Clean Energy Regulator
Stage 1: Small-scale Technology Certificate Projections

Final

Clean Energy Regulator
IS478100

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Jacobs Group (Australia) Pty Limited

Floor 13, 452 Flinders Street
Melbourne, VIC 3000
PO Box 312, Flinders Lane
Melbourne, VIC 8009
Australia

T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

Executive summary

The Clean Energy Regulator (CER) is responsible for administering Australian Government schemes for measuring, managing and reducing or offsetting Australia's carbon emissions. One of these schemes is the Small-scale Renewable Energy Scheme (SRES).

The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems. It does this through the creation of small-scale technology certificates (STCs), which Renewable Energy Target (RET) liable entities have a legal obligation to acquire and surrender to the CER on a quarterly basis.

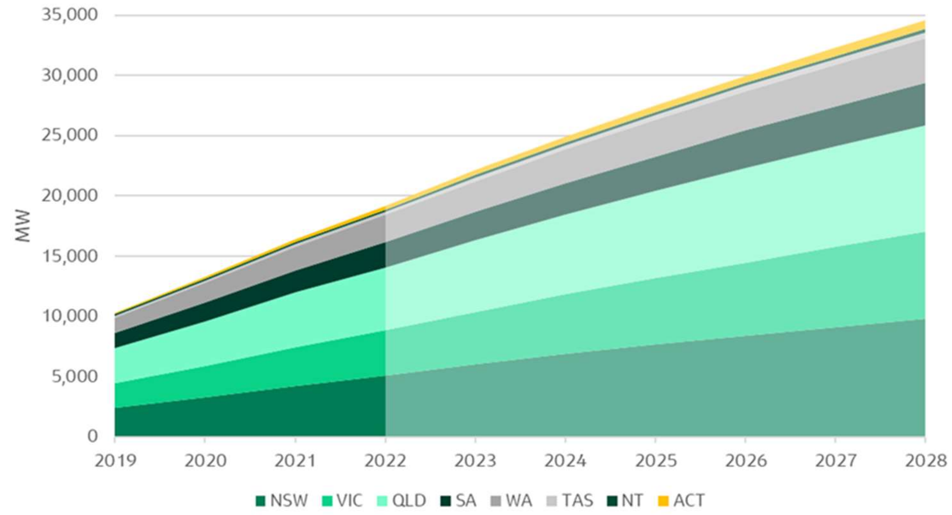
Participants can trade STCs on the open market, which enables the option of a varied STC price reflective of the market's supply and demand. Alternatively, scheme participants have the option of trading small-scale technology certificates (STCs) at a fixed price of $40 per certificate through the STC clearing house which is maintained by the CER.

Jacobs has been engaged by the CER to forecast the number of STCs and the installed capacity of small-scale solar PV systems in the calendar years of 2023 to 2028, inclusive.

Forecasting the installation of distributed energy resources (DER) is complex, and uptake occurs at different rates in residential and commercial sectors of the market. To project the uptake of DER in both sectors, Jacobs has employed an in-house agent-based model. Agent-based modelling is a bottom-up approach that models unique agents at the micro-level to simulate customer level decision making. The agents represent Australian households and businesses that are autonomous, have internal behaviours and characteristics, and make decisions in response to exogenous and endogenous factors. To forecast the creation of STCs for solar water heaters (SWH) and air source heat pumps (ASHP) Jacobs has used a time-series ARIMA model.

As illustrated in Figure 1, the projected cumulative installed rooftop PV capacity increases over the forecast period, rising from 21,926 MW at the end of 2023 to 34,434 MW by the end of 2028.

Figure 1: Small-scale PV state forecasts, cumulative installed capacity



Installed capacity in 2022 was the first year that marked a slowdown in annual uptake, following record growth in 2020 and 2021. This was largely attributed to the stagnated trend in rooftop solar PV system costs, and the continued decline of feed-in tariffs in many states. However, a slight rebound in annual installed capacity is expected by the end of 2023, with 2,977 MW[1] of capacity compared to 2,762 in 2022.

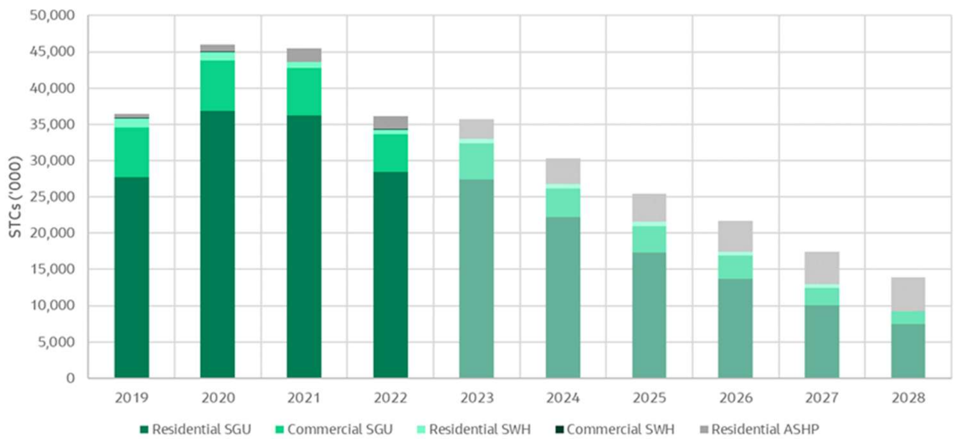
[1] Including 12-month creation estimates

Across the east coast of Australia, the National Electricity Market (NEM) had experienced prolonged periods of extremely high wholesale electricity prices. This was largely a result of the undersupplied global gas market, ultimately caused by the economic sanctions imposed on Russia. These sustained prices in the wholesale market will flow through to retail electricity prices from the second half of 2023 and is expected to re-incentivise a new wave in rooftop PV installations. However, the reduction in rooftop PV costs has slowed to the point of being outpaced by the reducing STC deeming period especially as current global inflationary pressures are expected to remain high for the near term. Further, the feed-in tariffs in a few states continue to fall despite increasing wholesale prices. These outcomes therefore act to offset the positive economic incentives brought on by the increasing retail prices. Annual uptake in 2024 is expected to remain relatively steady with 2,756 MW of total rooftop PV capacity by year-end.

System costs in 2026 are forecasted to cease falling and slightly rise as the diminished deeming period of STCs has fully outpaced any cost decline from technological innovation. Retail electricity prices and feed-in tariffs also continue falling, creating comparatively less attractive payback periods. Installed annual capacity is expected to continue declining with 2,303 MW of annual rooftop PV capacity in 2027, and 2,285 MW in 2028.

Figure 2 illustrates the STC creation projections by sector, including STCs created from installations of solar PV and hot water systems (wind and hydro STCs make up a negligible portion). In 2023, it's projected that a total of 36.2 million STCs will be created, which despite having an increase in SGU capacity, is slightly less than 2022.

Figure 2: Total STC annual projections



Overall trends in STC forecasts are largely linked to residential rooftop PV installations, which comprise the largest portion of STCs created. Commercially sized solar hot water units are expected to maintain their relatively low level of uptake with little influence on STC creation over the forecasting period. It is expected that domestic solar hot water systems will continue a steady decline. However, the recent climb in uptake of air source heat pumps is expected to continue for the remainder of the forecast horizon.

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Tables and figures

Acronyms and abbreviations

ABS	Australian Bureau of Statistics
ABM	Agent based model
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASHP	Air source heat pump
BESS	Battery energy storage systems
CER	Clean Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DLF	Distribution loss factor
ESC	Essential Services Commission (Victoria)
ERA	Economic Regulation Authority (Western Australia)
FiT	Feed-in tariff
FY	Financial year
IPART	Independent Pricing and Regulatory Tribunal
kW	Kilowatt
kWh	Kilowatt-hour
LRET	Large scale renewable energy target
LV	Low voltage
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales
NT	Northern Territory
OTTER	Office of the Tasmanian Economic Regulator
PA	Per annum

PV	Photo-voltaic
PWC	Power and Water Corporation
QCA	Queensland Competition Authority
QLD	Queensland
RET	Renewable energy target
SA	South Australia
SA3	Statistical Area Level 3
SGU	Solar generation unit
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificate
SWH	Solar water heaters
TAS	Tasmania
TLF	Transmission loss factor
VIC	Victoria
VPP	Virtual power plant
WA	Western Australia
WEM	Wholesale Electricity Market

1. Introduction

The Clean Energy Regulator (CER) is responsible for administering Australian Government schemes for measuring, managing and reducing or offsetting Australia's carbon emissions. One of these schemes is the Small-scale Renewable Energy Scheme (SRES).

The SRES is designed to achieve the following objectives:

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

The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems. It does this through the creation of small-scale technology certificates (STCs), which Renewable Energy Target (RET) liable entities have a legal obligation to acquire and surrender to the CER.

Participants can trade STCs on the open market, which enables the option of a varied STC price reflective of the market’s supply and demand. Alternatively, scheme participants have the option of trading small-scale technology certificates (STCs) at a fixed price of $40 per certificate through the STC clearing house which is maintained by the CER.

Whilst there is a limit on the number of STCs created for each eligible installation, there is no cap on the total number of STCs that can be created within the scheme. STC creation is based on an estimate of the amount of electricity that will be generated or displaced by the renewable energy sources over their economic lifetime. Because of this, the number of STCs created is influenced by the geographical location of the asset.

Up until the end of 2016, each installed system could create certificates equivalent to 15 years of expected generation from the system for small generating units and equivalent to 10 years for a renewable water heater. From 2017, the number of STCs per unit is calculated over a deeming period one year less than the previous year, with the intention being that the number of STCs created per eligible installation reduces to 2030.

The purpose of this report is to provide forecasts of the number of STCs that will be generated in the calendar years 2023 to 2028, inclusive. In developing this report, Jacobs has executed following tasks:

- Modelled expected small-scale technology installations (≤100 kW) and provided updated SRES forecasts for 2023-2028.
- Identified key factors affecting the type, number, and size of small-scale system installations and the trends in STC creation for various categories of systems, including residential and commercial uptake across Australian states and territories.
- Reviewed and updated previously developed models and methodologies to improve the accuracy of projections. Jacobs has identified and analysed changes to circumstances and trend breaks, and/or including alternative estimators. An in-house approach founded on agent-based modelling is utilised in this study, designed to better capture the impact of structural changes in the STC market.

All analysis and forecasts in this study are based on STCs created in the month of installation, including an estimate of additional STCs for that month to be created over the next 12 months. This report commences in Section 2 with an analysis of trends in the uptake of small-scale systems, followed in Section 3 by a description of current government incentives and solar PV policies. Section 4 describes the method of forecasting STCs, and the assumptions used are described in Section 5. Section 6 presents the results.

2. Trends in uptake

This section provides commentary on trends in the uptake of small-scale PV systems, which comprise the main element of STC creation.

2.1 Small-scale PV Systems

Figure 3 illustrates historical annual installed capacity of residential rooftop PV from (calendar year) 2006 to 2023, inclusive.

Figure 3: Installed residential capacity

Source: Jacobs' analysis of CER data, 2023 estimate

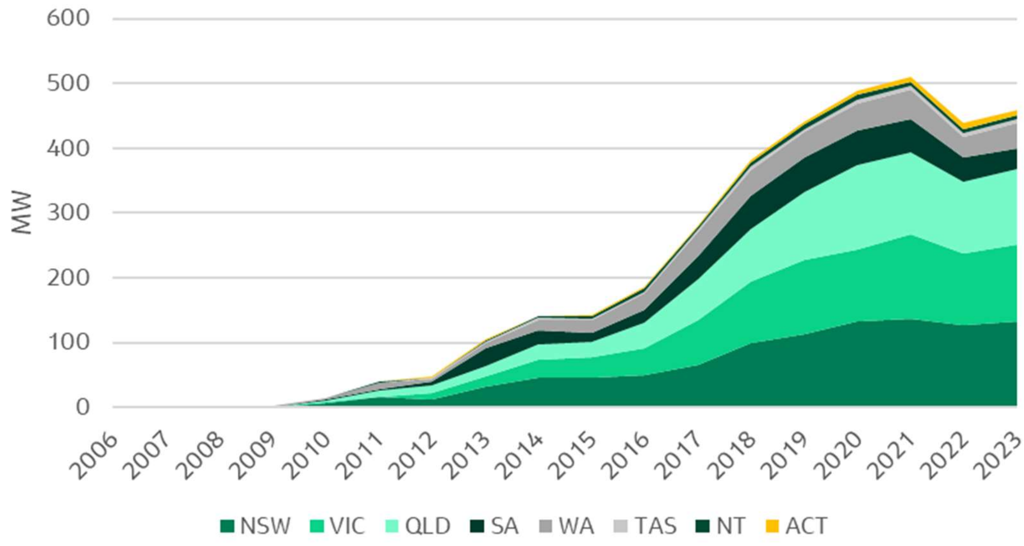
For the six years from 2016 to 2021, there has been an increase each year in annual small-scale PV uptake, including over 2020-2021, defying disruptions from the COVID-19 pandemic. However, 2022 saw a reduction in installed PV capacity, likely the result of a range of transient factors, including:

- The stagnation of capital cost decline.
- Lower feed-in tariff (FIT) rates.
- Wetter than average and persistent wet weather.
- Increased consumer uncertainty and cost of living pressures.
- Scarcity of available installers and tradespeople and supply chain constraints.

However, installed residential rooftop PV capacity is estimated to rebound in 2023. Wholesale electricity prices across the east coast of Australia reached unprecedented highs towards the end of 2022, largely because of record high coal and gas prices (globally, and domestically). In addition to feed-in tariffs subsequently increasing for some states, the widespread anticipation of a similar increase in retail electricity prices is likely to be a key influencing factor in the rebound of rooftop PV uptake.

Figure 4 illustrates the recent trends in installed PV capacity by schools and businesses. As with residential installations, strong growth in uptake has occurred since 2016. A distinct seasonal trend has emerged as businesses hasten to commit to installations prior to annual steps down in rebates applied to small scale technology. The COVID-19 pandemic also appeared not to affect the trend in commercial PV installations, despite the temporary closure of many small-medium sized enterprises. This may be attributable to government incentives that incentivised solar PV installations (such as the instant tax write-off) and growth in businesses that have benefitted from the transformation of the digital work and life environment post-COVID-19, such as data centres and online retailers. However, as with the residential data, there was a slowdown in the rate of growth of commercial solar installations in 2022 but is estimated to rebound in 2023 for similar reasons to those described for the residential sector.

Figure 4: Annual installed commercial capacity

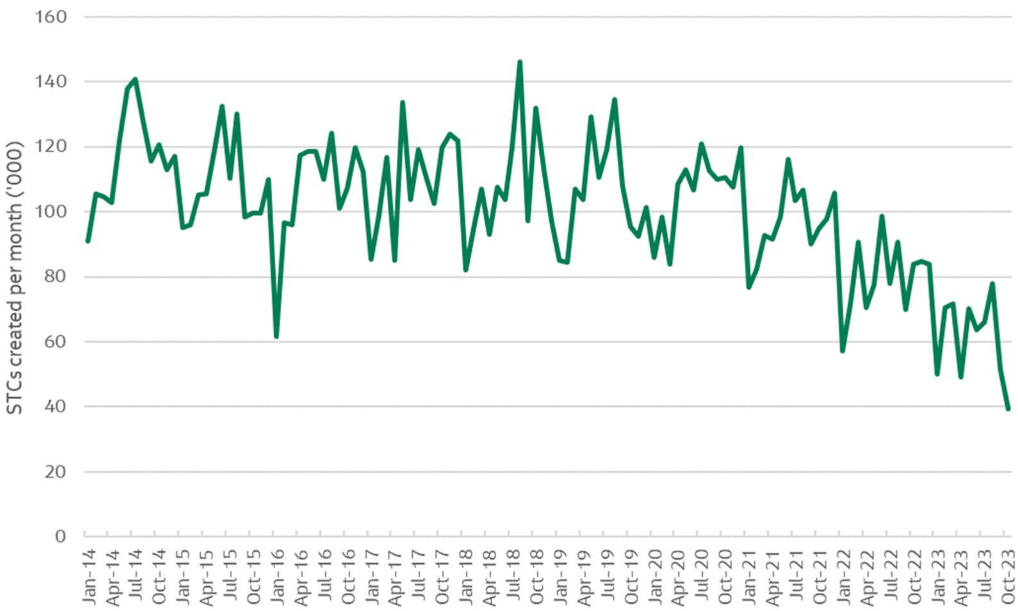


Source: Jacobs' analysis of CER data, 2023 estimate

2.2 Solar water heaters

Figure 5 shows the historical trend in the creation of STCs from installations of residential solar water heaters (SWH) from January 2014 to October 2023. There is a mild decline evident over the last four years; COVID-19 appears to have had a mildly negative impact on the sector, although the recent decline coincides with the acceleration of ASHP (see section 2.3).

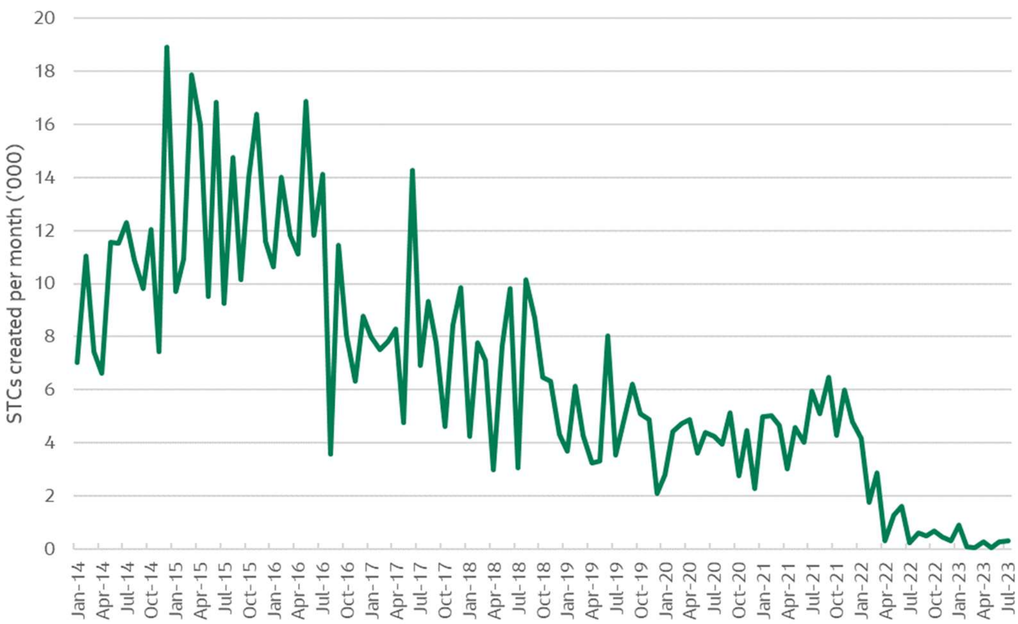
Figure 5: Monthly trend in STC creation from residential SHW



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, and a further decrease of around 80% in 2022, as can be seen in Figure 6. Monthly STCs dropped to a 20-year low in May 2023, most likely due to ASHP gaining rapid popularity within the commercial sector. Since the introduction of the NSW Peak Reduction Certificates (PRCs) in November 2022, businesses can receive additional incentives on top of energy savings certificates which has attributed a rise in commercial ASHP installations.

Figure 6: Monthly trend in STC creation from commercial SHW



Source: Jacobs' analysis of CER data

2.3 Air-sourced heat pumps

Historically, there was a brief period around 2011 when ASHPs were installed at commercial sites. However, no such units have been awarded STCs since 2013 and all units generating STCs presently are exclusive to the residential sector. Therefore, commercial installations of ASHPs have not been forecast.

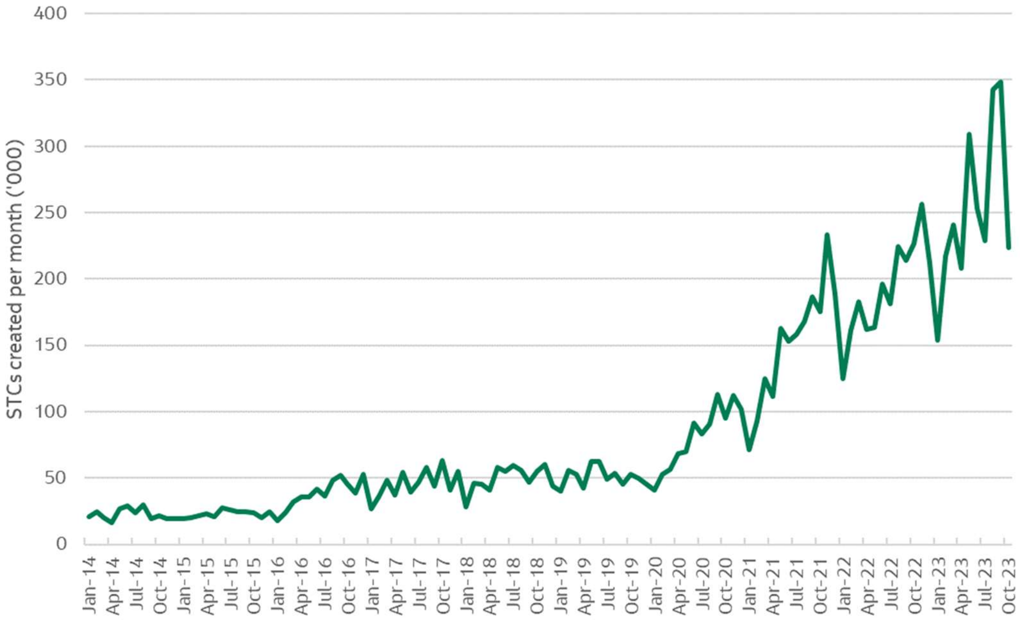
Figure 7 shows the monthly trend in uptake of residential ASHP. Uptake has been trending up since 2014, but a rapid acceleration has occurred since mid-2020. A distinct seasonal pattern has occurred in the last few years with monthly STC creation peaking each November before the year-end.

The uptake of ASHP has continued to accelerate throughout 2022 and 2023, with September 2023 being the highest month on record for STC creation from this technology.

Drivers for the uptake of ASHP appear to be:

- A growing acceptance of electric based ASHP, particularly in new housing estates.
- Additional support from some state governments.
- The fact that 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.

Figure 7: Monthly trend in STC creation from residential ASHP



Source: Jacobs' analysis of CER data

3. State government incentives and policies

The number of STCs created 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, state-based FiT schemes, and building standards. The energy efficiency building standards impact the choice of water heaters installed in new houses. The forecasts provided by Jacobs account for government policies and programs explicitly or implicitly.

3.1 Government policies

In terms of policies, the state-wide blackout in South Australia during September 2016 resulted in the South Australian Government shifting from providing energy saving incentives based on renewable generation to ones based on energy storage, such as the residential BESS program described below in Section 3.2.3. South Australia has also given the Australian Energy Market Operator (AEMO) authority to curtail rooftop solar when necessary for system benefit. New inverter standards for new rooftop solar installations have been enforced to enable AEMO more visibility and control of rooftop systems. However, it is expected that curtailment of rooftop solar will only occur under extreme circumstances, and therefore it is likely these rules will not have considerable impact on the uptake of PV in South Australia.

Western Australia and the Northern Territory have significantly reduced their standard FiT rates. This reduces the incentives for exports of solar generated power from rooftop systems, due to concerns of the impact of high PV penetration on grid stability. This is discussed further in Section 5.2.4.

3.2 Government programs

In terms of programs, in all jurisdictions in Australia except Tasmania there is in place at least one scheme to encourage the uptake of DER including rooftop solar PV and household batteries. The state-based schemes that may influence the uptake of solar PV and hot water systems are summarised below.

3.2.1 Victorian Solar Homes Program

In August 2018, the Victorian Labor Government announced a new solar rebate scheme for the installation of rooftop solar PV on eligible dwellings. The plan is means tested to households of combined taxable income less than $210,000 and is expected to fund the installation of rooftop PV systems on 720,000 homes over a 10-year period. According to the 2021 Australian Bureau of Statistics (ABS) Census, more than 98% of Victorian households would be eligible for the program as their annual household income is less than $210,000.

Since July 2021, the offer has been open to Victorian households and small businesses who may receive 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. Eligible Victorian residents have also been able to receive an interest free loan for a period of four years to finance the remainder of the cost of installation up to the value of their rebate.

Rebates of up to $2,950 and $1,000 are also being offered to install a solar-battery system or SWH unit, respectively, in eligible dwellings that have not previously received a Solar Homes rebate.

In addition, the Victorian Government has pledged to support uptake of rooftop 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. As of October 2023, the rebate is of $1,400 value.

3.2.2 Victorian Energy Upgrades Program

The Victorian Energy Upgrades (VEU) program was established by the Victorian Energy Efficiency Target (VEET) Act which originally commenced on 1 January 2009, and provides for the VEU program to operate until the end of 2030. The main objectives of the VEET Act are to reduce greenhouse emissions, encourage the efficient use of electricity and gas, and to incentivise investment and technology development in industries which reduce the use of electricity and gas by consumers.

The program provides financial incentives for the replacement of inefficient electric and gas water heaters with either electric boosted solar water heater or an air source heat pump water heater. These are also eligible for STCs under the SRES so the combination of both incentives may boost uptake.

The VEU program specifically establishes minimum energy efficiency requirements for eligible prescribed activities, and the methods needed to establish the amount of greenhouse gas equivalent emissions reduced by each activity.

Targets of 2.7 Mt CO_2-e per annum applied between 2009 and 2011 and were doubled to 5.4 Mt CO_2-e per annum between 2012 and 2016. Targets ramped up from 5.9 Mt CO_2-e in 2017 to 6.9 Mt CO_2-e in 2023. The set targets for 2024 and 2025 are 7.1 and 7.3Mt CO_2-e, respectively. Targets beyond 2025 are not yet defined.

3.2.3 South Australia – Home Battery Scheme

The South Australian Home Battery Scheme, introduced in 2018, comprised up to $100 million in government subsidies available for 40,000 homes for the installation of a BESS. Participating households were eligible to apply for finance to the Clean Energy Finance Corporation.

The battery subsidy was based on the size of the battery and was set at $300 per kWh storage for energy concession holders and $200 per kWh for all other households, with a maximum of $3,000 provided per battery installation. Strict specifications were required to ensure the batteries could also be aggregated to a Virtual Power Plant (VPP), although the participating household could choose whether to operate their battery as part of this system. The subsidy was open to households from October 2018 but was closed for applications in June 2022 due to low participation.

While the batteries themselves do not contribute to STC creation, they increase the benefit to households of load shifting and may encourage the installation of rooftop PV and battery packages, and may also encourage the installation of larger rooftop PV systems.

3.2.4 Australian Capital Territory – Home Energy Support program

In March 2022, the Australian Capital Territory (ACT) Government launched its Home Energy Support Program, which commits $50 million over four years. Eligible households can receive a rebate of up to $2,500 for the installation of a rooftop PV system and the option to finance the remaining costs with an interest-free loan. The second phase of the program offers an additional $2,500 rebate for heating and cooling systems, hot water heat pumps, and other energy efficiency products. Initially, eligible homes must be valued up to $750,000 based on the property's 2020 unimproved land value. However, as of July 2023 this criterion has been restricted to homes with an unimproved land value of less than $450,000.

4. Methodology

Forecasting DER is complex, and its uptake occurs at different rates, in different locations, and across different customer segments. Subject to exogenous constraints such as technical limits, technology choice, and environmental and regulatory factors, DER uptake is based on a combination of economic and non-economic behavioural factors.

Economic return depends on a range of price and cost factors such as income, underlying energy demand, electricity tariffs, and the cost of DER systems (both upfront capital and ongoing operation and maintenance), which together produce an accepted payback period for uptake.

The non-economic factors that can accelerate or decelerate an investment decision are largely behavioural and societal, such as additional value placed by an individual or a business on 'doing the right thing' for the environment, becoming energy independent or 'being seen to be contributing' to better community outcomes. In some cases, particularly for established technology, these influences are captured in historical data on decision making. In other cases, and particularly for newer technologies, these influences need to be assumed.

Overlaying this, some factors may have more permanent effects and others may be temporary or change over time. For example, the impact of COVID-19 has resulted in some persistent work-from-home trends that have the impact of increasing residential electricity use while mostly reducing commercial use. But recessionary impacts or those that relate to consumer confidence are generally temporary.

To account for all these factors, a bespoke agent-based model was employed to represent the households in each State across Australia to project their uptake of solar PV systems. However, for the projection of solar water heaters, and air source heat pumps, a secondary time-series ARIMA model is utilised. Both models are partly based on expected payback periods from installing new systems, as the main driver of uptake, with the payback periods influenced by projected trends in the cost of systems, level of government subsidy and expectations around future revenue streams, namely retail and feed-in tariffs. Transient or temporary drivers observed recently are reflected in trends on installation costs (with a return to long term trends projected), and an assumption that current shortfall in labour material dissipate over a two-year period. In the ARIMA model the impact of transient factors are captured through the residuals. And to the extent these have been changing it will be observed in changes in the residuals over time.

Under the SRES scheme, small generation units cover rooftop PV, wind, and hydro systems up to 100 kW in capacity. However, small-scale wind and hydro units have historically represented a negligible proportion of STCs (less than 0.02%), so only the future uptake of rooftop PV systems are considered in this study.

4.1 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 appropriate decisions (in terms of their assumed decision criteria) in response to both exogenous and endogenous factors.

Unlike traditional modelling approaches, agent-based modelling creates heterogeneity between agents, and may enable interaction among agents to influence behaviour and outcomes. This approach is especially suitable for modelling intricate, non-linear, and interrelated parameters in unstable and complex environments.

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 price signals, such as electricity price increases and falling technology costs, and macro-economic, technological, policy, and electricity-related variables to simulate the magnitude of DER installation over the next six years.

There are several steps to creating an agent-based model, as are described in the following sections, starting with setting up, or initialising, the agents in the model.

4.2 Agent initialisation

Agents are split into two broad groups – residential and commercial. Basic attributes are assigned to agents to proportionately reflect the real world, such as whether they are a renter or an owner-occupier. These exogenous variables are held fixed across the modelling time horizon for existing agents. However, the proportion of these variables may change over time. Therefore, new agents that are created as population grows may be assigned attributes in differing proportions to those assigned to the initial set of agents.

4.2.1 Residential agents

Residential agents are initialised with the following parameters:

- Location.
- Dwelling type (e.g., detached house, townhouse, apartment).
- Tenure type (e.g., owner-occupier, renter).
- Solar PV penetration status.

Parameters are initialised using available local information and/or ABS data and are allocated to agents based on cumulative probability distributions. Heterogenous location assignment is important because it allows agents from different regions to have different behaviours and characteristics. Within a region, it is assumed all agents share the same characteristics.

The dwelling and tenure type probability distributions are unique to each region. That is, each region has a dwelling and tenure type profile that is particular to that area.

In terms of rooftop suitability, this can be determined in different ways and depends on the circumstances of the environment being modelled. In some cases, there is publicly available satellite data to inform the proportion of rooftops and types of dwellings that have the potential to take rooftop solar panels. In most cases, an assumption is made based on which dwelling types can take solar, and upper saturation limits are applied. A common assumption is that only homeowners living in a detached dwelling (i.e., house, townhouse, or terrace) are likely to adopt a rooftop solar PV system, with renters and/or those living in apartments, flats, caravans, and so forth assumed to not purchase these systems.

To account for current penetration levels, the appropriate number of agents is assigned a rooftop PV system at the commencement of the model.

4.2.2 Commercial agents

Unlike residential households, businesses do not have the same degree of behavioural variation across regions. Rather, it is the size and electricity consumption of a business that presents a better point of differentiation. Therefore, while commercial agents are initialised with a region in the model, they are also assigned to an ‘underlying demand segment’ and are assumed to make decisions relating to their electricity consumption.

Within commercial agents, businesses are separated into schools, small businesses, and large businesses, depending on the availability of data. These groups of agents are modelled separately to each other because they are associated with different levels of demand, DER capacity, and retail tariffs, and sometimes subject to different regulation.

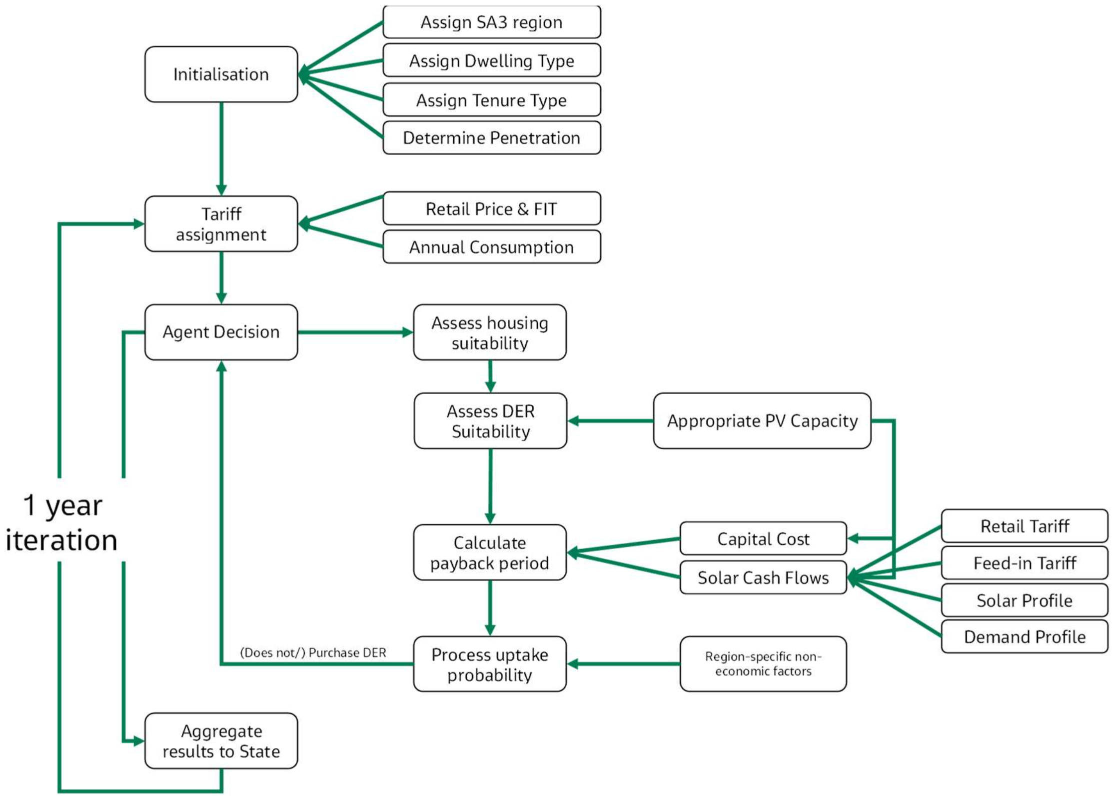
Like residential agents, the current penetration level for commercial agents is assigned at the commencement of the model based on available data.

Businesses tend to act in a more economically rational way relative to households. Therefore, it is assumed that commercial rooftop PV systems are optimised to their electricity consumption and are not oversized. Under this assumption, every commercial customer is assigned a system capacity based on their individual electricity consumption, not on their region's historical average capacity.

4.3 Economic agent decisions

Once agents are initialised, electricity tariffs are assigned, including retail prices for grid consumption and FiTs for electricity exports to the grid (from solar PV). Subsequently, a range of other price and non-price factors affecting an agent's decision of whether to take up solar systems are incorporated in the model, such that each agent follows a defined set of decisions. This set of decisions is illustrated in Figure 8 for a residential agent, and a commercial agent follows a similar path.

Figure 8: Residential agent framework



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

- Retail tariff.
- Feed-in tariff.
- Annual consumption.
- Hypothetical PV system capacity.
- Hypothetical BESS capacity.
- Associated capital costs.
- Operational and maintenance costs are assumed to be zero.

Using these assigned values, the agent calculates the average net cashflow that its system will provide over its assumed life, accounting for factors such as PV degradation. In these calculations, the retail tariffs and FiTs that reflect the customers' current situation are typically used. However, agents may also consider how these tariffs are anticipated to change in subsequent years. This is discussed in further detail in Section 4.4.

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 1 and Table 2, respectively.

Table 1: Cash flow equation variables

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

Table 2: Cash flow equation constants

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 across the system's assumed 20-year life. This is represented by the following equation, with the variables described in Table 3:

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

Table 3: 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	%

4.4 Uptake functions

Hundreds of thousands of households and businesses may calculate the same payback period for rooftop solar PV, yet they do not all make the same purchasing decisions. Despite sharing similar economics, people make different DER investment decisions due to factors like socioeconomic conditions, neighbourhood influence, beliefs, or different levels of awareness and understanding of the technology.

An uptake function is created and used to calculate the probability of uptake based on key economic parameters (e.g., payback period) to account for these real-world behavioural differences.

A solar uptake function analyses the historical rooftop PV uptake of eligible households and businesses in each region and plots the corresponding historical payback periods during each historical year. Various regressions are conducted to model different behaviours using a mix of linear and exponential equations. These behaviours include responsiveness to a certain level of DER economics or capturing the 'fear of missing out' (FOMO) effect from reducing feed-in tariffs and solar cash flows. With every timestep in the model, each agent calculates the payback period for a solar PV system. These metrics become an input to the relevant uptake function to calculate the probability of solar PV uptake.

4.5 Time-series modelling

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.

The water heater data were modelled by the number of STCs registered since, unlike PV, these time series were not distorted by a multiplier[2] 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 Australia. The projection also considers deeming reductions in future years.

[2] 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" Jacobs avoids performing time series analysis on the STC variable for rooftop PV systems. Instead, Jacobs chooses either to model installation numbers in combination with average capacity installed or to model capacity directly.

5. Inputs and assumptions

This section discusses the key assumptions used in the agent-based forecasting model. The model was built to forecast solar uptake for Australia's 336 SA3 regions, which are then aggregated to the state level. A range of de-identified rooftop PV data was supplied by CER, which informed historical, and future rooftop PV uptake.

5.1 Initialisation assumptions

As discussed in Section 4.2, agents are segmented into residential or commercial customers. The initialisation assumptions for each group are described in the following sub-sections, and Table 4 provides a summary of the data sources.

Table 4: Customer initialisation data sources

Category	Assumption	Source	Granularity
Residential demographics	Residential customer numbers and location	ABS Census 2021	SA3
	Dwelling type and tenure type	ABS Census 2021 microdata	
	Existing solar PV penetration	CER 2023	
Commercial demographics	Network system business customer numbers	AER, ESC, ERA, PWC	State
	Existing solar PV penetration	CER 2023	
School demographics	Existing solar PV penetration	CER 2023	
	Number of schools and location	ABS	
Historical residential energy characteristics	Energy consumption	AER, ESC, AusGrid, Essential Energy, Energex, Ergon Energy	SA3, Climate Zone
	Retail tariff	AER, ERAWA, ESC	State
	Feed-in tariff	IPART, ESC, QCA, Synergy, OTTER, NT Gov	
	Average retail bill	AER, IPART, ESCOSA	
	Solar profile	AEMO NemWeb	
	Capital costs	Solar Choice	
	Demand profile	CSIRO	National

5.1.1 Residential demographics

Information on residential customer numbers, location, dwelling type, and tenure type were sourced from the latest 2021 ABS census.

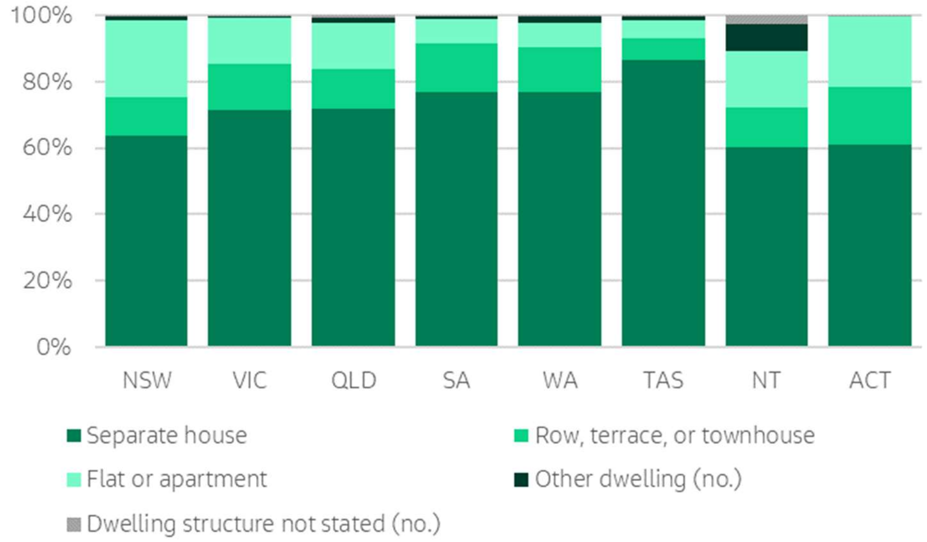
5.1.1.1 Residential dwelling type and tenure type

The ABS census 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.

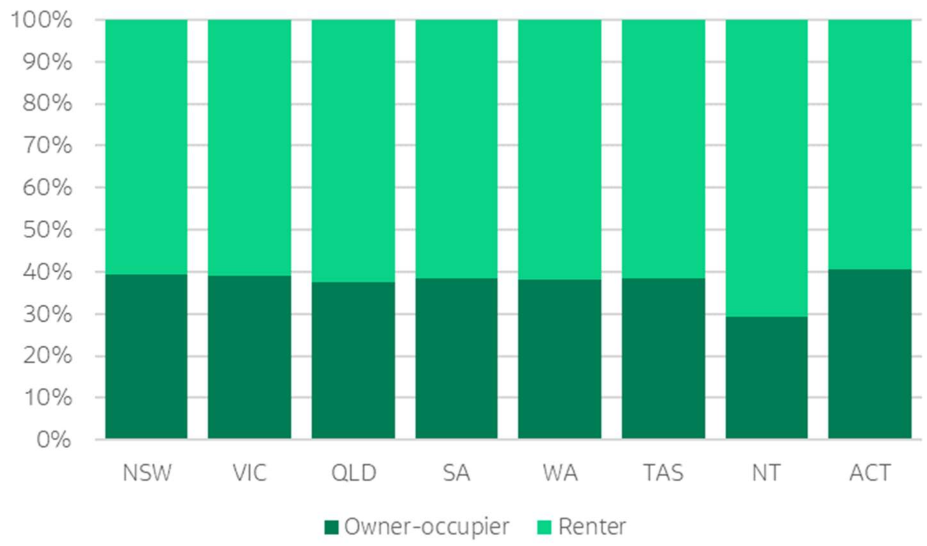
The state aggregated proportions of each dwelling type are illustrated in Figure 9. Out of the mainland states, New South Wales has the lowest proportion of detached dwellings, and the highest proportion of residents living in apartments or flats. Northern Territory, and the Australian Capital Territory also have a low proportion of detached dwellings. Tasmania has the highest share of houses and other detached dwellings.

Figure 9: State dwelling proportions



The state aggregated proportions of each tenure type for detached dwellings are illustrated in Figure 10. All states have similar home ownership rates, except for the Northern Territory which is lower.

Figure 10: Detached dwelling tenure proportions per state/territory



5.1.2 Commercial demographics

Information on commercial customer numbers and location were sourced from various sources, depending on the state.

5.1.2.1 Commercial customer numbers and classification

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 Australian Energy Regulator (AER) for New South Wales, Queensland, South Australia, Tasmania, and the ACT), Essential Services Commission (ESC) for Victoria, and Economic Regulation Authority (ERA) for Western Australia and used for all regions except the 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 5.

Table 5: 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) indicates a consistent distribution of installed capacity sizes over the years, as shown in Figure 11, which is assumed to remain constant throughout the forecast period. It is assumed that commercial rooftop PV systems are optimised to the electricity consumption of the business and are not oversized. Under these assumptions, systems within the same capacity segment, as displayed in Figure 12 and

Figure 13, belong to businesses with similar electricity consumption to each other. While residential agents are assigned proportionately to SA3 regions, commercial agents are assigned to a system capacity segment (representing business consumption and size), based on their business customer type. This segmentation is outlined in

Figure 13: Number of installations by capacity segment, 2021

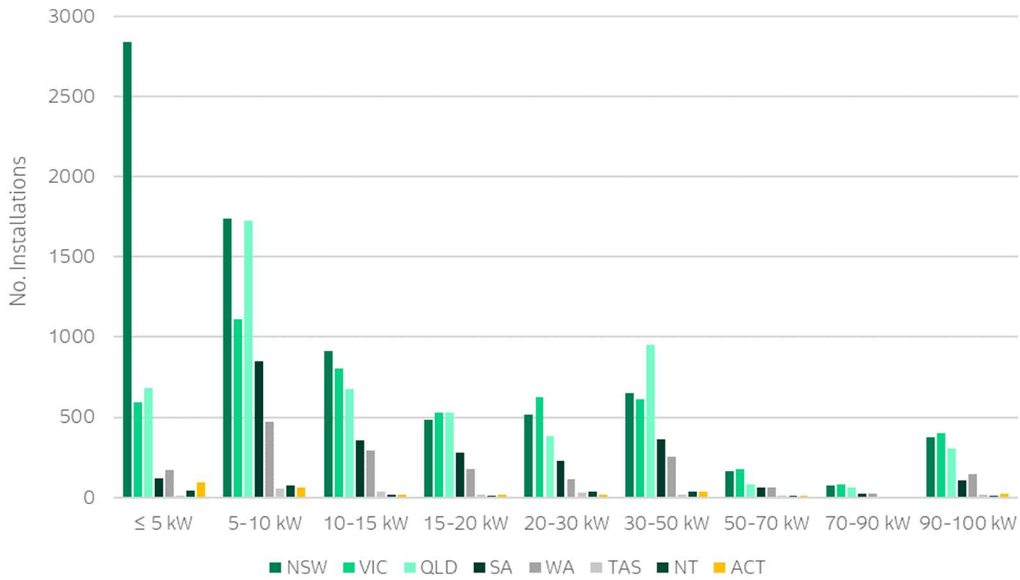
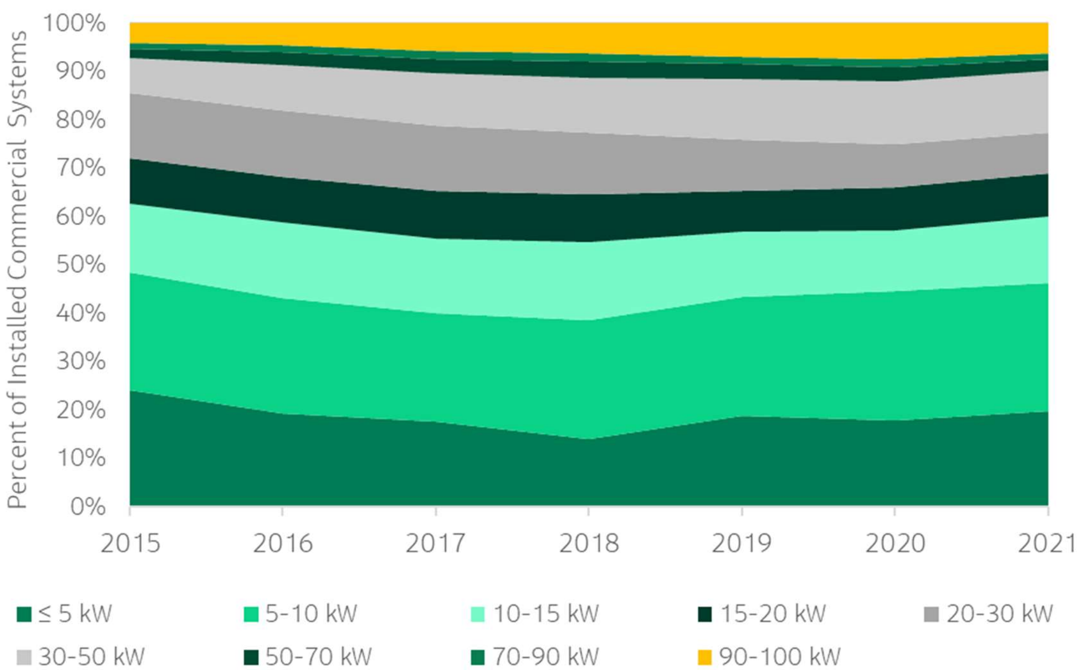


Table 6.

Figure 11: Historical distribution of commercial capacity segments, Australia



Source: Jacobs' analysis of CER data

Figure 12: Commercial capacity segment distribution, 2021

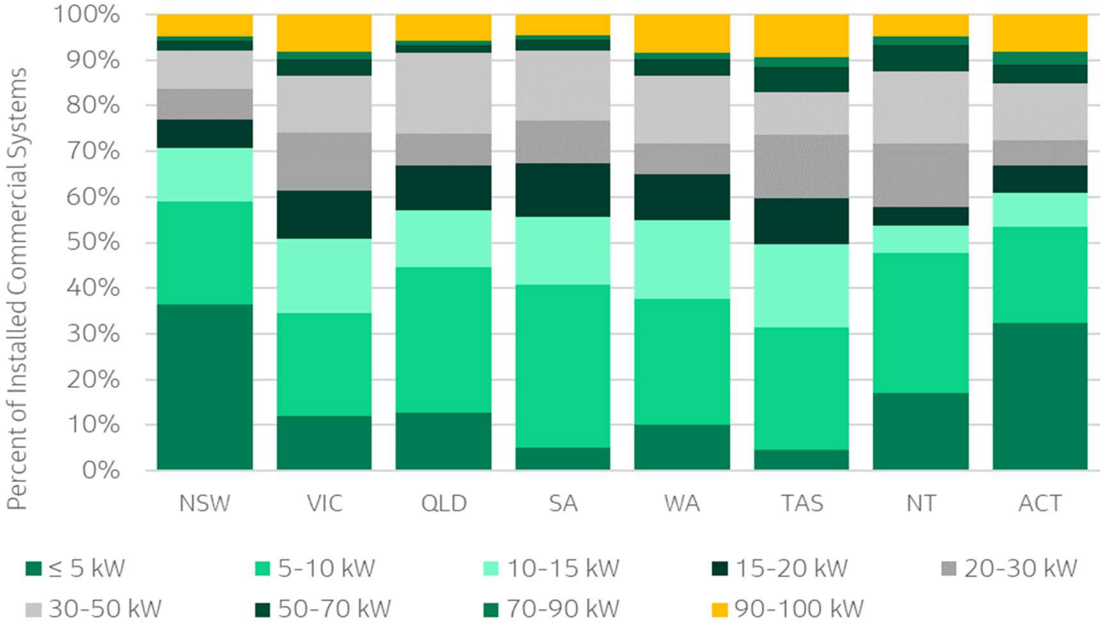


Figure 13: Number of installations by capacity segment, 2021

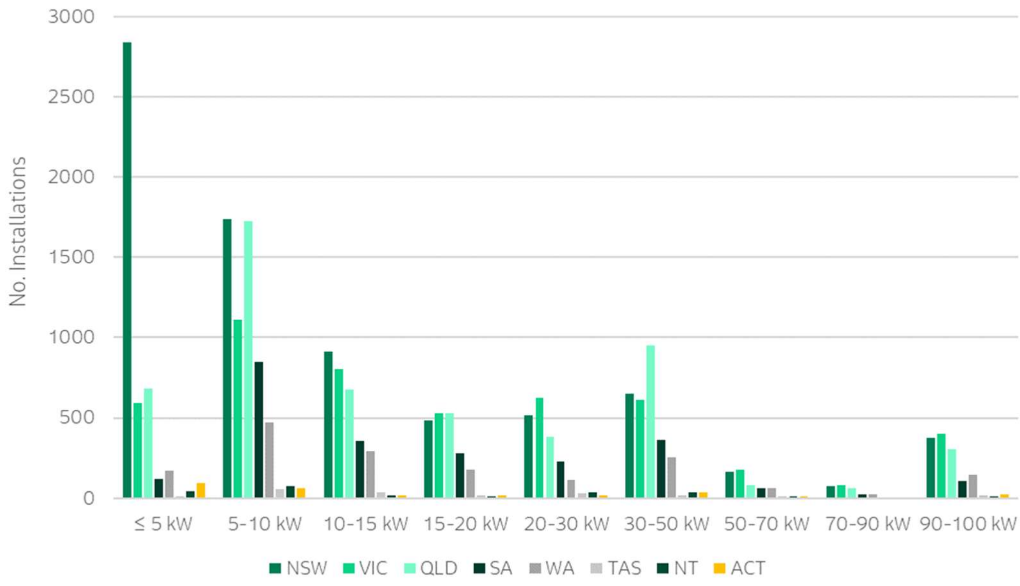


Table 6: Business customer segmentation

<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>5-10 kW</td></tr>
<tr><td>10-15 kW</td></tr>
<tr><td>15-20 kW</td></tr>
<tr><td>20-30 kW</td></tr>
<tr><td>30-50 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>50-70 kW</td><td rowspan="3">Large</td><td rowspan="3">Large</td><td rowspan="3">Large</td></tr>
<tr><td>70-90 kW</td></tr>
<tr><td>90-100 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 commercial and school agents are initialised using CER historical postcode data. Both agents subsequently follow a decision process like that illustrated in Figure 8.

5.1.3 Historical energy characteristics

As well as current data on customer demographics, a range of historical data was used to inform forward projections of underlying demand and solar and battery uptake, including:

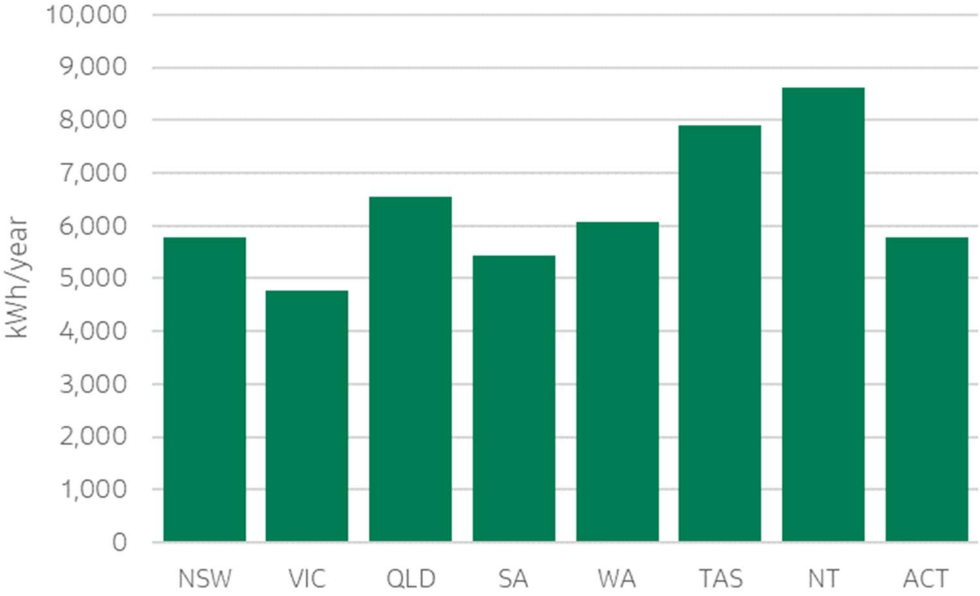
- Energy consumption.
- Retail tariffs.
- Feed-in tariffs.
- Average retail bills.
- Demand profiles.

- Solar generation profiles.
- Capital costs (provided by SolarChoice[3]).
- Installed rooftop PV capacity.

5.1.3.1 Electricity demand

Energy consumption is a critical component of calculating the potential savings for households and businesses of investing in rooftop solar PV. The average electricity consumption per year for each state is shown in Figure 14 using historical data from the AER, ESC, ERAWA, and regional distribution network service providers.

Figure 14: Average residential electricity consumption per annum

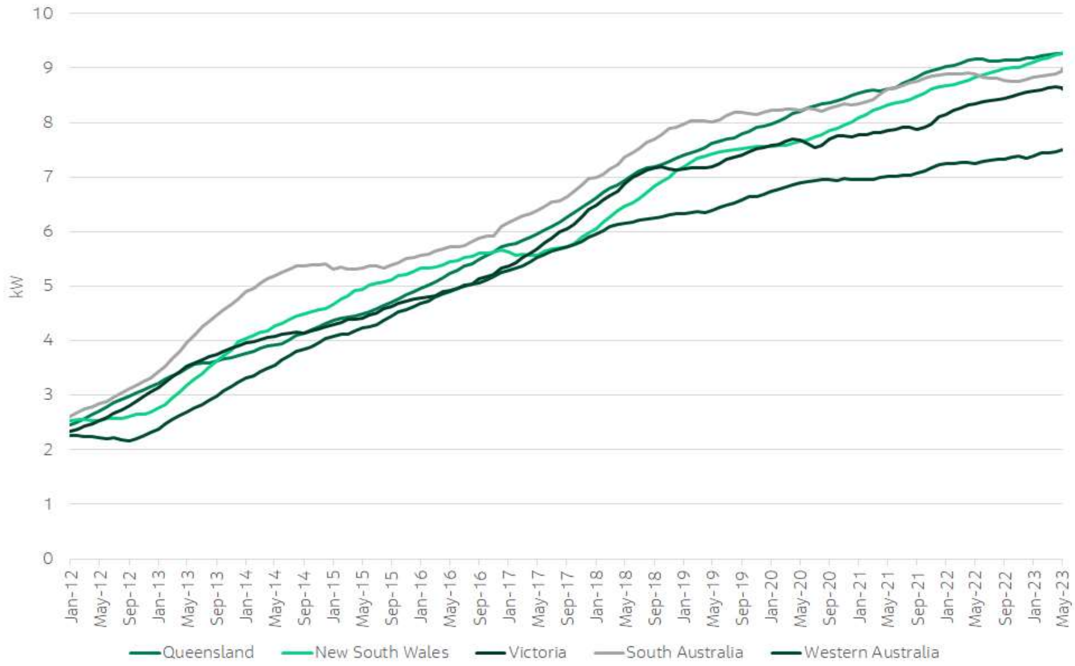


5.1.3.2 Rooftop PV system sizes

Figure 15 shows the trends in average PV system sizes being installed since January 2012. The graph indicates that average system size has continued to grow at a steady rate over the last six months, consistent with growth patterns since mid-2016.

[3] See https://www.solarchoice.net.au/blog/solar-power-system-deals-perth-wa

Figure 15: Trend of average residential PV solar system size, 12 month moving average, selected states



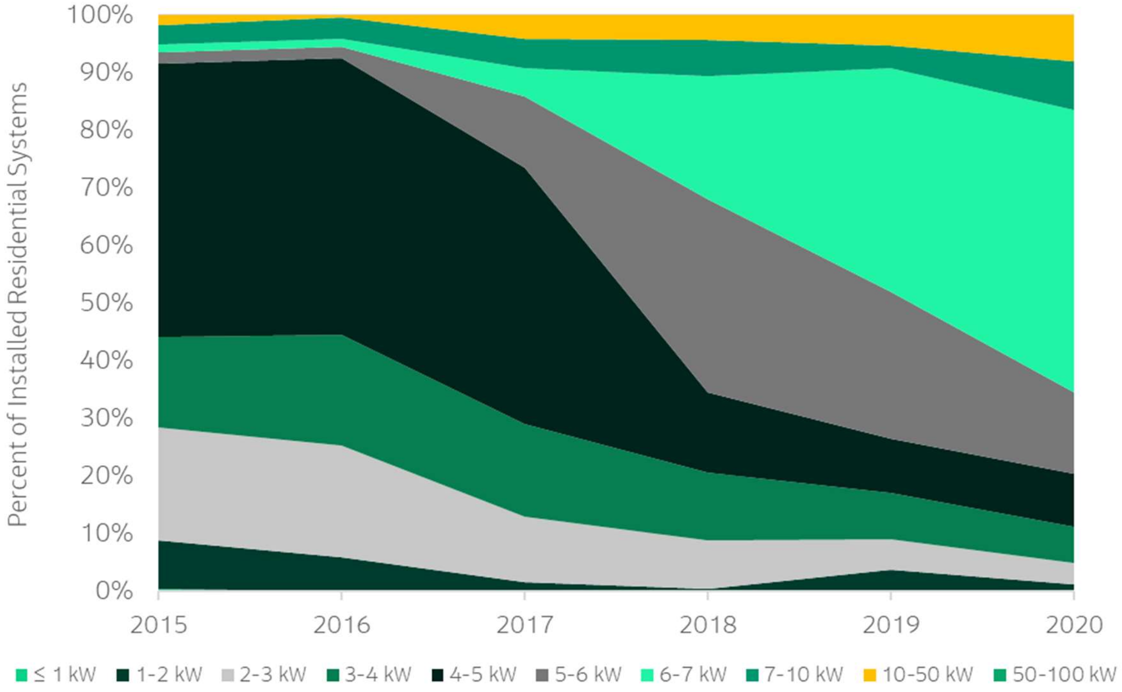
Source: Jacobs' analysis of CER data

Consumers have continued to install larger PV systems. This results in the average household that consumes about 15 kWh/day to export approximately 70% of energy produced from their solar system to the grid. For illustrative purposes, Figure 16 shows the historical capacity distribution in the Latrobe Valley, which indicates a strong emergence in systems of between 6-7 kW in recent years, and a slowly increasing uptake in larger systems of between 7-10 kW.

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

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

Figure 16: Historical residential system capacity distribution, Latrobe Valley



Source: Jacobs' analysis of CER data

Average system sizes will not likely continue to grow at the observed linear rate. 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 residential PV systems to a capacity of about 6.6 kW. This restriction combined with limited roof space, is expected to eventually curtail the average system size for residential properties. Power curves have been fitted in each SA3 region to reflect this assumed reduction in growth in system size to level at around 7.5 to 9.5 kW.

5.1.4 Time lag to registration

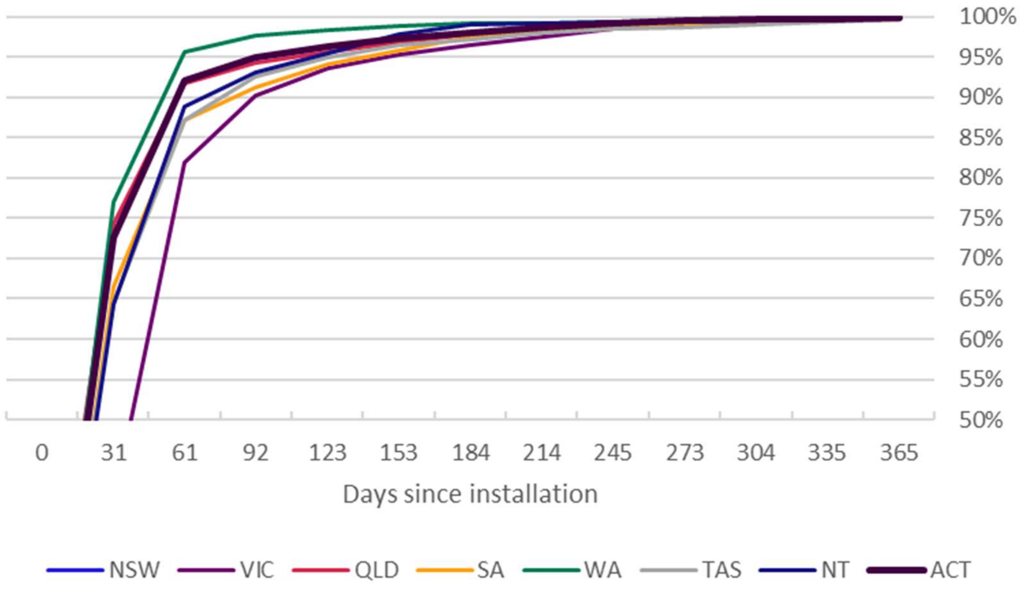
As there is a 12-month window from the date of installation in which to register eligible systems, the most recent registrations database will be missing records of systems that have already been installed, but which have not yet been registered. If not corrected, this will lead to an underestimate in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

The average duration between system installation, and the date of STC registration was examined. The data provided by the CER includes both the date of system installation and of the STC creation, so it is possible to calculate how many systems are registered one, two, three, or more months after the system was installed.

Residential and commercial data were analysed between November 2021 to October 2022 which was selected to reflect recent trends. Months for the years 2023 were not incorporated due to the bias that would occur in favouring the population of customers who install early rather than later, resulting in an underestimate of time taken to register PV systems.

Figure 17 shows the typical delay in registration for residential system installations by state.

Figure 17: Cumulative delay in STC creation from date of installation, residential SGUs (Nov 21 – Oct 22)



Source: Jacobs' analysis of CER data

From November 2022 through to October 2023, the residential installed capacity was divided by the percentage of registered installations to create an expected percentage of installations for the respective month, as shown in Table 7.

Table 7: Percentage of installed capacity used in modelling for residential systems

	ACT	NSW	NT	QLD	SA	TAS	VIC	WA
1/11/2022	100%	100%	100%	100%	100%	100%	100%	100%
1/12/2022	100%	100%	100%	100%	100%	99%	100%	100%
1/01/2023	99%	100%	99%	100%	99%	99%	99%	100%
1/02/2023	99%	99%	99%	99%	99%	99%	99%	99%
1/03/2023	99%	99%	99%	99%	99%	98%	98%	99%
1/04/2023	98%	99%	99%	98%	98%	98%	98%	99%
1/05/2023	98%	98%	99%	98%	97%	97%	97%	99%
1/06/2023	97%	97%	98%	97%	96%	96%	95%	99%
1/07/2023	96%	96%	95%	96%	94%	95%	94%	98%
1/08/2023	94%	95%	93%	94%	91%	93%	90%	98%
1/09/2023	91%	92%	89%	92%	87%	87%	82%	96%
1/10/2023	68%	73%	64%	74%	67%	64%	40%	77%

5.1.5 Solar PV 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. 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, 2017 – 2019.
- Power equation: Payback period vs. historical uptake, 2019 – 2021.
- Linear equation: Retail electricity price vs. historical uptake, 2015 – 2022 (excl. COVID-19).
- Power equation: Capital cost vs. historical uptake, 2015 – 2022 (excl. COVID-19).

5.2 DER uptake assumptions

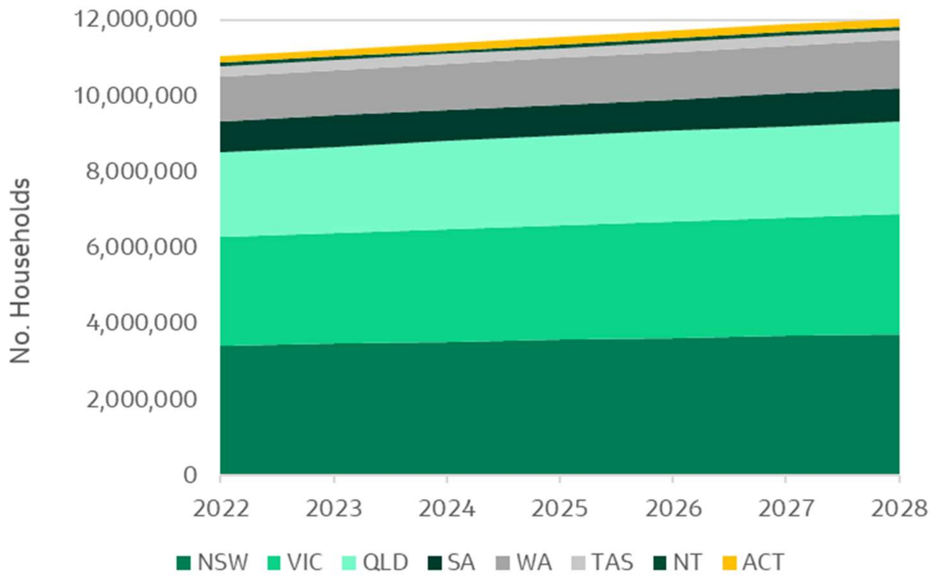
This section describes the assumptions that underpin the uptake forecasts for solar PV. While some of these measures have been discussed in the initialisation assumptions described in Section 5.1, they differ in the fact that in the previous section they referred to historical data used to set up and initialise agents, whereas in this section they refer to data used in forecasts of future years. Further, the assumptions in this section are the key economic and financial drivers that influence payback calculations used by customers to decide whether to take up rooftop solar systems, as well as the assumptions used to forecast changes in population.

5.2.1 Household growth

Household growth was indexed to the SA3 population or household growth forecasts from the respective state and territory governments (except Tasmania and Northern Territory). Using SA3 household numbers from the latest ABS 2021 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. This is due to the uncertainty in attributing outflows of agents in one location to inflows of agents in another.

The total household growth forecast is shown in Figure 18. 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 Tasmania and Northern Territory are assumed constant.

Figure 18: Household growth forecast



5.2.2 Solar PV system capital costs

Solar PV system costs had risen over the last two years, as the global oversupply on PV module manufacturing capacity diminished during COVID-19. From late 2020 until the end of 2022 there had 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. This volatility challenged logistic supply chains, and as a result freight costs had increased by a factor of 3-4 for shipments from China. Delivery times were also stretched because of these issues, which placed upward pressure on system prices. As a result of this, global average year on year capex for solar systems in 2022 did not decline.

Capital cost assumptions for PVs in 2023 are based on the Solar Choice website's[4] 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.

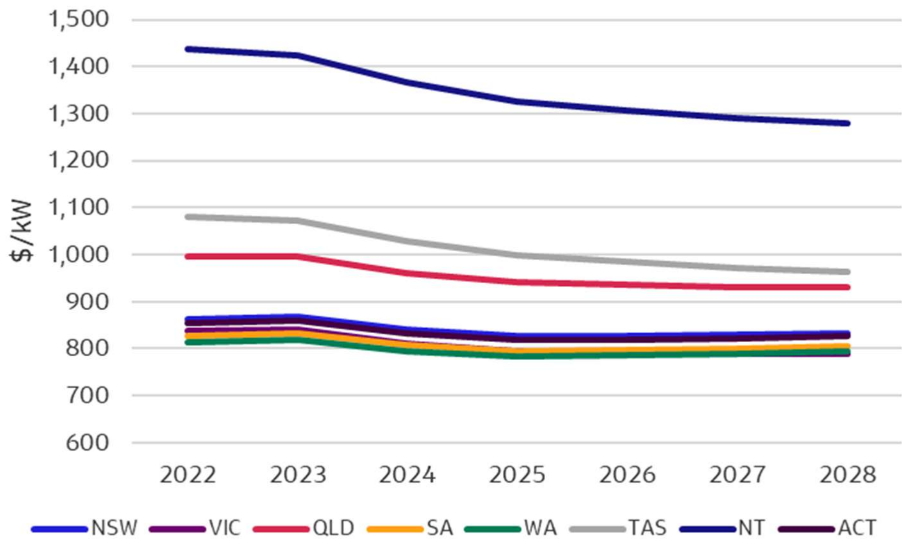
For residential systems, the price per system per kW for capacity sizes of 5 to 10 kW was trended over time, and forecasts for each State were performed by utilising the expected learning curve extrapolated from CSIRO's 2022-23 GenCost[5] forecasts for rooftop PV (Global NZE post-2050 scenario), illustrated in Figure 19. Current global inflationary pressures are expected to remain higher for longer from faster technological deployment to meet stronger climate policies. This is expected to slow the rate of decline from current highs. The diminishing STC discount largely offsets the yearly cost reductions throughout the forecast period.

The NT is expected to have the highest system prices starting at $1,450/kW in 2023 to under $1,300/kW in 2028. All other States and Territories are projected to have capital costs of between $800/kW to $1,100/kW over the projection period.

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

[5] https://data.csiro.au/collection/csiro%3A44228v10

Figure 19: Capital cost assumed for residential solar PV systems ($/kW 2022)

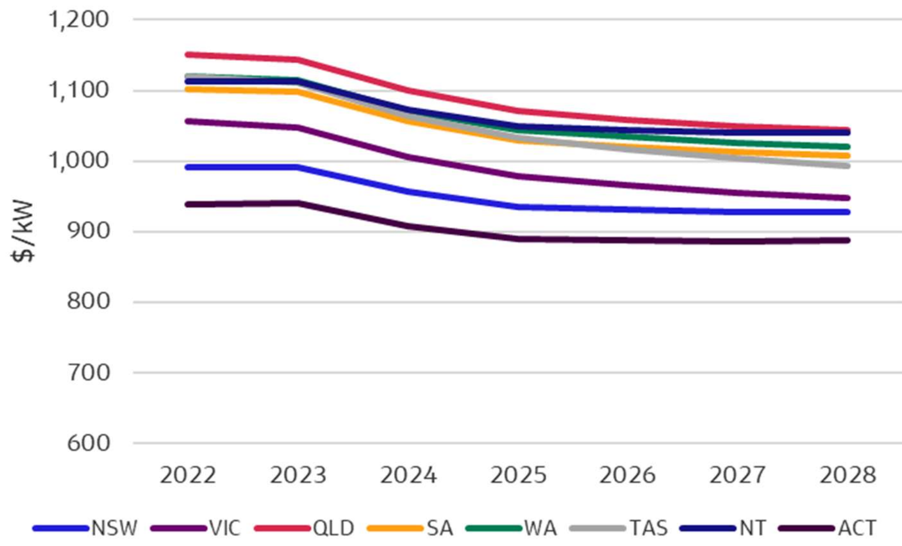


Source: Jacobs' market analysis, Solar Choice, CSIRO GenCost

A similar method was applied to costs of commercial systems, by utilising the data for systems between 10 kW and 100 kW. The average cost was plotted for all states, and the CSIRO's rate of decline was applied from 2023 to 2028.

The economies of scale were also less apparent in commercial systems, with little difference between cost per kilowatt for a 10-kW system versus a 100-kW system. Therefore, a ratio for economies of scale was not applied and the cost per unit was assumed to be constant. Figure 20 shows the historical and forecast costs assumed for commercial systems.

Figure 20: Capital costs assumed for commercial solar PV systems ($/kW 2022)



Source: Jacobs' market analysis, Solar Choice, CSIRO GenCost

5.2.3 Retail electricity tariffs

Jacobs' in-house 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 solar generation units (SGUs).

Jacobs has prepared the retail price projections using a bottom-up book build approach. This approach involves developing projections for each cost component of the retail tariff and adding up the components to formulate an overall retail price forecast. These cost components include network charges, wholesale charges, environmental scheme costs, market operator charges, and retailer charges and margins. The cost breakdown of the current retail price is used as a measure to calibrate the various components of the retail price.

5.2.3.1 Wholesale costs

The wholesale market costs faced by retailers include:

- Spot energy cost as paid to AEMO adjusted by the applicable transmission and distribution loss factors.
- Hedging costs around the spot energy price consisting of swaps, caps and floor contracts.

Retailers must formulate a contracting strategy that enables them to manage trading risk according to their own risk profile. Generally, contracts are available at a premium to spot market prices to reflect the protection against volatile prices.

Our analysis of the wholesale market[6] determined an allowance of 30% was added to wholesale market costs to account for both price risk and forecasting risk for smaller customer markets (i.e. residential and SME markets). For larger customers, Jacobs considered that the ability to forecast loads and the presence of temperature sensitivity in the loads may be lower for larger customers and reduced the risk premium to 13% for large commercial customers and to 10% for industrial customers.

There is also a strong relationship between this margin and the average price, with the margins being lower when the average price is lower (on the basis that lower average prices indicates an excess of supply or lowering of demand and hence the less likelihood of price spikes). Hence, we used a regression model that will map the uplift rates to projected average price, based on historical margins (on spot forward prices) against average prices.

Allowances for losses occuring across power lines in transmission and distribution are accounted for by applying transmission loss factors (TLFs) and distribution loss factors (DLFs).

The annual retail prices are built from quarterly wholesale price forecasts adjusted for seasonality based on regional monthly demand. The wholesale prices (real $/MWh) are based on Jacobs' market forecasts.

5.2.3.2 Network charges

Network charges are the costs associated with transmission and distribution of electricity for retailers. These costs are set by network service providers who own the transmission infrastructure. Network charges are found on the AEMC website in their electricity prices and trends report where the 'base year' values are actuals. Network determinations are set every five years. The current network determination period with published network charges ranges from FY2024 to FY2026. After FY2026, network charges are assumed to remain constant for the duration of the forecasting period.

5.2.3.3 Other charges

Large-scale renewable energy target (LRET) – The LRET provides a financial incentive to establish or expand renewable energy power stations by legislating the creation of Large-scale Generation Certificates (LGCs), where one LGC is equivalent to one MWh of eligible renewable electricity produced by an accredited power station. LGCs are sold to liable entities (mostly electricity retailers who must purchase a percentage of electricity from renewable sources each year) who must surrender them annually to the Clean Energy Regulator (CER).

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[6] See "Analysis of electricity retail prices and retail margins", May 2013, SKM-MMA (note this is a previous trading name of Jacobs), available at https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-market-performance-and-reporting/electricity-retail-prices-and-margins-reporting-2013

LGCs were introduced as a mechanism to achieve the Federal Government's target of 33,000 GWh of electricity from eligible large-scale renewable sources in the NEM by 2020. The annual target increased each year until 2020 and is now constant at 33,000 GWh per year to 2030, when the scheme ends.

The LGC price is anticipated to decline through to 2030 because the supply of LGCs should increase as more accredited renewable energy is established in the electricity market but demand for LGCs from liable entities should remain at about the same level, in line with the steady target. However, recent LGC forward prices have retained significant value. This may be because there is increasing additional demand from voluntary cancellations to meet private sector decarbonisation goals. For these reasons LGCs are likely to continue to retain value over the next few years.

The LGC projections are adjusted using the DLF and TLF applying to the generator.

Small-scale renewable energy scheme – Electricity retailers are liable entities under the SRES who surrender STCs to the CER to meet their SRES obligations. This imposed cost to electricity retailers are passed on to consumers through the retail electricity tariff.

Feed-in-tariffs – This is built up by calculating the proportion of solar generation in relation to operational demand and multiplying by the relevant state or territory FiT rate.

5.2.3.4 Market charges

Market fees are regulated to recover the costs of operating the wholesale market, the allocation of customer meters to retailers, and settlement of black energy purchases. These fees, charged by the Australian Energy Market Operator (AEMO) to retailers, are applicable to wholesale black energy purchases and are budgeted at $0.24/MWh in 2024 according to the AEMO 2024 budget[7].

Ancillary services charges are also passed through by AEMO to retailers. Retailers are charged ancillary service costs according to load variability. Over the last few years, the charges have varied over time and by region. Due to the volatility of these values, retailers are not able to foresee variations in these costs, and therefore the average values have been applied consistently over the study period. These market and ancillary service charges are adjusted by DLFs as the charges are related to the wholesale metered quantity purchased by retailers.

5.2.3.5 Retailer costs and margin

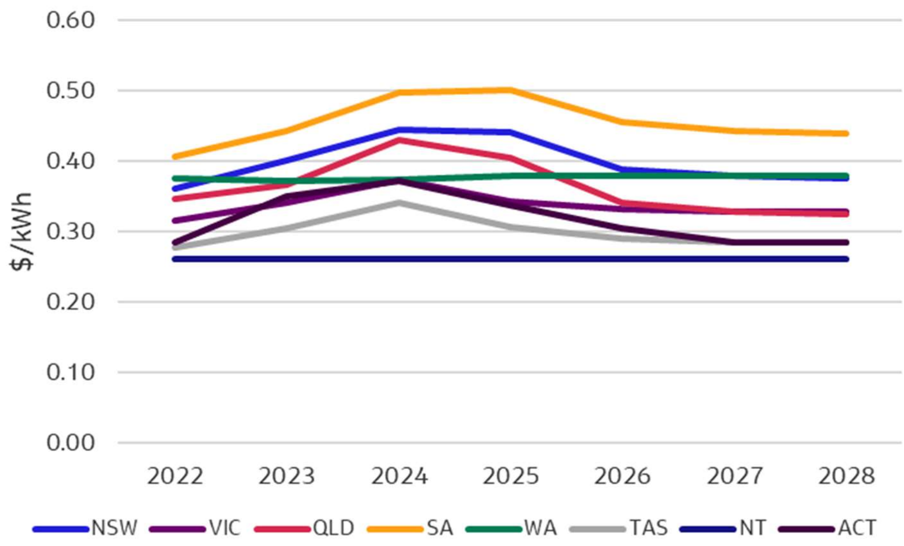
The retail margin is estimated from historical data from the AEMC. The proportion of the total retail tariff that encompass retailer costs and margins is given in its electricity price trends report. This is assumed to remain constant over the forecasting period.

5.2.3.6 Retail electricity tariff

Figure 21 shows the retail electricity prices for each state used in the forecasts. Northern Territory and Western Australian prices are regulated by the state government, and it is assumed these will remain constant for the projection period.

[7] "AEMO FY24 Budget and Fees", AEMO, June 2023

Figure 21: Residential retail electricity tariff forecasts



Source: Jacobs' market analysis

5.2.4 Feed-in tariffs

Feed-in tariffs in Australia for small-scale renewable energy generation are offered by retailers and, in some instances, they have an obligation imposed by the relevant state government to offer a minimum tariff for exports of electricity to the grid. Where the required data for FiTs and customers per retailer were available, a price based on the weighted average retail offer of the three largest retailers and a combination of remaining retailers was assumed in the modelling.

Both the Northern Territory and Western Australian governments have sharply reduced their standard FiTs to reduce incentives to export rooftop solar power because of the impact of high penetration of solar on grid stability. In April 2020, the Northern Territory standard FiT was reduced from 26.05c/kWh to 8.3c/kWh, applied to all new installations.

In Western Australia, the standard FiT rate of 7.135 c/kWh was lowered to 3c/kWh for exports prior to 3pm and 10c/kWh for exports between 3-9pm. This is a move to encourage the installation of west facing solar panels and BESS to shift exports to during the evening peak period. This change is in place for all new systems installed from September 2020.

In New South Wales, the benchmarked FIT has recently been revised upwards in response to rising wholesale electricity prices. The FY2023 benchmarked FiT has increased from 4.6-5.5 c/kWh in FY2022 to 6.2-10.4 c/kWh.

5.2.5 STC prices

Figure 22 shows the monthly historical STC prices for the period January 2018 to November 2023. During this period the STC prices hovered below $40, indicating that a surplus of STCs was being generated in the market. While $40 is in effect a ceiling price, and in the short-term prices may fluctuate beneath that level, it is assumed that prices converge and maintain at that level as annual targets are matched to projected levels of uptake.

Figure 22: Monthly historical STC price (nominal)

Source: Jacobs' analysis of Demand Manager data

5.2.5.1 STC zoning

The CER divides Australia into four regional zones based on the estimate of renewable energy that can be generated by a solar panel in each area, so installations in areas with high insolation[8] will create more certificates per kilowatt 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 kilowatt of installed capacity was calculated for the years 2013 to 2016 for each state and territory, which is the period when STC generation was not affected by multipliers or reduced deeming periods.

[8] Insolation is the amount of solar radiation received on a given surface in each time period.

Table 8 shows the effective multiplier for each state and territory used for conversion of the forecast capacity into STCs.

From 2017, the deeming period reduces by an additional year every year; therefore, systems installed in 2023 will have a maximum deeming period of 8 years. As a result, the number of STCs created per kW reduces by a greater rate each year.

Table 8: Average STCs generated per kW of PV installed

Region	Pre-2017[9]	2023	2024	2025	2026	2027	2028
New South Wales	20.7	11.2	9.8	8.4	7.0	5.6	4.2
Victoria	17.8	10.1	8.8	7.5	6.3	5.0	3.8
Queensland	20.6	11.0	9.7	8.3	6.9	5.5	4.1
South Australia	20.5	11.0	9.6	8.3	6.9	5.5	4.1
Western Australia	20.6	11.0	9.7	8.3	6.9	5.5	4.1
Tasmania	17.6	9.4	8.2	7.1	5.9	4.7	3.5
Northern Territory	23.2	12.3	10.8	9.2	7.7	6.1	4.6
Australia Capital	20.6	11.0	9.6	8.3	6.9	5.5	4.1

[9] For a 15-year deeming period

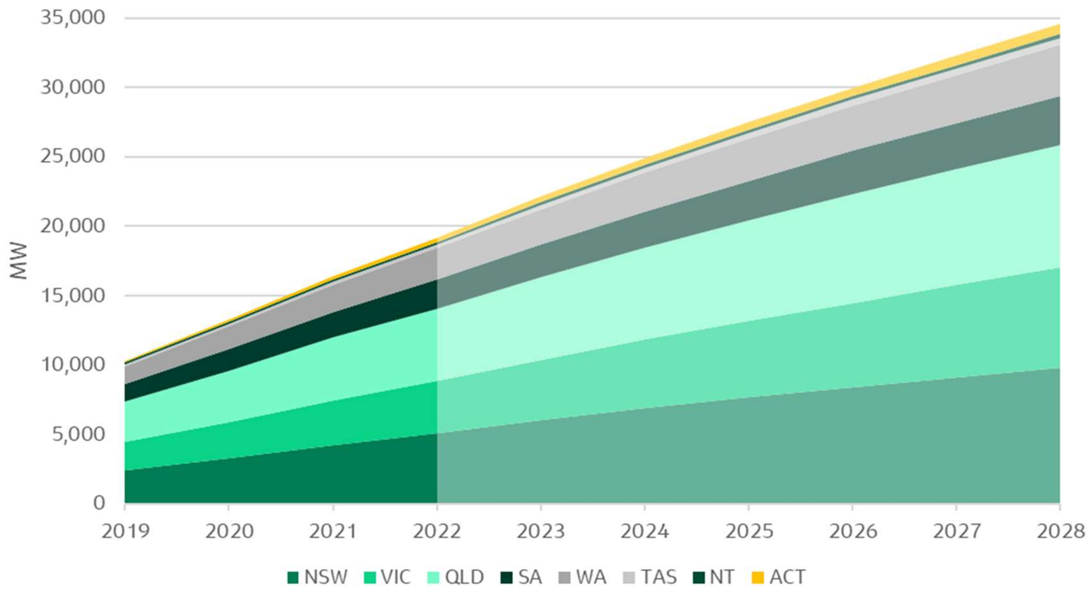
6. Results

This section presents the main projections from the agent-based and ARIMA time-series modelling undertaken by Jacobs. All results are provided in calendar years, and historical numbers from (at least) 2019 are given for context.

6.1 Rooftop PV capacity

The cumulative installed rooftop PV capacity increases over the forecast period, rising from 21,926 MW at the end of 2023, to 34,343 MW by the end of 2028, as shown in Figure 23.

Figure 23: Small-scale PV state forecasts, cumulative installed capacity



Installed capacity in 2022 was the first year that marked a slowdown in annual uptake, following record growth in 2020 and 2021. This was largely attributed to the stagnated trend in rooftop solar PV system costs, and the continued decline of feed-in tariffs in many states. However, a slight rebound in annual installed capacity is expected by the end of 2023, with 2,977 MW of capacity compared to 2,762 in 2022.

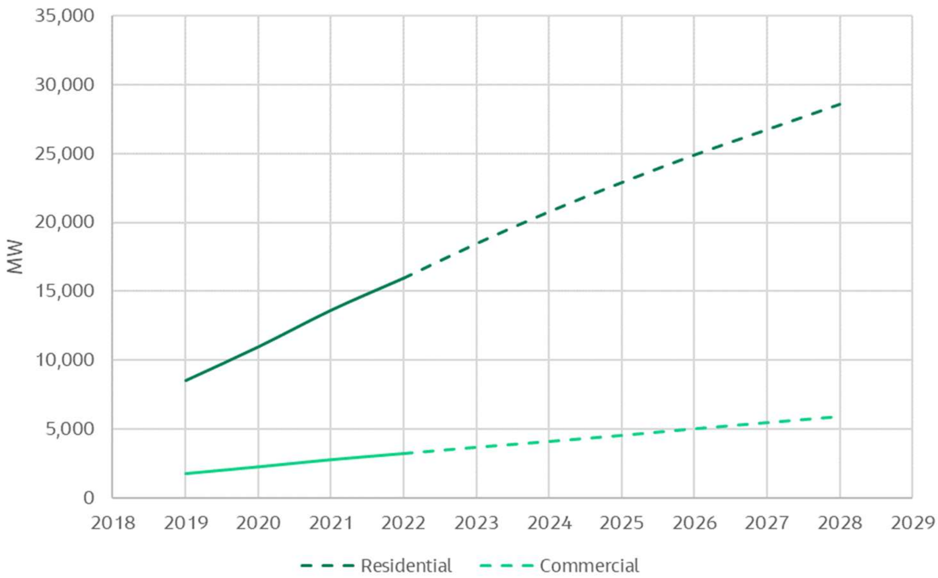
Across the east coast of Australia, the National Electricity Market (NEM) had experienced prolonged periods of extremely high wholesale electricity prices. This was largely a result of the undersupplied global gas market, ultimately caused by the economic sanctions imposed on Russia. These sustained prices in the wholesale market will flow through to retail electricity prices from the second half of 2023 and is expected to re-incentivise a new wave in rooftop PV installations. However, the learning rate of rooftop PV costs has slowed to the point of being outpaced by the reducing STC discount. Further, the feed-in tariffs of a few states continue to fall despite increasing wholesale prices. These outcomes therefore act to offset the positive economic incentives brought on by the increasing retail prices. Annual uptake in 2024 is expected to remain relatively steady with 2,756 MW of capacity by year-end.

The east coast wholesale electricity market largely recovered by early 2023 following the implementation of an emergency coal and gas price cap. Due to electricity retailer hedging, the NEM's wholesale price recovery in 2023 will eventually flow through to the retail electricity market from 2025, lowering retail prices in this year. As a result, annual installed capacity is forecast to decline by 6% to 2,579 MW.

System costs in 2026 are forecasted to cease falling and slightly rise as the diminished deeming period of STCs has fully outpaced any cost decline from technological innovation. Retail electricity prices and feed-in tariffs also continue falling, creating comparatively less attractive payback periods. Installed annual capacity is expected to continue declining with 2,303 MW of annual rooftop PV capacity in 2027, and 2,285 MW in 2028.

Figure 24 shows the forecasts of cumulative installed small-scall PV capacity, across the residential and commercial sectors.

Figure 24: Small-scale PV sector forecasts, cumulative capacity



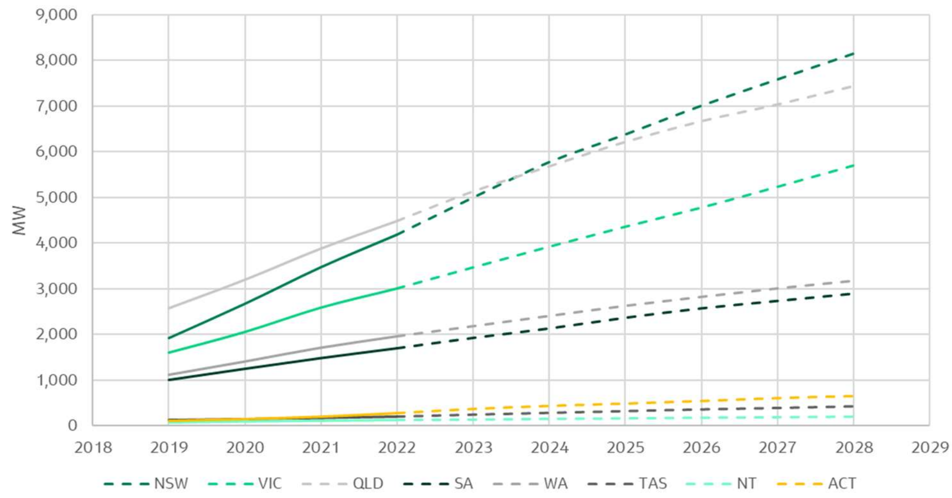
In 2022, residential cumulative capacity comprises 83.2% of total solar PV capacity in Australia, decreasing slightly to 82.7% by 2028. At the end of 2023, the residential and commercial sectors have 18,237 MW and 3,689 MW of installed PV capacity, respectively. By the end of 2028, there is 28,411 MW and 5,932 MW of cumulative capacity in the residential and commercial sectors, respectively.

Throughout the forecast period, residential installations convey more volatility than commercial uptake. A reason is that residential customers are more sensitive to changing FiT rates, as they are more dependent on solar export revenue from their relatively oversized PV systems than commercial customers. Conversely, commercial PV systems tend to be sized to meet their electricity grid consumption and are less responsive to changing FiTs.

6.1.1 State residential PV projections

The cumulative residential solar PV capacity forecasts of each state are shown in Figure 25.

Figure 25: State residential small-scall PV projections, cumulative capacity



All regions comprising the NEM have marginally higher annual installed PV capacity by the end of 2023, than in 2022. Although retail prices hadn't officially increased until mid-2023, the strong anticipation of these price hikes and prevalent coverage of the global energy crisis in mainstream forums is likely to have played a role in influencing installations. Western Australia and Northern Territory are the only two regions expected to see a decline in 2023 - both these regions have regulated retail electricity prices and were not affected to the same extent as households along the east coast.

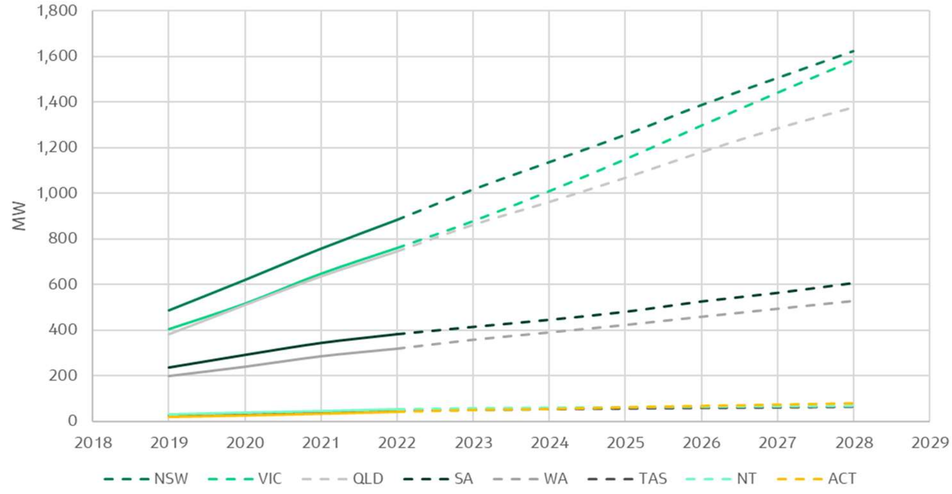
In 2024, most regions are forecasted to see a resurgence in PV uptake driven by the increase of residential electricity prices. NSW and Victoria are expected to increase by 9% and 8%, respectively over 2023 levels. The ACT has been the exception to the rest of country as the territory continued to break records in 2022 and 2023, following already high uptake in 2020 and 2021. The ACT Home Energy Support Program, launched in late 2021 has provided rebates to households, and interest-free loans for rooftop PV systems and other clean energy configurations. However, from 1 July 2023 requirements for eligible households have significantly tightened, with the maximum land value of participating households decreasing from $750,000 to $450,000. Annual installed capacity for ACT is expected to fall by 24% in 2024 from 87 MW to 66 MW.

NSW is expected to overtake Queensland as the leading state in cumulative installed residential capacity in 2025. This is due to steady growth in NSW incentivised by relatively higher retail and feed-in tariffs, as wells as dwindling uptake in Queensland which has historically been less influenced by retail price movements. By the end of the forecast period, NSW is forecast to have 8,050 MW cumulative installed capacity in the residential sector. Queensland and Victoria are expected to have 7,394 MW and 5,651 MW capacity, respectively.

6.1.2 State commercial PV projections

Figure 26 shows the cumulative installed commercial small-scale PV capacity forecasts. All regions except South Australia are expected to finish at the end of 2023 with marginally higher annually installed capacity than in 2022, as businesses anticipate higher retail prices. New South Wales, Victoria, and Queensland are projected to install 128 MW, 134 MW, and 111 MW by the end of 2023, respectively. However, unlike residential customers, commercial customers are not as reactive to changing FiTs since their systems are typically more efficiently sized to their electricity consumption and are not as reliant on solar export revenue.

Figure 26: State commercial small-scale PV projections, cumulative capacity



6.2 Water heater STCs

The ARIMA time series model forecasted the monthly STC creation of residential and commercial SWH and residential ASHP.

6.2.1 Solar water heaters

Figure 27 shows the historical actual and forecast data for the creation of STCs for SWH residential installations. The mild downtrend in uptake of these systems is projected to continue across the forecast horizon, as air source heat pumps rise in popularity amongst households and gradually replace its market share.

Figure 27: Residential STCs for SWH, monthly (<= 40 STCs per installation)

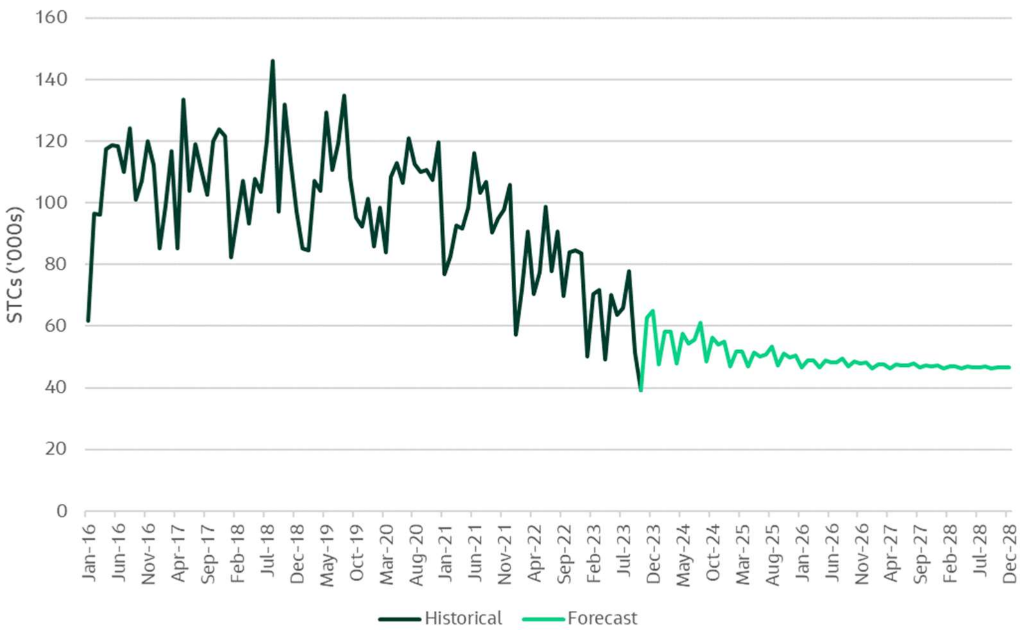
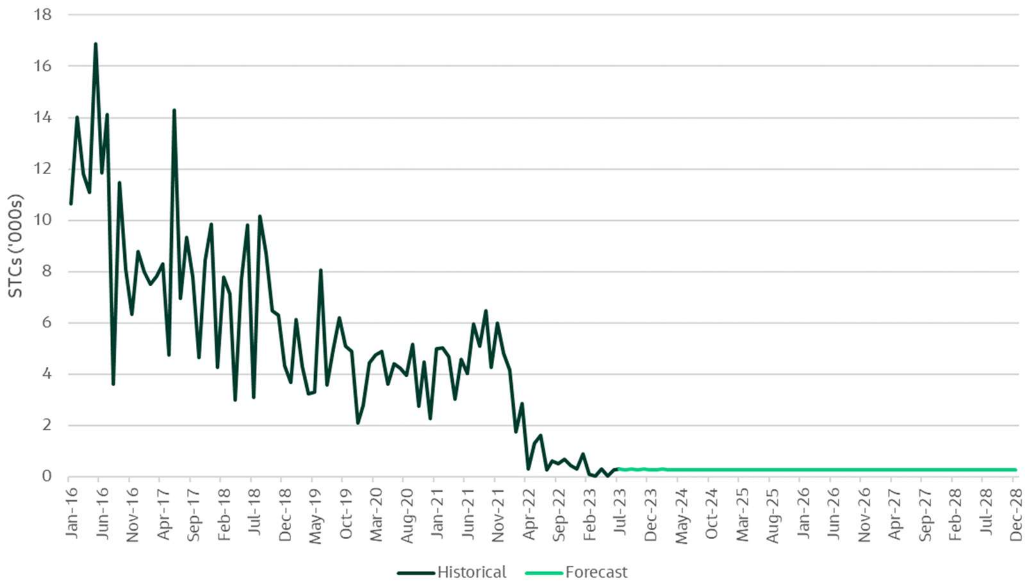


Figure 28 shows the historical actual and forecast data for the creation of STCs through SWH classified as commercial sized units. The number of installations and STCs generated for commercial SWH systems has dropped significantly in 2023, because air source heat pumps are also gaining popularity in the commercial sector. STCs generated are expected to remain stable at around 3,000 STCs per year.

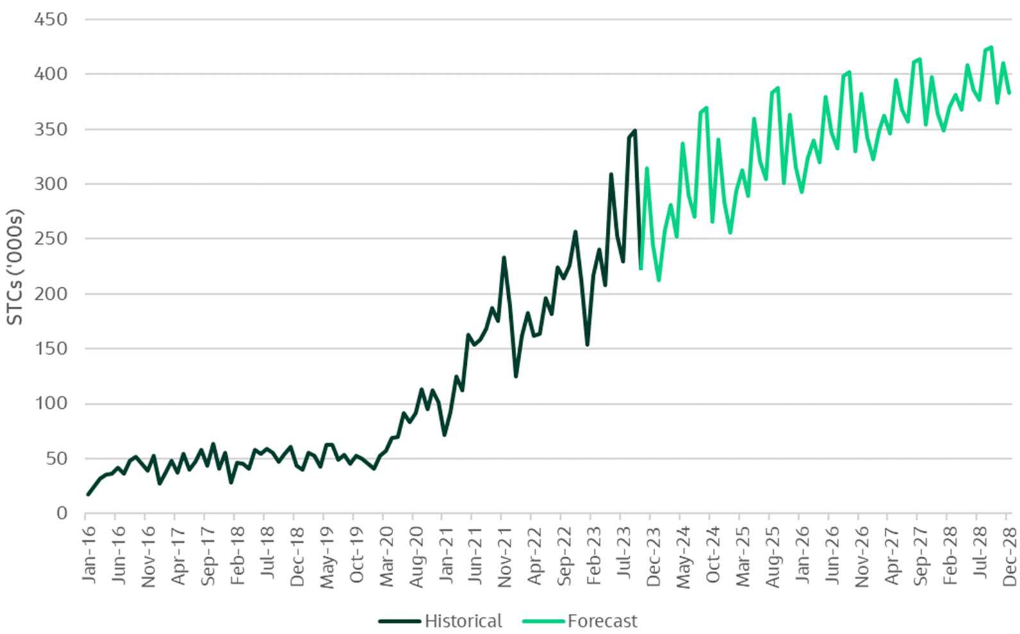
Figure 28: Commercial STCs for SWH, monthly (>40 STCs per installation)



6.2.2 Air source heat pump water heaters

Figure 29 shows the historical actual and forecast data for STC creation from ASHP. There has been a boost in uptake among households and this is expected to grow throughout the forecast period. As retail electricity prices increase over the forecast period, households will turn to more energy efficient options, aided by Government subsidies in some States. Further, Victoria and the ACT have banned gas connections to new home builds which will greatly incentivise the uptake of air source heat pumps.

Figure 29: Residential STCs for ASHP, monthly



6.3 STC Projections

The projections for STCs created are shown in Table 9. These projections include STCs created through the installation of solar PV and hot water systems (wind and hydro STCs make up a negligible portion). In 2023, a total of 36.2 million

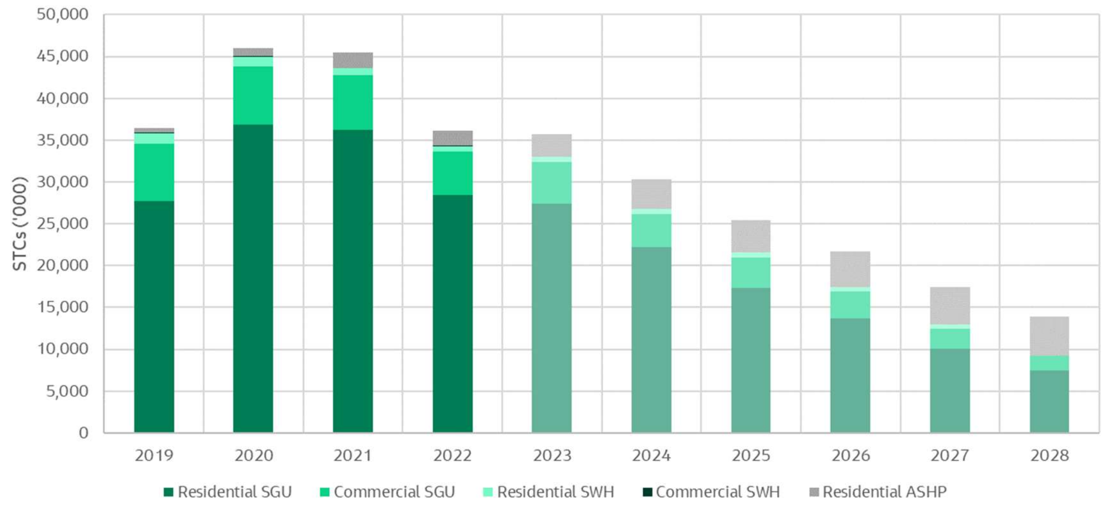
STCs is projected to be generated; despite having an increase in SGU capacity, this is less than 1% lower than 2022 due to the scheme's deeming period declining by another year, compared to the previous year.

Table 9: Small-scale technology certification (STC) creation projections ('000s)

	2023	2024	2025	2026	2027	2028
RESIDENTIAL						
Australian Capital Territory	1,020	640	414	386	353	173
New South Wales	9,127	7,622	5,095	4,428	3,234	2,374
Northern Territory	112	187	115	93	70	61
Queensland	7,176	5,322	4,450	3,145	2,027	1,669
South Australia	2,496	1,992	1,931	1,424	896	658
Tasmania	399	313	264	213	142	119
Victoria	4,638	3,971	3,290	2,616	2,287	1,749
Western Australia	2,448	2,152	1,813	1,349	1,022	679
Total Residential	**27,415**	**22,199**	**17,372**	**13,654**	**10,030**	**7,481**
COMMERCIAL						
Australian Capital Territory	86	41	62	41	31	23
New South Wales	1,492	1,175	1,005	914	666	495
Northern Territory	67	25	22	15	14	10
Queensland	1,289	963	874	778	572	381
South Australia	354	301	288	313	208	178
Tasmania	50	26	21	17	10	12
Victoria	1,187	1,157	1,056	931	724	535
Western Australia	433	308	271	248	193	141
Total Commercial	**4,959**	**3,995**	**3,597**	**3,257**	**2,419**	**1,776**
TOTAL SOLAR PV STCs	**32,374**	**26,194**	**20,969**	**16,910**	**12,449**	**9,257**
Residential Solar Hot Water	738	654	602	577	565	560
Commercial Solar Hot Water	3	3	3	3	3	3
Residential Air-sourced Heat Pump	3,085	3,524	3,888	4,191	4,443	4,654
ALL STCs	**36,200**	**30,376**	**25,462**	**21,682**	**17,461**	**14,474**

Figure 30 illustrates the STC creation projections by sector. Results for the projected SGU capacity can be found in Appendix A. STC trends are largely linked to residential rooftop PV installations which comprise the largest portion of STCs created. The decline in total STCs in 2022 is attributed to the fall of annual residential PV capacity, as discussed in Section 6.1.1. However, the fall in STCs between 2023 to 2028 is largely a result of fewer STCs generated per kW of small-scale solar as the deeming period continues reducing by an additional year in each subsequent year.

Figure 30: Total STC annual projections



Commercially sized SWH units are expected to maintain their relatively low level of uptake and are not expected to have considerable influence on STC creation across the forecasting period. It is expected that domestic SWH systems will continue modest negative growth, however the recent climb in uptake of ASHP systems is expected to continue for the remainder of the forecast horizon.

Appendix A: Annual small-scale PV capacity

Table 10: Annual installations of small-scale PV capacity (MW)

	2023	2024	2025	2026	2027	2028
RESIDENTIAL						
Australian Capital Territory	93	66	50	56	64	42
New South Wales	815	778	607	633	578	565
Northern Territory	9	17	12	12	11	13
Queensland	650	551	537	456	367	403
South Australia	227	207	234	207	163	159
Tasmania	42	38	37	36	30	34
Victoria	461	451	436	416	455	464
Western Australia	222	223	219	196	185	164
Total Residential	**2,519**	**2,332**	**2,133**	**2,012**	**1,853**	**1,844**
COMMERCIAL						
Australian Capital Territory	8	4	7	6	6	6
New South Wales	133	120	120	131	119	118
Northern Territory	5	2	2	2	2	2
Queensland	117	100	106	113	104	92
South Australia	32	31	35	45	38	43
Tasmania	5	3	3	3	2	3
Victoria	118	131	140	148	144	142
Western Australia	39	32	33	36	35	34
Total Commercial	**458**	**424**	**446**	**484**	**449**	**440**
Total Capacity	**2,977**	**2,756**	**2,579**	**2,495**	**2,303**	**2,285**