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Distributed Energy Resources and Electric Vehicle Forecasts

Prepared for AEMO

13 June 2019

ENERGEIA

Executive Summary

Background

AEMO is required under the National Electricity Rules (NER) to develop state level electricity consumption and peak demand forecasts on an annual basis. These forecasts feed into key system planning instruments including the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO), which are used by industry to plan investment in new generation and transmission capacity.

The uptake, sizing and operation of rooftop solar photovoltaic (PV) systems, battery storage and electric vehicles are increasingly impacting customer consumption and peak demand trends, and may become key drivers of maximum electricity demand and consumption trends over the next 20 years.

Accurate, stable forecasting of solar PV, battery storage and electric vehicles continues to challenge the forecasting industry in Australia, as evidenced by the wide range of forecasts produced in the last few years. This is in part due to the interactions between these three technologies, and their rapidly changing and uncertain drivers.

Since the ground-breaking *Smart Grid, Smart City* project in 2013, Energeia has been a leader in developing new methods to tackle the unique challenges presented by modelling distributed energy resources including rooftop solar PV, battery storage, and electric vehicles, and has developed an integrated, bottom-up approach.[1]

Scope and Approach

AEMO engaged Energeia to develop forecasts of uptake, consumption and 17,520 half-hourly load profile impacts for the following technologies:

- Rooftop Solar PV;
- PVNSG Solar PV Non-Scheduled Generation (PVNSG) (100 kW–30 MW);
- Behind-the-meter Battery Storage; and,
- Alternative fuelled vehicles, including Battery Electric (BEV) and Plug-in Hybrid (PHEV) electric vehicles

across residential and business customers on simple and smart tariffs[2] by scenario on an annual basis out to FY50.

Energeia's approach to delivering the above scope of work was to:

- Establish and maintain ongoing communication and engagement;
- Research and update common modelling inputs and assumptions;
- Develop scenario and sensitivity-aligned key assumption and input configurations;
- Configure model, generate outputs and validate results with AEMO and key stakeholders; and,
- Document our approach, key assumptions and results in a final report.

The following sections report on the outcomes of each step.

[1] See Appendix B – uSim Modelling and Assumptions for a detailed description of how our modelling platform works and the key assumptions we used.

[2] Simple tariffs are defined as flat tariffs, and smart tariffs are defined in this report as time-of-use energy or demand tariffs.

Scenarios

Energeia configured its modelling platform for each of AEMO's 2019 planning scenarios and sensitivities below.

AEMO Scenarios and their Sensitivities

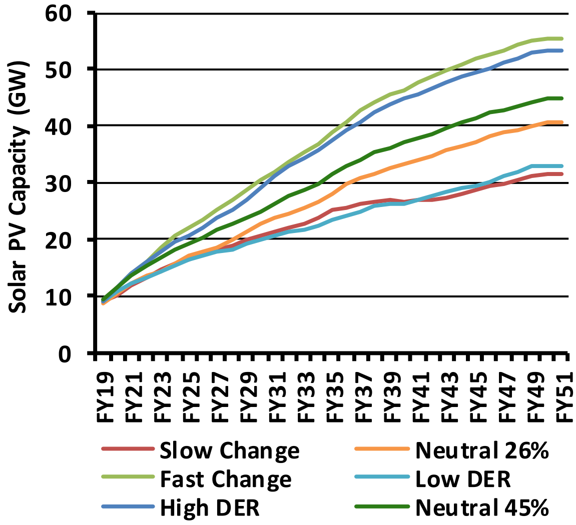
	Name	Description
Planning Scenarios	Fast Change	Strong economic and population growth, and aggressive emission reduction targets leading to relatively strong demand growth and rapid decarbonisation of both the stationary energy sector and the transport sector.
	Neutral 26%	Modest economic and population growth, existing emissions reduction targets are met and similarly extended. Consequently, grid demand is relatively static, and coal retirements drive large-scale generation mix.
	Slow Change	Weak economic and population growth, and a lesser ambition regarding future decarbonisation coupled with slow adoption of EVs. Demand growth is low, with potential for business closures leading to total consumption declines.
Sensitivities	High DER	A future similar to the Neutral scenario, but more decentralised.
	Neutral 45%	A future similar to the Neutral scenario
	Low DER	A future similar to the Neutral scenario, but less decentralised and with stricter emissions targets.

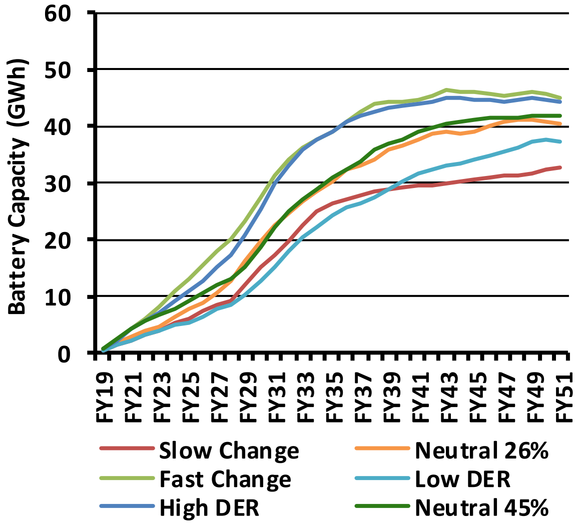
Where AEMO scenario drivers did not map directly to our modelling platform drivers, Energeia developed alternative mappings and validated them with AEMO.[3]

Capacity Outlooks by Scenario

Energeia's forecast of cumulative solar PV and battery capacity in the NEM is shown by scenario below.[4] Our modelling shows solar PV and battery capacity rising to almost 55 GW and 45 GWh by FY50 respectively, under the Fast Change and High DER futures, compared to around 31 GW and 32 GWh respectively in the Slow Change and Low DER scenarios. Solar PV capacity grows linearly with a slight tapering from FY3 onwards, while storage installation sharply increases after FY27 before plateauing around FY39 in most scenarios.

Rooftop Solar PV (left) and Battery (right) Capacity by Scenario (NEM)





Source: Energeia Modelling

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[3] See Section 3 for detail regarding our scenario driver mapping approach and results.

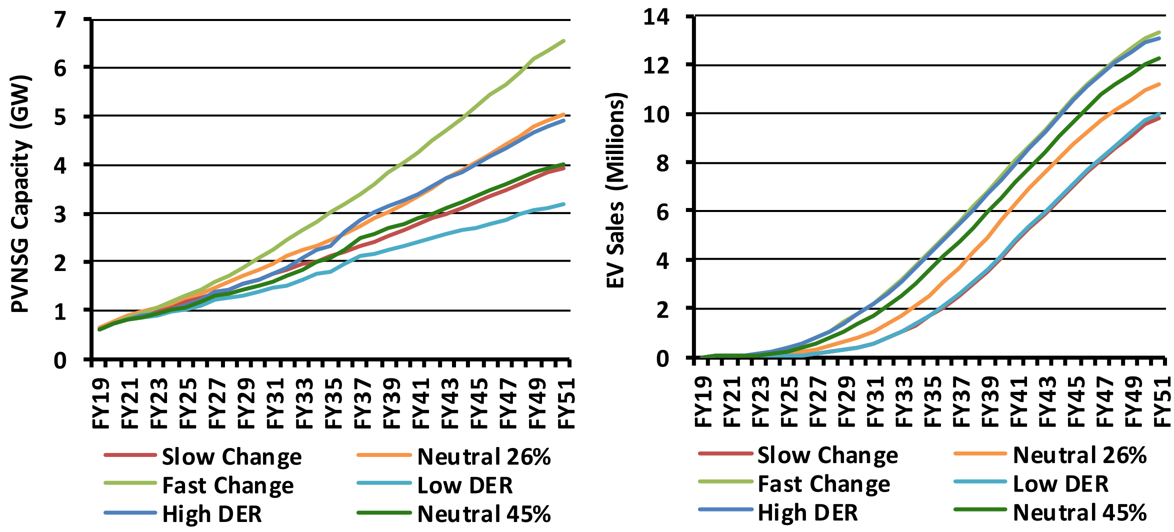
[4] Further reporting is available in the Outlook section on a State basis for the Neutral 26% scenario, and on an inter-scenario basis.

In terms of variation by scenario, the forecasts result in a 25 GW and 13 GWh solar PV and battery adoption range by FY50, respectively. There is slight variation between the sensitivities. However, there is noticeably greater variation between the Slow Change and Low DER sensitivity in the level of battery adoption.

Energeia's forecast of PVNSG capacity and EV adoption in the NEM is shown by scenario below. Our modelling shows PVNSG and EV installations rising to 6.5 GW by FY50 under the Fast Change scenario and just over 13 million by FY50 under the High DER scenario. In contrast, the Slow Change and Low DER scenarios only adopts around 10 million EVs by FY50. Interestingly, the lowest adoption of PVNSG are in the Low DER scenario with 3 GWs of installed capacity, followed by the Neutral 45% and the Slow Change scenario with around 4 GW. This is due to the differences in wholesale rates and PVNSG costs between the scenarios driving the uptake.

PVNSG installations grow linearly with a slight upward rate of growth over the period, while EV installations rise sharply from FY27 with the rate of growth tapering slowly until the end of the period.

PVNSG Capacity (left) and EV Sales (right) by Scenario (NEM)



Source: Energeia Modelling

In terms of variation by scenario, the forecasts result in a 3.5 GW and 3 million PVNSG and EV range by FY50, respectively. Similar to PV and batteries, there is less variation between the sensitivities for EVs, with the exception of the Neutral 26% and the Neutral 45% scenarios. For PVNSG however, there is significant variation between scenarios and sensitivities.

Installations, Capacity, Consumption and Load Profile Outlook for Neutral 26% Scenario

Energeia's cumulative forecast technology installation and capacity under the Neutral 26% scenario is shown side-by-side in the figures below. It shows batteries and EVs adoption exceeding that of solar PV by FY35 and FY40, respectively. This is mainly due to the larger market for storage and EVs, which are open to residents living in apartments and business working out of building suites.

As shown in the cumulative installed capacity figure below (right)[5], Energeia is forecasting rooftop solar PV capacity rising from 8 GW today to 41 GW by FY50. Storage capacity is forecast to increase from less than 1 GW to just over 40 GW over the same timeframe. This is independent forecast is broadly consistent with the 2016 Energy Networks Association National Transformation Roadmap[6].

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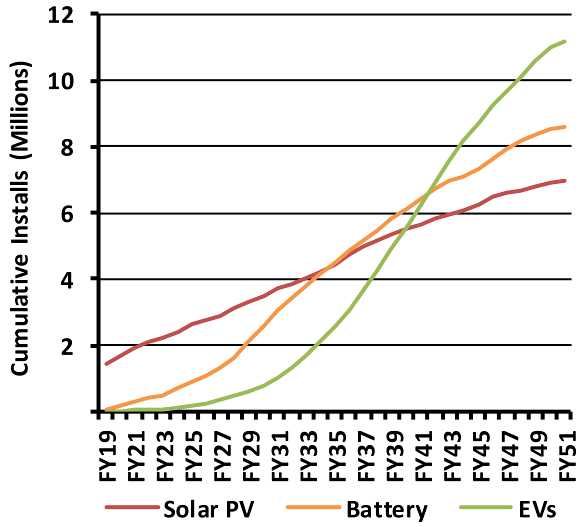
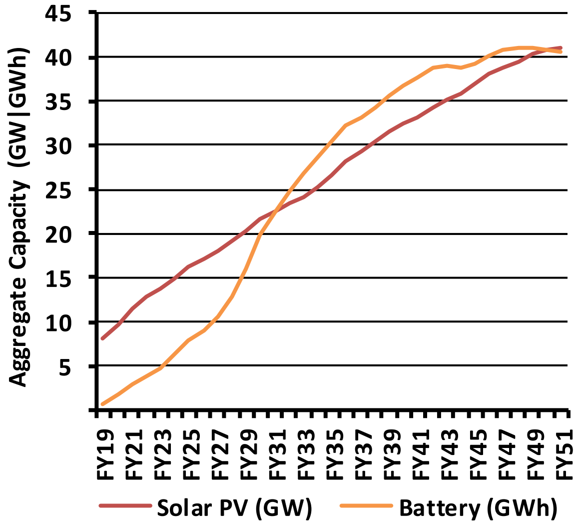
[5] Please refer to the Electric Vehicle Battery Capacity and Recycling case study in Section 4.1.2 for additional details on cumulative installed EV capacity.

[6] Energy Networks Association (2016) '*Network Transformation Roadmap: Work Package 5 – Pricing and Behavioural Enablers. Network Pricing and Incentives Reform*', available here https://www.energynetworks.com.au/sites/default/files/energeia_first_and_second_wave_pricing_october2016.pdf

Cumulative Installs (left) and Capacity (right) by Technology (NEM; Neutral 26% Scenario)

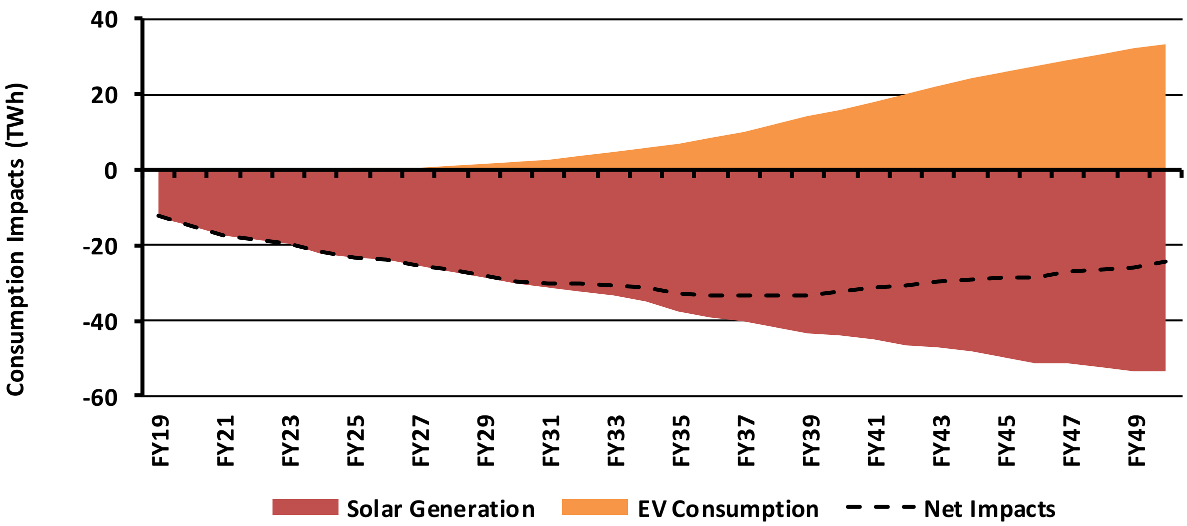




Source: Energeia Modelling; Note: Solar PV includes both behind-the-meter solar PV and solar PV non-scheduled generation.

Energeia's forecast the NEM's annual solar PV generation, EV consumption and net consumption impact by year for the Neutral 26% scenario is displayed below. The forecast of solar PV generation and EV consumption largely reflects the rates of adoption. On average, each solar PV system installed will generate 8 MWh of energy each year, which is significantly higher than the 2.6 MWh of grid impact from each EV. This results in excess generation produced by solar PV systems to be used either by the customer or exported to the grid.

Solar PV Generation, EV Consumption and Net Grid Impact by Year (NEM; Neutral 26% Scenario)

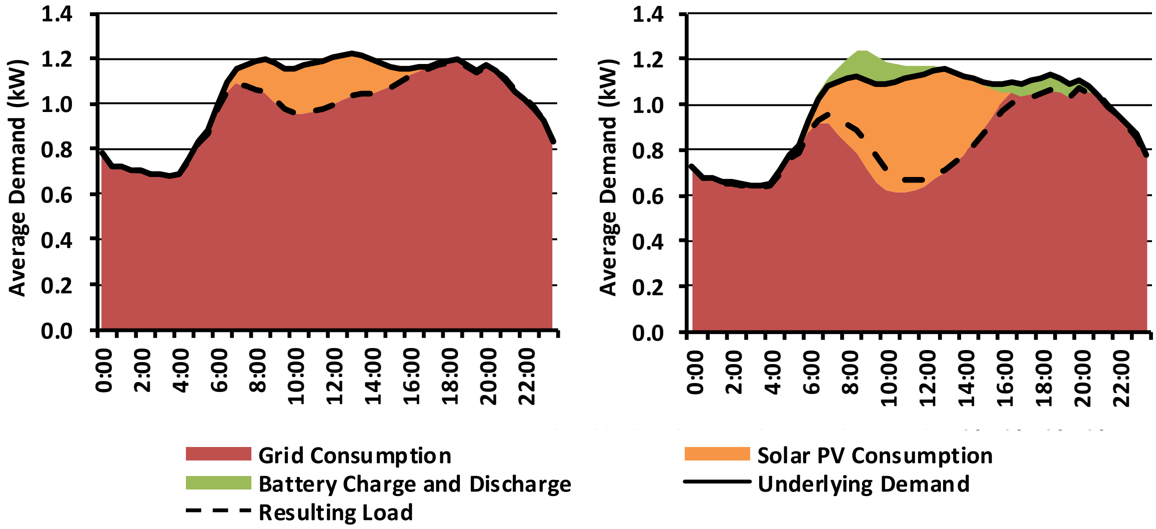


Source: Energeia Modelling

The figure below displays Energeia's forecast of the volume weighted average load profile for residential and business customers in the NEM in the Neutral 26% scenario.[7] It shows battery storage reducing the evening load peaks, while also working to charge from excess rooftop solar PV during the day.

[7] Industrial customers and PVNSG have been excluded.

Daily Average Load Profile in 2019 (left) and 2030 (right; NEM; Neutral 26% Scenario)



Source: Energeia Modelling

Overall, the forecast sees the resulting net load to be served by the NEM falling overall on a per customer basis due to the impact of solar PV, while also becoming significantly lower in the middle of the day, with the daily peak period shifting into the evening period.

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Disclaimer

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1. Background

The Australian Energy Market Operator (AEMO) is responsible the operation of the two largest electricity markets in Australia, namely the National Electricity Market (NEM), the power system interconnecting Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia, and the Wholesale Electricity Market[8] (WEM), which is the market for Western Australia's South West Interconnection.

AEMO is required under the National Electricity Rules (NER) to develop state level consumption and peak demand forecasts on an annual basis. These forecasts feed into key system planning instruments including the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO), which are used by industry to plan investment in new generation and transmission capacity.

The uptake, sizing and operation of rooftop solar, battery storage and electric vehicles (EVs) are increasingly impacting customer consumption and peak demand trends and are expected to become key drivers of state-level maximum electricity demand and consumption over the next 20 years.

1.1. Forecasting Rooftop Solar PV and Batteries

Accurate, stable forecasting of solar photovoltaic (PV) and battery storage systems continues to challenge the forecasting industry in Australia, as evidenced by the wide range of forecasts produced in the last few years. This is in part due to the interactions between these technologies and their rapidly changing and uncertain drivers.

1.1.1. Key Forecasting Uncertainties

Future adoption, sizing and operation of rooftop solar PV and storage is difficult to forecast because of significant uncertainty in the industry's understanding of their respective key drivers, including:

- **Customer Behaviour** – Early adoption, sizing and operation has been shown to be driven by non-financial factors like the environment and novelty, while early majority and late majority adoption can largely be explained by commercial drivers.
- **Policy Settings** – Government incentives have changed dramatically over the past 10 years across feed-in tariffs, small technology certificates (STCs), reliability and CO2 targets, and there is little clarity as to environmental policy settings over the next five years, let alone 30 years.
- **Technology Prices** – Solar PV prices have fallen faster in the last 10 years than anyone thought possible and Tesla cut battery costs in half overnight with the Powerwall 2. However, it is not clear whether solar PV and storage will continue along the same learning curve or vary from it.
- **Energy Prices** – Wholesale power prices have also gyrated over the past five years. How wholesale prices will evolve is highly uncertain, retail prices less so.

A scenario-based approach to developing up an internally consistent set of forecast drivers is the standard method for dealing with high levels of uncertainty – and the approach adopted for this project.[9]

1.1.2. Key Technology Adoption Forecasting Options

A key rooftop PV and storage modelling challenge is the selection of the most appropriate modelling approach given the target variable being modelled. In this case it is future installation numbers, sizes and mixes. Establishing the correct forecasting approach is non-trivial and a range of different approaches can be justified depending on the timeframe considered, the uncertainties considered and the nature of the environment.

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[8] For the 2019 WEM Electricity Statement of Opportunities, AEMO is bringing demand forecasting in-house.

[9] Energeia's approach to modelling how policy, technology and prices intersect is outlined in Appendix B – uSim Modelling and Assumptions and Appendix D – Solar PV Non-Scheduled Generation Forecasting Methodology and Assumptions.

Table 1 – Selection of Potential Demand Side Modelling Approaches

		Timeframe	What-if Analysis	Unstable Environment	Complex Environment
Stochastic		Short Term	✗	✓	✗
Econometric		Medium Term	✓	✗	✗
Neural Network		Short and Medium Term	✗	✓	✓
Model Base	Bass Diffusion	Long Term	✗	✗	✗
	Logit	Long Term	✓	✗	✗
Agent Based		All	✓	✓	✓

Source: Energeia Research

Australian technology adoption forecasts have mainly chosen econometric or logit-curve approaches that are best suited to steady-state and early adoption markets, respectively. Overseas, and in the US in particular, agent based methods are increasingly being adopted. They enable an integrated approach to modelling a wide range of complex, non-linear factors and interrelationships across customer behaviour, technology, policies and prices.

1.2. Forecasting Battery and Plug-in Hybrid Electric Vehicles

Accurate, stable forecasting of EVs also continues to challenge the forecasting industry in Australia, again evidenced by the wide range of forecasts produced in the last few years. While there may be interactions between solar PV and EV adoption, the main driver is the rapidly changing and uncertain market.

1.2.1. Key Forecasting Uncertainties

Future adoption and charging of EVs is difficult to forecast because of significant uncertainty in the industry's understanding of the key adoption and charging drivers, including:

- **Customer Behaviours** – Customers purchase of vehicles are driven by emotive and non-financial reasons. Historical data suggests model availability is therefore a key driver of adoption.
- **Policy Settings** – Federal, state and local government EV and charging incentives vary widely, and are highly uncertain into the future, with a wide potential variation across potential future scenarios.
- **Technology Prices** – EV costs are driven by lithium battery costs, as well as manufacture pricing strategies, which impact on vehicle premiums. Charging technology costs are also highly uncertain.
- **Energy Prices** – Petrol prices and wholesale energy prices are both highly uncertain, and future price trajectories could vary significantly due to oil prices, environmental policies, etc.
- **Technology Availability** – Vehicle availability is a key uncertainty, and the timing and degree of vehicle availability will depend on a range of factors including government incentives and regulation.

Here again, a scenario-based approach to developing up an internally consistent set of forecast drivers is the standard method for dealing with high levels of uncertainty and the approach adopted for this project.[10]

1.2.2. Key Technology Adoption Forecasting Options

Australia has largely relied to date on discreet, regression or adoption curve (e.g. logit) based methodologies, which are also typical of overseas approaches. However, Energeia expects agent-based, bottom-up modelling to become increasingly important as interdependencies increase, e.g. due to emerging vehicle-to-grid technology.

[10] Energeia's approach to modelling with the key uncertainties is outlined in Appendix C – evSim Modelling and Assumptions

2. Scope and Approach

This section summarises Energeia's scope of work and the approach adopted to deliver it for this engagement.

2.1. Scope

AEMO engaged Energeia to develop forecasts of uptake, consumption and 17,520 half-hourly load profile impacts for the following technologies:

- Rooftop Solar PV;
- Solar PV Non-Scheduled Generation (PVNSG) (100 kW–30 MW);
- Behind-the-meter Battery Storage; and,
- Alternative fuelled vehicles, including Battery Electric (BEV) and Plug-in Hybrid (PHEV) electric vehicles

across residential and business customers on simple and smart tariffs[11] by scenario on an annual basis out to 2050. Further details of AEMO's scope of work and requirements are included in Appendix A – AEMO's Scope and Inputs.

2.2. Approach

Energeia's approach to delivering the above scope of work was to:

- Establish and maintain ongoing communication and engagement;
- Research and update common modelling inputs and assumptions;
- Develop scenario and sensitivity-aligned key assumption and input configurations;
- Configure model, generate outputs and validate results with AEMO and key stakeholders; and,
- Document our approach, key assumptions and results in a final report.

The following sections report on the outcomes of each step.

2.2.1. Research and Update Common Inputs and Assumptions

The first foundational step of the project comprised the data-gathering and validation tasks required to configure our model with common inputs and assumptions. In this step, Energeia:

- **Managed the Request for Information Process** – AEMO's forecasting team supplied economic and electricity data from AEMO's databases for use in our DER, EV and PVNSG models;
- **Deliver Assumptions and Methodology Report** – Energeia presented our modelling methodology and key assumptions to AEMO in a formal report and workshop to validate both our chosen approach and the updated model drivers, inputs and assumptions.

2.2.2. Develop Scenario and Sensitivity Inputs and Assumptions

The second step of the project focused on aligning our modelling configuration with AEMO's planning scenarios and sensitivities. In this step, Energeia:

- **Agreed the Scenario Design** – AEMO specified three scenarios and three sensitivities which Energeia translated into sets of modelling inputs to drive our models (further details on the scenario mapping process are included in Section 3, and AEMO's draft scenario plan is included in Appendix A – AEMO's Scope and Inputs).

[11] Simple tariffs are defined as flat tariffs, and smart tariffs are defined in this report as time-of-use energy or demand tariffs.

2.2.3. Delivery, Validation and Documentation

Finally, Energeia delivered the forecasts in the required data templates, validated the results with AEMO and AEMO's key stakeholders before documenting them in this final report:

- **Update, Configure, Run and Report our Models** – Energeia configured and ran its utility (uSim) and EV (evSim) simulation platforms (uSim) to model solar, batteries and EVs for all of the and required State/Territory for the 2018/19 to 2050/51 period. The results of these model runs were then reported to AEMO using the agreed data templates.

  Energeia undertook two different stakeholder engagement processes, as shown in Table 2.

  Table 2 – Engagement with AEMO's Key Stakeholders

Date (Location)	Meeting	Agenda	Energeia Attendees
Monday 4 March 2019 (Melbourne)	EV Workshop	Understand key concerns of industry stakeholders	Mick Fell; Jacob Kharoufeh
Wednesday 27 March 2019 (Melbourne)	Forecasting Reference Group	Present modelling assumptions and methodology	Mick Fell; Dean Coulter; Nish Su; Eric Kotopoulis
Friday 5 April 2019 (Sydney)	Forecasting Reference Group	Draft outlook for the Neutral 26% scenario	Mick Fell; Ezra Beeman

- **Documentation** – Energeia developed this final report covering the project background, scope, approach, assumptions, methodologies and results.

3. Scenario Mapping

AEMO develop their Integrated System Plan (ISP) scenarios in consultation with industry via their Forecasting Reference Group (FRG) stakeholder engagement process. The scenarios incorporated in the 2019 ISP included the core planning scenarios from the previous year, but sensitivity scenarios shifted towards understanding the impact of more stringent emissions targets and different rates of uptake of DER and EV.

Energeia mapped AEMO's scenario design to the key model drivers in Energeia's modelling platform, using the process outlined in the following sections. The significant challenge that needed to be overcome was that AEMO's scenarios design was aligned with the key inputs into their ISP process, rather than the drivers of Energeia's solar and storage, and EV modelling tools. Energeia developed a process that identified how to map these outcomes to their inputs and agreed the resultant scenario design with AEMO.

3.1. Energeia Scenario Development Process

To generate the required scenarios, Energeia firstly needed to map AEMO's scenario design to the inputs that drive Energeia's solar and storage, and EV modelling tools, and agree on a finalised scenario design with AEMO.

Energeia first investigated what issues and drivers AEMO's design was testing, and then completed an analysis to identify what scenario settings could be directly inputted into our models and those that required mapping to Energeia's model drivers.

3.1.1. Strategic Dimensions

Energeia reviewed the scenario design supplied by AEMO[12], and identified the following strategic dimensions:

- **Emissions** – testing the sensitivity of the 2018 ISP's Neutral Scenario to emissions policy
- **Energy System Change** – testing economic outlook sensitivities (such as population, economic and peak demand growth)
- **Distributed Energy Resources Take-up** – testing high and low DER scenarios (including DER price declines)

These were used to identify the key drivers that differentiate between the scenarios, which would determine the key model drivers required by Energeia's modelling tools. Additional details on the strategic dimension mapping can be found in Section A.2. Scenario Strategic Dimension Mapping.

3.1.2. Driver Analysis

As well as splitting out the AEMO scenarios into their different strategic dimensions (to help understand what questions AEMO was testing with the scenario design), Energeia also reviewed the scenario settings against whether they could be inputted directly into Energeia's modelling platforms.

Some of the drivers could be inputted directly into Energeia's models (i.e. the driver was directly relatable to Energeia's model drivers), whereas others needed to be mapped to Energeia's model drivers (i.e. the AEMO drivers describes an outcome of our modelling process, and we needed to instead map the scenario driver to the model driver that would tend to deliver this result). These are outlined in Table 3. A description of each driver can be found in Section A.1. Scenario Framework which links these back to AEMO's original scenario framework.

Energeia then identified appropriate model drivers for AEMO's scenario assumptions, further detailed in Section A.3. Scenario Inputs and Outputs Mapping to RFI Inputs.

[12] The full scenario framework as provided by AEMO is detailed in Section A.1. Scenario Framework.

Table 3 – Driver Analysis

Inputs (scenario settings that ***relate directly***)	Outputs (scenario settings that ***require mapping***)
Economic Growth and Population Outlook	Rooftop PV up to 100 kW
Battery Cost Trajectories (Utility and Behind-the-Meter)	Non-scheduled PV above 100 kW (<30 MW)
Tariff Arrangements	Battery Storage Installed Capacity
Electric Vehicle Charging Times	Electric Vehicle Uptake
Battery Storage Aggregation	Emissions Reduction Trajectories

Source: Energeia Analysis

3.2. Agreed Final Scenario Design

Once the relevant AEMO scenario settings were mapped to Energeia's model inputs and drivers, Energeia constructed a final set of scenario settings for both the solar and battery storage and the EV modelling, as outlined in Table 4 and Table 5 respectively.

Energeia has split out the model drivers into five broad categories: growth drivers, technology costs, prices, tariff structures, and rebates and incentives. These reflect the key areas that drive Energeia's modelling platform, across volumes (growth), costs (technology costs) and revenues (prices, tariffs and incentives).

Table 4 – Solar and Battery Storage Modelling Scenario Settings

Energeia DER Model Drivers		Planning Scenarios			DER Sensitivities		
		Slow Change	**Neutral 26%**	**Fast Change**	**Low DER**	**Neutral 45%**	**High DER**
Growth Drivers	Population growth	AEMO Slow Change	AEMO Neutral	AEMO Fast Change	AEMO Neutral	AEMO Neutral	AEMO Neutral
	Peak demand growth						
	Energy growth						
Technology Costs	Solar PV	Weak	Neutral	Strong	Weak	Neutral	Strong
	Non-scheduled solar PV						
	Battery storage						
Prices	VWA RRP price forecast[1]	AEMO (26%)	AEMO (26%)	AEMO (45%)	Energeia (45%)	Energeia (45%)	Energeia (45%)
Tariff Structures	Current and future residential tariff structures	Opt-in Tariffs	Opt-in Tariffs	Opt-out Tariffs	Opt-in Tariffs	Opt-in Tariffs	Opt-out Tariffs
	Current and future commercial tariff structures						
	DSO/VPP orchestration year[2]	Weak Adoption (2027)	Neutral Adoption (2024)	Strong Adoption (2021)	Weak Adoption (2027)	Neutral Adoption (2024)	Strong Adoption (2021)
Rebates and Incentives	Solar PV rebates	No Additional Rebates	No Additional Rebates	STC Rebates Continue	No Additional Rebates	STC Rebates Continue	STC Rebates Continue
	Storage rebates[3]	No Rebates	No Rebates	$500/kWh	No Rebates	$500/kWh	$500/kWh

Source: Energeia; Note: 1. Energeia adopted AEMO's wholesale RRP which impacts the overall retail price of tariffs. Energeia's uSim model incorporates an internal feedback system allowing networks to recover their network revenue from customers. Additional information can be found in Appendix B – uSim Modelling and Assumptions. 2. Timing for battery storage aggregation based on the Network Transformation Roadmap (2017) Energy Networks Australia, 3. Storage rebates assume current SA battery rebate up to $6,000 per unit is rolled out to other states, (e.g. reduces the installed cost of a 14 kWh Tesla Powerwall II from ~$12,000 to $6,000).

Table 5 – Electric Vehicle Modelling Scenario Settings

Energeia EV Model Drivers		Planning Scenarios			DER Sensitivities		
		Slow Change	**Neutral 26%**	**Fast Change**	**Low DER**	**Neutral 45%**	**High DER**
Growth Drivers	Population growth	AEMO Slow Change	AEMO Neutral	AEMO Fast Change	AEMO Neutral	AEMO Neutral	AEMO Neutral
Technology Costs	EV cost premiums by vehicle type	Weak EV Parity (7 years)	Neutral EV Parity (5 years)	Strong EV Parity (3 years)	Weak EV Parity (7 years)	Neutral EV Parity (5 years)	Strong EV Parity (3 years)
Prices	Retail price forecasts by state and class	AEMO (26%)	AEMO (26%)	AEMO (45%)	Energeia (45%)	Energeia (45%)	Energeia (45%)
Tariff Structures	Current and future EV managed/unmanaged charging structures[1]	Slow Transition (7 years)	Neutral Transition (5 years)	Fast Transition (3 years)	Slow Transition (7 years)	Neutral Transition (5 years)	Fast Transition (3 years)
Rebates and Incentives	EV rebates over time by state[2]	No Rebates	No Rebates	$3,000	No Rebates	$3,000	$3,000

Source: Energeia; Note: 1. Transition to managed Level 2 EV charging coincides with the decline in EV price premium, 2. EV rebates assumed to be implemented from the 'Moderate Intervention' scenario in the 'Australian Electric Vehicle Market Study' (2018) Clean Energy Finance Corporation (equivalent to a $3,000 reduction in vehicle sticker price).

4. Outlook

The key modelling outcomes from Energeia's forecasting results for the Neutral 26% scenario include:

- **Installs** – The total number of solar PV systems, batteries and EVs installed over the forecast period capturing technology penetration and configurations overtime.
- **Capacity** – Total installed capacity of each technology type segmented by class and tariff type, showing total resource capacity over the period.
- **Imports and Exports** – The net impacts of solar PV and batteries purchasing behaviour on the system in terms of operational consumption and peak demand.
- **Load Profile Impact** – The net impact of solar PV and battery technologies on customer load profiles across the system by customer class and tariff type.

AEMO's central planning scenario, the neutral case with existing the Federal emissions reduction target (26-28% reductions relative to 2005 emissions), is explored in detail in Section 4.1 (NEM) and Section 4.2 (each state)[13].

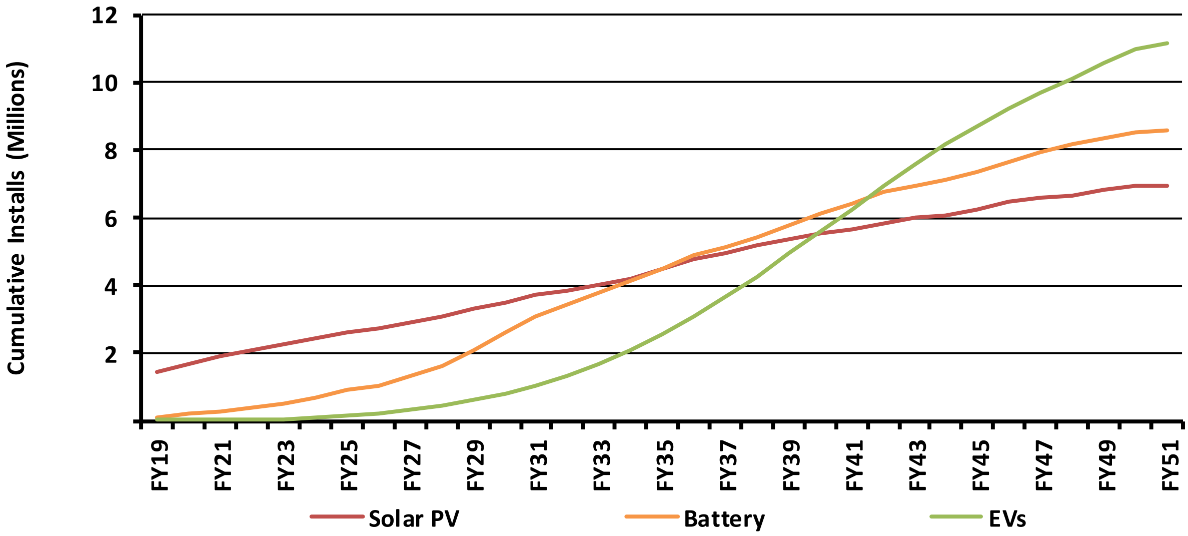
4.1. Neutral 26% Scenario – NEM

4.1.1. Installs

Installations of all technologies increase significantly over the forecast period as shown below in Figure 1. Solar PV installs are shown to have steady growth throughout the period starting from 1.5 million systems installed in FY19 to just under 7 million installations by FY51.

The steady growth of solar PV installs is contrasted by the rapid increase in uptake seen by battery energy storage systems and EVs after FY27 and FY30 respectively. By FY35 and FY39, the install and sales of batteries and EVs respectively exceed that of solar PV systems. The market for solar PV is limited to customers in detached dwellings, meaning residential customers in units and apartments and commercial customers in suites can only purchase batteries and EVs[14].

Figure 1 – Cumulative Installs by Technology (NEM; Neutral 26% Scenario)



Source: Energeia Modelling; Note: Solar PV includes both behind-the-meter solar PV and PVNSG.

[13] The relative impact of each additional scenario and/or sensitivity is explored in Section 4.3.

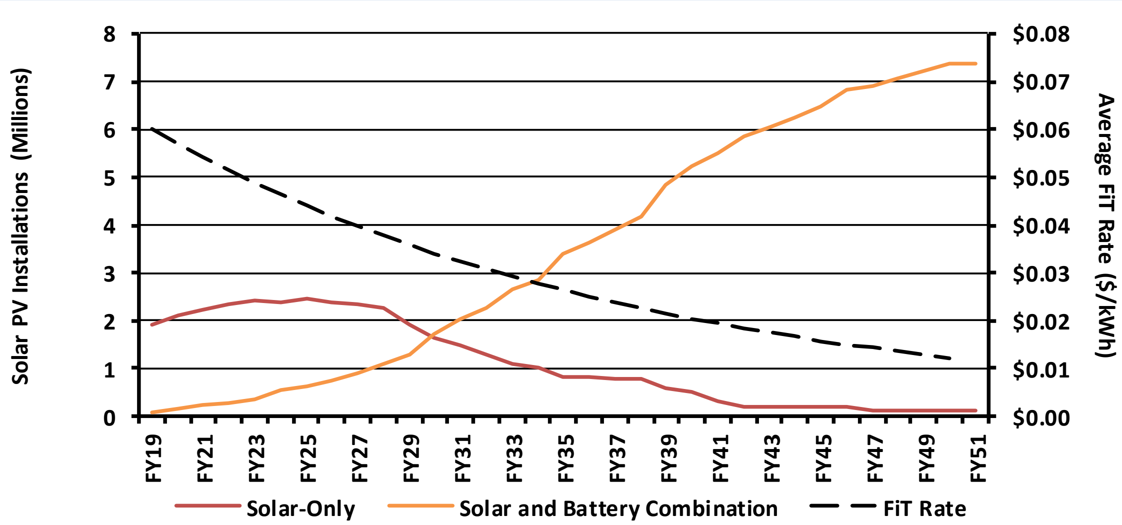
[14] Battery only installations are enabled through the savings created by tariff arbitrage under time of use and maximum demand tariffs.

Value of Additional Solar Installations:

With the continued uptake of solar PV over the modelling period, the purchasing behaviour of customers adapts with the changing economic environment to optimise their electricity bill.

Figure 2 shows the shift in uptake behaviour over time from adopting a solar-only solution to a solar and battery combination as it becomes more beneficial for consumers to shift their excess solar generation with a battery, rather exporting their excess solar generation to the grid. This is especially true as the FiT rate decreases and the cost of energy is forecast to increase over time, resulting a greater opportunity for customers to reduce their bill through storing their excess solar generation and using their stored energy during periods of no solar generation, particularly if the customer is on a smart tariff with more expensive peak components.

Figure 2 – Solar PV Installations by Configuration (NEM; Neutral 26% Scenario)

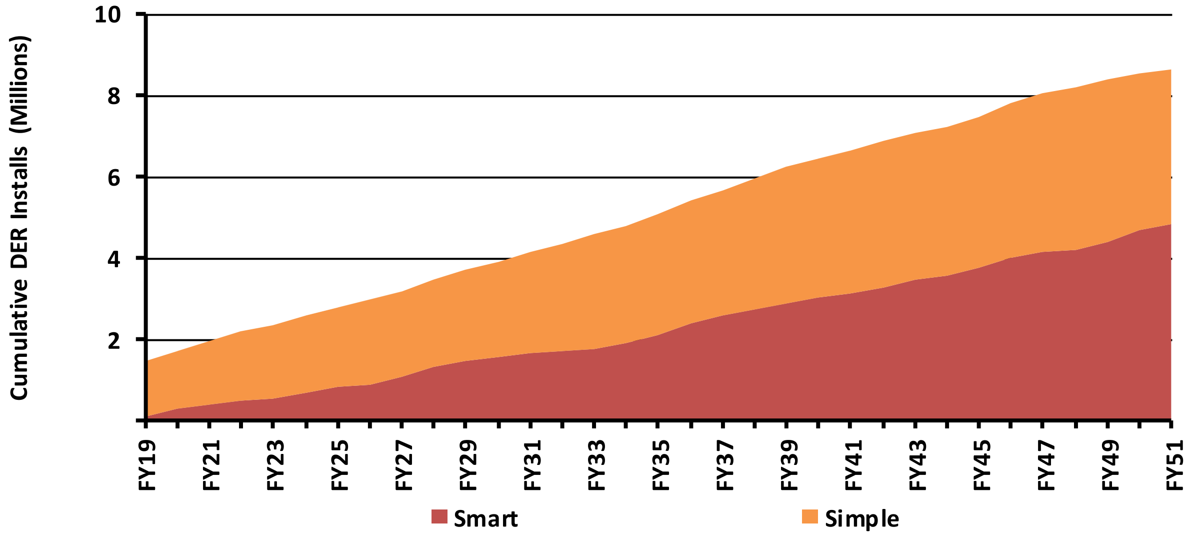


Source: Energeia Modelling

The split of solar PV and battery technology customers by tariff type adopted is shown in Figure 3 where the adoption of cost reflective tariffs, or smart tariffs, grows significantly over the period in this scenario. Initially, they make up a small proportion of customers purchasing solar PV and batteries with the majority of customers operating on a simple tariff.

Over the forecast period, the cumulative installs of solar PV and batteries on a smart tariff increases at twice the rate of those on a simple tariff as customers seek to minimise their consumption bill by using solar PV and batteries to clip their consumption during peak demand periods. By FY45, smart tariffs are forecast to be the dominant tariff type for solar PV and battery technology owners.

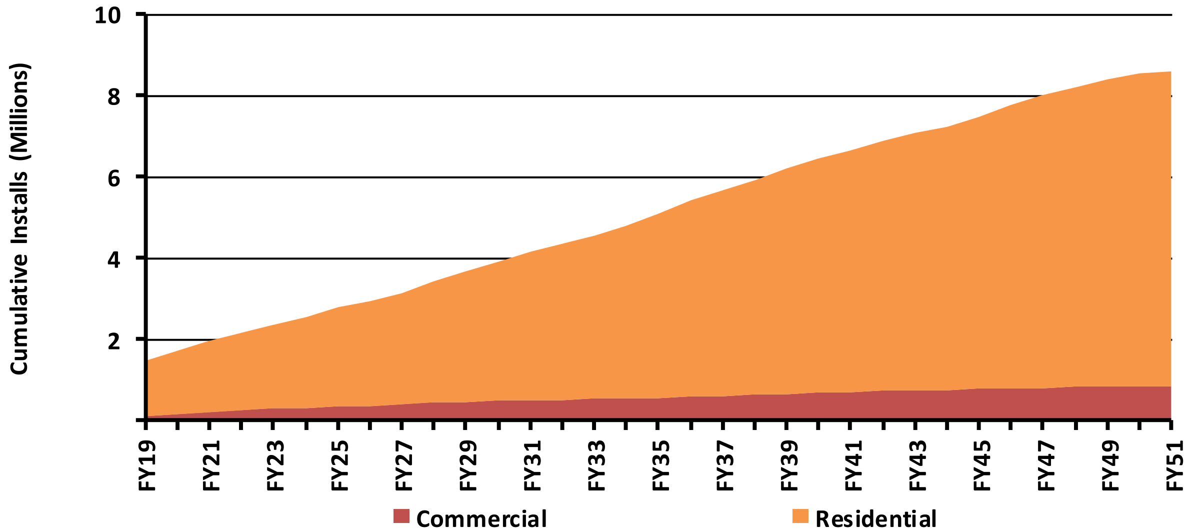
Figure 3 – Cumulative Solar and Battery Installs by Tariff Type (Excluding EVs; NEM; Neutral 26% Scenario)



Source: Energeia Modelling

As shown in Figure 4, the majority of solar PV and battery systems are purchased by the residential market, which remains the major proportion of installs throughout the forecast period. Commercial installs show a steady increase from their current low market penetration resulting to around 870,000 installations by FY51 which corresponds to a market penetration of 10%. Residential installs reach 90% over the same period.

Figure 4 – Cumulative Solar and Battery Installs by Customer Type (Excluding EVs; NEM; Neutral 26% Scenario)



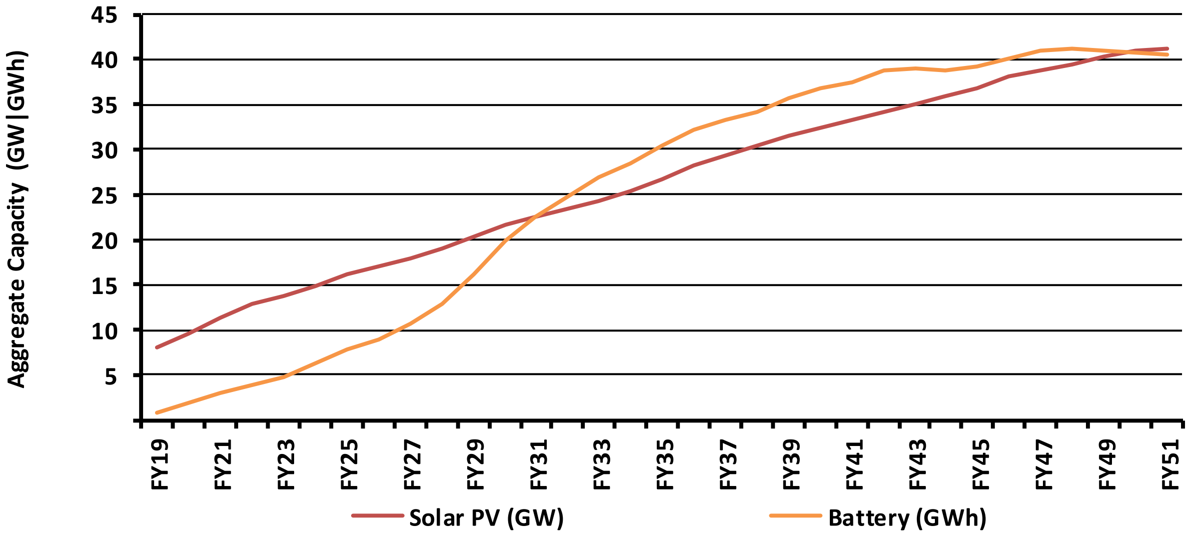
Source: Energeia Modelling

4.1.2. Capacity

Similarly, the cumulative installed capacity of both solar PV and batteries increases significantly over the forecast period, as shown in Figure 5[15]. Solar capacity is shown to steadily increase over time, with 8 GW in FY19 increasing to 41 GW in FY51.

Unlike solar PV, the effective capacity of batteries increases steadily until experiencing a rapid incline from FY27 due to increased battery adoption in the retrofit market[16]. The increase in battery capacity plateaus from FY43 onwards as the existing battery fleet degrades in capacity and offsets the new capacity installed each year[17].

Figure 5 – Cumulative Installed Capacity by Technology (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

Battery Purchasing Case Study 2019 vs 2029:

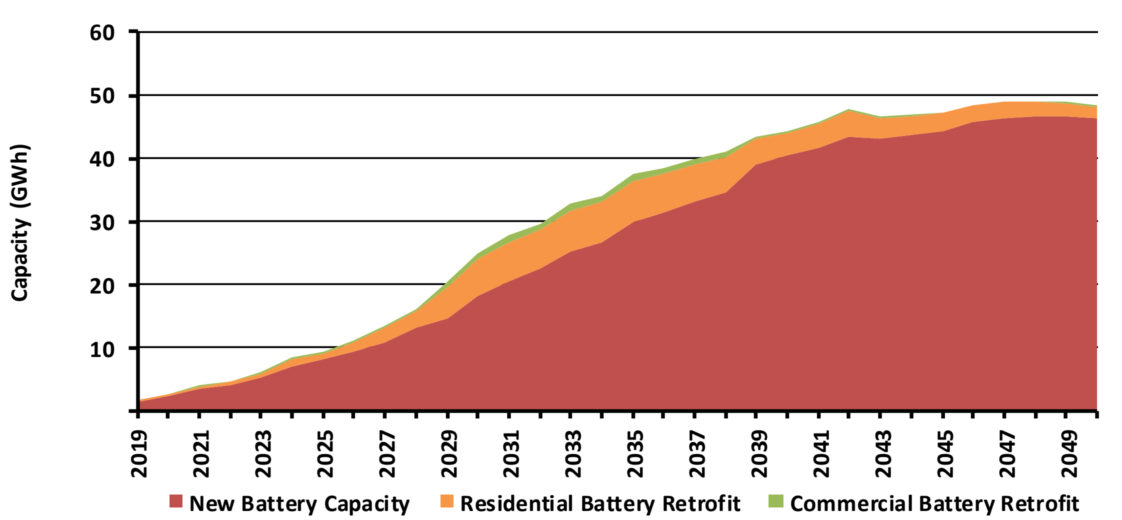
Significant changes in the economics of battery storage forecasted to occur in the next 10 years in the Neutral 26% scenario, with a large increase in battery uptake due to an increase in the retrofit market adoption from the late 2020's, where a customer adds a battery energy system to their existing solar PV configuration. This is shown in Figure 6, where the retrofit market predominantly in the residential sector is a key driver of the two-year increase in battery adoption seen in most states and in the NEM overall.

[15] Please refer to the Electric Vehicle Battery Capacity and Recycling case study for additional details on cumulative installed EV capacity.

[16] Please refer to the Battery Purchasing Case Study for further information.

[17] Please refer to the Driver of Battery Degradation case study for additional details.

Figure 6 – Battery Capacity by Purchase Configuration (NEM; Neutral 26% Scenario)



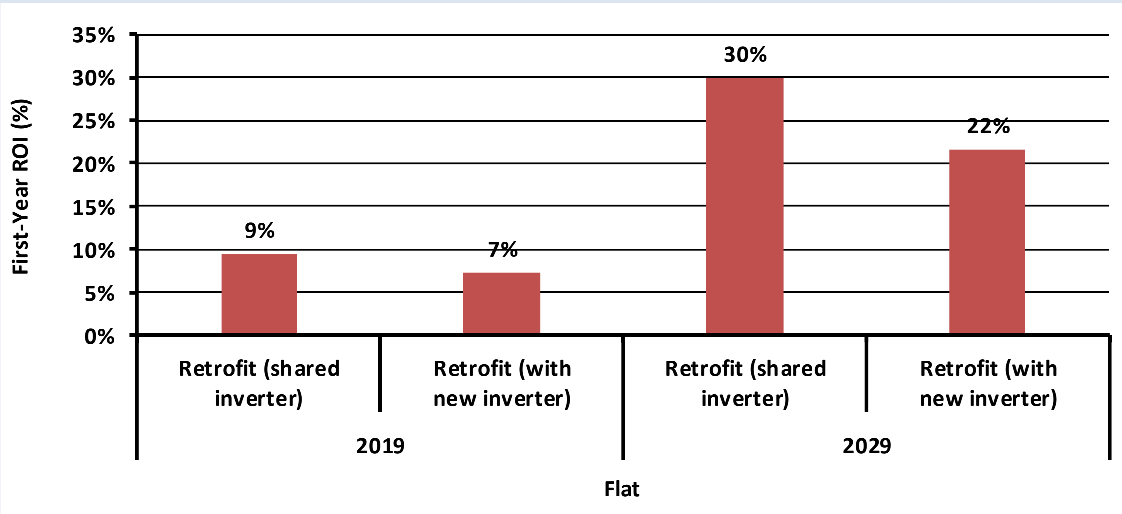
Source: Energeia Modelling

A customer's purchase behaviour to retrofit a battery is reflected in customer bill savings or return on investment (ROI). Figure 7 shows the ROI of retrofitting a battery onto an existing solar PV system in 2019 and 2029 for an Ausgrid residential customer on a simple (or Flat) tariff with an annual consumption of 6 MWh. In 2019, retrofitting a battery has a poor ROI with a payback period greater than 10 years. However, by 2029 battery cost reductions as well as forecast in tariff rate increases results in this becomes significantly more attractive decision with an ROI of 30%. This shows that battery investment moves from a poor option to an attractive option by 2029.

Importantly, ROI varies between customers due to differences in load profiles, customer incentives vary by investment option and tariff.

Additional results can be found in Appendix F – Battery Purchasing Case Study.

Figure 7 – Customer First Year ROI by Tech Configuration



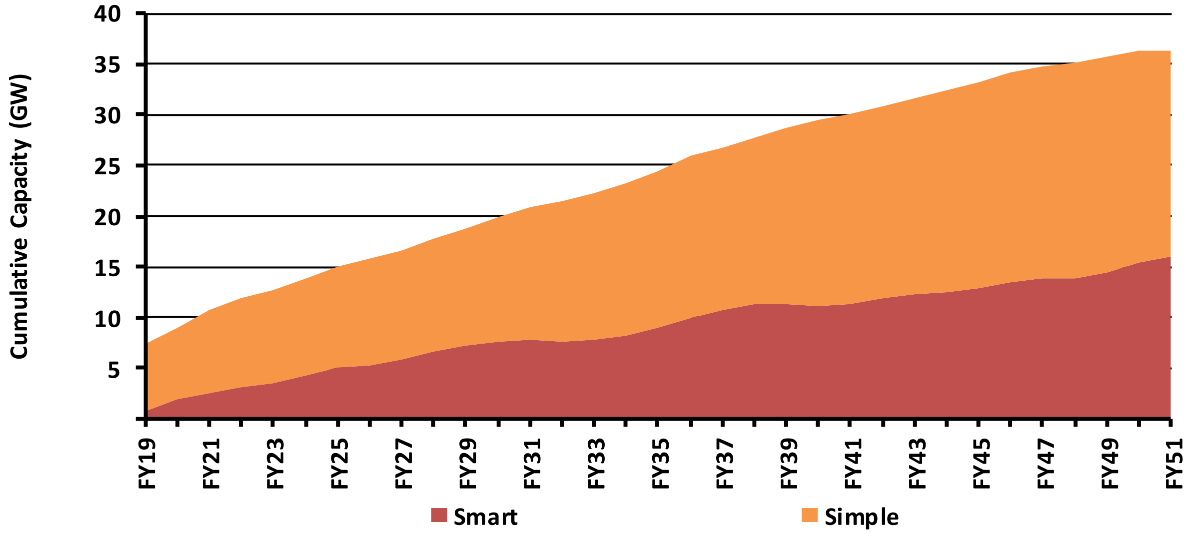
Source: Energeia Modelling

Rooftop Solar PV

The distribution of installed solar capacity by tariff type is shown in Figure 8, and largely reflects the corresponding install trend.

At the start of the forecast period, the majority of customers with solar PV systems have a simple tariff. As the forecasting period progresses, customers are assigned or take up a smart cost-reflective tariff with their solar PV system to minimise their retail bills. By the end of the forecast period, approximately 44% of all solar capacity are owned by customers on a smart tariff.

Figure 8 – Cumulative Installed Solar PV Capacity by Tariff (NEM; Neutral 26% Scenario)

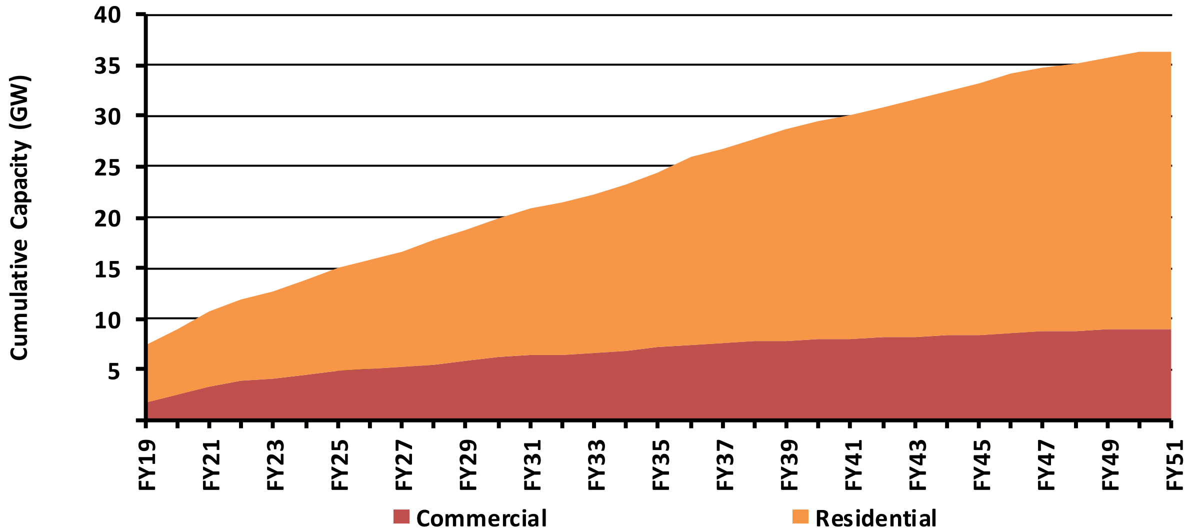


Source: Energeia Modelling

In the NEM, the majority of installed solar PV capacity is from the residential market as shown in Figure 9. Residential customers consistently account for 75-77% of the total installed solar PV capacity in the NEM, with a total installed capacity of 5.8 GW to 27.3 GW from FY19 to FY51 respectively.

Commercial customers have a larger market share of cumulative installed capacity relative to the number of installs in the total solar PV fleet. This is due to the installs of larger solar PV systems.

Figure 9 – Cumulative Installed Solar PV Capacity by Customer Type (NEM; Neutral 26% Scenario)



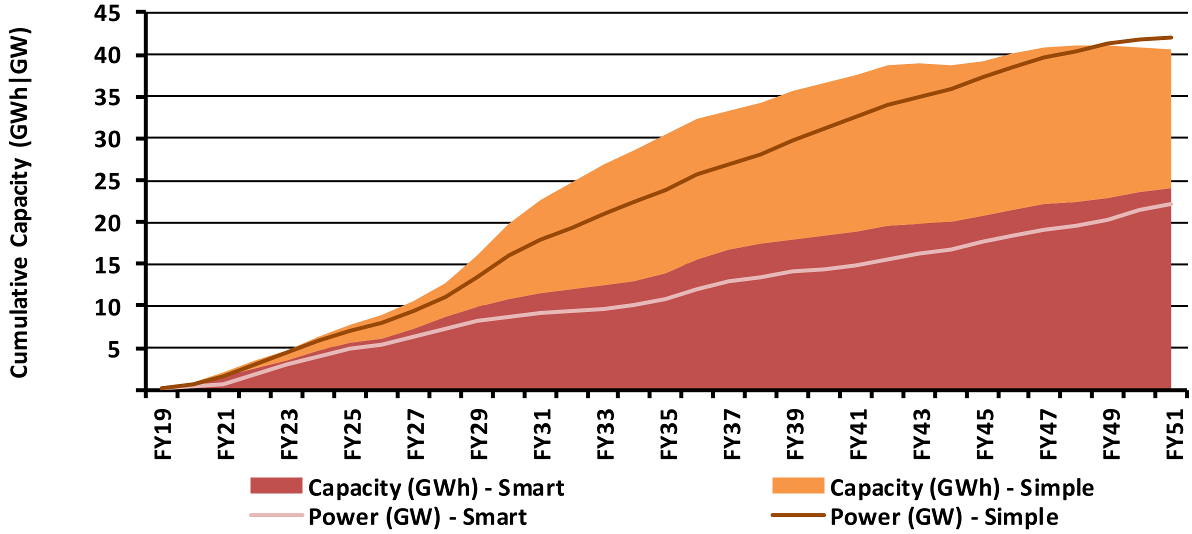
Source: Energeia Modelling

Battery Storage

Initial battery uptake in the period is comprised of customers on cost-reflective, or smart, tariffs who have more opportunity to arbitrage price differentials in their tariff structures. As the economics of batteries improve with continued price declines, customers on simple tariffs are also able to benefit from installing batteries. The plateauing and dipping of battery capacity post FY41 occurs due to reaching market saturation coupled with the ongoing degradation of the battery fleet as they operate[18].

Unlike the battery energy capacity, the battery power, or the inverter rating, for both customers on smart and simple tariffs continue to increase over time as inverters are not subject to degradation. However, inverter capacities do not completely increase at the same rate of battery capacities, particularly between FY29 and FY38 for customers on a simple tariff. This is mostly due to the sizing of the inverter, shared across both solar PV and battery, which would prioritise the solar PV system (if any) within a customer's configuration[19].

Figure 10 – Cumulative Installed Battery Energy Capacity and Power by Tariff (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

Driver of Battery Degradation:

Battery degradation is a key driver impacting the total effective capacity of batteries over time. The breakdown of battery degradation in the NEM in the Neutral 26% scenario is shown in Figure 11 consisting of the two degradation factors used in Energeia's uSim modelling:

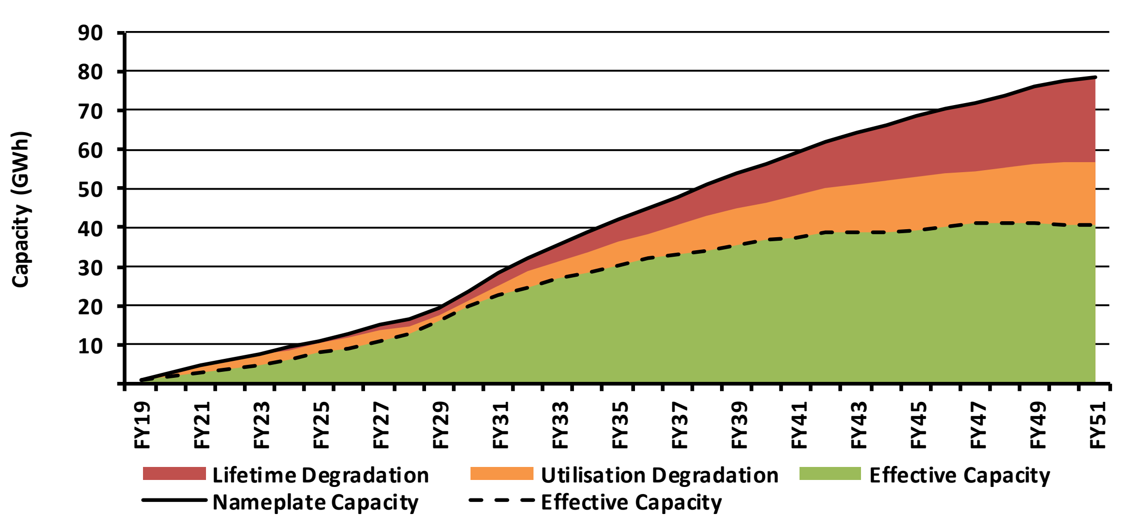
- **Lifetime Degradation –** degradation occurring due to the aging of the battery system.
- **Utilisation Degradation –** degradation occurring due to the usage of the battery system.

The nameplate capacity is shown to be degraded mainly by utilisation degradation in the initial modelling period as the batteries are used. However, lifetime degradation is the key driver for battery degradation in the later years as the battery fleet ages.

[18] Please refer to the Driver of Battery Degradation case study for additional details.

[19] Please refer to Section E.2.3. Technology Parameters for additional details.

Figure 11 – Battery Degradation by Driver (NEM; Neutral 26% Scenario)



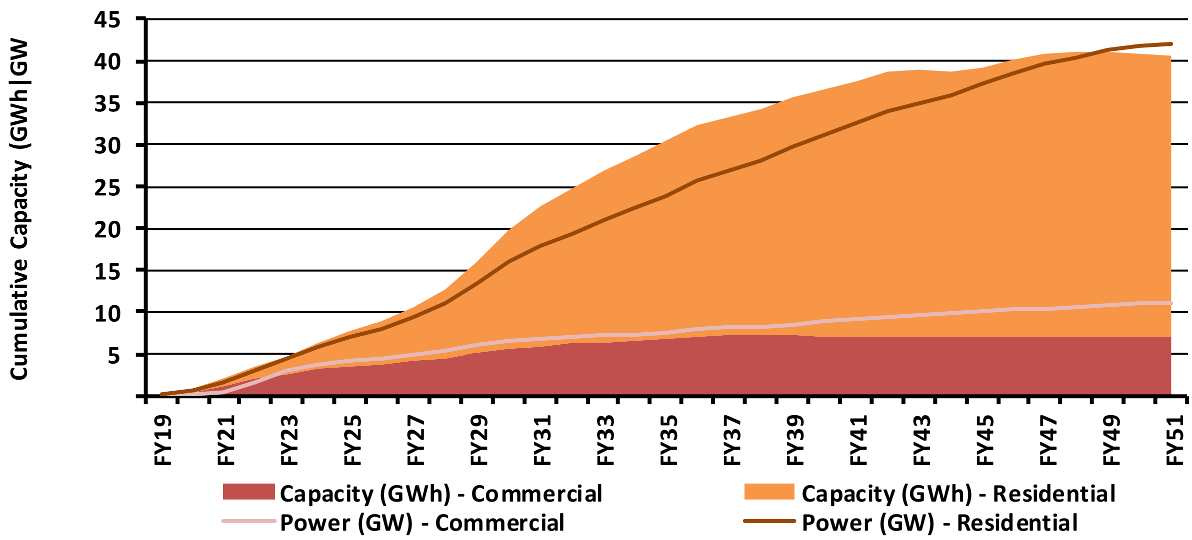
Source: Energeia Modelling

Additional information can be found in Appendix B – uSim Modelling and Assumptions.

Like solar PV, battery capacity is made up by majority residential installations across the NEM in the Neutral 26% scenario as shown in Figure 12. In FY51 residential customers make up 83% of the battery fleets capacity with 33.5 GWh, while commercial customers make up only 17% with 7.0 GWh of storage.

Similar to the inverter rating for customers split by tariff type, the battery power does not completely follow the capacity trajectory for each customer class due to the impact of battery degradation and the use of a shared inverter.

Figure 12 – Cumulative Installed Battery Energy Capacity and Power by Customer Type (NEM; Neutral 26% Scenario)



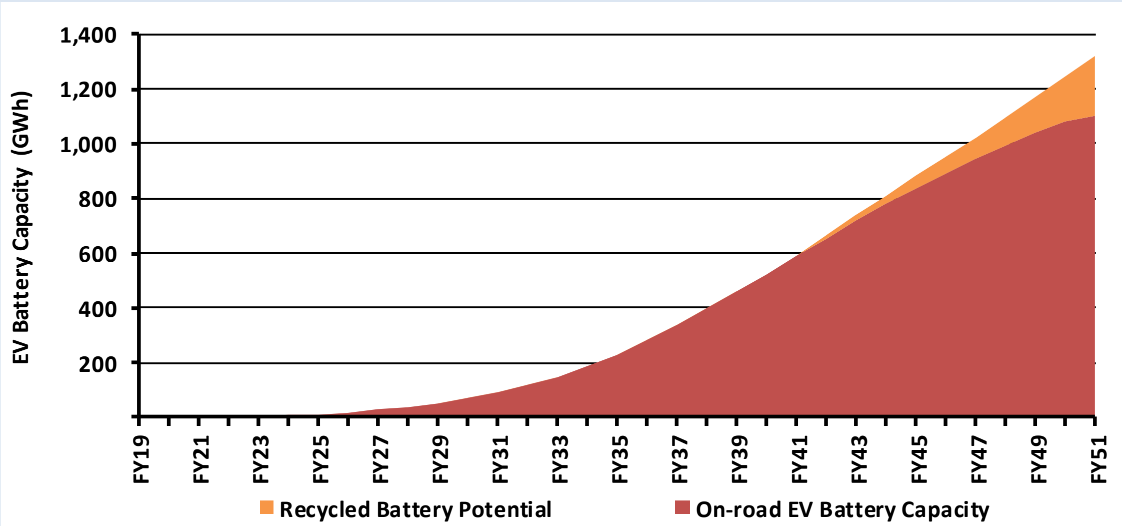
Source: Energeia Modelling

Electric Vehicle Battery Capacity and Recycling:

The transition to EVs will result in a large amount of latent battery potential in the NEM, reaching over 1 TWh by the end of the modelling period. This large volume of batteries opens the potential for a sizable recycling market for EV batteries as the EV reaches their lifetime of 18 years, even when accounting for the degradation of the batteries over this period.

The recycling of EV batteries was not incorporated as part of the forecast as it was out of scope, although Energeia acknowledges the potential reuse of EV batteries.

Figure 13 – Electric Vehicle Battery Capacity (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

Vehicle-to-Grid Potential

This large battery storage capacity has potential to be harnessed through emerging Vehicle to Grid (V2G) technology to provide customers with additional storage capabilities and assist the grid during peak demand events.

While there are OEMs currently pursuing this technology such as Nissan and Renault, there is evidence that discharging vehicle batteries can lead to accelerated degradation of the battery. Energeia has not modelled V2G capability in its forecasts, instead vehicles are modelled to have their charging behaviour managed to optimally charge at times of lower system demand and avoid contributing to peak demand. [1]

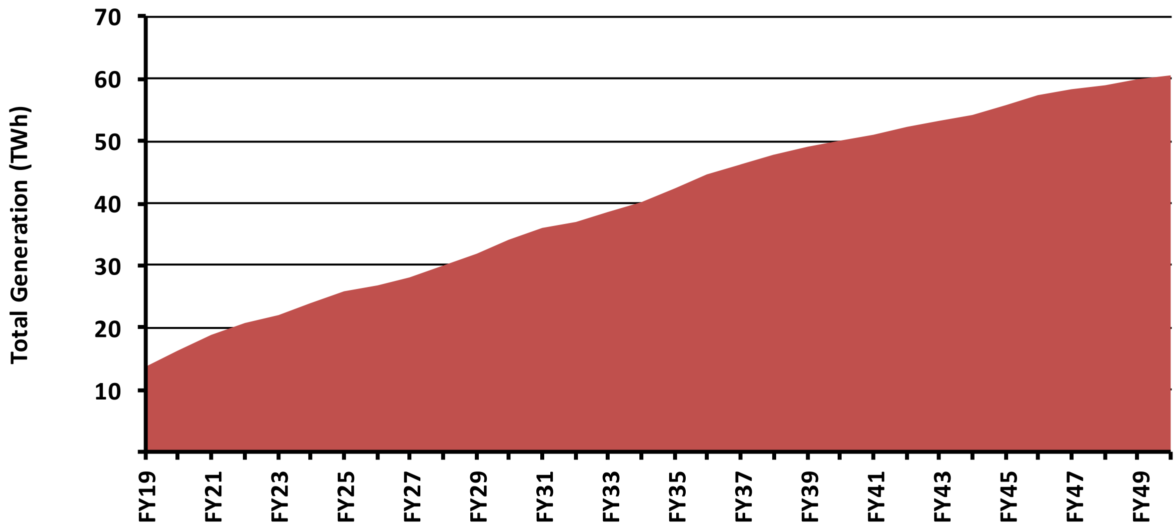
4.1.3. Generation and Consumption

Solar PV and battery impact network peak demand and consumption. The total annual solar generation from customers in the NEM is shown in Figure 14. Solar PV systems produce 13.7 TWh of energy in FY19 and steadily increases to 60.5 TWh of energy in FY51 as customers take up solar PV systems.

Rooftop Solar PV

The total annual solar generation reflects the solar PV installs numbers shown in Figure 1, with only slight differences due to the degradation of existing solar PV which reduce total generation.

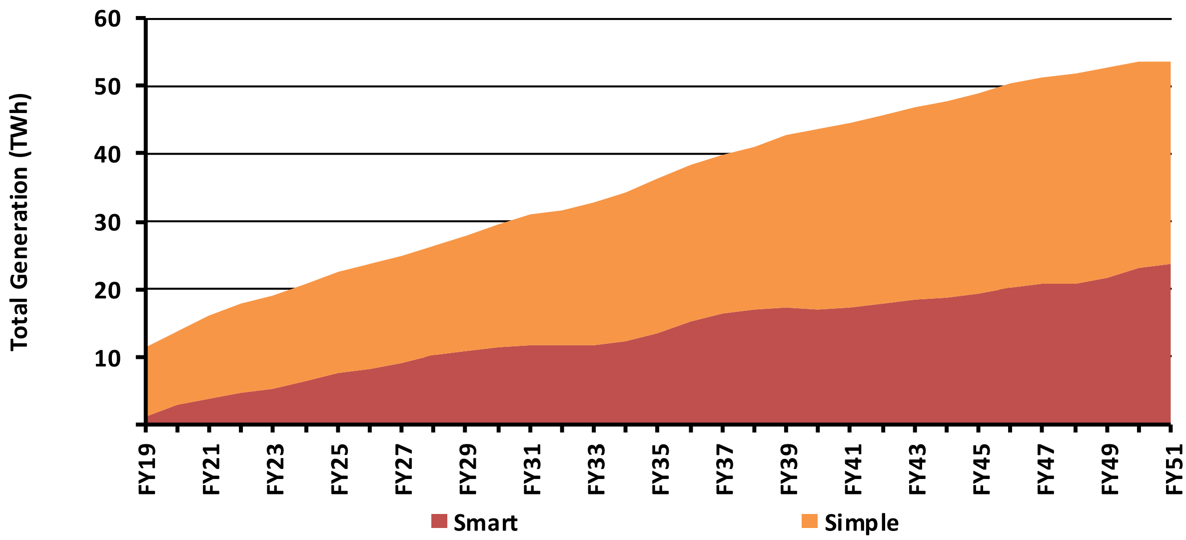
Figure 14 – Total Annual Solar Generation (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

Figure 15 shows the total annual solar generation by tariff type in the NEM. The overall generation split between tariff types largely mirrors the solar PV capacity. During the start of the forecast period, customers on a simple tariff with solar PV systems generate approximately 10.3 TWh of generation, or roughly 90% of the total annual solar generation. The proportion of solar generation from customers on simple tariffs decreases over time as customers shift onto a smart tariff. At the end of the forecast period in FY51, approximately 56% of total annual solar generation occurs from customers on a simple tariff, producing 29.8 TWh of generation.

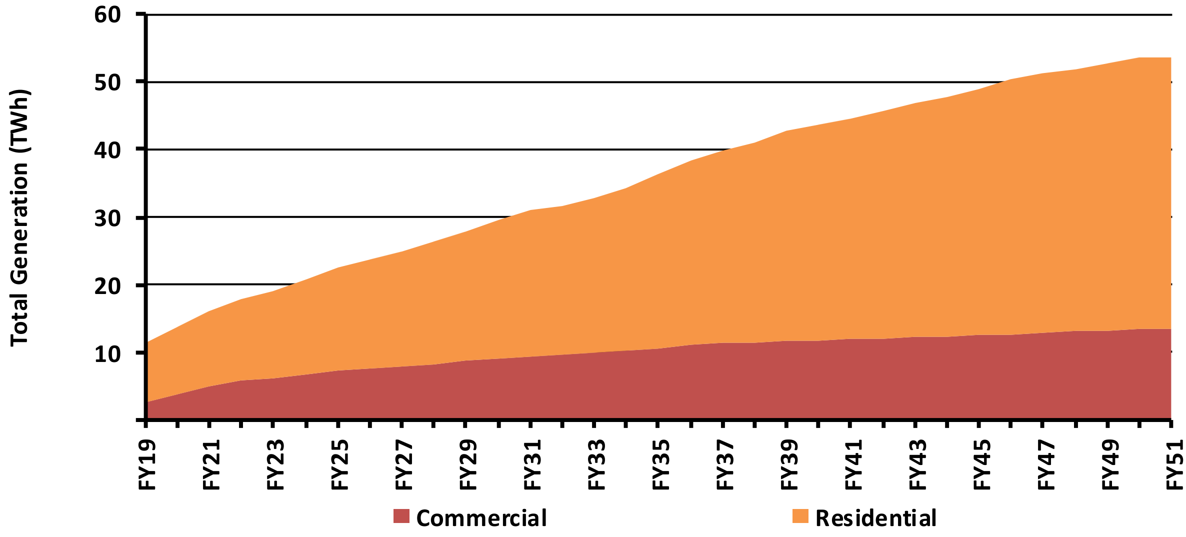
Figure 15 – Total Annual Solar Generation by Tariff Type (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

The total annual solar generation is segmented by residential and business customers in Figure 16. Over the forecast period, residential customers dominate the total annual solar generation. Residential customers consistently generate 75-77% of the total annual solar generation, with 8.9 TWh and 40.2 TWh of generation in FY19 and FY51 respectively.

Figure 16 – Total Annual Solar Generation by Customer Type (NEM; Neutral 26% Scenario)

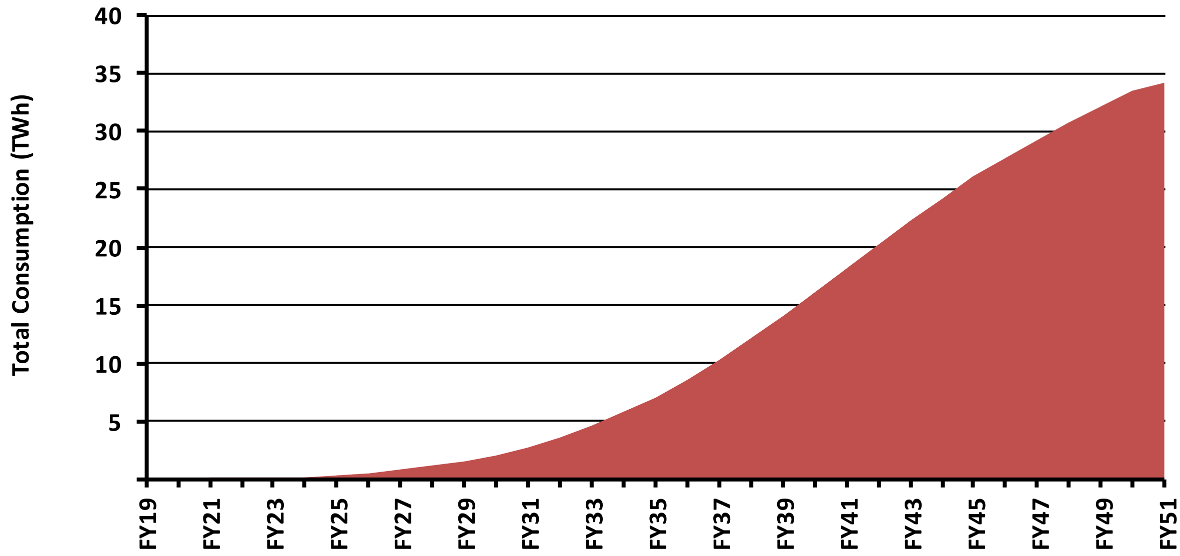


Source: Energeia Modelling

Electric Vehicles

The total consumption required to charge EVs is shown in Figure 17, which closely follows the trajectory of the number of EVs sold shown in Figure 1. Similar to the EV sales trajectory, EV consumption begins to rapidly increase from FY27. By the end of the forecast period in FY51, the total EVs in the NEM requires approximately 35 TWh of consumption.

Figure 17 – Total Annual EV Consumption (NEM; Neutral 26% Scenario)



Source: Energeia Modelling

4.1.4. Load Profile Impact

The adoption of solar PV and battery energy storage impacts customer load profiles. The extent of this impact will largely be determined by the customers initial load shape, which is a function of the class (residential and business), and their tariff assignment (simple vs smart). The tariff class of customers installing solar PV and batteries can be seen in the adoption of cost reflective tariffs, or smart tariffs, grows significantly over the period in this scenario. Initially, they make up a small proportion of customers purchasing solar PV and batteries with the majority of customers operating on a simple tariff.

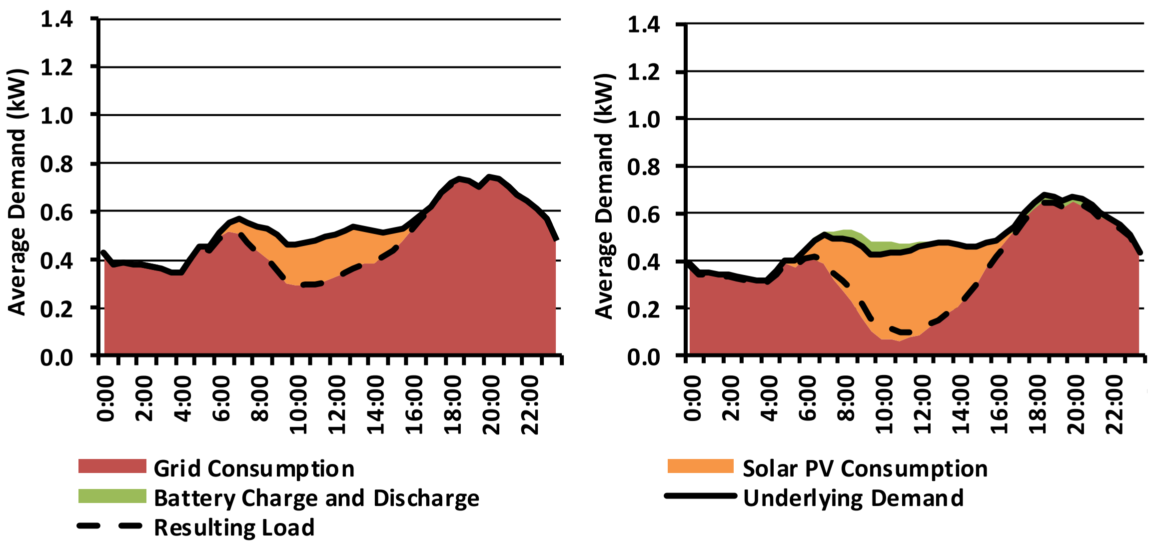
Over the forecast period, the cumulative installs of solar PV and batteries on a smart tariff increases at twice the rate of those on a simple tariff as customers seek to minimise their consumption bill by using solar PV and batteries to clip their consumption during peak demand periods. By FY45, smart tariffs are forecast to be the dominant tariff type for solar PV and battery technology owners.

. In FY19, only 7% of these customers are on smart tariffs increasing to 40% by FY30. This section reports on the forecast change in each customer segment's volume weighted average (VWA) daily profile in 2019 and 2030.

Residential Customer Segment

For the residential customer segment on simple tariffs, the VWA effect of solar and batteries on their energy use can be seen in Figure 18. The 2019 graphic reflects the current technology purchasing behaviour of customers in the NEM which is overwhelmingly solar PV. Solar PV is shown to reduce demand during the sunlight hours in the day. The 2030 profile shows the impact of continued uptake of solar PV and addition of battery storage. Simple tariff customers increasingly gain benefit from load shifting due to a declining FiT over the modelling period as it becomes cheaper to store excess solar and discharge when needed than it is to simply collect FiT revenue from excess solar generation.

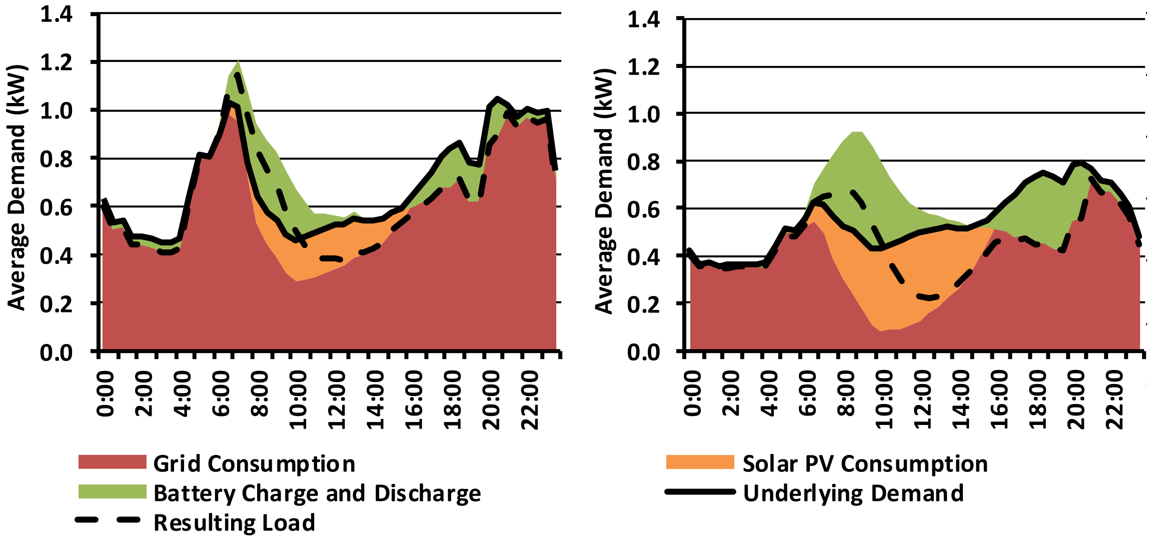
Figure 18 – VWA Residential Simple Tariff Average Day Load Profile Impacts 2019 (left) vs 2030 (right)



Source: Energeia Modelling

The load profile of residential customers on a smart tariff in 2019 and 2030 is shown in Figure 19. Similar to the VWA load profile of customers on a simple tariff, customers in 2019 are shown to have solar reducing demand during sunlight periods. However, unlike the simple tariff in 2019, there is an emerging presence of customers with batteries. Additionally, the utilisation of the battery is comparably different to that of simple customers. Customer segment's batteries are shown to reduce this customer segment's bill through charging with excess solar and shaving demand during the tariff's peak period later in the day. Smart tariffs structures allow batteries to be used to arbitrage price differentials between peak and off-peak periods.

Figure 19 – VWA Residential Smart Tariff Average Day Load Profile Impacts 2019 (left) vs 2030 (right)

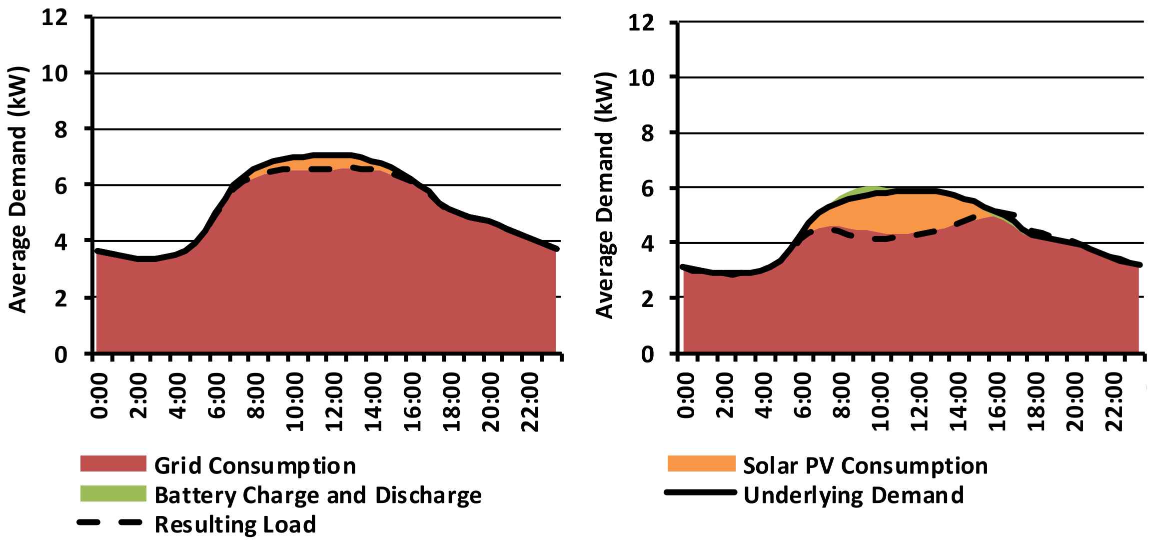


Source: Energeia Modelling

Commercial Customer Segment

The impacts to commercial customers on a simple tariff can be seen in Figure 20. This segment follows a similar trend to the equivalent residential segment. Similar to the residential segment in 2030, batteries are shown to be charging during solar periods and discharging when solar generation diminishes. Despite commercial customers consuming more solar PV generation, the impact of solar and storage is much less pronounced due to the volume of energy consumed by this customer segment.

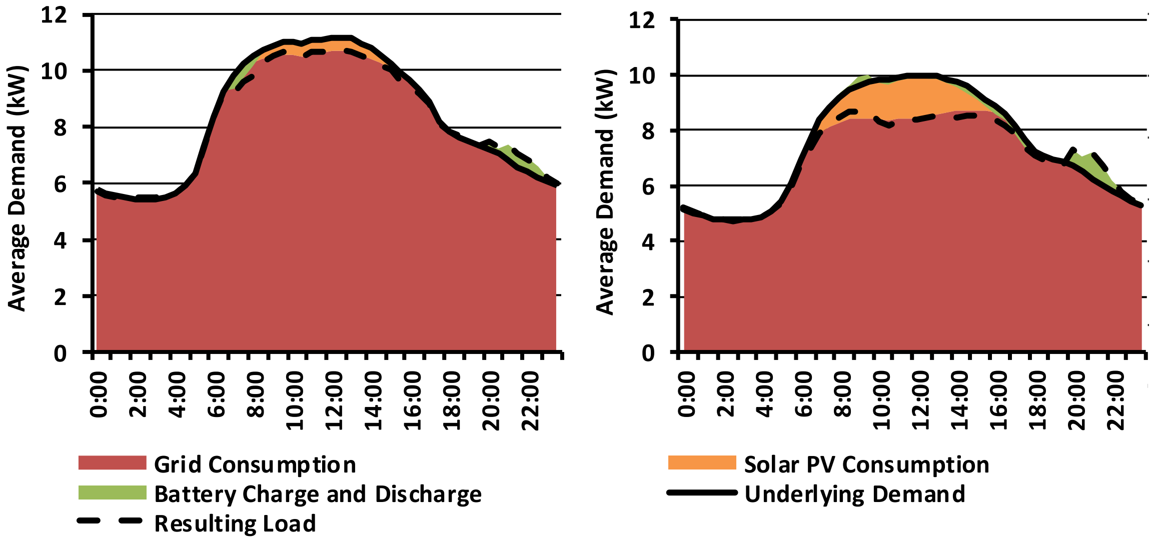
Figure 20 – VWA Commercial Simple Tariff Average Day Load Profile Impacts 2019 (left) vs 2030 (right)



Source: Energeia Modelling

Figure 21 shows the impact of technology on the smart tariff commercial customers. The major difference is the charging behaviour of batteries in both 2019 and 2030. Here, some batteries charge during the late-night period as commercial customers that are unable to install solar PV, such as those in suites, opt to charge during cheaper off-peak periods and arbitrage either peak periods or minimise the maximum demand charge within a MD tariff[20].

Figure 21 – VWA Commercial Smart Tariff Average Day Load Profile Impacts 2019 (left) vs 2030 (right)



Source: Energeia Modelling

4.2. Neutral 26% Scenario by State

The key modelling outcomes for the Neutral 26% scenario are further detailed by state, including the total solar PV, battery and EV installs, capacity and consumption impacts.

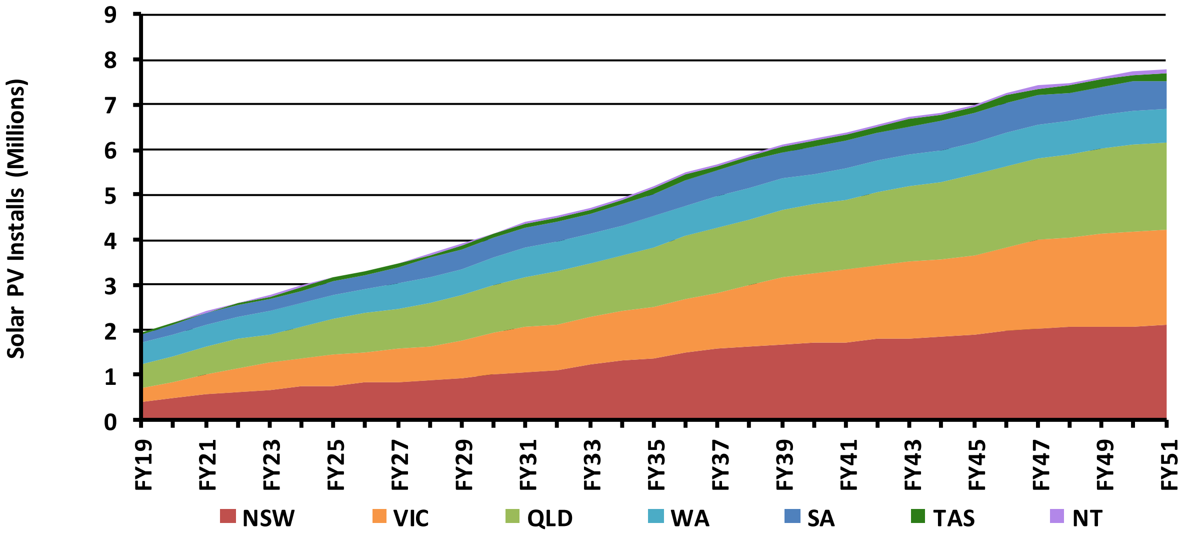
4.2.1. Installs

In the Neutral 26% Scenario, the DER and EV adoption market by FY51 are dominated by VIC, NSW, QLD and WA. TAS and NT state install the fewest number of solar PV, batteries and EVs in the forecast period.

Cumulative solar PV installs, as shown in Figure 22, are predominately in VIC, NSW and QLD due to their overwhelmingly dominating population in Australia. In FY51, these states make up 80% of the total Australian solar PV installs.

[20] The specific maximum demand tariff structures and 'peak' time calculations will vary by distribution network service provider. A breakdown of assumed tariff structures by DNSP is available in Section E.1.3. Retail Tariff Structures.

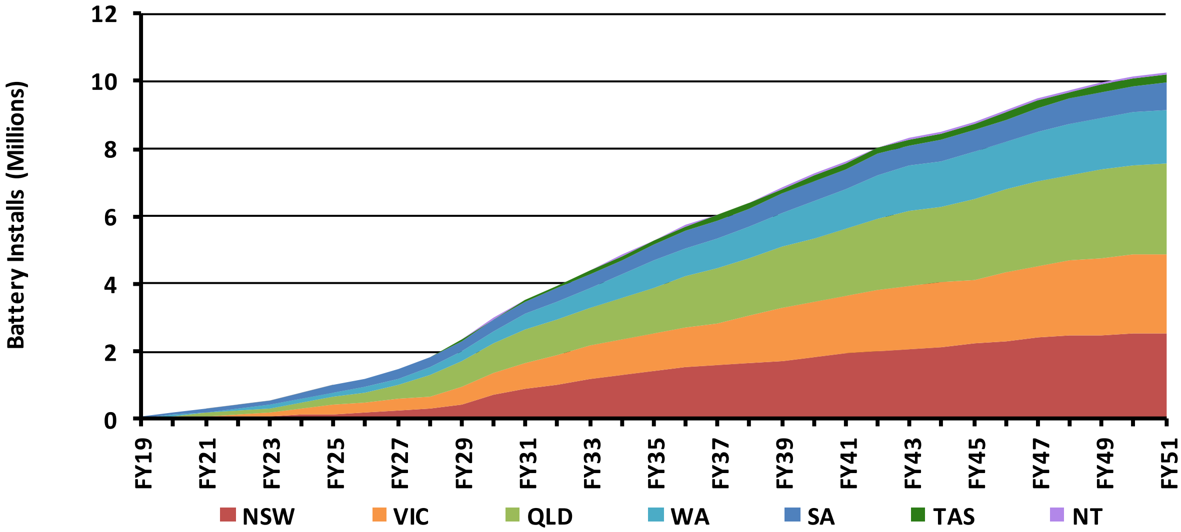
Figure 22 – Solar PV Installs by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

Similarly, the most populated states QLD, NSW and VIC show the most battery installs across Australia as seen in Figure 23. Together, these states represent 75% of Australia's total number of installed batteries in FY51.

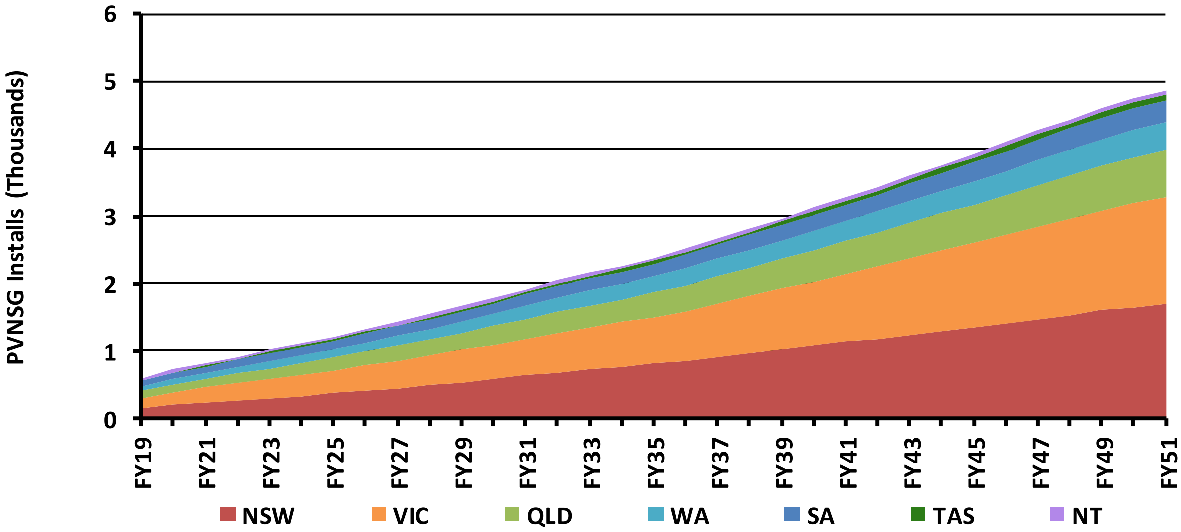
Figure 23 – Battery Installs by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

Energeia's forecast of PVNSG installs, shown in Figure 24, occur mostly in VIC and NSW with approximately 3,200 installs, or 70% of the total number of PVNSG installs in Australia in FY51 as these states historically had the most installs. QLD, WA and SA follow with around 700, 400 and 350 installs respectively.

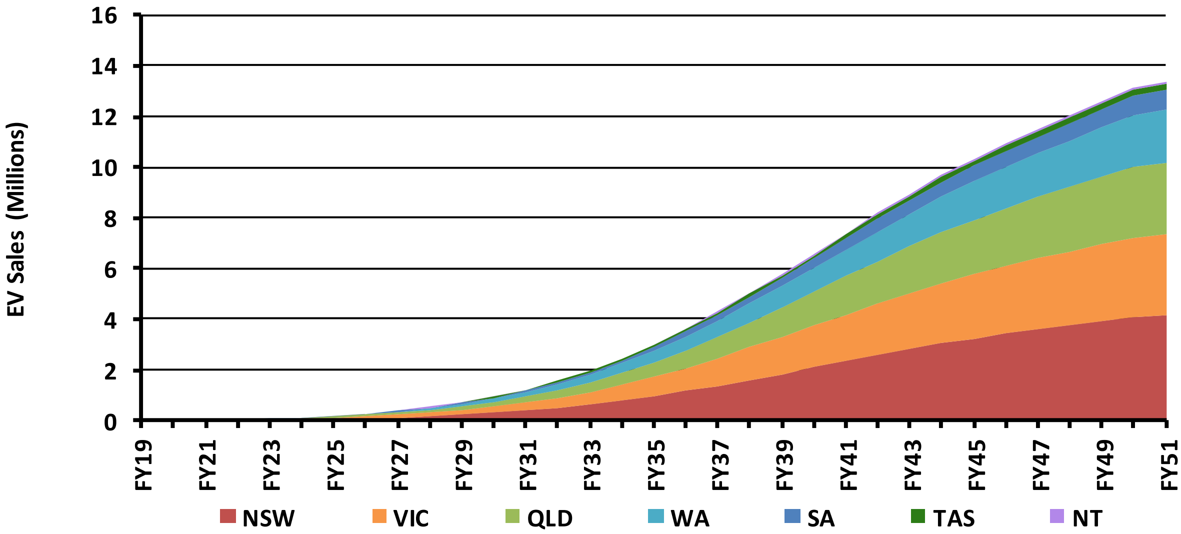
Figure 24 – PVNSG Installs by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

Figure 25 shows the cumulative sales of EVs by state. The most EV sales occur in NSW, with approximately 4.2 million EVs sold by FY51. This is closely followed by VIC and QLD with approximately 3.2 and 2.8 million EVs sold. There are significantly less EV sales in SA, TAS and NT with less than 1 million EVs sold cumulative in the forecast period.

Figure 25 – EV Sales by State (National; Neutral 26% Scenario)



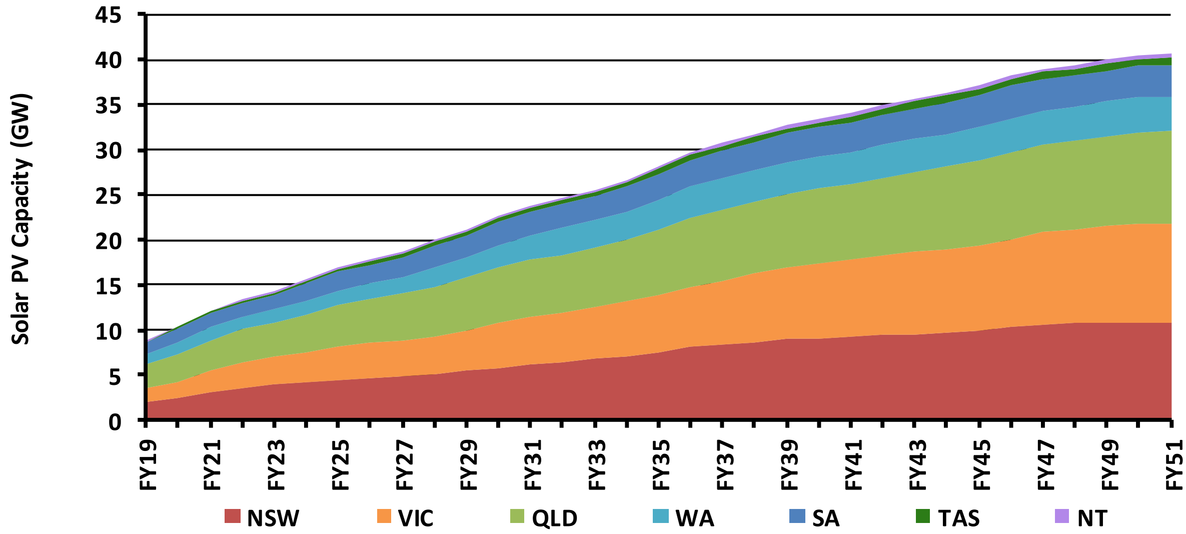
Source: Energeia Modelling

4.2.2. Capacity

Capacity trends largely follow installation patterns. The total solar PV, battery and PVNSG capacities are dominated by NSW, VIC and QLD with TAS and NT showing the smallest cumulative DER capacities in Australia in the forecast period.

Figure 26 shows the cumulative solar PV capacity by state which follow the installation ratios. VIC, NSW and QLD make up the majority of the total capacity in FY51 with close to 11 GW of solar PV installed in VIC and NSW, and more than 10 GW in QLD.

Figure 26 – Solar PV Capacity by State (National; Neutral 26% Scenario)

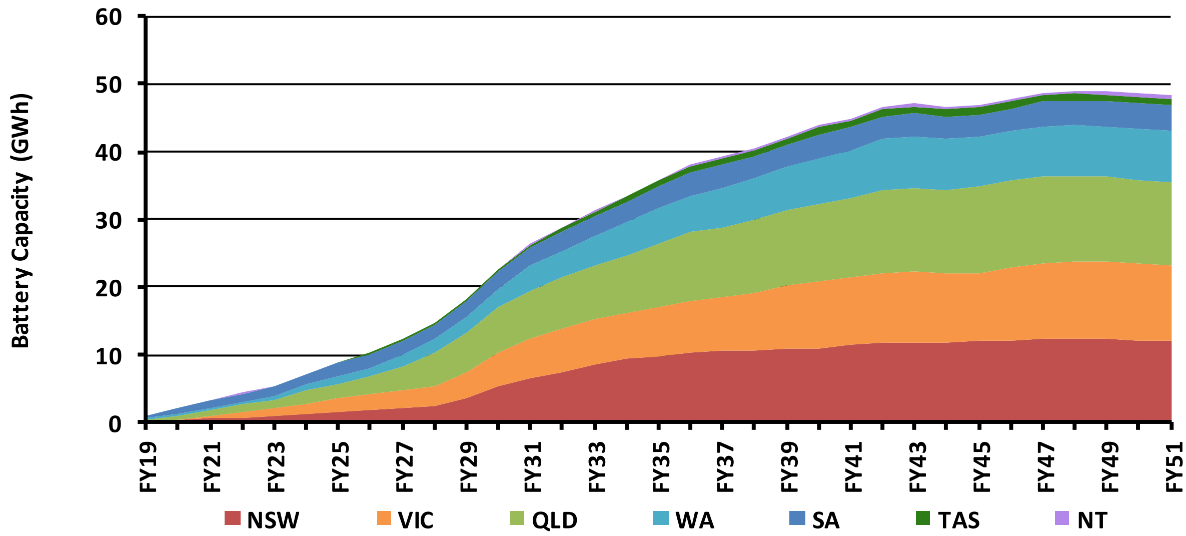


Source: Energeia Modelling

Additionally, VIC, NSW and QLD also show the most effective battery capacity in the forecast period with 11.2 GWh, 12 GWh and 12.4 GWh respectively as shown in Figure 27. These states account for 75% of the total effective capacity in FY51. WA and SA are closely behind the dominant states and together make up for 23% of the total effective capacity, with 7.5 GWh and 3.7 GWh respectively.

Overall, the state ratios of battery energy capacity shown in Figure 27 largely follow the corresponding installation patterns as shown in Figure 23. However, the battery energy capacity forecasts increases and decreases are more pronounced than in the installations trend. There is a larger uptick in battery energy capacity occurring in FY28 due to retrofitting of batteries to existing solar PV systems[21] and a decrease in FY44 due to the rate of battery degradation exceeding the adoption of batteries due to market saturation.

Figure 27 – Battery Energy Capacity by State (National; Neutral 26% Scenario)

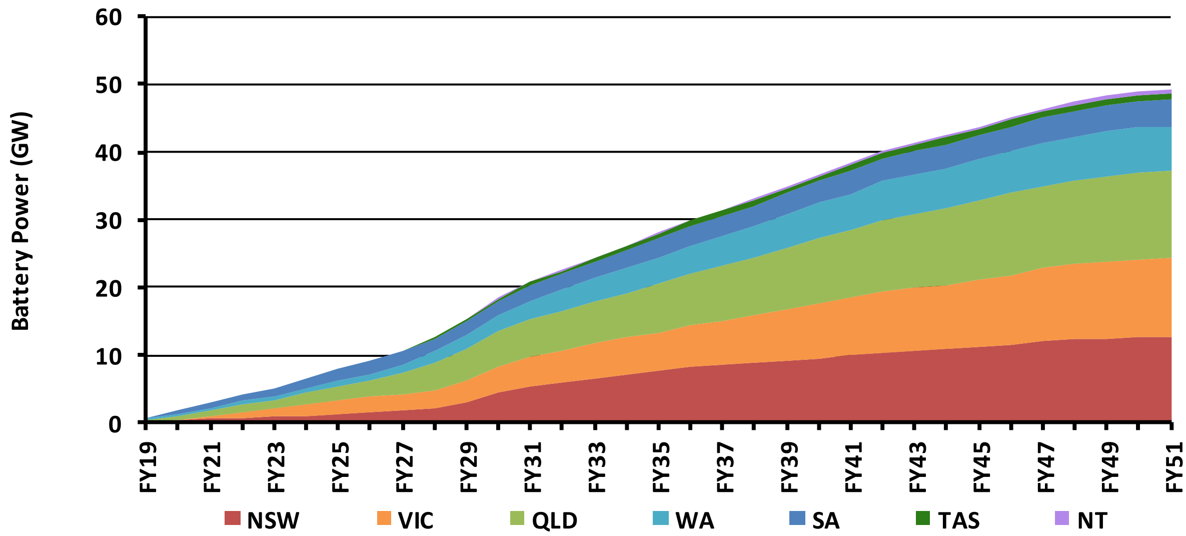


Source: Energeia Modelling

[21] Please refer to Battery Purchasing Case Study in Section 4.1.2 for further information.

The inverter rating of these battery systems follows the same relationship as the battery capacity and battery installs itself. QLD, NSW and VIC hold the most battery power by FY51 with a combined total of 37 GW, as shown in Figure 28. Similar to the battery capacity, there is a distinct uptick occurring in FY28. However, the inverter ratings do not degrade over time resulting in a consistent increase over time, closely mirroring the battery installations shown in Figure 23.

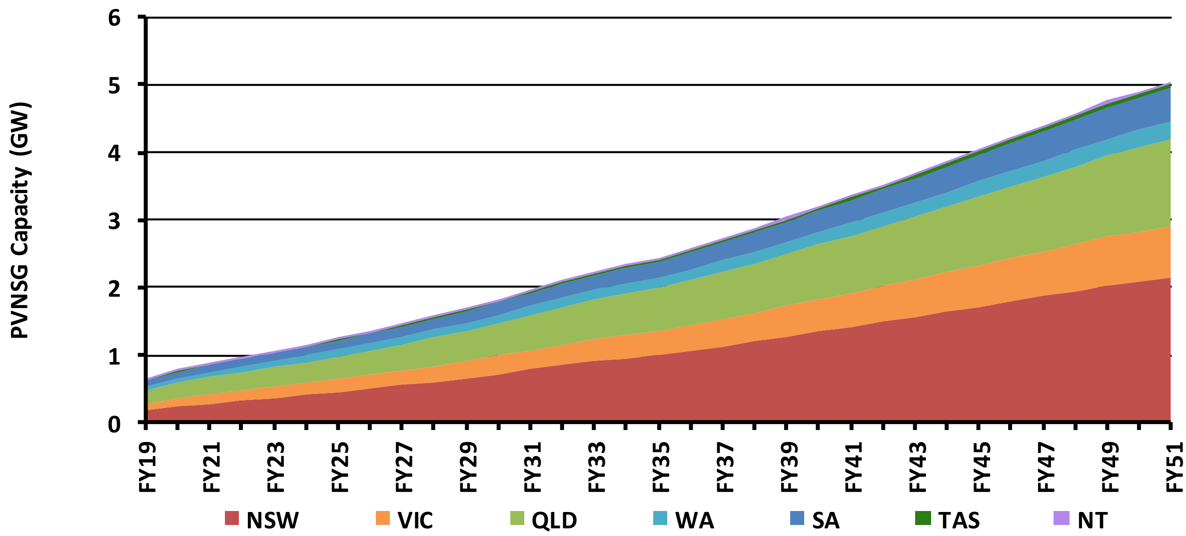
Figure 28 – Battery Power by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

Figure 29 shows the cumulative PVNSG capacity by state over the forecast period. Despite the most PVNSG installs occurring in VIC, NSW has the highest cumulative capacity by FY51 with 2.1 GW due to the install of larger systems. QLD and VIC follow with 1.3 GW and 0.75 GW of installed capacity respectively.

Figure 29 – PVNSG Capacity by State (National; Neutral 26% Scenario)

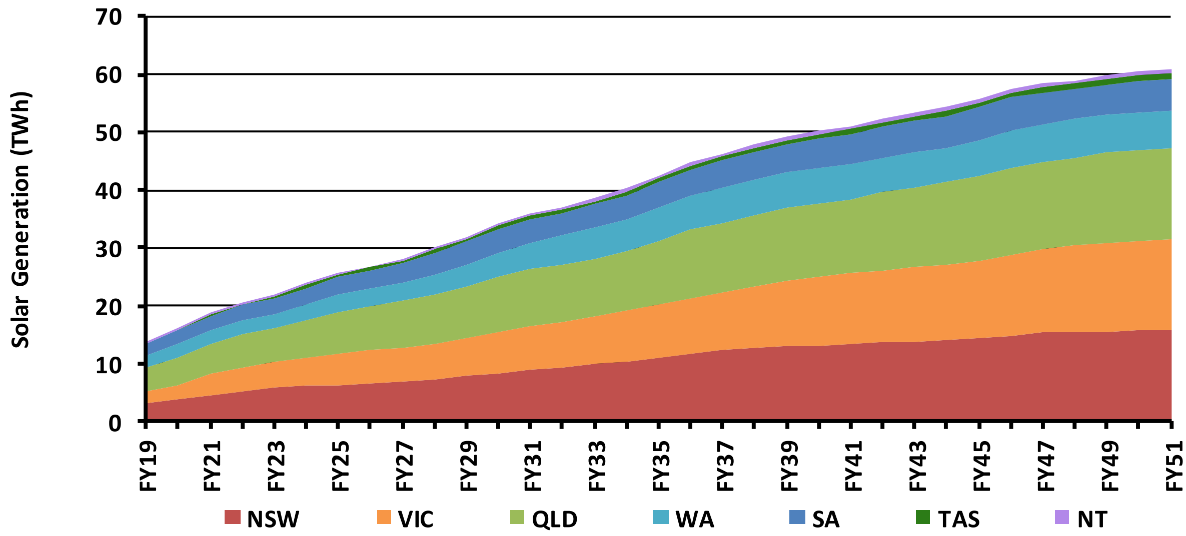


Source: Energeia Modelling

4.2.3. Consumption Impacts by State

Figure 30 shows the total solar generation by state, where QLD, NSW and VIC each generate approximately 15.7 TWh in FY51. The ratios of solar generation by state closely mirrors the total split of solar capacity as shown in Figure 26. Slight differences between the total solar generation and total solar capacities are due to solar PV degradation limiting the total generation produced each year.

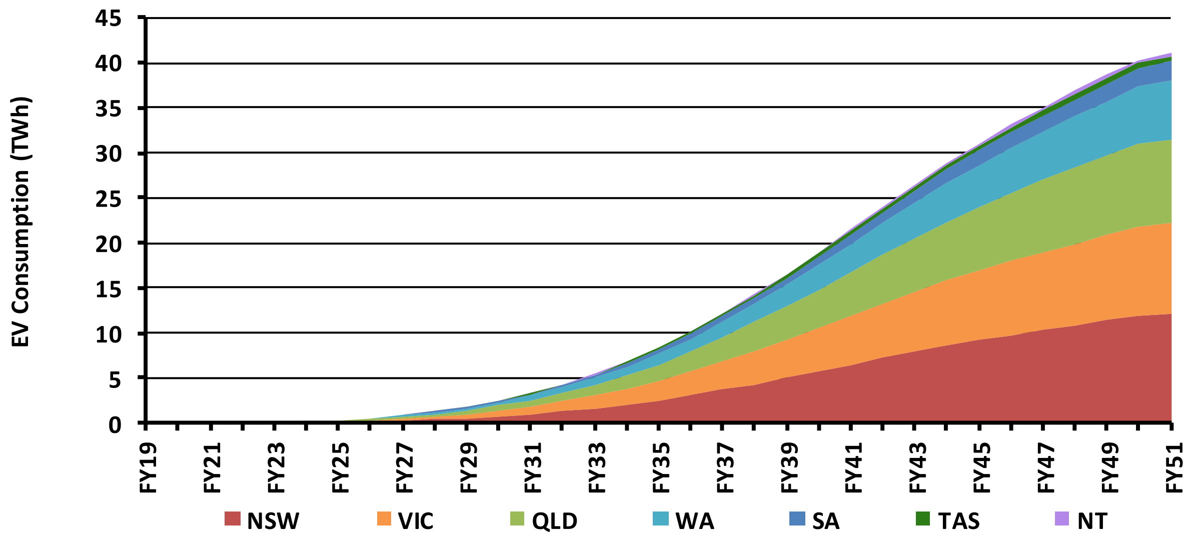
Figure 30 – Solar Generation by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

The state segmentation of EV consumption shown in Figure 31 follows a similar trajectory as the EV sales. NSW, VIC and QLD again dominate the with highest net consumption impact to the network. These states, with a respective total consumption of 12.1 TWh, 10.0 TWh and 9.4 TWh, account for approximately 80% of the total net consumption in FY51.

Figure 31 – EV Consumption by State (National; Neutral 26% Scenario)



Source: Energeia Modelling

4.3. Scenario Outlook – NEM

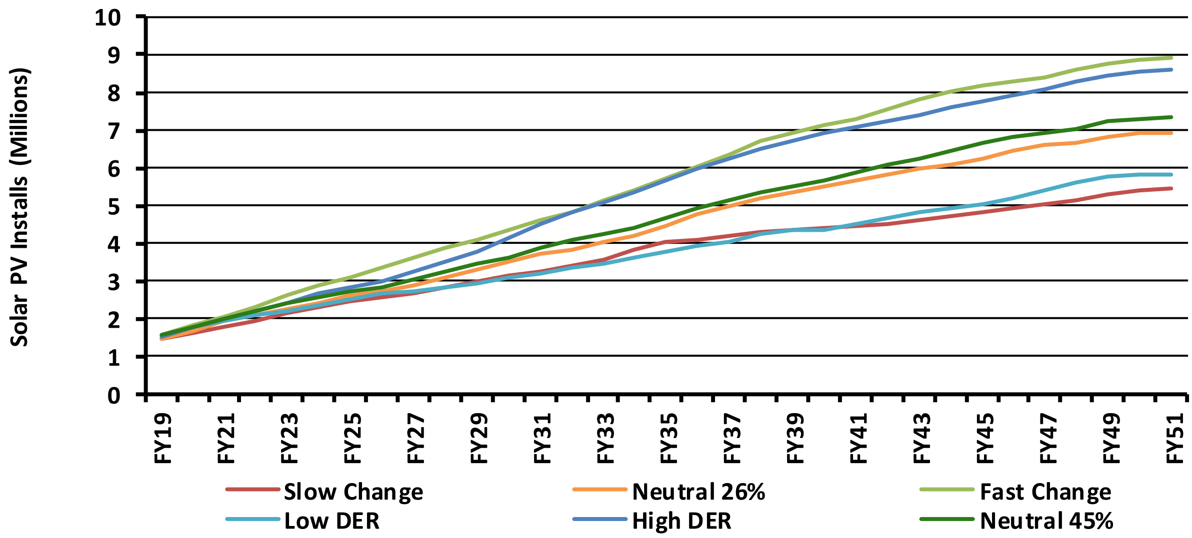
The following sections report on key results in the NEM by scenario. The scenario development process and outcomes are detailed in Section 3.

4.3.1. Installs

Figure 32 shows the total uptake of behind-the-meter solar PV in the NEM which shows the Slow Change and Low DER scenarios with the lowest solar PV uptake levels, with 5.4 and 5.8 million installs in FY51 respectively. The Fast Change and the High DER scenarios show the highest number of solar PV installs in the forecast period. The differences in solar PV cost trajectories are a key driver impacting the uptake rate, where the Slow Change and Low DER scenarios have the weakest cost decline and thus show the fewest number of installs.

Between the two sets of scenarios are the Neutral scenarios with approximately 7 million installs by FY51. The Neutral 45% is shown to have slightly more solar PV installs than the Neutral 26% scenario by the end of the forecast period, with an additional 400,000 systems installed. This is despite having the same rate of solar PV cost declines, which shows the impact of rebates on solar PV uptake. The current STC rebate scheme is assumed to continue in the Neutral 45% scenario, while in the Neutral 26% period, the program ends in 2031 as is currently scheduled.

Figure 32 – Solar PV Installs by Scenario (NEM)



Source: Energeia Modelling

Figure 33 presents a similar story for battery storage installs in the NEM as for solar PV installs. Similarly, the Slow Change and the Low DER scenarios have the lowest uptake of batteries in the forecast period with approximately 7 million installs, followed by the Neutral 26% and Neutral 45% scenarios with 8.5 million installs, and the Fast Change and the High DER scenarios with more than 10 million batteries.

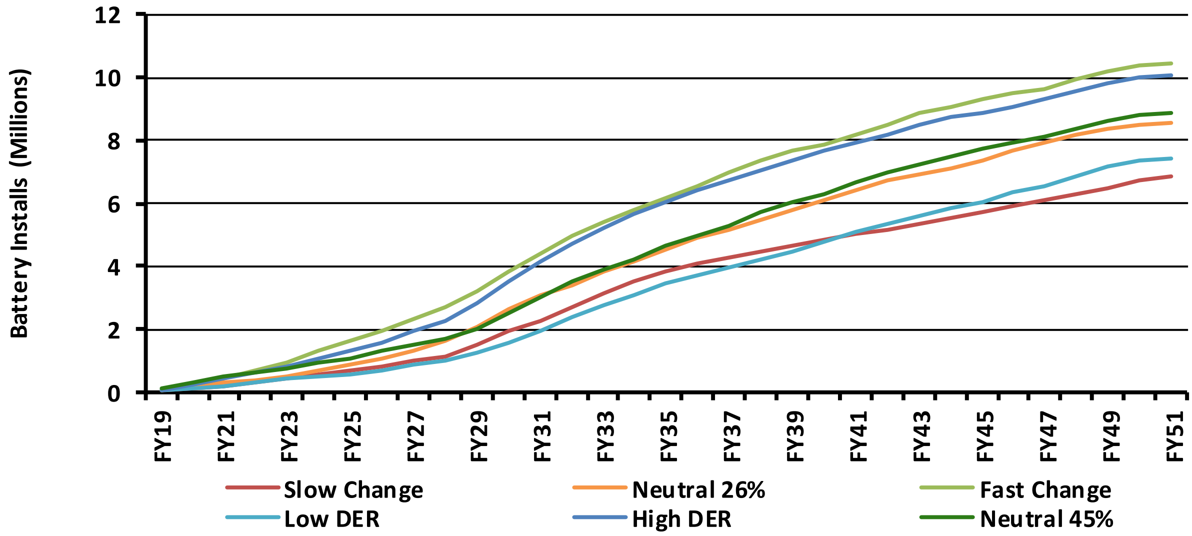
The difference in the cost of the system is the largest factor in determining the level of uptake, with the lowest cost in the Fast Change and High DER scenarios each returning the highest uptake of batteries. However, in all scenarios, battery installations ramp up between FY26 and FY29. This is driven by the viability of retrofitting a battery onto an existing solar PV system discussed earlier in Section 4.1.2.

It is worth noting that battery installs are predicted to be higher than solar PV installs across all scenarios by the end of the period. This is predominantly due to the assumption that all premises[22] can install a battery, but only premises with an accessible roof can install solar PV (i.e. detached dwellings like houses and warehouses, but not attached dwellings like units and suites). Therefore, batteries can service a larger market than solar PV.

For both solar PV and battery storage installs, minor differences between scenarios with the same DER price settings can be explained through the economic growth and population outlook scenario drivers.

[22] This includes renters, see Section E.2.2. Home Ownership for additional information.

Figure 33 – Battery Installs by Scenario (NEM)



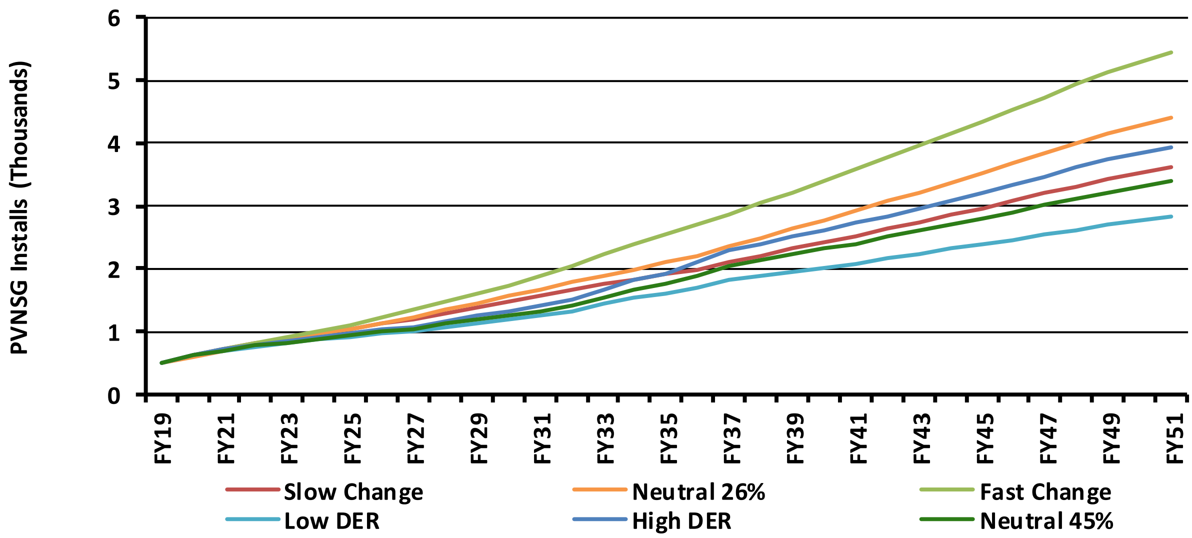
Source: Energeia Modelling

Figure 34 shows the uptake of PVNSG in each scenario. All scenarios initially have approximately 500 PVNSG installs before diverging in installs from FY23. By the end of the forecast period, the Fast Change scenario shows the highest number of installs with approximately 5,500 installs. However, unlike the solar PV installs trajectory shown in Figure 32, the Neutral 26% scenario follows with 4,400 PVNSG installs. This is followed by the High DER, the Slow Change, the Neutral 45% and the Low DER scenario.

Unlike rooftop solar PV, the assumed VWA RRP forecast plays a vital role in determining the uptake of PVNSG. The DER Sensitivity scenarios (Low DER, Neutral 45% and High DER) uses Energeia's forecast of a 45% emission reduction target which predicts lower wholesale prices due to the build out of large-scale renewables. Lower wholesale costs reduce the uptake trajectory relative to the Slow Change and Neutral 26% scenarios which uses AEMO's 26% emission target wholesale price forecasts resulting in relatively higher electricity prices.

Additionally, the cost of the system is important factor in the uptake of PVNSG in the NEM. A lower cost of system results in greater uptake levels, which is observable when comparing total installs in the Neutral 26% scenario to the Slow Change scenario. The Neutral 26% scenario has a lower technology cost curve than the Slow Change scenario, hence there are 22% more installations in the Neutral 26% scenario by FY51.

Figure 34 – PVNSG Installs by Scenario (NEM)



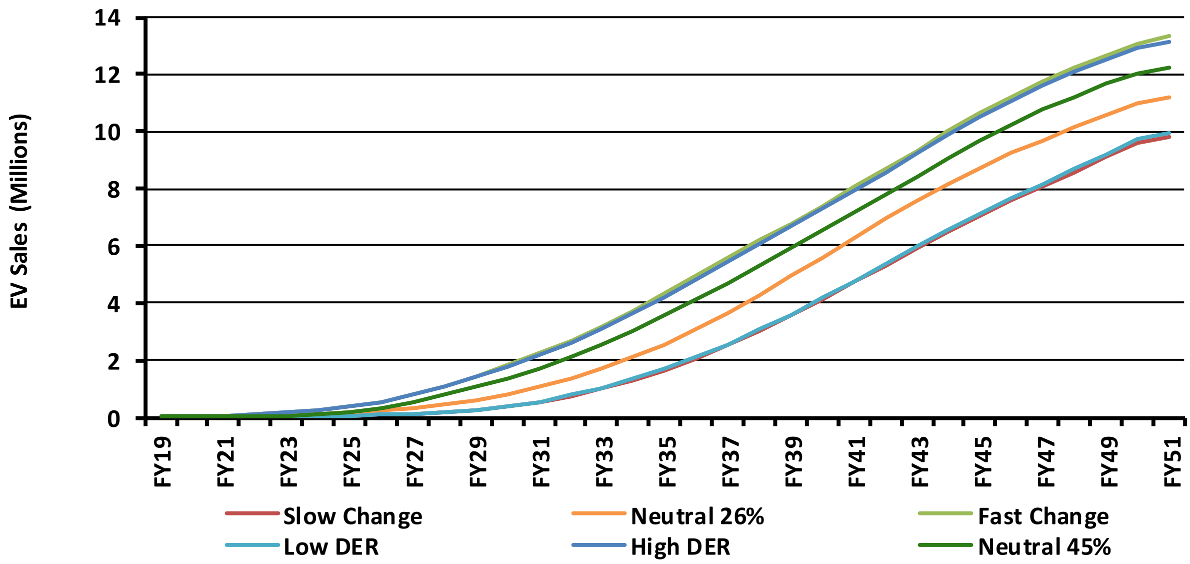
Source: Energeia Modelling

Figure 35 shows the sales of EVs in the NEM for each scenario. All scenarios show a slow rate of EV uptake prior to FY25 to FY29 where EV uptake increases significantly over the period.

The Fast Change and the High DER once again shows the largest EV adoption in the forecast period, with approximately 13 million EVs sold. The Low DER and the Slow Change scenarios also once again shows the smallest EV adoption with a little under 10 million EVs sold. This displays the impact of changing EV cost premiums relative to ICEs which determines the timeframe in which EVs hit mass-market and drives EV uptake. The scenarios where price parity occurs sooner in the forecast period, and thus model availability is increased, results in higher levels of total sales.

The Neutral 45%, Fast Change and High DER scenarios shows the significance of rebates on EV uptake where a $3,000 rebate is available. The Neutral 45% scenario, Fast Change and High DER scenarios result in a significantly higher uptake than in the Neutral 26%, where there is no rebate offered[23].

Figure 35 – EV Sales by Scenario (NEM)



Source: Energeia Modelling

Hydrogen Fuel Cell Electric Vehicles:

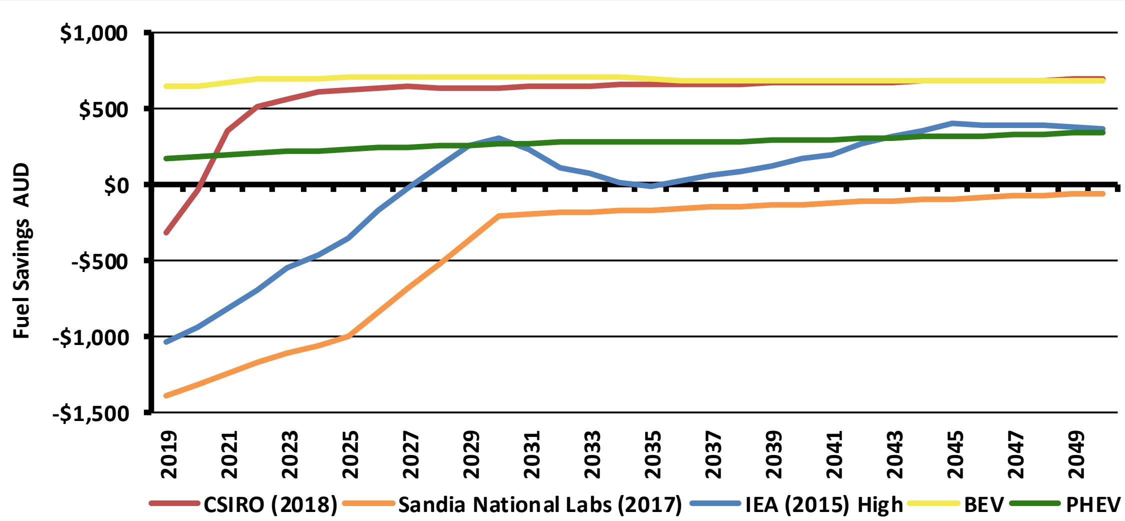
Energeia does not explicitly model Hydrogen Fuel Cell Vehicles (FCEV) when considering vehicle adoption from 2019 to 2050 in our evSim platform. Presently FCEV vehicles remain an expensive alternative to electric and internal combustion engine driven vehicles in terms of both capital and fuel costs.

Currently there is limited availability of vehicles in Australia, with the Hyundai NEXOS being the main production vehicle expected sold in 2019 at an estimated price of $80,000. In comparison a 2019 Hyundai Kona Electric (EV) carries a retail price of $60,000 and a 2019 Mitsubishi Outlander (ICE) carries a retail price of $33,800.

[23] Rebates are applied until the total capital cost (including a battery) of an electric vehicle reaches parity with the equivalent ICE for that class

Figure 36 shows the fuel savings for a SUV-M with different drive trains and hydrogen price trajectories. When considering future fuel costs with multiple cost projections of hydrogen there is a wide range of views, and even in the best case the technology will only reach fuel savings equivalent to a BEV in 2035.

Figure 36 – Fuel Savings by Technology Type and Hydrogen Price Sensitivity



Source: Energeia Analysis, CSIRO (2018) Hydrogen Roadmap, Sandia National Labs (2017) Hydrogen Analysis International Energy Agency (2015) Hydrogen Technologies and Fuel Cells

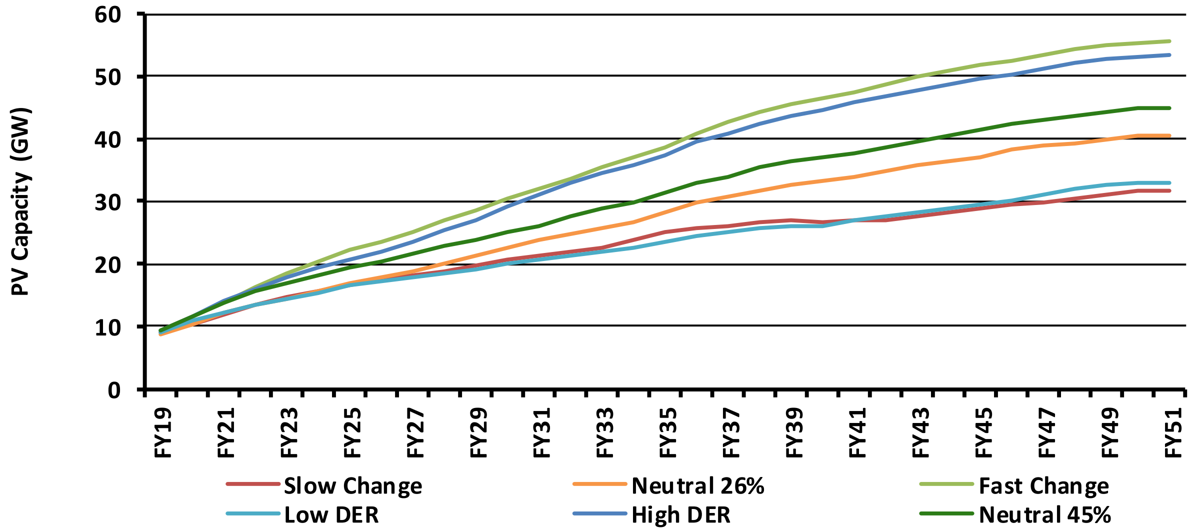
The restricted number of hydrogen cars presently available and uncertainty surrounding the solution to the large-scale storage and transportation of hydrogen fuel combined with lack of infrastructure and uncertainty about achieving model availability across all vehicle categories make the case of mass adoption of FCEVs over the modelling period weak.

1

4.3.2. Capacity

Figure 37 shows the predicted capacity of small-scale solar PV in the NEM for each scenario. Forecast solar PV capacity follows a similar path to installs and shares the same driving forces, with the Fast Change scenario having the largest small-scale solar PV capacity in the NEM by FY51, at 55 GW, and the Slow Change scenario having the smallest small-scale solar PV capacity in the NEM by FY51, at 31 GW. Between the scenarios there is a range of 24 GW in the of small-scale solar PV capacity in the NEM at the end of the modelling period. The spread between scenarios increases post FY30 as solar PV prices continue to decline together with the changing macro-economic drivers over the period.

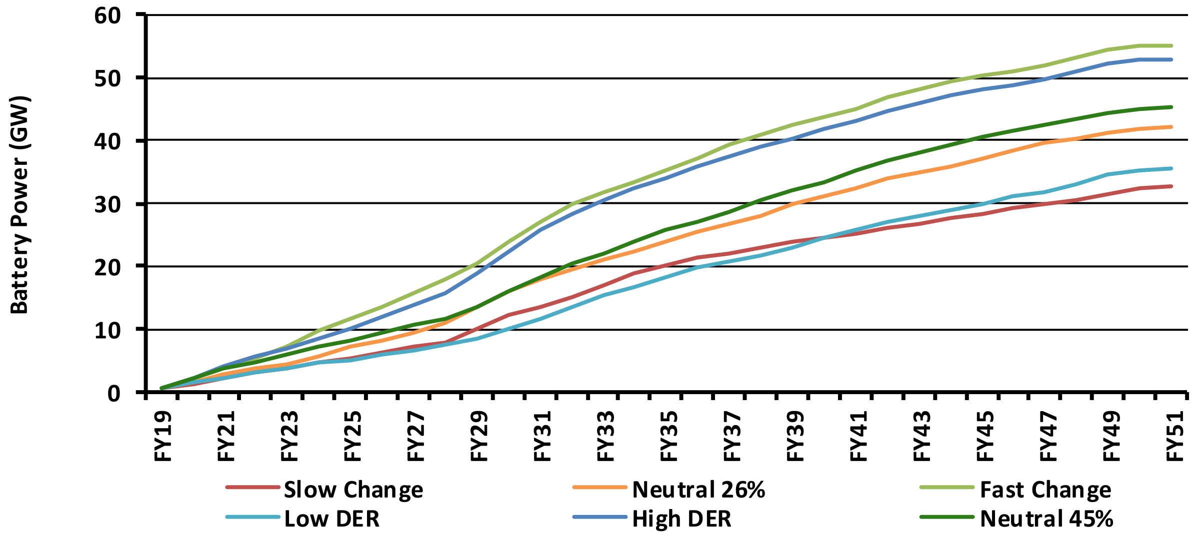
Figure 37 – Solar PV Capacity by Scenario (NEM)



Source: Energeia Modelling

Figure 38 and Figure 39 report on Energeia's forecast of battery power and capacity over the period in the NEM. While battery power follows a similar trajectory to cumulative installs, battery capacity begins to flatten post FY40, particularly in the Fast Change and High DER scenarios, which have the fastest DER uptake in the earlier years. This is the result of the high market penetration of storage earlier in the forecast period which results in a smaller available market to uptake later in the period and the ongoing degradation of the battery fleet through the system lifetime.

Figure 38 – Battery Power by Scenario (NEM)



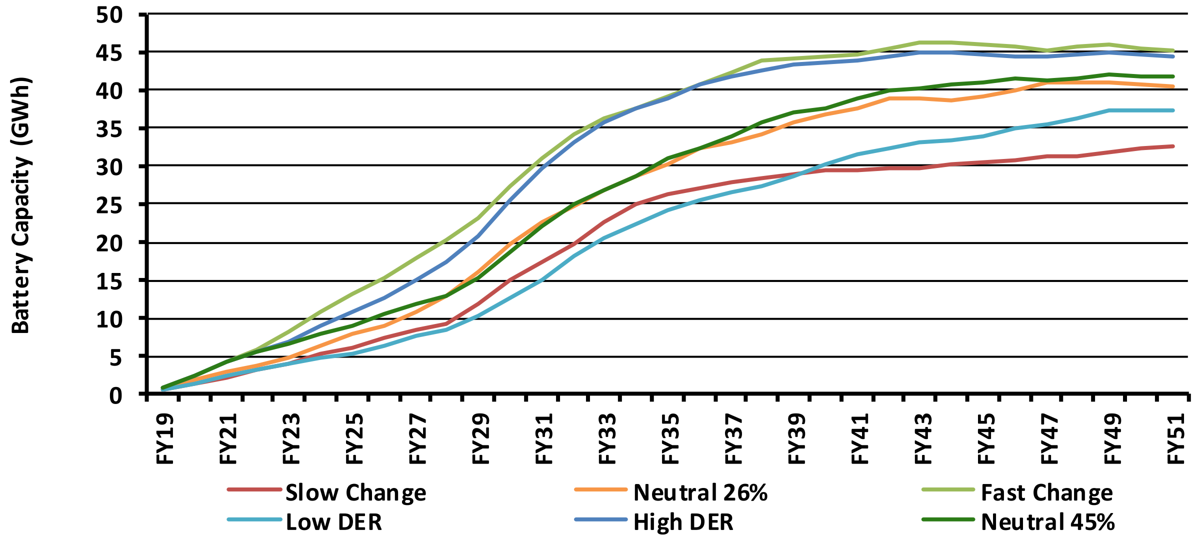
Source: Energeia Modelling

Energeia's modelling shows a variance of battery power in the NEM by FY51 of 22 GW between scenarios, the corresponding energy capacity shows a variance of 12 GWh in FY51 between the Fast Change and Slow Change scenarios.

An observable trend in both solar PV and battery storage capacity is that the Fast Change and High DER scenarios deviate from the Neutral scenarios faster than the Slow Change and Low DER scenarios do. This is caused by the assumption unique to the Fast Change and High DER scenarios that cost-reflective "smart" tariffs will be progressively assigned to consumers on an "opt-out" basis, as opposed to the other scenarios where consumers can always choose to remain on their "simple" tariff.

Consumers placed on smart tariffs may have greater incentive to purchase DER in any given year than if they remained on their simple tariff. Smart 'cost reflective' tariffs reward consumers who can shift consumption to low-demand periods of the day with lower rates. Utilising solar PV and storage facilitate this shift.

Figure 39 – Battery Energy Capacity by Scenario (NEM)

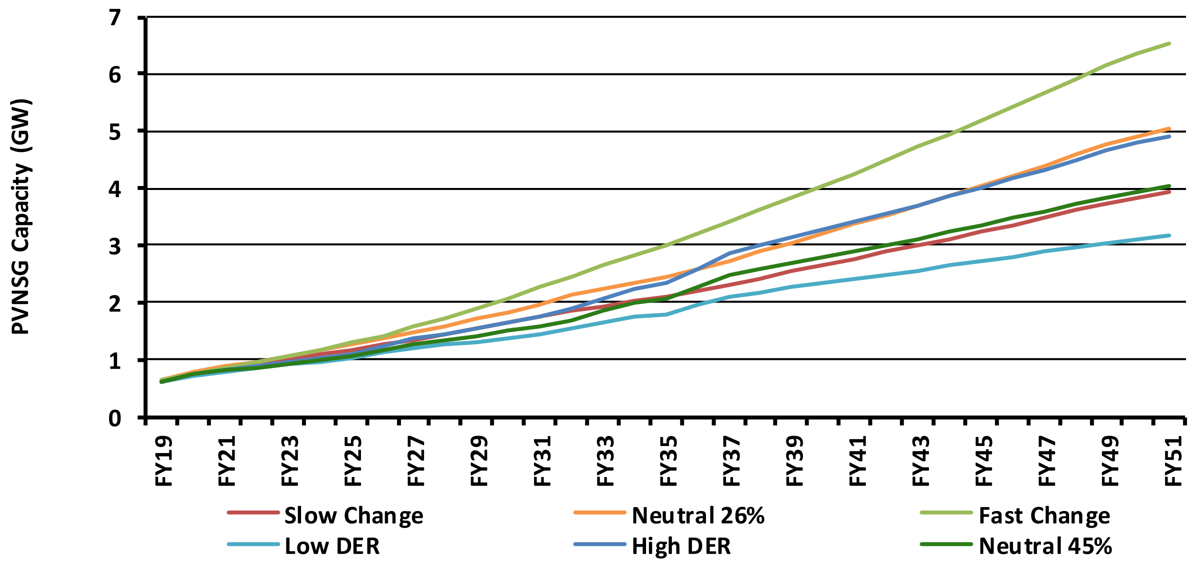


Source: Energeia Modelling

Figure 40 displays the forecasted capacity of PVNSG in the NEM for each scenario. The solar PV capacity of large commercial consumers is significantly smaller in magnitude to small-scale systems, despite having an average capacity of approximately 1-1.2 MW across all scenarios. The capacity forecast for PVNSG shares the same drivers as the cumulative installs forecast, with the Fast Change scenario having the highest capacity of 6.5 GW by FY51.

Unlike small-scale solar PV and battery storage, the deviation of the High and Low scenarios from the Neutral scenarios are more uniform. This is because retail tariffs are not an assumed factor in the decision of a large commercial customer in the purchase of NS solar PV, so the default tariff switch year is not relevant.

Figure 40 – PVNSG Capacity by Scenario (NEM)

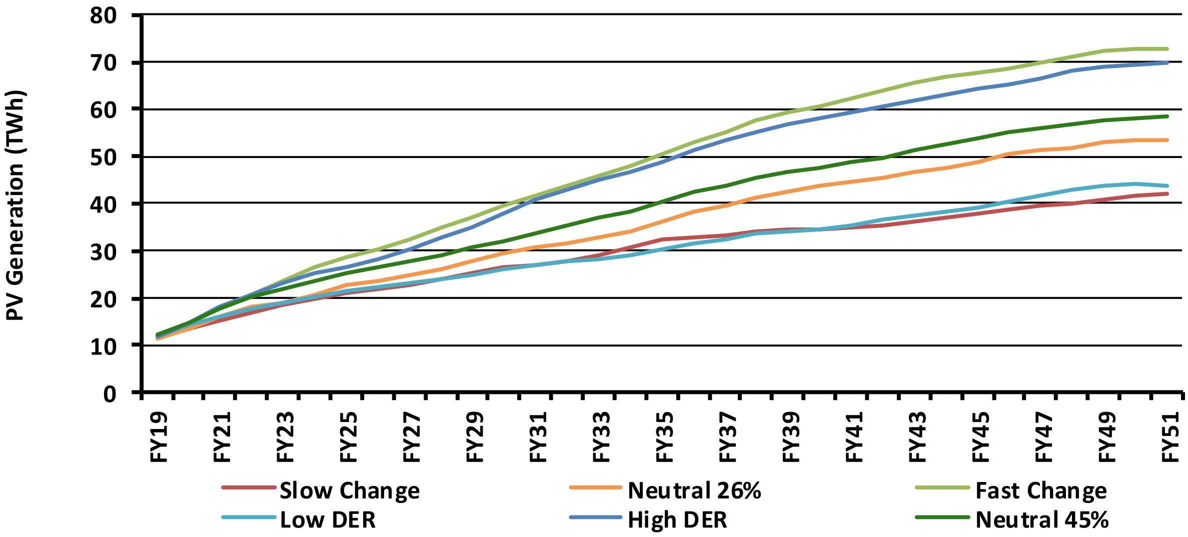


Source: Energeia Modelling

4.3.3. Consumption Impacts

Figure 41 presents the annual generation over the forecasted period that solar PV systems in the NEM would produce under each scenario. The range of potential generation from solar PV in the NEM is 30 TWh between the bounds of the modelling results.

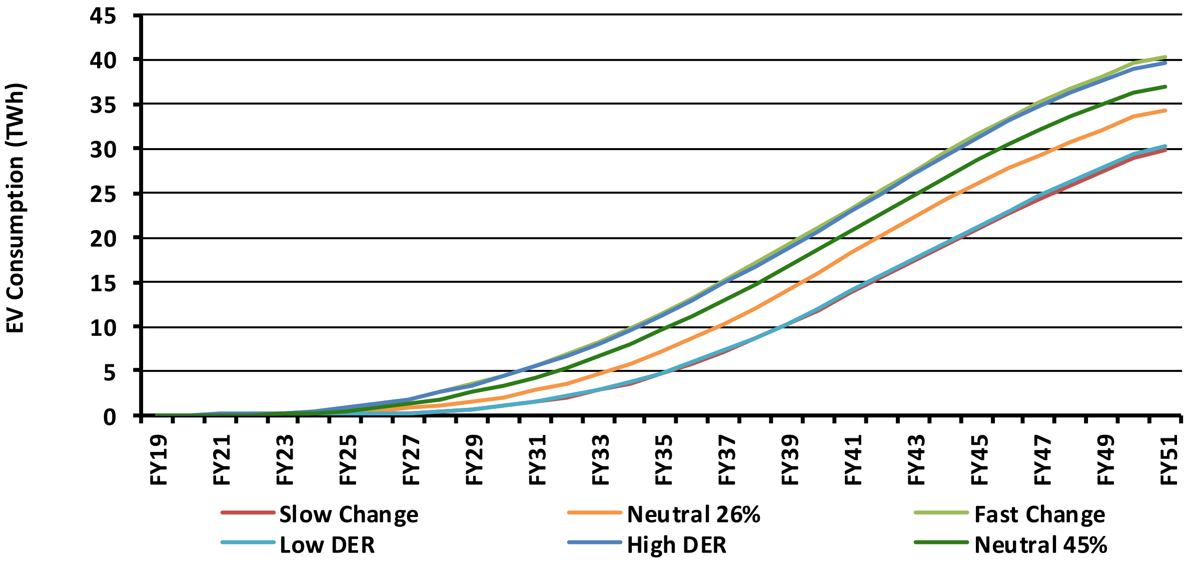
Figure 41 – Solar PV Generation by Scenario (NEM)



Source: Energeia Modelling

Figure 42 displays the level of consumption in the NEM that is forecast to be attributed to EVs for each scenario. In the highest consumption scenario, Fast Change, EV consumption is predicted to be at 49 TWh by FY51, this is equivalent to approximately 27% of current NEM operational consumption however this new demand is largely offset by the corresponding generation provided by solar PV uptake in each scenario.

Figure 42 – EV Consumption by Scenario (NEM)



Source: Energeia Modelling

Appendix A – AEMO's Scope and Inputs

A.1. Scenario Framework

Table 6 – AEMO Provided Scenario Settings

Demand Settings	Neutral v1 (Neutral 26%)	Neutral sensitivity (Neutral 45%)	Slow Change	Fast Change	High DER	Low DER
Economic growth and population outlook	Neutral	Neutral	Weak	Strong	Neutral	Neutral
Battery cost trajectories (utility and behind the meter)	Neutral	Neutral	Relatively weaker cost reductions than neutral	Relatively stronger cost reductions than neutral	Relatively stronger cost reductions than neutral	Relatively weaker cost reductions than neutral
Tariff arrangements	No significant change to existing / proposed tariff arrangements.	No significant change to existing / proposed tariff arrangements.	No significant change to existing / proposed tariff arrangements.	Significant change to existing / proposed tariff arrangements to foster and support a prosumer future, with customers embracing digital trends to take advantage of new tariff structures that lower consumer costs.	Significant change to existing / proposed tariff arrangements to foster and support a prosumer future, with customers embracing digital trends to take advantage of new tariff structures that lower consumer costs.	No significant change to existing / proposed tariff arrangements.
Electric Vehicle Charging Times	Central Estimate	Central Estimate	Slower adoption of consumer energy management opportunities, leading to less controllable charging times	Greater adoption of consumer energy management opportunities, leading to more controllable charging times	Greater adoption of consumer energy management opportunities, leading to more controllable charging	Slower adoption of consumer energy management opportunities, leading to lesser controllable charging
Battery storage aggregation by 2050	Central Estimate	Central Estimate	Slower adoption of energy aggregator opportunities, leading to lesser aggregation	Faster adoption of energy aggregator opportunities, leading to more aggregation	Fast, relatively faster than "Fast Change" per capita	Slow, relatively slower than "Slow Change" per capita
Rooftop PV - up to 100 kilowatts (kW)	Neutral	Neutral	Proportionally fewer household installations than the Neutral	Proportionally more household installations than the Neutral	Strong, relatively stronger than "Fast Change", per capita	Weak, relatively weaker than "Slow Change" per capita
Non-scheduled PV - above 100 kW (up to 30 MW in NEM)	Neutral	Neutral	Proportionally fewer commercial installations than the Neutral	Proportionally more commercial installations than the Neutral	Strong, relatively stronger than "Fast Change", per capita	Weak, relatively weaker than "Slow Change" per capita

Demand Settings	Neutral v1 (Neutral 26%)	Neutral sensitivity (Neutral 45%)	Slow Change	Fast Change	High DER	Low DER
Electric vehicle uptake	Neutral	Neutral	Weak	Strong, with EVs more rapidly reaching cost parity with ICE	Strong, with EVs more rapidly reaching cost parity with ICE	Weak, relatively weaker than "Slow Change" per capita
Battery storage installed capacity	Neutral	Neutral	Proportionally fewer household installations than the Neutral	Proportionally more household installations than the Neutral	Strong, relatively stronger than "Fast Change", per capita	Weak, relatively weaker than "Slow Change" per capita
Battery storage aggregation by 2050	Central Estimate	Central Estimate	Slower adoption of energy aggregator opportunities, leading to lesser aggregation	Faster adoption of energy aggregator opportunities, leading to more aggregation	Fast, relatively faster than "Fast Change" per capita	Slow, relatively slower than "Slow Change" per capita
Emissions reduction trajectories	26% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements – meaning no direct carbon pricing mechanism to signal action to consumers	45% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements – meaning no direct carbon pricing mechanism to signal action to consumers, as well as increased policies to support small-scale DER investments, increasing DER uptake	26% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements – meaning no direct carbon pricing mechanism to signal action to consumers	45% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements – meaning no direct carbon pricing mechanism to signal action to consumers, as well as increased policies to support small-scale DER investments, increasing DER uptake	45% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements - meaning no direct carbon pricing mechanism to signal action to consumers, as well as greatest direct policies to support small-scale DER investments, increasing DER uptake	45% 2005 – 2030 With achievement linked to large scale investment in renewables and earlier coal retirements – meaning no direct carbon pricing mechanism to signal action to consumers

A.2. Scenario Strategic Dimension Mapping

Energeia reviewed the scenario design supplied by AEMO[24], and identified the following strategic dimensions:

- **Energy System Change** –Testing economic outlook sensitivities:
    - Slow Change Scenario (weak population, economic and peak demand growth)
    - Fast Change Scenario (strong population, economic and peak demand growth)
- **Emissions** –Testing the sensitivity of the Neutral Scenario to emissions policy:
    - Neutral 26% Scenario (emissions reduced by 26% from 2005 levels)
    - Neutral 45% Scenario (emissions reduced by 45% from 2005 levels)
- **Distributed Energy Resources Take-up** –Testing high and low DER scenarios:
    - Low DER Scenario (weak DER price declines)
    - High DER Scenario (strong DER price declines)

AEMO's planning scenarios (the Neutral 26% scenario, and the Slow and Fast Change scenarios) are designed to test the rate of change in the energy system driven by population, and economic and peak demand growth. The strategic dimensions of AEMO's key scenarios are shown in Table 7.

Table 7 – Energeia's Identified Strategic Dimensions

		Planning Scenarios (Rate of Energy System Change) Low	Medium	High
DER Sensitivities (Technology Cost Decline Rates / Incentives)	Strong		High DER	
	Neutral	Slow Change	Neutral 26% Neutral 45%	Fast Change
	Weak		Low DER	

Emissions	Testing the sensitivity of the 2018 ISP's Neutral Scenario to emissions policy
Energy System Change	Testing economic outlook sensitivities (such as population, economic and peak demand growth)
DER Take-Up	Testing high and low DER scenarios (including DER price declines)

Source: Energeia Analysis

[24] The full scenario framework as provided by AEMO is detailed in Section A.3 Scenario Framework.

A.3. Scenario Inputs and Outputs Mapping to RFI Inputs

Table 8 – Directly Related AEMO Scenario Settings (Inputs)

AEMO Scenario Settings	Energeia Model Driver Mapping	Scenarios: Emission Sensitivity – Neutral (26%)	Scenarios: Emission Sensitivity – Neutral (45%)	Scenarios: Economic Sensitivity – Slow Change	Scenarios: Economic Sensitivity – Fast Change	Scenarios: DER Sensitivity – Low DER	Scenarios: DER Sensitivity – High DER
Economic Growth and Population Outlook	Population growth	AEMO Neutral	AEMO Neutral	AEMO Slow Change	AEMO Fast Change	AEMO Neutral	AEMO Neutral
	Peak growth						
	Energy growth						
Battery Cost Trajectories (Utility and BTM)	Battery storage split by inverter, storage and install per kWh	Neutral	Neutral	Weak	Strong	Weak	Strong
Tariff Arrangements	Current and future residential and commercial tariff structures, opt-in or opt-out years, default tariff switch year	Opt-in Tariffs	Opt-in Tariffs	Opt-in Tariffs	Opt-out Tariffs	Opt-in Tariffs	Opt-out Tariffs
Electric Vehicle Charging Times	Current and future EV managed/unmanaged charging structures, opt-in or opt-out years[1]	Neutral Transition	Neutral Transition	Slow Transition	Fast Transition	Slow Transition	Fast Transition
Battery Storage Aggregation by 2050	DSO/VPP orchestration year[2]	Neutral Adoption (2024)	Neutral Adoption (2024)	Weak Adoption (2027)	Strong Adoption (2021)	Weak Adoption (2027)	Strong Adoption (2021)

Source: Energeia Analysis; Note: 1. Transition to managed EV charging coincides with the decline in EV price premium; 2. Timing for battery storage aggregation based on the Network Transformation Roadmap (2017) Energy Networks Australia.

Table 9 – Indirectly Mapped AEMO Scenario Settings (Outputs)

AEMO Scenario Settings	Energeia Model Driver Mapping	Scenarios					
		Emission Sensitivity		**Economic Sensitivity**		**DER Sensitivity**	
		Neutral (26%)	**Neutral (45%)**	**Slow Change**	**Fast Change**	**Low DER**	**High DER**
Rooftop PV Up to 100 kilowatts (kW)	Solar PV costs split by inverter, solar PV and install per kW	Neutral	Neutral	Weak	Strong	Weak	Strong
Non-scheduled PV above 100 kW (<30MW)	Non-scheduled Solar PV costs split by inverter Solar PV and install per kW						
Battery Storage Installed Capacity	Battery storage split by inverter, storage and install per kWh						
Electric Vehicle Uptake	EV cost premiums by vehicle Type	Neutral EV Parity (5 years)	Neutral EV Parity (5 years)	Weak EV Parity (7 years)	Strong EV Parity (3 years)	Weak EV Parity (7 years)	Strong EV Parity (3 years)
	Future EV managed/unmanaged charging structure [1]	Neutral Transition (5 years)	Neutral Transition (5 years)	Slow Transition (7 years)	Fast Transition (3 years)	Slow Transition (7 years)	Fast Transition (3 years)
Emissions Reduction Trajectories	Volume weighted average price forecast by state	AEMO (26%)	AEMO (45%)	AEMO (26%)	AEMO (26%)	Energeia (45%)	Energeia (45%)
	Solar PV rebates over time by state	No Additional Rebates	STC Rebates Continues	No Additional Rebates	STC Rebates Continues	No Additional Rebates	STC Rebates Continues
	Storage rebates over time by state[2]	No Rebates	$500/kWh	No Rebates	$500/kWh	No Rebates	$500/kWh
	EV rebates over time by state[3]		$3,000		$3,000		$3,000

Source: Energeia Analysis; Note: 1. Transition to managed EV charging coincides with the decline in EV price premium; 2. Storage rebates assume current SA battery rebate up to $6,000 per unit is rolled out to other states, (e.g. reduces the installed cost of a 14kWh Tesla Powerwall II from ~$12,000 to $6,000); 3. EV rebates assumed to be implemented from the 'Moderate Intervention' Scenario in 'Australian Electric Vehicle Market Study' (2018) Clean Energy Finance Corporation (Equivalent to a $3,000 reduction in sticker price).

Appendix B – uSim Modelling and Assumptions

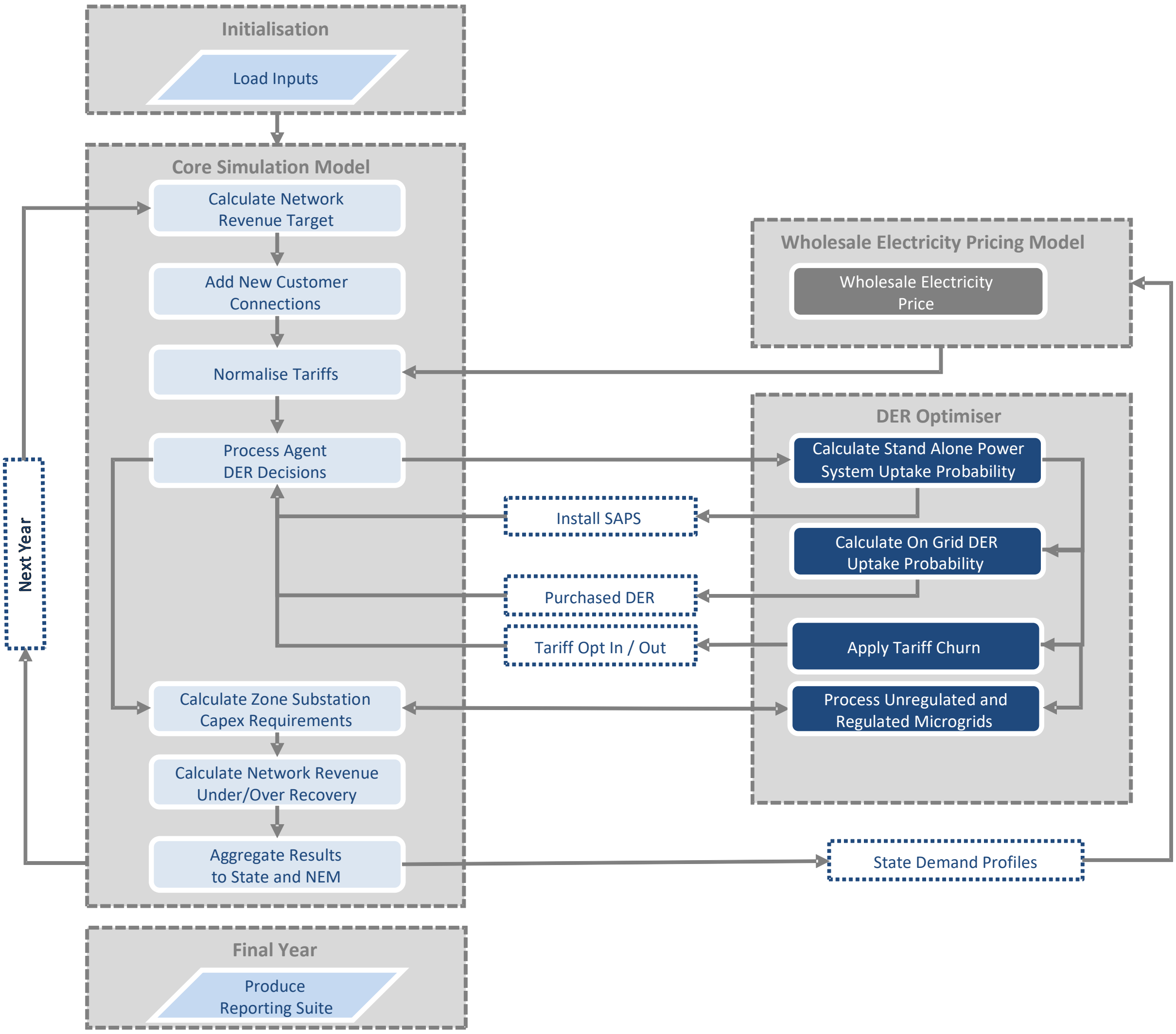
B1 Overview

uSim is an agent[25] based model which simulates customer level decision making with respect to DER investment and operation under different policy, regulatory, tariff, technology, and macro-economic settings, and estimates the corresponding impact of customer decision making on electricity networks and wholesale markets.

B1.1 Structure of the Model

uSim operates across a range of different functions and modules, through an iterative process year-on-year, for each year of the simulation period, working through the process loops shown in Figure 43.

Figure 43 – Overview of DER Simulation Platform



Source: Energeia

[25] Agents are the principal decision makers within the simulation. It is the decisions that agents (and the customers they represent) make that drive network decisions, energy prices and the outcomes of the grid.

uSim is built around two key modules include:

- **Core Simulation Platform** – Contains the main customer and network functions of the models (as outlined in the Core Simulation Platform section of this Appendix) and is linked to the DER Optimiser module.
- **Solar PV and Storage Optimiser** – Calculates the optimal solar PV and storage configuration for a customer given the provided constraints (explained in more detail in the solar PV and storage Optimiser section of this Appendix), forming a subset of the Core platform.

Decisions to purchase DER systems, switch tariffs/incentives or disconnect from the grid are made by agents. The results then feed back into load, and network operating and capital costs, which determine network revenue allocations in the following year.

B1.2 Methodology Selection

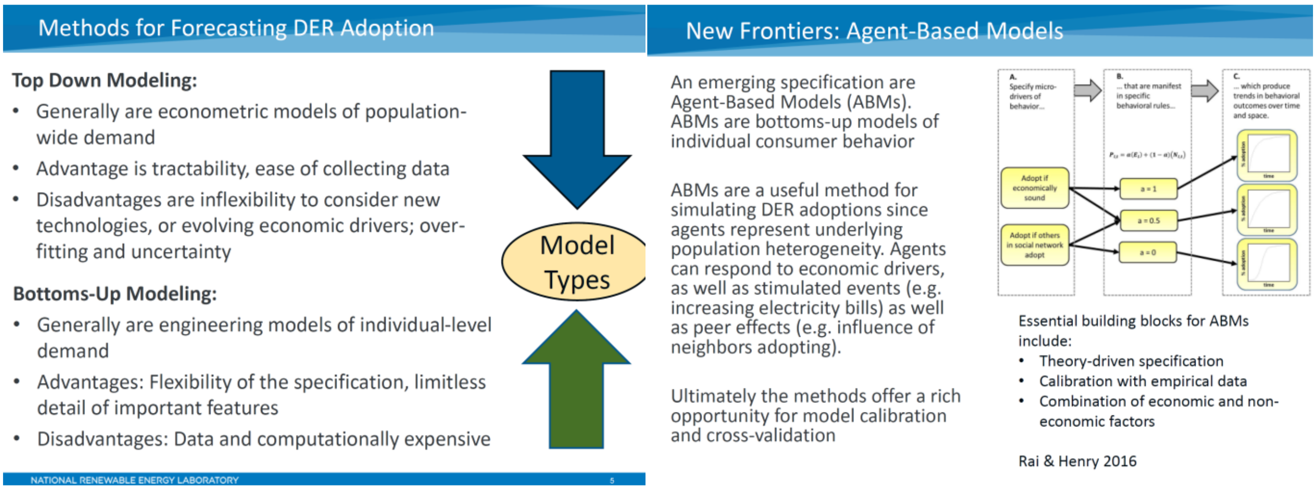
The emergence of new, interdependent DERs, e.g. electric vehicles and batteries, which impact on customer demand behaviour and each other, combine to make forecasting even more difficult into the future. The impact of new tariffs like maximum demand and VPP services on customer adoption and operation is also very material.

There is a growing consensus, that bottom-up, agent-based approaches are best suited to the unique challenges involved in forecasting DER, with their strong path dependency and interdependencies:

- An agent-based simulation approach was recently selected by the California Energy Commission as the winner of a state-wide tender for new DER forecasting tools.[26]
- National Renewable Energy Laboratory, NREL, the pre-eminent US National Energy Laboratory for forecasting DER, has highlighted agent based, bottom-up forecasting approaches as well suited to the specific challenges of DER forecasting.

The slides below are taken from a presentation to the California Energy Commission in 2017 on best practice forecasting methodologies,[27] highlighting the advantages of bottom up agent based modelling for DER forecasting, and therefore for load forecasting.

Figure 44 – Excerpts from NREL Presentation on Best Practice DER Forecasting



Source: NREL (2017)

[26] http://www.energy.ca.gov/contracts/GFO-17-305_NOPA.pdf

[27] Energeia can provide the full presentation upon request.

B1.3 History of Recent Model Development

Energeia's uSim bottom-up modelling system has been used since 2013 for some of Australia's highest profile, national modelling exercises, including the 2013 *Smart Grid, Smart City* initiative, and the 2017 *National Transformation Roadmap*.

During this time, it has been continually developed to consider new DER technologies, customer behaviour, policy settings and increased network asset granularity.

B1.4 Current Application

Energeia has applied the same modelling approach as was used in Energy Networks Australia's *National Transformation Roadmap*, with significant updates to inputs including:

- Updated solar PV installation starting point
- Updated network and retail tariff structures for all distribution networks
- Recalibration of the return-on-investment uptake function
- Current network zone substation capacity
- Updated network asset age distributions
- Technology cost curves

B2 Model Process and Modules

B2.1 Process

Energeia's uSim platform is comprised of two core modules:

- **Customer Processing Module** – For each distribution network uSim simulates the customer base represented by a sample set of agents. Each year these customers make economic decisions to optimise their electricity bill.
- **Asset Processing Module** – Following the decisions of customers the resulting load profiles are then aggregated to each network asset where investment decisions are made to augment, replace or move off-grid.

The functions and sub-functions of each of the above modules of the simulation platform are summarised below, including a high level of overview of interactions between different parts of the model, limitations of assumptions and their impact on modelling.

B2.2 Customer Processing

New Connections

New connections are a key driver of demand and consumption growth for electricity networks, and the energy sector as a whole. In the model, new connections are modelled by creating additional agents. One residential and one commercial agent is spawned each year for each network and is assigned randomly selected load profile within each class. These new connections are also assigned to the default tariff for their network.

Agents representing new connections are assigned scaling factors that represent the population of new customer connections on each zone substation. The population growth factors are exogenous model inputs and are unique to each zone substation.

The limitations of this approach are:

- The premise type of the new agent is selected at random from the two options (house/unit or warehouse/suite) with equal probability

- Probability weightings are not applied to demand profile selection, so a very large profile has the same probability of being selected as a standard customer profile. This is most noticeable for commercial connections, where the range of customer consumption is wider than for residential.

Load Growth

Each agent begins the model with a single year demand profile. As the model progresses, this demand profile is adjusted to represent underlying trends in customer electricity demand patterns. This is achieved through the application of two growth factors:

- **Peak Growth –** The growth rate applied to the largest 5% of all half hourly interval loads for a customer.
- **Consumption Growth –** The growth rate of total annual consumption for the agent, used for determining the growth rate applied to the lowest 95% of half hourly interval loads.

Tariff Normalisation

Tariffs are calculated each year to reflect changing rates customers will pay associated with network's recovering their revenue allowance, and changing wholesale generation costs. The following sections outlines the tariff components normalised each year.

Peak Revenue Allocation

Networks will recover revenue from the peak component of the tariff to cover the cost of the contribution to peak demand by each customer class. Peak components are tariff mechanisms that specifically allocate cost to customers during peak demand periods (these include the peak period of a time of use or maximum demand tariff, critical peak events, and similar components in other tariffs).

The amount of revenue recovered by peak mechanisms across all tariff classes by a network at the zone substation level is:

$$Coincident\ Peak\ Revenue\ (\$) = Coincident\ Peak\ (kW) * \ LRMC(\$/kWh)$$

Where the Coincident Peak (kW) is the peak half hour of the load of all residential and commercial customers during the year. The time of the coincident peak event does not have to be within the peak times defined by the tariff's peak mechanism. This is then divided between commercial and residential based on the percentage of the peak event that was due to each class.

Each tariff must be able to recover this amount from its peak mechanism such that the rate on the peak mechanism will be:

$$Peak\ Charge\ (\$\ per\ kWh) = \frac{Coincident\ Peak\ Revenue\ (\$)}{Chargeable\ Demand\ (kWh)}$$

For tariffs that do not have a peak mechanism, the non-peak mechanisms, or the residual, collect all revenue.

Residual Allocation

Network revenue that is not recovered through a peak mechanism is allocated to the residual components of a tariff. While some tariffs do not have a peak component, all tariffs have at least one residual component. The most common types of residual tariff components are a daily fixed charge and an energy charge that is billed on all consumption regardless of time of day.

Residual revenue is allocated between customer classes based on the allocation ratio implied by the current tariff settings by each network. As the model progresses, and the value of residual revenue allocated to the network rises, this ratio is retained.

Retail Overhead and Profit

Retail tariffs are the tariffs that customers see and pay. It is assumed that retail tariffs are structurally the same as their corresponding network tariff but with an additional wholesale, fixed and FiT component.

Retail tariffs are determined using an overhead plus profit margin calculation for each component of the tariff using the following formula:

$$Retail\ Price\ (\$) = Wholesale\ Price\ (\$) + Network\ Price\ (\$) * \left(1 + RetailOverheadPct\ (\%)\right) + Retail\ Profit\ (\$)$$

Where:

- The wholesale charge is based on energy consumed and is only applied to energy based tariff components
- The retail overhead factor is an additional charge retailers levy on network components. This charge means that as network prices change, retailer margins move in the same direction. This premium is the same for all applicable components of a tariff
- The retail profit margin is an additional charge that is set in the initial year of the simulation and held constant thereafter. Where a tariff is available today, the retail profit value is set so the charges equal those currently available to eligible customers. For new tariffs developed for the project, the retail profit value is an adjustable input.

DER Optimisation

In the uSim Platform, the behaviour of each individual agent is simulated to reflect customer behaviours in the real world. Agents will have the option to purchase DER technology and/or change their current tariff to minimise their bill or go defect off the grid. The following sections detail the pathways available to agents and the processes of the model which simulate these pathways.

Remaining On-Grid

Agents remaining connected to the grid are able to purchase DER technology and/or change tariffs. This decision is based on the combination of DER technologies sizes and tariffs which will provide the highest NPV based on the inputs provided. An uptake function (see Section B3.3 Distributed Energy Resources) is then applied to the best option to determine the uptake probability and whether the agent made a purchase. Agents that do not purchase any DER or change tariffs are eligible for the third and final decision-making step, tariff churn.

DER Technology and Tariffs Combinations

The Optimisation function takes a brute force approach, testing every valid combination of technologies, sizes and tariffs that are available for each customer or zone substation.

For each combination of DER and tariff, the first step taken by the optimiser is to apply the behaviour change effect of the tariff in the combination. The optimiser then loops through all the allowable sizes of solar PV, battery, inverter and diesel technologies, in that order, that are valid against a restrictive criterion. For example, an invalid combination would include a solar panel without an inverter or a battery with a DER restricted tariff.

The allowable sizes are subject to the following constraints:

- Minimum and maximum DER technology size for a single purchase and technology step size,
- Customer roof or storage space constraint, and
- Existing DER technology capacity.

Unlike inverters and diesel generators, solar PV and storage systems can both be augmented, with new purchases adding to the existing capacity installed. However, agents can only augment solar and storage systems up to the size that will fill their remaining space constraint.

If the minimum purchase size cannot fit in the customers remaining roof or storage space, no purchase can be made, and the current combination will be ruled invalid.

An agent will only consider taking up the DER and tariff configuration with the highest NPV, which includes the customer's retail bill, the cost of the DER technologies and the value of unserved energy (if any). The NPV formula uses the discount rate of the buyer and ongoing payments determined by the DER lifetime and system characteristics, including any bill savings from DER technology and associated costs. An example can be shown in Table 10. The payback of this "winning" combination is then used by the uptake function to determine if the agent purchases the combination.

Table 10 – Comparison of NPV for DER Technology Sizing (Indicative)

Solar Size (kW)	Storage Size (kWh)				
	2	4	6	8	10
2	-$4	$26	$55	-$34	-$141
4	$69	$95	$178	$42	-$51
6	$133	$156	$133	$99	-$9
8	$33	$64	$33	-$12	-$153
10	-$18	$17	-$18	-$69	-$230

Source: Energeia

If an agent purchases a DER system or changes tariff the simulation moves on to the next agent. If the agent did not make a change, they are sent to the tariff churn function.

Tariff Churn

Tariff churn is a function that is applied to agents that are connected to the grid and have not purchased a DER system or voluntarily changed tariff in the current year. Tariff churn represents the effect of changes in occupancy at a premise and new and replacement meters. When a customer moves in or out of a house or business premise or the meter on the premise is replaced, the connection is changed to the default network tariff.

Tariff churn is represented in the simulation by switching agents from their current tariff to the default tariff. All other characteristics of the agent are retained, including their load profile and DER systems they have previously purchased. The rate of tariff churn is an input, with values specified for every year, customer class and network. Because of the approach, agents that are already on the default tariff will not change.

For the agents that are potentially subject to this function, a random number is generated from a uniform distribution between 0 and 1. If the number generated for a particular agent is lower than the applicable rate of tariff churn for that agent, the agent's tariff is changed to the default tariff.

Defect Off-Grid

Customers are able to defect off-grid and become completely independent of the grid through Stand-Alone Power Systems, or SAPS. This decision is determined by calculating the mix of DER that optimises the cost of the system while minimising unserved energy, capital expenditure of the system and operation costs. Unlike customers remaining on-grid, diesel generators and larger DER technologies system sizes are available for customers who are looking to defect.

Once an agent has purchased an off-grid SAPS, they cannot revert to a grid connection. This constraint also extends to customers that switched to a SAPS tariff.

The value of unserved energy, or value of customer reliability (VCR) is crucial in this process. Agents value unserved energy and treat the cost of unserved energy in the same way they treat an electricity bill, minimising the bill to the extent it makes financial sense. The VCR is unique to different customer classes and networks and remains constant in real terms.

DER Uptake

An agent's decision to uptake their best configuration of DER and tariffs are dependent on the ROI uptake functionality based on the inputs provided.

Update Customer Bill and Load Profile

Based on the customer's tariff and DER decisions, the model will calculate the customer new consumption load profile adjusted by DER, which is then used to calculate the customer's retail electricity bill.

Each DER technology is applied to the customer's load profile in the following order:

- **Solar PV –** The solar generation profile is added to the customer's load profile
- **Battery –** The customer's solar adjusted profile will be used to calculate the battery charging and discharging profile. The battery algorithm differs depending on the customer's tariff. The battery is calculated after the solar PV because batteries will often utilise solar PV exports to obtain bill savings.

The customer's retail bill will be calculated based on the DER adjusted load profile.

B2.3 Asset Processing

Aggregation

After the customer processing procedures, the results, including new load profiles, DER quantities and bills, are aggregated upwards in the asset hierarchy. All assets are then processed and in turn undergo aggregation upwards in the asset hierarchy until the final hierarchy asset, usually the systems.

Update Load Profile

Load profiles are aggregated upwards in the asset hierarchy, from customers to feeders, feeders to zone substations, zone substations to networks and networks to states and systems. Each asset level is processed individually prior to aggregation.

Optimise Load Profile

Assets are able to optimise their load profile through either adopting network control of available batteries or leasing a battery to be used to reduce capacity constraints.

Network Control

If the scenario permits, assets can act as an aggregator and has the ability to control all agent's battery devices to limit network peak demand and prevent capacity breaches by discharging batteries during peak events.

Note that this is applied after the customer has used their battery functionalities to minimise their bill.

Network Leasing

If permitted in the scenario, assets have the option to lease a grid scale or aggregated battery on a one-year basis and place it at the asset (or to contract to customers within that asset). The battery is used to remediate shortfalls of the asset (due to demand exceeding capacity) by discharging when demand is above the asset's rated capacity.

The battery in general has no preference in terms of when it charges itself. The exception is when the asset has net negative demand caused by large volumes of rooftop solar PV exports by agents. When negative demand is available the battery will attempt to charge from this to increase minimum demand.

The utilisation rates of contracted batteries are generally very low, only discharging when demand is greater than the rated capacity of the zone substation, occurring a handful of times a year. Due to this low level of utilisation, battery degradation due to cycling is negligible in most cases and so is not included in the pricing function for the battery lease.

Note that the contracted battery will only operate to reduce demand to the rated capacity. It will not reduce demand further, solar shift or wholesale price arbitrage. Adding these capabilities to reduce the cost of the network is a future development direction.

Optimise Asset

The modelled cost of a network is built around the zone substation. The value of remaining network assets is largely held constant. The exception is the zone substation asset class, which has a set capacity and requires replacement and augmentation as the simulation progresses. Zone substations which have breached their capacity limits will require undergoing augmentation, replacement or other means to reduce their capacity breach, including the following:

- Leasing a battery to temporarily reduce peak demand;
- Taking the traditional option and augmenting the substation, or;
- Installing new equipment with higher rated capacities, to meet reliability targets, depending on the options allowed by each scenario.

Zone substations have finite lifetimes due to deterioration in their condition, and when the end of life is reached the substation must be replaced.

Capacity Limits

The simulation assumes all zone substations are rated on an N-1 basis[28]. This assumes individual zone substations have capacity more than their rated capacity but are required to have 100% asset redundancy at all times. The simulation allows for a reasonable amount of exceedance of the N-1 rating. This allowed exceedance is expressed as the number of half hour intervals per year when the demand on a zone substation is greater than its rated capacity. The number of intervals is an input into the simulation.

In reality, actual installation of N-1 redundancy differs by state, network and within networks. Some areas, such as CBDs, have greater than N-1 redundancy whereas others have no redundancy.

Demand Forecast

The construction of a new zone substation or a microgrid firstly requires knowledge about the future demand profile of the asset to be replaced. The chosen construction option must be built large enough to service demand decades into the future, and such limiting additional augmentation or replacement in the lifetime of the asset.

A linear extrapolation is used to produce a 20-year forecast of future demand, based on previous years' peak demand growth. For forecasts in the initial year of the simulation, when no historical demand is available to create a forecast from, a simulation wide default growth rate is used.

The growth rate derived from peak demand growth is applied uniformly over the asset's interval demand profile to generate a full year profile of half hourly demand for each forecast year.

The method used to forecast demand for determining asset build sizes has the following limitations:

- The forecast is dependent on two data points, current demand and demand growth of (up to) five years previously. If demand is volatile, the forecast may vary widely one year to the next. Therefore, the year when a constraint is breached may have a large influence on the augmented capacity of an asset

[28] N-1 refers to having the ability to supply all demand on the zone substation when one set of equipment (transformer, switchgear, sub transmission feeder line etc.) is down.

- Forecasts in the first few years of the model are unlikely to be representative of the long run given less historical data is available
- DER investment by customers may reduce demand over a period, resulting in a forecast decline, but if penetration of DER is near the maximum the declining demand may not be sustainable. This can lead to zone substation reaching the end of its life being replaced smaller than necessary for the target lifetime and require rebuilding a few years later when demand growth resumes
- All intervals are grown at the same rate. However, it is more likely the growth rate of the maximum value will be more extreme than the average growth rate of the individual intervals. The peak demand could also be declining while total consumption is rising. This issue applies only to microgrids as they use the full demand profile, whereas augmentation of the zone substation only requires sizing based on peak demand.

Augmentation

Network augmentation occurs when the network asset (zone substation or feeder) reaches either its asset age or when the network demand exceeds the rated capacity of the asset. Upon network augmentation, the cost of augmentation is allocated to the networks regulated asset base with which the network charges customers via network tariff charges. uSim utilises this functionality to optimise community costs by minimising customer bills.

- Asset age network augmentation: When assets reach their lifetime, the model replaces the asset with a newly built asset. Depending on the network demand on the asset the rebuild can be lower, higher or the same as the previously rated capacity. The model is built with functionality to restrict the build-down (replacing assets with a smaller rating) size to promote reliability of DSO functionalities. i.e. preventing smaller build back of assets maintains capacity on the asset which is required for DSO/VPP functionality.
- Network demand exceedance network augmentation: Assets can be augmented when the customer demand on the asset exceeds the rated capacity. Augmentation here is triggered when the rating of the asset is breached *n* times within a model year (where n is adjustable according to network settings). The upgrade min size and step sizes are adjustable for accuracy in the model.

Replacement

The traditional response to an ageing or over capacity zone substation is to replace it with a new, correctly sized substation. Despite the new options that are now available, a new substation is still the primary method for maintaining the network and supplying electricity to customers.

The process for constructing a new zone substation in the simulation is the same whether the reason for the upgrade is age or capacity increase. The peak demand forecast for the substation is used to determine an appropriate build size. The build size must be large enough that in the final forecast year the asset will not breach its rated capacity. Then an additional margin is applied to this size and the result is rounded up to the nearest available size.

$$MW_{New} = max\left(PeakMW_t, PeakMW_{t+y}\right) * (1 + margin\,\%)$$

The number of years the forecast is for is an input to the model. Zone substations have a lifetime of up to 50 years, and in some cases longer than this. However, they are typically built to accommodate 20 to 25 years of growth, with an upgrade mid-lifetime to reach the final configuration capacity.

Update Revenue Requirement

All changes in asset optimisation are reflected in the changes in network revenue requirements. The target network revenue represents the revenue that the network aims to recover across all customer classes. It is made up of operating expenses, capital costs, a balancing item and adjustment for under or over recovery of revenue in previous years.

The revenue target is calculated at the start of each year modelled using a simplified version of the methodology used by the AER when setting network revenue allowances:

$$Target\ (\$) = Opex\ (\$) + Return\ on\ RAB\ (\$) + Depreciation\ (\$) + Balancing\ Item\ (\$) + Unders\&Overs\ (\$)$$

Under and Over Recovered Revenue from Previous Year

When customers make decisions to change tariffs, purchase DER and move to a stand-alone power solution, the amount of revenue collected by the network will fall short of the revenue target for the year. To protect networks from lost revenue, and consistent with the revenue cap regulatory framework, an allowance is provided to recover the missed revenue during the following year.

$$Under\ and\ Over\ Recovered\ Revenue_t\ (\$) = \left((\$) - Revenue_{t-1}(\$)\right) * (1 + WACC(\%))$$

Where:

- The compensation for missed revenue is increased by the WACC to reflect the missed opportunity to reinvest the revenue that was not recovered in the previous year
- If the network over-recovered revenue during the previous year, this item will reduce the network's revenue in the current year.

B3 Common Assumptions

B3.1 Customers

Energeia created a customer base to represent the more than 9 million customers connected to the NEM and the WEM. The following sections detail the process Energeia conducted to produce the customer base used in the uSim model.

Segmentation

Each customer was created based on the following segmentations:

- **Customer Class** – The customer base was first segmented into residential and commercial customers. The number of residential and commercial customers was collected from network regulatory reporting statements (benchmarking RIN response) for all networks in Australia.
- **Dwelling Type** – Each customer was sub-segmented into two dwelling types:
  - *Detached Dwellings* – includes houses for residential customers and warehouses for commercial customers.
  - *Attached Dwellings* – includes units (or apartments) for residential customers and suites for commercial customers.

  Through acquiring ABS data on the number and share of attached and detached dwellings, Energeia proportioned the total customer base split by customer class into their corresponding dwelling type.
- **Annual Consumption** – A customer's annual consumption is critical in understanding the customer's future DER purchasing decisions. Customer consumption data was not available in the public domain. Instead, Energeia approximated each customer's annual consumption through a log-normal distribution of the average customer's annual consumption in each zone substation in a network. This was done using the total consumption of customers by customer class, and the number of customers by customer class taken from the RINs.

  Solar PV Usage – The next level of segmentation was whether customer have solar PV. Solar uptake was limited in our platform to houses and warehouses due to roof space constraints. Historic solar install data in Australia, including the number of installs and the size of existing solar PV systems, were collected from APVI and segmented into residential and commercial customers that are eligible to purchase solar PV. Additionally, Energeia determined the customer's historic purchase year through a random distribution of historic solar PV uptake. Energeia also ensured that the existing solar PV system for a customer is appropriate for their annual consumption (i.e. a "small" customers will not have a large solar PV system).

Using the segmentations listed, the resulting customer base was mapped to their corresponding lowest-level asset in the asset hierarchy, zone substations[29].

Connection Mapping

Energeia's customer base requires a connection to the lowest-level network asset available. Using zone substation annual consumption and customer connections by customer class from the RINs, Energeia mapped each customer to their corresponding zone substation based on their segmentation characteristics.

Agents

Modelling each of the more than 9 million customers connected to the NEM and the SWIS is not computationally feasible, so the customer base is represented by a smaller number of agents in the model. Each agent can represent hundreds of thousands of individual customers.

Allocation Method

Each agent has a unique set of characteristics (Agent Type) and represents a distinct group of customers or population segment. Agents are characterised and segmented by the properties shown in Table 11, similar to the customer creation process.

Table 11 – Agent Types by Customer Class, Premise Size and Solar PV Usage

		Business Customer Class		**Residential Customer Class**	
		Warehouse	**Suite**	**House**	**Unit**
Solar PV Usage	Yes	Agent Type 1	Agent Type 3	Agent Type 4	Agent Type 6
	No	Agent Type 2		Agent Type 5	

Source: Energeia

Further segmentation items included:

- **Customer Phase data** (Single vs three phase) – Includes the distinction between the phases of customers, either single-phased connections or three-phased connections which impacts customers' ability to utilise solar PV and export into the grid. Energeia collected electrical phase data from the network category analysis regulatory reporting statements[30] and applied these proportionally to the customer base. Customers with single phase were limited to a lower solar system size than three-phase customers.
- **Owners vs Renters** – Using home ownership data from the ABS, Energeia segmented the customer base between those who own their premise, and those who are renting. This entails the ability for customers to purchase DER.

The full customer base for each DNSP is segmented according to the above variables and allocated to the sample agents according to their annual consumption.

[29] Please refer to Section B3.2 Assets for further details on the asset hierarchy.

[30] AER Regulatory Information Notice Responses https://www.aer.gov.au/taxonomy/term/1495

Table 12 shows the number of agents per customer segment in the model by state.

Table 12 – Agent Allocation by State

	Residential				Commercial			
	Unit		House		Suite		Warehouse	
	No PV	Has PV	No PV	Has PV	No PV	Has PV	No PV	Has PV
NSW	293	×	267	27	276	×	262	13
VIC	301	×	268	35	373	×	347	24
QLD	121	×	90	31	120	×	86	34
SA	68	×	46	22	58	×	55	3
WA	57	×	48	9	63	×	52	8
NT	62	×	43	20	40	×	34	6
TAS	60	×	53	7	73	×	69	5

Source: Energeia

The limitations of the agent creation process are:

- The range of actual customers' annual consumption is wider than the range of annual consumptions in the load profiles of the agents. This meant that the largest and smallest agents represented all the customers in the tail of the distribution, which in some cases resulted in the agent having a much larger weight within the model than would be preferred
- This also applies to the uneven distribution of agent's annual consumption within the range of extremes. Where three agents have a very similar annual consumption, very few customers will have an annual consumption closer to the middle agent than the other two agents
- Customers are allocated to agents in each sub segment according to their respective annual consumption. If the sample agent consumption used to represent reality do not match the existing distribution of sample customers, it may result in some agents with a much larger weight in the model. i.e. some consumption bands have a relatively large number of customers and may be represented by the same number of agents as a less popular consumption band.

Selection Method

As agents represent various customers within a segment, each agent was mapped to their corresponding zone substation. As a result, a zone substation would be mapped to multiple agents, each representing a different number of customers in their customer base.

B3.2 Assets

Asset hierarchy in uSim modelling is as follows:

1. State
2. Networks
3. Zone Substations
4. Feeders (Excluded)
5. Distribution Transformer (Excluded)

Energy Systems

Energeia's uSim model can be configured for three energy systems in Australia.

- National Electricity Market (NEM): Includes NSW, QLD, VIC, SA and TAS
- South West Interconnected System (SWIS): Includes the South-West region of WA
- Northern Territory Electricity Market:

Networks

The simulation platform works primarily on a network level, with each network operating independently of other networks. This means that agent and network decisions are contained within a single network. The exception to this is the setting of wholesale electricity prices, which are set at the state level and were provided by AEMO.

Zone Substations

Zone substations are individually modelled. This is because of the importance of zone substations in determining network costs and especially costs incurred by peak demand growth. Peak demand management and reducing the cost of distributing energy is a key focus of the simulation and the zone substation is an important cost component. Their need for replacement and augmentation are what drive network expenditure, which in turn drives tariff rates for a network.

In the simulation platform, the term zone substation primarily refers to the substation itself, but also includes related network assets and their associated operating, maintenance and replacement costs. Related assets are modelled on a zero-growth basis (i.e. depreciation = repex) and operating and maintenance costs are fixed over time. Related assets include:

- Upstream sub-transmission feeder lines (defined as the length of line that cannot serve any other zone substation).
- Downstream HV feeder lines
- LV distribution assets.

Each zone substation is assigned a type from the AER classification system: Long Rural, Short Rural, Urban or CBD. The value of all network assets was obtained from each network's most recent Regulatory Information Notice and annual reports for Western Power and divided into asset categories. The value of each asset and operating and maintenance costs was normalised by a dividing factor (lines as $/km, vegetation management as $/km, substation value as $/kVA etc.).

The limitations of zone substations in the simulation are:

- No investment is required for augmentation of HV feeder lines and LV distribution assets over time despite growth in the number of connections
- Large scale industrial customers are those connected to a zone substation that does not serve any residential or commercial customers or are connected directly to a sub-transmission line or bulk supply point. These customers are not modelled in the simulation and are only relevant for determining prices in the spot market.
- The load profiles of large industrial customers do not change over the course of the simulation, and their load impacts on zone substations are accounted for in the asset balancing loads. This is explained in greater detail in

Technical

This section explains the defining technical characteristics of the assets in Energeia's database. Table 13 displays an example of how each individual asset is documented by Energeia.

Table 13 – Asset Data Example

Classification	Asset Name	Asset Type	Capacity (kVA)	Network	State	Age (Years)	Parent ID
Short	ES232	ZS	25300	Essential	NSW	2	976609
Urban	EN287	ZS	4280	Ergon	QLD	13	976607
Long	PC026	ZS	33400	Powercor	VIC	6	976612

Source: Energeia

Classification

Asset classifications for feeders and zone substations are taken from each DNSP regulatory information response for Urban and Rural (long and short) feeders and zone substations.

Connections

Energeia maps each zone substation to its parent asset, the network. The zone substations are real and based on information in network annual reports. The characteristics of the agents on each zone substation are derived by mapping the zone substation to its nearest postcode.

Capacity

Each zone substation in the network starts with its an N-1 capacity rating that determines how much energy demand it can comfortably handle. The ratings are based on network annual reports. These ratings are aggregated at the network level and determine the modelled network capacity in year 0.

Age and Lifetime

Each zone substation is assigned a starting age. The age determines when (or if) in the modelled period the zone substation needs to be replaced, thereby requiring additional network replacement expenditure for that year. The amount of expenditure required is increasing in the capacity rating of the replaced zone substation.

The zone substation age distribution for each network is estimated based on RIN information NEM and NT networks, and network annual reports for WA. Energeia assumes that a zone substation asset has a lifetime of 50 years, i.e. if a zone substation reaches 50 years of age, it needs to be replaced.

Financial

This section defines the financial classification of the assets in the model.

Capital Expenses

Capital costs are made up of two components, return on the RAB and a depreciation allowance:

$$Return\ on\ RAB\ (\$) = RAB\ (\$) * WACC\ (\%)$$

Where:

- The RAB is the RIN estimate for each asset. The WACC is unique to each network and was taken from the most recent AER determination for each network
- The weighted average cost of capital is fixed for each network. This assumes interest rates and the required rate of return on equity in Australia and the risk profile of electricity distribution businesses do not change over time.

Depreciation is calculated by multiplying the RAB value for each asset category by a depreciation rate:

$$Depreciation\ (\$) = \sum^{a} RAB_a\ (\$) * Rate_a\ (\%)$$

Where:

- The depreciation rate is unique to each asset and was calculated using data from each network's RIN by dividing reported depreciation by reported asset value for each category of asset
- This results in the depreciation allowance in the initial model year matching the year the RIN data was collected.

The RAB value for each asset is updated annually by the following formula:

$$RAB_{a,t}(\$) = RAB_{a,t-1}(\$) - Depreciation_{a,t-1}(\$) + Repex_{a,t-1}(\$) + Augex_{a,t-1}(\$)$$

Where:

- For all asset categories, excluding zone substation assets, repex is set equal to depreciation and augex is set to zero so the RAB value does not change. The only exception is when the asset is removed from the network, such as when it is made redundant by a conversion of a zone substation to a microgrid.
- For zone substation assets, a depreciation calculation is only required when replacement or augmentation expenditure is made. For subsequent years, the value of the asset depreciates to zero using straight line depreciation over the course of the assets' life.

Operating Expenses

Operating expenses for networks include all operating and maintenance costs. Where these costs can be assigned to individual network assets or categories of assets from RIN data they have been. All remaining operating expenses are assigned to an operating expense balancing item.

Long Run Marginal Cost (LRMC)

The LRMC, the cost-to-serve the network faces, is defined in the model as:

$$LRMC\left(\frac{\$}{kVA}\right) = \frac{Peak\ Revenue\ in\ year_0(\$)}{Peak\ Demand\ in\ year_0\ (kVA)}$$

Peak revenue refers to the revenue collected by the network cost-reflective tariff's peak component in year 0 (the year before forecasting begins). Peak demand refers to the weighted average peak demand for the year across all classes of customer on the network.

The LRMC is held constant throughout the duration of model and is what determines the peak revenue target in year t, and therefore the network price component of agent bills:

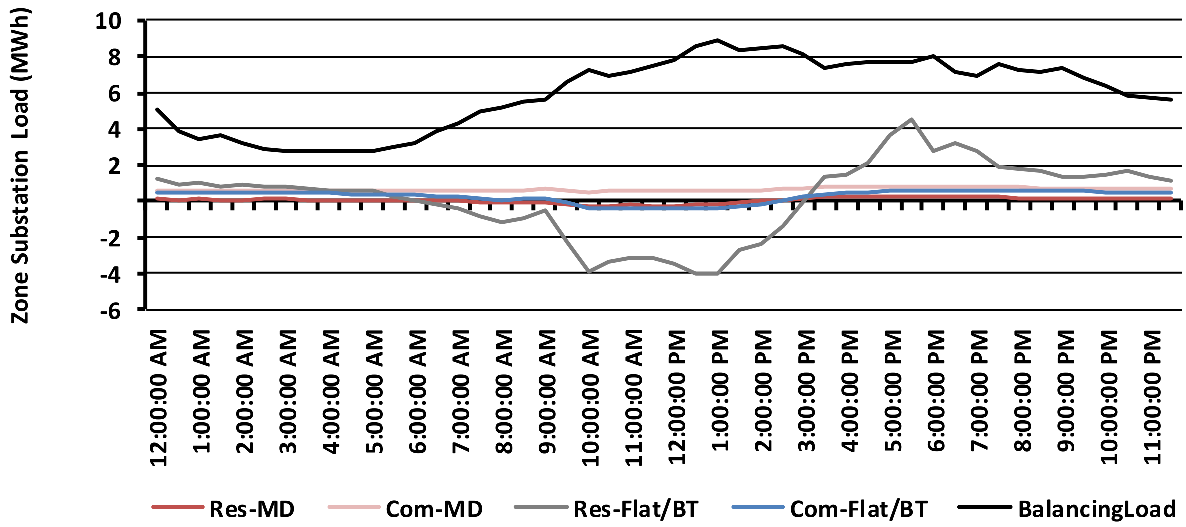
$$Peak\ Revenue\ Target_t(\$) = \ Peak\ Demand\ in\ year_t(kVA) \times LRMC\ (\frac{\$}{kVA})$$

Load Profiles

Industrial customers are not currently modelled in uSim. To account for their impact on the load on a zone substation (and therefore peak demand), each zone substation starts with a balancing load. This is the real energy demand profile on that zone substation in the starting year. It is taken from network websites, except for Western Power and NT Power and Water, who do not publish this information.

In the modelled years, the aggregated demand profiles grow and adjust with the agent's growth and energy decisions. An indicative load profile of a zone substation on a peak day is shown in Figure 45. The area under the balancing load not after subtracting residential and commercial loads can be considered the load of large commercial customers.

Figure 45 – Indicative Zone Substation Load on Peak Day



Source: Energeia Modelling

B3.3 Distributed Energy Resources

In uSim, agents face a decision each year on whether to either purchase DER, or if they already have DER, augment their system. DER refers to any of solar PV, storage and diesel generators[31].

Uptake

While the agents in uSim have prefect information regarding the true value of their DER decisions, this significantly differs from reality, where consumers are often unaware of the true costs and benefits of adopting a DER system. Energeia's solution to this problem is for agents to take up DER through the real-world relationship between market uptake of DER and the payback period of DER. In the technical sense, there exists an observed relationship between the probability of a consumer choosing to purchase DER in a given year and the ROI of that decision at the time of purchase.

To quantify this relationship, Energeia constructed an Excel modelling tool that calculates the historic first-year ROI of the average[32] solar PV purchase in a particular month. The benefit of constructing the relationship at monthly intervals is that often the FiT rates can change in the middle of a year. Energeia uses the following inputs in the ROI calculation:

- % of solar PV output that is exported to the grid – calculated using NREL annual solar profiles and SGSC annual load profiles, scaled to reflect consumption in each state
- Historic Feed-in-Tariff (FiT) rates at monthly and state-level granularity – gathered from a variety of state government and industry sources
- Historic electricity retail price at monthly and state-level granularity – taken from the annual AEMC Retail Trends reports
- Historic annual solar PV system price, net of STCs zoned by each state's capital city – derived from Solar Choice
- Historic monthly average PV system size – Estimated at the state-level using APVI data

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[31] In the rare case that an agent's optimal decision is to move off-grid. Diesel generators are not available to on-grid agents

[32] The average capacity of each solar PV system purchased in a given month and state

The first-year ROI of the average solar PV system purchase is then calculated as:

$$ROI = \frac{First\ Year\ FiT\ Revenue + Electricity\ Saved\ in\ the\ First\ Year}{Capital\ Cost\ of\ Average\ PV\ System}$$

Energeia has also researched the following inputs in the market uptake calculation

- Consumer solar PV uptake per month by state and size as the market uptake
- Number of eligible dwellings as the market size – the total number of dwellings in each state, excluding rented and attached dwellings

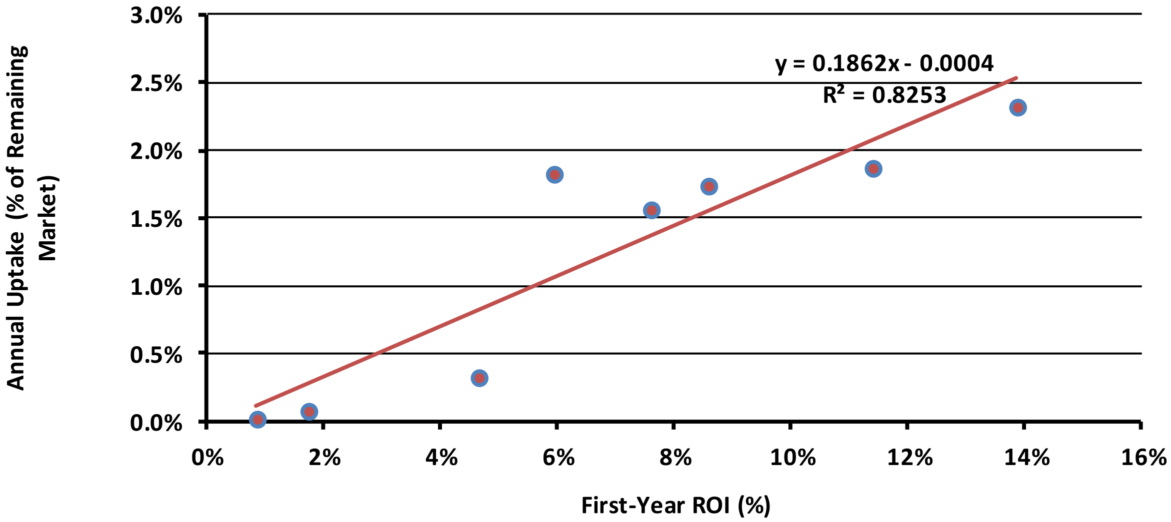
The % of uptake in a given month is then calculated as:

$$\%\ Uptake = \frac{PV\ Systems\ Purchased}{Eligible\ Dwellings\ without\ PV\ Systems}$$

The ROI and % Uptake are then annualised, and the linear relationship is then determined. The intercept and slope coefficients of the curve are then used in uSim to calculate the probability of an agent taking up their optimal DER combination. An example of the relationship is shown in Figure 46.

Note that for each state, the premium-FiT months are removed from the relationship. The customers who purchased solar PV in these periods have a level of certainty with their payback that pre and post premium-FiT customers are not privileged to.

Figure 46 – ROI vs Uptake Curve Example



Source: Energeia Modelling

Energeia applies the same uptake rate for batteries as solar PV. This is mainly due to the lack of reliable and detailed battery uptake data available in the public domain. Energeia believes that the historic uptake of solar PV and their corresponding ROI is applicable to batteries.

Solar PV

Technical

Residential and commercial agents face a separate minimum and maximum system size, as directed by AEMO's information request. The options are presented in Table 14, where Min (kW) is the smallest size solar PV system an agent can install, Max (kW) is the largest size solar PV system an agent can install and Step (kW) is the difference between each option an agent can consider. For example, a residential agent can choose between 2, 4, 6, 8 or 10 kW of solar PV.

Table 14 – Min/Max/Step Sizes – Solar PV

Class	Connection Type	Solar PV Size Min (kW)	Max (kW)	Step (kW)
Residential	On Grid	2	10	2
Residential	Off Grid	2	10	2
Commercial	On Grid	10	100	10
Commercial	Off Grid	10	100	10

Source: Energeia

The inverter is assumed to be between the solar PV and battery storage units and the house circuit. The solar PV unit can therefore charge the battery at the same time as it is exporting to the house circuit, which allows solar usage to be greater than inverter capacity. Therefore, the inverter capacity can be smaller than the output of the solar PV unit, and it is assumed the inverter limits power flowing above its capacity, rather than fully disconnecting the solar PV and battery storage system when overloaded.

For this reason, the inverter constraint is applied after the battery algorithm has run to calculate solar generation. The inverter also applies as a constraint within the battery algorithm.

Availability

Solar PV is available to agents in all modelled years, however there are two separate restrictions on agents taking up solar PV:

- Agents of attached premises (i.e. units and suites) are not allowed to take up solar PV in the model.
- Of the agents who are permitted to take up solar PV (houses and warehouses), the maximum amount of solar PV they can take up is limited by the roof-area of their premise. For example, even though the maximum available system size to a residential agent is 10kW, an agent with an 80m^2 roof can only take up a maximum of 8 kW.

The method used to model solar PV has the following limitations:

- All customers within one state have the same solar profile, which excludes the beneficial effects of geographic diversity on solar PV output. Clouds, which greatly reduce solar PV output, affect all panels within a state simultaneously
- The solar output profile source does not necessarily align to the original dates of the demand profiles that agents in the model have. In many cases, customer and network peak demand occurs on very hot, sunny days. Since the source data does not align, the network peak event may for example coincide with high cloud cover, rendering solar PV ineffective at reducing peak demand.

Financial

The associated cost to install a solar PV system comprises of multiple components. These include the capital cost of the solar PV system itself and the installation costs. Additionally, the costs of the inverter are included in these costs.

Operational costs are not applied to solar PV systems.

Energeia's solar PV costs are generated from several solar PV cost curves from reliable sources in the public domain and tested against our subject matter expertise.

Impacts

Solar PV is not controllable by its owner and is therefore unaffected by most variables once the size is determined. Due to this, solar PV is the first DER technology that is applied to the demand profile:

- A solar profile trace[33], multiplied by the size of the solar PV system, is subtracted from the demand profile. The simulation platform contains an annual solar PV output profile for each state. The same profile is applied to all residential and commercial customers and microgrids in the same state and is obtained from the actual output of a representative 1kW solar PV system. Since the profile is from an actual solar system's output, it includes the effects of seasons and weather effects such as cloud cover. Solar profiles do not change between years
- Solar PV systems do not degrade over time but have a finite life and fail immediately when the end of life is reached. However, if a solar PV system is augmented, the new system, including the capacity retained from the old system, will have the lifetime of a new system.

A solar PV system experiences degradation with usage. Energeia assumes a system degradation rate of 0.5% each year for the entire lifetime of a solar PV system.

Battery Storage

Technical

Residential and commercial agents face a separate minimum and maximum system size, to align with the treatment of solar PV in the model. The options are presented in Table 15 where Min (kWh) is the smallest size storage system an agent can install, Max (kWh) is the largest size storage system an agent can install and Step (kWh) is the difference between each option an agent can consider.

Table 15 – Min/Max/Step Sizes – Battery Storage

		Battery Storage Size		
Class	**Connection Type**	**Min (kWh)**	**Max (kWh)**	**Step (kWh)**
Residential	On Grid	8	32	8
Residential	Off Grid	8	32	8
Commercial	On Grid	16	80	16
Commercial	Off Grid	16	80	16

Source: Energeia

Unlike Solar PV, battery storage is available to all agents in all modelled year, regardless of premise type. This is because there is no consistent physical constraint to installing a battery storage system like there is with rooftop solar PV, which requires the premise to have a rooftop.

This then implies that it is possible for agents in our model to install a storage system without solar PV and arbitrage with cost reflective pricing, charging from the grid during times when the retail price is low, and discharging to avoid high retail costs.

Financial

Similar to solar PV costs, the overall installed capital cost of a battery includes the cost of balance of systems and installation costs. Inverter costs are applied separately only if the customer does not already possess an inverter.

Energeia does not apply any maintenance costs to operating the battery.

Energeia's battery cost curves are again produced based on publicly available and reliable battery costs together with Energeia's subject matter expertise.

[33] Energeia uses a 2013 state-based solar PV trace from north-facing per unit sized solar PV panels sourced from PVWatts (available here https://pvwatts.nrel.gov/).

Impacts

Batteries are used to increase the value of solar PV generation and to arbitrage tariffs by shifting the battery owner's grid demand to times when retail electricity prices are lower.

Batteries have a set of characteristics that limit their ability to complete their objectives:

- **Depth of Discharge** – The depth of discharge (DoD) of a battery is the maximum percentage of the battery's rated capacity that can be used. A battery with a rating of 1kWh and a 90% DoD can be discharged to a minimum level of 0.1kWh. At this point the battery must be recharged. This is a built-in feature by the manufacturer of the battery that improves the lifetime of the battery. Discharging to very low levels has a greater effect on the battery's degradation. However, the manufacturing cost of a battery is driven by the total capacity, which is a function of the volume of materials that go into the final product
- **Output Limits** – Batteries are constrained by how quickly they can be charged or discharged. Higher rates of charging or discharging generate additional heat and degrade the battery faster. The charging and discharging limit are measured by *c*, which is the number of times a battery can be discharged in one hour. For example, a battery with *c*=0.5 can be discharged fully in two hours. In the simulation, the same constraint is applied to both charging and discharging for a battery
- **Losses** – In the simulation, batteries incur losses during charging and discharging. The rate of losses can differ for charging and discharging, but does not vary based on the rate of charging of discharging. These factors are an input into the simulation and can be set uniquely for each battery variant
- **Battery Degradation** – Battery degradation is an important factor in determining the NPV of purchasing a battery. Unlike other DER technologies in the simulation platform, batteries degrade each year. Other DER technologies have a constant maximum capacity/output over their lifetimes and then fail immediately when they reach the end of their lives. Batteries do not have an end of life failure, they continue to operate indefinitely, albeit with a lower level of capacity

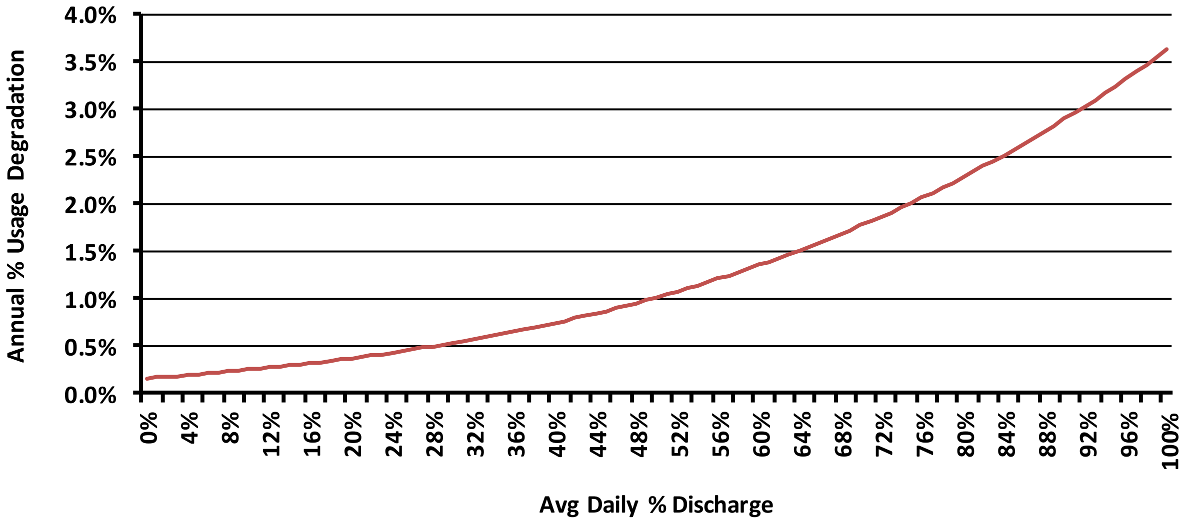
  Battery degradation is a factor of two effects, calendar degradation and cycle degradation.

  - *Calendar Degradation* – A decrease in capacity because of age, which is applied as a percentage reduction in remaining capacity at the end of each year.
  - *Cycle degradation* – Cycle degradation is caused by battery use and is dependent on the total amount of use the battery gets and how much of its capacity is discharged in a single cycle, as shown in Figure 47.

    A battery that is discharged fully each time it is used will degrade faster than a battery that cycles constantly between 90% and 100% of capacity. Cycle degradation is calculated for each charge, discharge cycle and summed across each year to calculate total degradation as a percentage of initial capacity.

    Since batteries degrade over time and do not have a finite lifetime, they are assigned a lifetime for the purposes of calculating the net present value (NPV) and payback of a battery purchase. This brings them into line with other DER technologies. The battery lifetime is the number of years until the battery is expected to degrade to 70% of its initial capacity. This is calculated by assuming the battery will degrade at the same rate every year as it did in the first year it was purchased.

Figure 47 – Rate of Cycle Degradation



Source: Energeia Modelling

The method used to model batteries has the following limitations:

- Each battery variant has the same *c*[34] for all sizes, which means the model will prefer purchasing a larger capacity battery when the customer needs a battery with a faster rate of discharge
- Only one battery variant is available to each customer class in the simulation so customers are not able to select between different battery characteristics that may be more optimal for a given situation
- There are additional technical factors that affect battery degradation, such as heat and the rate of charging and discharging, that are not incorporated into the degradation calculation
- The degradation calculation always assumes the battery is discharging beginning at 100% but actual degradation depends on how much the battery discharges and the levels the battery is discharging between. For example, a battery cycling between 20% and 30% will degrade more than a battery cycling between 45% and 55%
- Battery lifetime is calculated using a simplified assumption of constant degradation over time. However, degradation will vary over time as the discharge profile of the battery changes. The cause of this variation is due to customer demand changes, other technology purchases and previous degradation of the battery affecting how the remaining capacity can be used.

The battery algorithm determines when the battery charges and discharges. The inputs to the algorithm are:

- The characteristics of the battery
- The size of the inverter
- A demand profile
- A tariff

The battery algorithm aims to lower the battery owner's bill as much as possible by taking advantage of arbitrage opportunities present in the tariff. The algorithm runs across all battery sizes and the battery size associated with the highest NPV is selected.

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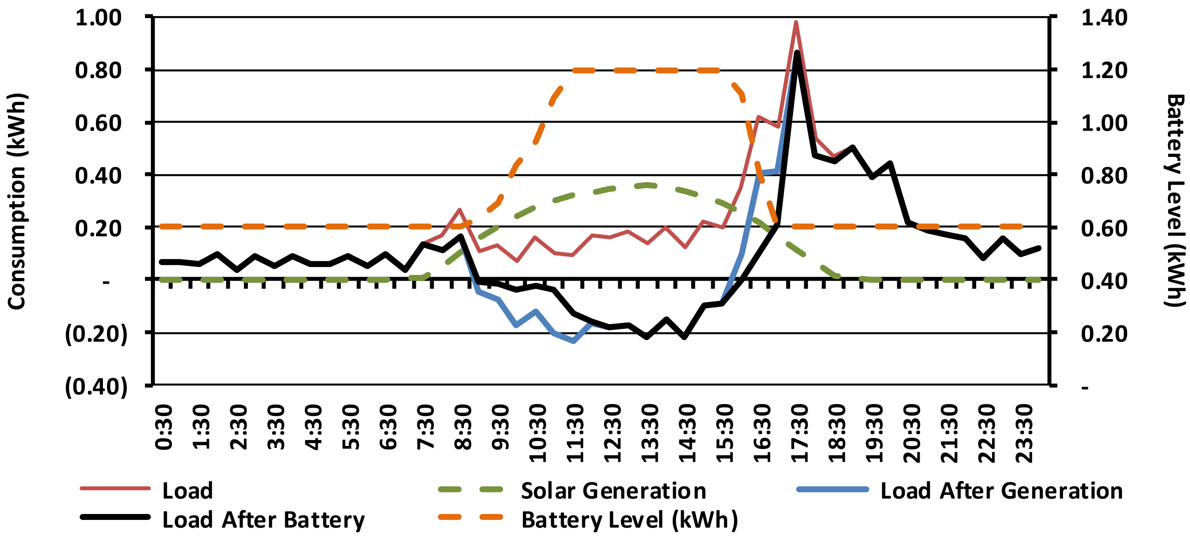
[34] A C-rate is a measure of the rate at which a battery is discharged relative to its maximum capacity. A 1C rate means that the discharge current will discharge the entire battery in 1 hour.

The battery algorithm works within the physical constraints of the battery and the inverter. The battery is not allowed to charge or discharge at a rate greater than the inverter size, unless it is charging from solar PV, when it is constrained only by the physical charge limit of the battery. This is because both systems are assumed to be 'behind' the inverter and can operate in DC to DC.

The battery algorithm achieves a near perfect optimisation. There is a trade-off between a perfect optimisation and processing time, which has meant a perfect optimisation has not been used in certain situations. However, for the clear majority of tariffs the algorithm achieves a perfect optimisation.

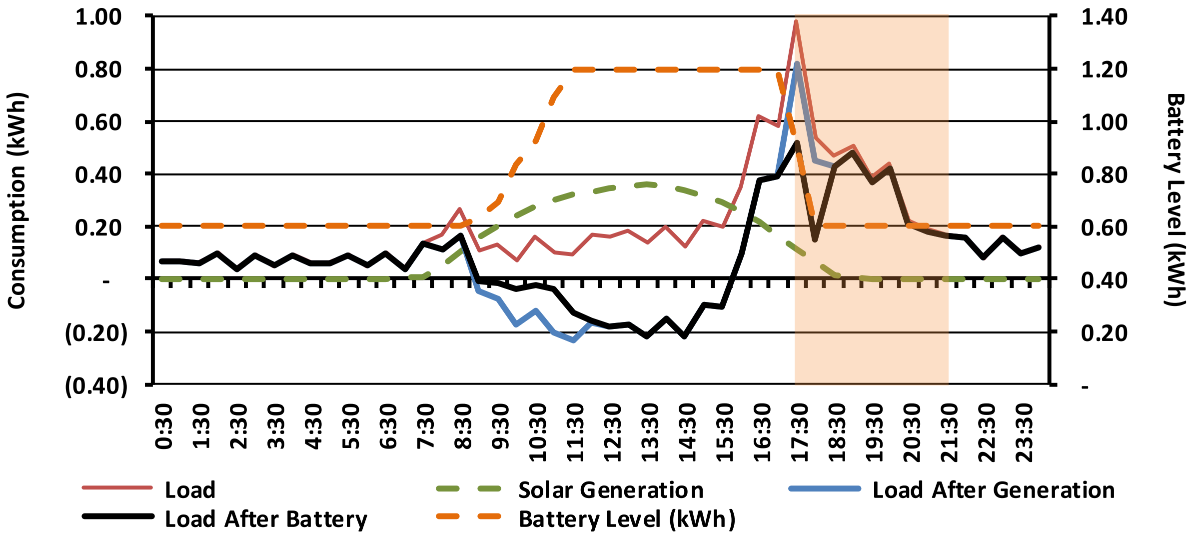
The algorithm is built based on the battery having perfect foresight of the owner's demand. This means the results of the battery algorithm (excluding a less than perfect optimisation as discussed above) set an upper limit for the savings achievable by a battery in a real-world situation. Figure 48, Figure 49 and Figure 50 show how the battery algorithms change depending on the tariff and technology choice. These are further detailed below.

Figure 48 – DER Impact on a Customer Load Profile on a Flat Tariff (Indicative)



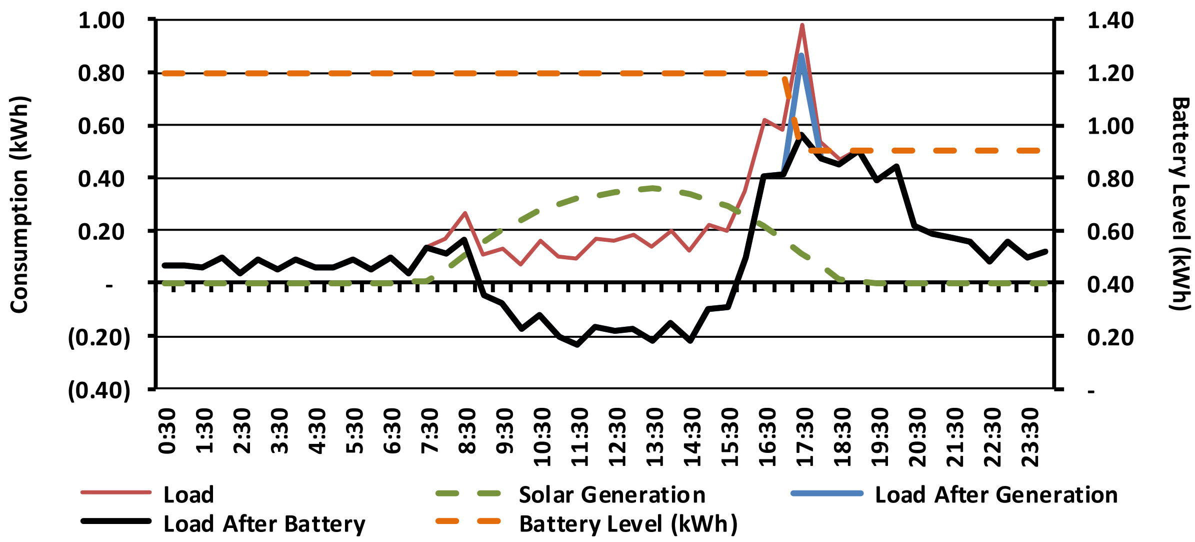
Source: Energeia

Figure 49 – DER Impact on a Customer Load Profile on a Time-of-Use Tariff (Indicative)



Source: Energeia. Note: The orange shaded area represents the peak period within the Time-of-Use tariff.

Figure 50 – DER Impact on a Customer Load Profile on a Max Demand Tariff (Indicative)



Source: Energeia

The algorithm will reduce a customer's retail electricity bill, starting with the most valuable action and progressing to lower value actions. A high value action is usually discharging in response to a peak mechanism in a tariff, such as clipping demand spikes in response to a maximum demand charge. Lower value actions include arbitraging price differentials for a time of use energy charge, charging during the off peak and discharging during the peak period and then possibly during the shoulder period.

The battery algorithm will charge the battery during the lowest cost period without triggering an increase in the peak demand charge (if any). This is often when there are solar PV exports which have a minimal cost to the customer of the foregone FiT revenue which would otherwise be received for exports.

The battery algorithm has the following limitations:

- All customers have the same algorithm effectively eliminating diversity. Large numbers of customers will charge at the same time, potentially causing new peak demand events

Appendix C – evSim Modelling and Assumptions

Energeia's Electric Vehicle (EV) uptake and charging impact forecasting methodology is outlined below, together with the key model inputs and drivers.

C.1. Overview

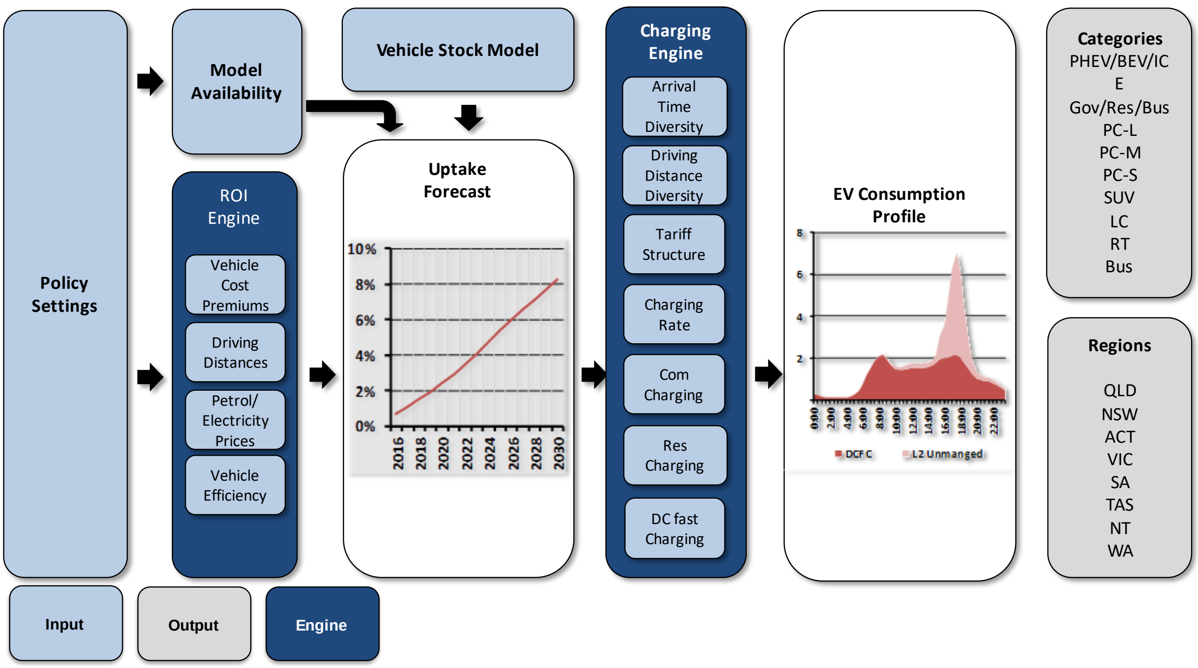
Energeia has developed, configured, and operated its EV simulation platform, evSim, to model the influence of various market and policy settings to influence electric vehicle uptake in Australia on a scenario basis. The developed modelling platform:

- is based on two-stage structure, with vehicle uptake forecast first, driven by the first year return-on-investment of the vehicle buying decision, and with charging impacts second, driven by driving patterns, tariff structures and load control methods.
- was developed progressively over the course of our forecasting work with AEMO, various Australian government bodies, and various DNSPs and retailers
- reflects enhancements (vehicle lifetimes, residential uptake segmentation, additional plug-in hybrid vehicle classes and technology uptake allocation) delivered in this round of modelling

C.1.1. Structure of the Model

evSim is a regression-based model that forecasts the technology composition of the vehicle sales market over the modelling period and determines electric vehicle charging impacts on the broader electricity system. A summary of the model process and structure is supplied Figure 51.

Figure 51 – Overview of EV Simulation Platform



Source: Energeia

evSim operates across a range of different functions, through a two-stage process first forecasting electric vehicle uptake then the charging impacts. The key modules include:

- **Uptake Module** – Comprised of the Return on Investment Engine (Calculates return on investment for purchasing a battery electric vehicle (BEV) or plug in hybrid (PHEV) for each of the vehicle categories considered) and a vehicle stock engine that models fleet growth and replacement.

- **Vehicle Charging Engine** – The charging behaviour and annual consumption of the forecast electric vehicle is calculated using both a managed and unmanaged case to determine the effect on peak demand

The functions and sub-functions of each of the above modules of the simulation platform are summarised below, including a high level of overview of interactions between different parts of the model, limitations of assumptions and their impact on modelling.

C.1.2. Methodology Selection

Over the course of more than 10 EV-related projects for major utilities, governments, and EV market players, Energeia has developed a suite of sophisticated tools and methodologies for answering the key questions facing our clients.

- **EV Uptake Modelling Tools** – Energeia's third-generation EV uptake model reflects more than $500K in investment. It is two generations more advanced than the typical Bass Diffusion models used by our competitors. Its advanced functionality is designed to deliver a much more accurate forecast with more driver and vehicle type granularity and scenario flexibility.
- **EV Charging Impact Modelling Tools** – Based on 7 years of specialised research and analysis of the PEV and charging market and technology evolution, Energeia has developed its own proprietary model of public and private charging. It reflects our view that PEV batteries are likely to reach 100 kWh or more over the next 3-5 years to achieve parity with gasoline-powered vehicles, and that public charges will be 350kW or more so that recharging will also reach parity with gas stations. It also reflects our view that most PEV drivers will charge at home, and the market for public charging will follow the gas station model but be smaller due to the impact of home charging.

C.1.3. History of Recent Model Development

Energeia's evSim has been progressively developed over the past 4 years, in that time three public forecasts have been released.

- **AEMO 2016** – This model was primarily focussed on assessing simple policy impacts such as fuel efficiency standards, introduction of priority lanes and a carbon price[35]. The charging of electric vehicles was only segmented by tariff structures (flat and controlled load) for residential customers with DC fast charging (DCFC) not being directly modelled.
- **AEMO 2017** – The next iteration of the model introduced the DCFC segment and further developed the vehicle charging behaviour engine[36]. Level 2 charging was controlled by an algorithm optimising the fleet of EV's to charge outside of system peak periods.
- **CEFC and ARENA 2018** – Additional policy inputs and drivers were implemented to the uptake model in 2018[37] which allowed for greater flexibility in determining technology outcomes given the high level of influence policy has on emerging technologies. These improvements included financial incentives, the possibility of additional negotiated models for sale in Australia, consideration of overseas importation policy and the segmentation impacts of charging infrastructure rollout.

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[35] AEMO (2016), 'Electric Vehicle Insights'

[36] AEMO (2017), 'Electric Vehicle Insights'

[37] CEFC (2018), 'Australian Electric Vehicle Market Study'

C.1.4. Current Application

This iteration of the model had the following enhancements developed and integrated:

- **Changing Vehicle Lifetimes –** Electric vehicle total effective lifetimes are highly uncertain currently and were modified to increase to reach parity with ICE vehicles as technology improvements are developed as previous iterations of the model had tied BEV lifetime the vehicles battery warranty (10 years).
- **Residential Uptake Segmentation –** In the early years of the modelling period the potential annual sales market for uptake of BEV's is limited by residential customer access to level 2 charging at home, those without access can uptake as public charging networks are rolled out nationwide.
- **Plug in hybrid additional vehicle classes –** As more plug in hybrid models have become available, they have been added to each vehicle class for uptake consideration.
- **Alternative Vehicle Technology Uptake Allocation –** Vehicle classes with multiple technology options for uptake (BEV and PHEV) are weighted by the magnitude of their uptake function result. This caps the number of alternative vehicle purchases in each year to ensure technology types are not overrepresented.

C.2. Model Process and Modules

The EV modelling process is a two stage process, where EV uptake is forecast first, and then charging impacts are developed.

C.2.1. Process

Energeia's EV forecasting model is comprised of two parts, namely EV uptake and EV charging:

- **Uptake Module –** The EV uptake component drives the forecasts of EV uptake as a percentage of annual vehicle sales for each category of vehicle type. This is based on vehicle model availability and the vehicle owner's return on investment.
- **Vehicle Charging Engine –** The EV charging component then applies a charging regime to each vehicle adopted based on the arrival and departure time of the vehicle at the point of charge, the number of kilometres travelled and any incentives or restrictions of the prevailing tariff.

C.2.2. Modules

Each of the two modules, the uptake forecasting and system size segmentation modules, are detailed in the following sections together with the applied post-model adjustments.

Uptake Module

The uptake module considers eight categories of vehicle types with their own specific characteristics which drive both uptake and charging, including purchase premium, energy consumption per km[38], and battery size. EV uptake is determined by a two-parameter function that describes vehicle uptake over time based on:

- **Return on Investment –** the first-year return to the vehicle owner investing in an EV in terms of reduced operational costs (fuel savings) on the premium paid compared to a conventional ICE vehicle.
- **Model Availability –** the percentage of models within a given vehicle class available in EV form.

This functional form accordingly considers the supply side constraints (lack of model availability) as well as demand-side drivers (reduced operational costs) in the vehicles owner's decision to adopt. The function is

[38] Fuel costs and average daily driving are based on state level factors.

derived from analysis of the diesel vehicle and hybrid electric vehicle markets in Australia whereby uptake can be explained by a combination of both these parameters.

The forecast uptake of EVs (both BEV and PHEV) is then fed into your vehicle stock model, which accounts for the turnover of the existing fleet and new vehicle purchases due to population growth

Uptake Function

EV uptake is determined by a two-parameter function that describes vehicle uptake over time based on:

1. EV premium payback more than two years:

$$EV\ Uptake_t = Total\ New\ Vehicle\ Sales_t * (a_t \times ROI_t + b_t \times Model\ Availability_t)$$

2. EV premium payback less than two years (tipping point):

$$EV\ Uptake_t = Total\ New\ Vehicle\ Sales_t *\ MIN(Upper\ EV\ Limit, Model\ Availability_t)$$

Where:

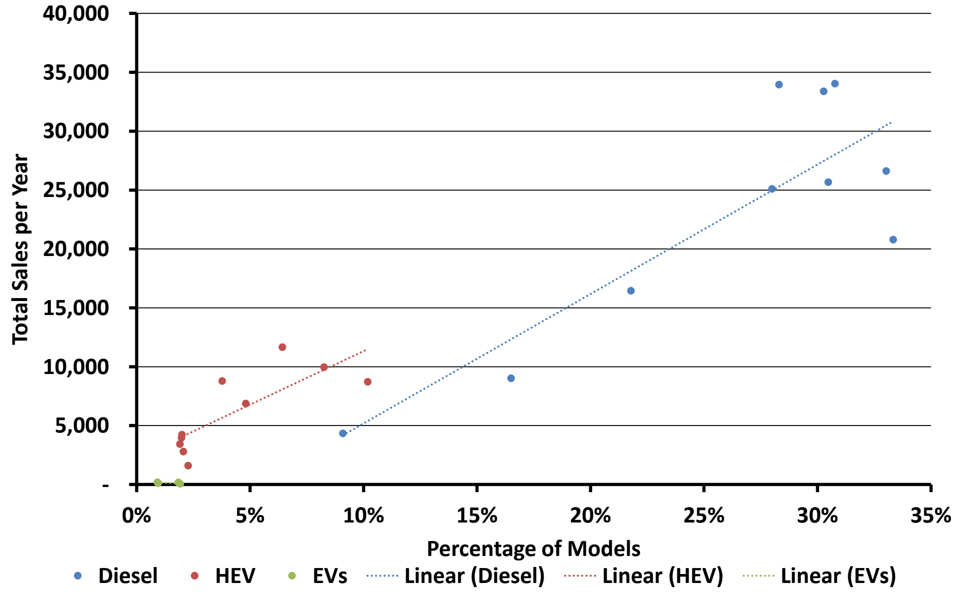
- $Total\ New\ Vehicle\ Sales_t$ = Total new vehicle sales within a given vehicle class in year t
- $Model\ Availability_t$ = Percentage of models within a given vehicle class available in EV form in year t. This inclusion of this factor reflects that, for the mass market, a primary driver of vehicle purchase is the availability of that model in EV form. This factor effectively places an upper bound on EV adoption, which is determined by a scenario based parameter.
- $Upper\ EV\ Limit$ = Upper model availability limit for all vehicles within a given vehicles class
- ROI_t = The first-year return on investment for the vehicle owner investing in an EV in year t in terms of reduced operational costs (fuel) and premium paid compared to the equivalent ICE vehicle
- a_t = Model coefficient derived from historical data of diesel and hybrid electric vehicle uptake for observed ROIs
- b_t = Model coefficient derived from historical data of diesel and hybrid electric vehicle uptake for observed model availability

EV uptake depends on the functional form assumed for model availability and change in ROI over time. It should be noted that Energeia's ROI calculation does not consider step changes in depreciation or salvage value due to increasing EV penetration.

Return on Investment (ROI)

The historical relationship between vehicle uptake and model availability in the Australia market for alternative technologies is shown in Figure 52.

Figure 52 – Relationship between EV Uptake and Model Availability



Source: Energeia

Each year for each vehicle category the return on investment of purchasing an alternative fuel vehicle is calculated (BEV or PHEV):

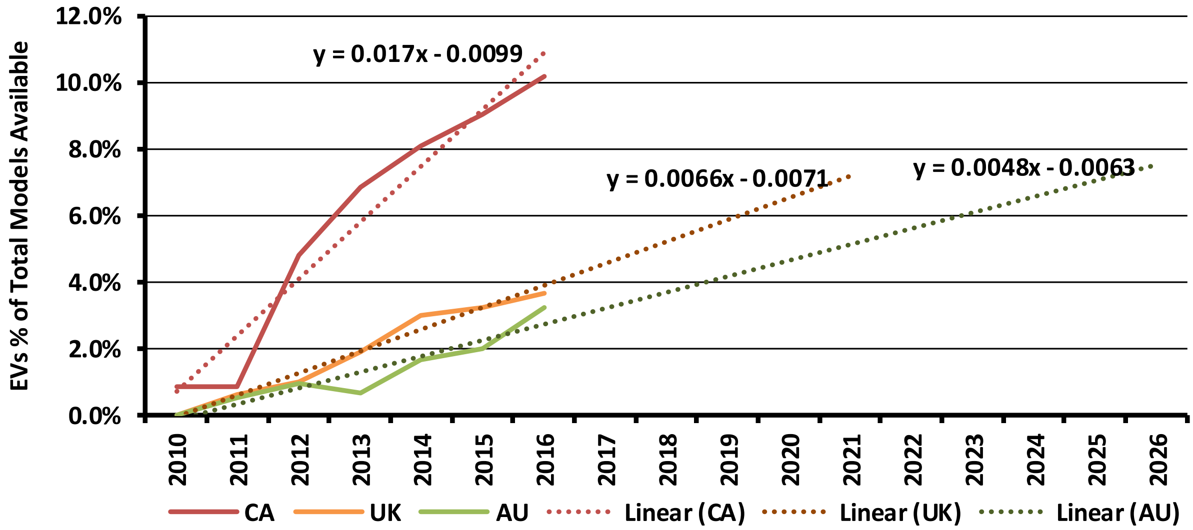
- This considers the annual average distance travelled by each vehicle category and calculates the total fuel consumption (electric or petrol) of the vehicle.
- The annual cost of the vehicle is then calculated and the return on investment for each vehicle type is reported.

Model Availability

Model availability determines the capability for a decision to purchase a vehicle to be a BEV. For BEV and PHEV uptake to be considered in a purchasing decision there must exist an equivalent model to an ICE in that vehicle category. The model availability forecast in the model captures the rate in which new vehicles are developed by OEMs and introduced to the market as competitors to existing ICE models.

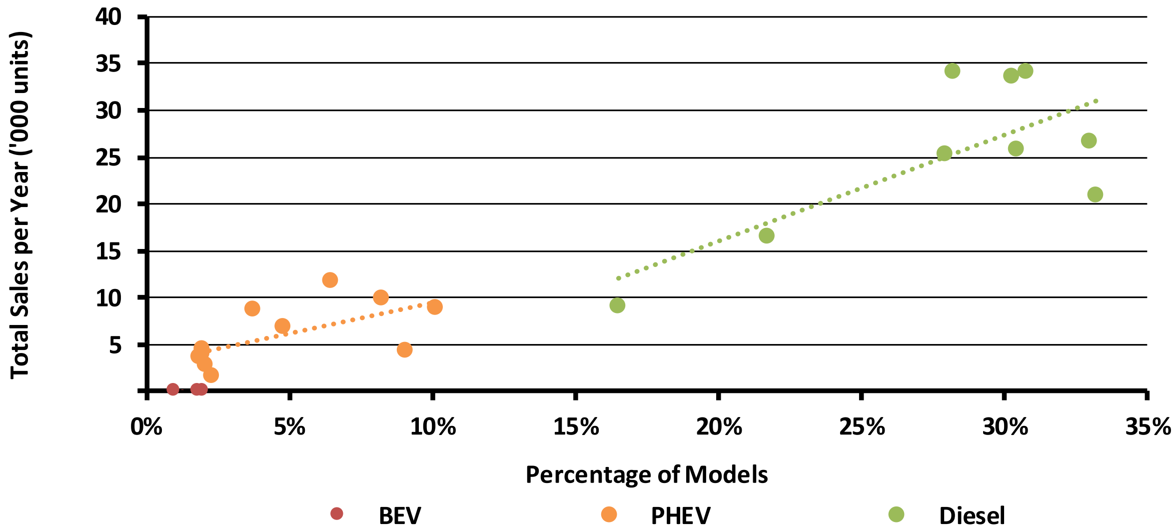
Energeia has developed its assumed rate of EV model availability based on an empirical analysis of model availability relative to the level of jurisdictional incentives. Figure B3 displays the results of our analysis of the UK, California and Australian markets. It shows that California, the market with the highest EV incentive at around $10,000 USD including Federal incentives, sees the fastest rate of new EV model introductions. The UK market, which offers around $5,000 USD in incentives, is higher than virtually incentive-free Australia.

Figure 53 – EV Model Availability by Year by Key Market



Source: Energeia

Figure 54 – Relationship between EV Uptake and Model Availability



Source: VFACTS, Energeia

Vehicle Stock Engine

Each year the annual vehicle sales are determined through the model's vehicle stock engine, which accounts for the turnover of the existing fleet and new vehicle purchases due to population growth. The mechanics of the engine is detailed is the equations below:

$$ICE_t = \sum^{i,j} \Big[ICE_{i,j(t-1)} + (Vehicle\ Sales_{i,j(t)} - EV\ Uptake_{i,j(t)}) - \text{if}\Big(t \le AvgLifetime\,, \frac{ICE_{i,j(0)}}{AvgLifetime}, 0\Big)\Big]$$

$$EV_t = \sum^{i,j} \left[EV_{i,j(t-1)} + EV\ Uptake_{i,j(t)} - \text{if}\left(t \leq AvgLifetime\,, \frac{EV_{i,j(0)}}{AvgLifetime}, 0\right)\right]$$

Where:

- ICE_t = Total stock of ICE vehicles in year t
- EV_t = Total stock of EV vehicles in year t
- ICE_0 = Opening stock of ICE vehicles
- $EV0$ = Opening stock of EV vehicles
- $ICE_{i,j(t-1)}$ = Stock of ICE vehicles in market i in class j in year t-1
- $EV_{i,j(t-1)}$ = Stock of EV vehicles in market i in class j in year t-1
- $EV\ Uptake_{i,j(t)}$ = % EV sales in market i in class j in year t
- $Vehicle\ Sales_{i,j(t)}$ = Vehicle sales in market i in class j in year t
- $Average\ Lifetime$ = Average vehicle lifetime

Vehicle Charging Engine

Energeia has developed a detailed, data-driven approach to forecasting the likely impact of EV charging on electricity demand, energy resources, and network assets. This approach is driven by the assumed rate structure and level, historical EV adoption patterns, driving patterns, charging infrastructure availability, and the availability of charging management systems.

Energeia's EV demand model is grounded in actual travel statistics, which drive when EVs are likely to be plugged in (arrival times), and the total energy they need to replenish (distance), and when any smart charging will need to have been completed by (departure time).

The EV charging module then applies a charging regime to each vehicle adopted based on its:

- charging type,
- arrival and departure time for home and workplace charging or transportation profile for DCFC,
- the number of kilometres travelled and
- grid load to optimise workplace and home charging.

The EV charging profile is determined by aggregating the unique charging profile of each individual electric vehicle adopted. The individual profiles are assigned based on:

- Whether the vehicle is assigned as L2 (9.6kW) home charging, L2 commercial charging (charges at work or depot location), or DCFC which is defined as the EV equivalent of a gas station (Charger rating up to 1MW station with 5 min charge time at the end of the modelling period)
- DCFC chargers enable drivers without a garage to own an EV, encourage EV charging during daytime hours of excess supply from solar PV, and extend EV range to enable EV use for any trip type
- The daily travel distance for both weekday and weekend travel (drawn from a database of regionally specific diversified travel distances[39]), which determines the amount of charge to be supplied by day type

[39] ABS Survey of Motor Vehicle Use (2016)

- An arrival time for both weekday and weekend travel (drawn from a database of diversified times specific to either home charging or commercial charging[40]) which dictates when charging starts, in the absence of any other tariff restrictions
- A departure time for both weekday and weekend travel (drawn from a database of diversified times specific to either home charging or commercial charging) which dictates when charging must cease in the absence of any other tariff restrictions
- For home and workplace charging, the optimal EV weekday and weekend demand profile for a given state to minimise whole-of-system cost
- For DFCF charging, the weekday and weekend DCFC demand profile is based on the weekday and weekend transportation demand profile, no demand management of DCFC load is assumed
- No vehicle-to-grid exporting of electricity from the vehicle to the grid is assumed

C.3. Inputs and Drivers

The inputs of evSim can be split into two categories:

- **Scenario Drivers** – These inputs are configurable by scenario and used to test macroeconomic outlooks, technology assumptions and policy settings.
- **Common Assumptions** – These inputs are typically static between scenarios and underpin the operation of the model and sub-models

C.3.1. Scenario Drivers

evSim can be configured with a number of scenario drivers to test different policy and industry settings on electric vehicle uptake. These drivers impact on the vehicle fleet size, the economic, technical and operational characteristics of the available vehicles by technology type, the financial incentives available to non-ICE vehicles, the availability of non-ICE models and the relative operating costs by technology type.

[40] Queensland Household Travel Survey (2017)

Table 16 – Configurable EV Specific Scenario Drivers AEMO (2019)

Category	Driver	Impact	Slow Change	Neutral 26%	Fast Change
Vehicle Fleet	Population Growth	Population growth underpins the vehicle stock engine that determines the fleet size over time.	Slow Change	Neutral	Fast Change
Vehicle Characteristics	Average Vehicle Lifetime (Years)	Relationship of future fleet replacement rates to current vehicle lifetimes	18	18	18
	EV Vehicle Price Parity (excl. Battery) in Years	Drives cost of ownership by reducing current differentials not explained by battery costs.	7	5	3
	EV Distance Parity (Years)	Drives cost of ownership by increasing size of battery and therefore costs.	7	5	3
	Battery Prices (CAGR)	Drives EV cost of ownership.	-8.00%	-8.00%	-8.00%
Financial Incentives	EV Policy Incentives ($)	Used to improve EV cost of ownership. Includes indirect subsidies, e.g. from vehicle energy efficiency standards.	$0	$0	$2,000
	EV Industry Incentives ($)	Used to improve EV cost of ownership. Includes upfront direct incentives.	$0	$0	$1,000
	Year Policy Incentive Applies	Determines when the incentive is applied.	Never	Never	2019
	Year Industry Incentive Applies	Determines when the incentive is applied.	Never	Never	2019
Model Availability	Additional Negotiated Models	Drives uptake model via availability coefficient. Focuses on volume for model strategy.	0	3	6
	Overseas Importation Policy	Increases model availability	Never	2022	2019
Operation Costs	Petrol Price	Drives relative economic performance of BEV and PHEV relatives to ICE	Slow Change	Neutral	Fast Change
	Retail Electricity Price	Drives relative economic performance of BEV and PHEV relatives to ICE	Slow Change	Neutral	Fast Change

Source: Energeia Modelling

C.3.2. Scenario Inputs

The majority of the scenario inputs are focused on the uptake module, as the only scenario available the vehicle charging engine is between managed and unmanaged charging.

Uptake Module

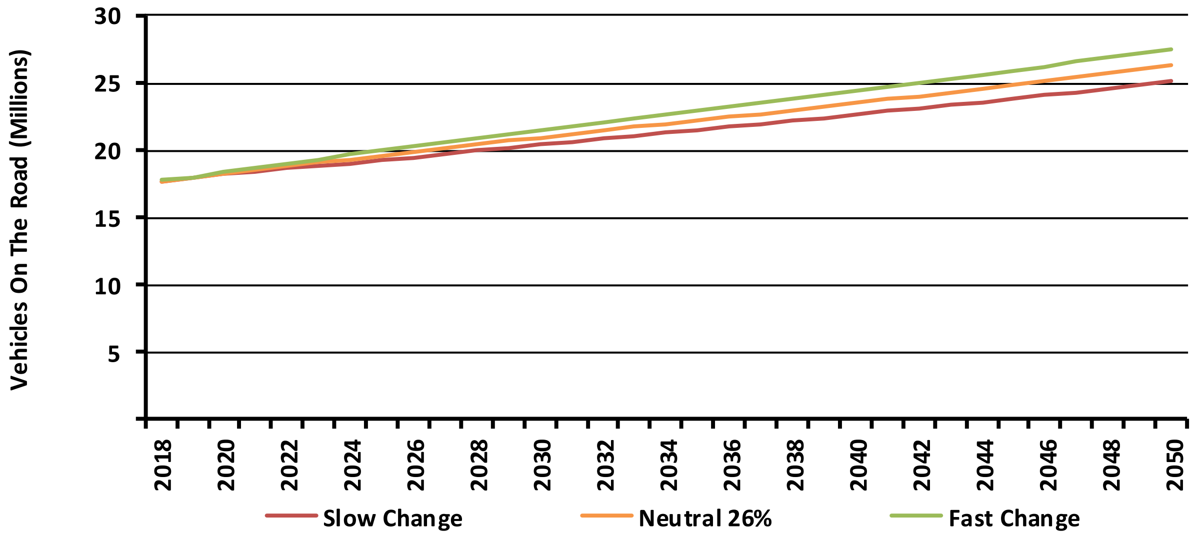
Energeia's uptake module is driven by a range of different scenario inputs that:

- Vehicle Fleet (population growth)
- Vehicle Characteristics (convergence of ICE and BEV/PHEV lifetimes over time; BEV/PHEV distance and price parity; battery cost declines)
- Financial Incentives (policy and industry incentive levels and starting years)
- Model Availability (additional models, importation policy)
- Operation Costs (refuelling and charging costs

Vehicle Fleet

Each year, each vehicle class in their respective market is assumed to grow at a constant rate per capita based on input population growth forecasts of low, neutral and high. Scenarios can be configured to test multiple population growth sensitivities which drive vehicle sales growth over the modelling period. This will determine the max market for vehicle sales in each year and the final vehicle fleet numbers for Australia.

Figure 55 – Total Vehicle Fleet Outlook (AUS)



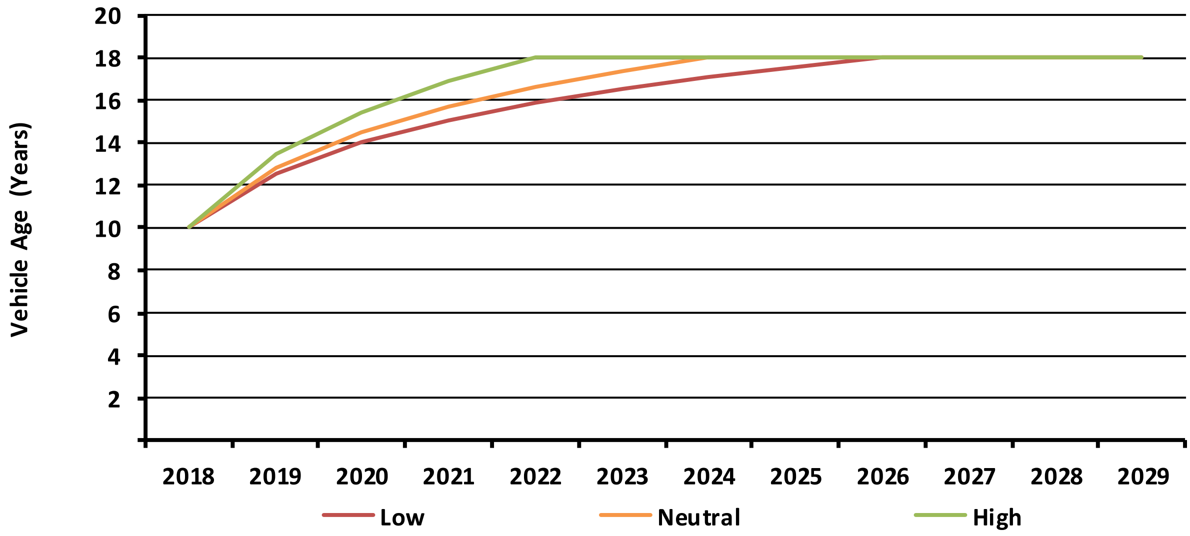
Source: Energeia Modelling

Average Lifetime

Average vehicle lifetime of all ICE vehicles is assumed to be 18 years based on ABS data[41], while the average vehicle lifetime of all EVs are assumed to be 10 years in 2019, extending to ICE equivalence at different trajectories based on the scenario configuration.

The EV uptake module forecasts EV uptake for each category of vehicle using vehicle model availability and the vehicle owner's return on investment as inputs. The forecast is allocated on a pro-rata basis to each state

Figure 56 – BEV Vehicle Lifetime Trajectory



Source: Energeia Modelling

[41] ABS 9208.0 - Survey of Motor Vehicle Use, Australia, 12 months ended 30 June 2016

Vehicle Capital Cost Curves

The vehicle purchase price is broken down into two components in the model as shown in Table 17. These costs determine the overall purchase premium of the vehicle which is used to calculate the annual return on investment of ownership.

Table 17 – Capital Cost

Cost Component	ICE	BEV	PHEV
Balance of System	✓	✓	✓
Battery		✓	✓

Source: Energeia Modelling

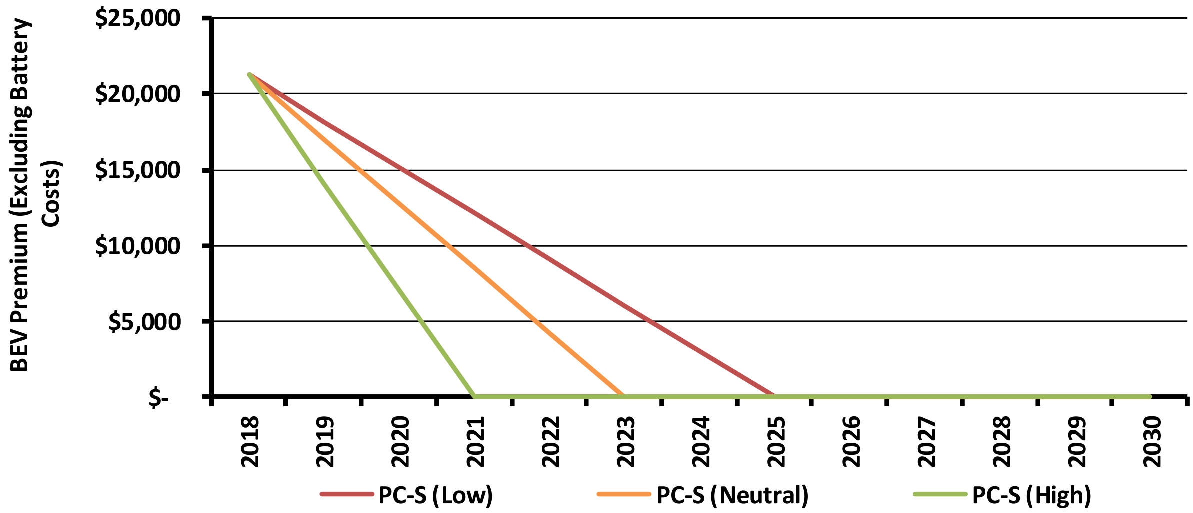
Electric vehicle premiums for each vehicle class are calculated based on currently available vehicles and their ICE equivalent. The premium is calculated from the balance of system of a vehicle, which encompasses all the components of the vehicle other than the EV batteries.

Table 18 – Estimated Current EV Premiums

Vehicle Class	Vehicle Technology	EV Premium	EV Premium (% of Total EV Cost)
Passenger Car Small	BEV	$ 21,237	31%
Passenger Car Medium	BEV	$ 22,886	57%
Passenger Car Large	BEV	$ 28,415	21%
Passenger Car Medium	PHEV	$ 6,100	8%
Passenger Car Large	PHEV	$ 9,371	3%
Sport Utility Vehicle Medium	BEV	$ 21,996	37%
Sport Utility Vehicle Large	BEV	$ 21,250	14%
Sport Utility Vehicle Medium	PHEV	$ 14,282	37%
Sport Utility Vehicle Large	PHEV	$ 30,374	20%
Light Commercial	BEV	$ 3,619	8%
Rigid Truck	BEV	$ 19,353	18%
Bus	BEV	$ 339,622	40%

Source: Energeia Research, OEM Websites

Figure 57 – Indicative BEV PC-S Premium Decline Trajectory (Excluding Battery Costs)



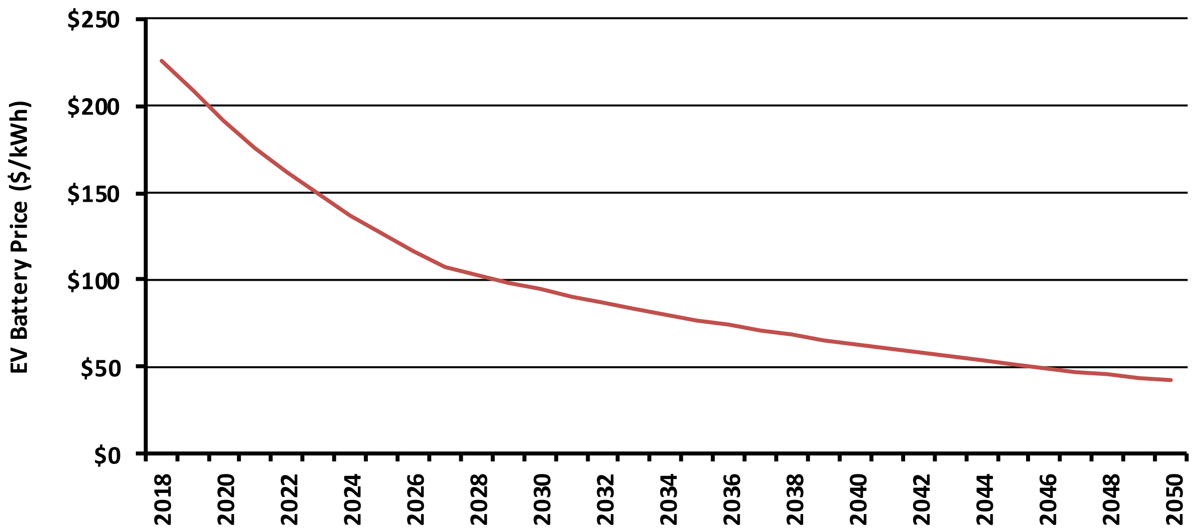
Source: Energeia Analysis

Battery Price

Energeia's short and medium-term battery price outlook is a function of expected improvements in lithium-based battery manufacturing and economies of scale, while the long-term battery price outlook is based on next generation storage technologies that will achieve higher energy densities with significantly less raw material.

The model assumes a decline in lithium battery prices over the modelling period leading to the battery cost projection shown in Figure 58. This forecast is based on a consensus average among leading international lithium battery price forecasters. This setting is configurable by scenario and the cost is applied to all vehicle sizes.

Figure 58 – EV Battery Cost Forecast



Source: Energeia Analysis, Mckinsey (2017) Electrifying Insights, Bloomberg New Energy Finance (2016), US DOE (2017), Tesla (2017)[42]

Incentives

Proposed government and industry incentives can be applied to the model to influence the economics of purchasing an electric vehicle through both direct financial incentives and indirect incentives.

Model Availability

The model enables the procurement of additional models to be available for sale in selected years, this allows for government or industry intervention to increase model availability which will increase the resultant annual uptake of electric vehicles in early years of the model. An assumed trajectory of model availability in Australia is a key input for each scenario.

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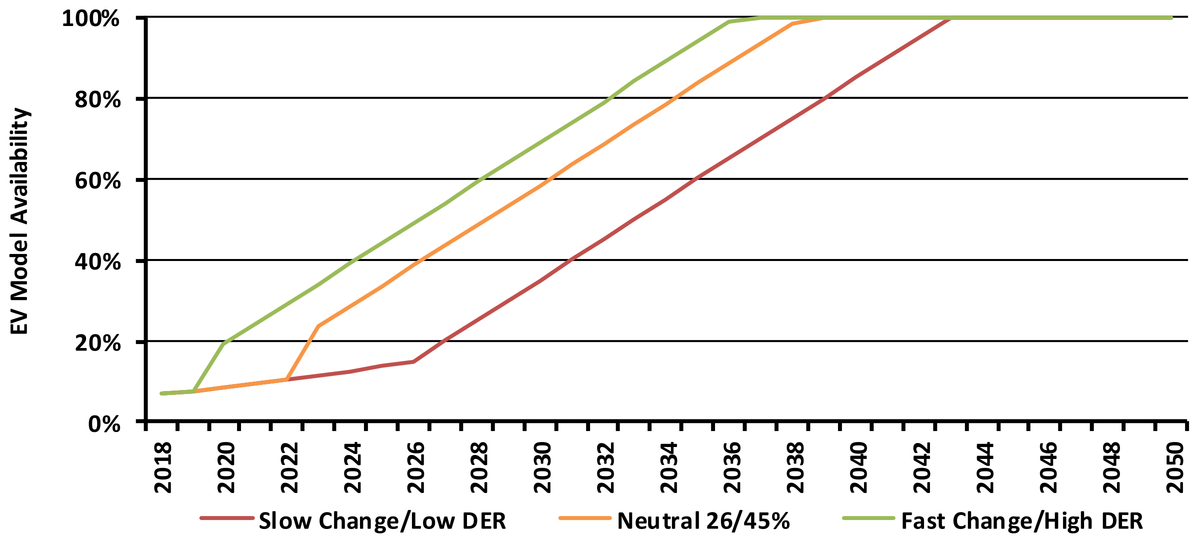
[42] Reported Tesla EV battery pack prices on kWh basis

Figure 59 – Model Availability Forecast AEMO (2019)



Source: Energeia Analysis

Operating Costs

Maintenance costs are not implemented in Energeia's EV model due to their minimal impact on a customer's purchase decision in part as a result of the warranty of new vehicle purchases.

Petrol and electricity costs can be input to the model for each scenario and region being modelled. Three fuel price scenarios can be configured at a time allowing for testing of a range of sensitivities.

- **Petrol Costs** – Energeia used petrol price forecasts from CEFC's 2018 Australian EV Market Study as shown in Table 19. These were developed using historical relationships between the price of petrol and the oil price, which are then projected using the scenario assumption for oil prices. These do not change by scenario.
- **Electricity Costs**– Retail electricity prices are an essential input to the model and scenario design. Three different price trajectory scenarios can be configured into the model to influence the annual fuel costs for electric vehicles.

Table 19 – Fuel Price by State

Year	WA	QLD	SA	TAS	ACT/ NSW	VIC
2017	$1.15	$1.15	$1.14	$1.21	$1.15	$1.14
2018	$1.17	$1.17	$1.16	$1.22	$1.17	$1.16
2019	$1.19	$1.18	$1.17	$1.24	$1.18	$1.17
2020	$1.20	$1.20	$1.19	$1.26	$1.20	$1.19
2021	$1.22	$1.21	$1.20	$1.28	$1.22	$1.20
2022	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2023	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2024	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2025	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2026	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2027	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2028	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2029	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2030	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2031	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2032	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2033	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2034	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2035	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2036	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2037	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2038	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2039	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2040	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22

Source: CEFC (2018) 'Australian EV Market Study Report'

C.3.3. Common Assumptions

Uptake Model

Vehicle Classes

A selection of the vehicle class described in the ABS survey of Motor Vehicle Use (2016) are modelled separately in with independent sales, stock and uptake forecasts. Passenger vehicles are further segmented into sub-categories to capture the diverse range of vehicle efficiency and price points.

- Passenger Car (PC)
  - Passenger Car Large (PC-L)
  - Passenger Car Medium (PC-M)
  - Passenger Car Small (PC-S)
  - Sport Utility Vehicle Medium (SUV-M)
  - Sport Utility Vehicle Large (SUV-L)
- Light Commercial (LC)
- Rigid Truck (RT)
- Bus (B)

Opening Stock

The opening stock of vehicles by vehicle class is sourced from VFACTS data for the calendar year 2016[43] for EV and ICE vehicles by state. The opening stock feeds into the vehicle stock model at t=0 in the above equations.

Charging Segmentation

The total eligible market for EV uptake in a given year is determined by the availability of charging in the region.

Modelled Technology Types

The model considers three vehicle technology types:

- **Battery Electric Vehicle –** Single electric drive train vehicles using a battery as its fuel store.
- **Plug-in Hybrid Electric Vehicle** – Vehicles containing both an electric and internal combustion drive train, while also having the ability to charge from an electrical outlet (Conventional hybrids or HEVs are excluded from this category).
- **Internal Combustion Vehicles** – Conventional vehicles containing an internal combustion drive train.

Travel Distances

The travel distance dictates energy requirements and therefore has a direct impact on both ICE vehicles and EV annual fuel expenditure. The model adopts an average driving distance in this application to determine annual vehicle costs that vary by state and by vehicle class as summarised in Table 20.

Table 20 – Travel Distance

State	Annual Average Distance Travelled (km/year)	
	Light Passenger	Light Commercial
NSW	12,300	17,100
ACT	12,800	18,200
VIC	13,800	17,700
QLD	13,300	17,100
SA	11,600	16,700
WA	12,400	17,200
TAS	11,600	12,100

Source: ABS Survey of Motor Vehicle Use

EV Range

EV ranges are based on what is currently reported for each vehicle type by OEMs as shown in Table 21. Each year, the vehicle's battery size increases linearly until it reaches the size required for distance parity with an equivalent ICE. The number of years this takes varies by scenario.

[43] Federal Chamber of Automotive Industries (2016), VFACTS

Table 21 – EV Range

Vehicle Class	Vehicle Technology	EV Range Parity Battery Size (kWh)
Passenger Car Small	BEV	82
Passenger Car Medium	BEV	94
Passenger Car Large	BEV	147
Sport Utility Vehicle Medium	BEV	121
Sport Utility Vehicle Large	BEV	137
Light Commercial	BEV	60
Rigid Truck	BEV	160
Bus	BEV	1,136

Source: Energeia Modelling, Vehicle OEM websites

Fuel Efficiency

Fuel efficiency in the model is a key factor in determining energy requirements and fuel costs. The underlying fuel efficiency of ICE vehicles and EVs stay constant in the model as combustion and electric engines are well understood and established technologies.

The assumptions for fuel consumption are summarised in Table 22. These estimates have been developed based on OEM reported efficiency data. These remain constant throughout the modelling period. Future considerations include sensitivities of efficiency improvements in both drive trains.

Table 22 – Fuel Consumption

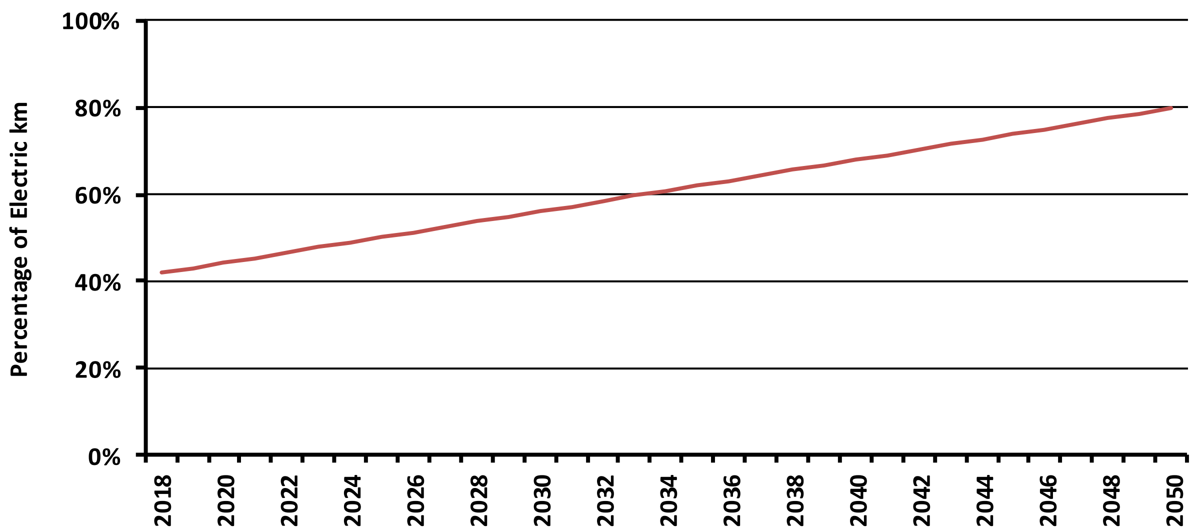
Vehicle Class	2017 Efficiency	
	EV kWh/km	ICE L/km
Passenger Car Small	0.137	0.052
Passenger Car Medium	0.178	0.063
Passenger Car Large	0.181	0.102
Sport Utility Vehicle Medium	0.181	0.064
Sport Utility Vehicle Large	0.181	0.104
Light Commercial	0.155	0.065
Rigid Truck	0.400	0.488
Bus	0.364	0.445

Source: Energeia, OEM websites

PHEV Drive Train Utilisation

Plug in hybrids are assumed to currently utilise their electric drive train a certain proportion of the time, this utilisation is assumed to increase overtime as battery storage capacity of the vehicles increases the forecast period.

Figure 60 – PHEV Percentage of Annual Kilometres Travelled Using Electricity



Source: Energeia analysis, Idaho National Laboratory (2015)

Charging Impacts Module

Charging Segmentation

Charging availability is determined by access to private parking for residential. Customers with direct access to level 2 charging can take up electric vehicles at the start of the modelling period, with those that require DCFC progressively become available to uptake as charging infrastructure is rolled out. Infrastructure roll out is configurable by scenario setting.

A vehicle can be assigned to either a L2 home charger, a L2 commercial charger or DCFC.

Passenger cars allocated to DCFC reflect the percentage of households in each state with more than one vehicle. Energeia expects these vehicles will use DCFC rather than try and share private parking space. Commercial vehicles are assumed to be charged at their respective depots. Detailed charge type assumptions are shown in Table 23.

Table 23 – Charger Access Segmentation

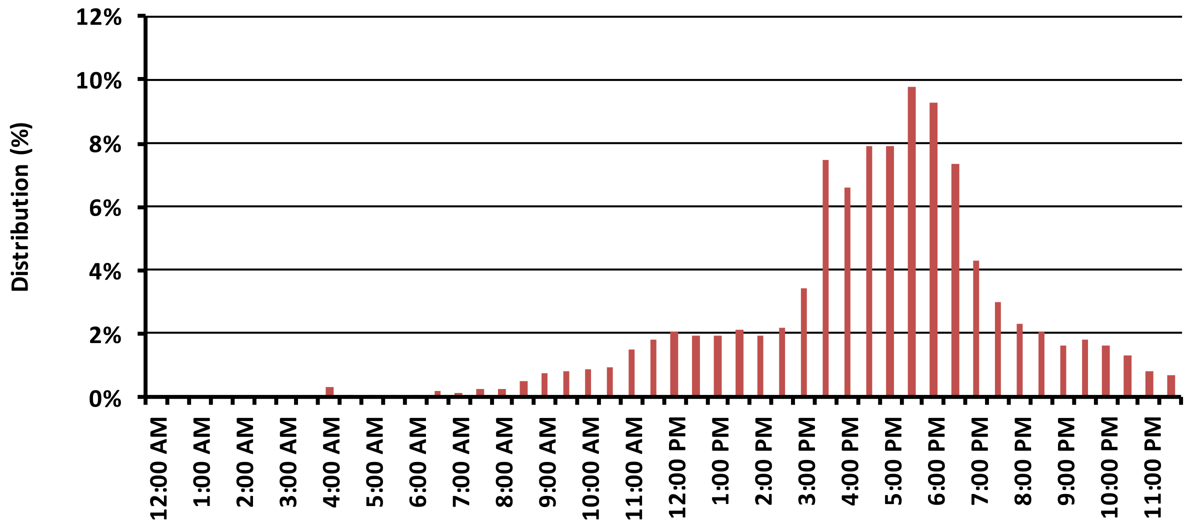
Vehicle Type	Charger Type	NSW	QLD	SA	VIC	WA	TAS	NT
Residential	Destination (Home) Charging	38.7%	38.2%	43.2%	40.0%	37.1%	42.7%	32.8%
	DCFC Public Charging	61.3%	61.8%	56.8%	60.0%	62.9%	57.3%	67.2%
Commercial	Destination (Home and Depot) Charging	100%	100%	100%	100%	100%	100%	100%

Source: Energeia analysis, ABS Household Survey (2016)

Driving Diversity

The charging engine uses the arrival time distribution shown in Figure 61.

Figure 61 – Vehicle Arrival Distribution

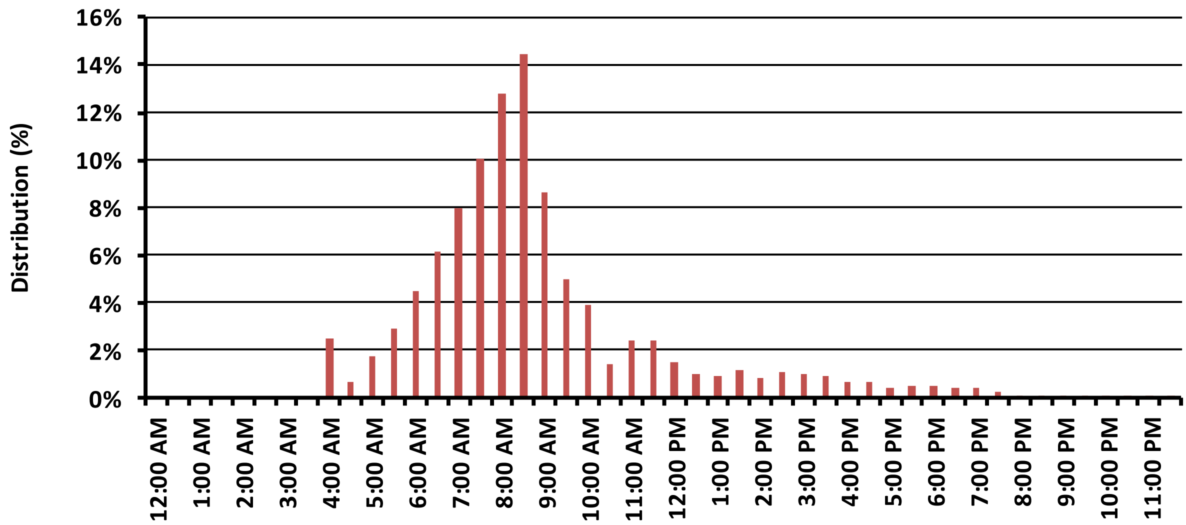


Source: Queensland Household Travel Survey

The charging completion time depends upon the start time, the assumed departure time, and the amount of charge required, which is in turn dependent on the daily driving distance. Generally speaking, the charging management function attempts to recharge the vehicle as quickly as possible while maximising the impact on minimum demand and minimising the impact on maximum demand.

The model uses the departure time distribution shown in Figure 62.

Figure 62 – Vehicle Departure Distribution

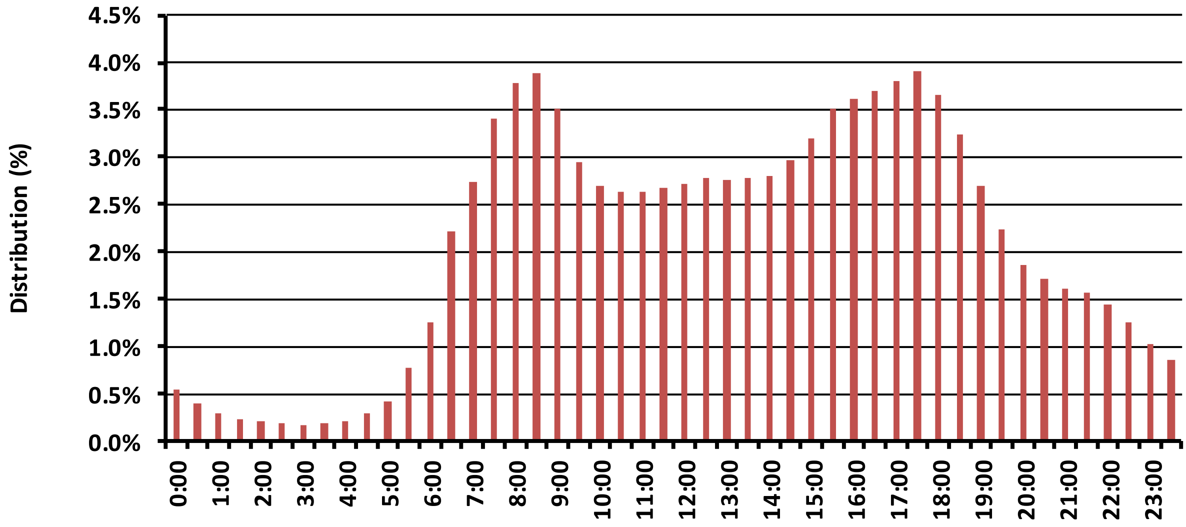


Source: Queensland Household Travel Survey

EV fast charging starts as soon as the vehicle arrives at the charging station and is completed within 5 minutes using 1MW chargers by 2036.

The charging start time is based on the Victorian Managing Traffic Congestion report and uses the traffic volume by time of day to determine the distribution of DCFC use, this is shown in Figure 63.

Figure 63 – Arrival Time Distribution



Source: VAGO (2013), Managing Traffic Congestion.

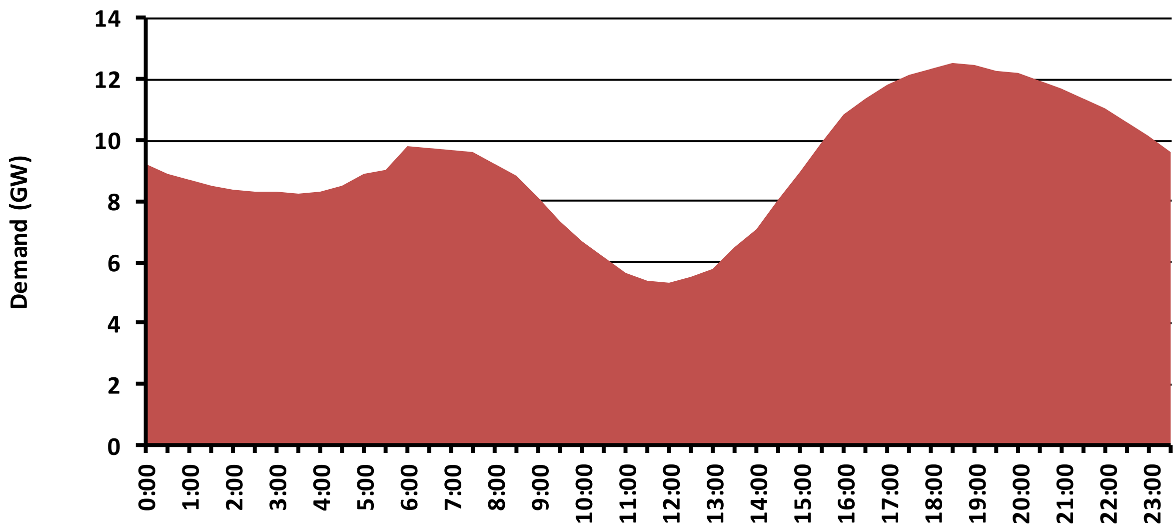
Managed Charging

Level 2 EV charge management can be enabled in the scenario settings of the model, this allows the charging profile of level 2 segment vehicles to be altered to reduce peak demand impact. This is modelled for each year using half-hourly interval data. Managed charging is optimised over two parameters:

- Vehicle availability to charge
- Current half-hourly demand

This allows for a minimisation of peak demand while increasing network asset utilisation by increasing average demand across the year.

Figure 64 – Indicative uSim NSW Average Day Profile (2035)



Source: Energeia Modelling

C.4. Outputs and Reporting

The standard reporting of both the uptake and charging engine are shown in the following sections.

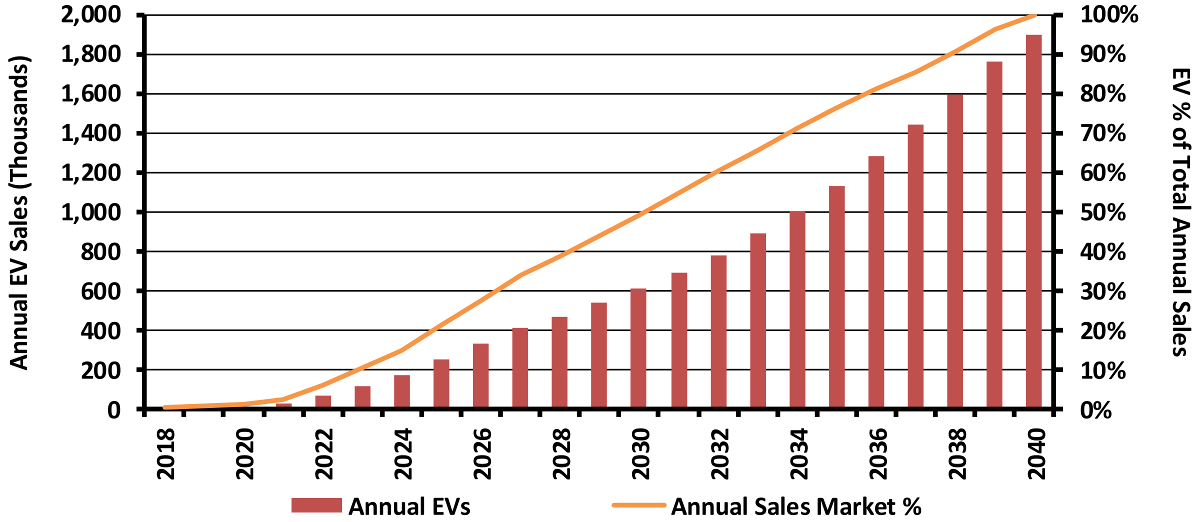
C.4.1. Uptake Module

The uptake module forecasts both annual and cumulative sales and fleet share.

Annual Vehicle Sales

Annual electric vehicle sales and market share can be reported on aggregate and by vehicle class, segment and region over the modelling period.

Figure 65 – Annual Vehicle Sales and Market Share

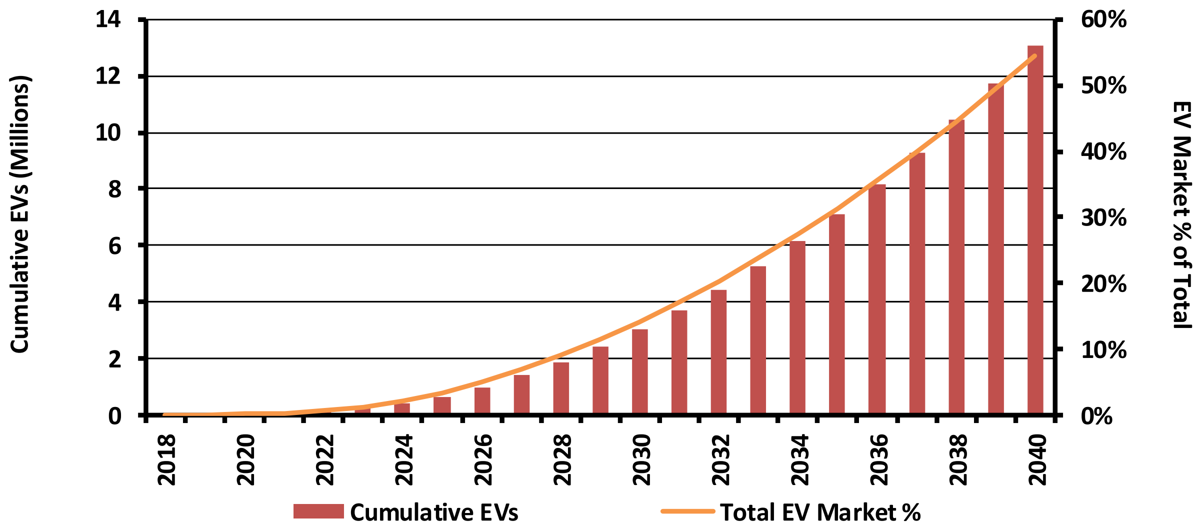


Source: Energeia Modelling

Fleet Share

Cumulative electric vehicle sales and fleet share can be reported on aggregate and by vehicle class, segment and region over the modelling period.

Figure 66 – Cumulative Vehicle Sales and Fleet Share



Source: Energeia Modelling

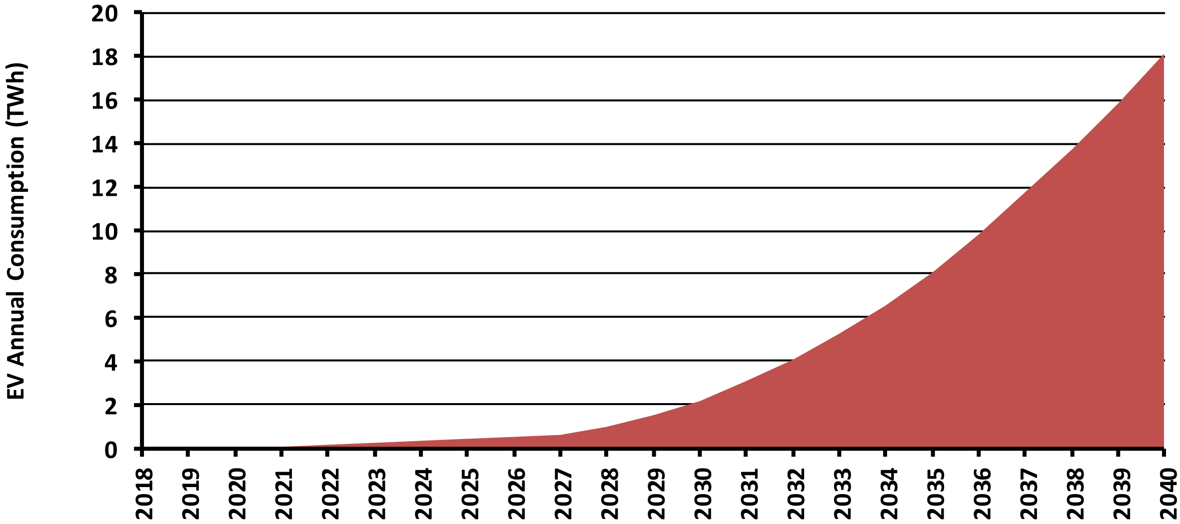
C.4.2. Vehicle Charging Engine

The Vehicle charging engine reports electric vehicle consumption and fleet charging profiles on a charger type and control basis.

Electric Vehicle Consumption

The vehicle charging engine reports the total electric vehicle consumption on aggregate and by vehicle class, segment and region over the modelling period.

Figure 67 – Annual Energy Consumption



Source: Energeia Modelling

Charging Profiles

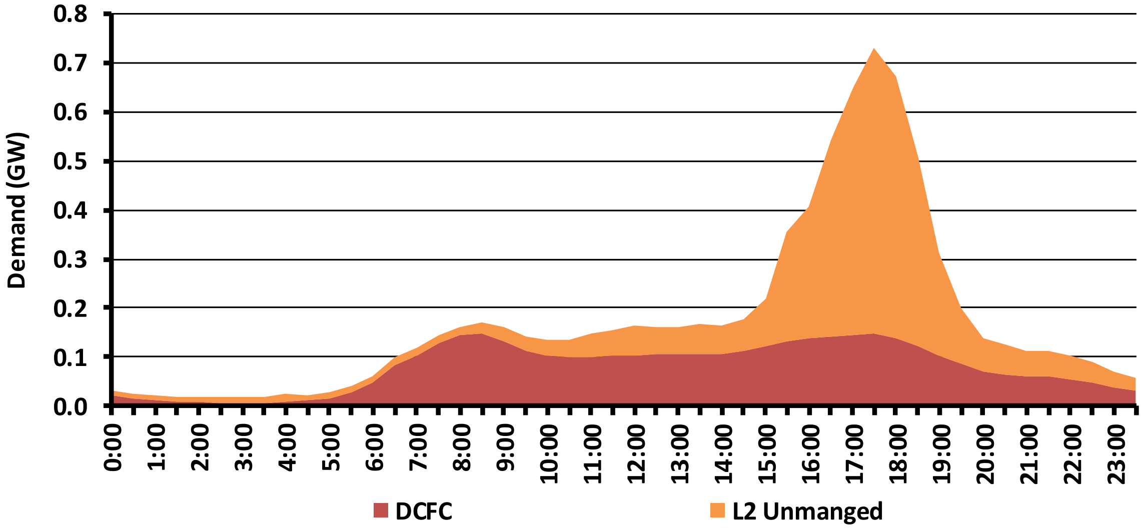
Charging profiles are reported on a managed or unmanaged basis for each year modelled, the profiles are segmented by charger type:

- DCFC
- Level 2 Unmanaged (for both residential and business customers)
- Level 2 Managed (for both residential and business customers)

Unmanaged

Unmanaged charging can be reported for weekdays or weekends segmented by charger type and vehicle class.

Figure 68 – Average Day Unmanaged Charging Profile

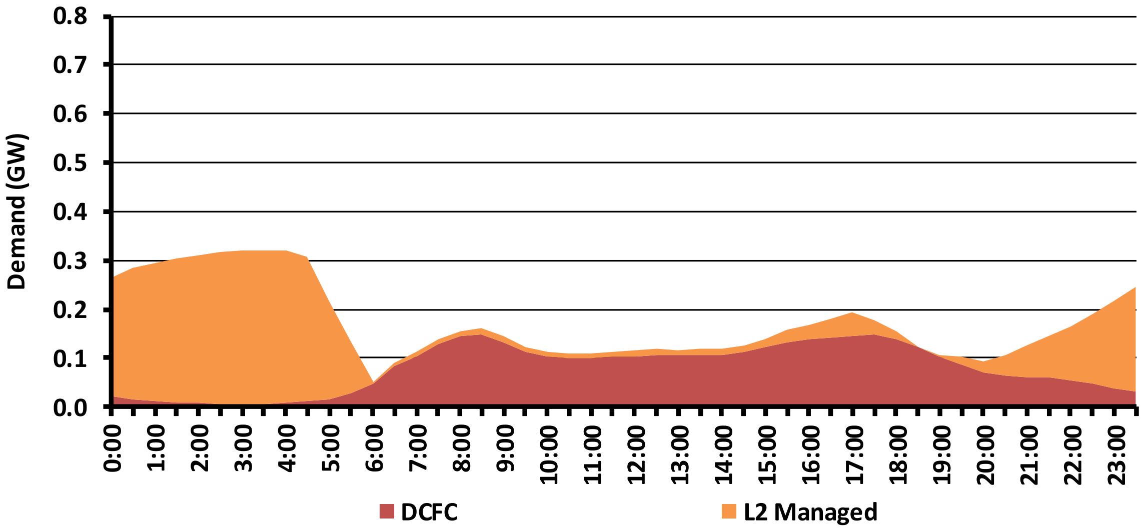


Source: Energeia Modelling

Managed

Managed charging can be reported for peak, average and minimum demand days segmented by charger type and vehicle class.

Figure 69 – Average Day Managed Charging Profile



Source: Energeia Modelling

C.5. Model Enhancements and Potential Improvements

C.5.1. Current Enhancements

This iteration of the model had the following enhancements developed and integrated:

- **Changing Vehicle Lifetimes –** Electric vehicle lifetimes were modified to increase to reach parity with ICE vehicles as technology improvements are developed as previous iterations of the model had tied BEV lifetime the vehicles battery warranty (10 years).
- **Residential Uptake Segmentation –** In the early years of the modelling period the potential annual sales market for uptake of BEV's is limited by residential customer access to level 2 charging at home, those without access are able to uptake as public charging networks are rolled out nationwide.
- **Plug-In Hybrid Additional Vehicle Classes –** As more plug in hybrid models have become available, they have been added to each vehicle class for uptake consideration. The total uptake of alternative fuel vehicles is the weighted sum of the uptake calculated for each technology type.

C.5.2. Future Improvements

Energeia's EV forecasts are independent of the base electricity price forecasts. That is, there is no feedback loop between the forecasted EV uptake and the corresponding response from networks, retailers or the wholesale market.

Further, there are a range of future possibilities as to how EV loads will be priced and how the EV market will integrate with the electricity market and it is foreseeable that tariff products could evolve to encourage increased charging of EVs during solar generation times. This analysis assumes initial EV tariffs for home and workplace charging reflect controlled load tariffs, which will be orchestrated to ensure they minimise peak demand impacts.

The household transport model upon which the EV forecast model relies are derived from the Queensland Household Travel Survey and the Victorian Auditor-General's Managing Traffic Congestion Report. That is, while the model reflects different average driving distances between states, it assumes that travel patterns (origins, destinations, arrival times and departure times) in all regions of Australia are consistent with those of Queensland drivers for passenger vehicles with access to private parking, while travel patterns for commercial EVs and vehicles without access to private parking are consistent with drivers in Victoria.

The EV uptake model is driven in part by the financial return on investment to vehicles owners based on the EV vehicle premium and reduced operational costs. The model does not consider costs associated with any required upgrade to the household switch board and/or service, which could add considerable cost. However, this is not expected to be a material number of households based on anecdotal evidence from pilots, etc.

Appendix D – Solar PV Non-Scheduled Generation Forecasting Methodology and Assumptions

Energeia's Solar PV Non-Scheduled Generation (PVNSG) annual capacity and installation forecasting methodology for solar PV systems in bands ranging from 100 kW – 1 MW, 1 MW – 10 MW and 10 MW – 30 MW by state is outlined in the sections below, together with the key model inputs and drivers.

D.1. Overview

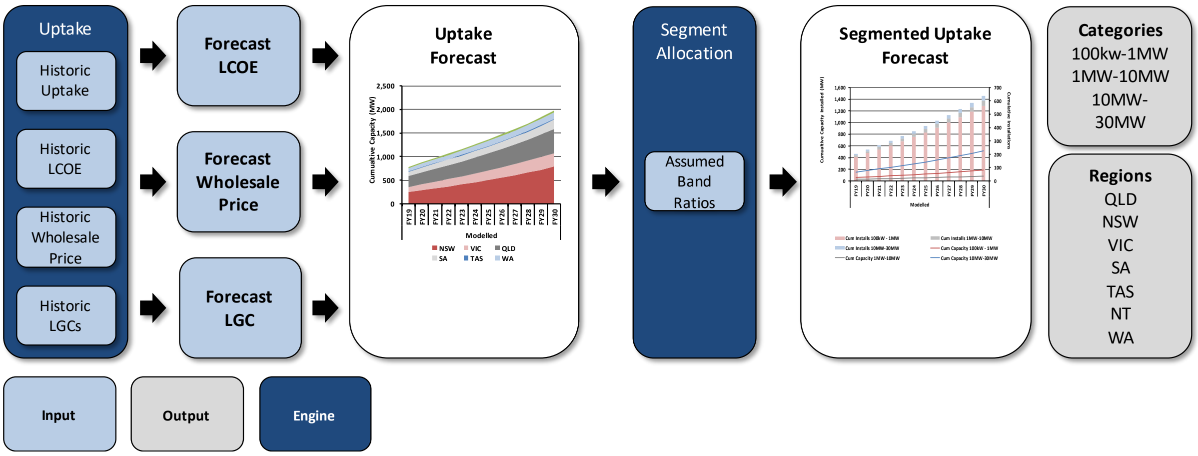
To generate an uptake forecast, Energeia ran a log-linear regression of the historic average annual net benefit of PVNSG, lagged by one year, on annual capacity installed and annual number of installs by state. The chosen model:

- Is based on two-stage structure uptake forecast first on a population basis, which is then segmented into system size bands;
- Was selected using goodness-of-fit criteria, applied across a process that tested a range of different regression-based methods for forecasting;
- Was further developed and improved using back-casting procedures to validate the uptake results and the segmentation reporting; and
- Will form the basis for further improvement of Energeia's modelling suite, sitting as it does between wSim (modelling traditional fossil fuel powered generation and renewable energy power generation in the wholesale market and transmission) and uSim (modelling network costs and revenue recoveries in the distribution network).

D.1.1. Structure of the Model

A summary of the methodology is provided by the flow chart shown in Figure 70.

Figure 70 – PVNSG Forecast Methodology Summary Flow Chart



Source: Energeia

A number of post model adjustments (further explained in Section D.2.2. Modules) are made to the final results.

D.1.2. Methodology Selection

The modelling method selection criteria (goodness-of-fit) and process (testing of same) are outlined in the following sections.

Criteria

The optimal method was selected based on the overall goodness-of-fit with each state's PVNSG annual capacity and installation data, whilst also considering the data available for each state. The key statistical measurements of goodness-of-fit were the Adjusted R^2 and p-values of the independent variables.

Process

Energeia tested a range of single and multivariate OLS[44] regression-based methods to forecast PVNSG capacity and installations. These included the functional forms:

- Linear
- Log-Linear
- Linear-Log
- Double Log

Energeia also considered a range of single and multivariate regressions on such variables as:

- Net benefit of PVNSG ($/MWh)
- Levelized Cost of Energy (LCOE) of PVNSG ($/MWh)
- Average wholesale price by state ($/MWh)
- LGC spot price ($/certificate)
- Large-scale PV system cost ($/MW)
- Average retail price by state ($/MWh)

These variables were tried with both no lag and a one-year lag to installation date. A lag was considered since there would likely be a significant delay between the decision to invest in an PVNSG and the actual installation of the system.

The optimal regression for each is then selected based on general performance across all states in goodness-of-fit, measured by R^2 and Adj-R^2 and significance of the beta coefficients, measured by the p-value of the beta coefficient. Based on this criterion, Energeia chose to use a Log-Lin OLS regression.

D.1.3. Model Development

Energeia determined that the key driver of PVNSG uptake in Australia has been the net benefit of installing an PVNSG system on a $/MWh basis. Energeia adopted a log-linear regression of the historic average annual net benefit of PVNSG, lagged by one year, on annual capacity installed and annual number of installs by state.

The population level uptake forecast is then back-casted against historic outcomes to validate the forecast, and then the historic relationships between the three different system size bands (100 kW – 1 MW, 1 MW – 10 MW and 10 MW – 30 MW) were used to segment the uptake forecasts (using the last three years of historic uptake data of systems size uptake on a state basis).

D.1.4. Future Application

PVNSG is forecasted separately to Energeia's broader energy system model, as the investment decision made by the large commercial and industrial buyers of these systems is not behind-the-meter, and the wholesale cost plays a direct role in the ROI of the decision. For the next iteration of forecasting, Energeia plans on integrating PVNSG uptake into uSim to gain a more precise understanding of the system-wide impacts of PVNSG uptake.

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[44] Ordinary Least Squares

D.2. Model Process and Modules

The PVNSG modelling process is a two stage process, where state level uptake is forecast on a population basis and then allocated into segments by system size bands.

D.2.1. Process

The PVNSG model is split into two modules, the uptake and segment allocation module, as outlined in the below sections:

- **Uptake Module** – Generates forecast system costs and revenues based on historic inputs (uptake, technology costs, wholesale prices, renewable certificate prices), using a regression on the basis of annual net benefit of PVNSG for both installs and capacity.
- **Segment Allocation Module** – Allocates the resultant uptake forecast into segmented system size bands on the basis of a historically validated system size.

Limited post model adjustments (conversion from calendar years; correction of skew in the WA system size distribution) were applied to the final results.

D.2.2. Modules

Each of the two modules, the uptake forecasting and system size segmentation modules, are detailed in the following sections together with the applied post-model adjustments.

Uptake Module

To estimate uptake, Energeia regressed the historic average annual net benefit of PVNSG, lagged by one year, on annual capacity installed and annual number of installs by state[45]. Further information on these inputs can be found in Section D.3. Inputs and Drivers.

The performance of the regression analysis is shown in Table 24 for capacity installed and Table 25 for the number of deployed systems.

Table 24 – Log-Lin OLS Regression Performance for Logged Annual PVNSG Capacity Installed

State	Independent Variables		Performance Measures				
	PVNSG Annual Net Benefit ($/MWh), Lagged One-Year	LCOE Lagged One-Year	R^2	Adj-R^2	Alpha	Beta	P-Value
NSW	✓	✗	0.695	0.633	3.534	0.015	0.020
VIC	✓	✗	0.777	0.732	2.605	0.012	0.009
QLD	✓	✗	0.778	0.723	2.699	0.023	0.020
SA	✓	✗	0.977	0.971	1.651	0.023	0.000
WA	✓	✗	0.672	0.590	1.876	0.027	0.046
TAS	✓	✗	0.898	0.872	0.310	0.016	0.004
NT[46]	✗	✓	0.898	0.872	44.795	-0.224	0.004

Source: Energeia Modelling

[45] The exception to this methodology is NT, where the wholesale price data was unavailable. Instead, the aggregate capacity installed and cumulative number of installs on the LCOE ($/MWh) of PVNSG generation lagged 1-year.

[46] NT regressed on aggregate capacity installed (not logged)

Table 25 – Log-Lin OLS Regression Performance for Logged Annual PVNSG Number of Installs

State	Independent Variables		Performance Measures				
	PVNSG Annual Net Benefit ($/MWh), Lagged One-Year	LCOE Lagged One-Year	R^2	Adj-R^2	Alpha	Beta	P-Value
NSW	✓	×	0.907	0.888	3.335	0.013	0.001
VIC	✓	×	0.957	0.949	3.288	0.014	0.000
QLD	✓	×	0.722	0.652	2.373	0.015	0.032
SA	✓	×	0.796	0.745	1.415	0.015	0.017
WA	✓	×	0.781	0.726	2.354	0.017	0.019
TAS	✓	×	0.773	0.717	0.567	0.005	0.021
NT[46]	×	✓	0.769	0.711	45.551	-0.218	0.022

Source: Energeia Modelling

Allocation Module

The models segments forecasts by the trend in size distribution over the last three years of historic uptake by state (2016-2018) to allocate the PVNSG capacity and installation forecasts into three system size bands (100 kW – 1 MW, 1 MW – 10 MW and 10 MW – 30 MW).[47]

Post Modelling Adjustments

Two minor adjustments were made to the model outputs:

- **Financial Year Conversion** – All annual forecast data was converted from calendar year to financial year by taking the average between the two calendar years that the financial year involves.
- **Western Australia Size Distribution** – The distribution of the system size bands for WA was adjusted to weight more installations to the smaller 100kW-1MW segment than what the historical trend states (from 90% to 94%). This was done to ensure the average size of the installations in the larger bands remained inside the allowable range specified by the band.

D.3. Inputs and Drivers

Energeia views that the key driver of historic PVNSG uptake by state has been the net benefit of PVNSG systems. The net benefit is increased by either falling costs or by higher benefits:

- **Technology Cost** – The LCOE of large-scale PV generation. As the system cost falls, the NPV of the purchasing decision increases.
- **Technology Benefit** – The benefit of investing in a PVNSG system is that the investor can earn returns by directly participating in the wholesale generation market, earning the spot price ($/MWh) and receiving payment through the LGC scheme per MWh generated:
    - *Wholesale Price of Electricity* – the daytime wholesale price per state per year weighted by the solar PV-output average
    - *Large-scale Generation Certificate* – the value of certificates for complying generation under the Renewable Energy target

The PVNSG model has been set up with some inputs that can be configured to drive scenarios, and others that are common across any chosen scenario design.

[47] This assumes that the size distribution of PVNSG systems by state will remain constant into the future.

D.3.1. Scenario Drivers

The regression is driven by the net benefits of PVNSG as determined by the revenues (prices and rebates) less costs (technology costs).

Table 26 – PVNSG Scenario Drivers

Energeia DER Model Drivers		Planning Scenarios			DER Sensitivities		
		Slow Change	Neutral 26%	Fast Change	Low DER	Neutral 45%	High DER
Technology Costs	PVNSG LCOE	Weak	Neutral	Strong	Weak	Neutral	Strong
Prices	Solar-output weighted average RRP	AEMO (26%)	AEMO (26%)	AEMO (45%)	Energeia (45%)	Energeia (45%)	Energeia (45%)
Rebates and Incentives	LGC forecast	LGC forecast is common across all scenarios					

Source: Energeia

The scenarios are driven off the technology costs and wholesale prices (the LGC rebate is common across all scenarios).

Technology Costs

In the model, the cost of a PVNSG system is the $/MWh LCOE of PVNSG generation. To determine the LCOE, the historic cost of a large-scale PV system was derived from Solar Choice, as the average state median price per kW. The forecasted large-scale PV system costed was taken from CSIRO's GenCost (2018) Large-Scale Solar PV capital cost projection under 4 degrees scenario. As the historic and forecasted prices were taken from different sources, Energeia made the decision to index Solar Choice's historic price data to CSIRO's price forecast, to smooth the transition between the historic and forecasted costs.

The LCOE was calculated using the following formula:

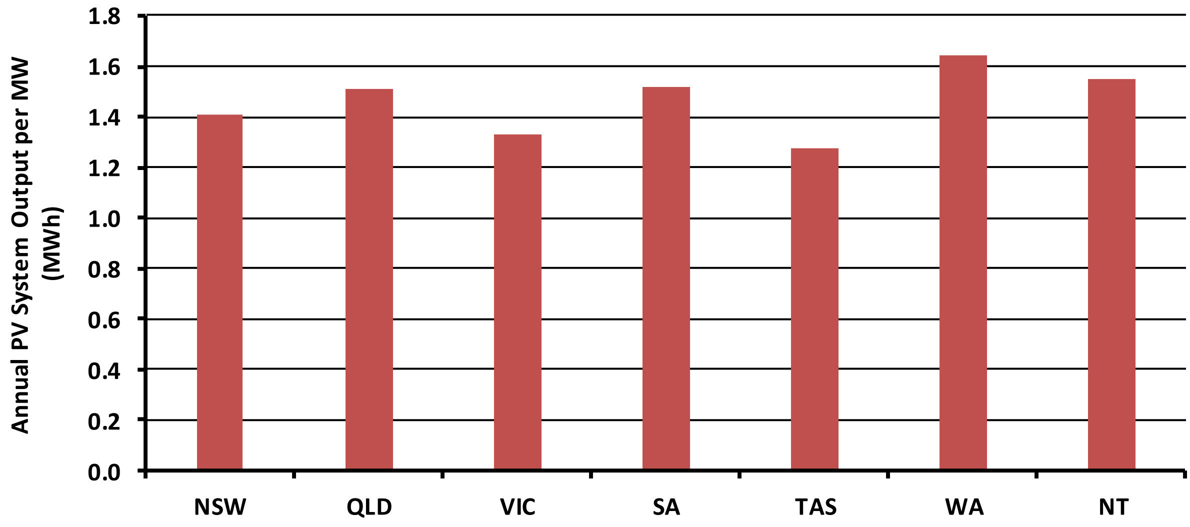
$$LCOE\left(\frac{\$}{MWh}\right) = \frac{Annual\ WACC\ Payment\ Required\ (\$)}{Average\ Annual\ System\ Output\ per\ MW\ (MWh)}$$

To calculate the annual payment required, Energeia assumed that an PVNSG system has a 20-year lifetime with no operation and maintenance cost, aligning with the uSim model. Energeia also assumes that the system cost is financed at a WACC of 8% (based on Gentailer average WACC).

To calculate the average annual system output per MW for the system lifetime, Energeia took the first-year solar PV output profile for each state's capital city as reported by NREL. To account for PV degradation of energy generation over the lifetime of the project, Energeia assumes that the PV output degrades by 0.5% pa[48], and after applying this rate for 20 years to the first-year system output and takes the average output per year as the average annual system output in the LCOE calculation. The resulting average annual system output per MW for each state is shown in Figure 71.

[48] As per the Australian Energy Council Solar Report (2019), https://www.energycouncil.com.au/media/15358/australian-energy-council-solar-report_-january-2019.pdf

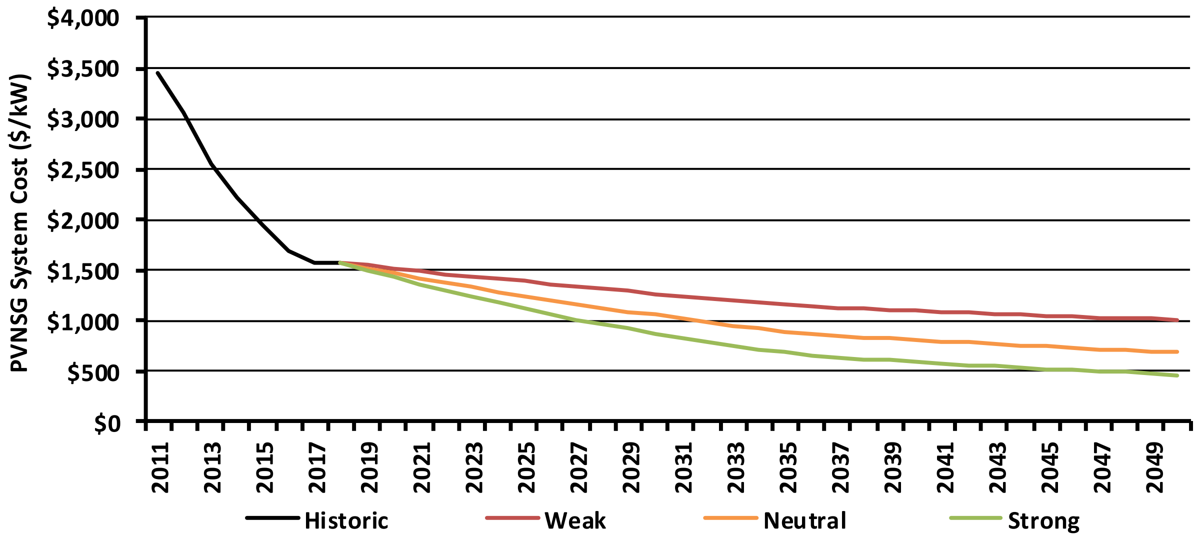
Figure 71 – 20-Year Average Annual System Output per MW (MWh) by State



Source: NREL (2019)[49], Energeia Analysis

The PVNSG cost curve by case is presented in Figure 72.

Figure 72 – PVNSG Cost Curve by Sensitivity



Source: Solar Choice (2019)[50], CSIRO (2018)[51], Energeia Analysis

The final input into the net benefit of PVNSG equation is the LCOE of PVNSG, which varies by sensitivity and state. The average LCOE for each state in the Neutral case is displayed in Figure 73.

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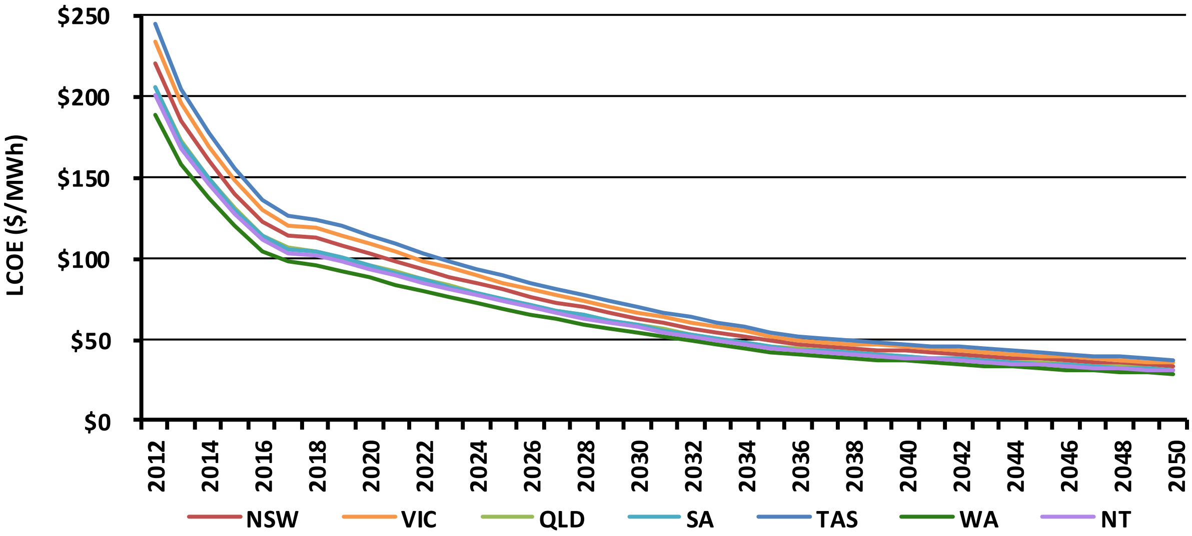
[49] https://pvwatts.nrel.gov/pvwatts.php

[50] Sourced from: https://www.solarchoice.net.au/blog/solar-power-system-prices

[51] CSIRO (2018), 'GenCost 2018' (sourced from: https://www.csiro.au/~/media/News-releases/2018/Annual-update-finds-renewables-are-cheapest-new-build-power/GenCost2018.pdf)

Figure 73 – LCOE of PVNSG by State in Neutral Case ($/MWh)



Source: Energeia Analysis

Macroeconomic Factors

In the model, the predominant revenue driver of PVNSG net benefit is the wholesale price they receive for their energy generation. Energeia developed both historic and projected prices on a state basis for PVNSG systems:

- **Historic Wholesale Prices** – To estimate the historic wholesale price that PVNSG systems received for their energy, Energeia calculates the annual solar PV output-weighted average RRP for each state and year modelled, where the historic average RRP was sourced from AEMO.
- **Projected Wholesale Prices** – The projected wholesale prices by state were provided by AEMO for this project for the 26% emissions reduction by 2030 scenario and the Fast Change scenario. For the 45% emissions reduction by 2030 scenario, Energeia used in house wholesale price modelling completed for this scenario, as AEMO were unable to make wholesale prices for this scenario available.

D.3.2. Common Assumptions

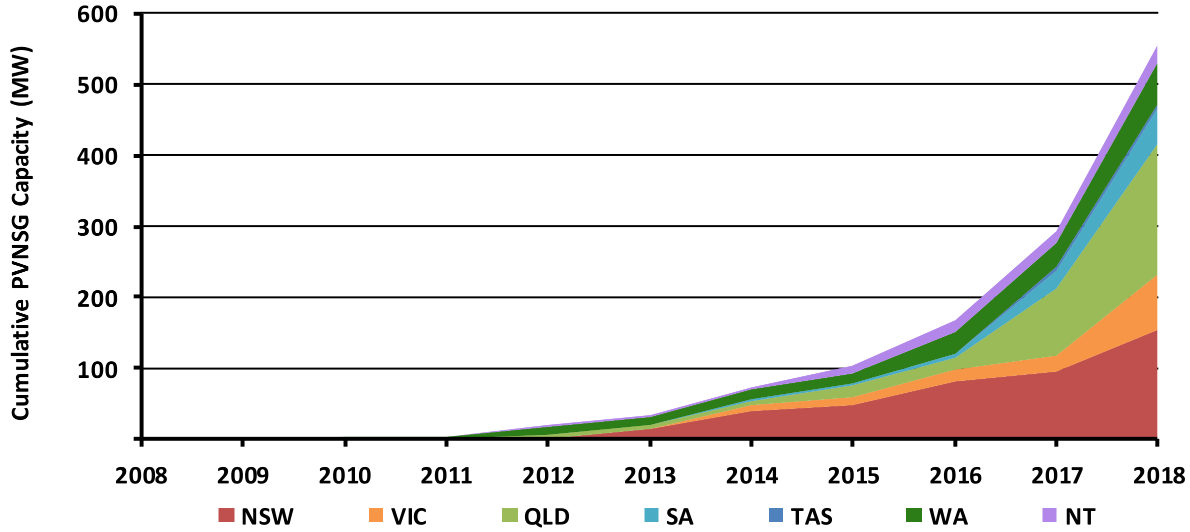
Uptake Module

Historic Uptake

Energeia used each state's annual PVNSG capacity and installations by year as the dependent variables in the regression analysis. The data is sourced from the Australian Photovoltaic Institute (APVI), which lists the state and capacity of each PVNSG system installed. The PV generators > 30MW were cleaned from the data to not influence the forecast, as they are out of scope. The details of these generators are sourced from APVI and cross-checked with AEMO's Generation Outlooks for each state. The APVI assumes that the PV system is installed on its accreditation date.

For this analysis, Energeia only considered PVNSG uptake from 2012 onwards. This is because 2012 is the first year where all states in Australia have at least one PVNSG installation recorded. Including previous years in the regression analysis would flatten the slope of the regressions and lower the forecasted uptake. Figure 74 demonstrates that the historic uptake of PVNSG is heavily skewed to the most recent years.

Figure 74 – Historic Cumulative PVNSG Capacity Installed by State (MW)



Source: APVI (2019)[52]

Each recorded installation in the APVI dataset was then segmented into one of three bands based on capacity size (100kW-1MW, 1MW-10MW, 10MW-30MW), to determine the annual distribution of PVNSG uptake, segmented by the size of the system.

LGC Certificate Pricing

To estimate the historic LGC certificate prices that PVNSG systems would have received from the Federal Government for energy generation, Energeia used a combination of sources[53] to develop a complete timeline of LGC $/certificate from 2011-2018.

To forecast LGC certificate prices, Energeia assumes that the LGC certificate price will fall at the same rate as large-scale PV system prices, as they share the same drivers. The forecasted LGC price does not vary by scenario and the program is assumed to end in 2031.[54]

The LGC certificate price curve is shown in Figure 75.

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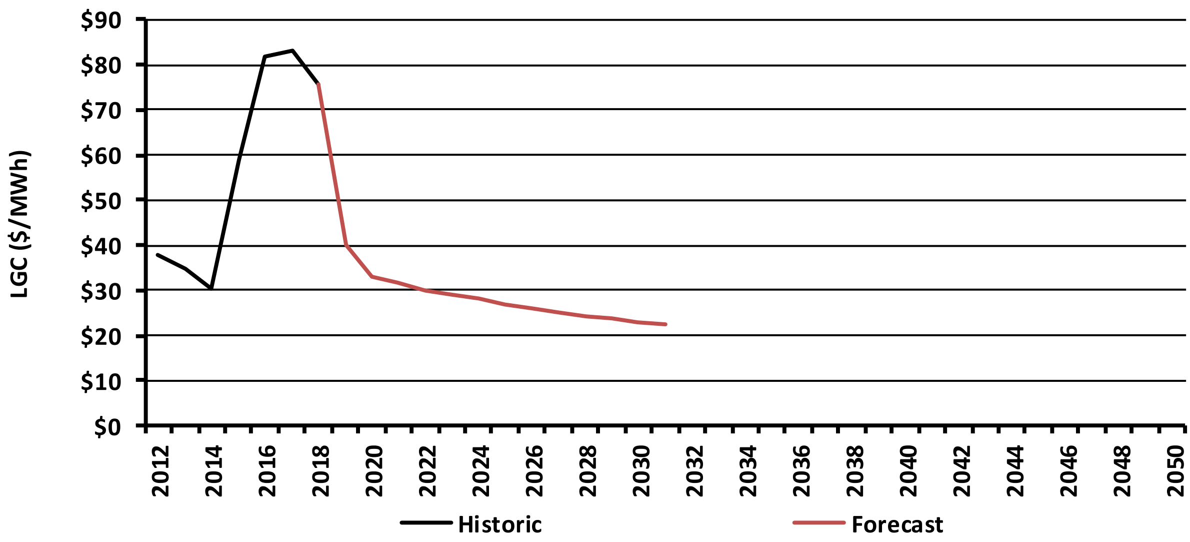
[52] Sourced from: http://pv-map.apvi.org.au/postcode

[53] Sources: TFS Green (2019), 'Large Scale Generation Certificate Market Update' (sourced from: http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Large-scale%20generation%20certificate%20market%20update%20by%20month/Large-scale-generation-certificate-market-update---February-2019.aspx); AW Solar (sourced from: https://www.awsolar.com.au/lgc-and-stc/); EurOz Securities (2017), 'Genex Power Ltd' (sourced from: http://www.genexpower.com.au/uploads/6/6/1/2/6612684/gnx_initiation_of_coverage_24jul17.pdf)

[54] The limitation to this LGC forecast is that it does not reflect the demand/supply dynamic effect that installing PVNSG capacity would have on LGC prices. It also does not account for the REC target being reached early and the scheme being removed earlier than 2031.

Figure 75 – Historical and Forecast LGC Price Curve ($/MWh)



Source: Energeia Analysis

PVNSG System Configuration and Performance

To simplify the analysis, Energeia has made the following high level assumptions regarding PVNSG system configuration and performance:

- **Panel Orientation** – Energeia assumes that PV panels are mounted, at a 20-degree tilt, 180-degree azimuth and generate power at an 86% efficiency. In reality, system owners are now likely to use 1-2 axis tracking, optimising tilt based on time of day/year.
- **Panel Degradation** – To account for PV degradation of energy generation over the lifetime of the project, Energeia assumes that the PV output degrades by 0.5% p.a.
- **System Lifetime** – Energeia assumes that PV panels have a useful lifetime of 20 years. Combined with our PV degradation assumption, this implicitly assumes that PV panels generate energy at above 90% of initial capacity for the entire duration of an PVNSG system's lifetime. Energeia recognises that PV panels tend to last for longer than this but has chosen a conservative assumption for this analysis.

In combination, these assumptions combine to underplay the role of PVNSG generation in the wholesale market but are consistent over the life of the forecast.

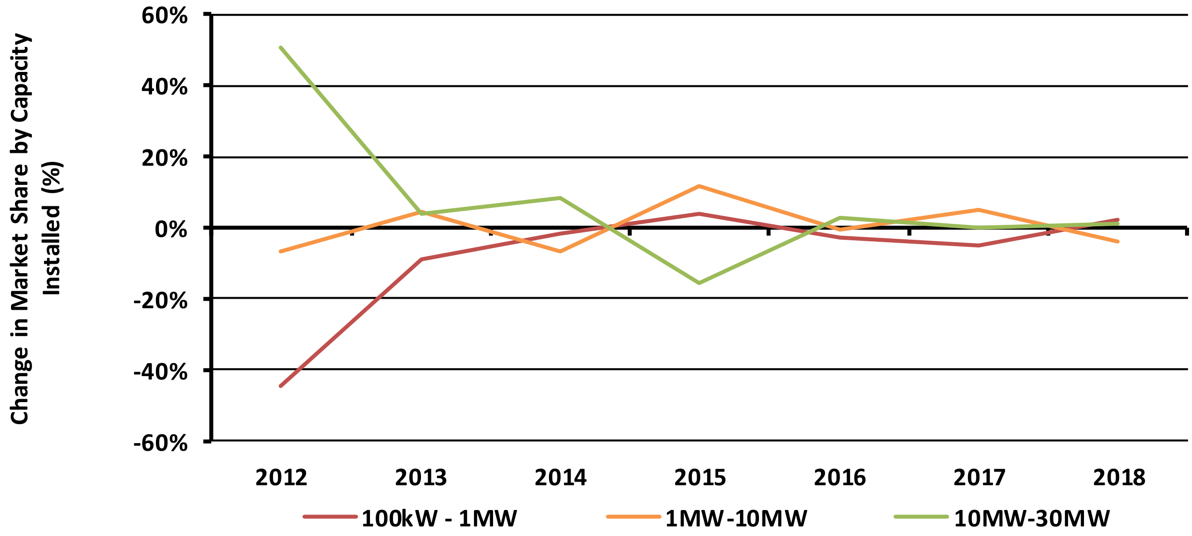
Financial Assumptions

Energeia has based its costs of capital on that of competing Gentailers in the wholesale market (i.e. competitors building scheduled, larger-scale, solar PV).

Allocation Module

This assumption is validated by Figure 76, which shows the Australian market share of each size band of PVNSG by capacity stabilise by 2016.

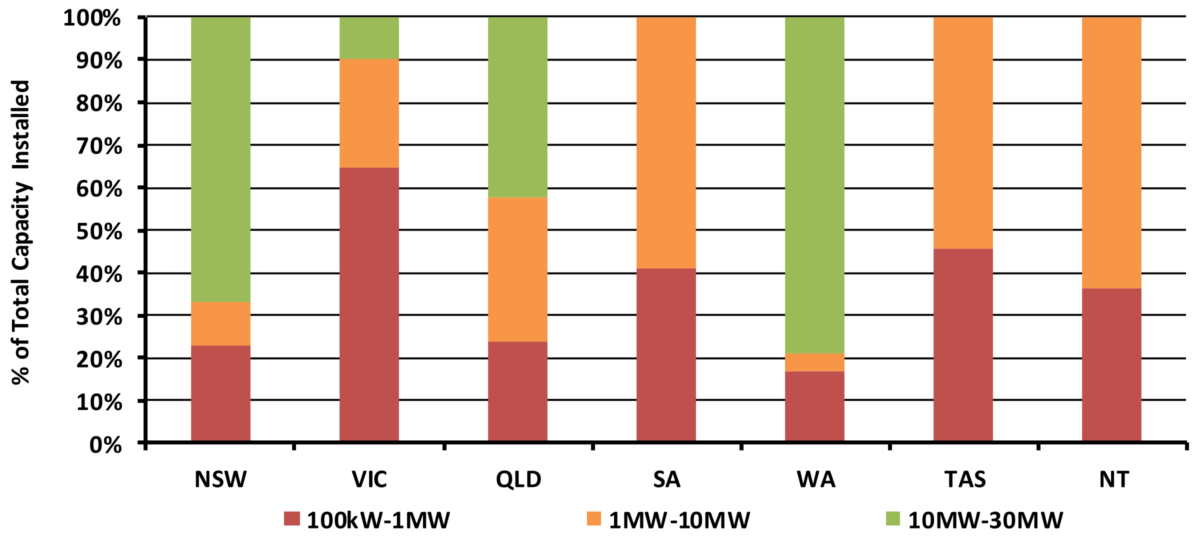
Figure 76 – Change in Market Share of PVNSG in Australia by Size Band (%)



Source: APVI (2019)[55]

The distributions[56] of total capacity and installations of PVNSG by system size band for each state are displayed in Figure 77 and Figure 78 respectively.

Figure 77 – Distribution of Total Capacity by PVNSG System Size Band



Source: APVI (2019)[57]

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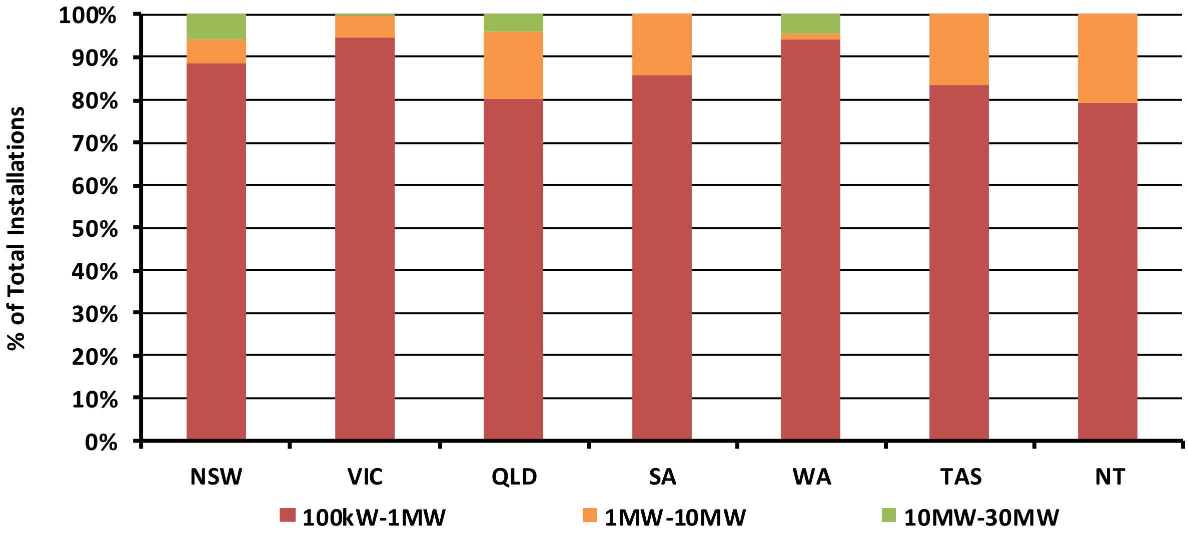
[55] Sourced from: http://pv-map.apvi.org.au/power-stations

[56] It is important to observe that there are currently no PVNSG systems above 10 MW in SA, TAS or NT. Therefore, our modelling is unable to predict in any scenario the uptake of PVNSG systems in the 10 MW–30 MW range for these states. Energeia notes this as a limitation to our current forecasting methodology.

[57] Sourced from: http://pv-map.apvi.org.au/power-stations

Figure 78 – Distribution of Total Installs by PVNSG System Size Band



Source: APVI (2019)[58]

D.4. Outputs and Reporting

The PVNSG model can produce capacity and installation reporting at both the aggregate and segmented level by month and year to FY51.

Energeia forecasted the uptake of PVNSG systems across the states of Australia at both the annual level to FY51, and the monthly level to FY21. The uptake was modelled in terms of both capacity installed and number of installations, across a range of scenarios. It was also further segmented by system size band, as explained in Section D.2.2. Modules. As part of the QA process, Energeia also reports the last 5 FYs of historic uptake by all segments.

D.4.1. Population Level Uptake

An example of the aggregate reporting the PVNSG model can produce is shown in Figure 79, which shows cumulative capacity installed by state, and Figure 80, which shows cumulative installations by state.

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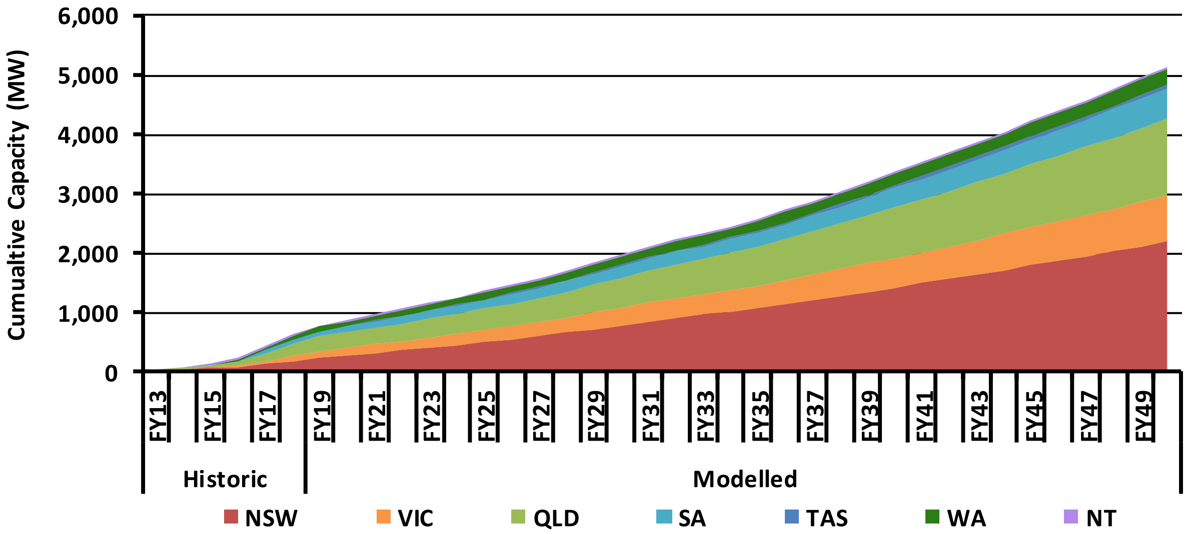
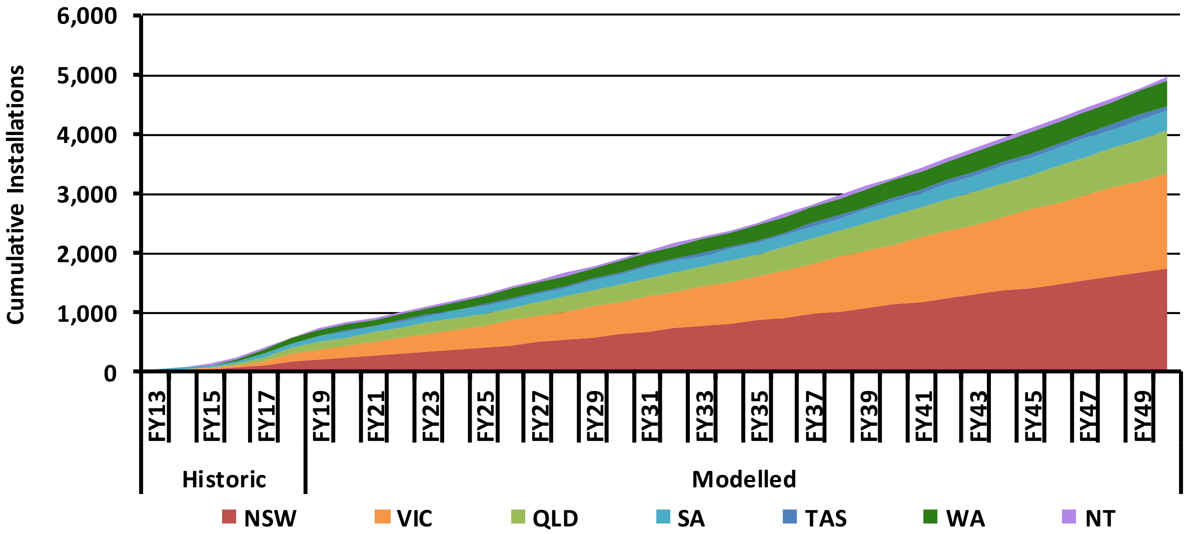
[58] Sourced from: http://pv-map.apvi.org.au/power-stations

Figure 79 – PVNSG Model Reporting Example #1 - Cumulative Capacity by State (Indicative)



Source: Energeia Modelling

Figure 80 – PVNSG Model Reporting Example #2 - Cumulative Installations by State (Indicative)

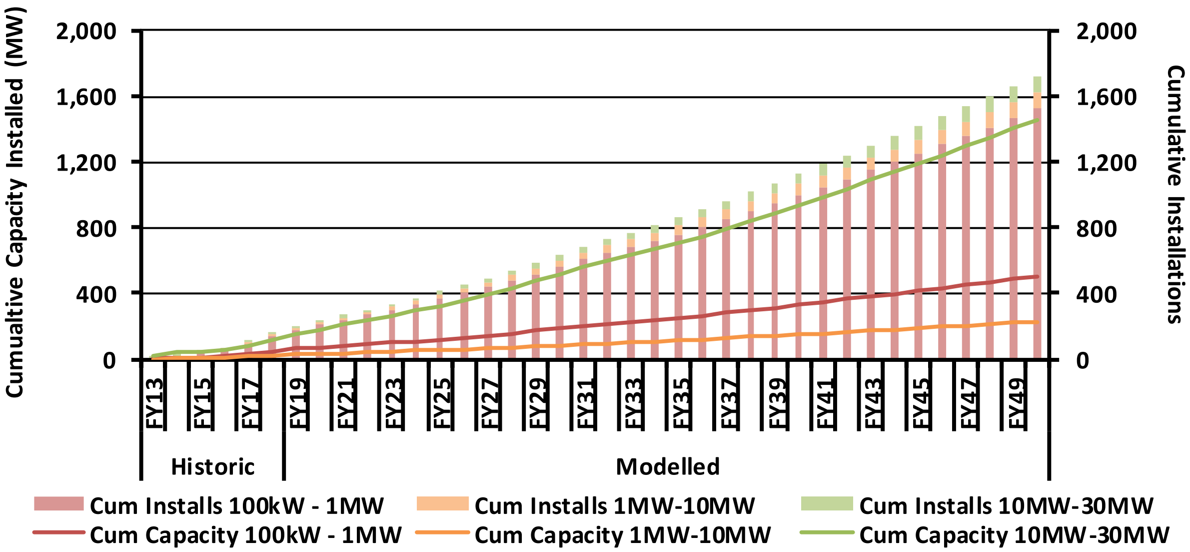


Source: Energeia Modelling

D.4.2. System Size Segmentation

An example of the specific reporting the PVNSG model can produce is shown in Figure 81. It displays the full reporting for the given state, which includes cumulative capacity and installations segmented by system size bands.

Figure 81 – PVNSG Model Reporting Example #3 (Indicative)



Source: Energeia Modelling

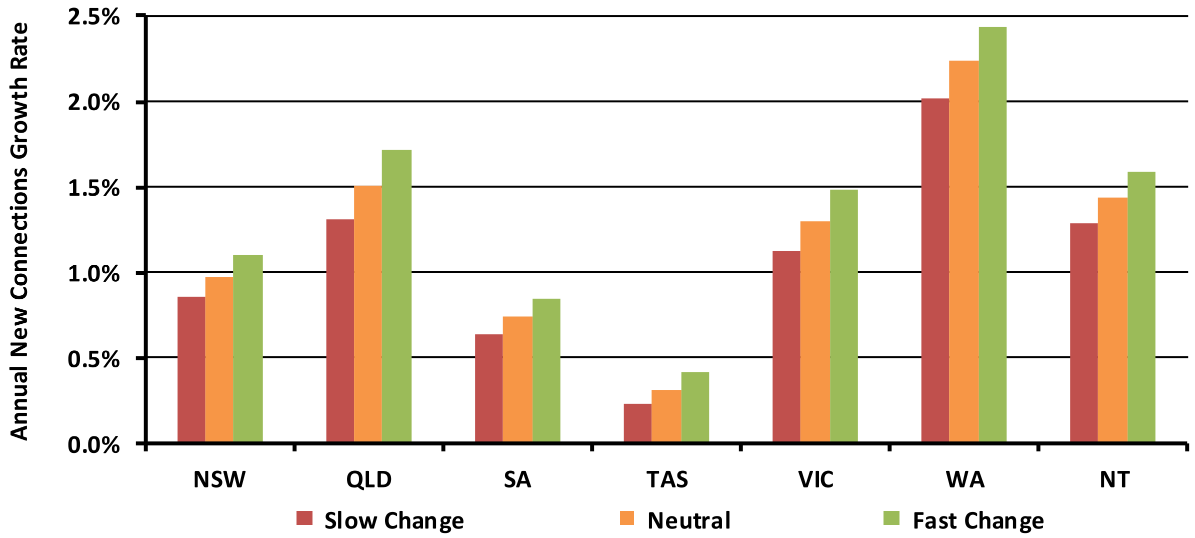
Appendix E – Additional Detailed Data Inputs and Assumptions

E.1. Economic Data and Assumptions

E.1.1. Connections Growth

The growth of new connections is viewed as a key driver of future DER uptake, mainly the scale in which DER technologies are installed by customers each year. Energeia uses the connections growth rate based on data supplied by AEMO, as shown in Figure 82. Note that connections growth was not supplied for the NT, where the ABS population growth data was used.

Figure 82 – Annual Connections Growth Rate

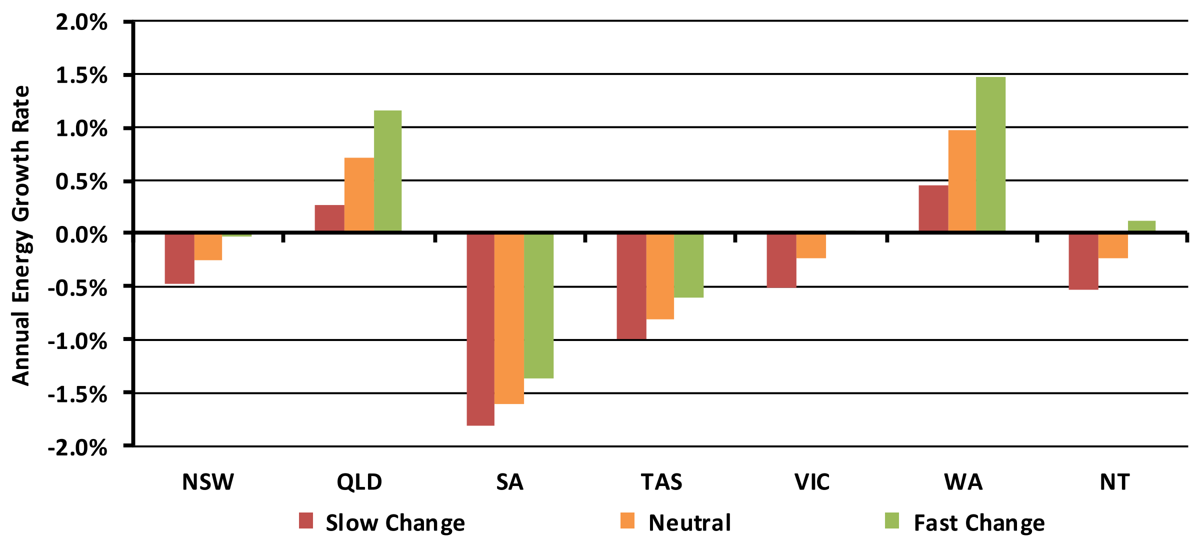


Source: AEMO, ABS Building Approvals (Jan 2019), Energeia Analysis

E.1.2. Energy and Peak Demand Growth

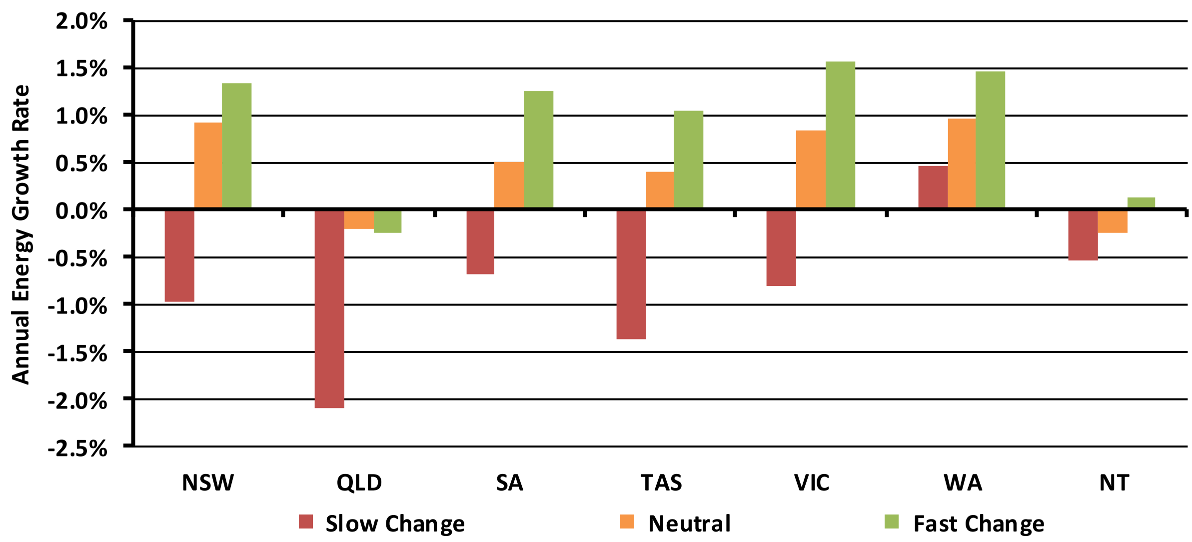
The load of each agent in the model is driven by their consumption and peak demand. Energeia adopts energy and peak demand growth from data provided by AEMO, the 2018 AEMO WEM ESOO and the NT Utilities Commission 2016-17 Power System Review, as shown in Figure 83, Figure 84 and Figure 85.

Figure 83 – Annual Residential Energy Growth Rate



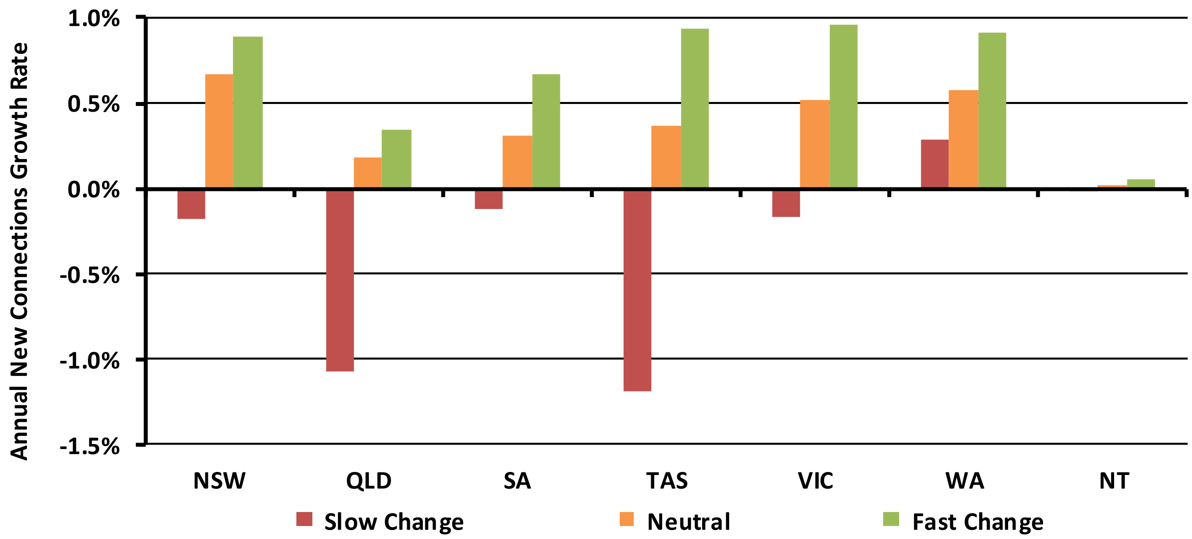
Source: AEMO, AEMO WEM ESOO (2018), The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

Figure 84 – Annual Business Energy Growth Rate



Source: AEMO, AEMO WEM ESOO (2018), The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

Figure 85 – Annual Peak Demand Growth Rate



Source: AEMO, Energeia Analysis, The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

E.1.3. Retail Tariff Structures

Tariffs play a significant role in the agent's decision making process. The implementation of various existing tariff structures will impact agent's investment in DER as agents attempt to maximise their bill savings. Tariff reform, and the introduction of cost reflective tariffs is an ongoing change in the pricing and regulatory environment which impacts on customer consumption and bills. Tariffs which reflect the timing of consumer demand will incentivise customers to change their behaviour to avoid consuming from the grid during higher-demand (and therefore, higher-priced) periods and take up DER to minimise their electricity bill.

Energeia's model initially sets all agents to the flat tariffs. These rates and structures are taken from each representative DNSP's Tariff Structure Statements (TSS). Additionally, each of the DNSP's TSS have proposed forms of cost-reflective pricing for residential and commercial customers through either Time-of-Use (ToU) or Maximum Demand (MD) tariffs. These are available to agents on an opt-in basis in the starting years, before being set as to the default tariff where agents can opt-out. The tariffs available are summarised in Table 27.

Table 27 – Retail Tariff Structure Summary

State	DNSP	Residential Tariffs			Commercial Tariffs		
		Flat/IBT	ToU	MD	Flat/IBT	ToU	MD
QLD	Energex	✓	✓	✓	✓	✓	✓
	Ergon	✓	✓	✓	✓	✓	✓
NSW	Ausgrid	✓	✓	✓	✓	✓	✓
	ActewAGL	✓	✓	✓	✓	✓	✓
	Endeavour	✓	✓	✓	✓	✓	✓
	Essential	✓	✓	✓	✓	✓	✓
VIC	Ausnet	✓	✓	✓	✓	✓	✓
	CitiPower	✓	✓	✓	✓	✓	✓
	Jemena	✓	✓	✓	✓	✓	✓
	PowerCor	✓	✓	✓	✓	✓	✓
	United Energy	✓	✓	✓	✓	✓	✓
SA	SA Power Networks	✓		✓	✓	✓	✓
TAS	TasNetworks	✓	✓	✓	✓	✓	✓
WA	Western Power	✓	✓		✓		✓
NT	Power and Water Corporation	✓	✓		✓	✓	

Source: Tariff Structure Statements (2018)

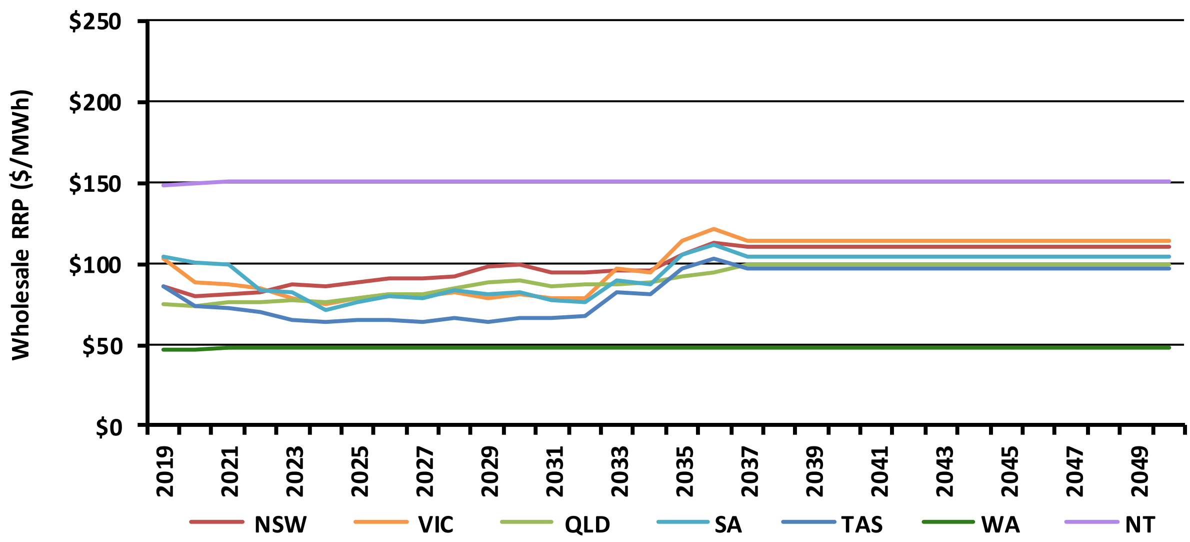
E.1.4. Growth of Tariff Rates

Tariffs available to customers are composed of a retail, a network and a wholesale component. The growth of tariff rates will impact the decision making process for agents to take up DER technologies.

Energeia's model forecasts the following key components of tariff rates:

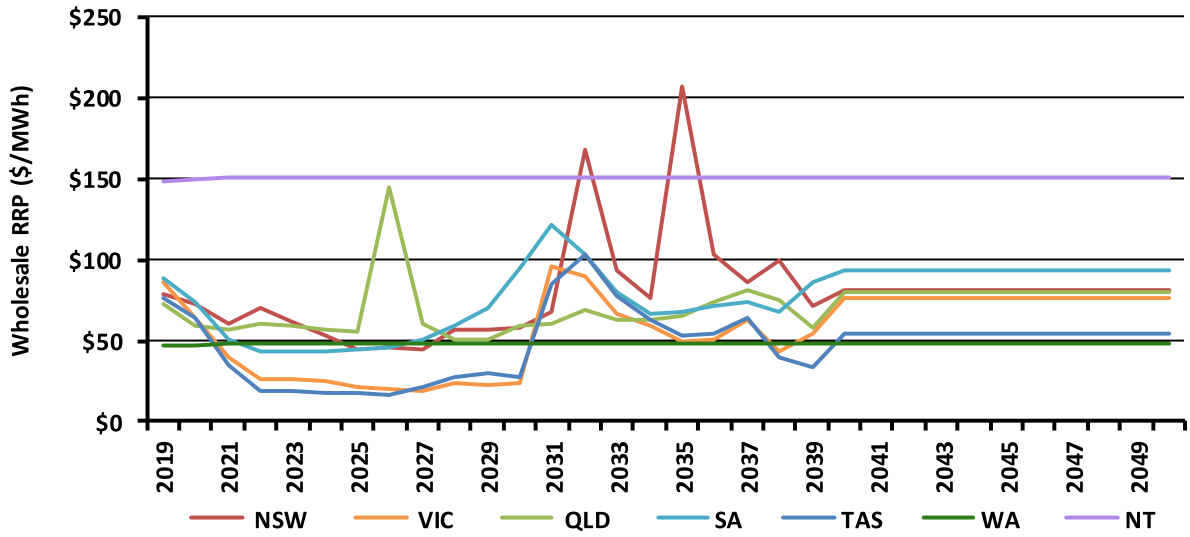
- **Retail Component** – The retail component of all tariffs includes the cost of the generation, or the wholesale RRP, a retailer's margin and a feed-in-tariff rate. The wholesale RRP for each scenario and the feed-in-tariff rates are shown in Figure 86, Figure 87, Figure 88 and Figure 89.
- **Network Component** – Each tariff includes the cost of using the network distribution system. These are updated and normalised within Energeia's modelling methodology. Further details can be found in Appendix B – uSim Modelling and Assumptions.

Figure 86 – Wholesale RRP Growth – AEMO 26%



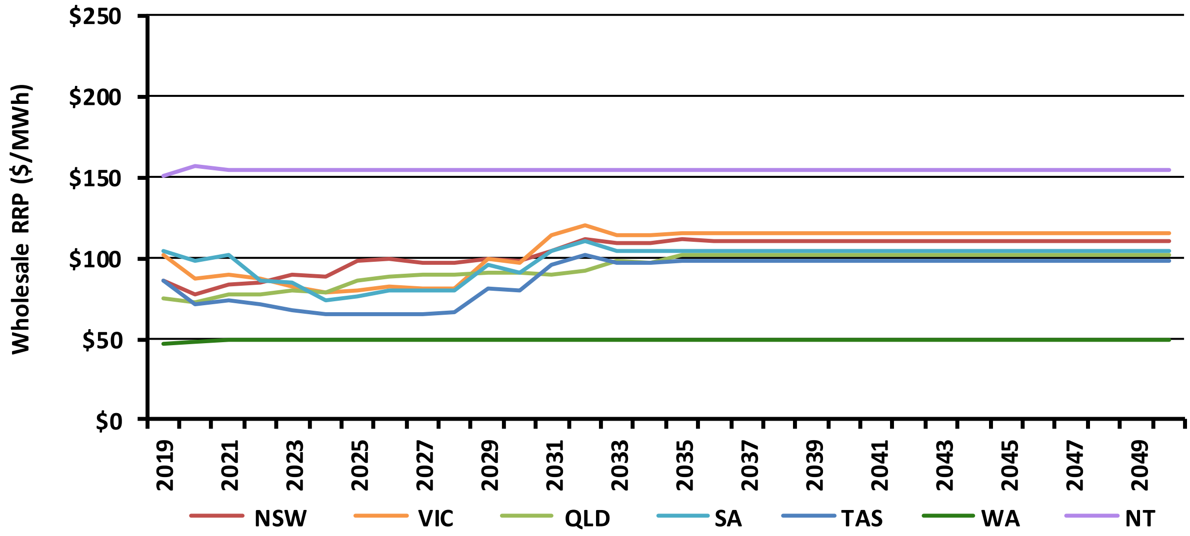
Source: AEMO, The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

Figure 87 – Wholesale RRP Growth – AEMO 45%



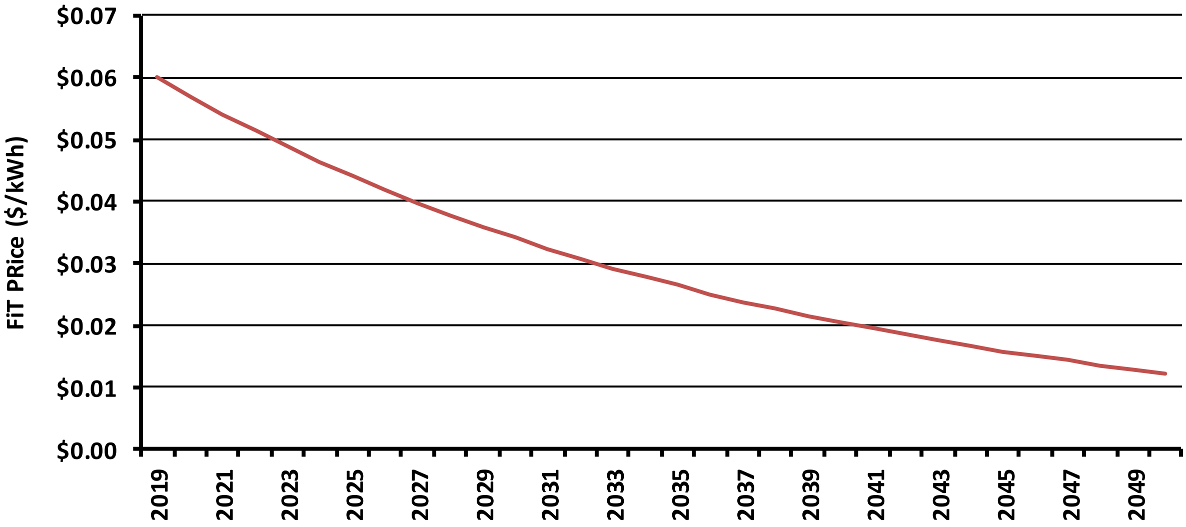
Source: AEMO, The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

Figure 88 – Wholesale RRP Growth – Energeia 45%



Source: Energeia Modelling, The Utilities Commission of the Northern Territory (2017) 'Power System Review 2016-17'

Figure 89 – Feed-in-Tariff Growth



Source: Energeia Analysis

E.1.5. DSO VPP Orchestration

Battery storage aggregation strategies allow an aggregator to orchestrate customer loads to reduce demand from network peak periods. Agents with storage systems are able to achieve further bill savings provided by aggregators, incentivising storage usage and additional take up of storage systems.

Energeia's model assumes aggregators have access to all customer batteries to use to reduce peak demand. Additional information can be found in Appendix B – uSim Modelling and Assumptions. The starting year for the implementation of storage aggregation differs between scenarios outlined in Section 3.2.

E.1.6. DER Cost Curves

Price plays a large role in a customer's decision to invest in DER technologies. Energeia's model assumes that a customer will take up DER technologies in conjunction with the bill savings attributed to the technology. Price will impact each agent's decision to invest in DER in a unique way, as the potential benefits will differ depending on how each customer uses energy.

The uptake of DER is highly influenced by the changing costs. Solar PV cost curves for both small and large scale applications are sourced from the 4 degrees scenario from CSIRO's 2018 report[59]. Storage and inverter cost forecasts are developed by Energeia's expert view and comprehensive research.

Energeia forecasts a continued decline in small- and large-scale solar PV, inverter and storage costs, driven by:

- **Battery Economies of Scale** – further steep decline in battery cell and inverter prices due to increasing economies of scale, as EV and battery sales grow.
- **DER Retail Margins** – retail margin compression is forecast to occur for DER as competition increases.
- **DER Installation Costs** – a combination of productivity increases, and cost sharing drive down installation costs over the medium to longer term.

The pricing trends of DER differ in each scenario as shown in Table 28 which depicts the CAGR of the total installed per unit cost of each DER technology. The forecast of these DER technologies used in each scenario are shown in Figure 90, Figure 91 and Figure 92. All costs do not include additional rebates provided either

[59] CSIRO 'GenCosts 2018' (2018), available here https://www.csiro.au/~/media/News-releases/2018/Annual-update-finds-renewables-are-cheapest-new-build-power/GenCost2018.pdf

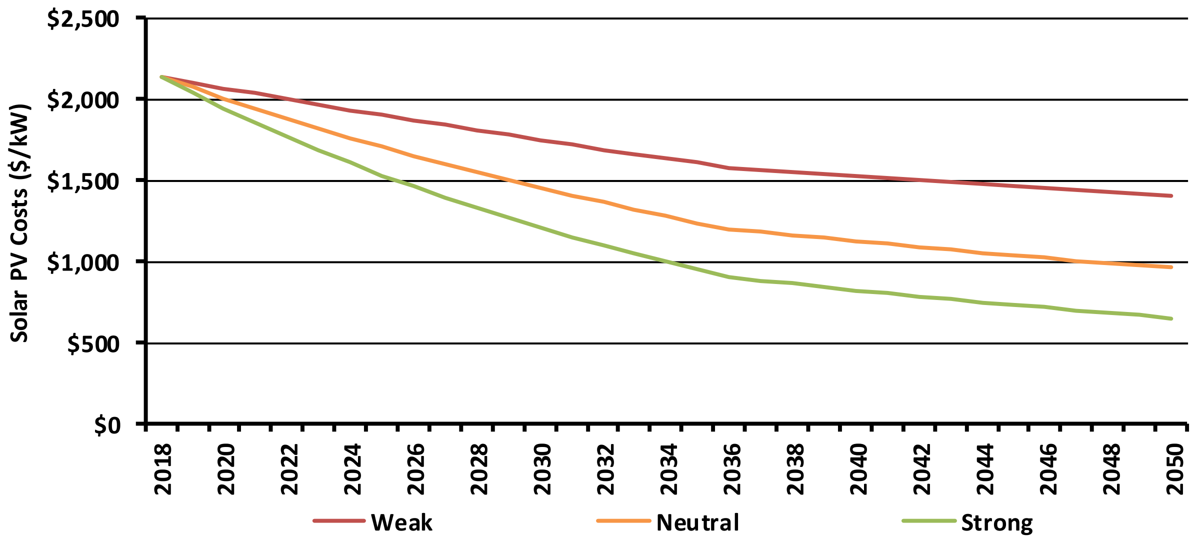
through government funding or Small-scale Technology Certificates (STCs). Solar costs are inclusive of inverter costs, unlike storage where only the system costs are shown.

Table 28 – CAGR for Installed Costs by Scenario and DER Technologies

	Weak	Neutral	Strong
Small Scale Solar PV	-1.8%	-3.3%	-4.8%
Battery	-3.5%	-5.0%	-6.5%
Inverter	-1.2%	-2.7%	-4.2%
Large Scale Solar PV	-1.8%	-3.3%	-4.8%

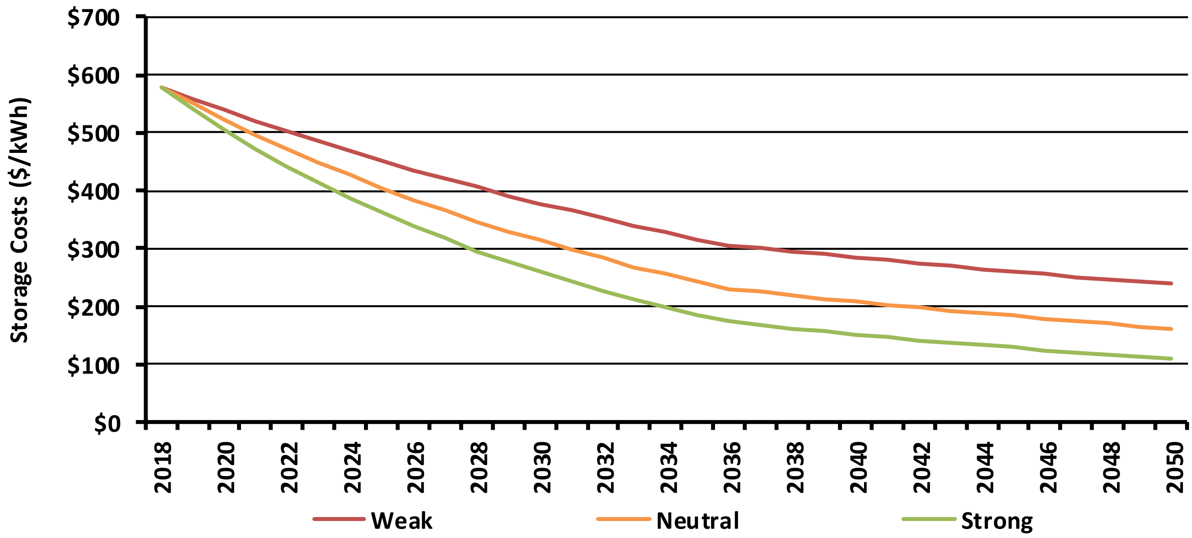
Source: Energeia Analysis

Figure 90 – Small Scale Solar PV Installed Cost Forecast



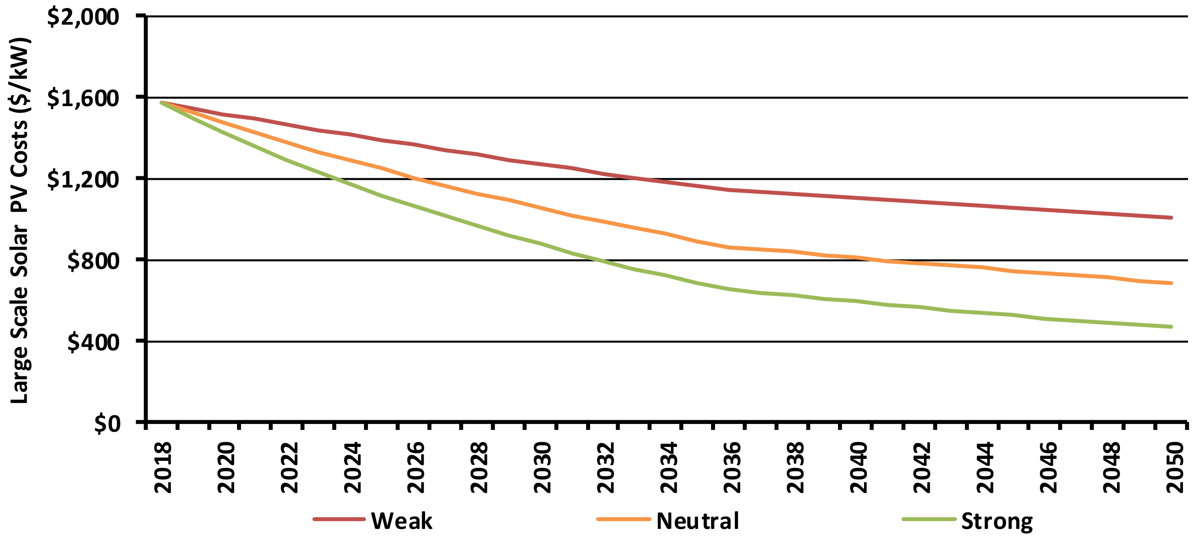
Source: CSIRO GenCost (2018), Energeia Analysis; Note: These costs include the cost of the inverter at a 1:1 size ratio.

Figure 91 – Small Scale Battery Installed Cost Forecast



Source: Energeia Analysis

Figure 92 – Large Scale Solar PV Installed Cost Forecast



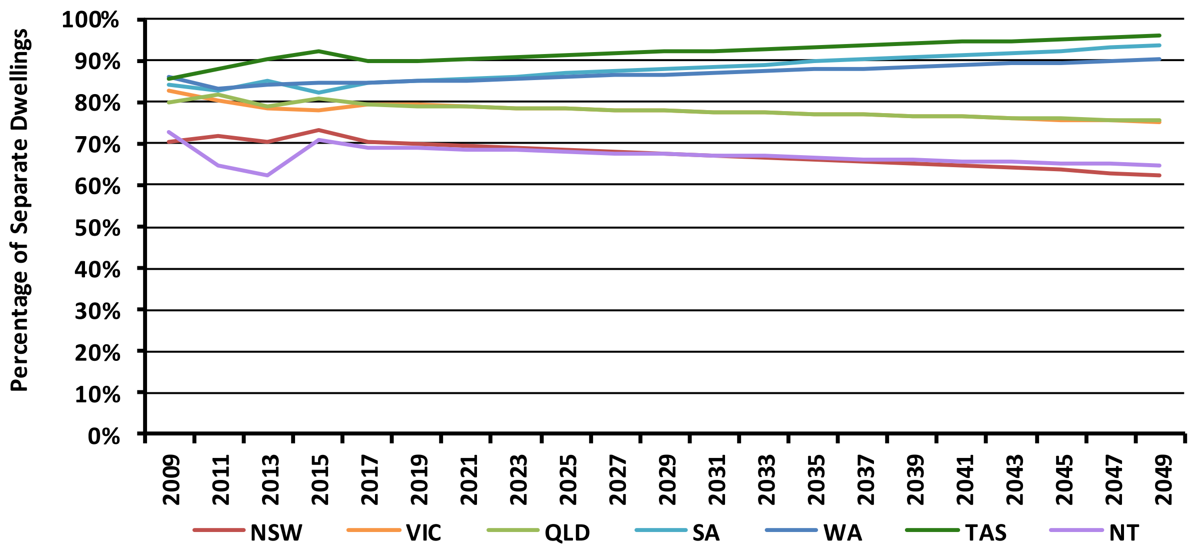
Source: CSIRO GenCost (2018), Energeia Analysis

E.2. Infrastructure Data and Assumptions

E.2.1. Dwelling Type

Energeia models the number of separate dwellings and attached dwellings with different roof-space availability. Considering solar uptake is limited by available roof space per dwelling, it is important to reflect trends of roof-space per dwelling over the forecasting period. Energeia has taken forward historic trends between separate dwelling and attached dwelling occupancy to forecast available roof-space on a customer basis, this is highlighted in Figure 93 and does not change by scenario.

Figure 93 – Percentage of Separate Dwellings



Source: ABS Household Occupancy and Costs (2016)

Only detached, separate dwellings are assumed to be available for solar PV uptake in Energeia's forecasting model. Customers residing in attached dwellings, such as apartments, unit and suites, are not available to purchase solar PV as incentives are fundamentally split between residents in the dwelling. The availability of community solar offers residents in attached dwellings the benefits of solar PV, however this is not modelled in Energeia's forecasting methodology. As a result, solar PV uptake is underestimated.

E.2.2. Home Ownership

Owners and renters have a different propensities to modify their homes with DER or EV charging infrastructure. Reflecting home ownership is critical in understanding the limits on technology adoption over the forecast period.

Energeia's modelling methodology does not distinguish between customers who rent or own their premise and assumes all separate dwellings are able to purchase a solar PV system. As a result, the number of solar PV installations may be overestimated. However, it is assumed that state governments will incentivise owners to purchase solar PV to unlock the customer and network economic benefits of solar PV, resulting in a total available market including both owners and renters.

E.2.3. Technology Parameters

Solar PV

A solar PV system's output is affected by various factors, including panel degradation and panel orientation. Energeia assumes a system degradation rate of 0.5%[60] each year for the entire lifetime of a solar PV system. Energeia's model also assumes all solar panels are north-facing. Solar panel owners are potentially transitioning towards west-facing panels to shift generation towards peak periods. The potential adoption of west-facing solar panels in the future will have a minimal impact on the solar generation relative to north-facing systems and is negligible[61].

Additionally, the export limitation of solar PV panel inverters is considered to have negligible impact under Energeia's modelling approach, as optimal sizes are smaller than export limits. Grid exports by customers on a single-phase (residential) connection and three-phase (commercial) connection are detailed in Table 29. On average, exports by single-phased customers and three-phased customers are limited by 5 kW and 30 kW respectively which are above the average customer uptake size of solar PV. Additionally, the increasing uptake of batteries will limit grid exports of excess solar as customers charge their batteries with solar spill to be used to offset peak energy and demand charges in the peak periods.

Table 29 – Solar PV Export Limitations by DNSP and Phase Type

	Single-Phase	Three-Phase
ActewAGL	5 kW	30 kW
Ausgrid	10 kW	?*
Essential	3 kW / 5 kW	?*
Endeavour	5 kW	30 kW
Energex	5 kW	15 kW
Ergon	5 kW	15 kW
Power Water	5 kW	7 kW
SAPN	5 kW	30 kW
TasNetworks*	10 kW	30 kW
United	10 kW	30 kW
CitiPower and PowerCor	5 kW	30 kW
Jemena	10 kW	30 kW
Ausnet	5 kW	15 kW
WesternPower	10 kW	30 kW

Source: SolarChoice (2017); Note: *Requires an application and review process from the DNSP

[60] Australian Energy Council 'Solar Report' (2018), available here: https://www.energycouncil.com.au/media/11188/australian-energy-council-solar-report_-january-2018.pdf

[61] Please see the case study Solar Panel Orientation Impacts for more details.

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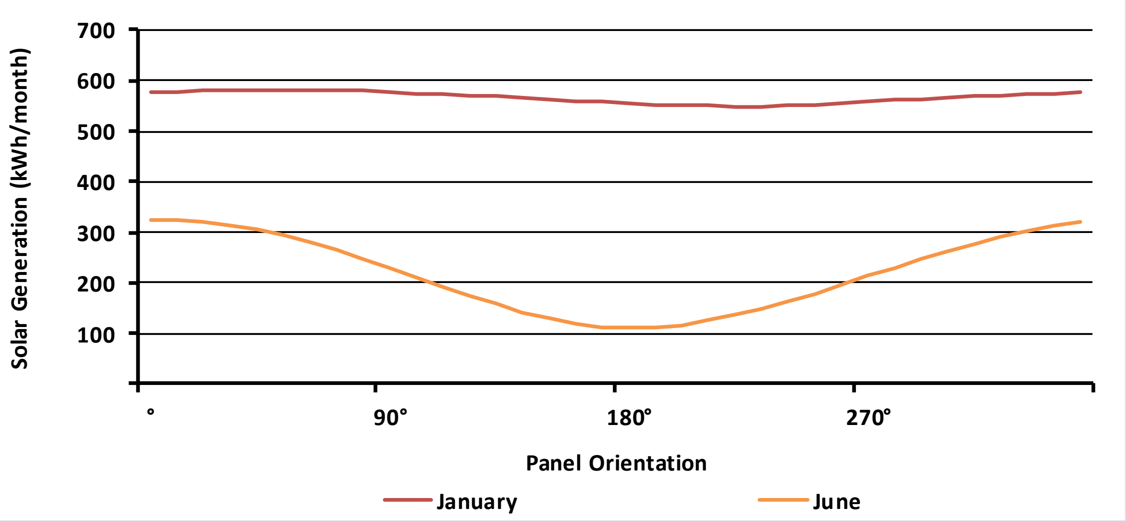
Solar Panel Orientation Impacts:

The direction a solar panel faces dictates the amount of solar radiation incident on the panel and thus plays a significant factor in energy output. Figure 94 shows the effect of orientation angle on power output for a solar panel located in Sydney. During January, orientation affects output by less than 10% whilst the effect is much more pronounced during June. Within the winter period, a north-facing panel improves system performance by 30% compared to a west-facing panel.

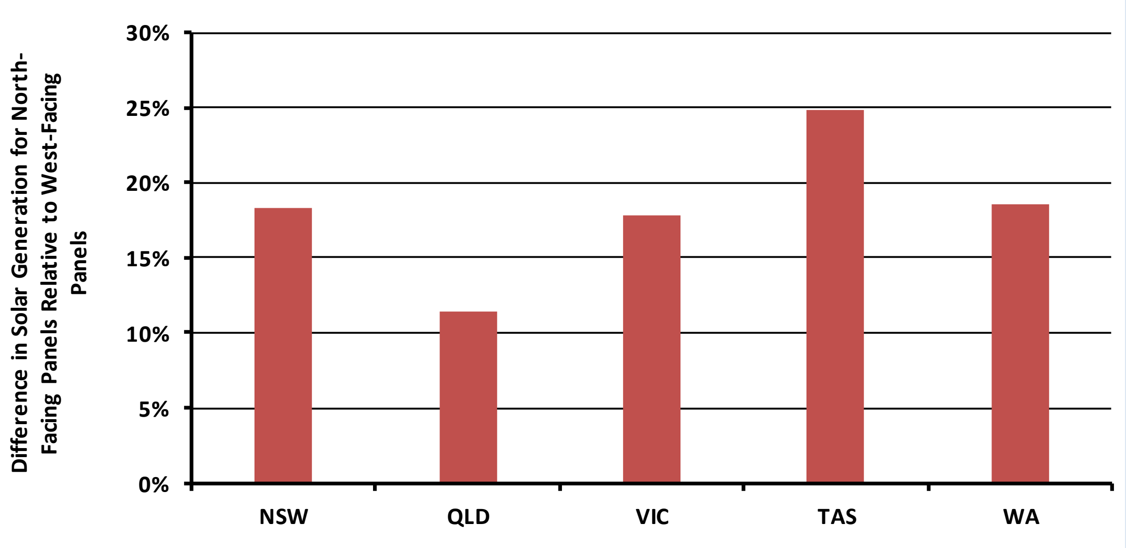
Figure 94 – Impact of Panel Orientation on Solar Generation during January and June



Source: NREL PVWatts, Energeia Analysis; Note: Solar generation is produced by a 4 kW system located in Sydney, with a tilt angle of 20°

As solar generation varies geographically in Australia, the effects of solar panel orientation will differ. As shown in Figure 95, southern states such a TAS will experience a larger difference compared to northern states. QLD shows the least difference in solar generation, with north-facing panels increasing the solar generation compared to west-facing panels.

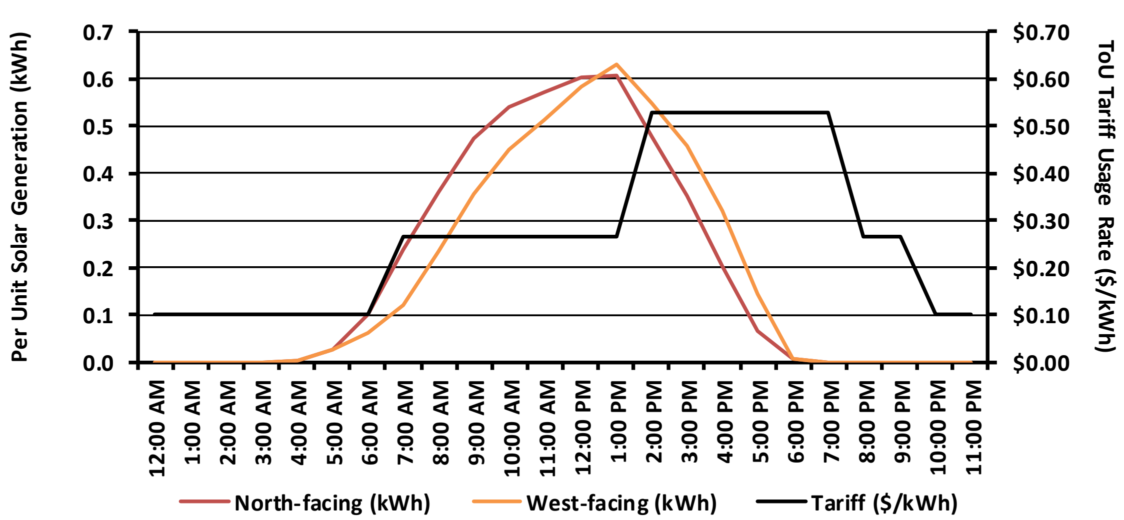
Figure 95 – Relative Improved Annual Performance for North-facing Panels Compared to West-facing Panels



Source: NREL PVWatts, Energeia Analysis; Note: Solar generation is produced by a solar panel system located across Australian capital cities, with a tilt angle of 20°

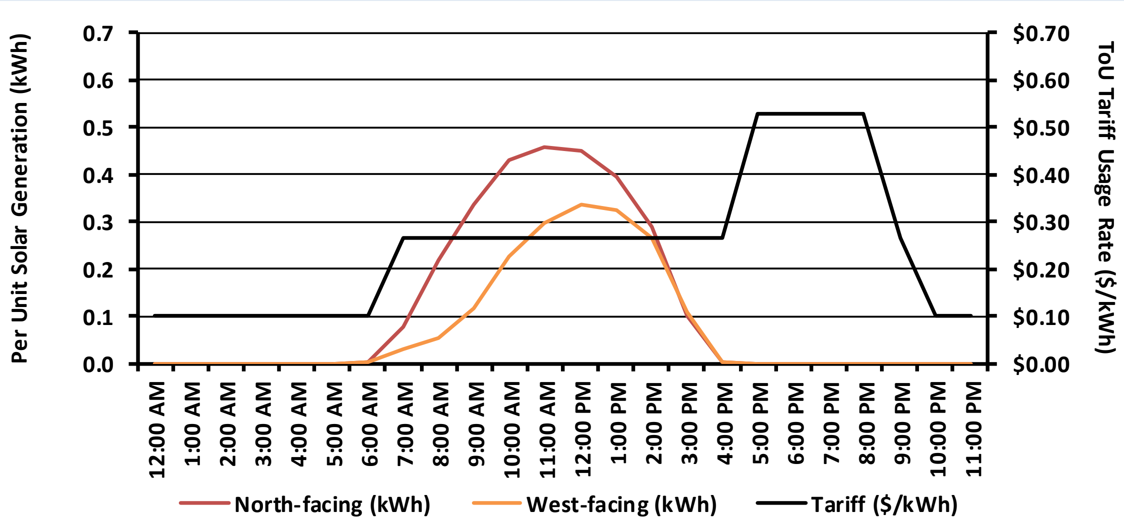
Although north-facing panels produce more energy over the day, west-facing panels peak in their production later in the day often aligning with peak periods structured in cost-reflective tariffs, such as the time-of use-tariff. This is shown in Figure 96. During an average day in January, west-facing panels can increase potential bill savings on the usage component of the bill by 5% compared to north-facing panels. However, the decrease in generation during June reduces the potential bill savings by 35% as shown in Figure 97.

Figure 96 – Average Daily Unit Solar Generation in January and Associated Cost Reflective Pricing



Source: NREL PVWatts, Retailer Fact Sheets, Energeia Analysis; Note: Average daily solar generation is produced by a solar panel with a tilt angle of 20° in Sydney, with a Time-of-Use tariff in the Ausgrid network

Figure 97 – Average Daily Unit Solar Generation in June and Associated Cost Reflective Pricing



Source: NREL PVWatts, Retailer Fact Sheets, Energeia Analysis; Note: Average daily solar generation is produced by a solar panel with a tilt angle of 20° in Sydney, with a Time-of-Use tariff in the Ausgrid network

Energeia assumes all solar panels are facing north. If in the future people begin to adopt west-facing panels due to the financial benefits of ToU tariffs, the effect of overall output on the model will be insignificant. Assuming north-facing panels are 25% more efficient than west-facing panels (Figure 95), the change in total solar generation within Australia will decrease by 10% if half of the solar PV population in Australia are west-facing compared to all north-facing solar PV panels. When considering the rate of uptake of solar, this difference is negligible.

Additionally, the increasing uptake of batteries will offset the peak charge, leaving panel orientation close to negligible in regards to ToU cost and hence panels will generally align to the north.

Battery

Batteries are used to increase the value of solar PV generation and to arbitrage tariffs by shifting the battery owner's grid demand to times when retail electricity prices are lower. Batteries have a set of characteristics that limit their ability to complete their objectives, which are shown in Table 30. Additional details on battery parameters can be found in Appendix B – uSim Modelling and Assumptions.

Table 30 – Battery Parameters

Battery Characteristics	
Depth of Discharge	90%
Charging and Discharging Efficiency	90%
Battery Degradation	2% per year and additional degradation due to charging and discharging

Source: Energeia Research

Inverter

Inverters are essential for solar PV and battery configurations. Energeia assumes a smart inverter is adopted for all DER installs, sharing the cost of the inverter between the two DER technologies. This technology is becoming increasingly available in the market, with the Victorian Government[62] requiring mandatory installations of a smart inverter within their Solar Homes program, and ARENA[63] having invested in the research and development of smart inverter technology.

The size of the inverter will be optimally sized to meet the outputs of either the solar PV or battery system. Often, the inverter is sized 1:1 to the solar PV system, suggesting it is oversized as it is unlikely that the solar system will generation 100% of its capacity.

EVs

Autonomous Vehicles

Autonomous vehicles have the potential for significant disruption to how consumers interact with vehicles in the future, both in usage and ownership trends. Leaders in the sector have begun to take the first steps in utilising this technology with Waymo launching the first commercially operating autonomous car sharing service in 2018[1]. Despite the technology being available for autonomous transport, Energeia sees the biggest hurdle for future adoption in Australia being legislation and the emergence of sustainable business models. Given the significant uncertainty in predicting future policy as well as the uncertain effect of autonomous vehicles on transport behaviour Energeia did not model changes in vehicle ownership trends in the Australian market.

E.2.4. Network Infrastructure Constraints

Energeia assumes that network infrastructure constraints are managed with a mix of non-network solutions and smart grid technologies that balance power quality appropriately.

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[62] The Victorian Government is requiring all inverters installed in the Solar Homes program to be smart inverters. Available here: https://www.pv-magazine-australia.com/2019/04/02/victoria-to-make-smart-inverters-mandatory-for-solar-homes/ Accessed 29/04/2019

[63] ARENA's Networks Renewed program assessed the benefits of adopting smart inverter technology. Available here: https://arena.gov.au/projects/networks-renewed/ Accessed 29/04/2019

E.3. Policy Data and Assumptions

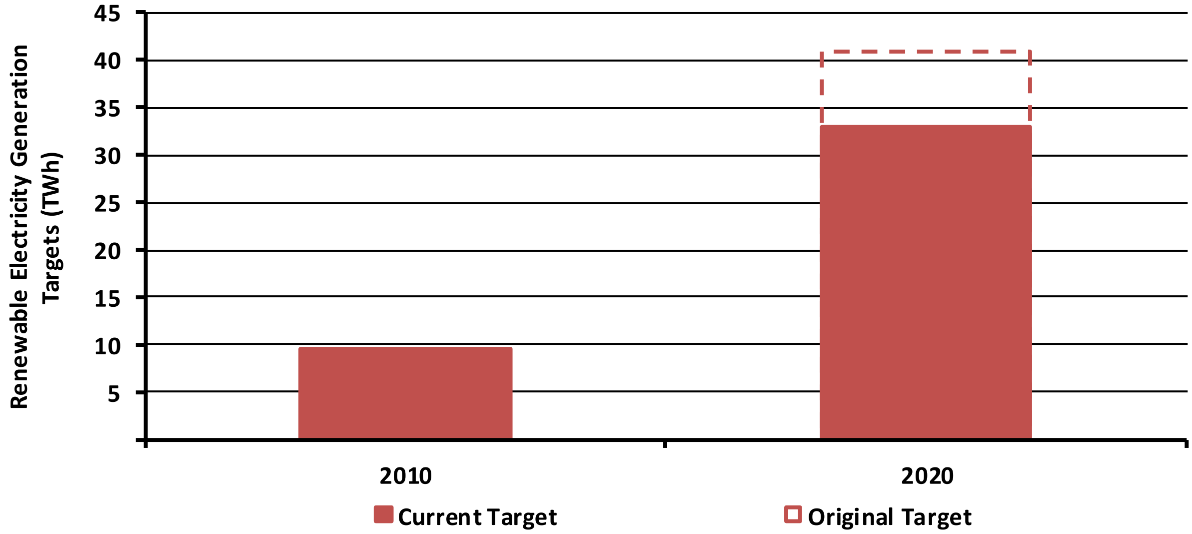
E.3.1. Federal Policies

Renewable Energy Target

In 2001, the Australian government legislated the Renewable Energy Target (RET) to ensure Australia's electricity is sourced from renewable generation and encourage the uptake of renewable energy. The RET scheme is composed of two components, the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET), which both offer financial incentives for households and larger renewable generation.

Since announcing an initial target of 9,500 GWh of renewable generation by 2010, as shown in Figure 98, Australia has positioned the electricity industry to exceed the 2020 target of 33,000 GWh of renewable generation prior to the deadline. The scheme will continue until 2030.

Figure 98 – Australia's Renewable Energy Target



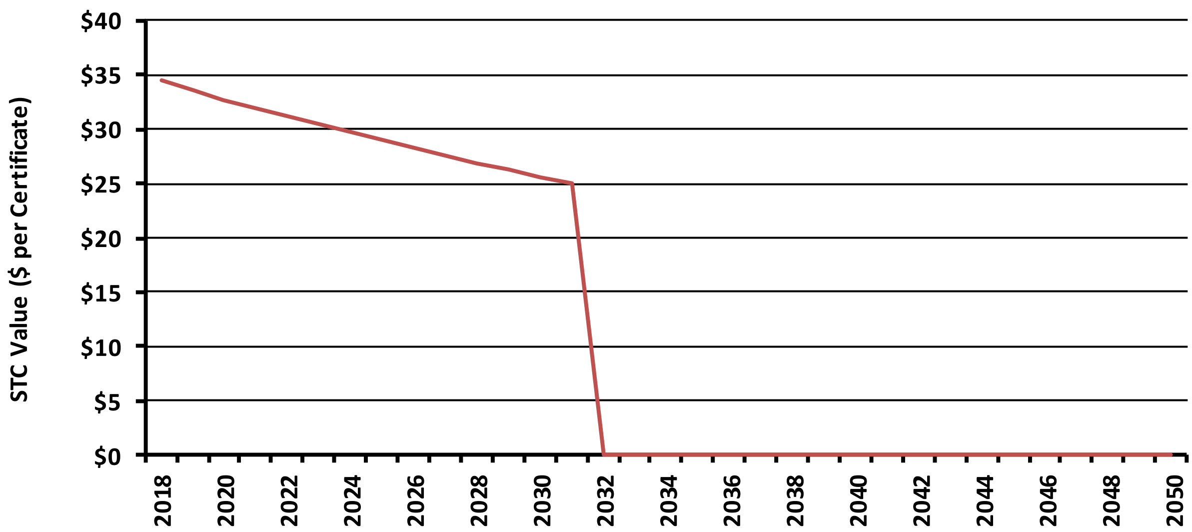
Source: Department of Energy and Environment (2019), Parliament of Australia (2010)

DER Rebates

Australia does not offer solar or storage system rebates on a federal level. Instead, financial incentives in the form of STCs and Large-scale Generation Certificates (LGCs) are available under the SRES and LRET components of the RET respectively. These rebates are included in the agent decision-making process in Energeia's modelling platform where the STC continues to steadily decreases in the value of STCs until 2031 as shown in Figure 99.

The deeming period for the STC continues as is for the Slow Change, Low DER, Neutral 26% and Neutral 45% scenarios. In the Fast Change, Neutral 45% and High DER scenarios, the STC is assumed to continue until the end of the forecasting period.

Figure 99 – Forecast STC Value



Source: Energeia Analysis

Carbon Emissions Targets

To limit the impacts of climate change on consumers and economic industries, countries are held accountable to their self-determined carbon emission targets. Since the Paris Climate Agreement, Australia has targeted to reduce emission to 26-28% on 2005 levels by 2030.

E.3.2. State Policies

Renewable Energy Targets

Independent of the federal renewable energy targets, various Australian states have announced their own targets for renewable generation, as shown in Table 31.

Both the ACT and TAS have both announced a 100% renewable target by 2020 and 2022 respectively. These are followed by a 50% renewable generation target by 2030 from both QLD and NT. VIC is striving for a 25% target by 2020, followed by a 40% target five years after.

The remaining states, NSW, SA and WA, do not have targets. However, SA has only recently removed their 50% renewables target by 2025 in mid-2018. Prior to the removal of their target, SA was on track to deliver their target well before the deadline. Despite this, SA still aims to reach net zero emissions by 2050.

These targets will impact customer bills, the generation mix of electricity as states implement regulations and policies to meet their targets.

Table 31 – State Renewable Energy Targets

State	Target
QLD	50% by 2030
NSW	-
ACT	100% by 2020
VIC	25% by 2020, 40% by 2025
TAS	100% by 2022
SA*	-
WA	-
NT	50% by 2030

Source: Government Websites. Note: *SA had removed their 50% target by 2025 in mid-2018.

DER Rebates

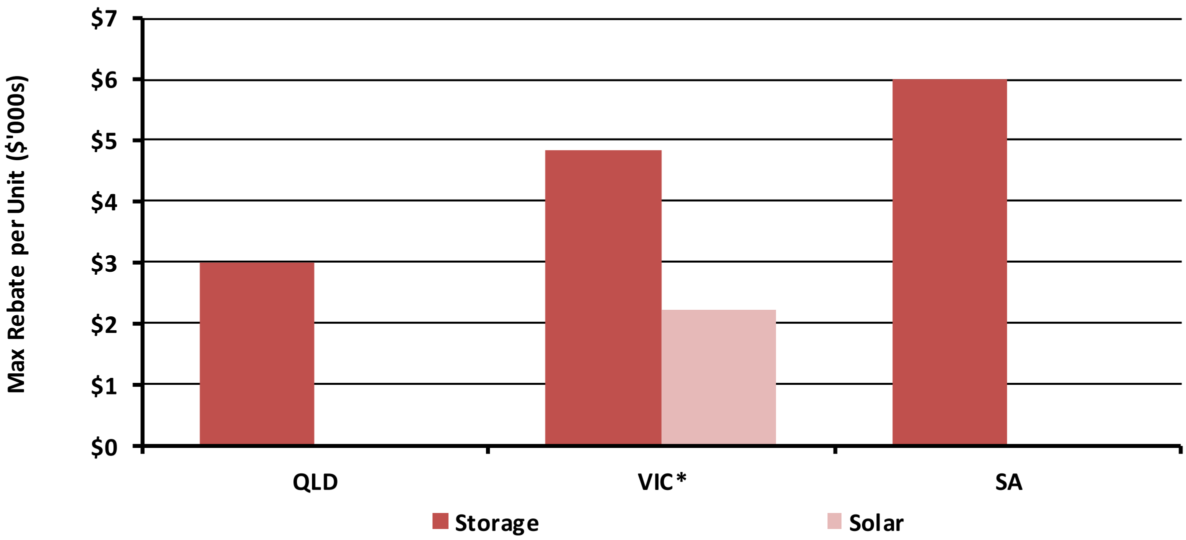
Various state governments offer subsidies and rebates to assist households in purchasing solar PV and storage systems to reduce consumption, energy bills and carbon emissions. The following DER rebates are currently available in Australia for newly installed solar and storage systems, as shown in Figure 100:

- **Queensland's Affordable Energy Plan** – Households and small businesses in Queensland can claim up to $3,000 in funding towards a storage system, or a solar and storage package. These rebates are set to expire in 2019.
- **Victoria's Solar Homes Package** – Since its implementation in 2018, households can claim up to $2,225 in subsidies for a newly installed solar PV system. This subsidy is set to expire in 2019.

  In November 2018, the Victorian Government announced their intention to extend the Solar Homes Package to include rebates for storage systems. An initial subsidy of $4,838 per household at maximum is planned, which will decline to $3,714 by 2026 reflecting declining storage costs. This subsidy is yet to be offered and is not factored in the modelling.
- **South Australia's Home Battery Scheme** – From October 2018 onwards, households in South Australia can apply for subsidies for installing a new storage system. Households are provided $500/kWh of installed capacity, up to a maximum of $6,000 per battery installed. This subsidy is available until 2020.

Energeia's modelling platform assumes each state will implement a rebate analogous to the South Australian Home Battery Scheme in the Fast Change, High DER and Neutral 45% scenarios. A maximum $6,000 per unit installed (or $500/kWh) rebate for batteries will be available from the initial year until 2021.

Figure 100 – DER Rebates Offered by State



Source: Government Websites. Note: *Storage rebate announced by the Victorian Labour Government is not yet available. The rebates are also set to be reduced to a maximum of $3,714 by 2026 due to falling storage system costs.

Appendix F – Battery Purchasing Case Study

Energeia conducted an analysis to investigate the impacts of purchasing DER between 2019 and 2029. For a single residential customer in Ausgrid with an annual consumption of 6MWh, Energeia calculated the customer's bill, segmented by retail bill paid for grid consumption and tech costs for solar PV and batteries, and the associated first-year ROI of taking up the DER configuration. These were calculated for various DER configurations for the following cases:

- **For Customers without Solar PV** – Energeia assessed the configuration of the following for customers who did not have any existing solar PV systems:
  - *No DER* – if the customer had no solar PV or batteries and thus consumed from the grid.
  - *Solar PV Only* – if the customer were to uptake a 4kW solar PV system (with an associated 4kW inverter).
  - *Solar PV + Battery* – if the customer were to uptake a 4kW solar PV system (with an associated 4kW inverter) and an 8kWh battery system.
- **For Customers with Solar PV** – Energeia assessed the configuration of the following for customers who had purchased a 4kW solar PV system (and associated 4kW inverter) five years prior to the assessed year:
  - Solar PV Only – if the customer does not purchase a battery
  - Retrofit (shared inverter) – if the customer were to purchase an 8 kWh battery system and does not need to replace their inverter.
  - Retrofit (with new inverter) – if the customer were to purchase an 8 kWh battery system and replaces their inverter.

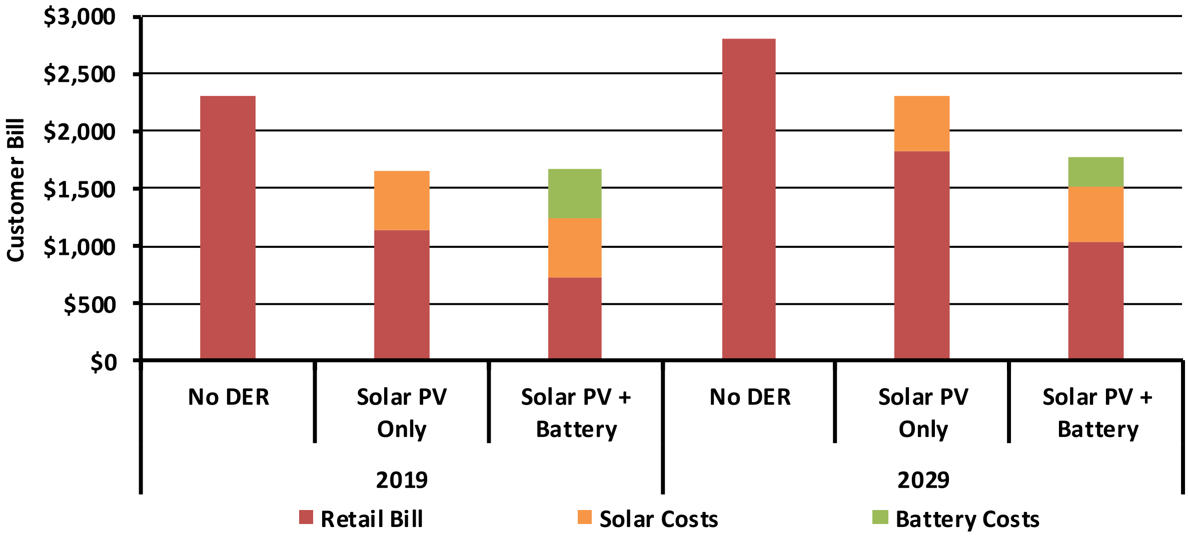
The following sections details the results of the analysis.

F.1. Simple Tariff

F.1.1. Customers without Solar PV

Figure 101 shows the customer bill for a customer on a simple tariff and does not have an existing solar PV system in 2019 and 2029.

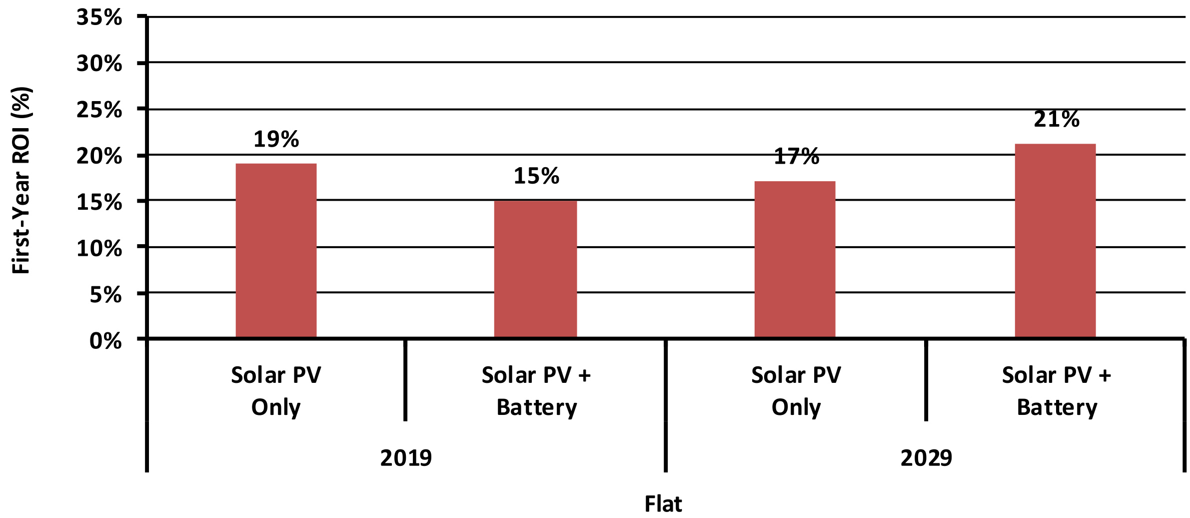
Figure 101 – Customer Bill for a Simple Tariff Customer with No Previous Solar PV



Source: Energeia Analysis; Note: Solar costs are inclusive of inverter costs.

In 2019, the cheapest annual cost option is to purchase a solar PV system rather than a solar + battery option. This ranking is also reflected in the associated ROI as shown in Figure 102. By 2029, purchasing both a solar PV and battery system would save the customer nearly $1,000 and is the cheapest option for this type of customer as retail rates increase and technology costs decrease over the time period. This is reinforced in Figure 102 as this option has the highest associated ROI with a 4.7 year payback period.

Figure 102 – First Year ROI for a Simple Tariff Customer with No Previous Solar PV



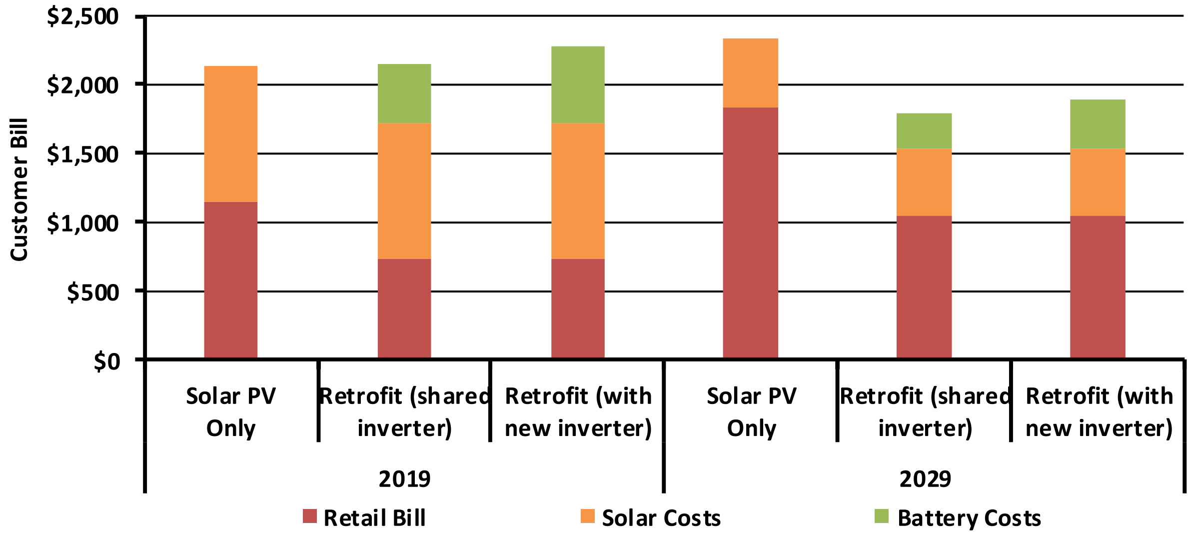
Source: Energeia Analysis

For customers on a simple Flat tariff that have no purchased any solar PV or battery systems prior to the assessed year, purchasing a solar PV system in 2019 and purchasing a solar PV and battery configuration in 2029 are the best options.

F.1.2. Customers with Solar PV

The customer bills and associated ROI for a customer on a simple tariff who had previously purchased a solar PV system five years prior and are seeking to retrofit a battery onto their configuration is shown in Figure 103 and Figure 104 respectively.

Figure 103 – Customer Bill for a Simple Tariff Customer with Previous Solar PV

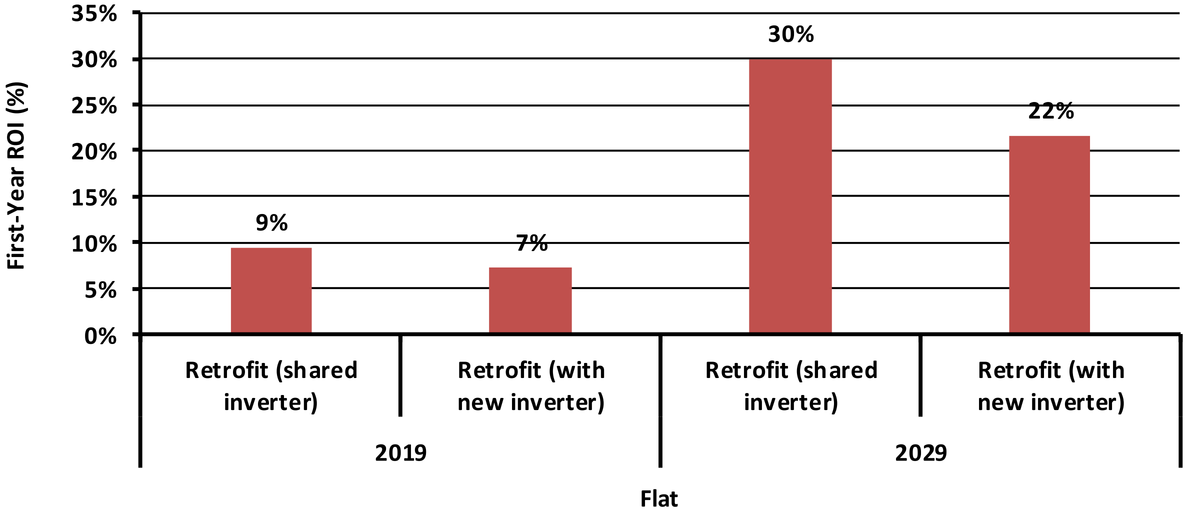


Source: Energeia Analysis; Note: Solar costs are inclusive of inverter costs, with the exception of the "Retrofit (with new inverter)" option, where the inverter costs are applied to the battery costs. We have assumed customers who retrofit a battery have purchased solar PV 5 years prior.

In 2019, this customer segment is not better off retrofitting a battery. Instead, a retrofit would increase their overall bill. The corresponding ROI is relatively low with a payback period greater than 10 years.

However, in 2029, the retail rates increase whilst the feed-in-tariff rate decreases which leads to a significantly larger customer bill relative to 2019 if the customer does not purchase any battery systems. Retrofitting a battery reduces the customer bill by $500 and results in an attractive ROI of 30% (assuming a shared inverter). Even in the case where the customer was required to replace their inverter with the retrofit of a battery system, the customer's bill is still cheaper than if the customer did nothing.

Figure 104 – First Year ROI for a Simple Tariff Customer with Previous Solar PV



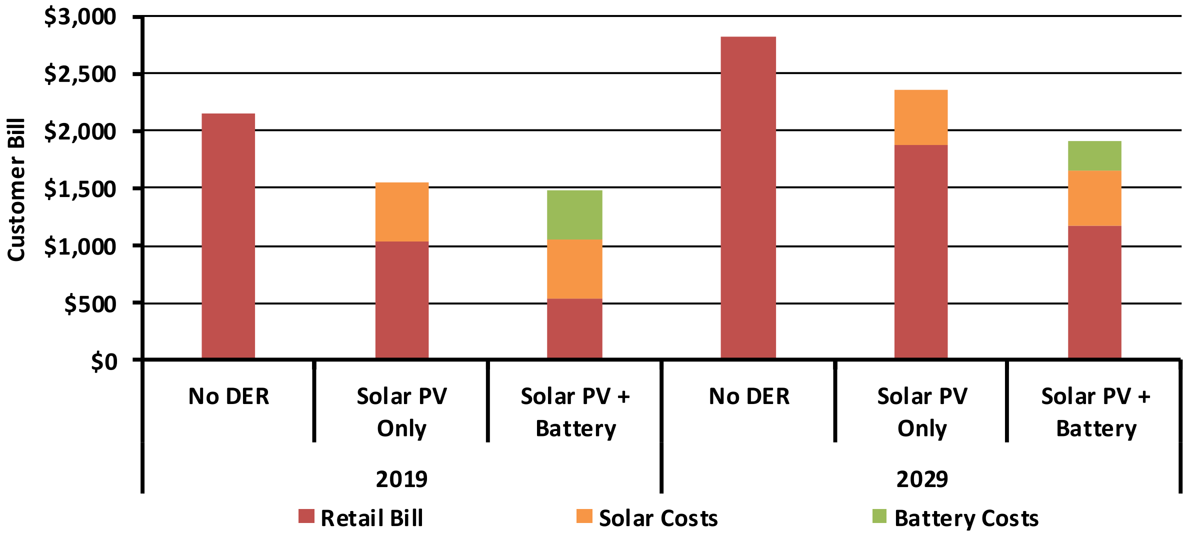
Source: Energeia Analysis

F.2. Smart Tariff

F.2.1. Customers Without Solar PV

The customer's bill and associated ROI in 2019 and 2029 with a smart ToU tariff are shown in Figure 105 and Figure 106 respectively. In contrast to the simple tariff analysis, in 2019 the cheapest annual customer bill is the option to purchase both a solar PV and battery system. However, the ROI for purchasing a solar only system is higher than that of purchasing both solar PV and battery due to the expensive capital cost of the battery system over its lifetime.

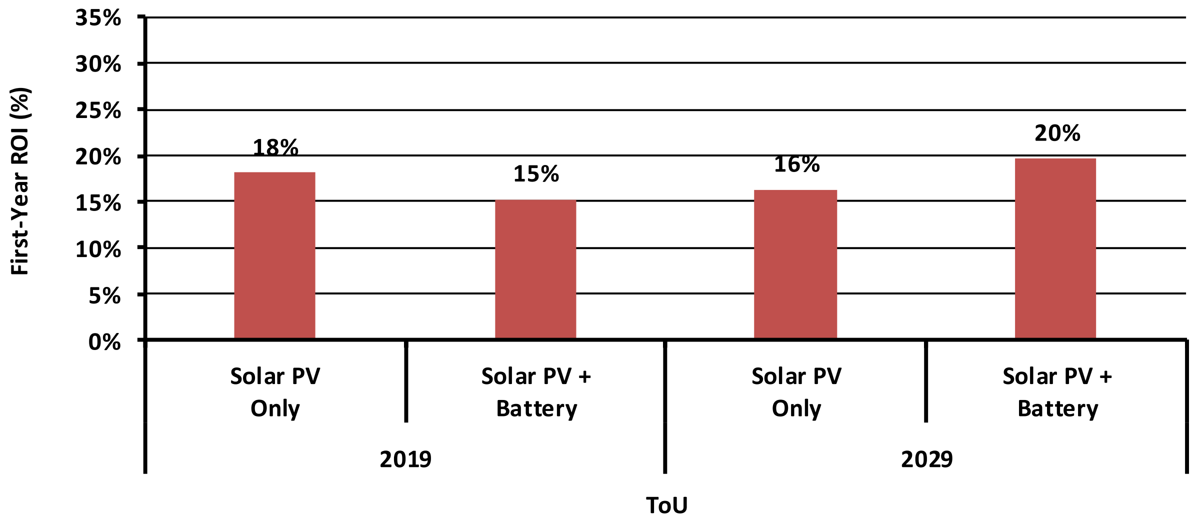
Figure 105 – Customer Bill for a Smart Tariff Customer with No Previous Solar PV



Source: Energeia Analysis; Note: Solar costs are inclusive of inverter costs.

However, in 2029, similar results can be seen where purchasing a solar + battery option is the optimal decision and saves the customer $900 compared to if the customer does not purchase any solar or battery systems.

Figure 106 – First Year ROI for a Smart Tariff Customer with No Previous Solar PV

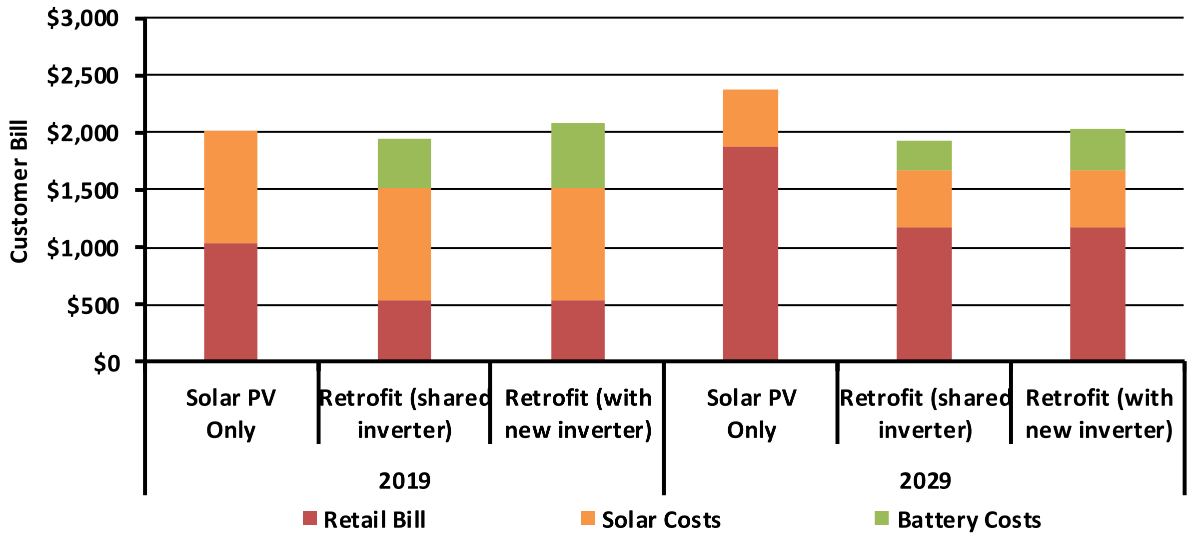


Source: Energeia Analysis

F.2.2. Customer With Solar PV

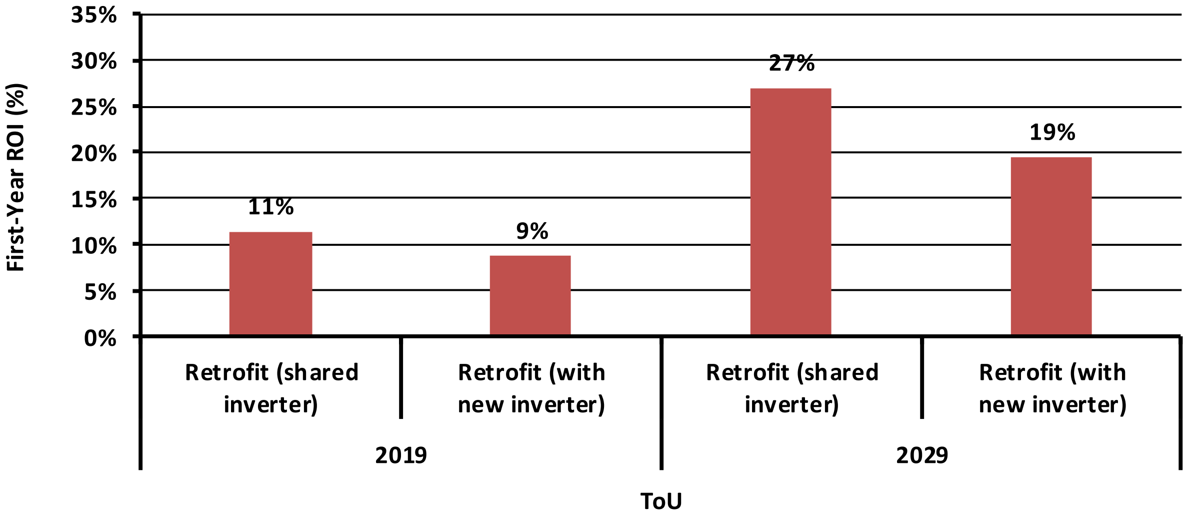
Figure 107 and Figure 108 show the customer bill and associated ROI for a customer on a smart tariff who had previously purchased a solar PV system in 2019 and 2029. Similar to the simple tariff analysis, retrofitting a battery in 2019 is not the optimal option, but becomes the most optimal option in 2029. By retrofitting a battery in 2029, this customer segment can save $450, or 19% of their bill. This purchasing decisions results in an ROI of 27% and a payback period of 3.7 years.

Figure 107 – Customer Bill for a Smart Tariff Customer with Previous Solar PV



Source: Energeia Analysis; Note: Solar costs are inclusive of inverter costs, with the exception of the "Retrofit (with new inverter)" option, where the inverter costs are applied to the battery costs. We have assumed customers who retrofit a battery have purchased solar PV 5 years prior.

Figure 108 – First Year ROI for a Smart Tariff Customer with Previous Solar PV



Source: Energeia Analysis

Between the two tariff types, a flat tariff with a solar PV system is marginally the optimal option in 2019. In 2029, a flat tariff provides a slightly higher ROI when purchasing a solar + battery configuration or retrofitting a battery onto a solar PV system. Note that the more optimal tariff is highly dependent on the customer's load profile.

Overall retrofitting is the most optimal option in 2029 in both tariff options.

Energeia's mission is to empower our clients by providing the evidence based advice using the best analytical tools and information available

Heritage

Energeia was founded in 2009 to pursue a gap foreseen in the professional services market for specialist information, skills and expertise that would be required for the industry's transformation over the coming years.

Since then the market has responded strongly to our unique philosophy and value proposition, geared towards those at the forefront and cutting edge of the energy sector.

Energeia has been working on landmark projects focused on emerging opportunities and solving complex issues transforming the industry to manage the overall impact.

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