



DISTRIBUTION ANNUAL PLANNING REPORT

December 2020

Disclaimer

The purpose of this document is to provide information about actual and forecast constraints on United Energy's distribution network and details of these constraints, where they are expected to arise within the forward planning period for this DAPR. This document is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity.

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This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts that, by their nature, may or may not prove to be correct. This document also contains statements about United Energy's plans. These plans may change from time to time without notice and should therefore be confirmed with United Energy before any action is taken based on this document.

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1 Executive Summary

The Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that United Energy proposes to undertake on its network. It covers information relating to 2020 as well as the forward planning period for this DAPR of 2021 to 2025.

United Energy is a regulated Victorian electricity distribution business. United Energy distributes electricity to more than 695,000 customers across east and south east Melbourne and the Mornington Peninsula, where the vast majority of the customers are residential. The network consists of more than 216,000 poles and over 13,400 kilometres of wires. Electricity is received via 78 sub transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages to distribution voltages.

The report sets out the following information:

- forecasts, including capacity and load forecasts, at the zone substation, sub-transmission and primary distribution feeder level;
- system limitations, which includes limitations resulting from the forecast load exceeding capacity following the outage, or retirements and de-ratings of assets;
- projects that have been, or will be, assessed under the regulatory investment test; and
- other high level summary information to provide context to United Energy's planning processes and activities.

The DAPR provides a high-level description of the balance that United Energy will take into account between capacity, demand and replacement of its assets at each zone substation, sub-transmission lines and primary distribution feeders over the forecast period. Transmission-distribution connection assets are addressed in a separate report.¹

Data presented in this report may indicate an emerging major constraint, where more detailed analysis of risks and options for remedial action by United Energy are required.

The DAPR also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at zone substations, sub-transmission lines and primary distribution feeders where remedial action may be required. The DAPR also provides preliminary information on constrained distribution substations and low voltage circuits as part of our consultation obligations under the Demand Management Incentive Scheme (**DMIS**). Information is also provided in MS-Excel format through the DAPR Systems Limitations Template which accompanies this

¹ Transmission-distribution connection assets are discussed in the Transmission Connection Planning Report which is available on the United Energy website at <https://www.unitedenergy.com.au/industry/mdocuments-library/>

report. Providing this information to the market facilitates the efficient development of the network to best meet the needs of customers.

The DAPR is aligned with the requirements of clauses 5.13.2(b) and (c) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.8 of the NER. In addition, the DAPR contains information consistent with the requirements of section 3.5 of the Electricity Distribution Code, as published by the Essential Services Commission of Victoria.

The Electricity Distribution Code was updated in 2020 to include additional DAPR reporting requirements for United Energy including reporting on its use of advanced metering infrastructure technology (**AMI**), and additional power quality voltage data. These requirements have been included in section 19 (for AMI) as well as the accompanying MS-Excel Distribution Voltage Information template as described further in section 16.4.1.

1.1 Public forum and consultation

United Energy intends to hold a public forum to discuss this DAPR in early 2021. All interested stakeholders are welcome to attend, including interested parties on United Energy's demand-side engagement register, and local councils.

United Energy invites written submissions from interested parties to offer alternative proposals to defer or avoid the proposed works associated with network constraints. All submissions should address the technical characteristics of non-network options provided in this DAPR and include information listed in the United Energy demand-side engagement strategy.

We also welcome feedback or suggestions for improvement on the structure or content presented in this year's DAPR, Systems Limitations Template or Distribution Voltage Information template.

All written submissions or enquiries should be directed to planning@ue.com.au.

Alternatively, United Energy's postal address for enquiries and submissions is:

United Energy
Attention: Manager Network Planning
PO Box 449
Mt Waverley VIC 3149

1.2 Overview of network constraints

The network constraints identified in this DAPR are listed below. Maps showing the location of the limitations can be found in Appendix B. Further details on each limitation can be found throughout this report, and in the attached Systems Limitations Template and United Energy network limitation Google Earth map.

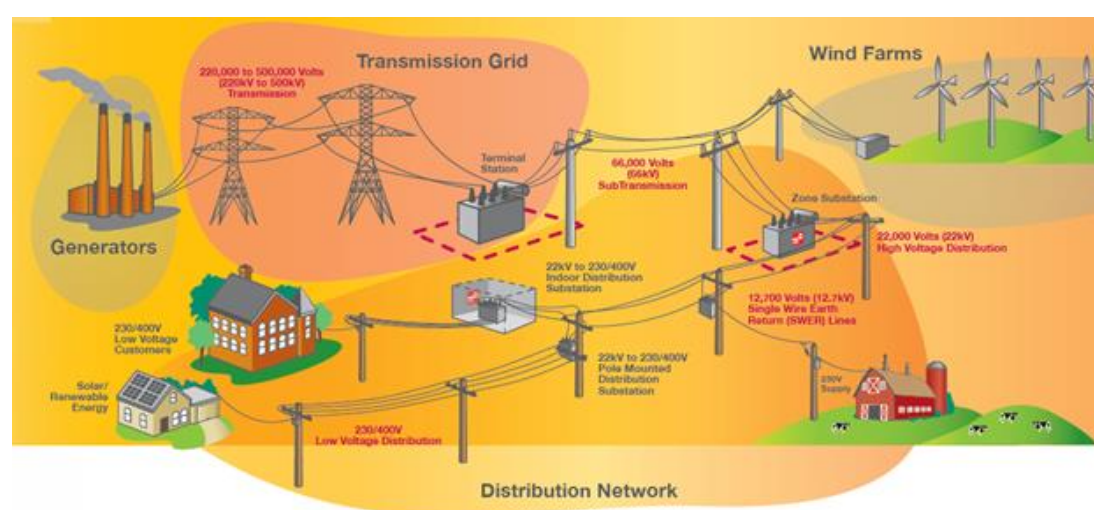
Table 1.1 United Energy network constraints summary

Limitation	Asset	Project type	Year
1	Keysborough (KBH) Zone Substation	Augmentation	2024
2	Doncaster (DC) Zone Substation	Augmentation	2025
3	East Malvern (EM) Zone Substation	Augmentation	2025
4	Mornington (MTN) Zone Substation	Augmentation	2026
5	FSH-31 (Frankston South) HV Feeder	Augmentation	2022
6	MGE-12 (Mulgrave) HV Feeder	Augmentation	2022
7	KBH-32 (Keysborough) HV Feeder	Augmentation	2022
8	Ormond (OR) #2 Transformer	Replacement	2022
9	Elwood (EW) #2 Transformer	Replacement	2022
10	Surrey Hills (SH) 6.6kV Conversion	Replacement	2022-24
11	Sandringham (SR) #3 Transformer	Replacement	2023
12	Gardiner (K) #3 Transformer	Replacement	2023
13	Bentleigh (BT) #1 Transformer	Replacement	2024
14	Hastings (HGS) #1 Transformer	Replacement	2024
15	Oakleigh East (OE) #1 Transformer	Replacement	2025
16	Bulleen (BU) #1 Transformer	Replacement	2025
17	East Malvern (EM) 11kV Indoor Switchboard	Replacement	2023
18	Elwood (EW) 11kV Indoor Switchboard	Replacement	2024
19	Beaumaris (BR) 22kV Indoor Switchboard	Replacement	2025
20	Oakleigh East (OE) 11kV Indoor Switchboard	Replacement	2025
21	Heatherton (HT) 22kV Outdoor Switchyard	Replacement	2023
22	Doncaster (DC) 22kV Outdoor Switchyard	Replacement	2024
23	Glen Waverley (GW) 22kV Outdoor Switchyard	Replacement	2024

2.1 Who we are

A high level picture of the electricity supply chain is shown in the diagram below.

Figure 2.1 The electricity supply chain



- **Generation:** generation companies produce electricity from sources such as coal, wind or sun, and then compete to sell it in the wholesale National Electricity Market (**NEM**). The market is overseen by the Australian Energy Market Operator (**AEMO**), through the co-ordination of the interconnected electricity systems of Victoria, New South Wales, South Australia, Queensland, Tasmania and the Australian Capital Territory.
- **Transmission:** the transmission network transports electricity from generators at high voltage to five Victorian distribution networks. Victoria's transmission network also connects with the grids of New South Wales, Tasmania and South Australia.
- **Distribution:** distributors such as CitiPower, Powercor and United Energy convert electricity from the transmission network into lower voltages and deliver it to Victorian homes and businesses. The major focus of distribution companies is developing and maintaining their networks to ensure a reliable supply of electricity is delivered to customers to the required quality of supply standards.

- **Retail:** the retail sector of the electricity market sells electricity and manages customer accounts. Retail companies issue customers' electricity bills, a portion of which includes regulated tariffs payable to transmission and distribution companies for transporting electricity along their respective networks.

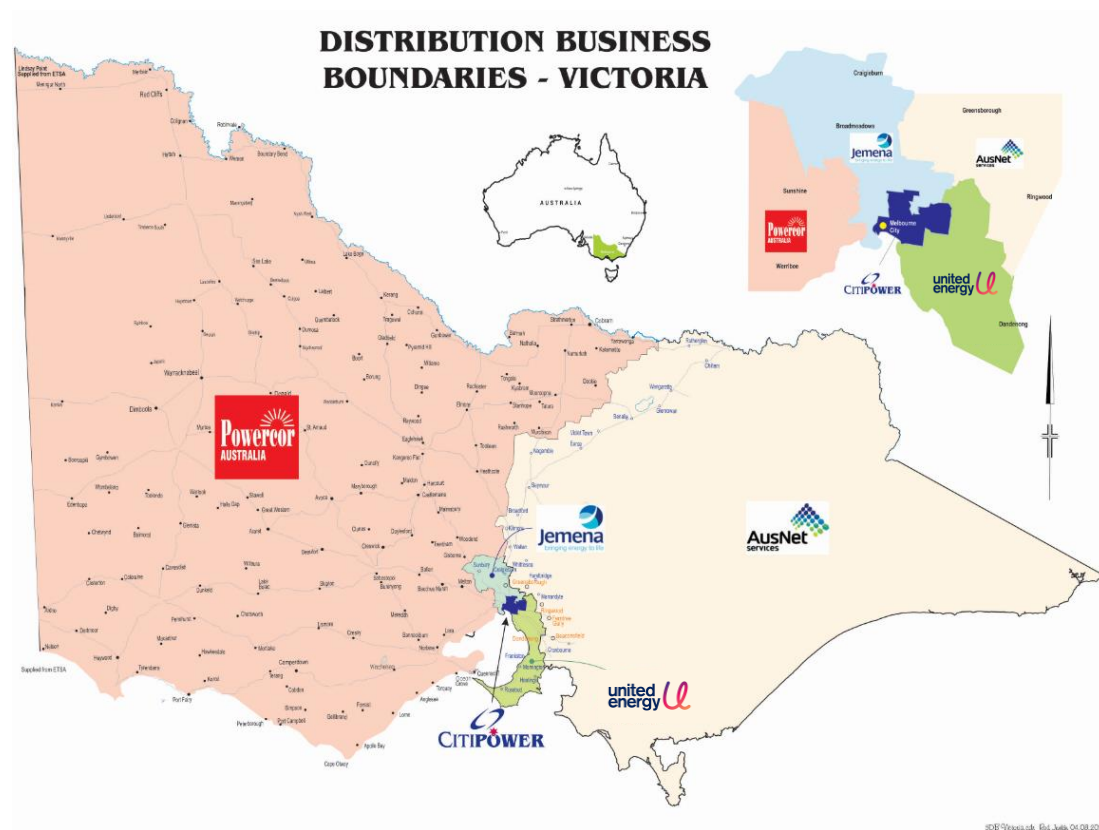
2.2 The five Victorian distributors

In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network in a prescribed geographic area. United Energy is one of those distribution businesses.

The United Energy network provides electricity to customers in Melbourne's south east and the Mornington Peninsula. United Energy's service area is largely urban and semi-rural, and although geographically small (about one percent of Victoria's land area), it accounts for around one-quarter of Victoria's population and one-fifth of Victoria's electricity maximum demand. In particular, the service area consists of:

- the northern region which is a leafy developed urban area in metropolitan Melbourne, bounded by the AusNet Electricity Services and CitiPower service areas and Port Phillip Bay. The area includes predominantly residential and commercial centres such as Box Hill, Caulfield, Doncaster and Glen Waverley, and light industrial centres such as Braeside, Clayton, Heatherton, Mulgrave and Scoresby;
- the central region is a mix of developed and undeveloped land and includes the industrial and commercial centre of Dandenong; and
- the southern region in which Frankston denotes the southern rim of the Melbourne metropolitan area and is the gateway to the Mornington Peninsula. Frankston is one of the largest retail areas outside the Melbourne CBD. The Mornington Peninsula is a 720 square kilometre boot-shaped promontory separating two contrasting bays: Port Phillip and Western Port. The Mornington Peninsula is surrounded by the sea on three sides, with coastal boundaries of over 190 kilometres.

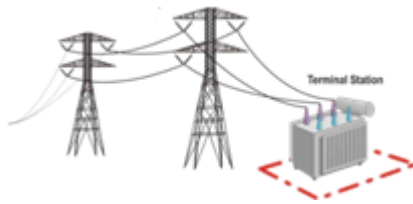
The coverage of United Energy is shown in the figure below.

Figure 2.2 United Energy distribution area

In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network and the associated transmission connection assets. In order to continue to provide efficient, secure and reliable supply to its customers, United Energy must plan augmentation of the network to match network capacity to customer demand. The need for augmentation is largely driven by customer peak demand growth and geographic shifts of demand due to urban redevelopment.

2.3 Delivering electricity to customers

Power that is produced by generators is transmitted over the high voltage transmission network and is changed to a lower voltage before it can be used in the home or industry. This occurs in several stages, which are simplified below.

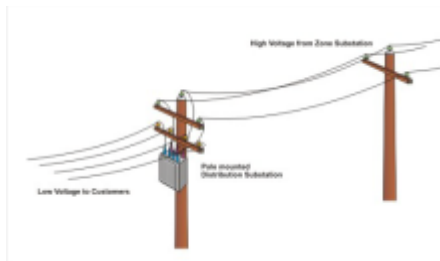


Firstly, the voltage of the electricity that is delivered to **terminal stations** is reduced by transformers. Typically in Victoria, most of the transmission lines operate at voltages of 500,000 volts (500 kilovolts, kV) or 220,000 volts (220kV). The transformer at the terminal station reduces the electricity voltage to 66kV. The United Energy network is supplied from the connection assets within the terminal stations.



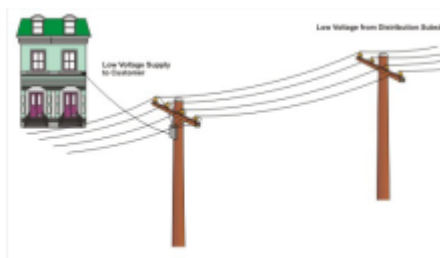
Second, United Energy distributes the electricity on the **sub-transmission system** which is made up of large concrete or wooden power poles and powerlines, or sometimes underground powerlines. The sub-transmission system transports electricity to United Energy's zone substations at 66kV and 22kV.

Third, at the **zone substation** the electricity voltage is converted from 66kV to 22kV, 11kV or 6.6kV. Electricity at this voltage can then be distributed on smaller, lighter power poles.



Fourth, **high voltage distribution lines** (or distribution feeders) transfer the electricity from the zone substations to United Energy's distribution substations.

Fifth, electricity is transformed to 400 / 230 volts at the **distribution substations** for supply to customers.



Finally, electricity is conveyed along the **low voltage distribution lines** to homes and businesses.

2.4 Operating environment and asset statistics

United Energy delivers electricity to approximately 695,000 homes and businesses in a 1,472 square kilometre area, or around 465 customers per square kilometre.

United Energy's customer base is 90 per cent residential (by number) across its urban and semi-rural service area.

The United Energy electricity network comprises a sub-transmission network which consists of predominately overhead lines which operate at 66kV with some at 22kV and a distribution network that operates at voltages of 22kV, 11kV with some at 6.6kV. The overall network consists of approximately 75 per cent overhead lines and 25 per cent underground cables.

The sub-transmission network is supplied from a number of terminal stations which typically operate at a voltage of 220kV or greater. This transmission network, including the terminal stations supplying United Energy, is owned and operated by AusNet Services.

The majority of the sub-transmission network nominally operates at 66kV and is generally configured in loops or in mesh to maximise reliability. The sub-transmission network operates at 22kV on some lines from the Malvern terminal station.

The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for the distribution to the surrounding area.

The distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment to provide effective protection and control. The majority of the high voltage distribution system nominally operates at 22kV and 11kV, there are notable exceptions:

- the high voltage distribution feeders from the Surrey Hills zone substation operate at 6.6kV;
- the high voltage distribution feeders at West Doncaster zone substation are at voltages of 11kV and 6.6kV; and
- a small Single Wire Earth Return (**SWER**) system supplying some customers in the Mornington Peninsula, which operates at 12.7kV.

Distribution feeders are operated in a radial mode from their respective zone substation supply points. In urban areas, distribution feeders generally have inter-feeder tie points which can be reconfigured to provide for load transfers and other operational contingencies.

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 (single-phase) or 400 (three-phase) volts. These voltages are derived from "distribution substations" which are located throughout the distribution network. The majority of the low voltage network is overhead however reticulations to new residential housing estates are typically underground. The low

voltage reticulation including service arrangements completes the final connections to the low voltage consumer points of supply.

At 31 December 2019, the United Energy network comprises approximately:

Table 2.1 United Energy network statistics

Item	Value
Peak coincident demand (summer 2019/20)	2,051 MW
Record peak coincident demand (summer 2008/09)	2,084 MW
Poles	216,103
Overhead lines	10,034 km
Underground cables	3,374 km
Sub-transmission lines	78
Zone substation transformers	114
Distribution feeders	445
Distribution substations	13,856

Appendix A provides a map which shows the location of United Energy's zone-substation assets and the connected terminal stations on a geographic basis.

3 Factors impacting the network

This chapter sets out the factors that may have a material impact on the United Energy network, including:

- demand: changes in electricity demand causing thermal capacity constraints, such as that caused from population growth resulting in new residential customers connecting to the network, or new or changed business requirements for electricity;
- fault levels: changes in fault (short-circuit) levels resulting in fault level rupture constraints, such as that caused by embedded generation being connected to the network;
- voltage levels: changes in steady state voltage levels resulting in voltage regulation constraints, such as lower voltages caused by long distances between the customer load and the voltage regulating equipment, or higher voltages caused by solar photovoltaic (**PV**) installation exports;
- other power system security requirements: changes that may impact system security for the Australian Energy Market Operator (**AEMO**) such as the connection of embedded generation, or changes in protection systems;
- quality of supply: changes in quality of supply such as that caused by the connection of new customer equipment. United Energy may carry out system studies on a case-by-case basis as part of the new large customer connection process; and
- asset condition: changes in asset condition over time, such as deterioration caused by ageing, which may lead to unreliable assets.

These factors are discussed in more detail below.

3.1 Demand

Changes in maximum demand on the network are driven by a range of factors. For example, this may include:

- population growth: increases in the number of residential customers connecting to the network;
- economic growth: changes in the demand from small, medium and large businesses and large industrial customers;
- retail prices: changes in the price of electricity impacts the use of electricity;
- weather: the effect of ambient temperature on demand largely due to temperature-sensitive loads such as air-conditioners and heaters; and
- customer equipment and embedded generators: the equipment that sits behind the customer meter including televisions, pool pumps, electric vehicles, solar panels, wind turbines, batteries, etc.

Forecasting for demand is discussed later in this document.

3.2 Fault levels

A fault is an event where an abnormally high electrical current is developed as a result of a short-circuit somewhere in the network. A fault may involve one or more line phases and ground, or may occur between line phases only. In a ground/ earth fault, charge flows into the earth or along a neutral or earth-return wire.

United Energy estimates the prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to select and set the protective devices that can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers, and fuses can act to interrupt the fault current to protect the electrical plant, and avoid significant and sustained outages as a result of plant damage.

Fault levels are influenced by a number of factors including:

- generation of all sizes;
- impedance of transmission and distribution network equipment;
- load including motors; and
- voltage level.

The following fault level limits apply to United Energy:

Table 3.1 Fault level limits

Voltage	Fault limit (kilo Amps, kA)
66kV	21.9 kA
22kV	13.1 kA
11kV	18.4 kA
<1kV	50 kA

Where fault levels are forecast to exceed the allowable fault level limits listed above, then fault level mitigation projects are initiated. This may involve, for example, introducing extra impedance into the network or separating network components that contribute to the fault such as opening the bus-tie circuit breakers at constrained zone substations to divide the fault current path.

3.3 Voltage levels

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors such as washing machines and refrigerators, or farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Electricity distributors are obligated to maintain customer voltages within specified thresholds, and these are further discussed in section 16. Similarly, manufacturers can

only supply such appliances and equipment that operate within the Australian Standards. Supply voltage at levels outside these limits could affect the performance or cause damage to the equipment as well as industry processes.

Voltage levels are affected by a number of factors including:

- generation of electricity into the network including distributed generation such as household solar photovoltaic (PV) generators;
- impedance of transmission and distribution network equipment;
- load;
- tap position of transformers in the network; and
- capacitors in the network.

United Energy manages the voltage drops caused by the long distance between the customer and the supplying substations with voltage regulating equipment and capacitor banks.

In recent times, uptake of solar PV generators are increasingly causing fluctuations in voltage levels in localised areas. United Energy is monitoring the voltages in these areas using smart meters, with higher voltage levels caused by solar generation now having to be monitored and managed.

3.4 System security

AEMO is responsible for managing the overall system security of the power grid. Embedded generation and protection systems within the distribution network influence the overall stability of the grid. United Energy undertakes joint planning with AEMO to ensure that the United Energy distribution network is planned and operated, and the loads and generators connected within it, maintain the security of the power grid.

3.5 Quality of supply

Where embedded generators or large industrial customers are seeking to connect to the network and the type of load is likely to result in changes to the quality of supply to other network users, United Energy may carry out system studies on a case-by-case basis as part of the new customer connection process.

3.6 Asset condition

The age profile of United Energy's distribution network reflects the large investment that took place in the electricity networks in Victoria with much of the area electrified post-World War. Assets on the United Energy network were first installed in Melbourne in the early part of 1900s although it wasn't until the late 1930s that network assets were being installed in large numbers. From the late 1950s the network started growing rapidly, with a large number of new customer connections driven by the economic growth in the post-war decades.

During the latter part of last century the capacity of the network continued to grow as air conditioners, new developments, computers and other household appliances drove significant demand growth across the network. Much of this area is now urbanised. The present implication is that an increasing number of assets are approaching their end-of-life and require replacement over the current and forward looking planning periods.

The growing proportion of aged assets reflects the uneven historical development of the network, particularly in the 1960s and 1970s. The relationship between asset age and the probability of asset failure is well known. Assets typically have a long period of serviceable life with a low failure rate, followed by a period of deterioration leading to increasing failure.

The failure characteristics will differ across asset categories. However, the generally accepted principle is that asset failure rates typically accelerate as assets approach their end of life; the rate of which can vary from asset to asset, and is affected by various factors including operating conditions and the environment. If an increasing proportion of assets are approaching the time period where the failure rate starts to increase, the risk of asset failures across the network increases.

As a prudent network company, United Energy anticipates and manages this risk via a wide range of tools and techniques to assess the condition of network assets. This information is used to drive a range of further activities including more frequent maintenance, asset replacement or alternative mitigation activities based on the results. This program aims to ensure that the asset remains safe and functional, whilst maximising asset life and focussing on a condition-based approach.

United Energy's strategy is to maintain reliability and network safety efficiently by complementing asset replacement with other strategies. For further details on United Energy's asset management approach and replacement projects, please refer to chapters 12, 13 and 14.

4 Network planning standards for augmentations

This chapter sets out the process by which United Energy identifies demand-driven constraints in its network.

4.1 Approaches to planning standards

In general there are two different approaches to network planning.

Deterministic planning standards: this approach calls for zero interruptions to customer supply following any single outage of a network element, such as a transformer. In this standard any failure or outage of individual network elements (known as the “N-1” condition) can be tolerated without customer impact due to sufficient resilience being built into the distribution network. A strict use of this approach may lead to inefficient network investment as resilience is built into the network irrespective of the cost of the likely interruption to the network customers, or the use of alternative options.

Probabilistic planning approach: the deterministic N-1 criterion is relaxed under this approach, and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. As such, the consideration of energy not served will likely lead to the deferral of projects that would otherwise be undertaken using a deterministic approach. This is because:

- under a probabilistic approach, there are conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
- the actual load-at-risk may be very small when considering the probability of a forced outage of a particular element of the network.

In addition, the probabilistic approach assesses load-at-risk under system normal conditions (known as the “N” condition). This is where all assets are operating but load exceeds the total capacity. Contingency load transfers or a non-network solution may be used to mitigate load-at-risk in the interim period until an augmentation is completed.

4.2 Application of the probabilistic approach to planning

United Energy adopts a probabilistic approach to planning including its zone substation, sub-transmission and primary distribution feeder asset augmentations.

The probabilistic planning approach involves estimating the probability of an outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability, to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint, and therefore

- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of energy-at-risk (which is discussed in section 6) is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of network augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the forced outage of a transformer at a zone substation during a period of high demand) when the available network capacity will be insufficient to meet actual demand and significant load shedding could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic equipment failure leading to extended periods of plant non-availability; and
- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

5 Forecasting demand

This chapter sets out the methodology and assumptions for calculating historic and forecast levels of demand for each existing zone substation, sub-transmission system and primary distribution feeder. The spatial forecasts are used to identify potential future constraints in the network.

Please note that information relating to transmission-distribution connection points are provided in a separate report entitled the “Transmission Connection Planning Report” which is available on the United Energy website.²

5.1 Maximum demand forecasts

United Energy has set out its forecasts for maximum demand for each existing zone substation, sub-transmission system as follows:

- zone substations: see Appendix C; and
- sub-transmission systems: see Appendix D.

5.2 Zone substations

This sub section sets out the methodology and information used to calculate the demand forecasts and related information that is set out in Appendix C.

5.2.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual load and demand values recorded across the distribution network. Determining the actual peak demand for each station is first corrected for system abnormalities (i.e. load transfers).

As peak demand is very temperature dependent, the actual peak demand values shown in Appendix C, are normalised in accordance with the relevant temperatures experienced across any given summer loading period. The temperature correction enables the underlying peak demand growth year-by-year to be estimated, which is used in making future forecast and investment decisions.

The temperature correction for the forecasts presented in this DAPR seeks to ascertain the “*10th percentile summer maximum demand*”. The 10th percentile demand represents the peak demand on the basis of a weather condition that would lead to a maximum demand that would be considered to be a one in ten year event. This relates to a maximum average daily temperature that will be exceeded, on average, once every ten years. By definition therefore, actual demand in any given year has a 10 per

² <https://www.unitedenergy.com.au/industry/mdocuments-library/>

cent probability of being higher than the 10th percentile demand forecast.³ It is often referred to as 10 per cent probability of exceedance (**10% PoE**).

5.2.2 Forecast demand

The historical temperature corrected demand values are trended forward and combined with known or predicted loads that may be connected to the network. This includes taking into account the number of customer connections and the estimated total output of known embedded generating units at a localised level.

United Energy has taken into account information collected from across the business relating to the load requirements of our customers, and the timing of those loads. This includes information of the estimated load requirements for planned, committed and developments under-construction across the United Energy service area and large load planned retirements or reduction.

These bottom-up forecasts for demand have been reconciled with top-down independent econometric forecasts provided by National Institute of Economic and Industry Research (**NIEIR**) to ensure that historical trend forward is adjusted for changes at the macro-economic level and post-model adjustment disruptors. United Energy also utilises a regression and simulation model developed by AECOM, and forecasts developed by the AEMO, to cross-check and reconcile the output of the NIEIR model.

5.2.3 Definitions for zone substation forecast tables

Appendix C contains other statistics of relevance to each zone substation, including:

- **Total Station Cyclic N rating:** this provides the maximum capacity of the zone substation assuming that the load follows a daily pattern, with a rating calculated using load curves appropriate to the season, and that equipment is in place under system normal conditions;
- **Cyclic N-1 rating:** this provides the cyclic capacity of the zone substation assuming the forced outage of one transformer. This is also known as the “firm” rating;
- **Hours load is \geq 95% of maximum demand (MD):** assesses the load duration curve and the total hours during the year that the load is greater than or equal to 95 per cent of maximum demand;
- **Station power factor at maximum demand (MD):** the ratio of the active power to the apparent power at maximum demand conditions.
- **Load transfers:** forecasts the available capacity of adjacent zone substations and feeder connections to take load away from the zone substation in emergency situations; and

³ Consequently there is also a 10% probability that demand will exceed forecast.

- **Generation capacity:** the total capacity of all embedded generation units greater than 1MW that have been connected to the zone substation at the date of this report.

5.3 Sub-transmission loops

This section sets out the methodology for calculating the historical and forecast maximum demands for the sub-transmission loops.

5.3.1 Historical demand

The historical actual demand and weather corrected 10% PoE demand for sub-transmission loops are calculated in a similar way to the zone substation methodology.

United Energy typically uses Amps to measure its sub-transmission line/loop demand and ratings and these are converted to MVA in this DAPR and the Systems Limitations template utilising the station nominal voltage and power factor.

5.3.2 Forecast demand

To calculate the 10% PoE sub-transmission loop forecast demand presented in this DAPR, United Energy escalates the historical actual loop maximum demand discussed above, using the percentage annual change between the combined actual and 10% PoE maximum demand forecasts for the zone substations contained within the sub-transmission system loop. That is, the sub-transmission loop forecast demand is derived from the diversified forecast demands of the zone substations contained within the sub-transmission loop. These forecasts are set out in Appendix D.

5.3.3 Definitions for sub-transmission loop forecast tables

Appendix D contains other statistics of relevance to each sub-transmission loop, including:

- **Loop N rating:** this provides the maximum capacity of the sub-transmission loop with all lines in service expressed in MVA;
- **Loop N-1 rating:** this provides the lowest capacity of the sub-transmission loop with one line out-of-service expressed in MVA⁴;
- **Hours load is \geq 95% of maximum demand (MD):** assesses the load duration curve and the total hours during the year that the load is greater than or equal to 95 per cent of maximum demand;
- **Power factor at maximum demand (MD):** the ratio of the active power to the apparent power at maximum demand conditions.

⁴ Note that a sub-transmission loop will have a different rating depending on which line is out of service. This is taken into account in any energy-at-risk assessment.

- **Load transfers:** forecasts the available capacity of alternative sub-transmission lines that can carry electricity to the zone substation in emergency situations; and
- **Generation capacity:** the total capacity of all embedded generation units that are greater than 1MW that have been directly connected to the sub-transmission loop at the date of this report.

5.4 Primary distribution feeders

This section sets out the methodology for calculating the forecast maximum demands for the primary distribution feeders.

5.4.1 Forecast demand

Primary distribution feeder 10% PoE maximum demand forecasts presented in this DAPR are calculated in a similar way to forecasts for zone substations. The feeder historical demand values are trended forward using the underlying zone substation growth rate and known or predicted loads and embedded generation that may be connected to the network.

6 Approach to risk assessment

This chapter outlines the high level process by which United Energy calculates the risk associated with the expected balance between capacity and demand over the forecast period for zone substations, sub-transmission lines and primary distribution feeders.

This process provides a means of identifying those zone substations or lines where more detailed analyses of risks and options for remedial action are required.

6.1 Energy-at-risk

As discussed in section 4.1, risk-based probabilistic network planning aims to strike an economic balance between:

- the cost of providing additional network capacity to remove any constraints; and
- the potential cost of having some exposure to loading levels beyond the network's firm capability.

A key element of this assessment for each zone substation and sub-transmission line is "energy-at-risk", which is an estimate of the amount of energy that would not be supplied if one transformer or a sub-transmission line was out of service during the critical loading period(s).

This statistic provides an indication of magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer without taking into account planned augmentation or operational actions, such as load transfers to other supply points, to mitigate the impact of the outage.

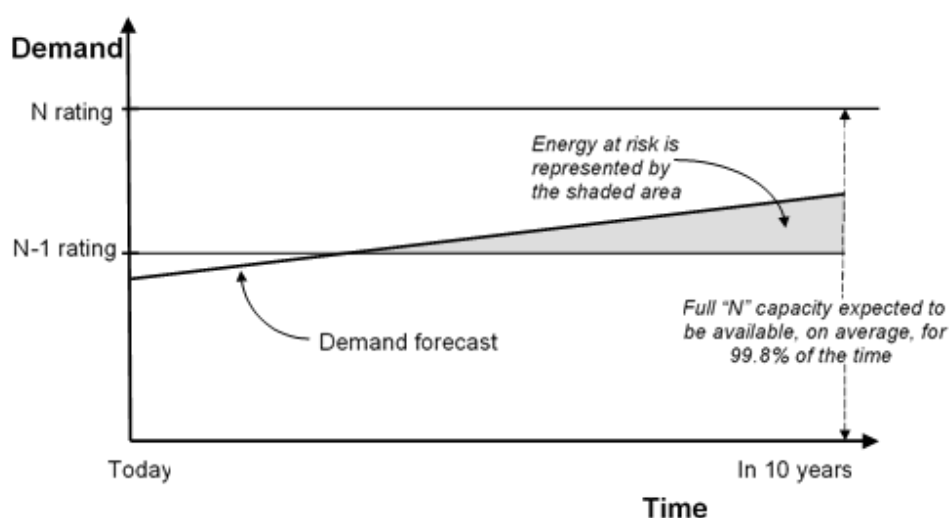
For sub-transmission lines, the same definition applies however, the failure rates and mean duration of an outage will differ. The failure rates and mean duration used for an outage for sub-transmission lines and zone substation transformers is discussed further in sections 6.4.

Although this DAPR focuses on the energy-at-risk for a 10th percentile demand forecast to highlight the risk, as discussed in sections 5.2 and 5.3, when undertaking an economic assessment of projects United Energy uses estimates the energy-at-risk based on a 30% and 70% weighting of the 10th and 50th percentile demand forecasts.

6.2 Interpreting energy-at-risk

As noted above, "energy-at-risk" is an estimate of the amount of energy that would not be supplied if one transformer or sub-transmission line was out of service during the critical loading period(s).

The capability of a zone substation with one transformer out of service is referred to as its "N minus 1" rating. The capability of the station with all transformers in service is referred to as its "N" rating. The relationship between the N and N-1 ratings of a station and the energy-at-risk is depicted in Figure 6.1 below.

Figure 6.1 Relationship between N, N-1 rating and energy-at-risk

Note that:

- under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand; and
- the risk of prolonged outages of a zone substation transformer leading to load interruption is typically very low.

The capability of a sub-transmission line network with one line out of service is referred to as the (N-1) condition for that sub-transmission network.

- under normal operating conditions, there will typically be more than adequate line capacity to supply all demand; and
- the risk of prolonged outages of a sub-transmission line leading to load interruption is typically very low and is dependent upon the length of line exposed and the environment in which the line operates.

6.3 Value of customer reliability (VCR)

For augmentation projects and major replacement projects such as those in section 14.1 United Energy undertakes a detailed assessment process to determine whether or not to proceed with the investment.

In order to determine the economically optimal level and configuration of distribution capacity (and hence the supply reliability that will be delivered to customers), it is necessary to place a value on supply reliability from the customer's perspective.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Nonetheless, there is information available (principally, surveys designed to estimate the costs faced by consumers as a result of electricity supply interruptions) that provides a guide as to the likely value.

A rule change made in July 2018 in the National Electricity Rules gave the Australian Energy Regulator (**AER**) the responsibility to determine the values different customers place on having a reliable electricity supply. The AER subsequently developed an updated methodology for deriving Value of Customer Reliability (**VCR**) values and published new VCRs in December 2019. The applicable United Energy VCR values from this publication are as per Table 6.1 below:

Table 6.1 Values of customer reliability

Sector	VCR (\$/kWh) \$2019
Residential (climate zone 6)	\$21.25
Commercial	\$44.52
Agricultural	\$37.87
Industrial	\$63.79

These values are to be multiplied by the relative weighting of each sector applicable to the customer composition in the affected area to estimate a composite single value of customer reliability for each area.

This is used to calculate the economic benefit of undertaking an augmentation or replacement, and where the net present value of the benefits outweighs the costs, and is superior to other options, United Energy is likely to proceed with the works.

From a planning perspective, it is appropriate for United Energy to have regard to the latest available VCR estimate. It is also important to recognise, however, that all methods for estimating VCR are prone to error and uncertainty.

United Energy notes that there has been a comparative reduction in the VCR estimates for the residential, commercial and agricultural sectors with a significant increase in the industrial component compared to the 2014 Australian Energy Market Operator (**AEMO**) study. This would tend to bias investment towards industrial areas compared to the previous VCR estimates. The uncertainty in VCR estimates are further illustrated by the wide differences between:

- AEMO's VCR estimate for 2013 of \$63 per kWh, which was based on the 2007-08 VENCORP study⁵;
- Oakley Greenwood's 2012 estimate of the New South Wales VCR⁶, of \$95 per kWh; and
- AEMO's 2014 Victorian VCR estimate of \$39.50 per kWh.

The wide range of VCR estimates produced by all these studies is likely to reflect estimation errors and methodological differences between the studies, rather than

⁵ See section 2.4 of the 2013 Transmission Connection Planning Report.

⁶ AEMO, Value of Customer Reliability Review Appendices, Appendix G, November 2014.

changes in the actual value that customers place on reliability. Moreover, the magnitude of the reduction in the VCR estimates from 2013 to today raises concerns that the investment decisions signalled by applying the latest VCR estimate may fail to meet customers' reasonable expectations of supply reliability.

6.4 Plant unavailability

The VCR is only one component in quantifying cost of loss of supply to customers. United Energy combines the VCR with the expected unavailability of distribution network plants based on forced outage rates and outage durations.

The base (average) major fault reliability data adopted by United Energy for its augmentation assessments used in this DAPR and the Systems Limitations template is shown in the following tables. The data is based on the Australian CIGRE Transformer Reliability Survey and United Energy's actual observed network performances. United Energy intends to update this data over time as more recent failure and repair time data become available from assets on the United Energy network.

Table 6.2 Zone substation transformer outage data

Major plant item: zone substation transformer		Interpretation
Transformer failure rate (major fault)	0.5% per annum	A major failure is expected to occur once per 200 transformer-years. Therefore, in a population of 100 zone substation transformers, for example, one major failure of any one transformer would be expected every two years.
Duration of outage (major fault)	2190 hours	A total of 3 months is required to repair / replace the transformer, during which time the transformer is not available for service.
Expected transformer unavailability per year	$\frac{\text{Repair time}}{\text{Repair time} + \frac{(24 \times 365)}{(\text{failure rate})}}$	On average, each transformer would be expected to be unavailable due to transformer fault for 0.125% of the time or approximately 11 hours in a year.

Table 6.3 Sub-transmission line outage data

Major plant item: sub-transmission lines		Interpretation
Line failure rate (sustained fault)	4.8 faults per 100 km per annum	The average sustained failure rate of United Energy's sub-transmission lines is 4.8 faults per 100 km per year.
Duration of outage (sustained fault)	12 hours	On average 12 hours is required to repair an overhead line however cable faults can take considerably longer.
Expected line unavailability per year	$\frac{\text{Repair time}}{\text{Repair time} + \frac{(24 \times 365)}{(\text{failure rate} \times \text{length})}}$	On average, a 10 km sub-transmission line is expected to be unavailable due to a fault for about 0.066% of the time, or approximately 6 hours in a year.

Note that in a detailed assessment process all site specific outage scenarios may also be taken into account. For example a 66kV line outage may also cause a transformer to be taken out of service. The base (average) outage data is also not applicable for replacement assessments which will take into account asset specific failure rate based on age and condition.

6.5 Value of expected energy-at-risk

The financial value of expected energy-at-risk is calculated by multiplying the “energy-at-risk”, the “value of customer reliability”, and the “plant unavailability”.

7 Zone substations review

This chapter reviews the zone substations where further investigation into the balance between capacity and demand over the next five years is warranted, taking into account the:

- forecasts for maximum demand to 2024/25; and
- seasonal cyclic N-1 ratings for each zone substation.

Where the zone substations are forecast to operate with 10 per cent probability of exceedance (**10% PoE**) maximum demands greater than their firm summer rating during 2020/21 and the energy-at-risk is material, or if an augmentation project is planned, then this section assesses the energy-at-risk for those assets.

United Energy sets out possible options to address the system limitations. United Energy may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire load-at-risk at times of maximum demand. At other times of lower load the available transfers may be greater. As a result, the use of load transfers under contingency situations may imply an interruption of supply for customers to protect network elements from damage and enable all available load transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. Solutions may also address sub-transmission constraints at the same time.

United Energy notes that all other zone substations that are not specifically mentioned below have loadings below the firm rating or the loading above the relevant rating results in minimal energy-at-risk.

Finally, new zone substations that are proposed to be commissioned during the forward planning period for this DAPR are also discussed.

7.1 Zone substations with forecast limitations overview

Using the analysis undertaken below in section 7.2, United Energy proposes to augment the zone substations listed in the table below to address system limitations during the five-year forward planning period for this DAPR.

Table 7.1 Proposed zone substation augmentations

Zone substation	Description	Direct cost estimate				
		2021	2022	2023	2024	2025
KBH	Install a second transformer with two new distribution feeders at Keysborough (KBH) in 2024.	-	-	2.1	4.2	-
DC	Install a fourth transformer with two new distribution feeders at Doncaster (DC) in 2025.	-	-	-	2.1	4.0
EM	Install a third switchboard with three new distribution feeders at East Malvern (EM) in 2025.	-	-	-	0.9	6.3
MTN	Install a feeder from Mornington (MTN) in 2021 with a third transformer with a new distribution feeder at in 2026 ⁷ .	0.9	-	-	-	2.3
Total		0.9	-	2.1	7.2	12.6

The options and analysis is undertaken in the sections below.

7.2 Zone substations with forecast system limitations

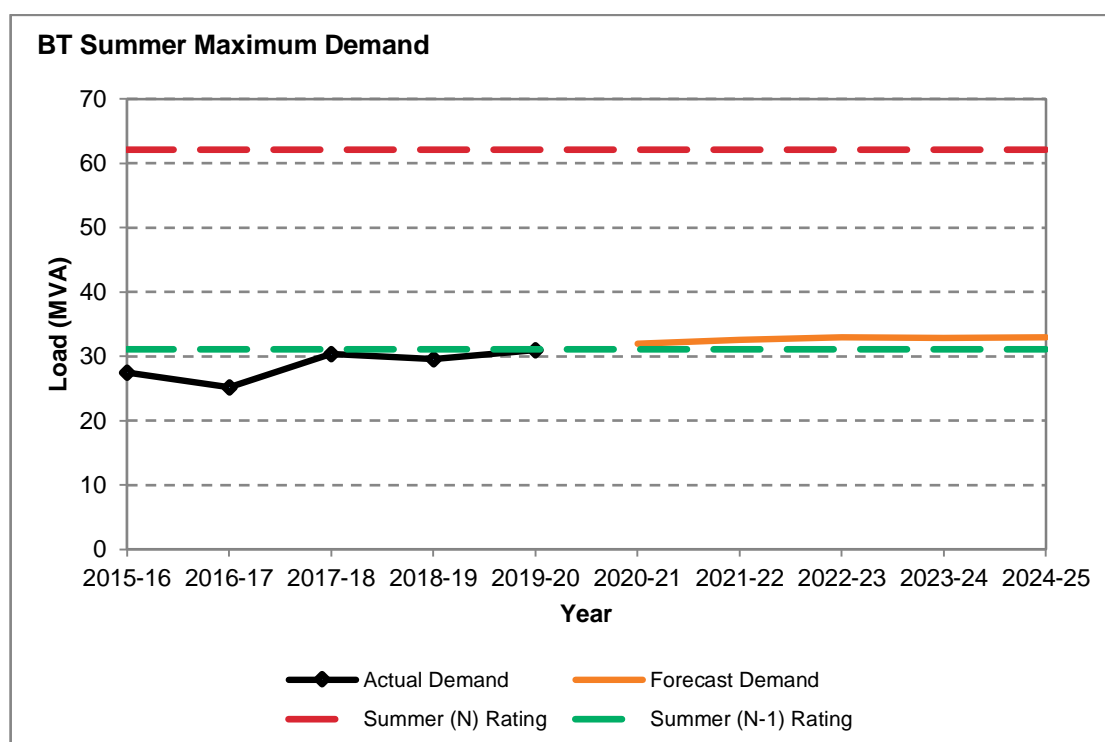
7.2.1 Bentleigh (BT) zone substation

Bentleigh (**BT**) zone substation is served by sub-transmission lines from the Heatherton Terminal Station (**HTS**). It supplies the areas of Bentleigh, Bentleigh East and McKinnon.

Currently, BT zone substation consists of two 20/30MVA transformers operating at 66/22kV.

The actual maximum demand at BT for summer 2019/20 was 30.9 MVA, which was just below the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

⁷ Partial cost only of 3rd transformer is shown in the table.

Figure 7.1 Forecast maximum demand for BT zone substation

United Energy estimates that in the summer of 2020/21 there will be 0.9MVA of load-at-risk if there is a failure of a transformer at BT. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BT zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of North Brighton (**NB**), Caulfield (**CFD**) and Moorabbin (**MR**) up to a maximum transfer capacity of 6.6MVA;
- install a third 20/33MVA transformer at BT zone substation at an estimated cost of \$6.5 million;
- establish a new zone substation nearby.

United Energy's preferred network option is to install a new transformer at the BT zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions will be used to mitigate the load-at-risk in the interim period.

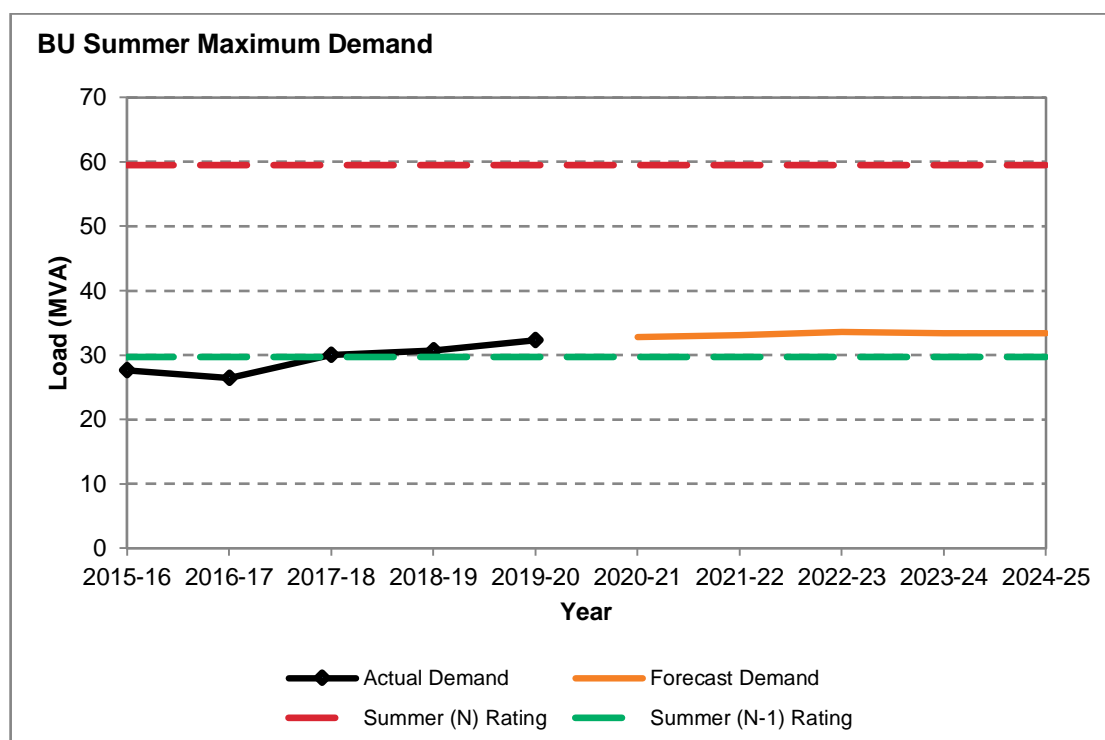
7.2.2 Bulleen (BU) zone substation

Bulleen (**BU**) zone substation is served by sub-transmission lines from the Thomastown Terminal Station (**TSTS**). It supplies the areas of Bulleen and Templestowe Lower.

Currently, BU zone substation consists of two 20/30MVA transformers operating at 66/11kV.

The actual maximum demand at BU for summer 2019/20 was 32.3 MVA, which was above the N-1 ratings for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.2 Forecast maximum demand for BU zone substation



United Energy estimates that in the summer of 2020/21 there will be 3.1MVA of load-at-risk if there is a failure of a transformer at BU. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BU zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substation West Doncaster (**WD**) up to a maximum transfer capacity of 6.8MVA;
- the BU switchboard assets are planned for replacement with modern equivalent assets due to aged and deteriorating condition. This will result in a minor ratings increase at BU and alleviate the constraints in the short to medium term;
- install a third 20/33MVA transformer at BU zone substation at an estimated cost of \$6.5 million;

- convert sections of BU feeders to 22kV and transfer them to Doncaster (**DC**) zone-substation. This solution assumes that a fourth transformer is installed at DC to alleviate the capacity constraints at DC (see section 7.2.6);
- establish a new zone substation in Templestowe (TSE).

United Energy's preferred network option in the long term is to install a new transformer at the BU zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions will be used to mitigate the load-at-risk in the interim period, followed by replacing the BU switchboard assets.

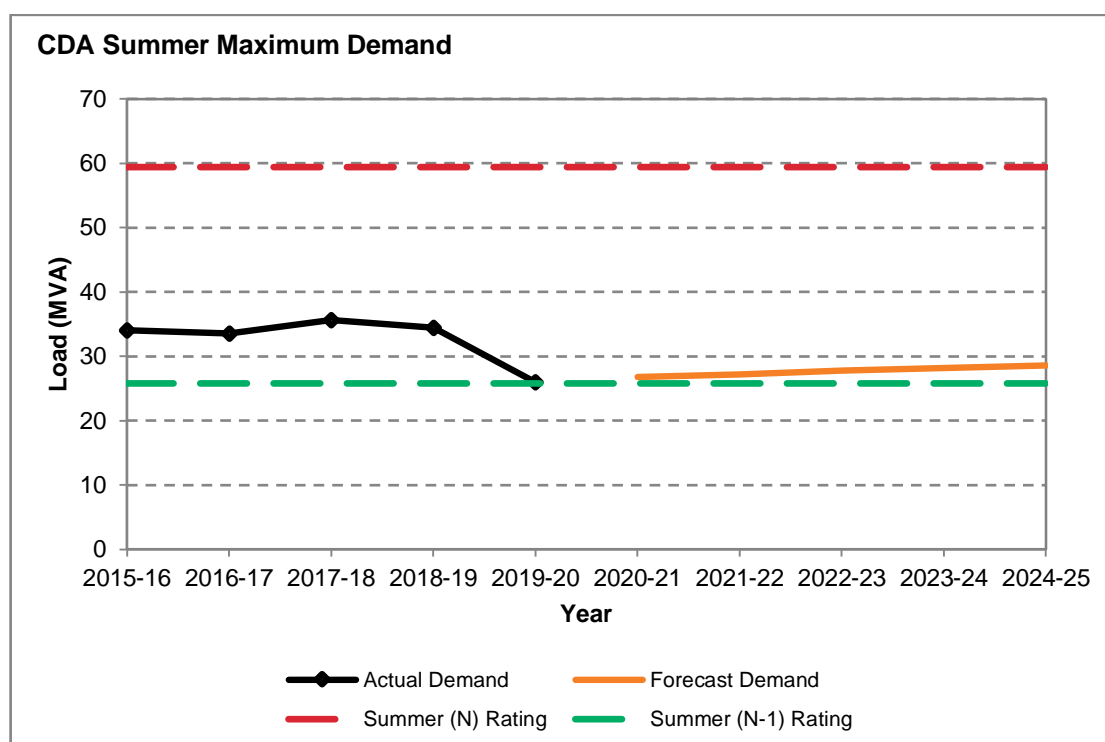
7.2.3 Clarinda (CDA) zone substation

Clarinda (**CDA**) zone substation is served by sub-transmission lines from the Springvale Terminal Station (**SVTS**). It supplies the areas of Clarinda and Oakleigh South.

Currently, the CDA zone substation consists of one permanent 20/33MVA transformer and a relocatable 12/20MVA transformer acting as a hot spare, both operating at 66/22kV.

Prior to summer 2012/13, CDA zone substation was equipped with a single transformer and relied on distribution feeder transfers from adjacent zone substation to cater for an outage of the main transformer. In lieu of installing a second transformer at CDA, United Energy relocated the 12/20MVA relocatable transformer from Dandenong Valley (**DVY**) zone substation. A larger capacity 20/33MVA transformer was subsequently installed at DVY. United Energy has also installed a standard spare 66/22kV 20/33MVA transformer at Dandenong South (**DSH**) zone substation. This limits the likelihood that the relocatable transformer at CDA may need to be used at another 66/22kV zone substation should a major unplanned outage of a transformer exist during summer maximum demand periods.

The actual maximum demand at CDA for summer 2019/20 was 26.0, which is above the N-1 rating for the zone substation based on the rating of the relocatable transformer. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. It should be noted that a load transfer was implemented to shift load away from CDA in 2019 which is reflected in the graph below. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.3 Forecast maximum demand for CDA zone substation

United Energy estimates that in the summer of 2020/21 there will be 1.0MVA of load-at-risk if there is a failure of the main transformer at CDA. That is, it would not be able to supply all customers during high load periods following the loss of that transformer.

To address the anticipated system constraint at CDA zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Heatherton (**HT**), Springvale South (**SS**) and Notting Hill (**NO**) up to a maximum transfer capacity of 22.1MVA;
- install a second 20/33MVA transformer at CDA zone substation at an estimated cost of \$6.7 million;
- establish a new zone substation nearby.

United Energy's preferred network option is to install a new transformer at the CDA zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of permanent and contingency load transfers, and/or non-network solutions will be used to mitigate the load-at-risk in the interim period.

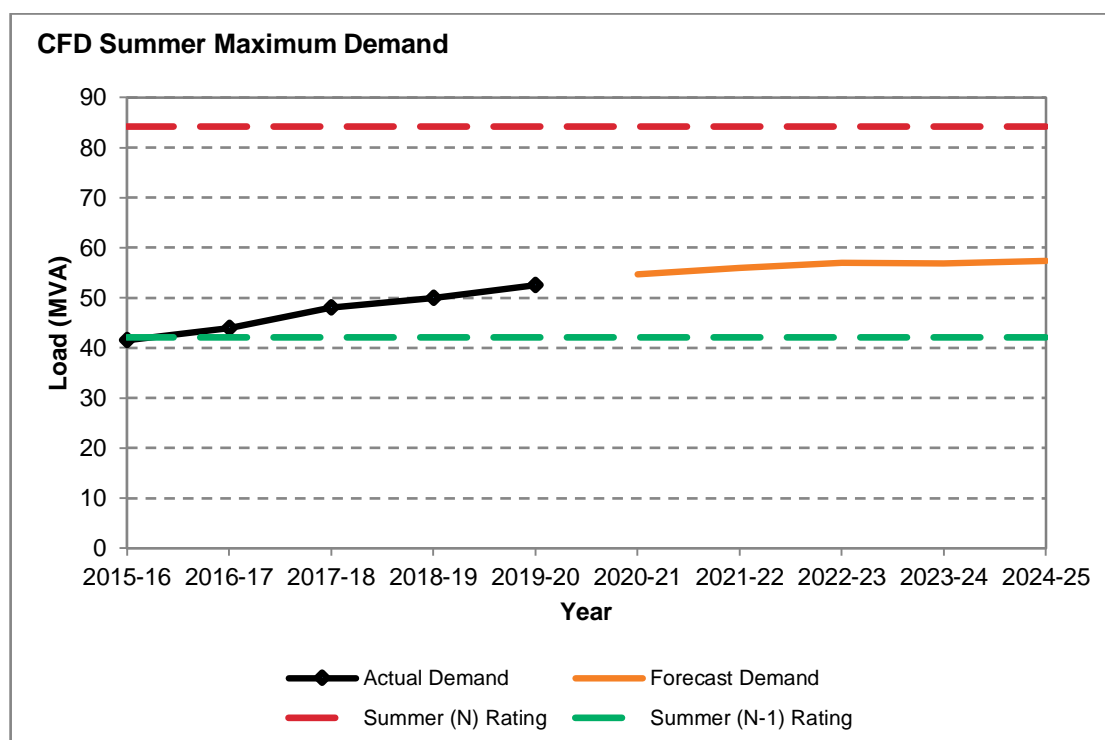
7.2.4 Caulfield (CFD) zone substation

Caulfield (**CFD**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the suburbs of Caulfield, Malvern and Glenhuntly including the Monash University Caulfield Campus precinct.

Currently, the CFD zone substation comprises two 20/33MVA transformers operating at 66/11kV.

The actual maximum demand at CFD for summer 2019/20 was 52.5MVA which was above the N-1 ratings for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.4 Forecast maximum demand for CFD zone substation



United Energy estimates that in the summer of 2020/21 there will be 12.6MVA of load-at-risk if there is a failure of one of the transformers at CFD. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at CFD zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations of Bentleigh (**BT**), Gardiner (**K**), Elsternwick (**EL**), Ormond (**OR**) and East Malvern (**EM**) up to a maximum transfer capacity of 12.2MVA;
- install a third switchboard at adjacent zone substation East Malvern (**EM**) with 3 new distribution feeders to offload some of the load-at-risk at CFD zone substation at an estimated cost of \$7.2 million; or
- establish a new zone substation nearby.

A number of surrounding adjacent zone substations including CFD, EM, Gardiner (**K**) and Ormond (**OR**) and the several feeders in the area are exhibiting load-at-risk. United Energy's preferred network option to address these limitations is to install a new switchboard with three new distribution feeders at the more lightly loaded EM zone substation in 2025 (see section 7.2.9). In the longer term a 3rd transformer will also likely be required at EM zone substation with further offloads of the adjacent zone substations including CFD occurring as load grows over time.

The use of contingency load transfers and/or non-network solutions will be used to mitigate the load-at-risk until this augmentation occurs.

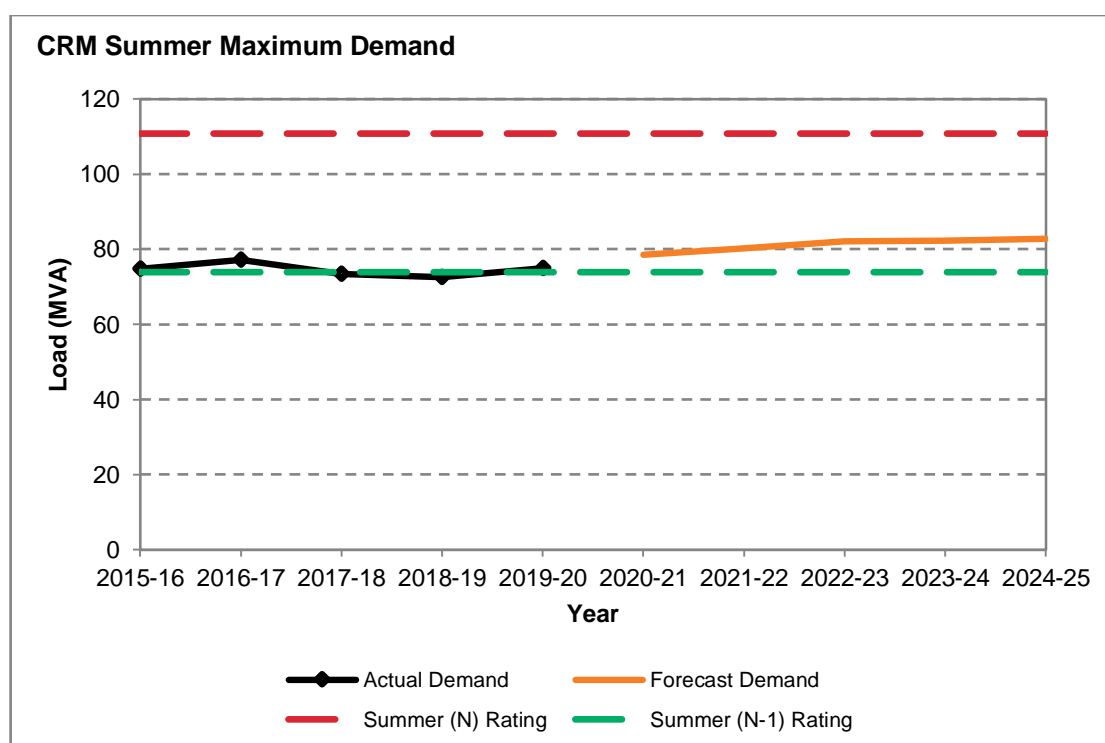
7.2.5 Carrum (CRM) zone substation

Carrum (**CRM**) zone substation is served by sub-transmission lines from the Cranbourne Terminal Station (**CBTS**). It supplies the areas of Bangholme, Carrum, Carrum Downs, Chelsea, Patterson Lakes, Skye and Sandhurst.

Currently, CRM zone substation consists of three 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at CRM for summer 2019/20 was 75.0 MVA, which was above the N-1 ratings for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.5 Forecast maximum demand for CRM zone substation



United Energy estimates that in the summer of 2020/21 there will be 4.7MVA of load-at-risk if there is a failure of a transformer at CRM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at CRM zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations Dandenong Valley (**DVY**), Frankston (**FTN**), and Mordialloc (**MC**) up to a maximum transfer capacity of 14.4MVA;
- install a new 20/33MVA transformer and distribution feeders at an adjacent Frankston zone substation, at an estimated cost of \$6.5 million. This may allow minimal offload of CRM;
- establish a new Skye (**SKE**) zone substation with five new distribution feeders at an estimated cost of \$25M.

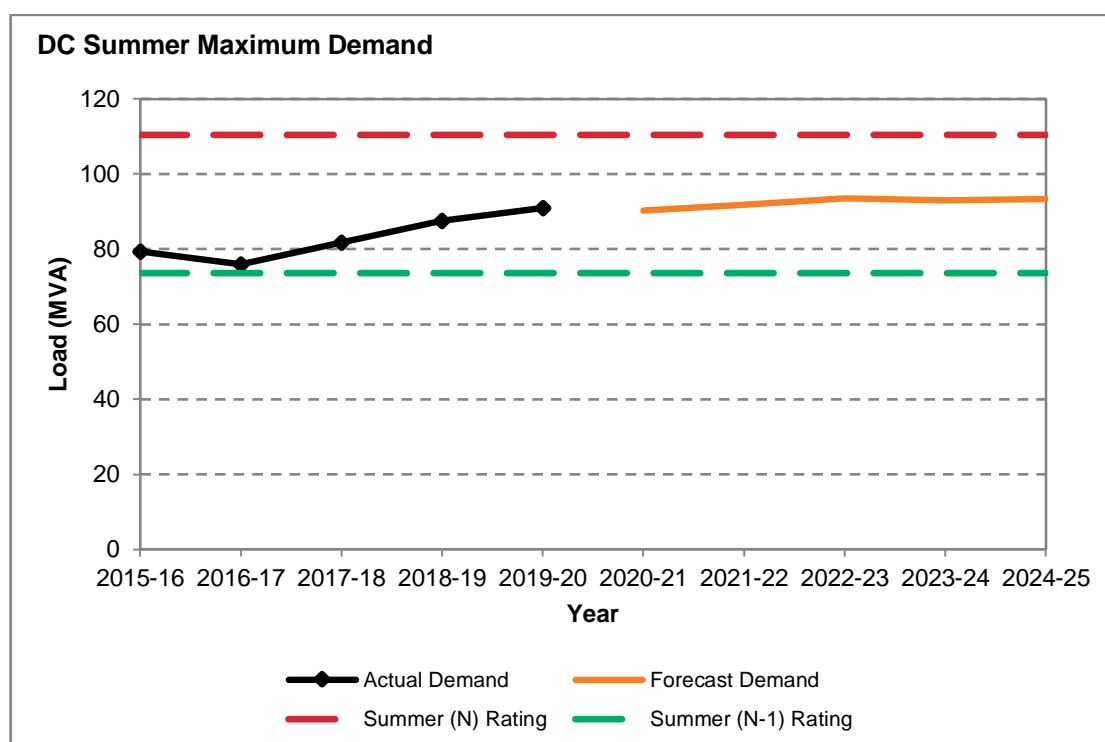
United Energy's preferred network option in the long term is to establish a new SKE zone-substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions will be used to mitigate the load-at-risk in the interim period.

7.2.6 Doncaster (DC) zone substation

Doncaster (**DC**) zone substation is served by sub-transmission lines from the Templestowe Terminal Station (**TSTS**). It supplies the areas of Box Hill North, Doncaster, Doncaster East, Doncaster Hill and The Pines precincts, Templestowe and parts of the Box Hill central precinct.

Currently, the DC zone substation is comprised of two 20/27MVA transformers operating at 66/22kV, and one 20/30MVA transformer operating at 66/22kV.

The actual maximum demand at DC for summer 2019/20 was 91.0MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. Being designated as Principal Activities Centres, the maximum demand in the Doncaster Hill and Box Hill areas is expected to continue to grow steadily over coming years. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.6 Forecast maximum demand at DC zone substation

United Energy estimates that in the summer of 2020/21 there will be 16.7MVA of load-at-risk if there is a failure of one of the transformers at DC. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at DC zone substation. Consequently, an unplanned outage on one of the sub-transmission lines in the TSTS–DC–TSTS sub-transmission loop would also result in an outage of one of the transformers at DC zone substation.

In addition all of the transformers at the zone substation are over 50-years of age with two of the three transformers in poor condition and have been assessed as being very close to end-of-life. United Energy is considering both the replacement and augmentation needs when developing a solution at DC in order to identify the lowest cost holistic solution.

United Energy is currently establishing a new feeder from BH before summer 2020/21, to offload DC and two of its highly loaded feeders, in order to partially address the risk and defer the need for 4th transformer at DC. The impact of this new feeder is presented in the chart above. To address the anticipated system constraint at DC zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Box Hill (BH) and Nunawading (NW) up to a maximum transfer capacity of 14.1MVA;

- install a 20/33MVA fourth transformer and two distribution feeders at DC zone substation before summer 2025/26 at an estimated cost of \$6.2 million. This will also address the replacement limitation since there will be additional capacity at DC zone substation to cope with a transformer failure due to poor condition;
- replace one DC transformer and establish two new feeders out of DC before summer 2024/25. This option will not address the need for a fourth transformer and will lead to higher overall cost.

United Energy's preferred network solution is to install a fourth transformer and two new feeders at DC before summer 2025/26. This option has been assessed as the lowest overall cost. This solution also removes the need to replace a transformer at DC. A RIT-D consultation will likely commence in 2023.

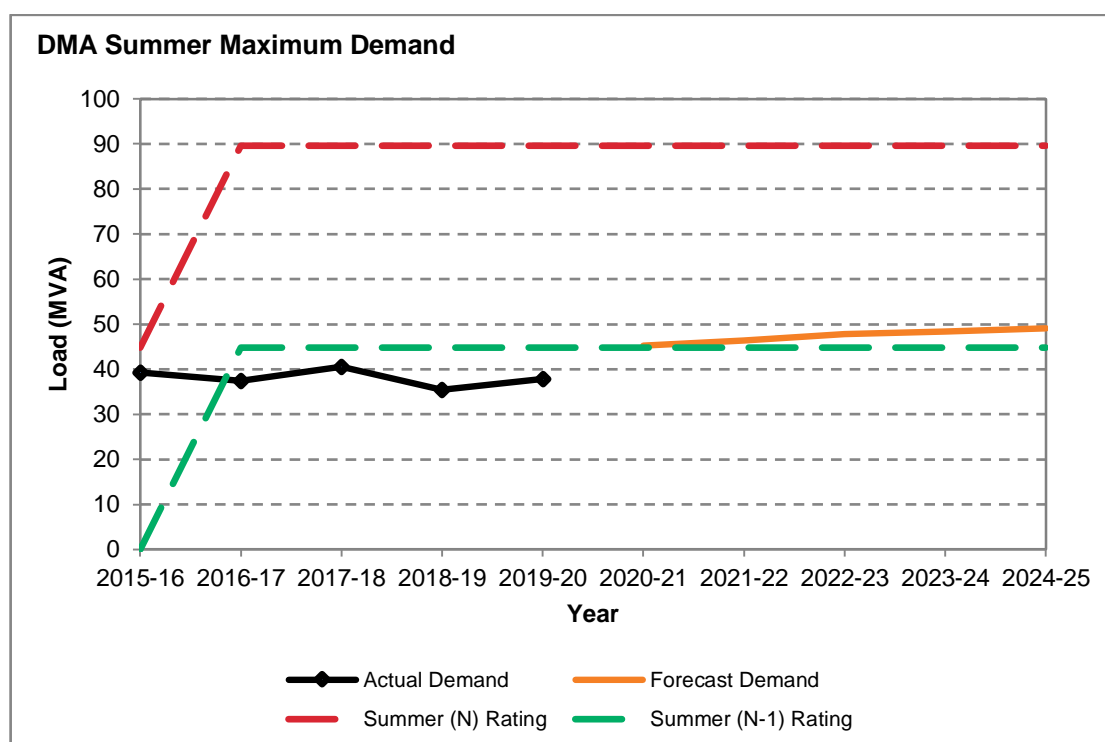
United Energy has already begun engagement with non-network providers to actively seek out demand-side options to potentially enable the deferral of part or all of the preferred network solution in the DC area. In the interim period, United Energy intends to continue to use contingency plans, and/or non-network solutions, will be used to mitigate the load-at-risk.

7.2.7 Dromana (DMA) zone substation

Dromana (**DMA**) zone substation is served by sub-transmission lines from the Tyabb Terminal Station (**TBTS**). It supplies the areas of Dromana, Mount Martha, Red Hill and Shoreham.

Currently, DMA zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at DMA for summer 2019/20 was 37.8 MVA, which was just below the N-1 ratings for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.7 Forecast maximum demand for DMA zone substation

United Energy estimates that in the summer of 2020/21 there will be 0.4MVA of load-at-risk if there is a failure of a transformer at DMA. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at DMA zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations Rosebud (**RBD**) and Mornington (**MTN**) up to a maximum transfer capacity of 21.5MVA;
- install a third 20/33MVA transformer at DMA zone substation at an estimated cost of \$6.5 million;
- establish a new zone substation nearby.

United Energy's preferred network option in the long term is to install a new transformer at the DMA zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions will be used to mitigate the load-at-risk in the interim period.

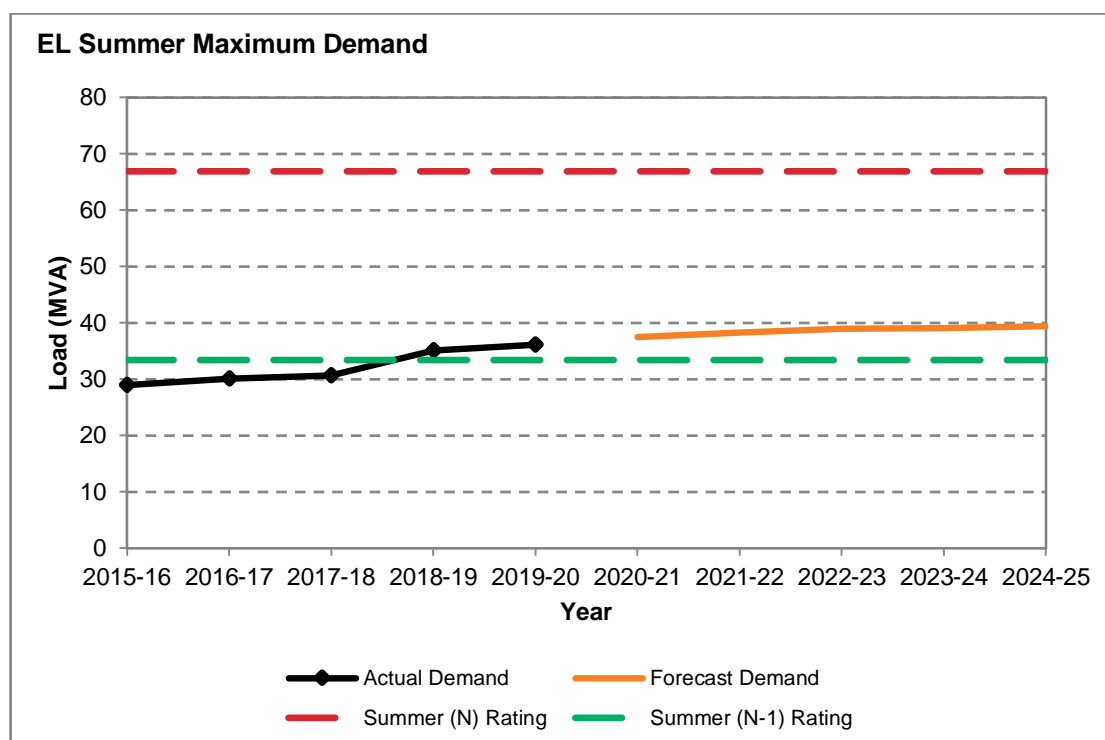
7.2.8 Elsternwick (EL) zone substation

Elsternwick (**EL**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the suburbs of Elsternwick and Caulfield.

Currently, the EL zone substation consists of two 20/27MVA 66/11kV transformers operating at 66/11kV.

The actual maximum demand at EL for summer 2019/20 was 36.1MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For the historic and forecast asset ratings, please refer to the System Limitations Template.

Figure 7.8 Forecast maximum demand for EL zone substation



United Energy estimates that in the summer of 2020/21 there will be 4.1MVA of load-at-risk if there is a failure of one of the transformers at EL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at EL zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into EL would also result in an outage of one of the transformers at EL zone substation.

To address the anticipated system constraint at EL zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Caulfield (**CFD**), Elwood (**EW**) and North Brighton (**NB**) up to a maximum transfer capacity of 7.5MVA;
- install third transformer at adjacent zone substation NB or EW zone substation along with distribution feeders to offload EL,

- Replace the ageing EL transformer No.3 with a modern equivalent which will increase the station rating (note that the other aged EL transformer #2 is to be replaced in 2021 for an estimated cost of \$2.4 million;
- install a third 20/33MVA transformer at EL zone substation at an estimated cost of \$6.5 million;

United Energy's preferred network solution is to replace the aged EL transformer No.3 with modern equivalent (20/33MVA) transformer after the aged EL transformer No.2 is replaced in 2021. However this is not currently expected in the forward planning period for this DAPR. It is anticipated that following the asset replacement of both transformers, the station's summer (N-1) rating will to be adequate to supply the maximum demand at EL zone substation.

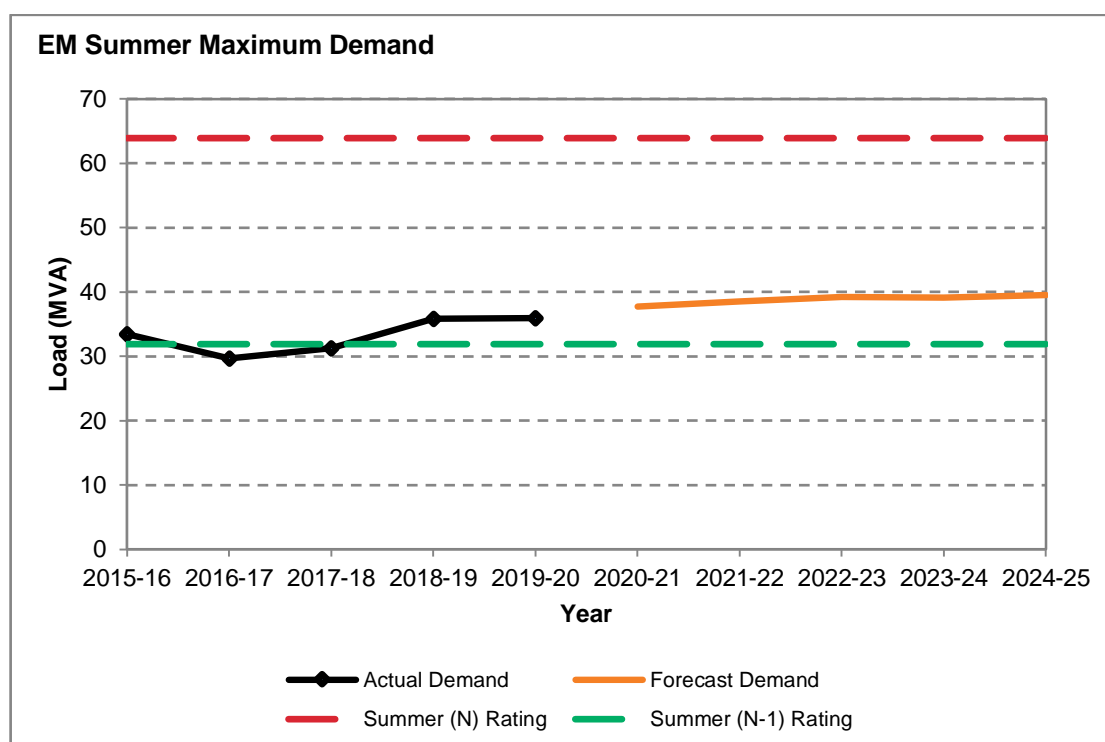
In the interim United Energy will utilise contingency load transfers, and/or non-network solutions, to mitigate the load-at-risk.

7.2.9 East Malvern (EM) zone substation

East Malvern (**EM**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the suburbs of Alamein, Carnegie, Chadstone and East Malvern.

Currently, the EM zone substation consists of two 20/27MVA transformers operating at 66/11kV.

The actual maximum demand at EM for summer 2019/20 was 35.9MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. Being a designated Principal Activities Centre, the demand around the Chadstone area is expected to continue to grow steadily over the coming years. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.9 Forecast maximum demand for EM zone substation

United Energy estimates that in the summer of 2020/21 there will be 5.8MVA of load-at-risk if there is a failure of one of the transformers at EM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at EM zone substation. Consequently, an outage on one of the sub-transmission lines into EM would also result in an outage of one of the transformers at EM zone substation.

It should be noted that a number of surrounding adjacent zone substations including EM, Caulfield (**CFD**), Gardiner (**K**) and Ormond (**OR**) and the associated feeders in the area are exhibiting load-at-risk. There is a combined 30.7MVA of load-at-risk across these stations in 2021 which rises to 40.0MVA by the end of the planning period in 2025. Of these zone-substations EM zone substation currently has the least load-at-risk but is a central point between the growth areas with several feeders approaching their limits.

To address the anticipated system constraints at EM zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Oakleigh (**OAK**) up to a maximum transfer capacity of 5.8MVA;
- install a third switchboard and three new distribution feeders at EM zone-substation before summer 2025/26 at an estimated cost of \$7.2M. This will alleviate several

of the feeder limitations, will offload the more highly loaded CFD and K zone-substations, and provide additional load transfer capacity in the area;

- install a third 20/33MVA transformer at EM zone substation with three new distribution feeders before summer 2026/27;
- install two new distribution feeders from K zone-substation and one new feeder at OR zone-substation to alleviate the feeder constraints in the area before summer 2026/27.

United Energy's preferred network option to address the limitations in the EM, CFD, K and OR areas, is to install a new switchboard with three new distribution feeders at the EM zone substation in 2025. In the longer term a 3rd transformer will also likely be required at EM zone substation with further offloads of the adjacent zone substations occurring as load grows over time. A RIT-D consultation will likely commence in 2023.

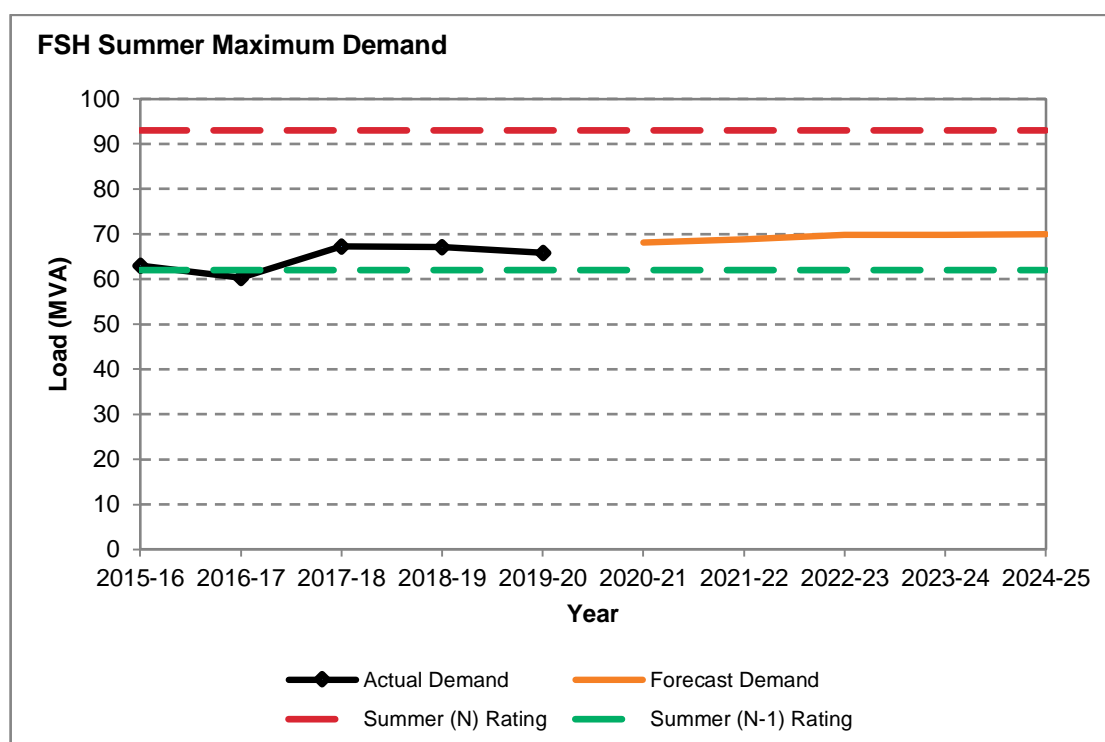
The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period. United Energy invites interested parties to submit their proposal or to engage in joint planning to defer or to avoid the proposed network augmentation.

7.2.10 Frankston South (FSH) zone substation

The Frankston South (**FSH**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Baxter, Frankston, Frankston South, Mount Eliza and Somerville.

Currently, the FSH zone substation comprises one 20/27MVA transformer and two 20/33MVA 66/22kV transformers, all operating at 66/22kV.

The actual maximum demand at FSH for summer 2019/20 was 65.9MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.10 Forecast maximum demand for FSH zone substation

United Energy estimates that in the summer of 2020/21 there will be 6.1MVA of load-at-risk if there is a failure of one of the transformers at FSH. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there is a 66kV sub-transmission line circuit breaker on the Mornington (**MTN**) to FSH sub-transmission line, but not on the TBTS–FSH sub-transmission line. Consequently, an unplanned outage on the TBTS–FSH sub-transmission line would also result in an outage of one of the transformers at FSH zone substation.

To address the anticipated system constraint at FSH zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston (**FTN**), Hastings (**HGS**), Langwarrin (**LWN**) and Mornington (**MTN**), up to a maximum transfer capability of 21.1MVA;
- replace the ageing FSH transformer No.1 with a modern equivalent which will increase the station rating (note that the other aged FSH transformer (No.3) was replaced in 2011) for an estimated cost of \$2.5 million;
- install a new third 66/22kV transformer at adjacent Frankston (**FTN**) zone substation together with long distribution feeders to offload some of the load-at-risk at FSH zone substation;
- establish a new 66/22kV zone substation at Somerville (**SVE**).

United Energy's preferred network solution is to replace the aged FSH transformer No.1 with modern equivalent (20/33MVA) transformer. However this is not currently expected in the forward planning period for this DAPR. It is anticipated that following the asset replacement, the station's summer (N-1) rating will be adequate to supply the maximum demand at FSH zone substation.

The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

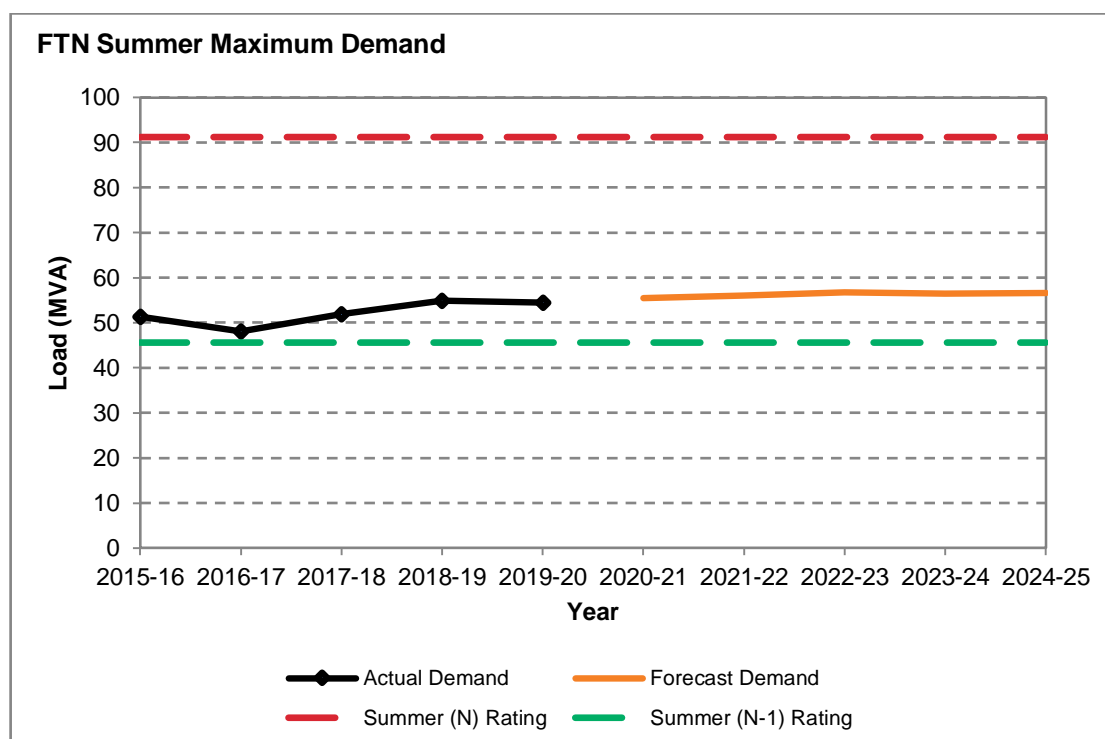
7.2.11 Frankston (FTN) zone substation

The Frankston (FTN) zone substation is served by sub-transmission lines from the Cranbourne terminal station (CBTS). It supplies the areas of Frankston, Frankston North, Seaford and Skye.

Currently, the FTN zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at FTN for summer 2019/20 was 54.5MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.11 Forecast maximum demand for FTN zone substation



United Energy estimates that in the summer of 2020/21 there will be 9.9MVA of load-at-risk if there is a failure of one of the transformers at FTN. That is, it would not be

able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at FTN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Carrum (**CRM**), Frankston South (**FSH**), and Langwarrin (**LWN**) up to a maximum transfer capacity of 17.9MVA;
- install a third 20/33MVA transformer at FTN zone substation at an estimated cost of \$6.7 million;
- establish a new 66/22kV zone substation at Skye (**SKE**) with five new distribution feeders.

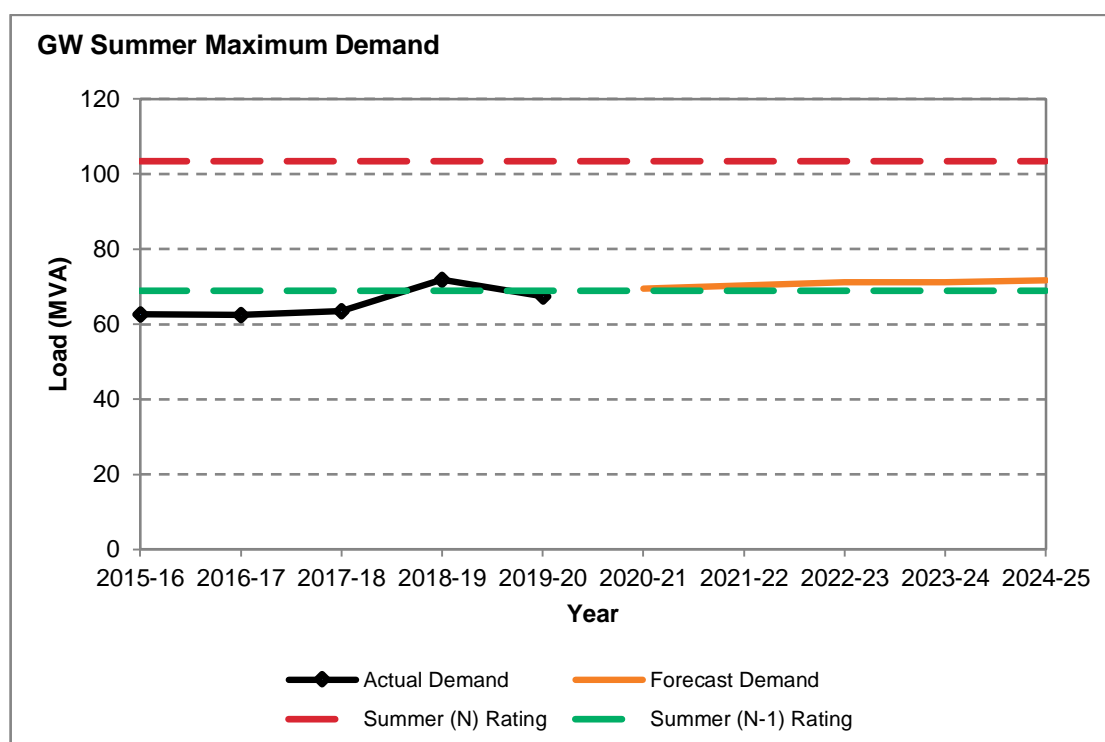
United Energy's preferred network option is to install a new transformer at the FTN zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.2.12 Glen Waverley (GW) zone substation

The Glen Waverley (**GW**) zone substation is served by sub-transmission lines from the Springvale terminal station (**SVTS**). It supplies the areas of Glen Waverley, Mount Waverley and Wantirna South.

Currently, the GW zone substation consists of two 20/27MVA transformers and one 20/33MVA transformer operating at 66/22kV.

The actual maximum demand at GW for summer 2019/20 was 67.5MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.12 Forecast maximum demand for GW zone substation

United Energy estimates that in the summer of 2020/21 there will be 0.6MVA of load-at-risk if there is a failure of one of the transformers at GW. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at GW zone substation. Consequently, an outage on one of the sub-transmission lines into GW would also result in an outage of one of the transformers at GW zone substation.

To address the anticipated system constraint at GW zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of East Burwood (**EB**), Mulgrave (**MGE**) and Notting Hill (**NO**) up to a maximum transfer capacity of 19.1MVA;
- utilise existing and new distribution feeders to permanently transfer load to the adjacent NO zone substation which had a third transformer installed in 2017;
- establish a new 66/22kV zone substation in the Scoresby area with five new distribution feeders at an estimated cost of \$17M.

United Energy's preferred network option is to permanently transfer load to NO via existing and new distribution feeders, and then establish a new zone substation in the Scoresby area at a later date. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

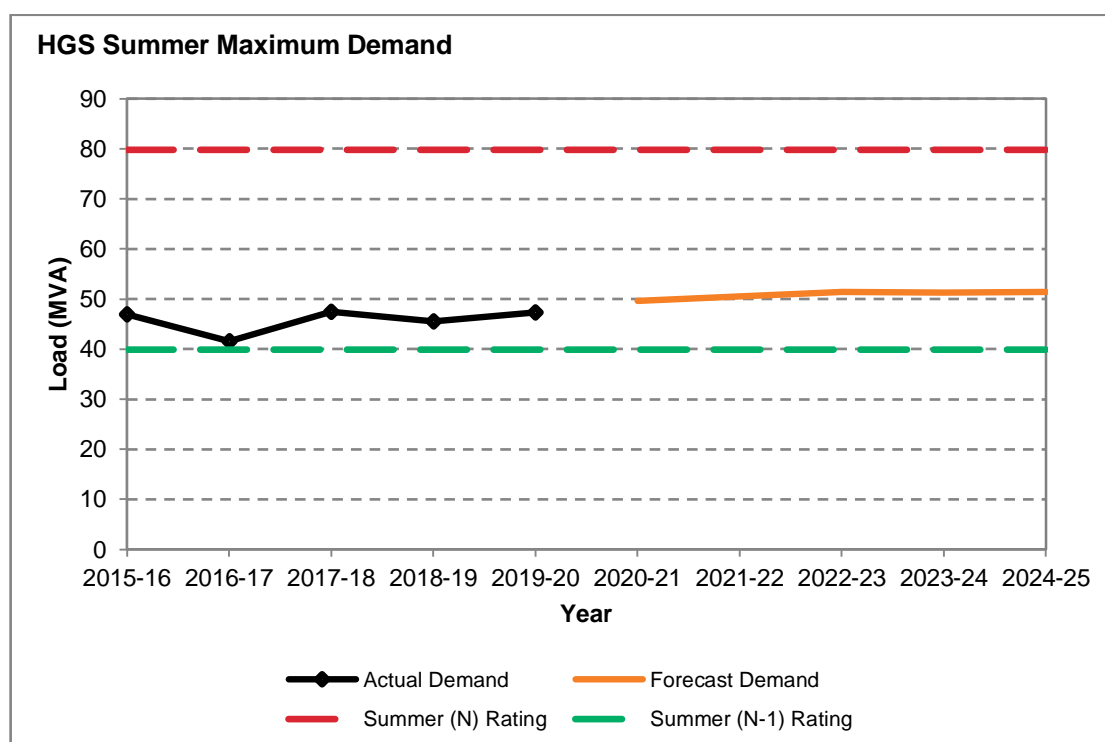
7.2.13 Hastings (HGS) zone substation

Hastings (**HGS**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Hastings, Merricks, Somerville and Tyabb.

Currently, the HGS zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at HGS for summer 2019/20 was 47.4MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.13 Forecast maximum demand for HGS zone substation



United Energy estimates that in the summer of 2020/21 there will be 9.7MVA of load-at-risk if there is a failure of one of the transformers at HGS. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at HGS zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into HGS would also result in an outage of one of the transformers at HGS zone substation.

To address the anticipated system constraint at HGS zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston South (**FSH**), Langwarrin (**LWN**) and Mornington (**MTN**) up to a maximum transfer capacity of 13.7MVA;
- The aged #1 transformer at HGS is planned for replacement in 2024. Post replace the ageing HGS #3 transformer could also be replaced with a modern equivalent which will increase the station rating for an estimated cost of \$2.5 million;
- install a third 20/33MVA transformer at HGS zone substation at an estimated cost of \$6.5 million;
- establish a new zone substation at Somerville (**SVE**).

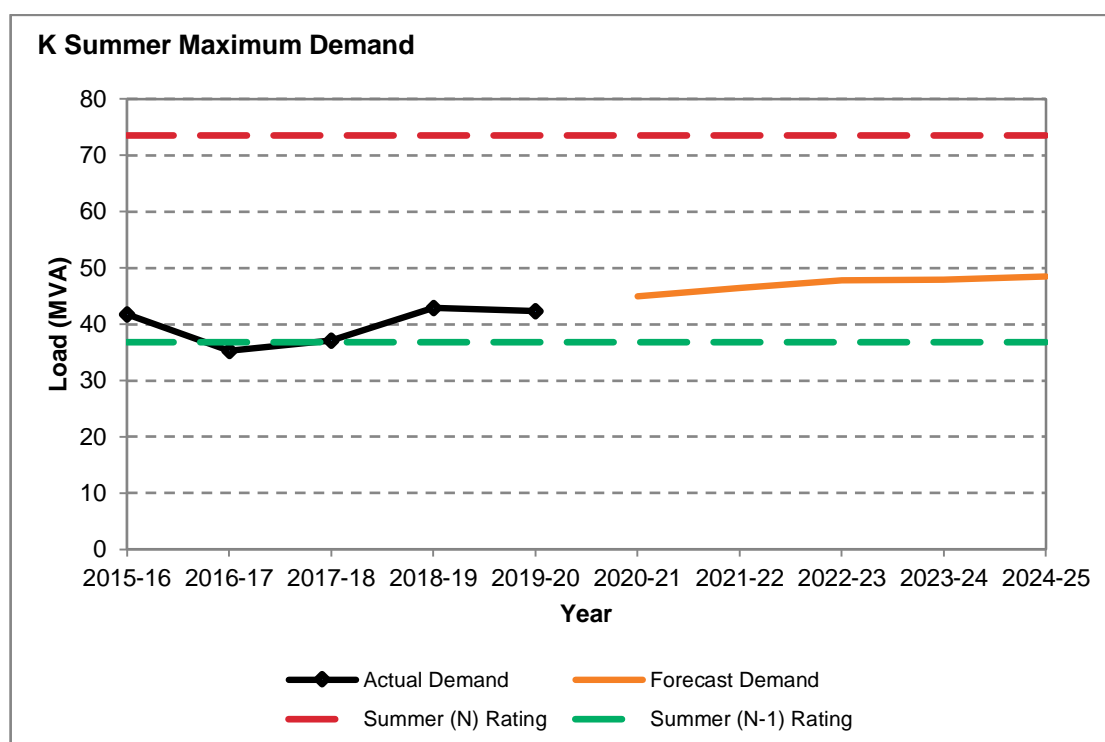
United Energy's preferred network option is to install a third transformer at HGS. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.2.14 Gardiner (K) zone substation

Gardiner (**K**) zone substation is served by sub-transmission lines from the Richmond terminal station (**RTS**). It supplies the areas of Glen Iris and Malvern.

Currently, the K zone substation consists of two 20/30MVA transformers operating at 66/11kV.

The actual maximum demand at K for summer 2019/20 was 42.3MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.14 Forecast maximum demand for K zone substation

United Energy estimates that in the summer of 2020/21 there will be 8.2MVA of load-at-risk if there is a failure of one of the transformers at K. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at K zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into K would also result in an outage of one of the transformers at K zone substation.

To address the anticipated system constraint at K zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations Caulfield (**CFD**), Camberwell (**CL**), Riversdale (**RD**), Armadale (**AR**) and East Malvern (**EM**) up to a maximum transfer capacity of 7.6MVA;
- install a third switchboard at adjacent zone substation East Malvern (**EM**) with 3 new distribution feeders to offload some of the load-at-risk at K zone substation at an estimated cost of \$7.2 million; or
- install a third 20/33MVA 66/11kV transformer at K zone substation;
- establish a new zone substation.

A number of surrounding adjacent zone substations including K, EM, Caulfield (**CFD**) and Ormond (**OR**) and the several feeders in the area are exhibiting load-at-risk. United Energy's preferred network option to address these limitations in the short to medium term is to install a new switchboard with three new distribution feeders at the more lightly loaded EM zone substation in 2025 (see section 7.2.9). In the longer term a 3rd

transformer will also likely be required at EM zone substation with further offloads of the adjacent zone substations including K occurring as load grows over time.

The use of contingency load transfers, and/or non-network solutions, will mitigate the load-at-risk in the interim period.

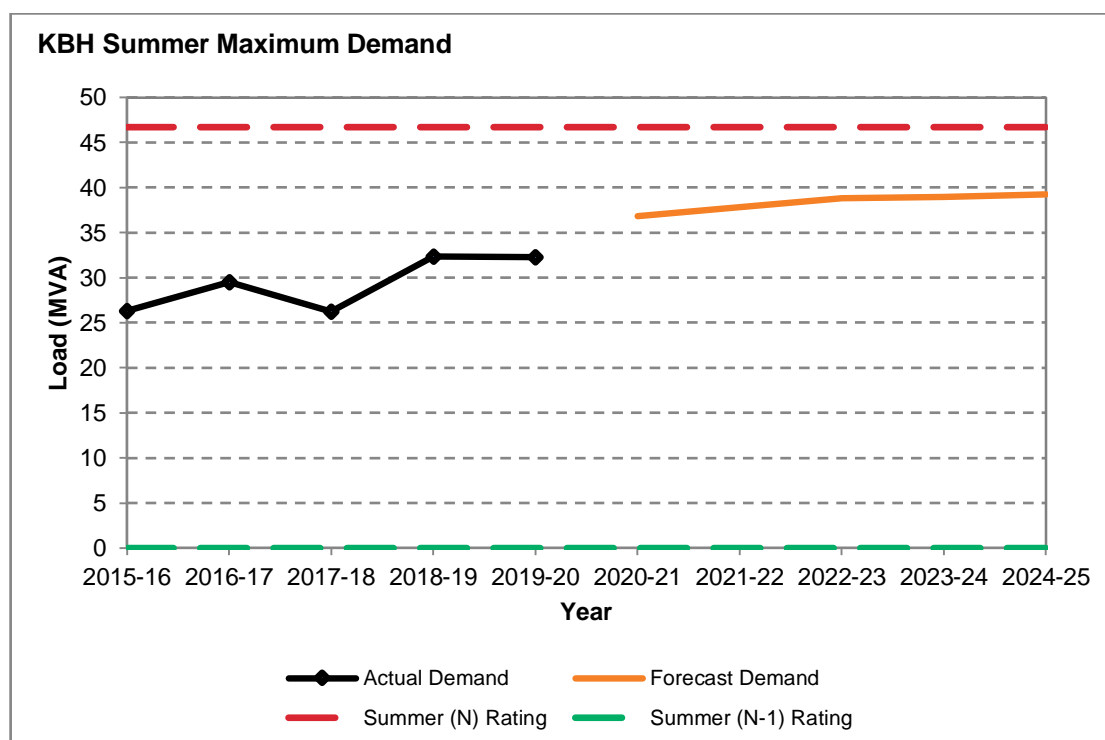
7.2.15 Keysborough (KBH) zone substation

Keysborough (KBH) zone substation is served by sub-transmission lines from the Heatherton terminal station (HTS). It supplies the areas of Dandenong, Keysborough and Noble Park.

Currently, KBH zone substation consists of only one 20/33MVA transformer operating at 66/22kV. United Energy commissioned KBH zone substation in 2014/15 to provide load relief for Dandenong South (DSH), Mordialloc (MC) and Noble Park (NP) zone substations, as well as to improve distribution feeder utilisation and supply reliability in these areas.

The actual maximum demand at KBH for summer 2019/20 was 32.3MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and nameplate ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.15 Forecast maximum demand for KBH zone substation



United Energy estimates that in the summer of 2020/21 there will be 36.9MVA of load-at-risk at KBH.

The (N-1) rating at KBH zone substation is zero because it is a single transformer zone substation. Therefore, customers supply would be normally restored via the distribution feeder network from neighbouring zone substations at Dandenong South (**DSH**), Mordialloc (**MC**) and Noble Park (**NP**), following the loss of the zone substation transformer or other fault resulting in the total loss of supply to KBH.

Whilst the probability of a transformer failure is low, the energy-at-risk resulting from a transformer fault is high, because customers supplied from this substation are exposed to such an event all year round.

To address the anticipated system constraint at KBH zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations Dandenong South (**DSH**), Dandenong (**DN**), Lyndale (**LD**) and Noble Park (**NP**) up to a maximum transfer capacity of 34.0MVA;
- install a second 20/33MVA transformer at KBH zone substation with two new distribution feeders at an estimated cost of \$6.3 million before summer 2024/25.
- establish a new feeder from DSH and re-conductor 1.1km of feeder NP-14 before summer 2023/24 in order to offload KBH. This option addresses only part of the demand at risk at KBH.
- establish a new feeder from DSH before summer 2022/23, followed by a second transformer and one distribution feeder before summer 2026/27.
- re-conductor 1.1km of feeder NP-14 before summer 2021/22, followed by a second transformer and two new distribution feeders before summer 2026/27.

United Energy's preferred network option is to install a new transformer at the KBH zone substation with two new distribution feeders in 2024. It is expected that a RIT-D consultation will likely commence in 2022.

The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.2.16 Langwarrin (LWN) zone substation

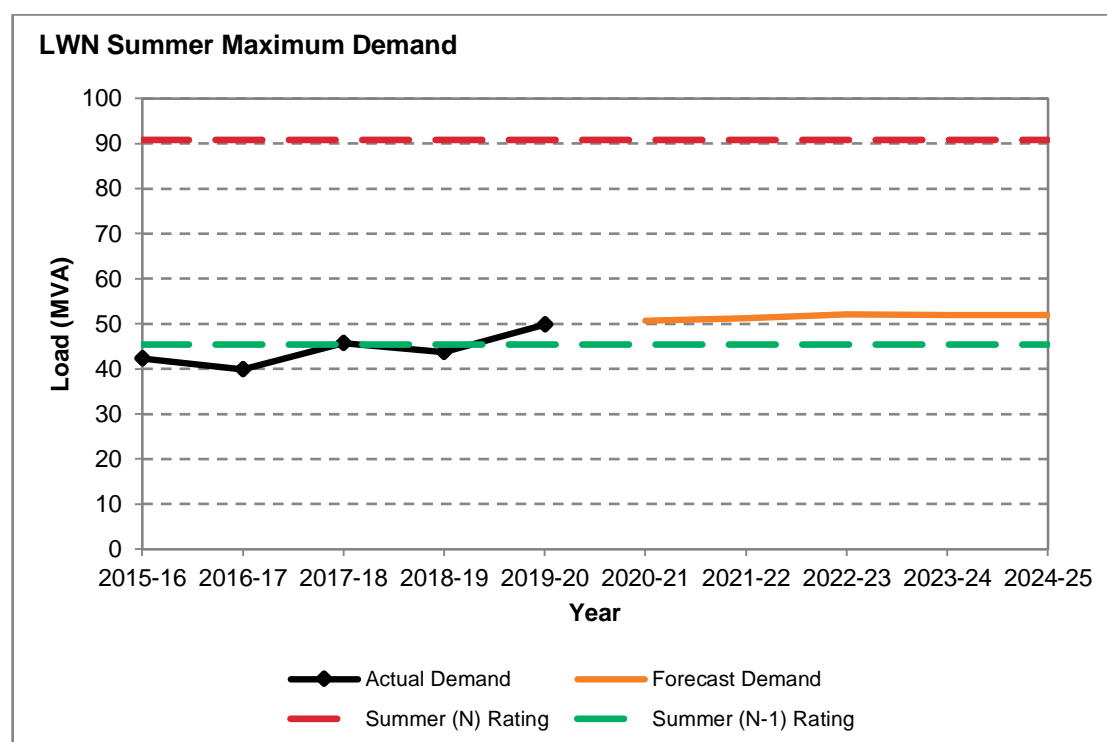
Langwarrin (**LWN**) zone substation is served by sub-transmission lines from the Cranbourne terminal station (**CBTS**). It supplies the areas of Cranbourne South, Langwarrin and Pearcedale.

Currently, the LWN zone substation consists of two 20/33MVA transformers operating at 66/22kV. LWN was commissioned in November 2009 with a second transformer installed in 2014 due to ongoing load growth in the area.

The actual maximum demand at LWN for summer 2019/20 was 49.8MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together

with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.16 Forecast maximum demand for LWN zone substation



United Energy estimates that in the summer of 2020/21 there will be 5.3MVA of load-at-risk if there is a failure of one of the transformers at LWN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at LWN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston South (**FSH**) and Frankston (**FTN**), up to a maximum transfer capacity of 27.3MVA;
- install a third 20/33MVA transformer at LWN zone substation at an estimated cost of \$6.5 million;
- establish a new zone substation.

United Energy's preferred network option is to install a new transformer at the LWN zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

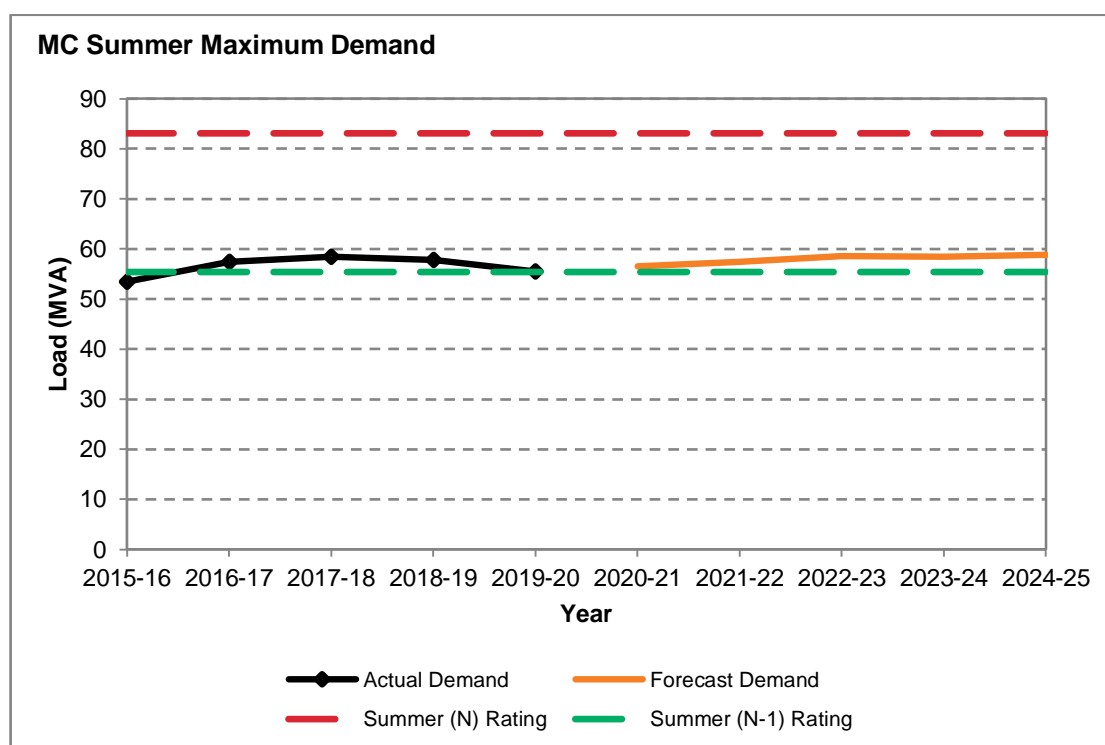
7.2.17 Mordialloc (MC) zone substation

Mordialloc (MC) zone substation is served by sub-transmission lines from the Heatherton terminal station (HTS). It supplies the areas of Aspendale, Braeside, Edithvale and Mordialloc.

Currently, the MC zone substation consists of two 20/27MVA transformers and one 20/33MVA transformer operating at 66/22kV.

The actual maximum demand at MC for summer 2019/20 was 55.5MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.17 Forecast maximum demand for MC zone substation



United Energy estimates that in the summer of 2020/21 there will be 1.2MVA of load-at-risk if there is a failure of one of the transformers at MC. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at MC zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into MC would also result in an outage of one of the transformers at MC zone substation.

To address the anticipated system constraint at MC zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Carrum (**CRM**), Noble Park (**NP**) and Springvale South (**SS**), up to a maximum transfer capacity of 18.7MVA;
- replace the existing two 20/27MVA transformers (manufactured in the late 1950s) with modern equivalent transformers (20/33MVA) due to age and deteriorating condition at an estimated cost of \$6 million;
- establish a new zone substation.

United Energy's preferred network solution is to replace the two 20/27MVA transformers with modern equivalent transformers (20/33MVA) to increase the station rating and defer the need for a new zone-substation. It is likely that this will be a staged replacement, however given the economic cost of the constraint, replacement of either transformer is not currently expected in the forward planning period for this DAPR.

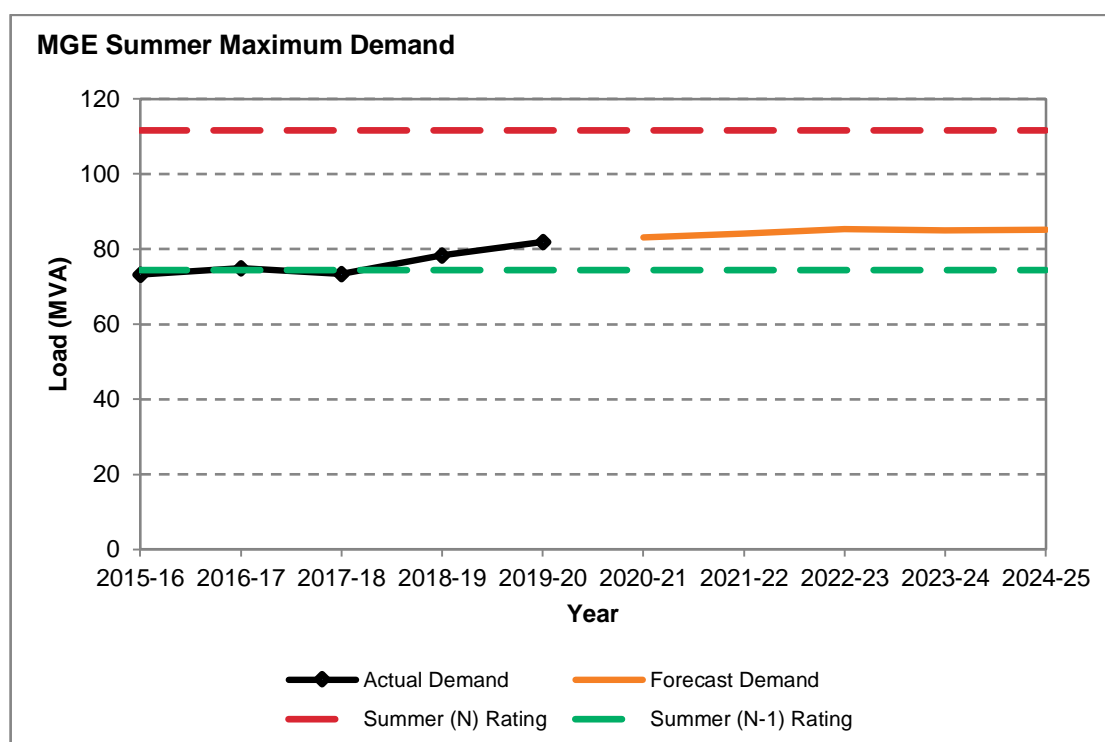
The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.2.18 Mulgrave (MGE) zone substation

Mulgrave (**MGE**) zone substation is served by sub-transmission lines from the Heatherton terminal station (**HTS**). It supplies the areas of Mulgrave, Rowville, Scoresby and Wheelers Hill.

Currently, the MGE zone substation consists of three 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at MGE for summer 2019/20 was 81.9MVA, which was slightly above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.18 Forecast maximum demand for MGE zone substation

United Energy estimates that in the summer of 2020/21 there will be 8.7MVA of load-at-risk if there is a failure of one of the transformers at MGE. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at MGE zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into MGE would also result in an outage of one of the transformers at MGE zone substation.

To address the anticipated system constraint at MGE zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Glen Waverley (**GW**), Lyndale (**LD**) and Springvale West (**SVW**), up to a maximum transfer capacity of 23.2MVA;
- permanently load transfer from MGE zone substation to LD zone substation, where a third transformer was installed in December 2012, at an estimated cost of \$2.0 million by upgrading existing feeders;
- offload parts of MGE onto the AusNet Services' proposed Rowville (**RVE**) zone substation
- establish a new Scoresby (**SCY**) zone substation at an estimated cost of \$17M.

United Energy's preferred network option is to transfer load from MGE to RVE augmenting existing, or establishing new, distribution feeders. However, given the

economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

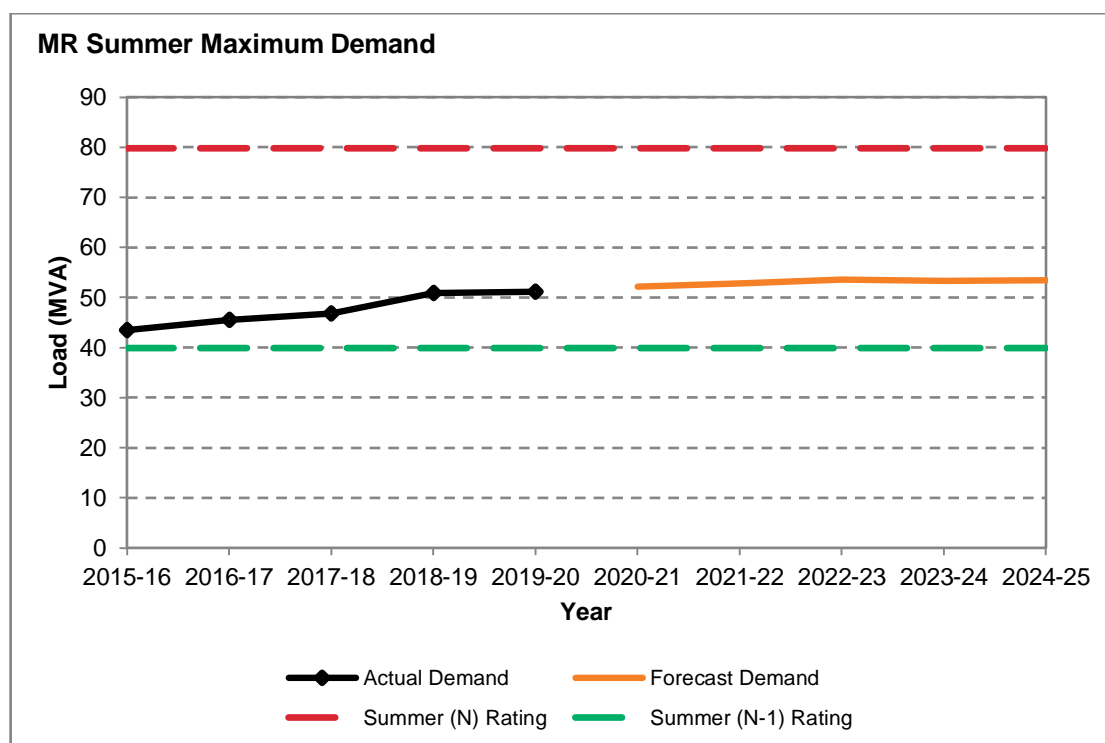
7.2.19 Moorabbin (MR) zone substation

Moorabbin (MR) zone substation is served by sub-transmission lines from the Heatherton terminal station (HTS). It supplies the suburbs of Brighton, Hampton East and Moorabbin.

Currently, the MR zone substation consists of two 20/33MVA transformers operating at 66/11kV.

The actual maximum demand at MR for summer 2019/20 was 51.2MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.19 Forecast maximum demand for MR zone substation



United Energy estimates that in the summer of 2020/21 there will be 12.3MVA of load-at-risk if there is a failure of one of the transformers at MR. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at MR zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations of Sandringham (**SR**), Bentleigh (**BT**), Ormond (**OR**) and North Brighton (**NB**) up to a maximum transfer capacity of 14.0MVA;
- install a third 20/33MVA transformer at MR zone substation for an estimated cost of \$6.7 million.

United Energy's preferred network option is to install a new transformer at the MR zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

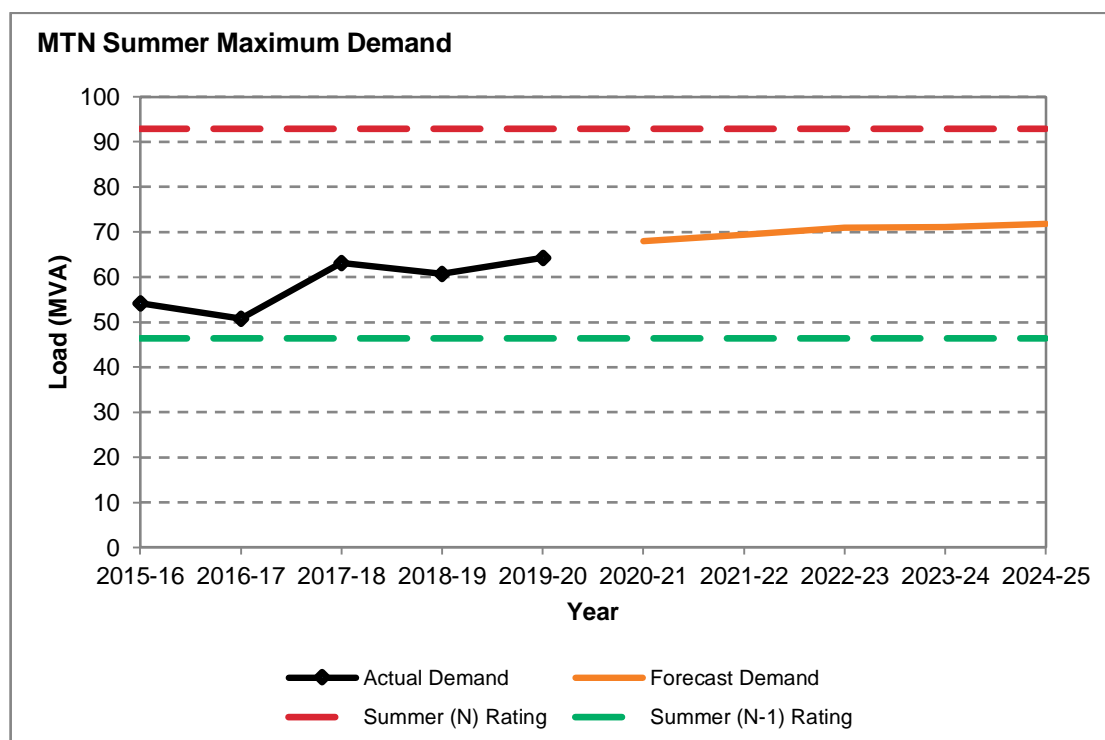
7.2.20 Mornington (MTN) zone substation

Mornington (**MTN**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Merricks North, Moorooduc and Mornington.

Currently, the MTN zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at MTN for summer 2019/20 was 64.3MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.20 Forecast maximum demand for MTN zone substation



United Energy estimates that in the summer of 2020/21 there will be 21.6MVA of load-at-risk if there is a failure of one of the transformers at MTN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at MTN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer away load via the distribution feeder network to adjacent zone substations of Dromana (**DMA**), Frankston South (**FSH**) and Hastings (**HGS**), up to a maximum transfer capacity of 14.9MVA;
- establish a new feeder from MTN before summer 2021/22, to offload two of MTN's highly loaded feeders, in order to partially address the risk in the area and defer the need for 3rd transformer and switchboard at MTN. The estimated cost of this augmentation is \$0.9 million. This project is already committed.

This will allow the deferral of the installation of a 20/33MVA third transformer and switchboard at MTN zone substation with an additional new distribution feeder, to before summer 2026/27 at an estimated cost of \$6.8 million.

- establish a new 20/33MVA third transformer and switchboard at MTN zone substation with two new distribution feeders, before summer 2025/26, at an estimated cost of \$7.6 million;
- Establish a new 22kV feeder from FSH before summer 2023/24, followed by a third transformer and switchboard at MTN zone substation with one new distribution feeder, before summer 2026/27.

United Energy's preferred network option is to install an additional feeder from MTN in 2021, and a subsequent third transformer, switchboard and an additional new distribution feeder at MTN just outside the planning period in 2026. The new feeder from MTN in 2021 is now a committed project and is underway.

The use of contingency load transfers, and/or non-network solutions, will be used mitigate the load-at-risk in the interim period.

7.2.21 North Brighton (NB) zone substation

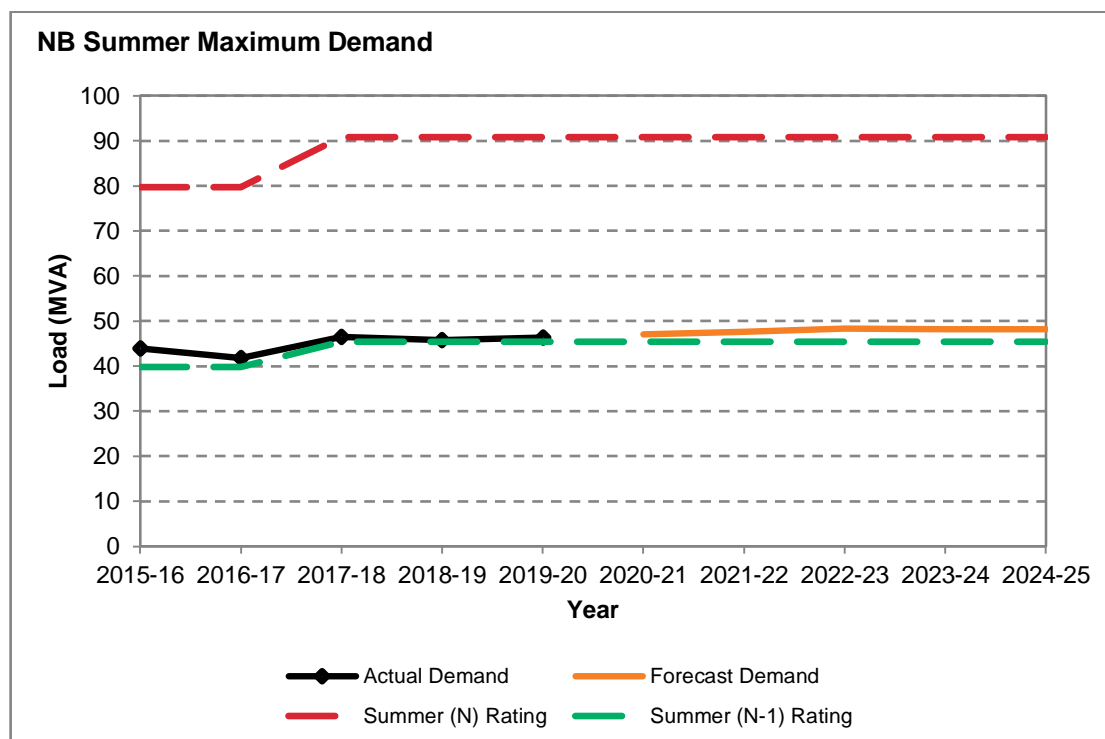
North Brighton (**NB**) zone substation is served by sub-transmission lines from the Heatherton terminal station (**HTS**). It supplies the areas of Brighton and North Brighton.

Currently, the NB zone substation consists of two 20/33MVA transformers operating at 66/11kV.

Due to age and deteriorating condition of this switchboard, United Energy replaced it with modern equivalent before June 2017. Once replaced, the station's summer ratings increased marginally as shown below.

The actual maximum demand at NB for summer 2019/20 was 46.4MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.21 Forecast maximum demand against station ratings for NB zone substation



United Energy estimates that in the summer of 2020/21 there will be 1.7MVA of load-at-risk if there is a failure of one of the transformers at NB. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at NB zone substation. Consequently, a forced outage on one of the sub-transmission lines into NB would also result in an outage of one of the transformers at NB zone substation.

To address the anticipated system constraint at NB zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Bentleigh (**BT**), Elwood (**EW**) and Moorabbin (**MR**) up to a maximum transfer capacity of 9.6MVA;
- permanently load transfer from NB zone substation to MR zone substation, once a third transformer is installed at MR;
- establish a new zone substation at an estimated cost of \$20 million.

United Energy's preferred network option is to perform load transfers to permanently offload NB to MR post the establishment of a 3rd transformer at MR. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

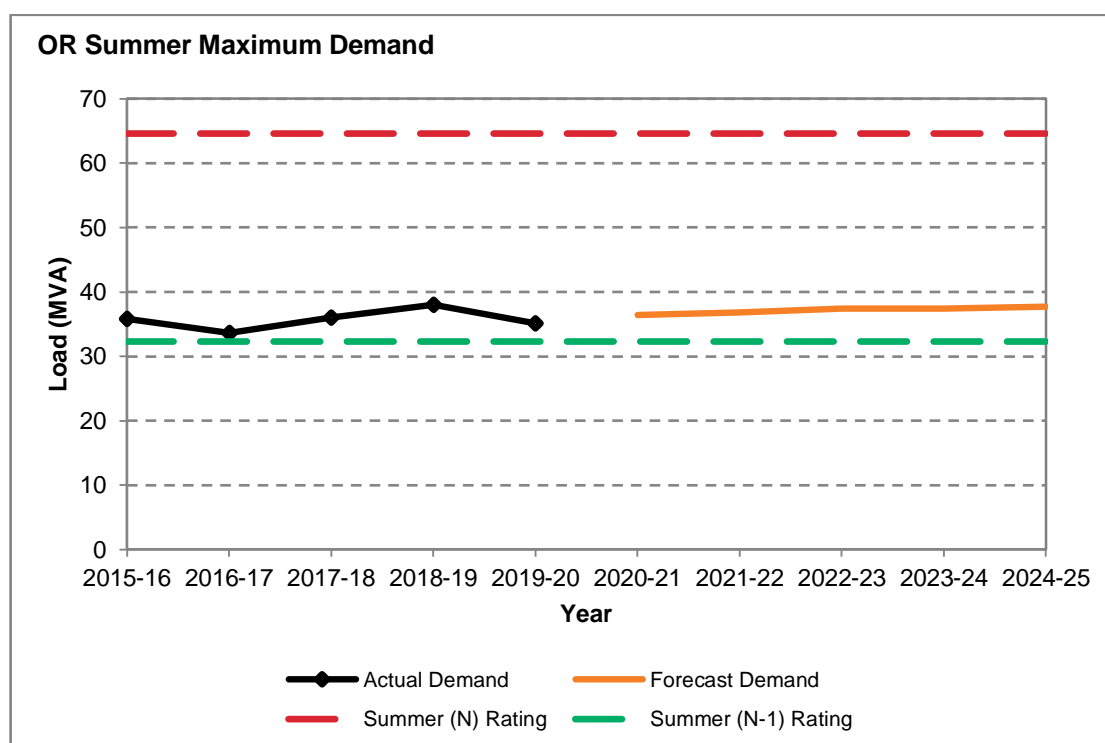
7.2.22 Ormond (OR) zone substation

Ormond (OR) zone substation is served by sub-transmission lines from the Malvern Terminal Station (MTS). It supplies the areas of Bentleigh East, Hughesdale and Murrumbeena.

Currently, the OR zone substation consists of two 20/27MVA transformers operating at 66/11kV.

The actual maximum demand at OR for summer 2019/20 was 35.1MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.22 Forecast maximum demand for OR zone substation



United Energy estimates that in the summer of 2020/21 there will be 4.1MVA of load-at-risk if there is a failure of one of the transformers at OR. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at OR zone substation. Consequently, an unplanned outage on one of the sub-transmission

lines into OR would also result in an outage of one of the transformers at OR zone substation.

To address the anticipated system constraint at OR zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Bentleigh (**BT**), Caulfield (**CFD**), East Malvern (**EM**) and Oakleigh East (**OE**) up to a maximum transfer capability of 5.6MVA;
- install a third switchboard at adjacent zone substation East Malvern (**EM**) with 3 new distribution feeders at an estimated cost of \$7.2 million. This will allow for more feeder transfer capacity in the area and possible permanent offloading of OR through future distribution feeder works; or
- install a third 20/33MVA transformer at OR zone substation at an estimated cost of \$6.5 million.

A number of surrounding adjacent zone substations including OR, EM, Caulfield (**CFD**) and Gardiner (**K**) and the several feeders in the area are exhibiting load-at-risk. United Energy's preferred network option to address these limitations in the short to medium term is to install a new switchboard with three new distribution feeders at the more lightly loaded EM zone substation in 2025 (see section 7.2.9). In the longer term a 3rd transformer will also likely be required at EM zone substation with further offloads of the adjacent zone substations including OR occurring as load grows over time.

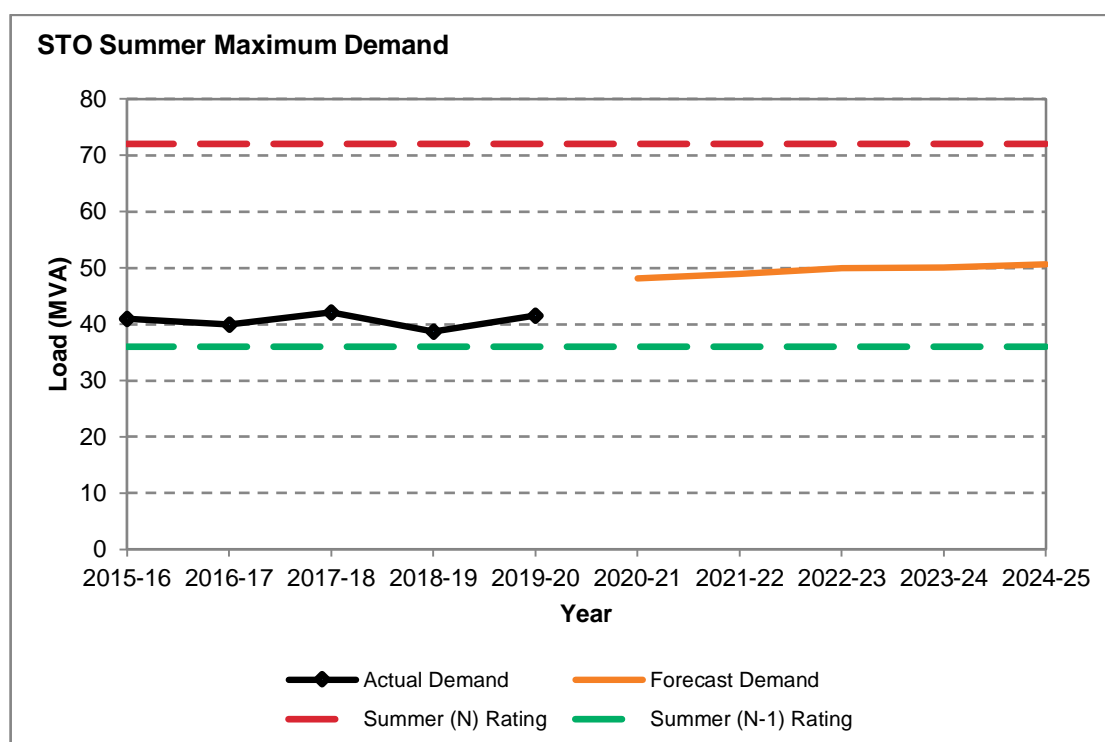
The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.2.23 Sorrento (STO) zone substation

Sorrento (**STO**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Blairgowrie, Portsea, Rye and Sorrento.

Currently, STO zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The maximum demand at STO normally occurs during the Christmas and New Year holiday periods due to increased activities along the tip of the Mornington Peninsula. The actual maximum demand at STO for summer 2019/20 was 41.6MVA, which was above the N-1 rating for the zone substation. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings. For more details please refer to the table in Appendix C or the System Limitations Template.

Figure 7.23 Forecast maximum demand for STO zone substation

United Energy estimates that in the summer of 2020/21 there will be 12.1MVA of load-at-risk if there is a failure of one of the transformers at STO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers or 66kV bus-tie circuit breaker at STO zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into STO would also result in an outage of one of the transformers at STO zone substation.

To address the anticipated system constraint at STO zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Dromana (**DMA**) and Rosebud (**RBD**) up to a maximum transfer capacity of 12.7MVA;
- install a third 20/33MVA transformer at STO zone substation at an estimated cost of \$6.7 million.

United Energy's preferred network option is to install a new transformer at the STO zone substation. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

7.3 Proposed new zone substations

This section sets out United Energy's plans for new zone substations. These substations are not taken into account in the forecasts that have been set out in Appendix C as that only relates to existing substations.

In summary, United Energy does not propose to build any new zone substations during the forward planning period for this DAPR.

8 Sub-transmission loops review

This chapter reviews the sub-transmission loops where further investigation into the balance between capacity and demand over the next five years is warranted, taking into account the:

- forecasts for N-1 maximum demand to 2025; and
- loop ratings for each sub-transmission loop.

Where the sub-transmission loop is forecast to operate with 10 per cent probability of exceedance (**10% PoE**) maximum demands greater than their summer rating under N-1 conditions during 2020/21 and the energy-at-risk is material, or if an augmentation project is planned, then this section assesses the energy-at-risk for those assets.

United Energy sets out possible options to address the system limitations. United Energy may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire load-at-risk at times of maximum demand. At other times of lower load the available transfers may be greater. As a result, the use of load transfers under contingency situations may imply a short interruption of supply for customers to protect network elements from damage and enable all available load transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. Solutions may also address zone substation constraints at the same time.

United Energy notes that all other sub-transmission lines that are not specifically mentioned below either have loadings below the relevant rating or the loading above energy-at-risk the relevant rating results in minimal load-at-risk.

Finally, sub-transmission lines that are proposed to be commissioned during the forward planning period for this DAPR are also discussed.

8.1 Sub-transmission loops with forecast limitations overview

Using the analysis undertaken below in section 8.2, there is an investment need on one sub-transmission loop during the forward planning period for this DAPR. This is known as the Lower Mornington Peninsula project.

As part of this project the construction of a new sub-transmission line from Hastings (HGS) to Rosebud (RBD) zone substations is currently being deferred by a Demand Management solution. United Energy will continue to monitor the demand growth and explore options to potentially extend this solution to deliver further deferment, post 2025, if it is identified as an economically and technically viable alternative. See sections 8.2.5 and 15.2 for further details.

The options and analysis is undertaken in the sections below.

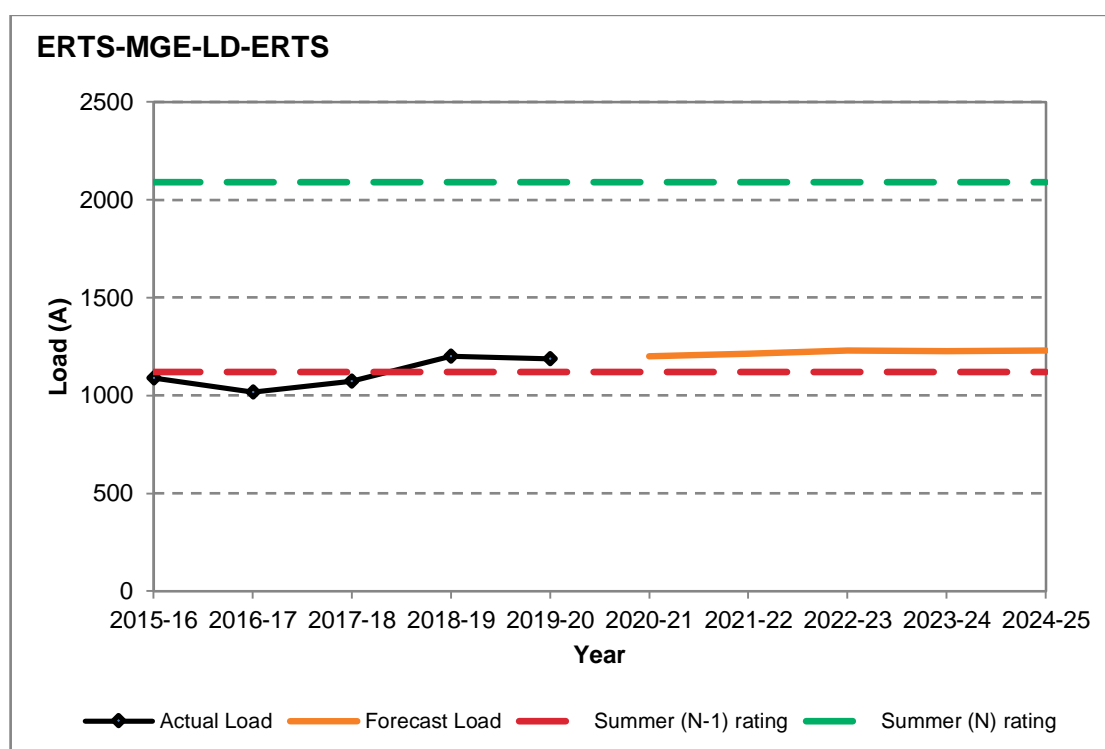
8.2 Sub-transmission lines with forecast system limitations

8.2.1 ERTS-LD-MGE-ERTS

The ERTS-LD-MGE-ERTS sub-transmission system supplies the Lyndale (**LD**) and Mulgrave (**MGE**) zone substations from East Rowville terminal station (**ERTS**) at 66kV.

The actual maximum demand on the ERTS-LD-MGE-ERTS sub-transmission system for summer 2019/20 was 1,186 Amps. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the operational summer (N) and (N-1) ratings.

Figure 8.1 Forecast maximum demand for ERTS-LD-MGE-ERTS system



The figure also shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 9.1MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise:

- on the ERTS-LD sub-transmission line for an outage of the ERTS-MGE sub-transmission line; or
- on the ERTS-MGE sub-transmission line for an outage of the ERTS-LD sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop system, United Energy considers the following network options are technically feasible to manage the load-at-risk:

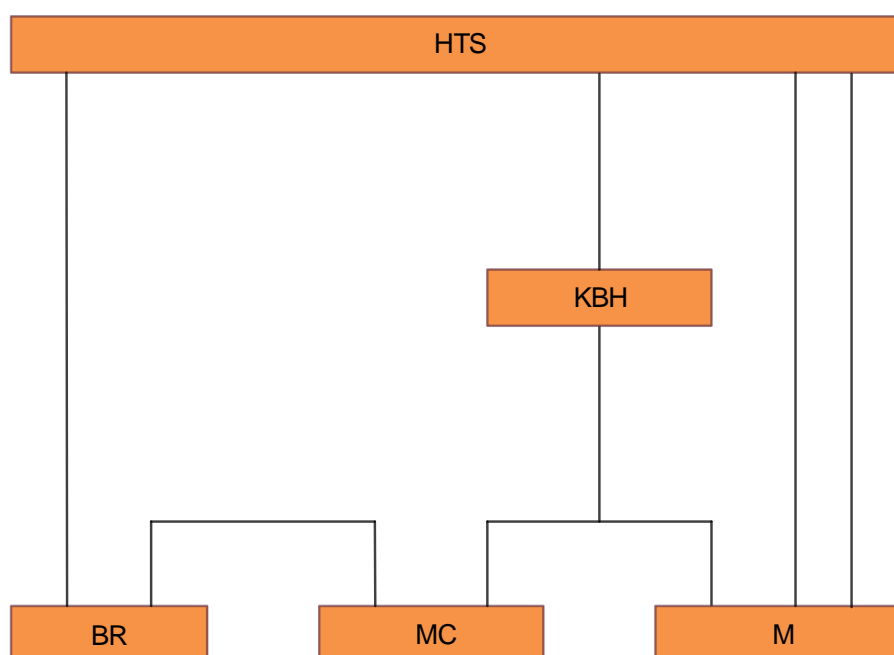
- maintain contingency plans to transfer load to adjacent sub-transmission systems and the use of dynamic line ratings. Transfer capability away from this system is assessed at 40.6MVA for summer 2020/21;
- establish a new 66kV line from ERTS to connect to the existing MGE-LD line at an estimated cost of \$2 million;
- offload parts of MGE and LD onto the AusNet Services' proposed Rowville (**RVE**) zone substation;
- establish a new Scoresby (SCY) zone-substation to offload MGE zone-substation at an estimated cost of \$16 million. The timing of this would depend on the zone-substation risk at MGE and the surrounding zone-substations.

United Energy's preferred network option is to offload MGE and LD to RVE. However, given the economic cost of the constraint, this project is not expected to occur in the forward planning period for this DAPR. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

8.2.2 HTS-BR-KBH-M-MC-HTS

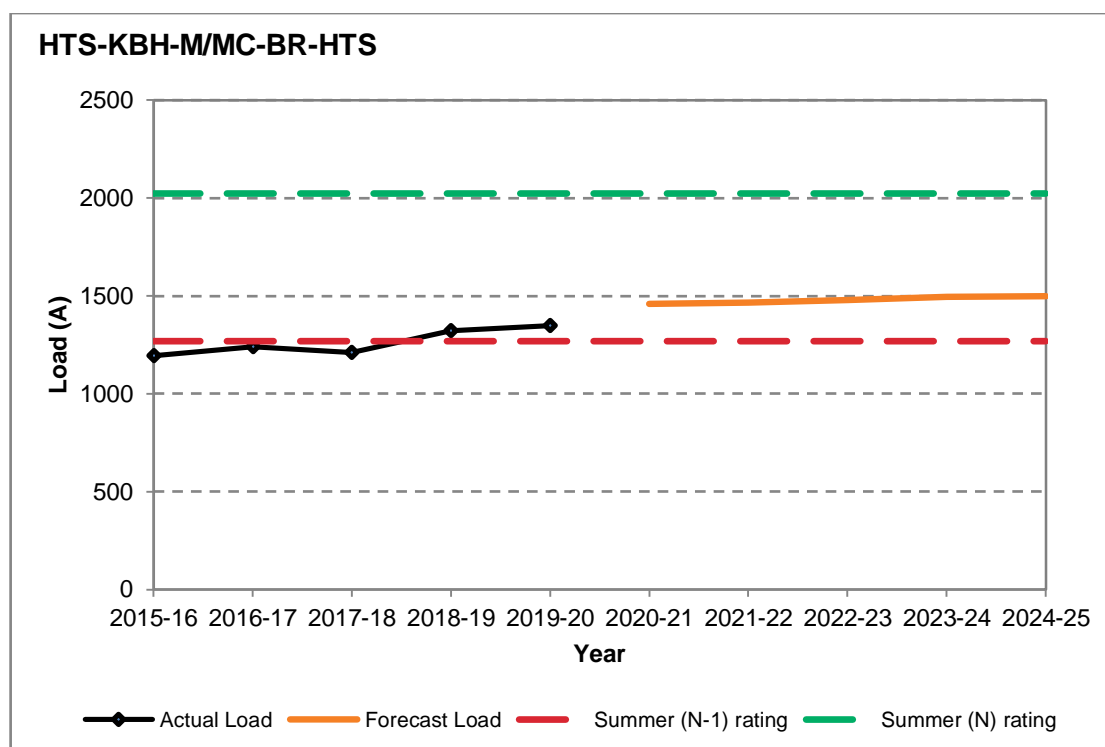
The HTS-BR-KBH-M-MC-HTS sub-transmission system supplies the Beaumaris (**BR**), Keysborough (**KBH**), Mentone (**M**), and Mordialloc (**MC**) zone substations from Heatherton terminal station (**HTS**) at 66kV, as shown below.

Figure 8.2 HTS-BR-KBH-M-MC-HTS sub-transmission system



The actual maximum demand on the HTS-BR-KBH-M-MC-HTS sub-transmission system for summer 2019/20 was 1,350 Amps. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the operational summer (N) and (N-1) ratings.

Figure 8.3 Forecast maximum demand for HTS-BR-KBH-M-MC-HTS system



The figure shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 20.1MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise:

- on the HTS-M No.2 sub-transmission line for an outage of the HTS-M No.1 sub-transmission line;
- on the HTS-BR sub-transmission line for an outage of the KBH-M-MC line; and
- on the KBH-M-MC sub-transmission line for an outage of the HTS-BR sub-transmission line.

To address the anticipated system constraints within this sub-transmission line system, United Energy considers the following network options are technically feasible to manage the load-at-risk:

- maintain contingency plans to transfer load to adjacent sub-transmission systems and the use of dynamic line ratings. Transfer capability away from this system is assessed at 60.9MVA for summer 2020/21;

- upgrade the HTS-M No.2 sub-transmission line at an estimated cost of \$520,000;
- upgrade the KBH-M-MC sub-transmission line at an estimated cost of \$520,000.

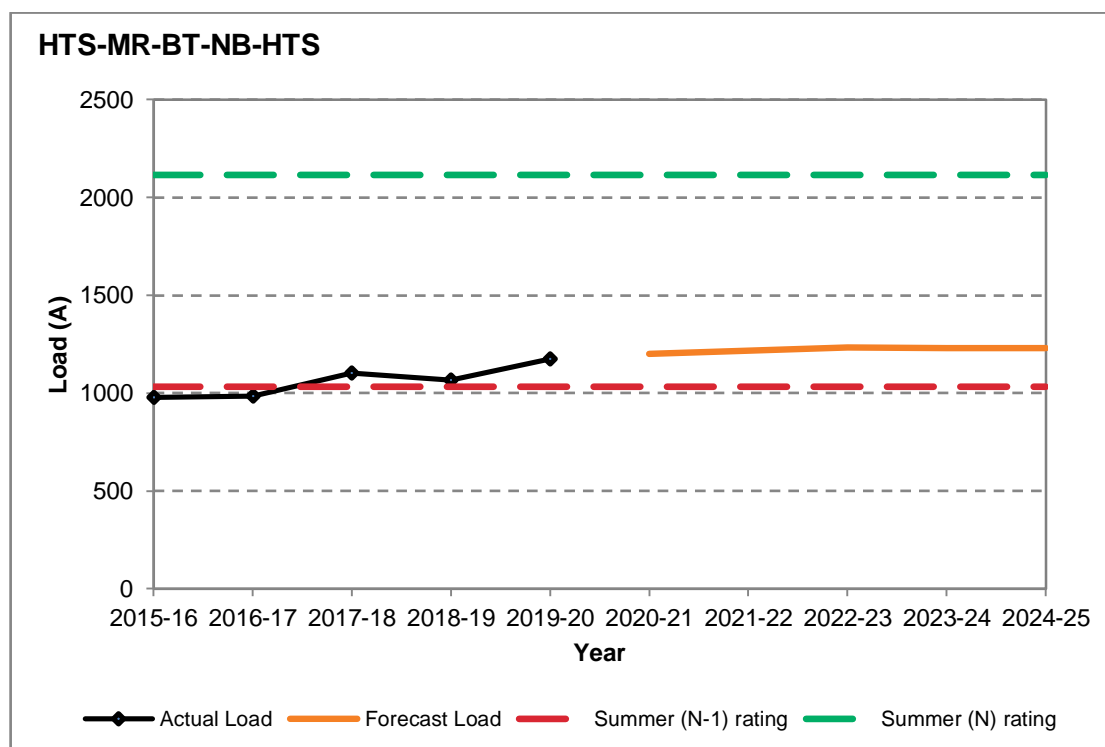
United Energy's preferred network option is to upgrade the KBH-M-MC sub-transmission line which will address the majority of the risk which occurs for the outage of the HTS-BR line. However, given the economic cost of the constraints, this project is not expected to occur in the forward planning period for this DAPR. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

8.2.3 HTS-MR-BT-NB-HTS

The HTS-MR-BT-NB-HTS 66kV sub-transmission loop supplies Moorabbin (**MR**), Bentleigh (**BT**) and North Brighton (**NB**) zone substations from Heatherton terminal station (**HTS**), at 66kV.

The actual maximum demand on the HTS-MR-BT-NB-HTS sub-transmission system for summer 2019/20 was 1176 Amps. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

Figure 8.4 Forecast maximum demand for HTS-MR-BT-NB-HTS system



The figure also shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 19.1MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise:

- Predominantly on the BT-MR sub-transmission line for an outage of the HTS-NB sub-transmission line;
- on the HTS-MR sub-transmission line for an outage of the HTS-NB sub-transmission line.

To address the anticipated system constraints within this sub-transmission line system, United Energy considers the following network options are technically feasible to manage the load-at-risk:

- maintain contingency plans to transfer load to adjacent sub-transmission systems and the use of dynamic line ratings. Transfer capability away from this system is assessed at 10.8MVA for summer 2020/21;
- thermally up-rate approximately 1.3 km of the BT-MR sub-transmission line at an approximate cost of \$500,000.

United Energy's preferred network option is to thermally up-rate the BT-MR sub-transmission line. However, given the economic cost of the constraints, this project is expected to occur just outside the forward planning period for this DAPR. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

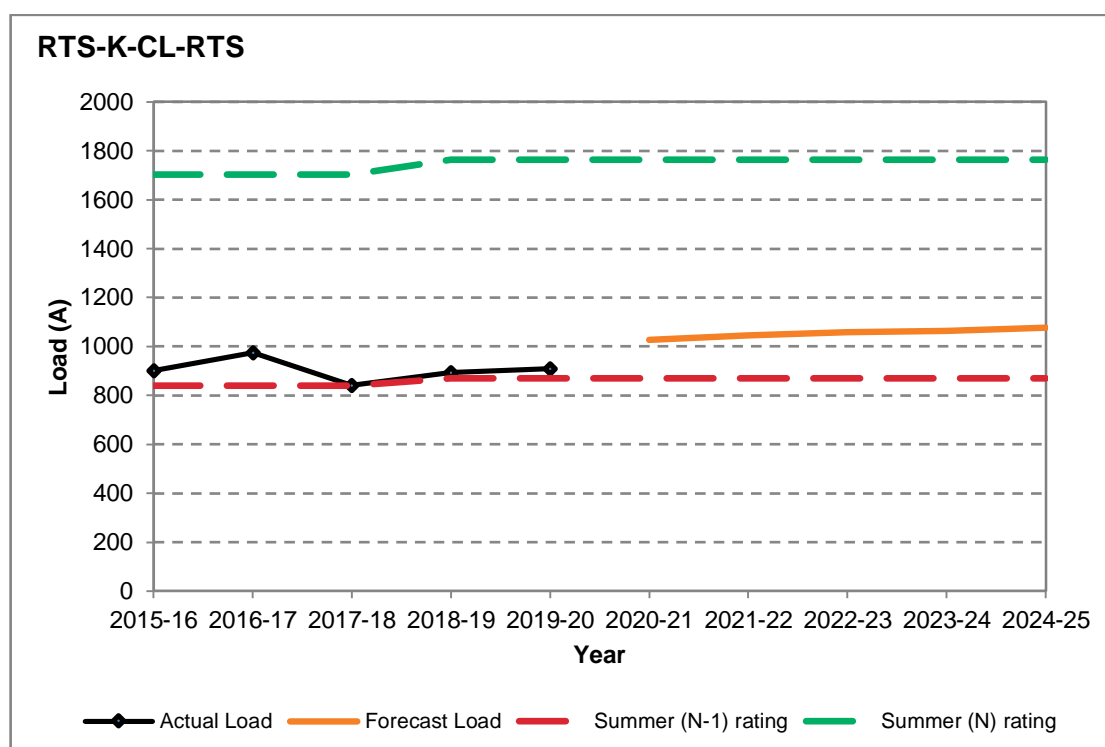
8.2.4 RTS-CL-K-RTS

The RTS-CL-K-RTS sub-transmission loop supplies the Camberwell (**CL**) and Gardiner (**K**) zone substations from Richmond terminal station (**RTS**), at 66kV. CL is a CitiPower zone substation, therefore planning on this system is undertaken jointly with United Energy. The ownership of the 66kV assets in this loop is as follows:

- RTS–K sub-transmission line is owned by United Energy;
- RTS–CL sub-transmission line is owned by CitiPower;
- CL–K sub-transmission line is owned by CitiPower.

The actual maximum demand on the RTS-CL-K-RTS sub-transmission system for summer 2019/20 was 909 Amps, which was above the loop N-1 rating. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

In 2017, AusNet Transmission Group commenced an asset replacement project at RTS to replace the ageing transformers and other plant, to address the limiting station assets. This resulted in a minor rating increase for summer 2018/19 as shown below.

Figure 8.5 Forecast maximum demand for RTS-CL-K-RTS system

The figure also shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 18.1MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the RTS-K sub-transmission line (owned and operated by United Energy) for an outage of the RTS-CL sub-transmission line.

To address the anticipated system constraints within this sub-transmission line system, United Energy considers the following network options are technically feasible to manage the load-at-risk:

- maintain contingency plan to transfer load to adjacent sub-transmission systems and the use of dynamic line ratings. Transfer capability away from K and CL zone substations is assessed at 12.0MVA for summer 2020/21;
- permanent offload of sub K or CL to adjacent substations, which may require the establishment of new distribution feeder ties. UE intends to offload K to EM as part of the EM 3rd switchboard and three new distribution feeders project planned in 2025;
- upgrade the RTS-K sub-transmission line at an estimated cost of over \$3 million or establish a new sub-transmission line to supply the loop.

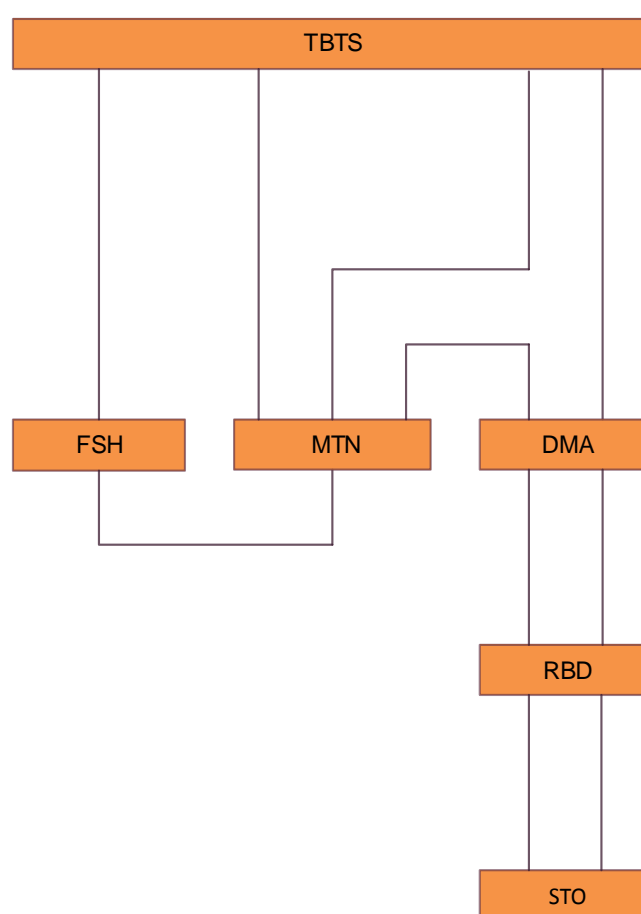
United Energy's preferred network option is to offload K as part of the EM 3rd switchboard and three new distribution feeders project planned in 2025. However,

given the economic cost of the constraints, this project is not expected to occur in the forward planning period for this DAPR. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems, and/or non-network solutions, will mitigate the load-at-risk in the interim period.

8.2.5 TBTS-DMA-FSH-MTN-TBTS

The TBTS-FSH-MTN-TBTS sub-transmission system supplies the Dromana (**DMA**), Frankston South (**FSH**) and Mornington (**MTN**) zone substations from Tyabb terminal station (**HTS**) at 66kV. Rosebud (**RBD**) and Sorrento (**STO**) zone substations are connected to DMA as a secondary system, and are supplied through the TBTS-DMA-MTN sub-transmission system as shown below.

Figure 8.6 TBTS-DMA-FSH-MTN-TBTS sub-transmission system



Prior to 2014, TBTS-FSH-MTN-TBTS and TBTS-DMA-TBTS were two independent sub-transmission systems. United Energy combined these systems to form the new TBTS-DMA-FSH-MTN-TBTS sub-transmission system to optimise the sub-transmission capacity utilisation in the Mornington Peninsula. However, capacity and voltage limitations remain on this system.

Given the multiple supply routes and voltage limitations in this system, the risk assessment for this system is more complicated compared with other sub-transmission

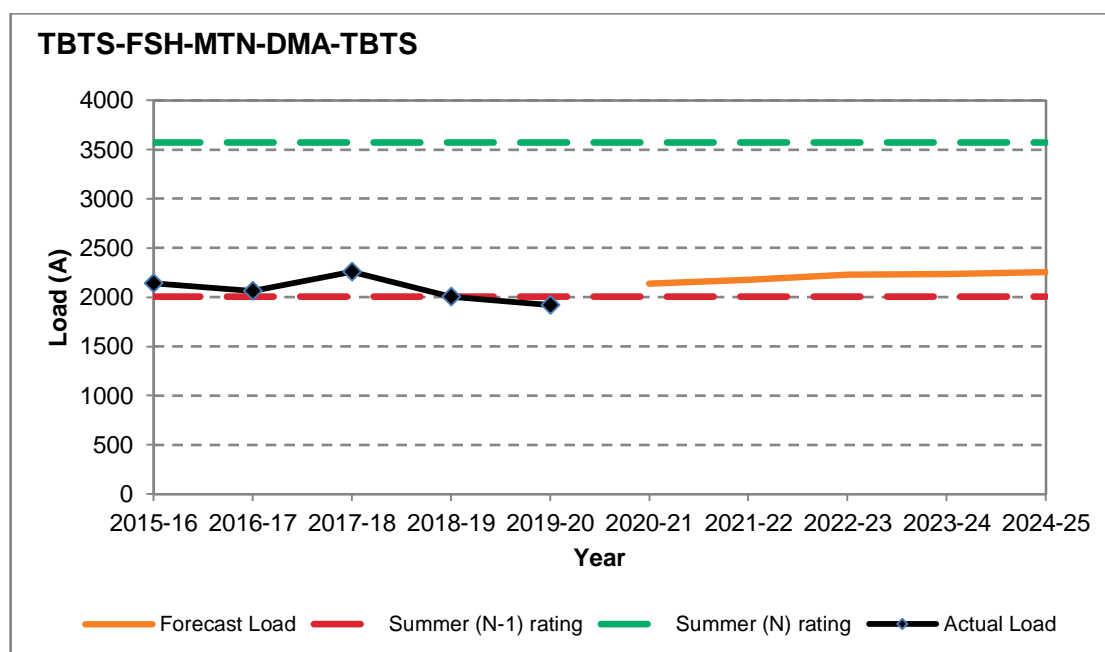
systems. Therefore, load flow results are used to undertake the risk assessment. The analysis is broken down as follows:

- TBTS-DMA-FSH-MTN-TBTS system capacity limitation;
- TBTS-DMA-MTN system capacity limitation;
- DMA-RBD-DMA system capacity limitation;
- RBD-STO-RBD system capacity limitation; and
- voltage collapse limitation in the lower Mornington Peninsula.

TBTS-DMA-FSH-MTN-TBTS

The actual maximum demand on the TBTS-DMA-FSH-MTN-TBTS sub-transmission system for summer 2019/20 was 1,920 Amps, which was just below the loop N-1 rating. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

Figure 8.7 Forecast maximum demand for TBTS-DMA-FSH-MTN-TBTS system



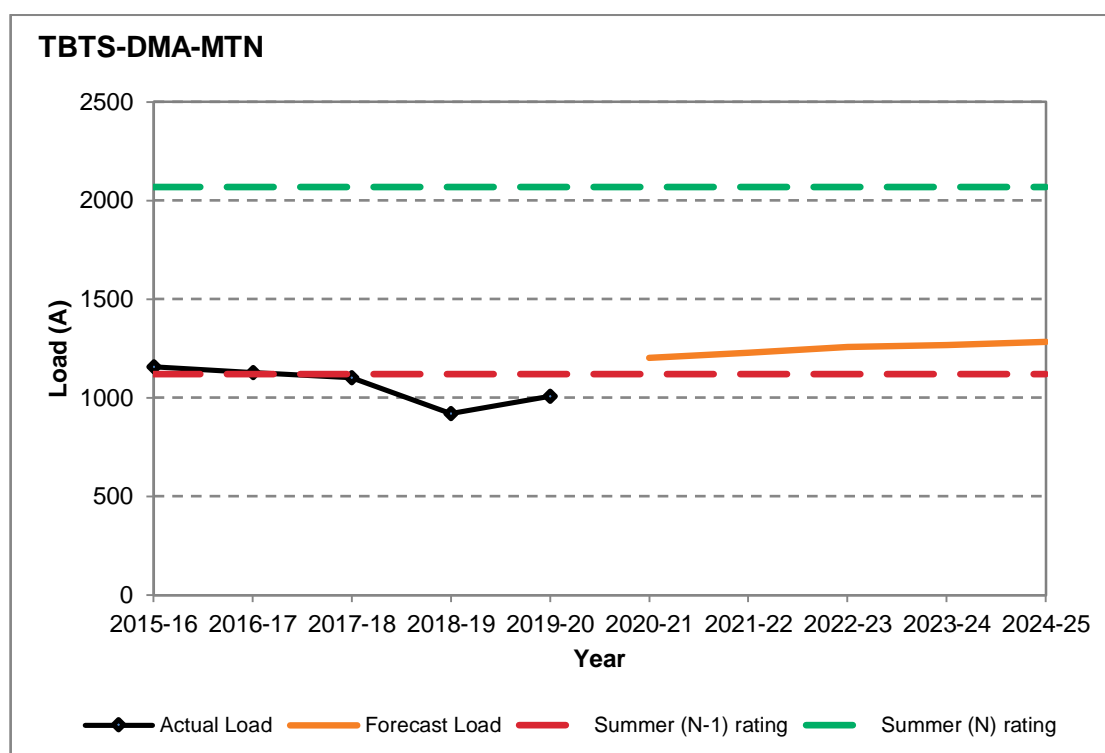
The figure shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 15.3MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the TBTS-MTN No.1 sub-transmission line for an outage of the TBTS-DMA sub-transmission line.

TBTS-DMA-MTN

This is a subset of the main TBTS-DMA-FSH-MTN-TBTS sub-transmission system. The actual maximum demand on the TBTS-DMA-MTN sub-transmission system for summer 2019/20 was 1,008 Amps. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

Figure 8.8 Forecast maximum demand for TBTS-DMA-MTN system



The figure shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 9.3MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the TBTS-DMA sub-transmission line for an outage of the MTN-DMA sub-transmission line, or vice versa.

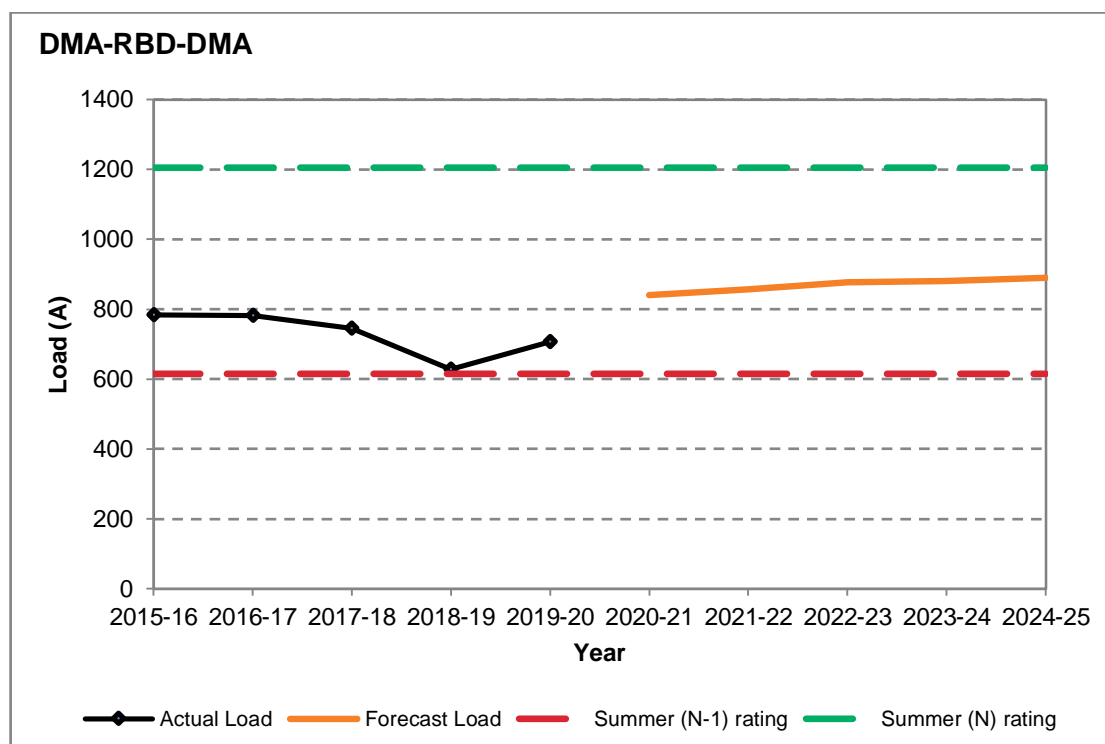
DMA-RBD-DMA

The DMA-RBD-DMA sub-transmission system supplies Rosebud (**RBD**) zone substation from Dromana (DMA) zone substation, at 66kV. The sub loop from RBD to Sorrento (**STO**) zone substation is separately assessed and currently has no energy-at-risk.

The actual maximum demand on the DMA-RBD-DMA sub-transmission system for summer 2019/20 was 706 Amps, which was above the loop N-1 rating. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum

demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

Figure 8.9 Forecast maximum demand for DMA-RBD-DMA system



The figure shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2020/21 there will be 25.8MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the DMA-RBD No.1 sub-transmission line for an outage of the DMA-RBD No.2 sub-transmission line, or vice versa.

Voltage collapse

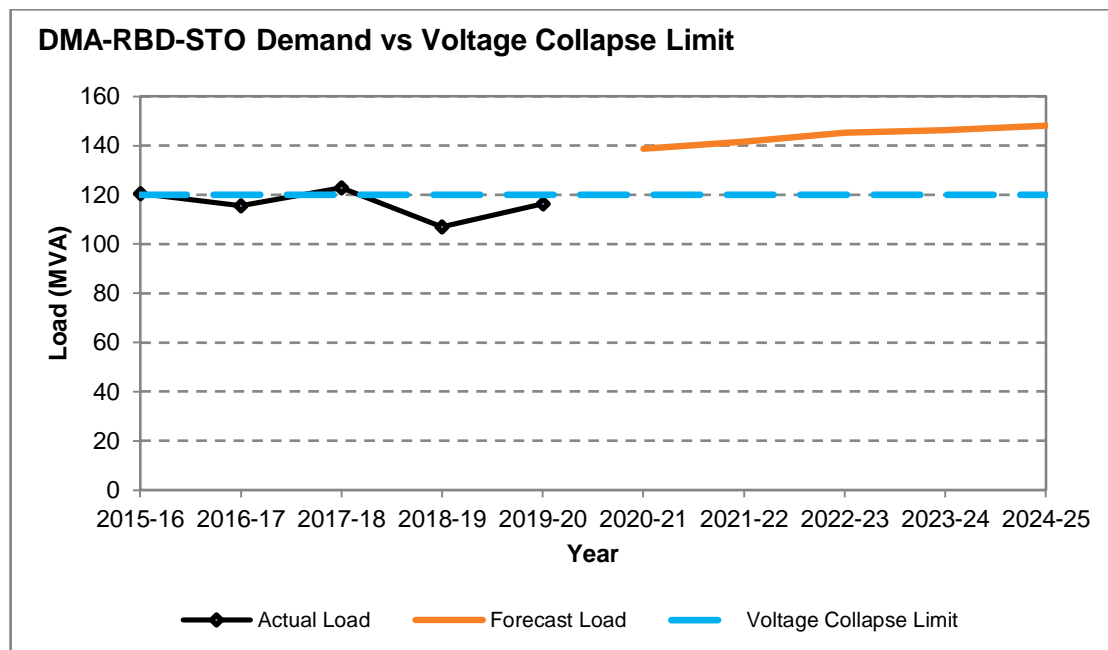
United Energy has also identified a risk of voltage collapse in the lower part of the Mornington Peninsula should an unplanned outage of either the MTN-DMA or the TBTS-DMA sub-transmission line occur during maximum demand periods, with the former being the more severe condition. Given the relatively long sub-transmission lines extending to STO from TBTS (approximately 59km), the voltage collapse limitation is considered to be prominent over the thermal capacity limitation.

United Energy already has installed capacitor banks at STO and RBD zone substations to provide reactive power compensation for the load. Although DMA zone substation is not equipped with any capacitor banks, the station also operates near unity power factor due to the use of pole-mounted capacitor banks within the 22kV distribution network.

The effectiveness of these devices together with the on-load tap changers (of zone substation transformers) to maintain voltage levels within acceptable levels is diminishing rapidly in the event of loss of one of the sub-transmission lines to DMA zone substation during maximum demand conditions because of the magnitude of the losses along the sub-transmission lines.

United Energy has identified that a DMA-RBD-STO load of 120MVA or greater, together with an unplanned outage of the MTN-DMA sub-transmission line, will likely cause voltage collapse of the loop. This is shown in the figure below.

Figure 8.10 Forecast voltage collapse limit for DMA-RBD-STO system



Therefore, pre-contingent load curtailment may be required to maintain regulatory compliance with respect to voltage. The impact of this increases as demand increases over the forward planning period for this DAPR.

Overall assessment

In May 2016, United Energy published a Final Project Assessment Report (**FPAR**) for the Lower Mornington Peninsula, which was the final stage in the Regulatory Investment Test for Distribution (**RIT-D**) process. The RIT-D assessment recommended a technically feasible and economic solution to mitigate the system constraints in the Mornington Peninsula sub-transmission network. The preferred solution was a combination of network and non-network options, namely:

- use of GreenSync's four year non-network solution which commenced in summer 2018/19 at an estimated cost of \$3.7 million,
- followed by the construction of a new sub-transmission line from Hastings (HGS) to RBD zone substations at an estimated cost of \$29.5 million (2015-16 dollars).

In 2020, after two years of support there became a need to renegotiate the final two years of the demand management agreement. United Energy was also looking at options to extend the solution to further defer the capex in light of reduced and uncertain peak demand growth going forward.

Therefore United Energy issued a new request for non-network proposals (via its demand side engagement register) to test the market for offers and determine the most economical solution going forward via a market benefit test. Three non-network options were received as part of this proposal from parties Aggreko, ENEL X and Starling Energy.

The market test demonstrated that ongoing demand management continues to be the most efficient solution. The preferred and most economic option was a for combined solution which included:

- 11MW of demand side generation hire from Aggreko from summer 2020/21 – to 2024/25; and
- 2MW of demand response from summer 2021/22 to 2024/25.

The total cost of the solution is estimated at \$4.3M across the 5 years. United Energy has committed to this solution with the first year of this new solution now in place to manage the risk on the sub transmission loop over summer 2020/21.

This non network solution:

- reduces energy-at-risk in the lower Mornington supply area;
- defers the network augmentation by 5 years;
- maximise net economic benefits for the electricity market;
- address capacity limitation on the DMA-RBD sub-transmission lines;
- address capacity limitation on the MTN-DMA sub-transmission line;
- address capacity limitation on the TBTS-DMA sub-transmission line;
- address capacity limitation on the TBTS-MTN No.1 sub-transmission line; and
- address voltage collapse limitation in the lower Mornington Peninsula.

United Energy will continue to monitor the load growth and explore options to extend the demand side solution on the Lower Mornington Peninsula further to potentially deliver further deferment of the network solution post 2025.

8.3 Proposed new sub-transmission lines

This section sets out United Energy's plans for new sub-transmission lines. These lines are not taken into account in the forecasts that have been set out in Appendix D as that only relates to existing sub-transmission lines.

The table below provides an overview of the sub-transmission lines that United Energy is proposing to build during the forward planning period for this DAPR.

Table 8.1 Proposed new sub-transmission lines

Name	Location	Proposed commissioning date	Reason
HGS-RBD	Hastings to Rosebud	Nov 2025 ⁸	Demand and voltage constraints in the lower Mornington Peninsula area.

Each of these lines is described in more detail below.

8.3.1 HGS–RBD sub-transmission line

Please refer to section 8.2.5 above and chapter 15 for more details.

⁸ Dependent on the possible continued deferment by the demand side solution.

9 Primary distribution feeder and substation reviews

Where practicable, United Energy has prepared forecasts for primary distribution feeders over the forward planning period for this DAPR that assesses the balance between capacity and demand. This chapter discusses the primary distribution feeders that are:

- currently overloaded; or
- forecast to experience an overload in the next two years.

Under probabilistic planning, distribution feeders are generally loaded to greater than 85 percent utilisation before they are considered for possible augmentation as this represents a typical trigger-point at which feeder augmentations may become economic. The transfer capabilities reserved for maintaining continuous supply to our customers during emergency conditions diminishes with increased distribution feeder utilisation.

United Energy has also prepared listings of distribution substations and LV circuits with constraint limitations. Under probabilistic planning, distribution substations are generally loaded to greater than 120% of their cyclic rating (100% of their short-time rating) and LV circuits loaded to their fuse rating before it is considered for augmentation or a non-network solution.

We invite non-network providers to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. United Energy anticipates an increasing number non-network options will emerge over the next few years particularly for distribution feeder and substation limitations, as the market and technology develops.

9.1 Overview of primary distribution feeders with forecast overload

The table below provides information regarding critical distribution feeder limitations where network augmentation to alleviate those limitations are likely to be economic and are currently planned in the next two years.

A number of options are considered in identifying suitable mitigation measures to alleviate thermal capacity and transfer capacity issues on distribution feeders, including:

- permanent load transfers to neighbouring feeders,
- feeder reconductoring,
- thermal uprate,
- reactive power compensation,
- new feeder ties or extensions,
- new feeders,

- non-network alternatives.

The most appropriate option is selected based on practical feasibility and least lifecycle cost.

Table 9.1 Distribution feeder limitations

Feeder	Feeder location	MD season	Forecast utilisation (%)		
			2020/21	2021/22	2022/23
OR 24	East Boundary / Centre Road, Bentleigh East	Summer	93%	97%	100%
MTN 31	Dunns Road / The Esplanade, Mount Martha	Summer	94%	99%	102%
FSH 31	Overport Road / Humphries Rd, Frankston	Summer	91%	96%	99%
MGE 12	Jells Road / Ferntree Gully Road, Wheelers Hill	Summer	89%	92%	96%
KBH 32	Hammond Road / Potter Street, Dandenong	Summer	90%	92%	95%

The section below identifies the amount of load reduction that would be required to defer the proposed augmentations by one year.⁹ It also identifies the proposed preferred network solution that would be undertaken in the absence of any commitment from interested parties to offer network support services through demand side management initiatives.

9.2 Primary distribution feeders with forecast overload

9.2.1 OR 24

OR 24 is a highly utilised feeders from Ormond (**OR**) zone substation. The feeder supplies residential loads in the Bentleigh East area. The adjacent feeders, BT 04 and BT 15 from Bentleigh (**BT**) zone substation and MR 22 from Moorabbin (**MR**) zone substation, which tie into OR 24, are also highly utilised.

United Energy's preferred network solution is to establish a new feeder from BT zone substation to offload the constrained feeder and supply further capacity to the area. The estimated cost of this augmentation is \$1.6 million. This project is now a committed project and is underway to be completed in the second half of 2021.

9.2.1 MTN 31

MTN 31 is a highly utilised 22kV feeder from Mornington (**MTN**) zone substation, and supplies a predominantly residential in the Mount Martha area. The identified need for a project in this area is based on the MTN zone substation limitation as well as the feeder limitation (see section 7.2.20 for discussion of the zone substation limitation).

⁹ This is an indicative figure only. The amount of load reduction required to defer the proposed augmentations will be finalised via a detailed risk assessment / business case.

United Energy's preferred network solution is to establish a new feeder from Mornington zone substation to offload MTN 31. The estimated cost of this augmentation is \$890,000. This project is now a committed project and is underway to be completed in the second half of 2021.

9.2.2 FSH 31

FSH 31 and FSH 33 are highly utilised feeders from Frankston South (**FSH**) zone substation. They supply the Mount Eliza and Frankston South areas.

United Energy's preferred network solution is to extend the lightly utilised FSH 12 feeder to offload FSH 31 and FSH 33 to enable better utilisation of assets. The estimated cost of this augmentation is \$300,000.

In order to defer the proposed augmentation by twelve months, a non-network solution would need to reduce the summer maximum demand on FSH 31 or FSH 33 feeders, between the hours of 17:00 to 20:00 on maximum demand days by approximately 0.7MVA. Any solution would need to be implemented by November 2022 for summer 2022/23.

The estimated annualised cost of the solution is around \$10,000. This provides a broad upper bound indication of the maximum contribution from United Energy which may be available to non-network service providers for deferring the proposed augmentation by twelve months. For more details please see the systems limitations template.

9.2.3 MGE 12

MGE 12 is a highly utilised feeders from Mulgrave (**MGE**) zone substation. It supplies the Wheelers Hill area.

United Energy's preferred network solution is to establish a new feeder from MGE zone substation to offload MGE 12. The estimated cost of this augmentation is \$1.5 million. United Energy have previously used demand response in this area to defer investment which it will once again explore using to once again defer investment while the extent of the anticipated growth is uncertain.

In order to defer the proposed augmentation by twelve months, a non-network solution would need to reduce the summer maximum demand on MGE12 feeders, between the hours of 14:00 to 17:00 on maximum demand days by approximately 0.6MVA. Any solution would need to be implemented by November 2022 for summer 2022/23.

The estimated annualised cost of the solution is around \$51,000. This provides a broad upper bound indication of the maximum contribution from United Energy which may be available to non-network service providers for deferring the proposed augmentation by twelve months. For more details please see the systems limitations template.

9.2.1 KBH 32

KBH 32 is a highly utilised 22kV feeder from Keysborough (**KBH**) zone substation, and supplies a predominantly residential load in the Dandenong area.

United Energy's preferred network solution is to upgrade KBH32 by upgrading and re-conductoring approximately 380m total. The estimated cost of this augmentation is \$100,000.

In order to defer the proposed augmentation by twelve months, a non-network solution would need to reduce the summer maximum demand in the KBH 35 feeder area, between the hours of 15:00 to 18:00 on maximum demand days by approximately 0.2MVA. Any solution would need to be implemented by November 2022 for summer 2022/23.

The estimated annualised cost of the solution is around \$3,000. This provides a broad upper bound indication of the maximum contribution from United Energy which may be available to non-network service providers for deferring the proposed augmentation by twelve months. For more details please see the systems limitations template.

9.3 Distribution substation and LV circuit limitations

Every year United Energy undertakes a program to rectify and prevent overloads on its distribution substations and LV circuits. United Energy utilises both traditional augmentation and non-network options including United Energy's own residential demand management "Summer Saver" program as options to alleviate limitations on distribution substation and LV circuits. The solution adopted for each site is based on an economic evaluation of costs and benefits.

For summer 2020/21, through the project evaluation process conducted in line with the Demand Management Incentive Scheme (**DMIS**) requirements, the Summer Saver program was identified as the preferred option and committed to for 214 capacity-constrained distribution substation and low-voltage circuit sites.

The table below outlines the summer 2020/21 sites with limitations where the Summer Saver program is being carried out and will likely be continued in future years. The location for each site is also provided via the Google Earth map accompanying this report. United Energy will update and finalise the list of summer 2021/22 sites with limitations around March 2021. As part of our consultation obligations under the DMIS, United Energy will publish this list and a request for non-network proposal through its contacts on the United Energy Demand Side Engagement Register for non-network service providers' consideration.

We invite non-network providers to consider whether alternative solutions could be deployed in these areas and to contact us with any enquiries or further details.

Table 9.2 United Energy 2020/21 Summer Saver Sites

Distribution Substation Name (based on intersecting street names)			
RICHMOND PEKINA	BLUFF-ARKARINGA 2	BOURNE-GLEN IRIS 4	HOLLOWAY-GREEN 2
ALDRIDGE CARDIGAN	WILSON VICTORIA 3	MONTROSE RAE 1	WELLINGTON VILLAGE BRAEBURN 3
BAXTER SWANWALK	BENWERRIN-BALMORAL 2	WESTPORT AZURE 8	CUMBERLAND 2 WELLGTN 2
MONIQUE BREESE	WHITON-KEVIN 1	KARDINIA-HIGH 3	MCHENRY-HOTHAM 3
AUSTIN ERWIN	HARTLEY-SYLVYERLY 1	GLADESVILLE CLEMATIS 3	BOLINDA-CENTRE 2
GEOFFREY CAXTON	WOODSIDE LAUREN 2	SPRAY SKYE 1	MARCUS-DAVID 2
SYLVIA BLUFF	VIVA-TOORONGA 4	STEWART-NEW 4	KILBURN PALMERSTON 1
SOUTHGATE MELALEUCA	SUNBIRD COCKATOO 1	VIVIEN IENA 1	LIVIANA SHEARER 5
CARRIER-NEPEAN	CAMBRIAN STRICKLAND 6	GLENBROOK SCOTCH 2	PUTT CORRIGAN 2
EDGBASTON STADIUM	BRETT-NORTH 3	KERFORD COPPIN 2	WOOD-LAWSON 3
NAGLE-LIBERTY	MARRIOT BAMBRA 1	BRIGGS HEATHERTON 2	MILLER-AVONDALE 2
STATION JONES	YALLAMBEE ALBANY 2	PAMAY KENDALL 1	GLENIFFER-SOUTH 1
RAY-BEACH	INGA WALPOLE 1	WARADGERY MUIRFIELD 4	BAY-CLARKSON 3
BAXTER TDN GRACEMERE	CONNIE-CENTRE 2	NICOL MARCHANT 1	DOWNING-LITHGOW 3
LINDRUM HAMPDEN	WARADGERY GILLIGANS 5	LWR DNG IVY 2	BAINBRIDGE OVERTON 1
VOGUE-HAWTHORN	STRUAN CLYDEBANK 3	ACACIA-GLEN EIRA 1	THOMAS N202 WALKER 2
CARAMUT-GRANDVIEW	TURNER-PEACE 1	DNG RETIRE VILL STUD 2	BOULEVARDE-CLANCYS 1
QUENTIN-RANFURLIE	FERNTREE G-VIEWBANK 1	YUILLE LYONS 1	MERVIN-ABBIN 1
BELLEVUE SEAVIEW	LOCHABER HEATHERHILL 2	FRANKLIN BEACH 4	SHERWOOD-DENT 1
GOVERNOR ROYAL	KINGSWOOD HARLEY 1	FORSYTH ASHLEIGH 2	TI TREE OLD MTN 2
SPRING-BLUFF	RIDDELL BELLBROOK 1	RETIREMENT CAPITAL 1	LUMEAH-GLEN EIRA 3
WILGAH BURUNDA	MCCORMICKS MUNDAY 2	WICKHAM-TELFORD 1	MEADOW-ALSTON 1
HILLTOP RITCHIE	TEDDINGTON MAY 3	WOODHOUSE STATION 3	PINNACLE-LINCOLN 1
MITCHELL STRACHANS	SIBYL HUMPHRIES 2	SANDYBAY TRUEMANS 1	CLYDEBANK EDITHVALE 2
WHITEHEAD WILSON	FOURTH-EBDEN 2	TIBROCKNEY-HIGHETT 2	KALIMNA MILLICENT 8
KINGSTON-LOBELIA	PORTER-CHURCH 2	BONDI GENOA 2	WELWYN-SUNLIGHT 1
MCARTHUR EAST	LUM SHERRINGHAM 1	EELRACE VALETTA 2	PATTERSON N120 RAILWAY 3
KARRAKATTA-BLUFF	FEWSTER EDINBURGH 1	BLUFF BAYVIEW 1	BELAR BENANEE 2
TOWNSEND GALLAGHERS	LIMA BETTINA 1	THOMPSON-MURRAY 1	LABUAN HUGHES 1
HUXLEY TIVERTON	LATONA-MILAN 1	POWER-WINBIRRA 5	LUCKNOW-HASLEMERE 1
OSWIN STONY PT	RETIREMENT OLIVE 1	NEW P3 NEWBAY 1	BENT EDGAR 2
SEYMOUR GLEN SHIAN	HAWTHORN 97-MAHONEY 1	LALWA-CNTRBY 5	WARREN-LAWBOROUGH 3
KENNINGTON PK SWISS	AGNES BUCKLEY 1	NORMANBY OXFORD 1	STREETON OAK 2
BREWER-MITCHELL	HENTY PRINCES 1	SWEET WATTLE-PETER 1	PILITA-SVALE 4
KINROSS-BLUFF	WILTSHIRE CARLA 1	DEEP CREEK-EDGERTON 4	WINTON-SOLWAY 1
HIGHETT-SPRING	KANGAROO-POATH 3	KEMP EMMA 2	STANHOPE-IRVING 2
SHORE ACRES PINEHURST	MCSWAIN-MARRIOTT 1	WATSON GRANGE 3	THOMPSON N21 GLADESVILLE 1
ISLAND SERPENTINE	WILSON-CARPENTER 4	AINTREE WHITEHAVEN 2	KEYLANA TESSA 2
SERENITY SAMUEL	ROSSTOWN-MILE END 3	JESSE-DUNDAS 1	THAMES WELLS 1
KEILLER-HIGHBURY	COLLINGTON-CHURCH 2	WARREN-CEDRIC 2	MAPLE-LANGTREE 2
BILBUNGRA BENJAMIN	YAMBILL CARRATHOOL 1	NORMANBY WILBY 2	VILLEROY-IMBROS 1
JENKINS TREEBY	KELVIN NEPEAN 1	MDLBORO WHORSE 2	BALCOMBE PARK BALCOMBE 2
SYCAMORE POPLAR	ST GEORGES-NICHOLAS 2	OAKHAM-MEDHURST 2	LABURNUM-MYRTLE 1
TOOMBAH PINEWOOD	FRASER STATION 1	NIGHTINGALE-WILLIAM 2	WERE-ROSLYN 5
HIGHETT-NICOL	GRACE-ROSTREVOR 6	DARVALL BONA 1	WATERWAYS SPRINGVALE 3
HOOD-MILLS	KERFERD-MUSWELL HILL 1	FRENCH NORTHCLIFFE 2	OSBORNE-COCHRANE 2
COOK BASS	BURROW QUEEN 2	DAROOK-BLKBURN 1	CENTRE DNONG GOLFLNK 5
DURBAN ST GEORGES	AUSTIN DOWNS 1	KONRAD-LEONIE 8	FOCH-KITCHENER 1
AUSTIN MORGAN 2	CHAMPION HILLTOP 4	HIGH SCHOOL EELRACE 3	SNOWDON-BAMBRA 2
DARBYSHIRE-PROSPECT 2	NAPIER STRACHANS 1	ALMER-SPRINGFIELD 2	RHODA FOREST PARK 2
NORTH YOUNGER 1	SCOTT BRIGHTON 1	LUGANO MONACO 1	PAISLEY STATION 2
MURAWA GOOLGOWIE 4	HARTLEY-SYLVYERLY 2	HOPE BURKE 1	DOCKER-ORMOND 1
SARA ITALLE 4	HARBOUR OCEANIC 4	KALIMNA WALKERS 1	
PASADENA-GARETH 1	DICKENS-MITFORD 3	VICTORY-ALAMEIN 3	

10 Joint Planning

This section sets out the joint planning with DNSPs and TNSPs in relation to zone substations and sub-transmission lines. Transmission connection asset planning is undertaken by United Energy, as a joint exercise, with other Victorian DNSP's and the Australian Energy Market Operator (**AEMO**), in its role as planner for the Victorian declared shared transmission network. Joint planning in relation to terminal stations in isolation is discussed in the Transmission Connection Planning Report.

United Energy has not identified any new projects from our joint planning activities with other DNSPs in 2020. Our joint planning activities have included sharing load forecast information and load flow analysis between Victorian distributors relating to the sub-transmission system. Where a constraint is identified on our network that may impact another distributor, then project specific joint planning meetings are held to determine the most efficient and effective investment strategy to address the system constraint.

United Energy has the following shared sub transmission loops with shared supply:

- ERTS-DN-HPK/DSH-DVY-ERTS shared supply with AusNet Electricity Services,
- RTS-EW-SK-RTS shared supply with CitiPower,
- RTS-K-CL-RTS shared supply with CitiPower,
- SVTS-EB-RD-SVTS shared supply with CitiPower.

Further information on the joint planning can be obtained from contacting United Energy by contacting planning@ue.com.au.

11 Changes to analysis since last year

11.1 Maximum demand forecast

The latest maximum demand forecast for the United Energy service area has been revised downwards by the National Institute of Economic & Industry Research (**NIEIR**) compared to that published in the 2019 DAPR.

At an overall United Energy service area level NIEIR forecasts, which were produced in August, have been revised downwards in response to the COVID-19 health and economic crisis with the greatest impact occurring for the 2021 summer maximum demand forecasts which reduces the forecast starting point. From 2021 the forecast shows a recovery and then a similar demand growth rate to the 2019 DAPR forecast.

The change in maximum demand for the overall United Energy service area over the 5 year period is reflected in the figure below.

Figure 11.1 United Energy 10% PoE summer maximum demand forecasts

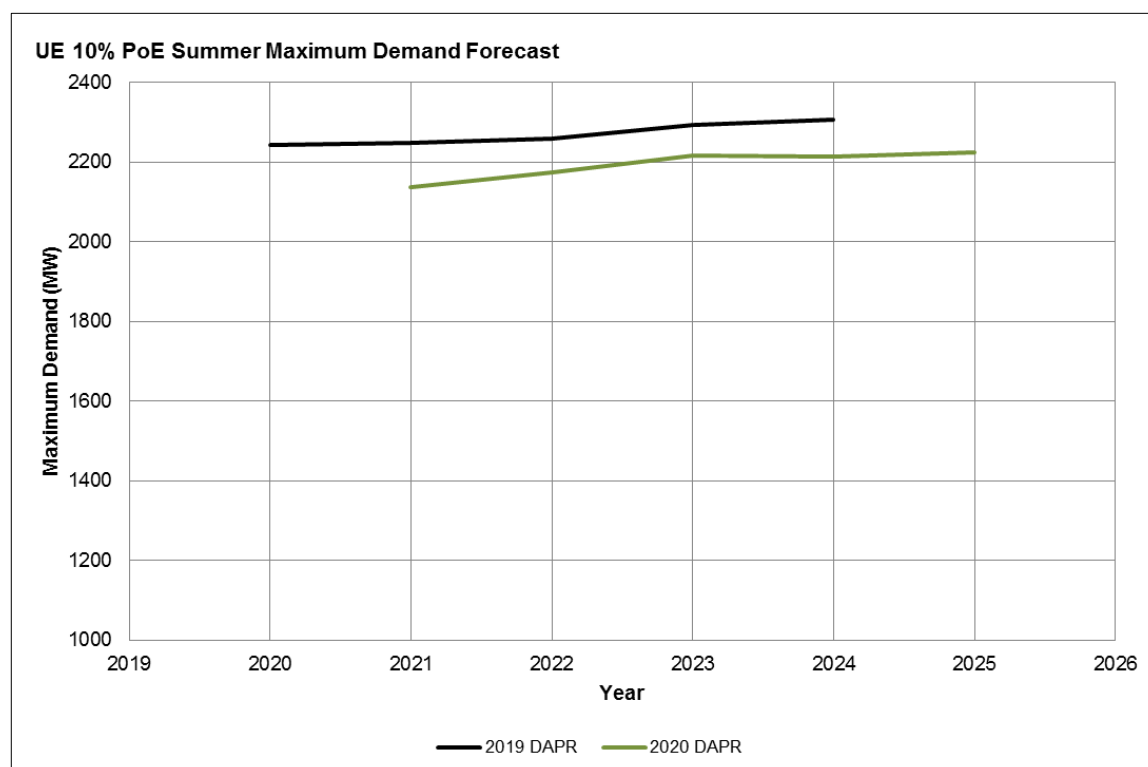


Table 11.1 below summarises the change in United Energy's 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast.

Table 11.1 Changes in United Energy's 10% PoE summer maximum demand forecast

10% PoE Summer maximum demand	2020 DAPR Forecast	2019 DAPR Forecast	Change
2020-2021 summer	2137 MW	2248 MW	-4.9%
2024-2025 summer	2225 MW	2355 MW	-5.5%
2028-2029 summer	2322 MW	2481 MW	-6.4%
Ten-year average growth rate	1.0% pa	1.1% pa	-0.1% pa

It should be noted that at this stage, with unprecedented change due to the COVID-19 pandemic, the impact on demand is highly uncertain and may not be as severe as predicted above. Also, our forecasts were undertaken before the Federal Government and Victorian Government budget stimulus announcements which would be expected to increase demand. It should also be noted that demand growth and the impacts of the COVID-19 pandemic will vary by geographical area. That is some areas may experience increased maximum demand due to the COVID-19 pandemic (e.g. residential areas or areas with government projects to stimulate the economy) and stronger demand growth than the network average, with other areas experiencing a drop off in demand due to the COVID-19 pandemic (e.g. commercial areas which experienced shutdowns) and lower or no demand growth forecast.

11.2 Value of Customer Reliability (VCR)

The Value of Customer Reliability (**VCR**) used by United Energy to calculate the cost of expected unserved energy is now provided by Australian Energy Regulator (**AER**) which published updated VCR values in December 2019.

United Energy notes that there has been a comparative reduction in the VCR estimates for the residential, commercial and agricultural sectors with a significant increase in the industrial component compared to the previous Australian Energy Market Operator (**AEMO**) study. This would tend to bias investment towards industrial areas compared to the previous VCR estimates.

United Energy has updated its investment plans to reflect these latest VCR values including calculating investment area specific VCRs. This has resulted in a reduction in VCR in some more residential areas, with other areas experiencing an increase in the VCR used compared to the 2019 DAPR.

11.3 Timing of proposed network augmentations

The network limitation assessment and timing of network augmentations presented in this DAPR are based on United Energy's 2020 post COVID-19 pandemic and pre budget stimulus maximum demand forecast and the latest AER VCR estimates. The timing is also based on the annualised cost of the network augmentation option.

While modest demand growth is expected for the overall United Energy network, there remain pockets of strong growth which typically occur in the parts of our network that are currently operating well above the average utilisation. The timing of our network augmentations has been determined on a case-by-case basis and may change over time as options are re-evaluated.

Compared with last year's forecast, the timing of network augmentations projects identified in this DAPR have typically been delayed by one to two years. However, there has been unprecedented change due to the COVID-19 pandemic. The full impact of the COVID-19 pandemic is not yet well understood as we are yet to experience the impact on demand during the summer peak. New working-from-home arrangements and government stimulus may increase demand beyond what has been forecast and similarly greater than expected declines in commercial sector activity may offset this (at a network level). Overall, the impact on demand is uncertain and projects timing may need to be revised next year once more information on the impacts become available.

Table 11.2 below summarises the change in timing of proposed major network augmentations.

Table 11.2 Changes in timing of proposed major network projects

Proposed Major Project	2020 DAPR	2019 DAPR
Keysborough (KBH) Supply Area: Install a second transformer with two new distribution feeders at Keysborough (KBH).	2024	2022
East Malvern (EM) Supply Area: Install a third switchboard with three new distribution feeders at East Malvern (EM).	2025	2023
Doncaster (KBH) Supply Area: Install a fourth transformer with two new distribution feeders.	2025	2024
Mornington (MTN) Supply Area: Install a third transformer and new feeder from Mornington (MTN).	2026	2025

11.4 Timing of proposed asset retirements / replacements and deratings

United Energy is now also required to detail information on its asset retirements / replacement projects and deratings in its DAPR as described in section 14. The timing of these may change subject to updated asset information, portfolio optimisation and realignment with other network projects, or reprioritisation of options to mitigate the deteriorating condition of the assets.

United Energy has made minor adjustments to the risk quantification for these locations. These changes primarily involve refinement of estimated failure probabilities for assets, as well as updated consequence values to incorporate additional data captured during 2019. The timing was also updated for the latest load forecast and VCR's as detailed above. The assessment of load-at-risk includes existing risk management controls (such as available load transfers, relocatable transformer readiness and switchgear spares holdings) where applicable. As a result, some asset retirements have been deferred, and other future retirements have been brought forward.

Table 11.3 below summarises the change in timing of proposed major network retirements/replacements.

Table 11.3 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2020 DAPR	2019 DAPR
West Doncaster (WD) #1 Transformer	Not Included	2024
Bulleen (BU) 11kV Indoor Switchboard	2022	Not included
Ormond (OR) #2 Transformer	2022	2021
Oakleigh East (OE) #2 Transformer	2025	Not included
Bulleen (BU) #2 Transformer	2025	Not included
Beaumaris (BR) 22kV Indoor Switchboard	2025	Not included
Oakleigh East (OE) 11kV Indoor Switchboard	2025	Not included

The main changes were for West Doncaster (**WD**) transformer replacement which has been deferred to outside the planning period and Bulleen (**BU**) 11kV switchboard replacement which has been brought forward as a result of re-prioritisation to align with the aged relay replacement. Note that BU 11kV indoor switchboard as well as OE #2 transformer, BU #2 transformer, BR 22kV indoor switchboard and OE 11kV indoor switchboard projects were previously just outside the five year 2019 DAPR forward planning period.

11.5 Feedback on United Energy's 2019 DAPR

In February 2020, United Energy held a public forum to discuss and seek feedback on the 2019 DAPR with the interested parties on United Energy's Demand Side Engagement Register. Feedback and discussions of constraints were very positive with no specific requests for changes or additional information.

Following the public forum, United Energy undertook a formal consultation with the market to seek proposals for non-network alternative solutions for the augmentation and demand management projects proposed in 2020. This was undertaken as part of the consultation requirements under the AER's Demand Management Incentive Scheme (**DMIS**). Feedback on this consultation process was positive and United

Energy received several high quality proposal from a demand management providers in response to these consultations.

In addition this is the first year that the Distribution Voltage Information Template has been published alongside the DAPR. United Energy welcomes any feedback on this new template in particular as well as for any improvements in relation to this year's DAPR and Systems Limitations Template.

12 Asset Management

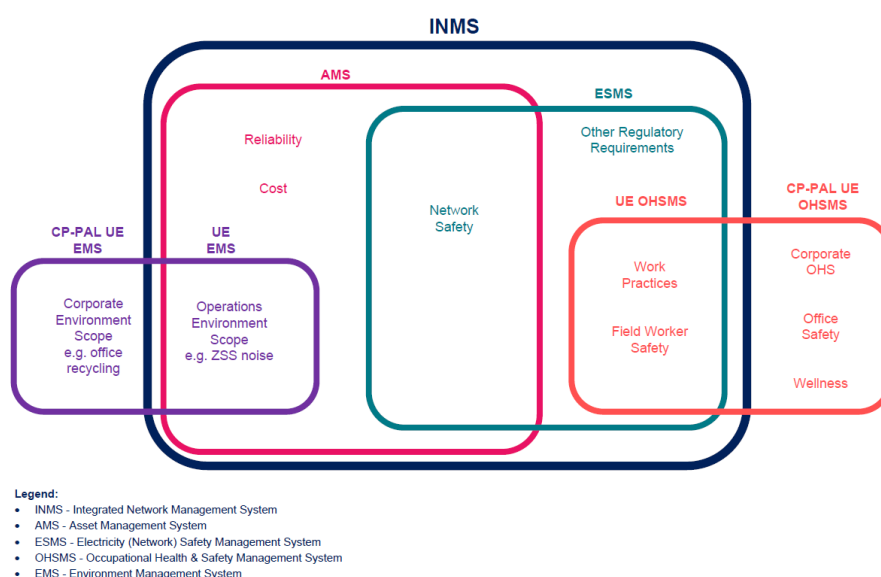
This chapter sets out United Energy's Integrated Network Management System (**INMS**), which underpins our asset management framework and ensures a clear 'line-of-sight' between the company's activities on the ground, and the overall Vision, Organisational Strategic Plan and Objectives.

12.1 Integrated Network Management System (INMS) Overview

The INMS, is underpinned by the United Energy enterprise risk management framework, and integrates the requirements of four management systems:

- Asset Management System (**AMS**),
- Electricity (Network) Safety Management system (**ESMS**),
- Occupational Health and Safety Management System (**OHSMS**),
- Environment Management Framework (**EMS**).

Figure 12.1 Scope of the integrated network management system



The INMS is limited to the United Energy electricity distribution network and the operating environment. It recognises industry technical and safety standards, codes and guidelines, and defines how United Energy plans to manage the safe design, construction, commissioning, operation, maintenance and decommissioning of its electricity network As Far As Practicable (**AFAP**).

The INMS articulates how business strategies, plans and aspects of the Asset management system, Occupational health and safety management system, Environmental management system and the Electricity safety management scheme

have been integrated to ensure the safe, reliable, cost effective operation of the electricity distribution network.

12.2 Asset Management System

United Energy's Asset Management System is an integrated framework of documents and processes in accordance with AS ISO 55001.

The United Energy Asset Management system intends to:

- Align with key aspects of the requirements of AS ISO 55001 Asset Management series;
- Provide a clear line of sight to ensure integration between customer, business and Asset Management requirements expressed in the following;
 - Corporate Plan and Objectives,
 - Asset Management Drivers,
 - Risk Appetite statement.
- Includes the following interdependent document deliverables;
 - Asset Management Policy - provide overarching principles that align with Corporate Objectives and Asset Management drivers.
 - Asset Management Strategy and Objectives for the management of assets that align with the Asset Management Policy.
 - Non-Asset and Asset Class plans that describe how each Non-Asset and Asset Class will achieve the requirements of the Asset Management Strategy and Objectives.
 - Asset Management Plan that provides an overview of Asset Management works programs for a 10 year period.
 - Capex / Opex Works Program (**COWP**) outlining the annual works program that is used by Service Delivery to deliver projects.

12.3 Asset Management Policy and Strategies

United Energy's Asset Management Policy defines the principles by which assets are managed.

The Asset Management Strategy and Objectives document expands on the requirements of the asset management policy, but also draws in other key principles and business objectives, which are prudent to consider in decision and strategy making.

United Energy's Strategic Asset Management Plan serves as guidance for decision making processes within the business to manage future uncertainty, and minimise risk around capital deployment being made redundant.

These three documents serve as the key input guidance for asset and non-asset class strategies, which analyse decision options and outcomes with respect to the objectives and considerations outlined in the aforementioned documents.

12.4 Asset Class Strategies and Plans

A key part of United Energy's Asset Management System is the development and maintenance of Asset Class Strategies for sub-transmission and distribution asset classes. These strategies describe the management of the various asset classes from creation through to disposal and include the maintenance and replacement strategies applied to each asset. The strategy documents take the high-level asset strategies and objectives and combine them with an in-depth knowledge of the specific assets to identify the requirements that will ensure delivery of optimum outcomes. The group for Asset Class Strategies and Plans are as follows:

- Primary Electrical Assets;
- Secondary Electrical Assets;
- Fleet;
- Metering;
- Operational Property.

12.5 Asset Management Plan and COWP

The Asset Management Plan (**AMP**) is a rolling 10-year plan that translates the asset strategy and asset performance data into a more detailed investment plan. It strikes a balance between efficient and cost-effective investment, the required level of service from the physical assets and an appropriate level of risk to develop a long-term plan. To develop the AMP, United Energy collects and analyses data, determines the necessary modifications to the network that are required, and then produces a capital plan to deliver the network investments with a rolling 10-year view.

The AMP is the list of projects that have been derived from the Strategic Planning process and is outlined in detail in the COWP.

The COWP explains in detail the execution of the AMP and reflects a two-year budget cycle, setting out the actions, responsibilities, resourcing and time scales for the activities in each program. Expenditures are associated with both capital and operational activities.

To optimise investments in replacement, demand and performance capital expenditure when formulating the AMP, United Energy balances three sets of requirements:

1. Customer requirements: analyse customer expectations and current performance in delivering to those requirements.
2. Technical requirements: a range of inputs drive the technical network requirements that need to be adhered to, including:
 - Network performance, asset maintenance and replacement programs: Driven by analysis of fault/performance/cost data and based on reliability centred maintenance analysis
 - Safety compliance: Based on United Energy's Energy Safe Victoria (**ESV**) accepted Electricity Safety Management Scheme which lays out United Energy's risk-based approach to managing electrical safety
 - Capacity planning: Based on probabilistic analysis and contingency planning
 - Risk analysis: Performed to ISO 31000 for significant asset risks
3. Economic requirements: All projects are subject to an appropriate level of economic analysis in accordance with regulatory requirements and prudent investment tests.

12.6 Contact for further information

Further information on United Energy's asset management strategy and methodology can be obtained by contacting planning@ue.com.au. Detailed enquiries may be forwarded to the appropriate representatives within United Energy.

13 Asset management methodology

An overview of United Energy's asset management system is given in Chapter 12. One of the core components of the system is the Asset management strategies, which define how United Energy manages network assets over their life cycle, from acquisition, operation & maintenance, and retirement in order to meet the asset management objectives (specified in Section 12.3).

In general, United Energy manages assets by adopting a minimum, whole-life, whole-system risk and cost approach (**WLWS**). As part of this, Reliability-Centred Maintenance (**RCM**) principles are used to manage all network assets over their normal operating life cycle. The RCM process determines the recommended maintenance of network assets, and what actions should be taken to ensure their cost-effective, reliable operation.

The process involves a number of key steps to analyse equipment and determine prudent maintenance tasks and time intervals, including the following steps;

- Breaking down the asset in question to key components and define asset functions;
- Performing a Failure Mode, Effects and Criticality Analysis (**FMECA**) to assess how components fail, and the effect of those failures on asset functions;
- Determining cost-effective techniques (where possible) to manage failure modes;
- Rolling up tasks into maintenance packages for implementation; and
- Reviewing asset and maintenance performance, and adjusting as necessary.

Where the performance of equipment changes, or it is no longer capable of performing the required function due to an internal or external system change, the suitable tasks are re-assessed for the asset. The trigger for a re-assessment can be driven from network changes, operational or business changes, as well as learnings from failure investigations and field observations, deterioration in condition or an increase in the likelihood of failure or consequence. Depending on the outcome of the assessment, asset replacement may be required. This is detailed further below.

13.1 Distribution Assets

The majority of distribution assets (namely 'poles and wires' assets) are replaced when condition assessment (including inspections) have identified that the equipment has reached the end of its' useful life and is no longer fit for service or has failed in service. The measures used to determine this vary between equipment types, and are chosen based on the key measures of asset condition for the particular equipment. Some examples include;

- Measurement of sound wood on poles;
- Partial Discharge (**PD**) testing of substations and cables;
- Thermography (overhead assets); or
- Monitoring of insulation levels (gas/oil).

Upon detection of an issue indicating the asset is near the end of its useful life or no longer fit for service, United Energy takes a variety of actions to manage risk. Actions taken include:

- More frequent condition assessment or inspections;
- Asset reinforcement (e.g. pole staking);
- Asset retirement;
- Overhaul / refurbishment;
- Non-network solutions; and
- Asset replacement.

The key assumptions and reasons considered in the assessment include technical equipment thresholds, safety, risk and economic assessments, as well as good industry practice. The decision is made based on the least-cost solution that delivers reliability and safety requirements.

13.2 Zone Substation Assets

The design of substations generally allows for a greater breadth of options available to manage risks associated with assets approaching the end of their useful life, due to the increased inter-connectivity and redundancy, and capability to monitor asset condition.

As zone substations provide a greater breadth of information on asset condition, the risk assessments and economic optimisation can be conducted at a more detailed level (compared to other distribution assets).

Additional condition assessments to those conducted for other distribution assets include:

- Dielectric Loss Angle (**DLA**) testing of bushings (various assets);
- Dissolved Gas analysis (**DGA**), Sweep Frequency Response Analysis (**SFRA**), moisture content assessment and insulating paper testing (transformers);
- PD testing and DLA testing of switchgear;
- Asset performance history; and
- Analysis of load-at-risk.

Given the higher breadth of complexity and structure of larger zone substations, United Energy considers a larger variety of practical options to identify the least-cost solution to manage risk, including:

- Increased ongoing condition assessments;
- Overhaul / refurbishment;
- Retrofit of on-line condition monitoring systems;
- Component replacement;
- Non-network solutions;
- Asset de-rating or retirement;

- Load transfers and increased redundancy; and
- Contingency plans and increased spares holdings.

Assessments of potential solutions are performed over a forward looking period of time (typically the next 10 years). This is then analysed to determine the optimal timing for the works by identifying the least-cost option over the period, and determining when the cost curve has a minimum (this indicates when the least-cost timing occurs).

Various risk mitigation techniques (mentioned above) are employed, where possible, to minimise the need to retire or replace an asset. In general, the asset is retired and/or replaced only when that is the most economically optimised decision that maintains safety and reliability standards. Economic optimisation considers:

- Cost of the intervention, task or measures available to address the risk;
- Evaluating the risk associated with the asset, including an assessment of:
 - Likelihood of occurrence;
 - Safety and environmental impact;
 - Substation design and redundancy;
 - Network economic impact;
 - Other costs;
- Assessment of how various options reduce the quantified risk by different amounts.

The asset replacements outlined in this document in Section 14 are forecast based on the number of historic asset replacements (typical for high volume assets such as poles), and for specific assets, based on an assessment of currently available condition data for the asset. Section 14 also includes methodologies used for the replacement of each type of asset, where relevant.

14 Asset Retirements and Deratings

This chapter sets out the planned network retirements over the forward planning period for this DAPR. The reference to asset retirements includes asset replacements, as the old asset is retired and replaced with a new asset.

In addition, this chapter discusses planned asset de-ratings that would result in a network constraint or system limitation over the planning period.

The accompanying System Limitations Template details a number of asset retirements and de-ratings that result in a system limitation.

All planned network retirements, or planned asset de-ratings that would result in a system limitation, are described individually below. Where more than one asset of the same type is to be retired or de-rated in the same calendar year, and the capital cost to replace each asset is less than \$200,000, then the assets are reported together below.

A summary of the individual assets that are planned to be retired/replaced is provided in the table below.

Table 14.1 Planned asset replacements

Asset	Location	Project	Retirement date ¹⁰
Elsternwick (EL) #2 Transformer	Elsternwick (EL) zone substation	Replacement	2021 (committed)
East Malvern (EM) #1 Transformer	East Malvern (EM) zone substation	Replacement	2022 (committed)
Ormond (OR) #2 Transformer	Ormond (OR) zone substation	Replacement	2022
Elwood (EW) #2 Transformer	Elwood (EW) zone substation	Replacement	2022
Surrey Hills (SH) 6.6kV Conversion	Surrey Hills (SH) zone substation	Replacement	2022-24
Sandringham (SR) #3 Transformer	Sandringham (SR) zone substation	Replacement	2023
Gardiner (K) #3 Transformer	Gardiner (K) zone substation	Replacement	2023
Bentleigh (BT) #1 Transformer	Bentleigh (BT) zone substation	Replacement	2024

¹⁰ Zone substation switchgear is generally replaced across multiple calendar years where more than one bus is required to be replaced.

Hastings (HGS) #1 Transformer	Hastings (HGS) zone substation	Replacement	2024
Oakleigh East (OE) #1 Transformer	Oakleigh East (OE) zone substation	Replacement	2025
Bulleen (BU) #1 Transformer	Bulleen (BU) zone substation	Replacement	2025
Elsternwick (EL) 11kV Indoor Switchboard	Elsternwick (EL) zone substation	Replacement	2021 (committed)
Sandringham (SR) 11kV Indoor Switchboard	Sandringham (SR) zone substation	Replacement	2021 (committed)
Bulleen (BU) 11kV Indoor Switchboard	Bulleen (BU) zone substation	Replacement	2022 (committed)
Bentleigh (BT) 11kV Indoor Switchboard	Bentleigh (BT) zone substation	Replacement	2022 (committed)
East Malvern (EM) 11kV Indoor Switchboard	East Malvern (EM) zone substation	Replacement	2023
Elwood (EW) 11kV Indoor Switchboard	Elwood (EW) zone substation	Replacement	2024
Beaumaris (BR) 22kV Indoor Switchboard	Beaumaris (BR) zone substation	Replacement	2025
Oakleigh East (OE) 11kV Indoor Switchboard	Oakleigh East (OE) zone substation	Replacement	2025
Heatherton (HT) 22kV Outdoor Switchyard	Heatherton (HT) zone substation	Replacement	2023
Doncaster (DC) 22kV Outdoor Switchyard	Doncaster (DC) zone substation	Replacement	2024
Glen Waverley (GW) 22kV Outdoor Switchyard	Glen Waverley (GW) zone substation	Replacement	2024

This chapter also sets out the committed investments to be carried out during the forward planning period for this DAPR worth \$2 million or more to address urgent and unforeseen network issues.

14.1 Individual asset retirements / replacements

This section discusses planned network retirements, or planned asset de-ratings that would result in a system limitation. For more details and data on these limitations please refer to the attached Systems Limitations Template. Note that the Systems Limitation Template includes a high level risk assessment only. A more detailed and accurate assessment will be carried out at the business case or Regulatory Investment Test for Distribution (**RIT-D**) stage.

14.1.1 Transformer Retirements / Replacements

Zone substation transformers are critical elements in the distribution network because of their high replacement cost, their strategic impact on customer supply and their long lead time for repair or replacement. An in-service failure will result in significant energy constraints for around 6 months.

The replacement of these assets is driven by multiple condition assessments of the insulating system, including oil, paper and mechanical withstand capability. An analysis of condition and risk is conducted for all transformers on an individual basis to determine a prudent program of proactive replacement.

Elsternwick (EL) #2 Transformer Retirement/Replacement

The existing EL transformers (#2 and #3) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #2 transformer at EL is in the poorest condition, based on several condition assessments. Based on the condition and risk assessments conducted the #2 Transformer is end of life and is economically justified for retirement and replacement by the end of 2021. The #3 transformer shall be subsequently condition tested and monitored to determine the exact replacement year, with a separate business case to be developed for its replacement.

Subsequently in 2020 United Energy commenced a project to implement its preferred network option to replace the #2 transformer in 2021 as stated as the preferred solution in 2019 DAPR. This project now is committed to proceed at an estimated cost of \$2.4M and will be completed in 2021.

East Malvern (EM) #1 Transformer Retirement/Replacement

The existing EM transformers (#1 and #2) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #1 transformer at EM is in the poorest condition, based on several condition assessments. Condition assessments thus far indicate that the #2 transformer will be reasonably reliable for service for the next five years. Based on the condition and risk assessments conducted the #1 transformer is end of life and is economically justified for retirement and replacement by the end of 2022.

Subsequently in 2020 United Energy commenced a project to implement its preferred network option to replace the #2 transformer before 2022 as stated as the preferred solution in 2019 DAPR. This project now is committed to proceed at an estimated cost of \$2.5M and will be completed in 2022.

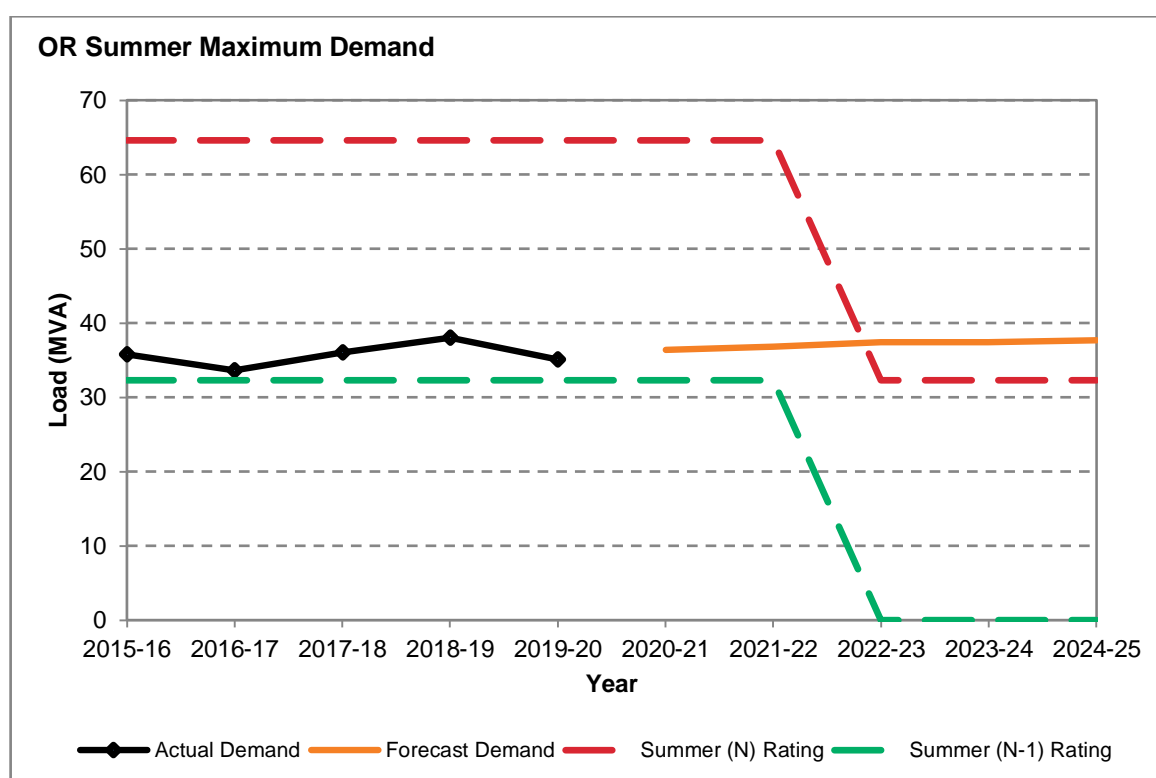
Ormond (OR) #2 Transformer Retirement/Replacement

The existing OR transformers (#2 and #3) are over 50 years old and their condition is assessed as being very close to end-of-life. Load transfers are limited, as the substation is located on the boundary of the 11kV and 22kV distribution networks.

The #2 transformer at OR is in the poorest condition, based on several condition assessments. Based on the condition and risk assessments conducted the #2 transformer is end of life and is economically justified for retirement and replacement by the end of 2022. The #3 transformer shall be subsequently condition tested to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2022.

Figure 14.1 Forecast maximum demand with transformer retirement at OR



The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 37.4MVA of lost load in summer 2022/23, in the event of a failure of the remaining transformer.

To address the anticipated system constraint at OR zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Bentleigh (**BT**), Caulfield (**CFD**), East Malvern (**EM**) and Oakleigh East (**OE**) up to a maximum transfer capacity of 5.6MVA;
- replace #2 transformer in 2022 at an estimated cost of \$2.5 million. The #3 transformer will be assessed for replacement in the future however, with the replacement of the #2 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #2 and #3 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a transformer failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 12.2MVA.

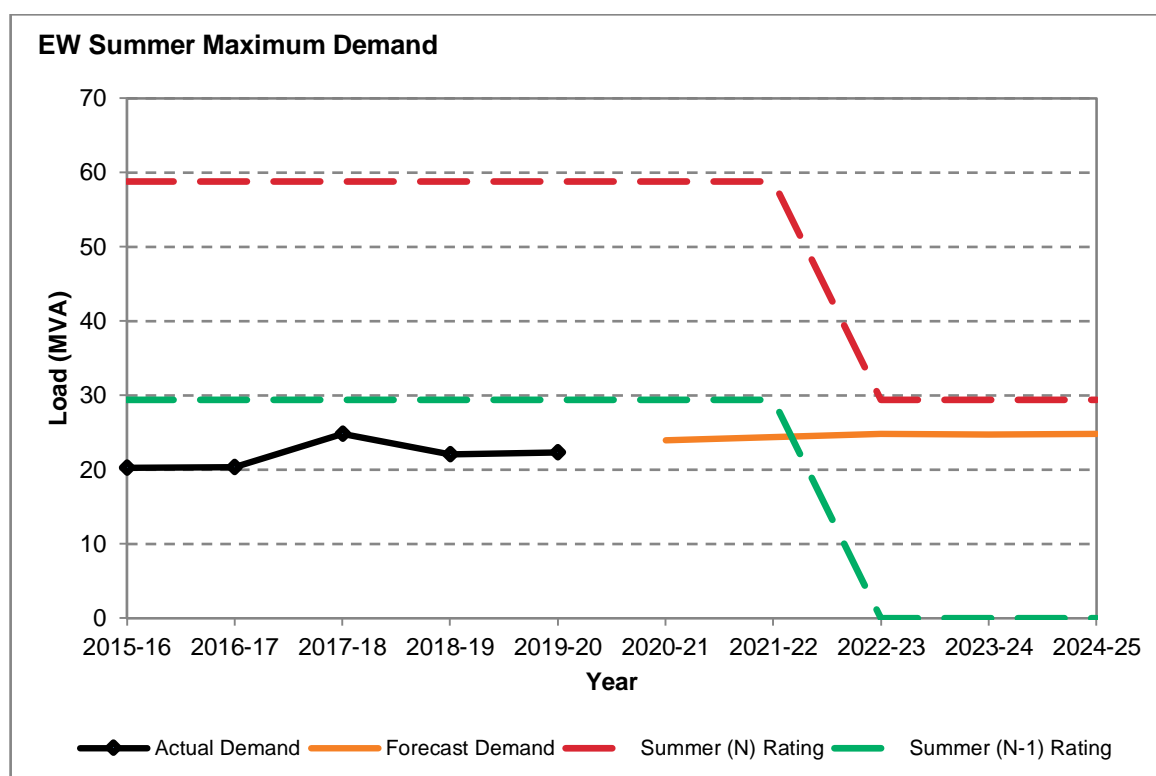
United Energy's preferred network option is to replace the #2 transformer at OR in 2022. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Elwood (EW) #2 Transformer Retirement/Replacement

The existing EW transformers (#1 and #2) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #2 transformer at EW is in the poorest condition, based on several condition assessments. Condition assessments thus far indicate that the #1 transformer will be reasonably reliable for service for the next five years. Based on the condition and risk assessments conducted the #2 transformer is end of life and is economically justified for retirement and replacement by the end of 2022.

The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2022.

Figure 14.2 Forecast maximum demand with transformer retirement at EW

The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 24.8MVA of lost load in summer 2022/23, in the event of a failure of the remaining transformer.

To address the anticipated system constraint at EM zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations North Brighton (**NB**) and Elsternwick (**EL**) up to a maximum transfer capacity of 5.4MVA;
- replace the #2 transformer in 2022 at EW at an estimated cost of \$2.3 million. The #1 transformer will be assessed for replacement in the future but is not expected to be replaced within the 5 year planning period;
- refurbishment of the #2 transformer;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a transformer failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 6.7MVA.

United Energy's preferred network option is to replace the #2 transformer at EW in 2022. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

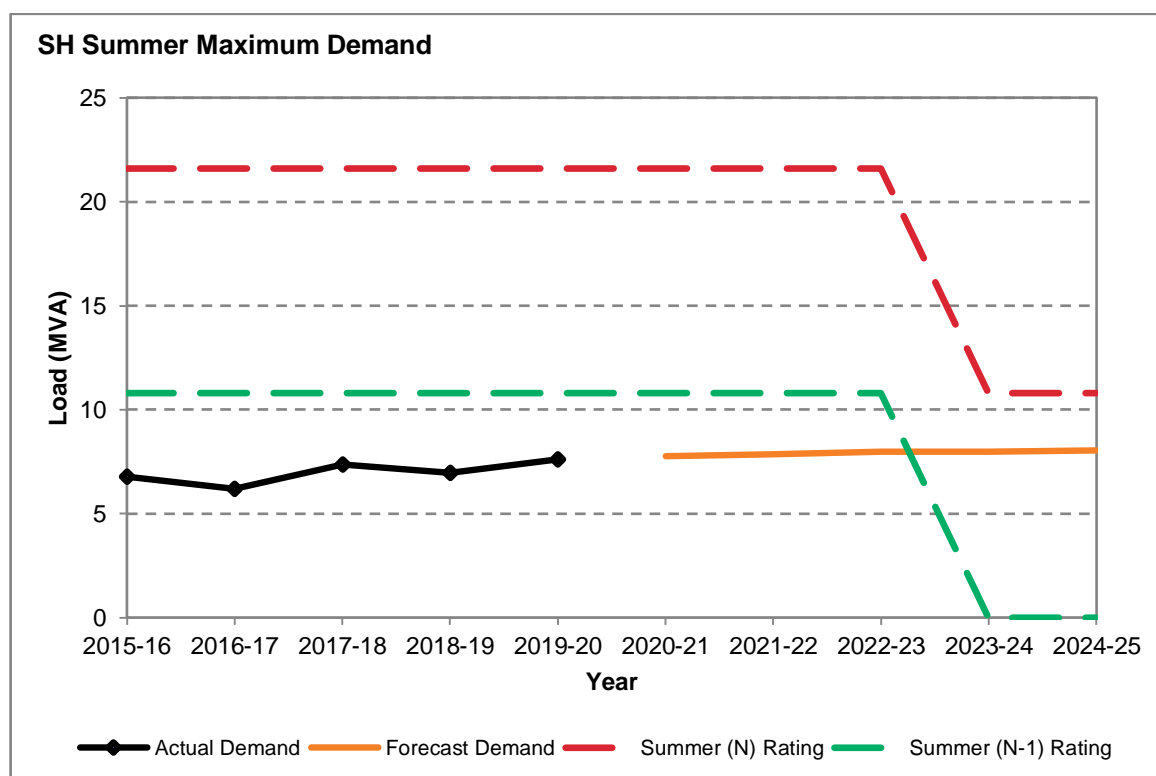
Surrey Hills (SH) Transformer Retirement/Replacement

The existing SH transformers (#2 and #3) are approaching 70 years of age (making them some of the oldest assets installed on the United Energy network). Both transformers are in poor condition.

Due to the isolated nature of the 6.6kV distribution network supplied by SH zone substation, a number of different network options are under consideration by United Energy, which are outlined below. In 2014-15, United Energy replaced the aged 6.6kV switchboard with a new switchboard capable of operating at 11kV or 22kV in the knowledge that conversion of the distribution network to either voltage to allow interconnection to other adjacent substations is a practical option.

The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer failed and retired in 2023.

Figure 14.3 Forecast maximum demand with transformer retirement at SH



The graph shows that retirement would lead to load-at-risk, with up to 8.0MVA of lost load in summer 2023/24, in the event of a failure of the remaining transformer.

To address the anticipated system constraint at SH zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Note: SH has no load transfer capacity;
- replace both of the aged transformers in 2023 and 2024;

- decommission the substation, convert the distribution network to 11kV, and transfer the load to Burwood (**BW**) zone substation;
- convert the distribution network to 11kV, and transfer part of the load to Burwood (**BW**) zone substation, and replace the two aged transformers at SH with a single 22/11kV replacement;
- decommission the substation, convert the distribution network to 22kV, and transfer the load to Doncaster (**DC**) and Box Hill (**BH**) zone substations;
- decommission both transformers, convert the SH distribution network to 11kV and use SH as a 11kV switching substation supplied from the existing 22kV sub-transmission lines at an estimated cost of \$3.6m from 2022 to 2024;
- decommission both transformers, convert the SH distribution network to 22kV, and use SH as a 22kV switching substation supplied from the existing 22kV sub-transmission lines;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a transformer failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 1.7MVA.

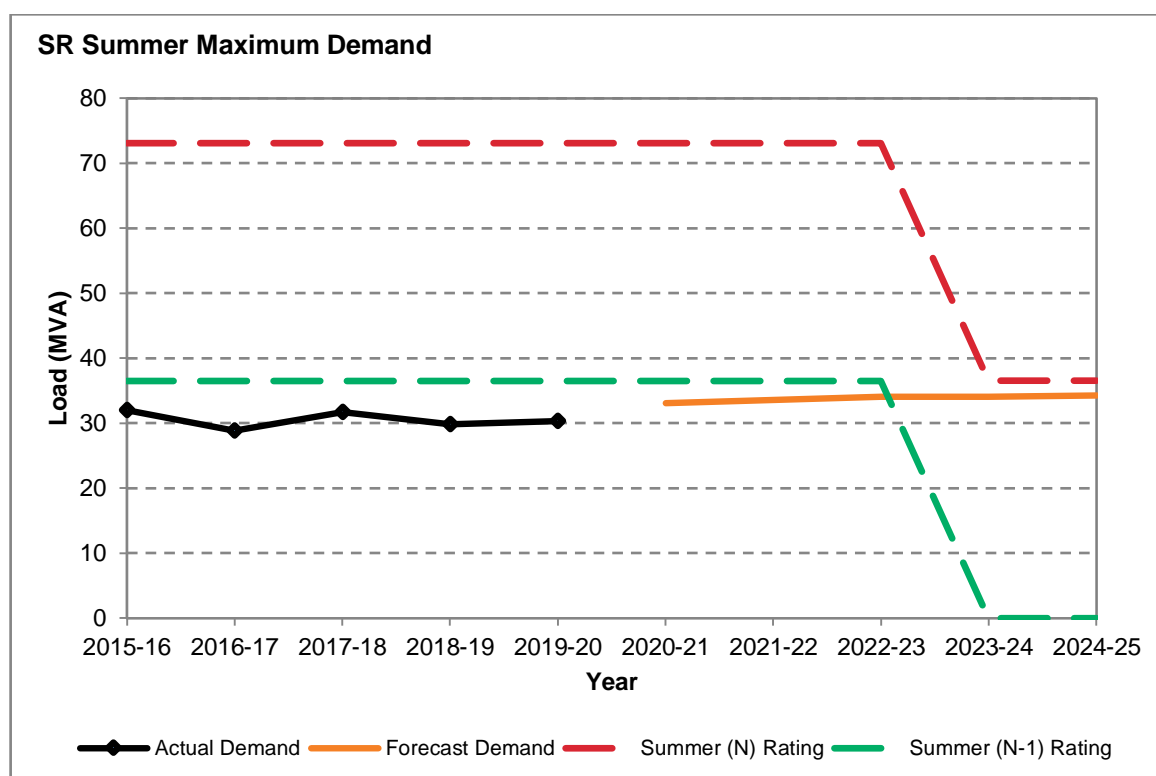
United Energy's current preferred network option is to decommission both transformers and convert SH to an 11kV or 22kV network beginning in 2022. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above.

Sandringham (SR) #3 Transformer Retirement/Replacement

The existing SR transformers (#2 and #3) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #3 transformer at SR is in the poorest condition, based on several condition assessments. Based on the condition and risk assessments conducted the #3 transformer is end of life and is economically justified for retirement and replacement by the end of 2023. The #2 transformer shall be subsequently condition tested and evaluated to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2023.

Figure 14.4 Forecast maximum demand with transformer retirement at SR

The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 34.1MVA of lost load in summer 2023/24, in the event of a failure of the remaining transformer. Furthermore, the forecast demand is above the rating of the remaining transformer.

To address the anticipated system constraint at SR zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Beaumaris (**BR**), Moorabbin (**MR**) and Cheltenham (**CM**) up to a maximum transfer capacity of 13.3MVA;
- replace #3 transformer in 2023 at an estimated cost of \$2.3 million. The #2 transformer will be assessed for replacement in the future however, with the replacement of the #3 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #2 and #3 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 5.3MVA.

United Energy's preferred network option is to replace the #3 transformer at SR in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

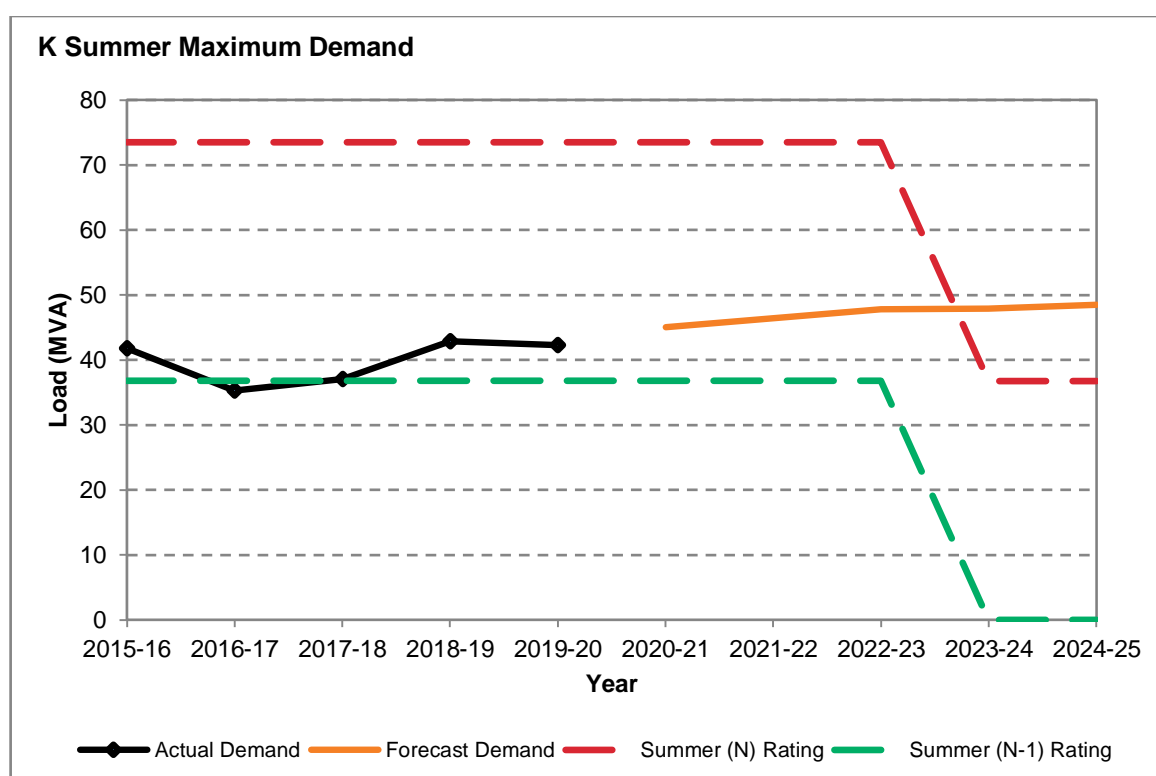
Gardiner (K) #3 Transformer Retirement/Replacement

The existing K transformers (#2 and #3) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #3 transformer at K is in the poorest condition, based on several condition assessments. Based on the condition and risk assessments conducted the #3 transformer is end of life and is economically justified for retirement and replacement by the end of 2023. The #2 transformer shall be subsequently condition tested and evaluated to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2023.

Figure 14.5 Forecast maximum demand with transformer retirement at K



The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 47.9MVA of lost load in summer 2023/24, in the event of a failure of the remaining transformer. Furthermore, the forecast demand is above the rating of the remaining transformer.

To address the anticipated system constraint at K zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Caulfield (**CFD**), Camberwell (**CL**), Riversdale

(RD), Armadale (AR) and East Malvern (EM) up to a maximum transfer capacity of 7.6MVA;

- replace #3 transformer in 2023 at an estimated cost of \$2.5 million. The #2 transformer will be assessed for replacement in the future however, with the replacement of the #3 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #2 and #3 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 15.0MVA.

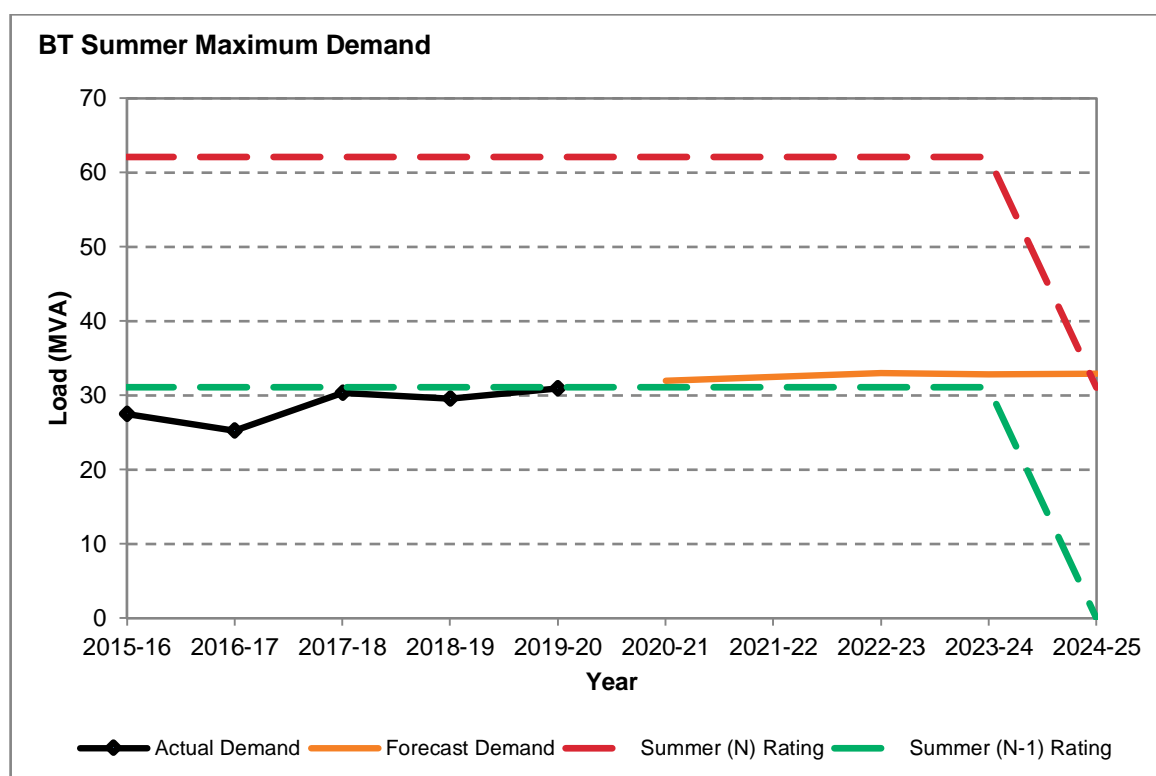
United Energy's preferred network option is to replace the #3 transformer at K in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Bentleigh (BT) #1 Transformer Retirement/Replacement

The existing BT transformers (#1 and #2) are 50 years old and their condition is assessed as being close to end-of-life.

The #1 transformer at BT is in the poorest condition of the two, based on several condition assessments. Based on the condition and risk assessments conducted the #1 transformer is end of life and is economically justified for retirement and replacement by the end of 2024. The #2 transformer shall be subsequently condition tested and evaluated to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2024.

Figure 14.6 Forecast maximum demand with transformer retirement at BT

The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 32.9MVA of lost load in summer 2024/25, in the event of a failure of the remaining transformer. Furthermore, the forecast demand is above the rating of the remaining transformer.

To address the anticipated system constraint at BT zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations North Brighton (**NB**), Moorabbin (**MR**) and Caulfield (**CFD**) up to a maximum transfer capacity of 6.6MVA;
- replace #1 transformer in 2024 at an estimated cost of \$2.5 million. The #2 transformer will be assessed for replacement in the future however, with the replacement of the #1 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #1 and #2 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 7.4MVA.

United Energy's preferred network option is to replace the #1 transformer at BT in 2024. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

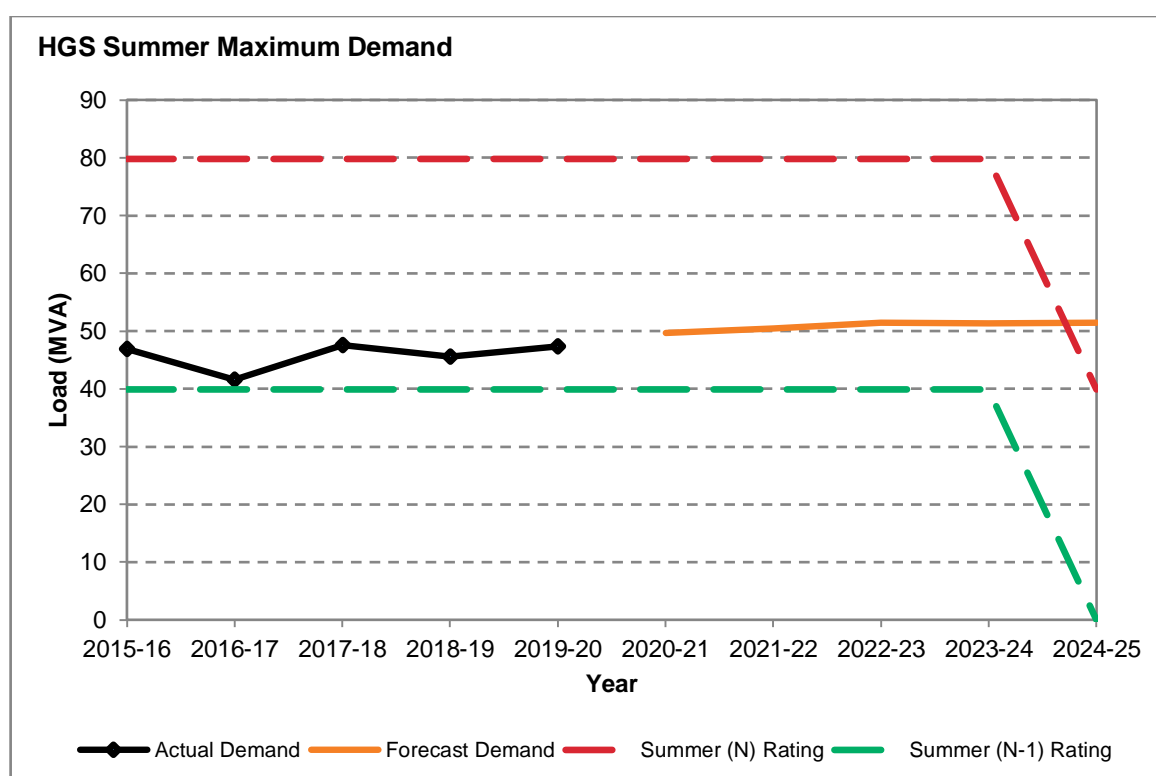
Hastings (HGS) #1 Transformer Retirement/Replacement

The existing HGS transformers (#1 and #3) are over 40 years old and their condition is assessed as being close to end-of-life.

The #1 transformer at HGS is in the poorest condition of the two, based on several condition assessments. Based on the condition and risk assessments conducted the #1 transformer is end of life and is economically justified for retirement and replacement by the end of 2024. The #3 transformer shall be subsequently condition tested and evaluated to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2024.

Figure 14.7 Forecast maximum demand with transformer retirement at HGS



The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 51.4MVA of lost load in summer 2024/25, in the event of a failure of the remaining transformer. Furthermore, the forecast demand is above the rating of the remaining transformer.

To address the anticipated system constraint at HGS zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder

network to adjacent zone substations Mornington (**MTN**), Frankston South (**FSH**) and Langwarrin (**LWN**) up to a maximum transfer capacity of 13.7MVA;

- replace #1 transformer in 2024 at an estimated cost of \$2.5 million. The #3 transformer will be assessed for replacement in the future however, with the replacement of the #1 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #1 and #3 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 11.9MVA.

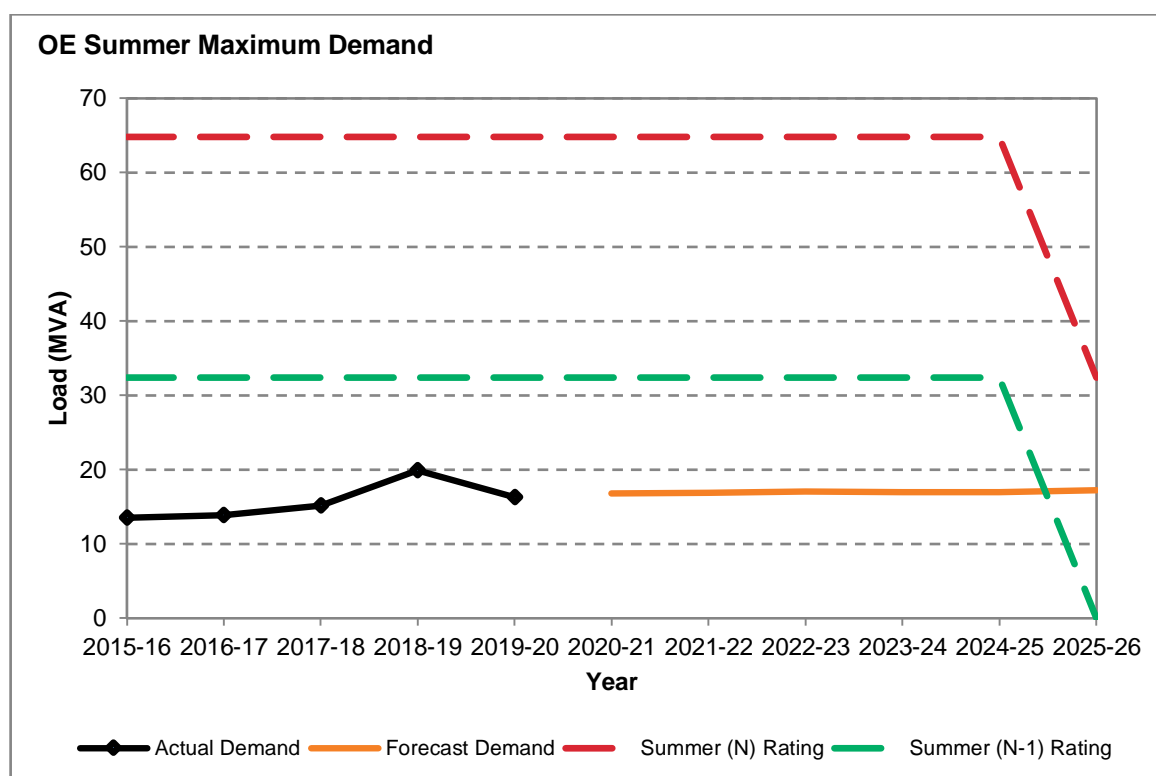
United Energy's preferred network option is to replace the #1 transformer at HGS in 2024. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Oakleigh East (OE) #1 Transformer Retirement/Replacement

The existing OE transformers (#1 and #2) are over 50 years old and their condition is assessed as being very close to end-of-life.

The #1 transformer at OE is in the poorest condition, based on several condition assessments. Condition assessments thus far indicate that the #2 transformer will be reasonably reliable for service for the next five years. Based on the condition and risk assessments conducted the #1 transformer is end of life and is economically justified for retirement and replacement by the end of 2025.

The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2025.

Figure 14.8 Forecast maximum demand with transformer retirement at OE

The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 17.2MVA of lost load in summer 2025/26, in the event of a failure of the remaining transformer.

To address the anticipated system constraint at OE zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substation Oakleigh (**OAK**) up to a maximum transfer capacity of 4.2MVA;
- replace the #1 transformer in 2025 at OE at an estimated cost of \$2.5 million. The #2 transformer will be assessed for replacement in the future but is not expected to be replaced within the 5 year planning period;
- refurbishment of the #1 transformer;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a transformer failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 5.5MVA in the event of a failure of the remaining transformer.

United Energy's preferred network option is to replace the #1 transformer at OE in 2025. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

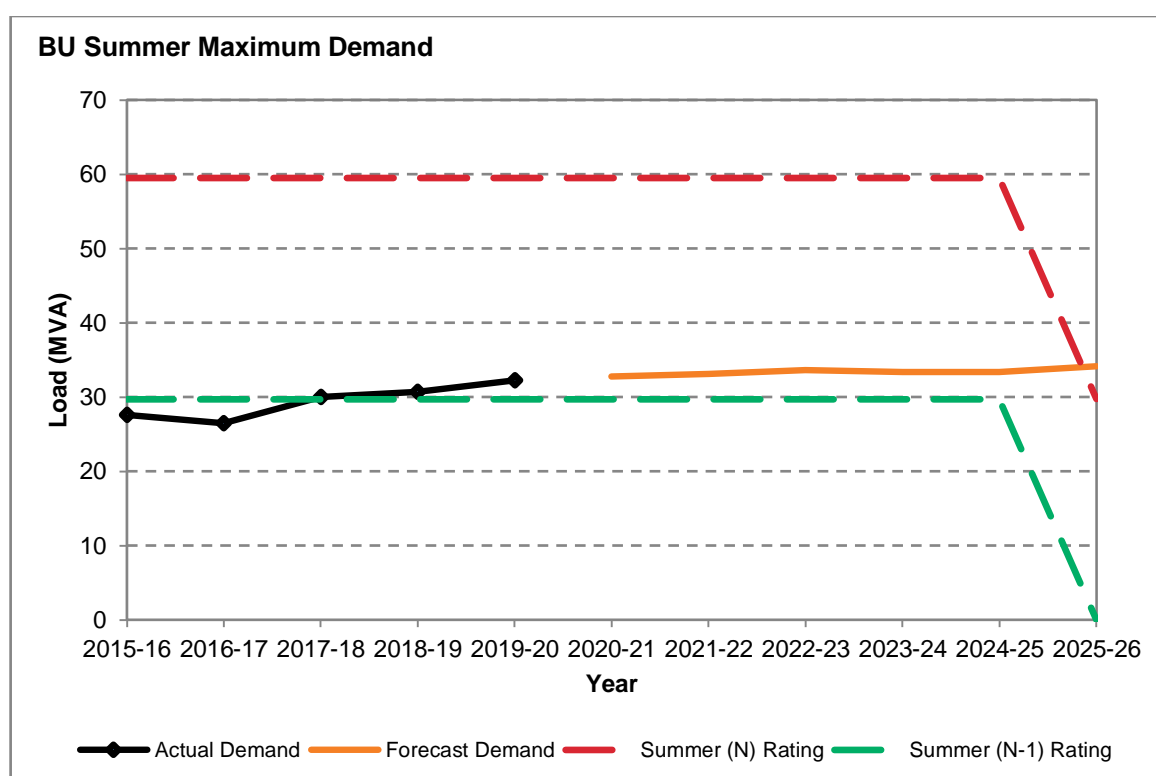
Bulleen (BU) #1 Transformer Retirement/Replacement

The existing BU transformers (#1 and #2) are over 50 years old and their condition is assessed as being close to end-of-life.

The #1 transformer at BU is in the poorest condition of the two, based on several condition assessments. Based on the condition and risk assessments conducted the #1 transformer is end of life and is economically justified for retirement and replacement by the end of 2025. The #2 transformer shall be subsequently condition tested and evaluated to determine the exact replacement year, with a separate business case to be developed for its replacement.

The figure below depicts the historical actual maximum demands, 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2025.

Figure 14.9 Forecast maximum demand with transformer retirement at BU



The graph shows that retirement would lead to a significant amount of load-at-risk, with up to 34.2MVA of lost load in summer 2025/26, in the event of a failure of the remaining transformer. Furthermore, the forecast demand is above the rating of the remaining transformer.

To address the anticipated system constraint at BU zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a transformer failure this would result in significant load-at-risk for up to 6 months until the failed transformer can be replaced. Contingency plans also exist to transfer load via the distribution feeder

network to adjacent zone substation West Doncaster (**WD**) up to a maximum transfer capacity of 6.8MVA;

- replace #1 transformer in 2024 at an estimated cost of \$2.7 million. The #2 transformer will be assessed for replacement in the future however, with the replacement of the #1 transformer, it is not expected to be justified within the 5 year planning period;
- refurbishment of the existing #1 and #2 transformers;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 6.6MVA.

United Energy's preferred network option is to replace the #1 transformer at BU in 2025. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

14.1.2 Switchgear Retirements / Replacements

Switchboards are critical infrastructure for the safe operation of a zone-substation. A switchboard allows the transfer of power from the zone-substation transformers through to the distribution feeders. They also provide the electrical protection for the transformer and each distribution feeder.

A switchboard has many failure modes that will lead to different levels of customer impact. The complete failure of a switchboard could lead to its associated feeders and associated power transformer being out of service for between 4 to 8 months while it is being repaired or replaced.

Elsternwick (EL) 11kV Switchboard Retirement/Replacement

The assets at the EL zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard was no longer economically prudent to operate beyond 2020.

Subsequently in 2019 United Energy commenced a project to implement its preferred network option to replace the switchboard as stated as the preferred solution in the 2018 and 2019 DAPR. This project is now committed to proceed at an estimated cost of \$2.8M and will be completed in 2021.

Sandringham (SR) 11kV Switchboard Retirement/Replacement

The assets at the SR zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2021.

Subsequently in 2020 United Energy commenced a project to implement its preferred network option to replace switchboard in 2021 as stated as the preferred solution in 2019 DAPR. This project now is committed to proceed at an estimated cost of \$2.3M and will be completed in 2021.

Bulleen (BU) 11kV Switchboard Retirement/Replacement

The assets at the BU zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is over 50 years old, and is experiencing a decrease in reliability and condition. A recent incident with BU switchboard further decreased the condition and energy supply capabilities.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2022. In addition to the decreasing condition the replacement of the 11kV switchboard was accelerated to align with an aged relay replacement scheduled for completion by the end of 2022. The recent issues with the switchboard have accelerated replacement.

Subsequently in 2020 United Energy commenced a project to implement its preferred network option to replace switchboard by 2022. This project now is committed to proceed at an estimated cost of \$2.6M and will be completed in 2022.

Bentleigh (BT) 11kV Switchboard Retirement/Replacement

The assets at the BT zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2022.

Subsequently in 2020 United Energy commenced a project to implement its preferred network option to replace switchboard by 2022. This project now is committed to proceed at an estimated cost of \$3.2M and will be completed in 2022.

East Malvern (EM) 11kV Switchboard Retirement/Replacement

The assets at the EM zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2023.

The table below shows the level of load-at-risk at EM in the event of a major failure of a switchboard (in this example, a major failure is assumed to be a probable scenario of affecting one of the two busses at the station).

Table 14.2 EM Switchboard failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	18.9	19.3	19.6	19.6	19.7

The table above shows that in summer 2023/24 there is forecast to be up to 19.6MVA of load-at-risk in the event of a major failure of one bus.

To address the anticipated system constraint at EM zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a switchboard failure, this would result in significant load-at-risk for between 4 to 8 months until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Gardiner (**K**) and Ormond (**OR**) up to a maximum transfer capacity of 5.8MVA;
- replace the switchboard in 2022 and 2023 at an estimated cost of \$3.0 million;
- refurbishment of the existing 11kV switchboard;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 14.6MVA in the event of a failure of a bus at EM.

United Energy's preferred network option is to replace the 11kV switchboard at EM beginning in 2022. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Elwood (EW) 11kV Switchboard Retirement/Replacement

The assets at the EW zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2024.

The table below shows the level of load-at-risk at EW in the event of a major failure of a switchboard (in this example, a major failure is assumed to be a probable scenario of affecting one of the two busses at the station).

Table 14.3 EW Switchboard failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	12.0	12.2	12.4	12.4	12.4

The table above shows that in summer 2024/25 there is forecast to be up to 12.4MVA of load-at-risk in the event of a major failure of one bus.

To address the anticipated system constraint at EW zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a switchboard failure, this would result in significant load-at-risk for between 4 to 8 months until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations North Brighton (**NB**) and Elsternwick (**EL**) up to a maximum transfer capacity of 5.4MVA;
- replace the switchboard in 2023 and 2024 at an estimated cost of \$2.6 million;
- refurbishment of the existing 11kV switchboard;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 2.0MVA in the event of a failure of a bus at EW.

United Energy's preferred network option is to replace the 11kV switchboard at EW beginning in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Beaumaris (BR) 22kV Indoor Switchboard

The assets at the BR zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is over 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2025.

The table below shows the level of load-at-risk at BR in the event of a major failure of a switchboard (in this example, a major failure is assumed to be a probable scenario of affecting one of the two busses at the station).

Table 14.4 BR Switchboard failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	14.8	15.0	15.3	15.3	15.3

The table above shows that in summer 2024/25 there is forecast to be up to 15.3MVA of load-at-risk in the event of a major failure of one bus.

To address the anticipated system constraint at BR zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a switchboard failure, this would result in significant load-at-risk for between 4 to 8 months until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Mentone (**M**) and Cheltenham (**CM**) up to a maximum transfer capacity of 8.0MVA;
- replace the switchboard in 2024 and 2025 at an estimated cost of \$2.8 million;
- refurbishment of the existing 22kV switchboard;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 1.1MVA in the event of a failure of a bus at BR.

United Energy's preferred network option is to replace the 22kV switchboard at BR beginning in 2024. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Oakleigh East (OE) 11kV Indoor Switchboard

The assets at the OE zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2025.

The table below shows the level of load-at-risk at OE in the event of a major failure of a switchboard (in this example, a major failure is assumed to be a probable scenario of affecting one of the two busses at the station).

Table 14.5 OE Switchboard failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	8.4	8.4	8.5	8.5	8.5

The table above shows that in summer 2024/25 there is forecast to be up to 8.5MVA of load-at-risk in the event of a major failure of one bus.

To address the anticipated system constraint at EM zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a switchboard failure, this would result in significant load-at-risk for between 4 to 8 months until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substation Oakleigh (**OAK**) up to a maximum transfer capacity of 4.2MVA;
- replace the switchboard in 2024 and 2025 at an estimated cost of \$3.0 million;
- refurbishment of the existing 11kV switchboard;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 1.4MVA in the event of a failure of a bus at OE.

United Energy's preferred network option is to replace the 11kV switchboard at OE beginning in 2024. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Heatherton (HT) 22kV Switchyard Replacement

A number of assets at HT zone substation are approaching the end of their life. The existing oil-filled circuit breakers are approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that it is economic to undertake works at HT.

The table below shows the level of load-at-risk at HT in the event of a failure of a feeder circuit breaker at HT (in this case the 10% POE feeder loading on HT 11 has been shown as an example).

Table 14.6 HT Switchgear failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	6.3	6.4	6.4	6.5	6.5

The table above shows that in summer 2023/24 there is forecast to be up to 6.5MVA of load-at-risk in the event of a failure at HT.

To address the anticipated system constraint at HT zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of an asset failure, this would result in significant load-at-risk for approximately one month until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to the adjacent zone substation Clarinda (**CDA**) up to a maximum transfer capacity of 19.0MVA;
- replace all the 22kV bus work and switchgear at an estimated cost of \$3.5 million in 2023;
- targeted replacement of 22kV assets which present the highest risk to the station at a cost of \$1.1 million in 2023;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by up to approximately 8.7MVA in the event of specific failures within the substation that will not be able to be transferred.

United Energy's preferred network option is undertake targeted replacement of 22kV assets at HT in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Doncaster (DC) 22kV Switchyard Replacement

A number of assets at DC zone substation are approaching the end of their life. The existing oil-filled circuit breakers are approaching 50 years old, and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that it is economic to undertake works at DC.

The table below shows the level of load-at-risk at DC in the event of a failure of a feeder circuit breaker at DC (in this case the 10% POE feeder loading on DC 1 has been shown as an example).

Table 14.7 DC Switchgear failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	11.1	11.1	11.2	11.3	11.4

The table above shows that in summer 2023/24 there is forecast to be up to 11.3MVA of load-at-risk in the event a failure at DC.

To address the anticipated system constraint at DC zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of an asset failure, this would result in significant load-at-risk for approximately one month until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to the adjacent zone substations Box Hill (**BH**) and Nunawading (**NW**) up to a maximum transfer capacity of 14.1MVA;
- replace all the 22kV bus work and switchgear at an estimated cost of \$3.5 million in 2023 and 2024;
- targeted replacement of 22kV assets which present the highest risk to the station at a cost of \$1.6 million in 2023 and 2024;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by up to approximately 3.7MVA in the event of specific failures within the substation that will not be able to be transferred.

United Energy's preferred network option is undertake targeted replacement of 22kV assets at DC beginning in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

Glen Waverley (GW) 22kV Switchyard Replacement

A number of assets at GW zone substation are approaching the end of their life. The existing oil-filled circuit breakers are over 50 years old, and are experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability to date indicate that it is economic to undertake works at GW.

The table below shows the level of load-at-risk at GW in the event of a failure of a feeder circuit breaker at GW (in this case the 10% POE feeder loading on GW 1 has been shown as an example).

Table 14.8 GW Switchgear failure load-at-risk

	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE Load-at-risk (MVA)	10.0	10.7	10.7	10.7	10.8

The table above shows that in summer 2023/24 there is forecast to be up to 10.7MVA of load-at-risk in the event of major failures at GW.

To address the anticipated system constraint at GW zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of an asset failure, this would result in significant load-at-risk for approximately one month until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to the adjacent zone substation Notting Hill (**NO**), Mulgrave (**MGE**) and East Burwood (**EB**) up to a maximum transfer capacity of 19.1MVA;
- targeted replacement of 22kV assets which present the highest risk to the station at a cost of \$800k;
- replace all the 22kV bus work and switchgear an estimated cost of \$3.5 million in 2023 and 2024;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by up to approximately 1.0MVA in the event of specific failures within the substation that will not be able to be transferred.

United Energy's preferred network option is undertake targeted replacement of 22kV assets at GW beginning in 2023. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers, and/or non-network solutions, will be used to mitigate the load-at-risk in the interim period.

14.2 Grouped asset retirements / replacements

This section discusses planned replacements for groups of assets. For more detail on United Energy's asset management methodologies please refer to sections 12 and 13.

14.2.1 Poles

Poles are located throughout the United Energy territory and replaced each year at various locations and timing depending upon asset condition. The location and timing of the asset replacement are not known before inspection. United Energy expects to replace a large number of poles during the forward planning period for this DAPR.

Routine inspection and rectification work maintains the general condition of all pole populations in a serviceable condition.

Pole replacement and reinstatement occurs as a result of a cyclic condition inspection that involves inspection and testing of poles to ensure that they are fit for purpose. The assessment criteria classifies poles as serviceable, limited life or unserviceable.

14.2.2 Pole top structures

Pole top structures consist of cross-arms, insulators, stay wires and associated hardware.

The wooden cross-arm population is aged and consequently the risk of asset failure and pole fires is increasing.

The condition of pole top structures and cross-arms is monitored as part of the routine asset inspection and replacement occurs based on condition. The location and the timing of the asset replacements are not known before inspection. United Energy expects to replace a large number of pole top structure assets during the forward planning period for this DAPR.

14.2.3 HV fuses

HV Outdoor Fuses consist of Boric Acid (**BA**), Expulsion Drop Out (**EDO**) and Powder Filled (**PF**) type fuses. The HV fuses are located through-out the United Energy overhead electrical distribution system. HV outdoor fuses are sacrificial devices used to provide overcurrent protection to downstream circuits and assets by interrupting high fault currents.

HV Fuses are currently performing at an acceptable level. Their condition is assessed as part of routine pole top asset inspection. The main drivers for replacement of HV fuse holders are:

- damage identified as part of asset inspection,
- in-service failure,
- unacceptable EDO fuse type,
- EDO replacement due to high fault levels.

The location and the timing of the asset replacements are not known before the inspection. Once identified, replacement of HV fuses may be proactive, depending on assessed condition and risk.

14.2.4 Distribution Switchgear

Overhead switchgear

Overhead switchgear comprises of pole mounted air-break switches (**ABS**), Automatic Circuit Reclosers (**ACR**), HV isolators and gas insulated switches.

Overhead switchgear is inspected for condition and to identify defects as part of routine 3/5 year overhead asset inspection. Thermal survey of ACRs is undertaken as part of the regular distribution overhead feeder thermal surveys. ACRs undergo 4-yearly maintenance alternating minor and major maintenance. Major maintenance involves functional testing, battery replacement and verification of protection time-current characteristics and general cleaning and tightening of components while minor maintenance only involves battery replacement and general cleaning.

ABS ceased to be installed on network in approximately 1994 and since then gas insulated switches are the standard. These switches are demonstrating an increasing rate of functional failure as a percentage of the population, indicating that their condition is deteriorating. Maintenance on these switches has proved ineffective as switch misalignment and maloperation persist. As a result of their ineffective operation and

potential health and safety issues posed to operators there is a reluctance to use these switches.

To address the ABS issues, United Energy strategy has been to proactively replace all ABS with gas-insulated switches over a 10 year period with targeted completion in year 2025 approximately. Switches are replaced as part of proactive programs and on failure. The location of replaced switches will be randomly distributed throughout the United Energy network.

LV switchgear installed on the overhead network comprises the two main groups i.e. LV open blade isolators or LV fused/switch disconnectors housed in an insulated enclosure. The condition of these switches is routinely determined as part of asset inspection and replacement scheduled based on condition.

LV switches are simple devices and do not have many working parts or maintainable/replaceable elements. It is not possible or cost effective to replace individual components or to undertake maintenance of these assets. Therefore, these assets are currently replaced when identified to be defective.

There is an increasing number of LV switches that have reached or exceeded their expected life. This has been experienced on the network as an increase in the number of LV switch replacements.

Ground Mounted Switchgear

Ground mounted switchgear is mostly a component of non-pole distribution substations but may also be standalone switchgear. HV switchgear provides load switching functionality plus transformer protection. There has been an array of switchgear on the network ranging from physically separated air-break gear with limited switching capacity through to fully integrated gas insulated switches with full network load-break/fault-make capabilities. The number and types of switching technology used has been progressively rationalised.

The condition of switchgear is assessed as part of routine six monthly asset inspections and where required corrective maintenance or replacement undertaken. The location and the timing of the asset replacement is not known until the inspection.

Modern current standard switchgear comprises gas-insulated ring main units (**RMU**). These are of varying ages with the oldest units up to 35 years old. The performance is in general considered satisfactory and no preventative maintenance is undertaken.

There are also varying non-preferred switchgear employing older air-break technology or having particular reliability issues and no longer supported by the manufacturer with spares. Non-preferred switchgear (particularly the indoor wall mounted air-break type) suffer from misalignment and maintenance is ineffective. Due to this and the potential H&S issues they are seldom used.

United Energy has a strategy to replace all non-preferred switchgear with modern gas insulated RMU technology over a 10 year period. The replacements will occur through targeted proactive programs in conjunction with replacements due to faults.

14.2.5 Pole mounted HV line capacitors

Line capacitors are assets that are located on HV feeders attached to poles, and consist of three single-phase capacitor cans and three single-phase switches. The switches control the connection to the distribution network, via a manual or automated switch, to manage power factor and voltage levels on local areas of the network. These are located throughout the distribution network.

The main deterioration drivers for line capacitors are:

- accumulated electrical stress causing degradation and insulation failure of capacitor cans;
- exposure to network harmonics results in accelerated aging of capacitors cans;
- degradation of control box housing, resulting in failure of the control box and the capacitor bank failing to operate correctly, remaining either switched in or out;
- accumulated switching operations deteriorates HV switches due to high inrush currents and may lead to switch failure; and
- damage from lightning strikes.

The condition of line capacitors is assessed as part of:

- the 3/5 year inspection of overhead assets;
- detailed pre-summer checks of all fixed capacitors; and
- switched capacitors (controlled by time, temperature or VAR) are checked remotely by using the information system PI. The system will look for step changes in feeder reactive power when the capacitors are switched.

Replacement drivers for line capacitors are based on in-service failures or replacements due to condition or defects as identified by inspection, as well as considering the distribution power factor levels at the substation. Location and the timing of the asset replacement are not known until the inspection.

14.2.6 Overhead conductor

United Energy has approximately 10,034 route km of overhead line, the large majority of which is bare conductors. Lines were initially hard drawn stranded copper or galvanized steel which now represents the oldest conductors in the overhead network. Steel Reinforced Aluminium Conductor (**ACSR**) was introduced in about 1960 followed by “All Aluminium” Conductor (**AAC**) in about 1975. Stranded Aluminium conductor now represents the predominant conductor in the network.

Aerial Bundled Cable (**ABC**) was introduced in the late 1980s and this is the current overhead line standard for new and replacement LV lines.

High voltage ABC and covered conductor has been used in special applications for managing fire risk and protecting trees of significant community value. United Energy expects to replace a large number of kilometres of overhead lines with insulated solutions during the forward planning period for this DAPR.

Overhead conductor condition is assessed as part of routine overhead asset inspection including use of elevated camera inspections. Replacement of conductor where poor performance is identified is based on results of elevated camera inspections or investigation of condition and tensile strength of in-service samples. The location and the timing of the asset replacement are not known until the time of the inspection.

The condition of existing copper and aluminium conductors is generally considered to be good. For the majority of the network there are no planned replacements considered necessary. The conductor that is replaced is identified via inspection or other condition monitoring to be in poor condition, requiring prompt replacement to address the risk of failure. The required replacement timeframe from detection of the defect to replacement is between 3 to 6 months.

The performance of existing ampact connectors is deteriorating. United Energy has a strategy to replace a portion of these connectors over a 5-year time period. The replacements will occur through targeted proactive risk-based replacement programs in conjunction with replacements due to faults.

14.2.7 Underground cables

The majority of underground cables on the United Energy network consist of cross-linked polyethylene (**XLPE**). XLPE cables have a generally good performance. Most of the issues are in the earliest vintage single core single jacket cables from the former Doncaster and Templestowe Council. These are up to 37 years of age and are suffering from water treeing related insulation failure. Elsewhere most cable failures are in joints on cables of early manufacture. The 66kV cables are not posing any issues.

Replacement decisions on underground cables are based on condition assessment, fault history and economic evaluation. It is expected that the majority of underground cable replacement will occur in the Doncaster and Templestowe region of United Energy during the forward planning period for this DAPR, however the timing of these replacements is not known at present.

14.2.8 Low voltage services

Services are network assets that connect a customer, from their residence to the electricity network. They can be overhead conductors or underground cables and supply all residential, industrial and commercial customers.

There are various types of services on the network reflecting a broad time span. They include:

- Neutral Screen (aluminium & copper);
- PVC grey twisted;

- XLPE black;
- other.

The condition of LV services is assessed as part of:

- the 3/5 year inspection of overhead assets;
- monitoring of neutral integrity through smart meters;
- Neutral & Supply Testing (**NST**) of non-smart meter premises.

The performance of neutral screened services has deteriorated with age and resulted in a relatively high number of electric shock incidents, commonly due to a broken or high impedance neutral connection.

Replacement drivers for LV services include:

- replace on failure or as identified to be faulty after inspection;
- replacement due to high neutral resistance as determined by smart meter or NST test;
- replacement of neutral screen services at sites without a smart meter;
- replacement as a result of service not meeting minimum required ground clearance;
- often a service breakaway device is installed on a low service or a service with a potential tree hazard;
- replacement due to property crossing issues; and
- 10 year proactive replacement program for specific service types (i.e. neutral screens and twisted pairs) based on the heightened risk profile.

United Energy's policy is that any non-preferred service cable encountered during maintenance works is replaced. Specifically this includes Twisted Pair, Neutral Screen Services and any services that do not conform to current height standards. Currently all services other than ABC services are considered to be "non-preferred" and will be opportunistically replaced with the current standard, when undertaking other LV planned works on a pole, or based on inspection or condition assessment.

Location and the timing of the asset replacement are not known until the inspection or condition assessment. United Energy expects that it will replace a large number of services during the forward planning period for this DAPR.

14.2.9 Distribution Transformers

Distribution substations are categorized as indoor, kiosk, ground mounted (compound) or pole mounted type substations. They are supplied via the High Voltage Distribution network from zone substations.

Distribution substations are comprised of high voltage switchgear and associated protection equipment (high voltage fuses or protection relays controlling high voltage circuit breakers), a transformer or transformers, and low voltage switchgear and associated protection equipment (generally fuses but can include low voltage circuit breakers). It

includes an earthing system and is constructed to ensure unauthorised access to the equipment by the general public is prevented.

The condition of distribution substations is monitored via visual inspection and thermal (infra-red) scanning. This is carried out on a routine basis. Pole top substations are inspected as part of the pole and line inspection program. Indoor and kiosk substations are inspected as part of a separate program aimed at ensuring the condition and security of these installations is maintained and the grounds and easements they are installed in are maintained in good condition.

Defects identified in these inspections are to be repaired in a timeframe commensurate with the severity of the defect or with the scheduled switchgear preventive maintenance where applicable, or scheduled for later repair in logical work packages to minimise the number of times customers are off supply.

There is no programmed replacement of substations as a whole. Replacement is triggered generally by load increase, failure, regulatory requirements or condition assessment.

Distribution transformers have a long life expectancy, and, except when replaced for increased load reasons are normally run to failure. Nevertheless, a small number, are replaced each year for various reasons including minor oil leaks and internal winding failure. The location and the timing of these replacements are not known until condition inspection or monitoring.

14.2.10 Surge Arresters

Surge arresters are located throughout the United Energy overhead electrical distribution system. Surge arresters are a sacrificial protective device. Their function is to protect other valuable assets from the high voltage spikes, such as those caused by lightning and switching surges. The location and the timing of the replacement are therefore not known in advance.

There is no corrective or preventative maintenance undertaken and surge arresters are run to failure.

The main drivers for replacement of surge arresters are:

- replace on failure or as identified to be faulty after inspection;
- targeted replacement of non-preferred surge arresters; and
- bulk replacement as part of Rapid Earth Fault Current Limiter (**REFCL**) projects of surge arresters that do not meet the required overvoltage duty.

14.2.11 66kV Transformer bushings

There have been a number of 66kV bushing failures on United Energy transformers over the past 15 years. The condition of all transformer bushings is monitored by a program of routine condition assessment. A bushing replacement program is in place driven by the results of these condition assessments and assessments of the failure consequence.

The replacement of bushings is not planned over the forward planning period for this DAPR, with a replacement required immediately, or within 6 months depending on the assessed condition of the plant. United Energy is not able to predict which specific substations will have a constraint introduced beyond the period specified. Therefore the location and the timing of the replacement cannot be planned, and United Energy is not able to predict which specific substations will have a retirement and at which time.

14.2.12 Protection Relays

Protection and control systems are critical to the safe and reliable operation of the network. These systems are designed to detect the presence of power system faults and/or other abnormal operating conditions and to automatically isolate the faulted network by the opening of appropriate high voltage circuit breakers. Failure to isolate power system faults will invariably result in severe damage to network plant and equipment, presents a serious health and safety hazard to the public, and greatly increases risk of fire starts.

The relaying technology used to implement these protection and control systems has evolved and changed significantly over the past 50 years and can be classified chronologically as electro-mechanical, analogue electronic and digital electronic (including numerical) technologies.

The decision to retire and renew protection and control systems is based on a number of factors broadly including:

- Adopting a programmed preventative maintenance (per RCM) coupled with planned relay replacement prior to failure based on asset condition and most economic lifecycle cost (determined by risk and consequence of failures) and
- Aligning with other works at the zone substation where it is economical to do so (e.g. align with switchboard or switchyard replacement works).

Protection and control relays at a number of zone substations are approaching end of life. The table below summarises United Energy's forecast replacement activity over the next five year period. In accordance with United Energy's economic assessment framework, asset replacement is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options including do nothing (replace on failure) and increased maintenance (replace on failure). The timing of each project is subject to an economic assessment using the most current input data.

Table 14.9 Relay Replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
Elsternwick (EL)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2021
Dandenong (DN)	Electro-mechanical, analogue electronic and digital relay replacement aligned with control building retirement works	2021
Sandringham (SR)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2021
Bulleen (BU)	Electro-mechanical and analogue electronic relay replacement	2022
Springvale (SV)	Digital and electro-mechanical relay replacement	2022
Bentleigh (BT)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2022
Hastings (HGS)	Electro-mechanical, analogue electronic and digital relay replacement aligned with control building replacement works	2022
Frankston South (FSH)	Electro-mechanical, analogue electronic and digital relay replacement aligned with control building replacement works	2022
Heatherton (HT)	Electro-mechanical, analogue electronic and digital relay replacement aligned with 22kV outdoor switchgear and control building replacement works	2023
East Malvern (EM)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2023
Glen Waverley (GW)	Digital and electro-mechanical relay replacement	2024
Elwood (EW)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2024
Beaumaris (BR)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2025
Dandenong Valley (DVY)	Digital relay replacement	2025
Oakleigh East (OE)	Digital relay replacement driven by 11kV indoor switchboard replacement works	2025

14.2.13 D.C. Systems

D.C. supply systems are critical to the safe and reliable operation of the zone substation and is required to support the operation of protection and control systems amongst other things. The D.C. supply system consists of battery banks, battery chargers, distribution boards and associated management and monitoring systems.

The life of a battery bank is largely determined by its design and actual operating conditions. A battery capacity less than 80% of the nominal capacity means the battery is at end of life. Battery bank replacements are forecast based on failure history of individual battery models and consequence of failure. Shorter term replacement decisions are also driven by condition assessment (per results of planned maintenance and/or online condition monitoring). Battery banks usually fail within two years of the first signs of significant deterioration.

Each battery bank is kept on charge via the application of a battery chargers which has a typical life expectancy of between 15-20 years. Battery charger replacements forecasts are based on failure history of individual battery charger models.

Replacement of zone substation battery banks and chargers are considered in-conjunction with other asset replacement works at the target zone substation where it is considered economic and consistent with United Energy's economic assessment framework.

The battery bank replacement works identified over the next five years are shown in the table below:

Table 14.10 Battery Bank Replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
RBD	Risk assessment based on historical failures and consequence of failure.	2021
SR	Replacement driven by 11kV indoor switchboard replacement works	2021
MTN, SH, HGS, BU	Risk assessment based on historical failures and consequence of failure.	2022
WD, M, EM, HT	Risk assessment based on historical failures and consequence of failure.	2023
BR, KBH, GW	Risk assessment based on historical failures and consequence of failure.	2024

The battery charger replacement works identified over the next five years are shown in the table below.

Table 14.11 Battery Charger Replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
Sandringham (SR)	Replacement driven by 11kV indoor switchboard replacement works	2021
Bulleen (BU)	Risk assessment based on historical failures aligned with planned relay replacement	2022
Springvale (SV)	Risk assessment based on historical failures aligned with planned relay replacement	2022
Hasting (HGS)	Risk assessment based on historical failures aligned with planned relay replacement	2022
Frankston South (FSH)	Risk assessment based on historical failures aligned with planned relay replacement	2022
Heatherton (HT)	Risk assessment based on historical failures aligned with planned relay replacement	2023
Glen Waverley (GW)	Risk assessment based on historical failures aligned with planned relay replacement	2024
Dandenong Valley (DVY)	Risk assessment based on historical failures aligned with planned relay replacement	2025

14.3 Summary of planned asset deratings

The rating of an asset is the rating at which the asset can operate reliably. Typically, this is generally set by the manufacturer of the asset, based on design criteria. However, where assets are operating beyond their design life, their condition may deteriorate such that a de-rating may be required to ensure reliable operation. This may be a prudent and more cost-effective option than replacing the asset.

United Energy's asset management strategies include for some assets (namely power transformers) the requirement to constantly monitor the asset condition, and to revise the cyclic rating based on;

- Observed differences between expected and actual asset performance;
- Identified condition assessment resulting in a different parameter to that assumed; during the previous rating allocation;
- Plant modifications;
- Changes in load profile affecting asset performance.

United Energy constantly undertake plant condition assessments, of which some assessments will be of key parameters that are used to determine the asset's rating. These assessments typically involve electrical, mechanical, moisture or thermal analysis. Any de-rating is promptly applied to manage risk once identified; thus, de-ratings are normally reactive in nature.

United Energy has no planned asset deratings in the forward planning period for this DAPR.

14.4 Committed projects

This section sets out a list of committed investments worth \$2 million or more to address urgent and unforeseen network issues.

United Energy recently experienced a network incident at Bulleen (BU) which resulted in a decrease in condition and supply reliability to the switchboard. This incident along with alignment to the relay replacement at the station have been drivers for the earlier replacement of the switchboard which was not included in last year's DAPR.

15 Regulatory tests

This section sets out information about large network projects that United Energy has assessed, or is in the process of assessing, using the Regulatory Investment Test for Distribution (**RIT-D**) during the forward planning period for this DAPR.

This chapter also sets out possible RIT-D assessments that United Energy may undertake in the future.

Large network investments are assessed using the RIT-D process. The RIT-D relates to investments where the cost of the most expensive credible option is more than \$6 million. The RIT-D has historically been used for large augmentation projects, and was extended to include replacement projects from 18 September 2017.

15.1 Current regulatory tests

The table below provides an overview of the regulatory test projects that are underway or completed by United Energy in 2020.

Table 15.1 Status of United Energy regulatory tests

Project name	Regulatory test status	Proposed commissioning date	Comments
Lower Mornington Peninsula Supply Area RIT-D	Completed in 2016	2018/19 (non-network solution)	NNOR published in November 2014. DPA published in November 2015. FPA published in May 2016. New and extended demand side solution contracted in 2020.

This RIT-D project and the developments since the conclusion of the RIT-D are further described below. More details and further examples can also be found in our Demand Side Engagement Document.¹¹

15.2 Lower Mornington Peninsula Supply Area RIT-D

In May 2016, United Energy published its Final Project Assessment Report (**FPA**) relating to constraints in the lower Mornington Peninsula area.

The purpose of the RIT-D was to address the following network limitations:

- from summer 2016/17, an unplanned outage of the sub-transmission line from Mornington (**MTN**) to Dromana (**DMA**) zone substation during summer maximum

¹¹ <https://www.unitedenergy.com.au/wp-content/uploads/2019/07/UE-PL-2202-Demand-Side-Engagement-Document.pdf>

demand conditions was expected to lead to voltage collapse in the lower Mornington Peninsula. This could lead to supply interruption to approximately 50,000 customers;

- from summer 2016/17, an unplanned outage of critical sub-transmission lines during summer maximum demand condition was expected to lead to supply interruptions in the lower Mornington Peninsula due to thermal overload of remaining in-service sub-transmission lines.

The table below sets out the options and net economic benefit of each option.

Table 15.2 Credible options considered in this RIT-D assessment

Option	Description	PV of estimated total cost (\$million) ¹²	PV of Gross Market Benefits (\$million) ¹³	NPV of Net Economic Benefit (\$million) ¹⁴	Ranking under RIT-D
1	Installing approx. 53 km of new 66kV line from HGS to RBD by 2020-21.	22.90	54.77	31.87	2
2	Implementing GreenSync's 4 year DM solution starting Nov 2018. Installing approx. 53 km of new 66kV HGS to RBD before Dec 2022.	23.07	55.21	32.14	1
3	Implementing Aggreko's 5 year EG solution at RBD from 2020 to 2024. Installing approx. 53 km of new 66kV line from HGS to RBD by 2024-25.	24.52	54.33	29.81	3

The preferred option, Option 2, is to implement GreenSync's 4-year demand management proposal by summer 2018/19 and establish a 53km new sub-transmission line from Hastings (**HGS**) to Rosebud (**RBD**) zone substation before December 2022. The total project cost, inclusive of operating costs, was estimated at \$23.07 million (in present value

¹² Includes capital and operating costs.

¹³ Gross Market Benefits under the base case scenario.

¹⁴ Net Market Benefits under the base case scenario.

terms). Subsequently United Energy entered into a network support agreement with GreenSync Pty Ltd.

In 2020, after two years of support there became a need to renegotiate the final two years of the demand management agreement. United Energy were also looking at options to extend the solution to further defer the capex in light of reduced and uncertain peak demand growth going forward.

Therefore United Energy issued a new request for non-network proposals (via its demand side engagement register) to test the market for offers and determine the most economical solution going forward via a market benefit test. Three non-network options were received as part of this proposal from parties Aggreko, ENEL X and Starling Energy.

The market test demonstrated that ongoing demand management continues to be the most efficient solution. The preferred and most economic option was a for combined solution which included:

- 11MW of demand side generation hire from Aggreko from summer 2020/21 – to 2024/25; and
- 2MW of demand response from summer 2021/22 to 2024/25.

The total cost of the solution is estimated at \$4.3M across the 5 years. United Energy has committed to this solution with the first year of this new solution now in place to manage the risk on the sub transmission loop over summer 2020/21.

15.3 Future regulatory investment tests

Based on the information contained within sections 7 and 14, United Energy expects to commence reviewing options to address the identified system limitations. The table below sets out the possible timeframes for consideration of RIT-D under clause 5.17 of the NER relating to investments where the cost of the most expensive credible option is more than \$6 million.

Table 15.3 Future RIT-D projects

Project name	Proposed RIT-D start date	Comments
Keysborough zone substation second transformer	2022	Install a second transformer with two new distribution feeders at Keysborough (KBH) in 2024.
East Malvern zone substation third transformer	2023	Proposed third switchboard and three new distribution feeders to address forecast load-at-risk at Caulfield (CFD), East Malvern (EM), Gardiner (K) and Ormond (OR) zone

		substations, as well as on the associated feeder network in 2025.
Doncaster zone substation fourth transformer	2023	Install a fourth transformer with two new distribution feeders at Doncaster (DC) in 2025.
Mornington zone substation third transformer	2024	Install third transformer with a new distribution feeder at Mornington (MTN) in 2026.

RIT-D consultation documents will be made available from the United Energy website and notified to participants registered on the Demand Side Engagement Register.

16 Network Performance

This section sets out United Energy's performance against its targets for reliability and quality of supply, and its plans to improve performance over the forward planning period for this DAPR.

16.1 Reliability measures and performance

United Energy is subject to a range of reliability measures and standards.

The key reliability of supply metrics to which United Energy is incentivised under the Service Target Performance Incentive Scheme (**STPIS**) are:

- system average interruption duration index (**SAIDI**): Unplanned SAIDI calculates the sum of the duration of each unplanned sustained interrupted customer minutes off supply (CMOS) divided by the total number of distribution customers. It does not include momentary interruptions that are one minute or less;
- system average interruption frequency index (**SAIFI**): Unplanned SAIFI calculates the total number of unplanned sustained interrupted customers divided by the total number of distribution customers. It does not include momentary interruptions that are one minute or less; and
- momentary average interruption frequency index (**MAIFIE**): calculates the total number of momentary interrupted customers divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate).

The reliability of supply parameters are segmented into urban and rural short feeder types.

The table below shows the reliability service targets set by the Australian Energy Regulator (**AER**) for United Energy in its Distribution Determination for the 2016-2020 regulatory period.¹⁵ United Energy reported to the AER its 2019 calendar year performance against those targets in its 2019 Regulatory Information Notice (**RIN**), and these figures are included in the table. In addition, United Energy has also forecast its outturn performance for the 2020 calendar year, based on actual performance for the period from 1 January 2020 to 30 September 2020, and then projected forward taking into account seasonal factors.

¹⁵ AER, United Energy distribution determination 2016 to 2020, Final, May 2016.

Table 16.1 Reliability targets and performance

Feeder	Parameter	AER target (2016-20)	2019 performance	2020 forecast performance (at 30 September 2020)
Urban	SAIDI	61.19	39.58	36.13
	SAIFI	0.90	0.55	0.55
	MAIFI	0.92	0.93	0.85
Rural short	SAIDI	151.60	83.56	66.21
	SAIFI	2.02	0.98	1.15
	MAIFI	2.98	3.03	2.94

In 2019, United Energy achieved within target results for SAIDI and SAIFI in both urban and rural short areas.

In 2020, United Energy is forecast to achieve within target results for all urban and rural short parameters. With approximately 8% of United Energy customers classified as supplied from Rural Short feeders, reliability results for such a small population can vary dramatically from year to year with small variations in the number of outage events.

Actual network performance is often influenced by external events such as storms, heat, flood, or third party damage which may be outside of United Energy's control. The influence of these factors on network performance can also vary significantly from one year to the next.

16.1.1 Corrective reliability action undertaken or planned

Actual network reliability performance is the result of many factors and reflects the outcomes of numerous programs and practices right across the network. To achieve long term and sustainable reliability improvements, United Energy continues to refine and target existing asset management programs as well as reliability specific works.

The processes and actions which United Energy undertakes to maintain reliability include (but are not limited to):

- undertaking the various routine asset management programs, including:
 - inspection of nearly 215,800 poles and pole tops;
 - testing of lines such as high-voltage feeder cables;
 - maintenance and replacement programs for overhead and underground lines (such as an ampact replacement program) , primary plant (for example, United Energy replaced a number of circuit breakers and current transformers) and secondary systems (such as replacement of ageing protection relays at zone substations);

- targeted installation of smart technologies to improve network monitoring, control and restoration of supply including automatic circuit reclosers (**ACRs**) and remote control gas switches (**RCGSs**), at strategic locations;
- targeted reduction of the exposure to faults on the distribution network by using:
 - thermography programs to detect over-heated connections;
 - Partial Discharge detection program for assets in zone substations, such as indoor switchgear;
 - condition-monitoring equipment in zone substations to proactively identify impending faults;
 - vegetation management programs to improve line clearances;
 - strategic distribution animal and bird proofing and conductor clashing mitigation measures to reduce the risk of 'flash-overs' and bushfire risk; and
 - targeted pole-top fire mitigation to reduce the risk of pole fires.
- network reconfiguration of the worst performing feeders to reduce the impact of faults;
- conduct fault investigations of significant outages and plant failures to understand the root cause, in order to prevent re-occurrences;
- continual improvements to outage management processes; and
- undertake asset failure trend analysis and outage cause analysis to identify any emerging asset management issues and to mitigate those through enhancing the related asset management plans, maintenance policies or technical standards.

Evaluation of the 2020 reliability improvement initiatives should be considered in the context of the longer term goals stipulated above and the volatility caused by uncontrollable events such as severe storms and the effect of third-party events.

16.2 Rapid Earth Fault Current Limiters (REFCLs)

This section sets out United Energy's existing installations and plans to install further Rapid Earth Fault Current Limiters (**REFCLs**) in the network. The primary purpose of installing REFCLs is to provide safety benefits to the community through reduced risk of electrical assets contributing to starting a fire.

A REFCL is a network protection device, normally installed at a zone substation, can reduce the risk of a fallen powerline or a powerline indirectly in contact with the earth causing a fire-start. It is capable of detecting when a powerline falls to the ground and almost instantaneously reduces the voltage to near-zero on the fallen line.

Customers that are, or plan to be directly connected, to United Energy's high voltage (**HV**) network may need to take action in response to United Energy's REFCL deployment program. On 20 August 2018, the Essential Services Commission of Victoria (**ESCV**) amended the Distribution Code which had the impact of transferring responsibility from distributors to HV customers for 'hardening' of the HV customer asset to withstand the higher REFCL voltages or isolating the connection from the network when a REFCL operates.

The zone-substations for which United Energy has REFCLs installed, or has plans to install a REFCL in the next 5 years, are as per the below:

- Frankston South (**FSH**) installed in 2009;
- Mornington (**MTN**) installed in 2018;
- Dromana (**DMA**) installed in 2019.

A map showing the zone-substation supply areas for the zone substations can be found in Appendix A.

Generally, the REFCLs will only impact the HV feeders directly connected to the REFCL zone substation. However during contingent events, the open points on the network may change resulting in feeders connected to non-REFCL zone substations being served from a REFCL zone substation and thus experiencing the higher voltages associated with the operation of a REFCL. As such HV customers connected or connecting nearby to the following supply regions may also be impacted:

Table 16.2 Other Impacted Areas of the network

Zone Substation	Other Impacted Feeders
Langwarrin (LWN)	LWN 21, 23, 24, 32, 33, 34, 35
Hastings (HGS)	HGS 22, 23, 33
Frankston (FTN)	FTN 11, 14, 22
Mulgrave (MGE) ¹⁶	MGE 32
Lyndale (LD) ¹⁶	LD 33
Rosebud (RBD)	RBD 12, 13, 21, 22

The impacted HV customers will need to take action to:

- ensure that their assets are compatible with the operation of a REFCL; and
- complete any required works prior to the commissioning of the relevant REFCL zone substation.

United Energy will work with effected customers to provide the relevant information and advice on the possible impacts and mitigation measures.

16.3 Power Quality Standards and Measures

United Energy is committed to not only a reliable supply for all customers but also ensuring power is delivered at a high quality. The projects and initiatives on power quality by United

¹⁶ Impacted post the installation of the AusNet Services Ferntree Gully (**FGY**) zone substation REFCL planned for 2021 subject to establishment of the proposed AusNet Services Rowville (**RVE**) zone substation.

Energy address power quality regulatory compliance requirements and maintain quality of supply levels on United Energy's network.

The regulatory obligations are to measure network power quality and to correct power quality where it is not within the specified limits. United Energy performs this by targeting power quality programs towards the worst-served customers first where there is an economically prudent case to do so. Furthermore, an increase in expenditure in some areas is required in response to increasing numbers of installed solar photovoltaic (**PV**) systems at customers' premises.

Power quality encompasses the parameters of steady-state voltages, voltage sags (dips), voltage swells (surges), flicker, harmonic distortion and unbalance of voltage for three-phase supply.

The main quality of supply measures that United Energy control are voltage and harmonics and are detailed further below.

16.3.1 Voltage

Voltage requirements are governed by the Electricity Distribution Code and the National Electricity Rules (**NER**).

The NER essentially requires that United Energy adheres to the 61000.3 series of Australian and New Zealand Standards. In April 2020 the Electricity Distribution Code was updated such that it more closely aligns the NER requirements.

The Electricity Distribution Code requires that United Energy must maintain nominal voltage levels at the point of supply to the customer's electrical installation in accordance with the Electricity Safety (Network Assets) Regulations 1999 or, if these regulations do not apply to the distributor, at one of the following standard nominal voltages:

- a) 230V;
- b) 400V;
- c) 460V;
- d) 6.6kV;
- e) 11kV;
- f) 22kV; or
- g) 66kV.

The Electricity Safety (Network Assets) Regulations 1999 were revoked on 8 December 2009 by regulation 104 (Schedule 1) of the Electricity Safety (Installations) Regulations 2009. Therefore the standard nominal voltages specified in the Code apply. Variations from the standard nominal voltages listed above are permitted to occur in accordance with the following table as updated in the 2020 Code changes.

Table 16.3 Permissible voltage variations¹⁷

STANDARD NOMINAL VOLTAGE VARIATIONS					
	Voltage Level in kV	Voltage Range for Time Periods			Impulse Voltage
		Steady State	Less than 1 minute	Less than 10 seconds	
1	< 1	AS 61000.3.100*			6 kV peak
2		+13% - 10%		Phase to Earth +50%, -100% Phase to Phase +20%, -100%	
3	1 – 6.6	± 6 %	± 10%	Phase to Earth +80%, -100% Phase to Phase +20%, -100%	60 kV peak
4	11	(± 10 % Rural Areas)			95 kV peak
5	22				150 kV peak
6	66	± 10%	± 15%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	325 kV peak

United Energy must use best endeavours to minimise the frequency of **voltage** variations allowed for periods of less than 1 minute (other than in respect of AS 61000.3.100 where the time period of less than one minute does not apply).

It should be noted that AS 61000.3.100 requires that the 99th percentile voltage at the customer's point of connection must be less than 253V and the 1st percentile voltage must be above 216V. This is a deviation from the previous requirements that stipulated a hard limit of 216V and 253V. The Code also stipulates that the distributors would be liable for equipment and property damages should the steady-state voltage be found to operate outside 207V and 260V.

United Energy is able to measure voltage variations at zone substations, as many have power quality meters installed. It also now has access to voltage data at individual customer level through the Advanced Metering Infrastructure (**AMI**) metering.

16.3.2 Harmonics

Voltage harmonic requirements are governed by the Electricity Distribution Code and the National Electricity Rules (**NER**).

The NER, with which the Electricity Distribution Code now aligns, essentially requires that United Energy adheres to the 61000.3 series of Australian and New Zealand Standards.

United Energy is required to ensure that the voltage harmonic levels at the point of common coupling (for example, the service pole nearest to a residential premise), with the levels specified in the following table from AS 61000.3.6:

¹⁷ Table 1 Clause 4.2.2 of the electricity distribution code.

Table 16.4 Voltage harmonic distortion limits

Odd harmonics non multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Order h	Harmonic voltage %	Order h	Harmonic voltage %	Order h	Harmonic voltage %
5	6	3	5	2	2
7	5	9	1.5	4	1
11	3.5	15	0.3	6	0.5
13	3	21	0.2	8	0.5
17	2	>21	0.2	10	0.5
19	1.5			12	0.2
23	1.5			>12	0.2
25	1.5				
>25	0.2 + $1.3 \cdot (25 / h)$				
NOTE – Total harmonic distortion (THD): 8%.					

16.4 Power Quality performance

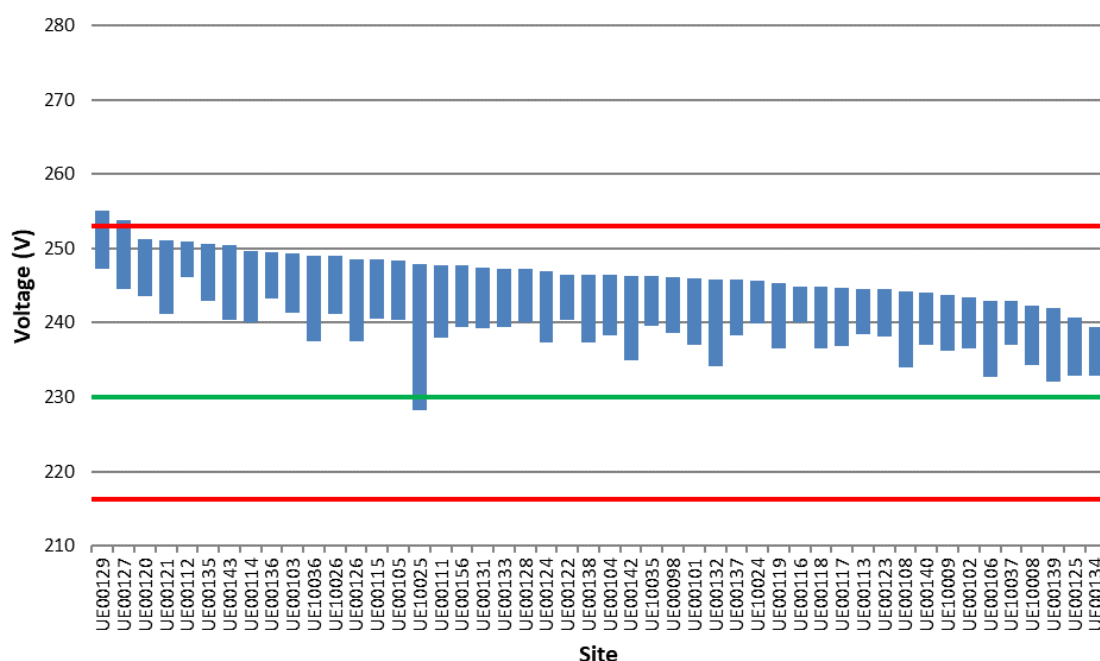
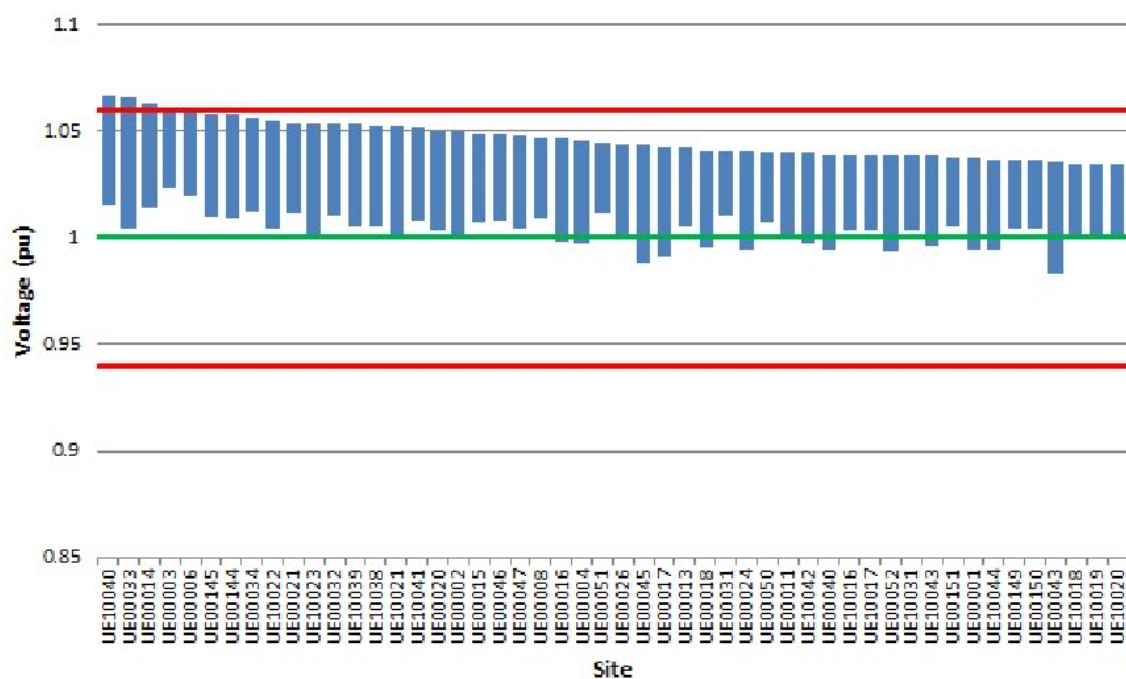
16.4.1 Steady state voltage

Power quality monitoring installed at our zone substations, revealed that in some instances the steady-state supply voltage is outside the regulatory limits. AMI metering has also identified that there were a large number of customers experiencing steady-state voltages outside the high side of the regulatory limit. This issue was previously unknown due to the absence of continuous voltage monitoring on the low-voltage network and has been revealed by United Energy's population of smart meters. It is likely this issue has been in existence for many decades, but it is confirmed that issues have been exacerbated recently by the increasing penetration of roof-top solar photovoltaic (**PV**) cells exporting power at customer premises.

As per the independent Power Quality Compliance Audit (**PQCA**) report prepared by University of Wollongong for FY2019-20. The report results presented in this DAPR are based on the HV power quality meters installed at each zone substation and the LV power quality meters installed at the start of one LV network connected to each zone substation.

It does not include the AMI data which would provide the most accurate representation of the power quality variance across at LV network.

The results indicates, about 4% of the 50 worst LV sites exceeds the upper voltage limit of 1.1 per unit (253V), at certain times during the year while 6% of the 50 worst medium-voltage sites exceed the upper voltage limit of 1.06 per unit as shown in the figures below. For the voltage distribution, upper and lower parts of bars indicate 99th and 1st percentile values, respectively.

Figure 16.1 – Steady State voltage distribution for LV Sites FY2019-20**Figure 16.2 – Steady state voltage distribution MV Sites FY2019-20**

In addition the Electricity Distribution Code was updated in 2020 to include additional DAPR reporting requirements for United Energy include AML voltage information in a Distribution Voltage Information template which has been published alongside this report in MS-excel format.

The voltage information required to be published is for on each voltage controlled section of the network, which is defined as any device or equipment that manages the medium

voltage (**MV**) feeder voltage starting from the zone substation. From UE's perspective, voltage information is therefore required and provided for each of its MV distribution feeders as there are no MV voltage regulators.

The voltage data to be published for each section is the aggregated 10-minute averaged voltage data over 3 months periods (December-November) by time of day into 6 hour periods (from 4am to 4am). United Energy has produced the 10 minute average voltage data by averaging its sampled 5 minute meter voltage reads. This is the first year of collecting this data and as such only from December 2019 to November 2020 has been provided in this first report. However the Distribution Voltage Information template will be added to annually and published as a rolling 5 year report.

It should be noted that this data provided is average voltage data only. It does not provide granular enough information to determine steady state voltage performance and non-compliances which is related to the minimum and maximum voltages at each connection point.

To proactively respond to non-compliance steady-state voltages, United Energy queries the AMI metering by exception, reporting only those customers outside the regulatory limits. These customers are then aggregated by common asset class to determine if the voltage problems are occurring in clusters. United Energy then remedies the voltage by prioritising according to the number of customers in each cluster and the duration for which the voltage excursions are occurring, then implement an ongoing programme to remedy these situations which includes:

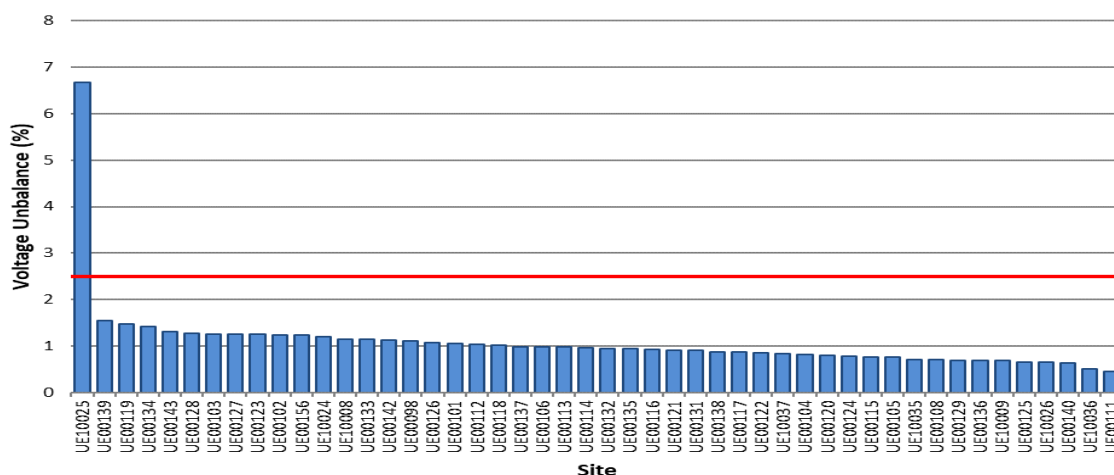
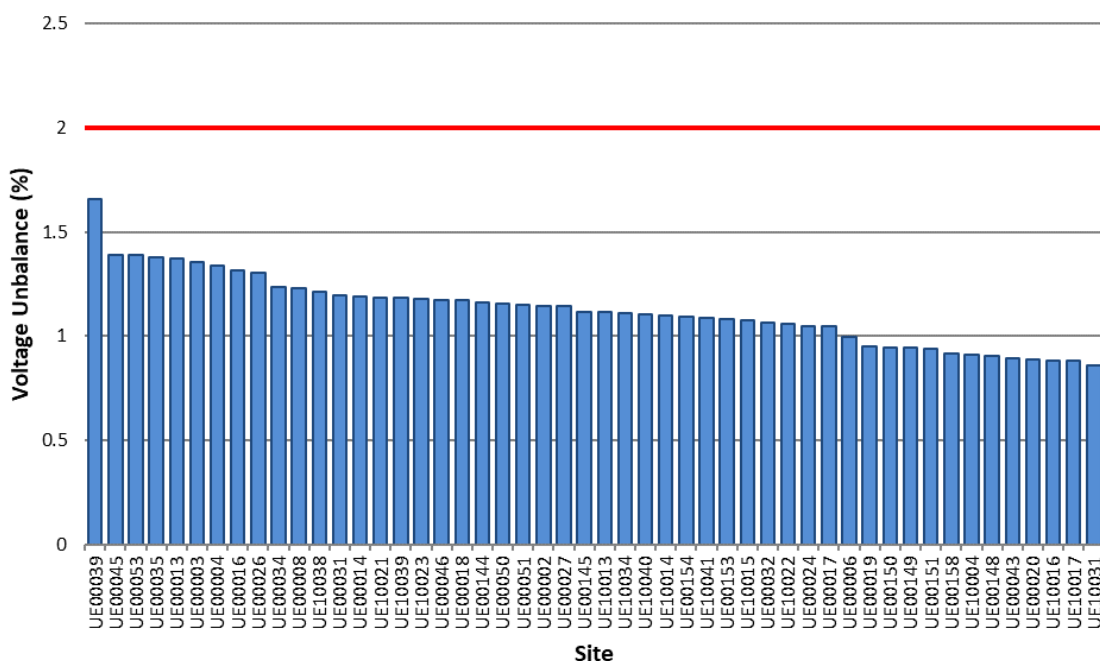
- adjusting the tap position at the distribution substation;
- adjusting the voltage set-point at the supply zone substation;
- compensating the reactive power by installation of pole-mounted capacitor banks;
- installing LV regulators;
- augmenting the LV network (LV feeder or distribution substations);
- augmenting the medium-voltage network (MV feeder);
- undertaking MV or LV open point changes or load balancing.

In 2017, United Energy was provided a grant from the Australian Renewable Energy Agency (**ARENA**) to deploy Dynamic Voltage Management System (**DVMS**) technology for the purposes of supporting demand response. This deployment also resulted in step improvements in steady state voltage compliance across the United Energy network at both LV and MV as described further in section 16.4.6.

16.4.2 Voltage unbalance

Voltage unbalance is known to cause overheating in transformers and customer motors due to negative-sequence components created in the unbalance.

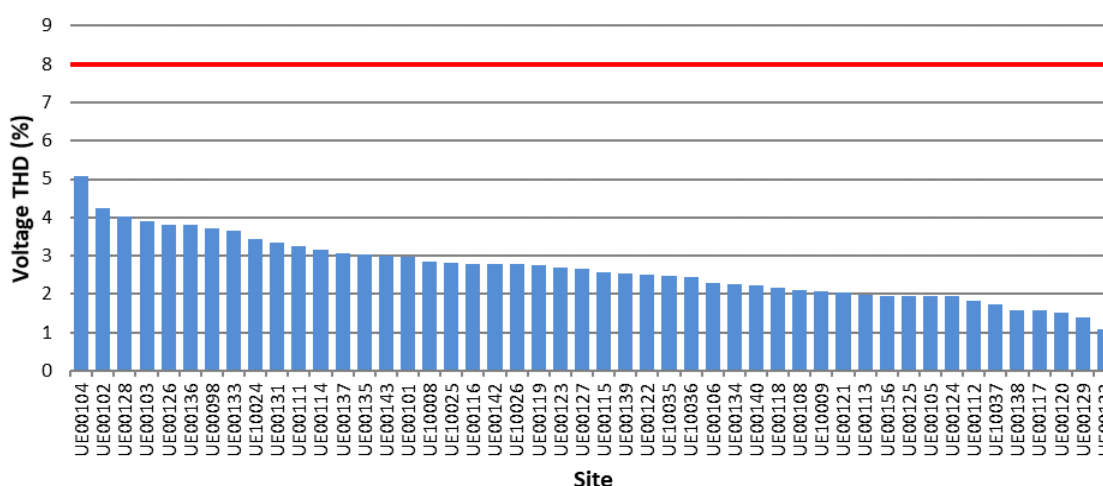
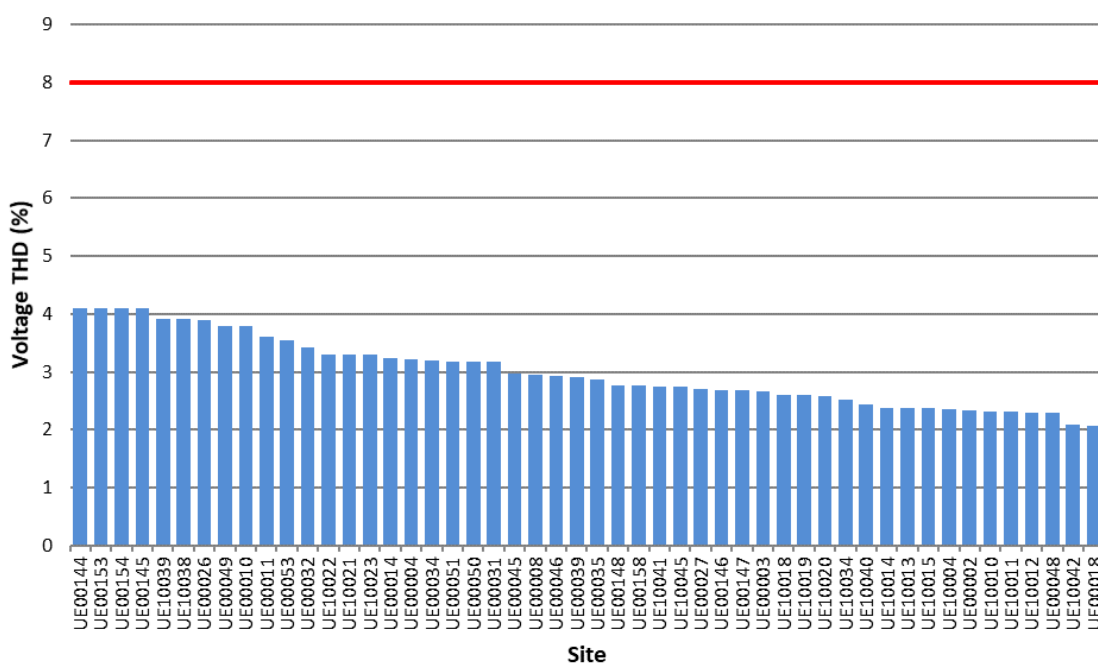
According to FY2019-20 PQCA results, the voltage unbalance at all but one of the monitored LV sites and all of the MV sites are within the requirements of the NER.

Figure 16.2 Voltage unbalance LV sites during FY2019-20**Figure: 16.3 Voltage Unbalance MV sites FY2019-20**

The worst performing zone substations for voltage unbalance include those that supply rural areas via two-phase or SWER systems.

16.4.3 Voltage harmonic distortion

Voltage harmonic distortion can vary significantly across the network. According to the FY2019-20 PQCA results, all monitored LV and MV sites are within the requirements of the NER.

Figure 16.4 Voltage harmonics distribution for LV sites FY2019-20**Figure 16.5 Voltage harmonics distribution for MV sites FY2019-20**

United Energy has observed fuse operations of capacitor banks on the network in the past which is directly attributed to harmonic resonance. Harmonic resonance can occur between capacitor banks and network reactance when the resonance frequency coincides with a harmonic frequency generated by non-linear loads. United Energy identified a number of problematic sites and installed various combinations of harmonic filtering and detuning reactors to address these issues. United Energy will continue to monitor harmonic and control harmonic levels going forward.

16.4.4 Flicker

In general, any load connected to the electricity network which generates significant voltage fluctuations can be the origin for flicker. Such voltage fluctuations are a result of significant cyclic variations, especially in the reactive component. According to the FY2019-20 PQCA results, the flicker levels at all monitored United Energy medium-voltage sites are within the national and local state regulatory limits.

United Energy considers the cause of emerging voltage fluctuations would be from micro-generation such as roof-top solar photovoltaic systems and micro-wind generation schemes where the connection requirements of the NER may not apply. It is critical that the impact of these systems on our network is well understood. To this end, our long-term objective is to establish voltage monitoring in the low-voltage network, investigate new technologies that can reduce voltage fluctuations and establish process / plans to monitor and control flicker levels.

Figure 16.6 Short-term flicker index during FY2019-20

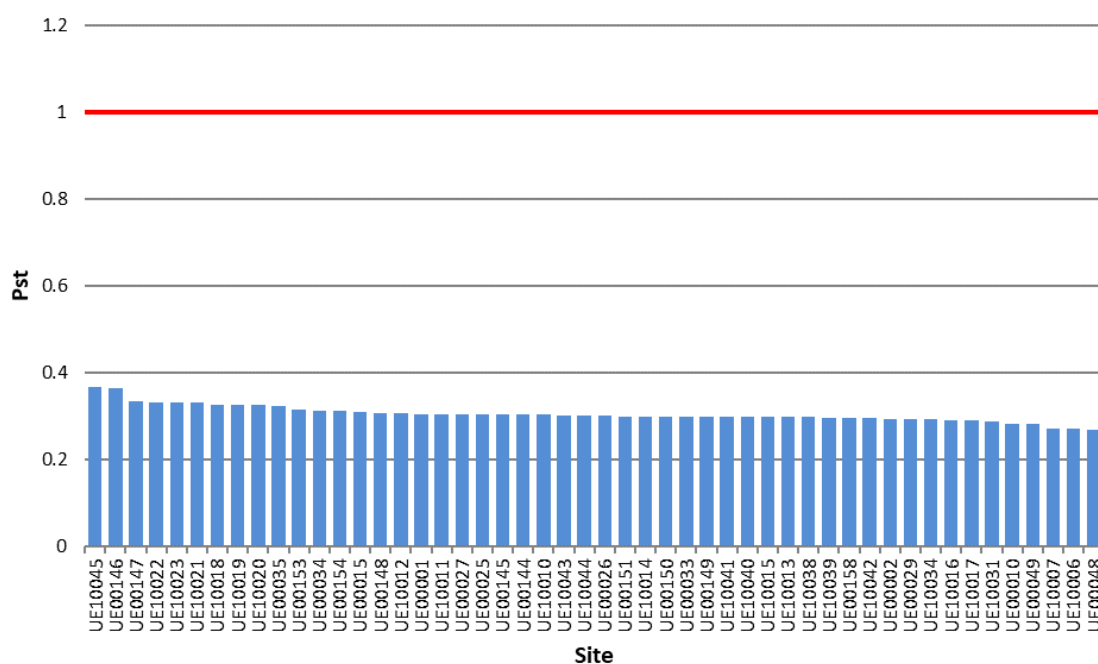
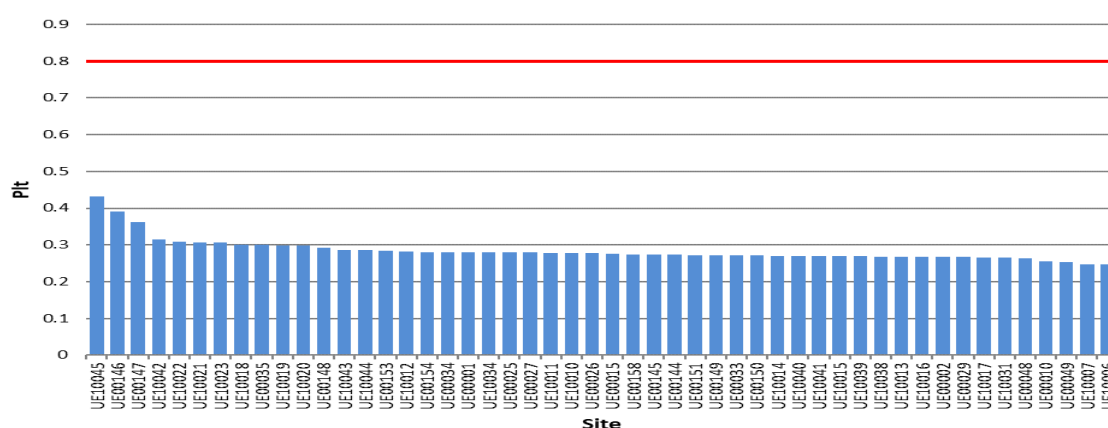
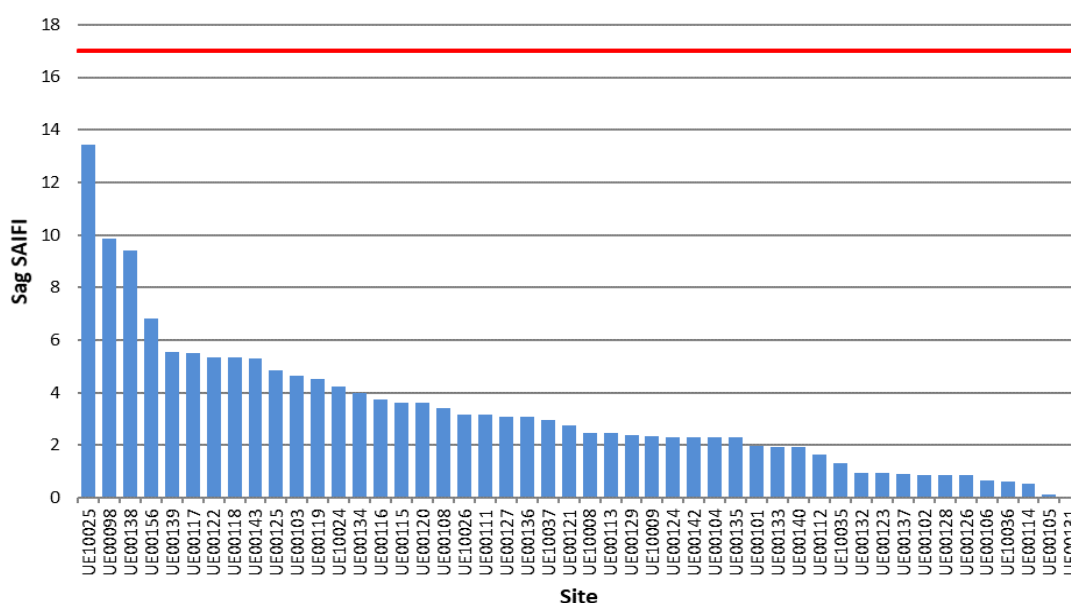


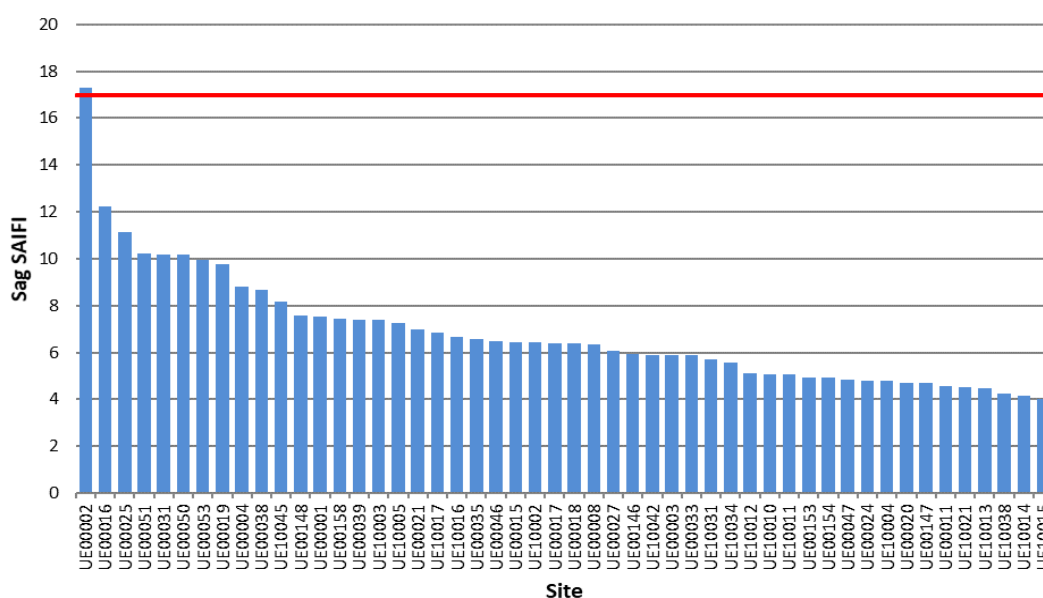
Figure 16.7 Long-term flicker index during FY2019-20

16.4.5 Voltage sags

Voltage sags, caused mainly by network faults depressing voltage levels across the network, are the main concerns customers have regarding power quality. According to the FY2019-20 PQCA results, the voltage sag SAIFI¹⁸ at LV as well as all but one MV sites are within limits.

Figure 16.8 Voltage sag SAIFI for LV sites during FY2019-20

¹⁸ The index used in the PQCA reports to assess sags.

Figure 16.9 Voltage Sag SAIFI for MV sites during FY2019-20

United Energy has attempted to address the issue of voltage sags with a number of initiatives including improving reliability, limiting fault current, and dynamically changing the point of common coupling. United Energy intends to further address this issue by introducing a number of new technologies to minimise the severity of voltage sags experienced by customers by reducing the current flowing on the distribution feeders during a fault.

United Energy has also implemented an economic network solution that helps to improve network performance with regard to voltage sags during network faults. United Energy has successfully implemented the automatic Bus-Tie Open Scheme at a number of zone substations supplying major industrial customers. This scheme improves voltage-sag performance without compromising system reliability. Given this, United Energy intends to further deploy the scheme over the next few years.

16.4.6 Power quality corrective actions and initiatives

United Energy has recently completed or plans to undertake a number of initiatives in the area of power quality as discussed below.

Zone Substation Dynamic Voltage Management System (DVMS)

United Energy utilised grant funding provided by ARENA to deploy DVMS technology across the United Energy network in 2018 and 2019. The technology provides the benefits of delivering step-change improvements in steady-state voltage compliance and delivering demand response capability.

DVMS technology works by taking AMI voltage data for all customers and assessing this data (grouped by zone substation) using a data analytics engine. The float voltage of each zone substation is then adjusted dynamically to optimise voltage compliance. All of our zone substations now have this capability.

Management of Rooftop Solar PV

The Victorian government is in the third year of its Solar Homes Program offering a rebate on solar PV systems to eligible homes. United Energy has observed a significant increase in solar PV connections since the introduction of this program. To mitigate against the possible effects of voltage rise from the accelerated uptake of solar PV, United Energy and the other Victorian DNSPs have adopted standard smart inverter settings to allow the networks to accommodate greater numbers of solar PV systems. The Solar Homes program now mandates the use of smart inverters to facilitate the application of the settings, and the AER has approved the revised Model Standing Offer which specifies the required settings.

In addition we will be implementing our Solar Enablement program from 2021/22 to increase the network's solar hosting capacity in areas where there are constraints through continuing our dynamic voltage management system initiative, changing the tap setting of distribution transformers, balancing the load on LV circuits, applying smart inverter settings on legacy sites, and undertaking targeted LV augmentation works where it is least cost and has a net economic benefit for customers.

Low-Voltage Regulation

Application of a low-voltage regulator can potentially tighten voltage spread and provide faster response to sudden changes in voltage. They facilitate the connection of intermittent renewable generation by smoothing out flicker impacts. At present, the range of sizes for this equipment is limited and they have only been trialled in a small number of sites on United Energy's network. United Energy has assessed from the trials that low-voltage regulators can only be used economically in niche applications where both over and under-voltages are being experienced on some parts of United Energy's low-voltage network.

On-Load Tap Changer (OLTC) Distribution Transformers

The distribution transformers on the United Energy distribution network operate on fixed discrete taps and do not operate from an OLTC. However, there are some types of distribution transformer available on the market with an OLTC capability. United Energy has trialled such transformers to evaluate their performance at regulating the low voltage and mitigating steady-state voltage variations as well as other benefits. It has been assessed from the trials that OLTC distribution transformers can only be used economically in niche applications where both over and under-voltages are being experienced on some part of United Energy's low-voltage network.

Terminal Station Power Quality Monitoring

Power quality monitoring is required at terminal stations to better understand power quality at transmission connection points and correlate this performance in the distribution network. Knowing the power quality levels at the connection points will enable United Energy to determine the components of power quality attributed to the transmission system, other DNSPs sharing connection points or distribution assets, or United Energy's

own network. This will assist with a better identification of sources of power quality problems, enable United Energy to confirm power quality simulation models and identify common-mode power quality trends. It will also allow reporting of power quality levels at transmission connection points in the future if required.

This work will be coordinated with AusNet Services Transmission Group.

AMI Power Quality Monitoring

The rollout of AMI meters has enabled United Energy to monitor basic power quality levels at individual customer premises. United Energy has developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. United Energy has enhanced the AMI architecture to provide an engineering user interface for customer power quality information and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Harmonic filtering

Harmonic filters are needed to manage the high levels of voltage harmonic distortion at some zone substations with the capacitor banks out of service or where multiple harmonic frequencies are problematic and where replacement of the inrush reactor alone does not achieve desired detuning effects. United Energy has already completed installation of harmonic filters at a number of zone substations and plans to continue to monitor the need for additional filters at zone substations with high levels of voltage harmonic distortion, caused by resonance conditions, that exceed regulatory limits.

Bus-tie open scheme

This scheme limits the severity of voltage sags created by faults on the medium-voltage network by isolating the healthy parts of the network from faulted parts by switching circuit breakers. While this scheme does not reduce the number of faults on the network, it does limit the number of customers exposed to severe voltage sags during a fault, without compromising overall system reliability and plant utilisation. United Energy plans to install similar schemes at zone substations which are currently experiencing high number of voltage sags.

16.5 Distribution Losses

Distribution losses refer to the energy used in transporting itself across distribution networks. In 2018/19, 4.77 per cent of the total energy into the United Energy network were calculated to be made up of losses. This is essentially calculated as the difference between the energy that United Energy procures and that which it supplies. These losses represent around 85.3 per cent of United Energy's total greenhouse gas emissions, as defined under the *National Greenhouse and Energy Report Act 2018-19*.

United Energy has a process to identify, justify and implement augmentation plans to address network constraints. Whilst loss reduction alone is not the main contributing factor in the decision of the preferred option, it is seen as the deciding factor if all other factors are equal.

United Energy, as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchases.

17 Embedded generation and demand management

This section sets out information on embedded generation as well as demand management activities during 2020 and over the forward planning period for this DAPR.

17.1 Embedded generation

17.1.1 Connection of Embedded Generation (EG) units

On 1 October 2014, the Australian Energy Market Commission (**AEMC**) established new requirements in Chapter 5 of the NER.¹⁹ These changes require the distribution businesses to better facilitate the connection of embedded generation in the NEM and to report on the following matters in the DAPR:

- key issues from applications to connect EG units over the past year; and
- a quantitative summary of connection enquires and applications to connect EG units received since 1 October 2014.

United Energy undertakes the connection process for embedded generator connections in accordance with Chapter 5 and Chapter 5A of the NER.

Chapter 5

- Applicable for all embedded generation with capacity above 5MW.
- Applicable where the connection applicant chooses the Chapter 5 connection process for embedded generation with capacity below 5MW.
- These generators must be registered (as per NER definition) or apply for an exemption with AEMO.
- This process is generally for larger embedded generation connections at distribution and or transmission high voltage level such as wind farms or peaking synchronous generators.

Chapter 5A

- Applicable for majority of below 5MW capacity embedded generation.
- These are non-registered generators (as per NER definition).
- This process is generally for smaller embedded generation connections at distribution high and or low voltage such as solar or small scale co/tri-generation systems.

A connection applicant with a generator connection below 5MW may choose to use the Chapter 5 connection process. This must be requested in writing to United Energy.

¹⁹ For connection application greater than 5 MW.

Further details on these matters are provided in Section 4.2.3 of United Energy Demand Side Engagement Document²⁰.

17.1.2 Key issues from applications to connect EG units in the past year

The potential issues that can be encountered in the connection of embedded generation are numerous, and depend greatly upon the specific location and proposed project. United Energy has identified the following issues associated with the application process to connect embedded generation units over the last year:

- Market developments are significantly influencing the economic viability of all generation type and scale. Proposal capacity and complexities have also been observed to be gradually increasing. Forecasting of project volume in this arena has, historically been difficult and highly unpredictable. As a consequence, the ability to facilitate proposals are constantly challenged, in particular from a resource perspective due to the specialist technical nature involved and evolution of project complexities.
- Obligations and liabilities need to be assessed on a case-by-case basis and negotiated with the proponents. For example, requirements and / or potential impact to other non-embedded generator customers as well as proponent's own installations can vary with each connection application.
- Technical standards and the regulatory framework have not been evolving to keep pace with market developments and the introduction of new technologies (especially in the area of energy storage) are significantly lagging. As a result, an industry wide initiative to bridge these gaps are emerging, but these developments will take time to filter through. Energy Networks Australia (**ENA**) has recently published guidelines for connection of distributed energy resources in an attempt to standardise the technical requirements across the industry.
- The fast evolving nature of the EG industry along with many new market entrants is increasing the diversity and spectrum of proponent and their capabilities. Consequently the technical nature of EG connection process challenges some proponents more than others with some projects requiring an increased engagement with the proponent. Such projects typically extend longer than originally envisaged with multiple iterations not uncommon accompanied by periods of hiatus for the proponent to appreciate and digest the technicalities to successfully comply with the connection criteria.
- Project coordination challenges are not uncommon particularly for complex proposals given multiple parties are involved at various stages of the connection application process (i.e. United Energy /Connection Applicant/AEMO/Design consultants /Primary constructor and sub-contractors etc.).
- With increasing penetrations of EG on the network, increasing number of EG connection applications require network augmentation or restrictions placed on the EG connection. Communicating network constraints to proponents have been challenging

²⁰ <https://www.unitedenergy.com.au/industry/mdocuments-library/>

as there have been instances where proponents have procured or installed the EG prior to their application.

- Ensuring satisfactory testing and commissioning of EG installations have been challenging due to the diversity and spectrum of proponent and their capabilities. Consequently, the timeframe it takes to close out an application is varied and can extend up to several months.

17.1.3 Quantitative summary of connection application to connect EG units

The table below provides a quantitative summary of the connection enquires under chapter 5 of the NER and applications to connect EG units received between 1 July 2019 and 30 June 2020.

Table 17.1 Summary of embedded generation connections²¹

Description	Quantity (> 5MW)
Connection enquires under 5.3A.5	4
Applications to connect received under 5.3A.9	0
The average time taken to complete application to connect	N/A

17.2 Demand Management Activities

Demand management is part of a broader range of non-network solutions designed to deliver lower cost solutions for the management of network constraints associated with peak electricity demand. United Energy defines non-network solutions as projects or programmes undertaken to meet customer demand by shifting or reducing demand on the network in some way, rather than increasing supply capacity through network augmentation. United Energy has led the industry with the implementation of several successful non-network solutions over the last few years and is keen to actively increase the implementation of non-network solutions over the forward planning period for this DAPR.

17.2.1 Network Support Agreements in the past years

Through our actions to promote non-network solutions, in the last five years United Energy has identified three economic demand management solutions to successfully defer the proposed augmentation on two distribution feeders, CRM 35 and MGE 12 and on the lower Mornington Peninsula sub-transmission network.

United Energy signed a Network Support Agreement with non-network services provider GreenSync Pty Ltd for two years, to provide 1.0 MW of demand management support on

²¹ The reporting period is over 12 months commencing from 1 July 2016 to 30 June 2017.

distribution feeder CRM 35, commencing from summer 2014-15. This service was called upon by United Energy when the network capacity in the area was insufficient to meet the peak demand (during summer periods). The agreement ended after two years of support due to a reduction in demand and VCR following AEMO's 2014 VCR survey.

United Energy also signed a second Network Support Agreement with non-network services provider GreenSync Pty Ltd for one year, to provide 0.8 MW of demand management support on distribution feeder MGE 12, for summer 2015-16. This service was called upon by United Energy when the network capacity in the area was insufficient to meet the peak demand (during summer periods). The agreement has now ended after one year of support due to a reduction in demand and the VCR. United Energy will continue to explore the use of this solution as demand grows in the area.

As detailed in section 15.2 United Energy has also committed to 5 more years of 13 MW for the implementation of a demand side solution on the lower Mornington Peninsula, from summer 2020/21. A demand side solution has been in place on the lower Mornington Peninsula since summer 2018/19 and was initially identified as a preferred solution through a Regulatory Investment Test for Distribution (**RIT-D**) consultation that concluded in 2016.

17.2.2 Demand Management Innovation Allowance initiatives in 2020

The Demand Management Innovation Allowance (**DMIA**) provides a limited regulatory allowance for United Energy over the regulatory period to fund projects that lead to the development of efficient non-network solutions to defer planned network augmentation.

For the 2016-2020 regulatory control period, United Energy has been allocated \$400,000 per annum in the AER's regulatory determination (\$2 million over five years) as an ex-ante allowance under the DMIA. We encourage non-network service providers approach United Energy (Refer to Section 9 of United Energy Demand Side Engagement Document²² for further detail) to enquire about opportunities to use DMIA funding for joint planning activities requiring specific studies, investigations or trials that may lead to the establishment of a non-network solution within the United Energy service area, in preparation for a future RIT-D.

The non-network proponent should provide United Energy an explanation of the non-network project for which DMIA funding is sought including:

- the nature and scope of the project;
- the aims and expectation of the project;
- information on how the project will be implemented;
- identification of benefits arising from the project, including any off-peak or peak demand reductions;

²² <https://www.unitedenergy.com.au/wp-content/uploads/2019/07/UE-PL-2202-Demand-Side-Engagement-Document.pdf>

- information on the costs of the project, including business case for the project and consideration of any alternatives;
- a description on how the proposal helps to meet the objectives of the DMIA.

The DMIA-funded projects United Energy has successfully undertaken in recent years are discussed in detail below.

Battery Energy Storage Systems

In 2018, United Energy submitted a DMIA request to the AER to trial medium-sized low-voltage grid-connected Battery Energy Storage Systems (**BESS**) in capacity-constrained areas of the United Energy distribution network. United Energy received in-principle approval from the AER.

In 2020, United Energy has successfully installed and commissioned two 30kW/75kWh LV BESS units. The first BESS unit was installed under Highett-Nicole substation on the 28th February 2020 and the second unit was installed on the 2nd May 2020 under Sylvia-Bluff substation. The selected BESS system has 22 battery modules, connected in two strings with each string connecting 11 modules in series.

The battery unit is connected to a four quadrant inverter, which converts the direct current (**DC**) voltage to 290V alternating current (**AC**) voltage. The inverter is rated for a maximum power output of 30kVA. The output from the inverter is filtered by an LC filter and a 30kVA star-delta transformer is used to tap up the voltage of the system to 415V to connect to United Energy LV distribution network. The BESS unit also includes a three-phase AMI meter, protection relay and control systems.

The functional components of the BESS units are housed in a 2.2m x 1.2m BESS cabinet. The BESS cabinet comes in two halves, inverter half and battery cabinet and are wrapped around a wooden LV pole as shown in Figure 17.2.



Figure 17.1: LV grid side BESS installed at Highett

The trial is the first LV grid connected pole mounted BESS installation in Australia. The project successfully demonstrates the feasibility of installing BESS system on the LV grid to address immediate capacity shortfalls and defer traditional network augmentation solutions.

It is expected that going forward the grid-side BESS can be taken into consideration as an option in addressing overloaded distribution substations and low-voltage circuits to address asset failures, outages, enable solar onto the network and used as an economic alternative to traditional network augmentation.

Summer Saver Program

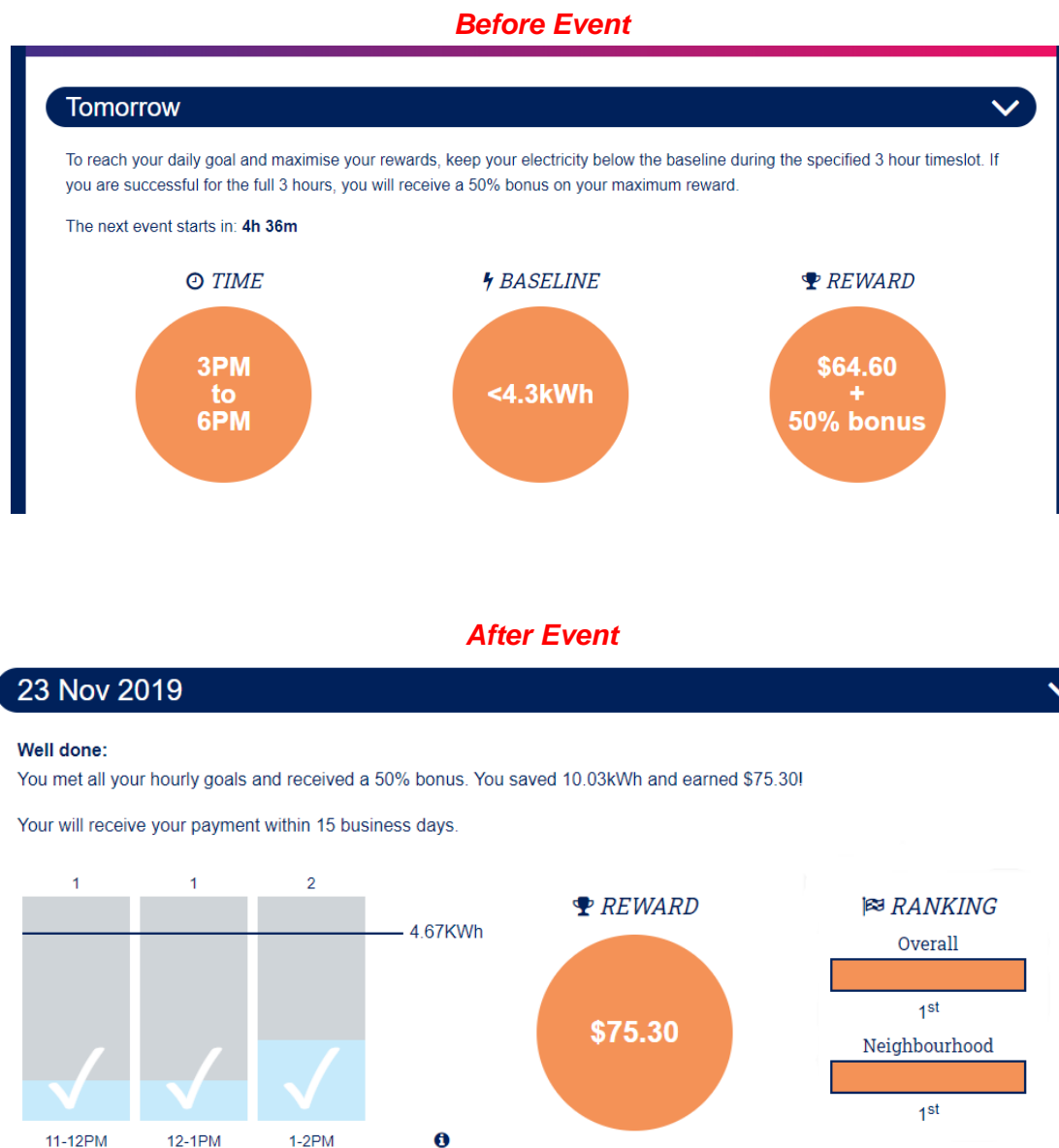
The Summer Saver program is a behavioural demand response program that incentivises customers to reduce their power usage during times of maximum demand. The Program targets constrained areas with highly utilised distribution transformers and low-voltage circuits that are at an elevated risk of overload outages during summer to defer network augmentation.

The program which initially began as a DMIA funded trial has transitioned into a business-as-usual programme from summer 2016-17. The funding for this program is now totally sourced from the deferral of network augmentation projects which would otherwise have been required in the absence of the Summer Saver Program.

Once registered, participants are requested to voluntarily reduce their power usage on a small number of hot weather 'event days' which typically are on weekdays over the summer

period. Customers are notified at least two days in advance of an ‘event day’ so they could plan how to reduce their energy consumption. Customers who successfully lower their energy consumption below their allocated baseline during the event are rewarded.

Figure 17.2 Summer Saver Program Customer Portal Screenshots



The Summer Saver Program utilises the capabilities of the Advanced Metering Infrastructure to encourage customer participation and engagement whilst lowering implementation costs.

1,896 customers registered for Summer Saver Program in summer 2019-20 which is an uptake rate of approximately 11% from a targeted customer base of 17,031. 74% of the customers registered for Summer 2019-20 had not participated in a previous Summer Saver Program.

United Energy called four events over summer 2019-20 with the event days falling on weekdays. United Energy noted 98% average participation rate per event. The Average Energy Usage Reduction per event was 8.5 MWh. The Total Energy Reduction across the four events was 33.86 MWh. Customers earned \$206 on average for their participation in the Program.

United Energy identified the Summer Saver Program as the preferred option, and is committed to undertaking the program for the management of 214 distribution substation and low voltage circuit limitations for summer 2020-21. See sections 9.3 and 17.3 for more details.

17.3 Actions taken to promote non-network solutions in the past year

United Energy has undertaken the following actions to promote non-network proposals in the last twelve months:

- United Energy has maintained our Demand Side Engagement (**DSE**) Register for customers, interested groups, industry participants and non-network service providers who wish to be regularly informed of our planning activities. United Energy has also continued an initiative with CitiPower / Powercor to expand each distribution businesses respective DSE registers by identifying where a potential businesses could provide non-network services across multiple areas.
- As at 30 September 2020, United Energy now has 99 registered organisations including 147 individuals on our DSE Register. Interested parties who wish to be included on our register should fill out their details on our website at:
<https://www.unitedenergy.com.au/contact-us/demand-side-engagement-registration/>
- United Energy notified all registered participants on our DSE Register of non-network opportunities identified in our 2019 DAPR and invited alternative proposals to defer or avoid the proposed network augmentations.
- United Energy invited all registered participants on our DSE Register to a public forum held in February 2020 to discuss the identified network limitations in our DAPR and non-network opportunities in further detail.
- United Energy published a request for non-network proposals for its distribution substations and low voltage circuits program, as part of its consultation requirements to meet the incentive requirements under the new DMIS scheme. One formal external non-network proposal was submitted however it was found to be more expensive than the United Energy Summer Saver demand management program. This demand management program will be deployed this summer to 214 capacity-constrained distribution substation and low-voltage circuit sites.
- This year's DAPR also provides preliminary information on the constrained distribution substations and low voltage circuits for next summer as part of our consultation obligations under the DMIS.

- United Energy published a request for non-network proposals for project OE-13 New Feeder as part of its consultation requirements to meet the incentive requirements under the new DMIS scheme. No non-network proposals were received.
- United Energy published a request for non-network proposals for the lower Mornington Peninsula supply area with, 3 proposals received and assessed, and a demand side solution committed to up until 2024/25. See section 8.2.5 and 15.2 for more details.
- United Energy and AusNet Services commenced a RIT-T and published the first stage Project Specific Consultation Report (**PSCR**) for the Cranbourne supply area.
- United Energy continued its active involvement in a number of workshops and rule changes related to demand management and distributed energy resources.
- United Energy has established a joint planning Memorandum of Understanding (**MoU**). United Energy currently has 7 MOUs in place. The MoUs facilitate a partnering arrangement which allows the free exchange of information and joint planning between parties well before a RIT-D to formulate alternative options for augmentation projects. This framework has led to United Energy signing three network support agreements with one of the parties to defer planned distribution feeder augmentations.
- United Energy hosted discussions and shared information with several non-network providers to facilitate early engagement for the development of potential demand side solutions in areas of future limitations.
- United Energy has published metered zone substation demand data for a 10-year period on our web-site to facilitate development of non-network solutions.
- United Energy has published a google earth constraint map on United Energy's website to highlight the geographical location of Sub-transmission, Zone Substation and Distribution Feeder limitations for the non-network service providers.
- United Energy has also continued participation in the Energy Networks Australia (**ENA**) Network Opportunity Maps (**NOM**) which are online interactive investment and constraint maps, aiming to identify the most valuable locations to invest in renewable energy, demand management and battery storage.

17.4 Plans for future non-network solutions

United Energy recognises early engagement with non-network service providers is critical for successful and efficient implementation of non-network solutions. United Energy anticipates an increasing number non-network options will emerge over the next few years particularly for distribution feeder and substation limitations, as the market and technology develops. In order to promote non-network proposals in the future, United Energy is committed to:

- Informing all registered participants on our DSE Register of non-network opportunities identified in this DAPR.
- Inviting all registered participants on our DSE Register to a public forum to be held in early 2021 to discuss identified non-network opportunities in further detail.

- Informing generator connection applicants at the enquiry stage of potential non-network opportunities.
- Exploring the use of joint planning MoU with other interested parties.
- Maintaining our DSE Register.
- Continuing to issue requests for non-network proposals, to continue to defer capital projects, onto its DSE register.
- Actively engaging with interested parties to submit credible alternative proposals to address identified network limitations in this DAPR.
- Actively investigating and evaluating each non-network solution (including network augmentations) using identical criteria that reflect both the regulatory requirements under the NER and our desire to implement the least lifecycle cost solution to address the identified need. This process is set out in more detail in Section 5 of our Demand Side Engagement Document.
- Exploring the use of Demand Management Incentive Scheme (**DMIS**) through broader consultation with industry to encourage uptake of demand management to defer or avoid network augmentation.
- Exploring the Demand Management Innovation Allowance (**DMIA**), a regulatory allowance over this regulatory period, to fund projects that lead to the development of efficient non-network solutions to defer planned network augmentations.
- Exploring the use of smart meters which have been rolled out across the United Energy network to enable customers to actively participate in the management of their energy use through the provision of timely, relevant information and control options. Smart meters give the ability to apply enhanced tariff arrangements, energy management, customer signalling and more sophisticated power usage monitoring.

17.5 Demand side engagement strategy and register

United Energy updated its published Demand Side Engagement Strategy in July 2019. The strategy is designed to assist non-network providers in understanding United Energy's framework and processes for assessing demand management options. It also details the consultation process with non-network providers. The Demand Side Engagement Strategy is available from:

<https://www.unitedenergy.com.au/wp-content/uploads/2019/07/UE-PL-2202-Demand-Side-Engagement-Document.pdf>

United Energy have also established and updated their Demand Side Engagement Interested Parties Register since 2013. To register as a Demand Management Interested Parties should fill out their details on our website at:

<https://www.unitedenergy.com.au/contact-us/demand-side-engagement-registration/>

18 Information Technology and communication systems

This section discusses the investments we have undertaken in 2020, or plan to undertake over the forward planning period for this DAPR 2021-2025, relating to information technology (IT) and communications systems.

18.1 Security Program

As new security threats emerge and grow over time, we keep investing in our cyber capabilities so we can continue protecting our network and our customers. Our ongoing program of works introduces increasingly sophisticated processes and systems that align with our commitment to proactively identify security threats and reduce security weaknesses in the organisation. Over the past twelve months a significant investment has been made to refresh our Cyber security strategy, program of works and operating model.

In early 2020, we refreshed our Cyber security strategy and presented a view of where we felt there were further opportunities to improve the way in which we manage our Cyber security risks. A three-year program of works was developed that would enable us to achieve our risk targets through the delivery of targeted initiatives addressing a broad range of capabilities. This strategy has now been approved by our executive team.

As a result, a significant program of works was delivered in the first half of 2020 to improve the state of a broad range of Cyber security controls that allow us to prevent, detect, respond to and recover from the possibility of a Cyber security breach impacting our Operating Technology (OT) network. The effectiveness of those controls has been independently validated through third party penetration testing and assurance.

Our current Cybersecurity strategy and program will be fully delivered over the 2021-2023 financial years. During the forward planning period for this DAPR we will also continue to align our security initiatives with relevant industry standards such as AESCSF, NIST and authorities such as the ASD to ensure that controls developed as part of our strategy are consistent recognised Australian and International best practices.

Furthermore, we will undertake security initiatives through our best practice program focusing on the capabilities of identify, detect, monitor, protect and governing our security program. This program seeks to maintain our current capability and proactively make the organisation more secure and in harmony with integrated systems within our IT landscape.

18.2 Currency

We routinely undertake system currency upgrades across the IT landscape in line with vendor software release life cycles and support agreements. These refresh cycles are necessary to ensure system performance and reliability are maintained and that the functional and technical aspects of our systems remain up to date.

In 2020 we completed a several activities including:

- **NAP Enhancements 2020** – During 2020, United Energy completed upgrades of its network analytics platform, in particular its pre-processing solution (Future Grid) as well as the virtual database server platform on which the analytics solutions operate.
- **DMS Patch Release** – United Energy also delivered a maintenance release on its DMS (Distribution Management System) in order to keep to an up to date service pack within its current version.
- **Cintellate upgrade and usage expansion**– Cintellate is the corporate Health, Safety and Environment (**HS&E**) tool, which required an upgrade to maintain vendor support. Cintellate was previously being used at United Energy to record network safety events that are reportable to Energy Safety Victoria (**ESV**), but is now extended to also cover logging of incidents and hazards by all United Energy employees.

During the forward planned period for this DAPR we will maintain the currency of the systems which manage our network (i.e. operational technology) such as the geospatial information system (**GIS**), outage management systems (**OMS**), SCADA and distribution management system (**DMS**). Maintaining currency of these systems is critical to maintaining the safe, reliable, secure and efficient delivery of network services.

We will also maintain the currency of other systems including our market systems which support the provision of energy data to market, business intelligence and warehousing, telephony and enterprise market systems. Our customers view reliability, affordability and the privacy of their data as top priorities – maintaining currency of our systems alongside our cyber security measures help ensure these objectives are met.

18.3 Compliance

We are focused on ensuring that, as regulated businesses, our IT systems support all regulatory, statutory, market and legal requirements for operating in the National Electricity Market (**NEM**). These obligations are regularly amended by various government bodies and regulators to ensure aptness in a changing energy market. Compliance is achieved via investment in systems, data, processes and analytics to provide the functionality and reporting capability to efficiently comply with statutory and regulatory obligations.

This year we have been continuing to implement 5-minute settlement, under which the settlement period for the electricity spot price is altered from 30 minutes to 5 minutes. This program will run through to December 2022 and includes enhancing storage to handle significantly more data, and changes to system architecture (e.g. Market Transaction System, Itron Enterprise Edition, CIS/OV, UIQ, Salesforce, SAP) as well as business and operational processes (e.g. billing, contract centres, reporting, network, AMI Operations and network analytics).

Phase 1 of five minute settlement and global settlement commenced in September 2019 and detailed design was completed in May 2020. The program was subsequently paused and was remobilised in August 2020 allowing the design to be completed in October 2020. Phase 2 of our 5-minute settlement program implementation began in November 2020 in

order to ensure our AMI metering fleet is compliant by 01 December 2022 as mandated by the AEMC.

Alongside the five minute settlement program we are continuing to deliver the global settlement program. The global settlement amendments change the differential treatment of the Local Retailer and will spread the “Unaccounted for Energy” (UFE) amongst all the retailers.

This year we have also set up a project team to make changes to the key market systems to ensure compliance with the updated procedures following the AEMC’s final rule to speed up the process for customers to transfer to a new electricity retailer. We are working towards a compliance date of 01 October 2021.

In our forward period our network will begin a new regulatory pricing period starting from 1 July 2021 and ending 30 June 2026. This new pricing period requires changes to Alternative Control Service (**ACS**), Quoted Services charges and tariffs. More specifically, we’ll need to do the following:

- Update, in partnership with our vendors, relevant market systems to reflect the updated ACS charges and introduced new product codes as approved by the AER.
- Amend billing and market data system to address the changes in how the demand component is calculated for demand tariffs, including the addition of seasons and a summer incentive demand component.
- Amendments to residential and small business to change from Australian Eastern Standard time to local time.
- Closure of tariffs and mass migration of businesses and customers to new tariffs.

In the forward DAPR planning period, we will continue to implement compliance projects as these arise through rules changes by AEMC, ESC, ESV or AEMO procedures which impact our IT systems and processes. We are also continuing to make changes to system and data controls to ensure customer, employee and asset data is hosted in Australia.

18.4 Infrastructure

We have an ever-growing need to store and recall data as well as to support applications, processes and functions within our IT systems. To support this, we must refresh our IT infrastructure to meet technical currency requirements and proactively manage the maintenance of the IT infrastructure to meet service level requirements.

During 2020, we established new applications supported by cloud-hosted infrastructure, while retaining our existing infrastructure on premise. In 2020 we also invested in uplifting our infrastructure to enable large scale remote working during the COVID-19 outbreak.

This included:

- Rollout of Microsoft Teams across all users to support collaboration while working remotely.

- Replaced the United Energy VPN SSL remote access solution (for users with corporate laptops) with a new, more secure solution that had capacity for eight times as many users as before.
- Doubled the capacity of the Citrix remote access solution for users unable to use the VPN SSL solution.
- Doubled the capacity of the United Energy internet links, and replaced the United Energy internet routers with higher capacity devices.
- Configured nearly all United Energy office users to work remotely (installing software, providing tokens for two factor authentication, training).
- Deployed a process for patching user's personal computers when working from home to ensure that the organisation continued to be protected from cyber-attack.
- We are building a new Windows 10 image that includes an "always on" VPN solution to seamlessly connect to simplify the remote working experience.

During the forward planning period for this DAPR, we will continue to upgrade our underlying infrastructure that supports the IT environments to ensure ongoing capacity, performance and availability to ensure continuity of IT service and a comprehensive business continuity capability. We will also undertake a program for gradually migrating some of our existing on premise IT and communications infrastructure to the cloud hosting.

18.5 Customer Enablement

The customer engagement stream incorporates our response to ongoing changes and demands from our customers for greater access and greater choice in electricity services.

In 2020, we delivered on the following:

- Enhanced telephony software (Verint) to provide speech analytics for improved customer interactions.
- Enhanced our SMS functionality during outage situations to increase coverage, message accuracy, reminders and timeliness (further improvements to come via Electricity Distribution Code (**EDC**) changes and Project Brockman).
- Delivered improvements in line with customer feedback gathered through a refreshed customer surveying approach. The refreshed approach has been expanded across 9 of our most customer impacting services.
- Improved online application and assessment tools for key niche processes such as High Load applications for oversize vehicle travel (presenting clearance dangers to our assets). Journey mapping identified problems that were addressed through enhanced system functionality, automated email receipts, standardised quoting and accompanying process streamlining.

In the forward planning period for this DAPR we will improve how our customers access information, saving them time and effort through unifying existing customer portals and using artificial intelligence to provide better services. This will include:

- Consolidating our existing online portals into a unified access point with additional automated processes, one username and password and a single interface.
- Automating connections and supply requests for all customers, including HV customers and embedded generators, by investing in the online connection's portal.

We will also improve the planned outage notification process for our customers, including providing more options around the medium for communications to reflect our customer preferences. We will ensure our improvements, at a minimum, reflect the Essential Services Commission final decision on the Distribution Code requirements in relation to planned outages.

18.6 Becoming a more digital network

Distribution networks across the world are currently going through some of their largest transformations in history. These transformations are being driven by changing customer requirements, including increased participations in new demand management programs, and the expected take-up of electric vehicles (EVs) and batteries.

We are responding to the energy transformation underway by building a smarter network that predicts and manages power flows on the low voltage network, ensuring we can run the network safely and more efficiently in the face of changing demands such as electric vehicles. Specifically, our digital network initiatives include:

- Promoting the uptake of new technologies – by allowing us to monitor the impact of increasing EV penetration on demand and optimise charging away from peak times, we will facilitate the uptake of EVs while mitigating the risk of excess demand at peak times (preventing the need for augmentation).
- Optimising load control of customer appliances – optimising existing hot water load control and enabling new load control programs (e.g. air conditioners, pool pumps), including through utilising excess solar in the middle of the day.
- Enhancing cost reflecting pricing – analysing meter data to construct more effective time-of-use tariffs or demand response to reduce peak demand and improve overall utilisation of the distribution network.
- Improving the equity of energy usage – identifying sites with bypass connections to reduce theft and monitoring variable unmetered supply to ensure energy usage is allocated fairly between customers.
- Proactively managing asset failures – develop greater predictive capabilities for asset condition to better determine when assets will fail, resulting in less network investment
- Avoiding overblown fuses – improving phase balancing, which will allow greater asset utilisation and avoid replacing blown fuses.
- Looking after vulnerable customers – more accurate mapping of customers to the network to ensure we keep more life support customers connected during outages and provide more accurate communications to customers on planned outages.
- Keeping customers safe – improving the way we identify loss of neutral at customers' homes, which can pose major safety issues of electric shocks if left unchecked.

18.7 Other communication system investments

To facilitate and maintain the protection, control and supervision of the network, we have continued to invest in Supervisory Control and Data Acquisition (**SCADA**) and associated network communication and control equipment. This is used to monitor and control the distribution network assets, including zone substations and feeders.

In 2020, we have focused on the following:

- Modernising the communications network and transitioning protection and SCADA services from mostly aerial copper supervisory cables to optical fibre and private IP/Ethernet network infrastructure.
- Replacement of legacy ADSL services, for zone substations at Mornington Peninsula, with more modern and reliable National Ethernet services enabling reliable SCADA telemetry and delivery of homogenous services across all the United Energy zone substations.
- Continuation of roll out of advanced communications services to new pole-top installations.
- Evaluation and trial of new 4G technology in readiness for the shutdown of the Telstra 3G network.
- Trial of pole mounted Battery Energy Storage System (**BESS**).

Over the forward planning period for this DAPR, our investment in SCADA will continue to increase, consistent with the growth and complexity of the network. Our SCADA expenditure will continue to modernise the communications network and ensuring adequate capability and capacity by installing larger systems.

In addition, we will continue to replace old communications systems with newer up-to-date systems. In some cases, this will be to address technical obsolescence where the manufacturer no longer supports the equipment, which we are no longer able to upgrade and there is a reduced pool of skilled workers able to maintain the system.

We will also modernise systems that rely on communications systems. For example, as Telstra is intending to switch off its 3G network, we will upgrade remote communications devices using the 3G network, such as Automatic Circuit Reclosers (**ACRs**) and remote controlled HV switches, to 4G and 5G. United Energy has also commenced replacing the legacy ADSL communications services at three zone substations, which are outside the reach of United Energy's private fibre optic infrastructure, with Telstra National Ethernet services for SCADA telemetry.

19 Advanced metering infrastructure benefits

This section discusses our use of advanced metering infrastructure (**AMI**) technology and how information generated by AMI is being used to better support life support customers, guide network planning and demand side response initiatives, and support network reliability initiatives.

19.1 Life support customers

We are using our AMI technology to service and support our vulnerable customers more effectively, allowing us to keep our communities safe.

We are keeping our customers and communities safe through being alerted to life support customers off supply more quickly through our AMI meters across our network. Our systems alert us if the supply to an AMI meter associated with a life support customer fails enabling us to more quickly resolve supply to the customer. This is key to our response planning for customer's off-supply and allows us to understand the criticality of the disruption.

Our AMI technology also assists us in rotating load in emergencies. By rotating load, we can share energy among our customers in times of emergency. As such, we can prioritise life-support customers in these cases to ensure their power remains on.

We plan to continue to leverage AMI data and services to develop further benefits for our customers, including life support customers, over the forward planning period. An example of an initiative we are proposing under our Digital Network program which is reliant on our AMI includes more accurate mapping of customers to supplying Low Voltage (**LV**) transformers to help keep more life support customers connected during emergency load shedding and provide more accurate communications to customers of planned outages.

19.2 Network planning and demand side response

AMI technology has been critical in allowing us to innovate in the way we operate the network and deliver effective customer service. Visibility of the LV network has improved customer outcomes by lowering prices through more efficient network management, improved network safety and reliability outcomes and improved responsiveness to customer needs.

Our AMI meters provide us with the ability to improve safety by identifying neutral faults at customer premises. Our systems alert us if the supply to an AMI meter has a neutral fault enabling us to more quickly resolve it. The system identifies unsafe situations as they develop, so corrective action can be initiated immediately. This is key for maintaining safety for our network and our customers.

Using Victorian AMI specification also allows us to manage voltages and prevent load shedding and blackouts on peak demand days.

Further the Victorian AMI is vital for enabling growth in distributed energy resources (**DER**) such as rooftop solar, batteries and electric vehicles. AMI provides us with the information

to manage the network and accommodate the dynamic and less predictable energy flows that result from the increasing uptake of DER technologies by Victorians. We also use our AMI data for more accurate spatial demand forecasting, ensuring we optimise timing of network augmentation. Information from our AMI meters also assist us with detecting of customer with solar connections that are not registered as solar customers and/or are exporting more than they are contracted to export.

Our AMI technology is also an essential input into our Digital Network program which will enable more demand response initiatives through our proposed DER management system as well as enable us to accommodate more solar with the existing network capacity. We plan to continue to leverage AMI data and services to develop new benefits for customers over our DAPR forward period. The following are some examples of initiatives we are proposing under our Digital Network program which are reliant on our AMI:

- Promoting electric vehicle uptake – monitoring and optimising EV charging to understand and estimate the impact of increasing demand on the distribution network resulting from EV penetration.
- Optimising load control of customer appliances – optimising existing hot water load control and enabling new load control programs (e.g. air conditioners and pool pumps), including through utilising excess solar in the middle of the day.
- Enhancing cost reflective incentives – analysing AMI interval data to construct more effective demand management incentives and time-of-use tariffs to reduce peak demand. This would improve overall utilisation of the distribution network, resulting in lower prices.
- Detecting electricity theft – identifying sites with bypass connections and reduction of theft, as well as identifying unregistered DER, often necessary in assisting pole investigations.
- Proactively managing asset failures—resulting in fewer fire-starts and avoided replacement expenditure.
- Avoiding overblown fuses—improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacement expenditure from blown fuses.

19.3 Network reliability

AMI information is being used to support our network reliability measures. We have shorter outages due to earlier identification of faults and more efficient restoration. This is because AMI meters give us almost instant notification of customers going off supply. We receive immediate notification of outages from the AMI meter which feeds into our outage management systems and automatically schedules and dispatches field crew to restore supply.

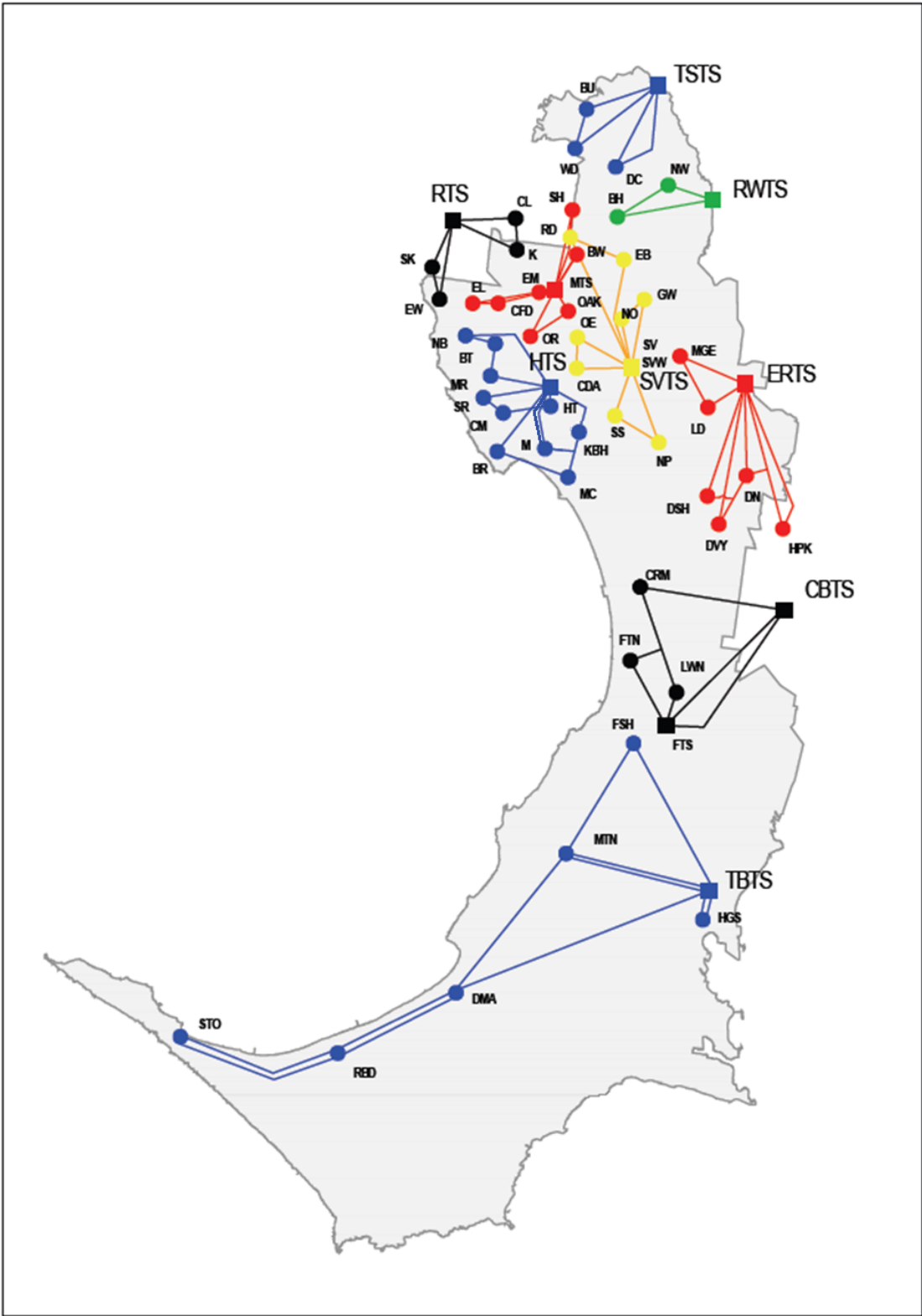
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the

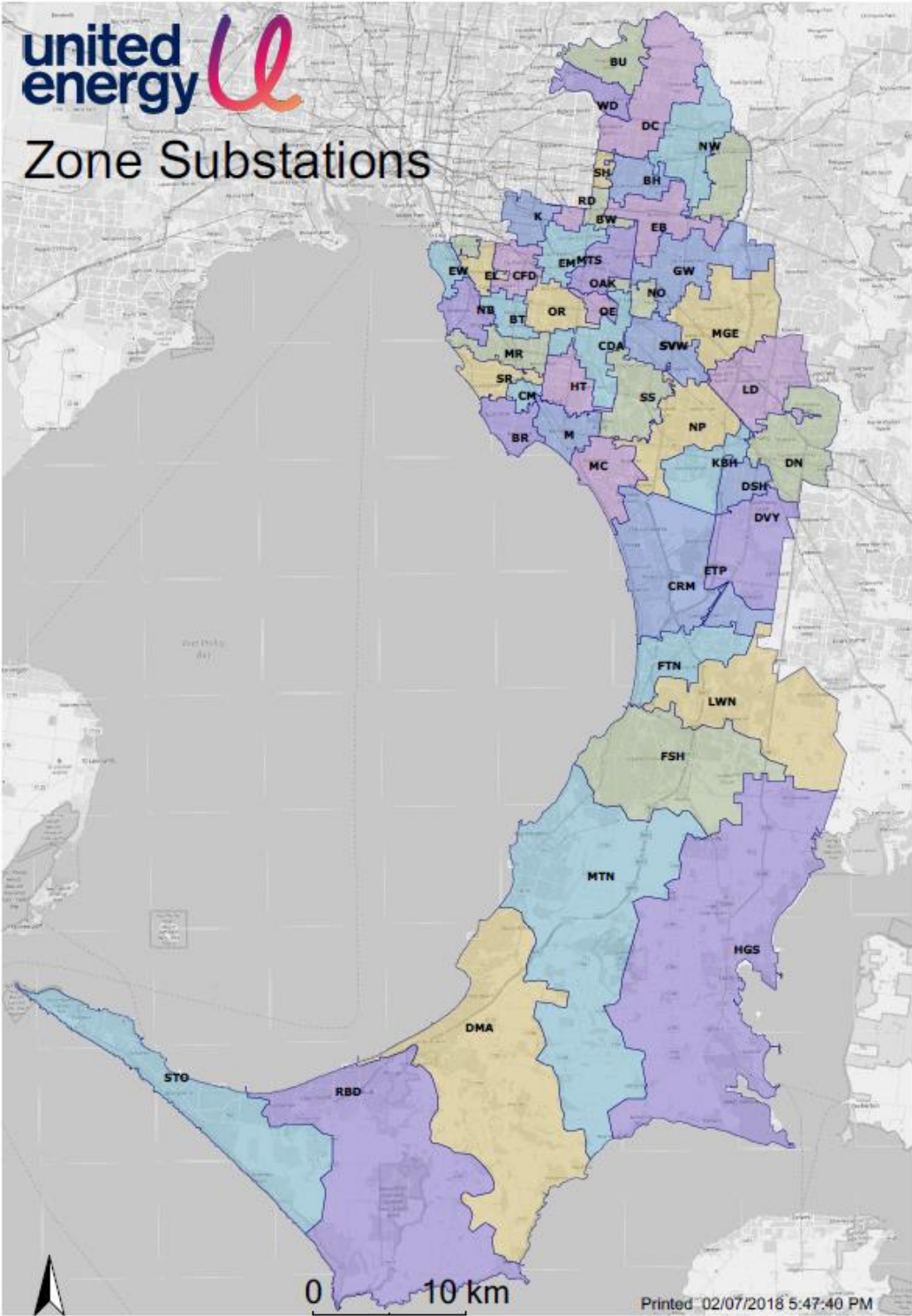
quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. We have enhanced the AMI architecture to provide an engineering user interface for customer power quality information and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Our AMI technology also allows for supply capacity control enabling us to more effectively target load shedding to minimise supply impacts.

There is also improved quality of information and customer services during outages. We have developed an Interactive Voice Response service and SMS service which automatically advises customers of outages identified in a timely way through the last gasp AMI function. The quality of supply of information throughout the network is also enabling better network load profiling, identification of safety risks and voltage management.

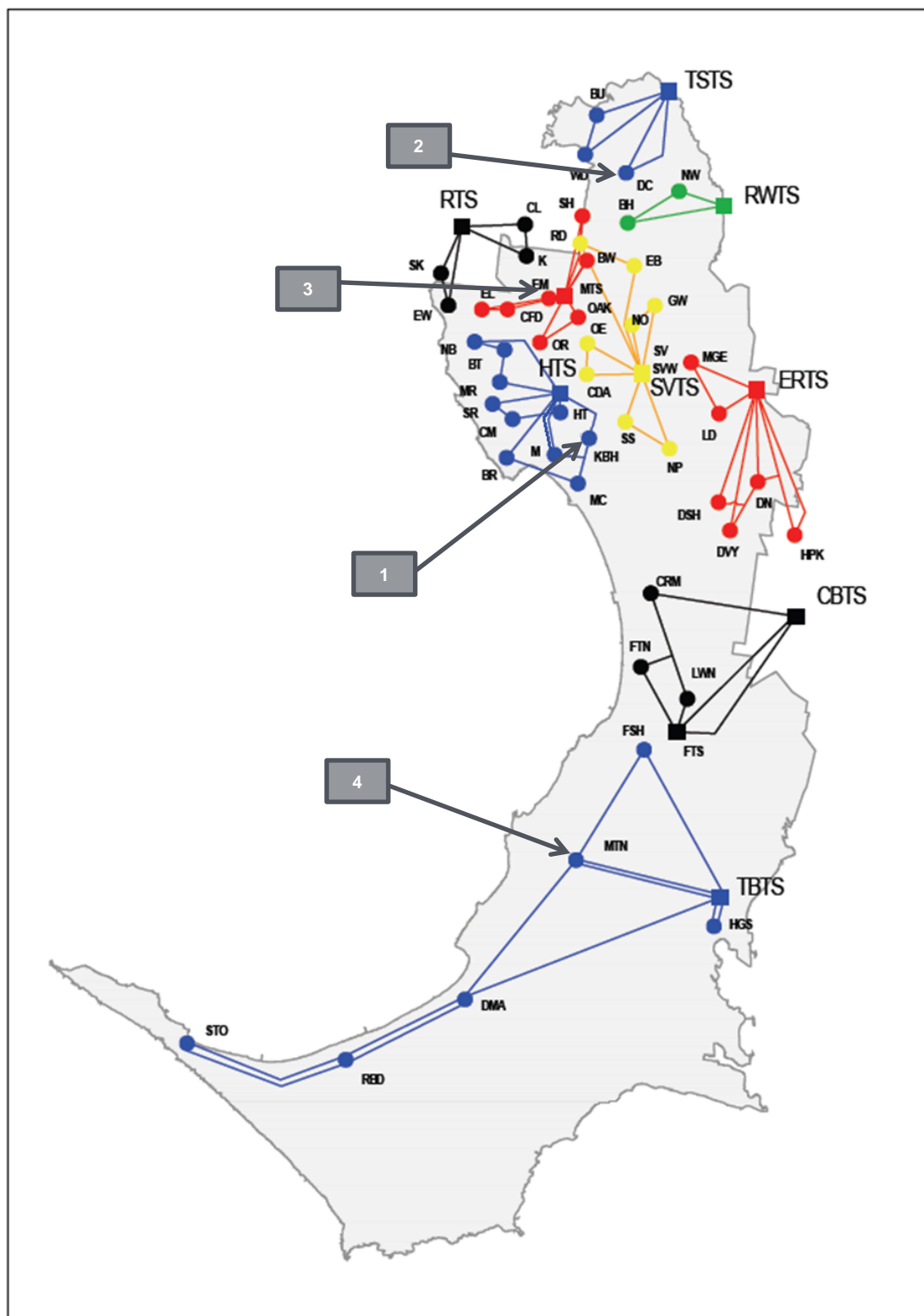
Appendix A Network Maps



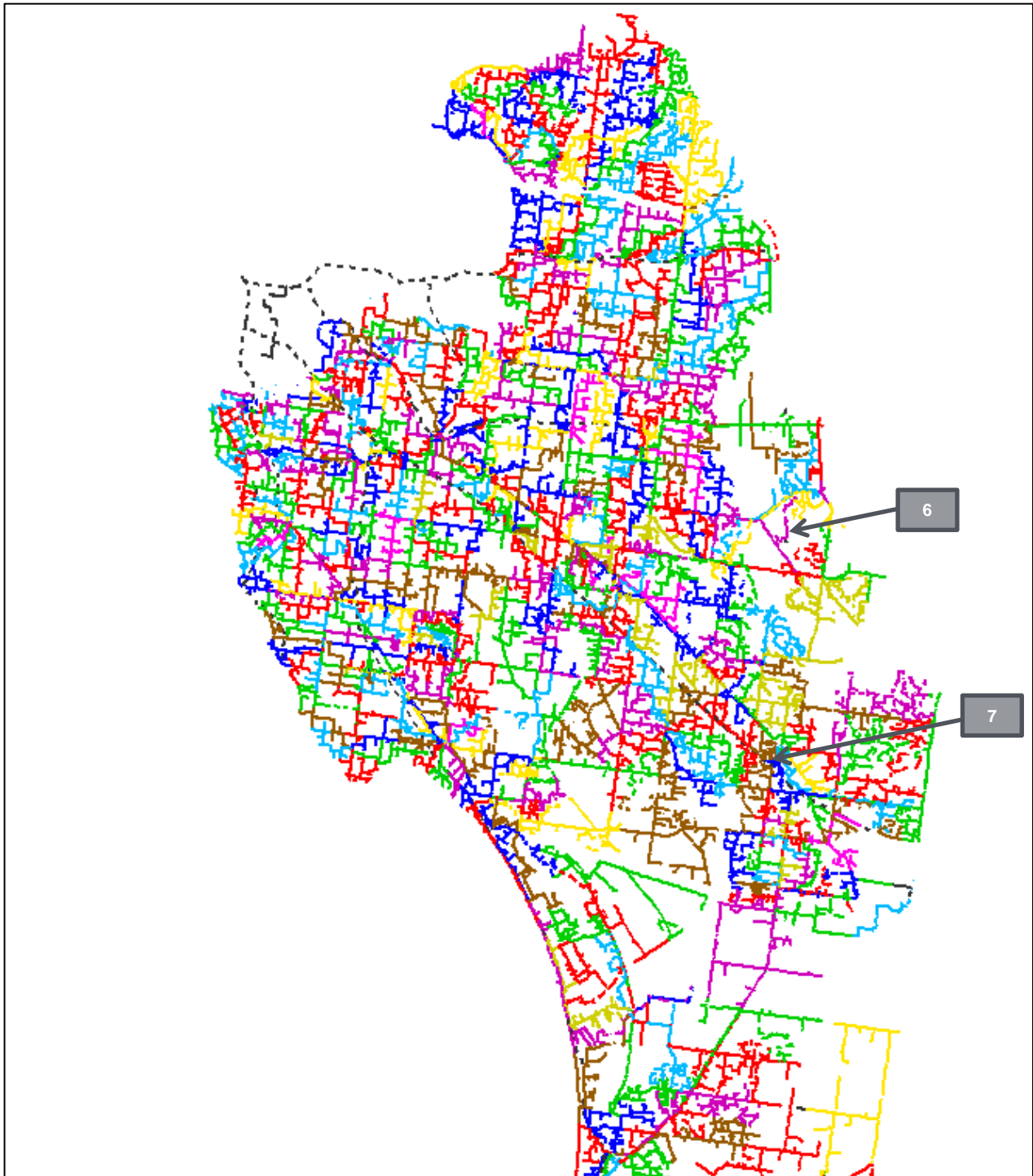


Appendix B Maps with forecast system limitations

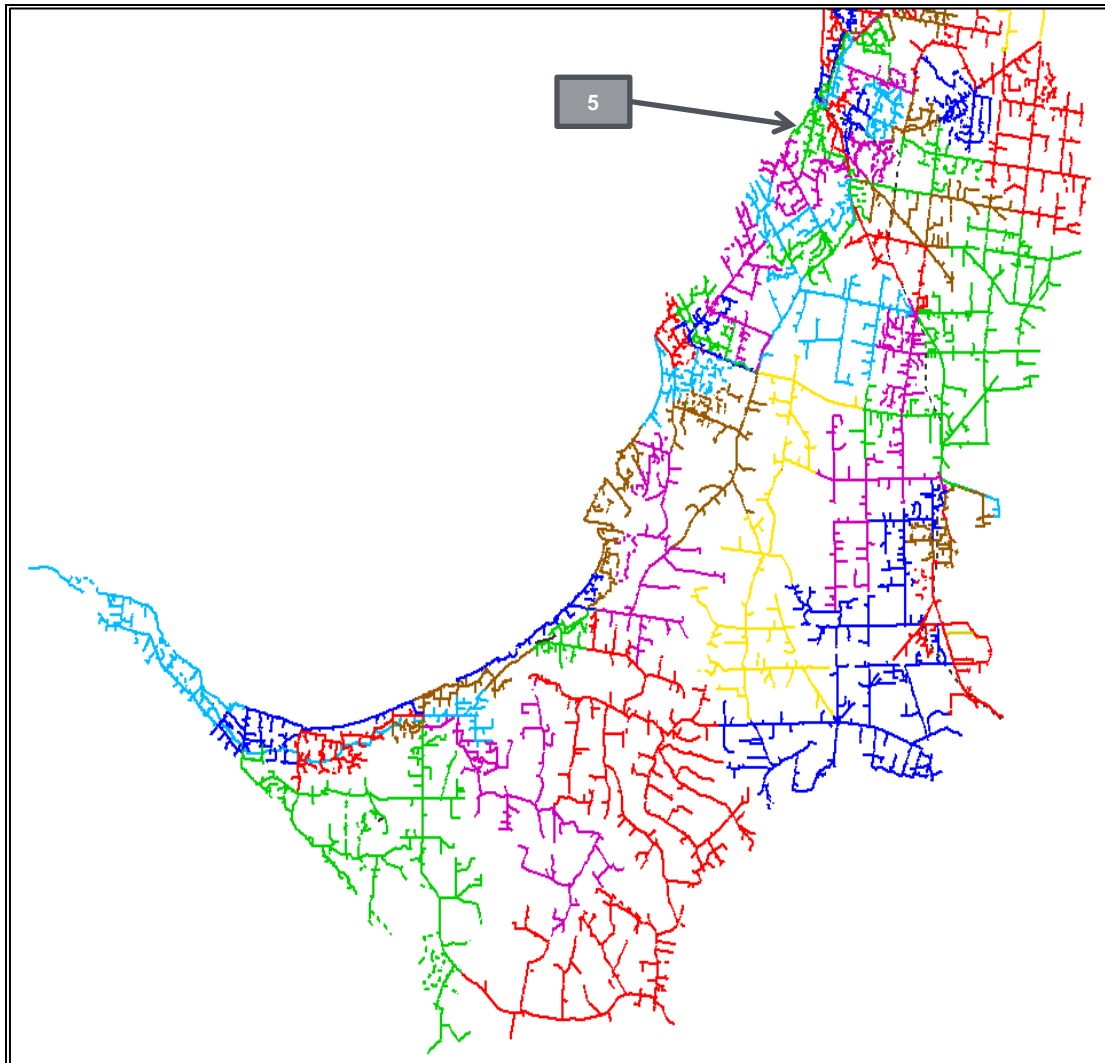
B.1. Zone-substation and sub-transmission limitations (Augmentation)



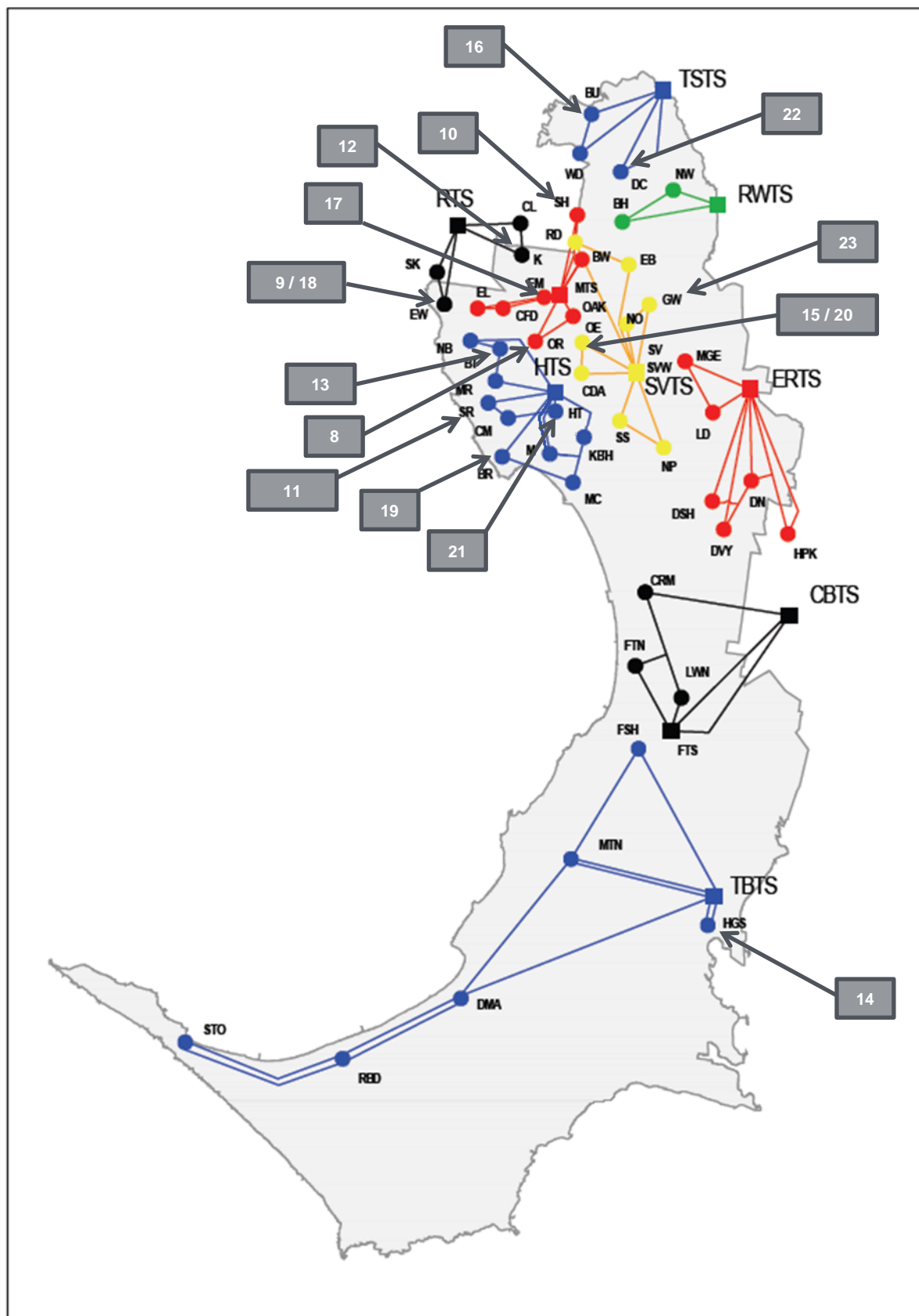
B.2. Distribution Feeder Limitations in northern part of network (Augmentation)



B.3. Distribution Feeder Limitations in southern part of network (Augmentation)



B.4. Zone-substation transformer and switchgear limitations (Replacement)



The tables below set out numbering for the limitations in the maps above. Note this also aligns with the Systems Limitations Template.

Limitation	Asset	Project type	Year
1	Keysborough (KBH) Zone Substation	Augmentation	2024
2	Doncaster (DC) Zone Substation	Augmentation	2025
3	East Malvern (EM) Zone Substation	Augmentation	2025
4	Mornington (MTN) Zone Substation	Augmentation	2026
5	FSH-31 (Frankston South) HV Feeder	Augmentation	2022
6	MGE-12 (Mulgrave) HV Feeder	Augmentation	2022
7	KBH-32 (Keysborough) HV Feeder	Augmentation	2022
8	Ormond (OR) #2 Transformer	Replacement	2022
9	Elwood (EW) #2 Transformer	Replacement	2022
10	Surrey Hills (SH) 6.6kV Conversion	Replacement	2022-24
11	Sandringham (SR) #3 Transformer	Replacement	2023
12	Gardiner (K) #3 Transformer	Replacement	2023
13	Bentleigh (BT) #1 Transformer	Replacement	2024
14	Hastings (HGS) #1 Transformer	Replacement	2024
15	Oakleigh East (OE) #1 Transformer	Replacement	2025
16	Bulleen (BU) #1 Transformer	Replacement	2025
17	East Malvern (EM) 11kV Indoor Switchboard	Replacement	2023
18	Elwood (EW) 11kV Indoor Switchboard	Replacement	2024
19	Beaumaris (BR) 22kV Indoor Switchboard	Replacement	2025
20	Oakleigh East (OE) 11kV Indoor Switchboard	Replacement	2025
21	Heatherton (HT) 22kV Outdoor Switchyard	Replacement	2023
22	Doncaster (DC) 22kV Outdoor Switchyard	Replacement	2024
23	Glen Waverley (GW) 22kV Outdoor Switchyard	Replacement	2024

Appendix C Maximum demands– zone substations

The tables below set out the forecasts for maximum demand for each United Energy zone substation and their capacity. These forecasts are used to identify potential future constraints in the network.

Please note that the availability of load transfer and generation capacity at maximum demand times cannot be guaranteed.

Zone substation	Station N Rating (MVA)	Station N-1 Rating (MVA)	Hours load is 95% of MD	Station Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	
BH	108.9	72.6	22	1.00	14.7	0	46.6	48.1	49.4	51.1	51.6	52.8	-
BR	63.0	31.5	5	0.99	8.0	0	28.7	29.6	30.0	30.5	30.5	30.6	-
BT	62.1	31.1	5	0.99	6.6	0	30.9	32.0	32.5	33.0	32.9	32.9	2.7%
BU	59.5	29.7	6	0.99	6.8	0	32.3	32.8	33.1	33.6	33.4	33.4	10.3%
BW	38.1	25.4	10	1.00	4.4	0	24.7	25.1	25.4	25.8	25.6	25.7	-
CDA ²³	59.4	25.8	2	1.00	22.1	0	26.0	26.8	27.2	27.8	28.2	28.6	3.8%
CFD	84.2	42.1	5	1.00	12.2	0	52.5	54.7	55.9	56.9	56.9	57.4	30.0%
CM	61.8	30.9	24	0.99	5.2	0	20.5	21.3	21.8	22.5	22.8	23.1	-
CRM	110.8	73.9	3	1.00	14.4	0	75.0	78.6	80.3	82.2	82.3	82.7	6.4%
DC	110.4	73.6	5	1.00	14.1	0	91.0	90.3	91.8	93.5	93.0	93.4	29.5%
DMA	89.6	44.8	3	1.00	21.5	0	37.8	45.2	46.4	47.8	48.3	49.1	0.9%
DN ²⁴	126.2	84.2	4	1.00	16.0	4.5	75.5	77.0	77.9	79.0	78.7	78.9	-
DSH	144.9	96.6	17	0.99	18.2	0	59.7	61.7	62.8	63.7	63.5	63.7	-

²³ Based on the relocatable transformer rating.

²⁴ Demand data shown in table excludes embedded generation.

Zone substation	Station N Rating (MVA)	Station N-1 Rating (MVA)	Hours load is 95% of MD	Station Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	
DVY	131.6	87.8	23	0.98	17.4	0	76.3	79.4	82.1	84.4	84.1	84.4	-
EB	101.8	67.8	4	0.98	14.8	0	62.9	64.3	65.1	66.3	66.1	66.3	-
EL	66.9	33.4	11	0.99	7.5	0	36.1	37.5	38.3	39.0	39.1	39.4	12.3%
EM	63.9	31.9	8	0.97	5.8	0	35.9	37.7	38.5	39.2	39.2	39.5	18.2%
EW	58.8	29.4	14	1.00	5.4	0	22.3	24.0	24.4	24.8	24.7	24.8	-
FSH	93.0	62.0	8	0.95	21.1	0	65.9	68.1	68.8	69.9	69.8	70.0	9.8%
FTN	91.2	45.6	8	1.00	17.9	0	54.5	55.5	56.1	56.7	56.5	56.5	21.8%
GW	103.4	68.9	13	0.99	19.1	0	67.5	69.5	70.4	71.2	71.1	71.6	0.9%
HGS	79.8	39.9	7	0.95	13.7	0	47.4	49.6	50.5	51.5	51.3	51.4	24.4%
HT	92.8	61.9	15	0.98	19.0	0	51.6	53.6	54.6	56.2	56.8	57.0	-
K	73.5	36.8	5	0.99	7.6	0	42.3	45.0	46.4	47.8	47.9	48.5	22.3%
KBH	46.7	0.0	3	1.00	34.0	0	32.3	36.9	37.8	38.8	38.9	39.2	100.0%
LD	101.1	67.4	13	0.97	29.8	0	54.2	54.6	55.2	55.9	55.7	55.8	-
LWN	90.8	45.4	4	0.98	27.3	0	49.8	50.7	51.2	52.1	51.9	51.9	11.7%
M	81.6	54.4	6	0.98	4.1	0	38.6	39.1	39.5	40.0	39.9	39.9	-
MC	83.1	55.4	8	1.00	18.7	0	55.5	56.6	57.5	58.6	58.5	58.8	2.1%
MGE	111.6	74.4	17	1.00	23.2	0	81.9	83.1	84.1	85.3	85.0	85.2	11.7%
MR	80.0	39.9	4	1.00	14.0	0	51.2	52.2	52.8	53.5	53.4	53.5	30.8%
MTN	92.9	46.4	6	1.00	14.9	0	64.3	68.0	69.4	70.9	71.0	71.9	46.6%
NB	90.8	45.4	4	0.99	9.6	0	46.4	47.1	47.6	48.3	48.1	48.2	3.7%
NO	111.0	74.0	21	0.94	9.7	0	42.7	45.8	46.5	47.2	47.2	47.4	-
NP	108.0	72.0	12	1.00	21.8	0	57.8	60.1	61.0	61.7	61.4	61.6	-
NW	133.0	89.0	10	0.98	23.5	0	66.7	67.7	68.3	69.0	68.7	68.9	-

Zone substation	Station N Rating (MVA)	Station N-1 Rating (MVA)	Hours load is 95% of MD	Station Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	
OAK	87.2	87.2	8	1.00	3.0	0	41.5	42.4	43.2	44.1	44.0	44.2	-
OE	64.8	32.4	17	0.89	4.2	0	16.3	16.8	16.9	17.1	17.0	17.0	-
OR	64.6	32.3	5	0.97	5.6	0	35.1	36.4	36.9	37.4	37.4	37.7	12.6%
RBD	91.6	45.8	5	0.98	14.7	0	36.9	45.4	46.3	47.5	47.8	48.4	-
SH	21.6	10.8	3	0.97	0.0	0	7.6	7.8	7.9	8.0	8.0	8.0	-
SR	73.1	36.5	3	0.99	13.3	0	30.3	33.1	33.6	34.1	34.1	34.3	-
SS ²⁵	80.2	40.1	7	0.93	15.8	7	43.4	41.6	41.9	42.3	42.1	42.2	3.8%
STO	72.0	36.0	3	0.94	12.7	0.5	41.6	48.1	48.9	50.0	50.0	50.6	33.6%
SV/SVW	160.1	120.1	20	0.96	16.9	0	101.8	104.1	105.1	106.7	106.6	106.9	-
WD	94.9	63.3	3	1.00	6.5	0	52.3	53.9	54.5	55.3	55.0	55.2	-

²⁵ Demand data shown in table excludes embedded generation.

Appendix D Maximum demands– sub-transmission lines

The tables below set out the forecasts for maximum demand for each United Energy sub-transmission line and their capacity. These forecasts are used to identify potential future constraints in the network.

Please note that the availability of load transfer and generation capacity at maximum demand times cannot be guaranteed.

Loop	Loop N Rating (MVA)	Loop N-1 Rating (MVA)	Hours load is 95% of MD	Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2020-21	2021-22	2022-23	2023-24	2024-25	
CBTS 66 kV												
CBTS-CRM-FTN-LWN-FTS-CBTS	251	184	4	0.95	40.9	0.0	183.5	186.4	189.9	189.6	190.2	-
ERTS 66 kV												
ERTS-DSH-DVY-DN-HPK-ERTS ²⁶	441	339	6	0.95	27.0	10.5	276.7	278.5	281.9	286.0	287.0	-
ERTS-MGE-LD-ERTS	239	128	13	0.95	40.6	0.0	137.1	138.7	140.6	140.2	140.4	7.1%
HTS 66 kV												
HTS-KBH-M/MC-BR-HTS	231	146	5	0.95	60.9	0.0	166.8	167.6	168.9	170.8	171.4	13.9%
HTS-MR-BT-NB-HTS	242	118	8	0.95	10.8	0.0	137.2	139.0	140.9	140.5	140.7	16.2%
HTS-SR-CM-HT-HTS	184	128	12	0.95	27.5	0.0	116.6	118.9	121.9	122.9	123.6	-
MTS 22 kV												
MTS-CFD-EL-EM-MTS	270	134	9	0.95	12.1	0.0	131.7	134.5	136.9	136.9	138.1	-

²⁶ Demand data shown in table excludes embedded generation.

Loop	Loop N Rating (MVA)	Loop N-1 Rating (MVA)	Hours load is 95% of MD	Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2020-21	2021-22	2022-23	2023-24	2024-25	
MTS-OR-OAK-MTS	158	82	7	0.95	9.0	0.0	76.3	77.5	78.9	78.9	79.3	-
MTS-SH-MTS	19	14	2	0.95	4.0	0.0	7.7	7.8	7.9	7.9	8.0	-
MTS-BW-MTS	39	27	7	0.95	4.0	0.0	21.5	21.8	22.1	22.0	22.0	-
RTS 66 kV												
RTS-EW-SK-RTS ²⁷	143	86	1	0.95	10.4	5.7	92.6	93.8	94.5	95.3	96.5	8.1%
RTS-K-CL-RTS	202	99.5	15	0.95	12.0	0.0	117.5	119.5	121.1	121.7	123.1	18.2%
RWTS 66 kV												
RWTS-BH-NW-RWTS	209	120	8	0.95	25.2	0.0	124.5	126.5	129.1	129.3	130.8	3.7%
SVTS 66 kV												
SVTS-EB-RD-SVTS	194	107	3	0.95	17.8	0.0	111.2	112.1	113.2	113.3	114.0	3.9%
SVTS-GW-NO-SVTS	240	128	11	0.95	15.5	0.0	112.7	114.2	115.6	115.5	116.2	-
SVTS-NP-SS-SVTS ²⁷	206	109	3	0.95	29.6	7.0	103.8	104.9	106.1	105.6	105.8	-
SVTS-OE-CDA-SVTS	115	65	11	0.95	26.3	0.0	41.3	41.8	42.5	42.8	43.2	-
SVTS-SV-SVW-SVTS	254	128	7	0.95	16.9	0.0	108.6	109.7	111.3	111.2	111.5	-
TBTS 66 kV												
TBTS-HGS-TBTS	171	91	9	0.95	13.7	0.0	46.7	47.5	48.5	48.3	48.4	-
TBTS-FSH-MTN-DMA-TBTS	408	229	2	0.95	25.5	0.0	244.6	249.1	254.7	255.5	258.1	6.7%
TBTS-DMA-MTN ²⁸	236	128	2	0.95	5.5	0.0	137.3	140.3	143.9	144.8	146.6	7.3%

²⁷ Demand data shown in table excludes embedded generation.

²⁸ Sub loop constraints of TBTS-FSH-MTN-DMA-TBTS loop.

Loop	Loop N Rating (MVA)	Loop N-1 Rating (MVA)	Hours load is 95% of MD	Power Factor at MD	Load Transfer Capability (MVA) (2020/21)	Embedded Generation Capacity (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Load Above N-1 Rating (2020/21)
							2020-21	2021-22	2022-23	2023-24	2024-25	
TBTS-DMA-TBTS ²⁸ (voltage collapse)	120	0	2	0.95	5.5	0.0	141.3	141.4	142.2	145.5	147.4	100.0%
DMA-RBD-DMA ²⁸	138	70	2	0.95	10.4	0.0	96.1	97.9	100.3	100.6	101.7	36.7%
RBD-STO-RBD ²⁸	114	57	2	0.95	12.7	0.0	47.3	48.2	49.2	49.2	49.8	-
TBTS 66 kV												
TSTS-BU-WD-TSTS	170	95	4	0.95	0.0	0.0	90.2	91.2	92.5	92.0	92.2	-
TSTS-DC-TSTS	201	101	3	0.95	14.1	0.0	97.1	98.6	100.3	99.8	100.2	-

Appendix E Glossary and abbreviations

E.1. Glossary

Common Term	Description
kV	kilo Volt
Amps	Ampere
MW	Mega Watt
MWh	Mega Watt hour
MVA	mega volt ampere
N Cyclic Rating	The station output capacity with all transformers in service. Cyclic ratings assume that the load follows a daily pattern and are calculated using load curves appropriate to the season. Cyclic ratings also take into consideration the thermal inertia of the plant.
N-1 Cyclic Rating or “Firm Rating”	The cyclic station output capability with an outage of one transformer.
Capacity of Line (Amps)	The line current rating which takes into consideration the type of line, conductor materials, allowable insulation temperature, effect of adjacent lines, allowable temperature rise and ambient conditions. It should be noted that United Energy operates many types of underground cables in its sub-transmission system. The different types of underground cables have varying operating parameters that in turn define their ratings.
% Above Capacity	The percentage by which the forecast maximum demand exceeds the N-1 cyclic rating.
Energy-at-risk	The amount of energy that would not be supplied if a major outage of a transformer or sub-transmission line occurs at the station or sub-transmission loop in that particular year, and no other mitigation action is taken.
Annual hours per year at risk	The number of hours in a year during which the 10 th percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.

E.2. Zone substations

Zone substation	Abbreviation	Transformation	Shared supply
Box Hill	BH	66/22 kV	No
Beaumaris	BR	66/11 kV	No
Bentleigh	BT	66/11 kV	No
Bulleen	BU	66/11 kV	No
Burwood	BW	22/11 kV	No
Clarinda	CDA	66/22 kV	No
Caulfield	CFD	66/11 kV	No
Cheltenham	CM	66/11 kV	No
Carrum	CRM	66/22 kV	No
Doncaster	DC	66/22 kV	No
Dromana	DMA	66/22 kV	No
Dandenong	DN	66/22 kV	No
Dandenong South	DSH	66/22 kV	No
Dandenong Valley	DVY	66/22 kV	No
East Burwood	EB	66/22 kV	No
Elsternwick	EL	66/11 kV	No
East Malvern	EM	66/11 kV	No
Elwood	EW	66/11 kV	No
Frankston South	FSH	66/22 kV	No
Frankston	FTN	66/22 kV	No
Glen Waverley	GW	66/22 kV	No
Hastings	HGS	66/22 kV	No
Heatherton	HT	66/22 kV	No
Gardiner	K	66/11 kV	CitiPower
Keysborough	KBH	66/22 kV	No
Lyndale	LD	66/22 kV	No
Langwarrin	LWN	66/22 kV	No
Mentone	M	66/11 kV	No
Mordialloc	MC	66/22 kV	No
Mulgrave	MGE	66/22 kV	No
Moorabbin	MR	66/11 kV	No
Mornington	MTN	66/22 kV	No
North Brighton	NB	66/11 kV	No
Notting Hill	NO	66/22 kV	No
Noble Park	NP	66/22 kV	No

Nunawading	NW	66/22 kV	No
Oakleigh	OAK	66/11 kV	No
Oakleigh East	OE	66/11 kV	No
Ormond	OR	66/11 kV	No
Rosebud	RBD	66/22 kV	No
Surrey Hills	SH	22/6.6 kV	No
Sandringham	SR	66/11 kV	No
Springvale South	SS	66/22 kV	No
Sorrento	STO	66/22 kV	No
Springvale	SV	66/22 kV	No
Springvale West	SVW	66/22 kV	No
West Doncaster	WD	66/11/6.6 kV	CitiPower

E.3. Terminal stations

Terminal station	Abbreviation	Supply voltage	Shared supply
Cranbourne	CBTS	66 kV	AusNet Electricity Services
East Rowville	ERTS	66 kV	AusNet Electricity Services
Frankston	FTS	66 kV	AusNet Electricity Services (switching station)
Heatherton	HTS	66 kV	No
Malvern	MTS	66 kV	No
Malvern	MTS	22 kV	No
Richmond	RTS	66 kV	CitiPower
Ringwood	RWTS	66 kV	AusNet Electricity Services
Ringwood	RWTS	22 kV	AusNet Electricity Services
Springvale	SVTS	66 kV	CitiPower
Templestowe	TSTS	66 kV	AusNet Electricity Services, CitiPower, Jemena
Tyabb	TBTS	66 kV	No