31 January 2023

Attachment 5.6.a: Maximum demand forecast

Ausgrid's 2024-29 Regulatory Proposal

Empowering communities for a resilient, affordable and net-zero future.

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1 Executive Summary

Electricity maximum demand forecasts are important in understanding future customer behaviour and form a key input into the network planning process. They guide strategic planning, including DER Integration Strategies, efficient tariff design and demand management, while informing broader capital investment in the network.

Ausgrid's forecasting approach takes into account the layered configuration of the network, with the majority of customers connected at the low voltage level, medium to large customers connected at 11kV and a relatively small number of very large customers connected into the transmission / subtransmission network. The global Ausgrid maximum demand forecast gives an indication of overall maximum demand growth (required for NEM generation and transmission planning). However, additional granularity and consideration of sub-components is needed to understand customer behaviour and network investment needs, as the usage patterns of large transmission customers and generators can dominate the global outlook.

Ausgrid develops and applies forecasts with differing perspectives at the different network levels depending on the analysis and decisions for which they are needed. These different types of forecasts are consistent in terms of the underlying assumptions which are common between them, for example AEMO ISP scenarios, while including unique characteristics which address their particular focus area.

1.1 Our Forecast Models

Ausgrid has an established forecasting capability and supporting forecasting models, leveraging both system level "traditional" spatial forecasts and customer NMI level forecasts as discussed below.

Spatial Maximum Demand Forecast

"Traditional" maximum demand forecasts are produced annually for over 200 zone and subtransmission substations. These forecasts are used for planning of zone substations and the subtransmission network as well as providing the data Ausgrid is required to share with AEMO/Transgrid for NEM planning and publishing for market participants.

For the initial years of this forecast trend analysis from weather normalised actual data is used, adjusted for known block loads. The forecast transitions to system level econometric modelling for later years, with the econometric model exclusively used from year 5 onwards. The model delivers both summer and winter peak demand forecasts.

Econometric factors considered by the models are:

- household income;
- electricity price; and
  gross state product.

Post modelling adjustments are made for:

- Population growth;
- energy efficiency;

- embedded generation (primarily rooftop PV);
- battery storage;
- electric vehicles (EV); and
- electrification of residential gas.

Ausgrid has used, and continues to use, 'agent based' models to assist in deriving the EV, PV, battery storage, and electrification of residential gas post modelling adjustments. This agent based model has been used in deriving Ausgrid's DER Integration Strategy.

*Distributed Energy Resource (**DER**) model – Customer NMI Level Forecasts*

In 2022, Ausgrid has developed a DER integration model, initially to assess DER hosting capacity, but with the potential to assess a wider range of issues once fully operationalised. This model applies forecast energy usage trends and patterns at the individual customer (**NMI**) level via "agents" representing the various customer types, to assess the impact on the supply network from customer up to zone substation 11kV busbar.

For the DER model, forecasts are developed at the agent level, with the characteristics of the agent changing over time to match the changing energy usage patterns resulting from the corresponding AEMO scenarios.

The DER model is not designed to produce an Ausgrid wide maximum demand forecast (it stops at the 11kv busbar and therefore does not include 132/66/33kV subtransmission connected loads and generation), but is designed to develop a forecast of constraints at the 11kV and low voltage level where the vast majority of Ausgrid's 1.8 million customers are connected. The model supports the identification of cost effective responses to DER constraints, including use of dynamic operating envelopes (**DOE's**), tariffs and network investments.

Subtransmission loads and generation are assessed by bespoke data and analysis consistent with AEMO and NEM processes.

1.2 Forecast Input Assumptions

In recent years Ausgrid, along with AEMO, have adopted a more scenario-based approach to forecasting given the level of uncertainty. For the current forecast Ausgrid has developed forecasts based on the four AEMO ISP 2022 scenarios:

- Slow Change;
- Progressive Change;
- Step Change; and
- Strong Electrification.

Step change has been identified as the most likely option in the 2022 ISP published by AEMO in June 2022. Subsequently Ausgrid has adopted Step Change forecast as the most likely scenario on which to apply planning models and expenditure forecasts.

1.3 AEMO ISP Scenarios

AEMO has published forecasts for NSW in the 2022 ISP which include the following scenarios:

a) **Slow Change** – represents a challenging economic environment with slower net zero emissions action. Slow Change would not reach the decarbonisation objectives of Australia's Emissions Reduction Plan. (4% likelihood assigned by AEMO in 2022 ISP)

b) **Progressive Change** - delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build up of momentum ending with deep cuts in emissions across the economy from the 2040s. (29% likelihood)

c) **Step Change** - moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2° compared to pre-industrial levels. Rather than building momentum as Progressive Change does, Step Change sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. (50% likelihood)

d) **Strong Electrification -** a variation on the AEMO 'Hydrogen Superpower' scenario which assumes the same emission reduction objectives, with limited hydrogen uptake. This scenario is consistent with strong global action and significant technological breakthroughs to achieve an even more rapid transition to net zero than Progressive or Step Change scenarios. (17% likelihood)

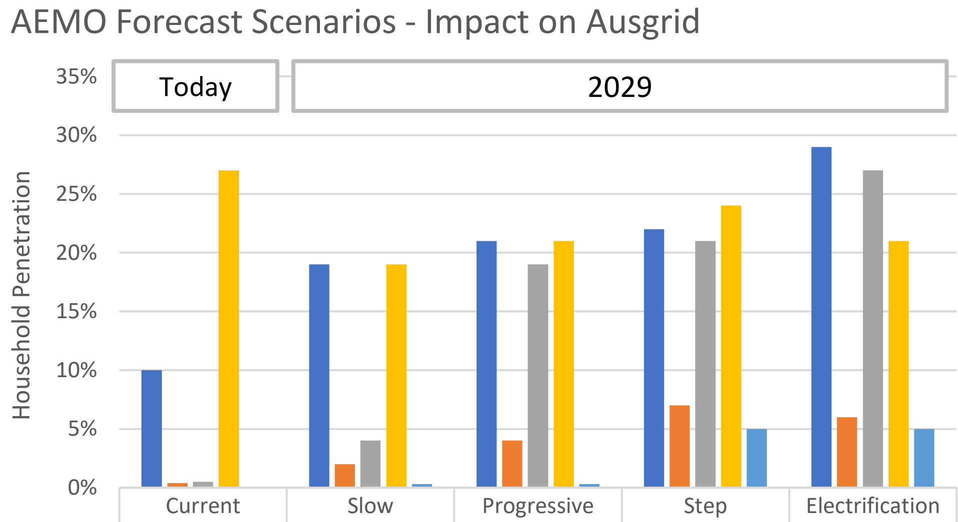
   Ausgrid has applied the Strong Electrification variation to reflect the highest growth (boundary condition) AEMO scenario in preference to the pure Hydrogen Superpower scenario because it has greater alignment with factors impacting distribution networks than a hydrogen led scenario. A Hydrogen Superpower scenario would be expected to have higher impact on transmission networks given its associated large-scale hydrogen production needs and place less pressure on distribution networks given it would require less electrification of transport and residential gas to achieve its targeted emissions objectives.

The table below sets out Ausgrid's rationale in applying the AEMO NSW wide forecast scenarios to Ausgrid's circumstances and demographics. Ausgrid supplies approximately 40% of NSW peak demand and around 36-38% of NSW energy delivered each year.

Forecast Element	Ausgrid allocation of AEMO NSW	Rationale
PV	30-35%	Ausgrid's catchment has a materially lower PV penetration than NSW peers due to a greater prevalence of apartments and lower quantities of greenfield freestanding housing. As a result Ausgrid has allocated less than a pro rata share of AEMO's NSW allocation of PV
Battery	25-35%	Customer batteries are most commonly installed in conjunction with PV. For similar reasons to those for PV above, Ausgrid has allocated less than a pro rata share of AEMO's NSW allocation of batteries.

<table>
<tr><th>Forecast Element</th><th>Ausgrid allocation of AEMO NSW</th><th>Rationale</th></tr>
<tr><td>EVs</td><td>55%</td><td>Ausgrid houses approximately 66% of NSW's current early EV uptake based on recent spatial data.
This is expected to moderate to 55% of NSW uptake in 2029 as uptake spreads to more suburban and regional areas, which is consistent with the current allocation of ICE vehicles across NSW
Where EV research and knowledge is directly relatable to the Ausgrid network, Ausgrid specific parameters are used rather than AEMO parameters.</td></tr>
<tr><td>Electrification of residential gas</td><td colspan="2">Electrification of residential gas was noted by AEMO in the 2022 ISP as being primarily driven by space heating in the cooler southern states such as Victoria and did not offer deep insights into the impacts in NSW.
Ausgrid has however adjusted its forecast to account for the likely impacts to LV networks associated with this transition.
Using a stock model of likely gas appliance transition to electrical equivalents and expected power draw profiles, a per customer demand impact has been derived which was then allocated using spatial gas usage datasets from Jemena.</td></tr>
<tr><td>Off Peak Hot Water (OPHW)</td><td colspan="2">OPHW is incorporated into general baseload in AEMO forecasts.
Ausgrid has undertaken trials of adjusting off peak hot water schedules to incorporate a percentage of 'solar soak' demand which is beneficial to network outcomes.
As a result, Ausgrid has implemented a change into the demand forecasts related to off peak hot water schedules based on local trials.</td></tr>
</table>

The customer technology adoption assumptions as applied by Ausgrid to each of the AEMO scenarios are summarised below.



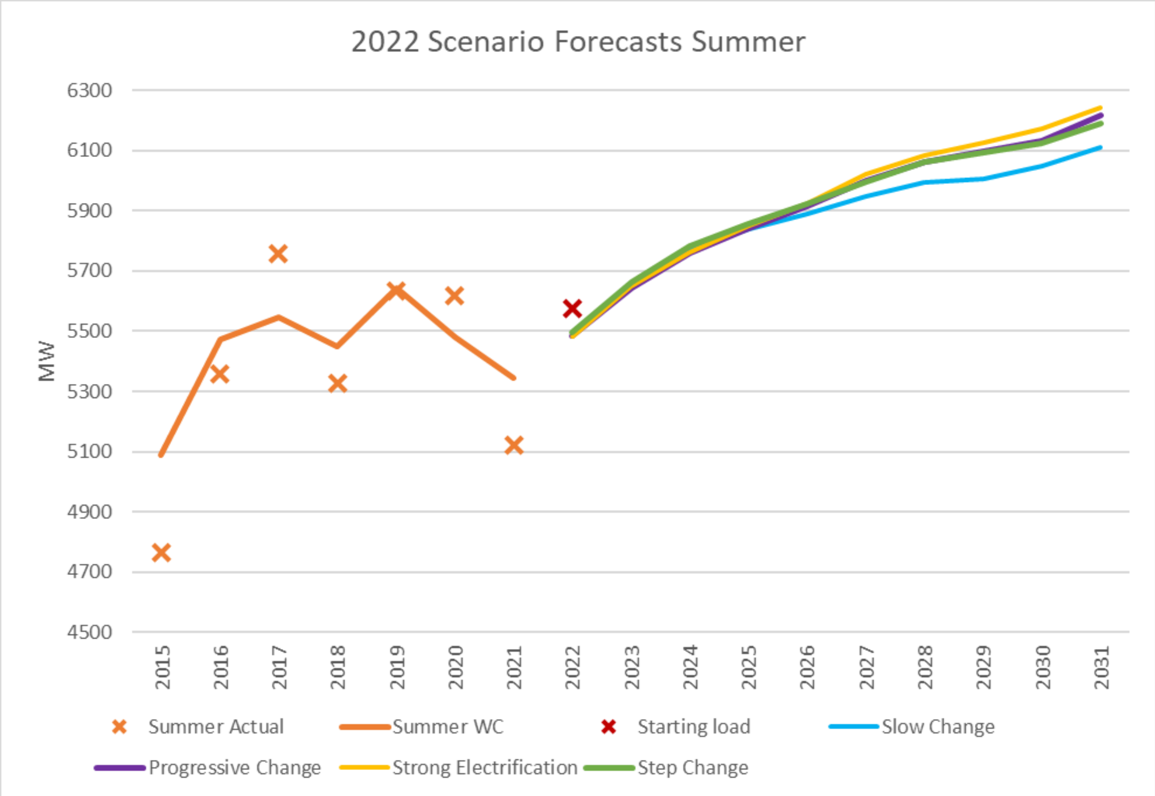
	Current	Slow	Progressive	Step	Electrification
PV	10%	19%	21%	22%	29%
Battery Storage	0.40%	2%	4%	7%	6%
EVs	0.50%	4%	19%	21%	27%
Off Peak Hot Water	27%	19%	21%	24%	21%
Electrification of Residential Gas	0	0.3%	0.3%	5%	5%

1.4 Forecast Outcomes – Spatial Maximum Demand Scenario Forecasts

The 2022 Maximum Demand forecast delivers the first suite of forecast scenarios building from Ausgrid's share of AEMOs inputs and assumptions for the NSW forecasts in the 2022 ISP. Historically, Ausgrid produced forecasts for a central case (normally aligned with AEMO's central case) and carried out broad sensitivity to alternate demand outcomes.

The scenario forecast spread by 2031 between lowest (Slow Change) and highest (Strong Electrification) is 130MW in Summer and 200MW in winter representing approx. 2% and 3% of forecast system total respectively. The spread between the highest three scenario in 2031 is only 50MW in summer and 100MW in winter.

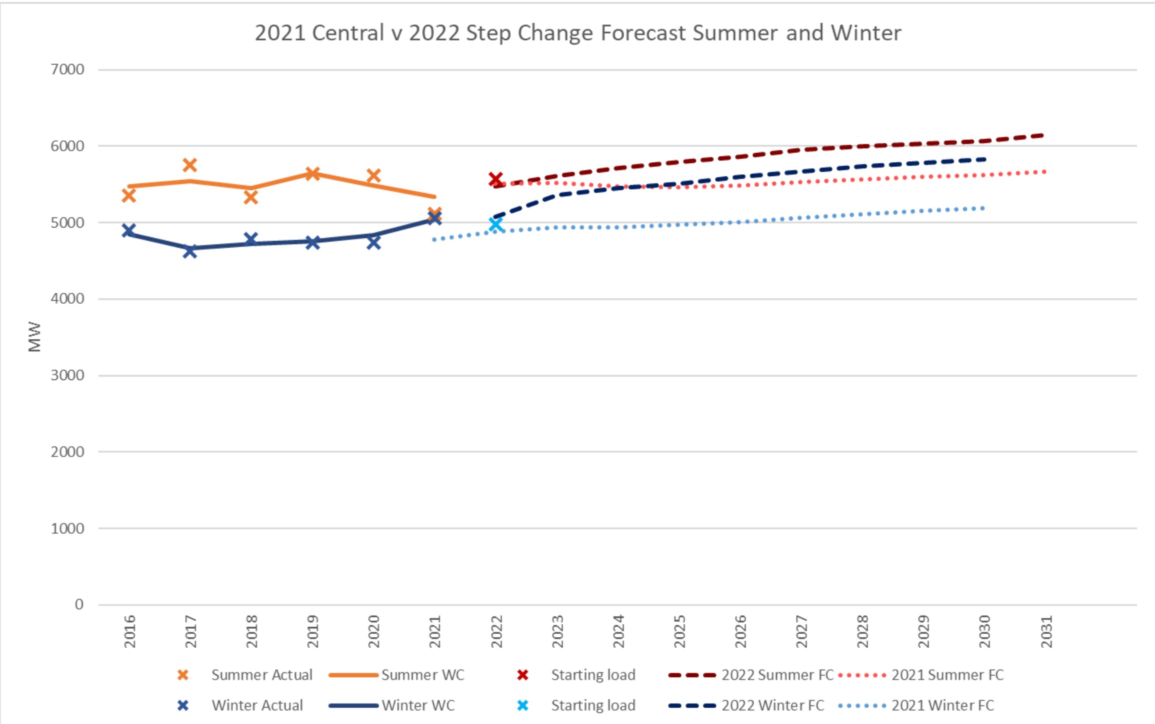
Scenario based forecast spreads are fairly narrow due to the counteracting nature of how forecast elements combine with uplift in demand by one driver being offset by a corresponding downward pressure on demand from another (e.g. greater EV activity offset by greater rooftop PV and energy efficiency).



1.5 Forecast Outcomes – Spatial Maximum Demand Step Change Forecast

The forecasts below have been prepared based on the AEMO 'step change' scenario assumptions applied to Ausgrid's customer demographic and network. In the 2022 ISP AEMO adopted the Step Change scenario as the most likely forecast.

The 2022 Ausgrid total maximum demand Step Change forecast is shown below.

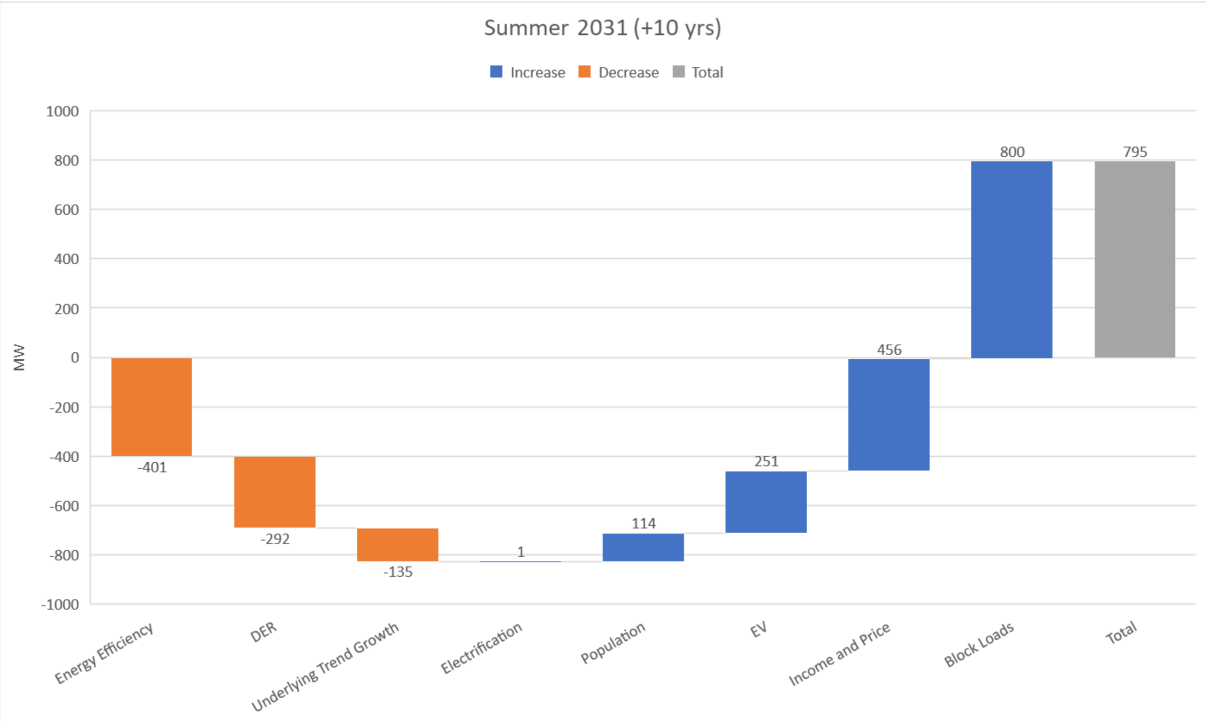


Note: WC = weather corrected, FC = forecast

The compound annual growth rate (**CAGR**) is 1.1% per annum for summer peak demand and 1.1% per annum for winter during the 2024-29 period. FY21 forecast was 0.5% in summer and 0.8% winter for the same period. Uplift in EV uptake forecast is the major contributor to this forecast demand increase over the FY21 forecast. Steady growth in summer maximum demand is underpinned by continuation of elevated levels of large customer connection activity, population growth, and EV uptake. This uplift in demand is offset by energy efficiency impacts and strong growth in PV system uptake.

Summer maximum demand is expected to remain higher than winter for at least the next 10 years, however the gap between summer (higher) and winter (lower) forecasts is expected to narrow. Factors which contribute to this narrowing include the downward pressure from PV being largely absent at the time of the winter peak, combined with electrical demand reduction and energy efficiency targets being more strongly focused on summer day loads such as air-conditioning.

The contribution of the factors impacting on summer growth to the 10-year horizon (from 2021 summer to 2031) are summarised in the waterfall chart below.



DER including PV and batteries place downward pressure on projections, however the forecast impact of energy efficiency has the largest downward impact. Electric vehicle adoption places upward pressure on demand to 2031 which is expected to accelerate post 2031.

Macro economic income and price factors, which drive existing customer decisions affecting electricity consumption are a significant source of growth to 2031 in the data used for the 2022 forecast.

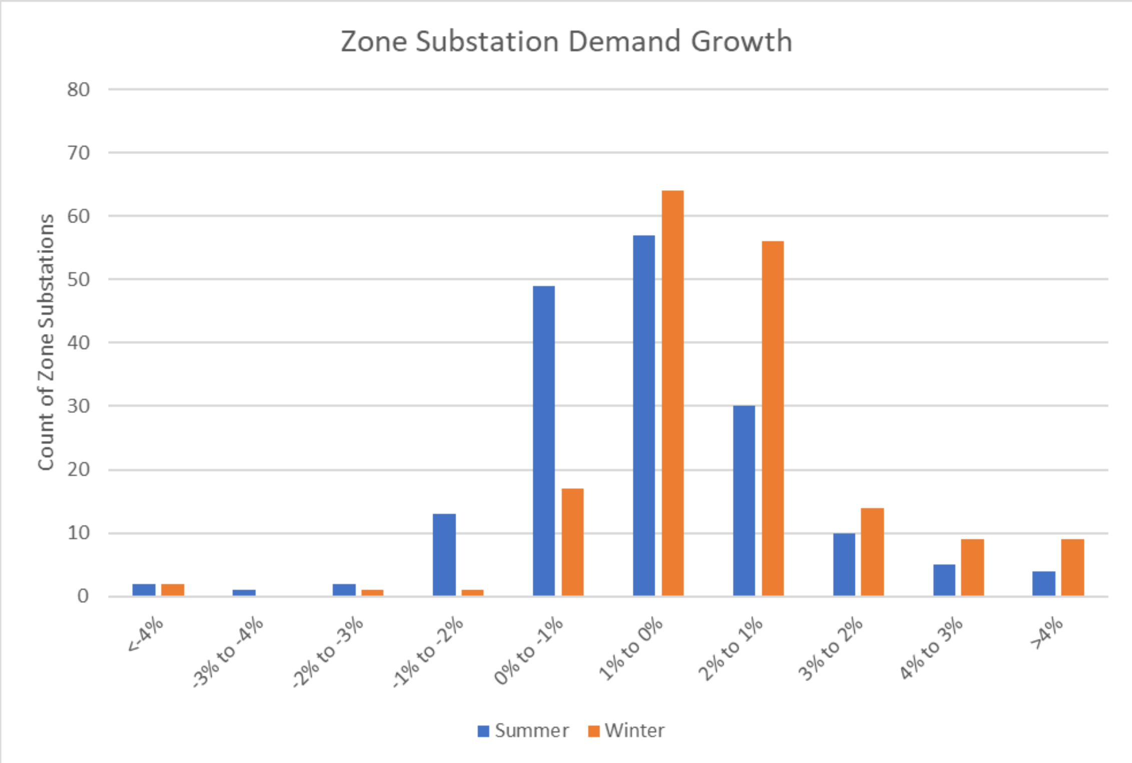
Block loads, which capture large new connections (typically >1MW up to 100+ MW) to the Ausgrid network, are also a dominant factor placing upward pressure on maximum demand growth.

Spatial Distribution of Maximum Demand Growth

While overall maximum demand growth provides a macro view of the rate of growth of the business, constraints and/or headroom on the network are highly variable depending on location and specific network assets used to supply that area or customer.

The chart below shows the distribution of growth across the approximately 180 Ausgrid zone substations.

2022 Step Change Forecast Zone Substation Growth Histogram



From the chart it can be seen that the growth for the majority of zones falls close to the overall CAGR, there are a material number of locations where growth is higher or lower than the average. When combined with an understanding of current utilisation levels this provides insights into limitations requiring action, or opportunities in terms of headroom available for connection of new loads[1]. CAGR calculations are based on growth to the end of the regulatory period in 2029.

1.6 DER Integration Forecasts

Ausgrid's DER Integration model includes both the agents which capture the forecast elements and the detailed network model used to assess the resulting network limitations. Details of this holistic modelling process and its outcomes are discussed as an adjunct to the

[1] Ausgrid publishes data on network limitations and opportunities via the Distribution and Transmission Annual Planning Report (DTAPR) and via the Network Opportunity Map (NOM) hosted by the ENA

DER Integration Strategy, but a high-level description is set out below to provide a context for the demand forecasting considerations.

- Ausgrid has a DER model for each zone substation (**ZS**) which includes all customers (NMI's) supplied from that ZS and reaches from the customer connection up to the 11kV zone substation busbar.
- The model considers:
  - loads/generation at customer connection points (NMI's);
  - current/ratings and impedances of low voltage mains, distribution centres (**DC**'s) and high voltage mains, which are typically the limitation on loads (including EV charging) in an urban network like Ausgrid's; and
  - voltage levels experienced by customers (and their solar invertors) which are typically the limitation on rooftop PV output.
- The model is run to establish a baseline based on current loadings and with revised inputs for time horizons which align with successive AER regulatory periods, i.e. 2022, 2024, 2029, 2034 and 2039
- An agent type is assigned to each customer where variations in load are expected due to DER related elements including rooftop PV, customer batteries, EV's, shifting of off-peak hot water loads (solar soak) and electrification of residential gas. Loads which do not vary with these factors are not assigned agents but are treated as fixed loads for the purposes of this model. Agent types are shown in the table below.

Agent type	Lower band (kWh)	Upper band (kWh)	Notes
Residential			
Apartment	1,000	20,000	All apartments/townhouses/etc
Res – Small	1,000	3,500	Bottom quartile of detached houses
Res – Med	3,500	9,000	Two middle quartiles of detached houses
Res – Large	9,000	20,000	Top quartile of detached houses (excluding above 20 MWh) - 1%
Non Residential			
Business – Small	2,000	40,000	Aligns with small LV business, flat, TOU and demand tariffs
Business – Med	40,000	160,000	Medium LV business and aligns with EA302
Business - Large	160,000	4,000,000	Large LV business and aligns with EA305, 310 and HV
HV	>4,000,000		11kV and above HV Customers

- Given their complexity as a potential load and/or source, EV's are subject to further targeted adjustments in addition to the agent impact. These adjustments, which are specific to EV's, consider a wider range of variables than an agent-based model can easily address such as charging typology (e.g. residential/fleet).
- The load associated with each agent is a composite of the underlying load for that customer and adjustments to reflect the combined impact of the various DER elements.

The net contribution of the agent types to peak and minimum demand are set out in the table below, on a kW per customer basis, along with how they are forecast to change over time.

Contribution to current and future peak demand (kW per customer)

Agent	% Customer	2022	2024	2029	2034	2039
Apartment	39%	1.1	1.1	1.0	0.9	0.8
Res - Small	12%	0.8	0.7	0.7	0.6	0.6
Res - Med	26%	2.2	2.1	2.0	1.7	1.4
Res - Large	13%	4.1	3.9	3.9	3.6	3.4
Bus - Small	8%	1.5	1.4	1.2	1.0	0.8
Bus - Med	1%	13	12	11	11	10
Bus - Large	1%	117	114	108	103	95
HV	0.07%	218	218	218	218	218

NB: percentages may not add to 100% due to rounding. Percent of total aggregate peak demand inclusive of all load up to 11kV

Contribution to current and future minimum demand (kW per customer)

Agent	% Customer	2022	2024	2029	2034	2039
Apartment	39%	0.04	0.03	0.02	0.03	0.06
Res - Small	12%	-0.05	-0.11	-0.13	-0.12	-0.10
Res - Med	26%	-0.03	-0.20	-0.29	-0.41	-0.44
Res - Large	13%	0.01	-0.25	-0.41	-0.51	-0.44
Bus - Small	8%	0.17	0.16	0.14	0.12	0.11
Bus - Med	1%	1.8	1.8	1.8	1.9	2.0
Bus - Large	1%	17	17	16	16	16
HV	0.07%	81	81	81	81	81

NB: percentages may not add to 100% due to rounding. Percent of total aggregate peak demand inclusive of all load up to 11kV

1.7 Independent Review

An independent review of Ausgrid's forecast methodology was conducted by KPMG in September 2022. The review determined that Ausgrid's forecast methodology was robust and accounted for all major contributors to future demand. KPMG noted:

> *"Ausgrid's methodology for maximum demand forecasting is comprehensive. It accounts for all major contributors that significantly affect future demands. Ausgrid has a strong understanding of the driving forces for each contributor, and they regularly test their assumptions on currency and applicability."*

Ausgrid also asked KPMG to provide commentary on the DER integration forecast methodology KPMG commented:

> *"Ausgrid's overall approach can be assessed as appropriate, useful, and reasonable for the given purpose"*

Finally KPMG noted with respect to both:

> *"KPMG encourage Ausgrid to continuously evolve the methodology to stay on track with, or ahead of, the industry trends"*

KPMG presented issues and opportunities within the current maximum demand forecast methodology, while noting that their qualitative materiality to the spatial demand forecast accuracy was medium to low. Ausgrid carried out sensitivity analysis to demand impacts on items raised and concluded there to be a low materiality to forecast expenditure.

KPMG also offered comments on the DER modelling methodology regarding the inclusion of more granular data on housing type and econometric data, which would tend to capture clustering of DER elements to a greater extent. Ausgrid acknowledges these improvement opportunities. When these issues are addressed, they will tend to concentrate the impact of DER in localised areas of the network to a greater degree – meaning that the current model would understate rather than overstate the impact on the network.

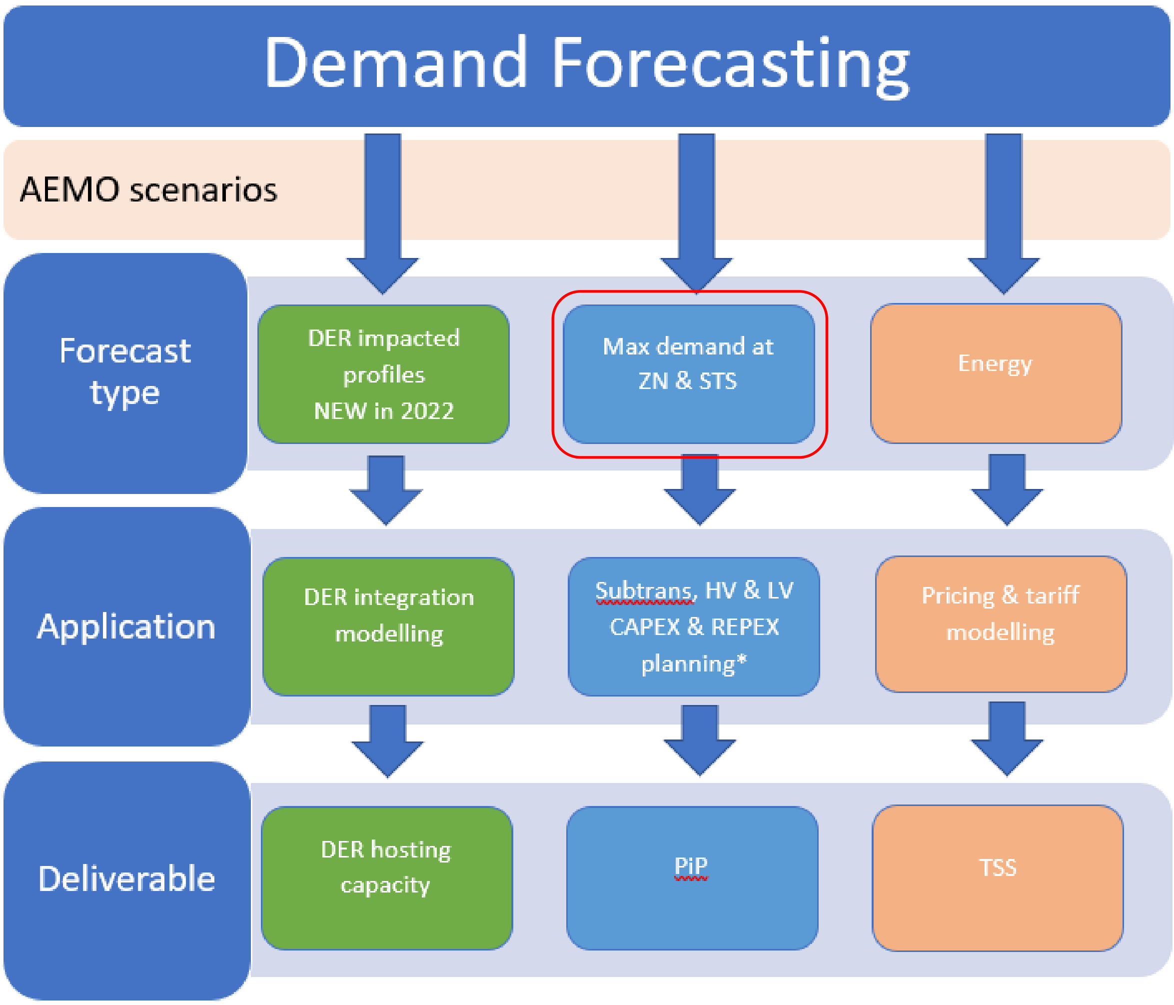
Additional EV modelling is already underway to consider the impact of additional clustering in parallel with receiving the KPMG findings. The feedback from KPMG will be considered in a similar light as models are refined, alongside the practicalities of acquiring the more granular input data required to address the items KPMG have identified.

2 Demand Forecast

2.1 Overview of Ausgrid Demand Forecasting Process and Results

The maximum demand forecast fits into a family of forecasts developed by Ausgrid for different purposes. The diagram below provides an overview of how demand forecasts are applied by Ausgrid:

- Energy demand forecasts are developed according to customer class groupings, e.g. residential and business customers, for the purposes of developing tariffs and pricing structures and pricing levels relevant for each tariff. Details of Ausgrid's tariffs are published in our Tariff Structure Statement (TSS) and are summarised in our Network Price Lists;
- Maximum demand forecasts are developed at over 200 major substation nodes, namely, at sub-transmission and zone substations, for use in network planning. These are a key input into determining our forecast network capital expenditure requirements; and
- In 2022, Ausgrid has developed its inaugural Distributed Energy Resource (DER) integration model. This model is developed at the customer-agent level (representative customer types) for the purpose of forecasting network augmentation requirements to accommodate increasing levels of DER on our network.



Across all forecasting streams, underlying assumptions around key drivers are aligned to ensure consistency. Forecasting scenarios are consistent with AEMO's 2022 Integrated System Plan document.

The maximum demand forecast at zone substations and sub-transmission substations is used directly in sub-transmission CAPEX and REPEX planning. HV and LV planning uses the growth rates derived from the zone substation maximum demand forecasts.

This document focuses on the maximum demand forecast used for network capital planning. (Blue column on the diagram above).

2.2 Forecast scenarios aligned with AEMO Draft 2022 Integrated System Plan

To ensure planned investment is robust and able to withstand scrutiny when assessed against a potential wide range of future demand outcomes and the high uncertainty associated, Ausgrid has developed 4 demand scenario forecasts. The 4 scenarios are Slow Change, Progressive Change, Step Change, and Strong Electrification which track differing paths of decarbonisation and are aligned with the NSW forecasts in AEMO's 2022 Integrated System Plan, applied in an Ausgrid context with Ausgrid's customer demographics.

The table below sets out Ausgrid's rationale in applying the AEMO NSW wide forecast scenarios to Ausgrid's circumstances and demographics.

Ausgrid supplies approximately 40% of NSW peak demand and around 36-38% of NSW energy delivered each year.

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Forecast Element	Ausgrid allocation of AEMO NSW	Rationale
Off Peak Hot Water (OPHW)	• OPHW is incorporated into general baseload in AEMO forecasts. • Ausgrid has undertaken trials of adjusting off peak hot water schedules to incorporate a percentage of solar soak demand which is beneficial to network outcomes. As a result, Ausgrid has implemented a change off peak hot water schedule based on local trials into the demand forecasts.	

A summary of the main points of each scenario is provided below along with implications for Ausgrid.

2.2.1 Slow Change

AEMO's Perspective[2]

Challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. Consumers continue to manage their energy needs through DER, particularly distributed PV. However, Slow Change would not reach the decarbonisation objectives of Australia's Emissions Reduction Plan.

What does the Slow Change scenario mean for Ausgrid?

As stated in the AEMO slow change scenario description, PV installs in the Ausgrid network area continue at trend before moderating slightly, however Battery Storage installs fail to take off beyond the current subdued trend. EV uptake lifts moderately, although the pace is slow compared to traditional accelerated take up trajectories of technology, with policy remaining unsupportive in Australia in comparison to other regions across the globe. Electrification remains driven by customers actively seeking out solutions to avoid gas consumption and therefore the pace of transition to fully electric energy consumption remains low.

As PV installs continue at pace, and flexible demand sources do not arrive at volume, voltage issues are prevalent along with emerging minimum demand issues. Off Peak Hot Water is transitioned to a solar soak schedule however the declining number of OPHW customers continues due to existing policy incentivising non electric hot water sources.

Slow Change	Customer penetration				
	PV	Battery Storage	EVs	Off Peak Hot Water	Electrification of Residential Gas
Current	10%	0.4%	0.5%	27%	n/a
2029	19%	2%	4%	19%	0.3%

[2] AEMO's Perspective commentary largely verbatim from the AEMO's 2022 Draft ISP Report from page 26-27 for Slow Change, Progressive Change, & Step Change Scenarios. Page 86 for Strong Electrification https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf

2.2.2 Progressive Change

AEMO's Perspective

Pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time. Progressive Change delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build-up of momentum ending with deep cuts in emissions across the economy from the 2040s:

- The 2020s would continue the current strong trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions;
- The 2030s would see commercially viable alternatives to emissions-intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification;
- The 2040s sees these commercially viable alternatives at scale and nearly doubling the total capacity of the NEM. EVs become more prevalent over time and consumers gradually switch to using electricity over gas in their homes and businesses; and
- Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2045.

What does the Progressive Change scenario mean for Ausgrid?

In the Progressive Change scenario, Ausgrid begins to see the concerted effort from all levels of government to achieve net zero emissions by 2050. In the short to medium term, minor steps in policy are taken to support an acceleration of decarbonisation beyond current trend, resulting in a modest increase in PV compared to trend, however battery storage doubles in uptake to 2029 when compared to the slow change scenario.

EV uptake accelerates to be equivalent to 19% of customers owning an EV, or just over 370,000 electric vehicles operating and charging in the Ausgrid network. While tentative steps are taken to align policy settings towards the electrification of residential gas, activity remains subdued in the 2024-29 regulatory period and accelerates in the years following.

Progressive Change	Customer penetration				
	PV	Battery Storage	EVs	Off Peak Hot Water	Electrification of Residential Gas
Current	10%	0.4%	0.5%	27%	n/a
2029	21%	4%	19%	21%	0.3%

2.2.3 Step Change

AEMO's Perspective

Rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action. Step Change moves much faster initially towards fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2° compared to pre-industrial levels:

- Rather than building momentum as Progressive Change does, Step Change sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM;
- On top of the Progressive Change assumptions, there is also a step change in global policy commitments, supported by rapidly falling costs of renewable energy production, including consumer devices;
- Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification;
- By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased; and
- Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2040.

What does the Step Change scenario mean for Ausgrid?

In the Step Change scenario, Ausgrid begins to see the concerted effort from all levels of government to achieve net zero emissions by 2050. Policy settings are supportive from mid 2020s to incentivise uptake of technology and influence consumer behaviours leading to significant impacts to electrical demand profiles in the long term.

PV installations in the Ausgrid catchment approach 1 in 4 customers using behind the meter generation to offset their household energy use, with a third of these solar customers also installing a battery storage system for managing solar PV exports. EVs uptake is slightly higher than progressive change scenario but broadly in line, with the uplift not material between the 2 scenarios. Step Change scenario sees policy take assertive steps to decarbonise residential gas use in the Ausgrid network area with 5% of customers making the transition away from gas to electric appliances.

Step Change	Customer penetration				
	PV	Battery Storage	EVs	Off Peak Hot Water	Electrification of Residential Gas
Current	10%	0.4%	0.5%	27%	n/a
2029	22%	7%	21%	24%	5%

2.2.4 Strong Electrification

AEMO's Perspective

AEMO has modelled a Strong Electrification sensitivity, as a potential alternative to Hydrogen Export scenario that assumes the same emission reduction objectives, but with limited hydrogen uptake. Stronger and faster electrification of transport and heavy industry is therefore needed to achieve the economy-wide emission reductions.

What does Strong Electrification mean for Ausgrid?

A future featuring a strong electrification of industrial processes and residential appliances to achieve decarbonisation of large portions of the economy who are currently dependent on gas and fossil fuel results in increased demand on electricity networks, in particular distribution networks.

The largest impact is evident in the strong electrification of transport with 3 out every 10 customers owning an EV, 30% higher than the Step Change scenario. Residential gas users transition to electric appliances at a similar rate to Step Change up to 2029, then accelerates in the following years.

With customers higher energy use in the Strong Electrification scenario, more customers install PV systems with approximately 3 in 10 customers using behind the meter PV generation to offset their household energy use. Battery storage is slightly lower in Strong Electrification when compared to Step Change due to the overall higher energy use, resulting in less overall net energy export from excess PV generation during the day and therefore less need for behind the meter storage.

Strong Electrification	Customer penetration				
	PV	Battery Storage	EVs	Off Peak Hot Water	Electrification of Residential Gas
Current	10%	0.4%	0.5%	27%	n/a
2029	29%	5%	30%	25%	5%

2.3 Forecast elements

Energy forecast:

- The energy demand forecasts used for pricing and tariffs are based on econometric models regressing price and income variables against energy demand to calculate econometric elasticities.
- Forecast behind the meter consumption and exports from Solar PV and Battery Storage are applied by customer agents which are aligned with tariff classes
- Energy Savings Scheme, Building Code of Australia, & Minimum Energy Performance Standards impacts allocated through business & residential split of programs

- Population adjustments extend current population trends and adjust for Ausgrid's share of future forecasted NSW population growth as described by the NSW population projections by LGA
- Large customer connections are subject to individually-tailored pricing structures;
- Off-peak hot water solar soak is currently in a trial phase and are not yet included in these forecasts. Should the trial be successful, future forecast versions will include this adjustment.
- Elements of Scenario forecasting for future PV, Battery & EV uptake have been applied to provide insights into potential shifts in demand profiles at zone substation locations for assessing tariff settings and structure for inclusion in the Tariff Structure Statement/ Tariff Directions Paper from Network Pricing.

Maximum demand forecast at zone and sub-transmission substations

- Econometric elasticities are applied in a similar method to the energy forecast however regression is performed on the relationship between income and price variables with respect to peak demand
- Solar PV, Battery storage and EV demand impacts are applied using average operation profiles and coincidence with local substation peak.
- Underlying trend is calculated at the local substation level and projected forward for the short term blending to econometric and post model adjustments in the medium to long term forecast
- Energy Efficiency applies peak demand adjustments arising from energy efficiency programs relating to the Building Code of Australia (BCA), Minimum Energy Performance Standards (MEPS) of appliances, Energy Efficiency Savings scheme, and the Peak Demand Reduction Scheme (PDRS)
- Population adjustments extend current population trends and adjust for Ausgrid's share of future forecasted NSW population growth as described by the NSW population projections by LGA further allocated by substation locational residential energy share.
- Sub-transmission Customer Connections at 33kV and above are applied by taking connecting customer information and scaling by industry specific probability and coincidence factors
- Distribution Customer connections at 11kV are applied by taking connecting customer information and scaling by generic probability factors linked to connection application staging (early-stage block loads scaled at 0.31 whereas late-stage block loads have more certainty and are scaled at 0.51). Connections are also adjusted for coincidence with local substation peak based on assigned generic customer connection load profiles
- Electrification profile impacts relating to the decarbonisation of residential gas analyses current trends on the prevalence of gas appliances in new builds, as well as existing residential gas use by LGA, and. Electrification of commercial gas supplies is assumed to require a connection application whereby the majority of the costs are borne by connecting customer
- Off-peak hot water solar soak is currently in a trial phase and are not yet included in these forecasts. Should the trial be successful, future forecast versions will include this adjustment. Impacts due to change from overnight hot water heating to solar

soak operation unlikely to have a material impact on peak demand due to low controlled load penetration in areas where early afternoon peaks are predominant
- Scenario Forecasts are produced for a number of key forecast elements and applied to underlying rates of growth

DER Integration model

- This model is primarily based on how estimated changes in load profiles due to forecast increased uptake in DER, consistent with our maximum and energy demand forecasts, may introduce localised constraints on parts of our low voltage and 11kV networks.
- Modelled forecast variables include Solar PV, Battery Storage, EVs, Off Peak Hot Water, and Electrification of Residential Gas.
- Solar PV, Off Peak Hot Water, and Electrification impacts are modelled as simple profile adjustments based on seasonal profiles (Summer, Winter, Shoulder) and local maximum/minimum demand coincidence.
- Impacts of EVs and Battery Storage in the DER integration modelling explore potential variation in customer behaviour relating to the use of these technologies. Features such as minimising export, tariff arbitrage, and VPP battery storage algorithms are explored with respect to battery storage. EV consumers are modelled using variation in charger size (similar to what is on market) and coincidence with local maximum and minimum demand. This methodology applies discrete adjustments to individual customer loads rather than average load impacts to adequately represent the noise inherent in individual customer profiles.
- Individual customer impacts are reallocated in multiple simulations with the same set of forecast parameters to account for the variation in network architecture where customers connect. This allows for model results to converge to a likely outcome, reducing the chance of analysis formulated on an initial allocation case that is an outlier and ensuring confidence in capturing network investment needs
- Scenarios are applied through varied technology uptake and variation in consumer behaviour previously mentioned above
- Post model adjustments such as econometric factors, energy efficiency, population growth and connections are deemed to be less relevant for this model in comparison to the inherent uncertainty featured in uptake of emerging technology and customer behaviours in use of technology which drives a material range in network outcomes,
- Electrification of commercial gas supplies is assumed to require a connection application whereby the majority of the costs are borne by connecting customer

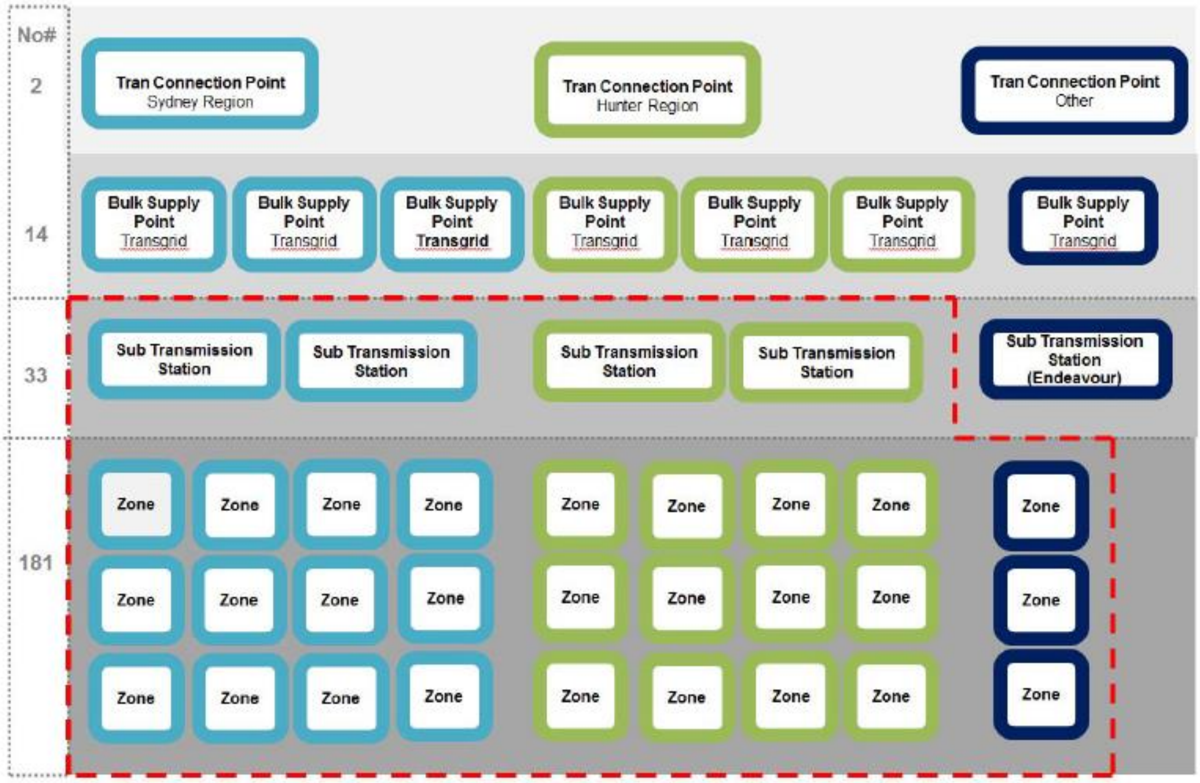
The table below summarises how each forecasting element is applied across the 3 streams:

Forecast Element	DER Integration Modelling – Customer Impact Forecast	Peak Demand Forecast Modelling – Zone and Sub-transmission Forecast	Pricing & Tariff Modelling – Energy Forecast
Scenario Forecasts	✓	✓	✓
Econometric	✗	✓	✓
Solar PV	✓	✓	✓
Battery Storage	✓	✓	✓
Electric Vehicles	✓	✓	✓
Underlying local Load Trend	✓	✓	✗
Energy Efficiency	✗	✓	✓
Population	✗	✓	✓
Major Customer Connections	✗	✓	✓
Large Distribution Customer Connections	✗	✓	✗
Electrification of residential gas	✓	✓	✗
Off Peak Hot Water – Solar Soak	✓	✗	✗

2.4 Ausgrid's Electricity Distribution Network Hierarchy

The diagram below depicts the distribution network hierarchy for Ausgrid's network area. Ausgrid produces separate winter and summer forecasts for each of our 178 zone substations and 34 sub-transmission substations.

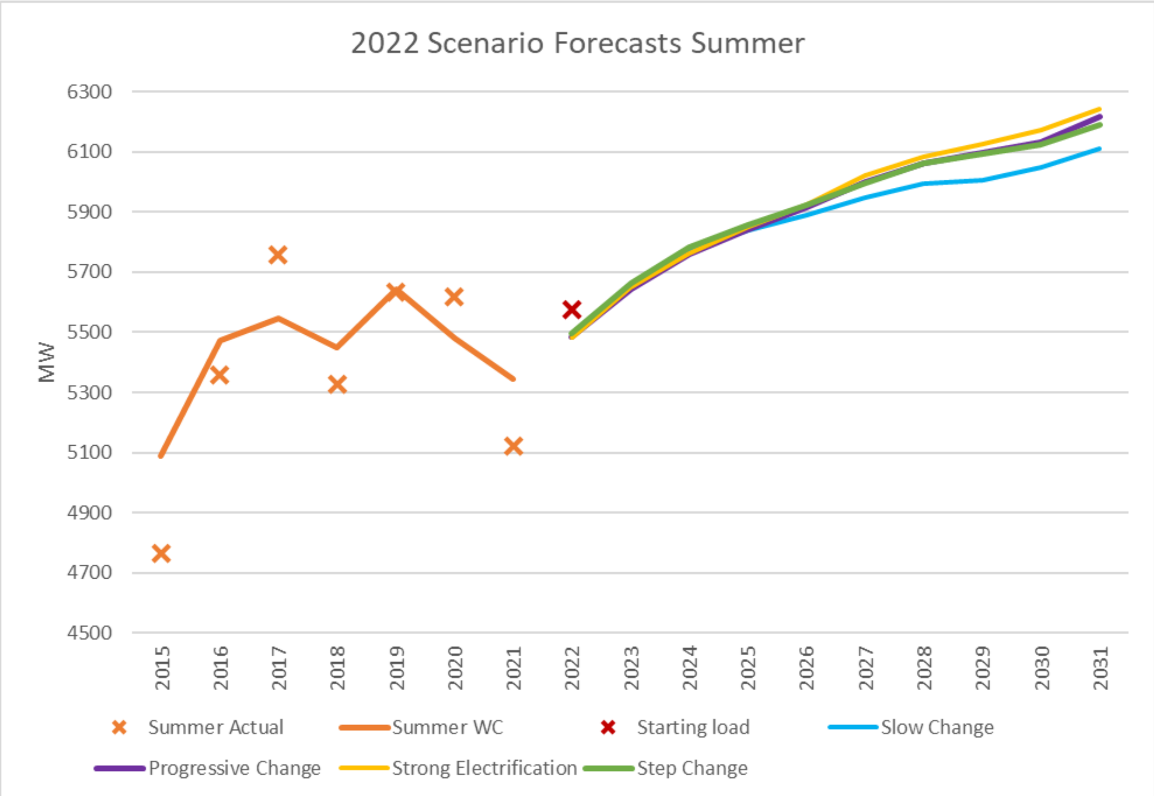
The red dotted line indicates the asset level forecasts that are included in the Electricity Demand Forecasts.


No#
2
14
33
181
Tran Connection Point
Sydney Region
Tran Connection Point
Hunter Region
Tran Connection Point
Other
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Bulk Supply Point Transgrid
Sub Transmission Station
Sub Transmission Station
Sub Transmission Station
Sub Transmission Station
Sub Transmission Station (Endeavour)
Zone

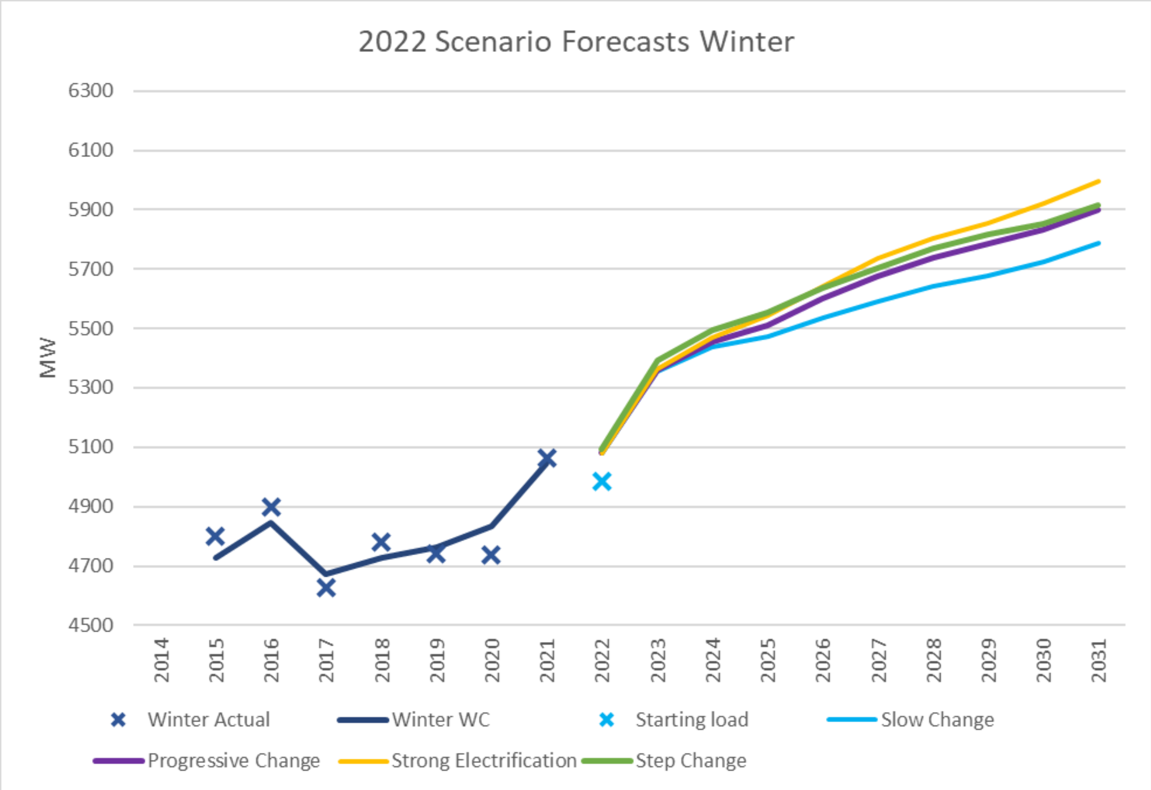
3 Spatial Maximum Demand Scenario Forecast Results

2022 delivered the first suite of forecast scenarios building from Ausgrid's share of AEMOs inputs and assumptions for the 2022 ISP. Historically, Ausgrid produced forecasts for a central case and carried out broad sensitivity to alternate demand outcomes.

Scenario spread for the 2022 forecast in summer is 130MW by 2031, representing approximately 2% of forecast system total peak demand. Forecast outcomes are narrow due to the counteracting nature of how forecast elements combine with and uplift in demand by one driver incentivising demand reduction through another. For example, enhanced EV activity incentivises increased activity in PV and energy efficiency rustling in stabilising long term demand growth.



Scenario forecast spread in for the 2022 forecast in winter is 200MW by 2031, representing approximately 3% of forecast system total. Similarly for winter, enhanced EV activity incentivises increased activity in PV and energy efficiency rustling in stabilising long term demand growth, however due to lower PV output coinciding with peak and elements of energy efficiency policy targeting summer peak only resulting in larger scenario spread in winter.



Scenario spread for the new suite of forecasts is expected to grow as additional forecast elements transition to the 2022 ISP scenarios whilst maintaining internally consistent demand driver combination and narrative. Part of the challenge in transitioning certain elements lies with assigning projections to forecasts that are consistent with the scenario narrative and are internally consistent with other forecast settings.

In particular, applying scenario projections for forecast elements relating to demand drivers not specifically related to net zero emissions obligations can be difficult to assign as application of judgement is required which can lead to personal bias. For example, applying higher population demand adjustments to scenarios with a narrative offering a faster trajectory to net zero without explicitly considering the links that lead to such a combination to be true. That is, forecast elements combine in a why that is “desirable” and not necessarily “most likely”.

Forecast Element	Updated for Scenario Forecast (Y/N)	Comment
PV	Y	Model optimised for scenario output
Battery Storage	Y	Model optimised for scenario output
Electric Vehicles	Y	Model optimised for scenario output
Energy Efficiency	Partial	Updated with scenarios for Energy Savings Scheme (ESS) and Peak Demand Reduction Scheme (PDRS). Energy efficiency for Building Code of Australia relating building shell and Minimum Energy Performance Standards applying to appliances have not yet been updated

Forecast Element	Updated for Scenario Forecast (Y/N)	Comment
Electrification	Partial	Residential gas conversion to electric has been updated, Commercial electrification has not yet been analysed
Population	N	Not yet transitioned
Econometric	N	Price/Income impacts not yet transitioned
Block Loads & Major Customer Connections	N	Not yet transitioned

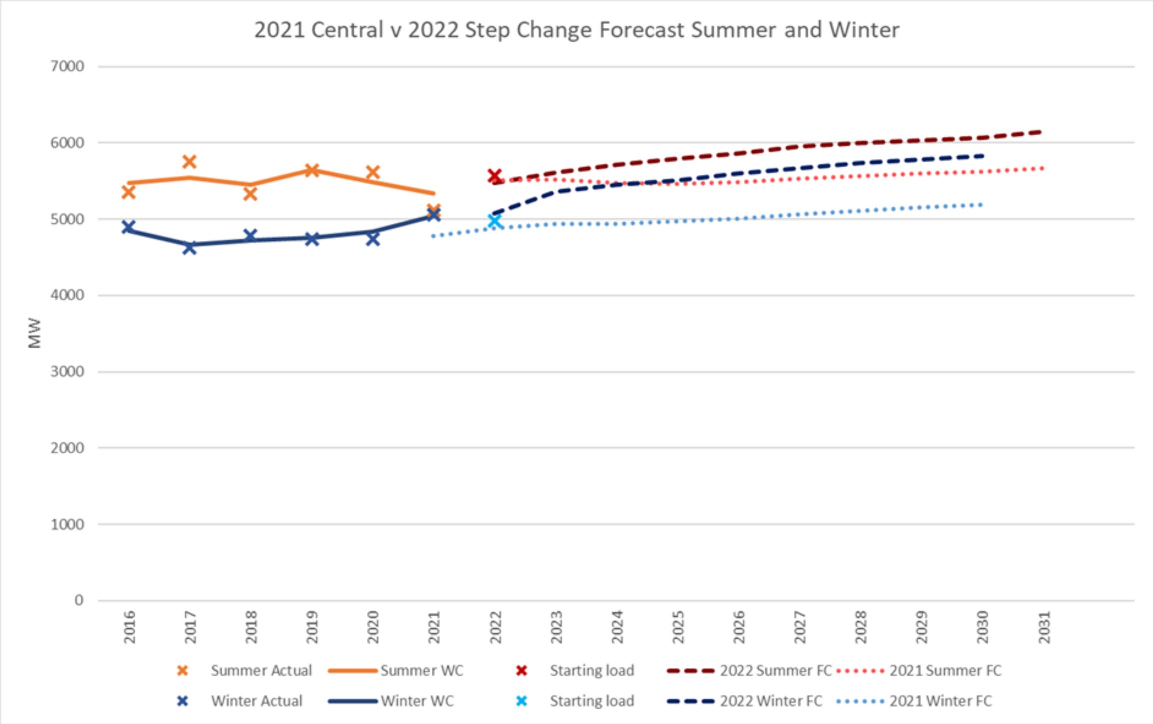
3.1 Step Change Maximum Demand Forecast Outcomes

The section outlines the key outcomes of Ausgrid's 2022 Step Change maximum demand forecasts for zone substations and sub-transmission substations.

The chart below shows the historical and forecast coincident maximum demand at the whole-of-system level. The 8 year compounded annual growth rate (CAGR) is +1.1% in summer and +1.9% in winter. Compared to the 2021 Central forecast, the 2022 Step Change forecast has a similar starting point as measured in 2022, however, growth out to 2030 is stronger in both seasons. A strong winter 2021 actual maximum demand and diminished impact of PV in winter, in addition to growth in EVs provides the impetus for the strong projected growth forecast.

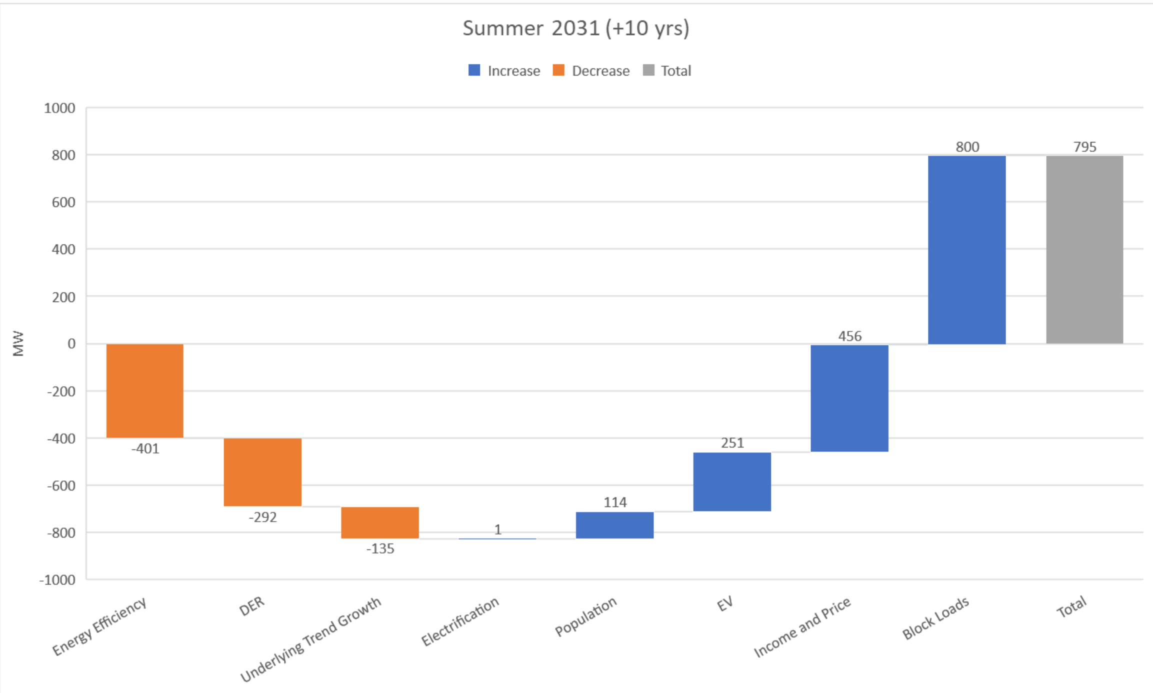
Steady growth in summer is underpinned by continuation of elevated levels of large customer connection activity, population growth, and EV uptake . This uplift in demand is offset by energy efficiency impacts and strong growth in PV system uptake. PV demand reductions are further enhanced in summer owing to the higher solar exposure coinciding with peak demand in the summer months when compared to winter.

A key observation is the gap between summer and winter forecasts expecting to narrow, in contrast to past forecasts which showed the Ausgrid network as being strongly summer peaking. This is primarily due to the forecast impact of increased solar uptake and government policy initiatives aiming at reducing summer peak demand which do not reduce winter peaks by as much as they reduce summer peaks.



A summary of the contributing elements of the summer forecast are shown below as a waterfall chart. In 2031, there is a projected net growth of 795 MW at the system total level. The majority of the positive contributions to growth are from block loads, prices and economic growth, and EV uptake offset by reductions mostly from DER and energy efficiency.

Component Demand Drivers from 2022 Step Change Forecast

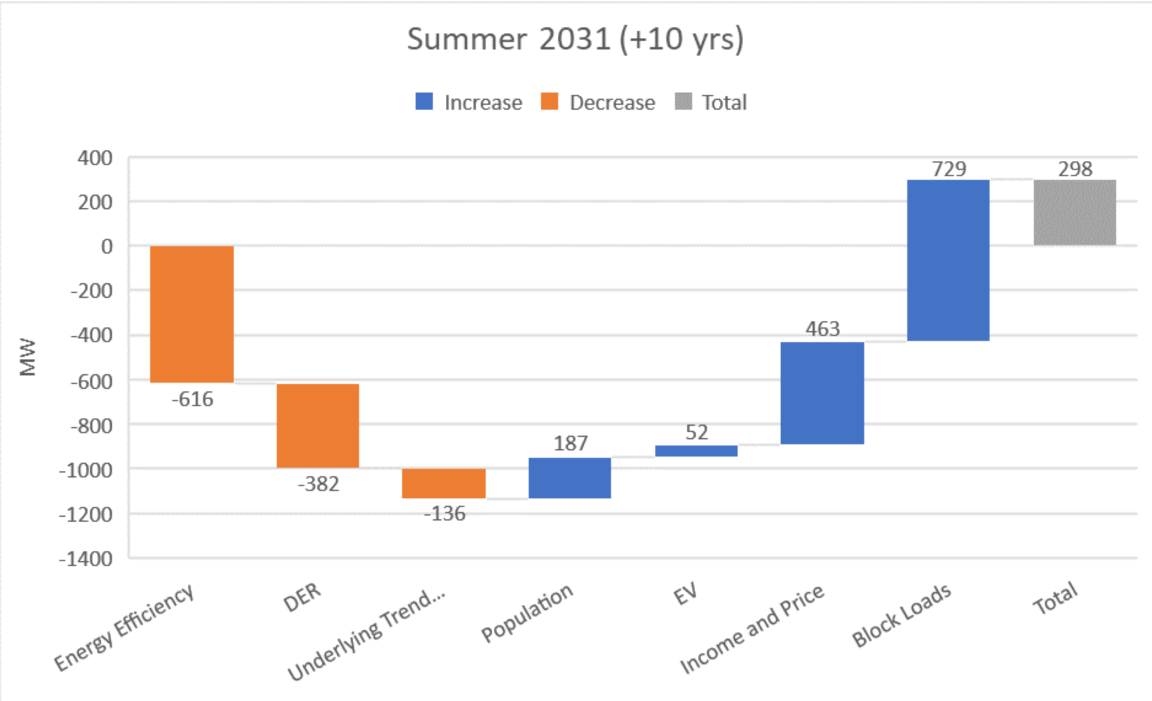


Demand driver implications from various forecast elements remained largely similar between the 2022 Step Change scenario forecast and the 2021 Central Forecast. 2022 Step Change Population adjustments, econometric adjustments in income and price, and Block Loads (large customer connections) are broadly in line with 2021 Central forecast. Similarly, there is minimal variation between the 2022 and 2021 forecasts in Underlying Trend and combined PV and Battery (DER) impacts in demand reductions.

Significant updates in demand driver inputs for Energy Efficiency and EVs result in an 29approx. 30% reduction in energy efficiency impacts and a five-fold increase in EV impacts. Energy Efficiency underwent a review of impacts due to the Energy Savings Schemes (ESS) and Peak Demand Impact Schemes (PDRS) which have come in lower than the 2021 forecast. EV impacts were revised upwards mostly due to the major increase in forecast EV uptake in the 2021 AEMO ESOO forecast. AEMO EV uptake forecasts are a key input into Ausgrid's EV demand models, hence the material uplift in impacts.

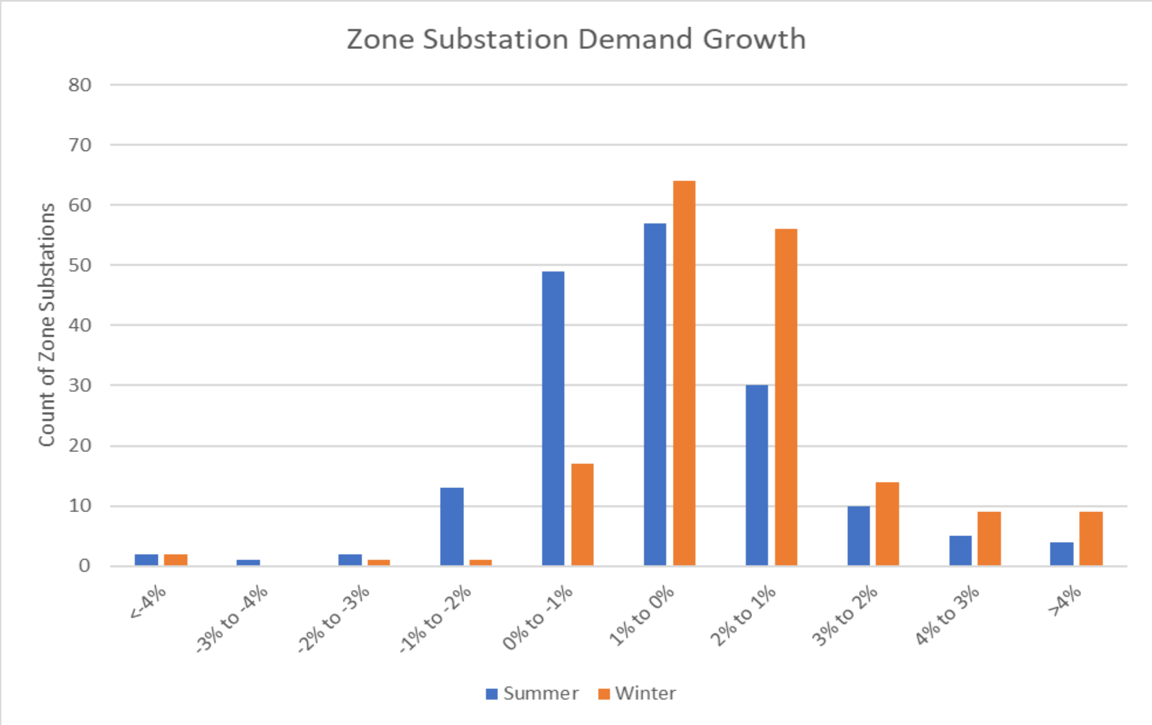
Electrification of residential gas has been introduced in the 2022 scenario forecasts with the Step change scenario indicating non-material impacts within 10 years with policy changes driving electrification of residential gas subdued until the early to mid 2030s when impacts begin to ramp up.

Component Demand Drivers from 2021 Central Forecast



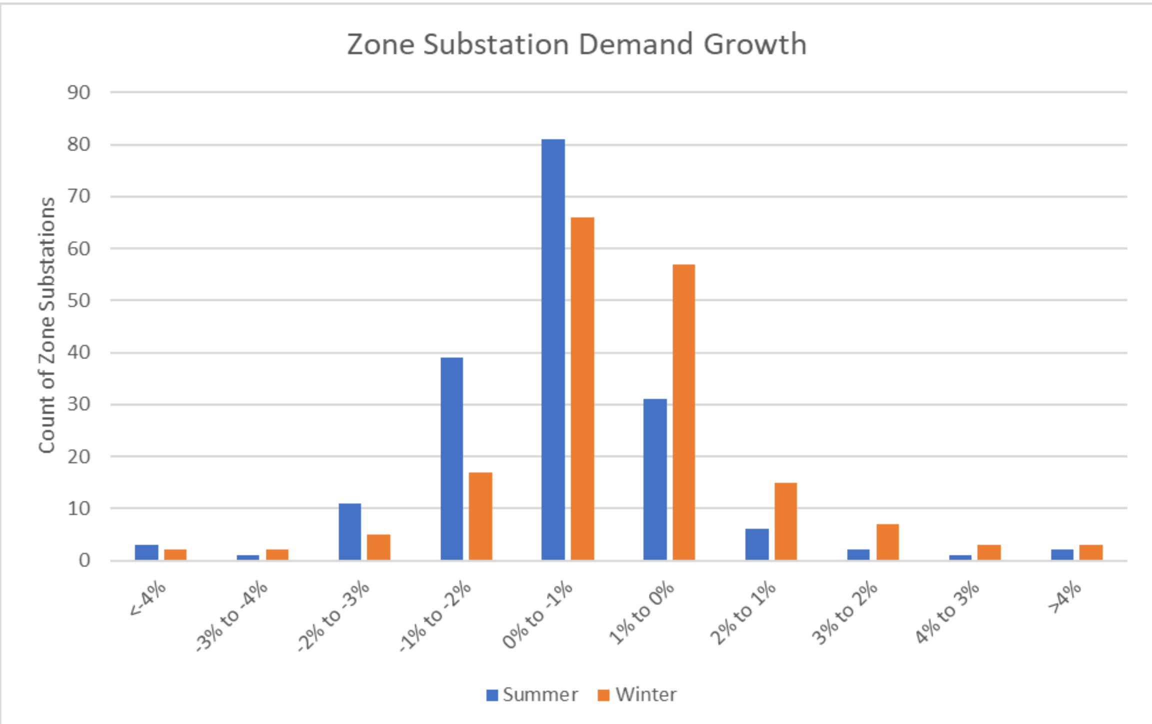
While the whole-of-system view is informative, it is the forecast at the spatial level that provides the most insight into the level of localised growth, which can drive investment in parts of the network and not in others. The following histogram chart summarises the resultant summer and winter 50 POE Step Change forecast zone substation growth out to 2029 (8 years) compounded (CAGR) rates, which reflects the diversity in rates of growth at the spatial level. While the majority of zone substations growth rates are in the range of -1% to 2% there is a broad range of growth rates at the local spatial level.

2022 Step Change Forecast Zone Substation Growth Histogram



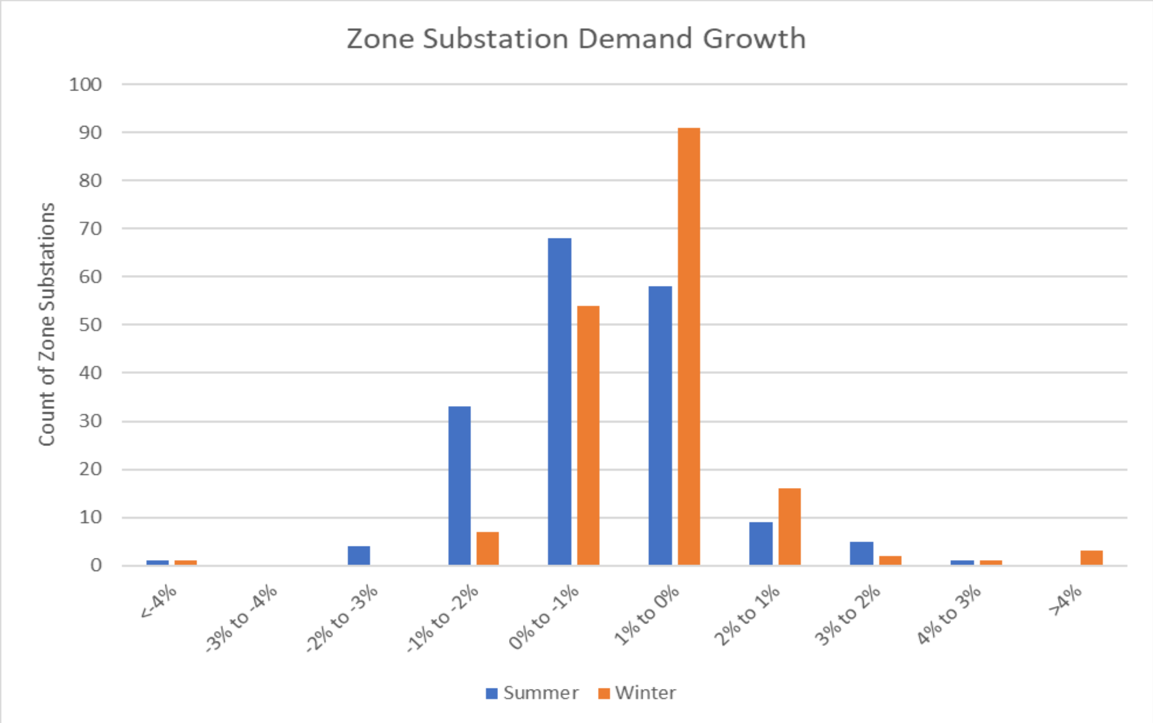
The 500+ MW increase in total system aggregate impacts over the 10 years to 2031 manifests in a shift to the right towards more positive growth values with the predominant Summer growth rate bracket shifting to 0 to 1% growth from -1 to 0% in 2021 forecast. Additionally, there is seasonal difference between Summer and Winter due to negative demand drivers such as PV and Batteries exhibiting enhanced demand reductions in Summer when compared to Winter. This results in a greater number of substations experiencing peak demand growth in Winter.

2021 Central Forecast Zone Substation Growth Histogram



Customer connection activity is a key influencer of spatial growth rates across all zone substations as block loads tend to cluster spatially driving both higher magnitudes of growth as well as resulting in broader variation of growth rates. This is illustrated in the histogram below where block loads were removed from the step change forecast by the increasing concentration of zone substations experiencing growth rates around 0% and a shift in median growth to the left on the x-axis in comparison to the full step change forecast graphic above.

2022 Step Change Forecast Without Block Loads Zone Substation Growth Histogram



3.2 Key Outcomes – By Forecast Element

The maximum demand forecast is constructed using several elements. The following sections provide further detail around these elements, including rationale and how they impact on the forecasts. All commentary relating to forecast element outcomes is based on the respective Progressive Change scenario forecast for each element listed.

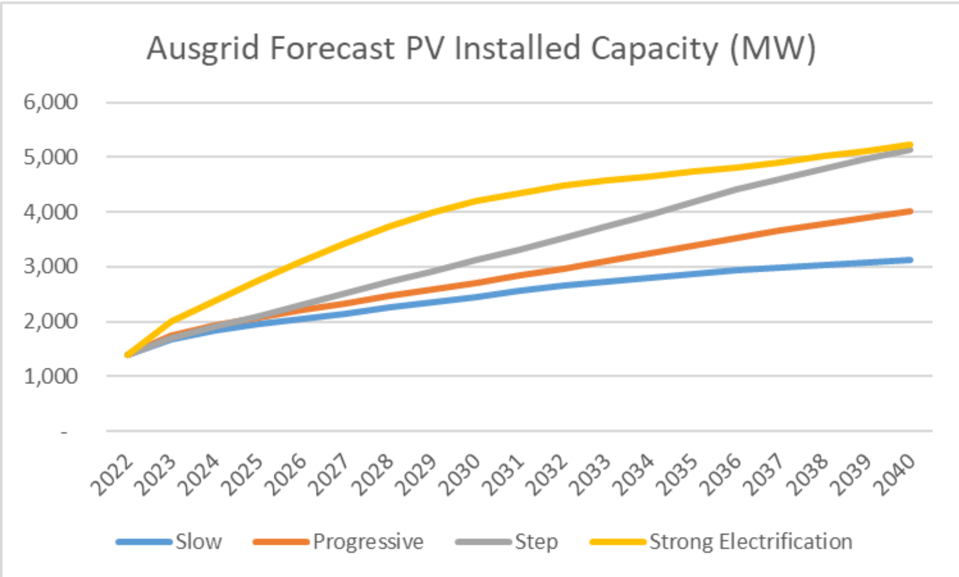
3.2.1 Customer Rooftop PV & Battery Storage Systems

The installation of customer rooftop PV systems generally reduces demand on network assets further upstream when the systems generate during the day, with the maximum reduction occurring at midday, subject to day-to-day weather conditions. The magnitude of the maximum demand reduction on a network asset depends largely on the correlation between the PV system's generation profile and the local time of peak at each asset.

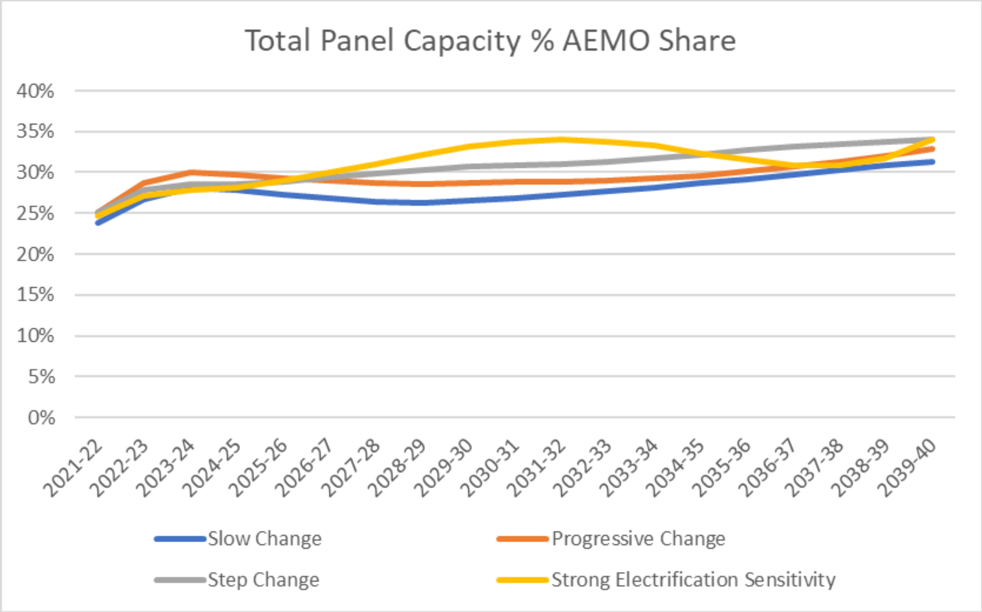
Similar to rooftop PV systems, battery storage systems will generally reduce maximum demand. Batteries are often paired with rooftop PV systems and when operating together, will reduce maximum demand to a greater extent than a PV system alone. Batteries can store excess energy generated during the day from PV systems or store energy from the grid overnight at cheaper off peak rates and can discharge at controllable times, often during peak periods. The Ausgrid forecasts of customer rooftop PV system and battery storage system uptake has been guided by AEMO 2022 ISP inputs and assumptions forecast models.

Growth in customer PV systems is expected to remain strong. In 2022, Ausgrid had around 1400MW of installed PV capacity. In 2030 this is expected to be approximately 3200MW however could be as high as 4200MW or as low as 2500MW as indicated by the strong electrification and slow change forecasts in the graph below. By 2040, the most likely installed capacity is 5000MW or as low as 3000MW.

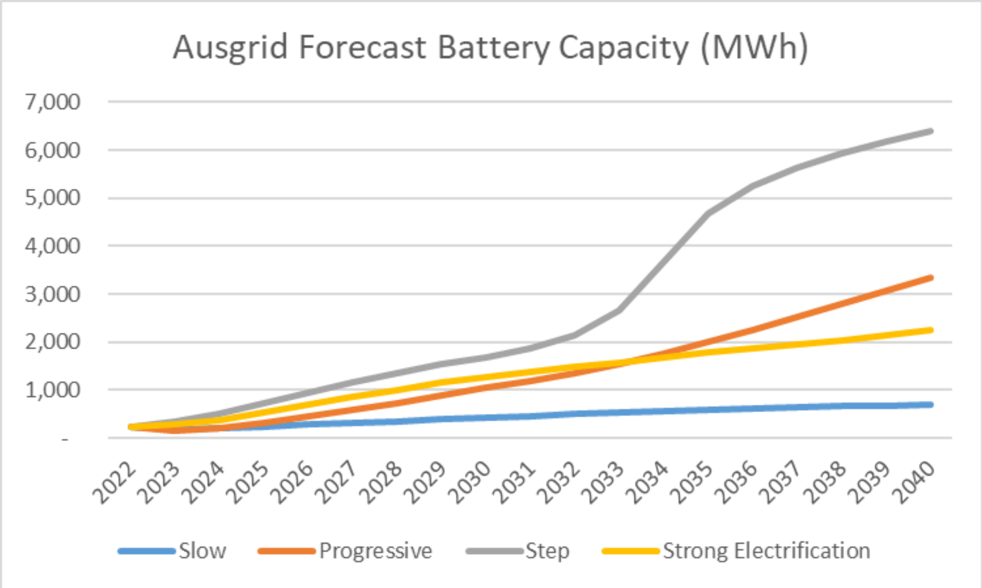
Scenario variation is driven largely in response to forecasted increased demand from EV take up (or lack thereof) and general increase in energy use incentivising customers to install PV offsetting the additional demand consumed. However existing trends do see an already elevated appetite for customers to offset their existing energy use with PV generation leading to significant installation activity even in scenarios that have lower EV uptake.



Ausgrid's current share of NSW region rooftop PV installs sits at approximately 25%. Near term projections of allocation sees Ausgrid close the gap raising to 30% before stablising over the ensuing years to be between 30-35% by 2040. This would be slighlty below an even share as a percentage of total NSW demand however Ausgrids network area incorporates higher density housing than other NSW DNSP and therefore diminished ability to host rooftop PV due to available roofspace.



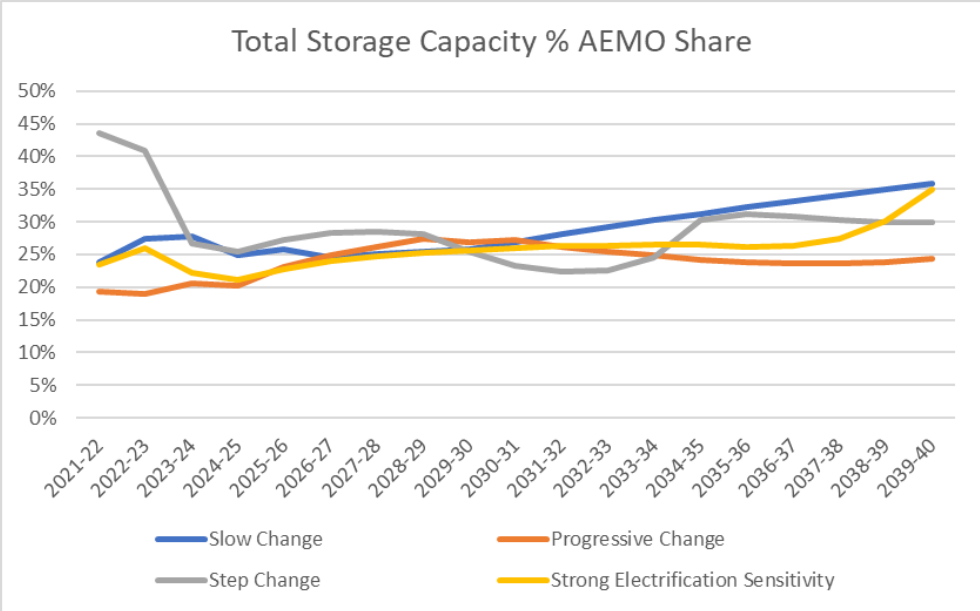
For customer battery storage systems, capacity of systems is forecast to grow from the current total of around 250MWh[3] in 2021 to around 1500MWh by 2030 and to around 6200MWh by 2040. The higher magnitude of installed battery storage capacity in the step change scenario reflects the the greater level of decentralisation that is forecasted for this scenario in comparison to the 3 other scenarios. The larger spread in forecast outcomes also reflects a higher level of uncertainty associated with battery storage uptake in comparison to other forecasts elements



Ausgrids share of AEMO's NSW forecast battery forecast begins at 20-25% of installed capacity raising slightly to 25-35% by 2040. Installations are lower in comparison to other

[3] 250MWh is an estimate based on scaling known battery storage install applications by 50% based on previous research indicating that half the battery population did not flow through to official databases

districts in NSW due to higher housing density providing physical barriers to uptake as space for retrofit is limited. Uptake is also subdued due to a greater proportion of customers being supplied in areas where stronger network connections provide higher reliability further eroding the case for battery install.



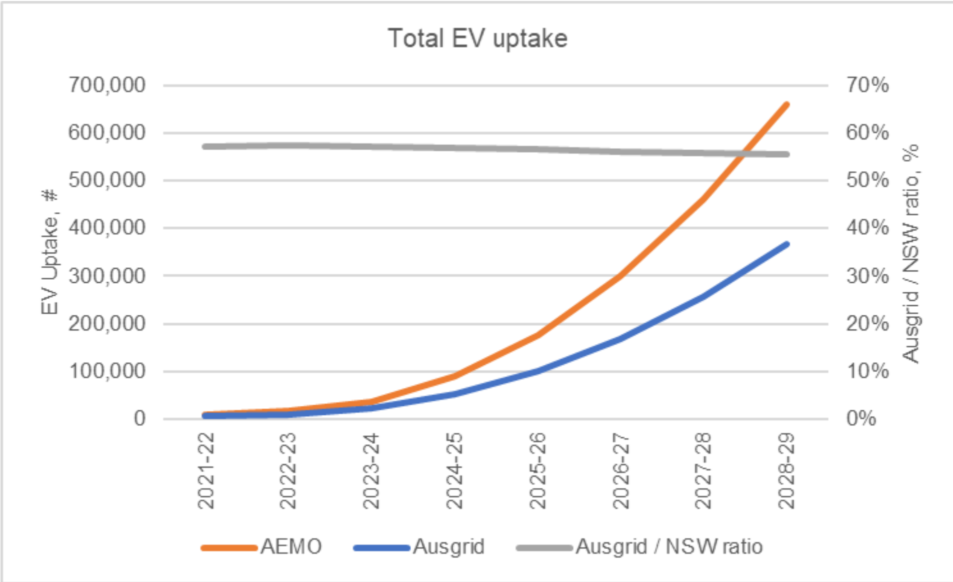
Solar and Battery results include the assumed profile impacts relating to tariff assumptions that modify customer behaviour and emerging technology end use. Feed in tariffs move lower over the forecast period influencing payback periods and therefore moderates future PV uptake. However a share of customers are modelled with cost reflective pricing which offers customers the potential for arbitrage and therefore lower payback periods resulting in higher PV uptake.

For residential customers, the share of cost reflective tariffs is 40% compared to 60% flat tariff customers and is held steady to reflect the reluctance of retailer pass through for residential customers. For business customers, the cost reflective share is the same as residential at the beginning of the forecast however transitions to 100% cost reflective by the mid 2040s

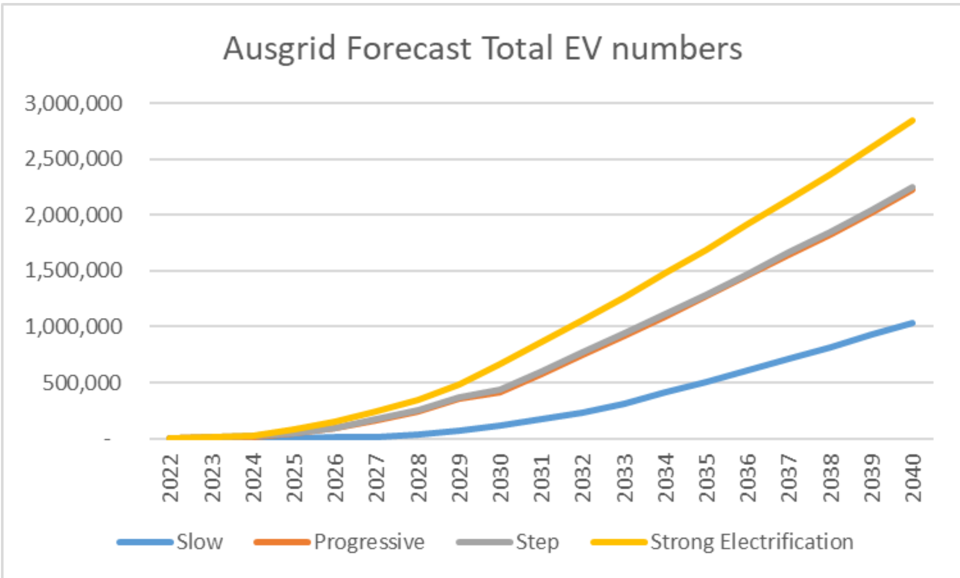
3.2.2 Electric Vehicles (EVs)

Electric vehicles are charged using charging points located at either private homes, public charging points or commercial depots and will result in a net increase in maximum demand. The Ausgrid EV forecast has been developed by Evenergi, with whom Ausgrid has partnered with since 2019 to undertake EV charging trials and EV owners customer surveys. Assumptions are based on a mix of Evenergi modelling, AEMO data and models, as well as experience obtained from EV charging trials and from EV owner customer surveys.

The predicted Ausgrid share of NSW EVs was informed by Evenergi modelling. We know that currently around 60% of EV sales in NSW are being garaged within Ausgrid's network based on the ABS Census information. However, in future, this share is expected to decline gradually as EV adoption becomes widespread throughout NSW owing to EV production economies of scale and combustion engine vehicles slowly being phased out. Ausgrid's share of NSW AEMO forecast follows a similar pattern in all scenarios as the grey plot in the graph below.



Under the Step Change scenario, it is estimated that there will be a total of around 400,000 EVs by 2029 and around 1,100,000 EVs by 2034 across all vehicle types. This is rapid growth considering that currently, there are only around 9,000 EVs in Ausgrid's network area. By 2040, predicted EV numbers range from around 1 million EVs in the Slow Change scenario to almost 3 million EVs in the Strong Electrification scenario.

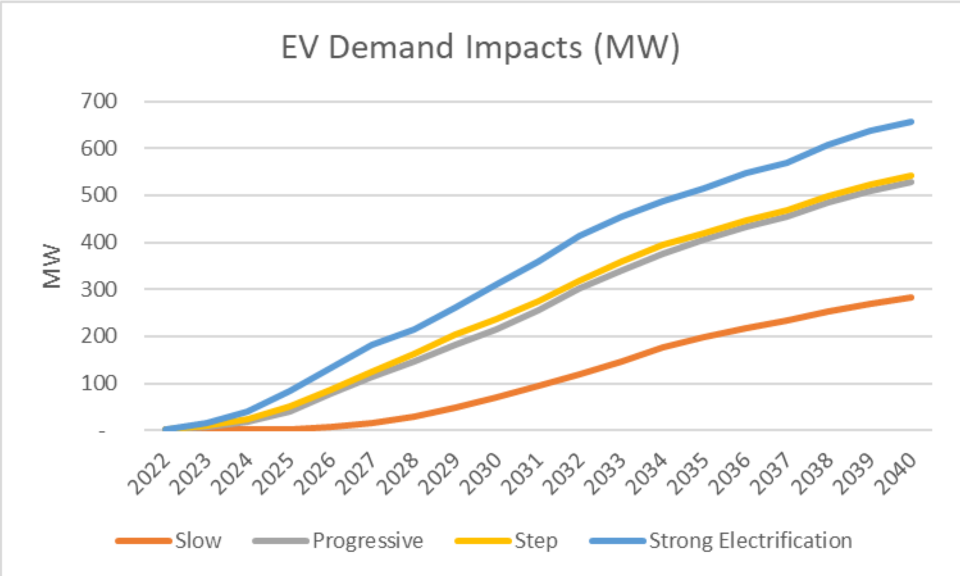


While a key uncertainty around EV impacts modelling relates to charging patterns, Ausgrid's view around residential EVs is that they will mostly be charged at home during off peak periods under existing time of use tariff arrangements. This assumption is supported by the "Charge Together" EV owners survey where across a sample of around 130 respondents:

- Around 5 in 6 (83%) charged their vehicles at home,
- Around 2 in 3 (65%) charged between 10pm-7am.

The EV model also accounts for other EV vehicle types, such as commercial fleet vehicles, light and heavy trucks and buses, each with their own modelled charging patterns and mileage (affects charging volume). Further details of the key EV model assumptions are tabulated in the Appendices.

The chart below forecasts the EV impact in summer across the entire Ausgrid network. From the early 2030s onwards, even though EV uptake remains elevated, there is a material change in the modelled EV charging behaviour such that a sufficient volume of EV charging is incentivised by tariffs. EV charging becomes less coincident with substation peak demand and it is possible for impacts to diminish despite ever-growing EV numbers



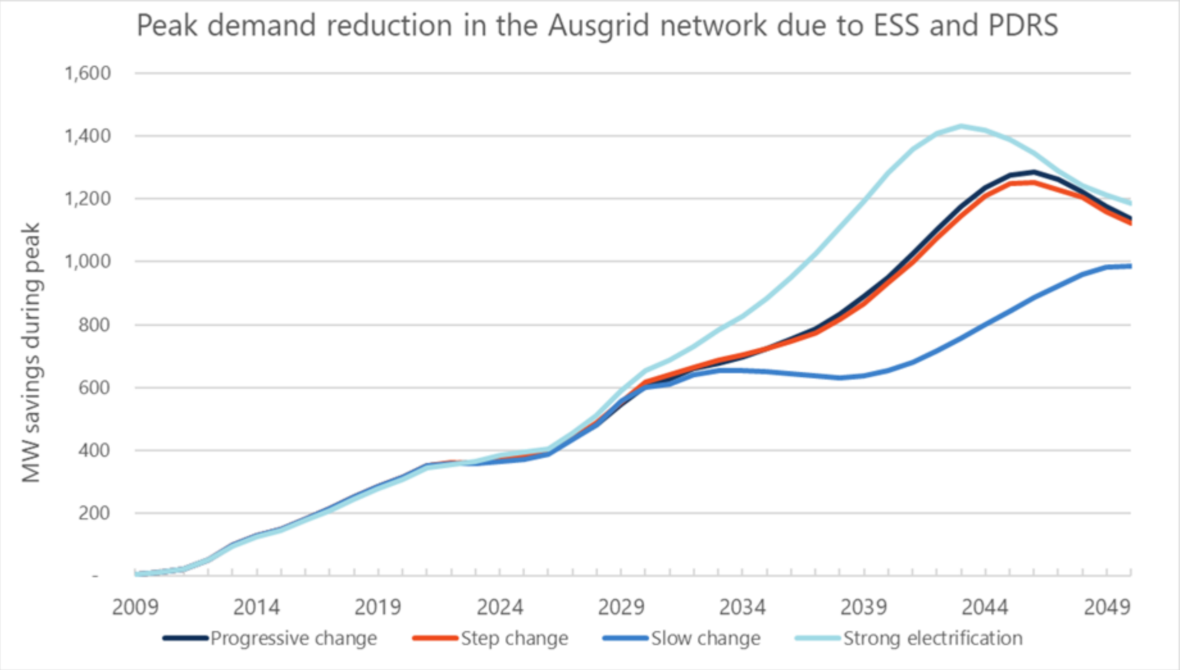
Results include the assumed profile impacts relating to tariff assumptions that modify customer behaviour and emerging technology end use. EV profiles are based on projected EV use patterns overlaying tariff assumptions to influence time of charging. For example, the residential EV charging profile assumes an increasing level of off peak charging into the future with material EV load charging in the 10pm to 7am off peak window where energy charges are lower and assume a level of effectiveness of cost reflective tariffs.

3.2.3 Energy Efficiency

In 2019, the NSW government released policies developing a pathway to net zero 2050 on o which was Energy Security Target (EST) consisting of the extended Energy Savings Scheme (ESS) and the new Peak Demand Reduction Scheme (PDRS). Since the 2020 forecast a placeholder adjustment was implemented to account for the PDRS which the NSW government were finalising its program scope and operation mechanisms. The PDRS impacts were formalised into forecast demand impacts in the 2022 Progressive Change forecast Scenario based on external consultant advice.

Energy Savings Scheme has driven significant reductions in demand during peak periods to date. This is not expected to increase substantially in the short term, with the certificate volume relatively stable until the mid 2020s, and no scheme incentive for sites participating in the ESS to invest in peak demand reduction. Once the Peak Demand Reduction Scheme starts in earnest, we see a significant increase in peak demand reductions under all scenarios, with very little difference in total reduction for most scenarios reflecting the relatively small difference in projected peak demand (other than the "slow change" scenario which is relatively muted from 2030). Peak demand reduction due to these schemes is expected to increase from the current level of approximately 400 MW to 1200 MW by the late 2040s

Overall, 200+ MW of total Energy Efficiency impacts decreased over 10 years of forecast relative to the 2021 forecast impacts due to the revision of the ESS and PDRS scheme impacts.



The other 2 components of Energy Efficiency relating to building shell energy efficiency improvements and appliance energy performance remained largely the same as last years forecast.

3.2.4 Electrification of Residential Gas

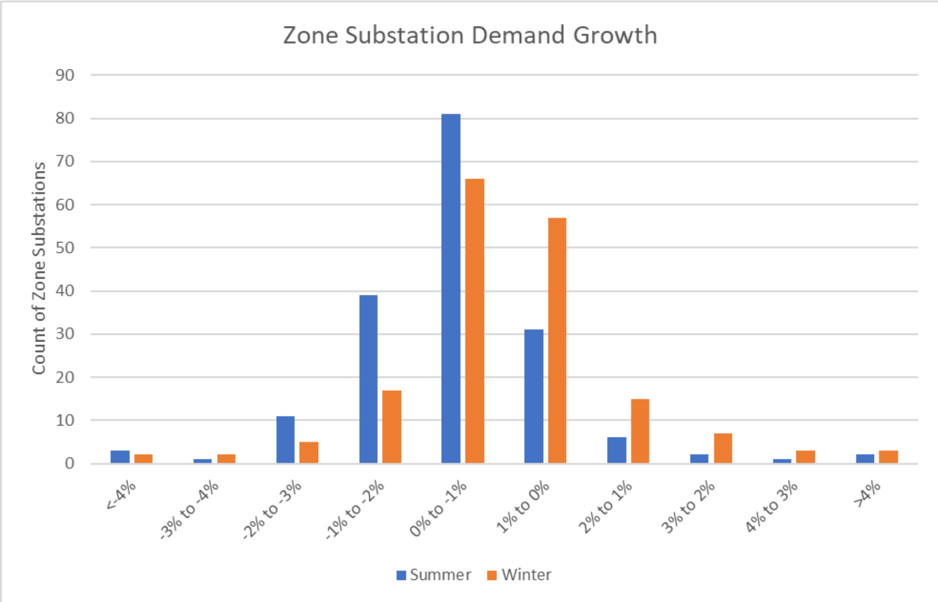
New to the 2022 suite of forecasts is a forecast element that models the decarbonisation of residential gas use arising as a transition of gas customers to electric appliance use. Currently, electrification trends are quite muted and lead by consumers actively seeking out electric over gas appliances. Government policy also currently leans towards gas appliances over electric due to gas having a lower carbon emissions intensity than electric energy sources at this current time however the trend to lower carbon emissions from electricity continue to accelerate.

It is forecasted to take some time to shift these policy settings towards supportive of gas decarbonisation in the direction of electrification and therefore electrification impacts accelerate in the years beyond the next regulatory period.

3.2.5 Block Loads – Customer Connections

The pipeline of large customer connections continues at an elevated pace with datacentres, road, and rail activity remaining strong. New transport projects have been initiated even as previous transport connections are commissioned for public use resulting no net loss of forecast load. Datacentres however continue to accelerate in connection number and size with an additional 150 MW in scaled datacentre demand coming to forecast over the past 5 years.

2021 Central Forecast Zone Substation Growth Histogram



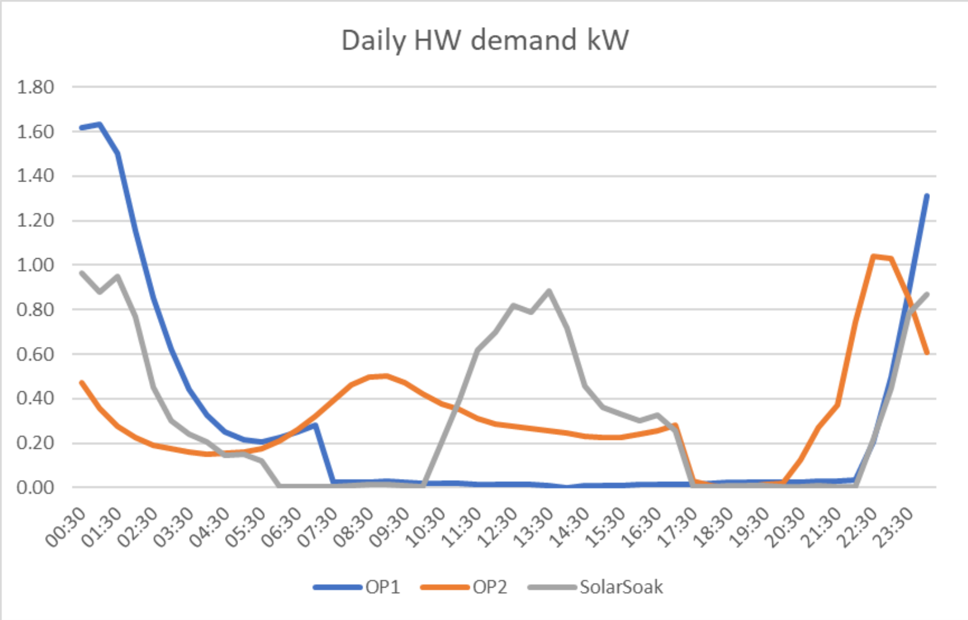
Recent NSW government announcements have delayed some large infrastructure projects, however the majority of those delays occur to projects outside of Ausgrid's area or were not in the stage of connection negotiation yet and therefore were not in Ausgrid's forecast. If the delay of large NSW Government infrastructure projects continues for a time, a moderation of elevated transport connections activity would ensue.

3.2.6 Off Peak Hot Water

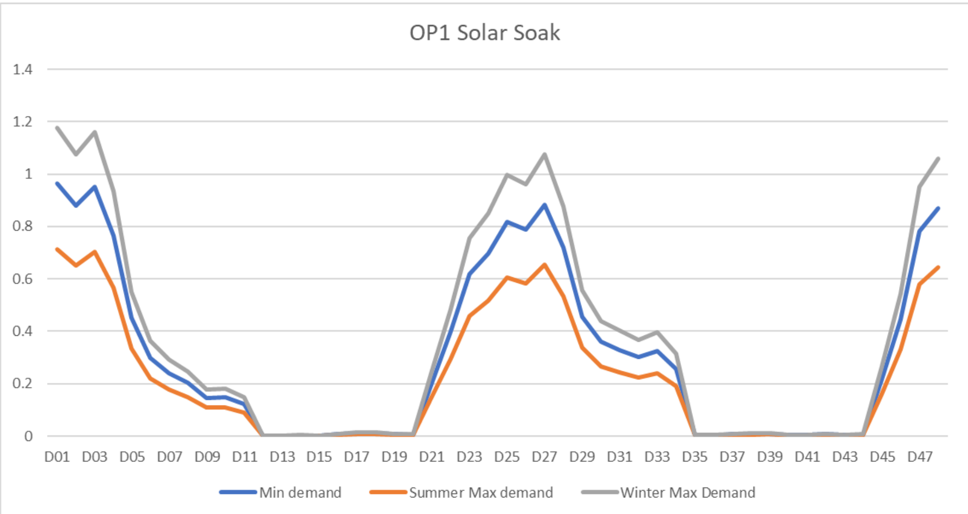
The off peak hot water adjustment models the effect of moving the existing controlled load "off-peak 1" (OP1) tariff customers from overnight hot water tank heating into the daytime to take advantage of excess solar generation, known as "solar soaking". Existing accumulation (basic) metered customers are progressively transitioned to smart meters, and it is estimated that around 10% of these will utilise the new meter for solar soaking either via network control or time-clock scheduling. As well, future on-demand hot water heating transition to OP1 and solar soaking.

The curves below were obtained from a hot water controlled load trial undertaken in late 2021 by Ausgrid where a 50% energy load shift was applied to move the existing overnight hot water energy consumption into the daytime.

Average customer demand before and after load shifting:



The chart below estimates the seasonal variability of applying this method of load shifting on a summer maximum demand, annual minimum demand and winter maximum demand day, as an average curve per customer. Savings are higher in winter since hot water usage is highest along with lower ambient temperatures in winter and vice versa for summer.



Forecast Off Peak Hot Water demand impacts shifting to a solar soak profile features predominantly in the DER integration study where its variation in forecast settings can influence the final network impact outcome more widely. There is no adjustment in the 2022 Progressive Change maximum demand forecast for OPHW as the time of typical peak demand at locations where OPHW customers reside coincides with periods of no hot water heating with the current off peak schedule. Additionally, locations where OPHW solar soaking may be additional to peak demand coincide with locations that have low OPHW customer penetration. See table below for top ten zone substations with highest modelled OPHW solar soak summer and winter impacts.

Rank	Zone name	OPHW Peak Impact (MW)	Time of Peak	peak day demand (MW)	Zone firm rating (MVA)	Utilisation
Summer						
1	RNS Hospital	0.20	14:00	11.6	54	22%
2	St Peters	0.17	13:30	56.9	89	64%
3	Marrickville	0.14	11:00	43.7	72	61%
4	Newcastle CBD	0.08	13:00	36.9	76	49%
5	Somersby	0.06	11:00	14.2	52	27%
6	Camperdown	0.04	14:00	26.3	61	43%
7	Gore Hill	0.04	12:00	43.7	97	45%
8	Clovelly	0.03	10:30	34.8	88	40%
9	Beacon Hill	0.03	10:30	17.8	27	67%
10	Kurnell South	0.02	10:30	4.7	38	12%
Winter						
1	Castle Cove	0.49	17:00	31.6	96	33%
2	Bankstown	0.47	13:30	34.7	65	54%
3	St Peters	0.29	13:30	52.3	89	59%
4	Mascot	0.06	11:30	22.5	82	28%
5	Green Square	0.06	14:30	45.8	114	40%
6	Campbell St	0.04	13:30	26.4	65	41%
7	Surry Hills	0.03	13:30	23.0	78	30%
8	Brookvale	0.03	10:30	32.2	54	59%
9	City South	0.005	14:00	62.5	130	48%
10	City North	0.0025	10:30	53.4	168	32%

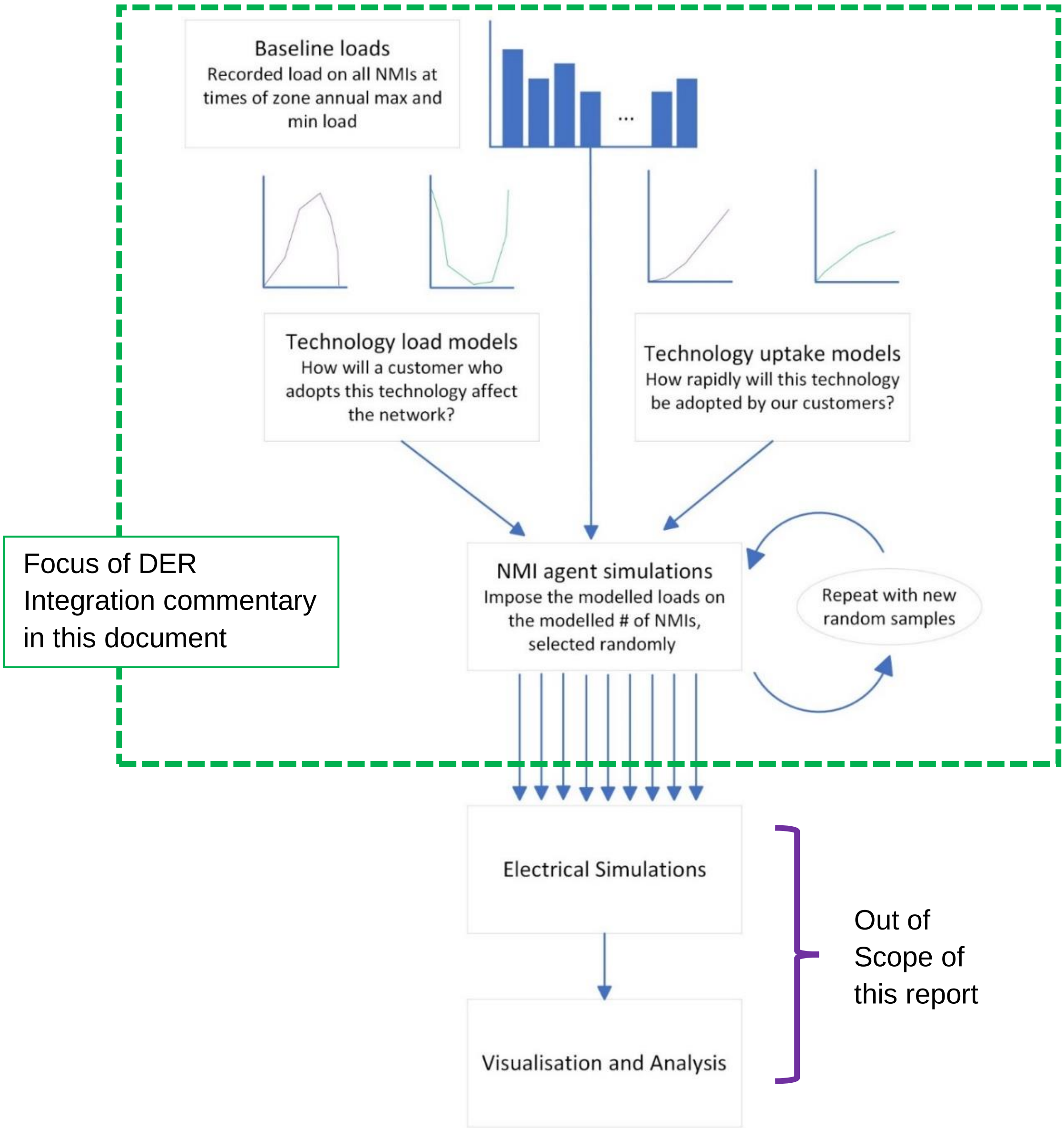
4 DER Integration Forecast

A new forecasting methodology was devised in 2022 in order to forecast network impacts due to the increasing uptake of Distributed Energy Resources (DER) by customers and varying customer behaviour associated with technology. Ultimately this new model resulted in an assessment of DER hosting capacity and future required network expenditure relating to increasing DER use by customers.

Typically demand impacts from increasing DER are applied as an average impact per install when adjusted for in traditional maximum demand forecasts as zone and STS. Assessment of demand impacts below the zone and sub transmission network level requires a more sophisticated approach to more closely model the inherent variability in customer uptake and energy use behaviour evident in LV networks.

Variability in distributed impacts can drive network issues that are otherwise hidden in average demand impact analysis. The DER integration forecasting methodology attempts to bridge the gap between macro themes at the zone substation level and apply impacts at the customer level where noise in demand profiles is more influential to overall network outcomes.

The diagram below sets out the end to end DER integration model incorporating the application of DER forecasts and network simulations. The forecasting component ends at the NMI agent simulation stage and is the focus of this document. The DER integration model then progresses to the electrical connectivity simulation stage where results for visualisation and analysis are produced, and are out of scope for this methodology document.



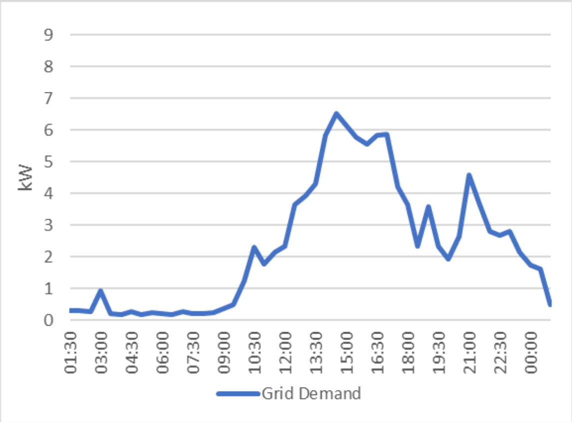
4.1 Demand Variability of Individual Customers

There are many binary factors that combine to make a customer's profile highly variable at any given moment including absence or presence of various appliances/technology and individual customer energy use behaviour. Simply a customer being at home can drive large variation in demand in comparison to when they are away from their residence.

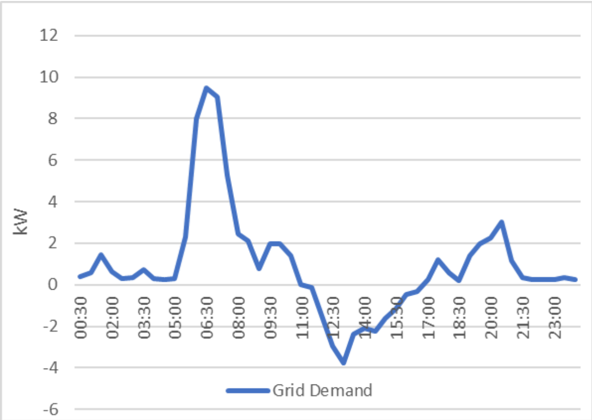
Other sources of variation include presence of solar PV, presence of battery storage and operation mode, presence and use of air conditioning, presence of an EV and if/when it is charging, and off-peak load schedules to name a few. Many of these load variations can combine in numerous permutations at the customer level in ways where the network may or may not be able to operate effectively.

Demand Profiles Illustrating Variation in Customer Energy Use

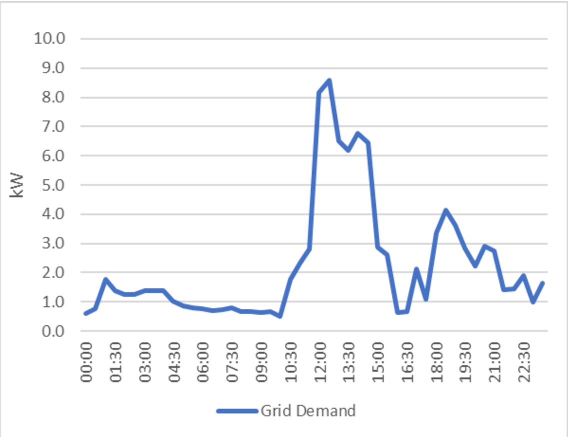
Aircon and no DER



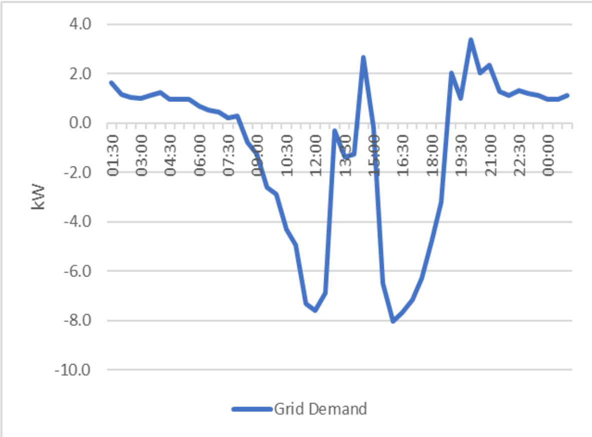
Solar and Battery



Electric Vehicle



Electric Vehicle and Solar PV



4.2 Agent Based Forecasting

Agent-based forecasting is a forecasting technique that enables a more nuanced approach to modelling highly variable customer demand impacts due to ever increasing DER. Disaggregation of customers into distinct groups or "agents" of customers that exhibit similar characteristics combining with additional knowledge and datasets of each agent class aids in the spatial allocation of demand impacts. Variation in customer energy use within agent classes can also be explored by adjusting individual customer demand based on the binary behavioural factors of DER technology.

Agent based forecasts have been in use at Ausgrid for the PV and Battery post model adjustment in the maximum demand forecast since 2018 locating PV and batteries in network areas where customers characteristics exhibit a higher return on investment and lower barriers to install. In 2022, this concept was extended to additional DER post model adjustments and applied lower down in the network.

Segment name	Lower band (kWh)	Upper band (kWh)	Notes
Residential			
Apartment	1,000	20,000	All apartments/townhouses/etc
Res – Small	1,000	3,500	Bottom quartile of detached houses
Res – Med	3,500	9,000	Two middle quartiles of detached houses
Res – Large	9,000	20,000	Top quartile of houses (excluding above 20 MWh) – 1%
Non Residential			
Business – Small	2,000	40,000	Aligns with small LV business, flat, TOU and demand tariffs
Business – Med	40,000	160,000	Medium LV business and aligns with EA302
Business – Large	160,000	4,000,000	Large LV business and aligns with EA305, 310 and HV
HV	>4,000,000		11kV and above HV Customers

4.3 Applying DER Forecasts at Customer Level

Outlined below is a high-level task list for applying DER demand impacts at the customer level I the DER integration model:

1. Initial Customer Demand and Classification
    a. Each customer is assigned an agent class based on their annual energy use, tariff type (residential or non-residential), and street address (indicating apartment).

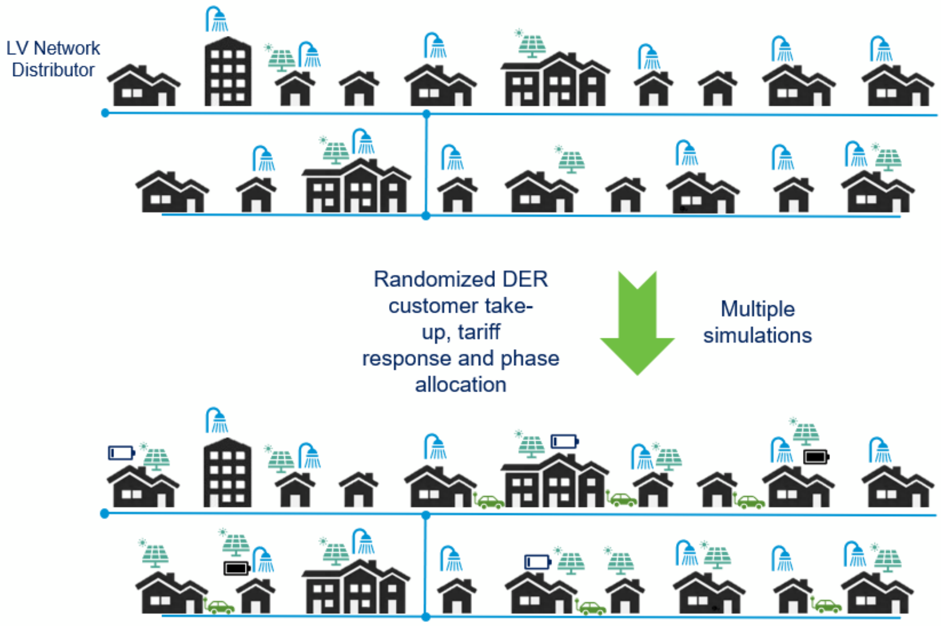
    b. Initial customer demand at local peak and minimum demand times is determined from metering data, on which future adjustments will be made. Where a customer uses accumulation metering, a proxy demand is allocated for peak and minimum demand by assigning demand values from a suitable proxy customer derived from a similar customer that has an interval meter.

    c. The actual distribution of current DER technology is assigned to those customers with recorded connected DER

    d. Where there is a gap between recorded DER customers and other known spatial datasets of historical DER take up, assigning unallocated DER is achieved through the application of the additional spatial dataset to the existing customer base.

2. Allocation of future DER
    a. DER forecasts produced in a disaggregated form assigning discrete forecasts for technology uptake and demand impacts by agent.
    b. Using information from the customer classification and initial conditions stage, customers are assigned DER impacts in a randomised process within each agent class until the agent class has exhausted its forecasted number of DER connections.
    c. Forecasted DER is only allocated to customers that do not currently own the technology being allocated. For example, a customer that already has PV will not be allocated additional PV in future years however this does not exclude them from allocation of other DER technology such as battery storage or an EV.
3. Customer Demand Impacts and Diversification of Demand
    a. Customers allocated DER technology in stage 2 are also allocated a particular consumer behaviour relating to the assigned technology. For example, battery customers can be assigned 3 different types of behavioural operational modes such as minimise export, tariff arbitrage, or VPP operation simulating the variation in customer priorities.
    b. Some DER technologies require a further step to ensure that individual customer actions relating to demand use reconcile with total diversified demand impacts of that technology. When allocated an EV, customers are assigned different sized chargers with demand impacts of that customer being the maximum draw of the charger rating. To ensure that EV demand diversity remains true to the average demand draw per vehicle at peak experienced by all EVs, the customer EV will also be assigned a charging/not charging status. This allows for an EV to draw the full capacity of its allocated charger imitating real world operation whilst several of their neighbours are not needing charge coincidently keeping overall average demand per EV at peak consistent with the total EV population.
4. Multiple DER and Behaviour Allocation Simulations
    a. Repeat steps 2 and 3 multiple times. Multiple simulations are needed to converge on a most likely outcome and avoid the potential in modelling a single outlier case where over or under investment can occur.

Allocation of DER Technology and Behaviour to Customers in the Network



Contribution to current and future peak demand (kW per customer)

Agent	% Customer	2022	2024	2029	2034	2039
Apartment	39%	1.1	1.1	1.0	0.9	0.8
Res - Small	12%	0.8	0.7	0.7	0.6	0.6
Res - Med	26%	2.2	2.1	2.0	1.7	1.4
Res - Large	13%	4.1	3.9	3.9	3.6	3.4
Bus - Small	8%	1.5	1.4	1.2	1.0	0.8
Bus - Med	1%	13	12	11	11	10
Bus - Large	1%	117	114	108	103	95
HV	0.07%	218	218	218	218	218

NB: percentages may not add to 100% due to rounding. Percent of total aggregate peak demand inclusive of all load up to 11kV

Contribution to current and future minimum demand (kW per customer)

Agent	% Customer	2022	2024	2029	2034	2039
Apartment	39%	0.04	0.03	0.02	0.03	0.06
Res - Small	12%	-0.05	-0.11	-0.13	-0.12	-0.10
Res - Med	26%	-0.03	-0.20	-0.29	-0.41	-0.44
Res - Large	13%	0.01	-0.25	-0.41	-0.51	-0.44
Bus - Small	8%	0.17	0.16	0.14	0.12	0.11
Bus - Med	1%	1.8	1.8	1.8	1.9	2.0
Bus - Large	1%	17	17	16	16	16
HV	0.07%	81	81	81	81	81

NB: percentages may not add to 100% due to rounding. Percent of total aggregate minimum demand inclusive of all load up to 11kV

4.4 Benefits of New Modelling Approach

Agent based forecasting enables the modelling of discrete individual consumer energy use incorporating a wider range of potential customer behaviour and aids in the testing of network sensitivity to emerging trends. The modular nature of building blocks within the modelling allows for the increased complexity of customer-customer and customer-technology relationships to be analysed and new relationships to be explored as they arise.

5 Independent Review

An independent review of Ausgrid's spatial demand forecast methodology with KPMG begun in September 2022. The main task was to assess the effectiveness and reasonableness of methodology and forecasting techniques applied in the spatial maximum demand forecast. The independent report commenting on the spatial maximum demand forecast stated:

> *"Ausgrid's methodology for maximum demand forecasting is comprehensive. It accounts for all major contributors that significantly affect future demands. Ausgrid has a strong understanding of the driving forces for each contributor, and they regularly test their assumptions on currency and applicability."*

Ausgrid also asked KPMG to provide commentary on the DER integration forecast methodology and found that is fit for purpose:

> *"Ausgrid's overall approach can be assessed as appropriate, useful, and reasonable for the given purpose"*

Finally noting with respect to both:

> *"KPMG encourage Ausgrid to continuously evolve the methodology to stay on track with, or ahead of, the industry trends"*

Maximum Demand Forecast

The review determined that Ausgrid's forecast methodology was robust and accounted for all major contributors to future demand. KPMG presented several risks and opportunities within current forecast methodology to pursue in the future. Ausgrid acknowledges the potential for continual forecast improvement with respect to the items identified, however the materiality to expenditure outcomes for the 2024-29 period is low.

KPMG noted that their qualitative assessment of materiality to the spatial demand forecast accuracy was medium to low. Subsequently, Ausgrid carried out sensitivity analysis to demand impacts on items raised and concluded there to be a low materiality to forecast expenditure.

Given that the materiality to expenditure outcomes for the 2024-29 period is low, we will address the recommendations via future iterations of the forecast and are currently preparing materials for inclusion in the 2023 Forecast.

DER Integration Forecast Inputs

Independent commentary was also sought on the application of agent-based DER forecasts and spatial allocation of DER in the newly development DER integration model with the understanding that the modelling process was not as established as the max demand forecast. KPMG noted that Ausgrid's overall approach to this type of modelling was appropriate, useful and reasonable given its stated purpose in assessing current and future DER hosting capacity and related expenditure.

KPMG also offered comments on the DER modelling methodology regarding the inclusion of more granular data on housing type and econometric data, which would tend to capture clustering of DER elements to a greater extent. Ausgrid acknowledges these improvement opportunities. When these issues are addressed, they will tend to concentrate the impact of

DER in localised areas of the network to a greater degree – meaning that the current model would understate rather than overstate the impact on the network.

Additional EV modelling is already underway to consider the impact of additional clustering in parallel with receiving the KPMG findings. The feedback from KPMG will be considered in a similar light as models are refined, alongside the practicalities of acquiring the more granular input data required to address the items KPMG have identified.

5.1 Maximum Demand Forecast Review

Forecast Element	Issue or Opportunity	KPMG Finding	KPMG Recommendation	Ausgrid Response	Ausgrid Action
Energy Efficiency	Issue	Energy efficiency does not consider recent Sustainable Buildings State Environmental Planning Policy (SEPP) update	Update energy efficiency impacts in future forecasts to account for change in policy settings	• SEPP release in Aug 2022 after 2022 Forecast release • Partially covered in other forecast elements such as electrification and PV model. • Sensitivity analysis revealed a 50% increase in energy impacts from buildings reduces system total demand by 0.2% pa to 2029.	• Plans to update for inclusion in 2023 forecast. • Expected impacts not expected to be material.
Historical Trends	Issue	COVID lockdowns impact demand data and introduce potential bias to historical trends	Remove the impact of COVID lockdowns from demand data noting potential for structural change e.g. WFH arrangements	• Ausgrid is summer peaking network with covid lockdowns featuring outside summer peak period. • Demand impacts on forecasts driving expenditure likely to be low	• Continue to analyse covid impacts on historical trends and monitor for short term forecast materiality

Forecast Element	Issue or Opportunity	KPMG Finding	KPMG Recommendation	Ausgrid Response	Ausgrid Action
Weather Correction	Opportunity	Climate change impacts are not explicitly modelled	Model future average temperature and incorporate demand impacts into forecast	• Ausgrid uses 10 yr weather series which will pick up trends more quickly than longer series used in the industry • Acknowledge potential materiality to long term forecast however low materiality to 2024-29	• Explore ways in which longer term temperature adjustments could be incorporated into long term forecasts • Likely to form part of scenario development in future forecasts
Solar PV & Battery	Opportunity	Concerns on data quality in PV installation register and flow on to demand impacts accuracy	Explore Artificial Intelligence (AI) techniques and satellite imagery to enhance accuracy of register data	• Ausgrid investigated third party photo imagery services using AI techniques to identify additional PV and found outcomes to be of low accuracy	• Continue current dataset corrections using internal metering and tariff datasets to supplement DER register. • Monitor AI techniques for potential to materially improve current processes
Solar PV & Battery	Opportunity	PV & Battery customer profiles are the same as used in 2019-24 regulatory period	Generation profile to be updated within next 5 years before 2029-34 submission to reflect changes in PV, e.g. panel degradation or technology improvements	• Average degradation rate of PV systems is less than 0.5% per year due to aging alone • balanced against other factors such as improved technology, monitoring and other operating factors.	• Explore ways to introduce a new factor for performance degradation based on the “average” age of PV systems for the future years. • Further research into the materiality of other factors required

5.2 Distributed Energy Resources Integration Review

Forecast Element	Issue or Opportunity	KPMG Finding	KPMG Recommendation	Ausgrid Response	Ausgrid Action
Solar PV & Battery	Issue	Agent class does not distinguish between townhouses and apartments which constitute 13% and 16% of all dwellings in Australia. More PV should be allocated to townhouses than to apartments	Update the agent types to allow townhouses the same chance of PV allocation as small houses	• If this issue is addressed, it will tend to cluster Solar PV & Battery to a greater extent – meaning that the current model would understate rather than overstate the impact on the network • DER integration model is not intended to pinpoint a particular constraint, but to project the overall expenditure envelope across the network, which is not as dependant on spatial accuracy. • Distinguishing between townhouses and apartments is a non-trivial task.	• Future DER model refinement to reassess benefits of distinguishing between town houses and apartments

Forecast Element	Issue or Opportunity	KPMG Finding	KPMG Recommendation	Ausgrid Response	Ausgrid Action
Solar PV & Battery	Issue	Ausgrid did not use econometric parameters to model PV allocation	Include two econometric characteristics (high net wealth and high energy bills with mortgages) will likely improve the forecast outcome	• If this issue was addressed, it will tend to cluster Solar PV & Battery to a greater extent – meaning that the current model would understate rather than overstate the impact on the network • Half of Ausgrid network risk is existing (before future take-up) so reflected in current actual load data. • Constraints in weaker networks tend to dominate suggesting network construction and density is the critical factor determining investment requirements	• DER model improvement will be required for future regulatory periods beyond 2024-29 once constraints due to existing DER penetration have been addressed

Forecast Element	Issue or Opportunity	KPMG Finding	KPMG Recommendation	Ausgrid Response	Ausgrid Action
Forecast Reconciliation	Opportunity	DER integration model is not integrated with the maximum demand model	Formally include DER integration model in the maximum demand forecast and project DER distribution more accurately	• Exploratory analysis and found there was limited (if any) impact on 11kV network risk • Hosting capacity limits for general network customers are currently at a LV level, not driving upstream investment	• Insights from work deriving hosting capacity may be useful in further developing the agent based modelling of DER and EV in future forecasts • Reconciliation of forecast streams is a worthy pursuit to ensure consistency
Solar PV & Battery	Opportunity	Current PV allocation does not account for the limitation of PV installations	Eliminate residential agents from PV allocation if they are not suitable for PV installation	• Similar comments to above points raised in response to econometric parameters and PV allocation	• As above, DER model improvement will be required for future regulatory periods beyond 2024-29
Solar PV & Battery	Opportunity	The existing model does not allow for the allocation of additional panels to customers who are early adopters	Adjust the model to allow allocation of PV to agents who can potentially install more panels	• Ausgrid also has identified this item as an avenue for further model improvement	• Likely to be introduced to the modelling in the next version

6 Appendices

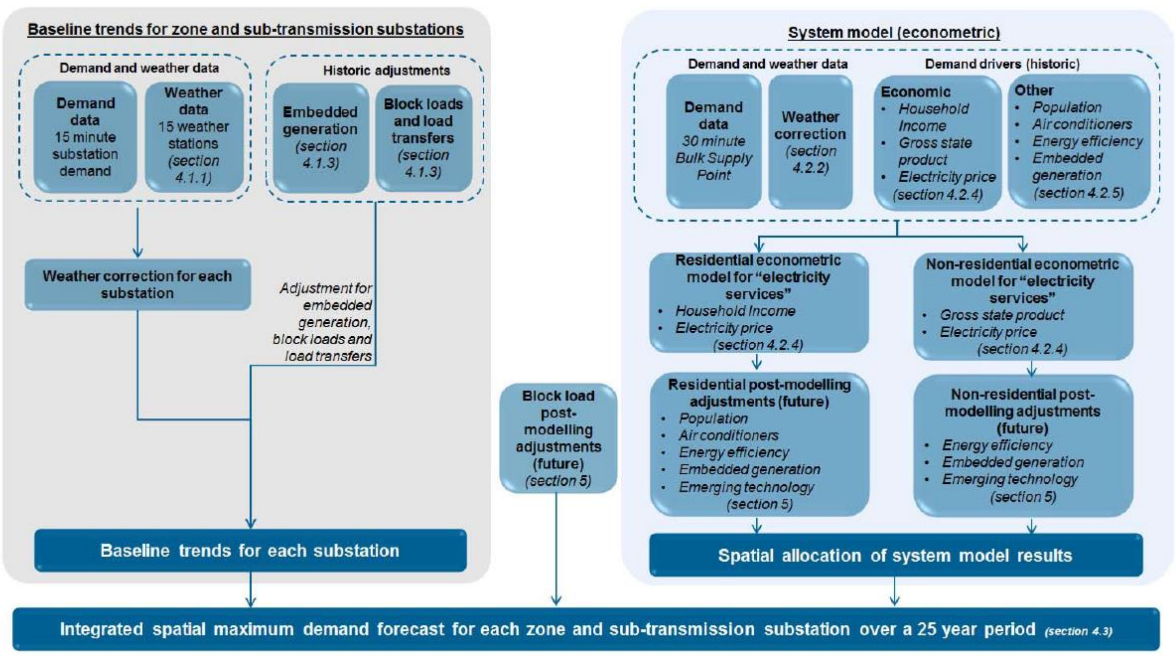
Appendix A – Maximum demand forecasting methodology

Zone and STS maximum demand forecast overview

The electricity maximum demand forecasts consist of two integrated components:

- A baseline trend for each zone and sub-transmission substation calculated using historical 15-minute demand data and weather data, adjusted for historical changes in embedded generation, block loads and load transfers; and
- A whole-of-system level econometric model taking into consideration historical information around the main drivers of household income, gross state product and electricity prices. Bulk Supply Point data in 30-minute intervals is used in this model. Post-modelling adjustments are also applied to model the impacts of energy efficiency, customer embedded generation systems, customer battery storage systems, electric vehicles and population growth

The methodology and process which guides Ausgrid's maximum demand forecasting for its zone and sub-transmission substations is shown below. Details on the methodology are described below.



Definitions

The following are definitions of terms which are used in this report:

Definitions	
Block load	An identified step change in demand due to a new large customer connection or disconnection
CAGR	Compounded Annual Growth Rate
Demand	Instantaneous energy flow at a given point of measurement typically measured in kW or MW
DER	Distribution Energy Resource
EV	Electric Vehicle
Probability of exceedance (POE)	The likelihood that a given level of maximum demand will be exceeded: 10 POE maximum demand is the level of maximum demand that is expected to be exceeded once every 10 years. 50 POE maximum demand is the level of maximum demand that is expected to be exceeded once every 2 years, and so on.
PV	PhotoVoltaic- in the context of this document, refers to solar generation from solar panels
Summer	For the purpose of the maximum demand forecast, taken to be the period 1 Nov to 15 Mar
STS	Subtransmission Substation- either 132/33kV, 132/66kV or 66/33kV substations
Winter	For the purpose of the maximum demand forecast, taken to be the period 1 May to 31 Aug
ZN	Zone Substation- either 132/11kV, 66/11kV or 33/11kV substations

Methodology overview – Models

The maximum demand forecast is comprised of a number of models:

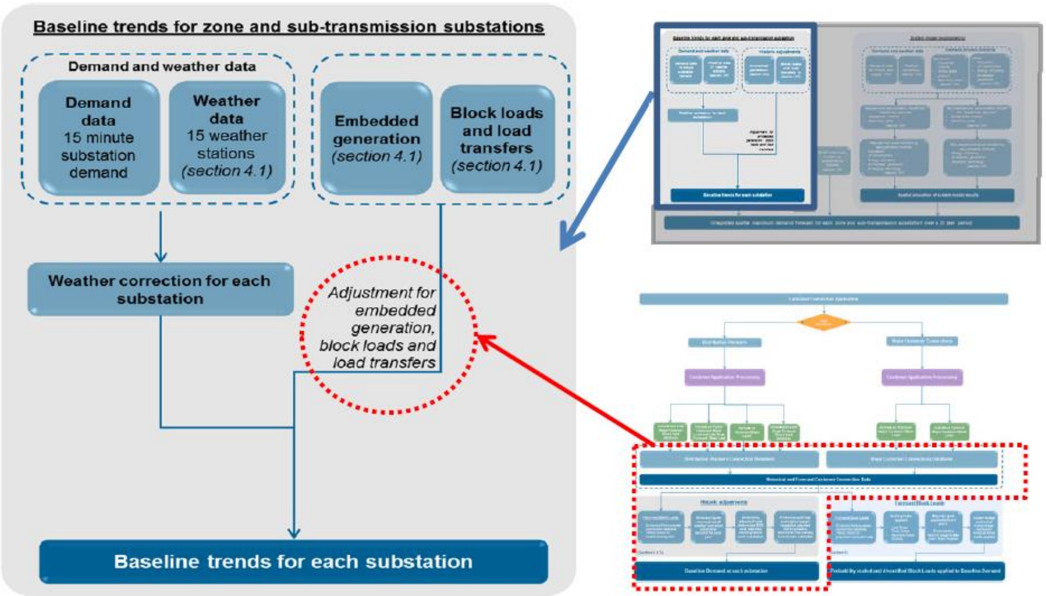
- Local substation historical trending;
- Historical and future block loads model;
- System-level econometric model;
- Energy efficiency model;
- DER model; and
- EV model.

Local substation historical trending

The first 2 years of forecast is based on trending analysis at each zone substation and sub-transmission substation based on the following:

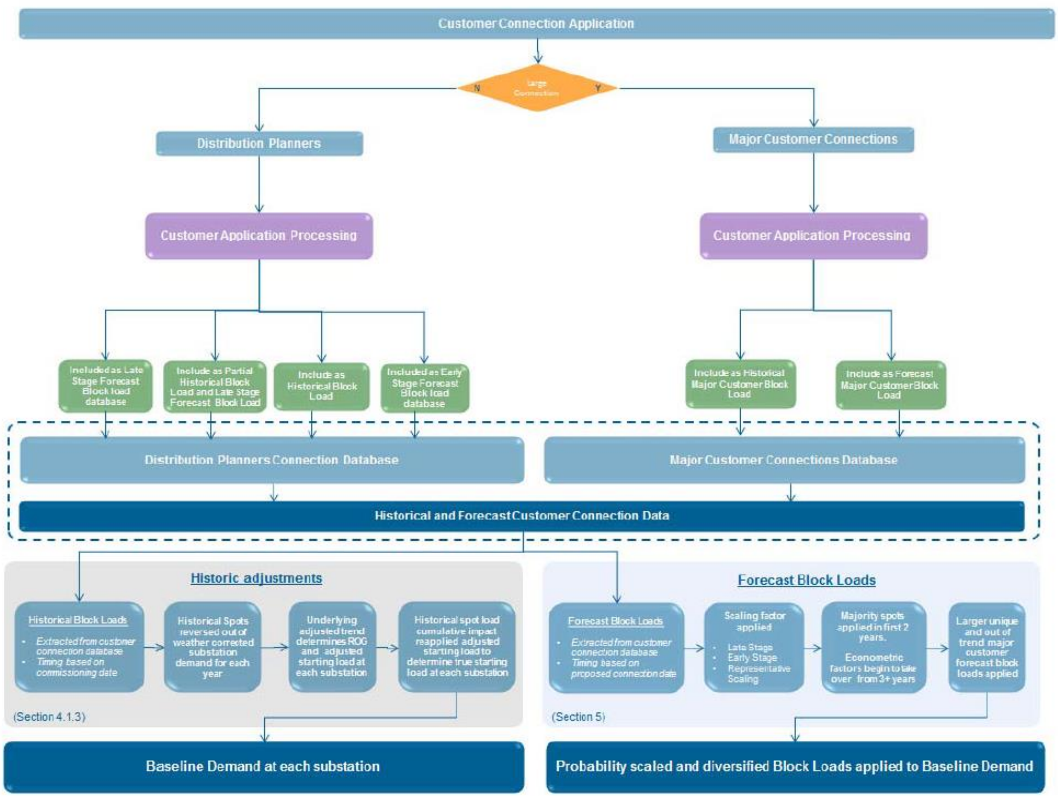
- Gathering and cleansing demand data and weather data;
- Weather normalisation;

- Adjusting for historical step changes in demand due to load transfers, block loads and embedded generation; and
- Determining the underlying trend rate of growth and starting point.



Historical and future connections and block loads

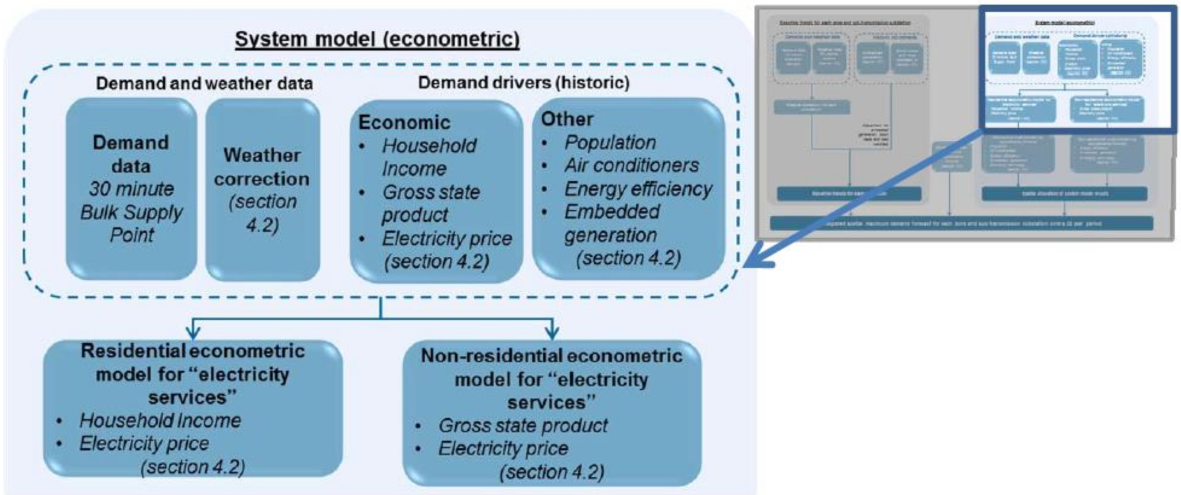
The adjustment for step changes in demand is a necessary step to reveal the "true" trend in demand at each substation. Historical changes are reversed to allow the trend rate to be calculated. The diagram below shows the decision process around how steps changes are sourced and applied in the forecast.



System-level econometric model

While historical trends are useful in determining the near-term forecast, the future is highly uncertain, and forecasts based on trends alone are unlikely to reflect the drivers of electricity demand in the long run. To account for this, Ausgrid applies a system level forecast based on an econometric model that estimates elasticities for electricity prices, household incomes and NSW gross state product (GSP). One key benefit of these types of models is that historical income, price and GSP data can be obtained from public sources such as the ABS. Their projections can be sourced from research institutions such as private consultancy firms.

Post-model adjustments are applied for to account for energy efficiency, rooftop PV, battery storage, electric vehicles and customer growth. Finally, the post model adjustments are spatially allocated to each zone substation. For further details of the post model adjustments, see sections below.



Energy efficiency model

Energy efficiency activity is largely policy driven and comprises the following elements:

- Equipment energy efficiency (E3) program and covers more than 50 distinct programs including implementation of various minimum energy performance standards and energy labelling initiatives across numerous household and commercial appliances. The E3 adjustments are based on consultant advice obtained in 2018;
- NSW Energy Saving Scheme (ESS) that was a program which was originally targeting commercial lighting upgrades. The NSW ESS expanded beyond commercial lighting and extended beyond its original end date as part of the NSW Governments Net Zero 2050 plan. The latest ESS adjustments are based on consultant advice obtained in 2022;
- NSW peak demand reduction scheme (PDRS) introduced in late 2021 as part of the NSW governments Energy Security Target (EST) and NSW Government policies in

its drive towards Net Zero 2050. Since the 2020 forecast a placeholder adjustment was implemented to account for the PDRS which was largely finalising its program scope operation mechanisms. The PDRS impacts were formalised into forecast demand impacts based on consultant advice obtained in 2022; and

- Building Code of Australia (BCA), building shell improvements. The BCA adjustments are based on consultant advice obtained in 2018.

DER model – rooftop PV and battery systems

The maximum demand impact from rooftop PV systems and battery storage systems on homes and businesses are determined based on PV-only and PV-plus-battery models. The DER model deals with small-scale behind the installations. Larger solar systems such as solar farms are typically connected at 33kV or above and are handled via the block loads model. It is necessary to separate these DER combinations since their impact on maximum demand can differ markedly. For both, the uptake number of solar and solar-plus-battery systems are derived from Ausgrid's share of AEMO's NSW region forecasts.

PV-only systems Historical adjustments from PV systems are based on each substation's time of maximum demand and using the well-known solar generation bell-curve. Ausgrid uses solar curves derived from analysis of around 27,000 solar customers that had gross metering during the heyday of the Solar Bonus Scheme, which incorporate as-built conditions.

PV-and-battery systems

One of the key drivers for customers to install a battery storage system is the ability to store excess solar energy and to later use it when electricity is more expensive. If the customer is on a time of use pricing plan, another possibility is by charging the battery during off peak times and discharging during peak times, in addition to charging from solar.

Maximum demand savings are based on representative customer types, known as "agents", where typical demand curves are derived for each agent and the operation of the combined PV-and-battery system is simulated to model the behaviour of each agent as they seek to maximise the benefit from using the battery to reduce their electricity bill. Customers select PV and battery system sizes to maximise their return on investment.

For allocation to each zone substation, customers are classified into the agent types and total impact at each zone substation is the sum of the agent impacts of connected customers (agents). The agent-based model approach is also done for PV-only customers, with the derivation of maximum demand impact being more straightforward since only a solar generation curve is needed to determine the reduction.

Electric vehicles (EVs)

The EV model is based on Ausgrid's involvement with EV trials in partnership with Evenergi and modified for additional charging profiles from AEMO's Insights Report and EV trials and studies.

The model starting point for the existing number of EVs per zone substation is derived from the 2021 ABS census data, allocated by postcode to each zone. The model assumes that globally, 20% of residential EVs are garaged in apartments and that initially, 70% of all EVs sold (new EVs) in NSW go into Ausgrid's network. This share declines over time due to economies of scale affecting EV production making them cheaper in future and the declining availability of new combustion engine vehicles.

In addition to residential EVs, the model also includes commercial EVs such as small and large trucks, buses and fleet passenger vehicles. The distribution of vehicle types is taken from AEMO. Charging locations for each vehicle type are from Evenergi.

Assumptions around mileage, leading to energy consumption and therefore charging requirements per vehicle type are from AEMO. Charging profiles are broadly classified according to charging behaviour, namely, convenience (anytime), daytime and night-time.

Appendix B – DER uptake outcomes

Forecast Element	Slow Change	Progressive Change	Step Change	Strong Electrification
PV Currently 1.0GW across 180k customers	• 340k customers in 2029 – 385k in 2034 • 2.3 GW in 2029 – 2.8 GW in 2034	• 360k customers in 2029 – 425k in 2034 • 2.5 GW in 2029 – 3.2 GW in 2034	• 390k customers in 2029 – 490k in 2034 • 2.8 GW in 2029 – 3.8 GW in 2034	• 510k customers in 2029 – 580k in 2034 • 3.9 GW in 2029 – 4.5 GW in 2034
Battery Estimated currently 75MWh across 7.5k customers	• 32k customers have a battery in 2029 – 48k in 2034 • 0.37 GWh battery storage capacity in 2029 – 0.56 GWh in 2034	• 68k customers have a battery in 2029 – 135k in 2034 • 0.8 GWh battery storage capacity in 2029 – 1.6 GWh in 2034	• 120k customers have a battery in 2029 – 260k in 2034 • 1.5 GWh battery storage capacity in 2029 – 3.0 GWh in 2034	• 90k customers have a battery in 2029 – 130k in 2034 • 1.1 GWh battery storage capacity in 2029 – 1.6 GWh in 2034
EVs Currently 12k NSW & 2k ACT registered EVs and PHEVs Estimate 9k in AG	• 65k vehicles in 2029 – 315k in 2034	• 315k vehicles in 2029 – 760k in 2034	• 376k vehicles in 2029 – 946k in 2034	• 538k vehicles in 2029 – 1.3M in 2034
Off Peak Hot Water Currently 330k OPHW on OP1	• 330k OPHW customers in 2029 – 350k in 2034	• 380k OPHW customers in 2029 – 450k in 2034	• 420k OPHW customers in 2029 – 480k in 2034	• 450k OPHW customers in 2029 – 530k in 2034
Electrification of Residential Gas Currently 800k residential gas customers in AG LGA	• 5k gas customers convert to electric in 2029 – 40k in 2034	• 5k gas customers convert to electric in 2029 – 150k in 2034	• 90k gas customers convert to electric in 2029 – 310k in 2034	• 90k gas customers convert to electric in 2029 – 310k in 2034

Appendix C – DER key assumptions summary

Forecast Element	Slow Change	Progressive Change	Step Change	Strong Electrification
PV	• Varying ROI coefficients were then used PV in each scenario • PV cost 10% increase by 2029, then 10% cost reduction by 2039	• Varying ROI coefficients were then used PV in each scenario • PV cost decrease of 40% by 2029, then 45% cost by 2039	• Varying ROI coefficients were then used PV in each scenario • PV cost decrease of 40% by 2029, then 45% cost by 2039	• Varying ROI coefficients were then used PV in each scenario • PV cost decrease of 40% by 2029, then 45% cost by 2039
	• Current trend of installs blended into agent ROI model			
Battery	• Varying ROI coefficients were then used for Battery Storage in each scenario • Battery cost decrease of 40% by 2029, then 50% cost by 2039	• Varying ROI coefficients were then used for Battery Storage in each scenario • Battery cost decrease of 60% by 2029, then 65% cost by 2039	• Varying ROI coefficients were then used for Battery Storage in each scenario • Battery cost decrease of 60% by 2029, then 65% cost by 2039	• Varying ROI coefficients were then used for Battery Storage in each scenario • Battery cost decrease of 60% by 2029, then 65% cost by 2039
	• Current trend of installs blended into agent ROI model			
EVs	• Only EV uptake is varied between scenarios			
Off Peak Hot Water Currently 100% overnight consumption OPHW	• 50% overnight consumption & 50% daytime consumption in 2029 • 35/65% overnight/daytime consumption split in 2034	• 50% overnight consumption & 50% daytime consumption in 2029 • 25/75% overnight/daytime consumption split in 2034	• 35% overnight consumption & 65% daytime consumption in 2029 • 15/85% overnight/daytime consumption split in 2034	• 25% overnight consumption & 75% daytime consumption in 2029 • 0/100% overnight/daytime consumption split in 2034
Electrification of Residential Gas Currently most Electric Hot Water System are Resistive Storage Type	• 16% of transitioning gas customers install Heat Pump hot water system by 2050 • 84% install resistive or other Hot water type	• 20% of transitioning gas customers install Heat Pump hot water system by 2050 • 80% install resistive or other Hot water type	• 20% of transitioning gas customers install Heat Pump hot water system by 2050 • 80% install resistive or other Hot water type	• 90% of transitioning gas customers install Heat Pump hot water system by 2050 • 10% install resistive or other Hot water type

Appendix D – Forecast Scenarios – DER Static Inputs

Forecast Element	Slow Change	Progressive Change	Step Change	Strong Electrification
PV Installed PV size Feed in Tariff Retail Tariff Tariff Allocation	• 6.7kW PV installation size for Residential agents, larger sizes for larger commercial agents up to 100kW • Forecast feed in tariff & forecast retail tariff changes over time are assumed the same in each scenario • Residential Retail tariff allocation remains fixed at current 40% ToU to 60% Flat tariff. • Business Retail tariff allocation transitions flat tariff customers to Demand tariffs over time with 40% ToU to 60% Demand tariff in 2050			
Battery Installed Battery size Feed in Tariff Retail Tariff Tariff Allocation	• 10kWh battery size for Residential agents, larger sizes for larger commercial agents up to 100kWh • Tariff assumptions for Battery Storage is the same as PV tariff assumptions			
EVs Charging Profiles by Typology & Agent EV consumption per day by vehicle type Tariff Assumptions	• Charging profiles do not materially vary between scenarios with the exception of magnitude due to various rates of EV uptake • EV consumption per day by vehicle type remains the same for each scenario ranging from 393kWh per day for an Articulated truck to 0.55kWh a day for motorcycle. Residential/private car consumption per day is around 6kWh a day. • Tariff assumptions influencing charging profiles remain fixed with pricing signals favouring overnight off peak charging particularly for residential charging			
Off Peak Hot Water Daily Consumption unchanged	• Summer 5kWh • Shoulder 7.5kWh • Winter 8.3kWh			
Electrification of Residential Gas Electric Appliance Profiles & consumption unchanged % of Aircon used for pre-cooling before 4pm	• Assumed consumption and demand profile of cooktop, oven, aircon remains static • 10% of customers pre-cool with aircon in 2030. Increase to 20% by 2035			