at 292,000 in 2011-12 and 246,000 in 2012-13. However, while the underlying cost of a solar system continued to fall, the rapid wind-back of feed-in tariffs by state governments and also reductions in the value of the STC rebate reduced the financial attractiveness of solar for residential consumers. At the same time retail-delivered price rises for electricity began to moderate after 2013 which reduced the extent to which residential consumers faced a psychological push factor leading them to investigate options to reduce their electricity bills. Consequently, the number of solar system sales fell dramatically to 160,000 in 2013-14, and then continued to decline before bottoming out at 123,000 in 2015-16.

Yet by the next year solar began a sales recovery. This was driven by ongoing declines in the purchase price of solar systems that managed to outpace the reduction in the value of the STC rebate, as well as another large jump in retail delivered electricity prices (particularly significant in the NEM states). What made this particular jump in power prices especially beneficial for solar in the NEM states was that the increase was due to higher wholesale electricity market prices, which also led to a lifting in the feed-in tariff for exported electricity from solar systems. We also suspect that increasing media attention on electricity prices and reliability during this time helped to focus and amplify householder concern about electricity prices. Another factor that has been important in this growth was the Victorian Government's introduction of a rebate of up to $2,225 per system from October 2018 (which has been progressively stepped down and currently is set at a maximum per system of $1,850). Although it is important to note that solar system sales have increased significantly across almost all states, not just Victoria.

By the 2019-20 financial year sales had reached almost 310,000 systems, up 252% on their 2015-16 trough. This growth in system sales has continued into the 2020-21 financial year and we expect that close to 334,000 systems will be sold by the end of June.

While this passage of growth since 2016 has captured considerable attention, it is important to note that in terms of system sales they still remain below the peak almost a decade ago. The reality is that in terms of customer sales the residential solar market is not a story of continuous ongoing growth, but rather two booms and a depression. The idea that solar sales might decline may be surprising to those that have been watching the very large and growing amounts of megawatts of capacity installed in the past few years. But when viewed in terms of numbers of system sales, rather than capacity, and with a longer timeframe it is apparent that customers interest in solar can wane as concerns about electricity price rises subside and financial attractiveness of a solar system deteriorates.

5.2.2 The next decade – declining daytime wholesale prices, and restructured tariffs lead to deteriorating outlook for residential solar systems.

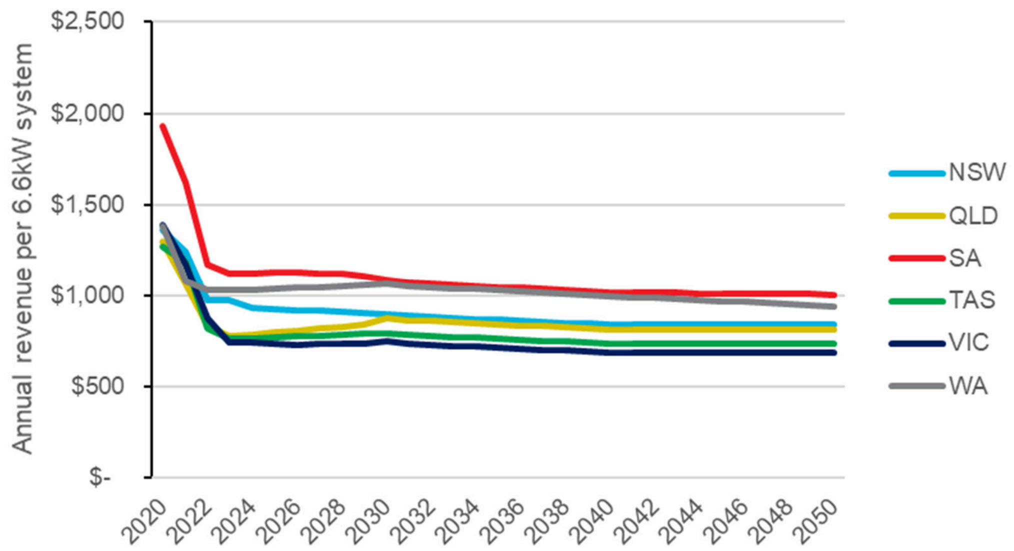
Sales of residential solar systems are expected to peak in 2020-21, but still remain above 300,000 in the subsequent year before suffering a significant fall to 2024 and then steadying until 2028 at between 215,000 to 237,000. Sales are then expected to drop significantly from 2029 until 2032 as a result of the Victorian Government's Solar Homes rebate program coming to an end in 2028 after it achieves the target of adding 700,000 additional systems. In 2032 sales bottom out at just above 151,000. While this represents a substantial fall from current levels above 300,000, it still remains above those experienced as recently as 2016-17.

The reason that sales never recover to their prior highs and experience a substantial fall over this decade is because we expect a general deterioration in paybacks for solar systems under the Current Trajectory scenario relative to the last few years.

As detailed in section 4.4.3 we expect that wholesale energy market prices during daylight hours will decline substantially from recent levels as a result of a substantial amount of both rooftop and large-scale solar capacity that has been added to the grid over the past few years and what is forthcoming from committed projects. Prices should then remain low because they should be tied to the levelized cost of new entrant solar farms. These lower wholesale flows through directly to feed-in tariffs offered for solar exports and also indirectly to retail electricity prices.

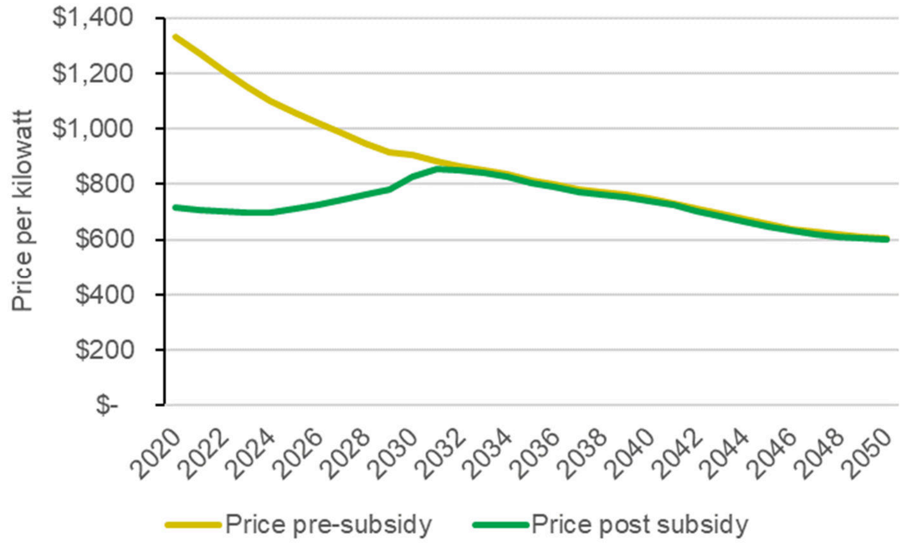
In addition, as detailed in section 4.4.2, the model assumes that residential electricity tariff structures shift the way costs are allocated across times of day. This involves a move away from an smoothed average single price per kilowatt-hour across all times of the day, to a structure where network and wholesale energy charges are lower over the daytime period until 3pm and then rise substantially over the peak demand period from 3pm until 9pm before subsiding during an off-peak period. The combination of the expected decline in the wholesale energy price during daylight periods and the shift of network charges towards the late afternoon and evening leads to a significant decline in revenue residential solar systems are expected to provide to owners (if not coupled with a battery system). This decline in revenues is universal across all states and all scenarios and is illustrated for the Current Trajectory scenario in Figure 5-17.

Figure 5-17 Annual revenue generated by a residential solar system (6.6kW) 2019 to 2051 (Current Trajectory Scenario)



During this period of declining revenues the underlying cost of a solar system is also declining. However, under the Current Trajectory Scenario, we assume that these cost reductions are outpaced by the declining value of government support for residential solar systems via STCs as the deeming rate declines. Consequently, as shown in the green line in Figure 5-18, householders see an increase in the purchase price of a solar system over the next decade.

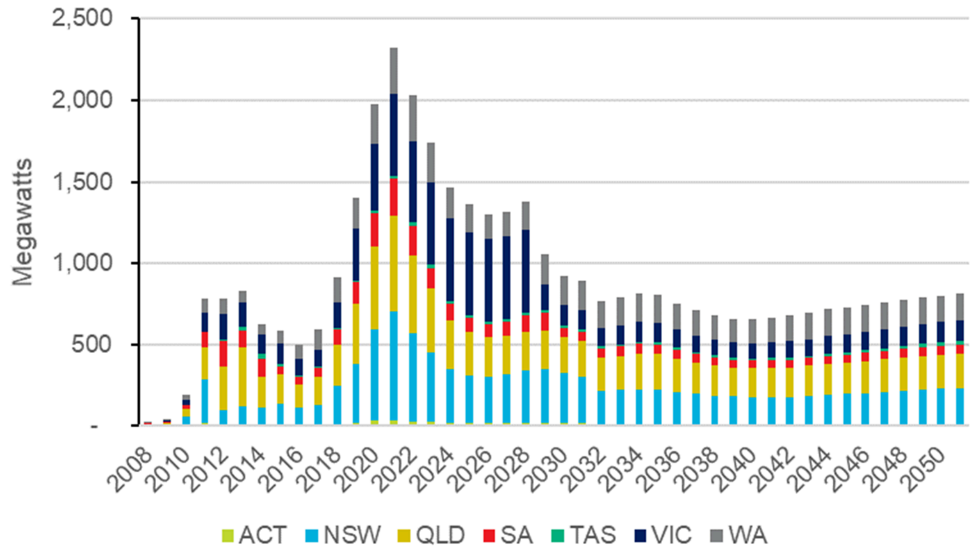
Figure 5-18 Underlying cost of solar per kilowatt and out of pocket cost to householders after STC discount
(Current Trajectory Scenario)



5.2.3 Decline in market moderated by Victorian rebate and emergence of system replacement and upgrade demand

In spite of the large decline in revenues and a small rise in the purchase price householders see for a solar system, solar sales over the next decade still manage remain noticeably above the levels seen back in 2015 and 2016 (when wholesale energy prices dropped to levels similar to those we anticipate during daytime periods). Also, as illustrated in Figure 5-19 megawatts of added capacity in the residential sector over the next decade remain substantially higher than they were during 2015 and 2016.

Figure 5-19 Megawatts of residential PV capacity added each year to the installed stock after deducting retirements (Current Trajectory Scenario)



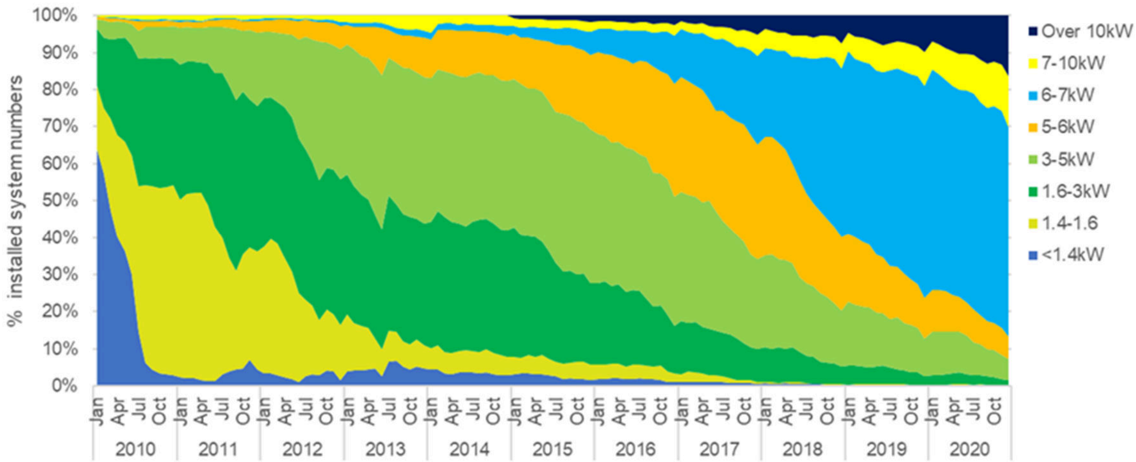
The reasons for why capacity additions remain above those seen in the years preceding the recent boom, in spite of a large fall in revenues, is a product of three factors:

1. The model assumes the Victorian Government will achieve its target to add close to 70,000 solar systems per annum to 2028;
2. As a result of module prices per watt being significantly lower than they were over 2010-2016 the solar industry is heavily geared towards installing much larger capacity per system than over 2010-2016.
3. A new source of sales emerges in replacing and upsizing the large number of small solar systems installed in the first solar boom over 2009-10 to 2013-14.

Point 1 is self-explanatory and its impact is seen by the outsized contribution of the Victorian dark blue segment in Figure 5-19 between 2021 to 2028.

In terms of point 2, while the number of system sales over the next decade average less than they did between 2010 to 2014, the capacity of each system is likely to be significantly larger than they were back then. The figure below illustrates how the Australian solar market has progressively evolved from 2010 to 2020 from being dominated by systems smaller than 3kW to systems larger than 6kW.

Figure 5-20 Proportion of residential solar systems within different capacity bands – National



Source: Green Energy Markets analysis of Clean Energy Regulator STC registry data

In terms of the third point we expect that replacement of the old systems from the first boom in solar over 2011 to 2013 will emerge as a new source of sales in this decade.

The growing gap in Figure 5-16 (several pages above) between the green sales line and the yellow line of completely new solar system sites is a function of the increasing number of old solar systems being replaced. Replacement is not necessarily because the solar modules have failed. Solar modules from large, established solar producers have proven to be remarkably durable, often still functioning quite well at 20 years of age, but replacements will also be spurred by inverters progressively breaking down (which typically have shorter warranted lives than modules) and also because households decide that they would be better off with a much larger capacity system than was originally installed.

While these replacement systems do not add to the cumulative number of systems shown in Figure 5-2 and Figure 5-5, they will increase the amount of cumulative capacity. This is because, as shown in the figure above, most of the systems installed over the first solar boom were far smaller capacity than what is typically installed now and what is economically optimal for households now given the large fall in solar module prices and the increase in their conversion efficiency. Furthermore, improvement in panel performance means that the average solar module installed today is about 50% more powerful than what was typically installed in 2011-12. So even if they replaced just the existing modules and added no extra, they'd increase system capacity by 50%.

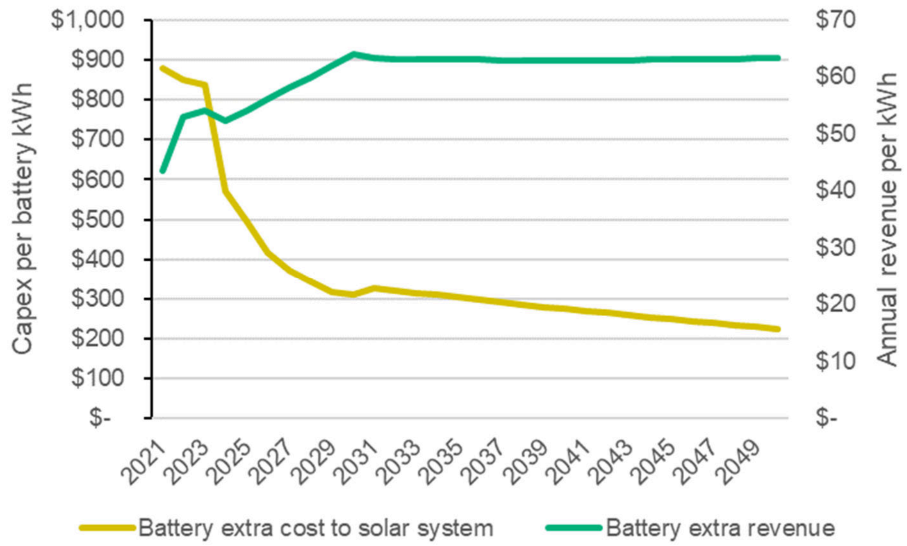
When older systems from 2010 to 2014, which were installed in large numbers, are replaced we expect most will be replaced with systems closer to the current industry standard of above 6kW.

5.2.4 Beyond 2030 – market supported by the emergence of cost-effective batteries and ongoing construction of new dwellings

The decline to solar revenues which unfolds over 2030 is expected to be a permanent feature that lasts until the end of the projection. However, expected declines in the cost of battery systems opens up the potential for households to cost-effectively store solar generation that would otherwise be exported at low feed-in tariffs and then use it after 3pm when both network charges and wholesale energy costs are expected to be significantly higher. This then helps to bolster solar sales as people elect to install them in conjunction with the battery system.

Figure 5-21 illustrates how under the Current Trajectory scenario revenue for a battery system (shown by the green line) rises while the capital cost for a battery (yellow line) plunges.

Figure 5-21 Revenue vs cost per kWh for household batteries (Current Trajectory Scenario)



In the first few years of the 2020's paybacks for batteries are quite long, in fact they exceed the typical warranted life of a battery of around 10 years until the mid 2020's under the Current Trajectory scenario. Consequently, they don't help improve the financial attractiveness of solar. Yet, in spite of long paybacks, there is already a market for residential battery systems. Because this market is relatively small and immature, we don't yet have a good understanding of the underlying drivers of uptake and how consumer uptake might respond in the future to changing financial attractiveness. Feedback from those involved in the solar and battery industry suggest that these customers adopt batteries based on either one or a combination of the following:

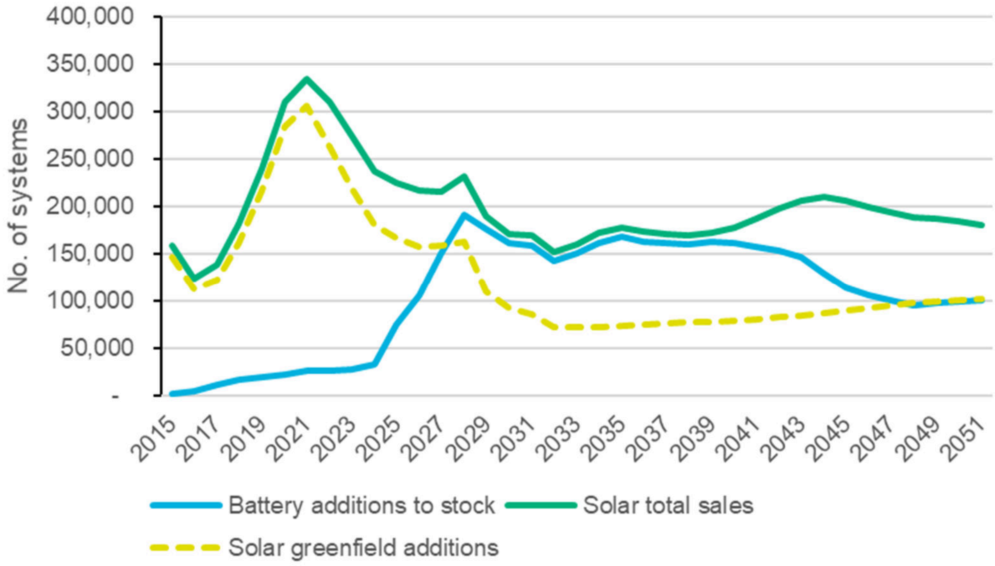
- Enhanced reliability of supply with the ability to maintain power in the event of grid outages;
- A strong affection for what is perceived as cutting-edge technology and the perceived status or bragging rights that comes with owning such technology;
- A desire to do their bit in addressing global warming by supporting a transition of the grid to variable renewable energy power supplies;
- A misapprehension that the battery will leave them financially better off or at least shield them from what they believe will be further large rises in electricity prices. This is often coupled with strong mistrust or resentment of electricity suppliers and a sense of injustice that exports from their solar system receive a price far below what they pay to import electricity from the grid.

We are not aware of any rigorous evaluation of the prevalence and strength of these kinds of motivational drivers amongst the Australian population and the degree to which they might drive purchasing behaviour of batteries at different purchase price points or paybacks. However, interviews with industry participants indicate that customers of solar systems almost always express a strong interest in adopting batteries, but they consider the current cost to be prohibitive. These suppliers expect that demand for batteries will be of similar size to that of solar systems, but only once batteries achieve substantial reductions in cost – with a halving in cost sometimes cited as a rule of thumb for an inflection in uptake.

Given the lack of rigorous data on likely purchasing behaviour the projections of battery uptake assume that historical levels of growth in battery installations will continue over the short to medium term given the ongoing reductions in battery prices assumed under the various scenarios. This is the case even though paybacks appear to be unattractive given alternative investment options. As paybacks approach similar levels as available for solar then we assume uptake will follow that of solar sales.

In Figure 5-22 the blue line details the model's Current Trajectory projection of annual additional battery systems (excludes systems replacing an existing battery system) in the residential sector, relative to solar system sales and additions. It is only by around the mid to late 2020's in the Current Trajectory Scenario that we envisage that batteries act to reduce the payback period for a solar system and it is around that time that we project a large uptick in battery uptake (note this inflection point occurs several years earlier in Sustainable Growth and Export Superpower and several years later in Slow Growth while Net Zero follows similar timing as Current Trajectory). By 2029 the model envisages in the Current Trajectory scenario that almost all new solar system sales will be coupled with a battery and hence the green and blue lines just about merge. This continues until the 2040's when additional battery systems subside down in line with solar system additions (systems that installed on a dwelling that has not previously had a solar system). The departure from battery additions in line with total solar sales to just additional solar systems is because by 2040's batteries will have been installed across a large proportion of the existing stock of solar systems. Consequently, new incremental additions to the battery stock only occur in circumstances where the premise is not replacing an existing solar system.

Figure 5-22 Number of additional residential battery systems relative to solar system additions and sales (Current Trajectory Scenario)



The implications of these system numbers in terms of megawatt-hours of battery capacity are illustrated in Figure 5-23 below, broken down by state.

Figure 5-23 Megawatt-hours of residential batteries added to stock by year (Current Trajectory Scenario)

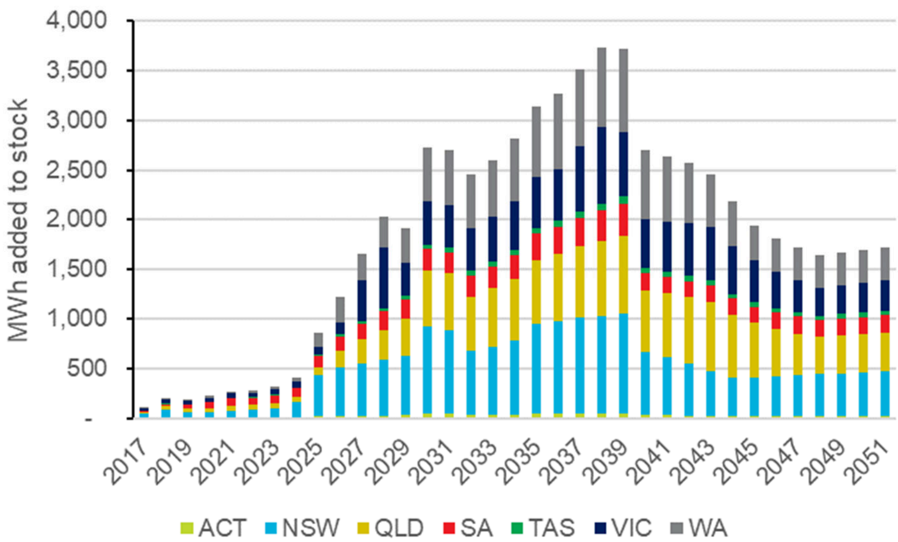


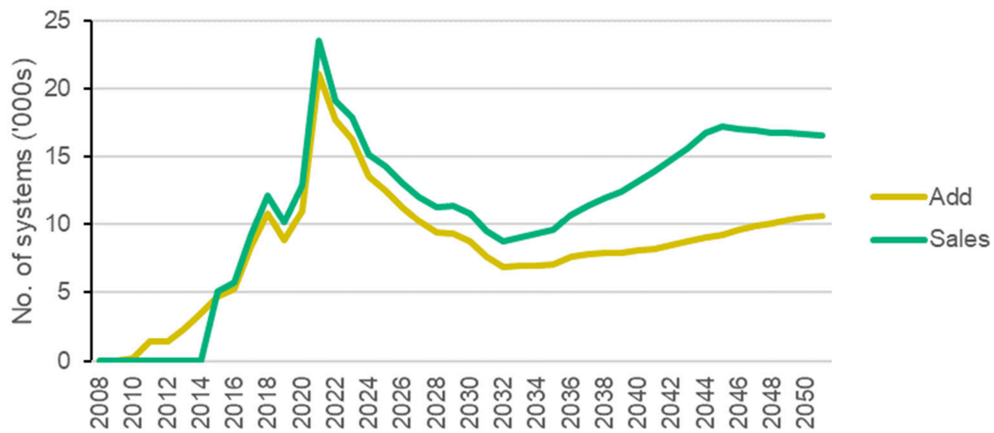
Figure 5-22 above shows that after 2028, when the Victorian Solar Rebate is assumed to end, new greenfield solar additions fall down to reach a base of above 70,000 systems in 2032. From this point growth resumes but is far more modest and steadier than past growth periods, rising to over 80,000 in the 2040's and 100,000 by 2050. This ongoing steady growth of new additions is tied to an assumption that Australia is assumed to build around 100,000 new detached or semi-detached dwellings each year, as part of ongoing population growth. Historical data indicates that solar adoption rates tend to be highest in areas of Australia that are subject to substantial new dwelling construction. The level of new solar additions (and batteries from 2045 onwards) is in line with these historical adoption patterns.

5.3 Commercial solar systems up to 100kW and associated batteries

Solar systems installed on commercial premises have historically been a much smaller proportion of installed capacity than residential but have been growing more quickly and now represent around 20% of installed rooftop solar capacity within the STC scheme.

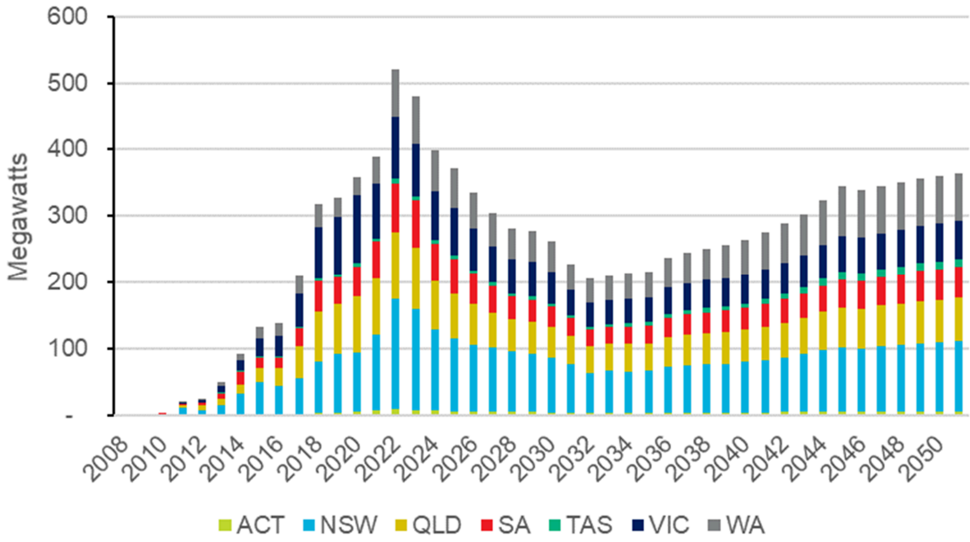
Figure 5-24 details the number of small commercial solar systems that are sold in each individual year (not cumulative). To provide some context, this chart details historical numbers stretching back to 2008, as well as projections from 2020-21 onwards for the Current Trajectory Scenario. The chart also details the number of these system sales which are new solar systems, as opposed to systems replacing a pre-existing solar system. The difference between total sales versus new incremental systems is only tracked from 2015 onwards because prior to this almost all solar systems sold were new additions rather than replacements and indeed there is still little difference between the two figures so far to date.

Figure 5-24 Number of commercial sub 100kW solar systems installed per annum (Historical and Current Trajectory Scenario)



While the number of solar systems within the sub-100kW commercial segment is small relative to residential, because each system is noticeably larger than in residential it is significant in terms of capacity, which is detailed in the figure below.

Figure 5-25 Capacity of commercial sub-100kW solar systems added to stock per annum (Historical and Current Trajectory Scenario)



5.3.1 Historical context

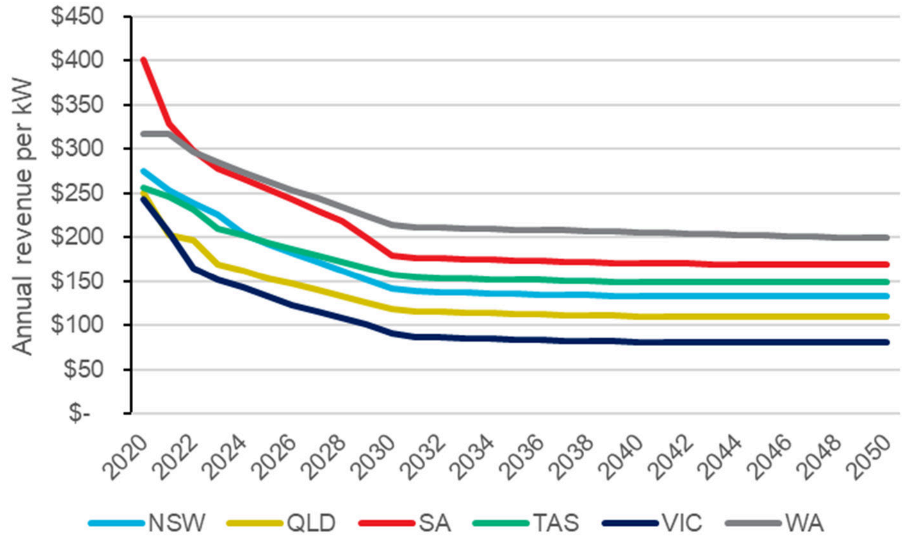
The commercial segment of the solar market only passed 100MW of annual installations by the 2013-14 financial year but has continued to grow rapidly and is expected to exceed 500MW in 2021-22. It missed the boom and subsequent-bust that unfolded over 2010 to 2015 period that the residential sector experienced because it was not offered the premium feed-in tariffs. Also the STC multiplier only applied to the first 1.5kW of a system and so made little impact on the larger commercial systems.

5.3.2 The next decade – commercial suffers similar fall in revenues as residential but more significant decline in sales

The sub-100kW segment follows a similar path as residential over the next decade however its decline is more noticeable due to the lack of support under the Victorian Solar Homes rebate program and less scope for capacity growth via the replacement of old systems with larger solar systems.

The reason for the decline in sales and capacity to 2030 in commercial is similar to that as residential. It sees a large decline in revenue, as it is assumed to face similar tariff structures and electricity costs as residential. In addition, the withdrawal of STC policy support to 2030 outpaces underlying cost reductions.

Figure 5-26 Annual revenue generated by a commercial solar system (per kW) 2020 to 2051 (Current Trajectory Scenario)



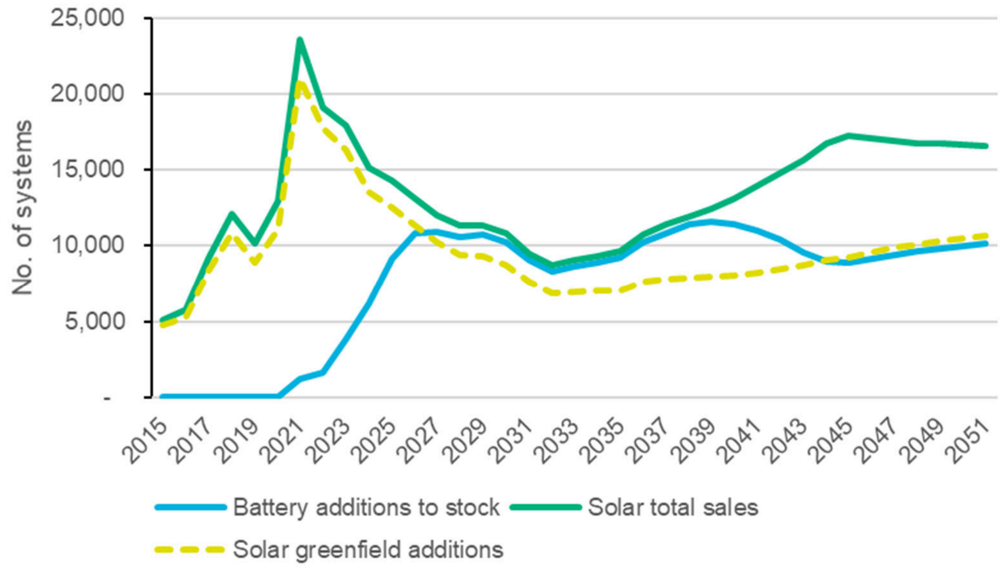
5.3.3 Commercial regains growth in 2030's and 2040's

Like residential capacity begins to grow again over the 2030's and 2040's although faster than residential. This is a product of the commercial sector having lower levels of market saturation.

5.3.4 Battery adoption follows similar path to residential

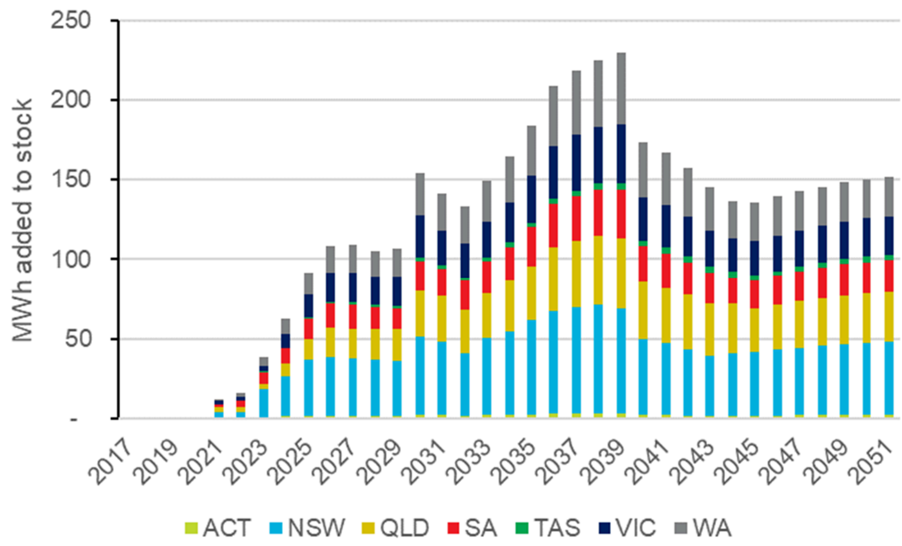
The figure below details the number of commercial battery systems added to the stock under the Current Trajectory scenario relative to solar system sales and new additions. In this sector the payback on a battery system reaches levels close to those of solar systems on a similar timeframe to residential. Just as in residential, we expect that towards the end of the 2020's almost all solar systems sold will be installed in conjunction with a battery system as the combination provides a superior payback than each in isolation. Also battery system additions to the stock drop down the level of new solar additions in the 2040's just like residential as the majority of the existing stock of solar systems are expected by that time to have a battery coupled with them.

Figure 5-27 Number of additional commercial battery systems relative to solar system additions and sales (Central Scenario)



The implications of these system numbers in terms of megawatt-hours of battery capacity are illustrated in the figure below, broken down by state.

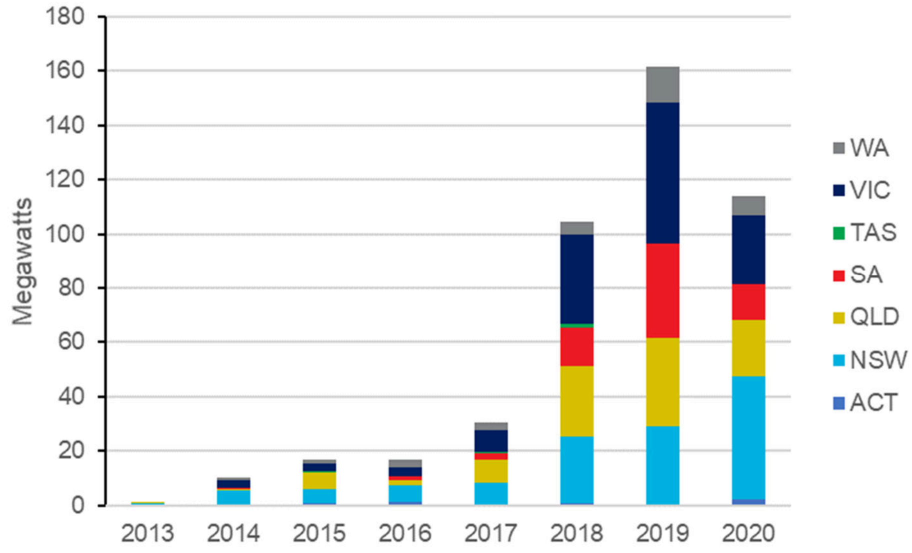
Figure 5-28 Megawatt-hours of commercial batteries added to stock by year (Current Trajectory Scenario)



5.4 Large commercial behind the meter systems (above 100kW)

As explained in section 3.6 and detailed in the figure below, the market for behind the meter solar systems above 100kW has only very recently emerged at a noticeable scale of capacity and still remains small relative to the residential sector.

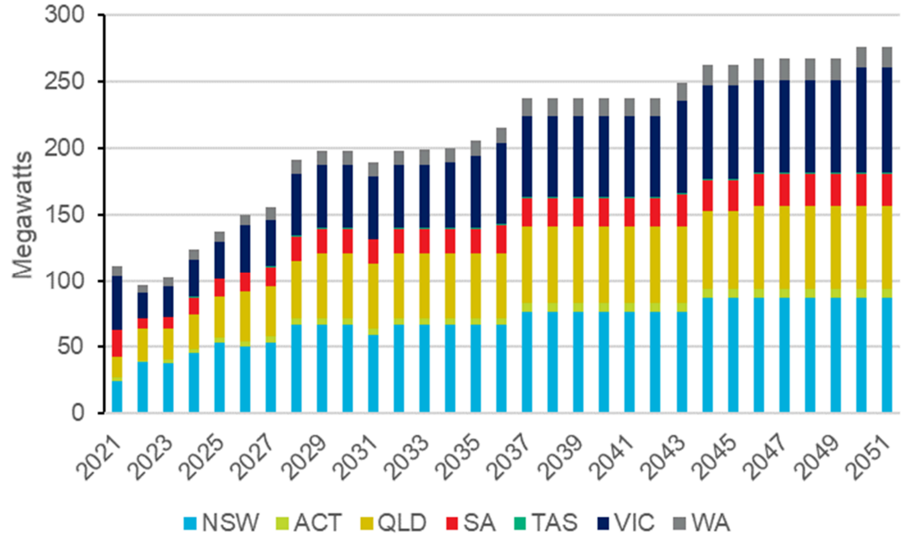
Figure 5-29 Capacity of behind the meter large commercial solar PV (by calendar year of accreditation)



Note: Accreditation data is as at March. There are lags in the awarding of accreditation to systems which means the capacity receiving a 2020 year accreditation is likely to be slightly higher than indicated.

Figure 5-30 details the amount of large commercial solar capacity added to stock by year and state that we project under the Current Trajectory Scenario. While the market is expected to contract substantially relative to 2019 levels over the next few years, from 2024 onwards the sector returns to growth. While the growth is not as spectacular as the 2015 to 2019 period it is steady and long-lived to the end of the projection period.

Figure 5-30 Capacity of large commercial solar systems added to stock per annum (Current Trajectory Scenario)



5.4.1 Historical context

Prior to 2016 solar systems installed above 100kW in scale in behind the meter installations were driven by non-financial motivations such as demonstrating a commitment to addressing climate change and installation levels were inconsequential relative to the residential solar market and the broader electricity market. The reason solar systems of this scale were not as attractive in financial terms as they were in the residential sector were a function of two things:

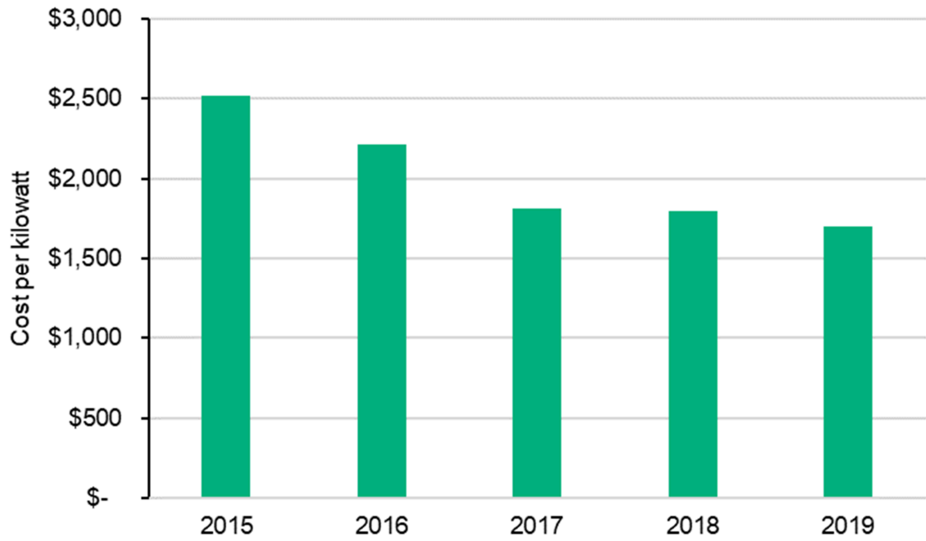
- Customers with enough electricity demand to support a system larger than 100kW tend to face much lower electricity prices per kWh of consumption, due mainly to a large proportion of network costs being recovered via demand charges;
- Government policy financial support for systems of this scale have historically been less than that provided to the residential market.

However, the market entered a significant growth phase beginning in 2016 driven by:

- Substantial reductions in capital costs;
- A large and rapid rise in wholesale energy market prices in the NEM;
- A large increase in the value of LGCs; and
- Increasing sophistication of the solar industry that enhanced its ability to service and market to large commercial customers that present a more complicated market than residential and small business.

Figure 5-31, based on the sample set provided by the Clean Energy Regulator, shows that system cost per kilowatt for large commercial systems declined by 29 percent between 2015 and 2018.

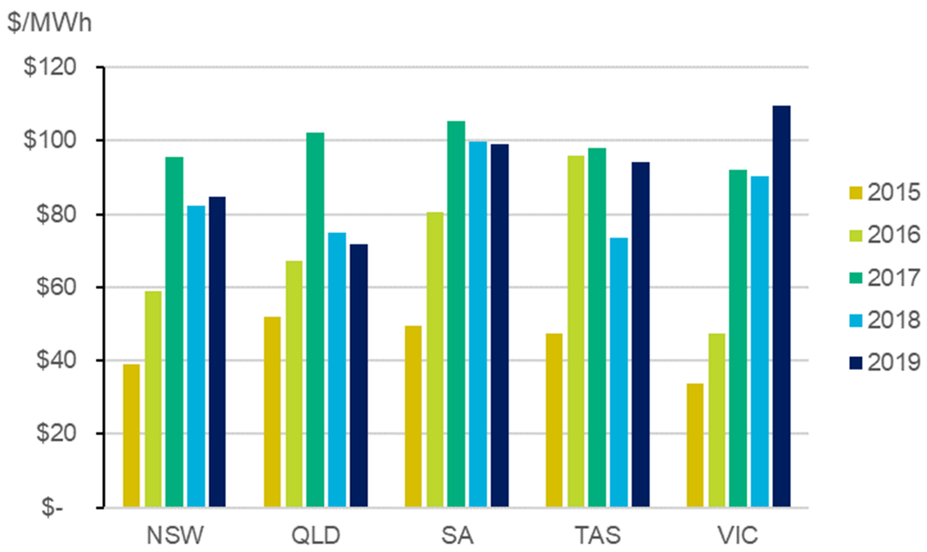
Figure 5-31 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)



Note: Off-grid or remote grid systems have been excluded because these usually involve substantial additional costs not faced by mains grid-connected systems which then act to skew the cost data upwards in years in which off-grid systems were accredited.

Meanwhile, over the same period we saw a dramatic rise in wholesale electricity prices in the east-coast National Electricity Market. The jump in prices began in 2016 but was greatest in 2017 for NSW, QLD and Victoria.

Figure 5-32 Average time-weighted wholesale electricity spot price by NEM state



The final factor that helped drive a dramatic improvement in the financial attractiveness of 100kW+ solar systems around 2016 was a significant rise in the LGC spot price that rose from close to $30 in January 2015 to surge above $80 by 2016 and remain there until the last quarter of 2018.

Combining the decline in system costs with the increase in revenue from higher wholesale prices and higher LGCs prices, we estimate the payback period on solar systems roughly halved for a range of customer sites likely to be suitable for 100kW+ behind the meter systems.

Coupled with this dramatic improvement in financial attractiveness was an increasing sophistication and capability of the solar industry that has made them better able to convert customer interest into a solar installation. It is important to recognise that Australia's solar industry has traditionally been dominated by selling and installing small, generic solar systems to residential households. Selling and installing such residential systems is usually much simpler than what's required for large commercial systems. Commercial clients have more varied tariff types, need a more tailored approach to system design, take a more involved and sophisticated approach in evaluating whether to purchase solar, are more prone to landlord-tenant split incentives, and the technical requirements of such systems are more difficult, in particular the grid connection process. Another factor that has been more important in the commercial sector than residential has been the provision of financing that avoids the need for clients to commit their own upfront capital to purchasing the system.

As the financial attractiveness of large commercial solar systems has improved and the levels of interest in installing solar has grown, the solar industry has gained much greater experience in the sale and installation of these larger systems. This has allowed them to become better at presenting and explaining the investment proposition for solar to clients involving multiple decision makers and detailed evaluation processes. In addition, they have become more adept at dealing with the needs and concerns of electricity networks, and likewise electricity networks have gained greater comfort and understanding in having 100kW+ solar systems operating within their network. Also financing products have been developed with more attractive terms such as lower interest rates, longer repayment periods, and repayments tied to consumption of electricity from the solar system otherwise known as power purchase agreements. These have helped to at least somewhat mitigate tenant-landlord split incentives, and the often myopic approach businesses take to allocating capital to non-core elements of their business (a problem of bounded rationality which is a well understood factor behind sub-optimal levels of investment in energy efficiency[23]).

5.4.2 Short decline followed by recovery to prior boom heights

While capacity installs of large commercial decline over the next few years relative to 2019, this decline is relatively shallow and short and growth resumes by 2024 and by 2027 large commercial is back to its prior boom levels of capacity.

Like the sub-100kW sector our model envisages that revenue for large commercial solar systems will decline significantly over this decade. However, the scale of the decline in revenue is far smaller than sub-100kW, because large commercial customers are assumed to be on demand-based network tariffs. Consequently, revenues aren't reduced by the shifting of a large proportion of network charges out of 9am to 3pm period and into 3pm to 9pm.

At the same time because large commercial solar systems receive less generous government support than sub-100kW systems, the capital cost declines achieved by solar systems are less obscured by simultaneous loss of government policy support.

[23] Sanstad and Howarth (1994) Consumer Rationality and Energy Efficiency, available here: https://www.aceee.org/files/proceedings/1994/data/papers/SS94_Panel1_Paper21.pdf

Figure 5-33 illustrates how system cost reductions manage to outpace revenue reductions. Consequently, large commercial, unlike residential, manages to achieve declining paybacks and this leads to a recovery in capacity installs unlike residential. In addition, unlike residential, we do not envisage significant market saturation effects that hinder uptake.

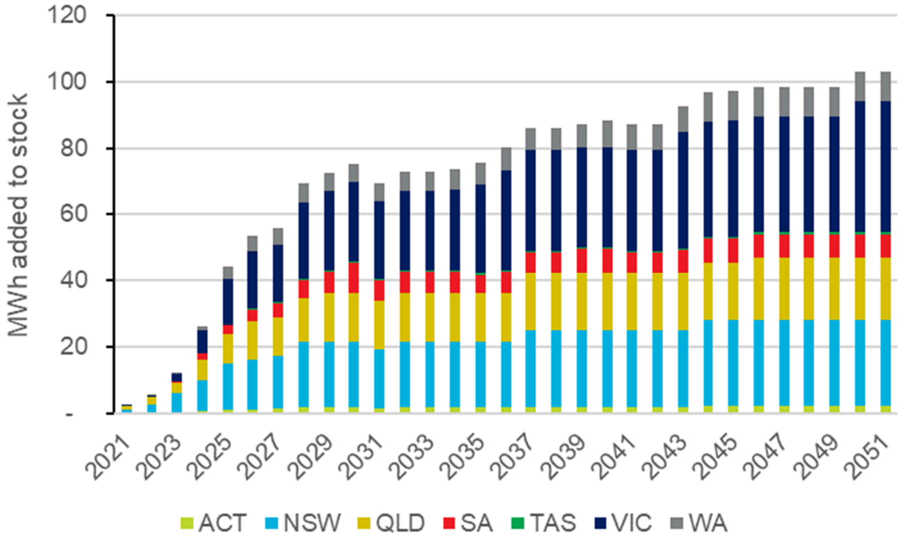
Figure 5-33 Annual revenue for NSW large commercial solar relative to capital cost (per kW) (Current Trajectory Scenario)

5.4.3 Battery adoption surges from 2024

While the market for batteries in the large commercial sector is currently very small, the model envisages batteries achieve attractive economics in this sector sooner than residential. This is a function primarily of batteries allowing customers to capture reductions in their demand charge on their own but crucially also by firming-up the demand charge reductions delivered by the solar system.

As a result, battery uptake is expected to increase rapidly from 2024 onwards in the Current Trajectory Scenario and by the mid to late 2020's (depending on the state) almost all solar systems are installed coupled with a battery.

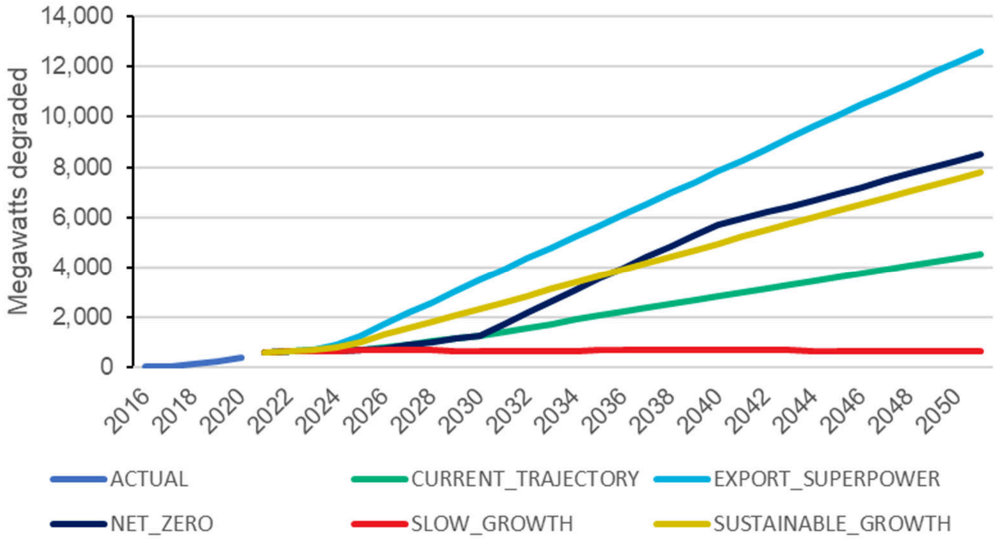
Figure 5-34 Megawatt-hours of commercial batteries added to stock by year (Central Scenario)



5.5 Power stations 1MW - 30MW

The figure below details cumulative installed degraded capacity of power stations projected under each scenario. It illustrates how capacity additions are expected to slow over the next few years. Under Export Superpower and Sustainable Growth though strong growth resumes by the mid 2020's. Current Trajectory levels of additions don't recover to recent historical levels until after 2027 while Net Zero departs markedly from Current Trajectory after 2030 consistent with a step up in emission reduction efforts under this scenario. Meanwhile in Slow Growth no further capacity additions are assumed for small power stations consistent with this scenario's expectation of depressed electricity market conditions and slow capital cost reductions.

Figure 5-35 Cumulative degraded capacity of sub-30MW power stations



5.6 Battery system charge and discharge profiles

To assist AEMO in assessing the possible aggregate impact of non-scheduled batteries on electricity demand and supply, we used AEMO supplied historical 30 minute interval data of estimated solar output stretching back several years within our payback model to assess how the battery would charge or discharge its power under two different battery operation modes Solar Shift and Tariff Optimisation which are both explained in the respective headings below:

Solar Shift Mode

in this mode the battery only charges up when solar generation is excess to the site load (until it is charged to its full kilowatt-hours) of capacity. It then only discharges to cover load where this is excess to the solar system's output. It will discharge until it is fully depleted or until solar generation covers or exceeds load again. The battery never exports power offsite to the grid, instead only seeking to cover load within the site.

Tariff Optimisation Mode

Just like in the solar shift mode, the battery charges up when solar generation is excess to the site load but in addition it will also charge from grid imports in circumstances where the solar excess to the load for the day is insufficient to fully charge the battery. The formula assesses if solar exports for the day ahead are inadequate to charge to full capacity and if so, then extra charge from the grid is taken during the solar tariff period. The way the formula is designed assumes that battery software would be capable of perfectly forecasting that day's level of solar exports which is unlikely to be possible. However systems are capable of reasonably accurately forecasting a solar system's output 12 hours ahead and considerable software development is being dedicated to learning algorithms that aim to forecast a household or business' electricity consumption by monitoring how energy consumption changes relative to a range of other measured variables such as weather, the day of the week and other factors such as production schedules.

The battery is discharged to cover a consumer site's residual consumption left over after solar but unlike the solar shift mode it will only begin discharging during the peak period (3pm-9pm) first and will then continue discharging until 3am if it still has charge.

It is worth noting that this algorithm has been designed in a way that is designed to function reasonably well with the single tariff structure we have assumed (although it is far from optimised). In reality customers will face a range of tariff structures and this will change what is the best way to charge and discharge the battery.

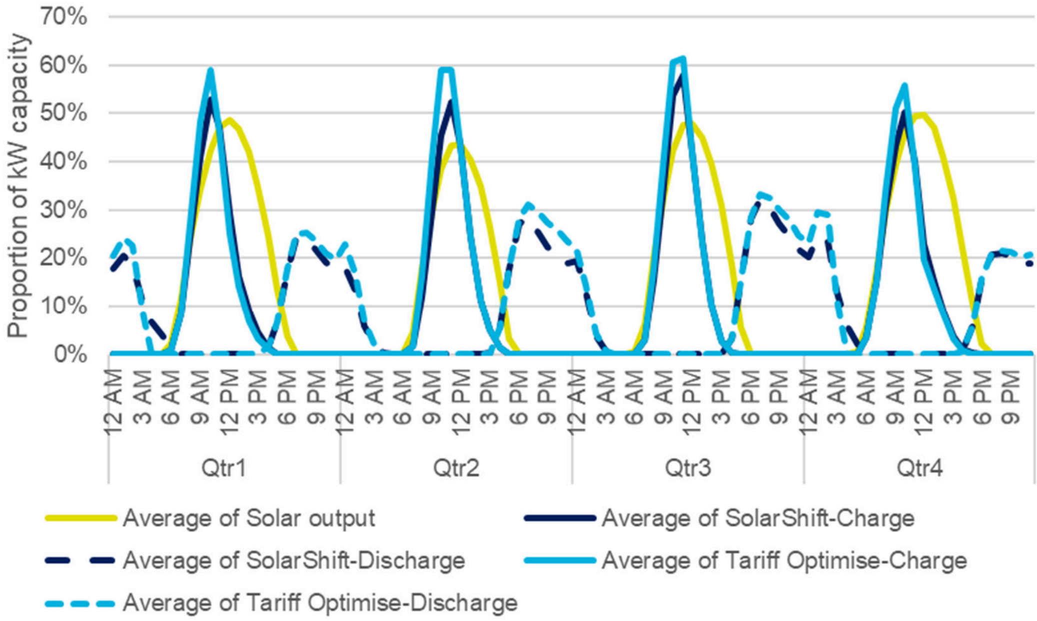
5.6.1 Results

The figure below illustrates the averaged quarterly pattern of the battery's charging (solid blue lines) and discharging (dashed blue lines) behaviour per kW of battery capacity by hour of day for a NSW residential consumer assumed to have a 6.6kW solar system and 10kWh battery capable of a maximum charge or discharge of 4kW (these solar and battery system size assumptions are the same across all states and the two modes for residential sector. The yellow line shows the quarterly averaged hourly solar generation profile per kW of capacity. The light blue line is for the Tariff Optimisation mode while the dark blue covers the Solar Shift mode. For the residential sector there is relatively little difference in the battery charge-discharge behaviour across the modes because:

1. the solar system almost always generates enough power excess to the load to fully charge up the battery
2. It is rare that load exceeds solar generation before 3pm so batteries in the solar shift mode usually tend to discharge after 3pm and so don't behave all that

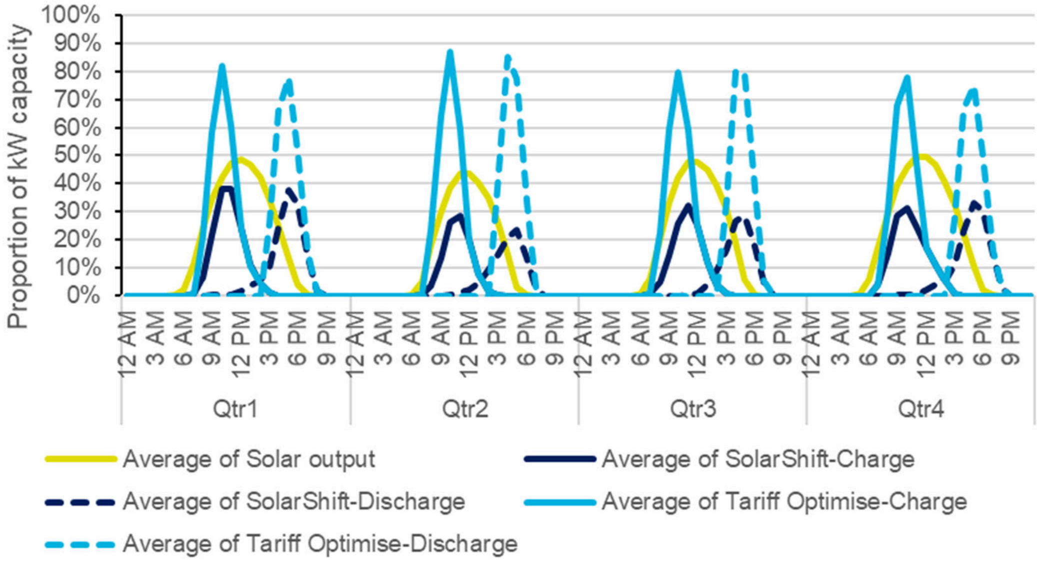
differently to the tariff optimisation mode that only allows discharge after 3pm when the peak tariff period commences.

Figure 5-36 Quarterly averaged charge-discharge profile NSW residential example



Things look quite different in the chart below which illustrates the charge-discharge profile for a battery held by a NSW small commercial consumer assumed to have a 20kW solar system and 10kWh battery capable of a maximum charge or discharge of 4kW (these solar and battery system size assumptions are the same across all states and the two modes for small commercial). The solar profile is exactly the same as residential, however our model sizes the solar system in a way that is intended to keep exports reasonably low (20% or less of total solar generation compared to about 70% for the residential consumer). This leads to a far more marked difference in battery charge and discharge behaviour across the modes than occurs in residential.

Figure 5-37 Quarterly averaged charge-discharge profile NSW small commercial example



Firstly, in the solar shift mode the battery rarely gets fully charged due to insufficient solar excess, while the Tariff Optimisation mode uses grid imports to top-up the battery to full capacity where solar excess is insufficient for the day. The second thing is that under solar shift mode the battery will begin discharging sooner than the 3pm peak because solar output is insufficient to cover the site's load sooner in time than what is common for residential solar sites. This also results in a greater contrast between the two battery operation modes relative to the residential sector because Tariff Optimisation only allows discharging after 3pm to ensure it takes advantage of higher prices during this period. One other critical difference of note between commercial and residential is that the battery in Commercial under Tariff Optimisation fully discharges its battery far faster than residential. This is because the battery is of similar storage capacity but its load is far larger than a residential site.

The figure below shows the charge-discharge profile estimated for a battery held by a large commercial customer. The assumed solar system of the modelled customer is 300kW. The profile illustrated below is for such a customer in NSW which is assumed to have a 90kWh battery capable of a maximum charge or discharge of 36kW. The same was assumed for QLD, however in other states it made sense for larger battery systems to be installed (150KWh for the remaining states while the ratio of kW to kWh remains the same at 0.4). Just as for small commercial our model sizes the solar system so that exports are kept low (below 20% of total solar generation). Consequently, we see a very similar charge and discharge pattern for this customer segment where the tariff optimisation mode gets substantially greater utilisation from the battery than solar shift. And discharge under solar shift begins sooner than 3pm.

Figure 5-38 Quarterly averaged charge-discharge profile NSW large commercial example