Augmentation

This page has been intentionally left blank.

Approval and Amendment Record

VERSION	AMENDMENT OVERVIEW
1	UE Final 30 April 2015

Table of contents

List of Tables

Table of Figures

1. Purpose of this document

This document explains and justifies at a high level UE's Augmentation capital expenditure for our standard control services for the next regulatory control period (1 January 2016 to 31 December 2020). This document supports our Regulatory Proposal and references other supporting documents for further detail.

All capital expenditure is presented in real 2015 dollars and is expressed in total costs (i.e. direct costs plus escalations and overheads).

This document links to UE's Demand Strategy & Plan (UE PL 2200) by presenting our strategy and associated capital expenditure works plans to meet the forecast maximum demand growth requirements in UE's service area over the next regulatory control period, preserving existing levels of energy-at-risk, that is, reliability maintained. UE's network planning philosophy approaches energy-at-risk in the context of:

- Condition-based plant ratings;
- Probabilistic risk assessment of loss-of-supply; and
- Customer valuation of supply security,

as quantified in UE's Distribution Annual Planning Report (UE PL 2209) and managed operationally by our detailed Contingency Plans (UE MA 2204).

UE details good asset management practice in our overarching Asset Management Policy (UE PO 2000), Asset Management Investment Policy (UE PO 2001) and Asset Management Strategy & Objectives (UE PL 2000). The proposed Augmentation capital expenditure reflects these documents and provides 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 projections in this document are underpinned by UE's summer maximum demand forecasts and are supported by an independent assessment of maximum demand growth by the National Institute of Economic and Industry Research (NIEIR). The NIEIR forecast is specifically tailored to predict maximum demand growth on UE's electricity network and has proven to be a reliable index for predicting demand. UE has further strengthened its top-down maximum demand forecasting capabilities by leveraging recent work by AECOM in developing an independent macro-economic maximum demand forecasting method and tool. UE has prepared a separate summary document that justifies our maximum demand forecast and method. In this document, UE has discussed reconciliation of our forecast to AEMO's forecast. UE's method for forecasting maximum demand aligns with the approach recommended by Acil Allen Consulting in its report to AEMO titled "A nationally consistent methodology for forecasting maximum electricity demand", dated 26th June 2013.

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. However, up until 2013 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. In response to the deteriorating economic conditions in Australia and increases in electricity prices, the UE maximum demand forecast has been progressively revised downward by NIEIR over the current regulatory control period. 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 and prices stabilise to return to maximum demand growth. As a result, Augmentation capital expenditure projections for the next regulatory control period and actual expenditure for the current period are lower than those that were forecast in 2010. Despite overall growth being lower across UE's network, there remain pockets of strong growth, particularly in and around the developing suburbs from Keysborough through to Carrum Downs, and parts of the Mornington Peninsula. These areas are the predominant drivers of Augmentation capital expenditure in the next period.

The Augmentation capital expenditure forecast is developed from our base case (expected) maximum demand forecast scenario taking into account post-model adjustments from disruptive technologies. UE uses a bottom-up forecasting approach, which involves identifying specific emerging network constraints from network loading capabilities. This expenditure forecast is supported through a number of strategic area plan justifications (documents commencing UE PL 2220+). The forecast is further reconciled against our top-down capital expenditure estimate, and with the AER's top-down Augex model.

These expenditure forecasts are the base (pre-escalation) forecasts and are reported in the body of this document.

To reflect changes in the real input costs of labour and materials expected over the forthcoming regulatory period, we have escalated the base forecasts and have separately shown the impact of this real escalation increase from the underlying forecasts. Forecast costs are shown exclusive of real escalators within this document to facilitate comparison between forecasts developed using the AER's Augex Model. A comparison of base expenditure forecasts and escalated expenditure forecasts for augmentation programs are summarised in the table below.

Table 1: Base and escalated capital expenditure– Augmentation

	2016	2017	2018	2019	2020	Total
Base (pre-escalation)	33.79	30.58	35.27	35.34	24.10	159.07
Weighted average escalator	0.88	1.70	2.57	1.57	0.75	7.47
Escalated	34.67	32.28	37.84	36.91	24.85	166.54

1.1. Cost Escalators

The escalators applied to materials were developed internally using raw-commodity level data provided by an independent expert, BIS Shrapnel, to forecast real material cost escalations for the forthcoming regulatory period. A copy of BIS Shrapnel's report entitled "Real Labour and Material Cost Escalation Forecasts to 2020" has been provided to the AER as an attachment to this Regulatory Proposal.

The methodology used to derive the material cost escalator involved applying the network-related materials escalators (at the raw-commodity level) provided by BIS Shrapnel (i.e. wood, aluminium, copper, steel, oil, concrete etc.) to the estimated mix of these material components required to construct and/or maintain our distribution network. This provided a weighted average escalator for each year that has been applied to our capex forecast. The escalators are outlined in the table below.

Table 2: Real cost escalators

Labour and Material	2016	2017	2018	2019	2020
Labour	0.90	1.30	1.80	2.10	1.80
Copper	3.50	7.70	2.10	-10.00	-6.10
Aluminium	8.00	8.20	5.10	-7.00	-5.20
Steel	4.70	3.00	2.70	-11.00	-3.40
Oil	-1.10	4.30	2.50	-7.70	-5.00
Concrete	-1.00	-2.00	-4.90	-3.20	1.30
Wood	2.20	1.70	0.90	2.20	3.90
Other	0.00	0.00	0.00	0.00	0.00

The model that we have used to derive the labour and material escalators is provided to the AER as part of this Regulatory Proposal.

2. Structure of this document

This document is structured as follows:

- Section 3 details UE's Augmentation capital expenditure profile for the previous, current and forthcoming regulatory control periods;
- Section 4 explains the conceptual nature of Augmentation capital expenditure and why it is necessary;
- Section 5 explains and justifies UE's actual Augmentation capital expenditure against the AER's allowance in the current regulatory control period as well as the outcomes that it has delivered;
- Section 6 explains UE's forecasting methodology for Augmentation capital expenditure for the next regulatory control period and justifies why UE considers that it is the most reasonable methodology for regulatory forecasting;
- Section 7 details UE's Augmentation capital expenditure forecast for the next regulatory control period and what UE expects to achieve by delivering it;
- Section 8 explains how UE considers that our Augmentation capital expenditure forecast meets the capital expenditure objectives and criteria in clause 6.5.7 of the NER, having regard for the capital expenditure factors; and
- Section 9 details the supporting documentation relevant to UE's Augmentation capital expenditure forecast.

3. Expenditure profile

This section examines UE's Augmentation capital expenditure profile for the previous, current and forthcoming regulatory control periods.

UE's Augmentation capital expenditure for the 2006-2010, 2011-2015 and 2015-2020 regulatory control periods is presented below in Tables 3, 4 and 5 respectively. UE's Augmentation capital expenditure is projected to be lower in the next period because of reductions in maximum demand observed in the current period resulting in capex deferral.

Table 3 Previous expenditure ($2015M)

	2006	2007	2008	2009	2010	TOTAL
Regulatory Proposal	24.569	30.800	25.675	32.813	23.197	137.054
Distribution Determination	19.101	24.166	20.473	27.062	19.501	110.302
Actual	21.695	27.942	22.192	56.244	45.447	173.521

Table 4 Current expenditure ($2015M)

	2011	2012	2013	2014	2015	TOTAL
Regulatory Proposal	60.771	58.978	57.008	55.760	53.798	286.315
Distribution Determination	42.212	44.601	32.190	37.246	49.585	205.834
Actual / Forecast	30.246	56.309	36.210	35.894	20.212	178.871

Table 5 Forecast expenditure ($2015M)

	2016	2017	2018	2019	2020	TOTAL
Regulatory Proposal	33.787	30.581	35.270	35.336	24.097	159.071
Distribution Determination	-	-	-	-	-	-
Forecast Total	33.787	30.581	35.270	35.336	24.097	159.071
-Traditional	33.787	30.581	35.270	34.336	22.597	156.571
-Non Traditional (behind the meter storage)	0.000	0.000	0.000	1.000	1.5000	2.500

UE's 2016-2020 forecast Augmentation capital expenditure is:

- 23% ($47M) lower than the 2011-2015 current period regulatory allowance;
- 11% ($20M) lower than the 2011-2015 current period actual spend;
- 8% ($14M) lower than the 2006-2010 previous period actual spend; and
- Contains $2.5M of non-traditional augmentation capital expenditure in the form of behind-the-meter storage.

These variances can be attributed to the following:

- The 2006-2010 actual Augmentation capital expenditure was significantly higher than the regulatory allowance for the period because of higher than anticipated growth in maximum demand. This was a result of the strong performance of the Australian economy in the years immediately preceding the global financial crisis (GFC). During this period, population growth and air-conditioning sales were also relatively strong and the impacts of disruptive technologies such as solar PV were negligible;

- The 2011-2015 actual Augmentation capital expenditure has been lower than the regulatory allowance because of reductions in forecast maximum demand growth rates each year since 2012 as a result of the slowdown in the economy following the wind-back of economic stimulus packages and increases in retail electricity prices. UE has been reducing Augmentation capital expenditure in this period in response to the impact of weakening economic conditions and higher prices. During this period, population growth and air-conditioning sales remained relatively strong and disruptive technologies such as solar PV were causing small but not insignificant reductions in maximum demand;
- The 2016-2020 forecast Augmentation capital expenditure is lower than the current period actual expenditure as a result of declining demand in the last couple of years due to electricity price rises and a slow economy providing some deferral of capital expenditure. During the next period, population growth is expected to remain relatively strong, particularly with the amount of building development activity occurring and planned. Air-conditioning sales are expected to remain strong, stimulated by the recent effects of the 2014 heatwave. Disruptive technologies such as solar PV are expected to have greater downward pressure on maximum demand growth in the next period, but are still expected to remain a relatively small contributor to reducing maximum demand, particularly at local levels with the peaks in our residential areas occurring much later in the day than the peak solar PV output; and
- Falling prices of storage during the period may result in economic behind-the-meter installation of storage.

4. Nature and categorisation of expenditure

This section explains the conceptual nature of Augmentation capital expenditure (previously known as Reinforcement capital expenditure) and why it is necessary.

In preparing our documentation for capital expenditure, we have adopted the AER's categorisation of standard control services capital expenditure being:

- Augmentation;
- Connections;
- Replacement; and
- Non-network.

These sub-categories of capital expenditure are separately explained in other Sub-Category Overview Documents Submitted to the AER with our Regulatory Proposal.

4.1. Regulatory obligations or requirements

Augmentation capital expenditure is required to meet or manage capacity constraints in the electricity distribution network as a result of growth in maximum electricity demand. UE also has obligations under the Victorian Electricity Distribution Code.

There are no defined planning standards for distribution businesses in Victoria (apart from Melbourne CBD obligations which do not apply to UE). Instead UE adopts a probabilistic planning approach to our network planning and Augmentation capital expenditure decision making. This economically sound approach to network planning and expansion considers the expected cost to customers of losing supply in the event the demand exceeds the available network capacity. This is done either with all plant in service or by considering the probability of a single credible contingency. The associated cost is then compared against the annualised cost of removing the capacity constraint either with a network augmentation or non-network solution. When the cost to customers is greater, the solution to remove the capacity constraint is economically justified. This approach is consistent with the approach used by AEMO[1] for its shared transmission network planning in Victoria, and is consistent with the Regulatory Investment Test for Distribution (RIT-D) and the AER's RIT-D Guidelines.

The obligations and planning framework ensure that UE makes efficient investment decisions (either traditional, non-traditional or non-network) for our network planning and expansion which will in turn facilitate the efficient development of our distribution network in the long term interests of customers.

The obligations under the NER require UE (among other things) to:

- Undertake annual planning reviews;
- Prepare a distribution annual planning report (DAPR)[2];
- Incorporate demand-side engagement into our planning activities[3];

[1] UE's approach differs slightly to AEMO in that UE assumes post-contingent load shedding when demand exceeds the rating except where there is a regulatory obligation (such as to maintain voltages within Regulatory limits). AEMO assumes post-contingent load shedding only to the extent that the demand exceeds rating but remains within the emergency short-term rating after which pre-contingent load shedding is assumed.

[2] http://www.uemg.com.au/about-us/regulatory-framework/electricity-regulation/network-planning-reports.aspx

[3] http://www.uemg.com.au/about-us/regulatory-framework/electricity-regulation/demand-side-engagement.aspx

- Undertake joint planning with other network businesses[4]; and
- Apply the RIT-D[5].

These obligations provide transparency in UE's network planning activities and maximise opportunities to consider non-network alternatives to network augmentation.

The obligations under the Victorian Electricity Distribution Code require UE (among other things) to maintain steady-state voltages within prescribed limits.

4.2. Distinction between Augmentation capital and other expenditure categories

Augmentation capital expenditure relates to augmentation programmes and projects for UE's low voltage networks, distribution substations, high voltage feeders, zone substations and sub-transmission systems.

Augmentation capital expenditure is derived from network capacity constraints within the distribution system and is relatively independent of other regulatory expenditure categories. However, there are instances where Augmentation capital expenditure could be seen to overlap with (but not double-count) other regulatory expenditure categories, such as:

- Replacement – where an asset that is scheduled to be replaced as a result of an asset at end of its life provides an increase in network capacity. This capital expenditure is classified by UE as Reliability and Quality Maintained (RQM);
- Replacement – where a network augmentation that is triggered as a result of an identified capacity constraint substitutes an existing asset for a new asset. This capital expenditure is classified by UE as Augmentation;
- Performance – where a network augmentation that is triggered as a result of an identified capacity constraint contributes to maintaining network reliability or achieving voltage (quality of supply) compliance. This capital expenditure is classified by UE as Augmentation;
- Environment, Safety & Legal – where a network Augmentation option contributes to meeting our safety, environmental and legal obligations. This capital expenditure is classified by UE as Augmentation; and
- Customer Connections – where a customer connection triggers an upstream augmentation that results in an increase in capacity upstream with the use of standard equipment. This capital expenditure is classified by UE as New Customer Connections.

Examples of where double counting of capital expenditure in the next regulatory control period have been avoided include:

- North Brighton zone substation switchboard replacement project – the switchboard is currently limiting the capacity of this zone substation; however the switchboard is deemed to be at end of life and is identified for replacement. The switchboard will be replaced with a standard switchboard that has a higher capacity. Given this replacement project will alleviate the capacity constraint at this zone substation, no augmentation capital expenditure is planned at this zone substation; and
- Mordialloc and Frankston South zone substation transformer replacement projects – the aged transformers are currently limiting the capacity of these zone substations, however the transformers are deemed to be at the end of their lives and are identified for replacement. The transformers will be replaced with standard transformers that have a higher capacity and standard impedance that will

[4] UE has in place a joint planning memorandum of understanding with AEMO and the other distribution businesses.

[5] http://www.uemg.com.au/about-us/regulatory-framework/electricity-regulation/regulatory-investment-test-for-distribution-(rit-d).aspx

allow load balancing at the substation. Given that these replacement projects will alleviate the capacity constraints at these zone substations, no augmentation capital expenditure is planned at these zone substations.

UE's Network Planning Guidelines (UE GU 2200) and Asset Management Planning processes – in particular the Expenditure Forecasting Guidelines (UE GU 2206, UE GU 2202 and UE GU 2203) – avoid the risk of double-counting forecast capital expenditure. For example, there is a detailed section in the Network Planning Guidelines that identifies when an upstream augmentation is considered to be New Customer Connections capital and when it is Augmentation capital. Furthermore, the Distribution System Augmentation programme developed for the Augmentation expenditure forecast is developed by the same UE personnel that develop the Customer Connections forecast expenditure. This centralised approach to capital expenditure forecasting minimises the risk of double-counting. Asset management planning between the Network Planning and Asset (Primary & Secondary) teams coordinates and identifies timing and synergies of Augmentation projects and Asset Replacement (i.e. RQM) projects to ensure that expenditure is minimised and optimised over both the forthcoming regulatory period and the 10 to 20 year planning horizon.

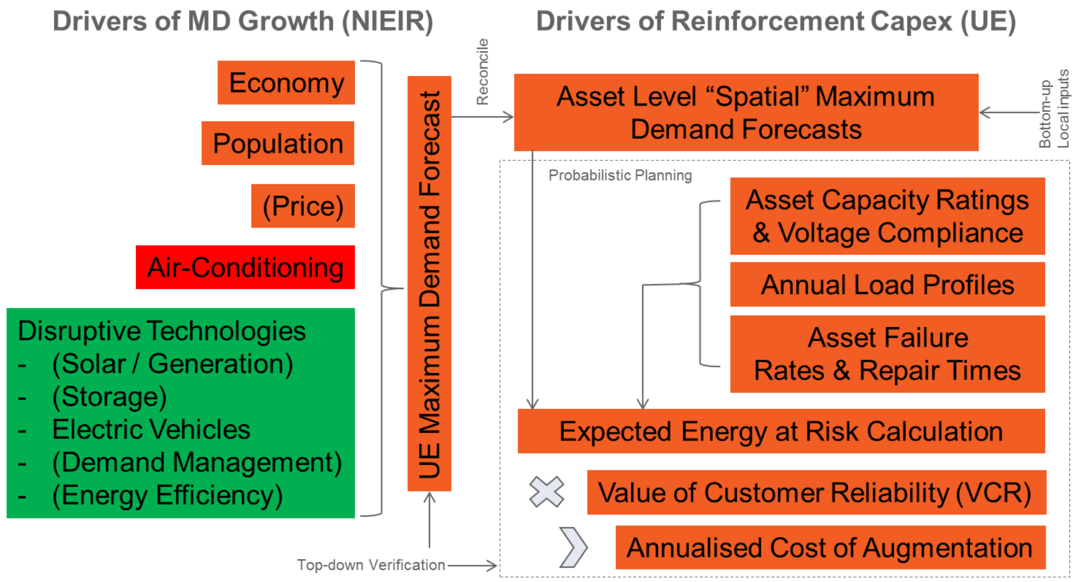
4.3. Key drivers of expenditure

The primary driver for Augmentation 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 "spatial" forecasts that explicitly 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. UE has prepared a separate Overview Paper included with this Regulatory Proposal that justifies our maximum demand forecast.

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 UE's service area. A number of potentially significant emerging developments are occurring or are 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. The use of distributed embedded generation is increasing, stimulated by reduced technology cost, subsidies and increased environmental awareness. A prime example is solar photovoltaic panels. This trend is likely to continue and new technologies will emerge. Furthermore, electric vehicles, distributed storage and demand management applications are also on the horizon. All have the potential to impact maximum demand growth.

Figure 1 shows how the above drivers feed into developing UE's Augmentation capital expenditure forecast.

Figure 1 – Drivers of Augmentation 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 UE 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 (AECOM) model, the disruptive technologies are separately modelled and applied to the forecast 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 Network Planning Guidelines (UE GU 2200) is then applied to assess whether (and when) identified constraints can be economically relieved with an augmentation investment (either traditional such as a transformer upgrade for example, or non-traditional such as a storage device behind the meter). 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 a top-down approach, including using the AER's Augex model. This process is detailed in the Network Planning Expenditure Forecast Guidelines (UE GU 2206).

4.3.1. Economy

UE engages NIEIR each year to provide a whole-of-UE service area maximum summer and winter demand forecast for ten years. NIEIR prepares the forecasts 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 growth given its cyclic nature.

Total gross regional product for the UE region is expected to rise by an average rate of 1.4 per cent between 2015 and 2025. The inner suburbs of Melbourne in UE's service area are experiencing high rates of economic growth due to their access to infrastructure, such as transport, health and education, as well as major shopping centres and high-rise, high density building developments.

The ongoing uncertainty about the global and Australian economies is likely to have an ongoing dampening effect on growth, especially energy growth. While the Australian economy has proven to be fairly resilient to international pressures since the global financial crisis, 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 progressively reduced its maximum demand forecasts for UE throughout the current regulatory control period. This lower growth has resulted in some economic deferrals of UE's Augmentation capital expenditure requirements.

4.3.2. Population

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. The strongest increase in population over the 2015 to 2025 period is expected in the outer Melbourne metropolitan suburbs within UE's service area (1.4 per cent per annum). Population growth is expected to remain modest in the other areas of UE's service area.

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 between 2015 and 2025 under the baseline scenario. The strongest percentage increases in the dwelling stock are expected in the Mornington Peninsula Local Government Area. The total stock is expected to increase by an average rate of 1.6 per cent between 2015 and 2025 in the Mornington Peninsula.

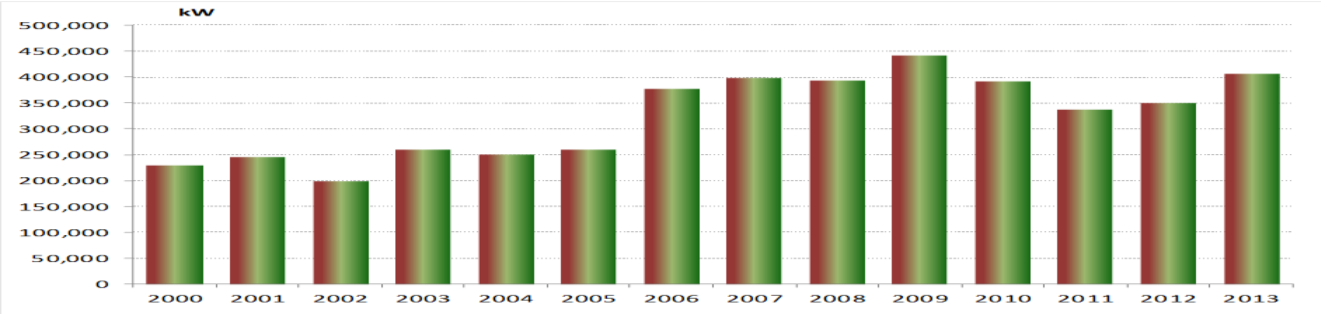
4.3.3. Price

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 significant (being the biggest driver in reduced demand in recent years) and is explicitly modelled in the macro-economic maximum demand forecasting model.

4.3.4. Air-conditioning

Maximum demand growth exceeding energy growth has been anecdotally attributed to the growing affluence of the average electricity customer who is increasingly installing energy intensive devices, such as air conditioning for use during hot weather. 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. Figure 2 shows that total Victorian air-conditioning sales have remained strong over the current regulatory control period. Following the heatwave in 2014, this trend is not expected to slow over the next regulatory control period.

Figure 2 – Victorian air-conditioning sales



4.3.5. Disruptive technologies (Post model adjustments)

Disruptive technologies are likely to have an increasingly influential impact on maximum demand growth and hence Augmentation capital expenditure. These are considered in UE's expenditure forecasts for the 2016-2020 regulatory control period as post-model adjustments on the maximum demand forecast documented in NIEIR's Part A report.

UE engaged NIEIR and Acil Allen Consulting to forecast the impact of post-model adjustments on UE's maximum demand and these are documented in the accompanying consultants' Part B reports. The post-model adjustments quantified for UE include:

- Distributed embedded generation;
- Electric vehicles;
- Distributed storage;
- Demand-side management (including Demand tariffs); and
- Energy efficiency.

Three plausible maximum demand scenarios were developed using the above adjustments – base, low and high are documented in UE's Demand Strategy & Plan (UE PL 2200).

Table 6 Post model adjustment scenarios

Scenario	Solar PV	EV	Storage	Demand -Side	Efficiency
Base Maximum Demand Forecast	Average of reconciled NIEIR and Acil Allen	NIEIR Base	DMIS + planned economic installations only	DMIS + Tariff	VEET, MEPS, LED
Low Maximum Demand Forecast	Acil Allen	Acil Allen (NIEIR Low)	DMIS + planned economic installations only	DMIS + Tariff + Non-network	VEET, MEPS, LED
High Maximum Demand Forecast	Reconciled NIEIR	NIEIR High	Zero	Zero	VEET only

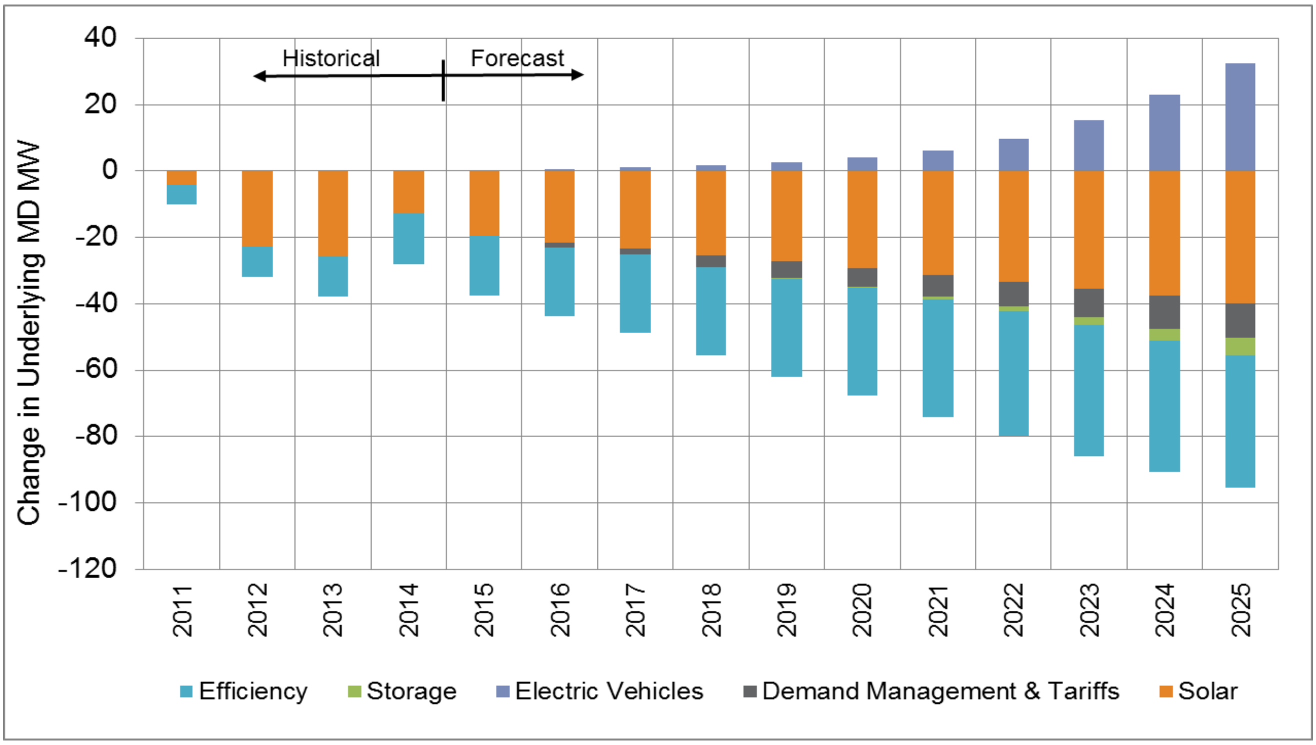
UE's Augmentation capital expenditure forecast is based on the "base" scenario (most likely scenario) and combinations of the above post-model adjustments.

The models developed by NIEIR and Acil Allen Consulting are available with our regulatory proposal to test the post-model adjustment forecast sensitivity to various input parameters and they are developed over a 10-year horizon.

The impact of the post-model adjustment base scenario on UE's maximum demand forecast is presented in Figure 3.

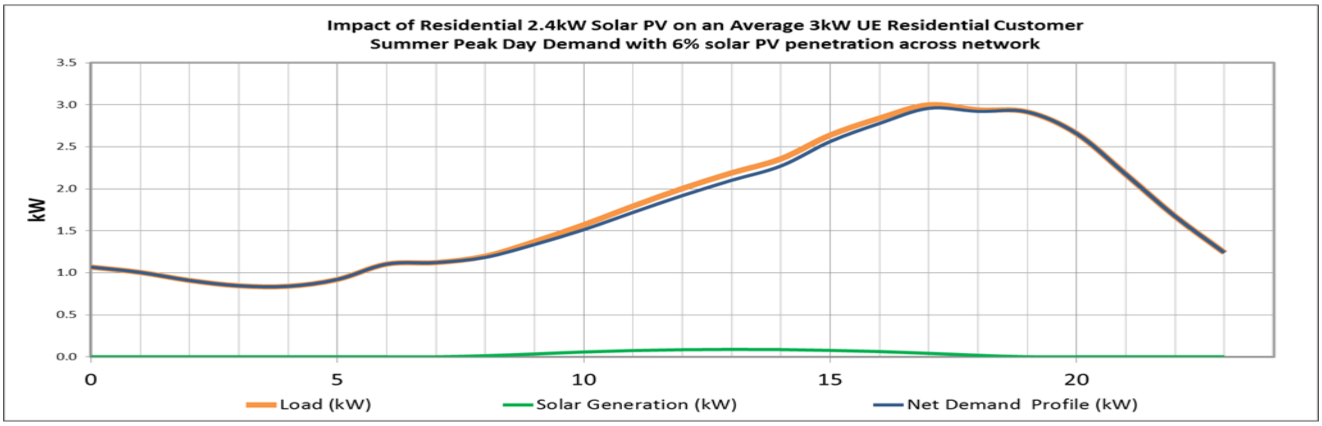
Figure 3

Figure 3 – Maximum demand scenario post-model adjustments



While these represent the contributions at the UE service area level (boundary load), the contribution of solar PV to reducing maximum demand is diluted at the asset "spatial" forecast maximum demand level. This is because the timing of residential installed solar PV does not coincide with residential maximum demand. This is illustrated for UE's network in Figure 4.

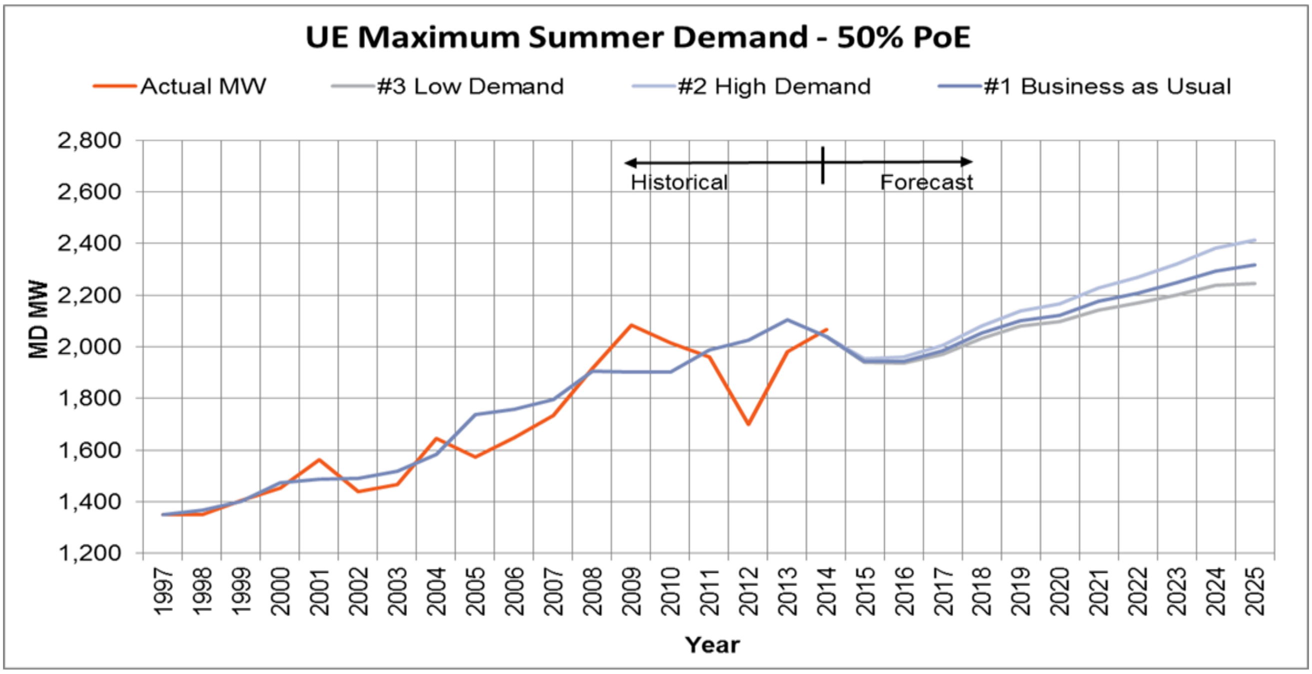
Figure 4 – Impact of Residential Solar PV on Summer Peak Day Demand



4.3.6. Maximum Demand Forecasts

Figure 5 shows UE's base "boundary load" maximum demand forecast developed for UE by NIEIR with high and low scenarios applied for the post-model adjustments defined above. This forecast underpins UE's Augmentation capital expenditure forecasts for the 2016-2020 regulatory control period. Figure 5 is presented based on the 50% probability of exceedance maximum demand forecast to demonstrate how the forecast maximum demand compares with the historical actual maximum demand and the weather-corrected actual demand.

Figure 5 – Maximum summer demand – 50% PoE

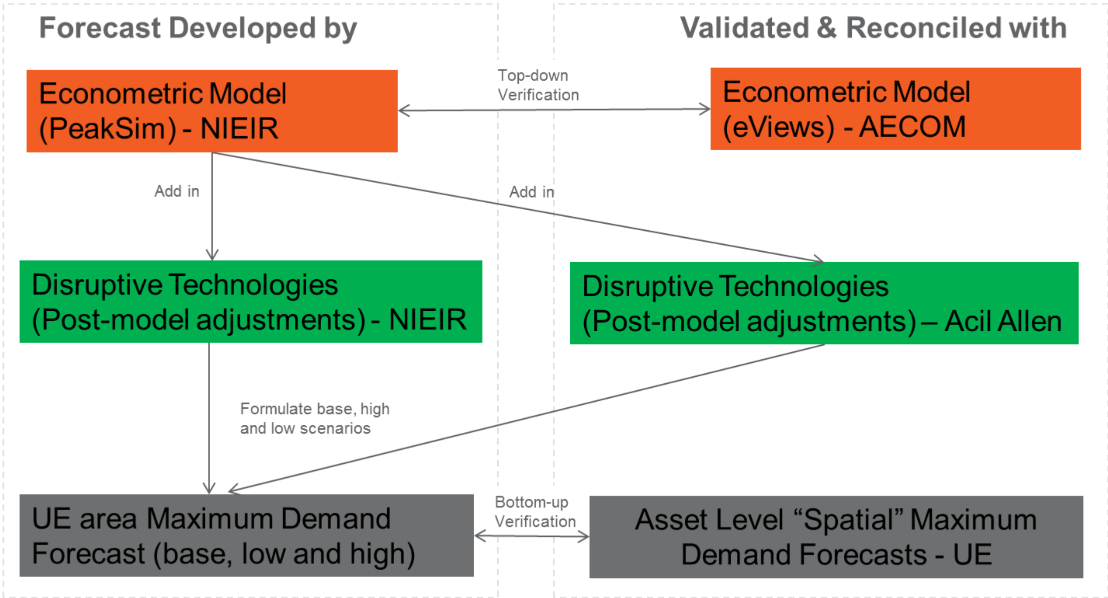


Under all scenarios, the impact of disruptive technologies on UE's maximum demand is likely to be insufficient to stifle maximum demand growth over the 2016-2020 regulatory control period. Economic drivers and price remain by far the largest drivers of growth in maximum demand over the next period.

A separate Overview Paper has been prepared to justify UE's maximum demand forecast. It also discusses reconciliation between UE's and AEMO's forecast. The maximum demand forecasting model developed by AECOM for UE is also available to verify the macro-economic model used by NIEIR in the baseline maximum demand forecast.

The overall UE boundary maximum demand forecast is then used to reconcile UE's internally–developed bottom-up asset "spatial" maximum demand forecasts produced for each asset at each network level including sub-transmission, zone substations, high-voltage feeders and distribution substations. It is these asset level "spatial" maximum demand forecasts that drive the Augmentation capital expenditure. The maximum demand forecast validation process is summarised below.

Figure 6 – Maximum demand validation



UE's maximum demand forecasting method is explained in detail in our Maximum Demand Forecasting Method (UE PR 2200) and details our bottom-up forecasting approach, NIEIR's top-down "Peaksim" maximum demand forecasting model and AECOM's top-down "eViews" maximum demand forecasting model. UE's method for forecasting maximum demand aligns with the approach recommended by Acil Allen Consulting in its report to AEMO titled "A nationally consistent methodology for forecasting maximum electricity demand", dated 26th June 2013.

4.3.7. Planning Standard (Probabilistic Planning)

The Network Planning standards and design standards adopted by a DNSP are internal drivers which can significantly influence the level of capital expenditure. There are no externally defined planning standards for distribution businesses in Victoria (apart from Melbourne CBD obligations which do not apply to UE). Instead UE adopts a probabilistic planning approach to our network planning and Augmentation capital expenditure decision making. This economically sound approach to network planning and expansion considers the expected cost to customers of losing supply in the event the demand exceeds the available network capacity by taking into account asset capacity ratings, annual load profiles and asset failure rates and repair times. This is done either with all plant in service or by considering the probability of a single credible contingency. The associated cost which is determined by multiplying the expected energy-at-risk by the VCR is then compared against the annualised cost of removing the capacity constraint either with a network augmentation or non-network solution. When the cost to customers is greater, the solution to remove the capacity constraint is economically justified. This approach is consistent with the approach used by AEMO for its shared transmission network planning in Victoria, and is consistent with the Regulatory Investment Test for Distribution (RIT-D) and the AER's RIT-D Guidelines. UE's probabilistic planning approach results in a lower Augmentation capital expenditure outcome compared to deterministic planning. UE's planning approach is detailed in the Network Planning Policy (UE PO 2200), Demand Strategy & Plan (UE PL 2200) and Network Planning Guidelines (UE GU 2200).

4.4. Relevance to incentive schemes

The Rules require us to explain how our forecast capital expenditure relates to incentive schemes. This is detailed set out below and in further detail in our Regulatory Proposal.

4.4.1. Service Target Performance Incentive Scheme (STPIS)

Our Augmentation programme is derived using the information published in our Distribution Annual Planning Report (DAPR – UE PL 2209), which justifies capital expenditure on the basis of the Value of Customer Reliability (VCR). We have applied a VCR using AEMO's 2014 VCR survey results, calculated on data specific to the summer peak period only (refer UE GU 2208 VCR Application Guidelines) in accordance with AEMO's VCR Application Guide. This is the time of the year when unserved energy is expected to occur for this category of capex. Chapter 15 of our Regulatory Proposal explains the relationship between the VCR and our reliability targets under the STPIS. This notes that currently, the VCR estimates in the STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia. The AER has indicated that it will update these values as part of the determination process.

We support the AER updating the STPIS VCR values with the Victorian headline VCR using AEMO 2014 VCR survey results calculated on data across all sectors and all seasons (i.e. $39,500/MWh). However, we emphasise that this value of the VCR would not be appropriate for our Augmentation capital expenditure. This is because our stakeholders have expressed support for the VCR values that we have used to forecast our Augmentation capex (data specific to the summer peak period only), having regard for their desire for us to maintain current levels of reliability performance. We also note that clause 5.2 of the Victorian Electricity Distribution Code requires us to use our best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.

To this end, should the AER apply the same VCR value for the STPIS and our Augmentation capital expenditure, calculated based on the AEMO 2014 VCR for all sectors and all seasons (i.e. $39,500/MWh), then the AER should also:

1. Significantly relax (i.e. increase) our STPIS targets, recognising the impact of a lower capital expenditure allowance and VCR. This is required because the VCR is lower in the next regulatory period than it has been in the current period and therefore our capital expenditure is proportionately lower; and
2. Reduce the revenue at risk to 1 per cent, given uncertainty around transitioning to lower level of reliability.

4.4.2. Demand Management Incentive Scheme (DMIS)

The Demand Management Incentive Scheme (DMIS) as set out in clause 6.6.3(a) of the National Electricity Rules provides incentives for UE to implement efficient non-network alternatives through demand-side or generation solutions. For the 2011-2015 regulatory control period, UE was allocated $0.4M per annum in the AER's distribution determination (i.e. $2M over five years) as an ex-ante allowance under the Demand Management Innovation Allowance (DMIA). UE plans to spend this full allocation by the end of this current regulatory period on three projects. The success to date of each of these projects and the likely use of the full allocation of DMIS funding in the current period has prompted UE to propose an increase in DMIS funding allocation for the next regulatory control period (2016-2020) to $6.6M to further explore demand management opportunities and capabilities.

Our vision for demand management is to manage demand in real time with a finer level of control, enabling intelligent demand shaping capable of moving discretionary loads to off-peak times, in order to reduce capital expenditure on network augmentation and to minimise the risk of overload-related load shedding. To do this, UE needs to build on our demand management capabilities over time. During the next regulatory control period (and by 2020), UE wants to:

- Develop new demand management capabilities funded by the 2016-2020 DMIA to provide additional and enhanced levers for managing demand;
- Incorporate demand management options into our network planning business cases such that new demand management capabilities developed during the regulatory period are available on a “business-as-usual” basis, economically ranked against more traditional network augmentations;
- Have IT systems established, funded by the 2016-2020 IT regulatory allowance, to support the new or enhanced demand management capabilities; and
- Demonstrate that our demand management initiatives are capable of deferring network augmentation.

UE’s Demand Management and DMIS Strategy (UE PL 2210) sets out our plans for increasing our suite of demand management capabilities for the next regulatory control period and details the planned investment in DMIS-related initiatives.

4.4.3. Capital Expenditure Sharing Scheme

From the commencement of the next regulatory period, we will be subject to a capital expenditure sharing scheme (CESS). The CESS will provide financial rewards if we deliver capital expenditure savings, and will impose financial penalties if our capital expenditure exceeds the AER’s allowance. Our customers will benefit from the CESS because it strengthens incentives for us to minimise capital expenditure while maintaining service performance. In effect, the scheme encourages us to find smarter ways of delivering the outputs that customers want.

5. Current period expenditure and outcomes

5.1. Actual expenditure versus AER allowance

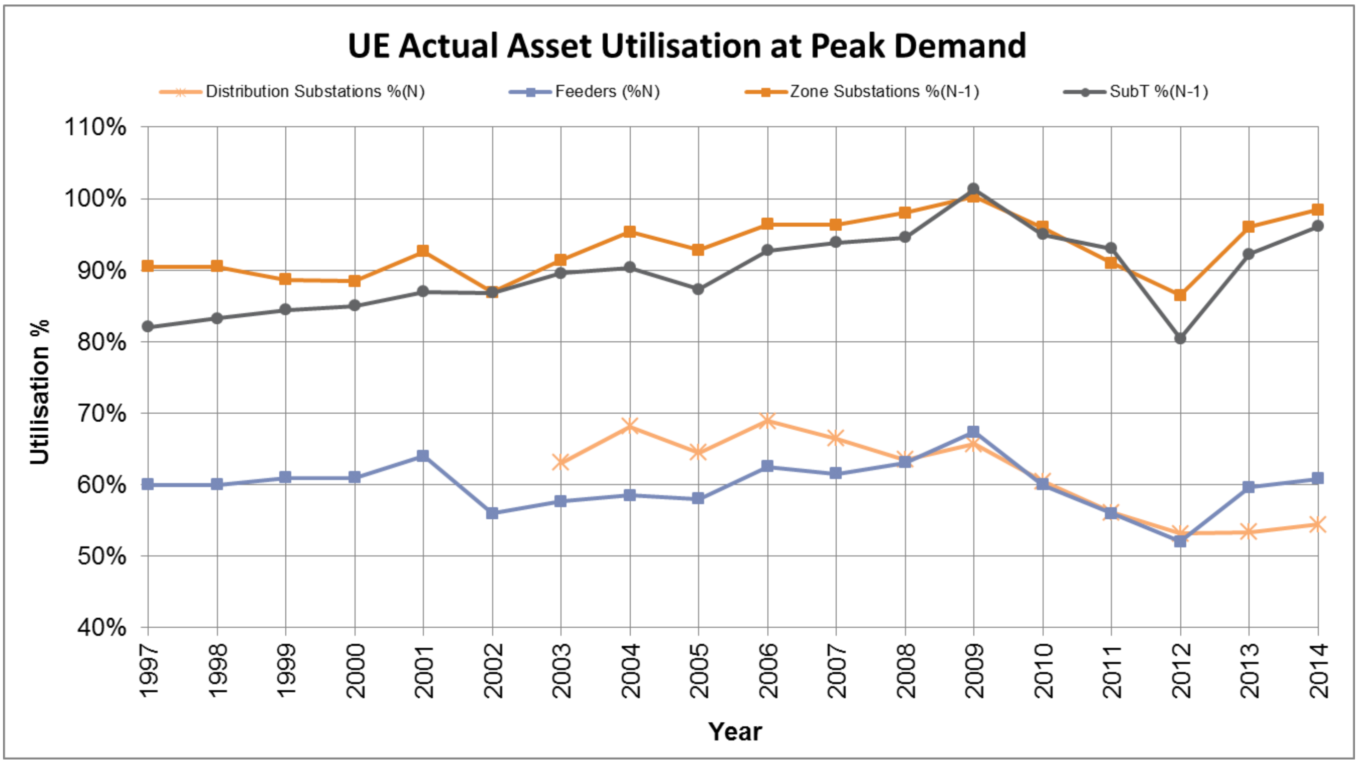
Table 7 current period expenditure ($2015M)

Augmentation	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Estimated	Total Estimated	Variance Estimated
UE actual expenditure	30.246	56.309	36.210	35.894	20.212	178.871	(26.963)
AER allowance	42.212	44.601	32.190	37.246	49.585	205.834	(13.1%)

UE's actual Augmentation expenditure during the 2011-2015 period was $27M (13%) less than the regulatory allowance (in real 2015 dollars). This was primarily due to lower than forecast maximum demand growth, which resulted in substantial economic deferral opportunities.

The identified economic deferrals were prudent because they did not impact energy-at-risk for UE's customers. This is reflected in UE's asset utilisation levels being maintained during the period as shown in Figure 7 below.

Figure 7 – Actual Asset Utilisation at Peak Demand



Declines in distribution substation utilisations over the period are a direct result of increased investment in the Distribution System Augmentation programme during the current period to target extremely overloaded distribution substations and our worst served customers. This prudent increase in expenditure was triggered by overloaded distribution transformers and LV circuits during the heat-wave of 2009 causing UE to incur 24 SAIDI minutes. During this heat-wave, UE incurred 54 transformer failures and 950 fuse operations due to overload in four days. By comparison, for the 2014 heat-wave, UE incurred 11 transformer failures and 650 fuse operations over 6 days. While UE's strategy is to maintain overall reliability levels, the increase in expenditure since 2009 is having a directly measurable reliability performance improvement for those customers experiencing reliability levels that are considerably worse than the performance experienced by the "average" UE customer.

It is important to note that underspending against the AER's allowance, while not impacting energy-at-risk, is in the long-term interests of UE's customers because it means that UE's regulatory asset base is lower than it would otherwise be and its future revenue requirements are also correspondingly lower.

5.2. Explanation of variances

The differences between UE's 2011-2015 forecast and actual Augmentation expenditures reflect a range of project level variances.

A number of projects that were forecast for the 2011-2015 period were not undertaken in this period due to changed circumstances, including:

- Local maximum demand growth being lower than expected, which resulted in an economic deferral of capital;
- Planned projects being abandoned due to a lower cost alternative project being identified and delivered; or
- A change in business focus in response to deteriorating SAIDI that prioritised asset replacement and performance expenditure over Augmentation.

A number of unforeseen Augmentation projects were initiated during the 2011-2015 regulatory control period due to changed circumstances, including:

- Local maximum demand growth being higher than expected in already capacity constrained areas;
- Projects being adopted as a lower cost alternative to planned projects;
- Additional scope (or projects) required to support the forecast proposed augmentations; or
- Insufficient technical information about the nature of the constraints at the time of the 2010 forecast.

The total additional cost of the unforeseen projects was significantly lower than the total cost of the projects not undertaken in the original 2010 forecast, resulting in a net under-spend of Augmentation capital expenditure allowance in the 2011-2015 regulatory control period.

Lower maximum demand growth was the primary reason for actual expenditure for 2011-2015 period being less than was forecast. It is estimated that this alone contributed to around 70% of the observed expenditure variance through identified economic deferral opportunities. In 2010, UE was forecasting a 2014 50% PoE UE "boundary load" maximum demand of 2142MW. The 50% PoE weather-corrected actual maximum demand in 2014 was only 2038MW, 104MW (4.9%) lower than that forecast back in 2010. With respect to the individual drivers of maximum demand growth, the following estimations can be made:

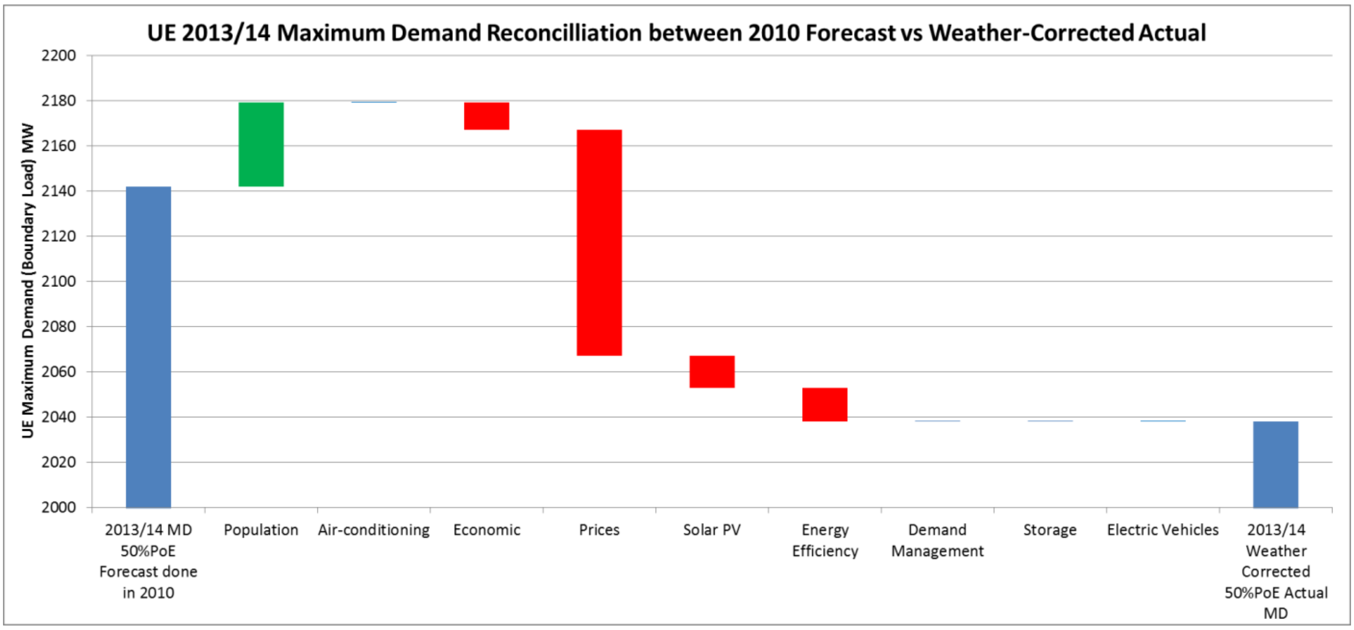
- Economic factors make up 12MW of the observed reductions in forecast maximum demand taking into account 1% (over 5 years) reduction in the forecast GSP since 2010 for the 2011-2015 period assuming a peak demand elasticity to GSP of +0.6;
- Population growth projections have been relatively accurate during the 2011-2015 regulatory control period. This is supported by our customer connections capital expenditure and customer number growth remaining relatively strong during the period. Total customer numbers at the end of 2013 were however approximately 2% higher than that forecast in 2010. Taking into account a peak demand elasticity to population growth of around +0.9, this represents around 37MW increase in forecast maximum demand;
- Air-conditioning sales during the 2011-2015 period have remained consistent with the sales observed in the previous regulatory control period and therefore the impact on maximum demand growth during

the period from changes in air-conditioning sales is considered to be negligible. This is supported by falling weather-corrected load-factor during the period from 0.50 to 0.456;

- Price rises during the 2011-2015 regulatory control period is having an impact on reducing maximum demand growth. Taking into account a peak demand elasticity to price of around -0.117 and the size of the price rises over the 2011-2015 period, this represents around 100MW of reduction in forecast maximum demand; and
- Disruptive Technologies including solar PV and energy efficiency acting at times of peak demand was estimated to be contributing up to 29MW in 2014 at reducing the forecast maximum demand.

These unforeseen impacts back in 2010 are illustrated below.

Figure 8 – Maximum summer demand reconciliation EDPR Forecast vs. Observed – 50% PoE



6 UE: Demand Strategy & Plan (UE PL 2200)

7 Acil Allen: Part B report – Post Model Adjustments.

5.3. Benchmarking

Current period benchmarking by the AER indicates that UE compares favourably against other DNSPs as illustrated in Figures 9, 10 and 11 below, sourced from the AER Category Analysis Benchmarking Report.

Figure 9 – Total augex per MVA of installed capacity

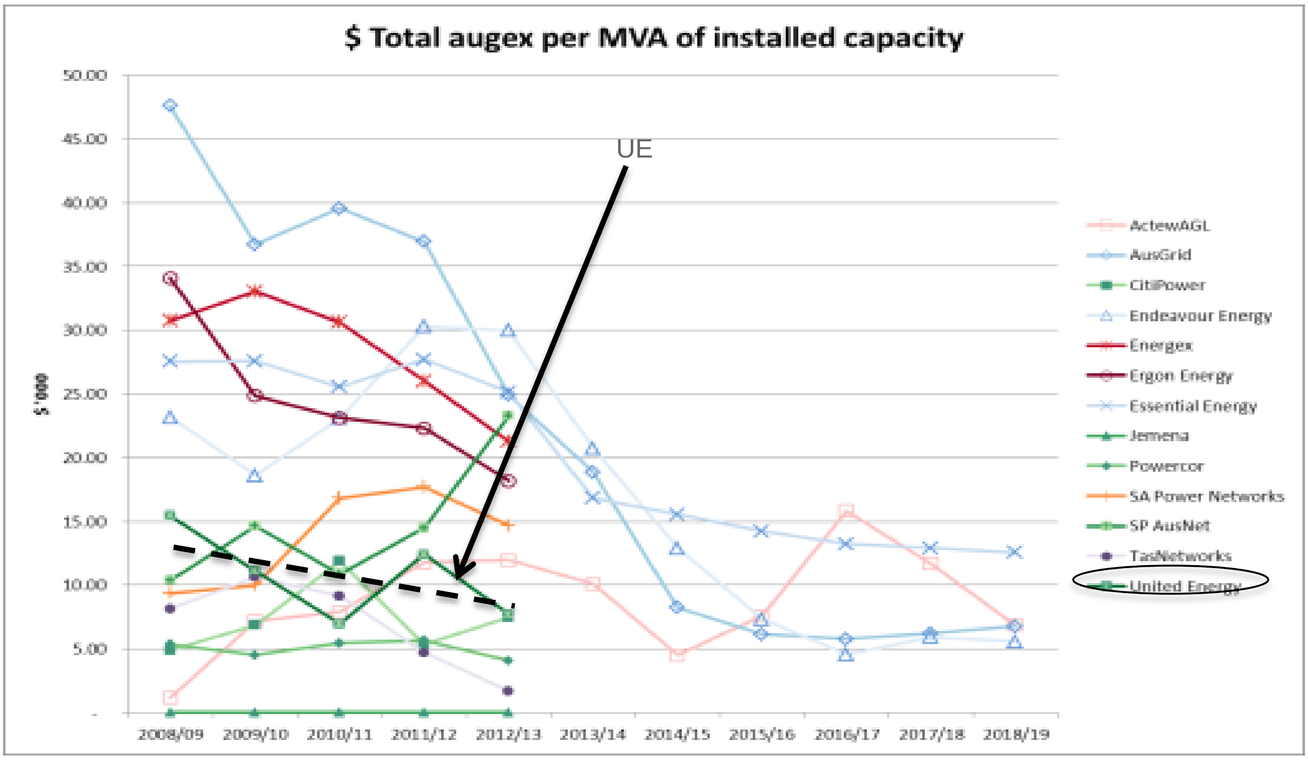


Figure 10 – Total augex per unit of MD

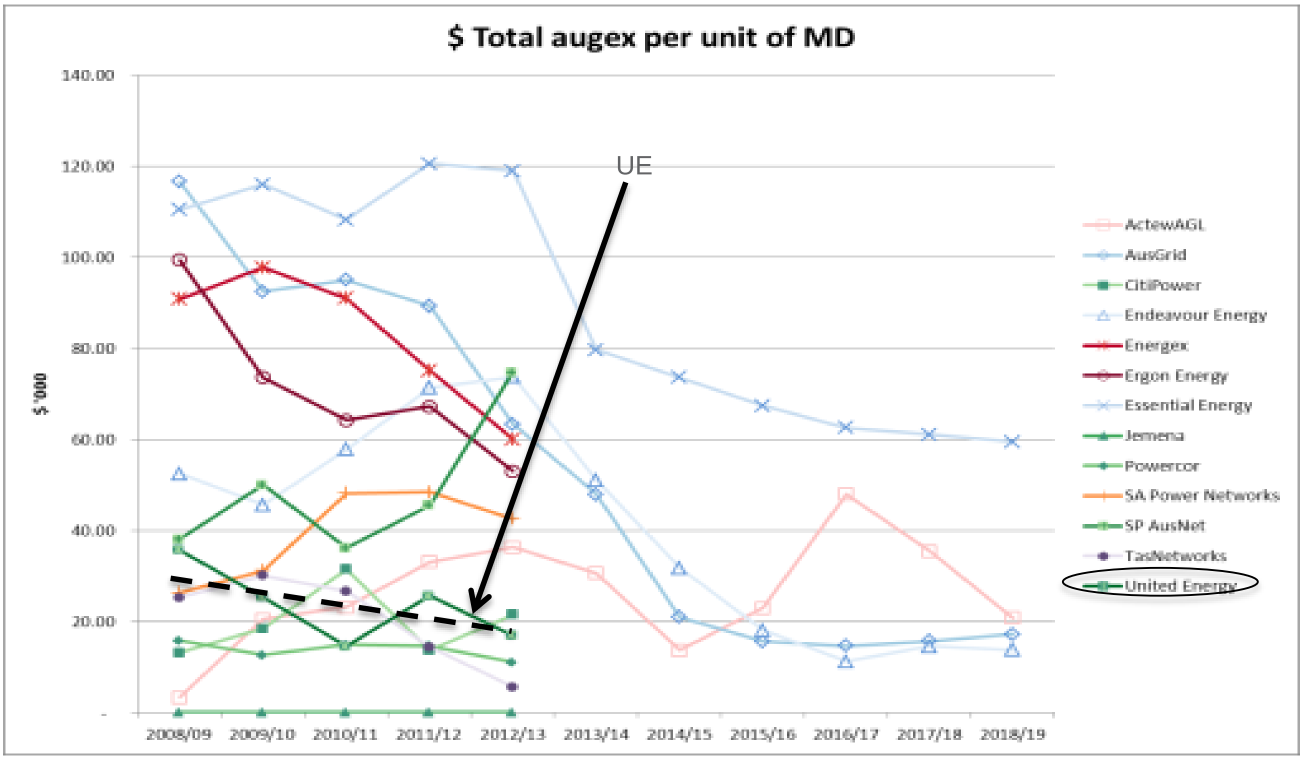
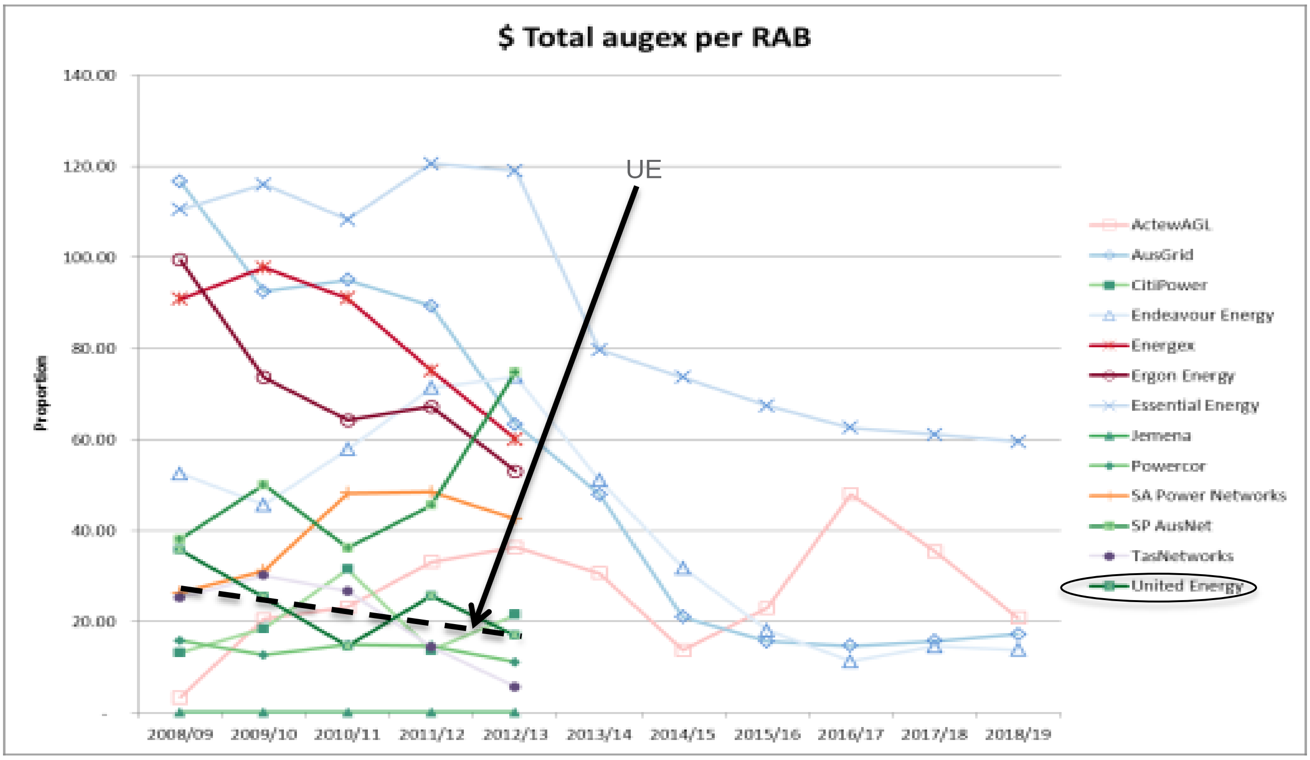
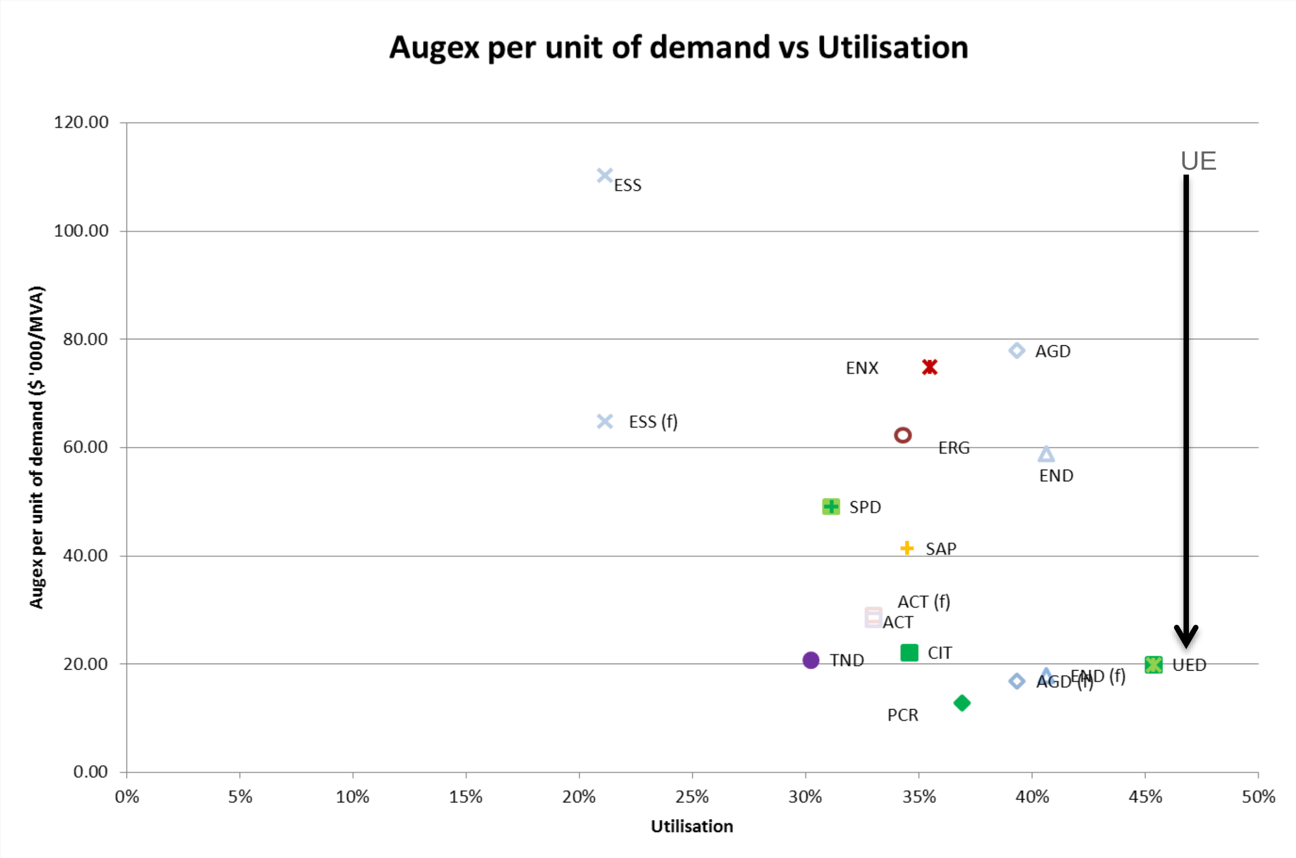


Figure 11 – Total augex per RAB



UE's Augmentation capital expenditure per unit of installed capacity, maximum demand and RAB is one of the lowest in the NEM with an improving trend over the last five years due to reducing growth rates in maximum demand. While UE is expecting this trend to continue with lower Augmentation capital expenditure forecast for the 2016-2020 period compared to the current regulatory control period, the reductions are not expected to be as significant as that forecast for some of the northern states' DNSPs. This is because UE's historical Augmentation expenditure has been prudent and efficient, delivering low network charges to our customers relative to our peers. Our well established network planning philosophy and processes ensure our expenditure will continue to remain prudent into the next period.

Figure 12 – Augex per unit of demand vs Utilisation



UE has the highest utilised electricity distribution network in the NEM and has the 4th lowest Augmentation expenditure per unit of demand in the NEM indicating that UE's Augmentation expenditure is highly efficient. This result is attributed to UE's prudent probabilistic planning techniques which balance the cost of Augmentation against the cost of loss-of-supply to customers through sophisticated risk management planning supported by detailed operational contingency planning.

5.4. Efficiency of expenditure

The above benchmarks support UE's view that our Augmentation capital expenditure is efficient and prudent:

- UE benchmarks very favourably against other DNSPs according to the AER's Benchmarking Report; and
- UE's asset utilisation levels have been maintained over the 2011-2015 period – a decrease would indicate over-investment and an increase would indicate under-investment.

UE's Augmentation capital expenditure is efficient and prudent because the following controls are in place for all Augmentation projects and programmes of work:

- Cost–benefit analyses are undertaken and business cases are prepared for all projects and programmes of work. Benefits (avoided risks and network losses) are calculated according to UE's Network Planning Guidelines (UE GU 2200). Costs are calculated by our Service Delivery department according to recent historical pricing using their pricing database. The cost-benefit analyses are undertaken using UE's Capital Expenditure Evaluation Spreadsheet and are documented in business cases which are signed-off according to the business' delegated financial authority. UE considers credible network and non-network options on a level playing field in our economic evaluations;

- All business cases consider alternative options including the status-quo (do-nothing). The selected option is based on the least-lifecycle cost. Under a probabilistic planning philosophy, the least-lifecycle cost option may be to do nothing (i.e. economic project deferrals). Projects are identified which are least cost technically acceptable that meet current and future requirements according to UE's Network Planning Expenditure Forecasting Guideline (UE GU 2206);
- UEs' capital investment review board (comprising UE's executive leadership team members and the CEO) are required to endorse all capital projects values over $1M before the project can proceed. This step ensures that the project is adequately explained to, and understood by, the executive leadership in terms of the need (the nature of the constraint and the risks), the life-cycle cost (capital costs, ongoing operational costs and residual risks), the optimum economic timing and the assumptions made;
- UE's contracting model enables projects to be competitively sourced from our two contracted Service Providers, or in the case of large projects, competitively sourced from the market. UE also collaborates with our Service Providers to increase their capacity to complete more projects before the start of summer so that project benefits are maximised earlier, without increasing project costs;
- UE undertakes a reforecast every year based on the past summer's performance and the latest forecast maximum demand growth rates. This ensures the planned works programme is adaptable to changing conditions and is reflective of the latest available information. This information is published in our Distribution Annual Planning Report (UE PL 2209);
- UE identifies synergy opportunities with asset replacement activities, performance initiatives and customer initiated projects to ensure that no double-counting of capital expenditure is made;
- UE applies a probabilistic planning philosophy to network planning with contingency planning to enable prudent deferrals using risk management. The probabilistic planning approach to network planning 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. This is done in accordance with UE's Network Planning Guidelines (UE GU 2200);
- RIT-Ds are undertaken for all Augmentation projects greater than $5M (post 2013) applied according to the AER's RIT-D Guidelines and the NER. This framework provides opportunities to consult on network constraints and allows alternative solutions to be put forward by interested parties which may result in lower cost outcomes for customers;
- Joint planning MoUs have been signed with seven non-network providers and demand-side engagement is undertaken to ensure non-network solutions are identified wherever possible. This initiative complements the RIT-D process by allowing UE to engage with non-network service providers at a detailed planning level before the RIT-D commences. This arrangement, documented in our Demand Side Engagement Document (UE PL 2202) allows UE and the non-network service providers to develop tangible non-network solutions in the lead up to the RIT-D to improve the success rate of an economically viable non-network solution;
- UE is utilising DMIA funding to explore opportunities to better manage peak demand as described in our Demand Management & DMIS Strategy (UE PL 2210). A number of projects are underway in the areas of district energy services, solar and storage technologies, and demand-side trials, all of which could be used in future as business-as-usual activities to defer more expensive network augmentations; and
- Joint planning MoUs have been signed with AEMO and the other Victorian DNSPs to ensure that boundary/interface constraints are addressed with optimal solutions.

5.5. Benefits of expenditure to customers

Overall, UE's probabilistic planning approach has consistently delivered cost-effective network performance outcomes for UE customers. This has contributed to UE delivering lower-cost network charges to our customers compared with other distribution businesses around Australia. UE, by industry benchmarks, has a very highly utilised and optimised network. Our probabilistic network planning approach, backed up by a set of appropriate contingency plans, is delivering a consistently satisfactory level of supply security and reliability at an acceptable level of cost to the community. Our reliability outcomes due to our probabilistic planning approach have remained relatively steady over time, with the observed deterioration in UE's reliability in recent times attributed primarily to other asset specific factors such as increased volumes of asset failures, dealt with under the RQM category.

Our expenditure also has tangible benefits to our customers experiencing reliability of supply performance much worse that the average performance. An example of this is our expenditure on the Distribution System Augmentation programme which involves the reinforcement of distribution substations and low voltage circuits. Reliability performance for our worst served customers has improved markedly between the 2009 heatwave and the comparable 2014 heatwave. During the heatwave summer of 2009, UE experienced 960 fuse operations and 54 distribution substation transformer failures interrupting supply to many thousands of customers for extended periods of time. The outages resulted in around 24 SAIDI minutes during the heatwave. In 2009, around 13% of the distribution substation population was utilised above 120% of the cyclic rating. Since the 2009 heatwave, UE significantly ramped up annual expenditure in the Distribution System Augmentation programme to proactively address the over-utilised distribution substations and LV circuits. Following the expansion of this programme, UE's reliability performance was significantly better during the similar 2014 heatwave. By comparison, for the 2014 heatwave, UE incurred 650 fuse operations and only 11 transformer failures with SAIDI of around 5.4 minutes. The increase in expenditure since 2009 is having a directly measurable reliability performance improvement for those customers with reliability much worse than the UE average. Augmentation expenditure is needed over the next regulatory control period to continue to address these problems for our worst served customers where it is economically prudent to do so, although our forecast is lower than our estimated expenditure for the current period.

6. Expenditure forecasting method for forthcoming period

This section explains UE's forecasting methodology for Augmentation capital expenditure for the next regulatory control period and justifies why UE considers that it is the most reasonable methodology for regulatory forecasting.

6.1. Approach / process

6.1.1. UE's Annual Planning Process

UE's Network Planning department prepares a 10-year capital and operating works programme as part of the annual asset management planning cycle for Augmentation capital expenditure based on the base economic forecast summer maximum demand for each asset. UE's overall maximum demand forecast is distributed across each asset according to various localised growth conditions in the network, for each network level that forms the power delivery chain from the transmission connection points to the customers' point of supply. This forecast is prepared according to UE's Maximum Demand Forecasting Method (UE PR 2200). Results are documented in UE's Load Forecast Manual (UE MA 2203), Demand Strategy & Plan (UE PL 2200) and Distribution Annual Planning Report (DAPR – UE PL 2209). This annual planning process is summarised in the left side of Figure 13.

UE's planning criteria and network design standards influence the level of capital expenditure for accommodating growth in customer demand, and the underlying security of supply. The planning approach adopted by UE is probabilistic, taking into account the combination of load profiles, network topology, plant ratings and plant failure rates to quantify the exposure of customers to loss of supply. This approach allows an economic balance to be achieved between the cost of network reinforcement and the probability-weighted cost of loss of supply to customers. UE's electricity distribution network is augmented based on a probabilistic planning approach where the cost of power supply interruption to customers is assessed against the annualised cost of a network augmentation. When the annualised cost of power supply interruptions to customers exceeds the annualised cost of augmentation, the augmentation becomes economically viable. This approach means that plant is loaded above its cyclic (N-1) rating before an augmentation can become economic. In other words, UE absorbs some level of load-at-risk before augmenting the network.

To adequately identify and to minimise the impact of load shedding events in circumstances where the (N) rating is exceeded, UE plans on a one-in-ten year weather temperature probability (i.e. 10% PoE), using a base (expected) economic growth maximum demand forecast to facilitate identifying economic circumstances where maximum demand can be supplied with all plant in-service for all but one-in-ten years. The probabilistic planning approach is then applied to cater for a single contingency using a suitable weighting of 10%, 50% and 90% PoE maximum demand forecasts and plant failure details. This ensures that an economic balance is struck between the cost of augmentation and some exposure to possible loss of supply when the thermal capability of the network is exceeded either with all plant in service or in the event of an asset outage.

In order to determine the economically optimum level of augmentation, it is necessary to place a value on supply reliability from the customers' perspective. It is recognised that this value may depend on the customers involved (and the duration of the outage) and estimating such a value is inherently difficult. It is common practice by many utilities to use an average marginal value of reliability, referred to as the VCR. The VCR used by UE is based on a value derived from AEMO's 2014 VCR survey considering the summer peak period and outage durations for the expected unserved energy. VCR is an important signal for investment and determining reliability levels. In establishing a case for an augmentation project, location specific VCR values are used to reflect the different classes of customers served by the augmented facility. To satisfy the requirements of a RIT-D, a set of scenarios is applied to test the sensitivity of the economic viability of a proposed augmentation against credible variations in VCR.

A major consequence of the probabilistic planning approach adopted by UE is a reduced level of network redundancy and system security at times of high demand when assets are highly utilised. To ensure reliability performance of the network is not compromised, 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 the summer season of high demand. The purpose of the contingency planning is to reduce the impact of unplanned outages should they occur at times of maximum demand. In a network planned in accordance with the probabilistic approach, there are conditions under which the entire load cannot be supplied with a network element out-of-service. Contingency plans are therefore developed to restore supply for such events as quickly as possible. As demand and network utilisation increase over time, the efficacy of contingency plans to manage network risks reduces, at some point triggering further capacity augmentation.

6.1.2. UE's Augmentation Capital Expenditure Forecast

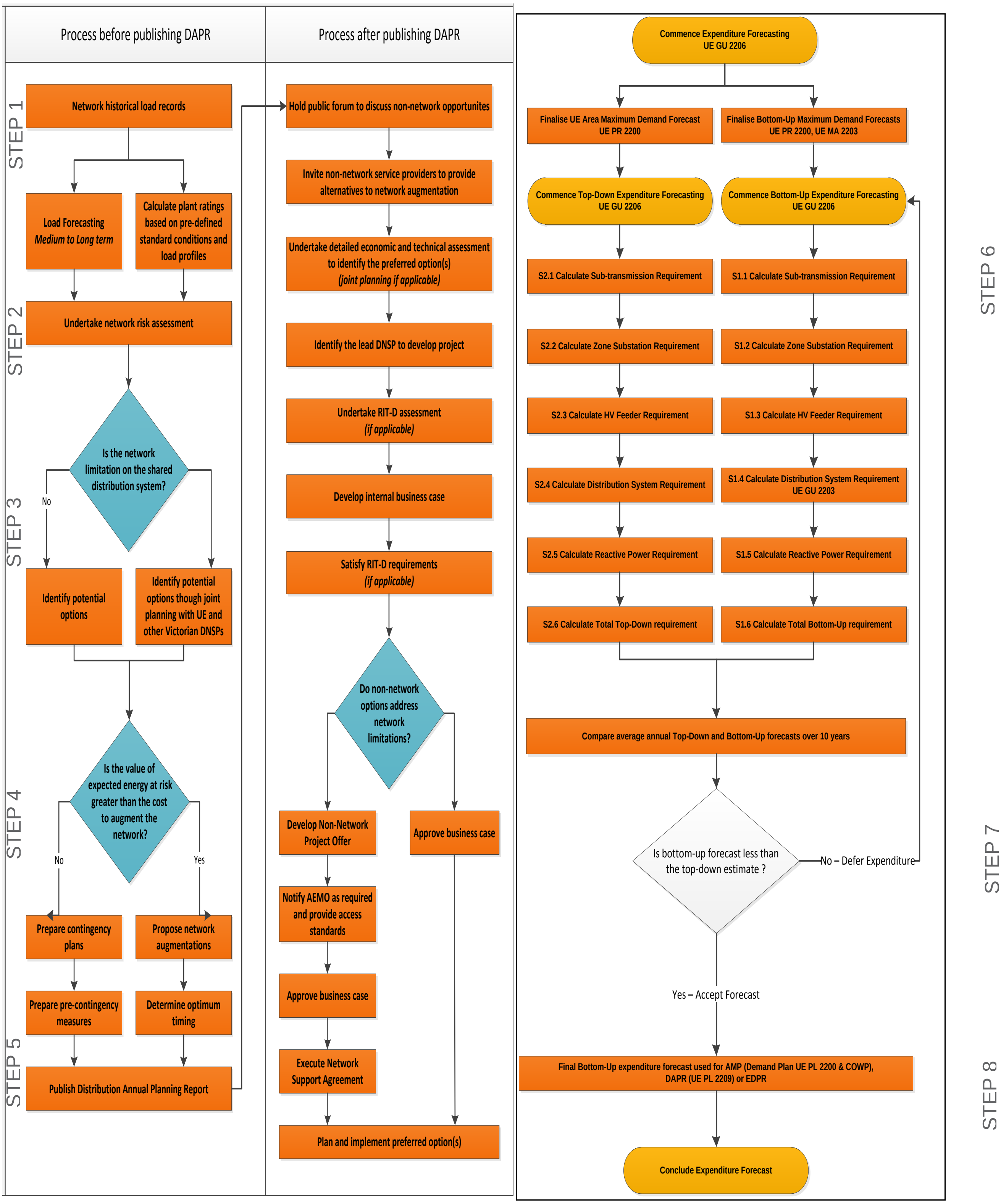
The Augmentation capital expenditure forecasting method is applied using a two-staged approach, a top-down and bottom-up stage. The bottom-up stage provides the expenditure forecasts. The top-down method verifies the bottom-up expenditure forecasts. The expenditure forecast method is documented in the process flow chart in Figure 13 and is detailed in UE's Network Planning Expenditure Forecasting Guideline (UE GU 2206) and Distribution System Augmentation Expenditure Forecasting Guideline (UE GU 2203). UE validates its expenditure forecast using a top-down approach including the AER's Augex model.

The main process steps in Augmentation expenditure forecasting include:

- STEP 1: Forecast the maximum demands;
- STEP 2: Identify assets forecast to be utilised above their firm rating during the planning period;
- STEP 3: Apply risk-assessments using probabilistic planning to quantify the value of energy-at-risk (cost to customers);
- STEP 4: Identify when the cost to customers exceeds the annualised cost of the least lifecycle cost augmentation;
- STEP 5: Enter the project into the forecast Augmentation works programme for the year that this occurs (if at all);
- STEP 6: Reconcile bottom-up with top-down forecasts;
- STEP 7: Seasonalise the project to take into account project lead time and smooth expenditure profile over the regulatory period.
- STEP 8: Document in the Demand Strategy & Plan and Distribution (Capital and Operating Works Programme)

The process flow chart for Augmentation expenditure forecasting is presented below in Figure 13:

Figure 13 – UE's Annual Planning and Expenditure Forecasting Processes



The key inputs that are used in the Augmentation capital expenditure forecasting approach include:

- Network Planning standards (contained in the Network Planning Policy UE Po 2200 and Network Planning Guidelines – UE GU 2200);
- Maximum demand (historical and forecast growth – asset level and service area level);
- Plant utilisations and ratings;
- Observed fuse operations;
- Unit pricing and project level pricing;
- Annual load profiles;
- Temperature profiles;
- Power factor;
- Load flow results;
- Failure rates, repair times, transfer capability, switching times;
- Contingency plans;
- Network support (if applicable) - demand management, embedded generation, solar PV;
- Regulatory requirements;
- Customer numbers;
- Network topology;
- Value of Customer Reliability (VCR); and
- Project lead times.

6.1.3. Value of Customer Reliability

The level of reliability implied by the Augmentation capital expenditure is directly related to the VCR. UE adopts a level of VCR consistent with the values derived from AEMO's 2014 VCR survey for summer peak periods. AEMO has now concluded its 2014 VCR review and while the aggregated weighted average VCR has dropped substantially from current levels, the VCR from AEMO's review specifically relating to energy-at-risk during summer peak periods for rotational load-shedding is only slightly lower than the present VCR value. Hence the outcomes of the AEMO 2014 VCR review in-UE's opinion are unlikely to have any material impact on UE's forecast Augmentation capital expenditure in the 2016-2020 regulatory control period. This means the UE Augmentation capital expenditure forecast is based on reliability being maintained into the next regulatory control period. This is discussed further in UE's Value of Customer Reliability (VCR) Guideline (UE GU 2208).

It should be noted that reliability associated with Augmentation capital expenditure generally refers to outages that are low probability but high impact because of the need for an asset failure to occur at high demand. This generally coincides with days of extreme temperature. Therefore while the long term reliability is maintained, the variation from year to year may be substantial. However, adopting AEMO's new baseline VCR (without regard to the time of year at which the expected unserved energy is occurring or the duration of the outages) would see a one to three year deferral of UE's forecast augmentation projects. This approach would lead to outages occurring even without an asset failure at high demand.

In UE's opinion, the approach to weighting the VCR to time-of-year and outage duration (according to the AEMO 2014 VCR report), means our forecast expenditure is prudent and follows good asset management practice.

6.2. Key assumptions

Key probabilistic planning assumptions used by UE are identified in UE's Network Planning Guidelines (UE GU 2200) with the main ones reproduced here:-

Table 8 key assumptions

Equipment	Outage Rate (pa)	Outage Duration
Zone Substation Transformer (major failure)	0.005	3 months
Zone Substation Transformer (minor failure)	0.010	48 hours
66kV Sub-transmission lines per km	0.051	8 hours
Transformer outage caused by sub-transmission line outage	n/a	1 hour
HV Feeders per km	0.070	4 hours
11 or 22kV bus (only used if credible contingency)	0.020	24 hours
11 or 22kV CB fail (only if credible contingency)	0.003	24 hours
66kV bus (only used if credible contingency)	0.005	24 hours
Load transfers (manual, multiple feeders or subT)	n/a	2 hours
Load transfers (manual, single feeder)	n/a	55 minutes
Load transfers (remote control)	n/a	10 minutes

6.3. Models

Economic justification of UE's Augmentation expenditure is undertaken using the Energy-at-Risk Assessment Tools whose procedure is documented in UE PR 2210. The results of the tools are then supplied to the standard UE economic evaluation model.

The energy-at-risk quantified as the expected energy not supplied is generally derived from the following formula:

$$EENS(MWh) = \frac{n \times F}{8766} \times \sum_{T=1}^{8766} \{\sum_{t=T+L}^{T+R-1} max(0, Load_{excess} - Load_{transfer}) + \sum_{t=T}^{T+L-1} (Load_{excess\ 2\ hour})\}$$

n = Number of parallel elements
F = Failure rate (number of outages per annum)
L = Load transfer time (hours)
R = min (Replacement time, Repair time) (hours)
T, t = Time in year (hours)
$Load_{transfer}$ = Transfer Capability (MW) at time 't'
$Load_{excess}$ = Load Above (N-1) Cyclic Rating (MW) at time 't'
$Load_{excess\ 2\ hour}$ = Load Above (N-1) 2 hour Rating (MW) at time 't'

The value of this energy-at-risk is derived from the following formula and this is what is used to compare against the annualised cost of augmentation:

$$Risk\ Value\ (\$) = EENS \times VCR$$

EENS = Expected Energy Not Supplied (MWh)
VCR = Value of Customer Reliability ($/MWh)

The results are output into UE's Distribution Annual Planning Report (UE PL 2209).

6.4. Other matters

6.4.1. Stakeholder / consumer engagement

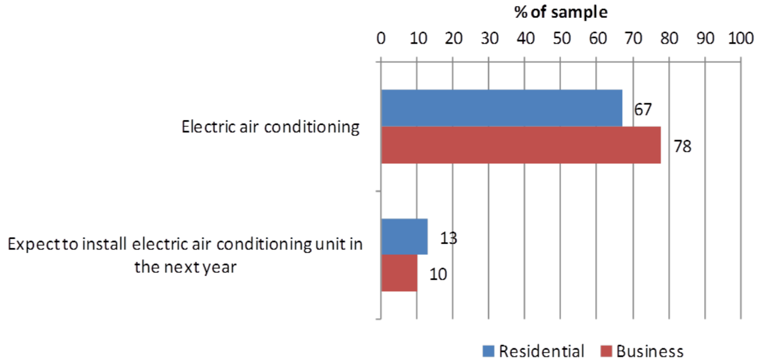
The forecast Augmentation expenditure proposed by UE will ensure the following outcomes for customers:

- reliability and security of supply outcomes being maintained at lowest cost, achieved by targeting expenditure at locations when the expected value of unserved energy exceeds the annualised lifecycle cost of augmentation, and by complying with Clause 5.17.1 of the NER for those expenditures subject to a RIT-D; and
- compliance with regulatory obligations with respect to maintaining voltage levels at customers' point of connection under system normal and for any credible single contingency.

The Augmentation capital expenditure forecast has been informed from the concerns of electricity consumers identified by UE in the course of our recent engagement with electricity consumers and interested stakeholders. These are detailed below.

Need to use air-conditioning during hot weather

Maximum demand on the UE network always occurs on extreme hot days during the summer season. UE customers were surveyed to identify whether they have plans to install air-conditioners for use on hot days which would require expenditure under the Augmentation capital expenditure category. The survey indicated that 10-13% of UE customers are expected to install an air-conditioner over the next year and therefore customers would expect to be able to operate these air-conditioners during the hot weather. The Augmentation capital forecast allows our customers to continue to connect new air-conditioners without deterioration in supply reliability.



Concerns about prolonged outages and not knowing when supply will be restored

One of the key issues raised by our customers was not so much that the power goes off but not knowing when it is going to come back on. Historically, outages which have occurred on hot days when the demand is high have been very long in duration and hitting the same customers multiple times, particular for outages that result in fuse blows due to overloads on distribution substations and low voltage circuits. During the 2014 heatwave, UE experienced 650 low-voltage circuit fuse events and 11 transformer failures. The huge volume of these outages occurring at the same time meant that customers were off supply for typically more than four hours in hot weather until either the demand reduced or field crews became available to replace the fuses. During such emergency response periods, it is extremely difficult to provide customers with an accurate time for supply restoration. If the number of simultaneous fuse operations can be controlled, the restoration times become much easier to predict. UE has made some inroads into reducing the number of fuse operations through our Augmentation expenditure over the current regulatory control period as similar temperature conditions in 2009 resulted in 950 low-voltage circuit fuse events and 54 transformer failures. The forecast Augmentation capital expenditure continues with this improving trend for customer service. While it maintains our reliability overall, it has a substantial benefit to those customers currently experiencing reliability levels much worse than the “average” customer.

Customers not in favour of improving reliability or increasing costs

UE’s customer survey showed that only 57% of customers wanted improvements in reliability of supply. Given this result and the community perception that electricity prices are already too high, the Augmentation expenditure forecast is set to only maintain current levels of reliability. There are no plans to improve reliability overall in the Augmentation forecast. Under clause 5.2 of the Victorian Electricity Distribution Code, UE is required to meet customers' reasonable expectations of reliability. The survey suggests customers are satisfied with their current levels of reliability, and as such the expenditure forecast is developed to maintain reliability.

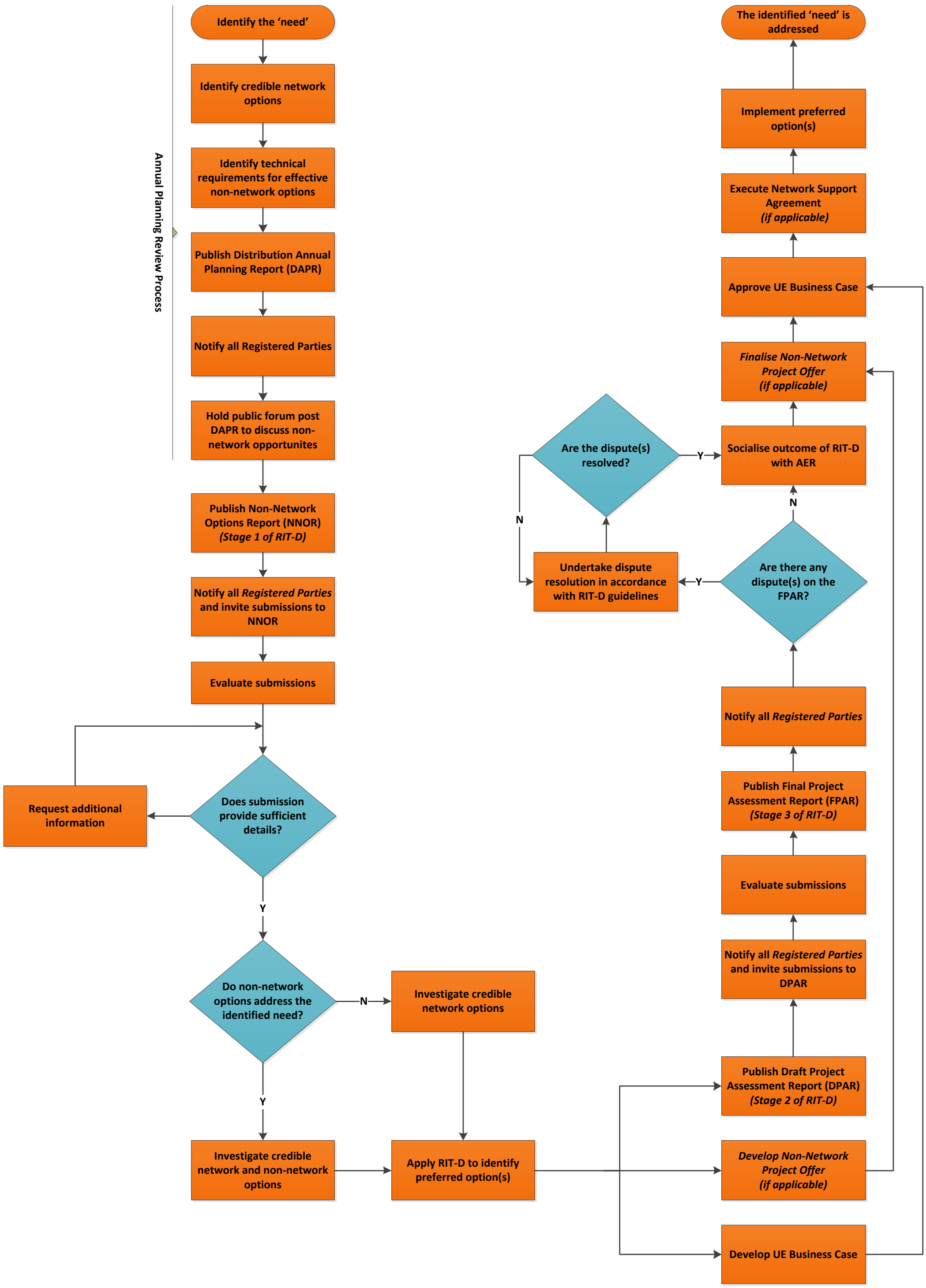
The lower maximum demand growth projections for the next regulatory control period compared to the current period has resulted in a substantial reduction in Augmentation capital expenditure allowance for the next regulatory control period.

Due to UE’s diligent and prudent approach to network Augmentation over a long period of time and our highly optimised network, the levels of Augmentation capital expenditure reductions UE forecasts are not as significant as those proposed by our peers in NSW or Queensland. This is confirmed in the results of the Augex model. Nevertheless, there are tangible reductions in Augmentation capital expenditure which will have downward pressure on prices.

Engagement of Non-network stakeholders and Local government

UE has a very proactive approach to non-network stakeholder engagement. This approach is documented in our Demand Side Engagement Strategy (UE PL 2202) and essentially follows the process identified below.

Figure 14 – UE's Demand Side Engagement Process



UE has established a Demand Side Engagement Register for industry participants, customers, interest groups and non-network service providers who wish to be regularly informed of our planning activities. The Demand Side Engagement Register has already been populated with contact details contained in an existing register that UE maintains for our large customer and embedded generator connections and connection enquiries. New registrations are being added as they are received by UE. As of March 2015 we have 78 people registered on our Demand Side engagement register across 44 organisations.

UE notifies all parties on our Demand Side Engagement Register by email of non-network opportunities identified in our published DAPR. UE publish the DAPR on our web site in December each year detailing areas where non-network opportunities exist. The DAPR seeks to engage the wider community in our network development planning, and encourages proposals for alternative non-network solutions.

UE undertakes a public forum following the publication of each DAPR to discuss identified non-network opportunities in further detail. This public forum is held annually in late January or early February. All parties from our Demand Side Engagement Register are invited to attend. Feedback from the forum held in February 2014 and February 2015 was very positive from attendees.

UE proactively advises generator connection applicants at the enquiry stage of potential non-network opportunities to maximise the opportunity for non-network options to be assessed under the RIT-D process.

UE intends to facilitate non-network initiatives with the establishment of Memorandum of Understanding (MoU) with local councils and other organisations seeking to explore non-network solutions to achieve shared strategic objectives for more efficient energy delivery. UE has already signed a MoU with the City of Manningham and 7 non-network providers to facilitate the development of non-network projects in UE’s service areas.

UE has also signed a network support agreement with GreenSync Pty Ltd to provide 1MW of demand management services to economically defer a planned network augmentation in Chelsea Heights for 2 years. Other opportunities for non-network support are being explored.

UE undertakes public consultation during the RIT-D process with all reports published on the UE website and parties on our Demand Side Engagement Register notified by email.

UE shares our planning information and negotiates with proponents of potential non-network options to further develop solutions prior to undertaking a RIT-D assessment. UE recognises early engagement with non-network service providers is critical for successful and efficient implementation of non-network solutions. UE is committed to actively engage with non-network service providers through joint planning initiatives.

6.4.2. Unit costs

The majority of our Augmentation capital expenditure relates to non-unitised projects – these are individually costed projects because they have a complexity, which means that they cannot be costed upfront based purely on unitised rates. We forecast project costs using a combination of:

- Actual historical costs from previous completed projects;
- Expert Estimation tools;
- Statement of Works from the Service Provider based on their procurement policies and processes;
- Open tender processes;
- Customised cost estimates, where there is no relevant benchmark; and
- Verification by an Independent Estimator.

In this way, our non-unitised projects require tailored costings.

There is only a very small amount unitised work for Augmentation, relating to upgrading of distribution transformer in response to in-service overload failures. We forecast unitised projects by multiplying work volumes by unit costs. Our unit rates are sourced from our OMSAs with our Service Providers These rates are the best we have available for developing our capex forecasts given that they are market tested through the establishment of the OMSAs under competitive arrangements that were explained in our regulatory proposal and revised regulatory proposal for the current regulatory control period. A modular pricing tool has also been developed for bulk pricing of individual Distribution System Augmentation projects within the programme.

6.4.3. Cost escalations

All forecast Augmentation capital expenditure costs are presented in real 2015 Australian dollars. UE has applied both labour and material cost escalators to its capital expenditure forecasts.

For further details, please refer to our Regulatory Proposal and to BIS Shrapnel's report entitled "Real Labour and Material Cost Escalation Forecasts to 2020" November 2014 that has been provided to the AER as an attachment to our Regulatory Proposal.

6.4.4. Overheads

All forecast Augmentation capital expenditure costs include all overheads. Costs given are reflective of total project capitalised costs.

6.4.5. Capex-Opex substitution

Potentially all of Augmentation capital expenditure could be substituted with operating expenditure in the event that non-network solutions are identified for all capital expenditure projects. The demand side engagement work that UE has undertaken as part of the Distribution Planning & Expansion Framework has resulted in a number of memorandum of understanding (MoU) being signed with demand aggregators, generators and local government to undertake joint plans to identify non-network solutions to defer network augmentations. At present UE has such MoUs with:

- Manningham City Council;
- Clean Technology Partners;
- Aggreko;
- SunCorp Renewable Energy;
- GreenSync;
- AGL Energy Ltd;
- Reposit Power; and
- Energy Developments

and working towards establishing another MoU with Eastern Alliance for Greenhouse Action (EAGA) whose membership comprises of a number of councils within UE's service area.

So far the engagement has identified one economically viable non-network solution for which UE has contracted network support with GreenSync to defer a planned network augmentation. Given the early stages in identifying economic non-network deferrals, UE has developed its Augmentation forecast assuming all requirements are addressed through capital expenditure only. Our plan is to avoid or defer capital expenditure wherever possible during the next period at the time economic non-network solutions are identified and required through the joint planning MoU and RIT-D processes and to use the annualised deferral value of the capital expenditure allowance as an operating expenditure payment to the non-network service provider.

It should also be noted that UE has requested an increased DMIA operating expenditure for the next regulatory control period to fund non-economic non-network solutions or trials to facilitate a greater range of non-network solutions to manage peak demand.

6.4.6. Regulatory tests

UE is currently either progressing or has completed RIT-D consultations in relation to a number of major projects contained with the forecast Augmentation expenditure. These projects and RIT-D consultations are:-

1. Dromana Supply Area (DMA 2nd transformer)
   a. Identified network option was to establish DMA 2nd 66/22kV transformer by 2015/16
   b. NNOR published 28th March 2014
   c. DPAR published 14th August 2014
   d. FPAR published 17th October 2014
   e. RIT-D consultation concluded 10th November 2014

2. Submissions from both GreenSync and Cogent indicated there were no viable non-network solutions identified
3. Preferred option identified from RIT-D is to establish DMA 2nd 66/22kV transformer and this option has been included in the Augmentation forecast.
4. Supply to the Lower Mornington Peninsula (HGS-RBD New 66kV sub-transmission line)
    a. Identified network option was to establish a new HGS-RBD 66kV line by 2017/18
    b. NNOR published 19th December 2014 for an extended consultation period
    c. DPAR expected to be published in July 2015
    d. FPAR expected to be published in October 2015
    e. RIT-D consultation currently underway
    f. Preliminary submission from GreenSync indicates there may be a viable non-network solution to defer the network augmentation by two years.
    g. Preferred option not known at this stage but identified network option has been included in the Augmentation forecast.
5. Notting Hill Supply Area (NO 3rd transformer)
    a. Identified network option was to establish a NO 3rd 66/22kV transformer by 2017/18
    b. NNOR expected to be published in June 2015
    c. DPAR expected to be published in October 2015
    d. FPAR expected to be published in February 2016
    e. RIT-D consultation not currently underway
    f. Work currently underway to identify non-network solutions under our joint planning MoUs.
    g. Preferred option not known at this stage but identified network option has been included in the Augmentation forecast.

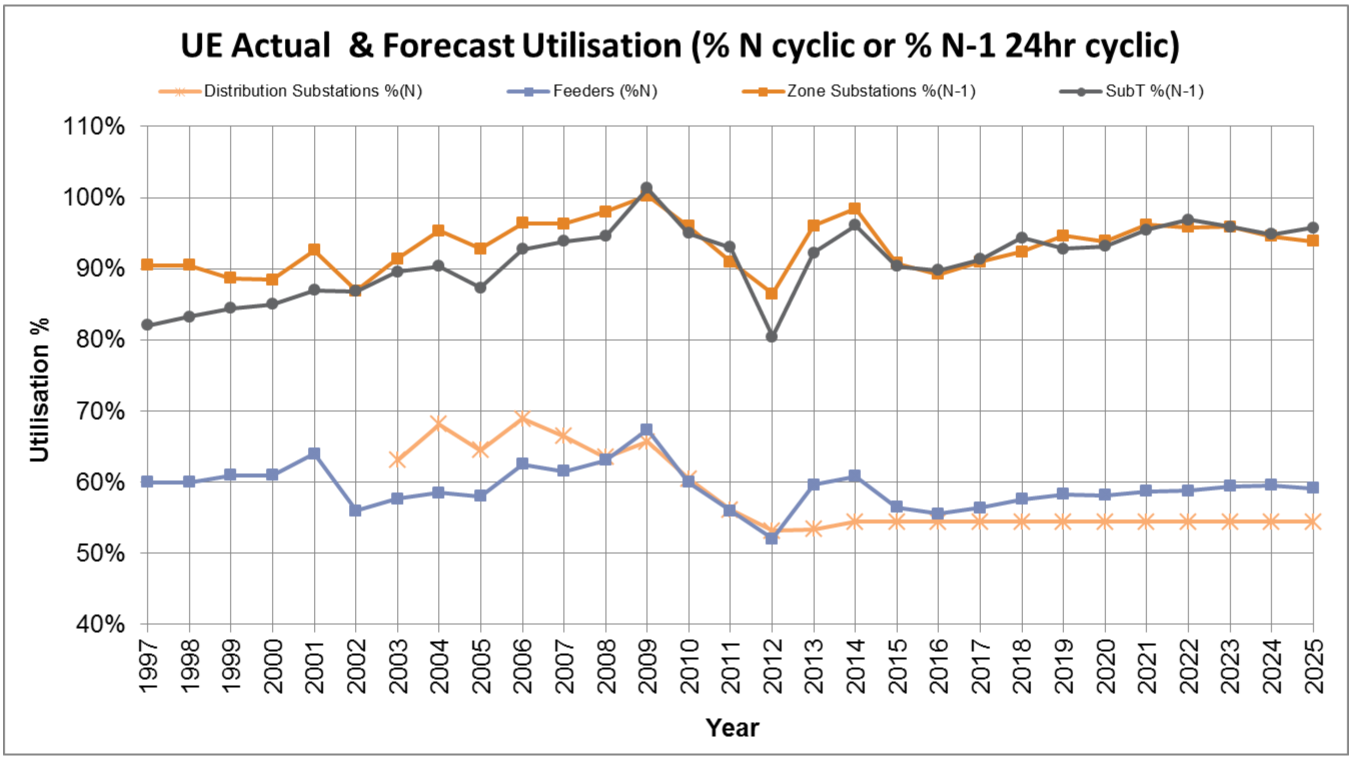
UE forecasts that the following RIT-Ds will need to be commenced during the 2016-2020 regulatory control period.

- Carrum Downs / Skye Supply Area (SKE new zone substation & sub-transmission line)
- Doncaster / Templestowe Supply Area (DC 4th transformer & associated sub-transmission line upgrades)
- Mornington Supply Area (MTN 3rd transformer)

6.4.7. Benchmarking

UE's forecast Augmentation capital expenditure is set to maintain energy-at-risk at current levels, that is, reliability maintained. This is reflected in the utilisation chart below showing historical and forecast utilisation levels.

Figure 15 – UE's Actual and Forecast Network Utilisation



6.4.8. External review / validation

The expenditure forecasts have been reconciled with the AER's Augex model. UE engaged Nuttall Consulting to independently populate and calibrate the AER's Augex model to validate UE's Augmentation expenditure forecast for the 2016 – 2020 regulatory control period. Separate forecasts were developed for each of the main expenditure categories including sub-transmission lines, zone substations, high-voltage feeders and distribution system (substations and low voltage circuit).

It can be observed that the Augex model is forecasting higher Augmentation capital expenditure for the 2016 – 2020 regulatory control period when compared to UE's forecast Augmentation capital expenditure for the EDPR submission.

Table 9 UE forecast expenditure versus Augex ($2015M)

Augmentation	2016	2017	2018	2019	2020	Total	Relative
UE forecast expenditure	**33.787**	**30.581**	**35.27**	**35.336**	**24.097**	**159.071**	**100%**
Distribution Substations & LV	13.923	11.371	12.205	11.45	6.738	55.687	0.35
HV Feeders	8.007	5.595	7.385	4.562	3.352	28.901	18%
Zone Substations	7.449	5.42	3.919	8.93	8.569	34.286	22%
Sub Transmission	4.408	8.196	11.761	10.393	5.438	40.197	25%
Augex forecast expenditure	**45.168**	**41.701**	**39.45**	**38.05**	**37.234**	**201.602**	**100%**
Distribution Substations & LV	11.39	10.059	9.059	8.294	7.701	46.503	23%
HV Feeders	9.308	8.411	7.739	7.238	6.864	39.561	20%
Zone Substations	16.762	16.193	15.798	15.56	15.458	79.771	40%
Sub Transmission	7.707	7.039	6.854	6.957	7.21	35.767	18%

The differences can be explained as follows with UE’s forecast having:

- marginally higher distribution substation and low voltage network expenditure because this is where our worst served customers are experiencing reliability levels much worse than the UE average;
- substantially lower zone substation expenditure because in the 2011-2015 period there were large value rural-to-urban zone substation rebuild projects (e.g. MTN rebuild) which are not required in the 2016-2020 period; and
- higher sub-transmission expenditure because of the inclusion of one very large value project in the 2016-2020 period (HGS-RBD 66kV line), for which a similar type project was not required in the 2011-2015 period.

A detailed discussion of the Augex modelling and reconciliation with the UE expenditure forecast can found in Nuttall Consulting’s Augex Modelling report.

7. Expenditure forecasts and expected outcomes for forthcoming period

7.1. Significant variations between forecast and historical expenditure

Table 10 Forecast vs. current period expenditure ($2015M)

Augmentation	Year 1	Year 2	Year 3	Year4	Year 5	Total
UE forecast expenditure 2016-2020	33.787	30.581	35.270	35.336	24.097	159.071
UE actual expenditure 2011-2015	30.246	56.309	36.210	35.894	20.212	178.871
Variance estimated						(19.8) (11.1%)

Some points to note about the 2016-2020 forecast Augmentation capital expenditure are that it is:

- 23% ($47M) lower than the 2011-2015 current period regulatory allowance;
- 11% ($20M) lower than the 2011-2015 current period actual spend;
- 8% ($14M) lower than the 2006-2010 previous period actual spend; and
- Includes $2.5M of economic behind-the-meter storage ($1.0M in year 4 and $1.5M in year 5).

Due to UE's diligent and prudent approach to network augmentation over a long period of time and our highly optimised network, the levels of Augmentation capital expenditure reductions UE forecasts are not as significant as those proposed by our peers in NSW or Queensland. This is confirmed with the results of the Augex model. Nevertheless, there are tangible reductions in the Augmentation capital expenditure that UE is forecasting which will have downward pressure on prices.

7.2. Major Project & Programmes

The following is a list of major projects and programmes of work under Augmentation capital expenditure for the 2016-2020 regulatory control period with total value greater than $5M.

Table 11 major projects and programmes ($2015M)

Project / Programme	Supporting Document	RIT-D Status	Total Project Value $M	Expected Energy at Risk ($k)	Summer Timing	Description
DMA 2nd transformer	UE PL 2220	NNOR Complete DPAR Complete FPAR Complete	8.3	2015 = 701 2016 = 732 2017 = 843 2018 = 1060 2019 = 1447 2020 = 1743 2021 = 2032 2022 = 2574 2023 = 3203 Source RIT-D FPAR	2016/17	This project is targeted at increasing capacity in the Dromana, Safety Beach and Red Hill areas in response to increases in electricity demand and worsening reliability performance. The project involves the installation of a new transformer at the Dromana substation
NO 3rd transformer	UE PL 2223	Pending	5.8	2015 = 200 2016 = 280 2017 = 530 2018 = 900 2019 = 2080 2020 = 3150 2021 = 4140 2022 = 5080 2023 = 5190 2024 = 9500 Source page 36 of strategic area plan UE PL 2223	2017/18	This project is targeted at increasing capacity in the Notting Hill, Clayton and Springvale areas in response to increases in electricity demand particularly in the commercial/light industrial area of Notting Hill, Mt Waverley. The project involves installation of a new transformer at the Notting Hill substation.

Project / Programme	Supporting Document	RIT-D Status	Total Project Value $M	Expected Energy at Risk ($k)	Summer Timing	Description
HGS-RBD New 66kV sub-transmission line	UE PL 2220	NNOR published	23.2	2015 = 375 2016 = 325 2017 = 716 2018 = 1563 2019 = 30067 2020 = 4053 2021 = 5296 2022 = 7803 2023 = 11670 Source: RIT-D NNOR	2018/19	This project is targeted at alleviating major quality of supply and security of supply issues on the south-western Mornington Peninsula. This network currently supplies Dromana, Arthurs Seat, Safety Beach, Rosebud, Rye, Redhill, Blairgowrie, Sorrento and Portsea via two power lines in operating in close proximity. During high electricity demand periods (hot weather, school holidays or public holidays), a fault on either of these two power lines caused by a bushfire, car-into-pole, equipment failure or vandalism (for example) will result in wide-spread blackouts in these areas. This project involves establishing a third line into the area to support the existing two lines. An explanation of the forecast capex on easements required for this project is set out in the Non-network general assets - Other overview document. That document also explains all other easement capital expenditure requirements for the forthcoming regulatory period.
SKE new zone substation & sub-transmission line	UE PL 2224	Pending	23.4	2015 = 900 2016 = 1000 2017 = 1100 2018 = 1200 2019 = 1500 2020 = 1950 2021 = 2150 2022 = 2500 2023 = 3000 2024 = 3500 2025 = 4000 2026 = 4900 Source: page 59 of strategic area plan UE PL 2224	2020/21	This project is targeted at increasing capacity in the Skye and Carrum Downs areas in response to increases in electricity demand due to new housing developments in Skye and Sandhurst, and industrial developments in Carrum Downs, and worsening reliability performance in all of these areas. The project involves the installation of a new substation supplied from the nearby transmission substation in Cranbourne at a yet to be purchased piece of land in Skye.

Project / Programme	Supporting Document	RIT-D Status	Total Project Value $M	Expected Energy at Risk ($k)	Summer Timing	Description
DC 4th transformer & associated sub-transmission line upgrades (in lieu of TSE new zone substation & sub-transmission line $19800k)	UE PL 2221	Pending	6.8	2015 = 470 2016 = 510 2017 = 550 2018 = 610 2019 = 670 2020 = 730 2021 = 820 2022 = 990 2023 = 1230 2024 = 1540 2025 = 2070 2026 = 2710 2027 = 3370 2028 = 3930 2029 = 4550 2030 = 5010 Source: page 45 of strategic area plan UE PL 2221	2019/20	This project is targeted at increasing capacity in the Doncaster, Box Hill and Templestowe areas in response to increases in electricity demand due to new housing developments in Doncaster Hill and surrounds, and commercial developments in Box Hill, and worsening reliability performance in Templestowe. The project involves either the installation of a new transformer at an existing substation in Doncaster or a new substation supplied from the nearby transmission substation in Templestowe at a UE owned piece of land in Templestowe.

Project / Programme	Supporting Document	RIT-D Status	Total Project Value $M	Expected Energy at Risk ($k)	Summer Timing	Description
MTN 3rd transformer	UE PL 2220	Pending	7.6	2015 = 100 2016 = 150 2017 = 200 2018 = 250 2019 = 300 2020 = 450 2021 = 600 2022 = 800 2023 = 1000 2024 = 1200 2025 = 1350 2026 = 1600 2027 = 2150 2028 = 2400 2029 = 2900 2030 = 3400 Source: page 33 of strategic area plan UE PL 2220	2021/22	This project is targeted at increasing capacity in the Mornington and Mt Martha areas in response to increases in electricity demand. The project involves the installation of a new transformer at the Mornington substation
Land Acquisition for SKE	UE PL 2211	No RIT-D required	2.0		2016-2020	This programme is to strategically purchase vacant land for identified future zone substation sites. Purchases are planned within five years of the proposed substation developments. Where possible, sites will be purchased in commercial or industrial areas. One site has been earmarked for purchase in the next regulatory control period in the Skye/Carrum Downs area.
Distribution System Augmentation Programme	UE PL 2201	No RIT-D required	39.8		2016-2020	This programme of works involves upgrading low voltage wires and transformers in streets to accommodate increases in load caused predominantly by air-conditioning equipment. This will avoid fuse blows due to circuit and transformer overloads. Streets that have had prolonged outages on hot summer days will be targeted in this programme. Approximately 100 sites per year will be targeted from a population of around 13,000 sites across the UE service area.

Project / Programme	Supporting Document	RIT-D Status	Total Project Value $M	Expected Energy at Risk ($k)	Summer Timing	Description
Feeder Augmentation / Pole Top Capacitor Programmes	UE PL 2200 UE PL 2209	No RIT-D required	27.1		2016-2020	This programme of works involves upgrading high voltage wires and cables in streets or conditioning equipment on poles to accommodate increases in load caused predominantly by air-conditioning equipment. This will avoid blackouts due to circuit overloads during hot weather.

7.3. Outcomes

The intended outcomes of our proposed Augmentation expenditure for the 2016-2020 regulatory control period include:

- Maintaining reliability performance and system security risk at present levels (no net improvement);
- Identifying reliability improvement opportunities for our worst-served customers who are exposed to risk of long-duration outages on days of extreme temperature;
- Maintaining asset utilisation at present levels, while looking for economic opportunities that can increase asset utilisation without increasing overall risk to customers;
- Reducing Augmentation expenditure over the next period in response to lower maximum demand forecasts to put downward pressure on electricity prices for customers;
- Interchanging capital expenditure from the regulatory allowance with operating expenditure to fund economically prudent non-network opportunities identified through the RIT-D process and our joint-planning MoUs; and
- Migrating DMIA-funded trials to business-as-usual tools to manage peak demand when this is economically prudent to do so.

8. Meeting Rules' requirements

This section explains and justifies United Energy's augmentation capital expenditure forecast against the capital expenditure objectives, criteria and factors in clause 6.5.7 of the NER. It also details matters that our building block proposal must address under clause S6.1.2 of the Rules.

It therefore outlines why the AER should approve this augmentation capital expenditure forecast as part of its distribution determination for United Energy's forthcoming regulatory control period.

8.1. The capital expenditure objectives

The Rules set out the objectives the proposed capital expenditure for the forthcoming regulatory control period is required to achieve.

Clause 6.5.7(a) is:

(a) A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *capital expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(3) to the extent that there is no applicable *regulatory obligation or requirement* in relation to:

(i) the quality, reliability or security of supply of *standard control services*; or

(ii) the reliability or security of the *distribution system* through the supply of *standard control services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *standard control services*; and

(iv) maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and

(4) maintain the safety of the *distribution system* through the supply of *standard control services*.

Standard control services are core network services, connection services requiring augmentation and customer initiated works to reconfigure the distribution assets (including undergrounding of power lines). The proposed augmentation expenditure is required to provide these services.

Meeting and managing expected demand for standard control services, as required by clause 6.5.7(a)(1), is the predominant objective of United Energy's proposed augmentation capital expenditure. This expenditure is required to reinforce the network in order to meet or manage local capacity constraints within localised parts of the network as a result of growth in maximum electricity demand. Our demand forecasts are explained and justified in chapter 9 of the Regulatory Proposal.

The augmentation capital expenditure that United Energy proposes is necessary to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services, as required by clause 6.5.7(a)(2). These include the requirements of the Electricity Distribution Code. Clause 5.2 of this Code provides that:

> *A distributor must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

United Energy does not have any targets published under clause 5.1. As a consequence, it must meet the targets specified under the Service Target performance Incentive Scheme and the reasonable reliability expectations of customers. United Energy's "Customer engagement initiatives and outcomes" document explains that customers indicated a desire for their current average levels of reliability performance to be maintained in the next regulatory period.

Accordingly, the augmentation capital expenditure proposed by United Energy is required to meet or manage growth in localised maximum demand whilst maintaining average levels of reliability across the network over the current period in accordance with the Electricity Distribution Code.

8.2. Capital expenditure criteria

The Rules set out the expenditure criteria that are relevant to United Energy's augmentation capital expenditure forecast for the forthcoming regulatory control period.

Clause 6.5.7(c) is:

(c) The *AER* must accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast capital expenditure for the *regulatory control period* reasonably reflects each of the following (the *capital expenditure criteria*):

(1) the efficient costs of achieving the *capital expenditure objectives*;

(2) the costs that a prudent operator would require to achieve the *capital expenditure objectives*; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.

United Energy developed its forecast using a probabilistic planning approach in order to deliver the economically optimum level of augmentation. This approach to network planning and expansion considers the expected cost to customers of losing supply in the event that demand exceeds the available network capacity by taking into account asset capacity ratings, annual load profiles and asset failure rates and repair times. This is done either with all plant in service or by considering the probability of a single credible contingency. The associated cost which is determined by multiplying the expected energy-at-risk by the average marginal value of reliability – the VCR – is then compared against the annualised cost of removing the capacity constraint. When the cost to customers is greater than the annualised cost of removing the customer constraint, taking action is economically justified. This approach provides a better economic outcome than deterministic planning.

For augmentation capital expenditure United Energy has applied a VCR using AEMO's 2014 VCR survey results calculated on data specific to the summer peak period only. The document UE GU 2208 VCR Application Guidelines sets out the rationale for the VCR values that have applied. If AEMO's headline VCR is adopted, a lower forecast augmentation capital expenditure results and document UE GU 2208 outlines the risks from this lower VCR value.

Further evidence of the prudence and efficiency of United Energy's augmentation capital expenditure is provided in section 5.4 above.

In relation to the efficiency criterion:

- Forecast work volumes are formed through robust asset management plans and investment governance arrangements;
- Augmentation capex is validated by the AER's augex model. The augex model is forecasting substantially higher augmentation capital expenditure for the forthcoming regulatory period across all categories when compared to United Energy's augmentation capital expenditure;
- Forecast unit costs are derived from our competitively tendered contracting model. The efficiency of our business model is demonstrated by our benchmark performance with our peers in other states, which shows us to be close to the frontier; and
- The Capital Investment Review Board ensures that opportunities for synergies across operating and capital expenditure work programs are fully reflected in the capital expenditure forecasts.

In relation to the prudency criterion:

- Regulatory obligations are reflected in United Energy's asset management plans and strategies; and

- Life cycle strategies and work programs actively manage risk to ensure that work programs are both prudent and efficient.

United Energy's demand forecasts are explained and justified in chapter 9 of the Regulatory Proposal.

United Energy forecasts unitised projects by multiplying work volumes by unit costs. Unit rates are sourced from OMSAs with our service providers, Tenix and ZNX, which were reached under competitive arrangements that were explained in United Energy's regulatory proposal and revised regulatory proposal for the current regulatory control period. The unit rates are based on the actual costs incurred from 1 July 2013 to 30 June 2014 escalated in accordance with forecasts provided by BIS Shrapnel for the forthcoming regulatory period. Unit pricing is not used, however, except for a small amount relating to upgrading of distribution transformers in response to in-service overload failures.

Project costs are developed for complex work that cannot be costed upfront based purely on unitised rates. United Energy forecasts project costs using a combination of:

- Actual historical costs from previous completed projects;
- Its Expert Estimation tools;
- Statement of Works from the Service Provider based on their procurement policies and processes;
- Open tender processes;
- Customised cost estimates, where there is no relevant benchmark; and
- Verification by an Independent Estimator.

8.3. Capital expenditure factors

The Rules set out the capital expenditure factors to which regard must be had in considering United Energy's augmentation capital expenditure forecast for the forthcoming regulatory control period.

Clause 6.5.7(e) is:

(e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c), the *AER* must have regard to the following (the *capital expenditure factors*):

(1) [Deleted]

(2) [Deleted]

(3) [Deleted]

(4) the most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*;

(5) the actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8A or 6.6.2 to 6.6.4;

(9) the extent the capital expenditure forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms;

(9A) whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b);

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient and prudent non-*network* alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p) or (s):

(12) any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is a *capital expenditure factor*.

In relation to subparagraph (4), the AER's November 2014 benchmarking report, discussed in section 5.3, shows United Energy benchmarks very favourably against other DNSPs. Moreover, UE's asset utilisation levels have been maintained over the 2011-2015 period – a decrease would indicate over-investment and an increase would indicate under-investment.

In relation to subparagraph (5), United Energy has set out, in section 5.1, its actual capital expenditure during the previous regulatory control period (2005-10) and actual and expected capital expenditure in the current regulatory control period (2011-15). To accompany this information, United Energy has presented the actual and expected capital expenditure by reference to the allowance approved by the AER (and, for the 2005-10 regulatory control period, the ESC) and in section 5.2 explained the factors that have contributed to any variance from these allowances.

In relation to subparagraph (5A), United Energy has conducted a comprehensive program of customer engagement to identify the concerns of customers and to ensure that its proposed capital expenditure addresses those concerns. As discussed in section 6.4, the principle outcome of this engagement is the knowledge that our customers' reasonable expectations of reliability for the purposes of the Electricity Distribution Code are for the current average level of reliability to be maintained. However, other concerns of our customers relating to installation of air conditioners and prediction of restoration times during emergency response periods are also addressed by our augmentation capital expenditure.

In relation to subparagraph (6), United Energy interchanges augmentation capital expenditure with opex to fund economically prudent non-network opportunities identified through the RIT-D process and our joint-planning memoranda of understandings (MoU).

In relation to subparagraph (7), as discussed in section 6.4.5 the demand side engagement work that United Energy has undertaken has resulted in a number of MoU being signed with demand aggregators, generators and local government to undertake joint plans to identify non-network solutions to defer network augmentations. Given the early stages in identifying economic non-network deferrals, United Energy has developed its augmentation capital expenditure assuming all requirements are addressed through capital expenditure only. Our plan is to avoid or defer capital expenditure wherever possible during the forthcoming regulatory period at the time economic non-network solutions are identified and required through the joint planning MoU and RIT-D processes and to use the annualised deferral value of the capital expenditure allowance as an operating expenditure payment to the non-network service provider.

In relation to subparagraph (8), as discussed above, our network planning and expansion relies on the use of the VCR. The use of VCR is consistent with the Service Target Performance Incentive Scheme (STPIS) whose rates are ultimately derived from the VCR. Also, as noted above, for augmentation capital expenditure United Energy has applied a VCR using AEMO's 2014 VCR survey results calculated on data specific to the summer peak period only. If AEMO's headline VCR is adopted, a lower forecast augmentation capital expenditure results from this lower VCR value and a commensurate reduction in the service performance targets is required. In addition, United Energy is proposing to increase its demand management incentive scheme funding in the forthcoming regulatory period to build on our demand management capabilities and reduce augmentation capital expenditure over time.

In relation to subparagraph (9), our contracts with our service providers were competitively tendered on an arms' length basis. This was described in our Regulatory Proposal for the current regulatory period and accepted by the AER in its Distribution Determination.

In relation to subparagraph (9A), none of the augmentation capital expenditure should be included as a contingent project.

In relation to subparagraph (10), as discussed in subparagraph (7), the identification of non-network solution is in the very early stages, however, our plan is to avoid or defer capital expenditure wherever possible during the forthcoming regulatory period at the time economic non-network solutions are identified and required through the joint planning MoU and RIT-D processes. The augmentation capital expenditure forecast includes includes $2.5 million of non-traditional network investment (i.e. storage). This investment will save $0.5 million by avoiding $3 million of traditional augmentation capital expenditure in the forthcoming regulatory period.

In relation to subparagraph (11), United Energy has published one final project assessment report in relation to the Dromana Supply Area (DMA 2nd transformer). Submissions indicated there were no viable non-network solutions.

In relation to subparagraph (12), the AER has not identified to United Energy any other relevant factors for consideration.

9. Supporting documentation

The following documents support UE's Augmentation Capital Expenditure submission for the 2016-2020 regulatory control period.

Regulatory Proposal Overview Documents

UE's Maximum Demand Overview Paper

Capital Expenditure Overview - Augmentations

Capital Expenditure Overview - New Customer Connections

Capital Expenditure Overview – Power Quality (RQM)

Asset Management System Plans and Strategies

UE PO 2200	Network Planning Policy
UE PL 2200	Demand Strategy & Plan
UE PL 2202	Demand Side Engagement Document
UE PL 2203	Power Quality Strategy & Plan
UE PL 2204	Steady State Voltage Strategy
UE PL 2208	Solar PV Penetration Strategy
UE PL 2209	Distribution Annual Planning Report (DAPR)
UE PL 2210	Demand Management & Demand Management Incentive Scheme (DMIS) Strategy

Strategic Area Plans (business cases supporting major forecast capital expenditure)

UE PL 2220	Mornington Peninsula Strategic Plan
UE PL 2221	Upper Northern Area Strategic Plan
UE PL 2223	Springvale Clayton Notting Hill Strategic Plan
UE PL 2224	Carrum Downs Skye Lyndhurst Strategic Plan
UE PL 2201	Distribution System Augmentation (DSS) Strategy
UE PL 2211	Land Acquisition Strategy

Asset Management System Guidelines and Procedures

UE GU 2200	Network Planning Guidelines
UE GU 2202	Customer Initiated Capital (CIC) Expenditure Forecasting Guidelines
UE GU 2203	Distribution System Augmentation (DSS) Expenditure Forecasting Guidelines
UE GU 2206	Network Planning Expenditure Forecasting Guideline
UE GU 2207	Electrical Losses Guideline
UE GU 2208	Value of Customer Reliability (VCR) Guideline
UE PR 2200	Maximum Demand Forecasting Method
UE PR 2201	NLM Business Process Design

Asset Management System Manuals

UE MA 2203	Load Forecast Manual
UE MA 2204	Contingency Plans

RIN Procedures

UE PR 2203	Population of PQ Data for RIN & ESC
UE PR 2206	Population of Demand Data for RIN & ESC
UE PR 2208	Preparation of DMIA Data for RIN and DMIS Report
UE PR 2209	Population of Demand Data for Benchmark RIN
UE PR 2211	Population of Connections Data for CA RIN
UE PR 2212	Population of Augex Project Data for CA RIN
UE PR 2213	Population of Demand Data for CA RIN
UE PR 2220	Population of Demand Data for EDPR RIN
UE PR 2221	Population of Connections Data for EDPR RIN
UE PR 2222	Population of Augex Project Data for EDPR RIN
UE PR 2223	Population of Augex Model Data for EDPR RIN

Expert Consultant Documents

University of Wollongong - Economic Evaluation of Power Quality Disturbances
Part 1 – Literature Review Costing PQ
Part 2 – PQ Economic & Technical Analysis

Acil Allen – Electricity Consumption Forecasts
Part B – Post Model Adjustments (including Acil Allen models)

NIEIR – Energy, Demand and Customer Number Forecasting
Part A – Maximum Demand Forecasts (including NIEIR model)
Part B – Post Model Adjustments (including NIEIR models)

Nuttall Consulting
Reconciliation of UE's Augmentation Expenditure Forecast against the Augex Model
Populated and calibrated Augex model

AECOM
Maximum Demand Forecasting Model
Populated eViews model for maximum demand verification

Australian Construction Industry Forum (ACIF) report

Regulatory Investment Tests

Dromana Supply Area

Mornington Peninsula Supply Area

http://www.uemg.com.au/about-us/regulatory-framework/electricity-regulation/regulatory-investment-test-for-distribution-(rit-d).aspx

10. Glossary

Abbreviations	
AER	Australian Energy Regulator
CB	Circuit Breaker
CBD	Central Business District
DAPR	Distribution Annual Planning Report
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DPAR	Draft Project Assessment Report
EENS	Expected Energy Not Supplied
FPAR	Final Project Assessment Report
GU	Guideline
LED	Light Emitting Diode
MA	Manual
MD	Maximum Demand
MEPS	Minimum Efficiency Performance Standards
MOU	Memorandum of Understanding
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NNOR	Non-Network Options Report
PL	Strategic Plan
PO	Policy
POE	Probability of Exceedance
PR	Procedure
PV	Photo-voltaic
RIT-D	Regulatory Investment Test for Distribution
RQM	Reliability and Quality Maintained
SAIDI	System Average Interruption Duration Index
STPIS	Service Target Performance Incentive Scheme
TOU	Time of Use
UE	United Energy Distribution
VCR	Value of Customer Reliability

Abbreviations	
VEET	Victorian Energy Efficiency Target