Projections of uptake of small-scale systems

Australian Energy Market Operator

Final

9 June 2017

Projections of uptake of small-scale systems

Project No:	RO072200
Document Title:	Uptake of small-scale systems
Revision:	Final
Date:	9 June 2017
Client Name:	Australian Energy Market Operator
Project Manager:	Walter Gerardi
Author:	Walter Gerardi, Damien O'Connor

Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
Melbourne VIC 8009 Australia
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

Contents

Executive Summary

This report presents PV uptake forecasts prepared by Jacobs for the Australian Energy Market Operator (AEMO). These forecasts will feed into the electricity operational consumption and peak demand modelling that will be used to produce the 2017 National Electricity Forecasting Report (NEFR) and the 2017 Wholesale Electricity Market Electricity Statement of Opportunities (WEM ESOO).

Three scenarios were explored as part of this modelling exercise: "Neutral", "Strong" and "Weak" scenarios. Last year AEMO changed its basic approach to formulating the market scenario. Whereas previously AEMO attempted to capture the full range of what may eventuate in the electricity market, they now reflect a narrower range of economic conditions against a most likely future development path. Economic conditions considered include factors such as population growth, the state of the economy and consumer confidence. The neutral scenario reflects a neutral economy with medium population growth and average consumer confidence, the strong scenario reflects a strong economy with high population growth and strong consumer confidence and the weak scenario represents a weak economy with low population growth and weak consumer confidence. For the modelling of PV uptake, different expectations around cost of systems (subject to the different exchange rates adopted in each scenario) ground each scenario. For the NEM regions, there were also differences in retail tariffs, for the WEM, the retail tariffs were the same across all scenarios.

The modelling of battery storage is challenging because this technology is emerging and rapidly changing. In particular, the future cost, life and technical capacity of batteries is subject to considerable uncertainty and these elements drive the future uptake of PV systems with storage. In this study, data for battery costs were obtained from published data sources with an assumed cost reduction based on recent published studies. The forecast uptake of PVs with and without storage is based on Jacobs' DOGMMA model, an optimisation tool that seeks to minimise total energy supply costs.

The study has found trends in uptake for PV and Integrated PV and Storage Systems (IPSS) in all regions can be explained by trends in financial incentives provided, declining installation costs of the systems, changes in retail prices, and assumptions on the transition to a time-of-use tariff structure and steady population growth.

The annual uptake of PV systems in Australia is forecast to grow over the next decade in response to increases in wholesale prices and continuing reductions in system costs. Beyond that period, uptake slows as network tariffs move to higher proportion of the fixed tariff component and the move to time of use pricing sees lower retail price offsets. This results in a total uptake in 2037 in the Neutral scenario of 19.7 GW of capacity in the NEM regions and 2.8 GW in the South West Interconnected in Western Australia. Uptake in the commercial sector is forecast to continue increasing to a penetration of around 26% of total systems installed by 2037. IPSS are projected to have a strong and steady growth in uptake especially after 2020, coinciding with further reduction of their installation costs and the transition to a more cost reflective tariff structure. IPSS capacity is expected to grow to around 5.3 GW of systems being adopted by the end of the forecast period, with battery storage capacity of around 5.8 GW and 11.5 GWh.

In Queensland, the strong growth of PV and IPSS uptake continues over the next decade before lower offsets sees growth slow in the residential sector. Growth in the commercial sector is projected to be higher than for the residential sector. The total capacity of systems at the end of forecast period is 5,134 MW.

New South Wales is found to have the strongest growth of all States in PV systems installed in both residential and commercial segments, with IPSS representing greater than 30% of annual PV installations after 2020. The total capacity of systems installed in the state is forecast to be 7,800 MW in 2038.

Growth in uptake of residential PV systems in South Australia declines because saturation has been reached in some regions, with the commercial sector forecast to have a steady growth.

The study forecasts a steady adoption of PV systems in Victoria will continue up until when saturation is reached in some regions (expected around 2030). The faster transition to a time-of-use tariff structure in this state contributes to rapid penetration of PV systems with battery storage so that there is a projected storage capacity of 2,400 MWh installed at the end of 2038.

Growth of PV installations in both the residential and commercial segments is slowest in Tasmania due to lower insolation levels that results in lower financial attractiveness of the systems.

Both the residential and commercial sectors in the South West Interconnected System in Western Australia show a steady uptake of PV and IPSS systems throughout the entire forecast period. Due to the prevalence of SWIS residential subscribers undertaking flat tariffs, the small difference between peak and off-peak time-of-use prices is projected to be insufficient to stimulate significant uptake of IPSS systems.

By 2038, the uptake of systems across the NEM and the WEM in the Strong scenario was found to be 20% higher than the Neutral scenario, and the uptake in the Weak scenario was 18% lower than the Neutral scenario. The deviations between the three scenarios are due to the different installation capital costs of the systems and the different population levels assumed in each scenario.

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to provide estimates of uptake of PV and storage systems in the residential and commercial sectors across Australia, in accordance with the scope of services set out in the contract between Jacobs and AEMO (the Client). That scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, information provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context.

This report has been issued in accordance with the provisions of the contract between Jacobs and the Client. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

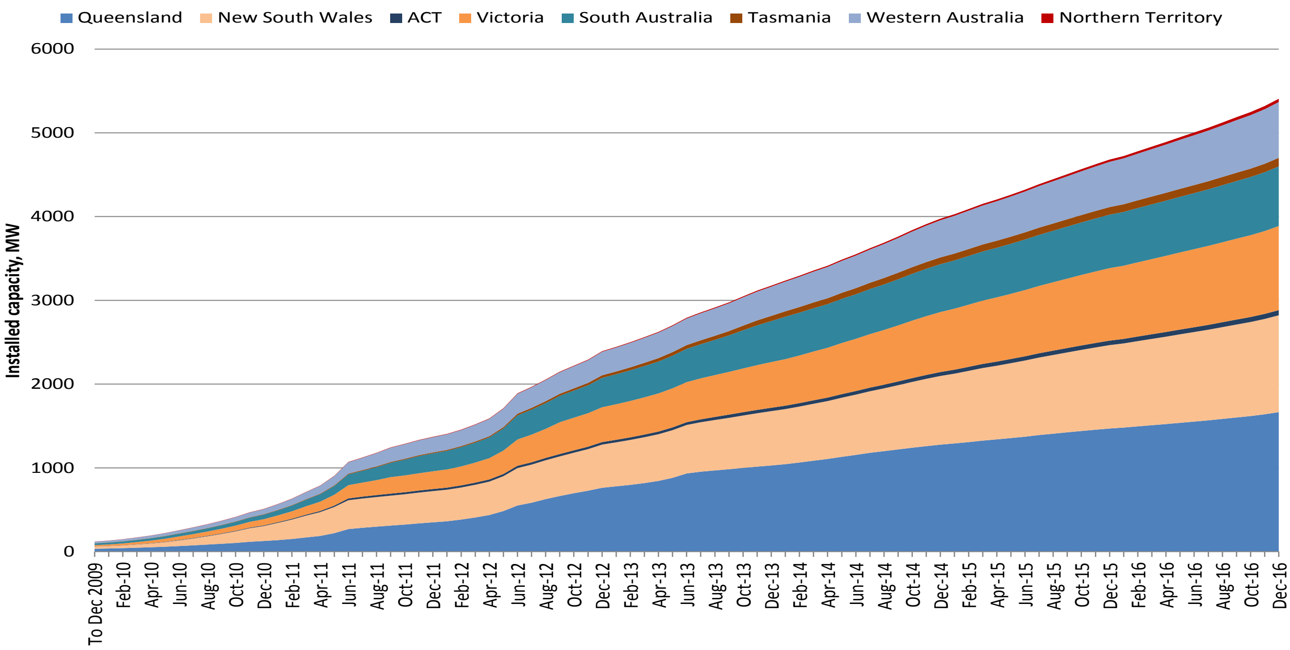
1. Introduction

AEMO has prepared forecasts of electricity consumption as part of the 2017 National Electricity Forecasting Report (NEFR) and the 2017 WEM ESOO. Forecasts of uptake of small-scale electricity generation systems and generation from those systems are required to determine the energy consumption and peak demand forecasts. Jacobs has been commissioned by AEMO to provide forecasts for solar PV generation and battery storage uptake for each of the States and Territories in the NEM and the SWIS regions of Western Australia up to 2037/38. Forecasts were provided for three scenarios described as Neutral, Strong and Weak scenarios. The scenario labels refer to the state of the economy, and broadly speaking respectively reflect average, low and high levels of consumer confidence.

2. Historical trends

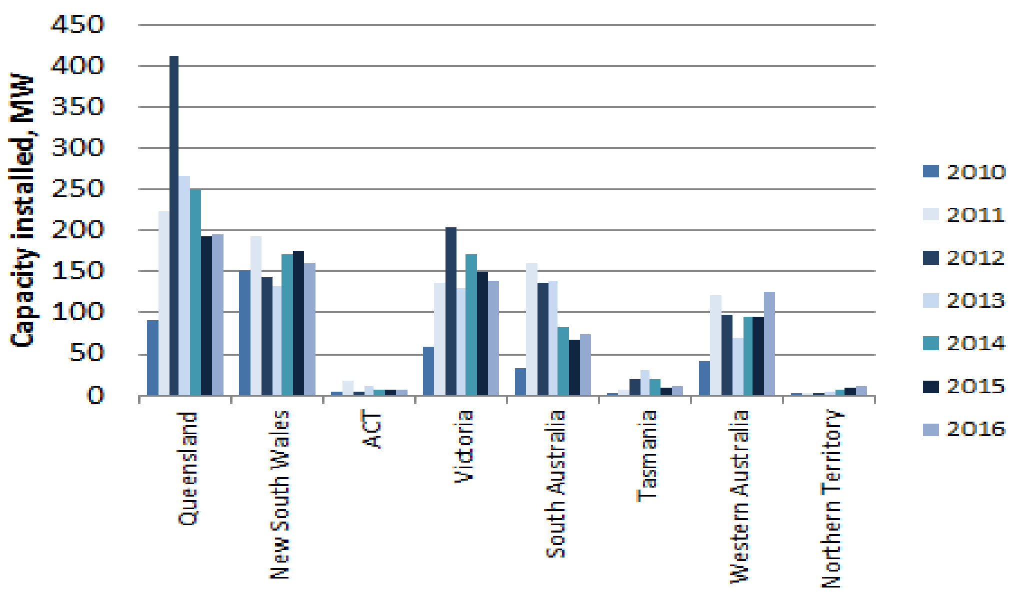
The historical capacity of small scale PV installed from 2009 to the end of 2016 by state and territory is shown in Figure 1. The aggregated small-scale PV capacity was estimated to be around 5,300 MW by the end of 2016 based on the latest Clean Energy Regulator (CER) data. The Australian PV market has grown significantly over that time period with growth rates peaking in 2012 (Figure 2) due to the rapid decline of the PV installation costs, supported by high state-based feed in tariffs and the Solar Credit Multiplier.

Figure 1: Small-scale solar PV capacity by state and territory



Source: Jacobs. Based on postcode data provided by the CER as at May 2017. As it can take up to 6 months for installed capacity to get registered, the data for the latter part of 2016 may be updated as more data is collected.

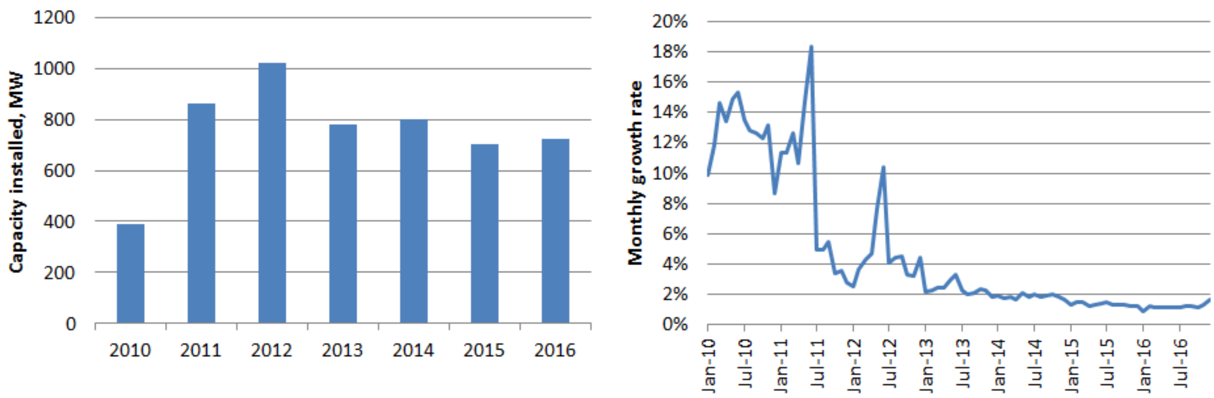
Figure 2: Small-scale solar PV capacity by state and territory



Source: Jacobs. Based on postcode data sourced from the Clean Energy Regulator

Since 2012 annual installed capacity has declined as the support mechanisms have progressively unwound, and the growth rate has slowed to around 1.5% per month (Figure 3). There has been a pick up over the last 6 months, which is particularly evident in Western Australia where uptake in 2016 is the highest recorded.

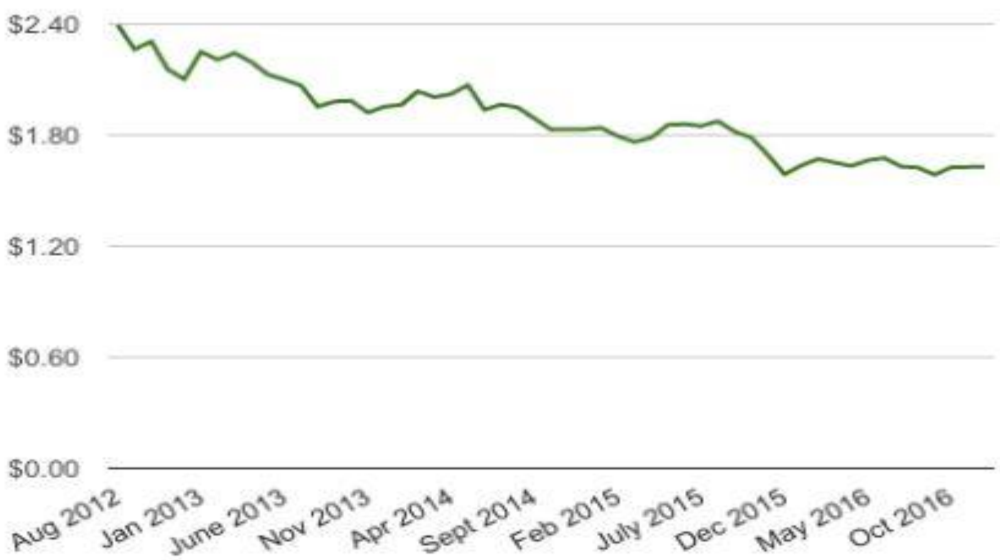
Figure 3: Small-scale solar PV annual capacity installed (left), historical growth rate (right)



Source: Jacobs. Based on postcode data sourced from the Clean Energy Regulator

The main driver for this uptake is the steady decline in PV system costs as shown in Figure 4 below.

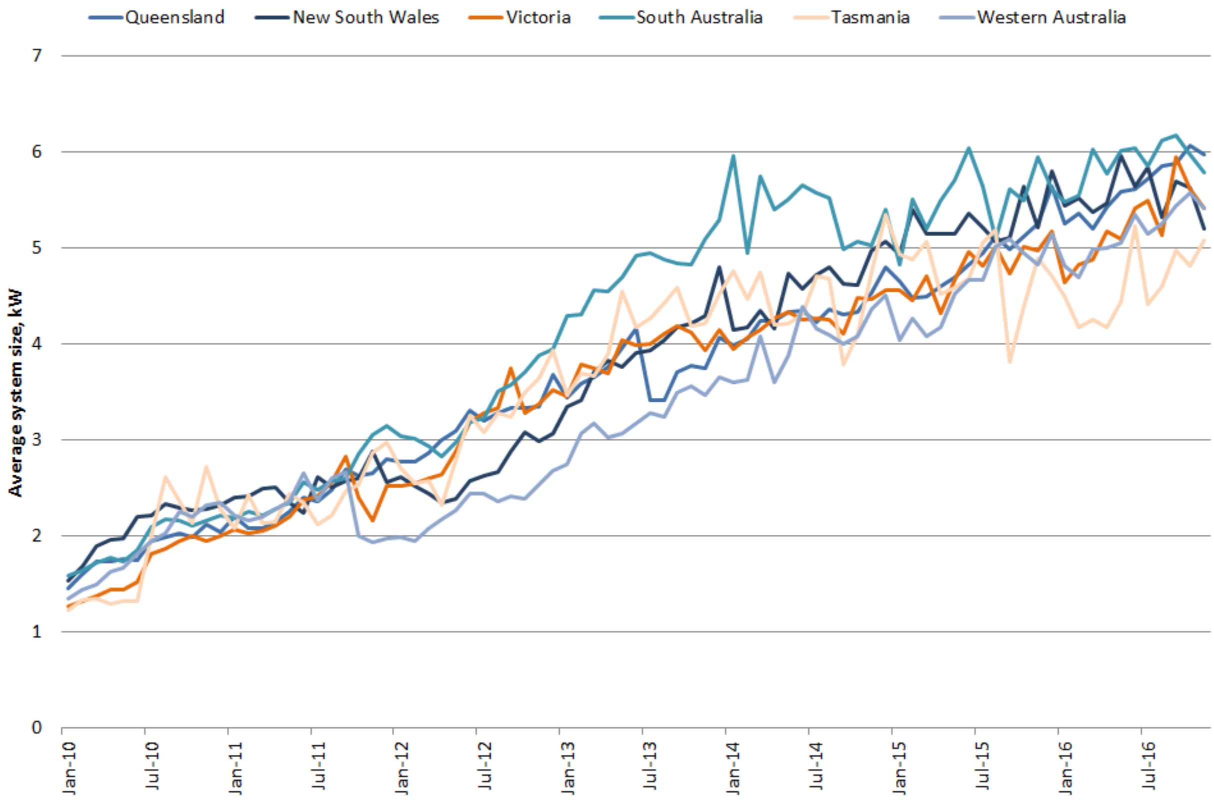
Figure 4: Average installed cost for all system sizes, $/W



Source: Solar Choice (2017), "Solar PV Power System Prices", March 2017 edition. The data points are the average of average $/W for each system size net of STCs.

At the same time, as shown in Figure 5, the average size of PV systems installed has shown strong growth since 2009 due to significant cost reductions that made larger PV systems more affordable to households and a higher level of uptake in the commercial sector (which can install larger system sizes).

Figure 5: Average PV system size



Source: Jacobs.

3. Methodology

3.1 Overview

Uptake of small-scale renewable distributed generation was forecast using Jacobs' structural model of distributed and embedded generation called *DOGMMA* (Distributed On-site Generation Market Model Australia). The model determines the uptake of small-scale renewable technologies based on comparing the net cost of generation against the net cost of grid delivered power. The model operates on a spatial and market basis, separately providing projections by region and customer class.

The factors considered are as follows:

- Eligible system Small-scale Technology Certificates (STC) creation for previous years, showing the historical trend in small-scale technology uptake;
- Change in cost of small-scale PV systems and Integrated PV and Storage Systems (IPSS) due to new technological and manufacturing improvements and changes in the cost of system components;
- State and Commonwealth incentive schemes and any expected changes to these schemes over the timeframe, including the impact of potential changes to the state-based feed-in tariffs;
- Changes to avoidable electricity retail prices, potential re-introduction of a carbon price mechanism, network regulatory reform (e.g. a number of networks are re-adjusting their tariffs to provide a higher revenue share from capacity based charges rather than variable charges);
- The forecast number of new dwellings;
- PV and IPSS system output and exports;
- Relevant legislative changes to the eligibility rules and criteria for small-scale PV systems;
- Global financial conditions, such as changes in currency values, and changes to the cost of raw materials;
- Changes in financial innovation, e.g. Clean Energy Finance Corporation loans, and business models;
- STC price; and
- Limiting factors for PV and IPSS uptake for households and businesses.

The model uses existing data as the starting point for the optimisation. The data includes:

- A database of historical installations has been collected from the Clean Energy Regulator website. The database contains monthly small-scale installation numbers and capacity by postcode from January 2010.
- ABS data on household numbers by postcode.
- Solar Choice data on installed cost of systems.

3.2 DOGMMA

DOGMMA determines the uptake of renewable technologies with and without storage based on net cost of generation (after revenue from exports of surplus generation and other subsidies are deducted from costs) versus the cost of grid delivered power avoided by self-generation.

Avoided grid costs from small-scale generation will vary by location because of differing insolation[1] levels which will affect the capacity factor of the units, as well as differing retail charges based on the network area of operation. The model is loaded with estimates of location specific insolation and tariff data enabling it to estimate generation and avoided grid costs from newly installed system.

The cost of small scale renewable energy technologies is treated as an annualised cost so that the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component[2], discounted using an appropriate weighted average cost of capital calibrated to match typical payback periods expected by customer groups (7 years for residential customers and 5 years for commercial customers).

The returns earnt by installed systems include:

- Revenues earnt from the sale of surplus electricity to the grid calculated using volume weighted electricity prices on the wholesale market[3];
- Avoided network costs under any type of tariff structure, including upgrade costs if these can be captured[4]; and
- The cost of avoided purchases from the grid based on the assumed variable portion (volumetric charge) of retail tariffs.

The net cost is determined by deducting revenues from annualised costs. Daily returns are aggregated to an annual basis, and DOGMMA then calculates the net cost by deducting annual returns from annual costs. In other words, the annual costs of distributed generation are offset by annual returns earnt on exports and by the avoided cost of electricity not purchased from the grid. The optimisation will continue to increase uptake (subject to the constraints imposed) until annual costs of uptake just exceeds the annual returns earnt.

3.2.1 Optimisation approach

The model selects the level of small-scale generation that minimises electricity supply costs to each region (where region is defined by ABS Statistical Areas). That is, the level of uptake that minimises the sum of the costs from operating roof-top PV systems (including annualised capital costs) and the cost of grid supplied electricity.

The level of uptake of small scale systems increases to the point where any further uptake leads to higher costs of electricity supply[5]. In each region, the average capacity factor dimishes with uptake on the presumption that additional systems are installed on roofs with less favourable aspects or with greater shading. The prices received for exported output (reflecting the cost of the wholesale component of electricity supply) also diminishes with higher uptake. There comes a point where these factors outweighs any benefit from installing PV systems (in the form of avoided delievered cost of electricity from the grid).

The optimisation matches the cost of small scale systems (capital costs and any operating costs) to the avoided grid supplied electricity costs (as would have been experienced by the customer in the absence of the system). The costs of small-scale systems may be reduced by being eligible for a subsidy (for example, the sale of certificates generated under the SRES scheme), or the ability to earn revenue either through sale of surplus

[1] Insolation is defined as the amount of solar energy received by a surface area on the earth over a period of time. The Bureau of Meteorology provides hourly Global Horizontal Irradiance (GHI) data measured in watts per square metre.
[2] Assumed lifespan is 25 years for PV modules, 15 years for inverters, and 10 years for batteries. An annual fixed cost is applied to each system to represent the replacement cost (annualised over the assumed lifespan) of each component.
[3] The wholesale price earnt on electricity exports is a volume weighted price where the hourly wholesale price is weighted by hourly pattern of PV generation.
[4] Although this is able to be calculated in the model, for this study it was assumed that avoided network upgrade costs were not able to be captured.
[5] The model allows a premium above grid supply costs for PV systems to account for the purchase behaviour of customers who are willing to pay more for their systems. The premium diminishes to zero as uptake increases on the assumption that only a portion of customers are willing to pay this premium.

electricity generation (surplus to the needs of the householder or commercial business) or from enacted feed-in tariffs.

The optimisation is affected by a number of constraints[6], which are as follows:

- There is a limit to the maximum number of householders and commercial businesses that can install a system:
    - The maximum proportion of residential households that can purchase the system is currently the same for each region and it is set at 55% of all households in the region[7]. This limit was determined by the number of separate dwellings (on the assumption that only separate dwellings would install systems) that are privately owned (on the assumptions that only privately owned dwellings would install systems), and allowing for some limits on installations for heritage or aesthetic reasons. For this modelling exercise, this limit was relaxed over time to account for the potential use of leasing arrangements in rented dwellings. The limit was gradually relaxed to 65% over a 20 year period commencing 2016.
    - The maximum proportion of commercial businesses that can install a system is 65% of electricity demand. Commercial customers are those in the wholesale and retail trade, schools, hospitals and government offices.
- There are limits on the rate of uptake of each technology in each region. This constraint is designed to ensure there is not a sudden step up in installation rates once a flip point is reached (the point at which the cost of PV and IPSS becomes cheaper than grid supplied electricity) and to account for any logistic constraints. Once the initial simulation is performed, these constraints are progressively relaxed if it appears the constraint is binding uptake for an extended period[8].
- There are limits on the number of homes and business premises that can accommodate the large sized systems of above 5 kW. We do not have data on the distribution of size of household roof space by region, so this constraint is enforced to limit uptake to around 20% of total households in each region[9].

The technology costs are also adjusted with premiums so that uptake predicted by the model matches historical uptake more closely. The premium reflects the willingness of some consumers to purchase PV systems even if the cost is above the avoided grid supply costs. We calculate the premium based on market survey data and other published market data. The premium is assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers)[10].

The costs avoided by small-scale PV systems with or without battery storage comprise wholesale electricity purchase costs (including losses during transmission and distribution), market and other fees, variable network costs, and retail margins.

---

[6] In previous modelling studies we were assuming that each household or business can invest either to a solar water heater or a PV system due to space scarcity. This constraint is no longer used.

[7] According to the ABS (see ABS (2013), *Household Energy Consumption Survey, Australia: Summary of results, 2012*, Catalogue No. 4670.0, Canberra, September), there are 8.7 million households in 2012 in Australia. Around 89.2% of these households where either separate dwellings or semi-detached dwellings (townhouses, flats). Around 67% of dwellings are privately owned. Assuming that this number is applied to separate dwellings means that around 59.2% of households could install PV systems under our assumptions. We removed an extra 4% to cater for other constraints on installation.

[8] That is, if the annual uptake limit appears to be constraining uptake for more than 5 years and across a large number of regions then the limit will be relaxed to the point where annual uptake is only constrained across a few region and a small number of years.

[9] This applies to residential systems of equal to or greater than 5 kW.

[10] The premium is meant to capture uptake by early adopters who are willing to pay more for their systems than they expect to save from avoided electricity purchases. For the current study, as the level of uptake to 2016 is already high, we assumed that these customers are now largely saturated (i.e. have all adopted PV systems) so that the premium did not apply to any further installations over the projection period. That is, in this study DOGMMA projected installations based only on supplying customers at minimum cost.

3.2.2 Model Structure

DOGMMA is characterised by:

- A regional breakdown, where each region is defined by ABS Statistical Areas Level 4. Transmission connection points have been grouped geographically by Statistical Area and their demand forecasts aggregated. Currently the model comprises 87 regions (see Table 1).
- The handling of different technologies of differing standard sizes including PV systems, solar water heaters, small-scale wind and mini-hydro systems with and without battery storage systems. The sizes depend on typical sized units observed to be purchased in the market. For this study the technologies and systems used include:
  - For the residential sector: solar water heater[11], 1.0 kW PV system, 1.5 kW PV system, 3 kW PV system, 5 kW PV system, and 3 kW or 5 kW IPSS systems.
  - For the commercial sector: 5, 10, 30 and 100 kW PV systems; 10, 30 and 100 kW IPSS systems.
- Differentiation between the commercial and residential sectors where each sector is characterised by standard system sizes, levels of net exports to the grid, tariffs avoided, funding approaches and payback periods. The assumptions on these used for this study are shown in Table 2.
- The ability to test implications of changing network tariff structures and changes to Government support programs including the proportion of network tariffs that are not ‘volume based’ (that is, that are independent of average energy use). In practice such tariffs could be fixed supply charges, or linked to peak demand (‘capacity charges’). These are not differentiated within Jacobs’ model, which assumes that all Victorian customers move away from volume-based network tariffs over the period to 2023 [12]so that by 2023 50% of network tariff charges are derived from capacity charges and the remaining 50% of network tariff charges are derived from a variable component (on average, there are variations across network service providers).

  Other states and territories are assumed to move away from fully volume-based network tariffs by 2027. Fixed capacity and supply charges are assumed to make up 50% of network tariffs by:

  - 2025 in states with higher penetration of rooftop PV (i.e. Queensland, Western Australia and South Australia), and
  - 2027 in rest of Australia (i.e. New South Wales, ACT, Tasmania and Northern Territory).

Table 1: Number of regions modelled in DOGMMA

State	No of regions
Queensland	19
NSW (including ACT)	29
Victoria	17
South Australia	7
Tasmania	4
SWIS regions of Western Australia	9
Northern Territory	2

Source: Jacobs’ analysis based on data provided by AEMO, IMO and ABS

[11] Solar water heater uptake affects uptake of roof-top PV in that assumptions are made on the proportion of premises with solar water heaters that can also install PV systems, with this proportion changing over time starting at 105 of dwellings with solar water heaters can install a roof-top PV systems increasing over 10 years to 100% of dwellings with hot water systems.

12 According to published data most electricity distributors will have 50% variable charges by 2020 with the exception of CitiPower (20%) and Jemena (80%).

Table 2: System characteristics by customer sector

Sector	% of output exported	Funding approaches	Payback period[13]
Residential	0% for smaller systems (1 and 1.5 kW) 40% for larger systems (2 kW and higher)	Upfront purchase either by debt financing or outright purchase	7 years
Commercial	40% for up to 10 kW 25% for 30 kW 20% for 100 kW	10 year leases	5 years

[13] Based on anecdotal evidence of the payback periods applying to each sector.

4. General Assumptions

The following section presents our key modelling assumptions. Capital cost assumptions for small-scale are based on the January and February 2017 *Solar PV price check* article on the Solar Choice website[14], which is based on price data from over 100 solar installation companies across Australia. The battery storage costs are sourced from CSIRO's "Future energy storage trends" report prepared for the Australian Energy Market Commission in September 2015, as modified with the latest market data[15]. The population projections are based on the latest Australian Bureau of Statistics data.

4.1 Scenario assumptions

The three market scenarios that were explored for this study were the Neutral, Strong and Weak scenarios. The scenario labels refer to the state of the economy, and broadly speaking respectively reflect average, low and high levels of consumer confidence. Table 3 summarises the key scenario assumptions in this modelling study.

Table 3 Summary of different scenarios assumptions

	Neutral	Weak	Strong
Economic growth	2016 NEFR[16] **medium** economic growth scenario	2016 NEFR **low** economic growth scenario	2016 NEFR **high** economic growth scenario
Household Growth	ABS 3236.0 Series II. SWIS residential connections are estimated using the household projections in *Western Australia Tomorrow, Population Report No. 10, 2014-2026, July 2015.*	ABS 3236.0 Series III. SWIS residential connections are estimated using the household projections in *Western Australia Tomorrow, Population Report No. 10, 2014-2026, July 2015.*	ABS 3236.0 Series I. SWIS residential connections are estimated using the household projections in *Western Australia Tomorrow, Population Report No. 10, 2014-2026, July 2015.*
New Connections	AEMO Forecast, Neutral, April 2017	AEMO Forecast, Weak, April 2017	AEMO Forecast, Strong, April 2017
Carbon price	COP21 emissions target	As per Neutral scenario	As per Neutral scenario
Retail prices	Jacobs' Neutral scenario retail price forecast	Jacobs' Weak scenario retail price forecast	Jacobs' Strong scenario retail price forecast
Exchange rate	1 AUD = 0.75 USD	1 AUD = 0.65 USD	1 AUD = 0.95 USD
Oil price	$USD 60/bbl	$USD 30/bbl	$USD 90/bbl
Gas price	Core Energy Group's **reference** gas price scenario	Core Energy Group's **low** gas price scenario	Core Energy Group's **high** gas price scenario

[14] http://www.solarchoice.net.au/blog/residential-solar-pv-system-prices-february-2017; http://www.solarchoice.net.au/blog/news/commercial-solar-system-prices-jan-2017
[15] Such as for the Tesla Powerwall 2. See https://www.tesla.com/en_AU/powerwall
[16] The March 2017 update of the 2016 NEFR was used

Gas prices underpinning electricity prices in Western Australia (delivered to Perth city gate) is assumed to start around $7/GJ and remain flat at those levels over the projection period.

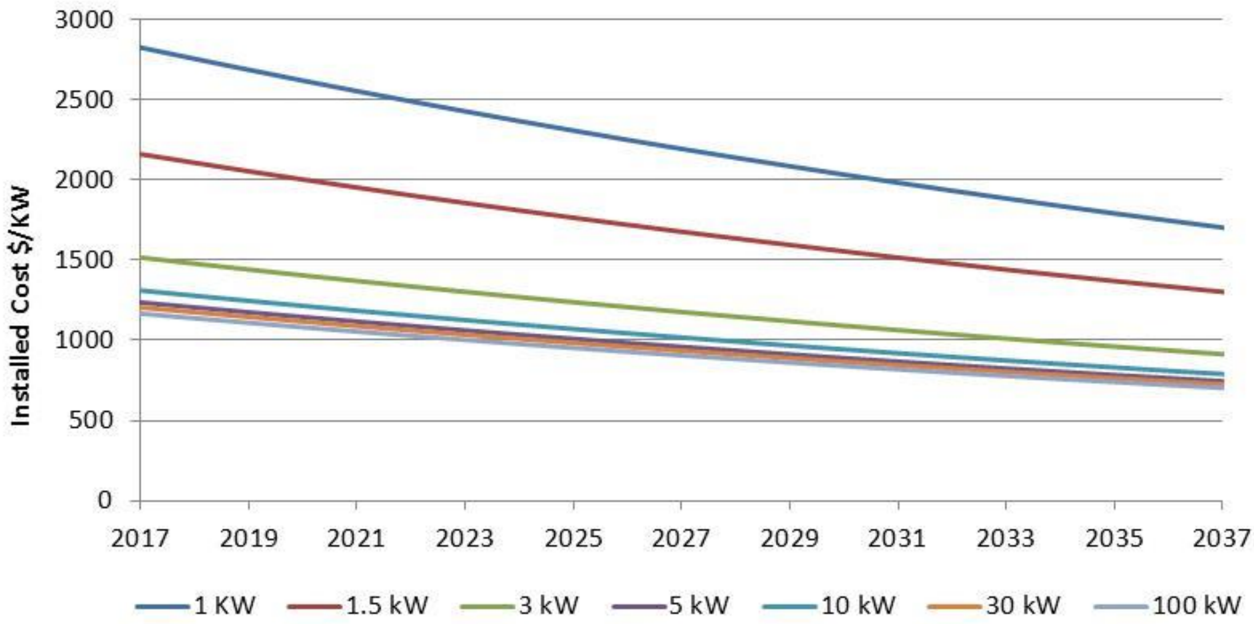
4.2 System assumptions

4.2.1 PV systems costs

Neutral Scenario

PV systems cost assumptions for the Neutral Scenario are shown in Figure 6. The costs in 2017 are sourced from trade data and include balance of system and installation costs while they exclude the STCs rebates. The costs are lower for larger system sizes reflecting economies associated with installing larger systems. The capital costs are projected to decline by 1.5% per annum in real terms based on international and Australian related studies.

Figure 6: Neutral scenario Installed total cost assumptions for PV small scale systems

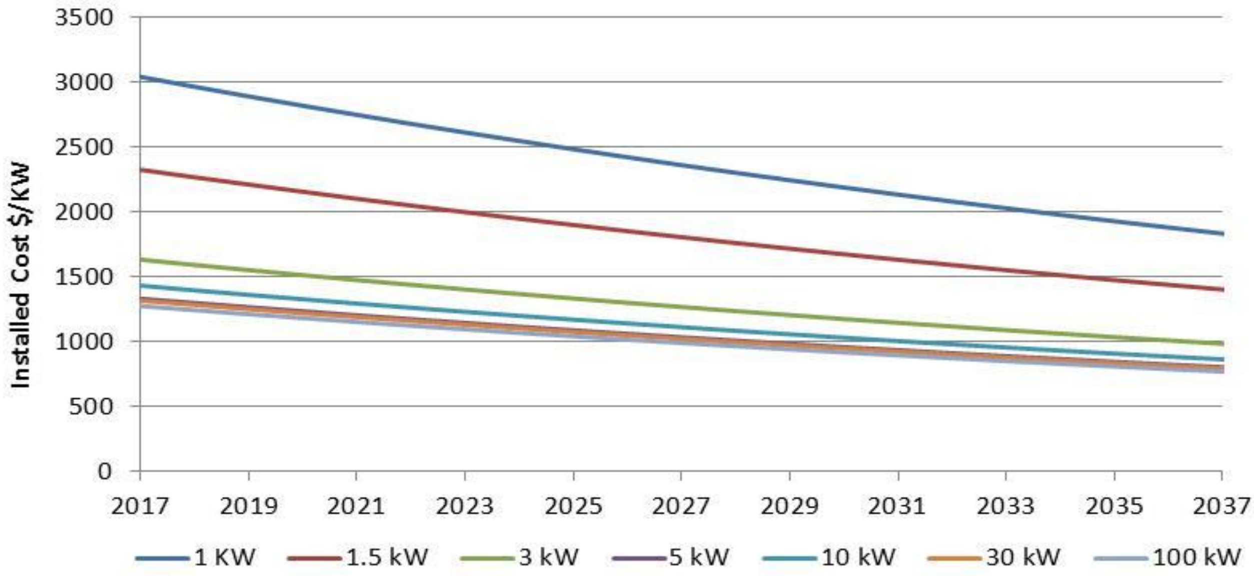


Source: Jacobs analysis based on 2017 data on installed cost supplied in Solar Choice (2017), "Solar PV Power System Prices", January and February 2017 edition. Published total system installation cost data are net of the rebate obtained from Small-scale Technology Certificates.

Weak Scenario

For the Weak Scenario the lower exchange rate (AUD/USD=0.65 instead of 0.75) impacts the price of the imported components which is higher at the commercial systems (60% imported) than at the residential systems (50% imported). The costs are shown in Figure 7 and include balance of system and installation costs while they exclude the STCs rebates. The annual cost decline remains at 1.5%.

Figure 7: Weak scenario installed total cost assumptions for PV small scale systems

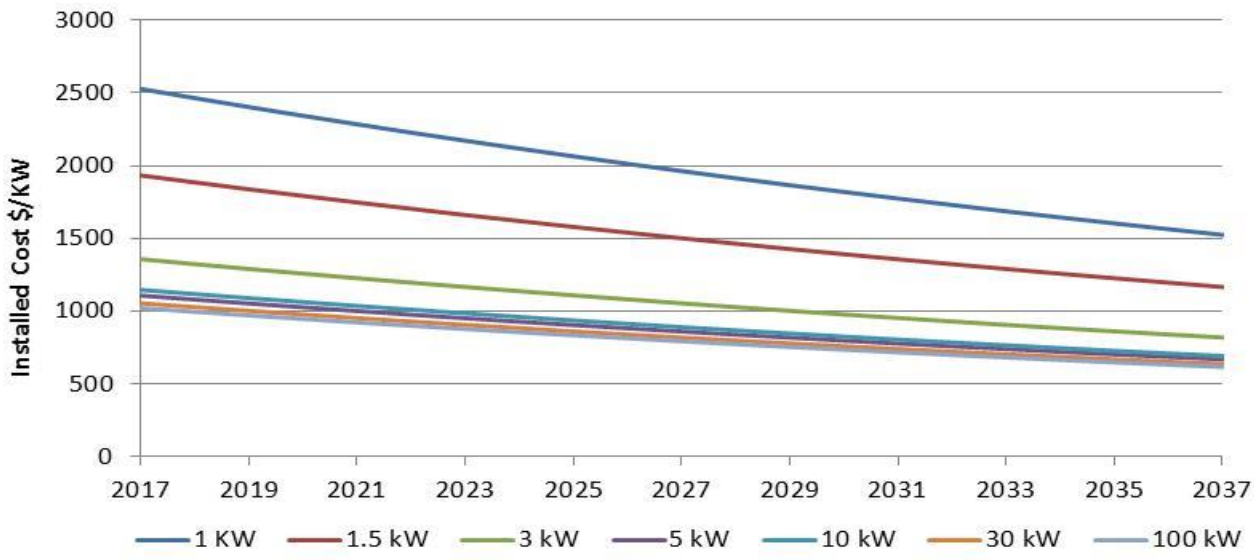


Source: Jacobs analysis based on 2017 data on installed cost supplied in Solar Choice (2017), "Solar PV Power System Prices", January and February 2017 edition. Published total system installation cost data are net of the rebate obtained from Small-scale Technology Certificates. The costs have also been adjusted for a lower exchange rate.

Strong Scenario

The Strong Scenario has a higher exchange rate (AUD/USD=0.95 instead of 0.75) therefore lowering the price of the imported components as shown in Figure 8. The annual cost decline remains 1.5%.

Figure 8: Strong scenario installed total cost assumptions for PV small scale systems



Source: Jacobs analysis based on 2017 data on installed cost supplied in Solar Choice (2017), "Solar PV Power System Prices", January and February 2017 edition. Published total system installation cost data are net of the rebate obtained from Small-scale Technology Certificates. The costs have also been adjusted for a higher exchange rate.

4.2.2 PV capacity factors

Previously the DOGMMA model has used state wide capacity factors for the selected technology options due to a lack of regional data. The model has now been updated to use solar capacity installation data (by postcode) from the Clean Energy Regulator and insolation data (by coordinates) from the Bureau of Meteorology from 2009 to 2015 to calculate a unique capacity factor parameter for each of the 87 regions[17] in the model.

The average capacity factor over all capacity for each technology in each State diminishes as the level of capacity increases in each region. This is based on the notion that as more systems are installed, they are progressively in less favourable roof spaces (for example, roof spaces facing other than north or due to shading). The parameters of the function determining average capacity factors are varied so that the projected uptake rates for the first year match actual installation data for each region[18].

The initial capacity factors applying in each State are shown in Table 4. PV systems with storage are assumed to have a lower initial capacity factors due to energy losses occurring during charging and discharging cycles.

Table 4: Initial load factors for small-scale PV systems by region

	Victoria	New South Wales (including ACT)	Tasmania	South Australia	Queensland	Western Australia
PV	10.7-12.7%	11.2-12.3%	10.2-11.2%	12.2-13.4%	12.1-14.6%	12.1-15.4%
IPSS	9.9-11.8%	10.4-12.3%	9.5-10.4%	11.3-12.4%	11.2-13.5%	11.2-14.2%

Source: Jacobs' analysis based on data provided by CER and BoM.

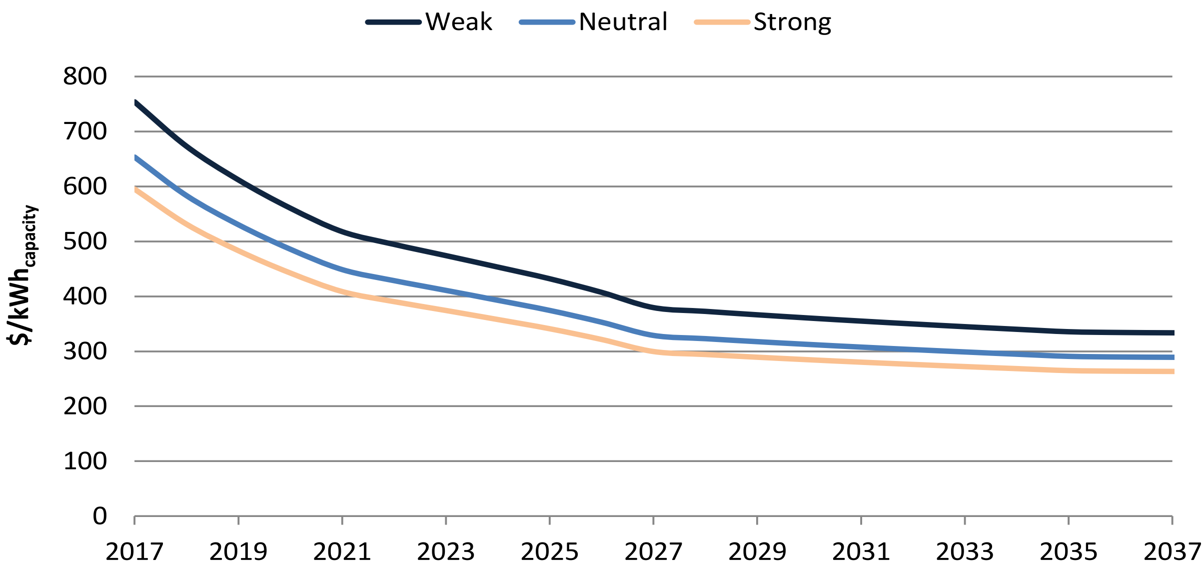
4.2.3 Battery costs

The future of cost of batteries is subject to considerable uncertainty and it is the main driver on the future uptake of PV systems with storage. For the Neutral scenario, this study has adopted the base Li-ion battery cost trajectories from CSIRO's "Future energy storage trends" report that was prepared for the AEMC in September 2015, as modified by more recent market data[19]. These costs have been adjusted for the Weak and Strong scenarios based on the exchange rate assumed for each scenario. The cost trajectories for all scenarios are shown in Figure 9. The illustrated costs do not include inverter and installation costs.

The battery performance parameters used for the modelling are given in Appendix A.

[17] Including nine regions associated with the SWIS system in Western Australia
[18] Postcode data on the number of installations is published by the Clean Energy Regulator.
[19] Sourced from the CSIRO

Figure 9: Projected capital cost trajectories of LI-ion batteries for Neutral, Weak and Strong scenarios

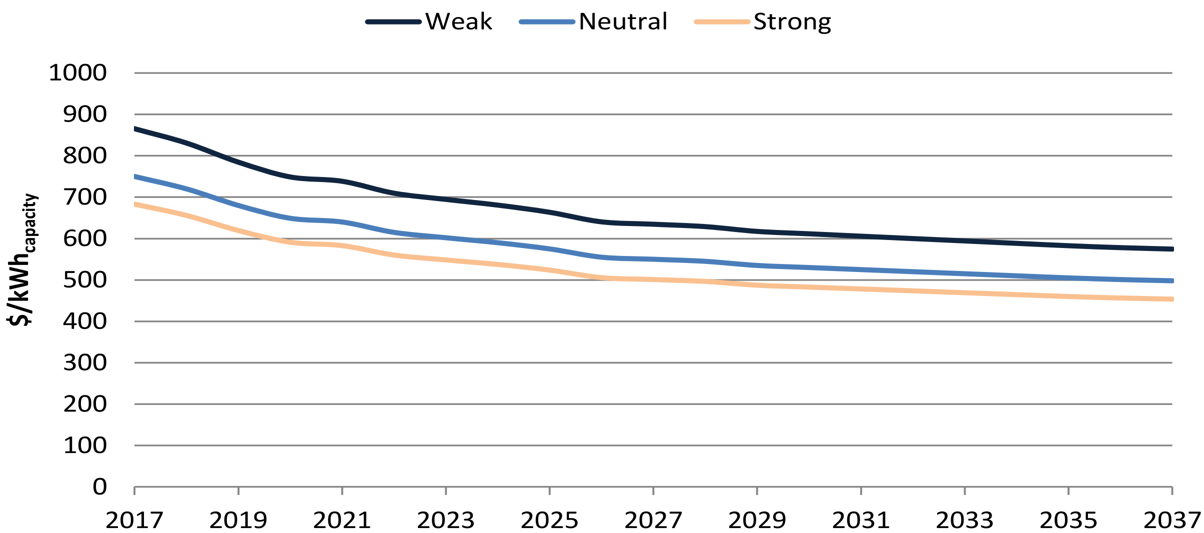


Source: Jacobs' analysis based on CSIRO's ""Future energy storage trends"

The inverters for battery storage can both transmit and receive electricity (inverter-chargers) and are therefore more complex than the most common PV inverters. In the DOGMMA model, when an already installed PV system adds a battery system (retrofitting) it is assumed that a new inverter will also need to be installed to accommodate the new system[20]. More recent battery storage options, however, include a bidirectional inverter and the costs of battery will reflect this option and will be lower than the combined cost of separately installing a battery and a replacement inverter. Given the improving affordability of small-scale IPSS, DOGMMA was modified to project separately the uptake of IPSS as both:

- the retrofit of a battery to existing PV-only systems, and
- the installation of new IPSS (with a bidirectional inverter) where customers did not have any PV or battery.

Figure 10: Projected inverter cost trajectories for Neutral, Weak and Strong scenarios



Source: *Jacobs' analysis based on CSIRO's ""Future energy storage trends"*

[20] CSIRO (September 2015), *" Future energy storage trends"*, Report prepared for the Australian Energy Market Commission

Battery capacity (MW) and battery storage capacity (MWh) were derived using the relationships in the following table

Table 5: Ratios used to derive battery storage capacity

IPSS PV system size (kW)	Battery capacity (kW)	Battery storage capacity (kWh)
Rooftop PV - 3.0 kW + storage - residential	3 kW per installation	2 x battery capacity
Rooftop PV - 10.0 kW + storage - commercial	7 kW per installation	2 x battery capacity
Rooftop PV - 5.0 kW + storage - residential	7 kW per installation	2 x battery capacity
Rooftop PV - 30.0 kW + storage - commercial	30 kW per installation	2 x battery capacity
Rooftop PV - 100.0 kW + storage - commercial	50 kW per installation	2 x battery capacity

In other words, an IPSS with 10kW of PV is assumed to have 7kW / 14kWh of battery capacity.

4.2.4 Feed in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems.

Between 2008 and 2012, state governments in most states mandated feed-in tariff payments to be made by distributors to owners of generation systems (usually solar PV). A list of such schemes is provided in Table 6. Following a commitment by the Council of Australian Governments in 2012 to phase out feed-in tariffs that are in excess of the fair and reasonable value of exported electricity, most of these schemes are now discontinued and have been replaced with feed-in tariff schemes with much lower rates.

However, the costs of paying feed-in tariffs from those schemes to customers must still be recouped as eligible systems continue to receive payments over a period that could be as long as twenty years. Network service providers provide credits to customers who are eligible to receive feed-in payments, and recover the cost through a jurisdictional scheme component of network tariffs. Networks are able to estimate the required payments each year and include these amounts in their tariff determinations adjusting estimated future tariffs for over and underpayments annually as needed. Where this has occurred, it would be reasonable to assume that cost recovery components are included in the distribution tariffs under 'jurisdictional' charges, so no additional amounts are included in the Jacobs' estimates of retail price (see Section 4.2.6 for estimates of retail price). In all cases where distributors are responsible for providing feed-in tariff payments, the distributors would have been aware of the feed-in tariffs prior to the latest tariff determination, so it is reasonably safe to assume inclusion.

Retailers offer market feed-in tariffs, and the amount is set and paid by retailers or jurisdictional regulators. Where such an amount has been mandated, the value has been set to represent the benefit the retailer receives from avoided wholesale costs including losses, so theoretically no subsidy is required from government or other electricity customers. Going forward, the tariff rates are set using Jacobs wholesale price projections for typical PV weighted generation profiles[21] – this should enable the capture the potential impact of high penetration rates on daytime electricity prices.

[21] That is, the projected hourly wholesale prices are weighted by the typical proportion of PV generation in each hour.

Table 6: Summary of mandated feed-in tariff arrangements since 2008

State or territory	Feed-in tariff	Cost recovery
Queensland	*Queensland solar bonus scheme (legacy)* The Queensland solar bonus scheme provides a 44 c/kWh feed-in tariff for customers who applied before 10 July 2012 and maintain their eligibility. The scheme was replaced with an 8 c/kWh feed-in tariff which applied to 30 June 2014. The scheme is now closed to new solar customers. The tariff provided to existing solar customers is recovered through an impost in the network tariffs of Ergon Energy, Energex and Essential Energy. These networks must apply annually to the AER for a pass through of these costs which are expected to diminish over time.	Network tariffs include provision for legacy payments.
	Regional mandated feed-in tariffs From 1 July 2014, retailers in regional Queensland are mandated to offer market feed-in tariffs that represent the benefit the retailer receives from exporting solar energy, ensuring that no subsidy is required from government or other electricity customers. The feed-in tariff is paid by Ergon Energy and Origin Energy for customers in the Essential Energy network in south west Queensland. The amount set in 2016/17 is 7.447 c/kWh.	Assume 7.447 c/kWh over projection period.
NSW	*NSW Solar Bonus scheme* This scheme began in 2009 offering payment of 60 c/kWh on a gross basis, reduced to 20 c/kWh after October 2010. The scheme closed in December 2016 when legacy payments made by distributors and are recovered through network tariffs ended. IPART now regulates a fair and reasonable rate range for new customers who are not part of the SBS, where the minimum rates in 2011/12 were 5.2 c/kWh, 6.6 c/kWh for 2013/14, 5.1 c/kWh for 2014/15, and 4.7 c/kWh from 2015/16, and 5.5 c/kWh for 2016/17. The rate is set to increase in 2017/18 to 13 c/kWh reflecting expected higher wholesale prices. However offering the minimum rate is optional.	Network tariffs include some provision for legacy payments which is topped up by retailer contribution.
ACT	*ACT feed-in tariff (large scale)* ACT feed-in tariff (large scale) supports the development of up to 210 MW of large-scale renewable energy generation capacity for the ACT. This scheme has been declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. *ACT feed-in tariff (small scale, legacy)* ACT feed-in tariff (small scale), is already declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. In July 2008 the feed-in tariff was 50.05 c/kWh for systems up to 10 kW in capacity for 20 years, and 45.7 c/kWh for systems up to 30 kW in capacity for 20 years. The feed-in tariff scheme closed on 13 July 2011.	Network tariffs include provision for feed-in tariffs.
Victoria	*Premium and transitional feed-in tariff scheme (legacy)* The Victorian Government introduced the premium feed-in tariff of 60 c/kWh in 2009 and closed it to new applicants in 2011. Consumers eligible for the premium rate are able to continue benefiting from the rates until 2024 if they remain eligible to do so. The Transitional Feed-in Tariff was then introduced with a feed-in rate of 25 c/kWh. The transitional and premium feed-in tariffs are cost recovered through distribution network tariffs.	Network tariffs include provision for feed-in tariffs.
	Minimum feed-in tariffs The Essential Services Commission (ESC) in Victoria is required to determine the minimum electricity feed-in tariff that is paid to small renewable energy generators for electricity they produce and feed back into the grid. The minimum feed-in tariff is determined by considering wholesale electricity market prices, distribution and transmission losses avoided through the supply of distributed energy, avoided market fees and charges, and avoided social cost of carbon. These payments are made by retailers and have shifted to a financial year basis. The ESC has determined that the minimum energy value of feed-in electricity for 2017/18 is 11.3	Assume a feed-in tariff of 11.3 c/kWh, to recover likely retailer rates.

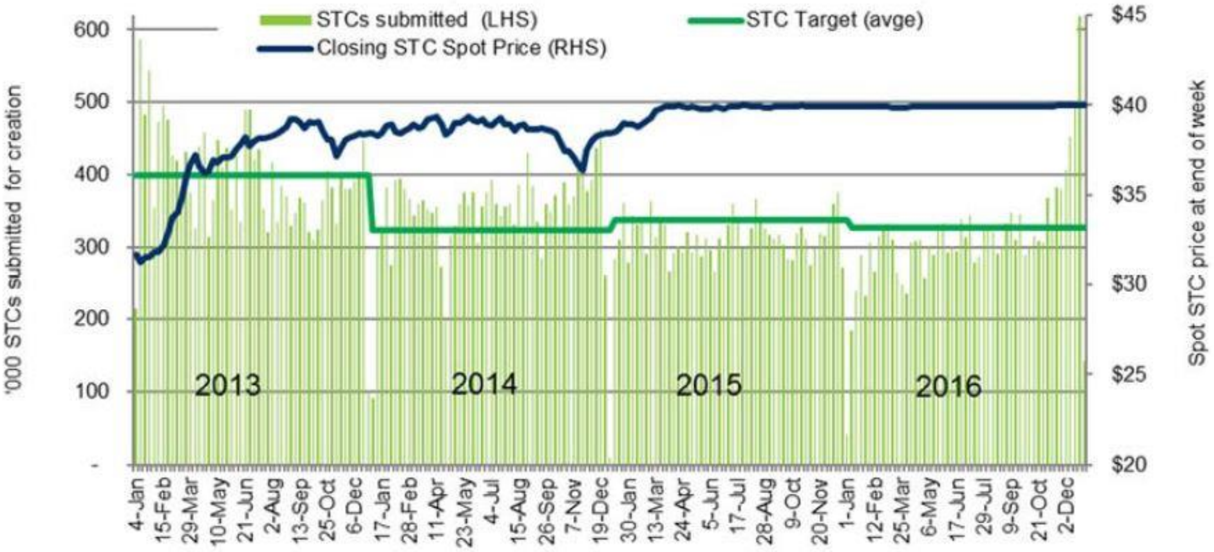
State or territory	Feed-in tariff	Cost recovery
	c/kWh, compared with a January 2016 to July 2017 value of 5 c/kWh, a 2015 value of 6.2 c/kWh and a 2014 and 2013 value of 8 c/kWh.	
South Australia	*Premium feed-in tariff scheme (legacy)* In July 2008 the South Australian government introduced a feed-in tariff scheme providing 44 c/kWh for 20 years until 2028. In 2011, this amount was reduced to 16 c/kWh for 5 years until 2016. This scheme was closed to new customers in September 2013.	Network tariffs include provision for feed-in tariffs.
	Retail feed-in tariff / Premium feed-in tariff bonus A retailer contribution is also available, as set by the SA regulator (Essential Service Commission of South Australia or ESCOSA), where the minimum tariff is set to 6.8 c/kWh in 2016. For 2017, ESCOSA has not set a minimum amount for the retailer feed-in tariff (R-FiT) scheme. Each retailer will determine its own R-FiT amount and structures, and publicly demonstrate the benefits to solar customers. ESCOSA is monitoring R-FiT prices and will re-set a minimum price if in the best interest of consumers.	Assume a feed-in tariff of 6.8 c/kWh over the projection period.
Tasmania	*Metering buyback scheme (legacy)* In Tasmania, Aurora (TasNetworks) offered a feed-in tariff which offered customers a one-for-one feed-in tariff at the regulated light and power tariff for residential customers or general supply tariff for small business customers for their net exported electricity. This program was closed to new customers in August 2013 and replaced with a transitional feed-in tariff of 20 c/kWh for residential customers and a similar blocked feed-in tariff for commercial customers.	Network tariffs include provision for feed-in tariffs.
	Post reform The Tasmanian regulator has now stipulated smaller rates which are now 6.67 c/kWh for 2016/17, compared with 5.5 c/kWh for 2015/16, 5.55 c/kWh in 2014/15 and 8.28 c/kWh for the first half of 2014. These rates are now a component of standing offer tariffs provided by retailers.	Assume a retailer tariff of 6.67 c/kWh to recover retailer costs.
SWIS	*Renewable energy buyback scheme* Government-owned retailers in Western Australia must offer eligible customers a buyback scheme, which covers the price that PV owners can sell their excess energy to Synergy and Horizon Power. The retailers establish their own terms and conditions (including rates) for buying excess energy and are responsible for running the scheme. Meter charges apply to participate in the scheme. See https://www.synergy.net.au/Your-home/Manage-your-account/Solar-connections-and-upgrades	Set initially at 7.135 c/kWh for residential customers.

4.2.5 Small-scale Technology Certificates (STCs)

The price of STCs has been stable over the last three years with a spot price plateauing just below $40.

The assumed STC price in DOGMMA is $40 in 2017 and remains stable in nominal terms until 2030. Between 2017 and 2030 the SRES will follow a declining deeming rate by one year in each year. That means that systems installed in 2017 will create certificates for 14 years of output while systems created in 2030 are deemed to create certificates for only one year of output.

Figure 11: STC value

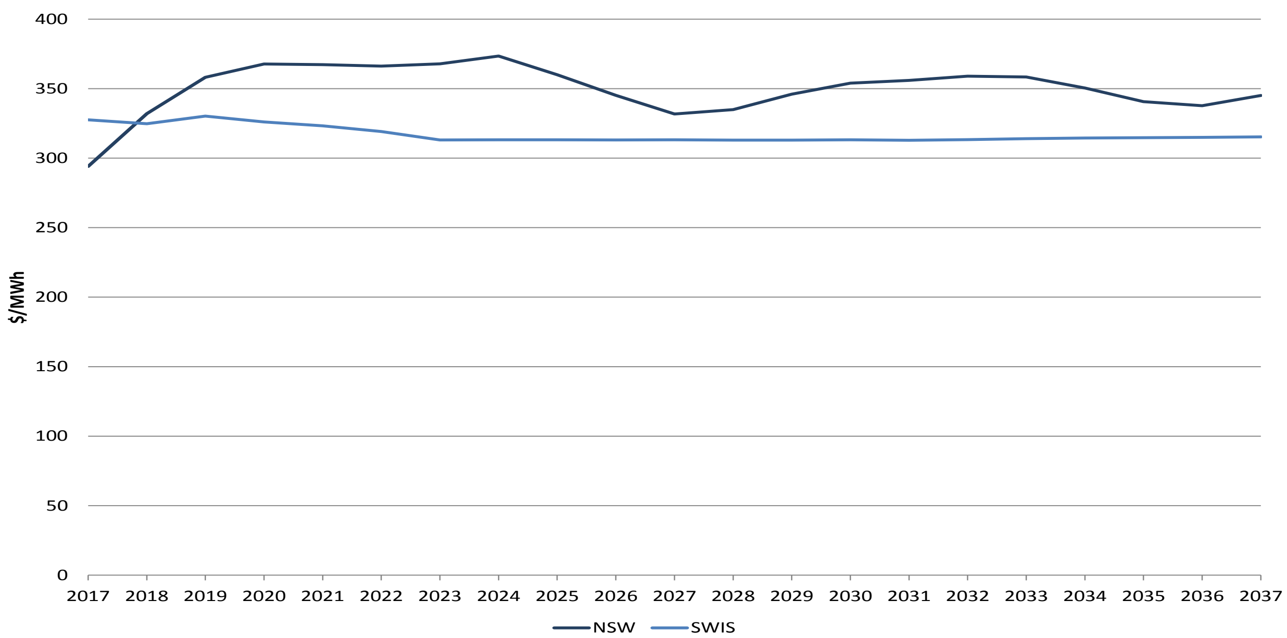


Source: Green Energy Markets

4.2.6 Retail electricity prices

The retail electricity prices are an important component to the calculations in DOGMMA since every kWh of output from a PV system that is consumed by the owner is an avoided cost. The electricity retail prices adopted for the NEM for this study are the price outcomes from Jacobs' "Retail electricity price history and projections" report for AEMO, since the scenarios and the underlying assumptions are the same for both studies. For the SWIS, there was a gradual rise in wholesale price to 2020 that underpinned rising retail prices, but then wholesale prices, and hence retail prices, were assumed to remain relatively constant to 2037. The cost of purchasing Large-scale Generation Certificates under the Large-scale Renewable Energy Target stablises and reduces from 2020, which helps to stabilise prices in the SWIS.

Figure 12: Representative residential retail tariffs, neutral scenario



4.2.7 Net cost

The net cost of the PV systems is a key variable in explaining the uptake of these systems in the DOGMMA model, which is a forward looking optimisation model that seeks to minimise total energy supply costs from the consumer's viewpoint

The net cost is defined as follows:

- Sum of capital cost including installation
- Less
  - Value of any available government rebates
  - Revenue from the sale of RECs and/or STCs
  - Net present value of future feed-in tariff payments and/or retailer payments for export to the grid
  - Net present value of the avoided cost of electricity

Costs avoided by customers are in one of two ways:

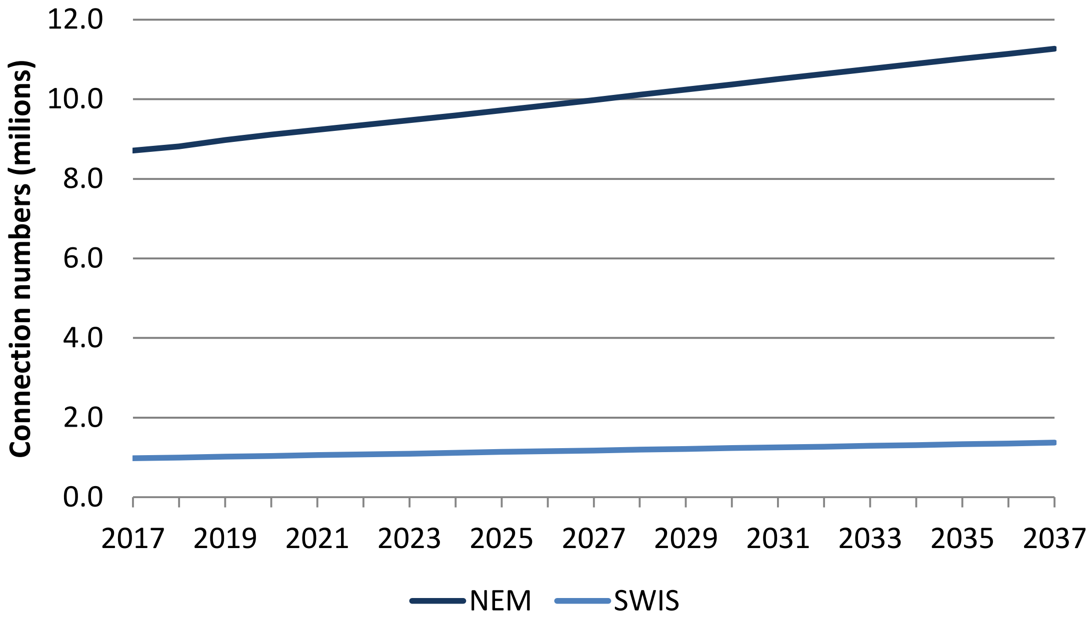
- Avoided retail tariffs on electricity produced by the PV system and used in the premise.
- Revenue earned from exports of electricity that is not used on the premises. This price for exported electricity is equal to the wholesale price weighted to the hourly profile of PV generation plus network losses. This revenue acts a negative cost in the model.

4.2.8 Population growth

The population growth is a key input to DOGMMA, since the maximum uptake of PV systems is constrained by the total population in each region. The assumed population growth used for the Neutral, Weak and Strong scenarios is taken from the three main series (A, B and C) of ABS population for the NEM regions. The Neutral scenario is using Series B projection and follows a medium growth largely reflecting current trends in fertility, life expectancy at birth and NOM, whereas high (series A) and low (series C) are based on high and low assumptions for each of these variables respectively. The projected population is converted to new connections and allocated to residential and commercial connections as shown in Figure 13 and Figure 14 for the Neutral scenario.

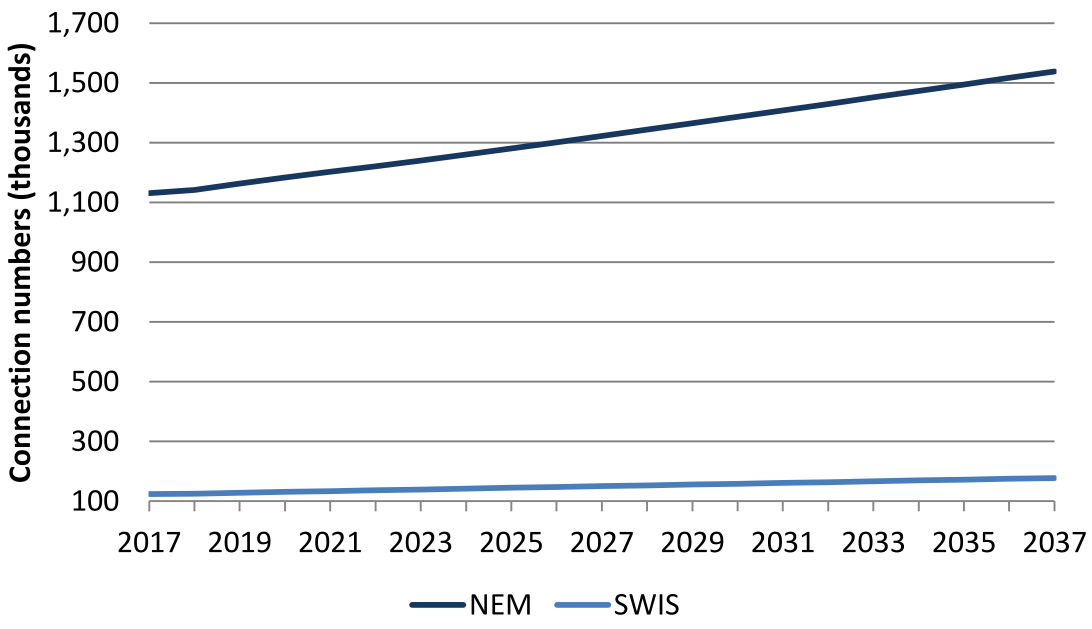
For Western Australia, the household connection and population projections was sourced from the *Western Australia Tomorrow, Population Report No. 10, 2014-2026, July 2015.*

Figure 13: Projected residential connections in the NEM and SWIS, neutral scenario



Source: AEMO and Jacobs

Figure 14: Projected commercial connections in the NEM and SWIS, neutral scenario



Source: AEMO and Jacobs

4.3 Behavioural change due to solar PV generation and uptake of battery storage

There are two behavioural assumptions modelled:

- A willingness to pay premium which represent the amount above avoided grid supply costs that consumers are prepared to tolerate in choosing a PV system. From the starting value, this premium reduces to zero with increasing uptake levels. For standalone PV systems, the premium is now assumed to be zero, and choice is purely based on the comparison of economic cost of PV systems versus supply from the grid. For battery systems the premium is assumed to reduce to zero by 2020 in all regions.

- For PV systems with storage it is assumed PV generation excess to internal load is not exported but instead charges up the battery (to its capacity limit). This stored electricity is used to displace internal energy use in the peak evening period.

4.4 SWIS assumptions

Structural assumptions in the modelling done for the SWIS projections include:

- The majority of the retail tariff is currently set start at the volumetric charge. In Western Australia, it is assumed that the volumetric charge covers 100% of the retail tariff (except for daily supply charge component). It is assumed to gradually move to 50% volumetric and 50% fixed (demand) charges) over a ten year period starting in 2020.

- Installed costs for PV systems decrease over time at a rate of 1.5% per annum. Battery costs (based on Tesla 2 models) are assumed to decrease using a power curve relationship, which means that the cost reduction diminishes over time staring at 11% per annum in 2017 and reaching 4% per annum in 2027. For both technologies, 50% of the installed cost is assumed to be sourced overseas and affected by assumed exchange rate movements (with US$:$A rates of 0.75 for neutral scenario, 0.65 for the weak scenario and 0.95 for the strong scenario).

- The model allows for economies of scale in installed cost with system size. Installed cost (in 2017) varies from $2,789/kW for a 1 kW_{ac} system to $1,500/kW for a 100 kW_{ac} system[22].

- The model also allows premises to install solar water heaters. However, based on observed behaviour, only a portion of households install both systems, with this portion assumed to increase over time. In 2017, 10% of households can install both a solar water heater and a PV system. This increases to 100% of households over a 10 year period (to 2027). That is, only 10% of household that have a solar water heater will also install PV systems in 2017. This proportion increase so that by 2027 100% of households with solar water heaters can install PV systems.

- Retail tariffs move from a 100% volumetric basis to a 50% volumetric and 50% fixed (demand charge based on kW usage) basis over a 10 year period starting in 2020.

- A proportion of production is assumed to be exported receiving a tariff reflecting fair and reasonable avoided costs (set at the wholesale prices weighted to PV generation profile plus a factor to cover market fees and network losses) ranging (in the SWIS regions) for residential systems from 0% for a 1.0 kW system to 40% for a 5 kW system, and for the commercial sector from 40% for a 5 kW system to 20% for a 100 kW system (reduces for the commercial sector due to the association with large systems and larger host loads).

- In commercial sector, installed systems are assumed to be allowed to be depreciated over a 5 year period for taxation purposes (for owner installed systems).

4.5 Modelling uncertainties, limitations and exclusions

Some of the main uncertainties regarding this modelling are:

- There is uncertainty regarding the trajectory of PV installation costs. While there is a general consensus that internationally the costs will continue to decline, Australia's differentiating dynamics (high wages, low

[22] These costs take published costs and remove the subsidy component of the STC certificates and then adjusted to convert DC capacity to AC capacity.

barriers to entry, high amount of Tier 2 or Tier 3 products) is making it more difficult to forecast this cost trajectory.

- The future financial incentives for PV systems such as the FiTs and its terms of payment are considered uncertain.

- In the commercial sector there are a lot of uncertainties regarding the potential size of the market. Among the factors that are difficult to determine is the number of businesses that own the commercial facilities and also the roof space that they have to install a large (>10 kW) system. Furthermore, there is a great uncertainty regarding the number of businesses that consume enough electricity during daylight hours so as to make it financially attractive to invest to PV system.

- Battery storage is an emerging technology in its infancy with no existing patterns and no recording mechanism at the moment. The future of energy storage technologies is subject to considerable uncertainty although it is generally expected to have a sharp decline in costs over the next five years.

- The financial attractiveness of PV systems and IPSS systems is heavily dependent on the future tariff structure in the NEM and the SWIS that is still undetermined. As part of a general drive towards cost-reflective pricing it is expected that the structure will move to time-of-use pricing over time.

- Future policies impacting the uptake of PVs and storage are still uncertain. The historical rapid uptake of rooftop PV during the implementation of generous financial incentives set by the Federal and State governments is a good example of how significant these are for determining the future uptake of the systems.

Furthermore, there are some further issues that will affect the future of PV uptake and battery storage that have not been considered in this study. Some of them are:

- The upgrades, expansions and replacement of residential PVs. Many existing rooftop PV owners have small systems (less than 3 kW) and some of them will consider expanding these systems in response to higher electricity costs and lower PV installation costs. Furthermore, there is the possibility that the transition to a time-of use tariff structure will incentivise the installation of west-facing panels so as to cut peak demand.

- No fall in battery performance over time has been considered.

- Behavioural drivers have not been modelled (i.e. early adopters, business preference to invest in core activities instead of PVs etc.) except as captured under the premium assumptions applied to IPSS systems (in the period to 2020).

- No system optimisation based on individual customers' load profiles has been explored. Especially in the commercial sector, it is expected that the systems will be optimised increasing the financial attractiveness of PVs with and without battery storage.

- In the model the average demand profile of households and commercial businesses has been assumed instead of individual ones, something that potentially underestimates the cost savings caused by sharper load spikes.

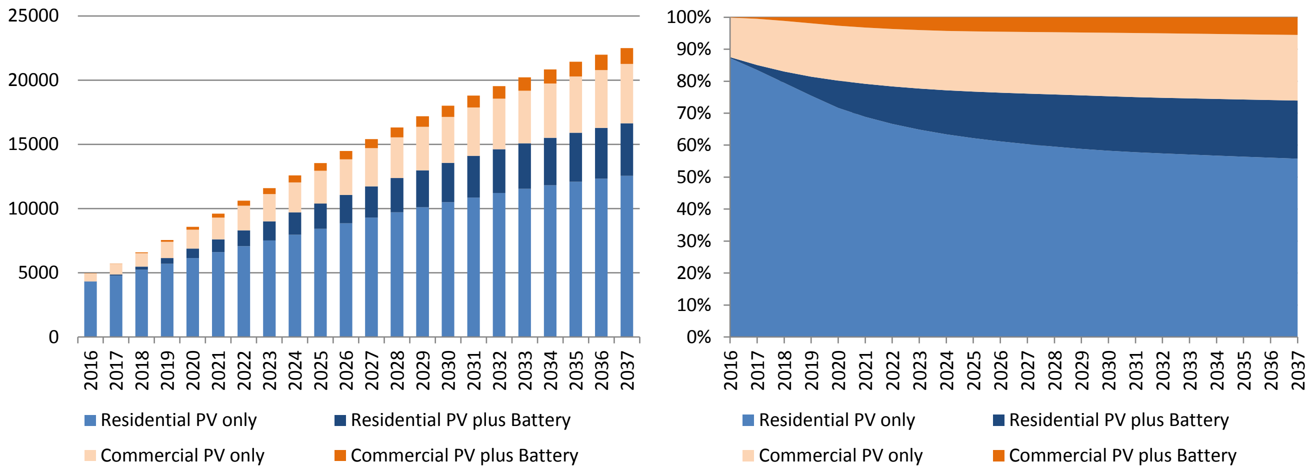
5. Rooftop PV and Battery Storage Forecasts

5.1 Overview

The PV uptake remains relatively stable in the short term with the falling installation costs of PV systems offsetting the gradual fade out of the SRES incentive starting from 2017. Growth rates remain high until the mid-2020s when the assumed transition to a time-of-use tariff structure reduces the payback from roof-top systems slowing growth down. From the early 2030s, the decline in annual installations numbers also occurs due to saturation in some regions.

Figure 15 shows the forecasted total installed capacity of rooftop PV, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 15: Total installed capacity of rooftop PV and IPSS in the NEM and WEM, Neutral scenario



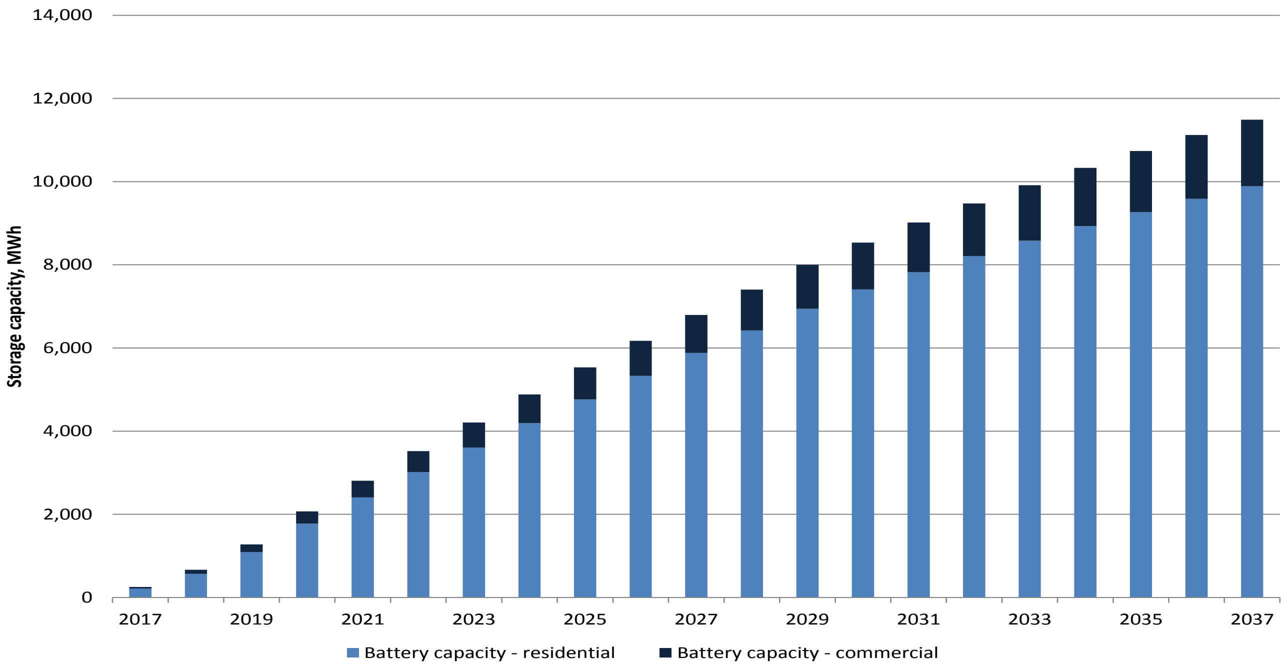
The residential annual PV uptake is projected to be stable until 2027/28 when time of use retail tariffs and the breakdown of network fees into 50% fixed components starts to impact on uptake. Beyond 2027/28 uptake rates fall due to declining retail price offsets and penetration reaching assumed saturation levels in some regions. The total capacity of PV and IPSS systems at the end of 2037 is 12,545 MW.

Growth of PV system uptake in the commercial sector is projected to be relatively stable for the entire modelled horizon, reaching around 4,620 MW in 2037 and accounting for 27% of total capacity.

IPSS system uptake starts slowly and picks up especially after 2020 in both the residential and the commercial sectors, resulting to around 5,335 MW installed at the end of 2037. Uptake of IPSS systems is lower in the commercial sector due to proportionally lower returns to storing electricity for use in other periods (as the peak for many commercial operations occurs in the middle of the day as opposed to the typical evening peak for residential systems.

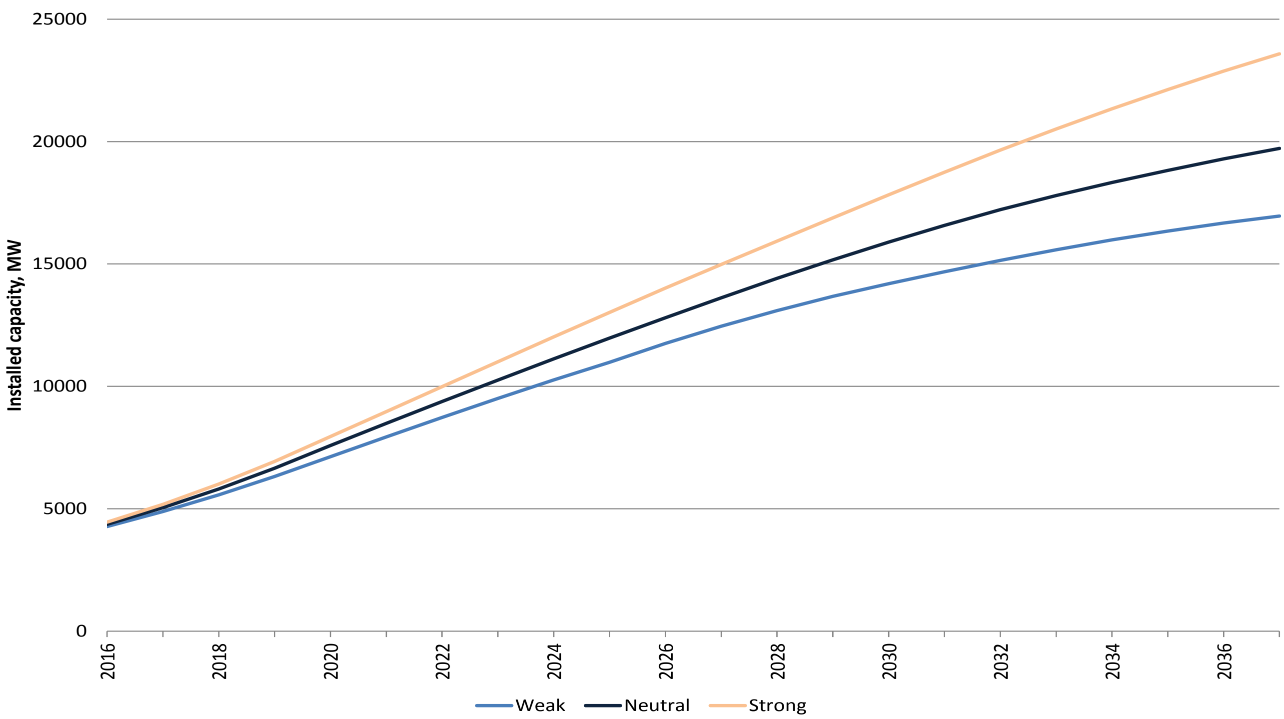
Figure 16 shows the total battery storage capacity installed for the neutral scenario. As capital costs decline and there is transition to a time-of-use tariff structure, more residential battery storage is forecasted to be adopted resulting to a total of 11,489 MWh of battery storage in both the sectors at the end of 2037.

Figure 16: Total installed battery storage capacity, Neutral scenario



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in the NEM are given in Figure 17. The main drivers for the deviating results in the Strong and Weak scenarios are the different capital costs of PV and IPSS systems resulting from different applied exchange rates. At the end of the forecast period in the Strong scenario the NEM has around 23,580 MW of PV and IPSS systems installed (20% higher than the Neutral scenario), while in the Weak case around 16,960 MW is installed (16% lower than the Neutral scenario).

Figure 17: NEM rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

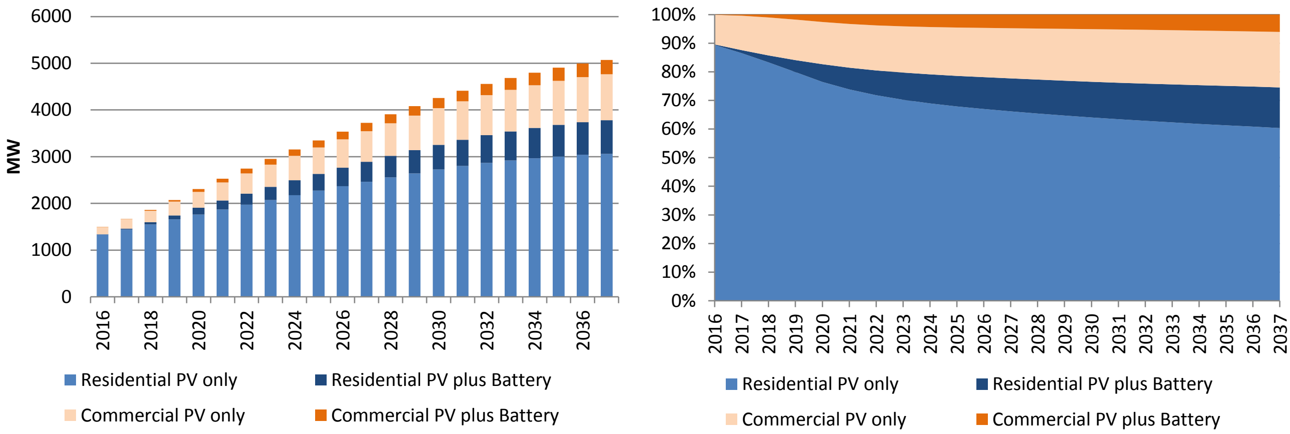


5.2 Queensland forecasts

In the short term, the main drivers for PV and IPSS uptake in both the residential and commercial segments are the existing financial incentives for these systems (STCs and FiTs). As the SRES is gradually fading out from 2017 onwards, the falling system installation costs and the increase of retail prices are becoming the key determinants for PV and IPSS installations for the next decade.

Figure 18 shows the forecast total installed capacity of rooftop PV in Queensland, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 18: Total installed capacity of rooftop PV and IPSS in Queensland, neutral scenario



Although Queensland has already a high level of PV penetration in the residential segment, with around one quarter of total dwellings having installed a PV system, the residential rooftop PV in the state continues to have a steady uptake of installations until the early 2025 when penetration in some regions reaches saturation and the move to time of use tariffs with higher fixed cost components reduces the financial returns from PV systems. The move to time of use tariffs has a big impact on the long term uptake as the level of installed PV systems (small and utility scale systems) depresses daytime wholesale prices. This effect is partially offset by steady growth in the commercial sector.

The total forecast residential PV and IPSS capacity in 2037 is around 3,780 MW while the commercial is 1,290 MW accounting for around 25% of total installations.

IPSS system uptake starts slowly during the first three years and continues with a steady growth after that accounting for around 20% of total annual installations in the forecast period. Figure 19 shows the total battery storage capacity installed in Queensland. Initially it is predominantly commercial battery storage that is being installed, but as the IPSS system costs continue to decline, residential uptake becomes prevalent and the total battery storage at the end of the modelled horizon reaches 2,234 MWh.

The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in Queensland are given in Figure 20. Since the population growth and the retail prices have relatively small differences in all scenarios, the main drivers for the deviating results in the Strong and Weak scenarios are the different capital costs of PV and IPSS systems resulting from different exchange rates. Growth in the Strong scenario is also constrained by penetration levels reaching saturation points in many regions. At the end of the forecast period in the Strong scenario, Queensland has around 5,700 MW capacity of PV and IPSS systems installed (12% higher than the Neutral scenario), while in the Weak case around 3,880 MW capacity is installed (31% lower than the Neutral scenario).

Figure 19: Total installed battery storage capacity in Queensland

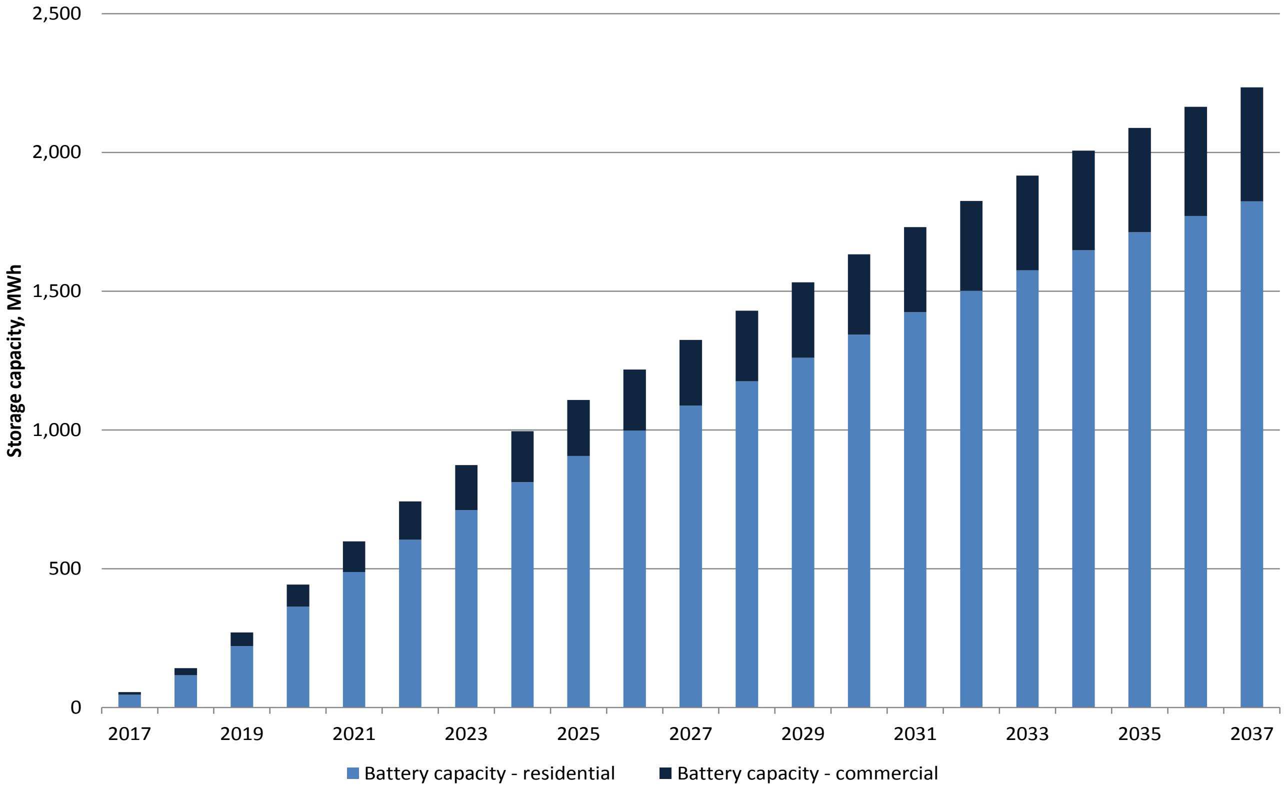
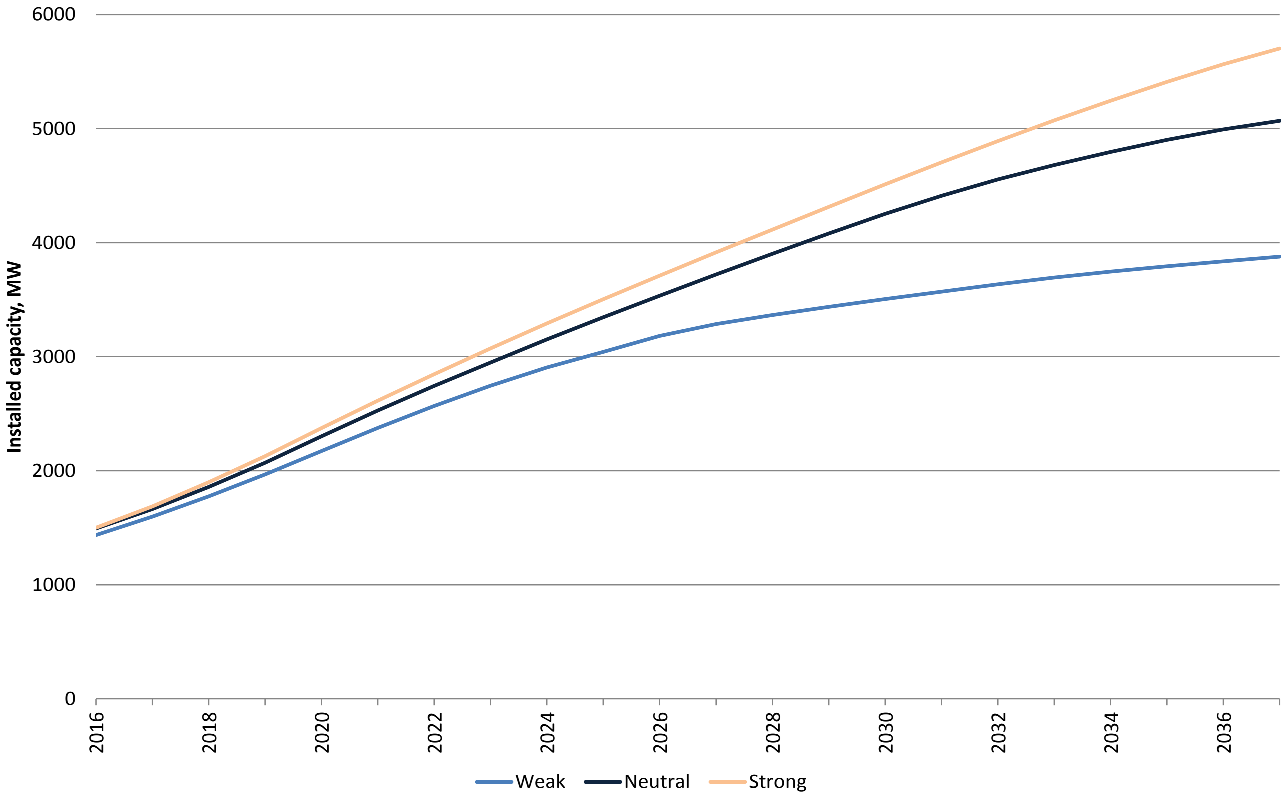


Figure 20: Queensland rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

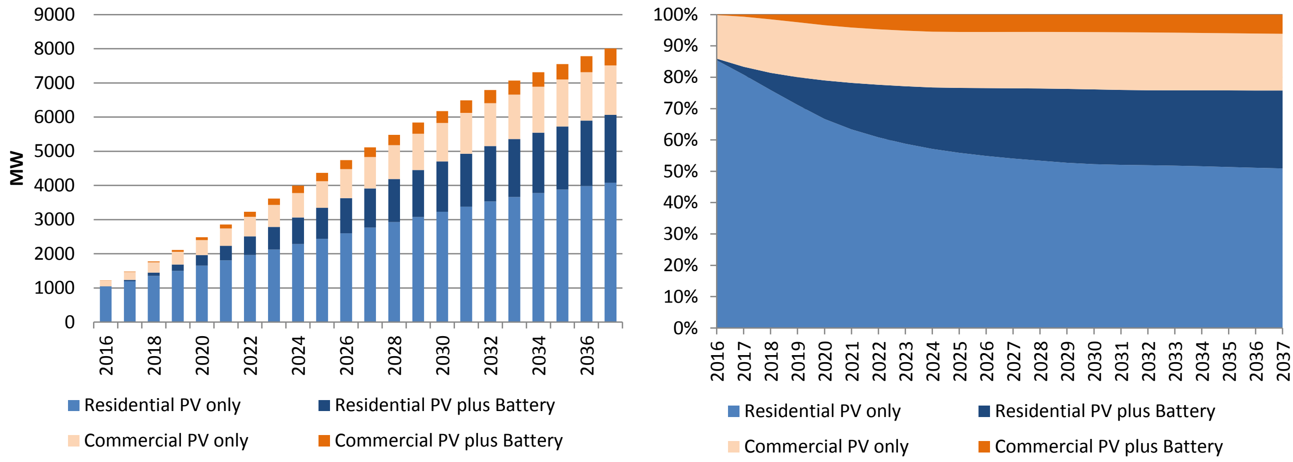


5.3 New South Wales[23] forecasts

The installations of PV and IPSS systems in New South Wales are predominantly driven by the existing financial incentives that increase the economic viability of these systems. As these incentives gradually decline the falling capital costs of the PVs and IPSS and higher retail prices drive steady PV and IPSS uptake over the next decade. However, the move to time of use tariffs reduces uptake in the latter half of the forecast period.

Figure 21 shows the forecasted total installed capacity of rooftop PV in New South Wales, and the fraction of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 21: Total installed capacity of rooftop PV and IPSS in New South Wales



In New South Wales the installations of PV in both the residential and the commercial sector continue to grow steadily reaching a total cumulative capacity of around 5,220 MW in 2037. Just over one quarter of that capacity (or 1,450 MW) is installed in the commercial sector. A reason for this continuous uptake is the current low penetration levels in that state (compared to Queensland and South Australia).

Households have a moderate growth of IPSS installations in the next 5 years with stronger growth after 2020 resulting in 1,990 MW installed by 2037. On average, around one quarter of total annual installations after 2020/21 are IPSS systems. Uptake is steady in the commercial sector, although at lower levels than for the residential sector. The total capacity of IPSS in both sectors in 2037 is around 2,480 MW.

Figure 22 shows the total battery storage capacity installed in New South Wales. The declining IPSS system costs and the rising retail prices drive a strong residential uptake in the period to 2025/26. At the end of the modelled period NSW is forecast to have installed around 5,330 MWh of battery storage with 85% of that in being installed in the residential sector.

The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in New South Wales are given in Figure 23. The main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2037, the total installed capacity of PV and IPSS for the Strong scenario is around 9,230 MW (15% higher than the Neutral case), while for the Weak scenario it is 7,270 MW (which is 10% lower than the Neutral scenario).

[23] The uptake of PV and IPSS systems in ACT is incorporated in the New South Wales results.

Figure 22: Total installed battery storage capacity in New South Wales

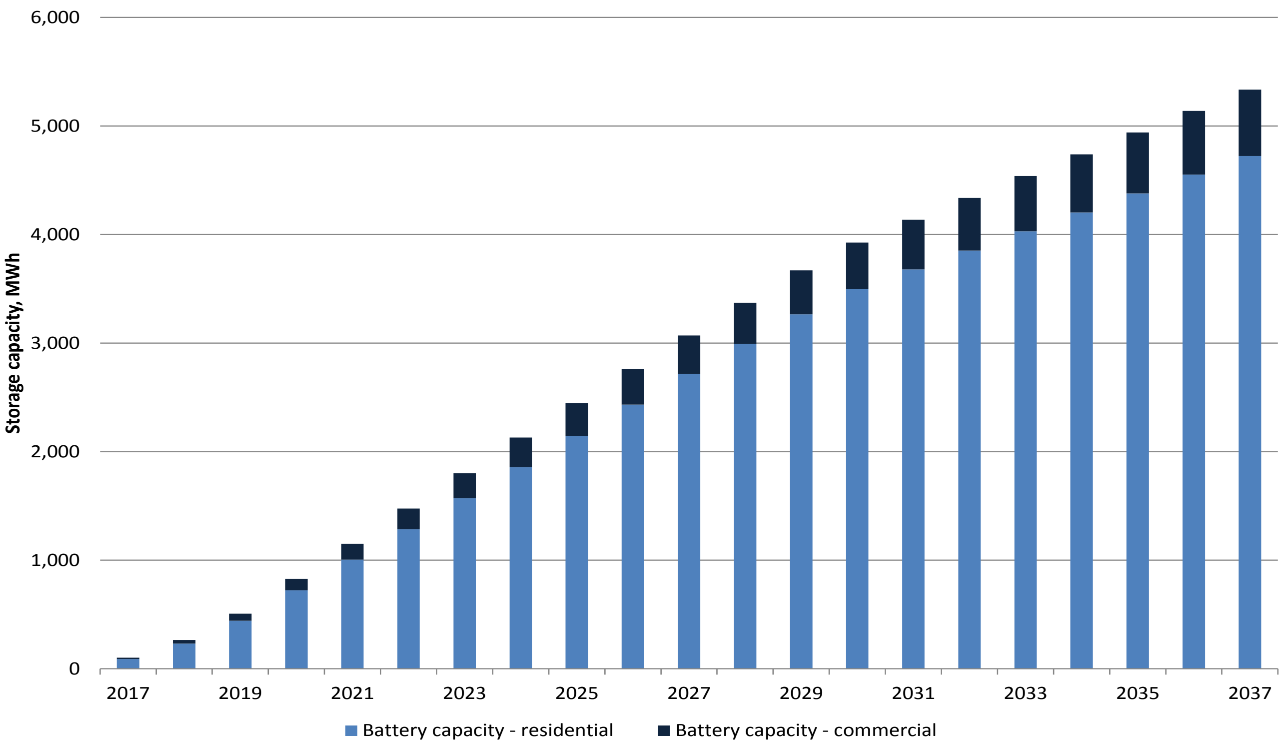
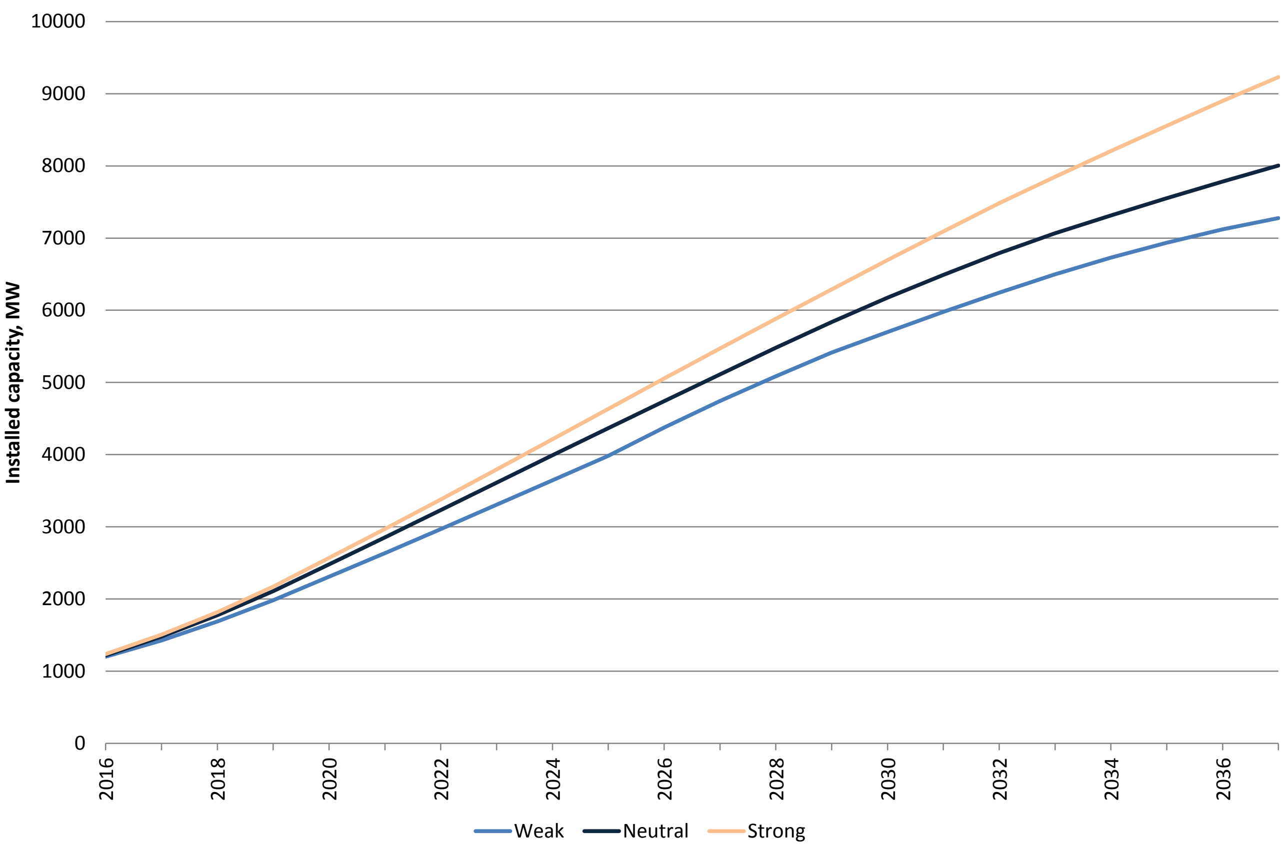


Figure 23: New South Wales rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

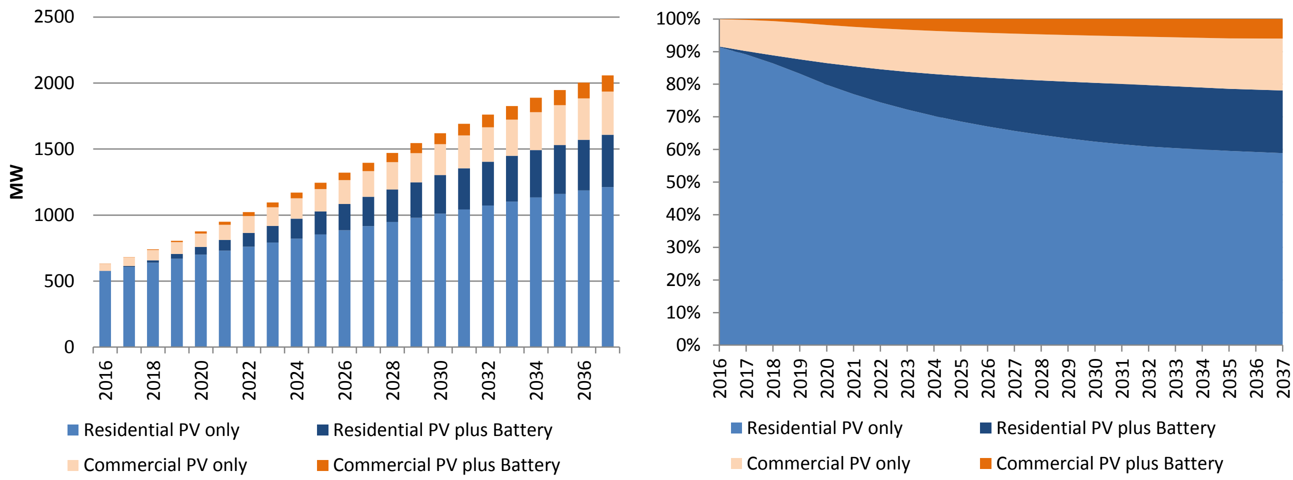


5.4 South Australia forecasts

South Australia currently has the highest penetration of residential PVs in Australia and that along with the falling STC incentives is leading to a moderate decline in the growth of households' installations. Conversely, there is a rise of PV uptake in the commercial sector mainly driven by the falling installation costs and the projected higher retail prices. Residential PV uptake falls after 2025 but commercial sector uptake remains relatively steady over the forecast period.

The forecast total installed capacity of rooftop PV in South Australia, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS is shown in Figure 24.

Figure 24: Total installed capacity of rooftop PV and IPSS in South Australia



The residential PV uptake shows a continuous decline in the modelled horizon reaching a total installed capacity of around 1,210 MW in 2037. This is offset by the increase of PV installations in the commercial sector that reach saturation in some regions in the early 2030s. At the end of the forecasted period commercial PV capacity is around 330 MW accounting for 21% of total PV installed.

IPSS system uptake becomes significant after 2019/20 in both the residential and commercial sectors, mainly driven by the falling system costs but also by the increasing retail prices. The total IPSS capacity installed at the end of the modelled period is around 520 MW accounting for slightly more than 25% of total installed capacity.

The cumulative installed battery storage capacity in South Australia is shown in Figure 25. The total storage installed in 2037 is 1,070 MWh with 15% of that being installed in the commercial sector.

The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in South Australia are given in Figure 26. As in the previous states, the main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2037, the total installed capacity of PV and IPSS for the Strong scenario is around 2,330 MW (13% higher than the Neutral case), while for the Weak scenario it is 1,860 MW (which is 11% lower than the Neutral scenario).

Figure 25: Total installed battery storage capacity in South Australia

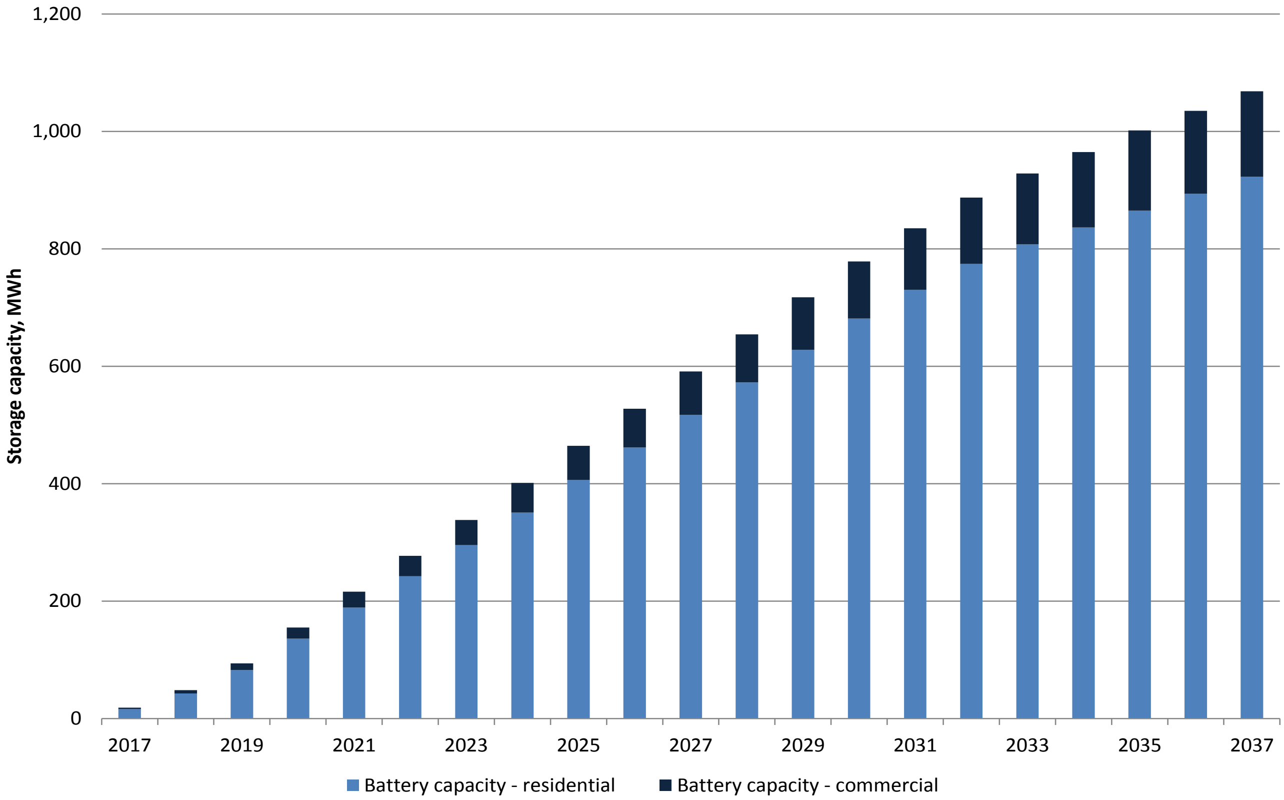
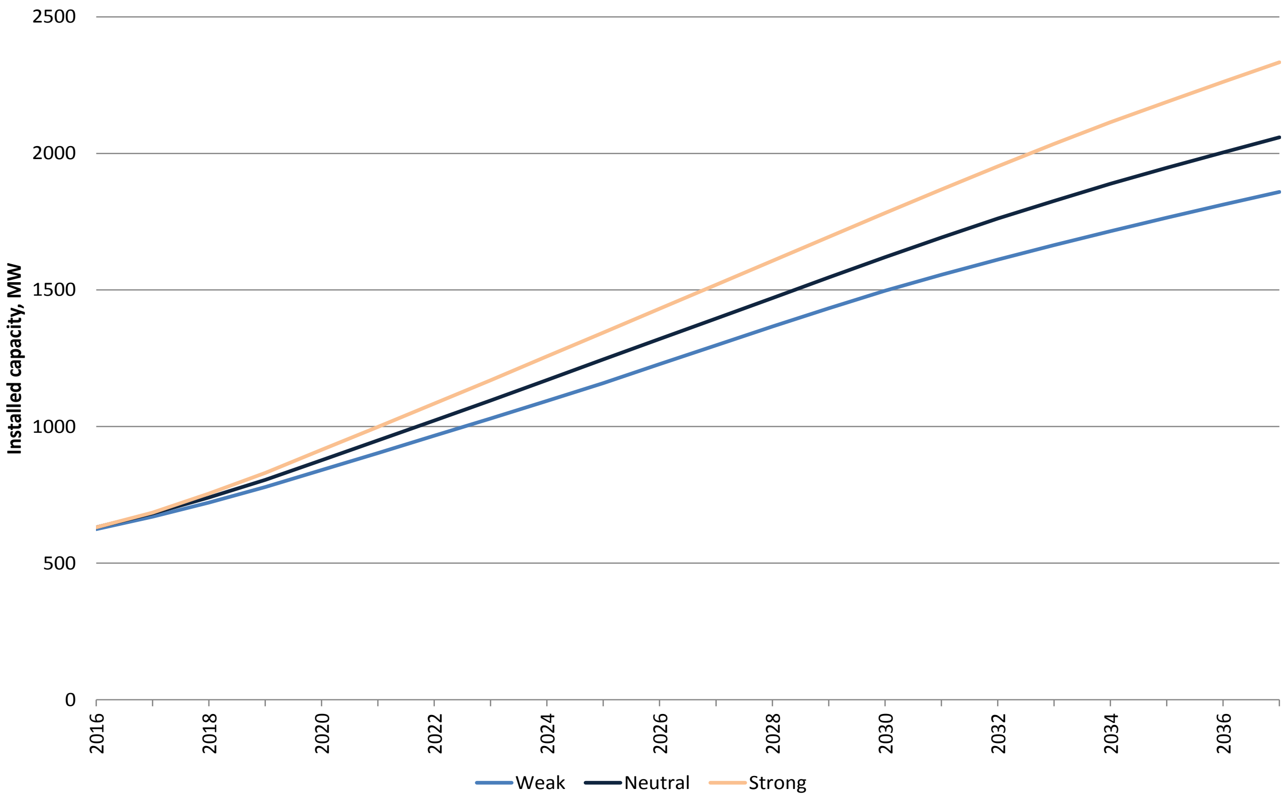


Figure 26: South Australia rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

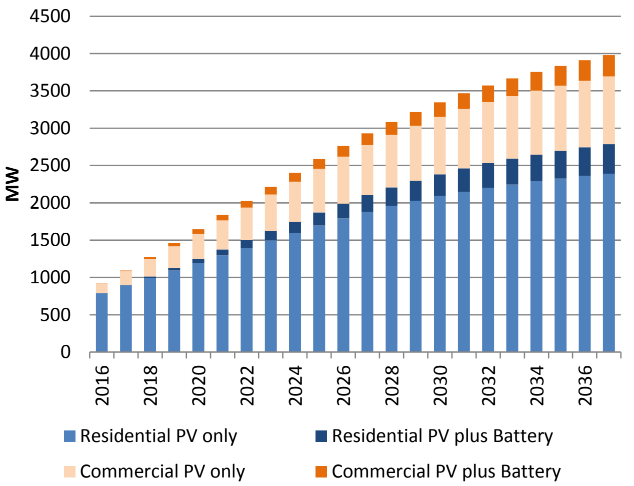


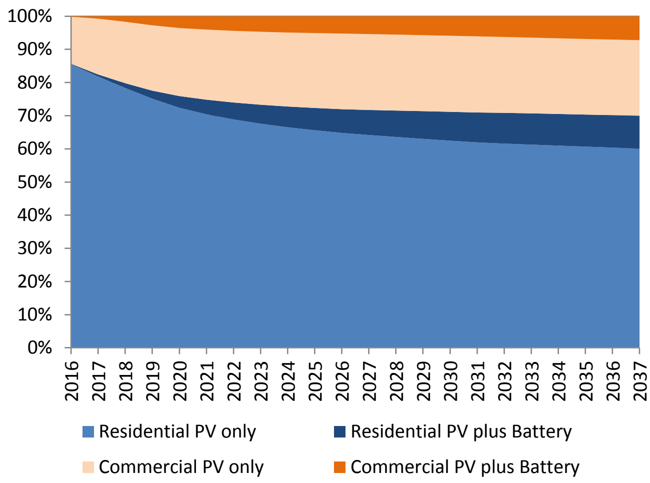
5.5 Victoria forecasts

The main drivers for PV and IPSS systems installations in Victoria are the financial incentives (STCs and FiTs) in the short term, and the declining capital costs and rise of retail prices in the long term. Big increases in wholesale prices (and hence retail prices) drive growth in the near term. In the residential sector, the growth of systems uptake is strong until 2021/22 when saturation is reached in some regions of the state and when time of use tariffs are fully adopted. The installations in the commercial sector remain steady through after 2025 when uptake starts to fall off. The faster transition to a time-of-use tariff structure relative to the other states, leads to a high penetration of IPSS systems.

Figure 27 shows the forecasted total installed capacity of rooftop PV in Victoria, and the fraction of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 27 Total installed capacity of rooftop PV and IPSS in Victoria





As the figure shows, the uptake of PV systems in Victoria continues to grow in both the residential and the commercial segments. The household installations reach saturation levels in some regions after 2033/34. At the end of the modelled horizon the total installed PV capacity in the state is 3,330 MW with 28% of that being installed in businesses.

Regarding the uptake of IPSS systems, it starts slowly in both sectors during the first 4 years and continuous strongly after that accounting for around 30% of total annual installations during the 2020s and 40% during the 2030s. The total installed IPSS capacity in 2037 is around 680 MW with 395 MW of those installations taking place in households. At the end of the forecast period, the percentage of IPSS capacity is 17 % of total capacity. Figure 28 shows the total battery storage capacity installed in Victoria. Both the residential and the commercial sectors have a steady growth of IPSS systems throughout the forecasted period leading to a total uptake of 1,305 MWh of battery storage with 30% of that being installed in businesses.

The forecasts of total PV and IPSS capacity installed in Victoria for the all three modelled scenarios (Neutral, Weak and Strong) are given in Figure 29. The main drivers for the differences between the scenarios remain the different capital costs of PV and IPSS systems resulting from different applied exchange rates and the differing household growth rates. At the end of the forecast period in the Strong scenario Victoria has around 5,890 MW capacity of PV and IPSS systems installed (36% higher than the Neutral scenario), while in the Weak case around 3,740 MW capacity is installed (16% lower than the Neutral scenario).

Figure 28: Total installed battery storage capacity in Victoria

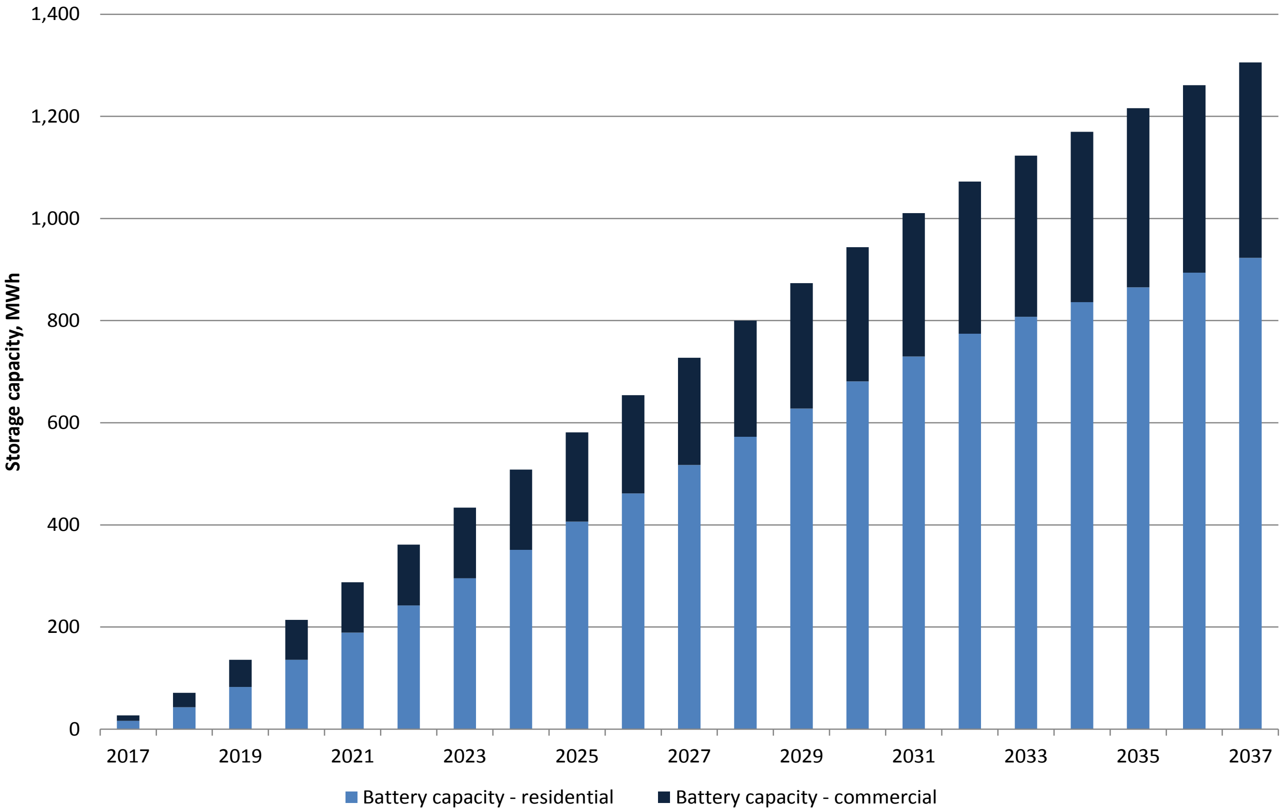
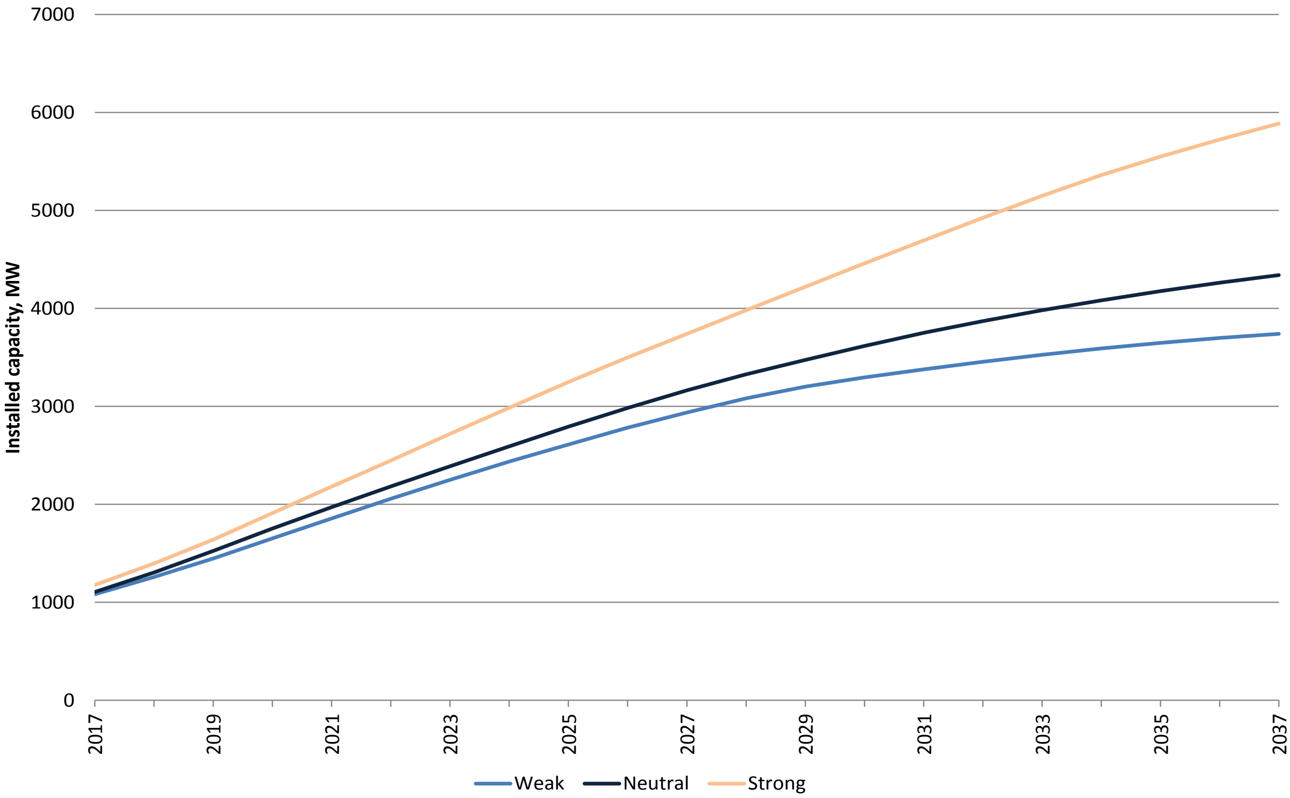


Figure 29: Victoria rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

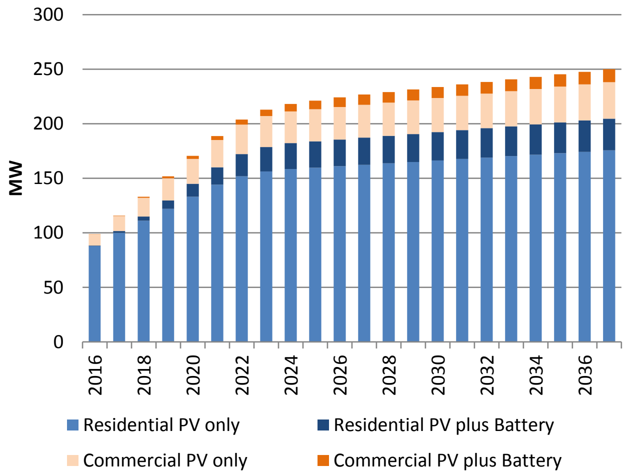


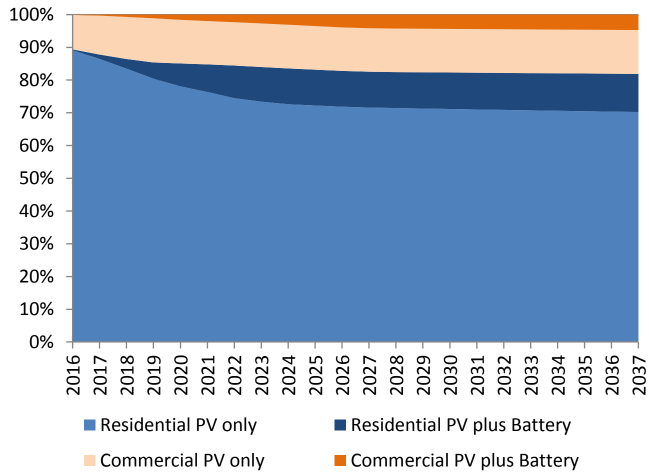
5.6 Tasmania forecasts

The PV and IPSS systems in Tasmania have a steady uptake up until 2024/25 when the move to time of use tariffs starts to impact on uptake. The main drivers for this uptake are the STCs incentives initially, with lower installation costs and higher electricity prices stimulating the installations to the mid-2020s.

The forecasted total installed capacity of rooftop PV in Tasmania, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS is shown in Figure 30.

Figure 30 Total installed capacity of rooftop PV and IPSS in Tasmania





Both the residential and commercial sectors show a steady uptake to mid-2020s then declining uptake of PVs, with the total installed capacity in households and businesses reaching 176 MW and 33 MW respectively in 2037.

The uptake of IPSS systems is weak in Tasmania since the state has the lowest solar resource. The total installed capacity in 2037 is 41 MW with 29% of that being adopted by commercial businesses.

The cumulative installed battery storage capacity in Tasmania is shown in Figure 31. The total storage installed at the end of the forecast period is 95 MWh with 16% of that being commercial battery storage.

The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in Tasmania are given in Figure 32. As in the other States, the main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2037, the total installed capacity of PV and IPSS for the Strong scenario is around 430 MW (70% higher than the Neutral case), while for the Weak scenario it is 205 MW (which is 22% lower than the Neutral scenario).

Figure 31 Total installed battery storage capacity in Tasmania

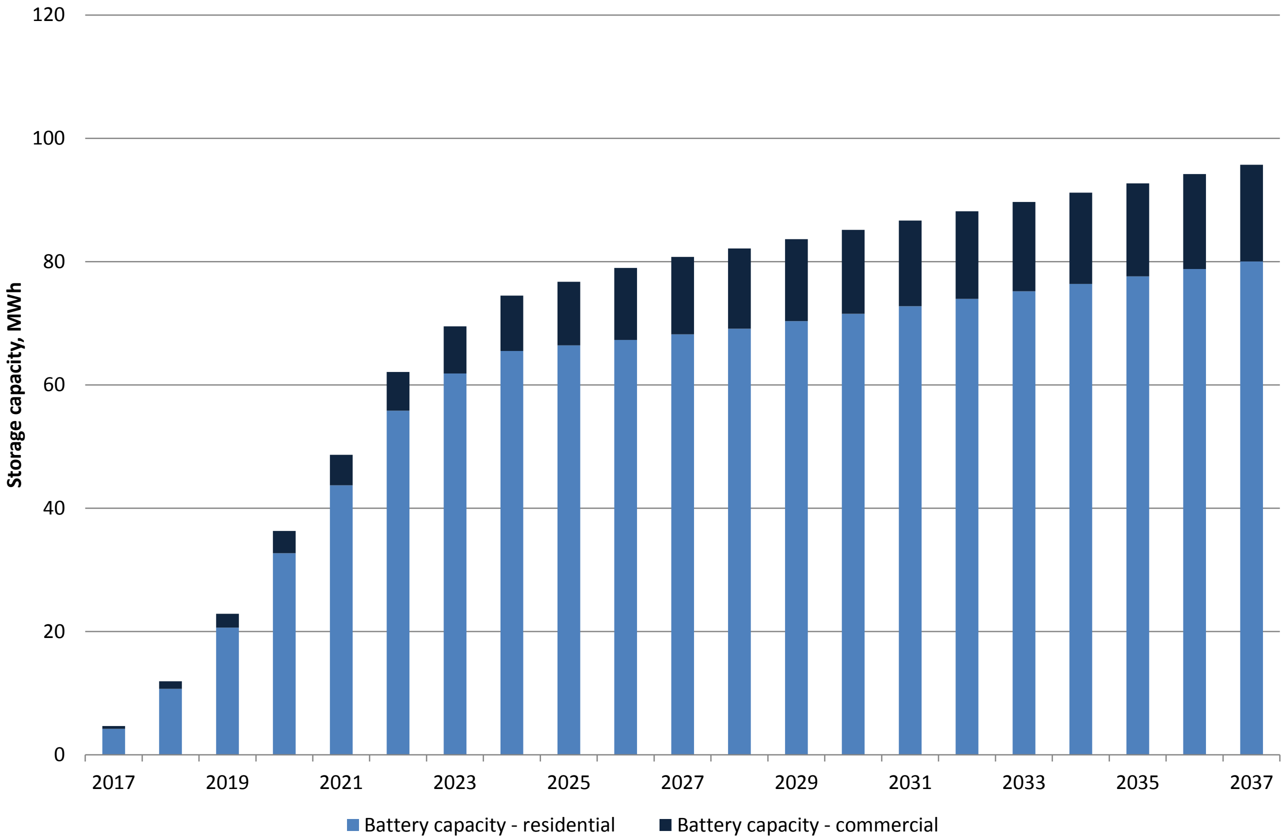
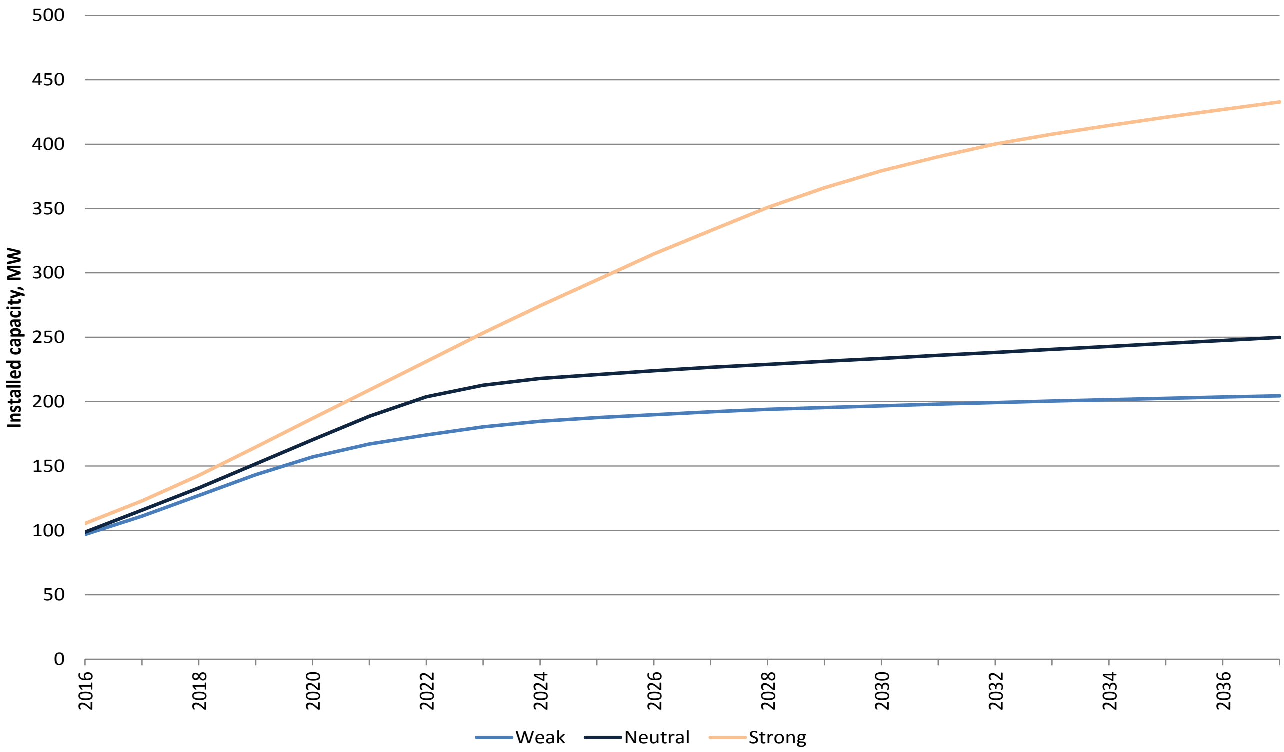


Figure 32 Tasmania rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

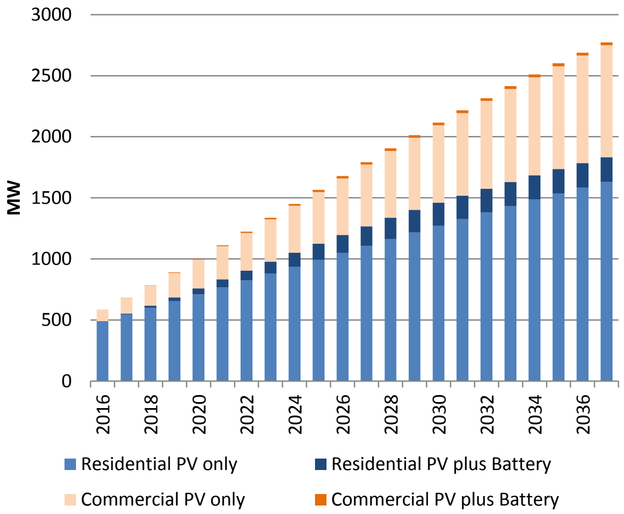


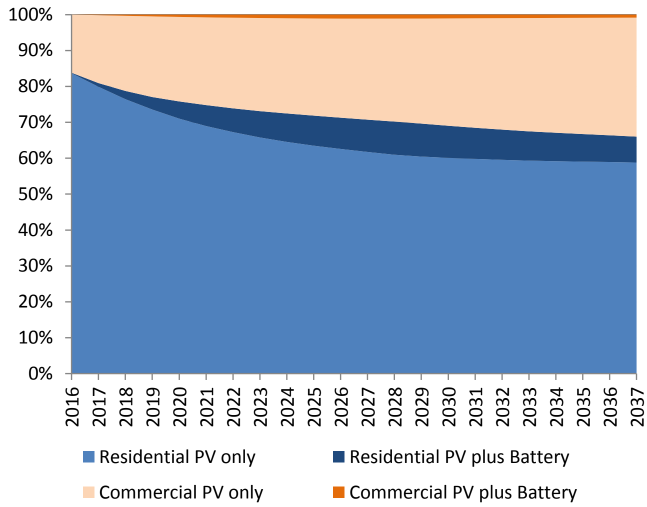
5.7 SWIS forecasts

The PV and IPSS systems in the South West interconnected System in Western Australia have a steady uptake throughout the forecast period. The main drivers for this uptake are the STCs incentives initially, with lower installation costs relative to electricity prices stimulating the installations in the long term.

The forecasted total installed capacity of rooftop PV in the SWIS, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS is shown in Figure 33.

Figure 33: Total installed capacity of rooftop PV and IPSS in the SWIS





Both the residential and commercial sectors show a steady uptake, with the total installed capacity of PV systems in households and businesses reaching 1,630 MW and 920 MW respectively in 2037.

The uptake of IPSS systems is relatively modest in the SWIS there is not that large a difference under time of use pricing between evening prices and middle of the day prices[24]. The total installed capacity in 2037 is around 225 MW with just over 10% of that being adopted by commercial businesses.

The cumulative installed battery storage capacity in the SWIS is shown in Figure 34. The total storage installed at the end of the forecast period is around 430 MWh with the majority (around 90%) being installed in the residential sector.

The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in the SWIS are given in Figure 35. As in the other States, the main drivers of the differences are the PV and IPSS capital costs chosen in each scenario as well as difference in the number of households. In 2037/38, the total installed capacity of PV and IPSS for the Strong scenario is around 3,170 MW (14% higher than the Neutral case), while for the Weak scenario it is around 2,270 MW (which is 22% lower than the Neutral scenario).

[24] This mainly affects uptake in the period when time of use tariffs are assumed to be adopted. The wholesale prices across a day and season in the WEM are not as volatile as in the NEM. There are also lower price limits set in the WEM which cap the level of variability in prices.

Figure 34: Total installed battery storage capacity in the SWIS

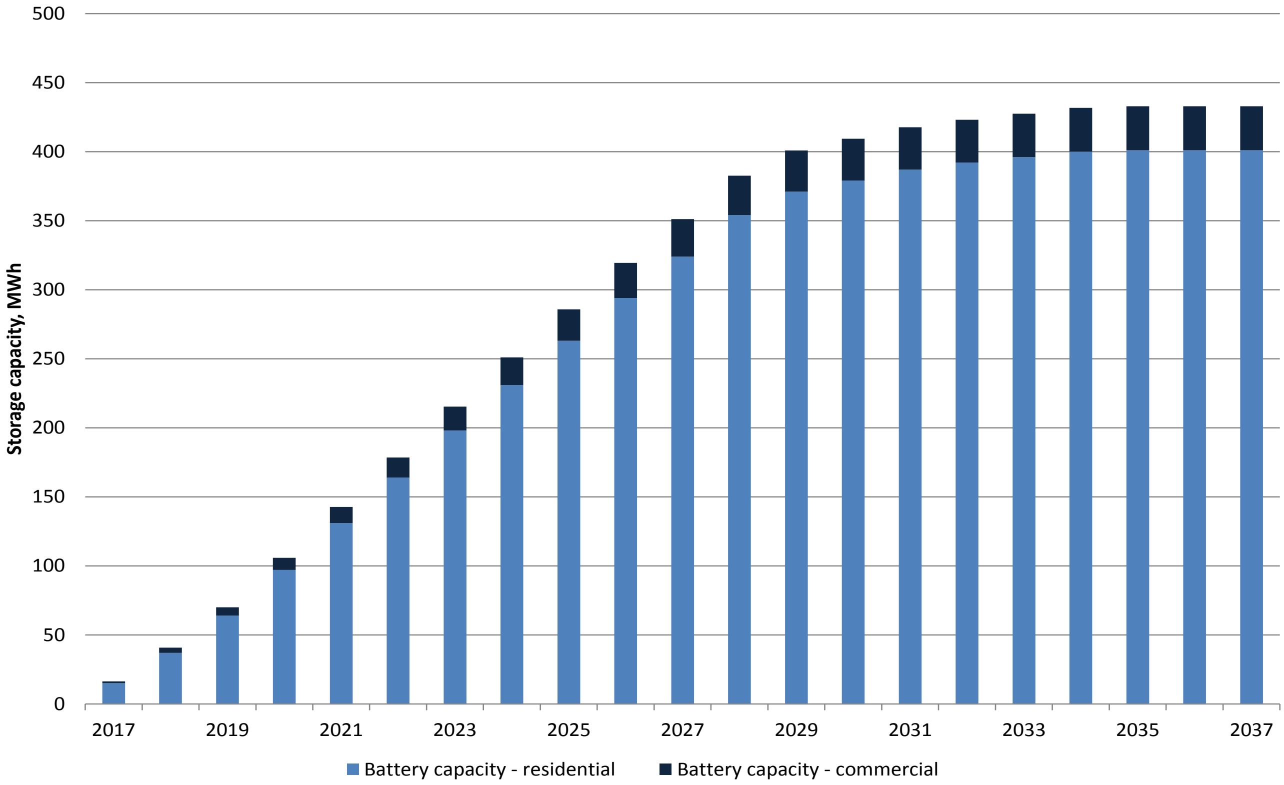
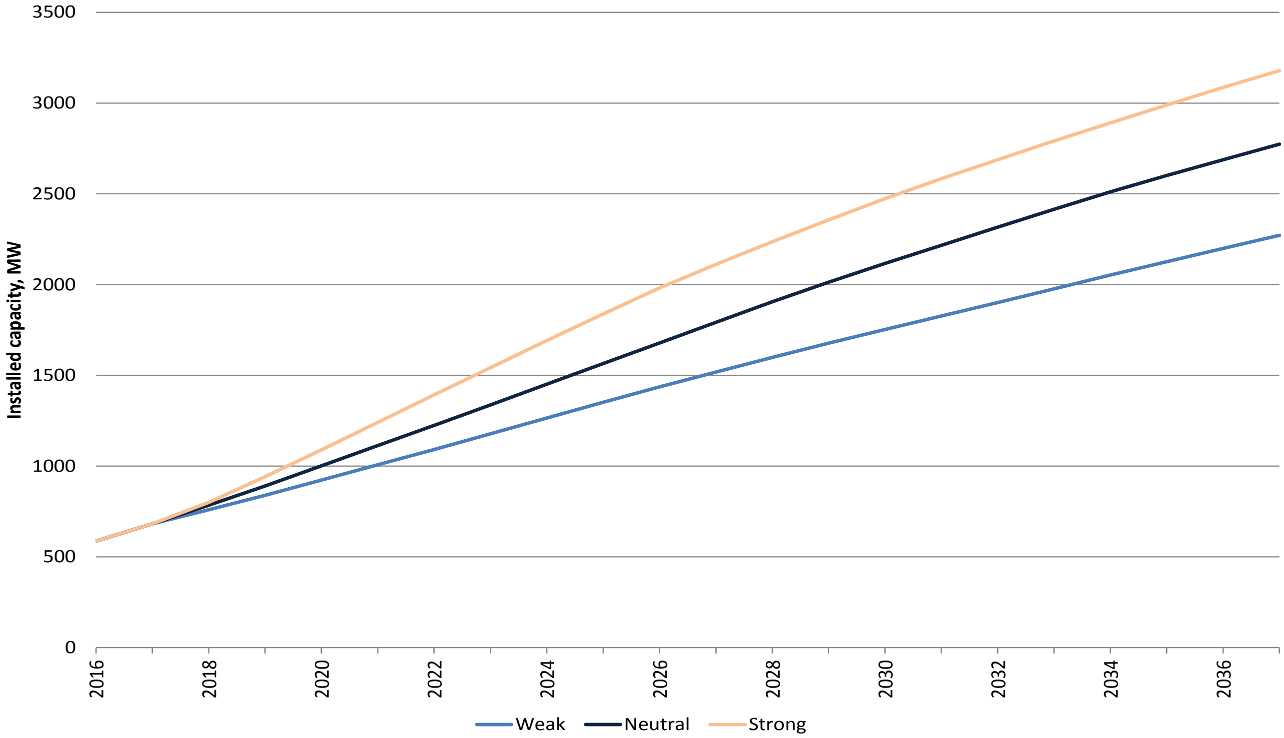


Figure 35: SWIS rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios



6. Key insights

The main drivers of PV uptake in all regions are the following:

- The financial incentives provided for the systems (STCs and FiTs)
- The declining installation costs of PVs and PV with storage. For PV systems in the short term, it is predominantly a decline of the “soft costs”[25] that include marketing and customer acquisition, system design, installation labour, permitting and inspection costs, and installer margins. In the longer term better system efficiencies and improvements from research and development are expected to reduce the installation costs. For the battery component, economies of scale in manufacturing and increased competition are considered to be the main causes of the downward pressure on costs.
- The increase in retail electricity tariffs particularly a big jump in prices in most regions in the near term. This is causing annual uptake to be projected to approach near historical highs over the next 5 years.
- A steady population growth across Australia, allowing for more PV systems to be adopted before saturation is reached.
- The transition to a time-of-use tariff structure that enables consumers to gain greater value from IPSS. However, the use of time of use tariffs is slowing uptake of PV systems as a result of lower retail prices in the middle of the day (reflecting the “duck” curve effect whereby wholesale prices in the middle of the day crashes as a result of the high level of solar PV generation – this is more marked than in previous forecasts due not only to the high level of roof-top PV uptake but also much higher levels of utility scale PV uptake, which affects the wholesale price in the middle of the day).

The phase out of STCs, starting from 2017, is gradually offset by the declining cost of PV installations, and the increase of retail tariffs (especially in the period to 2025).

Over the modelled period, South Australia and Queensland residences are the first to reach saturation levels for some areas by around 2030.

Battery storage has a steady uptake after 2021 in both the residential and the commercial sectors. This is driven by higher retail electricity prices, rapid decline of battery costs and the transition to a time-of-use tariff structure. However, uptake is much stronger in the residential sector, as the stored electricity has a higher value (avoiding retail tariffs in the evening time) whereas in the commercial sector the peak occurs in the middle of the day with lower amount of consumption in the high price evening period.

Some of the key messages resulting from this modelling study are:

- PV uptake remains relatively strong in the medium term since the falling installation costs of PV systems is offset by the gradual fade out of the SRES incentive. Increased electricity prices drive some additional growth to the sector for the next 10 years. After that, some decline in new annual installations numbers is observed since in some regions saturations levels are reached and the move to time of use pricing limits the retail price offsets that can be earnt from self-generation.
- The level of commercial PV installations is expected to increase over the modelled horizon, due to the decline of installation costs and the projected increase in electricity prices.

[25] Soft costs refer to non-hardware balance-of-system costs

- PVs with storage are forecasted to slowly emerge over the next few years as the cost of batteries is forecast to sharply reduce as a result of economies of scale and increased competition. The cumulative battery storage installed by 2037/38 is around 11,755 MWh.
- Queensland continues to have a steady uptake of installations until 2032 with growth in the commercial sector offsetting saturation reached in some residential areas. After 2032 a rapid decline in annual installations is evident with saturation reached in most regions. The fact that Queensland has already high installed capacity of residential PVs prevents a high penetration of battery storage since no retrofitting of batteries to existing systems has been considered to be economic.
- In New South Wales both residential and commercial uptake of PVs continues to grow across the entire forecasted period with installations reaching saturation only in some regions at the end of the horizon. There is also a strong growth of PVs coupled with battery storage in the state especially after 2020. The main drivers for this being the decline battery costs and the transition to a time-of-use tariff structure.
- South Australia currently has the highest penetration of residential PVs of all the NEM regions, and sees a decline of new rooftop PV installations throughout the modelled period due to (i) phasing out of the SRES incentive, and (ii) saturation reached in some regions. Some of the decline in new installations is offset by a higher uptake of commercial PVs. Residential prices also boost PV with battery storage installations in both the residential.
- Residential PV uptake in Victoria has a steady growth until 2025 when time of use tariffs start impacting on uptake of stand-alone systems. Uptake in the commercial sector remains steady across the forecast period and the installation of systems with battery storage is driven by a faster transition to a time-of-use tariff structure than in other states.
- Tasmania continues to have slower growth of PV installations in both the residential and commercial segments when compared to the other states, due to lower insolation levels and consequently lower financial attractiveness of the systems.
- In Western Australia, uptake continues to grow strongly due mainly to population growth and reducing system costs. Uptake is stronger for standalone systems as the relatively flat time of use retail price structure limits the benefits of storage uptake over the long term.
- At the end of the modelled horizon, the uptake of PVs and IPSS is forecasted to be 20% higher in the Strong scenario than in the Neutral scenario and 18% lower in the Weak scenario than in the Neutral scenario. These differences arise from the differences in the scenarios including different installation capital costs of the systems and different population levels.

Appendix A. Assumptions in the model

Table 7: Performance characteristics of batteries modelled

Technology	Lithium-ion
Depth of discharge (DoD) (%)	90
Cycle life (No of cycles)	4000
Lifetime (years)	10
Round-trip efficiency (%)	90

Note: The DoD refers to the amount of energy that is actually usable in a battery. The value of the cycle life represents the number of cycles of complete discharge (down to the DoD) that a battery can go through before its performance degrades substantially. Therefore, it is assumed that once a battery has reached its cycle life it would be replaced. The lifetime has a similar purpose to the cycle life, in that it represents the number of years for which a battery's performance is warranted. Although a battery may last beyond its lifetime, its performance will be degraded. Therefore, we assumed that once a battery has reached its lifetime it would be replaced. The round-trip efficiency is the percentage of energy a battery releases, relative to the energy provided. The round-trip efficiency is used in the modelling to represent loss of energy of ES.