



Maximum demand and customer numbers

UE APP03 - Maximum demand and
customers - Jan2020 - Public

Regulatory proposal 2021–2026

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1 Overview

This document summarises our approach to forecasting maximum demand growth and customer number growth. We forecast maximum demand and customer numbers as drivers of the size of the network.

1.1 Maximum demand

Maximum (or peak) electricity demand is the highest demand, measured in megawatts (**MW**), experienced by the network, in any 30-minute interval. This is in contrast to average demand that represents the average demand per customer generally over a 12 month period. Maximum demand is an important measure of the required capacity of the network, as the network needs to be able to accommodate at least the maximum demand at any given 30-minute interval.

Our total maximum demand for the network can be:

- coincident—a particular 30-minute interval where the summated demand across terminal or zone substations is the highest
- non-coincident—a sum of the highest demands at each terminal or zone substation, regardless of which 30-minute interval each maximum demand occurs.

The non-coincident maximum demand forecasts are the most relevant in planning the network's capacity, as we need to examine each network area considering the characteristics of that part of our network. We also use the sum of all non-coincident terminal station level maximum demand in our rate of change calculation for forecasting operating expenditure, as a measure of the change in scale of output.

We engaged the National Institute of Economic and Industry Research (**NIEIR**) to develop top-down maximum demand forecasts for both the United Energy boundary level demand (coincident), and at the terminal station level (non-coincident), using National Electricity Market (**NEM**) boundary metering. We then forecast a bottom-up maximum demand forecast at each zone substation and reconciled the aggregated demand with the top-down forecasts, taking into account network losses to develop the final maximum demand forecasts.

Data sources used for the bottom-up forecasts include (amongst others) our actual Supervisory Control and Data Acquisition (**SCADA**) system data, Advanced Metering Infrastructure (**AMI**) data, network topology changes, and information about new connections and disconnections. The network level forecasts, coincident and non-coincident calculated as a sum of non-coincident demand at each terminal station, are shown in table 1.

Table 1 Maximum demand forecasts, coincident and non-coincident weather adjusted 50% probability of exceedance (POE)

United Energy	2021/22	2022/23	2023/24	2024/25	2025/26
Coincident (boundary)	2,035	2,073	2,091	2,117	2,160
Non-coincident (terminal station)	2,116	2,156	2,174	2,202	2,247

Source: UE ATT022: NIEIR, United Energy maximum demand forecasts, July 2018 and UE MOD 9.07 - Maximum demand forecasts - Jan2020 - Public

We are experiencing continued strong demand in parts of our network. In particular, areas around Doncaster/Box Hill, Keysborough, Mornington and East Malvern are growing rapidly. For more details on growth areas refer to our regulatory proposal augmentation chapter.

1.2 Customer numbers

Our customers range by type, including residential, commercial and unmetered supplies (e.g. telecommunications box). We provide electricity supply and various other services to each customer type. As our customer base grows we must expand our services to meet each customer's needs. We therefore use customer

number forecasts in the rate of change calculation for forecasting operating expenditure, as a measure of the change in scale of output.

We engaged Centre for International Economics (CIE) to develop independent customer number forecasts by customer type¹. Table 2 summarises their forecasts for the 2021–2026 regulatory period.

Table 2 Forecast customer number per customer type for the 2021–2026 regulatory period

	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	657,731	667,591	677,025	686,166	694,968
Non-residential	46,661	46,717	46,772	46,827	46,883
Low voltage	11,593	11,746	11,900	12,054	12,207
High voltage	100	100	100	100	100
Unmetered	10,239	10,614	10,989	11,364	11,739
Other	-	-	-	-	-
Other customers	726,323	736,767	746,785	756,510	765,896

Source: UE MOD 9.03 - CIE customer number forecasts - Jan2020 - Public

¹ Customer types are as per the Australian Energy Regulator's Economic Benchmarking Regulatory Information Notice template, 3.4 Operational data

2 Maximum demand forecasts

Our maximum demand forecast approach includes four key steps:

- develop top-down macro-economically-derived independent maximum demand forecasts at terminal stations (non-coincident) and at the United Energy boundary (coincident), including 'post-model' adjustments (e.g. block loads, embedded generation, energy efficiency etc.) from independent sources
- confirm the independent top-down forecast with United Energy's eViews regression and monte-carlo simulation maximum demand forecasting model to ensure accuracy of the independent forecast
- develop bottom-up spatially-derived maximum demand forecasts at each zone substation, based on recent historical growth of weather-adjusted demand, information about connections and disconnections (generation and load), and network topology changes
- reconcile and align the aggregated bottom-up zone substation forecasts (taking into account losses and diversity) with the top-down independent forecasts.

2.1 Top-down maximum demand forecasts at terminal stations and boundary

We engaged NIEIR to forecast both the non-coincident maximum electricity demand at the terminal stations and a coincident maximum electricity demand for the United Energy boundary area. The overall approach that NIEIR used for forecasting maximum electricity demand was consistent with the best practice methodology described by ACIL Allen in their 2013 report to the Australian Energy Market Operator (**AEMO**) for connection point forecasting.²

We summarise the NIEIR approach below. For a complete explanation of their approach, refer to attachment UE ATT022 - NIEIR - Maximum demand forecasts - Jul2018 - Public.

The NIEIR model is built around:

- a regression of historical demand to derive regression coefficients and elasticities for the various drivers of maximum demand growth;
- a 50-year sample of historical weather data used to generate synthetic weather profiles for a monte-carlo simulation, using 1,000 simulations per half hour period
- disruptor models (applied as post-model adjustments), in cases where history is not representative of future uptake or behaviour (e.g. a change in government policy or subsidy, or new technology).

NIEIR forecasts are based on statistical modelling that estimates the historic relationship between demand drivers; for example, the relationship between demand and electricity prices, population growth and economic growth, and the relationship of these drivers with temperature. The projected driver variables are then used to estimate demand based on the historical relationships. To ensure robustness of the modelling, each terminal station model incorporates at least ten years of our most recent historical data.

The key drivers of demand for electricity considered by NIEIR include:

- electricity price indices
- consumer price indices
- national gross domestic product

² UE ATT023 - ACIL Allen - Connection point forecast - Jun2013 - Public. This is a nationally consistent methodology for forecasting maximum electricity demand.

- gross state product (**GSP**)
- household disposable income
- population
- air-conditioning sales
- temperature.

2.1.1 Forecasting summer and winter maximum demand

Maximum demand occurs during the summer season for United Energy, however NIEIR develops both summer and winter top-down forecasts of maximum demand. NIEIR use 96 separate half-hourly models (48 each for summer and winter) to predict demand at different times of the day in each season. This allows for relationships between the temperature and calendar variables to vary throughout the day and between seasons.

As weather patterns cannot be accurately forecasted over the time horizon required, NIEIR simulated future weather, using historical weather data, to obtain predicted maximum demand for 1,000 summers and winters for each forecast year.

The results of the simulation give a distribution of maximum demand for each year of the forecast period. From the distribution of weather outcomes for a given year, NIEIR then predict maximum demand through Probability of Exceedance (**POE**) forecasts. These forecasts encompass:

- variations in economic, financial and industrial conditions
- current and forecast energy market conditions and pricing
- existing and proposed energy and environmental policy measures
- existing and likely technological developments
- developments in stock and usage of electrical appliances (in particular space conditioning equipment and lighting)
- variations in temperature patterns (after controlling for climate variations due to urban and global warming)
- random or stochastic variations in residential, commercial and industrial consumption.

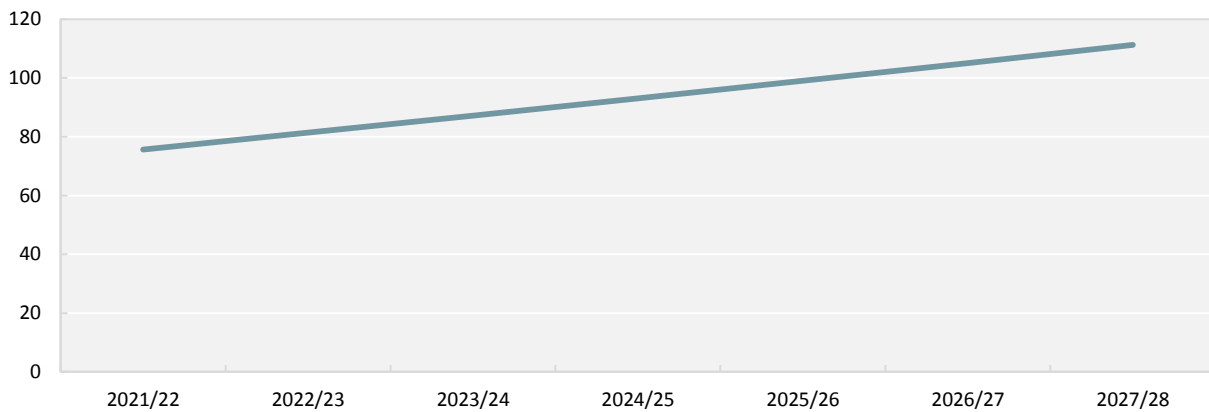
2.1.2 Post-model adjustments

The key disruptors of demand for electricity modelled by NIEIR as post-model adjustments include:

- solar photovoltaics
- battery storage
- energy efficiency
- demand response programs
- plug-in electric vehicles
- block loads.

The largest post-model adjustment for new technologies is the impact of solar PV on the network. However, this excludes estimates of solar PV resulting from the Victorian Government 'Solar Homes' policy, due to the timing of the announcement.

Figure 1 Post-modelling adjustment for solar PV generation on United Energy maximum demand, MW



Source: UE MOD 9.07 - Maximum demand forecasts - Jan2020 - Public

2.1.3 Comparison to AEMO terminal station maximum demand forecasting methodology

We sought NIEIR's independent forecasts, rather than using AEMO's 2018 terminal station connection point forecasts, for the following reasons:

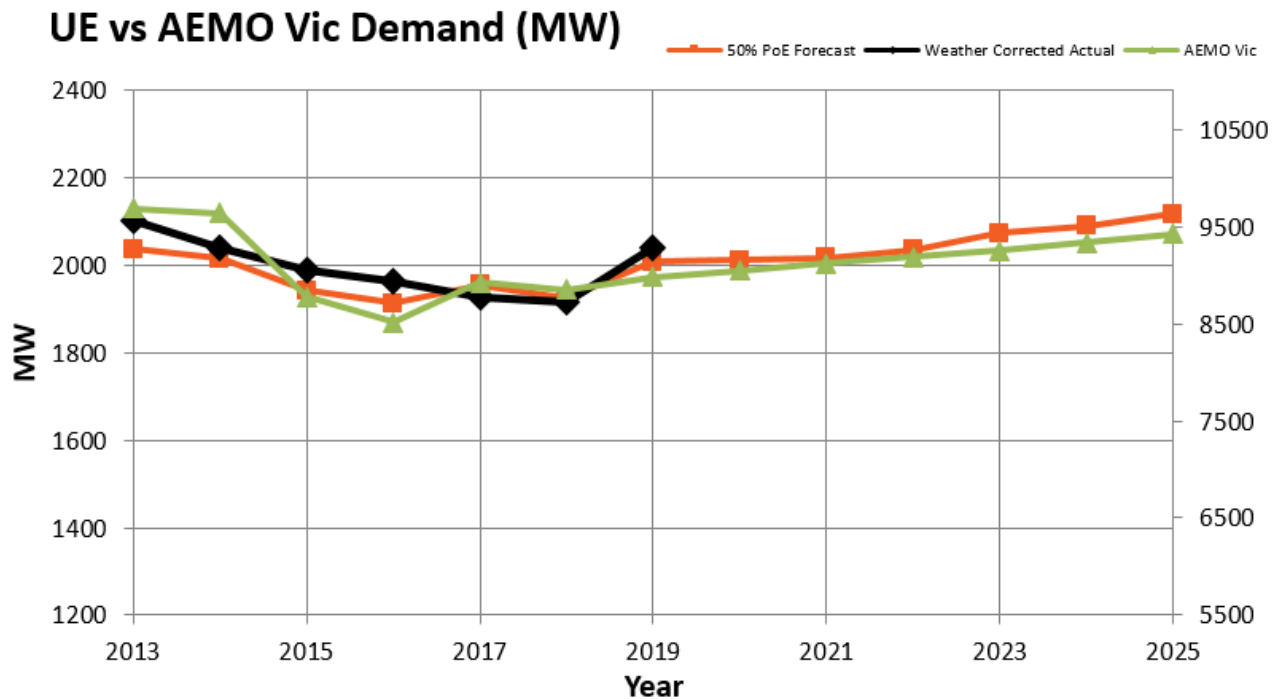
- NIEIR forecasts measure changes in drivers of electricity demand at each terminal station, allowing for any changes in drivers to be captured (e.g. areas where houses are replaced with apartment blocks)
- NIEIR forecasts use our actual data and our own mapping of customers to terminal stations, whereas AEMO's mapping of each network's assets to terminal stations differs. The AER has previously acknowledged and noted the range of differences in the datasets used by AEMO and has noted that the AEMO forecasts were not 'tailor-made' for each distributor.³

The main difference between NIEIR's and AEMO's forecasting approach is that NIEIR estimate demand based on forecast drivers across each terminal station, whereas AEMO's approach is to forecast demand based on observed trends in the data at a terminal station level, which is then reconciled to regional forecasts. In short, NIEIR's forecasts measure if there are changes in trends at each terminal station while AEMO's forecast assume historical trends at each terminal station are indicators of future trends at the same station. As demand patterns can change at each terminal station based on the demographic changes in those areas, we consider NIEIR's approach will more correctly capture those changes.

Figure 2 compares NIEIR's annual coincident maximum demand forecast for United Energy against the actual observed weather-adjusted demand and the AEMO forecast at 50% POE.

³ For example, see UE ATT199: AER, Draft decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure, November 2014, p. 6-90.

Figure 2 Total annual coincident maximum demand forecasts compared to AEMO's forecasts, United Energy



Source: NIEIR, Maximum demand forecasts for United Energy terminal stations to 2030 (MOD 9.07)

2.1.4 Top-down maximum demand forecasts

Table 3 indicates the final network level maximum demand for United Energy, as a sum of non-coincident maximum demand at each terminal station, and the coincident demand at the United Energy boundary.

Table 3 Maximum demand forecasts, coincident and non-coincident weather adjusted 50% POE

United Energy	2021/22	2022/23	2023/24	2024/25	2025/26
Coincident (boundary)	2,035	2,073	2,091	2,117	2,160
Non-coincident (terminal station)	2,116	2,156	2,174	2,202	2,247

Source: UE MOD 9.07 - Maximum demand forecasts - Jan2020 - Public

2.2 Bottom-up zone substation forecasts

We conduct bottom-up zone substation forecasts using an in-house forecasting method that relies on actual 30-minute data and trends observed at each zone substation, taking into account diversification factors. This gives us confidence that the differences between the zone substations at one terminal station are appropriately captured, while the summation of the zone substations aligns with the top-down independent forecasts for the terminal station, taking into account losses.

This ensures our zone substation forecasts reflect local drivers and are not simply an allocation of the terminal station econometric analysis forecast.

To ensure an accurate launch-point for forecasting further growth at each zone substation, the actual metered maximum demand data is weather-adjusted to ensure that weather effects are removed from the underlying growth, and any abnormal impact of day-of-week or public holidays are removed.

Growth rates are then derived for each zone substation based on recent historical growth in the weather-adjusted maximum demand, and adjusted for any changes in new connections or disconnections (load and generation) in the area, or any changes in network topology that results in a load transfer.

Before conducting the reconciliation of top-down and bottom-up forecasts, we review the top-down forecasts by using United Energy's eViews regression and monte-carlo simulation maximum demand forecasting model to ensure accuracy of the independent top-down forecast. When we achieve alignment between the two top-down forecasts, we adjust the bottom-up forecasts to align with the NIEIR top-down forecasts to ensure that all macro-economic and post-model adjustment impacts are reflected in the bottom-up forecasts.

3 Customer number forecasts

We engaged CIE to develop our customer number forecasts for 2019–2029 period. Figure 3 summarises CIE's approach to forecasting growth in each customer type, while Table 2 summarises customer number forecasts for the 2021–2026 regulatory period.

Figure 3 Forecast approach for each customer type

Tariff category	Forecast approach
Residential	Forecast using projected dwelling growth, adjusted in 2019 to reflect historically lower growth of customers than dwellings due to embedded networks. An adjustment is made in 2020 for the Government policy to ban new residential embedded networks
Non-residential	Continuation of historical time trend observed from 2006 through 2016, from most recent data point (2018) The final two years of historical data were excluded from the trend calculation because small commercial customers using more than 60MWh and less than 120MWh have been reclassified from non-residential customers not on demand tariff to low voltage demand tariff, resulting in a structural break in 2017
Low voltage	Continuation of historical time trend observed from 2006 through 2016, from most recent data point (2018) The final two years of historical data were excluded from the trend calculation because small commercial customers using more than 60MWh and less than 120MWh have been reclassified from non-residential customers not on demand tariff to low voltage demand tariff, resulting in a structural break in 2017
High voltage	Zero growth from most recent data point
Un-metered	Assumed to increase by 375 per year due to the installation of telecommunication infrastructure (e.g. roll out of the NBN the expected future transition from 4G to 5G network)
Other customers	Assumed to remain at zero

Source: UE ATT019 - CIE - Customer number forecast - Jun2019 - Public

For more information on their approach, refer to attachment UE ATT019 - CIE - Customer number forecast - Jun2019 - Public.