APPENDIX 16

Maximum Demand, Customer and Energy Forecasting Methodologies

Energex

Maximum Demand, Customer and Energy Forecasting Methodologies

Asset Management Division

energex

positive energy

Version control

Version	Date	Description
1	August 2014	Final draft
2	September 2014	Final version

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager

Corporate Communications

Energex

GPO Box 1461

BRISBANE QLD 4001

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1 Executive summary

1.1 Background

Soundly based forecasts for the growth and usage of electricity are fundamental to the planning and operation of an electricity distribution network that meets the long-term needs of customers. Forecasts are formulated from a number of often variable inputs that need constant monitoring and adjustment over time.

Energex has established a robust methodology for forecasting future requirements of the South East Queensland network to provide a platform for sound planning of the electricity distribution system. This demand forecasting methodology was recently refined to reflect apparent structural changes in customer demand for electricity in the current regulatory control period. This refinement accounted for the impact of the global financial crisis and associated developments in the Australian economy, and increased penetration of solar photo voltaic (PV) cells on the network.

Energex performs the following forecasts for planning purposes, being:

- Maximum demand forecasts at the system, substation and 11 kV feeder levels of the distribution network, which is measured by the amount of capacity in Megawatts (MW) served by the network during peak times.
- Number of new connections (or alternatively total connections), which is measured by the number of new (or alternatively total) customers connected to the distribution network.
- Energy, which is measured by the total amount of electricity in kilowatt hours (kWh) consumed.

1.2 Purpose

The purpose of this document is to outline the processes and methodology used to develop each of these forecasts for the period 2014 to 2020. The base year for the forecasts contained in this report is 2013-14.

1.3 Structure

This document comprises the following sections:

- Section 2 – Overview of Energex forecasting
- Section 3 – System maximum demand forecasts
- Section 4 – Substation maximum demand forecasts

- Section 5 – 11 kV feeder maximum demand forecasts
- Section 6 – Customer number forecasts
- Section 7 – Energy sales, purchases and consumption forecasts
- Section 8 – Customer requested work forecasts
- Section 9 – Application to planning
- Section 10 – Compliance checklist

The following is set out in appendices at the end of this document:

- Attachment A – References
- Attachment B – SIFT Documentation Summary
- Attachment C – Reconciliation of models to Regulatory Templates – Supporting Information
- Attachment D – Procedure 00569: Annual Review of Contingency Plans and Network Load at Risk Data
- Attachment E – Demand-related capex projects or programs for zone substations.

2 Overview of Energex forecasting

Soundly based forecasting is a complex yet essential task which underpins planning and development of the electricity supply network. Energex has adopted a detailed and mathematically rigorous approach to the forecasting of maximum demand, customer numbers and energy. Energex also ensures that its forecasting models are audited and reviewed by external forecasting specialists.

The preparation of forecasts is a core business function of Energex. Forecasts are prepared for a diverse range of business planning purposes, significantly these inform internal business decisions such as network, revenue and financial planning; and the preparation of planning reports such as the DAPR. Forecasts prepared for these purposes then inform the preparation of regulatory responses, such as those addressing AER Regulatory Information Notices (RINs). This document sets out how the forecasts required by the AER are derived from the forecasts developed and used for operational purposes.

2.1 Forecast procedures

Procedural documents outlining the internal processes followed when preparing maximum demand, customer number and energy forecasts are stored on the Energex Register of Electronic Documents and can be retrieved by Energex personnel. Key documents are set out below in Table 2.1 and can be provided upon request. The documents detail the processes used to develop the forecasts including inputs, sources of data and specific internal Energex systems that should be used.

Table 2.1 – Relevant Energex Procedural Documents

Process Document	Description
443 - Produce a Ten Year Bulk Supply and Zone Substation Demand Forecast	The steps taken to develop ten year zone substation and bulk supply substation 50POE and 10POE maximum demand forecasts in SIFT(Substation Investment Forecasting Tool)
569 - Annual Review of Contingency Plans and Network Load at Risk Data	The process used to review Contingency Plans and Network Load at Risk Data on an annual basis.
669 – Produce Electricity Consumption and Maximum Demand Projections for Energex	How the energy and demand forecasts are developed for Powerlink Queensland.
666 – Produce a Peak MW Demand Forecast	The process used to develop the Energex Peak MW System demand forecast for Summer and Winter.
681 – Produce an Energy Sales and Purchasing Forecast by Major Customers and other Tariff Segments for the Budget Year for Pricing Purposes(TUOS and DUOS)	How the energy and demand forecasts the next financial year for Network Prices.

Process Document	Description
667 – Produce a Short Term Demand Forecast	The process used by Energex to prepare nine day ahead system demand forecast for Network Operations
675 – Produce a Zone Substation Annual Growth rate Projection	The process used by Energex to develop individual growth rates for each zone substation for the ten year forecast period.
674 – Produce Seasonal Zone and Bulk Supply substation 50%POE – 10% POE Adjustment Factors	The process used by Energex to develop individual 50POE and 10POE Adjustment factors for each zone substation.
762 – Joint Workings – Load Forecasting – System Maximum Demand Guidelines – ACIL Tasman	The methodology adopted by Energex to develop 50POE and 10POE system demand forecasts
763 – Joint Workings – Load Forecasting – System Energy Guidelines – ACIL Tasman	The methodology adopted by Energex to develop system energy forecasts
764 – Joint Workings – Load Forecasting – Spatial Demand Guidelines – ACIL Tasman	The methodology adopted by Energex to develop 50POE and 10POE substation demand forecasts
Guideline for Producing and Documenting the Peak MW Demand Forecast	The process used to statistically test the system maximum demand forecasting model.

Annual external audits are conducted to provide assurance that Energex develops forecasts in accordance with its procedural documents.

Further, Frontier Economics, which has expertise in undertaking a verification of forecasts, was engaged by Energex to examine the reasonableness of the methodology, processes and assumptions used to determine its demand and energy forecasts. The results of this examination are set out in the report attached to Energex's Regulatory Proposal.

2.2 Forecasting model tools

A range of databases and models are used by Energex for forecasting. Energex's maximum demand forecasting models are primarily based on multiple regression models, with rigorous statistical testing applied to validate the models. The maximum demand forecasting models incorporate a Monte Carlo simulation of likely daily maximum demands based on 30 years of temperature data.

The models used to forecast maximum demand and number of new connections are summarised in Table 2.2.

Table 2.2 – Maximum demand and new connections forecast models

Forecast	Name	Description
System maximum demand	System demand model	Excel-based forecasts based on historical data and a range of economic and temperature variables
Substation maximum demand	Substation Investment Forecasting Tool (SIFT)	Corporate database incorporating historical peak demands, proposed block loads, growth rates, load transfers, diversity factors, PoE adjustment factors, losses and reconciliation factors. Further details about the operations and functions of SIFT is provided at Attachment B.
11 kV feeder maximum demand	Netplan	Database that stores forecasts as a series of events in date order for each zone substation 11 kV feeder.
Large customer numbers	Large customer numbers forecast	Excel-based forecasts based on Individually calculated values (supplied to AER)
Non-residential customer numbers	Non-residential customer numbers forecast	Excel-based model based on economic indicators and long term trends in customer numbers (supplied to AER)
Residential customer numbers	Residential customer numbers forecast	Excel-based model based on population growth and trends in persons per household (supplied to AER)
Controlled load customer numbers – tariff 31	Controlled load customer numbers – tariff 31 forecast	Excel-based model based on economic indicators and long term trends in customer numbers (supplied to AER)
Controlled load customer numbers – tariff 33	Controlled load customer numbers – tariff 33 forecast	Excel-based model Excel-based model based on economic indicators and long term trends in customer numbers (supplied to AER)
Unmetered supply	Unmetered supply forecast	Excel-based model of energy trends (supplied to AER)
Streetlighting	Streetlighting forecast	Excel-based model Excel-based model based on economic indicators and long term trends in customer numbers (supplied to AER)

It is noted that Regulatory Template 5.3 is populated directly from, and is therefore consistent with, the system demand model. Likewise, Regulatory Template 5.4 is populated directly from Substation Investment Forecasting Tool (SIFT) meaning that forecasts provided for each network element are therefore consistent with this model.

2.3 Forecasting inputs

Energex uses a range of input data, including but not limited to the inputs listed below, in its forecasting models to gain a good understanding of the drivers of electricity usage. Table 2.3identifies the key forecasting inputs.

Table 2.3 – Forecast inputs

Category	Inputs
Demand	Demand data, SCADA data, weather data, solar PV, embedded generation
Customer Numbers	Population, persons per household
Energy	Billing data, customer numbers, solar PV, purchases, embedded generation
Economic	Queensland (Gross State Product) GSP, retail electricity price
Demographic	Population, persons per household, air conditioning

2.4 Forecasting methodologies

2.4.1 Maximum demand forecasts

Under the National Electricity Rules (Rules), Energex is required to produce maximum demand forecasts to support its Regulatory Proposal to the AER; and for publication in the Distribution Annual Planning Report (DAPR) on an annual basis. Maximum demand forecasts are used to identify emerging network limitations, to identify network risks, and to determine the timing and scope of capital expenditure, or for the establishment of demand reduction strategies and for risk management plans.

Energex maximum demand forecasts comprise three levels of analysis being:

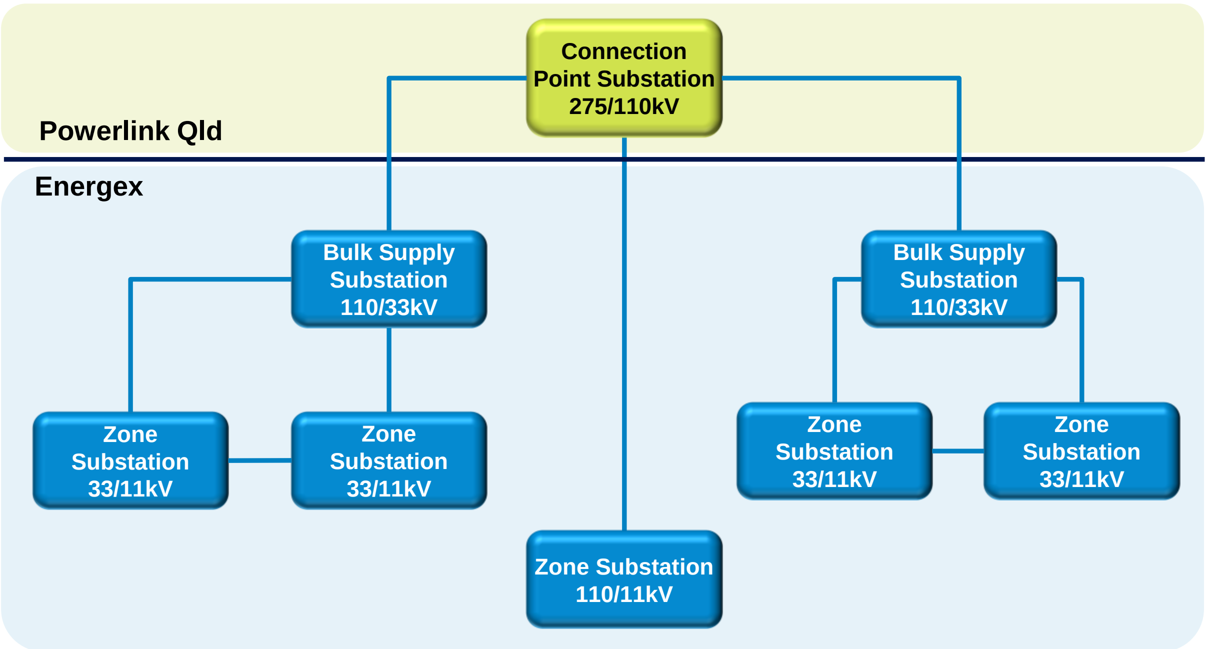
- System maximum demand, which is a top-down forecasting method used for validating bottom-up forecasts, and for planning, primarily on the subtransmission network and to a lesser extent on the distribution network.
- Substation maximum demand, which is a bottom-up forecasting method used for planning on the subtransmission network.
- 11 kV feeder maximum demand, which is a bottom-up forecasting method used for planning on the distribution network.

System maximum demand forecasts are based on a multiple regression equation for the relationship between demand and maximum temperature with temperature data, Gross State Product (GSP) and other economic indicators. Thirty years of summer maximum demand data is then used to produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands. This top-down assessment is used to validate substation and 11 kV feeder maximum demand forecasts.

Substation maximum demand forecasts incorporate weather corrected starting demand, growth rates, block loads, load transfers and demand management reductions. Energex develops and publishes ten year maximum demand forecasts of zone substation, bulk supply substation and connection point for the all existing and planned substations, on a twice-yearly basis.

Transmission connection point demand forecasts are an aggregation of the bulk supply substations and the direct transformation substations; while the bulk supply substations are an aggregation of the zone substations connected to them (this is summarised schematically in Figure 2.1). The aggregated demand forecasts are reconciled with the total system demand forecast for summer and winter, day and night.

Figure 2.1 – Summary of Energex network configuration



Energex prepares 11 kV feeder maximum demand forecasts on a feeder by feeder basis for summer and winter. This involves firstly establishing a feeder load starting point by undertaking bi-annual 50% PoE temperature corrected load assessments. Then, using a statistical distribution, the 10% PoE load value, used for determining voltage limitations, is extrapolated from the 50% PoE load assessment.

Energex records historic maximum demand in MW, MVA, MVAr and Amperes (A).

Energex develops both coincident and non-coincident maximum demand forecasts for all levels of the network above the 11 kV substation bus, with 11 kV feeder maximum demand forecasts prepared for non-coincident demand only. Energex is required to prepare both

50% PoE and 10% PoE maximum demand forecasts for each level of the network and include Summer Day, Summer Night, Winter Day and Winter Night maximum demand forecasts. Demand values and the models which are contained in by network element are summarised below in Table 2.4.

Bottom up maximum demand forecasts are aggregated up to the next level of network by including diversity and losses. Overall bottom up coincident maximum demand forecasts are reconciled with the top down economic maximum demand forecast after each season.

Table 2.4 – Demand values and models by network element

	Demand value		Model		
	Non-Coincident Demand	Coincident Demand	SIFT	Netplan	Load Flow Models
System	✔	✔	✔		
110/132kV Feeders					✔
Connection Points	✔	✔	✔		
Bulk Supply Substations	✔	✔	✔		
33kV Feeders					✔
Zone Substations	✔	✔	✔		
11 kV Feeders	✔			✔	✔

As discussed above, Energex prepares maximum demand forecasts for a number of purposes, key forecasts being used for: Internal planning, the preparation of the DAPR, and the preparation of responses to AER Regulatory Information Notices (RINs). As this information is sourced from the same systems it can be reconciled.

Information extracted from the Energex maximum demand forecasting models reconciles to, and is therefore consistent with, information provided in Regulatory Templates 5.3 and 5.4 of the Reset RIN. That is:

- System wide data reported in Regulatory Template 5.3 is sourced directly from the System demand model
- Network elements data reported in Regulatory Template 5.4 is sourced directly from SIFT.

Supporting information, which provides a reconciliation between the regulatory templates and output from the models is provided at Attachment C.

Further, for joint planning purposes, Energex prepares forecasts using the System Demand Model and SIFT. These models are also used by Energex for the purposes of its Regulatory Proposal.

2.4.2 Customer number and energy forecasts

Customer number and energy forecasts incorporate economic conditions, population growth and historical energy trends by customer classes.

Customer number forecasts are disaggregated into tariff categories with a ten-year customer number forecast segmented into customer classes and network tariffs for all customers. Energex's customer number forecasts are a key input to its Program of Work.

Broadly, Energex's new connections forecasts, feed into its customer number forecasts given that these are simply an aggregate of existing connections to forecast new connections (or customer number forecasts). Therefore, discussion of customer number forecasts in this document will inherently cover forecast new connections.

Residential customer forecasts are prepared by adding the forecast number of new connections to a base year. For the purpose of the customer number and energy forecasts in the regulatory proposal, 2013-14 was the base year. New connections are estimated by applying the forecast South East Queensland population growth rate to the existing number of customers, then dividing this by the forecast number of people per household. Non-residential customer forecasts are developed by applying economic indicators such as GSP to long term trends in Energex non-residential customer numbers.

Energex annually produces ten-year energy forecasts for each of the transmission connection points, customer classes, network tariffs and the next financial year forecasts for large contestable customers for network billing purposes. The ten-year energy forecasts are validated using the demand forecasts and the corresponding load factor trends.

Energex energy sales and purchase forecasts are used to develop the network prices, distribution loss factors and projections of network revenue for budgeting purposes. The energy forecasts are monitored on a monthly basis and variations in revenue are reported and reconciled.

It is important to note that connections data captured through Regulatory Template 2.5 of the Reset RIN reports active and de-energised NMIs while the customer number forecasts used by Energex and reported within in this document included active NMIs only. Active NMIs were forecast by customer type and network tariff for the purposes of calculating energy sales forecasts.

2.5 Energex's key forecasting outputs

In summary, the suite of forecasts produced by Energex include the following:

1) Maximum demand forecasts for:
   - Total system
   - Connection points with Powerlink Queensland (Powerlink)
   - Approximately 400 Energex and customer, zone and bulk supply substations
   - Major customers, and
   - Short term system forecasts at the substation level.
2) New connections and customer number forecasts by customer category and network tariff.
3) Energy forecasts for:
   - Total system
   - Connection points with Powerlink
   - Consumption of large customers
   - Network tariff categories, and
   - Sales by customer category.
4) Customer requested work forecasts.

2.6 External validation process

Independent consultants regularly review forecasting models to confirm that Energex is using appropriate model specifications and testing procedures. This involves analysing the data used, the structure of the models and assessing of the capability of the model to predict the future without bias.

Energex annually engages the National Institute of Economic and Industrial Research (NIEIR) to validate forecasts by providing an independent forecast of maximum demand, customer numbers and energy growth for the Energex supply area. The forecasts produced by NIEIR are based on a 'top down' economic growth perspective, with high, medium and low growth scenarios and predicted levels of embedded generation.

Energex also compares its forecasts with independently produced forecasts where these can be sourced from providers such as AEMO and Powerlink.

3 System maximum demand forecasts

3.1 Introduction

System maximum demand forecasts are developed and reviewed twice each year following analysis of demand from the previous summer period and the most recent winter. Separate scenarios are developed that model factors such as the impact of demand side management initiatives, greenhouse gas reduction strategies, energy efficiency initiatives, and penetration of embedded generation on the distribution network. The likelihood of scenarios is assessed with the most likely set of scenarios used for the system maximum demand forecasts.

The purpose of system maximum demand forecasts is to validate sub-transmission and distribution network bottom-up forecasts. This is a particularly important tool for the sub-transmission network assessment and Energex will ensure that substation maximum demand forecasts reconcile to the system maximum demand forecasts.

3.2 Inputs

The following were inputs into the system maximum demand forecasts:

- Historical daily maximum demand for the season being modelled
- Daily temperature data
- Queensland economic data, including GSP and population growth
- Electricity price data, sourced from AEMO.
- Policy changes such as the repeal of the ban on electric hot water systems and the solar feed in tariff

3.3 Methodology

Energex calculates maximum demand at probability of exceedance (PoE) temperatures in accordance with the AEMO definition of PoE, with reference to the maximum demand and the probability that the forecast will be met or exceeded in a given timeframe.

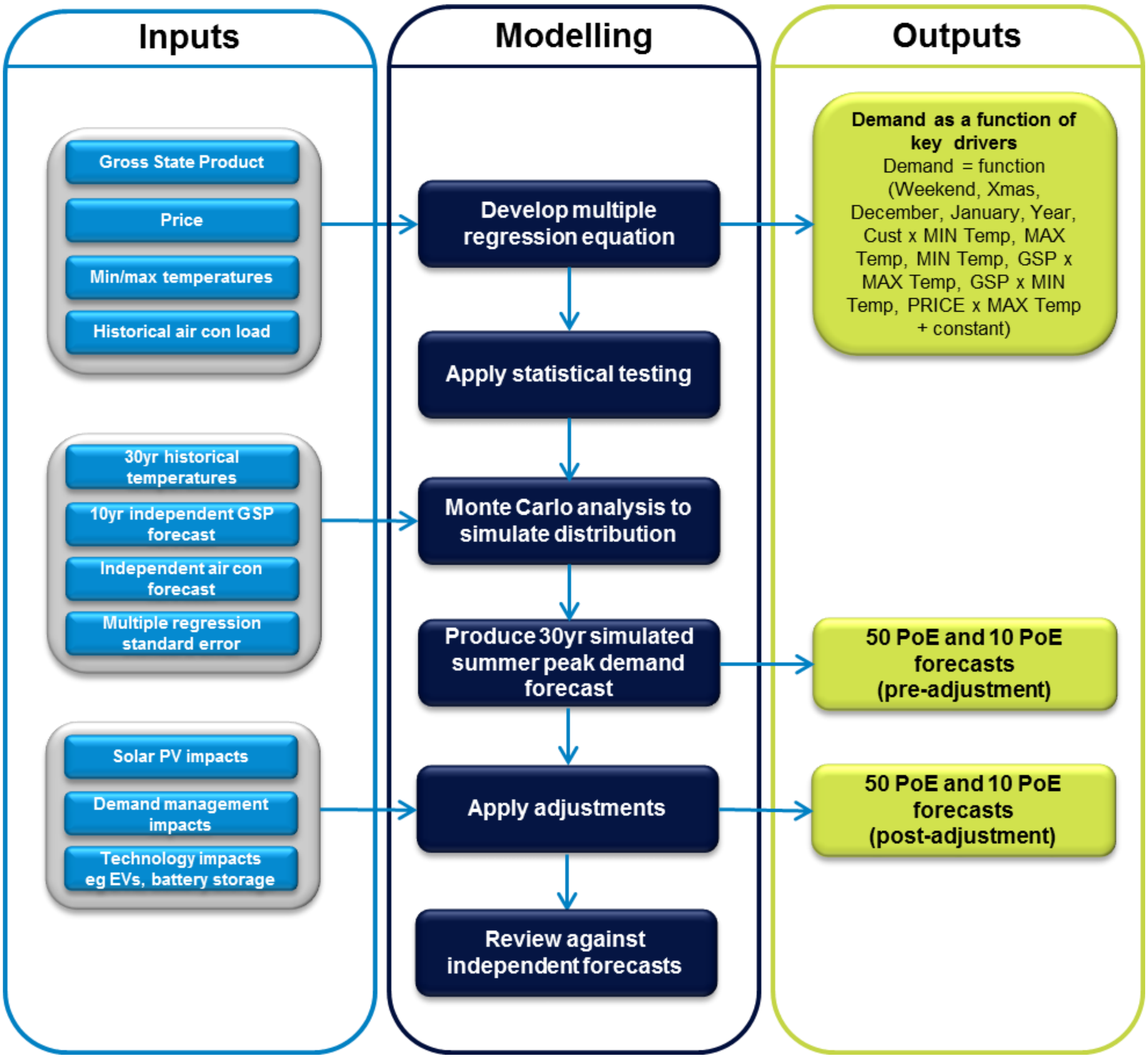
Weather conditions in South East Queensland have a significant effect on maximum summer and winter demands and Energex produces demand forecasts for the following conditions:

- A 10% PoE forecast, corresponding to one year in ten hot summer or cold winter conditions

- A 50% PoE forecast, corresponding to one year in two (average summer or average winter) conditions
- A 90% PoE forecast, corresponding to nine years in ten (average summer or average winter) conditions.

The methodology Energex uses to develop the system maximum demand forecast is outlined in Figure 3.1 and described below.

Figure 3.1 - System maximum demand forecast methodology (top down)



The methodology applied by Energex and as recommended by consultants ACIL Tasman, was as follows:

- Develop a multiple regression equation for the relationship between demand and maximum temperature with GSP, minimum temperature by GSP, and December to February temperature data that excludes weekends and public holidays plus days with average temperature at Amberley <23.5C. Statistical testing was applied to the model before its application to ensure that there was minimum bias in the model.

- Use a Monte Carlo process to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures and an independent 10 year GSP forecast and an independent air conditioning load forecast.

- Use the 30 year summer peak maximum demands to produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.

- Apply the model error factor to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the maximum demand rather than the regression average demand.

- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment was also made in the forecast for solar PV and the expected impact of electric vehicles.

- Compare the final forecast with NIEIR and AEMO maximum demand forecasts to confirm that the forecast is reasonable.

The planning process utilised three forecast scenarios – a “base case” – as well as “high” and “low case” scenarios. The high and low case scenarios were derived from high and low case customer number and GSP forecasts.

The methodology produced a distribution of maximum demands for each year of the historical data. The 50% and 10% PoE values were determined from the distribution by calculating the MW value for an average event (50% PoE) and for a 10% probability event (10% PoE).

The system maximum demand forecasting model was specified as follows:

Demand MW = function(Weekend, Xmas, December, January, year, Cust_Min, Max, Min, GSPMax, GSPMin, Price_Max, C).

Where,

- *Weekend, Xmas, December, January = dummy variables capturing load variation*
- *Cust_Min = interaction term between customers and minimum temperature*
- *Max, Min = each day’s maximum & minimum temperatures*
- *GSPMax, GSPMin = interaction terms between Gross State Product and the maximum and minimum temperatures*
- *Price_Max = interaction term between an index of real prices for customers and businesses and maximum temperatures*
- *C = the constant/intercept*

3.3.1 Validation

To validate the econometric model statistical tests were performed on a range of parameters used in the model. The parameters tested are set out in Energex's forecast guidelines (see Table 2.1). This list was recently reviewed by Frontier Economics, which recommended the use of additional test parameters which will be included in future versions of the Forecast Guidelines. The Frontier Economics report is an appendix to the Energex Regulatory Proposal.

3.3.2 Weather correction

In 2008 Energex used a temperature adjustment methodology that involved plotting the daily maximum demand against daily average temperature and extrapolating the highest demand to the 50% PoE and 10% PoE temperatures using the regression slope. This process was difficult to replicate and did not stand up to the statistical rigor required by the AER.

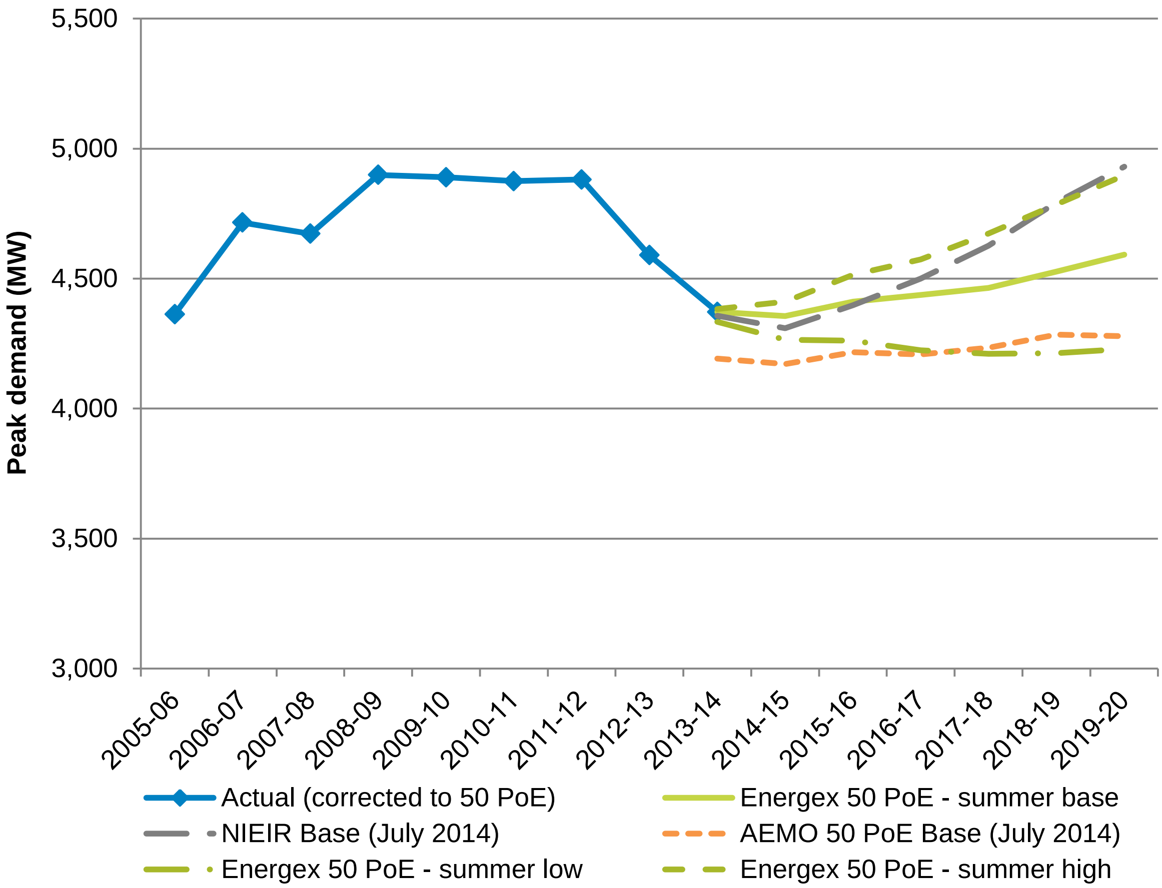
Energex then developed the current methodology for system maximum demand and substation maximum demand, with the assistance of ACIL Tasman, which has been applied since 2009. Each year the actual maximum demand recorded was corrected to a normalised or 50% PoE value by adjusting the demand up or down depending on the actual temperature recorded at the Amberley weather station versus the standard temperature and economic conditions.

3.4 Reconciliation to AEMO and Powerlink demand information

Energex prepared the system demand forecasts using a methodology incorporating rigorous statistical testing and simulation processes. The forecast at 50% PoE and 10% PoE was then compared with externally provided demand forecasts from Powerlink, AEMO and NIEIR. This process was used to review Energex forecast output to ensure that it was consistent with other key stakeholders.

AEMO is preparing to develop Connection Point demand forecast for Queensland by June 2015 and these will help Energex to validate the bottom up demand forecasts developed internally. A simple comparison of the external forecasts for 2014 is shown below in Figure 3.2. Energex's 50% PoE forecasts for low, high and base cases are set out in this figure.

Figure 3.2 - System Demand Forecast Comparison



3.5 Key assumptions

3.5.1 Review of recent actual system maximum demand data

Energex reviews the system maximum demand data at the end of each season and uses this data to identify issues with the previous forecasts and any emerging trends that have not been evident in previous reviews. These trends are analysed and where possible incorporated in the new econometric model structure. Energex's system demand models have continued to change each year in response to changing usage patterns and emerging trends.

In each of the past five years, Energex's system maximum demand forecasts progressively reduced. Slower than expected recovery from the GFC and the recovery of economic growth following the floods in recent years, rapid increase in residential solar PV and a general reaction to conserve energy by customers impact by high price increases have contributed to the static demand growth in South East Queensland over the past six summers.

In the current regulatory control period, the GFC and its adverse impact on commodity exports, as well as floods, cyclones and drought impacted Queensland. The strength of the

Australian dollar also had a severe impact on international tourism, international education and manufacturing.

The table below summarises Energex's actual and corrected (50% PoE) demands for summer and winter based on Amberley temperatures and associated maximum demand growth over the past five years.

Table 3.1 – Actual Maximum Demand Growth

Demand	2009-10	2010-11	2011-12	2012-13	2013-14
Summer Actual (MW) [2]	4,760	4,689	4,464	4,475	4,373
Growth (%)	3.6%	-1.50%	-4.8%	0.25%	-2.28%
Summer 50% PoE (MW)	4,890 [1]	4,875	4,881	4,590	4,372
Growth (%)	-0.18%	-0.30%	0.2%	-5.96%	-4.75%
	2009	**2010**	**2011**	**2012**	**2013**
Winter Actual (MW)	3975	3,799	4008	3814	3,568
Growth (%)	-8.5%	-4.4%	5.5%	-4.8%	-6.44%
Winter 50% PoE (MW)	4,194	4,391	4,112	4,053	3701
Growth (%)	4.7%	4.7%	-6.4%	-1.4%	-8.68%

Note 1 – The temperature corrected demand for 2009-10 was calculated using the nine summer ACIL Tasman model.
Note 2 – The Summer Actual Demand has been adjusted to take account of embedded generation operating at the time of System Peak Demand.

The 2013-14 summer native demand peaked at 4,373MW at 3pm on Wednesday 22 January 2014, when the day's maximum temperature reached 38.1 degrees at Amberley. The temperature adjusted maximum demand for summer 2013-14 was calculated to be 4,372MW. Maximum demand fell short of the 50% PoE forecast of 4710 MW (forecast last year) by 338MW (7.1%) due primarily to:

- Cautious customer sentiment, which appears to be suppressing spending on services like electricity
- The impact of subdued economic conditions, compounded by a change in the relationship between economic activity and maximum demand.

Energex's maximum demand forecast was therefore revised down substantially at the system level. While Energex does not invest in its network based on the system level, the aggregation of total growth at the zone substation level system needs to be reconciled with the total system level growth.

Reconciliation was important, as the change in behaviour of the existing customer base has been large enough to lower the system level maximum demand growth, despite continued growth in customer numbers. This could result in the risky assumption that subdued peak MW growth at the system level indicates the need for investment at the zone substation level. In reality, there are a multitude of very different factors driving investment at the zone substation level, including:

- Continued strong maximum demand growth at the zone substation level, in various pockets of the network
- Establishment of new suburbs, requiring extensions to the existing network
- Asset replacement
- Safety upgrades.

3.5.2 Queensland GSP growth

In the 2015-20 period, there is considerable divergence in independent forecasts regarding the strength of the Queensland economy. However, Queensland economic conditions appear to be improving and growth is generally predicted to remain between 2.6% and 4.0% by a range of economic consultants.

Energex has assumed the base case GSP growth prepared by AEMO in February 2014 in its summer maximum demand model. This was considered an independent and authoritative source.

Table 3.2 – GSP growth forecasts

	2015-16	2016-17	2017-18	2018-19	2019-20
GSP forecast	321,118	333,829	345,366	355,047	364,353
Growth %	3.84%	3.96%	3.46%	2.80%	2.62%
Source: Frontier Economics for AEMO February 2014					

3.5.3 Impact of weather

One of the key inputs into Energex's system maximum demand forecasts was temperature, with the key assumption being that a system peak was likely to be correlated with higher temperatures. Consequently, the model used daily minimum and maximum temperature data, and maximum demand data for forecasting.

Temperature sensitivity

A key driver of Energex's system maximum demand is the amount of temperature sensitive load, particularly from air-conditioning and refrigeration. On high temperature days, this load can significantly increase both maximum demand and energy consumption. Although temperature sensitivity was not a specific input into the forecast model for current forecasts, Energex has regard for this metric and will take this into account in future forecasts.

Data collected by Energex shows the continuing sensitivity of customer load to temperature. For instance, in South East Queensland, summer 2013-14 was much warmer than the previous three summers with three distinct hot spells during the season. As Figure 3.3 shows, four working days in summer had an average temperature that exceeded the standard 50% PoE temperature of 30.4°C at Amberley (that is a probability of exceeding the value every two years).

Figure 3.3 – Number of days with averages exceeding 30.4°C at Amberley

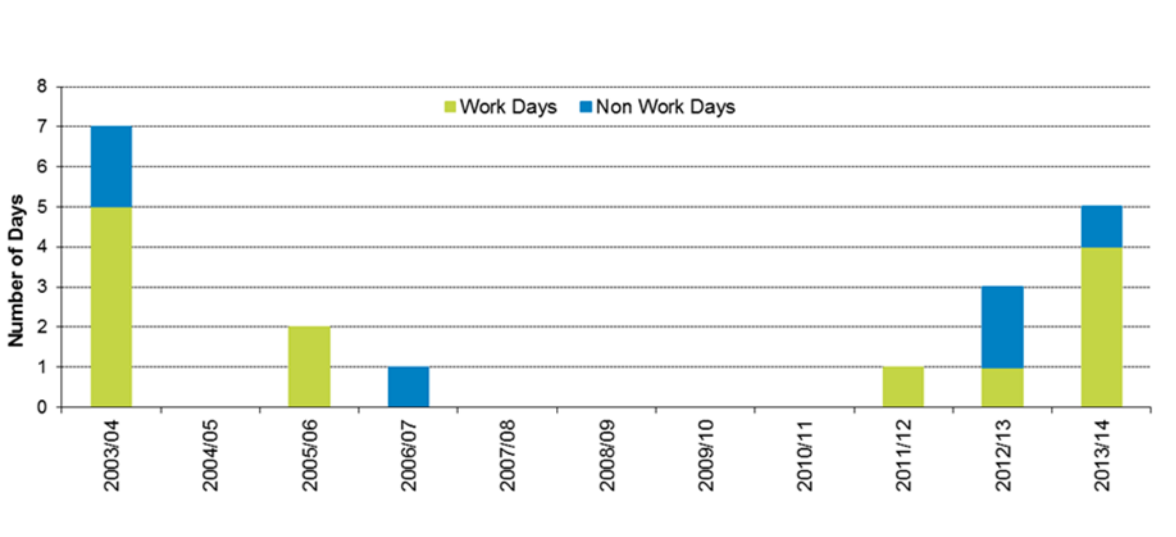
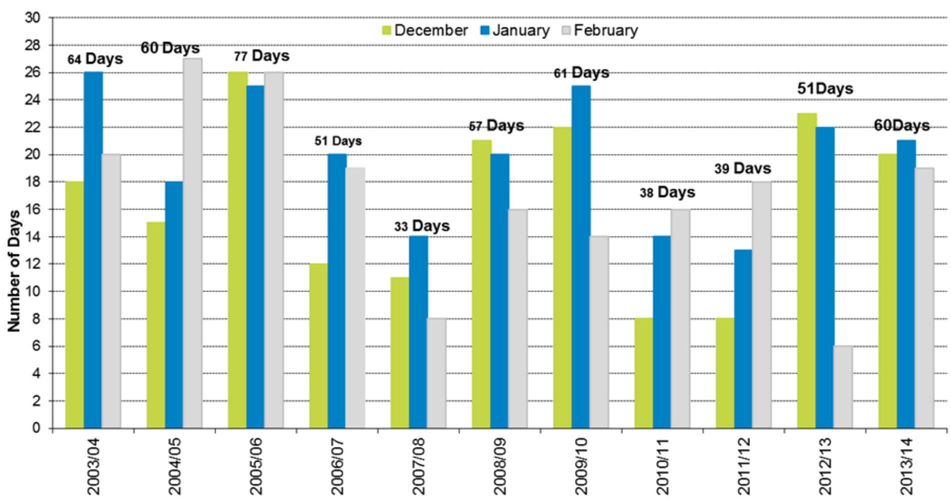


Figure 3.4 below compares hot days (maximum temperatures above 30°C) for the past eleven summers using Amberley temperature data.

Figure 3.4 – Number of days with Maximums exceeding 30°C at Amberley

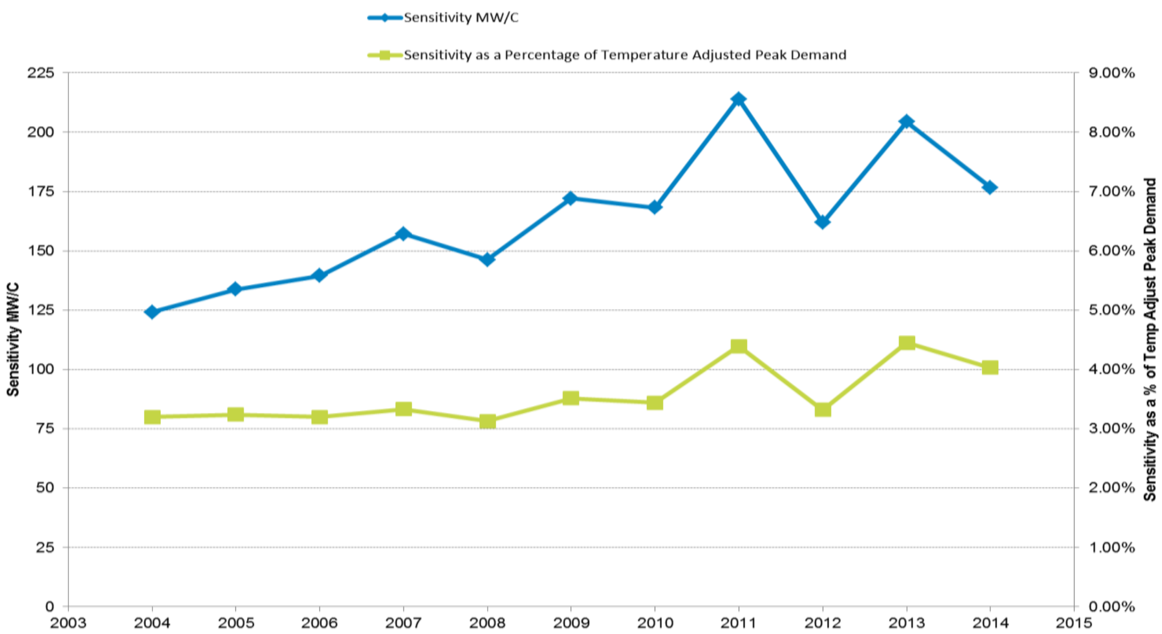


Both of the above figures indicate that the temperature over the past two years has started to return to more normal summer seasons, reflecting the decline of the La Nina weather influence.

The temperature sensitivity was modelled by calculating a coefficient that compares system maximum demand to average daily temperature at Amberley for each summer season. In 2013-14 the calculated coefficient was 177 MW/°C, compared with 204 MW/°C and 162 MW/°C for 2012-13 and 2011-12 respectively.

The trend in weather sensitivity has continually increased since 2003-04, although it is starting to flatten out as shown in Figure 3.5 below. If the trend continues, the anticipated temperature sensitivity of Energex's maximum demand will be approximately 188 MW/°C for a normal summer in 2014-15. The figure also shows the historical increasing trend of the ratio between temperature sensitivity and the temperature corrected maximum demand.

Figure 3.5 – Summer Demand Temperature Sensitivity



Energex used Amberley temperature to adjust the recorded system maximum demand. Amberley data was used due to the reliability of the historic data set, and its close proximity to Brisbane. The long-term average temperatures for Amberley are displayed in Table 3.3 below.

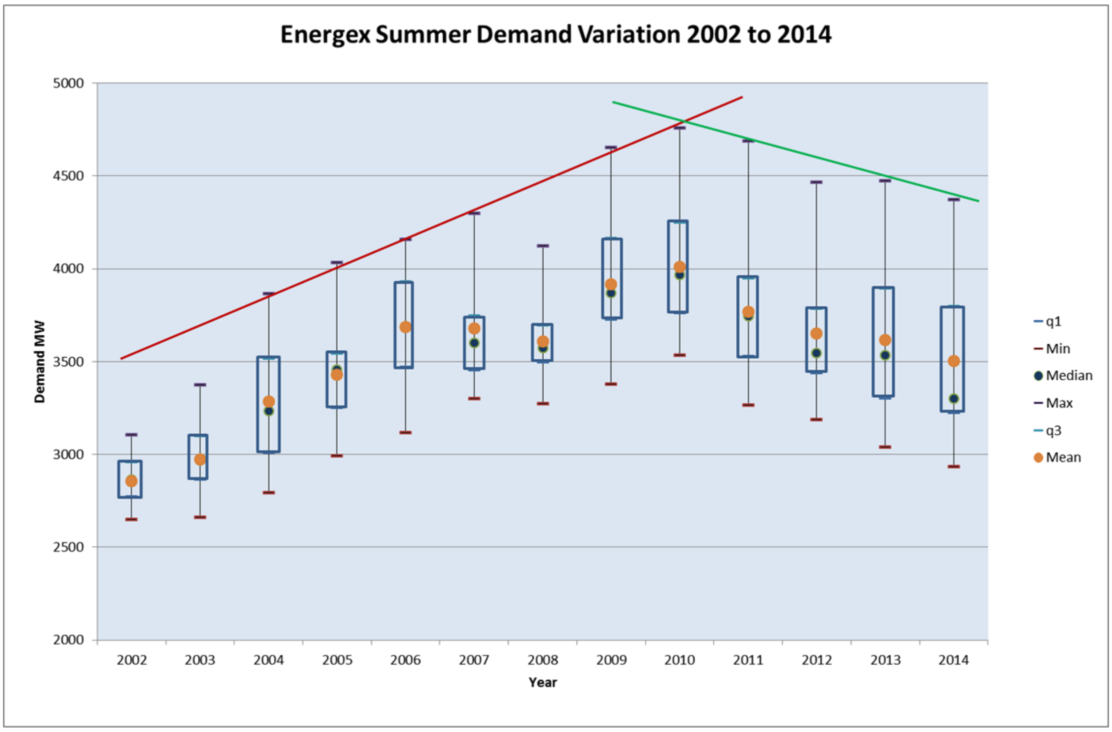
Table 3.3 – Long Term Average Temperatures at Amberley

	Summer	Winter
10% PoE	32.1	6.9
50% PoE	30.4	8.6
90% PoE	28.6	9.6

The data from localised weather stations, for demand / temperature relationship analysis, was used for the zone substation demand adjustments. These adjustments were based on minimum and maximum daily temperatures. Data was taken from the Bureau of Meteorology (BOM) sites at Coolangatta airport, Maroochydore airport, Brisbane airport and Archerfield.

Figure 3.6 below shows the divergence of the spread of daily maximum demands during the past 13 summers. It indicates how the recorded maximum demand has decreased over the past four years with key influences from mild weather, price sensitivity and slow economic recovery.

Figure 3.6 - Energex's summer demand variation



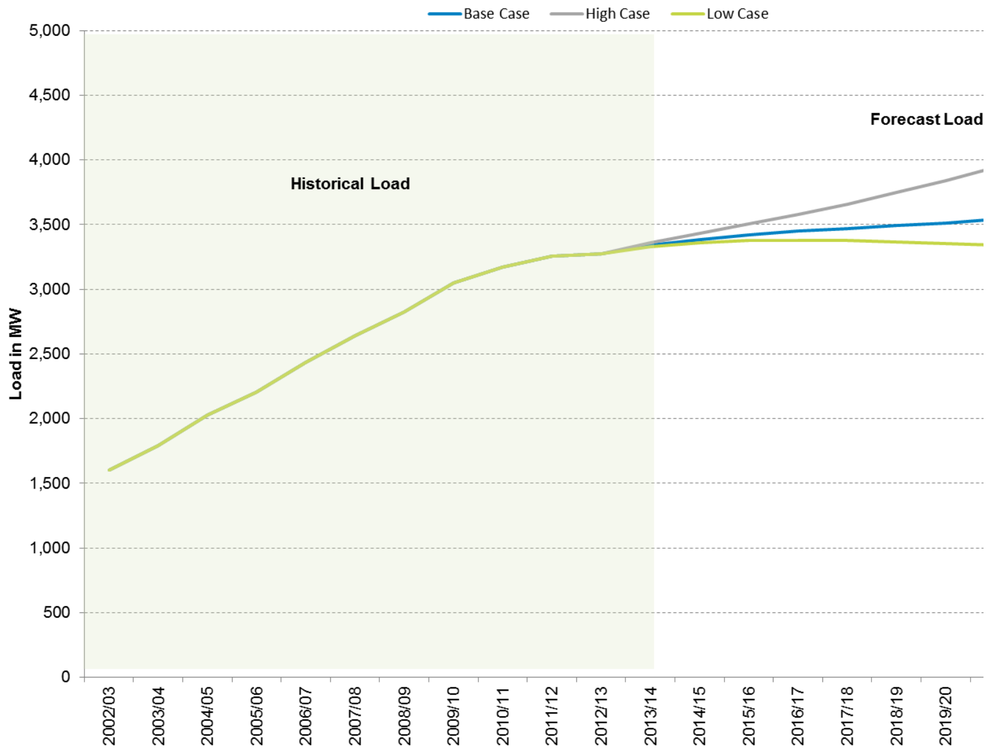
3.5.4 Air Conditioning in SE Queensland

Air conditioning load was inherently included in historical load data and was therefore included in load forecasts. Nonetheless, as air conditioning represents a significant load, Energex monitors forecast air conditioning load and had regard for this in validating its forecasts.

Energex engaged Energy Consult Pty Ltd (March 2014) to prepare independent air conditioning forecasts for the South East Queensland based on air conditioning sales data by air conditioner type. The air conditioning load base case variable was used in the final maximum demand forecast model.

Air conditioning load in South East Queensland is continuing to increase as shown in Figure 3.7 below. However, growth has slowed as a direct result of milder summers, improved appliance efficiencies and the impact of customer behaviour.

Figure 3.7 – Air Conditioning Connected Load Forecast



Energex notes that this forecast air conditioning load was an input to the system demand forecast model. Not all air conditioners in South East Queensland operate or draw full power at the same time. Due to this diversity, the data does not represent the net contribution of air conditioner load to the system maximum demand.

Importantly, while air conditioning load growth is beginning to flatten, the sensitivity of the large air conditioning load already on the network must be managed. Whilst maximum demand sensitivity to temperature appears to be flattening somewhat, given normal hot summers, Energex has assumed that the temperature sensitive load on its network will continue to heavily influence maximum demand on the network over the 2015-20 period.

3.5.5 Impact of electricity prices

Electricity prices also influence maximum demand. The most straight-forward approach to modelling the impact is to directly relate a relevant price[1] to maximum demand. This is because price elasticity for electricity estimates generally relate to energy sales rather than maximum demand sensitivity. Even within maximum demand price sensitivity, there is

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[1] AEMO's State Data Economic Forecast.

logically no single figure because price sensitivity typically varies according to the extremeness of the season[2].

To directly relate a relevant price[3] to maximum demand Energex constructed a price index using:

- Both customer and business prices, with equal weights, reflecting that they have roughly equal shares of energy consumption.
- Real price changes, to better reflect the impact of the price increases between 2006 and 2013, and to preserve its integrity with the GSP values which are quoted in 2011-12 dollars.
- A smoothed series, reflecting that if a prediction and avoiding fluctuations in predicted MW.
- An interaction term with maximum daily temperature, to capture the temperature sensitive change in demand.
- An index, to expose relative price changes only.

To complete the scenario, Energex investigated customer response to recent electricity price increases, which contributed to a reduced customer load at the 50% PoE temperature conditions, well below long term average trends. This was also impacted by the amount of solar PV connected to the network over the past two years. Price forecasts were sourced from the AEMO Price Forecast for Queensland.

Customer behaviour drivers are now incorporated into the Energex model used for system demand forecasting and use data from the Australian Bureau of Statistics (ABS), Queensland Government, Australian Energy Market Operator (AEMO), an independently produced Queensland air conditioning forecast, and Energex solar PV connection data and historical maximum demand data.

3.6 System maximum demand forecasts

Energex derived a system ten year 50% PoE and 10% PoE maximum demand forecast for each of high, low and base case scenarios using the above forecasting methodology.

Energex also engaged NIEIR to produce an independent ten year maximum demand forecast using NIEIR models in July 2014. The results of the two forecasts are compared in Figure 3.8 below. Demand management load reductions are included in both forecasts.

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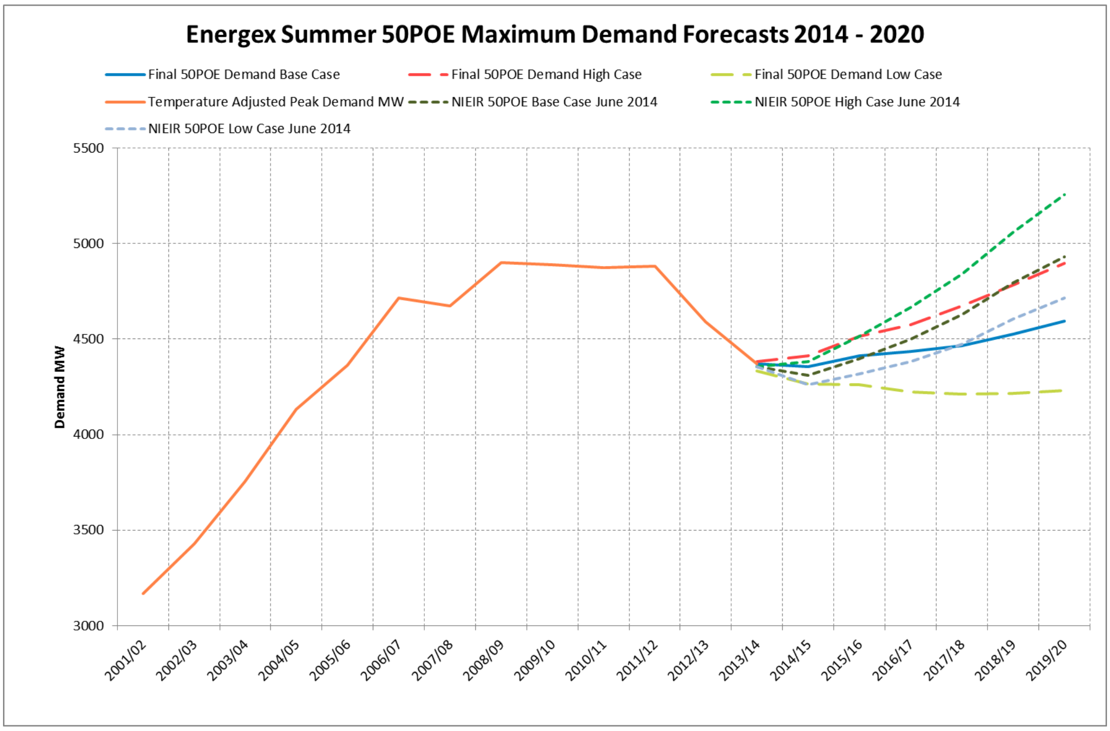
[2] This occurs for at least two reasons. Firstly, because the more extreme the weather, the greater the emotional drive to use the air conditioning. Secondly, more extreme weather is by definition – rare – so the less impact it has on the total energy/bill for a year.

[3] AEMO's State Data Economic Forecast.

Figure 3.8 - Energex Maximum demand Forecasts July 2014



Energex's system maximum demand forecasts for the 2015-20 period are presented in Table 3.4 below.

Table 3.4 – Maximum Demand Forecast (MW)

Forecast [1,2]	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Summer (50% PoE)	4,356	4,411	4,437	4,465	4,527	4,593
Growth (%)	-0.37%	1.26%	0.59%	0.63%	1.39%	1.46%
Summer (10% PoE)	4,869	4,968	5,018	5,102	5,176	5,281
Growth (%)	0.52%	2.03%	1.01%	1.67%	1.45%	2.03%
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Winter (50% PoE)	3,819	3,894	3,958	4,045	4,147	4,523
Growth (%)	3.19%	1.96%	1.64%	2.19%	2.52%	2.55%
Winter (10% PoE)	3,982	4,057	4,122	4,213	4,315	4,425
Growth (%)	3.29%	1.88%	1.60%	2.21%	2.42%	2.55%

Note 1 – The five year demand forecast was developed using Amberley data as recommended by ACIL Tasman and includes the impact of summer 2013-14.

Note 2 – The demand forecasts include the impact of the forecast economic growth as assessed in April 2014.

The forecast of solar PV used in this assessment for the future summer maximum demand was adjusted outside the demand model and is shown below in the table below. It is important to note that the reduction in system maximum demand does not result in reduced substation maximum demand for the majority of substations which peak from after 4.30pm (exact timing depends on the individual substation).

Table 3.5 – Solar PV Contribution to summer system maximum demand

	2015	2016	2017	2018	2019	2020
Solar PV Capacity impact on System Maximum demand (MW)	299	340	380	420	460	499

In preparing the system maximum demand forecast Energex also included a small contribution from electric vehicle load. While it is anticipated that the take up of this technology will be slow, it has the potential to increase significantly if costs decline or government incentives are introduced. The forecast prepared by Energex is shown in Table 3.6.

Table 3.6 – Electric Vehicle Contribution to summer system maximum demand

	2015	2016	2017	2018	2019	2020
Electric Vehicle Load impact on System Maximum demand MW	0.1	0.3	0.6	1.3	2.8	5.9

Note – This assessment assumes that home vehicle charging is on controlled tariffs.

Energex has also developed a preliminary model for the adoption of battery storage with the impact on maximum demand driven by the use of the system. Use of battery storage with solar PV could significantly impact on energy sales and maximum demand. However, if storage is charged at off peak times the impact will provide the benefit of reducing peak demand. This outcome was built into the low scenario for forecasting purpose. For the 2015-20 maximum demand forecasts, Energex assumed initial take up to be small isolated sites.

4 Substation maximum demand forecasts

4.1 Introduction

Energex prepares individual substation (for zone substations, bulk supply substations and connection points) and feeder maximum demand forecasts to identify and analyse limitations and address these constraints with prudent investments. Forecasts at this level are important because distribution network investment is not directly driven by system maximum demand. Rather, capital investment is driven by the need to ensure security and reliability of supply whilst managing growth in demand for electricity and resultant limitations at substations and on feeders.

While growth in maximum demand remained static at a system level, there can be significant growth at a localised substation level where there are a multitude of very different factors driving investment, including:

- Continued strong maximum demand growth at the zone substation level, in various pockets of the network, which requires reinforcement investment
- Establishment of new suburbs, requiring extensions to the existing network, and can indirectly lead to reinforcement investment further up the network
- Replacement life-expired assets
- Safety upgrades.

The distribution of growth rates for bulk supply substations and zone substations over the current and forthcoming regulatory control periods are shown in the figure below.

Figure 4.1 - Zone substation annual compound growth distribution 2015 – 2020

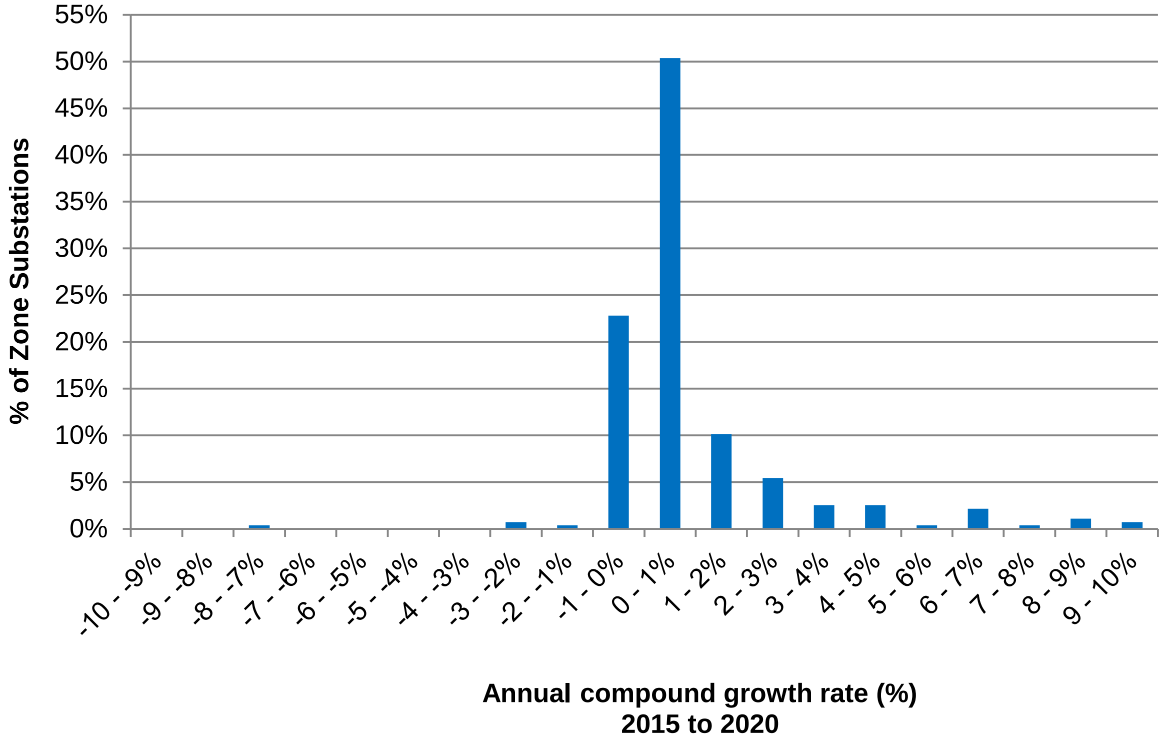


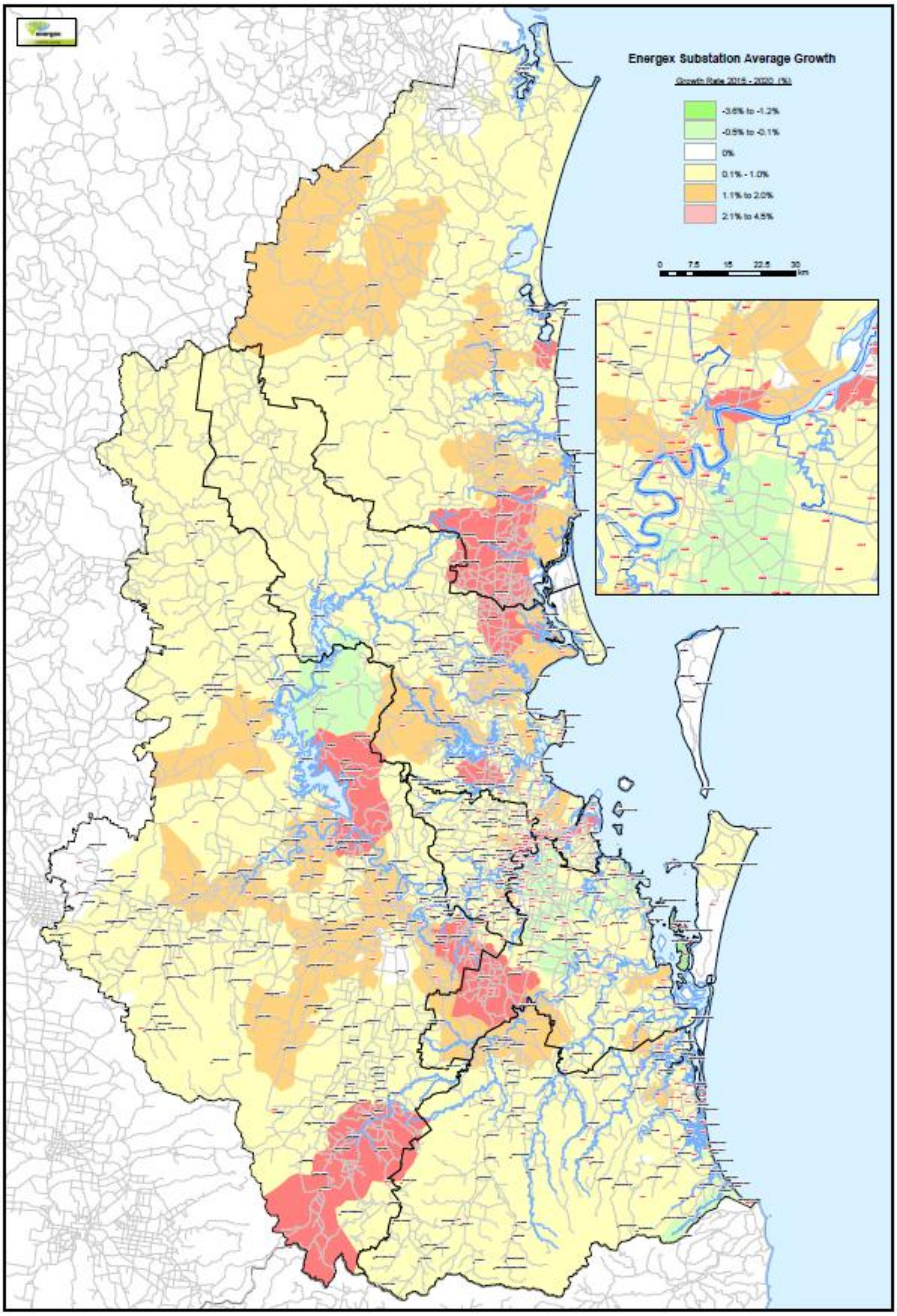
Figure 4.1 shows that approximately 15.2 per cent of substations have an annual compound growth rate greater than 2 per cent, with 7.2 per cent exceeding an annual compound growth rate of 4 per cent. This growth indicated that augmentation of some substations was likely to be required to meet the additional demand on the network in these areas.

Energex produced ten year maximum demand forecasts for all of the zone substations, bulk supply substations and transmission connection points that is reconciled with the system demand forecasts. These forecasts included 50% PoE and 10% PoE values using three scenarios, base case, high case and low case.

The substation maximum demand forecasts were used to identify emerging network limitations. These limitations were assessed by Energex planners and addressed in accordance with Energex planning standards.

Figure 4.2 below shows Energex substation average growth rates across 2015-20. Red areas indicate a growth rate of 2.1% to 4.5% and green areas indicate a negative growth rate of 3.6% to 1.2%.

Figure 4.2 – Energex substation average growth 2015-20



4.2 Inputs

The following were inputs into the substation maximum demand forecasts:

- Summer and winter system demand forecasts – 50% PoE and 10% PoE base case, low case and high case
- Temperature data for five BOM weather stations
- Load transfer data
- Block load data
- Projected substation demand growth rates

4.3 Methodology

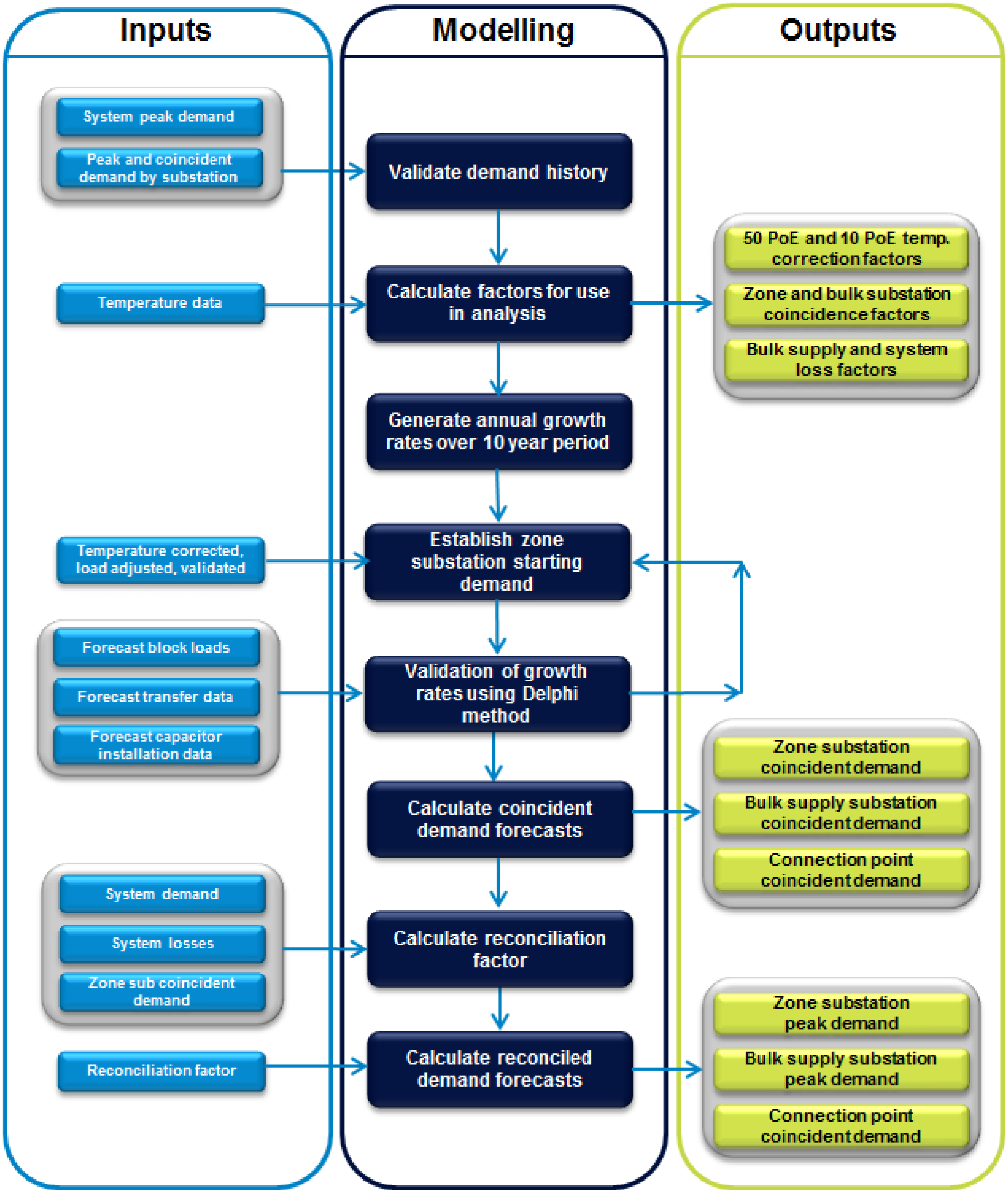
Energex produced ten year maximum demand forecasts for all of the zone substations, bulk supply substations and transmission connection points, which were then reconciled with the system maximum demand forecasts. These forecasts produced 50% PoE and 10% PoE values using three scenarios, base case, high case and low case.

Energex employed a bottom up approach to develop the ten year zone substation maximum demand forecasts using validated historical maximum demands, and demographic and appliance information in 400 metre grids. Larger block loads were included separately after validation for size and timing by Asset Managers.

The zone substation maximum demand forecasts were then aggregated up to the ten year bulk supply point, and transmission connection point demand forecasts take into account diversity of individual zone substation maximum demands and network losses. This aggregated forecast was then reconciled with Energex's system maximum demand forecast and adjusted as required.

The detailed process used to develop the ten year substation demand forecast is outlined in Figure 4.3 and discussed below.

Figure 4.3 – Substation maximum demand forecast methodology (bottom up)



The methodology can be summarised as follows:

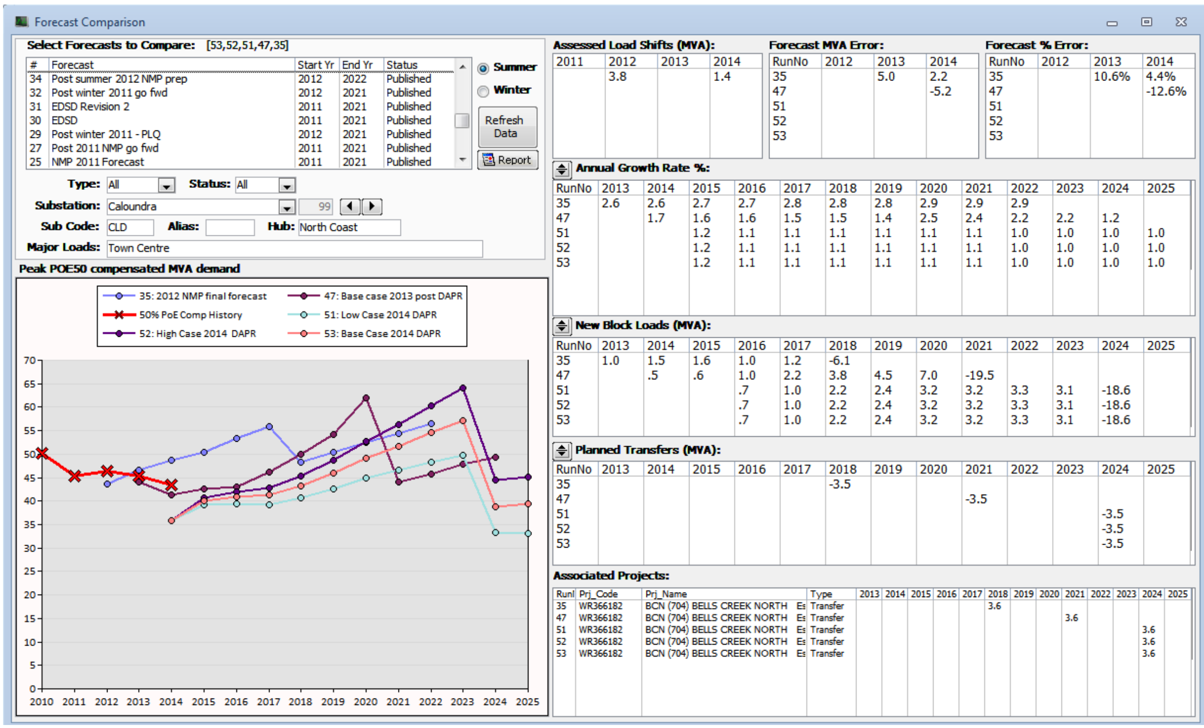
- Validated uncompensated substation maximum demands were determined for summer 2013-14 from the Energex SCADA data system.
- Minimum and maximum temperature at five BOM weather stations were regressed against substation daily maximum demand to assess the impact of each set of weather data on substation demand (Amberley, Archerfield, Coolangatta, Brisbane

airport and Maroochydore airport); The ‘best fit’ relationship was used to determine the temperature adjustment.

- Industrial substations tend not to be sensitive to temperature therefore the 50% PoE and 10% PoE adjustments were based solely on demand variation.
- Previous substation maximum demand forecasts were reviewed against temperature adjusted results and causes of forecast error were identified, using the Forecast Comparison Tool (Figure 4.4 below provides a screenshot for a sample substation).
- Starting values for maximum MVA, MW and MVAr were calculated for four periods, being summer day, summer night, winter day and winter night.
- Demographic and population analysis was undertaken and customer load profiles were prepared for Energex by consultants.
- Yearly maximum demand growth rates were determined from the customer load profiles prepared for Energex, historical growth trends and local knowledge from Asset Managers using a panel review (Delphi) process.
- Size and timing of new block loads were reviewed and validated by Asset Managers before inclusion in the forecast.
- Size and timing of load transfers were also reviewed by Asset Managers before inclusion in the forecast.
- Timing and scope of proposed sub-transmission projects were reviewed by development planners before inclusion in the forecast.
- The growth rates, block loads, transfers and sub-transmission projects were applied to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis.
- Zone substation forecast maximum demands were aggregated up to transmission connection point demands through the bulk supply substations using appropriate coincidence factors and losses.
- Total aggregated demand was reconciled with the independently produced system maximum demand forecast to ensure consistency for the ten year forecast period.

Substation maximum demand forecasts were reviewed and compared each season against previous forecasts, and major differences were investigated using SIFT, using the built in comparison tool. The substation forecast modelling tool can differentiate between approved and proposed projects in the process.

Figure 4.4 - Forecast Comparison Tool



The forecast comparison tool was used to assess the previous forecasts against the temperature corrected actual peak demands. This report also showed the growth rates, block loads and load transfers that combined to form the ten year forecast. Understanding the difference between the forecast value and the actual value assisted Energex to improve the substation maximum demand forecasts.

4.3.1 Treatment of block loads, transfers and switching

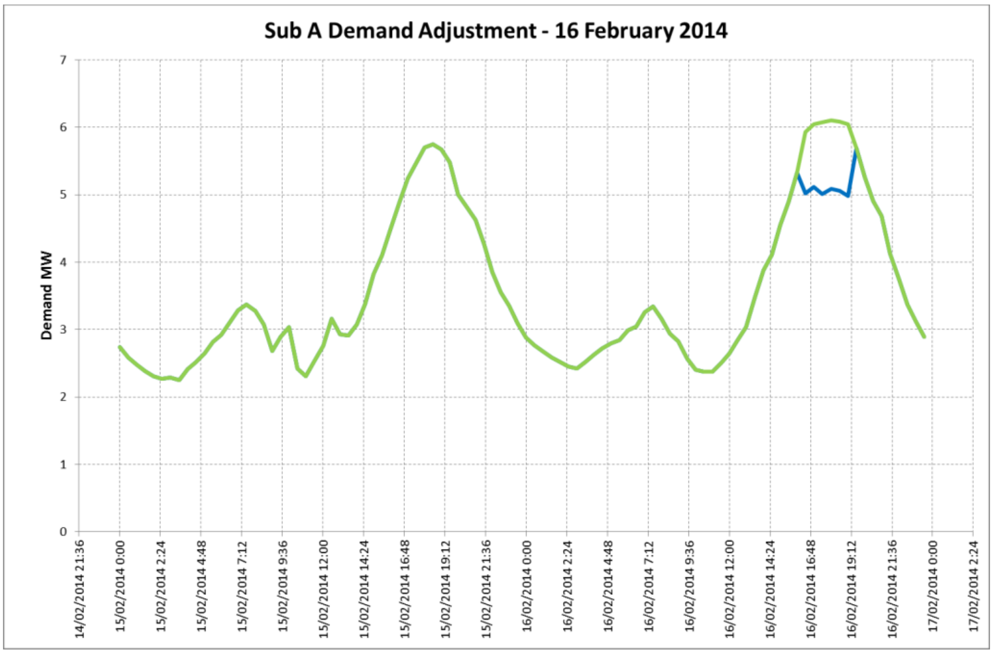
The forecasting process accounted for block loads at the substation and 11 kV feeder level by assessing the maximum load and the timing of the block load. Block loads were loaded into SIFT from the Block Load database and were assigned to zone substations. The load was reviewed and often reduced to allow for coincidence and overestimation by customer consultants. To prevent double counting of the block loads, only those that exceed 5.0% of the load on the substation and were categorised as firm or expected were included in the forecasts. Smaller block loads were excluded and considered to be part of the underlying growth of the substation.

Load transfers were captured in SIFT through planned transfers to or from adjacent zone substations. Load assessments were undertaken between seasons to capture load transfers that were completed and would affect the forecast. Load transfers in place for more than two weeks were considered to be permanent and captured in the system diagrams and the load forecast.

Switching was taken into account when reviewing maximum demand at the conclusion of each season. Energex made an adjustment for temporary load transfers when the peak load was affected and the load was estimated from adjacent days. Figure 4.5 below shows a typical adjustment to obtain a peak demand.

Any abnormal loads, that could not be adjusted for transfers were excluded from the analysis, usually by referring to the next largest maximum demand for that substation.

Figure 4.5 - Typical adjustment to obtain a peak demand



4.3.2 Load control and solar PV cells

Energex incorporated demand management initiatives into the summer and winter substation forecasts and the resulting reductions were captured in Substation Investment Forecasting Tool (SIFT) and the ten year maximum demand forecasts.

The demand management initiatives captured were the broad application of control capability for air conditioning, pool pump and hot water. Demand management is also being targeted at network limitation substations in an effort to defer capital expenditure. The approach used was to target commercial and industrial customers with incentives to reduce maximum demand through efficiency and power factor improvements.

Solar PV output was assumed to be part of the historical load for each substation that peaks during the day. Residential substations that peak in the evening are generally not affected by solar PV generation.

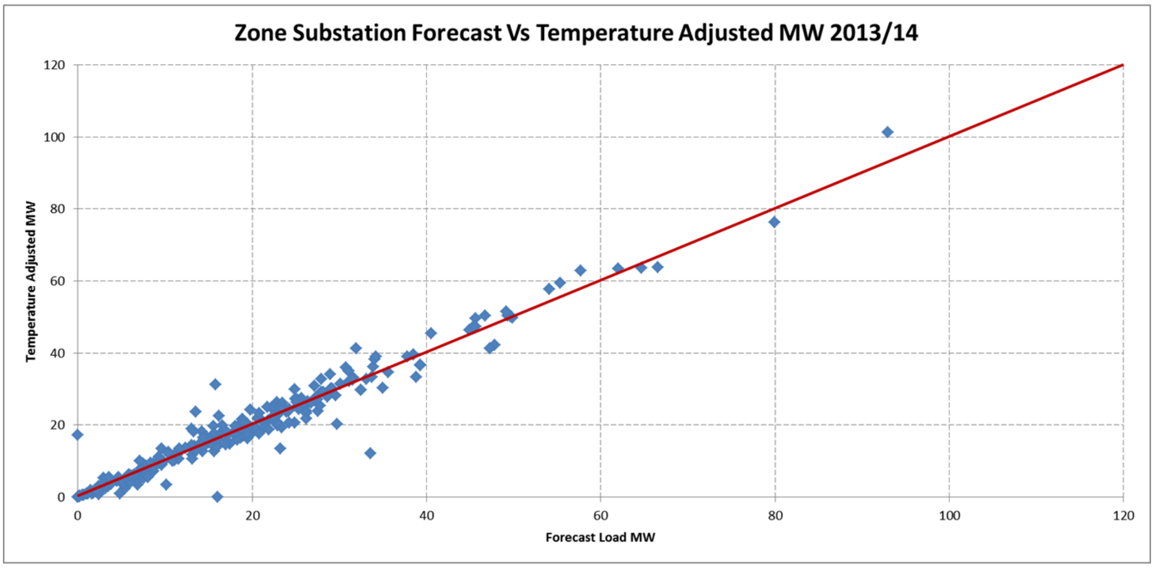
4.3.3 Tools and testing

SIFT was used by Energex to prepare, monitor and review substation demand forecasts. This tool was built in-house and incorporates historical maximum demands, proposed block loads, growth rates, load transfers, diversity factors, PoE adjustment factors, losses and reconciliation factors.

Ten year summer and winter maximum demand forecasts are produced and reviewed before internal distribution to relevant planning areas of Energex. These are prepared directly from SIFT to minimise errors and improve efficiency of business planning functions such as planning the capital program and managing assets. These also inform AER Regulatory Information Notice (RIN) responses and DAPR reports.

Forecast error assessment at zone substations and bulk supply substations was assessed annually to identify improvements for the following forecast run. A review of the Mean Absolute Percentage Error (MAPE) was calculated for all zone substations. A review of forecast to actual was also assessed using a graphical approach as shown in Figure 4.6 below. Ideally the forecast should match the actual temperature adjusted maximum demand.

Figure 4.6 – Zone substation forecast vs temperature adjusted MW 2013-14



4.4 Key assumptions

The following assumptions were applied to developing substation maximum demand forecasts:

- Summer peak demand is associated with higher temperatures whilst winter peak demand is associated with lower temperatures.
- Output from solar PV is generally coincident with commercial and industrial (C&I) customer maximum demand. Although there are limited numbers installed at this time, increasing penetration of solar PV at C&I premises is expected to provide benefits through reduced substation and feeder maximum demands.
- The benefit of solar PV at residential premises is typically negligible due to the coincident maximum demand on substations and feeders occurring from after 4.30pm.

- Zone substation growth rates were determined through a process of growth analysis, neural network modelling and discussions with Asset Managers.
- Temperature adjustment based on one of five Bureau of Meteorology weather stations in the Energex area of supply.

5 11 kV feeder maximum demand forecasts

5.1 Introduction

The objective of 11 kV feeder demand forecasts is to identify in advance where limitations may occur on the 11 kV feeder network and to quantify the magnitude of any limitation. These forecasts are used in planning for the distribution network. These limitations can include exceeding the rating of circuit breakers sections of overhead or underground conductors and equipment installed on the 11 kV network.

5.2 Inputs

The following inputs were used in determining the 11 kV feeder demand forecast to capture historic events and apply planned future network changes:

- Historic temperature corrected load data.
- Assessed day and night 11 kV feeder loads at 50% PoE for summer and winter.
- Actual step changes in 11 kV feeder 50% PoE load (Assessed Steps) due to load transfers, block loads or changes in customer behaviour.
- Future planned network changes.
- Block loads expected to be commissioned on 11 kV feeders.
- 11 kV feeder growth rates aligned with zone substation growth rates by weighted average.
- Approved capital projects that affect the 11 kV feeder network by commissioning or de-commissioning 11 kV feeders, transferring load between 11 kV feeders, changing the thermal rating of 11 kV feeders, changing the secondary system limits of 11 kV feeders, or establishing a new block load.

5.3 Methodology

11 kV feeder maximum demand forecasts were performed on a feeder by feeder basis. The summer assessment covers the period from 1 November to 31 March, and the winter assessment from 1 June to 31 August. The methodology applied to these forecasts was as follows:

- a feeder load starting point was established by undertaking bi-annual 50% PoE temperature corrected load assessments. This involved:

- identifying and removing any temporary (abnormal) loads and transfers
- analysing daily peak loads for day and night to identify the load expected at a 50% PoE temperature.

- Using a statistical distribution, the 10% PoE load value was extrapolated by using 80% of the temperature sensitivity from the 50% PoE load assessment.

The 10% PoE load forecast was used for determining voltage limitations.

5.3.1 Tools and testing

The 11 kV feeder forecast was modelled by the NetPlan database that stores the forecast as a series of events in date order for each zone substation 11 kV feeder, and calculates the resulting forecast load in amps for summer day, summer night, winter day and winter night. It uses rating data to calculate thermal and secondary system utilisation forecasts for the same four seasons.

An event can be one of the following:

- Historic
- Summer assessment
- Winter assessment
- Assessed step
- Growth rate
- Load transfer
- Block load

After each season's load assessments were completed the following tests were carried out using the NetPlan database:

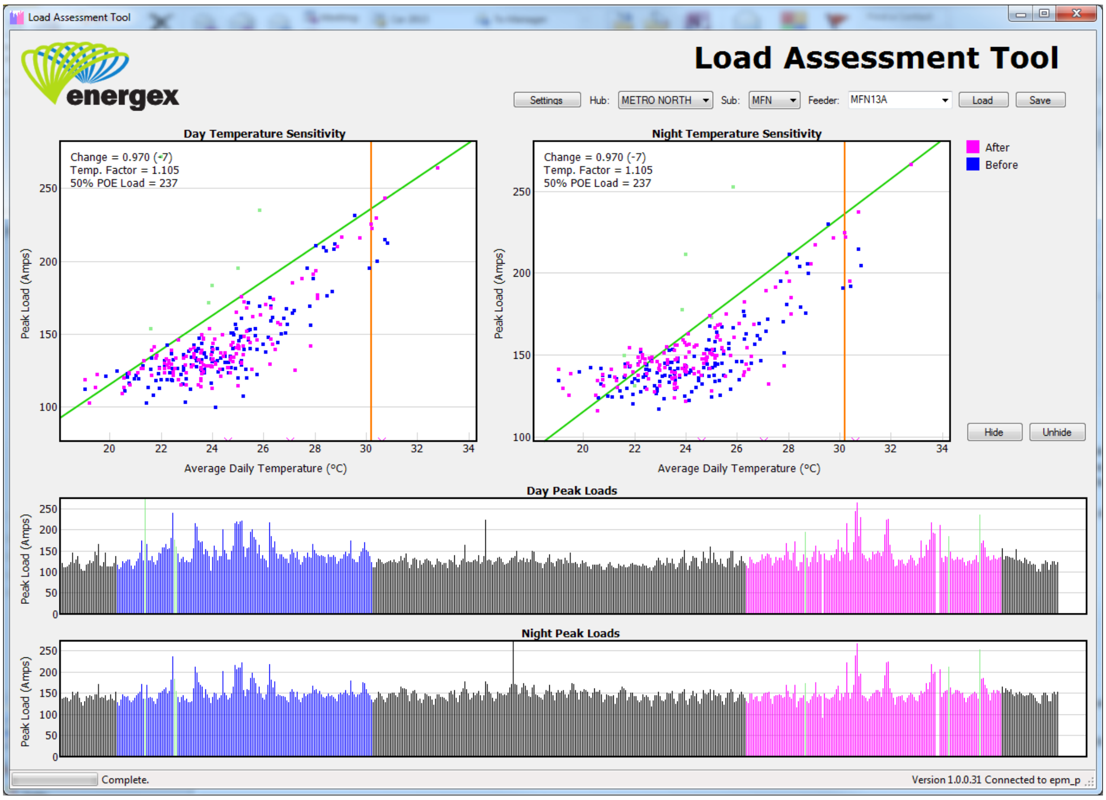
- Check that all commissioned 11 kV feeders have an assessment
- Check that the annual change for day and night were consistent
- Check that the day and night temperature factors were consistent
- Calculate the median annual change for day and night
- Determine the number of feeders assessed
- Calculate the weighted average temperature factor for day and night using the formula:

Weighted average =

[sum(50%PoE load x (temperature factor -1))/ sum(50%PoE load)] + 1

The Load Assessment Tool was used to assess the summer and winter day and night 50% PoE loads. It did this by charting daily peak load against average daily temperature from Amberley for either the summer or winter period using the current season and the corresponding season from the previous year. The points from each year were aligned to provide the annual change in load. A line of best fit through the middle of the points was then raised to the top of the points envelope is used to intersect the vertical 50% PoE line to give the assessed 50% PoE load. A typical Load Assessment is shown below.

Figure 5.1 – Typical Load Assessment



The same Load Assessment Tool was used to assess step load changes on a feeder at 50% PoE.

5.4 Key assumptions

The following assumptions were applied in developing 11 kV feeder maximum demand forecasts:

- Weighted average growth rate of feeders are supplied from a single substation agree with the substation annual growth rate

- Temperature sensitivity at 10% POE is reduced to 80% of the temperature sensitivity at 50% POE due to air conditioning load saturation
- 50% POE and 10% POE temperatures were based on the last thirty years of temperature data from Amberley weather station.

5.5 11 kV feeder forecasts

An example of the 11 kV feeder forecasts is shown below for Arana Hills Zone Substation.

Figure 5.2 - Arana Hills Zone Substation forecast

Hub	CENTRAL WEST								
Sub	AHL - Arana Hills								
Feeder	AHL11A	AHL12A	AHL14A	AHL15B	AHL4A	AHL5A	AHL6A	AHL8A	AHL9A
	50POE Amps	50POE Amps	50POE Amps	50POE Amps	50POE Amps	50POE Amps	50POE Amps	50POE Amps	50POE Amps
SD50POE 2014/15	162	200	264	178	107	166	183	256	140
SD50POE 2015/16	158	204	267	180	105	166	183	261	136
SD50POE 2016/17	155	208	270	181	103	166	183	266	132
SD50POE 2017/18	152	212	272	183	101	166	183	272	128
SD50POE 2018/19	149	216	275	185	99	166	183	277	124
SD50POE 2019/20	146	221	278	187	97	166	183	283	120
SN50POE 2014/15	166	219	262	191	119	182	213	282	160
SN50POE 2015/16	162	224	265	193	116	182	213	287	155
SN50POE 2016/17	159	228	268	195	114	182	213	293	150
SN50POE 2017/18	156	233	270	197	112	182	213	299	146
SN50POE 2018/19	153	237	273	199	109	182	213	305	141
SN50POE 2019/20	150	242	276	201	107	182	213	311	137
SN50POE 2020/21	147	247	279	203	105	182	213	317	133
WD50POE 2015	106	149	191	139	80	105	136	167	95
WD50POE 2016	104	152	193	141	79	105	136	171	92
WD50POE 2017	102	155	195	142	77	105	136	174	89
WD50POE 2018	100	158	197	144	76	105	136	178	87
WD50POE 2019	98	161	199	145	74	105	136	181	84
WD50POE 2020	96	164	201	146	73	105	136	185	82
WN50POE 2015	151	213	225	190	106	154	211	216	153
WN50POE 2016	148	217	227	192	104	154	211	221	149
WN50POE 2017	145	222	230	194	102	154	211	225	144
WN50POE 2018	142	226	232	196	100	154	211	229	140
WN50POE 2019	139	231	234	198	98	154	211	234	136
WN50POE 2020	136	235	237	200	96	154	211	239	132

6 Customer number forecasts

6.1 Introduction

For the number of customer connections (customer numbers) Energex prepares a ten year customer number forecast by total system, and by network tariff and customer categories. Customer number forecasts are used to prepare the energy sales forecasts for each customer category; and are used for selected expenditure categories in Energex's base-step-trend model.

Over the last four years, Energex's residential customer number growth has been weaker (approximately 1.2%) than the population growth rate (approximately 2.0%). The reasons for this are not yet apparent, but could be due to economic circumstances and cost of living pressures. Recent growth is slower than the longer term.. This is expected to continue for the 2015-20 regulatory control period. Anecdotal evidence suggested that the high cost of housing, limited rental opportunities and high youth unemployment have contributed to this trend. This indicated that the number of persons per household may increase resulting in increasing average consumption per household.

6.2 Inputs

Economic activity, employment prospects and the relative value of dwellings drive population changes. An understanding of the changing demographic environment is therefore essential to understanding the growth of customer numbers.

The following were inputs into the residential customer number forecasts:

- Existing Energex customer numbers
- South East Queensland population growth, sourced from the ABS and Queensland Government
- Natural growth, interstate migration and international migration figures for Queensland sourced from the ABS
- Long term trend in persons per household, sourced from Housing Industry Association (HIA).

The following were inputs into the non-residential customer number forecasts:

- Economic indicators, being GSP; and
- Long term trends in Energex customers numbers

6.3 Methodology

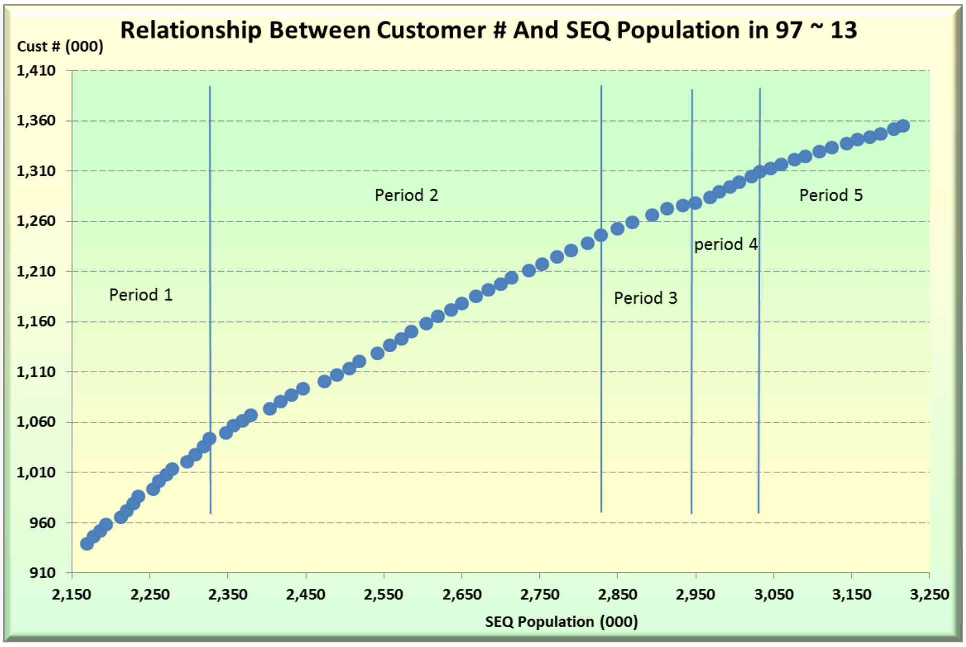
Energex derived customer number forecasts by firstly analysing the relationship between customer numbers (both residential and non-residential) and population in south east queensland, then performing calculations on the basis of this analysis for each of residential and non-residential customers. These processes are discussed in the following subsections.

6.3.1 Relationship between Customer Numbers and South East Queensland Population

The number of customer connections to the Energex network is primarily driven by the total population numbers in South East Queensland (SEQ), the Energex supply area. A segmented regression model was constructed to capture the underlying relationship between customer numbers and population, and was used to forecast annual customer increases over the next 11 years.

The relationship between customer numbers and SEQ population was firstly analysed by performing a visual check, plotting a scattered chart for the two variables. Figure 6.1 illustrates the results for the period September 1996 to December 2013 on a quarterly basis.

Figure 6.1 - Relationship between Customer Numbers and South East Queensland Population



The above figure shows a strong, positive, correlation between customer numbers and SEQ population. It also demonstrates that customer number growth rates varied over the period September 1996 to December 2013. Growth was quite strong in some years but weakened afterwards, before it accelerated again and slowed in recent years. Due to these changes between periods, Energex segments the annual customer numbers into five sub-periods:

- Sep-1996 to Jun-2000

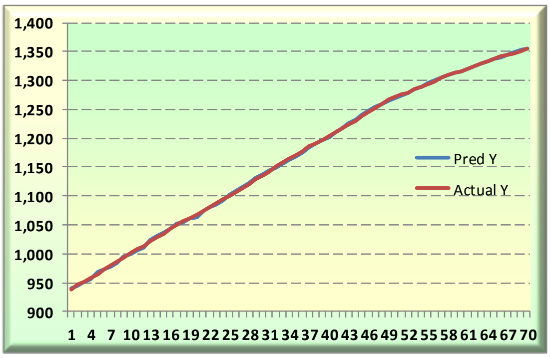
- Sep-2000 to Dec-2007
- Mar-2008 to Jun-2009
- Sep-2009 to Dec-2010
- Mar-2011 to Dec-2013

Accordingly, South East Queensland population was also sub-divided into those five periods and treated directly as the five main drivers to capture the different impacts on customer numbers over those periods. Figure 6.2 shows the estimated results based on the built-in Excel statistical regression module.

Figure 6.2 - Customer Numbers and Population estimates based on Linear Regression Model

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9999
R Square	0.9998
Adjusted R^2	0.9998
Std Error	1.7030
Observations	70



ANOVA

	df	*SS*	*MS*	*F*	*Signif F*
Regression	5	1136734	227346.9	78387.19	9.4E-120
Residual	64	185.6196	2.900306		
Total	69	1136920			

	Coeffs	*Std Error*	*t Stat*	*P-value*	*Lwr 95%*	*Upr 95%*	
Intercept	- 3,979	26.32	- 151.20	0.000	- 4,032	- 3,927	
X Variable 1	**0.652**	0.01	103.52	0.000	0.640	0.665	**SEQ1: 09/96 ~06/00**
X Variable 2	**0.411**	0.00	236.72	0.000	0.407	0.414	**SEQ2: 09/00 ~12/07**
X Variable 3	**0.251**	0.01	27.28	0.000	0.232	0.269	**SEQ3: 03/08 ~06/09**
X Variable 4	**0.367**	0.02	23.90	0.000	0.336	0.397	**SEQ4: 09/09 ~12/10**
X Variable 5	**0.251**	0.01	34.94	0.000	0.236	0.265	**SEQ5: 03/11 ~12/13**

Y: Cust # (000)
Xs: Segmented SEQ Pop (000)
Smpl: Sep-96 ~ Dec-13 Qrtly Data

The model achieved very good results. The R-square reached 99.9%, and all of those five explainable variables have correct signs and were highly significant (p-values = 0 for all). The magnitudes of those five coefficients (highlighted purple in the table), confirmed what Energex found in Figure 6.1, that is:

- The strongest growth path of 0.652 during Sep-1996 to Jun-2000
- Slowing to 0.251 over Mar-2008 to Jun-2009 before strengthening again to 0.367 in Sep-2009 to Dec-2010
- Settling down to 0.251 in recent years.

The values of the five coefficients were critical in forecasting. Energex used them, along with the allocated weights, to form three forecasting scenarios of a short term, a long term and historical path.

The magnitudes of those coefficients measured the impacts of SEQ population on the customer numbers. For example, the 0.251 for variable 5 (i.e. the SEQ population during

March 2011 to December 2013), indicated that for every 1000 increases in SEQ population, around a quarter of them (i.e. 25.1%) will become Energex's (newly connected) customers.

6.3.2 Residential customer numbers

Subsequent to analysis of customer numbers and SEQ population, residential customer numbers were forecast using the following approach:

- Existing customer numbers were sourced from Energex systems using 2013-14 data as the base year.
- Forecast SEQ population growth is divided by the forecast number of persons per household to forecast the number of additional households, or customers.
- Total forecast customer numbers were calculated by aggregating existing customer numbers and forecast future customers.

6.3.3 Non-residential customer numbers

Non-residential customer numbers were generated using the historical relationship between Energex customer numbers and economic indicators such a GSP. Relation models were developed that indicate when economic growth is strong a flow on effect creates a growth in small non-residential businesses.

Block loads were not relevant to customer number forecasts except for the purpose of forecasting the new customers associated with each of those block loads.

6.3.4 Reconciliation with Reset RIN

It is important to note that Energex customer number forecasts were based on the number of active NMIs. This means that customer number forecasts provided in the Reset RIN, which require active and inactive NMIs, will not reconcile.

6.4 Key Assumptions

6.4.1 Residential customers

The Queensland population forecast used by Energex in forecasting residential customer numbers is presented in Table 6.1.

Table 6.1 – Population growth forecasts

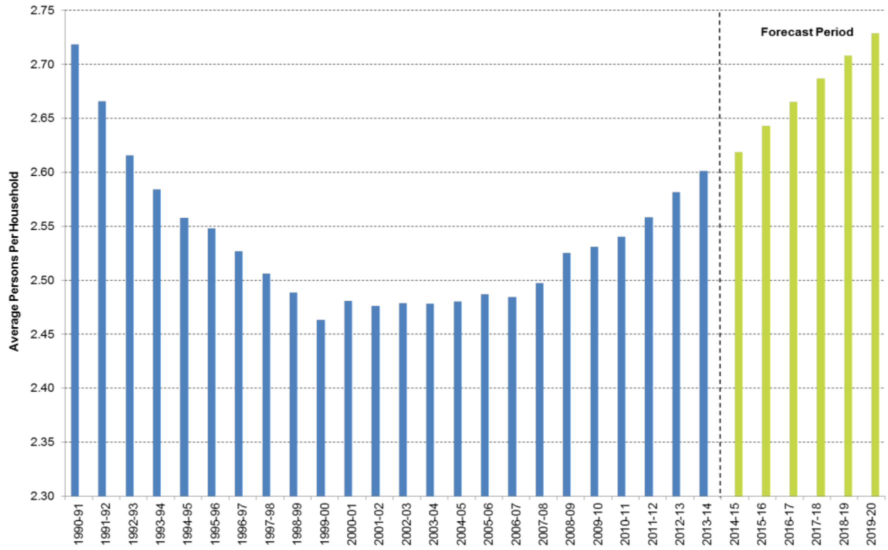
	2015-16	2016-17	2017-18	2018-19	2019-20
Queensland population	4,957,561	5,061,002	5,163,719	5,266,484	5,369,893
Growth %	2.31%	2.09%	2.03%	1.99%	1.96%
Source: ABS					

Energex used the total Queensland population (ABS data) to estimate forecast population in the South East Queensland region for use in the model.

Energex used data from the Housing Industry Association (HIA) to estimate the long term trend in persons per household which is influenced by a range of economic factors that have substantially changed since 2009. That is, the initial trend towards fewer persons per household, driven by an ageing population and an increase in single person households, had been expected to contribute to stronger customer growth. However, this effect has been offset by the growth in 'stay at home young adults' and older members of the family remaining in the family home. The number of persons per household is now expected to increase slightly over the next ten years.

Figure 6.3 below shows the long term trend of persons per household calculated by Energex on the basis of ABS and Queensland Government data.

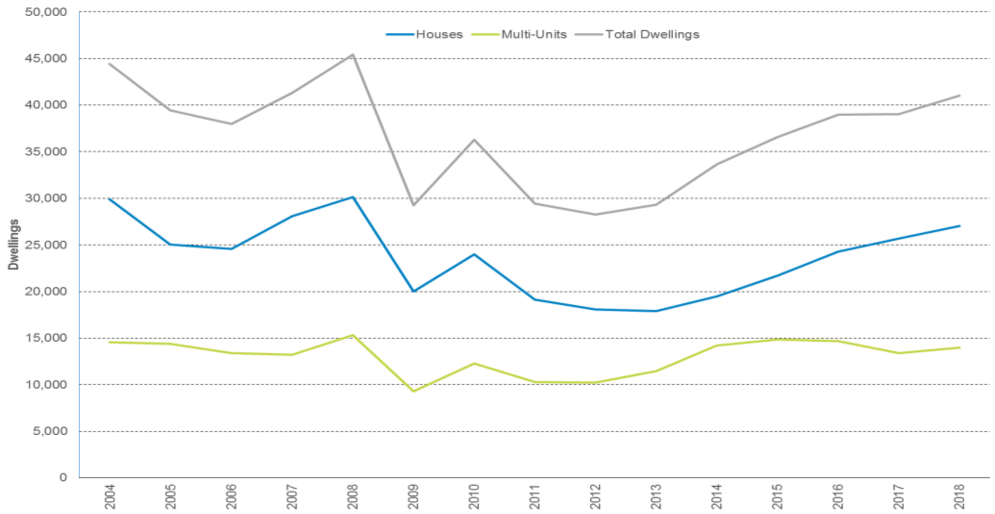
Figure 6.3 – Average Number of Persons per Household in SEQ



To validate forecast residential customer numbers Energex used new dwelling statistics from HIA. Dwelling starts (i.e. buildings due to commence construction) in Queensland appears to have bottomed out with the HIA in February 2014 predicting increasing growth to 2014-15. HIA produce regular updates on housing starts in each state and their February 2014 predictions for Queensland are shown below in. It is predicted that the housing market in Queensland will start to recover slowly over the next couple of years, spurred on by interest rate cuts and a general housing shortage.

Figure 6.4 presents the HIA's historical and forecast dwelling starts series.

Figure 6.4 – HIA Queensland Dwelling Forecasts



6.4.2 Non-residential customers

Forecasts of non-residential customer numbers were determined using econometric model based on economic data and historical trends. A check for this model is the summation of the residential and non-residential customer numbers matching the top down total customer numbers. Both of these models were based on population projections published by the ABS. Residential customers numbers were derived from persons per household and total customer numbers were based on population natural growth, interstate migration and international migration. Individual Non-residential network tariff customer number forecasts were based on long term customer growth trends and allows for adjustment of customers moving from one network tariff to another. The summation of the network tariff customer numbers is reconciled with the top down non-residential customer numbers

6.5 Customer number forecasts

The new total new customer number forecast is shown in the figure below. These were forecast to grow from 1.381 million connections in 2014-15 to 1.473 million connections in 2019-20, representing an average compound growth rate of 1.3 per cent over the 2015-20 regulatory control period as illustrated in the figure below.

Table 6.2 – Total customer numbers forecast

	2015-16	2016-17	2017-18	2018-19	2019-20
Total customer numbers	1,400,584	1,418,622	1,436,546	1,454,484	1,472,527
Growth %	1.4%	1.3%	1.3%	1.2%	1.2%

Figure 6.5 - Actual and Forecast Annual Customer Number Increases

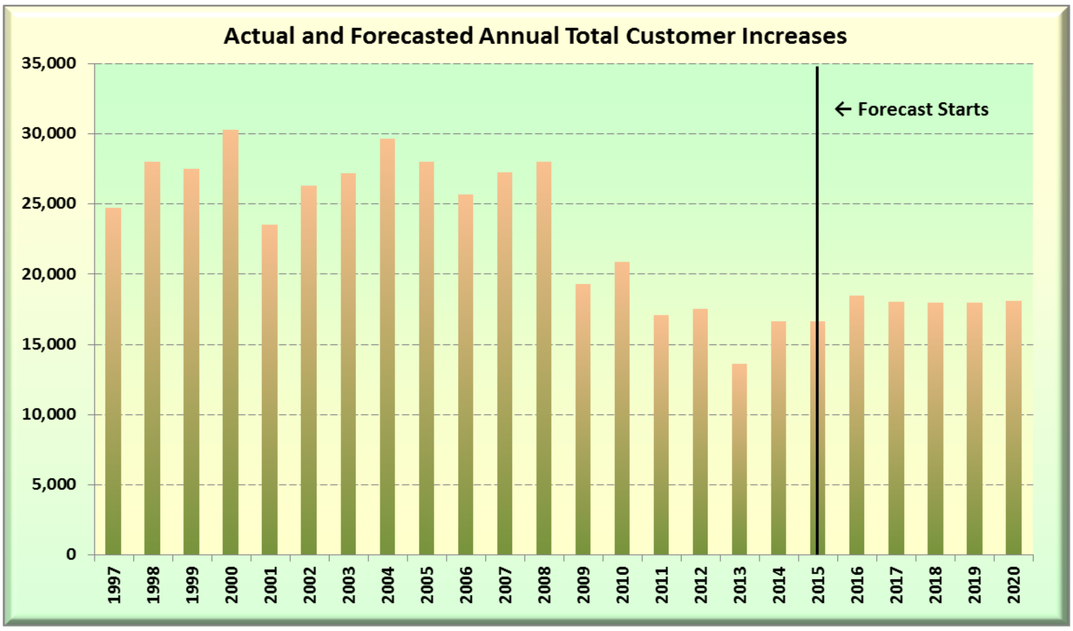


Table 6.2 and Figure 6.5 show that while the annual customer increases were lowest in 2012/13, 2013/14 and 2014/15 will be similar. A small boom is forecast for 2015/16 before slowing down to an annual average of approximately 18,000 for the remainder of the forecast period.

The strong South East Queensland population growth, as forecast by ABS, NIEIR and OESR, again will be the main contributor to the strong customer number growth in 2015/16. The table also shows that, on average, annual increases of customer numbers will be around 18,000 over the next six years, which is higher than the annual average of 16,300 during 2010/11 to 2013/14, but is much lower than the annual average of 26,100 over the 1996/97 to 2009/10.

Although Energex doesn't need to provide the customer numbers on a monthly basis, the model has this functionality and is also useful for Energex monthly/quarterly energy sales forecasts. Figure 6.6 shows the monthly movements (i.e. customer number increases) for some actual and forecasting years (it is dynamic and those years can be selected via the tick-boxes built in the model).

Figure 6.6 - Monthly Customer Number Increases for the Selected Years

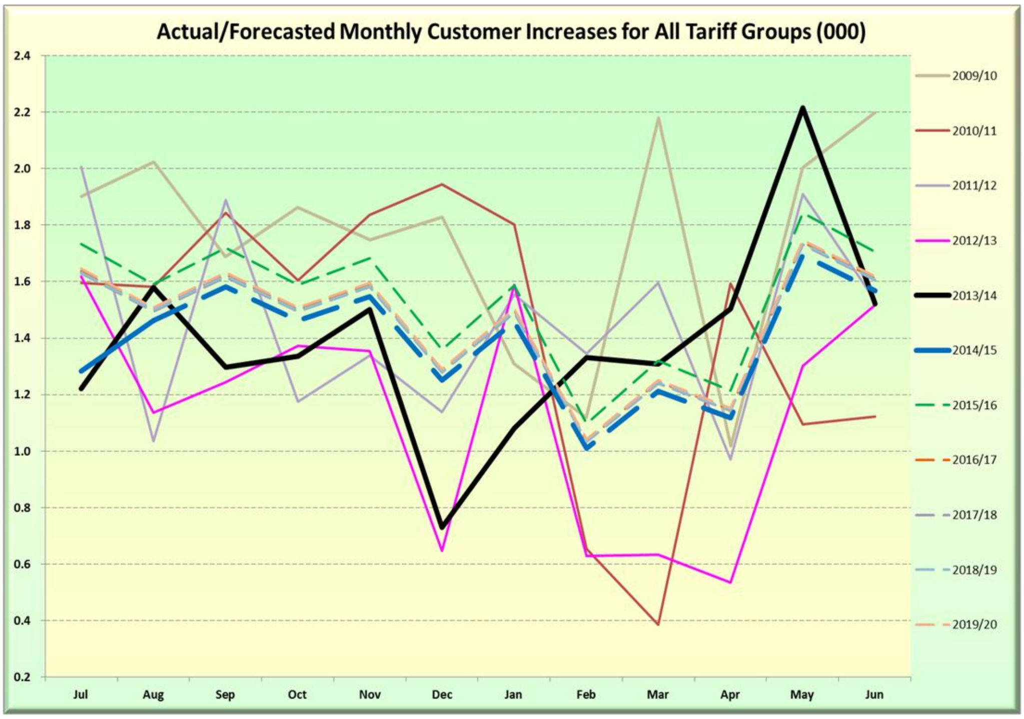
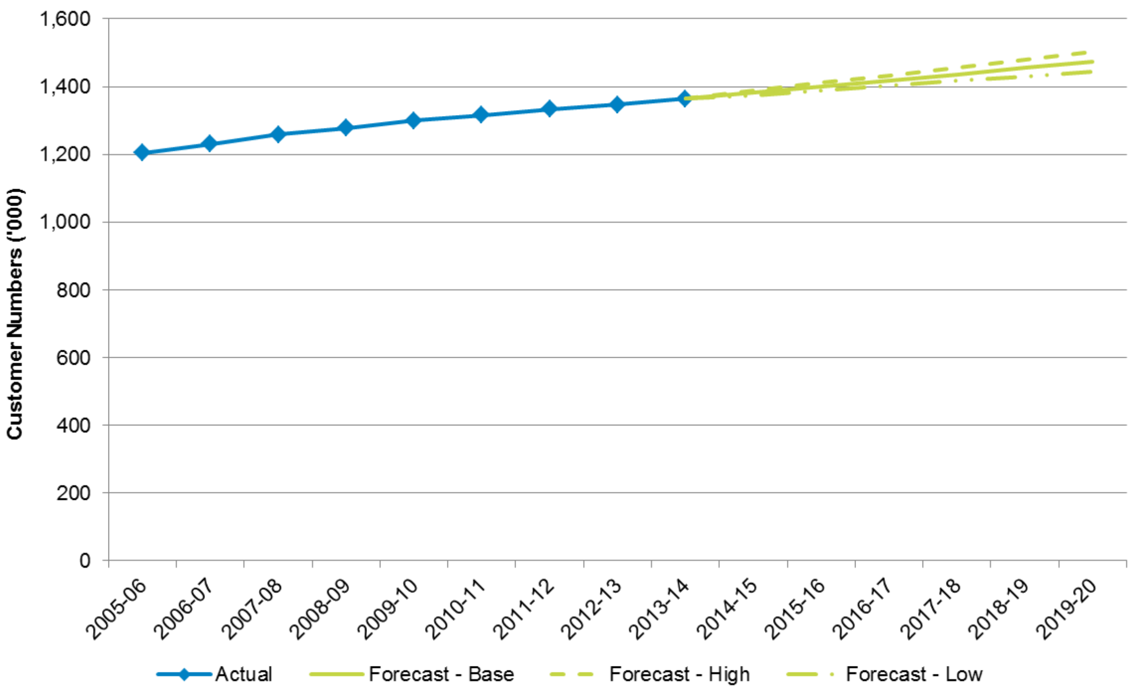


Figure 6.7 - Customer Growth Forecasts



Stronger overseas migration, and steady interstate migration due to the better than the national average of GSP (based on NIEIR's forecasts) over the next five years should increase new customer connections from 1.0% in 2012-13 to 1.2% in 2019-20.

Expected new customer numbers are likely to average about 18,000 customers per year for the next five years. This is lower than historical values but reflects trends in key drivers.

It is noted that Energex currently applies a top-down approach to its customer number forecasts, but seeks to validate this approach in the future using a bottom-up approach. To perform this bottom-up approach Energex will need reliable trend data, which will be collected over coming years.

6.5.1 Residential customer forecasts

Overall, customer number growth on Energex's network was subdued for the past three years as a direct result of the economic slowdown in Queensland; the reduced employment opportunities; and an increase in the number of persons per household.

Population growth in Queensland remains relatively steady. However, new dwelling connections have been slow partly as a result of the increasing level of average persons per household. This resulted in some offsetting trends, with fewer new households contributing less to energy and demand, while the increase in average persons per household was forecast to drive up per household consumption.

Table 6.3 – Residential customer numbers forecast

	2015-16	2016-17	2017-18	2018-19	2019-20
Residential customer numbers	1,276,206	1,293,580	1,310,873	1,328,203	1,345,652
Growth %	1.5%	1.4%	1.3%	1.3%	1.3%

6.5.2 Non-residential customer forecasts

Non–residential customer numbers were forecast to slowly decline over the first few years of the forecast period before rebounding with a small growth rate. Non-residential customer numbers were calculated from the top down analysis based on total customer numbers minus the residential customer numbers. Primarily this was a check against the bottom up customer number forecast by network tariffs.

Table 6.4 – Non-Residential customer numbers forecast

	2015-16	2016-17	2017-18	2018-19	2019-20
Non-Residential customer numbers	124,378	125,042	125,673	126,281	126,875
Growth %	0.6%	0.5%	0.5%	0.5%	0.5%

7 Energy sales, purchases and consumption forecasts

7.1 Introduction

Energex uses ten year energy forecasts for budgeting, revenue assessments, and forecasting likely movements in the system load factor. These forecasts are published and transmission connection point energy forecasts are made available to Powerlink Queensland for revenue and billing purposes.

Energex also uses 12 month detailed customer energy forecasts to prepare customer pricing for contestable market customers. These forecasts are also key inputs into the annual distribution loss factor assessment, as required under the Rules.

Energex validates actual energy consumption data against the monthly energy forecasts on a monthly basis.

7.2 Inputs

The following inputs were used to prepare energy sales, purchases and consumption forecasts for the forthcoming regulatory control period:

- Historical energy sales by network and customer category
- Historical solar PV export energy
- Customer numbers history and forecast
- New technology impacts
- Government and policy and rule changes, such as the repeal of the ban on electric hot water systems and the solar feed in tariff.

7.3 Methodology

The forecasting approach adopted by Energex was a combination of statistically based time series analysis, multifactor regression analysis, and the application of extensive customer knowledge and industry experience.

7.3.1 Forecasting process

The forecasting methodology Energex used to prepare its energy forecasts can be summarised as follows:

- Review economic data, trends, drivers and consultant's economic reports to consolidate the information into an economic review document covering international conditions, Australian conditions and Queensland conditions. Data input sources include Federal and State Governments, ABS, QECD, BIS Shrapnel, major banks, Reserve Bank and others.
- Review historical energy consumption and purchases data for each customer segment and embedded generators.
- Review historical customer connections for each customer segment and compare with population trends and forecasts.
- Review and analyse consumption drivers by customer category in accordance with economic conditions and trends in specific customer segments.
- Produce a draft forecast for customer numbers and energy by customer classes for review by peers.
- Review system losses and the impact of embedded generation.
- Review energy forecasts and demand forecast using calculated load factors trends.
- Compare and review Energex energy and customer number forecasts against the independently produced energy and customer number forecasts by NIEIR.
- Produce final energy forecasts by customer category and by network connection points.

7.3.2 Customer group forecasts

Regression models and consultant reviews were used to substantiate the forecasts, which were separately formulated for each of the following sectors:

- Residential
- Non-residential
- Network tariffs

For each of the sectors listed above, forecasts were produced for the total customer numbers and the assumed amount of energy usage per connection or customer. The forecasts of customer numbers and average usage per customer were then multiplied together to obtain total energy consumption for each segment. Total system energy was the summation of each of the components. This was a market sector or 'bottom-up' approach and provided a reasonable basis for constructing forecasts for total system energy use.

Each customer sector is affected by different underlying drivers of growth. An understanding of these sensitivities provided Energex with the flexibility to treat the different sectors independently, rather than taking a more generalised approach . For example, population and income growth are generally of greater significance in driving energy use in the residential sector, whereas GSP growth is of more importance in the commercial sector.

Energex recently developed energy sales forecasts based on network tariff classes to assist with electricity pricing decisions. This approach followed a similar methodology where assumed average consumption was modelled and multiplied by the number of customers under each tariff. It involved using multiple regression techniques. The advantage of this approach has been that weather, pricing and solar PV usage drivers could be modelled separately giving greater insight into energy sales.

Energex is in the process of moving to more econometric models based on individual drivers of energy sales by network tariff. This approach has proven to be more efficient and repeatable.

In addition, Energex used an econometric electricity purchases model to forecast at a total system level. This forecast was used to review and compare the 'bottom up' energy sales forecast after accounting for network losses.

7.3.3 Tools and testing

Forecasts prepared for the business are reviewed annually to determine the variance between actual results and forecasts. This information is used to improve the modelling and, if necessary, change the approach to individual components of the forecast.

In addition, standard statistical testing is performed on the models prior to publishing the forecast results.

7.3.4 Factor Analysis

Energex used factor analysis to answer the "what-if" questions through comparative analysis. This involved changing the values of the key drivers, and comparing the outcomes of their actual versus long term average values.

To illustrate, total energy sales decreased by around 173.3 GWh to November 2013 compared to the same period of last year. Factor analysis identified the main contributors as follows:

- Temperature made the biggest contribution. If temperature followed its long term average rather than the actual mild 2013 winter, the energy sales (for residential customers) would have been 52.2 GWh more than what has was actually sold.
- Average Domestic Price, which increased from 23.7 cents per kWh in 2013 to 25.6 cents per kWh in 2014 (based on NIEIR's estimation), contributed 41.5 GWh of the total energy fall.

- The number of new solar PV Connections impacted adversely on energy sales. By holding new connection numbers constant, the analysis indicated that residential customers would use 30.7 GWh more electricity for the year to November 2013.
- An output reduction and/or the shut-down of some big industrial customers, reduced electricity consumption by around 24 GWh.
- Lower new connection numbers than long-term expected new connections in residential customers was also estimated to reduce energy sales by 12.8 GWh.

In aggregate, these factors resulted in a drop of 161 GWh for the year to November 2013, leaving 12.2 GWh impacted by unknown factors.

7.4 Key forecasting assumptions for 2015-20 forecasts

Energex's 'Outlook for Electricity Demand for South East Queensland in the long-term' report (Outlook), considers the future trends in demand for the use of electricity within South East Queensland. The Outlook is developed annually and reviewed regularly to assess the future trends and patterns in the electricity consumption and customer numbers.

The most recent Outlook revealed a number of key findings about forward-looking electricity use in South East Queensland and how much will be needed into the future. Findings included:

- Electronic technology and its associated innovation represent the largest driver of demand for electricity.
- Increasing efficiency will play a key role in the future growth in energy sales, with efficient lighting and variable speed motors already having demonstrated this impact.
- The expanding PV market has, and will continue to, reduce electricity sales, particularly for the residential sector, particularly depending on the level of government policy support provided.
- Increasingly commercial and industrial customers are considering installing larger scale PV cells.
- The demographics of the population have a significant bearing on electricity consumption, including an ageing population and increasing urbanisation.
- Economic growth and increasing living standards underpin growth in the use of electricity.
- Growth in energy consumption typically lags demographic changes and economic activity by about 9-12 months.

7.4.1 Economic overview

Economic growth is a major driver of energy consumption and a key driver of energy consumption and sales.

Forecasts of Queensland GSP to 2019-20 were based on information from Queensland Treasury, the Office of Economic and Statistical Research, Queensland Investment Corporation, the major financial institutions and economic consultants.

7.4.2 Population & customer numbers overview

Population changes are substantially driven by economic activity, employment prospects and relative value of dwellings. An understanding of the changing demographic environment is essential to the understanding of the growth of customer numbers.

7.4.3 Residential customer numbers

As discussed in section 6 of this paper, it is assumed that customer numbers will grow at around 1.3% per annum over the next five years.

7.4.4 Small PV cells

In recent years Energex customers have taken advantage of high rebates and feed-in tariffs to use new technology, such as solar PV cells, and reduced their direct consumption of electricity from the network thereby significantly affected the electricity sales. Solar PV impacts energy sales forecasts in two ways: exports of electricity from solar PV cells back into the network; and avoided energy sales (the reduction in sales due to the internal consumption of the solar generation).

The exported energy from solar PV's offsets the energy purchases from Powerlink and was included in embedded generation. The avoided internal use of solar PV energy is consumed with the home and offsets energy sales from Energex. The impact over the past three years is evident by the reduction in energy sales to the residential market as shown in the figure below.

Importantly, solar PV capacity was expected to continue to grow but at a steadier rate than the rapid growth observed up to 2013 due to weaker tariff incentives. This assumption has been built into Energex's future energy and demand forecasts.

Future exports of electricity from small PV cells are estimated using the Energex PEACE customer numbers and billing data. With the withdrawal of the high feed-in tariff, customer numbers taking up small PV cells is around 1.0% per month and steady. At 31 May 2014, Energex had 258,000 customers with small PV cells exporting 480 GWh per annum, and this was expected to grow steadily.

Avoided sales were also taken into account. It was estimated that over 55% of electricity generated was currently used internally, however this ratio is quite volatile and could change significantly if electricity prices change or there is a Time of Use tariff introduced. It was expected that more electricity will be used internally as the impact of the 44c feed-in tariff dissipates. Forecast solar PV was forecast to grow at a slower rate than seen in 2011-12 and 2012-13.

Figure 7.1 – No of Solar PV Installations

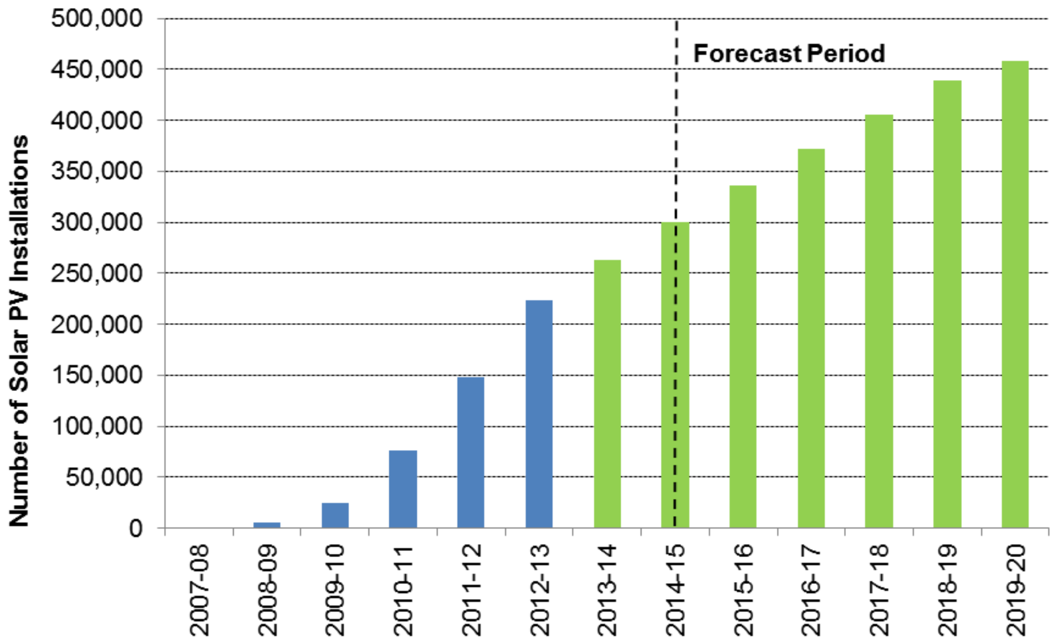
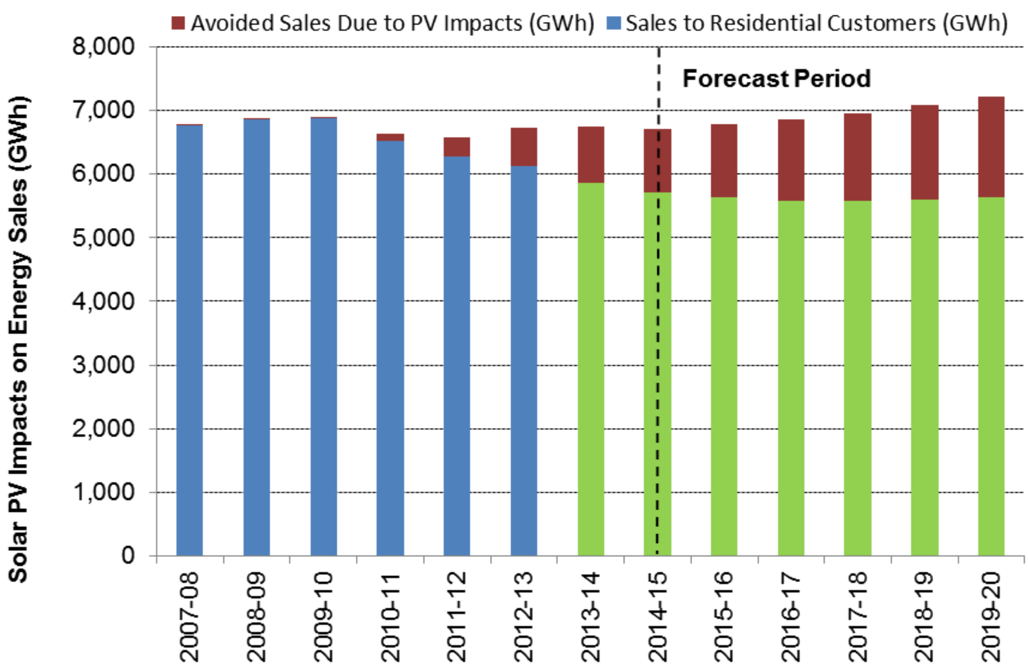


Figure 7.2 indicates Energex's assumptions for the 2015-20 period regarding avoided energy sales due to the impact of solar PV.

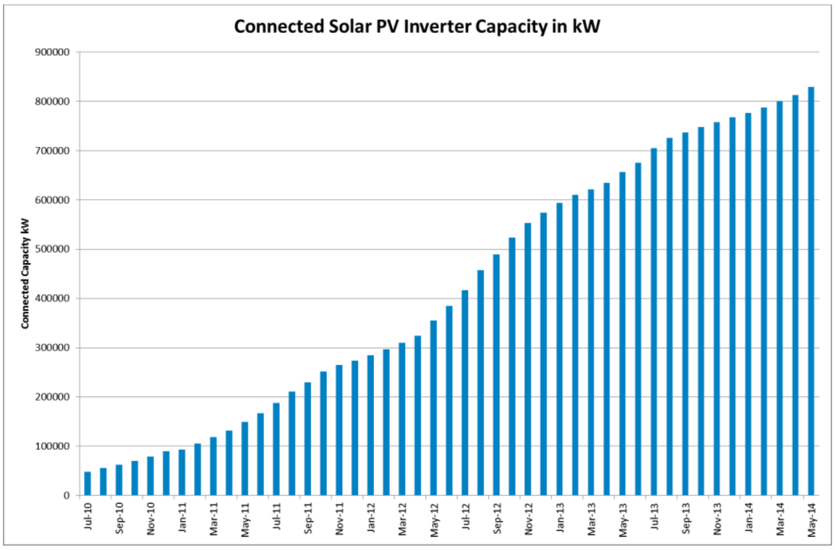
Figure 7.2 – Solar PV Impacts on Energy Sales



Looking ahead, the number of PV connections will continue to result in slower than historical growth rates in residential energy sales over the next ten years. Forecasts showed that total new solar PV connection numbers will reach 46,000 for the 2013-14 year, but will slowly decrease to 25,000 per annum in 2020. As a result, it will boost internal (non-export) consumption from 879 GWh in the 2013-14 year to 1,584 GWh in the 2019-20 year (assuming solar exposures follow the long term trend).

In addition to small scale residential solar PV, Energex has an increasing amount of larger scale PV capacity connected to its network. Figure 7.3 below shows the historical growth of solar PV inverter capacity from early 2010 to May 2014.

Figure 7.3 – Growth in solar PV capacity (2010-2014)



7.4.5 Electric vehicles and use of battery storage

The take up of electric vehicles has been slow and this slow take up is reflected in forecasting assumptions.

The following are relevant to considering the impact the take up of electric vehicles:

- Current literature suggests that until relative prices for electric cars drop substantially there will be little take up of these vehicles.
- Unless there is a significant technological breakthrough, the installation of batteries as storage devices will be slow and lag the use of electric vehicles.
- Current costs of large long life deep cycle batteries make them prohibitive for the average customer.

When storage batteries are used in the average home, the dynamics of the network will change significantly with supply and demand dropping during high priced periods. Also these storage devices could be used for storing off-peak network electricity. This transfer of electricity has the potential to 'valley fill' but has yet to be developed in any meaningful way.

7.4.6 Effects of electricity price increases

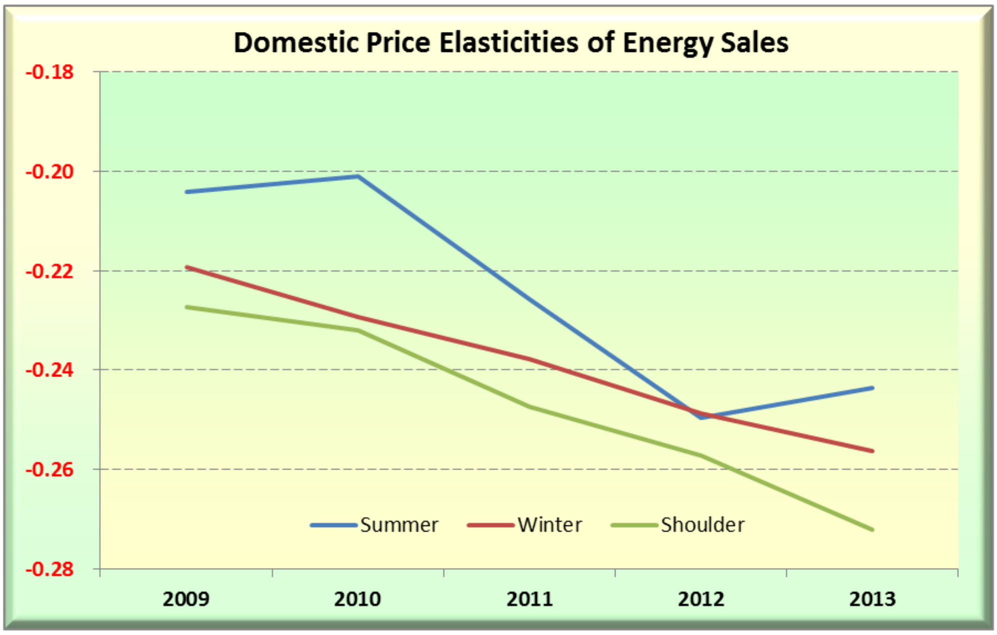
Electricity price increases have been significant in recent years and have affected electricity consumption on the Energex network.

An econometric model was constructed by using some key drivers (including residential electricity price) to develop the energy forecasts and factor analysis. It showed that on average, price elasticity (with respect to domestic energy sales) was around -0.24 over 2009-13. This means that for a 1.0% price increase in price, electricity sales decreased by 0.24%. This result is broadly consistent with elasticity estimates prepared by other electricity utilities and very similar to NIEIR's residential price elasticity of demand estimates. The analysis also found that price elasticity has increased (in terms of absolute value) since July 2011, with the value rising to -0.258.

Seasonal comparison (see Figure 7.4 below) shows that the price elasticity of electricity sales was lower in summer (in absolute values) than in both winter and shoulder seasons. This was due to the fact that people normally are less willing to turn off air conditioning in hot summer days.

Over the past five years, seasonal price elasticity (either in summer, winter or shoulder periods) increased in trend terms (in absolute value), indicating that people have become more concerned about the price increases. However, the overall absolute magnitude of the price elasticity estimates is still well below 1.0, indicating that energy consumption remains relatively inelastic.

Figure 7.4- Price Elasticity in Three Different Seasons



It is noted that the higher the line sits, the less responsive is consumption to changes in the electricity price.

Residential consumption sales were adjusted for the estimated past electricity price increases with assumed future prices rises based on forecast CPI increases.

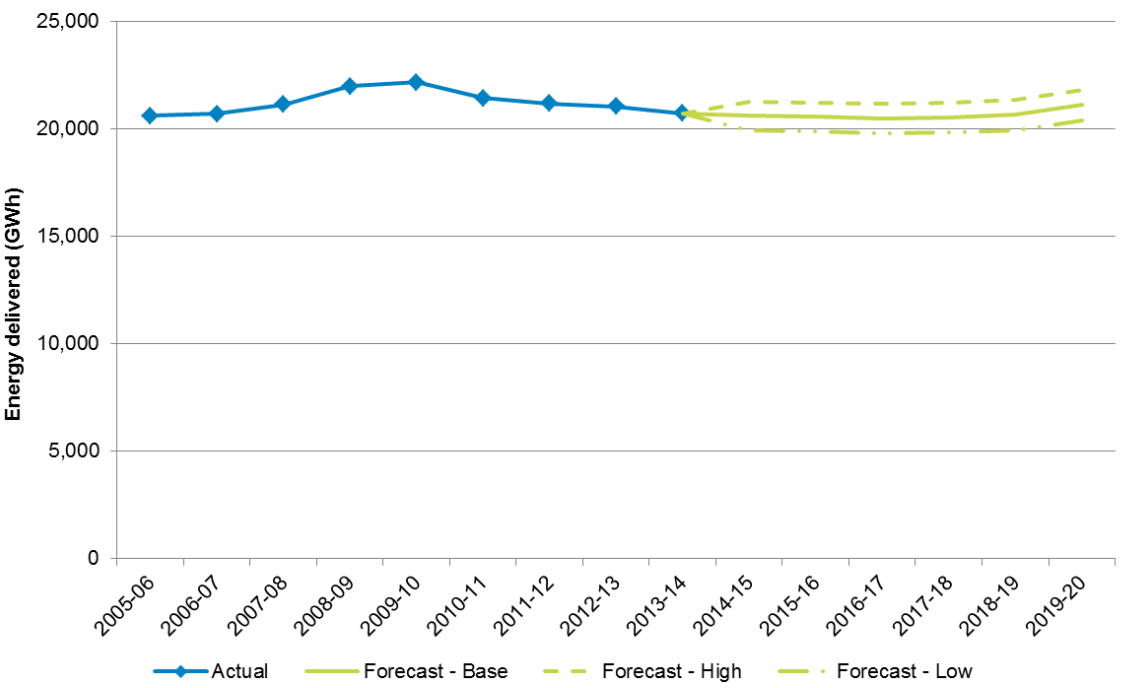
7.5 Energy sales forecasts

Simple analysis was employed to forecast energy sales under the three cases: base, high, and low. These scenarios correspond to the variability in the following three key drivers of energy consumption:

- Hot/mild summers (December, January and February with 1.0^{0}C variation of the long term average)
- High and low PV connections (15% above/below the current trend)
- Strong/weak customer connections (short term forecasts are based on Australia overseas migration forecasts provided by the Department of Immigration and Citizenship; and long term forecasts based on NIEIR's annual QLD GSP forecasts)

Under the base case scenario, energy sales were forecast to grow from 20,628 GWh in 2014-15 to 21,121 GWh in 2019-20, representing an average annual growth rate of approximately 0.5 per cent over the 2015-20 regulatory control period as illustrated in the figure below.

Figure 7.5 – Actual and forecast energy sales



7.5.1 Residential GWh

Residential energy (GWh) sales in Energex have been declining since 2009-10 when they peaked at around 8,700 GWh or around 40% of the Energex load. It is now below 7,500 GWh or 30% of the total load and declining. In the last four years there was significant change in the sales of electricity by residential customers. The influences of the GFC, solar PV cells with a high feed-in tariff, high electricity prices and mild weather effects meant that forecasting electricity sales was challenging.

Whilst growth was around 5.0% per annum historically, Energex forecasts energy sales will be flat over the next ten year horizon. Continuing increases in electricity prices and improving appliance efficiencies have changed the long term outlook for domestic energy sales.

Furthermore, electricity sales for water heating weakened for several reasons, including prevailing mild weather conditions, policies to reduce electric storage systems, and increases in energy efficiency measures in the construction of multi-unit dwellings. Despite the recent withdrawal of a Queensland Government directive for solar, gas and heat pumps to replace electric hot water heating, the long term decline in controlled electric hot water installations is expected to continue with new developments incorporating gas, heat pumps or solar hot water heating.

Table 7.1 provides a breakdown of Energex's residential sales forecasts for the 2015-20 period.

Table 7.1 – Residential energy sales GWh

	2015-16	2016-17	2017-18	2018-19	2019-20
Residential energy sales	7,144	7,100	7,101	7,154	7,234
Growth %	-1.24%	-0.61%	0.01%	0.75%	1.11%

7.5.2 Non-Residential GWh

This sector is principally made up of Commercial/Industrial customers but also includes Traction, Rural and Street Lighting categories. The industrial and rural customers in Energex supply area have declined for some time and this is expected to continue. The commercial side grew substantially, from below 40% of the total load to close to 50%. Over the forecast period the dominant driver for load growth within Energex is expected to be commercial activity. Activity has been weak and is expected to be so for about two years given the expected weak GSP growth, albeit that there are a number of buildings currently under development and construction which are expected to commence in two years.

Energex forecasts for commercial and industrial customer consumption growth was related to expected changes in GSP and the trend in changing average consumption. Commercial customer numbers were growing at around 1.9% p.a. but declined by -1.6% in 2012-13, and were expected to fall further by -0.9% and -0.5% in 2013-14 and 2014-15 respectively, while industrial customer numbers stabilised.

Research was undertaken to determine the effect of increased commercial solar PV Cell installations but given the current growth pattern and the literature analysis, it is expected that this will be taken up outside the forecast period.

Table 7.2 provides a breakdown of Energex's non-residential sales forecasts for the forthcoming regulatory control period.

Table 7.2 – Non-residential energy sales GWh

	2015-16	2016-17	2017-18	2018-19	2019-20
Non-residential energy sales	13,425	13,404	13,446	13,526	13,888
Growth %	0.22%	-0.15%	0.31%	0.59%	2.67%

7.5.3 Electricity purchases from Powerlink

Energy and demand forecasts are required by transmission connection point for Powerlink, in order for it to determine its TUOS prices and assist in its planning process for transmission augmentation. Energex electricity sales are used to calculate electricity purchases from Powerlink by applying a loss factor to the estimated sales.

It is evident that Energex electricity purchases from Powerlink will continue to decline due to the impact of solar PV cells. Purchases will only grow should commercial growth exceed the growth of solar PV Cells.

Table 7.3 – Purchases from Powerlink

	2015-16	2016-17	2017-18	2018-19	2019-20
Total sales GWh	20,569	20,504	20,547	20,681	21,121
Growth %	-0.29%	-0.32%	0.21%	0.65%	2.13%
Powerlink Purchases	21,515	21,436	21,470	21,598	22,049
Growth %	-0.35%	-0.37%	0.16%	0.60%	2.09%

8 Customer requested work forecasts

8.1 Introduction

Energex's capital expenditure program is driven in part by customer demands for network extensions and new connections.

Energex develops separate forecasts for:

- Meter Connection Callouts, for example the installation of a meter at new premises.
- Alterations and Additions (Alts and Adds), which is initiated by the customer and requires an Energex visit, for example connecting a hot water system to a controlled tariff.
- Solar PV Connections - A category of Alts and Adds that is forecast separately owing to the scale of its influence.
- Electric Vehicles Sales/population, which are then converted to their maximum demand impact.
- Commercial projects, which is a significant network investment or extension that has been initiated by a commercial customer, that is those works exceeding $50,000.

Forecasts are reviewed and updated once a year, between December and January.

8.2 Inputs

The capital expenditure program has been extremely volatile over the last few years. A number of factors were therefore taken into consideration in preparing forecasts, including:

- The Global Financial Crisis, which began to impact on commercial work in late 2007
- The exponential growth in installations of solar PV systems over a number of years
- Changes in the scale and pattern of international and interstate migration, which have impacted on the number of new connections
- A range of incentives and regulation changes regarding controlled loads for hot water systems and pool pumps
- The availability of finance, required levels of "pre-commitments", and precautionary investment behaviour.

8.3 Methodology

Total Initial Connections (meter installations)

The forecasts were based on the customer number forecasts (base, high and low) discussed in chapter 6 of this paper.

Importantly, upcoming tariff reform for small customers will create an incentive for customers to switch to tariffs which require 'smart meters'. These tariffs are expected to be introduced in the 2016-17 financial year, and the uptake of these tariffs will be limited by the speed at which appropriate metering can be installed on the customer's premise. Energex estimates there is a total pool of 900,000 customers potentially interested in adopting such tariffs during the 2015-20 regulatory control period.

To estimate the number of customers wanting to change tariffs and therefore requiring a new meter, Energex has benchmarked the incentives of the tariff change against the cost of installing a solar PV system. The tariff change has less of a financial incentive than PV, but also less up front commitment. The size of the market is potentially slightly larger for the tariff change, but it is expected that the retailers will not have a significant financial incentive to promote the changes to the customer.

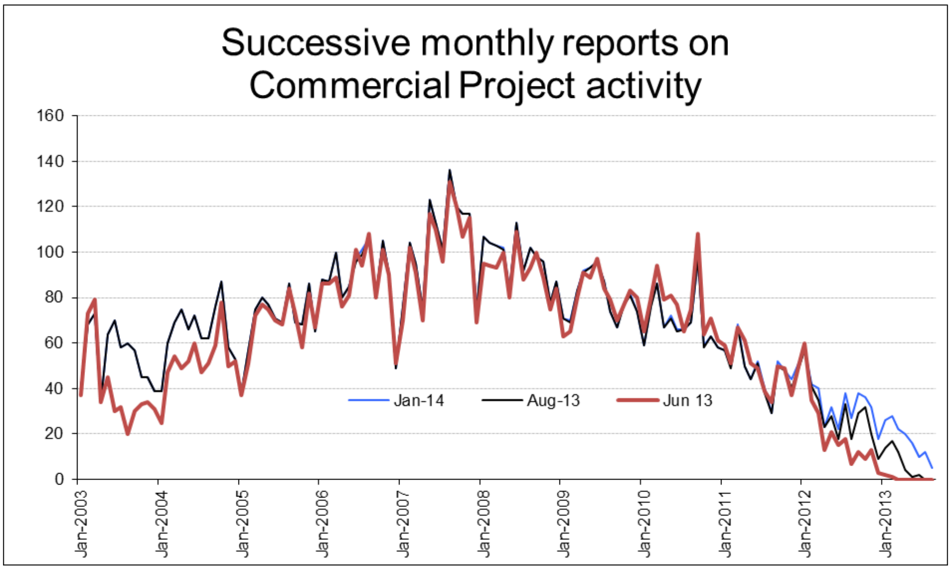
From a resourcing perspective, the number of meter changes that Energex is capable of making in a year is also capped by the size and utilisation of our workforce. As a result a forecast has been created at 5.0% of the possible market (45,000 from the 900,000), for the high case scenario only, as an annual rate starting from the year after the scheduled tariff change.

Commercial projects

Forecasting commercial project activity is notoriously difficult. The data is very unstable as the monthly figures are continually changing until they are around 18 months old – meaning that the forecasts cannot use the most recent data. In addition, for the past couple of years, the most recent data has tended to continue the downward trend which started with the GFC in 2007 and trended towards zero.

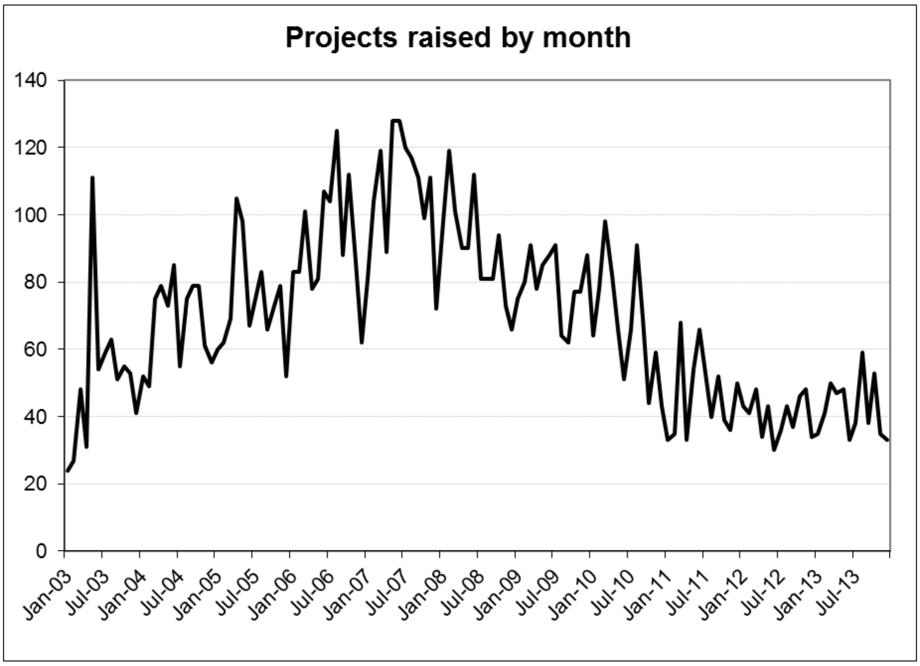
Recently a new trend emerged with the number of commercial projects appearing to stabilise at around 20 to 40 a month between early 2012 and late 2013. This has been the first solid indication of a halt to the progressive decline that Energex has seen over the past few years as indicated in the figure below.

Figure 8.1 – Commercial project activity



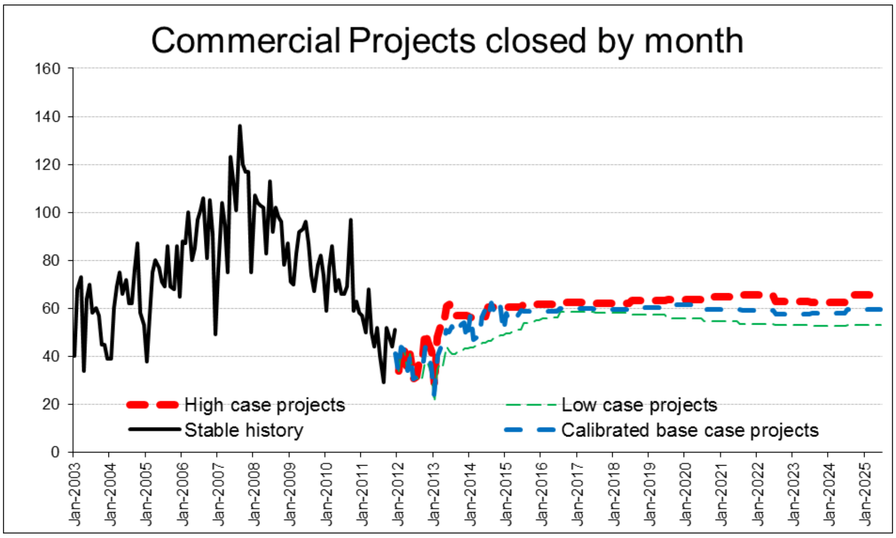
To attempt to gain a more recent insight into the market, the number of projects "raised" by month was also modelled, confirming that the decline appeared to halt in 2012, with some stability in volumes since then as indicated in the figure below.

Figure 8.2 – Commercial projects raised per month



Energex's commercial projects forecast used historical monthly data from 2006 to 2012, as this is the most stable timeframe. During this period the predicted values drift above the actuals, and then below, in a fairly stable trend. This is likely to be a reflection of the market moving above and below equilibrium point, as did the overall economy. As a result, the high, low and base case commercial projects forecasts were all calibrated to reflect the market's current ratio, but with different timings. The high case reaches equilibrium after around a year, the base case two years, and the low case around four years as indicated in the figure below.

Figure 8.3 – Commercial projects closed by month



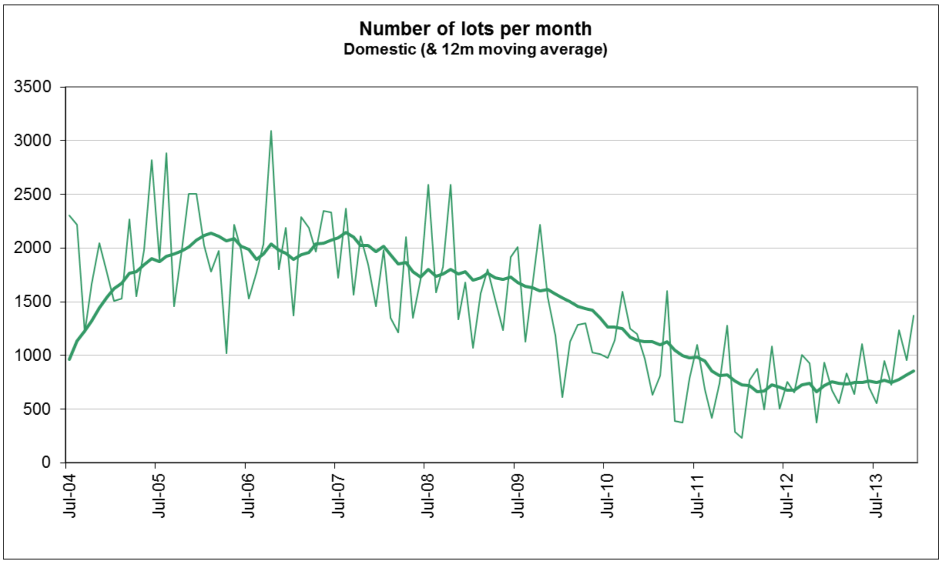
Domestic lots

The domestic lots forecasts were based on the customer connections forecasts. It should be noted that these are subject to a number of influences, from the timing of land releases to competitive/strategic decision making by the developers and therefore can display significant volatility which is not related to fundamental drivers[4].

Domestic lots have a longer term correlation of 0.72 which enables a regression to be used to forecast lots. However, the two can move independently in the short term. Like commercial projects, after a period of decline, the number of domestic lots have moved above the 12 month moving average as indicated in the figure below.

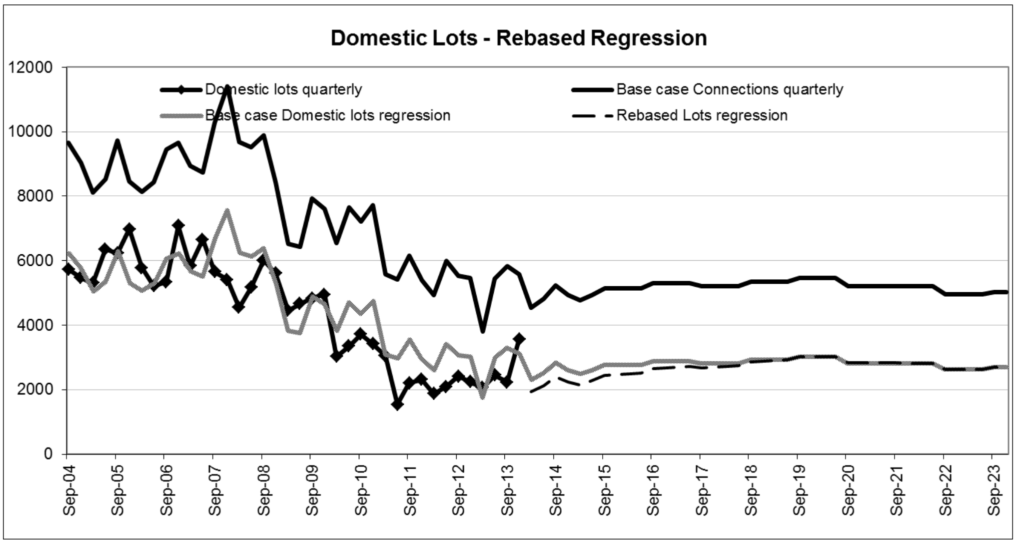
[4] In any event, the creation of a lot may only precede the construction of a house and the connection of a customer by 6 months, which is not that significant for a 10 year forecast.

Figure 8.4 – Domestic lots per month



Like the commercial projects model, the domestic lots model showed a trend drift away from its predicted values, and this has been used to recalibrate the forecast in the short term, before a gradual return to equilibrium.

Figure 8.5 – Domestic lots rebased regression

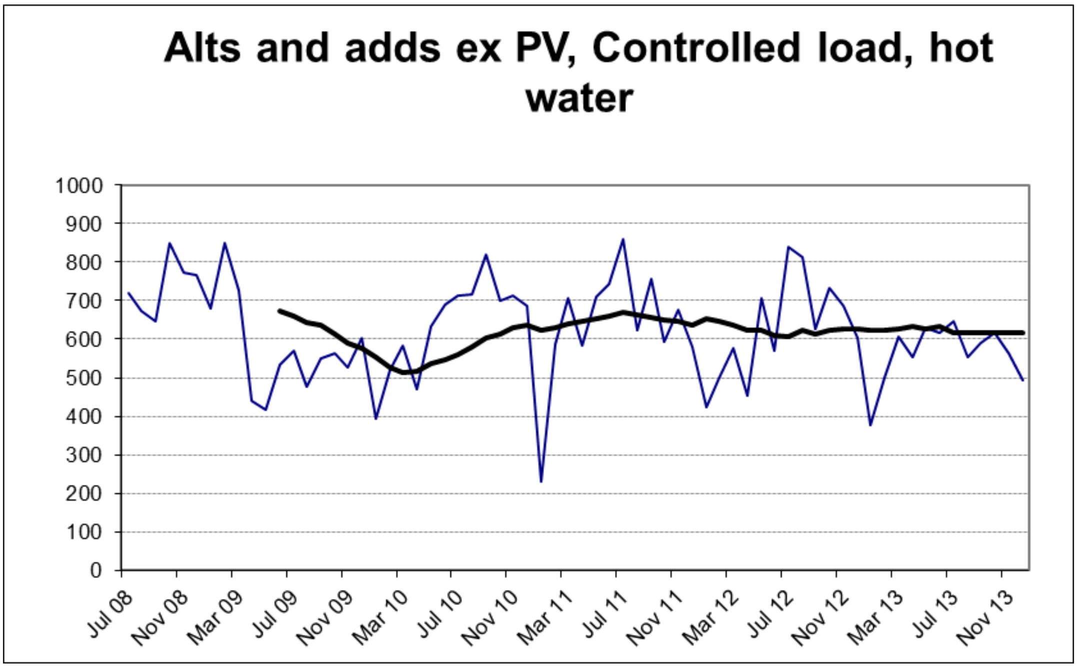


Alts and Adds (without PV connections)

The Alts and Adds sector comprises a number of different connection types, including hot water, controlled load, PV (not included in the analysis here) with each being influenced by its own set of drivers.

The chart below shows the remaining Alts and Adds connections, excluding solar PV, controlled load and hot water connections. The chart shows that Alts and Adds connections are volatile in the short term but reasonably stable in the long term. As such, these connections types were forecast to remain at around their current rolling average levels, but allowing for a trend increase in line with the overall growth of the Energex customer base.

Figure 8.6 – Additions and alterations (excluding solar PV, controlled load)

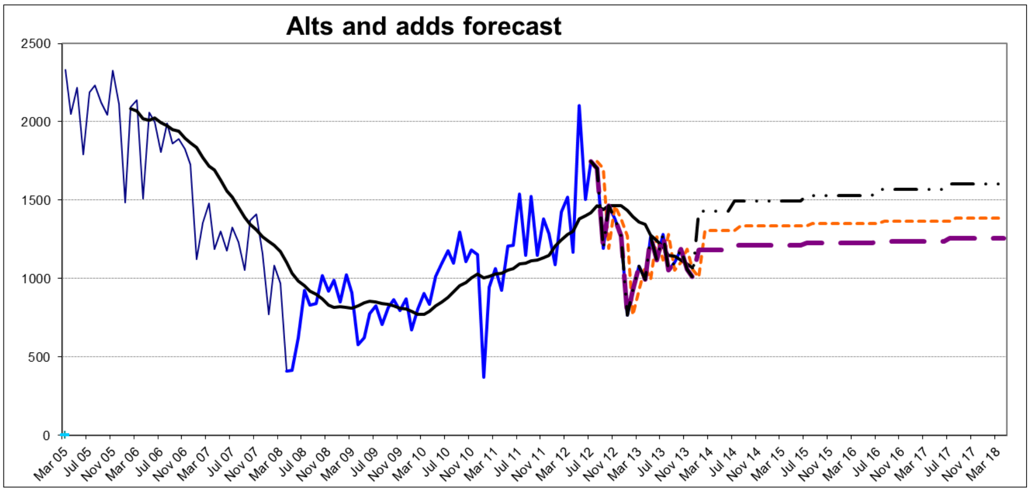


The Alts and Adds market was boosted by an increase in the “installed controlled load” jobs following the relaxation of the Tariff 33 pool pump wiring restrictions in June 2011. There was a further pick up in jobs from September 2011, following Energex’s introduction of a $250 rebate to convert a pool pump to Tariff 33. The rebate ended on 30 June 2013.

Historically, the electric hot water system market was impacted by two major regulatory changes. The first was in March 2006 when all new houses and townhouses were required to install a greenhouse-efficient hot water system. The second took effect from 1 January 2010 when existing houses and townhouses located in a reticulated natural gas area were required to install a greenhouse-efficient hot water system when the electric hot water system needs replacing. A subsequent change in government policy, once again allowing electric hot water systems, resulted in a modest increase.

Energex’s base case forecast was built on the assumption that the status quo will continue. The low case is based on a trend which partly incorporates the low volumes seen during the time that the restrictions on hot water were in place. The high case is set higher than the base case by the same difference as the low was from the base case. All three scenarios have a growth rate set to the overall growth rate of Energex’s customer base.

Figure 8.7 – Additions and alterations forecast



Solar PV connections

The number of solar PV connections was subject to more regulatory volatility than any other category, with changes (both expected and unexpected) to the solar credits multiplier; the size of system allowed to be connected to; and the rate of payment for, the Queensland Feed in Tariff; and the opening and closing of overlapping state and Federal government schemes.

In 2012-13 approximately 75,000 systems were connected. However, the most recent figures up to December clearly show that the rate has slowed, with an expected 48,000 systems expected to be connected in 2013-14.

While the significant year-on-year growth in the installation of solar PV systems ended with the closing of the 44c Feed in Tariff to new entrants in Queensland, the solar PV market is expected to continue to see significant numbers of new customers.

8.3.1 Tools and testing

The customer initiated forecasts are reviewed annually to determine the variance between actual results and forecasts. This information is used to improve the modelling and, if necessary, change the approach to individual components of the forecast.

8.4 Customer requested work forecasts

The following provides the forecast customer requested work forecasts, by category, for the forthcoming regulatory control period.

Table 8.1 – Customer requested work forecasts

	2015-16	2016-17	2017-18	2018-19	2019-20
Meter connection callouts[1]	20,557	21,190	20,824	21,416	21,828
Alterations and Additions (no PV)	16,221	16,410	16,612	16,823	17,012
Solar PV Connections	35,000	30,000	29,000	27,000	25,000
Electric vehicle - takeup	282	633	1,405	3,044	6,271
Electric vehicle – Peak MW contribution	0.3	0.6	1.3	2.8	5.9
Commercial projects	706	721	712	726	736
Domestic lots	9,904	10,705	10,805	11,612	12,067

Notes:

1 The scale of the callouts can be affected by a change in the available tariff options, as changes could prompt switching

9 Application to planning

Energex forecasts of maximum demand are critical to adequate planning of the network. The following sections set out some of the key issues associated with forecasts and network planning.

9.1 Contingency planning process and risk management

Energex undertakes a contingency planning process which involves the development and annual review of a series of contingency plans for managing network failures and events in the short term such as exceptional hot weather. The contingency plans encompass a number of aspects, being:

- Network contingency and load transfer plans to cater for single contingencies (e.g. loss of a single major item of plant).
- Strategies for spares and replacement of major plant such as power transformers.
- Emergency response procedures covering management of major network incidents, including escalation as documented in the Corporate Emergency Management Plan.
- Availability of mobile generators for deployment to provide an emergency supply in situations where it is possible.
- Availability of two Energex-owned 33/11 kV mobile substations for deployment to provide an emergency supply where practicable.
- Application of available demand management options.

Risk is managed across the Energex network by developing plans that incorporate strategies such as load sharing across network elements and non-network solutions to peak demand events.

The contingency planning process, including risk management strategies is summarised in the following sections. Attachment D sets out the procedure for the annual review of contingency plans and network load at risk data.

9.1.1 Contingency plans for summer (system normal conditions)

Each year the whole network is reviewed to ensure that all substations and feeders can supply a 10% PoE load for the following summer under system normal conditions (i.e. NCC ratings). Short term mitigation strategies are developed where it is identified that forecast loads exceed ratings for the following summer and augmentation works may not be completed in time. These strategies include a range of options such as load transfers, small capital works projects (possibly temporary), or demand management options such as generation or customer load curtailment.

Energex has also developed a process (hot weather technical committee) to monitor loads during the summer period so that as hot weather develops, emerging “hot spots” where demand growth may have exceeded the previous annual forecasts are identified. In these cases, corrective action to avoid an overload is taken well before a capacity constraint occurs.

9.1.2 Contingency plans for summer (N-1 Conditions)

Network contingency plans detail what load transfers and load management options are available to restore supply following a single contingency event affecting bulk supply substations, zone substations and HV feeder networks. These contingency plans are prepared annually and any identified N-1 conditions are provided as input into the network development planning process.

As part of the summer preparedness plans, Energex develops plans for all bulk supply substations, zone substations and 132/110/33 kV feeder networks. In cases where load transfer capability is not sufficient to enable supply to be restored following single contingency, more comprehensive plans may be developed depending on the tolerability of the risk level identified. These include strategies such as:

- The design and possible construction of small temporary capital works (e.g. a few spans of overhead mains to allow for temporary rearrangement of the network after a contingency); or
- The positioning of spare power transformers at substations considered to be at high risk (high likelihood or significant consequence) of an extended outage due to a major transformer failure.

9.1.3 Power transformer contingency plan

Identification and allocation of contingency spare power transformers is now accommodated within the Joint Strategic Spares Strategy developed by Energex and Ergon. Power transformers held as strategic spares have been identified for rationalisation to enable minimal stocks to be held to cover both Energex and Ergon Energy requirements.

The definition for Strategic Spares was jointly agreed as:

> *“an item of plant held in stock and may be required to be used to replace (permanently or temporarily) a critical network or system element that has incurred damage due to a system fault or failure. The Strategic Spare would only be used where supply to customers cannot be maintained without its use or network security is unacceptably compromised”.*

9.1.4 Mobile generators for emergency response

Energex has available a fleet of mobile standby generators that are used to provide emergency response to sub-transmission and distribution network faults that cannot be rectified by switching. This helps to limit interruption to supply in a manner that minimises customer inconvenience and improves reliability. This fleet of mobile generators also provides the flexibility for 11 kV feeder support during extreme temperature events where existing network assets need to be supplemented.

In addition to its own equipment, Energex hires low voltage generators if necessary, to ensure there are enough generators for 11 kV feeder support during extreme summer events.

9.1.5 Demand management network support (system normal conditions)

In addition to the measures detailed above regarding the use of mobile generators and enhanced emergency response procedures to improve reliability of supply during extreme temperature events, Energex negotiates network support agreements with customers who are located in network load at risk areas for summer preparedness each year.

These programs require commercial agreements with customers who have suitable load profiles that could be influenced on exceptional hot weather days. Initiatives include agreements with customers who have:

- Shiftable load.
- Private standby generation that can provide network support.
- Have agreements allowing Energex to locate generators onsite for network support.

9.2 Application of ratings to capacity determination

The following sections set out how Energex's Customer Outcome Standard (COS) is applied to ensure prudent capital and operating costs to deliver the appropriate level of service outcomes and value to the customer. This includes discussion of how normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines.

9.2.1 Customer Outcome Standard

The safety net approach complies with the jurisdictional obligations within Energex's DA. The safety net targets are defined by the maximum number of customers and the load impacted over durations of time as illustrated by Figure 9.1 and Table 9.1. The targets as set out in the Energex DA are set out below in Table 9.1.

Figure 9.1 - Monthly Customer Number Increases for the Selected Years

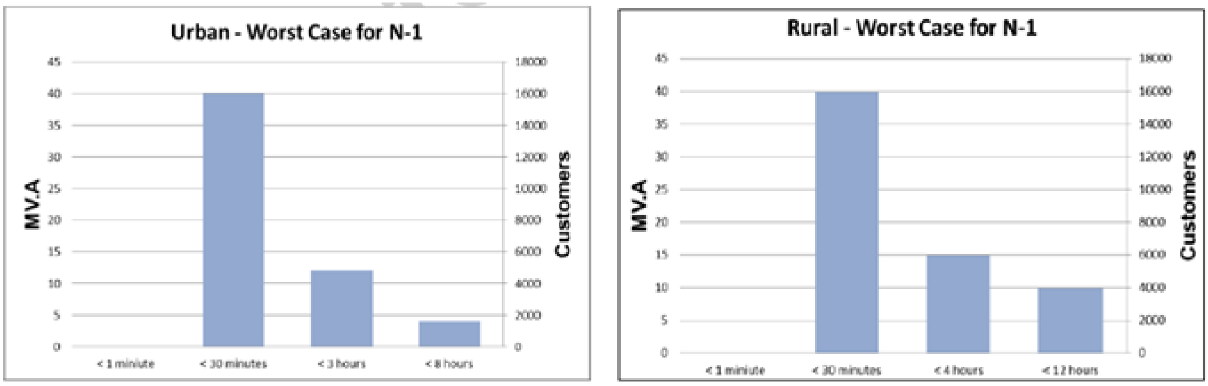


Table 9.1 - Service Safety Net Targets

Feeder type	Targets
CBD	Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute.
Urban	No greater than 40MVA (16,000 customers) without supply for more than 30 minutes. No greater than 12MVA (5,000 customers) without supply for more than 3 hours. No greater than 4MVA (1,600 customers) without supply for more than 8 hours.
Rural	No greater than 40MVA (16,000 customers) without supply for more than 30 minutes. No greater than 15MVA (5,000 customers) without supply for more than 4 hours. No greater than 10MVA (1,600 customers) without supply for more than 12 hours.

9.2.2 Application of COS

The basis of network planning is that no transmission or sub-transmission network asset is planned to be operated above its normal cyclic capacity (NCC) for a 10% PoE forecast load under normal network conditions.

The introduction of COS is to support the principle that applies to the operation of network assets under network contingency conditions. System contingency related capability is assessed against a 50% PoE forecast load, available load transfers, emergency cyclic ratings, non-network suppliers, mobile plant, mobile generators and short term ratings of plant and equipment where this is available.

9.3 Demand-related capex projects or programs for HV feeders

Energex proposes to commence or continue a range of demand-related HV feeder Capex Projects during the Forthcoming regulatory control period. This section sets out the range of factor taken into consideration and associated assumptions applied, for these forecast projects. Specific projects are not referenced due to the one to two year planning horizon applied to these projects.

9.3.1 Load assumptions

The following assumptions were applied to load forecasts:

- Forecasting of 11kV feeder requirements were performed on a feeder by feeder basis. Available load transfers were calculated for each feeder based on load flow studies as part of normal planning processes.

- The feeder growth rates were calculated based on a weighted average of the growth of its associated zone substation.

- Specific known block loads were added and events associated with approved projects were also incorporated (such as load transfers and increased ratings) to develop the feeder forecast.

9.3.2 Existing embedded generation capacity

Existing embedded generation is connected and operational when the 50% PoE load assessment is performed for summer and winter peak loads. This ensures that the existing embedded generation is accounted for in the forecast.

9.3.3 Assumed future embedded generation capacity

Growth rates for HV feeders are aligned with their zone substation by weighted average. This ensures that underlying load growth incorporates the expected load reduction associated with embedded generation growth in an area.

9.3.4 Existing non-network solutions

Existing non-network solutions are connected and operational when the 50% PoE load assessment is performed for summer and winter peak loads. This ensures that the existing embedded generation is accounted for in the forecast.

9.3.5 Assumed future non-network solutions

Future non-network solutions are assessed during the production of a DAPR. Once approved any non-network solutions would be included in the forecast as a negative block load. For longer term non-network solutions with a wide impact, impact is modelled at zone substation level and HV feeder growth rates are adjusted discussed above.

9.3.6 Diversity between feeders

Diversity between HV feeders is not considered as part of the HV feeder forecasting process.

9.4 Demand-related capex projects or programs for zone substations

Energex proposes to continue six, and commence 16, Demand-Related Capex Projects during the Forthcoming regulatory control period on a zone substation or relevant substations for a sub-transmission line.

Attachment E sets out the following in relation to each of these projects:

- Assumed future load transfers between related substations, which sets out the load that can be transferred to other sources of supply, either as an automatic transfer (within 1 minute), remote transfer (within 3 minutes), or manual transfer (within 3 hours).
- Assumed underlying load growth rates (exclusive of transfers and specific customer developments) for winter and summer periods.
- Assumed specific customer developments (block loads), timings and associated demand assumptions.
- Existing embedded generation capacity, and associated assumptions on the impact on demand levels.
- Assumed future embedded generation capacity, and associated assumptions on the impact on demand levels.
- Assumed future non-network solutions, and associated assumptions on the impact on demand levels.
- Average ten year diversity with related substations.

There are no existing non-network solutions listed in Energex's forecast tools, further Energex has not received inquiries as a result of the release of its DAPR. It is therefore assumed to have no impact on demand levels.

10 Compliance checklist

Table 10.1 sets out the requirements and relevant reference for each of the Reset RIN Schedule 1 clauses relating to demand and customer number forecasts.

Table 10.1 - Compliance Checklist

Clause	Description	Response
8.1(a)	Provide and describe the methodology used to prepare maximum demand forecasts for the forthcoming regulatory control period.	Sections 2.4.1 / 3.3 / 4.3 / 5.3
8.1(b)	Provide and describe the methodology used to prepare number of new connections forecasts for the forthcoming regulatory control period.	Sections 2.4.2 / 6.3
8.2 (a)	Provide the model(s) Energex used to forecast customer numbers and maximum demand.	Excerpt from System Demand Model is provided as Attachment C, the Excel-based document can be provided on request Excel-based document that replicates SIFT database can be produced on request for a limited number of substations. The database is too large to provide. Graphical interface of the Netplan model is set out in section 5.3. The database is too large to provide. Energex produces customer number forecast models for each tariff class which can be provided on request.
8.2 (b)	Provide, where Energex's approach to weather correction has changed, historically consistent weather corrected maximum demand data as per the format in regulatory templates 5.3 and 5.4 using Energex's current approach. If this data is unavailable, explain why.	Section 3.3.2
8.2 (c)	Provide for number of new connections, volume data requested in regulatory template 2.5.	RIN Template 2.5
8.2 (d)	Provide any supporting information or calculations that illustrate how information extracted from Energex forecasting model(s) reconciles to, and explains any differences from, information provided in regulatory templates 2.5, 5.3 and 5.4	Attachment C Sections 2.4.1 / 2.4.2
8.3 (a)	For each of the methodologies provided and described for maximum demand and number of new connections, and, where relevant, data requested for weather correction and volume data for number of new connections, …explain the models used.	Section 1.2
8.3 (b)	…explain global top down and spatial bottom up forecast	Sections 3.3 / 4.3 / 5.3 / 6.3 / 6.5

Clause	Description	Response
8.3 (c)	…provide the inputs and assumptions used in the models, including in relation to economic growth, customer numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions.	Sections 3.5 / 4.4 / 6.4
8.3 (d)	…provide the weather correction methodology	Section 3.3
8.3 (e)	…outline treatment of block loads, transfers and switching	Section 4.3.1 / 6.3.3
8.3 (f)	…provide information on each appliance model used, where used, or assumptions relating to average customer energy usage(by customer type)	Section 3.5.4
8.3 (g)	…provide how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and substations)	Sections 3.3 / 4.3 / 5.3 / 6.3 / 6.5
8.3 (h)	…explain how the resulting forecast data is consistent across forecasts provided for each network element identified in regulatory template 5.4 and system wide forecasts.	Section 2.2 Attachment C
8.3 (i)	…explain how the forecasts resulting from these methods and assumptions have been used in determining the following: i. capital expenditure forecasts ii. operating and maintenance expenditure forecasts	Regulatory Proposal Chapters 8 - 10
8.3 (j)	…explain whether Energex used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal	Section 2.4.1.
8.3 (k)	..explain whether Energex forecasts both coincident and non-coincident maximum demand at the feeder, connection point, sub-transmission substation and zone substation level, and how these forecasts reconcile with the system level forecasts, including how various assumptions that are allowed for at the system level relate to the network level forecasts	Section 2.4.1.
8.3 (l)	…state whether Energex records historic maximum demand in MW, MVA or both	Section 2.4.1.
8.3 (m)	…provide the probability of exceedance that Energex uses in network planning	Section 9.2.2
8.3 (n)	…explain the contingency planning process, in particular the process used to assess high system demand	Section 9.1
8.3 (o)	…explain how risk is managed across the network, particularly in relation to load sharing across network elements and non-network solutions to peak demand events	Section 9.1
8.3 (p)	…explain whether and how the maximum demand forecasts underlying the regulatory proposal reconcile with any demand information or related planning statements published by AEMO,	Section 3.4

Clause	Description	Response
	as well as forecasts produced by any transmission network service providers connected to Energex's network	
8.3 (q)	…explain how the normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines	Section 9.2
8.3 (r)	…provide, where Energex proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder: i. for each feeder from the zone substation that is the connecting zone substation for the relevant HV feeder, and any other feeders that the relevant HV feeder can transfer load to or from: (A) assumed future load transfers between feeders (B) assumed feeder underlying load growth rates (exclusive of transfers and specific customer developments) (C) assumed block loads, and associated demand assumptions ii. existing embedded generation capacity, and associated assumptions on the impact on demand levels iii. assumed future embedded generation capacity, and associated assumptions on the impact on demand levels iv. existing non-network solutions, and the associated assumptions on the impact on demand levels v. assumed future non-network solutions, and associated assumptions on the impact on demand levels vi. the diversity between feeders.	Section 9.3
8.3 (s)	…provide where Energex proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line): i. assumed future load transfers between related substations ii. assumed underlying load growth rates (exclusive of transfers and specific customer developments) iii. assumed specific customer developments, and associated demand assumptions iv. existing embedded generation capacity, and associated assumptions on the impact on demand levels v. assumed future embedded generation capacity, and associated assumptions on the impact on demand levels vi. existing non-network solutions, and the associated assumptions on the impact on demand levels vii. assumed future non-network solutions, and associated assumptions on the impact on demand levels viii. diversity with related substations.	Section 9.4 Attachment E
8.4 (a)	Provide evidence that any independent verifier engaged by Energex has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts.	Frontier Economics Report is provided as an appendix to the Regulatory Proposal

Clause	Description	Response
8.4 (b)	Provide documentation, analysis and/or models that provide reasonable evidence of the results of each independent verification referred to in sub-paragraph (a) above.	Frontier Economics Report is provided as an appendix to the Regulatory Proposal

APPENDICES

Attachment A – References

Energex consulted the following documents in preparing its forecasts:

- The own price elasticity of demand for electricity in NEM regions (NIEIR – June 2007)
- ABS Statistics, Current CPI, Building Approvals, Australian National Accounts, Labour Force, and Demographics
- ABS, Population Projections Australia, November 2014
- ABS, Revision of Estimated Resident Population, 2014
- ABS, Household Energy Use and Costs, 2014
- ABS, Household Income and Income Distribution, 2011-12
- AECOM, Forecast Uptake and Economic Evaluation of Electric Vehicles in Victoria, May 2011
- AEMO, Economic Projections for Queensland February 2014
- BIS Shrapnel, Economic Outlook and Building Outlook, March and September 2013 Conferences, et al
- Energex, Forecast Guidelines
- NIEIR, Economic Outlook for Australia to 2024-25, July 2014
- NIEIR, Economic Outlook for Queensland to 2024-25, July 2014
- OESR Qld Treasury Qld Government, Population Projections to 2031, 2011
- Powerlink, Annual Planning Report, January 2014

Attachment B – SIFT White Paper

TOPIC:

The goal of this white paper is to provide an understanding of the SIFT (Substation Investment Forecast Tool) application at the business planning level.

This paper covers

- The positioning of SIFT within the Network Capital Planning business and its relative interface to other Sparq systems.
- The applications data and functions within Energex and its possible application in Ergon.
- Differences between SIFT and the Ergon application LIMS (EIM Project).
- Current and proposed interfaces with a summery of the short to medium term plans for its future in Energex.

HIGH LEVEL:

SIFT is the genesis of Substations and their Projects. These projects are generally Sub Transmission as the Distribution Projects are currently held in the DISTPLAN application. The Substation information includes Current and Planned Plant, Projects, Distribution Load Transfers, Block Loads, Sub-transmission network connectivity; Current Daily Profile, Positioning and Property, Reliability, Emergency Load Transfer Availability, Load History, Profiles, Load Categories .

SIFT uses the Substation level and Scenario based Project data to generate substation demand forecasts with the variations of Peak, Reconciled and Compensated figures with the ability to tailor the forecasts for approved only projects, etc. and present them for AER submissions and Annual Network Management Budget Planning activities. It does so in a transparent, auditable and consultative way with the forecast information available to all planners if required via direct means or published reports.

SIFT is currently a Microsoft Access Presentation layer with a Microsoft Server database (currently 6G in each of the 4 environments). Reports are delivered via the Microsoft Report Server Interface. The security is based on Windows Groups. Changes to the database are fully audited. Published forecasts are stored as separate structures.

SIFT uses a reconciled bottom-up and top-down approach to generating load forecasts and is different in its approach and outcomes to LIMS (As part of the Ergon EIM Planning project) which is bottom-up with Load profiles based on past bills and temperature and growth over time (based on bills history). SIFT supports the “Meets Security Standard” requirement given a budget; LIMS does not have the planned capacity delivery as part of budget planning. LIMS goes down to distribution transformers for capacity connection points and tariff; SIFT stops at the Zone Substation. SIFT includes planned Block Loads and Transfers with 20 years into the future substation planning; LIMS deals with the current network as available from ECORP. LIMS was primarily designed to assist the RAMS in making informed decisions on distribution capacity planning and transformer longevity; SIFT was primarily designed to support the Strategic planning. (SEE SIFT and LIMS comparison)

DAA (Itron product) does not cover the multiple scenario based project approach delivered by SIFT. It deals with Asset based proposed improvements but does not support the many to many environment for company wide forecasting. Currently it does not delivery the flexibility to forecast in house as the substation data is shipped offshore to be modelled and the model shipped back. Typically a yearly process. Energex operates in an iterative improvement environment continuously improving the forecast as new information comes to hand with periodic published forecasts which SIFT supports.

SIFT gets substation plant rating data from NFM and ERAT; distribution load transfer and block load data from DISTPLAN; System Forecasts from ACIL Tasman forecasting models; Growth Rates from published demographic data, Planning and Infrastructure forecasting unit and local knowledge provided by Asset managers

SIFT provides the Substation and Strategic Project data propagated through Primavera and ultimately to Ellipse.

BUSINESS BENEFITS:

CURRENT FEATURES

- AER Compliance and Reporting – Mandatory Governance Requirement support. SIFT has been identified as a primary tool for delivering the information required to support the AER requirements for Network Capital Planning.
- More Accurate Capacity Planning – better targeting of resources towards better forecasted capacity. Example of which is the identification of an excessive number of planned project delivered capacitors given the current forecast
- Better Communication between the Planning groups – The original Substation Access shared database provided the starting point for information sharing between the planners and the forecasters. SIFT has carried this further with a stable auditable platform and enhanced reporting features.

PLANNED FEATURES

- Scenario and Forecast Comparison – Reports to compare and contrast successive forecasts to improve planning capability and forecast confidence. Planning Scenario comparisons to provide assistance with getting “More Bang for Buck”
- Ability to optimise project deferral to assess when a project can be deferred to before the substation does not meet its designated security standard. This is straightforward for substation plant upgrades, however for projects involving load transfers is much more complicated.
- Ability to report substations sorted by Load exceeding Substation Security Standard and Residual Load at Risk (Bulks able to be sorted including and excluding Powerlink bulk supplies)
- Ability to incorporate full automated transfers, remote (screen witching) transfers and manual transfers in assessing security standard and (Residual) Load at Risk for Bulks and Zones.

- Global substation view incorporating multiple sort categories
- Incorporation of switchgear /bay ratings for 33kV and 110kV feeders.
- Reporting/graphing of Bulk and Zone substations not meeting security standard (number by year) and reporting/graphing of Load at Risk / Residual Load at Risk
- Ability to report projects by Load at Risk and Residual Load at Risk addressed.
- Possible loading of 110kV and 33kV Load Flow data into SIFT for NMP reporting

Common Network Demand Forecasting Methodologies - Joint Workings Project

ENERGEX and ERGON are about to engage a consultant to review the forecasting methodologies being used by both organisations for system demand, substation demand, feeder demand and energy forecasting. The objective of this work is to identify, adopt and implement the most appropriate forecasting methodology in both organisations as part of the ongoing joint workings project.

In 2008/09 ENERGEX have applied the ACIL Tasman recommendations for the development and implementation of the SIFT forecasting tool for the ENERGEX AER submission. The ERGON forecasting team have indicated an interest in assessing the capability of this tool for use in forecasting demand at the ERGON zone substations and connection points. The SIFT forecasting tool is designed to develop demand forecasts for each level of the network from the 11 kV/22kV bus upwards. This tool will complement the LIMS tool that ERGON have been developing for the 11 kV and 22kV feeder load forecasts.

SOLUTION DETAILS:

HISTORY

FORPAC / FORNET – the substation forecast was originally produced from a Dbase4 based application (FORPAC), developed in 1994/5 by consultants. In 2005, the essence of this product was upgraded in-house to an MS Access based application, providing increased functionality, an interactive GUI and extensive reporting.

Substation database – in 2004 an MS Access based application was developed to capture/manage substation property, plant and supply area development information, and transmission capital project data.

It was recognised that these two systems were interdependent and therefore needed closer integration. Further, an increasing requirement for data preservation and auditability led to the need for both systems to be merged into a corporate supported database environment.

STRUCTURE

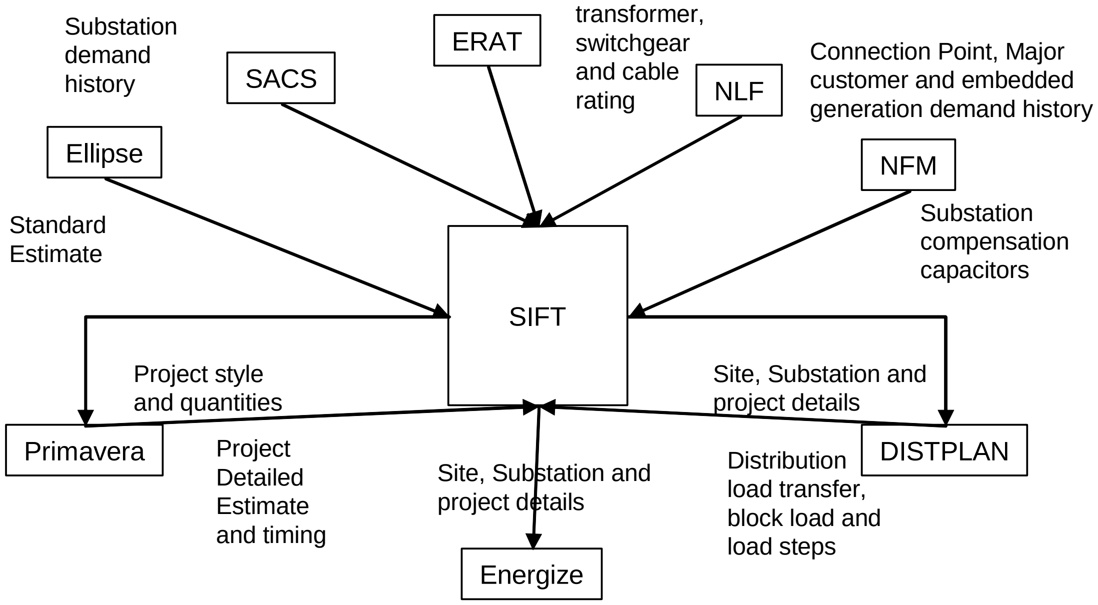
The SIFT database is currently housed in an SQL Server 2005 server. There are two databases – FORNET which contains the current data for the two sub applications Dplan and Fornet and FNETBK which contains the published forecast data. The forecast engine is housed as TSQL within the database providing the auditablity required by AER Compliance. Where practical, business logic is contained in the database with MS Access only providing the User Interface. Changes to the current view of the data are audited via database triggers into an audit table which is freely available for scrutiny on each table. Exceptions are the transitory forecast tables, but the products of these tables are stored in FNETBK.

Security is through Windows Groups. There is a Read Only level for viewers of both sub applications, an update level for each sub application which allows access to the update procedures and an Administrative level which allows update access directly to the table data. As the interfaces are developed the Administrative privileges may change, but not in the short term.

The Report Server as part of the MS SQL Server Suite provides the web based report interface. Security is through Windows Groups

Archival of SIFT will only be for 3 year old audit data and as projects are commissioned and cease to be relevant to the planning process they will be purged from the current data. The size of FORNET will not increase dramatically but the FNETBK will increase at a steady rate of approx 2 G per year.

INTERFACES



Imports :-

The bulk of the data imports are achieved through MS Access with some via nightly jobs on the database

- NFM – original source of substation compensation capacitor information
- ERAT – source of substation transformer, switchgear and cable rating information

- Primavera – source of project detailed estimate and timing information
- Ellipse - source of standard estimate information
- SACS – source of substation demand history information
- NLF – source of connection point, major customer and embedded generation demand history information
- DISTPLAN – source of distribution load transfer, block load and load step information

Exports :-

- DISTPLAN - takes the site and substation details (currently ref's the old SubID but we can change to SUB_SUN), and it takes the Project No (should be PRJ_SUN) and description bits of project.
- Primavera - takes the Project style and quantities of cables etc. from the Project Estimates. Due to a mismatch in understanding of a "Project Style" the interface is misbehaving - Primavera thinks a style is the project estimate rather than a template for a new project -- the current review of interfacing between Ellipse/Primavera/SIFT may need to exercise caution not to repeat the problem.
- Forecasts go to: Powerlink QLD for coordination planning studies and input to their annual AEMO forecast submission, Development Planning for Network Management Plan and load flow studies, Risk and Contingency for Summer Prep studies and used in development of Distribution network loss factors.
- Energize – Substation Summary pdfs for the website

SIFT AND LIMS COMPARISION

Topic	**SIFT**	**LIMS**
Forecast Generation Method	Reconciled Top-Down System and bottom-up Substation load. Load History at Substation level (current and future) taking into account project delivered Transfers and Plant, Block Loads and Growth expected for the future with capacitors and connectivity calculated at each period.	Bottom-Up modelling of forecasted connection point (premise) tariff usage by year and temperature, with aggregated forecasts based on current network configuration. Load growth modelling is based on the correlation between the average daily temperature and the consumption (kWh) recorded on the premises monthly or quarterly bills
Budget vs Meeting Security Standards	Covered	Not Covered

Topic	SIFT	LIMS
Strategic Projects and the future delivered capacity	Up to 20 years into the future on Substations and their plant with costs associated with it	Current Network only
Original Primary Purpose	To support statutory requirements on Strategic Planning and Forecasting	To assist the RAMS in making informed decisions on distribution capacity planning and transformer longevity
Data View Time Slot	Season Period (e.g. Summer Day 2013)	Half Hourly
Switching Sheet Support	Nil	Shows load forecast at the switching level on the feeder with normal state changes
Support for DMS	Limited	Load profiles at the connection point to support load balancing.
SCADA Data requirements	Period based Load History and peaks for MW and MVAR. Half hourly for background information only	Complete set of half hourly for all channels available.
Future Substation Requirements		Planned – Predicting best geographical position of future substation based on modelled consumption and future Council land parcel releases and zonings.

SUMMARY:

SIFT continues to attract attention as the source of Forecasting, Substation and Strategic Project information. It is differentiated in the forecasting space by its unique treatment of available data. It will continue to be the source of AER reporting information and its future within the Network Capital Planning business is counted on in the effort of continuous improvement of forecasting methodology and data.

Attachment C – Reconciliation of models to Regulatory Templates – supporting information

This appendix provides supporting information, through three case studies, to illustrate how forecast data is consistent across forecasts provided for each network element and system wide forecasts. This can also be used to confirm that information extracted from Energex forecasting models reconciles to the Regulatory Templates. The three case studies set out below relate to substations at Grovely, Hamilton Lands and Carole Park.

For each case study, an export from SIFT to Excel sets out the calculations that are applied to reconcile zone substation forecasts. That is, the line item "Reconciliation" sets out the reconciliation factor that is applied to SIFT substation forecasts to ensure that these reconcile to the system wide forecast. Energex uses reconciled values of substation maximum demand for its forecasts and for the population of the Reset RIN. A screen view from SIFT shows the system interface and demonstrates that what is displayed in SIFT reconciles to calculations exported to Excel for illustrative purposes.

It is noted that the same reconciliation factors are applied to all substation forecasts, except large industrial substations (single customer), in a given year. These factors are set out in Figure C.1.

Figure C.1 – Reconciliation factors by year and season

Forecast Trim:

	Summer		Winter	
Year	Trim%	Sub Count	Trim%	Sub Count
2014	-100.0%	0	-4.7%	277
2015	-6.4%	281	-4.7%	282
2016	-6.8%	284	-6.1%	286
2017	-8.7%	287	-5.8%	287
2018	-9.7%	288	-4.6%	287
2019	-9.2%	288	-3.8%	287
2020	-8.9%	288	-3.3%	288
2021	-10.0%	289	-1.8%	288
2022	-10.6%	289	-0.5%	288
2023	-11.2%	289	1.0%	288
2024	-11.5%	290	2.6%	289
2025	-11.3%	290	4.3%	289

Figure C.2 – Grovely Maximum Demand Forecast (SIFT export)

Substation	GLY Grovely

Load History

		SD			
		MW	MVAr	Comp	MVA
Peak	Recorded	21.79	5.87	0.00	22.57
	Adjustment	0.00	0.00	0.00	
	Total	21.79	5.87	0.00	22.57
Coinc	Recorded	17.56	5.87	0.00	18.51
	Adjustment	0.00	0.00	0.00	
	Total	17.56	5.87	0.00	18.51

POE Adjust	
◉ 50POE	-4.7%
○ 10POE	8.9%

Starting Demand	50POE		
	Coinc Load	*Assessed Steps*	*Starting Demand*
MW	17.56	0.00	16.73
MVAr (uncomp)	5.87	0.00	5.59
Power Factor			0.92

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reconciliation		0.00	0.94	0.93	0.92	0.91	0.91	0.92	0.91	0.90	0.90	0.90	0.90
Growth		0.53%	0.52%	0.55%	0.53%	0.50%	0.47%	0.46%	0.43%	0.42%	0.41%	0.40%	0.40%
MW Coincidence Factor		0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Block Loads													
	MW coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prev Block Loads													
	MW coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Load Transfers													
	MW coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Generator													
	MW Coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr Coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coincident (no generator)													
Unreconciled	MW	16.73	16.82	16.91	17.00	17.09	17.17	17.25	17.32	17.40	17.47	17.54	17.61
	MVAr uncomp	5.59	5.62	5.65	5.68	5.71	5.74	5.76	5.79	5.81	5.84	5.86	5.88
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	16.74	16.82	16.92	17.01	17.09	17.17	17.25	17.33	17.40	17.47	17.54	17.61
	MVA uncomp	17.64	17.74	17.83	17.93	18.02	18.10	18.19	18.26	18.34	18.42	18.49	18.56
Reconciled	MW	16.73	15.74	15.80	15.68	15.62	15.66	15.79	15.77	15.74	15.70	15.70	15.80
	MVAr uncomp	5.59	5.26	5.28	5.24	5.22	5.23	5.28	5.27	5.26	5.24	5.25	5.28
	Comp (Mvar)	5.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA comp	16.74	16.60	16.66	16.54	16.47	16.52	16.65	16.63	16.59	16.55	16.55	16.65
	MVA	17.64	16.60	16.66	16.54	16.47	16.52	16.65	16.63	16.59	16.55	16.55	16.65
Coincident (with generator)													
Unreconciled	MW	16.73	16.82	16.91	17.00	17.09	17.17	17.25	17.32	17.40	17.47	17.54	17.61
	MVAr uncomp	5.59	5.62	5.65	5.68	5.71	5.74	5.76	5.79	5.81	5.84	5.86	5.88
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	16.74	16.82	16.92	17.01	17.09	17.17	17.25	17.33	17.40	17.47	17.54	17.61
	MVA uncomp	17.64	17.74	17.83	17.93	18.02	18.10	18.19	18.26	18.34	18.42	18.49	18.56
Reconciled	MW	16.73	15.74	15.80	15.68	15.62	15.66	15.79	15.77	15.74	15.70	15.70	15.80
	MVAr uncomp	5.59	5.26	5.28	5.24	5.22	5.23	5.28	5.27	5.26	5.24	5.25	5.28
	Comp (Mvar)	5.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA comp	16.74	16.60	16.66	16.54	16.47	16.52	16.65	16.63	16.59	16.55	16.55	16.65
	MVA uncomp	17.64	16.60	16.66	16.54	16.47	16.52	16.65	16.63	16.59	16.55	16.55	16.65
Peak (no generator)													
Unreconciled	MW	20.77	20.88	21.00	21.11	21.21	21.31	21.41	21.50	21.59	21.68	21.77	21.85
	MVAr uncomp	8.96	9.01	9.06	9.11	9.15	9.20	9.24	9.28	9.32	9.35	9.39	9.43
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	21.08	21.19	21.31	21.43	21.54	21.65	21.75	21.85	21.95	22.04	22.13	22.22
	MVA uncomp	22.62	22.74	22.87	22.99	23.10	23.21	23.32	23.42	23.52	23.61	23.71	23.80
Reconciled	MW	20.77	19.54	19.62	19.47	19.39	19.44	19.61	19.58	19.53	19.48	19.49	19.61
	MVAr uncomp	8.96	8.43	8.46	8.40	8.36	8.39	8.46	8.45	8.43	8.41	8.41	8.46
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	21.08	19.78	19.86	19.70	19.61	19.67	19.84	19.81	19.77	19.71	19.72	19.85
	MVA uncomp	22.62	21.28	21.37	21.20	21.11	21.18	21.35	21.32	21.28	21.22	21.23	21.36
Peak (with generator)													
Unreconciled	MW	20.77	20.88	21.00	21.11	21.21	21.31	21.41	21.50	21.59	21.68	21.77	21.85
	MVAr uncomp	8.96	9.01	9.06	9.11	9.15	9.20	9.24	9.28	9.32	9.35	9.39	9.43
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	21.08	21.19	21.31	21.43	21.54	21.65	21.75	21.85	21.95	22.04	22.13	22.22
	MVA uncomp	22.62	22.74	22.87	22.99	23.10	23.21	23.32	23.42	23.52	23.61	23.71	23.80
Reconciled	MW	20.77	19.54	19.62	19.47	19.39	19.44	19.61	19.58	19.53	19.48	19.49	19.61
	MVAr uncomp	8.96	8.43	8.46	8.40	8.36	8.39	8.46	8.45	8.43	8.41	8.41	8.46
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	21.08	19.78	19.86	19.70	19.61	19.67	19.84	19.81	19.77	19.71	19.72	19.85
	MVA uncomp	22.62	21.28	21.37	21.20	21.11	21.18	21.35	21.32	21.28	21.22	21.23	21.36

A

Figure C.3 – Grovely master forecast (SIFT screenshot)

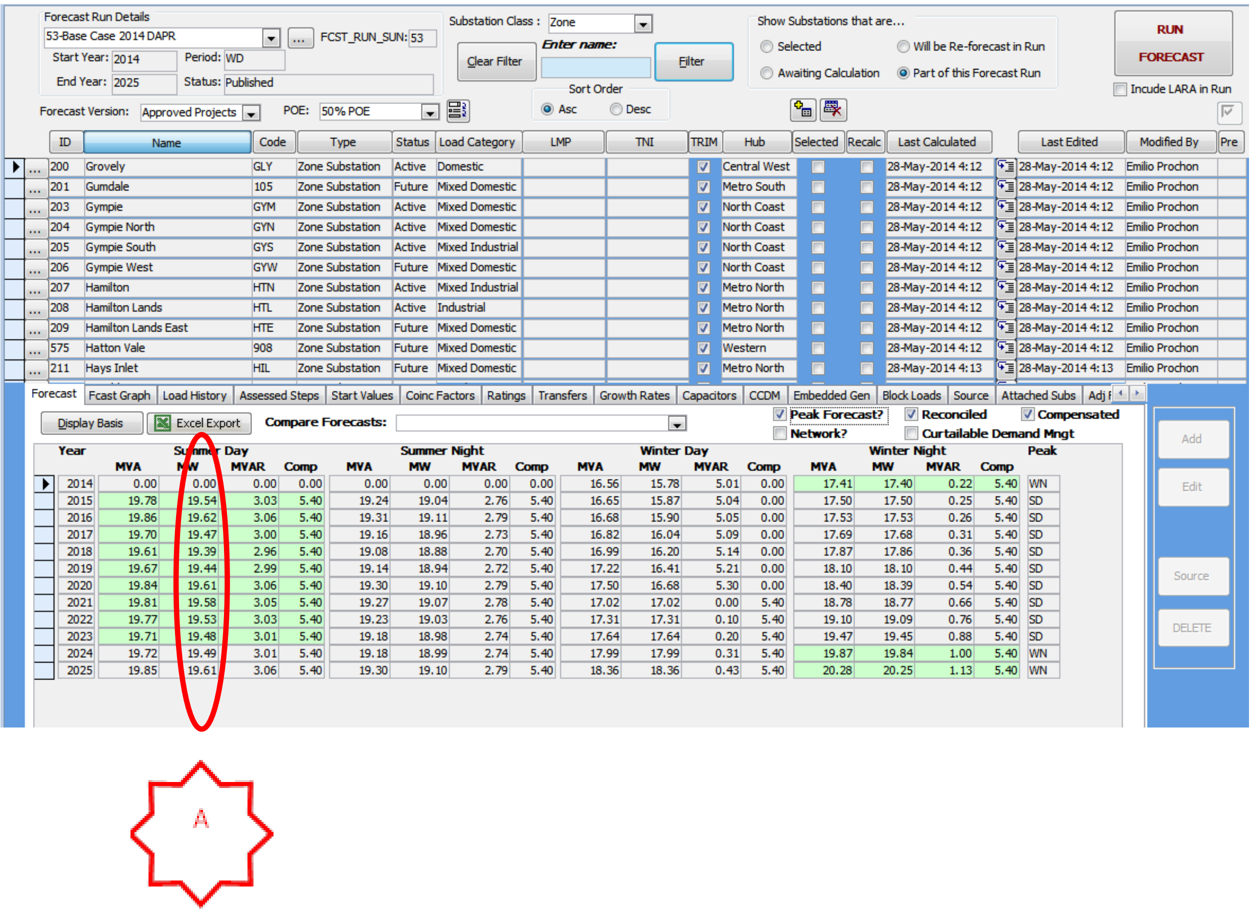


Figure C.4 - Hamilton Lands Maximum Demand Forecast (SIFT export)

Substation		HTL	Hamilton Lands		
Load History		**SD**			
		MW	**MVAr**	**Comp**	**MVA**
Peak	Recorded	20.19	5.67	0.00	20.97
	Adjustment	0.00	0.00	0.00	
	Total	20.19	5.67	0.00	20.97
Coinc	Recorded	18.30	3.76	0.00	18.68
	Adjustment	0.00	0.00	0.00	
	Total	18.30	3.76	0.00	18.68

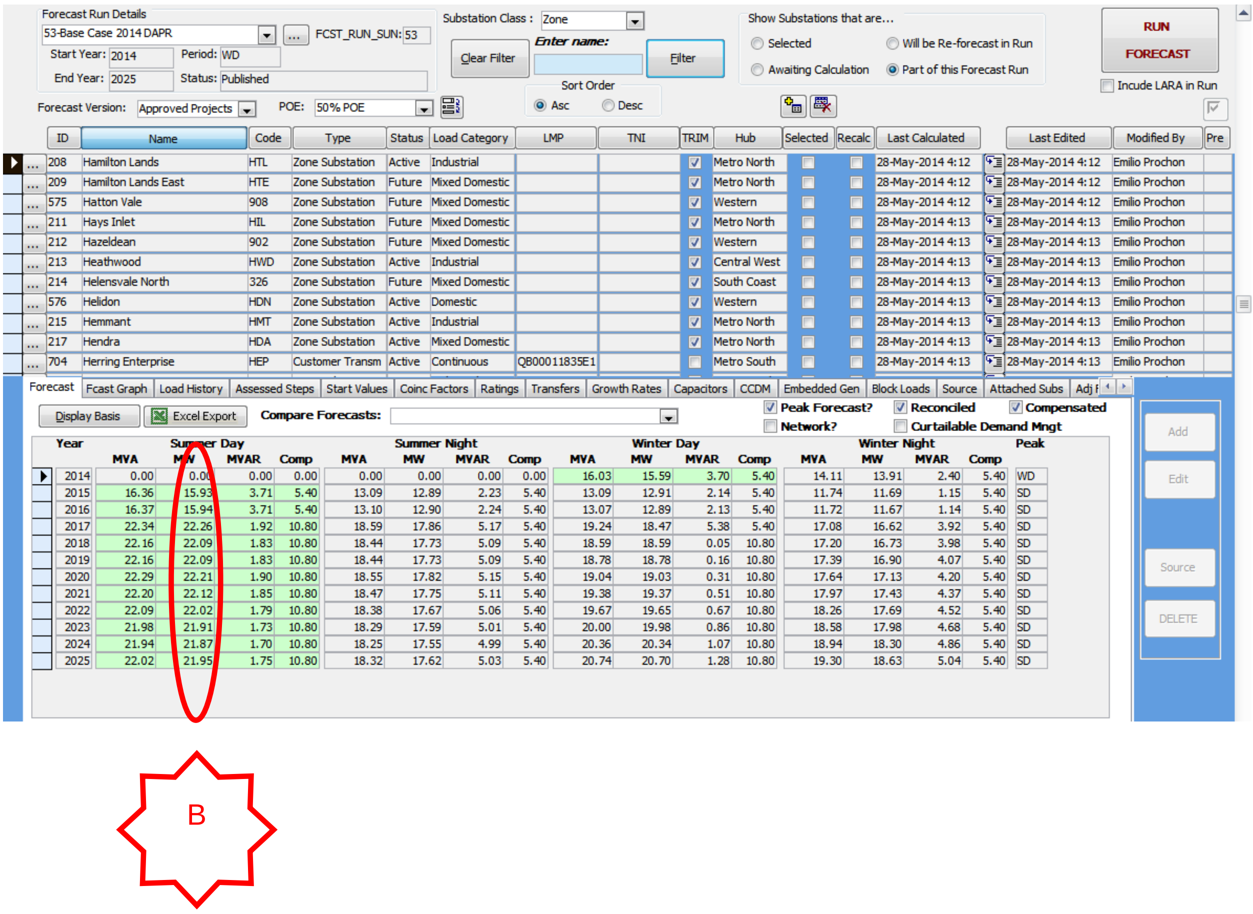
POE Adjust		
◉	50POE	0.0%
○	10POE	5.0%

Starting Demand	**50POE**		
	Coinc Load	*Assessed Steps*	*Starting Demand*
MW	18.30	0.00	18.30
MVAr (uncomp)	3.76	0.00	3.76
Power Factor			0.87

		2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Reconciliation		0.00	0.94	0.93	0.92	0.91	0.91	0.92	0.91	0.90	0.90	0.90	0.90
Growth		0.28%	0.27%	0.28%	0.28%	0.27%	0.29%	0.30%	0.30%	0.30%	0.29%	0.28%	0.27%
MW Coincidence Factor		0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Block Loads													
	MW coinc	0.00	2.40	0.00	6.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	1.31	0.00	3.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prev Block Loads													
	MW coinc	0.00	0.00	2.40	2.40	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76
	MVAr coinc	0.00	0.00	1.31	1.31	4.78	4.78	4.78	4.78	4.78	4.78	4.78	4.78
Load Transfers													
	MW coinc	0.00	-5.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	-3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Generator													
	MW Coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr Coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coincident (no generator)													
Unreconciled	MW	18.30	15.43	15.47	21.87	21.91	21.94	21.98	22.02	22.06	22.10	22.14	22.18
	MVAr uncomp	3.76	2.07	2.08	5.55	5.55	5.55	5.56	5.56	5.56	5.56	5.56	5.57
	Comp (Mvar)	0.00	0.00	0.00	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.68	15.57	15.60	21.87	21.91	21.95	21.98	22.02	22.06	22.10	22.14	22.18
	MVA uncomp	18.68	15.57	15.60	22.56	22.60	22.64	22.68	22.71	22.75	22.79	22.83	22.86
Reconciled	MW	18.30	14.44	14.45	20.17	20.02	20.02	20.13	20.05	19.96	19.86	19.82	19.90
	MVAr uncomp	3.76	1.94	1.94	5.12	5.07	5.07	5.09	5.06	5.03	5.00	4.98	4.99
	Comp (Mvar)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA comp	18.68	14.57	14.58	20.81	20.65	20.65	20.76	20.68	20.58	20.48	20.44	20.51
	MVA	18.68	14.57	14.58	20.81	20.65	20.65	20.76	20.68	20.58	20.48	20.44	20.51
Coincident (with generator)													
Unreconciled	MW	18.30	15.43	15.47	21.87	21.91	21.94	21.98	22.02	22.06	22.10	22.14	22.18
	MVAr uncomp	3.76	2.07	2.08	5.55	5.55	5.55	5.56	5.56	5.56	5.56	5.56	5.57
	Comp (Mvar)	0.00	0.00	0.00	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.68	15.57	15.60	21.87	21.91	21.95	21.98	22.02	22.06	22.10	22.14	22.18
	MVA uncomp	18.68	15.57	15.60	22.56	22.60	22.64	22.68	22.71	22.75	22.79	22.83	22.86
Reconciled	MW	18.30	14.44	14.45	20.17	20.02	20.02	20.13	20.05	19.96	19.86	19.82	19.90
	MVAr uncomp	3.76	1.94	1.94	5.12	5.07	5.07	5.09	5.06	5.03	5.00	4.98	4.99
	Comp (Mvar)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA comp	18.68	14.57	14.58	20.81	20.65	20.65	20.76	20.68	20.58	20.48	20.44	20.51
	MVA uncomp	18.68	14.57	14.58	20.81	20.65	20.65	20.76	20.68	20.58	20.48	20.44	20.51
Peak (no generator)													
Unreconciled	MW	20.19	17.02	17.06	24.13	24.17	24.21	24.26	24.30	24.34	24.39	24.43	24.47
	MVAr uncomp	11.54	9.73	9.75	13.79	13.82	13.84	13.87	13.89	13.92	13.94	13.96	13.99
	Comp (Mvar)	10.80	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	20.20	17.57	17.61	24.32	24.36	24.40	24.45	24.50	24.54	24.59	24.63	24.67
	MVA uncomp	23.25	19.61	19.66	27.80	27.84	27.89	27.94	27.99	28.04	28.09	28.14	28.18
Reconciled	MW	20.19	15.93	15.94	22.26	22.09	22.09	22.21	22.12	22.02	21.91	21.87	21.95
	MVAr uncomp	11.54	9.11	9.11	12.72	12.63	12.63	12.70	12.65	12.59	12.53	12.50	12.55
	Comp (Mvar)	10.80	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	20.20	16.36	16.37	22.34	22.16	22.16	22.29	22.20	22.09	21.98	21.94	22.02
	MVA uncomp	23.25	18.35	18.36	25.64	25.44	25.44	25.58	25.48	25.37	25.24	25.19	25.29
Peak (with generator)													
Unreconciled	MW	20.19	17.02	17.06	24.13	24.17	24.21	24.26	24.30	24.34	24.39	24.43	24.47
	MVAr uncomp	11.54	9.73	9.75	13.79	13.82	13.84	13.87	13.89	13.92	13.94	13.96	13.99
	Comp (Mvar)	10.80	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	20.20	17.57	17.61	24.32	24.36	24.40	24.45	24.50	24.54	24.59	24.63	24.67
	MVA uncomp	23.25	19.61	19.66	27.80	27.84	27.89	27.94	27.99	28.04	28.09	28.14	28.18
Reconciled	MW	20.19	15.93	15.94	22.26	22.09	22.09	22.21	22.12	22.02	21.91	21.87	21.95
	MVAr uncomp	11.54	9.11	9.11	12.72	12.63	12.63	12.70	12.65	12.59	12.53	12.50	12.55
	Comp (Mvar)	10.80	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	20.20	16.36	16.37	22.34	22.16	22.16	22.29	22.20	22.09	21.98	21.94	22.02
	MVA uncomp	23.25	18.35	18.36	25.64	25.44	25.44	25.58	25.48	25.37	25.24	25.19	25.29

B

Figure C.5 - Hamilton Lands master forecast screenshot (SIFT screenshot)



Year	Summer Day MVA	MW	MVAR	Comp	Summer Night MVA	MW	MVAR	Comp	Winter Day MVA	MW	MVAR	Comp	Winter Night MVA	MW	MVAR	Comp	Peak
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.03	15.59	3.70	5.40	14.11	13.91	2.40	5.40	WD
2015	16.36	15.93	3.71	5.40	13.09	12.89	2.23	5.40	13.09	12.91	2.14	5.40	11.74	11.69	1.15	5.40	SD
2016	16.37	15.94	3.71	5.40	13.10	12.90	2.24	5.40	13.07	12.89	2.13	5.40	11.72	11.67	1.14	5.40	SD
2017	22.34	22.26	1.92	10.80	18.59	17.86	5.17	5.40	19.24	18.47	5.38	5.40	17.08	16.62	3.92	5.40	SD
2018	22.16	22.09	1.83	10.80	18.44	17.73	5.09	5.40	18.59	18.59	0.05	10.80	17.20	16.73	3.98	5.40	SD
2019	22.16	22.09	1.83	10.80	18.44	17.73	5.09	5.40	18.78	18.78	0.16	10.80	17.39	16.90	4.07	5.40	SD
2020	22.29	22.21	1.90	10.80	18.55	17.82	5.15	5.40	19.04	19.03	0.31	10.80	17.64	17.13	4.20	5.40	SD
2021	22.20	22.12	1.85	10.80	18.47	17.75	5.11	5.40	19.38	19.37	0.51	10.80	17.97	17.43	4.37	5.40	SD
2022	22.09	22.02	1.79	10.80	18.38	17.67	5.06	5.40	19.67	19.65	0.67	10.80	18.26	17.69	4.52	5.40	SD
2023	21.98	21.91	1.73	10.80	18.29	17.59	5.01	5.40	20.00	19.98	0.86	10.80	18.58	17.98	4.68	5.40	SD
2024	21.94	21.87	1.70	10.80	18.25	17.55	4.99	5.40	20.36	20.34	1.07	10.80	18.94	18.30	4.86	5.40	SD
2025	22.02	21.95	1.75	10.80	18.32	17.62	5.03	5.40	20.74	20.70	1.28	10.80	19.30	18.63	5.04	5.40	SD

Figure C.6 – Carole Park Maximum Demand Forecast (SIFT export)

Substation	CPK	Carole Park

Load History		SD MW	SD MVAr	SD Comp	SD MVA
Peak	Recorded	19.44	-1.41	9.22	20.95
	Adjustment	0.00	0.00	0.00	
	Total	19.44	-1.41	9.22	20.95
Coinc	Recorded	17.55	-1.97	9.13	18.95
	Adjustment	0.00	0.00	0.00	
	Total	17.55	-1.97	9.13	18.95

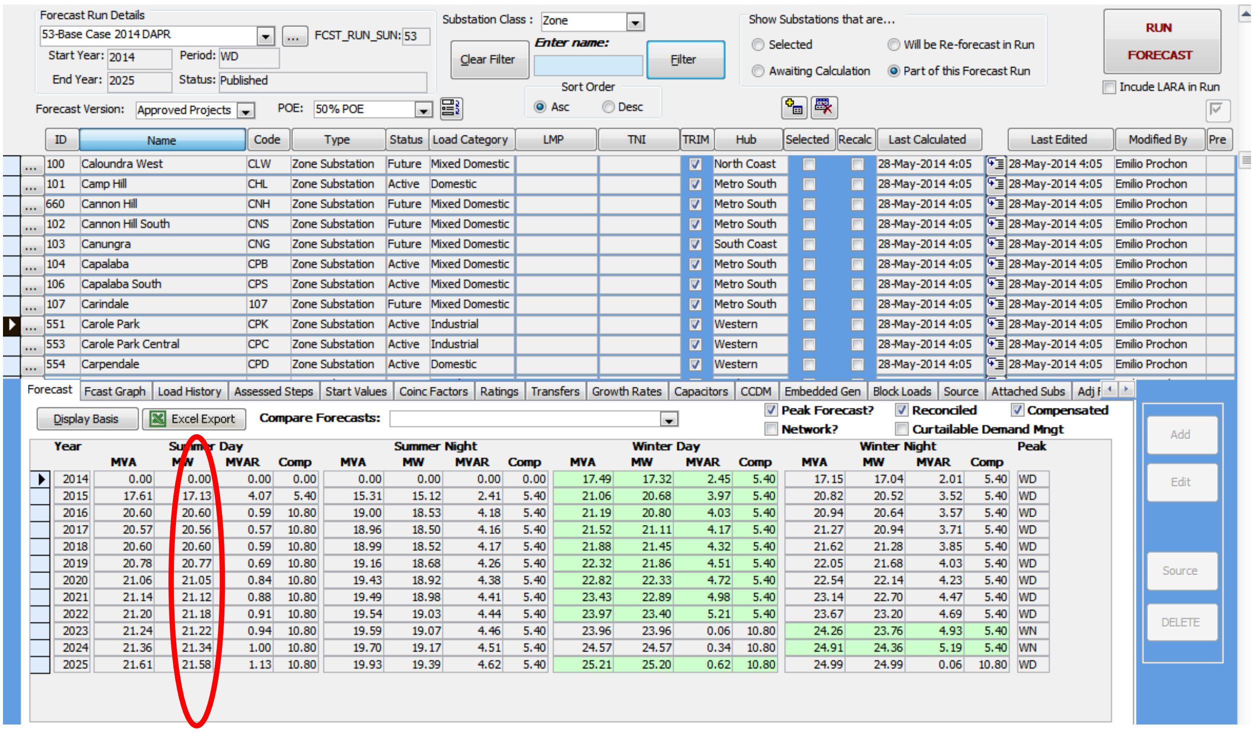
POE Adjust	
◉ 50POE	3.3%
○ 10POE	7.0%

Starting Demand	50POE		
	Coinc Load	*Assessed Steps*	*Starting Demand*
MW	17.55	0.00	18.12
MVAr (uncomp)	7.15	0.00	7.39
Power Factor			0.88

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reconciliation		0.00	0.94	0.93	0.92	0.91	0.91	0.92	0.91	0.90	0.90	0.90	0.90
Growth		0.96%	1.03%	1.13%	1.35%	1.29%	1.23%	1.13%	1.09%	1.07%	1.05%	1.08%	1.08%
MW Coincidence Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Block Loads													
	MW coinc	0.00	0.00	3.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	0.00	1.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prev Block Loads													
	MW coinc	0.00	0.00	0.00	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
	MVAr coinc	0.00	0.00	0.00	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
Load Transfers													
	MW coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr coinc	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Generator													
	MW Coinc	0.00	3.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVAr Coinc	0.00	1.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coincident (no generator)													
Unreconciled	MW	18.12	18.30	22.04	22.29	22.54	22.77	22.99	23.20	23.41	23.62	23.83	24.05
	MVAr uncomp	7.39	7.46	9.42	9.52	9.62	9.72	9.81	9.89	9.98	10.06	10.15	10.24
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.23	18.42	22.41	22.67	22.93	23.18	23.41	23.63	23.85	24.07	24.30	24.54
	MVA uncomp	19.56	19.77	23.97	24.24	24.50	24.76	24.99	25.22	25.45	25.67	25.91	26.14
Reconciled	MW	18.12	17.13	20.60	20.56	20.59	20.77	21.05	21.12	21.18	21.22	21.34	21.58
	MVAr uncomp	7.39	6.98	8.80	8.78	8.79	8.87	8.98	9.01	9.03	9.04	9.09	9.19
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.23	17.20	20.88	20.84	20.87	21.06	21.35	21.42	21.48	21.53	21.66	21.91
	MVA	19.56	18.50	22.40	22.36	22.39	22.59	22.88	22.96	23.02	23.07	23.20	23.46
Coincident (with generator)													
Unreconciled	MW	18.12	18.30	22.04	22.29	22.54	22.77	22.99	23.20	23.41	23.62	23.83	24.05
	MVAr uncomp	7.39	10.12	9.42	9.52	9.62	9.72	9.81	9.89	9.98	10.06	10.15	10.24
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.23	18.90	22.41	22.67	22.93	23.18	23.41	23.63	23.85	24.07	24.30	24.54
	MVA uncomp	19.56	20.91	23.97	24.24	24.50	24.76	24.99	25.22	25.45	25.67	25.91	26.14
Reconciled	MW	18.12	17.13	20.60	20.56	20.59	20.77	21.05	21.12	21.18	21.22	21.34	21.58
	MVAr uncomp	7.39	9.47	8.80	8.78	8.79	8.87	8.98	9.01	9.03	9.04	9.09	9.19
	Comp (Mvar)	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
	MVA comp	18.23	17.61	20.88	20.84	20.87	21.06	21.35	21.42	21.48	21.53	21.66	21.91
	MVA uncomp	19.56	19.57	22.40	22.36	22.39	22.59	22.88	22.96	23.02	23.07	23.20	23.46
Peak (no generator)													
Unreconciled	MW	18.12	18.30	22.04	22.29	22.54	22.77	22.99	23.20	23.41	23.62	23.83	24.05
	MVAr uncomp	10.02	10.12	12.19	12.33	12.46	12.59	12.71	12.83	12.94	13.06	13.18	13.30
	Comp (Mvar)	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	18.70	18.90	22.09	22.35	22.60	22.84	23.07	23.29	23.51	23.73	23.95	24.18
	MVA uncomp	20.70	20.91	25.19	25.47	25.75	26.02	26.27	26.51	26.75	26.99	27.24	27.49
Reconciled	MW	18.12	17.13	20.60	20.56	20.59	20.77	21.05	21.12	21.18	21.22	21.34	21.58
	MVAr uncomp	10.02	9.47	11.39	11.37	11.39	11.49	11.64	11.68	11.71	11.74	11.80	11.93
	Comp (Mvar)	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	18.70	17.61	20.60	20.57	20.60	20.78	21.06	21.14	21.20	21.24	21.36	21.61
	MVA uncomp	20.70	19.57	23.53	23.50	23.53	23.74	24.05	24.13	24.20	24.25	24.39	24.66
Peak (with generator)													
Unreconciled	MW	18.12	18.30	22.04	22.29	22.54	22.77	22.99	23.20	23.41	23.62	23.83	24.05
	MVAr uncomp	10.02	10.12	12.19	12.33	12.46	12.59	12.71	12.83	12.94	13.06	13.18	13.30
	Comp (Mvar)	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	18.70	18.90	22.09	22.35	22.60	22.84	23.07	23.29	23.51	23.73	23.95	24.18
	MVA uncomp	20.70	20.91	25.19	25.47	25.75	26.02	26.27	26.51	26.75	26.99	27.24	27.49
Reconciled	MW	18.12	17.13	20.60	20.56	20.59	20.77	21.05	21.12	21.18	21.22	21.34	21.58
	MVAr uncomp	10.02	9.47	11.39	11.37	11.39	11.49	11.64	11.68	11.71	11.74	11.80	11.93
	Comp (Mvar)	5.40	5.40	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
	MVA comp	18.70	17.61	20.60	20.57	20.60	20.78	21.06	21.14	21.20	21.24	21.36	21.61
	MVA uncomp	20.70	19.57	23.53	23.50	23.53	23.74	24.05	24.13	24.20	24.25	24.39	24.66

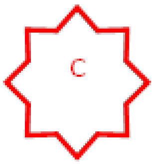
C

Figure C.7 – Carole Park master forecast screenshot (SIFT screenshot)

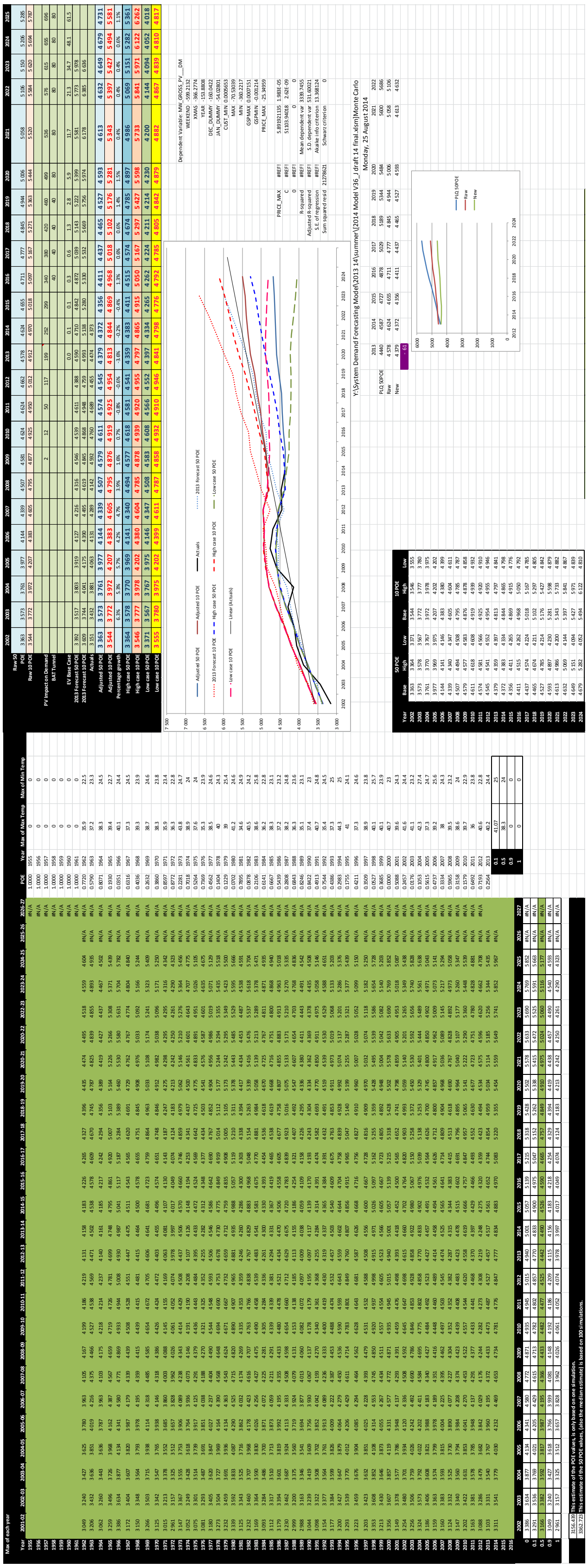


ID	Name	Code	Type	Status	Load Category	TRIM	Hub	Last Calculated	Last Edited	Modified By
100	Caloundra West	CLW	Zone Substation	Future	Mixed Domestic	✓	North Coast	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
101	Camp Hill	CHL	Zone Substation	Active	Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
660	Cannon Hill	CNH	Zone Substation	Future	Mixed Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
102	Cannon Hill South	CNS	Zone Substation	Future	Mixed Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
103	Canungra	CNG	Zone Substation	Future	Mixed Domestic	✓	South Coast	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
104	Capalaba	CPB	Zone Substation	Active	Mixed Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
106	Capalaba South	CPS	Zone Substation	Active	Mixed Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
107	Carindale	107	Zone Substation	Future	Mixed Domestic	✓	Metro South	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
551	Carole Park	CPK	Zone Substation	Active	Industrial	✓	Western	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
553	Carole Park Central	CPC	Zone Substation	Active	Industrial	✓	Western	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon
554	Carpendale	CPD	Zone Substation	Active	Domestic	✓	Western	28-May-2014 4:05	28-May-2014 4:05	Emilio Prochon

Year	Summer Day				Summer Night				Winter Day				Winter Night				Peak
	MVA	MW	MVAR	Comp	MVA	MW	MVAR	Comp	MVA	MW	MVAR	Comp	MVA	MW	MVAR	Comp	
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.49	17.32	2.45	5.40	17.15	17.04	2.01	5.40	WD
2015	17.61	17.13	4.07	5.40	15.31	15.12	2.41	5.40	21.06	20.68	3.97	5.40	20.82	20.52	3.52	5.40	WD
2016	20.60	20.60	0.59	10.80	19.00	18.53	4.18	5.40	21.19	20.80	4.03	5.40	20.94	20.64	3.57	5.40	WD
2017	20.57	20.56	0.57	10.80	18.96	18.50	4.16	5.40	21.52	21.11	4.17	5.40	21.27	20.94	3.71	5.40	WD
2018	20.60	20.60	0.59	10.80	18.99	18.52	4.17	5.40	21.88	21.45	4.32	5.40	21.62	21.28	3.85	5.40	WD
2019	20.78	20.77	0.69	10.80	19.16	18.68	4.26	5.40	22.32	21.86	4.51	5.40	22.05	21.68	4.03	5.40	WD
2020	21.06	21.05	0.84	10.80	19.43	18.92	4.38	5.40	22.82	22.33	4.72	5.40	22.54	22.14	4.23	5.40	WD
2021	21.14	21.12	0.88	10.80	19.49	18.98	4.41	5.40	23.43	22.89	4.98	5.40	23.14	22.70	4.47	5.40	WD
2022	21.20	21.18	0.91	10.80	19.54	19.03	4.44	5.40	23.97	23.40	5.21	5.40	23.67	23.20	4.69	5.40	WD
2023	21.24	21.22	0.94	10.80	19.59	19.07	4.46	5.40	23.96	23.96	0.06	10.80	24.26	23.76	4.93	5.40	WN
2024	21.36	21.34	1.00	10.80	19.70	19.17	4.51	5.40	24.57	24.57	0.34	10.80	24.91	24.36	5.19	5.40	WN
2025	21.61	21.58	1.13	10.80	19.93	19.39	4.62	5.40	25.21	25.20	0.62	10.80	24.99	24.99	0.06	10.80	WD



System Demand Forecasting Model



Attachment D – Procedure 00569: Annual Review of Contingency Plans and Network Load at Risk Data

Attachment E – Demand-related capex projects or programs for zone substations