Review of Ausgrid's Maximum Demand Forecasting Methodology and Conceptual Review of the DER Integration Model

December 2022

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Glossary

Abbreviation	Definition
ABM	Agent-based modelling
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BCA	Building Code of Australia
BSP	Bulk supply point
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DoCCEEW	Department of Climate Change, Energy, the Environment and Water
E3	National Equipment energy efficiency
EE	Energy Efficiency
ESS	Energy Savings Scheme (New South Wales)
EV	Electric Vehicle
GSP	NSW gross state product
HIA	NSW Housing Industry Association
HV	High Voltage
LV	Low Voltage
IGC	Investment Governance Committee
ISP	Integrated System Plan
NCC	National Construction Code
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
PDRS	Peak Demand Reduction Scheme
POE	Probability of Exceedance
PV	Photovoltaic
SEPP	State Environmental Planning Policy
STS	Sub transmission Substation
ZSS	Zone Substation

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Daniel Sim

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16 December 2022

Dear Daniel

Maximum Demand Forecast and DER Integration Model (Hosting Capacity) Review

Thank you for the opportunity to assist Ausgrid with validating and reviewing your Maximum Demand Forecast for the 2024-29 regulatory submission and reviewing your DER Integration model concept for forecasting hosting capacity.

In terms of the objectives and scope of services outlined in our discussions dated 3 August 2022 and further adjusted to tailor the Ausgrid needs, this report sets out our findings regarding the appropriateness of modelling assumptions, inputs, and a forecast performance verification, as well as an assessment of the consistency between key aspects of the forecast methodology. It also provides a high-level review of the methodology for the DER Integration model prototype currently under development.

Note that the report's scope is limited to reviewing the methodology and assumptions used for both the maximum demand forecast and the DER integration model. KPMG's review did not validate that calculations were performed correctly per the methodology and internal Ausgrid processes.

We thank you for your assistance provided in conducting this engagement, and we look forward to continuing to provide services to Ausgrid.

Yours sincerely,

Deepak Sambhi

Deepak Sambhi

KPMG Representative

1 EXECUTIVE SUMMARY

KPMG conducted a review of the Maximum Demand Forecast prepared by Ausgrid for the 2024-29 regulatory submission and a conceptual review of the DER Integration model (hosting capacity) prototype currently in development. The maximum demand forecast provides significant input into the determination of future capital expenditure that will support structural network changes caused by growth/decline in demand. KPMG focused on reviewing both summer and winter demand forecasts with particular attention to the four selected sample zone substations: Macquarie Park, Muswellbrook, Lindfield and City North.

This report outlines the evidence to support and improve Ausgrid's methodology and assessment of the demand forecast and DER hosting capacity of the low voltage (LV) levels. KPMG reviewed Ausgrid's existing maximum demand and DER forecasting methodologies through the presentation of documented evidence and interviews with staff at Ausgrid. Demand forecasting models and algorithms were verified through a detailed review of the following key aspects:

- Forecast Accuracy
- Qualitative Assessment
- Forecast Anomaly Investigation

KPMG has applied statistical, engineering, and econometric analysis to verify the demand forecasting process, including how Australian Energy Market Operator's (AEMO) forecasts are used to inform Ausgrid's forecast and the comprehensiveness of factors considered for modelling.

KPMG also performed a conceptual review of Ausgrid's DER Integration model, a new process that Ausgrid is developing for the 2024-29 regulatory submission. Ausgrid commenced developing this model earlier this year and it is in the prototype stage. They have plans to productionise the model to incorporate it into BAU planning. It will estimate the growth in energy generation by customers and its implications on the local levels: zone substation and below. Ausgrid's model is currently under rapid development, so the review was conducted based upon the limited information they provided about the methodology, inputs and assumptions.

1.1 Recommendations

KPMG evaluated the effectiveness and reasonableness of their methods to:

1) build the demand forecast model for the 2024-29 regulatory period; and
2) predict hosting capacity in relation to increasing DER for the 2024-29 regulatory period.

Issues and opportunities identified during the review have been summarised in Table 1 and Table 2 for the maximum demand forecast and in Table 3 for the DER Integration model prototype. For the purposes of this report, *issues* are findings that require adjustments and *opportunities* are recommended improvements for the existing methodology components.

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. However, in some areas, Ausgrid may undervalue the significance of trends such as the effect of the COVID-19 lockdowns on the energy demand in 2020-2021. Another notable observation is the use of the energy efficiency model that may be built on outdated assumptions especially in relation to the energy efficiency of buildings. Overall, Ausgrid's methodology was found to be solid, with some issues identified during the review.

Through the interviews, we discovered that the rapid change in the energy industry and the complexity of the relationship between the contributing factors led to the need to produce increasingly accurate forecasts enabled by data science advancements. Therefore, KPMG's recommendations aim to improve forecasting methodology, including the data sources. One of the major findings was identifying rapidly evolving contributors such as energy efficiency and rooftop solar PV uptake.

Ausgrid's methodology for the DER Integration model prototype was in the early development stages without supporting documentation of the detailed methodology. Ausgrid's efforts to build the model to understand hosting capacity align with industry trends to avoid curtailment of energy generated by rooftop solar PV. The prototype model aims to identify hosting capacity limitations on their network downstream of zone substations. The modelling is conducted at the low voltage network level: an agent-based modelling (ABM) approach is used at the customer level; and EV distribution is built at the postcode level. However, the input and complexity of the modelling of the individual elements can be improved: they can account for the econometric differences between customers and the characteristics of dwellings. It would be useful for Ausgrid to consider incorporating the input from the DER Integration model when it reaches the deployment stage (testing completed) into the maximum demand forecast. This will avoid the need to model the effect of DER adaptation independently inside the maximum demand forecast and align the projections of the two models.

The main finding from the modelling of the DER Integration was numerous risks of curtailment across the existing network. As such, Ausgrid aims to focus on addressing the existing LV network issues at the regulatory submission 2024-29 before investing in the issues related to the forecasted DER growth. As a result, the recommendations provided for the DER Integrated model are general in nature and could not be verified with the maximum demand forecast at this stage.

Ausgrid's overall approach can therefore be assessed as appropriate, useful and reasonable for the given purpose. Some innovations come in the form of new developments with agent-based modelling to evaluate DER adoption. The recommendations below do not undermine the existing robustness of the methodology but provide ways to improve it. KPMG encourage Ausgrid to continuously evolve the methodology to stay on track with or ahead of the industry trends.

1.1.1 Maximum demand forecast recommendations

The following recommendations are based on identified issues affecting the accuracy of the maximum demand forecast in the next regulatory period (2024-2029). The materiality rating (Low, Med, or High) is a **qualitative measure** based on relative importance to the maximum demand forecast on a substation and network level. The following tables do not specify the quantitative impact on the maximum demand forecast.

Table 1. Summary of Issues from Maximum Demand Forecast

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
1	Issue	*6.3.2.1 Energy efficiency adjustments*	The Building Code of Australia (BCA) component of the energy efficiency adjustments is outdated (last updated in 2018) and does not account for recent policy development such as the Sustainable Buildings State Environmental Planning Policy (SEPP).	Med	Due to the rapid advancements in the energy efficiency area and multi-factored dependency, energy efficiency forecasts should be updated for each new forecast submission, including the BCA forecast for this regulatory period.
2	Issue	*6.3.1.3. extraction of historical trends*	The current methodology does not remove the effect of the COVID lockdowns on the historical demand. Restricted movement may result in an unnatural redistribution of maximum load, causing bias in the resulting trend.	Med	Demand data from the lockdown and periods of restricted movement should be ignored for generating the historical trend. There may be value in identifying the proportion of demand that moved from offices to homes, such that a factor of that adjustment can be applied to account for the work-from-home behaviour in the future.

The following recommendations are based on identified opportunities that may materially improve the accuracy of the maximum demand forecast beyond the next regulatory period (beyond 2029).

Table 2. Summary of Opportunities from Maximum Demand Forecast

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
3	Opportunity	***6.3.1.1 Weather correction***	The best practice recommended for preparing a forecast that factors in the effects of climate change would involve estimating changes in average temperatures throughout the forecast and adjusting the heating and cooling turning points correspondingly (Azevedo, Chapman, & Muller, 2015). This finding will be of greater materiality in regulatory periods beyond the scope of this review.	Low	It is recommended that Ausgrid create a forecast of average temperatures expected in different sections of their network grouped by decade to enable the adjustment of their forecast to account for future changes to NSW's climate effectively.
4	Opportunity	***6.3.1.2 Removal of block loads, block transfers, and embedded generation***	There is some uncertainty around the accuracy of the magnitude of the PV adjustment needed due to the input data quality in the PV installation register.	Low	Current technology allows the extraction of information from satellite data to quantify the type and number of PV systems installed using AI to extrapolate objects only partially captured in satellite images. This advanced analysis of the imagery is not currently part of Ausgrid’s methodology, but the technologies are available to carry out the analysis. It is suggested that Ausgrid

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
					consider either developing similar capabilities in-house or outsourcing this augmentation of their PV installation data to a trusted contractor. That will also apply to the DER Integration model.
5	Opportunity	***6.3.2.2 PV and battery system adjustments***	The generation profile used by Ausgrid of PVs and battery systems for the 2024-29 forecast is the same as the one used for the 2019-24 period. These generation profiles are likely to change due to PV system degradation and technological advancement.	Low	It is recommended that the generation profile be recalculated within the next five years (before the 2029-34 regulatory submission) to reflect changes in the age and associated degradation of PV systems and the progress made in PV technology.

1.1.2 DER Integration model recommendations

The following recommendations have been provided for the DER Integration model prototype. These are improvements that can be made along with their potential impact on forecast results (i.e. materiality), but should not be viewed as an assessment of the impact on the DER investment forecast.

The materiality rating is a **qualitative measure** provided for information purposes only since the model is still under development. The materiality references the impact of the issue or opportunity on demand forecasting that would be one of the drivers influencing the need for expenditure at a substation level.

The findings, materiality and recommendations apply to how the prototype can model future DER growth; they do not apply to the modelling of DER currently existing on the Ausgrid network.

Table 3. Summary of Issues and Opportunities for the DER Integration model

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
1	Issue	***6.5.3 PV and battery allocation***	Allocation of DER by residential type does not distinguish between townhouses, which constitute on average 13% of dwellings in Australia, and apartments (16% of dwellings), and more PV should be allocated to townhouses than to apartments.	High	Update the agent types to allow townhouses the same chance of PV allocation as small houses. Note: that the materiality assessment refers to the network's spatial level. The materiality of the overall volume assessment for this item would be ‘Low’ as the simulation aspect of the DER Integration model provides a wide variety of outcomes that converge to identify the most concerning network risks.

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
2	Issue	***6.5.3 PV and battery allocation***	Ausgrid did not use econometric parameters to model PV allocation.	High	Including two econometric characteristics (high net wealth and high energy bills in households with mortgages) will likely improve the forecast outcome (Best, Burke, & Nishitateno, 2019). Note: that the materiality assessment refers to the network's spatial level. The materiality of the overall volume assessment for this item would be 'Low' as the simulation aspect of the DER Integration model provides a wide variety of outcomes that converge to identify the most concerning network risks.
3	Opportunity	***6.5.1 Overview***	The current maturity of the DER Integration model could limit accurate DER representation in the maximum demand forecast model.	High	Even though the current Maximum Demand Forecast methodology captures the DER representation of the PV, batteries and EV, the inclusion of the new DER Integration model into the Maximum Demand Forecast will enhance the latter by projecting DER distribution more accurately. Note: It is recognised that development of the DER Integration model is ongoing and that the reviewed

#	Issue / Opportunity	Section	Findings	Materiality (Low, Med, High)	Recommended actions
					DER Integration model was a work in progress at the time of this review and report.
4	Opportunity	***6.5.3 PV and battery allocation***	Current PV allocation does not account for the limitation of the PV installations.	Low	Ausgrid can enhance its models by eliminating residential agents from PV allocation if they are not suitable for PV installation.
5	Opportunity	***6.5.3 PV and battery allocation***	The existing model does not allow the allocation of additional PV panels to agents who are early adopters of PV.	Low	It is recommended to adjust the model to allow allocation of PV to agents who can potentially install more panels.

2 SCOPE

2.1 Purpose

The purpose of this report is to provide Ausgrid with an evaluation of the effectiveness and reasonableness of their methods to:

1) build the demand forecast model for the 2024-29 regulatory period; and
2) predict hosting capacity from the growing DER for the 2024-29 regulatory period.

Ausgrid engaged KPMG to provide a review of their forecasting methodology and assumptions applied for the maximum demand forecast. In addition, KPMG performed a conceptual review of the new DER Integration model, identifying areas for improvement and providing recommendations based on the materiality of those findings.

2.2 A maximum demand forecast review

The scope and objectives of the review of Ausgrid's maximum electricity demand forecasts for the 2024-29 period were:

- to gain a technical understanding of the methodology, processes and assumptions used by Ausgrid and to identify any reasonable alternative processes based on accepted industry practices that may improve the forecast precision;
- to identify materiality and quantify, where possible, the difference between Ausgrid's approach and the reasonable alternatives; and
- to explain the review process, key findings and their material effect on the forecast.

To achieve these objectives, KPMG investigated the methods, processes and assumptions used to develop the forecasts and their outcomes and results.

A review of the maximum demand forecast was conducted at two levels:

1. at the network level; and
2. at the zone substation level based on a sample selection of 15 zone substations, with an in-depth analysis of four zone substations that provide a representative selection of the Ausgrid network (commercial, rural, urban stand-along housing, urban high-rise areas)

The evaluation consisted of the following activities:

Methodology detailing and understanding

This review focused on the current approach taken by Ausgrid to forecast maximum electricity demand at the aggregated system that was broken out at the zone substation level. The demand forecasting methodology's effectiveness was reviewed at 15 sample zone substations. Short-term modelling was assessed based on trend analysis of weather normalised data, intermediate forecasts (aggregation of short and long term) and long-term forecasts based on multiple factors (including econometric, energy efficiency, weather corrections, PV and battery systems, EV systems, electrification and population growth).

Consistency check of the forecast with previous periods

The forecast outcomes were compared for consistency with previous Ausgrid forecasts at individual locations for the sample zones and at an aggregate network level. Some sample zones were selected to be an area of significant network development due to the construction of major commercial loads like data centres and population growth.

Significant areas of network development generally coincide with high forecast demand growth and high potential consequences of unreliability, such as the Macquarie Park and City North zone substations.

Review of post-model adjustments

We verified the post-model adjustments (rooftop solar, battery storage, EVs, etc.) applied to the forecast model. This review included understanding and evaluating the agent-based models that assist in applying the post-modelling adjustment.

2.3 DER Integration model (agent-based) forecast

The scope and objectives of the DER Integration model forecast review were as follows:

- to understand the concept of the model and data sources used;
- to evaluate the effectiveness of the approach and identify the alternative strategies and their materiality in comparison with Ausgrid's methods; and
- to document the review process, findings and recommendations.

To achieve these objectives, KPMG evaluated the methods and assumptions used to develop the model and its outcomes and results. The evaluation consisted of the following activities:

A conceptual review of the DER Integration model

The concept of Ausgrid's new DER Integration model was reviewed to understand the high-level methodology of the modelling and its accuracy in assessing DER hosting capacity. As the methodology for the model was not documented at the time of the review, relevant information was extracted from the provided supporting documentation (Investment Governance Committee (IGC) paper and planners' training material) and workshops with Ausgrid's experts.

Recommendations and report writing

The findings for the DER Integration model were evaluated and we provided recommendations to improve the forecasting model.

2.4 Limitations

The following limitations apply to the maximum demand forecast:

- The review was undertaken based on the documentation provided by Ausgrid and interviews with Ausgrid network planners. Some of the reports received for review were in a draft state, which may affect the applicability of findings and recommendations for the final report. As KPMG did not independently verify the input information, KPMG does not accept liability concerning the unverified information, including errors and omissions in this report caused by the quality of the originating sources.
- Our review assumed that Ausgrid followed its documented processes and that those processes were free from errors.
- A rigorous analysis of the forecasting computer models or data cleansing activities was not performed.
- A comparison of quantitative results of the post-model adjustments with industry benchmarks was not performed.
- The recommendations provided in this report are based on the assumptions and KPMG's understanding of the Ausgrid methodology as described in this report.
- Evaluation of the 2017 maximum demand forecast methodology has not been performed. The output has been examined, and the documentation of unchanged components of the methodology was utilised where detail was lacking in the 2022 draft documentation.
- Energy pricing and tariff modelling were out of the scope of this review.

The following limitations apply to the DER Integration model:

- The review was undertaken based on the documentation provided by Ausgrid and interviews with Ausgrid network planners. A detailed methodology was not provided for the DER Integration model, due to which KPMG has relied on the preliminary high-level description of the model, which may affect the applicability of findings and recommendations in the final report. As KPMG did not independently verify the input information, KPMG does not accept liability concerning the unverified information, including errors and omissions in this report caused by the quality of the originating sources.
- Analysis of any computer models or algorithms and assessed concept level was not performed.
- Numeric data for this model was not provided. The materiality assessment was based on industry practices and was qualitative.
- The recommendations provided in this report are based on the assumptions and KPMG's understanding of the Ausgrid methodology as described in this report.
- A review of the current distribution of DER elements across the Ausgrid LV network was not conducted.
- Energy pricing and tariff modelling were out of the scope of this review.

3 CONTEXT

Ausgrid is an electricity distribution network service provider (DNSP) operating under the National Electricity Rules (NER). Under the NER, Ausgrid is required to submit its regulatory proposal for the period 1 July 2024 to 30 June 2029 (2024-29) to the Australian Energy Regulator (AER) by 31 January 2023. The demand forecast is essential to this submission (AEMC, n.d.).

Ausgrid serves 1.8 million customers through its network of 181 zone substations. Their network area covers 22,275 square kilometres, taking in much of metropolitan Sydney and then northwards to the Central Coast, Newcastle and the Hunter Valley. The types of customers served include residential dwellings, high-density apartments, commercial and industrial, dense CBD areas through to rural towns and remote customers.

Ausgrid uses a traditional maximum demand forecast (summer, winter) at the network level for planning and capital expenditure decision-making in relation to their zone substations and the sub-transmission network and for compliance with their regulatory reporting requirements.

The electricity sector globally is undergoing extensive transition driven by a combination of decarbonisation, decentralisation of electricity generation and the digitalisation of systems. These drivers are shaping the future planning and design of distribution networks across Australia, including their ability to host increasing amounts of Distributed Energy Resources (DER) on their networks, along with the evolution of the regulatory frameworks that apply to DNSPs in this regard (Ausgrid, AEMC Distributed Energy Resources - Updating Regulatory Arrangements Consultation Paper, 2020).

In response to the increasing amount of DER on their network, Ausgrid has developed a DER Integration model (Ausgrid, Investment Governance Committee Paper, 2022), which is a forecast that predicts the hosting capacity of DER on their LV network. Ausgrid intends for this model to support decision-making towards improving demand management and aiding investment decisions for a modern grid that can support a growing number of customers with rooftop PV, batteries and EVs (Ausgrid, Ausgrid's Regulatory Proposal, 2018). This hosting capacity analysis will also highlight the need for grid balancing and firming services that can be performed internally or outsourced to a third party.

4 ASSESSMENT FRAMEWORK

4.1 Application of the Integrated System Plan (ISP) scenarios

AEMO created a comprehensive roadmap (2022 ISP) for the National Electricity Market (NEM) to support the transformation of the electricity sector in response to the rapid transition in how electricity is generated and used. This roadmap was created through extensive engagement with a wide range of stakeholders across the industry. It aims to help navigate the complexity and uncertainty of the transition in the electricity sector.

Outlined in the 2022 ISP (AEMO, 2022), AEMO developed four scenarios through industry consultation that span a range of plausible futures with varying rates of emission reductions, electricity demand, and decentralisation. These four scenarios are shown in Table 4.

Table 4. Description of ISP scenarios (AEMO, 2022)

ISP scenario	Description
Slow Change	This scenario assumes slow net zero actions with customer adoption of PV driving the need for DER. This path would not reach the economy-wide decarbonisation objectives of Australia's Emissions Reduction Plan.
Progressive Change	Progressive change is a continuation of the 2020s trend of NEM's emission reduction; the emergence of commercially viable alternatives to emissions-intensive heavy industry in the 2030s; and economy-wide decarbonisation in the 2040s to achieve an economy-wide net zero emissions by 2050.
Step Change	A step change is a fast-paced transition from fossil fuel to renewable energy with heightened global policy commitments. Falling energy production costs support this, increasing digitalisation enabling better demand management and grid flexibility, advancement in energy efficiency and electrification. Domestic hydrogen production supporting the transport and industrial applications post-2040.
Hydrogen Superpower	Hydrogen Superpower quadruples the NEM energy consumption to support a hydrogen export industry. This enables the transformation of transport and domestic manufacturing, retaining Australia's place as a global energy resource exporter. Households with gas connections progressively switch to a hydrogen-gas blend before appliances adopt 100% hydrogen use.

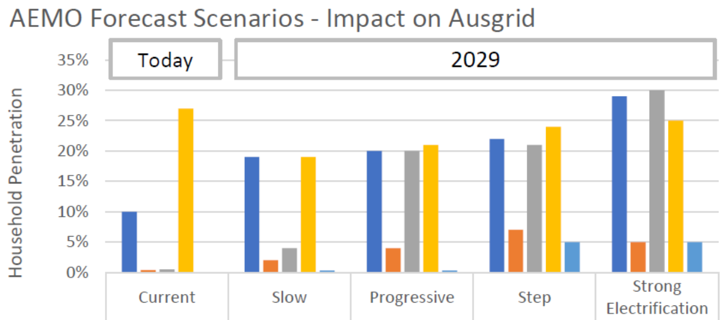
The defining characteristics of each of the four scenarios can be seen in Figure 1.

DEMAND	Slow Change		Progressive Change		Step Change		Hydrogen Superpower	
Electrification	2030	2050	2030	2050	2030	2050	2030	2050
- Road transport that is EV (%)	2	36	5	84	12	99	18	94
- Residential EVs still relying on convenience charging (%)	82	58	75	44	70	31	66	22
- Industrial Electrification (TWh)	-24	-21	4	92	27	54	37	64
- Residential Electrification (TWh)	0	0	0.2	15	4	13	2	4
- Energy efficiency savings (TWh)	8	19	14	40	22	55	22	56
Underlying Consumption								
- NEM Underlying Consumption (TWh)	163	213	201	394	222	336	243	330
- Hydrogen consumption - domestic (TWh)	0	0	0	32	0.1	58	2	132
- Hydrogen consumption - export, incl. green steel (TWh)	0	0	0	0	0	0	49	816
- Total underlying consumption (TWh)	**163**	**213**	**201**	**425**	**223**	**394**	**294**	**1,278**
SUPPLY								
Distributed PV Generation (TWh)	39	58	39	80	45	93	51	112
Household daily consumption potential stored in batteries (%)	3	5	5	22	12	38	13	39
Underlying consumption met by DER (%)	24	27	20	19	20	24	17	9
Coal generation (% of total electricity production)	32	5	38	2	21	0	6	0
NEM emissions (MT CO_2-e)	53.3	13.0	77.2	22.4	48.1	6.8	20.6	6.6
2020 NEM emissions (% of)	38	9	54	16	34	5	15	5

Figure 1. 2022 ISP scenario (AEMO, 2022)

Ausgrid has adapted the values for the scenarios shown in Figure 1 to match their needs based on: the present level of DER uptake experienced across their network; their regulatory submission cycle; Ausgrid network coverage; and other parameters. Ausgrid has transformed ISP scenario values to be applicable to Ausgrid's network (Figure 2), as documented in the IGC paper (Ausgrid, Investment Governance Committee Paper, 2022).

Ausgrid used the Progressive Change scenario to publish the initial version of their demand forecast in their IGC paper in June 2022. However, upon the release of AEMO's 2022 Integration System Plan (AEMO, 2022) which selected the Step Change scenario as the most likely scenario to occur, Ausgrid recognised the necessity to align their demand forecast to the industry standard as it came to exist. As such the final maximum demand forecast included in the regulatory submission will utilise the Step Change scenario. This report does not provide an assessment of the adaption of the ISP forecast numbers to Ausgrid's numbers. The methodology of the maximum demand forecast does not depend on the scenario selected, and it is only the input values to the scenarios that vary. KPMG did not independently verify the validity of the ISP scenarios.



	Current	Slow	Progressive	Step	Strong Electrification
PV	10%	19%	20%	22%	29%
Battery Storage	0.40%	2%	4%	7%	5%
EVs	0.50%	4%	20%	21%	30%
Off Peak Hot Water	27%	19%	21%	24%	25%
Electrification of Residential Gas	0	0.30%	0.30%	5%	5%

Figure 2. Ausgrid adaptation of the four ISP scenarios

4.2 Assessment framework and assumptions

The review process conducted by KPMG considered documents provided by Ausgrid in the lead-up to the 2024-29 Regulatory Proposal submission. Additional information was obtained via interviews with the planning and forecasting teams.

As the FY22 Demand Forecast in IGC (Ausgrid, Investment Governance Committee Paper, 2022) does not outline the full methodology adopted, the stakeholder interview indicated that KPMG should assume that the detailed methodology outlined in FY17 Electricity Demand Forecast Report (Ausgrid, Ausgrid's Regulatory Proposal, 2018) holds true unless stated otherwise by Ausgrid Demand Management and Forecasting team. These exceptions have been outlined in Section 6.2.1.

KPMG's understanding and assessment of Ausgrid's demand forecasting methodologies are based on stakeholder interviews supported by documents that were in draft. KPMG's findings and recommendations may not apply to further drafts and finalised documents that outline Ausgrid's FY22 maximum demand and the DER Integration model.

Ausgrid initially developed the FY22 Demand Forecast (Ausgrid, Investment Governance Committee Paper, 2022) under the Progressive Change ISP scenario. As described above, Ausgrid’s demand planning management decided to adopt scenario assumptions for Step Change instead of Progressive Change for its final FY22 demand forecast.

The assessment outcomes produced by KPMG are based on the currently available FY22 Demand Forecast with Progressive Change values derived from the 'Maximum Demand Forecast IGC Paper' dated 24 June 2022. Based on our assumption that no material changes to the forecast methodology occur when the scenario changes, it is expected that the findings will be applicable to the future FY22 Demand Forecast with Step Change values.

4.3 Assessment process

4.3.1 Assessment process – Maximum Demand Forecast

KPMG was engaged by Ausgrid to provide a review of their Maximum Demand Forecast for the Regulatory Proposal 2024-29. The review was based on the evaluation of information from the combination of sources prepared for this and the previous 2017 submission, as Ausgrid was still finalising the methodology documents for this proposal.

The principle Ausgrid documents considered during the maximum demand forecast review were:

1. FY22 Maximum Demand Forecast Investment Governance Committee paper
2. 2017 Electricity Demand Forecasts Report - January 2018
3. Ausgrid post-modelling adjustments 2018 V1
4. Network-wide EV modelling methodology report dated 13 July 2022
5. Data extracts for fifteen ZSS (sampling)

The assessment process consisted of the following three steps:

1. Forecast Accuracy (Section 6.2)

   This step contains Section 6.2.1, which first outlines the changes between demand forecasting methodology in 2017 and demand forecasting methodology in 2022. An example of this is the removal of the econometric post-model adjustment of air conditioners.

   Then, KPMG selected and examined maximum demand data for 15 sample zone substations between 2017 and 2021 (inclusive). This demand data is then benchmarked against historical summer and winter demand forecasts to generate the absolute error (in MVA) and percentage error (in %).

2. Qualitative assessment of the Maximum Demand Methodology (Section 6.3)

   This step goes through every stage of the maximum demand methodology to identify opportunities for improvement and associated recommended actions that have the potential to improve forecasting accuracy moving forward.

3. Forecast Anomaly Investigation (Section 6.4)

   By observing the forecast from FY22 and beyond, anomalies were identified in terms of post-modelling adjustments, such as energy efficiency and PV. KPMG has sought clarifications for the reasons behind these fluctuations and has provided recommendations based on explanations received.

4.3.2 Assessment process – DER Integration model

Ausgrid decided to include the DER Integration model in the regulatory submission to obtain funding allowance for the investments related to the DER hosting capacity in their network. KPMG was tasked to perform a conceptual review of the DER Integration model.

The principle Ausgrid documents considered during the DER Integration model review were:

1. FY22 Maximum Demand Forecast Investment Governance Committee (IGC) paper.
2. Ausgrid post-modelling adjustments 2018 V1
3. Network-wide EV modelling methodology report dated 13 July 2022
4. Planning training materials for Distributed Energy Resources dated 4 August 2022

KPMG obtained an understanding of the concept of the DER Integration model from the description provided in the IGC paper. It was combined with the information obtained from the Ausgrid planners' presentation and stakeholder interviews to fill in the conceptual gaps in the methodology. Then, KPMG described the key elements of the methodology, provided observations and findings, and suggested improvement opportunities.

As per our understanding, the model is fast-evolving and is undergoing rigorous testing to meet the regulatory submission deadline. KPMG’s review is specific to the DER Integration model presented to the IGC. Therefore, some of the findings/recommendations may not be applicable to the version of the model used for the regulatory submission.

5 METHODOLOGY DESCRIPTIONS

5.1 Overview

Two different methodologies were adopted by Ausgrid to evaluate the network capacity for the 2024-29 regulatory period. One is modelling maximum demand by substation at 11kV level and above, and the other is modelling the hosting capacity required for DER at 11kV level and below.

Forecasting of maximum demand by a substation is made up of two models: the short-term forecast model and the long-term forecast model. The short-term forecast model is derived from historical demand trends adjusted for weather and block loads, and planned transfers, whereas the long-term forecast model is an econometric model that uses a longer period of historical data adjusted for known drivers of demand changes, including forward-looking uptake of PVs and adoption of EVs. This methodology is described in detail in Section 5.2.

A new agent-based model (ABM) has been used to model the hosting capacity of DERs on the LV network. By simulating behaviours of customer groups, including energy consumption, energy export configurations and EV adoption, the model examines aggregated effects on network capacity due to the shift from centralised energy generation to distributed energy generation. This methodology is described in detail in Section 5.3.

5.2 Ausgrid maximum demand forecast methodology

The process has been shown diagrammatically below:

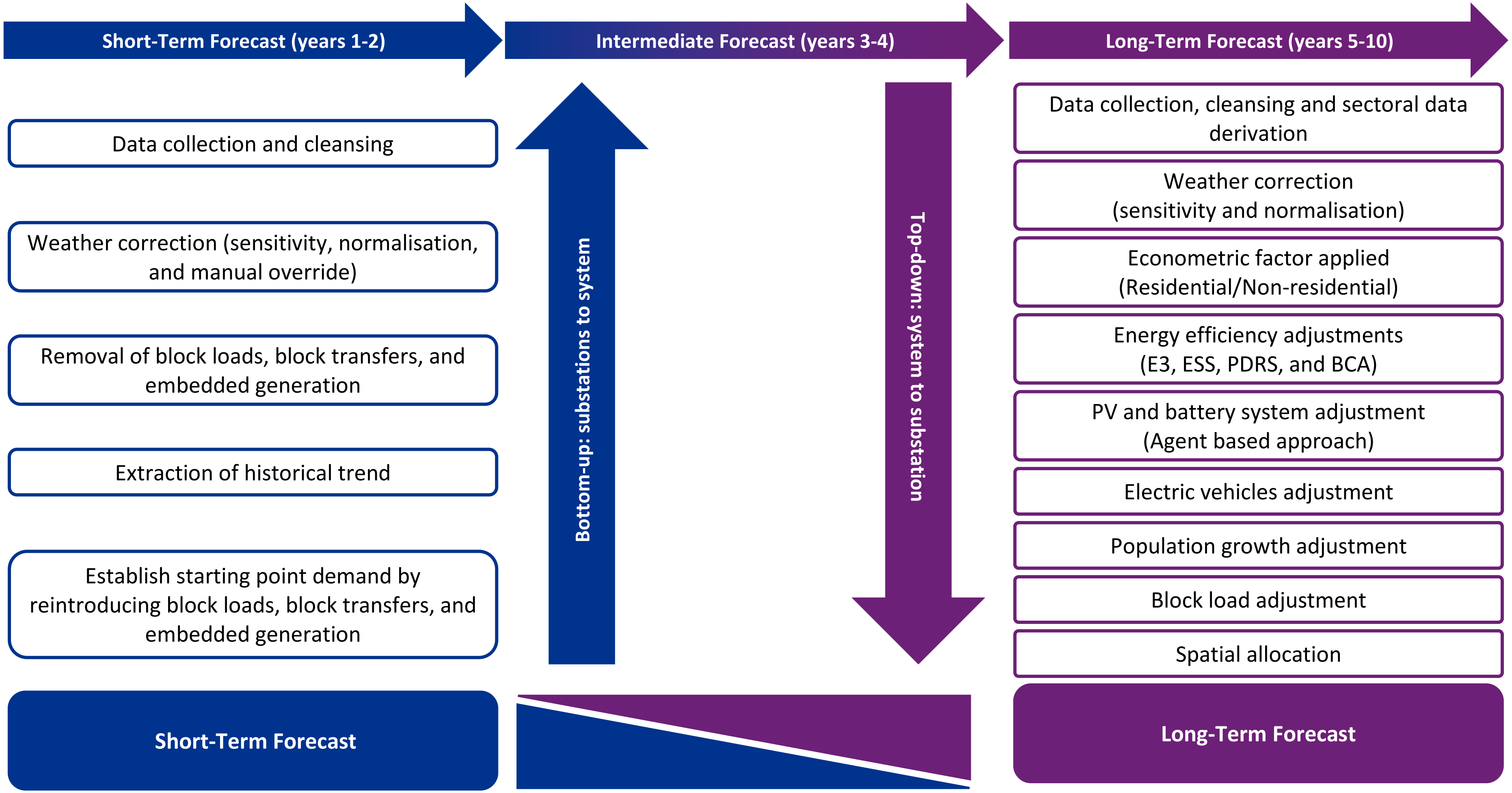
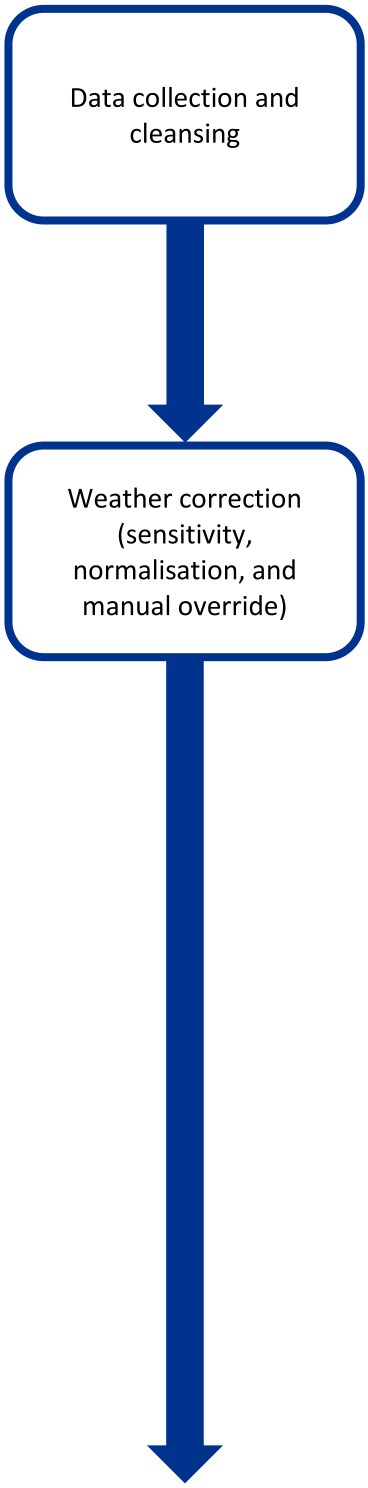


Figure 3: Demand forecast methodology overview

5.2.1 Short-term demand forecast

5.2.1.1 Data collection and cleansing



The first step in creating the short-term demand forecast was to collect and prepare the historical demand data in 15-minute intervals over the last 7 years.

The initial processing of this data is the removal of abnormalities. This is done by replacing the days where abnormal loads, caused by network switching or unusual configurations, with the interpolation of neighbouring days. The way abnormal loads are identified is through visualisations such as scatter plots, temperature plots, and 3D plots.

The remaining data will be the cleansed interval demand data for each summer and winter day for each location.

5.2.1.2 Weather correction

The Bureau of Meteorology collects 30-minute weather data across 15 weather stations in the Sydney, Central Coast and Hunter Regions. Contingent upon data quality and availability, each zone substation and sub-transmission substation is assigned the geographically closest weather station. Weather correction does not apply to major customers that are connected to sub-transmission substations and large generators as they do not exhibit a weather correlation.

Daily average temperatures are calculated for each weather station using data for the past 10 years, grouped according to:

- Seasons; and
- Working days, weekends, Christmas holidays or other public holidays, noting different implications for residential and commercial customers.

It was plotted against daily maximum demand on a scatter plot to determine temperature sensitivity, specifically knee point temperatures for summer and winter.

The historical daily average temperatures over 10 years are randomly selected to simulate 2,000 seasons, capturing the maximum for each iteration and determining the probability of exceedance (POE) level based on the appropriate percentile, the most common POE forecasts are:

- POE 10 forecast, which refers to 1 out of every 10 seasons;
- POE 50 forecast, which refers to 1 out of every 2 seasons; and
- POE 90 forecast, which refers to 9 out of every 10 seasons.

5.2.1.3 Removal of block loads, block transfers, and embedded generation

In addition to the removal of abnormal loads and adjusting for weather, discretionary changes to the network configuration should also be taken into account.

Step changes that need to be reversed include:

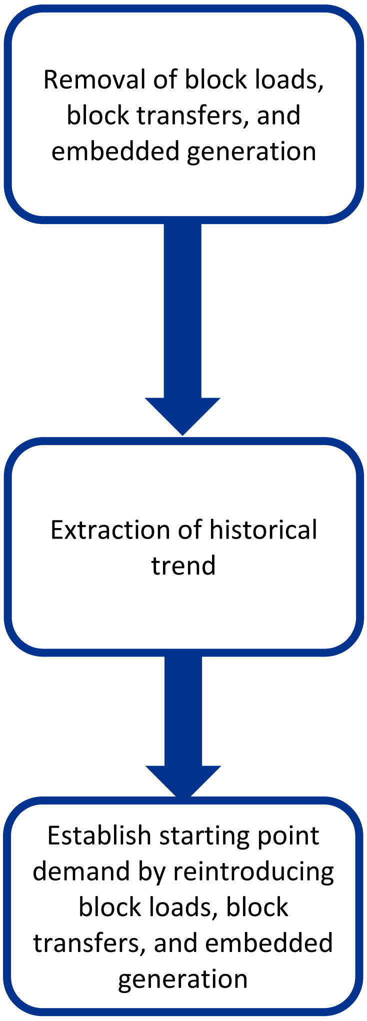
- Block loads – jump in demand resulting from a new large customer connection;
- Load transfers – transfer of load from one substation to another; and
- Embedded generation – reduced peak demand due to downstream embedded generation.

5.2.1.4 Extraction of historical trend

A regression model can be applied to the fully adjusted maximum demand, using a line of best fit identify the trend rate of growth for each zone and sub-transmission station.

5.2.1.5 Establish starting point demand by reintroducing block loads, block transfers, and embedded generation

Post-model adjustment involves reintroducing step changes reversed in step 5.2.1.3. Beyond historical adjustments, the probability-adjusted future block loads are also introduced for the corresponding forecasted interval. The starting point for the forecast depends on the data processed when the forecast was created. For example, for the provided forecast, the last available processed data was Summer 2021.



5.2.2 Long-term demand forecast

5.2.2.1 Data collection, cleansing and sectoral data derivation

The first step in formulating the long-term forecast is to gather the raw metered electricity demand data from all customers in 30-minute intervals since 2003, measured with bulk supply point meters and interval meters.

Abnormal data from interval meter data are removed. Whereas bulk supply point data is treated similarly to the short-term forecast: abnormal data are either replaced by interpolated demand levels or entirely removed depending on whether the error occurred on a maximum demand day.

Finally, data is segmented using a linear regression model to allocate demand to either the residential or non-residential sectors. The non-residential sector is further broken down into large, medium and small subcategories to enable differentiation in the application of weather corrections.

5.2.2.2 Weather correction

Ten years of half-hourly Sydney Observatory Hill weather data is gathered from the Bureau of Meteorology. The station is chosen as the most representative across Ausgrid's entire network due to its proximity to the areas of greatest load.

Similar to weather correction for the short-term forecast, daily average temperatures are calculated and plotted against daily maximum demand to identify temperature sensitivity for different customer sectors, with the exception of large non-residential customers as they are assumed not to exhibit weather sensitivity.

Non-working days were then excluded from capturing the most consistent demand data, and a linear fit was applied to both the summer and winter data separately. The fit follows the following formula

$$D = S\ x\ temp + c$$

Where

$$D = Maximum\ demand\ for\ each\ customer\ sector$$

$$S = Derived\ temperature\ sensitivity\ for\ each\ customer\ sector$$

$$temp = Daily\ average\ temperature\ for\ \text{Sydney Observatory Hill}$$

$$c = intercept$$

The standard error (SE) is also calculated for simulation.

Identical to the simulation for a short-term forecast, 10 years of weather data is drawn at random to calculate the maximum demand for the given temperature using the following formula based on the best fit equation established earlier.

$$D = S\ x\ temp + C + N(0, SE)$$

Where

$$D = Simulated\ maximum\ demand\ for\ each\ customer\ sector$$

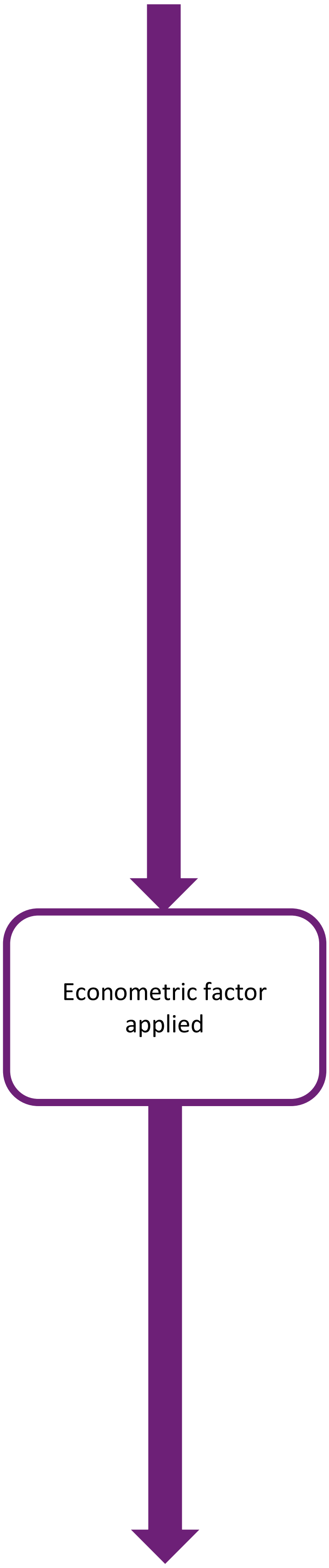
$$S = Estimated\ temperature\ sensitivity\ for\ each\ customer\ sector$$

$$temp = Simulated\ daily\ average\ temperature\ drawn\ randomly$$

$$C = Constant\ of\ regression$$

$$N(0, SE) = A\ random\ number\ drawn\ from\ a\ normal\ distribution\ with\ mean = 0\ and\ standard\ deviation\ = SE.$$

The simulation is repeated for every day of the season and a total of 2,000 seasons. The 50 POE is calculated by taking the median of the simulated demand figures.



5.2.2.3 Econometric factor applied

To predict the ongoing economic pressures on electricity demand, an econometric model that accounts for electricity prices, household incomes, and NSW gross state product (GSP) is constructed.

Historical data inputs are obtained from public sources, like the Australian Bureau of Statistics (ABS), and from research institutions, like consultancy firms, for modelling for each customer sector. While electricity price is a key input for all customers, household income and gross state product are specific inputs to the models for residential and non-residential customers, respectively.

5.2.2.4 Energy efficiency adjustments

Energy efficiency adjustments

Energy efficiency changes expected to take place over the forecasted period are primarily driven by government policies, technology development and customer behaviour. The policies accounted for in this forecast are the following:

- National Equipment energy efficiency (E3) program;
- NSW Energy Saving Scheme (ESS);
- NSW Peak Demand Reduction Scheme (PDRS); and
- Building Code of Australia (BCA).

The adjustments made for each policy are based on consultant advice obtained specifically for this purpose. The effect of the equipment energy efficiency (E3) program on the Ausgrid forecast was reviewed and provided by an external consultancy in March 2018. The initial purpose of the adjustment was to prepare the revised regulatory submission for 2019-24. Now, Ausgrid uses the forecasted numbers for the next reporting period. In a similar manner, Ausgrid uses Strategy Policy Regulation for BCA modelling developed in 2018.

PDRS is a scheme established by NSW to reduce peak electricity demand by encouraging users not to use certain appliances (air conditioners, pool pumps, etc.) during peak hours. PDRS was formally published in September 2021, and the new certificate scheme started in the summer of 2022-23. Ausgrid engaged external contractors to model this scheme into their forecast in 2022.

NSW ESS provides financial incentives to install and use energy-efficient appliances and equipment in residential and non-residential areas. The ESS has been in force since 2009 and has led to a significant reduction in energy use in peak hours up to mid-2020. Ausgrid assumes that there will be no significant increase in the reduction in the short-term until PDRS comes into effect. The PDRS will become active before the forecasted period starts. Ausgrid expects that the peak demand reduction due to both schemes will increase from 400MW to 1200MW by the late 2040s.

5.2.2.5 PV and Battery System Adjustment

PV and Battery System Adjustment

Electricity generated from the installed PV and stored in batteries reduces the demand over certain periods of time during the day that does not necessarily align with the peak demand. However, combined PV and battery installations tend to be more predictable in the reduction of the demand in the evening peak hours. These types of energy generation have significant dependence on weather and seasons.

Small-scale PV and battery systems can be broken down into systems with and without a battery and are forecasted using an agent-based model (ABM). Large-scale installations like solar farms are handled in a similar manner as block loads, see Section 5.2.2.8.

Solar PV systems without a battery system make up the majority of installations, with solar energy generated when there is sunlight lowering the customer's energy demand from the grid. Excess solar energy can be exported to the grid at an agreed Feed-In-Tariff if no restriction has been imposed by the network (i.e. curtailing).

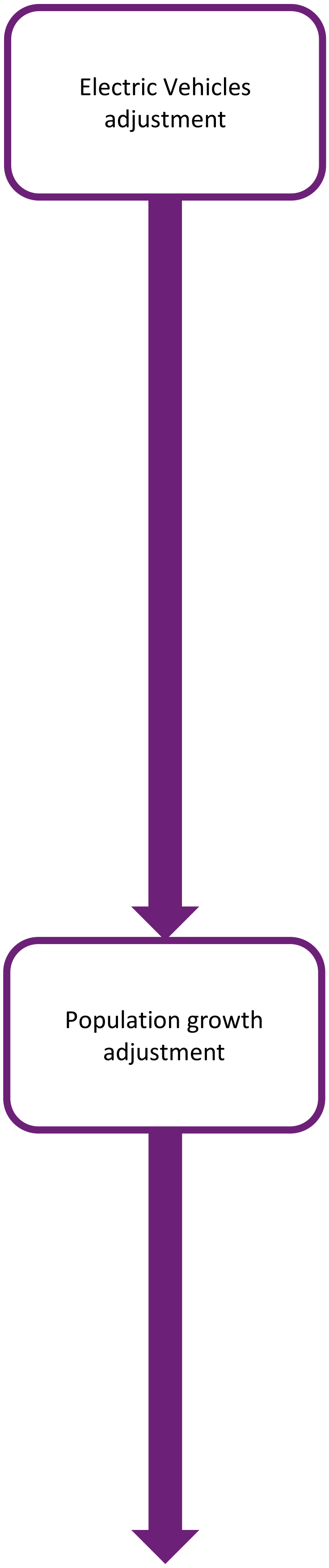
Combined PV and battery storage systems only store energy when there is excess solar energy after consumption. When solar generation is less than consumption, the battery is used to meet the power demand, and the further shortfall is imported from the grid.

The spatial allocation of PV uptake in the Ausgrid network is based on state-wide data provided by AEMO's ISP.

The magnitude of dampening maximum demand from PV is measured by using data collected from metered solar customers to develop an ABM. An example is commercial battery storage, which has three typical battery sizes (10kWh, 30kWh and 100kWh) for small, medium and large customers. The sum of the effect of each agent within a substation is then totalled and applied to the maximum demand at a substation level.

Historically, Ausgrid had lower uptake of PV DER in comparison to other DNSPs in the NEM due to Ausgrid having a higher percentage of customers living in apartments without individual rooftops. Therefore, the impact of PV generation for Ausgrid is smaller in comparison to other DNSPs.

5.2.2.6 Electric Vehicles adjustment



EV uptake is one element of electrification that will increase demand, including during the evening peak.

Partnering with Evenergi, Ausgrid developed modelling software for the impact of EV uptake on demand at a postcode level (Evenergi, 2022). This model produced half-hourly demand profiles for summer weekday and weekend, winter weekday and weekend. The model distinguishes between residential and non-residential customers and can accommodate any ISP scenarios. The model also accounts for various types of chargers: residential, bus depot, shopping centres, etc. The model includes charging profiles developed from EV trials by Evenergi and upon data from the 2021 ABS census and AEMO's Insights report. The model diverges from AEMO forecasts as it claims to cover more parameters than the AEMO model.

The EV demand model aggregates from the postcode level to the zone substation and above.

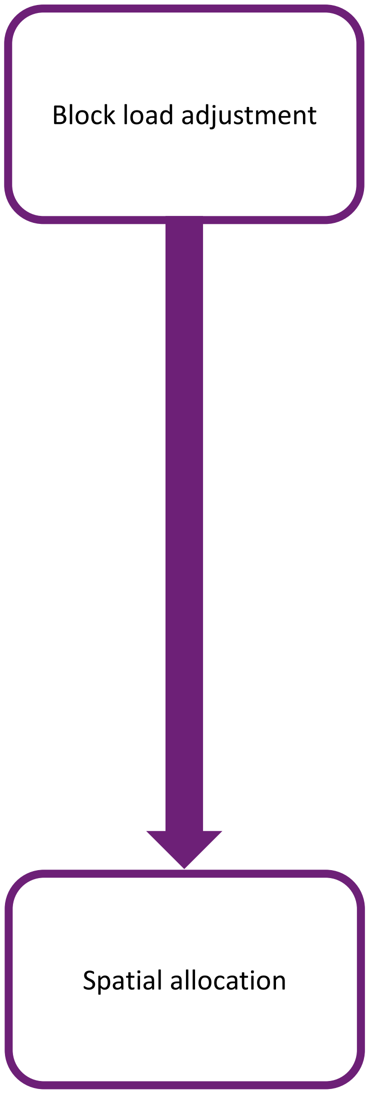
Ausgrid forecasts that 70% of new EVs in NSW will be garaged in Ausgrid's network area. Step Change predicts an increase from the present 9,000 vehicles to 375,000 vehicles by 2029 and 950,000 vehicles by 2034.

Based on Ausgrid's analysis, demand data and surveys suggest that a negative maximum demand impact is possible through influencing charging behaviour via changes in tariff.

5.2.2.7 Population growth adjustment

Population growth is estimated using NSW Housing Industry Association's (HIA) annual percentage change data to estimate the short-term population growth between FY22 and FY25. An average growth rate is taken from FY20 to FY25 at 0.7% and applied beyond FY26 as a constant growth rate.

5.2.2.8 Block load adjustment



Note that there was no removal of block loads in the historical trend used for projection from the last 7 years. The post-model adjustment is applied based on Ausgrid's assessment of the expected large customer connections that impacts the local zone substation demand in the next 4 years.

The assessment process tracks connections that can increase (e.g. new load) or decrease (e.g. new generator) the forecast load greater than 50A at 11kV and all applications at 33kV and above. Block loads that meet these criteria are then classified as one of three block load types.

These block load types are applied with different probability scaling factors based on initially requested maximum demand vs. resultant maximum demand in the past:

1. Early-Stage Block Loads – 34% of requested demand capacity
2. Late-Stage Block Loads – 78% of requested demand capacity
3. Major customer connections
    a. 80% of capacity for commercial customers
    b. 90% of capacity for infrastructure customers

5.2.2.9 Spatial allocation

The resulting system-level maximum demand is allocated to zone substations using allocation techniques based on the forecasting element:

Allocation technique	Forecast element
Allocated using a proportion of residential and non-residential demand for each zone substation.	Income/GSP Price Energy Efficiency
Allocated using current penetration of rooftop PVs by zone substation.	Rooftop PV Battery Storage
Allocated using Evenergi's GridFleet platform to specific geographical areas (Evenergi, 2022).	Electric Vehicles
Allocated spatially upon HIA data at the local government area level, adjusted for substation service boundaries.	Population
Specific to each zone substation as per connection requirements.	Block loads

5.2.3 Blended forecast preparation

5.2.3.1 Merging short- and long-term forecasts

Merging short- and long-term forecasts

As depicted in 5.2, the short-term forecast methodology outlined in 5.2.1 is applied to forecast years 1 and 2. Whereas the long-term forecast methodology outlined in 5.2.2 is applied to forecast years 5 to 10.

For forecast years 3 and 4, both methodologies are applied, and the resulting maximum demand forecast is scaled:

- For year 3, the short-term forecasted demand is scaled to 67%, whereas the long-term forecasted demand is scaled to 33%.
- For year 4, the long-term forecasted demand is scaled to 33%, whereas the long-term forecasted demand is scaled to 67%.

Then these are aggregated together to form the maximum demand for years 3 and 4, respectively.

5.3 DER Integration model (agent-based modelling)

5.3.1 Introduction

Reduction in the cost of renewable energy generation and industry decarbonisation led to a significant increase in DER in residential and non-residential settings. As a result, the traditional role of the distribution networks has been augmented by the rapidly growing amount of surplus electricity transferred from customers' DER back into the network. Therefore, DNSPs need to consider what happens in the distribution networks that connect to residential and commercial customers producing energy (AEC, 2022). A growing number of PVs are expected to be complimented by the growing adoption of batteries as economies of scale and technological advancement reduce production costs. The electrification of transport and heating will increase the demand for electricity over the coming years. Water heating contributes 25% to 30% of household energy consumption in NSW. Network control approaches that optimise the times of vehicle charging and water heating may provide opportunities to reduce the peak demand in the distribution network. Ahead of regulatory requirements, Ausgrid is building their DER Integration model that can forecast the hosting capacity of DER.

5.3.2 Overview

A review of Ausgrid's network hosting capacity modelling has been conducted to examine which parts of the network require the most attention to accommodate two-way energy flows. A proactive approach has been taken by Ausgrid to address the growth of DER to minimise or prevent the future curtailment of customer exports of PV-generated energy.

With changing priorities from regulators that reflect customer support for net zero, as well as Ausgrid's identification of DER being a strong growth area, a DER strategy has been formulated.

In light of a paradigm shift as Ausgrid customers become potential energy suppliers, Ausgrid's DER strategy seeks to understand customer needs in terms of energy demand as well as in terms of energy export pricing (Feed-In-Tariff), ultimately to lower maximum demand, increase utilisation of the network around the clock, and avoid curtailment that results in loss of energy generation efficiency.

Capabilities to achieve the strategy include:

- Tariff reform to manage the level of DER export at any given time;
- Customer education and collaboration;
- Improved network visibility by acquiring more network and customer data;
- Incorporation of Dynamic Operating Envelopes into Ausgrid's operational technology platforms;
- Coordinated optimisation of voltage through network assets;
- Investment in network augmentation; and
- Planned curtailment.

Initial case studies conducted by Ausgrid reveal that LV feeders/distributors have varying levels of impedance (ordered from lowest to highest impedance), with longer LV feeders/distributors having higher impedance and vice versa:

- Underground (34% of the network);
- Overhead aerial bundled cables (ABC) (14% of the network); and
- Overhead open wire (52% of the network).

Conductors with lower impedance enable more DERs. As such, the most concerning areas for DER hosting capacity are network lines with overhead open wires (52% of the network).

Voltage imbalance and voltage drop are other factors that reduce the ability of Ausgrid's network to host DER. Voltage imbalance can cause a range of up to +/- 3.5V from the network voltage of 240V, and voltage drop could expand that range to between +3.5V to -15.5V on the LV network.

Ausgrid noted that through the modelling of DER integration to the network, they uncovered numerous network risks across the existing LV network, 70% of which are present with the initial load in the forecast.

Thus, instead of relying on the maximum demand forecast from a system level, Ausgrid decided to model DER growth at the National Meter Identifier (NMI) level to identify the bottlenecks in the LV network and prioritise the improvements based on the results. Ausgrid initiated the development of the DER integration model earlier this year. Currently, the model is in the prototype stage, and they plan to include it in the BAU planning when it reaches the production stage.

5.3.3 Holistic modelling of DER Integration

Ausgrid DER Integration model includes inputs from the ABM that capture the current and predicted DER and the detailed network model that allows identifying weaknesses at the LV level. The DER model was built for each substation with the inclusion of all active customers supplied from that zone substation and reached from the customer connection up to the 11kV zone substation busbar. The main inputs for the model are:

1. Loads/generation of an agent, current/ratings on LV mains;
2. Distribution centres and high voltage (HV) mains, which are typical limitations of loads in urban network areas; and
3. Voltage levels experienced by customers (typical limitation on rooftop PV output).

The main variables in the model are rooftop PV, PV + batteries, EVs, hot water heating and electrification of residential gas (heating, cooking etc.). Loads which do not depend on any of these variables were counted as constant in the model. Each agent could have been assigned more than one DER, and thus, the model calculated the combined effect of all assigned elements.

The model was created to establish a baseline based on current loading and aligned with the regulatory reporting periods: 2024, 2029, etc.

5.3.4 Agent-based modelling

Ausgrid used a two-step approach in producing the DER Integration model (Figure 4): top-down for allocation of future DER and bottom-up to establish aggregated results from the agent-based simulation.

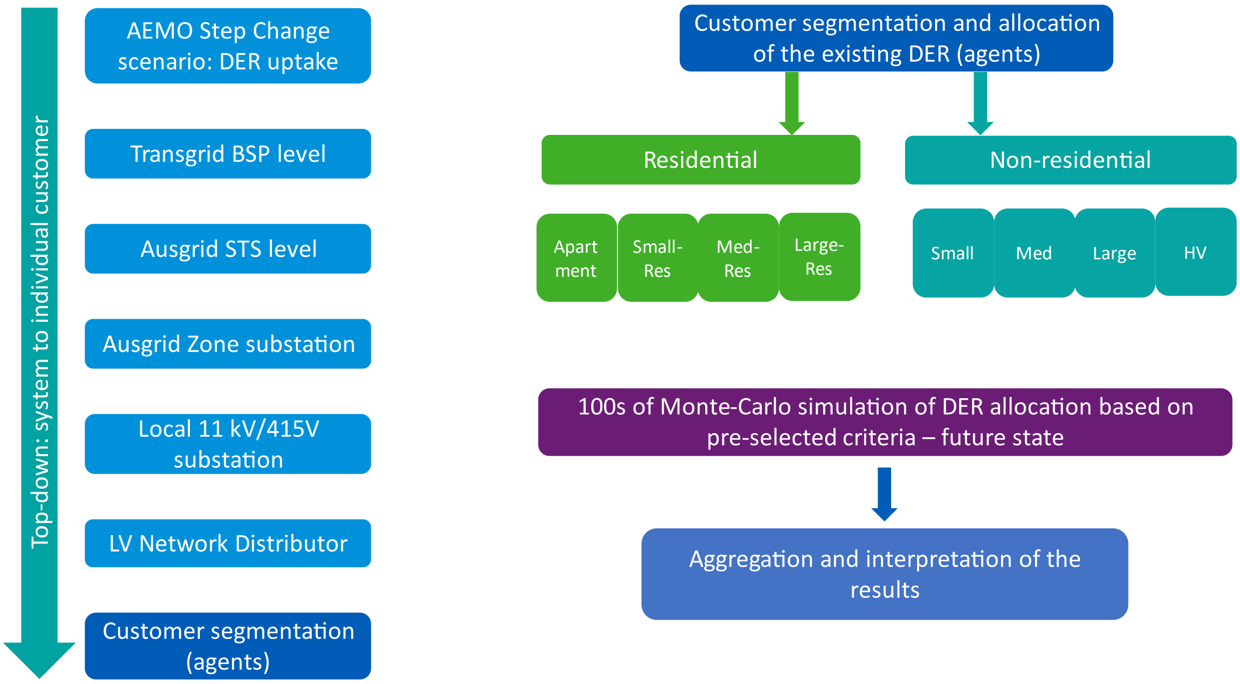


Figure 4. Concept of the DER Integration model

Initially, DER uptake from the AEMO Step Change macro scenario was broken down to obtain the values for Ausgrid's network. Then, Ausgrid used a top-down approach to distribute the uptake from the Transgrid BSP level to LV Network Distributor by stepping down in this sequence: Transgrid BSP -> Ausgrid STS -> Ausgrid Zone Substation -> Local 11kV/415V substation -> LV Network Distributor -> Agent (end metered customer). This allocation adopted a multi-factored approach (load, suburban characteristics, etc.) to divide the DER into the lower levels. This method does not adopt econometric factors such as income, age, etc.

Low voltage distribution level resources were split among the individual customers (NMI) using a customer segmentation method similar to the tariff segmentation. The customer segmentation is based on residential and non-residential customer types. The residential segment is broken further down (Figure 5) into attached housing (apartment, townhouses), small, medium and large housing based on power consumption, whereas the non-residential customers are broken down based on their consumption into small, medium, large and HV. Each modelled customer (agent) is updated with the current state of the PV/battery/EV adoption as per available data.

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	above 4,000,000		11 kV and above HV Customers

Figure 5. Customer segmentation

Once future DERs are assigned to the agents based on the criteria provided in the table above, Ausgrid aggregate the results up to the substation level depending on the purpose of assessing the hosting capacity.

5.3.5 PV allocation per agent

As described in the methodology above, PV was allocated using a top-down approach from the network to the agent level. The model simulated PV allocation based on certain rules, including the type of agent. The starting modelling point contained the existing PV installations (year 2021). They conducted 100s of simulations to predict future PV locations. Agents with existing solar panels were excluded from the process to avoid double counting.

The agents who were assigned future PV were split by having smart or interval metres and having accumulation meters, which cannot detect the time of day of electricity consumption. The agents with the accumulation meters would be assigned interval consumption/generation profiles based on the data extracted from the interval meters. There is no detailed examination on whether these profiles are representative of customers with accumulation meters that have been conducted as part of this conceptual review and may potentially be a subject for future reviews.

Summer and winter power generation profiles are developed independently and empirically from the customer survey data due to the notable difference in power generated between seasons and the lack of comprehensive historical data.

5.3.6 Battery allocation

Some agents with PV are allocated batteries that are capable of storing most of the PV generation that can be used when no solar energy is available. Due to the variety of batteries available on the market and different customer behaviour, it is hard to assign a specific profile to each agent. Therefore, Ausgrid developed three types of customer behaviour: virtual powerplant scheme; tariff sensitive; and regular.

The virtual powerplant is the most comprehensive energy-sharing application of the battery, where the customer agrees for Ausgrid to fully manage their battery use. Tariff sensitivity assumes that the customer adjusts the battery usage to get the best tariff deal from Ausgrid: i.e. to use the battery during peak hours. Regular customers use their battery for their own needs and do not adjust usage behaviour to match the tariff. The model does not consider the age of the battery and the deterioration of its characteristics over time.

5.3.7 EV allocation (house electrification)

Forecasting EV on an agency level depends on more factors than PV/battery allocation: the ABM for EV considers more variables, such as including the type of charger (residential/fleet).

Ausgrid partnered with Evenergi to develop the modelling platform GridFleet to emulate the impact of EVs on the network at a postcode level. GridFleet contains two interrelated models, a peak power model and an energy model, each made out of sub-models for buses, car parks, direct-current fast charging, fleets and residential. The combination of the model and sub-model considers a list of different factors in generating load curves for summer, winter, weekdays and weekends, with a focus on annual peaks.

Multiple assumptions are applied to build the charging profile for the agents. The average charger applied in the model is level 3 fast charger (non-commercial) agents. The model delivers aggregated values with assumptions that customers have different charging behaviours. The behaviours depend on tariff, availability of PV/battery, distance travelled, number of EVs per agent, etc.

The model also accounts for the possible movement of the EV and that it can be charged in different locations: at home, at work, and at shopping centres. The different locations have different charging profiles, for example, the work location will mostly be used during the day, and the home location will be used predominantly at night.

When comparing Evenergi's energy model outputs with AEMO's NSW energy demand, the aggregate energy demand for Ausgrid's network remains around 70% of the entire NSW energy demand due to EV charging (Evenergi, 2022).

Comparing aggregated EV uptake of the energy model with AEMO's vehicle uptake, the energy model estimates a higher vehicle uptake in Ausgrid's network as it incorporates the electric bus uptake based on Transport for NSW (TfNSW) electrification plans. The average EV uptake in Ausgrid's network settles at 55% of the total NSW EV uptake by 2050.

Average energy consumption per vehicle is found to be very similar between the energy model and AEMO's estimate, with the exception of buses. Evenergi's energy model took into account energy consumption parameters from the BetterFleet software, which analyses actual bus schedules in NSW.

Ausgrid allocated EV modelling to the agents based on their postcode and agent class.

5.3.8 Phasing out gas for electricity (home electrification)

The current trend of reducing the use of gas is leading to increases in electricity consumption. AEMO’s Progressive scenario assumes a very low rate (0.3%) of domestic gas replacement by electricity in 2022-2029. AEMO's Step Change scenario is more aggressive (5% increase), and the precision of allocation is more important for the step change. The biggest uses of gas at home are heating, water-heating (detailed in the next section) and cooking. 10% of Ausgrid customers use gas for heating.

5.3.9 Changes to off-peak water heating patterns

Hot water heating has the biggest energy consumption after room heating in homes. Due to the change of the pattern when cheap energy is available from night-time to daytime, Ausgrid developed tariff adjustments to encourage customers with smart or interval meters to heat their water tanks during hours when PV generation is available. However, water will still need to be heated during the early morning hours to make it available for the morning. Ausgrid believes all customers will move to daytime water heating by 2034, thus, consuming the available excess of solar energy at the time of generation.

It is also expected that more customers will move away from regular meters and be more interested in using energy during the day to benefit from a cheaper tariff or use their own PV. Assumptions such as more energy being required for heating during winter than summer are used to create consumption profiles for agents.

6 METHODOLOGY ASSESSMENTS

6.1 Overview

Three primary approaches were used to assess the effectiveness of the maximum demand forecast methodology described in Section 5.2. Firstly, the methodology used for the 2022 forecast has only had a small number of changes from the 2017 forecast. As such, the validity of the 2017 forecast is likely indicative of the validity of the 2022 forecast. The absolute and percentage error of the 2017 forecast has been calculated for 15 zone substations to quantify the 2017 forecast accuracy. Secondly, the forecast of four zone substations was examined in further detail to observe any large changes in behaviour that cannot be clearly linked to a specific and well-justified part of the forecast. Finally, the methodology has been examined to identify any factors that have not been accounted for in the existing methodology. These factors were then assessed to understand the potential impact their omission would cause.

The DER Integration model was only assessed on a conceptual level based on the available documentation and our understanding of the model. In particularly, the methodology has been examined to identify any factors that have not been accounted for in the existing methodology. These factors were then assessed to understand the potential impact their omission would cause.

6.2 Forecast Accuracy

6.2.1 Identification of differences

By comparing the methodologies outlined in the 2017 forecast for the 2019-24 regulatory submission and the 2022 forecast for the 2024-29 submission, all systemic changes can be identified to assess the impact of the changes.

The short-term forecast has had no systemic changes to the methodology.

In the econometric model, the air conditioner penetration component of the model has been removed as air conditioning has now been adopted by enough customers to render modelling the adoption of air conditioning unnecessary as it will not meaningfully change the maximum demand. As the effects of this factor had diminished to the point that it was not worth modelling, its removal will not materially impact the 2022 forecast.

Another change made to the long-term forecast is the handling of PV and battery adjustments, as they are now handled with an ABM that simulates the adoption of PV and battery technology over the grid and is tuned to approximate the older methodology for PV and battery post-model adjustment.

Additionally, a new ABM has been created by Evenergi for the adoption of EV technology which allocates the new vehicles to a postcode. This was to improve the accuracy of the associated demand geographically.

Finally, the population forecast was based, in part, on a report from the NSW Department of Planning. Instead, that component of the forecast has been replaced with the long-term growth rate observed by Ausgrid (0.7%).

6.2.2 Calculation of accuracy

The error of the 2017 forecast was measured against the actual demand by calculating the difference (error) between the forecast and the demand, with negative values representing an under forecast and positive values representing an over forecast. The percentage error is the difference divided by the forecasted value with the same convention as the difference.

In Table 5 (winter forecast) and Table 6 (summer forecast), the percentage error has been coloured red or green based on the magnitude and sign of the percentage error, capped at 15%.

Table 5. Winter forecast

Winter Forecast	2017		2018		2019		2020		2021	
Zone	Absolute Error	Percentage Error	Absolute Error	Percentage Error	Absolute Error	Percentage Error	Absolute Error	Percentage Error	Absolute Error	Percentage Error
Argenton 132_11kV	-3.6	-16%	-2.9	-14%	-4.1	-20%	-12.2	-62%	-8.0	-40%
Auburn 33_11kV	1.6	8%	0.5	2%	1.2	7%	-1.9	-11%	-4.1	-23%
Bankstown 132_11kV	0.0	0%	1.2	3%	3.1	8%	1.9	5%	-2.4	-6%
Charmhaven 132_11kV	5.2	14%	1.7	4%	1.9	5%	3.5	10%	-0.8	-2%
City North 132_11kV	26.3	31%	35.3	33%	27.0	26%	46.4	45%	30.8	30%
Gateshead 33_11kV	-0.2	-1%	-2.3	-17%	-2.4	-18%	-1.6	-12%	-3.6	-28%
Jannali 33_11kV	1.6	5%	5.4	16%	3.6	11%	1.3	4%	-0.1	0%
Kogarah 132_11kV	3.7	5%	5.1	7%	4.3	6%	4.8	7%	9.6	13%
Leichhardt 132_11kV			17.4	58%	-1.9	-7%	-13.9	-49%	-16.8	-58%
Leichhardt 33_11kV	5.6	19%								
Lindfield 33_11kV	4.3	13%	4.0	12%	3.3	11%	1.2	4%	-4.8	-15%
Macquarie Park 132_11kV	7.3	11%	22.6	26%	24.3	27%	30.7	32%	48.5	48%
Mona Vale 33_11kV	1.9	6%	1.2	4%	-0.2	-1%	-1.5	-5%	-2.8	-9%
Muswellbrook 33_11kV	-0.1	-1%	0.7	6%	-2.6	-24%	-2.1	-19%	-2.9	-26%
Peats Ridge 33_11kV	-0.2	-2%	0.2	2%	-0.5	-6%	-0.7	-8%	-1.0	-11%
Pennant Hills 132_11kV	6.4	9%	12.8	16%	-1.7	-3%	-4.5	-8%	-8.6	-14%

Table 6. Summer forecast

Summer Forecast	2018		2019		2020		2021	
Zone	Absolute Error	Percentage Error	Absolute Error	Percentage Error	Absolute Error	Percentage Error	Absolute Error	Percentage Error
Argenton 132_11kV	-2.9	-9%	-0.1	0%	-5.1	-18%	-3.9	-14%
Auburn 33_11kV	1.4	5%	0.9	3%	1.4	5%	1.2	5%
Bankstown 132_11kV	2.1	4%	4.7	9%	7.3	14%	11.2	21%
Charmhaven 132_11kV	-3.0	-7%	-3.4	-8%	-4.6	-11%	-5.8	-14%
City North 132_11kV	17.1	17%	29.2	23%	30.6	24%	38.8	30%
Gateshead 33_11kV	-2.4	-15%	-0.5	-3%	-3.4	-23%	-3.6	-24%
Jannali 33_11kV	0.4	1%	-1.8	-6%	-3.8	-13%	-1.2	-4%
Kogarah 132_11kV	6.3	8%	-2.2	-3%	5.2	6%	9.7	12%
Leichhardt 132_11kV			-3.4	-14%	-7.1	-30%	-13.2	-55%
Leichhardt 33_11kV	11.7	51%						
Lindfield 33_11kV	4.0	12%	-0.7	-2%	-1.0	-3%	-1.4	-4%
Macquarie Park 132_11kV	19.2	18%	23.8	22%	32.3	28%	37.2	31%
Mona Vale 33_11kV	-0.3	-1%	-1.9	-6%	-3.0	-9%	-2.4	-7%
Muswellbrook 33_11kV	-0.9	-7%	-5.0	-37%	-4.6	-34%	-6.1	-44%
Peats Ridge 33_11kV	-0.3	-2%	0.5	4%	-0.1	-1%	-0.2	-2%
Pennant Hills 132_11kV	1.1	1%	12.1	13%	-11.0	-14%	-1.1	-1%

In the above tables, it is clear that there are some material errors in the forecast as a predictor of actual maximum demand. That said, the changes associated with COVID and shifts in block loads, like recent datacentre trends, could not have been reasonably predicted when the 2017 forecast was being created, so some inaccuracy is to be expected, and the early forecast is reasonably accurate. Additionally, there is no clear trend or bias between over and under forecasting, which indicates there is not a clear systemic error within the methodology that drives forecasted demand up or down.

Ultimately the analysis of the error present in the projections from the 2017 forecast supports the conclusion that the output is a useful approximation of future demand. As the methodology of the 2022 maximum demand forecast is similar to the 2017 methodology (see Section 6.2.1) it stands to reason that the 2022 projections will be useful and valid for planning purposes.

6.3 Qualitative assessment of the Maximum Demand Methodology

Each stage of the methodology detailed in Section 5 was examined to ascertain if there were any improvement opportunities for each stage. Sections that had opportunities identified have been included below. Stages not referenced below were found to be uncontentious, robust, and sufficient.

6.3.1 Short-term demand forecast

6.3.1.1 Weather correction

Current weather corrections are made based on 10 years of historical data, mapped against maximum demand. This enables the turning points for both heating and cooling. It is known that these turning points are different based on the average temperatures of the area being modelled (Azevedo, Chapman, & Muller, 2015) and will likely be affected by average temperature changes caused by climate change. The 10 years of historical data used by Ausgrid would be less affected by this than the 40 years of data used more commonly by the industry.

Finding:

The best practice recommended for preparing a forecast that factors in the effects of climate change would involve estimating changes in average temperatures throughout the forecast and adjusting the heating and cooling turning points correspondingly (Azevedo, Chapman, & Muller, 2015). This finding will be of greater materiality in regulatory periods beyond the scope of this review.

Recommendation:

It is recommended that Ausgrid create a forecast of average temperatures expected in different sections of their network grouped by decade to enable the adjustment of their forecast to account for future changes to NSW's climate effectively.

6.3.1.2 Removal of block loads, block transfers, and embedded generation

Currently, the effects of the block loads caused by PV systems are calculated based on Ausgrid’s installation records on the type and number of PV systems in a given area but do not always capture every installation when it occurs. These records are supplemented with information gathered from satellite imagery to confirm the presence of a solar panel.

Finding:

There is some uncertainty around the accuracy of the magnitude of the PV adjustment needed due to the input data quality in the PV installation register.

Recommendation:

Current technology allows the extraction of information from satellite data to quantify the type and number of PV systems installed using AI to extrapolate objects only partially captured in satellite images. This advanced analysis of the imagery is not currently part of Ausgrid’s methodology, but the technologies are available to carry out the analysis. It is suggested that Ausgrid consider either developing similar capabilities in-house or outsourcing this augmentation of their PV installation data to a trusted contractor. That will also apply to the DER Integration model.

6.3.1.3 Extraction of historical trends

When examining the methodology of the demand forecast going forward, no special provisions or adjustments have been made to account for the changes in demand caused by COVID-19. The total consumption of electricity fell by 2% in Australia in the second quarter of 2020 in comparison with the same period last year, and a significant increase was noted in the residential area during the lockdowns (10-30% increase based on Victorian data) (ACCC, 2020). As such, the change in the demand on the substation level varied by more than 2% at some locations as some areas were affected more than others depending on the proportion of residential/non-residential customers.

A strong correlation was identified between the COVID lockdown condition and energy consumption: stricter conditions led to a decrease in demand. It was noted that during the lockdowns, the demand consumption during workdays was comparable with consumption on Sundays, based on international experience (World Economic Forum, 2020). This means that the short-term demand trend is affected in an unscrutinised way by the lockdowns in both residential and non-residential areas, as no adjustment was made for the lockdowns. The mid-term trend may be affected in residential areas and office areas (an increased proportion of people working from home). The occupancy of an office building significantly affects the amount of energy consumed by the building as large occupancy drives more usage of air conditioning, light, and power for ICT equipment. As such, flexible working conditions over a long period may affect the energy demand for offices. (Mantesi, Chmutina, & Goodier, 2022).

Finding:

The current methodology does not remove the effect of the COVID lockdowns on the historical demand. Restricted movement may result in an unnatural redistribution of maximum load, causing bias in the resulting trend.

Recommendation:

Demand data from the lockdown and periods of restricted movement should be ignored for generating the historical trend. There may be value in identifying the proportion of demand that moved from offices to homes, such that a factor of that adjustment can be applied to account for the work-from-home behaviour in the future.

6.3.2 Long-term demand forecast

Ausgrid uses multiple econometric parameters for the long-term model, including population expansion and economic growth. The other important parameters that may influence the energy demand are changes in the behaviour of individuals and organisations and the pace of technological development – they present multiple sources of uncertainty (Ruijven, Cian, & Wing, 2019) and indirectly account for energy efficiency adjustments.

Layered on top of this are the additional uncertainties in the timing and intensity of future temperature changes—both at the global level, driven by trajectories of global greenhouse gas emissions and radiative forcing, and at finer geographic scales, determined by the effects on future regional climates (Ruijven, Cian, & Wing, 2019). The top-down model aggregating national statistics and future trends provide less uncertainty than the bottom-up model for forecasting the maximum demand. A top-down method makes it possible to develop ex ante climate-induced potential impacts prior to any direct or indirect adjustment induced by market interactions between future technological or behavioural changes with energy supplies and the rest of the economy through price changes (Ruijven, Cian, & Wing, 2019). Therefore, Ausgrid's choice of a top-down model for the long-term forecast was found appropriate until it can be replaced by the bottom-up model capable of accounting for the complexity and uncertainty of the future condition.

6.3.2.1 Energy efficiency adjustments

Energy efficiency adjustments are made based on four elements, the E3 program, NSW ESS, NSW PDRS and BCA. The Ausgrid forecast contains major current policies/regulations that drive energy efficiency.

Residential buildings consume 24% of overall energy use based on national data. Many existing buildings in NSW were built before any building performance standards were introduced and as such, have poor energy performance (DoCCEEW). One of the government priorities is to further develop policies to improve the energy efficiency of buildings, including stricter requirements for new buildings/renovation, the efficiency rating of new buildings and data collection (DoCCEEW). The current National Construction Code (NCC) that includes sustainability requirements applies to both new builds and some renovations. The NSW Government has recently issued a new State Environmental Planning Policy (Sustainable Buildings) that introduces stricter requirements on the energy efficiency for new buildings (some exclusions apply) (DoPaE, 2022). In view of the recent policy development and government priorities, the energy efficiency of buildings may improve at a faster rate than was estimated a few years ago.

The adjustments to account for the content of the BCA were last reviewed in 2018 by the expert consultants. They do not account for the recently announced State Environmental Planning Policy (Sustainable Buildings SEPP) and increased greenhouse emission targets. The Sustainable Buildings SEPP will come into effect on 1 October 2023, which is within the forecast period.

PDRS encourages shifting electricity use for tasks that are not time critical. It will evolve over the next few years (Figure 6) to encourage residential and non-residential customers to use energy outside of times of peak demand, and especially to use energy during times when excess solar-generated energy is available. The scheme aims to reduce the peak demand gradually, however, it creates complexity in modelling the future demands as it potentially needs to have different adjustments for each milestone in Figure 6. Therefore, it is deemed sufficient for Ausgrid to use the recent modelling for PDRS, but it is recommended to review this for the 2029-34 regulatory period.

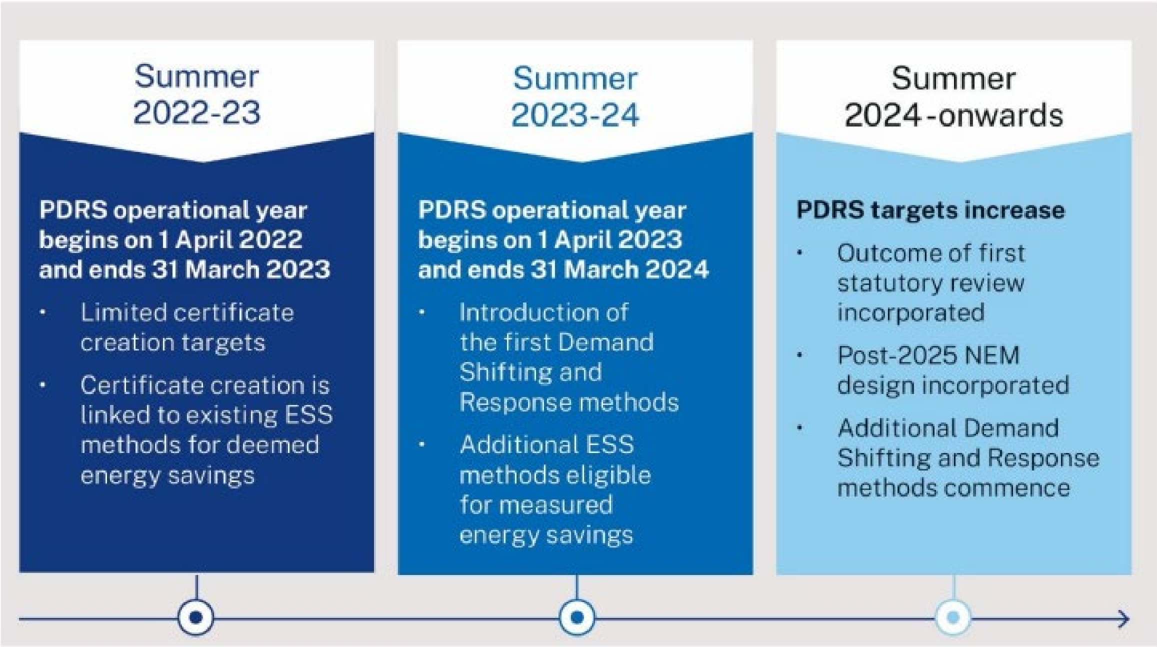


Figure 6. PDRS Milestones (OECC, 2022)

The Energy Saving Scheme Rule is updated annually to maintain the effectiveness of the program by modifying saving factors.

All components of energy efficiency are rapidly evolving and will have a material discrepancy if Ausgrid uses models that are not updated for the purpose of each regulatory submission. The recently issued *Climate Change Bill 2022 (Cth)* raised the national greenhouse emissions reduction target to 43% by 2030, however, the NSW target set in September 2021 is already at 50%. Thus, it is expected that the new bill and NSW enhanced target will continue to have a ripple effect on energy efficiency measures, with stricter and broader policies to be issued in the coming years. KPMG recommends updating the existing energy efficiency models with the input from recent research, including that listed below:

The Residential Baseline Study projects energy consumption for all categories of residential appliances and equipment until 2040 - *Report: 2021 Residential Baseline Study for Australia and New Zealand for 2000 — 2040 | Energy Rating*

E3 Prioritization Plan for 2021-22 focuses on a smaller number of higher-value policies to deliver them earlier (*Equipment Energy Efficiency Prioritisation Plan 2021-22 (energyrating.gov.au)*).

Finding:

The Building Code of Australia (BCA) component of the energy efficiency adjustments is outdated (last updated in 2018) and does not account for recent policy development such as the Sustainable Buildings State Environmental Planning Policy (SEPP).

Recommendation:

Due to the rapid advancements in the energy efficiency area and multi-factored dependency, energy efficiency forecasts should be updated for each new forecast submission, including the BCA forecast for this regulatory period.

6.3.2.2 PV and Battery System Adjustment

PV and Battery system adjustment is based on an aggregated generation profile created by measuring the output of PV systems over the course of many days. This generation profile may change over time as PV and technology improve and as older PV systems age and degrade (Brakels, 2019). The average expected battery lifespan is about 15-25 years, depending on the type of battery and its usage, with effective storage capacity decreasing over time. Similarly, the output of solar panels decreases over time (i.e. degradation). Research from the US Department of Energy's National Renewable Energy Laboratory (NREL) indicates a median panel degradation rate of 0.5% per year (Mow, 2018).

Finding:

The generation profile used by Ausgrid of PVs and battery systems for the 2024-29 forecast is the same as the one used for the 2019-24 period.

These generation profiles are likely to change due to PV system degradation and technological advancement.

Recommendation:

It is recommended that the generation profile be recalculated within the next five years (before the 2029-34 regulatory submission) to reflect changes in the age and associated degradation of PV systems and the progress made in PV technology.

Another option that was considered is developing a more complex agent-based model capable of tracking the ageing of PV systems over the timeframe of the forecast. However, based on the rate of degradation, it seemed like this would not provide an improvement sufficient to justify the effort required to implement it. As such, this was not included in the recommendations table.

6.4 Forecast Anomaly Investigation

To verify that the models and calculations come together to result in a valid forecast, the outputs were examined for four substations (Macquarie Park 132_11kV, Muswellbrook 33_11kV, Lindfield 33_11kV and City North 132_11kV), and any unusual changes were identified and raised with Ausgrid to identify the justification for the unusual behaviour or identify the source of the error.

6.4.1 Review of Macquarie Park substation

In 2048 and 2049, there is a spike for the Macquarie Park substation and then an immediate reversal in demand associated with PV and batteries (Figure 7). Ausgrid explained that normally DER, EV and energy efficiencies are modelled with the incremental increase in values year-to-year. However, Ausgrid expect the shift in peak hours over the forecasting period driven by energy efficiency measures. As such, the significance of the DER impact in the peak hours changes over the given period and leads to the spikes for the Macquarie Park forecast model.

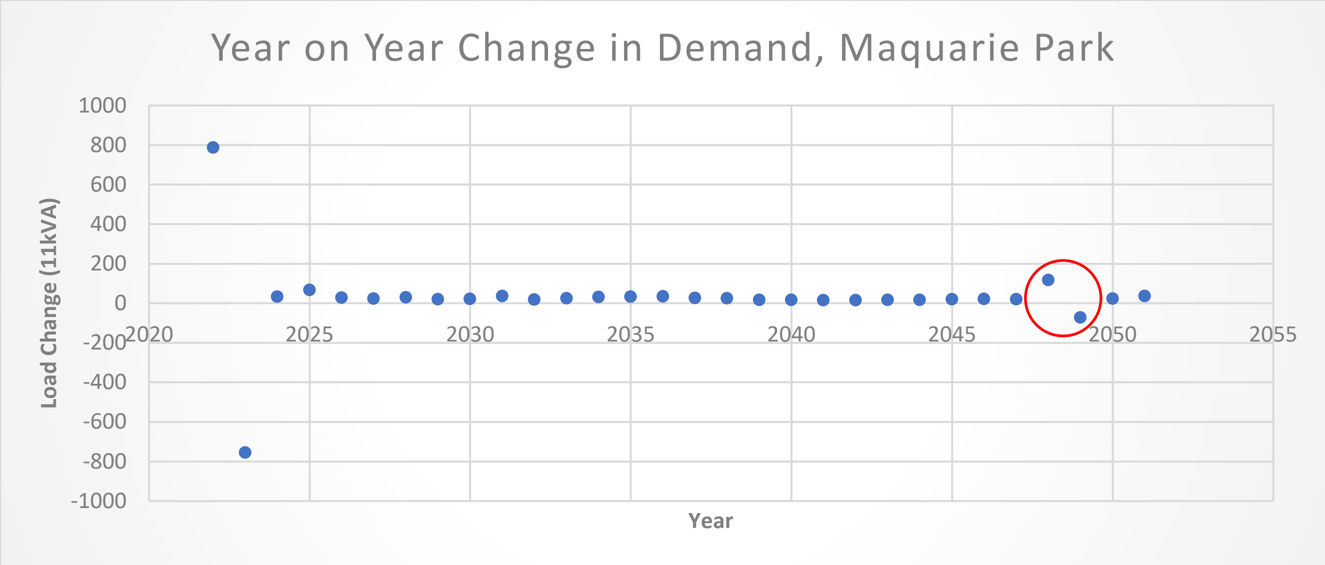


Figure 7. Year on Year Change in demand, Winter Macquarie Park

6.4.2 Review of City North substation

In 2031 City North substation has a sharp spike in the energy efficiency effect on maximum demand before a sharp reversal (Figure 8). Ausgrid explained that the graph movements in the identified period are driven by the overlay of four components of the energy efficiency modelling: BCA, MEPS, PDRS and NSW ESS. BCA/MEPS impacts were continuously growing over the forecast period, whereas the PDRS/NSW ESS impacts were decreasing. The combination of these two factors led to an unusual spike in 2031.

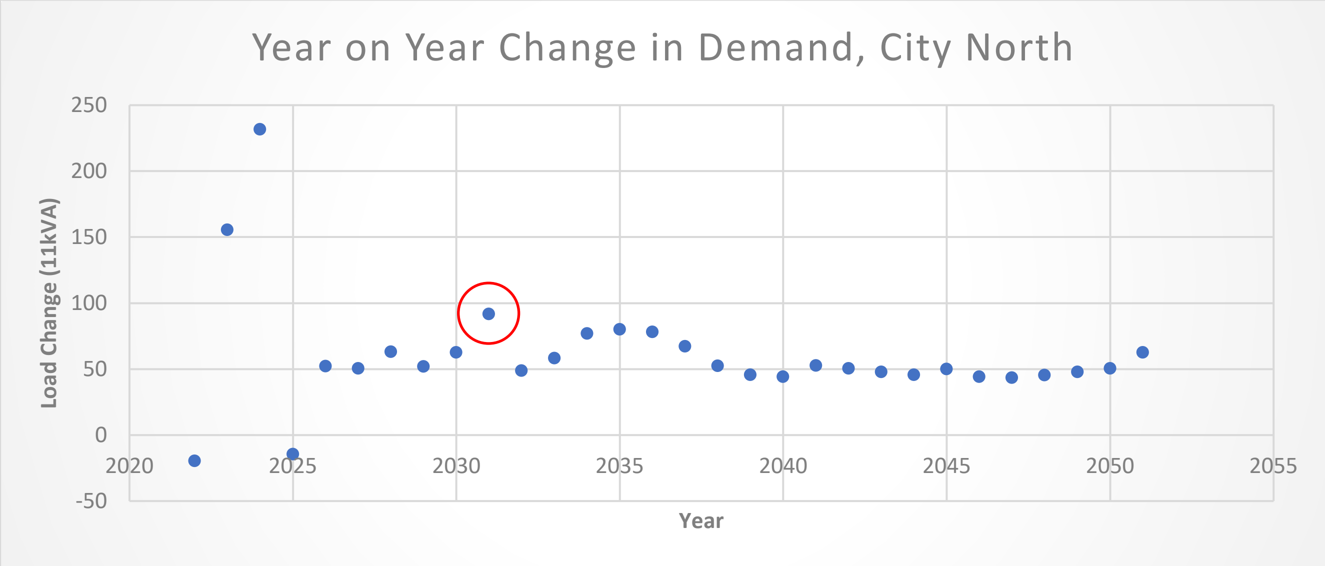


Figure 8. Year on Year Change in demand, Winter City North

6.4.3 Review of Muswellbrook substation

Muswellbrook has an increase in energy efficiency from 2033 to 2040 Winter and 2037/38 to 2044/45 Summer (Figure 11 and Figure 12). Energy efficiency is the primary driver for the reduction in the maximum demand in both the summer demand forecast from 2037/38 to 2044/45 and the winter demand forecast from 2033 to 2040.

Ausgrid explained that the modelling for the energy efficiency post-model adjustment was achieved by a combination of PDRS/NSW ESS forecast and BCA/MEPS forecast. The resulting model has a decrease in energy consumption from 2035 and increase in 2045. That is reflected in the behaviour of the demand model for the Muswellbrook substation.

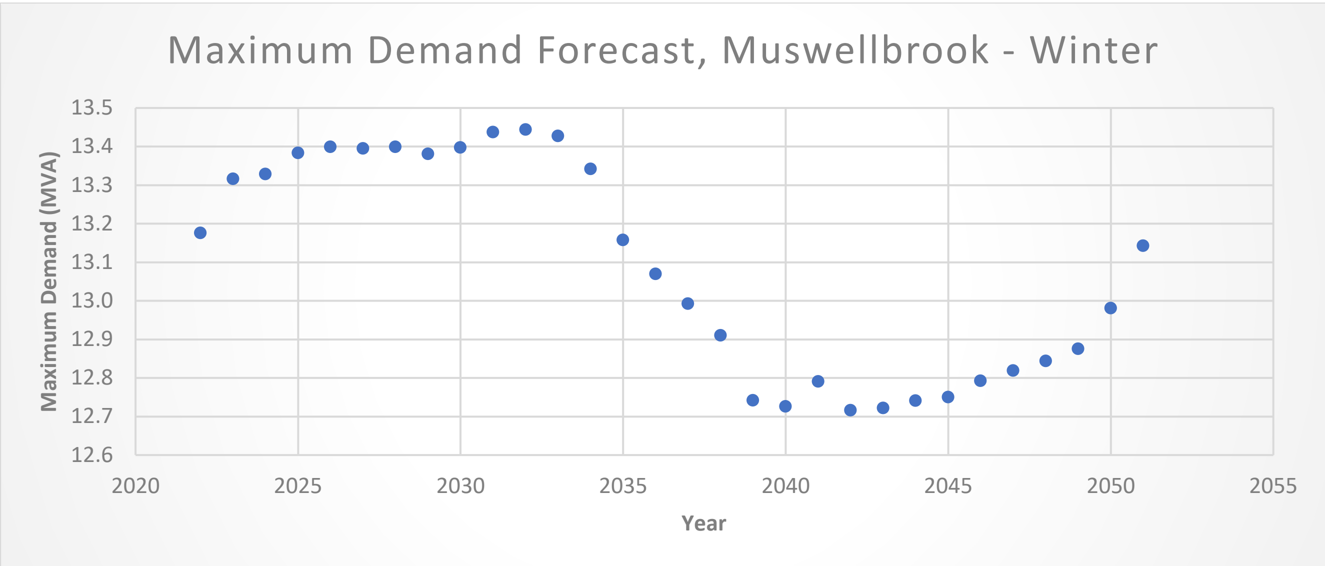


Figure 9: Maximum Demand, Winter Muswellbrook

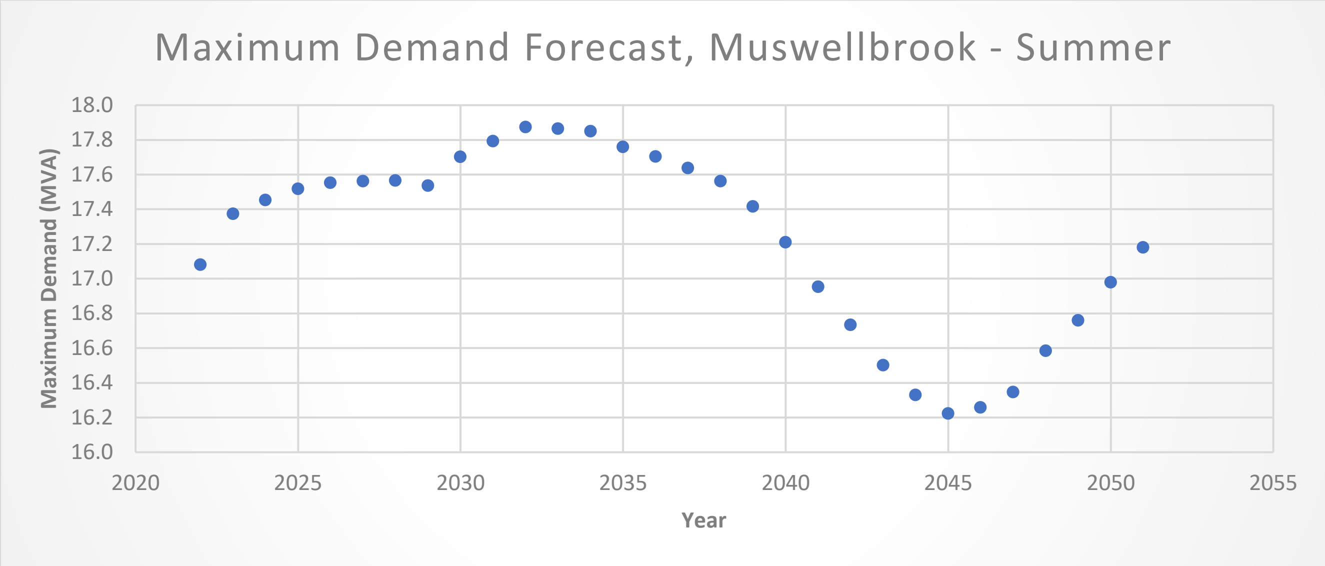


Figure 10: Maximum Demand, Summer Muswellbrook

6.4.4 Review of Lindfield substation

Lindfield substation has an increase in demand across both Summer and Winter forecasts. Increases in maximum demand during both Summer and Winter forecasts are largely driven by EV acquisition and mitigated by PV installation. This behaviour is expected in an affluent residential area where residents are more likely to have the capital to invest in EVs and PV systems. There are step changes in both EV and PV values consistent with changes in time for peak demand, as discussed in Section 6.4.1. As this behaviour is consistent with expected behaviour and shares an explanation of its anomalies with Section 6.4.1, no further explanation was required to be provided by Ausgrid.

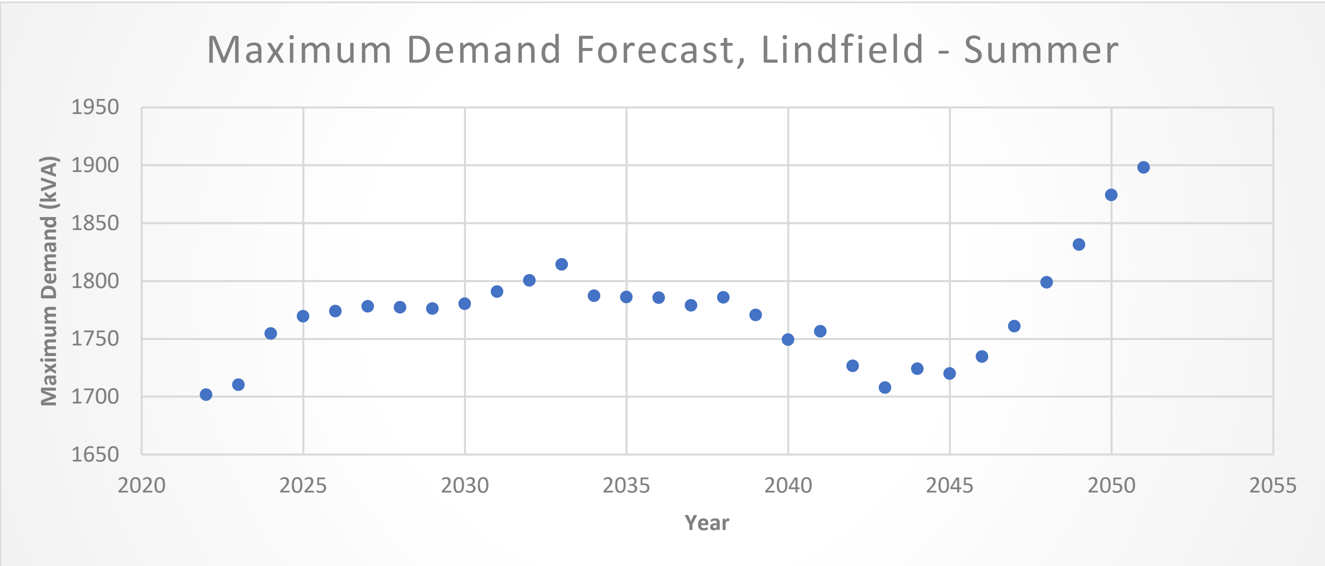


Figure 11: Maximum Demand, Summer Lindfield

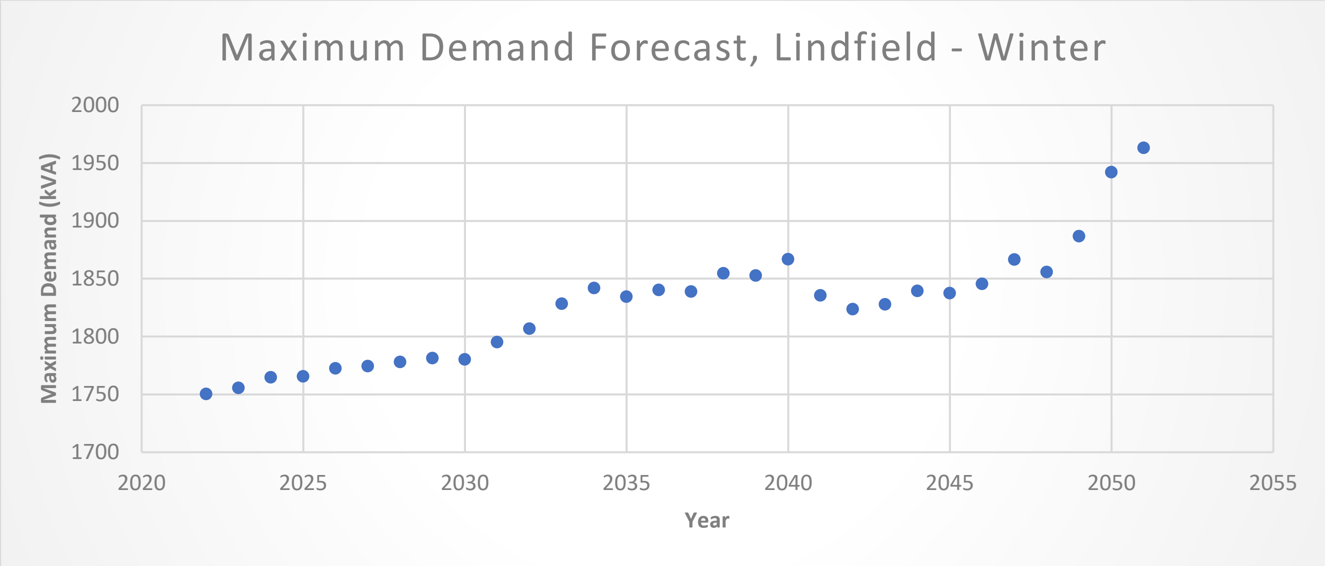


Figure 12: Maximum Demand, Winter Lindfield

6.5 DER Integration model (agent-based modelling)

6.5.1 Overview

The documents provided for the review of the DER Integration model were either the high-level overview of the model or internal training materials. As Ausgrid aims to include the results of this modelling in the regulatory submission, it is recommended to document the methodology of the model at a detailed level. This will provide clarity on the capability, assumptions and limitations of the model to the relevant stakeholders. It is assumed that Ausgrid will have the detailed methodology available for the 2024-29 regulatory submission.

As Ausgrid works towards a more comprehensive model to calculate the impact of DER adoption, primarily in residential areas, it can be very useful for the demand forecast. However, the input from the DER Integration model is not accounted for in the maximum demand forecast model as Ausgrid uses a different method to forecast future allocation of DER. As the DER Integration model contains simulation and is more comprehensive than the current approach for DER adjustment, it is recommended to incorporate the output from the DER Integration model as an input to the maximum demand forecast.

Finding:

The current maturity of the DER Integration model could limit accurate DER representation in the maximum demand forecast model.

Recommendation:

Even though the current Maximum Demand Forecast methodology captures the DER representation of the PV, batteries and EV, the inclusion of the new DER Integration model into the Maximum Demand Forecast will enhance the latter by projecting DER distribution more accurately.

Note: It is recognised that development of the DER Integration model is ongoing and that the reviewed DER Integration model was a work in progress at the time of this review and report.

6.5.2 Agent-based modelling

ABM is the fastest-growing type of modelling for complex business problems. It commonly uses a bottom-up approach where the network is described as a collection of agents. The Ausgrid agent is a constructed model of the individual customers (NMI) who were assigned certain characteristics that can facilitate the modelling of DER allocation: PV, PV + battery, and EV. ABM provides flexibility in the desirable complexity of the models (number of parameters, dependencies, etc.). Considering that DER adoption among customers is multi-factored, the ABM approach has a good fit in the prediction of hosting capacity.

As Ausgrid actively develops this model, it is recommended to follow best coding practices to ensure the highest value is obtained from the model in the short and long term:

- make the model open for inclusion or exclusion of certain parameters;
- make it capable of adapting to different needs (maximum demand);
- keep it connected to the input data sources to avoid manual efforts to update the input data;
- code it efficiently;
- ensure version control of the code for the transparency of their regulatory submissions; and
- use a platform/language which will not require translation to a new platform in the next few years.

As this recommendation is common in nature, it has not been added to the recommendation list.

6.5.3 PV and battery allocation

Ausgrid forms the agent using a scale similar to tariffs. The benefit of this approach is that they can reuse some of the modelling created for other parts of the businesses instead of building the model from scratch. However, the downside is that the allocation of DER by the customer residential type does not distinguish between townhouses and apartments. Townhouses will have a higher likelihood of installing DER per customer than the average apartment as they have more available roof space. This issue mostly applies on the LV level of the network where the correct allocation of PV at the agent level is important for the outcome. However, this issue only applies to the areas where townhouses are present as a type of dwelling, as such it may not be applicable to some of the substations located in the areas comprises of detached houses. Also, the variety of the allocation during the simulation downsizes the effect of the difference in allocation between apartment and townhouses on the overall demand.

Finding:

Allocation of DER by residential type does not distinguish between townhouses, which constitute on average 13% of dwellings in Australia, and apartments (16% of dwellings), and more PV should be allocated to townhouses than to apartments.

Recommendation:

Update the agent types to allow townhouses the same chance of PV allocation as small houses.

Note: that the materiality assessment refers to the network's spatial level. The materiality of the overall volume assessment for this item would be 'Low' as the simulation aspect of the DER Integration model provides a wide variety of outcomes that converge to identify the most concerning network risks.

Ausgrid did not use econometric parameters in the modelling of the PV allocation due to uncertainty in the driving criteria. However, the white paper suggests that two factors (high net wealth and high energy bills in households with mortgages) have a strong correlation with the choice to install PV. Similar to the issue above, the allocation on the agent level is important for the LV network level demand but has less influence on the overall network level. This happens as the aggregation removes the effect of local offsets in demand prediction.

Finding:

Ausgrid did not use econometric parameters to model PV allocation.

Recommendation:

Including two econometric characteristics (high net wealth and high energy bills in households with mortgages) will likely improve the forecast outcome (Best, Burke, & Nishitateno, 2019).

Note: that the materiality assessment refers to the network's spatial level. The materiality of the overall volume assessment for this item would be 'Low' as the simulation aspect of the DER Integration model provides a wide variety of outcomes that converge to identify the most concerning network risks.

The current battery installations are limited to the particular type of roof that needs to have proper position, structure and tilt (ARUP); therefore, Ausgrid can enhance their models by eliminating the residential agents from PV allocation if they are characterised as not suitable for PV installation. For example, it can be a block of townhouses or apartment buildings constructed in a way not suitable for PV installation; or aged houses whose roofs no longer have the strength to safely hold the weight of PV panels.

Finding:

Current PV allocation does not account for the limitation of the PV installations.

Recommendation:

Ausgrid can enhance its models by eliminating residential agents from PV allocation if they are not suitable for PV installation.

Also, the agent model does not account for the extension of the PV panel installation, i.e. if the PV panel is found to be installed, it prevents this agent from getting an extra allocation of solar panels. The assumption that the customer installed the maximum panel capability may be challenged. If there is a monetary incentive to produce more power, the customer may consider the installation of additional panels. The existing owner of the panel is more likely to install additional panels if electrical hardware (controller, wiring) can support additional generation as it will be more cost-effective than a new installation.

Finding:

The existing model does not allow the allocation of additional PV panels to agents who are early adopters of PV.

Recommendation:

It is recommended to adjust the model to allow allocation of PV to agents who can potentially install more panels.

Refer to post-model adjustment for the maximum demand forecast for more suggestions related to the improvement of battery/PV allocation.

6.5.4 EV allocation

Evenergi provided an in-depth analysis of the growing EV fleet within the Ausgrid network. It accounts for major differentiators, such as the split between small cars and large vehicles (e.g. buses). The model was built up to the postcode level; it is not clear from the provided methodology if Evenergi used the agent-modelling approach down to the individual customer level with further integration up to the postcode level or if the postcode level was the lowest point of disaggregation. The output data is provided on the postcode level that needs further disaggregation into the Ausgrid agent-based model. The disaggregation has a risk of incorrect allocation of the large non-residential chargers across the affected postcode. For example, if the postcode area has a bus depot and other non-residential agents, the other non-residential agent may take part in the EV allocation from the bus depot, such as bringing allocation error at the LV level. Therefore, it is recommended to either improve the granularity of the output data from the Evenergi model to the agent level or add an additional type of agent with high EV charging energy demand.

7 CONCLUSION AND RECOMMENDATIONS

Upon the completion of the review of the maximum demand accuracy, methodology and output, it is evident that Ausgrid has a robust approach to forecasting maximum demand that is fit for purpose as a planning and investment tool. In general, Ausgrid's approach meets or exceeds the industry standard for detail and completeness. The short- and long-term approaches to the maximum demand forecast are logically sound, and the transition between them neatly coincides with the horizon of the information provided for new connections.

As good as the existing methodology is, there have been some recommendations made for continual improvement of this process. The key recommendations are as follows:

- It is recommended that Ausgrid create a forecast of average temperatures expected in different sections of their network grouped by decade to enable the adjustment of their forecast to effectively account for future changes to NSW's climate;
- It is recommended that the demand data from the COVID-19 lockdown/ restricted movement periods be removed from the historical trend to prevent planning around ongoing lockdowns. Additionally, there may be value in evaluating demand against the percentage of the population working from home and applying an adjustment based on estimates for that behaviour in the future; and
- Due to rapid advancements in the field of energy efficiency as well as multi-factored dependency, energy efficiency forecasts need to be updated frequently and at least once for each new regulatory submission forecast. Thus, the BCA forecast is recommended to be updated for this regulatory submission (2024-2029).

If Ausgrid implements these recommendations, it should be able to further improve forecast accuracies for future planning purposes.

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