SRES STC Projections

Clean Energy Regulator

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Jacobs

SRES and Small-scale PV Projections

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Executive Summary

The Clean Energy Regulator (CER) is responsible for the regulation of the Australian Government's climate change laws and programmes, including the Renewable Energy Target (RET). One of its functions is to administer the Small-scale Renewable Energy Scheme. The SRES scheme is designed to achieve generation of electricity from small-scale renewable sources, reduce emissions of greenhouse gases in the electricity sector, and ensure that renewable energy sources are ecologically sustainable.

The SRES scheme offers small-scale technology certificates (STCs) at a price of $40 per certificate through the STC clearing house to purchasers of eligible solar water heaters (SWH), air source heat pump water heaters (HPWH) and small-scale photovoltaic (PV), wind and hydro systems. STCs are also traded on the open market.

There is no cap for the number of STCs that can be created. Up until 2017, each installed system could create certificates equivalent to 15 years of expected generation from the system for a small-scale renewable generator and equivalent to 10 years for a renewable water heater. From 2017, the number of STCs generated per unit is one year less than the previous year, with the intention being that the scheme tapers off in a gradual linear manner.

The purpose of this report is to forecast the number of STCs, and small-scale PV capacity installed that will be generated in the calendar years of 2021 up to and including 2025. This will assist in determining the number of STCs each electricity retailer is obliged to surrender.

Historically, the majority of uptake has been through solar hot water units and residential solar PV generation. Uptake in solar PV generation has now largely supplanted uptake from solar hot water and has been influenced by reductions in the installed cost of new solar PV systems, growing market acceptance of these technologies, higher electricity retail prices and government incentives.

High retail electricity tariffs have increased growth in the rate of PV installations. Continuing strong uptake for commercial installations are also projected over the forecast period driven by perceived economic benefits. Over the projection period, we see uptake also boosted by state-based incentives particularly in Victoria.

Table 1 shows our projections of STC creation. The approach for the projections involved the development of a hybrid ARIMA time-series model and agent-based model for residential solar PV uptake. In this instance, we used the agent-based model as a check of the veracity of the short-term forecasts provided through the ARIMA approach. The projections indicated below are based on the time-series modelling approach.

The ARIMA time series model provides robust forecasts over a short-medium timeframe, while the agent-based model enables the longer-term market saturation effects to be explored. We have used several relevant independent regressors to estimate the impact of electricity prices, interest rates, feed-in tariffs, capital costs and capital rebates, as well as instrumental variables to mimic shocks (such as the COVID-19 pandemic) and policy changes.

For estimating the commercial models, we have used national ARIMA based timeseries approach utilising the same independent variables as discussed above.

The solar PV uptake projections have been used to calculate the STC projections as included in Table 1. The outputs indicate that STC creation is expected to peak in 2021 before a downward trend is observed as the STC scheme tapers to completion by 2030.

The projected installed capacity and installation numbers of small-scale rooftop solar are shown in Table 2 and Table 3 respectively. Modest growth in installed capacity is expected over the projection horizon.

Table 1: Small scale technology certificate creation projections, ('000s)[1]

	2021	2022	2023	2024	2025
ACT	540	560	572	535	503
NSW	10,776	10,640	10,224	9,700	8,961
Northern Territory	95	94	94	93	88
Queensland	9,513	9,537	9,112	8,729	8,045
South Australia	2,840	2,117	1,599	1,240	972
Tasmania	356	389	423	396	374
Victoria	5,635	5,357	4,888	4,382	3,845
Western Australia	4,451	4,158	3,570	3,603	3,153
Commercial <15kW	978	1,451	1,587	1,546	1,453
Commercial 15kW-90kW	2,824	2,601	2,360	2,131	2,126
Commercial 90kW-100kW	878	1,562	1,457	1,028	645
Residential Solar Hot Water	1,113	1,053	1,028	1,017	1,013
Commercial Solar Hot Water	51	50	50	50	50
Heat Pump Water Heater	1,666	2,139	2,369	2,482	2,537
All STCs	41,716	41,708	39,333	36,932	33,765

Table 2: Projected installed capacity of small-scale PV systems (MW)[2]

	2021	2022	2023	2024	2025
ACT	40	45	52	56	61
NSW	796	858	927	1,005	1,083
Northern Territory	6	7	8	9	9
Queensland	700	770	828	906	974
South Australia	209	172	146	129	118
Tasmania	31	37	45	48	53
Victoria	467	501	514	526	539
Western Australia	325	337	325	375	383
Commercial <15kW	80	121	149	165	181
Commercial 15kW-90kW	231	216	221	228	265
Commercial 90kW-100kW	76	130	136	110	81
All small-scale PV installations	2,961	3,192	3,350	3,558	3,749

[1] State based totals are for rooftop PV for the residential sector. The commercial sector for rooftop PV is reported Australia-wide by capacity band, and water heater category totals are Australia-wide.
[2] State based totals are for the residential sector, and the commercial sector is reported Australia-wide by capacity band.

Table 3: Projected number of installations of small-scale PV systems[3]

	2021	2022	2023	2024	2025
ACT	4,902	5,226	5,837	6,084	6,506
NSW	95,505	106,524	111,944	118,207	124,267
Northern Territory	1,203	946	1,047	1,150	1,252
Queensland	87,285	92,979	97,144	103,571	108,629
South Australia	28,011	21,133	17,455	15,065	13,435
Tasmania	4,352	5,049	5,999	6,246	6,718
Victoria	69,805	69,805	69,805	69,805	69,805
Western Australia	51,079	49,335	46,383	52,176	52,027
Commercial <15kW	11,845	17,872	21,985	24,488	19,727
Commercial 15kW-90kW	7,520	7,038	7,183	7,413	5,874
Commercial 90kW-100kW	771	1,314	1,378	1,111	519
All small-scale PV installations	362,280	377,221	386,160	405,316	408,759

[3] State based totals are for the residential sector, and the commercial sector is reported Australia-wide by capacity band.

1. Introduction

The Clean Energy Regulator (CER) is responsible for the regulation of the Australian Government's climate change laws and programmes. One of its functions is to administer the Small-scale Renewable Energy Scheme. The SRES scheme is designed to achieve the following objectives:

- Generation of electricity from renewable energy sources.
- Reduced emissions of greenhouse gases in the electricity sector.
- Ensuring that renewable energy sources are ecologically sustainable.

The SRES scheme offers small-scale technology certificates (STCs) at a fixed price of $40 per certificate through the STC clearing house to purchasers of eligible solar water heaters (SWH), air source heat pump water heaters (HPWH) and small-scale photovoltaic (PV), wind and hydro-electric systems. STCs are also traded on the open market, historically usually at a discount to the clearing house price. There is no cap for the number of STCs that can be created.

The number of STCs created is based on an estimate of electricity generated or displaced by the renewable energy sources over their economic lifetime. The number of STCs created is also influenced by geographical location.

The purpose of this report is to forecast the number of STCs that will be generated in the calendar years of 2021, 2022, 2023, 2024 and 2025. This will assist liable entities to anticipate the extent of their liability over the coming years.

The STC forecast is developed through the completion of several tasks including:

- Modelling of expected small-scale technology installations (⩽100 kW) and provision of updated SRES forecasts for 2021-2025, including projections of the number of STCs and installed capacity for 2021 in addition to the four compliance years from 2022 to 2025.
- Identification of key factors affecting the type, number and size of small-scale systems installed and the trends in STC creation by various categories including residential and commercial uptake across states and territories in Australia.
- Review and update previously developed models and methodologies to improve accuracy of projections. This has been done by analysing and identifying changes to circumstances, trend breaks and/or inclusion of alternative estimators. In addition, we have introduced a new modelling approach founded solely on agent-based modelling. This is designed to better capture the impact of structural changes in the small-scale certificate market.

Historical data has been supplied by the CER containing detailed information on the number of STCs created and registered including the type and location of unit installed. Data was provided from April 2001 until June 2021 to assist with the forecasts. All analysis and forecasts in this study are based upon STCs created in the month of installation and STCs are only considered if they have passed validation.

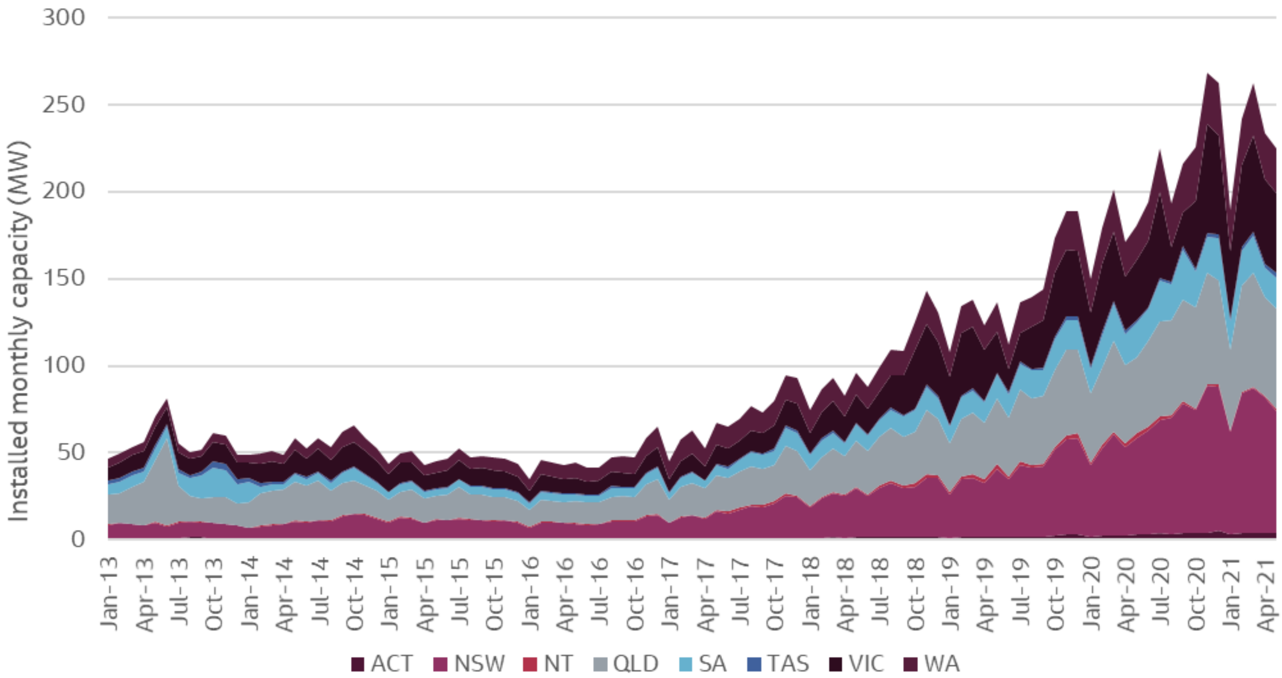
This report continues with an analysis of the trends in uptake in section 2, followed by a description of the current Government incentives and solar PV policies in section 3. Section 4 describes the method, and the assumptions are discussed in section 5. Section 6 presents the results, which are summarised in section 7. The appendices include detailed modelling outputs, statistics, data table and references.

2. Trends in Uptake

2.1 Small-scale PV Systems

Figure 1 illustrates the monthly residential rooftop PV capacity installed from the beginning of 2013. The first half of 2021 is indicating some signs of a slowdown in the rate of growth of residential installations, which began accelerating from the beginning of 2017. Installation growth had continued accelerating throughout 2020 despite the generally negative socio-economic impacts of COVID.

Figure 1: Monthly installed residential capacity across states



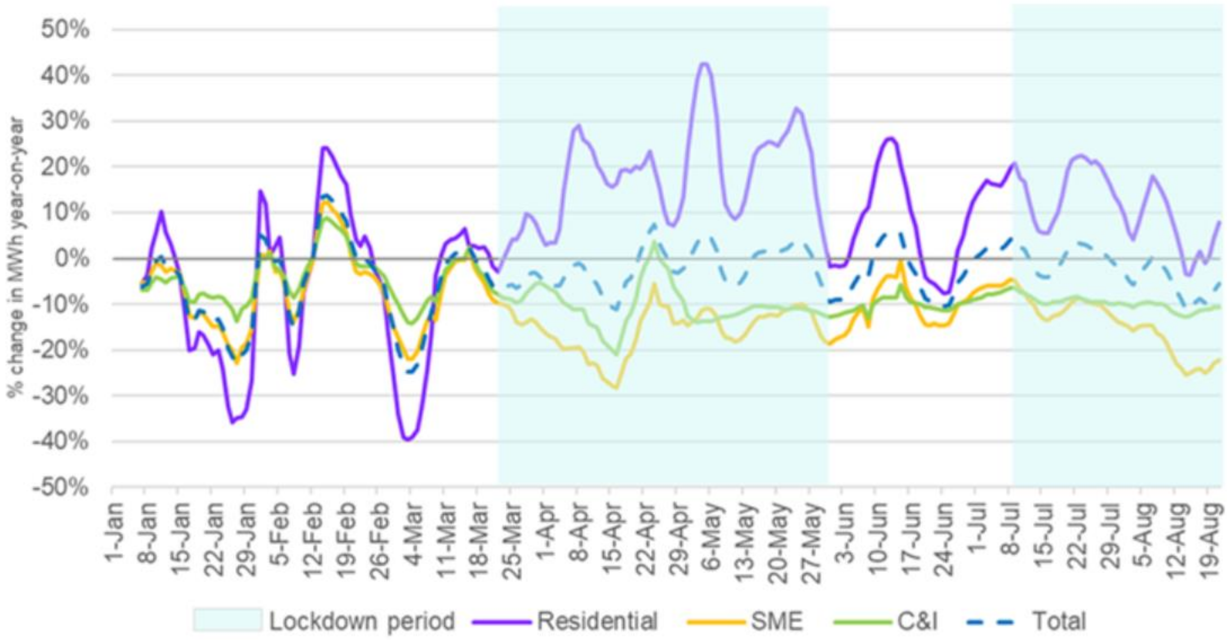
Source: Jacobs' analysis of CER data, data from Jan– May 2021 includes estimates due to registration lag

The impact of COVID-19 and the subsequent nation-wide lockdowns, government stimulus packages and consumer behaviour has had a two-speed effect on the economy. While the net impact of the extensive lock downs and strict social distancing rules imposed has reduced gross domestic product, some sectors have prospered. Small-scale solar PV installations appear to be one of these sectors. With consumers in lockdown and unable to spend on outdoor entertainment, dining out and travel, the result has been a shift to an increase in spending on household items. Additionally, the extra consumption of power during daylight hours from the shift to working from home and record low interest rates makes the installation of PV systems attractive.

However, the long-term effects of the COVID-19 crisis are still unclear and they could impact consumers' ability to invest in solar PV in the medium to long-term.

Examining recent changes to Australian electricity consumption by consumer illustrates the impact of COVID-19 on residential electricity demand (see Figure 2). The analysis indicates that industrial demand has seen relatively little impact, with commercial demand reductions being offset by higher residential demand. Overall annual consumption has reportedly been reduced by about 2% as a direct result of COVID-19.

Figure 2: Year-on-year change in demand for 2020



Source: Figure 1 from ACCC 2020 'Electricity prices fall and COVID spikes residential demand'
https://www.accc.gov.au/media-release/electricity-prices-fall-and-covid-spikes-residential-demand

The rise in uptake of rooftop PV installation since 2017 is also attributed to the elevated electricity prices in addition to higher feed-in tariffs. The retail price of electricity increased in NEM states in 2017, driven by rising wholesale costs resulting from higher wholesale gas prices and the retirement of the Hazelwood power station. Higher wholesale prices also flow through indirectly to the feed-in tariffs offered as the value of solar exports to an energy retailer is proportional to the wholesale price of electricity. Feed-in-tariffs jumped in 2016 and 2017 to levels double those in prior years.

However, this trend has reversed in 2021, with feed-in-tariffs across most regions in the NEM falling, following the broad decline in the NEM's wholesale electricity prices.

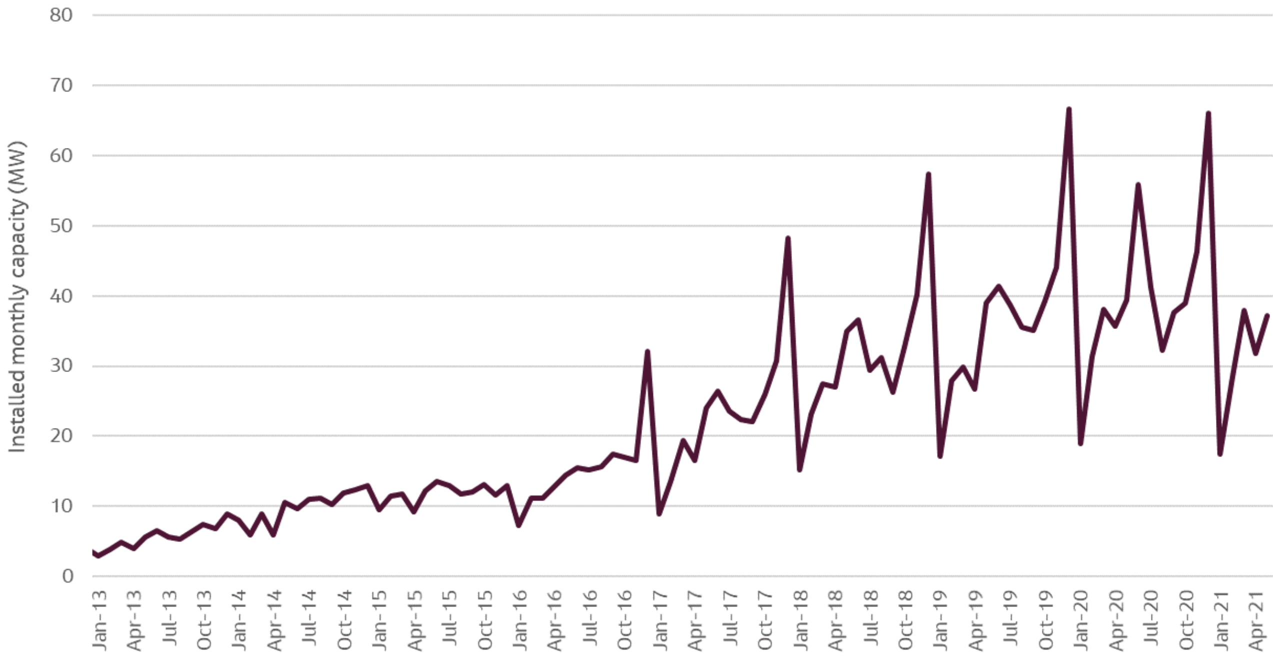
There are several other factors contributing to the rise in rooftop PV installations:

- Reductions in capital cost of installations.
- Low cash and mortgage rate.
- Increasing environmental awareness.
- Increase in awareness via advertising, word of mouth, neighbourhood uptake.

Figure 3 illustrates the recent trends in installed capacity by schools and businesses. A strong growth in uptake has occurred since 2017. A distinct seasonal trend has emerged as business hastens to commit to installations prior to annual step down in rebates applied to small scale technology. The COVID-19 phenomenon also appears to have had a positive influence on commercial PV installations, despite the temporary closure of many small-medium enterprises. This may be attributed to government incentives (such as the instant tax write-off) and the SME's that have benefitted from the lock downs such as data centres and online retailers.

As with the residential uptake data, there is an indication that a slowdown in the rate of installation growth is emerging in the first part of 2021.

Figure 3: Monthly trend in STC creation from commercial solar PV installations

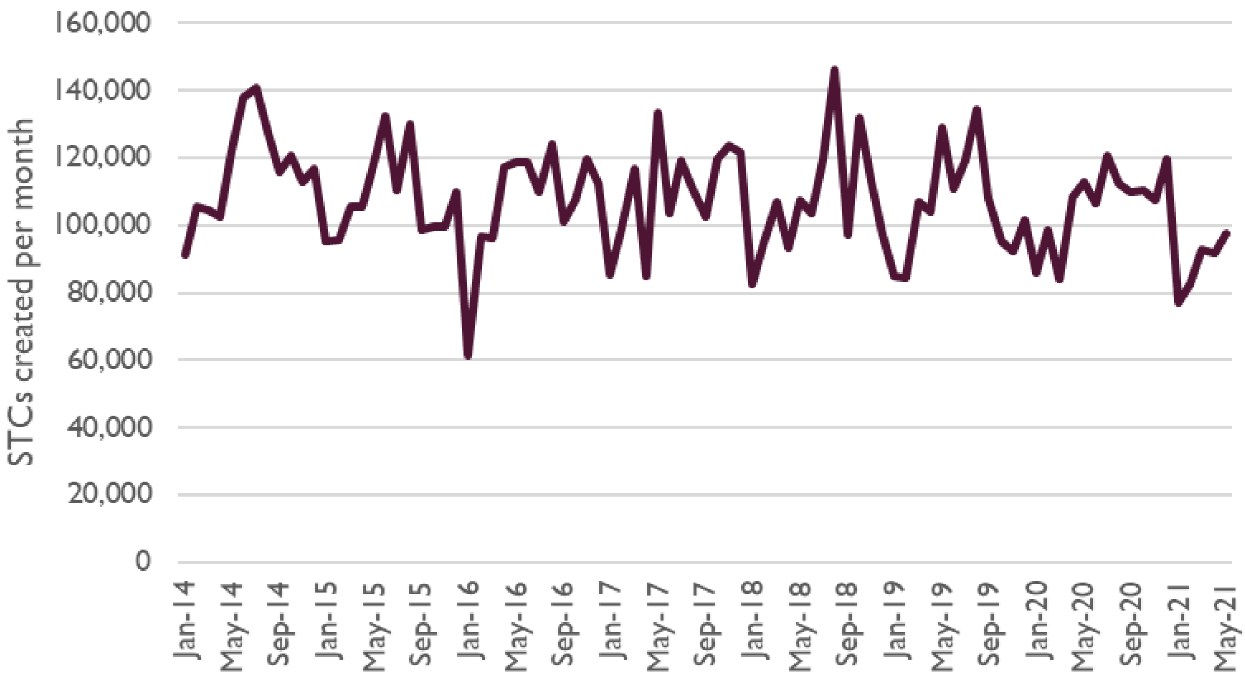


Source: Jacobs' analysis of CER data, months Jan 2013 - May 2021 include estimates due to registration lag

2.2 Solar water heaters

Figure 4 shows the trend in creation of STCs by the installation of residential solar hot water systems. There is a mild decline evident over the last 7 years, which has been punctuated by some pauses. COVID-19 seems to have had a mildly negative impact on the sector, although the decline in 2020 coincides with the acceleration of air-sourced heat pump water heaters (see section 2.3).

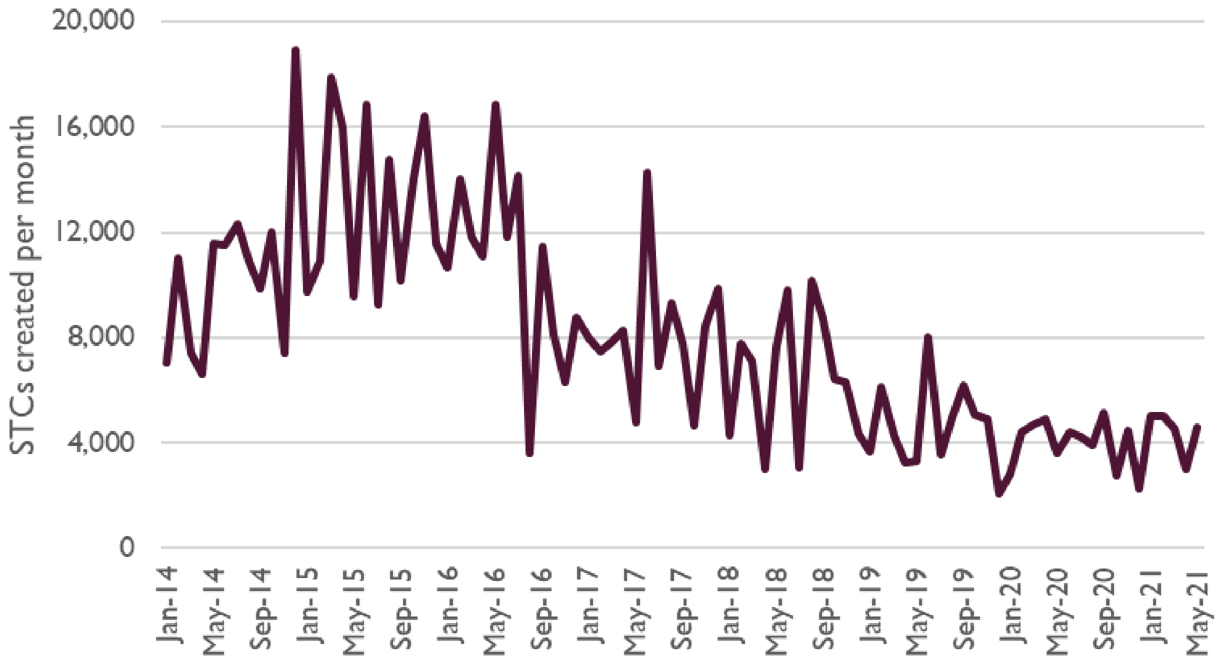
Figure 4: Monthly trend in STC creation from residential SHW



Source: Jacobs' analysis of CER data

STC creation from commercially sized units continues to decline with a decrease of 29% in 2019 and a 14% reduction in 2020, as can be seen in Figure 5. COVID-19 seems to have had a stabilising impact on commercial installation as the 7-year monthly low recorded in December 2019 has not been breached.

Figure 5: Monthly trend in STC creation from commercial SHW



Source: Jacobs' analysis of CER data

2.3 Air-sourced heat pump water heaters

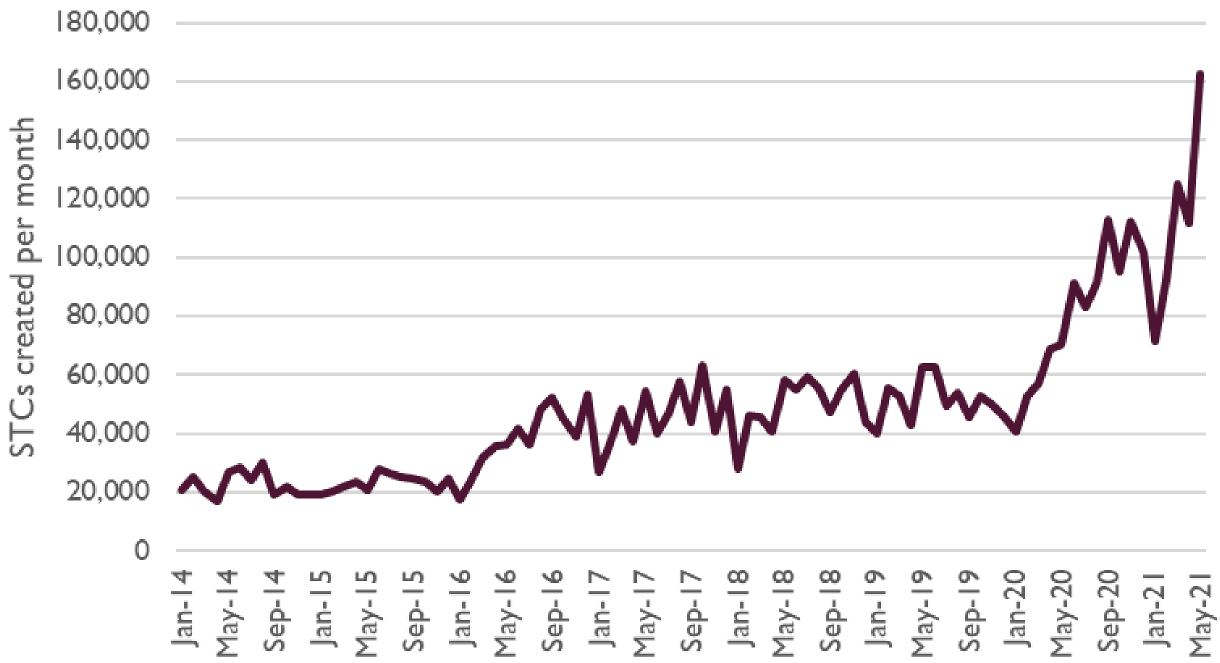
Historically there was a brief period around 2011 when air-sourced heat pump water heaters were taken up by commercial sites. However, no such units have been awarded STCs since 2013 and all units generating STCs presently are exclusive to the residential sector. Figure 6 shows the monthly trend in uptake of residential air-sourced heat pumps. Uptake has been trending up since 2014, but a rapid acceleration has occurred since mid-2020, which has coincided with the outbreak of COVID.

The uptake of air-source heat pumps has continued to accelerate throughout 2021, with May 2021 being the highest month on record of STC creation.

There appear to be several drivers for the uptake of air-sourced heat pump water heaters including:

- Growing acceptance (in new estates in particular) of using electric based air-sourced heat pumps instead of gas water heaters.
- They do not take up roof space, allowing households to install both solar panels and low emission water heaters. This fits in with the trend towards larger PV sizes, allowing households to reserve roof space for solar panels only.

Figure 6: Monthly trend in STC creation from residential HPWH



Source: Jacobs' analysis of CER data

3. Government Incentives and Policies

The number of STCs generated is dependent on uptake of eligible technologies by households and businesses which is in turn influenced by financial incentives and regulations such as federal and state rebates, the state-based FiT schemes, and building standards. The energy efficiency building standards in place still impact the choice of water heaters installed in new houses.

The blackout in South Australia during September 2016 has shifted the state government from incentives based purely on energy saving and renewable generation to focus more on energy security in the form of energy storage. This has made the government realign incentives towards residential battery storage systems.

More recently, South Australia has given AEMO authority to curtail rooftop solar when necessary. The plan aims to better integrate distributed energy resources (DER). New inverter standards for new rooftop solar have also been enforced, which would allow AEMO to gain more visibility on the capacity of rooftop systems. It is expected that curtailment of rooftop solar would only occur under extreme circumstances, and therefore it is likely that these new rules would not have considerable impact on the uptake of rooftop solar in South Australia.

Western Australia and the Northern Territory have also significantly reduced their standard feed-in-tariffs in a move to reduce incentives for export of solar generated power from rooftop systems due to concerns on the impact on grid stability. This is discussed further in section 5.6.

All jurisdictions in Australia except Tasmania have in place at least one scheme to encourage uptake of distributed renewable resources including rooftop solar PV and household batteries. This section outlines state-based schemes and regulations that could influence the uptake of solar PV and hot water systems.

3.1 Solar Homes Program - Victoria

In August 2018, the Victorian Labor government announced a new solar rebate scheme for the installation of eligible rooftop solar PV. The plan is means tested to households of income less than $180,000 and is expected to fund the installation of PV systems on 720,000 homes over a 10-year period. According to the latest ABS Census data, approximately 11% of Victorian households would be ineligible for the program due to an annual household income exceeding $180,000.

The offer is currently open to Victorian households and small businesses for a rebate to cover half the cost of a solar PV system up to a maximum of $1,400 for households and $3,500 for small businesses from July 2021. From July 2019, eligible Victorian residents will also be able to receive an interest free loan for a period of 4 years to finance the remainder of the capital cost of installation up to the value of their rebate. Rebates of up to $1,000 are also being offered for the installation of solar hot water units in dwellings that are unsuited for solar PV installations.

In addition, the Victorian Labor Party has pledged to support uptake of solar on rental properties. This component involves an additional $82 million package of 50,000 rebates to be delivered over a 10-year period to eligible tenants and landlords that agree to share the remaining costs of the system. Up until the end of FY 2021, the rebate is of $1,850 value.

3.2 Home Battery Scheme – South Australia

The South Australian Home Battery Scheme comprises $100 million in government subsidies available for 40,000 homes for the installation of a battery component. Participating households are eligible to apply for finance via the Clean Energy Finance Corporation.

The battery subsidy is based upon the size of the battery and is currently set at $300 per kWh storage for energy concession holders and $200 per kWh for all other households; a maximum subsidy of $3,000 is set per battery installation. Strict specifications need to be met to ensure that batteries can also be aggregated to the Virtual

Power Plant, although the participating household can choose whether to operate their battery as part of this system. The subsidy is open to household applications from October 2018.

While the batteries themselves will not contribute to STC creation, it is expected that the increase in benefit to households via load shifting may encourage the installation of rooftop PV and battery packages.

3.3 Virtual Power Plant – South Australia

In early 2018, the South Australian government announced plans to engage with Tesla to develop a Virtual Power Plant in that State in a scheme that aims to aggregate 50,000 residential batteries to work together. The expected $800 million scheme is expected to add 250 MW of dispatchable power to the grid over a 4-year period.

The Virtual Power Plant is set to roll out in 3 stages.

1. A trial of 1,100 housing trust properties, each provided a 5 kW solar panel system and 13.5 kWh Tesla Powerwall battery, installed at no charge and financed via the sale of electricity throughout 2018.

2. Systems set to be installed to a further 24,000 housing trust properties in South Australia.

3. Similar deal offered to all low-income households available upon assessment of original trial.

Other VPP schemes are now available for South Australian residents to participate in, including Virtual Power Plants from AGL, Simply Energy, and Discover Energy.

3.4 Residential solar and battery incentive schemes – New South Wales

In September 2018, the NSW government announced an initiative to install free rooftop PV systems in place of a cost of living rebate targeted to low income households. The $15 million scheme offers eligible households the option to forego the $285 energy bill deduction “living rebate” payment in exchange for the installation of a 3 kW rooftop solar system. The scheme is available for up to 3,000 eligible households, with an expectation that they will be up to $600 better off per year by accepting this offer.

The NSW Government announced early in 2019 a program to provide interest-free loans for solar batteries and solar and battery storage systems through a 10-year Empowering Homes program. This will target approximately 300,000 households. This program provides interest free loans of up to $9,000 for a battery system and up to $14,000 for a solar plus storage system. Eligible households must be owner-occupier and have an annual household income of up to $180,000. The first battery or solar-battery system was available for installation under this program in the 2019/2020 summer.

3.5 Solar for low income households – Australian Capital Territory

From December 2017, pensioners in the ACT are eligible to apply for a rebate of up to 60% on costs for the supply and installation of a rooftop solar PV system capped at $3,000. A 3-year interest free loan to ActewAGL is also available to pay back the remaining cost over a 3-year period. The scheme is available to pensioners only and is expected to assist approximately 500 households.

3.6 Next Generation Energy Storage – Australian Capital Territory

As witnessed in several other jurisdictions, the Australian Capital Territory is promoting distributed energy storage solutions as a means towards a low emissions future. Under the Next Generation Energy Storage program, the ACT Government is supporting up to 5,000 battery storage systems in ACT homes and businesses.

The current rebate is $825 per kilowatt (kW) up to a maximum of 30 kW. A standard household with a 5 kW system would typically be eligible for around $4,000 in support.

For residents without a current rooftop system, the combined PV and energy storage system would cost between $13,000 and $18,000 including the rebate. This is still a significant upfront capital cost, and for this study we assume that only residents already considering PV uptake would consider an application for this scheme.

3.7 Affordable Energy Plan – Queensland

As part of "The Affordable Energy Plan", the Queensland government has 3 initiatives to encourage the uptake of distributed renewable generation and storage:

1. An $4,500 interest free loan for up to 7 years is available for homeowners that receive the family Tax Benefit Part B. Eligible households not only must receive this benefit, but also must have had electricity costs greater than $1,000 for the past 6 months or $2,000 for the past year.

2. From 19 November 2019, Queensland householders can apply for interest free loans for up to $10,000 and grants of $3,000 to purchase combined solar-battery systems. Small businesses are also eligible to apply.

3. Grants of $3,000 and interest free loans of up to $6,000 are available for households that already have solar to install batteries.

The government has allocated $21 million over three years to fund the no-interest loans and rebates. The funding is restricted to 3,500 solar assistance packages and 1,000 solar and battery systems and 500 battery only systems and will be available for Queensland residents until the funding is exhausted or until 30 June 2019.

3.8 Western Australia – DER roadmap

In December 2019, the West Australian government outlined a roadmap that enables the transition of the South West Interconnected System (SWIS) network from a synchronous, centrally controlled network to one with more intermittent generation and increasingly decentralised supply.

It is recognised that if DER are to displace traditional generators they need to be integrated into the operation of the power system, and subject to remote management and operating standards to stabilise the power system.

The continued uptake of rooftop solar PV will see daytime demand fall to levels at which there is significant risk that the stability of the SWIS will be compromised – this is forecast to occur around 2022. In response, the Australian Energy Market Operator (AEMO) is expected to intervene more frequently and to a greater extent to maintain system security, increasing costs for customers.

The government acknowledges that the high levels of rooftop PV in the SWIS are beginning to contribute to technical issues at the distribution network level. Generation output from rooftop solar PV is now flowing two ways and causing problems for network operation as the physical limits are reached. Without improving the rooftop PV integration in the network, resolution of these issues in the SWIS would require costly infrastructure investment, or imposition of limits on the size and number of rooftop solar PV systems customers can install.

The Roadmap outlines proposed steps to fully integrate distributed energy resources into the operation of the power system. The aim is that customers are rewarded for providing services that support the system.

The steps outlined in the roadmap largely address the following areas:

1. Upgrades to DER functions to see them automatically help mitigate network and system disturbances.

2. Distribution battery storage deployment.

3. Pilot tariff structures that support uptake and optimal utilisation.

4. Ensuring all customers can continue to install DER.

3.9 Home and Business Battery Scheme – Northern Territory

Territorian homeowners and business can apply for a grant of up to $6,000 through the Home and Business Battery Scheme to install batteries and inverters. From July 2021, eligible applicants can receive $450 per kilowatt-hour of usable battery system capacity, up to $6,000. From August 2021, the grant will only be eligible for approved battery systems which are virtual power plant capable. Successful applicants may use this grant to also install a solar PV system if it is in conjunction with a new eligible battery; the minimum capacity for eligible batteries is 7 kilowatt-hours.

4. Modelling Method

The forecast of STC creation for calendar years 2021 to 2025 has been undertaken using two approaches:

- A time-series model.
- A detailed agent-based model, built up from postcode-level data.

4.1 Time series modelling

Using a time-series approach, the uptake of renewable technologies is determined based on trends in historical data, including testing for inclusion of the use of net consumer benefit - or a mix of upfront costs and system benefits - as regression variables. In addition, we have included several control variables testing for the impact of current interest rate levels, state gross product, population levels and the impact of COVID19.

A time series is a sequence of data points measured at different points in time, and its analysis comprises methods for extracting meaningful characteristics of the data (e.g. trend, seasonality, autocorrelation). Forecasting using time series techniques involves predicting future events based on a model of the data built upon known past events. Unlike other types of statistical regression analysis, a time series model accounts for the natural order of the observations and will reflect the fact that observations close together in time will generally be more closely related than observations further apart.

4.1.1 Small generation unit modelling

Under the SRES scheme small generation units cover the following technologies up to 100 kW in capacity:

- Rooftop PV
- Wind
- Hydro

The model utilised for the forecasting of residential STC creation is an ARIMA time series model combining autoregressive components with exogeneous economic control variables. Only rooftop PV systems were included in the time series projections due to the very small proportion of STCs (less than 0.02%) being created by small-scale wind and hydro units[4].

Python software was utilised for the time series forecasting, using time series models with additional economic control variables as external regressors.

4.1.1.1 Residential and commercial system categorisation

Small generation unit (SGU) installations in the data supplied by CER are classified as either Unknown, Residential, Commercial, or School. All data is flagged as 'Unknown' prior to September 2013, though by October 2014 all data is classified as a type of installation.

For use in the time-series modelling, unknown property types were classified as commercial or residential based on their capacity - those less than 15 kW were considered residential, and those 15 kW or above were considered commercial. Schools were combined with the commercial data due to their similarity in size and function.

The residential data was then processed and aggregated into monthly steps to create time series by technology for each state.

[4] The erratic and volatile nature of historical uptake of wind and hydro units invalidates using a time series approach for predicting future uptake.

Due to the limited number of commercial installations, commercial data remained at a nationally aggregated level.

Small-scale commercial uptake samples were split into three categories:

- Rooftop solar PV systems under 15 kW.
- Rooftop solar PV systems between 15 kW and 90 kW.
- Rooftop solar PV systems of 90 kW up to 100 kW.

The split into these three categories is based on several considerations.

The bulk of all commercial developments is in the 15 kW to 90 kW category and this segment has seen the highest historical growth rates, while the category of systems below 15 kW shows the lowest growth rates.

Commercial systems of 90 kW to 100 kW are separated as we understand most of these systems are deliberately scaled back to this size or are likely part of larger developments split into multiple phases or as separately metered connections to take advantage of the STC benefits.

Analysis performed by Jacobs suggests that systems of 100 kW show better returns than systems from 100 kW up to 120 kW, because of their entitlement to STCs. In addition, planned systems up to approximately 260 kW are likely to have better returns if they are connected in multiple stages or as separately metered connections of 100 kW maximum limit. Systems above 260 kW are generally more likely to generate higher returns taking advantage of LGCs than similar large systems that are split to receive STCs.

4.1.1.2 Sample size

The sample size has been restricted for residential uptake to only include data from 2012 onwards for large states and from 2013 onwards for small states and territories[5]. This approach was taken because during the early growth phase of the PV technology, the uptake was strongly affected by policy changes, subsequent economic benefits and other behavioural factors such as early adopters or environmental decisions, most of which are not likely to apply at the current time.

The sample size was determined after visually examining the uptake data. For example, historical data suggests that commercial rooftop PV systems under 15 kW did not show significant take-up before late 2014 and therefore we have included uptake from January 2015 onwards in our modelling sample. For systems between 15 kW and 90 kW uptake significantly ramped up in 2010, but with volatility. However, from 2012 onwards this category showed stable growth rates and therefore the sample was set to include uptake from 2012. The systems in the largest commercial small-scale uptake category (90-100 kW) only had significant uptake from 2013 onwards and therefore the sample was set to include data starting January 2013.

4.1.1.3 Dependent variables

The number of installations was utilised as the depended variable for the residential PV projections. This was to allow the incorporation of these results into our customised agent-based model, where the agents represent household decision makers.

For the commercial PV projections, the installed capacity was utilised as the dependent variable. This enables modelling of the greater variance in installed capacity that exists across the commercial segment.

Utilising STC as the dependent variable was not considered the best choice due to the scaling down of deeming period of the STC scheme.

[5] The sample size selection was based upon the best statistical fit for each state for the different ARMIA models utilised.

4.1.1.4 Independent variables in residential SGU modelling

There exists a relationship between the uptake of PV technology and consumer costs and benefits. As the capital cost, STC rebates, electricity price and the feed-in tariff are the main indicators residential energy users take into consideration when deciding to invest in rooftop PV, these drivers are the building blocks of our models. Dummy variables are included as an indicator of policy changes or specific impacts of policy or other unknown shocks (e.g. the step-down in deeming period as the forecasts enter a new calendar year).

The onset of the global COVID pandemic and resulting lockdowns appears to have had a positive impact on the residential rooftop PV sector. With a significant and sudden shift to work from home mindset, consumers are now able to utilise their rooftop systems to a greater extent. The shift of certain sectors to a working from home environment is also likely to be permanent.

Furthermore, with consumers in lockdown and unable to spend on outdoor entertainment, dining out and travel, the result has been a shift to spending on household items. Record low interest rates and an increase in household energy consumption make the installation of a PV system a beneficial choice.

This has implications on the independent variables utilised in the model. For example, Gross State Product (GSP) per capita is historically a good predictor to capture general growth, however the COVID related economic downturn sharply contradicts the recent increases in residential rooftop PV uptake.

For these reasons, we have incorporated a dummy COVID variable into the regressions to reflect its impact on the market. This is incorporated from March 2020 onwards for the residential models. In some cases, the COVID variable only improves the model when its span is limited, for example, from March 2020 to December 2020, and in some cases the COVID dummy does not add anything to the model. We have therefore discontinued the extent of the COVID impact in all residential models by mid-2021 to reflect its diminishing influence. We have also decided not to include a GSP related variable in the model.

Additional variables that we have tested include: consumer confidence, cash rate, home-loan rate, all ordinaries stock price index. Modelling showed that the interest rate variables showed significant correlation with the installed PV capacity. During the modelling process we dropped the consumer confidence and stock price variables as they were not significant and did not improve the models.

In several cases, lagged independent variables have been used to improve significance of the variable and overall model-fit. For example, it is likely that consumers use electricity bills that are a few months old or have an existing agreement with a retailer based on temporary fixed (older) price levels. Therefore, it is likely that there will be a lag of the impact of electricity prices and FiTs on the uptake of rooftop PV.

Further details of the independent variables utilised in the models can be found in Appendix B.

4.1.1.5 Variables used in commercial SGU modelling

Small scale commercial systems were modelled using an ARIMA time-series model, utilising historical PV uptake data from January 2012 onwards for 15 kW to 90 kW systems, from January 2013 onwards for systems from 90 kW up to and including 100 kW systems and for systems below 15 kW from January 2015. The different start dates reflect the period in time when the statistical properties of the time series of each category enable valid time series analysis. For example, in January 2012 there was only 15 kW of installations for the smallest size category and no installations for the largest size category, whereas there were 959 kW of installations for the mid-size category. January 2012 was the lowest uptake month for the mid-size category in 2012, whereas monthly uptake for the other two categories in 2012 continued to be very low and was quite erratic.

The upfront net capital cost (total capital cost minus rebates) and the electricity price as a proxy for future benefits, were tested as independent variables in the model as well as the interest rate. Due to a general reduction in electricity prices over the last few years this variable did not prove to be a good fit for the recent growth trends and was subsequently discarded.

Gross Domestic Product (GDP) is a variable that provides a proxy for the economic health of the nation and is used in most econometric time-series models as a control variable. The GDP indicates whether the economy as a whole is contracting or expanding. Unlike in the residential sector where the lockdowns and home working environment shifts have insulated the rooftop PV segment from economic downturns, this is not the case for small to medium enterprises and this variable has been left in the models.

Despite the economic downturn in 2020, small-scale commercial rooftop installations still showed modest growth. This is potentially the result of government stimulus packages supporting consumer spending and the instant asset write-off awarded to eligible businesses. For this reason, we have incorporated a dummy variable that runs from March 2020 until March 2021 when the job seeker and job keeper packages expired.

Further details of the independent variables utilised in the models can be found in Appendix B.

4.1.1.6 Model fitting

The time series at the state level were stationary when modelled using the extended benefit, economic and dummy variables, showing no evidence of changing mean or variance over time. The models were examined for stationarity and autocorrelation.

Once the sample size was determined (discussed in section 4.2.2), we examined different formulations of the model, including time-series only analysis, single regression variable models, and combinations of variables, rejecting any models that were statistically inadequate.

Inadequate models included:

- Models with a statistically poor fit as measured through the Akaike's AIC criterion (where available) goodness of fit tests.
- Non-stationary models as assessed with the augmented Dickey–Fuller test and/or Durbin-Watson test.

The developed ARIMA model includes independent variables such as net upfront cost, system benefit (e.g. electricity price, FITs), economic control variables and (policy) shock dummy variables as regressors as well as auto regression modelling to the residuals. This approach allows the modelling to consider external cost functions but also allows for appropriate consideration of recent time trends which is useful in time series approaches because of inherent autocorrelation in the dataset.

The residential models were estimated by the different states and territories, while the commercial sector is modelled nationwide.

4.1.2 Saturation limits

Jacobs has developed a saturation model to assist with the projection of uptake of small-scale PV systems projected using a time-series approach, with this model being a simpler version of the agent-based model described in the next section. The key benefits of this model are that it can encompass the probability of monthly uptake as derived from our time series models whilst accounting for effects of market saturation and behavioural characteristics in key market segments.

The model is a bottom-up method which models unique agents at the micro-level to simulate customer level decision making. In the model, there are agents who are autonomous, have internal behaviours and characteristics, and make the appropriate decisions in response to both exogenous and endogenous factors.

In the context of Australia's energy market and DER uptake, agents in the saturation model are defined as households with similar household characteristics (e.g. homeowner, renter) and dwelling type within a similar proximity to each other.

Residential agents are first assigned a dwelling type (house, terrace/townhouse, flat/apartment) by cumulative probability distribution. A similar method is utilised to allocate a tenure type (owner, renter, other). These probabilities are based upon data from the Australian Bureau of Statistics.

The probability of uptake is then adjusted based on the agent properties. For example, agents that are assigned with a flat dwelling type are given a zero probability of uptake, however the probability of uptake is increased for houses.

Initially, these probability factors are calibrated to reasonably fit the historical data. Every year, the residential agents who are eligible but have not yet adopted iterate into a probability based decision-making process. These agents include the non-adopted original agents, and the newly introduced growth agents.

The time series model is combined with the saturation model as follows:

- The rate of uptake derived from the time series model is compared to historical rates of uptake. The ratio of these rates is then used to adjust the calibrated probability of uptake.
- Saturation is naturally captured by this modelling process, which keeps track of the number of viable households able to take up rooftop PV within each SA3 region. If there are no remaining viable households in a region for a particular year, then no more rooftop PV is taken up in that particular SA3 region.

4.1.3 Time series model for water heaters

The water heater data were modelled by number of STCs registered since, unlike PV, these time series were not distorted by a multiplier[6] and they were also directly reflective of water heater uptake volumes.

The original water heater time series were non-stationary, showing both a changing mean and changing variance over time. However, the logarithm of the original time series was found to be stationary after the trend was removed.

In summary, the time series analysis of the data for the water heaters was carried out by fitting univariate ARIMA models to the logarithm of the monthly number of registered STCs by water heaters, split into domestic and commercial categories for all of Australia. The projection also considers deeming reductions in future years.

4.2 Agent based modelling

Agent-based modelling is a bottom-up approach, which models unique agents at the micro-level to simulate customer level decision making. Agents are autonomous, have internal behaviours and characteristics, and make the appropriate decisions (in terms of their assumed decision criteria) in response to both exogenous and endogenous factors. This approach is especially suitable for modelling several intricate, non-linear, and interrelated parameters in unstable and complex environments. Unlike traditional modelling approaches, agent-based modelling creates heterogeneity between agents, and may enable interaction among agents to influence behaviour and outcomes.

In the context of Australia's energy market and rooftop PV uptake, agent-based modelling can allow agents (representing Australian households, businesses, and schools) to respond to events (e.g. price increases, falling capital costs) and macro-economic, technological, policy, and electricity-related variables to simulate the magnitude of rooftop PV installation over the next five years.

[6] The SRES scheme in the past applied a multiplier to the STCs created by a rooftop PV system, thereby increasing the subsidy offered for these systems. For example, from 1 July 2011 until 30 June 2012 each MWh of generation was awarded 3 STCs. As a result of this "distortion" we avoid performing time series analysis on the STC variable for rooftop PV systems. Instead we choose to model installation numbers in combination with average capacity installed, or we model capacity directly.

4.2.1 Agent initialisation

Residential Agents

As a bottom-up model, residential agents are initialised with the following parameters which proportionately reflect the real world:

- Location – Statistical Area Level 3 (SA3 level).
- Dwelling type (e.g. detached house, townhouse, apartment).
- Tenure type (e.g. owner, renting).
- Rooftop PV penetration status.

All parameters are initialised using ABS census data and are allocated to agents based on cumulative probability distributions. A sample calculation for the probability of an agent being assigned to the Latrobe Valley SA3 region is outlined below:

$$Pr(Latrobe\ Valley) = \frac{\text{Private households in Latrobe Valley}}{\text{Total households in Australia}}$$

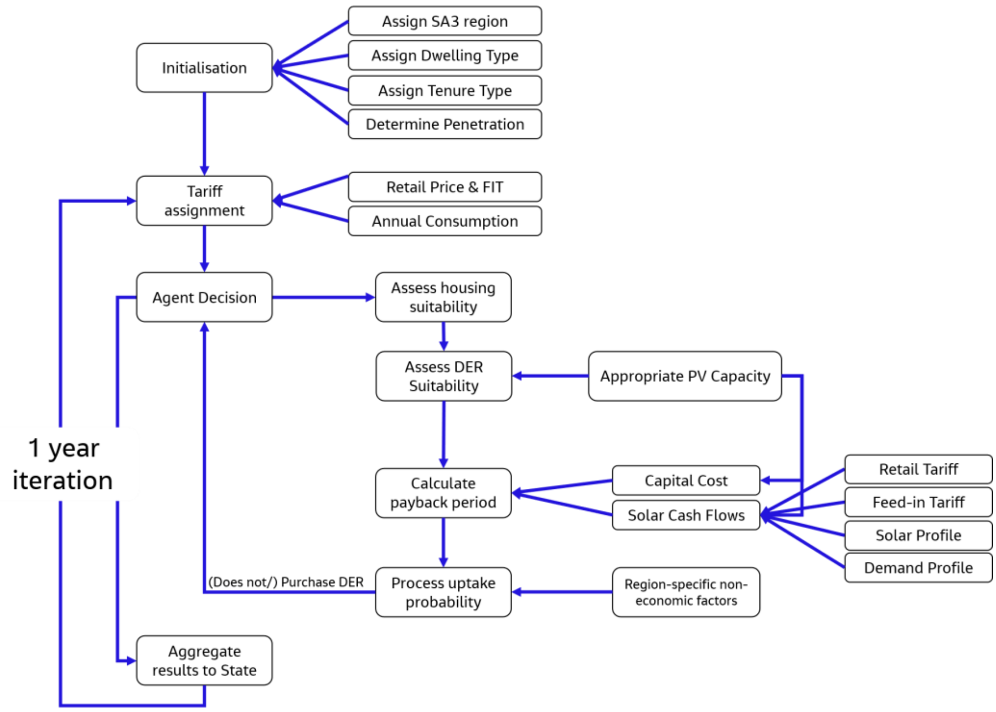
Heterogenous location assignment is important because it allows agents of different regions to have different behaviours and characteristics. We assume that all agents within the same region share the same characteristics. The appropriate region size is therefore that which is necessary to adequately segment households. The SA3 level was chosen as the ideal region classification since it is small enough to create 336 segments across Australia, yet large enough to each have a statistically sufficient number of residents.

The dwelling and tenure type probability distributions are unique to each SA3 region. The model assumes that only homeowners living in a private detached dwelling (i.e. house, townhouse, or terrace) are likely to adopt a rooftop solar PV system. Renters, and/or those living in apartments, flats, caravans and so forth are assumed to not purchase these systems.

To account for current penetration levels, the appropriate number of agents are assigned a rooftop PV system at the commencement of the model. Small-scale postcode data provided by CER flag all residential installations from 2014 onwards. Any unknown installation type less than 10 kW capacity is assumed as residential.

Once an agent has been initialised, it follows a defined set of decisions (see Figure 7) which are discussed in the subsequent report sections.

Figure 7: Residential agent framework



Commercial and school agents

Unlike residential households, businesses do not have the same degree of behavioural variation across SA3 regions. Rather, it is the size of the business is the point of differentiation. Commercial and school agents are therefore only assigned a state-level location and are modelled separately within this forecast due to different rates of uptake. Commercial and school installations were flagged by the CER from 2014 onwards; any unknown installations greater or equal to 10 kW capacity are assumed to be a commercial installation.

Commercial agents are assigned to a state or territory based on the number of business customers for each region. 'Small', and 'Large' business customer numbers were sourced from the AER (NSW, QLD, SA, TAS, ACT), ESC (VIC), and ERAWA (WA) and used for all regions except Northern Territory. 'Low Voltage' non-residential customer numbers were sourced from Power and Water Corporation and used for NT. However, each state has a different definition of the customer classifications as outlined in Table 4.

Table 4: Business customer definitions

Business Customer	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
Small	≤ 100 MWh pa	≤ 100 MWh pa	≤ 100 MWh pa	≤ 160 MWh pa	≤ 150 MWh pa	≤ 150 MWh pa	-	≤ 100 MWh pa
Large	> 100 MWh pa	> 100 MWh pa	> 100 MWh pa	> 160 MWh pa	> 150 MWh pa	> 150 MWh pa	-	> 100 MWh pa
Low Voltage	-	-	-	-	-	-	≤ 750 MWh pa	-

An analysis of historical commercial installations (excluding schools) indicate a consistent distribution of installed capacity sizes over the years (see Figure 8) and are assumed to remain constant throughout the forecast period. Secondly, businesses tend to act in a more economically rational way, relative to households; it is assumed that commercial rooftop PV systems are optimised to their electricity consumption and are not oversized. Therefore, under these assumptions, systems within the same capacity segment (**Figure 9**) belong to businesses with similar electricity consumption to each other. Whilst residential agents are assigned proportionately to SA3 regions, commercial agents are assigned into a system capacity segment (representing business consumption/size), based on its business customer type. This segmentation is outlined in Table 5.

Figure 8: Historical distribution of commercial capacity segments, Australia

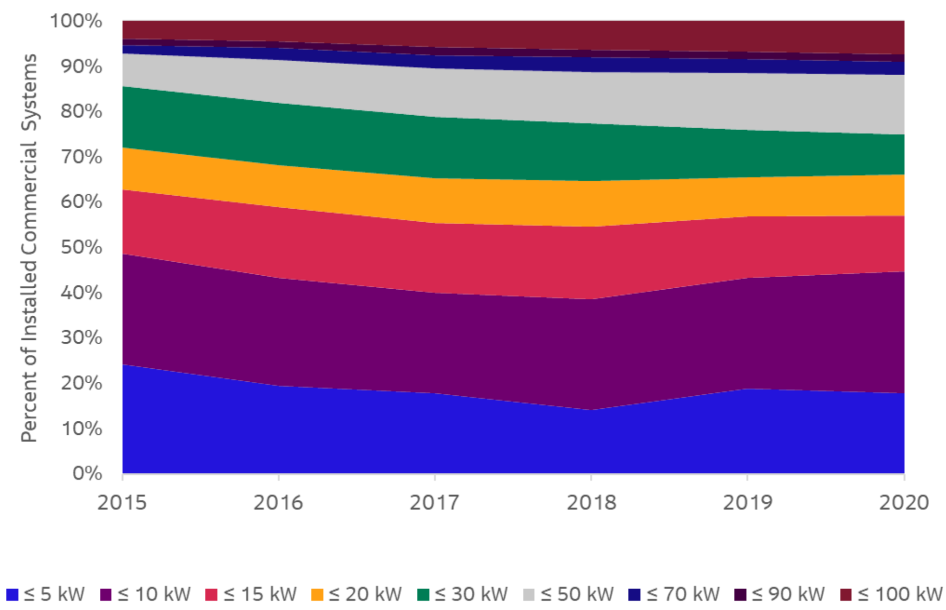


Figure 9: Commercial capacity segment distribution (2020)

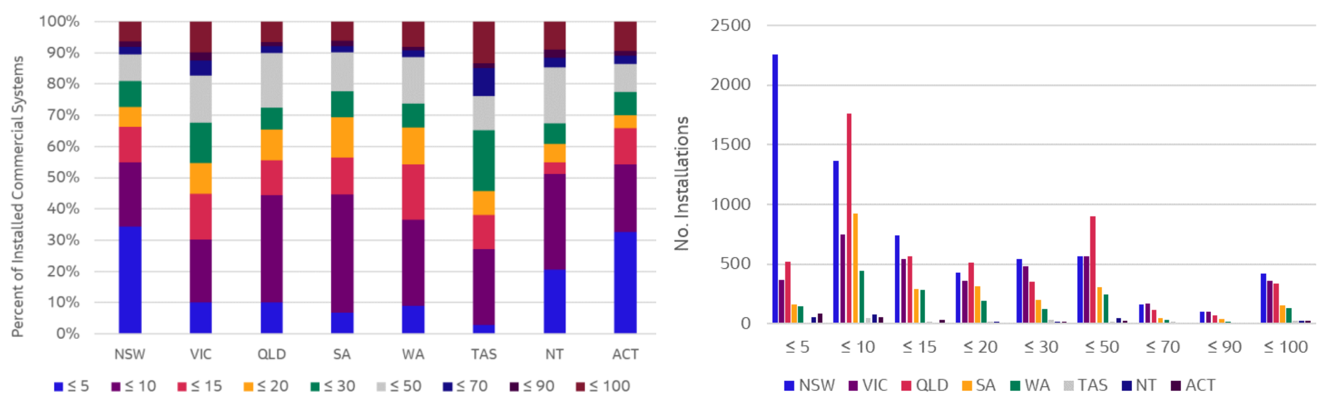


Table 5: Business customer segmentation

<table>
<tr><th>Capacity Segment</th><th>NSW</th><th>VIC</th><th>QLD</th><th>SA</th><th>WA</th><th>TAS</th><th>NT</th><th>ACT</th></tr>
<tr><td>≤ 5 kW</td><td rowspan="5">Small</td><td rowspan="5">Small</td><td rowspan="5">Small</td><td rowspan="6">Small</td><td rowspan="6">Small</td><td rowspan="6">Small</td><td rowspan="9">LV</td><td rowspan="5">Small</td></tr>
<tr><td>≤ 10 kW</td></tr>
<tr><td>≤ 15 kW</td></tr>
<tr><td>≤ 20 kW</td></tr>
<tr><td>≤ 30 kW</td></tr>
<tr><td>≤ 50 kW</td><td rowspan="4">Large</td><td rowspan="4">Large</td><td rowspan="4">Large</td><td rowspan="4">Large</td></tr>
<tr><td>≤ 70 kW</td><td rowspan="3">Large</td><td rowspan="3">Large</td><td rowspan="3">Large</td></tr>
<tr><td>≤ 90 kW</td></tr>
<tr><td>≤ 100 kW</td></tr>
</table>

School agents are assigned to a state or territory based on school numbers from the ABS. The current penetration level for both commercial and school agents are initialised using CER historical postcode data. Both agents subsequently follow a decision process similar to that illustrated in Figure 7.

4.2.2 Economic agent decisions

After an agent has been initialised, if it is eligible to uptake and does not currently own a rooftop solar PV system, it is assigned the following data at the commencement of each year:

- Retail tariff (residential or SME).
- Feed-in tariff.
- Annual electricity consumption.
- Hypothetical PV capacity.
- Associated capital costs.

Using these assigned values, an agent calculates the average net cashflow that its system will provide. The equation to calculate the cash flow earned in year, n for a PV system is:

$$CF_{pv,n} = (Deg_{PV})^{n-1} \times \left[\left(\sum_{i=1}^{17520} (PVo_i - PVs_i)\right)(T_r) + \left(\sum_{i=1}^{17520} PVs_i\right)(T_{fi})\right]$$

All equation variables and constants are summarised in **Table 6**.

Table 6: Cash flow equation variables and constant

Variable	Description	Unit
$CF_{pv,n}$	The cash flow earned in year, n for a rooftop PV system	$
T_r	Retail tariff	$/kWh
T_{fi}	Feed-in tariff	$/kWh
PVo_i	PV output during 30-min interval, i	kWh
PVs_i	PV surplus during 30-min interval, i	kWh
Constant	**Description**	**Value**
Deg_{PV}	PV degradation factor	0.993

Using these cash flow values, each agent then calculates the corresponding payback period of the nominated system for the respective year. With an assumed 20-year system life, the equation is as follows:

$$PB_n = \frac{20 \times C_s(1+r)}{\sum_{i=1}^{20} CF_i}$$

Table 7: Payback period equation variables

Variable	Description	Unit
PB_n	The payback period of a system for year, n	Years
C_s	The total capital cost of a system	$
r	The discount rate	%

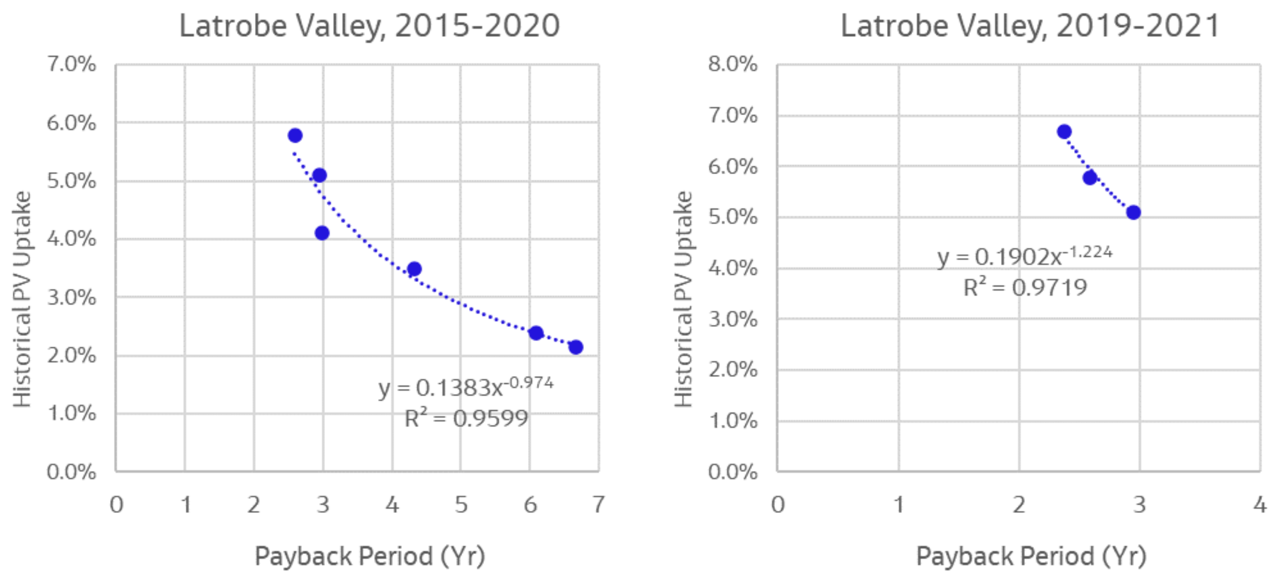
4.2.3 Uptake function

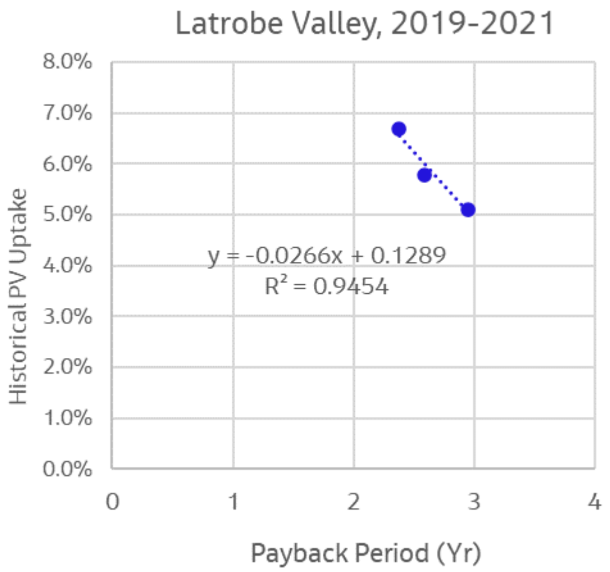
In reality, thousands of households may calculate the same payback period for a rooftop solar PV system, yet they do not all make the same purchasing decisions. Despite sharing similar economics, people respond differently due to factors like socioeconomic conditions, neighbourhood influence, beliefs, or different levels of awareness and understanding of the technology. An uptake function is used to calculate the probability of uptake based on a given payback period to account for these real-world behavioural differences. For residential agents, this function is unique to each SA3 region; for commercial agents, it is unique for each state/territory capacity segment.

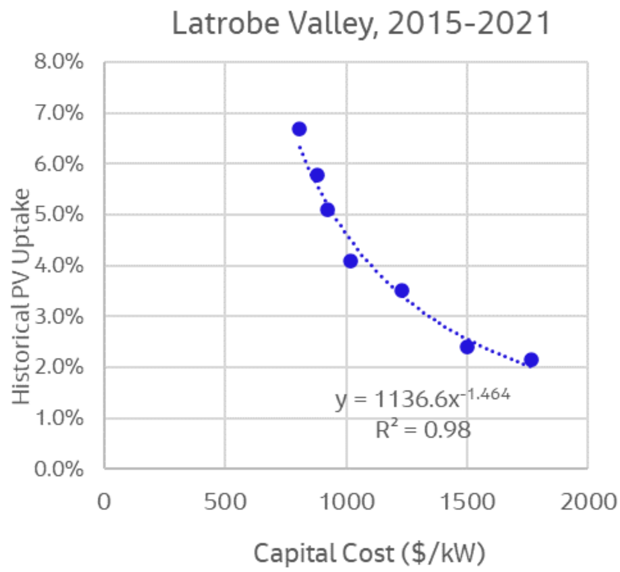
The uptake function analyses the historical rooftop PV uptake of eligible households in each region and plots the corresponding historical payback periods during each historical year. A power regression is conducted for all data sets to provide a power equation (Figure 10). If the relationship's R^2 value is greater than 0.70, the agent inputs their calculated payback period to calculate the probability of uptake. However, the payback/uptake relationship is not necessarily perfect for every region. For this reason, multiple regression equations are computed for each SA3 region, and the uptake function chooses which one to use based on the R^2 value, and the resultant probability. Due to the uncertainty of 2020, as well as the possible shift in behaviour in the last four years in some areas, the following relationships are used in the uptake function:

- Power equation: Payback period vs. historical uptake, 2015 – 2020
- Power equation: Payback period vs. historical uptake, 2019 – 2021
- Linear equation: Payback period vs. historical uptake, 2019 – 2021
- Power equation: Capital cost vs. historical uptake, 2015 – 2021

Figure 10: Rooftop PV uptake functions




Latrobe Valley, 2019-2021
Historical PV Uptake
Payback Period (Yr)
y = -0.0266x + 0.1289
R² = 0.9454
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
0
1
2
3
4


Latrobe Valley, 2015-2021
Historical PV Uptake
Capital Cost ($/kW)
y = 1136.6x-1.464
R² = 0.98
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
0
500
1000
1500
2000

5. Assumptions

This section outlines the key modelling assumptions utilised for the forecasting models, with the key assumptions summarised in Table 8.

Table 8: Summary of key assumptions

	Units	2021	2022	2023	2024	2025
Average SGU capital cost residential [7]	$/kW	1,503	1,503	1,442	1,388	1,335
Average SGU capital cost commercial [8]	$/kW	1,384	1,384	1,329	1,275	1,224
SGU Capital cost decline	%	N/A	0%	-4%	-4%	-4%
Weighted average electricity cost	$/MWh	294	281	285	291	294
Weighted average Feed-in-Tariff [9]	c/kWh	9.7	7.4	7.7	8.4	8.6
STC prices [10]	$/MWh	38.3	37.6	36.8	35.9	35.1

5.1 Financial benefits

The financial benefit of installing a PV system have historically been the key measurable drivers to the uptake of residential and commercial systems. There are various contributing factors that determine the overall financial benefit of the installation of a PV system, including:

- Capital cost of installation.
- State and federal government rebates.
- Retail cost of electricity.
- Cost of capital (e.g. home-loan rate).
- Feed-in-tariffs.
- Expected solar generation usage versus export to the grid.

Critical assumptions in the calculation of the upfront cost is the historical and forecast capital cost of installation of a PV or SHW system, capacity of the system, potential STC benefits from installation and any other state or federal based rebates.

Key factors to assess the lifetime benefit of a system include assumptions surrounding the retail electricity cost and capacity of the system. For small generation units, the feed-in tariffs and expected net export of electricity to the grid are also important considerations.

[7] Excluding STC rebate
[8] Excluding STC rebate
[9] The weighted average feed-in-tariff price for 2020 was 11.3 c/kWh.
[10] Real Dec-20 dollars

Both export and self-use of solar PV generation are important factors in the investment decision. It is difficult to determine what the exact preference is for consumers regarding usage versus export, therefore we have used both variables directly in our regression rather than calculated a fixed benefit based on predetermined shares of usage and export. In addition, with the introduction of small-scale battery storage and EVs, the reliance on export and thus FITs may reduce as a result of the ability for consumers to shift load using their storage device or charge their electric vehicle.

The time-series model utilises historical and forecast calculations of these indicators as potential regressors. However, since 2018 the retail electricity price rises observed across most of the states have levelled off, and in several states has reduced through 2019 to 2021. Meanwhile growth in PV installation rates have been observed in the same states.

For these reasons, these variables are no longer incorporated as regressors in all states. It is acknowledged that the financial benefits are still key drivers, however as rooftop solar provides such a reasonable payback, there are potentially other drives of the current growth rate such as advertising, word-of-mouth and neighbourhood presence. These factors are difficult to measure and are captured in the time-series trends of our models.

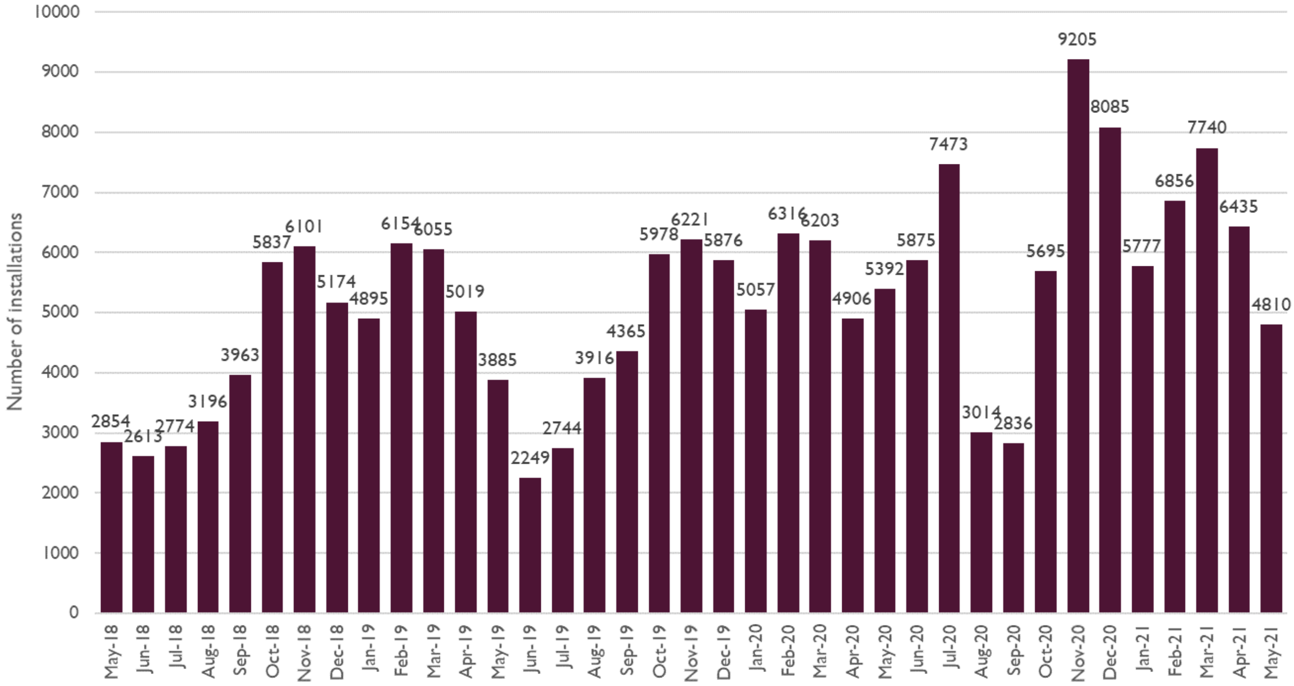
5.2 Rebate assumptions

For the purposes of this study, the South Australian government's battery scheme, Virtual Power Plant scheme, ACT Solar for low incomes, NSW solar rebates and Victorian rebates will be treated separately.

5.2.1 Victorian Solar Rebate Scheme

The introduction of the Victorian solar homes rebate, commencing from 19 August 2018, resulted in a flood of installations of rooftop PV on Victorian homes. **Figure 11** shows the number of monthly residential instalments since January 2018. The large increase in installations highlights the popularity of the subsidy, which has rebounded strongly following the extended Victorian lockdown.

Figure 11: Number of monthly residential PV installations in Victoria since May 2018



Source: Jacobs' analysis of CER data (estimates for 2021 will be affected by lag in registrations)

Due to the popularity of the scheme, the initial allocation of 24,000 households to the end of June 2019 was increased to 32,000 before the government temporarily stopped the program on 12th of April 2019, with view of reopening it again in July. The program was reopened again in May and offered to customers who had installed panels but had been locked out of the program.

The policy from July 2019 originally offered 3,333 rebates per month. In late August, the Government increased the number of rebates on offer each month and are currently at 5,000 per month.

As with other states in Australia, the impact of COVID-19 initially had a positive impact on the number of rooftop installations. However, during August, Stage 4 restrictions were imposed to the metropolitan Melbourne and Mitchell shires, which prohibited the PV installers from continuing to work within these regions.

Due to the popularity of the state government rebates and the expected impact of stage 4 COVID restriction in Victoria, it is not suitable to project installations in Victoria utilising our time series models. Projections are instead based on the following assumptions:

- The Victorian Solar Homes scheme will go ahead in its entirety and 650,000 owner occupied homes will have rooftop solar installed by the end of FY 2030 under the scheme.
- The rebate will continue for the next 9 years with the remaining Government funds to be distributed over this period with an increasing number of installations and decreasing value per installation into the future.
- About 11% of households that are ineligible for the scheme will continue to install PV systems at a rate of 290 installations per month. This assumes that 11% of 31,733 residential installations that occurred in the year to June 2018 were from households earning over $180,000 per year, and that these will continue at a constant rate.
- The average size of systems installed continues to increase, as per the observed historical trend (see section 5.4).

Based on these assumptions, Table 9 outlines the number of installations, capacity installed and STCs produced in Victoria until the end of 2025.

Table 9: Assumptions on Victorian residential PV installations, capacity and STC generation for forecasting period[11]

Time period	Owner Occupied installations	Rental installations	Ineligible owner installations	Total Installations	Average size (kW)	Capacity (MW)	STCs '000s
2021	62,158	4,167	3,480	69,805	6.93	483	5,789
2022	62,158	4,167	3,480	69,805	7.17	500	5,356
2023	62,158	4,167	3,480	69,805	7.36	514	4,888
2024	62,158	4,167	3,480	69,805	7.54	527	4,384
2025	62,158	4,167	3,480	69,805	7.72	539	3,845

5.2.2 South Australian Virtual Power Plant Scheme

Tesla has completed the installation of the first two stages of installing 1,100 units committed to the scheme and has now progressed to the third stage of the scheme, which could encompass up to 50,000 households in total.

Phase 1 and Phase 2 results, estimated to have completed in October 2019, have already been tallied in the actuals. As Phase 3 is primarily targeted at private home owners and not lower income households, it is assumed

[11] STCs are calculated by multiplying the deeming period ratio by capacity by the expected STCs per kW per region

for this study that only households already in a position to consider installation of PV will apply for the program, and therefore these are assumed to be incorporated in our standard regression modelling.

5.2.3 NSW Solar Rebate

The NSW Solar rebate has been open to low-income households since December 2018. Due to the maturity of the scheme, we have assumed that the time series component of the model has factored this scheme into the growth rate.

As the NSW Empowering Homes scheme is primarily targeted at the installation of household battery systems, the assumption is that only households who were already planning on installing a solar PV system will apply for the interest free loan. It is therefore not expected to have a significant influence on the uptake of residential rooftop solar systems in NSW.

5.2.4 Solar for Low Income Households

The ACT solar for low income household scheme is expected to affect approximately 500 pensioner households. With the assumption that these 500 installations of 4 kW will occur evenly over a 3-year period, the assumption is that half of the capacity expected to be installed under this scheme would have occurred by mid-2019. Furthermore, as these installations are included as part of the dependent variable in the time series model, it is assumed that the time-series component has factored in the growth rate under this scheme, and for these reasons the STC's assumed as part of this scheme will not be added to our time-series projections.

5.2.5 Western Australia Distributed Energy Roadmap plan

The West Australian Distributed Energy Roadmap's aim is that all customers continue to install distributed energy resources in a manner that supports the network. However due to the issues that high rooftop PV penetration is beginning to cause in the SWIS, it is not expected that any steps will be placed in the near future to accelerate the uptake of rooftop PV systems.

Reducing the feed-in-tariff from 7.135c/kWh to 3.0c/kWh before 3pm during the day is expected to negatively impact the uptake of residential PV systems in Western Australia and is incorporated into our time-series modelling.

5.3 Capital cost

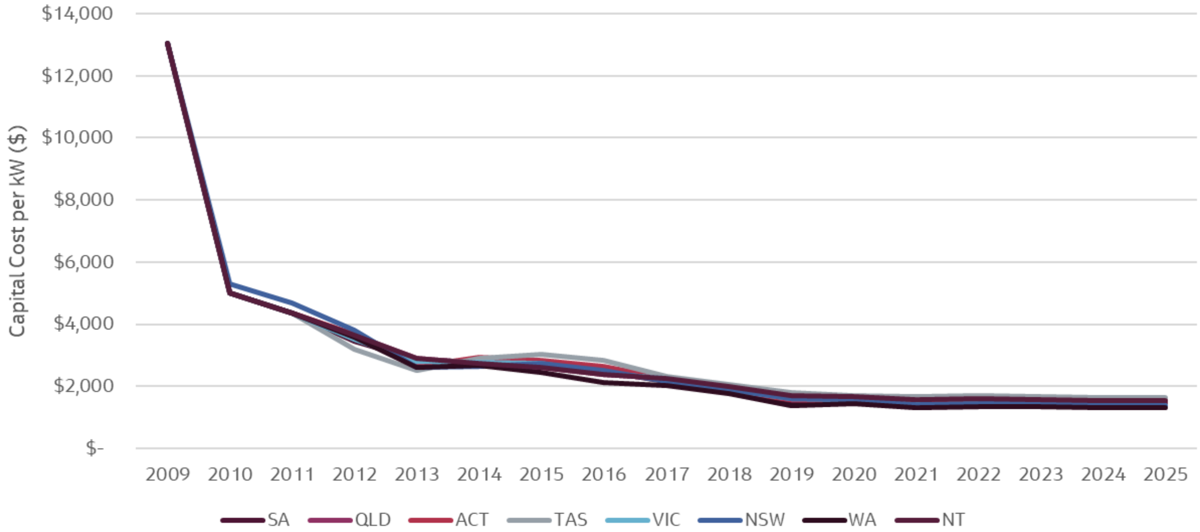
The global oversupply on PV module manufacturing capacity has diminished. This has put upward pressure on system prices, but at the same time there is also a restructuring of the industry which is seeing large capacity manufacturing plant replacing the older and smaller manufacturing facilities. The larger plants allow for the capture of economies of scale in production and have minimised increases in system costs and may even lead to further decreases in costs.

Recently there has been a shortage on manufacturing capacity (due to greater than anticipated global demand for solar PV systems), which have also been coupled with higher costs of module raw materials and higher costs of freight. The impact of raw material costs is being ameliorated by an increase in demand for alternative module materials that were being phased out. However, increases in freight costs are not expected to decline in 2021. They have been caused by volatile global demand for goods driven by the imposition and easing of lockdowns due to COVID-19. This volatility has challenged logistic supply chains, and as a result freight costs have increased by a factor of 3-4 for shipments from China. Delivery times have also been stretched as a consequence of these issues, which also puts upward pressure on system prices. As a result of this, industry commentators have flagged the possibility that global average year on year capex for solar systems in 2021 may not decline.

Capital cost assumptions for PVs in 2021 are based on the Solar Choice website's[12] monthly unit pricing overview, which is based on price data from 125 solar installation companies across Australia. These were converted into real dollars using historical CPI data.

For residential systems, the price per system per kW for capacity sizes of 5 to 10 kW was trended over time, and forecasts for each State were performed by utilising the expected learning curve extrapolated from CSIRO's 2020-21 GenCost[13] forecasts for rooftop PV. However, due to the short-term cost headwinds faced by the solar industry, we have assumed no cost decline in 2022. These forecasts are illustrated in Figure 12.

Figure 12: Capital cost assumed for residential solar PV systems ($/kW 2021)



Source: Jacobs' market analysis, Solar Choice monthly system cost estimates 2012 – 2021, CSIRO

A similar method was applied to costs of commercial systems, by utilising the data for systems between 10 kW and 100 kW. Due to the limited number of commercial systems installed, and therefore subject to outliers when filtered to state level, it was decided to aggregate the commercial systems at a national level. The average cost was plotted for all states, and the CSIRO's rate of decline was applied from 2023 to 2025. No cost decline was assumed for 2022.

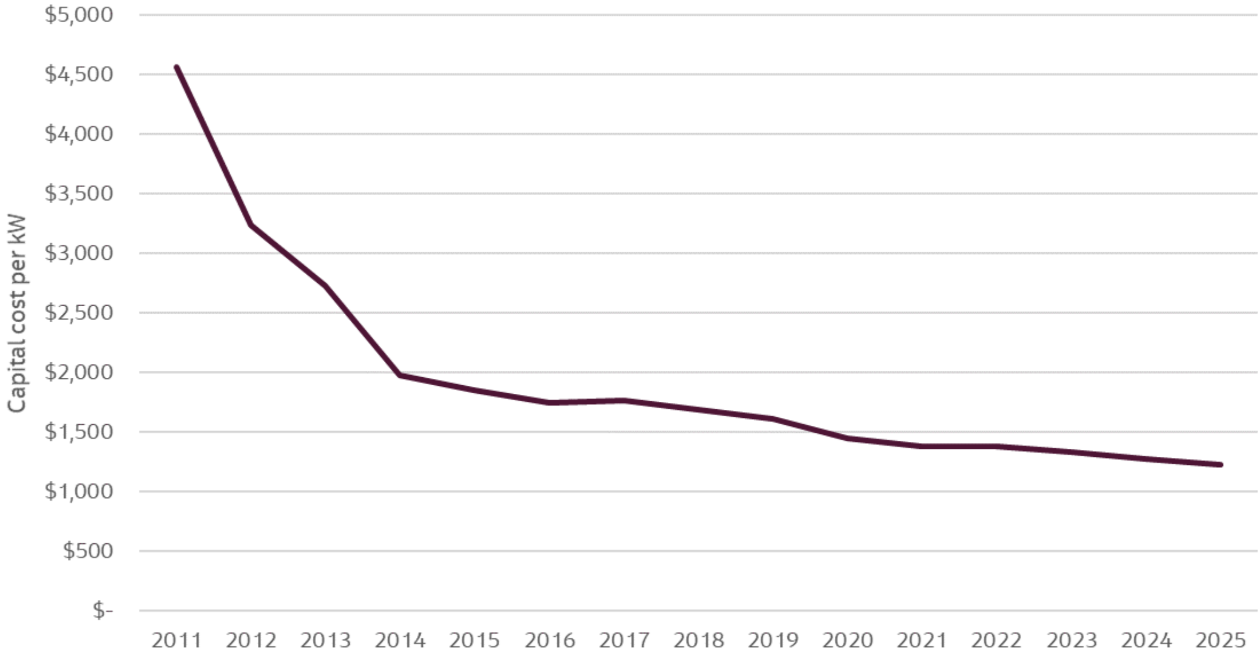
The economies of scale were also less apparent in commercial systems, with little difference between cost per kW for a 10 kW system versus a 100 kW system. Therefore, a ratio for economies of scale was not applied, and rather the cost per unit was assumed to be constant.

Figure 13 shows the historical and forecast costs assumed for commercial systems.

[12] http://www.solarchoice.net.au/blog/

[13] https://publications.csiro.au/rpr/pub?list=BRO&pid=csiro:EP208181&expert=false&sb=RECENT&n=10&rpp=2

Figure 13: Capital costs assumed for commercial solar PV systems ($/kW 2021)



Source: Jacobs' market analysis, Solar Choice monthly system cost estimates 2012 – 2021, CSIRO

5.4 Residential system size

Figure 14 shows the trends in average PV system sizes being installed since January 2015. The graph shows that average system size has continued to grow at a consistent rate over the last six months, consistent with growth patterns since mid-2016.

Another observation is that consumers have continued to install large PV systems, now averaging above the 6.6 kW limit imposed by many distribution network service providers. This would also result in the average household consuming approximately 15 kWh/day to export roughly 70% of energy produced via their solar system to the grid.

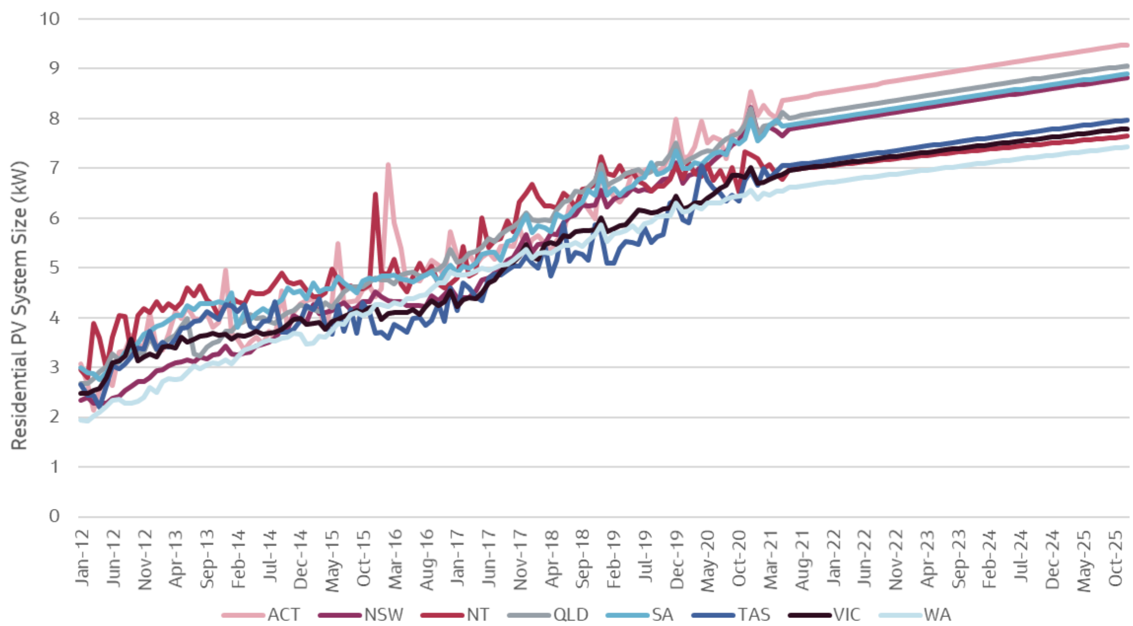
The tendency to oversize could be driven by several reasons including:

- Generous Feed-in-tariffs offered by many retailers.
- Residents hedging against future electricity price increases.
- Residents hedging for future demand increases such as electrification of appliances and electric vehicles.
- Increasing environmental awareness and consumers wishing to contribute to the grid.
- Economies of scale offered by installers for larger systems.
- Continued improvement in capture efficiency of PV panels.

We expect that average system sizes will not grow at the observed linear rate indefinitely. Residential system sizes will become constrained by available roof space, and most states have a restricted inverter capacity of 5 kW_{ac} for residential phase 1 systems, which limits many residential PV systems to a capacity of 6.6 kW. We expect this restriction in combination with the availability of roof space to eventually curtail the average system size for residential properties.

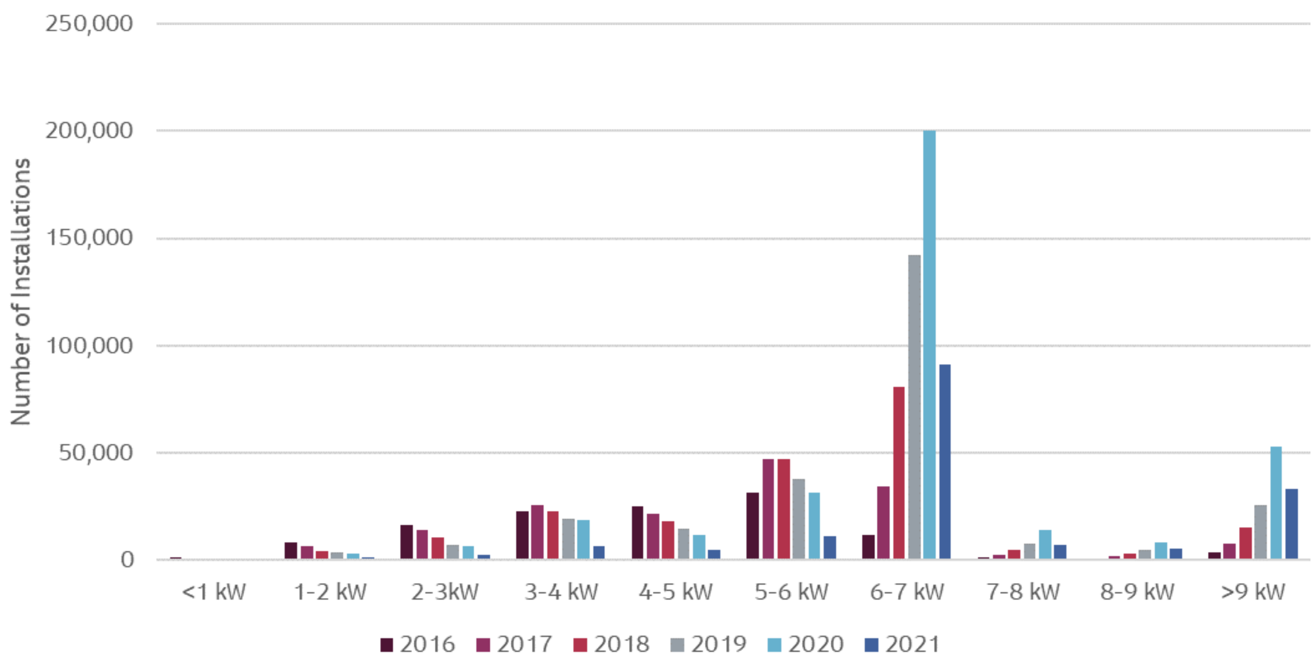
Power curves have been fitted in each state to reflect this assumed reduction in growth rate.

Figure 14: Monthly trend and forecast for average residential PV solar system size, selected states



Source: Jacobs' analysis of CER data

Figure 15: Residential system size brackets since 2016



Source: Jacobs' analysis of CER data, 2021 incomplete dataset

5.5 Electricity price projections

Jacobs' wholesale electricity price predictions were used as the basis for estimating retail electricity prices, which in turn were used in calculating future electricity savings and/or revenues for SGUs.

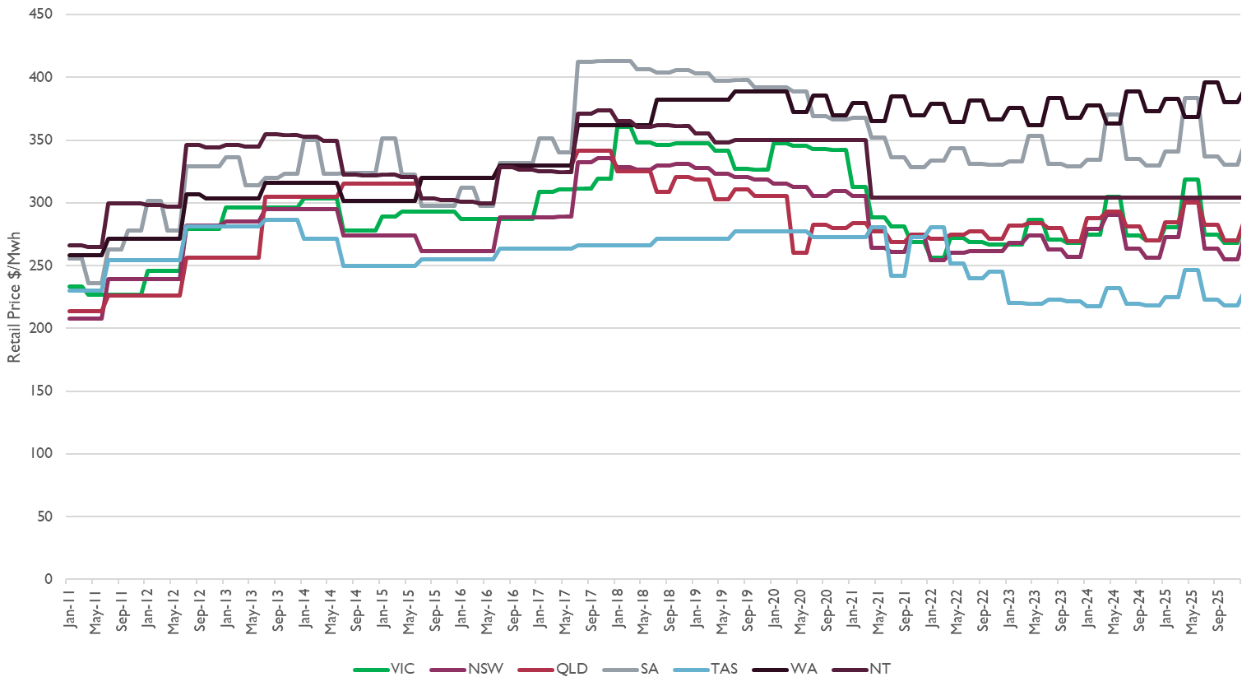
The wholesale prices were based upon market modelling studies employing a set of assumptions, including median economic demand growth, median gas price and median technology cost projections. A separate model was then used to convert wholesale prices to retail prices by applying average network tariffs and retail marketing expenses. These wholesale prices were also utilised to project commercial retail prices for SMEs for forecasting the economic benefits of commercial based solar installations.

Figure 16 shows the residential electricity prices used in the modelling for NEM states. Electricity prices peak in 2019, before a downward trend is projected over the period of 2019 to 2022. This is primarily due to the influx of large-scale renewable plant expected during this period. Electricity prices are expected to rise again in 2023 as a result of Liddell Power Station's retirement.

In Western Australia, retail prices were historically subsidised. In 2009, the state government introduced a policy to increase retail prices to eventually reflect the cost of production and distribution. It is expected that parity will be reached in 2022 and our projections are that price rises will continue until then.

The Northern Territory prices are heavily regulated by the state government and it is assumed that these prices will remain constant for the projection period.

Figure 16: Residential retail price - historical trend and forecast for selected states



Source: ABS, Jacobs Analysis

5.6 Feed-in tariffs

Feed-in tariffs in Australia for small-scale renewable energy generation are offered by the retailers and in some instances, they have an obligation imposed by the relevant state government to offer a minimum tariff. Where the required data of retailers' tariffs and customers per retailer were available, a price based on the weighted average retail offer of the three largest retailers and combination of remaining retailers was assumed in the modelling. In ACT, where ActewAGL supplies the bulk of the market, the ActewAGL tariff was selected. In 2021 average feed-in-tariffs in the major NEM regions (NSW, Queensland, Victoria and South Australia) have all had reductions in the order of 20% - 30%, reflecting the ongoing decline in average wholesale prices.

Due to the projected decreases in retail electricity prices over the forecasting period for NEM states, the FIT for each state was then calculated as a percentage of the most recent retail price. Moving forward, the FIT was then assumed to move relative to the retail price based on this initial proportion.

Both the Northern Territory and West Australian governments have sharply reduced the standard feed-in-tariffs in a move to reduce incentives to export rooftop solar power due to concerns relating to the stability of the grid.

In April 2020, the Northern Territory standard feed-in-tariff was reduced from 26.05 c/kWh to 8.3c/kWh which is applied to all new installations.

In Western Australia, the standard feed-in-tariff rate of 7.135 c/kWh was changed to 3 c/kWh prior to 3pm and 10 c/kWh after 3pm. This is a move to encourage the installation of west facing panels and energy storage systems to encourage export during the evening peak period. This change is to occur in all systems installed from September 2020.

These reduction of feed-in-tariffs in Western Australia and the Northern Territory are expected to impact the market and have been incorporated into our ARIMA models.

5.7 Export tariffs

In March 2021 the Australian Energy Market Commission (AEMC) put forward a draft determination designed to integrate more rooftop solar PV into the grid. The proposed reform package included allowing Distribution Network Service Providers (DNSPs) to use two-way pricing to better manage congestion in their network at peak export times. The AEMC's modelling accompanying the determination indicated a tariff of about 2c/kWh for exports in the middle of the day. This charge would not be applied to all exports, but only when there is congestion. This determination has been met with opposition, with the Queensland and Victorian governments as well as some renewable peak bodies reacting negatively to it.

As part of a compromise to address resistance to the proposal, the AEMC have since stated that an export charge will be not be mandatory, and network businesses may opt not to impose it. The proposed reform will take effect from 1 July 2022, but the next tariff review for DNSPs commences in 2024 and will not happen in some jurisdictions until 2026.

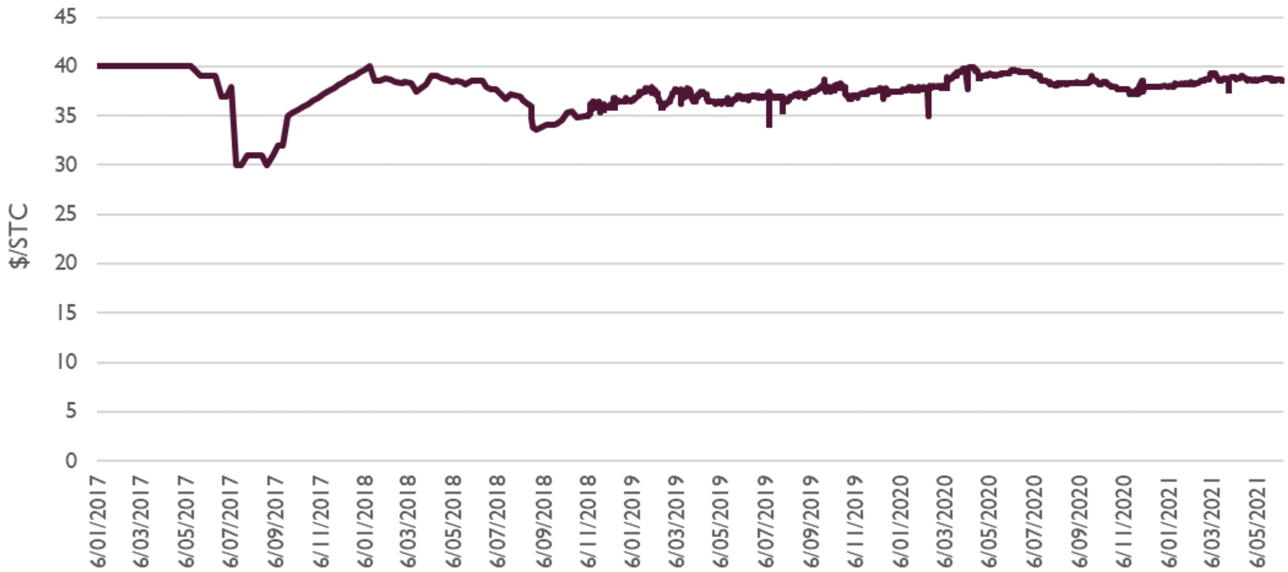
We have decided not to impose export tariffs on any feed-in-tariff assumptions used in the modelling for two reasons:

- The uncertainty surrounding this proposal.
- It will not take effect until the second half of 2024, and some regions will not be affected by it at all over the 2025 projection horizon.

5.8 STC prices

Figure 17 shows the weekly historical STC prices for the period January 2017 to May 2021. During this period the STC prices have continued to hover below the target of $40, indicating that a surplus of STCs is being generated in the market. We have used the forward curve, which extends until 2022, to project STC prices and have thereafter assumed the price asymptotes to $40/certificate by 2030.

Figure 17: Weekly historical STC price (nominal)



Source: Demand Manager and Jacobs' analysis

5.8.1 STC zoning

CER divides Australia into four regional zones based on the estimate of renewable energy that can be generated by a solar panel in a given area, so installations in areas with high insolation will create more certificates per kW than rooftop installations based in areas in the south of the country. Zones are defined by postcodes. To convert the capacity of solar panels installed to the number of STCs produced, the average STC per kW of installed capacity was calculated for the years 2013 to 2016 for each state and territory, the effective period when STC generation was not affected by multipliers or reduced deeming periods. The average commercial STC per kW of solar PV installed was calculated for this period too at a national level. Table 10 shows the effective multiplier for each state and commercial installations utilised for conversion of the forecast capacity into STCs.

Table 10: Average STC generated per kW PV installed

Region	STCs per kW
Residential	
ACT	20.7
NSW	20.8
NT	23.3
QLD	20.8
SA	20.6
TAS	17.8
VIC	17.8
WA	20.7
Commercial	
National	20.2

5.9 Time lag to registration

As there is a 12-month window from the date of installation in which to register systems, the most recent registrations database will be missing records of systems that have already been installed, but which have not yet been registered. If not corrected for, this will lead to an underestimate in the number of systems installed in the most recent few months. This is particularly relevant for the time-series forecasting, which is sensitive to the most recent data points.

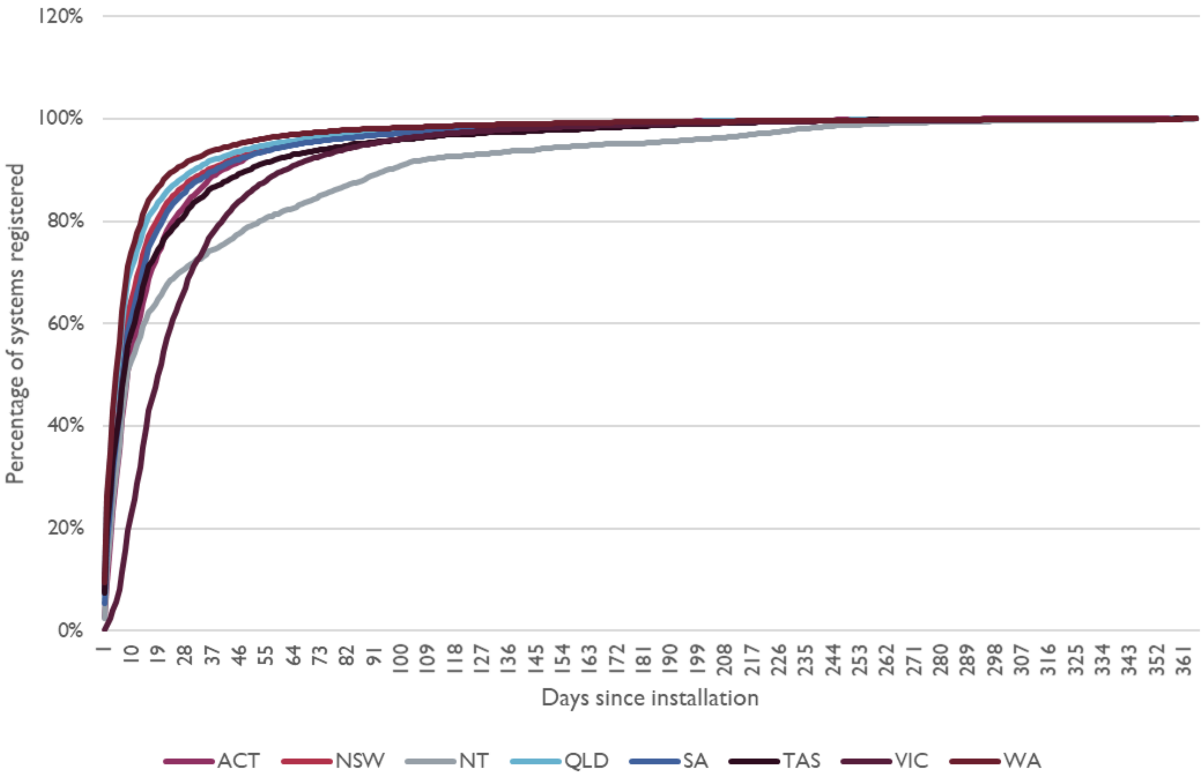
We have examined how long it takes before eligible systems are registered for STCs. The data provided by the CER includes both the date of system installation and of STC creation, so we can calculate how many systems are registered one, two, three, or more months after the system itself was installed.

Data was analysed for the period of calendar year 2020, with the assumption that all PV systems installed in 2020 were registered by 31st of December 2020. This period was selected as it would reflect current trends whilst still maintaining an adequate sample. Months for the year of 2021 were not incorporated in this analysis due to the bias that would occur favouring the population who install early rather than later, resulting in an underestimate of time taken to register PV systems.

Figure 18 shows the typical delay in registration for residential system installations by state.

For December 2020 through to May 2021, the residential installed capacity was divided by the percentage of registered installations for the expected percentage of installations for the respective month as shown in Table 11.

Figure 18: Delay in STC creation from installation, 2020 residential SGUs



Source: CER data

Table 11: Percentage of installed capacity used in modelling for residential and commercial systems

Month	ACT	NSW	NT	QLD	SA	TAS	VIC	WA	Commercial
Jan 2021	99%	99%	94%	99%	99%	98%	98%	99%	97%
Feb 2021	98%	98%	93%	98%	98%	97%	97%	99%	95%
Mar 2021	97%	97%	90%	98%	97%	96%	95%	98%	92%
Apr 2021	95%	95%	82%	96%	95%	93%	90%	97%	87%
May 2021	86%	89%	72%	90%	88%	84%	72%	92%	74%

5.10 Agent-based model assumptions

5.10.1 Customer segmentation

As discussed in section 4.2.1, agents are segmented into either the residential, or non-residential (commercial or school) sector. The initialisation assumptions are outlined below.

The latest ABS census (2016) details the proportion of dwelling type for each SA3 region, and tenure type. Only dwellings characterised as a separate house, or a semi-detached dwelling (terrace house, townhouse) are assumed eligible to adopt a rooftop solar PV system. Similarly, it is assumed only owner-occupiers can uptake a system due to constraints on renters' ability to modify their home.

Although households have different dwelling characteristics and electricity consumption behaviours, the trends in a region's average installed capacity are relatively homogenous; it is therefore acceptable to assign residential agents with their region's average capacity size because the standard deviation is small. The same approach cannot be used for commercial agents, however, because a typical Small Business customer may consume anywhere from 5 MWh to 100 MWh of electricity every year and install a PV system ranging from 4 kW to 30 kW. For this reason, commercial agents are assigned a capacity size based on its given annual consumption. This is calculated by the identified relationship between a business' electricity use and its installed capacity.

An optimisation model was conducted which found the optimal system capacity that maximises its NPV under given parameters (retail tariff, electricity consumption, capital costs). On average, it was determined that a business consumes 3,400 kWh of electricity per annum for every kilowatt of installed rooftop capacity. In other words, if a business consumes 20 MWh per year, it is assumed it will select a 5.9 kW system to install. Similarly, a business that has installed a 15 kW system in the past is assumed to consume 51 MWh of electricity per year. The segmented consumption values are outlined in Table 12.

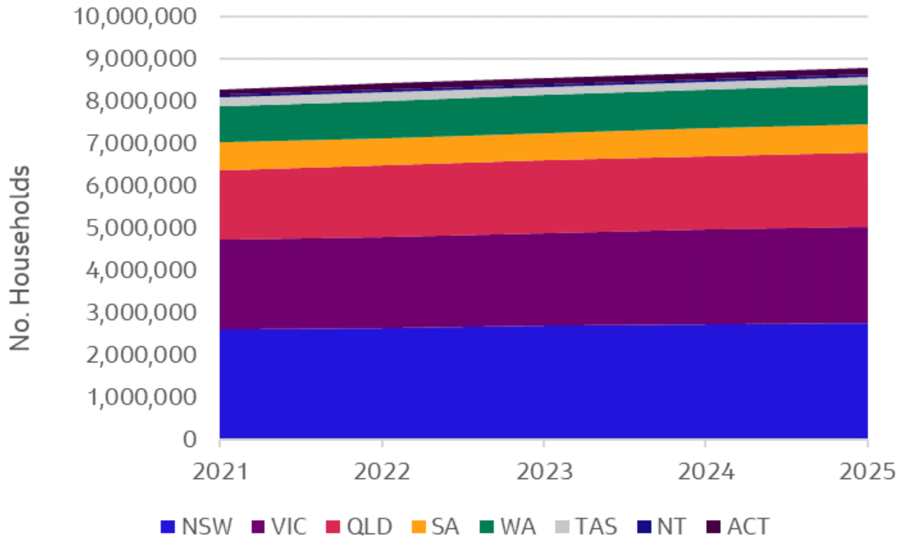
Table 12: Electricity consumption segments

Installed System Capacity	Annual Electricity Consumption
≤ 5 kW	≤ 17 MWh
≤ 10 kW	≤ 34 MWh
≤ 15 kW	≤ 51 MWh
≤ 20 kW	≤ 68 MWh
≤ 30 kW	≤ 102 MWh
≤ 50 kW	≤ 170 MWh
≤ 70 kW	≤ 238 MWh
≤ 90 kW	≤ 306 MWh
≤ 100 kW	≤ 340 MWh

5.10.2 Household growth

Household growth was indexed to the SA3 population or household growth forecasts from the respective state and territory governments (except TAS and NT). Using SA3 household numbers from the latest ABS Census, household growth followed the trend of its corresponding SA3 household/population forecast using its state government's central case. Where an SA3 region experiences negative growth during a given year, zero growth is assumed; the net state growth rate remains true despite this assumption. The total household growth forecast is shown in Figure 19. Within the agent-based model, the appropriate number of agents are introduced every year to account for household growth. These new agents are initialised using the initial assumptions discussed in section 4.2.1, and subsequently follow the same decision process. Due to accounting for only 3% of Australian households, the number of dwellings in TAS and NT are assumed constant.

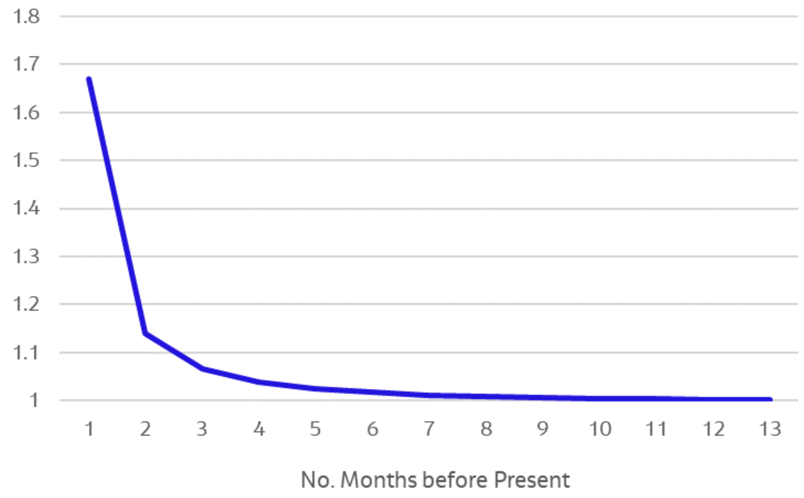
Figure 19: Household growth forecast



5.10.3 Annualising 2021 data

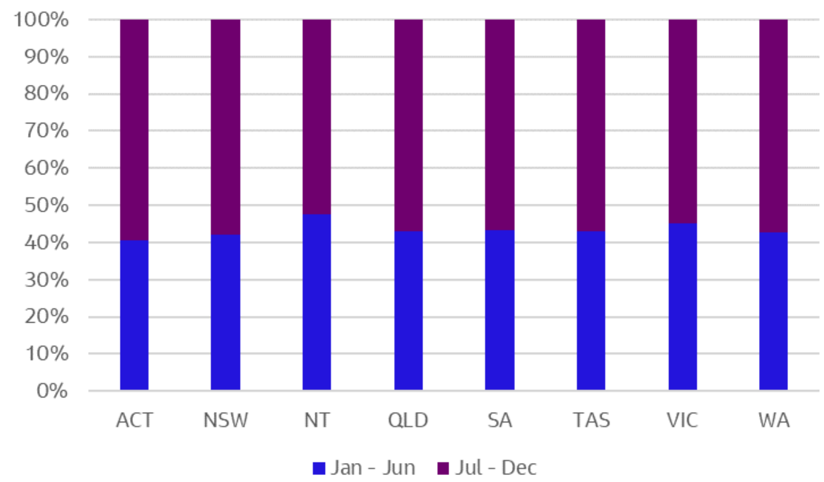
Since the agent-based model uses annual input data, the incomplete 2021 data provided must be annualised appropriately. In addition to the apparent lag between the STC registration date and the system installation date, there is also a lag in recorded installations; typically, numbers are continually adjusted by CER within the next 12 months of the original installation month. Two datasets were provided by CER, sourced one month apart. The discrepancy in recorded installation numbers of the same historical months between both datasets was used to calculate a monthly installation lag multiplier (Figure 20). Using these factors, it is assumed that all recorded installations from one month ago should be multiplied by a factor of 1.67 to account for the expected underestimation from lag; similarly, on July 1, all installations recorded two months prior in May 2021 are multiplied by a factor of 1.14. Adjustments are most significant within the first 2 months, with the lag multiplier then slowly converging to 1.0 after 12 months.

Figure 20: Residential Installation Monthly Lag Multiplier



For 2021, data is provided until June 30. Adjusted installations within these six months were then annualised by weighting it to the historical proportion of systems installed in each month (Figure 21). Historically in all states, more rooftop PV systems are installed in the last quarter of the year than in all other months.

Figure 21: Monthly residential installation distribution

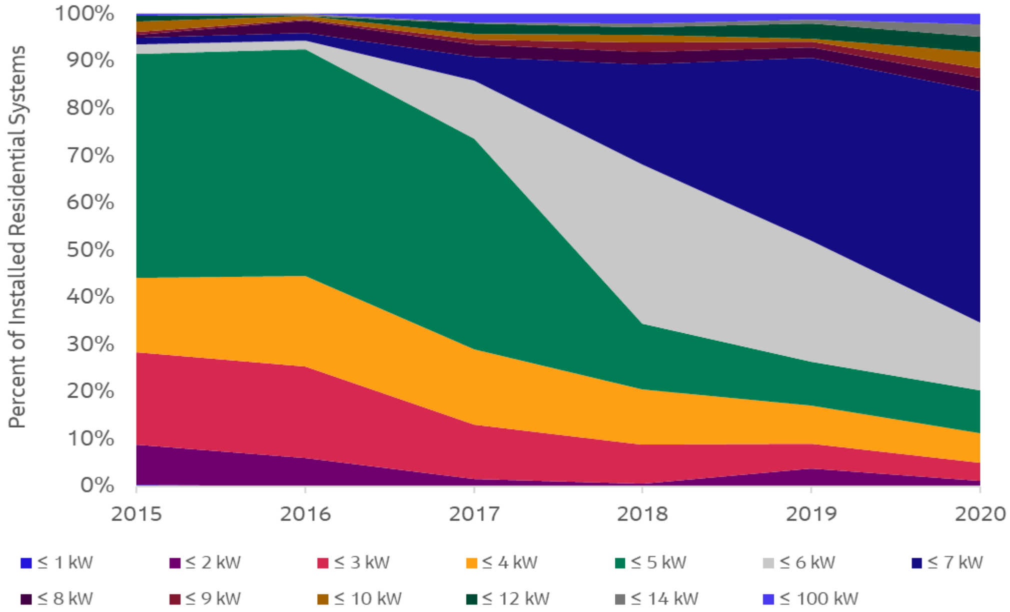


5.10.4 Installed capacity

As discussed in Section 5.4, system sizes will become constrained by available roof space, and most states have a restricted inverter capacity of 5 kW_{ac} for residential phase 1 systems, which limits many residential PV systems to a capacity of 6.6 kW. A small proportion of households with 3-phase power can install larger system sizes, slightly raising the average household PV system size. Despite this, historical installation data indicate a strong continued trend in average residential capacity size, with all state averages already above 6.5 kW in 2021. Figure 22 shows the historical system capacity distribution in Latrobe Valley. In the last few years there is a clear uptake in 6.6 kW systems as its market share quickly becomes the most installed segment in 2020. However as shown in the upper area of the graph, there is a slow but continued increase in larger systems between 7-14 kW which will push the average system size above 6.6.

A power regression was conducted for all SA3 regions' historical average capacity size, to forecast the average installed capacity until 2025. The weighted state average forecasts are illustrated in Figure 23. New South Wales is projected to have the highest average system size with 8.98 kW by 2025.

Figure 22: Historical system capacity distribution, Latrobe Valley



System sizes for commercial agents vary significantly depending on its size and demand. Using CER postcode data, the average installed capacity size for each capacity segment was calculated (Figure 24). Due to the assumption that businesses within the same capacity segment have similar energy consumption, and all businesses do not oversize their systems, the average system capacity per segment is assumed constant throughout the forecast period.

Figure 23: Residential solar PV system size forecasts

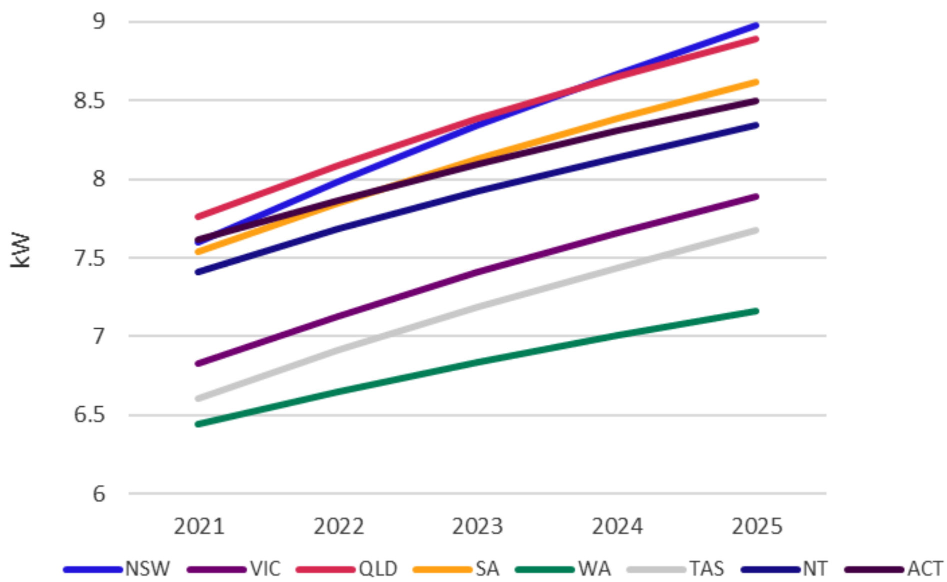
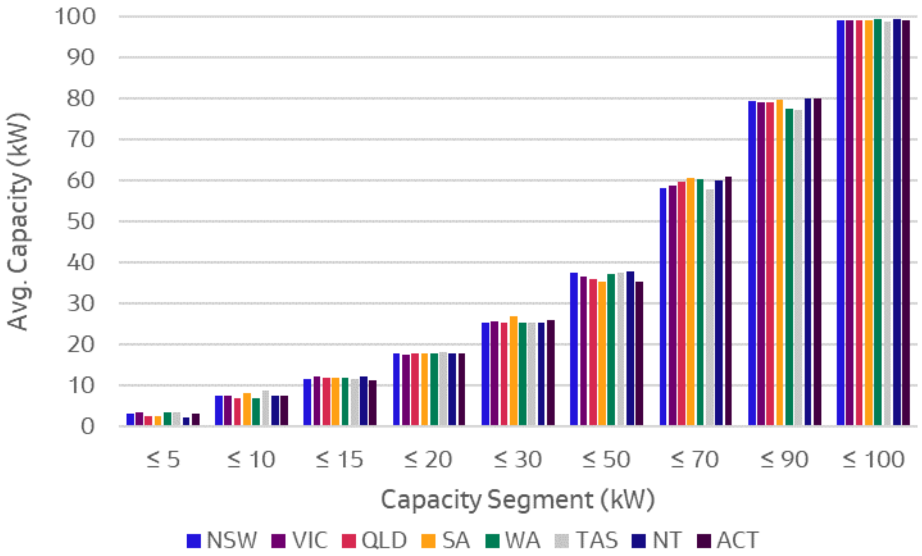
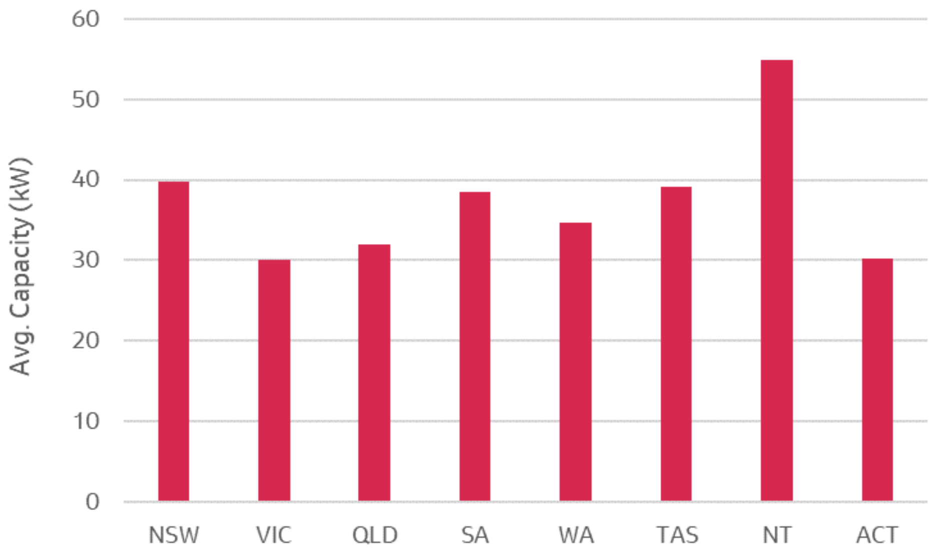


Figure 24: Average commercial system capacity



Similarly, for school agents the average system size is calculated per state using postcode data provided by CER and is assumed constant throughout the model.

Figure 25: Average school system capacity



6. Projections

This section presents the outcome of the time series modelling, as well as the outcome of the agent-based modelling. In all cases results are presented in calendar years.

6.1 Time series model

The hybrid model represents the time series model with uptake adjusted as estimated saturation levels are reached for the various market segments.

6.1.1 Residential system uptake

The state based residential forecasts were derived by first projecting the number of installations, then converting this to expected capacity for PV systems followed by inferring the STCs per unit of installed capacity from historical data.

Figure 26 shows the historical actual and projected total installed capacity for residential systems in New South Wales. New South Wales shows the greatest growth of all states in terms of MW capacity. Overall, the long-term growth trend is projected to continue and there is little impact from market saturation.

Figure 26: Historical and projected installed capacity for NSW residences

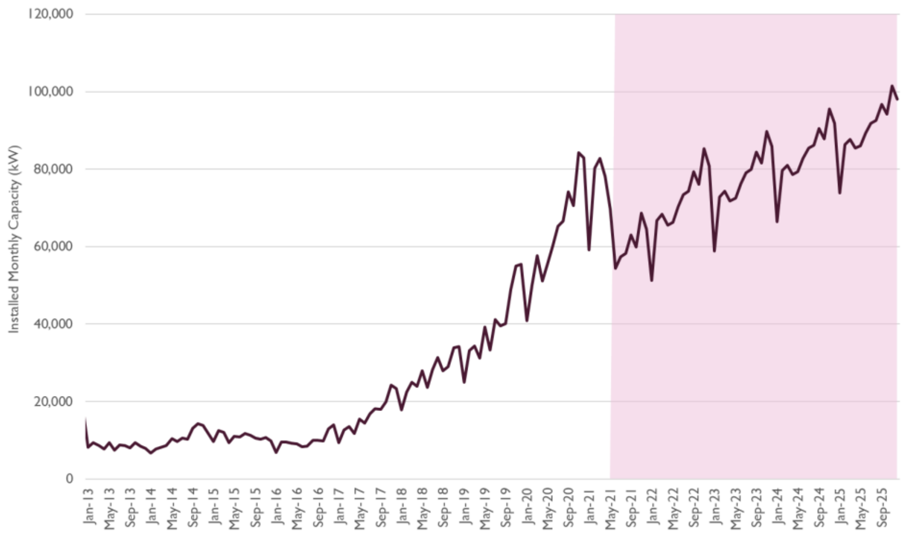
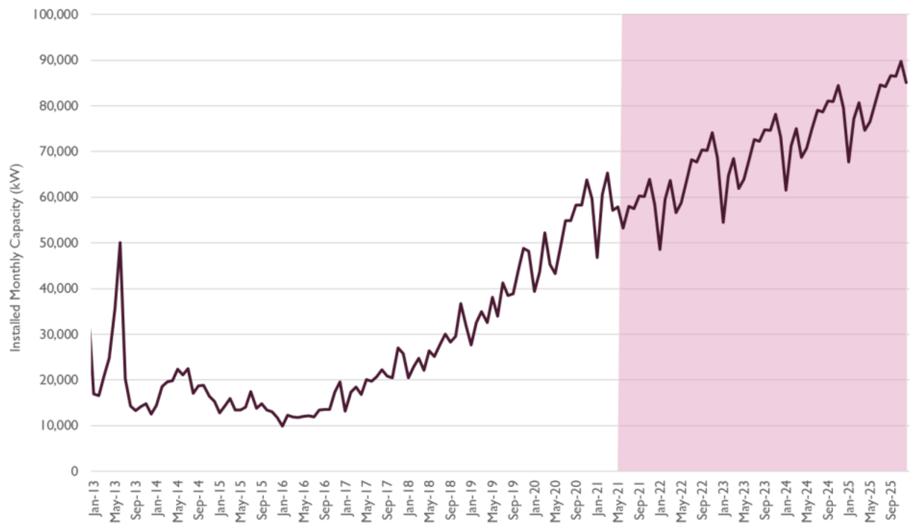


Figure 27 shows the fitted data of installed monthly capacity for residential systems in Queensland. Uptake growth in Queensland is also expected continue, although the higher historical saturation levels trigger some saturation impacts in SA3 regions with historically high rooftop PV uptake. Ignoring this saturation effect would have resulted in Queensland exceeding New South Wales in terms of absolute MW growth in PV capacity.

Figure 27: Historical and projected installed capacity for Queensland residences



Historical actual and fitted data for the uptake of residential PV in South Australia are shown in Figure 28. The historical numbers are indicating peak uptake has occurred in September 2020, with a distinct downtrend in installed capacity since then. This is likely related to the new rules for the installation of rooftop solar PV in South Australia, which were announced in September 2020. The new rules included higher standards for new inverters, including internet capability, and the capability of PV systems to be disconnected remotely.

The downtrend in installations in South Australia is projected to continue throughout the forecast period.

Figure 28: Historical and projected installed capacity for SA residences

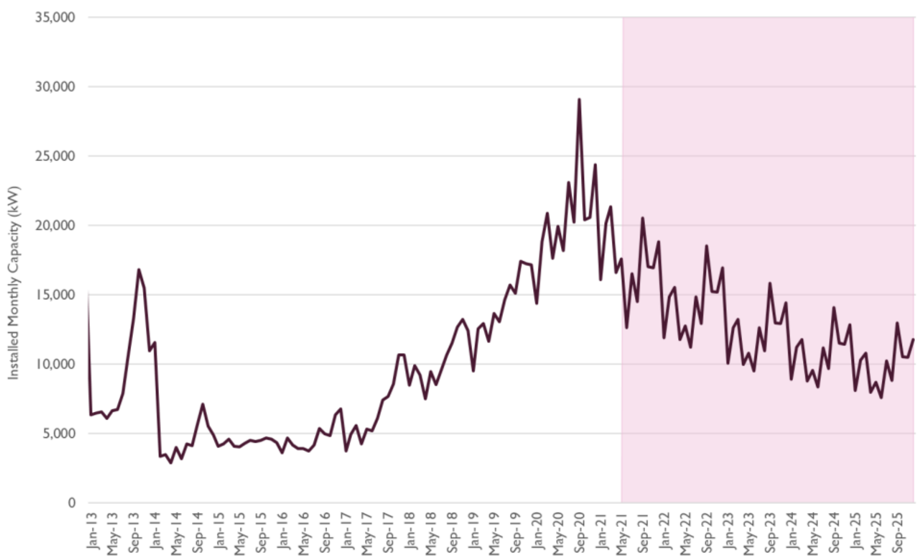


Figure 29 shows the historical actual and projected solar PV uptake for residential systems in Western Australia. The reduction in the rate of growth from the year 2021 onwards is partly driven by the reduction in feed-in-tariffs and partly by the triggering of saturation in historically high growth areas of Western Australia. Increases in retail prices towards the end of the projection period also contribute to slightly higher uptake rates.

Figure 29: Historical and projected installed capacity for WA residences

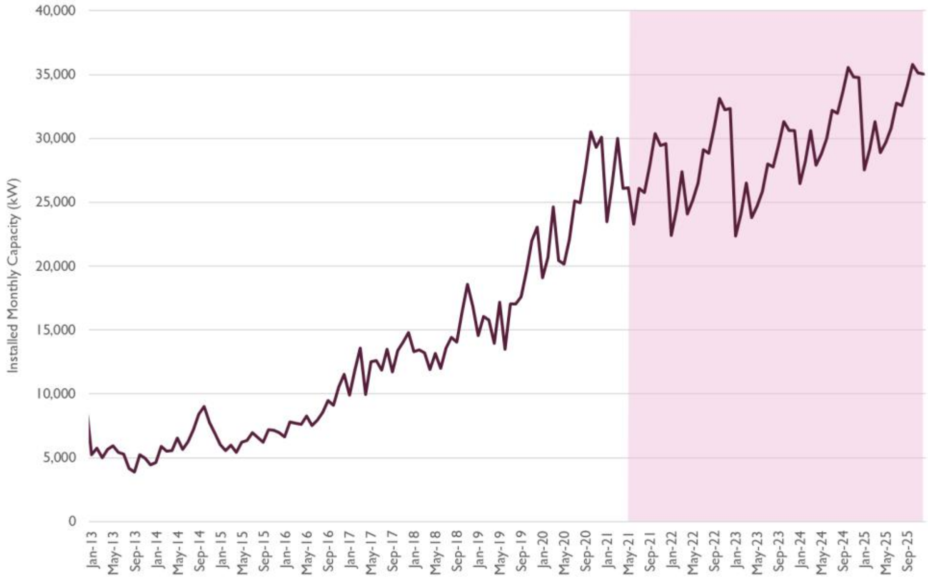


Figure 30 shows solar PV forecast used for STC creation in Tasmania. The low insolation levels in combination with low GDP growth in 2017 only saw modest growth of STC creation in the years 2017 and 2018. The continual reduction in capital cost and reductions in the cash rate created favourable conditions for uptake of solar PV during 2019 and an increase in uptake was observed. This has continued throughout 2020 and into 2021, with a new 7-year monthly high recorded in March 2021. The ARIMA model predicts a continuation of growing uptake, despite falling retail prices in Tasmania.

Figure 30: Historical and projected installed capacity for Tasmania residences

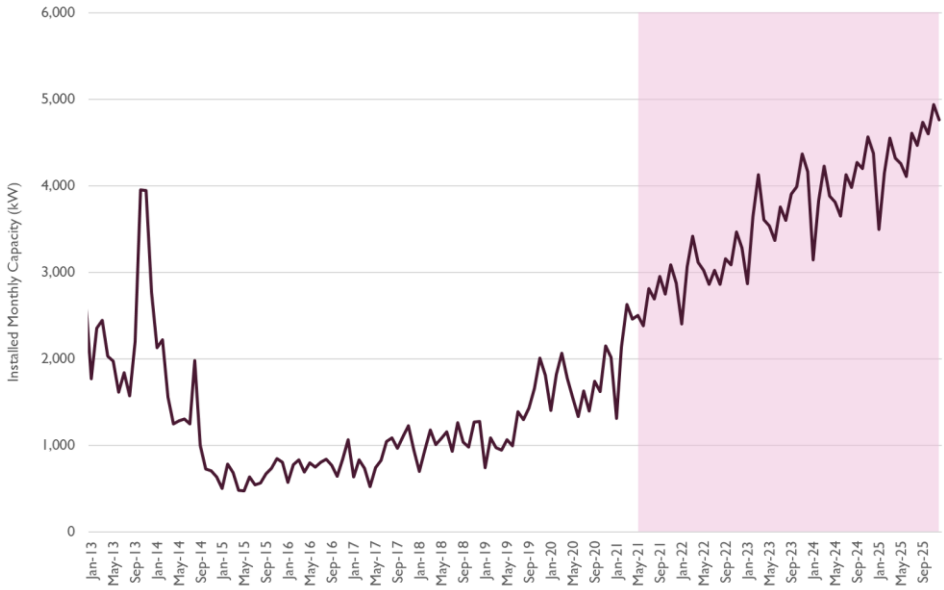


Figure 31 shows the solar PV forecast used for STC creation in the Australian Capital Territory. As with New South Wales, a relatively strong growth rate is expected for the projection period, although this is punctuated by a brief pause in growth in mid to late 2021. The strong medium-term growth is driven by a high level of house ownership and low levels of saturation.

Figure 31: Historical and projected installed capacity for ACT residential properties

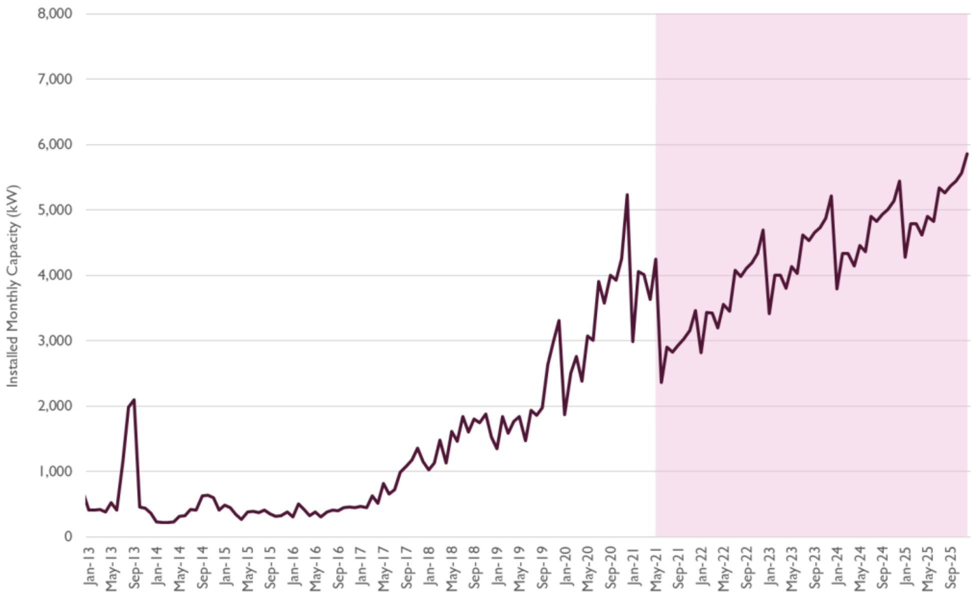
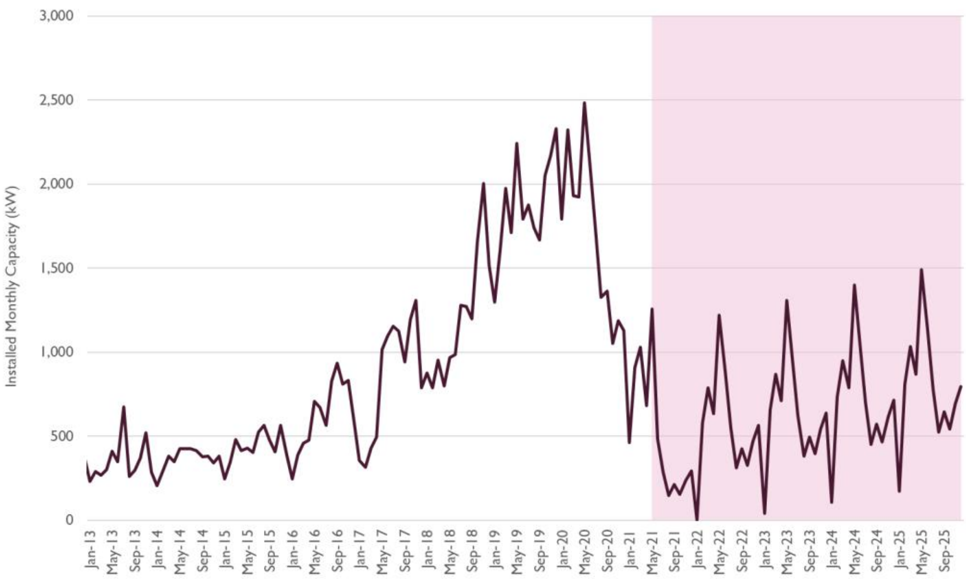


Figure 32 shows the solar PV forecast used for residential STC creation for the Northern Territory. Good insolation levels, high feed in tariffs and reductions in capital costs of PV installation has resulted in good economic benefits of PV installations during 2019 and early 2020. This has driven increasing levels of uptake over this time period. However, the sharp reduction in FIT from 23c/kWh to 8.3c/kWh has resulted in a slowdown in the historical growth rate, which is now similar to 2016 uptake levels. The model is projecting uptake to dip below recent levels, with an increase over the medium term reflecting the downward pressure on capital costs expected over this time frame.

Figure 32: Historical and projected installed capacity for NT residential properties



6.1.2 Commercial systems uptake

Uptake of commercial solar PV systems has been modelled for three different sizes.

Figure 33 shows the historical and projected installed rooftop PV capacity for commercial systems smaller than 15 kW. As with residential systems, the impact of COVID 19 also appears to have had a positive impact on the rate of installation of these systems. Uptake is expected to continue its growth trajectory after a pause in 2021. This is driven by the strengthening of the economic recovery expected post COVID.

Figure 33: Historical and projected installed capacity for <15kW commercial properties

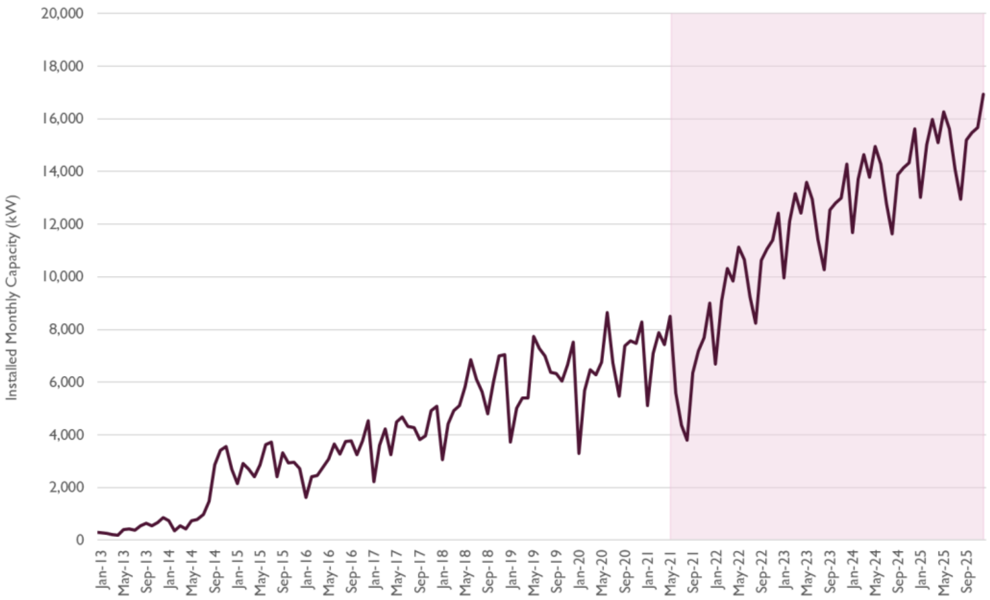
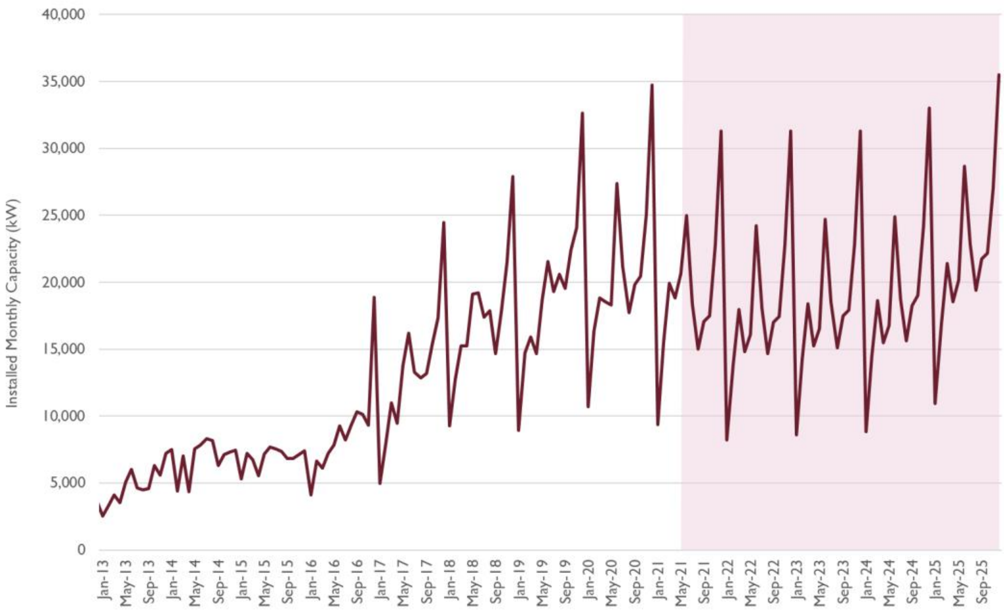


Figure 34 includes the uptake of solar PV projections for systems between 15 kW and 90 kW, which is the largest category of systems. There is a more pronounced seasonal uptake (December - January) than observed at the residential system uptake projections. The latter is expected, as it is likely that businesses are more aware of and sensitive to the scaling down of the deeming period than residential consumers.

The outlook for this capacity segment is flatter than that of the smaller segment (<15 kW) as it has a logarithmic relationship to the identified exogenous variable.

Figure 34: Historical and projected installed capacity by month, 15 kW to 90 kW

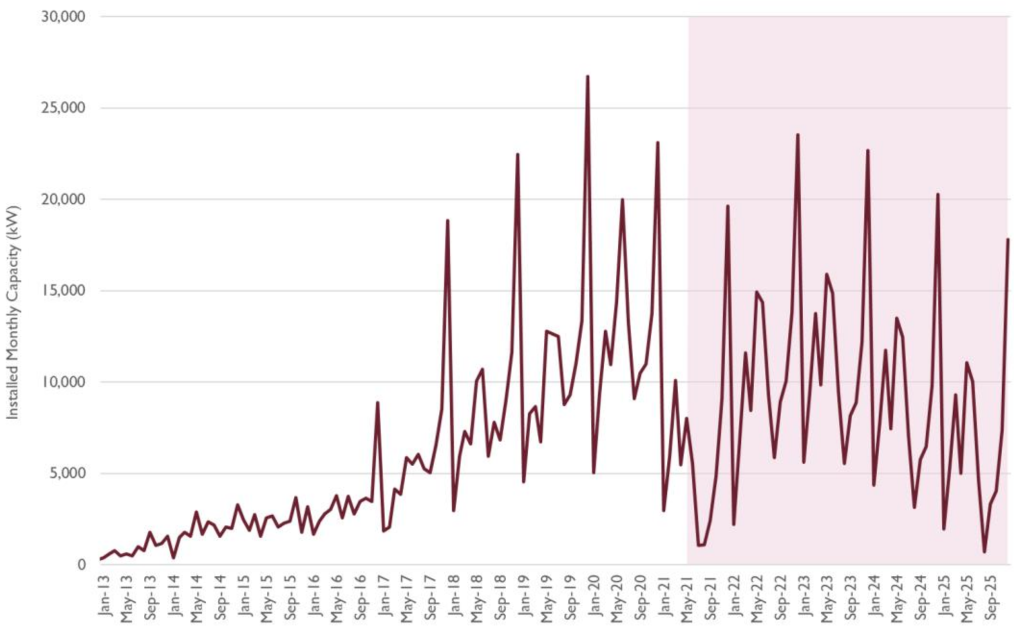


The final commercial category includes 90 kW up to and including 100 kW commercial solar PV systems and is displayed in Figure 35. There is a similar seasonal pattern observable as for the previous category, although the

December peak is even higher. As indicated earlier, it is likely that most systems installed in this category are part of a larger system likely to be installed in multiple phases or as separately metered sections, to take full advantage of the STCs and therefore the scaling down of the STCs is likely to have a very significant impact on the push to invest before the end of each year.

The first five (historical) months of 2021 are exhibiting a marked decline in capacity uptake for this segment. This is reflected in the projection for the remainder of 2021, which continues the downward trend. Some recovery is projected in 2022 to 2023, driven by the GDP economic control variable, but uptake is projected to decline again towards the end of the projection period.

Figure 35: Historical and projected installed capacity by month, >90kW systems



6.1.3 Solar water heaters

Figure 36 shows the historical actual and forecast data for the creation of STCs via solar hot water residential installations. The mild downtrend in uptake of these systems is projected to continue across the forecast horizon.

Figure 36: Historical and projected residential STCs for solar water heaters (<=40 STCs per installation)

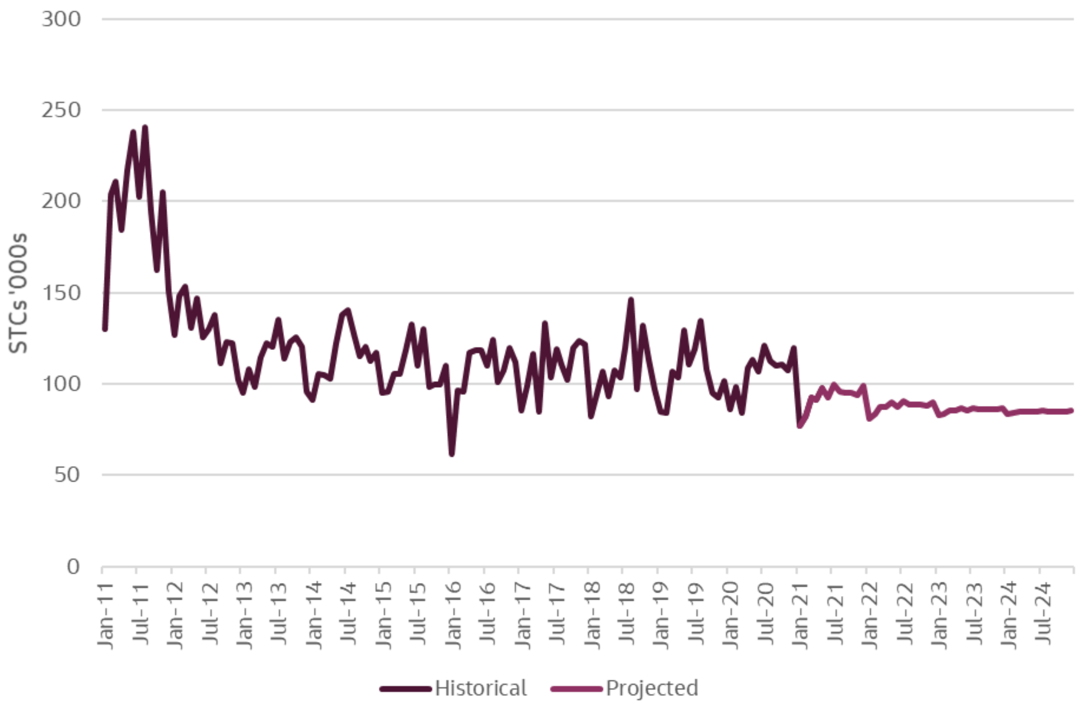
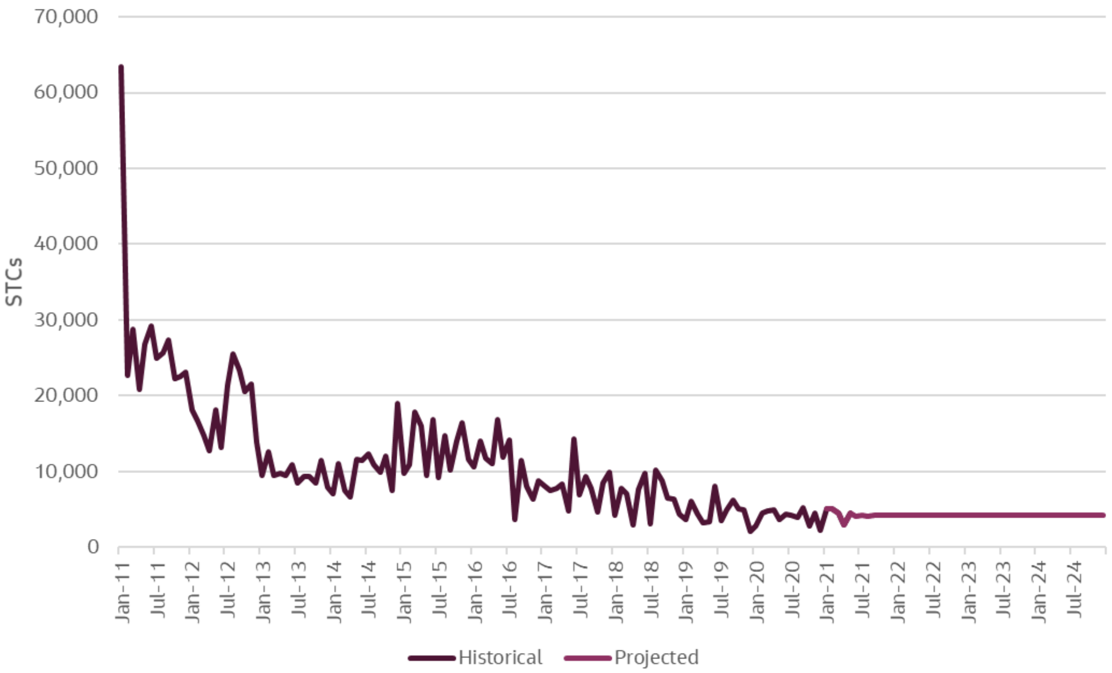


Figure 37 shows the historical actual and forecast data for the creation of STCs via solar hot water systems classified as commercial sized units. This declining trend is in contrast with the commercial installation of small-scale solar PV systems, which have been experiencing a growth rate over the same period. It is likely that this is no coincidence as the elevated cost of electricity and the net benefit of such systems begin to far outweigh the economic benefit that solar hot water heaters bring.

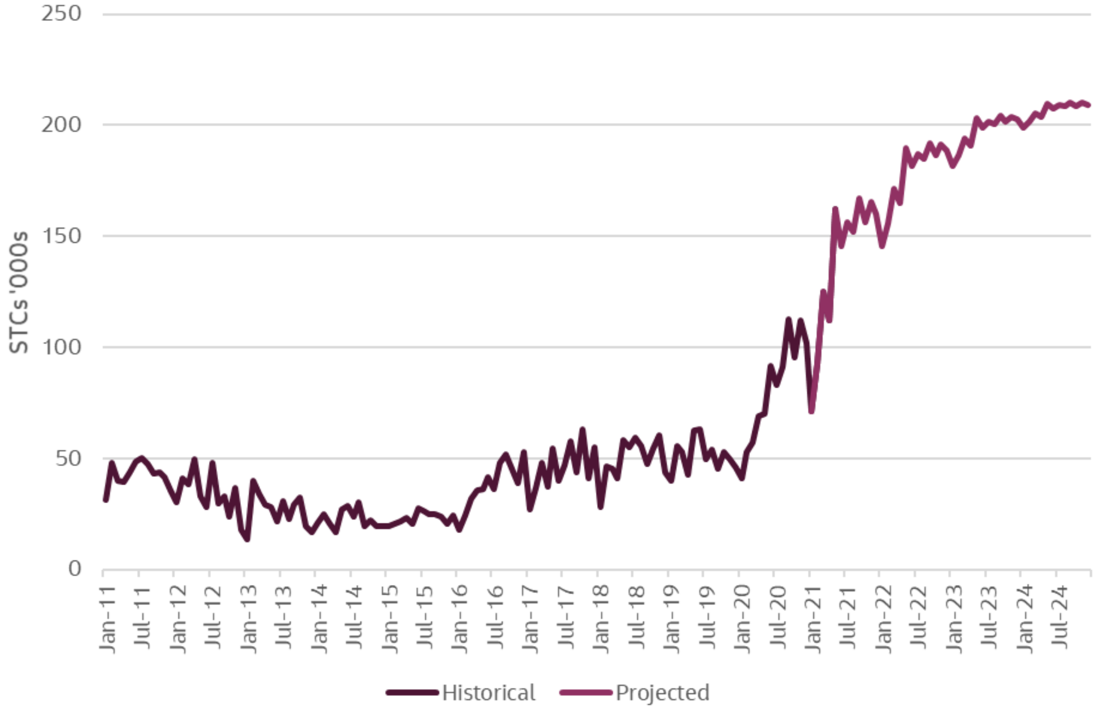
Figure 37: Historical and projected commercial STCs for solar water heaters (>40 STCs per installation)



6.1.4 Air-sourced heat pump water heaters

Figure 38 shows the historical actual and forecast data for STC creation from air-sourced heat pumps. There has been a boost in uptake in this sector with the onset of COVID, and it has continued through to 2021. As a result, uptake is projected to be strong and is expected to continue to grow throughout the forecast horizon, albeit at a declining rate of growth.

Figure 38: Historical and projected STCs for residential air-sourced heat pumps



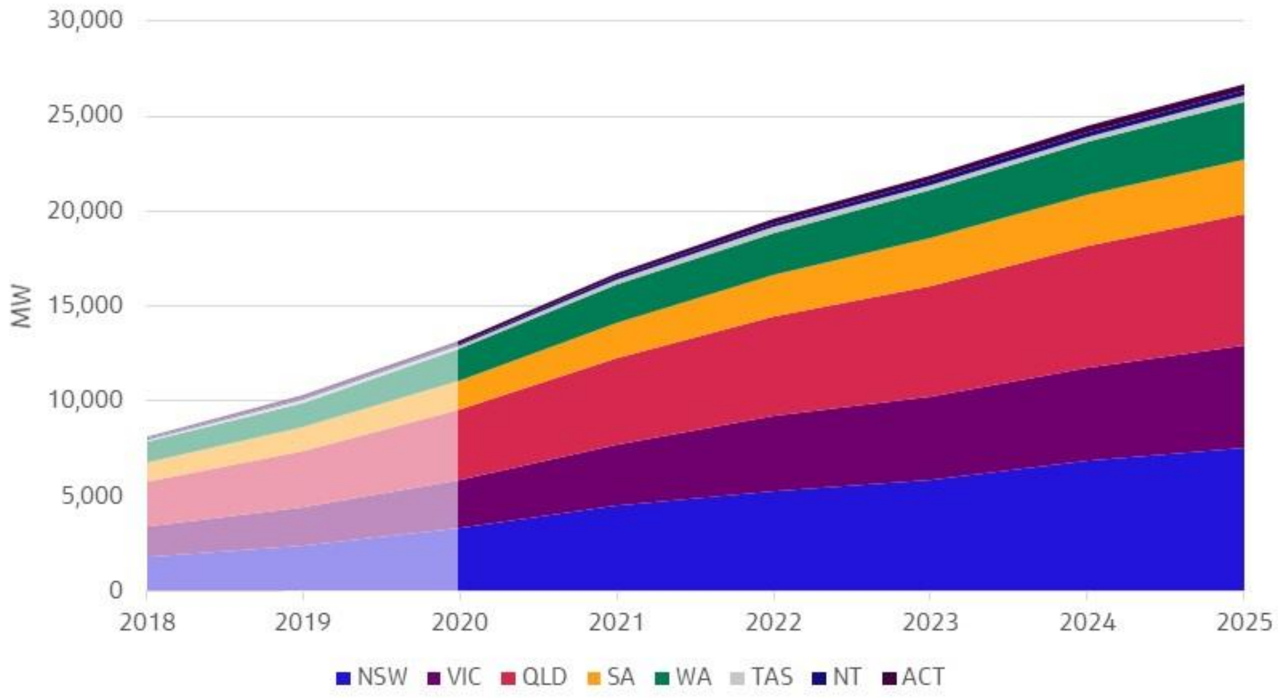
6.2 Agent-based model

The cumulative installed rooftop PV capacity increases steadily over the forecast period, rising from 16,750 MW at the end of 2021, to 26,700 MW at the end of 2025 (see Figure 39). Installation capacity in 2021 continues its unprecedented growth with 3,532 MW of newly installed capacity, versus 2,918 MW in 2020. The rate of uptake gradually decreases every subsequent year with 2,221 MW installed by 2025, which is the lowest level of historical or projected uptake since 2019.

Despite yearly installed capacity still exceeding 2019 levels during the last four years of the forecast period, the growth rate has decelerated due to the stagnated economics of installing a rooftop PV system. Continually falling capital costs are largely offset by the decline of retail prices and stalled feed-in tariffs.

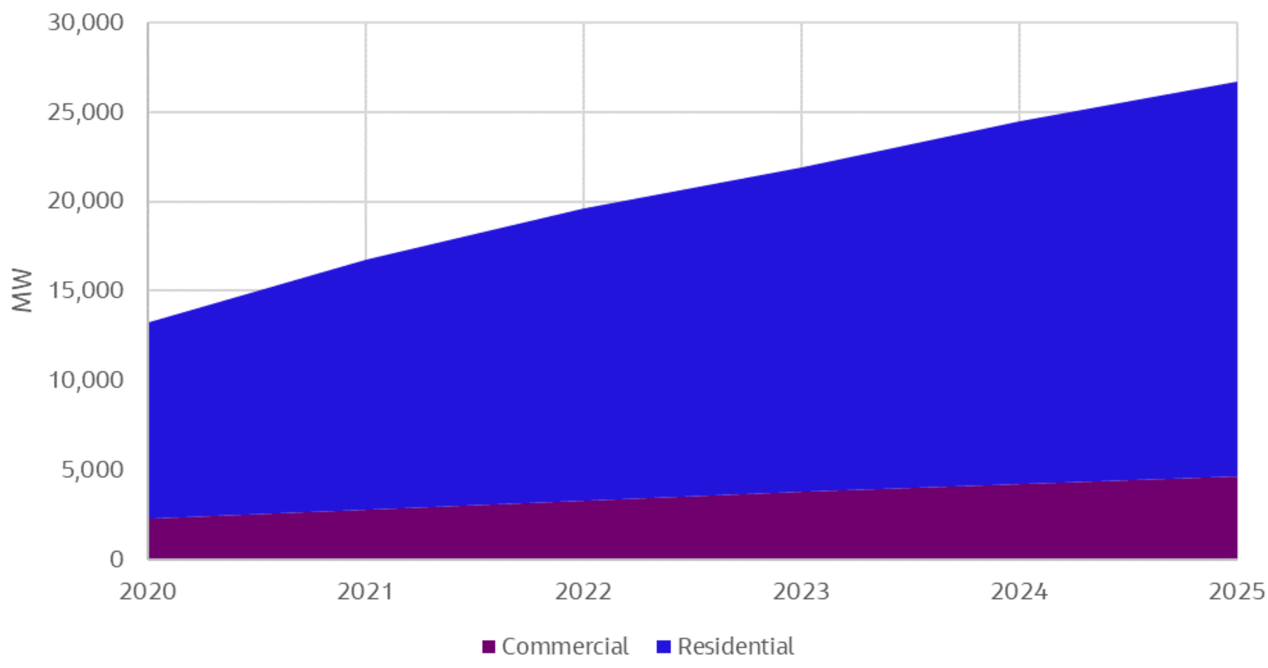
New South Wales overtakes Queensland in cumulative installed capacity by 2023 and projected to be the fastest growing state in rooftop PV. By 2025 New South Wales has 7,533 MW versus Queensland's 6,892 MW of rooftop capacity. Victoria has the second highest rate of uptake in the country with 5,3946 MW of cumulative installed capacity by the end of the forecast period: a 110% increase from the end of 2020. Tasmania is projected to have the lowest growth rate with 334 MW by 2025 (82% increase from 2020).

Figure 39: Small-scale PV state forecasts, agent-based model



The residential sector grows steadily from 13,951 MW of cumulative installed capacity in 2021, to 22,074 MW by 2025 (Figure 40). The commercial sector (including schools) rises from 2,799 MW at the end of 2021, to 4,627 by the end of the forecast period. 3,011 MW and 521 MW of rooftop solar are installed in the residential, and commercial sectors, respectively during 2021. Compared to 2020 this is a 24% increase in yearly residential installed capacity, and an 8% increase for yearly commercial installed capacity which is consistent with previous years.

Figure 40: Small-scale PV sector forecasts



7. Summary

We have undertaken two approaches to forecast small-scale PV uptake and associated STC creation. The forecast uptake under the time series approach tended to be significantly higher than the forecasts obtained with the agent-based modelling.

We have adopted the time series forecasts (as indicated in Section 6.1), which is based on the time series model but with saturation levels imposed. This approach was adopted because:

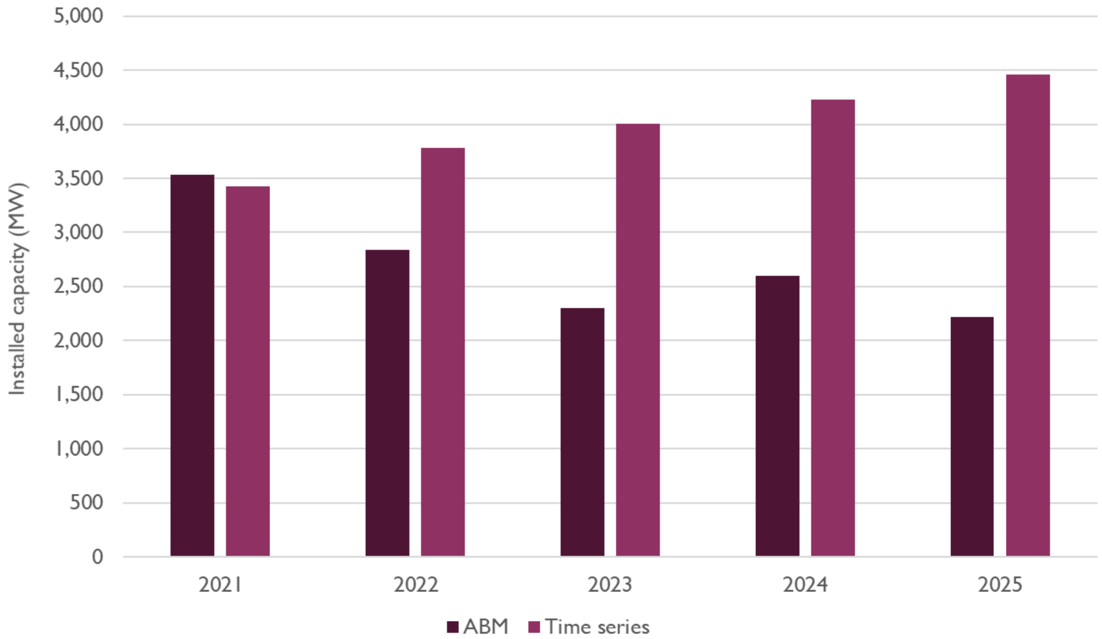
- The forecast from the ARIMA time series model tends to continue with the momentum of recent trend with only limited regard for structural changes in the market. This results in high projected uptake but has been muted by the saturation model employed, which has been introduced to account for saturation and to account for recent structural changes, especially in South Australia and Western Australia.

- The exogenous cost regressors for the ARIMA model tend to have low coefficients, and therefore their influence is rather limited. Other variables, such as retail price do have more of an impact, although these feature in the smaller regions. What this is implying is that other behavioural factors or influences (neighbourhood uptake, beliefs) are as large drivers of uptake as economic factors. This tends to fit the pattern of continuing strong uptake observed in recent historical data in the face of declining retail tariffs and feed-in tariffs.

The projections based on our agent-based model, on the other hand, is showing a slow-down in uptake due to a weakening of the economic drivers for installing these systems. The capital cost decline is slowing down, the FiTs are reducing and retail prices are projected to decline, and all these factors would normally act to slow down uptake (by effectively increasing the payback periods for new systems). This is being reflected in the projections derived from the agent-based model.

The resulting projections for each approach are starkly different as can be observed in the following chart. On balance we have used the projections from the time series model because they represent a continuation of buoyant uptake, which appears to be largely driven by non-economic factors, as best captured in the time-series model.

Figure 41: Comparison of uptake projections between ABM and time series models



7.1 Projections

The projections for STC creation are shown in Table 13. These projections include STCs created through both solar PV and hot water systems (wind and hydro STCs make up a negligible portion). In 2022, we project a total of 41.7 million STCs generated despite the scheme entering another year of scaling down by a ratio of 1/15 or 6.7% when compared with 2021.

Uptake in 2020 was affected by constraints on installations due to various lockdown measures preventing installers from operating. This would normally have created pent up demand in 2021 boosting installations. However, the time-series data indicate that uptake has levelled off in the early period in 2021.

Table 13: Small scale technology certificate creation projections, ('000s)[14]

	2021	2022	2023	2024	2025
ACT	540	560	572	535	503
NSW	10,776	10,640	10,224	9,700	8,961
Northern Territory	95	94	94	93	88
Queensland	9,513	9,537	9,112	8,729	8,045
South Australia	2,840	2,117	1,599	1,240	972
Tasmania	356	389	423	396	374
Victoria	5,635	5,357	4,888	4,382	3,845
Western Australia	4,451	4,158	3,570	3,603	3,153
Commercial <15kV	978	1,451	1,587	1,546	1,453
Commercial 15kV-90kV	2,824	2,601	2,360	2,131	2,126
Commercial 90kV-100kV	878	1,562	1,457	1,028	645
Residential Solar Hot Water	1,113	1,053	1,028	1,017	1,013
Commercial Solar Hot Water	51	50	50	50	50
Heat Pump Water Heater	1,666	2,139	2,369	2,482	2,537
All STCs	41,716	41,708	39,333	36,932	33,765

Figure 42 illustrates the small-scale technology certificate creation projections by sector. Results for the projected number of installations and capacity can be found in Appendix A.

Residential rooftop installations in 2020, continuing through to 2021 have occurred at a rapid growth rate, fuelled at least in part by forced lockdowns and an increase in spend on household items. The change to a work from home mentality, while not at the same extent of 2020, is expected to continue into the foreseeable future with a lasting increase of the benefits of household PV.

However, the rapid growth in rooftop PV is beginning to have a negative impact on the network in fringe locations. The West Australian, South Australian and Northern Territory governments have all made moves to mitigate the rise in rooftop PV systems until grids and processes can be effectively augmented and managed.

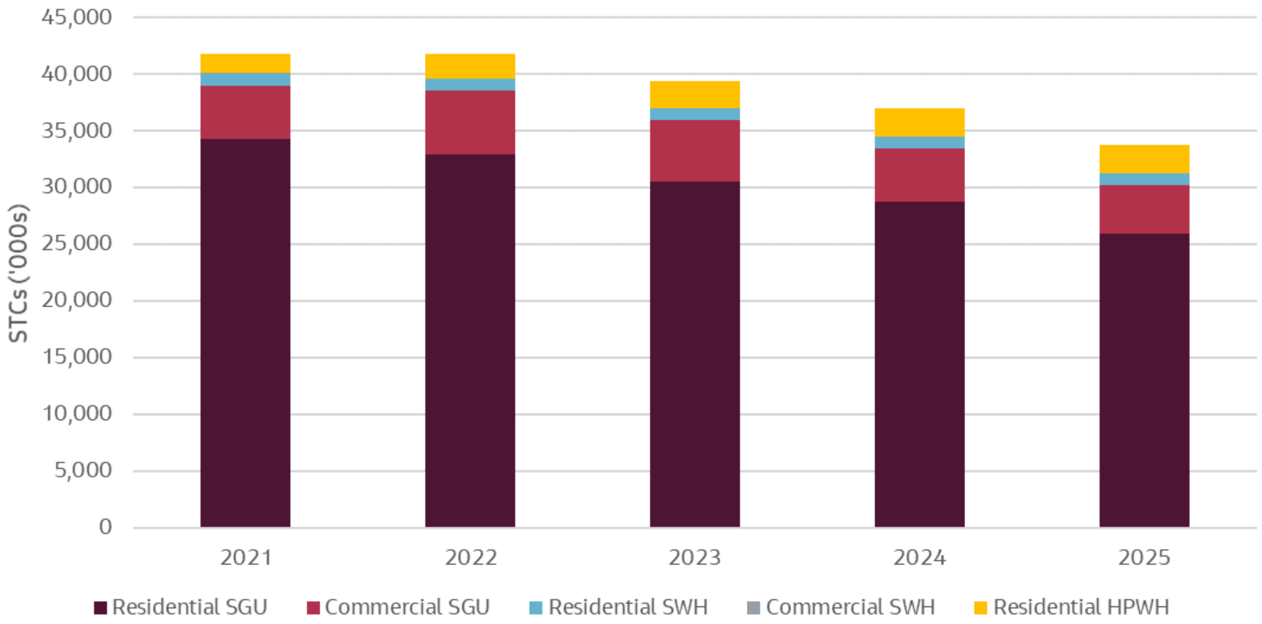
[14] State based totals are for rooftop PV for the residential sector. The commercial sector for rooftop PV is reported Australia-wide by capacity band, and water heater category totals are Australia-wide.

This has had an impact in uptake numbers in the first part of 2021 and projected uptake for all three regions is now lower than the previous study.

With the incorporation of our agent-based modelling, we also see that market saturation has a greater impact on growth from 2022 onwards in the high growth states of Queensland and Western Australia. South Australia is not impacted by this factor due its negative growth outlook.

The expected slowdown in the commercial sector is emerging in the early 2021 data, and this has had an impact on uptake, particularly for the two larger capacity segments for the rest of 2021. A rebound is projected to occur in 2022, led by the smallest and largest capacity sectors as economic conditions improve, and mild growth is projected thereafter.

Figure 42: Small scale technology certificate creation projections by sector



Commercially sized solar hot water units are expected to maintain their relatively low level of uptake and are not expected to have considerable influence on small-scale technology certificate creation for the duration of the forecasting period.

Domestic size solar hot water systems are expecting modest negative growth, but the recent climb in uptake of air-sourced heat pumps is expected to continue for the remainder of the forecast horizon.

Appendix A. Projected Capacity and Installations of PV Systems

These tables summarize the projected number of installed small-scale systems and total capacity installed over the forecasting period.

Table 14: Projected installed capacity of small-scale systems (MW)

	2021	2022	2023	2024	2025
ACT	40	45	52	56	61
NSW	796	858	927	1,005	1,083
Northern Territory	6	7	8	9	9
Queensland	700	770	828	906	974
South Australia	209	172	146	129	118
Tasmania	31	37	45	48	53
Victoria	467	501	514	526	539
Western Australia	325	337	325	375	383
Commercial <15kW	80	121	149	165	181
Commercial 15kW-90kW	231	216	221	228	265
Commercial 90kW-100kW	76	130	136	110	81
All small-scale PV Installations	2,961	3,192	3,350	3,558	3,749

Table 15: Projected number of installations of small-scale systems

	2021	2022	2023	2024	2025
ACT	4,902	5,226	5,837	6,084	6,506
NSW	95,505	106,524	111,944	118,207	124,267
NT	1,203	946	1,047	1,150	1,252
QLD	87,285	92,979	97,144	103,571	108,629
SA	28,011	21,133	17,455	15,065	13,435
TAS	4,352	5,049	5,999	6,246	6,718
VIC	69,805	69,805	69,805	69,805	69,805
WA	51,079	49,335	46,383	52,176	52,027
Commercial <15kV	11,845	17,872	21,985	24,488	19,727
Commercial 15kV-90kV	7,520	7,038	7,183	7,413	5,874
Commercial 90kV-100kV	771	1,314	1,378	1,111	519
All small-scale Installations	362,280	377,221	386,160	405,316	408,759

Appendix B. ARIMA Model Exogenous Variables

The following table outlines a description of the exogenous variables utilised in the ARIMA time series models.

Independent Variable	Source	Explanation - impact
Electricity Price ($/MWh)	ABS Historical price-index for electricity for each capital city. Jacobs' retail and wholesale price forecasting models for projections.	The electricity price is the first of the two major benefits from a small-scale rooftop solar PV system. As the small-scale PV system is built behind the meter it is able to displace electricity usage from the grid and therefore generate equivalent benefits for the residential customer. We expect there will be a positive significant correlation between the electricity price and the PV uptake in the models we specify, as higher electricity prices will increase potential benefits of rooftop solar PV.
Net capital cost ($)	Data obtained via Solar Choice website. Projections based on CSIRO GenCost cost reduction rate.	The variable includes the capital cost per kW of a small-scale rooftop PV systems over time, reduced by the benefits from the STC rebate. The expectation is that with decreasing capital costs the uptake of small-scale rooftop solar PV will increase and visa-versa. Therefore, we are expecting a negative correlation with the dependent variable.
Cash rate	The Reserve Bank of Australia (RBA). We assumed the cash-rate plus a 2.5% mark-up.	The cash rate is an indicator for the home loan rates and subsequent cost of capital for a residential customer or an opportunity cost for cash savings. The residential customer is likely to finance the PV system through their mortgage or if they have savings, forgo the return on a savings account in favour of an investment in a rooftop PV system. We expect that the cash-rate correlates negatively with the uptake of small-scale solar PV as higher rates will make the direct cost and/or opportunity cost of taking up small-scale PV higher and therefore should reduce the uptake and vice-versa.
Gross State Product (GSP), Gross Domestic Product (GDP)	ABS time series 5220 – Australian National Accounts: State Accounts	Gross State Product is a variable that provides a proxy for the economic health of the respective State and is used in most econometric time-series models as a control variable. The GSP indicates whether the economy of the state as a whole is contracting or expanding. The expectation is that expanding economies will see higher general levels of investment and therefore we expect a positive correlation with small-scale PV uptake. For commercial projections we have used the aggregated state products of all states and territories as these projections are nationwide.
State Population, Aggregated State Population	ABS time series 3101 – Australian Demographic Statistics	State population as a stand-alone variable has not been considered in the modelling but rather used as a component of an interaction variable as described below. For commercial projections we have used the aggregated state population as these projections are nationwide.

Appendix C. ARIMA Time Series Models

A range of variables were tested. The final model was selected based on a number of parameters including goodness of fit tests (e.g. AIC), residual analysis (e.g. Durbin-Watson statistic), significance of included independent variables and Ljung-Box test.

The final variables selected for each model are:

New South Wales:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- A dummy to represent the impact of COVID-19.
- One autoregressive term, one order of differencing and one seasonal order of differencing.

Queensland:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- A dummy to represent the impact of COVID-19.
- One dummy to represent high outliers in the input sample.
- One autoregressive term, one order of differencing and one seasonal order of differencing.

Northern Territory:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- A dummy to represent the impact of COVID-19.
- Two autoregressive terms, one order of differencing and one seasonal order of differencing.

Western Australia:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- The natural log of the Electricity Price – log(ElecPrice).
- A dummy to represent the impact of COVID-19.
- One dummy to represent outliers in the input sample.
- One autoregressive term, one order of differencing and one seasonal order of differencing.

Tasmania:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- The natural log of the Electricity Price with a lag of 4 – log(ElecPrice)(-4).
- One dummy to represent outliers in the input sample.
- One order of differencing, one seasonal autoregressive term and one seasonal order of differencing.

South Australia:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- The natural logarithm of the Gross State Product divided by the Population – *GSP/POP*.
- A dummy to represent the impact of COVID-19.
- One dummy to represent outliers in the input sample.
- One order of differencing, one seasonal autoregressive term and one seasonal order of differencing.

Australian Capital Territory:

- The Cash Rate multiplied by Net Capital Cost of residential systems squared – *(CSH_RATE*NET_CAPITAL)^2*.
- A dummy to represent the impact of COVID-19.
- One dummy to represent high outliers in the input sample.
- One order of differencing, one seasonal autoregressive term and one seasonal order of differencing.

Commercial Systems < 15kW:

- The Gross Domestic Product divided by the Population with a lag of 6 – *GDP(-6)/POP(-6)*.
- A dummy to represent the impact of COVID-19.
- One autoregressive term, one order of differencing and one seasonal order of differencing.

Commercial Systems 15-90 kW:

- The natural logarithm of the Gross Domestic Product divided by the Population – *log(GDP(-4)/POP(-4))*.
- The Net Capital Cost of commercial systems – *NET_CAPITAL*.
- A dummy to represent outliers in the input sample.
- One autoregressive term, one order of differencing and one seasonal order of differencing.

Commercial Systems >90 kW:

- The natural log of the Gross Domestic Product divided by the Population – *log(GDP(-5)/POP(-5))*.
- A dummy to represent the impact of COVID-19.
- One autoregressive term, one order of differencing and one seasonal order of differencing.