

DISTRIBUTION ANNUAL PLANNING REPORT

December 2022

Disclaimer

The purpose of this document is to provide information about actual and forecast limitations on United Energy's electricity distribution network and details of these limitations, 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 Distribution Annual Planning Report (**DAPR**) has been prepared in accordance with the National Electricity Rules (**NER**), in particular Schedule 5.8, as well as the Victorian Electricity Distribution Code of Practice (**VEDCoP**) Section 19.4.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and maximum demand 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

This 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 2022, as well as the forward planning period for this DAPR of 2023 to 2027.

United Energy is a regulated Victorian electricity distribution business. United Energy distributes electricity to more than 707,000 customers across east and south-east Melbourne and the Mornington Peninsula, where the vast majority of the customers are residential and located in urban areas. The network consists of more than 204,000 poles and over 13,470 kilometres of overhead lines and underground cables. Electricity is received via 92 sub-transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages to distribution voltages.

The DAPR sets out the following information:

- import capacity and associated maximum demand forecasts, and export capacity and associated minimum demand forecasts at the zone substation, sub-transmission and primary distribution feeder levels;
- system limitations resulting from the forecast maximum demand breaching its import capacity, or from the forecast minimum demand breaching its export capacity, following forced outages, retirements or asset de-ratings;
- projects that have been, or will be, assessed under the Regulatory Investment Test for Distribution (**RIT-D**); and
- other high-level information providing context for United Energy's planning processes and activities.

The DAPR provides a high-level description of the balance that United Energy will take between investing in augmentation and replacement of its assets over the forecast period, with network risk, performance, and compliance outcomes and requirements. Transmission connection assets supplying the distribution network are addressed in a separate report called the Transmission Connection Planning Report (**TCPR**).[1]

Information presented within this DAPR may indicate an emerging limitation where a more detailed analysis of risks and options for remedial action by United Energy are required. These emerging limitations are potential opportunities for prospective proponents to provide alternative non-network solutions to address the network need, at the identified zone substations, sub-transmission loops and primary distribution feeders. The DAPR also provides preliminary information on distribution substation

[1] The Transmission Connection Planning Report is available on the United Energy website at https://www.unitedenergy.com.au/network-management/network-planning/network-data

and low-voltage circuit limitations as part of our consultation obligations under the Demand Management Incentive Scheme (**DMIS**).

Network limitation information is also provided in MS-Excel® format, within the System Limitations Template accompanying this report. Providing this information to the market, facilitates the efficient development of the network by broadening the range of options available, to best meet the needs of customers.

The DAPR is aligned with the requirements of Clauses 5.13.2(b) and (c) of the 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 19.4 of the VEDCoP, as published by the Essential Services Commission of Victoria (**ESC**).

The VEDCoP was updated in 2022 to include additional DAPR reporting requirements for United Energy including reporting on its use of Advanced Metering Infrastructure (**AMI**), and additional power quality voltage data. These reporting requirements have been included in Chapter 20 of this DAPR, as well as the accompanying MS-Excel® Distribution Voltage Information template, described further in Section 17.4.1.

1.1 Public forum and consultation

United Energy intends to hold a public forum to discuss the contents of this DAPR in early 2022. All interested stakeholders are welcome to attend, including interested parties registered on United Energy's Demand-Side Engagement (**DSE**) 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 the identified network limitations. All submissions should address the technical characteristics of non-network options provided in this DAPR and include information listed in United Energy's DSE Document[2].

We also welcome feedback or suggestions for improvement on the structure or content presented in this year's DAPR, System 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: Head of Network Planning
PO Box 449
Mt Waverley VIC 3149

[2] The Demand-Side Engagement Document is available on the United Energy website at https://media.unitedenergy.com.au/factsheets/UE-PL-2202-Demand-Side-Engagement-Document.pdf

1.2 Overview of network limitations

The United Energy distribution network limitations identified in this DAPR are listed in Table 1.1. Maps showing the location of the limitations are in Appendix B. Details on each limitation are further documented in this report, and in the attached System Limitations Template and United Energy network limitation Google Earth map.

Table 1.1 United Energy network limitations summary

Limitation	Asset	Project type	Year
1	Doncaster (**DC**) Zone Substation	Augmentation	2025
2	Keysborough (**KBH**) Zone Substation	Augmentation	2025
3	East Malvern (**EM**) Zone Substation	Augmentation	2026
4	Mornington (**MTN**) Zone Substation	Augmentation	2027
5	MGE 12 (Mulgrave) HV Feeder	Augmentation	2024
6	BU 25 (Bulleen) HV Feeder	Augmentation	2023
7	FSH 33 (Frankston South) HV Feeder	Augmentation	2023
8	Surrey Hills (**SH**) Transformers	Replacement	2024
9	Sandringham (**SR**) #3 Transformer	Replacement	2024
10	Elwood (**EW**) #2 Transformer	Replacement	2027
11	Gardiner (**K**) #3 Transformer	Replacement	2027
12	Glen Waverley (**GW**) 22kV Outdoor Switchyard	Replacement	2025
13	Doncaster (**DC**) 22kV Outdoor Switchyard	Replacement	2024
14	Elwood (**EW**) 11kV Indoor Switchboard	Replacement	2027
15	Heatherton (**HT**) 22kV Outdoor Switchyard	Replacement	2024

2 Background

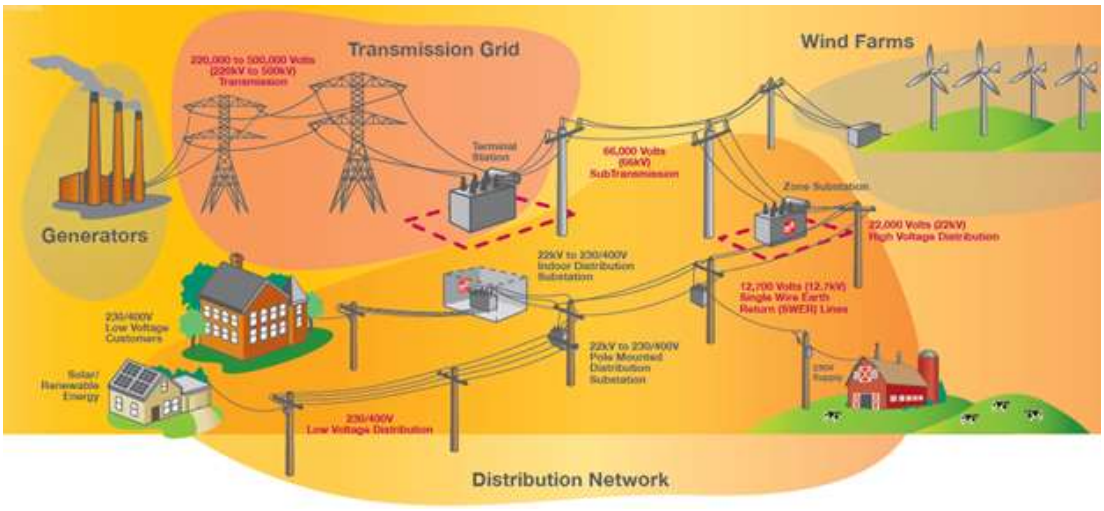
This chapter sets out background information on United Energy Distribution Pty. Ltd. (**United Energy**) and how it fits into the electricity supply chain.

2.1 Who we are

United Energy is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. United Energy owns the poles, wires and substations which supply electricity to homes and businesses.

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

Figure 2.1 The electricity supply chain



The distribution of electricity is one of four main stages in the supply of electricity to customers. The four main stages of the supply chain are:

- **Generation**: generation companies produce electricity from sources such as coal, gas, hydro, 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 centralised 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 role of DNSPs is in developing and maintaining their networks to ensure a safe, reliable supply of electricity is delivered to customers, to the required quality of supply standards, at least cost.

- **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

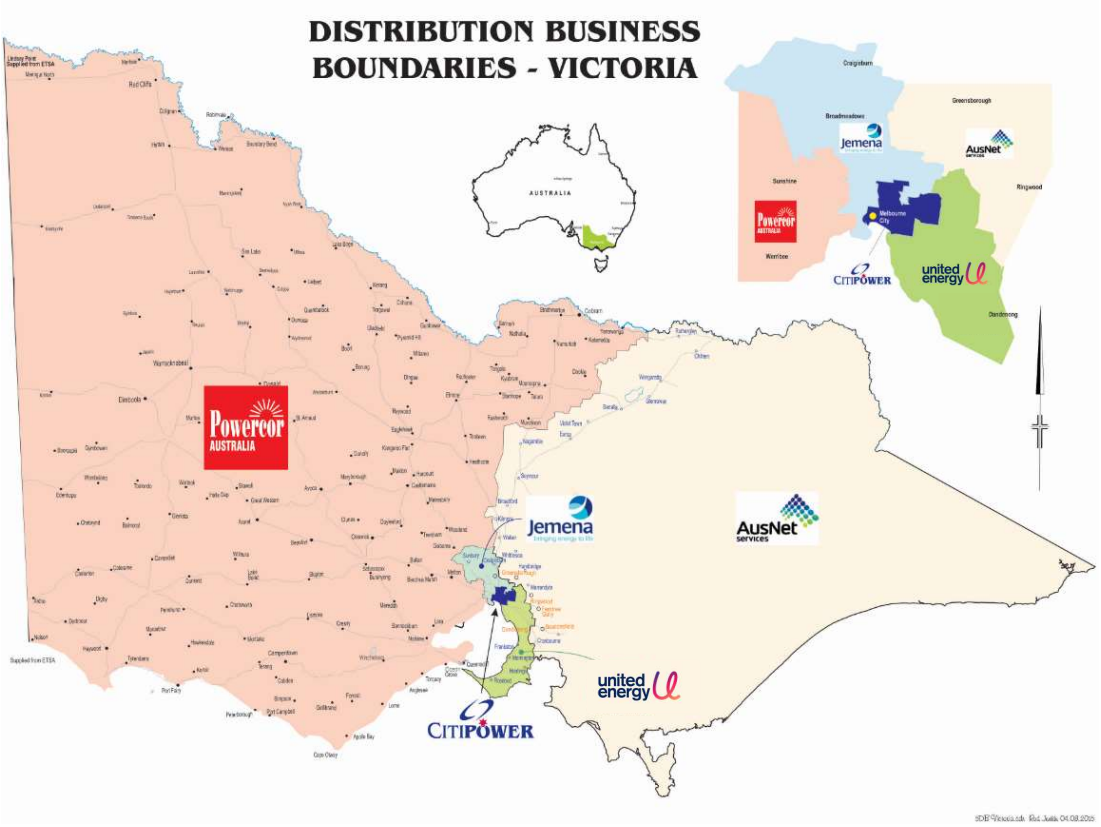
In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network in a prescribed geographic area. United Energy is one of those distribution businesses.

The United Energy distribution network transports 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, with light industrial centres such as Braeside, Clayton, Heatherton, Mulgrave and Scoresby;
- the central region, being a mix of developed and undeveloped land. It includes the industrial and commercial centre of Dandenong, and many of United Energy's greenfield growth areas such as Keysborough, Lyndhurst and Bangholme; and
- the southern region, from Frankston down to Hastings and Portsea. 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 of 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's service area relative to the other Victorian DNSPs is shown in Figure 2.2.

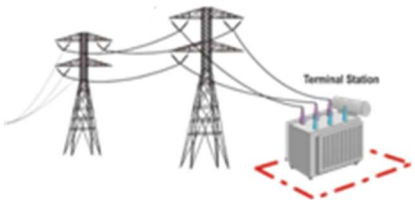
Figure 2.2 United Energy distribution service area



In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network and the associated transmission connection assets. DNSPs are also responsible for the lifecycle management of their assets including asset replacements and retirements. In order to continue to provide an efficient, safe and reliable supply to its customers, United Energy must plan for the augmentation and replacement expenditure needs of the network. The need for augmentation is largely driven by customer maximum demand growth and geographic shifts of demand due to urban redevelopment. The need for replacement is largely driven by asset condition, safety and performance.

2.3 Delivering electricity to customers

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

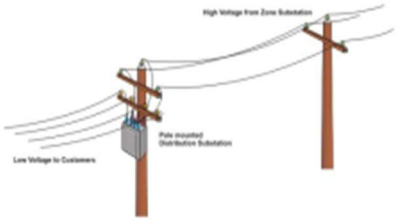


Firstly, the voltage of the electricity that is delivered by transmission at 220,000 Volts (220kV), is reduced by transformers within **terminal stations** down to 66kV or 22kV. The United Energy network is supplied from the transmission connection assets within these terminal stations.



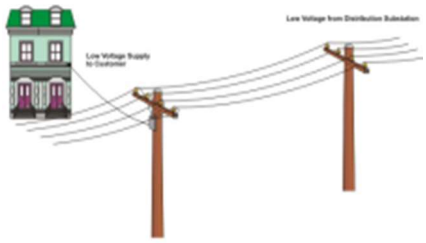
Secondly, United Energy transports the electricity from the terminal stations through its **sub-transmission network**, made up of large power poles, overhead lines and underground cables, to its zone substations.

Thirdly, at the **zone substation** the electricity voltage is converted by transformers down to 22kV, 11kV or 6.6kV. Electricity at this voltage can then be distributed throughout the service area on distribution feeders.



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

Furthermore, electricity is transformed down to 400 Volts (3-phase) or 230 Volts (single-phase) at the **distribution substations,** being at a voltage level suitable for supply to customers.



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

Traditionally, the flow of electricity has been from large-scale generators (connected at the transmission or sub-transmission level) to the low-voltage network. For more than a decade, our customers are also installing increasing amounts of Distributed Energy Resources including solar photovoltaic, batteries and electric vehicles in their homes and businesses. These Distributed Energy Resources are now producing electricity locally at the low-voltage level and exporting it back into the network.

2.4 Operating environment and asset statistics

United Energy delivers electricity to approximately 707,000 homes and businesses in a 1,472 square kilometre service area, around 478 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 predominantly overhead lines that operates at 66kV (with some at 22kV), and a distribution network that operates at voltages of 22kV and 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 operate at a voltage of 220kV. 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 local areas.

The high-voltage distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment providing effective protection and control. The majority of the high-voltage distribution network nominally operates at 22kV and 11kV. There are some 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, operates at 12.7kV.

Distribution feeders are operated in a radial mode from their respective zone substation supply points. 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 most consumers is provided through the low-voltage distribution systems that nominally operate at 230 (single-phase) or 400 (3-phase) Volts. These voltages are derived from "distribution substations" which are located throughout the distribution network. The majority of United Energy's 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 customer points of supply.

The United Energy network maximum demand and asset statistics as at 30 June 2022, are presented in Table 2.1.

Table 2.1 United Energy network statistics

Item	Value
Peak coincident demand (summer 2021-22)	1,754 MW
Record peak coincident demand (summer 2008-09)	2,084 MW
Poles	204,399
Overhead lines	10,020 km
Underground cables	3,455 km
Sub-transmission lines	92
Zone substation transformers	115
Zone substations	47
Distribution feeders	489
Distribution substations	14,004

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 have a material impact in driving network limitations within the United Energy distribution network. These include:

- **maximum demand**: increases in electricity maximum demand levels can result in thermal capacity limitations, such as that caused by new residential customers connecting to the network (population growth), or new or changed business requirements for electricity;
- **minimum demand**: increases in reverse power flows (observed as negative demand) can result in thermal capacity limitations, such as that caused by new embedded generators connecting to the network;
- **fault-levels**: changes in short-circuit levels resulting in switchgear rupture limitations or unsafe step-and-touch potentials (for example), such as that caused by some types of embedded generation being connected to the network;
- **voltage levels**: changes in steady state voltage levels resulting in voltage compliance limitations, due to changes in power flow through network impedances. Examples include lower voltages caused by increased power demand between voltage regulating equipment and customer load at maximum demand, or higher voltages contributed by solar photovoltaic (**PV**) systems exporting into the network at minimum demand, reversing the direction of power flows;
- **system security and reliability**: changes that may impact either system security for AEMO, such as the connection of embedded generation or changes in protection systems, or reliability such as changes in the configuration and sectionalisation of the network, or its operating environment;
- **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 customer connection process; and
- **asset condition**: changes in asset condition over time which may lead to unreliable assets, such as deterioration caused by ageing, exposure to short-circuit currents, or adverse environmental conditions.

These factors are discussed in more detail below.

3.1 Maximum demand

At present, increases in maximum demand on the electricity network drives essentially all of the thermal capacity limitations and some of the voltage limitations observed on United Energy's network. Maximum demand is influenced by a range of factors including:

- **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 retail price of electricity influences the demand for electricity from the network; and
- **extreme weather**: the effect of ambient temperature extremes on demand largely due to increasing use of cooling (and heating) appliances, such as reverse cycle air-conditioners.

Further increases in maximum demand is expected over the short to medium horizon with increased uptake of Electric Vehicles (EV) and electrification of customer loads.

3.2 Minimum demand

Reductions in daytime minimum demand will become increasingly important for United Energy over time, as it is likely to to compound existing voltage limitations when minimum demand is negative, with thermal capacity limitations on the electricity network. It is influenced by a couple of key factors including:

- **embedded generators**: increased adoption of solar PV systems by customers, is the primary contributor to reductions in daytime minimum demand. When power starts to reverse its flow upstream into the network due to solar PV exports, voltage and thermal capacity limitations may start to materialise; and
- **energy efficiency**: improved efficiency in customer appliances and in the behavioural use of those appliances.

Forecasting of demand is discussed further in Chapter 5.

3.3 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 fault, current flows into the earth or along a neutral or earth-return wire.

United Energy estimates the prospective fault current level, 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 electrical plant, avoiding significant and sustained outages resulting from plant damage.

Fault-levels are influenced by a number of factors including:

- generation of all sizes, but particularly non-inverter based systems;
- impedance of transmission and distribution network equipment;
- earthing arrangements;
- load, including motors; and
- voltage level.

The following fault-level limits apply to the United Energy distribution network:

Table 3.1 Fault-level limits

Voltage	Fault-level Limit
66kV	21.9 kA
22kV	13.1 kA
11kV	18.4 kA
6.6kV	21.9 kA
<1kV	50.0 kA

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

There are presently no fault level limitations within United Energy's network that require corrective action.

3.4 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 a certain voltage range.

DNSPs are obligated to maintain customer voltages within limits prescribed by the VEDCoP, and these are further discussed in Chapter 17 of this DAPR. Similarly, manufacturers only supply appliances and equipment that operate within the Australian Standards. Supply voltage at levels outside these limits, could affect the performance of (or cause damage to) this equipment.

Voltage levels are influenced by a number of factors including:

- impedance of transmission and distribution network equipment;
- load levels and power factor;
- distributed generation, such as household solar PV systems;
- tap position of transformers in the network; and
- capacitor banks within the network.

United Energy manages the voltage variations caused by changes in power flows through the network impedance between the customer and the supplying substations, using its voltage regulating equipment and capacitor banks.

Over the last decade, increasing uptake of solar PV systems by customers is causing higher voltage levels in localised areas of the network while they export. In response to this broader uptake of solar PV across the network and its impact on voltage levels, United Energy established a network-wide Dynamic Voltage Management System (**DVMS**). This system provides closed-loop voltage control using AMI smart meters as the source of customer voltage information, to control low-voltage network voltages using the zone substation voltage regulation equipment. This system is now in operation to continuously monitor and manage network voltages, accommodating greater levels of solar PV connections to United Energy's network. Refer to Section 17.4.1 for further details. In parallel to the operation of the DVMS, United Energy monitors low-voltage network voltages using AMI smart meter analytics tools, to identify any residual network voltage limitations not addressed by the DVMS, for possible localised mitigation solutions.

3.5 System security and reliability

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

United Energy is responsible for the reliability of its distribution network. Changes in the configuration and sectionalisation of the network, or its operating environment influence the reliability performance outcomes of the network. For example, network augmentation or network performance projects are likely to result in reliability improvements for customers in the parts of the network affected.

3.6 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 its customer connection process.

3.7 Asset condition

The age profile of United Energy's distribution network assets reflects the large investment that took place in the electricity networks in Victoria, with much of the area electrified post-world wars. Assets on the United Energy network were first installed in Melbourne in the early part of the 1900s, although it wasn't until the late 1930s that network assets were being installed in large numbers. From the late 1950s the United Energy 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 and in the first decade of the current, the capacity of the network continued to grow with new and infill residential and business developments, growth in air-conditioning, computers, home entertainment systems,

and other household appliances, all contributing to significant maximum demand growth across the network.

The cycles of investment in network augmentation, means that there is a wide variation in the age of assets in service within the United Energy network. The growing proportion of aged assets reflects the uneven historical development of the network. The present implication is that an increasing number of assets are approaching their end-of-life and are likely to require replacement over the current and future forward-looking planning periods.

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 rates.

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 is approaching the time period where the failure rate starts to increase, the risk of asset failures across the network increases.

United Energy anticipates and manages this risk via a wide range of asset management 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 13, 14 and 15.

3.8 Distribution System Operator (DSO) enhanced capability

To respond to the future challenges of the network for least cost it is recognised that United Energy needs to implement and support new capabilities under an enhanced DSO role. IT investments in this area have been articulated in Chapter 19. These capabilities are broadly around the workstreams of:

- Enabling distributed energy resources export and increasing hosting capacity whilst addressing minimum demand and other system security obligations that may be placed on the DNSP;
- Utilising batteries to manage constraints and value stacking arrangements with third-parties to demonstrate multiple benefits;
- Enabling competition for non-network solutions through expanded platforms for sharing network constraints;

- Develop Dynamic Operating Envelope capability that is flexible to more dynamically manage the network and enable third-party service offerings on the distribution network .

Chapter 18 details the specific projects that United Energy is delivering in terms of demand management and non-network solutions.

4 Network planning standards for augmentations

This chapter sets out the process by which United Energy identifies maximum and minimum demand-driven limitations 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 (or no curtailment of embedded generation) following any single outage of a network element, such as a transformer. For 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 redundancy being built into the distribution network. A strict use of this approach may lead to inefficient network investment as redundancy is built into the network irrespective of the cost of the likely interruption to customers (or the cost of curtailing generation).

Probabilistic planning approach: the deterministic N-1 criterion is relaxed under this approach, and simulation studies are undertaken to assess the amount of expected energy that would not be supplied (or that would need to be curtailed) if an element of the network is out of service. As such, the consideration of Expected Unserved Energy (**EUE**) 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 (or some generation needs to be curtailed) with a network element out of service (hence the N-1 criterion is not met); however
- the EUE may be very small relative to the cost of alleviating the limitation, after considering the low probability of a forced outage of a particular element of the network.

The probabilistic approach also assesses EUE under system normal conditions (known as the “N” condition). This is where all assets are operating but the demand breaches either the total import or export capacity. Contingency load transfers or a non-network solution may be used to mitigate the risk in the interim period until it is ecomomically viable for an augmentation to be completed.

4.2 Application of the probabilistic approach to planning

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

The probabilistic planning approach involves estimating the probability of an asset outage occurring within a peak loading period, and:

- the EUE cost that will be incurred from expected supply interruptions if no action is taken to address an emerging limitation, and therefore

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

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

- the cost of providing additional network capacity to remove limitations; and
- the cost of having some exposure to demand levels beyond the network's capability to import or export power.

In other words, recognising that very extreme demand conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that a network asset outage occurs at the same time.

The probabilistic approach requires expenditure to be justified with reference to the benefits of lower EUE. This approach provides a reasonable estimate of the expected net present value to customers 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 or generation curtailment 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 maximum or minimum 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 method and assumptions for calculating historical 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 limitations in the network.

Please note that information relating to maximum and minimum demand forecasts at transmission-distribution connection points are provided in a separate report entitled the "Transmission Connection Planning Report" which is available on the United Energy website.[1]

5.1 Maximum and minimum demand forecasts

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

- zone substation maximum demands and export capacity: refer to Appendix C;
- sub-transmission system maximum demands and export capacity: refer to Appendix D;
- zone substation minimum demands and export capacity: refer to Appendix E; and
- sub-transmission system minimum demands and export capacity: refer to Appendix F.

5.2 Zone substations

This section sets out the method and inputs used to calculate the demand forecasts for the zone substations and related information that is set out in Appendix C and Appendix E.

5.2.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual transformer-summation, non-coincident maximum and minimum demand values recorded at each zone substation across the distribution network. Determining the actual maximum or minimum demand for each zone substation is first corrected for system abnormalities (i.e., load transfers, load-shedding, or generation curtailment).

As maximum and minimum demands are very weather dependent, the actual maximum and minimum demand values shown in Appendix C, are normalised in accordance with the relevant weather conditions experienced across any given period. Maximum demand is very dependent on the ambient temperature, whereas minimum daytime demand is very dependent on the amount of cloud cover. The weather-correction enables the historical, underlying maximum and minimum demand growth rate, to be estimated year-by-year. It also establishes a launch point from which to forecast future maximum and minimum demand growth.

The weather-correction for the maximum demand forecasts presented in this DAPR seeks to ascertain the "*10th percentile summer maximum demand*". This 10th percentile demand represents the maximum demand on the basis of a weather condition that would lead to a one-in-ten year maximum demand. 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 cent probability of being higher than the 10th percentile maximum demand forecast.[3] It is often referred to as 10 per cent probability of exceedance (**10% PoE**).

The weather-correction for the minimum demand forecasts presented in this DAPR seeks to ascertain the "*10th percentile annual minimum demand*". This 10th percentile demand represents the minimum demand on the basis of a weather condition that would lead to a one-in-ten year minimum demand[4]. It is often referred to as 10 per cent probability of under-reach (**10% PoU**).

5.2.2 Forecast demand

The historical weather-corrected demand values are trended forward, and combined with known or predicted loads or embedded generators that may be connected to (or disconnected from or transferred away to different parts of) the network. This includes taking into account customer connections and the estimated total output of known embedded generating units at a localised level.

United Energy has taken into account information relating to the load requirements of our customers, and the timing and diversification of those loads. This includes information of the estimated load requirements for planned, committed and under-construction developments across the United Energy service area, and large load planned retirements or reductions. United Energy has also taken into account information relating to DER installations by our customers.

These bottom-up forecasts for maximum demand have been reconciled (and scaled if necessary) with top–down independent econometric forecasts provided by the 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 (i.e., the maximum and minimum demand impacts of growth in solar PV, storage, EVs and energy efficiency).

5.2.3 Definitions for zone substation forecast tables

Appendix C contains other details of relevance for each zone substation, including:

- **Station N (import or export) rating**: this is the maximum cyclic capacity of the zone substation (for forward and reverse power flows respectively) assuming that

[3] Consequently, there is also a 10% probability that demand will exceed the maximum demand forecast.

[4] Consequently, there is also a 10% probability that demand will be lower than the minimum demand forecast.

the net load follows a daily pattern, with a rating calculated using load curves appropriate to the season, and that all equipment is in service, expressed in MVA;

- **Station N-1 (import or export) rating**: this is the cyclic capacity of the zone substation (for forward and reverse power flows respectively) with one transformer out-of-service that gives the lowest result, expressed in MVA. This is also known as the “firm” rating;
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the zone substation net load is greater than or equal to 95 per cent of the maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the zone substation net load is less than or equal to 95 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 105 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Station power factor at maximum or minimum demand:** this is the ratio of the active power to the apparent power at the times of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent zone substations and their adjacent feeder connections at times of maximum demand, available to take load away from the zone substation in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units greater than 1MW, and less than or equal to 1MW, that have been connected within the zone substation supply area at the date of this report.

5.3 Sub-transmission loops

This section sets out the method for calculating the historical and forecast maximum and minimum demands for the sub-transmission loops and related information, that is set out in Appendix D and Appendix F.

5.3.1 Historical demand

The historical actual demand and weather-corrected 10% PoE and 10% PoU for maximum and minimum demands at the sub-transmission loops are calculated in a similar way to the zone substation method.

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

5.3.2 Forecast demand

The 10% PoE sub-transmission loop forecast maximum demand, is derived from the growth rate of the aggregated diversified 10% PoE forecast maximum demands of the zone substations contained within the sub-transmission loop. United Energy escalates the weather-corrected sub-transmission loop maximum demand, using this growth rate. A similar approach is applied for minimum demand. These forecasts are set out in Appendix D and Appendix F.

5.3.3 Definitions for sub-transmission loop forecast tables

Appendix D contains other details of relevance for each sub-transmission loop, including:

- **Loop N (import or export) rating**: this is the maximum capacity of the sub-transmission loop (for forward and reverse power flows respectively) with all lines in service, taking into account the load sharing of lines within the loop, expressed in MVA;
- **Loop N-1 (import or export) rating**: this is the capacity of the sub-transmission loop (for forward and reverse power flows respectively) with one line out-of-service that gives the lowest result, expressed in MVA[5];
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the sub-transmission loop load is greater than or equal to 95 per cent of maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the sub-transmission loop load is less than or equal to 95 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 105 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Power factor at maximum demand or minimum demand:** this is the ratio of the active power to the apparent power at the times of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent sub-transmission loops, their zone substations and adjacent feeder connections at times of maximum demand, available to take load away from the sub-transmission loop in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units that are greater than 1MW, and less than or equal to 1MW, that have been connected within the sub-transmission loop supply area at the date of this report.

[5] 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.

5.4 Primary distribution feeders

This section sets out the method for calculating the forecast maximum and minimum demands for the primary distribution feeders.

5.4.1 Forecast demand

Primary distribution feeder 10% PoE maximum and minimum demand forecasts presented in this DAPR are calculated in a similar way to forecasts for zone substations. The feeder historical weather-corrected maximum and minimum demand values are trended forward using the underlying zone substation growth rates. Individual feeders are adjusted for specific planned loads and embedded generation connecting to the feeder, making sure the aggregated feeders' forecast reconciles with the zone substation forecast.

5.5 Transmission-distribution connection points

This section sets out the method and inputs used to calculate the demand forecasts for the terminal stations and related information, that is set out in Appendix G (for minimum demand) and in the Transmission Connection Planning Report (for maximum and minimum demands).

5.5.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual transformer-summation, non-coincident maximum and minimum demand values recorded at each terminal station. Determining the actual maximum or minimum demand for each terminal station is first corrected for system abnormalities (i.e., load transfers, load-shedding, or generation curtailment).

As maximum and minimum demand are very weather dependent, the actual maximum and minimum demand values shown in the Transmission Connection Plannning Report and Appendix G, are normalised in accordance with the relevant weather conditions experienced across any given period. Maximum demand is very dependent on the ambient temperature, whereas minimum daytime demand is very dependent on the amount of cloud cover. The weather-correction enables the historical, underlying maximum and minimum demand growth rate, to be estimated year-by-year. It also establishes a launch point from which to forecast future maximum and minimum demand growth.

5.5.2 Forecast demand

The historical weather-corrected demand values are trended forward, and adjusted for the changes in the zone substation growth rates of the zone substations connected to that terminal station.

5.5.3 Definitions for transmission-distribution connection point forecast tables

The Transmisson Connection Planning Report and Appendix G contains other details of relevance for each terminal station, including:

- **Station N (import or export) rating**: this is the maximum cyclic capacity of the terminal station (for forward and reverse power flows respectively) assuming that the net load follows a daily pattern, with a rating calculated using net load curves appropriate to the season, and that all equipment is in service, expressed in MVA;
- **Station N-1 (import or export) rating**: this is the cyclic capacity of the terminal station (for forward and reverse power flows respectively) with one transformer out-of-service that gives the lowest result, expressed in MVA. This is also known as the “firm” rating;
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the terminal station net load is greater than or equal to 95 per cent of maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the terminal substation net load is less than or equal to 95 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 105 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Station power factor at (maximum or minimum) demand:** this is the ratio of the active power to the apparent power at the time of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent terminal stations and their adjacent feeder and sub-transmission connections at times of maximum demand, available to take load away from the terminal station in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units greater than 1MW, and less than or equal to 1MW, that have been connected within the terminal station supply area at the date of this report.

Further information on transmission-distribution connection points is reported in the “Transmission Connection Planning Report”.

6 Approach to risk assessment

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

This process provides a means of identifying those network assets 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 limitations; and
- the potential cost of having some exposure to demand levels beyond the network's capability to import or export power.

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 to load, or would need to be curtailed from embedded generators, if one transformer or a sub-transmission line was out of service during a critical import or export loading condition, respectively.

This measure provides an indication of magnitude of loss of load (or generation curtailment) 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 of sub-transmission lines and zone substation transformers is discussed further in Section 6.5.

Although this DAPR focuses on presenting the energy-at-risk for a 10th percentile demand forecast (as discussed in Chapter 5), when undertaking an economic assessment of projects to address an identified need, United Energy moderates the energy-at-risk using a 30% and 70% weighting of the 10th and 50th percentile demand forecasts. Doing this takes into account the impacts of the year-on-year weather variability on energy-at-risk.

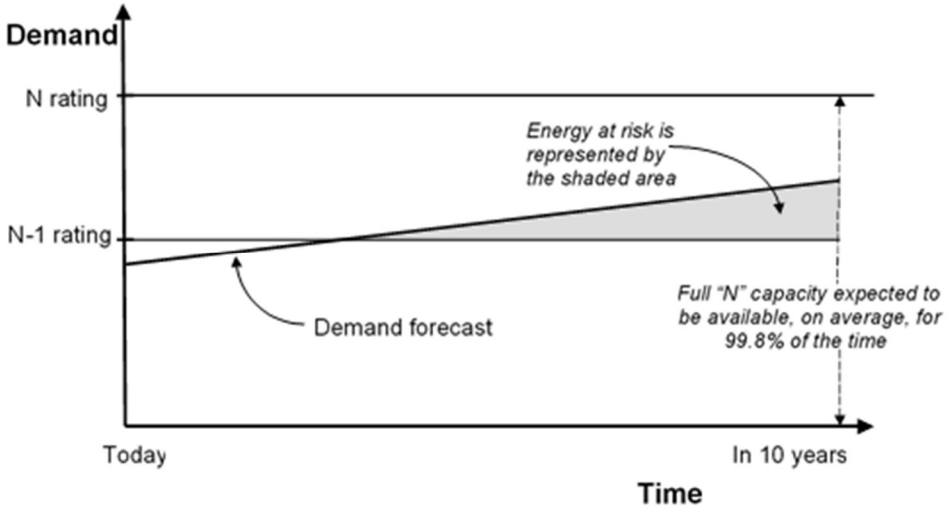
6.2 Interpreting energy-at-risk

As noted above, "energy-at-risk" is an estimate of the amount of energy that would not be supplied to load, or would need to be curtailed from embedded generators, if one transformer or sub-transmission line was out of service during a critical import or export loading condition, respectively.

The capability of a zone substation with one transformer out of service is referred to as its “N-1” firm rating. The capability of the zone substation with all transformers in service is referred to as its “N” rating. When the zone substation is importing power (i.e., power flowing towards the customer load), the import rating applies. When the zone substation is exporting power (i.e., power flowing towards the transmission network), the export rating applies.

The indicative relationship between the N and N-1 cycle ratings of a zone substation and the energy-at-risk (assuming maximum demand conditions), is depicted in Figure 6.1 below. The annual energy-at-risk is moderated by the load-duration curve of the demand, on the basis that the critical loading period only occurs for a small proportion of the year.

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



For augmentation projects and major replacement projects such as those listed in Table 1.1, United Energy undertakes a detailed assessment process to determine whether or not to proceed with the investment.

6.3 Value of customer reliability (VCR)

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 customers’ 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 customers as a result of electricity supply interruptions) that provides a guide as to the likely value.

A rule change in July 2018 made the Australian Energy Regulator (**AER**) responsible for determining the values different classifications of 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) $2022
Residential (climate zone 6)	$22.04
Commercial	$46.18
Agricultural	$39.28
Industrial	$66.16

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

The composite VCR is used to calculate the economic benefit of undertaking an augmentation or replacement. When 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.

6.4 Value of generation curtailment

In order to determine the economically optimal level and configuration of distribution capacity that would be provided to embedded generators for the export of power into the network, it is necessary to place a value on energy curtailed from embedded generators at times when the export capacity is breached.

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change[6]. Under the Rule change, the AER is required to develop customer export curtailment values ("CECV"), which are an estimate of the detriment to customers and the market of export curtailment due to network limitations (in $ per kWh of exports curtailed). CECVs are expected to play a similar role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is expected that the CECVs will be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology. At the same time, the AER also published a DER Integration Expenditure Guidance Note[7], which includes direction on how distribution network service providers should I)

[6] AEMC, Rule Determination, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, 12 August 2021.

[7] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure-guidance-note/final-decision

develop business cases for network investment integrating higher levels of customer DER and quantify DER values, ii) develop DER integration plans and investment proposals, and ii) quantify DER benefits in a cost-benefit analysis.

United Energy has not published values for generation curtailment in this DAPR as the method and value for determining generation curtailment is still being assessed. It is intended to publish these values in next year's DAPR.

6.5 Plant unavailability

The value of customer reliability (or the value of generation curtailment) is only one component in quantifying the cost of loss-of-supply risk for customers (or curtailment risk for embedded generators). United Energy combines these values with the expected unavailability of distribution network assets 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 Table 6.2 and Table 6.3. 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	$\frac{Repair\ time}{Repair\ time + \frac{(24 \times 365)}{(failure\ rate)}}$	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	$\frac{Repair\ time}{Repair\ time + \frac{(24\ \times 365)}{(failure\ rate\ \times length)}}$	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.

In a detailed assessment process, all site-specific outage scenarios may also be considered. For example, a sub-transmission line forced outage may also cause a transformer to be taken out of service because of the switching arrangement at the zone substation. The base (average) outage data is also not applicable for replacement assessments which will consider asset-specific failure rates based on effective age and condition.

6.6 Value of expected energy-at-risk

The financial value of expected energy-at-risk is calculated by multiplying the "energy-at-risk", with the "plant unavailability", and either the "value of customer reliability" or the "value of generation curtailment", depending on whether the energy-at-risk is an import or export limitation.

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, considering the:

- Import limitations
    - forecasts for maximum demand to 2026-27; and
    - relevant seasonal cyclic N-1 ratings for each zone substation (firm rating).
- Export limitations
    - forecasts for minimum demand to 2026-27; and
    - relevant cyclic N-1 export ratings for each zone substation (firm export rating).

Where the zone substations are forecast during 2022-23 to operate with 10% PoE maximum demand or 10% PoU minimum demand in breach of their firm import or export rating respectively, 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 energy-at-risk at times of maximum or minimum demand. At other times, the available transfers may be greater. As a result, the use of transfers under contingency situations may imply an interruption of supply for customers or embedded generators to protect network elements from damage whilst all available load transfers take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those augmentation programs set out in this section may be suitable. Solutions may also address sub-transmission limitations at the same time.

The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

United Energy notes that all other zone substations that are not specifically mentioned below have maximum or minimum demand levels within the firm rating, or the demand is not more than 5% in breach of the relevant rating, resulting in negligible 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

Based on the analysis presented in Section 7.2 below, United Energy proposes to augment the import-limited zone substations listed in the following table to address system limitations during the five-year forward planning period for this DAPR.

Table 7.1 Proposed import-limited zone substation augmentations

Zone substation	Description	Direct cost estimate ($m)				
		2023	2024	2025	2026	2027
DC	Install a fourth transformer with two new distribution feeders at Doncaster (**DC**) for summer 2025-26.	-	2.1	4.1	-	-
KBH	Install a second transformer with two new distribution feeders at Keysborough (**KBH**) for summer 2025-26.	-	2.2	4.2	-	-
EM	Install a third switchboard with three new distribution feeders at East Malvern (**EM**) for summer 2026-27.	-	-	0.9	6.3	-
MTN	Install a third transformer with a new distribution feeder at Mornington (**MTN**) for summer 2027-28.	-	-	-	2.3	4.6
Total		**-**	**4.3**	**9.2**	**8.6**	**4.6**

There are currently no identified export limitations during the five-year forward planning period for this DAPR. It should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

United Energy is currently investigating a range of options in readiness for the expectation of future export limitations at our zone substations including:

- Reducing float voltages, or applying LDC settings at zone substations;
- Installing reactors at zone substations;
- Network reconfigurations and augmentations;
- Reviewing zone substation power transformer tap changer specification;

- Optimising existing capacitor bank switching settings at zone substations; and
- Non-network options.

Our Dynamic Voltage Management System (DVMS) continues to actively manage voltage on our network. United Energy will continue to monitor the declining minimum demand levels on some of our zone substations and explore the feasibility of specific options to alleviate any forecast export limitations that cannot be managed by the DVMS, on a case-by-case basis.

The options and analysis are undertaken in the sections below.

7.2 Zone substations with forecast system limitations

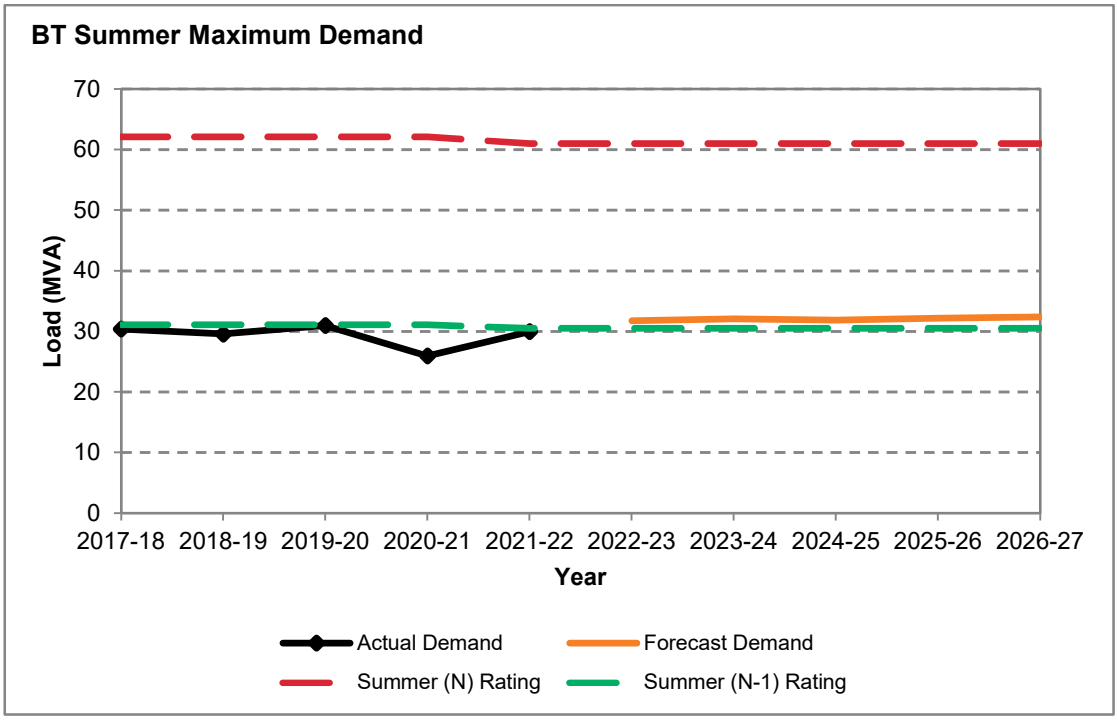
7.2.1 Bentleigh (BT) zone substation

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

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

The actual maximum demand at BT for summer 2021-22 was 30.0MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. For more details, please refer to the table in Appendix C or the System Limitations Template.

Figure 7.1 Forecast maximum demand for BT zone substation



United Energy estimates that in the summer of 2022-23, there will be 1.2MVA 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.

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

To address the anticipated system limitation 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 North Brighton (**NB**) and Caulfield (**CFD**) up to a maximum transfer capacity of 5.0MVA;
- install a third 20/33MVA transformer at BT zone substation at an estimated cost of $6.5 million;
- install a third transformer at adjacent MR zone substation along with distribution feeders to offload BT (see Section 7.2.18), at an estimated cost of $7.7 million.

The least cost technically acceptable option in the long term is to install a third transformer at adjacent MR zone substation along with distribution feeders to offload BT. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

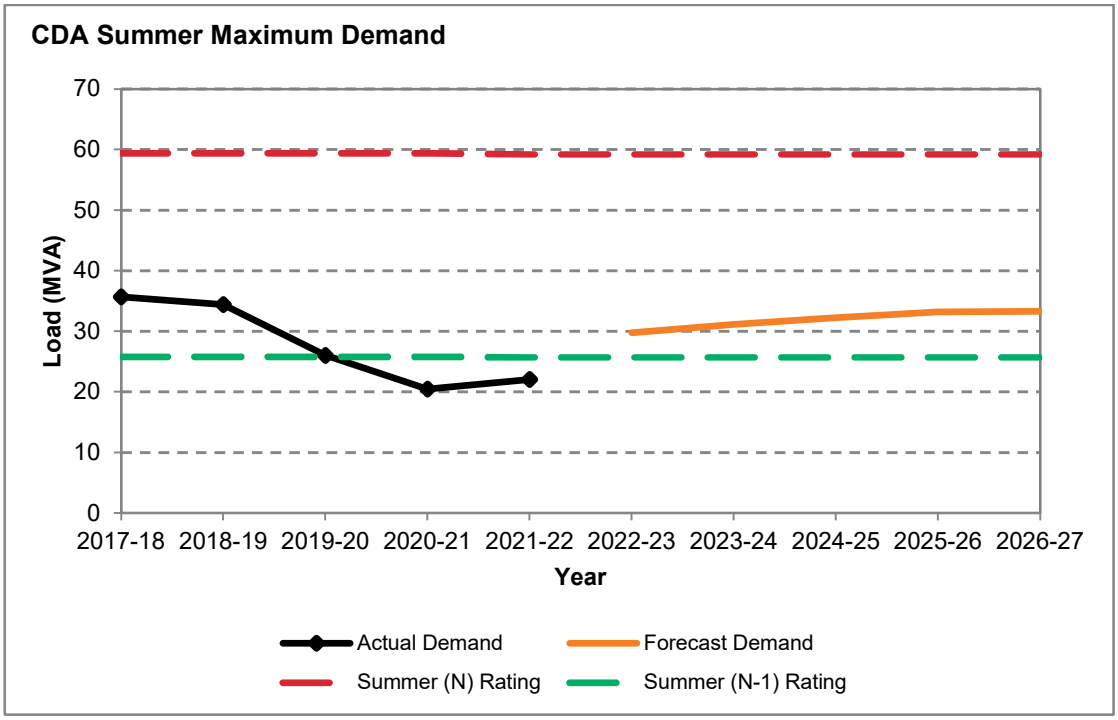
7.2.2 Clarinda (CDA) zone substation

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.

The actual maximum demand at CDA for summer 2021-22 was 22.0MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation’s summer (N) rating, and (N-1) rating based on the relocatable transformer. 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 7.2 Forecast maximum demand for CDA zone substation



United Energy estimates that in the summer of 2022-23, there will be 4.0MVA of load-at-risk if there is a failure of the permanent 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 limitation 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 9.2MVA;
- install a second 20/33MVA permanent transformer at CDA zone substation at an estimated cost of $6.7 million.

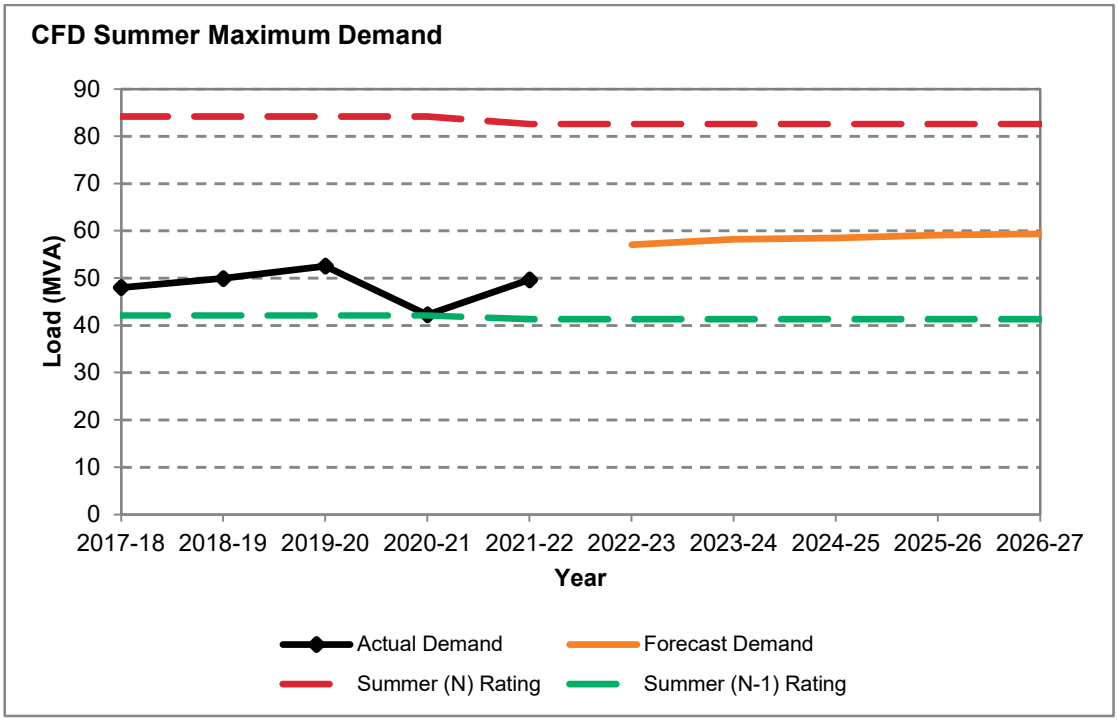
The least cost technically acceptable option is to install a new transformer at the CDA zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.3 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 2021-22 was 49.7MVA 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 zone substation's summer (N) and (N-1) ratings. For more details, please refer to the table in Appendix C or the System Limitations Template.

Figure 7.3 Forecast maximum demand for CFD zone substation



United Energy estimates that in the summer of 2022-23, there will be 15.8MVA 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 limitation 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 (leaving 3.6MVA of load-at-risk even after the transfers);
- 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.

A number of surrounding adjacent zone substations to CFD including EM, K and OR, and several feeders in the area are exhibiting load-at-risk. The least cost technically acceptable option to address these limitations, is to install a new switchboard with three

new distribution feeders at the more lightly loaded EM zone substation before summer 2026-27 (see Section 7.2.8).

The use of contingency load transfers will be used to mitigate the load-at-risk until this augmentation occurs.

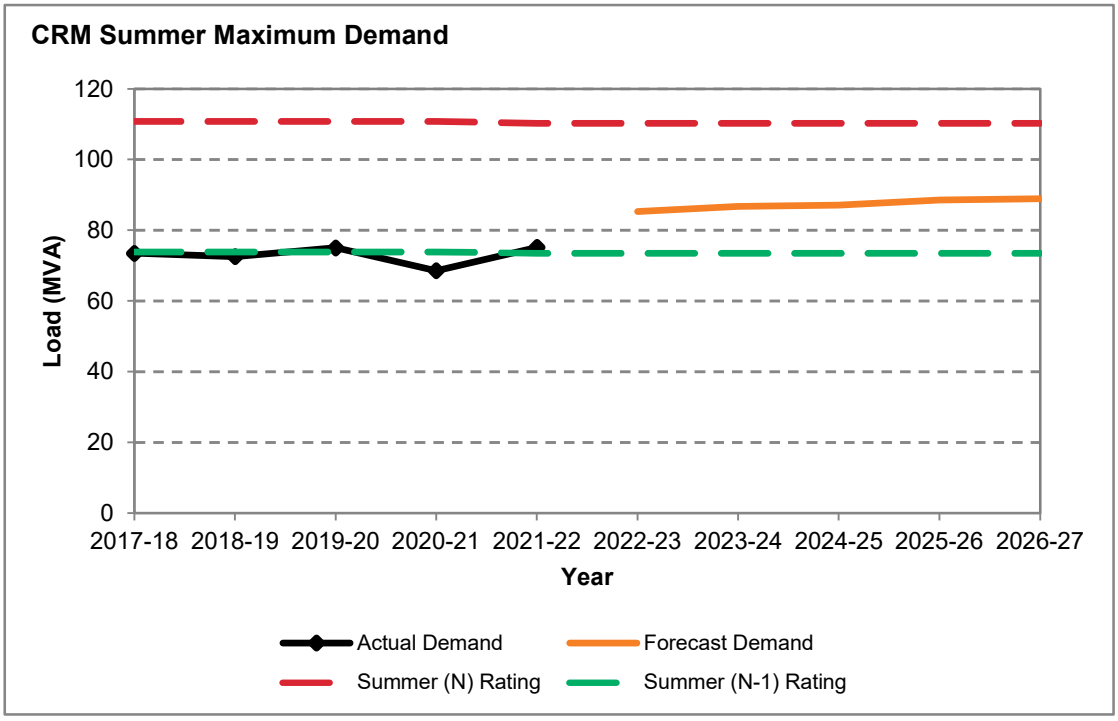
7.2.4 Carrum (CRM) zone substation

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 2021-22 was 75.2MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 CRM zone substation



United Energy estimates that in the summer of 2022-23, there will be 11.8MVA 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 limitation 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 17.8MVA;
- install a new 20/33MVA transformer and distribution feeders at FTN, at an estimated cost of $6.5 million. This may only allow a minimal offload of CRM;
- establish a new Skye (**SKE**) zone substation with new distribution feeders at an estimated cost of $25 million.

The least cost technically acceptable option in the long term is to establish a new SKE zone-substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.5 Doncaster (DC) zone substation

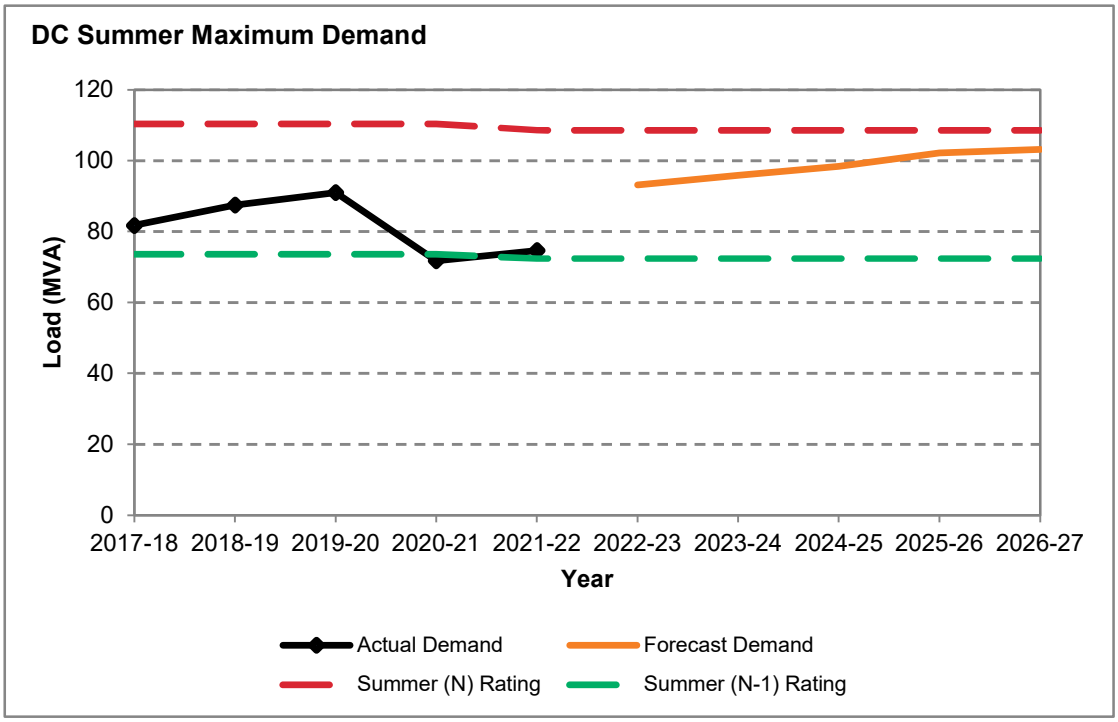
Doncaster (**DC**) zone substation is served by sub-transmission lines from the Templestowe Terminal Station (**TSTS**). It supplies the areas of Box Hill North, Doncaster, Doncaster East, Doncaster Hill and The Pines precincts, Templestowe and parts of the Box Hill central precinct.

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 2021-22 was 74.6MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. It should be noted that a load transfer was implemented to shift load away from DC in 2020. This transfer and the impact of mild summer on maximum demand is reflected in the graph below. Being designated as a Metropolitan activity centre by the Victorian Government under Plan Melbourne 2017-2050[8], 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.

[8] https://www.planmelbourne.vic.gov.au/

Figure 7.5 Forecast maximum demand at DC zone substation



United Energy estimates that in the summer of 2022-23, there will be 20.7MVA 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 established a new feeder from Box Hill (**BH**) zone substation in 2020 to offload DC and two of its highly loaded feeders, in order to partially address the risk at DC. The impact of this new feeder is presented in the chart above.

To address the anticipated system limitation 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 BH and Nunawading (**NW**) up to a maximum transfer capacity of 21.2MVA;

- install a fourth 20/33MVA 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. This option will not address the need for a fourth transformer and will lead to higher overall cost.

The least cost technically acceptable 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 imminently replace a transformer at DC. A RIT-D consultation will likely commence in 2023.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand in the DC supply area, between the hours of 15:00 to 21:00 on hot summer days by at least 2.2MVA. Any solution would need to be implemented by November 2025 for summer 2025-26.

The estimated annualised cost of the solution is around $210,000. 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 one year. For more details, please refer to the System Limitations Template.

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 to mitigate the load-at-risk.

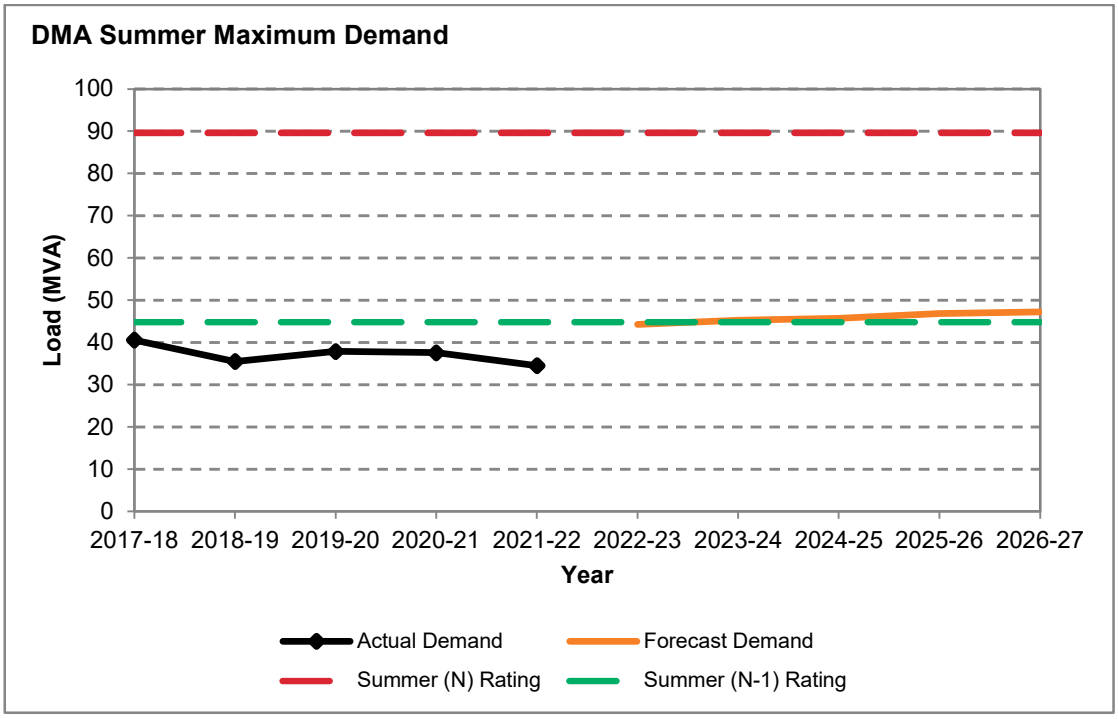
7.2.6 Dromana (DMA) zone substation

Dromana (**DMA**) zone substation is served by sub-transmission lines from the Tyabb Terminal Station (**TBTS**). It supplies the suburbs of Dromana, Arthurs Seat, Mount Martha, Red Hill, Safety Beach, Shoreham, and parts of Cape Schanck and Flinders.

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

The actual maximum demand at DMA for summer 2021-22 was 34.5MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation’s summer (N) and (N-1) ratings. For the historic and forecast asset ratings, please refer to the System Limitations Template.

Figure 7.6 Forecast maximum demand for EL zone substation



United Energy estimates that in the summer of 2023-24, there will be 0.4MVA of load-at-risk if there is a failure of one of the transformers 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 limitation 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 of Mornington (**MTN**) and Rosebud (**RBD**) up to a maximum transfer capacity of 25.1MVA;
- install a third transformer and switchboard at adjacent MTN zone substation along with distribution feeders to offload DMA before summer 2027-28 at an estimated cost of $6.8 million (see section 7.2.19);
- install a third 20/33MVA transformer at DMA zone substation at an estimated cost of $6.5 million.

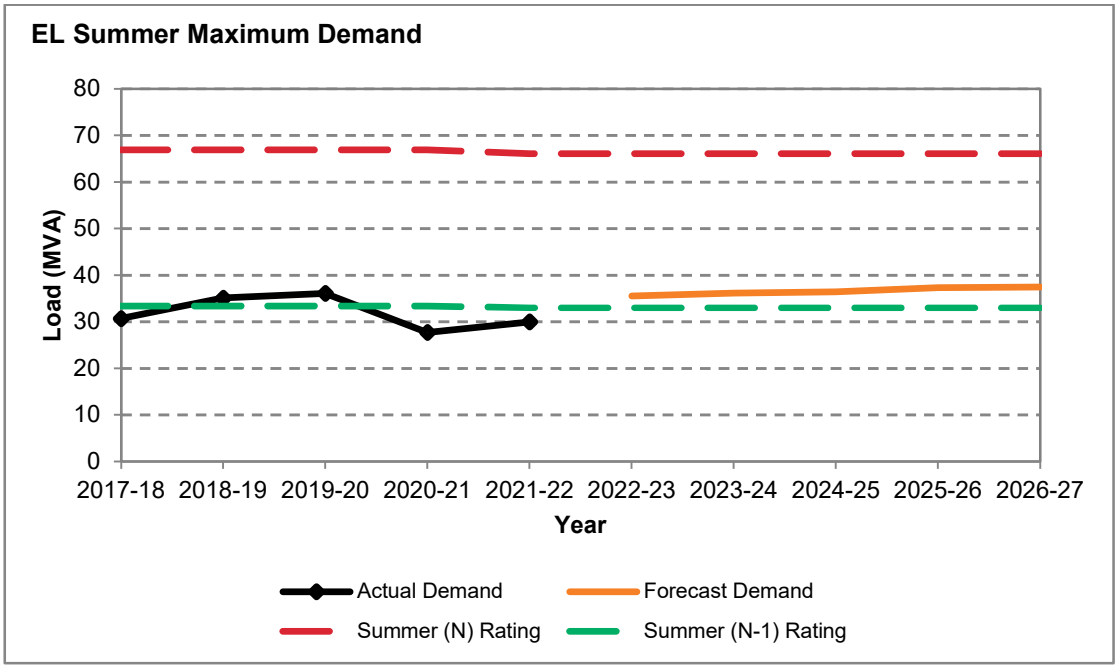
The least cost technically acceptable option is to install a third transformer and switchboard at adjacent MTN zone substation along with distribution feeders to offload DMA before summer 2027-28. In the interim, United Energy will utilise contingency load transfers to mitigate the load-at-risk.

7.2.7 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 one 20/27MVA and one 20/33MVA transformer, each operating at 66/11kV. The actual maximum demand at EL for summer 2021-22 was 30.0MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. For the historic and forecast asset ratings, please refer to the System Limitations Template.

Figure 7.7 Forecast maximum demand for EL zone substation



United Energy estimates that in the summer of 2022-23, there will be 2.5MVA 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 limitation 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 8.9MVA;
- install a third transformer at adjacent zone substations NB or EW along with distribution feeders to offload EL;
- Replace the ageing EL transformer No.3 with a modern equivalent which will increase the zone substation rating (note that the other aged EL transformer No.2 was 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.

The least cost technically acceptable solution is to replace the aged EL transformer No.3 with a modern equivalent (20/33MVA) transformer, such that the zone substation's summer (N-1) rating will be adequate to supply the maximum demand at EL zone substation. However, this replacement is not currently expected in the forward planning period for this DAPR.

In the interim, United Energy will utilise contingency load transfers to mitigate the load-at-risk.

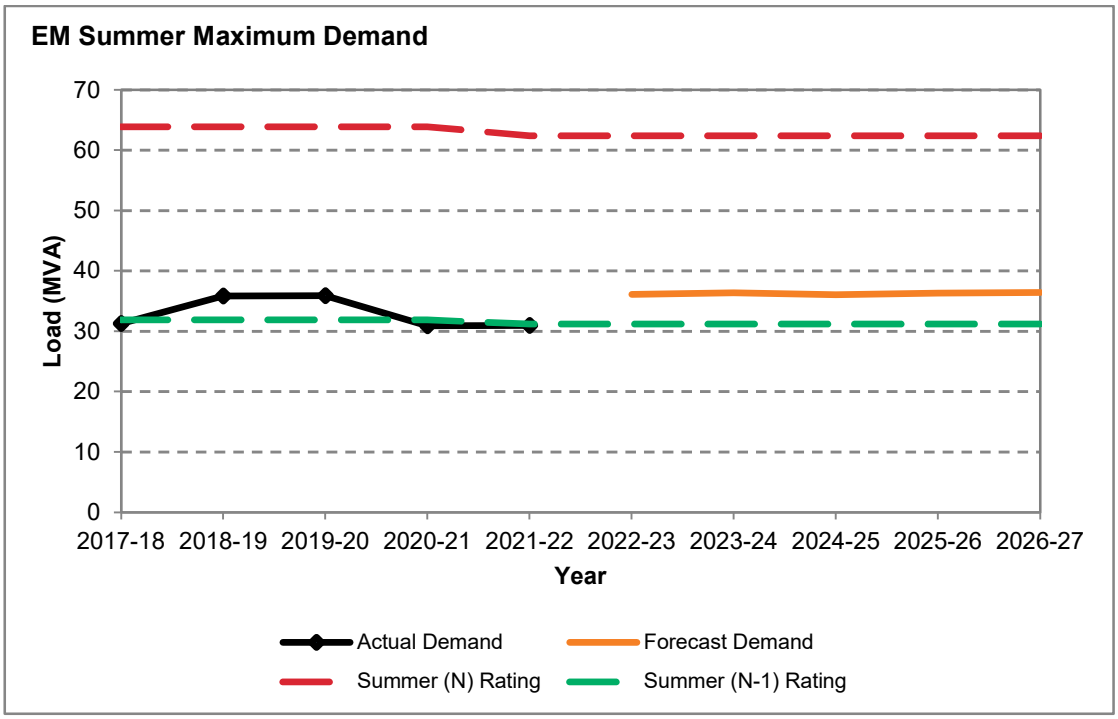
7.2.8 East Malvern (EM) zone substation

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 2021-22 was 31.0MVA. 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. 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 7.8 Forecast maximum demand for EM zone substation



United Energy estimates that in the summer of 2022-23, there will be 4.9MVA 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 to EM including Caulfield (**CFD**), Gardiner (**K**) and Ormond (**OR**) and the associated feeders in the area are exhibiting load-at-risk. There is a combined 29.8MVA of load-at-risk across these zone substations in 2022-23 which rises to 36.9MVA by the end of the planning period in 2026-27. 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 limitations 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 Gardiner (**K**) and Ormond (**OR**), up to a maximum transfer capacity of 6.7MVA;
- install a third switchboard and three new distribution feeders at EM zone-substation before summer 2026-27 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; or
- install two new distribution feeders from K zone substation and one new feeder at OR zone substation to alleviate the feeder limitations in the area.

The least cost technically acceptable option to address the limitations in the EM, CFD, K and OR supply areas, is to install a new switchboard with three new distribution feeders at the EM zone substation before summer 2026-27. A RIT-D consultation will likely commence in 2024.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand in the EM, CFD, K and/or OR supply areas, between the hours of 15:00 to 21:00 on hot summer days by at least 2.1MVA. Any solution would need to be implemented by November 2026 for summer 2026-27.

The estimated annualised cost of the solution is around $244,000. 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 one year. For more details, please refer to the System Limitations Template.

The use of contingency load transfers 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.

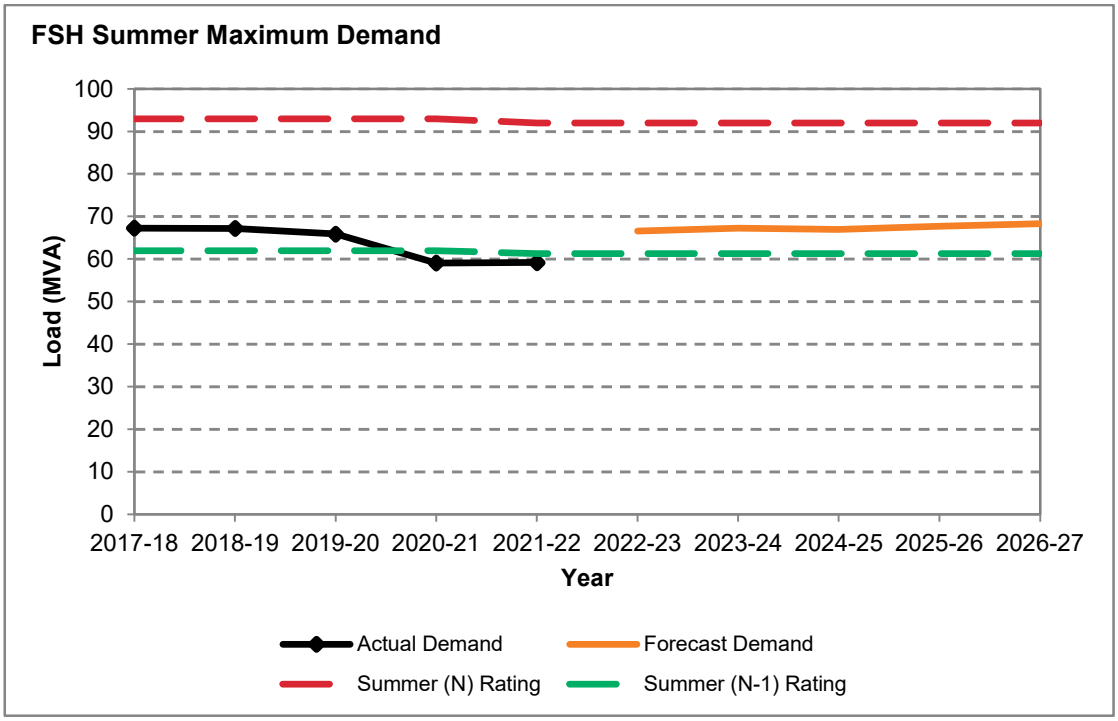
7.2.9 Frankston South (FSH) zone substation

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 2021-22 was 59.2MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. Being designated as a Metropolitan activity centre by the Victorian Government[8], the maximum demand in the Franskton area 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 7.9 Forecast maximum demand for FSH zone substation



United Energy estimates that in the summer of 2022-23, there will be 5.3MVA 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 MTN-FSH sub-transmission line, but not on the FTS–FSH sub-transmission line.

Consequently, an unplanned outage on the FTS–FSH sub-transmission line would also result in an outage of one of the transformers at FSH zone substation.

To address the anticipated system limitation 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 20.7MVA;
- replace the ageing FSH transformer No.1 with a modern equivalent which will increase the zone substation rating 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; or
- establish a new 66/22kV zone substation at Somerville (**SVE**).

The least cost technically acceptable solution is to replace the aged FSH transformer No.1 with a modern equivalent (20/33MVA) transformer, so that the zone substation's summer (N-1) rating will be adequate to supply the maximum demand at FSH zone substation. However, this replacement is not currently expected in the forward planning period for this DAPR.

The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

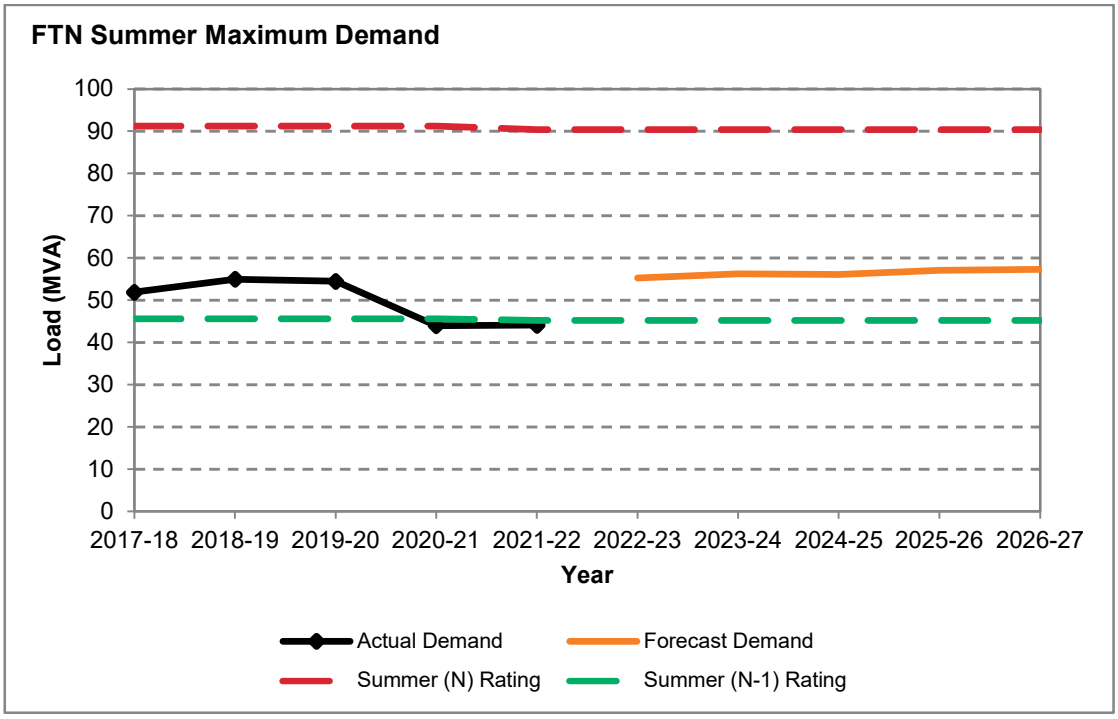
7.2.10 Frankston (FTN) zone substation

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 2021-22 was 44.1MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. Being designated as a Metropolitan activity centre by the Victorian Government[8], the maximum demand in the Franskton area 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 7.10 Forecast maximum demand for FTN zone substation



United Energy estimates that in the summer of 2022-23, there will be 10.1MVA 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 limitation 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 21.4MVA;
- 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 new distribution feeders.

The least cost technically acceptable option is to install a new transformer at the FTN zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR.

The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

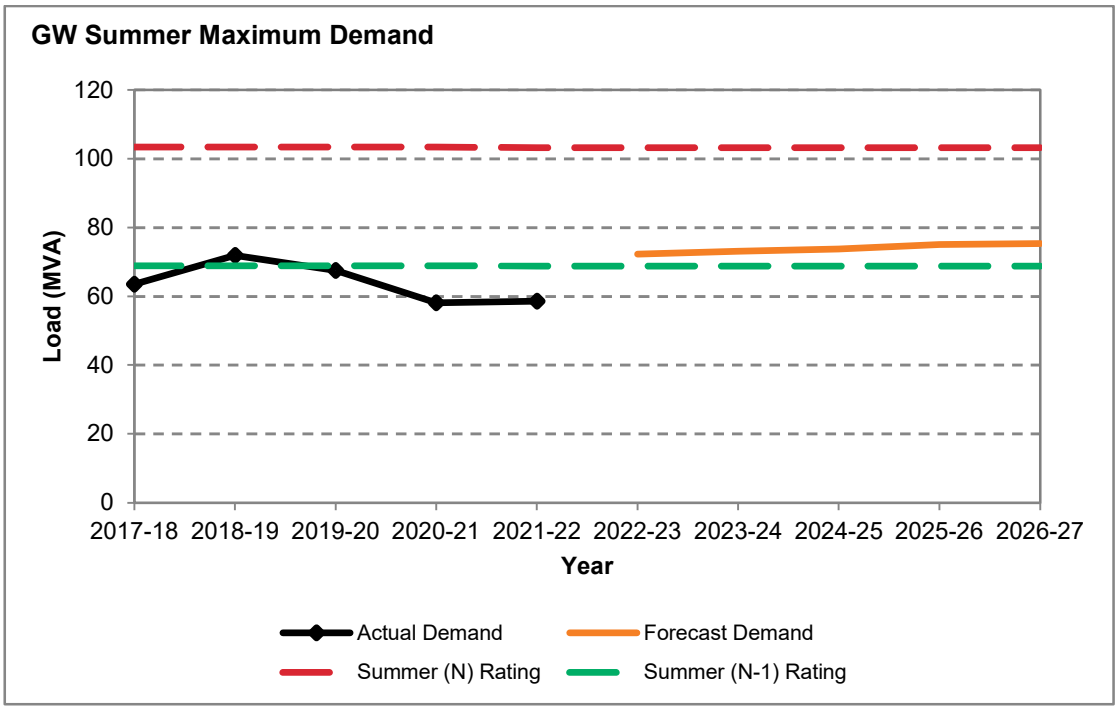
7.2.11 Glen Waverley (GW) zone substation

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

Currently, the GW zone substation consists of three 20/27MVA transformers operating at 66/22kV.

The actual maximum demand at GW for summer 2021-22 was 58.6MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 GW zone substation



United Energy estimates that in the summer of 2022-23, there will be 3.4MVA 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 unplanned 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 limitation 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 18.6MVA;
- install new distribution feeders at the adjacent NO zone substation and transfer load to NO, at an estimated cost of $2.0 million;
- install a fourth 20/33MVA transformer at GW zone substation at an estimated cost of $6.5 million.

The least cost technically acceptable option is to install new distribution feeders at the adjacent NO zone substation and transfer load from GW to NO. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

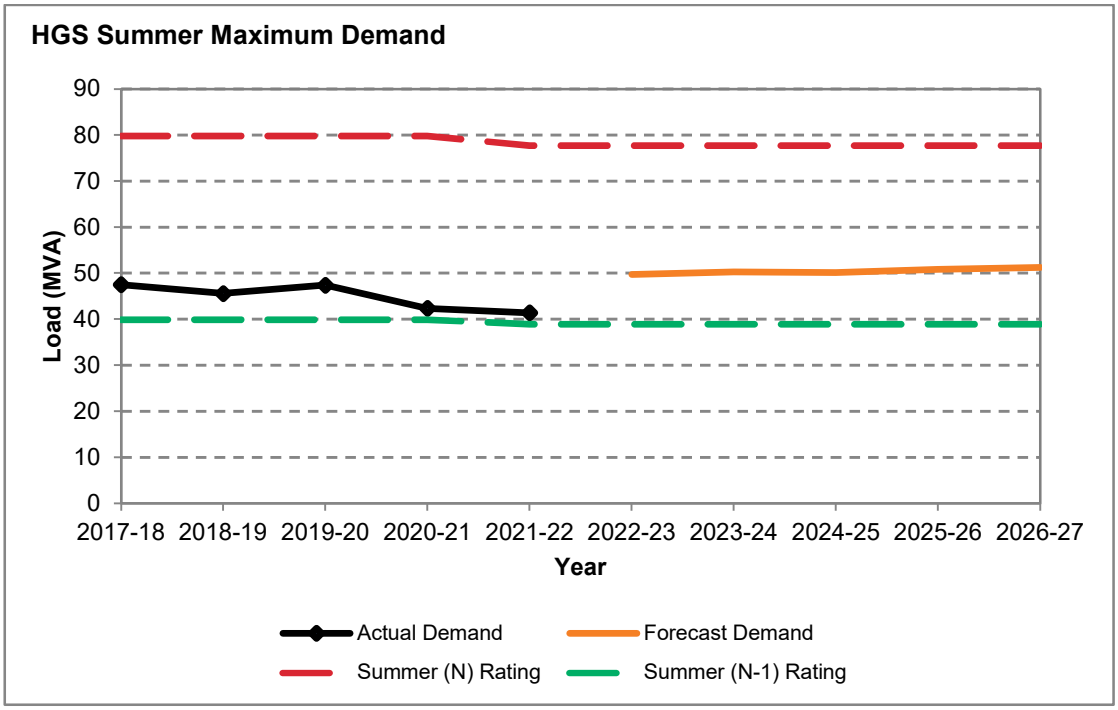
7.2.12 Hastings (HGS) zone substation

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 2021-22 was 41.4MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 HGS zone substation



United Energy estimates that in the summer of 2022-23 there will be 10.8MVA 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 limitation 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 12.7MVA;
- the aged #1 transformer at HGS is planned for replacement in 2026. Post replacement, the ageing HGS #3 transformer could also be replaced with a modern equivalent which will increase the zone substation 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**).

The least cost technically acceptable option is to install a third transformer at HGS. However, given the economic cost of the limitation, this project is not expected to occur

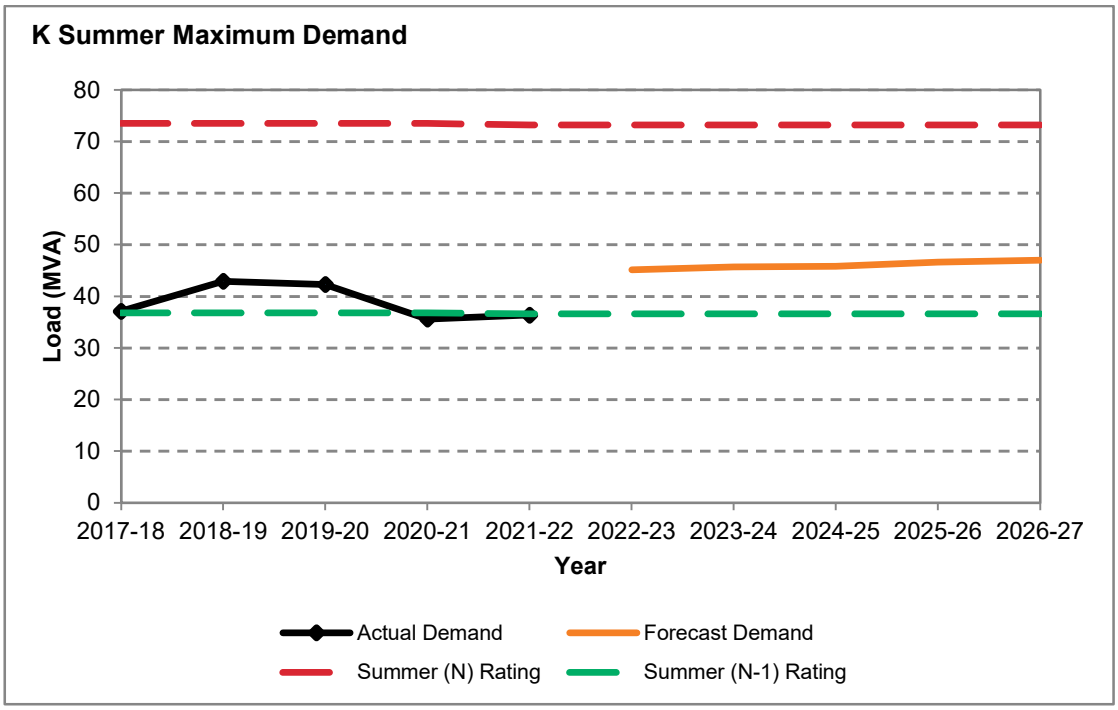
in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.13 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 2021-22 was 36.4MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 K zone substation



United Energy estimates that in the summer of 2022-23 there will be 8.5MVA 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 limitation 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 9.4MVA;
- install a third switchboard at the 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.

A number of surrounding adjacent zone substations at K including EM, CFD and Ormond (**OR**) and several feeders in the area are exhibiting load-at-risk. The least cost technically acceptable 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 before summer 2026-27 (see Section 7.2.8).

The use of contingency load transfers will mitigate the load-at-risk in the interim period.

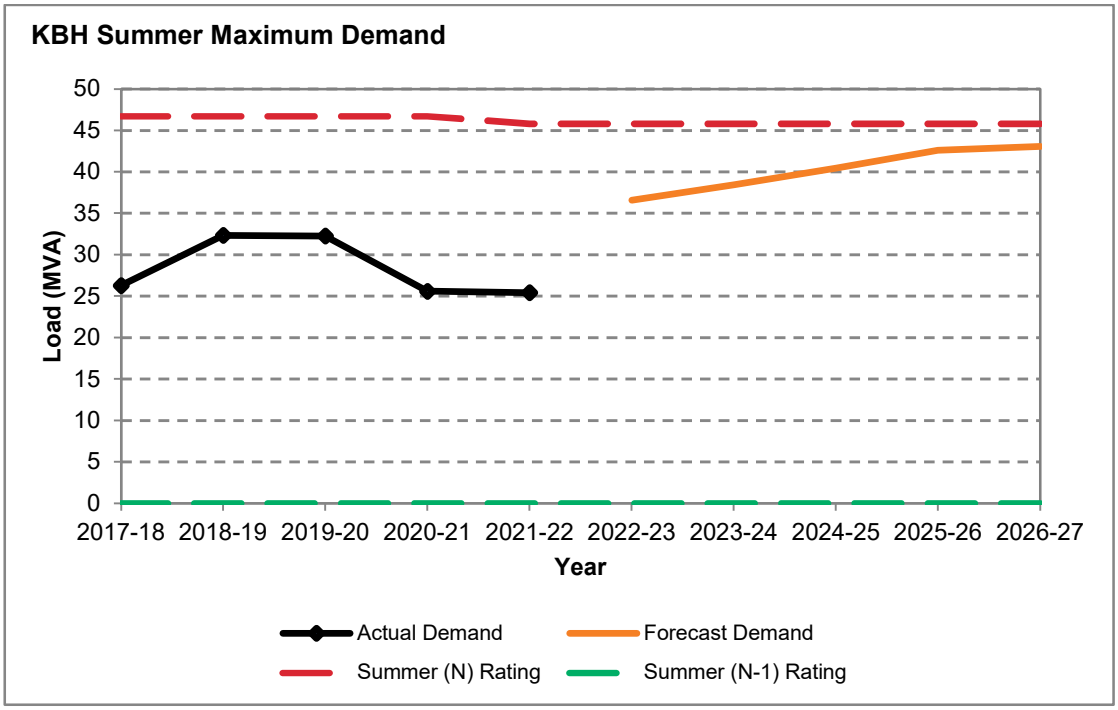
7.2.14 Keysborough (KBH) zone substation

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 2021-22 was 25.4MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. Being designated as a Metropolitan activity centre and a National employment and innovation cluster by the Victorian Government[8], the maximum demand in the Dandenong area 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 7.14 Forecast maximum demand for KBH zone substation



United Energy estimates that in the summer of 2022-23 there will be 36.6MVA 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, 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 limitation 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 36.6MVA;
- install a second 20/33MVA transformer at KBH zone substation with two new distribution feeders at an estimated cost of $6.4 million before summer 2025-26;
- establish a new feeder from DSH and re-conductor 1.1km of feeder NP-14 before summer 2025-26 in order to offload KBH. This option addresses only part of the energy-at-risk at KBH.

The least cost technically acceptable option is to install a new transformer at the KBH zone substation with two new distribution feeders before summer 2025-26. It is expected that a RIT-D consultation will likely commence in 2023.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand in the KBH supply area, between the hours of 12:00 to 18:00 on hot summer days by at least 1.3MVA. Any solution would need to be implemented by November 2025 for summer 2025-26.

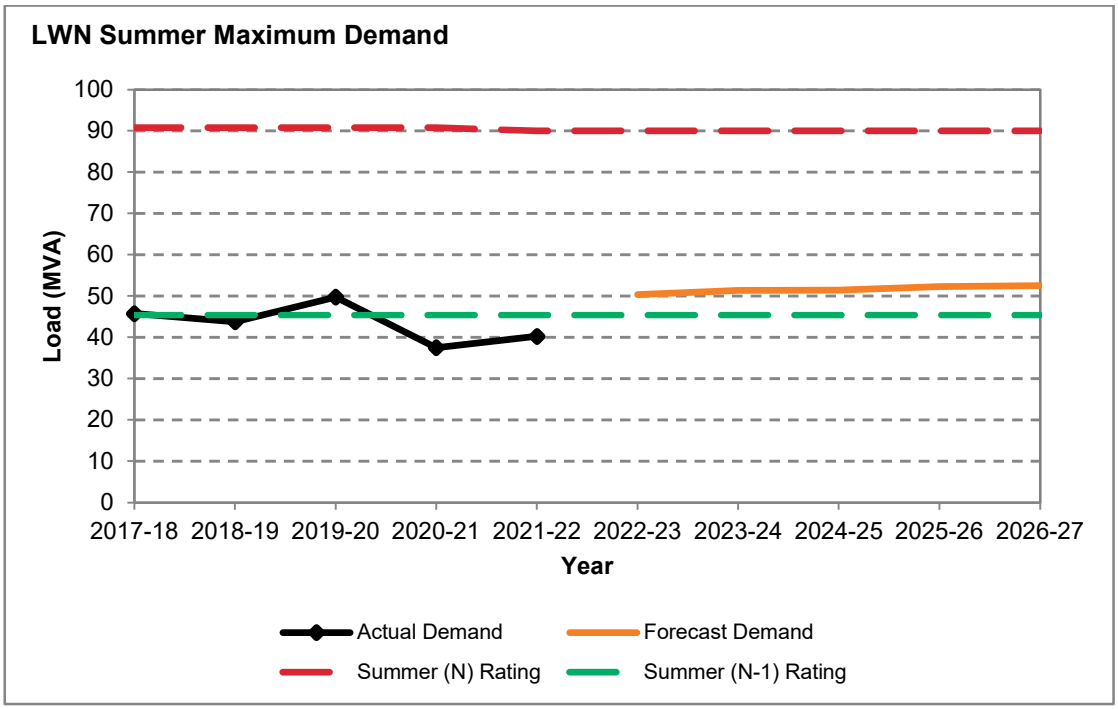
The estimated annualised cost of the solution is around $214,000. This provides a broad upper bound indication of the maximum contribution from United Energy which may be available to non-network service providers for deferring the proposed augmentation by one year. For more details, please refer to the System Limitations Template. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.15 Langwarrin (LWN) zone substation

Langwarrin (**LWN**) zone substation is served by sub-transmission lines from the Frankston terminal station (**FTS**). It supplies the areas of Langwarrin, Botanic Ridge, Cranbourne South, and Skye. Currently, the LWN zone substation consists of two 20/33MVA transformers operating at 66/22kV.

The actual maximum demand at LWN for summer 2021-22 was 40.2MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation's summer (N) and (N-1) ratings. For more details, please refer to the table in Appendix C or the System Limitations Template.

Figure 7.15 Forecast maximum demand for LWN zone substation



United Energy estimates that in the summer of 2022-23, there will be 5.0MVA 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 limitation 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 (**FTN**) and Frankston South (**FSH**), up to a maximum transfer capacity of 26.7MVA;
- install a third transformer at neighbouring FTN zone substation with new distribution feeders and permanently transfer load to FTN, at a cost of $5.7 million;
- establish a new Skye (**SKE**) zone substation with new distribution feeders at an estimated cost of $25 million.

The least cost technically acceptable option is to install a third transformer at neighbouring FTN zone substation and transfer load from LWN to FTN by installing new distribution feeders. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

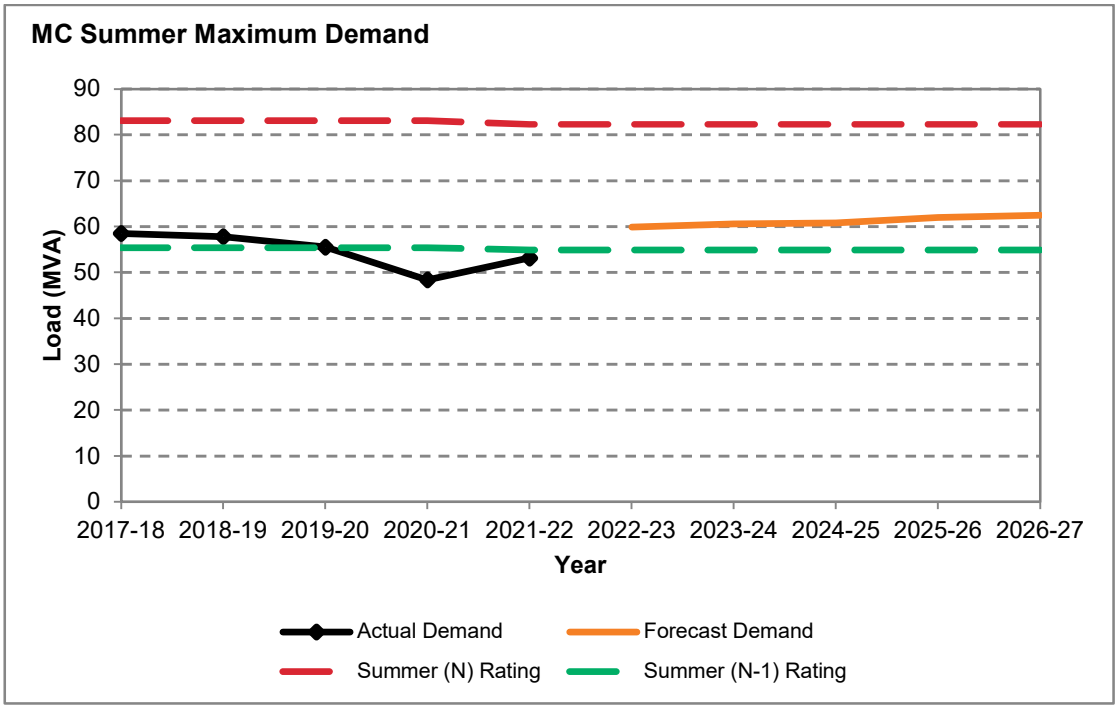
7.2.16 Mordialloc (MC) zone substation

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

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

The actual maximum demand at MC for summer 2021-22 was 53.1MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation’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 MC zone substation



United Energy estimates that in the summer of 2022-23, there will be 5.0MVA 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 limitation 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 CRM, Noble Park (**NP**), and Springvale South (**SS**), up to a maximum transfer capacity of 16.3MVA; or
- install new distribution feeders at neighbouring NP zone substation, and permanently transfer load to NP, at an estimated cost of $2.0 million.

The least cost technically acceptable option is to install new distribution feeders at neighbouring NP zone substation, and transfer load from MC to NP. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

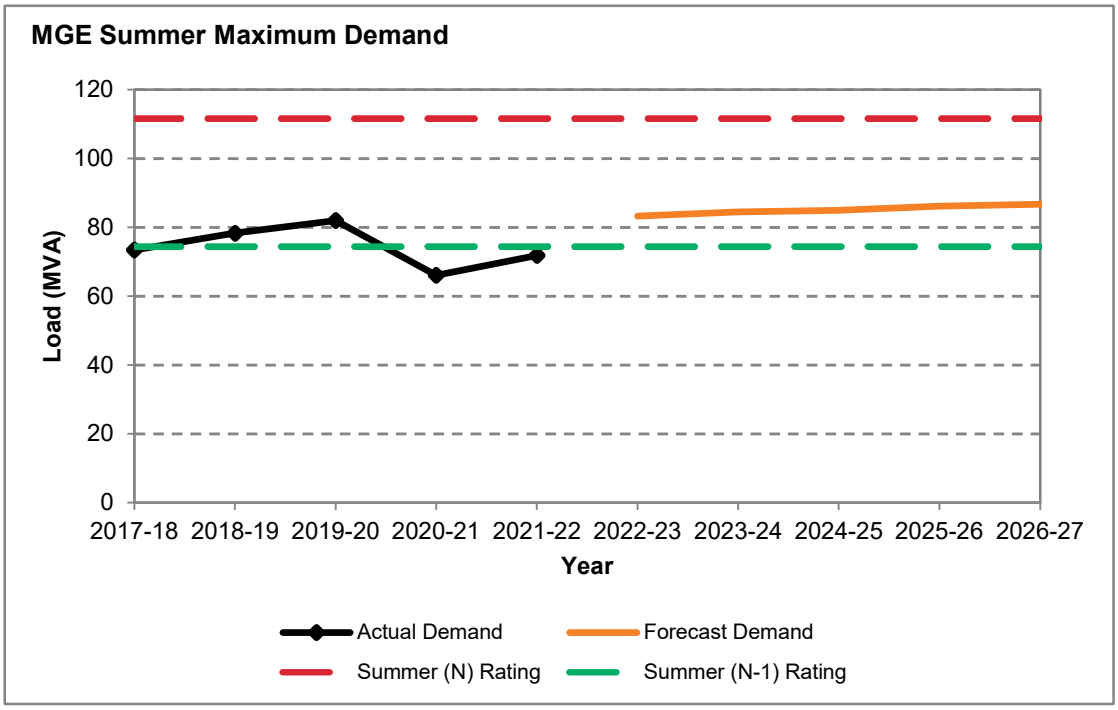
7.2.17 Mulgrave (MGE) zone substation

Mulgrave (**MGE**) zone substation is served by sub-transmission lines from the East Rowville terminal station (**ERTS**). 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 2021-22 was 71.8MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 MGE zone substation



United Energy estimates that in the summer of 20221-23 there will be 8.9MVA 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 limitation 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 26.3MVA;
- permanently transfer load from MGE zone substation to LD zone substation at an estimated cost of $2.0 million by upgrading existing LD feeders;
- offload parts of MGE onto the AusNet Services' proposed Rowville (**RVE**) zone substation at a cost of $2.0 million.

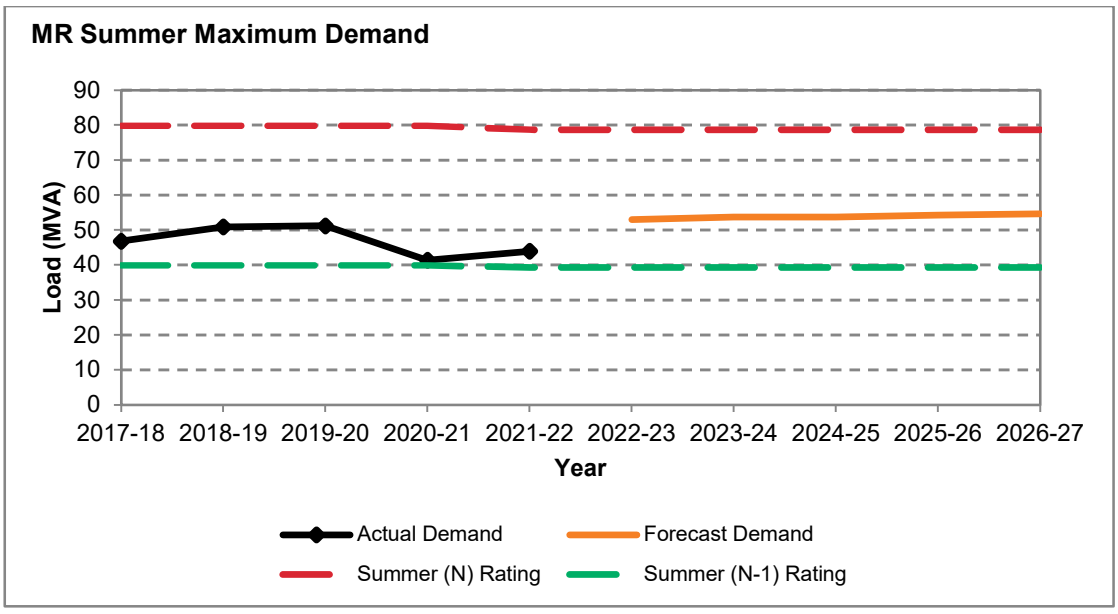
The least cost technically acceptable option is to transfer load from MGE to RVE by augmenting existing, or establishing new, distribution feeders. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.18 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 2021-22 was 43.9MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 MR zone substation



United Energy estimates that in the summer of 2022-23 there will be 13.6MVA 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 limitation 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 13.7MVA;
- install a third 20/33MVA transformer at MR zone substation for an estimated cost of $6.7 million.

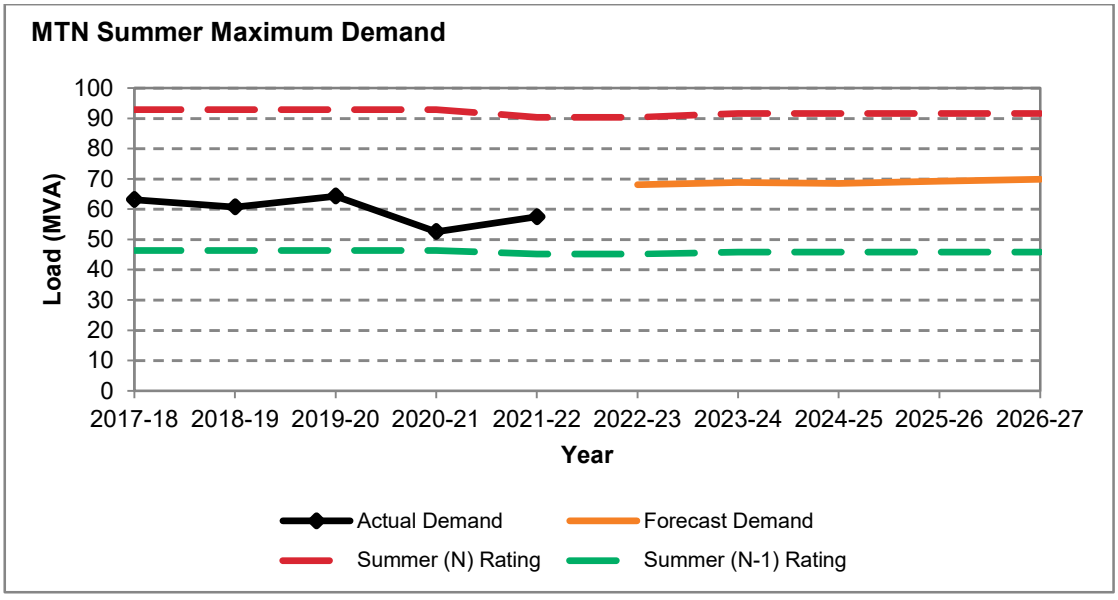
The least cost technically acceptable option is to install a new transformer at the MR zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.19 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 2021-22 was 57.5MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 MTN zone substation



United Energy estimates that in the summer of 2022-23, there will be 22.3MVA 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 limitation 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 19.2MVA;
- establish a new feeder from MTN before summer 2022-23, 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 2027-28 at an estimated cost of $6.8 million;

The least cost technically acceptable option is to install an additional feeder from MTN in 2022, and a subsequent third transformer, switchboard and an additional new distribution feeder at MTN before summer 2027-28. The new feeder from MTN in 2022 is now a committed project and is underway.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand in the MTN supply area, between the hours of 15:00 to 21:00 on hot summer days by at least 1.3MVA. Any solution would need to be implemented by November 2027 for summer 2027-28.

The estimated annualised cost of the transformer solution is around $231,000. 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 one year. For more details, please refer to the System Limitations Template.

The use of contingency load transfers will be used mitigate the load-at-risk in the interim period.

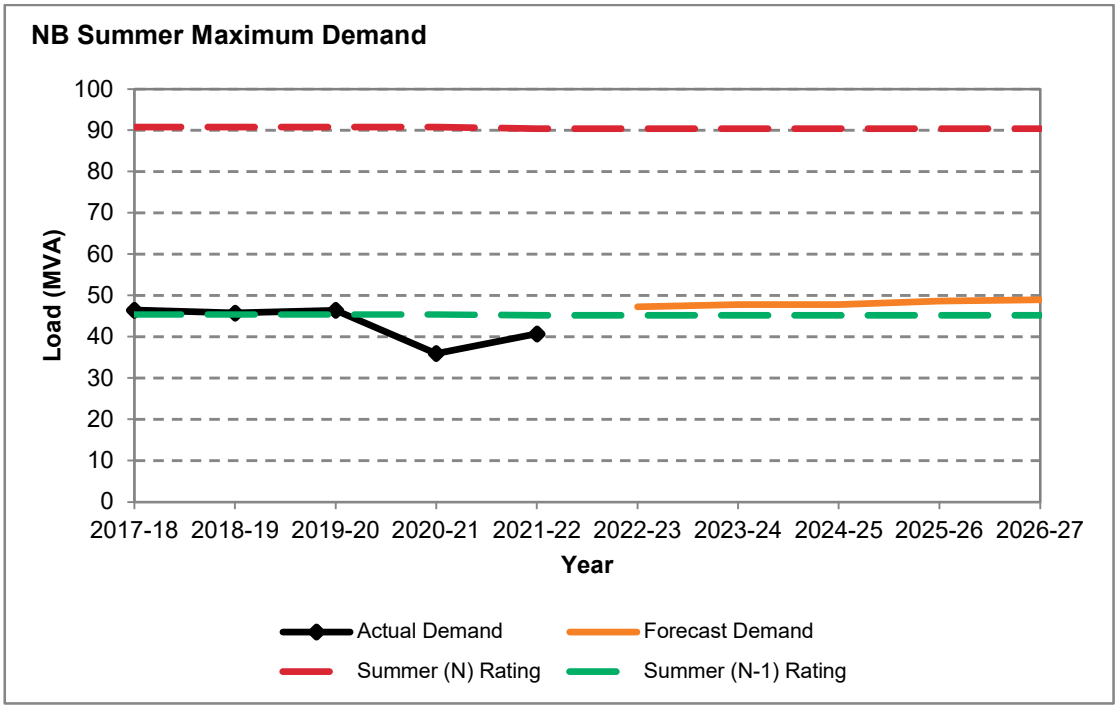
7.2.20 North Brighton (NB) zone substation

North Brighton (**NB**) zone substation is served by sub-transmission lines from the Heatherton Terminal Station (**HTS**). It supplies the areas of Brighton, Brighton East, North Brighton, and Gardenvale.

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

The actual maximum demand at NB for summer 2021-22 was 40.7MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 NB zone substation



United Energy estimates that in the summer of 2022-23, there will be 2.1MVA 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, an unplanned 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 limitation 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**), Elsternwick (**EL**), Elwood (**EW**), and Moorabbin (**MR**) up to a maximum transfer capability of 10.7MVA;
- install a third transformer at adjacent MR zone substation along with distribution feeders to offload NB (see Section 7.2.18), at an estimated cost of $7.7 million;
- install a third 20/33MVA transformer at NB zone substation at an estimated cost of $6.5 million.

A number of surrounding adjacent zone substations to NB including BT, EL and MR, and several feeders in the area are exhibiting load-at-risk. The least cost technically acceptable option to address these limitations in the short to medium term is to install a third transformer at adjacent MR zone substation along with distribution feeders, to offload NB. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR.

The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

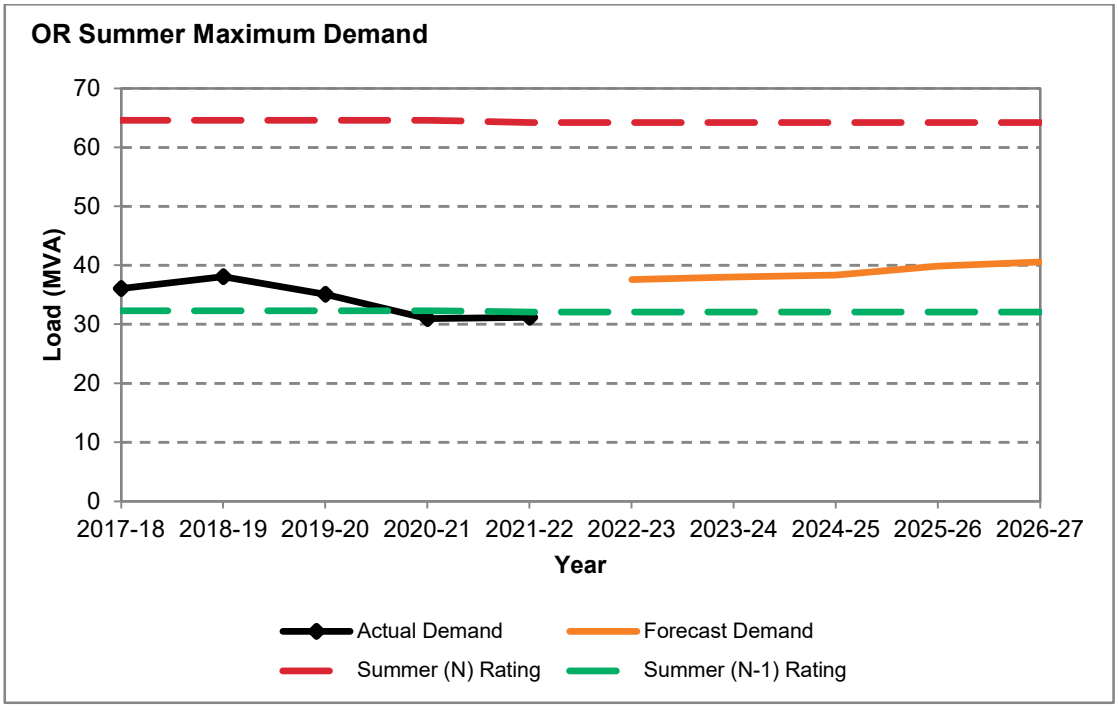
7.2.21 Ormond (OR) zone substation

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

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

The actual maximum demand at OR for summer 2021-22 was 31.2MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 for OR zone substation



United Energy estimates that in the summer of 2022-23 there will be 5.5MVA 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 limitation 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 5.9MVA;
- 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;
- 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 to OR including EM, CFD and K, and several feeders in the area are exhibiting load-at-risk. The least cost technically acceptable 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 before summer 2026-27 (see Section 7.2.8). In the longer term further offloads to the adjacent zone substations is likely as load grows over time.

The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

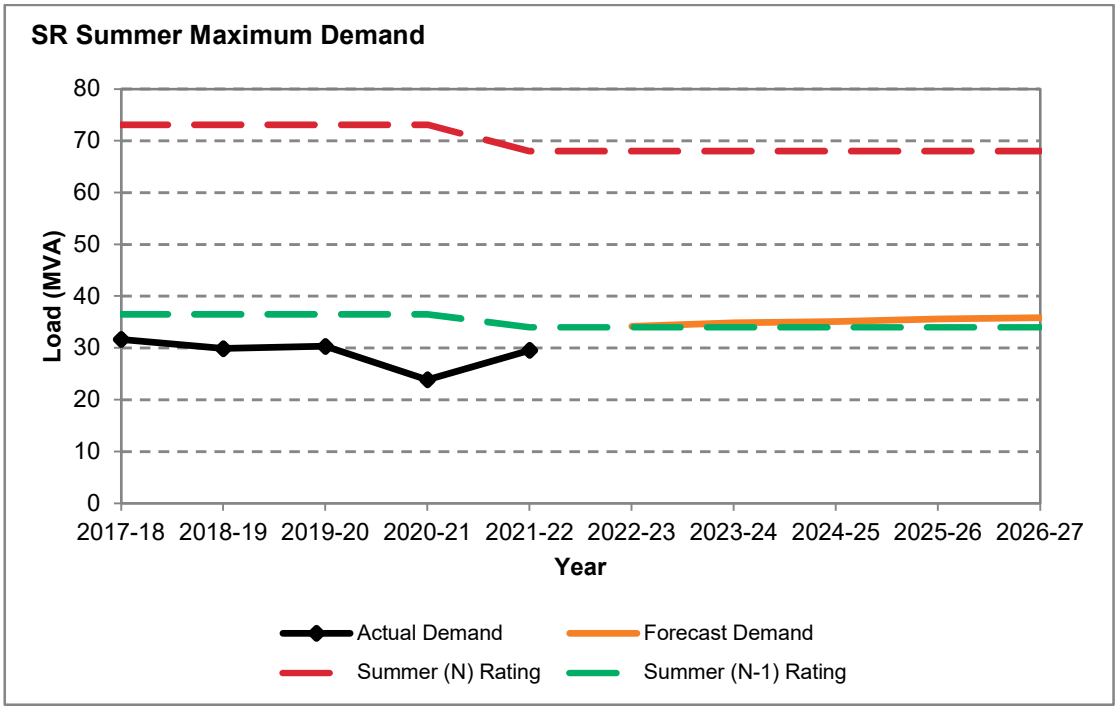
7.2.22 Sandringham (SR) zone substation

Sandringham (**SR**) zone substation is served by sub-transmission lines from the Heatherton Terminal Station (**HTS**). It supplies the areas of Sandringham, Hampton, and Highett.

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

The actual maximum demand at SR for summer 2021-22 was 29.5MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation’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 SR zone substation



United Energy estimates that in the summer of 2022-23, there will be 0.3MVA of load-at-risk if there is a failure of one of the transformers at SR. 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 limitation at SR 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 Beaumaris (**BR**), Cheltenham (**CM**), and Moorabbin (**MR**) up to a maximum transfer capability of 11.8MVA;
- install a third 20/33MVA transformer at SR zone substation at an estimated cost of $6.5 million; or
- install a third transformer at adjacent MR zone substation along with distribution feeders to offload SR (see Section 7.2.18), at an estimated cost of $7.7 million.

The least cost technically acceptable option in the long term is to install a third transformer at adjacent MR zone substation along with distribution feeders to offload SR. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

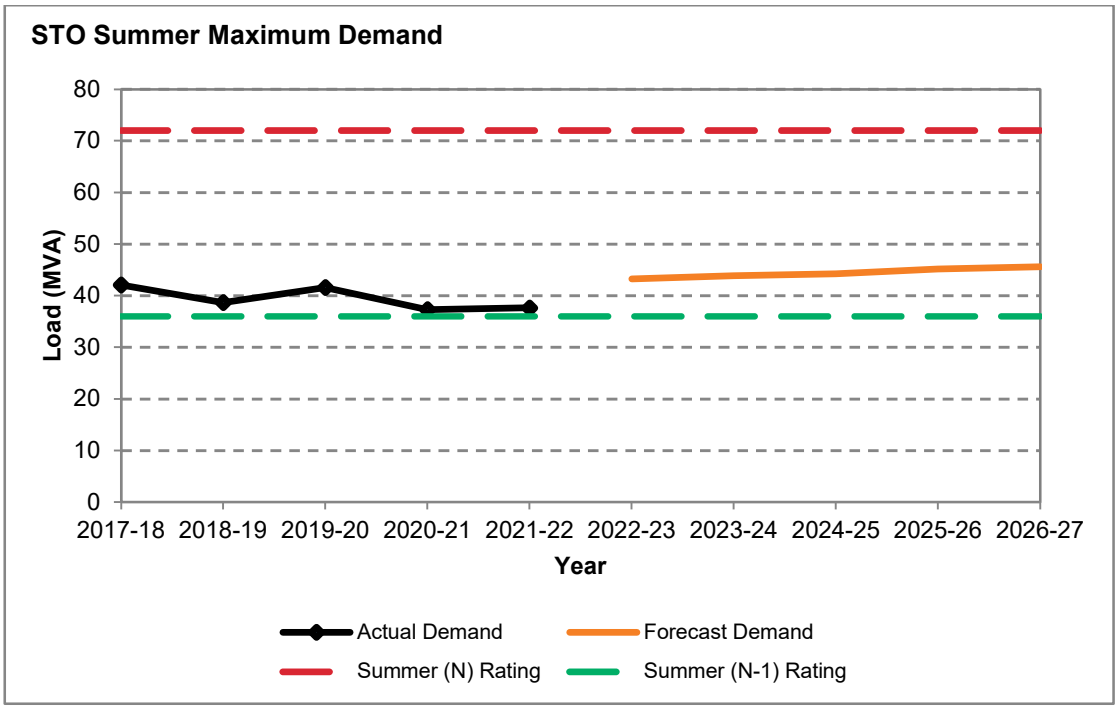
7.2.23 Sorrento (STO) zone substation

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 2021-22 was 37.6MVA. The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the zone substation'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 2022-23 there will be 7.2MVA 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 limitation 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 13.3MVA; or

- install a third 20/33MVA transformer at STO zone substation at an estimated cost of $6.7 million.

The least cost technically acceptable option is to install a third transformer at the STO zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.3 Proposed new zone substations

United Energy does not propose to build any new zone substations during the forward planning period for this DAPR to address any future loading level.

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, considering the:

- Import limitations
    - forecasts for maximum demand to 2026-27; and
    - relevant seasonal N-1 ratings for each sub-transmission loop.
- Export limitations
    - forecasts for minimum demand to 2026-27; and
    - relevant N-1 export ratings for each sub-transmission loop.

Where the sub-transmission loop is forecast during 2022-23 to operate with 10% PoE maximum demand or 10% PoU minimum demand in breach of their firm import or export rating respectively, 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 or minimum demand. At other times, the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage whilst all available load transfers take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those augmentation plans set out in this chapter may be suitable. Solutions may also address zone substation limitations at the same time.

The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation

United Energy notes that all other sub-transmission lines that are not specifically mentioned below either have maximum or minimum demand levels within the relevant rating, or the demand in breach of the relevant rating results in negligible energy-at-risk.

Finally, new 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 import-limited sub-transmission loop during the forward planning period for this DAPR. This is referred to as the Lower Mornington Peninsula project.

As part of this Lower Mornington Peninsula project, the proposed construction of a new 66kV sub-transmission line from Hastings (HGS) to Rosebud (RBD) zone substations is currently being deferred by a contracted non-network solution providing network support services. United Energy will continue to monitor the maximum demand growth and explore options to potentially extend this non-network solution to deliver further deferment, post 2025, if it is identified as an economically and technically viable alternative to the augmentation. See Section 8.2.6 for further details. There are currently no identified import-limited sub-transmission line augmentations during the five-year forward planning period for this DAPR.

There are currently no identified export limitations during the five-year forward planning period for this DAPR. It should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

United Energy is currently investigating a range of options in readiness for the expectation of future export limitations on our sub-transmission lines including:

- Reducing float voltages, or applying LDC settings at terminal stations;
- Installing reactors at terminal stations;
- Network reconfigurations and augmentations;
- Engaging with AusNet to review terminal station power transformer tap changer specification;
- Engaging with AEMO for opportunities to reduce transmission voltages at minimum demand;
- Engaging with AEMO to optimise existing capacitor bank switching controls at terminal stations; and
- Non-network options.

United Energy will continue to monitor the declining minimum demand levels on some of our sub-transmission lines and explore the feasibility of specific options to alleviate any forecast export limitations, on a case-by-case basis.

The options and analysis are presented in the sections below.

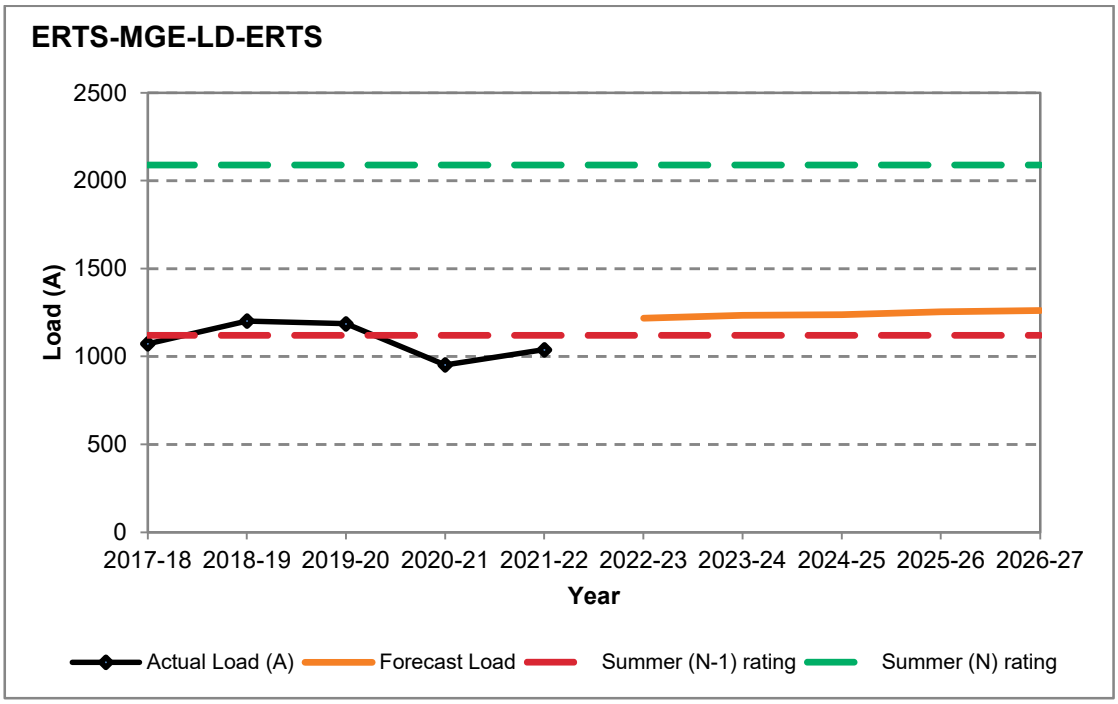
8.2 Sub-transmission lines with forecast system limitations

8.2.1 ERTS-MGE-LD-ERTS

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

The actual maximum demand on the ERTS-MGE-LD-ERTS sub-transmission system for summer 2021-22 was 1421 Amps (162MVA). 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-MGE-LD-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 2022-23 there will be 11.3MVA 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 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 limitations 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 41.8MVA for summer 2022-23;
- 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.

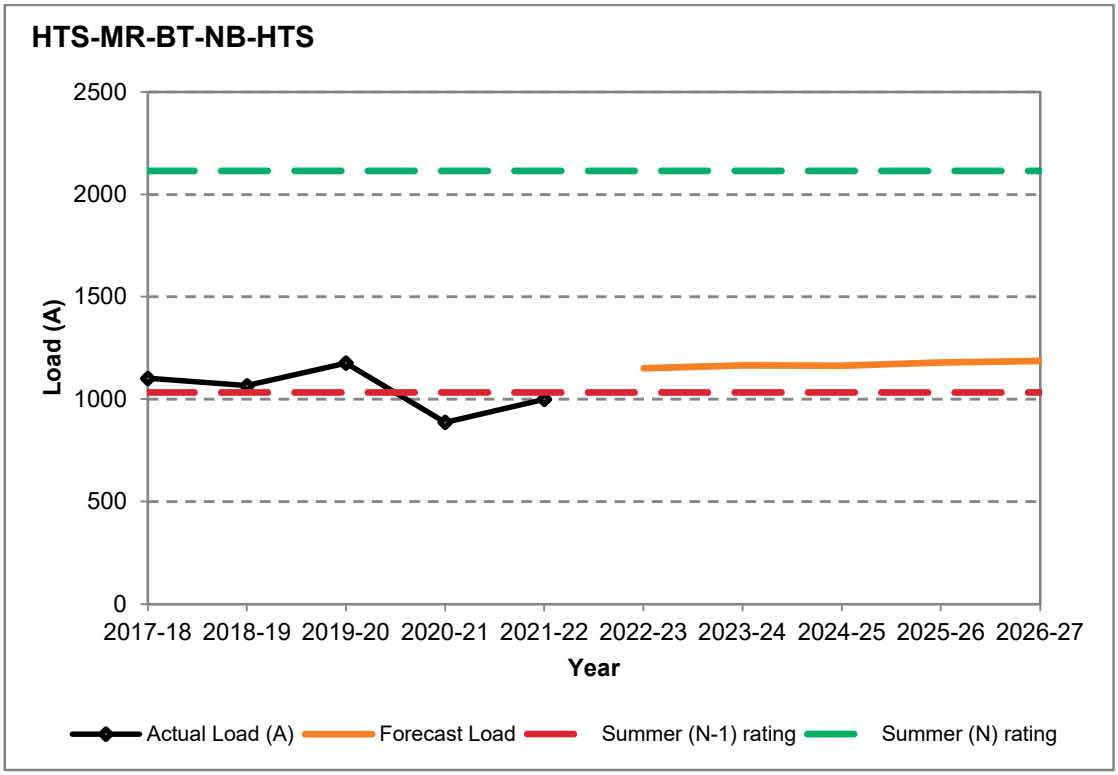
The least cost technically acceptable option is to offload MGE and LD to RVE. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems will be used to mitigate the load-at-risk in the interim period.

8.2.2 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 2021-22 was 1000 Amps (114MVA). 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 8.2 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 A,ppendix D or the System Limitations Template.

United Energy estimates that in the summer of 2022-23, there will be 13.5MVA 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;

To address the anticipated system limitations 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 11.7MVA for summer 2022-23;
- thermally up-rate approximately 1.3 km of the BT-MR sub-transmission line at an approximate cost of $500,000.

The least cost technically acceptable option is to thermally up-rate the BT-MR sub-transmission line. However, given the economic cost of the limitations, 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 will be used to mitigate the load-at-risk in the interim period.

8.2.3 RTS-CL-K-RTS

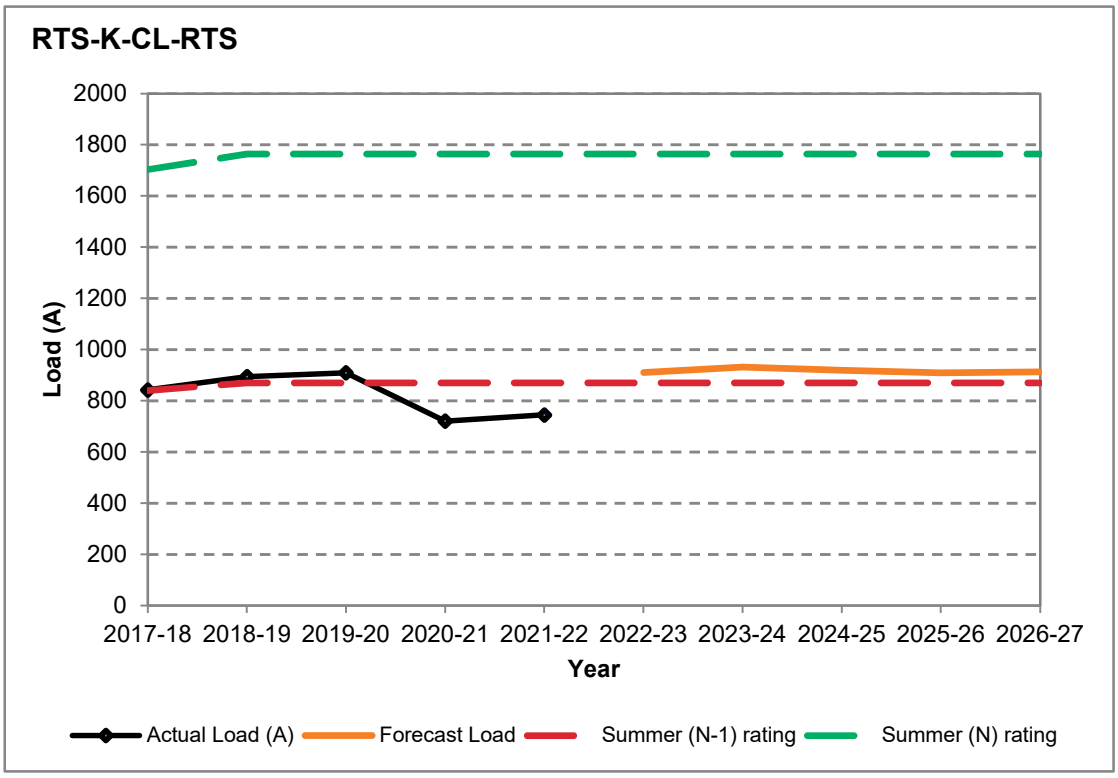
The RTS-CL-K-RTS sub-transmission loop supplies the Camberwell (**CL**) and Gardiner (**K**) zone substations from Richmond terminal station (**RTS**), at 66kV. CL is a CitiPower zone substation, therefore planning on this system is undertaken jointly with United Energy. The ownership of the 66kV assets 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 2021-22 was 740 Amps (85MVA). 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.

AusNet Transmission Group concluded 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 8.3 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 2022-23 there will be 4.6MVA 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 limitations 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 13.7MVA for summer 2022-23;
- permanent offload of sub K or CL to adjacent zone substations, which may require the establishment of new distribution feeder ties. United Energy intends to offload K to EM by creating new distribution feeders before summer 2026-27;
- 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.

The least cost technically acceptable option is to offload K to EM by creating new distribution feeders before summer 2026-27. The use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems will be used mitigate the load-at-risk in the interim period.

8.2.4 SVTS-EB-RD-SVTS

The SVTS-EB-RD-SVTS sub-transmission loop supplies the East Burwood (**EB**) and Riversdale (**RD**) zone substations from Springvale terminal station (**SVTS**), at 66kV.

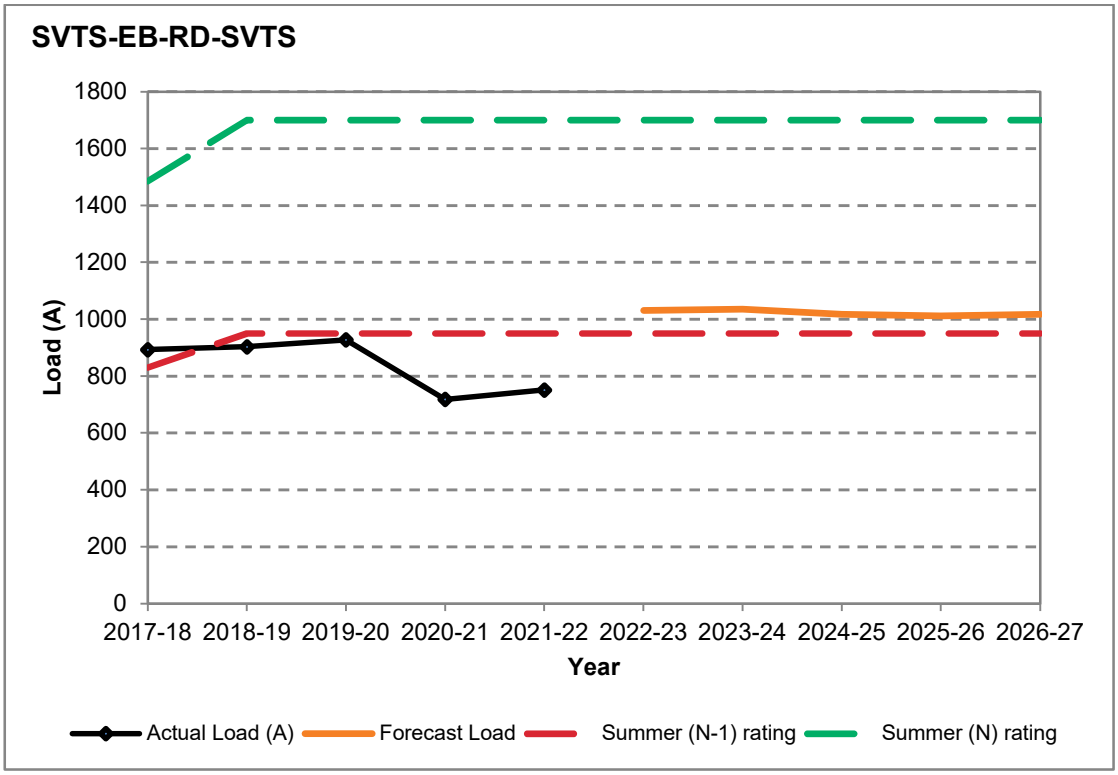
The actual maximum demand on the SVTS-EB-RD-SVTS sub-transmission system for summer 2021-22 was 751 Amps (86MVA). The figure below depicts the historical actual maximum demands, 10% PoE summer maximum demand forecast together with the sub-transmission system's operational summer (N) and (N-1) ratings.

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

United Energy estimates that in the summer of 2022-23, there will be 9.2MVA 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 SVTS-EB and EB-RD sub-transmission lines (owned and operated by United Energy) for an outage of the SVTS-RD sub-transmission line (owned and operated by CitiPower). Similarly, for an

outage of the SVTS-EB 66 kV line, the EB-RD 66 kV line (owned and operated by United Energy) would become overloaded.

Figure 8.4 Forecast maximum demand for SVTS-EB-RD-SVTS system



To address the anticipated system limitations 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 EB and RD zone substations is assessed at 18.6MVA for summer 2022-23;
- up-rating the SVTS-EB 66 kV line by 2028-29 at an estimated cost of $0.53 million;
- Transferring RD zone substation from SVTS to MTS to create the SVTS-EB-SVTS and MTS-RD-BW-MTS systems. This option involves converting BW zone substation from 22 kV to 66 kV. The cost of the sub-transmission portion of the works was estimated to be $8 million;
- establish a new sub-transmission tee connection of SVTS-EB into GW to alleviate loop loading issues by 2028-29 at an estimated cost of $0.45 million.

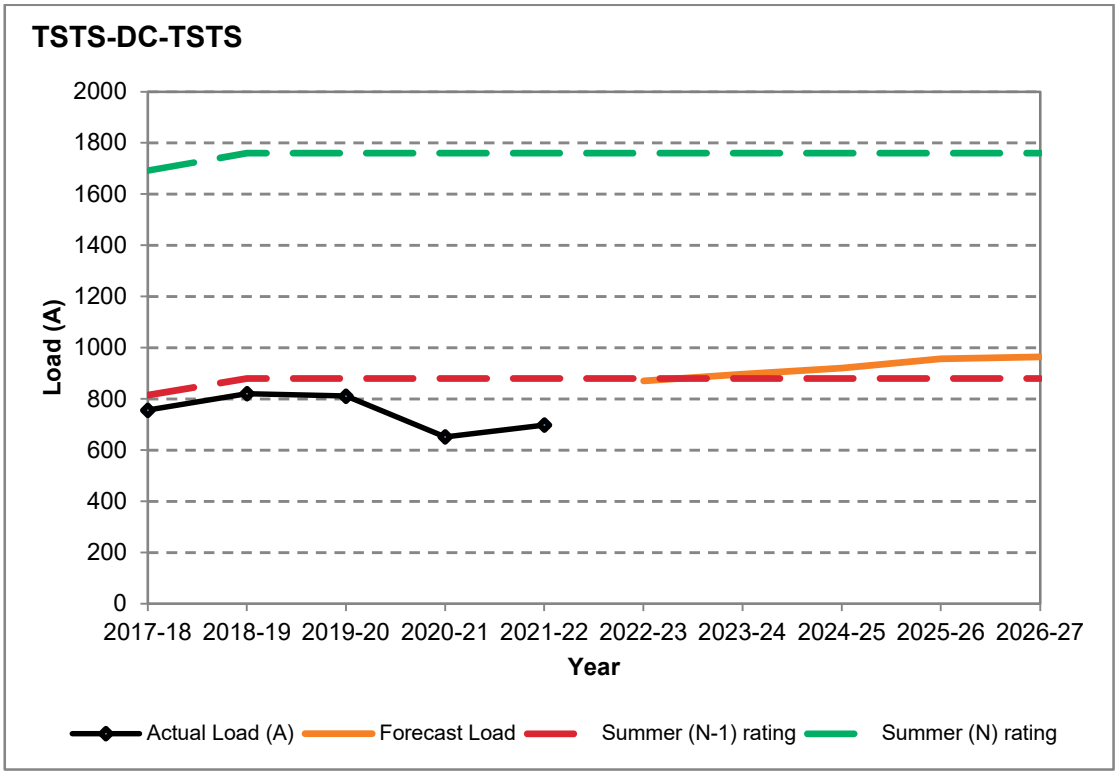
The least cost technically acceptable option is to establish a new tee connection of SVTS-EB into GW to alleviate loop loading issues. However, given this project is expected to occur just outside the forward planning period for this DAPR, the use of the contingency plans, including the use of dynamic line ratings and load transfers to adjacent sub-transmission systems will be used to mitigate the load-at-risk in the interim period.

8.2.5 TSTS-DC-TSTS

The TSTS-DC-TSTS sub-transmission loop supplies the Doncaster (**DC**) zone substation from Templestowe terminal station (**TSTS**), at 66kV.

The actual maximum demand on the TSTS-DC-TSTS sub-transmission system for summer 2021-22 was 698 Amps (80MVA). 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 8.5 Forecast maximum demand for TSTS-DC-TSTS 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 2023-24, there will be 1.8MVA 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 TSTS-DC No.1 66 kV line for an outage of the TSTS-DC No.2 66 kV line during maximum demand period. Similarly, for an outage of the TSTS-DC No.1 66 kV line, the TSTS-DC No.2 66 kV line would become overloaded.

To address the anticipated system limitations 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 DC zone substation is assessed at 21.2MVA for summer 2022-23;
- re-conductor 0.7 km of TSTS-DC No.1 66 kV line and 1.3 km of TSTS-DC No.2 66kV line by summer 2030-31 at an estimated cost of $1.15 million.

The least cost technically acceptable option is to re-conductor the two sub-transmission line. However, given 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, will be used to mitigate the load-at-risk in the interim period.

8.2.6 TBTS-FSH-MTN-DMA-TBTS

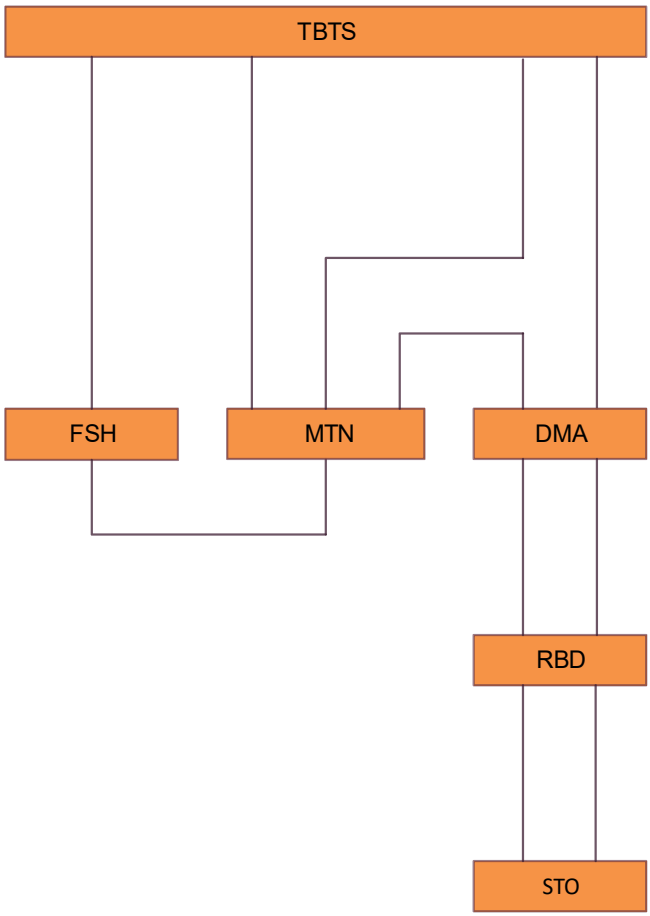
The TBTS-FSH-MTN-DMA-TBTS sub-transmission system supplies the Frankston South (**FSH**), Mornington (**MTN**) and Dromana (**DMA**) zone substations from Tyabb terminal station (**HTS**) at 66kV. Rosebud (**RBD**) and Sorrento (**STO**) zone substations are connected to DMA as a secondary system and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

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-FSH-MTN-DMA-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-FSH-MTN-DMA-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.

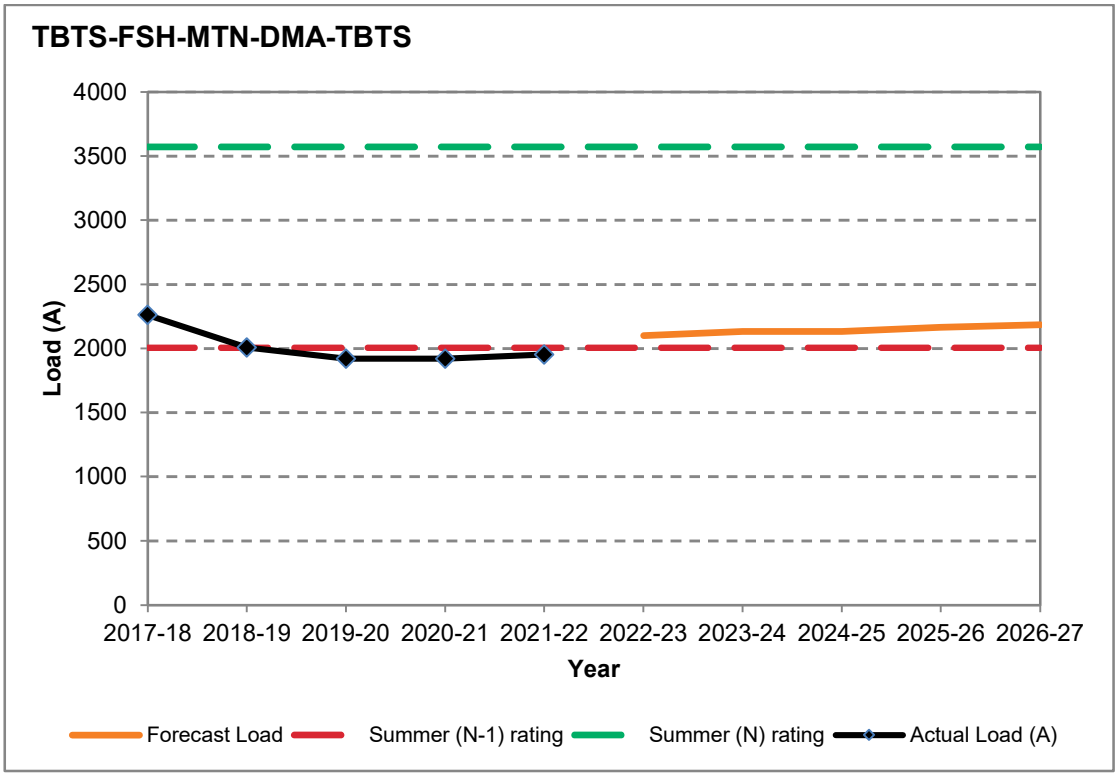
Figure 8.6 TBTS-FSH-MTN-DMA-TBTS sub-transmission system



TBTS-FSH-MTN-DMA-TBTS

The actual maximum demand on the TBTS-FSH-MTN-DMA-TBTS sub-transmission system for summer 2021-22 was 1953 Amps (223MVA). 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-FSH-MTN-DMA-TBTS system



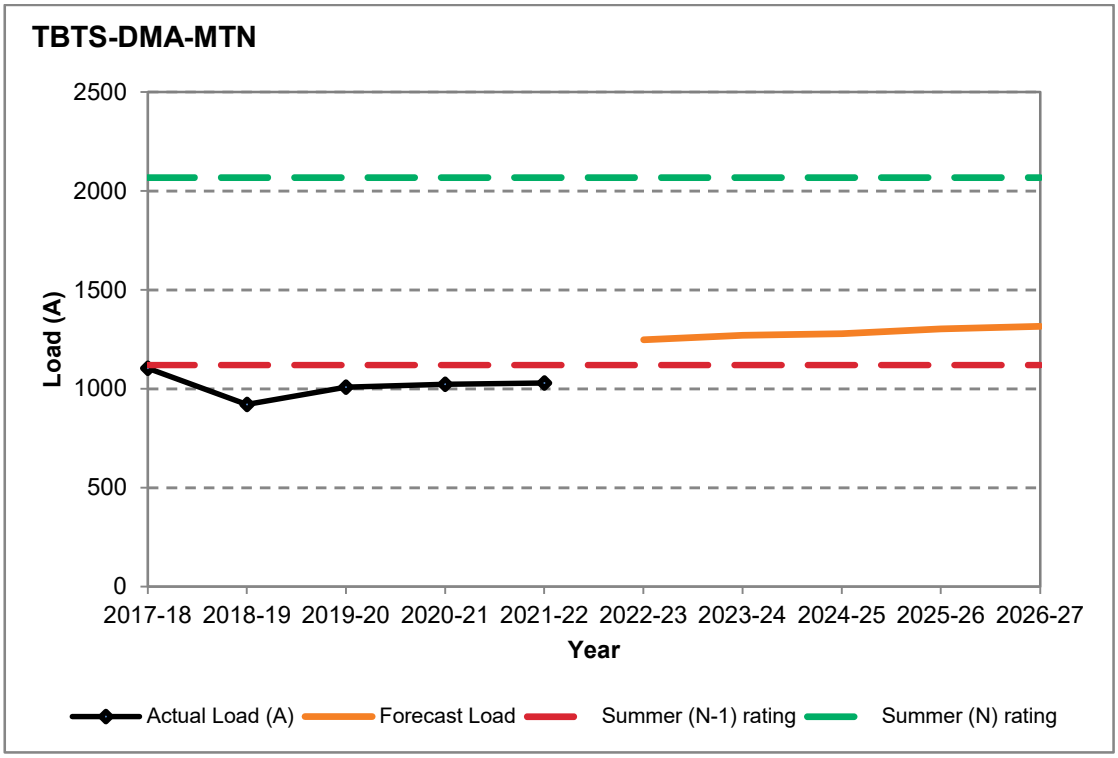
The figure shows that maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details, please refer to the table in Appendix D or the System Limitations Template.

United Energy estimates that in the summer of 2022-23, there will be 11.0MVA 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-FSH-MTN-DMA-TBTS sub-transmission system. The actual maximum demand on the TBTS-DMA-MTN sub-transmission system for summer 2021-22 was 1029 Amps (118MVA). 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.

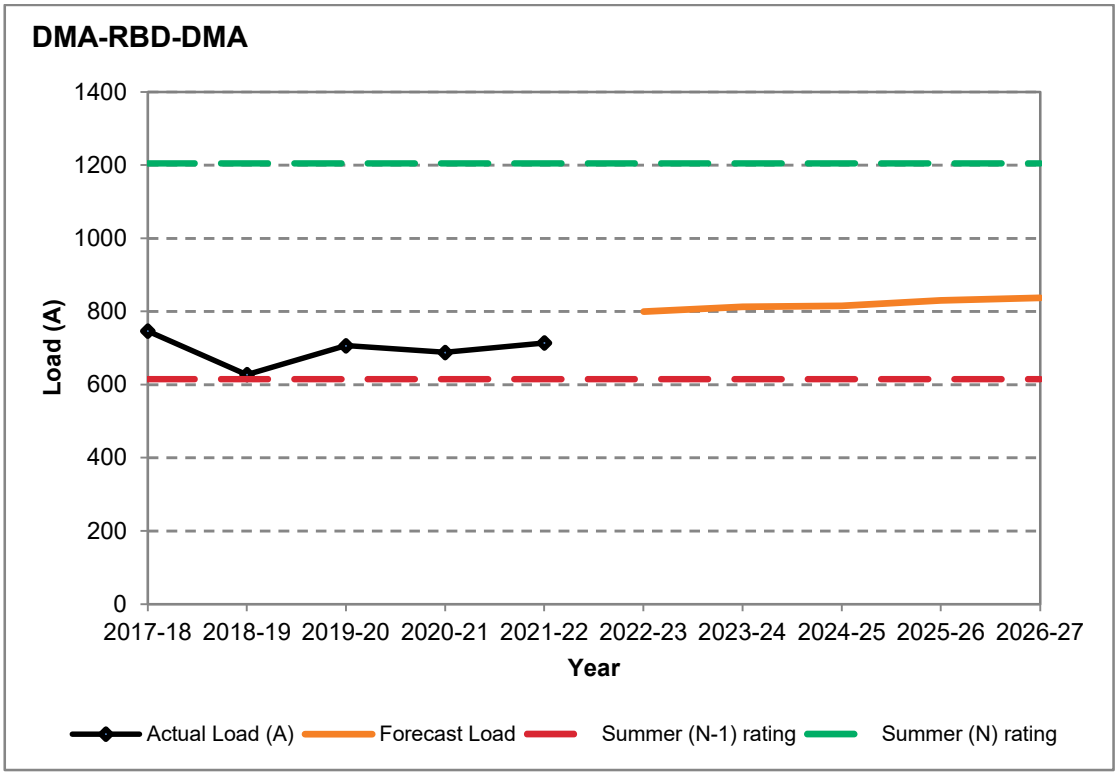
United Energy estimates that in the summer of 2022-23, there will be 14.6MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the TBTS-DMA sub-transmission line for an outage of the MTN-DMA sub-transmission 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 line 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 2021-22 was 714 Amps (82MVA). 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 2022-23, there will be 21.2MVA 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

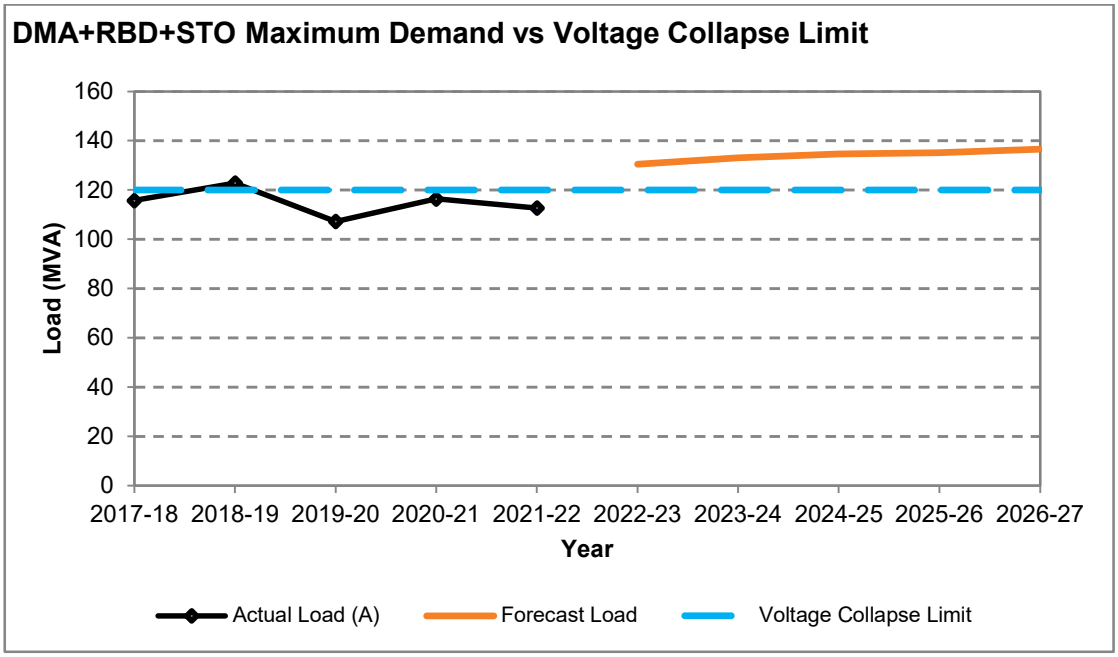
United Energy has also identified a risk of voltage collapse in the lower part of the Mornington Peninsula should an unplanned outage of either the MTN-DMA or the TBTS-DMA sub-transmission line occur during maximum demand periods, with the former being the more severe condition. Given the relatively long sub-transmission lines extending to STO from TBTS (approximately 59km), the voltage collapse limitation is considered to be more 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 upstream 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 limitations in the Mornington Peninsula sub-transmission network. The least cost technically appropriate solution was a combination of network and non-network options, namely:

- use of 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 network support by the non-network solution there became a need to renegotiate the final two years of the demand management agreement. United Energy also looked at options to extend the solution to further defer the augmentation in light of reduced and uncertain maximum 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 request for proposals.

The market test demonstrated that ongoing demand management continues to be the most efficient solution. The least cost technically appropriate option was for a combined solution which included:

- 11MW of demand-side generation hire 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 two years of this new solution now completed, having managed the risk on the sub-transmission loop over summers 2020-21 and 2021-22.

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 non-network 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 considered 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 to address future loading levels.

Table 8.1 Proposed new sub-transmission lines

Name	Location	Proposed commissioning date	Reason
HGS-RBD	Hastings to Rosebud	November 2025[9]	Demand and voltage limitations in the lower Mornington Peninsula area.

8.3.1 New HGS–RBD sub-transmission line

In order to alleviate the capacity and voltage collapse conditions in the lower Mornington Peninsula, UE plans to establish a new HGS-RBD 66 kV line. As part of this project, the existing TBTS-HGS 66 kV lines are likely to require upgrading at the same time due to the additional load imposed on this system. Please refer to Section 8.2.6 above for more details.

[9] Dependent on the possible continued deferment by the non-network solution.

9 Transmission-distribution connection point reviews

This chapter reviews the terminal stations where further investigation into the balance between capacity and demand over the next five years is warranted, considering the:

- Import limitations
    - These are addressed in the Transmission Connection Planning Report.
- Export limitations
    - forecasts for minimum demand to 2026-27; and
    - relevant N and N-1 export ratings for each terminal station.

Where the terminal station is forecast to operate with 10 per cent probability of under-reach minimum demand in breach of its export rating under N-1 conditions during 2022-23 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 energy-at-risk at times of maximum or minimum demand. At other times, the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage whilst all available load transfers take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those augmentation plans set out in this chapter and in the Transmission Connection Planning Report may be suitable. Solutions may also address zone substation limitations at the same time.

The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation

United Energy notes that all other terminal stations that are not specifically mentioned below have minimum demand levels within export rating, or the demand in breach of the export rating results in negligible energy-at-risk.

9.1 Terminal stations with forecast export limitations overview

United Energy has to date, not identified any terminal stations with export limitations.

Whist there are currently no identified limitations from the forecast use of distribution services by embedded generating units at transmission-distribution connection points, it should be noted that the export ratings currently used for terminal stations are thermal

ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the terminal station's thermal rating. Work is underway to quantify the impacts of system limitations on terminal station export ratings. Until that work is finalised, thermal ratings are applied.

10 Primary distribution feeder and substation reviews

Where practicable, United Energy has prepared maximum and minimum demand 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 have demand levels that are:

- currently in breach of their import or export ratings; or
- forecast to be in breach of their import or export ratings.

Under United Energy's probabilistic planning, distribution feeders are generally loaded to greater than 85 percent maximum demand utilisation of their import rating before they are considered for possible augmentation eligibility, 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. For minimum demand, the threshold applied is 100 percent minimum demand utilisation of their export rating.

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

We invite non-network providers to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those set out in the analysis may be suitable. United Energy anticipates an increasing number of non-network options will emerge over the next few years, particularly for distribution feeder and low-voltage limitations, as the market and technology develops and matures.

10.1 Overview of primary distribution feeders with forecast overload

The table below provides information regarding critical distribution feeder import limitations where network augmentation to alleviate those limitations are likely to be economic and are currently planned within 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 10.1 Distribution feeder import limitations

Feeder/ Voltage	Feeder location	Import Rating (MVA)	Forecast utilisation (%)				
			2022 /23	2023 /24	2024 /25	2025 /26	2026 /27
MGE 12 (22kV)	Jells / Ferntree Gully Road, Wheelers Hill	9.9	86%	93%	101%	106%	108%
BU 25 (11kV)	Atkinson Street / Fitzsimons Lane, Templestowe	5.5	92%	94%	94%	95%	97%
FSH 33 (22kV)	Walkers / Canadian Bay Road, Mount Eliza	11.8	97%	101%	102%	103%	105%

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

A number of options are considered in identifying suitable mitigation measures to alleviate generation export issues on primary distribution feeders, including:

- tuning our DVMS at that zone substation;
- in-line feeder HV voltage regulators;
- network reconfigurations or augmentations to shorten feeders or split feeders;
- optimisation of capacitor bank switching settings on existing in-line feeder shunt capacitor banks; and
- non-network options.

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

Table 10.2 Distribution feeder export limitations

Feeder/ Voltage	Feeder location	Export Rating (MVA)	Forecast utilisation (%)				
			2022 /23	2023 /24	2024 /25	2025 /26	2026 /27
SS 11 (22kV)	Clayton South	-10.0	86%	87%	89%	90%	90%

The section below identifies the amount of load or generation reduction that would be required to defer the proposed augmentations by one year.[10] It also identifies the least cost technically appropriate solution that would be undertaken in the absence of any commitment from interested parties to offer network support services through demand side management initiatives.

10.2 Primary distribution feeders with forecast overload

10.2.1 MGE 12

MGE 12 is a highly utilised 22kV feeder from Mulgrave (**MGE**) zone substation. It supplies the Wheelers Hill and Caribbean Park[11] areas.

The least cost technically acceptable solution is to establish a new feeder from MGE zone substation to offload MGE 12. The estimated cost of this augmentation is around $1.5 million. United Energy has previously used demand response in this area to defer investment.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand on the MGE 12 feeder, between the hours of 14:30 to 17:30 on hot summer working days by at least 1.3MVA. Any solution would need to be implemented by November 2024 for summer 2024-25.

The estimated annualised cost of the solution is around $50,000. 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 one year. For more details, please refer to the System Limitations Template.

10.2.2 BU 25

BU 25 is a highly utilised 11kV feeder from Bulleen (**BU**) zone substation and supplies a predominantly residential load in the Lower Templestowe area.

The least cost technically acceptable solution is to upgrade BU 25 by uprating and re-conductoring approximately 200m of powerlines. The estimated cost of this augmentation is around $150,000.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand in the BU 25 feeder area, between the hours of 15:30 to 18:30 on hot summer days by at least 0.12MVA. Any solution would need to be implemented by November 2023 for summer 2023-24.

The estimated annualised cost of the solution is around $5,000. This provides a broad upper bound indication of the maximum contribution from United Energy which may be

[10] 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.

[11] https://caribbeanpark.com/

available to non-network service providers for deferring the proposed augmentation by one year. For more details, please refer to the System Limitations Template.

10.2.3 FSH 33

FSH 33 is a highly utilised 22kV feeder from Frankston South (**FSH**) zone substation and supplies a predominantly residential customer base as well as a commercial precinct in the Mount Eliza area.

The least cost technically acceptable solution is to extend neighbouring feeder FSH 11 and to permanently transfer load away from FSH33. The estimated cost of this augmentation is around $570,000.

In order to defer the proposed augmentation by one year, a non-network solution would need to reduce the summer maximum demand on the FSH 33 feeder, between the hours of 17:00 to 20:00 on hot summer working days by at least 0.8MVA. Any solution would need to be implemented by November 2023 for summer 2023-24.

The estimated annualised cost of the solution is around $20,000. 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 one year. For more details, please refer to the System Limitations Template.

10.2.4 SS 11

SS 11 is a highly utilised, export-limited 22kV feeder connected to Springvale South (**SS**) zone substation. It supplies a predominantly residential and commercial load in the Clayton South area. There are high-levels of generation on this feeder including from the Clayton landfill-gas generation site and from a large number of roof-top solar PV systems. This generation causes the feeder to regularly export into SS zone substation during the daytime hours. The SS 11 feeder export capability is limited by its thermal export ratings.

United Energy's preferred option is to take no action, but to continue to monitor the minimum demand levels on this feeder, and identify further options in a couple of years if the minimum demand continues to decline.

10.3 Distribution substation and LV circuit limitations

Every year United Energy undertakes a program of works to rectify and prevent overloads on its 230 Volt distribution substations and low-voltage (**LV**) circuits. United Energy utilises both traditional augmentation and non-network options, Inteligent Automation and United Energy's own residential demand management "Summer Saver" program, to alleviate limitations on distribution substations and LV circuits. The solution adopted for each site is based on an economic evaluation of costs and benefits.

For summer 2022-23, through the project evaluation process conducted in accordance with the Demand Management Incentive Scheme (**DMIS**) requirements, a combined

demand management program with Summer Saver and Intelligent automation was identified as the preferred option, and was implemented to alleviate limitations at 187 LV circuit sites and 37 distribution substation sites.

The table below outlines the summer 2022-23 sites with limitations where the demand management program is being implemented and will likely be continued in future years, in the absence of a lower cost solution. The location of each site is also provided via the Google Earth map accompanying this DAPR.

United Energy will update and finalise the list of eligible summer 2023-24 sites with limitations around April 2023. As part of our consultation obligations under the DMIS, United Energy will publish this list and issue a request for non-network proposals through its contacts on the United Energy DSE 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 10.3 United Energy 2022-23 Summer Saver Sites

Substation / LV Circuit Name (street name location and its closest intersecting street)			
ALBION-ST GEORGES	GLOSSOP DISNEY 1	CASSIA HILLCREST 8	MCCORMICKS GAMBLE 1
MONIQUE BREESE	GRANT OLSON-BOURKE 1	ROSS-ELIZABETH 1	GYMPIE-CUTHBERT 1
MELALEUCA FRASER	HENDERSON CORRIGAN 2	HILLCREST-EUMERELLA 1	THE CREST JASPER 2
SERENITY JOANNE	HENNESSY-TENNYSON 1	EALING SPRING 2	OAKPARK-SWANSON 1
HARBOUR OCEANIC	HOLLOWAY-BLUFF 1	LUGANO MONACO 1	CAMPBELL BREWER 2
DUNLAVIN-PAGE	KRONE COLLOCOTT 3	GRIMWADE PANMURE 1	OCEANIC HARBOUR 1
THURLOO-MARGOT	LALWA-CNTRBY 5	FANTAIL LYREBIRD 2	NEW SOUTH 3
PURDY SIXTH	MARCHANT-ADVANTAGE 3	AXFORD-OLD DANDENONG 1	BARRY FELLOWES 2
SUNNYSIDE HERBERT	MEREDITH-BARKLY 3	MURRAY-PRINCE EDWARD 3	BROWNFIELD-DAVEY 2
ROBERT ANN	MITCHELL JOHNSTONE 1	KINGSTON WATTLETREE N379 1	DALGETTY-HOTHAM 3
MILTON-ELGAR	MOSSGIEL HEATHMERE 1	MCCLELLAND LIGHTWOOD 4	NURTEN BRANNIGAN 2
BIRCH KARINGAL	OAKHAM-MEDHURST 2	LEICESTER ELIZAWAY 1	NOVA-HAVERSHAM 4
JUNE-SERPELLS	PORTER-CHAPLIN 2	NEWMAN-OAKLEIGH 2	BRUARONG GRANGE 1
NORFOLK SOMERSET	ROYDEN-LONSDALE 3	HOWARD-WAVERLEY 4	WATERWAYS SPRINGVALE 3
HIGHETT-BLUFF	SPRAY PT MELBOURNE 2	OSWALD-ELSTER 1	ROSEDALE HAZELDINE 2
HERBERT SHANDON	STATION-MORTON 1	LUDSTONE-EARLSFIELD 2	ALISON-MCKINNON 1
PERCIVALE KINGARTHUR	STERLING-BEAUMARIS 3	THIRD DENVER 2	HAROLD TROYS 1
GEOFFREY CAXTON	TARENE KIRKHAM 2	WANDA MACKIE 1	MANNING-DARLING 4
CAM-CROW	TOWNSEND GALLAGHERS 1	OBAN HEATHMERE 1	BURNELL KOETONG 1
ROBERT-WAVERLEY	TURNER-PEACE 1	BORONIA-BROUGHTON 2	PARK MCKENZIE 1
OUTLOOK-SURREY	VALERIE-THOMPSONS 3	HOPE BURKE 1	VERBENA-KOONUNG 3
ETHEREAL WODALLA	VINCENT-WATTLETREE 1	PINE FTON DNONG 1	PACIFIC ROWDEN 2
MORAY-BROWNS	WEEDEN-SVALE 4	ST MITCHELL CARLA 1	WARREGO JARDINE 1
EMERALD GARNET	CLEARY CHARLOTTE 1	NIBLICK FEATHERY 1	PLAIN GUEST 1
HAROLD-CALDERWOOD	PRINCE GLENEAGLES 1	PARK DENBIGH 2	COORONG BINGLEBAY 4
DUNLOE-ELGAR	ENTERPRIZE REBECCA 1	GREENWAYS CROSBY 1	WARADGERY MUIRFIELD 4
REGENT-SANDHAM	BALMORAL REGENT 2	MARRIOT BAMBRA 1	BORONIA-CENTRE 2
MARY BALMORAL	WASHINGTON-WATTLE 2	ROTHSCHILD-LAURA 2	SHEFFIELD-WARWICK 2
AUSTIN DOWNS	HOPETOUN-DUDLEY 2	RIX-PARKIN 2	COAST BANKSIA CIRRUS 3
KEEN-MARTIN	ALFREDA-HIGHETT 2	LANDSCAPE-TAURUS 1	WILLIAM-MANNINGHAM 4
AINSLIE FT GULLY	ESSEX-BAMFIELD 2	CUMMINS-NEPEAN 2	RUFFEY-JAMES 2
AQUEDUCT LANGEWAN	TEDDINGTON MAY 4	LUM SHERRINGHAM 1	CARAMUT-GRANDVIEW 1
MILLEWA-WAVERLEY	HALLEY-LAKE 2	WELLINGTON VILLAGE BRAEBURN 3	KING GEORGE NUNNS 1
THIRD-NEPEAN	CLYDEBANK EDITHVALE 2	MAROUBRA KINGSCLERE 2	SANOMA RHONE 6
HAZEL-ROONEY	YUILLE LYONS 1	MANNA GUM PARKSIDE 4	VICTORIA-WELLINGTON 4
ISLAND SERPENTINE	VIVA-TOORONGA 4	NORWOOD-MILLS 2	AUSTIN MORGAN 2
RANGEVIEW STABLE	BRIGGS HEATHERTON 2	WESTGARTH-CENTRAL PARK 3	LUDSTONE SMITH 2
ABBOTT-BEAUMONT 1	GOLFWOOD KIMBER 1	BELUGA CHOPARD 2	WELWYN-SUNLIGHT 1
AMRON NORMAN 1	JOHNSON COSIER 2	SARGOOD-MYRTLE 4	LADY EMILY COACH HOUSE 3
ARDYNE-KANGAROO 2	SILVERLEAF-JEAN 2	HOLLAND-PIPPIN 2	COLLINGTON-CHURCH 2
BARRY FOAM 2	BLACK WALLABY SPRINGHILL 1	CARLINGA-DEVLIN 1	GLADESVILLE NANDA 2
BLUFF BAYVIEW 2	BELLBROOK FROST 1	PARKVIEW-PARK 1	MACKIE-UNION 2
BLYTHE-POATH 2	CLAYTON STRELDEN 2	KULNINE-NYMPH 2	RAYNES PARK MAY 2
BOLINDA-CENTRE 2	KENEALLY ALLAN 3	YALLAMBEE ALBANY 2	HENSLEY CONRAN 1
COLLINS ELIZABETH 2	MULGRAVE-JORDAN 3	DURRANT-WILLANSBY 5	AUSTIN ERWIN 2
DEAN-FYFE 1	WEBB BARRY 1	BENWERRIN-BALMORAL 2	BRADY WINGATE 2
DROMANA NEPEAN 1	EBB LAURA 1	ELIZABETH GLEN EIRA 2	WATTS-PAYNES 3
DRYDEN-ASCOT 2	BRUNNING-LOBATOR 1	THIRD NEPEAN 2	PALM BEACH KEELING 2
ELEY-BLKBURN 3	HUNTINGDALE-ARTHUR 3	WALLACE HILLCREST 3	AIRLIE ARMSTRONGS 1
ELLERY-ATKINSON 1	CANTERBURY-PARK 1	SASSELLA-MCGUINESS 1	WIMBLEDON WIMBORNE 2
ELMHURST-MDLBORO 2	WISE MARTHA 1	PEMBERTON CRAVEN 2	MADIGAN NORTHAM 7
FLORENCE-MITCHAM 1	BURKE KNOX 2	FRALLON KARINGAL 2	ST JAMES-AMBER 1
MORANG-CHATSWORTH 2	WEEROONA BRIGHTS 1	WESTON ADISON 3	MAUDE-KNEALE 2
ROSCIUS-LADY NEL 4	MULGOA GLADSTONE 2	HELMICH BIANCA 3	FTN FLIND CRESWELL 6

CYPRESS DUNEARN 2	KELVIN NEPEAN 1	CENTRAL FIRST 1	PORTER-CHURCH 2
IKARA DUNNS 2	INDRA FULTON 2	MACKINTOSH LUM 2	CAMPBELLS SAHARA 1

11 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 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.

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 limitation 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 limitation.

United Energy has identified one new project from our joint planning activities with other NSPs and AEMO in 2022, as described below.

Schedule 5.8(o) of the NER requires United Energy to report on analysis of known and potential interactions between control systems relevant under clause 5.13.1(d)(6) of the NER, including a description of proposed actions to be undertaken to address any adverse interactions, taking into account the most recent general power system risk review undertaken by AEMO under clause 5.13.1(d)(5) of the NER.

In July 2022, AEMO published its final report on the Power System Frequency Risk Review[12] which details the adverse impacts that increasing levels of distributed embedded generation has on the Under Frequency Load Shedding (UFLS) control scheme, causing minimum operational demand to fall below technically acceptable thresholds needed for the effective operation of the control scheme.

Under clause 4.3.1 of the NER, AEMO has primary responsibility for power system security, however there is a general obligation on NSPs under clause 4.3.3 of the NER to respond to AEMO's direction by developing and implementing solutions to mitigate power system security risks.

In August 2021, AEMO issued a directive to Victorian NSPs to identify and implement measures to restore emergency under-frequency response to as close as possible to

[12] https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf, AEMO, July 2022.

the level of 60% of underlying load in all periods, as required by clause 4.3.1(k) of the NER. In response, a working group was set up between the Victorian Department of Environment, Land, Water and Planning (DELWP), AEMO and the Victorian NSPs to collaboratively identify solutions to address emerging issues associated with minimum demand and the UFLS scheme in Victoria.

Initial options posed by the working group to address the identified need (to date) have focussed on Cranbourne Terminal Station as a transmission-connection point case study where reverse power flows are occurring at times of minimum demand.

The feasibility of options is currently being investigated, and solutions may include (among others):

- blocking of 66kV sub-transmission lines from being tripped by the UFLS scheme when undergoing reverse power flow;
- installing and/or enabling under-frequency tripping relays at the lower voltage levels within the United Energy and/or AusNet distribution networks; and
- applying AMI direct load control capabilities to interrupt customers that are exporting power at times when the UFLS scheme is needed to operate.

The inclusion of AMI as part the solution is currently requiring significant consultation between members of the working group and with the AMI manufacturers, to assess the ability of AMI to meet the security, performance and capability requirements needed for the UFLS scheme. The consultation is also being used for the needs associated with the emergency backstop solar PV curtailment mechanism, to maintain supply-demand balance at times of minimum operational demand.

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

12 Changes to analysis since last year

12.1 Maximum demand forecast

The latest maximum demand forecast for the United Energy service area has been revised upwards by the National Institute of Economic & Industry Research (**NIEIR**) compared to that published in the 2021 DAPR.

At an overall United Energy service area level, NIEIR forecasts which were produced in August 2022, have been revised upwards in response to the expected recovery from the COVID-19 health and economic crisis. From 2023, the forecast shows an earlier recovery with an increased maximum demand launch point, and then in the latter years, a higher maximum demand growth rate compared to the 2021 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 12.1 United Energy 10% PoE summer maximum demand forecasts

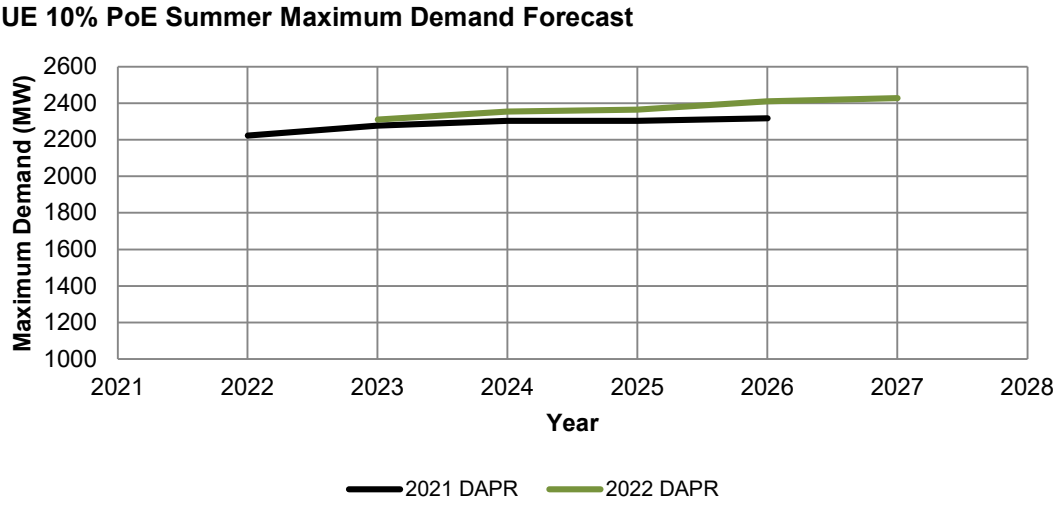


Table 11.1 below summarises the change in United Energy's 10 per cent probability of exceedance (**10% PoE**) summer maximum demand forecast.

Table 12.1 Changes in United Energy's 10% PoE summer maximum demand forecast

10% PoE Summer maximum demand	2022 DAPR Forecast	2021 DAPR Forecast	Change
2022-2023 summer	2312 MW	2278 MW	+1.5%
2026-2027 summer	2428 MW	2360 MW	+2.9%
2030-2031 summer	2565 MW	2450 MW	+4.7%
Ten-year average growth rate	1.4% pa	1.2% pa	+0.2% pa

12.2 Value of Customer Reliability (VCR)

As noted in section 6.3, the VCR used by United Energy to calculate the cost of expected unserved energy is provided by the AER, which published updated VCR values in December 2021.

United Energy has updated its investment plans to reflect these latest VCR values including escalating the VCR values to 2022 dollars and calculating investment area specific VCRs.

12.3 Timing of proposed network augmentations

The network limitation assessment and timing of network augmentations presented in this DAPR are based on United Energy's 2022 maximum demand forecast and the escalated AER VCR estimates. The timing is also based on the annualised cost of the network augmentation option.

While subdued maximum 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 augmentation projects identified in this DAPR have remained the same. The impact of the COVID-19 pandemic on maximum demand remains uncertain and project timings may need to be revised next year once more information on the longer-term impacts become available.

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

Table 12.2 No changes in timing of proposed major network projects

Proposed Major Project	2022 DAPR	2021 DAPR
Doncaster (**DC**) Supply Area: Install a fourth transformer with two new distribution feeders at Doncaster (DC).	2025	2025
Keysborough (**KBH**) Supply Area: Install a second transformer with two new distribution feeders at Keysborough (KBH).	2025	2025
East Malvern (**EM**) Supply Area: Install a third switchboard with three new distribution feeders at East Malvern (EM).	2026	2026
Mornington (**MTN**) Supply Area: Install a third transformer and new feeder from Mornington (MTN).	2027	2027

12.4 Timing of proposed asset retirements / replacements and deratings

United Energy is also required to detail information on its asset retirements / replacement projects and deratings in its DAPR as described in Chapter 15. 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 2021. The timing was also updated for the latest maximum demand forecast and VCRs 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 and deratings.

The main changes in timing relate to asset condition and site risk assessments, reduced energy at risk, and demand growth forecasts.

Table 12.3 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2022 DAPR	2021 DAPR
East Malvern (**EM**) #2 Transformer	2023	2023
Surrey Hills (**SH**) Transformers	2024	2023
Sandringham (**SR**) #3 Transformer	2024	2023
Elwood (**EW**) #2 Transformer	2027	2024
Gardiner (**K**) #3 Transformer	2027	2025
Hastings (**HGS**) #1 Transformer	Not included	2026
Glen Waverley (**GW**) 22kV Outdoor Switchyard	2025	2023
Doncaster (**DC**) 22kV Outdoor Switchyard	2024	2024
Elwood (**EW**) 11kV Indoor Switchboard	2027	2025
Heatherton (**HT**) 22kV Outdoor Switchyard	2024	2026

12.5 Feedback on United Energy's 2021 DAPR

In February 2022, United Energy held a public forum to discuss and seek feedback on the 2021 DAPR with the interested parties on United Energy's Demand Side Engagement Register. Feedback and discussions of limitations 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 2022. This was undertaken as part of the consultation requirements under the AER's Demand Management Incentive Scheme (**DMIS**).

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

13 Asset management

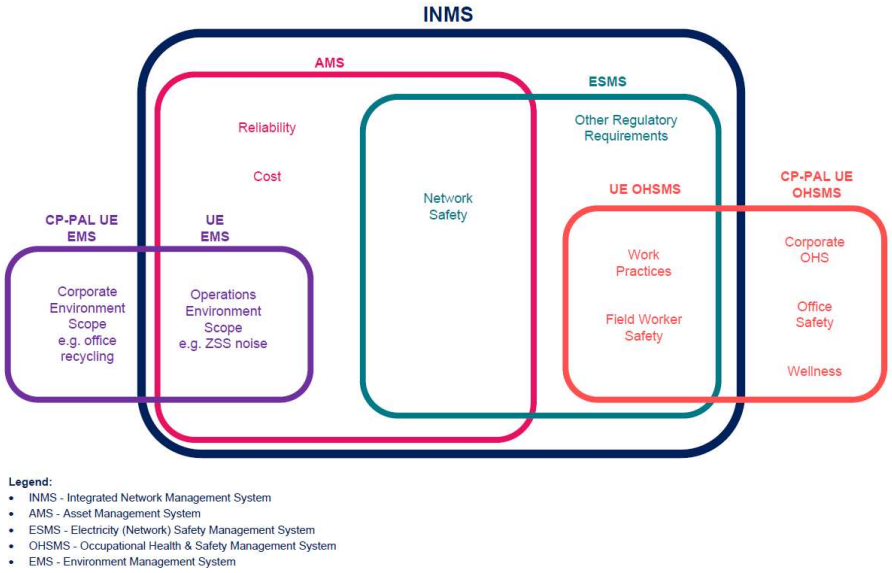
This chapter sets out United Energy's Integrated Network Management System (**INMS**), which underpins our asset management framework and ensures a clear 'line-of-sight' between the company's activities on the ground, and the overall Vision, Organisational Strategic Plan and Objectives.

13.1 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**),
- Environmental Management System (**EMS**).

Figure 13.1 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 AMS, OHSMS, EMS and the ESMS have been integrated to ensure the safe, reliable, cost effective operation of the electricity distribution networks.

13.2 Asset management system

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

The United Energy AMS 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 (**AMP**) 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.

13.3 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 (**SAMP**) 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.

13.4 Asset class strategies and plans

A key part of United Energy's AMS 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; and
- Operational Property.

13.5 Asset management plan and COWP

The 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.

13.6 System limitations identified through asset management

All of the system limitations (and the actions to resolve those limitations) within this DAPR have been identified within United Energy's asset management framework.

- Chapters 7, 8, 9, and 10 outlines the system limitations and network augmentation projects related to growth (demand and customer connections) and use of distribution services by embedded generating units.
- Chapter 15 outlines the system limitations and network replacement projects related to asset condition assessment as described in United Energy's asset class strategies.

13.7 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.

14 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 13.3).

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.

14.1 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.

14.2 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 Chapter 15 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. Chapter 15 also includes methodologies used for the replacement of each type of asset, where relevant.

15 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 limitation 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 15.1 Planned asset replacements

Asset	Location	Project	Retirement date
East Malvern (**EM**) #2 Transformer	East Malvern (**EM**) zone substation	Replacement	2023 (committed)
Surrey Hills (**SH**) 6.6kV Conversion	Surrey Hills (**SH**) zone substation	Replacement	2024
Sandringham (**SR**) #3 Transformer	Sandringham (**SR**) zone substation	Replacement	2024
Elwood (**EW**) #2 Transformer	Elwood (**EW**) zone substation	Replacement	2027
Gardiner (**K**) #3 Transformer	Gardiner (**K**) zone substation	Replacement	2027
Glen Waverley (**GW**) 22kV Outdoor Switchyard	Glen Waverley (**GW**) zone substation	Replacement	2025
Doncaster (**DC**) 22kV Outdoor Switchyard	Doncaster (**DC**) zone substation	Replacement	2024
Elwood (**EW**) 11kV Indoor Switchboard	Elwood (**EW**) zone substation	Replacement	2027
Heatherton (**HT**) 22kV Outdoor Switchyard	Heatherton (**HT**) 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.

15.1 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 System Limitations Template. Note that the System 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.

15.1.1 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 limitations 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.

East Malvern (EM) #2 Transformer Retirement/Replacement

The existing EM transformer #2 is over 50 years old and condition is assessed as being very close to end-of-life.

The #2 transformer at EM is in poor condition, and requires significant remediation works to mitigate noise to the surrounding residential area. Based on the condition, noise and risk assessments conducted United Energy commenced a project in 2021 to replace the transformer by 2023 at an estimated cost of $3.1M, and will be completed in 2023.

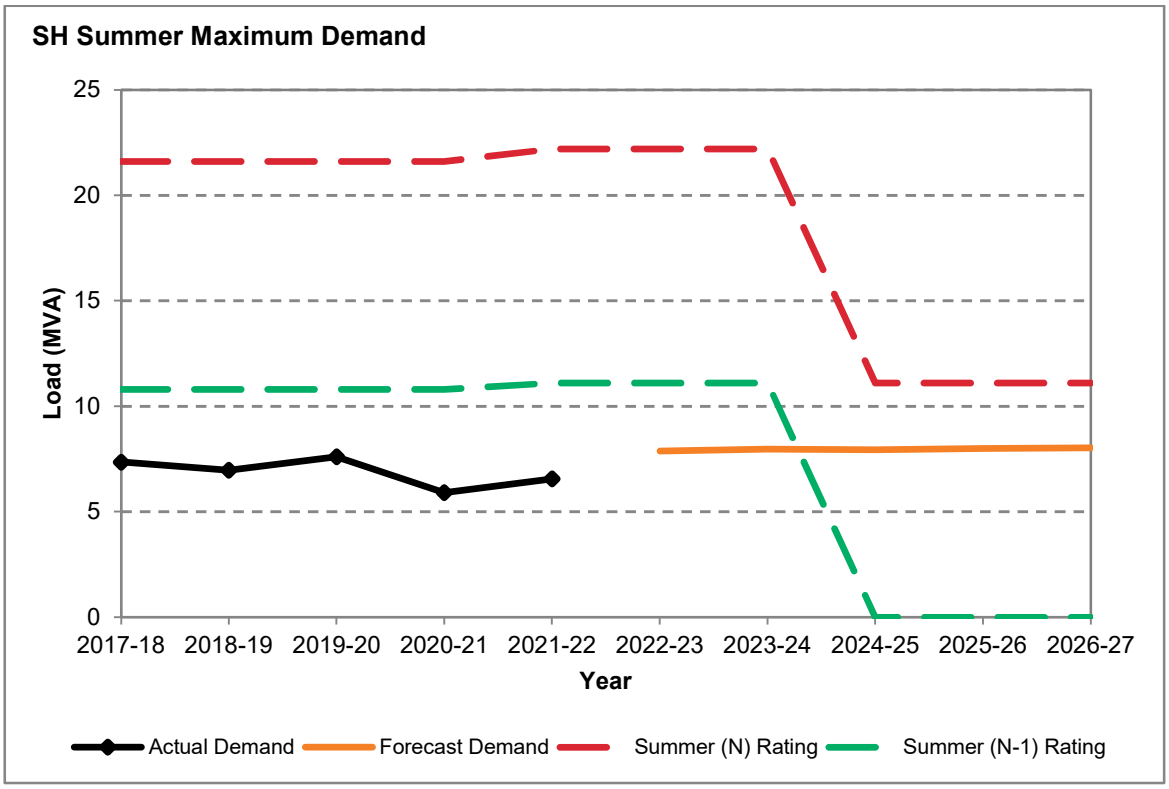
Surrey Hills (SH) Transformer Retirement/Replacement

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 2024-25.

Figure 15.1 Forecast maximum demand with transformer retirement at SH



The graph shows that retirement would lead to load-at-risk, with up to 7.9MVA of lost load in summer 2024-25, in the event of a failure of the remaining transformer.

To address the anticipated system limitation 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 2024 and 2025;
- replace one of the aged transformers in 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 replace the two aged transformers at SH with 22/11kV replacements;
- 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 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 1.0MVA.

The least cost technically acceptable option is to replace the #3 transformer at SH like-for-like 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 will be used to mitigate the load-at-risk in the interim period.

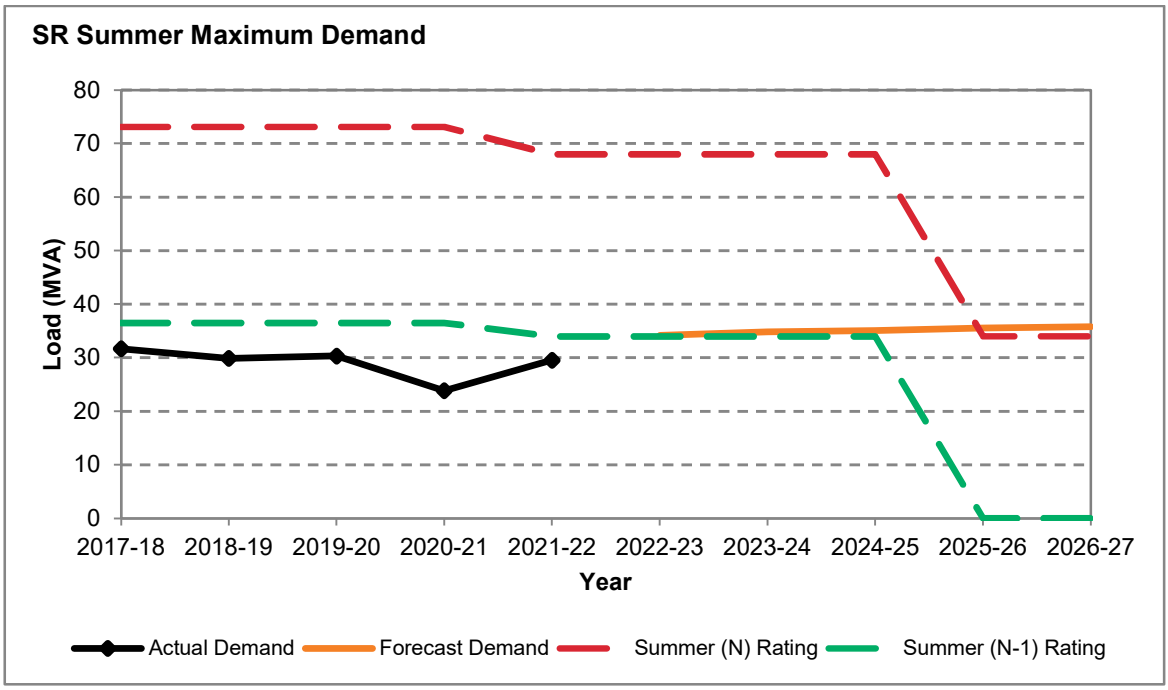
Sandringham (SR) #3 Transformer Retirement/Replacement

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 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% 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 15.2 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 35.1MVA 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 limitation 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 9.2MVA;
- replace #3 transformer in 2023 at an estimated cost of $3.1 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 economic within the 5 year planning period;
- 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 5.5MVA.

The least cost technically acceptable option is to replace the #3 transformer at SR 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 will be used to mitigate the load-at-risk in the interim period.

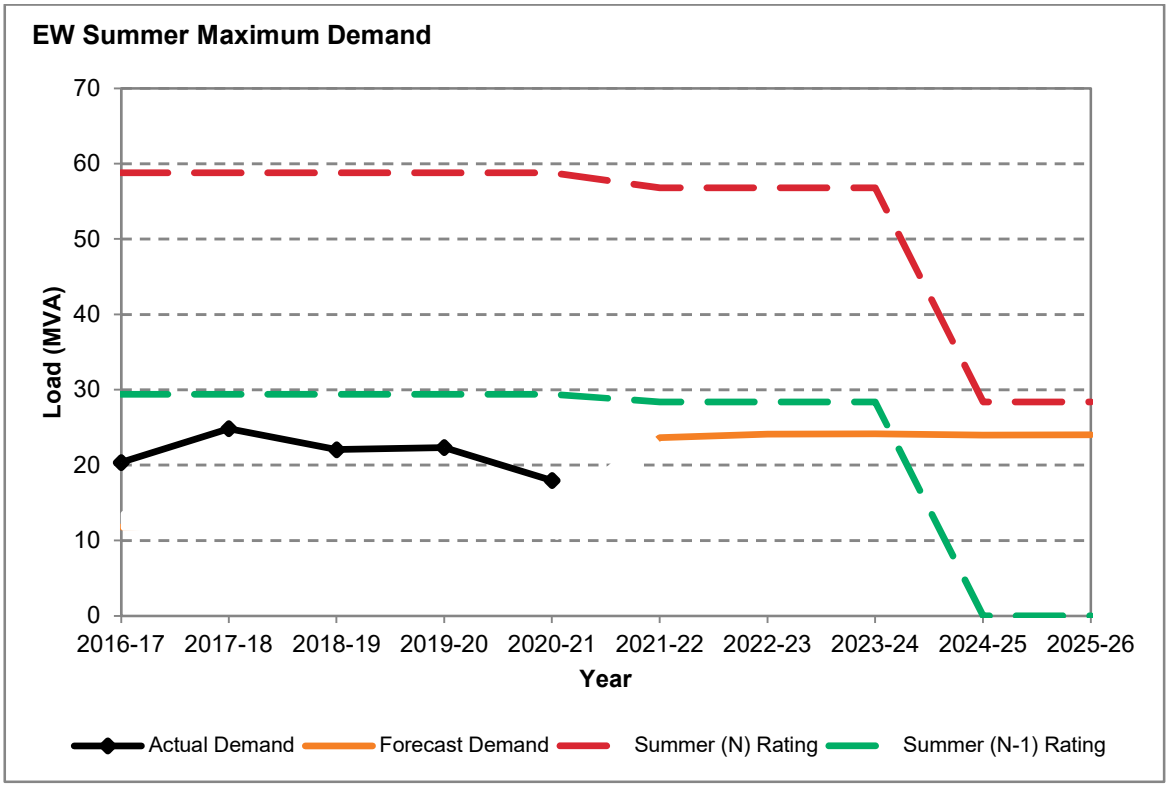
Elwood (EW) #2 Transformer Retirement/Replacement

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 2027.

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 2027.

Figure 15.3 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 26.1MVA of lost load in summer 2026-27, in the event of a failure of the remaining transformer.

To address the anticipated system limitation 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 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 3.0MVA;
- replace the #2 transformer in 2024 at EW at an estimated cost of $3.3 million. The #1 transformer will be assessed for replacement in the future but is not expected to be economic within the 5 year planning period;
- 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 8.3MVA.

The least cost technically acceptable option is to replace the #2 transformer at EW in 2027. 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 will be used to mitigate the load-at-risk in the interim period.

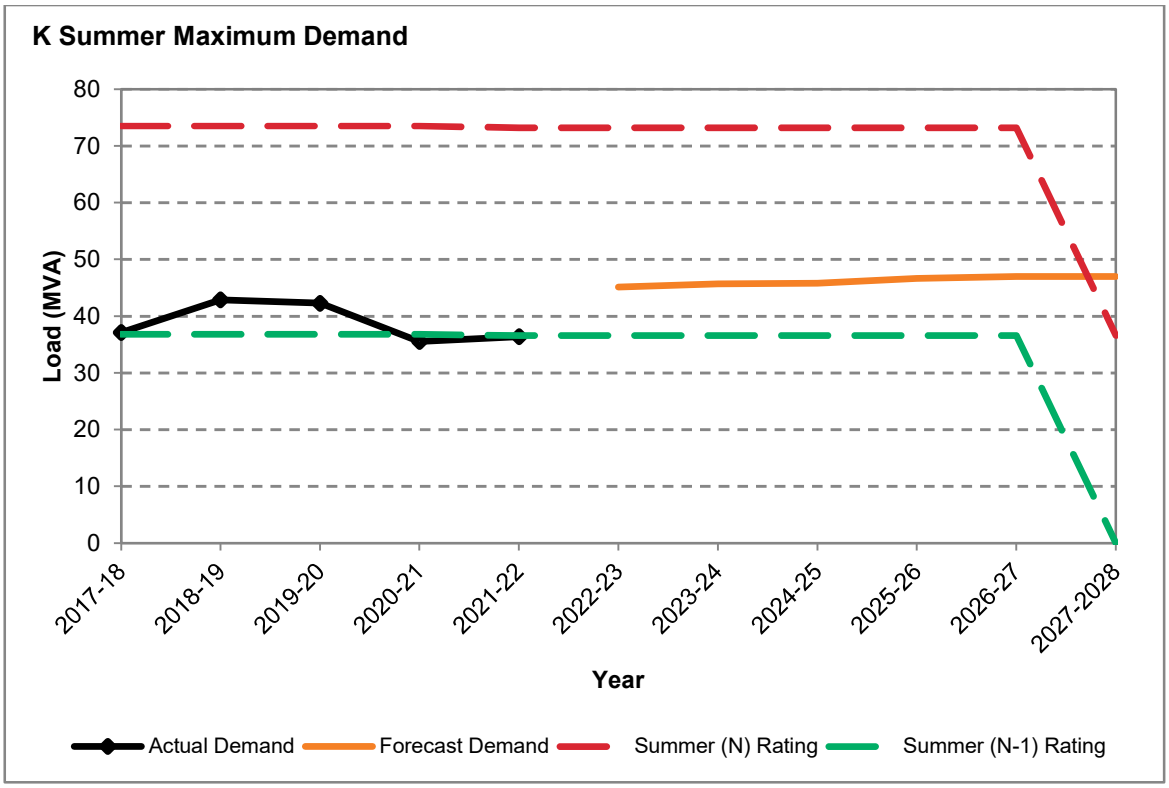
Gardiner (K) #3 Transformer Retirement/Replacement

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 2027. 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% PoE summer maximum demand forecast together with the station's summer (N) and (N-1) ratings before and with a transformer retired in 2027.

Figure 15.4 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 47.0MVA of lost load in summer 2026-27, 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 limitation 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 7.2MVA;

- replace #3 transformer in 2027 at an estimated cost of $3.1 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 economic within the 5 year planning period;
- 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 10.3MVA.

The least cost technically acceptable option is to replace the #3 transformer at K in 2027. 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 will be used to mitigate the load-at-risk in the interim period.

15.1.2 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.

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 15.2 GW Switchgear failure load-at-risk

	2022-23	2023-24	2024-25	2025-26	2026-27
10% PoE Load-at-risk (MVA)	9.3	9.5	9.7	9.9	10.0

The table above shows that in summer 2024-25 there is forecast to be up to 9.7MVA of load-at-risk in the event of major failures at GW.

To address the anticipated system limitation 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 substations Notting Hill (**NO**), Mulgrave (**MGE**) and East Burwood (**EB**) up to a maximum transfer capacity of 18.2MVA;
- targeted replacement of 22kV assets which present the highest risk to the station at a cost of $1.0M;
- replace all the 22kV bus work and switchgear an estimated cost of $3.5 million in 2024 and 2025;
- 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 9.1MVA in the event of specific failures within the substation that will not be able to be transferred.

The least cost technically acceptable option is to undertake targeted replacement of 22kV assets at GW 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 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 15.3 DC Switchgear failure load-at-risk

	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**
10% PoE Load-at-risk (MVA)	11.1	11.3	11.4	11.5	11.6

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 limitation 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 20.4MVA;
- 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 $1.7 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 6.9MVA in the event of specific failures within the substation that will not be able to be transferred.

The least cost technically acceptable option is to 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 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 2027.

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 15.4 EW Switchboard failure load-at-risk

	2022-23	2023-24	2024-25	2025-26	2026-27
10% PoE Load-at-risk (MVA)	11.3	11.4	11.5	11.6	11.8

The table above shows that in summer 2026-27 there is forecast to be up to 11.8MVA of load-at-risk in the event of a major failure of one bus.

To address the anticipated system limitation 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 7.0MVA;
- replace the switchboard in 2026 and 2027 at an estimated cost of $3.3 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 9.0MVA in the event of a failure of a bus at EW.

The least cost technically acceptable option is to replace the 11kV switchboard at EW beginning in 2027. 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 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 15.5 HT Switchgear failure load-at-risk

	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**
10% PoE Load-at-risk (MVA)	5.9	5.9	5.9	6.0	6.1

The table above shows that in summer 2024-25 there is forecast to be up to 5.9MVA of load-at-risk in the event of a failure at HT.

To address the anticipated system limitation 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 25.6MVA;
- replace all the 22kV bus work and switchgear at an estimated cost of $3.5 million in 2024 and 2025;
- targeted replacement of 22kV assets which present the highest risk to the station at a cost of $1.4 million in 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 5.7MVA in the event of specific failures within the substation that will not be able to be transferred.

The least cost technically acceptable option is to undertake targeted replacement of 22kV assets at HT 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 will be used to mitigate the load-at-risk in the interim period.

15.2 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 Chapters 13 and 14.

15.2.1 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.

15.2.2 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.

15.2.3 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.

15.2.4 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 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.

15.2.5 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 is 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 in rush 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.

15.2.6 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.

15.2.7 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.

15.2.8 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.

15.2.9 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.

15.2.10 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.

15.2.11 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 limitation 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.

15.2.12 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 15.6 Relay replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
Hastings (HGS)	Electro-mechanical, analogue electronic and digital relay replacement aligned with control building replacement works	2023
Frankston South (FSH)	Electro-mechanical, analogue electronic and digital relay replacement aligned with control building replacement works	2023
Heatherton (HT)	Electro-mechanical, analogue electronic and digital relay replacement aligned with 22kV outdoor switchgear and control building replacement works	2024
Glen Waverley (GW)	Digital and electro-mechanical relay replacement	2025
Dandenong Valley (DVY)	Digital relay replacement	2026
East Malvern (EM)	Electro-mechanical, analogue electronic and digital relay replacement aligned with switchboard replacement works	2026

15.2.13 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 and 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 15.7 Battery Bank Replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
WD, M, EM, HGS, 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
MC, NP	Risk assessment based on historical failures and consequence of failure.	2025

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

Table 15.8 Battery charger replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
Hasting (HGS)	Risk assessment based on historical failures aligned with planned relay replacement	2023
Frankston South (FSH)	Risk assessment based on historical failures aligned with planned relay replacement	2023
Heatherton (HT)	Risk assessment based on historical failures aligned with planned relay replacement	2024
Glen Waverley (GW)	Risk assessment based on historical failures aligned with planned relay replacement	2025
Dandenong Valley (DVY)	Risk assessment based on historical failures aligned with planned relay replacement	2026
East Malvern (EM)	Risk assessment based on historical failures aligned with planned relay replacement	2026

15.3 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.

15.4 Committed projects

There were no committed investments worth $2 million or more to address urgent and unforeseen network issues.

16 Regulatory tests

This chapter 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.

16.1 Current regulatory tests

The table below provides an overview of the regulatory test projects that are underway or completed by United Energy in 2022.

Table 16.1 Status of United Energy regulatory tests

Project name	Regulatory test status	Proposed in-service date	Identified need	Comments
Cranbourne Terminal Station Electricity Supply **RIT-T**	Completed	2025-26	Expected unserved energy at Cranbourne Terminal Station. (Refer to the 2022 Transmission Connection Planning Report for further details)	Joint RIT-T with AusNet Electricity Services. Project Specification Consultation Report (PSCR)[13] published in June 2020. Project Assessment Draft Report (PADR)[14] published in June 2022. Project Assessment Conclusions Report (PACR)[15] published in October 2022.

[13] https://aemo.com.au/en/consultations/current-and-closed-consultations/cranbourne-terminal-station-electricity-supply-rit-t---pscr

[14] https://aemo.com.au/consultations/current-and-closed-consultations/maintaining-supply-reliability-in-the-cranbourne-area-padr

[15] https://aemo.com.au/consultations/current-and-closed-consultations/maintaining-supply-reliability-in-the-cranbourne-area-pacr

No RIT-D consultations were undertaken during 2022. More details and examples on the RIT-D can also be found in our Demand Side Engagement Document[2]. One recently concluded RIT-T consultation was undertaken during 2022. Refer to the Cranbourne Terminal Station section of the 2022 Transmission Connection Planning Report for further details.

16.2 Future regulatory investment tests

Based on the information contained within Chapters 7 and 15, 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 16.2 Future RIT-D projects

Project name	Proposed RIT-D start date	Comments
Doncaster zone substation fourth transformer	2023	Install a fourth transformer with two new distribution feeders at Doncaster (**DC**) in 2025.
Keysborough zone substation second transformer	2023	Install a second transformer with two new distribution feeders at Keysborough (**KBH**) in 2025.
East Malvern zone substation third switchboard	2024	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 2026.
Mornington zone substation third transformer	2025	Install third transformer with a new distribution feeder at Mornington (**MTN**) in 2027.

RIT-D consultation documents will be made available from the United Energy website and notified to participants registered on the Demand Side Engagement Register.

17 Network performance

This chapter 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.

17.1 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 three minutes 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 three minutes 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 2021 reliability service targets set by the Australian Energy Regulator (**AER**) for United Energy. This is a consolidation of the targets from the Distribution Determination for the 2016-2020 regulatory period and 2021/22-2025/26 regulatory period.[16] In addition, United Energy has also forecast its outturn performance for the 2022 calendar year, based on actual performance for the period from 1 January 2022 to 30 September 2022 and then projected forward taking into account seasonal factors.

[16] AER, United Energy distribution determinations - 2016 to 2020, Final, May 2016 & 2021 to 2026, Final April 2021.

Table 17.1 Reliability targets and performance

Feeder	Parameter	AER target (2021)	2021 Performance	Projected 2022 Performance (as at 30th September 2022)
Urban	SAIDI	53.36	29.84	29.4
	SAIFI	0.80	0.40	0.37
	MAIFIe	0.94	0.93	0.90
Rural short	SAIDI	141.94	83.09	67.6
	SAIFI	1.97	1.07	1.06
	MAIFIe	3.5	1.98	2.53

In 2021, United Energy achieved within target results for SAIDI, SAIFI and MAIFIe in both urban and rural short areas.

In 2022, 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.

17.1.1 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 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 (**ACR**s) and remote control gas switches (**RCGS**s), 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;
  - Conductor clashing mitigation measures to reduce the risk of 'flash-overs' and bushfire risk;
  - Targeted pole-top fire mitigation to reduce the risk of pole fires; and
  - Analysis of LiDAR data to identify locations of conductor clashing risk.
- 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 2022 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. An annual review of United Energy's reliability against its targets is undertaken and where necessary, corrective actions are implemented to facilitate United Energy meeting its reliability targets. This review is used for planning future year's budgets. The current budget projections are as follows:

Table 17.2 Forecast reliability expenditure ($ million, real 2022)

2022	2023	2024	2025	2026
4.3	5.0	5.0	4.4	4.4

17.2 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 (**REFCL**s) 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 Electricity 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 are as per the below with no further REFCL installations planned:

- 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 17.3 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**) [17]	MGE 32
Lyndale (**LD**) [17]	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 affected customers to provide the relevant information and advice on the possible impacts and mitigation measures.

17.3 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 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.

[17] 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.

17.3.1 Voltage

Voltage requirements are governed by the VEDCoP and the NER.

The NER requires that United Energy adheres to the 61000.3 series of Australian and New Zealand Standards. In October 2022, the VEDCoP was updated such that it more closely aligns with the NER requirements.

The VEDCoP 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 (General) Regulations 2019 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.

Variations from the standard nominal voltages listed above are permitted to occur in accordance with the following table as per the VEDCoP.

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 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 VEDCoP 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. The VEDCoP stipulates the above mentioned voltage levels should be at the meter closest to and applicable to the point of supply. AS 61000.3.100 also recognises that for distribution companies like United Energy, with hundreds of thousands of customers spread over a large geographic area, that achieving 100% compliance for all customers at all times is not economically or practically possible. Therefore, a network is considered to be 'functionally compliant' if it can achieve voltage within each limit for 95% of sites.

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.

Table 17.4 Permissible voltage variations[18]

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*	+ 13% - 10%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	6 kV peak
2**		+ 13% - 10%			
3	1 – 6.6	± 6% (± 10% Rural Areas)	± 10%	Phase to Earth +80%, -100% Phase to Phase +20%, -100%	60 kV peak
4	11				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

17.3.2 Harmonics

Voltage harmonic requirements are governed by the VEDCoP and the NER. The NER, with which the VEDCoP 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 premises), with the levels specified in the following table from AS 61000.3.6.

[18] Table 2 Clause 20.4.2 of the VEDCoP.

Table 17.5 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 · (25 / h)				
NOTE – Total harmonic distortion (THD): 8%.					

17.4 Power Quality performance

17.4.1 Steady state voltage

Power Quality Monitoring Data

Power quality monitoring has been in service at our zone substations as well as towards the end of the longest distribution feeders for over 20 years.

We pariticpate in the independent Power Quality Compliance Audit (**PQCA**) report independently prepared by University of Wollongong for FY2021-22. The results are based on the medium-voltage power quality meters installed at each zone substation, and the low-voltage power quality meters installed at the start of one low-voltage circuit connected toward the end of the longest distribution feeder of each zone substation.

The results indicate none of the low-voltage sites exceed the upper voltage limit of 1.1 per unit (253V) or lower limit of 0.94 per unit (216V). For the voltage distribution, upper and lower parts of bars indicate 99th and 1st percentile values, respectively.

The medium-voltage sites Bentleigh and Cheltenham zone substation as shown in Figure 16.2 below slightly exceeded 99th percentile limits. Both the sites voltage level are now rectified.

Figure 17.1 – Steady State voltage distribution for LV Sites FY2021-22

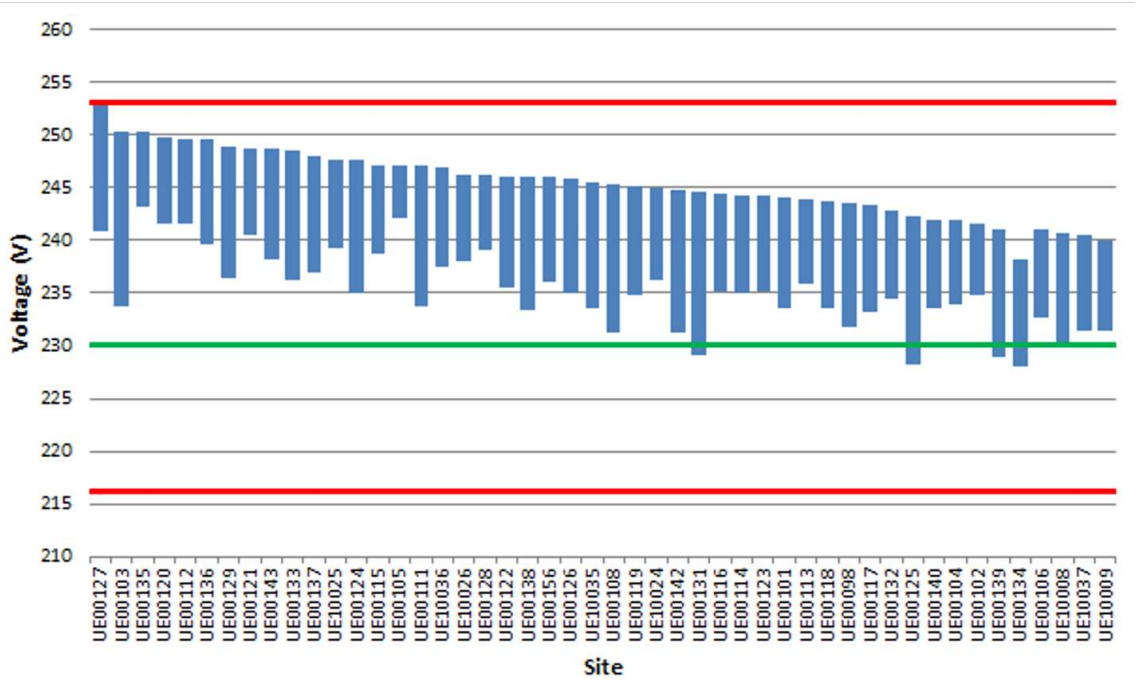
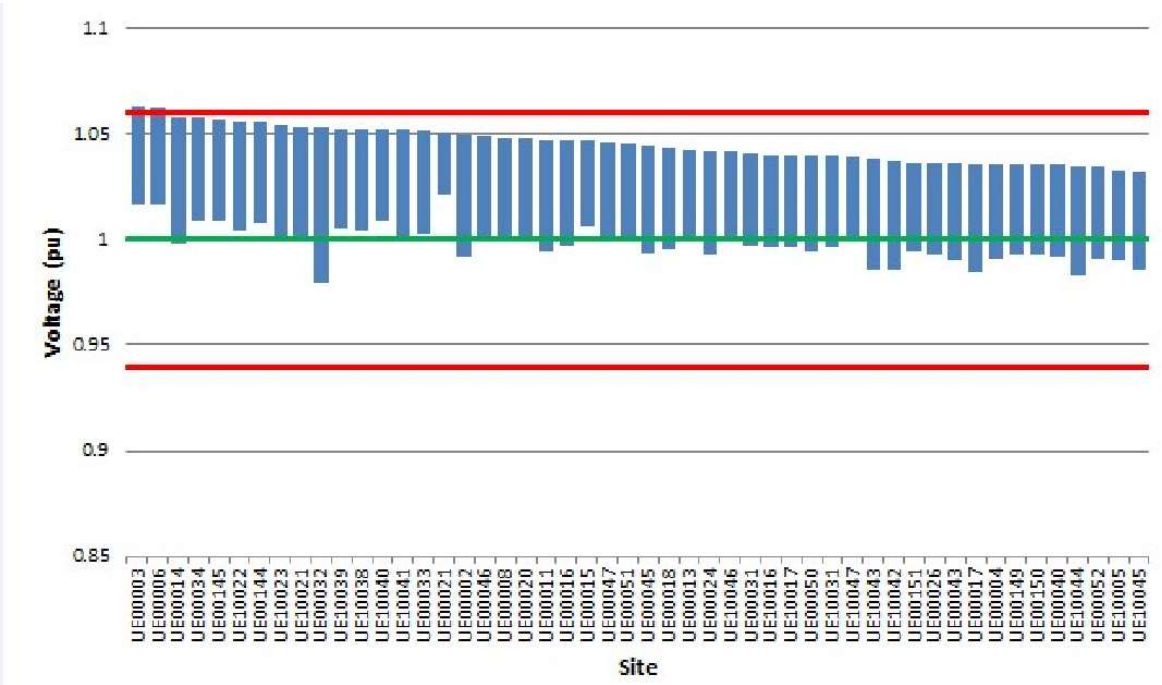


Figure 16.2 – Steady state voltage distribution MV Sites FY2021-22



Distribution Limitations Template and AMI voltage data

AMI smart metering (deployed across the network less than 10 years ago), identified that there were a large number of customers experiencing steady-state voltages outside the regulatory limits; more regularly at the high voltage limit end (253V). This issue was previously largely unknown due to the absence of continuous voltage monitoring on the low-voltage networks and was subsequently revealed by United Energy's population of smart meters. These issues have been exacerbated recently by the increasing penetration

of roof-top solar photovoltaic (**PV**) cells exporting power, further increasing voltages, and being limited in operation at customer premises.

The Electricity Distribution Code was updated in 2020 to include additional DAPR reporting requirements for United Energy, including AMI voltage information in a Distribution Voltage Information template, which has been published alongside this DAPR in MS-Excel® format.

The voltage information required to be published is for each voltage-controlled section of the network, which is defined as any device or equipment that manages the distribution feeder voltage, starting from the zone substation. Voltage information is therefore required and provided for each of United Energy's distribution feeders given it has no in-line voltage regulators.

The voltage data to be published for each section is the aggregated 10-minute average voltage data, aggregated 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.

The data required under the VEDCoP is average voltage data only. It does not provide granular information to determine steady-state voltage performance and non-compliances which is related to the minimum and maximum voltages at each customer point of supply.

A monthly breakdown of the network-wide average voltage from 5-minute voltage reads is illustrated in Figure 17.2. United Energy upper end V99 and the lower end V1 compliance percentage from January 2021 is also shown in Figure 17.3 and Figure 17.4 below.

Figure 17.2 Monthly Average Voltage FY2021-21



Figure 17.3 Monthly V99% 253V Customer Compliance FY2021-22

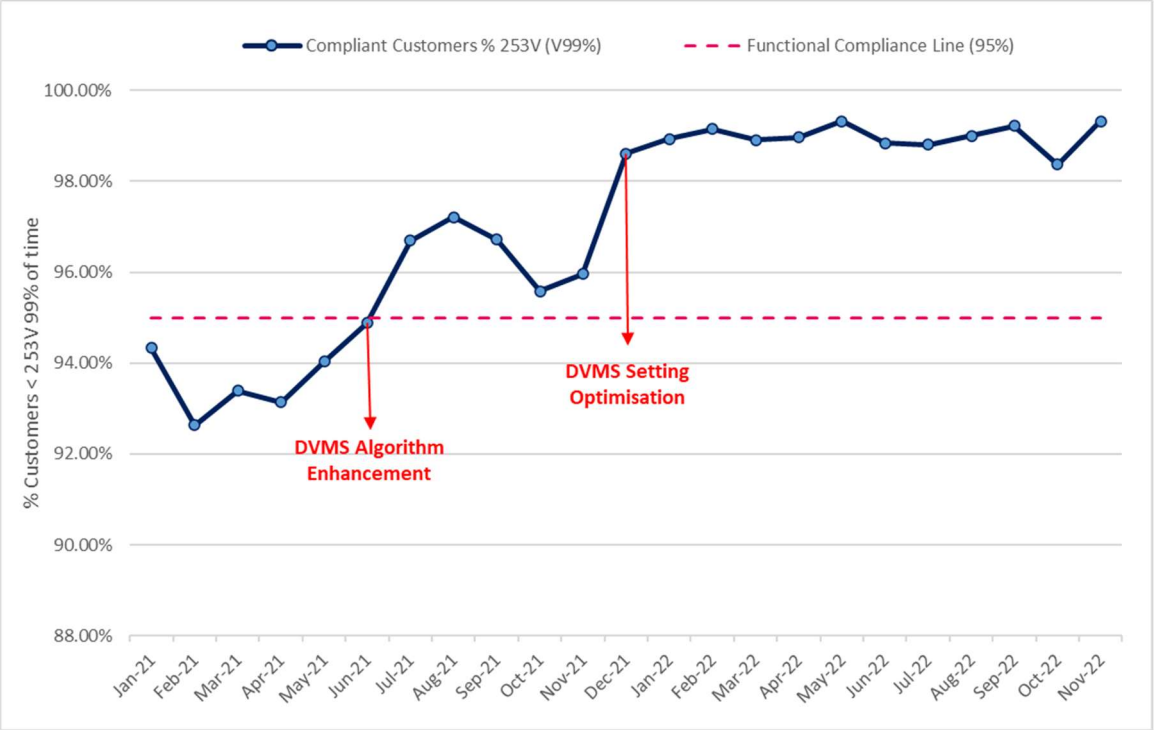
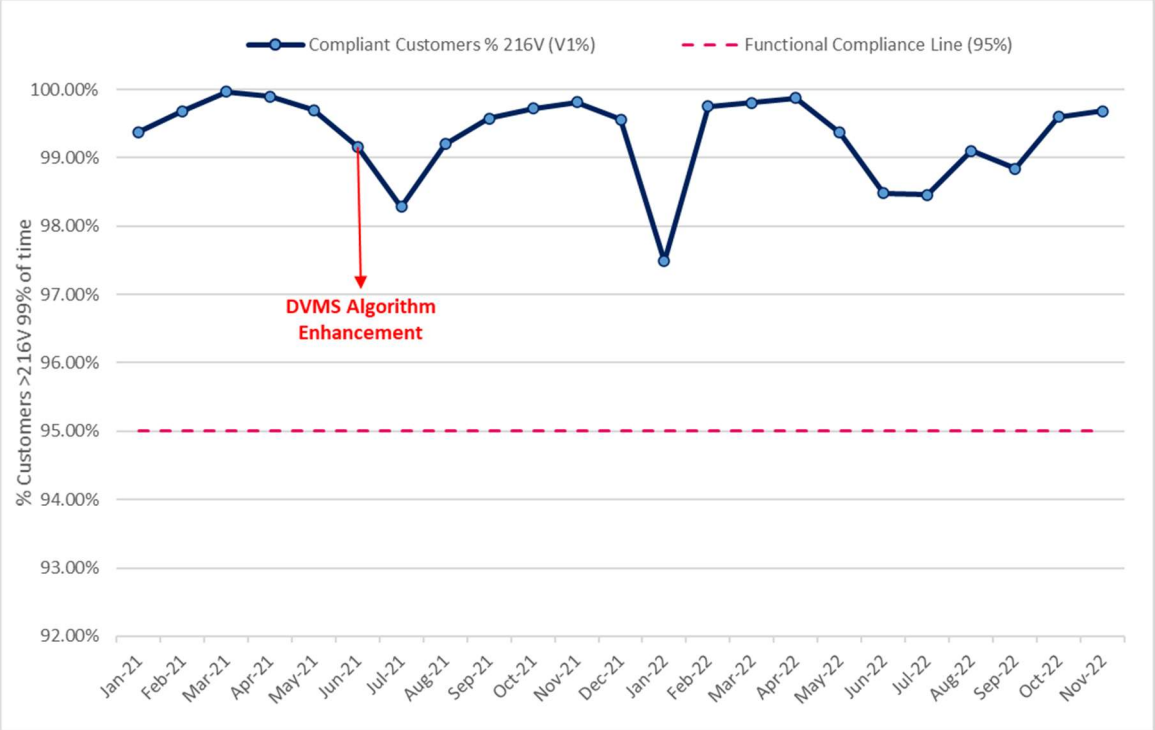


Figure 17.4 Monthly V1% 216V Customer Compliance FY2021-22



Since the installation of smart meters United Energy has been progressively improving its voltage compliance across the network. Most notably 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.

More recently United Energy determined an innovative enhancement that could be applied to its DVMS system which would allow United Energy to lower voltages under light load and high solar times when high voltages occur while not impacting peak demand times which are the likely under-voltage times. This enhancement was implemented in June 2021 which has led to a significant step up in compliance, with the V99 limit level currently operating within the 95% functional compliance limits. Further optimsations were ongoing in 2022, which maintained overvoltage compliance while lowering the average voltage across the network.

Solar PV inverter compliance to AS 4777 is a key priority area for United Energy to maintain votlage and improve Solar PV hosting capacity. On 1 October 2022, United Energy introduced a new commissioning sheet process to embed inverter compliance within our export approval system. Advanced DVMS analytics trialled throughout the period have allowed us to detect and verify compliance rates. Initial results suggest inverter compliance has improved by approximately 13% throughout the period. This will be a continued focus going forward. Achieving near 100% installation compliance is crucial to maximising the amount of rooftop solar PV that can be accommodated on the network, whilst maintaining network-wide functional voltage compliance.

In the 2021-22 period, United Energy has also undertaken rectification works including tap changes, phase balancing, augmentation and other capital works at over 115 sites, benefiting more than 7,000 customers. This does not include DVMS enhancement impacts which also benefited customers across the network. Further details of DVMS and works being undertaken to rectify steady state voltage issues and connect rooftop solar PV are described in Section 17.4.6.

17.4.2 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 FY2021-22 PQCA results, based on the zone substation and end-of-feeder power quality meters, the voltage unbalance at end-of-feeder LV sites and all of the Zone Substation MV sites are within the requirements of the NER.

Figure 17.5 Voltage unbalance LV sites during FY2021-22

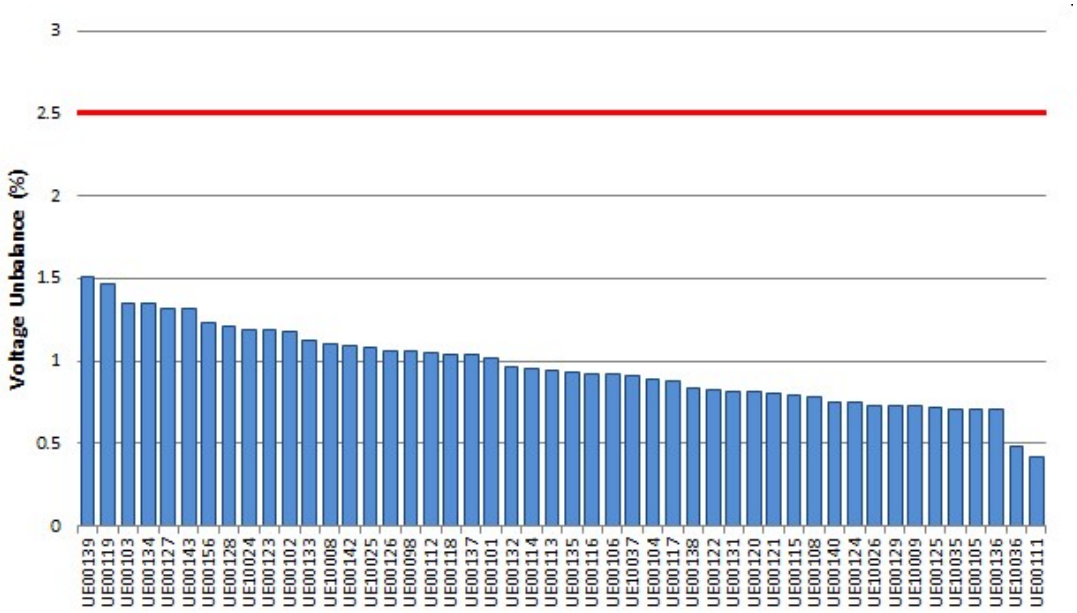
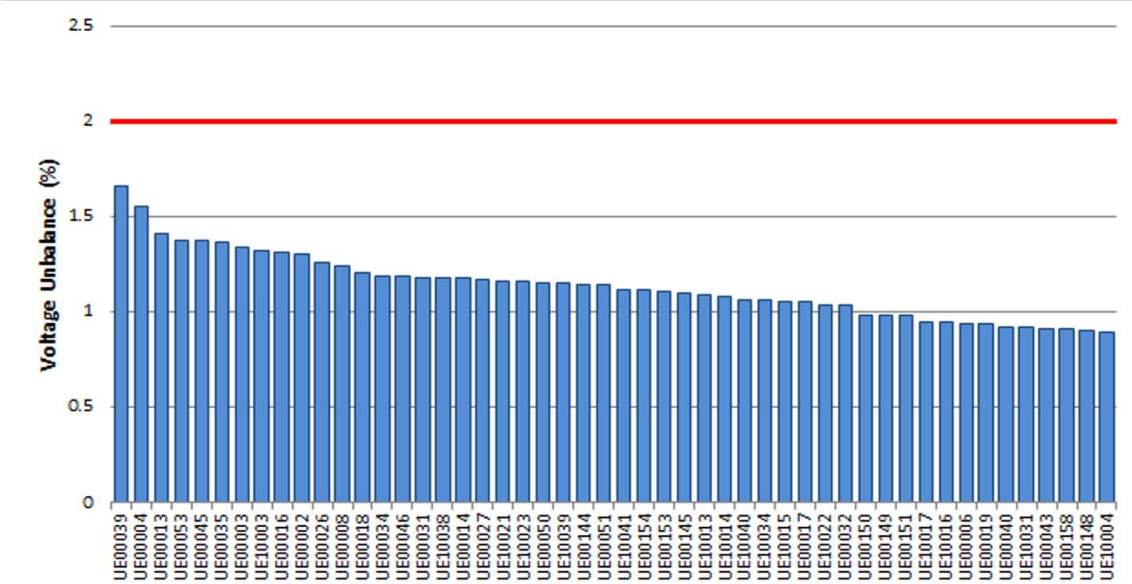


Figure: 17.6 Voltage Unbalance MV sites FY2021-22



The worst performing zone substations for voltage unbalance include those that supply rural areas via two-phase or SWER systems.

17.4.3 Voltage harmonic distortion

Voltage harmonic distortion can vary significantly across the network. According to the FY2021-22, PQCA results which use the zone substation and end-of-feeder power quality meters, all monitored low-voltage and medium-voltage sites are within the requirements of the NER.

Figure 17.7 Voltage harmonics distribution for LV sites FY2021-22

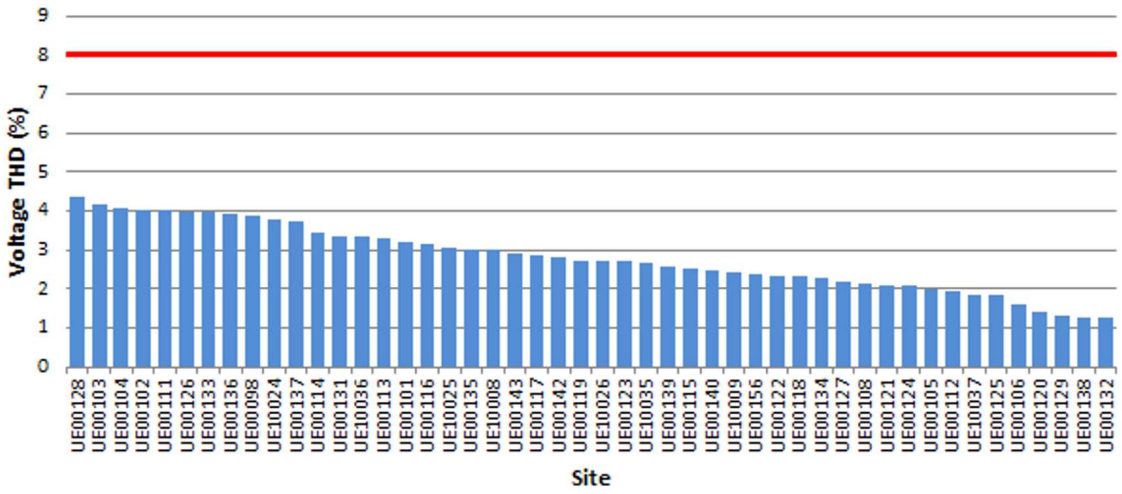
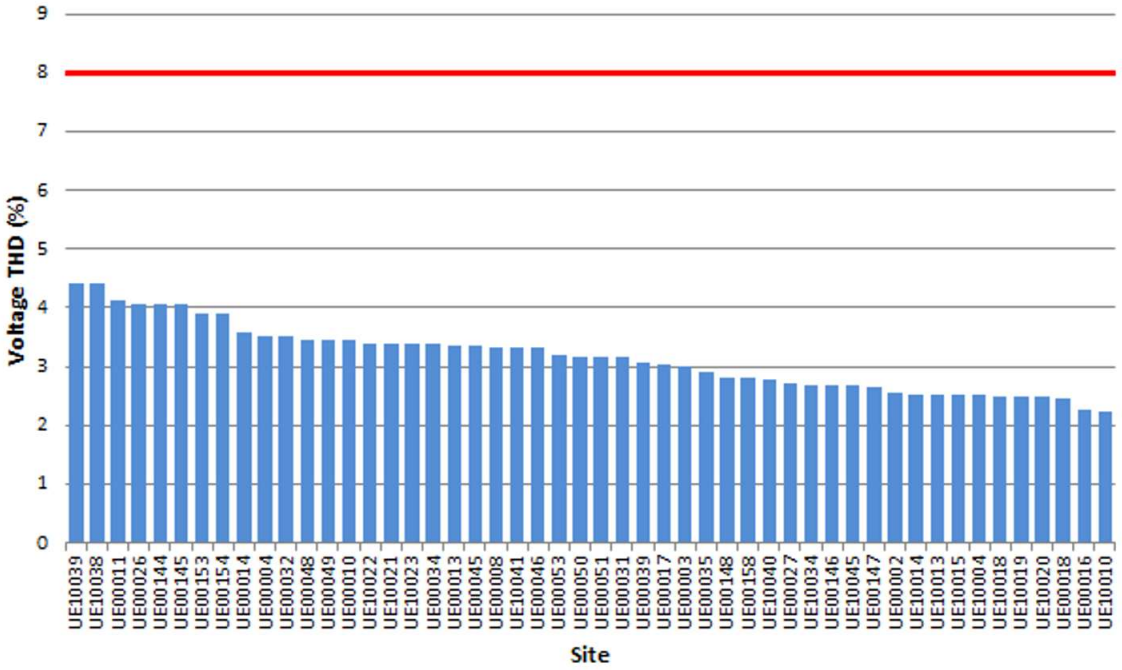


Figure 17.8 Voltage harmonics distribution for MV sites FY2021-22



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 voltage distortion and control harmonic levels going forward.

17.4.4 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

FY2021-22 PQCA results, the flicker levels at all monitored United Energy medium-voltage sites are within the national and local state regulatory limits.

Causes of emerging voltage fluctuations may occur from micro-generation such as roof-top solar photovoltaic systems and micro-wind generation schemes. It is critical that the impact of these systems on our network is monitored and well understood.

Figure 17.9 Short-term flicker index during FY2021-22

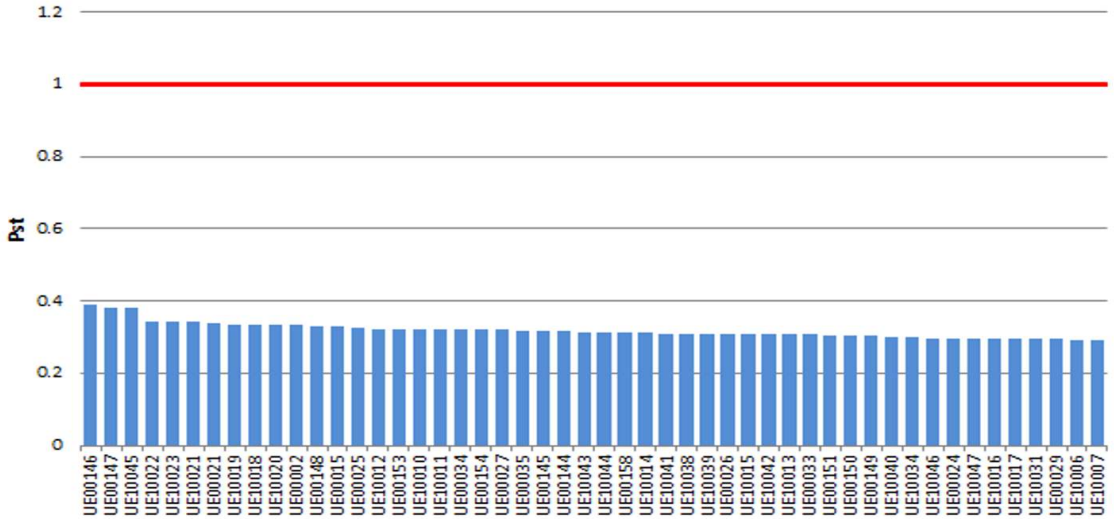
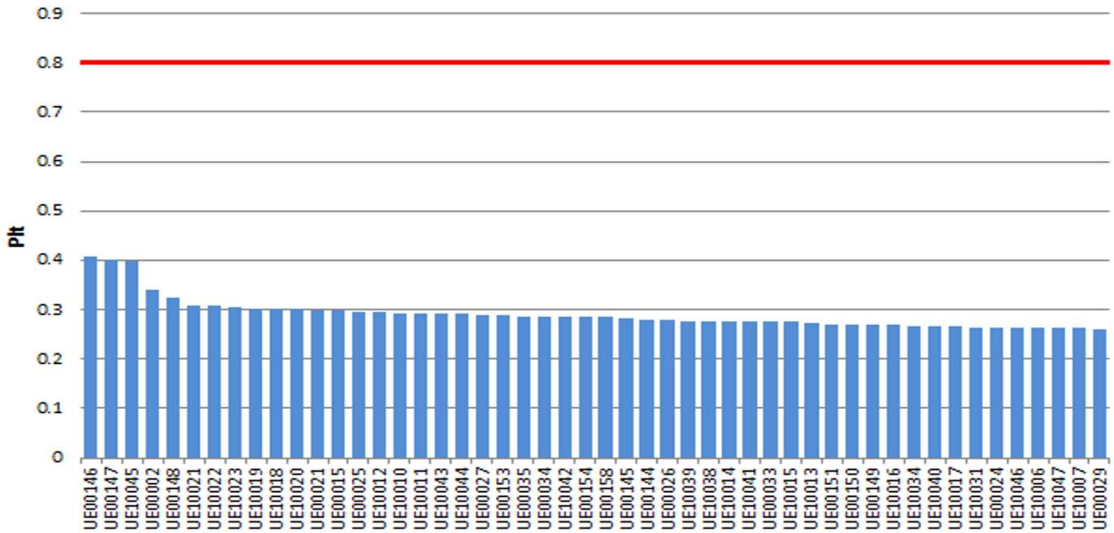


Figure 17.10 Long-term flicker index during FY2021-22



17.4.5 Voltage sags

Voltage sags, caused mainly by network faults depressing voltage levels across the network, are one of the main concerns customers have regarding power quality. According to the FY2021-22 PQCA results which use the zone substation and end-of-feeder power

quality meters, the voltage sag SAIFI[19] at low-voltage level are all within the required limits. Beaumaris and Sorrento Zone Substation medium-voltage sites were outside the required limits, which can be attributed to increased storm activity and zone substation transformer tap setting generally being reduced closer to their nominal level to reduce network voltages to accommodate more solar PV connections.

Figure 17.11 Voltage sag SAIFI for LV sites during FY2021-22

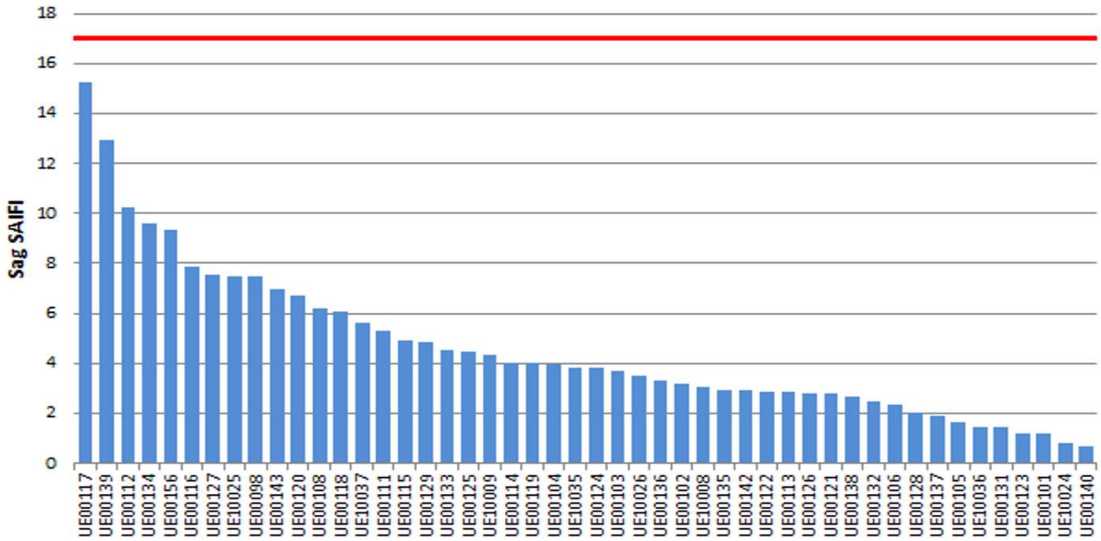
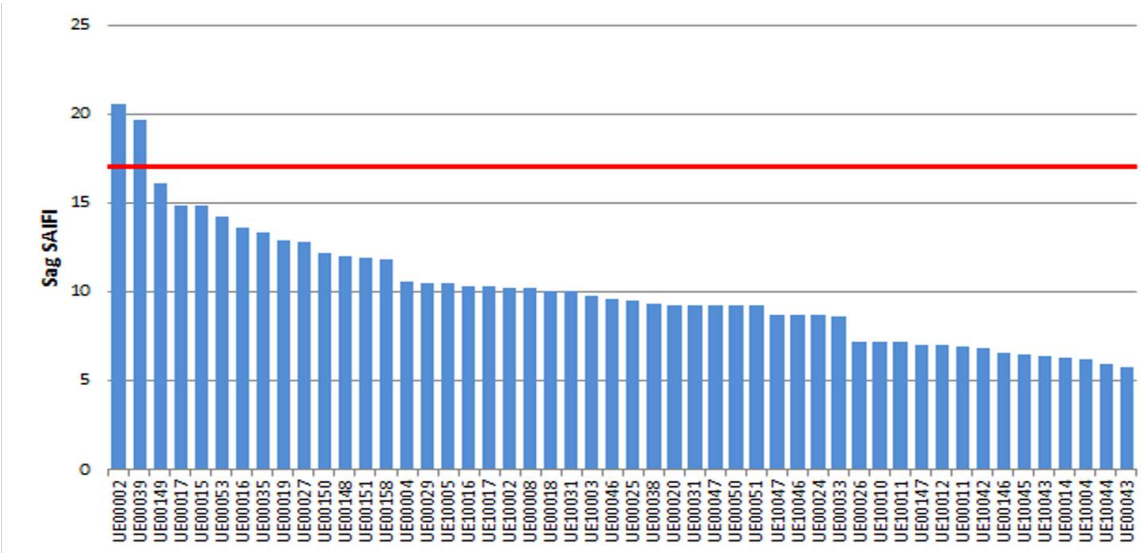


Figure 17.12 Voltage Sag SAIFI for MV sites during FY2021-22



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

[19] The index used in the PQCA reports to assess 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.

17.4.6 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.

As described in 17.4.1 above in June 2021, United Energy implemented an enhancement to its DVMS algorithm which allows United Energy to lower voltages under light load and high solar PV export times when higher voltages occur while not impacting peak demand times. This has resulted in a further step up in the upper limit steady state voltage compliance. It should be noted that a number of United Energy's zone-substation transformers are now reaching their tapping limit at certain times, meaning that they are unable to lower voltages down any further without some form of augmentation.

Management of Rooftop Solar PV

The Victorian Government is in the fourth 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 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 a greater amount of solar PV systems and their export. 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.

Also as mentioned in 17.4.1, during 2022, United Energy worked with manufacturers, installers, and customers that have identified issues, to rectify solar PV installations and

inverter setting non-compliance issues, and improve installation compliance going forward. This will be a continued focus going forward. Achieving near 100% installation compliance is crucial to maximising the amount of rooftop solar PV that can be accommodated on the network, while maintaining network-wide functional voltage compliance.

United Energy has now begun implementing its Solar Enablement program to increase the network's solar hosting capacity and improve voltage compliance in areas where there are limitations. This includes continuing our dynamic voltage management system initiative, changing the tap setting of distribution transformers, balancing the load on low-voltage circuits, applying smart inverter settings on legacy sites, and undertaking targeted augmentation works where it is least cost and has a net economic benefit for customers. In 2022 United Energy has undertaken rectification works at over 115 sites (as at the end of November 2022) benefiting 8,000 customers. United Energy plans to ramp up these works further in 2023 with a bulk transformer tap setting and augmentation work program to be completed in early 2023.

United Energy commissioned a Local Generation Connection Approval tool (LGCA) that went live in June 2022. LGCA is a pre-approval tool used by customers when applying for new solar PV connections. At the pre-approval stage, customers input their requested export level for the site and PV system they are seeking to install and the pre-approval tool then assesses their allowable export level without causing constraints on the network.

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 any future 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.

17.5 Distribution losses

Distribution losses refer to the energy used in transporting itself across distribution networks. In 2019-20, 4.11 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 limitations. 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.

18 Embedded generation and demand management

This chapter sets out information on embedded generation as well as demand management activities during 2022 and over the forward planning period for this DAPR.

18.1 Embedded generation

18.1.1 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.[20] 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.

Further details on these matters are provided in Section 5.2.3 of United Energy's Demand Side Engagement Document[2] for further detail).

[20] For connection application greater than 5 MW.

18.1.2 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 fast enough to keep pace with market developments and the introduction of new technologies (especially in the area of energy storage). As a result, an industry-wide initiative to bridge these gaps is underway, but these developments will take time to filter through. Energy Networks Australia (**ENA**) has published guidelines for connection of distributed energy resources 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 proponents 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 limitations to proponents have been challenging 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 proponents and their capabilities. Consequently, the timeframe it takes to close out an application is varied and can extend up to several months.

18.1.3 Quantitative summary of connection application to connect EG units

The table below provides a quantitative summary of the connection enquires under chapters 5 and 5A of the NER and applications to connect EG units received between 1 July 2021 and 30 June 2022.

Table 18.1 Summary of embedded generation connections during FY 2021-22

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
Description	**Quantity (>= 30kW and < 5MW)**
Connection enquires under 5A.D.2	113
Applications to connect received under 5A.D.3	154

18.2 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 limitations associated with maximum 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 several years and is keen to actively increase the implementation of non-network solutions over the forward planning period for this DAPR.

18.2.1 Network Support Agreements in recent 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 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.

United Energy has also committed to 5 more years for the implementation of a 13 MW 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.

The required demand-side solution is reviewed in June of each year to determine total amount required for upcoming summer. Due to an increase in the numbers solar panels installed in the lower Mornington peninsula, total required demand side solution has been reduced to 11 MW.

18.2.2 Demand Management Innovation Allowance initiatives

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 2016-20 regulatory control period, United Energy was allocated $400,000 per annum in the AER's regulatory determination ($2 million over five years) as an ex-ante allowance under the DMIA. In our forward planning period we encourage non-network service providers approach United Energy (Refer to Chapter 9 of United Energy's Demand Side Engagement Document[2] for further detail) to enquire about future 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;
- 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 (BESS)

In 2020, United Energy successfully installed and commissioned two 30kW/75kWh low-voltage BESS units. The first BESS unit was installed under Highett-Nicol substation on the 28th February 2020 and the second unit was installed on the 2nd May 2020 under Sylvia-Bluff substation. Both BESS units have now completed more than 10,000 operational hours.

The pilot project was the first low-voltage, grid-connected, pole-mounted BESS installation in Australia. The project successfully demonstrates the feasibility of installing BESS systems on the low-voltage network, to address immediate capacity shortfalls and defer traditional network augmentation solutions.



Figure 18.1: LV grid side BESS installed at Highett

In 2021, United Energy partnered with ARENA to expand the project from a pilot to a trial project by installing 40 additional BESS units across United Energy's distribution network, to have a combined capacity greater than 1.0 MW. United Energy has also partnered with Simply Energy to test the market benefits. The design and construction of the first advanced unit has been completed, with the roll-out of a new prototype in April 2022. Learnings from this new design has allowed UE to lockdown the design and commence

production of the remaining 39 units. UE are planning to have 10 units commissioned by February 2023, and the remaining 30 units fully operational by October 2023.



Figure 18.2: First UE BESS unit installed at Mount Waverley

It is expected that going forward, the grid-side BESS can be taken into consideration as an option for addressing overloaded distribution substations and low-voltage circuits, to address asset failures, outages, enable solar PV exports onto the network, and used as an economic alternative to traditional network augmentation.

Summer Saver Program

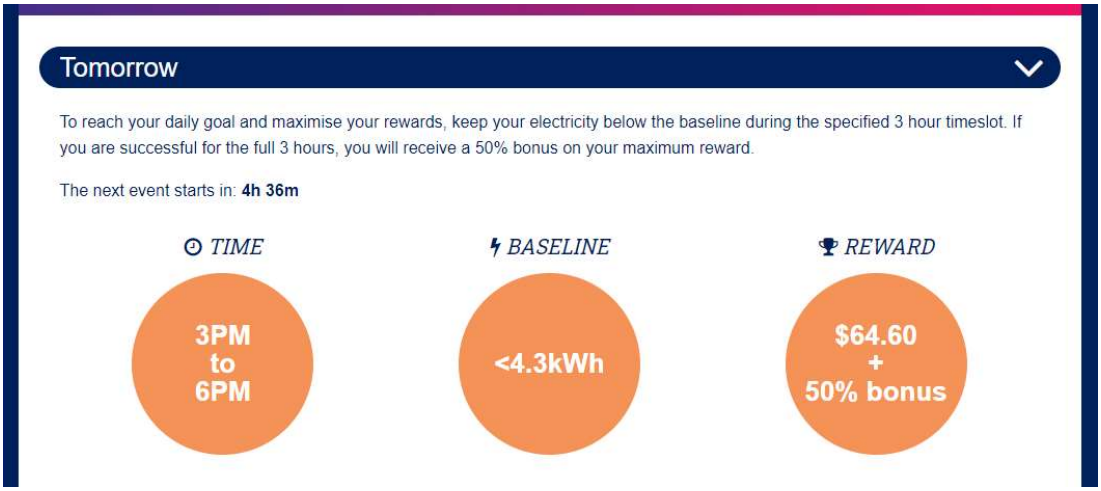
The Summer Saver program is a behavioural demand response program that incentivises customers to reduce their power usage during times of maximum demand. The Program targets constrained areas with highly utilised distribution transformers and low-voltage circuits that are at an elevated risk of overload 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.

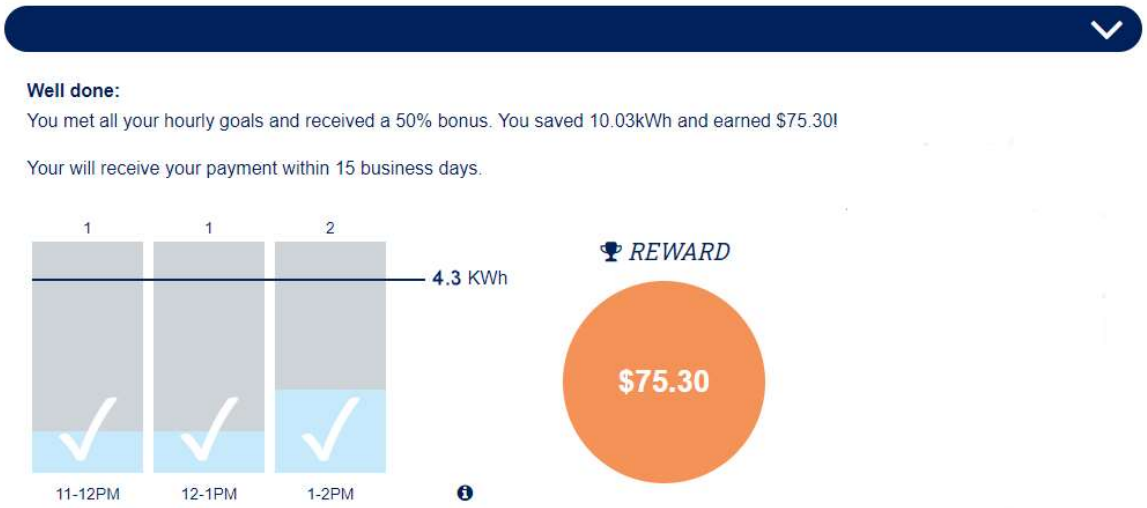
Once registered, participants are requested to voluntarily reduce their power usage on a small number of hot weather ‘event days’, which typically are on weekdays over the summer period. Customers are notified at least two days in advance of an ‘event day’ so they could plan how to reduce their energy consumption. Customers who successfully lower their energy consumption below their allocated baseline during the event are rewarded.

Figure 18.2 Summer Saver Program Customer Portal Screenshots

Before Event



After Event



The Summer Saver Program utilises the capabilities of the Advanced Metering Infrastructure to encourage customer participation and engagement whilst lowering implementation costs.

1,270 customers registered for Summer Saver Program in summer 2021-22 which is an uptake rate of approximately 6% from a targeted customer base of 21,762.

United Energy called five events over summer 2021-22, with the event days falling on weekdays. United Energy noted 89% average participation rate per event. The total energy reduction across the program was 11 MWh. Customers earned $28 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 35 distribution substation and 178 low-voltage circuit limitations for summer 2022-23. Refer to Sections 10.3 and 18.3 for more details.

18.3 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 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 potential businesses could provide non-network services across multiple areas.
- As of 30th October 2022, United Energy has 162 individuals from 120 registered organisations on our DSE Register.[21]
- United Energy notified all registered participants on our DSE Register of non-network opportunities identified in our 2021 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 2021 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. Several formal external non-network proposals were submitted however they were found to be more expensive than the United Energy Summer Saver demand management program. This demand management program will be deployed this summer to 35 capacity-constrained distribution substation and 178 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 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.

[21] The Demand-Side Engagement Form for interested parties to register at is available on the United Energy website at https://www.unitedenergy.com.au/demand-side-engagement-form

- 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 limitation 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 ENA Network Opportunity Maps (**NOM**) which are online interactive investment and limitation maps, aiming to identify the most valuable locations to invest in renewable energy, demand management and battery storage.
- United Energy participated in a feasibility study, led by Powercor and in partnership with 12 community energy groups and local councils, CitiPower, and supported by the Department of Environment, Land, Water and Planning (DELWP) through the Neighbourhood Battery Initiative (NBI) program. This study aimed to identify opportunities for neighbourhood batteries and develop supporting information to assist community groups who are looking to explore a neighbourhood battery project. The outcomes of the study included the proposal of a potential program of battery projects to DELWP, i.e., the Powerful Neighbours Report[22], a comprehensive guideline for future battery projects as well as a series of animations to improve community and customer understanding of neighbourhood batteries.
- Through the feasibility study, it was also identified that there is an interest from community energy groups, local councils, research organisations and DELWP in having a greater understanding of their local distribution network. Investigation has commenced regarding how this information may be shared with these stakeholders, with a prototype network visualisation tool being trialled with NBI partners. This mapping tool would also be able to demonstrate the locations and scale of network opportunities which may be addressed by non-network solutions.

18.4 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.

[22] https://media.unitedenergy.com.au/reports/12011-Powercor_Powerful-Neighbours-Report-and-Guide_WEB_FA.pdf

- Inviting all registered participants on our DSE Register to a public forum to be held in early 2022 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.
- 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 Chapter 5 of United Energy's DSE 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.

18.5 Demand side engagement document and register

United Energy updated its published DSE Document in July 2019. The document 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 DSE Document is available from:

https://media.unitedenergy.com.au/factsheets/UE-PL-2202-Demand-Side-Engagement-Document.pdf

United Energy has also established and updated its DSE Register since 2013. To register as an interested party on the DSE Register, applicants should fill out their details on United Energy's website at:

https://www.unitedenergy.com.au/demand-side-engagement-form

19 Information Technology and Communication Systems

This chapter discusses the investments we have undertaken in 2022, or plan to undertake over the forward planning period for this DAPR 2023-2027, relating to Information Technology (**IT**) and communications systems.

19.1 Security program

With a continuously evolving cybersecurity threat landscape, we continue investing in our cyber capabilities to enable us to protect our network and our customers. Our on-going cyber security program of works introduces increasingly sophisticated processes and systems that proactively prevent, detect, respond to, and recover from security threats that have the potential to disrupt the operation of the distribution network and our services.

Through our Cybersecurity strategy, we have delivered uplift programs to email, identity and cloud security. We have also completed a transformational program to uplift our 24 x 7 Security Operation Center (**SOC**) as well as our Security Incident and Event Management (**SIEM**) system.

Our 2023 program will continue to deliver on further maturing our web, identity, and operational technology (**OT**) cybersecurity posture.

Our current cyber security strategy will be fully delivered by 2025. We will continue to align our security strategy and initiatives with relevant industry standards such as Australian Energy Sector Cyber Security Framework (**AESCSF**), and authorities such as Australian Signals Directorate (**ASD**) / Australian Cyber Security Centre (**ACSC**) to ensure that controls implemented are consistent with recognised Australian and international best practices. Our program of work will meet the compliance requirements for the Security of Critical Infrastructure Act (**SOCI**) 2018 and the associated Risk Management Program (**RMP**) Cyber and Information Security Hazard rules.

19.2 Currency

We routinely undertake system currency upgrades across our IT systems to reflect 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 current.

In 2022, we began the following upgrades:

- Distribution Management System (**DMS**) upgrade – this included upgrading our current DMS to improve resilience and currency and enable advanced DMS capability to ensure effective management of the network continues;
- Telephony refresh – this includes an upgrade of our existing system which is nearing its end of life to deliver a more resilient platform to avoid the risk of incidents to the system.

During the forward planned period for this DAPR we will continue to maintain the currency of our systems. Upgrades expected in the forward planning period include:

- Market system upgrade – uplift capability of market systems applications, which support market transitions and data to be provided to the market.

19.3 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 reflect the changing energy market. We ensure compliance through prudent investment in systems, data, processes, and analytics that provide the requisite functionality and reporting capability to efficiently comply with statutory and regulatory obligations.

This year we implemented Phase 2 of the five-minute settlement program which included:

1) preparedness and readiness for the installation of 5-minute enabled meters by 1 December 2022;

2) ensuring AMI meter fleet installed after 1 December 2018 are configured to collect and send data in 5-minute intervals by 1 December 2022. Key Phase 2 changes include:

- Upgrading of all key metering applications to be five-minute settlement compliant;
- Ensure all required meters are collecting, storing, and processing data in five-minute intervals.

This wider 5MS program, included enhancing storage to handle significantly more data and changes to system architecture (e.g. Market Transaction System, Itron Enterprise Edition UIQ, Salesforce, SAP) as well as business and operational processes (e.g. billing, contract centres, reporting, network, advanced metering infrastructure (AMI) operations and network analytics).

This year we also updated our key market systems to:

- Deliver three new trial tariffs designed in consultation with external stakeholders and the Victorian Government to support the rapidly changing energy market;
- Update the structure of B2B transactions in line with the B2B 3.7 procedure changes to improve communication between market participants;
- Improve our MSATS Standing Data in line with the determination arising from AEMO's MSATS standing data review;
- Update our systems to facilitate AEMO's Global Settlement approach for retail market settlements;
- Enhanced our systems to support two sets of Industry Change Forms (ICF) arising from market participants and AEMO identifying market processes that require correction or improvement.

In the forward DAPR planning period, we will continue to implement compliance projects as these arise. We will also continue to amend our system and data controls to ensure customer, employee and asset data remains hosted in Australia.

19.4 Infrastructure

We have an increasing need to store and recall data, as well as support applications, processes, and functions across our IT systems. To support this, we must ensure our IT infrastructure remains technically current, meets relevant security requirements, and meets our service level requirements to our customers and energy markets.

During 2022, we established new applications, supported by cloud-hosted infrastructure, while retaining our existing infrastructure on premise.

This included:

- Deploying additional storage and data backup infrastructure to accommodate growing data volumes;
- Migrated from a NetBackup data protection solution to a new Commvault solution to provide a more secure and cost-effective data protection solution for critical United Energy data;
- Refreshed critical network infrastructure to ensure that we are on a fully supported solution, have the capacity to accommodate increasing network traffic volumes and ensure that our network devices are able to have security patches applied to protect against cyber-attacks;
- Upgraded our cloud connectivity to accommodate the growing number of applications hosted on public cloud infrastructure;
- Upgraded server infrastructure to ensure that we operate on fully supported solutions and have the capacity to accommodate increasing application demands and ensure that our servers are able to have security patches applied to protect against cyber-attacks;
- Completed the rollout of a new Windows 10 image, including providing new laptop devices to many users. The new Windows 10 solution includes an "always on" remote connectivity solution to seamlessly connect and simplify the remote working experience.

During the forward planning period for this DAPR, we will continue to upgrade our infrastructure to ensure we have sufficient ongoing capacity, performance and system availability to ensure continuity of distribution services to our customers. We will also undertake a program for gradually migrating some of our existing on-premises IT infrastructure to cloud hosting.

We have also initiated a program to consolidate the United Energy IT infrastructure into the Victorian Power Networks (**VPN**) data centres to achieve efficiencies and cost savings for both organisations.

19.5 Customer enablement

Customer enablement incorporates our response to ongoing changes and demands from our customers for greater access and greater choice in their distribution services.

Outage communications is one of the most important services we provide to customers. In 2022, we improved the planned outage notification process for our customers, including providing more options around the mediums for communication to better reflect our customer preferences. The initiative included the implementation of a new customer portal design as a virtual front counter that is destined to become a single log-in one stop shop for customers to access our online services. These improvements were reflective of the Essential Services Commission's final decision on the Electricity Distribution Code requirements in relation to planned outages.

In 2022 we also completed the following key technology initiatives:

- We digitised the capturing of customer reported faults; tracking of progress and rectification of these. This improves the user experience as customers are kept informed of the progress and closure of their claim;
- We implemented a new customer connections online portal to manage connections and customer project related requests and enquiries. This project was focused on improving the customer experience to manage the customer requests by saving customers hours annually in submitting, tracking and reviewing their requests.

We are currently undergoing a refresh of our customer strategy to ensure our future priorities are still appropriate and emerging themes and customer needs have been considered, keeping in mind the fast pace in which the energy system is evolving.

19.6 Becoming a more digital network

Australia is supporting the uptake of local low carbon technologies such as roof top solar, home and community batteries and electric vehicles. We also want to support greater customer choice and provide the flexibility for greater independence in their energy usage decisions.

The implementation of a strategic network analytics capability in 2019-20 has allowed us to implement in 2021 an active and dynamic voltage management solution across United Energy's network which allows greater uptake of rooftop solar whilst maintaining system security on high demand days. This was further refined in 2022 along with other technology investments to assist with analysis and reporting on solar compliance obligations and improve the solar approvals connection processes.

2022 also saw the implementation of a number of pole top network batteries which will trial a third-party facing interface to enable other market participants access to network assets to participate in market services such as frequency control ancillary services (**FCAS**) and energy arbitrage.

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats. In 2022, we trialled making network

performance information available to a selected set of trial external users using a visualisation tool that is used within the business.

Over the forward planning period we will continue the Digital Network journey by focusing on enhancing asset data models, network granularity and forecasting, data quality, and analytics to further improve how we manage the network. The aim to develop a "Digital Twin" capability that will support the changing role of the distribution network. Specific initiatives include:

- Development of Dynamic Operating Envelope (**DOE**) methodologies based on AMI and other sensor data to determine how best to implement DOEs and guide investment requirement for ubiquitous integration in the future;
- Trial an implementation of DOEs for commercial customers and residential customers to improve overall solar hosting capacities;
- Implement a first generation operational forecasting capability along with a complete digital network model from Terminal Station (transmission connection) to the customer connection;
- Expand the visualisation of network performance to more community groups and entities.

19.7 Field 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 2022, we have focused on the following:

- Started replacement of 3G devices in readiness for the shutdown of the Telstra 3G network in 2024;
- Commenced selection of MPLS technology to ease capacity issues on some sections of united energy's optical fibre network;
- Continued replacement of legacy copper services, for zone substations at Mornington Peninsula, with more modern and reliable National Ethernet services enabling reliable SCADA telemetry across all the United Energy zone substations;
- Deployment of communications infrastructure for 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.

Old communications systems will continue to be retired and replaced with newer up-to-date systems, addressing technical obsolescence where:

- the manufacturer no longer supports the equipment which can no longer be upgraded; and
- there is a reduced pool of skilled workers able to maintain the system.

We continue to modernise systems that are dependent on communications systems such as remote communications devices presently using the Telstra 3G Cellular network, such as Automatic Circuit Reclosers, Gas Switches and remote controlled HV switches, to 4G and 5G. United Energy will also be investing in MPLS technology to increase capacity to meet the future network needs.

20 Advanced metering infrastructure benefits

This chapter 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. AMI technology is also being leveraged in our digital network initiatives presented in section 19.6 above.

20.1 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 by 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 customers 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 their 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.

20.2 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 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 the 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 such as rooftop solar PV, 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 customers with solar PV connections that are not registered as solar PV 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 within 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.

20.3 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.

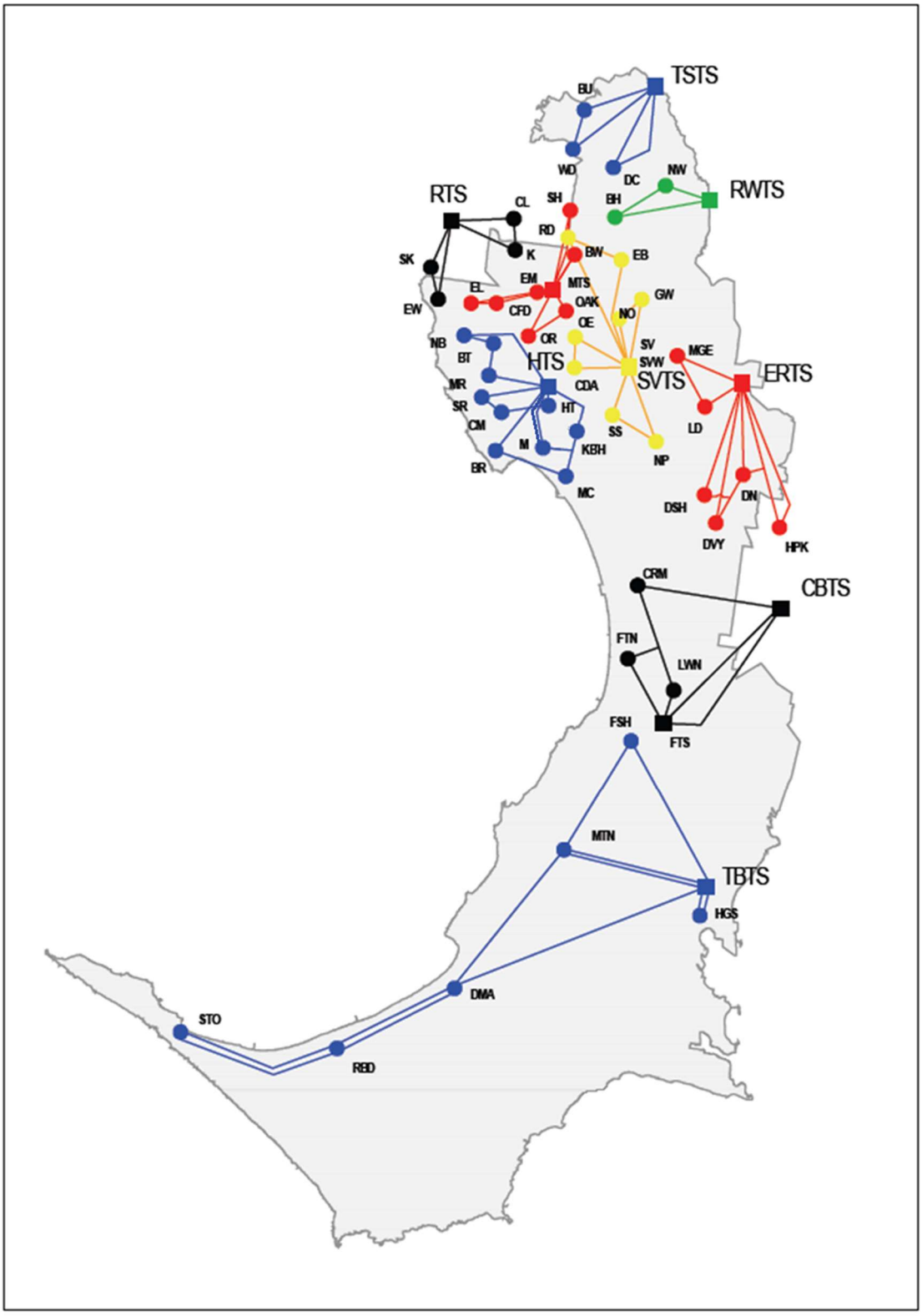
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality

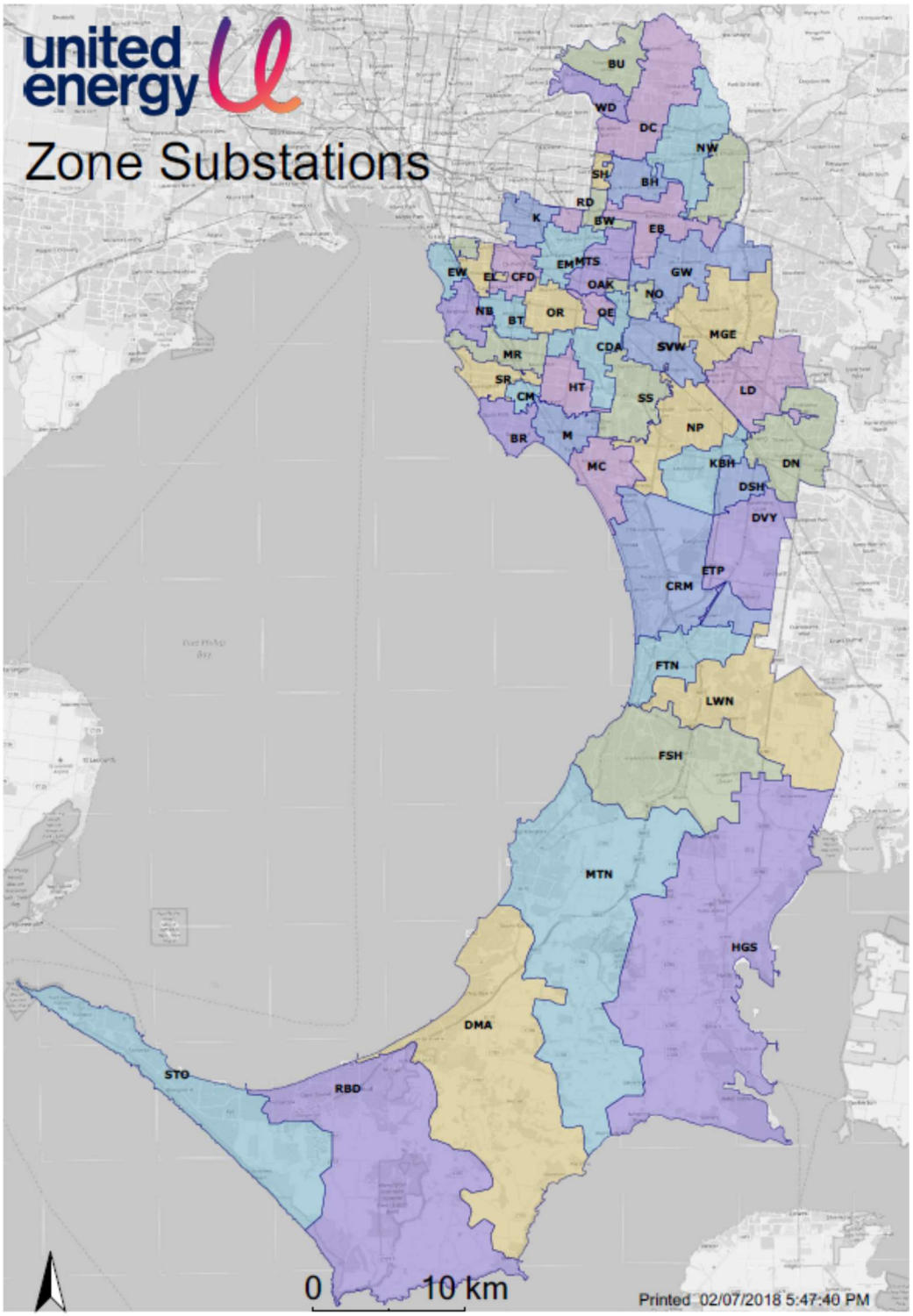
of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. We have enhanced the AMI architecture to provide an engineering user interface for customer power quality information, and to facilitate investigations into poor power quality performance. The interfaces 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 loss of 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 improved voltage management.

Appendix A Network maps




united energy
Zone Substations
BU
WD
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MTS
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CRM
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FSH
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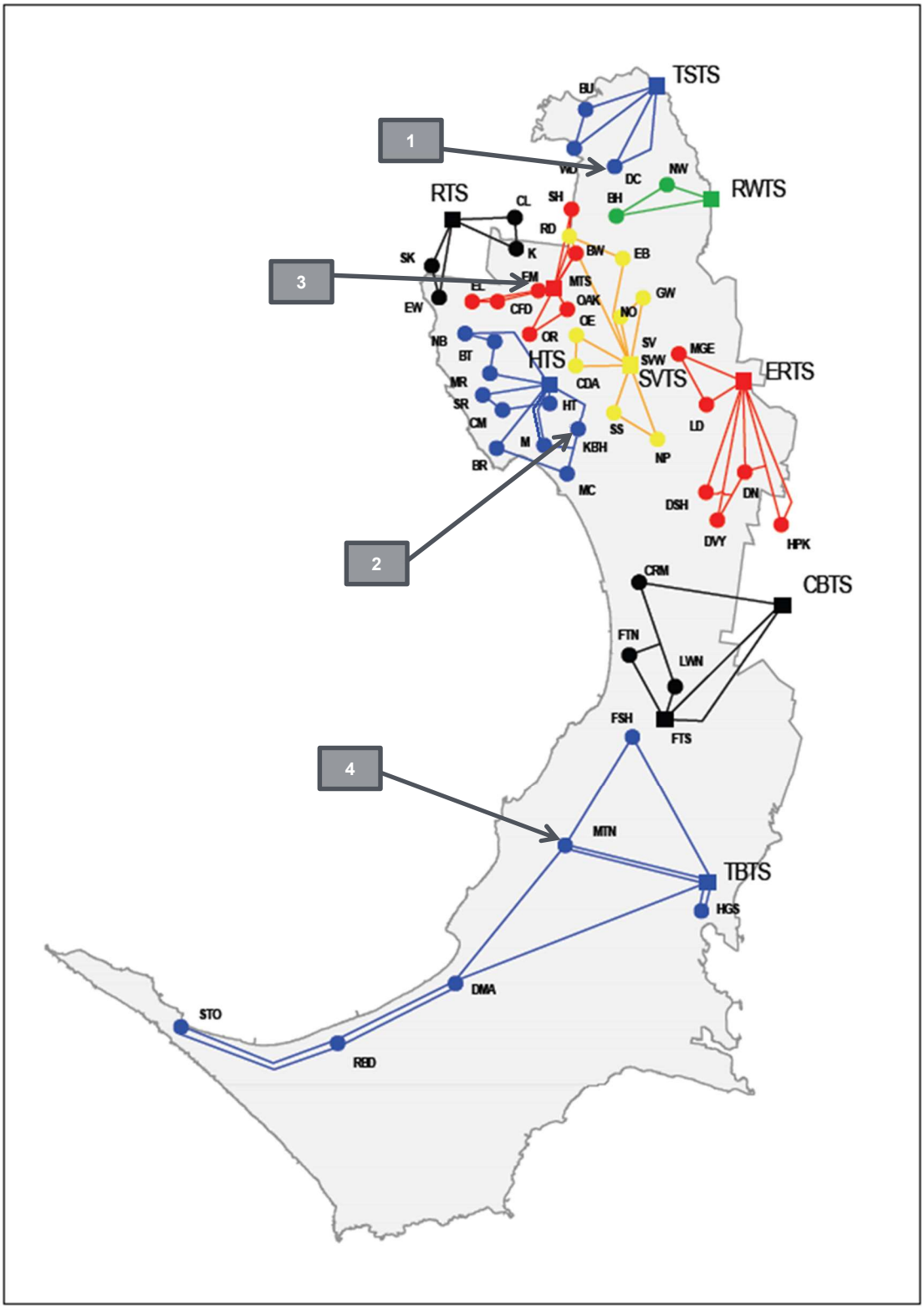
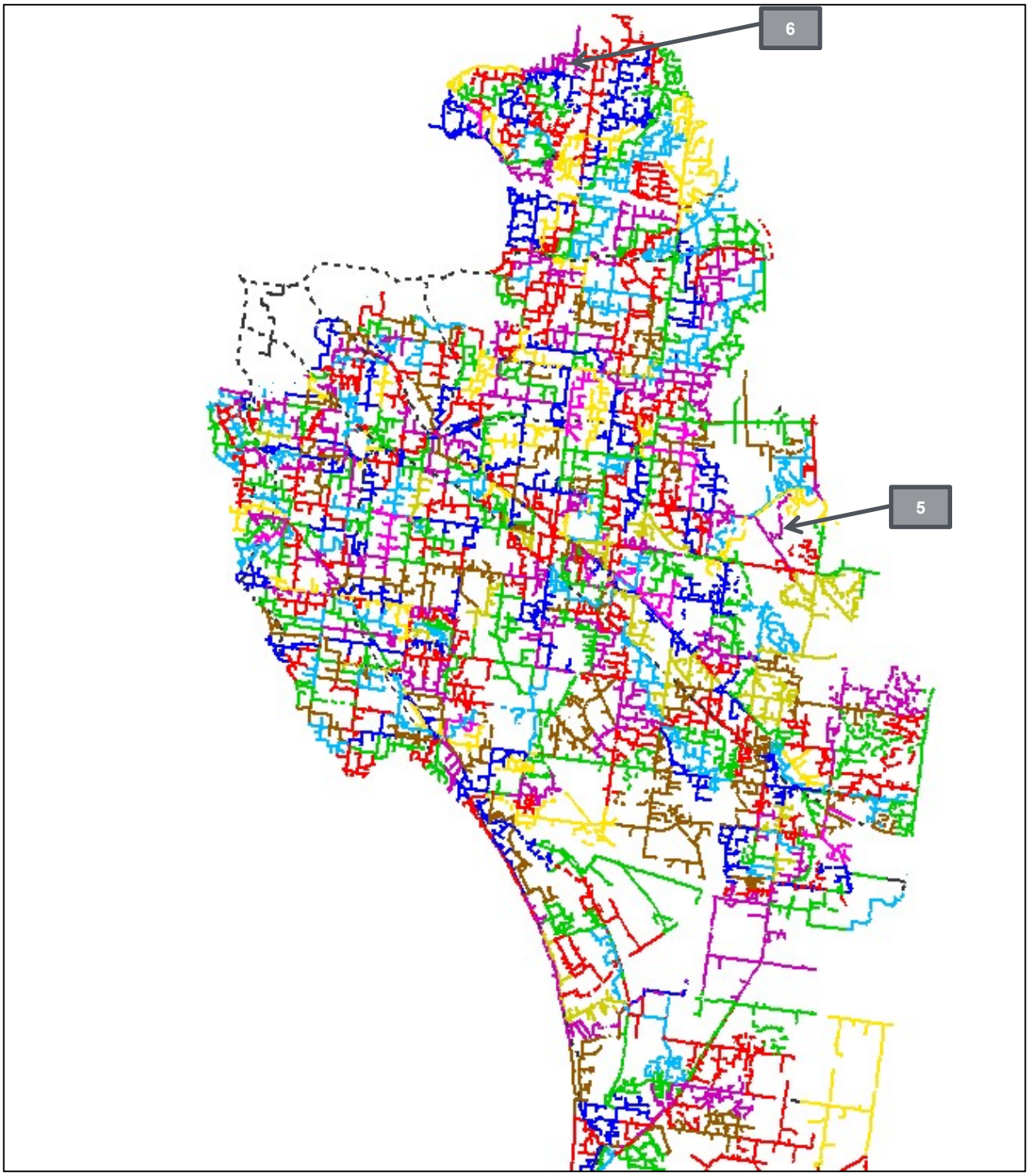
Appendix B Maps with forecast system limitations

Table 1.1 sets out numbering for the limitations in the maps below. Note this sequence also aligns with the System Limitations Template.

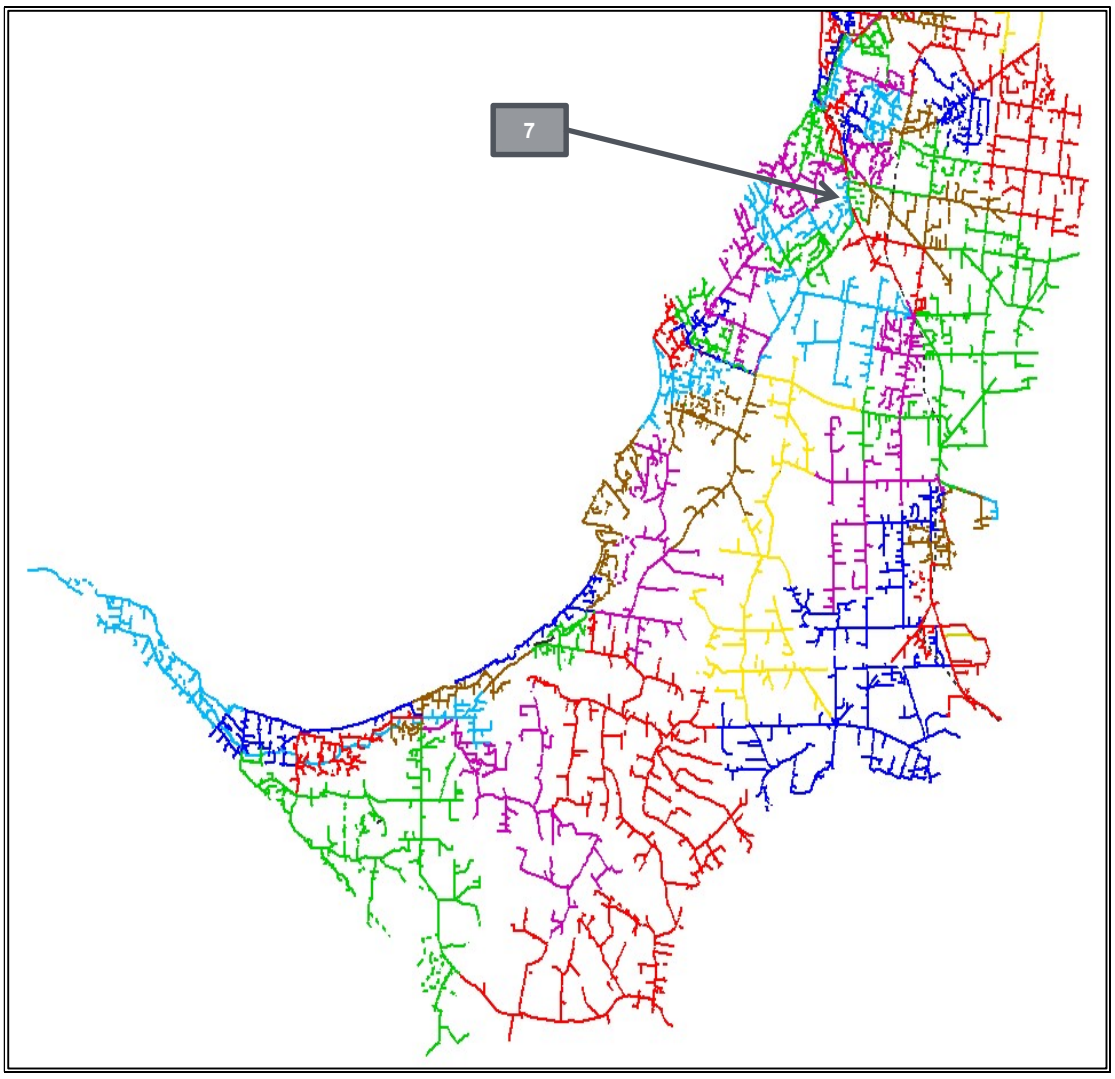
B.1. Zone-substation and sub-transmission limitations (Augmentation)



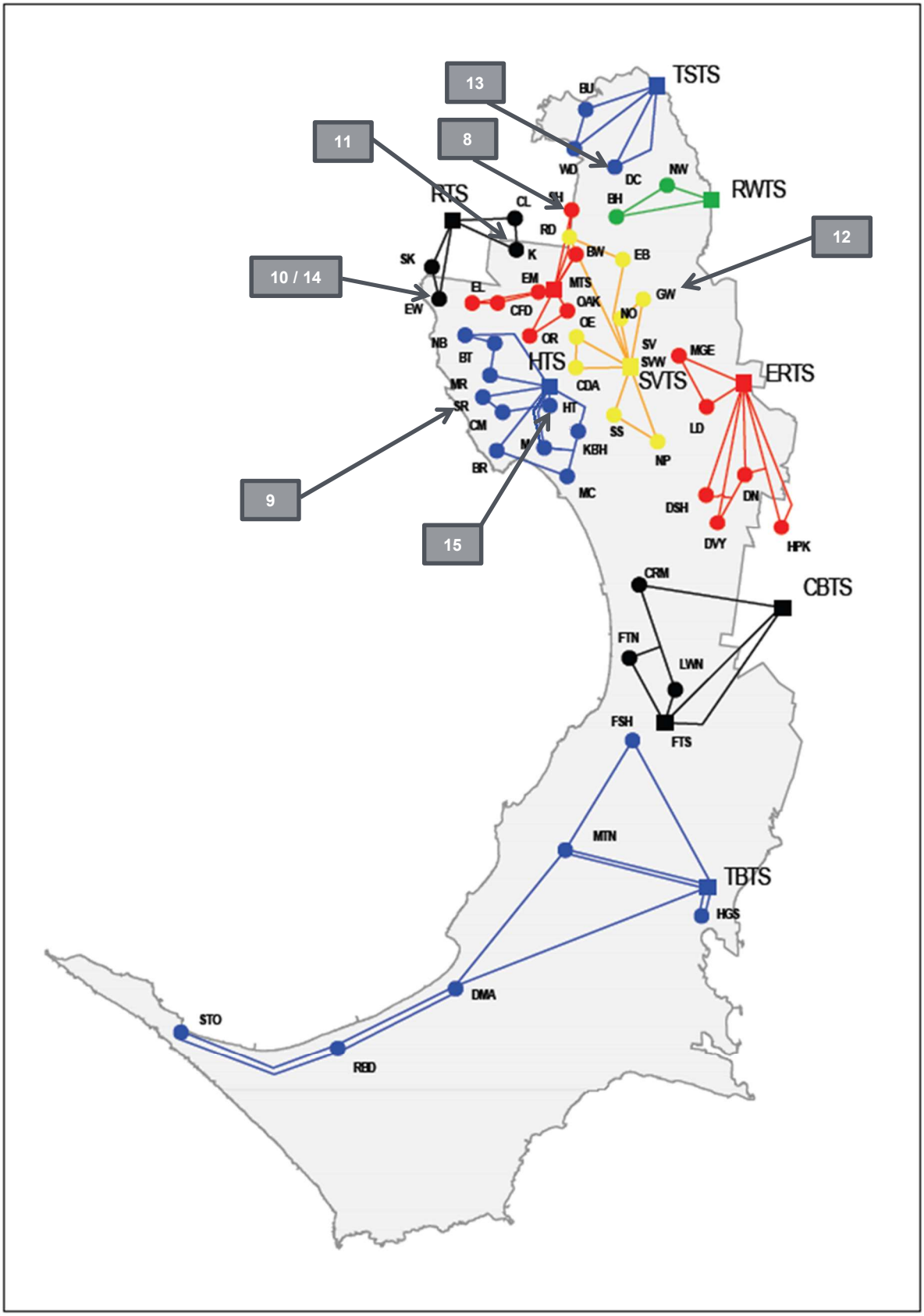
B.2. Distribution feeder limitations in northern part of network (Augmentation)



B.3. Distribution feeder limitations in southern part of network (Augmentation)



B.4. Zone-substation transformer and switchgear limitations (Replacement)



Appendix C Maximum demands – zone substations

The tables below set out the forecasts for maximum demand for each United Energy zone substation and their import capacity. These forecasts are used to identify potential future limitations in the network.

Please note that the availability of load transfer and generation capacity at maximum demand times cannot be guaranteed.

Zone Sub	Station N Import Rating (MVA)	Station N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Station Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
BH	107.7	71.8	1	1.00	22.4	7.2	46.8	53.0	54.7	56.5	59.0	59.3	-	-
BR	61.6	30.8	5	0.99	8.0	8.4	26.7	30.8	31.1	30.9	31.3	31.5	-	-
BT	61.0	30.5	5	1.00	5.0	7.1	30.0	31.7	32.1	31.8	32.1	32.4	4.1%	1.2
BU	69.0	34.5	10	0.99	7.2	8.0	27.8	32.8	33.3	33.0	33.5	33.9	-	-
BW	37.8	25.2	12	0.99	4.2	7.3	21.0	25.3	25.5	25.3	25.5	25.7	0.6%	0.1
CDA[23]	59.2	25.7	17	0.95	9.2	6.0	22.0	29.7	31.1	32.2	33.2	33.3	15.8%	4.0
CFD	82.6	41.3	6	0.99	12.2	7.6	49.7	57.1	58.2	58.5	59.1	59.3	38.2%	15.8
CM	60.9	30.5	25	1.00	4.3	2.3	21.8	25.0	26.6	27.9	28.7	29.0	-	-
CRM	110.3	73.5	3	1.00	17.8	36.2	75.2	85.3	86.8	87.1	88.6	89.0	16.1%	11.8
DC	108.6	72.4	6	1.00	21.2	22.4	74.6	93.1	95.8	98.3	102.2	103.2	28.6%	20.7
DMA	89.6	44.8	3	1.00	25.1	16.6	34.5	44.2	45.2	45.7	46.8	47.2	-	-
DN[24]	126.2	84.2	4	1.00	0.0	30.2	67.0	82.6	83.4	83.5	84.8	85.4	-	-

[23] Based on the relocatable transformer rating.

[24] Demand data shown in table excludes large metered embedded generation.

Zone Sub	Station N Import Rating (MVA)	Station N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Station Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
DSH	144.8	96.6	19	0.99	19.7	6.0	60.1	65.6	66.3	65.8	66.5	67.0	-	-
DVY	131.1	87.4	34	0.97	15.4	18.5	77.4	82.4	83.2	82.4	83.3	83.9	-	-
EB	100.9	67.2	4	1.00	15.6	16.7	50.8	60.4	61.5	61.5	62.2	62.4	-	-
EL	66.1	33.0	13	1.00	8.9	4.5	30.0	35.5	36.1	36.4	37.3	37.5	7.7%	2.5
EM	62.4	31.2	8	1.00	6.7	8.4	31.0	36.1	36.4	36.0	36.3	36.5	15.7%	4.9
EW	56.8	28.4	14	0.99	3.2	3.4	20.3	25.5	25.7	25.6	25.9	26.1	-	-
FSH	92.0	61.3	8	1.00	20.7	16.9	59.2	66.6	67.3	67.0	67.7	68.4	8.6%	5.3
FTN	90.4	45.2	8	1.00	21.4	26.2	44.1	55.3	56.2	56.0	57.0	57.3	22.3%	10.1
GW	103.2	68.8	14	0.99	18.6	18.9	58.6	72.2	73.1	73.7	75.0	75.3	5.0%	3.4
HGS	77.7	38.9	7	1.00	12.7	21.5	41.4	49.7	50.2	50.1	50.8	51.3	27.8%	10.8
HT	92.1	61.4	12	1.00	26.4	10.5	45.5	50.1	51.4	51.4	52.3	52.7	-	-
K	73.2	36.6	6	1.00	9.4	5.3	36.4	45.1	45.7	45.8	46.6	47.0	23.3%	8.5
KBH	45.8	0.0	5	0.96	36.6	14.0	25.4	36.6	38.4	40.4	42.6	43.1	100%	36.6
LD	100.2	66.8	13	0.99	26.3	19.3	44.9	53.8	54.3	54.1	54.9	55.2	-	-
LWN	90.0	45.4	5	0.96	26.7	18.1	40.2	50.4	51.3	51.4	52.3	52.5	11.0%	5.0
M	79.0	52.6	7	0.99	4.6	9.5	34.2	41.4	41.8	41.8	42.3	42.6	-	-
MC	82.3	54.9	9	0.94	16.3	16.9	53.1	59.9	60.6	60.8	62.0	62.5	9.1%	5.0
MGE	111.6	74.4	18	1.00	26.3	23.2	71.8	83.3	84.5	84.9	86.1	86.7	11.9%	8.9
MR	78.7	39.3	6	1.00	13.7	12.0	43.9	52.9	53.7	53.7	54.3	54.7	34.7%	13.6
MTN	91.6	45.8	8	1.00	19.2	26.7	57.5	68.1	68.8	68.5	69.3	69.9	48.7%	22.3
NB	90.4	45.2	4	1.00	10.7	7.5	40.7	47.3	47.8	47.8	48.6	49.0	4.6%	2.1
NO	109.6	73.0	21	0.99	7.1	11.3	36.2	43.0	44.9	46.1	47.2	47.4	-	-

Zone Sub	Station N Import Rating (MVA)	Station N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Station Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA)	Actual Summer Maximum Demand (MVA)	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
NP	105.9	70.6	12	1.00	21.0	21.6	48.2	58.7	59.2	58.8	59.3	59.5	-	-
NW	132.4	88.3	11	1.00	22.3	18.5	55.9	66.0	66.7	66.6	67.3	67.9	-	-
OAK	85.7	42.8	15	1.00	7.4	8.0	35.0	41.1	41.5	41.3	42.0	42.2	-	-
OE	62.3	31.1	18	0.99	4.8	3.5	14.0	16.7	16.8	16.8	17.2	17.2	-	-
OR	64.2	32.1	4	0.97	5.9	9.2	31.2	37.6	38.0	38.3	39.8	40.6	17.1%	5.5
RBD	91.2	45.6	3	1.00	16.2	16.7	36.8	44.6	45.3	45.3	45.9	46.4	-	-
SH	22.2	11.1	4	0.98	0.0	1.7	6.6	7.9	8.0	7.9	8.0	8.0	-	-
SR	67.7	33.9	5	1.00	11.8	7.4	29.5	34.2	34.8	35.1	35.6	35.8	0.9%	0.3
SS[24]	79.9	39.9	1	1.00	0.0	34.0	32.2	39.7	40.1	39.9	40.4	40.5	-	-
STO[24]	72.0	36.0	1	1.00	13.3	13.8	37.6	43.2	43.9	44.2	45.2	45.6	20.1%	7.2
SV/SVW	159.4	120.0	15	0.99	24.6	21.3	87.5	101.8	105.0	106.0	109.2	109.6	-	-
WD	93.7	62.4	4	0.99	4.4	5.9	47.6	58.3	59.7	60.1	60.9	61.6	-	-

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 limitations in the network.

Please note that the availability of load transfer and generation capacity at maximum demand times cannot be guaranteed.

Loop	Loop N Import Rating (MVA)	Loop N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA) 2022/23	Actual MVA	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
CBTS 66 kV														
CBTS-CRM-FTN-LWN-FTS-CBTS	249	184	4	0.95	35.1	71.2	162.4	189.8	193.4	193.6	197.3	198.2	3.2%	5.9
ERTS 66 kV														
ERTS-DSH-DVY-DN-HPK-ERTS[24]	441	339	7	0.95	22.5	63.5	243.5	277.1	279.8	278.3	281.8	283.8	-	-
ERTS-MGE-LD-ERTS	239	128	11	0.95	41.8	41.2	118.6	139.3	141.1	141.4	143.3	144.3	8.8%	11.3
HTS 66 kV														
HTS-KBH-M/MC-BR-HTS	231	145	5	0.95	64.8	48.8	130.7	146.2	149.0	150.7	154.3	155.6	0.8%	1.1
HTS-MR-BT-NB-HTS	242	118	8	0.95	11.7	26.6	114.3	131.6	133.2	133.0	134.7	135.7	11.5%	13.6

Loop	Loop N Import Rating (MVA)	Loop N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA) 2022/23	Actual MVA	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
HTS-SR-CM-HT-HTS	184	128	12	0.95	34.0	20.2	103.5	116.9	120.7	122.4	124.8	125.7	-	-
MTS 22 kV and 66 kV														
MTS-CFD-EL-EM-MTS	270	134	9	0.95	13.8	20.5	108.7	126.5	128.4	128.6	130.4	131.0	-	-
MTS-OR-OAK-MTS	158	82	7	0.95	13.2	17.2	63.5	75.5	76.3	76.4	78.5	79.4	-	-
MTS-SH-MTS	19	14	2	0.95	4.2	1.7	6.5	7.9	7.9	7.9	8.0	8.0	-	-
MTS-BW-MTS	39	27	7	0.95	4.2	7.3	18.6	22.5	22.7	22.4	22.6	22.8	-	-
RTS 66 kV														
RTS-EW-SK-RTS[24]	143	86	1	0.95	8.2	4.6	66.5	89.3	91.6	89.3	88.3	89.3	4.2%	3.3
RTS-K-CL-RTS	202	99.5	17	0.95	13.7	10.4	85.1	104.1	106.5	105.0	103.9	104.3	4.7%	4.6
RWTS 66 kV														
RWTS-BH-NW-RWTS	209	120	8	0.95	36.4	25.7	101.0	117.1	119.4	121.1	124.2	125.0	-	-
SVTS 66 kV														

Loop	Loop N Import Rating (MVA)	Loop N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA) 2022/23	Actual MVA	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
SVTS-EB-RD-SVTS	194	109	3	0.95	18.6	22.6	85.9	117.8	118.4	116.2	115.6	116.2	8.5%	9.2
SVTS-GW-NO-SVTS	240	128	11	0.95	14.6	30.1	94.3	114.7	117.4	119.2	121.6	122.1	-	-
SVTS-NP-SS-SVTS[24]	206	109	3	0.95	33.3	55.5	86.7	112.8	113.8	113.1	114.2	114.6	3.9%	4.2
SVTS-OE-CDA-SVTS	115	65	12	0.95	13.9	9.5	35.8	46.2	47.7	48.8	50.0	50.2	-	-
SVTS-SV-SVW-SVTS	254	128	7	0.95	24.6	21.3	88.5	103.0	106.2	107.2	110.5	110.9	-	-
TBTS 66 kV														
TBTS-HGS-TBTS	171	91	7	0.95	12.7	21.5	41.9	50.4	50.9	50.7	51.4	51.9	-	-
TBTS-FSH-MTN-DMA-TBTS	408	229	2	0.95	24.1	60.2	223.2	240.3	243.6	243.8	247.6	249.9	4.8%	11.0
TBTS-DMA-MTN[25]	236	128	2	0.95	10.9	43.3	117.6	142.7	145.2	146.0	148.9	150.4	11.4%	14.6

[25] Sub loop limitations of TBTS-FSH-MTN-DMA-TBTS loop.

Loop	Loop N Import Rating (MVA)	Loop N-1 Import Rating (MVA)	Hours load is 95% of Maximum Demand	Power Factor at Maximum Demand	Load Transfer Capability (MVA) 2022/23	Embedded Generation Capacity (MVA) 2022/23	Actual MVA	10% PoE Forecast Summer Maximum Demand (MVA)					% Import Above N-1 Import Rating 2022/23	MVA Import Above N-1 Import Rating 2022/23
							2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		
TBTS-DMA-TBTS (voltage collapse)[25]	120	0	2	0.95	10.9	16.6	107.6	130.5	133.0	134.6	135.1	136.7	100%	130.5
DMA-RBD-DMA[25]	138	70	2	0.95	11.7	16.7	81.6	91.5	92.9	93.2	94.9	95.8	30.1%	21.2
RBD-STO-RBD[25]	114	57	2	0.95	13.3	13.8	41.4	47.5	48.2	48.6	49.7	50.1	-	-
TSTS 66 kV														
TSTS-BU-WD-TSTS	170	95	4	0.95	0.0	13.9	77.2	93.4	95.3	95.4	96.7	97.9	-	-
TSTS-DC-TSTS	201	101	3	0.95	21.2	22.4	79.8	99.6	102.4	105.1	109.2	110.3	-	-

Appendix E Minimum demands – zone substations

The tables below set out the forecasts for minimum demand for each United Energy zone substation and their export capacity. These forecasts are used to identify potential future limitations in the network.

Zone Sub	Station N Export Rating (MVA)	Station N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Station Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Annual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
BH	99.0	66.0	4.5	0.95	7.2	9.1	6.1	6.4	7.0	7.2	6.2	-
BR	60.0	30.0	1.5	0.93	8.4	2.8	1.9	1.2	0.4	-0.8	-1.8	-
BT	60.0	30.0	0.5	1.00	7.1	4.6	3.9	2.8	1.7	0.3	-1.5	-
BU	49.6	24.8	1.5	0.90	8.0	3.6	3.3	2.5	1.7	-1.2	-2.5	-
BW	29.8	19.9	1.5	0.63	7.3	2.3	0.6	-1.2	-2.1	-3.1	-4.3	-
CDA[23]	40.0	20.0	1.5	0.94	6.0	3.8	2.0	2.8	2.6	1.2	0.4	-
CFD	66.0	33.0	15.5	0.89	7.6	10.8	8.5	8.5	8.2	7.6	7.0	-
CM	53.8	26.9	8.0	0.96	2.3	3.6	0.6	0.8	1.0	1.0	1.0	-
CRM	78.8	52.6	1.0	0.98	36.2	11.5	8.5	7.4	6.6	4.4	1.6	-
DC	81.0	54.0	3.5	0.94	22.4	11.4	9.7	7.7	5.4	-1.6	-7.2	-
DMA	66.0	33.0	0.5	0.42	16.6	2.6	-0.4	-1.3	-2.3	-3.4	-4.4	-
DN[27]	99.0	66.0	1.0	0.93	30.2	9.1	6.1	3.6	2.0	-0.6	-3.5	-
DSH	103.2	77.4	8.0	0.96	6.0	9.6	6.6	6.6	6.6	7.4	7.4	-
DVY	99.0	66.0	0.5	0.80	18.5	4.9	2.5	1.9	2.0	1.9	1.1	-
EB	90.0	60.0	2.0	0.98	16.7	9.1	7.1	5.1	2.6	-0.6	-4.9	-

[26] Negative MVA indicates exporting active power, irrespective of the direction of the reactive power flow.

[27] Demand data shown in table includes large metered embedded generation.

Zone Sub	Station N Export Rating (MVA)	Station N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Station Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Annual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
EL	54.0	27.0	3.0	0.92	4.5	5.7	5.8	5.7	5.3	4.8	3.8	-
EM	54.0	27.0	0.5	0.97	8.4	6.7	5.1	4.7	4.2	3.7	2.9	-
EW	53.8	26.9	32.0	0.74	3.4	5.8	4.8	4.7	4.6	4.5	4.4	-
FSH	81.0	54.0	1.0	0.94	16.9	5.1	2.4	-1.9	-4.1	-6.0	-9.4	-
FTN	66.0	33.0	2.0	0.49	26.2	3.4	5.9	4.8	4.2	3.3	-3.4	-
GW	81.0	54.0	1.0	0.99	18.9	8.7	8.9	6.6	3.6	-2.2	-7.6	-
HGS	66.0	33.0	1.0	1.00	21.5	3.1	0.1	-1.5	-2.3	-3.2	-4.9	-
HT	81.0	54.0	1.0	0.96	10.5	5.9	4.6	3.9	3.0	1.9	-1.2	-
K	60.0	30.0	47.0	0.65	5.3	10.4	10.3	10.5	10.5	10.3	9.8	-
KBH	33.0	0.0	1.0	0.35	14.0	-2.8	-5.3	-6.9	-8.4	-10.1	-12.4	-
LD	90.0	60.0	2.0	0.92	19.3	3.8	0.8	-1.0	-2.7	-4.5	-7.1	-
LWN	66.0	33.0	1.0	0.62	18.1	2.2	-0.8	-1.6	-2.5	-3.3	-4.2	-
M	81.0	54.0	0.5	1.00	9.5	3.7	2.6	1.2	-0.5	-1.7	-3.3	-
MC	78.2	52.2	1.0	0.94	16.9	2.3	-0.7	-2.4	-0.7	-1.6	-3.1	-
MGE	99.0	66.0	1.0	0.90	23.2	8.3	5.3	3.0	-1.0	-5.4	-10.9	-
MR	66.0	33.0	1.5	0.93	12.0	7.3	5.2	3.9	2.3	0.7	-2.3	-
MTN	66.0	33.0	1.0	1.00	26.7	4.7	3.5	2.1	-1.3	-3.4	-5.7	-
NB	66.0	33.0	33.5	0.94	7.5	7.3	6.2	5.4	4.7	3.9	2.2	-
NO	90.0	60.0	1.0	0.97	11.3	8.9	9.9	10.3	10.6	10.2	9.8	-
NP	83.8	55.8	2.5	1.00	21.6	4.5	1.5	-0.5	-2.8	-5.6	-8.5	-
NW	99.0	66.0	5.5	0.97	18.5	7.5	4.5	2.0	-2.2	-5.3	-10.0	-
OAK	66.0	33.0	7.5	0.77	8.0	8.4	7.4	6.5	5.4	4.2	2.5	-
OE	56.1	28.1	1.0	0.99	3.5	2.0	1.7	1.2	-0.9	-1.5	-2.4	-

Zone Sub	Station N Export Rating (MVA)	Station N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Station Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Annual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
OR	54.0	27.0	1.0	1.00	9.2	3.6	2.9	2.0	1.1	0.2	-2.1	-
RBD	66.0	33.0	0.5	0.41	16.7	2.5	-0.5	-1.6	-2.8	-4.2	-6.2	-
SH	19.6	9.8	1.5	0.99	1.7	0.8	0.7	0.6	0.4	0.2	-0.1	-
SR	54.0	27.0	14.5	0.96	7.4	5.3	2.3	1.7	1.0	0.3	-0.8	-
SS[27]	66.0	33.0	0.5	0.88	34.0	-4.4	-7.4	-8.3	-9.3	-10.5	-12.1	-
STO[27]	53.3	26.6	0.5	0.81	13.8	2.3	1.4	-1.2	-2.7	-4.4	-6.0	-
SV/SVW	132.0	99.0	4.0	0.97	21.3	22.3	17.1	16.7	16.1	13.4	10.0	-
WD	81.0	54.0	0.5	0.96	5.9	8.2	8.8	7.6	6.1	4.8	3.5	-

Appendix F Minimum demands – sub-transmission lines

The tables below set out the forecasts for minimum demand for each United Energy sub-transmission line and their export capacity. These forecasts are used to identify potential future limitations in the network.

Loop	Loop N Export Rating (MVA)	Loop N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Loop Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
CBTS 66 kV												
CBTS-CRM-FTN-LWN-FTS-CBTS	249	190	9	0.95	71.2	25.4	18.4	15.4	13.0	9.2	-1.2	-
ERTS 66 kV												
ERTS-DSH-DVY-DN-HPK-ERTS[27]	441	339	1	0.95	63.5	27.0	7.6	4.6	3.1	0.9	-3.1	-
ERTS-MGE-LD-ERTS	239	128	4	0.95	41.2	12.3	7.3	3.3	-2.4	-8.7	-16.7	-
HTS 66 kV												
HTS-KBH-M/MC-BR-HTS	231	145	19	0.95	48.8	9.8	2.8	-2.5	-4.9	-9.7	-16.3	-
HTS-MR-BT-NB-HTS	242	118	20	0.95	26.6	21.3	15.1	12.0	8.6	5.1	2.9	-
HTS-SR-CM-HT-HTS	184	128	5	0.95	20.2	15.5	8.5	7.4	6.0	4.2	0.1	-
MTS 22 kV and 66 kV												
MTS-CFD-EL-EM-MTS	270	134	670	0.95	20.5	21.8	17.9	17.5	16.2	14.4	12.0	-
MTS-OR-OAK-MTS	158	82	3	0.95	17.2	10.8	9.3	7.5	5.6	3.4	2.0	-
MTS-SH-MTS	19	14	2	0.95	1.7	0.8	0.3	-0.1	-0.1	-0.5	-1.1	-
MTS-BW-MTS	39	27	11	0.95	7.3	2.2	0.8	-0.4	-0.3	-1.4	-3.1	-
RTS 66 kV												
RTS-EW-SK-RTS[27]	143	86	16	0.95	4.6	5.9	8.4	8.4	8.3	8.2	8.2	-
RTS-K-CL-RTS	202	99	222	0.95	10.4	18.0	14.9	16.0	15.8	14.9	14.1	-

Loop	Loop N Export Rating (MVA)	Loop N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Loop Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
RWTS 66 kV												
RWTS-BH-NW-RWTS	209	120	3	0.95	25.7	16.4	11.4	9.2	5.6	2.7	-3.0	-
SVTS 66 kV												
SVTS-EB-RD-SVTS	194	109	3	0.95	22.6	8.1	6.6	4.4	1.5	-2.4	-7.2	-
SVTS-GW-NO-SVTS	240	128	6	0.95	30.1	17.7	17.1	15.2	12.5	7.9	7.1	-
SVTS-NP-SS-SVTS[27]	206	109	11	0.95	55.5	1.7	-3.3	-6.2	-9.5	-13.5	-18.0	-
SVTS-OE-CDA-SVTS	115	65	23	0.95	9.5	5.9	2.8	3.1	2.3	0.3	-0.5	-
SVTS-SV-SVW-SVTS	254	128	3	0.95	21.3	14.9	17.1	16.7	16.1	13.4	10.0	-
TBTS 66 kV												
TBTS-HGS-TBTS	171	91	2	0.95	21.5	3.1	0.1	-1.5	-2.3	-3.2	-4.9	-
TBTS-FSH-MTN-DMA-TBTS	408	229	3	0.95	60.2	18.8	11.8	8.0	-6.6	-15.1	-25.8	-
TBTS-DMA-MTN[25]	236	128	1	0.95	43.3	8.1	3.0	0.8	-3.7	-6.8	-10.1	-
TBTS-DMA-TBTS[25] (voltage collapse)	120	0	1	0.95	16.6	2.6	-0.4	-1.3	-2.3	-3.4	-4.4	-
DMA-RBD-DMA[25]	138	70	1	0.95	16.7	4.8	-0.5	-1.6	-2.8	-4.2	-6.2	-
RBD-STO-RBD[25]	114	57	1	0.95	13.8	2.3	1.4	-1.2	-2.7	-4.4	-6.0	-
TSTS 66 kV												
TSTS-BU-WD-TSTS	170	95	4	0.95	13.9	11.9	10.7	8.6	6.2	4.2	5.1	-
TSTS-DC-TSTS	201	101	10	0.95	22.4	11.4	9.7	7.7	5.4	-1.6	-7.2	-

Appendix G Minimum demands - transmission-distribution connection points

The table below sets out the forecasts for minimum demand for each of United Energy's transmission-distribution connection points and their export capacity. These forecasts are used to identify potential future limitations in the network. Forecasts for shared stations ERTS, SVTS, and TSTS include the contributions of neighbouring distribution utilities as well. Forecasts for shared station RWTS are prepared by Ausnet Services and minimum demand forecasts for shared station RTS are prepared by Citipower. For more details, refer to the Transmission Connection Planning Report.

Station "N" export rating is determined based on transformer nameplate rating; and Station "N-1" export rating is determined based on transformer nameplate rating with an outage of one transformer. These ratings have not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of lower export ratings.

Terminal Station (Voltage level)	Station N Export Rating (MVA)	Station N-1 Export Rating (MVA)	Hours load is 95% of Minimum Demand	Station Power Factor at Minimum Demand	Embedded Generation Capacity (MVA) 2023	Actual Minimum Demand (MVA)[26]	10% PoU Forecast Annual Minimum Demand (MVA)[26]					% Export Breaching N-1 Export Rating 2023
						2022	2023	2024	2025	2026	2027	
ERTS 66 kV	600	450	1	-0.98	180.9	44.5	25.6	17.7	13.1	-21.6	-35.7	-
FTS 66 kV[28]	251	208	2	-0.98	87.5	21.8	11.9	8.3	4.8	-2.1	-7.0	-
HTS 66 kV	450	300	2	-0.99	86.7	43.4	25.7	14.3	6.5	-11.8	-26.7	-
MTS 66kV	450	225	39	-0.91	33.1	36.8	34.8	29.8	23.9	17.9	10.1	-
MTS 22kV	120	60	1	-0.74	9.4	3.0	1.0	-1.1	-1.9	-3.0	-4.4	-
RTS 66kV	675	450	17	0.97	29.8	52.4	61.1	73.6	86.0	86.0	84.4	-
RWTS 66kV	600	450	32	-0.99	167.6	53.3	19.7	3.8	-8.7	-24.1	-41.7	-
RWTS 22kV	150	75	2	-0.96	24.7	8.3	8.7	3.7	1.4	-2.3	-6.5	-
SVTS 66 kV	600	450	2	-0.98	125.0	69.4	37.6	27.2	16.6	-12.8	-31.1	-
TBTS 66 kV	450	300	2	-0.70	119.3	23.4	24.2	15.8	-9.2	-18.5	-29.9	-
TSTS 66 kV	450	300	2	-0.88	88.4	55.9	49.6	40.7	31.7	21.8	-22.8	-

[28] At FTS switching station, export ratings for subtransmission lines have been shown from the Transmission Connection Planning Report.

Appendix H Glossary and abbreviations

H.1. Glossary

Common Term	Description
N Cyclic Rating	The available capacity with all network elements 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 or "Firm" Rating	The available capacity assuming the most critical network element is out of service.
Import rating	Import ratings define the network capability to transfer forward power flows (i.e., flows downstream towards customer loads) at that location.
Export rating	Export ratings define the network capability to transfer reverse power flows (flows from that location upstream towards the transmission point of connection).
Maximum demand	The highest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak load, as seen by the network.
Minimum demand	The lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units (as seen by the network, in aggregate) for the year. This is also referred to as the peak supply, as seen by the network.
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 to load (for import conditions), or curtailed from generation (for export conditions) 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 10th percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.

H.2. Abbreviations

Common Term	Description
AAC	All Aluminium Conductor
ABC	Aerial Bundled Cable
ABS	Air-Break Switch
A.C.	Alternating Current
ACR	Automatic Circuit Recloser
ACS	Alternative Control Services
ACSR	Aluminium Conductor Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AFAP	As Far As Practicable
AMI	Advanced Metering Infrastructure
Amps (or A)	Amperes
AMP	Asset Management Plan
AMS	Asset Management System
ARENA	Australian Renewable Energy Agency
ASD	Australian Signals Directorate
BA	Boric Acid
BESS	Battery Energy Storage System
COWP	Capex / Opex Works Program
DAPR	Distribution Annual Planning Report
D.C.	Direct Current
DER	Distributed Energy Resources
DLA	Dielectric Loss Angle
DGA	Dissolved Gas Analysis
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelopes

DSE	Demand Side Engagement
DSO	Distribution System Operator
DVMS	Dynamic Voltage Management System
EDO	Expulsion Drop Out
EG	Embedded Generation
EMS	Environment Management System
ENA	Energy Networks Australia
ESC	Essential Services Commission of Victoria
ESMS	Electricity (Network) Safety Management System
ESV	Energy Safe Victoria
EUE	Expected Unserved Energy
EV	Electric Vehicle
FMECA	Failure Mode, Effects and Criticality Analysis
FPAR	Final Project Assessment Report
GIS	Geospatial Information System
HV	High Voltage
INMS	Integrated Network Management System
IT	Information Technology
kV	Kilo Volt (Voltage)
LV	Low Voltage
MAIFIe	Momentary Average Interruption Frequency Index event
MDP	Meter Data Provider
MoU	Memorandum of Understanding
MPLS	Multi-Protocol Label Switching
MS	Microsoft®
MV	Medium Voltage
MW	Mega Watt (Active Power)
MWh	Mega Watt hour (Active Energy)
MVA	Mega Volt Ampere (Apparent Power)
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NIST	National Institute of Standards and Technology

NOM	Network Opportunity Maps
NST	Neutral and Supply Testing
OHSMS	Occupational Health and Safety Management System
OLTC	On-Load Tap Changer
OMS	Outage Management Systems
OT	Operation Technology
PD	Partial Discharge
PF	Powder Filled
PoE	Probability of Exceedance
PoU	Probability of Under-reach
PV	Photovoltaic
RCGS	Remote Control Gas-insulated Switch
RCM	Reliability-Centred Maintenance
REFCL	Rapid Earth Fault Current Limiter
RIN	Regulatory Information Notice
RIT	Regulatory Investment Test (-D for Distribution, -T for Transmission)
RMU	Ring Main Unit
SAMP	Strategic Asset Management Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFRA	Sweep Frequency Response Analysis
SOC	Security Operations Capability
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TCPR	Transmission Connection Planning Report
VCR	Value of Customer Reliability
VEDCoP	Victorian Electricity Distribution Code of Practice
WLWS	Whole-Life Whole-System
XLPE	Cross-Linked PolyEthylene

H.3. 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

H.4. 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