Attachment 5.04

(INV-STD-10022) Planning Standard - Demand Forecast & related documents

May 2014

Planning Standard INV-STD-10022

Demand Forecasting

Approver:	M – Assets and Network Planning	Approved:	6 Dec 2013
Owner:	M – Demand Management	Version	1
Parent Policy/ Corporate Driver:	INV-POL-10001 - Network Investment Policy		
Regulatory Requirements:			

1 Scope

This standard establishes the requirements for preparing Ausgrid's spatial demand forecast for zone substations and sub-transmission substations.

This standard does not cover feeder forecasts, which are derived from the spatial demand forecast using load flow analysis.

2 Requirement / standard

The spatial demand forecast is produced annually and establishes the expected peak customer demand (load) for planning and operating purposes. Preparation of the forecast is initiated at the end of the summer season (end of March) and key outputs completed for both winter and summer seasons by 1 June. The most recent summer and winter actual loads are included in the historical load data that forms the basis for the forecast.

The key outputs of the forecasting process are outlined in section 3 of this standard; and key inputs and approach taken when preparing the spatial demand forecast are outlined in section 4.

3 Outputs of the spatial demand forecast

The spatial demand forecast (the forecast) process produces four key outputs: a weather corrected POE50 Maximum Demand Forecast, a 25 year forecast summary; the 132kV TransGrid report; and the 132kV CSV file. These are prepared by 1 June each year.

In addition, a POE10 forecast, system coincident demand forecast and transformer forecast are produced.

These outputs are described in detail below.

3.1 Weather corrected POE50 maximum demand forecast

The weather corrected and normalised 50% probability of exceedance (POE50) maximum demand forecast is produced for each zone substation (Zn) and subtransmission substation (STS) in Ausgrid's jurisdiction. Each substation forecast contains:

- The full substation name and primary and secondary supply voltage (e.g. Auburn 33_11kV);
- Historical actual loads for the most recent 7 years;
- Forecast loads for 10 years arranged by geographic supply area;
- 10 years of year-on-year demand growth rates;
- Justification for selected growth rates;
- Incorporation of econometric drivers in the growth rates[i];
- Firm capacity;
- Total capacity;
- Historical and future committed spots and transfers; and
- The weather correction factor.

3.2 25 year forecast summary

The 25 year forecast summary is a one page summary of the weather corrected and normalised POE50 maximum demand forecast. The 25 year forecast summary shows, for each year:

- Peak load in MVA for both summer and winter; and
- Firm capacity in MVA for both summer and winter.

3.3 132kv TransGrid report

The 132kV TransGrid report provides TransGrid with input for their load flow modelling of the Ausgrid network. The 132kV TransGrid report contains MW, MVAr and uncompensated power factor[ii] per year for the most recent actual year and 10 forecast years for each:

- 132kV connection point (subtransmission substations, 132/11kV zone substations and 132kV customers); and
- Zone substations supplied from other Distribution Network Service Providers (DNSPs) (e.g. Epping, Leightonfield, Hunters Hill) irrespective of supply voltage.

3.4 132kv CSV file

The 132kV csv file is an import data file used for load flow modelling of the 132kV network. It is produced as an Excel workbook with fields as follows:

Column	Field	Description
A	ForecastType	Forecast scenario (eg base)
B	Season	Summer or Winter
C	Region	Sydney or Hunter[iii]
D	STS/Zone	substation name
E	PrimaryVoltage	kV
F	SecondaryVoltage	kV
G	DivFactor	Diversity factor[iv]
H	Year	Year of forecast load
I	Unit	MW or MVAr
J	Value	peak load value

The MW and MVAr values are the peak substation load multiplied by the diversity factor[v].

Where reactive plant is present, the reported MVAr assumes reactive plant is fully switched in for 132/11kV zones. For STS, the reactive plant is assumed not to be connected.

3.5 Weather corrected POE10 maximum demand forecast

A weather corrected and normalised 10% probability of exceedance (POE10) maximum demand forecast is produced for each zone substation (Zn) and subtransmission substations (STS) in Ausgrid's jurisdiction. It is prepared prior to each summer for use by operational staff as input for preparing Ausgrid's summer preparedness program.

The POE10 forecast follows the same format as used for the POE50 forecast described above.

3.6 System total coincident demand forecast

A forecast of the total Ausgrid system maximum demand is calculated from the diversified aggregate of the spatial forecast using subtransmission substations, zone substations with 132kV primary voltage and zone substations supplied from external DNSPs.

3.7 Transformer forecast

A forecast of the maximum demand of each transformer at zone substations and subtransmission substations is calculated from the zone substation forecast by applying the transformer to total substation load diversity factor to each substation load.

4 Preparing the demand forecast

The key inputs and approach taken when preparing the spatial demand forecast are outlined in the following sections.

4.1 Source load input data

Historical interval load data for the spatial demand forecast is sourced from the following two systems:

- SCADA data from the Distribution Network Management System (DNMS) system; and
- Metering data from the Meter Data Warehouse.

This data is adjusted as part of the forecasting process to remove the effects of load spikes and abnormal switching.

4.2 Customer negotiated capacity

Where a customer has negotiated a higher standard of service than the default in the Licence Conditions and the agreed financial terms have been met, the forecast is adjusted accordingly so that the capacity is reserved for that customer.

If a customer has negotiated a lower standard of service (e.g. to reduce their costs), this is generally not incorporated into the forecast. Generally these requests are considered during network planning or inherent in the connection of the customer.[vi]

4.3 Embedded generation

The historical load data includes the impact of downstream embedded generation that was generating at the time of peak[vii].

Where a generator has a material impact on peak load that is not accurately reflected in the historical data and information is available about generator output and reliability, the forecast is adjusted to reflect the expected impact of the generator, taking into account:

- The historical reliability of the generator and expectations about its future reliability, including weather dependency where relevant;
- When the generator was installed and whether it is a temporary or permanent installation;
- Contractual obligations for Ausgrid to provide backup or standby supply to a site; and
- Network support agreements with the generator.

Larger generators that are relied on for network support are generally included as a negative spot load. In determining whether a generator is 'large' use the same approach as is used for spots and transfers (refer to section 4.7)

4.4 Capacitors

Reactive compensation for locations with known capacitor installations is modelled according to the following guidelines:

- Growth rates are applied to uncompensated MVAr prior to switching in capacitors. In other words, growth rates are not applied to capacitors.
- The amount of reactive compensation for forecast years is applied according to the step size and maximum available MVAr capacity such that the resultant power factor is as close to unity as possible but does not result in a leading power factor.

4.5 Weather correction and load normalisation

Historical loads are weather corrected and load normalized, to enable statistical trend line calculation of growth rates and determination of probabilistic forecast loads. The weather correction and load normalisation factor is the percentage difference between the weather corrected and actual load in the most recent historical year. This correction factor can be negative, positive or zero.

Weather correction and load normalisation is applied according to the following rules:

- Maximum demands[viii] are weather corrected and normalised with a probability of exceedance of 50% (POE50);
- Each substation uses Bureau of Meteorology (BOM) data from the geographically closest BOM weather station;
- Apparent temperature is used, which includes the effects of humidity, wind speed and ambient temperature; and
- Weather correction and load normalisation is applied using a Monte-Carlo simulation method to determine the POE50 maximum demand. The simulation incorporates non-working days to model the effect of substations that can peak on a non-workday[ix].

4.5.1 Exceptions

Weather correction and load normalisation is not applied to Zn or STS where the load does not exhibit weather dependency for that season or where the load exhibits weather dependency that does not follow the general trend expected for that season, based on examination of the seasonal load versus temperature relationship; or to dedicated customer loads (connected at the Sub-transmission level).

4.6 Rate of growth

The rate of growth is calculated according to the following process:

- The historical spots and transfers are adjusted out of the historical weather corrected loads to reveal the underlying trend;
- The weather corrected and adjusted trends are reviewed by an expert panel to consider factors that could influence the growth rates such as Local Government Plans;
- A range of econometric factors are incorporated from the 4th year onwards via an adjustment to the growth rates; and
- A growth rate of zero is applied to Dedicated Customer loads[x] (connected at the Sub-transmission level).

Note: The growth rate can be negative

4.7 Spots and transfers

Spots and transfers are included after the application of growth rates. A spot or transfer can result in either an increase or decrease in the forecast load (e.g. load can be transferred to or from a zone; just as a new connection will increase load and a disconnection will reduce load.

Only spots and transfers for committed projects are included in the forecast. All load transfers are included in the forecast. Spot loads are included according to the following guidelines:

For…	**Aggregate of spots per year is included if it is greater than…**
Non-firm substation (<10MVA peak load)	10A @ 11kV (approx 0.2 MVA)
Substations with firm capacity between 10 to 25MVA	25A @ 11kV (approx 0.5 MVA)
Substation with firm capacity >25MVA	50A @ 11kV (approx 1 MVA)

In addition to the above table, distribution planners may apply some discretion to include spot loads that are considered abnormal for a given area. For example, a small industrial spot load in an area dominated by residential load would be considered abnormal for that area, even if the spot is below the numeric threshold. Similarly, a cluster of small spot loads resulting from a local council zoning change to an area would be considered as a single spot load increase for each year.

A flat scaling factor of 80% is applied to spot loads to reflect the difference between the capacity applied for as part of a customer connection application, and the eventual load from that connection. The exception to this rule is Sydney CBD, where this scaling factor is already applied.

5 Related and dependent documents

Document	File Location / Link
INV-STD-10018 Embedded Generation	http://infoshare.energy.com.au/sites/SP0350/SP0200/InvestmentManagement/Embedded%20Generation.doc

6 Key terms, acronyms or abbreviations and definitions

Term	Definition
Apparent temperature	Weather measurement calculated based on air temperature, wind speed, humidity
BOM	Bureau of Meteorology
Committed project or spot load	Means a project has received financial authorisation
Diversity Factor	Ratio of load at time of system peak vs time of local peak Diversity Factor = Load @ system peak / Load @ local peak
DNSP	Distribution Network Service Provider
Embedded Generation (EG)	Any form of generation which is intended to operate whilst electrically connected to the distribution network. It can be connected directly to a the network or indirectly through customer's own electrical installation
Firm Capacity	The amount of power available at a substation with one element out of service due to a credible contingency
Licence Conditions	A set of Design, Reliability and Performance Licence Conditions for NSW Distribution Network Service Providers imposed by the Energy Minister in NSW
power factor (pf)	The ratio of real power (MW) to apparent power (MVA)
Probability of Exceedence (POE)	This refers to the probability that a certain value will be exceeded in a season. E.g. POE50 means that there is a 50% chance that the selected value will be exceeded each season
ROG	Rate of Growth
SCADA	Supervisory Control and Data Acquisition
Spatial Demand Forecast (the forecast)	The spatial demand forecast is produced annually and establishes the expected peak customer demand (load) for planning and operating purposes
Spot (or Spot Load)	A step change in load caused by a new customer connection, a disconnection or an upgrade of an existing connection
Subtransmission Substations, (STS)	A substation that transforms 132kV into 66/33kV which is then used to supply zone substations and some high voltage customers.

Term	Definition
load transfer	Existing load that is transferred between distribution feeders, zone transformers, zone substations or subtransmission substations.
Weather Correction Factor	Percentage of how much the historical actual load has been adjusted in the weather correction process.
Zone Substation (Zn)	A substation that transforms electricity from 132kV, 66kV or 33kV down to a lower voltage (usually 11kV) for distribution
MVA	Mega Volt Amp; unit of electrical apparent power
MW	Mega Watt; unit of electrical real power
MVAr	Mega Volt Amp reactive; unit of electrical reactive power
DNMS	Distribution Network Management System

[i] At present, econometric growth drivers are introduced into the forecast from the 4th year forecast year and onwards.

[ii] Uncompensated power factor is the ratio of MW to MVA excluding the effect of reactive compensation.

[iii] There are some differences in the way that the power system model is structured in the Sydney and Hunter. This field is used to determine how the forecast data is formatted.

[iv] Diversity factor for forecast years is calculated using a rolling 5 year average.

[v] This allows planning officers to load the values directly into their load flow software without adjusting them.

[vi] The Licence Conditions 14.7 allows Ausgrid to ‘agree with a customer to apply higher or lower standards of service at the customer’s point of supply than the design planning criteria relevant to that customer’

[vii] Consequently, the forecast includes the impact of small scale generation (such as rooftop solar installations).

[viii] The Licence Conditions defines ‘demand forecast’ as ‘seasonal peak demand forecast with 50% probability of being exceeded’.

[ix] This supersedes the Public Holiday Factor that was used in previous forecasts.

[x] The electricity usage patterns of such customers do not generally follow the wider network.

Supporting Reference to Attachment 5.04

Maximum Demand Forecasting Methodology for Zone Substations and Subtransmission Substations

Contents

1 Introduction

1.1 Purpose

This document sets out the methodology used by Ausgrid for forecasting maximum demand at its zone substations (ZN) and subtransmission substations (STS). The maximum demand forecast is a key input into network planning and related processes for Ausgrid.

The maximum demand forecast (the forecast) is produced annually at the end of the summer season and uses the latest summer and winter actual demands. The methodology descriptions that follow are based on the forecast using summer 2012/13 and winter 2012 actual demands.

1.2 Definitions

Ausgrid's maximum demand forecast is produced for summer and winter only. It is not produced for autumn or spring since maximum demands do not occur during these seasons.

The forecast is produced at a 50% Probability of Exceedance (POE50) level as stipulated by NSW jurisdictional requirements.

The forecast is produced for ZN and STS only. It is not produced for feeders. The forecast for feeders is undertaken as a planning activity which necessarily relies on loadflow simulation and uses the maximum demand substation forecast as an input.

2 Overview of Methodology

The methodology consists of the following steps:

- Gather data
- Cleanse data
- Normalise Data
- Determine growth rate
- Determine starting point
- Calculate forecast demand
- Application of growth rate

2.1 Gather Data

The first step is to gather the necessary data and manage it appropriately. The data can be grouped into the following categories:

- Demand data
- Weather data
- Network configuration data

2.1.1 Demand Data

The raw demand data is taken from data sources measured at each ZS or STS in the form of 15 min interval data. The interval demand data is sourced from metering and SCADA systems and uploaded into the forecasting SAS system. The raw interval demand data is typically messy and is required to undergo a cleansing step to remove anomalies such as data spikes and switching prior to any calculation steps.

The cleansed interval demand data is used to determine the seasonal peak demand, power factor, diversity factor and, in conjunction with weather data, the weather normalised demand. For example, the peak demand is determined by simply taking the maximum of the cleansed interval demand data over the required timeframe.

See Appendix F for details of power factor.

See Appendix E for details of diversity factor.

The interval demand data is taken either directly from a single measurement source or by applying a rules-based calculation from multiple measurement sources. The multiple measurement method is used where the operating configuration for a particular substation is complex. Most substations use the single measurement method.

2.1.2 Weather Data

Weather is the most significant explanatory variable in determining peak demand, which typically occurs during very hot or very cold days.

The task of forecasting peak demand is made more complicated by the seasonal volatility of weather. This volatility must be accounted for in some way.

The weather volatility of peak demand is accounted for through the process of weather normalisation. The weather data used in the weather normalisation process is sourced from the Bureau of Meteorology (BoM) weather stations. A total of twelve weather stations are used throughout Ausgrid's area and each ZS or STS is assigned the geographically closest weather station, data quality permitting.

The weather scale used in the methodology is daily **average apparent temperature**[1], which considers intra-day maximum and minimum temperatures and weather variables such as humidity and wind speed in addition to the ambient temperature. It is a measure of how people perceive the weather.

Calculation of daily average temperature is determined differently for summer and winter. A summer day follows the same convention as a calendar day – 00:00 hrs to 23:45 hrs. However, a winter day is taken to be 09:00 to 23:45 (00:00 to 08:45 are excluded). The reasons are as follows:

In summer, a high maximum demand will occur on a day where the average daily temperature is high. In other words, a high maximum temperature and a high minimum temperature. The peak demand experienced on the network as a whole typically occurs between 4:00pm and 5:00pm. On any day, the maximum temperature occurs in early afternoon and the minimum temperature occurs in early morning before sunrise. Also, Ausgrid supply area is primarily coastal and is subject to the "cool change" in late afternoon/early evening which can provide dramatic cooling relief to what was a very hot day. Therefore, a calendar day encompasses the key daily temperature drivers for summer: the minimum temperature, the maximum temperature and the cool change effect.

In winter, a high maximum demand will occur on a day where the average daily temperature is low. In other words, a low maximum temperature and a low minimum temperature. The early morning minimum temperature is not indicative of the following night's peak demand, particularly if during the day it gradually warmed up and consequently the following night may be mild. Since winter maximum demand typically occurs at 6:00pm, capturing the minimum of the previous morning can be misleading. Instead, the minimum of the following morning (next calendar day) is more appropriate since a cold early morning temperature usually means it was also cold the previous evening. Hence, the choice of a winter day *should* straddle two calendar days to capture the maximum early afternoon temperature and the minimum early morning temperature of the next calendar day. The choice to truncate a winter day instead of straddling multiple calendar days was made largely due to implementation difficulties within the SAS software system.

See Appendix A for details of apparent temperature.

2.1.3 Network Configuration Data

The configuration of the electricity network changes over time. These changes must be captured and managed appropriately to ensure that forecast maximum demands are calculated based on accurate data and that key forecast outputs such as growth rates are meaningful.

Configuration information is recorded in spreadsheets as input sources. The input sources and their functions are listed below:

Input source name	Function
Location Master	Data for ZS, STS and dedicated supplies to customers connected at 33kV or 66kV.
Transformer Master	Data for transformers at ZS and STS.
Reactive Plant Master	Data for ZS and STS capacitors.
Location Actuals Rules	Locations where total demand is calculated using more than one point of measurement.

[1] Any reference to temperature refers to apparent temperature.

Major Customer Forecast	Demand data for large individual customers connected at 33kV or 66kV.
STS Transfers	ZS that change STS supply source
STS Summation Points	STS that supply ZS able to be supplied from multiple STS
Spots and transfers extract	Snapshot of database that stores data relating to spot loads and load transfers.

2.2 Cleanse Data

Once the data is gathered a cleansing process is carried out to remove any anomalies that may be present in the data. Failure to do so will result in calculations being performed on erroneous data sets, false trends will be developed and consequently the forecast is likely to be misrepresentative. Anomalies may arise from data spikes, data gaps and step changes such as spot loads, load transfers and embedded generation. Both the weather data and demand data undergoes a cleansing process.

The weather data is cleansed by removing date/time values that have a missing apparent temperature variable (eg ambient temperature, humidity or wind speed) and removing days that have more than 4 hours missing.

The demand data is cleansed through an automated process called clustering and a manual assessment process.

2.2.1 Automated cleansing: Clustering

The automated step follows a cleansing process called Clustering, where interval demand data is grouped based on load shape into clusters, which is then used to identify days where the load shape is atypical or where portions of the load are atypical.

Mean values as well as upper and lower bounds, based on +/- 2 standard deviations, are established. Observed interval demand data values outside the upper or lower bounds, data gaps or data values that display rapid changes from the previous interval/s are smoothed using an automated algorithm.

See Appendix B for details of Clustering.

2.2.2 Manual cleansing

The manual step for cleansing the demand data involves removing days where spikes, load switching and outliers are present. The interval data is visually represented using a 3D graph to allow spikes and load switching to be easily identified.

Outliers are most easily identified by correlating daily peak demand data against daily temperature data for a given season to determine the weather sensitivity of demand in that season. Most substations in the Ausgrid network display a weather dependency, in other words, peak demand increases as temperatures increase in summer and with decreasing temperature in winter. Outliers are those days that do not correlate well with the other observed days in the season. An example of an outlier that would be typically excluded is a high load occurring on a day with mild temperature. High load at an extreme temperature is not typically excluded, since it consistent with the theory that extreme temperatures cause higher peak demands.

Any occurrences of spikes, load switching and outliers are removed from the dataset using an override facility, where the entire day is removed from the dataset. The overrides are stored in Excel files and read-in by SAS during each run.

2.3 Normalise Data

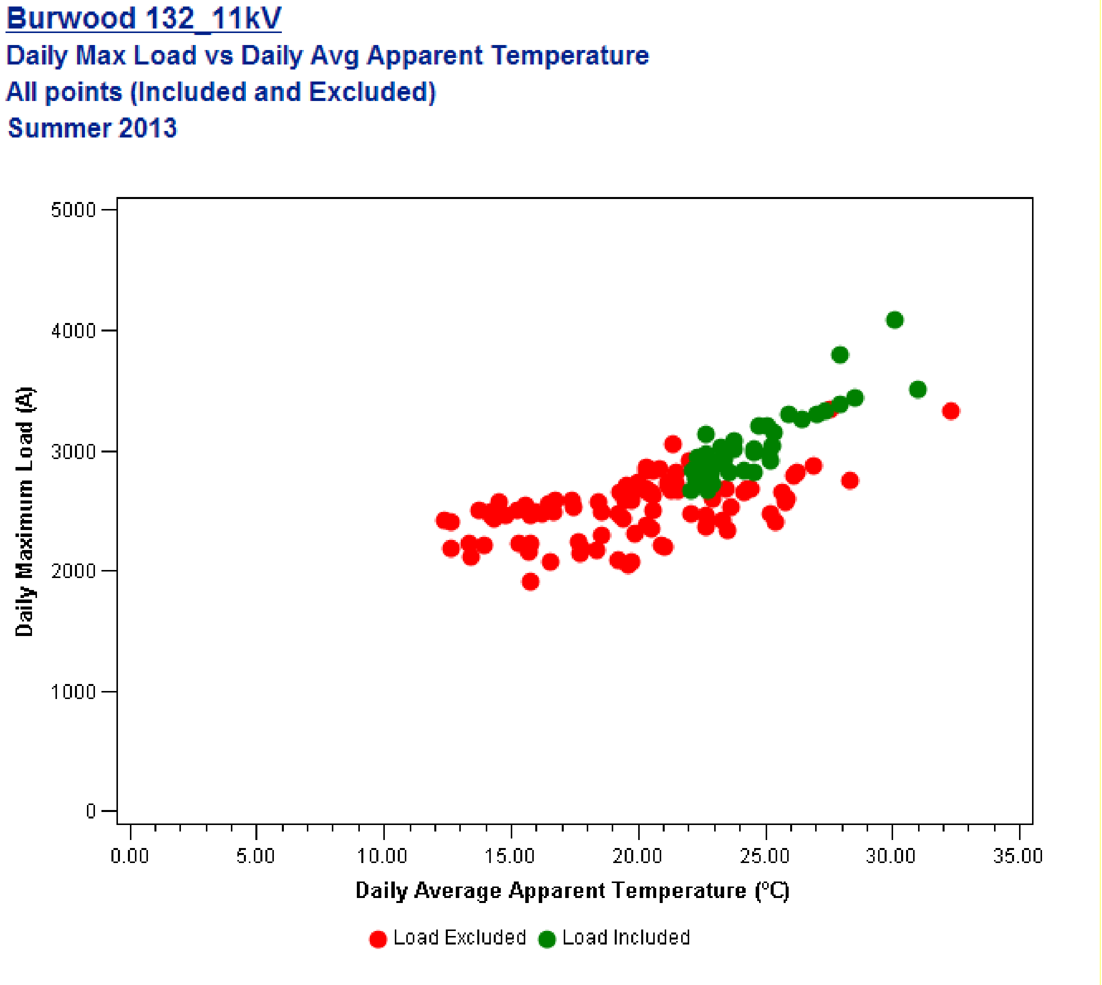
After cleansing, normalisation is carried out to remove the random element of demand out of the historical demand data prior to the forecasts being produced.

The NSW jurisdictional requirement for normalising the maximum demand forecast is stipulated in the *Design, Reliability and Performance Licence Conditions for DNSPs, 1 Dec 2007*. Forecast demand is defined as “the licence holder’s seasonal peak demand forecast with 50% probability of being exceeded (POE50)”. This means that expected demand values should be exceeded once every two years.

The method of normalisation accounts for both weather and non-weather variability. Normalisation is carried out at the substation level on a seasonal basis. The following steps are followed for each substation for the each season. This assumes the cleansing step has already been carried out:

2.3.1 Plot demand vs weather

Since weather is the most significant explanatory variable in determining peak demand, the daily peak demand is plotted against daily average apparent temperature to determine the relationship (or in some cases the lack thereof) between demand and weather. This plot is also used during the cleansing step to remove outlier days.



2.3.2 Remove non weather dependent days

Remove the non weather dependent days below the knee-point temperature. The knee point temperature is where demand begins showing a weather dependency. It is necessary to exclude the non weather dependent days since they do not contribute to the determination of peak demand and would distort the demand vs temperature relationship developed later.

For most substations the knee point temperature is 22^{o}C in summer and 15^{o}C in winter, hence these values are assigned as default. However, there are some cases where the knee point temperature has been overridden.

2.3.3 Separate working days and non-working days

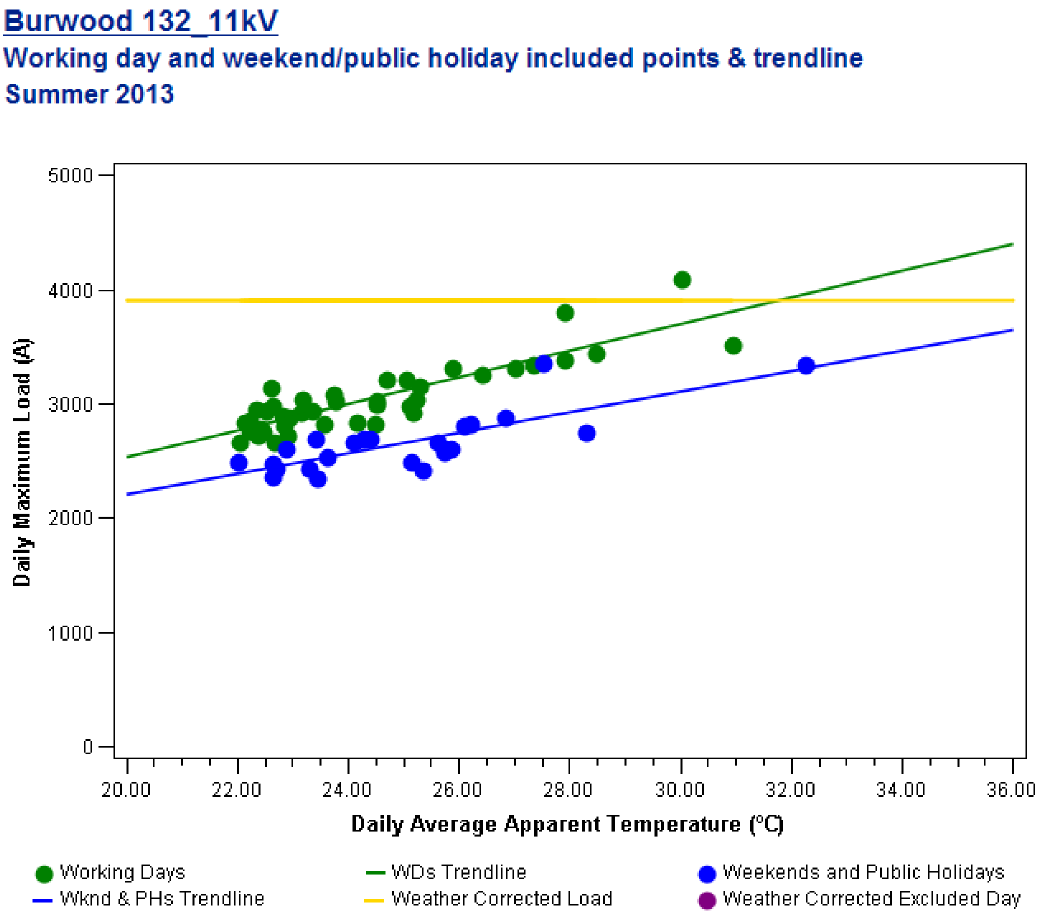
The remaining days are the weather dependent days. These are separated into working days and non-working days. During the normalisation step the working days and non-working days are modelled separately due to differences in customer behaviour on working days compared to non-working days.

Non-working days include weekends, public holidays and the Christmas holiday period between 21 Dec and 5 Jan in summer.

2.3.4 Model demand vs temperature relationship

The daily peak demand vs temperature relationship is modelled using a linear regression based on sum of least squares fit. The slope, intercept and standard error of regression fit are calculated for the working day set and non-working day set.

The result is that separate linear regressions are calculated for working days and non-working days.



2.3.5 Perform normalisation

Normalisation is carried out using a simulation technique. A large number of seasons are modelled by simulating daily temperature and daily maximum demand. The required POE level maximum demand is then extracted from the simulated seasonal maxima. Simulation is performed using the following steps:

2.3.6 Establish monthly temperature distributions

Ten years of daily average apparent temperature data is collected from weather stations and arranged into months. There will be approximately 300 observations (10 years x 30 days per month) per month per weather station. The monthly temperatures are modelled using a normal distribution. The mean and standard error are calculated.

The result is that each month will have a mean and standard deviation, specific to each weather station.

2.3.7 Set up season to be simulated

The start and end dates for the season to be simulated are defined:

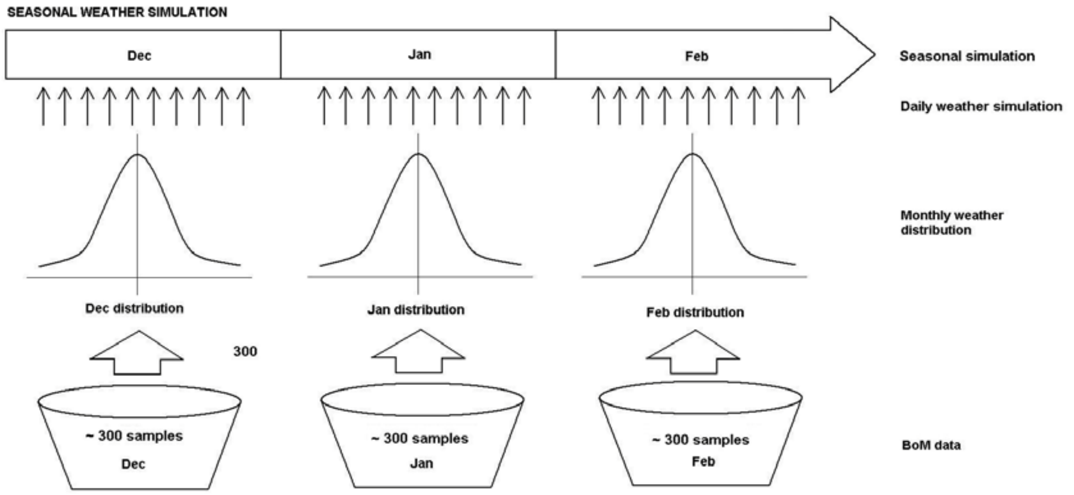
- 1 Nov to 31 Mar for summer
- 1 May to 31 Aug for winter

The day of the week (Mon to Sun) for the first day of the season is randomized. Simulation can now begin.

2.3.8 Simulate daily temperature

Daily temperature is simulated by randomly drawing a temperature from the appropriate monthly temperature distribution established in step 5a. The substation that is being modelled uses the weather data (ie the monthly mean and standard deviation parameters) from the geographically closest weather station. If a November day is simulated, the random temperature is drawn from the November distribution and so on. This is repeated for each day in the season.

No distinction is made between working days and non-working days when simulating daily temperature.



2.3.9 Simulate daily peak demand

For each day, the simulated peak demand is determined by the equation:

$$D = a * T + b + \varepsilon$$

where

D = demand for that day

T = temperature for that day

a = regression slope

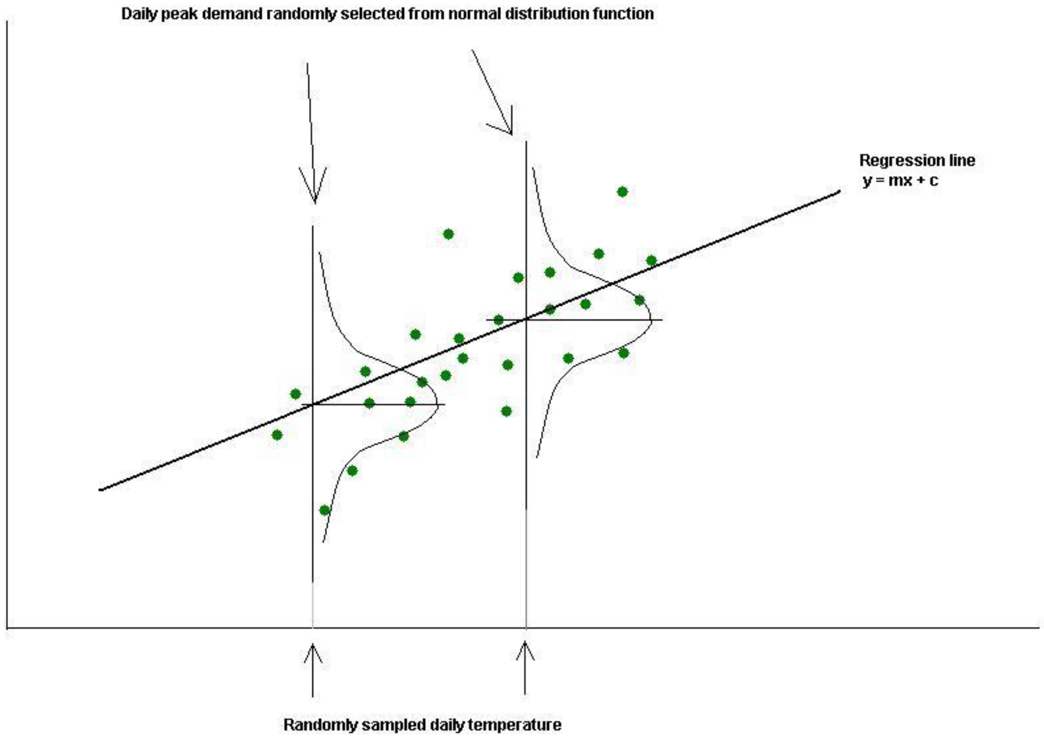
b = regression intercept

ε = error term

The temperature for that day uses the result of step 5c above. If a working day is being modelled, the slope, intercept and standard error is taken from the working days regression line and likewise for non-working days.

In other words, for each day in the season, the daily peak demand is found by substituting the corresponding simulated weather value into the regression function to determine expected demand for that temperature plus an error term.

The error term (ε) represents the non-weather variability (or scatter) around the expected demand for a given temperature. It is modelled by randomly drawing a number from a normal distribution with a mean equal to zero and standard deviation equal to the standard error of the regression fit.



2.3.10 Obtain season peak and POE level

The above process of modelling a season by simulating daily temperature and daily peak demand is repeated for 2000 iterations, resulting in 2000 simulated seasons. The maximum demand is recorded for each season, resulting in 2000 simulated peak demands.

The desired POE level can now be obtained by taking the appropriate percentile value from the 2000 simulated peak demands. The POE level is calculated using the formula:

$$POE(x) = Percentile(100 - x)$$

where x is the desired POE level expressed as a percentage.

The POE50 is the 50th percentile, the POE10 is the 90th percentile and so on.

2.3.10.1 Exceptions

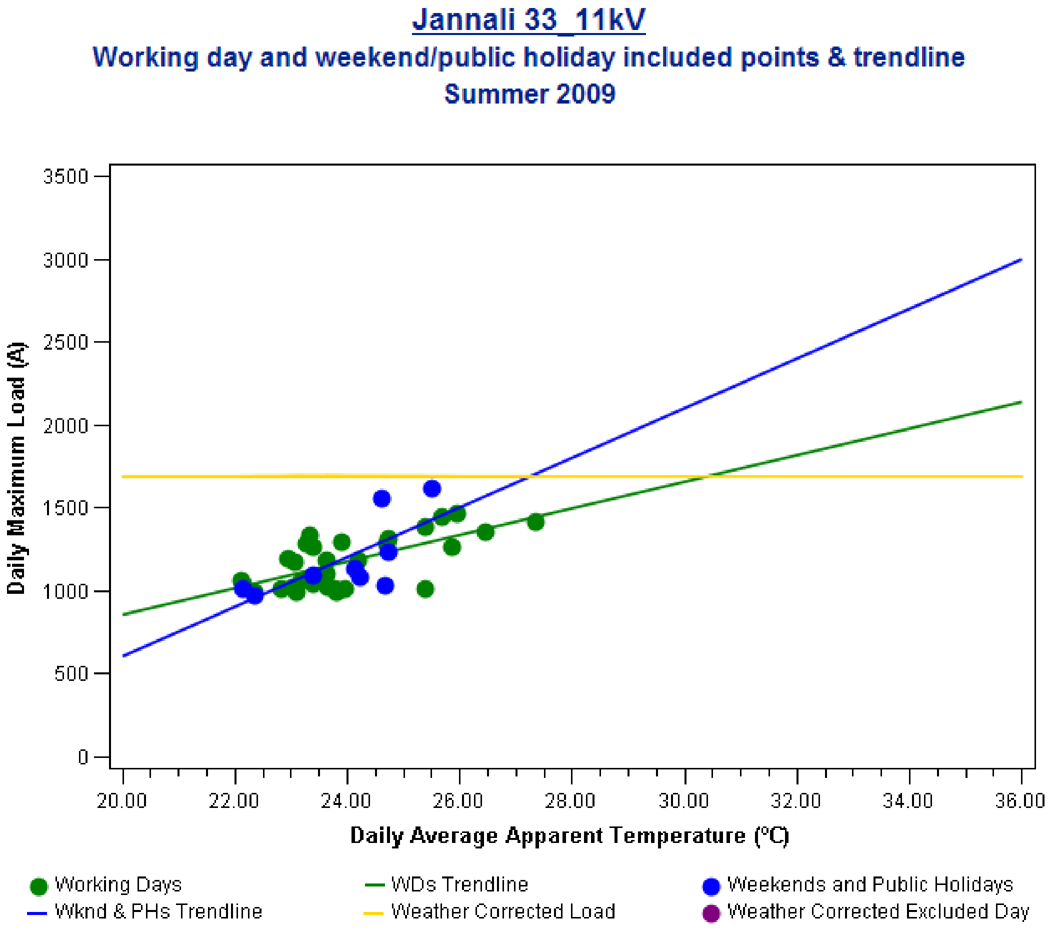
The above normalisation process is not carried out for dedicated customer supplies and generators. It is also not performed where the demand does not display a weather dependency or the weather dependency is in the opposite direction than expected.

2.3.10.2 Adjustments

Adjustments were made to the normalised loads for two summer seasons, summer 2008/09 and summer 2011/12.

Summer 2008/09 – Australia day weekend

Weather conditions on Saturday 24/1/2009 were a combination of a high max temperature (37-38 deg) and a low min temperature (13-14 deg) resulting in a low calculated average temperature. However, the demand on this day at the zone substation level was close to the seasonal peak demand for many locations. The combination of low average temperature and very high demand resulted in the non-working days regression line being very steep for some locations. This resulted in a very high summer 2008/09 normalised demand for the affected locations.



A quantitative method was developed to identify locations where the steepness of the non-working days trendline was not justified, and subsequently, the effect of the non working days were excluded from the normalisation calculation.

See appendix C for details of the adjustment.

Summer 2011/12 – very mild summer

Summer 2011/12 was an abnormally mild summer season which saw a significantly lower number of days in the high temperature ranges where peak loads are most likely to occur. According to the Bureau of Meteorology, summer 2011/12 for NSW had the 2nd coldest mean maximum temperatures on record

http://www.bom.gov.au/climate/current/season/aus/archive/201202.summary.shtml#temperatures

This resulted in the slope of the regression fit being dominated by the points at the milder end of the temperature scale. This led to a lower slope parameter for summer 2011/12 and consequently the normalisation result was unreasonably low, when comparing against the normalisation results of previous years.

The summer 2011/12 slope was adjusted by incorporating regression parameters of the previous summer.

See appendix D for details of the adjustment.

2.4 Determine growth rate

The growth rate is a key variable in determining forecast demand. The methodology to determine the growth rate is calculated by taking historical data, making necessary adjustments and trending the adjusted data.

Growth rates are determined for each substation and are calculated as follows:

2.4.1 Time series of normalised demand

Arrange 7 years of normalised historical demand in a time series

2.4.2 Adjust for historical step changes

Historical demand may contain instances of step changes which may arise due to load switching, spot loads and embedded generation. It is necessary to account for these step changes if meaningful trends, and subsequently growth rates, are to be developed.

The historical step changes are first reviewed by planners to ensure each historical load transfer, spot load and known embedded generator is accurate. The records of load transfers, spot loads and known embedded generators are kept in a database. The review reconciles the planning values against actual values. For example, when a particular load transfer project is initiated, the planner may estimate that 5MVA is to be transferred. This is the planning estimate. However, after the project is implemented, the result may be that only 4MVA was actually transferred. Hence, the database entry for this load transfer will need to be adjusted down from 5MVA to 4MVA before it is useable in the forecast.

The step changes are then arranged cumulatively in a time series, in a similar manner as the historical normalised demand. These cumulative step changes are then "reversed out" of the historical normalised demand according to the following formula:

$$D_{adj,x} = D_x - \sum \Delta D_x$$

where

$D_{adj,x}$ = Adjusted normalised demand in year x

D_x = Normalised demand in year x

$\sum \Delta D_x$ = cumulative step changes in year x

Procedurally, calculations are performed using MW and MVAr and trending is performed on MVA. Historical power factors are applied to historical spot loads and load transfers.

2.4.3 Calculate trendlines

Linear 5 and 7 year regression lines are fitted onto the adjusted normalised demand, which represent a medium and longer view of growth trends.

Calculated growth rates are capped at +/- 3% to restrict the values to within "sensible" bounds since growth rates outside these limits are highly unusual.

2.4.4 Expert panel assessment

The calculated growth trends are then subjected to a judgment-based assessment with planners and demand management representatives. Planners and demand management are local area experts and may have knowledge of local factors such as Local Government Plans that may have an impact on growth rates.

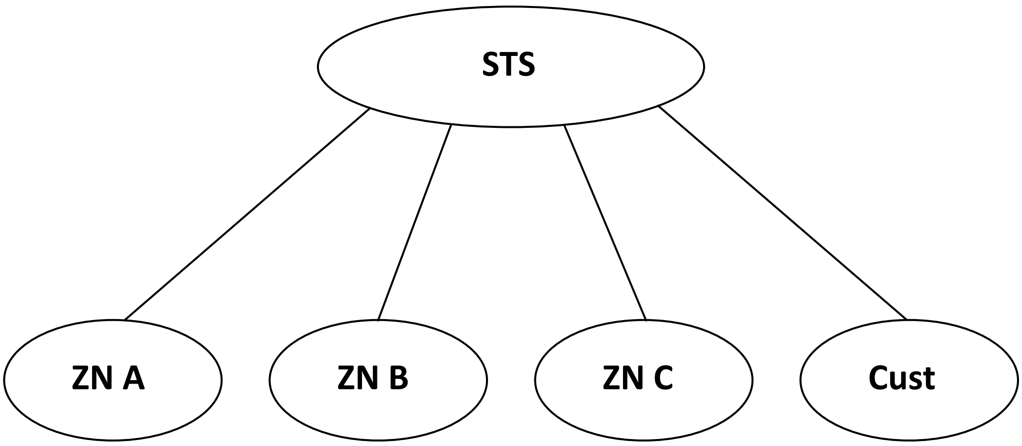
In practice, in the absence of any influencing factors, the longer term growth rate (7 years) was taken for the majority of cases. The calculated 5 year growth rates represented post-GFC conditions and were reflected in the calculations as having lower growth rates. Whilst the 5 year growth rate was selected for a few locations, due mainly to questionable data in the 7 year trend, the GFC conditions are expected to be a transient economic condition rather than a permanent one.

2.4.4.1 Exceptions

In general, growth rates are not applied to dedicated customer supplies and generators. In such cases, the growth rate is defaulted to zero.

2.4.5 Subtransmission Substations

The growth rates for STS are calculated based on a weighted average of growth rates from downstream substations and dedicated customer supplies.



For the above system consisting of an STS supplying three ZNs A, B and C and a dedicated customer supply, the growth rate for the STS is calculated by:

$$ROG_{STS} = \frac{ROG_A D_A + ROG_B D_B + ROG_C D_C + ROG_{cust} D_{cust}}{D_A + D_B + D_C + D_{cust}}$$

where

ROG_{STS} = growth rate at the STS

ROG_X = growth rate at X

D_X = demand at X

2.5 Determine starting point

The starting point is the other key variable and is the point from which the first forecast year is calculated. The starting point is calculated using the same adjusted normalised trendline used to calculate the growth rate. The following formula is used:

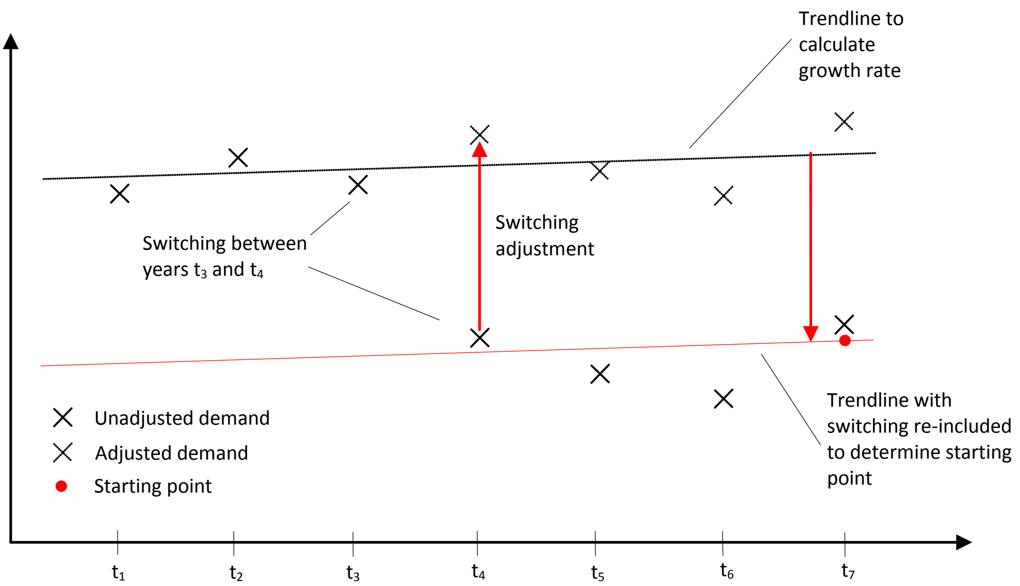
$$S = m * T + c + \sum \Delta D$$

where

S	= Starting point
T	= Most recent historical year (eg 2013)
m	= adjusted normalised trendline slope
c	= adjusted normalised trendline intercept
$\sum \Delta D$	= cumulative historical step changes

The starting point is the point on the adjusted normalised trendline in the most recent historical year PLUS any cumulative historical step changes re-included.

An example of determining the growth rate and starting point is shown diagrammatically below. The unadjusted demand points include switching (in this case some load is switched away from the substation) between years t_3 and t_4. The reversing out of this switching is represented by the adjusted demand points from year t_4 onwards. The growth rate is calculated by trending the adjusted demand points. The starting point is found by re-inclusion of the switching adjustment and taking the point on the trendline in the most recent year (t_7).



2.6 Calculate forecast demand

Following the determination of growth rate and starting point, the forecast demand is then calculated. Demands are broken down into their real power (MW) and reactive power (MVAr) components where growth rates, capacitors and step changes from spot loads, load transfers and embedded generation are applied.

2.6.1 Real power

The MW forecast demand for each year is calculated according to the following formula:

$$D_{MW,t} = D_{MW,t-1} * (1 + ROG) + \Delta D_{MW,t}$$

where

$D_{MW,t}$ = Forecast MW demand in year “t”

$D_{MW,t-1}$ = Forecast MW demand in year “t-1”

ROG = growth rate

$\Delta D_{MW,t}$ = net MW step changes due to spots, transfers and EG in year “t”

The MW forecast demand for each year is calculated by taking the previous year’s MW forecast demand and multiplying by the growth rate and adding the net of any MW load transfers, spot loads and embedded generation. If the MW forecast is to be calculated for the first forecast year, growth rate is applied to the MW forecast starting point.

2.6.2 Reactive power

The MVAr forecast demand for each year is calculated according to the following formula:

$$D_{MVAr,t} = D_{uMVAr,t-1} * (1 + ROG) + \Delta D_{MVAr,t} - C$$

where

$D_{MVAr,t}$ = Forecast MVAr demand in year “t”

$D_{uMVAr,t-1}$ = Uncompensated forecast MVAr demand in year “t-1”

ROG = growth rate

$\Delta D_{MVAr,t}$ = net MVAr step changes due to spots, transfers and EG in year “t”

C = MVAr reactive compensation due to capacitors

The MVAr forecast demand for each year is calculated by taking the previous year’s uncompensated MVAr forecast demand and multiplying by the growth rate and adding the net of any MVAr load transfers, spot loads and embedded generation. Reactive compensation due to capacitors is then subtracted. This way, the growth rate is not applied to the capacitors. The capacitors are assumed to be switched in to achieve a compensated power factor as close as possible to unity according to their step size and maximum available capacitance.

If the MVAr forecast is to be calculated for the first forecast year, growth rate is applied to the MVAr forecast starting point.

The forecast demand in amps and MVA are calculated once the MW and MVAr have been determined.

2.6.3 Future step changes

For the zone substation forecast, the conversion into MW and MVAr of step changes in demand uses the uncompensated power factor in the previous year. It is necessary to use the previous year's pf to avoid circular reference issues since the forecast is built up for each respective year across all locations before the next year is calculated and so on. The decision to use the source or destination substation's power factor depends on the step change:

- Load transfer: upf at source substation
- Spot load: upf at destination substation
- Embedded generator: upf at destination substation

For STS, the step changes are "rolled up" from the downstream substations using the relevant diversity factor (see Appendix E) between each respective ZN and the STS. The conversion of step changes into MW and MVAr as seen at the STS uses the upf at the STS is used as a proxy.

2.6.4 Only committed step changes included

Only financially committed future step changes are included in the forecast. Spot loads, load transfers and embedded generators that have not progressed to become financially committed are excluded from the forecast.

2.6.5 Spot loads

Spot loads have a scaling factor of 80% applied to represent the probability and ultimate magnitudes of spot loads occurring. Spot loads only appear in the first 3 forecast years.

Spot loads are eliminated from the 4th forecast year onwards due to econometric factors being included in the growth rates from this point. This is done to avoid potentially double-counting spot loads.

2.7 Application of growth rate

The growth rates used in the peak demand forecast methodology incorporates a mixture of historical trends overlaid with known short-term step changes in demand (spot loads and load transfers) for the short term forecast and econometric drivers for the medium to long term forecast.

2.7.1 Years 1 to 3

The growth rate applied in the first 3 years is determined using the method described in section 2.4 "Determine Growth Rate".

2.7.2 Years 4 to 10

Econometric factors are included in the forecast from the 4th year onwards.

The rationale is that for the short term (years 1 to 3), it is expected that historical trends overlaid with known spot loads and load transfers will provide the best indication of the near term forecast. Beyond this point, there is less certainty that trends developed using historical data will be accurate. Factors that influence the wider economy should in turn drive customer behaviour in electricity consumption.

The mechanism for inclusion of the econometric drivers in the forecast is via an adjustment to the short term growth rates on a year by year and regional basis using regional growth rates.

Regional growth rates are evaluated based on residential and non-residential segment contributions and are based on the following key drivers:

- Projected residential customer numbers
- Projected changes in average annual electricity consumption per customer, which is itself driven by projected real disposable income and real retail electricity prices.
- Expected impacts of ongoing solar PV penetration (including cessation of the Solar Bonus Scheme in 2017),
- Expected impacts of the NSW Energy Savings Scheme,
- Air conditioning penetration and saturation.

See Appendix G for details of the long term growth rate method.

Regional growth rates are evaluated for 5 broad regions in Ausgrid's supply area, which allows the use of regional data such as long term housing projections and rates of air conditioning penetration as key driver variables. The 5 regions are:

- Inner Metro
- North Shore
- Central Coast
- Lower Hunter
- Upper Hunter

The adjustment is performed by adjusting the short-term growth rate at each zone substation, in each year between years 4 and 10, such that the aggregated substation year on year change in demand in a region, expressed as a growth rate, matches that region's growth rate in that same year.

Any instances of spot loads are removed from the forecast in this period since they are implicit in the econometric driver variables.

See Appendix H for details of the econometric growth rate adjustment.

2.7.3 Years 11 to 15

From the 11th forecast year until the 15th forecast year, the 10th year growth rate (after applying the econometric adjustment) is linearly ramped up or down towards the 16th year growth rate.

2.7.4 Year 16 onwards

From the 16th forecast year onwards, the growth rate is the same as the growth rate for that region. It is considered that factors driving activity in the wider economy will in turn drive growth rates on the electricity network and that the statistically derived growth rates calculated by adjusting historical data, as is applied to the first 3 forecast years, is not applicable at this point.

3 Implementation

The peak demand forecast is implemented using SAS software and was purpose built in-house at Ausgrid. Input data relating to the configuration of the electricity network and known historical and future changes to the network is maintained in Excel spreadsheets. Computations are performed within the SAS software, with a couple of exceptions outlined below, and the resulting forecast outputs are printed in Excel spreadsheets.

The computational processes carried out external to the SAS system are:

- Sydney CBD forecast
- Econometric growth rate adjustment

Instead, these processes are performed using Excel spreadsheets. This is due to timing issues associated with building the SAS forecast system and internal forecast delivery deadlines.

The Sydney CBD is geographically small, covering less than 3 km^2, but is the densest portion of Ausgrid’s network due to the high concentration of office buildings and apartments. The area is the commercial heart of Sydney, which demands a higher level of network reliability. The network topology employs a triplex architecture, and is planned differently to the rest of Ausgrid’s network. The Sydney CBD is highly interconnected and individual loads can be readily switched to be supplied from different supply points, substation capacity permitting. Accordingly, this is reflected in the CBD forecast method, where individual substations in the CBD are added together and the forecast is performed on the summated lump. Growth and demand is determined for the CBD as a whole and then divided amongst the individual CBD substations based on historical load splits.

The econometric growth rate adjustment allows the incorporation of macro economic drivers into the forecast. Econometric growth rates across 5 broad regions are used to adjust the growth rates at the individual substation level based on quantum of demand at the substation relative to the total demand in that region.

Appendix A: Apparent Temperature

There are several Weather Variables that can be used to try and establish the correlation between Maximum Demand for the day, and “The Weather” - including:-

- Raw Temperature – just the °C. Maximum Temperature in Summer and Minimum Temperature in Winter
- Apparent Temperature – which is derived from a BoM [2] equation that modifies raw °C by also taking into account both the wind and the humidity.
- Average Temperature – which takes account of both the Maximum and Minimum for the day, not just what the temperature got to, but also where it came from.

The choice of Weather Variable selection is based on a measure of people’s perception of, and reaction to the weather: *Average Apparent Daily Temperature.*

Apparent Temperature

As indicated above, the Apparent Temperature is not just the temperature in raw °C. It is the raw temperature modified by a BoM equation that also takes account of both the humidity and the wind. Particularly with respect to people’s propensity to turn air conditioners on in Summer, the Apparent Temperature should incorporate the fact that humidity tends to make a given raw temperature feel worse, and a breeze tends to make a given raw temperature feel better.

The equation for Apparent Temperature is:

$$AT = Ta + 0.33 \times e - 0.70 \times ws - 4.00$$

$$e = \frac{rh}{100} \times 6.105 \times \exp\left(\frac{17.27 \times Ta}{(237.7 + Ta)}\right)$$

where

AT = Apparent Temperature (°C).

Ta = Ambient Temperature (°C).

e = Water Vapour Pressure (hPa).

ws = Wind Speed (m/s).

rh = Relative Humidity (%).

Average Temperature

Rather than just using Maximum Temperatures in Summer and Minimum Temperatures in Winter, there is a general consensus (particular reference to our discussions with Energex) that how people perceive and react to the weather “now” is not just an outcome of what the weather is doing at the time – but is also influenced by how the weather may have changed leading up to the time of interest.

For example, if the preceding night, and the early part of the day were reasonably pleasant – and then a hot and humid afternoon occurs, people may react more slowly to turn the air conditioners on. However, if the preceding nightly Minimum was higher, and the morning is hot - then as the temperature and/or humidity

[2] Bureau of Meteorology.

progressively increase during the afternoon, people are likely to get fed up sooner and turn the air conditioners on earlier (or more people turn them on).

Conversely in Winter, if you're heading into a really cold night, people would be far more likely to turn the heating on when they arrive home (or turn more heating on) if they've been "pre-conditioned" by a cold and windy miserable day.

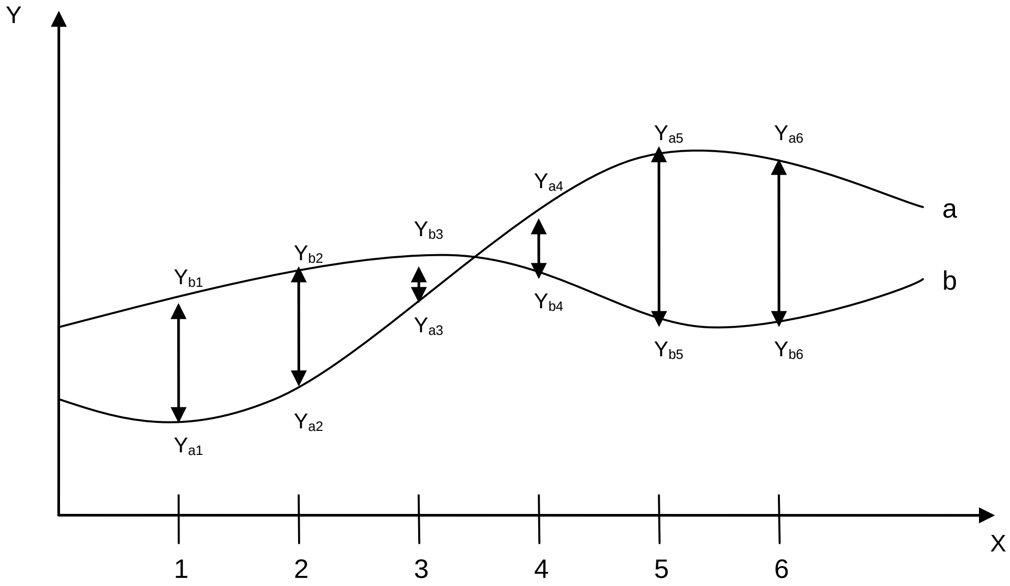
We have elected to use Average Temperature because it provides a measure of both the Seasonal extreme (Maximum for Summer and Minimum for Winter) and the variation in the temperature prior to the extreme. It also provides a consistent variable that can be used throughout the whole year and does not introduce seasonal discontinuities into the graphical processes.

Appendix B: Clustering

This appendix describes the automated data cleansing step called Clustering. Clustering is a process that groups daily demand profiles with a similar shape into “clusters”. The clusters are used to assess each daily demand profile and allows anomalies to be identified and data gaps to be interpolated.

Clustering is performed by first obtaining raw interval data from multiple seasons and removing days where all load values for the day are zero or null. The distance between each daily load curve across the 96 fifteen minute time intervals of each day is calculated using the Euclidean distance method:

Euclidean distance



The Euclidean distance between the above curves (a) and (b) across 6 time intervals is calculated as follows:

$$D_{ab} = \sqrt{|Y_{b1} - Y_{a1}|^2 + |Y_{b2} - Y_{a2}|^2 + |Y_{b3} - Y_{a3}|^2 + |Y_{b4} - Y_{a4}|^2 + |Y_{b5} - Y_{a5}|^2 + |Y_{b6} - Y_{a6}|^2}$$

For 96 time intervals, the above equation is extended by adding extra terms for each interval:

$$D_{ab} = \sqrt{|Y_{b1} - Y_{a1}|^2 + |Y_{b2} - Y_{a2}|^2 + ... + |Y_{b96} - Y_{a96}|^2}$$

The distance between each daily load profile is calculated and the results are arranged in a distance matrix (or table). If there are 3 curves (a), (b) and (c), the size of the matrix will be 3 x 3:

$$\begin{array}{c} \\ a \\ b \\ c \end{array} \begin{array}{c} \begin{array}{ccc} a & b & c \end{array} \\ \begin{bmatrix} 0 & X & X \\ D_{ab} & 0 & X \\ D_{ac} & D_{bc} & 0 \end{bmatrix} \end{array}$$

For "n" curves the size of the matrix will be n x n.

Note: The matrix is symmetrical since:

- The distance between curves (a) and (b) is the same as the distance between curves (b) and (a) and so on for each pair of curves.
- The main diagonal has zeroes since the distance between any curve and itself is zero.

Clusters

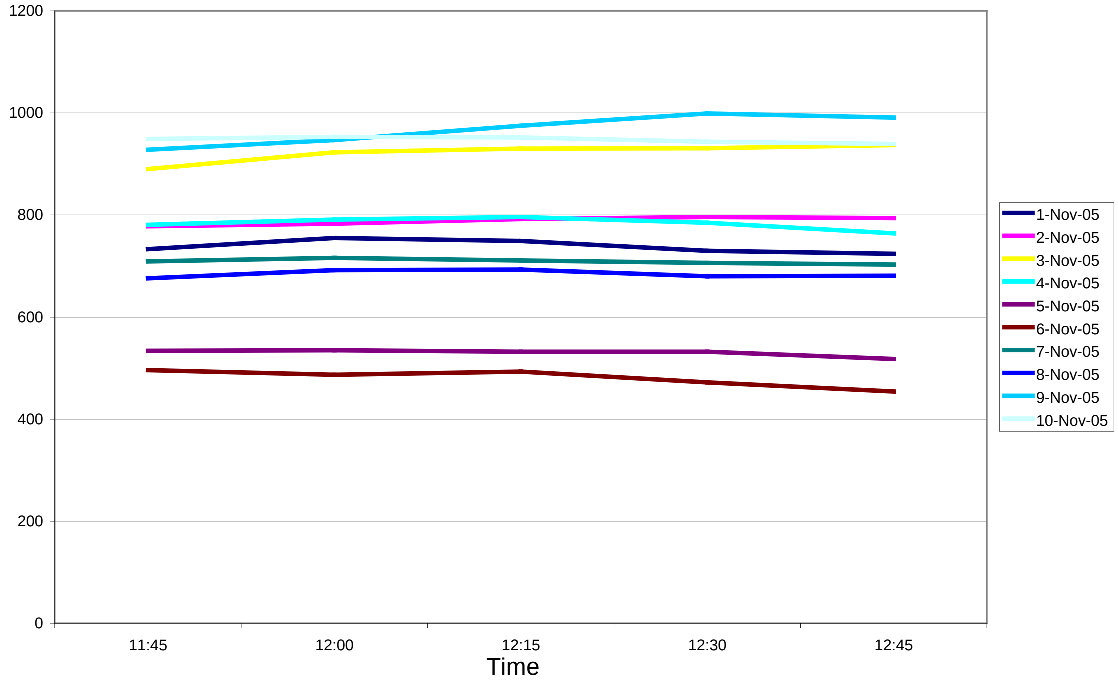
Using the distance matrix, identify the clusters by iteration. Only the matrix elements under the main diagonal need to be considered due to matrix symmetry:

- Locate the two curves with the least distance from each other by finding the lowest number in the matrix.
- Combine the two curves identified and recompute the distances to the other curves.
- Regenerate the distance matrix. The size of the matrix will reduce by 1.
- Repeat until only a 2 x 2 matrix remains.

Example

The following is a clustering example based on loads in Bass Hill 33/11kV.

The loads occur over ten days between 1 Nov 2005 and 10 Nov 2005. Five time intervals per day between 11:45 and 12:45 are analysed.



Loads are as follows:

TIME	A	B	C	D	E	F	G	H	I	J
	1-Nov	2-Nov	3-Nov	4-Nov	5-Nov	6-Nov	7-Nov	8-Nov	9-Nov	10-Nov
11:45	733	778	890	781	534	496	709	676	928	949
12:00	755	783	923	791	535	487	716	692	947	953
12:15	749	792	930	796	532	493	711	693	975	952
12:30	730	796	931	785	532	472	706	680	999	944
12:45	724	794	937	764	518	454	703	681	991	939

Next, generate the distance matrix using the Euclidean distance method. Begin the iterative process of identifying the lowest element, combining the two curves and regenerate the distance matrix. Curves B and D are the lowest with distance 33.

Iteration 0 Matrix

	A	B	C	D	E	F	G	H	I	J	
A											
B	118										
C	414	299									
D	102	**33**	314								
E	466	578	878	566							
F	577	691	990	678	114						
G	68	179	478	167	400	512					
H	121	234	533	222	345	457	56				
I	519	404	108	419	981	1094	583	637			Minimum distance
J	468	356	71	367	933	1044	533	588	82		33

In this example, there are eight iterations after the initial matrix:

Iteration 1 Matrix

	A	B,D	C	E	F	G	H	I	J
A									
B,D	109								
C	414	306							
E	466	572	878						
F	577	684	990	114					
G	68	173	478	400	512				
H	121	227	533	345	457	**56**			
I	519	411	108	981	1094	583	637		
J	468	361	71	933	1044	533	588	82	

Minimum distance

56

Iteration 2 Matrix

	A	B,D	C	E	F	G,H	I	J
A								
B,D	109							
C	414	306						
E	466	572	878					
F	577	684	990	114				
G,H	94	200	506	373	485			
I	519	411	108	981	1094	610		
J	468	361	**71**	933	1044	561	82	

Minimum distance

71

Iteration 3 Matrix

	A	B,D	C,J	E	F	G,H	I
A							
B,D	109						
C,J	440	333					
E	466	572	905				
F	577	684	1017	114			
G,H	94	200	533	373	485		
I	519	411	**89**	981	1094	610	

Minimum distance

89

Iteration 4 Matrix

	A	B,D	C,J,I	E	F	G,H
A						
B,D	109					
C,J,I	466	358				
E	466	572	930			
F	577	684	1042	114		
G,H	**94**	200	558	373	485	

Minimum distance 94

Iteration 5 Matrix

	A,G,H	B,D	C,J,I	E	F
A,G,H					
B,D	169				
C,J,I	527	358			
E	403	572	930		
F	515	684	1042	**114**	

Minimum distance 114

Iteration 6 Matrix

	A,G,H	B,D	C,J,I	E,F
A,G,H				
B,D	**169**			
C,J,I	527	358		
E,F	459	628	986	

Minimum distance 169

Iteration 7 Matrix

	A,G,H,B,D	C,J,I	E,F
A,G,H,B,D			
C,J,I	460		
E,F	527	986	

Minimum distance 460

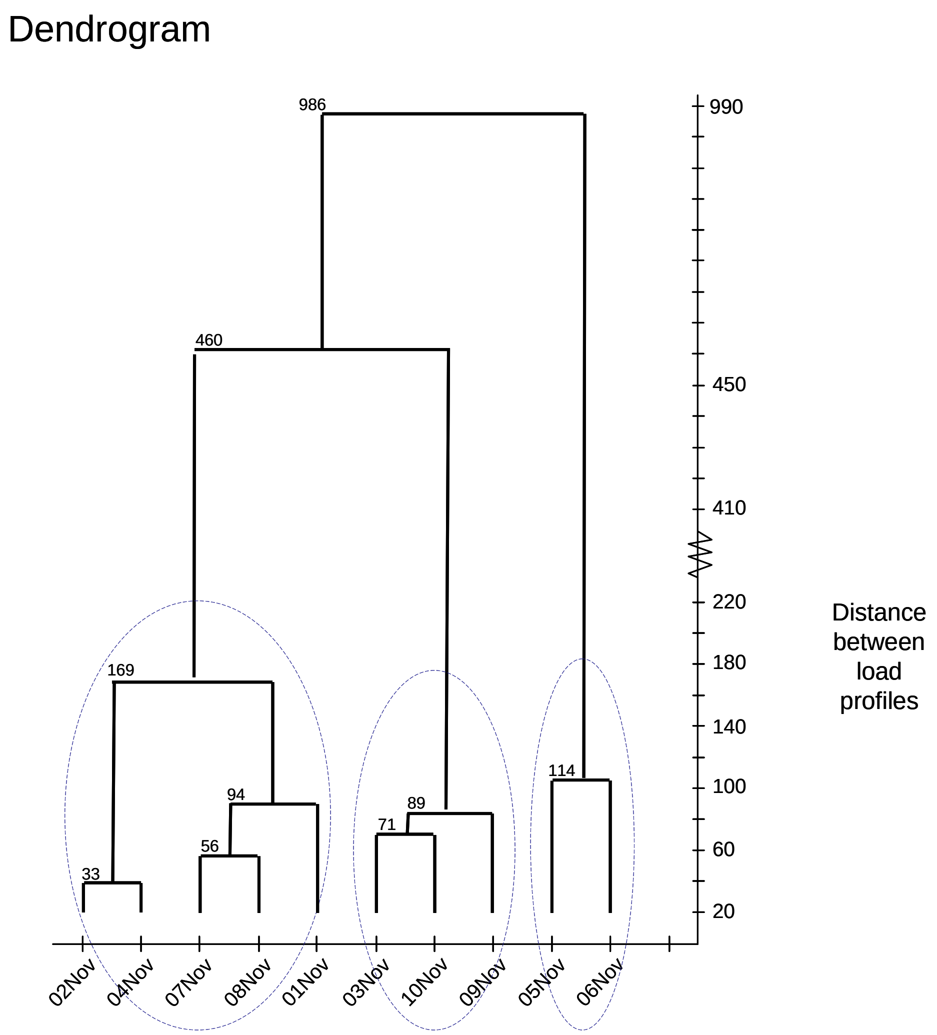
Iteration 8 Matrix

	A,G,H,B,D,C,J,I	E,F
A,G,H,B,D,C,J,I		
E,F	986	

Minimum distance

986

The distance matrix has been reduced to 2 x 2 so the process is finished. The result can be displayed in a tree diagram (dendrogram).



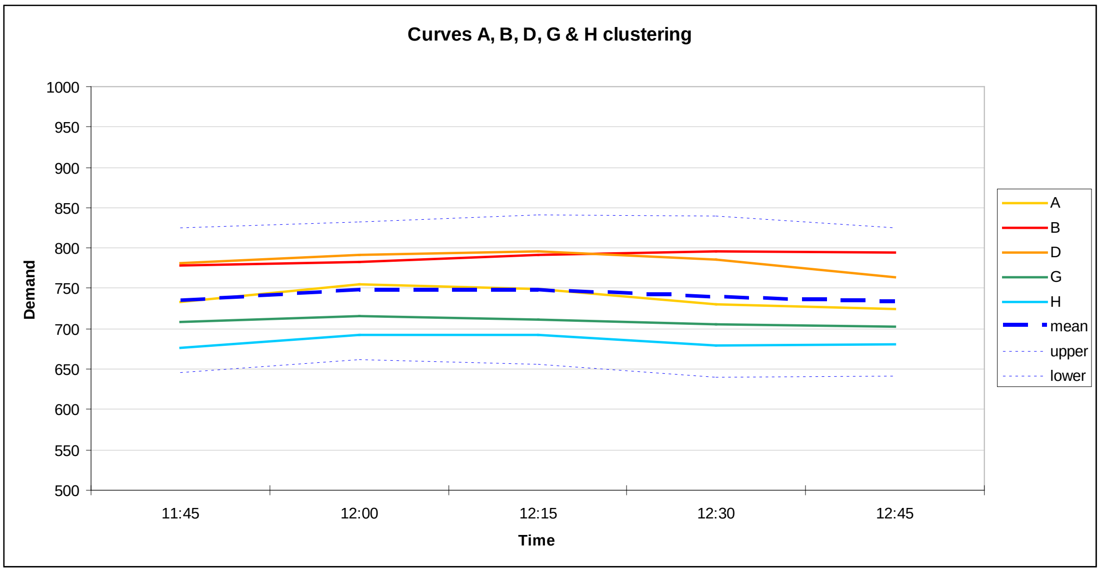
Within SAS, two input parameters are specified to act as constraints on the selection of clusters:

- Minimum number of clusters: the number of clusters must be greater than or equal to this value. This parameter is set to 2.
- The number of clusters must have a Cubic Clustering Criterion (CCC) statistic value greater than a specified threshold. This parameter relates to a statistical test similar to those used in hypothesis testing. This parameter is set to 3.

The final selection of the number of clusters is the minimum number that satisfies the two criteria above. In this example there are 3 clusters.

The process of selecting the minimum number of clusters and the CCC parameters can be represented on the dendrogram as calibrating the height of an imaginary horizontal line and counting the number of “stems” below that line. The higher the CCC parameter, the lower the position of the line, and consequently the larger the number of clusters expected.

For each cluster, the mean and upper and lower bounds using +/- 2 standard deviations are then calculated based on the curves in that cluster. In the example, curves B, D, G, H and A (the left-most cluster in the dendrogram) comprise a cluster, so the mean and upper and lower bounds are calculated based on these curves which is shown below.

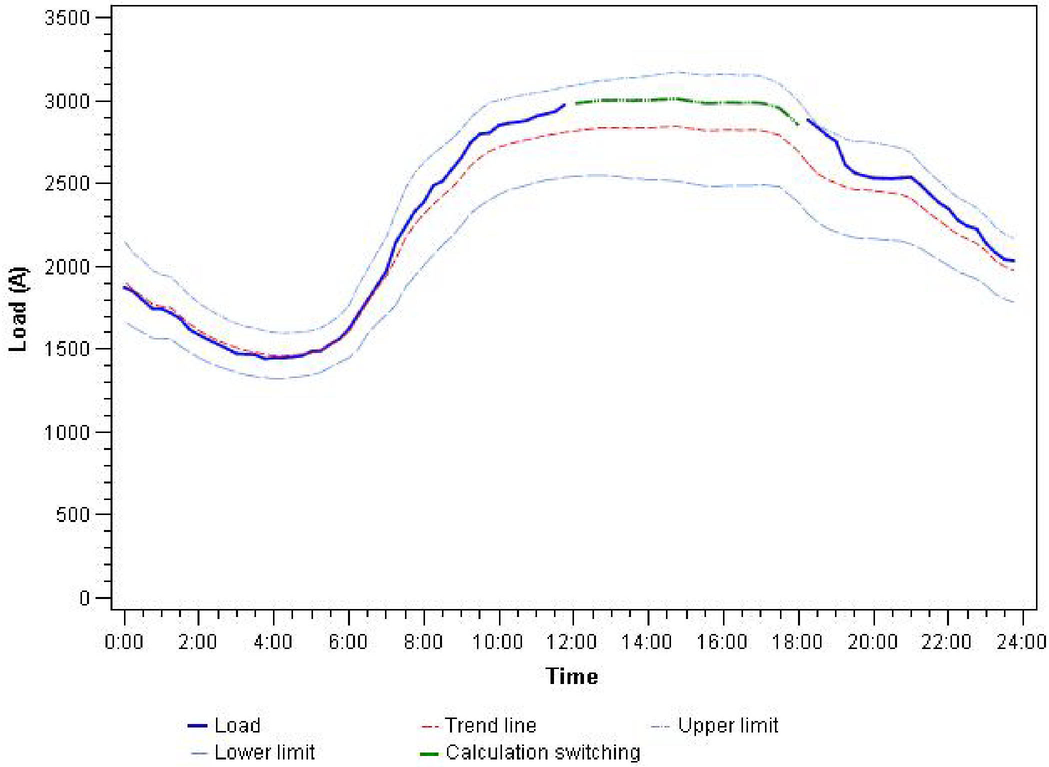


This process is similarly followed for the other two clusters using their respective curves.

Next, for the season being cleansed, each daily demand curve is assigned the appropriate cluster. Each daily demand curve is then compared against the mean, upper and lower bounds of the assigned cluster for each interval and is either smoothed, trimmed, interpolated or unmodified based on boundary conditions for that interval and the position of that interval relative to the upper/lower bounds of the cluster.

Below is an example of missing interval data at Burwood 132/11kV ZN being interpolated using the cluster properties.

Burwood 132_11kV
Daily Load Profile (Corrected)
Date: WED / 15DEC2010



The missing data between approximately 12:00 and 18:30 has been interpolated (green segment) using the mean of the cluster (red dashed line).

Appendix C: Summer 2008/09 Adjustment

This appendix describes the method used to account for unusually high weather normalised demands at several substations arising from unique weather conditions experienced on Saturday 24/1/2009. For these locations, the summer 2008/09 weather normalised demand has been adjusted down.

Background

The weather normalisation methodology is based on:

- Developing a linear relationship between daily maximum demand vs daily average apparent temperature[3] for each season;
- Using a 50/50 weighting of daily maximum and minimum temperatures;
- Incorporating non-working days into the simulation. Separate regression lines are fitted to working days and non-working days. This enables removal of the public holiday allowance factor which was present in previous forecasts.

Taking into consideration the above methodology features, the following weather and demand conditions were observed during the Australia Day long weekend in summer 2008/09:

- Weather conditions on Saturday 24/1/2009 resulted in a high maximum temperature (37-38 deg) and a low (13-14 deg) minimum temperature resulting in a mild calculated average temperature;
- Demands experienced on this day were close to the max seasonal demand for many locations. The combination of high load and mild average temperature occurring on a weekend caused the gradient of the non-working day regression line being very steep for some locations. This in turn resulted in very high weather normalised demand for summer 2008/09 for the affected locations.

Consequently, all locations were assessed to validate the steepness of the non-working day trendline. For cases where the trendline steepness was not justified, an override was applied to negate the weather normalised demand contribution from the non-working days.

Method

The method to validate the steepness of the summer 2008/09 non-working days trendline considers the separate contributions made to the seasonal weather normalised demand from working days and non-working days. The summer 2008/09 daily peak demand vs daily temperature scatter graph is examined for each substation.

The validity of the summer 2008/09 is examined based on the following conditions:

- Day of season peak: working day or non-working day
- Non-working days only weather normalised demand > working days only weather normalised demand
- Number of non-working day season peaks over the past 7 years.

Where the calculated summer 2008/09 season weather normalised demand is not considered reasonable for a location, an override is applied to negate the non-working days contribution to the seasonal weather normalised demand.

Reasons for applying an override include:

[3] Hereafter, any mention of temperature refers to apparent temperature.

- Season peak occurs on a working day but the non-working days only weather normalised demand > working days only weather corrected demand.
- Number of seasonal peak demands occurring on a non-working day in the past 7 years is two or less but non-working days only weather normalised demand > working days only weather corrected demand.
- Slope of non working days regression line is excessively steep.

The following locations were identified as requiring an override:

Arncliffe 33_11kV	Gwawley Bay 33_11kV	Noraville 33_11kV
Avondale 33_11kV	Harbord 33_11kV	Nulkaba 33_11kV
Berowra 132_11kV	Hunters Hill 66_11kV	Peakhurst 132_33kV
Blakehurst 33_11kV	Jannali 33_11kV	Pennant Hills 132_11kV
Boolaroo 33_11kV	Killarney 33_11kV	Rathmines 132_11kV Temp
Branxton 66_11kV	Kirrawee 132_11kV	Rose Bay 33_11kV
Carlton 33_11kV	Kotara 33_11kV	Sans Souci 33_11kV
Charlestown 33_11kV	Kuring-gai 132_33kV	Scone 33_11kV
Charmhaven 132_11kV	Kurri 33_11kV	St Ives 33_11kV
Concord 33_11kV	Leichhardt 33_11kV	Stockton 33_11kV
Cronulla 132_11kV	Lindfield 33_11kV	Thornton 33_11kV
Drummoyne 132_11kV	Maryland 132_11kV	Turramurra 33_11kV
Dulwich Hill 33_11kV	Meadowbank 132_11kV	Umina 66_11kV
East Maitland 33_11kV	Miranda 33_11kV	Waverley 33_11kV
Edgeworth 33_11kV	Narrabeen 33_11kV	Williamtown 33_11kV
Five Dock 33_11kV	Newport 33_11kV	Wyong 132_11kV

Appendix D: Summer 2011/12 Adjustment

This appendix describes the method used to adjust the summer 2011/12 regression parameters to account for the abnormally mild summer 2011/12 season.

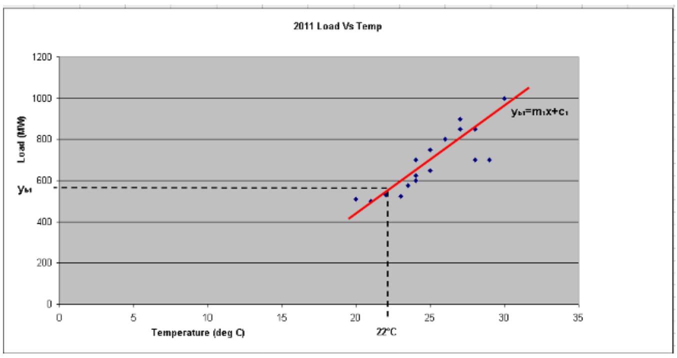
Background

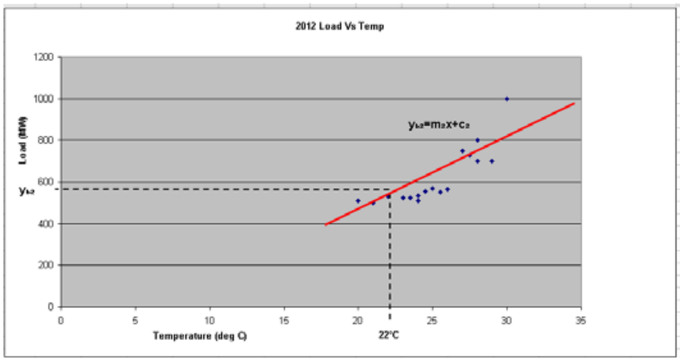
Raw data from the mild summer 2011/12 season, represented using the daily peak demand vs daily temperature[4], saw a significantly lower number of days where the average temperature was above the knee-point threshold of 22˚C. For a considerable number of substations, there were very few, if any, data points above an average temperature of 28˚C.

A lack of data points in the high end of the temperature scale resulted in the regression fit of the daily peak demand vs daily temperature being dominated by the cluster of points at the low end of the temperature scale. As a result, the summer 2011/12 slope was depressed and the resultant weather normalised demand was unreasonably low, when comparing the difference between actual peak demand vs weather normalised demand for summer 2011/12 (the correction) and the correction results of previous years.

Methodology

A methodology for adjusting the summer 2011/12 slope was developed to modify the slope to a more reasonable value that incorporated the previous year's regression parameters. At the heart, the method adjusts the slope and intercept for summer 2011/12 using the slope and intercept for summer 2010/11.





The daily peak demand vs daily temperature relationship uses a linear fit:

$$D(T) = m * T + c$$

[4] The word "temperature" refers to apparent temperature.

where

$D(T)$ = demand

m = regression slope

c = regression intercept

T = average apparent temperature

Slope adjustment

The adjusted summer 2011/12 slope is determined scaling the summer 2010/11 slope by the ratio of the summer 2011/12 base load to the summer 2010/11 base loads. The base load corresponds to the flat section of the bathtub curve and can be obtained by substituting the knee point temperature into the regression function. For a knee point temperature of 22^{o}C the adjusted slope is:

$$m'_{2012} = \frac{D_{2012}(T = 22)}{D_{2011}(T = 22)} * m_{2011}$$

where

m'_{2012} = adjusted summer 2011/12 slope

m_{2011} = summer 2010/11 slope

$D_{2012}(T=22)$ = base demand in summer 2011/12

$D_{2011}(T=22)$ = base demand in summer 2010/11

Substitute slope and intercept parameters:

$$m'_{2012} = \frac{m_{2012} * 22 + c_{2012}}{m_{2011} * 22 + c_{2011}} * m_{2011}$$

where

m_X = slope for year X

c_X = intercept for year X

Intercept adjustment:

The adjusted summer 2011/12 intercept is determined by fixing the adjusted summer 2011/12 slope to the 22˚C knee point for summer 2011/12.

$$
\begin{aligned}
c &= D(T) - m * T \\
c'_{2012} &= D_{2012}(T = 22) - m'_{2012} * 22 \\
&= m_{2012} * 22 + c_{2012} - \frac{m_{2012} * 22 + c_{2012}}{m_{2011} * 22 + c_{2011}} * m_{2011} * 22
\end{aligned}
$$

Adjusted function

The adjusted function for summer 2011/12 incorporating the adjusted slope and adjusted intercept is:

$$
\begin{aligned}
D(T) &= m * T + c \\
D'_{2012}(T) &= m'_{2012} * T + c'_{2012} \\
&= \left(\frac{m_{2012} * 22 + c_{2012}}{m_{2011} * 22 + c_{2011}} * m_{2011} \right) * T + \left(m_{2012} * 22 + c_{2012} - \frac{m_{2012} * 22 + c_{2012}}{m_{2011} * 22 + c_{2011}} * m_{2011} * 22 \right)
\end{aligned}
$$

Appendix E: Diversity Factor

This appendix sets out the methodology used to calculate diversity factor, which is an important parameter used in the planning of the electricity network.

Background

The diversity factor in a transmission or distribution network is the ratio of peak demand of the upstream network to the peak demand at the local network. It indicates how much demand an individual substation or customer contributes to its upstream network peak. Diversity factor is a number between 0 and 1.

Diversity factor can be calculated at any layer of the network depending on planning requirements. For example, the diversity factor calculated at a zone substation with respect to a subtransmission substation represents the percentage contribution of a zone substation peak demand towards the subtransmission substation at the time of its peak demand. Similarly, the diversity factor of a feeder with respect to an upstream can also be calculated.

Diversity factor is specific to a particular network configuration and load cycle. If load cycle changes, such as residential load replacing industrial load, or the network topology changes, then the diversity factor may also change. Hence, diversity factor is a changing parameter and calculated based on a snapshot at a particular time.

For these reasons, Ausgrid has adopted the following convention when applying diversity factor:

- For the network planning process (ie. forward looking), the changing nature of diversity factor is addressed by averaging the diversity factor over a number of seasons.
- When analysing historical data (ie. backward looking), historical (actual) diversity factor for a particular year is used.

Calculation

The following steps are followed to calculate the diversity factor of a downstream element (eg. zone substation) with respect to an upstream element (eg. subtransmission substation):

Obtain the upstream element peak load day and time based on daily peak demand for the previous 5 seasons. If the location does not have interval data for the top 1 value, then retrieve the load at the top 2 peak date and time.

- Obtain the downstream element demand at those load times obtained from Step 1 over the 5 seasons.
- Obtain the downstream element peak demand for each of the 5 seasons. If the peak demand is overridden, the overridden value will be used in the calculation.
- Calculate the ratio of demand obtained from Step 2 and peak demand obtained from Step 3 over the 5 seasons.
- Calculate the 5 year average of the ratios from Step 4.

Conventions

The following diversity factor conventions are applied:

- For calculation of diversity factors at subtransmission substations, it should be calculated with respect to either the region, ie. Hunter or Sydney.
- For zone substations with two supplying subtransmission substations, the diversity factor should be the average of diversity factors calculated from each zone substation transformer groups with respect to the supplying subtransmission substations.

- If the network configuration has significantly changed, the calculations prior to the change will no longer be relevant. The final diversity factor should be the rolling average consists of the seasons after the change only.
- Data used in the calculation should be consistent with the data used in the forecast. Cleansed data free of abnormal switching should be used. Locations with data issues should be considered separately with option to override or remove the value when required.
- For customer and generator diversity factor calculations: For Summers < 2011 and Winter < 2011, raw interval load data is to be used, as cleansed interval load data is not available.
- If a calculated diversity factor is not available or deemed unacceptable, an override is required. To override each diversity factor, an updated value and associated comment is required to be entered into a spreadsheet. The spreadsheet will then be bulk loaded into SAS and an updated report will be produced to show the change is complete.
- For transformer diversity factor, only the most recent year's data is used hence no rolling average is applied in the calculation.

Appendix F: Power Factor

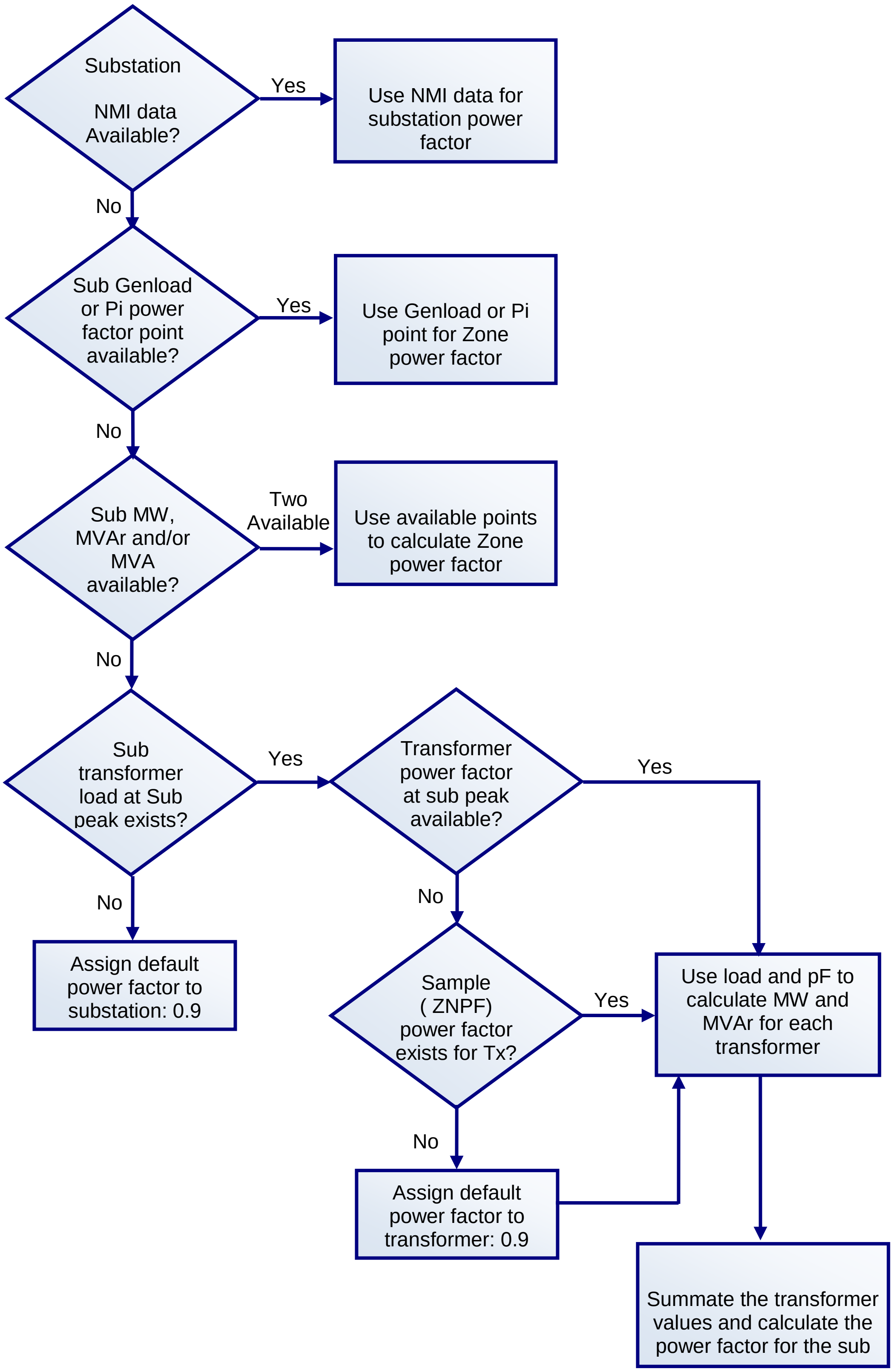
This appendix describes the methodology used to calculate power factor in the forecast. Power factor is the ratio of real power to apparent power and is used to convert between MW, MVAr and MVA.

For the forecast, power factor is calculated using a rolling 5 year average of the individual power factors in each season for each location.

The method to obtain power factor is different for each substation. This is largely a legacy issue due to historical amalgamations and restructuring that have occurred in the electricity supply industry, with former now-defunct jurisdictions each having their own conventions for metering and data acquisition and consequently, different data acquisition systems each having different measured quantities.

To allow for differing levels of data availability, a descending hierarchy is used to determine power factor. In the best case, power factor is measured directly from the data source and in the worst case, an assumed value is used where all other possible options have been exhausted.

The calculation of power factor is summarised in the following flowchart:


Substation
NMI data Available?
Yes
Use NMI data for substation power factor
No
Sub Genload or Pi power factor point available?
Yes
Use Genload or Pi point for Zone power factor
No
Sub MW, MVAr and/or MVA available?
Two Available
Use available points to calculate Zone power factor
No
Sub transformer load at Sub peak exists?
Yes
Transformer power factor at sub peak available?
Yes
No
Assign default power factor to substation: 0.9
No
Sample (ZNPF) power factor exists for Tx?
Yes
Use load and pF to calculate MW and MVAr for each transformer
No
Assign default power factor to transformer: 0.9
Summate the transformer values and calculate the power factor for the sub

Appendix G: Long term growth rate methodology

This appendix sets out the method used to determine to the long-term growth rates used in the forecast. The long term growth rates influence the individual substation growth rates from the 4th year onwards.

The residential and non-residential customer segments are modelled separately and then combined to provide the overall long term growth rates for Ausgrid. The long term growth rates are derived using an end-use model for the residential segment and econometric modelling for the non-residential segment.

Residential segment

Estimation of the residential segment contribution to the long term growth rates is based on estimating the historical residential segment contribution to peak demand using sample data, applying projections of driver variables into an end-use model and overlaying the impact of post-model adjustments which account for known or expected future changes.

Estimation of the residential segment contribution to peak demand is based on load research of a random sample of 109 interval-metered residential customers between 2009 and 2011. The sample customers were grouped according to those with air conditioning and those without air conditioning. Average load profiles were produced for both with and without air conditioning groups and the daily demands at time of Ausgrid system peak demand were weather corrected to POE50. These average weather corrected demands were then multiplied by estimates of the number of residential customers with and without air conditioning.

The projection of the residential segment contribution to peak demand is based on the following drivers:

- Projected residential customer numbers
- Projected changes in average annual electricity consumption per customer, which is itself driven by projected real disposable income and real retail electricity prices.
- Expected impacts of ongoing solar PV penetration (including cessation of the Solar Bonus Scheme in 2017),
- Expected impacts of the NSW Energy Savings Scheme,
- Air conditioning penetration and saturation.

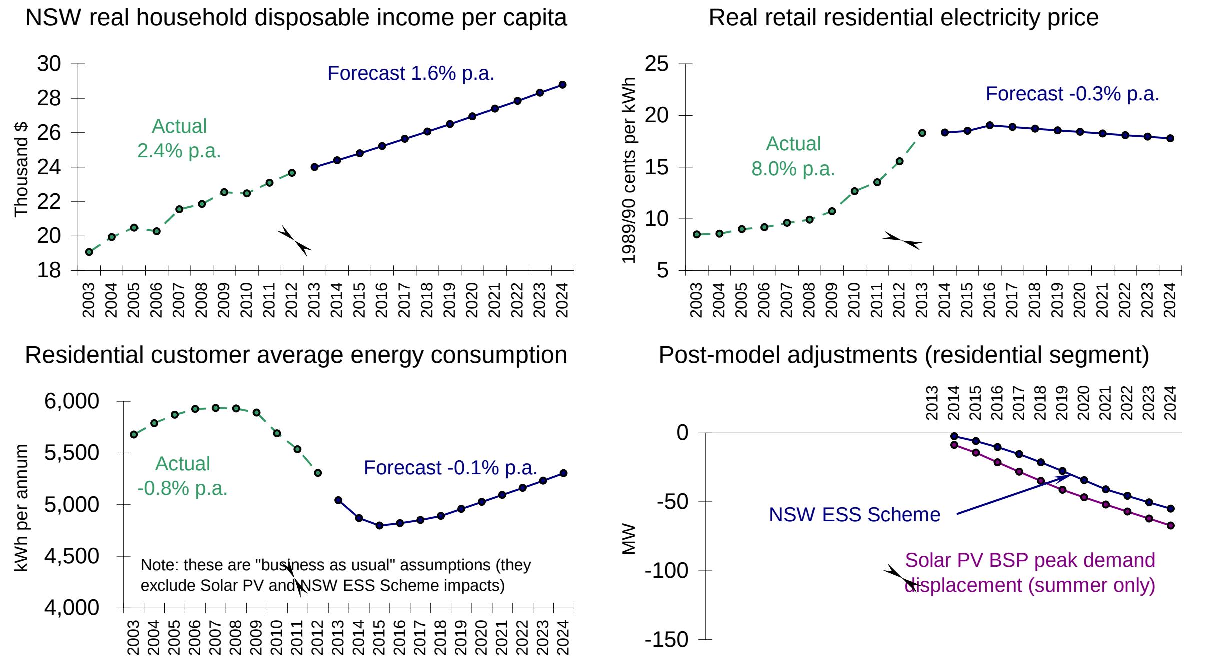
The sources of the residential segment driver projections are summarised below:

Driver	Source of projections
Total residential customer numbers	Ausgrid System Planning Section: The customer number projections correspond with those developed in November 2012 for connections-related capital expenditure forecast.
Air conditioning penetration	Ausgrid Network Forecasting Section: For existing customers it is assumed that the penetration rate will increase by 2% per annum until a penetration rate of 80% is reached in 2017/18. It is assumed that 80% of new customers' premises will be air conditioned.
Real disposable income per capita	NIEIR projections commissioned by Networks NSW to ensure consistency among the input assumptions to be relied on by the three NSW DNSPs in preparing their regulatory proposals. For peak demand forecasting purposes the annual projections used are the average of the 2014 to 2024 period.

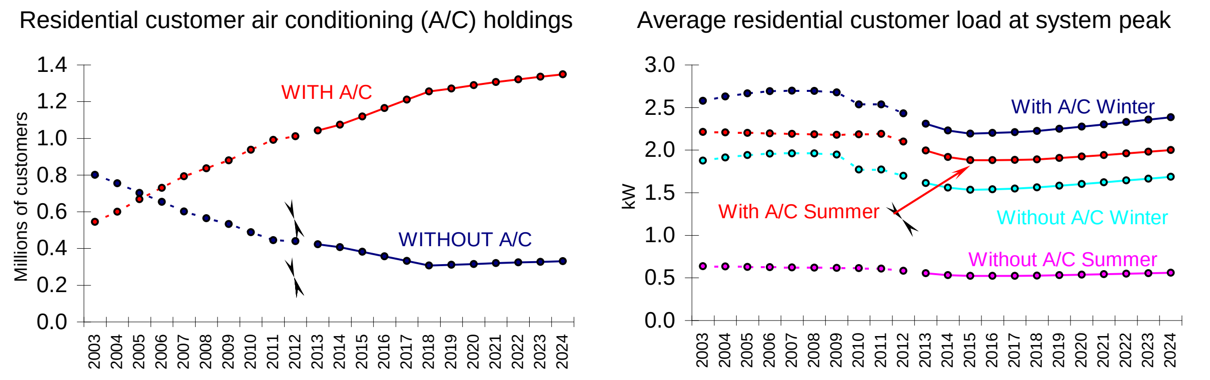
Driver	Source of projections
Real retail residential electricity price	IPART “Review of regulated retail prices and charges for electricity” (June 2013) forms the basis for the assumed 2013/14 retail price change. NIEIR projections (commissioned by Networks NSW to ensure consistency among the input assumptions to be relied on by the three NSW DNSPs in preparing their regulatory proposals) are used for the post 2013/14 period. The annual NIEIR projections have been relied on out to 2015/16 (the year of the next carbon tax impact). Thereafter the annual projections used are the average of the 2017 to 2024 period.
Average annual residential energy consumption	Ausgrid Network Forecasting Section: The average energy consumption forecasts which result from inputting the same driver projections into the residential energy model are used to derive an annual “energy efficiency” factor. The annual change in this factor is assumed to also apply to the average kW loads in the peak demand end-use model.
Post-model adjustments – Solar PV impact	NIEIR “Post modelling adjustments of energy demand forecasts by Ausgrid, Endeavour Energy and Essential Energy” (a report commissioned by the AER2 Project Team, February 2013). This report provided solar PV impacts on annual metered energy consumption. In translating the energy impacts into system-wide peak demand impacts it has been assumed that solar PV units have an average load factor of 14% and are operating at 35% of capacity at the typical time of summer system peak demand. It is also assumed that all of the NIEIR’s assessed solar PV impacts will be in the residential segment. The solar PV adjustment only impacts on the summer peak demand forecasts, as winter system-wide peak demands occur after sunset.
Post-model adjustments –NSW Energy Savings Scheme (ESS) impact	NIEIR “Post modelling adjustments of energy demand forecasts by Ausgrid, Endeavour Energy and Essential Energy” (a report commissioned by the AER2 Project Team, February 2013). This report provided ESS impacts on annual energy consumption, and assessed that the residential segment would account for 30% of ESS impacts on energy consumption. In translating the energy impacts into system-wide peak demand impacts it has been assumed that the annual energy impact is spread evenly throughout each hour in a year. In collaboration with Endeavour Energy, Essential Energy and Networks NSW it has been agreed that only 40% of the NIEIR’s estimated impact of the NSW ESS would be applied to the energy volume forecasts, and that agreed figure has also been applied to the system-wide peak demand forecasts.

The projected trends in the residential segment driver variables are illustrated below.

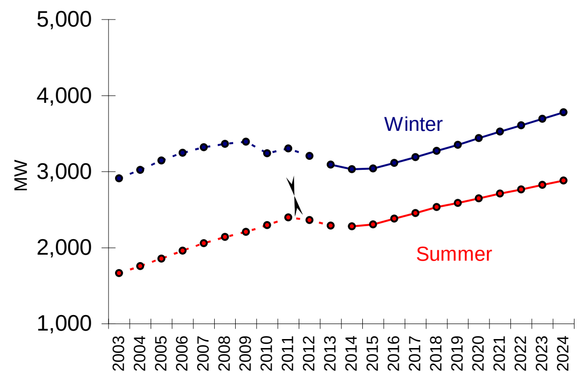
Drivers of residential segment contribution to system-wide peak demand



Residential segment end-use model



Forecast of residential segment contribution to system-wide peak demand



The residential segment contribution to system-wide peak demand forecast is the product of:

(1) Projected residential customer numbers by status of air conditioning holdings ("with" and "without" a/c)

and

(2) The modelled average kW load at time of system-wide peak, by status of air conditioning holdings ("with" and "without" a/c)

Non-residential segment

The non-residential segment[5] contribution is based on an econometric approach. The estimated historical series for the non-residential estimated contribution to overall peak demand is derived as the overall weather corrected system peak demand less the estimated POE50 residential peak demand.

The econometric model for the non-residential system wide peak forecast is of the form:

$$\ln D_{NR} = +0.69 \ln GSP - 0.39 \ln P$$

where

D_{NR} = Non-residential system-wide peak demand (weather and day-type corrected

GSP = NSW real Gross State Product

P = Produce Price Index for electricity (average of years t and t-1)

The projection of the contribution of the non-residential segment to system-wide peak demand forecast is determined by inputting the projections of the driver variables, GSP and electricity price, into the model and overlaying the impact of post-model adjustments which account for known or expected changes which are not implicit in the model elasticities.

The sources of the non-residential segment driver projections are summarised below:

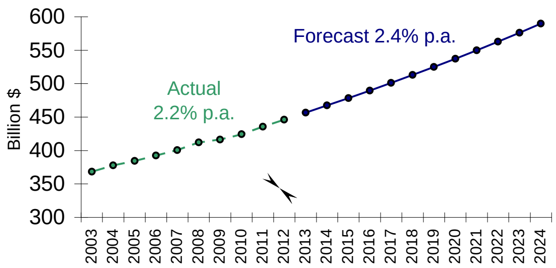
Driver	Source of projections
NSW GSP	NIEIR projections (commissioned by Networks NSW to ensure consistency among the input assumptions to be relied on by the three NSW DNSPs in preparing their regulatory proposals). The annual projections used are the average of the 2014 to 2024 period.
Real retail non-residential electricity price	IPART and NIEIR It is assumed that non-residential retail electricity prices will move in line with residential prices.
Post-model adjustments – NSW Energy Savings Scheme (ESS) impact	NIEIR "Post modelling adjustments of energy demand forecasts by Ausgrid, Endeavour Energy and Essential Energy" (a report commissioned by the AER2 Project Team, February 2013). NIEIR assessed that the non-residential segment would account for 70% of ESS impacts.
Post-model adjustment – Major loads	Advice regarding temporary or permanent curtailments to major customer loads. Such curtailments are generally only known for the upcoming 1 to 2 years.

The projected trends in the non-residential segment driver variables are illustrated below.

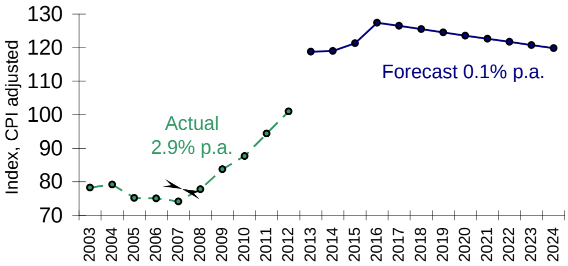
[5] For legacy reasons and to ensure consistency with past reporting of peak demand, loads associated with Hydro Aluminium, OneSteel Newcastle and Essential Energy transfers are excluded from Ausgrid's definition of the non-residential segment.

Drivers of non-residential segment contribution to system-wide peak demand

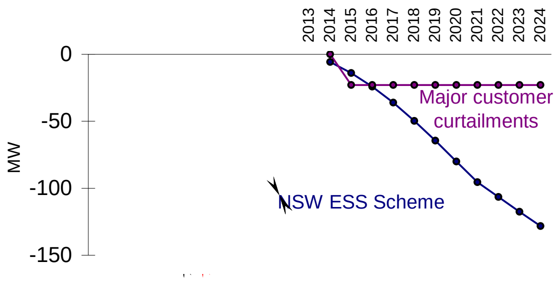
NSW real gross state product



Real non-residential electricity price index

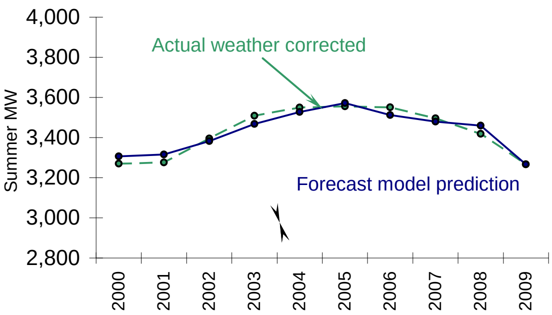


Post-model adjustments (non-residential segment)



Non-residential peak demand model

Non-residential econometric model - goodness of fit



Non-residential model elasticities (and t-values)

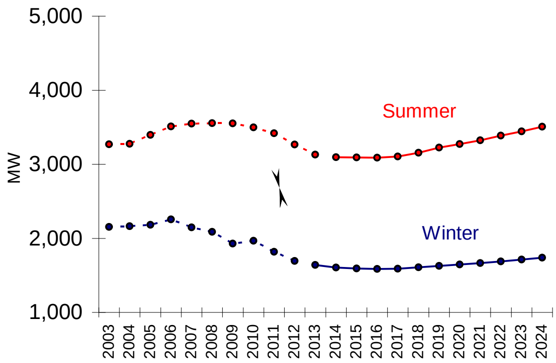
GSP	0.69 *	(t = 10.4)
Price:	-0.39 **	(t = -4.9)

* 1% change in NSW GSP will induce a 0.69% change in non-residential peak demand

** 1% change in price will induce a -0.39% change in non-residential peak demand
** [Price = average of years (t),(t-1) prices]

Model R^2 = 0.9022

Forecast of non-residential segment contribution to system-wide peak demand



The non-residential segment econometric model applies to summer peak demand.

The same elasticities have been assumed for the purposes of calculating winter non-residential peak demand forecasts.

Combined system-wide econometric growth rates

The Ausgrid system-wide long term growth rates are determined by combining the residential and non-residential segment contributions.

The growth rates are disaggregated into five regions:

- Inner Metropolitan Area
- North Shore
- Central Coast
- Lower Hunter
- Upper Hunter.

This regional division takes into account available regional projections for two key residential segment variables – long term housing number projections from the NSW Department of Planning and variations in the regional rates of air conditioning penetration which are taken from the ABS survey of appliance use in 2006. For the non-residential segment, there is no reasonable basis for applying regional distinction, so the system-wide non-residential segment contribution projection has been apportioned across regions based on region contribution to system-wide peak demand.

The resulting long term growth rates by region are shown below:

Summer					
Year	Five Region Forecasts				
	Inner-Metro	North Shore	Central Coast	Lower Hunter	Upper Hunter
2017	1.70%	1.85%	2.11%	1.14%	0.57%
2018	2.59%	2.28%	1.74%	1.84%	1.51%
2019	2.26%	2.04%	2.04%	2.06%	1.51%
2020	1.84%	1.48%	2.05%	2.07%	1.45%
2021	1.88%	1.50%	2.06%	2.08%	1.47%
2022	1.92%	1.62%	2.17%	2.19%	1.59%
2023	1.85%	1.63%	2.17%	2.20%	1.61%
2024	1.87%	1.65%	2.18%	2.21%	1.63%
2025	1.23%	1.08%	1.59%	1.59%	0.96%
2026	1.06%	0.94%	1.44%	1.42%	0.78%
2027	1.01%	0.85%	1.35%	1.36%	0.76%
2028	1.02%	0.86%	1.36%	1.37%	0.77%
2029	1.01%	0.84%	1.34%	1.35%	0.76%
2030	1.02%	0.86%	1.35%	1.36%	0.77%

2017 refers to summer 2016/17 and so on.

Winter					
Year	Five Region Forecasts				
	Inner-Metro	North Shore	Central Coast	Lower Hunter	Upper Hunter
2016	1.20%	1.36%	2.07%	1.67%	0.23%
2017	1.50%	1.44%	2.18%	1.64%	0.59%
2018	2.15%	1.63%	1.93%	2.09%	1.44%
2019	1.90%	1.50%	2.35%	2.42%	1.47%
2020	1.92%	1.49%	2.33%	2.40%	1.46%
2021	1.93%	1.50%	2.33%	2.41%	1.48%
2022	1.97%	1.64%	2.45%	2.52%	1.62%
2023	1.98%	1.64%	2.45%	2.52%	1.63%
2024	1.99%	1.66%	2.45%	2.52%	1.64%
2025	1.39%	1.15%	1.91%	1.95%	0.99%
2026	1.23%	1.02%	1.77%	1.79%	0.82%
2027	1.16%	0.89%	1.64%	1.69%	0.79%
2028	1.17%	0.91%	1.64%	1.69%	0.81%
2029	1.15%	0.89%	1.62%	1.66%	0.78%
2030	1.16%	0.90%	1.62%	1.66%	0.80%

Appendix H: Econometric growth rate adjustment

This appendix outlines the method is used to adjust the statistically determined growth rates for a zone substation to include econometric drivers, resulting in a “weighted adjusted growth rate”. The growth rate adjustment occurs from the fourth year to the tenth year in the forecast.

The weighted adjusted growth rate is calculated by adding an adjustment factor to the statistical growth rate used for the initial 3 years. The adjustment factor is the difference between the regional econometric growth rate and the aggregated substation growth rate in that region. The regional econometric growth rate is defined according to the five BSP regions in Ausgrid’s electricity supply area:

- Inner Metro
- North Shore
- Central Coast
- Lower Hunter
- Upper Hunter.

The adjustment factor is constant per year per region. The following is a mathematical description of the adjustment factor.

Definitions UNITS

$Load_X = Load\ on\ zone\ "X"$ ....(MW)

$ROG_X = Growth\ rate\ on\ zone\ "X"\ (years\ 1\ to\ 3)$ ....(%)

$ROG_E = regional\ econometric\ growth\ rate$ ....(%)

$df_X = Diversity\ Factor\ of\ zone\ "X"$

$wROG_X = Weighted\ adjusted\ growth\ rate$ ....(%)

$Raw\_growth_X = Load_X * ROG_X$ ....(MW)

$Div\_load_X = df_X * Load_X = Diversified\ load\ on\ zone\ "X"$ ....(MW)

$Div\_growth_X = df_X * Raw\_growth_X = Diversified\ growth\ on\ zone\ "X"$ ....(MW)

$w\_growth_X = wROG_X * Div\_load_X = Weighted\ adjusted\ diversified\ growth\ on\ zone\ "X"$ ....(MW)

$Div\_growth_E = ROG_E * \sum Div\_load_X = regional\ econometric\ growth$ ....(MW)

The weighted adjusted growth rate is determined by adding an adjustment factor :

$$wROG_X = ROG_X + \textit{Adjustment factor} = ROG_X + S$$

The adjustment factor is the difference between the regional econometric growth rate and the aggregate spatial growth rate

$$S = ROG_E - \frac{\sum Div\_growth_X}{\sum Div\_load_X}$$

$$wROG_X = ROG_X + ROG_E - \frac{\sum Div\_growth_X}{\sum Div\_load_X}$$

VERIFICATION OF METHOD

Let the "N" zone system (ie a BSP region) comprise of (zone A, zone B, ..., zone N).

The total weighted growth is calculated by :

$$\sum w\_growth_X = w\_growth_A + w\_growth_B + ... + w\_growth_N$$

$$= wROG_A * Div\_load_A + wROG_B * Div\_load_B + ... + wROG_N * Div\_load_N \qquad ....(A)$$

The total diversified load is calculated by :

$$\sum Div\_load_X = Div\_load_A + Div\_load_B + ... + Div\_load_N \qquad ....(B)$$

Now we need to check that the resulting total weighted adjusted diversified growth rate in the "N" zone system is equal to the regional econometric growth rate. The following must be true :

$$\frac{\textit{Total weighted adjusted growth}}{\textit{Total diversified load}} = \frac{\sum w\_growth_X}{\sum Div\_load_X} = ROG_E$$

PROOF

$$\frac{\sum w\_growth_X}{\sum Div\_load_X} = \frac{wROG_A * Div\_load_A + wROG_B * Div\_load_B + ... + wROG_N * Div\_load_N}{Div\_load_A + Div\_load_B + ... + Div\_load_N} \qquad ....\frac{(A)}{(B)}$$

$$= \frac{(ROG_A + S) * Div\_load_A + (ROG_B + S) * Div\_load_B + ... + (ROG_N + S) * Div\_load_N}{\sum Div\_Load_X}$$

$$= \frac{ROG_A * Div\_load_A + ROG_B * Div\_load_B + ... + ROG_N * Div\_load_N + S * (Div\_load_A + Div\_load_B + ... + Div\_load_N)}{\sum Div\_load_X}$$

$$= \frac{Div\_growth_A + Div\_growth_B + ... + Div\_growth_N}{\sum Div\_load_X} + S * \frac{\sum Div\_load_X}{\sum Div\_load_X}$$

$$= \frac{\sum Div\_growth_X}{\sum Div\_load_X} + S$$

$$= \frac{\sum Div\_growth_X}{\sum Div\_load_X} + ROG_E - \frac{\sum Div\_growth_X}{\sum Div\_load_X}$$

$$= ROG_E$$

Glossary

Term	Meaning
AER	Australian Energy Regulator
Amps	Unit of measure for current
BoM	Bureau of Meteorology
BSP	Bulk Supply Point
df	Diversity Factor
IPART	Independent Pricing and Regulatory Tribunal
kV	Kilovolts
MW	Megawatts. Unit of measure for real power.
MVA	Mega Volt-Amps. Unit of measure for apparent power.
MVAr	Mega Volt-Amps reactive. Unit of measure for reactive power.
NIEIR	National Institute of Economic and Industry Research.
NMI	National Metering Identifier.
pf	Power factor. Ratio of real power to apparent power.
upf	Uncompensated power factor. Pf before applying reactive compensation (usually capacitors).
cpf	Compensated power factor. Pf after applying reactive compensation (usually capacitors).
POE	Probability of Exceedance
PV	Photovoltaic. Conversion of light energy into electrical energy.
ROG	Rate of growth.
SAS	Statistical Analysis Software.
SCADA	Supervisory Control and Data Acquisition.
Spot (spot load)	An increase in demand above the growth rate usually arising from a new load connection to the network.
STS	Subtransmission substation. A substation that transforms a primary voltage of 132kV into either 33kV or 66kV.
Summer	1 Nov to 31 Mar
Winter	1 May to 31 Aug
ZN	Zone substation. A substation that transforms a primary voltage of 33kV or 66kV into 11kV.