Demand Strategy & Plan 2015/16-2034/35

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Demand Strategy & Plan

2015/16 – 2034/35

UNITED ENERGY

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1. Executive Summary

This Demand Strategy & Plan sets out the strategy and associated plans for capital expenditure works to meet the forecast customer connection and maximum demand growth requirements in the UE service area over the next 20 years, preserving existing levels of energy-at-risk (reliability maintained). The Demand Strategy & Plan approaches energy-at-risk in the context of condition-based plant ratings, probabilistic risk assessment of loss-of-supply, customer valuation of reliability and contingency planning.

The objectives of the Demand Strategy & Plan are to follow good asset management practice as contemplated in the overarching Asset Management Policy (UE PO 2000) and Asset Management Strategy & Objectives (UE PL 2000) documents by providing capacity for customers' maximum demand growth requirements in accordance with Chapter 5 Part B of the National Electricity Rules (NER), and UE's Network Planning Policy (UE PO 2200) and Network Planning Guidelines (UE GU 2200). The outcomes include maximising asset utilisation with a prudent risk management contingency plan, avoiding overloads which may damage plant, managing network electrical losses, maintaining system reliability, and prudent economic investments within a capital budget allowance.

The projections in this Demand Strategy & Plan are underpinned by new connection and summer maximum demand forecasts developed by UE and supported by an independent assessment of maximum demand growth by the National Institute of Economic and Industry Research (NIEIR). The NIEIR index is specifically tailored to predicting maximum demand growth on the UE electricity network and while this index has proven to be a reliable index for predicting demand, UE has strengthened its in-house top-down maximum demand forecasting capabilities by leveraging off the work that AECOM has recently completed with the development of an internal macro-economic maximum demand forecasting method and tool based on the eViews software package.

The last five years have seen a decrease in UE's actual maximum demand since the record demand levels observed in 2009 due predominantly to milder summer weather conditions in the non-holiday period, a slowdown in the economy, electricity price increases and increased solar PV penetration. The weather-corrected actual maximum demand trend on UE's distribution system has been steadily increasing for more than 10 years and this has been attributed to historically good (but slowing) local economic conditions, ongoing population growth and increasing penetration of domestic air conditioning. In response to the deteriorating economic conditions in Australia, this year's UE maximum demand forecast has been revised downward by NIEIR since last year's forecast. The revised forecast effectively shows UE's overall service area maximum demand declining over the next couple of years after which economic conditions are predicted to improve to return to maximum demand growth. As a result, growth capex projections in this Demand Strategy & Plan are lower than those forecast in last year's plan. Whilst lower growth is the case for the overall UE network, there remain pockets of strong growth within UE's service area, particularly in and around the developing suburbs of Keysborough through to Carrum Downs, and parts of the Mornington Peninsula. These areas are the predominant drivers of capital expenditure over the next several years.

The capital expenditure programme provided with this Demand Strategy & Plan is developed from our base case (expected) maximum demand forecast scenario taking into due consideration the impact of disruptive technologies such as solar PV and energy efficiency (for example). A bottom-up probabilistic approach is used to identify specific emerging network constraints from network loading capabilities. This analysis has provided the following 10-year capex profile for Demand (Augmentation) and CIC (Customer Connections) expenditure requirements.

Table 1-1: Forecast Capital Expenditure Programme (excluding cost escalators)

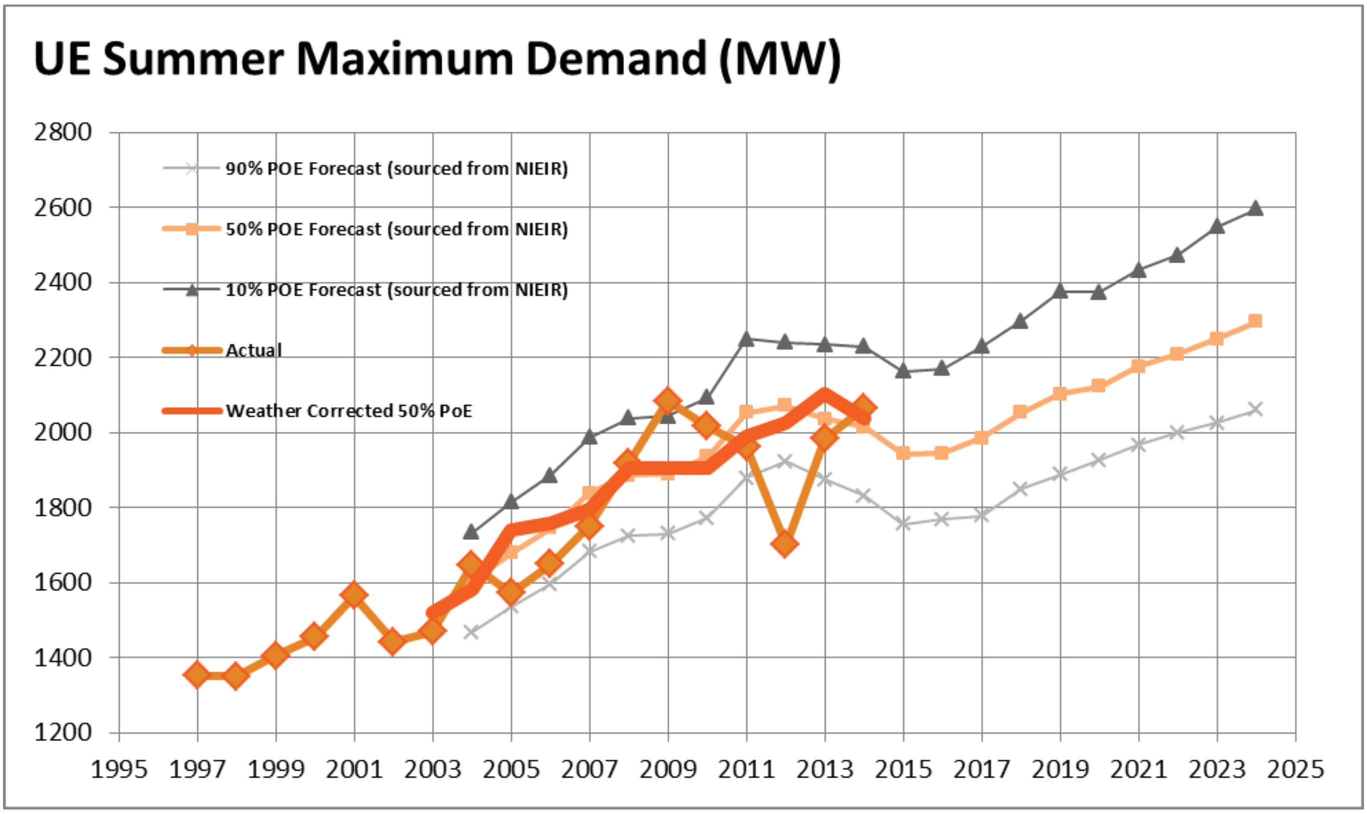
Financial Year Ending $k 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Customer Initiated (CIC)	$55,584	$54,661	$55,184	$55,575	$55,871	$56,983	$58,148	$58,977	$60,058	$61,139
Augmentation (Demand)	$28,088	$26,293	$29,283	$28,053	$30,326	$28,033	$23,460	$27,439	$37,453	$35,658

2. Introduction

2.1. Maximum Demand

While the last five years have seen a decrease in UE's actual maximum demand since the record demand levels observed in 2009 (due predominantly to milder weather conditions, a slowdown in the economy, price increases and increased solar PV penetration), the weather-corrected actual maximum demand trend on UE's distribution system has been steadily increasing for more than 10 years. This is attributed to historically good (but slowing) local economic conditions, ongoing population growth and increasing penetration of domestic air conditioning. Only in the last year have we seen a possible downturn in our weather-corrected actual maximum demand as illustrated below. In response to this and the deteriorating economic conditions in Australia, this year's UE maximum demand forecast has been revised downward by the National Institute of Economic & Industry Research (NIEIR) since last year's forecast. The revised forecast effectively shows UE's overall service area maximum demand declining over the next couple of years after which economic conditions are predicted to improve, returning to maximum demand growth. As a result, growth capex projections in this Demand Strategy & Plan are lower than those forecast in last year's plan. Whilst lower growth is the case for the overall UE network, there remain pockets of strong growth within UE's service area, particularly in and around the developing suburbs of Keysborough through to Carrum Downs, and parts of the Mornington Peninsula.

Figure 2-1: UE Boundary Load Maximum Demand Historical and Forecast



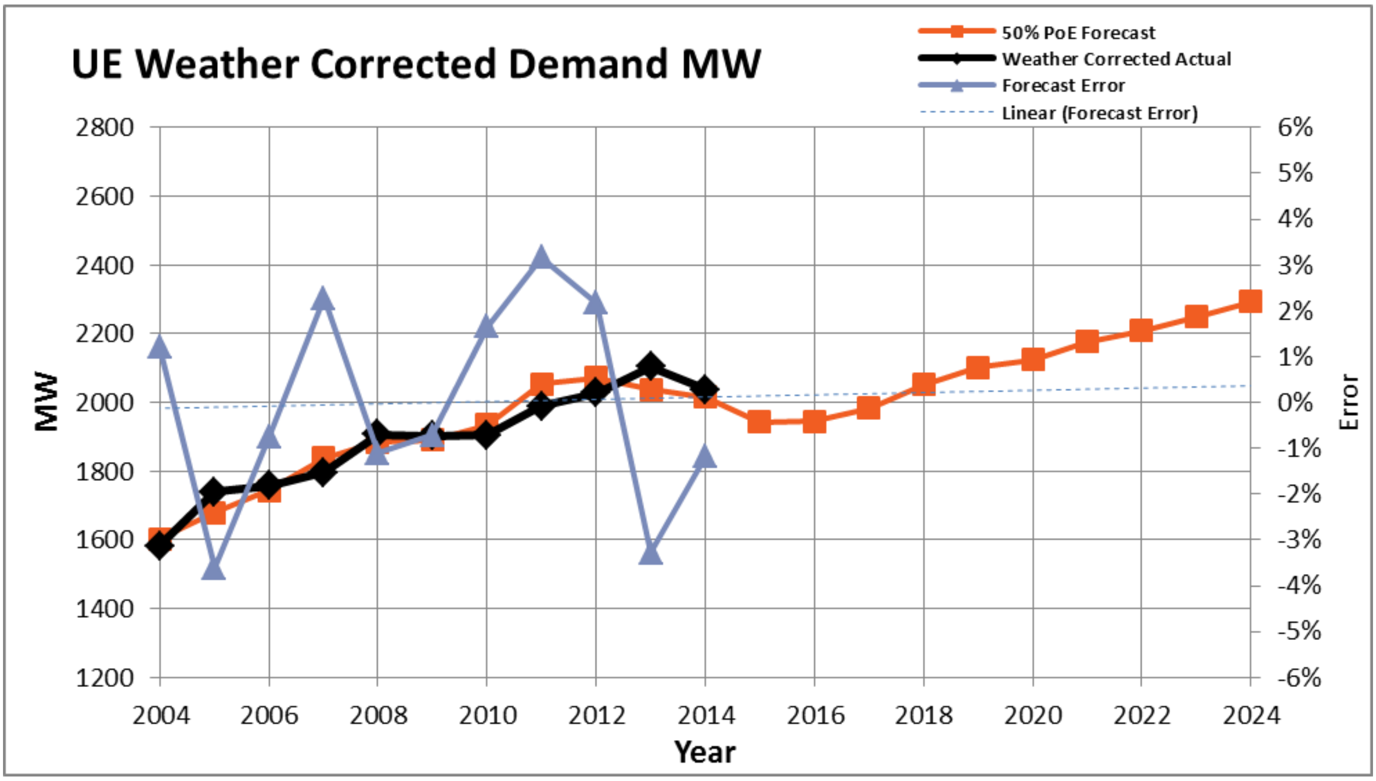
Lasting for only short periods (predominately over the summer months) and fluctuating year by year, peak demand is being driven by the increasing penetration of air conditioning and other lifestyle appliances, as well as underlying economic and population growth. Peak demand growth is the strongest driver for investment in network augmentation under the augmentation (demand) capital expenditure category.

The week commencing 13th January 2014 saw unprecedented weather conditions in Melbourne. Victoria had its hottest four-day period on record for both maximum and average temperature, with all days exceeding 40 degrees.

Melbourne's average temperature on Thursday 16th January 2014 was 35.45 degrees representing a 2% PoE, narrowly eclipsing the previous high of 35.4 set on January 30, 2009. The UE boundary load (as measured by half-hourly NEM metering) recorded a maximum demand during this week of 2066MW for the half-hour ending 18:00 (local time) on Thursday 16th January 2014. On this day, UE had a major unplanned outage (unrelated to load) of its Frankston Zone Substation (FTN) totalling 51MW which was not fully restored until after the peak demand. Had FTN been in service, the UE boundary load would have reached 2077MW for half-hour ending 17:30. This is marginally lower than the record peak of 2084MW which occurred on 29th January 2009, however back in 2009 there was virtually no solar PV installed on the UE network, and the maximum demand occurred much later in January when loads are naturally expected to be higher outside of the summer holiday period. For the summer of 2014 there was approximately 87MW of installed solar PV capacity embedded in the UE network contributing (according to NIEIR modelling) approximately 13MW of negative demand at the time of maximum demand.

Using the process of weather-correction (normalisation), the maximum demand is observed to have an increasing trend with some signs of decline over the last year. UE's weather-corrected actuals and historical forecasting accuracy are shown below. It demonstrates forecasting accuracy has been well within ±4% with an average error of 0.0% and a standard deviation of 2.3%.

Figure 2-2: UE's Maximum Demand Forecast and Forecasting Accuracy

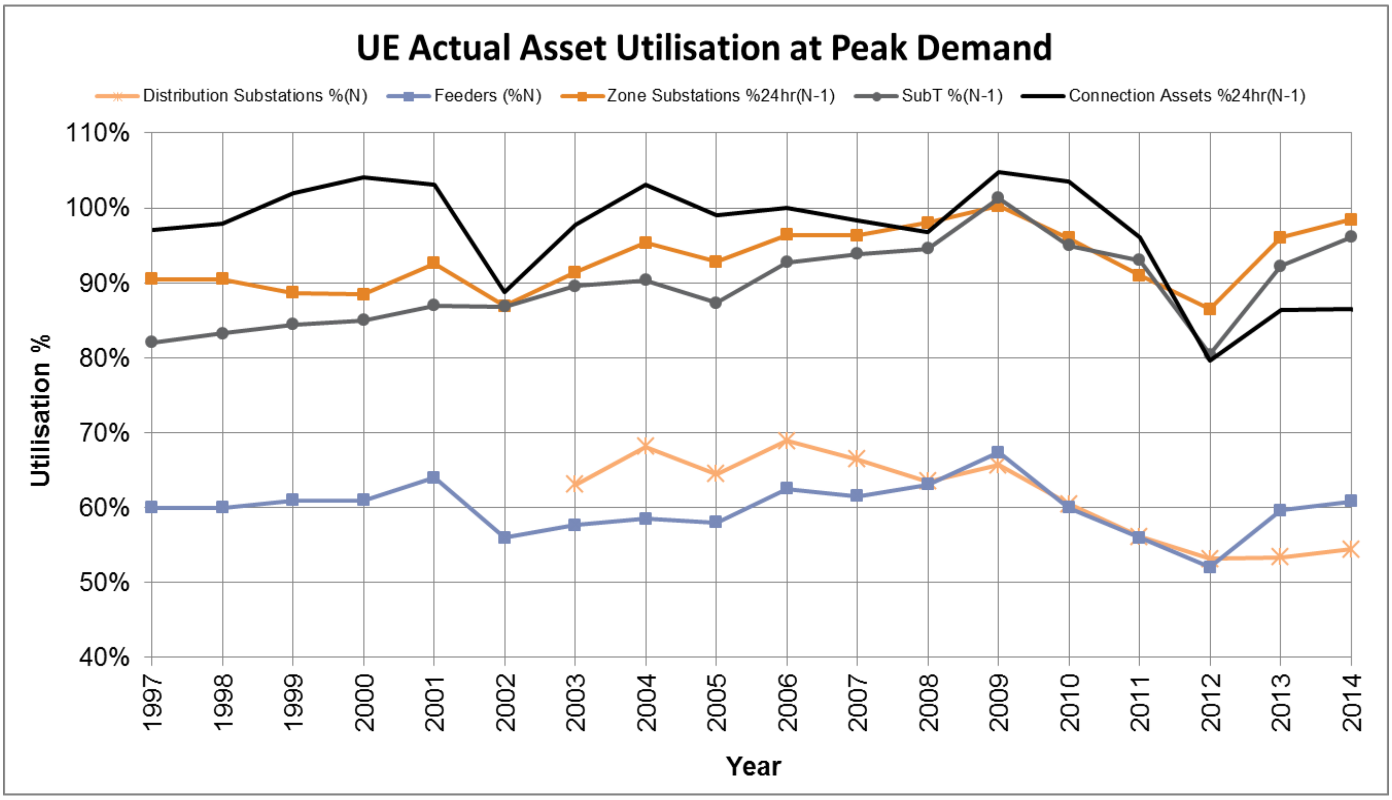


Forecasts by NIEIR still indicate a continued growth in electricity peak demand in the medium-term primarily due to increasing penetration of domestic air conditioners, albeit at a lower rate compared to that published last year due to the ongoing weak economic conditions impacting the local economy. This ten-year UE maximum demand growth has reduced from 1.7% pa in 2013 down to 1.4% pa in 2014 for the 50% PoE maximum demand. Compared with the 2.6% pa average growth rates observed in the first decade of this century, growth in maximum demand is now substantially lower.

2.2. Asset Utilisation

Distribution network capacity constraints are generally related to thermal capacity of plant in summer, when network loading is at its highest and plant rating is at its lowest, but in some cases may be related to voltage limitations. The following chart presents an aggregate of historical connection asset, zone substation, sub-transmission, distribution feeder and distribution transformer capacity utilisations based on actual loads and plant ratings at peak demand expressed as a percentage of N cyclic rating or 24-hour limited N-1 cyclic rating.

Figure 2-3: Average Historical Utilisation of Assets



This chart shows a reduction in utilisations in 2010, 2011 and 2012, but recovers thereafter. These changes are a reflection of milder summers and therefore lower recorded maximum demand. For instance, the maximum demand recorded in January 2012 was 18% lower than that recorded in 2009. This trend has since reversed after 2012. The explanation for the lower than expected maximum demands between 2010 and 2012 are as follows:

- 2010 – The maximum demand in 2010 was lower than that of 2009 because the extreme hot temperature conditions of 2009 represented a 4% probability of exceedance level, whereas the warm temperature conditions of 2010 represented a 22% probability of exceedance.
- 2011 – The maximum demand occurred on Tuesday 1st February at 1pm (EST) where the hot temperature conditions represented a 15% probability of exceedance level. However the early arrival of a cool change at this time resulted in a significant drop-off in demand and hence the demand was never able to reach its typical 4-5pm (EST) peak.
- 2012 – The maximum demand occurred on Tuesday 24th January at 4pm (EST) where the mild temperature conditions represented an 82% probability of exceedance level. Furthermore, the time of year immediately followed the industry shutdown period and was two days prior to the Australia Day public holiday.

The utilisation is now increasing with the slightly warmer summer experienced in 2013 with a 77% PoE temperature condition and the extreme summer experienced in 2014 with a 2% PoE temperature condition (albeit in the middle of the January school holiday period).

Asset utilisation in this context is defined as the thermal loading of assets at times of maximum demand expressed as a proportion of their thermal rating or capability at 40 degrees Celsius ambient (under an N-1 scenario for zone substations and sub-transmission loops or N for distribution feeders). The utilisation chart indicates a network with very high asset utilisation. On average the utilisation of UE's sub-transmission lines and zone substations has increased as a direct result of a pursuit of efficiency through the application of sophisticated probabilistic capacity planning techniques. At present about half of these assets have an N-1 utilisation over 100% at peak demand. For the radial distribution feeders, the average utilisation of distribution feeders at peak demand has trended around 60%. The average utilisation of distribution substations has fallen over recent years as a direct result of increased expenditure on the Distribution System Augmentation programme to target extremely overloaded distribution substations. This increase in expenditure was triggered as a direct result of the 24.2 UE SAIDI minutes incurred during the heat-wave of 2009 as a result of overloaded distribution transformers and LV circuits. During the 2009 heat-wave, UE incurred 54 transformer failures and 960 fuse operations due to overload over a period of four days. By comparison, for the 2014 heat-wave, UE incurred 11 transformer failures and 650 fuse operations over a period of 6 days incurring a SAIDI of 5.4 minutes. The increase in expenditure since 2009 is having a directly measurable reliability performance improvement for our worst-served customers.

2.3. Augmentation (Demand) Capex

Investment decisions to augment the distribution network to meet forecast maximum demands are based on a least lifecycle-cost technically-acceptable analysis of considering either STPIS and opex costs in the case of a business impact assessment or energy-at-risk which includes consideration of the probability-weighted impacts on reliability of supply due to unlikely events (generally referred to as probabilistic planning) for a RIT-D / customer impact assessment. The approach provides a sound estimate of the expected cost to UE and the community and aims to ensure that an economic balance is struck between the cost of augmentation and some exposure to possible loss of supply when thermal capability of the network is exceeded in the event of an asset outage.

A major consequence of the probabilistic planning approach is a reduced level of network redundancy and system security at times of high demand when assets are highly utilised. To ensure reliability performance can be maintained, in developing and augmenting the network, UE aims to maintain risks associated with network capacity at manageable levels. UE achieves this by undertaking detailed contingency planning prior to seasons of high demand. The purpose of the contingency plans is to reduce the impact of unplanned outages should they occur at times of peak demand (worst case scenario planning). As demand and network utilisation increases over time, the efficacy of contingency plans in terms of managing network risks reduces; at some point triggering further capacity augmentation.

Overall, probabilistic planning has delivered more cost effective network performance outcomes for customers and this has contributed to UE delivering lower cost network charges to its customers relative to other distributors around Australia. UE, by industry benchmarks, has a very highly utilised and optimised network.

While probabilistic planning will remain as the principal tool for network investment, UE plans to continue to invest to augment its network so that the energy-at-risk associated with thermal capability of plant can be maintained at manageable levels, effectively maintaining reliability. Energy-at-risk levels are quantified in UE's Distribution Annual Planning Report (DAPR) (UE PL 2209).

The augmentation plan derived from this planning approach for the next 20-years includes the following key major investments on the UE network:

- 16 new zone substation transformers (0.8 per annum) at UE's existing and 6 new single-transformer zone substations (0.3 per annum) to maintain UE's energy-at-risk for zone substations;
- Approximately 163 feeder augmentations including new feeders to maintain UE's energy-at-risk for high-voltage feeders;

- Augmenting 10 existing 66kV sub-transmission lines and establishing 4 new sub-transmission lines to maintain UE's energy-at-risk for sub-transmission assets;
- Approximately 100 distribution transformer and/or LV circuit augmentations per annum but declining over the period to around 70 per annum to maintain distribution transformer energy-at-risk.

Coming into the 2016-2020 regulatory price review period, the augmentation plan derived from this planning approach for the next regulatory period includes the following key major investments on the UE network:

- 3 new zone substation transformers (DMA, NO, DC) at UE's existing zone substations, and 1 new single-transformer zone substation (SKE) to maintain UE's energy-at-risk for zone substations;
- 32 high voltage feeder augmentations (including new feeders) to maintain UE's energy-at-risk for high-voltage feeders;
- Augmenting 3 66kV sub-transmission lines and establishing 2 new sub-transmission lines to maintain UE's energy-at-risk for sub-transmission assets;
- Approximately 80 distribution transformer and/or LV circuit augmentations per annum to maintain distribution transformer energy-at-risk.

An ongoing investment in distribution substations and the low voltage network is required to effectively mitigate the risk of further plant failure due to thermal overload predominantly due to air-conditioning load during hot weather and the impacts of solar PV installations pushing up steady state voltage.

To improve low voltage network performance under future heatwave situations and to accommodate increasing penetrations of solar PV, UE has developed systems and processes to leverage the Advanced Metering Infrastructure (AMI). We can now provide day-behind monitoring of highly-loaded distribution substations and low-voltage circuits. The benefits of these investments has been to identify local capacity constraints prior to equipment failure thereby reducing prospective equipment damage and avoiding prolonged supply interruptions to customers at time of extreme heat. UE is also developing up capabilities to manage peak demand in other ways including the use of demand management, distributed generation and storage.

2.4. Customer-Initiated Capital (CIC)

The Customer Capital expenditure consists of three major components:

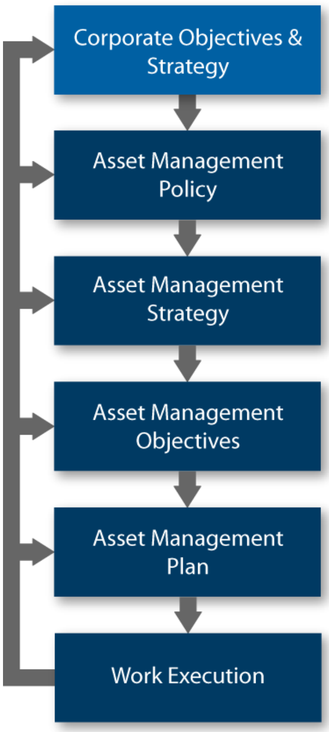
- Business Supply Projects;
- Urban Residential Supply and Urban Multiple Occupancy Supply; and
- Recoverable Works.
- New Public Lighting Projects

The internally-developed CIC model forecasts expenditure based on relevant industries growth indices derived from construction activity forecasts provided by the Australian Construction Industry Forum (ACIF).

3. Asset Management Alignment

This Demand Strategy & Plan forms a key role within the overall United Energy Asset Management System and in ensuring a clear 'line-of-sight' between the company's activities on the ground, and the overall Vision, Organizational Strategic Plan and Objectives. This is shown in the diagram below.

Figure 3-1: Fit within Good Practice 'Line-of-Sight

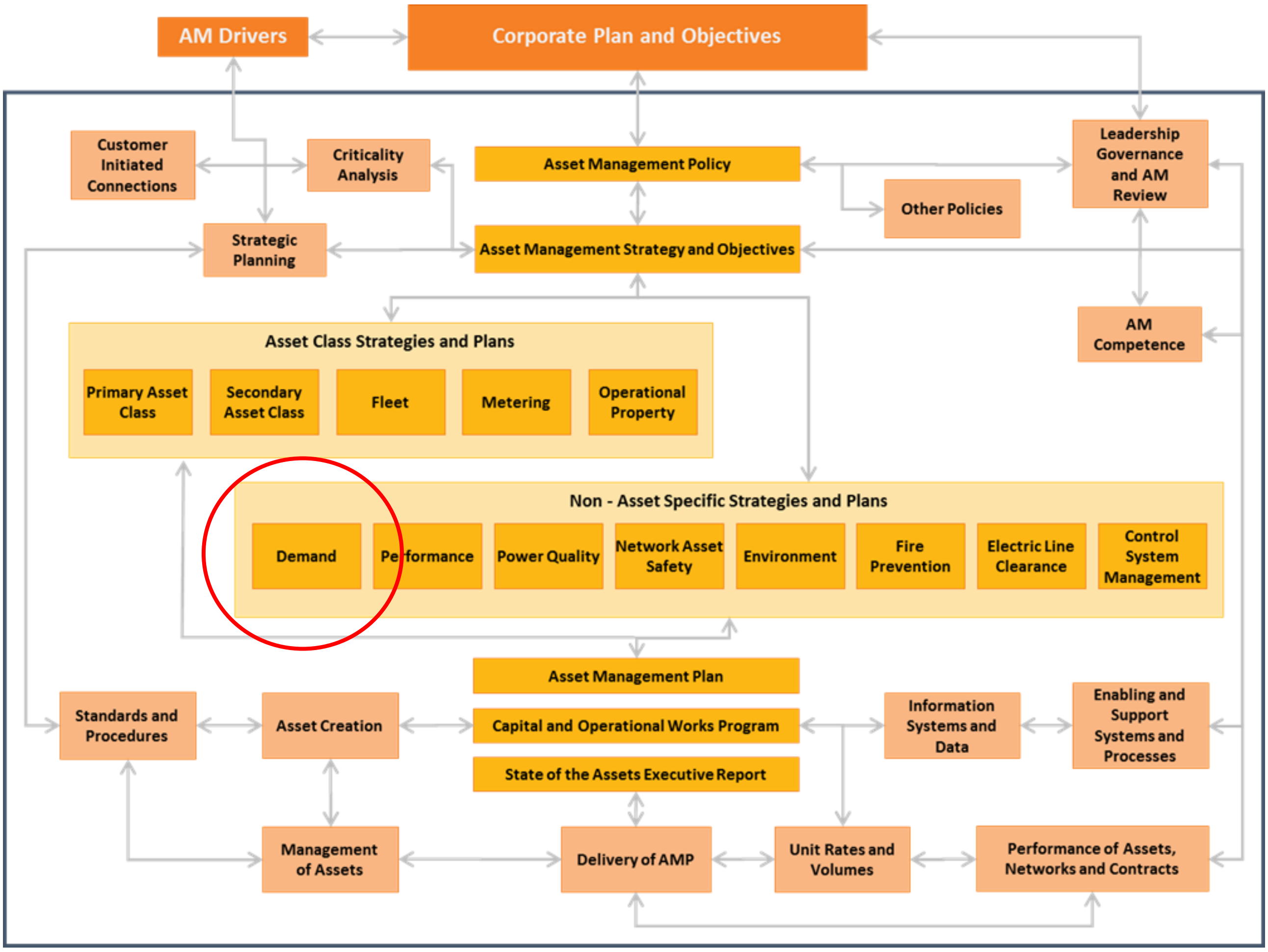


Specifically, this Demand Strategy & Plan (UE PL 2200) incorporates the key elements of both the Asset Management Strategy and the Asset Management Objectives, for augmentation and customer connections. The Demand Strategy & Plan itself includes the key principles and objectives for the management of network utilisation and risk as described in the Asset Management Policy. However, this document supplemented by our Distribution Annual Planning Report (UE PL 2209), through our thorough, comprehensive and transparent approach to Asset Management, evidences and justifies augmentation that support the delivery of the required outputs (e.g. safety, asset and network capacity, capability and service reliability, and availability). It also evidences that this is planned to be achieved with risk controls and where appropriate, at minimum whole-life, whole-system cost.

This document's role within the overall United Energy Asset Management System is shown below. This diagram also shows the incorporation of existing UE documents into the whole Asset Management system to align with the requirements of ISO 55000.

The Demand Management and DMIS Strategy (UE PL 2210) is intended to accompany this Demand Strategy & Plan in the Asset Management System to facilitate development of our demand management, distributed generation and storage capabilities.

Figure 3-2: Role in Asset Management System



4. Demand Strategy

4.1. Introduction

This Demand Strategy sets out the strategy to meet the forecast customer connection and maximum demand growth requirements in the UE service area over the next 20 years, preserving existing levels of reliability. UE approaches reliability in the context of condition-based plant ratings, probabilistic risk assessment of loss-of-supply, customer valuation of reliability and contingency planning, consistent with Chapter 5 Part B of the National Electricity Rules (NER) and prudent asset management.

The projections in this Demand Strategy & Plan are underpinned by new connection and summer maximum demand forecasts developed by UE and supported by an independent assessment of maximum demand growth by the National Institute of Economic and Industry Research (NIEIR). The NIEIR index is specifically tailored to predicting maximum demand growth on the UE electricity network and while this index has proven to be a reliable index for predicting demand, UE has strengthened its in-house top-down maximum demand forecasting capabilities by leveraging off the work that AECOM has recently completed with the development of an internal load forecasting method and tool based on the eViews software package.

This Demand Strategy & Plan covers the 20-year period from 2015-2016 to 2034-2035. Given the long-term nature of this plan and hence the increasing uncertainty in later years, three forecast maximum demand scenarios have been developed to capture the likely impacts of foreseeable changes in customers' electricity usage behaviour over time using modelling results provided by Acil Allen[1] and NIEIR[2]. The base case scenario is formulated on a growth scenario which represents the most likely growth scenario based on information we have today about future changes in customers' electricity usage, while the two sensitivities represent a higher growth scenario and a lower growth scenario based on credible variations in the assumptions used for the base (business-as-usual) case. All scenarios assume a base economic growth forecast which is considered the most appropriate forecast to use for long-term planning.

The capital expenditure programme provided with this Demand Strategy & Plan is developed from the base case scenario using a bottom-up approach, identifying specific emerging network constraints against network loading capabilities based on:

- Base (expected) economic growth summer maximum demand forecasts with a weighted 10th and 50th percentile probability of exceedance (PoE) for temperature;
- 40°C ambient temperature rating;
- 3m/s summer wind velocity with a direction of 15° from conductor axis for overhead conductors outside the zone substation;
- 0.61m/s summer wind velocity with a direction of 90° from conductor axis for equipment inside the zone substation;
- Soil thermal resistivity of 0.9 °Cm/W for all zone substations with the exception of SS, STO, RBD and FTN where an average figure of 1.2 °Cm/W is utilised; and
- Transformer Winding Hot Spot Temperature (WHST) of 140^{o}C with units >30 years old using WHST of 130^{o}C.

The constraints are then addressed with proposed network or non-network augmentations consistent with the Asset Management objectives which are to:

1. Minimise harm to people, property and environment;

[1] Part B – Demand Forecasting 2014 Report – "Electricity Consumption Forecasts – Post Model Adjustments" – Acil Allen, 30th April 2014

[2] Part B – Demand Forecasting 2014 Report – "Energy, Demand and Customer Number Forecasting for United Energy to 2025" – NIEIR, 14th May 2014

2. Comply with all relevant legislation and regulation obligations;
3. Ensure prudent and efficient investment;
4. Identify and manage risks to as-low-as-reasonably-practicable;
5. Understand and meet customer expectations; and
6. Develop an asset management team of capable and engaged people.

The objectives of the Demand Strategy & Plan are to:

- manage network electrical losses, consistent with Asset Management Objective 1;
- provide capacity for customers' maximum demand growth requirements according to the requirements of the RIT-D, the NER, the Victorian Electricity Distribution Code, and UE's Network Planning Guidelines (UE GU 2200) and Network Planning Policy (UE PO 2200), consistent with Asset Management Objective 2;
- plan economically viable investments within the capital budget allowance, consistent with Asset Management Objective 3.
- maximise asset utilisation while avoiding damage to plant due to overloads with a prudent risk management contingency plan, consistent with Asset Management Objective 4; and
- maintain system reliability, consistent with Asset Management Objective 5.

To balance these sometimes conflicting objectives, UE has adopted a probabilistic approach to network planning which tolerates a manageable level of risk for loss of supply in circumstances involving outage of critical plant at infrequent times of high network loading. A probabilistic approach leads to an optimised allocation of expenditure across the network. Implicit in its use however, is the acceptance of a certain degree of risk and, when supplemented by contingency planning, provides a better economic outcome than deterministic planning.

UE's current Contingency Plans (UE MA 2204) consist of a suite of risk mitigation and controls including:

- emergency switching instructions at the distribution and sub-transmission levels to transfer demand from one zone substation or terminal station to another with implementation times between 10 minutes and 2 hours;
- emergency voltage reduction to temporarily reduce demand by up to 5% on a particular zone substation for up to 2 hours;
- one 66/11kV and one 66/22kV relocatable transformer that can be redeployed to a suitable zone substation within 48 hours; and
- an established emergency management structure to respond to mobilise resources to respond to emergencies.

The aim of this Demand Strategy & Plan is to continually improve the management of peak demand and its impact on end user electricity prices through the optimisation of the network augmentation capex works program (including leveraging new technology or planning solutions), while giving due consideration to alternative non-network solutions where opportunities exist to provide economical network support. Non-network solution proponents are provided the opportunity to defer a network solution through the publication of planning reports which highlight upcoming network constraints, joint planning initiatives with UE and the RIT-D process. Solutions offered by non-network proponents may include demand management, avoided demand with the use of alternative energy sources, energy storage or embedded electricity generation. UE currently offers network tariffs that provide incentives to encourage demand management and power factor correction by customers connected to our network at times of peak demand. The ability for non-network proponents to offer credible solutions has improved with the introduction of the RIT-D process on 1st January 2013 for proposed network augmentation projects above $5M in value. It is anticipated that non-network solution proponents would enter into Network Support Agreements (NSA) with UE to provide services to defer a proposed network solution in return for an opex payment commensurate with the deferral value of the network solution and the reliability provided. UE has already developed a standard NSA.

UE's Demand Management & Demand Management Incentive Scheme (DMIS) Strategy (UE PL 2210) also seeks to increase UE's suite of demand management capabilities over time to better manage peak demand, particularly in an environment of increasing uncertainty in maximum demand growth. UE has been using the DMIS allowance to explore opportunities for managing peak demand in other ways including demand management and storage trials.

This Demand Strategy & Plan maintains existing levels of reliability performance on the distribution system consistent with UE's current objectives; however UE plans to explore opportunities for increased utilisation without increased energy-at-risk to reduce capex requirements with initiatives such as:

- a more secure zone substation topology with the installation of 66kV line circuit breakers in lieu of more expensive additional zone substation transformers in instances where adequate transfer capacity exists to further increase zone substation utilisation. Coupled with a dynamic ratings and load shedding scheme in the Distribution Management System (DMS), this will allow operation of the zone substations above their 10-minute emergency short term ratings, a present operational constraint for our zone substations.
- moving to a more meshed sub-transmission arrangement which allows substantial increases in utilisation of sub-transmission lines while maintaining current overall sub-transmission system utilisation levels. This will require modifications to the transmission load shedding schemes. A pilot scheme is currently being established at Tyabb Terminal Station with UE jointly working with AusNet and AEMO.
- use of aggregated AMI data to more accurately target distribution substation augmentations and hence increase the average utilisation of UE's fleet of distribution substations.
- a more incremental or alternative approach to capacity based augmentation using non-network solutions and alternative technologies such as the Virtual Power Plant (VPP).
- use of incentivised voluntary customer demand management programmes;
- allowing demand on existing under-utilised assets to increase without augmentation which will naturally increase average utilisation levels.

These measures could lead to substantive savings in capex going forward with negligible impact on reliability.

The Demand Strategy & Plan includes network augmentation and new customer connections projects required to cater for new customer connections and increased load requirements of existing customers for the next 20 years. Based on the projects proposed in this Demand Strategy & Plan, the following diagrams show the UE network as it presently is in 2014-2015 and the likely network required to support the base case forecast 2034-2035 maximum demand scenario.

Figure 4-1: UE Network in 2015

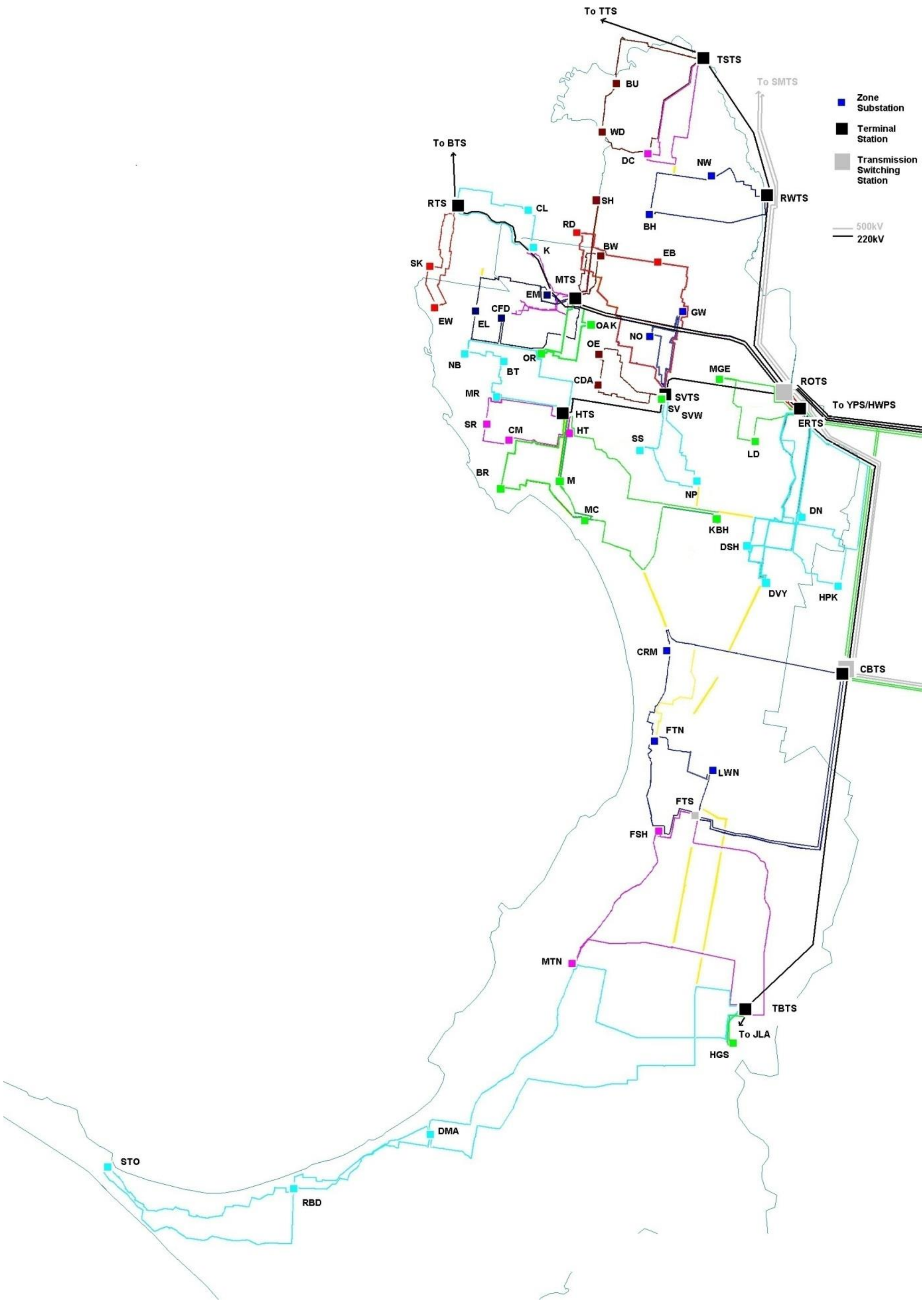
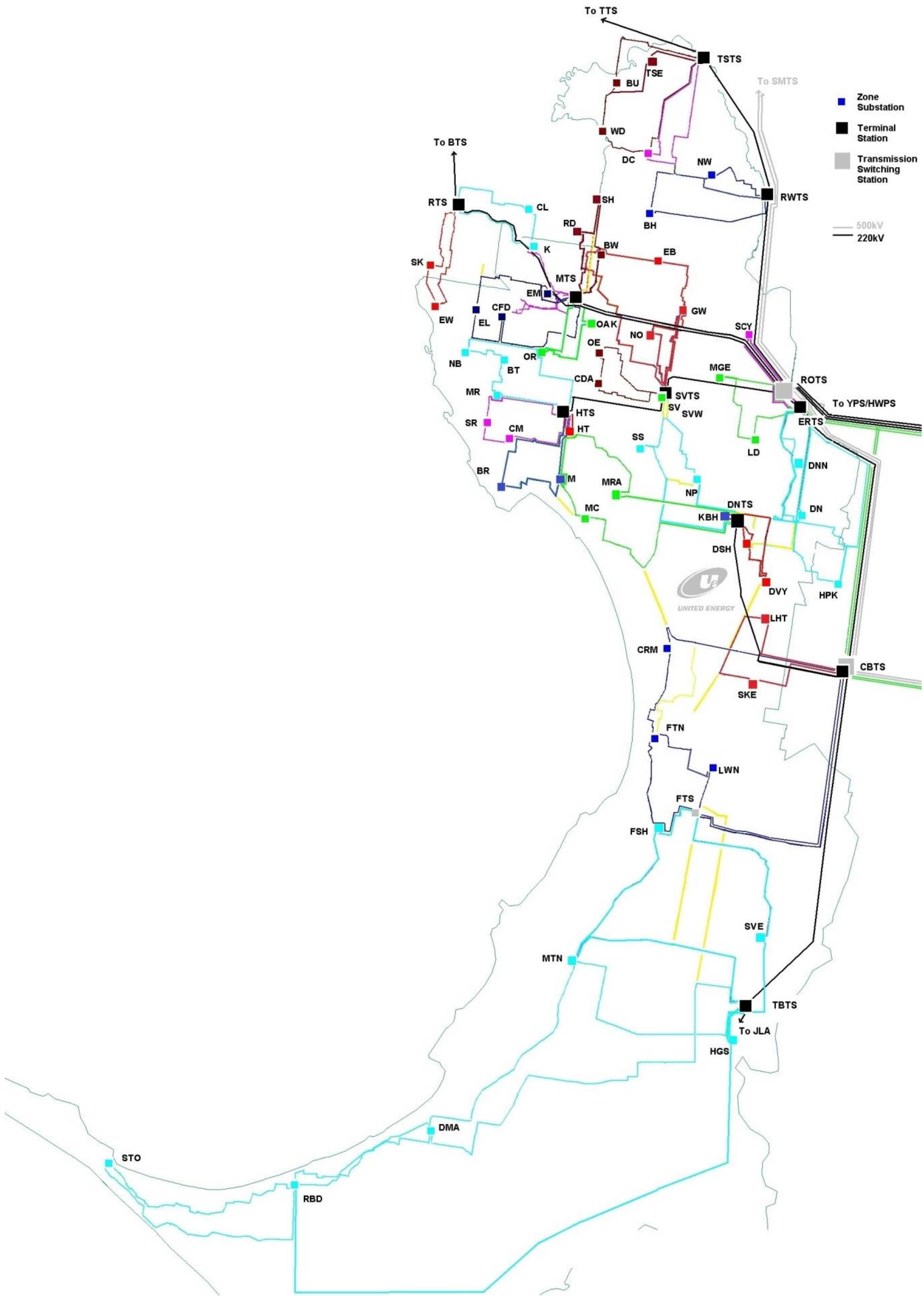


Figure 4-2: UE Network in 2035

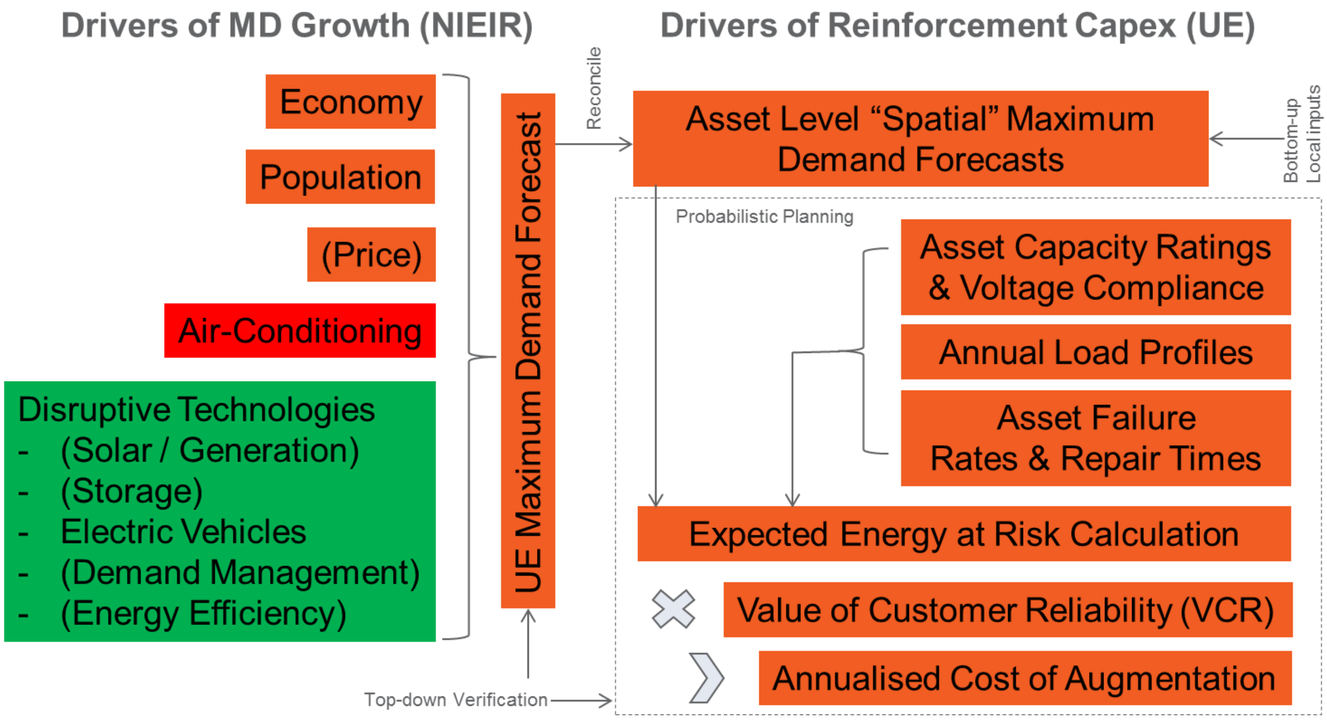


4.2. Factors Influencing Demand Growth Investment

The primary driver for Demand capital expenditure is the growth in maximum demand within localised parts of the UE distribution network where there is a local capacity constraint. While UE forecasts maximum demand for the overall UE supply area (boundary load), it is the lower-level forecasts that drive capital expenditure. Maximum demand forecasts are developed by UE at the transmission connection asset level, sub-transmission level, zone substation level, distribution feeder level and distribution substation level for each asset.

Economic growth, population growth and increased penetration of temperature sensitive load such as air-conditioning and evaporative cooling over the last 15 years have been the major drivers for maximum demand growth in the UE service area. A number of potentially significant emerging developments are occurring or about to occur in the way customers use their electricity and these developments will ultimately have a measurable impact on the maximum demand growth (either positive or negative) and therefore UE's augmentation capital expenditure. Increased use of distributed embedded generation stimulated through reduced technology cost, subsidies and increased environmental awareness is already being experienced with solar photovoltaic panels. This is likely to continue as well as the emergence of new technologies. Furthermore, electric vehicles, distributed storage and demand management applications are also on the horizon, all having various impacts on maximum demand growth. Tri-generation technology that replaces electricity as a source of heating and cooling using distributed hot water and chilled water with electricity generation as a by-product, could also impact UE's peak demand with such a scheme proposed at Doncaster Hill.

Figure 4-3: Drivers influencing UE's Demand Growth Investment



The above chart shows how the various drivers feed into influencing UE's Demand capital expenditure. The economy, population and retail electricity prices have traditionally had the largest effects on UE's maximum demand growth. Over the last 15 years, air-conditioning (cooling) has been a significant influence causing maximum demand to switch from winter to summer across the entire network. These parameters are all factored into the macro-economic forecasting model prepared by NIEIR. Following the modelling of the maximum demand and verification through UE's eViews model, the disruptive technologies are separately modelled and applied to the forecasted maximum demand as post-model adjustments. The overall forecast is then reconciled against the bottom-up build of asset level "spatial" maximum demand forecast developed from localised information about customer connections and changes in customer demand. The probabilistic planning approach detailed in our Energy at Risk Assessment Tools Procedure (UE PR 2210) and our Network Planning Guidelines (UE GU 2200) is then applied to assess whether (and when) identified constraints can be economically relieved with an augmentation investment. If it can, the project is entered into the forecast Augmentation works programme for the required year. The bottom-up build of Augmentation works is then verified against the top-down approach and other tools such as the AER's Augex model.

4.2.1. Economic Growth

UE engages NIEIR each year to provide a whole-of-UE service area maximum summer and winter demand forecast for ten years. The forecasts are provided by NIEIR based on a low, base (expected) and high macro-economic growth basis. The base economic growth forecast is always used for forecasting UE's long term growth capital requirements as this represents the best estimate of expected longer-term economic growth. While the high and low economic growth scenarios are useful for assessing the impacts of short term changes in the economy on maximum demand, over the long term it is highly unlikely that the economy will continue to maintain successive years of above or below baseline economic growth given the cyclic nature of economic growth.

Total gross regional product (GRP) for the UE region is expected to rise by an average rate of 1.4 per cent between 2015 and 2025, below the forecast Victorian average growth rate of 1.7 per cent over this period. The middle eastern suburbs of Melbourne are experiencing high rates of growth due to their access to infrastructure, such as transport, health and education, as well as major shopping centres.

The ongoing uncertainty surrounding the global and Australian economic situation is likely to have an ongoing dampening effect on growth, especially energy growth. While the Australian economy has proved to be fairly resilient to date, there has been a slowdown in the mining and manufacturing sectors with weaker commodity prices and recent large factory closures which are having flow-on effects to the rest of the Australian economy. NIEIR has therefore reduced its maximum demand forecasts for UE from the maximum demand forecasts provided last year. This result has been verified by UE's eViews maximum demand forecasting model. This lower growth will have deferral impacts on UE's augmentation capex requirements.

Table 4-1: Change in NIEIR 10% PoE UE Summer Maximum Demand Forecast

10% PoE UE Maximum Demand	2014 Forecast	2013 Forecast	Change
2014-2015 Summer	2163 MW	2294 MW	(5.7%)
2023-2024 Summer	2596 MW	2651 MW	(2.1%)
Ten Year Horizon Growth Rate	1.7 % pa	1.7 % pa	0.0%

Table 4-2: Change in NIEIR 50% PoE UE Summer Maximum Demand Forecast

50% PoE UE Maximum Demand	2014 Forecast	2013 Forecast	Change
2014-2015 Summer	1942 MW	2093 MW	(7.2%)
2023-2024 Summer	2294 MW	2427 MW	(5.5%)
Ten Year Horizon Growth Rate	1.4 % pa	1.7 % pa	(0.3%)

UE allocates the NIEIR forecast maximum demand growth across its assets by assessing the localised variation in economic growth throughout the UE service area such that the bottom-up build of coincident maximum demand forecasts, taking into account network losses, matches the top-down forecast provided by NIEIR. The method by which UE does this is contained in document UE PR 2200.

This Demand Strategy & Plan assumes NIEIR's official 2014 base economic growth summer maximum demand forecast for all scenarios up to 2024-2025. Beyond this time, in the absence of any better data, the forecast demand is projected up to 2034-2035 using a curve of best fit through the NIEIR forecast, then adjusted for the three scenario assumptions discussed in section 4.3.

4.2.2. Population Growth

The population in Melbourne is projected by the Australian Bureau of Statistics to increase substantially over the 20 years effected by a number of factors including increased international migration, natural increase due to higher birth rates, interstate and intrastate migration.

The highest contributors to the increase in population are international migration and natural increase, with the number of people moving interstate or between metropolitan regions and rural regions considered to be minimal in terms of Victoria for the next 20 years. The increase in Melbourne's population can theoretically be applied proportionally to the population within the UE network as much of the network falls within the metropolitan region.

As shown below the short-term growth is quite large with the population of Melbourne increasing by 12.5% within the next five years. Nearly half of this increase can be attributed to international immigration, meaning that these people are likely to directly impact the maximum demand growth, especially in high urban growth and infill areas within the UE network.

Table 4-3: Melbourne Population Forecasts to 2034

Melbourne Population Forecast							
Year	Forecast Time	High		Mid		Low	
		Gross	%	Gross	%	Gross	%
2012	Actuals	4248344	N/A	4248344	N/A	4248344	N/A
2013		4338526		4335684		4333558	
2014	1	4429118	2.1%	4422724	2.0%	4419383	2.0%
2015	2	4523133	4.3%	4513519	4.1%	4508434	4.0%
2016	3	4620314	6.5%	4605993	6.2%	4597943	6.1%
2017	4	4719765	8.8%	4699149	8.4%	4686535	8.1%
2018	5	4820767	11.1%	4792223	10.5%	4773242	10.1%
2019	6	4923271	13.5%	4885136	12.7%	4858195	12.1%
2024	11	5453746	25.7%	5347459	23.3%	5258367	21.3%
2029	16	6002748	38.4%	5803768	33.9%	5631230	29.9%
2034	21	6561559	51.2%	6251951	44.2%	5985303	38.1%

Total population in the UE region is expected to increase steadily over the projection period. An increase of around 150,000 persons is projected between 2015 and 2025 under the base scenario, giving an average annual growth rate of 1.0 per cent compared to 1.3 per cent average for Victoria.

The strongest increase in population over the 2015 to 2025 period was in Southern Outer (1.4 per cent per annum). Population growth remains modest in the southern inner and south eastern areas of Melbourne. Urban infill and apartment construction is impacting on many areas within UE's service area as a result of changes to planning regulations and strong underlying demand for dwellings within 20 kilometres of the Melbourne CBD.

The total dwelling stock within the UE region is forecast to grow by an average rate of 1.1 per cent under the baseline scenario between 2015 and 2025. This compares to a growth rate across total Victoria of 1.6 per cent per annum over the same period. The strongest increases in the dwelling stock are in the Mornington Peninsula Local Government Area. The total stock increases by an average rate of 1.6 per cent between 2015 and 2025 in Mornington Peninsula outer statistical sub-division.

4.2.3. Prices

Increasing retail electricity prices (in real terms) over recent years has put downward pressures on maximum demand growth. However current tariff structures mean that higher prices principally affect energy consumption rather than maximum demand. Customers implementing energy efficiency, reduced energy consumption and distributed generation in response to price have a much bigger impact on annual energy consumption than it does on maximum demand. Nevertheless, the impact of price is captured in the macro-economic maximum demand forecasting model.

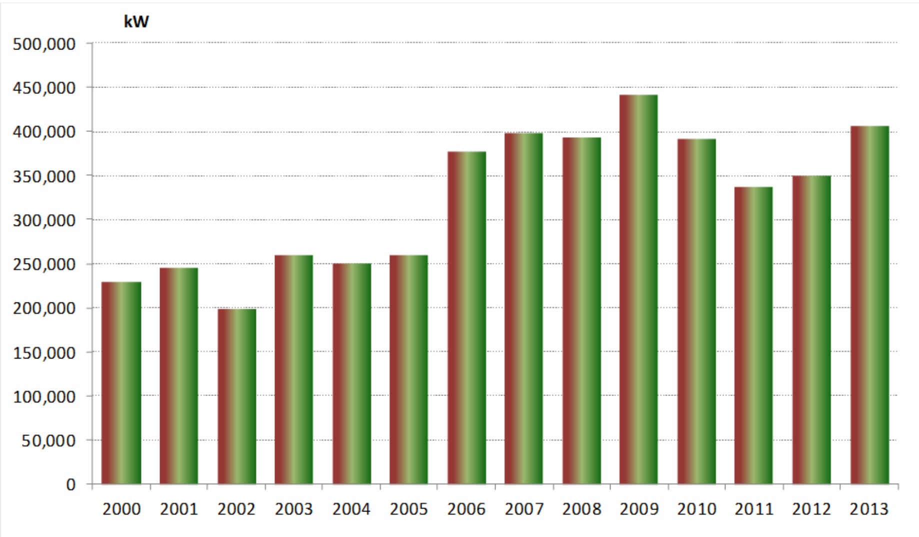
4.2.4. Temperature Sensitive Load

Over the past decade there has been a trend of divergence between average demand (energy) and weather-corrected peak demand, with peak demand the principal driver of network augmentation investment. This peak demand has a significant cost impact on the entire electricity network, from generation through to the end customer. This is because the network (and generation capacity) must be built to accommodate the peak demand regardless of the energy consumed and generally peak demand only occurs for a fraction of the year due to the high sensitivity of the load to high ambient temperatures. If the peak demand grows at a faster rate than the energy consumed, the average utilisation[3] of the network falls and therefore the cost of delivering electricity increases. This is compounded by the fact that at higher ambient temperatures (and hence higher demand), the rating of network assets reduces. This increasing 'peakiness' of the demand also causes uncertainty in the forecasting of load on the network such that traditional network planning techniques for forecasting network upgrades based on quarterly consumer consumption data is becoming increasingly unreliable. Increased monitoring through SCADA, AMI and other devices deployed in the field is seen as a way of better managing this uncertainty into the future and UE has now incorporated this information into our business-as-usual network planning processes through the Network Load Management (NLM) and OSI-PI information systems.

Peak demand growth exceeding energy growth has been anecdotally attributed to the growing affluence of the average electricity consumer who is increasingly installing energy intensive devices such as air conditioning to be used during hot weather but also implementing energy efficiency initiatives through the rest of the year. The marginal cost of supply escalates exponentially on days of extreme peak demand because of the need to invest in infrastructure that is only utilised for small proportions of the time to cover the short duration peaks. Air conditioning has had a significant impact on the UE summer maximum demand to the point where virtually all areas of the network are now peaking in summer, that is, the ratio of the maximum demand to the asset rating is the highest in summer.

Total Victorian airconditioning sales remain strong as indicated below.

Figure 4-4: Total annual air-conditioner sales in Victoria (2000 to 2013)[4]



[3] Average utilisation is equal to the peak utilisation multiplied by the load factor.

[4] Includes new and replacements – total installed capacity purchased.

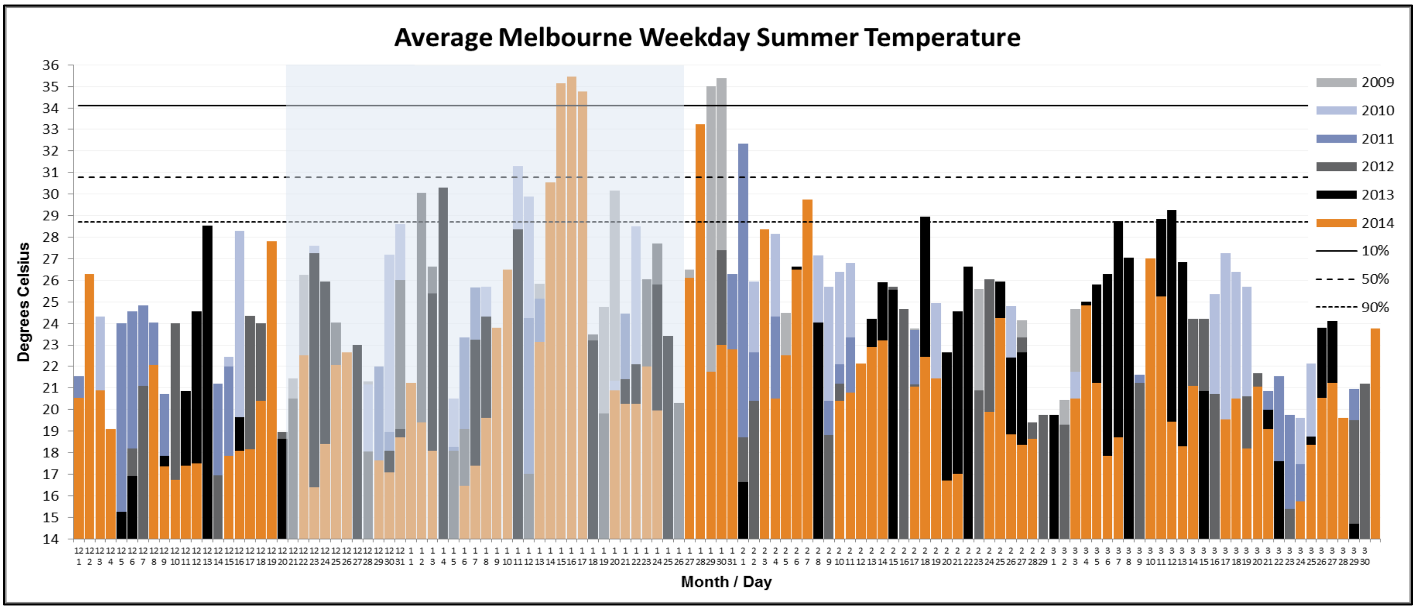
The sensitivity of the demand to high ambient temperatures and in particular consecutive hot weekdays requires a probability to be assigned to the weather conditions to quantify the chances of the demand exceeding the maximum demand forecast one or more times in any given summer. Three weather probabilities of exceedance are defined, 10%, 50% and 90% and each of these are associated with a particular average temperature condition based on the daily minimum and the daily maximum temperatures. Using 50 years of historical temperature data, the temperature conditions which achieve these probabilities based on average daily temperature (arithmetic average of the daily minimum and the daily maximum) are shown below.

Table 4-4: Average Summer Day Temperatures (1959/60 to 2013/14)

Probability of Exceedance (PoE)	Melbourne	Scoresby	Cerberus
10th Percentile	34.7º C	33.4º C	31.4º C
50th Percentile	31.5º C	-	-
90th Percentile	29.4º C	-	-

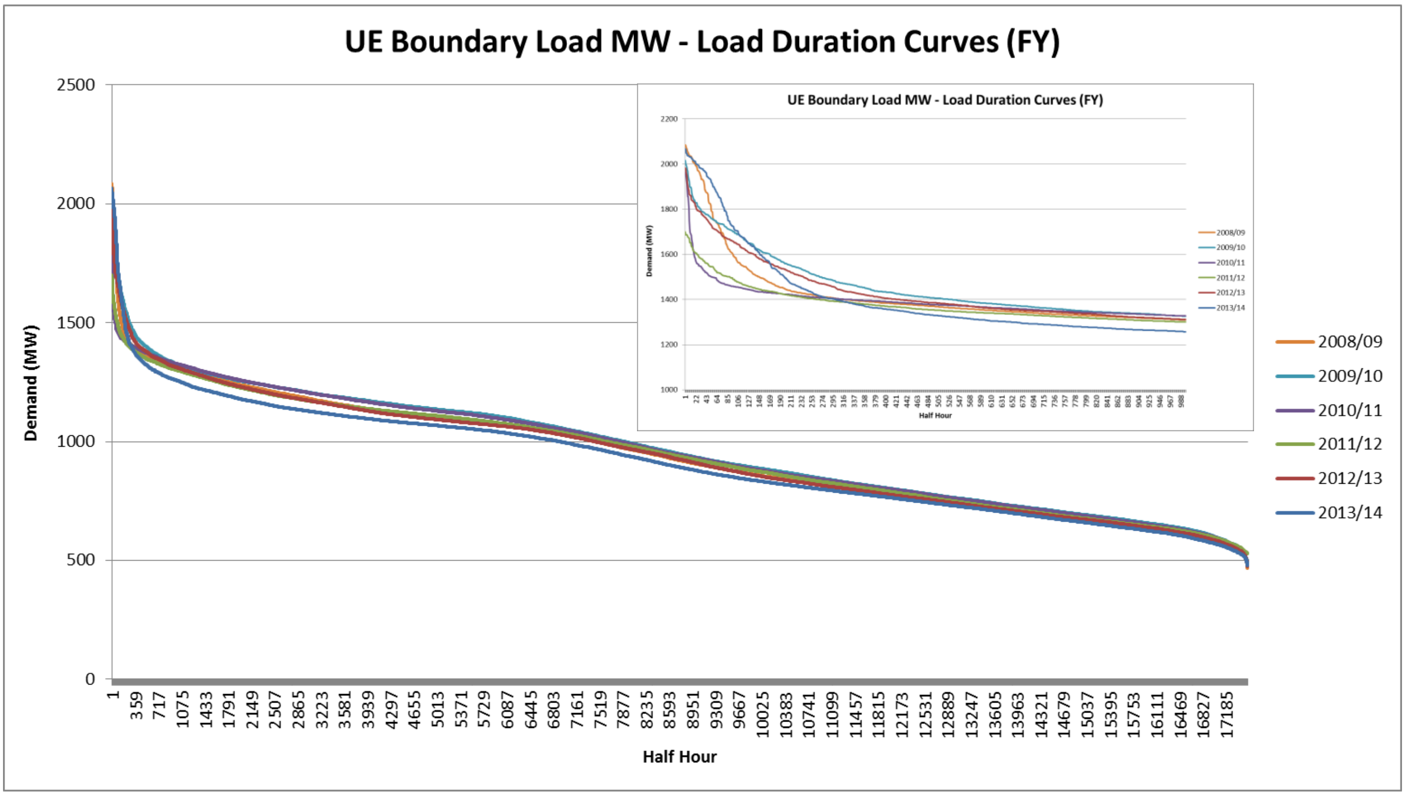
Based on the above, if the average Melbourne daily temperature on a day reaches 34.7ºC, then the weather condition is considered to be a 1 in 10 year event (generally referred to as 10th percentile probability of exceedance, or 10% PoE). The forecast maximum demand associated with this particular temperature condition is referred to as a 10% PoE forecast maximum demand. The recent historical average weekday temperature profile for Melbourne is shown below. The shaded area represents the industry shutdown and school holiday period for which maximum demand is expected to be lower.

Figure 4-5: Recent historical temperature profile



The 2013/14 load duration curve presented below demonstrates that the top 750MW of the approximately 2000MW peak is used for less than 5% of the year (440 hours per annum). Furthermore, the top 500MW is used for less than 1.5% of the year (130 hours per annum), all of which occur on hot summer days.

Figure 4-6: UE's Historical Load-Duration Curves



This Demand Strategy & Plan assumes NIEIR's official 2014 summer maximum demand forecast for all scenarios up to 2024-2025. Beyond this time, the forecast demand is projected up to 2034-2035 using a curve of best fit through the NIEIR forecast, then adjusted for the scenario assumptions discussed in section 4.3.

4.2.5. Distributed Generation (Large)

Connection of large distributed generation to the UE network is dealt with on a case-by-case basis via the formal National Electricity Rule (NER) connection application process with proponents funding the full cost of any augmentation of the electricity network to allow for the connection. Such funding may typically include fault level mitigation works or protection system upgrades. UE's embedded generation connection standard is contained in document UE ST 2008. Large generators are excluded from UE's forecast demand unless a formalised Network Support Agreement (NSA) is in place to enable a generator to alleviate a network constraint and defer a planned network augmentation. In the absence of a network support agreement, large generators are not considered in the planning process and have no impact on UE's network development plans because they cannot be relied upon to be operating at critical network loading periods. UE does not presently have any NSAs in place with any generators however this is likely to change with the introduction of the RIT-D. UE has developed an NSA with standard terms and conditions for the RIT-D. Despite the absence of any existing NSAs, there are currently a number of large embedded generating units connected to the UE distribution network. A summary of these generators is provided below along with their typical operating characteristics:

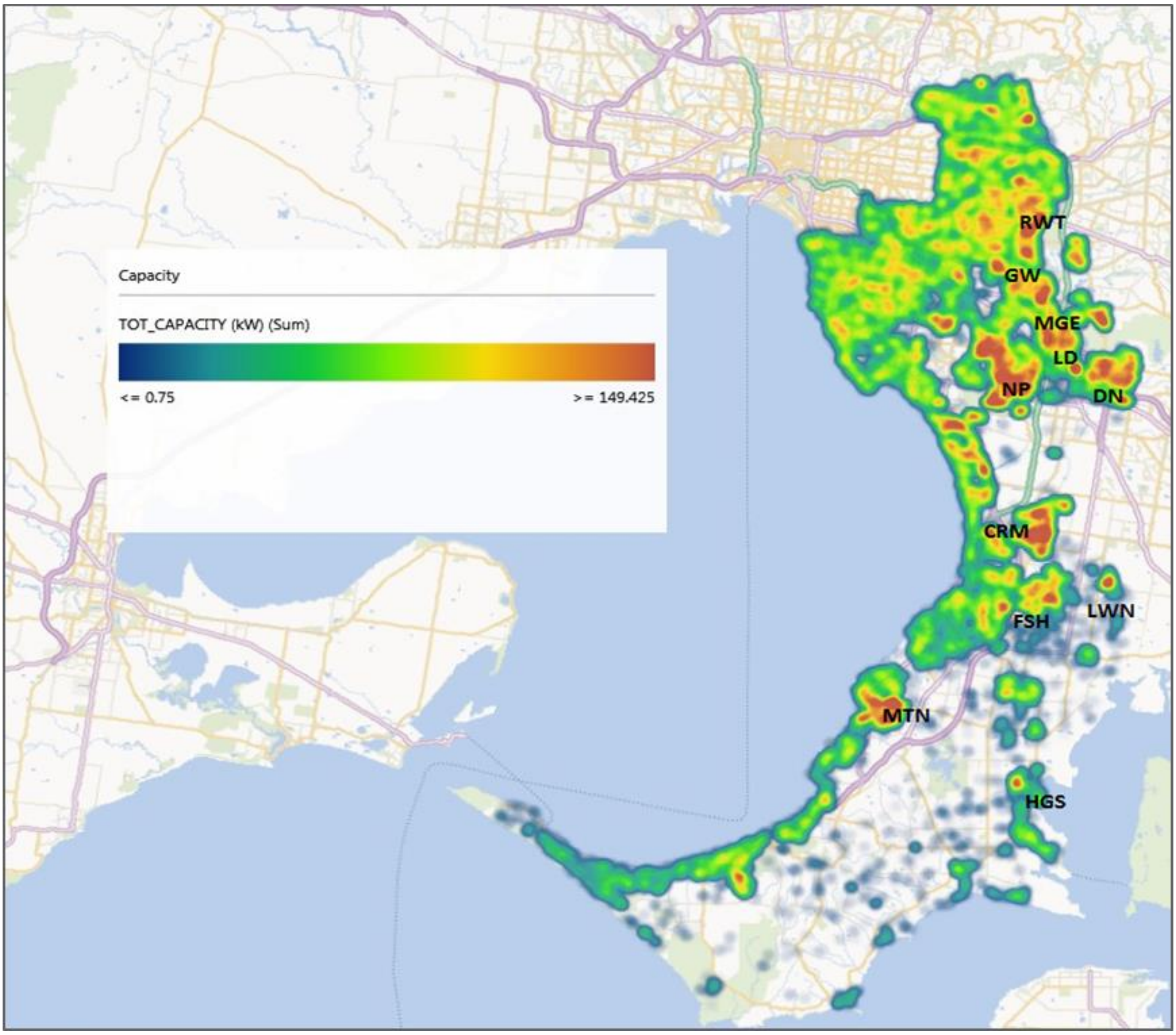
Table 4-5: UE Network connected large generators

Site	Connected to	United	Fuel Type	Comments
Dandenong PEP	DN ex ERTS34	1 x 2,576kVA unit	Natural Gas	In service from 7:00am to 11:00pm Mon to Fri.
Dandenong Hospital	DN ex ERTS34	1 x 7,375kVA unit	Natural Gas	In service from 7:00am to 11:00pm Mon to Fri but likely to reduce its peak output to less than 1000kVA from 2013.
Eastern Treatment Plant (ETP)	CRM ex CBTS	7 x 1,680kVA units	Sludge gas	Units are brought into service as required by ETP
Clayton Landfill	SS ex SVTS12	11 x 1,460kVA units	Landfill gas	Units are brought into service, from 7:00am to 11:00pm Mon to Fri, as required service
Springvale Landfill	SS ex SVTS12	4 x 1,275kVA units	Landfill gas	Units are brought into service, from 7:00am to 11:00pm Mon to Fri, as required service
Rye Landfill	STO ex TBTS	1 x 1,000kVA unit	Landfill gas	In service 24 hours/day, 7 days/week
Mornington	MTN ex TBTS	1 x 650kVA unit 1 x 813kVA unit	Diesel	In service when required by operator
Notting Hill	NO ex SVTS34	1 x 450kVA unit	Hydro	In service when required by operator
Glen Waverley	GW ex SVTS34	1 x 560kVA unit	Hydro	In service when required by operator
Box Hill Hospital	DC ex TSTS	1 x 1200kVA unit	Trigeneration	Expected to be commissioned in late 2014
Telstra Data Centre	SVW ex SVTS12	8 x 2000kVA unit	Diesel DRUPS	Expected to be commissioned in late 2014

4.2.6. Distributed Generation (Solar PV)

Small generators up to 30kW three-phase or 10kW single-phase with inverters compliant with AS4777, have automatic access to the UE network, that is, they are not required to submit a formal connection application under the NER, but a simplified connection form advising UE of the connection. Given the large volumes and diversity of micro-embedded generation, these generators are catered for in UE's demand forecasts as negative loads. Hence the level of uptake of micro-generators can potentially have an impact on UE's network development plans, particularly as they do not fund any deep connection costs. It is therefore important that UE attempts to forecast the uptake of micro-embedded generators and assess their impacts on the network development plans and capex programme. To date, the only significant form of micro-generation has been solar PV making up more than 99% of the micro-generation connected to UE's network. The following chart shows the locational density of solar PV installed on UE's network. Clustering of solar PV is predominately occurring in the outer suburban areas of UE's service area.

Figure 4-7: Density ofSolar PV



The historical capacity and volumes of distributed solar PV within the UE service area is shown below.

Figure 4-8: Actual Small Scale Solar PV uptake (cumulative)

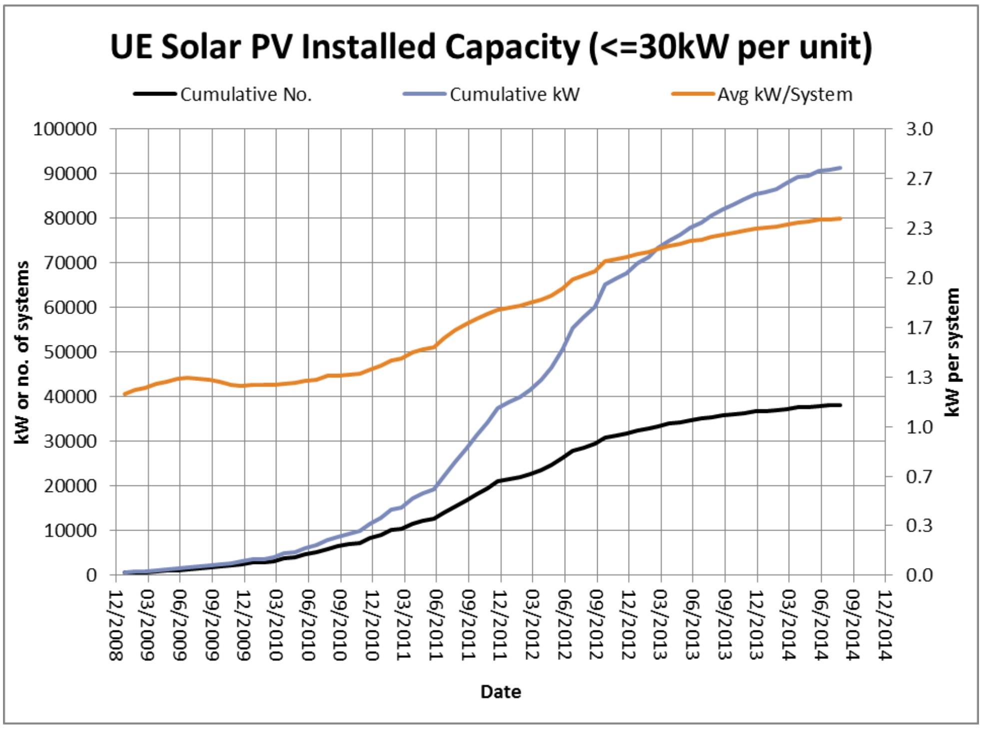
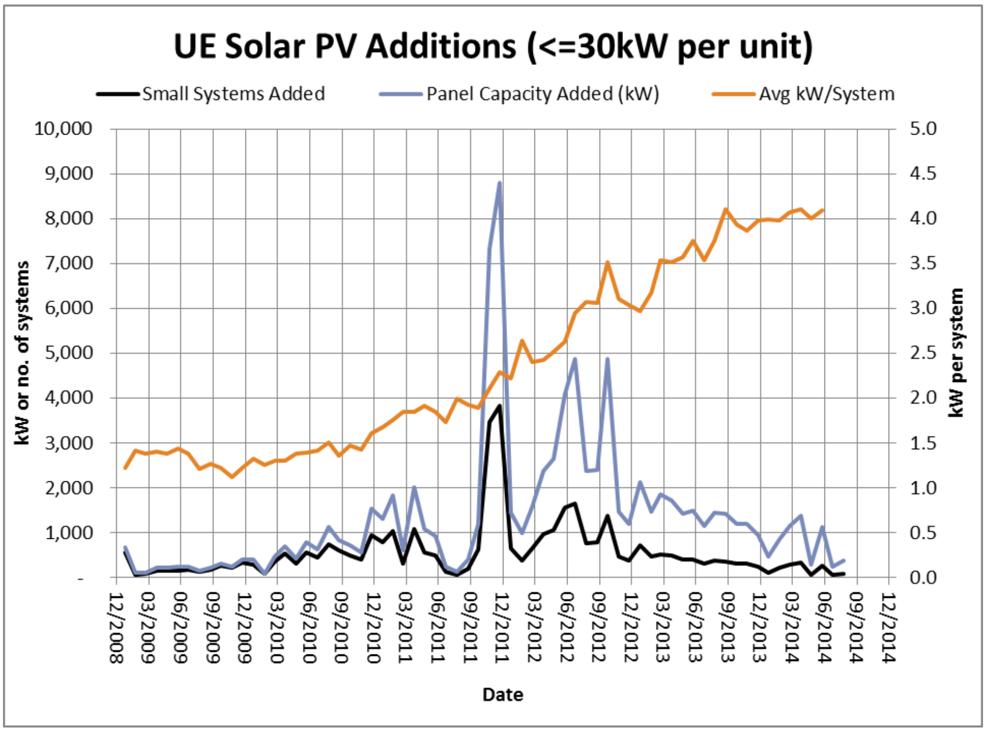
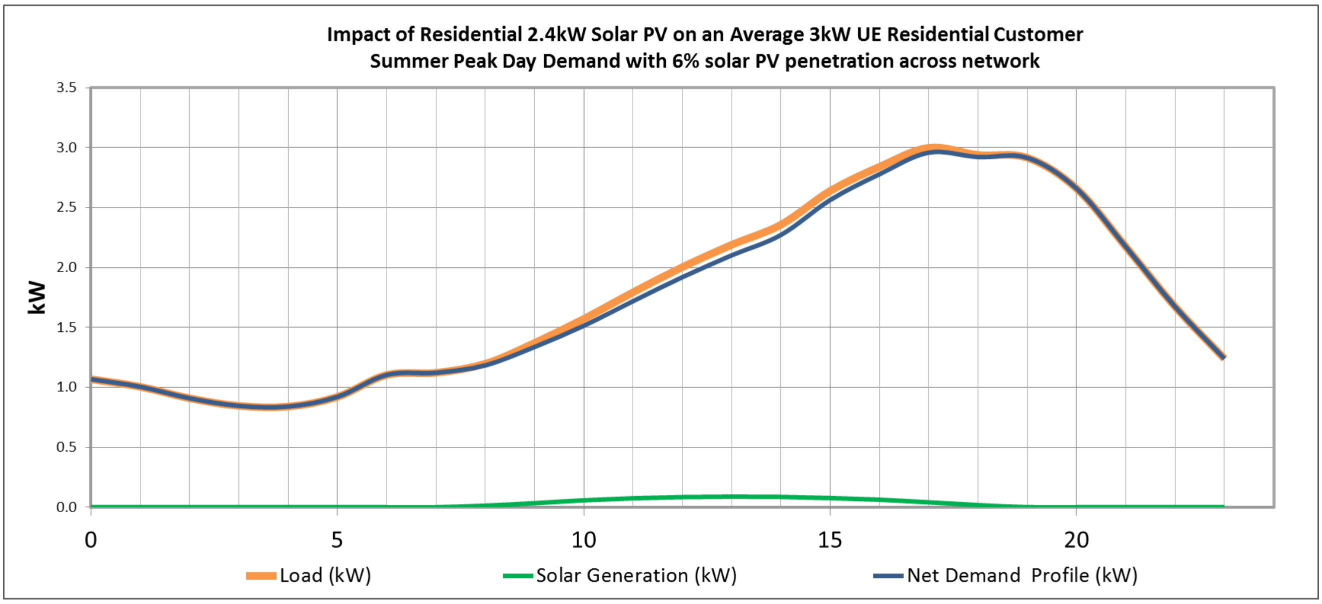


Figure 4-9: Actual Small Scale Solar PV uptake (monthly)



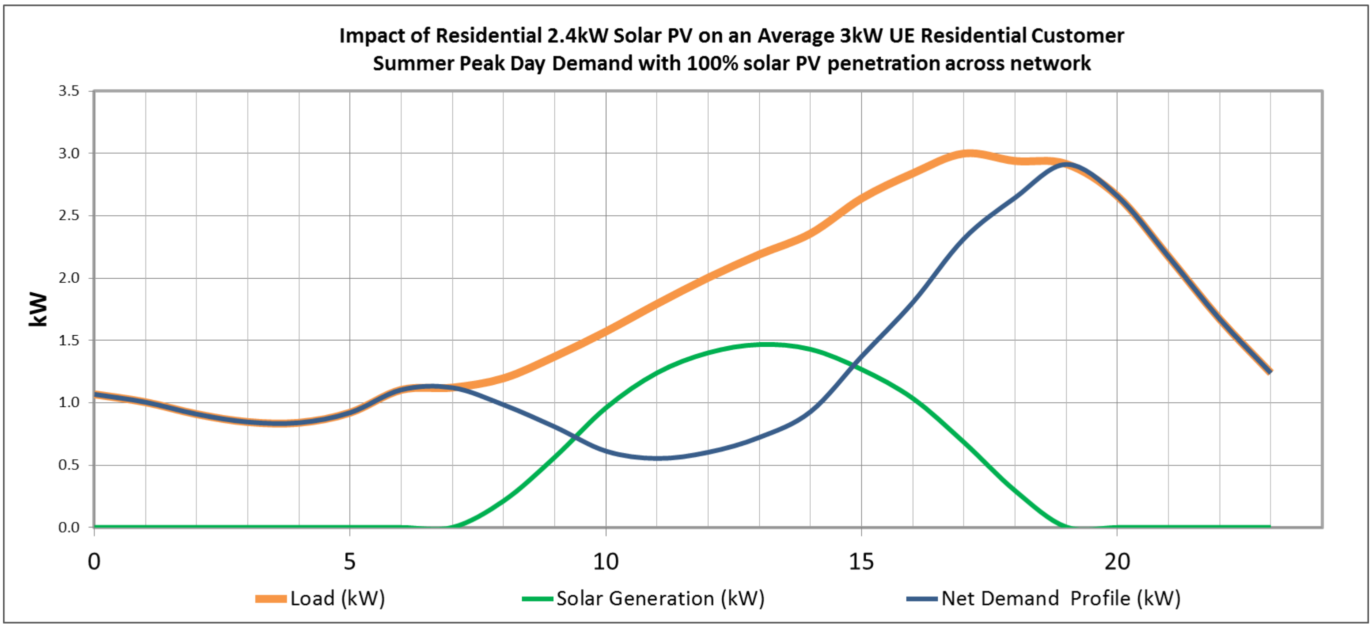
It should be noted that the contribution of residential solar PV to reducing maximum demand becomes diluted at the asset "spatial" forecast maximum demand level. This is because the timing of residential installed solar PV output does not coincide with residual maximum demand. Furthermore, with present penetration levels around 6%, the impact of localised residential solar PV on the localised residential peak demand is very small, around 1.4% with the peak occurring at the same time at 5pm. This is illustrated for UE's network below assuming, an average ADMD residential peak demand of 3.0kW and an average 2.4kW solar generation profile with 6% penetration of solar PV.

Figure 4-10: Residential Solar PV and Residential Load on Day of Peak Demand (6% penetration)



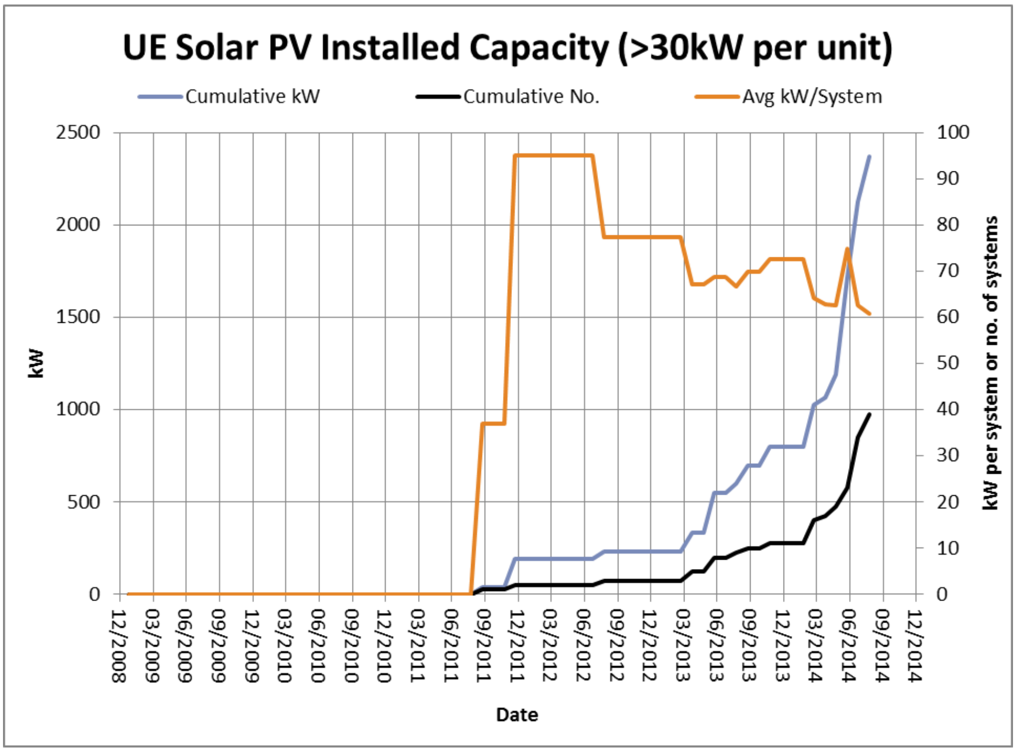
By comparison, with homes that have solar PV installed, the impact on demand is shown below with the peak pushed out to 7pm. Even so, the impact of residential solar PV on reducing the residential peak is only 3.0% even at 100% penetration.

Figure 4-11: Residential Solar PV and Residential Load on Day of Peak Demand (100% penetration)



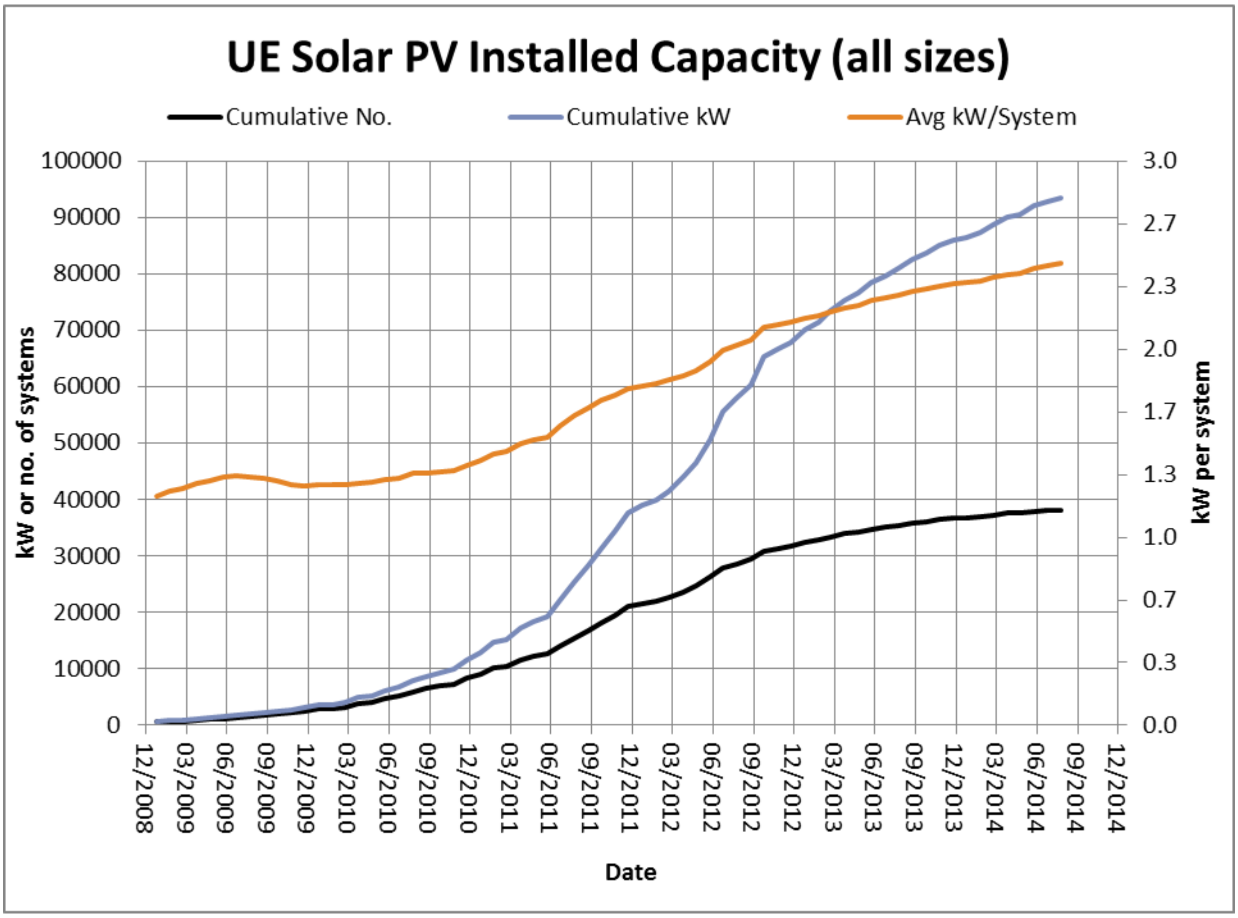
Medium sized generators over 30kW in size are also appearing in the network often appearing as commercial solar PV installations. These are tracked through our generator connection application process. While in its infancy, commercial and industrial solar PV is a potential growth area of renewable embedded generation within the UE network. These sites have a much better impact at reducing localised maximum demand as the output of the solar PV tends to align much better with commercial and industrial load profiles.

Figure 4-12: Actual Medium Scale Solar PV uptake (cumulative)



Considering all of residential, commercial and industrial solar PV installations, for 2014/15 there is presently around 91 MW of installed capacity of distributed solar PV generation on the UE network providing around 20% of its installed capacity towards negative demand at peak UE system demand. At the present uptake rate of solar PV, this will continue to accumulate around 2 MW of additional negative demand at peak demand each year.

Figure 4-13: Actual Total Solar PV uptake (cumulative)



UE engaged Acil Allen and NIEIR in 2014 as part of the next price review supporting documentation to undertake an investigation into the uptake of solar PV on the network over a 10-year horizon. The results of their study are presented below showing additional volumes and capacity over each regulatory period.

Table 4-6: Forecast installed capacity (MW) of Solar PV[5]

Solar PV Scenario	Actual	Forecast								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2024/25	2029/30	2034/35
Base[6]	87	97	106	116	125	134	144	196	252	309
High[7]		103	120	137	154	170	187	274	367	465
Low[8]		90	92	94	96	99	101	118	136	154

Three solar PV scenarios (low, base and high) have been developed based on the forecasts provided by Acil Allen and NIEIR. The base forecast is the average of the reconciled NIEIR and Acil Allen forecasts, the high is the Acil Allen forecast, and the low is the reconciled NIEIR forecast.

The forecasts were developed to provide expected contribution of solar PV at the time of UE's service area maximum summer demand, and at the time of terminal station summer maximum demands. NIEIR also provided estimated actual PV outputs for the last 5 years at times of UE's service area maximum summer demand based on NIEIR's solar irradiance PV model.

The uptake of solar PV systems in UE's network area was projected using a financial analysis approach, estimating the relationship between the historical uptake of PV systems in UE's area and the financial return to customers from installing PV systems from regression. Customer financial returns include the i) value of electricity that is generated by the PV system and used on site – valued at the prevailing retail price; ii) electricity exported to the network – valued at the feed in tariff rate that prevailed when the system was installed; and iii) government policy support including (at various times) the Solar Homes and Communities Program, the Renewable Energy Target and the Small-scale Renewable Energy Scheme. Residential and non-residential systems were dealt with separately because of the different energy use and price characteristics. The projected uptake of PV systems was produced by combining the regressions with the projections of the cost of PV systems and the retail price of electricity.

The impact on maximum demand was estimated in two steps – i) develop an estimate of the total output of solar PV systems using a PV efficiency model; and ii) estimate when that electricity would be generated using solar irradiance data from Melbourne Airport. This produced a set of half-hourly outputs of PV systems in UE's area. Aligning this with the time of maximum demand (typically 1700 EDST), the expected impact on the UE maximum demand can be calculated from the samples.

The penetration of solar PV (by customer numbers) on UE's network under these three scenarios are as follows.

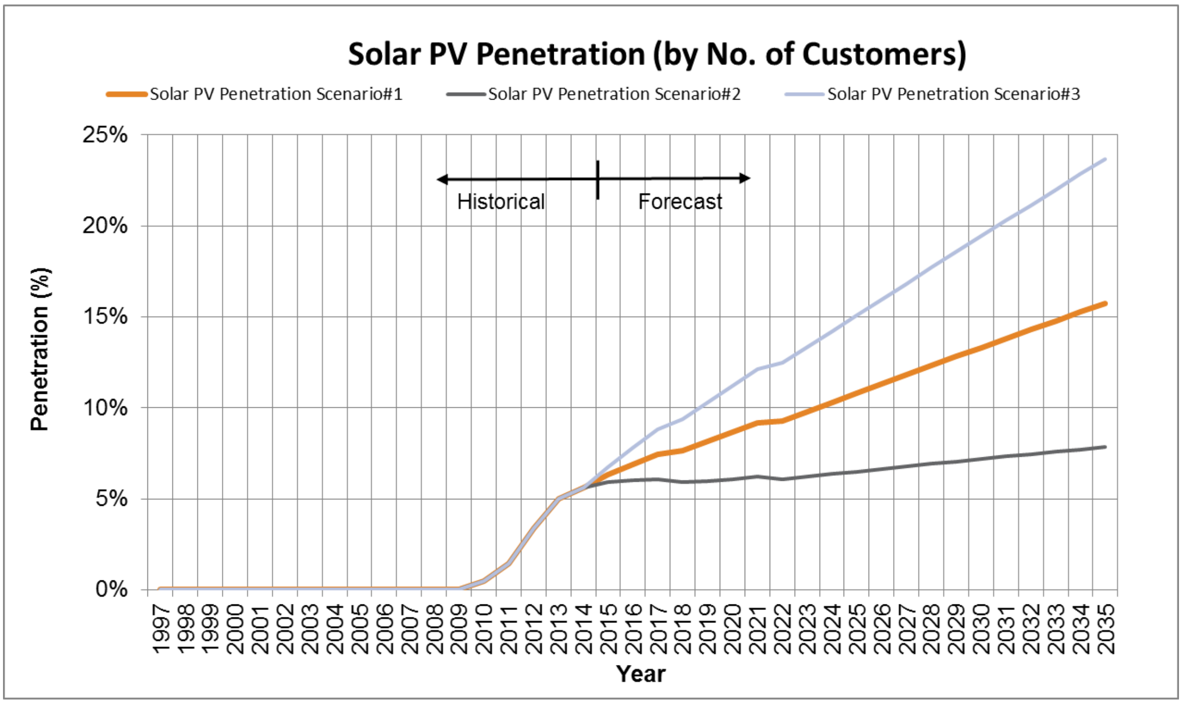
[5] While the variability from year to year can be significant, the expected reduction in UE's overall peak demand is approximately 20% of the total solar PV installed capacity. The Solar PV includes all residential, commercial and industrial sectors.

[6] Source: Average of NIEIR and Acil Allen forecasts – Part B reports, September/April 2014.

[7] Source: Acil Allen - UE Demand Adjustments – Part B report, April 2014.

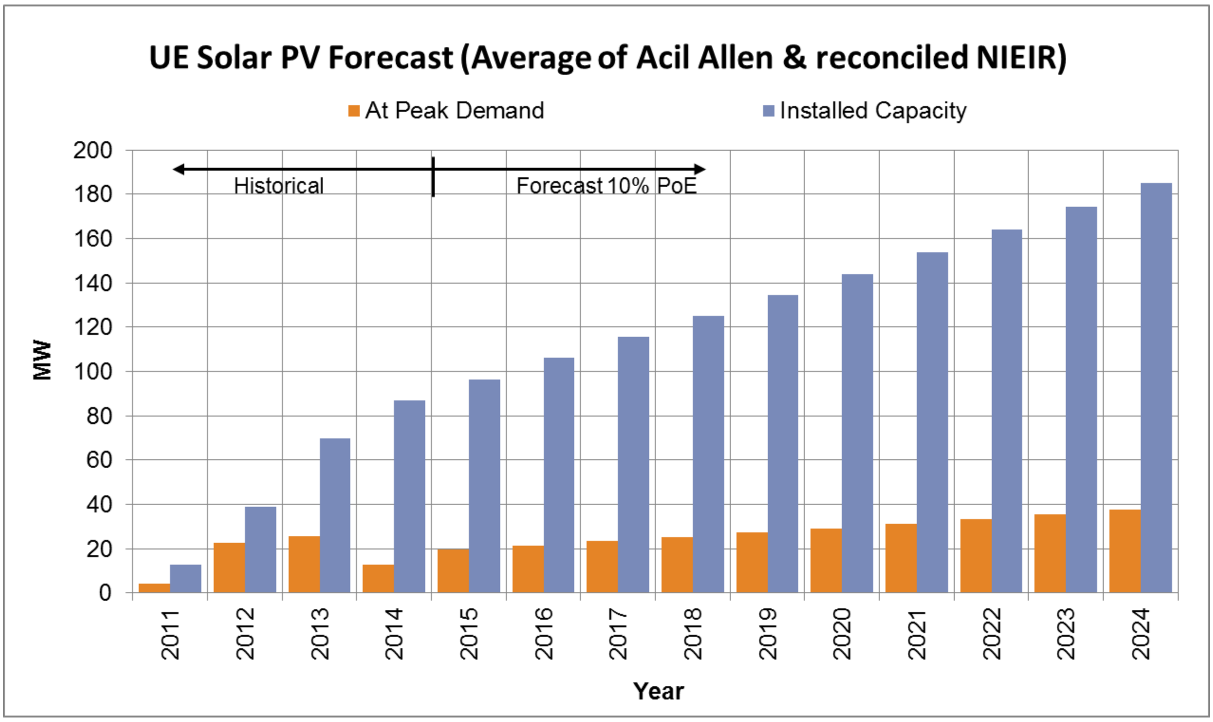
[8] Source: NIEIR - Energy, Demand and Customer Number Forecasting for United Energy to 2025 – Part B report, September 2014 plus 12MW for reconcilliation.

Figure 4-14: UE Solar PV penetration



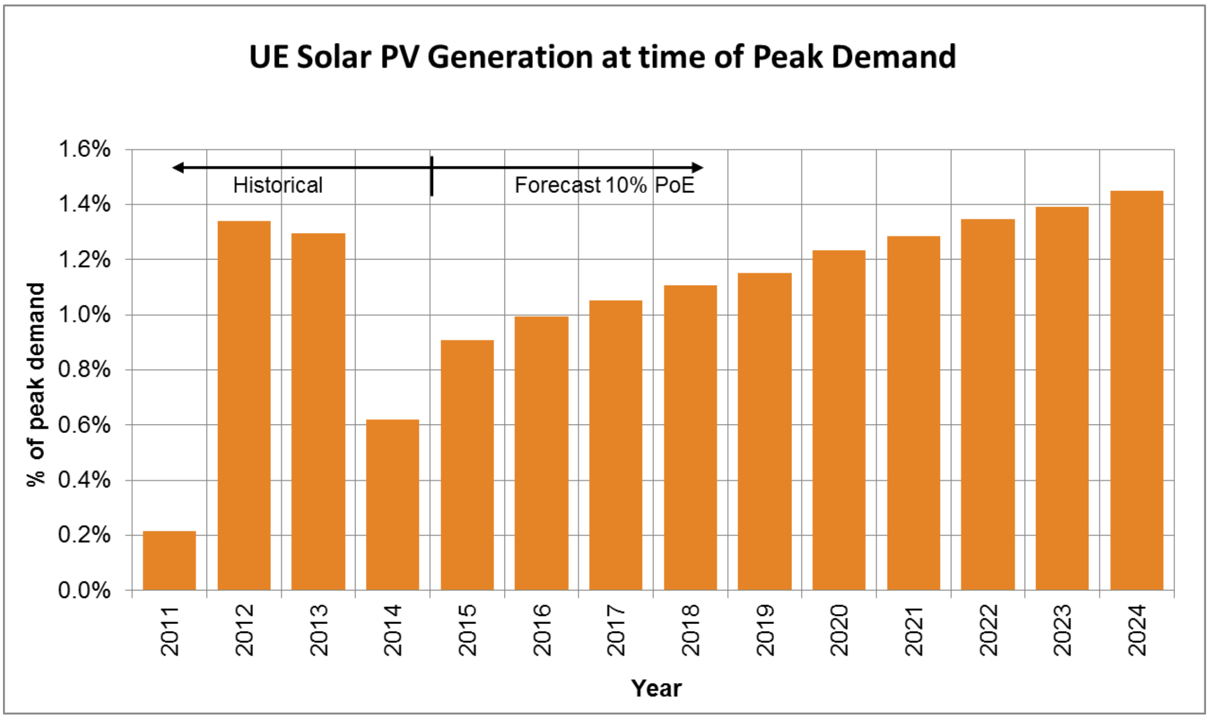
Only a small fraction of the installed solar PV capacity contributes to reducing maximum demand. This is typically around 20%. The key reason is that PV are rarely contributing near their rated capacity when UE maximum demand occurs, as this is typically late in the day. The expected impact of solar PV on the UE maximum demand is shown below.

Figure 4-15: UE Solar PV forecast & impact on maximum demand



The contribution of solar PV to reducing maximum demand as a percentage of the maximum demand is shown below.

Figure 4-16: Solar PV contribution to reducing UE maximum demand



Update of other types of micro-generation technologies at this stage is likely to significantly smaller than solar PV uptake.

As small wind generators are not economically viable in areas of low average wind speeds, take-up rates vary geographically. Wind generators tend to not be economically viable in highly built up areas as wind velocity is adversely affected by the surrounding landscape and the proximity of neighbouring dwellings. For viable performance, wind turbines would only be installed in areas where average wind speeds are at least 4.5 metres per second. As such, the majority of take-up of wind turbines in UE's service area may occur in the Mornington Peninsula which, being categorised as 'open coastal', experiences the highest wind speed. Regardless, the forecast wind-turbine take-up rates are consistently low across all scenarios.

Combined Heat and Power (CHP) operating from natural gas, is likely to experience higher take-up rates if carbon-dioxide prices through the carbon tax (or subsequent emission trading scheme) are low (as per the low scenario) rather than under a more ambitious emissions reduction target and higher prices. The micro-CHP medium and high scenarios both presume that mass production of CHP units has been achieved and therefore, as all other assumptions (including capital cost, carbon prices and gas prices) are also the same, the forecast take-up rates for these scenarios are identical.

Significant reductions in the forecast rate of growth of solar PV on the UE network over the next 20 years has resulted in stronger energy and maximum demand forecasts compared to that forecast last year. This is a result of the evident slowdown in the uptake rate of solar PV over the last year.

4.2.7. Electric Vehicles

Plug-in electric vehicles have become commercially available from car dealerships in Australia since the beginning of 2012 from a range of manufacturers. Approximately 500 vehicles were sold Australia wide over the last year with the most popular being the Nissan Leaf, followed by the GM Volt. It is expected that EV sales over the next year will be around 1000 vehicles.

Electric vehicle technology in the absence of alternative technology is likely to see an increase in market share of future motor vehicle sales within Australia. Electric vehicles hold the promise of reducing society's dependence on oil and have the ability to reduce greenhouse and noxious gas emissions when charged from low emission generation sources. Designed to connect to the electricity distribution network for recharging, plug-in electric vehicles could surpass air-conditioning as the most influential customer appliance that impacts electricity network investment decisions. The plug-in capability offers advantages for consumers in that electricity is already ubiquitously accessible and requires no significant technological breakthrough for vehicle integration with the grid. Furthermore, running costs relative to today's vehicles are low, being 25-30% of the fuel cost of conventional petroleum internal combustion engine vehicles.

Barriers presently exist for the mass uptake of plug-in electric vehicles; however barriers are well understood by the industry and government, and are progressively being dismantled. With a pricing differential for small cars of around $30k against equivalent internal combustion engine vehicles, the upfront capital cost is a significant deterrent. The production of a range of electric vehicles from multiple providers is bringing competition into the market. Coupled with further improvements in battery technology, electric vehicle costs will become more economic over time. A lack of public charging infrastructure is being addressed with charging infrastructure providers establishing tolling type accounts for recharging services and deploying public recharging stations ahead of a committed customer base. Currently facilitated financially by governments through electric vehicle trials, purchases of electric vehicles and installation of public charging infrastructure through initiatives such as Smart Grid, Smart City and the Victorian Electric Vehicle Trial should also facilitate the adoption of electric vehicles by society. The Victorian Government's Electric Vehicle Trial trialled electric vehicles at more than 180 households (including clusters within the UE service area such as Forest Hill and Templestowe which occurred in 2012/13), with public charging stations deployed in various locations across metropolitan Melbourne.

While uptake rates are an important consideration for UE in planning to adapt to this emerging load, the clustering and timing of electric vehicle charging is of more importance for UE because it will directly impact the performance and utilisation of the electricity distribution network in specific locations earlier. Plug-in electric vehicles driven for the current average daily distance of 40km will increase the energy consumption of an average household by up to one-third for each vehicle, contributing 2.1MWh to the annual household energy consumption with a peak demand of up to 3.4kW. This could have significant implications for the low voltage networks (and to a lesser extent the high voltage network) if significant numbers of vehicles cluster and charge simultaneously. The time of charging is crucial for network investment decisions because without any incentive to charge away from peak, many vehicles will start charging from 6pm when vehicles return home from work. This corresponds in time with the existing household air-conditioning.

The evening peak in low voltage systems supplying residential areas has been identified as the critical driver for network augmentations triggered by the emergence of electric vehicles. However the scale of augmentation would be substantially reduced if electric vehicles are included in a utility demand management portfolio. UE estimates that coincident maximum demands could be as low as 25% of the undiversified maximum demand if controlled charging is implemented for demand management while not adversely impacting customer drivability. Opportunities exist to develop suitable tariffs or engage with charging infrastructure providers and retailers to shape the charging profile of vehicles, using them as a form of scheduled, aggregated load. This is feasible in two ways – firstly, if vehicles are supplied from charging stations monitored and controlled by independent charging operators, UE can contract with these operators to provide aggregated demand management to support the network; and secondly, AMI could be leveraged for control of home charging either through price signalling or direct load control via tariffs. The Victorian Electric Vehicle Trial in conjunction with UE has trialled controlled charging of electric vehicles in 2012.

In future, vehicle-to-grid (V2G) technology could allow vehicle storage to be used as a generation source, although this capability is lagging the introduction of plug-in electric vehicles by 5-10 years.

To assess the uptake of plug-in electric vehicles within the UE area, models were independently developed by Acil Allen and NIEIR in 2014, complementing the forecasting model developed by UE in 2010, to assess the economic performance of plug-in electric vehicles against traditional internal combustion engine vehicles. The models estimate the conditions required to achieve price parity, the point where the capital and lifecycle fuelling costs of electric vehicles matches that of internal combustion engine vehicles, a key factor in determining uptake. The results of the models suggest price parity will occur in the mid-2020's for the average diving distance of 40km per day, taking into account increasing fuel and electricity prices and decreasing electric vehicle prices over time.

The results of the economic models were combined with a social acceptance model of new technology, taking into account a certain level of uptake occurring before price parity by early adopters and a lag of uptake occurring after price parity for those more resistant to new technology. The relatively low vehicle turnover rate of 10% in Melbourne will tend to defer uptake initially however uptake is expected to accelerate rapidly beyond price parity. The model estimates penetration levels of plug-in electric vehicles (EV) for the UE area and the results are presented below as three scenarios.

Table 4-7: Forecast plug-in electric vehicles reductions on peak demand (MW)

Plug-in EV Scenario	Actual	Forecast								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2024/25	2029/30	2034/35
Base[9]	0	0	-1	-1	-2	-3	-4	-32	-108	-238
High[10]		-1	-1	-2	-4	-6	-8	-65	-220	-482
Low[11]		0	-1	-1	-2	-3	-4	-14	-27	-45

The base forecast assumed is the NIEIR 2014 base scenario forecast. The high forecast is the NIEIR 2014 high scenario forecast and the low forecast is the Acil Allen 2014 base scenario forecast (effectively the NIEIR 2014 low scenario).

4.2.8. Distributed Storage

Distributed storage solutions are currently uneconomic; however some commercialised products for use at the household, business or precinct level may become economically viable in the next 5-15 years.

Australia's geographic size and dispersed population means that we have one of the largest integrated electricity networks in the world. With most of Australia's electricity network infrastructure built throughout the 1960s and 70s, major investment is occurring to replace and upgrade infrastructure assets (such as transformers, poles, wires etc.) as they reach their end of service life.

UE is entering an uncertain time for distribution businesses. There is a real chance that within the next 7 years, technological advancements and ongoing price reductions in solar energy and storage may result in a substantial number of customers bypassing the grid or using the grid as back-up supply only. This has been identified as a potential threat to our existing business model. However improvements in solar and storage technology can be viewed as an opportunity for UE.

To date, distribution companies have not been actively involved in the solar market. However there exists an opportunity to harness the potential Distributed Generation and Storage (DGS) for the benefit of the network and our customers. New business models are appearing where utilities support the installation of DGS into customer premises. This has the potential to be leveraged by utilities to reduce the cost of supplying electricity to customers, improve network reliability, defer augmentation projects and stabilise grid voltages.

[9] Source: NIEIR - Energy, Demand and Customer Number Forecasting for United Energy to 2025 – Part B report, September 2014.

[10] Source: NIEIR - Energy, Demand and Customer Number Forecasting for United Energy to 2025 – Part B report, September 2014.

[11] Source: Acil Allen - UE Demand Adjustments – Part B report, April 2014.

The challenge for UE is how do we adopt this business model and apply it to Victoria which has a privatised and disaggregated electricity industry with full retail contestability. Simple business models which exist for vertically integrated utilities are not suitable to be applied within this environment.

UE is currently exploring the economics of storage at the household level with its Virtual Power Plant (VPP) project. If this trial is successful, storage coupled with solar PV could be a viable way to defer network augmentation. With the rapidly falling price of solar PV and battery storage, UE is eager to explore the use of solar PV and controlled battery storage technology to develop an incremental approach to addressing immediate capacity shortfalls and defer traditional network augmentation solutions which by comparison, provided a much larger step-change in available capacity. This could be a useful alternative in low peak demand growth environments, targeting those areas of the network where future peak demand could decline, potentially leading to under-utilised network assets or where the cost of additional capacity on the network is higher than average. The aim of the project is to validate or otherwise, the use of a VPP to manage embedded generation and storage in a residential setting for the provision of efficient and prudent non-network augmentation. The VPP integrates the operation of both supply and demand-side assets to meet customer demand for energy services in both the short and long-term. To match short-interval load fluctuations, the VPP makes extensive and sophisticated use of information technology, advanced metering, automated control capabilities, and electricity storage. The VPP concept also treats long-term load reduction achieved through energy efficiency investments, distributed generation, and verified demand response on an equal footing with supply expansion. Thus, this approach extends the boundary of utility capacity investments through the meter, with its expanding communication and control capabilities, all the way to customer-side equipment. The current hardware cost for each VPP residential pilot site is estimated to be $35k, ignoring the one off setup costs. In certain areas of the network where existing augmentation costs are high, it is expected the VPP solution would be a viable economic solution today with the current site hardware costs. Existing trending for the VPP site hardware cost indicates that within the next five to seven years it is likely to reduce below $15k. If the cost falls as expected then VPP will have even wider application as an economically viable augmentation solution for our network.

A possible alternate form of storage is the storage capability offered by plug-in electric vehicles with vehicle-to-grid (V2G) capability. This is still an emerging technology within the electric vehicle market and will therefore represent only a component of that market. As private vehicles are generally parked for 95% of the time a key driver for successful V2G systems will be establishing benefits associated with providing energy whilst they are parked. Given the current somewhat speculative nature of the V2G technology and small forecasts even using bullish assumptions, the impacts to the electricity grid from V2G power in the short to medium term (up to 2030) are expected to be minimal in the UE service area.

Table 4-8: Forecast storage reductions on peak demand (MW)

Storage Scenario	Actual	Forecast								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2024/25	2029/30	2034/35
Base	0	0	0	0	0	0	1	6	39	117
High		0	0	0	0	0	1	6	39	117
Low		0	0	0	0	0	0	0	0	0

4.2.9. Demand Management

Smart meters currently being rolled out across the UE service area have the potential to enable customers to actively participate in the management of their energy use through the provision of timely, relevant information and control options. Smart meters give the ability to apply enhanced tariff arrangements, energy management, customer signalling and more sophisticated power usage monitoring. Incentives put in place by the AER with the Demand Management Incentive Scheme (DMIS) are encouraging trials in this area. UE has been allocated $2M over the 2011-2015 regulatory period to spend on demand management initiatives. Approximately $0.4M has been allocated to a district energy services scheme in the Doncaster Hill area facilitated by an MoU with Manningham City Council, and the balance has been allocated to the VPP project and Bulleen Demand Response Pilot.

For the summer 2013/14 UE piloted a Summer Energy Demand Trial as part of the broader Bulleen Demand Response Pilot aimed at directly targeting and financially incentivising customers to reduce their demand at times of high demand. The trial was targeted at 6,500 customers who live in the Bulleen and Lower Templestowe area fed by four feeders that are likely to require upgrade in the next few years.

Further details about UE's demand management plans are contained in the Demand Management & DMIS Strategy (UE PL 2210) which is targeted at expanding UE's suite of demand management capabilities.

From an asset management perspective, the information provided by smart meters can be aggregated by smart grid applications to provide more accurate information regarding asset utilisation. Further, leveraging off the smart meter communications network, smart grid applications can be implemented with distributed sensing to improve condition monitoring of power system equipment and to allow the equipment to be used to its full capabilities without impacting asset condition and asset life. Real-time balancing of supply and demand and the real-time control and monitoring of the flow of electricity within the network gives the ability to dynamically optimise the operation of the network to minimise losses, maximise reliability and optimise asset utilisation.

In 2013, UE signed an MoU with demand-side aggregator Greensync to undertake joint planning to identify economically feasible demand management opportunities as an alternative to network augmentation.

Hence there is significant opportunity for enabling demand management solutions with a flourishing smart grid, provided UE is able to engage with customers and its stakeholders.

Table 4-9: Forecast demand management reductions on peak demand (MW)

Demand Management Scenario	Actual	Forecast								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2024/25	2029/30	2034/35
Base	0	0	0	1	3	4	5	10	15	20
High		0	1	4	11	15	18	36	53	70
Low		0	0	0	0	0	0	0	0	0

4.2.10. Energy Efficiency

Improved standards in air-conditioning efficiency (Minimum Efficiency Performance Standards - MEPS) will lead to reductions in the rate of increase of maximum demand as these more efficient air-conditioners are purchased over time for new stock and replacement of existing installed stock.

Both Acil Allen and NIEIR conclude in their 2014 demand adjustment reports that the impact of energy efficiency policies is expected to be small over the forecast period. The only significant additional energy efficiency policy that may contribute to reducing UE's growth in peak demand is MEPS for air-conditioners, forecast at 3MW/annum cumulative.

The now defunct Victorian Energy Efficienct Target (VEET) scheme's impact on peak demand growth (currently estimated at 12MW) is expected to decline over time and have negligible impacts by the end of the 10-year period.

Table 4-10: Forecast energy efficiency reductions on peak demand (MW)

Energy Efficiency Scenario	Actual	Forecast								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2024/25	2029/30	2034/35
Base	15	18	21	24	27	30	33	40	55	70
High		18	21	24	27	30	33	40	55	70
Low		15	15	15	15	15	15	7	0	0

4.3. Future Load Growth Scenarios

Three forecast maximum summer demand scenarios have been defined for this Demand Strategy & Plan as being representative of three credible future states. These are based on the expected maximum demands under different customer usage outcomes discussed above.

4.3.1. Demand Scenario #1: Business-As-Usual (Expected Demand)

The Demand Scenario #1 is the base case scenario where the current trends seen in uptake of solar PV and air-conditioning continue under an expected economic growth forecast. The AMI programme is completed in full and customer engagement through voluntary demand management schemes start to flourish amongst those customers wishing to participate particularly with the introduction of flexible tariffs. Plug-in electric vehicles are assumed to remain at a cost disadvantage compared to alternative vehicles, however they are assumed to be adopted by fleet operators, 'early adopters' and other environmentally inclined consumers. Economic storage systems for peak shaving become economic towards the end of the 20 year horizon but their usage is limited. Smart grid applications at the network level are implemented, particularly in the areas of condition monitoring, use of AMI information in planning, automation, dynamic ratings and reactive power management to optimise network utilisation. Energy efficiency measures predominantly through the improved efficiency of air-conditioners and LED lighting starts to take effect.

This scenario is defined by the following key assumptions:

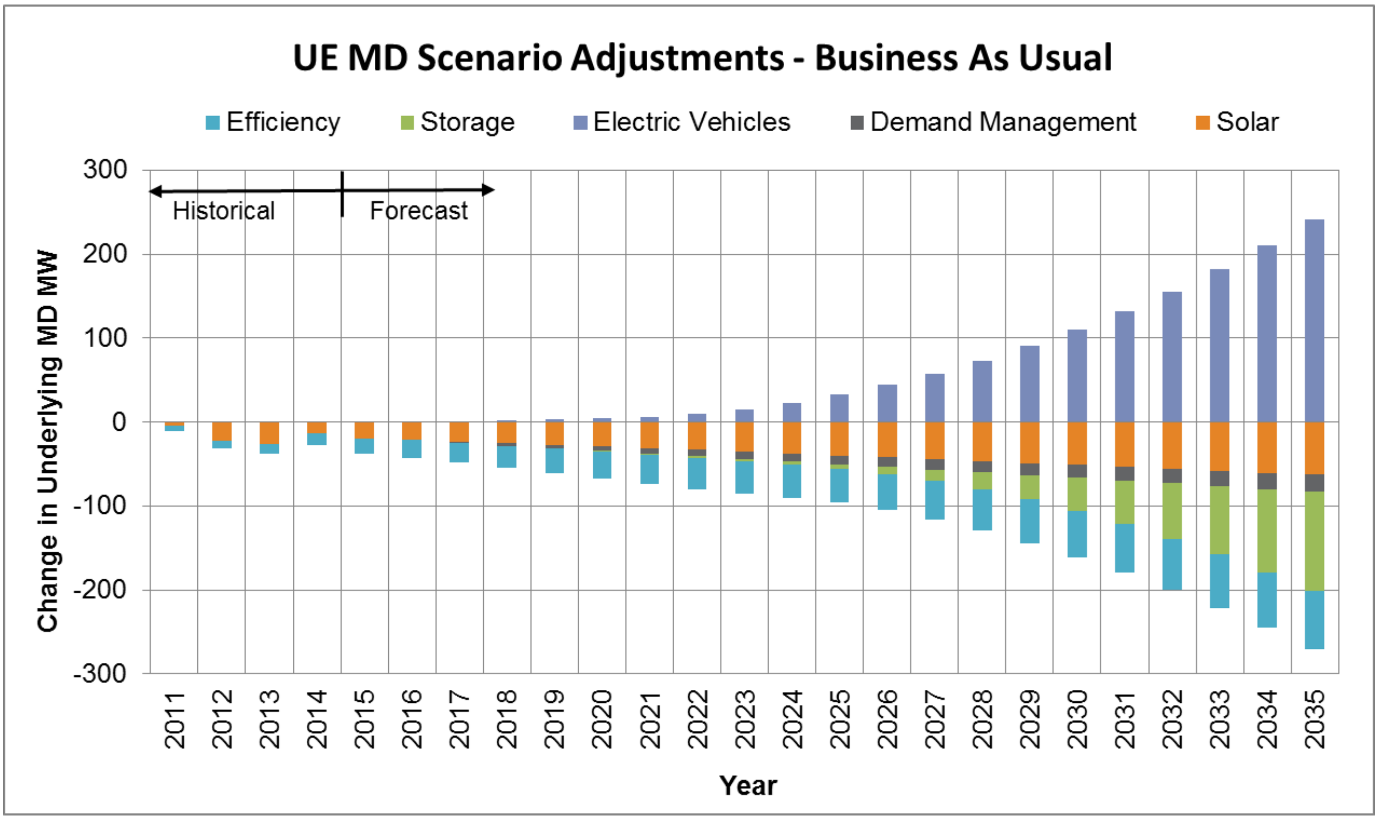
Table 4-11: Demand Scenario #1: Expected Demand

Demand Scenario	Demand Scenario #1 Business-as-Usual					
	Economic Growth	Solar PV Uptake	EV Uptake	Storage Uptake	Demand Management	Energy Efficiency
Base	✓	✓	✓	✓	✓	✓
Low						
High						

Table 4-12: Forecast cumulative contribution to peak demand MW – BAU Scenario

Contribution	2015	2020	2025	2030	2035	Change
BASE 10% POE MD MW	2200	2437	2676	2881	3077	877
Solar PV	-19.6	-29.3	-39.8	-51.1	-62.8	-43
Electric Vehicle Charge	0.2	4.1	32.2	110.0	240.8	241
Distributed Storage	0.0	-0.5	-5.5	-39.7	-118.4	-118
Demand Management	0.0	-5.1	-10.3	-15.3	-20.2	-20
Energy Efficiency	-17.9	-32.5	-39.7	-54.7	-69.7	-52
NET 10% POE MD MW	2163	2374	2613	2830	3047	884
NET GROWTH PA	1.7%	2.0%	2.0%	1.7%	1.5%	2.0%

Figure 4-17: Forecast cumulative adjustments to peak demand MW – BAU scenario



4.3.2. Demand Scenario #2: High Demand

The Demand Scenario #2 is a world where customers do not engage with the smart meter capabilities to any significant extent even though the deployment of meters finishes and remain predominantly passive consumers. Uptake of solar PV continues but at a slower rate due to reduced subsidies, and air-conditioning continues to contribute to demand growth under an expected economic growth forecast. Plug-in electric vehicles are assumed to become economically competitive compared to alternative vehicles, and are taken up by many consumers, however V2G (storage) capability is not incorporated in vehicles or used by consumers to any significant extent. Vehicle charging is not controlled, so that most vehicles are charging at time of peak demand. Economic storage systems for peak shaving remain uneconomic. Smart grid applications at the network level are adopted only where there is a regulatory incentive to deploy the technology particularly in the areas of condition monitoring, automation, dynamic ratings and reactive power management. AMI information is used to its full capabilities for asset management activities. New energy efficiency measures do not materialise at time of peak demand.

This scenario is defined by the following key assumptions:

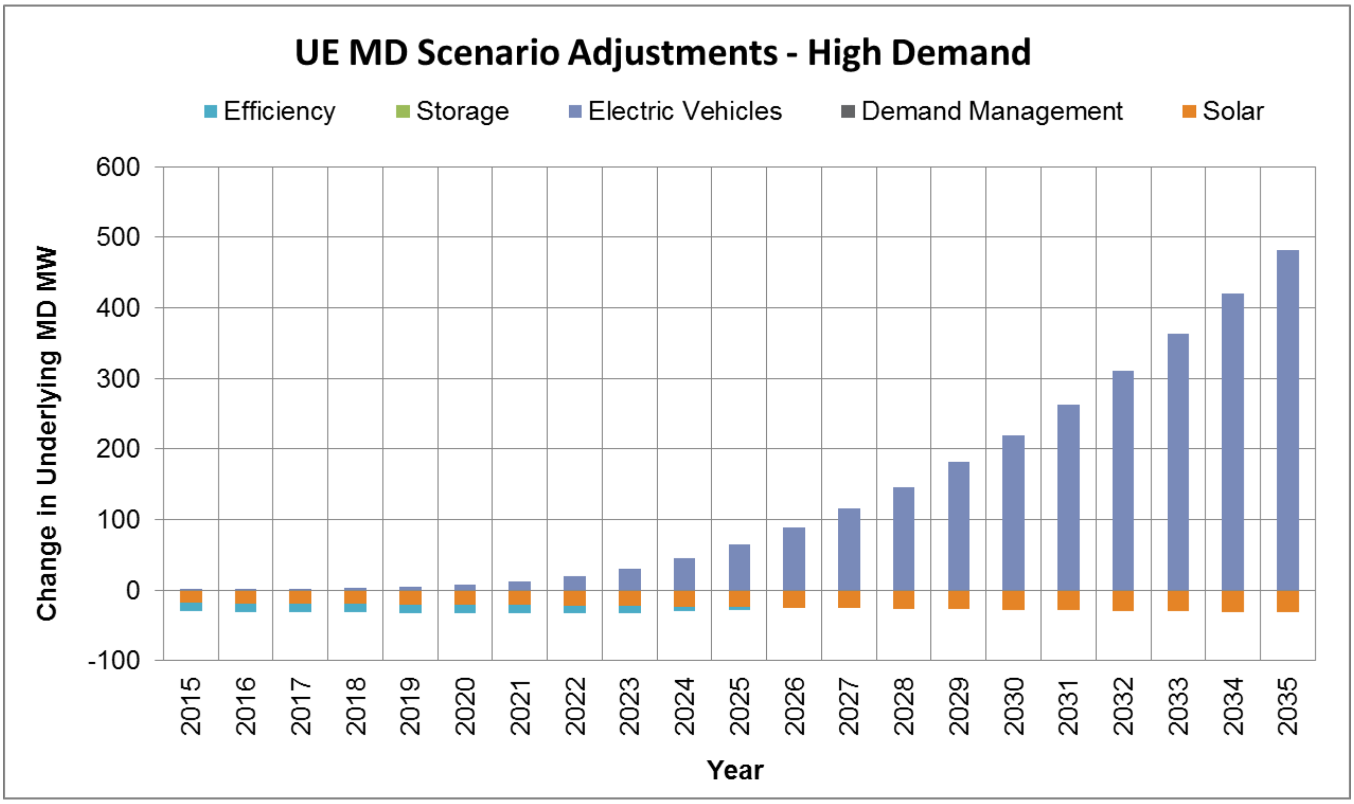
Table 4-13: Demand Scenario #2: High Demand

Demand Scenario	Demand Scenario #2 High Demand Scenario					
	Economic Growth	Solar PV Uptake	EV Uptake	Storage Uptake	Demand Management	Energy Efficiency
Base	✓					
Low		✓		✓	✓	✓
High			✓			

Table 4-14: Forecast cumulative contribution to peak demand MW – High Demand Scenario

Contribution	2015	2020	2025	2030	2035	Change
BASE 10% POE MD MW	2200	2437	2676	2881	3077	877
Solar PV	-18.4	-20.6	-24.0	-27.6	-31.3	-13
Electric Vehicle Charge	0.5	8.4	65.1	220.0	481.7	481
Distributed Storage	0.0	0.0	0.0	0.0	0.0	0
Demand Management	0.0	0.0	0.0	0.0	0.0	0
Energy Efficiency	-12.0	-12.0	-4.0	0.0	0.0	12
NET 10% POE MD MW	2170	2413	2713	3073	3528	1357
NET GROWTH PA	1.7%	2.2%	2.5%	2.7%	3.0%	3.1%

Figure 4-18: Forecast Cumulative Adjustments to Peak Demand MW – High Demand Scenario



4.3.3. Demand Scenario #3: Low Demand

The Demand Scenario #3 is a world where smart grid flourishes through the deployment of network level smart grid applications and widespread consumer engagement. Uptake of solar PV and other forms of distributed micro-generation grows at a faster rate due in response to government incentives and reducing costs of low emission generation technologies. Air-conditioning continues to grow under an expected economic growth forecast. Plug-in electric vehicles are assumed to become economically competitive compared to alternative vehicles, and are taken up by many consumers however vehicle charging is controlled to a 'trickle charge' to limit charging rates at peak demand periods without impacting vehicle range. V2G capability starts to be incorporated in vehicles and is used by consumers to a limited extent. Economic storage systems for peak shaving or stand-alone start to become economic. Smart grid applications at the network level flourish, particularly in the areas of condition monitoring, automation, dynamic ratings and reactive power management to optimise network utilisation and performance. AMI information is used to its full capabilities for asset management activities. Energy efficiency measures predominantly through the improved efficiency of air-conditioners starts to take effect.

This scenario is defined by the following key assumptions:

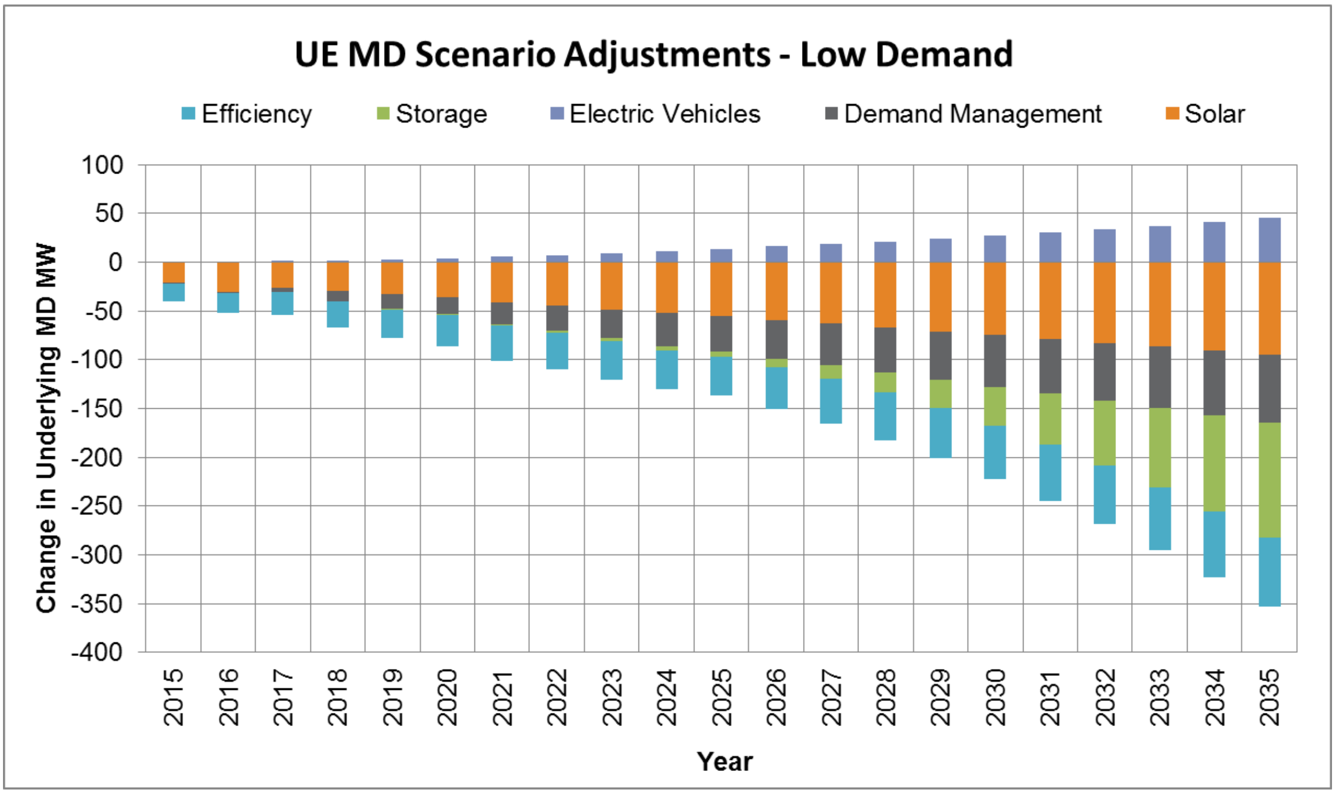
Table 4-15: Demand Scenario #3: Low Demand

Demand Scenario	Demand Scenario #3 Low Demand Scenario					
	Economic Growth	Solar PV Uptake	EV Uptake	Storage Uptake	Demand Management	Energy Efficiency
Base	✓					
Low			✓			
High		✓		✓	✓	✓

Table 4-16: Forecast cumulative contribution to peak demand MW – Low Demand Scenario

Contribution	2015	2020	2025	2030	2035	Change
BASE 10% POE MD MW	2200	2437	2676	2881	3077	877
Solar PV	-20.9	-35.6	-55.6	-74.6	-94.4	-74
Electric Vehicle Charge	0.3	4.3	14.0	27.3	45.2	45
Distributed Storage	0.0	-0.7	-5.5	-39.3	-118.4	-118
Demand Management	-1.0	-17.6	-35.8	-52.9	-69.9	-69
Energy Efficiency	-17.9	-32.5	-39.7	-54.7	-69.7	-52
NET 10% POE MD MW	2161	2355	2553	2686	2770	609
NET GROWTH PA	1.7%	1.8%	1.7%	1.1%	0.6%	1.4%

Figure 4-19: Forecast cumulative adjustments to peak demand MW – Low Demand Scenario



4.3.4. Summary of Maximum Demand Scenarios

The 10% PoE and 50% PoE maximum demand forecasts are illustrated below for each of the three Demand Scenarios considered.

Figure 4-20: Summer maximum demand 50% PoE forecast – demand scenario #1, #2 & #3

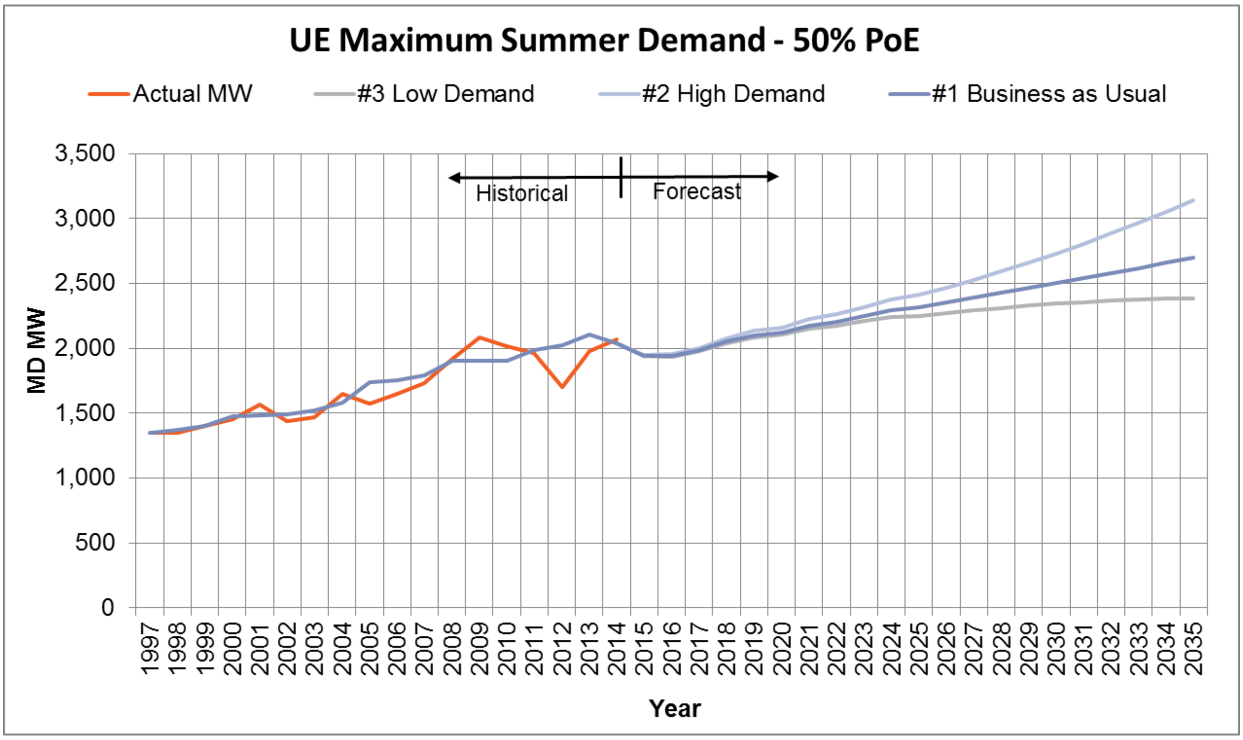
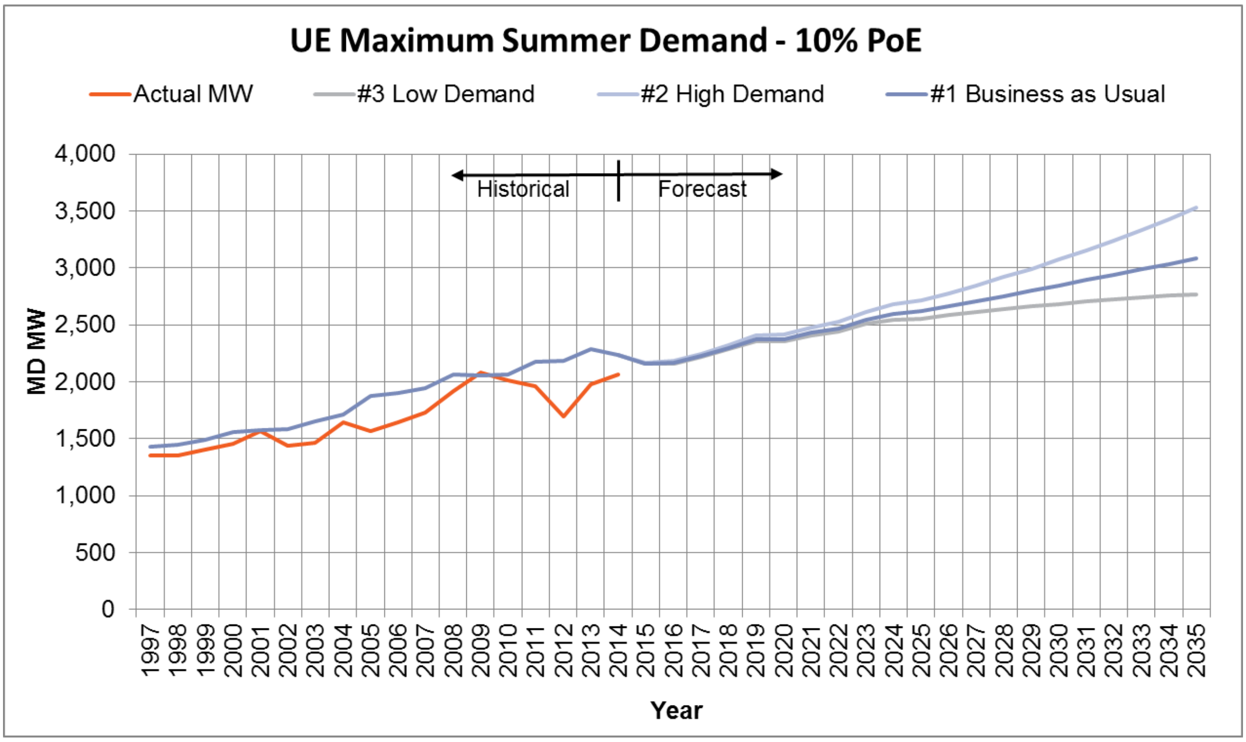


Figure 4-21: Summer maximum demand 10% PoE forecast – demand scenario #1, #2 & #3



In all three scenarios, maximum demand growth is expected over the 20-year period.

4.4. Network Forecasts

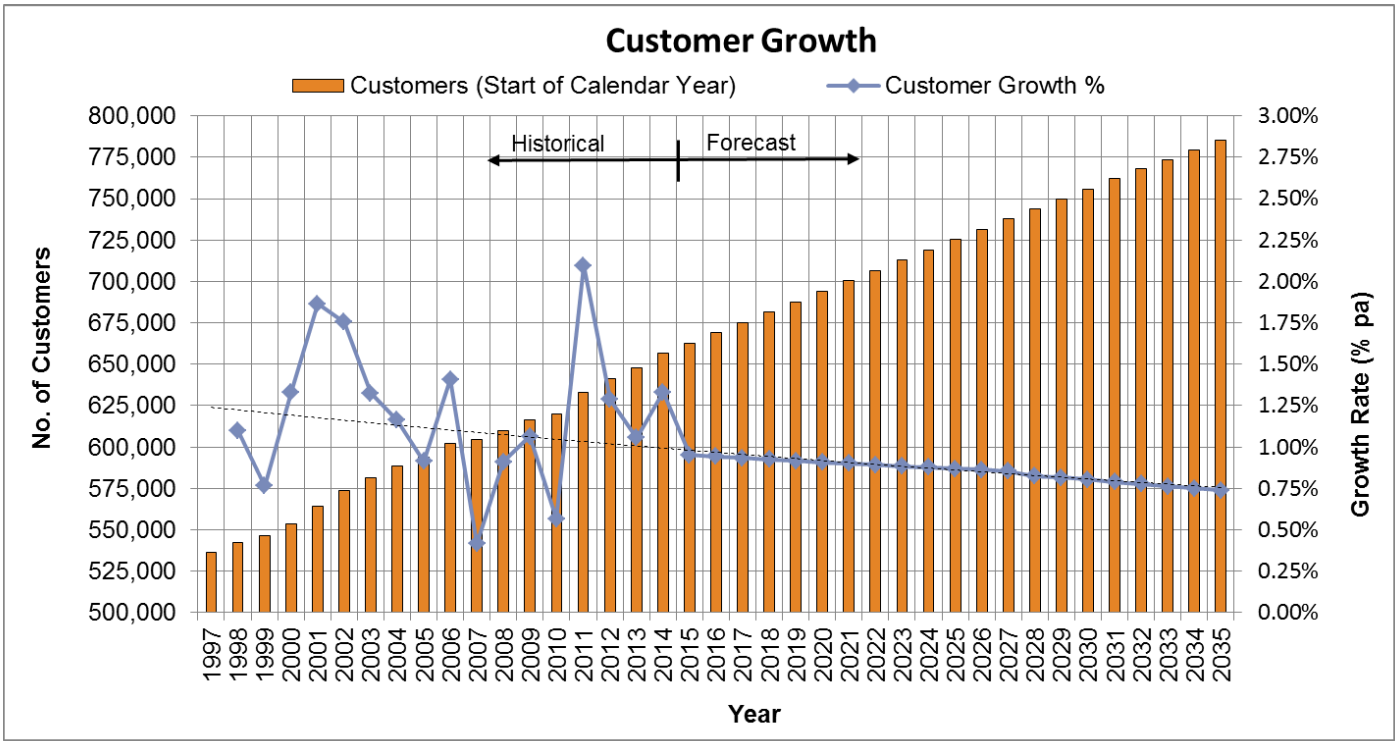
The UE network forecasts are presented below up to 2034-2035. Where appropriate, forecasts for each of the three scenarios are provided for comparison.

4.4.1. Customer Number Forecast

The average annual growth in UE customer numbers at present is 0.9%. This is expected to decline over time at a rate similar to historical trends due predominantly to an increased customer base within a fixed service area.

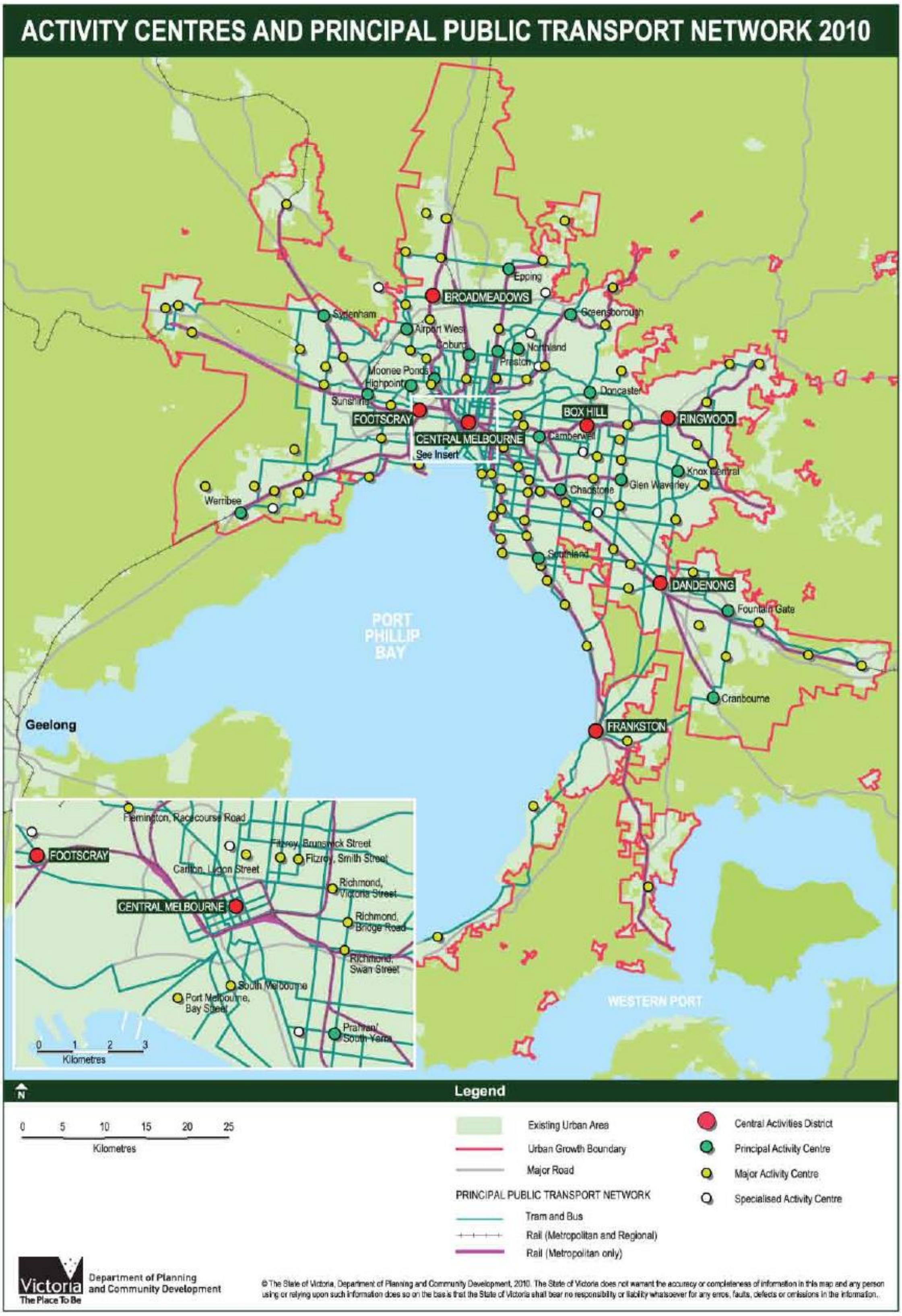
The chart below presents historical growth in customer numbers over the past 15 years and projected growth over the next 20 years.

Figure 4-22: UE Customer numbers and growth trend



Reducing availability of land within the UE service area will see a need by state government to consider adjusting the present urban growth boundary within the 20-year planning horizon to cater for projected growth in Melbourne's population. Significant growth in population is however expected within the existing urban growth boundary with the development of defined Activity Centres shown below through the development of high density residential infill, many of which fall within the UE service area.

Figure 4-23: Activity Centres across UE's territory



A number of areas within the UE service area have also been identified as strategically important national employment areas in the Victorian Government's Plan Melbourne Metropolitan Planning Strategy published in 2014. The strategy also foresees an upgraded Port of Hastings to rival the existing Port of Melbourne and upgraded electric rail services on a number of lines within UE's service area including the proposed new Rowville rail line.

Figure 4-24: Victorian Government's 'Plan Melbourne' Metropolitan Planning Strategy

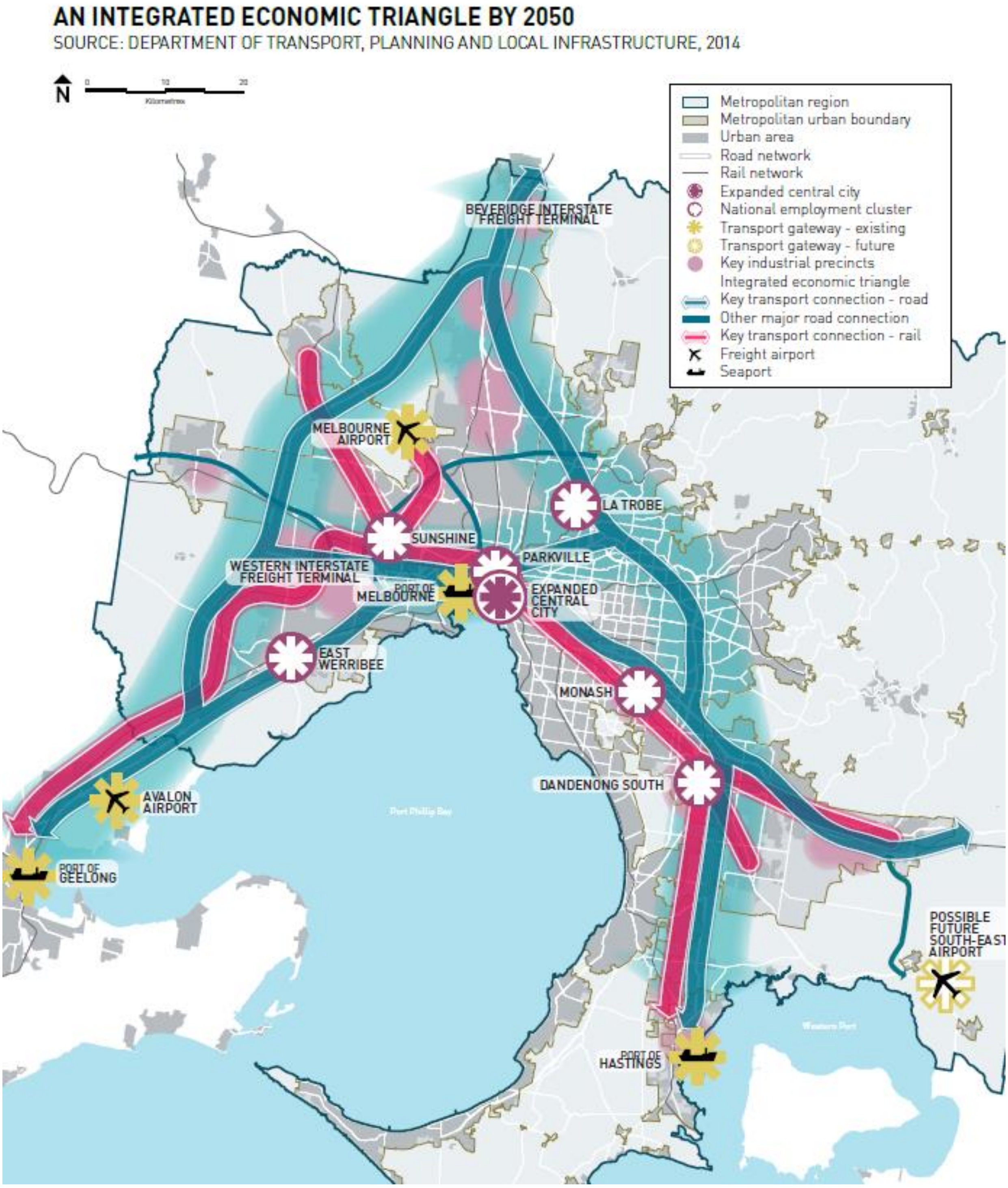
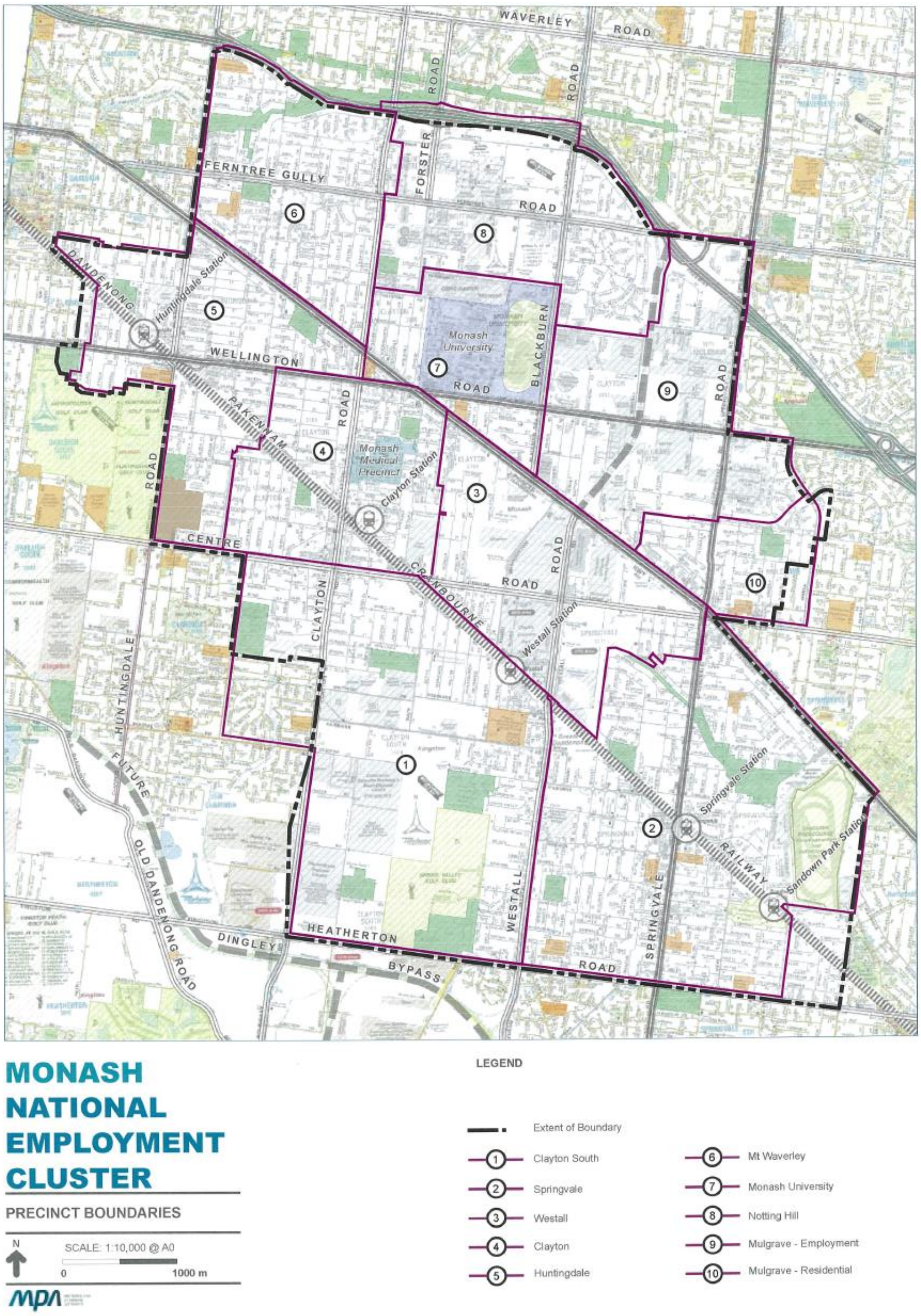


Figure 4-25: ‘Plan Melbourne’ Monash National Employment Cluster



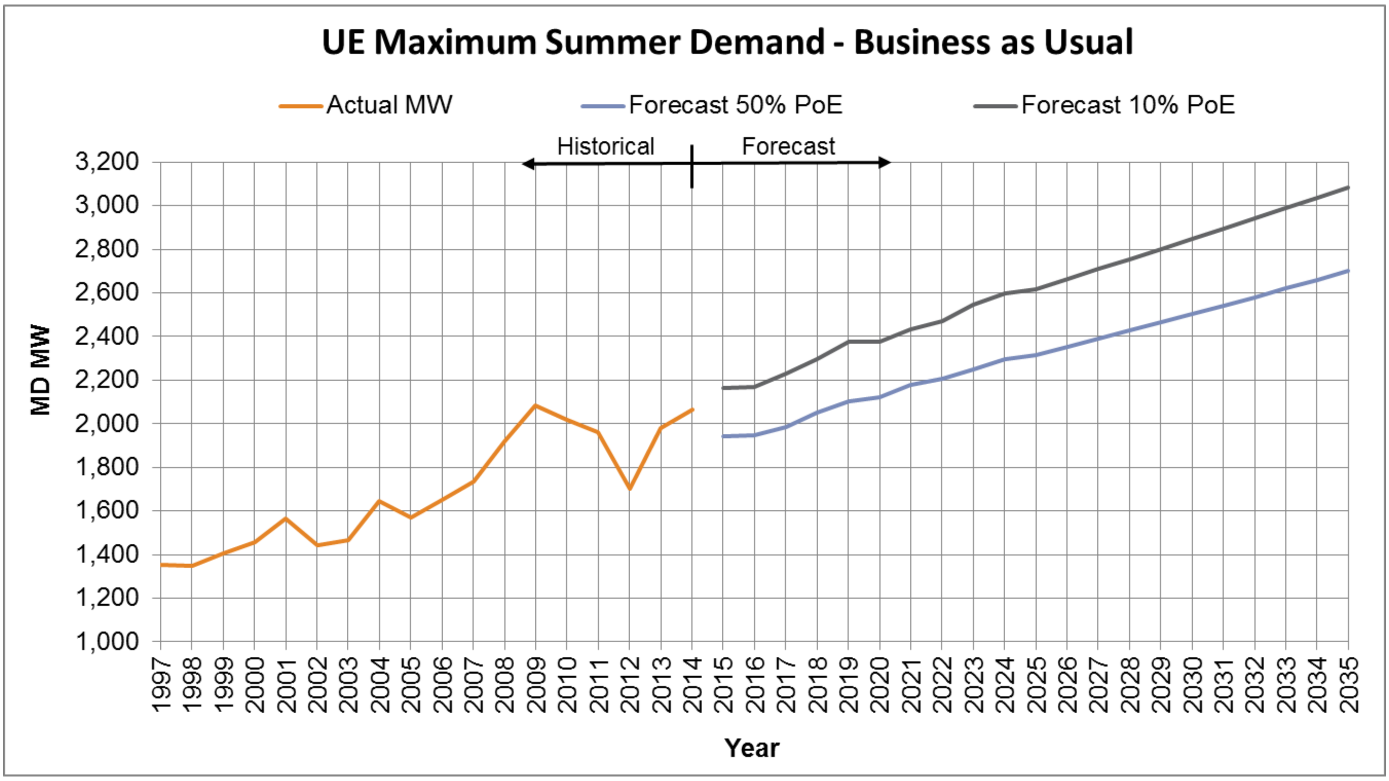
4.4.2. Maximum Demand Forecast

Maximum summer demand growth is the principal driver for network augmentation investment. UE’s overall summer peak demand is generally expected to occur on a weekday between 15th November and 15th March. The last time UE reached a record peak demand was in summer 2008-2009 when the peak demand reached 2,084 MW at 1:00pm AEST on 29 January 2009 at an ambient temperature of 44ºC (this day corresponded to 4% probability of exceedance). On the same day and around the same time, there was a widespread load shed within the UE network due to outages in the Victorian transmission network and significant numbers of distribution substation supply interruptions. In the absence of these outages, it is estimated that the UE network would have recorded a peak of around 2,110 MW at 3:00pm AEST. Since this time the recorded peak demands have been lower than this, mainly attributed to the comparatively milder weather conditions observed during these subsequent summers and the growth in solar PV.

The maximum demand last summer was 2066MW on a 2% probability of exceedance summer day and occurred in the middle of the school holiday period on 16th January 2014. The week commencing 13th January 2014 saw unprecedented weather conditions in Melbourne. Victoria had its hottest four-day period on record for both maximum and average heat, with all days exceeding 40 degrees. Melbourne's average temperature on on the day of peak demand was 35.45 degrees.

Based on NIEIR medium economic forecasts up until 2024-2025, the forecast UE maximum summer demand 10% PoE and 50% PoE temperature conditions are shown below with 15 years of historical demand. Projections up to 2034-2035 are based on linear extrapolation of the NIEIR forecasts modified with the customer usage adjustments described in the Business-As-Usual Demand Scenario #1.

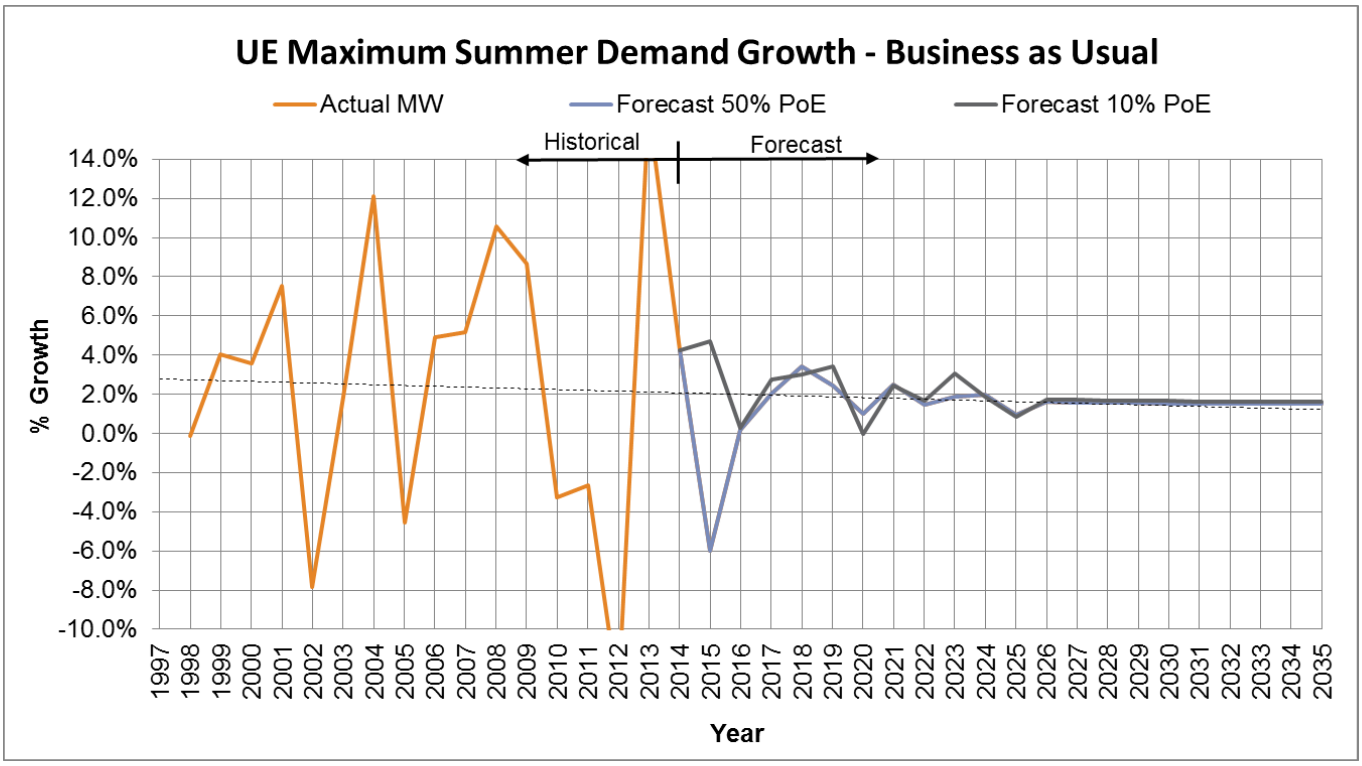
Figure 4-26: Summer maximum demand forecast – demand scenario #1: BAU



This forecast is supported by the NIEIR Part A Demand Forecasting report.

Average annual growth in 10% PoE maximum demand is estimated at 1.7% over the next ten years under the NIEIR base economic growth scenario. The chart below presents historical growth in maximum demand over the past 15 years and projected growth over the next 20 years.

Figure 4-27: Summer maximum demand growth forecast – demand scenario #1: BAU



The base (most probable) economic growth scenario with a 10% probability of exceedance (1 in 10 years) with due regards to energy policies of federal and state governments has been chosen as the basis for projection of capital expenditure in this Demand Strategy & Plan.

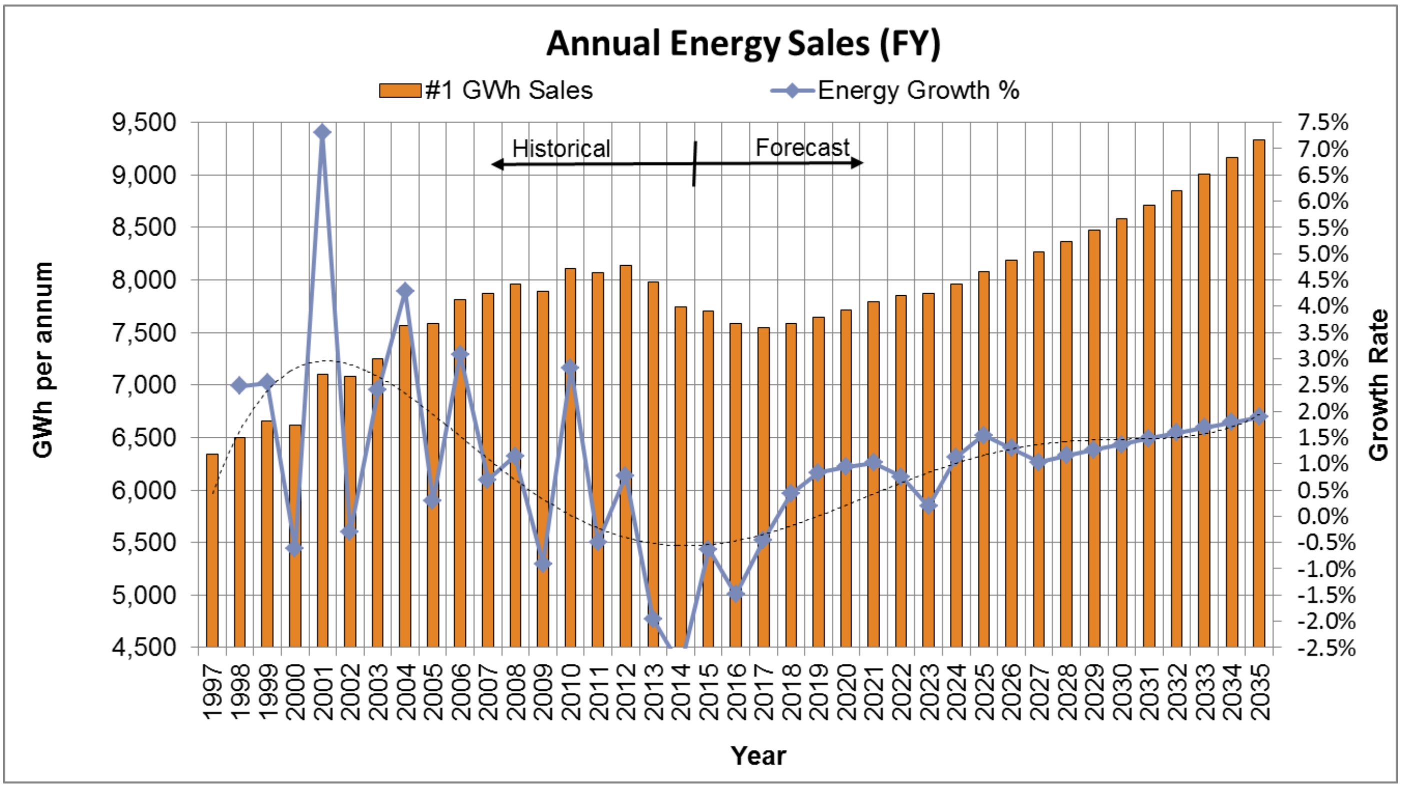
The peak demand forecast is predominantly used to trigger investigation into the economic viability of augmentation options which are economically assessed based on expected energy-at-risk.

4.4.3. Annual Energy Forecast

Government policies, particularly those encouraging energy efficiency and distributed generation, the increasing average overnight temperatures, and the ongoing uncertainty in the global economy will continue to have a significant impact on energy sales in the UE service area. It is projected that growth in energy sales will remain close to zero for the next the regulatory period in an environment of marginally increasing maximum demand. Growth in energy consumption is expected to pick up to around 1.5% pa as the local economy recovers and as energy efficiency measures and price impacts taper off.

Based on NIEIR medium economic forecasts up until 2023-2024, the forecast UE annual energy sales and historical annual energy sales are shown below. Projections up to 2033-2034 are based on the NIEIR forecast trend adjusted for a flattening load factor as air-conditioning penetration saturates over time, modified with the customer usage adjustments described in the Business-As-Usual Demand Scenario #1.

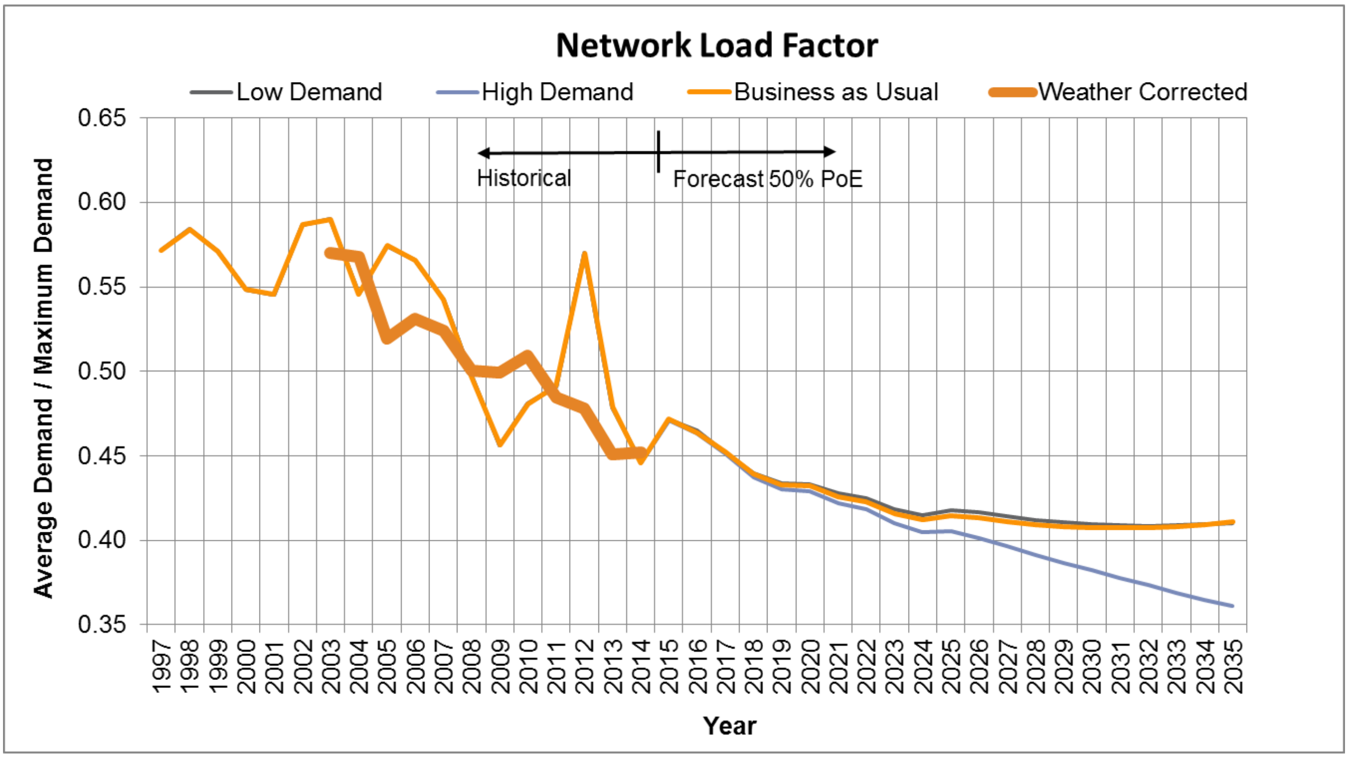
Figure 4-28: Annual forecast of energy sales – demand scenario #1: BAU



4.4.4. Load Factor Forecast

Network load factor, defined as the ratio of annual energy sales to the maximum demand multiplied by 8766, is a good indicator of the variability of the demand throughout the year. A low load factor means there is less energy supplied per unit of demand supplied and therefore a greater divergence between the average demand and the maximum demand. The historical and forecast load factors are illustrated below for the 20 year horizon for each of the three demand scenarios.

Figure 4-29: Historical & Forecast load factor



Decreasing load factor puts pressure on distribution pricing. In general new network investment is driven by increasing maximum demand but the corresponding revenue is recovered through the energy sales, which is not forecast to increase at the same rate. This can result in inefficient network utilisation and higher tariffs. UE has attempted to address this by developing network tariffs which encourage demand management at times of network maximum demand, for example, the summer demand incentive charge, but further tariff development and demand management initiatives associated with smart meters is needed to improve the load factor.

During the heatwave in 2014, the load factor on the UE network reached a record low of 0.45. The prior summers in 2010, 2011 and 2012 were not as low, but still in line with a downward trend as shown by the weather-corrected load factor. The load factor is expected to remain above 2014 levels in the short term. In 2013/14, the summer peak was 33% (approx. 500MW) higher than the winter peak demand and this comprises predominantly of air-conditioning and evaporative-cooling load. This additional capacity to supply the summer peak was needed for only 130 hours (or 1.5%) of the year. Given that utilities invest in their networks to meet peak demand, continuing to invest in this way in large network augmentations within the distribution and transmission networks which is utilised for 1.5% of the year is unsustainable over the long term. Future investment in distributed generation for network support and demand-side management is needed to reverse the trend. Recent regulatory changes surrounding Demand Capex investment is geared to encourage alternative investments.

4.4.5. Power Factor Forecast

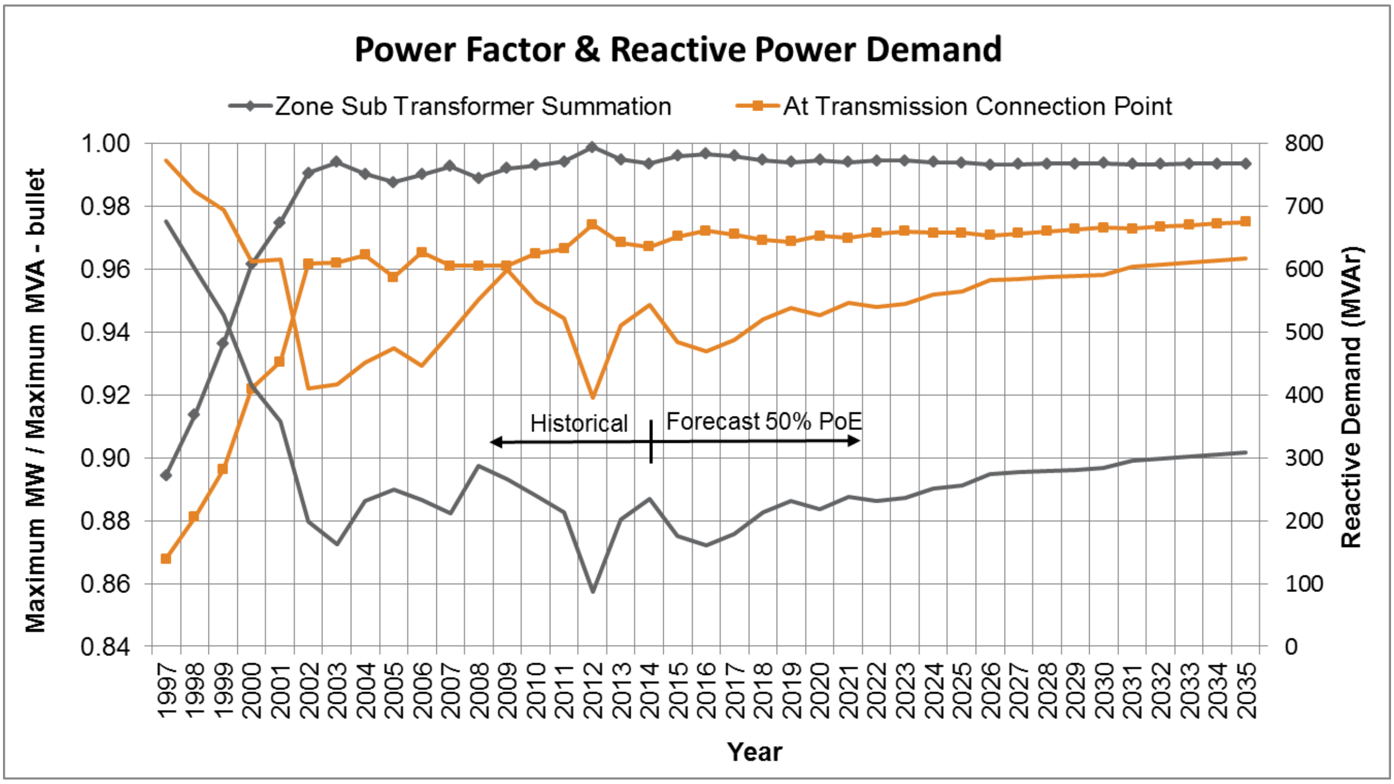
Poor power factor consumes network capacity. Releasing this capacity through the installation of power factor correction capacitors defers more expensive network augmentations and can address unforeseen constraints quickly.

UE has developed innovative pole mounted switchable capacitor banks for installation along HV feeders in conjunction with manufacturers and has become an Australian leader in this practice. UE now has 520 capacitor bank units, providing about 443MVAr of reactive support for the network. This is in addition to 330MVAr of capacitor banks already installed at the zone substations.

Average power factor at time of summer peak at zone substations (transformation summation) has improved from 0.894 in 1997 to 0.994 in 2014. At the transmission connection points, the average power factor improved from 0.868 in 1997 to 0.967 in 2014 (excluding terminal station capacitor banks). This improvement is depicted in the following chart. In many parts of the high voltage distribution system, the power factors at demand peaks are near unity. This indicates that there are only targeted opportunities for using pole-top capacitors to defer further demand-related augmentation. Targeted deployment of capacitors (on distribution feeders as well as at the zone substations) will continue over the 20-year planning period in order to further optimise the network.

Improvements in customer power factor have also been delivered following the introduction of kVA demand charges into UE's tariff structure in 2000. The power factor and system reactive power demand forecasts are shown below assuming the proposed works programme in this Demand Strategy & Plan.

Figure 4-30: Overall power factor & reactive power demand

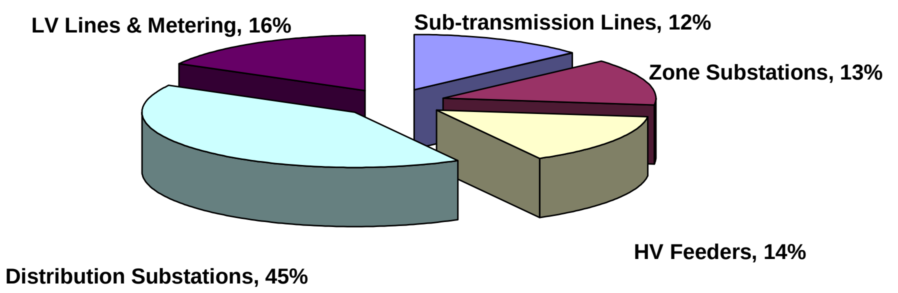


4.4.6. Network Losses Forecast

UE network losses in 2012-2013 (as submitted to the Australian Energy Regulator - AER in conjunction with Distribution Loss Factors) were calculated to be 4.3% as a percentage of sales and represented an energy loss of 341GWh. This was based on the difference between the energy purchased at the bulk supply points and the energy sold to customers taking into account large embedded generation.

The allocation of electrical losses across the network in 2012-2013 is shown below.

Figure 4-31: Allocation of electrical losses

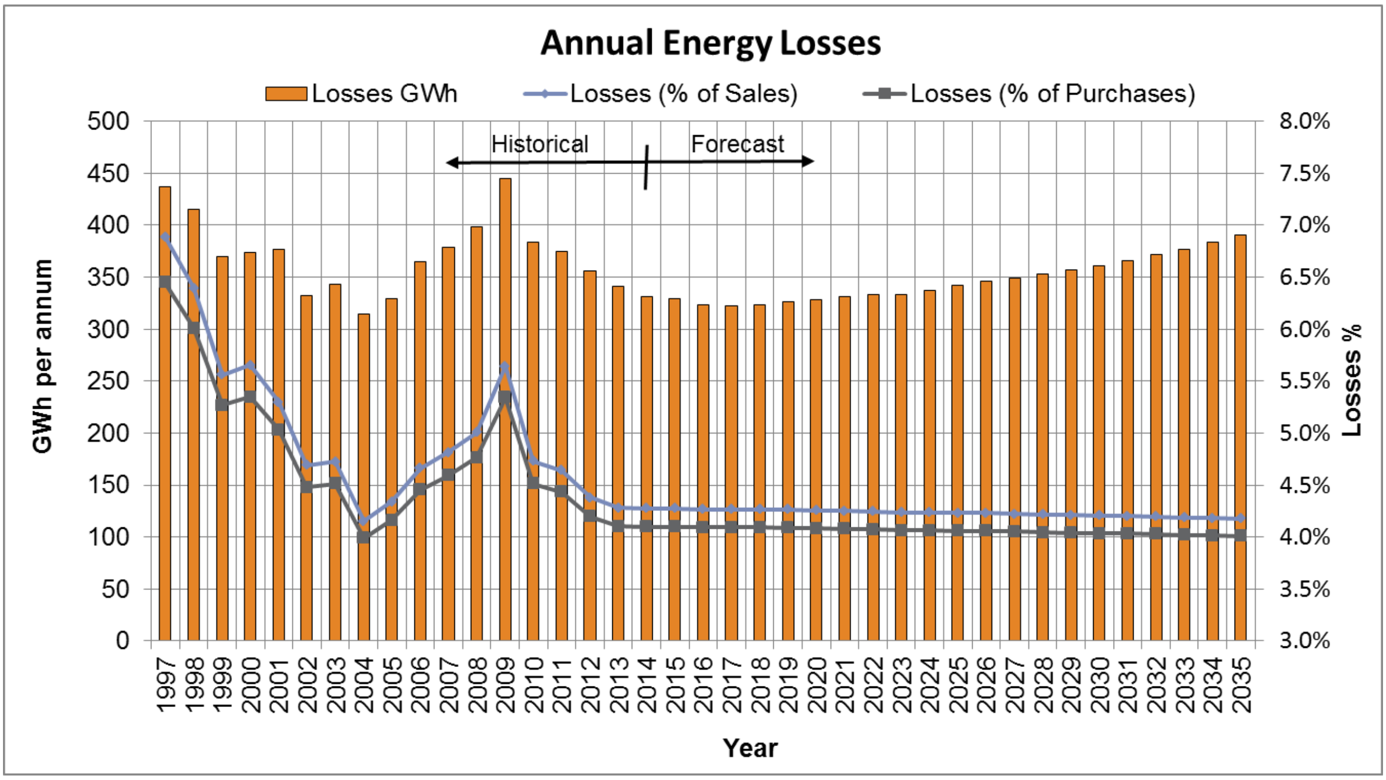


The UE level of losses compares favourably with ESAA published comparison figures which rank UE as the distributor with the fourth lowest losses as a percentage of sales for Australian utilities (based on the ESAA 2012-2013 benchmarking report of 14 distributors).

The figure below summarises UE's recent history of network losses. Substantial reduction in losses is attributed to aggressive pole-mounted capacitor installation programme implemented between 1997 and 2004.

UE plans to target key parts of the network with the installation of capacitor banks to maintain losses at their current levels over the medium term. Other types of network augmentations and replacement of aged higher loss transformers with low loss more efficient units generally has a downward effect on losses. The forecast losses are presented below assuming the proposed works program in this Demand Strategy & Plan.

Figure 4-32: Distribution Network Losses



Under the Greenhouse Challenge Cooperative Agreement, UE made a commitment to reduce electrical losses to 5% of sales by 2004. UE not only succeeded in reaching the target well before 2004, it has also managed to maintain the network losses below the 5% of sales up to now (except in 2009). UE's long term objectives are to maintain losses below 4.5% of sales by the end of 2034.

Possible options available to further reduce electrical losses include:

- Targeting high loss distribution feeders. Network analysis reveals that feeders with utilisation as low as 40% may still have high-energy losses. Unfortunately, most high loss feeders that do not have high utilisation are feeders that extend over long distances in rural areas. Re-conductoring, installing line capacitors or establishing new feeders to reduce losses is generally uneconomic for lightly utilised feeders;
- Targeting high loss transformers to be replaced with more efficient low loss units;
- Promoting kVA tariff, summer demand incentive tariff and other tariffs which help to shift the usage from summer peak periods to off-peak periods for smaller customers;
- Addressing losses created by poor power quality (eg. harmonic and unbalance); and
- Promoting the growth of renewable energy sources and embedded generation.

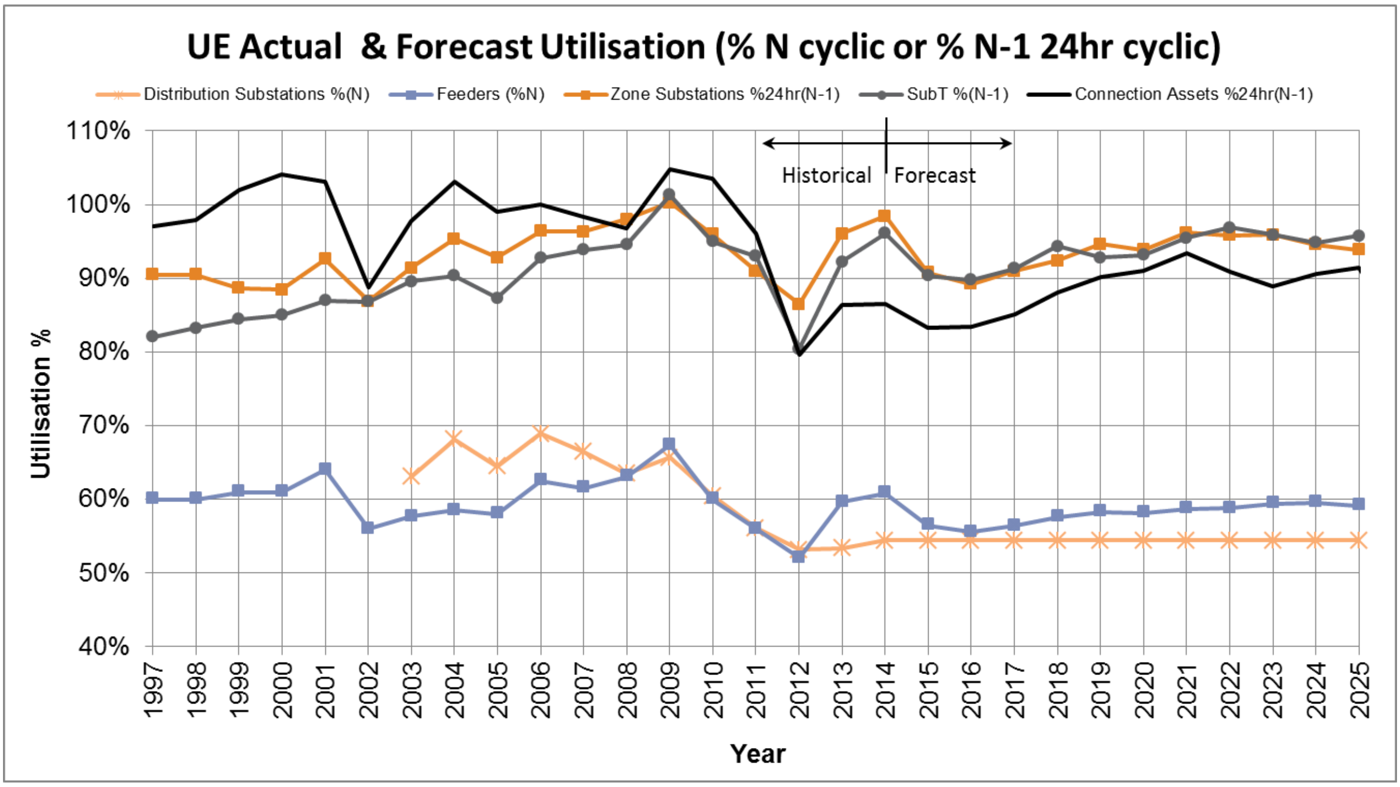
UE currently has an obligation to report and forecast network energy losses as part of the annual Distribution Loss Factor (DLF) submission process. These are approved by the AER prior to publication by the Australian Energy Market Operator - AEMO by 1 April annually. Losses are compared with other networks by the AER.

UE attempts to minimise the cost of losses in its network investments. UE currently achieves this by procuring plant whose life cycle cost includes the cost of losses. In every major network capital expenditure project (demand augmentation and asset replacement), UE evaluates the energy loss reduction that could be obtained from each feasible option, including network and non-network solutions. Network energy loss reduction benefits are valued based on the long run marginal cost of electricity generated in Victoria (the market average spot price), and the value of distribution network capacity that is made available when energy losses are reduced (the released capacity benefit). Energy losses are therefore valued on the current cost of energy in such a way as to minimise the overall cost of electricity for customers. This method is in accordance with RIT-D.

4.5. Asset Utilisation Forecasts

Distribution network and connection asset capacity constraints are generally related to thermal capacity of plant in summer, when network loading is at its highest and plant rating is at its lowest. Asset utilisation in this context is defined as the thermal loading of assets at times of maximum demand expressed as a percentage proportion of their thermal limited cyclic N-1 rating (under an N-1 scenario for connection assets, zone substations and sub-transmission loops or N rating for distribution feeders and distribution substations) being normal planning attributes. The historical asset utilisation and forecast utilisation (assuming the works programme in this Demand Strategy & Plan proceeds) is shown below.

Figure 4-33: Historical & Forecast Asset Utilisation at Peak Demand



On average the utilisation of UE's sub-transmission lines has steadily increased over the years except in the last few years when milder weather conditions have prevailed. Last summer saw the return of hot weather and this is reflected in the asset utilisations above for 2014. Most of the highly utilised loops have now been reconducted to achieve maximum rating. UE will continue to manage this utilisation by augmenting sub-transmission loops into meshed loops which can provide substantial increases in rating at a much lower cost than establishing completely new sub-transmission loops. Regardless, a steady investment in sub-transmission augmentation is forecast.

Connection assets saw utilisation maintained in 2014 because of the major augmentation that occurred at TBTS just prior to the 2013/14 summer. Connection asset utilisation used to be the highest of all the HV asset classes but with recent augmentations is now in line with zone substation and sub-transmission asset utilisation levels. UE has managed the risk at terminal stations by establishing sub-transmission emergency ties between critical stations to increase the emergency transfer capability, post contingency.

Feeder utilisation has remained fairly steady over time. UE's distribution feeder planning criteria aims to preserve 33% spare capacity (at N rating) to accommodate a 50% load transfer from an adjacent feeder in the event of an outage of the adjacent feeder (N-1 scenario) on average across the population of feeders. On this basis, a 67% average distribution feeder utilisation means that on average UE's distribution feeders will be loaded to 100% when required to pick up an adjacent feeder load (67% + 33% = 100%). Whilst this remains the overarching philosophy, the trigger for considering augmentation of individual distribution feeders is generally set at 85% utilisation under 10% PoE loading conditions.

UE's use of probabilistic planning techniques over the last 15 years has deferred augmentation expenditure to the benefit of end-customers through lower distribution prices relative to other distribution businesses without any measurable deterioration in reliability of supply. These techniques have led to increased network utilisation.

The following table presents a high level summary of the number of assets which are expected to exceed their thermal rating for summer 2014-2015.

Table 4-17: Forecast 2014-2015 asset utilisation

Network Elements	Total number of elements	Number of assets forecast to exceed their rating in summer 2014-2015 for 10%PoE
Transmission Connection Assets	11	2 forecast above (*N-1) 24hr Cyclic* rating 0 forecast above (*N) Cyclic* rating
Sub-transmission Systems	25	10 forecast above (*N-1)* rating 0 forecast above (*N)* rating
Zone Substations	47	2 zone substations have single transformers (KBH & DMA) 15 forecast above (*N-1) 24hr Cyclic* rating of which 12 forecast above (*N-1) 2hr Cyclic* rating 0 are forecast above (*N) Cyclic* rating
HV Distribution Feeders	439	71 forecast above 85% of their rating of which 0 are forecast above 100% of their rating

Each of the asset levels are now discussed in detail.

4.5.1. Connection Assets

UE takes bulk supply at 66kV (and some 22kV) from 11 terminal stations owned by AusNet. While UE does not own the assets, UE is however responsible for planning the connection assets at these terminal stations which include the 220/66kV (or 22kV) transformers, buses and sub-transmission feeder exits. At seven terminal stations, supply is shared with other distribution businesses and therefore joint planning and risk sharing arrangements exist.

Table 4-18: UE supply

TERMINAL STATION	UE ZONE SUBSTATIONS & SUBT	SHARE OF MD
Cranbourne Terminal Station (CBTS/FTS 66kV)	CRM-LWN-FTN	UE 41% SPIE 59%
East Rowville Terminal Station (ERTS 66kV)	DN-DSH-DVY, LD-MGE	UE 72% SPIE 28%
Heatherton Terminal Station (HTS 66kV)	NB-BT-MR, SR-CM-HT, KBH-M-MC-BR	UE 100%
Malvern 66kV Terminal Station (MTS 66kV)	CFD-EL-EM, OAK-OR	UE 100%
Malvern 22kV Terminal Station (MTS 22kV)	BW-SH	UE 100%
Richmond Terminal Station (RTS 66kV)	EW, K	UE 9% CitiPower 91%
Ringwood 66kV Terminal Station (RWTS 66kV)	BH-NW	UE 23% SPIE 77%
Ringwood 22kV Terminal Station (RWTS 22kV)	RWT12, RWT13, RWT23, RWT24, RWT34 & RWT35	UE 36% SPIE 64%
Springvale Terminal Station (SVTS 66kV)	CDA-OE, EB, GW-NO, NP-SS, SV-SVW	UE 94% CitiPower 6%
Tyabb Terminal Station (TBTS 66kV)	DMA-RBD-STO, FSH-MTN, HGS	UE 100%

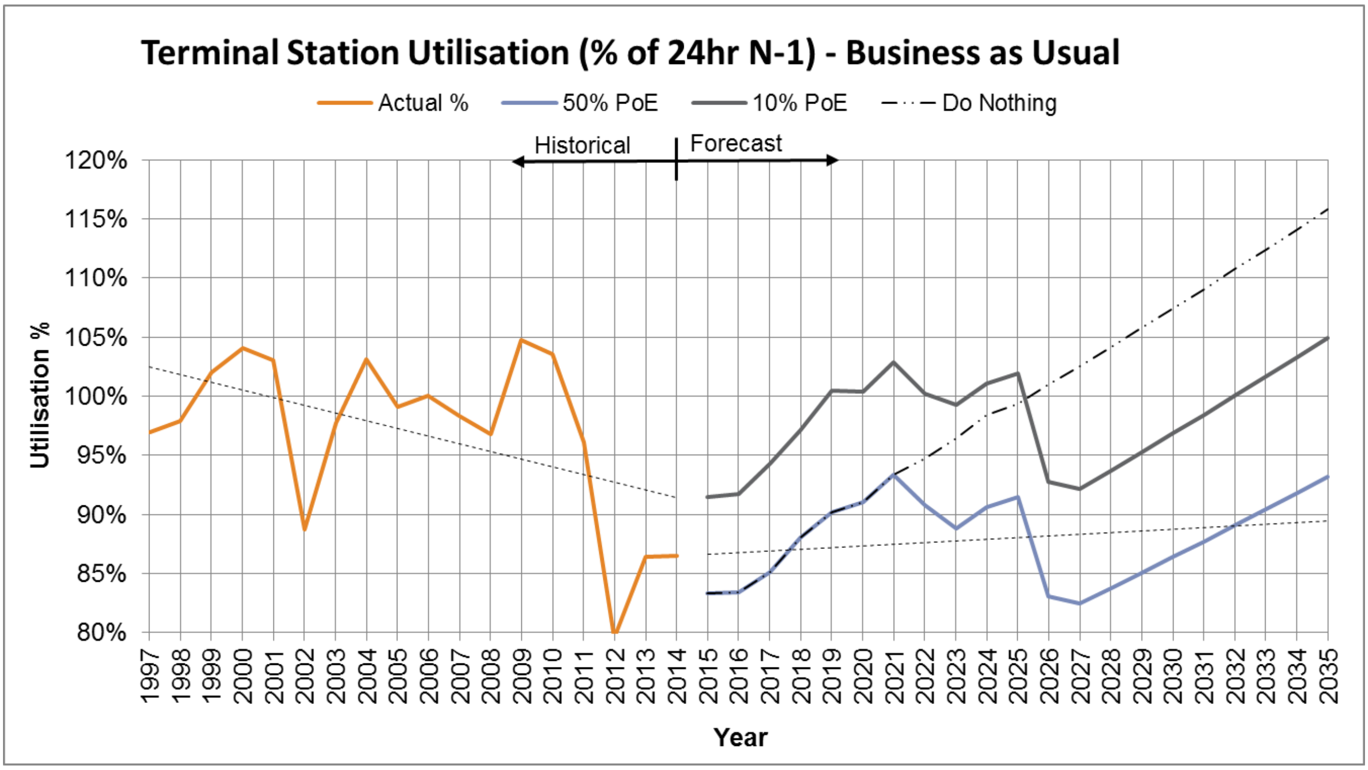
TERMINAL STATION	UE ZONE SUBSTATIONS & SUBT	SHARE OF MD
Templestowe Terminal Station (TSTS 66kV)	BU-WD, DC	UE 40%, CitiPower 27%, SPIE 25%, JEN 8%

The cost of maintaining and upgrading these points of supply is passed to UE by AusNet as connection charges via Transmission Use of System (TUOS) charges. Generally all augmentations to a connection point will require a RIT-T to be undertaken for economic justification. Although capex invested in the connection assets is not UE capex, it is in UE's interest to ensure that any capital expenditure performed at the terminal stations is prudent and efficient.

With the present loading levels, the connection assets at the supply point terminal stations are expected to remain within their (N-1) ratings for most of the time in a year, except on hot working weekdays in summer at a number of terminal stations. To ensure that the connection assets operate within the ratings provided by the asset owner (AusNet) at all times, an automatic load shedding scheme is enabled at highly loaded terminal stations. The scheme, referred to as OSSCA (Overload Shedding Scheme for Connection Assets), monitors the loading at the supply point terminal stations and sheds load at the sub-transmission level to avoid damage to plant following a contingency. The scheme is armed by AusNet when the station load is expected to exceed its 24 hour limited (N-1) cyclic rating.

During the last record maximum demand in summer 2009-2010, terminal stations' loadings, on average, reached 105% of their 24 hour (N-1) cyclic rating. The figure below presents average summer terminal station utilisation over the past 15 years together with their projected average summer utilisation over the next 20 years based on a bottom-up forecast of connection asset related projects for a 50% and 10% PoE. The steady trend over the period is in line with UE's plan to maintain the risk at connection assets within 100% utilisation levels.

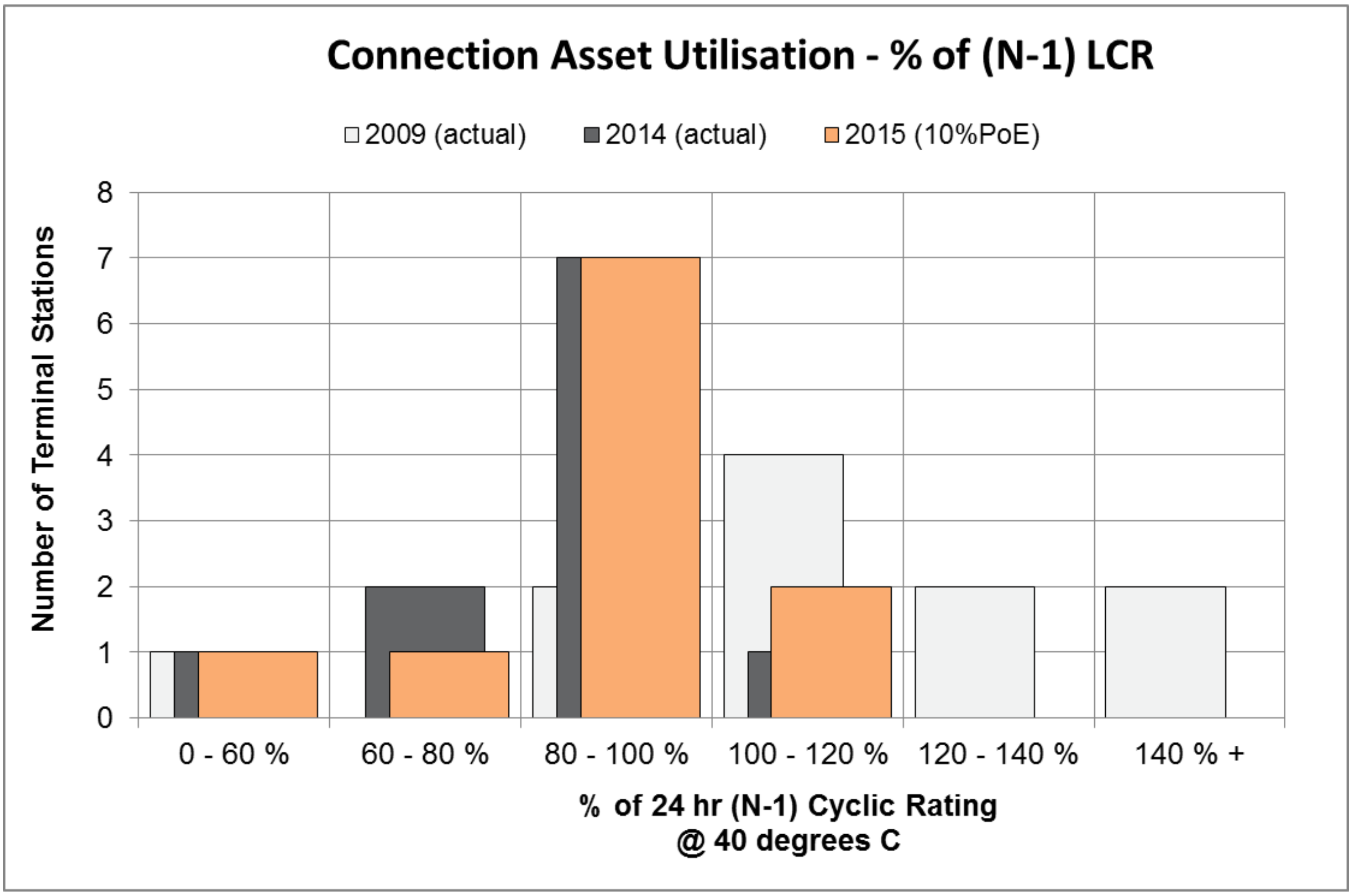
Figure 4-34: Average summer terminal station utilisation and long term trend



The major step down in 2026 is due to the establishment of a proposed new terminal station in the Dandenong area.

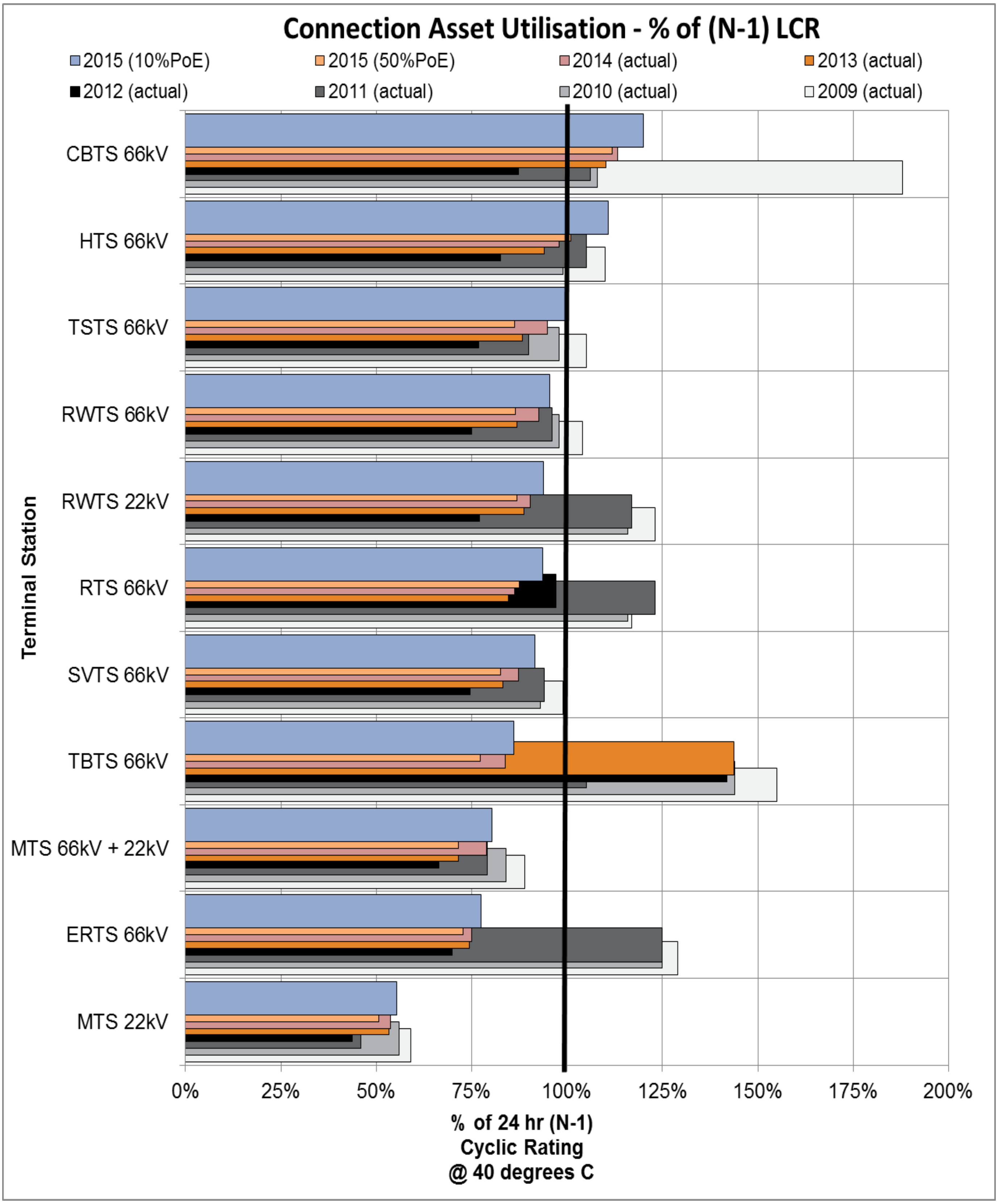
The (N-1) utilisations for each connection asset are presented below.

Figure 4-35: Connection asset (N-1) utilisation distribution (2014-2015 forecast)



Under a medium economic growth 10% PoE scenario, it is projected that 2 terminal stations (CBTS and HTS) will exceed their 24 hour (N-1) cyclic rating in the 2014-2015 summer.

Figure 4-36: Connection asset (N-1) utilisation (ranked by 2014-2015 forecast utilisation)



UE has the following plans to address immediate and emerging (N-1) risks at the connection assets. These plans are supported by risk assessments undertaken for the Transmission Connection Planning Report (TCPR):

1. **CBTS 66kV:** This station was augmented with a new 3rd 150MVA 220/66kV transformer for summer 2009-2010. It is planned to augment the station with a 4th 150MVA 220/66kV transformer for summer 2021-2022.

2. **HTS 66kV:** No immediate short term plans. AusNet plans to replace the ageing assets including three 220/66kV transformers in 2017. Longer term plans are to establish a new terminal station in the Dandenong area to offload HTS in 2025-2026. Further capacity addition at HTS is constrained by the thermal rating of the SVTS-HTS 220 kV radial lines.

3. **TSTS 66kV:** No immediate short term plans. It is planned to augment the station with a 4th 150MVA 220/66kV transformer for summer 2025-2026.

4. **RWTS 66kV:** No immediate short term plans. It is planned to augment the station with a 5th 150MVA 220/66kV transformer for summer 2023-2024.

5. **RWTS 22kV:** The asset owner, AusNet, has replaced the ageing equipment including two 220/22kV transformers for summer 2013-2014. This has reduced the risk at RWTS 22kV by providing a marginal increase in the (N-1) rating. A 3rd 220/22kV transformer will be required by 2026-2027.

6. **RTS 66kV:** A temporary 5th 150MVA 220/66kV transformer was installed at this terminal station in 2012. This station did have a significant (N-1) load at risk. At RTS 66kV, the asset owner, AusNet, has indicated that their present plan is to replace the ageing equipment over the next three years this will involve replacement of five 150MVA 220/66kV transformers with three 225MVA 220/66kV transformers. Further CitiPower has intentions of augmenting RTS 66kV with a fourth 225MVA 220/66kV transformer and establishing BTS 66kV with three 220/66kV transformers within the next three years to relieve the risk at RTS 66kV. UE also installed a sub-transmission emergency tie line between RTS and MTS in 2012 to mitigate load at risk.

7. **SVTS 66kV:** AusNet plans to replace the ageing assets including three 220/66kV transformers in 2021. Longer term plans are to establish a new terminal station in the Dandenong area to offload SVTS in 2025-2026.

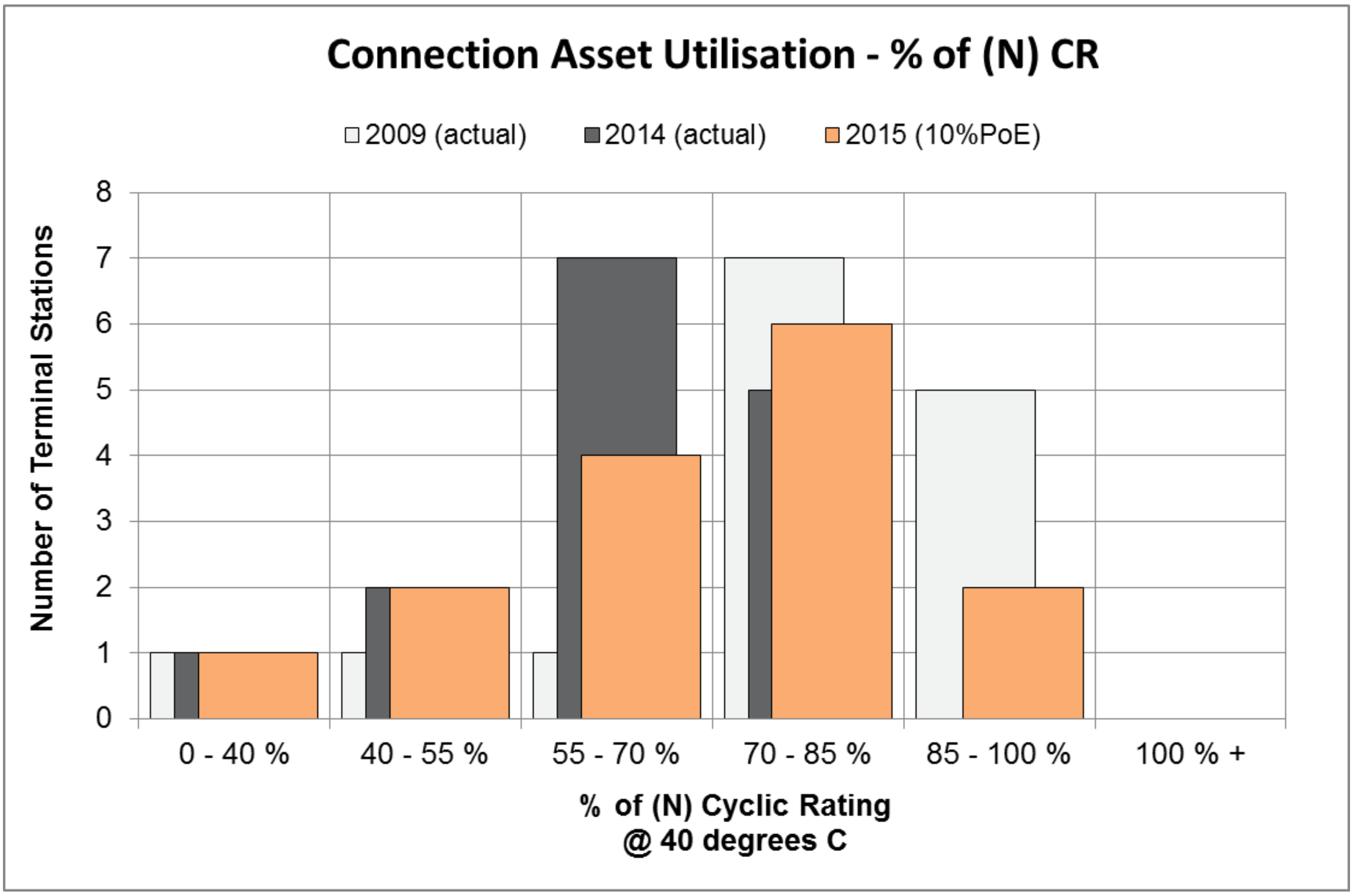
8. **TBTS 66kV:** No immediate short term plans. This station was augmented with a 3rd 150MVA 220/66kV transformer during 2013.

9. **MTS 66kV and 22kV:** No immediate short term or medium term plans for augmentation.

10. **ERTS 66kV:** This station was augmented with a new 4th 150MVA 220/66kV transformer for summer 2011-2012. Longer term plans are to establish a new terminal station in the Dandenong area to offload ERTS.

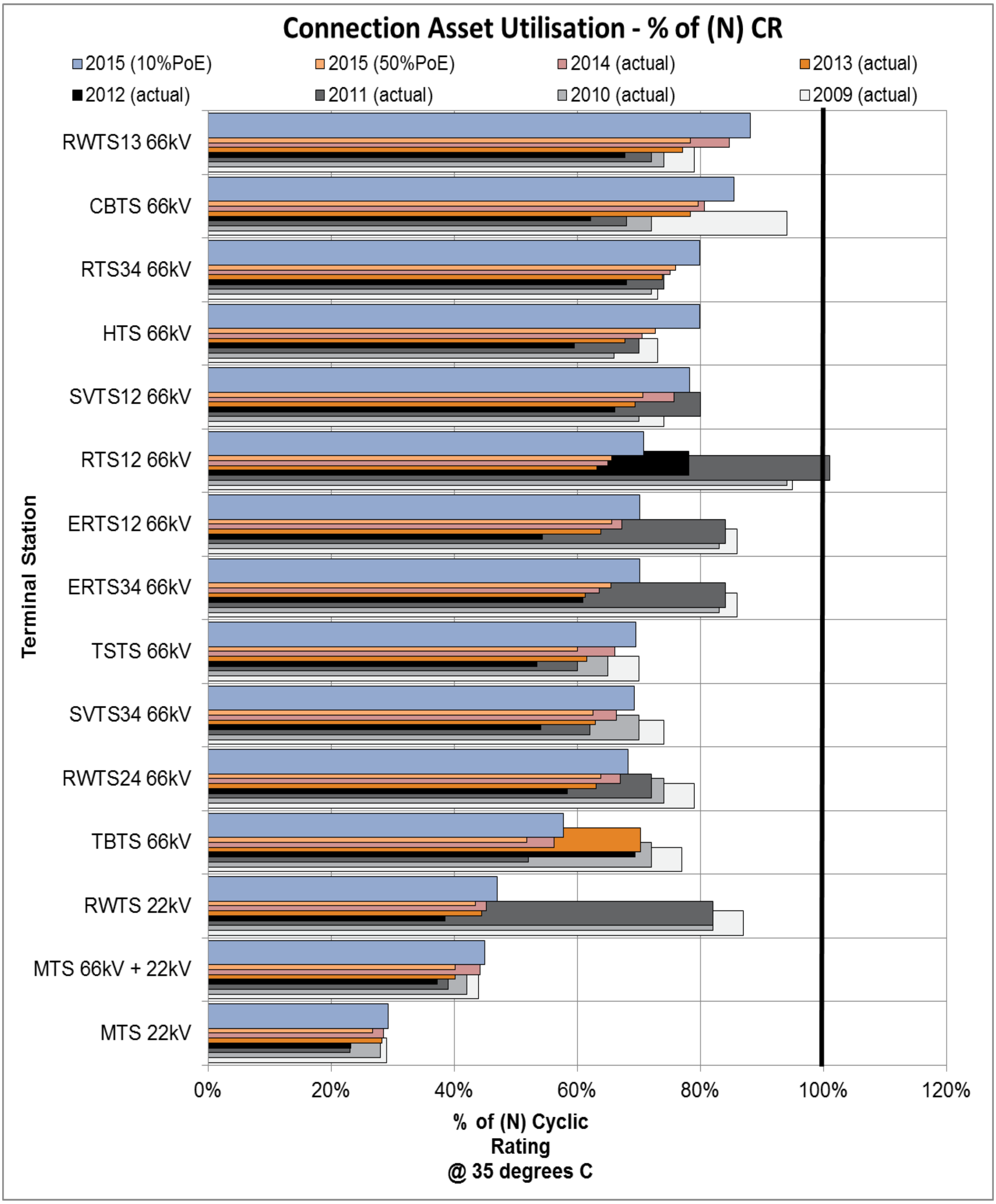
The (N) utilisations for each connection asset are presented below.

Figure 4-37: Connection Asset (N) Utilisation Distribution (2014-2015 Forecast)



Under a medium economic growth 10%PoE scenario, it is projected that no terminal stations will exceed (N) cyclic ratings in the 2014-2015 summer.

Figure 4-38: Connection asset (N) utilisation (ranked by 2014-2015 forecast utilisation)



UE has the following plans to address immediate and emerging (N) risks at the connection assets. These plans are supported by risk assessments undertaken for the Transmission Connection Planning Report (TCPR):

1. **RWTS13 66kV:** It may be required to rebalance the loads on the 13 and 24 66kV bus groups to defer the need to augment RWTS 66kV or install power factor correction on 13 group. This will reduce the risk at RWTS13 66kV of exceeding the (N) rating. It is planned to augment the station with a 5th 150MVA 220/66kV transformer for summer 2023-2024.

2. **CBTS 66kV:** This station was augmented with a new 3rd 150MVA 220/66kV transformer for summer 2009-2010. It is planned to augment the station with a 4th 150MVA 220/66kV transformer for summer 2021-2022.

3. **RTS34 66kV:** The asset owner AusNet will rebuild RTS over the next few years, replacing the existing 150MVA transformers with 225MVA transformers. This will address the emerging risk of exceeding the N rating on this bus group.

4. **HTS 66kV:** AusNet plans to replace the ageing assets including three 220/66kV transformers in 2017. Longer term plans are to establish a new terminal station in the Dandenong area to offload HTS in 2025-2026. Timing of this project is driven by (N-1) constraints on ROTS-SVTS 220kV.

5. **SVTS12 66kV:** The 34 bus group is more lightly loaded than the 12 bus group. UE plans to balance the buses in 2020-2021 by transferring OE and CDA between the two groups at the time of the SVTS rebuild, prior to establishing a new terminal station in the Dandenong area in 2025-2026. Timing of this project is driven by (N-1) constraints on ROTS-SVTS 220kV.

The risk at each terminal station is assessed based on the initial load to be shed following a transformer outage, and the residual load at risk following completion of load transfers. The risk assessment for the 2014/15 summer based on a 10% PoE maximum demand are summarised below.

Table 4-19: Transmission connection asset load at risk

Terminal Station Risks & Transfer Capability Assessment Summer 2014/15

Basis: 10%Probability of Exceedance

Terminal Station	kV	OSSCA setting at 40 deg C Amp	OSSCA setting at 40 deg C MVA	PROJECTED 10%PoE SUMMER 2012/13 MD (worst case contingency resulting in loss of cap banks) MW	MVAr	MVA	Amp	Load in Excess of OSSCA setting MVA	UE Share	Share of Load above OSSCA setting (MVA) UED	CitiP	AusNet	JEN	UE's REQUIRED LOAD TRANSFERS MVA	Automatic Load Shedding by OSSCA Under Overload Conditions	HV Transfer Capability MVA	SubT Transfer Capability MVA	Load at Risk After Transfers MVA	Comments
CBTS	67.0	3296	382.5	440.2	129.8	458.9	3955	76.4	41%	31.3		45.1		31.3	CRE followed by FTS, CRM, LWN, FTN followed by CLN, NRN, BWN, PHM, LLG, OFR if required	33	180	0	
ERTS	67.0	5064	588	449.3	22.2	449.8	3876	0.0	72%	0.0		0.0		0.0	BGE & FGY followed by None if required	42	57	0	
HTS	67.0	2930	340	376.6	86.3	386.4	3329	46.3	100%	46.3				46.3	BT, MR, NB followed by BR, M, MC if required	61	231	0	
MTS22	22.6	2073	81	43.5	10.7	44.8	1134	0.0	100%	0.0				0.0	SH followed by BW if required	7	0	0	
MTS	67.5	2467	288	225.8	50.2	231.3	2023	0.0	100%	0.0				0.0	OAK & OR followed by EL & EM if required	16	96	0	
RTS	67.0	5600	650	598.8	146.6	616.5	5312	0.0	9%	0.0	0.0			0.0	CL & K followed by AR, BC & TK	10	97	0	
RWTS22	22.7	2416	95	89.2	1.2	89.2	2320	0.0	36%	0.0		0.0		0.0	RWT25 followed by RWT15, 24, 22, 11, 28, 14, 16 if required	11	0	0	
RWTS	67.0	4536	526	500.7	131.2	517.6	4460	0.0	23%	0.0		0.0		0.0	BH & NW followed by LDL, WYK & RWN if required	40	0	0	
SVTS	67.5	4457	521	474.1	40.6	475.8	4070	0.0	94%	0.0	0.0			0.0	GW & NO followed by NP & SS if required	76	66	0	
TBTS	67.5	2976	348	297.8	81.4	308.7	2701	0.0	100%	0.0				0.0	HGS followed by DMA, RBD & STO followed by FSH & MTN if required	26	86	0	
TSTS	67.0 67.0	2745 3192	319 (1) 370	363.6 363.6	116.0 116.0	381.7 381.7	3289 3289	63.1 11.2	40% 40%	25.2 4.5	17.0 3.0	15.8 2.8	5.0 0.9	25.2 4.5	ELM followed by BU & WD if required	24 24	0 0	2 0	

UE TS Supportable Demand 2489 MVA

(1) Alarm only - disables transformer OLTC operation as the limitation is due to over-voltage limit on taps

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Whilst there are 2 terminal stations with load at risk under (N-1), no terminal stations have residual load at risk after load transfers.

The detailed assessment of connection asset constraints and load at risk is provided in the 2014 Transmission Connection Planning Report (TCPR), a joint Victorian Distribution Business publication revised annually with a 10-year outlook.

Based on the 20-year load forecasts at each terminal station and the need to provide additional sub-transmission exit capability from the terminal stations, the major augmentation works proposed at the connection points over the next 20 years with corresponding commissioning summers are presented below. These plans are supported by risk assessments undertaken for the Transmission Connection Planning Report (TCPR):

Table 4-20: Transmission connection asset project list

Connection Asset	Next planned augmentation within 20-year horizon	Timing
CBTS / FTS	CBTS 4th Transformer and 66kV line rearrangements CBTS one new exit for SKE zone substation CBTS one new exit for LHT zone substation	2021-2022 2020-2021 2032-3033
ERTS	ERTS 66kV new feeder exit(s) for SCY	2025-2026
HTS	DNTS New Dandenong Terminal Station[12]	2025-2026
MTS	MTS 66kV two new feeder exits for BW and SH	Beyond 20 years
RWTS	RWTS 5th B transformer RWTS 3rd L transformer	2023-2024 2026-2027
SVTS	SVTS New Feeder CBs to transfer OE and CDA to Bus 3/4 group at SVTS or at time of SVTS rebuild	2023-2024
TBTS	TBTS-HGS 66kV feeder exit upgrades	2018-2019
TSTS	TSTS BU, WD, DC No. 1 and No. 2 feeder exit upgrades TSTS 4th Transformer TSTS 66kV one new feeder exit for TSE	2019-2020 2025-2026 Beyond 20 years[13]

220kV transmission lines are the planning responsibility of AEMO, however there are a number of circuits which supply UE radially, thereby introducing common mode failure risk, unique to UE's service area. Two radial double circuit 220kV transmission lines from ROTS 220kV and one radial double circuit 220kV transmission line from CBTS 220kV are the source of supply to four terminal stations supplying UE, being HTS, MTS, SVTS, and TBTS. Each 220kV line comprises lattice braced steel towers supporting two 220kV overhead circuits. Loss of any one of these tower lines will result in total loss of supply to the terminal stations connected to it. The table below summarises the UE demand at risk associated with the failure of a tower line:

[12] During 2014, AEMO undertook a pre-RIT-T economic study into the constraints associated with the ROTS-SVTS 220kV lines. The results of the study indicate that is is economically viable to offload or reinforce the ROTS-SVTS 220kV by 2025/26. One of the options being considered by AEMO is establishment of DNTS. This option would alleviate the ROTS-SVTS 220kV constraint by offloading these lines, and address UE's subtransmission and connection asset constraints in the area at the same time.

[13] May be required earlier if establishing TSE passes the RIT-D in lieu of DC 4th transformer.

Table 4-21: Radial transmission risk

Radial Double Circuit 220kV Transmission Line	Connecting Terminal Stations	% of UE Demand at Risk
ROTS-SVTS-HTS	HTS (& SVTS)	37%
ROTS-MTS	MTS	8%
CBTS-TBTS	TBTS	13%
TOTAL UE DEMAND AT RISK		58%

In the unlikely event of loss of a tower line, a significant part of UE's load could be off supply for one week or more, however the following risk reduction actions are presently in place:

- Re-configuration of the distribution system at 22kV and 11kV in progressively restoring customer supply from adjacent terminal stations. In most cases the re-configuration can be completed in 2 hours by manual field switching. If remote controlled switches are available, restoration time may be reduced to 2 minutes per switching zone.
- Re-configuration of the 66kV sub-transmission system to restore part customer demand from adjacent terminal stations. A number of emergency 66kV ties have already been constructed for CBTS, ERTS, HTS, MTS, RTS, RWTS, SVTS, TBTS and TSTS. It is expected that, in most cases, part supply can be restored in 2 hours (per tie) by making use of the emergency ties. The present 66kV remote-controlled switchgear at Frankston Terminal Station (FTS) will provide for quick restoration of supply to areas supplied by CBTS and TBTS. These 66kV emergency ties have reduced (but not eliminated) the double-circuit transmission tower risk.
- In addition to the above, AusNet, the owner of the 220kV tower lines, has in place emergency by-pass measures, utilising temporary structures and mobile cranes. These allow for restoration of full supply within 12 hours in over half of the possible tower failure cases or two-weeks for all other towers. They also have emergency measures to restore full supply to MTS within 6 hours from the adjacent ROTS-RTS transmission line.

UE is currently undertaking joint planning activities to continue to manage exposure to radial double circuit transmission line failure.

Further details are contained in UE's 2014/15 Contingency Plans (UE MA 2204).

4.5.2. Sub-transmission

UE has a network of predominantly 66kV and some 22kV lines which connect the connection assets at the AusNet terminal stations to UE's zone substations. These lines are generally arranged in looped and meshed systems to enable the connected zone substations to continue to operate at full supply with the loss of any single circuit. UE's probabilistic approach to planning does however allow these systems to be loaded above this firm capability such that there is some level of load-at-risk. A detailed assessment of sub-transmission asset constraints and load at risk is provided in the Distribution Annual Planning Report (DAPR), a UE publication revised annually with a 5-year outlook.

A total of 9 sub-transmission systems exceeded their (N-1) thermal rating based on a 40°C ambient temperature and wind velocity of 3m/s at 15 deg to conductor axis in summer 2013-2014. The average utilisation of UE's sub-transmission systems reached 96% in summer 2013-2014, below the record peak in 2008-2009 of 101%. The figure below presents average summer sub-transmission utilisation over the last 15 years together with projected average summer utilisation over the next 20 years (Note: Projected utilisations are shown for a 50% and 10% probability of exceedance).

Figure 4-39: Average sub-transmission summer peak utilisation & long term trend

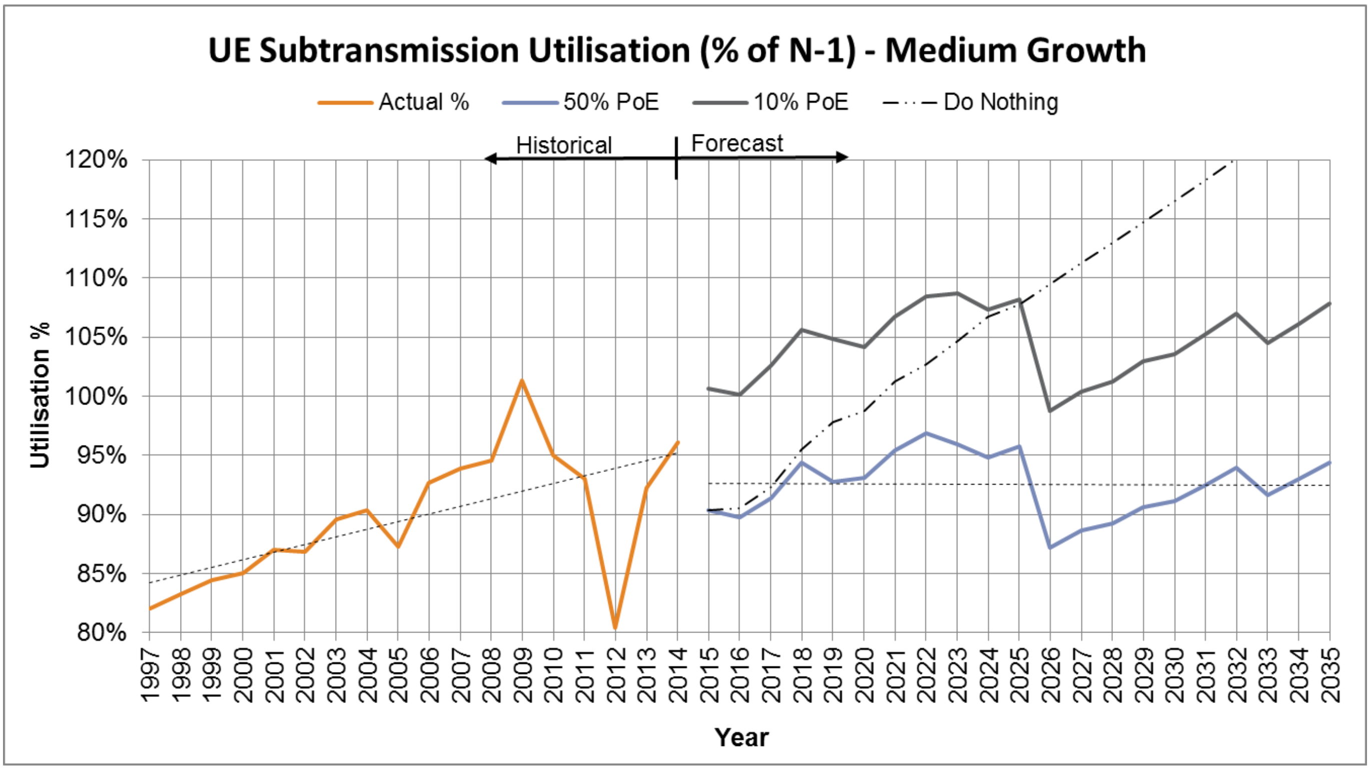
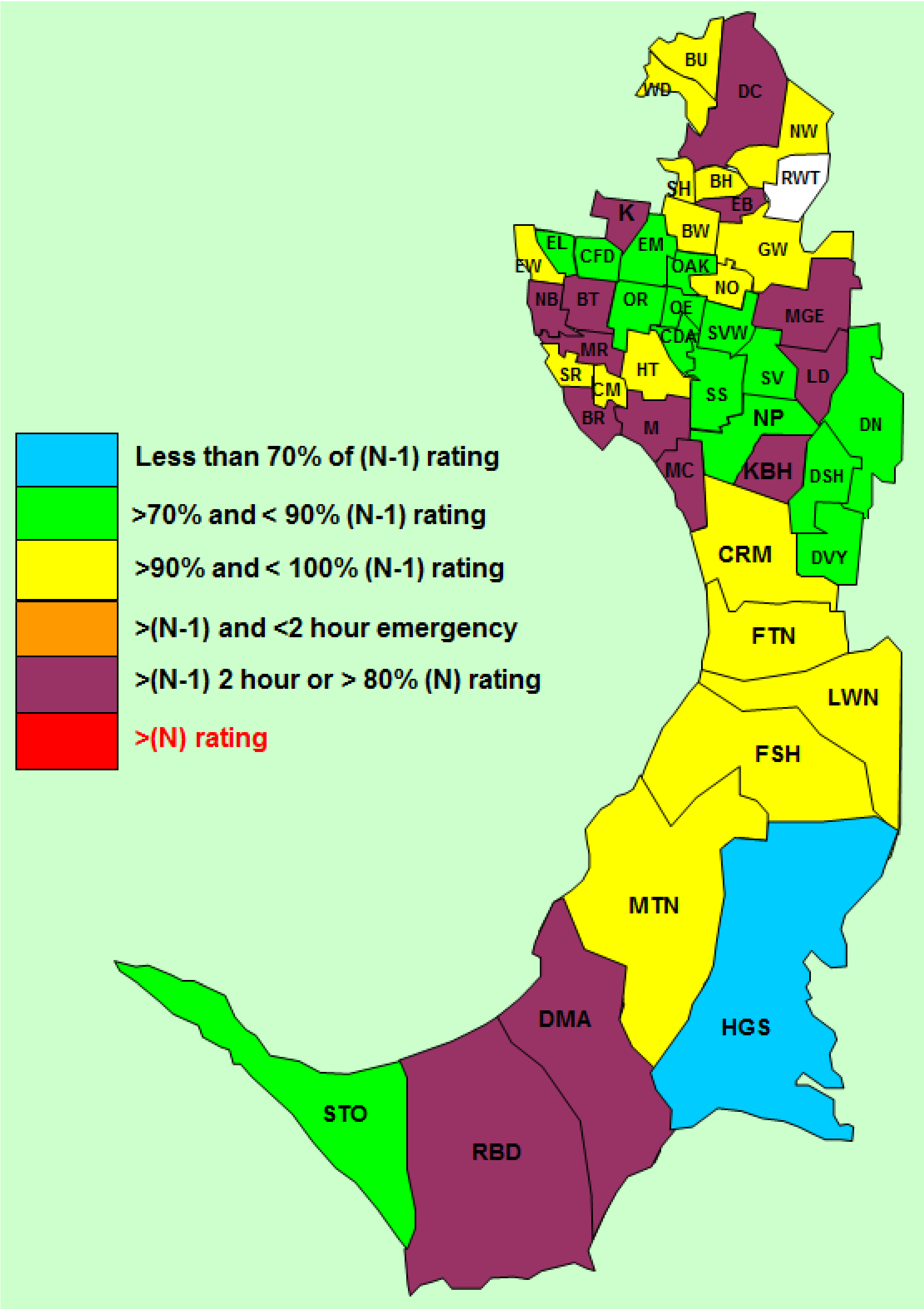
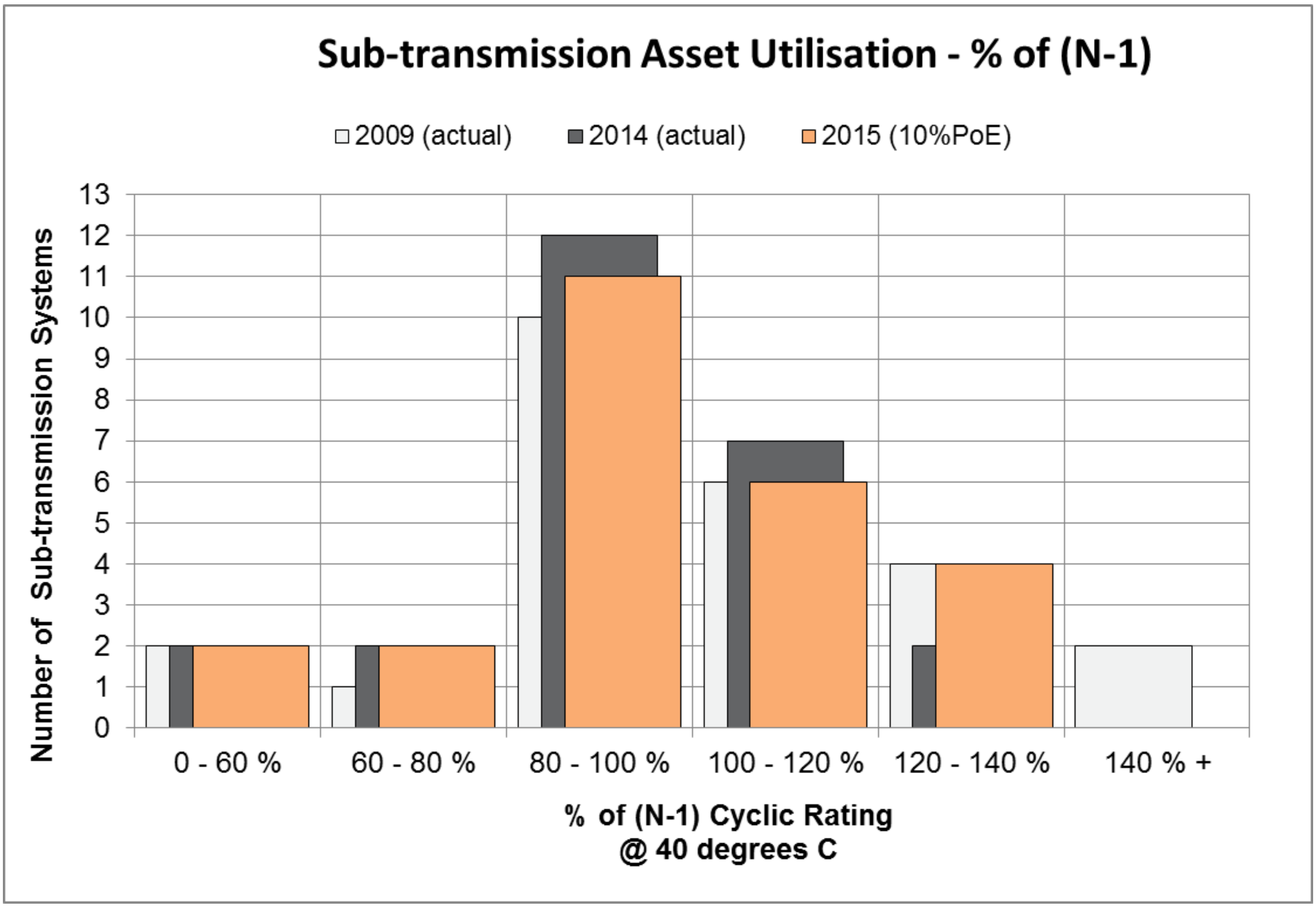


Figure 4-40: Subtransmission forecast summer 10% PoE peak utilisation (2014-2015)



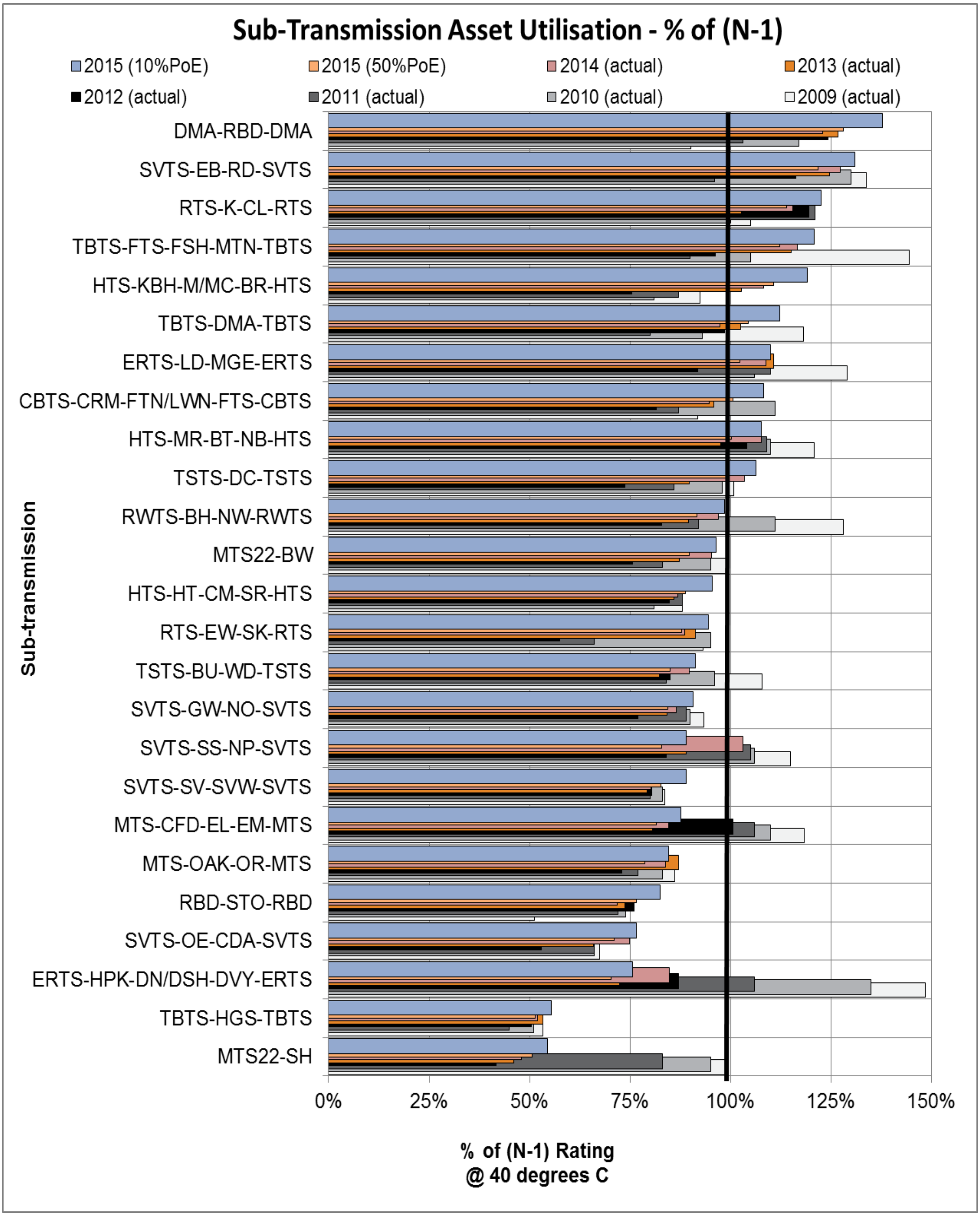
The (N-1) utilisations for each sub-transmission system are presented below.

Figure 4-41: Sub-transmission line (N-1) utilisation distribution (2014-2015 forecast)



Under a medium economic growth 10%PoE scenario, it is projected that 10 sub-transmission systems will exceed their (N-1) rating in the 2014-2015 summer.

Figure 4-42: Sub-transmission Line (N-1) utilisation (ranked by 2013-14 forecast utilisation)



UE has the following plans to address immediate and emerging (N-1) risks for the sub-transmission systems. These plans are supported by risk assessments undertaken for the Distribution Annual Planning Report (DAPR) (UE PL 2209) and the Strategic Area Plans UE PL 2220+:

1. **DMA-RBD-DMA:** It is planned to manage the risk on this loop by managing the transfer capability to transfer load upstream, then augment the network with a new transformer at DMA to increase the transfer capacity away from RBD, followed by the establishment of a new 66kV line from HGS to RBD within the next 5 years.
2. **SVTS-EB-RD-SVTS:** It is planned to reconductor the SVTS-EB 66 kV line over the next 2 years.
3. **RTS-K-CL-RTS:** Only one side of the loop (tower line side) is under-rated. It is planned to manage the risk on this loop by upgrading the connections at RTS as part of AusNet's redevelopment project. Load transfers from K to EM will be used to manage loop loading longer term.
4. **TBTS-FTS-FSH-MTN-TBTS:** The risk on this system is currently being managed with the meshing of this loop with the TBTS-DMA system in 2013. It is planned to manage the risk on this system over the longer term by the establishment of a new 66kV line from HGS to RBD within the next 5 years.
5. **HTS-KBH-M/MC-BR-HTS:** This loop is being upgraded in 2014 with the establishment of the new Keysborough (KBH) zone substation by establishing a second HTS-M circuit and uprating the HTS-BR leg at BR. In the future the KBH-M-MC line will need to be reconductored.
6. **TBTS-DMA-TBTS:** It is planned to establish a new 66kV line from HGS to RBD within the next 5 years to support this system. This system has both thermal and voltage collapse issues.
7. **ERTS-LD-MGE-ERTS:** It is planned to manage the risk on this loop by augmenting the surrounding distribution network to improve transfer capability, until the new proposed Scoresby (SCY) zone substation is eventually established to offload the loop.
8. **CBTS-CRM-FTN/LWN-FTS-CBTS:** It is planned to offload this system in future by establishing the proposed Skye (SKE) zone substation.
9. **HTS-MR-BT-NB-RTS:** The BT-MR leg currently limits the rating of this loop. It is planned to upgrade this leg in 2015.
10. **TSTS-DC-TSTS:** It is planned to thermally uprate this loop just beyond thenext 5 years.

The risk on each sub-transmission system is assessed based on the initial load to be shed following the most critical line outage, and the residual load at risk following completion of load transfers. The risk assessment for the 2014-2015 summer based on a 10% PoE maximum demand are summarised below.

Table 4-22: Sub-transmission asset load at risk

Subtransmission Risks & Transfer Capability Assessment

Summer 2014/15

Basis: 10% Probability of Exceedance

SUBTRANSMISSION LOOP		kV	Loop (N-1 Min. Rating MVA	Loop (N-1 Min. Rating Amps	Summer Forecast MVA	Summer Forecast Amps	Total Risk MVA	UE Share of Demand %	UE Share of Rating MVA	TF NSFER CAP ILITY UE MVA	Others MVA	Total MVA	Load at Ris after Transfe MVA UE share	Others	Other Post Contingent Actions
CBTS-CRM-FTN/LWN-FTS-CBTS		66	178	1555	180	1571	1.9	100%	178	32.9		32.9	0.0	0.0	
ERTS-HPK-DN/DSH-DVY-ERTS	(1)(2)	66	337	2949	250	2187	0.0	70%	236	14.9	8.0	22.9	0.0	0.0	
ERTS-HPK-DN/DSH-DVY-ERTS	(1)(3)	66	337	2949	255	2231	0.0	70%	236	14.9	8.0	22.9	0.0	0.0	
ERTS-LD-MGE-ERTS		66	128	1120	141	1232	12.8	100%	128	44.9		44.9	0.0	0.0	
HTS-BR-KBH-M-MC-HTS		66	145	1267	157	1378	12.7	100%	145	49.9		49.9	0.0	0.0	
HTS-MR-BT-NB-HTS		66	120	1047	129	1128	9.3	100%	120	14.7		14.7	0.0	0.0	
HTS-HT-CM-SR-HTS		66	118	1035	113	988	0.0	100%	118	9.2		9.2	0.0	0.0	
MTS22-BW/SH		22	25	665	24	641	0.0	100%	25	6.8		6.8	0.0	0.0	
MTS-CFD-EL-EM-MTS		66	135	1184	118	1036	0.0	100%	135	16.6		16.6	0.0	0.0	
MTS-OAK-OR-MTS		66	82	715	69	605	0.0	100%	82	12.4		12.4	0.0	0.0	
RTS-EW-SK-RTS	(1)(2)	66	86	750	83	728	0.0	19%	16	4.3	5.0	9.3	0.0	0.0	
RTS-EW-SK-RTS	(1)(3)	66	86	750	83	728	0.0	19%	16	4.3	6.0	10.3	0.0	0.0	
RTS-K-CL-RTS	(1)	66	96	840	105	918	8.9	45%	43	9.2	10.0	19.2	0.0	0.0	
RWTS-BH-NW-RWTS		66	120	1050	118	1034	0.0	100%	120	40.1		40.1	0.0	0.0	
SVTS-OE-CDA-SVTS		66	65	570	50	436	0.0	100%	65	31.7		31.7	0.0	0.0	
SVTS-EB-RD-SVTS	(1)	66	95	830	113	992	18.5	64%	60	16.9	3.0	19.9	0.0	0.0	
SVTS-GW-NO-SVTS		66	128	1120	116	1016	0.0	100%	128	22.8		22.8	0.0	0.0	
SVTS-SS-NP-SVTS	(2)	66	109	950	97	846	0.0	100%	109	42.4		42.4	0.0	0.0	
SVTS-SS-NP-SVTS	(3)	66	109	950	104	907	0.0	100%	109	42.4		42.4	0.0	0.0	
SVTS-SV-SVW-SVTS		66	128	1120	114	996	0.0	100%	128	21.3		21.3	0.0	0.0	
TBTS-DMA-TBTS	(4)	66	128	1120	144	1258	15.8	100%	128	22.3		22.3	0.0	0.0	
DMA-RBD-DMA		66	70	615	97	847	26.5	100%	70	15.0		15.0	11.5	0.0	2% voltage reduction at RBD & STO = 3MVA
RBD-STO-RBD		66	57	500	47	412	0.0	100%	57	12.5		12.5	0.0	0.0	
TBTS-FTS-FSH-MTN-DMA-TBTS		66	282	2469	267	2337	0.0	100%	282	0.0		0.0	0.0	0.0	
TBTS-HGS-TBTS		66	91	800	51	443	0.0	100%	91	12.3		12.3	0.0	0.0	
TSTS-BU-WD-TSTS		66	93	815	85	744	0.0	100%	93	0.0		0.0	0.0	0.0	
TSTS-DC-TSTS		66	93	815	99	867	5.9	100%	93	23.7		23.7	0.0	0.0	

(1) For shared loops, the owner of the line will be responsible for reducing the total amount of overload first, then the other DB will be called in to reduce load by an amount equal to their load share.

(2) Risk assessment with embedded generation in service.

(3) Risk assessment with embedded generation out of service.

UE Subtransmission Supportable Demand 2397 **MVA**

(4) Voltage collapse risk exists on this loop.

Whilst there are 9 sub-transmission loops with load at risk, only 1 sub-transmission loop has residual load at risk after load transfers and voltage reduction, being DMA-RBD. Further details are contained in UE's 2014/15 Contingency Plans (UE MA 2204).

Based on the 20 year load forecasts for each sub-transmission loop and the need to supply additional zone substations, the major augmentation works proposed at the sub-transmission level over the next 20 years with corresponding commissioning summers are presented below. These plans are supported by risk assessments undertaken for the Distribution Annual Planning Report (DAPR) (UE PL 2209) and the Strategic Area Plans UE PL 2220+:

Table 4-23: Sub-transmission asset project list

Sub-transmission loop	Next planned augmentation within 20-year horizon	Timing
CBTS-CRM/FTN-LWN-FTS=CBTS	SKE New 66kV subtransmission line to supply Skye (SKE) zone substation LHT New 66kV subtransmission line to supply Lyndhurst (LHT) zone substation	2020-2021 2032-2033
ERTS=DN-HPK/DVY-DSH-ERTS	Dandenong (DNTS) Terminal Station subtransmission works to transfer DSH (& possibly DVY to DNTS)	2025-2026
ERTS-LD-MGE-ERTS	New 66kV sub transmission line(s) for Scoresby (SCY) zone substation	2025-2026
HTS-KBH-M/MC-BR-HTS	Reconductor KBH-M-MC 66kV sub-transmission line Dandenong (DNTS) Terminal Station subtransmission works to transfer KBH (& possibly MC to DNTS) Reconductoring HTS-M #2 66kV sub-transmission line Reconductor HTS-BR 66kV subtransmission line	2022-2023 2025-2026 2027-2028 2029-2030
HTS-MR-BT-NB-HTS	BT-MR 66kV line retension	2015-2016
HTS-HT-CM-SR-HTS	Establish new 66kV loop for HT use spare lines available from DNTS	Beyond 20 years
MTS=BW/SH=MTS	New 66kV lines from MTS to BW and SH	Beyond 20 years
MTS-CFD-EL/EM=MTS	MTS-CFD Reconductor	Beyond 20 years
MTS-OAK-OR-MTS	MTS-OR 66kV Reconductor	Beyond 2020
RTS-EW-SK-RTS	RTS-EW Upgrade droppers RTS-EW 66kV Line Works associated with RTS redevelopment	2021-2022 2015-2016
RTS-K-CL-RTS	RTS-K 66kV Line Works associated with RTS redevelopment	2017-2018
RWTS-BH-NW-RWTS	RWTS-NW-BH loop - 3rd 66 kV line	2023-2024
SVTS-OE-CDA-SVTS	Transfer CDA and OE to Bus 3/4 group at SVTS at time of SVTS rebuild	2020-2021
SVTS-EB-RD-SVTS	SVTS-EB reconductor (and CitiPower to reconductor SVTS-RD)	2016-2017
SVTS-GW-NO-SVTS	Combine GW/NO loop with EB/RD loop	2022-2023
SVTS-NP-SS-SVTS	Dandenong (DNTS) Terminal Station subtransmission works to transfer NP (& possibly SS to DNTS)	2025-2026
SVTS-SV-SVW-SVTS	Nil	
TBTS=DMA=RBD=STO	HGS-RBD New 66kV sub-transmission line RBD-STO #1 and #2 66kV sub-transmission lines reconductoring	2018-2019 Beyond 20 years
TBTS-FTS-FSH-MTN-TBTS	Install 2km of new 66kV line to connect in the new Sommerville (SVE) zone substation	2024-2025
TBTS-HGS-TBTS	TBTS-HGS 66kV sub-transmission line uprate	2018-2019
TSTS-BU-WD-TSTS	Uprate 66kV lines and droppers TSE 66kV line works for TSE (3rd leg for BU/WD loop)	Beyond 2020 Beyond 20 years[14]
TSTS-DC-TSTS	Uprate 66kV lines and droppers Offload DC onto TSE via the 22kV network	2019-2020 Beyond 20 years

[14] Timing dependent on economic viability of DC 4th transformer vs. establishment of TSE.

4.5.3. Zone Substations

UE's distribution feeder network is supplied by 47 zone substations which convert sub-transmission voltages (66 and 22kV) down to distribution feeder voltages (22, 11 and 6.6kV). These zone substations are generally arranged in a fully switched configuration with one, two or three transformers. A detailed assessment of zone substation asset constraints and load at risk is provided in the Distribution Annual Planning Report (DAPR), a UE publication revised annually with a 5 year outlook.

The average utilisation of zone substations reached 98% in summer 2013-2014, marginally lower than the record peak in 2008-2009 of 100%. The figure below presents average summer zone substation utilisation over the last 15 years together with projected average summer utilisation over the next 20 years (Note: Projected utilisations are shown for a 50% and 10% probability of exceedance).

Figure 4-43: Average zone substation summer peak utilisation & long term trend

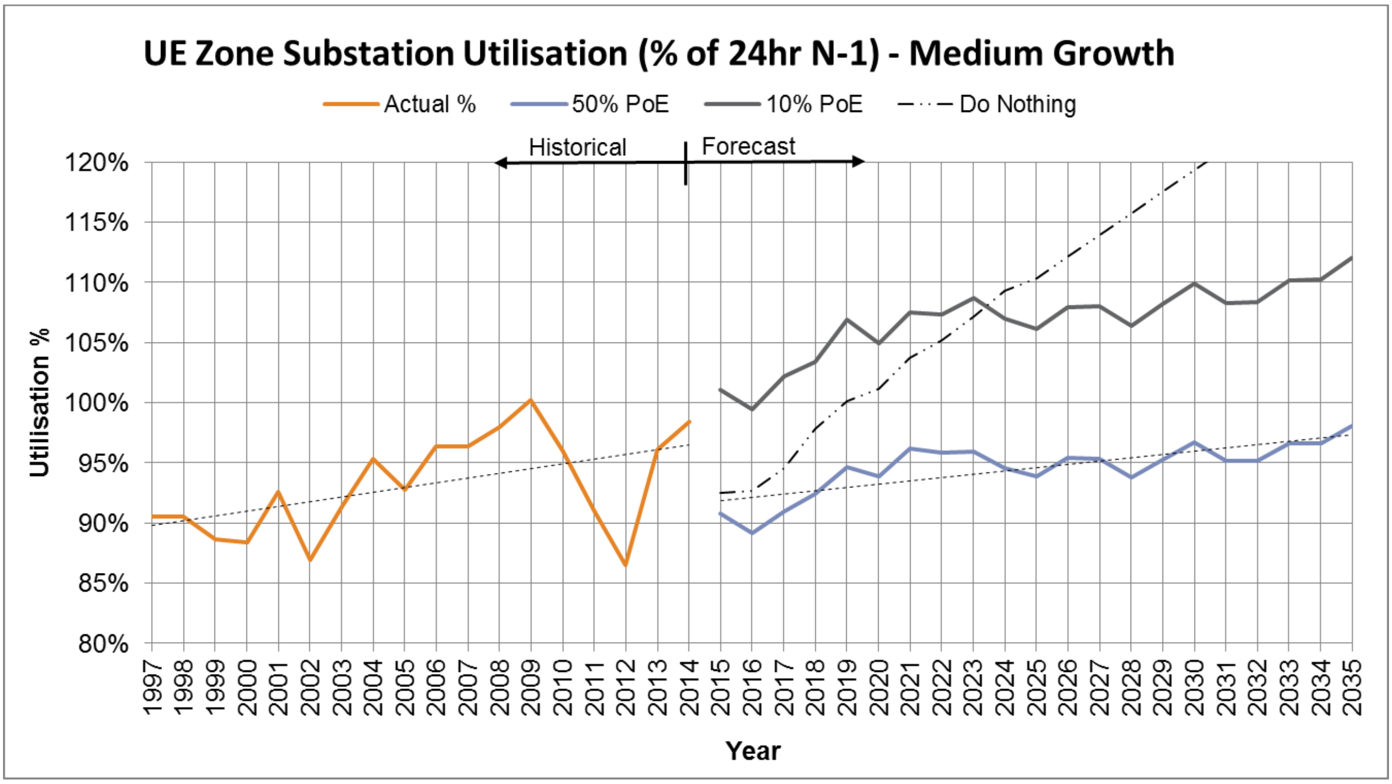
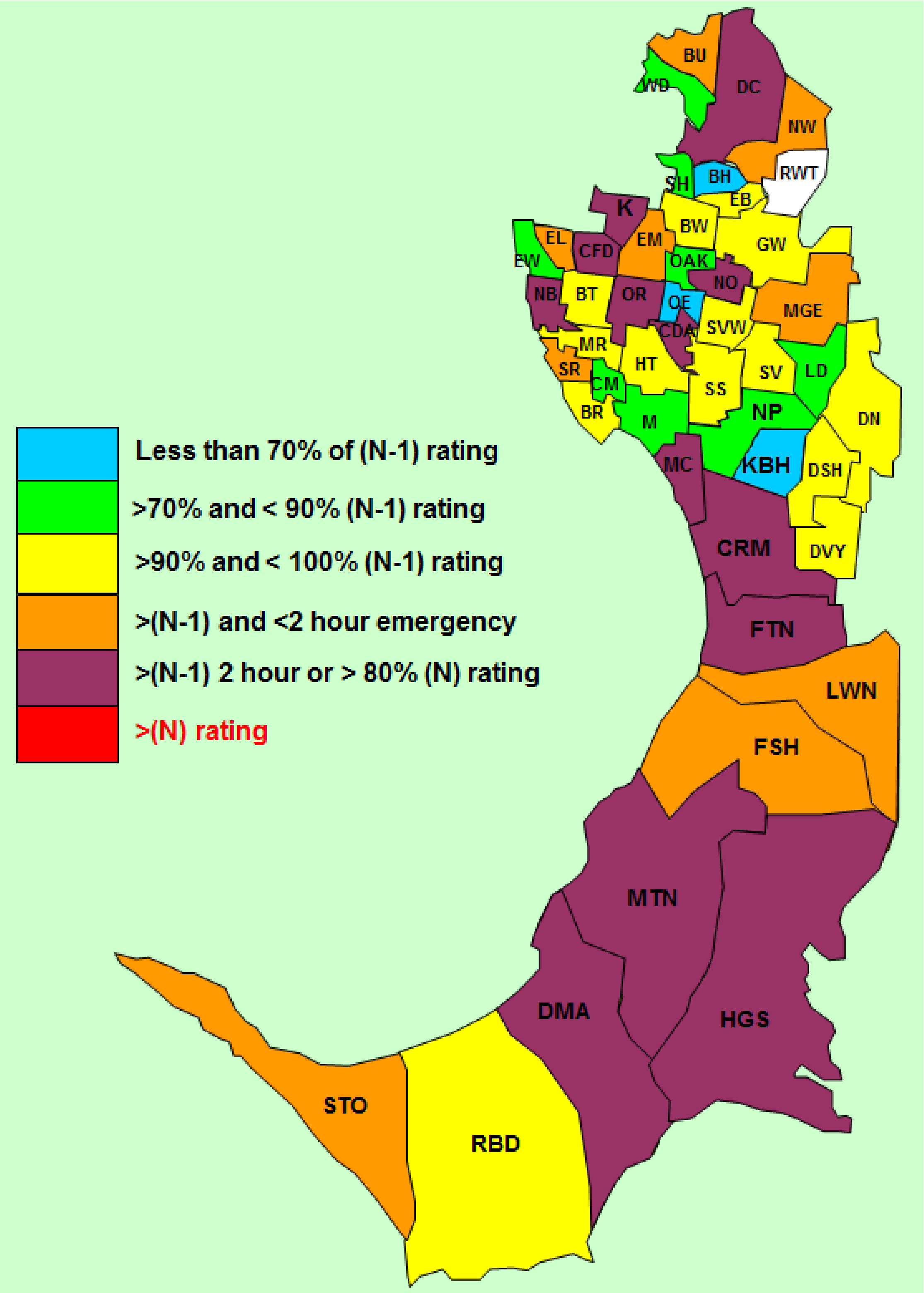
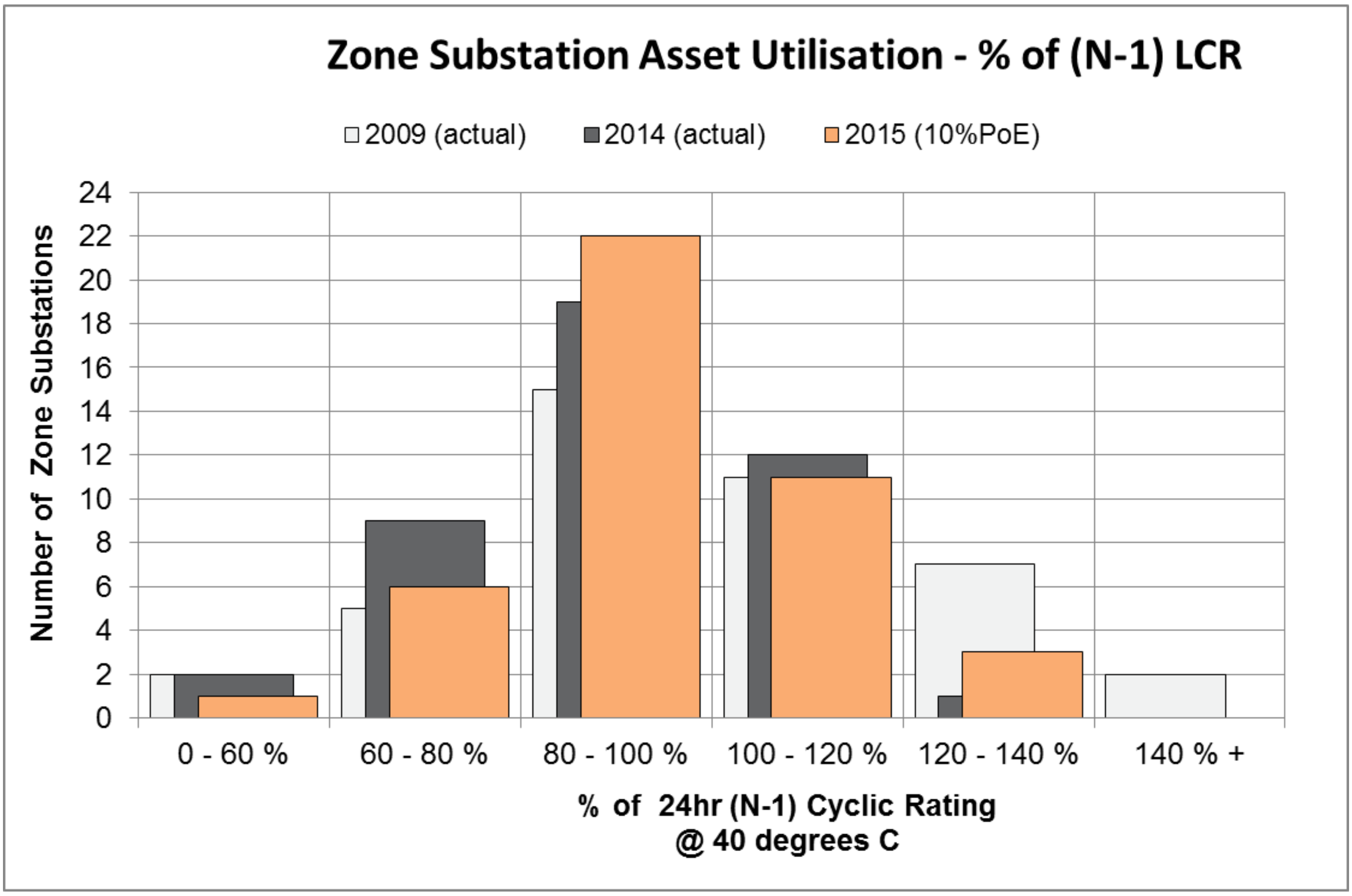


Figure 4-44: Zone substation forecast summer 10% PoE peak utilisation (2014-2015)



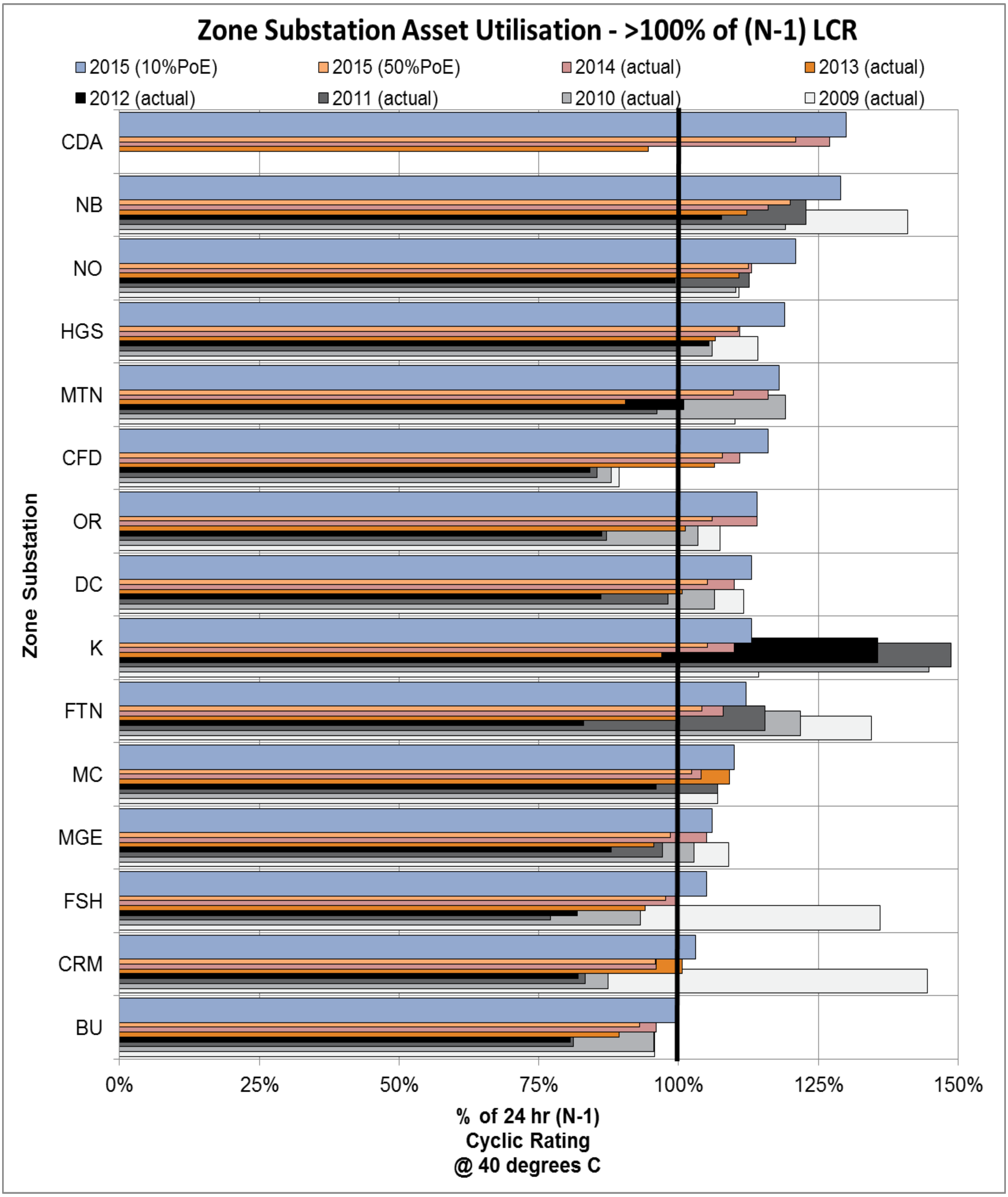
The (N-1) utilisations for each zone substation are presented below.

Figure 4-45: Zone substation (N-1) utilisation distribution (2014-2015 forecast)



Under a medium economic growth 10%PoE scenario, it is projected that 14 zone substations will exceed their (N-1) 24-hour rating in the 2014-2015 summer.

Figure 4-46: Zone substation (N-1) utilisation (ranked by 2014-2015 forecast utilisation)



Note: CDA utilisation is based on the smaller relocatable transformer rating.

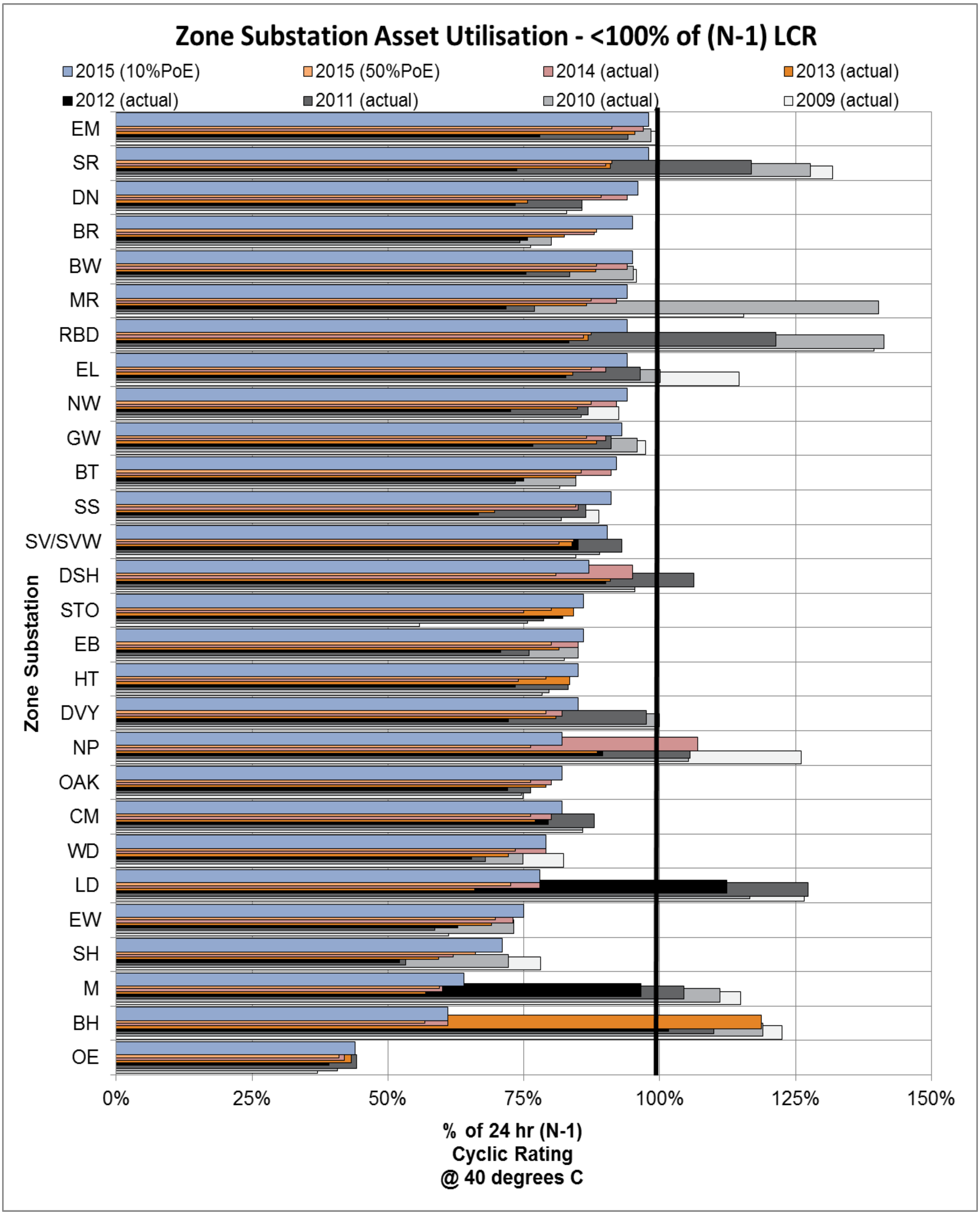

Zone Substation Asset Utilisation - <100% of (N-1) LCR
2015 (10%PoE)
2015 (50%PoE)
2014 (actual)
2013 (actual)
2012 (actual)
2011 (actual)
2010 (actual)
2009 (actual)
Zone Substation
EM
SR
DN
BR
BW
MR
RBD
EL
NW
GW
BT
SS
SV/SVW
DSH
STO
EB
HT
DVY
NP
OAK
CM
WD
LD
EW
SH
M
BH
OE
0%
25%
50%
75%
100%
125%
150%
% of 24 hr (N-1)
Cyclic Rating
@ 40 degrees C

Figure 4-47: Zone substation (N) utilisation distribution (2014-2015 forecasts)

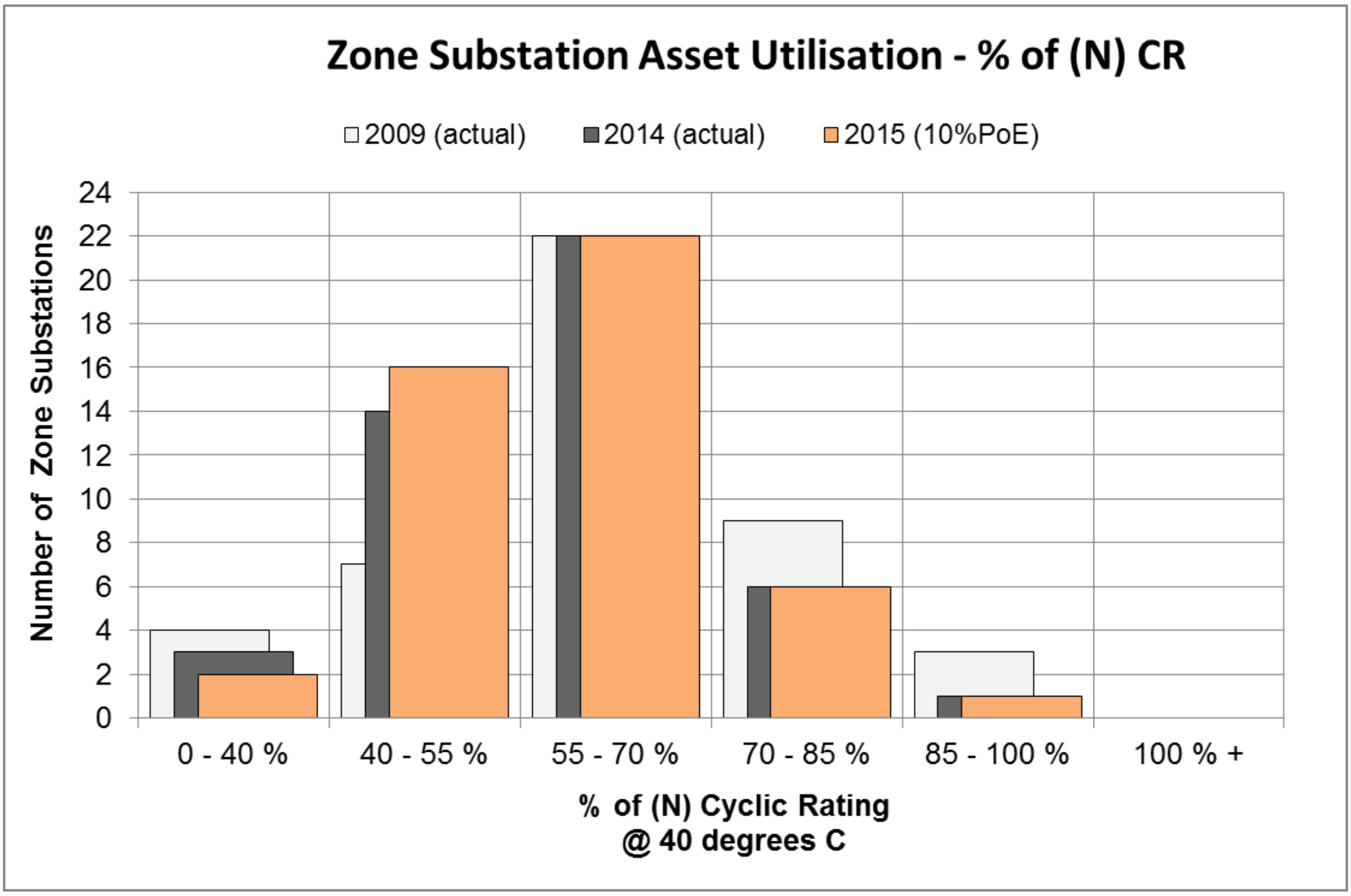
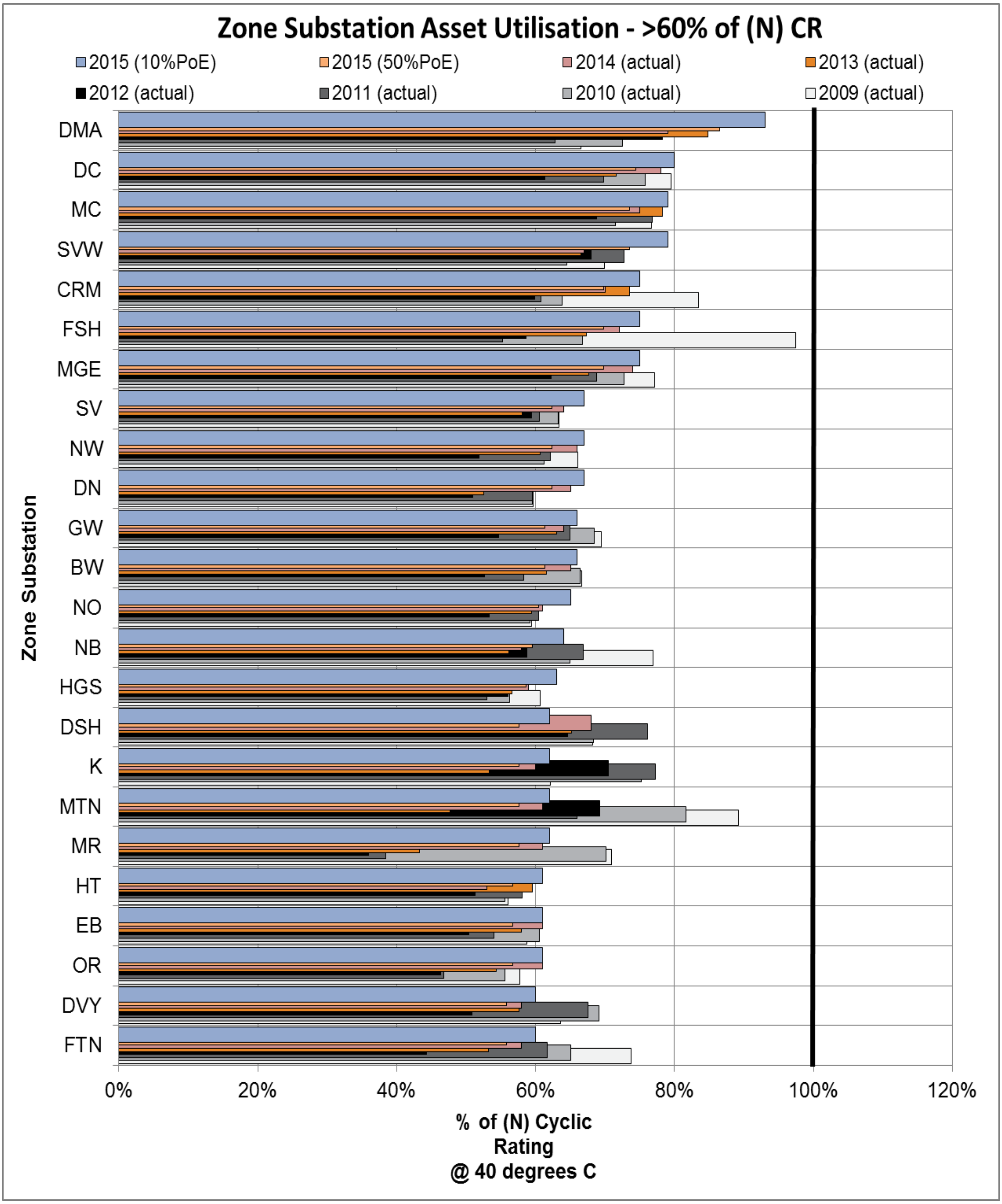
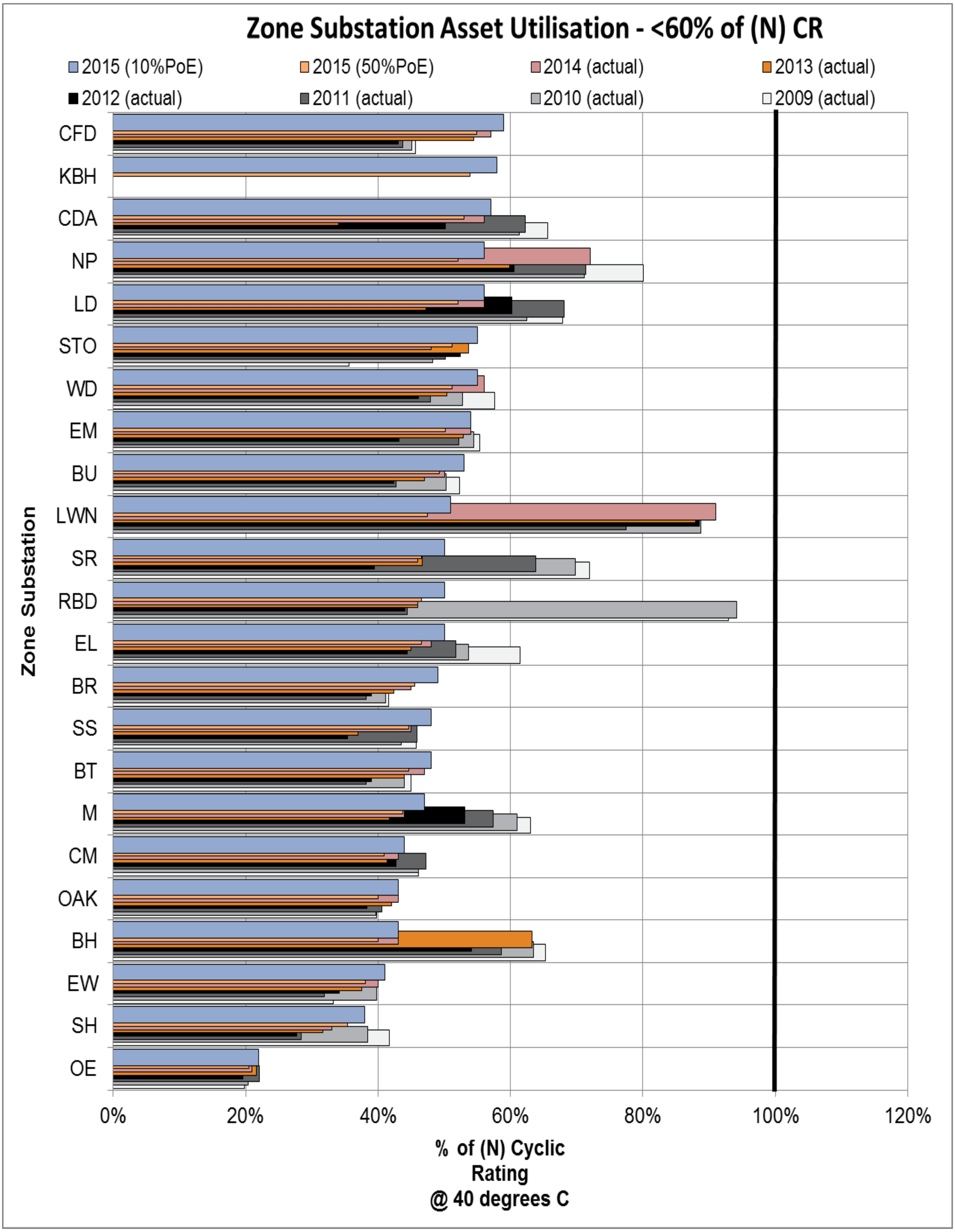


Figure 4-48: Zone substation (N) utilisation (ranked by 2014-2015 forecast utilisation)




Zone Substation Asset Utilisation - <60% of (N) CR
2015 (10%PoE)
2015 (50%PoE)
2014 (actual)
2013 (actual)
2012 (actual)
2011 (actual)
2010 (actual)
2009 (actual)
Zone Substation
CFD
KBH
CDA
NP
LD
STO
WD
EM
BU
LWN
SR
RBD
EL
BR
SS
BT
M
CM
OAK
BH
EW
SH
OE
0%
20%
40%
60%
80%
100%
120%
% of (N) Cyclic
Rating
@ 40 degrees C

UE has the following plans to address immediate and emerging (N-1) and (N) risks for the zone substations. These plans are supported by risk assessments undertaken for the Distribution Annual Planning Report (DAPR) (UE PL 2209) and the Strategic Area Plans UE PL 2220+:

1. **DMA:** It is planned to install a 2nd transformer at DMA zone substation in 2016.
2. **NB:** It is planned to manage the risk with load transfers to adjacent zone substations prior to replacing the switchboard at NB within the next few years. The 11kV switchboard limits the station's capability by 500 Amps.
3. **NO**: It is planned to install a 3rd transformer at NO zone substation in 2017/18.
4. **HGS**: It is planned to manage load on HGS through load transfers to DMA and MTN.
5. **MTN**: It is planned to install a 3rd transformer at MTN zone substation in 2021/22.
6. **CFD:** It is planned to offload CFD to EM by installing a 3rd transformer at EM in 2023/24.
7. **OR**: It is planned to offload OR to EM by installing a 3rd transformer at EM in 2023/24.
8. **DC:** It is planned to install a 4th transformer at DC in 2019/20.
9. **K:** It is planned to offload K to EM by installing a 3rd transformer at EM in 2023/24.
10. **FTN:** It is planned to manage load on FTN with load transfers to LWN.
11. **MC**: It is planned to replace the aged transformers at MC which currently limit the station's capability.
12. **FSH:** It is planned to replace the aged transformers at FSH which currently limit the station's capability.
13. **CRM:** It is planned to offload the station to a new Skye (SKE) zone substation in 2020/21.

The risk on each zone substation is assessed based on the initial load to be shed following the most critical transformer outage, and the residual load at risk following completion of load transfers. The risk assessment for the 2014-2015 summer based on a 10% PoE maximum demand are summarised below.

Table 4-24: Zone substation asset load risk

Zone Substation Risks & Transfer Capability Assessment **Summer** **2014/15**

Basis: 10% Probability of Exceedance

Zone Substation		PROJECTED 2014/15 SUMMER MVA	(N-1) STATION RATING CYCLIC MVA	24 HOUR MVA	2 HOUR MVA	10 MIN MVA	LOAD IN EXCESS OF (N-1) RATING CYCLIC MVA	24 HOUR MVA	2 HOUR MVA	10 MIN MVA	AVAILABLE TRANSFER CAPABILITY MVA	HOW ?	LOAD IN EXCESS OF (N-1) RATING AFTER TRANSFERS CYCLIC MVA	24 HOUR MVA	2 HOUR MVA	Other Post Contingent Actions
BH		47.1	72.6	77.3	87.7	87.7	0.0	0.0	0.0		22.0	To DC, EB & NW				
BR		30.7	31.5	32.4	32.4	32.4	0.0	0.0	0.0		4.1	To: CM & SR				
BT		29.7	31.1	32.3	32.3	32.3	0.0	0.0	0.0		7.1	To: NB & CFD				
BU		31.3	29.7	31.3	31.3	31.3	1.6	0.0	0.0	0.0	5.9	To: WD				
BW		24.1	24.3	25.4	25.4	25.4	0.0	0.0	0.0		6.8	TO: EM & RD				
CDA		33.8	25.8	26.1	29.1	31.0	8.0	7.7	4.7	2.8	23.6	To: HT, NO & SS				
CFD		49.8	42.1	43.1	49.0	54.9	7.7	6.7	0.8		8.4	To: EL, BT, K & EM				
CM		27.3	30.9	33.2	33.9	33.9	0.0	0.0	0.0		5.3	To: BR, M & SR				
CRM		83.2	73.9	80.9	82.8	82.8	9.3	2.3	0.4	0.4	15.9	To: FTN & MC				
DC		88.6	73.6	78.6	81.4	83.0	15.0	10.0	7.2	5.6	23.7	To: BH & NW				
DMA		41.8	0.0	0.0	0.0	0.0	41.8	41.8	41.8		22.3	To: MTN & RBD	19.5	19.5	19.5	Relocatable Transfomer = 25MVA
DN	(1)	84.0	84.2	87.6	92.5	92.5	0.0	0.0	0.0		14.4	To: DSH, DVY & LD				
DN	(2)	89.0	84.2	87.6	92.5	92.5	4.8	1.4	0.0		14.4	To: DSH, DVY & LD				
DSH		57.2	61.3	65.8	67.5	69.0	0.0	0.0	0.0		21.6	To: DVY & DN				
DVY		79.5	87.8	93.7	94.7	94.7	0.0	0.0	0.0		21.6	To: DSH, FTN & CRM				
EB		62.0	67.8	72.5	80.9	80.9	0.0	0.0	0.0		16.9	To: BH, GW & NW				
EL		33.6	33.4	35.8	38.4	38.4	0.2	0.0	0.0		7.5	To: CFD, EW & NB				
EM		34.7	31.9	35.4	38.0	38.0	2.8	0.0	0.0		10.1	To: K, OR & CFD				
EW		24.0	29.4	32.0	32.0	32.0	0.0	0.0	0.0		4.3	To: EL & NB				
FSH		70.1	62.0	66.6	70.2	70.2	8.1	3.5	0.0		12.8	To: FTN, LWN, HGS & MTN				
FTN		54.4	45.6	48.7	48.7	48.7	8.8	5.7	5.7	5.7	19.9	To: CRM, FSH, LWN & DVY				
GW		68.7	68.9	73.8	78.6	78.6	0.0	0.0	0.0		18.6	To: EB, MGE & NO				
HGS		50.3	39.9	42.4	46.9	47.6	10.4	7.9	3.4	2.7	12.3	To: FSH, MTN, DMA & LWN				
HT		56.5	61.9	66.2	71.8	71.8	0.0	0.0	0.0		5.0	To: CDA				
K		45.7	36.8	40.4	43.7	45.0	8.9	5.3	2.0	0.7	9.2	To: CFD, EM & AR				
KBH	(4)	27.2	0.0	0.0	0.0	0.0	27.2	27.2	27.2		28.5	To: DSH, LD & NP				
LD		56.5	67.4	72.3	77.3	77.3	0.0	0.0	0.0		29.7	To: DN, NP, MGE & SVW				
LWN		46.4	45.4	48.3	48.3	48.3	1.0	0.0	0.0		25.1	To: FSH & FTN				
M		38.4	54.4	59.8	59.8	59.8	0.0	0.0	0.0		4.3	To: BR & CM				
MC		65.8	55.4	59.6	60.0	69.0	10.4	6.2	5.8		17.9	To: CRM, NP & SS				
MGE		84.0	74.4	79.0	86.3	86.3	9.6	5.0	0.0		26.9	To: GW, LD & SVW				
MR		45.0	48.0	48.0	59.0	59.0	0.0	0.0	0.0		8.4	To: NB, BT, OR & SR				
MTN		57.9	46.4	48.9	48.9	48.9	11.5	9.0	9.0	9.0	12.0	To: DMA, HGS & FSH				
NB		51.3	39.8	39.8	39.8	39.8	11.5	11.5	11.5	11.5	13.6	To: BT, EW & MR				
NO		48.1	37.0	39.7	42.4	45.0	11.1	8.4	5.7	3.1	16.8	To: SVW, CDA & GW				
NP		60.1	72.0	73.0	81.8	81.8	0.0	0.0	0.0		25.3	To: DSH,SV,SVW,SS,MC&LD				
NW		67.7	67.4	72.3	74.3	74.3	0.3	0.0	0.0		23.9	To: BH, EB & RWT				
OAK	(3)	37.8	43.6	46.4	46.7	46.7	0.0	0.0	0.0		6.8	To: EM & OE				
OE		14.2	32.4	32.4	32.4	32.4	0.0	0.0	0.0		4.0	To: OAK & OR				
OR		39.6	32.3	34.7	34.9	36.0	7.3	4.9	4.7	3.6	5.6	To: BT, EM, CFD & OE	1.7			Voltage Reduction = 5% (up to 2MVA)
RBD		45.8	45.8	48.5	48.5	48.5	0.0	0.0	0.0		15.0	To: DMA & STO				
SH		8.1	10.8	11.5	12.0	12.0	0.0	0.0	0.0		0.0	Nil				
SR		36.8	36.5	37.5	38.8	38.8	0.3	0.0	0.0		10.3	To: BR, CM & MR				
SS	(1)	38.7	40.1	42.6	46.4	48.5	0.0	0.0	0.0		21.1	To: CDA, HT, MC & SV				
SS	(2)	45.7	40.1	42.6	46.4	48.5	5.6	3.1	0.0		21.1	To: CDA, HT, MC & SV				
STO		40.0	36.0	45.9	47.8	47.8	4.0	0.0	0.0		12.5	To: RBD				
SV/SVW		53.3	80.0	86.6	94.0	94.0	0.0	0.0	0.0		21.3	To: NP,MGE,NO,CDA,LD&SS				
WD		52.6	63.3	66.4	68.5	68.5	0.0	0.0	0.0		5.3	To: BU				

UE Zone Sub Supportable Demand **2315** **MVA**

(1) **Risk assessment with embedded generation in service**
(2) **Risk assessment with embedded generation out of service**
(3) ***N-1*** **rating for OAK take into account the ratings of the respective relocatable transformer.**
(4) **Rating may not be available all summer due to incomplete works.**

Whilst there are 25 zone substations with load at risk, only 2 zone substations have residual load at risk after load transfers and voltage reduction, being OR and DMA. Further details are contained in UE's 2014/15 Contingency Plans (UE MA 2204).

Based on the 20 year load forecasts for each zone substation and the need to supply additional feeders, the major augmentation works proposed at the zone substation level over the next 20 years with corresponding commissioning summers are presented below. These plans are supported by risk assessments undertaken for the Distribution Annual Planning Report (DAPR) (UE PL 2209), 2014/15 Load Forecast Manual (UE MA 2203), and the Strategic Area Plans (UE PL 2220+):

Table 4-25: Zone substation asset project list

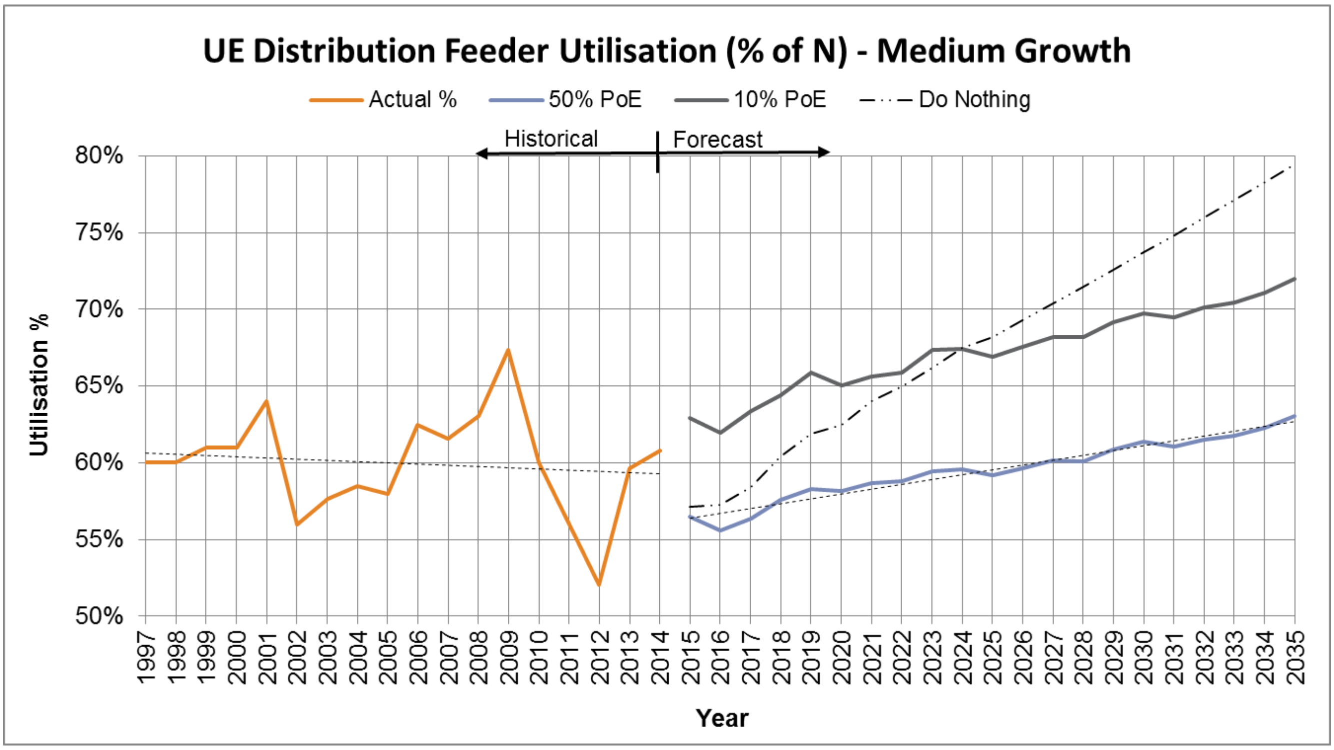
Zone substation	Possible next planned augmentation within 20-year horizon	Timing
BH	See DC, SH	
BR	BR 3rd transformer	Beyond 20 years
BT	BT 3rd transformer	2033-2034
BU	BU 3rd transformer	2027-2028
BW	Convert BW to 66/11kV	Beyond 20 years
CDA	CDA 2nd fixed transformer	2027-2028
CFD	See EM, OR, EL & K	
CM	See SR	
CRM	SKE Land Acquisition for Skye zone substation SKE New Skye zone substation SKE 2nd transformer	2016-2017 2020-2021 2027-2028
DC	DC 4th transformer TSE Establish new single transformer zone substation	2019-2020 Beyond 20 years
DMA	DMA 2nd transformer	2016-2017
DN	DNN Land Acquisition for Dandenong North zone substation DNN New Dandenong North zone substation	2027-2028 2032-2033
DSH	See KBH	
DVY	LHT Land Acquisition for Lyndhurst zone substation LHT New Lyndhurst Zone substation	2026-2027 2032-2033
EB	See BH, GW, NW, RWT	
EL	EL 3rd transformer	Beyond 20 years
EM	EM 3rd transformer	2023-2024
EW	EW 3rd transformer	Beyond 20 years
FSH	Replace aged transformers SVE New Somerville zone substation	(Asset Replacement) 2024-2025
FTN	FTN 3rd transformer	2030-2031
GW	See NO & MGE	
HGS	HGS 3rd transformer	2031-2032
HT	See CDA	
K	See EM K 3rd transformer	 2026-2027
KBH	KBH 2nd transformer	2023-2024
LD	See DN	
LWN	LWN 3rd transformer	Beyond 20 years
M	See BR	
MC	Replace aged transformers	(Asset Replacement)

	MRA Land Acquisition Moorabbin Airport zone substation MRA New Moorabbin Airport zone substation	2024-2025 2029-2030
MGE	SCY Land Acquisition Scoresby zone substation SCY New Scoresby zone substation	2021-2022 2025-2026
MR	MR 3rd transformer	Beyond 20 years
MTN	MTN 3rd transformer	2021-2022
NB	Replace 11kV switchboard	2016-2017 (Asset Replacement)
NO	NO 3rd transformer	2017-2018
NP	See DSH	
NW	See DC, RWT	
OAK	See EM OAK 2nd fixed transformer	 2030-2031
OE	OE 3rd transformer	Beyond 20 years
OR	See EM OR 3rd transformer	 Beyond 20 years
RBD	RBD 3rd transformer	Beyond 20 years
RWT	See Transmission Connection Assets	
SH	SH New 66/22kV zone substation	Beyond 20 years
SR	SR 3rd transformer	Beyond 20 years
SS	SS 3rd transformer	2024-2025
STO	STO 3rd transformer	Beyond 20 years
SV	SV 3rd transformer	Beyond 20 years
SVW	SVW 3rd transformer	2022-2023
WD	See BU	

4.5.4. Distribution Feeders

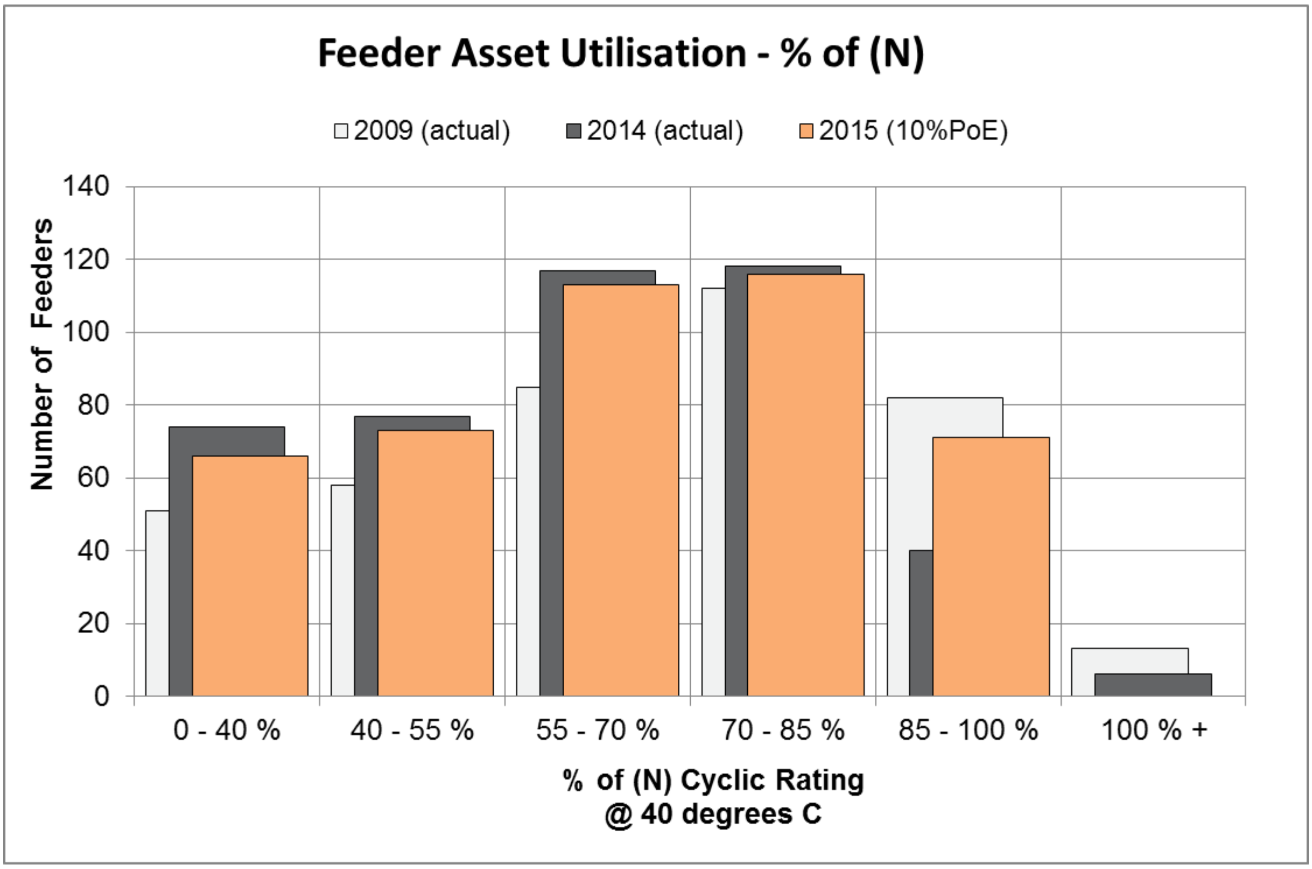
UE's distribution substations are supplied by 439 distribution feeders operating at 22, 11 and 6.6kV. A number of legacy SWER systems operate at 12.7kV, however these will eventually be retired. Distribution feeders are arranged in a radial configuration with normally open points between adjacent feeders to provide transfer capability. The average utilisation of distribution feeders has historically been 60%. In the heatwave of summer 2008-2009, the average utilisation reached a record 67%. The figure below presents average summer feeder utilisation over the last 15 years together with projected average summer utilisation over the next 20 years (Note: Projected utilisations are shown for a 50% and 10% probability of exceedance).

Figure 4-49: Average summer feeder utilisation and long term trend



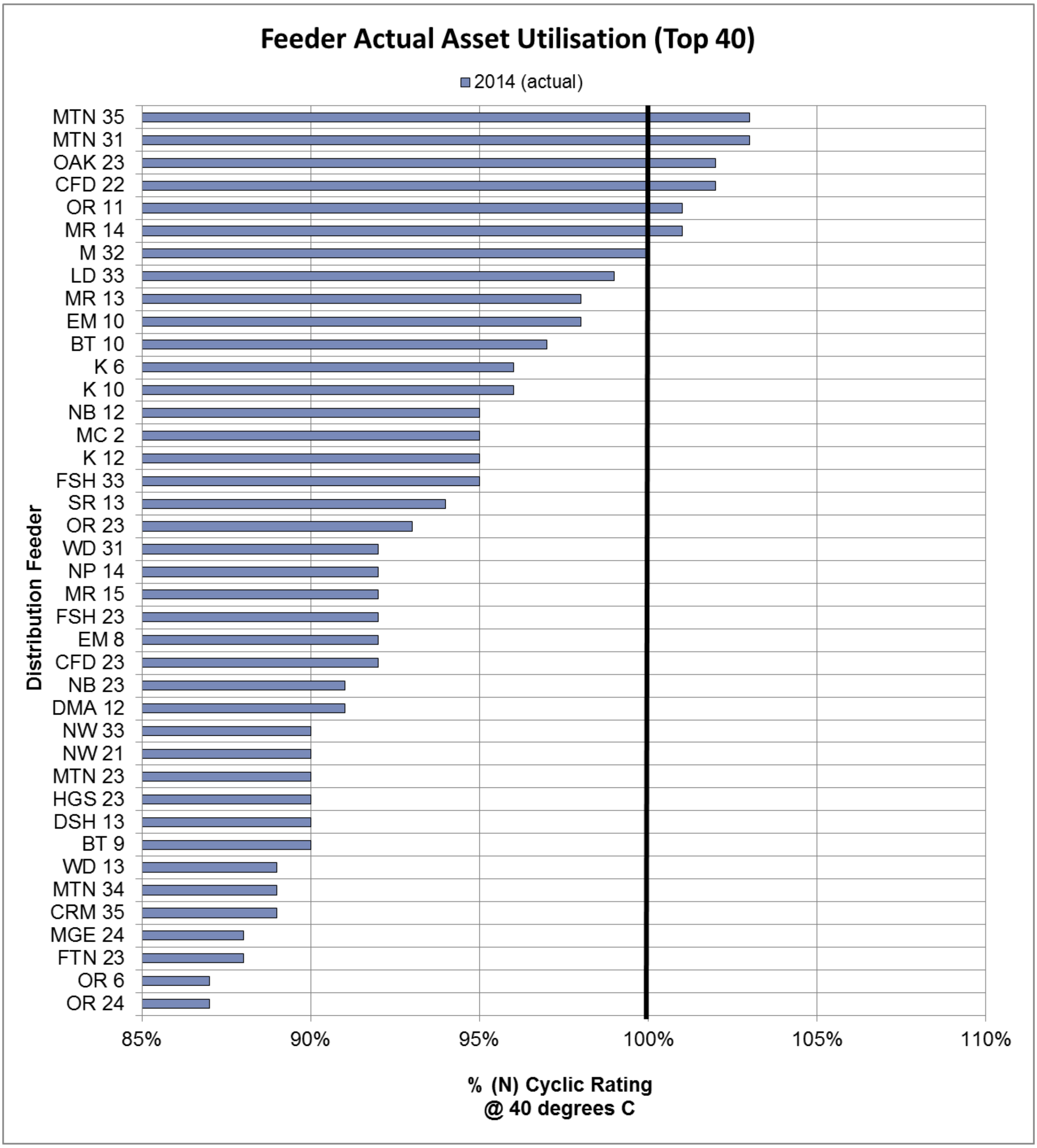
It is expected that the average feeder utilisation will be maintained around 60% throughout the planning period to 2034-2035 assuming the augmentation plans proposed in this Demand Strategy & Plan.

Figure 4-50: HV distribution feeder utilisation distribution – 2014-2015 forecasts



The utilisations for the top 40 utilised distribution feeders are presented below for the 2013-2014 summer.

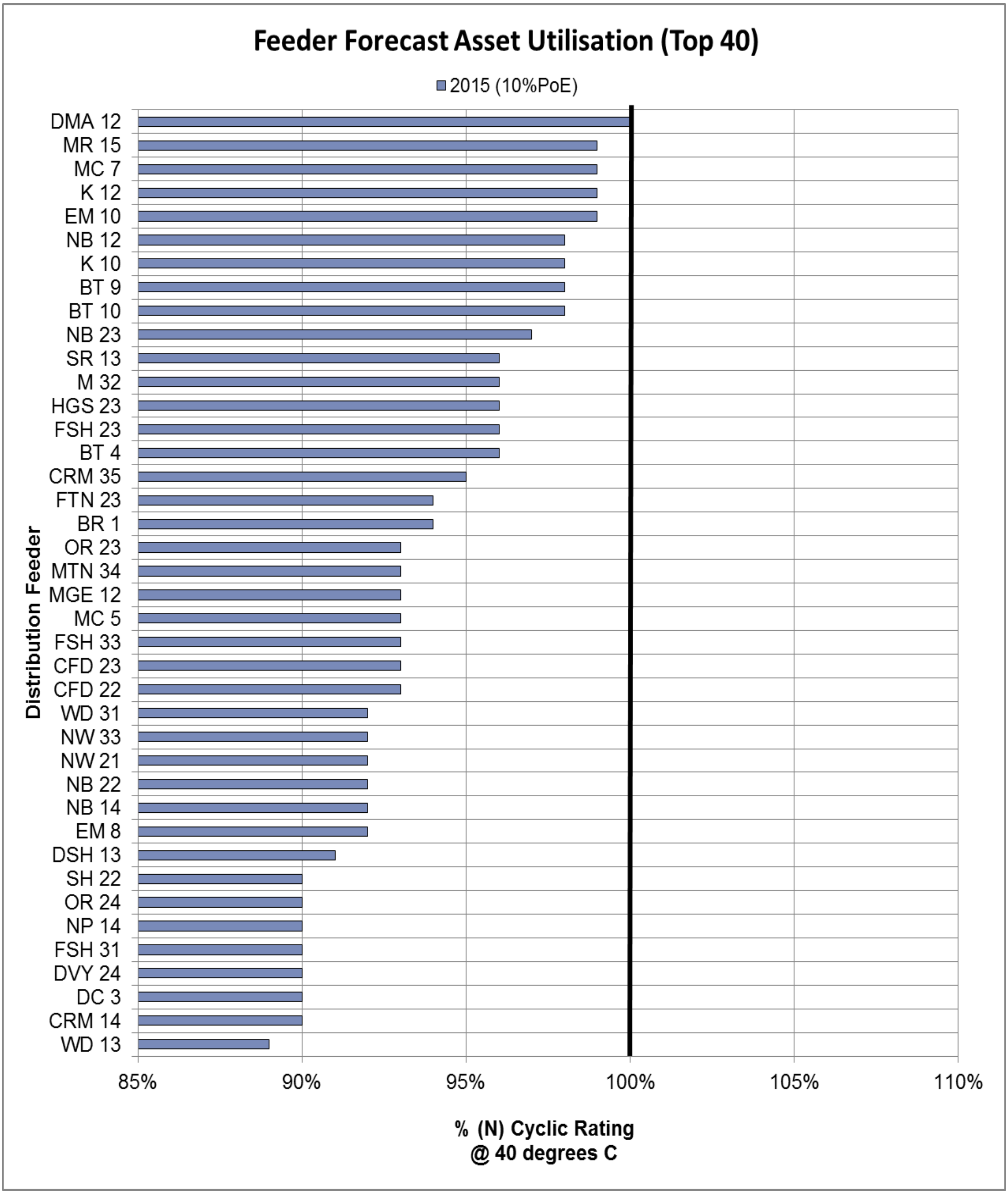
Figure 4-51: HV distribution feeder utilisation – 2013-2014 Actuals



Last summer 6 feeders (MTN35,MTN31, OAK23,CFD22,OR11 and MR14) exceeded their (N) cyclic rating with a further 40 feeders exceeding 85% of their rating.

The forecast 2014-2015 summer utilisations for the top 40 utilised distribution feeders are presented below using a 10% PoE weather forecast.

Figure 4-52: HV distribution feeder utilisation – 2014-2015 forecasts



For a 10% PoE next summer, no feeders are expected to exceed their (N) cyclic rating . 71 feeders are expected to exceed 85% of their rating. The following zone substations have 3 or more highly utilised feeders – BT, BU, CRM, EM, FSH, K, LD, MGE, MTN, NB, and OR which could limit transfer options between feeders.

Distribution feeder augmentations to address highly utilised feeders will comprise of a combination of reconductoring, one-off new feeders, piggy-back of existing feeders or power factor correction.

Based on the 5-year load forecasts for each feeder, the augmentation works proposed at the feeder level over the next 5-years with corresponding commissioning summers are presented below. These plans are supported by the Distribution Annual Planning Report (DAPR) (UE PL 2209) and the 2014/15 Load Forecast Manual (UE MA 2203):

Table 4-26: HV Feeder asset project list

Next planned augmentation within 5-year horizon	Timing
BR01 feeder exit upgrade	2015/16
CFD New feeder	2015/16
DSH21 tie line	2015/16
DVY11 New feeder	2015/16
EM01 - OAK22 Tie	2015/16
EM10 Reconductor	2015/16
EW05 new feeder	2015/16
FSH24 New Feeder	2015/16
MC7 feeder reconductor	2015/16
MGE New Feeder	2015/16
MR33 new feeder	2015/16
OR 23 upgrade feeder	2015/16
OR 25 upgrade feeder	2015/16
SR13 load transfer	2015/16
CRM24 Feeder extension (deferred by Greensync)	2016/17
FTN23 feeder reconductor	2016/17
BU14 reconductor	2017/18
CRM13 Feeder upgrade	2017/18
CRM15 New 22kV feeder	2017/18
DN11 reconductor	2017/18
HGS14 New 22kV feeder	2017/18
KBH35 feeder extension	2017/18
LD07 reconductor	2017/18
LD34 new feeder	2017/18
M 32 feeder exit cable upgrade	2017/18
OAK23 upgrade	2017/18
RBD11 Feeder extension	2017/18
BR14 New Feeder	2018/19
BU06 upgrade	2018/19
BW21 Tie Line	2018/19
FSH14 New feeder	2018/19
MTN33 New Feeder	2018/19
NW 21 feeder reconductor	2018/19
DC05 Tie Line	2019/20
FTN14 re-arrangement	2019/20
MC8 New Feeder	2019/20

4.5.5. Distribution Substations & LV Circuits

In summer 2008-2009, the record heatwave revealed significant localised overloads at the distribution substation and low voltage level driven primarily by the continuing rapid growth of domestic air conditioning load. As a result, a large number of distribution substations exceeded their thermal rating under system normal. The quantum of the localised peak demand increase far exceeded forecasts. Equipment, including transformers, connections, high voltage and low voltage fuses failed under thermal overload. This resulted in loss of supply to customers totalling 24.2 UE SAIDI minutes.

Since that summer, a substantial increase in investment in distribution substations and the low voltage network was allocated in the budgets to effectively mitigate the risk of further plant failure due to thermal overload. The experience of the 2008-2009 summer also highlighted some inherent weaknesses in the historically rather rudimentary industry approach to low voltage network planning and forecasting.

UE experienced around 650 LV over-load fuse operations in both regions over the recent 2014 heat-wave and 11 transformer failures, compared to 950 LV fuse operation in 2009 and 54 transformer failures for similar temperature conditions but a larger number of days in 2014 . The reliability impact incurred in 2014 as a result of overloads during this heat-wave was 5.4 UE SAIDI minutes. This indicates that the distribution system augmentation programme undertaken over recent years is making inroads into addressing over-load risk and addressing reliability issues for our worst-served customers.

Unlike sub-transmission, zone substations and HV networks, the majority of the distribution substations and LV network do not have SCADA metering installed, however the AMI rollout is rapidly changing this with some 99% of customers now connected to the AMI network.

Historically distribution substation and LV network augmentation was initiated on either a pro-active or reactive basis.

On a proactive basis the maximum demand of distribution substations and the LV network were estimated using a program called Transformer Load Management (TLM). Estimation of substation and LV circuits maximum demand were analysed on an annual basis using quarterly energy consumption and assumed load profiles. The results of the analysis formed the basis for distribution substation and LV network load management and the formulation of the capital budget.

On a reactive basis, the analysis was carried out after the distribution substation and/or LV circuit experiences some form of load related interruption, typically occurring with ambient temperatures above 35ºC during the summer period or ambient temperatures below 10ºC during the winter period. Customer complaints regarding supply quality also initiated reactive analysis. Projects resulting from reactive analysis usually had a higher priority than the pro-active projects. This is because customers may have experienced numerous outages and/or supply quality issues in the past and if the problems are not rectified within the required time frame (generally 6-9 months), complaints are likely to be lodged with the Ombudsman.

In both the pro-active and reactive approach, demand on distribution substations and LV circuits were verified through load measurements. Load measurements were often taken for period of one week. The maximum demand recorded is only for the week the meter is installed and therefore it was necessary to scale up the recorded demand to estimate the maximum demand. This estimated maximum demand and voltage profile, along with transformer and LV circuit ratings, were used to determine the design and the necessary works that are required to rectify the issue.

With the rollout of AMI and the recent installation of the Network Load Management (NLM) system which aggregates the interval metering data to each asset level, it is no longer required to make assumptions regarding distribution substation and LV circuit loading and voltage levels. Hence the process above is now undertaken using actual load profiles and combined into a single proactive programme.

The AMI voltage variation data being captured as part of the meter power quality functionality is also being used to identify customers with steady state voltage outside of the Electricity Distribution Code limits. Whilst most of the rectifications will be opex related in terms of tap position adjustments, the distribution augmentation program can also be focussed in part on addressing these problems.

From a total population of more than 13,000 distribution substations, the utilisation of distribution substations observed in the summer of 2013/14 is shown below.

Figure 4-53: Distribution substation spatial utilisation

2013/14 Distribution Substation Utilisation

(as a percentage of cyclic rating)

P1: Red >160%

P2: Orange > 140%

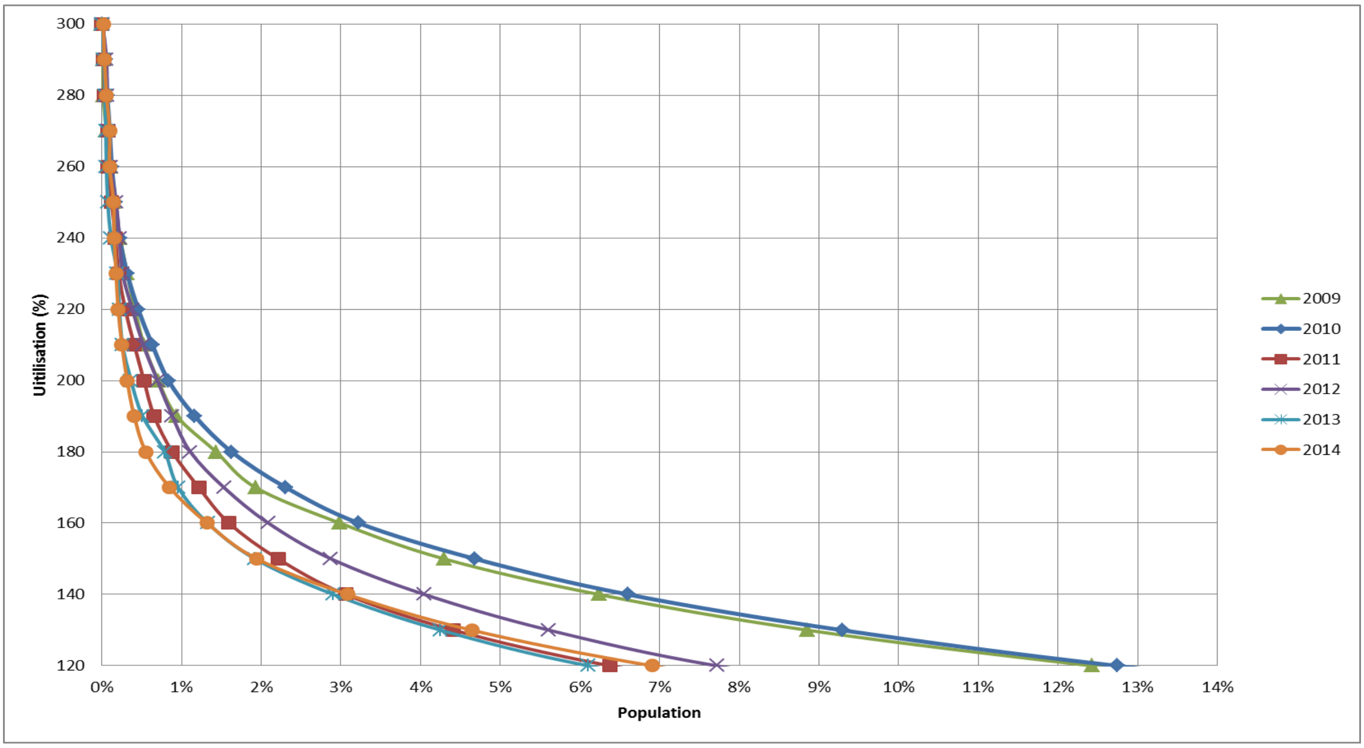
P3: Yellow > 120%

P4: Green > 100%

The following chart shows the historical distribution substation utilisation at peak summer demand and the impact of the Distribution System Augmentation expenditure since 2009 on distribution substations with utilisation greater than 120% of cyclic rating[15].

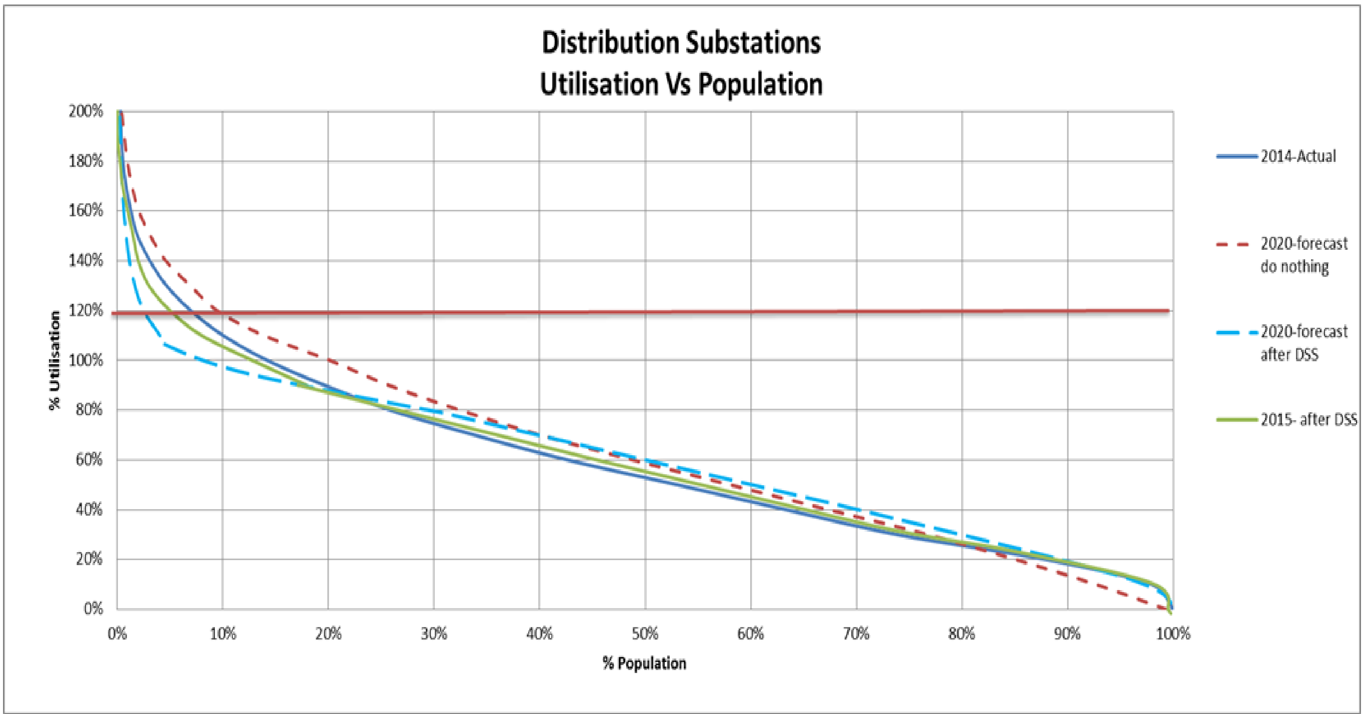
[15] 120% of cyclic rating is regarded as 100% of the emergency short time rating for distribution transformers, hence distribution substations are typically not considered for upgrade until 120% utilisation is achieved.

Figure 4-54: Historical distribution substation utilisation chart



The following chart shows the historical and forecast distribution substation utilisation at peak summer demand assuming the distribution substation augmentation program proposed in this Demand Strategy & Plan for the whole population.

Figure 4-55: Forecast distribution substation utilisation chart



It is planned by 2020 less than 4% of distribution substations will exceed 120% of cyclic rating. The Distribution System Augmentation Strategy (UE PL 2201) provides further details on UE's strategy and plans for managing the distribution substation and low voltage circuit population.

4.6. Growth Capital Requirements

UE's method for determining growth capital requirements requirements are documented in document UE GU 2206 Expenditure Forecast Guideline.

4.6.1. Augmentation (Demand) Capex

Meeting the anticipated maximum demand with an economic level of reliability risk is the primary driver for augmentation capex. If customer demand requirements continue to grow, network capacity must be reinforced to cover any shortfall that cannot be economically and satisfactorily met by non-network solutions such as demand management and embedded generation, to maintain existing reliability levels.

Safety and Environment are also drivers for network augmentation capex (demand capex) investment. This is because overloaded electricity plant or plant operated beyond its fault level limits poses a significant health and safety risk and can result in explosions, oil spillages or excessive step and touch potentials. Heavily loaded plant has an effect of increasing greenhouse gas emissions.

Reliability and Quality of supply drives network augmentation capex investment because overloaded plant may result in customer load shedding to avoid loss of life to plant where the cost of investment is outweighed by benefits in the form of reduced energy at risk and supply voltages may be outside of regulatory limits.

For economies of scale, network augmentations generally result in step increases in capacity rather than incremental increases particularly at the higher network levels, to meet increases in demand. As a result, augmentation capex is generally "lumpy" from year to year. Whilst there is some discretion to smooth out augmentation capex, the timing is predominately determined by an economic evaluation study on the preferred option versus the do nothing option being optimised.

UE intends to ensure that augmentation capex allocation is invested efficiently by:

- Undertaking a RIT-D on all projects above $5m to ensure than non-network solutions are adequately assessed;
- Ensuring that all technically feasible options are adequately assessed in business cases including short term deferment options, or options that will increase the capability of UE's monitoring and control to achieve more efficient asset utilisation;
- Aligning projects with asset replacement activities where appropriate or with other distributors where common boundary issues exist;
- Rigorous engineering analysis and feasibility planning is undertaken on large projects prior to developing a business case to confirm constraints and a project's effectiveness in alleviating the constraint; and
- Maintaining a long term focus for network development to ensure assets are developed according to a strategy, but adapting and updating the strategy over time.

UE's Augmentation Capex investments above $5m from the 1st January 2014 is subject to the Regulatory Investment Test (RIT-D). Through the RIT-D process, UE is required to identify the credible options that maximise the net present value of market economic benefits.

The RIT-D is based on a cost-benefit analysis of reasonable scenarios for each credible option compared to the "do-nothing" scenario. It includes a level of analysis that is proportionate to the scale and potential impact of the credible options, and should be applied in a predictable, transparent and consistent manner, including consideration of potential market benefits.

4.6.2. Customer Initiated Connections (CIC) Capex

Customer initiated connections capital expenditure (CIC capex) accounts for a significant proportion of UE's total capital expenditure. The CIC expenditure consists of three major components - Business Supply Projects, Urban Residential Supply and Urban Multiple Occupancy Supply, and Recoverable Works.

CIC capex is not directly controllable by UE in that UE must respond to a variable level of customer project demand primarily driven by prevailing economic and population growth conditions. The predicted value of CIC capex is therefore derived through an analytical process that combines economic and customer number forecasts of UE's customer base with unit rates that UE anticipates for discrete capital activities based on recent historical costs. As CIC capex projects are made up of a large number and broad range for project types, with varying project costs, unit rate forecasts for each activity are developed by breaking down historical expenditure.

The UE CIC model forecasts expenditure based on relavent industries activities forecast by the Australian Construction Industry Forum (ACIF). Residential type activities forecasts are used for deriving residential related CIC expenditure such as Medium Density Housing (CH) category. ACIF forecasts for non-residential and engineering type activities are used for deriving business related CIC expenditure, particularly for the Business Supply (CB), Recoverable Works (CR) and new public lighting (CL) categories.

UE intends to ensure that CIC capex allocation is invested efficiently by:

- Periodically reviewing and comparing forecast CIC capex with actuals with a view to increase forecasting accuracy;
- Optimise connection costs by reviewing the designs options prepared by the Service Providers to ensure the least cost technically acceptable connection is adopted consistent with the long term development plans for the network;
- Monitor the commercial arrangements for every project to ensure the full recovery of allowable customer contribution is achieved including implications on upstream network augmentations; and
- Tariff assignment for each new connection (especially business supplies) is checked to ensure accurate assignments.

4.6.3. High-Level Requirement

This section seeks to present a high level overview of the annual Demand Capex requirements for the United Energy network based on the present maximum demand forecast for 2015/16 – 2024/25 using a top-down approach. This is used to sanity-check the subsequent bottom-up forecasts that are used for the AMP.

UE prepares a 10 year Capex works programme as part of the AMP each year for Demand Capex expenditure based on a 10% PoE summer maximum demand medium economic growth forecast for the UE service area provided by NIEIR. This forecast is distributed across each asset according to various localised growth conditions in the network for each of the following network levels which form the power delivery chain from the transmission connection points to the customers' point of supply:

- Sub-transmission
- Zone Substations
- High Voltage Distribution Feeders
- Distribution Transformers and Low Voltage Circuits

While the build-up of the works programme is bottom-up and highly technical in nature, a simplified top-down set of calculations can be performed to estimate the high level Demand Capex requirements to confirm the bottom-up detailed requirements. This top down assessment is set out below.

UE's latest forecast 10%PoE maximum demand for the service area next summer is 2163MW.

NIEIR is forecasting that 10% PoE maximum demand growth for the UE service area over the next 10 years will average 1.7% per annum. This equates to 2163 x 1.7% = 37 MW of growth across the UE network each year comprising of new customer connections (approximately 8,000 per annum or 50% of the demand increase based on a 2.3kW ADMD) and increases in the existing customer base load (accounting for the remaining 50% of the demand increase).

The entire power delivery chain from transmission connection point to customer connection point is affected by this increase in maximum demand. Therefore we must consider the Capex requirements at each of these network levels individually, with the total Capex requirement being the sum of all the components. This is presented below.

The typical capacity provided by a newly installed sub-transmission loop is 128MW. UE's historical utilisation of sub-transmission lines has been approximately 50% of (N) on average, such that with one side of the loop out of service, the remaining side of the loop is able to carry 100% of the demand.

With 37MW of growth each year and two lines per loop, the number of new sub-transmission loops required each year would be 37 ÷ 128 ÷ 50% ÷ 2 = 0.29. That is 1 new loop every 3 to 4 years.

At a typical cost of $22M[16] per loop, the average annual Capex requirement is around 22 x 0.29 = $6.4M, although this tends to be lumpy.

The incremental cost of sub-transmission augmentation is 22 ÷ 128 ÷ 50% ÷ 2 = $172/kVA.

The typical cyclic capacity provided by a newly installed zone substation transformer is 40MW. UE's historical utilisation of zone substation transformers has been approximately 67% of (N) on average, that is, with one transformer out of service, the remaining two transformers at the zone substation are able to carry 100% of the demand. In situations where the zone substation is fully developed with three transformers, a new single transformer zone substation may need to be established with land purchase.

With 37MW of growth each year, the number of new zone substation transformers required each year would be 37 ÷ 40 ÷ 67% = 1.4. That is, 1 to 2 new zone substation transformer every year, and in the absence of space at some sites, 1 new single transformer zone substation every 5 years.

At a typical cost of $6.5M[17] per transformer or $15M[18] per new single transformer zone substation, the annual Capex requirement is around 6.5 x 1.2 + 15 x 0.2 = $10.8M.

The incremental cost of existing zone substation augmentation is 6.5 ÷ 40 ÷ 67% = $243/kVA.

The typical capacity provided by a newly installed high voltage feeder is 6.5MW for 11kV and 13MW for 22kV (the average being 9.75MW). UE's historical utilisation of high voltage feeders has been approximately 67% of (N) on average, that is, with one feeder out of service, the adjacent two feeders are able to carry 100% of the demand.

With 37MW of growth each year, the number of new feeders required each year would be 37 ÷ 9.75 ÷ 67% = 5.7. That is 6 new feeders every year.

Given that at least 2 new feeders are always established with a new zone substation transformer, the capex requirement is reduced for new feeders. Hence the total new feeders per year is likely to be only 4.

At a typical cost of $1.6M[19] per new feeder, the annual Capex requirement is around 1.6 x 3.7 = $5.9M.

The incremental cost of distribution feeder augmentation is 1.6 ÷ 9.75 ÷ 67% = $245/kVA.

The typical capacity provided by a newly installed distribution transformer is 0.5MW. UE's historical utilisation of distribution transformers has been approximately 50% of (N) on average, however there are a large number of overloaded transformers that are currently being attended to through the existing Capex programme over the next 10 years regardless of demand growth.

With 37MW of growth each year, the number of new distribution transformers and associated LV systems required each year would be 37 ÷ 0.5 ÷ 50% = 148. That is 148 new transformers every year.

Given that approximately 50% of the growth is attributed to new customer connections (budgeted under Customer Initiated Capital - CIC), only 50% of the growth needs to be attributed to Demand Capex. Hence the total new distribution substations and LV systems per year associated with Demand Capex is likely to be only 148 x 50% = 74.

At a typical cost of $0.125M per new distribution substation and LV system, the annual Capex requirement is around 0.125 x 74 = $9.3M.

The incremental cost of augmentation due to distribution transformers and LV circuits is 125 ÷ 0.5 ÷ 50% = $500/kVA.

[16] Calculated from the Cost of Augmentation model and verified against the cost of establishing the HGS-RBD 66kV line.

[17] Calculated from the Cost of Augmentation model and verified against the cost of BH 3rd transformer.

[18] Calculated from the Cost of Augmentation model and verified against the cost of KBH plus land minus sub-transmission costs.

[19] Calculated from the Cost of Augmentation model and verified against the cost of BH13 new feeder.

The total annual demand capex requirement will be the sum of all network level components, however before this is done, there is another component to consider which takes into account the reactive demand component of growth.

For 37MW of demand growth each year, the increase in reactive power demand is likely to be 50% of this based on past experience. UE has pole top capacitor banks we use to address this growth in reactive demand each sized at 0.9MVAr. At $0.04M per capacitor bank, the Demand Capex requirement for reactive power compensation is 37 x 50% ÷ 0.9 x 0.04 = $0.82M.

The incremental cost of augmentation due to reactive power compensation is 40 ÷ 0.9 ÷ 50% = $90/kVA. The incremental cost of augmentation due to reactive power compensation implemented at the HV feeder level offsets the cost of HV distribution feeders resulting in a net HV feeder augmentation cost of 245 – 90 = $155/kVA.

Capex Code	Network Level	Demand Capex	Cost per kVA
(DO)	Sub-transmission	$6.4M pa	172
(DZ) (GP)	Zone Substations	$10.8M pa	243
(DSA)	High Voltage Distribution Feeders	$5.9M pa	245
(DSS)	Distribution Transformers and LV	$9.3M pa	500
(DL)	Reactive Power Compensation	$0.8M pa	(90)
(D)	**TOTAL Demand Capex**	**$33.2M pa**	**$1070/kVA**

The top-down high-level 10-year Capex budget for Demand has an average annual expenditure of $33M providing capacity at a cost of $1070/kVA in 2015 dollars.

It is important to note that the above analysis is based on averages of growth over a 10-year period, and average utilisations.

In reality, each network asset needs to be planned to support the localised demand within the relevant subsection of the UE service area for which it supports, and be operated within 100% of its utilisation capability.

Using average utilisations for the whole network means that there are some assets in the population that are currently operating well above the average utilisation and some operating well below. Furthermore there are some assets experiencing higher than average demand growth and some that are experiencing lower than average demand growth. Therefore it is conceivable that augmentation requirements for those assets operating well above the average utilisation and in higher than average demand growth areas could be independent of changes in average maximum demand growth.

Hence if the average maximum demand growth rate halves (for example) then it may take some time (likely to be more than 5 years) before the Demand Capex requirement also halves.

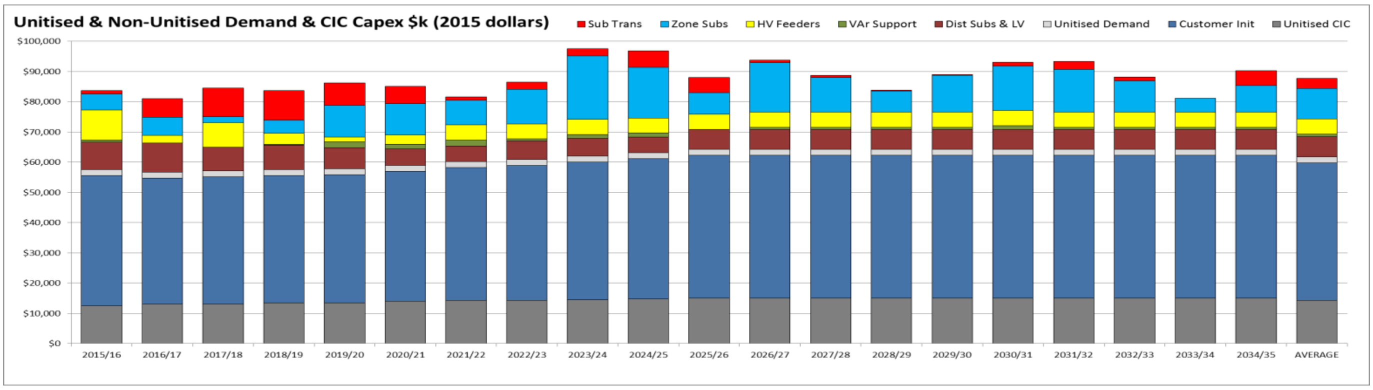
The bottom-up capex forecasts are now presented.

4.6.4. Demand Scenario #1: Business-As-Usual

The Demand Scenario #1 sees a growth of 211MW in the 10% PoE summer maximum demand over the next five years and 884MW between 2014-2015 and 2034-2035. This equates to 2.0% per annum over 5 years, or 2.0%

per annum over 20 years. Based on this growth, the capex expenditure and timing of augmentations (based on bottom-up forecast localised network constraints) required to achieve the forecast utilisations in this Demand Strategy & Plan are presented below.

Figure 4-56: Seasonalised growth capex requirements by network level



The capex requirements by activity code (unitised and non-unitised) associated with the base case Demand Scenario #1: Business-As-Usual is presented below in 2015 dollars.

Table 4-27: Forecast growth capex Requirement (10 Year) – BAU scenario (cost escalators excluded)

Financial Year Ending $k	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CB	$27,189	$26,599	$26,772	$26,682	$26,771	$27,183	$27,793	$28,408	$29,041	$29,669
CD	$9,790	$10,275	$10,331	$10,591	$10,651	$11,117	$11,348	$11,262	$11,438	$11,646
CE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CH	$6,404	$5,838	$6,112	$6,278	$6,374	$6,478	$6,674	$6,865	$6,940	$7,032
CL	$1,607	$1,582	$1,579	$1,582	$1,589	$1,590	$1,601	$1,624	$1,652	$1,668
CM	$2,275	$2,389	$2,412	$2,463	$2,483	$2,593	$2,651	$2,642	$2,689	$2,743
CN	$344	$344	$343	$346	$345	$347	$350	$358	$361	$365
CR	$6,947	$6,606	$6,611	$6,617	$6,646	$6,650	$6,692	$6,781	$6,899	$6,971
CS	$1,030	$1,029	$1,023	$1,017	$1,012	$1,027	$1,039	$1,036	$1,038	$1,044
Customer Initiated (CIC)	**$55,584**	**$54,661**	**$55,184**	**$55,575**	**$55,871**	**$56,983**	**$58,148**	**$58,977**	**$60,058**	**$61,139**
DL	$700	$0	$0	$0	$700	$0	$700	$700	$0	$0

Financial Year Ending $k	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
DO	$1,161	$6,021	$9,410	$9,710	$7,461	$5,709	$1,101	$2,360	$2,300	$5,400
DS	$20,894	$14,136	$17,805	$13,696	$10,359	$10,507	$12,169	$13,009	$12,759	$12,149
DZ	$5,333	$4,136	$2,068	$4,648	$11,805	$11,816	$7,490	$11,370	$22,394	$16,108
GP	$0	$2,000	$0	$0	$0	$0	$2,000	$0	$0	$2,000
Augmentation (Demand)	**$28,088**	**$26,293**	**$29,283**	**$28,053**	**$30,326**	**$28,033**	**$23,460**	**$27,439**	**$37,453**	**$35,658**

Table 4-28: Forecast growth capex Requirement (20 year) – BAU scenario (cost escalators excluded)

Financial Year Ending $k	2016-2020 pa	2021-2025 pa	2026-2030 pa	2031-2035 pa	Average first 10 Years pa	Average over 20 Years pa
Customer Initiated (CIC)	$55,375	$59,061	$62,231	$62,231	$57,218	$59,725
Augmentation (Demand)	$28,408	$30,409	$26,398	$26,971	$29,409	$28,047

The comparison of the next 10-year average bottom-up forecast with the top-down forecast is shown below.

Capex Code	Network Level	Top-Down	Bottom-Up
(DO)	Sub-transmission	$6.4M pa	$5.1M pa
(DZ) (GP)	Zone Substations	$10.8M pa	$10.3M pa
(DSA)	High Voltage Distribution Feeders	$5.9M pa	$4.9M pa
(DSS)	Distribution Transformers and LV	$9.3M pa	$8.9M pa
(DL)	Reactive Power Compensation	$0.8M pa	$0.3M pa
(D)	**TOTAL Demand Capex**	**$33.2M pa**	**$29.4M pa**

The sensitivity of the forecast to each of the alternative demand scenarios is now presented below.

4.6.5. Demand Scenario #2: High Demand

The Demand Scenario #2 sees a growth of 242MW in the 10% PoE summer maximum demand over the next five years and 1357MW between 2014-2015 and 2034-2035. This equates to 2.2% per annum over 5 years, or 3.1% per annum over 20 years. Based on this growth, the capex program requirements are presented below.

Table 4-29: Forecast growth capex Requirement – High Demand Scenario (cos escalators excluded)

Financial Year Ending $k	2016-2020 pa	2021-2025 pa	2026-2030 pa	2031-2035 pa	Average first 10 Years pa	Average over 20 Years pa
Customer Initiated (CIC)	$55,375	$59,061	$62,231	$62,231	$57,218	$59,725
Augmentation (Demand)	$30,264	$36,793	$40,900	$49,435	$33,529	$39,348

4.6.6. Demand Scenario #3: Low Demand

The Demand Scenario #3 sees a growth of 194MW in the 10% PoE summer maximum demand over the next five years and 609MW between 2014-2015 and 2034-2035. This equates to 1.8% per annum over 5 years, or 1.4% per annum over 20 years. Based on this growth, the capex program requirements are presented below.

Table 4-30: Forecast growth capex Requirement – Low Demand Scenario (cost escalators excluded)

Financial Year Ending $k	2016-2020 pa	2021-2025 pa	2026-2030 pa	2031-2035 pa	Average first 10 Years pa	Average over 20 Years pa
Customer Initiated (CIC)	$55,375	$59,061	$62,231	$62,231	$57,218	$59,725
Augmentation (Demand)	$27,873	$26,989	$17,886	$10,517	$27,431	$20,816

UNITED ENERGY

5. Demand Plan

This Demand Plan sets out the capital expenditure works programme (without cost escalators) to meet the forecast customer connection and maximum demand growth requirements in the UE service area over the next 20 years, preserving existing levels of reliability.

5.1. CIC

Activity	Project	Commission Year	Budget Total Cost ($k)	Area
CB	Customer business supply	2015/16	13691	North
CB	Customer business supply	2015/16	13497	South
CS	Low density / small business supply less than 10kVA	2015/16	1030	South
CH	Medium density housing	2015/16	1642	North
CH	Medium density housing	2015/16	4762	South
CL	Public lighting capital projects	2015/16	1172	North
CL	Public lighting capital projects	2015/16	435	South
CR	Special capital works / recoverable works	2015/16	3347	North
CR	Special capital works / recoverable works	2015/16	3599	South
CB	Customer business supply	2016/17	13394	North
CB	Customer business supply	2016/17	13205	South
CS	Low density / small business supply less than 10kVA	2016/17	1029	South
CH	Medium density housing	2016/17	1496	North
CH	Medium density housing	2016/17	4341	South
CL	Public lighting capital projects	2016/17	1153	North
CL	Public lighting capital projects	2016/17	428	South
CR	Special capital works / recoverable works	2016/17	3183	North
CR	Special capital works / recoverable works	2016/17	3423	South
CB	Customer business supply	2017/18	13481	North
CB	Customer business supply	2017/18	13290	South
CS	Low density / small business supply less than 10kVA	2017/18	1023	South
CH	Medium density housing	2017/18	1567	North
CH	Medium density housing	2017/18	4545	South
CL	Public lighting capital projects	2017/18	1152	North
CL	Public lighting capital projects	2017/18	427	South
CR	Special capital works / recoverable works	2017/18	3185	North
CR	Special capital works / recoverable works	2017/18	3426	South
CB	Customer business supply	2018/19	13436	North
CB	Customer business supply	2018/19	13246	South
CS	Low density / small business supply less than 10kVA	2018/19	1017	South
CH	Medium density housing	2018/19	1609	North
CH	Medium density housing	2018/19	4669	South
CL	Public lighting capital projects	2018/19	1154	North
CL	Public lighting capital projects	2018/19	428	South
CR	Special capital works / recoverable works	2018/19	3189	North
CR	Special capital works / recoverable works	2018/19	3429	South
CB	Customer business supply	2019/20	13481	North
CB	Customer business supply	2019/20	13290	South
CS	Low density / small business supply less than 10kVA	2019/20	1012	South
CH	Medium density housing	2019/20	1634	North
CH	Medium density housing	2019/20	4740	South
CL	Public lighting capital projects	2019/20	1159	North
CL	Public lighting capital projects	2019/20	430	South
CR	Special capital works / recoverable works	2019/20	3202	North
CR	Special capital works / recoverable works	2019/20	3444	South
CB	Customer business supply	2020/21	13689	North
CB	Customer business supply	2020/21	13495	South
CS	Low density / small business supply less than 10kVA	2020/21	1027	South
CH	Medium density housing	2020/21	1660	North
CH	Medium density housing	2020/21	4817	South
CL	Public lighting capital projects	2020/21	1160	North
CL	Public lighting capital projects	2020/21	430	South
CR	Special capital works / recoverable works	2020/21	3204	North
CR	Special capital works / recoverable works	2020/21	3446	South
CB	Customer business supply	2021/22	13996	North
CB	Customer business supply	2021/22	13797	South
CS	Low density / small business supply less than 10kVA	2021/22	1039	South
CH	Medium density housing	2021/22	1711	North
CH	Medium density housing	2021/22	4963	South
CL	Public lighting capital projects	2021/22	1168	North
CL	Public lighting capital projects	2021/22	433	South
CR	Special capital works / recoverable works	2021/22	3224	North
CR	Special capital works / recoverable works	2021/22	3467	South
CB	Customer business supply	2022/23	14305	North
CB	Customer business supply	2022/23	14103	South
CS	Low density / small business supply less than 10kVA	2022/23	1036	South
CH	Medium density housing	2022/23	1760	North
CH	Medium density housing	2022/23	5106	South
CL	Public lighting capital projects	2022/23	1185	North
CL	Public lighting capital projects	2022/23	440	South
CR	Special capital works / recoverable works	2022/23	3267	North
CR	Special capital works / recoverable works	2022/23	3514	South
CB	Customer business supply	2023/24	14624	North
CB	Customer business supply	2023/24	14417	South
CS	Low density / small business supply less than 10kVA	2023/24	1038	South
CH	Medium density housing	2023/24	1779	North
CH	Medium density housing	2023/24	5161	South
CL	Public lighting capital projects	2023/24	1205	North
CL	Public lighting capital projects	2023/24	447	South
CR	Special capital works / recoverable works	2023/24	3324	North
CR	Special capital works / recoverable works	2023/24	3575	South
CB	Customer business supply	2024/25	14941	North
CB	Customer business supply	2024/25	14729	South
CS	Low density / small business supply less than 10kVA	2024/25	1044	South
CH	Medium density housing	2024/25	1803	North
CH	Medium density housing	2024/25	5229	South
CL	Public lighting capital projects	2024/25	1217	North
CL	Public lighting capital projects	2024/25	452	South
CR	Special capital works / recoverable works	2024/25	3359	North
CR	Special capital works / recoverable works	2024/25	3612	South
CB	Customer business supply	2025/26	15271	North
CB	Customer business supply	2025/26	15055	South
CS	Low density / small business supply less than 10kVA	2025/26	1049	South
CH	Medium density housing	2025/26	1840	North
CH	Medium density housing	2025/26	5339	South
CL	Public lighting capital projects	2025/26	1232	North
CL	Public lighting capital projects	2025/26	457	South
CR	Special capital works / recoverable works	2025/26	3399	North
CR	Special capital works / recoverable works	2025/26	3655	South
CB	Customer business supply	2026/27	15271	North
CB	Customer business supply	2026/27	15055	South
CS	Low density / small business supply less than 10kVA	2026/27	1049	South
CH	Medium density housing	2026/27	1840	North
CH	Medium density housing	2026/27	5339	South
CL	Public lighting capital projects	2026/27	1232	North
CL	Public lighting capital projects	2026/27	457	South
CR	Special capital works / recoverable works	2026/27	3399	North
CR	Special capital works / recoverable works	2026/27	3655	South
CB	Customer business supply	2027/28	15271	North
CB	Customer business supply	2027/28	15055	South
CS	Low density / small business supply less than 10kVA	2027/28	1049	South
CH	Medium density housing	2027/28	1840	North
CH	Medium density housing	2027/28	5339	South
CL	Public lighting capital projects	2027/28	1232	North
CL	Public lighting capital projects	2027/28	457	South
CR	Special capital works / recoverable works	2027/28	3399	North
CR	Special capital works / recoverable works	2027/28	3655	South
CB	Customer business supply	2028/29	15271	North
CB	Customer business supply	2028/29	15055	South
CS	Low density / small business supply less than 10kVA	2028/29	1049	South
CH	Medium density housing	2028/29	1840	North
CH	Medium density housing	2028/29	5339	South
CL	Public lighting capital projects	2028/29	1232	North
CL	Public lighting capital projects	2028/29	457	South
CR	Special capital works / recoverable works	2028/29	3399	North
CR	Special capital works / recoverable works	2028/29	3655	South
CB	Customer business supply	2029/30	15271	North
CB	Customer business supply	2029/30	15055	South
CS	Low density / small business supply less than 10kVA	2029/30	1049	South
CH	Medium density housing	2029/30	1840	North
CH	Medium density housing	2029/30	5339	South
CL	Public lighting capital projects	2029/30	1232	North
CL	Public lighting capital projects	2029/30	457	South
CR	Special capital works / recoverable works	2029/30	3399	North
CR	Special capital works / recoverable works	2029/30	3655	South
CB	Customer business supply	2030/31	15271	North
CB	Customer business supply	2030/31	15055	South
CS	Low density / small business supply less than 10kVA	2030/31	1049	South
CH	Medium density housing	2030/31	1840	North
CH	Medium density housing	2030/31	5339	South
CL	Public lighting capital projects	2030/31	1232	North
CL	Public lighting capital projects	2030/31	457	South
CR	Special capital works / recoverable works	2030/31	3399	North
CR	Special capital works / recoverable works	2030/31	3655	South
CB	Customer business supply	2031/32	15271	North
CB	Customer business supply	2031/32	15055	South
CS	Low density / small business supply less than 10kVA	2031/32	1049	South
CH	Medium density housing	2031/32	1840	North
CH	Medium density housing	2031/32	5339	South
CL	Public lighting capital projects	2031/32	1232	North
CL	Public lighting capital projects	2031/32	457	South
CR	Special capital works / recoverable works	2031/32	3399	North
CR	Special capital works / recoverable works	2031/32	3655	South
CB	Customer business supply	2032/33	15271	North
CB	Customer business supply	2032/33	15055	South
CS	Low density / small business supply less than 10kVA	2032/33	1049	South
CH	Medium density housing	2032/33	1840	North
CH	Medium density housing	2032/33	5339	South
CL	Public lighting capital projects	2032/33	1232	North
CL	Public lighting capital projects	2032/33	457	South
CR	Special capital works / recoverable works	2032/33	3399	North
CR	Special capital works / recoverable works	2032/33	3655	South
CB	Customer business supply	2033/34	15271	North
CB	Customer business supply	2033/34	15055	South
CS	Low density / small business supply less than 10kVA	2033/34	1049	South
CH	Medium density housing	2033/34	1840	North
CH	Medium density housing	2033/34	5339	South
CL	Public lighting capital projects	2033/34	1232	North
CL	Public lighting capital projects	2033/34	457	South
CR	Special capital works / recoverable works	2033/34	3399	North
CR	Special capital works / recoverable works	2033/34	3655	South
CB	Customer business supply	2034/35	15271	North
CB	Customer business supply	2034/35	15055	South
CS	Low density / small business supply less than 10kVA	2034/35	1049	South
CH	Medium density housing	2034/35	1840	North
CH	Medium density housing	2034/35	5339	South
CL	Public lighting capital projects	2034/35	1232	North
CL	Public lighting capital projects	2034/35	457	South
CR	Special capital works / recoverable works	2034/35	3399	North
CR	Special capital works / recoverable works	2034/35	3655	South

5.2. Unitised Capex

Activity	Project	Commission Year	Budget Total Cost ($k)	Area
CM	Contestable metering	2015/16	1490	North
CM	Contestable metering	2015/16	785	South
CD	Dual and multiple occupancy	2015/16	6477	North
CD	Dual and multiple occupancy	2015/16	3313	South
CN	T5 public lighting	2015/16	121	North
CN	T5 public lighting	2015/16	223	South
CM	Contestable metering	2016/17	1564	North
CM	Contestable metering	2016/17	824	South
CD	Dual and multiple occupancy	2016/17	6798	North
CD	Dual and multiple occupancy	2016/17	3477	South
CN	T5 public lighting	2016/17	121	North
CN	T5 public lighting	2016/17	223	South
CM	Contestable metering	2017/18	1580	North
CM	Contestable metering	2017/18	833	South
CD	Dual and multiple occupancy	2017/18	6835	North
CD	Dual and multiple occupancy	2017/18	3496	South
CN	T5 public lighting	2017/18	121	North
CN	T5 public lighting	2017/18	222	South
CM	Contestable metering	2018/19	1613	North
CM	Contestable metering	2018/19	850	South
CD	Dual and multiple occupancy	2018/19	7006	North
CD	Dual and multiple occupancy	2018/19	3584	South
CN	T5 public lighting	2018/19	122	North
CN	T5 public lighting	2018/19	224	South
CM	Contestable metering	2019/20	1626	North
CM	Contestable metering	2019/20	857	South
CD	Dual and multiple occupancy	2019/20	7047	North
CD	Dual and multiple occupancy	2019/20	3605	South
CN	T5 public lighting	2019/20	122	North
CN	T5 public lighting	2019/20	223	South
CM	Contestable metering	2020/21	1698	North
CM	Contestable metering	2020/21	895	South
CD	Dual and multiple occupancy	2020/21	7355	North
CD	Dual and multiple occupancy	2020/21	3762	South
CN	T5 public lighting	2020/21	122	North
CN	T5 public lighting	2020/21	225	South
CM	Contestable metering	2021/22	1736	North
CM	Contestable metering	2021/22	915	South
CD	Dual and multiple occupancy	2021/22	7507	North
CD	Dual and multiple occupancy	2021/22	3840	South
CN	T5 public lighting	2021/22	123	North
CN	T5 public lighting	2021/22	227	South
CM	Contestable metering	2022/23	1730	North
CM	Contestable metering	2022/23	912	South
CD	Dual and multiple occupancy	2022/23	7451	North
CD	Dual and multiple occupancy	2022/23	3811	South
CN	T5 public lighting	2022/23	126	North
CN	T5 public lighting	2022/23	232	South
CM	Contestable metering	2023/24	1761	North
CM	Contestable metering	2023/24	928	South
CD	Dual and multiple occupancy	2023/24	7567	North
CD	Dual and multiple occupancy	2023/24	3871	South
CN	T5 public lighting	2023/24	127	North
CN	T5 public lighting	2023/24	234	South
CM	Contestable metering	2024/25	1797	North
CM	Contestable metering	2024/25	947	South
CD	Dual and multiple occupancy	2024/25	7705	North
CD	Dual and multiple occupancy	2024/25	3941	South
CN	T5 public lighting	2024/25	129	North
CN	T5 public lighting	2024/25	237	South
CM	Contestable metering	2025/26	1822	North
CM	Contestable metering	2025/26	960	South
CD	Dual and multiple occupancy	2025/26	7795	North
CD	Dual and multiple occupancy	2025/26	3988	South
CN	T5 public lighting	2025/26	130	North
CN	T5 public lighting	2025/26	240	South
CM	Contestable metering	2026/27	1822	North
CM	Contestable metering	2026/27	960	South
CD	Dual and multiple occupancy	2026/27	7795	North
CD	Dual and multiple occupancy	2026/27	3988	South
CN	T5 public lighting	2026/27	130	North
CN	T5 public lighting	2026/27	240	South
CM	Contestable metering	2027/28	1822	North
CM	Contestable metering	2027/28	960	South
CD	Dual and multiple occupancy	2027/28	7795	North
CD	Dual and multiple occupancy	2027/28	3988	South
CN	T5 public lighting	2027/28	130	North
CN	T5 public lighting	2027/28	240	South
CM	Contestable metering	2028/29	1822	North
CM	Contestable metering	2028/29	960	South
CD	Dual and multiple occupancy	2028/29	7795	North
CD	Dual and multiple occupancy	2028/29	3988	South
CN	T5 public lighting	2028/29	130	North
CN	T5 public lighting	2028/29	240	South
CM	Contestable metering	2029/30	1822	North
CM	Contestable metering	2029/30	960	South
CD	Dual and multiple occupancy	2029/30	7795	North
CD	Dual and multiple occupancy	2029/30	3988	South
CN	T5 public lighting	2029/30	130	North
CN	T5 public lighting	2029/30	240	South
CM	Contestable metering	2030/31	1822	North
CM	Contestable metering	2030/31	960	South
CD	Dual and multiple occupancy	2030/31	7795	North
CD	Dual and multiple occupancy	2030/31	3988	South
CN	T5 public lighting	2030/31	130	North
CN	T5 public lighting	2030/31	240	South
CM	Contestable metering	2031/32	1822	North
CM	Contestable metering	2031/32	960	South
CD	Dual and multiple occupancy	2031/32	7795	North
CD	Dual and multiple occupancy	2031/32	3988	South
CN	T5 public lighting	2031/32	130	North
CN	T5 public lighting	2031/32	240	South
CM	Contestable metering	2032/33	1822	North
CM	Contestable metering	2032/33	960	South
CD	Dual and multiple occupancy	2032/33	7795	North
CD	Dual and multiple occupancy	2032/33	3988	South
CN	T5 public lighting	2032/33	130	North
CN	T5 public lighting	2032/33	240	South
CM	Contestable metering	2033/34	1822	North
CM	Contestable metering	2033/34	960	South
CD	Dual and multiple occupancy	2033/34	7795	North
CD	Dual and multiple occupancy	2033/34	3988	South
CN	T5 public lighting	2033/34	130	North
CN	T5 public lighting	2033/34	240	South
CM	Contestable metering	2034/35	1822	North
CM	Contestable metering	2034/35	960	South
CD	Dual and multiple occupancy	2034/35	7795	North
CD	Dual and multiple occupancy	2034/35	3988	South
CN	T5 public lighting	2034/35	130	North
CN	T5 public lighting	2034/35	240	South

Activity	Project	Commission Year	Budget Total Cost ($k)	Area
DS	DSJ - Pole TX upgrade 200-500kVA	2015/16	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2015/16	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2016/17	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2016/17	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2017/18	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2017/18	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2018/19	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2018/19	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2019/20	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2019/20	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2020/21	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2020/21	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2021/22	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2021/22	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2022/23	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2022/23	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2023/24	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2023/24	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2024/25	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2024/25	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2025/26	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2025/26	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2026/27	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2026/27	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2027/28	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2027/28	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2028/29	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2028/29	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2029/30	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2029/30	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2030/31	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2030/31	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2031/32	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2031/32	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2032/33	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2032/33	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2033/34	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2033/34	216	Both
DS	DSJ - Pole TX upgrade 200-500kVA	2034/35	1743	Both
DS	DSM - Pole TX upgrade <200kVA	2034/35	216	Both

5.3. Sub-transmission

Activity	Project	Commission Year	Budget Total Cost ($k)	Area	Substation
DO	BT-MR 66kV - thermal uprate	2015/16	276	North	BT
DO	EW RTS-EW Upgrade droppers at EW	2015/16	See Note 85	North	EW
DO	RTS 66kV Line Works associated with RTS redevelopment (Stage 1)	2015/16	1000	North	EW
DO	TSTS-WD and TSTS-DC#1 Lines survey for uprate	2015/16	300	North	WD
DO	SVTS-EB 66kV line reconductor	2016/17	421	North	EB
DO	RTS 66kV Line Works associated with RTS redevelopment (Stage 2)	2017/18	900	North	K
DO	HGS-RBD New 66kV sub-transmission line	2018/19	23499	South	HGS
DO	MTS-OR 66 kV Reconductor	2018/19	See Note 30	North	OR
DO	TBTS-HGS 66kV sub-transmission line augmentation	2018/19	290	South	HGS
DO	DC upgrade duo roll switches	2019/20	110	North	DC
DO	TSTS-DC No. 1 66kV line reconductor	2019/20	427	North	DC
DO	TSTS-DC No. 2 66kV line reconductor	2019/20	998	North	DC
DO	TSTS-WD 66kV line reconductor	2019/20	217	North	WD
DO	SKE New 66kV subtransmission line to supply Skye zone substation	2020/21	11418	South	SKE
DO	CBTS 66kV Line Rearrangement	2021/22	546	South	CBTS
DO	CDA & OE Transfer to Bus 3/4 group at SVTS (align with SVTS rebuild)	2021/22	556	North	CDA
DO	GW/NO loop combine with EB loop	2022/23	500	North	NO
DO	KBH-M-MC 66kV sub-transmission line reconductor	2022/23	360	South	MC
DO	RWTS-NW-BH loop - 3rd 66 kV line	2023/24	3000	North	NW
DO	SVE 2km of new 66kV subtransmission line to supply Sommerville zone substation	2024/25	1200	South	SVE
DO	DNTS Subtransmission works	2025/26	7000	South	DNTS
DO	SCY New 66kV sub transmission loop for Scoresby	2025/26	3000	North	SCY
DO	HTS-M #2 66kV sub-transmission line reconductor	2027/28	1458	South	M
DO	HTS-BR 66kV sub-transmission line reconductor	2029/30	600	South	BR
DO	LHT New 66kV subtransmission line to supply Lyndhurst zone substation	2032/33	5184	South	LHT

Note: Exact timing of the low cost MTS-OR and RTS-EW upgrades still being assessed. Both projects are likely to be able to be deferred.

5.4. Zone Substation

Activity	Project	Commission Year	Budget Total Cost ($k)	Area	Substation
DZ	DMA 2nd transformer	2015/16	8000	South	DMA
GP	SKE Land Acquisition for Skye zone substation	2016/17	2000	South	SKE
DZ	NO 3rd transformer	2017/18	6204	North	NO
DZ	DC 4th transformer	2019/20	6454	North	DC
DZ	SKE New Skye zone substation	2020/21	12599	South	SKE
GP	SCY Land Acquisition Scoresby zone substation	2021/22	2000	North	SCY
DZ	MTN 3rd transformer	2021/22	8003	South	MTN
DZ	SVW 3rd transformer	2022/23	6203	North	SVW
DZ	EM 3rd transformer	2023/24	6203	North	EM
DZ	KBH 2nd transformer	2023/24	7750	South	KBH
GP	MRA Land Acquisition Moorabbin Airport zone substation	2024/25	2000	South	MRA
DZ	SS 3rd transformer	2024/25	6203	North	SS
DZ	SVE New Somerville zone substation	2024/25	18381	South	SVE
DZ	SCY New Scoresby zone substation	2025/26	9840	North	SCY
DZ	K 3rd transformer	2026/27	5750	North	K
GP	LHT Land Acquisition for Lyndhurst zone substation	2026/27	1500	South	LHT
DZ	BU 3rd transformer	2027/28	6500	North	BU
DZ	CDA 2nd fixed transformer	2027/28	6500	North	CDA
GP	DNN Land Acquisition for Dandenong North zone substation	2027/28	1500	South	DNN
DZ	SKE 2nd transformer	2027/28	6500	South	SKE
DZ	MRA New Moorabbin Airport zone substation	2029/30	13840	South	MRA
DZ	FTN 3rd transformer	2030/31	6500	South	FTN
DZ	OAK 2nd fixed transformer	2030/31	6500	North	OAK
DZ	HGS 3rd transformer	2031/32	6500	South	HGS
DZ	DNN New Dandenong North zone substation	2032/33	12000	South	DNN
DZ	LHT New Lyndhurst Zone substation	2032/33	12000	South	LHT
DZ	BT 3rd transformer	2033/34	6500	North	BT

5.5. Distribution Feeder

Activity	Project	Commission Year	Budget Total Cost ($k)	Area	Substation
DS	BR01 feeder exit upgrade	2015/16	160	South	BR
DS	CFD New feeder	2015/16	1144	North	CFD
DS	DSH21 tie line	2015/16	361	South	DSH
DS	DVY11 New feeder	2015/16	828	South	DVY
DS	EM01 - OAK22 Tie	2015/16	206	North	EM
DS	EM10 Reconductor	2015/16	369	North	EM
DS	EW05 new feeder	2015/16	1645	North	EW
DS	FSH24 New Feeder	2015/16	1414	South	FSH
DS	HV switches	2015/16	200	North	n/a
DS	MC7 feeder reconductor	2015/16	313	South	MC
DS	MGE New Feeder	2015/16	998	North	MGE
DS	MR33 new feeder	2015/16	1326	North	MR
DS	OR 23 upgrade feeder	2015/16	240	North	OR
DS	OR 25 upgrade feeder	2015/16	253	North	OR
DS	SR13 load transfer	2015/16	359	North	SR
DS	CRM24 Feeder extension (deferred by Greensync)	2016/17	330	South	CRM
DS	FTN23 feeder reconductor	2016/17	486	South	FTN
DS	HV switches	2016/17	200	South	n/a
DS	BU14 reconductor	2017/18	184	North	BU
DS	CRM13 Feeder upgrade	2017/18	436	South	CRM
DS	CRM15 New 22kV feeder	2017/18	1067	South	CRM
DS	DN11 reconductor	2017/18	433	South	DN
DS	HGS14 New 22kV feeder	2017/18	2783	South	HGS
DS	HV switches	2017/18	200	North	n/a
DS	KBH35 feeder extension	2017/18	449	South	KBH
DS	LD07 reconductor	2017/18	211	South	LD
DS	LD34 new feeder	2017/18	695	South	LD
DS	M 32 feeder exit cable upgrade	2017/18	318	South	M
DS	OAK23 upgrade	2017/18	160	North	OAK
DS	RBD11 Feeder extension	2017/18	1368	South	RBD
DS	BR14 New Feeder	2018/19	683	South	BR
DS	BU06 upgrade	2018/19	358	North	BU
DS	BW21 Tie Line	2018/19	201	North	BW
DS	FSH14 New feeder	2018/19	1996	South	FSH
DS	HV switches	2018/19	200	South	n/a
DS	MTN33 New Feeder	2018/19	954	South	MTN
DS	NW 21 feeder reconductor	2018/19	234	North	NW
DS	DC05 Tie Line	2019/20	141	North	DC
DS	FTN14 re-arrangement	2019/20	94	South	FTN
DS	HV switches	2019/20	200	North	n/a
DS	MC8 New Feeder	2019/20	728	South	MC
DS	DVY32 Feeder re-conductoring	2020/21	313	South	DVY
DS	HGS11 New 22kV feeder	2020/21	1212	South	HGS
DS	HV switches	2020/21	200	South	n/a
DS	LD02 reconductor	2020/21	200	South	LD
DS	MR24 cable upgrades	2020/21	153	North	MR
DS	WD new feeder	2020/21	471	North	WD
DS	WD16 & WD26 conversion to 11kV	2020/21	1080	North	WD
DS	Feeder Augmentations	2021/22	2500	North	n/a
DS	Feeder Augmentations	2021/22	2500	South	n/a
DS	Feeder Augmentations	2022/23	2500	North	n/a
DS	Feeder Augmentations	2022/23	2500	South	n/a
DS	Feeder Augmentations	2023/24	2500	North	n/a
DS	Feeder Augmentations	2023/24	2500	South	n/a
DS	Feeder Augmentations	2024/25	2500	North	n/a
DS	Feeder Augmentations	2024/25	2500	South	n/a
DS	Feeder Augmentations	2025/26	2500	North	n/a
DS	Feeder Augmentations	2025/26	2500	South	n/a
DS	Feeder Augmentations	2026/27	2500	North	n/a
DS	Feeder Augmentations	2026/27	2500	South	n/a
DS	Feeder Augmentations	2027/28	2500	North	n/a
DS	Feeder Augmentations	2027/28	2500	South	n/a
DS	Feeder Augmentations	2028/29	2500	North	n/a
DS	Feeder Augmentations	2028/29	2500	South	n/a
DS	Feeder Augmentations	2029/30	2500	North	n/a
DS	Feeder Augmentations	2029/30	2500	South	n/a
DS	Feeder Augmentations	2030/31	2500	North	n/a
DS	Feeder Augmentations	2030/31	2500	South	n/a
DS	Feeder Augmentations	2031/32	2500	North	n/a
DS	Feeder Augmentations	2031/32	2500	South	n/a
DS	Feeder Augmentations	2032/33	2500	North	n/a
DS	Feeder Augmentations	2032/33	2500	South	n/a
DS	Feeder Augmentations	2033/34	2500	North	n/a
DS	Feeder Augmentations	2033/34	2500	South	n/a
DS	Feeder Augmentations	2034/35	2500	North	n/a
DS	Feeder Augmentations	2034/35	2500	South	n/a

5.6. Distribution Substations and LV network

Activity	Project	Commission Year	Budget Total Cost ($k)	Area
DS	DSS North P1	2015/16	2075	North
DS	DSS North P2	2015/16	1975	North
DS	DSS North P3	2015/16	850	North
DS	DSS South P1	2015/16	2000	South
DS	DSS South P2	2015/16	1525	South
DS	DSS South P3	2015/16	695	South
DS	DSS North P1	2016/17	350	North
DS	DSS North P2	2016/17	1390	North
DS	DSS North P3	2016/17	3420	North
DS	DSS South P1	2016/17	90	South
DS	DSS South P2	2016/17	1260	South
DS	DSS South P3	2016/17	3135	South
DS	DSS North P1	2017/18	50	North
DS	DSS North P2	2017/18	922	North
DS	DSS North P3	2017/18	3107	North
DS	DSS South P1	2017/18	440	South
DS	DSS South P2	2017/18	650	South
DS	DSS South P3	2017/18	2675	South
DS	DSS North P1	2018/19	50	North
DS	DSS North P2	2018/19	1572	North
DS	DSS North P3	2018/19	3317	North
DS	DSS South P1	2018/19	100	South
DS	DSS South P2	2018/19	490	South
DS	DSS South P3	2018/19	2550	South
DS	DSS North P1	2019/20	392	North
DS	DSS North P2	2019/20	912	North
DS	DSS North P3	2019/20	3125	North
DS	DSS South P1	2019/20	40	South
DS	DSS South P2	2019/20	390	South
DS	DSS South P3	2019/20	2060	South
DS	DSS North P2	2020/21	700	North
DS	DSS North P3	2020/21	2685	North
DS	DSS South P2	2020/21	300	South
DS	DSS South P3	2020/21	1795	South
DS	DSS North P1	2021/22	50	North
DS	DSS North P2	2021/22	150	North
DS	DSS North P3	2021/22	3120	North
DS	DSS South P2	2021/22	50	South
DS	DSS South P3	2021/22	1840	South
DS	DSS North P2	2022/23	640	North
DS	DSS North P3	2022/23	2860	North
DS	DSS South P2	2022/23	400	South
DS	DSS South P3	2022/23	2150	South
DS	DSS North P2	2023/24	940	North
DS	DSS North P3	2023/24	2920	North
DS	DSS South P2	2023/24	200	South
DS	DSS South P3	2023/24	1740	South
DS	DSS North P2	2024/25	1000	North
DS	DSS North P3	2024/25	2070	North
DS	DSS South P2	2024/25	150	South
DS	DSS South P3	2024/25	1970	South
DS	DSS North P2	2025/26	950	North
DS	DSS North P3	2025/26	2550	North
DS	DSS South P2	2025/26	500	South
DS	DSS South P3	2025/26	2660	South
DS	DSS North P2	2026/27	950	North
DS	DSS North P3	2026/27	2550	North
DS	DSS South P2	2026/27	500	South
DS	DSS South P3	2026/27	2660	South
DS	DSS North P2	2027/28	950	North
DS	DSS North P3	2027/28	2550	North
DS	DSS South P2	2027/28	500	South
DS	DSS South P3	2027/28	2660	South
DS	DSS North P2	2028/29	950	North
DS	DSS North P3	2028/29	2550	North
DS	DSS South P2	2028/29	500	South
DS	DSS South P3	2028/29	2660	South
DS	DSS North P2	2029/30	950	North
DS	DSS North P3	2029/30	2550	North
DS	DSS South P2	2029/30	500	South
DS	DSS South P3	2029/30	2660	South
DS	DSS North P2	2030/31	950	North
DS	DSS North P3	2030/31	2550	North
DS	DSS South P2	2030/31	500	South
DS	DSS South P3	2030/31	2660	South
DS	DSS North P2	2031/32	950	North
DS	DSS North P3	2031/32	2550	North
DS	DSS South P2	2031/32	500	South
DS	DSS South P3	2031/32	2660	South
DS	DSS North P2	2032/33	950	North
DS	DSS North P3	2032/33	2550	North
DS	DSS South P2	2032/33	500	South
DS	DSS South P3	2032/33	2660	South
DS	DSS North P2	2033/34	950	North
DS	DSS North P3	2033/34	2550	North
DS	DSS South P2	2033/34	500	South
DS	DSS South P3	2033/34	2660	South
DS	DSS North P2	2034/35	950	North
DS	DSS North P3	2034/35	2550	North
DS	DSS South P2	2034/35	500	South
DS	DSS South P3	2034/35	2660	South

5.7. Reactive Power Compensation

Activity	Project	Commission Year	Budget Total Cost ($k)	Area	Substation
DL	Reactive power compensation	2015/16	350	North	n/a
DL	Reactive power compensation	2015/16	350	South	n/a
DZ	KBH reactive power compensation	2018/19	346	South	KBH
DZ	LWN Install 6MVAr capacitor bank	2019/20	1354	South	LWN
DL	Reactive power compensation	2019/20	350	North	n/a
DL	Reactive power compensation	2019/20	350	South	n/a
DZ	BR cap bank recommissioning	2020/21	1515	South	BR
DZ	HGS Install 6MVAr capacitor bank	2021/22	1354	South	HGS
DL	Reactive power compensation	2021/22	350	North	n/a
DL	Reactive power compensation	2021/22	350	South	n/a
DL	Reactive power compensation	2022/23	350	North	n/a
DL	Reactive power compensation	2022/23	350	South	n/a
DZ	DMA 6MVAr capacitor bank	2023/24	1354	South	DMA
DZ	MTN 6MVAr capacitor bank	2024/25	1354	South	MTN
DL	Reactive power compensation	2026/27	350	North	n/a
DL	Reactive power compensation	2026/27	350	South	n/a
DL	Reactive power compensation	2027/28	350	North	n/a
DL	Reactive power compensation	2027/28	350	South	n/a
DL	Reactive power compensation	2028/29	350	North	n/a
DL	Reactive power compensation	2028/29	350	South	n/a
DL	Reactive power compensation	2029/30	350	North	n/a
DL	Reactive power compensation	2029/30	350	South	n/a
DZ	KBH 6MVAr capacitor bank	2030/31	1230	South	KBH
DL	Reactive power compensation	2031/32	350	North	n/a
DL	Reactive power compensation	2031/32	350	South	n/a
DL	Reactive power compensation	2032/33	350	North	n/a
DL	Reactive power compensation	2032/33	350	South	n/a
DL	Reactive power compensation	2033/34	350	North	n/a
DL	Reactive power compensation	2033/34	350	South	n/a
DL	Reactive power compensation	2034/35	350	North	n/a
DL	Reactive power compensation	2034/35	350	South	n/a