PowerWater

Maximum Demand And Customer Connections Forecasting Procedure

Power and Water Corporation Procedure

CONTROLLED DOCUMENT

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IMPORTANT NOTICE

Purpose

AEMO has prepared this document on behalf of PWC Power Networks to provide information about the methodology, data and assumptions used for forecasting maximum demand (MD) and customer connections for the three networks in Darwin-Katherine, Tennant Creek and Alice Springs, as at the date of publication.

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1 Purpose

This procedure documents PWC Power Networks' method for forecasting maximum demand (MD) and customer connections for the three networks in Darwin-Katherine, Tennant Creek and Alice Springs. The forecasts underpin network planning studies, capital and operating expenditure programs as well as regulatory information notice (RIN) fulfilment.

2 Scope

The procedure documents the forecasting process for customer connections, annual consumption and MD as outlined in Table 1.

Table 1 Scope of forecasts

Forecast	Outlook period	Scope	Primary forecast outputs
Customer connections forecast	10 years	The number of customers connected to the 3 regulated networks. This forecast supports the regional energy consumption forecast.	Number of connections at financial year ending, for each of the three regulated networks.
Regional energy consumption forecast	10 years	This forecast incorporates regional-level drivers for projecting future energy consumption. This forecast drives the regional MD forecast.	Energy consumption in GWh on a financial year basis for each of the three regulated networks.
Regional MD forecast	10 years	MD forecast for Darwin-Katherine, Tennant Creek and Alice Springs, using annual consumption forecast information. MD for the combined systems will also be calculated.	Historical actual MD and weather-corrected MD for historical and forecast years in MW. Weather corrected MD is calculated for 50% and 10% probability of exceedance (POE).
Zone substation (ZSS) MD forecast	10 years	All zone substations and modular substations. These forecasts are reconciled to the regional MD forecast.	Historical actual MD and weather-corrected MD for historical and forecast years in MW and MVA. Weather corrected MD is calculated for 50% and 10% POE.
High Voltage feeder MD forecast	5 years	MD on 22 and 11kV feeders. These forecasts screened for agreement with the zone substation MD forecast.	Historical actual MD and forecast MD in amps.

3 Data and information

The data and information required to prepare the forecasts is detailed in this section.

3.1 Data requirements

Table 2 describes the internally-sourced data used in developing the forecasts. Externally sourced data is described in Table 3.

Table 2 Internally-sourced data

Category	Description
Embedded generators	Generators in the distribution network (downstream of the zone substations). Effects of embedded generation may be removed during forecasting to better capture customer demand. A size threshold of >1MW is applied.
Outage information, load transfers and shedding or curtailment events	This is usually in the form of high-voltage feeder analysis (zone substation SCADA data) and is combined into the historical load datasets. The data assists in identifying atypical network operation and can be inspected to detect load shedding and transfer events.
Historical Load	Half-hourly historical load or generation data for building forecasting models: - MW at regional-level (scheduled generation from generator connection points) - MVA , MVAR and MW loads at substations, switching stations and transmission terminal stations - MVA loads high-voltage feeders - Embedded generation (MW) where the generator is separately metered at half-hourly resolution. - Half-hourly industrial load historical data (MW)
Losses	Information on losses between generator and zone substation.
SLDs	Single Line Diagrams support forecaster understanding of the networks.
Industrial Facilities	To link industrial and commercial loads to terminal stations and zone substations. The top 10 largest loads (by annual consumption) is set to capture key loads.
Block Loads, Load transfers	Future load changes are identified in the Load Log. These provide the forecaster with understanding on future load changes and a historical view on how well commitment status reflects project go-ahead. Historical load changes are identified in the historical load data using feeder-level analysis.
CP Metadata	Customer numbers at each zone substation, reflective of current conditions and customer composition.
Rooftop solar PV	Installed capacity of rooftop solar PV systems at the zone substation level are used to make adjustments to historical data, create a forecast for future installations, and make adjustments to forecast for future installations.
Energy Storage Systems	Where analysis suggests this technology is material for the forecasts, historical installation records are used to estimate impact and set a baseline for future growth estimates.
Energy Efficiency	Where analysis suggests energy efficiency is material for the forecasts, historical analysis of programs and changing appliance use and building materials will help set a baseline for future growth estimates.
Development Plans	Developments that will affect demand at zone substations, modular substation and transmission terminal stations including: - Embedded generators, - Capacitor banks,

Category	Description
	- New substations, - Greenfield sites for residential or business developments. Development plans will be mainly identified in the load log.
Demand Management	Any demand management impacts not already identified in other datasets. This includes price-sensitive and controllable loads, and commercial agreements for load shedding.
Business/residential consumption split	Historical business and residential load or consumption split as provided by the Australian Energy Council.

Table 3 Externally-sourced data

Category	Description
Weather data	Data is obtained from the Bureau of Meteorology (BoM). Weather data is discussed further in Section 3.2.
Economic Projections and Historical Information	• For regional level forecasting, projections of Gross State Product (GSP) data is obtained from NT Treasury. • Population estimates and projections are obtained from NT Treasury and Australian Bureau of Statistics (ABS). • Where demand is expected to be driven by changing electricity prices, price forecasts are also developed.

The information that is discussed in Sections 3.2 to 3.5 relates to the annual regional forecast, the regional maximum/minimum demand forecast, and the zone substation forecasts to ensure a consistent treatment of historical data (adjustments for large step changes, network outages, and future large loads).

3.2 Weather Data

Weather data provides the capability to explain changes in demand with changes in weather. Weather data should be as representative as possible of the weather impacting customers. At the regional level, half hourly weather data is used. At more granular levels in the network (e.g. zone substations) daily data is used.

Weather stations used for regional forecasts are detailed in Table 4. Weather stations used for the ZSS forecasts are selected based on proximity to the substation's load centre.

Table 4 Weather stations for regional forecasting

Region	Stations	Parameters Considered
Darwin-Katherine	Darwin Airport and Tindal RAAF (Katherine area)	Temperature, humidity, dew point temperature, and wind speed
Tennant Creek	Tennant Creek Airport	Temperature, humidity, dew point temperature, and wind speed
Alice Springs	Alice Springs Airport	Temperature, humidity, dew point temperature, and wind speed

Where gaps are present in the weather data, linear interpolation is used to fill small gaps while records are excluded if the gap is longer than 6 hours.

3.3 Demand Data

Half hourly generation data at generator connection points is aggregated and referred to as system demand and is used in the regression models. As this data can contain periods of network outages some cleaning and omission of data is required to ensure that these events do not impact results when considering more general trends.

Further, exploratory data analysis is conducted to identify outliers in the data. The outliers identified are then assessed to determine whether these outliers are due to data quality or network outages that had not been flagged, or whether the outliers are simply a phenomenon of Normally distributed data. If the outliers are due to data integrity or network outages the observations are removed.

3.4 Installed capacity of Solar PV Systems

An estimate of the average system size for the current number of households in the regulated PWC network is calculated using the PWC PV database and Geographic Information System (GIS). The installations are grouped by ZSS and also by network. The current level of installed capacity is then used to set a baseline for installed capacity forecasts for each of the three networks. Installed capacity forecasts may either be prepared in-house or procured.

3.5 Historical rooftop solar PV generation

Estimates of historical rooftop solar PV panel generation are derived from a generation model. The model considers geographic location, orientation and tilt, shading, solar radiation and installed capacity to estimate the generation at disparate locations in the networks. The rooftop solar PV model is required to produce estimates of half-hourly panel output (in watts) for each substation or geographic location such that site-specific conditions are accounted for and the estimates can be combined with half-hourly demand data. If the model provides normalised generation (watts generated per watt of installed capacity) this is multiplied by the installed capacity to derive total generation for a given substation, network node or region.

This procedure does not cover the operation of the rooftop solar PV model as it may be developed in-house or normalised generation traces may be procured.

4 Procedure – The Number of Customer Connections

4.1 Overview

The number and type of connections (that is, number of sites connected to the regulated electricity network) are important factors to consider as the growth and demography can change over time and lead to significant changes in electricity consumption. The increase in the number of connections is one of the main elements of the residential energy consumption forecast. The growth in the number of connections tends to push upwards the total demand, counterbalancing downward drivers such as energy efficiency gains and the influence of rooftop solar PV. The number of new connections is driven by demographic and social factors such as population projections and changes in the household structure.

Connections in the business and industrial sector are more difficult to model due to the differing usage behaviours for different business types. For the 2019-2024 PWC Network Determination, growth in residential connections, and business and industrial connections, use a different approach:

- Residential connections – Refer to Section 4.2 for an outline of the methodology.
- Business and industrial connections – Growth is calculated using economic indicators such as Gross State Product (GSP) and the large load registry that PWC manage for the large customers in the network.

4.2 Residential Connections Forecast Methodology

To forecast the number of residential connections PWC have sought independent population, dwellings and housing construction forecasts for generating expected trends over the next ten years. The 2012 Australian Bureau of Statistics (ABS) NT population forecasts have been considered along with the NT Treasury population forecasts (2014) that contain sub-Territory level projections. To provide more granularity on household formation – an important factor when estimating household size and density – housing construction forecasts compiled by the Housing Industry Association (HIA) in 2017 will be used to produce a dwelling forecast at the territory (NT) level. The HIA uses population projections from the ABS economic trends, recent data of building stocks, and surveys to key participants in the construction sector as inputs.

The dwelling forecast is split for the three regulated networks. The process for producing the connections forecast is as follows:

- The number of residential electricity meters in each of the three regulated networks is obtained by PWC as the base number for the number of electricity connections in each regulated network.
- The number of current dwellings is estimated by using the latest 2016 ABS population and household density for the NT (regional and urban).
- New dwellings are forecast using the HIA dwelling forecasts modified so the long term growth rate converges smoothly with the rate of the long-term ABS population projections. The recently released 2016 ABS Census results will be used to guide the population forecasts to ensure they reflect the most up-to-date view of the NT population trends.
- To ensure the connections forecast only applies to those dwellings inside the regulated networks, the dwelling forecast will be calibrated to the number of electricity connections in PWC's regulated network.

5 Procedure – Annual consumption

5.1 Overview

The annual consumption forecasts are designed to capture the main historical drivers in electricity consumption and expected drivers and trends over the ten year forecast horizon. This trajectory is then used when generating the maximum demand (MD) forecasts to capture the year-on-year variation.

The annual consumption forecast is primarily a weather-based regression model built from daily system consumption data correlated against weather data from weather stations in close proximity to demand centres. This is then used to create a 'base year' forecast. The base forecast year assumes a median weather data to capture seasonal effects in electricity consumption.

The forecast is then grown on an annual basis applying both positive (e.g. connections growth) and negative demand drivers (e.g. rooftop solar PV). The main drivers that lead to large consumption changes in electricity consumption are:

- Residential connection growth,
- Gross State Product (GSP) growth[1] and large load variations,
- Solar PV installations/Battery Energy Storage System (BESS).

Other drivers such as new appliance uptake and energy efficiency will be considered, subject to data availability and an assessment of materiality on the forecast.

The following sections discuss the modelling approach for incorporating weather variability and the main identified drivers into the forecast.

Figure 1 outlines the key steps in the annual consumption forecasting process.

[1] State Final Demand (SFD) data from the NT Treasury will be considered as an additional indicator for economic activity as GSP considers exported commodities and off-shore oil and gas which lie outside the regulated networks

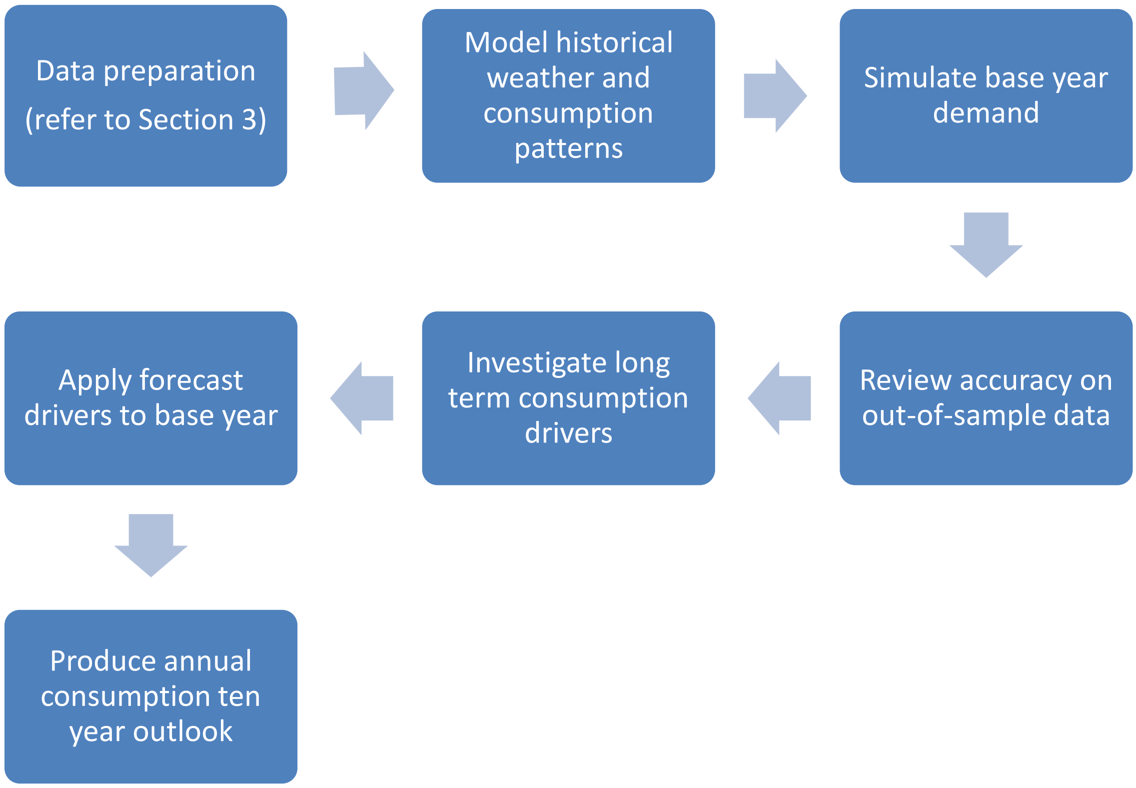

Figure 1 Annual consumption forecasting process

5.2 Weather Variability

The relationship of daily electricity consumption with daily weather data enables an assessment of the changes in electricity consumption due to customer behavioural responses with appliance usage such as air conditioners and heaters resulting from hot and cold weather.

The methodology uses a linear based regression model to capture the historical relationships by testing the correlation with different meteorological variables (such as temperature, humidity, wind speed, dew point). Splitting the consumption behaviour into heating and cooling components enables a more thorough assessment of MD forecasts as weather is the dominant driver for MD (discussed in Section 8).

To help determine cooling load levels, PWC will use a Cooling Degree Day (CDD) parameter as an indicator of outside temperature levels above what is considered a comfortable temperature (usually 18 to 21°C). If the average daily temperature rises above comfort levels, cooling is required, with many air conditioners preconfigured to switch on if the temperature rises above this mark. CDDs are determined by the difference between the average daily temperature (denoted as T_{avg}) and the base comfort level temperature (denoted as T_{base}).

The formula for the CDD is denoted by the following:

$$CDD = Max(T_{avg} - T_{base}, 0)$$

Similar to the approach taken for the CDD, to determine heating load levels a Heating Degree Day (HDD) parameter is defined as an indicator of outside temperature levels below what is considered a comfortable temperature (usually 18°C). HDDs are also determined by the difference between T_{avg} and T_{base} with the formula denoted by the following:

$$HDD = Max(T_{base} - T_{avg} ,0)$$

To obtain the best correlation of HDDs and CDDs with demand, T_{base} is chosen upon examining the correlation between grid demand on a daily level against multiple values of T_{base} as differences can occur across climate regions.

To capture latent heating and cooling effects (e.g. a heatwave or a cold snap over a few days) that drive a larger increase in electricity demand that is not captured byT_{avg} alone, lagged CDD and HDD variables will also be tested against grid data in the regression model for their significance in driving electricity consumption. Other meteorological variables (wind speed, wind direction, humidity and dew point) will be trialled in the regression model in a step-wise fashion with their inclusion based on their level of significance when performing out-of-sample testing on the model.

As electricity demand is also shown to exhibit differences on weekends, public holidays and across holiday periods, additional categorical parameters that reflect day types are included in the regression model to best capture expected consumption behaviours on these days.

The performance of the model is then assessed and the most significant parameters selected that best describe electricity consumption in terms of heating, cooling and base load for the base year.

5.3 Residential Consumption Forecast

A representative or average annual residential bill for a household in the NT is calculated using a combination of metered data, survey data and/or publicly available data. If possible, the bill is split into base, cooling and heating loads to enable monitoring of different growth patterns over the forecast horizon. The forecast is calculated on a per connection basis by taking an average customer's usage multiplied by the number of residential connections expected over the forecast period (Section 4). The growth in consumption expected from new residential connections is then added to the base year consumption as determined by the regression model. Forecast solar PV output over the next ten years is then (see Section7.6.3) removed from the total forecast to calculate a total expected forecast for residential connections.

5.4 GSP Forecasts and Large Loads

GSP forecasts, in conjunction with a registry of expected large loads, are used to derive the consumption forecast for non-residential customer sectors.

Economic activity and electrical consumption will be correlated by examining the historical relationship of GSP with non-residential consumption providing a baseline relationship for the growth forecast. Historical GSP and future estimates are used to calculate NT growth forecasts. For the Tennant Creek and Alice Springs networks, the GSP forecast is calibrated separately to reflect the differences in demand and consumption.

The load log is also used to capture any committed projects in the pipeline that may not be captured by examining GSP forecasts. Projects that are not committed may be considered for inclusion if expected to be reasonably likely to proceed and well justified, and network augmentation lead times are longer than project commitment times. The certainty around the likelihood of these loads proceeding is generally limited to 24 months in advance. For this forecast PWC only consider those loads logged in this time period unless further confirmation is obtained.

6 Procedure – Regional Maximum Demand (MD)

6.1 Overview

Regional MD is developed using a probabilistic methodology, as demand is dependent on weather conditions and random shocks in response to weather. Due to this random nature, forecast MD is represented as a distribution (probability of exceedance (POE)) rather than a point forecast. For any given season or year:

- A 10% POE MD value is expected to be exceeded, on average, one year in ten.
- A 50% POE MD value is expected to be exceeded, on average, one year in two.

Figure 2 outlines the key steps in the regional MD forecasting process.

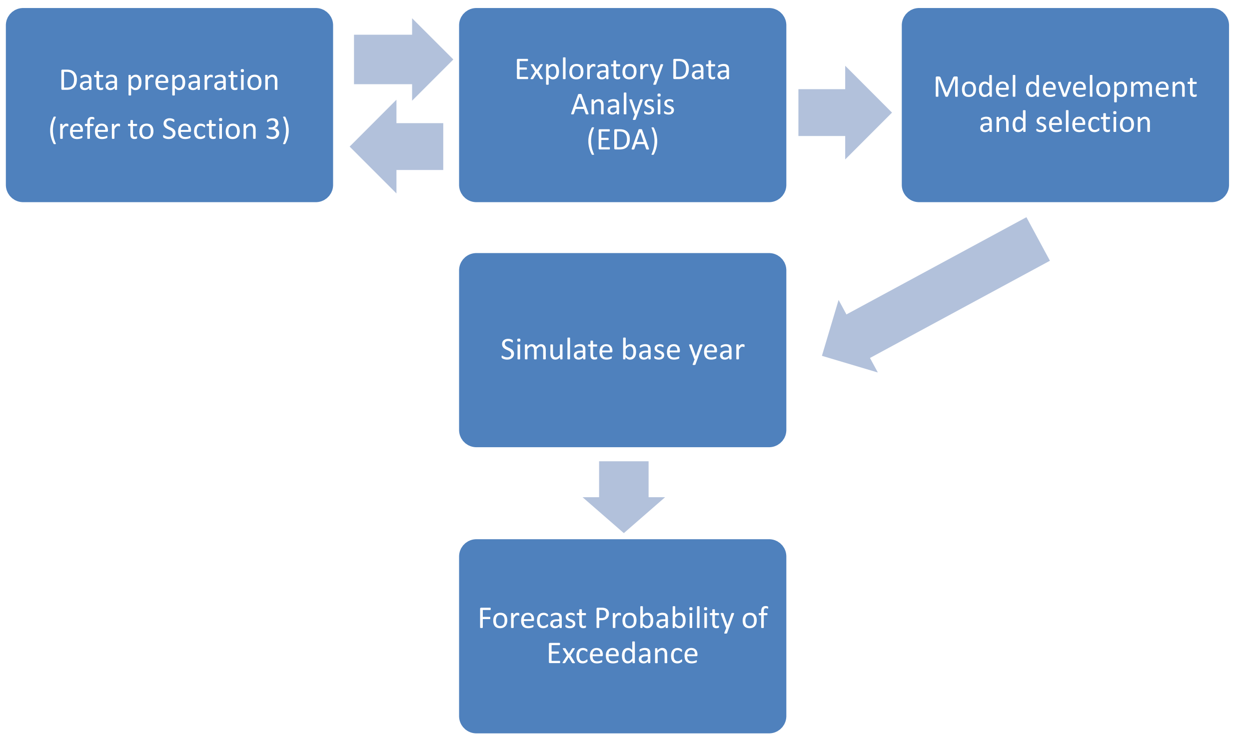

Figure 2 Maximum demand forecasting process

6.2 Exploratory data analysis (EDA)

Exploratory data analysis (EDA) is used to detect outliers and identify important demand drivers for the model development stage.

The analysis aims to identify any outliers due to atypical network operation that were not flagged during data preparation. Outliers, once identified, are verified as atypical based on PWC network knowledge and fed back to the data preparation step for exclusion.

EDA also identifies key variables that drive demand by examining the summary statistics of each variable, the correlation between each explanatory variable to identify multicollinearity, and the correlation between the explanatory variables and demand. Broadly, the EDA process examines:

- Weather - Temperature variables including CDD and HDD outlined in Section 5.2, and
- Calendar/seasonal variables (including weekend and public holiday Boolean (true/false) variables).

6.3 Model development and selection

This process specifies 24 models (for each hour of the day) for each of the networks using the variables identified as important in the EDA step and 3 years of historical data at half-hourly frequency. The hourly demand models using half-hourly data results in 2 data points for each hourly model.

These models describe the relationship between underlying demand and explanatory variables including calendar effects (public holidays, day of the week, and month in the year) and weather effects (CDD and HDD as described in Section 5.2).

6.4 Simulate base year (weather normalization)

This process uses the models for each region from the previous step to simulate demand for the base year. This process focuses on simulating historical weather events to develop a weather distribution to weather normalize demand and simulate random shocks in response to demand drivers.

Equation 1

$$MW_{hh} = f(x_{hh}) + \varepsilon_{hh}$$

where

- $f(x_{hh})$ is the relationship between demand and the demand drivers (such as weather), and
- ε_{hh} represents random Normally distributed[2] changes in demand not explained by the model demand drivers.

The weather simulation process bootstraps historical weather observations (x_{hh}, the first term in Equation 1) to create a year consisting of 17,520 half-hourly weather observations. The weather simulation process does this 500[3] times to create 500 weather years of simulated weather data each consisting of 17,520 half-hourly weather observations. These synthetic years are then used to generate the demand under the synthetic weather conditions using Equation 1.

The random shock simulation process statistically simulates the component of consumption that is not explained by weather conditions and other demand drivers (ε_{hh}, the second term in Equation 1). This recognises that consumers' consumption behaviour is not perfectly deterministic but rather follows a Normal distribution. The process produces half-hourly demand traces for 500 synthetic years.

The simulation process recognises that there are several drivers of demand including, weather, day of week, hour of day as well as random, Normally distributed shocks in demand. The process also preserves the probabilistic relationship between demand and the drivers of demand.

6.5 Forecast probability of exceedance (POE)

This process then grows all the components of demand in the half-hourly demand traces, produced by Equation 1 and the simulation process, by the growth in annual consumption.

The annual growth index is found by considering the forecast year-on-year change in annual consumption described in Section 5. The forecast year-on-year change is then applied to each of

[2] A fundamental assumption of Ordinary Least Squares (OLS) is that the error term follows a Normal distribution. This assumption is tested using graphical analysis and the Jarque–Bera test.
[3] Previous tests have found that 500 Monte Carlo simulations is a sufficient number of simulations to converge to a stable result that varies by less than half a percent.

the 17,520 half-hours for each simulation and each forecast year to grow the demand for each half-hour in the relevant forecast year.

The MD values, which is the maximum or minimum half-hourly prediction of the 17,520 half-hourly predictions in a given year, are extracted for each year in the forecast horizon, such that there are 500 values for each forecast year. From the 500 simulated maxima and minima, the 50% and 10% POEs are extracted.

In Figure 4 below, the first Bell (or Normal) curve represents the distribution of the 17,520 half-hours for each simulation for each forecast year. Data for one half-hour, indicated by the red box and arrow, is extracted from the 17,520 half-hours (the minima or the maxima) to generate the second smaller Bell curve. This is repeated for each simulation. The second smaller Bell curve represents the distribution of maxima/minima which may or may not be Normally distributed[4].

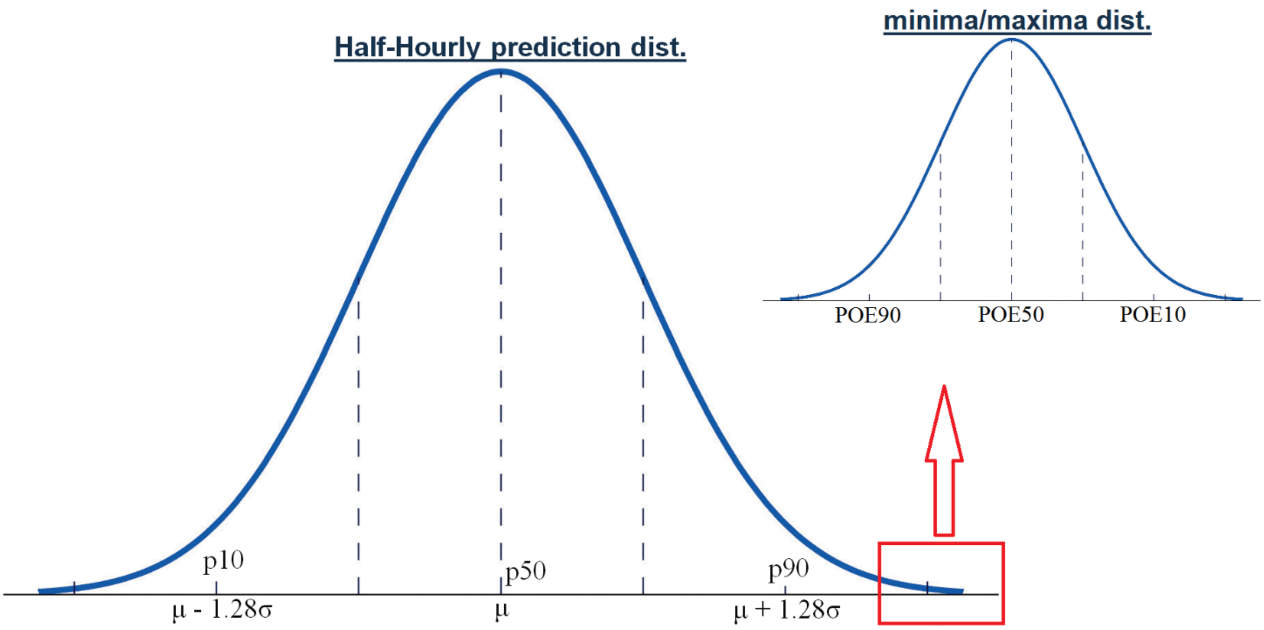

Figure 3 Distribution of yearly half-hourly data to derive minima/maxima distribution

[4] It is not necessary for the minima or maxima to follow a Normal distribution. Regardless of whether the distribution is skewed, leptokurtic, mesokurtic or platykurtic, the percentiles can be found by ranking the minimum/maximum demand values and extracting the desired percentile.

7 Procedure – Zone substation (ZSS) Maximum Demand (MD)

7.1 Overview

Figure 4 outlines the key steps in the ZSS MD forecasting process.

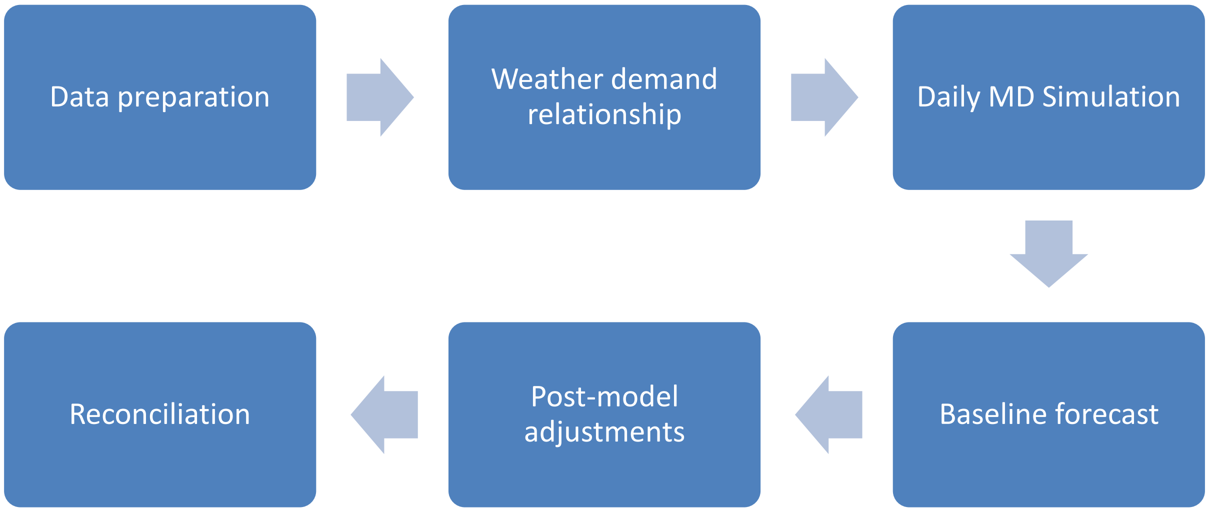

Figure 4 Zone Substation Forecasting process

7.2 Data preparation

Adjusted demand data from the substation SCADA data files is used. The adjusted half-hourly time series accounts for historical load transfers and switching using feeder-level analysis. The purpose of this step is to recreate historical demand that reflects the current network configuration.

Embedded generation that is not under the control of the system operator at the time of MD is removed from the half-hourly demand data. This provides the base demand dataset for the forecast.

The effect of rooftop solar PV generation may be removed from the demand trace at this point using the estimates of rooftop solar PV generation (Section 3.5). This produces an estimate of underlying customer demand which allows the forecast model to consider customer demand and rooftop solar PV generation separately.

The adjusted data is summarised into daily maxima, grouped by year and by season and combined with maximum daily temperatures, producing the weather-demand dataset. Where data analysis suggests cold weather causes high demand, minimum daily temperature may also be used or replace maximum temperature. At this stage the data is inspected for linear association with temperature and detected outliers are investigated for atypical network operation that was not flagged during data preparation, justifying exclusion. Furthermore, significant block loads that caused step changes in demand can be identified and the historical daily time series can be adjusted to remove the influence of these step-changes.

7.3 Weather demand relationship

Linear models for each year and season are developed from the daily weather-demand dataset.

Models are of the form specified in Equation 2.

Equation 2 ZSS demand-weather model form

$$MD_d = m \times Max\ Temp_d + n \times Min\ Temp_d + p \times Year1 + q \times Year2 + c + \varepsilon$$

Where

- $MD_d = maximum\ demand\ on\ day\ d$
- $MaxTemp_d = maximum\ temperature\ on\ day\ d$
- $MinTemp_d = minimum\ temperature\ on\ day\ d\ (if\ used)$
- $Year1, Year2 = binary\ variables\ for\ data\ from\ adjacent\ years\ to\ the\ year\ examined$
- $c = the\ y - intercept$
- $\varepsilon = model\ error$

The binary data-pooling variables *Year1* and *Year2* are used if the forecaster elects to pool demand data from a moving three-year window (Section 7.3.1). Some days are excluded in order to better estimate the model in the high-demand space. Exclusions are considered in the following instances:

- Weekends and public holiday periods where demand is lower than weekdays and unlikely to lead to MD,

- Atypical events that are not able to be corrected-for in the substation SCADA dataset, such as outage periods,
- Mild-weather days where there is a comparatively weak association between the maximum temperature and demand on the day.

The weather demand relationship is discarded in preference of a constant model of the form:

Equation 3 ZSS constant model form

$$MD_{\mathrm{d}} = \gamma + \varepsilon$$

when the weather-demand relationship is weak and, as a rule of thumb, this is determined when the R^2 (measure of model performance) value is less than 0.3.

The constant model is generally applicable to industrial loads where weather is not a key demand driver. The R^2 value for residential loads is generally expected to be above 0.65. If the value is lower than 0.65, weather-demand plots should be reviewed again to determine whether atypical events have been missed or exclusions should be added.

The reliability of the weather-demand relationship for longer-term forecasting is supported by the presence of model coefficients that are similar from one year to the next, and evolve gradually over time. If the coefficients exhibit large changes over time pooling can be used to stabilise the model coefficients for longer-term forecasting.

7.3.1 Pooling

The weather demand relationship is usually developed using one year of demand data, however more than one year of weather-demand data can be pooled to develop the relationship. Pooling provides more data points for a better-defined relationship. Pooling up to 3 years of weather-demand data is usually adequate. Extending the pooling period beyond 3 years is not recommended because the models from one year to the next will be developed on common data and this restricts the model coefficients evolving over time which in turn means load growth and changes in demand response to temperature can be mis-represented in the results.

7.4 Daily MD simulation

The response in demand to a wide range of plausible weather conditions is simulated to weather-normalise the estimate of MD for each weather-demand relationship.

Daily MD data is used, and the length of the weather record used is between 15 and 30 years (*nYearsWeather*). The minimum length is set to ensure a wide-enough range of weather conditions is used and the maximum is set to minimise the influence of long-term climate change effects.

The procedure for simulating MD for each ZSS is outlined in Figure 5.

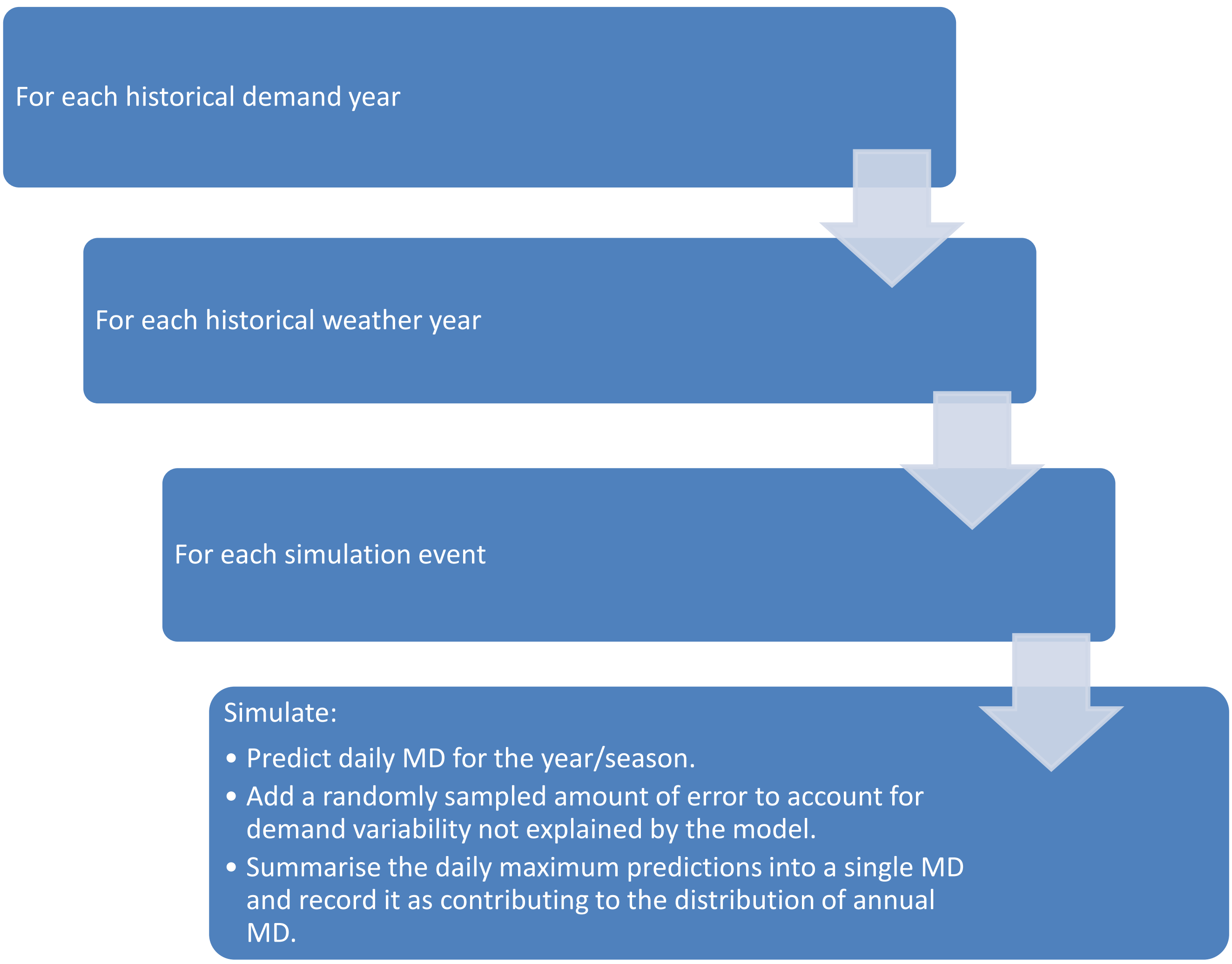

Figure 5 Zone Substation Simulation of MD

The number of simulation events is set to be 500 (*nSim*), or alternatively a number where the distribution is demonstrably stable and well-populated.

The randomly sampled amount of error is drawn from a Normal distribution based on a mean of zero and a standard deviation equal to the standard error of the weather-demand relationship.

Upon completion of the simulation, (*nSim*nYearsWeather)* demand values will be recorded and from this distribution the 90th percentile represents the 10% POE and the 50th percentile represents the 50% POE. A distribution is available for each weather-demand relationship.

7.5 Baseline forecast

The baseline forecast is developed by drawing a linear trend through the 10% and 50% POE levels derived from the simulation.

The linear trend is evaluated and adopted as the baseline forecast if it represents a plausible estimate of underlying MD growth or decline. Forecaster judgement and statistical tests are used to verify its appropriateness.

If the linear trend is rejected, an alternate baseline forecast is developed using population growth, and/or new Connections estimates.

7.6 Post-model adjustments

Post model adjustments are required to account for structural effects or technological effects that aren't modelled in the weather-demand relationship.

Post model adjustments are discussed separately as follows.

7.6.1 Block loads and load transfers

Future block loads and load transfers are included as post-model adjustments.

7.6.2 Embedded generation

Embedded generation that can be reliably assumed to operate at the time of MD is reintroduced as a block load adjustment. The precise amount is based on historical operation or contractual agreements (if not yet operating).

7.6.3 Rooftop solar PV

If the baseline forecast is derived from data that has rooftop solar PV effects removed then this power source needs to be reintroduced at a level that reflects the difference in demand between grid demand without PV and grid demand with PV. Any growth in the number of installations is also accounted for.

The adjustment for rooftop solar PV is made last so that the timing of generation can be combined with a typical high-demand load profile to derive the new 'with-PV' peak.

7.7 Reconciliation to regional forecast

After the post-model adjustments are made, the total of all the ZSS MD forecasts may not add up to the regional forecast. Furthermore, they represent the substation's MD which does not necessarily coincide with the regional MD ('non-coincident' forecasts). The substation forecasts are converted to 'coincident' forecasts (at time of regional MD) and then reconciled to the regional forecast to account for population growth, economic effects and other regional-level features not treated at the substation level. This is done by considering diversity factors to make sure coincidence is accounted for. This step also provides consistency with the regional level forecast.

7.7.1 Converting non-coincident to coincident

A diversity factor representing the ratio between the MD of the substation and substation demand at the time of the regional MD is developed by averaging the last 5 year-specific factors. This factor is applied to the non-coincident forecasts for reconciliation. It converts the non-coincident forecast to a coincident forecast.

7.7.2 Reconciling the non-coincident MD

The non-coincident forecasts are reconciled to the growth rate of the regional forecast using an indexing approach.

7.7.3 Reconciling coincident MD

Forecasts are aggregated into an unreconciled total and scaled in proportion to the difference between the unreconciled total and the regional forecast. The difference is represented as a factor, the 'scaling factor', and there is one for each forecast data point.

8 Procedure – High-Voltage Feeder Maximum Demand (MD)

8.1.1 Overview

The high voltage feeder MD forecast is based on a linear model capturing changes in historical, adjusted MD over time. It is used to study feeder utilisation and overloading.

8.1.2 Data preparation

Feeder data from SCADA is obtained and MD levels in amps are adjusted to account for load transfers and switching, embedded generation, load curtailment, atypical fluctuations and block load changes in MD. This produces a corrected MD history.

8.1.3 Forecast

A linear relationship between change in MD and time is developed from the corrected MD history. This is then projected forward for the duration of the outlook period.

Where the load history produces an unrealistic forecast or there is a short or no load history (new feeders) growth rates and starting points are set using original sources of demand information.

8.1.4 Post-model adjustments

To account for step-changes in MD, post-model adjustments are applied to account for:

- Block loads (such as new customers, closures, new residential/commercial developments);
- Network configuration changes (load transfers);

- Structural breaks or changes in customer consumption (new technologies or changing consumption patterns due to rooftop solar PV/embedded generation).

The adjustments that are applied should not double-count any load growth that is already part of the historical trend. This is generally achieved by making equivalent adjustments to the historical MD and using forecaster judgement. The feeder forecasts are compiled in the Feeder Forecast Excel files (one for each substation).

8.1.5 Reconciliation to substation-level

The high-voltage feeder MD forecast is a non-coincident forecast in amps. The reconciliation step involves the conversion to MVA for comparison with the zone substation forecasts. The reconciliation step aims to verify that the non-coincident feeder forecasts add up to be greater than the zone substation forecast.

For situations where the unreconciled feeder forecasts are less than the substation forecast:

- Block loads are reviewed for consistency with the substation forecast
- Growth rates are reviewed and adjusted for consistency with the substation forecast.

A threshold of 20% is set to screen for situations where the unreconciled feeder forecasts are greater than the substation forecast. If this occurs:

- Block loads are reviewed for consistency with the substation forecast.
- The difference is compared to historical records to judge whether it is realistic.
- Growth rates are reviewed and adjusted for consistency with the substation forecast.
- Growth rates of the feeder forecasts when aggregated to the regional level are compared to the system forecast and reviewed for consistency.

This feeder forecast reconciliation is done using the Feeder Utilisation and Zone Substation Reconciliation Excel file.

9 Records

Information from this procedure is captured, stored and managed in the PWC Electronic Document and Records Management System.

10 Review

This procedure will be reviewed, at a minimum, every five years or in the event of any significant change in system or process.

11 Document History

Date of Issue	Version	Prepared By	Description of Changes
23 June 2017	1.0	AEMO	Draft version of Forecast Procedure
7 July 2017	2.0	AEMO	Final version of Forecast Procedure

Appendix A: Glossary

Term	Definition
System demand	Power supplied to each of the three power systems. For Darwin-Katherine this consists of generation from Channel Island, Weddell, Berrimah, Pine Creek A and B and Katherine. For Alice Springs this consists of generation from Owen Springs, Uterne, Brewer and generation sources connected at the 11kV and 22kV busses at Sadaddeen substation. For Tennant Creek this consists of Tennant Creek Power Station.
Energy efficiency	Potential annual energy consumption or maximum demand that is mitigated by the introduction of energy efficiency measures.
Installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop solar PV installed capacity represents the generating capacity of rooftop solar PV panels.
Maximum demand	The highest amount of electrical power drawn from the transmission grid, or forecast to be drawn, at any one time in a year. Averaged over a 30-minute period.
System consumption	Energy consumed from system demand.
Probability of Exceedance (POE)	The probability, as a percentage, that a maximum or minimum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a 10% POE maximum demand for any given season is expected to be met or exceeded, on average, one year in 10 – in other words, there is a 10% probability that the projected maximum demand will be met or exceeded.
Rooftop solar photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop, to convert sunlight into electricity and offset the owner's consumption of electricity from the grid.
Summer / Wet season	Unless otherwise specified, refers to the period 1 November – 31 March.
Underlying consumption/ demand	Actual consumption/demand by consumers, as met by any type of generation, including rooftop solar PV generation.
Winter	Unless otherwise specified, refers to the period 1 June – 31 August in the same calendar year.