



AusNet Electricity Services Pty Ltd

Electricity Distribution Price Review 2022-26

Appendix 7B: Demand Forecasting Methodology

Submitted: 31 January 2020

PUBLIC



Demand Forecasting Methodology

Electricity Distribution Network

Document number	
Issue number	2.0
Status	DRAFT
Approver	
Date of approval	

Demand Forecasting Methodology – Electricity Distribution Network

ISSUE/AMENDMENT STATUS

Issue Number	Date	Description	Author	Approved by
1	03/08/2011	Creation	H de Beer L Russell D Postlethwaite	A Parker
1.1	03/07/2014	Updated for new process	L Russell	N Cimdins
1.2	20/04/2015	Minor revisions	L Russell	N Cimdins
2.0	13/09/2019	Major revision for new AMI data process	J Harding	

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1 Executive Summary

This document describes the process by which AusNet Services forecasts the spatial distribution of maximum demand which connected customers will place on its electricity distribution network. This forecasting process will produce best practice maximum demand forecasts featuring:

- Accuracy and a lack of bias;
- Transparency and repeatability;
- Incorporation of key drivers; and
- Validation and testing.

1.1 Obligations

The Electricity Distribution Code requires distributors to submit annual plans detailing how the predicted demand for electricity will be supplied at transmission network connection points, at zone substations and high voltage lines in the distribution network. These plans must contain historical demand and forecasts of demand.

The National Electricity Rules require a distribution network service provider to submit operating and capital expenditure forecasts necessary to meet or manage the expected demand for standard control services.

1.2 Use

AusNet Services' demand forecasts are based on the key premise that higher cumulative temperatures drive higher aggregate demand in summer-peaking network areas, and that lower cumulative temperatures drive higher aggregate demand in winter-peaking network areas. Customer characteristics and forecast customer number growth also drive demand forecasts. These figures are developed at the HV feeder, zone substation and terminal station levels.

The Australian Energy Regulator uses load demand forecasts to assess and define the future revenue requirements for distributors to meet the expected demand for services from connected customers. Load demand forecasts are also used in the annual development of distribution loss factors to enable an equitable allocation of network operating costs to connected customers.

1.3 Forecasting Process

The fundamental steps in the current forecasting process are:

- Extract historical customer numbers by asset type from internal database
- Develop spatial customer number forecasts based on government growth estimates;
- Extract historical demand data for asset type both from SCADA and smart meter data;
- Validate historical demand data for network configuration;
- Extract ambient temperature data and develop temperature metrics;
- Curate historical demand data to determine representative days;
- Correlate historical demand and ambient temperature metrics;
- Generate spatial demand forecasts for asset type at PoE10 and PoE50 levels; and
- Validate spatial demand forecasts.

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2 Purpose

This document describes the process by which AusNet Services forecasts the spatial distribution of maximum demand which connected customers will place on its electricity distribution network for the purposes of:

- Ensuring service standards are maintained;
- Planning augmentations to the distribution network;
- Planning augmentations to connections to the Victorian electricity transmission network; and

The methodology as presented in this document should provide readers with an easily accessible overview of the key steps undertaken, the systems and data used and the rationale for approaches adopted by AusNet Services.

3 Obligations

The Electricity Distribution Code¹ requires distributors such as AusNet Electricity Services Pty Ltd to submit an annual plan detailing how the predicted demand for electricity will be supplied:

- At transmission network connection points where the distribution network connects to the declared shared transmission network. This plan must contain historical and forecast demand for the following ten calendar years compared with the capacity of each transmission connection.
- By its distribution network, including subtransmission lines, zone substations and high voltage lines over the following five calendar years. This plan must contain historical and forecast demand compared with the capacity of each zone substation, an assessment of the impact of loss of load for each subtransmission line and zone substation and a description of feasible options for meeting forecast demand including opportunities for embedded generation and demand management.

The National Electricity Rules² require a distribution network service provider such as AusNet Electricity Services Pty Ltd to submit an operating expenditure forecast and a capital expenditure forecast for the relevant regulatory control period which is required to:

- meet or manage the expected demand for standard control services;
- comply with regulatory obligations or requirements associated with standard control services;
- maintain the quality, reliability and security of supply of standard control services; and
- maintain the reliability, safety and security of the distribution system.

¹ Electricity Distribution Code, Essential Services Commission Victoria.

² National Electricity Rules, Australian Energy Market Commission.

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4 Use of Forecasts

4.1 Network Planning

Annual load demand forecasts are the starting point for electricity distribution network planning studies which quantify the need for network augmentation to maintain the quality, reliability and security of supply to meet or to manage the expected demand for service from the network.

Figure 1 below, illustrates how demand forecasts are a critical input to the identification of network needs which is the first fundamental step in network planning.

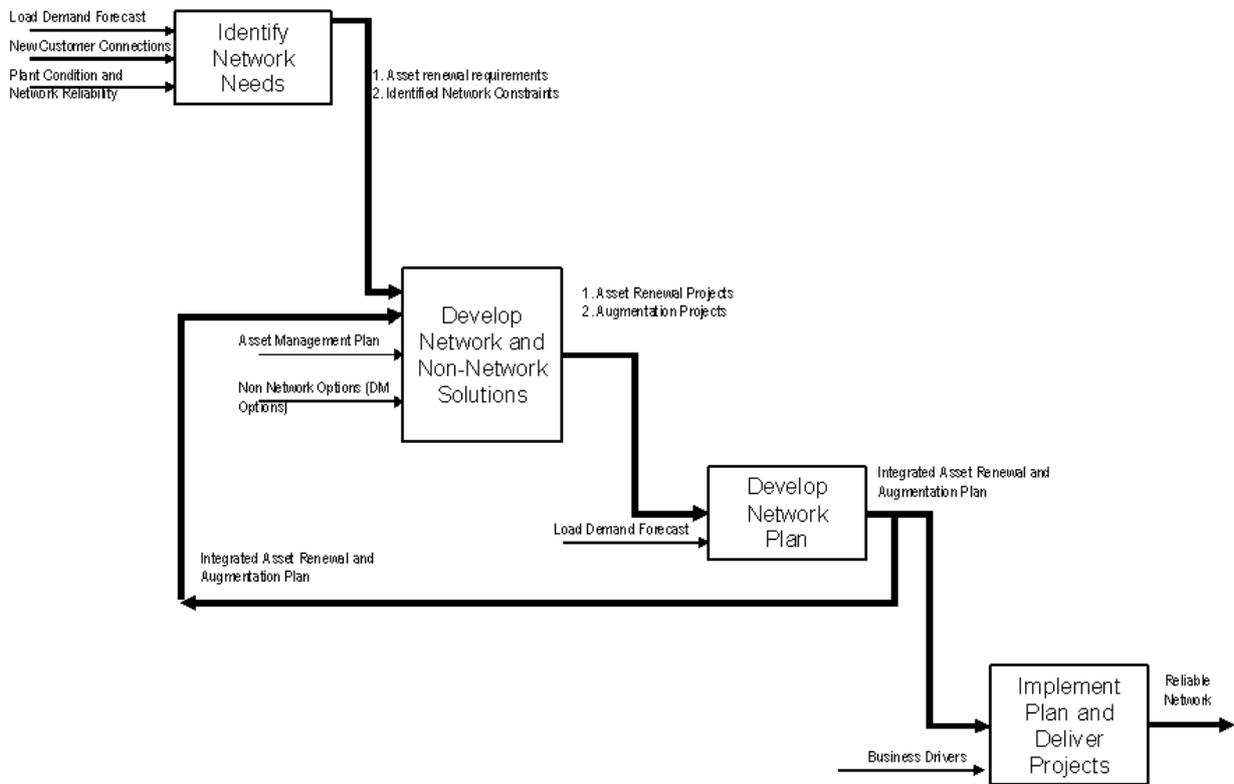


Figure 1: Demand Forecasts precede network planning process

4.2 Other Uses

The Australian Energy Regulator uses load demand forecasts to assess and define the future revenue requirements for distributors to meet or manage the expected demand for service from connected customers.

Load demand forecasts are also used in the annual development of distribution loss factors to enable an equitable allocation of network operating costs to connected customers.

Less obvious is the use which other industry participants make of demand forecasts. The Australian Energy Market Operator aggregates the demand forecasts made by distributors to plan the technical capability and manage the equitable distribution of operating costs associated with the interconnected national electricity transmission network by:

- Calculating inter-regional loss factors and intra-regional loss factors;

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- Administration of PASA and operational planning, assessing network adequacy;
- Central generation dispatch;
- Statement of Opportunities;
- National Transmission Development Plan and the Victorian Annual Planning Report;
- Regulatory Investment Tests;
- Demand Side Management;
- Power Factor obligations under automatic access standard;
- Load shedding facilities; and
- Demand management incentive schemes.

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5 Demand Forecasts

5.1 Overview

In summary, demand forecasts are prepared by analysing actual network demand and AMI energy interval data. Customer growth forecasts are mapped to zone substations and apportioned at feeder level. These operational data sets are then subjected to detailed analytical modelling techniques and trended forward for predicting future maximum loading. The applied analytical modelling considers: customer classes, energy profiles and weather regions. Segmentation by build year is used when predicting demand for future residential dwellings.

A bottom-up approach to maximum demand is then derived using the cumulative thermal effect described by the Cooling Degree Day (CDD) of Heating Degree Day (HDD) calculation which depicts a positive relationship between demand and temperature. Finally, this output is then adjusted by a delta factor that represents losses and unmetered loads to account for the difference between historical, actual network and AMI interval data.

Ten-year demand forecasts are prepared for 66kV/22kV zone substations and 22kV feeders each year. They are prepared for 10% Probability of Exceedance (POE) and 50% POE to reflect the temperature sensitivity of load demand. The following inputs are incorporated:

- Load demand growth information of future economic trends in the relevant area, including information from government agencies regarding identified growth areas and long term development plans;
- Actual maximum demands for the most recent 12 months;
- Daily maximum demands for the past 3 to 5 years for the summer and winter periods are weather normalised for establish relationship between demand and temperature;
- Recent load growth trends over the previous 5 year period;
- Any known specific new loads expected on the network.

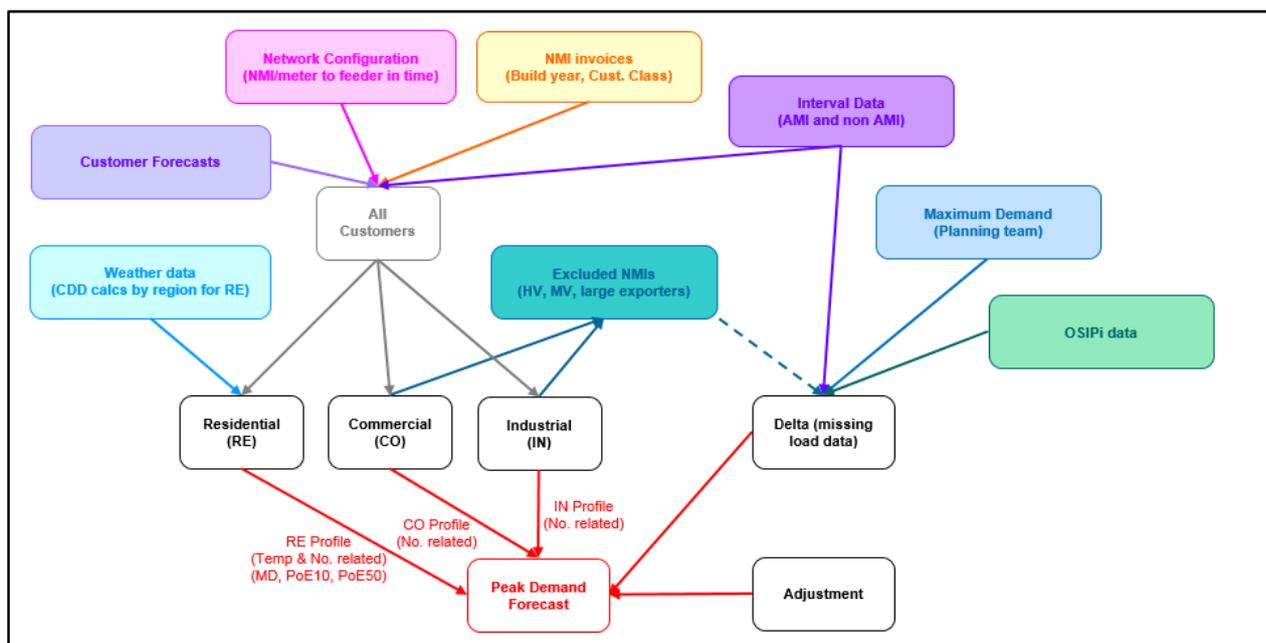
The load demand forecasts provide recorded maximum demands for each of the previous five summers and winters and include a megawatt (MW) forecast for each summer and winter period for the next 10 years.

Terminal Stations forecasts are currently taken from AEMO and are cross-checked against the bottom-up zone substation forecasts to ensure consistency in growth rates and reasonable agreement of magnitude.

Figure 2: Flow chart of data sources Figure 2 maps out the various data sources that feed into the demand forecasting methodology.

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Figure 2: Flow chart of data sources used in the demand forecasting methodology



5.2 Process Summary

This section sets out an overview of the demand forecasting methodology. More detail on each step in the process is included in section 6.

The fundamental steps in the current spatial and trend analysis forecasting process are:

- Extract historical customer numbers;
- Create spatial customer forecasts based government growth estimates;
- Extract historical demand data for asset type and validate data for network configuration;
- Extract ambient temperature data and generate temperature metrics;
- Curate historical demand data to determine representative days;
- Correlate historical demand and ambient temperature metrics;
- Generate spatial demand forecasts for asset type; and
- Validate spatial demand forecasts.

5.2.1 Extract historical customer numbers

Historic customer numbers and growth rates are a major driver of future demand and in particular spatial demand forecasts. Customer numbers are extracted by asset type and customer type from the tariff database and spatial asset database to provide both a launch point for the forecasts and a trend on which to inform projections over the forecast period.

5.2.2 Create customer forecasts based on trend and Victorian government growth estimates

Customer number forecasts are compiled by having reference to both the historical trend in customer growth and the Victorian government's projections of structured private dwellings (SPD) in the Victoria in

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Future (VIF) planning publication.³ Where there is evidence that the VIF forecast growth rates are not reflective of actual growth, more weight may be given to historical trends and local knowledge of customer connection inquiry volumes.

5.2.3 Extract historical demand data

Demand data is extracted at several levels. Half hourly customer consumption data is sourced from an interval meter database. Demand on various network elements (such as feeders and zone substations) is sourced from OSI-Pi that records Supervisory Control and Data Acquisition (SCADA) sensor data. These data are then cleansed of any abnormal readings (which can arise from data errors or temporary changes to network configuration) and corrected to account for known embedded generation. The resultant dataset is used as the basis for estimating the demand per customer which is a key element of the forecast.

5.2.4 Extract ambient temperature data and calculate Cooling and Heating Degree Days

Ambient temperature data relevant to each feeder and zone substation is also extracted from OSI-Pi (populated by BOM data) in a similar manner to the extract process for demand data and is validated via comparison to backup weather station data. Three primary BOM weather stations are used to represent the three major geographical network areas of North, Central and East. Temperature data is used to calculate Cooling Degree Days (CDDs) and Heating Degree Days (HDDs) which are in turn used to produce forecasts at probability of exceedance levels of 50% (PoE50) and 10% (PoE10).

The CDD is calculated as the average temperature excursion above 21degC across a day, and the HDD is calculated as the average temperature deficit below 18degC across a day. The CDD is calculated as both a CDD across a single day (CDD1) and across two days (CDD2) to reflect that cooling demand can in some cases be driven by the cumulative heat absorption of buildings across multiple days.

5.2.5 Curate historical demand data to determine representative days

Demand can be affected by a number of non-thermal impacts such as public holidays, event days, school holidays, weekends, public announcements related to energy conservation and weather conditions that cause abnormal patterns of solar PV production. For each asset subject to demand forecasts, the observed maximum demand days are compared to CDD values to identify outliers that may warrant being excluded, and to develop a curated set of data that is representative of the relation between maximum demand and CDD for the asset in question. This process relies on subject matter expertise to identify abnormalities and select the curated data set.

5.2.6 Correlate historical demand and temperature

Unitised maximum demands from residential customers have been found to correlate best to a combination of CDD1 and CDD2, rather than to just CDD1 or to maximum temperature. For each asset in question, a customised temperature metric equation is developed that combines CDD1 and CDD2 in such a way to maximise the degree of correlation between the temperature metric and unitised maximum demand. Calculating the maximum CDD1 and CDD2 for each of the historical years of temperature data means the PoE50 and PoE10 years can be determined. Average demand per residential customer is then able to be produced for PoE50 and PoE10 conditions.

For non-residential customers there is no observed relationship between CDD and demand give the different responses of different types of businesses to hot weather. Therefore no temperature effects are included for non-residential customers.

³ <https://www.planning.vic.gov.au/land-use-and-population-research/victoria-in-future>

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5.2.7 Generate spatial demand forecasts

The residential customer unitised maximum demand for PoE50 and PoE10 conditions are then multiplied by the customer number forecast to derive the total customer demand on the asset in question. The build year of dwellings is also factored into this process via a matrix that sets out the unitised demand for dwellings of a particular build-year. A delta offset to capture losses and unmetered loads is also re-applied.

This process is undertaken by automated toolsets in order to provide a consistent outcome across the network and reduce manual processing.

5.2.8 Validate spatial demand forecasts

Regional network planning engineers in conjunction with the subtransmission planning engineer validate the relevant forecasts. Validation involves magnitude checks and trend line checks informed by knowledge of the loadings and network configuration changes recently completed and pending. Adjustments may be undertaken to improve the accuracy of the forecast by addressing factors such as:

- Large customers that are known to have connected recently or will connect in the near term
- Impact of known network projects that have recently been undertaken or are in train such as feeder reconfigurations
- Inconsistencies in AMI data that lead to offsets in the final forecast

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6 Detailed Process

6.1 Extract historical customer numbers

Current customer numbers are extracted from the customer tariff database and spatial asset database, in order to cross-reference each customer's billing status with their location. The key customer attributes which are relevant for the forecast include:

- The customer's classification, i.e. residential, commercial, or industrial, classified according to their tariff type.
- The feeder and zone substation supplying the customer. Network configurations can change over time, or on certain days (e.g. a customer can be supplied by Feeder X on one day, but Feeder Y on another). These changes are accounted for by taking a historical annual snapshot of the customers assigned to the network asset at the time of maximum demand.
- Whether the customer has rooftop solar PV installed.

Once the customer data is extracted, the customers are grouped into the three classifications (residential, commercial, industrial), by the relevant network element (e.g. feeder or zone substation). This serves two purposes:

- Firstly, it establishes the trend of growth (or decline) of the various types of customers on the network element
- Secondly, it establishes the starting point for the forecast.

Once this trend and starting point have been established, the forecasting process can commence.

6.2 Create customer number forecasts

Demand forecasts require a forecast of the number of customers at various levels. The lowest level currently required for distribution demand forecasting is the feeder. Because feeders are supplied by discrete zone substations customers numbers can be rolled up or down depending on the network element being forecast. Zone substations are connected to terminal stations (transmission connection points) via a subtransmission network that may be arranged in a loop. Therefore, customer numbers on a zone substation may not be assigned discretely to a specific terminal station as their load is often shared between more than one terminal station.

6.2.1 Residential customers

AusNet Services begins with an independent assessment of the projected growth in customers over the forecast horizon. The independent forecast used by AusNet Services is the Victorian Government's *Victoria in Future* (VIF) publication. The VIF report provides five-yearly snapshot forecasts of population and dwelling numbers for regions defined as *Victoria in Future Small Areas* (VIFSA). VIFSA regions are smaller than Local Government Areas (LGAs), often around half the size. Since the vast majority of dwellings are connected to the electricity networks, these dwelling projections can be used as a starting point for the growth in residential electricity customers.

The VIFSA level forecasts can be approximately mapped to zone substation regions and then up and down to feeders and terminal stations. For example, if Zone Substation A supplies all customers in VIFSA 1, 50% of customers in VIFSA2 and 30% of customers in VIFSA 3, the projected growth in dwellings in those three VIFSA can be adopted as a forecast for the growth in the number of residential customers connected to the zone substation, with the respective apportionment.

Below the zone substation level, feeders are also apportioned to the nearest VIFSA (or multiple VIFSAs) in order to derive forecast customer numbers. Particularly in growth corridors it needs to be assumed that feeders are extended over time with a consistent spread of geographic capture of each relevant VIFSA. As the feeder is extended over time, decisions by network planners and design engineers on which customers

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are to be served by which feeder will take into account the forecasts, and the final feeder design will be captured in the next round of forecasting subsequent to the feeder extension project.

This approach is considered adequate where the VIF projections are shown to be accurate. Where there is evidence of VIF projections not reflecting actual growth,⁴ the VIF forecasts are adjusted to reflect AusNet Services' own view of the likely growth, based on recent trends and an assessment of local conditions (for instance, by utilising the knowledge of network planners responsible for particular regions, or other sources such as specific connection inquiries and information made available by housing developers and industry bodies).

6.2.2 Non-residential customers

The above process for residential customers is not able to be replicated for non-residential customers, because VIF does not produce forecasts for the growth in the number of commercial or industrial businesses.

As such, estimating future commercial/industrial customer movements is less certain than residential forecasts, as there is a lack of dependable sources of data on which to base the forecast, and they represent a much smaller proportion of customer numbers. The technique used by AusNet Services is to apply the relationship between the respective ZSS/feeder residential customer make-up, and the established commercial/industry on each feeder, and to linearly project this relationship forward based on the residential customer number forecast.

This approach reflects the typical situation where Local Government town planning parameters are consistent within the geographic coverage of a feeder, such as the land allowed for commercial customers within a residential development area. This results in a relatively stable and smooth outworking of the residential to commercial customer ratio.

As an example, Figure 3 shows the proportion of commercial to residential customers on the Clyde North zone substation. The growth rate in commercial customers in the past two years has dropped and is projected to continue to drop but at a slower rate.

Figure 3 Residential to Commercial customer number ratio



This approach to forecasting non-residential customer growth has been accepted by the Australian Energy Regulator (AER) in previous price determinations, including the 2016-20 Electricity Distribution Price Review and the 2018-22 Gas Access Arrangements Review.

A moderator to this is the available general trend data around commercial and industrial movements. Larger commercials and industrial customers require special consideration and this tends to result in manual interventions. Where local knowledge is available for upcoming commercial and industrial customer connections or disconnections, manual adjustments may also be made.

⁴ For example, as noted here: <https://www.theaustralian.com.au/nation/politics/melbourne-population-predictions-blown-away-by-the-boom/news-story/11bcd68da07eb1e8238b4a11be3c36e> (accessed 2 Aug 2019)

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6.2.3 Finalising the customer number forecasts

Once the customer forecasts for the various network elements have been developed, they are reviewed against historical growth rates as a top-down check that the forecast growth rates are consistent with the trend for the specific network element. For example, if a feeder is showing signs of an initial ramp up in growth rates, the forecast will be reviewed to ensure that the growth over the short to medium term (and into the long term) is reflective of this stage of the feeder's growth cycle.

At the end of the process, AusNet Services has a customer number forecast for each network element that requires a forecast of demand. Since the demand on the network is a function of the number of customers and the demand per customer, the next step is to establish the existing demand per customer.

6.3 Extract historical demand data

In order to obtain an informed understanding of the existing demand on the network, AusNet Services extracts demand data from a number of sources.

Interval data (kWh of consumption) from both AMI and non AMI meters is collected in half hourly intervals. This data is then aggregated into customer tariff classifications and network elements so that the demand can be applied to the customer forecasts described above. In addition, demand data is sourced from SCADA sensors or a series of sensors at each connection point that AusNet Services' forecasts.

Data collection at both the customer (interval meter) and network (SCADA) level allows AusNet Services to drill into a fine degree of detail, whilst ensuring that the overall demand on the network element is captured and compared to the consumption recorded at the customer level. The two data sets are reconciled by comparing the peak demand of each set and quantifying the difference. The difference between interval and SCADA values is made up of system losses, unmetered supplies and certain types of customers (e.g. high voltage customers), and is compensated through application of a fixed offset adjustment (referred to as a "delta") when the forecast is developed.

Because the forecasts are primarily bottom-up utilising individual customer metered consumption data that is measured in kWh, forecasts are developed in MW rather than MVA for both feeders and zone substations. Network Planning engineers then apply the relevant power factor parameters for each network element in order to determine loadings in Amps for feeders and MVA for zone substations.

Because this combination of historical data is used as the basis for forecasting maximum demand, it is imperative that the data excludes any values which are not reflective of the true underlying demand on the network element. This can come about, for example, when the network is temporarily reconfigured and one feeder is supplying load to customers which it would not ordinarily supply, or if embedded generators are offsetting the load on a feeder. Data errors with the telemetry or storing of meter data can also occur. These data points, and if severe enough the entire day of data will be excluded from the analysis.

Data is cleansed in the following ways:

- **Planned temporary feeder reconfiguration:** Where a feeder has been planned to be reconfigured on a peak demand day by Network Planning Engineers, a correction should have already been applied to the data provided to the forecasting team. If this process has been missed, and a step-change in the SCADA data is observed during the selected peak demand day, a correction is applied to the data to remove the step change and create a synthesised data segment for the period of reconfiguration.
- **Unplanned operational feeder reconfigurations:** The network operations control centre may apply unplanned reconfigurations as part of the real time operation of the network. These reconfigurations will show up in the SCADA data as a step-change in loading, with subsequent reversal. As above, a correction is applied to the data to remove the step change and create a synthesised data segment for the period of reconfiguration.
- **Large embedded generation:** The impact of large embedded generation (i.e., excluding generation that is installed behind the meter of load customers such as rooftop solar) is removed from the SCADA data trace. Synthesised data is created by adding the generation exports back onto the SCADA values. A register of embedded generation is used to undertake this process, and any generators that are missing from the register are identified through the process of comparing AMI interval data to SCADA data.

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- **Missing data:** A delta adjustment is added to accommodate for losses and unaccounted load. When there is missing AMI data, a different day is chosen.

AusNet Services also extracts the creation date of each customer's National Meter Identifier (NMI) as a proxy for the year that construction of the house started. This information is used to determine the impact of build year on demand (e.g. to detect if newer houses have a different demand than older houses).

Demand data for each network element being forecast is then "unitised" or averaged by dividing the total demand for a customer class by the number of customers in that class.

Once the data has been collected, aggregated, cleansed and unitised, it is used as a key input to AusNet Services' demand forecasting algorithm. The next key input is weather conditions.

6.4 Extract temperature data and calculate Cooling and Heating Degree Days

Time series temperature data is accessed from three Bureau of Meteorology weather stations representing the three major geographical areas within AusNet Services' network. The geographical areas and corresponding weather stations are:

- **Central:** Scoresby Weather station (86104), back-up Moorabbin weather station (86077)
- **East:** East Sale (85072), back-up Bairnsdale Airport Weather station (85279)
- **North:** Wangaratta Weather station (82138), back-up Benalla (82170).

The average temperature observed at these weather stations is then converted into Cooling Degree Days (CDDs) and Heating Degree Days (HDDs) across time intervals of both one day (to reflect single extreme days) and two days (to reflect build-up of thermal demand across multiple extreme days) in accordance with the following formulae:

- $CDD = \max(0, \text{Average daily temp} - CT_{sum})$
- $HDD = \max(0, CT_{win} - \text{Average daily temp})$

Where $CT_{sum} = 21\text{ }^{\circ}\text{C}$ and $CT_{win} = 18\text{ }^{\circ}\text{C}$

The parameters of CT_{sum} and CT_{win} are standard industry values applied in Australia for heating, ventilation and cooling design applications.

AusNet Services calculates CDDs and HDDs to determine the relationship between temperature and demand for summer peaking and winter peaking network segments respectively. This is the next step in the process.

6.5 Curate historical demand data to determine representative days

Demand can be affected by a number of non-thermal impacts such as public holidays, event days, school holidays, weekends, public announcements related to energy conservation and weather conditions that cause abnormal patterns of solar PV production. For each asset subject to demand forecasts, the observed maximum demand days are compared to CDD values to identify outliers that may warrant being excluded, and to develop a curated set of data that is representative of the relation between maximum demand and CDD for the asset in question.

This process relies on subject matter expertise to identify abnormalities and select the curated data set. Abnormalities can include:

- Hot water related peaks (at night)
- Evidence of large non-thermally driven loads such as caused by public event
- Temporary Load transfer between feeders
- Network outages/ Load shedding events
- Instances where large customers are included/not included temporarily
- CPD tariff event days

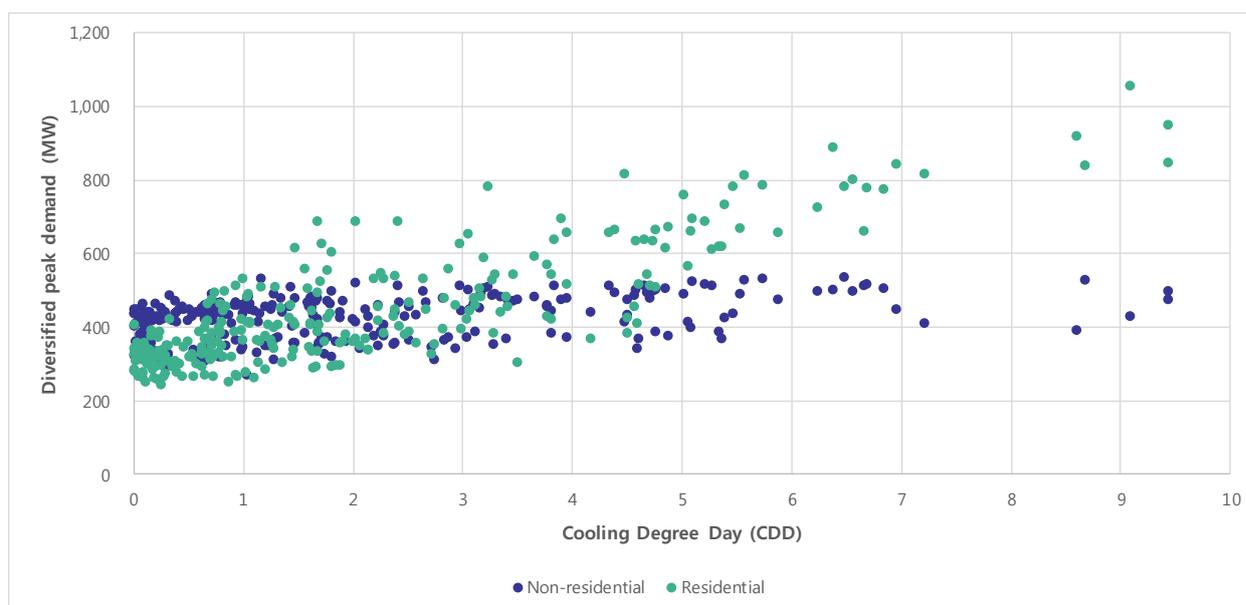
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6.6 Correlate historical demand and temperature

Temperature is one of the key drivers of maximum demand. The examples provided in the following sections focus on summer peaking rather than winter peaking network elements, given that most of AusNet Services' feeders are heavily weighted towards residential customers who drive summer peak demand in the early evening when air conditioners are being used on hot days.

The relationship between temperature and peak demand for non-residential customers is significantly weaker than it is for residential customers and is not uniform. Some types of commercial customers may increase demand on hot days (where cooling loads increase) whereas other types will reduce demand (where production is shut down or operations scaled back under high temperatures) Figure 4 plots the aggregated demand by customer type at 1700 AET for each day between 1 Jan 2017 – 31 Dec 2018, against the CDD on the relevant day, where the CDD was greater than zero. Whilst the baseload for non-residential customers is higher (that is, the demand at low CDD levels), the demand sensitivity to CDD is strong for the residential customer group and is weak for the non-residential group, flattening to zero at higher CDDs that would be associated with maximum network peak demand.

Figure 4: AusNet Services distribution diversified peak demand at 1700 AET v. CDD



Due to the evidence of a weak relationship between temperature and non-residential demand that flattens to zero gradient at high CDDs, AusNet Services only applies a demand-temperature correlation to the residential component of demand when determining POE levels.

The above chart is a simplified illustration of the relationship between temperature and demand for different customer segments. When preparing demand forecasts, the process is more complex. To account for the relationship between customer demand and both a single extreme heat day as well as latent heat build-up across multiple days, both the single day CDD (referred to as CDD1) and the 2 day cumulative CDD (referred to as CDD2) are used.

The correlation process involves for each network element:

- Generating a unitised residential demand by dividing total demand by customer numbers
- Generating a logarithmic fit between unitised demand and CDD1
- Extracting the error values between the logarithmic fit and the unitised demand
- Generating a logarithmic fit between the error values and CDD2

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These two logarithmic equations shown in Figures 5 and 6 define the relationship between unitised demand and temperature and are used to generate the actual forecast (POE10 and POE50) of maximum demand for that network element according to the formula:

$$\text{Demand (CDD1,CDD2)} = \text{Log curve 1(CDD1)} + \text{Log curve 2(CDD2)}$$

Figure 5: Unitised demand vs CDD1 (Residential)

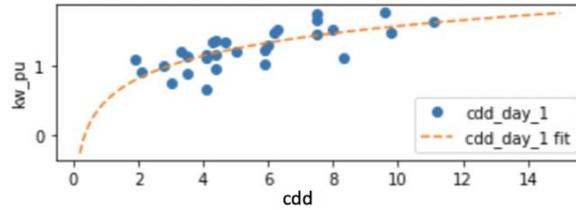


Figure 6: Error of (Unitised demand vs CDD1) vs CDD2 (Residential)

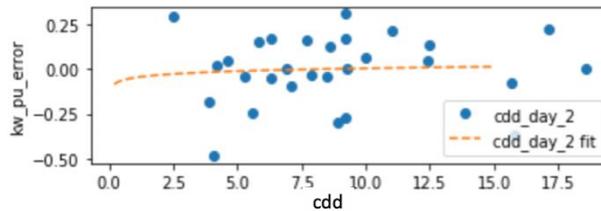


Figure 5 shows a series of data points of hot days (from most recent summer period). It shows the unitised demand (average kW per customer) of residential customers on CRE21 feeder graphed against the CDD1 value for that day. There is a logarithmic trend line fitted to this series.

Figure 6 is the error (distance from trend line) of the unitised values from Figure 5 graphed against CDD2 values.

A scaling factor is calculated when the unitised value (kW) of a PoE(X) year is substituted into the algorithm and compared with the unitised value (kW) for the most recent summer. For example:

$$\text{Scaling Factor} = \frac{F(x)PoEX}{F(x)MD_{actual}}$$

The scaling factors allow that an observed maximum demand value can be converted into equivalent PoE10 and PoE50 maximum demand values.

A different set of curves is generated for each feeder/zone substation.

Once the demand data has been extracted and the correlation with temperature has been developed, it is then time to prepare the spatial forecasts.

6.7 Generate spatial demand forecasts

AusNet Services produces its spatial demand forecasts by running its in-house forecasting algorithm on the data it has gathered. The main stages include:

- Selecting the PoE50 and PoE10 values for annual maximum CDD or HDD applicable to each network element
- Scaling the curated day unitised maximum demand to P50 and P10 levels
- Factoring in the “year of construction” of dwellings
- Multiplying the unitised demand forecasts by the customer number forecast
- Adding the “delta” value that represents the offset between AMI data and SCADA data

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6.7.1 Algorithm first stage: Selecting the P50 and P10 values

For each of the three planning regions, the highest CDD1 is obtained for each summer season across the past 11 years and ranked. The highest value is classified as representing a PoE10 year, and the central value (6th) is classified as representing a PoE50 year.

For each network element being forecast, the unitised demand value for the PoE50 and PoE10 CDDs are looked up according to the correlations in Section 6.6, and used to generate scaling factors between the observed maximum demand from the most recent summer period and the PoE50 and PoE10 demand.

6.7.2 Algorithm second stage: Scaling the curated day unitised day unitised maximum demand

The result once running the algorithm for the MD and POE10/POE50 is used to determine the scaling factor. The scaling factor is calculated using the equation in section 6.6.

The scaling factor is multiplied by the forecast maximum demand to predict future POE10 and POE50 demands.

6.7.3 Algorithm third stage: Factoring in the “year of construction”

The unitised maximum demand of residential customers has changed over the years according to changing construction standards. This means that houses built in different years have different levels of demand – e.g. houses built in 2018 use less power on average than houses built in 2015 as they have been constructed to a higher thermal efficiency and may have utilised more efficient appliances. Different unitised values are assigned to the houses built in the specified years. The unitised values are based on observed data across the growth areas of our network and are developed individually for each feeder.

Table 1: Residential Build Year impact on Unitised Demand

Forecast Year ↓	Build Year/Year of construction →					
	2016	2017	2018	2019	2020	2021
2019	1.76	1.71	1.68	1.15	0.00	0.00
2020	1.76	1.71	1.68	1.67	1.15	0.00
2021	1.76	1.71	1.68	1.67	1.67	1.15
2022	1.76	1.71	1.68	1.67	1.67	1.67
2023	1.76	1.71	1.68	1.67	1.67	1.67

Table 1 is an example of unitised energy usage of the residential customer type (in kw/customer). The year being forecasted is shown on the left. The construction year of houses are across the top. The table shows that if a house is built in 2016, its unitised usage will remain the same in the future (moving down the table). This is the same for years 2017 and 2018. 2019 has abnormally low usage as houses built this year are not fully built which is why the average usage per customer appears very low. An appropriate number has been substituted when forecast forward for houses being built now and in the future.

6.7.4 Algorithm fourth stage: Multiply the unitised demand by customer number forecast

The above unitised demand is then multiplied by the customer forecast. This will return the total amount of consumption on the feeder/zone substation as the unitised demand and the customer forecast is customer type specific.

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6.7.5 Algorithm fifth stage: Adding the “delta” value

As there is a difference between the SCADA data coming in from OSIPi and interval data, the delta value must be added back into the maximum demand POE10 and POE50 forecast numbers to account for this difference. This delta value accounts for losses, unmetered loads and excluded customers such as MV/HV/public lighting customers.

At the conclusion of this process, AusNet Services has preliminary demand forecasts for the various network elements it requires. However, in certain circumstances there are factors that may influence the forecast which are not present in the forecasting algorithm. These factors are identified and addressed via the validation stage.

6.8 Validate spatial demand forecasts

The outputs of each forecast are then checked both by the forecaster and by the network planners of each region for consistency with history, knowledge of future plans, and any other information which might result in a more accurate forecast. Where appropriate adjustments may be made to the forecast which include:

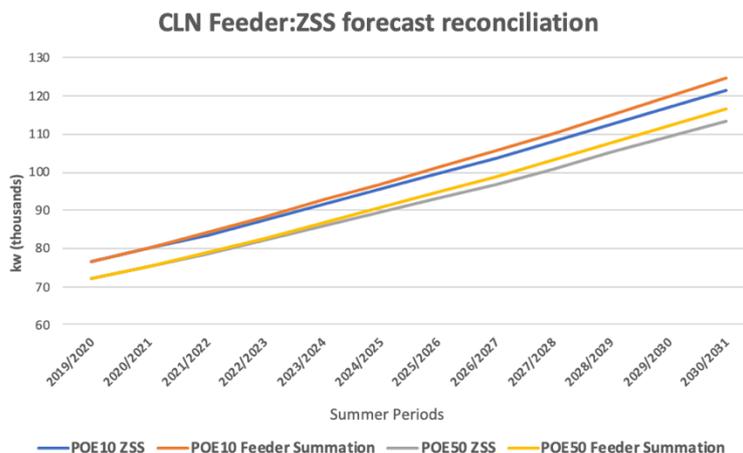
- Expected major load changes (e.g. new factory, shopping centre, etc.):
 - Where the major load exceeds 5% of current load.
 - Where the major load exceeds growth forecast.
- Load transfers to other feeders or stations.
- Expected improvement in reactive flow due to capacitor installations (both station and pole mounted capacitors).
- Planned addition of new zone substations and feeders:

6.8.1 Top-down v. bottom-up reconciliation

By using the same AMI data in a bottom-up build of forecasts for both feeders and zone substations, the forecasts are inherently consistent between feeders and zone substations. As such, a rigorous reconciliation process is not required, however a sample of forecasts is manually reconciled for completeness.

Manual reconciliation verifies that the sum of the feeder maximum demand forecasts for a particular zone substation align to the forecast maximum demand of the zone substation. A difference between the two values is expected due to the fact that feeder peak demand times will never perfectly coincide with one another. Visualising the degree of coincidence is sufficient to verify the alignment of the forecasts between feeders and zone substations.

Figure 7: Feeder to Zone Substation Reconciliation



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Figure 7 depicts the summation of Clyde North feeder forecasts compared to the Zone Substation level forecast. Coincidence is very high initially and gradually reduces over time, remaining within a few percentage points of each other.

7 Forecast Outputs

During the forecasting process draft forecasts are stored in a working folder located at:

- NSD on cbdshare\Smart Networks\09 Planning\10 Output\01 Demand Forecast

Network planners can view, review and provide input to draft forecasts in the working folder.

Once forecasts are finalised and validated, certificates are generated to endorse the forecasts for use in network planning processes.

The forecasting process leader is responsible for archiving endorsed forecasts and historic forecasts.

8 Planned methodology improvements

AusNet Services adopts a continuous improvement model to the demand forecasting methodology in order to progressively improve the forecasts and respond to changing parameters such as the impact of new technologies and the availability of new data sets.

The improvements that are planned to be incorporated over the next few years include:

- Less manual, more automated processing
- Faster data curation processing
- More efficient process for collection of MD dates, times and other information from Network Planners
- Incorporate distributed energy resource uptake into forecasts i.e. EV, solar, battery contributions
- Develop and implement a method of forecasting minimum demand in addition to maximum demand