Small-scale Technology Certificate Projections

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CER STC Projections
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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 encourages individuals and small businesses to install eligible renewable energy systems by offering financial incentives. These incentives come from small-scale technology certificates (STCs), which electricity retailers are legally required to buy and submit to the Clean Energy Regulator every quarter.

Participants can sell STCs on the open market, where prices vary based on supply and demand. Alternatively, they can trade STCs at a fixed price of $40 each through the Clean Energy Regulator's STC clearing house. Until the end of 2016, systems could create STCs based on 15 years of expected generation for small-scale generation units, and until the end of 2021, solar or heat pump water heaters could create STCs based on 10 years. Since 2017, the number of STCs per system has been calculated using a 'deeming period' that shortens by one year annually, gradually reducing the number of certificates issued until the scheme ends in 2030.

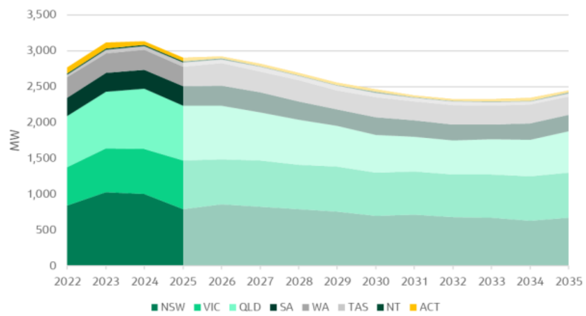
Jacobs has been engaged by the CER to forecast the number of STCs and the installed capacity of small generation units (SGU) in the calendar years of 2025 to 2035, inclusive. Small-scale wind and hydro units are assumed negligible, so SGUs comprise solely of rooftop solar PV systems.

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 model based on the autoregressive integrated moving average (ARIMA) method.

As illustrated in Figure ES 1, the projected annual installed rooftop PV capacity decreases over the forecast period, from 2,903 MW at the end of 2025 to 2,449 MW by the end of 2035.

Figure ES 1: Small-scale PV state forecasts, annual installed capacity – Base scenario



Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

These forecasts are subject to some uncertainty that may impact the outlook of installed systems. Government policy is a major influence on both the electricity market, and consumer behaviour. Uncertainty can arise from newly created policies where there is little program data from which direct impacts can be based.

Annual installed small-scale rooftop solar PV capacity is displayed in Table ES 1 for each state, territory, and sector.

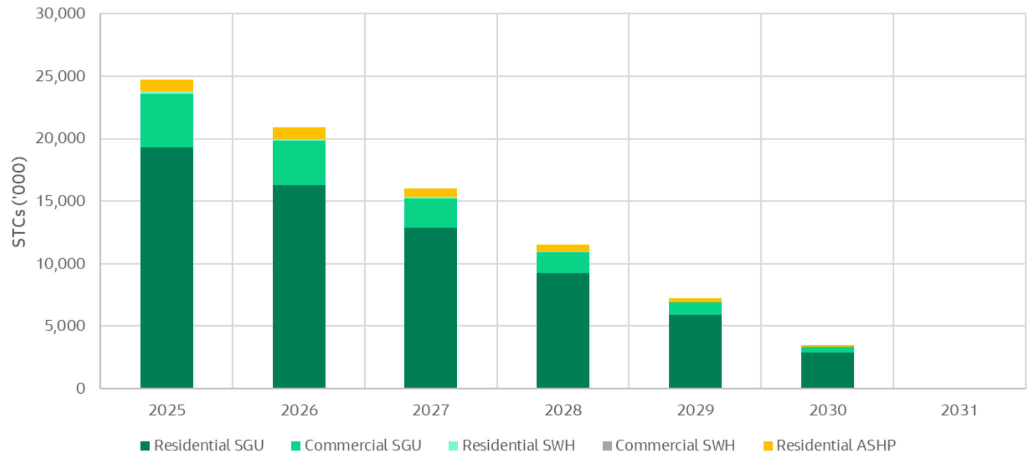
Table ES 1: Annual installed small-scale rooftop solar PV capacity (MW) – Base scenario

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
RESIDENTIAL											
Australian Capital Territory	43	20	27	26	25	32	22	20	21	39	29
New South Wales	645	723	705	678	658	610	632	602	603	557	604
Northern Territory	12	16	4	11	4	11	7	3	7	5	14
Queensland	648	614	576	520	471	449	427	422	439	459	529
South Australia	219	219	225	206	191	216	195	200	180	203	196
Tasmania	47	48	65	49	64	58	45	54	47	40	36
Victoria	527	493	528	517	535	507	513	516	527	543	551
Western Australia	234	269	251	266	236	241	232	241	239	235	227
Total Residential	**2,375**	**2,402**	**2,381**	**2,272**	**2,183**	**2,124**	**2,073**	**2,058**	**2,064**	**2,080**	**2,187**
COMMERCIAL											
Australian Capital Territory	9	6	5	5	4	4	4	5	4	3	3
New South Wales	144	135	121	110	101	85	80	74	70	69	68
Northern Territory	6	3	4	3	3	3	3	3	2	3	2
Queensland	120	135	97	112	92	74	62	54	51	48	48
South Australia	53	62	50	48	39	35	32	21	24	25	29
Tasmania	7	6	6	5	4	5	5	4	4	5	5
Victoria	150	131	114	102	94	99	88	79	75	79	76
Western Australia	39	44	37	33	32	32	30	28	28	29	29
Total Commercial	**528**	**522**	**435**	**418**	**371**	**338**	**303**	**268**	**258**	**261**	**262**
Total Capacity	**2,903**	**2,924**	**2,815**	**2,691**	**2,554**	**2,462**	**2,376**	**2,326**	**2,322**	**2,341**	**2,449**

Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

Figure ES 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).

Figure ES 2: Total STC annual projections, Base scenario



Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

Overall trends in STC forecasts are dominated by residential rooftop PV installations, which historically comprise the largest portion of STCs created. Commercially sized solar water heaters are expected to remain a small part of the market and are unlikely to significantly impact STC creation during the forecast period. STC creation from domestic solar water heaters is expected to keep declining, while uptake of air source heat pumps is likely to remain steady. The number of STCs from these systems will gradually fall due to the shortening deeming period.

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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
ARIMA	Autoregressive integrated moving average
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
ERA	Economic Regulation Authority (Western Australia)
ESC	Essential Services Commission (Victoria)
ESC	Energy Savings Certificate
ESS	Energy Saving Scheme (NSW)
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
PDRS	Peak Demand Reduction Scheme
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	Small generation unit
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificate
SWH	Solar water heaters
TAS	Tasmania
TLF	Transmission loss factor
VEU	Victorian Energy Upgrades program
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 encourages individuals and small businesses to install eligible renewable energy systems by offering financial incentives. These incentives come from small-scale technology certificates (STCs), which electricity retailers are legally required to buy and submit to the Clean Energy Regulator every quarter.

Participants can trade STCs on the open market, which enables the option of a varied certificate price reflective of the market’s supply and demand. Alternatively, scheme participants have the option of trading certificates 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 certificates created for each eligible installation, there is no cap on the total number 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 an assumed lifetime. Because of this, the number of certificates created is influenced by levels of insolation attributable to the geographical location of the asset.

Until the end of 2016, systems could earn STCs based on 15 years of expected generation for small-scale generation units, and until the end of 2021, solar or heat pump water heaters could create STCs based on 10 years. Since 2017, the deeming period has reduced by one year annually, gradually decreasing the number of STCs issued per installation until the scheme concludes in 2030.

The purpose of this report is to provide forecasts of the number of STCs that will be generated in the calendar years 2025 to 2035, inclusive. In developing this report, Jacobs has executed following tasks:

- Modelled expected small-scale technology installations (≤100 kW) and provided updated SRES forecasts for 2025-2035
- 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 refined existing models and methods to improve projection accuracy. This included identifying trend changes, incorporating alternative estimators, and addressing structural shifts in the STC market. The study uses an in-house agent-based modelling approach to better capture these dynamics

All analysis and forecasts in this study are based on STCs created in the month of the technology is installed. Additionally, a forecast of additional STCs for the same installation month is undertaken to account for all STCs to be created over the next 12 months (of the same year).

2. 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 forecasts provided by Jacobs account for government policies and programs explicitly or implicitly.

2.1 Government policies

2.1.1 Small-scale renewable energy scheme

In 2011, the Renewable Energy Target (RET) was split into two parts to better manage both small-scale, and large-scale renewable energy projects. One part is the SRES which aims to support small-scale systems like rooftop solar, solar water heaters, and heat pumps.

As of 1 July 2025, battery storage systems are also eligible under the SRES as part of the Australian Government Cheaper Home Batteries program. On similar principles to rooftop solar, STCs are awarded based on a battery's usable capacity, which reflect into an upfront discount to the consumer. In 2025, 9.3 STCs are created per kWh of usable battery capacity, however this rate reduces every year out to 2030. Assuming one STC is priced at $40, in 2025 this translates to a discount of $372/kWh.

The rising uptake of batteries will increase the average rooftop PV system size in the future as consumers are less restricted by export limits, as a result of maximised self-consumption. Whilst this impact has been accounted for in the forecast, it is not explicitly based on the direct impacts of the Cheaper Home Batteries program. However, the resultant outcomes are expected to be broadly consistent with what's been assumed.

2.1.2 NSW Energy Security Safeguard

Under the Energy Security Safeguard, the NSW Energy Saving Scheme (ESS) was established in 2009 to incentivise NSW households and business to reduce electricity consumption by investing in energy saving projects. Under the ESS, SWH and ASHP which replace electric water heaters are eligible to receive rebates through the creation of Energy Savings Certificates (ESC). One ESC represents 1 MWh of energy saved, with a typical ASHP (replacing an electric hot water system) historically generating around 40 certificates. At the current spot price of $18.60, this equates to around $784 in savings. Initially, a minimum co-payment of $30 (exclusive of GST) was required by the end user to receive these benefits. As of 19 June 2024, this co-payment was increased to $200 (plus GST). Under the same rule change, the certificate creation methodology was revised potentially decreasing the number of ESCs created per installation.

Also under the Energy Security Safeguard, the Peak Demand Reduction Scheme (PDRS) was created in 2022 to reduce peak electricity demand in NSW. The scheme provides financial incentives to households and businesses to reduce electricity consumption during peak demand hours through the adoption of eligible technologies. Originally, small commercial ASHP were eligible under the PDRS, in addition to the ESS and SRES. The permitted stacking of multiple scheme benefits created very attractive financial incentives which was a key driver in NSW ASHP uptake in the last two years. However, from 1 August 2024, eligible ASHP under the PDRS will be limited to large units that cannot receive SRES benefits (minimum volumetric capacity of 425 litres).

From November 2024, new incentives under the PDRS were extended to behind-the-meter batteries, however this will cease on 1 July 2025 due to the Australian Government Cheaper Home Batteries program. Under the PDRS, customers are also offered an upfront incentive (up to $550 for a 10-kWh battery) for participating in a Virtual Power Plant (VPP), however this isn't considered in the scope of this study.

2.1.3 Victorian Gas Substitution Roadmap

First released in 2022 but updated in 2024, the Victorian Gas Substitution Roadmap is Victoria's strategic plan to transition away from fossil gas by promoting electrification, energy efficiency, and renewable gases.

As part of this roadmap, Victoria has banned gas connections to new dwellings that require planning approvals as of 1 January 2024. With over 50,000 new homes built in Victoria each year, the government estimates that this policy will prevent around 40,000 new gas connections annually. The shift to all-electric homes will increase demand for alternative appliances for cooking and heating purposes. This includes increased uptake of SWH and ASHPs.

2.1.4 Renewable Energy Guarantee of Origin

The Renewable Energy Guarantee of Origin (REGO) scheme is part of Australia's Guarantee of Origin (GO) scheme which was formally established in November 2024. The REGO scheme is a voluntary certificate mechanism which will build on the large-scale generation certificate (LGC) framework and will continue post-2030 once LGCs conclude. However, specific policy rules for registration have not yet been finalised for aggregated systems, so the REGO scheme has not been considered in the scope of this forecast.

2.2 Government programs

2.2.1 Victorian solar homes program

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

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. From July 2023, interest-free loans up to $8,800 were also available for battery systems installed alongside a solar PV system, before ending this offer in June 2025. Under the scope of Jacobs' forecasts, interest-free loans are not considered for future battery systems.

Rebates of $1,000 are also being offered to install a SWH or ASHP unit, in eligible dwellings that have not previously received a Solar Homes rebate. However, from 1 July 2025 a higher rebate of $1,400 is available to households that choose an eligible hot water product that is locally made.

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 value is $1,400. However, historically the number of awarded rebates to renters have made up a very small percentage of annual Victorian installs (less than 2%), so this study maintains the broad assumption that renters are ineligible to install a rooftop PV system.

2.2.2 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 an electric boosted solar water heater or an air source heat pump water heater.

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 7.3 Mt CO_2-e, respectively. Targets beyond 2025 are not yet officially defined, however they have been proposed to be 4.4 and 4.6 Mt CO_2-e for 2026 and 2027, respectively.

2.2.3 WA Residential Battery Scheme

Launching from 1 July 2025, the WA Residential Battery Scheme offer Western Australian households further rebates to battery systems in conjunction with the national Cheaper Home Batteries Program. Synergy and Horizon Power customers can receive an additional $130/kWh, and $380/kWh discount, respectively, which can be stacked together with the rebates offered under the SRES. Additionally, interest-free loans of up to $10,000 are available to households with a combined annual income of less than $210,000.

3. Methodology

Forecasting uptake of small-scale systems 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, uptake is based on a combination of economic and non-economic behavioural factors.

The economic return from installing a system depends on several factors, including income, energy use, electricity tariffs, and both the upfront and ongoing costs of the system. Together, these determine the payback period that influences 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 influenced by neighbourhood norms. 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. The relative weight of non-economic factors towards uptake varies by sub-region. For the residential sector, uptake was modelled at the Statistical Area level 3 (SA3) region which are geographical boundaries defined by the Australian Bureau of Statistics (336 SA3 regions across Australia), designed to reflect regional identity with both geographic and socio-economic similarities. All regions will have some degree of non-economic factors as the minority driver of uptake, however a small portion of regions (with no historical correlation to economic factors) may be assumed to be fully driven by non-economic reasons (calibrated by historical uptake).

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 considered to be temporary. Growing rooftop PV system sizes exceeding network export limits has been observed over the last few years as consumers pivot away from exporting to the grid, as the rise of batteries help maximise self-consumption. The impact that growing battery uptake will have on increasing rooftop PV system sizes has been accounted for in the forecast by assuming an extrapolated growth rate of systems above 6.6 kW (see Section 4.1.3.2).

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 time-series ARIMA model is utilised. Both models partly rely on expected payback periods as the main driver of system uptake. These payback periods are influenced by projected trends in system costs, government subsidies, and expected revenue from retail and feed-in tariffs.

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 is considered in this study.

3.1 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 installations 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.

3.2 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.

3.2.1 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) 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.

3.2.2 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.

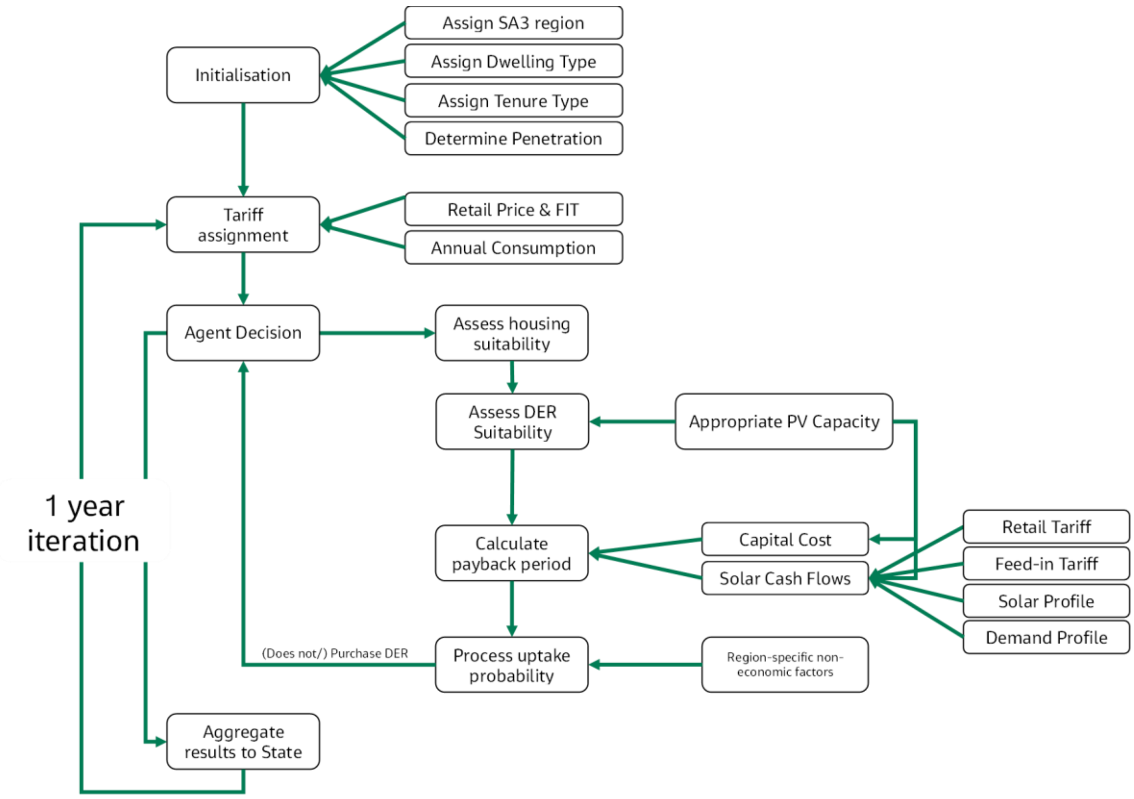
Like residential agents, the current penetration level for commercial agents is assigned at the commencement of the model based on available data.

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.

3.3 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 3-1 for a residential agent, and a commercial agent follows a similar path.

Figure 3-1: Residential agent framework



After an agent has been initialised, if it does not currently own a rooftop solar PV 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 (which are generally assumed to be zero).

In each year that an agent is deciding, using the assigned values they calculate 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 used. However, agents may also consider how these tariffs are anticipated to change in subsequent years. This is discussed in further detail in Section 3.5.

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 3-1 and Table 3-2, respectively.

Table 3-1: 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 3-2: 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 3-3:

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

Table 3-3: 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	%

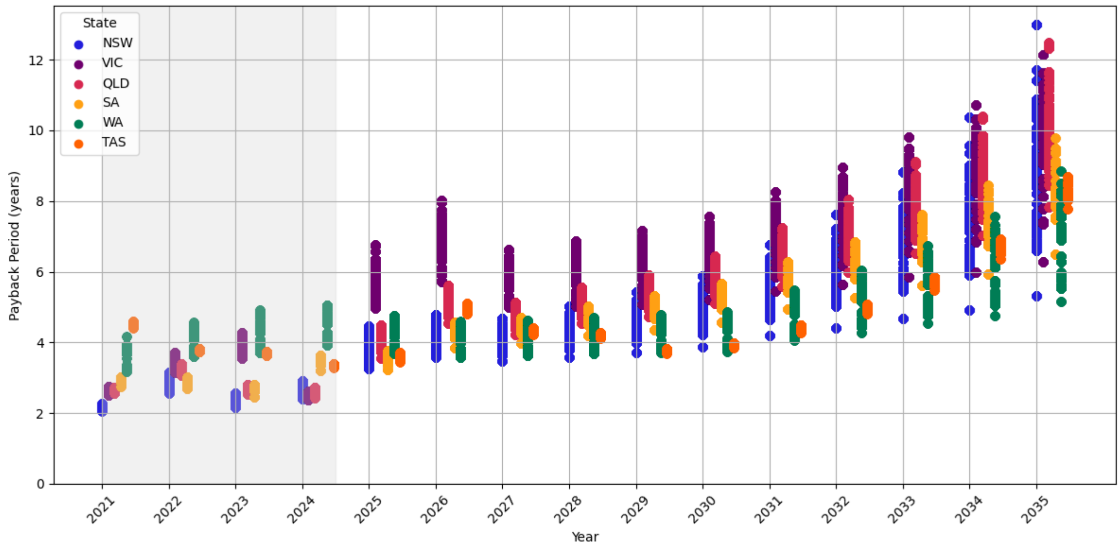
3.3.1 Replacement decision

Throughout the forecast period, agents that have installed a rooftop PV system will make decisions to replace or upgrade their system upon the end of its technical life. At the end of the incumbent's system's lifetime, agents will undergo a similar process as described in Section 3.3, where the economic return will be reevaluated to determine the probability of replacement. Generally, the replacement decision will begin for rooftop PV systems older than 25 years, however older systems installed in the 2000s may be replaced as early as 15 years.

3.4 Payback periods

The spread of forecasted payback periods for a standalone rooftop PV system, which varies across SA3 regions in each state is illustrated in Figure 3-2.

Figure 3-2: Scatter plot of derived historical and forecasted standalone rooftop PV system payback periods



Estimated historical payback periods are also shown for the period 2021–2024. Variation within each state occurs because each SA3 region will have a different system size and electricity usage. Over the forecast period, the movement of payback periods will reverse its long-term historical trend and will increase throughout. A noticeable increase occurs in 2025 driven by the sharp fall in feed-in tariffs (FIT). This is particularly the case in Victoria because from 1 July 2025 there is no longer a mandated minimum feed-in tariff, so retailers will reduce their FIT to a greater level. The overall trend is primarily correlated to the movement in forecasted feed-in tariffs, which offsets the benefits from rising retail electricity prices, and falling system costs. Over time, the spread of payback periods widens across SA3 regions as the variation in system sizes increase, with some households opting for bigger capacities (with diminishing benefits, without a co-located battery). Note that these are the payback periods of hypothetical configurations, so don't all represent the point when households install a standalone PV system. The relationship between the payback period, and the level of uptake is discussed in Section 3.5. As the upper spread of payback periods for a standalone rooftop PV system increase over time, a greater proportion of households choose to install a combined battery.

3.5 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 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.

3.6 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 installations. 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 installations[1] by water heaters, split into domestic and commercial categories for Australia. The projection also considers deeming reductions in future years.

[1] Defined by the time of physical installation, and has had had STCs passed within 12 months from installation

4. 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.

4.1 Initialisation assumptions

As discussed in Section 3.2, agents are segmented into residential or commercial customers. The initialisation assumptions for each group are described in the following sub-sections, and Table 4-1 provides a summary of the data sources.

Table 4-1: 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 2025	
Commercial demographics	Network system business customer numbers	AER, ESC, ERA, PWC	State
	Existing solar PV penetration	CER 2025	
School demographics	Existing solar PV penetration	CER 2025	
	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	SolarChoice	
	Demand profile	CSIRO	National

4.1.1 Residential demographics

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

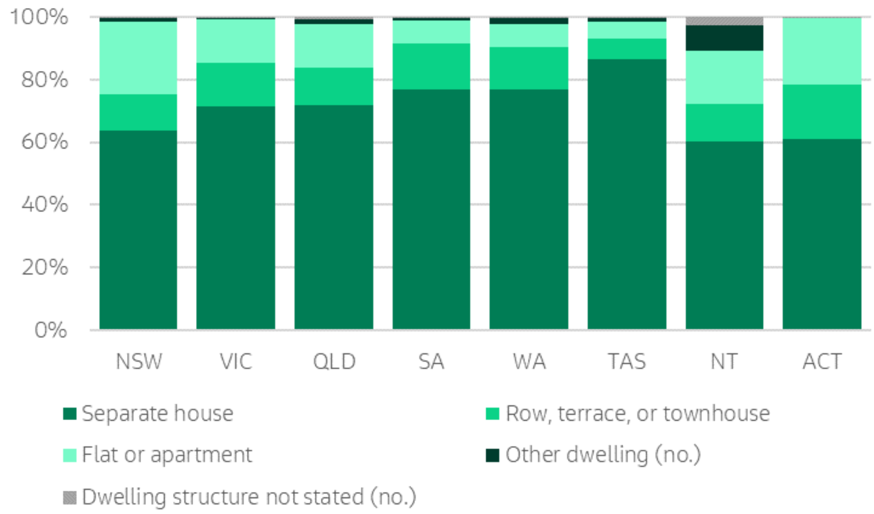
4.1.1.1 Residential dwelling type and tenure type

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 4-1. 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.

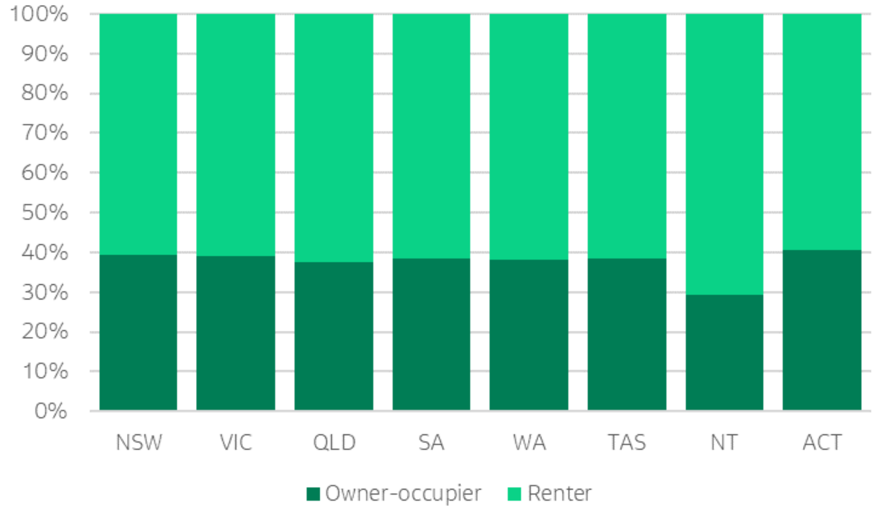
Figure 4-1: State dwelling proportions



Source: Jacobs' analysis of ABS Census 2021 data

The state aggregated proportions of each tenure type for detached dwellings are illustrated in Figure 4-2. All states have similar home ownership rates, except for the Northern Territory which is lower.

Figure 4-2: Detached dwelling tenure proportions per state/territory



***Source**: Jacobs' analysis of ABS Census 2021 data*

4.1.2 Commercial demographics

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

4.1.2.1 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.

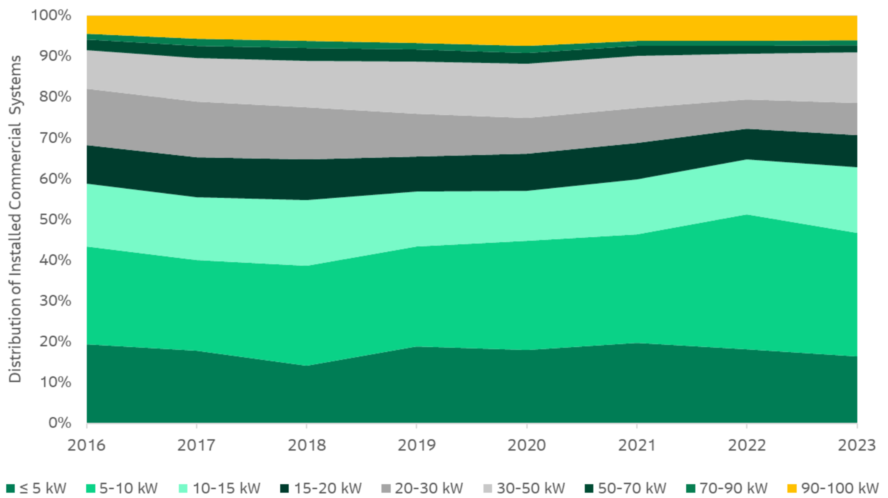
However, each state has a different definition of the customer classifications as outlined in Table 4-2.

Table 4-2: 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 4-3, 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.

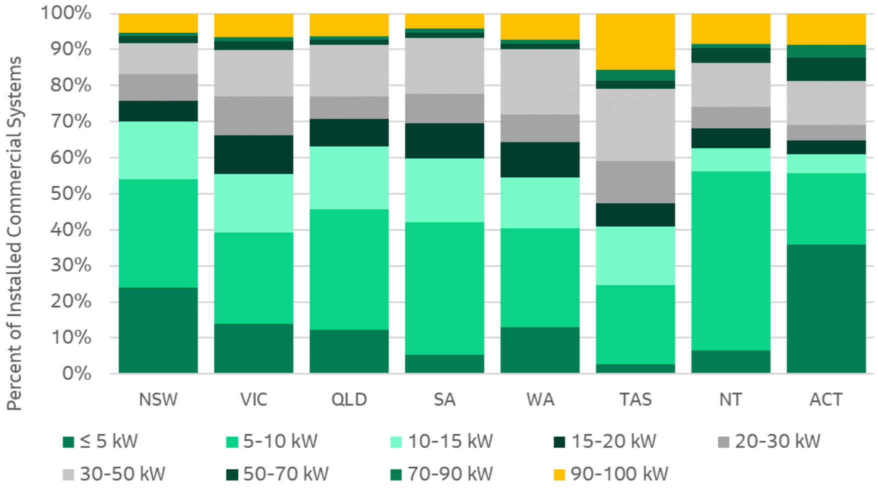
Figure 4-3: Historical distribution of commercial capacity segments, Australia



***Source**: Jacobs' analysis of CER data*

Under these assumptions, systems within the same capacity segment, as displayed in Figure 4-4 and Figure 4-5, belong to businesses with similar electricity consumption to each other.

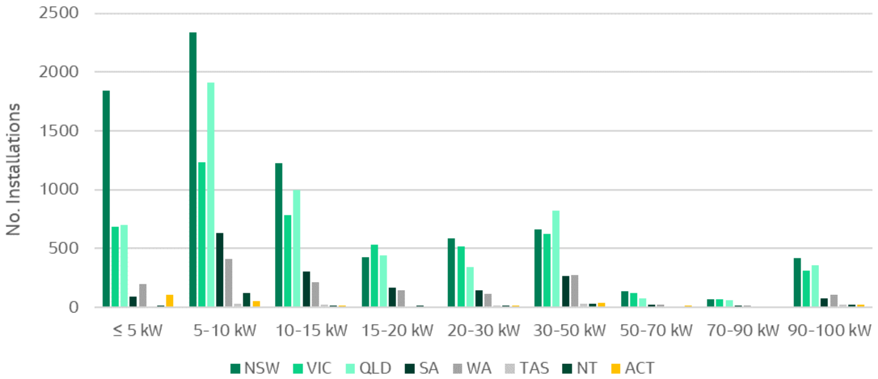
Figure 4-4: Commercial capacity segment distribution, 2023



***Source**: Jacobs' analysis of CER data*

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.

Figure 4-5: Number of installations by capacity segment, 2023



***Source**: Jacobs' analysis of CER data*

This segmentation is outlined in Table 4-3.

Table 4-3: 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 3-1.

4.1.3 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 uptake, including:

- Energy consumption.
- Retail tariffs.
- Feed-in tariffs.
- Average retail bills.
- Demand profiles.
- Solar generation profiles.
- Capital costs (provided by SolarChoice[2]).
- Installed rooftop PV capacity.

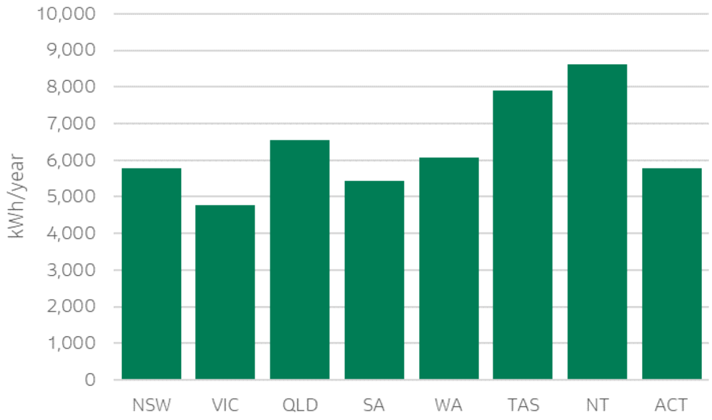
4.1.3.1 Underlying electricity consumption

Energy consumption is a critical component of calculating the potential savings for households and businesses of investing in rooftop solar PV. The underlying electricity consumption (i.e., without a behind-the-meter system) was assumed for each SA3 region, using historical local government area (LGA) energy consumption data provided by various regional DNSPs (including self-consumed rooftop solar PV generation). In regions where their respective DNSP has not provided this data, an annual electricity

[2] See https://www.solarchoice.net.au/solar-panels/solar-power-system-prices/

consumption value was assigned depending on the SA3 region's climate zone, as published by the AER[3]. The state average underlying electricity consumption per year is shown in Figure 4-6.

Figure 4-6: Average residential underlying electricity consumption per annum

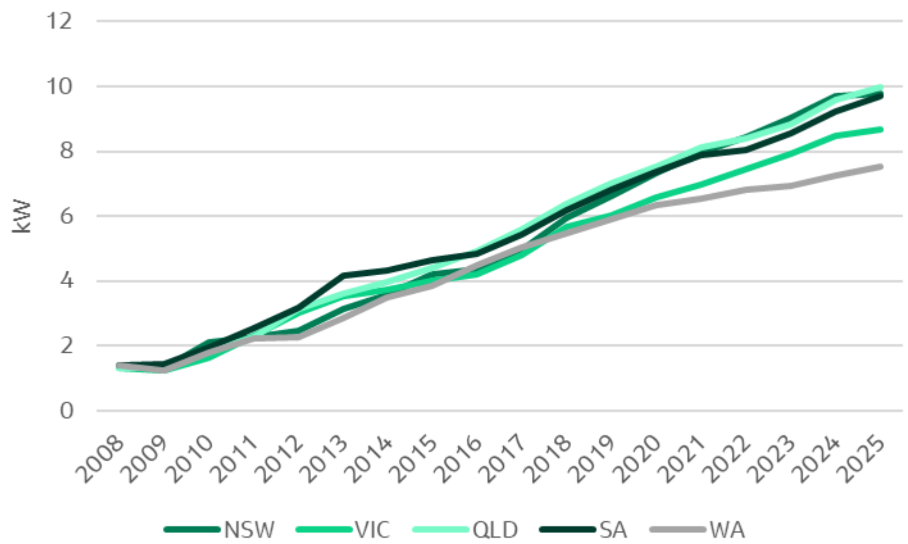


***Source**: Jacobs' analysis of DNSP and AER data*

4.1.3.2 Rooftop PV system sizes

Figure 4-7 shows the trends in average PV system sizes being installed since January 2008. The graph indicates that average system size has continued to grow at a steady rate throughout 2025, consistent with growth patterns since mid-2016.

Figure 4-7: Trend of average residential PV solar system size, 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 4-8 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 an increasing uptake in larger systems of between 7-15 kW.

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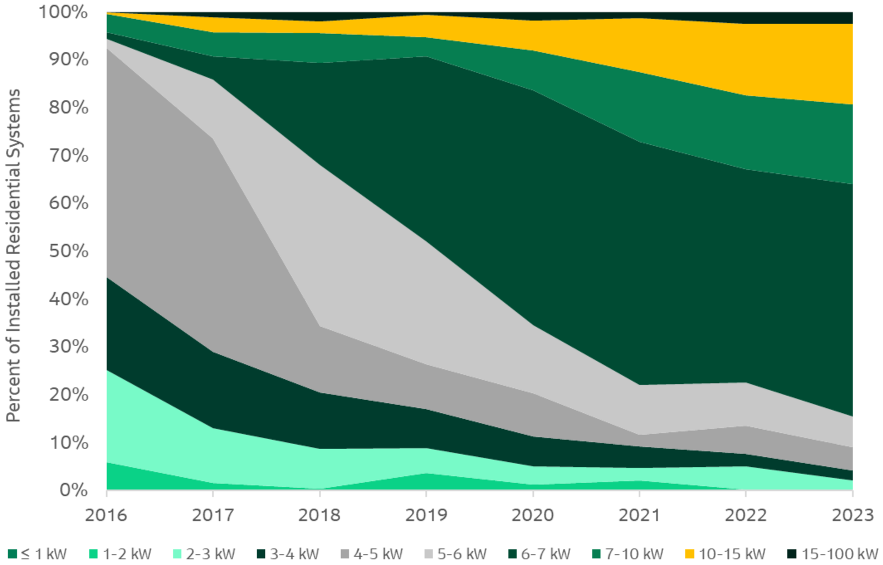
[3] See https://www.aer.gov.au/industry/registers/resources/guidelines/electricity-and-gas-consumption-benchmarks-residential-customers-2020

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 4-8: 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 in certain geographical area, is expected to eventually curtail the average system size for residential properties. However, as observed in Figure 4-8, installations between 7-15 kW have been steadily increasing in the last four years. This can be attributed to households with three-phase connections which have higher inverter export limits, as well as households opting for larger systems for self-consumption (and/or battery charging) despite the 5 kW inverter export limit. Power curves have been fitted in each SA3 region to reflect these changes in system size (Figure 4-9).

Figure 4-9: Weighted average rooftop PV residential system size forecast, select States

Source: Jacobs' analysis

At the end of 2024, NSW has the largest average residential system size (9.68 kW) out of the mainland states, closely followed by Queensland (9.58 kW). Western Australia has the smallest average residential system size in Australia (7.27 kW). From February 2022, all new solar systems in Western Australia with an inverter capacity higher than 5 kW will have an export limit of the greater between 1.5 kW and 5% of the inverter capacity; this has therefore greatly disincentivised any system above 6.6 kW. This regional spread in average system capacity is expected to persist throughout the forecast period, although NSW is projected to have a slightly higher growth rate (due to higher uptake in sub-regions with larger system sizes). Mostly consistent with historical trends, the increase in projected average system capacity for all regions is largely driven by households opting for larger systems for self-consumption despite prescribed export limits; as battery uptake increases, households will be less bound by export limits since excess generation can be self-consumed later in the evening. By the end of the forecast period, some households are expected to install larger systems as big as 19 kW. By 2035, the average residential system size for NSW is 13.69 kW, and 9.73 kW for Western Australia.

4.1.4 Time lag to registration

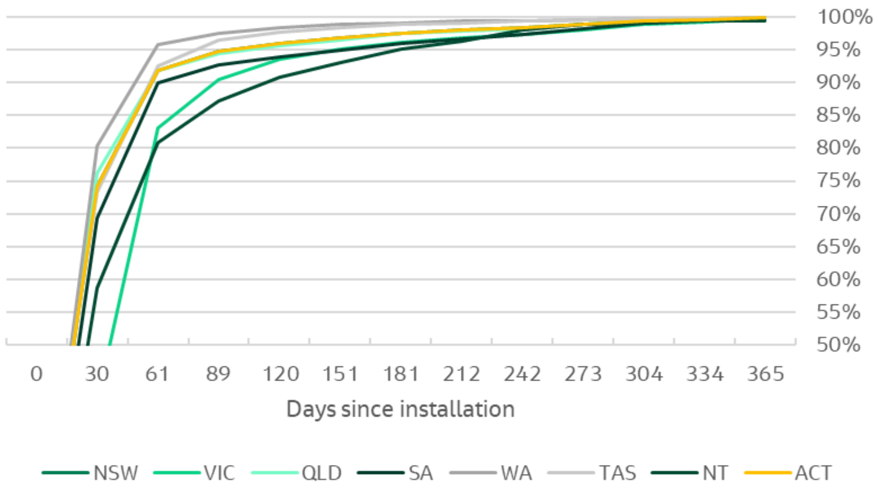
As there is a 12-month window from the date of installation in which to register eligible systems, the most recent registrations database will be missing records of systems that have already been installed, but which have not yet been registered. If not corrected, this will lead to an underestimate in 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 May 2023 to April 2024 which was selected to reflect recent trends. Installations from the previous 12 months 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 4-10 shows the typical delay in registration for residential system installations by state.

Figure 4-10: Cumulative delay in STC creation from date of installation, residential SGUs (May 23 – Apr 24)



Source: Jacobs' analysis of CER data

From May 2024 through to April 2025, 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 4-4: Percentage of installed capacity used in modelling for residential solar PV systems

	ACT	NSW	NT	QLD	SA	TAS	VIC	WA
1/05/2024	100%	100%	99%	100%	100%	100%	100%	100%
1/06/2024	100%	100%	99%	100%	100%	100%	99%	100%
1/07/2024	99%	99%	99%	99%	99%	100%	99%	100%
1/08/2024	99%	99%	99%	99%	98%	100%	98%	100%
1/09/2024	99%	98%	98%	98%	97%	99%	97%	99%
1/10/2024	98%	98%	96%	98%	97%	99%	97%	99%
1/11/2024	98%	98%	95%	97%	96%	99%	96%	99%
1/12/2024	97%	97%	93%	96%	95%	98%	95%	99%
1/01/2025	96%	96%	91%	96%	94%	98%	94%	98%
1/02/2025	94%	95%	87%	94%	93%	96%	91%	98%
1/03/2025	91%	92%	81%	92%	90%	92%	83%	96%
1/04/2025	69%	74%	59%	76%	69%	73%	41%	80%

4.1.5 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-squared[4] value is sufficient, 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 best fit, and the resultant probability.

The following relationships are used in the uptake function:

- Payback period versus historical uptake.
- Retail electricity price versus historical uptake.
- Capital cost versus historical uptake.
- Feed-in tariff versus historical uptake.
- Home mortgage rates versus historical uptake.

4.2 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 4.1, 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.

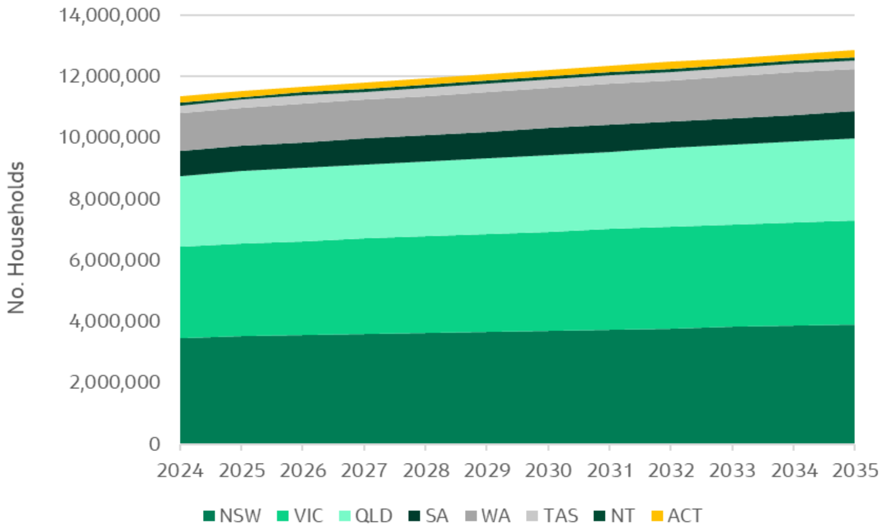
4.2.1 Household growth

Household growth was indexed to the Centre for Population's state and territories population forecasts. Using SA3 household numbers from the latest ABS 2021 Census, household growth followed the trend of its corresponding population forecast.

The total household growth forecast is shown in Figure 4-11. 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 3.2.1, and subsequently follow the same decision process.

[4] R-squared (R^2) is a statistical measure that reflects how well the model fits the data, ranging from 0 to 1 (1 meaning a perfect fit).

Figure 4-11: Household growth forecast



4.2.2 Solar PV system capital costs

Solar PV system costs have increased in recent years due to reduced manufacturing capacity during COVID-19 and a surge in global demand from late 2020 to 2022. This was compounded by rising raw material and freight costs, with shipping prices from China increasing three to four times and delivery times lengthening. However, growing demand for alternative materials and expanded manufacturing capacity have recently eased these pressures. While system prices have begun to stabilise, year-on-year capital cost reductions over the past year have been modest.

Capital cost assumptions for PVs in 2025 are based on the Solar Choice website's[5] 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 2024-25 GenCost[6] forecasts for rooftop PV (Global NZE post-2050 scenario) in alignment with AEMO's central Step Change scenario, illustrated in Figure 4-12. These cost projections only account for single inverter systems; uptake of microinverters were not considered in this study. Current global inflationary pressures are expected to remain higher for longer from faster technological deployment to meet stronger climate policies aligned with governments meeting their Nationally Determined Contributions (NDCs). This is expected to slow the rate of decline. 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 $1,270/kW in 2025 to $1,430/kW in 2035. All other States and Territories besides Tasmania are projected to have capital costs roughly between $800/kW to $1,100/kW over the projection period.

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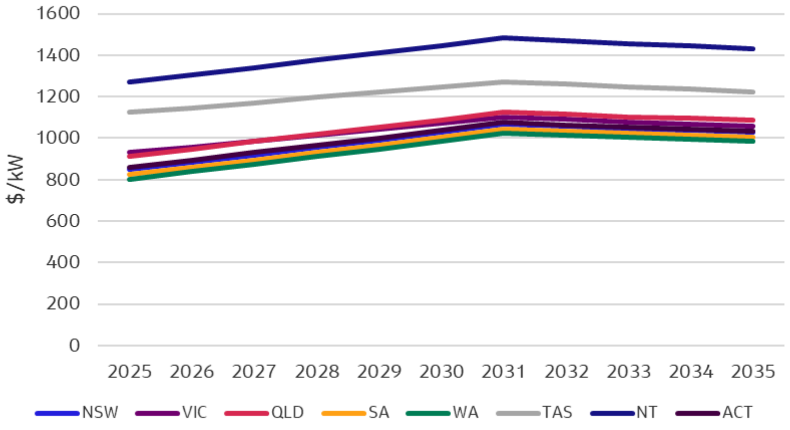
[5] https://www.solarchoice.net.au/solar-panels/solar-power-system-prices/

[6] https://data.csiro.au/collection/csiro:44228

Figure 4-12: Net capital costs, residential solar PV systems ($/kW 2025)

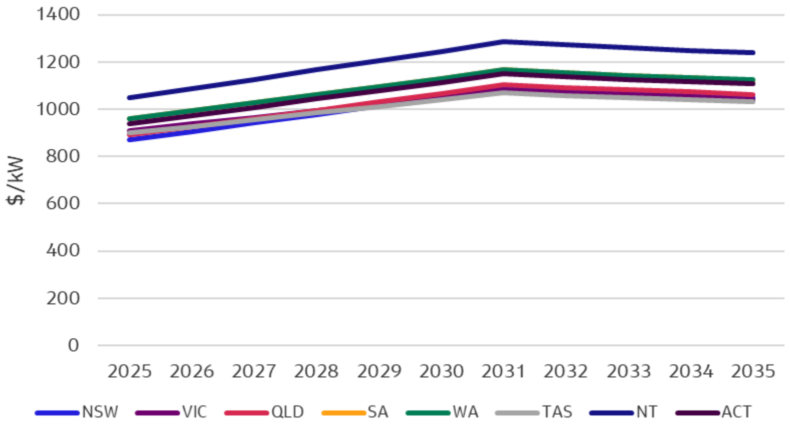


Source: Jacobs' market analysis, Solar Choice, CSIRO GenCost 2024-25

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 2025 to 2035.

Economies of scale are not 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 4-13 shows the forecasted costs assumed for commercial systems.

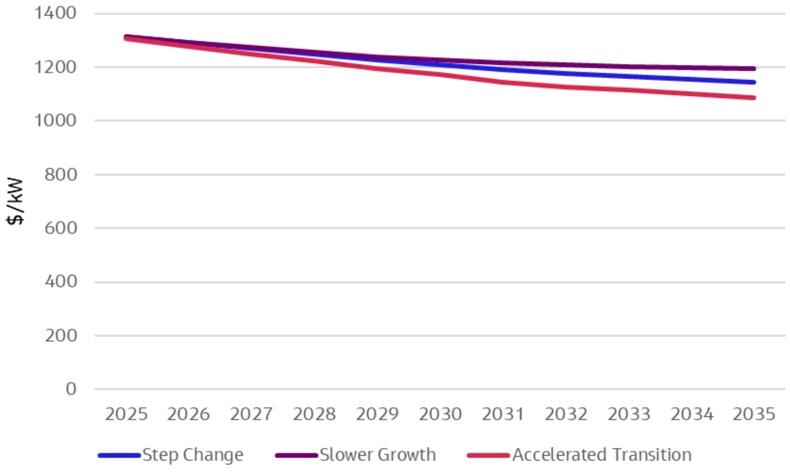
Figure 4-13: Net capital costs, commercial solar PV systems ($/kW 2025)



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

AEMO's Step Change scenario was used for the central forecast. AEMO's Slower Growth, and Accelerated Transition scenarios were used for a low and high capital cost forecast, respectively (Figure 4-15).

Figure 4-14: AEMO 2025 IASR Capital Costs projections (CSIRO GenCost 2024-25)



4.2.3 Retail electricity tariffs

Jacobs' in-house wholesale electricity price forecasts were used as the basis for estimating retail electricity prices at the commencement of the forecast period. Forecasted retail electricity tariffs were then derived using AEMO 2025 IASR retail electricity price NEM indices.

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.

4.2.3.1 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[7] 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

[7] 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

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. More detail on the market modelling assumptions and methodology is provided in Appendix A: Annual System Installations.

4.2.3.2 Network charges

Network charges are the costs associated with transmission and distribution of electricity for the retailers. These costs are set by network service providers who own the transmission infrastructure. The 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 2024 to 2029.

As large interconnector upgrades for transmission systems are expected in the NEM in the medium term, Jacobs has estimated additional charges expected to be passed onto customers.

The costs have been annualised over a 50-year period utilising a weighted average cost of capital (WACC) of 7.4%. This WACC is also utilised for renewables build-out in Jacobs' wholesale price modelling. The first year in which the annualised cost is applied is 1 year prior to assumed construction commencement date of the interconnector upgrades. The annual costs are then divided by the forecasted regional demand to present a cost per MWh of electricity usage.

4.2.3.3 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 CER.

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 forward prices have retained significant value. In the future, additional demand from voluntary cancellations to meet private sector decarbonisation goals is expected to continue rapidly increasing, being the primary driver for retaining value of LGCs.

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[8] in relation to operational demand and multiplying by the relevant state or territory FiT rate.

4.2.3.4 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 energy purchases. These fees, charged by the AEMO to retailers, are applicable to wholesale black energy purchases and are $0.57/MWh in FY2024 according to the AEMO 2023-24 Budget and Fees. AEMO has forecast an increase of 4.5% in NEM fees from FY2023 to FY2025. For the years beyond FY2025, Jacobs has assumed a continuation of the previous growth per year (approximately 2% for NEM fees) up to FY2030.

In addition to these fees, AEMO also recovers the costs for Full Retail Contestability ($0.094/MWh in FY2023) and Energy Consumers Australia (ECA), a body which promotes the long-term interests of small energy consumers (approximately $0.04/MWh for residential and SME customers, annualised). The NEM 5 Minute and Global Settlements (5MS) charge and NEM Distributed Energy Resources (DER) program charges are now $0.24/MWh and $0.0296/MWh respectively.

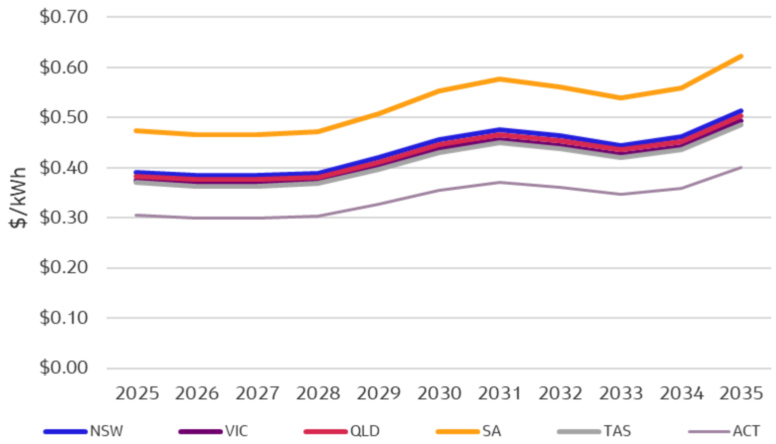
4.2.3.5 Retailer costs and margin

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.

4.2.3.6 Retail electricity tariff

Figure 4-15 shows the retail electricity prices for each state in the National Electricity Market (NEM). Northern Territory and Western Australian prices are regulated by the state government, and it is assumed these will remain constant.

Figure 4-15: Residential retail electricity tariff forecasts, NEM regions

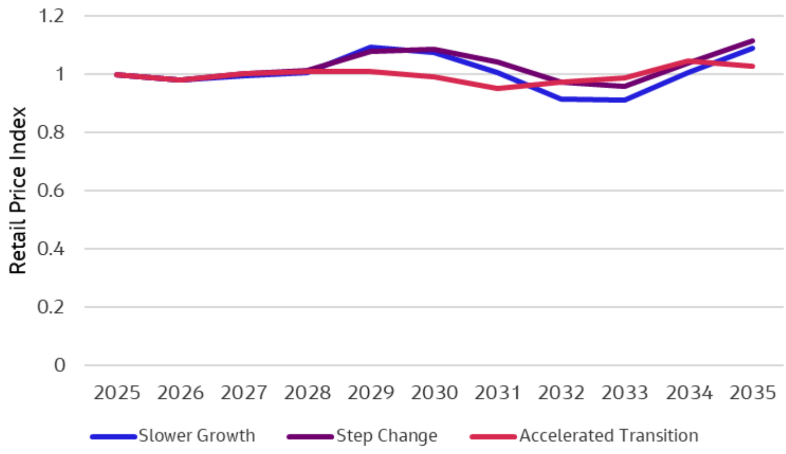


Source: Jacobs' market modelling; AEMO 2025 IASR

AEMO's Step Change scenario was used for the central forecast. AEMO's Slower Growth, and Accelerated Transition scenarios were used for a low and high retail price forecast, respectively (Figure 4-16).

[8] Jacobs noted the ability of certain operators having export limit (back to the grid) which is assumed to be small percentage of the base currently. The impact will be significant in the future as more behind the meter technologies continue to grow, assuming networks limit remain the same or very limited augmentations.

Figure 4-16: AEMO 2025 IASR Retail Electricity Price Indices



4.2.4 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.

The Northern Territory and Western Australian governments have reduced their 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 2.25c/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 downwards in response to the recovered wholesale electricity prices, and further diminished value of solar generation from low daytime demand (from high rooftop PV penetration), and high daytime supply (from utility solar). The FY2025 benchmarked FiT has lowered from 7.7-9.4 c/kWh in FY2024 to 4.9-6.3 c/kWh. Similarly in Victoria, the minimum flat feed-in tariff has been reduced to 3.3 c/kWh in 2025, from 4.9 c/kWh in 2024.

4.2.5 STC prices

Figure 4-17 shows the historical STC prices for the period January 2018 to June 2024. 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 4-17: Monthly historical STC price (nominal)

Source: Jacobs' analysis of Demand Manager data

4.2.5.1 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[9] 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. Table 4-5 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 2024 will have a maximum deeming period of 7 years. As a result, the number of STCs created per kW reduces by a greater rate each year.

Table 4-5: Average STCs generated per kW of PV installed

Region	Pre-2017[10]	2024	2025	2026	2027	2028	2029	2030
New South Wales	20.7	9.8	8.4	7.0	5.6	4.2	2.8	1.4
Victoria	17.8	8.8	7.5	6.3	5.0	3.8	2.5	1.3
Queensland	20.6	9.7	8.3	6.9	5.5	4.1	2.8	1.4
South Australia	20.5	9.6	8.3	6.9	5.5	4.1	2.8	1.4
Western Australia	20.6	9.7	8.3	6.9	5.5	4.1	2.8	1.4
Tasmania	17.6	8.2	7.1	5.9	4.7	3.5	2.4	1.2
Northern Territory	23.2	10.8	9.2	7.7	6.1	4.6	3.1	1.5
Australia Capital	20.6	9.6	8.3	6.9	5.5	4.1	2.8	1.4

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

[10] For a 15-year deeming period

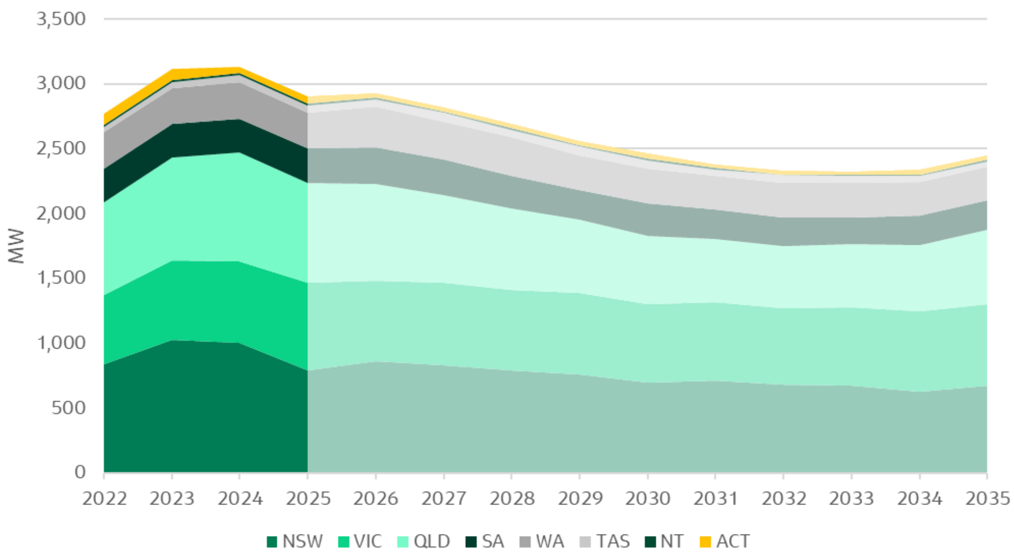
5. Results

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) 2022 are given for context.

5.1 Rooftop PV capacity

Historically, rooftop solar PV installations in Australia have had successive years of increased uptake rates driven by premium feed-in tariffs, falling capital costs, and attractive government rebates and interest-free loans. Notably, even during the COVID-19 era there continued to be record-breaking levels of rooftop PV uptake. However, although there is variation among different states/territories and across different sectors, nationally, the rate of uptake has begun to slow down compared to previous years. Across Australia, 2,903 MW of rooftop PV capacity is expected to be installed by the end of 2025 (Figure 5-1). By comparison, in 2023 and 2024 there was 3,116 MW and 3,133 MW rooftop PV capacity installed, respectively.

Figure 5-1: Small-scale PV state forecasts, annual installed capacity, Base scenario



Source CER dataset, Jacobs' projections

Several drivers are responsible for the fall in annual installed capacity, some of which are projected to continue impacting future uptake throughout the forecast period. Retail electricity tariffs have historically had a positive correlation to rooftop PV uptake in many regions across Australia (particularly across the east coast). During the 2022 energy crisis, the National Electricity Market (NEM) experienced prolonged periods of high wholesale electricity prices, largely caused by the undersupplied global gas market. These sustained prices in the wholesale market flowed through to retail tariffs from the second half of 2023 boosting rooftop PV uptake as consumers looked to reduce their need to import electricity from the grid. Although the Australian east coast wholesale electricity market recovered in 2023 (down from record high prices in 2022), these price reductions have only been reflected in retail tariffs (independent of the Energy Bill Relief Fund) from 2025 due to the lag caused by retail hedging practices. As a result, lower electricity prices reduce the net financial benefit of PV systems leading to an expected decline in annual installed capacity for 2025.

Retail electricity prices are forecasted to continue falling until 2026-2027 (driven by similar reductions to wholesale electricity prices), before reversing in 2028 and steadily climbing until the end of the forecast period.

Stagnant capital costs and falling feed-in tariffs are key factors driving the decline in rooftop PV uptake. From 2026, the rate of cost reductions is expected to slow and is now being outpaced by the decreasing value of

STC subsidies, which drop each year as the deeming period shortens. System costs are still recovering from inflationary pressures linked to global demand, while feed-in tariffs continue to fall in several states due to increased solar supply, reducing the value of daytime generation. As a result, payback periods have become less attractive, leading to a projected decline in annual rooftop PV installations—from 2,815 MW in 2027 to 2,462 MW by 2030. After 2030, uptake is expected to stabilise, averaging 2,363 MW annually from 2031 to 2035, as capital costs resume their decline and retail electricity prices rise.

The cumulative installed rooftop PV capacity increases from 28,313 MW at the end of 2025 to 53,574 MW by the end of 2035.

Table 5-1 displays the annual installed rooftop PV capacity for each state/territory and sector. Annual installations per region are tabulated in Appendix A: Annual System Installations. Forecasts for small-scale rooftop PV systems are also provided under a low and high scenario, also found in Appendix A.

Table 5-1: Annual installed rooftop PV capacity (MW), Base scenario

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
RESIDENTIAL											
Australian Capital Territory	43	20	27	26	25	32	22	20	21	39	29
New South Wales	645	723	705	678	658	610	632	602	603	557	604
Northern Territory	12	16	4	11	4	11	7	3	7	5	14
Queensland	648	614	576	520	471	449	427	422	439	459	529
South Australia	219	219	225	206	191	216	195	200	180	203	196
Tasmania	47	48	65	49	64	58	45	54	47	40	36
Victoria	527	493	528	517	535	507	513	516	527	543	551
Western Australia	234	269	251	266	236	241	232	241	239	235	227
Total Residential	2,375	2,402	2,381	2,272	2,183	2,124	2,073	2,058	2,064	2,080	2,187
COMMERCIAL											
Australian Capital Territory	9	6	5	5	4	4	4	5	4	3	3
New South Wales	144	135	121	110	101	85	80	74	70	69	68
Northern Territory	6	3	4	3	3	3	3	3	2	3	2
Queensland	120	135	97	112	92	74	62	54	51	48	48
South Australia	53	62	50	48	39	35	32	21	24	25	29
Tasmania	7	6	6	5	4	5	5	4	4	5	5
Victoria	150	131	114	102	94	99	88	79	75	79	76
Western Australia	39	44	37	33	32	32	30	28	28	29	29
Total Commercial	**528**	**522**	**435**	**418**	**371**	**338**	**303**	**268**	**258**	**261**	**262**
Total Capacity	**2,903**	**2,924**	**2,815**	**2,691**	**2,554**	**2,462**	**2,376**	**2,326**	**2,322**	**2,341**	**2,449**

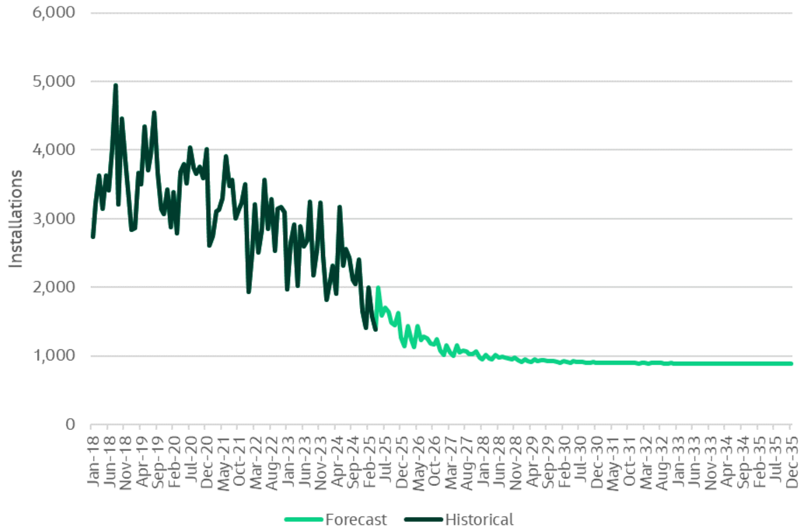
5.2 Water heater Installations

The ARIMA time series model forecasted the monthly installations of residential and commercial solar water heaters and residential air source heat pumps. Annual multipliers were applied to the forecasted installations to project the resultant number of STCs.

5.2.1 Solar water heaters

Figure 5-23 shows the historical and forecasted installations for residential solar water heaters across Australia. Historical installations have been declining since late 2018, which has coincided with the rise in residential air source heat pumps. This mild downtrend is expected to continue across the forecast period as air source heat pumps continue to rise in popularity amongst households and gradually replace its market share. In the long-term, residential installations are expected to stabilise to a baseline level which reflect the demand for solar water heaters independent of cost-competitive alternatives like air source heat pumps. Forecasted installations are tabulated in Appendix A.

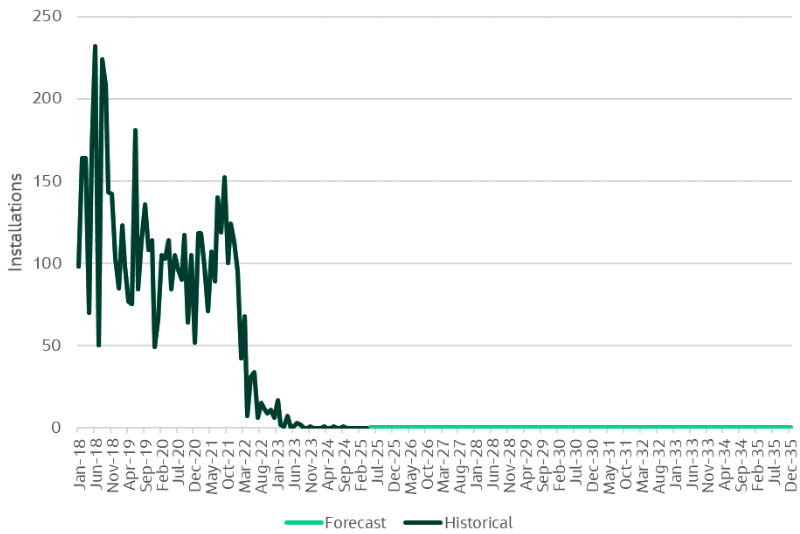
Figure 5-2: Australian residential solar water heater installations, monthly (≤40 STCs per installation)



Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

Historical and forecasted installations for commercial solar water heaters are shown in Figure 5-34. Since early 2022, the number of commercial installations has dropped significantly, decreasing to less than 200 installations per year across Australia. Like residential solar water heaters, the slump in commercial installations is likely attributed to air source heat pumps which have also gained popularity in the commercial sector. In the future, it is projected that only a handful of commercial solar water heaters will be installed every year, whilst businesses opt instead for the energy efficient air source heat pumps.

Figure 5-3: Australian commercial solar water heater installations, monthly



Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

5.2.2 Air source heat pump water heaters

Historical and forecast installations for residential air source heat pumps are shown in Figure 5-45. There have been no STCs awarded to commercial units since 2013, therefore, commercial installations of ASHPs have not been forecast. Prior to 2022, the majority of air source heat pump installations were attributed solely to Victoria which provided financial incentives through its Victorian Energy Upgrade (VEU) program. From late 2022, the commencement of NSW's Peak Demand Reduction Scheme (PDRS) provided attractive incentives in addition to those from the Energy Saving Schemes (ESS) and SRES. This caused a significant spike in air source heat pump installations in NSW, peaking in September 2023. However, from 1 August 2024 air source heat pumps eligible under the SRES had been excluded from the PDRS, decreasing the financial incentives available to it and sharply reducing uptake for air source heat pumps in NSW. Conversely, Victoria and ACT have banned gas connections to new home builds which will increase demand for residential air source heat pumps in these regions. Over the next two years, air source heat pump installations are projected to continue at its current rate of uptake as rising installations in Victoria are offset by the slightly falling rate of uptake in NSW. In the long-term, all regions are projected to install at a steady rate. The forecasted installations for each state and territory are tabulated in Appendix A.

Figure 5-4: Australian Residential installations for air source heat pumps, monthly

Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

5.3 STC Projections

The projections for STCs created are shown in Table 5-23. 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 2025, a total of 24.7 million STCs is projected to be generated.

Table 5-2: STC creation projections ('000s)

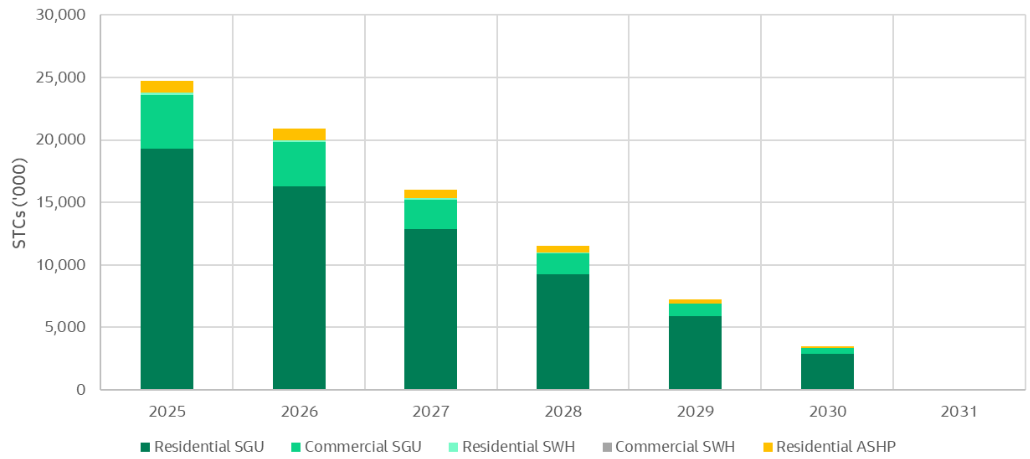
	2025	2026	2027	2028	2029	2030
RESIDENTIAL Solar PV						
Australian Capital Territory	355	141	147	107	69	44
New South Wales	5,419	5,059	3,948	2,845	1,841	854
Northern Territory	114	124	24	51	12	17
Queensland	5,366	4,235	3,179	2,155	1,299	619
South Australia	1,806	1,506	1,237	849	525	297
Tasmania	333	281	304	174	150	68
Victoria	3,971	3,100	2,657	1,949	1,345	637
Western Australia	1,933	1,854	1,387	1,100	650	333
Total Residential	**19,298**	**16,300**	**12,882**	**9,229**	**5,891**	**2,869**
COMMERCIAL Solar PV						

Australian Capital Territory	75	44	29	19	12	5
New South Wales	1,207	946	676	461	284	119
Northern Territory	59	24	24	15	11	5
Queensland	996	930	538	465	255	103
South Australia	440	426	277	198	107	48
Tasmania	47	33	29	19	10	6
Victoria	1,133	822	573	385	237	125
Western Australia	318	306	202	137	88	45
Total Commercial	**4,275**	**3,531**	**2,349**	**1,699**	**1,004**	**455**
TOTAL SOLAR PV STCs	**23,573**	**19,831**	**15,231**	**10,928**	**6,896**	**3,324**
Residential Solar Hot Water	235	221	152	105	67	33
Commercial Solar Hot Water	0.072	0.090	0.072	0.054	0.036	0.018
Residential Air-sourced Heat Pump	918	950	716	527	348	174
ALL STCs	**24,726**	**21,002**	**16,099**	**11,559**	**7,311**	**3,530**

Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

Figure 5-56 illustrates the STC creation projections by sector. STC trends are largely linked to residential rooftop PV installations which comprised the largest portion of STCs created. The fall in STCs between 2025 to 2030 is a result of both fewer STCs generated per kW of small-scale solar, and the decline in annual installed small generation unit (SGU) capacity.

Figure 5-5: Total STC annual projections



Source CER dataset, 2025 incomplete dataset, Jacobs' analysis

Commercially sized solar water heating 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 solar water heating systems will continue a modest decline, and the uptake of air source heat pump systems is expected to continue for the remainder of the forecast horizon, with its STCs falling only with the deeming period.

Appendix A. Appendix A: Annual System Installations

A.1 Small-scale PV

Table A-1 shows the total projected annual installations of small-scale PV systems for each Australian state and territory. Installations for 2025 are estimates from historical data accounting for registration lag.

Table A-1: Total projected annual small-scale PV installations – Base Case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	74,786	66,864	72,219	24,482	31,342	5,507	1,174	4,566
2026	79,584	58,762	70,264	25,410	37,314	5,532	1,731	2,217
2027	74,642	60,980	64,961	25,452	34,671	7,240	719	2,686
2028	69,612	57,592	59,559	22,545	36,336	5,422	1,293	2,445
2029	66,080	57,203	52,889	20,757	32,727	6,769	742	2,262
2030	60,000	53,294	50,323	22,665	32,690	5,995	1,237	2,664
2031	61,553	52,891	48,264	20,483	32,915	4,673	991	1,847
2032	57,830	52,445	48,058	20,764	33,383	5,403	718	1,740
2033	59,300	53,228	50,937	19,817	33,734	4,489	929	1,774
2034	51,846	53,379	45,706	20,148	30,221	3,774	755	2,997
2035	51,354	50,389	46,677	17,488	28,557	3,536	1,361	1,956

Source: Jacobs' projections

Table A-2: Total projected annual small-scale PV installations – Low case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	74,786	66,864	72,219	24,482	31,342	5,507	1,174	4,566
2026	75,187	47,914	62,027	20,679	38,004	4,675	1,246	2,269
2027	65,660	50,424	56,860	21,699	34,548	3,325	1,159	1,621
2028	60,679	45,433	50,716	22,850	33,781	3,075	825	1,993
2029	55,508	50,374	51,332	18,344	33,518	3,661	796	2,213
2030	55,636	45,758	49,620	17,483	30,369	2,254	958	1,728
2031	48,565	43,619	45,956	20,885	28,363	2,713	856	2,191
2032	49,211	45,322	42,513	18,898	29,735	3,040	949	1,727
2033	48,200	48,664	45,189	21,430	31,874	2,756	809	3,092
2034	48,145	41,605	44,199	16,049	26,095	3,078	750	1,774
2035	44,486	46,684	35,311	16,370	28,082	1,715	1,041	1,907

Source: Jacobs' projections

Table A-3: Total projected annual small-scale PV installations – High case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	74,786	66,864	72,219	24,482	31,342	5,507	1,174	4,566
2026	79,628	65,492	72,101	30,257	39,939	5,219	1,471	1,831
2027	78,182	66,869	67,039	26,402	36,973	5,103	844	1,964
2028	73,819	60,743	62,926	24,607	35,570	5,433	971	2,660
2029	64,391	61,635	57,233	23,602	34,780	5,897	1,048	2,201
2030	66,321	56,758	51,499	22,976	35,228	6,030	846	2,607

2031	55,725	56,291	47,640	21,718	32,714	4,340	1,069	2,508
2032	58,669	56,749	48,984	20,811	36,414	3,794	1,466	2,334
2033	60,213	60,374	53,814	23,774	35,504	4,853	1,094	2,238
2034	52,472	54,612	48,653	19,754	34,977	2,857	1,367	2,351
2035	51,446	53,835	47,732	15,205	30,375	2,866	522	2,769

Source: Jacobs' projections

Total annual installed capacity for small scale solar PV under the base, low and high cases are outlined below.

Table A-4: Total projected annual small-scale PV capacity (MW) – Base case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	789	677	768	272	272	54	19	52
2026	858	624	748	281	313	53	19	27
2027	826	642	673	275	288	71	8	32
2028	788	619	633	253	299	55	14	31
2029	759	629	563	230	268	68	8	29
2030	695	607	523	251	274	63	14	36
2031	712	601	489	227	262	50	10	26
2032	676	595	476	221	269	58	6	24
2033	673	602	491	204	267	51	9	26
2034	626	622	507	228	263	45	8	42
2035	672	628	578	225	256	41	17	32

Table A-5: Total projected annual small-scale PV capacity (MW) – Low case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	789	677	768	272	272	54	19	52
2026	805	513	657	234	297	44	14	28
2027	698	521	576	232	274	31	14	19
2028	666	487	518	242	269	31	9	24
2029	611	523	519	196	259	35	8	26
2030	617	483	488	185	234	24	11	20
2031	537	456	438	205	205	27	9	26
2032	535	467	393	185	215	32	10	20
2033	519	501	397	193	224	30	7	34
2034	554	449	435	158	183	32	8	23
2035	529	505	402	166	208	21	12	24

Source: Jacobs' projections

Table A-6: Total projected annual small-scale PV capacity (MW) – High case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	789	677	768	272	272	54	19	52
2026	861	675	765	326	327	51	17	22
2027	862	696	697	286	305	50	9	24
2028	834	655	669	272	297	55	11	33
2029	742	674	604	262	284	59	11	29
2030	770	638	535	255	292	63	9	36

2031	646	632	484	242	262	46	11	34
2032	682	644	485	227	289	41	13	32
2033	685	686	516	246	276	55	11	31
2034	633	640	542	226	300	34	15	34
2035	675	677	590	200	269	33	6	46

Source: Jacobs' projections

Total annual STC creation from small scale solar PV under the low and high cases are outlined below.

Table A-7: Total projected annual small-scale PV STCs ('000) – Base case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	6,626	5,104	6,362	2,245	2,252	381	174	430
2026	6,005	3,922	5,166	1,932	2,161	314	148	184
2027	4,624	3,230	3,717	1,514	1,589	333	48	176
2028	3,306	2,334	2,620	1,047	1,236	192	65	126
2029	2,125	1,581	1,555	633	738	160	23	81
2030	973	762	722	345	378	74	21	49
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-

Source: Jacobs' projections

Table A-8: Total projected annual small-scale PV STCs ('000) – Low case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	6,626	5,104	6,362	2,245	2,252	381	174	430
2026	5,636	3,225	4,533	1,608	2,047	256	106	193
2027	3,909	2,620	3,180	1,280	1,511	148	86	104
2028	2,797	1,836	2,145	999	1,111	108	41	98
2029	1,711	1,315	1,432	539	714	82	24	71
2030	863	607	674	254	323	28	16	27
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-

Source: Jacobs' projections

Table A-9: Total projected annual small-scale PV STCs ('000) – High case

	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
2025	6,626	5,104	6,362	2,245	2,252	381	174	430
2026	6,006	4,224	5,156	2,169	2,236	299	129	151
2027	4,807	3,495	3,791	1,543	1,638	238	55	134
2028	3,477	2,467	2,719	1,071	1,196	193	50	136
2029	2,089	1,682	1,611	707	779	140	35	77

2030	1,068	791	736	344	380	77	12	47
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-

Source: Jacobs' projections

A.2 Water heaters

Table A-10 shows the total projected annual installations of water heater per technology.

Table A-10: Total projected annual water heater installations

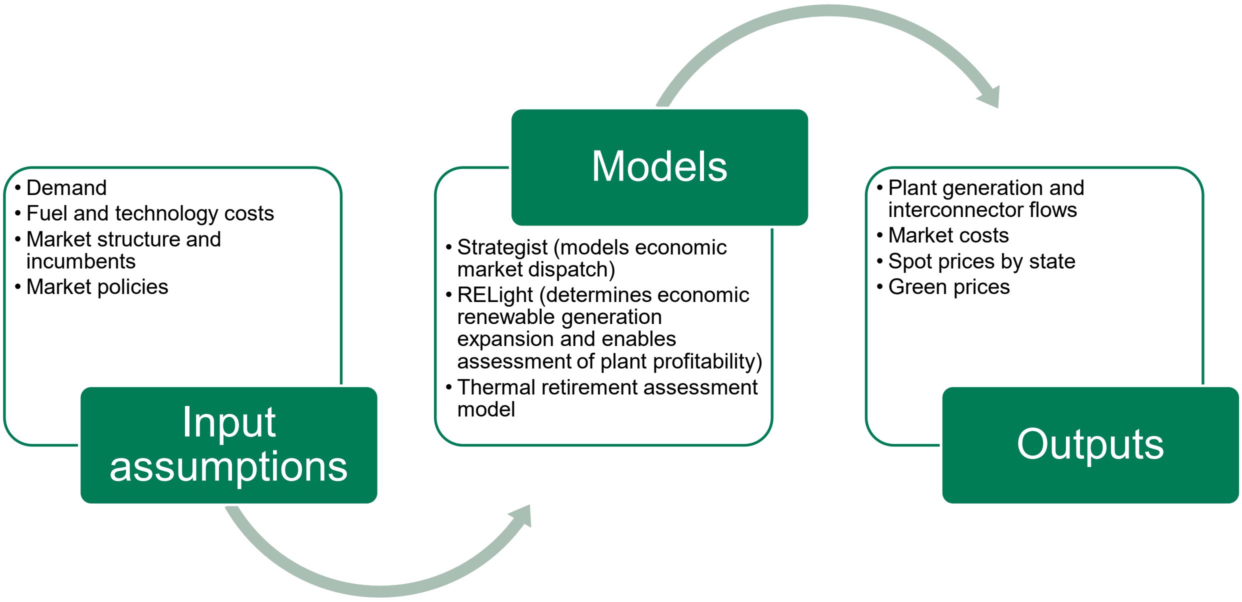
	Commercial Solar Water Heater	Residential Solar Water Heater	Air Source Heat Pump
2025	3	19,148	75,475
2026	4	14,812	65,403
2027	4	12,697	61,727
2028	4	11,665	60,505
2029	4	11,162	60,070
2030	4	10,917	59,907
2031	4	10,797	59,843
2032	4	10,738	59,818
2033	4	10,710	59,808
2034	4	10,696	59,804
2035	4	10,689	59,802

Source: Jacobs' projections

Appendix B. Appendix B: NEM modelling method and assumptions

A.1 Overview

Market models have been developed to determine a least cost market development plan and the likely outcome with respect to each scenario's underlying assumptions. Market models create the foundation for the wholesale price projections. An overview of the approach is displayed below with additional detail to be provided in later sections of this report.



The market forecasts consider regional demand forecasts, generating plant performance, timing of new generation including embedded generation, existing interconnection limits, and the potential for interconnection development. Jacobs used its Strategist and RELight models to develop long-term time weighted prices to the year 2030. Strategist models the NEM, whilst RELight models the details of the renewable energy market.

The dynamic programming method in Strategist selects new capacity on a least-cost basis. In Jacobs' experience the model has been generally accurate in the prediction of the future generation mix, with the main deviations from predicted investment the result of:

- Economies of scale.
- Pre-emptive new entry.
- Fuel supply arrangements.
- Interconnection upgrades included in the Strategist modelling as development options in competition with new generation capacity.

Future wholesale electricity prices and related market outcomes are driven by the supply and demand balance, with long-term prices being effectively capped at the cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and emissions intensity threshold will have a noticeable impact on long-term price forecasts.

Year-to-year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power.

Negative price period prices are limited in the modelling for the following reasons:

- We model hourly demand profiles for typical weeks in each month of the projection period.
- The modelling is optimised over average weather conditions (50% probability of exceedance) so does not model outcomes for when we have warmer than normal days in winter or hotter than normal days in summer.
- Modelling includes transmission and interconnector upgrades, which will relieve network constraints and remove bottlenecks on interconnectors.
- Significant uptake of storage and EV charging (in the long-term) which means that middle of day demand is boosted.
- Continuing uptake of solar PV in our models is limited by the level of profitable entry. If we have too many zero or negative price periods, then prospective new plants may not earn enough revenue to recover capital and investment costs, and hence they do not enter the market. Similarly, if there are too many zero price periods, then eventually some incumbent thermal plants become unprofitable and are retired.
- We have included an emission penalty, which does increase dispatch prices for thermal plant in middle of the day.

Key assumptions used in the modelling include:

- Capacity is installed to meet the target reserve margin in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets. It is assumed that this is already included in the demand forecasts provided by AEMO.
- Wind generation is based on observed wind power generation profiles for each region in 2019.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Infrequently used peaking resources are bid near the market price cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- The LRET target is for 33,000 GWh of renewable generation by 2020. Additional renewable energy is included for expected GreenPower sales and desalination purposes.