Distribution Annual Planning Report

2021 – 2025

Issue number	8
Status	Approved
Approver	Tom Langstaff
Date of approval	21 December 2020

ISSUE/AMENDMENT STATUS

Issue Number	Date	Description	Author	Approved by
1	20/12/2013	2014-2018 Issue (First Issue)	M Wickramasuriya S Lees M Cavanagh	D Postlethwaite
2	19/12/2014	2015-2019 Issue	S Lees M Cavanagh	J Bridge
3	24/12/2015	2016-2020 Issue	M Wickramasuriya S Lees M Cavanagh	J Bridge
4	23/12/2016	2017-2021 Issue	M Wickramasuriya S Sao M Cavanagh	J Bridge
5	22/12/2017	2018-2022 Issue	M Wickramasuriya T Langstaff	J Bridge
6	27/12/2018	2019-2023 Issue	M Wickramasuriya J Pollock	T Langstaff
6.1	30/04/2019	Revision to 2019-2023 Issue to include geographic areas subject to a REFCL condition, as per Electricity Distribution Code V.9A (amended August 2018).	M Wickramasuriya J Pollock S Sao	T Langstaff
7	20/12/2019	2020-2024 Issue	J Pollock A Erceg S Sao	T Langstaff
7.1	13/01/2020	Updated RIT timeframes (Section 8.2) and other minor amendments including broken links	J Pollock A Erceg S Sao	T Langstaff
8	18/12/2020	2021-2025 Issue	J Pollock S Sao D Johnstone	T Langstaff

Disclaimer

Contact

This document is the responsibility of the Regulated Energy Services Division, AusNet Services. Please contact the indicated owner of the document with any inquiries.

Tom Langstaff
AusNet Services
Level 30, 2 Southbank Boulevard
Melbourne Victoria 3006
Ph: (03) 9695 6859

Table of Contents

1 Executive Summary

AusNet Services is a regulated Victorian Distribution Network Service Provider that serves approximately 740,000 customers. AusNet Services' distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area. This report, the Distribution Annual Planning Report 2021-2025, is prepared in accordance with the requirements of clause 5.13.2 and schedule 5.8 of the National Electricity Rules (NER).

The report includes a description of our network, asset management approach, planning and forecasting methods and forecasts, and a summary of demand management activities. It also provides information on the capacity of the network and system limitations for sub-transmission lines, zone substations and 22 kV feeders, along with the options being considered to address those limitations. Information on our planned asset replacement, retirement and de-rating works, along with our metering and information technology systems expenditure plans and our network performance and targets in the areas of power quality and reliability is also provided.

The report also covers obligations under the Victorian Electricity Distribution Code.

Information regarding planning for transmission to distribution connection points, required by clause 5.13 of the NER, is covered in the Transmission Connection Planning Report (TCPR)[1].

Within the five-year planning period, this Distribution Annual Planning Report identifies one zone substation and ten distribution feeders requiring demand driven augmentation, one new zone substation development, along with works at other existing zone substations, to achieve and maintain rapid earth fault current limiter (REFCL) compliance obligations, and seven zone substations required asset replacement works to maintain acceptable service levels over the next five-year period.

The report also outlines major network developments completed in the past twelve-month period, which included implementation of rapid earth fault current limiter (REFCL) technology at Ringwood North Zone Substation (RWN) and Woori Yallock (WYK), and as well as completion of a rebuild at the Yallourn Power Station 11 kV switchyard.

[1] A copy of the 2020 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet Services' website: AusNet - Rosetta Data Portal (ausnetservices.com.au)

2 Introduction

This Distribution Annual Planning Report 2021-2025 is prepared by AusNet Electricity Services Pty Ltd regarding its electricity distribution network and in accordance with the requirements of clause 5.13.2 of the National Electricity Rules[2].

2.1 Purpose

The purpose of this report is to describe AusNet Services' distribution network, explain the approach to network planning, provide forecasts for the forward planning period, describe constraints on the network and detail plans to address these constraints.

2.2 AusNet Electricity Services Pty Ltd

AusNet Services is a diversified energy infrastructure business that owns and operates the primary regulated Victorian electricity transmission network as well as an electricity distribution network in eastern Victoria and a gas distribution network in western Victoria.

AusNet Electricity Services Pty Ltd, a member of the AusNet Services' group of companies, holds an electricity distribution licence in Victoria issued by the Essential Services Commission (ESC) in October 1994. The licence authorises AusNet Electricity Services Pty Ltd to distribute electricity in its distribution area subject to certain conditions. These include requirements that AusNet Electricity Services Pty Ltd:

- Provide specified distribution services to electricity users within the distribution area, including connection services, services to other distributors and public lighting services.
- Offer to enter into a use of system agreement for the use of its distribution network on request by a retailer.
- Comply with codes and guidelines issued by the ESC including the Victorian Electricity Distribution Code (EDC), which regulates the provision of distribution services and connection to AusNet Electricity Services Pty Ltd.'s distribution network by electricity users.

Revenues derived from AusNet Electricity Services Pty Ltd.'s distribution network are regulated by the Australian Energy Regulator (AER) in accordance with the National Electricity Rules (NER) and other jurisdictional obligations set out in the Victorian Electricity Industry Act 2000.

AusNet Electricity Services Pty Ltd is obliged to comply with the NER and is also required to meet the technical requirements of the Electricity Safety Act 1998.

Hereafter, AusNet Electricity Services Pty Ltd will be referred to as AusNet Services.

[2] A copy of the National Electricity Rules can be found at the Australian Energy Market Commission's website: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

3 Electricity Distribution Network

This section presents an overview of AusNet Services' electricity distribution network, in accordance with the requirements of schedule 5.8 (a) of the National Electricity Rules.

3.1 Network Location

AusNet Services operates and manages an electricity distribution network serving the fringe of the northern and eastern Melbourne metropolitan area and the eastern half of rural Victoria (see Figure 1) delivering electricity to approximately 740,000 consumers.

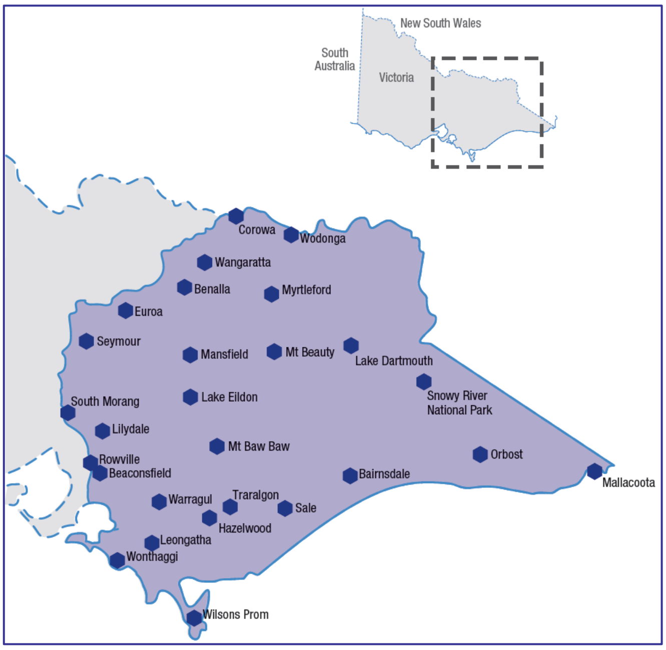


Figure 1: AusNet Services' Electricity Distribution Network

AusNet Services' distribution network is split into three regions, Central, East and North, as shown in Figure 2 below.

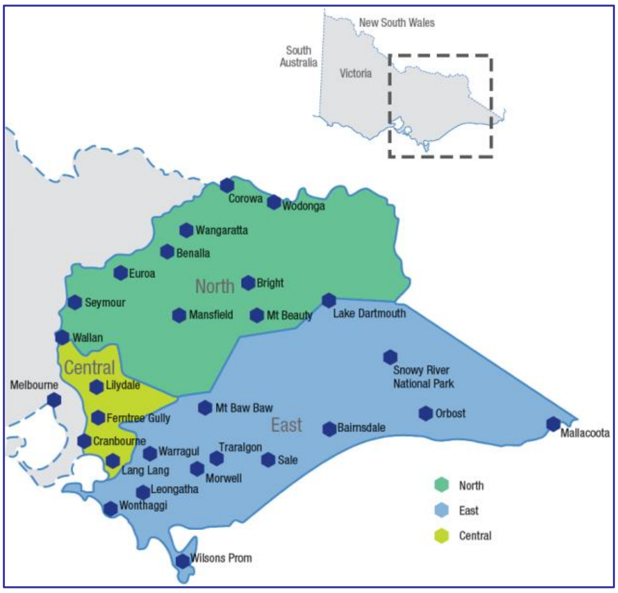


Figure 2: AusNet Services' Service Delivery Regions

The distribution network is in a climate which is classified as temperate. The network area does not span across different classifications of climate.

The distribution network is located in areas where the average annual rainfall ranges from 600 mm to 1,200 mm. Some parts of the network in the Northern and Eastern regions are affected by flooding hazards. Approximately 35% of all network feeders have some parts in flood hazardous areas.

Approximately two-thirds of the distribution network is in areas designated as Bushfire Prone.

There are around 370 distribution feeders, of which 14% are classified as Long Rural, 42% are classified as Short Rural and 44% are classified as Urban. A large proportion of feeders supply low density (lot sizes > 2000 m^2) customer areas. Twenty-nine percent of distribution feeders have less than ten customers per kilometre of line length. Customers supplied in these areas amount to 16% of the total customers served by AusNet Services.

The electricity network comprises a 'sub-transmission' network that consists of predominantly overhead lines that operate at 66 kV, and a 'distribution' network, which generally operates at a voltage of 22 kV and consists mainly of overhead lines but also includes underground cables. Some customers in remote and low population density rural areas are supplied by Single Wire Earth Return (SWER) Medium Voltage (12.7 kV) distribution networks. Most customers are supplied by Low Voltage reticulation via distribution transformers.

3.2 High Voltage Sub-Transmission Network

The sub-transmission network is supplied at eleven connection points from the Extra High Voltage (500 kV, 330 kV, 275 kV and 220 kV) transmission network that is owned and operated by AusNet Transmission Group Pty Ltd.

The sub-transmission network consists of overhead electricity lines operating at 66 kV, which are generally formed in loops fed from individual terminal stations. Although more interconnections have recently been established, these sub-transmission loops are generally not interconnected except under abnormal or emergency conditions. The loop configuration serves to maximise the reliability of the sub-transmission network by providing most zone substations with at least two sources of supply.

The length of each 66 kV sub-transmission loop depends on the proximity of the load centres to the terminal stations. The sub-transmission network has been developed over many years and therefore incorporates differing technologies, design standards, and plant and equipment types. As a result of these variations in the network, it has differing supply capacities. The capacity of each network loop is determined by numerous factors, including:

- Design working temperature
- Design of the particular network (which may impose loading or operational constraints)
- Thermal loading under outage conditions
- Voltage stability under outage conditions
- Conductor size and type
- Plant and equipment ratings.

Zone substations are generally supplied from more than one incoming 66 kV line, which are connected to the buses via circuit breakers. Within the zone substation, the incoming supply is transformed via one or several 66/22 kV transformers, ranging in size from 5 MVA to 33 MVA, and typically connected in parallel, unless separated to manage fault current levels to within regulatory and asset limits, or to manage rapid earth fault current limiter (REFCL) sensitivity required to meet compliance on total fire ban (TFB) days. The 22 kV windings of the transformers are usually 'star' connected and earthed directly or via a Neutral Earthing Resistor (NER) or a REFCL to limit the phase-ground fault current. Most zone substation power transformers are equipped with on-load tap changing (OLTC) facilities to provide automatic control of the operating voltage. Additional reactive power support is provided by capacitor banks installed at most zone stations.

3.3 Protection

Protection of the sub-transmission system is achieved by a combination of current and voltage transformers, circuit breakers and protection devices arranged in schemes, which monitor the voltages and currents for abnormal conditions and initiate disconnection of supply in accordance with pre-established protocols. Protection schemes include:

- Distance
- Differential
- Over Current
- Earth Fault
- Residual Over Voltage/Neutral Displacement.

- Under / Over Voltage and Under Frequency to initiate Load Shedding.

The protection applied to the sub-transmission network is duplicated and coordinated with that at the terminal stations, other zone substations and associated distribution network feeders. As per the existing industry practice, bare conductor overhead lines are fitted with automatic reclose facilities to minimise the impact of transient faults.

3.3.1 Earthing

Plant and equipment within the sub-transmission network employ local earthing whereby each piece of electrical equipment and conductive structure is directly connected to the general mass of earth via a dedicated earth connection. The 66 kV networks are referenced to earth via the connection transformers within the transmission network, which have their 66 kV winding star-points connected directly to the respective terminal station earthing grids.

The sub-transmission network is an 'effectively' earthed system. In the event of a fault to earth on this network the earthing assets enable the flow of electricity to the general mass of earth, under such circumstances that step, touch and transfer voltages are managed, fire ignition is minimised and electrical protection systems operate to limit network damage.

3.4 Medium Voltage Distribution Network

The 22 kV distribution network is currently supplied by fifty-seven zone substations, which are located near to the load centres. Additionally, three terminal stations supply 22 kV distribution feeders. Three 22/6.6 kV step-down substations supply the Mount Dandenong area via three 6.6 kV feeders. The Latrobe Valley power stations and mines are in part supplied via dedicated substations.

The Medium Voltage (MV) distribution network consists of approximately 370 feeders. These feeders predominately operate at 22 kV, with three 6.6 kV feeders supplying the Mt. Dandenong area and a further seven 6.6 kV and two 11 kV feeders supplying the coal fired power stations, associated mines, and support workshops within the Latrobe Valley. A total of approximately 463 customers are partly served by feeders from adjacent Distribution Network Service Providers, one United Energy feeder (NW13) and two Essential Energy (EE) feeders (TRC01 and BOM8M3[3]).

Distribution feeders are generally operated in radial mode. In urban areas they can often be operated in open-loop arrangement via switches installed to provide alternative points of supply and thus improve the reliability of the network.

In rural areas, the average feeder length is 156 km (including spurs) with few alternative points of supply. Distribution feeders are usually three-phase, but some spur lines, especially in rural areas, are single-phase supplied from two of the three available phases.

Remote and low population density rural areas are often supplied by Single Wire Earth Return (SWER) MV distribution networks. AusNet Services over 500 SWER networks. The SWER networks are supplied from two phases of the three-phase network via an isolating transformer, which provides the appropriate voltage transformation, regulation, and electrical isolation between the two networks. The SWER networks operate at 12.7 kV, with most overhead lines constructed using 3/2.75 mm steel conductor.

3.4.1 Distribution Substations

Distribution substations are located throughout the MV distribution network and provide transformation from the 22 kV reticulation to the customer's nominal service voltage (230/400 V or 230/460 V).

They range in capacity from 10 kVA to 2000 kVA and are classified into the following major types:

- Pole Mounted
- Ground Mounted
- Kiosk
- Indoor.

Distribution transformers on the three-phase network have a delta-star winding arrangement with a common voltage rating of 22 kV/433-250 V, while those on a single-phase network generally have a centre point earthed

[3] AusNet Services identifies EE's BOM8M3 feeder as BM8B31, BM8B32 and BM8B33 feeders.

secondary winding and the voltage rating of 22 kV/250 V/500 V is common. Distribution transformers installed on the SWER circuits commonly have voltage ratings of 12.7 kV/250 V/500 V. The off-load voltage taps on each transformer are capable of delivering the nominal voltage standard of 230 V/400 V and 230 V/460 V within +10%/-6% at the customers' point of connection.

3.4.2 Protection

Protection equipment, including protective relaying schemes, in conjunction with circuit breakers, automatic circuit reclosers, sectionalisers and fuses are applied to the distribution system to:

- Ensure safety of the general public and electricity workers by minimising any hazardous step, touch or transfer potential by isolating the faulted section of the plant within the protected zone.
- Ensure service continuity by sectionalising faulted elements of the network from unaffected portions of the network and therefore minimise disruption to most customers.
- Minimise equipment damage.

3.4.3 Earthing

Within zone substations the star-point of the 22 kV windings are connected to the station earth grid, directly or via a neutral earthing resistor, and thus to the general mass of earth.

Metallic MV equipment frames, switch handles, cable screens, conductive structures (e.g. concrete poles), surge diverters, exposed metal parts containing or supporting the MV conductors, and all interconnected metallic parts, are directly connected to a local MV earth and thus to the general mass of earth. These earthing systems are designed to:

- Ensure correct functioning of the protection systems.
- Limit over-voltages during fault conditions.
- Manage step, touch and transfer potential in high risk and well frequented areas.
- Co-ordinate transfer voltages with other authorities' assets in the vicinity.

3.4.4 Rapid Earth Fault Current Limiter (REFCL)

AusNet Services is installing Rapid Earth Fault Current Limiter (REFCL) technology at twenty-two zone substations. The electrical protection technology is designed to minimise the fault current (energy) dissipated from phase to earth (wire to ground) faults on the 22 kV network to reduce the risk of fire ignition associated with network incidents. Implementation and testing by government of two different types of REFCL technology was completed at Kilmore South zone substation on a limited 40 km section of network in 2014. Based on a sample period of network fault data, analysis undertaken by the Government and CSIRO predict network fire related incidents associated with the nominated zone substations can be reduced by between 50-55%.

The Ground Fault Neutraliser (GFN) is a product that falls under the Rapid Earth Fault Current Limiter (REFCL) technology umbrella which reduces single phase to earth fault currents on a network. The GFN does this by using resonant earthing with an enhanced 'residual current compensation feature' that injects current into an arc suppression coil (ASC) at 180° out of phase with the residual fault current. The GFN instantaneously eliminates the large fault current, reducing it to under 25 A and then close to 0 A within 3 cycles or 60ms. Its operation causes the phase voltage of the faulted phase to be reduced to near earth potential (zero volts), whilst the healthy phases rise by 173%, nominally from 12.7 kV to 22 kV. The implication of higher voltages on the healthy phases means that implementation of the REFCL technology can require significant asset replacement investment to ensure that all assets are rated for the higher phase voltages that they would be exposed to under fault conditions.

AusNet Services is also in the process of commissioning a second REFCL technology, the Trench device developed by Siemens, at multiple sites within the distribution network. The Siemens Trench uses similar technology to the GFN and has proven successful at the test site, KLK.

3.4.5 Overhead Lines

There are approximately 415,000 poles supporting distribution and sub-transmission networks.

Most overhead lines utilise aluminium conductors, although copper was previously used and remains in service in some (generally older) areas. Steel conductors are predominantly utilised in rural (including SWER circuits) distribution areas.

The most common conductors used in the MV overhead network are; Steel Conductor (SC) – 3/2.75, Aluminium conductor steel-reinforced (ACSR) – 3/4/2.5, 6/1/2.5, 6/1/3.0, 6/1/3.75, 6/1/4.75 and 6/4.75/ 7/1.60 and All Aluminium Conductor (AAC) – 7/2.5, 7/3.0, 19/3.25,19/3.75, 37/3.75, 7/4.75 and 19/4.75.

High Voltage Aerial Bundled Cable (HV ABC) is utilised for some 22 kV lines in environmentally sensitive treed areas, such as the Dandenong Ranges, to mitigate fire risk and minimise the incidence of tree and bark related faults. The main sizes of HV ABC used on the networks are 35 mm^2 and 185 mm^2 with aluminium conductors and non-metallic screens. A new type of HV ABC has been introduced to improve reliability. The new type is the Light Duty Metallic Screened HDME sheathed HVABC. This is generally known as LD MS HVABC and the standard conductor sizes are 35 mm^2 Al & 185 mm^2 Al. These cables can be used as the standard form of construction for both new overhead HV and for replacement of bare overhead HV in AusNet Services HV distribution network.

AusNet Services has also trialled and introduced the Spacer Cable System as a standard MV cable system permitted for use on AusNet Services' distribution network. The 22 kV Spacer Cable System consists of three covered conductors which are separated using a 'Spacer' and the whole system is supported by a tensioned catenary (messenger) wire. Spacers are generally placed every 10-12 metres along the span hung on the messenger wire. This system is suitable for heavy tree areas including where tree overhang is present (56Ms). The standard conductor sizes are 35 mm^2 Al, 50 mm^2 Al & 150 mm^2 Al.

AusNet Services for the first time introduced a Hybrid Underground system during 2015. The hybrid system is a system which contains underground HV cables and where the existing substations, protection devices and low voltage network is left pole mounted and overhead. The hybrid system is an alternative supply arrangement in areas where the overhead medium voltage (22 kV, 11 kV or 6.6 kV) network is replaced with underground cable and where there is no space available to install kiosk substations. The standard conductor sizes are 35 mm^2 Al, 185 mm^2 Al, 240 mm^2 Al & 300 mm^2 Al and the cable types are standard underground cables.

3.4.6 Underground Lines

Approximately 2,500 km (route length) of medium voltage underground cables are utilised for distribution in new urban residential developments and where other circumstances may apply such as visual impact, vegetation management, etc. The cables have cross-linked polyethylene (XLPE) insulation, aluminium conductors and 3-core construction. The main sizes are 35 mm^2, 185 mm^2, 240 mm^2 and 300 mm^2. There are also significant quantities of HSL (Hochstadter type cable - Paper insulation, screen type and lead sheath on each core, steel wire armour) underground cables utilised in the underground distribution network.

3.4.7 Electric Line Construction (Codified) Areas

Amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013 introduced 1 May 2016 require any planned conductor replacement (1 kV to 22 kV) of four or more consecutive spans or any new medium voltage electric line to be constructed with insulated or covered conductor within codified areas.

The locations of medium voltage lines specified within the regulations are defined as those lines being within an "electric line construction area" (codified area). The codified areas within AusNet Services' franchise area are illustrated in Figure 3 (red shaded areas). Further information may be found in AusNet Services' "Bushfire Mitigation Plan – Electricity Distribution Network"

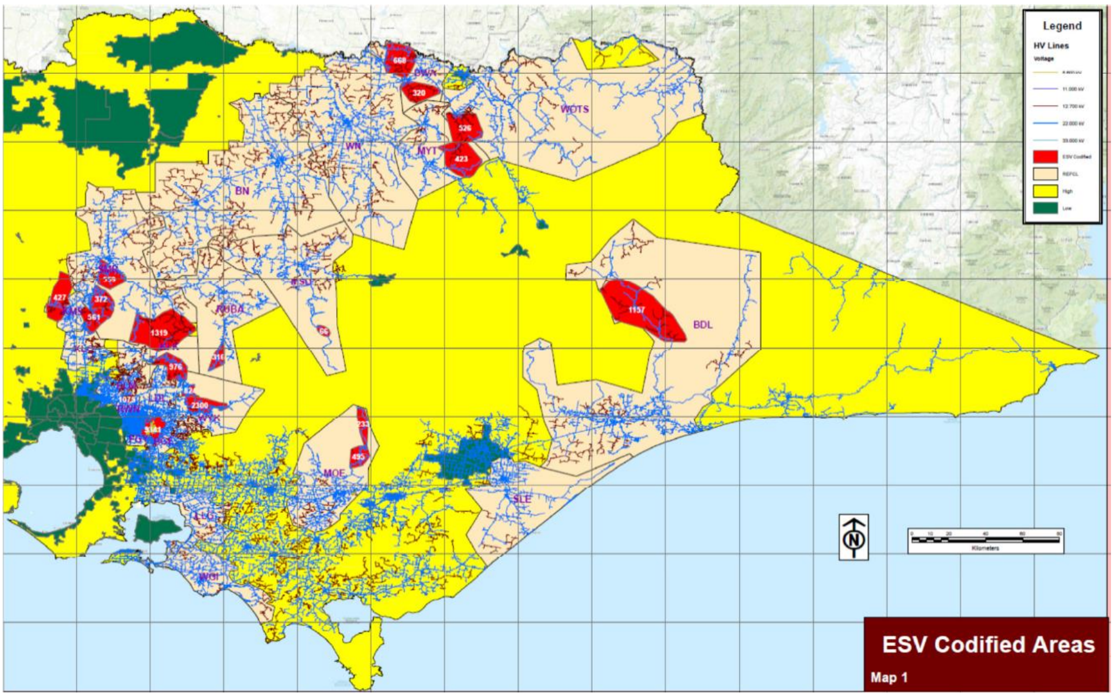


Figure 3: Codified Areas within AusNet Services' Franchise Area

3.5 Low Voltage Distribution Network

In urban and some rural locations reticulation at Low Voltage (LV) is utilised to supply small groups of customers. The LV lines are typically either three-phase (400 V) or two-phase (460 V) [with +10%/-6% voltage band] circuits with a neutral conductor. Insulated customer service cables are connected to these LV lines.

There is generally no permanent connection between adjacent LV circuits in urban areas although switching devices enable interconnections between some areas and load transfers in emergency conditions.

The LV overhead reticulation network consists of both open (bare) wire and insulated wire, Low Voltage Aerial Bundled Cable (LV ABC), construction.

- Bare Conductor – Most of the LV bare conductors are of aluminium construction; although, some copper is in service in older areas. Typically, the standard conductor utilised for LV reticulation is 19/3.25 mm all aluminium conductor (AAC); although, there are other types and sizes of conductors still in service that were utilised on the LV network in the past.
- LV ABC – LV ABC is cross linked polyethylene (XLPE) insulation over each of four aluminium cores. Typical conductor sizes are 95 mm^2 and 150 mm^2.
- LV Cable – LV underground cables are sized to suit the application but are generally 185 mm^2 and 240 mm^2 with aluminium conductors and XLPE insulation.

3.5.1 Protection

The LV network protection is provided by fuses or in some cases moulded case circuit breakers installed on the LV side of the distribution transformers. The fuses are rated and the circuit breaker tripping is set to suit the application, substation loading and coordination with MV fuses. Other considerations such as LV circuit lengths and fault current limits are also considered.

3.5.2 Earthing

The following types of earthing are applied within the LV distribution network:

- Individual Multiple Earthed Neutral (IMEN) – An earthing arrangement where the LV neutral conductor is permanently connected to earth at the substation supplying the system, all customers' premises and an auxiliary earth at the remote end of the LV reticulation Network.
- Interconnected Multiple Earthed Neutral – An earthing arrangement where the LV neutral conductor is permanently connected to earth at the multiple substations supplying the system, all customers' premises and at any point throughout the neutral system as required.

- Common Multiple Earthed Neutral (CMEN) – An earthing arrangement where all the MV and LV equipment is permanently connected to a common earth. The LV neutral conductor is connected to earth as per interconnected Multiple Earthed Networks and is used to bond other MV earthing points within the Network.
- Direct Earth – An earthing system where the customer's neutral conductor is directly connected to the Distribution Substation earth via underground cable sheath or dedicated overhead earth conductor.

3.5.3 Services

Connection from the customer point of supply to the LV distribution network is achieved via service cables. Service cables may be placed either overhead or underground. The aerial service cables are typically XLPE insulated 2 core or 4 core construction with aluminium conductors of 25 mm^2 and 35 mm^2 and, as required, 95 mm^2 and 150 mm^2 aerial bundled cables. The underground service cables are tapped from the underground LV reticulation cables using tee joints. Standard service cables are 16 mm^2, 35 mm^2 and 50 mm^2 with copper conductors and XLPE insulation.

3.6 Communications Network

The communication network provides services for the following applications:

- Power system protection signalling.
- System Control and Data Acquisition (SCADA) for zone substations, Automatic Circuit Reclosers, and Sectionalisers.
- Operational Voice communications.
- Power Quality monitoring.
- Asset condition monitoring.
- 'Smart' metering.

These services are provided by either the private communication network or third party leased services. Third party leased services can be used for all applications except power system protection signalling because of the stringent technical requirements. Where there is no requirement for power system protection, the choice of using the private network or leased services is determined on lowest economic cost.

Most zone substations are connected by optical fibre. Eleven zone substations and about 2,300 pole top devices are connected by 3G/4G/satellite and 159 by TRIO point-to-multipoint radio. There are 51 WiMAX base stations connected by point-to-point microwave radio.

3.6.1 Communication Asset Types

Communication assets include telephone exchanges, Ethernet switches, routers, and communication network nodes. The communication network nodes used are Plesiochronous Digital Hierarchy (PDH), Synchronous Digital Hierarchy (SDH), and Wave Division Multiplexers (WDM). Other assets include WiMAX point-to-multipoint radio, TRIO point-to-multipoint, and point-to-point microwave radios. There are two types of optical fibre assets installed to support the communications network, All Dielectric Self Supporting (ADSS) and Optical Ground Wire (OPGW). Both are supported on the distribution network poles.

3.7 Distribution Asset Summary

Table 1 lists common asset types, sub-types, and quantities.

#	Asset Type	Description	Number
1	Connection Points	Terminal Stations (66 kV Connection Point)	11
2	Connection Points	Terminal Stations (22 kV Connection Point)	2
3	Connection Points	Terminal Stations (11 kV Connection Point)	1
4	Connection Points	Zone Substations (66/22 kV)	57
5	Connection Points	Substations (22/6.6 kV)	3
6	Connection Points	Zone Substations (Single Customer)	9
7	Connection Points	Switching Station	1
8	Transformers	Zone Substations Transformers	125
9	Transformers	Distribution Transformers (Pole Mounted)	56,698
10	Transformers	Distribution Transformers (Kiosk, Ground Outdoor or Indoor Chamber Mounted)	4,977
11	Circuit Breakers	High Voltage (>22 kV)	254
12	Circuit Breakers	Medium Voltage (≤22 kV)	2,190
13	Feeders	Number of 22 kV feeders	356
14	Feeders	Number of 11 kV feeders	2
15	Feeders	Number of 6.6 kV feeders	10
16	Conductors	Overhead (Low Voltage, <1 kV) (km)	6,603
17	Conductors	Overhead (SWER) (km)	6,414
18	Conductors	Overhead (Medium Voltage) (km)	22,617
19	Conductors	Overhead (High Voltage) (km)	2,537
20	Conductors	Underground (Low Voltage) (km)	5,012
21	Conductors	Underground (Medium Voltage) (km)	2,459
22	Conductors	Underground (High Voltage) (km)	13
23	Conductors	Number of Overhead Service Lines	209,432
24	Poles	Wood Poles	185,266
25	Poles	Concrete Poles	132,509
26	Poles	Steel Poles (Towers)	433
27	Poles	Public Lighting Poles	97,377
28	Poles	Cross-arms	407,754
29	Communications	Optical fibre – ADSS, OPGW (km)	680
30	Communications	Point to point radio links - Zone Substations (non AMI)	5
31	Communications	Point to point radio links - Zone Substations	63
32	Communications	WiMAX base stations - AMI	51
33	Communications	TRIO base stations	16
34	Communications	Network Nodes (SDH, WDM and PDH)	268

35	Communications	Routers and Switches	158
36	Communications	Telephone exchanges	6

Table 1: Number and types of assets

3.8 Methodologies used in preparing the Distribution Annual Planning Report

The DAPR covers a five-year forward planning period. The annual planning process commences after the extended summer season ending 31 March each year. The demand forecasts for connections points, zone substations, sub-transmission lines and distribution feeders are developed using the method described in Section 4.1, and network limitations are identified using the Probabilistic Planning Philosophy.

3.8.1 Planning Process

The planning activities are discussed in this section of the report and consist of the following steps:

- Review the long-term strategy for the distribution system with due consideration of network reliability, network capacity, quality of supply, network safety, environmental requirements, and asset management and regulatory strategies.
- Forecast the load demand for the next ten-year period.
- Forecast the network capacitive current for the next ten-year period.
- Confirm the capability of the existing network.
- Identify network constraints or network performance issues.
- Formulate options to resolve network constraints or needs.
- Seek non-network options including demand side options. Publish a non-network options report under RIT-D requirements where appropriate.
- Study these options to ensure compliance with technical limits, planning philosophies, regulatory criteria and guidelines, reliability and quality of supply standards and asset management strategies.
- Develop cost estimates for each option as well as cost savings and benefits of each option and establish the most cost-effective alternative that meets the technical and other requirements.
- Investigate the economic viability of the most cost-effective option by comparing the economic cost of the probability weighted energy at risk due to the contingency, reliability or performance gap with the cost of reducing this risk or improving the network performance.
- Prepare a planning report documenting all considerations and recommendations.
- Prioritise the different distribution projects based on the company's business strategy and funding guidelines.
- Obtain approval of the recommended plans, document plans and initiate execution of the projects in the plan.
- Publish draft and final project assessment reports under RIT-D requirements as appropriate.

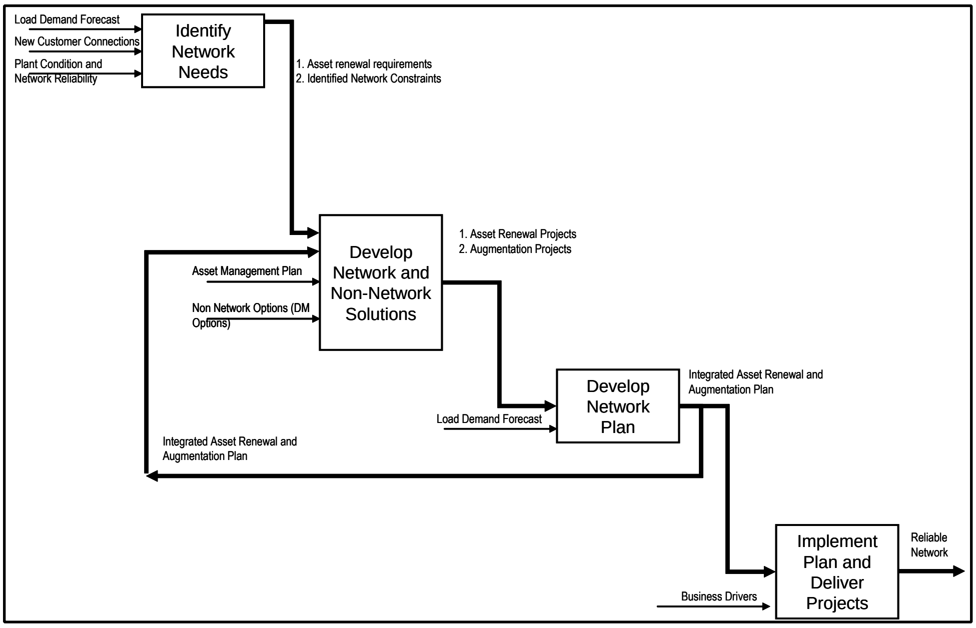


Figure 4: Distribution Network Planning Process

3.8.2 Identification of network needs or constraints

Network augmentation is essentially required to provide additional power transfer capacity to meet increasing customer load or, in the case of rapid earth fault current limiter (REFCL) protected zone substation, additional capacity to meet network capacitive current growth. Asset retirement and, where economically justified, replacement is required when the deteriorated condition of existing assets poses a service level risk, driven by reliability, safety, network security, environmental and plant damage risks, that outweighs the cost of retirement and/or replacement. The need for network augmentations or asset retirement and replacement is generally driven by the following factors:

- Increased load demand at existing supply points.
- New loads connecting to the distribution network.
- New network, resulting in capacitive current growth, to supply new connections.
- New generation connections or increased generation at existing connection points.
- Meeting quality of supply requirements.
- Improving the reliability of the network in response to the regulatory incentive scheme.
- High network losses supporting the justification for network augmentation based on reduced energy and demand losses as well as environmental benefits.
- Environmental requirements.
- Deteriorating condition of ageing assets.
- Risk mitigation.
- Increased penetration of Solar PV and other forms of generation have resulted in significant reverse power flow at light load conditions in some parts of the network. The full impact of bi-directional power flow is yet to be observed, but it is envisaged that network augmentation may be required in future to cater for this emerging change in power system behaviour.
- In response to the reduction in minimum demand and changes in the load shape driven by increased penetration of Distribution Energy Resources (DER), AusNet Services intends to develop ‘minimum demand’ forecasts to better understand this new phenomenon.

3.8.3 Overall objective of network planning

The planning standards and criteria applied in network development are a significant determinant of network-related costs. Costs associated with distribution connection facilities can be considered to comprise of two parts:

- The direct cost of the service (as reflected in network use of system charges and the costs of losses).
- Indirect costs borne by customers as a consequence of supply interruptions caused by network faults.

In developing and applying their planning standards and investment criteria, AusNet Services' aims to develop network facilities in an efficient manner that minimises the total (direct plus indirect) life-cycle cost of network service borne by customers.

This basic concept is illustrated in Figure 5 below.

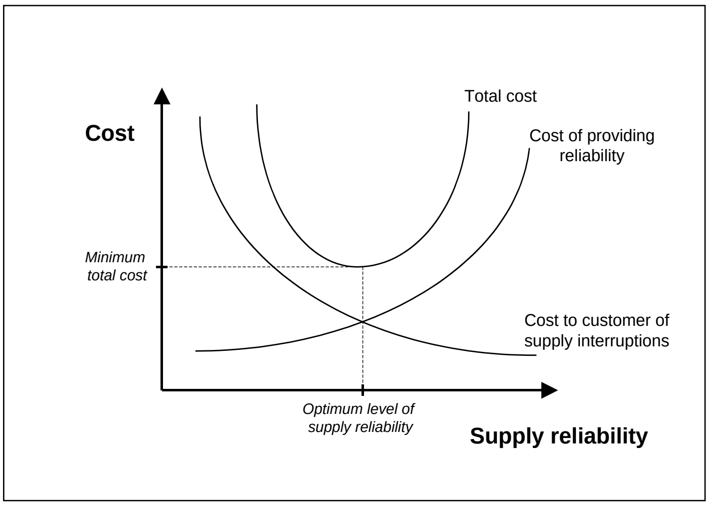


Figure 5: Balancing the direct cost of service and the indirect cost of service level risks including supply interruption

Additionally, AusNet Services' distribution connection investment decisions aim to maximise the net present value to customers, having regard to the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not limited to, demand-side management and embedded generation.

3.8.4 Overall approach to distribution planning and investment evaluation

AusNet Services uses a probabilistic planning approach consistent with the Australian Energy Market Operator (AEMO).

Under the probabilistic approach, the deterministic N-1 criterion applied in some networks is relaxed and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element, or elements, of the network were out of service. The application of this approach often leads to the deferral of augmentation that would otherwise proceed under a deterministic standard. Under a probabilistic network planning approach, conditions often exist where some the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however, the value of the energy not supplied is insufficient to justify additional investment, considering the probability of a forced outage of a particular network element.

The transmission connection assets for which the Distribution Network Service Providers (DNSP) have planning responsibility form part of the Victorian electricity transmission network. Given that AEMO applies a probabilistic network planning approach to the development of the shared transmission network, the Victorian DNSPs consider it appropriate to adopt a similar approach to transmission connection planning and investment decision analysis. AusNet Services considers it is appropriate to plan the distribution network (i.e. zone substations and sub-transmission lines) in a manner consistent with the planning for the 'upstream' network and connection points. Implicit in the use of a probabilistic approach is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available zone substation or 66 kV loop capacity will be insufficient to meet actual demand and significant load shedding could be required.

The distribution feeder risk assessment is based on feeder load carrying capability under peak load conditions. In this regard a more traditional deterministic planning approach is applied alongside the probabilistic planning appraoch.

3.8.5 Valuing supply reliability from the customer's perspective

To determine the economically optimal level and configuration of network capacity, and hence the supply reliability that will be delivered to customers, it is necessary to place a value on supply reliability from the customer's perspective. This is referred to as the value of customer reliability (VCR).

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

In July 2018, a final Rule determination on the VCR came into effect giving the AER responsibility for developing and publishing a VCR methodology and VCR estimates. In December 2019, the AER published its VCR methodology and VCR estimates4.

The VCR represents, in dollar terms, the estimated aggregated value that customers place on the reliable supply of electricity. This value varies by customer type and outage characteristics, and therefore varies at different locations within in the network based on the mix of customer types at that point. As customers cannot directly specify the value they place on reliability, the VCR plays an important role in determining the efficient level of investment in electricity services required by customers.

Table 2 below shows the AER's sector and composite VCR estimates for December 2019, along with the December 2020 values escalated by AusNet Services using the CPI escalation method.

Sector	Dec 2019 VCR ($/kWh)	Dec 2020 VCR ($/kWh)
Residential (Victorian composite)	21.43[5]	21.79
Commercial	44.52	38.50
Agricultural	37.87	45.27
Industrial	63.79[6]	64.86

Table 2: VCR estimates by sector.

3.8.6 Application of the probabilistic approach to distribution network planning

The probabilistic planning approach involves estimating the probability of various network conditions coinciding, such as plant outages coinciding with peak loading conditions, and weighting the service level costs of such events by their probability of occurrence to assess:

- The energy at risk of not being supplied if no risk mitigation action is undertaken; and
- Whether it is economic to invest in risk mitigation action to reduce the forecast service level risk.

The quantity and value of energy at risk is a critical parameter in assessing a prospective risk mitigation investment. Probabilistic planning aims to ensure that an economic balance is struck between the cost of:

- Providing supply redundancy and increased levels of safety to manage service level risk; and
- Exposure to the conditions (plant outages or network loading levels) that result in the identified supply level risk being realised.

In other words, recognising that plant outages and very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to retire and replace poor condition plant or provide additional capacity to cover the possibility of a network outage under extreme conditions. Rather, the probabilistic approach indicates that service level risk mitigation action should take place only when the service level risk has increased to the extent that the value of expected unserved energy and risk exceeds the investment cost to reduce the level of expected unserved energy and risk.

4 AER, Final Report on VCR values, December 2019, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision

5 The Victorian residential VCR is estimated for four different climate zones, as shown in Table 1.1 of the AER's Final Report. For simplicity, the value shown here is the composite Victorian residential VCR as per Table 1.2 of the AER's Final Report.

6 For customers with a maximum demand below 10 MVA, as per Table 1.3 of the AER's Final Report on VCR values, December 2019.

This approach provides a sound estimate of the expected net present value to consumers of distribution system augmentation, retirement or replacement. However, implicit in its use is acceptance of the risk that there may be circumstances when the available distribution network will be insufficient to meet actual demand. The extent to which investment should be committed to mitigate that risk is a balance between engineering and economic analysis; having regard for:

- The results of probabilistic and deterministic studies of possible outcomes, and the inherent uncertainty of those outcomes.
- Regulatory and other legal compliance obligations.
- The potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic plant failure leading to extended periods of plant unavailability.
- The availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.
- The Victorian DNSPs' obligation (under clause 5.2 of the Victorian Electricity Distribution Code) to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.

3.8.7 Methodology for assessing risk at Zone Substations

The methodology includes assessing magnitude, probability and impact of loss of load at each zone substation.

The following key data are calculated for each zone substation:

- **Energy at risk**: This is the amount of energy, weighted by the demand conditions considered (10% POE and 50% POE), that would not be supplied from a zone substation if outage of a transformer, circuit breaker or instrumentation transformer occurs at that station in that particular year. This statistic provides an indication of the magnitude of energy that would not be supplied in the unlikely event of a major network outage.
- **Expected unserved energy:** This is the energy at risk weighted by the probability of potential network outages. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year considering the low probability that a transformer, circuit breaker or instrumentation transformer at the zone station fails and is out of service.

Risk assessments for each zone substation provide estimates of energy at risk and expected unserved energy based on the demand forecasts.

3.8.8 Interpreting 'energy at risk'

As noted above, 'energy at risk' is an estimate of the amount of energy that would not be supplied if a zone substation network asset were out of service during the critical loading season(s), for a given demand forecast. Generally the worst-case outage for zone substation risk is outage of a transformer, and this condition is referred to as its 'N-1' rating. The capability of the station with all transformers in service is referred to as its 'N' rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in Figure 6.

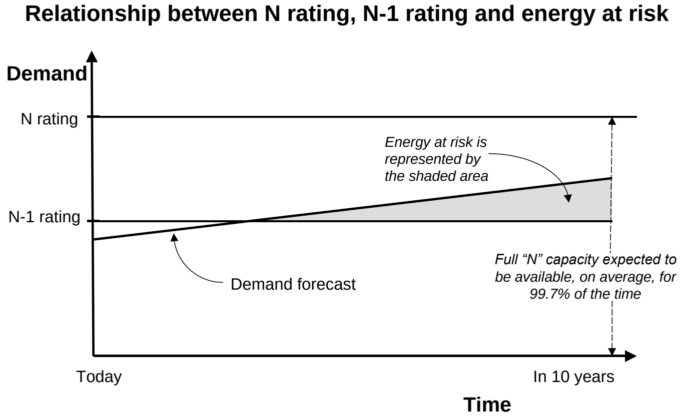


Figure 6: Relationship between N rating, N-1 rating and energy at risk

While it depends on the condition of the individual asset, it is expected that:

- On average over the long term, each transformer will be unavailable for 19 hours per year.
- Under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand.
- The risk of prolonged outages of a zone substation transformer leading to load interruption is typically very low.

3.8.9 Assessing service level risk

AusNet Services' risk-cost model quantifies the benefits of potential investment options by comparing base service level risk, assuming no risk mitigation action is taken, with the reduced service level risk assuming the credible option is place. The investment cost to implement the credible option is then subtracted from the monetised benefit to compare credible options and identify the option that maximises the net economic benefit (the proposed preferred option).

The initial screening assessments presented in the DAPR only present the base level risk, without attempting to quantify of the residual risk, and therefore net benefit, of the various options presented.

The areas of service level risk costs, and risk cost reduction benefits, that AusNet Services considers include:

- Supply risk.
- Safety risk.
- Collateral damage risk.
- Reactive replacement.
- Environment risk.
- Operations and maintenance costs.
- Losses.

3.8.10 Reliability statistics for zone substation assets

To provide a consistent assessment of the condition of an asset, AusNet Services applies a common condition scoring methodology. This methodology uses the known condition details of each asset and grades that asset against common asset condition criteria.

Asset condition is measured with reference to an asset health index on a declining condition scale from C1 to C5, as outlined in Table 3.

Condition Score	Condition	Condition Summary
C1	Very good	Initial service condition
C2	Good	Deterioration has minimal impact on asset performance. Minimal short-term asset failure risk.
C3	Average	Functionally sound showing some wear with minor failures, but asset still functions safely at adequate level of service.
C4	Poor	Advanced deterioration – plant and components function but require a high level of maintenance to remain operational.
C5	Very Poor	Extreme deterioration approaching end of life with failure imminent.

Table 3: Asset condition scoring methodology.

These conditions scores are then used to determine an effect condition-based age for each asset, which is in turn used calculate individual asset failure rates using the Weibull Hazard Function, as presented in Equation 1.

Equation 1: Weibull Hazard Function

$$r(t) = \frac{\beta t^{\beta-1}}{\eta^{\beta}}$$

Where:

t = Time (condition-based age)

η = Characteristic life (Eta)

β = Shape Parameter (Beta)

A Beta (β) value of 3.5 has been used to calculate the failure rates of all assets considered in the zone substation risk-cost model.

The condition-based age (t) depends on the specific asset's condition and characteristic life (η), where the characteristic life represents the average asset age at which 63% of the asset class population is expected to have failed. Table 4 presents the characteristic life values for each asset class considered in the zone substation risk-cost model.

Equipment	Characteristic Life (η) (years)
Power transformers	50
Circuit breakers	45
Voltage transformers	40
Current transformers	30

Table 4: Zone Substation Equipment Characteristic Life Values

3.8.11 Methodology for assessing sub-transmission loop risk

The methodology includes assessing magnitude, probability and impact of loss of load for each sub-transmission loop. Sub-transmission loops are expected to fail with consequent loss of supply to all customers if an outage occurs whilst the loop is operating above its N-1 voltage collapse limit or above its N-1 thermal rating.

The following key data are calculated for each sub-transmission line:

- **Hours at risk:** For a given demand forecast, this is the number of hours per annum that a sub-transmission loop operates above its firm rating.
- **Load at risk:** For a given demand forecast, this is the amount of load that would be lost should a failure of the 66 kV loop occur due to an outage occurring coincident with operation of the loop above its N-1 rating.
- **Repair time:** This is the time taken to repair and restore a 66 kV loop's supply once it has failed.
- **Expected unserved energy:** For a given demand forecast, this is the probability that an outage occurs whilst the loop is operating above its N-1 rating multiplied by the load at risk and the repair time. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year.

Risk assessments for each individual sub-transmission loop provide estimates of energy at risk and expected unserved energy based on the demand forecasts.

3.8.12 Cost of sub-transmission line outages

In estimating the expected cost of sub-transmission line outages, this report considers the first order contingency condition ('N-1') only. It is recognised that there is a significant amount of energy at risk if two lines of a sub-transmission loop are out of service at the same time, due to a major outage. However, the probability of such an event occurring during peak load periods is very low and is therefore not considered in the initial screening studies presented in the DAPR. Where relevant, multiple contingency risk is included in detailed assessments undertaken prior to network investment.

3.8.13 Base reliability statistics for sub-transmission lines

Estimates of the expected unserved energy of each sub-transmission loop must be based on the expected reliability performance of the relevant sub-transmission lines. The basic reliability data for sub-transmission lines has been established and is shown in Table 5.

Major plant item	Expected Sub-transmission Line unavailability due to a major outage per line-year	Interpretation
Urban Sub-transmission Line	1hr/line/year	On average, each line would be expected to have one failure per annum each with a duration of one hour.
Rural Sub-transmission Line	2hrs/line/year	On average, each line would be expected to have two failures per annum each with a duration of one hour each.

Table 5: Statistical reliability data for sub-transmission lines

3.8.14 Feasible options for meeting forecast demand

Developed options for a project may include demand management or other non-network solutions, refurbishment, replacement, augmentation, or a combination of these solutions. The options for zone substation and sub-transmission loop energy at risk is economically assessed to identify feasible solutions.

Network support in the form of demand management contracts and/or embedded generation, may individually or in combination with network augmentation, form feasible options for the elimination or mitigation of constraints.

3.9 Significant changes in aspects of forecasts and information provided

This section provides details required by schedule 5.8 (a) (5) in covering any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from those presented in the preceding year.

3.9.1 Key changes relating to network development plans

Following more detailed assessment of REFCL networks, and with ever-evolving REFCL technology, AusNet Services has updated its plans for maintaining REFCL compliance. Key changes include:

- Maintain REFCL Compliance at FGY: To maintain compliance at FGY it is proposed to establish a new non-REFCL Rowville Zone Substation (RVE) at an estimated cost of $22.6 million. This option includes feeder transfers from FGY to RVE. These works were scheduled to be completed by September 2020, as reported in the 2019 DAPR. While works have commenced, commissioning has now been delayed to November 2021, partly due to the COVID-19 Pandemic delaying site works.
- Maintain REFCL compliance at BDL: In the 2019 DAPR, to maintain compliance at BDL it was proposed to establish a new REFCL protected Lakes Entrance (LKE) Zone Substation by 2022 at an estimated cost of $23.1 million. This option was to include feeder transfers from BDL to LKE.

  With evolving REFCL technology, installing a third REFCL at a single site is considered an increasing feasible option. If installing a third REFCL at a single site proves successful, establishing a new LKE zone substation will not be required to maintain REFCL compliance at BDL in the forecast planning period. Instead, the proposed option is now installation of a third REFCL along with replacement of the existing No.3 transformer and rearrangement of the 22 kV feeders to accommodate the ASC limitations. Due to the lead-time to procure and install a third REFCL and replace the transformer, it may be necessary to install isolation transformers as a temporary measure.

  The expected cost for this option is $14.1; a saving of $9 million compared to the previously identified least cost feasible option.
- Maintain REFCL compliance at ELM: To achieve and maintain compliance at ELM it was previously proposed to establish a new REFCL protected Diamond Creek (DCK) Zone Substation by 2025 at an estimated cost of $21.5 million. This option was to include feeder transfers from ELM to DCK.

  With evolving REFCL technology, installing a third REFCL at a single site is considered an increasing feasible option. If installing a third REFCL at a single site proves successful, establishing a new DCK zone substation will not be required to maintain REFCL compliance at ELM in the forecast planning period. Instead, the proposed option is now installation of a third REFCL along with rearrangement of the 22 kV feeders to accommodate the ASC limitations. Due to the lead-time to procure and install a third REFCL, it may be necessary to install isolation transformers as a temporary measure.

The expected cost for this option is $9.1; a saving of $12.4 million compared to the previously identified least cost feasible option.

- Maintain REFCL compliance at KLO: To achieve and maintain compliance at KLO it was previously proposed to establish a new REFCL protected Kalkallo North (KLN) Zone Substation by 2023 at an estimated cost of $46.7 million. This option was to include transfer of all overhead feeders away from KLO to KLN such that KLO would only supply underground feeders, would not be REFCL protected, and would be exempt from the regulations.

  With evolving REFCL technology, installing remote REFCLs to REFCL protect only fire risk sections of the network, rather the entire zone substation supply area, is considered an increasing feasible option. If allowed for under exemptions to the regulations, AusNet Services intends to install two remote REFCLs and isolation transformers on feeder KLO14 and KLO24 obtain a specific exemption for the unprotected parts of the network.

  The expected cost for this option is $39.5 million; a saving of $7.2 million compared to the previously identified least cost feasible option.

- Maintain REFCL compliance at WOTS: To maintain compliance at WOTS it was previously proposed to establish a new REFCL protected Baranduda Zone Substation (BDA) by 2021 at an estimated cost of $29.3 million.

  With evolving REFCL technology, installing remote REFCLs to REFCL protect only fire risk sections of the network, rather the entire zone substation supply area, is considered an increasing feasible option. If allowed for under exemptions to the regulations, AusNet Services intends to install two remote REFCLs and isolation transformers on WOTS11 and WOTS25, along with permanent transfer of a section of WOTS25 to feeder WO31.

  The expected cost for this option is $13.5 million; a saving of $15.8 million compared to the previously identified least cost feasible option.

- Maintain REFCL compliance at BGE: To maintain compliance at BGE it is proposed to install a remote REFCL on BGE13 and install isolation transformers on BGE 22, at an estimated cost of $9.9 million.

4 Forecasts for the Forward Planning Period

This section summarises the methodology applied in developing demand forecasts, and presents the actual and forecast demands for the five-year forward looking period, as required under schedule 5.8 (b) of the National Electricity Rules (NER).

4.1 Demand Forecasting Methodology

Ten-year forward-looking demand forecasts are prepared annual for AusNet Services' zone substations and feeders. They are prepared for 10% Probability of Exceedance (POE) and 50% POE conditions, for both summer and winter, to reflect the temperature sensitivity of demand. At a high level, the following inputs are incorporated:

- Load demand growth information of future economic trends in the relevant area, including information from government agencies regarding identified growth areas and long-term development plans;
- Actual maximum demands for the most recent twelve-month period;
- Daily maximum demands for the past three to five years are weather normalised to establish relationships between demand and temperature;
- Recent load growth trends over the previous five-year period;
- Any known specific new loads expected to connect to the network.

Terminal station demand forecasts are currently based on AEMO's Transmission Connection Point Forecasts[7], which AusNet Services cross-checks against the bottom-up zone substation forecasts to ensure consistency in growth rates and reasonable agreement of magnitude.

4.2 Spatial Demand Forecasting Process

Spatial demand forecasts, at the zone substation and feeder level, are prepared by analysing actual network demand and advanced metering infrastructure (AMI) interval data. Customer growth forecasts are mapped to zone substations and apportioned at feeder level. These operational data sets are then subjected to detailed analytical modelling techniques and trended forward for predicting future maximum demand. The applied analytical modelling considers customer classes, energy profiles and weather regions. Segmentation by build year is used when predicting demand for future residential dwellings.

A bottom-up approach to maximum demand is then derived using the cumulative thermal effect described by the Cooling Degree Day (CDD) (Summer) or Heating Degree Day (HDD) (Winter) calculations, which specify a relationship between demand and temperature. Finally, this output is adjusted by a delta factor that represents losses and unmetered loads to account for the difference between historical (actual) network loading and AMI interval data.

The fundamental steps in the current spatial and trend analysis forecasting process is outlined in more detailed in the sections that follow, and include:

- Extract historical customer numbers;
- Create spatial customer forecasts informed by government growth estimates;
- Extract historical demand data;
- Extract ambient temperature data and generate temperature metrics;
- Curate historical demand data to determine representative days;
- Correlate historical demand and ambient temperature metrics;
- Generate spatial demand forecasts for asset type; and
- Validate spatial demand forecasts.

4.2.1 Extract historical customer numbers

Customer numbers and growth rates are a major driver of future demand, particularly spatial demand, forecasts. Historic customer numbers are extracted by asset and customer type from the tariff database and spatial asset

[7] AEMO. Transmission Connection Point Forecasts for Victoria. Available: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Victoria

database to provide both a launch point for the forecasts and a trend on which to inform projections over the forecast period.

4.2.2 Create spatial customer forecasts informed by government growth estimates

Customer number forecasts are compiled with reference to both the historical trend in customer growth and the Victorian government's projections of structured private dwellings (SPD) in the Victoria in Future (VIF) planning publication.[8] Where there is evidence that the VIF forecast growth rates are not reflective of actual growth, more weight may be given to historical trends and local knowledge of customer connection inquiry volumes including reference to annual local government authority (LGA) and monthly Australian Bureau of Statistics (ABS) data estimates.

4.2.3 Extract historical demand data

Demand data is extracted at several levels. Half-hourly customer consumption data is sourced from the interval meter database and commercial metering data. Demand on various network elements (such as feeders and zone substations) is sourced from OSI-Pi, which records Supervisory Control and Data Acquisition (SCADA) sensor data. After extraction, these data sets are cleansed of any abnormal readings, which can arise from data errors or temporary changes to network configuration, are corrected to account for known embedded generation. The resultant dataset is used as the basis for estimating the demand per customer, which is a key element of the forecast.

4.2.4 Extract ambient temperature data and generate temperature metrics

Ambient temperature data relevant to each feeder and zone substation is extracted from OSI-Pi, which is populated by time series Bureau of Meteorology (BOM) data, in a similar manner to the extract process for demand data and is validated via comparison to backup weather station data and published BOM data. Three primary BOM weather stations are used to represent the three major geographical network areas of North, Central and East. Temperature data is used to calculate Cooling Degree Days (CDDs) and Heating Degree Days (HDDs) which are in turn used to produce forecasts at probability of exceedance levels of 50% POE and 10% POE.

The CDD is calculated as the average temperature excursion above 21°C across a day, and the HDD is calculated as the average temperature deficit below 18°C across a day. The CDD is calculated as both a CDD across a single day (CDD1) and across two days (CDD2) to reflect that cooling demand can in some cases be driven by the cumulative heat absorption of buildings across multiple days.

4.2.5 Curate historical demand data to determine representative days

Selection of an appropriate representative day for load demand for an asset is critical for upscaling loads based on thermal impacts; non-representative thermal demands can lead to the calculation of poor POE values. Demand can be affected by various non-thermal impacts such as public holidays, event days, school holidays, weekends, public announcements related to energy conservation and weather conditions that cause abnormal patterns of solar photovoltaic (PV) energy production. For each asset subject to demand forecasts, the observed maximum demand days are compared to CDD values to identify outliers that may warrant being excluded, and to develop a curated set of data that is representative of the relation between maximum demand and CDD for the asset in question. This process relies on subject matter expertise to identify abnormalities and select the curated data set that has loads driven by high temperature events, such as the exclusion of hot water peaks in summer.

4.2.6 Correlate historical demand and temperature

Unitised maximum demands from residential customers have been found to correlate best to a combination of CDD1 and CDD2, rather than to just CDD1 or to maximum temperature. For each asset in question, a customised temperature metric equation is developed that combines CDD1 and CDD2 in such a way to maximise the degree of correlation between the temperature metric and unitised maximum demand. The 50% POE and 10% POE years are determined by calculating the maximum CDD1 and CDD2 for each of the historical years of temperature data. Average demand per residential customer is produced for both 50% POE and 10% POE conditions.

The relationship between CDD and demand for non-residential customers is diverse dependent on different types and sizes of businesses. Specific knowledge of each business type in a localised area is required to effectively forecast both current and future demand. This leads to a very high level of complexity and is currently unfeasible to address due to sporadic distribution of different businesses. In forecasting current and future demands for

[8] https://www.planning.vic.gov.au/land-use-and-population-research/victoria-in-future

commercial customers, unitised maximum demands have been determined for the most recent period in localised areas.

4.2.7 Generate spatial demand forecasts

Demand forecasts are based on a summation of profiles to determine an overall maximum demand that, over time, may shift during the day as dominant factors change. The unitised residential customer maximum demands for 50% POE and 10% POE conditions are multiplied by the residential customer number forecast to derive the total residential customer demand on an asset, in the form of a profile. The build-year of dwellings is also factored into this process via a matrix that sets out the unitised demand for dwellings of a particular build-year, including assumptions for future demand levels. This allows the addition and subtraction of different aged residences over time to be included in the residential demand.

Commercial demand is determined from the commercial unitised demands, estimated at the localised level, and customer number forecasts, in the form of a profile. This is added to the residential demand.

New commercial builds are based on localised maximum demands applied to network unitised profiles. The maximum demand for the summed profiles is determined and then a delta offset, to capture losses and unmetered loads, is applied to determine total demand.

This process is undertaken by automated toolsets to provide a consistent and repeatable outcome across the network and reduce manual processing.

4.2.8 Validate spatial demand forecasts

Regional network planning engineers, in conjunction with the sub-transmission planning engineer, validate the relevant forecasts. Validation involves magnitude and trend checks informed by knowledge of the loadings and network configuration changes recently completed and planned. Adjustments may be undertaken to improve the accuracy of the forecast by addressing factors such as:

- Large customers that are known to have connected recently or will connect in the near term.
- Impact of known network projects that have recently been undertaken or are in train, such as feeder reconfigurations.
- Inconsistencies in AMI data that lead to offsets in the final forecast.

4.3 Forecasting methodology planned improvements

AusNet Services adopts a continuous improvement model to the demand forecasting methodology in order to progressively improve the forecasts and respond to changing parameters, such as the impact of new technologies and the availability of new data sets.

The improvements that are planned to be incorporated over the next few years include:

- Less manual, more automated processing.
- Faster data curation processing.
- More efficient process for collection of historical maximum demand data, including demand, dates, times and other relevant information.
- Incorporate distributed energy resource uptake into the demand forecasts.
- Develop and implement a method of forecasting minimum demand in addition to maximum demand.

4.4 Network Capacitive Current Forecasting Methodology

To ensure the ongoing compliance of the REFCLs (refer Section 4.9.1), a forecast of network capacitive current was developed. The forecasts were prepared following a capacitive current forecasting methodology developed by AusNet Services with input from The Centre for International Economics (The CIE).

The forecasting methodology considers the following three components which are considered the primary drives of capacitive current growth:

- Network growth.
- Replacement programs.
- Network augmentation.

Network growth considers the impact of new underground residential developments and the new cables and substations required to supply these newly developed areas. In line with the demand forecasting methodology, this network growth forecast uses AusNet Services' customer growth forecast, which is informed by government growth estimates.

In developing the network growth forecasting methodology, a back-casting assessment of network growth compared to customer number growth, between 2015 and 2019, was undertaken. From this assessment, a direct link to the customer number growth forecast was established, with a network growth rate of:

- 12 meters of new underground cable per customer for rural areas.
- 8 meters of new underground cable per customer for urban areas.

Replacement programs include programs where existing overhead conductors are replaced by covered conductor or underground cable, usually driven by bushfire mitigation programs.

Network augmentation accounts for the replacement of pole top transformers with larger units, to meet increases in demand, and the construction of any new distribution feeders and zone substations.

4.5 Network Capacitive Current Forecasts

Table 6 presents the capacitance current forecast for each REFCL zone substation. The grey shaded cells highlight where the capacitance forecast exceeds the arc suppression coil (ASC) limits for the number of ground fault neutralisers (GFNs) installed at the zone substation. For zone substations that do not yet have a REFCL installed, and are therefore yet to have their ASC limit determined through field measurement, an ASC limit of 100A has been assumed.

Table 6: Capacitance Forecast Results (as at 21 December 2020)

ZSS	Region	Number of Feeders	Number of GFNs	ASC Limit/s	2020 Capacitive Current	2025 Capacitive Current
BDL	East	8	2	100	244	258
BGE	Central	6	2	111/107	297	297
BN	Central	5	1	100	81	83
BWA	North	4	1	129	69	71
ELM	Central	8	2	100	204	237
FGY	Central	10	2	100	255	261
KLK	Central	3	1	85	60	64
KLO	Central	7	2	100	321	367
KMS	North	2	1	80	64	82
LDL	Central	8	2	100	212	231
LLG	Central	3	1	100	68	83
MSD	North	8	2	100	61	70
MOE	East	8	2	100	103	105
MYT	North	4	1	122	49	50
RUBA	North	3	1	130	59	61
RWN	Central	7	1	100	115	123
SLE	Central	4	1	100	67	75
SMR	North	6	2	134	142	147

ZSS	Region	Number of Feeders	Number of GFNs	ASC Limit/s	2020 Capacitive Current	2025 Capacitive Current
WGI	East	8	1	153	161	175
WN	North	7	2	152	177	183
WOTS	North	6	2	100	248	260
WYK	Central	4	2	130	251	253

4.6 Asset Loading Forecasts

The asset loading forecasts presented herein are for the five-year forward planning period. They address summer and winter separately and provide observations (actual loadings) from 2019 and forecasts for the five-year forward planning period of 2020-2024.

50% POE and 10% POE represents the probability of exceedance demands (or load). Each demand is expressed as the probability or the likelihood the forecast would be met or exceeded. For example, a 50% probability of exceedance (POE) demand, represented in the table as 50% POE, implies there is a 50% probability of the forecast maximum demand being met or exceeded[9].

4.6.1 Load forecasts at the transmission-distribution connections points

Schedule 5.8 (b)(2)(i) of the NER requires load forecasts at the transmission-distribution connections points. However, clause 5.13.2(d) stipulates that a Distribution Network Service Provider (DNSP) is not required to include in its Distribution Annual Planning Report information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation.

DNSPs in Victoria are required, under clause 3.4 the Victorian Electricity Distribution Code (EDC)[10], to publish load forecasts at the transmission-distribution connection points in the Transmission Connection Planning Report (TCPR). The current TCPR covers the period of 2020-2029 and to avoid duplication the forecasts are generally not repeated in this report.

4.6.2 Load forecasts for sub-transmission lines

This section provides details required by schedule 5.8(b)(2)(ii) of the NER in covering load forecasts for sub-transmission lines and provides the additional information specified by (iv) to (ix). Sub-transmission lines are grouped into normally interconnected loops or circuits.

Table 7 and Table 8 present:

- The installed capacity of the AusNet Services' sub-transmission lines or loops (aggregate line rating);
- the firm capacity of sub-transmission loops (the capacity of the loop with the worst-case line outage and rating being reached on one of the remaining lines, N-1);
- historical peak load of the line or loop (non-diversified aggregate loop zone substation loading), the line or loop power factor at peak load; and
- the load forecasts for winter and summer inclusive of line losses under single contingency (non-diversified aggregate loop zone substation 50%POE loading).

Table 9 and Table 10 present:

- The load transfer capacity (to zone substations outside the 66 kV line or loop at time of need, 50%POE);
- embedded generation capacity; and

[9] Regional Demand Definition, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Generation-and-Load

[10] A copy of the Victorian Electricity Distribution Code can be viewed at the Victorian Essential Services Commission's website: https://www.esc.vic.gov.au/document/energy/36109-electricity-distribution-code-version-9-3/

- estimated hours per year that 95% of peak line or loop load is expected to be reached in winter and summer.

		Winter							
			Historical		Forecast 50%POE (MVA)				
Subtransmission Lines	Subtransmission Lines	Firm Capacity Winter (MVA)	2020 Power Factor	2020 Maximum Demand (MVA)	2021	2022	2023	2024	2025
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	283	1.00	218.1	196.0	199.2	202.2	205.2	208.0
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	190	0.99	156.5	139.1	138.8	138.3	137.8	137.3
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	109	1.00	85.7	85.5	84.9	84.3	83.6	82.9
ERTS-DN-HPK-DSH-DVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	379	0.98	275.8	266.7	295.2	297.1	296.7	297.1
RWTS-BRA-BWR-CYN-RWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	291	0.98	153.9	167.8	167.9	168.1	168.1	168.0
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	0	1.00	20.0	20.6	20.6	20.6	20.6	20.6
TSTS-ELM	Templestowe Terminal Station - Eltham	77	1.00	57.4	47.7	47.4	47.1	46.7	46.3
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South - Kalkallo	300	0.99	142.0	131.7	133.3	134.9	136.4	137.8
SMTS-EPG	South Morang Terminal Station - Epping	126	1.00	46.1	57.9	58.8	59.5	60.2	60.8
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	126	0.99	84.2	99.1	99.7	100.4	101.4	101.9
TTS-TT	Thomastown Terminal Station - Thomastown	91	0.96	63.9	66.0	66.5	66.8	67.2	67.5
GNTS-BN	Glenrowan Terminal Station - Benalla	112	0.99	47.8	64.8	64.8	65.0	64.9	64.8
BN-MSD	Benalla - Mansfield	0	0.99	29.0	33.5	33.4	33.4	33.3	33.1
MSD-MJG	Mansfield - Merrijig	0	0.98	11.2	15.7	15.5	15.4	15.2	15.1
GNTS-WN	Glenrowan Terminal Station - Wangaratta	83	1.00	63.8	78.5	78.2	77.9	77.5	77.1
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	49	1.00	29.7	36.0	35.9	35.7	35.5	35.3
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	0	1.00	7.9	9.8	9.8	9.8	9.7	9.7
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	0	1.00	50.0	51.5	51.5	51.5	51.5	51.5
WOTS-WO	Wodonga Terminal Station - Wodonga	87	0.99	43.8	50.9	50.8	50.6	50.4	50.2
WO-BWA	Wodonga - Barnawartha	0	0.99	9.0	10.6	10.6	10.5	10.5	10.4
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	0	0.98	29.0	29.9	29.9	29.9	29.9	29.9
MWTS-YPS-MOE-WGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	130	0.99	83.1	83.3	84.2	84.9	85.6	86.3
MWTS-TGN-SLE-MFA-BDSS-BDL	Morwell Terminal Station -Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	120	0.98	136.3	153.1	153.9	154.6	155.4	156.1
BDL-NLA	Bairnsdale - Newmerella	0	1.00	12.0	11.7	11.7	11.7	11.7	11.7
NLA-CNR	Newmerella - Cann River	0	1.00	2.5	2.8	2.8	2.8	2.8	2.8
DRN-KLK-MDI-RUBA-YEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South	35	0.99	44.0	47.8	47.5	47.2	46.9	46.5
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	131	0.96	111.8	116.4	116.0	115.6	115.2	114.8
LGA-WGI	Leongatha - Wonthaggi	43	0.93	55.8	54.4	54.0	53.7	53.3	52.9
WGI-PHI	Wonthaggi - Phillip Island	0	0.95	19.6	18.5	18.5	18.4	18.4	18.3

Table 7: AusNet Services' Sub-transmission Lines – Historic and Forecast Demand (MVA) – Winter

		Summer							
			Historical		Forecast 50%POE (MVA)				
Subtransmission Lines	Subtransmission Lines	Firm Capacity Summer (MVA)	2020 Power Factor	2020 Maximum Demand (MVA)	2021	2022	2023	2024	2025
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	243	1.00	269.6	314.0	315.1	323.0	331.1	339.9
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	177	0.99	181.5	189.6	189.9	191.3	192.8	194.4
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	102	1.00	107.0	118.6	118.8	119.2	119.7	120.2
ERTS-DN-HPK-DSH-DVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	352	0.98	274.7	323.3	325.4	325.8	327.2	331.4
RWTS-BRA-BWR-CYN-RWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	260	1.00	194.0	216.9	216.4	218.2	220.3	222.5
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	0	1.00	20.0	20.6	20.6	20.6	20.6	20.6
TSTS-ELM	Templestowe Terminal Station - Eltham	77	1.00	74.5	83.3	83.8	84.7	85.5	86.4
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South - Kalkallo	268	0.94	181.6	201.9	202.9	207.4	212.3	217.5
SMTS-EPG	South Morang Terminal Station - Epping	117	1.00	72.0	81.7	81.6	83.5	85.5	87.6
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	117	1.00	130.7	141.5	141.5	142.2	142.4	143.3
TTS-TT	Thomastown Terminal Station - Thomastown	88	1.00	80.2	86.3	86.0	86.2	86.5	86.8
GNTS-BN	Glenrowan Terminal Station - Benalla	105	0.99	59.4	66.3	66.8	67.1	67.6	68.1
BN-MSD	Benalla - Mansfield	0	0.99	24.3	26.9	27.2	27.4	27.6	27.9
MSD-MJG	Mansfield - Merrijig	0	1.00	4.1	4.3	4.3	4.3	4.3	4.3
GNTS-WN	Glenrowan Terminal Station - Wangaratta	83	0.99	75.7	86.0	86.5	87.0	87.3	88.0
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	33	1.00	25.7	28.2	28.3	28.5	28.6	28.9
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	0	0.90	4.2	4.5	4.5	4.5	4.5	4.5
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	0	1.00	50.0	51.5	51.5	51.5	51.5	51.5
WOTS-WO	Wodonga Terminal Station - Wodonga	65	0.97	58.2	61.3	61.6	61.9	62.3	62.6
WO-BWA	Wodonga - Barnawartha	0	0.94	12.2	12.7	12.8	12.9	13.1	13.1
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	0	1.00	29.0	29.9	29.9	29.9	29.9	29.9
MWTS-YPS-MOE-WGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	114	1.00	100.8	111.0	112.8	114.7	116.9	119.0
MWTS-TGN-SLE-MFA-BDSS-BDL	Morwell Terminal Station -Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	120	1.00	151.7	195.9	197.4	198.9	200.6	202.2
BDL-NLA	Bairnsdale - Newmerella	0	1.00	9.9	10.4	10.4	10.5	10.5	10.5
NLA-CNR	Newmerella - Cann River	0	1.00	2.5	2.6	2.6	2.6	2.6	2.6
DRN-KLK-MDI-RUBA-YEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South	35	0.89	48.3	55.0	55.6	56.2	56.9	57.7
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	92	0.99	125.4	144.0	145.7	146.7	147.9	149.3
LGA-WGI	Leongatha - Wonthaggi	32	0.99	68.0	75.5	76.9	77.7	78.5	79.4
WGI-PHI	Wonthaggi - Phillip Island	0	1.00	24.1	25.6	26.2	26.4	26.6	26.9

Table 8 AusNet Services' Sub-transmission Lines – Historic and Forecast Demand (MVA) – Summer

				Winter			
Subtransmission Lines	**Subtransmission Lines**	**Terminal Station**	**Installed capacity (MVA)**	**Firm Capacity Winter (MVA)**	**Load Transfer Capacity (MVA)**	**Embedded Generation Capacity (MVA)**	**Estimated Hours at 95% of Peak Load**
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	CBTS	406	283	47.9	0	7.2
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	RWTS	438	190	32.3	0	1.2
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	ERTS	203	109	23.6	0	3.0
ERTS-DN-HPK-DSH-DVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	ERTS	469	379	12.4	0	3.6
RWTS-BRA-BWR-CYN-RWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	RWTS	453	291	40.7	0	3.9
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	TSTS	54	0	0	4	0.0
TSTS-ELM	Templestowe Terminal Station - Eltham	TSTS	154	77	20.9	0	4.4
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South - Kalkallo	SMTS	385	300	37.9	0	2.3
DRN-KLK-MDI-RUBA-YEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South	SMTS	93	35	2.7	0	2.5
SMTS-EPG	South Morang Terminal Station - Epping	SMTS	234	126	15.7	0	0.4
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	TTS	234	126	16.5	0	1.5
TTS-TT	Thomastown Terminal Station - Thomastown	TTS	176	91	11.2	0	1.7
GNTS-BN	Glenrowan Terminal Station - Benalla	GNTS	209	112	2.3	0	3.3
BN-MSD	Benalla - Mansfield	GNTS	65	0	0.5	0	1.2
MSD-MJG	Mansfield - Merrijig	GNTS	64	0	9	0	0.4
GNTS-WN	Glenrowan Terminal Station - Wangaratta	GNTS	205	83	4.3	0	1.0
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	MBTS	73	49	1.6	0	0.7
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	MBTS	41	0	0	0	0.6
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	WOTS	65	0	0	50	0.0
WOTS-WO	Wodonga Terminal Station - Wodonga	WOTS	139	87	0.5	0	0.6
WO-BWA	Wodonga - Barnawartha	WOTS	64	0	7.1	0	2.1
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	MBTS	20	0	0	29	0.0
MWTS-YPS-MOE-WGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	MWTS	214	130	4.3	0	1.2
MWTS-TGN-SLE-MFA-BDSS-BDL	Morwell Terminal Station -Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	MWTS	295	120	9	109.3	2.9
BDL-NLA	Bairnsdale - Newmerella	MWTS	19	0	2	0	5.8
NLA-CNR	Newmerella - Cann River	MWTS	48	0	3	0	2.1
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	MWTS	245	131	3	21	0.8
LGA-WGI	Leongatha - Wonthaggi	MWTS	82	43	3	106.6	2.7
WGI-PHI	Wonthaggi - Phillip Island	MWTS	41	0	8.6	0	3.9

Table 9: AusNet Services' Sub-transmission Lines – Additional Information – Winter

				Summer			
Subtransmission Lines	**Subtransmission Lines**	**Terminal Station**	**Installed capacity (MVA)**	**Firm Capacity Summer (MVA)**	**Load Transfer Capacity (MVA)**	**Embedded Generation Capacity (MVA)**	**Estimated Hours at 95% of Peak Load**
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	CBTS	406	243	47.9	0	11.38
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	RWTS	438	177	32.3	0	11.91
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	ERTS	203	102	23.6	0	12.43
ERTS-DN-HPK-DSH-DVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	ERTS	469	352	12.4	0	5.88
RWTS-BRA-BWR-CYN-RWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	RWTS	453	260	40.7	0	6.79
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	TSTS	54	0	0	4	0.00
TSTS-ELM	Templestowe Terminal Station - Eltham	TSTS	154	77	20.9	0	8.57
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South - Kalkallo	SMTS	385	268	37.9	0	14.84
DRN-KLK-MDI-RUBA-YEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South	SMTS	93	35	2.7	0	11.70
SMTS-EPG	South Morang Terminal Station - Epping	SMTS	234	117	15.7	0	0.84
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	TTS	234	117	16.5	0	8.78
TTS-TT	Thomastown Terminal Station - Thomastown	TTS	176	88	11.2	0	5.22
GNTS-BN	Glenrowan Terminal Station - Benalla	GNTS	209	105	2.3	0	3.67
BN-MSD	Benalla - Mansfield	GNTS	65	0	0.5	0	5.43
MSD-MJG	Mansfield - Merrijig	GNTS	64	0	9	0	22.15
GNTS-WN	Glenrowan Terminal Station - Wangaratta	GNTS	205	83	4.3	0	0.21
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	MBTS	73	33	1.6	0	5.88
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	MBTS	41	0	0	0	2.09
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	WOTS	65	0	0	50	0.00
WOTS-WO	Wodonga Terminal Station - Wodonga	WOTS	139	65	0.5	0	0.21
WO-BWA	Wodonga - Barnawartha	WOTS	64	0	7.1	0	2.09
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	MBTS	20	0	0	29	0.00
MWTS-YPS-MOE-WGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	MWTS	214	114	4.3	0	12.85
MWTS-TGN-SLE-MFA-BDSS-BDL	Morwell Terminal Station -Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	MWTS	295	120	9	109.3	7.71
BDL-NLA	Bairnsdale - Newmerella	MWTS	19	0	2	0	2.93
NLA-CNR	Newmerella - Cann River	MWTS	48	0	3	0	2.51
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	MWTS	245	92	3	21	10.03
LGA-WGI	Leongatha - Wonthaggi	MWTS	82	32	3	106.6	7.52
WGI-PHI	Wonthaggi - Phillip Island	MWTS	41	0	8.6	0	6.69

Table 10: AusNet Services' Sub-transmission Lines – Additional Information – Summer

4.6.3 Load forecasts zone substations

This section provides details required by schedule 5.8(b)(2)(ii) of the NER in covering load forecasts for zone substations and provides the additional information specified by (iv) to (ix).

Table 11 and Table 12 present:

- The capacity of the AusNet Services' zone substations (total station nameplate capacity).
- the firm capacity of the zone substation (the capacity of the station with the worst-case transformer outage and rating being reached on one of the remaining transformers, (N-1).
- the historical peak load of the zone substation.
- the power factor at peak load.
- the load forecasts (50% POE) for winter and summer.

Table 13 and Table 14 present:

- The load transfer capacity at time of need (50% POE).
- embedded generation capacity.
- estimated hours per year that 95% of peak load is expected to be reached in winter and summer.

			Winter							
				Historical		Forecast 50%POE (MVA)				
ZSS	Name	Name Plate Rating (MVA)	Firm Capacity Winter (MVA)	2020 Power Factor	2020	2021	2022	2023	2024	2025
BDL	Bairnsdale	81.0	95.2	0.97	48.1	50.4	50.8	51.1	51.5	51.9
BGE	Belgrave	66.0	47.3	1.00	28.6	25.3	25.1	25.0	24.8	24.6
BN	Benalla	40.5	36.8	0.98	18.7	27.0	27.1	27.3	27.3	27.4
BRA	Boronia	99.0	86.1	0.99	46.5	49.9	49.9	49.8	49.7	49.5
BRT	Bright	40.0	30.0	1.00	13.3	15.3	15.2	15.2	15.1	15.1
BWA	Barnawatha	33.0	0.0	0.99	9.0	10.1	10.1	10.0	10.0	9.9
BWN	Berwick North	33.0	48.1	1.00	24.4	15.6	15.5	15.4	15.3	15.1
BWR	Bayswater	81.0	78.6	0.99	51.9	51.1	51.2	51.5	51.7	51.8
CF	Clover Flat	10.0	7.3	0.98	5.7	9.1	9.0	9.0	8.9	8.8
CLN	Clyde North	66.0	47.8	1.00	54.3	46.9	48.9	51.0	53.1	55.2
CNR	Cann River	10.0	0.0	1.00	2.5	2.7	2.7	2.6	2.6	2.6
CPK	Chirnside Park	66.0	48.6	1.00	35.2	27.3	27.4	27.5	27.6	27.7
CRE	Cranbourne	66.0	46.3	1.00	37.7	34.1	34.5	34.9	35.2	35.5
CYN	Croydon	99.0	94.0	0.97	55.5	57.3	57.3	57.3	57.2	57.1
DRN	Doreen	66.0	49.1	1.00	52.4	47.7	48.9	50.0	51.1	52.2
ELM	Eltham	99.0	89.1	1.00	57.4	45.0	44.7	44.4	44.1	43.7
EPG	Epping	99.0	92.4	1.00	46.1	54.6	55.5	56.2	56.8	57.3
FGY	Ferntree Gully	93.0	67.4	0.99	57.1	55.4	55.0	54.5	54.1	53.7
FTR	Foster	66.0	49.0	0.99	20.0	19.2	19.1	19.0	18.8	18.6
HPK	Hampton Park	99.0	90.7	0.99	54.2	33.1	32.9	32.7	32.5	32.3
KLK	Kinglake	10.0	7.4	0.99	9.4	6.2	6.1	6.0	6.0	5.9
KLO	Kalkallo	66.0	49.1	1.00	33.5	24.3	24.9	25.5	26.1	26.6
KMS	Kilmore South	30.0	14.5	0.98	12.2	8.7	8.8	8.8	8.9	8.9
LDL	Lilydale	99.0	96.9	0.99	65.8	53.0	52.7	52.3	51.9	51.5
LGA	Leongatha	73.0	41.6	1.00	36.1	37.2	37.3	37.4	37.5	37.6
LLG	Lang Lang	33.0	0.0	1.00	20.2	21.1	21.3	21.4	21.5	21.5
LYD	Lysterfield	33.0	0.0	1.00	14.9	13.8	13.8	13.7	13.7	13.6
MBY	Mt Beauty	30.0	21.4	1.00	7.9	9.8	9.7	9.7	9.6	9.6
MDI	Murrindindi	10.0	0.0	0.98	0.2	4.9	4.9	4.9	4.8	4.8
MFA	Maffra	40.0	37.8	0.97	23.4	26.1	26.2	26.4	26.5	26.7
MJG	Merrijig	20.0	0.0	0.98	11.2	14.9	14.8	14.7	14.5	14.4
MOE	Moe	40.5	36.3	0.99	27.8	23.4	23.3	23.1	22.9	22.7
MSD	Mansfield	26.0	19.2	1.00	17.8	17.0	17.0	17.1	17.2	17.2
MWL	Morwell	66.0	49.5	0.91	28.8	30.6	30.6	30.7	30.8	30.9
MYT	Myrtleford	20.0	12.9	1.00	16.4	19.0	18.9	18.8	18.7	18.5
NLA	Newmerella	10.0	7.5	1.00	9.5	8.5	8.5	8.5	8.5	8.5
NRN	Narre Warren	33.0	48.1	0.99	25.8	15.9	15.7	15.6	15.5	15.3
OFR	Officer	66.0	48.8	1.00	36.3	36.5	37.4	38.3	39.1	39.9
PHI	Phillip Island	26.0	16.3	0.95	19.6	17.6	17.6	17.6	17.5	17.4
PHM	Pakenham	66.0	47.3	1.00	42.2	35.2	35.3	35.4	35.5	35.6
RUBA	Rubicon 'A'	40.0	30.2	0.98	11.8	9.5	9.5	9.4	9.3	9.2
RWN	Ringwood North	66.0	45.2	0.99	41.3	34.7	34.5	34.3	34.1	33.9
SLE	Sale	60.0	38.7	0.94	22.5	22.1	22.0	21.9	21.7	21.6
SMG	South Morang	66.0	49.1	1.00	32.6	23.3	23.2	23.1	23.0	22.8
SMR	Seymour	38.5	29.8	0.97	28.2	28.6	28.4	28.3	28.1	27.9
TGN	Traralgon	60.0	36.7	1.00	32.7	32.1	32.4	32.7	33.0	33.3
TT	Thomastown	84.0	68.4	0.96	63.9	64.1	64.5	64.9	65.2	65.5
WGI	Wonthaggi	40.5	38.9	0.91	36.2	31.8	31.5	31.2	31.0	30.7
WGL	Warragul	84.0	70.5	0.99	55.3	52.3	53.2	54.1	54.9	55.7
WN	Wangaratta	66.0	43.4	0.99	34.1	37.1	37.0	36.8	36.6	36.5
WO	Wodonga	99.0	81.5	0.99	34.8	37.9	37.8	37.7	37.6	37.4
WOTS	Wodonga TS	70.4	50.5	0.95	39.5	38.2	38.4	38.7	38.9	39.0
WT	Watsonia	109.0	83.7	0.99	41.0	45.6	46.0	46.4	46.9	47.3
WYK	Woori Yallock	66.0	48.2	1.00	25.1	24.8	24.6	24.4	24.2	24.0
Total		3,059.4	2,373.2		1,676.7	1,582.9	1,588.7	1,594.1	1,598.4	1,602.2

Table 11: AusNet Services' Zone Substations – Historic and Forecast Demand (MVA) – Winter

			Summer							
				Historical		Forecast 50%POE (MVA)				
ZSS	Name	Name Plate Rating (MVA)	Firm Capacity Summer (MVA)	2020 Power Factor	2020	2021	2022	2023	2024	2025
BDL	Bairnsdale	81.0	88.0	1.00	56.6	58.9	59.6	60.2	60.9	61.5
BGE	Belgrave	66.0	40.4	1.00	29.5	31.5	31.6	31.7	31.9	32.0
BN	Benalla	40.5	30.7	0.98	35.1	34.6	34.8	34.9	35.1	35.3
BRA	Boronia	99.0	77.8	1.00	75.1	78.1	77.9	78.6	79.2	80.0
BRT	Bright	40.0	27.9	1.00	10.2	10.4	10.5	10.6	10.7	10.8
BWA	Barnawatha	33.0	0.0	0.94	12.2	12.1	12.2	12.3	12.5	12.5
BWN	Berwick North	33.0	38.9	1.00	31.7	34.0	34.2	34.6	34.9	35.2
BWR	Bayswater	81.0	66.2	1.00	51.9	57.3	57.0	57.6	58.5	59.5
CF	Clover Flat	10.0	6.7	1.00	1.8	1.9	1.9	1.9	1.9	1.9
CLN	Clyde North	66.0	43.5	1.00	73.4	85.9	86.2	89.9	93.7	97.6
CNR	Cann River	10.0	0.0	1.00	2.5	2.5	2.5	2.5	2.5	2.5
CPK	Chirnside Park	66.0	48.8	1.00	55.4	52.0	52.1	52.6	53.3	53.9
CRE	Cranbourne	66.0	41.1	1.00	46.5	59.0	59.2	60.0	61.0	61.9
CYN	Croydon	99.0	83.0	1.00	67.0	69.3	69.2	69.6	70.0	70.4
DRN	Doreen	66.0	45.9	1.00	76.5	80.7	81.0	83.7	86.7	89.7
ELM	Eltham	99.0	80.7	1.00	74.5	78.6	79.1	79.9	80.7	81.5
EPG	Epping	99.0	82.0	1.00	72.0	77.1	77.0	78.7	80.7	82.6
FGY	Ferntree Gully	93.0	61.8	1.00	77.5	80.3	80.4	80.7	81.0	81.4
FTR	Foster	66.0	49.1	0.98	22.3	22.8	22.8	22.8	23.0	23.1
HPK	Hampton Park	99.0	81.6	1.00	56.2	59.4	59.4	60.0	60.6	61.2
KLK	Kinglake	10.0	7.4	1.00	5.1	5.3	5.3	5.3	5.3	5.3
KLO	Kalkallo	66.0	49.1	1.00	42.3	44.5	44.2	44.8	45.3	46.0
KMS	Kilmore South	30.0	16.6	1.00	14.5	15.3	15.7	16.1	16.6	17.1
LDL	Lilydale	99.0	90.1	1.00	63.6	66.9	66.9	67.3	67.6	68.0
LGA	Leongatha	73.0	41.5	1.00	35.1	39.5	39.7	39.9	40.1	40.4
LLG	Lang Lang	33.0	0.0	1.00	21.2	22.2	22.4	22.7	23.1	23.5
LYD	Lysterfield	33.0	0.0	1.00	22.4	23.7	23.8	24.1	24.5	24.8
MBY	Mt Beauty	30.0	19.9	0.90	4.2	4.5	4.5	4.5	4.5	4.5
MDI	Murrindindi	10.0	0.0	1.00	1.6	1.7	1.7	1.7	1.7	1.7
MFA	Maffra	40.0	31.1	0.99	28.5	35.9	36.0	36.1	36.2	36.4
MJG	Merrijig	20.0	0.0	1.00	4.1	4.1	4.1	4.1	4.1	4.1
MOE	Moe	40.5	33.2	1.00	35.9	34.7	34.8	35.0	35.3	35.5
MSD	Mansfield	26.0	18.1	0.98	20.2	21.5	21.8	22.0	22.2	22.5
MWL	Morwell	66.0	49.5	0.99	35.4	37.6	37.7	37.8	37.9	38.1
MYT	Myrtleford	20.0	13.4	0.99	15.5	16.4	16.4	16.5	16.5	16.7
NLA	Newmerella	10.0	7.5	1.00	7.4	7.4	7.4	7.5	7.5	7.5
NRN	Narre Warren	33.0	38.9	1.00	23.3	23.8	23.9	23.9	23.9	24.1
OFR	Officer	66.0	48.6	1.00	48.9	53.7	53.9	56.0	58.1	60.5
PHI	Phillip Island	26.0	14.6	1.00	24.1	24.4	24.9	25.1	25.3	25.6
PHM	Pakenham	66.0	43.9	1.00	48.7	52.9	52.9	53.6	54.3	54.9
RUBA	Rubicon 'A'	40.0	30.0	0.59	11.8	12.2	12.1	12.1	12.1	12.1
RWN	Ringwood North	66.0	41.0	1.00	43.1	45.4	45.6	46.1	46.5	47.0
SLE	Sale	60.0	39.7	1.00	18.7	30.1	30.2	30.4	30.7	31.0
SMG	South Morang	66.0	45.0	1.00	44.1	45.5	45.4	45.5	45.7	45.9
SMR	Seymour	38.5	25.4	0.97	37.2	38.5	39.4	40.0	40.8	41.7
TGN	Traralgon	60.0	36.2	1.00	40.8	46.9	47.3	47.7	48.2	48.6
TT	Thomastown	84.0	58.6	1.00	80.2	83.8	83.5	83.7	84.0	84.3
WGI	Wonthaggi	40.5	38.2	0.98	43.9	44.2	45.0	45.5	46.0	46.6
WGL	Warragul	84.0	61.9	0.99	64.9	66.3	67.8	69.3	71.0	72.7
WN	Wangaratta	66.0	37.2	0.99	50.0	51.4	51.6	51.9	52.1	52.4
WO	Wodonga	99.0	74.9	1.00	46.0	45.7	45.9	46.1	46.3	46.6
WOTS	Wodonga TS	70.4	44.0	0.99	36.8	36.9	37.5	38.0	38.6	39.2
WT	Watsonia	109.0	81.6	1.00	73.4	76.5	76.4	76.7	77.1	77.5
WYK	Woori Yallock	66.0	46.2	1.00	29.8	31.0	30.9	31.0	31.1	31.2
Total		3,059.4	2,177.4		2,050.6	2,176.9	2,185.3	2,210.9	2,239.0	2,268.3

Table 12: AusNet Services' Zone Substations – Historic and Forecast Demand (MVA) – Summer

ZSS	Name	Name Plate Rating (MVA)	Winter			
			Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity(MVA)	Estimated Hours at 95% of Peak Load
BDL	Bairnsdale	81.0	95.2	3.5	0.0	16.0
BGE	Belgrave	66.0	47.3	15.4	3.8	8.7
BN	Benalla	40.5	36.8	1.6	0.2	20.2
BRA	Boronia	99.0	86.1	22.9	2.0	4.2
BRT	Bright	40.0	30.0	2.0	0.0	2.0
BWA	Barnawatha	33.0	0.0	7.1	0.0	2.5
BWN	Berwick North	33.0	48.1	26.9	0.0	1.2
BWR	Bayswater	81.0	78.6	24.6	0.0	12.0
CF	Clover Flat	10.0	7.3	0.0	0.0	5.5
CLN	Clyde North	66.0	47.8	30.1	0.0	21.2
CNR	Cann River	10.0	0.0	3.0	0.0	3.0
CPK	Chirnside Park	66.0	48.6	21.5	0.0	1.5
CRE	Cranbourne	66.0	46.3	25.8	0.0	22.0
CYN	Croydon	99.0	94.0	34.2	0.0	4.8
DRN	Doreen	66.0	49.1	27.3	0.0	17.7
ELM	Eltham	99.0	89.1	20.9	0.0	10.2
EPG	Epping	99.0	92.4	15.7	9.8	1.0
FGY	Ferntree Gully	93.0	67.4	24.2	0.0	21.0
FTR	Foster	66.0	49.0	3.0	0.0	0.5
HPK	Hampton Park	99.0	90.7	12.4	8.8	4.0
KLK	Kinglake	10.0	7.4	1.0	0.0	0.0
KLO	Kalkallo	66.0	49.1	9.6	0.0	1.5
KMS	Kilmore South	30.0	14.5	5.2	0.0	1.3
LDL	Lilydale	99.0	96.9	21.4	7.2	14.2
LGA	Leongatha	73.0	41.6	3.0	1.8	12.0
LLG	Lang Lang	33.0	0.0	24.6	0.0	12.5
LYD	Lysterfield	33.0	0.0	24.7	0.2	9.0
MBY	Mt Beauty	30.0	21.4	3.5	0.0	2.5
MDI	Murrindindi	10.0	0.0	0.0	0.0	0.7
MFA	Maffra	40.0	37.8	6.5	3.9	26.5
MJG	Merrijig	20.0	0.0	9.0	0.0	0.0
MOE	Moe	40.5	36.3	4.3	10.8	6.5
MSD	Mansfield	26.0	19.2	1.5	0.0	3.0
MWL	Morwell	66.0	49.5	8.0	0.5	5.3
MYT	Myrtleford	20.0	12.9	1.6	0.0	3.5
NLA	Newmerella	10.0	7.5	3.2	0.0	14.7
NRN	Narre Warren	33.0	48.1	26.9	6.8	1.2
OFR	Officer	66.0	48.8	17.2	0.0	8.0
PHI	Phillip Island	26.0	16.3	6.0	0.0	3.2
PHM	Pakenham	66.0	47.3	20.6	0.0	9.7
RUBA	Rubicon 'A'	40.0	30.2	0.5	19.9	0.7
RWN	Ringwood North	66.0	45.2	15.8	0.0	14.7
SLE	Sale	60.0	38.7	2.5	0.0	14.0
SMG	South Morang	66.0	49.1	18.2	0.0	1.0
SMR	Seymour	38.5	29.8	4.5	0.0	6.2
TGN	Traralgon	60.0	36.7	9.7	10.0	10.0
TT	Thomastown	84.0	68.4	11.2	0.0	30.7
WGI	Wonthaggi	40.5	38.9	4.0	12.0	0.2
WGL	Warragul	84.0	70.5	3.2	0.0	10.5
WN	Wangaratta	66.0	43.4	4.3	2.3	16.0
WO	Wodonga	99.0	81.5	3.5	0.0	1.0
WT	Watsonia	109.0	83.7	16.5	0.0	5.3
WYK	Woori Yallock	66.0	48.2	0.0	0.9	2.0

Table 13: AusNet Services' Zone Substations – Additional Information – Winter

			Summer			
ZSS	Name	Name Plate Rating (MVA)	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity(MVA)	Estimated Hours at 95% of Peak Load
BDL	Bairnsdale	81.0	88.0	3.5	0.0	7.0
BGE	Belgrave	66.0	40.4	15.4	3.8	1.8
BN	Benalla	40.5	30.7	1.6	0.2	6.0
BRA	Boronia	99.0	77.8	22.9	2.0	5.3
BRT	Bright	40.0	27.9	2.0	0.0	0.5
BWA	Barnawatha	33.0	0.0	7.1	0.0	2.5
BWN	Berwick North	33.0	38.9	26.9	0.0	5.3
BWR	Bayswater	81.0	66.2	24.6	0.0	4.3
CF	Clover Flat	10.0	6.7	0.0	0.0	0.0
CLN	Clyde North	66.0	43.5	30.1	0.0	3.0
CNR	Cann River	10.0	0.0	3.0	0.0	2.5
CPK	Chirnside Park	66.0	48.8	21.5	0.0	5.0
CRE	Cranbourne	66.0	41.1	25.8	0.0	8.5
CYN	Croydon	99.0	83.0	34.2	0.0	15.2
DRN	Doreen	66.0	45.9	27.3	0.0	2.8
ELM	Eltham	99.0	80.7	20.9	0.0	5.3
EPG	Epping	99.0	82.0	15.7	9.8	0.5
FGY	Ferntree Gully	93.0	61.8	24.2	0.0	5.5
FTR	Foster	66.0	49.1	3.0	0.0	0.8
HPK	Hampton Park	99.0	81.6	12.4	8.8	6.3
KLK	Kinglake	10.0	7.4	1.0	0.0	3.0
KLO	Kalkallo	66.0	49.1	9.6	0.0	3.3
KMS	Kilmore South	30.0	16.6	5.2	0.0	0.9
LDL	Lilydale	99.0	90.1	21.4	7.2	1.5
LGA	Leongatha	73.0	41.5	3.0	1.8	1.0
LLG	Lang Lang	33.0	0.0	24.6	0.0	2.3
LYD	Lysterfield	33.0	0.0	24.7	0.2	3.3
MBY	Mt Beauty	30.0	19.9	3.5	0.0	0.8
MDI	Murrindindi	10.0	0.0	0.0	0.0	0.0
MFA	Maffra	40.0	31.1	6.5	3.9	0.5
MJG	Merrijig	20.0	0.0	9.0	0.0	0.0
MOE	Moe	40.5	33.2	4.3	10.8	1.5
MSD	Mansfield	26.0	18.1	1.5	0.0	2.8
MWL	Morwell	66.0	49.5	8.0	0.5	3.1
MYT	Myrtleford	20.0	13.4	1.6	0.0	7.0
NLA	Newmerella	10.0	7.5	3.2	0.0	1.5
NRN	Narre Warren	33.0	38.9	26.9	6.8	5.3
OFR	Officer	66.0	48.6	17.2	0.0	4.8
PHI	Phillip Island	26.0	14.6	6.0	0.0	0.8
PHM	Pakenham	66.0	43.9	20.6	0.0	3.1
RUBA	Rubicon 'A'	40.0	30.0	0.5	19.9	0.0
RWN	Ringwood North	66.0	41.0	15.8	0.0	2.5
SLE	Sale	60.0	39.7	2.5	0.0	3.0
SMG	South Morang	66.0	45.0	18.2	0.0	0.5
SMR	Seymour	38.5	25.4	4.5	0.0	2.0
TGN	Traralgon	60.0	36.2	9.7	10.0	1.8
TT	Thomastown	84.0	58.6	11.2	0.0	3.0
WGI	Wonthaggi	40.5	38.2	4.0	12.0	0.8
WGL	Warragul	84.0	61.9	3.2	0.0	1.8
WN	Wangaratta	66.0	37.2	4.3	2.3	7.0
WO	Wodonga	99.0	74.9	3.5	0.0	11.0
WT	Watsonia	109.0	81.6	16.5	0.0	6.1
WYK	Woori Yallock	66.0	46.2	0.0	0.9	3.5

Table 14: AusNet Services' Zone Substations – Additional Information – Summer

4.7 Asset Loading Forecasts

This section provides details regarding the forecast for future assets. It covers schedule 5.8 (b)(3) of the NER and includes transmission-distribution connection points, future sub-transmission lines and zone substations.

4.7.1 Transmission to distribution connection points

Clause 5.13.2(d) of the NER stipulates that a DNSP is not required to include in its Distribution Annual Planning Report information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation. DNSPs in Victoria are required by the Victorian Electricity Distribution Code (EDC) Clause 3.4[11] to publish load forecasts at the transmission-distribution connection points in the TCPR covering the period 2020-2029[12].

In mid-2021, AusNet Services commenced a Regulatory Investment Test for Transmission (RIT-T), jointly with United Energy and in consultation with AEMO, to assess options to mitigate the thermal loading risk on the Cranbourne Terminal Station (CBTS) 220/66 kV connection assets transformers. This RIT-T is expected to result in risk mitigation action within the next five years.

4.7.2 Sub-transmission lines

In the next five years, AusNet Services plans to commence one new Regulatory Investment Tests for Distribution (RIT-Ds), to investigate options to secure supply in the Cranbourne, Pakenham, Lang Lang 66 kV loop, emanating from Cranbourne Terminal Station. We will also continue with the East Gippsland Supply risk RIT-D commenced in 2020.

Depending on the outcome of these RIT-Ds, it may be economically feasible to augment these 66 kV sub-transmission networks.

4.7.3 Zone Substations

In the next five years, AusNet Services plans to commission one new zone substation, augment capacity at ten existing zone substation (one for maintain supply capacity due to demand growth and nine to maintain REFCL compliance due to network capacitance growth), undertake major asset replacement within seven existing zone substations and achieve compliance at the remaining REFCL designated zone substations.

The new zone substation planned to be built in the next five-year period required achieve REFCL compliance, is:

- Rowville Zone Substation (RVE): to maintain compliance at FGY it is proposed to establish a new non-REFCL Rowville Zone Substation (RVE) by November 2021 at an estimated cost of $22.6 million. This option includes feeder transfers from FGY to RVE.

The zone substation where capacity augmentation is proposed is:

- Clyde North Zone Substation (CLN): Under 10% POE conditions, the loading at CLN is forecast to reach 85.9 MVA by summer 2019/20, increasing to 97.6 MVA by 2024/25 and it is expected to be economic to install a third 20/33 MVA transformer and third 22 kV switchboard at the station by December 2023.

  This proposed augmentation is subject to the outcome of a future RIT-D assessment.

The eight zone substations where major asset replacement is expected in the next five-year period, due to deteriorated assets, are:

- Bairnsdale (BDL), Bayswater (BWR), Benalla (BN), Maffra (MFA), Thomastown (TT), Traralgon (TGN), Warragul (WGL) and Watsonia (WT).
- The twenty-two REFCL zone substations include Kinglake (KLK), Woori Yallock (WYK), Kilmore South (KMS), Wangaratta (WN), Rubicon A (RUBA), Barnawartha (BWA), Seymour (SMR), Myrtleford (MYT), Wonthaggi (WGI), Benalla (BN), Ringwood North (RWN), Eltham (ELM), Ferntree Gully (FGY), Belgrave (BGE), Lilydale (LDL), Bairnsdale (BDL), Moe (MOE), Sale (SLE), Mansfield (MSD), Wodonga Terminal Station 22 kV switchyard (WOTS), Lang Lang (LLG), and Kalkallo (KLO).

[11] A copy of the Victorian Electricity Distribution Code can be viewed at the Victorian Essential Services Commission's website: https://www.esc.vic.gov.au/document/energy/36109-electricity-distribution-code-version-9-3/

[12] A copy of the 2020 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet Services' website: AusNet - Rosetta Data Portal (ausnetservices.com.au).

- Of the twenty-two REFCL zone substation sites, ten sites are currently in service, including BWA, KMS, MSD, MYT, RUBA, RWN, SMR, WGI, WN and WYK, and a further three are expected to be in service by late-December 2020, including BGE, KLK and LDL. Of the in-service sites, compliance has been achieved at six sites, including WN, MYT, BWA, RUBA, SMR and KMS.

4.8 Forecasts of the DNSP performance against STPIS reliability targets

This section provides details required in schedule 5.8 (b)(4) of the NER covering forecasts of performance against reliability targets in the Service Target Performance Incentive Scheme (STPIS). Details of the STPIS are found at the Australian Energy Regulators website[13].

Table 15 shows AusNet Services' network reliability performance against STPIS targets for the period 2016-2020.

Measure	Feeder Class	2018		2019		2020	
		Target	Actual	Target	Actual	Target	Forecast**
Unplanned SAIDI	Urban	80.90	85.86	80.58	77.86	80.26	111.42
	Rural Short	187.14	222.21	186.68	204.46	186.23	227.62
	Rural Long	232.74	252.40	232.12	382.67	231.50	293.32
Unplanned SAIFI	Urban	1.09	0.97	1.08	0.86	1.08	1.09
	Rural Short	2.28	2.47	2.27	2.24	2.26	2.34
	Rural Long	2.81	2.83	2.80	2.95	2.79	2.78
Unplanned MAIFI	Urban	2.79	2.60	2.79	2.80	2.79	2.92
	Rural Short	5.81	5.95	5.81	5.20	5.80	5.87
	Rural Long	11.36	9.72	11.36	9.46	11.35	9.65

** Actual after removing exclusions*

*** End of year forecast based on year-to-date performance as at 30 November 2020*

Table 15: AusNet Services' network reliability performance against STPIS targets.[14]

AusNet Services has achieved improved performance against SAIDI and SAIFI targets in recent years. This is due to an increase in reliability centred capital investments along with somewhat favourable weather conditions. This is a good outcome for customers who have received improved reliability performance.

4.9 Factors that may have material impact on distribution network

This section provides details of factors other than demand growth that may have a material impact on the AusNet Services' network. These factors include network capacitive current, fault levels, voltage levels, other power

[13] A copy of the Electricity Distribution Network Service Providers' Service Target Performance Incentive Scheme can be viewed at the Australian Energy Regulator's website: http://www.aer.gov.au/

[14] Average Annual Target – FINAL DECISION AusNet Services distribution determination 2016 to 2020. Attachment 11 – Service target performance incentive scheme, May 2016 p. 11-9.

system security requirements, quality of supply, ageing and potentially unreliable assets. The contents of this section covers schedule 5.8 (b)(5) of the NER.

Network capacitive: With the implementation of rapid earth fault current limiter (REFCL) technology, the size and balance of network capacitance has become increasingly important and has and is expected to continue to be a primary driver of network augmentation into the future.

Fault levels: Fault levels in certain areas of the distribution network are reaching its allowable limits due to connection of new embedded generators and network augmentations.

Voltage levels: Voltage levels are generally maintained within the distribution code limits. However, in certain areas voltages are outside code limits and corrective actions are taken when these violations are observed. A survey undertaken by an external agency shows that the steady state voltage received by customers are generally closer to the upper boundary of the allowable limits and need to be carefully managed.

Other security system requirements: There are number of zone substations fed from a single sub-transmission line and/or single transformer or un-switched zone substations. These sites will have supply security issues when a credible contingency occurs. Improvements in system security for these sites will be considered when an augmentation is proposed either due to increase loading or ageing assets.

Quality of supply to other network users: Comprehensive system studies are carried out prior to connecting disturbing loads to determine suitability of the proposed new customer connections and corrective actions are taken where necessary to maintain quality of supply to all customers within the code requirements.

Ageing and potentially unreliable assets: AusNet Services' Asset Management strategy outlines the process undertaken to manage ageing and potentially unreliable assets.

These factors are discussed in more detail below:

4.9.1 Network capacitive current

The installation and application of REFCL technology are governed by two key pieces of legislation:

- Electricity Safety Act 1998; and
- Electricity Safety (Bushfire Mitigation) Regulations 2013.

The Electricity Safety (Bushfire Mitigation) Regulations 2013 defines part of the "Required Capacity" as, in the event of a phase-to-ground fault on a polyphase electric line, the ability to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone station for high impedance (25.4 kΩ) faults to 250V within 2 seconds.

For the REFCL to operate within the criteria, the magnitude of network dissymmetry (or network capacitive balance) must be reduced significantly and maintained within a narrow band. Moreover, the size (total capacitance) of the network must also be limited.

Compliance is achieved through the sensitivity equation:

$$R_f = \frac{U_{ph}}{I_{CE}}\left[\frac{\left(\frac{1}{U_{ENt}} - 1\right)}{d + k}\right]$$

Where:

R_f (fault resistance) is legislated to 25.4kΩ

Uph (phase voltage) is fixed at 12.7kV

UENt (trigger neutral voltage) is 3 times Uen (standing neutral voltage) in per unit

d (damping) is a network construction parameter (resistive leakage current) in per unit

k (dissymmetry) is mostly the capacitive imbalance in per unit

ICE (total capacitance to earth) is the tune point in Amps

Of the equation, the two variables that are easiest to manipulate are k (capacitive balance) and I_{CE} (network capacitance size).

k (capacitive balance)	• Should be large enough for the REFCL to tune (typically greater than 30mA). • Should be small enough to detect to allow the REFCL to detect faults (less than 80mA but can be extend if I_{CE} is reduced). • Should be balanced by remote controlled switching section, so the network stays compliant and the ground fault neutraliser does trip the feeder if a field device operates.
I_{CE} (network capacitance size)	• Should not be less than 20A because coil cannot tune well below this level. • In general and from a forward planning perspective should not be more than 100A, although the actual limit is location specific because it is affected by network damping and the level of capacitive balance.

A capacitance forecast has been developed to assist in determining when the network capacitive current is nearing the limit of the sensitivity equation that defines the ability to achieve compliance and indicates augmentation is required.

4.9.2 Fault Levels

Fault level at any given point of the electric power supply network is the current that would flow in case of a short circuit fault at that point. The purpose of fault level calculations is:

- For selecting short circuit protective devices of adequate short circuit breaking capacity
- For selecting circuit breakers & switches of adequate short circuit making capacity
- For selecting busbars, busbar supports, cables & switches, designed to withstand thermal & mechanical stresses because of short circuit and
- To carry out current based discrimination between protective devices
- To indicate the level of system strength and a location's ability to facilitate new generation

Fault levels are determined utilising numerous factors including:

- Installed generation
- Impedance of transmission and distribution network assets.
- Connected load including motors.
- Network voltage.

Switchgear, plant and lines in an electrical network have a maximum allowable three phase and single-phase to ground short circuit fault level rating. The EDC also specifies that embedded generators must not cause fault levels to exceed levels in the distribution network specified in Table 16. Fault levels at some terminal station 66 kV and 22 kV buses exceed these limits by agreement in Use of System Agreements for those stations. Fault level studies are carried out to ensure that the distribution system is operated within plant ratings and EDC requirements.

Voltage Level (kV)	System Fault Level (MVA)	Short Circuit Level (kA)
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50

Table 16: Distribution System Fault Levels

The requirements place an obligation on system planners to ensure that:

- Any augmentation to the network will maintain short circuit fault levels within allowable limits.

- The addition of distributed generation or embedded generation which increases fault levels is assessed for each new connection to ensure limits are not infringed.
- When an augmentation such as a new zone substation, line upgrade or new transformer is contemplated that fault levels are checked to ensure that they do not exceed the allowable limits.

Fault levels are commonly managed by splitting buses at stations when fault level would otherwise exceed limits.

4.9.3 Network Fault Level Issues

When fault levels reach the designed limits as outlined in the EDC (ref Table 16), the following corrective actions will be investigated and appropriate fault level mitigation measured will be taken to comply with the code. These corrective actions include:

- Install 66 kV line reactors or 22 kV transformer reactors or 22 kV feeder reactors to reduce the fault levels.
- Shift the 22 kV feeder open points to transfer generation to a neighbouring station with a higher fault level margin.
- Operate the station with a normally open bus tie.
- Operate the station with one transformer as a hot standby.

As noted previously, comprehensive network studies are undertaken prior to connecting embedded generators and the proponents are advised of the corrective actions required to maintain fault levels within safe limits.

Fault Levels at a number of stations are reaching the allowable limits as described in Table 16 above. The stations with fault level issues are listed below, including the mitigation arrangements.

Watsonia Zone (WT) Substation Fault Level Issue

Watsonia zone substation has a fault level mitigation arrangement where one transformer is maintained as a hot spare and does not share load with the other two transformers. This arrangement will continue into the foreseeable future to maintain fault levels within limits on 22 kV switchgear (assets).

Morwell Terminal Station (MWTS) Fault Level Issue

Similarly, 66 kV buses at MWTS have been opened between Buses 1 and 2 and between 2 and 3 to maintained fault levels within allowable limits.

Ringwood Terminal Station (RWTS) Fault Level Issue

Series reactors have been installed at RWTS on each of the 22 kV feeders to maintain fault levels below 13.1 kA. A new Neutral Earth Resistor (NER) has also been installed to further reduce Phase to Ground fault levels.

Epping Zone Substation (EPG) Fault Level Issue

As part of a network support initiative to manage loads supplied from DRN zone substation, the Wollert Power Station connection is being relocated to DRN. Due to this generator relocation from EPG zone substation to DRN zone substation, the previously noted EPG 22 kV bus fault level issue has now been resolved.

4.9.4 Voltage Levels

Electricity distributors are obliged to maintain customer voltages within specified limits. The Victorian Electricity Distribution Code specifies the voltage levels that must be maintained at the point of supply to the customer's electrical installation. These levels are discussed in Section 12.4 of this report.

Network voltage can be affected due to a number of factors including:

- Customer load
- Generation of electricity into the network (at various voltage levels)
- Transmission and distribution line impedances
- Transformer impedances
- Capacitors in the network (or static var compensators)

Voltage levels from the respective connection points to customers' point of connections are managed by application of on-load-tap changes in zone substation transformers, reactive power compensations at various points in the network; line voltage regulators and utilising off-load taps in distribution transformers.

Due to increased penetration of solar PV over the last few years, maintaining voltage within code limits at customers' point of connections has become a challenge. However, these issues are identified, and corrective actions are taken to minimise the impact on customers.

AusNet Services actively undertakes works to improve supply quality for customers connected to its distribution network. These works are carried out when voltage issues are identified through AMI meters or to respond to customer complaints regarding supply voltage. There are no specific areas where these issues are emerging at present. The steady state voltages monitored through dedicated power quality monitoring instruments and customers' AMI meters have revealed that there are many customers experiencing voltages close to the upper limit of the code requirements. As part of network planning activity, steady state voltages are brought back well within the code limits where possible.

4.9.5 Negative Sequence Voltage

Based on investigations in 2010, the following sub-transmission loops have been identified as having negative sequence voltage issues:

- East Gippsland sub-transmission network – zone substations NLA and CNR.
- TTS–KLK–Rub A–KMS sub-transmission loop – zone substations KLK, Rub A and SMR.
- South Gippsland sub-transmission loop – zone substations FTR, LGA, WGI and PHI.
- GNTS–BN–MSD loop – zone substations MSD and MJG.
- WOTS–WO loop – zone substation WO.
- RWTS–RWN loop – zone substation RWN.
- RWTS–LDL–WYK loop – zone substation LDL.
- RWTS–BRA–BWR loop – zone substations BRA and BWR.

Although these loops were identified as having negative sequence voltage issues, AusNet Services has not received complaints from customers supplied from these loops and zone substations. However, several measures have been taken to minimise the negative sequence voltage deviation, including implementing transpositions on 66 kV sub-transmission lines and load balancing.

4.9.6 Other power system security requirements

The National Electricity Rules under clause 4.3.4 (g) – (i) requires DNSPs to plan and operate their networks in accordance with network stability guidelines published by the Australian Energy Market Operator. AusNet Services carries out its planning and network operations in accordance with these guidelines.

4.9.7 Quality of supply to other network users

AusNet Services undertakes system studies as part of the connection process when connecting disturbing loads such as embedded generators or large industrial customers to investigate the impact on quality of supply to other network users. The network studies described above can also be undertaken by a consultant nominated by the customer in consultation with AusNet Services. The required network data will be provided to the respective consultant and the final report will be reviewed by AusNet Services and approved before the customer is allowed to be connected.

4.9.8 Ageing and potentially unreliable assets

AusNet Services' three energy networks are accredited to ISO 55001, the international standard for Asset Management. Adoption of this standard enables AusNet Services to achieve its objectives through effective and efficient management of its assets. AusNet Services' ongoing commitment to maintain ISO 55001 Asset Management accreditation ensures an auditable asset management system facilitating customer's expectations to safely maintain the quality, reliability and security of supply in an economic manner.

AusNet Services has an ageing electricity distribution network, with a significant proportion of these assets approaching the end of their technical lives.

ISO 55001 requires the asset management plans to include specific tasks and activities required to optimise costs, risks and performance of the assets. A key activity carried out to optimise the costs, risk and performance of ageing and potentially unreliable assets is the development of asset category risk profiles based on asset condition data.

Condition monitoring techniques are utilised to detect early stages of asset degradation before poor condition becomes a significant risk to the safety of personnel, network reliability and the environment. A range of condition monitoring techniques is used to monitor and analyse the mechanical and electrical condition and performance of the various asset classes to accurately forecast future augmentation and replacement requirements.

Zone substation plant and equipment is subject to a combination of periodic and duty cycle inspection and maintenance programs derived from manufacturer recommendations and industry experience. Line assets are subject to cyclic inspection and other techniques such as automated image processing using high resolution aerial images, Smart Aerial Imaging and Processing (SAIP), for conductor condition assessment.

The risks associated with network assets are quantified through the application of dependability management techniques incorporating reliability centred maintenance (RCM) process. Dependability management requires the analysis of availability performance and the influencing factors of reliability, maintainability, and maintenance support under given conditions over a specified period for individual network assets. Failure Mode Effect Analysis (FMEA) of historical asset failure data determines typical root causes of functional failures and the effects these causes have on key performance measures including network safety, reliability, and availability. Asset condition data collected during scheduled maintenance tasks is used to determine dynamic time-based probability of failures and percentage of remaining service potential (RSP) of the asset in that lifecycle phase.

Dependability models output risk profiles for each asset category which are used to establish optimised maintenance and asset replacement plans.

5 Network Asset Retirements and De-ratings

This section, coupled with Section 9, addresses the requirements for reporting of network asset retirements and de-ratings as described in Schedule 5.8 (b1) and (b2) of the National Electricity Rules. The information is presented in two categories: Individual assets and Grouped assets.

The assets categories reflect the relative size or significance of the asset and the approach to management of asset retirement and replacement. Items listed in the individual asset category are usually the subject of a proactive planned retirement process. These assets are typically retired and, where proven to be economically feasible replaced. Items listed in the grouped asset category are usually retired and replaced as part of a program of work in response to inspection programs throughout the network.

The assets assigned to the individual and grouped asset categories are listed in Appendix D.

5.1 Individual asset retirement and de-ratings

Individual assets include zone substation transformers, circuit breakers, instrumentation transformers and capacitor banks. Transformers, circuit breakers and instrumentation transformers are assessed on individual failure rates depending on their overall asset condition. AMS 10-13, Condition Monitoring, describes AusNet Services' strategy and approach to monitoring the condition of assets as summarised in this section. Asset condition is measured with reference to an asset health index, on a scale of C1 to C5. As described in Section 3.8.10, the C1 to C5 condition range is consistent across asset types and relates to the remaining service potential of the asset.

Where AusNet Services is planning or has committed to retire and, where economically justified, replace individual assets, these works are summarised in Section 9.

In 2018, AusNet Services reviewed and revised its zone substation transformer cyclic ratings. The ratings are reflected in the firm capacity MVA ratings, presented in the tables of Section 4.6.3, and the network limitations identified in Section 6.2. The cyclic ratings are based on daily load curves for each zone substation and are prepared in line with Australian Standard AS 2374.7 – 1997 Loading Guide for Power Transformers, as outlined in AusNet Services' asset management strategy AMS 20-101.

5.2 Grouped asset retirement and de-ratings

Summaries of asset retirement and de-ratings of Grouped assets is contained in Appendix E. The asset statement for each Group provides an overview of the methodologies and assumptions used in the development of the asset management strategies that influence the retirement or de-rating of the asset group. The complete asset management strategies are available upon request to the contacts outlined in Appendix F of this report. The complete asset management strategies were provided to the Australian Energy Regulator as part of the Electricity Distribution Price Reset submission.

6 System Limitations for Sub-Transmission Lines and Zone Substations

This section provides details required by schedule 5.8 (c) of the National Electricity Rules covering information on system limitations for sub-transmission lines and zone substations. The assessments and information on the limitations cover what is required in (1) to (5) and include:

- Estimates of the location and timing of the system limitations.
- Analysis of any potential load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment.
- A brief discussion of the types of potential solutions that may address the system limitation in the forward planning period.

Where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least twelve months, the following has been provided:

- An estimate of the month and year in which a system limitation is forecast to occur.
- The relevant connection points at which the estimated load reduction may occur.
- The estimated reduction in forecast load (MW) or improvements in power factor needed to defer the forecast system limitation.

None of the system limitations identified in Section 6 have an impact on the capacity at transmission-distribution connection points.

6.1 Sub-transmission line limitations

This section discusses sub-transmission line limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor line limitations that exist under contingency conditions, but where there is sufficient load transfer capability to supply the load, are not discussed in detail in this section, but are reported in the tables of Section 4.6.2

6.1.1 CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS 66 kV loop

The Cranbourne Terminal Station (CBTS) to Lysterfield (LYD) to Narre Warren (NRN) to Pakenham (PHM) to Officer (OFR) to Berwick North (BWN) to Lang Lang (LLG) to Clyde North (CLN) 66 kV loop supplies over 90,000 customers via the seven zone substations listed. This 66 kV loop has energy at risk over the summer period from December to March. The worst-case outage is the loss of the CBTS-LYD 66 kV line where loading on the CBTS-BWN 66 kV line will exceed its rating at maximum demand. The firm capacity of this loop is 243 MVA. The summer 2020/21 forecast total peak coincident 66 kV loop maximum demand under single contingency outage is 314.0 MVA increasing to 339.9 MVA in summer 2024/25.

The level of overload exceeds the load transfer capacity to zone substations supplied from other adjacent 66 kV loops, and AusNet Services is investigating options to mitigate the network limitation and identified supply risk. Figure 7 shows the single line diagram of this loop along with the constrained line segments (coloured in red) under single order contingency.

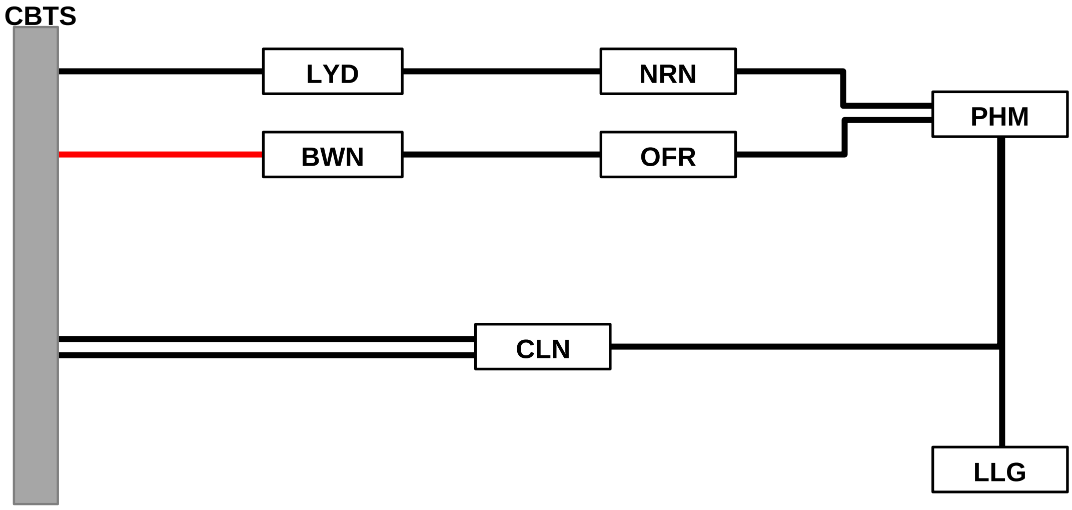


Figure 7: CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN 66 kV Loop

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations up to a maximum transfer capacity of 47.9 MVA in the event of a line outage.

AusNet Services has also established an option to extend the 66 kV network to allow Lysterfield Zone Substation (LYD) and Narre Warren Zone Substation (NRN) to be supplied radially from East Rowville Terminal Station (ERTS), as well as BWN and OFR to be supplied radially from ERTS, thereby offloading this CBTS 66 kV loop, during network contingency events. While this contingency plan supports network supply capacity under contingency events, it requires LYD and NRN, as well as BWN and OFR to be supplied radially from ERTS, thereby significantly increasing the network supply risk for subsequent outages. To support loading on the CBTS loop, a 1MW temporary generator will be located at LLG over the summer maximum demand period.

Longer term options being considered to mitigate the identified supply risk, include:

- Establish a third CBTS-CLN 66 kV line and a second CLN-LLG 66 kV line.
- Establish a second PHM-LLG 66 kV line.
- Re-conductor the existing CBTS-LYD 66 kV line.
- Generator or demand response network support.

These, and any other, potential supply risk mitigation options will be subject to the outcome of a future RIT-D assessment.

6.1.2 LGA-WGI-PHI 66 kV loop

The Leongatha (LGA) to Wonthaggi (WGI) loop and radial 66 kV line to Phillip Island (PHI) supplies over 30,000 customers via the two zone substations at Wonthaggi and Phillip Island. This LGA – WGI 66 kV loop has energy at risk over the peak tourism seasons including school holidays, long weekends and special events such as the motorcycle Grand Prix. An outage of either the LGA – LSSS, LSSS - WGI or LGA - LSSS/WGI

66 kV lines will result in voltage collapse of this network and loss of supply at both zone substations if loading exceeds 56.0 MVA, and load shedding if the thermal loading exceeds 32.0 MVA. Maximum coincident demand occurs in summer and is expected to reach 75.5 MVA in summer 2020/21, increasing to 79.4 MVA in summer 2024/25. The BHWF output also reduces risk in this part of the network. Figure 8 shows the single line diagram of this loop along with the constrained line segment (coloured in red) under single order contingency.

In late-2020, AusNet Services published a request for proposals (RFP) to enter into a 10 MW/300 MWh network support contract in the PHI area. This RFP closed on 21 December and AusNet Services will assess proposals in early-2021.

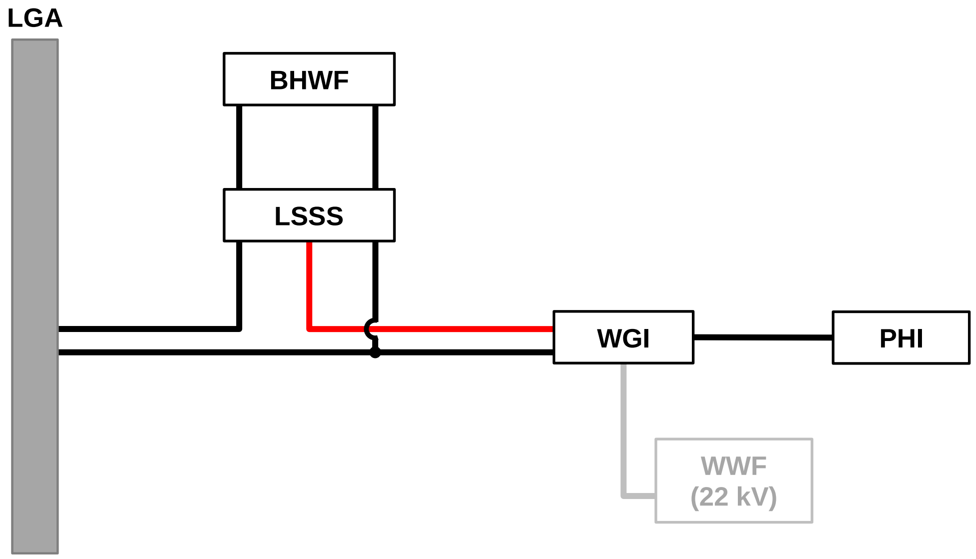


Figure 8: LGA-WGI-PHI 66 kV Loop

Other options considered by AusNet Services included:

- Re-conductor up to 27 kilometres of existing 6/1/.186 ACSR conductor to 19/4.75 AAC conductor in the LSSS – WGI and LGA – LSSS/WGI 66 kV lines.
- Contract network support via embedded generation connected to WGI or PHI to reduce demand during risk periods.
- Contract for network support via demand management to reduce demand during risk periods.

Additionally, a contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations up to a maximum transfer capacity of 3.0 MVA in the event of a line outage.

6.1.3 MWTS-LGA-FTR-WGI-PHI 66 kV loop

The Morwell Terminal Station (MWTS) to Leongatha (LGA) to Foster (FTR) to Wonthaggi (WGI) to Phillip Island (PHI) 66 kV network supplies over 50,000 customers via the four zone substations at Leongatha, Foster, Wonthaggi and Phillip Island. This 66 kV loop has energy at risk over the peak tourism season of Christmas and early January. An outage of either of the MWTS-LGA No. 1 or the No. 3 66 kV line will result in thermal overload of the MWTS-LGA No. 2 66 kV line, requiring load shedding if loading exceeds 92.3 MVA. Maximum coincident demand under single contingency outage in summer is expected to reach 144.0 MVA in summer 2020/21 increasing to 149.3 MVA in summer 2024/25. The 106 MW Bald Hills Wind Farm (BHWF), connected into this 66 kV loop in 2015, generates sufficient output to eliminate the risk of overload under single contingency, and for most of the time.

Figure 9 shows the single line diagram of this loop along with the constrained line segment (coloured in red) under single order contingency.

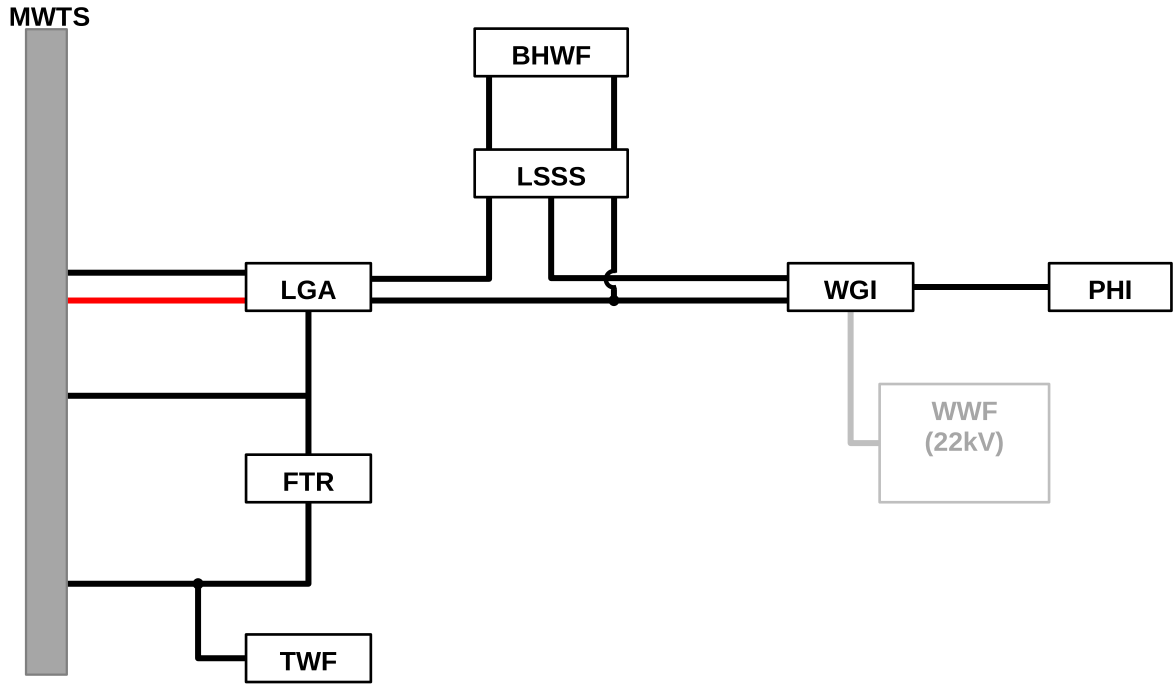


Figure 9: MWTS-LGA-FTR-WGI-PHI 66 kV Loop

AusNet Services has been examining options to address this summer constraint and the following are being considered:

- Re-conductor up to 22 kilometres of existing 6/1/.186 ACSR conductor to 19/4.75 AAC conductor MWTS-LGA No. 2 66 kV line.
- Contract network support via embedded generation connected to LGA, WGI or PHI, to offset demand during risk periods.
- Contract for network support via demand management, to reduce demand during supply risk periods.

It is not expected that any of these options will be implemented in the next five years as they are not yet economic considering the probabilistic planning approach.

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations up to a maximum transfer capacity of 3.0 MVA in the event of a line outage.

6.1.4 MWTS-TGN-SLE-MFA-BDSS-BDL-NLA-CNR 66 kV loop

The East Gippsland 66 kV network, which emanates from Morwell Terminal Station (MWTS), supplies over 66,000 customers via six AusNet Services zone substations, including Traralgon (TGN), Sale (SLE), Maffra (MFA), Bairnsdale (BDL), Newmerella (NLA) and Cann River (CNR).

Demand in this loop is currently supported by local embedded generation, including through a network support agreement with Bairnsdale Power Station (BPS). The network support agreement has been in place since March 2000 and while it was due to expire in March 2020, has been extended to March 2022. Network support is provided at levels between 20 MW and 40 MW to supply the afternoon and evening peaks, and the overnight water heating peak.

In late-2020, AusNet Services published a non-network options report outlining the risks on this 66 kV network, Submissions to this non-network options report close on 8 January 2021. More information on the network limitations and the RIT-D process can be found on AusNet Services' website (Regulatory Investment Test (ausnetservices.com.au)).

Figure 10 shows the single line diagram of this loop along with the constrained line segments (coloured in green) under single order contingency.

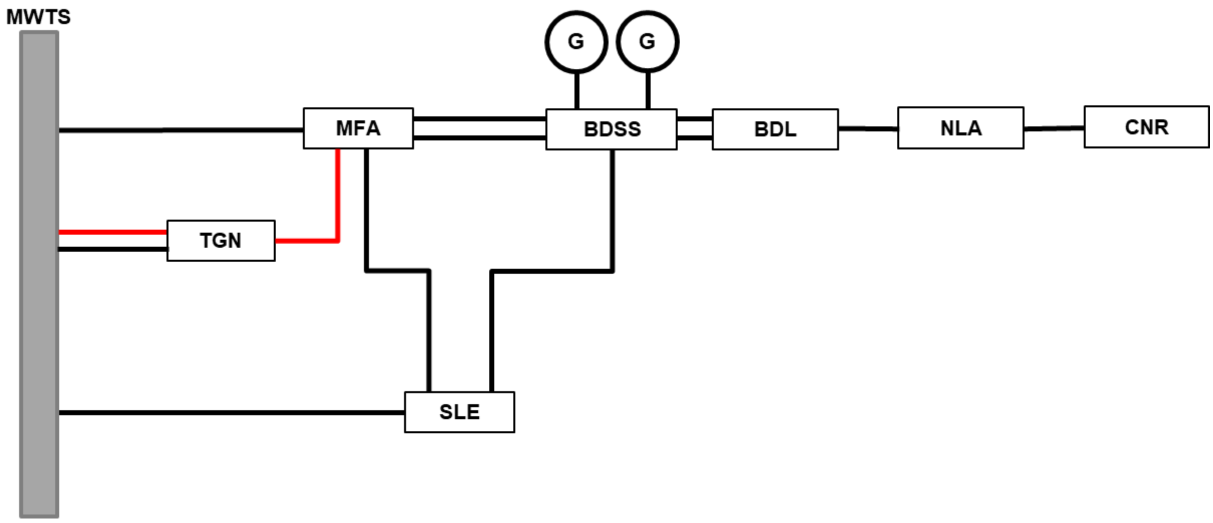


Figure 10: MWTS-TGN-SLE-BDSS-BDL-NLA-CNR 66 kV Loop

6.1.5 SMTS-DRN-KLK-MDI-RubA-YEA-SMR-KMS 66 kV loop

The Doreen (DRN) to Kinglake (KLK) to Rubicon A (RubA) to Seymour (SMR) to Kilmore South (KMS) 66 kV loop supplies approximately 18,000 customers via the four zone substations at Kinglake, Rubicon A, Murrindindi, and Seymour. The supplies to KLO, KMS and DRN are secured by duplicated 66 kV lines, but the sections beyond these stations are at risk. This 66 kV loop has energy at risk over the summer period from December to March inclusive as well as the winter period from June to August inclusive. An outage of the KMS-SMR 66 kV line results in voltage collapse of the network and loss of these four zone substations if the combined loading on these four zone substations exceeds 35.0 MVA. No other line outage is expected to result in loss of customer load. Maximum coincident demand in summer is expected to reach 55.0 MVA under single order contingency in summer 2020/21 increasing to 57.7 MVA in summer 2024/25. Figure 11 shows the single line diagram of this loop along with the constrained line segment (coloured in green) under single order contingency. It also shows the new KLO-DRN 66 kV line, which was commissioned in July 2018.

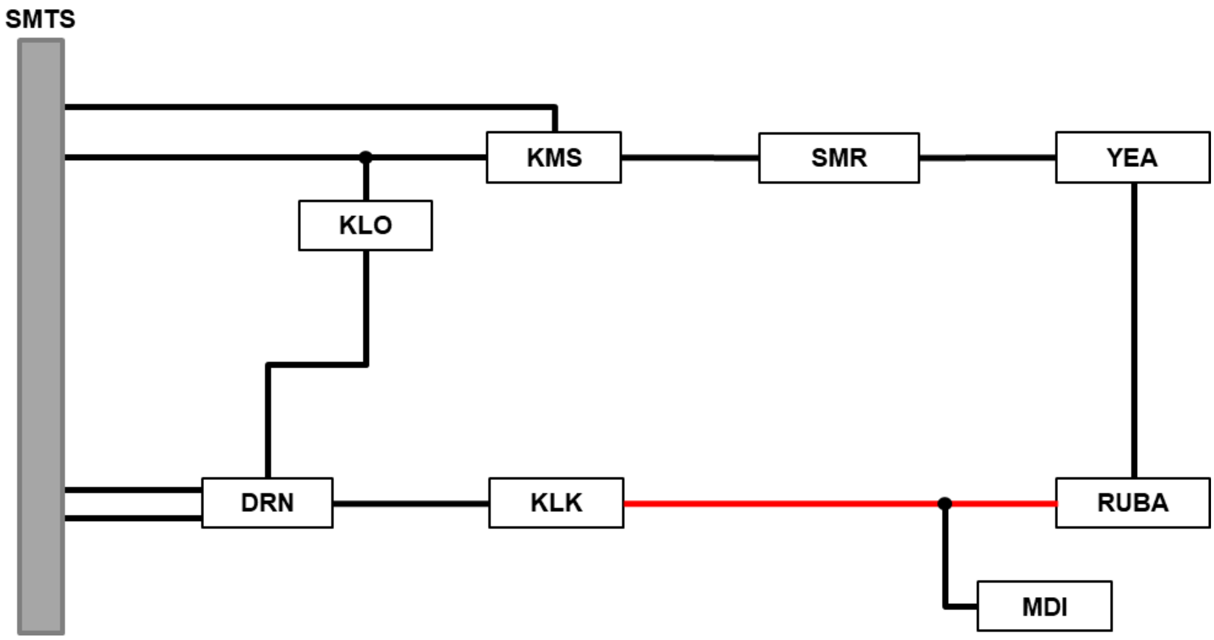


Figure 11: SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS 66 kV Loop

AusNet Services has been examining options to address the voltage collapse constraint, and the following have been considered:

- Construct new KMS-SMR No. 2 66 kV line. This option is expected to cost in excess of $30 million and is not currently considered economically feasible.

- Contract network support via embedded generation connected at Seymour, to reduce network loading during risk periods.
- Contract for network support via demand management, to reduce demand during risk periods.

It is not expected that any work will be implemented in the next five years as they are not yet economic considering the probabilistic planning approach. A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations in the event of a line outage, however this is only for a maximum transfer capacity of 2.7 MVA.

6.1.6 TTS-WT-NH 66 kV loop

The Thomastown Terminal Station (TTS) to Watsonia (WT) to North Heidelberg (NH) to TTS 66 kV loop supplies approximately 45,000 customers (including around 25,000 AusNet Services customers) via the two zone substations at Watsonia and North Heidelberg. The NH zone substation is owned by Jemena. This 66 kV loop has energy at risk over the summer period from December to March inclusive. Both the TTS-WT (line owned by AusNet Services) and TTS-NH (line owned by Jemena) 66 kV lines have a rating of 1,025 amps (117.2 MVA) in summer. The maximum coincident demand is forecast to reach 141.5 MVA in summer 2020/21, growing slowly to 143.3 MVA by summer 2024/25. Figure 12 shows the single line diagram of this loop along with the constrained line segments (coloured in red) under single order contingency.

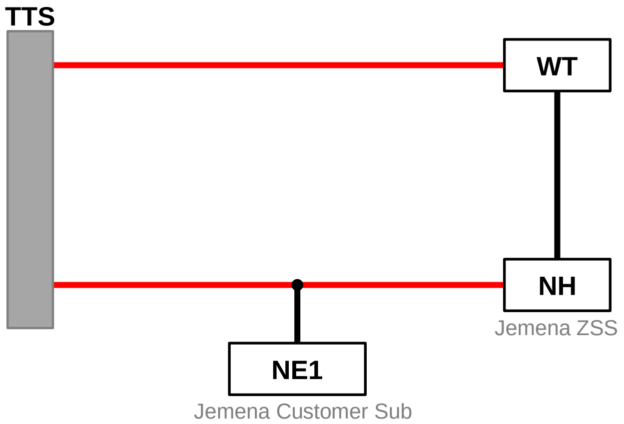


Figure 12: TTS-WT-NH 66 kV Loop

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations up to a maximum transfer capacity of 16.5 MVA (AusNet Services) in the event of a line outage. Further transfer capacity may be available via the Jemena network.

6.1.7 MWTS-YPS-MOE-WGL-MWTS

The Morwell Terminal Station (MWTS) to Yallourn Power Station (YPS) to Moe (MOE) to Warragul (WGL) 66 kV loop supplies close to 40,000 customers. This 66 kV loop has energy at risk over the summer period from December to March. The worst-case outage is the loss of the YPS-WGL No.1 66 kV line where loading on the YPS-WGL/MOE 66 kV line between YPS and the tee point will exceed its rating at maximum demand. The firm capacity of this loop is 114 MVA. The summer 2020/21 forecast total peak coincident 66 kV loop maximum demand under single contingency outage is 111.0 MVA increasing to 119.0 MVA in summer 2024/25.

The level of overload just exceeds the 4.3 MVA load transfer capacity to zone substations supplied from other adjacent 66 kV loops, and AusNet Services is investigating options to mitigate the network limitation and identified supply risk. Figure 7 shows the single line diagram of this loop, including the normally open section of line (dashed) and the single order contingency constrained line segment (coloured in red).

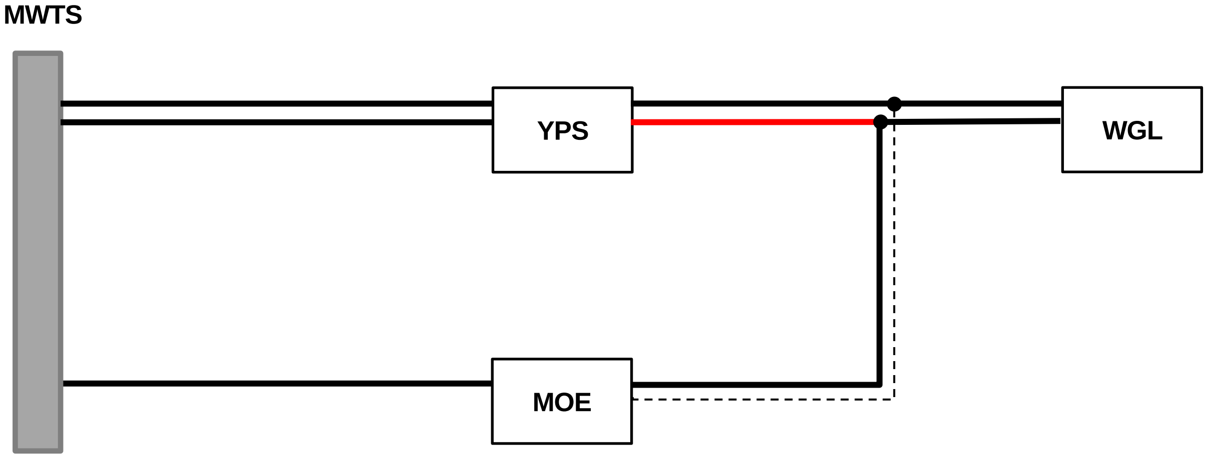


Figure 13: MWTS-YPS-MOE-WGL 66 kV Loop

A contingency plan has been developed to transfer load away via 22 kV links to adjacent zone substations up to a maximum transfer capacity of 4.3 MVA in the event of a line outage.

AusNet Services is currently examining options to address the thermal constraint including:

- Thermally uprate the YPS-WGL/MOE 66kV line between YPS and the tee point.
- Reconductor the YPS-WGL/MOE 66kV line between YPS and the tee point.
- Contract network support via embedded generation connected to WGL or MOE, to offset demand during risk periods.
- Contract for network support via demand management, to reduce demand during supply risk periods

6.1.8 Radial 66 kV lines

AusNet Services has nine zone substations, including Barnawartha (BWA), Cann River (CNR), Clover Flat (CF), Lang Lang (LLG), Mansfield (MSD), Merrijig (MJG), Mount Beauty (MBY), Newmerella (NLA) and Phillip Island (PHI), which are supplied via single radial 66 kV lines. All of these lines have sufficient capacity over the next five years to supply the forecast demand, however all customers supplied from these zone substations face outages whenever the 66 kV supply line has an outage. Reinforcing these radial 66 kV networks with the construction of a second 66 kV line depends on the reliability performance of the existing radial 66 kV line, and the resultant expected unserved energy.

In each of the nine cases, AusNet Services' planning criteria shows that it is not currently economic to duplicate the 66 kV line. While 66 kV line duplication is not economic, we are open to network support and other innovative options to mitigate the supply risks.

To support the NLA and CNR radial 66 kV network, AusNet Services is installing a large-scale battery to be known as Mallacoota Area Grid Storage (MAGS). MAGS is an innovative project that is expected to improve power reliability in Mallacoota by around 90 per cent. The project involves the establishment of a power storage facility, made up of a large-scale battery, generator, and associated equipment, connected to the AusNet network in Mallacoota.

The heart of MAGS is a lithium ion battery array with a total storage capacity of 1 MWh. The MAGS battery will be charged from the grid and will then feed power back into the grid during local outages. The facility will be located at the East Gippsland water treatment plant, just outside the Mallacoota township.

For this project, AusNet services has been able to re-purpose the battery used at Thomastown for the grid energy storage system (GESS) trial which was completed in 2017. While delayed due to the 2019/20 bushfires and the COVID-19 Pandemic, the battery and generator has been moved to Mallacoota and is expected to be commissioned in 2021.

6.2 Zone substation limitations

This section presents the zone substations that are carrying, or are forecast to carry, significant service level risk in the five-year forward planning period. This service level risk is also quantified alongside commentary outlining the primary drivers of the identified risk.

In many cases the load transfer capacity is sufficient to cover the N-1 supply risk. However, the service level risk and supply risk cost also considers and quantifies other risk factors such as safety, collateral damage and reactive replacement costs.

Where AusNet Services considers it economic to do so, network development plans are outlined in Section 9 of this DAPR.

6.2.1 Doreen Zone Substation (DRN)

Doreen (DRN) Zone Substation consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and eight 22 kV feeder circuits. The substation supplies approximately 28,600 residential, commercial, industrial and agricultural customers in Victoria's southeast growth corridor.

DRN Zone Substation is a summer peaking substation with a forecast maximum demand growth rate averaging 3.6% per annum over the next 10-year period. The growth in demand is predominately driven by the significant expansion of residential and commercial development in Melbourne's northern growth corridor. The load transfer capability of the feeder interconnections between DRN and its neighbouring zone substations is 22.1 MVA.

Table 17 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

DRN	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	31.2	31.5	34.2	37.2	40.2
10% POE Max Overload (%)	63%	64%	69%	75%	81%
Hours at Risk (h)	19	24	39	63	87
EUSE (MWh)	6.1	7.9	10.1	13.0	18.5
Cost of EUSE ($M)	0.20	0.26	0.34	0.44	0.62

Table 17: Estimated energy at risk at DRN Zone Substation

A summary of the condition of key assets at DRN Zone Substation is provided in Figure 15 below.

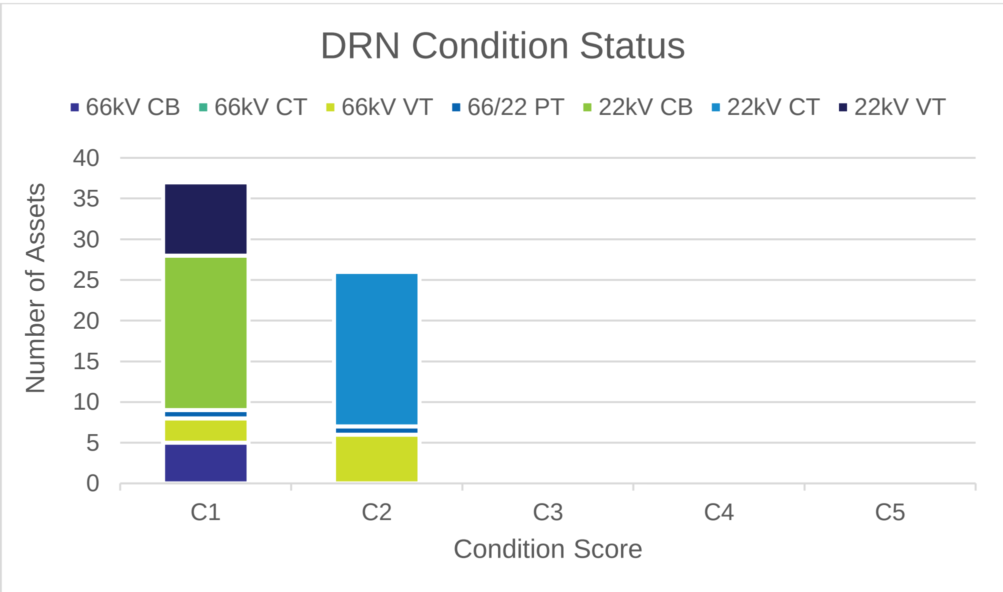


Figure 14: Estimated energy at risk at DRN Zone Substation

Upon thorough options analysis, the chosen option works will include establishing a new 66/22 kV transformer, a 66 kV circuit breaker to facilitate connection of the new transformer, and a new 22 kV switchboard to facilitate connection of the new transformer and future 22 kV feeders required to meet the growing demand.

6.2.2 Clyde North Zone Substation (CLN)

Clyde North (CLN) Zone Substation consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and seven 22 kV feeder circuits. The substation supplies approximately 31,000 residential, commercial, industrial and agricultural customers in Victoria's southeast growth corridor.

CLN Zone Substation is a summer peaking substation with a forecast maximum demand growth rate averaging 4.1% per annum over the next 10-year period. The growth in demand is predominately driven by the significant expansion of residential and commercial development in Melbourne's southeast growth corridor. The load transfer capability of the feeder interconnections between CLN and its neighbouring zone substations is 21.9 MVA.

Table 18 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

CLN	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	42.4	42.7	46.4	50.2	54.1
10% POE Max Overload (%)	97%	98%	107%	115%	124%
Hours at Risk (h)	62	71	96	124	154
EUSE (MWh)	4.7	7.8	19.5	48.6	105.3
Cost of EUSE ($M)	0.17	0.28	0.70	1.74	3.77

Table 18: Estimated energy at risk at CLN Zone Substation

A summary of the condition of key assets at CLN Zone Substation is provided in Figure 15 below.

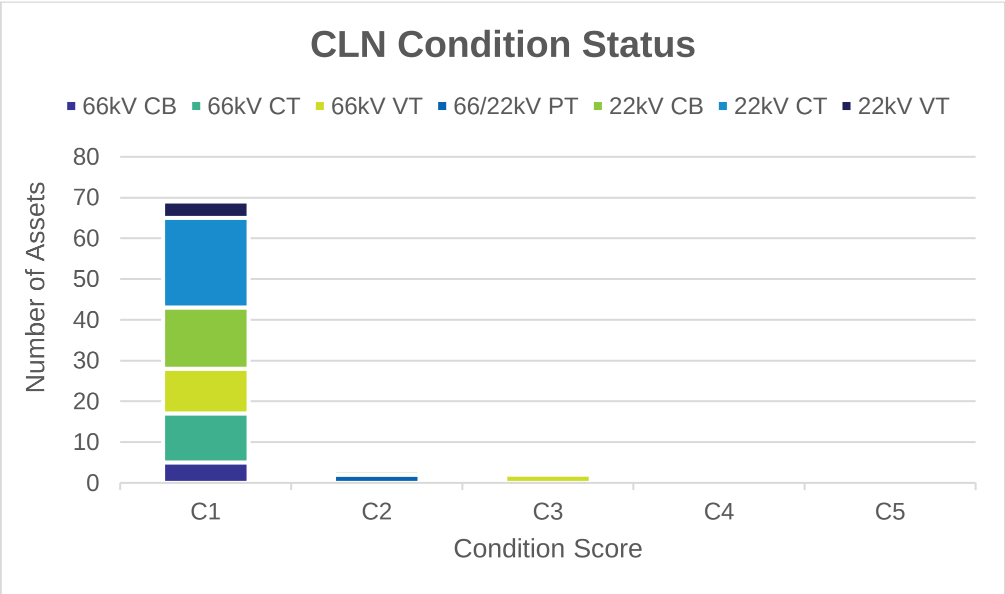


Figure 15: Estimated energy at risk at CLN Zone Substation

Upon thorough options analysis, the chosen option works will include establishing a new 66/22 kV transformer, a 66 kV circuit breaker to facilitate connection of the new transformer, and a new 22 kV switchboard to facilitate connection of the new transformer and separation of the temporarily piggybacked feeders that are currently in the construction phase.

6.2.3 Maffra Zone Substation (MFA)

Maffra (MFA) is located approximately 220km east of Melbourne supplying approximately 8,350 customers. The load at MFA includes town and rural based residential, with some town based commercial, industrial and farming.

MFA is a summer peaking station and the peak electrical demand reached 36.1MVA in the summer of 2017/18. The recorded peak demand during the winter of 2018 was 26.2MVA. MFA demand is forecast to grow steadily at around 1% per annum. The load transfer capability of the feeder interconnections between MFA and its neighbouring zone substations is 6.5 MW.

Table 19 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

MFA	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	4.8	4.9	5.0	5.1	5.3
10% POE Max Overload (%)	15%	16%	16%	16%	17%
Hours at Risk (h)	0	0	0	0	0
EUSE (MWh)	53.4	58.9	64.9	71.4	78.6
Cost of EUSE ($M)	2.37	2.62	2.88	3.17	3.49

Table 19: Estimated energy at risk at MFA Zone Substation

A summary of the condition of key assets at MFA Zone Substation is provided in Figure 16 below. Approximately 48% of asset at MFA Zone Substation are in poor to very poor condition, C4 and C5 respectively.

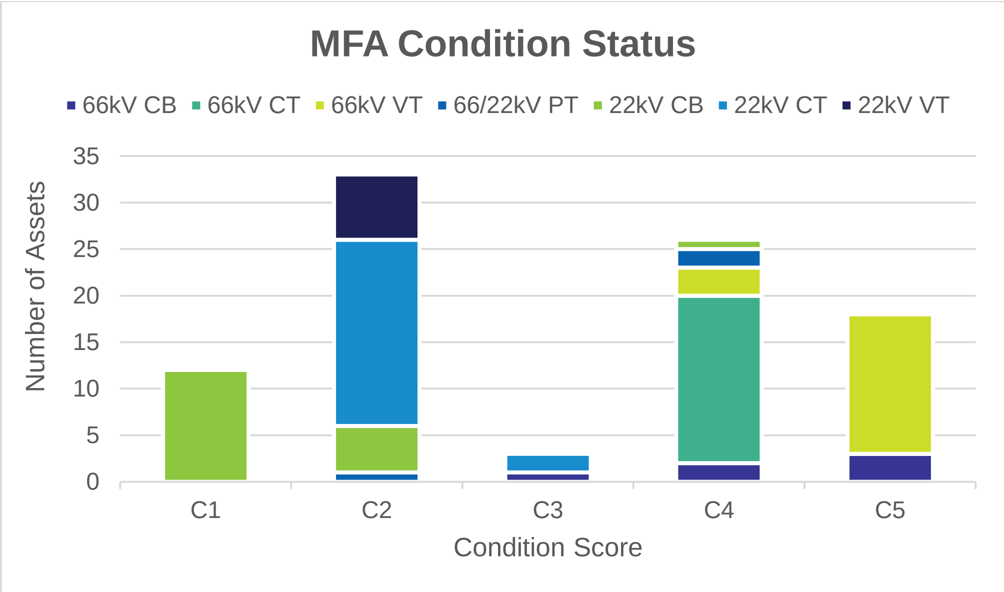


Figure 16: Estimated energy at risk at MFA Zone Substation

The service level risk to customers supplied from MFA Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing the 66kV circuit breakers by 2020.

6.2.4 Thomastown Zone Substation (TT)

Thomastown (TT) Zone Substation is located in the northern suburbs of metropolitan Melbourne. It is the main source of electricity for the suburbs of Thomastown, Lalor, Reservoir, Kingsbury and Bundoora. TT supplies approximately 28,600 customers, split evenly with AusNet Services supplying approximately 14,100 customers and Jemena supplying approximately 14,500 customers. The load at TT is urban in nature and includes mostly residential and industrial load with some commercial loads.

TT zone substation is a summer peaking station and the peak electrical demand reached 75.6MVA in the summer of 2017/18. The peak demand at TT is forecast to increase slowly at approximately 0.4% per annum. The load transfer capability of the feeder interconnections between TT and its neighbouring zone substations is 21.5 MVA.

Table 20 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

TT	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	25.2	24.9	25.1	25.4	25.7
10% POE Max Overload (%)	43%	42%	43%	43%	44%
Hours at Risk (h)	63	62	62	64	65
EUSE (MWh)	90.5	99.2	108.9	119.6	131.3
Cost of EUSE ($M)	3.87	4.24	4.65	5.11	5.61

Table 20: Estimated energy at risk at TT Zone Substation

A summary of the condition of key assets at TT Zone Substation is provided in Figure 17 below. Approximately 73% of asset at TT Zone Substation are in poor to very poor condition, C4 and C5 respectively.

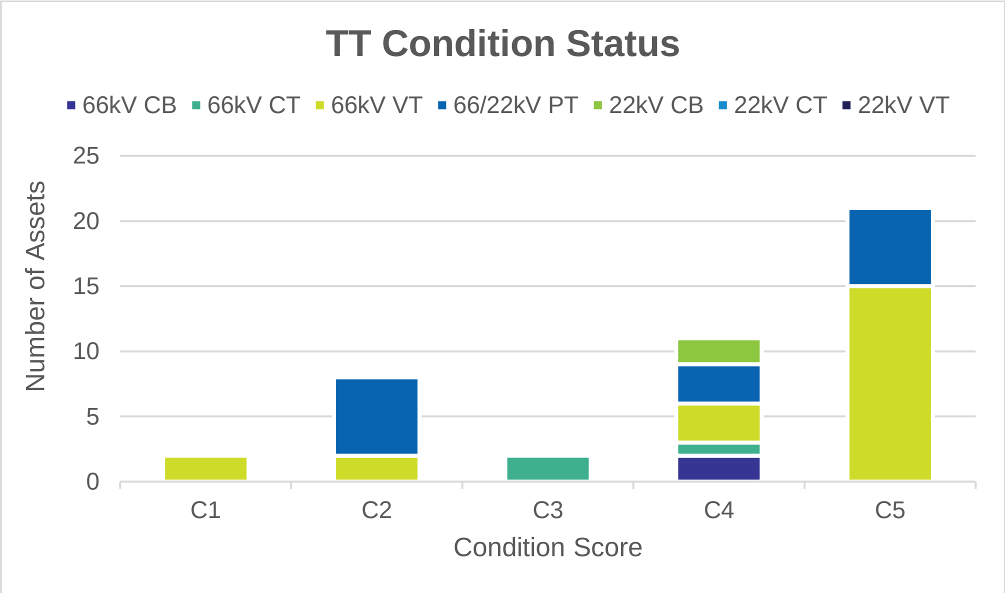


Figure 17: Estimated energy at risk at TT Zone substation

The service level risk to customers supplied from TT Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing both the 66kV and 22kV circuit breakers by 2021.

6.2.5 Watsonia Zone Substation (WT)

Watsonia (WT) Zone Substation is located in the northern suburbs of metropolitan Melbourne approximately 20km north of Melbourne. WT is the main source of supply for the suburbs of Watsonia, Greensborough, Montmorency, Lower Plenty, Macleod and Bundoora. WT supplies approximately 23,460 AusNet Services customers and 145 Jemena customers. The load at WT includes mostly residential and commercial urban load with some industrial loads and a few farm loads.

WT is a summer peaking station and the peak electrical demand reached 61.2MVA in the summer of 2017/18. The recorded peak demand in winter 2018 was 43MVA. The demand at WT is forecast to increase slowly at a growth rate of less than 1% per annum. The load transfer capability of the feeder interconnections between WT and its neighbouring zone substations is 15.4 MVA.

Table 21 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

WT	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	0.0	0.0	0.0	0.0	0.0
10% POE Max Overload (%)	0%	0%	0%	0%	0%
Hours at Risk (h)	0	0	0	0	0
EUSE (MWh)	34.2	36.8	39.6	42.5	45.6
Cost of EUSE ($M)	1.31	1.41	1.52	1.63	1.75

Table 21: Estimated energy at risk at WT Zone Substation

A summary of the condition of key assets at WT Zone Substation is provided in Figure 18 below. Approximately 70% of asset at WT Zone Substation are in poor to very poor condition, C4 and C5 respectively.

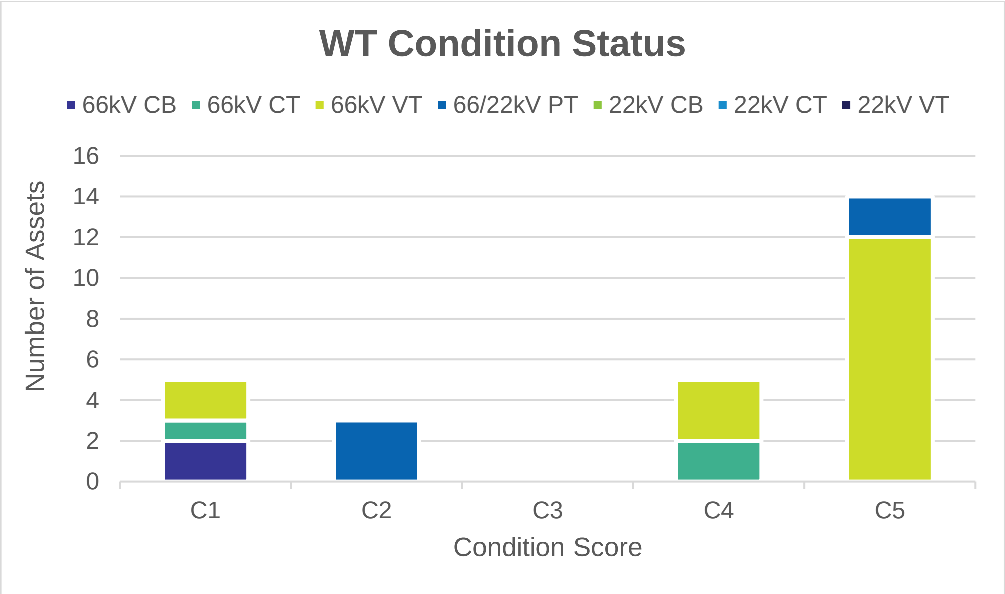


Figure 18: Estimated energy at risk at WT Zone substation

The service level risk to customers supplied from WT Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing the 22kV circuit breakers by 2020.

6.2.6 Benalla Zone Substation (BN)

Benalla (BN) is located approximately 212 km north-east of Melbourne and is the main source of supply for the rural towns of Benalla, Euroa, Lima South, Tatong, and Goormbat townships. BN supplies approximately 12,100 AusNet Services' customers. The customer base supplied from BN is predominately made up of residential (66%) and farming (24%), with some commercial and industrial.

BN is a summer peaking station and the peak electrical demand reached 36.2MVA in summer 2018/19, and is forecast to grow slowly at approximately 0.3% per annum to 36.7MVA by 2024/25. The load transfer capability of the feeder interconnections between BN and its neighbouring zone substations is 1.6 MW.

Table 22 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

BN	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	3.9	4.1	4.2	4.4	4.6
10% POE Max Overload (%)	13%	13%	14%	14%	15%
Hours at Risk (h)	22	25	27	29	32
EUSE (MWh)	26.1	28.4	30.8	33.3	36.0
Cost of EUSE ($M)	1.11	1.20	1.31	1.41	1.53

Table 22: Estimated energy at risk at BN Zone Substation

A summary of the condition of key assets at BN Zone Substation is provided in Figure 19 below. Approximately 58% of asset at BN Zone Substation are in poor to very poor condition, C4 and C5 respectively.

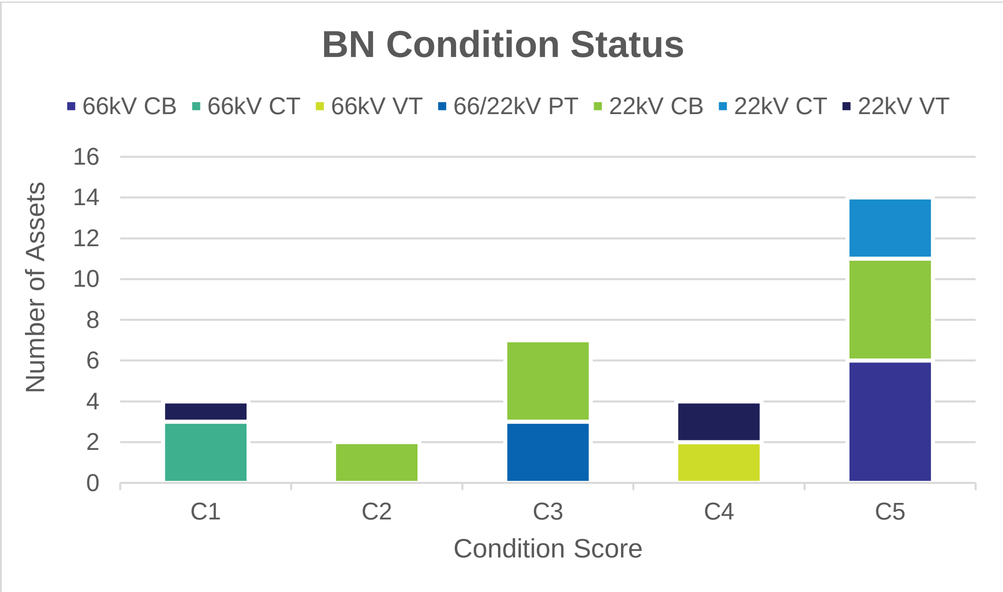


Figure 19: Estimated energy at risk at BN Zone substation

The service level risk to customers supplied from BN Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing both the 66kV and 22kV circuit breakers by 2020.

6.2.7 Bayswater Zone Substation (BWR)

Bayswater (BWR) is located in the eastern suburbs of metropolitan Melbourne approximately 29km east of Melbourne and is the main source of supply for the suburbs of Bayswater, Croydon South, Kilsyth South, Wantirna and Heathmont. BWR supplies approximately 16,800 AusNet Services' customers. The load at BWR includes mostly residential and commercial urban load with some industrial loads.

BWR is a summer peaking station and the peak electrical demand reached 58.4MVA in the summer of 2017/18. The recorded peak demand in winter 2018 was 43MVA. The demand at BWR is forecast to increase slowly at a growth rate of less than 0.5% per annum. The load transfer capability of the feeder interconnections between BWR and its neighbouring zone substations is 27.0 MVA.

Table 23 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

BWR	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	0.0	0.0	0.0	0.0	0.0
10% POE Max Overload (%)	0%	0%	0%	0%	0%
Hours at Risk (h)	0	0	0	0	0
EUSE (MWh)	37.9	41.0	44.3	47.7	51.4
Cost of EUSE ($M)	1.61	1.74	1.88	2.03	2.19

Table 23: Estimated energy at risk at BWR Zone Substation

A summary of the condition of key assets at BWR Zone Substation is provided in Figure 20 below. Approximately 65% of asset at BWR Zone Substation are in poor to very poor condition, C4 and C5 respectively.

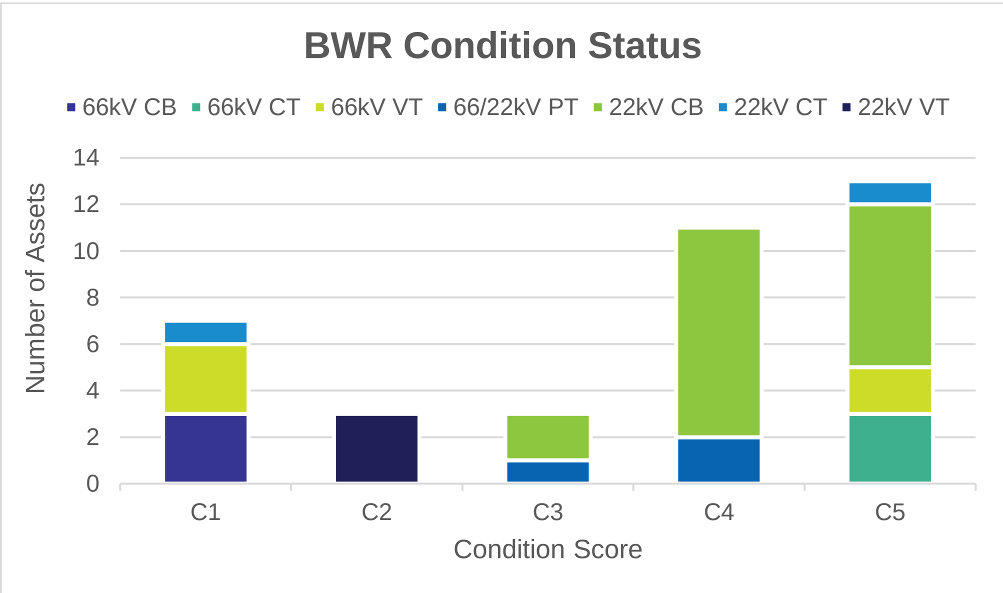


Figure 20: Estimated energy at risk at BWR Zone substation

The service level risk to customers supplied from BWR Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing the 22kV switchgear by 2020.

6.2.8 Traralgon Zone Substation (TGN)

Traralgon (TGN) is located approximately 170km east of Melbourne and is the main source of supply for Traralgon, Glengarry, Calilgnee, Gormandale, Rosedale, and surrounding areas. TGN supplies approximately 17,500 customers. The load at TGN includes town and rural based residential, with some town based commercial, industrial, and farming.

TGN is a summer peaking station and the peak electrical demand reached 45MVA in the summer of 2017/18. The recorded peak demand during the winter of 2018 was 31MVA.The demand at TGN is forecast to grow at approximately 1% per annum. The load transfer capability of the feeder interconnections between TGN and its neighbouring zone substations is 9.6 MW.

Table 24 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

TGN	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	10.7	11.1	11.5	12.0	12.4
10% POE Max Overload (%)	30%	31%	32%	33%	34%
Hours at Risk (h)	1	2	4	7	10
EUSE (MWh)	22.3	24.2	26.5	28.9	31.6
Cost of EUSE ($M)	0.87	0.95	1.03	1.13	1.23

Table 24: Estimated energy at risk at TGN Zone Substation

A summary of the condition of key assets at TGN Zone Substation is provided in Figure 21 below. Approximately 27% of asset at TGN Zone Substation are in poor to very poor condition, C4 and C5 respectively.

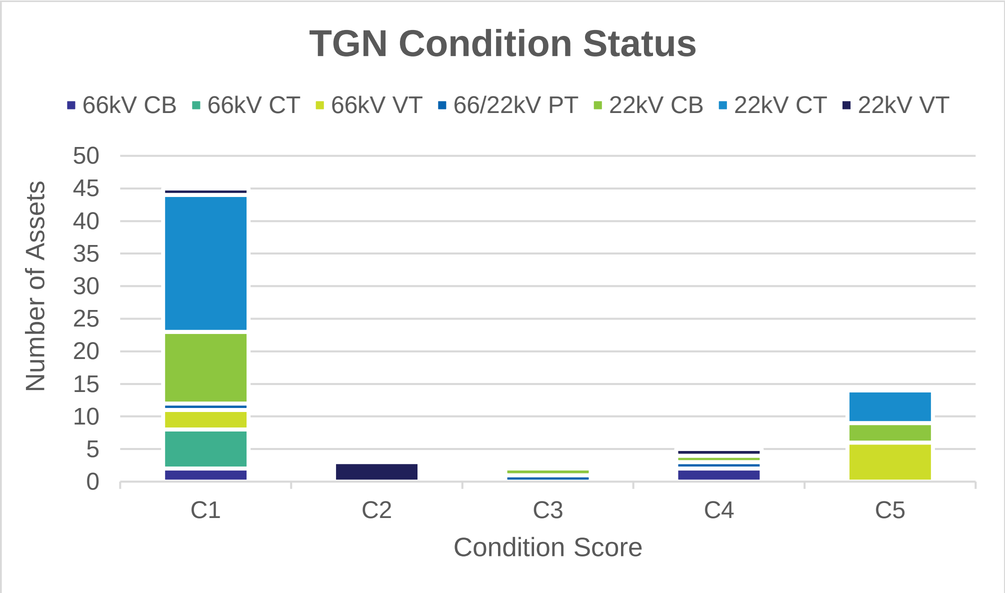


Figure 21: Estimated energy at risk at TGN Zone substation

The service level risk to customers supplied from TGN Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing two transformers, 66kV circuit breakers and 22kV switchgear by 2020.

6.2.9 Warragul Zone Substation (WGL)

Warragul (WGL) is located approximately 100km south east of Melbourne and is the main source of supply for the suburbs of Warragul, Drouin, Longwarry, Bunyip, Darnum, Noojee, and surrounding areas. WGL supplies approximately 23,300 AusNet Services' customers. The load at WGL includes mostly residential with some farming, commercial and industrial loads.

WGL is a summer peaking station and the peak electrical demand reached 66.2MVA in the summer of 2017/18. The recorded peak demand in winter 2018 was 50MVA. The demand at WGL is forecast to increase at a growth rate of approximately 3% per annum. The load transfer capability of the feeder interconnections between WGL and its neighbouring zone substations is 3.1 MW.

Table 25 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

WGL	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	4.4	5.9	7.4	9.1	10.8
10% POE Max Overload (%)	7%	10%	12%	15%	17%
Hours at Risk (h)	2	5	9	15	19
EUSE (MWh)	30.1	34.2	39.2	45.5	52.9
Cost of EUSE ($M)	1.25	1.42	1.62	1.88	2.19

Table 25: Estimated energy at risk at WGL Zone Substation

A summary of the condition of key assets at WGL Zone Substation is provided in Figure 22 below. Approximately 25% of asset at WGL Zone Substation are in poor to very poor condition, C4 and C5 respectively.

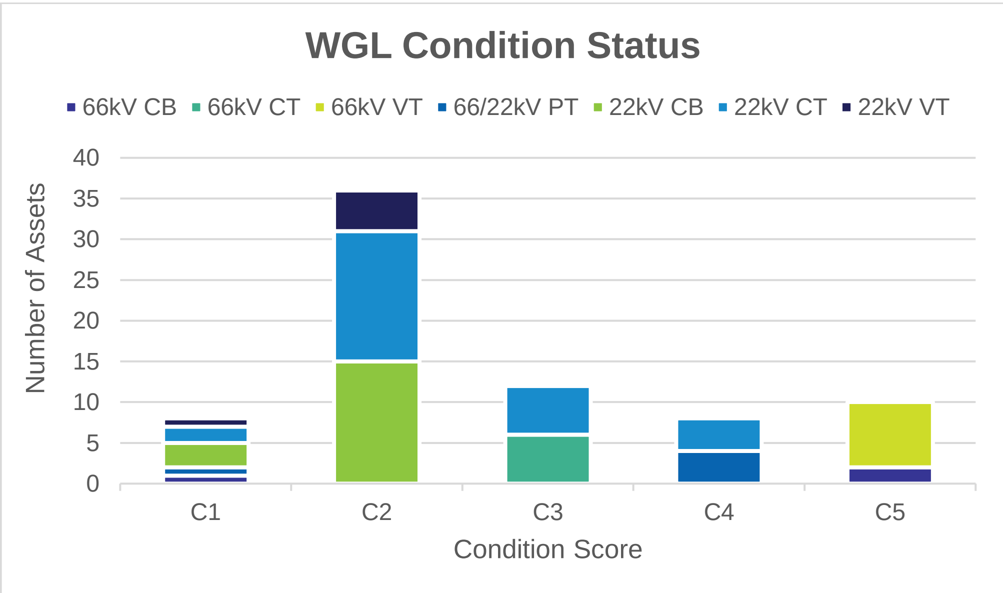


Figure 22: Estimated energy at risk at WGL Zone substation

The service level risk to customers supplied from WGL Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing four transformers with two transformers, replace the existing capacitor bank and install two new 66kV circuit breakers by 2020.

6.2.10 Newmerella Zone Substation (NLA)

Newmerella (NLA) is located approximately 370km east of Melbourne (VicRoads map reference 85 H-5) and is the main source of supply for Newmerella, Orbost, Bemm River, Lake Tyers, and surrounding areas. NLA supplies 3,717 customers in total. The load at NLA includes town and rural based residential, with some town based commercial, industrial, and farming.

NLA is a winter peaking station and the peak electrical demand reached 8.5MVA in winter 2018. The recorded peak demand during the summer of 2017/18 was 7.3MVA. The demand growth at NLA is forecast to be flat. The load transfer capability of the feeder interconnections between NLA and its neighbouring zone substations is 3.2 MW.

Table 26 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE).

NLA	2021	2022	2023	2024	2025
10% POE Max Load at Risk (MVA)	1.2	1.2	1.2	1.2	1.2
10% POE Max Overload (%)	16%	16%	16%	16%	16%
Hours at Risk (h)	0	0	0	0	0
EUSE (MWh)	16.1	17.6	19.4	21.2	23.1
Cost of EUSE ($M)	0.59	0.65	0.71	0.78	0.85

Table 26: Estimated energy at risk at NLA Zone Substation

A summary of the condition of key assets at NLA Zone Substation is provided in Figure 23 below. Approximately 76% of asset at NLA Zone Substation are in poor to very poor condition, C4 and C5 respectively.

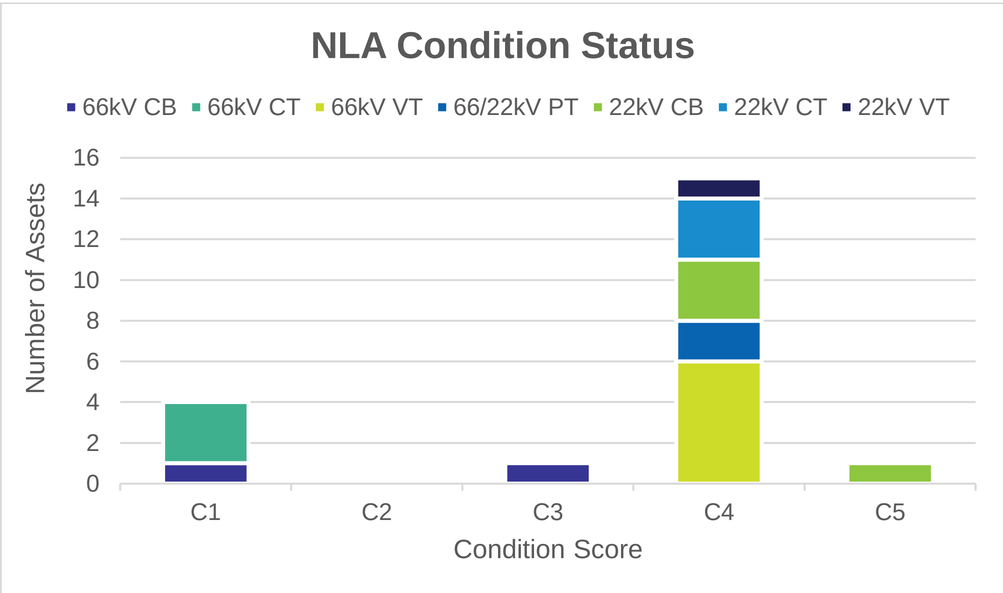


Figure 23: Estimated energy at risk at NLA Zone substation

The service level risk to customers supplied from NLA Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing the transformers and 22kV switchgear by 2026.

7 Overloaded Primary Distribution Feeders

This section outlines the primary distribution feeders that are currently overloaded or are forecast to become overloaded within the next two years. This section addresses the requirements of the National Electricity Rules schedule 5.8 (d).

Distribution feeders that are overloaded or are forecast to become overloaded in the next two years are presented in Table 27, along with the extend of overload forecast and the number of customer that the feeder supplies.

Table 27: Overloaded feeders for 50% and 10% probability of exceedance conditions

Feeder	Number of customers connected	Summer Rating (A)	Based on 2021 Summer Maximum Demand Forecasts					
			50%POE			10%POE		
			2020/21	2021/22	2022/23	2020/21	2021/22	2022/23
			%	%	%	%	%	%
CLN22	3987	375	91	96	104	97	98	107
CLN23	5642	323	87	93	103	90	96	106
DRN11	5459	326	94	96	102	97	98	105
ELM34	4104	320	96	97	98	99	99	101
KLO14	4647	360	100	100	103	102	102	106
BN1	4637	285	115	116	116	118	119	119
SMR14	2295	157	118	120	122	119	122	124
SMR24	3294	350	102	104	106	103	106	108
WOTS25	3434	260	99	103	106	102	106	109
SLE31	4959	297	99	100	101	100	101	102

There are no feeders during winter periods that are currently or forecast to overload by 2021/22.

Potential solutions to the feeder overloads identified are highlighted in Table 28. This covers the types of potential solutions that may address the overload or forecast overload. Common solutions include feeder reconfiguration, utilising embedded generation (temporarily or permanently), demand management and circuit augmentation.

Feeder	Potential Solutions
CLN22	The forecast feeder overload is due to the expected new housing growth in the area fed from this feeder. The following options are considered to address the overload: 1. New CLN11E Feeder in 2021 2 Explore Non-network solutions.
CLN23	The forecast feeder overload is due to the expected new housing growth in the area fed from this feeder. The following options are considered to address the overload: 1. New Feeder CLN24 has been constructed. Additional tie required by 2022 to reduce demand on CLN23. 2. Explore Non-network solutions.

Feeder	Potential Solutions
DRN11	The forecast feeder overload is due to the expected new housing growth in the area fed from this feeder. The following options are considered to address the overload: 1. Non-network solution will come online in 2021 to reduce demand on this feeder.
ELM34	1. Risk manage the feeder beyond 2030. 2. Explore non-network solutions.
KLO14	The forecast feeder overload is due to the expected new housing growth in the area fed from this feeder. The following options are considered to address the overload: 1. Risk Manage the feeder until 2025. 2. A feeder will be extended during 2021 to offload part of KLO14. 3. Transfer a section to KMS12 following upgrade of REFCL unit. 4. Explore Non-network solutions.
BN1	1. Temporary generation of 2.6 MW is currently deployed during the peak periods to limit the feeder load currents below the 285A feeder rating. 2. As required under future maximum demand forecasts, 2.6 MW of temporary generation will be deployed during the summer peak period.
SMR14	This feeder may experience overload during extreme weather conditions. Demand Management of 600kW is available on this feeder.
SMR24	The forecast feeder overload is small and is less than 110% of the feeder rating. It is proposed to risk manage the feeder, during above overloading situations to manage the over loading situation.
WOTS25	The forecast feeder overload is due to the expected new housing growth in the area fed from this feeder. The following options are considered to address the overload: 1. Feeder reconfiguration to transfer load to WO31 and WOTS12 2. Explore Non-network solutions. 3. Network augmentation.
SLE31	Immediate actions are to deploy temporary generation for summer 2020/21. Long-term action involves thermal upgrade of feeder.

Table 28: Potential solutions for overloaded feeders.

7.1 Demand reduction required to defer overload by 12 months

Table 29 provides details of the estimated reduction in forecast load that would be required to eliminate a forecast feeder overload for a period of 12 months. The table covers a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload and the estimated reduction in forecast load in MW needed to defer the forecast system limitation. The estimate of the year in which the overload is forecast to occur is apparent from the forecast loads.

Feeder	Forecast Overload Timing	Load Reduction Required for 12-month Deferral (MW)	Comments
CLN13	December 2023	1.0	Feeder can be risk managed until 2026. The proposed new feeder may be completed by 2023. Non-network solutions will be considered.
CLN21	December, 2023	0	Feeder can be risk managed until 2026. The proposed new feeder may be completed by 2023. Non-network solutions will be considered.
CLN22	December, 2022	1.5	Feeder can be risk managed until 2024. The proposed new feeder may be completed by 2023. Non-network solutions will be considered.
CLN23	December, 2023	1.5	Feeder can be risk managed until 2024. The proposed new feeder may be completed in 2023. Non-network solutions will be considered.
DRN11	December, 2022	0	Feeder can be risk managed until 2024. A non-network solution will come online during 2021 to address this issue.
DRN12	December, 2023	0	Feeder can be risk managed until 2026. A non-network solution will come online during 2021 to address this issue.
DRN22	December, 2023	0	Feeder can be risk managed until 2027. A non-network solution will come online during 2021 to address this issue.
ELM34	December, 2022	0	Feeder can be risk managed past 2030.
KLO14	December, 2020	0.7	Feeder can be risk managed until 2024. The proposed new feeder may be completed in 2021. Non-network solutions will be considered.
OFR23W	December, 2023	0	Feeder can be risk managed until 2027. The proposed new feeder may be completed by 2025.
BN1	December 2020	2.6	Approximately 2.6MW Temporary generation support will be used on days when the feeder load reaches over 275 A, depending on over loaded amount. A contract exists for Demand Management with a large customer. Long term Non-network solutions will be considered.

SMR14	December 2020	1.4	600 kW Demand Management is available. Long term Non-network solutions will be considered.
SMR24	December 2020	1.1	RMR will be in force during peak load conditions. Long term non-network solutions will be considered.
WOTS25	December, 2020	0.9	Feeder can be risk managed until 2022 with temporary transfers.
SLE31	December, 2020	0.4	Deploy temporary generation for summer 2020/21. Non-network solutions will be considered.

Table 29: Details of Load Reduction required to defer overload.

8 Regulatory Investment Tests

The regulatory investment test for distribution (RIT-D) is an economic cost-benefit test used to assess and rank potential investments capable of meeting an identified need. The purpose of the RIT-D is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT–D was initially introduced in March 2013, with Version 55 of National Electricity Rules (NER), with a focus on augmentation expenditure, and was amended in September 2017 to include replacement expenditure planning.

8.1 RIT-D projects recently completed or in progress

This section provides details required by schedule 5.8 (e) in covering projects where the Regulatory Investment Test for Distribution (RIT-D) has been completed in the preceding year or is in progress:

8.1.1 East Gippsland Electricity Supply RIT-D

On 15 September 2020, AusNet Services published Stage 1, the non-network options report, of the East Gippsland Electricity Supply RIT-D. This RIT-D is to evaluate options to provide ongoing electrical supply capacity to customers in the East Gippsland supply area, with loading on the existing East Gippsland 66 kV network reaching its thermal and voltage limits.

Submissions to the non-network options report were due to close on 18 December 2020 but AusNet Services elected to extend the consultation period, which now closes on 8 January 2021.

AusNet Services currently expects to publish Stage 2 of the East Gippsland Electricity Supply RIT-D, the draft project assessment report (DAPR), in the second quarter of 2021. However, the DPAR publication timing is dependent on the submissions received, and therefore analysis complexity, to the Stage 1 report.

Further information on the East Gippsland Electricity Supply RIT-D is available on AusNet Services' website: https://ausnetservices.com.au/About/Projects-and-Innovation/Regulatory-Investment-Test

8.1.2 REFCL Tranche 2 RIT-D

In October 2018, AusNet Services published a notice advising there is no credible non-network alternatives to Tranche 2 of the REFCL installation projects. AusNet Services has since discontinued this RIT-D due to exemption provisions provided under NER clause 11.99.6.

8.1.3 CBTS Electricity Supply RIT-T

As outlined in Section 4.7.1, AusNet Services has commenced a Regulatory Investment Test for Transmission (RIT-T) jointly with United Energy, and in consultation with AEMO, to assess options to mitigate the thermal loading risk on the Cranbourne Terminal Station (CBTS) 220/66 kV connection assets transformers. This RIT-T is expected to result in risk mitigation action within the next five years.

Further information on the CBTS Electricity Supply RIT-T is available on AusNet Services' website: https://ausnetservices.com.au/About/Projects-and-Innovation/Regulatory-Investment-Test

8.2 Future RIT-D projects

This section provides details required by schedule 5.8 (f) for each identified system limitation for which a Distribution Network Service Provider has determined a Regulatory Investment Test for Distribution (RIT-D) is required and is expected to commence in the next five-year period. In the five-year period, AusNet Services expects to commence the RIT-Ds outlined in Table 30.

System Limitation	Proposed Project Commissioning	Estimated RIT-D Commencement	Section reference
East Gippsland Electricity Supply RIT-D	To be determined	Commenced September 2020	6.1.4 and 8.1.1
REFCL Tranche 3 initial compliance	March 2023	February 2021	9.23
Eltham Zone Substation REFCL compliance maintained	2025	February 2023	9.7
Kalkallo Zone Substation REFCL compliance maintained	2023	February 2021	11.2.1
Wodonga Zone Substation REFCL compliance maintained	2021	May 2021	9.20
Clyde North Zone Substation capacity limitation	2023	January 2021	6.2.1 and 9.5
Cranbourne 66 kV network limitations	2027	June 2023	6.1.1
Doreen Zone Substation capacity limitation	2027	February 2024	9.6
Bairnsdale Zone Substation asset condition risk	2021	January 2021	9.1
Bayswater Zone Substation asset condition risk	2022	January 2021	0
Benalla Zone Substation asset condition risk	2022	January 2021	9.4
Maffra Zone Substation asset condition risk	2022	January 2021	9.12
Newmerella Zone Substation asset condition risk	2026	June 2023	9.14
Thomastown Zone Substation asset condition risk	2022	January 2021	9.16
Traralgon Zone Substation asset condition risk	2023	January 2021	9.17
Warragul Zone Substation asset condition risk	2023	January 2021	9.18
Watsonia Zone Substation asset condition risk	2023	January 2021	9.19
Mount Hotham underground cable condition risk	August 2022	January 2021	E.9

Table 30: Identified system limitations that are subject to the RIT-D

9 Completed, Committed and Planned Zone Substation Developments

This section provides details required by schedule 5.8 (b1), for individual assets planned to be retired, and for schedule 5.8 (g), being for projects within the forward planning period where investments of over $2 million in value are being implemented to address a refurbishment need, replacement need, or an urgent or unforeseen investment. Some planned or in progress projects have a cross-over with the twenty-two REFCL stations, as identified.

9.1 Bairnsdale Zone Substation rebuild and REFCL installation

AusNet Services completed a partial rebuild of Bairnsdale Zone Substation (BDL) in December 2016. This rebuild replaced half of the outdoor 22 kV switchgear with a new 22 kV indoor switchboard, and installation of a new 20/33 MVA 66/22 kV transformer, in addition to older three 10/16 MVA transformers.

AusNet Services now plans to retire and replace the remaining 22 kV outdoor assets and 66 kV circuit breakers at the Bairnsdale Zone Substation. The condition of these assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental, and plant damage risks from possible destructive failure.

A project to address these issues was planned to be implemented by 2023 but has since been brought forward to 2021 to coincide with the Rapid Earth Fault Current Limiter (REFCL) works planned for this station.

The asset replacement works have been brought forward to coincide with the REFCL works for two key reasons:

- Following detailed assessment of the 22 kV assets, it was identified that the 22 kV switchgear requires replacement to ensure the assets are capable of withstanding the higher REFCL voltages.
- There is a cost advantage to completing the 66 kV asset replacement works at the same time as the REFCL works, due to project and crew establishment cost savings.

BDL is a tranche two REFCL nominated station, and AusNet Services has scoped its REFCL and associated asset replacement works to ensure that the station can withstand the higher phase-to-ground voltages that the un-faulted (healthy) phases are subjected to under fault conditions with the REFCL in service.

The REFCL is planned to be implemented by 2021, and includes the following key scope items:

- Replace remaining 22 kV outdoor switchgear with a new 22 kV indoor switchboard.
- Install two ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Install two 22 kV switched neutral bus kiosks.
- Install two new 750 kVA kiosk type Station Service Transformers.
- Install one REFCL room to house REFCL associated protection, control, inverters, and AC changeover units.
- Install one new modular battery room.
- Replace the existing No.1 capacitor bank with a new four-step 3.0 MVAR REFCL compliant metal enclosed capacitor bank.
- Install a new No.4, four-step 3.0 MVA compliant metal enclosed capacitor bank.
- Replace and install associated secondary and protection equipment.

In addition to the REFCL works, the asset replacement works to address the remaining service level risk include:

- Replace outdoor minimum oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers.
- Replace outdoor 66 kV current transformers with new 66 kV current transformers.

To achieve and maintain REFCL compliance at BDL, AusNet Services is now planning installation of a third REFCL along with replacement of the existing No.3 transformer and rearrangement of the 22 kV feeders to accommodate the ASC limitations. Due to the lead-time to procure and install a third REFCL and replace the transformer, it may be necessary to install isolation transformers as a temporary measure. The expected cost for this option is $14.1 million.

9.2 Bayswater Zone Substation rebuild

AusNet Services is currently in the early stages of scoping a project to selectively retire and replace assets at the Bayswater Zone Substation (BWR). BWR was established in 1968 and contains outdoor bulk oil 22 kV circuit breakers and instrument transformers that were installed when the station was originally built. Some equipment panels have asbestos containing materials and live exposed wires at the rear of the secondary panels. The condition of these assets, as well as the high voltage transformer bushings, has deteriorated considerably and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental, and plant damage risks from possible destructive failure.

A project to address these issues, including the following key scope items, is expected to be implemented by 2022:

- Replace 22 kV outdoor switchgear with three new 22 kV indoor switchboards.
- Establish a new control room.
- Replace 22 kV and 66 kV instrument transformers.

This project will address asset failure risks due to deteriorated electrical equipment. The total project cost is approximately $12.5 million ±30%.

Alternative options considered include:

- Replace 22 kV equipment along with the No.2 66/22 kV transformer. Although this option would deliver higher benefits, these additional benefits are currently insufficient to economically justify the additional cost.
- Replace 22 kV equipment along with the No.1 and No.2 66/22 kV transformers. Although this option would deliver higher benefits, these additional benefits are currently insufficient to economically justify the additional cost.

9.3 Belgrave Zone Substation REFCL installation

Belgrave Zone Substation (BGE) is a tranche two REFCL nominated station, and AusNet Services is currently commissioning the REFCL system. A follow up compliance maintained project will be carried out to address high capacitance and damping on the BGE network.

The REFCL is planned to be in service by late-December 2020, and includes the following key scope items:

- Install two new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Installing a new REFCL room to house the inverter, grid balancing unit and the new AC changeover system for the new GFN.
- Replace the existing station service transformers with two new 750 kVA kiosk type units.
- Install two new 22 kV switched neutral bus kiosks.
- Replace the existing capacitor bank with a REFCL compliant metal enclosed capacitor bank.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $9.9 million.

9.4 Benalla Zone Substation rebuild and REFCL installation

AusNet Services is planning to retire and replace the 22 kV outdoor switchgear and 66 kV bulk oil circuit breakers at the Benalla Zone Substation (BN). The condition of these assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental, and plant damage risks from possible destructive failure and subsequent oil fires. There is also concern that the 22 kV switchgear is not capable to the higher REFCL voltages.

A project to address these issues, including the following key scope items, is expected to be implemented by 2022:

- Replace outdoor bulk oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers.
- Replace 22 kV outdoor switchgear with a new 22 kV indoor switchboard.

This project will address asset failure risks due to deteriorated electrical equipment, whilst ensuring integration with the implementation of REFCL technology (see section 13.5.3). The estimated total project cost is approximately $9.0 million ±30%.

Alternative options considered include:

- Replace 66 kV assets with a new 66 kV ring bus, along with the proposed replacement of the outdoor 22 kV switchgear with a new indoor switchboard. This option is more expensive but only delivers marginally higher benefits than the proposed preferred option.
- Replace only the highest risk outdoor bulk oil 66 kV circuit breakers and 22 kV circuit breakers in situ. This option is slightly lower in cost than the preferred option but would deliver lower benefits due to the remaining elevated failure risk assets.

9.5 Clyde North Zone Substation Capacity Augmentation

AusNet Services is planning to augment the supply capacity at Clyde North Zone Substation (CLN) to avoid overload of the existing two 66/22 kV 20/33 MVA transformers. CLN has energy at risk during both the summer and winter periods. The level of load at risk under outage conditions and 10%POE forecast conditions is 42.4 MVA in summer 2020/21, increasing to 54.1 MVA by 2024/25. Load transfer capacity of 21.9 MVA exists to transfer the load at risk away from the station in the event of a transformer outage.

A project to address the demand growth driven service level risk, including the following key scope items, is planned to be implemented by 2024:

- Install an additional (third) 66/22kV 20/33 MVA transformer.
- Install an additional (third) 22 kV indoor switchboard.
- Install associated protection and control works.

Alternative options considered include:

- Install an additional (third) 66/22kV 20/33 MVA transformer, connected into the existing No.2 22 kV bus alongside the existing No.2 transformer. This is a lower cost option but does not provide for additional feeder exit connections which are required to supply the growing demand.
- Contract at least 10 MVA of network support via embedded generation.
- Contract for network support via demand management to reduce demand during risk periods.

9.6 Doreen Zone Substation Capacity Augmentation

AusNet Services is planning to augment the supply capacity at Doreen Zone Substation (DRN) to avoid overload of the existing two 66/22 kV 20/33 MVA transformers. DRN has energy at risk during both the summer and winter periods. The level of load at risk under outage conditions and 10%POE forecast conditions is 32.2 MVA in summer 2020/21, increasing to 40.2 MVA by 2024/25. Load transfer capacity of 22.1 MVA exists to transfer the load at risk away from the station in the event of a transformer outage.

A project to address the demand growth driven service level risk, including the following key scope items, is planned to be implemented after 2026:

- Install an additional (third) 66/22kV 20/33 MVA transformer.
- Install an additional (third) 22 kV indoor switchboard.
- Install associated protection and control works.

Alternative options considered include:

- Install an additional (third) 66/22kV 20/33 MVA transformer, connected into the existing No.2 22 kV bus alongside the existing No.2 transformer. This is a lower cost option but does not provide for additional feeder exit connections which are required to supply the growing demand.
- Contract at least 10 MVA of network support via embedded generation.
- Contract for network support via demand management to reduce demand during risk periods.

9.7 Eltham Zone Substation REFCL installation

Eltham Zone Substation (ELM) is a tranche two REFCL nominated station, and AusNet Services is currently finalising construction of the REFCL assets and asset replacements.

The REFCL is planned to be implemented by 2022, and includes the following key scope items:

- Install two new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.

- Installing a new REFCL room to house the inverter, grid balancing unit and the new AC changeover system for the new GFN.
- Replace the existing station service transformers with two new 750 kVA kiosk type units.
- Install two new 22 kV switched neutral bus kiosks.
- Replace the existing outdoor 22 kV switchgear with new indoor 22 kV switchboards.
- Replace the existing capacitor bank with a REFCL compliant metal enclosed capacitor bank.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $13.3 million.

9.8 Ferntree Gully Zone Substation REFCL installation

Ferntree Gully Zone Substation (FGY) is a tranche three REFCL nominated station, and AusNet Services is currently finalising construction.

The REFCL is planned to be implemented by 2023, and includes the following key scope items:

- Install two new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Installing a new GFN control room to house the inverters and associated protection and control equipment.
- Replace the existing station service transformers with two new 750 kVA kiosk type units.
- Replace the existing 10 MVA 1A and 1B 66/22 kV transformers with a single 20/33 MVA 66/22 kV transformer
- Replace the existing 22 kV surge arrestors at FGY, Upwey (UWY) and Sassafras (SFS).
- Install two new 22 kV switched neutral bus kiosks.
- Replace the two existing capacitor banks with new REFCL compliant units.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $11.4 million.

To achieve and maintain REFCL compliance at FGY, AusNet Services in also planning to establish a new non-REFCL protected Rowville Zone Substation (RVE) and transfer underground 22 kV feeders from FGY to RVE to reduce the network capacitance at FGY to within the station's REFCL capability.

9.9 Kinglake Zone Substation REFCL installation

AusNet Services is in the final stages of commissioning the Kinglake Zone Substation (KLK) REFCL system.

The REFCL is planned to be in service by late-December 2020, and includes the following key scope items:

- Replace outdoor 22 kV circuit breakers with new indoor 22 kV switchgear.
- Replace one 66 kV circuit breaker.
- Land purchase and zone substation establishment/extension.
- Replacement of equipment not capable of 22 kV phase-to-ground.
- Associated protection and secondary system upgrades.
- Install a new Siemens-Trench REFCL unit, to replace the underrated Ground Fault Neutraliser REFCL that was the initial REFCL test site unit.

To achieve and maintain REFCL compliance at KLK, AusNet Services in also planning to isolate underground cable sections to reduce the network capacitance seen at the KLK 22 kV zone substation bus to within the existing zone substation REFCL's capability. AusNet Services has been granted a time extension in relation to its REFCL compliance obligations at KLK and is continuing work to achieve compliance with the regulations.

9.10 Lang Lang Zone Substation REFCL Installation

Lang Lang Zone Substation (LLG) is a tranche three REFCL nominated station, and AusNet Services is currently finalising its design scope for the REFCL installation and associated asset replacement works, to ensure that the station can withstand the higher phase-to-ground voltages that the un-faulted (healthy) phases are subjected to under fault conditions with the REFCL in service. The REFCL is planned to be implemented by 2023, and includes the following key scope items:

- Install one Siemens-Trench REFCL unit including Arc Suppression Coil (ASC), Inverter and Neutral Bus Kiosk.
- Replace existing 22 kV switchboard with the new modular switchboard.
- Installing a new AC changeover board in the existing control room.
- Replace, or upgrade, the existing station service transformers with two new 500 kVA kiosk type units.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $13.6 million.

9.11 Lilydale Zone Substation REFCL installation

Lilydale Zone Substation (LDL) is a tranche two REFCL nominated station, and AusNet Services is currently commissioning the REFCL assets.

The REFCL is planned to be in service by late-December 2020, and includes the following key scope items:

- Install two new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Installing a new AC changeover board in the existing control room.
- Replace, or upgrade, the existing station service transformers with two new 750 kVA kiosk type units.
- Install two new 22 kV switched neutral bus kiosks.
- Install a new REFCL compliant capacitor bank, to ensure adequate voltage support when the 22 kV busses are split.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $10.1 million.

9.12 Maffra Zone Substation rebuild

AusNet Services is planning to selectively retire and replace assets at the Maffra Zone Substation (MFA). MFA was established with two 10 MVA 66/22 kV transformers in 1960 and contains 66 kV minimum oil circuit breakers and oil filled current transformers that were installed when the station was built. A third transformer was installed in 1998. The condition of the circuit breakers and current transformers has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure and subsequent oil fires. The condition of the transformers is also deteriorating; however, the replacement of these assets has been deferred to beyond 2026.

A project to address the switchgear condition is expected to be implemented by 2022, and includes the following key scope items:

- Replace outdoor minimum oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers.
- Replace outdoor 66 kV current transformers with new 66 kV current transformers.

This project will address asset failure risks due to deteriorated electrical equipment. The total project is approximately $11.5 million ±30%.

Alternative options considered include:

- Replace the two 10 MVA 66/22 kV transformers as well as the 66 kV equipment. This is much higher cost option and replacement of the existing C4 condition transformers is not currently economically justified.
- Replace the 66 kV outdoor switchgear with gas insulated switchgear, while maintaining the original 66/22 kV transformers. This is a high-cost option, due to the increased costs associated gas insulted switchgear, that would deliver less benefits than the proposed preferred option due to the remaining elevated failure risk associated with the two original transformers.
- Replace the 66 kV outdoor switchgear with new outdoor 66 kV switchgear and replace one of the two original 66/22 kV transformers. This is a lower cost option than the proposed preferred solution, but also has lower benefits due to the remaining elevated failure risk associated with the one original transformer that would not be replaced.

9.13 Moe Zone Substation REFCL installation

MOE is a tranche two REFCL nominated station, and AusNet Services is commissioning the REFCL and associated asset replacement works to ensure that the station can withstand the higher phase-to-ground voltages that the un-faulted (healthy) phases are subjected to under fault conditions with the REFCL in service.

The REFCL is planned to be implemented by March 2021, and includes the following key scope items:

- Install ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Install two 22kV switched neutral bus kiosks.
- Install two new 750kVA kiosk type station service transformers.
- Install a new modular battery room.
- Re-configure the existing AIS 22 kV switchyard and feeders via the installation of a new building to house an indoor switchboard and REFCL associated protection, control, inverters and AC changeover units.
- Replace the existing No.1 capacitor bank with a new three-step 3.0 MVA REFCL compliant metal enclosed capacitor bank.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $13.2 million.

9.14 Newmerella Zone Substation rebuild

AusNet Services is planning to retire and replace assets at the Newmerella Zone Substation (NLA). NLA is a small remote zone substation containing two 5 MVA 66/22 kV transformers and a single outdoor 22 kV bus with outdoor 22 kV automatic circuit recloser (ACR) switches in place of traditional 22 kV circuit breaker switchgear. The condition of the two transformers and the 22 kV switchgear has deteriorated and they now have an elevated risk of failure. The assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure and subsequent oil fires and loss of supply.

A project to address these issues was planned for 2024 but has now been delayed to 2026 following more detailed assessment of the service level risk.

Key scope items include:

- Replace the two 66/22 kV transformers
- Replace outdoor 22 kV circuit breakers with a new indoor 22 kV switchboard.
- Replace the high voltage 66 kV transformer bushings.

This project will address the service level risk associated with the 66/22 kV transformers and 22 kV assets. The total project cost in 2018 real dollars is approximately $12.9 million ±30%.

Alternative options considered include:

- Replace only the existing outdoor 22 kV switchgear with a new indoor 22 kV switchboard. This is lower cost option but does not address the service level risk associated with the poor transfer condition.
- Replace the 66/22 transformers, while maintaining the existing outdoor 22 kV switchgear. This is medium cost option, due to the transformer replacements, however the benefits are limited due to the remaining elevated failure risk associated with the existing outdoor 22 kV switchgear.

9.15 Ringwood North Zone Substation REFCL installation

In 2020 AusNet Services completed a project to install REFCL assets at Ringwood North Zone Substation (RWN).

The project included the following key scope items:

- Install a new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) unit.
- Installing a new REFCL room to house the inverter, grid balancing unit and the new AC changeover system for the new GFN.
- Replace the existing station service transformers with two new 500 kVA kiosk type units.
- Install a new 22 kV switched neutral bus kiosk.
- Replace the existing capacitor bank with a REFCL compliant metal enclosed capacitor bank.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $5.6 million.

9.16 Thomastown Zone Substation rebuild

AusNet Services is currently in the early stages of scoping a project to selectively retire and replace assets at the Thomastown Zone Substation (TT). TT was established in the early 1950s and contains 66 kV and 22 kV bulk oil circuit breakers that were installed when the station was built. The condition of these circuit breakers has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues, including the following key scope items, is expected to be implemented by 2021:

- Replace outdoor bulk oil 22 kV circuit breakers with three new indoor 22 kV switchboards.
- Replace outdoor bulk oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers.
- Associated protection and secondary system upgrades.

This project will address asset failure risks due to deteriorated electrical equipment. The total project cost in 2017 real dollars is approximately $16.2 million ±30%.

9.17 Traralgon Zone Substation rebuild

AusNet Services is currently in the early stages of scoping a project to selectively retire and replace assets at the Traralgon Zone Substation (TGN). TGN was established with two 10/13.5 MVA 66/22 kV transformers and contains outdoor 66 kV and 22 kV oil filled switchgear that was installed when the station was built. A 20/33 MVA transformer, in addition to the two original 10/13.5 MVA transformers, was installed in 2013. The condition of the two original transformers and the 66 kV and 22 kV assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues is expected to be implemented by 2023, and includes the following key scope items:

- Replace the two 10/13.5 MVA 66/22 kV transformers with a single 20/33 MVA 66/22 kV transformer.
- Replace two 66 kV minimum oil circuit breakers.
- Replace outdoor 22 kV switchgear with a new indoor 22 kV switchboard.
- Replace the high voltage 66 kV transformer bushings.

This project will address the asset failure risks due to deteriorated electrical equipment. The total project cost in 2018 real dollars is approximately $9.5 million ±30%.

Alternative options considered include:

- Replace the 66 kV and 22 kV assets, while maintaining the existing transformers. This is a lower cost option than the proposed preferred solution but results in lower net economic benefits due to the remaining elevated failure risk associated with the two 66/22 kV transformers.
- Replace only the 22 kV assets, while maintaining the existing 66 kV assets and transformers. This is a much lower cost option than the proposed preferred solution but results in lower net economic benefits due to the remaining elevated failure risk associated with the 66 kV assets and the two 66/22 kV transformers.

9.18 Warragul Zone Substation rebuild

AusNet Services is currently in the early stages of scoping a project to selectively retire and replace assets at the Warragul Zone Substation (WGL). WGL was established with two 10/13.5 MVA 66/22 kV transformers and contains outdoor 66 kV and 22 kV oil filled switchgear that was installed when the station was built. A 20/33 MVA transformer, in addition to the two original 10/13.5 MVA transformers, was installed in 2013. The condition of the two original transformers and the 66 kV and 22 kV assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues is expected to be implemented by 2023, and includes the following key scope items:

- Replace the four 10 MVA 66/22 kV transformers with two 20/33 MVA 66/22 kV transformers.

- Replace the No.2 capacitor bank.
- Install two new 66 kV circuit breakers to complete a fully switched ring bus.

This project will address the asset failure risks due to deteriorated electrical equipment and provide some additional capacity to supply the station load. The total project cost in 2018 real dollars is approximately $13.7 million ±30%.

Alternative options considered include:

- Replace the four 10 MVA transformers, and the No.2 capacitor bank, with like-for-like assets. This is a high cost, due to the number of transformers to be installed, but delivers less benefits than the proposed preferred solution because four like-for-like transformers would provide a lower capacity than two 20/33 MVA transformers.
- Replace the No.2 capacitor bank and the four 10 MVA transformers with two 20/33 MVA transformers. This is a medium cost option but delivers lower net benefits due to the lack of redundancy from not having a complete 66 kV ring bus.

9.19 Watsonia Zone Substation rebuild

AusNet Services is planning to selectively retire and replace assets at the Watsonia Zone Substation (WT). WT was established with two 66/22 kV transformers in the late 1950s, with a third transformer installed in 2010, and contains 22 kV bulk oil circuit breakers that were installed when the station was built. The condition of the two original transformers and the 22kV circuit breakers has deteriorated considerably and they now have an elevated risk of failure. The 22kV assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues, including the following key scope items, is expected to be implemented by 2023:

- Replace outdoor bulk oil 22 kV circuit breakers with new indoor 22 kV switchgear.
- Associated protection and secondary system upgrades.

Alternative options considered include:

- Replace the two poor condition 66/22kV transformers and the 22 kV switchgear. This is higher cost option that was previously proposed. However, following more detailed assessment of the service level risk, replacement of the 66/22 kV transformers is not currently economic.

This project will address 22kV asset failure risks but will carry the 66/22 kV transformer failure risk. The total project cost is approximately $15.3 million ±30%.

9.20 Wodonga Terminal Station REFCL installation

The Wodonga Terminal Station (WOTS) 22 kV switchyard is a tranche two REFCL nominated station, and AusNet Services is currently finalising its design scope for the REFCL installation and associated asset replacement works, to ensure that the station can withstand the higher phase-to-ground voltages that the un-faulted (healthy) phases are subjected to under fault conditions with the REFCL in service.

The REFCL is planned to be implemented by 2021, and includes the following key scope items:

- Install two new ground fault neutraliser (GFN) Arc Suppression Coil (ASC) units.
- Replace the two 22 kV neutral earthing compensators and the neutral earthing reactor with REFCL compliant assets.
- Installing a new REFCL room to house the inverter and control equipment.
- Replace the existing station service transformers with two new 750 kVA kiosk type units.
- Install two new 22 kV switched neutral bus kiosks.
- Replace the existing capacitor bank with a REFCL compliant capacitor bank.
- Replace and install associated secondary and protection equipment.

The estimated capital cost for the REFCL implementation works is $9.7 million.

To achieve and maintain REFCL compliance at WOTS, AusNet Services in also planning to install two remote REFCLs and isolation transformers on WOTS11 and WOTS25, along with permanent transfer of a section of WOTS25 to feeder WO31. The expected cost for this option is $13.5 million.

9.21 Woori Yallock Zone Substation REFCL installation

In 2020 AusNet Services completed a project to install REFCL assets at Woori Yallock Zone Substation (WYK).

The project included the following key scope items:

- Install a new REFCL and Arc Suppression Coil (ASC) unit.
- Replace the existing 22 kV capacitor bank with a REFCL compliant unit.
- Replace the existing station service transformers.
- Associated protection and secondary system upgrades.
- Isolation of underground cable sections from the REFCL network.

The estimated capital cost for the REFCL implementation works is $4.8 million.

9.22 Yallourn Power Station 11 kV switchyard rebuild

In 2020 AusNet Services completed a project to replace assets at the Yallourn Power Station 11 kV switchyard (YPS11).

The project included the following key scope items:

- Replace outdoor 11 kV circuit breakers with new indoor 11 kV switchgear.
- Retire the No.1 220/11 kV transformer.
- Replace the remaining poor condition 66/11 kV transformer with a new 66/11 kV 35 MVA unit.
- Replace existing 11 kV capacitor banks.
- Associated protection and secondary system upgrades.

9.23 Further REFCL installation and geographic footprint

The installation and application of REFCL technology at twenty-two of AusNet Services' zone substations was enacted in the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016, on 1 May 2016 by the Victorian Government. The Regulations are highly prescriptive and ambitious, detailing a seven-year implementation timeframe and performance standards that will be administered by Energy Safe Victoria (ESV).

The Bushfire Mitigation Regulations stipulate three tranches, with delivery due by May 2019, 2021 and 2023.

The twenty-two REFCL zone substations include Kinglake (KLK), Woori Yallock (WYK), Kilmore South (KMS), Wangaratta (WN), Rubicon A (RUBA), Barnawartha (BWA), Seymour (SMR), Myrtleford (MYT), Wonthaggi (WGI), Benalla (BN), Ringwood North (RWN), Eltham (ELM), Ferntree Gully (FGY), Belgrave (BGE), Lilydale (LDL), Bairnsdale (BDL), Moe (MOE), Sale (SLE), Mansfield (MSD), Wodonga Terminal Station 22 kV switchyard (WOTS), Lang Lang (LLG), and Kalkallo (KLO).

Of the twenty-two REFCL zone substation sites, ten sites are currently in service, including BWA, KMS, MSD, MYT, RUBA, RWN, SMR, WGI, WN and WYK, and a further three are expected to be in service by late-December 2020, including BGE, KLK and LDL. Of the in-service sites, compliance has been achieved at six sites, including WN, MYT, BWA, RUBA, SMR and KMS.

The Electricity Distribution Code (Version 9A), amended in August 2018, requires AusNet Services to identify all areas affected under a 'REFCL condition' in its Distribution Annual Planning Report. Figures 23 and 24 below identify the geographic locations where a REFCL condition may be experienced.

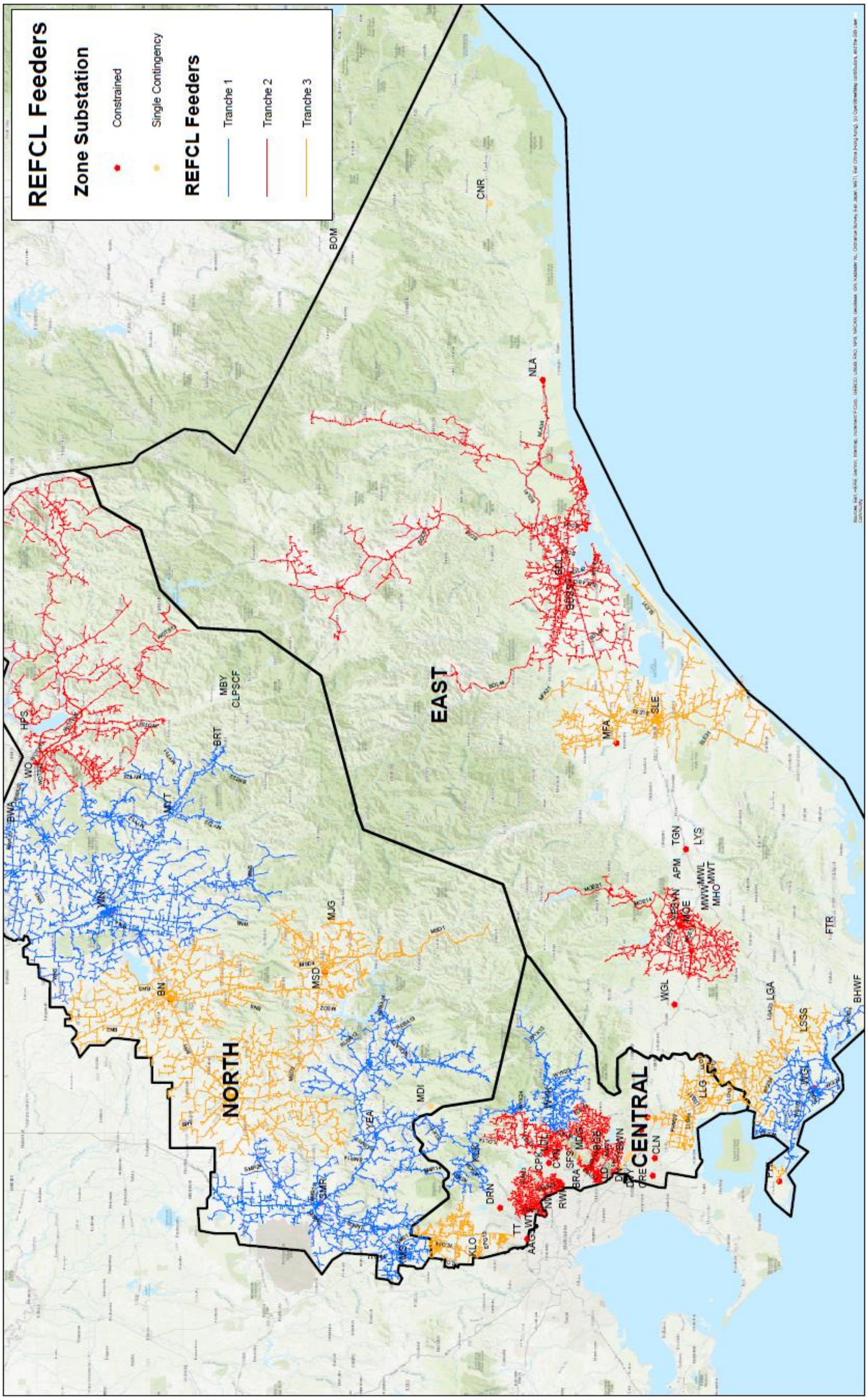
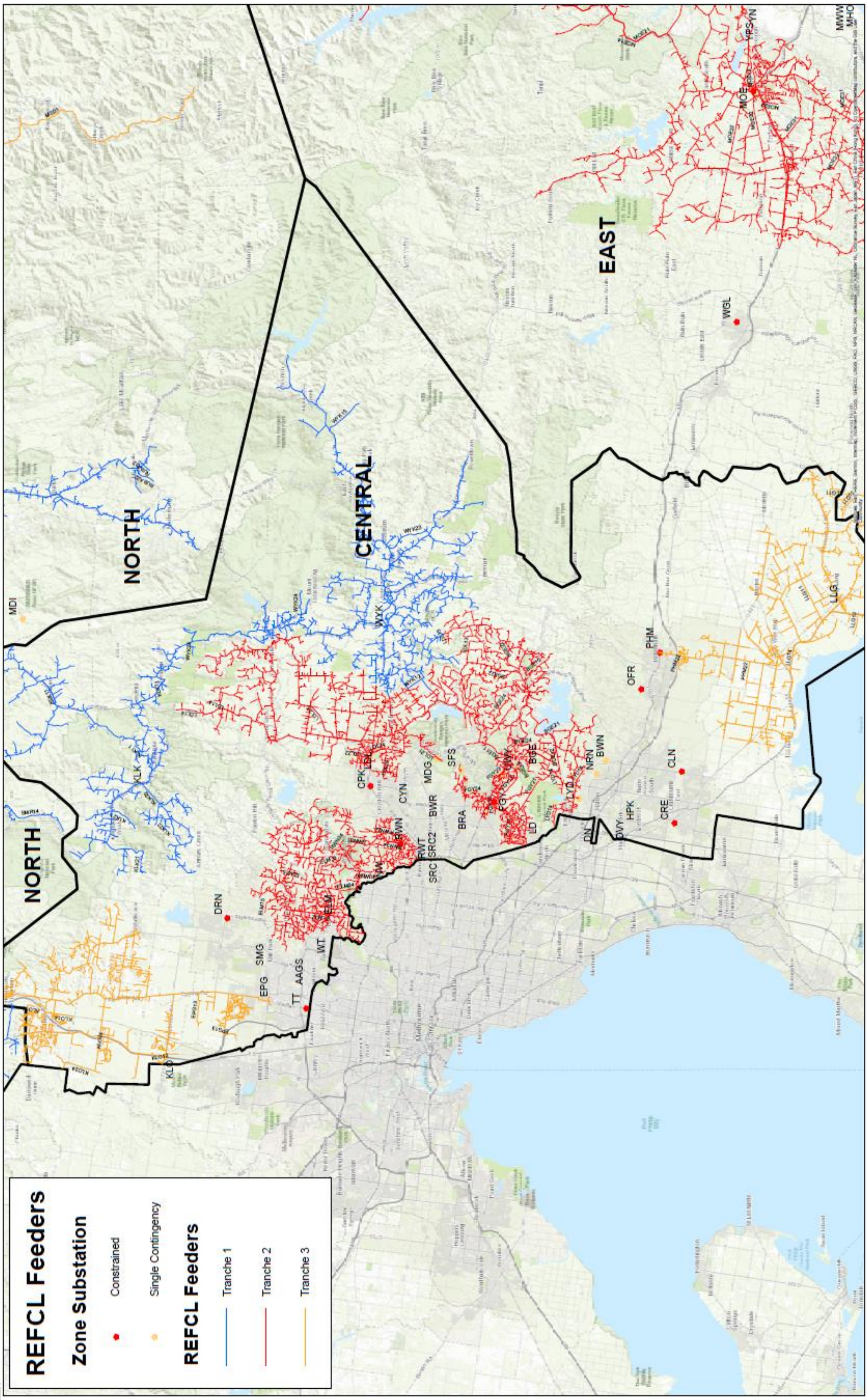


Figure 24. Feeders subject to a REFCL condition, by tranche (ref. Figure 27, REFCL Delivery Timetable).



yhuj

Figure 25. Feeders subject to a REFCL condition, by tranche – Central region focus

10 Joint planning with the Transmission Network Service Provider

In accordance with clause 5.14.1(a)(1) of the National Electricity Rules (NER), the Australian Energy Market Operator (AEMO) and the Victorian Distribution Network Service Providers (DNSPs) undertake joint planning to ensure the efficient development of the shared transmission and distribution networks and the transmission connection facilities. To formalise these arrangements, the parties have agreed a Memorandum of Understanding (MoU).

The MoU sets out a framework for cooperation and liaison between AEMO and the DNSPs regarding the joint planning of the shared network and connection assets in Victoria. The MoU sets out the approach to be applied by AEMO and the DNSPs in the assessment of options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and the shared transmission network. Under the MoU, the DNSPs and AEMO have agreed that, subject to the thresholds set out in the Rules, joint planning projects should be assessed by applying the Regulatory Investment Test for Transmission (RIT-T). The DNSPs also liaise regularly with AusNet Services' Transmission Group, the majority owner of the Victorian transmission network, to coordinate their transmission connection augmentation plans with AusNet Services' Transmission Group's asset renewal and replacement plans.

Clause 5.13.2(d) of the National Electricity Rules stipulates that a Distribution Network Service Provider is not required to include in its Distribution Annual Planning Report information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation (i.e., the Victorian Electricity Distribution Code clause 3.4[15]). The information for schedule 5.8 (h) regarding the results of any joint planning undertaken with the Transmission Network Service Provider (TNSP) has been included in the Transmission Connection Planning Report (TCPR) covering the period 2020-2029[16] and to avoid duplication is generally not repeated in this report. As required under schedule 5.8 (h), the TCPR contains a summary of the process and methodology used, a brief description of investments that have been planned (including the estimated capital costs of the investment and an estimate of the timing), and references to where additional information may be obtained.

As explained in section 4.7.1, AusNet Services and United Energy have commenced a RIT-T in relation to the thermal loading on the Cranbourne Terminal Station 220/66 kV connection asset transformers. This is the only active joint planning work currently underway.

[15] A copy of the Victorian Electricity Distribution Code can be viewed at the Victorian Essential Services Commission's website: Electricity Distribution Code | Essential Services Commission

[16] A copy of the 2020 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet Services' website: AusNet - Rosetta Data Portal (ausnetservices.com.au).

11 Joint planning with other Distribution Network Service Providers

This section provides details required by Schedule 5.8 (i) covering projects which AusNet Services is developing under joint distributor arrangements that are expected to commence in the next five-year period to 2023.

11.1 Distribution Network Service Providers' Joint Planning Process

AusNet Services engages with neighbouring Distribution Businesses (DB) when required to plan for network upgrades where networks cross the boundaries between a neighbouring DB. AusNet Services has one 66 kV sub-transmission loop that is shared with United Energy and one 66 kV sub-transmission loop that is shared with Jemena. There are also some small sections of 22 kV feeders that provide energy to customer's in a neighbouring DB and vice versa.

11.2 Jointly planned projects

Excluding joint planning of transmission connection assets, which are discussed in the Transmission Connection Planning Report, AusNet Services currently has one joint distribution planning project underway, as described below.

11.2.1 Kalkallo and Coolaroo REFCL compliance

In 2019 AusNet Services and Jemena Electricity Networks engaged WSP to undertake an area planning study for the Kalkallo and Coolaroo distribution areas to determine the most economical solution to achieve compliance with the Electricity Safety (Bushfire Mitigation) Regulations 2013 and the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017 (the Act) at Kalkallo Zone Substation (KLO) and Coolaroo Zone Substation (COO). These regulations require KLO and COO zone substations to be REFCL compliant by 1 May 2023 at the latest.

Joint planning was initiated because KLO is owned by AusNet Services and supplies four feeders that are owned by Jemena Electricity Networks. COO supplies the area adjacent to KLO and is owned by Jemena Electricity Networks. Both zone substations have significant underground distribution networks which cause the technical threshold of the REFCLs to be exceeded, requiring more than the relatively straightforward implementation of REFCLs at these zone substations to achieve and maintain compliance. Due to the interrelationship between these two zone substations, both businesses agreed to undertake joint planning to identify the most suitable option to meet compliance at both zone substations.

WSP was engaged to coordinate the joint planning process by leading discussions and consolidating data and options developed by AusNet Services and Jemena. With the data and options provided to them, WSP independently developed other potential options and undertook both qualitative and quantitative assessment of potential options to determine the proposed preferred solution.

The joint planning report was completed by WSP in December 2019, with the proposed preferred solution being to:

- Build a new REFCL protected Kalkallo North Zone Substation (KLN);
- Retain the existing KLO as a non-REFCL zone substation, by transferring overhead and fire risk network to KLN; and
- Installing two REFCLs at COO and transferring COO's underground 22 kV feeders to Somerton Zone Substation (ST).

Since then, discussions have continued to find a solution that balances the reduction in fire risk with the forecast underground network growth in the area, while reducing the overall cost. As of December 2020, the following scope of work is being considered for AusNet Services:

- Install Remote REFCL units on KLO14 and KLO24 feeders. These feeders are the only AusNet Services overhead feeders from KLO.
- Replace all overhead network up to the Remote REFCL installations with covered conductor.
- Install isolation transformers on underground cable sections in Wallan to reduce capacitance seen by the Remote REFCL installations.

The scope of work for Jemena includes the following:

- Replace overhead conductor on KLO22 with covered conductor or underground cable.

These works are proposed to be completed by 2023.

11.3 Additional Information on Jointly Planned Projects

Additional information on the investments may be obtained by contacting the listed representatives in Appendix F: Contacts.

12 Performance of AusNet Services' Network

This section highlights the performance of AusNet Services' Distribution Network required under schedule 5.8 (j).

12.1 Reliability measures and standards in applicable regulatory instruments

The Distribution Use of System (DUoS) charges that AusNet Services levies to electricity retailers and some large customers are adjusted each year in accordance with price controls established by the Australian Energy Regulator (AER).

The Service Target Performance Incentive Scheme (STPIS) provides financial incentives for Distribution Network Service Providers (DNSP) to maintain and improve service performance. Performance targets are set based on historical performances of the individual DNSP; thus, providing financial rewards for DNSPs beating their targets and financial penalties for failing to meet targets.

The STPIS applying to AusNet Services has three components:

- A reliability of supply component (S-Factor) which adjusts the revenue that a DNSP earns depending on reliability of supply.
- A customer service performance component that provides an incentive for the time taken to answer telephone calls.
- A Guaranteed Service Level (GSL) component which sets threshold levels of service for DNSPs to achieve and requires direct payments to customers who experience service worse than the predetermined level.

Table 31 shows the targets for the reliability of supply and customer service components of the scheme for the period 2016 to 2020 period and Table 32 shows the targets for the stub period (1 January 2021 to 30 June 2021) and the 2021-2026 regulatory control period.

Measure	Feeder Class	2016	2017	2018	2019	2020
Unplanned SAIDI	Urban	81.5390	81.2180	80.8970	80.5770	80.2560
	Rural Short	188.0490	187.5930	187.1380	186.6820	186.2260
	Rural Long	233.9770	233.3560	232.7360	232.1160	231.4960
Unplanned SAIFI	Urban	1.0990	1.0930	1.0880	1.0820	1.0770
	Rural Short	2.2910	2.2840	2.2760	2.2690	2.2610
	Rural Long	2.8290	2.8190	2.8100	2.8010	2.7920
Unplanned MAIFI	Urban	2.7960	2.7940	2.7920	2.7900	2.7880
	Rural Short	5.8250	5.8190	5.8140	5.8080	5.8030
	Rural Long	11.3740	11.3680	11.3620	11.3560	11.3500
Telephone answering parameter		80.3300	80.3300	80.3300	80.3300	80.3300

Table 31: 2016/2020 Final decision performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter

Source: FINAL DECISION AusNet Services distribution determination 2016 to 2020. Attachment 11 – Service target performance incentive scheme, May 2016 p. 11-9.

Measure	Feeder Class	Stub Period	2021-2026
Unplanned SAIDI	Urban	44.48473	76.748
	Rural Short	87.31703	188.097
	Rural Long	101.83266	270.869
Unplanned SAIFI	Urban	0.55751	0.828
	Rural Short	1.15861	1.977
	Rural Long	1.28453	2.582
Unplanned MAIFI	Urban	1.40751	2.696
	Rural Short	3.14188	5.758
	Rural Long	5.78742	10.557
Telephone answering		80.33	-

Table 32: Stub Period and draft 2021-2026 performance targets for USAIDI, USAIFI and MAIFI

Source: FINAL DECISION Six-month extension – variation decision, October 2020, pp. 2-22 and DRAFT DECISION AusNet Services Distribution Determination 2021 to 2026 Attachment 10 Service target performance incentive scheme, September 2020, pp10-2.

Notes:

- USAIDI (Unplanned System Average Interruption Duration Index, or the average minutes a customer is off supply each year resulting from unplanned outages).
- USAIFI (Unplanned System Average Interruption Frequency Index, or the average number of times a customer is off supply each year resulting fromunplanned outages).
- MAIFI (Momentary Average Interruption Frequency Index or the average number of times a customer is off supply for less than 1 minute each year).
- Call centre performance (the percentage of fault calls progressing to an operator that are answered within 30 seconds).
- For the 2021-2026 regulatory control period, AusNet Services' have opted to apply a Customer Service Incentive Scheme (CSIS) rather than the STPIS telephone answering parameter, however it is proposed that AusNet Services continue to report on the telephone answering parameter for transparency purposes.

In its final determination for the 2016-2020 EDPR, the AER concluded that it is bound to apply the existing Victorian GSL scheme under Section 6 of the Electricity Distribution Code. The AER notes that while worst performing feeders are not specifically targeted by the STPIS, the worst served customers are compensated by the GSL scheme. Table 33 summarises the supply restoration and low reliability payments schemes applicable in the current (2016 to 2020) EDPR period.

Measure	Condition	Amount
Cumulative Duration	Where the customer experiences more than 20 hours of unplanned sustained interruptions per year; or	$ 120
	Where the customer experiences more than 30 hours of unplanned sustained interruptions per year; or	$ 180
	Where the customer experiences more than 60 hours of unplanned sustained interruptions per year;	$ 360

Duration of Individual interruption	Where the customer is supplied by a CBD feeder or an Urban feeder and experiences an unplanned sustained interruption of more than 12 hours, and 20 hours or less of unplanned sustained interruptions in that year;	$ 80
	Where the customer is supplied by a short rural feeder or a long rural feeder and experiences an unplanned sustained interruption of more than 18 hours, and 20 hours or less of unplanned sustained interruptions in that year;	$ 80
Cumulative Number of Sustained Outages	Where the customer experiences more than 8 unplanned sustained interruptions per year; or	$ 120
	Where the customer experiences more than 12 unplanned sustained interruptions per year; or	$ 180
	Where the customer experiences more than 24 unplanned sustained interruptions per year	$ 360
Cumulative Number of Momentary Outages	Where the customer experiences more than 24 momentary interruptions per year; or	$ 30
	Where the customer experiences more than 36 momentary interruptions per year.	$ 40

Table 33: GSL Supply Restoration and Low Reliability Payments – 2016 to 2020

Source: Electricity Distribution Code, April 2011, pp. 19-20.

Measure	Condition	Amount
Duration	Where the customer experiences more than 18 hours of unplanned sustained interruptions per year; or	$ 130
	Where the customer experiences more than 30 hours of unplanned sustained interruptions per year; or	$ 190
	Where the customer experiences more than 60 hours of unplanned sustained interruptions per year;	$ 380
	Major event day (12 hours or more)	$90
Number of Sustained Outages	Where the customer experiences more than 8 unplanned sustained interruptions per year; or	$ 130
	Where the customer experiences more than 12 unplanned sustained interruptions per year; or	$ 190
	Where the customer experiences more than 20 unplanned sustained interruptions per year	$ 380
Number of Momentary Outages	Where the customer experiences more than 24 momentary interruptions per year; or	$ 40
	Where the customer experiences more than 36 momentary interruptions per year.	$ 50

Table 34: GSL Supply Restoration and Low Reliability Payments – 2021 to 2026

Source: Electricity Distribution Code review – customer service standards, Final decision, 16 November 2020, pp. 45-46

12.1.1 Exclusion Criteria

Section 3.3 of the revised Electricity Distribution Network Service Providers – STPIS Nov 2018 outlines the exemption criteria applicable in the EDPR period 2016-2020. The same set of criteria is applicable to the EDPR period 2016-2020. Events that fall in any of the following conditions may be excluded in calculating the revenue increment or decrement as well as annual performance under the STPIS scheme.

Exclusions include:

- Load shedding due to a generation shortfall.
- Automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition.
- Load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator.
- Load interruptions caused by a failure of the shared transmission network.
- Load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.
- Load interruptions caused by a failure of transmission connection assets except where the interruptions were due to:
  - (a) actions, or inactions, of the DNSP that are inconsistent with good industry practice; or
  - (b) inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.
- Example: a DNSP omits to suppress back-up earth fault (BUEF) protection when undertaking network switching operation that results in momentary paralleling of supplies from two different terminal stations, where this is inconsistent with the standard practice.
  - Load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
  - Load interruptions caused or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction.
  - An event may also be excluded where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day (MED) boundary.

In addition to the above set of criteria, the AER considers that avoidable supply interruptions due to the suppression of the auto-recloser system under an approved Electricity Safety Management Scheme would meet the exclusion criteria under clause 3.3(a)(7) of the STPIS.

12.2 Performance against reliability measures and standards

Outlined in the subsections below is a summary of AusNet Services' performance against the measures and standards.

12.2.1 Network Performance – Reliability

Table 35 summarises the reliability performance of the electricity distribution network for the calendar year 2019. Total performances with and without exemptions are shown along with individual targets, which include exemptions, for each feeder category. USAIFI and MAIFI performances were favourable (with exemptions) while USAIDI was unfavourable.

Measure	Feeder Class	2019		
		Target	Total	Net
Unplanned SAIDI	Urban	80.58	108.74	77.86
	Rural Short	186.68	389.89	204.46
	Rural Long	232.12	817.45	382.67
Unplanned SAIFI	Urban	1.08	1.08	0.86
	Rural Short	2.27	2.74	2.24
	Rural Long	2.80	3.43	2.95
Unplanned MAIFI	Urban	2.79	2.93	2.80
	Rural Short	5.81	5.68	5.20
	Rural Long	11.36	11.14	9.46

Table 35: Network Performance Summary 2019

The Electricity Distribution network calendar year 2019 USAIDI net performance was 179.28 minutes with total exemptions of 159.85 USAIDI minutes. Excluded in the year-end reliability performances (i.e., SAIDI, SAIFI, MAIFI) are customer interruptions affected by major storms in January, November and bushfires in December which exceeded the Major Event Day (MED) threshold for CY19 at 9.98 USAIDI minutes. Also excluded are the impact of the AEMO-initiated load shedding interruptions on 25th January of ~7 minutes.

Some sustained outages during declared Total Fire Ban (TFB) days were also eligible for exclusion. These were outages from protective devices (i.e., Feeder CB, ACRs) where auto-reclose operation was suppressed, and no credible cause ("unknown") were identified during line patrol. These exclusions are summarised in Table 36.

Event Description	Exclusion Criteria	Date	USAIDI, Minutes
Major Event Day – Storms	STPIS Exclusion 6.4(b)	Various date	143.92
Load shedding	STPIS Exclusion 6.4(a)(4)	25 January	6.98
REFCL impact during tests	STPIS Exclusion 6.4(a)(7)	Various dates	6.46
Total Fire Ban (TFB) day	STPIS Exclusion 6.4(a)(7)	Various dates	2.47
Transmission events	STPIS Exclusion 6.4(a)(6)	Various dates	0.01
Total			**159.85**

Table 36: Summary of exemptions 2017

Table 37 summarises the GSL performance for 2019. The total GSL amount for 2019 is ~84% higher than 2018. The total number of customers eligible for GSL payments in 2019 is ~51% higher than 2018. The significant increase in GSL amount and customers eligible for GSL payments was mainly due to more inclement weather conditions and major bushfires in 2019 than prior. CY19 experienced more moderate-sized storms compared CY18. In terms of average wind speed across AusNet's service area in 2019, there was ~4% (or ~15 days) increase in number of days with maximum wind between 28 and 50kph compared to 2018. There was also a ~1% (or 3.5 days) increase in days where wind speed exceeded 50kph (storms) year on year. The combined

USAIDI minutes lost from vegetation and weather-related faults in CY19 was only ~3.6% higher than CY18 (after removing exclusions).

Measure	Supply Interruption Condition	Penalty Rate per Customer	Number of eligible customers	Amount
Duration of Interruption	>20 hrs.	$120	18,970	$2,276,400
	>30 hrs.	$180	13,920	$2,505,600
	>60 hrs.	$360	5745	$2,068,200
	Urban feeder unplanned event - 18hr > D < 20hr	$80	2,282	$182,560
	Rural feeder unplanned event - 18hr > D < 20hr	$80	836	$66,880
Number of Sustained Outages	> 8 interruptions	$120	23,517	$2,822,040
	> 12 interruptions	$180	6,781	$1,220,580
	> 24 interruptions	$360	0	$0
Number of Momentary Outages	> 24 interruptions	$30	11,343	$340,290
	> 36 interruptions	$40	4,246	$169,840
TOTAL			**87,640**	**$11,652,390**

Table 37: Summary for Reliability of Supply GSL 2019

12.2.2 Low Reliability Feeders

AusNet Services' 2019 Annual Feeder Performance report identifies 146 distribution feeders in the Lower Reliability (LR) feeder category as shown in Table 38**Error! Reference source not found.**. An LR feeder is a feeder for which the average minutes off supply (for planned and unplanned interruptions) and/or frequency of momentary interruptions (for feeder and section levels) is above the thresholds specified in Table 39.

Feeder Class	Number of Low Reliability feeders (Calendar Year 2019) with respect to 2018 feeder count		
	SAIDI	MAIFI	Total (unique feeder)
Urban	56 (↓5%)	18 (↑20%)	61 (↓3%)
Rural Short	55 (↑8%)	19 (↓10%)	60 (↑9%)
Rural Long	24 (↑60%)	3 (↓63%)	25 (↑19%)
Total >	135 (↑8%)	40 (↓9%)	146 (↑5%)

Table 38: Low reliability feeders by network type for CY18

Network Type	Average annual minutes off supply (SAIDI) for planned and unplanned interruptions	Momentary interruptions (MAIFI)
Urban	270	5
Rural Short	600	12
Rural Long	850	25

Table 39: Thresholds for low reliability feeders by network type

Notes:

- The LR thresholds originated from the 2006-2010 EDPR period. DNSPs were also required to provide reliability improvement plans for each LR feeder in the annual feeder performance report during that period. In the current (i.e., 2016-2020) EDPR period which covers CY19, the AER report template no longer requires LR feeders to be identified.

Overall, there were 146 LR feeders in CY19, which is 5% higher year-on-year. In comparison to CY18 performance, CY19 had teen more feeders under the LR SAIDI measure but four less feeders under the LR MAIFI measure.

12.3 Corrective Actions – Reliability

The following subsections detail corrective actions that have been taken in relation to reliability and quality of supply.

12.3.1 Corrective Action – Reliability

AusNet Services is focusing on improving the distribution network's reliability performance by systematically reviewing poorly performing segments and investing in technology that automatically reconfigures the affected network to minimise the number of customers affected by outages.

AusNet Services will continue to monitor the reliability performance and take appropriate actions to outperform the targets. These include installing additional switches, fuses, ACRs, vegetation management, animal proofing and protection coordination improvements.

12.3.2 Performance Evaluation Method

When evaluating reliability performance, it is important to use a methodology that employs statistical analysis of long run trends rather than a year-to-year or year-to-target comparison. This avoids implementing an investment strategy that reacts to recent events, rather than a predictive strategy focussed on closing the gap between current performance and future targets. Accordingly, AusNet Services:

- Normalises the impact of external factors, such as weather, on annual performance.
- Uses weighted five-year performance to identify underperforming circuits.
- Employs statistical mean and standard deviation to analyse the significance of variations in performance indicators.
- Internally reports daily reliability performance against targets, for both unplanned and planned outages.
- Conducts regular meeting between the reliability improvement team, to discuss improvement measures for current reliability issues.
- Closely monitors low reliability feeders.
- Participates in benchmarking study to identify the strengths and the weaknesses of regional areas when compared to best practice.
- Assesses in detail how the network performed during storm events to maintain trending data and determine opportunities future asset programs.
- Monitors repetitive faults in the network monthly to establish emerging problems.
- Monitors performance of distribution feeders for which new initiatives have been implemented to identify their effectiveness and if opportunities exist to extend these programs.
- Undertakes analysis of any event that contributed 0.3 USAIFI or more and any large event that contributed 2.0 USAIDI minutes or more, to determine improvement opportunities in terms of AusNet Services' response to the outage events from both an operational and strategic perspective.

12.4 Quality of supply standards

The quality of supply standards that apply to Victorian DNSPs are stipulated in the Electricity Distribution Code (EDC) published by the Essential Services Commission (ESC), Victoria. The Electricity Distribution License issued by the ESC to AusNet Electricity Services Pty Ltd requires compliance with the EDC. The EDC provides standards and guidelines in relation to following quality of supply parameters.

AusNet Services' is committed to maintaining power supply quality within the limits specified in the above code and relevant standards. The following power quality parameters are discussed in this section:

- Voltage standards

- Power factor
- Harmonics
- Inductive interference
- Load balancing (Negative sequence voltage)
- Flicker

12.4.1 Voltage Standards

The Victorian Electricity Distribution Code specifies the voltage levels that must be maintained at the point of supply to the customer's electrical installation. These levels are:

- 230 V
- 400 V
- 460 V
- 6.6 kV
- 11 kV
- 22 kV
- 66 kV.

The Victorian Electricity Distribution Code (EDC) clause 4.2 specifies the Standard Voltage Variations limits at each voltage level. These levels are specified in Table 40 below.

<table>
<tr><th rowspan="2"></th><th rowspan="2">Voltage
Level in kV</th><th colspan="4">Voltage Range for Time Periods</th></tr>
<tr><th>Steady
State</th><th>Less than
1 minute</th><th>Less than
10 seconds</th><th>Impulse
Voltage</th></tr>
<tr><td>1</td><td rowspan="2">< 1</td><td colspan="3">As 61000.3.100*</td><td rowspan="2">6 kV peak</td></tr>
<tr><td>2</td><td colspan="2">+13 %
-10 %</td><td>Phase to Earth +50%-100%
Phase to Phase +20%-100%</td></tr>
<tr><td>3</td><td>1-6.6</td><td rowspan="3">± 6 %
(± 10 %
Rural Areas)</td><td rowspan="3">± 10 %</td><td rowspan="3">Phase to Earth +80%-100%
Phase to Phase +20%-100%</td><td>60 kV peak</td></tr>
<tr><td>4</td><td>11</td><td>95 kV peak</td></tr>
<tr><td>5</td><td>22</td><td>150 kV peak</td></tr>
<tr><td>6</td><td>66</td><td>± 10%</td><td>± 15%</td><td>Phase to Earth +50%-100%
Phase to Phase +20%-100%</td><td>325 kV peak</td></tr>
</table>

Table 40: Standard Nominal Voltage Variations

Notes:

* The voltage range for time periods less than 1 minute and 10 seconds do not apply to AS 61000.3.100.

* For the purposes of clause 4.2.7, which deals with the circumstances in which a distributor must compensate a person whose property is damaged due to voltage variations, rows 2 to 6 apply.

* Row 2 values (steady state, less than 1 minute, and less than 10 seconds), and not row 1 values, are applicable for the purposes of clause 4.2.7. In this way, the row 2 values operate separately from the AS 61000.3.100 requirements.

As per the Version 11 (April 2020) of the EDC, the Phase to Earth voltage variations in Table 40 above does not apply during the period in which a REFCL condition is experienced on the distribution system (including when a REFCL condition arises from the commissioning and testing of a REFCL). Under these conditions the Phase-to-Phase voltage variations in supply to that part of the 22kV distribution system experiencing the REFCL condition.

Voltage Level in kV	PHASE TO PHASE NOMINAL VOLATGE VARIATIONS			
	Steady State	Less than 1 minute	Less than 10 seconds	Impulse Voltage
22	± 6% (± 10% rural areas)	± 10%	Phase to Phase +20%-100%	150kV peak

Table 41: Standard Nominal Voltage Variations

The Australian Standard AS 61000.3.100-2011 is also used as appropriate for assessment of steady state voltage limits. Electricity Safety (Bushfire Mitigation) Regulations 2013[17] introduced on 1 May 2016 require AusNet Services to install Rapid Earth Fault Current Limiter (REFCL) devices. These devices are to be deployed in high fire risk areas prior to 1 May 2023.

REFCLs reduce energy release in powerline earth faults (fallen wire, tree touching wire, etc.) by rapidly displacing network voltages to bring the voltage on the faulted conductor close to zero. On a 22kV network, REFCL response to an earth fault will very quickly reduce the voltage on the faulted conductor from around 12,700 volts to less than 250 volts. This displacement necessarily causes the phase-to-earth voltages on two un-faulted conductors to increases to 173% (i.e., the square root of three) of their pre-fault level.

12.4.2 Power Factor

The EDC clause 4.3 requires a customer to ensure that the customer's demand for reactive power does not exceed specified limits. These limits are shown in Table 42.

Supply Voltage in kV	Power Factor Range for Customer Maximum Demand and Voltage					
	Up to 100 kVA		Between 100 kVA-2 MVA		Over 2 MVA	
	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading
<6.6	0.8	0.8	0.8	0.8	0.85	0.85
6.6 11 22	0.8	0.8	0.85	0.85	0.9	0.9
66	0.85	0.85	0.9	0.9	0.95	0.98

Table 42: Power Factor Limits

A customer must use best endeavours to keep the power factor of its electrical installation within the relevant range set out in Table 42. AusNet Services' supply policy and connection agreements stipulate these requirements and therefore power factor limits are maintained at most connection points. AusNet Services uses tariffs on reactive power for its large customers to incentivise compliance.

12.4.3 Harmonics

The EDC clause 4.4, requires the distributor to ensure that the harmonic levels in the voltage at point of common coupling (PCC) nearest to a customer's point of supply comply with the levels specified by the system standards set out in Schedule 5.1a, clause S5.1a.6 of the NER.

Further, subject to clause 4.4.1, a distributor must comply with the system standards set out in Schedule 5.1a, clause S5.1a.6 of the NER, particularly establishment of the 'planning level' by the distributor.

[17] Electricity Safety (Bushfire Mitigation) Regulation 2013, Version 004, 05/01/2016

As per the existing EDC, a customer must keep the harmonic currents below the limits specified in Table 43 and otherwise comply at its nearest PCC with IEEE standard 519-1992 “Recommended practices and Requirements for Harmonic Control in Electrical Power Systems”. The joint Australian/New Zealand Technical Report TR IEC 61000.3.6.2012 will also be used as appropriate for the allocation of voltage harmonic limits to disturbing loads or generators.

I_{sc}/I_L	Maximum Harmonics Current Distortion in Precent of I_L					
	Individual harmonics Order ‘h’ (Odd Harmonics)					THD
	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	
<20	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

Table 43: Current Harmonic Distortion Limits

Notes:

1. Even harmonics are limited to 25% of the odd harmonics listed above.
2. Current distortions that result in a DC offset, e.g., half-wave converters, are not allowed.
3. *All power generation equipment is limited to these values of current distortion, regardless of actual ISC/IL.
4. Isc = maximum short-circuit current at point of common coupling.
5. IL = maximum demand load current (fundamental frequency component) at point of common coupling.

AusNet Services maintains harmonic voltages within limits at most of its supply points. Harmonic voltages are known to have deviated from the allowable limits at several locations in the network. These instances were observed from analysis of metered data and from customer enquiries. Where harmonic voltage is suspected to be outside limits, it is investigated, and corrective measures are developed.

12.4.4 Inductive Interference

The EDC clause 4.5 requires the distributor to ensure that inductive interference caused by its distribution system is within the limits specified in AS/NZ 2344-2016.

AusNet Services’ design standards avoid generation of radio frequency interference (RFI) or Television interference (TVI) on the network. This is mainly achieved by type tested equipment and suitably designed components. In addition, routine cyclic inspections and maintenance procedures ensure that the network is maintained in a good condition to ensure RFI & TVI is not generated or limited to levels that will not affect customers.

12.4.5 Load Unbalance (Negative Sequence Voltages)

The EDC clause 4.6 requires the distributor to maintain the negative sequence voltage at the PCC to a customer’s three-phase electrical installation in accordance with the system standard in Schedule 5.1a, clause S5.1a.7 of the NER.

12.4.6 Flicker

The EDC clause 4.8 requires the distributor to maintain voltage fluctuation at the point of common coupling at a level no greater than the levels specified in accordance with the system standards set out in Schedule 5.1a, clause S5.1a.5 of the NER.

Appropriate flicker allowances are given to customers with disturbing loads prior to supply connection approval. These allowances are given based on the aforementioned Standards.

There have been no recent flicker related complaints.

12.5 Performance against quality of supply measures and standards

Outlined in the subsections below is a summary of AusNet Services' performance against the measures and standards.

12.5.1 Network Performance – Quality of Supply

As per the EDC clause 4.2.6, AusNet Services monitors and records steady state voltages and voltage variations. The recorded quality of supply performance is reported to the Australian Energy Regulator which publishes it in the form of the 'Victorian Electricity Distribution Businesses – Comparative Performance Report'[18]. Other quality of supply issues are dealt with on an as needs basis according to the EDC Clause 9.1.5. Further information on how AusNet Services manages Quality of Supply issues can be found in section 12.6. Table 44 shows the network quality of supply performance statistics, by calendar year, from 2015 to 2018.

Quality of Supply - Voltage Variation	2015	2016	2017	2018	2019
Voltage variations - steady state (zone sub)	591	944	663	1,298	2,949
Voltage variations - one minute (zone sub)	0	491	327	3,320	134
Voltage variations - 10 seconds (zone sub) Min<0.7	978	1,333	619	1,069	965
Voltage variations - 10 seconds (zone sub) Min<0.8	1,470	2,195	901	1,598	1,537
Voltage variations - 10 seconds (zone sub) Min<0.9	3,169	4,745	1,953	4,046	5,679
Voltage variations - steady state (feeder)	4,826	3,644	15,389	10,961	12,542
Voltage variations - % zone subs monitored	58%	93%	100%	93%	98%
Voltage variations - % feeders monitored	42%	55%	100%	81%	98%

Table 44: Summary of Voltage Variations for Calendar Years 2015-2018

Since 2016, AusNet Services have been installing new and replacement feeder extremity meters to address existing issues as mentioned above. Installations where completed in mid-2017 which has brought up the percent coverage and data quality from zone substation and feeder extremity meters. In the same year, AusNet Services completed the $1.4m project that saw the upgrade of old ION Enterprise software into Power Monitoring Expert (PME) and the automation of ION and EDMI data into PME. Automated regulatory and business reports were also delivered along with the establishment of service level agreements (SLA) to ensure both data and PME system are maintained.

Quality of supply monitoring is becoming increasingly important given the technology shift occurring in the industry, and the corrective action taken or planned to maintain quality of supply within the EDC limits are described in the following sections.

12.5.2 Network Performance – Voltage Level Reporting

In accordance with clause 3.5.1 and 3.5.4 of the Electricity Distribution Code (EDC), AusNet Services is required to publish annual voltage level reporting information in the detailed in Schedule 1 of the EDC. The aggregated 10-minute-averaged voltage data identified in Table 6 of Schedule 1 of the EDC for each calendar year for the past 5 years are published in our website in easily accessible CSV format:

[18] A copy of the report can be found at the Australian Energy Regulator's website: http://www.aer.gov.au/node/483

https://dapr.ausnetservices.com.au/ausnet_data/Voltage%20data%20averages.csv

12.5.2.1 Network Performance – Voltage Level Reporting Methodology

The methodology used to produce the voltage data and other categories of information is described herin:

- The voltage data published in the CSV file is the 10-minute averaged voltage data over 3 months of the aggregated AMI population of each Voltage Control Section (VCS). The relevant 3-month periods are as follows:
    - 1 December – 28 (or 29) February (depending on the year).
    - 1 March – 31 May.
    - 1 June – 31 August.
    - 1 September – 30 November.
- The voltage data are populated for four different time bands for each Voltage Control Section over the 3-month period. The time-blocks defined in Table 6 of Schedule 1 include the start and end time is inclusive of the hour, which will double count the transition hour. For aggregation of data, the time blocks indicated below are considered to finish one minute before end time (e.g., 10:00-16:00 is considered to be 10:00-15:59).
    - 10:00 – 16:00
    - 16:00 – 22:00
    - 22:00 – 04:00
    - 04:00 – 10:00
- Schedule 1 of the EDC defines a voltage control section (VCS) as any device or equipment, which manages the feeder voltage, starting from the zone substation on-line tap changer. Therefore, each feeder comprises of voltage control sections starting from the distribution zone substation and where applicable VCS sections are identified downstream of line voltage regulators and SWER isolating transformers.
- AusNet services receives 5-minute instantaneous voltage data from AMI meters. The existing 5-minute instantaneous voltage data (from AusNet Services' Power Quality dataset) are used to derive the averaged voltage data over each 3-month period for each time block for each voltage-controlled section. This method is used because a similar outcome is achieved by averaging the 5-minute instantaneous data as calculating the 10-minute averaged voltage data for each voltage control section over the specified time blocks on 3-month periods.
- In addition to voltage data, standing data on feeders are provided as specified in Schedule 1 of the EDC. The standing data used in the voltage report comes from different sources; some are historical (time-bound) and others are current. Therefore, some of the standing data represents the state of the network as at present and some data being correct as of the historical analysis date. The table below details whether a column in the resultant dataset is time-bound or as-is. The customer counts (and customers with small embedded generation) are based on unique NMIs. As the source of customer counts is joined by the analysis date, the counts reflect what it was at the analysis dates.

  The geographical location details of voltage control devices (Column IDs: VCS_Latitude and VCS_Longitude) and type of VCS devices (Column ID: VCS_Type) are also included in the voltage report.

Table 45: Standing data details

Column ID	Column Description	Time-bound (historic) data	As-at (current) data
ZONE_SUB	Zone Substation		✓
FEEDER	Feeder		✓
FEEDER_CLASS	Feeder class (urban, short rural or long rural)		✓
VCS_NAME	Name of VCS		✓
BUSINESS_ID	Detailed name of VCS		✓
AMI_CUSTOMERS	Customers with AMI	✓	
AMI_CUSTS_WITH_EG	AMI customers with embedded generation	✓	
PCT_AMI_CUSTS_WITH_EG	Percentage of AMI customers with embedded generation	✓	

12.6 Corrective Action – Quality of Supply

At a high level, AusNet Services' aims to maintain sub-transmission network voltages (66 kV) within the code limits utilising the methods described below:

- Terminal Station transformer on load tap change (OLTC)
- Terminal Station reactive support
- Line voltage regulators (66 kV)
- Establishing optimum 66 kV voltage set points at each terminal station.
- AusNet Services' the terminal station secondary (i.e. 66 kV) bus voltages were reviewed during 2015 and the setting points were informed to the AEMO as part of the annual reporting requirement. There were no changes from the previous year at the eleven connection points.

At a high level, AusNet Services' aims to maintain distribution feeder voltages (22 kV) within the code limits utilising the methods described below:

- Zone Substations on load tap change (OLTC)
  - Zone substations reactive support
  - Line voltage regulators (22 kV)
  - Pole mounted 22 kV capacitor banks (typically 900 kVAr at a location)
  - Establishing optimum 22 kV voltage set points at each zone substation.
- Distribution feeder voltages are reviewed on an ongoing basis and where necessary adjustments are made to existing line voltage regulators, feeder configurations, capacitors and zone substation voltage set points. The secondary bus voltages (i.e., 22 kV) at a number of zone substations were lowered during the year to cater for increased penetration of solar photovoltaic arrays. AusNet Services' utilises voltage profiles captured by AMI meters to implement optimum distribution feeder voltages.
- AusNet Services' low voltage network voltages (230/400 V) are maintained within the code limits utilising the methods described below.
- Distribution transformer off-loads tap change
  - Upgrading or constructing new distribution substations
  - Load balancing
  - Low Voltage line augmentation

12.6.1 Voltage compliance corrective action

With the increased penetration of distributed generation, such as solar PV, increasing network voltages and voltage operating bands, AusNet Services has increased its voltage monitoring capabilities, utilising AMI data, and developed proactive programs to improve voltage compliance and distributed energy resources (DER) integration. The voltage monitoring tool and the three key voltage management and DER integration programs are outlined in the following sections

Utilisation of AMI data in voltage compliance monitoring and corrective action

In addition to the above traditional methods, AusNet Services has developed a tool, known as Explore, that uses AMI data and network analytics to monitor the level of voltage compliance within AusNet Services' distribution network. Explore provides an up-to-date view of the level of voltage compliance and stores historical data to give a view of how voltage compliance has changed over time.

The target for 'functional compliance' to the Australian Standard, AS 61000.3.100, is to have less than 5% of customers experiencing voltages outside the 216-253 Volts target range on the low voltage network.

Figure 26 shows how the level of voltage compliance improved between December 2014 and December 2020, with overvoltage (high breach) non-compliance reducing from approximately 30% to 10%. It also shows that compliance with the undervoltage (low breach) limits has been mostly maintained.

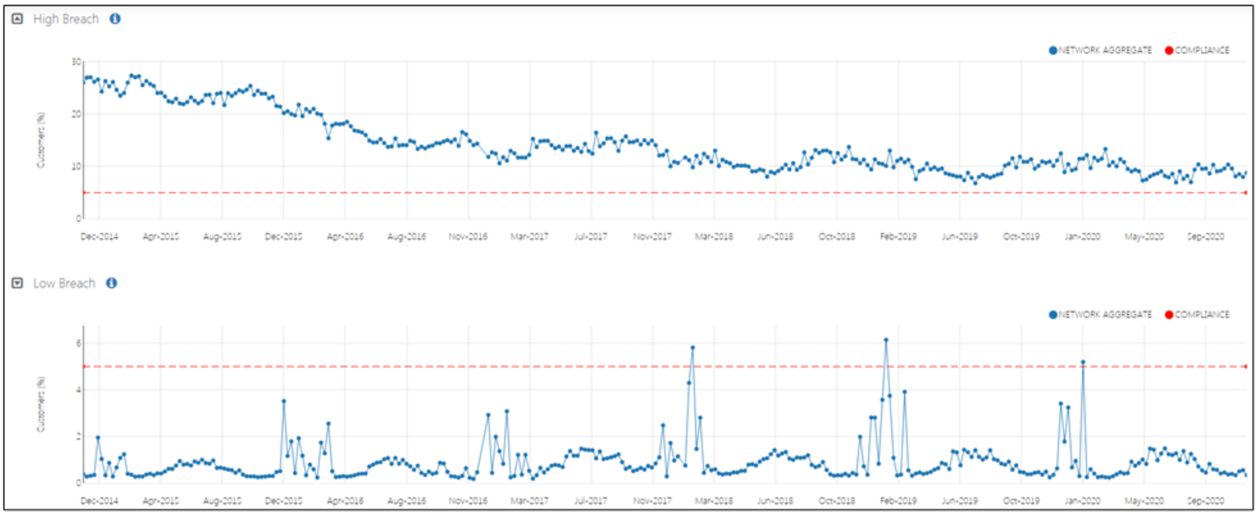


Figure 26: Improvement in voltage compliance

The improvement in voltage compliance seen in Figure 26 is primarily due to voltage regulator setting changes that have been actively made to improve voltage levels. Many of the regulators were changed from line-drop compensation to uncompensated settings. These setting changes have been made gradually since 2014 to improve voltage levels and allow better integration of embedded generation such as residential solar PV.

Customer supply compliance program

This is a reactive program that addresses quality of supply issues identified by customers within AusNet Services' electricity distribution network. It focuses on taking immediate corrective actions in response to customer complaints.

Where customer issues can be resolved by adjusting transformer tap settings or phase balancing, these are allocated to the appropriate operational cost code and are not included in this program.

The typical work undertaken under this program includes:

- Upgrading distribution transformers
- Rearranging the network to distribute customers evenly
- Reducing circuit loading by upgrading, or splitting circuits
- Splitting LV networks by installing new distribution substations

Steady state voltage compliance program

This a proactive forward-looking investment plan to manage the existing and emerging voltage constraints in AusNet Services' 22 kV and low voltage distribution network.

AusNet Services has developed an economic approach to valuing the impact of overvoltage on solar generation. This approach uses outputs from AusNet Services' Substation Health tool (part of the Explore tool) and future voltage compliance assessment, which classifies potential solutions to the existing and future voltage non-compliance issues at a distribution substation level.

The approach estimates the cost of solar generation that is constrained due to voltage non-compliance issues and compares this to the cost of augmentation options that will enable that solar generation to be unconstrained or less constrained.

The following is a summary of the approach:

- A solar forecast with a moderate uptake is applied to each non-compliant distribution substation to determine the expected exported energy to the distribution network.
- The expected exported energy is valued using the minimum feed-in tariff (FiT).
- The network topology is extracted from AusNet Services' geo-spatial system, SDMe, to determine where in the network the constrained substations are positioned and the critical equipment likely to be causing the voltage non-compliance, i.e., zone substation, line voltage regulator, distribution substation etc.
- The expected exported energy is aggregated to the equipment that has been identified as causing the voltage non-compliance issues. This is the value of constrained expected exported energy due to voltage non-compliance and forms the value of unserved generation.
- The constrained expected exported energy per annum is used to calculate the benefits of potential network and non-network solutions.
- A net present value (NPV) assessment is made to determine the highest NPV option. A potential solution is justified when the value of estimated enabled export of previously constrained generation exceeds the cost of the augmentation that allows that generation.
- The justified NPV option with the largest net benefit is then included into our network development plans

The proposed program expenditure is derived from an assessment approach that aims to maximise the net economic benefit to customers by augmenting the network to enable increased export of solar PV generation. The economic assessment observes actual customer voltage performance and values the unserved generation of rooftop-solar due to voltage constraints using the feed-in-tariff (FiT).

In identifying the proposed preferred program to improve steady state voltage compliance, AusNet Services considered four alternative options:

- Option 1 - Do nothing
- Option 2 - Only address existing voltage issues
- Option 3 - Address both existing and future voltage issues
- Option 4 - Aiming for zero constraints

Options 2 and 3 following the economic approach. Option 4 applies a similar approach to Options 2 and 3, considering multiple solutions to remove constraints in the low voltage and the 22 kV network to allow for zero constraints, however the preferred solution does not necessarily deliver the most positive net benefit to all customers. Instead, it is focussed on delivering the largest generation export possible, regardless of net benefit.

AusNet Services' proposed preferred solution is Option 3, at a cost of $38 million ($2018) over the 2022-26 EDPR period, which represents a prudent and efficient network augmentation investment to address voltage constraints.

Applying a discount rate of 6.44% per annum, this proposed program option has a net economic benefit of $453 million (Real $2018) over the forty-five-year assessment period. It will improve the voltage performance of approximately 228,000 customers and will increase presently constrained generation export by 70% over the 2022-26 period.

DER Integration technology program

This program addresses the requirements of the technology platform to enable better visualisation, optimisation and orchestration of DER.

Traditionally the most modelling of the network has occurred at higher voltage levels, with little to no analysis being done on the LV network. Uptake of DER and bi-directional flows places an emphasis on the LV network to understand its impact on the upstream network as customers produce and consume electricity.

At AusNet Services, the power-flow models of the network are currently derived from the geo-spatial system, SDMe, and fed into a power-flow engine, namely Siemens PSS Sincal. Only the 22 kV network data is extracted into the Sincal platform with load data approximated by a manual process involving SCADA measurements and AMI data.

AusNet Services have identified significant limitations in the current modelling process:

- Lack of usable data for the LV section of the network.
- Lack of automation and incorporation of times-series AMI and SCADA data as inputs to the model

A fully functional HV to LV model will enable AusNet Services to better plan, integrate and manage the impact of DER allowing 'what if' scenario analysis.

In the current regulatory period, AusNet Services has carried out a trial on 22kV feeder HPK21 to test the HV to LV modelling concept. AusNet Services plans to extend its learnings from this trial in the next regulatory period.

The technology program also includes activities on establishment of the foundation required for a future ready forecasting model and DENOP.

The investments proposed in this program of work comprise of the following activities:

- Future Ready Forecasting Model – Enhancement of current Demand Forecasting model, including automation, additional data inputs and inclusion of DER uptake forecast
- HV LV Modelling – Development of the foundation for a HV to LV network load flow model and analytical capability for entire network to enable better planning. This includes the extension of HPK21 trial in current regulatory period, using PSS Sincal.
- GIS Network Data Quality Improvements – Work to improve the quality of data in the GIS, to overcome current limitations of SDMe. This will feed into the HV to LV Model.
- Spatial Application Rationalisation – Work to rationalise existing SAMS and SAMS OPS spatial applications into the SDMe Network Viewer, and repoint downstream interfaces from SAMS and SAMS OPS to SDMe or the Data Lake
- Demand Response Management Enablement – Productionise demand response incentives for residential and DER customers, including payment structures and innovative tariff options.
- Distributed Energy Resource Control/Optimisation (DENOP) – Work to expand and productionise the DENOP platform under trial in the current period
- P2P trading – Activities to facilitate AusNet Services providing meter data to third party trading platforms. This investment includes funding to enable manual data transfer to and from retailers, with data collected and sent via email.

Other power quality related issues are discussed below and how they are maintained within the code limits.

12.6.2 Power Factor

Customer connection agreement stipulates the power factor requirement as per the EDC.

12.6.3 Harmonics

Investigations are carried out where harmonics have deviated from the limits and corrective actions will be instigated where necessary. The zone substation power quality meters (PQM) provide voltage harmonics data. This information shows that voltage harmonics are generally within the code limits except at few zone substations. It should be noted here that some PQM have failed to communicate resulting in loss of data. This issue is being investigated and is expected to be resolved during the year.

12.6.4 Inductive interference

By design the generation of radio or TV interference on the network is avoided. This is mainly achieved using type tested equipment and suitably designed components. In addition, routine cyclic inspections and maintenance procedures ensure that the network is maintained in a good condition to ensure RFI & TVI is not generated or limited to levels not affecting the customers.

12.6.5 Negative Sequence Voltage

The South Gippsland network has experienced negative sequence voltage issues for some time (ref. Section 4.5.4). AusNet Services has attempted to bring this within code by initiating a number of projects. This includes transposing 66 kV sub-transmission lines at strategic locations. However, due to the onerous nature of the EDC limits, it is not economical to bring the negative sequence within limits.

12.6.6 Monitoring Quality of Supply

In previous years AusNet Services' fleet of power quality monitors have not been providing sufficient data to meet all of the EDC clause 4.2.6 requirements. In 2017 AusNet Services initiated a project to improve this situation. The scope of the project included upgrading power quality monitoring software, establishing Ethernet/fibre communication to all Zone Substation PQ meters, establishing communication to all Feeder Extremity meters and an automated process for developing Compliance and Business reports.

This project was successfully completed in early 2018. As a result, PQ data is captured from dedicated PQ meters to meet the compliance as per the above clause.

AusNet Services is continuing trialling a new PQ meter to be used for Feeder Extremities PQ measurements replacing the current EDMI fleet.

Additionally, AusNet Services is continually developing its AMI meter data analytics to monitor the level of voltage compliance in accordance with AS 61000.3.100.

12.7 Processes to ensure compliance with the measures and standards

AusNet Services strives to ensure compliance with the measures and standards for reliability and quality of supply. The processes AusNet Services has in place are described in this section.

12.7.1 Processes for compliance – Reliability

AusNet Services monitors its network reliability against the targets set by the AER in the EDPR for the period 2011-2015. Distribution network investments are undertaken to improve network reliability using the STPIS incentive mechanism. The reliability focus investments include:

- Distribution feeder sectionalising by installing Automatic Circuit Reclosers (ACR) and Automatable Gas Switches (GS).
- Implementing Distribution Feeder Automation (DFA).
- Automating kiosks substations to implement DFA in underground reticulation networks.
- Installing Animal Proofing Insulation, particular on distribution pole substations.
- Following an 'S' Factor centred asset management program – i.e., focus on key feeder sections to increase reliability and improve DFA opportunities.
- Installing Fuse-savers to minimise fuse operations due to transient events.
- In AusNet Services reliability improvements is a continuous process. Apart from the specific programs targeting network locations where investments are needed to improve reliability, the ongoing maintenance, inspections, and replacement of deteriorated assets will also contribute to improving network performance. The reliability maintenance strategy is discussed in Section 13.3.

12.7.2 Processes for compliance – Quality of Supply

AusNet Services monitors quality of supply utilising power quality monitors permanently installed at zone substations and feeder extremities as well as AMI data as outlined previously. In addition to these power quality measurements, measurements using portable devices are undertaken to investigate customer complaints on power quality. These unforeseen reactive actions are necessary due to changes in the customer load profile or unexpected localised network loading issues. The actions taken to resolve power quality issues include:

- Distribution feeder upgrades, new feeders, or feeder reconfiguration.
  - Distribution substation upgrades or installing new substations.
  - Low Voltage network upgrades, new LV lines or fuse upgrades.
  - SWER network augmentations including upgrading or providing new isolating transformers.

12.8 Service Target Performance Incentive Scheme Information from the EDPR

Table 46 and Table 47 outline the information on the Service Target Performance Incentive Scheme (STPIS) contained in AusNet Services' most recent submission to the AER which was for the 2016-2020 Electricity Distribution Price Review (EDPR) period.

12.8.1 AER's Preliminary Decision on STPIS 2016-2020 Electricity Distribution Price Review (EDPR)

AusNet Services Proposal	AER Preliminary Decision
(11.6.1) Cap on revenue at risk of ±5%	Cap on revenue at risk of ±5%
(11.6.2) MED Threshold beta of 2.8	MED threshold beta of 2.8
(11.6.3) Propose to modify historical averages because of the application of a lower VCR for capex planning purposes	The AER does not accept AusNet Services' proposal. AusNet Services' performance targets will be based on its five years historical average.
(11.8) Exclusion of supply interruptions due to Demand Management Incentive Schemes (DMIS)	Supply interruptions due to DMIS will not be excluded

Table 46: AusNet Services' 2016-2020 EDPR Submission

Measure	Feeder Class	2016	2017	2018	2019	2020
Unplanned SAIDI	Urban	81.5390	81.2180	80.8970	80.5770	80.2560
	Rural Short	188.0490	187.5930	187.1380	186.6820	186.2260
	Rural Long	233.9770	233.3560	232.7360	232.1160	231.4960
Unplanned SAIFI	Urban	1.0990	1.0930	1.0880	1.0820	1.0770
	Rural Short	2.2910	2.2840	2.2760	2.2690	2.2610
	Rural Long	2.8290	2.8190	2.8100	2.8010	2.7920
Unplanned MAIFI	Urban	2.7960	2.7940	2.7920	2.7900	2.7880
	Rural Short	5.8250	5.8190	5.8140	5.8080	5.8030
	Rural Long	11.3740	11.3680	11.3620	11.3560	11.3500
Telephone answering parameter		80.3300	80.3300	80.3300	80.3300	80.3300

Table 47: Performance targets for SAIDI, SAIFI, MAIFI, telephone answering parameter, and GSL: 2016-2020.

13 Asset Management

This section provides information on AusNet Services' asset management approach. This includes a summary of AusNet Services' asset management system and how distribution losses are addressed.

13.1 Asset Management System

Until April 2014, AusNet Services' asset management system conformed to the requirements of the British Standards Institute's Publicly Available Specification PAS 55-1:2008 for Asset Management.

In 2014, the Asset Management System was certified to the requirements of ISO 55001 Asset Management and was recertified in 2017.

Compliance with ISO 55001 requires the demonstration of robust and transparent asset management policies, processes, procedures, practices, and a sustainable performance framework. Accreditation is recognised as an indicator of good practice in asset management.

Effective and efficient asset management enables an organisation to achieve its objectives. It provides the framework to facilitate the development of strategies and works programs to ensure the objectives are achieved consistently and sustainably over time.

13.2 Scope of the Asset Management System

The scope of the asset management system includes all assets providing network services to customers as identified in the Electricity Distribution Licence issued to AusNet Electricity Services Pty Ltd by the Essential Services Commission.

More specifically this includes:

- Sub-transmission and distribution lines, power cables and associated easements and access tracks.
- Distribution zone substations, switching stations, communication stations and depots including associated electrical plant, buildings, and civil infrastructure.
- Protection, control, metering, and communications equipment.
- Related functions and facilities such as spares, maintenance, and test equipment.
- Asset management processes and systems such as System Control and Data Acquisition (SCADA) and the Enterprise Asset Management system, SAP.

13.3 Asset Management Framework

Consistent with ISO 55001 requirements, the AusNet Services asset management system contains an asset management policy statement, strategic asset management plan, asset management objectives and a detailed suite of integrated asset management strategies and the annual production of a five-year asset management plan.

The asset management process is informed by an assessment of the external business environment and the corporate business and financial plans. It responds to stakeholder engagement which incorporates customer, generator, regulator, shareholder, and government views in the development of asset management strategies.

The Asset Management Policy acknowledges the company's purpose and directs the content and implementation of asset management strategies, objectives and plans for the energy delivery networks.

The interrelationship between the policy and related key planning documents is illustrated in Figure 27.

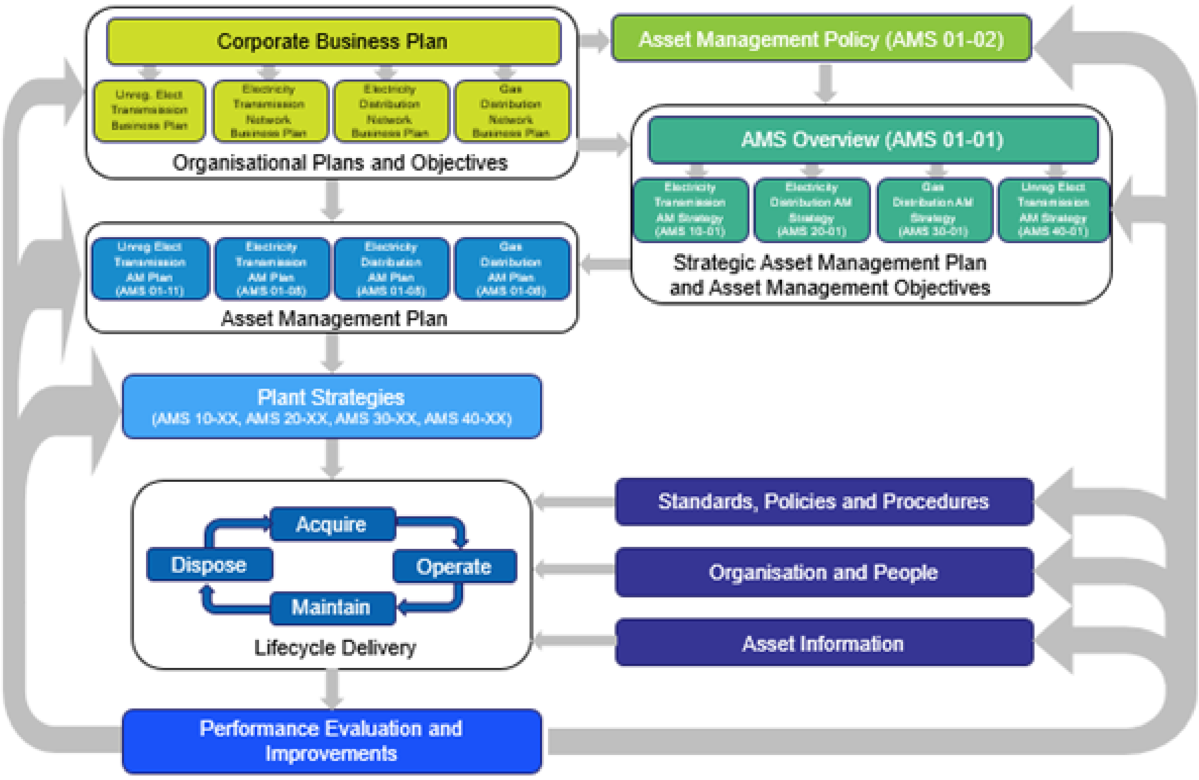


Figure 27: Asset Management Framework

13.4 Asset Management Methodology

AusNet Services is focused on delivering optimal distribution network performance at efficient costs. Except in the case where outputs are mandated, this requires an explicit cost benefit analysis to be undertaken in order to assess whether the overall economic value of expenditure is positive.

In doing this, AusNet Services assesses the incremental costs of delivering an incremental change in network performance to customers, relative to the incremental benefits accruing to customers from the delivery of that enhanced network performance.

The asset strategy ensures that all decisions to augment, replace, or maintain network assets are justified on economic grounds. The benefits are a function of the explicit customer value proposition, or proxy via the adoption of minimum performance standards, which are stipulated in legislation or other statutory or regulatory instruments.

The various drivers that are brought to bear when undertaking AusNet Services' Cost Benefit Analysis are summarised in Figure 28.

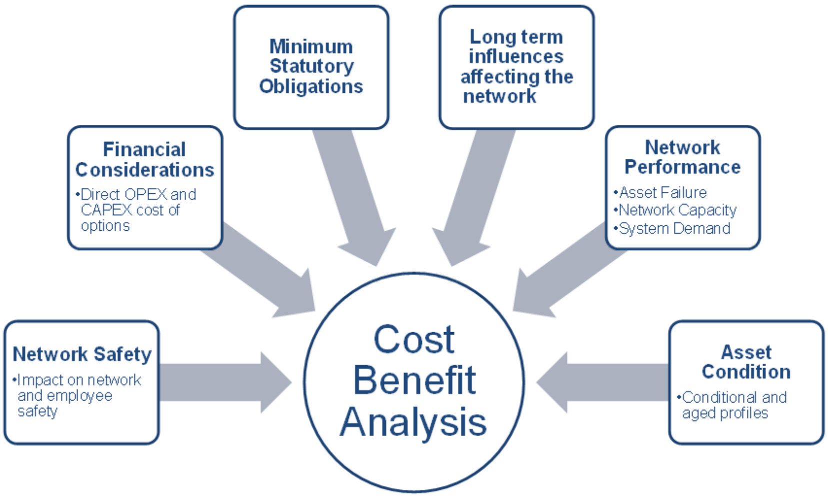


Figure 28 - Cost Benefit Analysis Drivers

An annual review of the various drivers and the outcome of cost benefit analysis is developed in the form of an Asset Management Plan. This plan provides a five-year view of the key issues and risks affecting the network and details the expenditure program.

13.5 Key Asset Management Strategies

A list of the current Asset Management strategies for the electricity distribution network is attached in Asset Management Strategy Reference. Appendix C: Asset Management Strategy Reference.

In the current low demand growth environment, the key strategies affecting the forward works program are the Enhanced Network Safety Strategy and the individual plant strategies. Additionally, AusNet Services is required to deliver Rapid Earth Fault Current Limiting (REFCL) technology.

The Enhanced Network Safety Strategy describes opportunities to develop and implement network asset management initiatives and programs that continuously reduce network related health and safety risks 'as far as practicable' (AFAP) for customers, public and personnel, in line with the requirements of the Electricity Safety Act 1998. This incorporates AusNet Services' aspiration to reduce serious incidents through successive regulatory periods.

The individual plant strategies describe how AusNet Services intends to focus on stabilising failure trends and risk trends. In particular, the emphasis is on stabilising equipment failure trends over time by matching replacement rates to the deterioration rate of those assets nearing the end of their effective service life.

Consistent with amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013[19], introduced on 1 May 2016, AusNet Services is developing and implementing REFCL technology in 22 nominated zone substations by 1 May 2023.

13.5.1 Enhanced Network Safety Strategy

The Enhanced Network Safety Strategy describes the safety related risks apparent on the network and the program of economically justified work that is intended to meet the regulatory obligation to reduce risk AFAP.

The key risks arise through asset failures resulting in the risk of electrical shock and fire ignition. The risk of ground fires which occur in densely populated, heavily vegetated areas in extreme weather conditions is of particular significance as there are major consequences that can result from these fires.

Modelling of the risks associated with the failure of some classes of assets such as cross-arms, poles and conductor has been completed using a fire loss consequence model. This model assists in identifying the economic volume of asset replacements and the location of the assets which present the greatest risk.

Several programs of work arise from the analysis and modelling.

These programs result in one of the following actions:

---

[19] Electricity Safety (Bushfire Mitigation) Regulations 2013, Version 004, 05/01/2016

- Replacement of deteriorated assets in specific areas (in some cases the consequence of asset failure is so great that the replacement of an asset is 'brought forward' so that the asset does not reach a state of advanced deterioration before it fails); and
- Programs to prevent external factors impacting the network such as fitting animal and bird proofing to complex high voltage overhead structures to reduce the risk of fire ignition due to animal and bird impact.

13.5.2 Plant Strategies

Failure mode, effects, and criticality analysis (FMECA) is used to identify the root causes of network unreliability and the effects of asset failure. This analysis is used to inform the strategies applied to specific classes of assets. The focus is to stabilise failure and risk trends over time by intervention including maintenance, refurbishment, or renewal of assets.

Assets are typically divided into:

- High-volume, low-value assets; and
- Low-volume, high-value assets.

Condition-based replacement triggered by inspection programs is the fundamental strategy used to manage most high-volume, low-value assets.

Lines assets including poles, crossarms and conductors are inspected on a regular cycle that meets the obligations imposed by Energy Safe Victoria (ESV) through the Electricity Safety (Bushfire Mitigation) Regulations 2013.

The fundamental strategy underpinning the management of low-volume, high-value assets is risk-based replacement aimed at maintaining the risk of failure.

Probabilities of failure are determined for each asset based on its assessed condition. Asset condition is determined by inspection, testing and condition monitoring using an array of techniques. For example, zone substation assets are inspected and tested on a regular cycle, including tests such as oil condition analysis.

The probabilities of failure are combined with the potential consequences of failure to quantify the risk of asset failure.

The main programs that arise from the strategy to maintain network reliability are:

- Timber pole replacement and reinforcement.
- Timber crossarm replacement (high voltage timber crossarms are replaced with steel crossarms).
- Replacement of deteriorated overhead conductor, particularly steel and copper conductor.
- Replacement of zone substation equipment including transformers, circuit breakers and protection and control systems in integrated rebuild or partial rebuild projects.
- Replacement of distribution transformers.
- Clearing vegetation from around lines and removing hazardous trees.

13.5.3 Rapid Earth Fault Current Limiter (REFCL) Implementation

A REFCL is electrical protection technology being installed to reduce the risk of fire ignition associated with phase to earth faults on the 22 kV network.

A REFCL operates when a single phase-to-earth fault occurs. Its operation causes the phase voltage of the faulted phase to be reduced to near earth potential (zero volts), thereby working to eliminate the flow of fault current. This compensation also results in phase to ground voltage rise from a nominal 12.7 kV to 22 kV on the un-faulted (healthy) phases, adding more stress to assets on the medium voltage network.

The location and timing for implementation of the REFCL technology is prescribed in Schedule 2 of the Electricity Safety (Bushfire Mitigation) Regulations 2013 and is illustrated in Figure 29.

The Bushfire Mitigation Regulations stipulate three Tranches with delivery due by the first of May in the years 2019, 2021 and 2023.

In order to install the technology, various assets will require replacement. The scope of AusNet Services' asset replacement and augmentation works required by the installation of this technology are discussed in AusNet Services' contingent project applications found at the Australian Energy Regulators' website[20].

Further information may be found on AusNet Services' website[21] and in AusNet Services' Bushfire Mitigation Plan – Electricity Distribution Network[22]

The Victorian government information on REFCL deployment can be found at the Department of Environment, Land, Water, and Planning (DELWP) website[23].

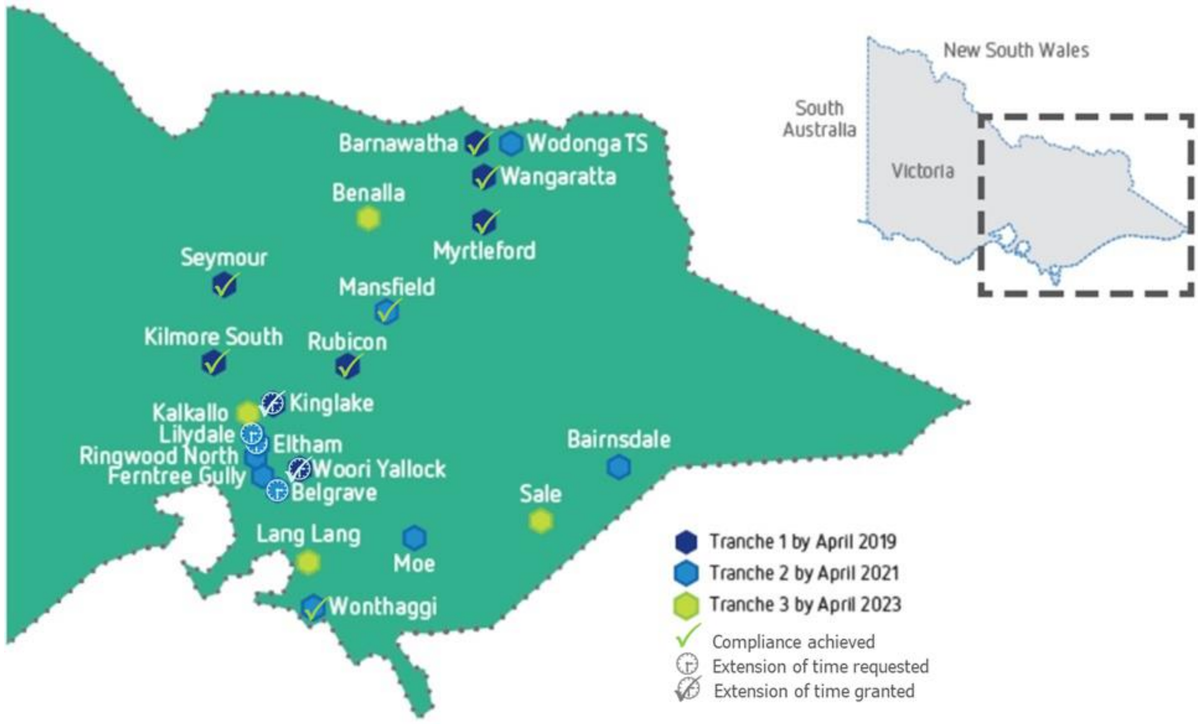


Figure 29: REFCL Location and Delivery Timetable

13.6 Distribution losses

This section provides details required by Schedule 5.8 (k) (1A) of the National Electricity Rules v.65[24], and explains how AusNet Services takes into account the cost of distribution losses.

[20] AusNet Services - Contingent project - installation of Rapid Earth Fault Current Limiters - tranche 1: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/ausnet-services-contingent-project-installation-of-rapid-earth-fault-current-limiters-tranche-1

[21] https://www.ausnetservices.com.au/About/Community/Powerline-Bushfire-Safety-Program/Rapid-Earth-Fault-Current-Limiters

[22] AusNet Services, Bushfire Mitigation Plan – Electricity Distribution Network. Available: https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Publications/BFM-10-01-BFM-Plan-Distribution-v26.ashx?la=en

[23] https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program/research-and-development/rapid-earth-fault-current-limiter/

[24] Schedule 5.8 "Distribution Annual Planning Report", National Electricity Rules v.65, accessed 12 November 2016.

Section 3.1(b) of the Electricity Distribution Code (EDC)[25] issued by the Essential Services Commission in August 2018 states:

> "A distributor must use best endeavours to:
>
> …….
>
> (b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections… to minimise the risks associated with the failure or reduced performance of assets; and in a way which minimises costs to customers taking into account distribution losses."

In the EDC, the terms:

- 'Distribution losses' means electrical energy losses incurred in distributing electricity over a distribution system.
- 'Distribution system' in relation to a distributor, means a system of electric lines and associated equipment at nominal voltage levels of 66 kV or below.

Further, NER Chapter 5, clause 5.17.1 (c)(4)(vii) requires changes in electrical energy losses to be considered in the regulatory investment test for distribution.

In compliance with these obligations, AusNet Services considers network losses in planning and development of distribution assets.

AusNet Services fully accounts for the economic value of reductions in system losses (or increases if this were the case) in the economic assessment of augmentation and asset replacement projects. This is achieved through the following analysis:

- Network power flow studies are used to determine the change in MW system losses both before and after project implementation at maximum demand.
- A load loss factor of 0.4 (ratio of losses at average demand to losses at peak demand) is applied to determine average network losses.
- This is multiplied by 8,760 hours per annum for network projects to determine energy savings per annum from network losses reduction. For network support options such as generation the expected annual hours of operation are used in the calculation.
- This is multiplied by $45 to provide an annual economic benefit for the reduction in system losses associated with project work. A figure of $45 represents typical cost of electricity but is a higher end figure to account for the fact that losses are proportional to the square of the load and are much higher at higher demands. This figure will be escalated by the square of the load growth to reflect the relationship between network losses and load growth.
- This economic benefit is included in Net Present Value analysis to determine projects options that deliver the highest overall economic benefit. Issues that may impact on system limitations identified through asset management.

Issues, including those that impact on system limitations, are identified through the Asset Management System and the planning process mentioned in the previous sections.

13.7 Further information on Asset Management

Further information on the asset management system, asset management strategies, and the methodology adopted by AusNet Services may be obtained by contacting the listed representatives in Contacts.

[25] Section 3 "Asset Management", Electricity Distribution code, Version 9. December 2015.

14 Demand Management Activities

Schedule 5.8 (l) of National Electricity Rules addresses demand management activities undertaken on the AusNet Services' network. Since 2012 when AusNet Services embarked on a strategy to strengthen its Demand Side Participation (DSP) capability, AusNet Services has undertaken several Embedded Generation and Demand Management (DM) activities.

AusNet Services' Network Innovation team conducts trial projects, analyses options and provide input to network planning processes. The Distribution Network Planning team are responsible for the Demand Management portfolio and consider deployment of embedded generation and non-network solutions as part of the network planning process.

The Demand Side Engagement Strategy aims to facilitate co-operative engagement in network planning between DNSPs and proponents of non-network solutions and is published on AusNet Services' external website[26].

14.1 Non-Network Solutions

The following non-network solutions were deployed by AusNet Services in the past year (i.e., 2020).

1. *Mobile generation:* 2.4 MW of temporary generation was installed to manage residential summer peak demand in Euroa. The fleet was also deployed during the 2019/20 bushfires to temporarily restore supply to customers in Omeo, Mallacoota, and Corryong. Outside of the summer months, generators were deployed to reduce the impact of planned outages to customers during asset replacement and augmentation works.
2. *Contracted embedded generation:* Bairnsdale Power Station (40 MW) continues to operate under a network support agreement due to expire early in 2022. A RIT-D has been initiated to assess options that could mitigate the network risks on the East Gippsland sub-transmission loop. Non-network options will be considered in this RIT-D assessment.
3. *Demand Management (DM):* A portfolio of commercial & industrial (C&I) customers has been maintained over the past few years, particularly on feeders with emerging summer peak demand constraints.
4. *West Gippsland and Phillip Island Non-Network Opportunities:* In June and November, the business released requests for proposals on the corporate website and notified service providers on its Demand Side Engagement Register of these two opportunities for providers to deploy non-network solutions to address identified constraints on the distribution network. An annual network support payment will be made to service providers that operate a solution that will reduce peak demand during the periods required by AusNet Services, or supplement transfer capacity to improve network reliability.

   The West Gippsland non-network solution will be installed in Longwarry and will be contracted to provide up to 3 MW of network support.

Prior to each summer, feeders forecasted to reach thermal overload in all three regions were analysed for C&I DM potential. Areas of network with contingency risk were also analysed. Large C&I customers were contacted to gauge their interest in providing demand management services across the summer period.

Presently, the portfolio across the three regions comprises approximately ~5 MW of demand reduction capacity, from a total of 9 MW last summer. This was due to a number large C&I customers opting not to renew expired agreements.

Overall, AusNet Services currently has in place agreements for the provision of 45 MW of total network support, consisting of embedded generation in Bairnsdale (40 MW) and Commercial & Industrial Demand Management contracts (5 MW), with the forthcoming non-network solutions soon to add approximately 10 MW to this overall capacity.

[26] A copy of the Demand Side Engagement Strategy can be viewed at AusNet Services' website: http://www.ausnetservices.com.au/About+Us/Regulatory+Publications.html

14.2 Key issues arising from applications to connect embedded generation

AusNet Services received 31 enquiries to connect embedded generators during 2019.

Out of these 31 enquiries, 4 reached the 'connection agreement' stage (refer Table 48).

The key issues identified during the connection enquiry stage were:

1. Obligations and liabilities needed to be assessed on a case-by-case basis and negotiated with the proponents.
2. Project coordination challenges were not uncommon, particularly with multiple proposals at the same site, at various stages of the connection application process.
3. Time taken for system studies to be completed by the proponent.
4. Enquiry stage is an iterative process, with considerable amount of time elapsing before an agreement is reached for connection.

14.3 Actions taken to promote non-network proposals

Actions taken during 2020 to promote non-network solutions in AusNet Services' distribution network included:

14.3.1 Good Grid Residential Demand Management Program

The program commenced in 2018-19 enlisted close to 1,000 customers across specific areas with known summer constraints, and utilised smart meter data to help determine the overall network benefit provided by the participating customers. Participating customers were financially rewarded for their response to Good Grid events.

This program will run again for the 2020/21 summer period.

14.3.2 Non-Network Opportunities

In 2020, AusNet Services issued requests for proposals on the corporate website and to service providers listed on its Demand Side Engagement Register. The requests sought proposals from the service providers for non-network solutions such as demand management, embedded generation, and energy storage to address identified network constraints (refer to 14.1). More information on non-network opportunities is available on the AusNet Services website: Non-Network Opportunities (ausnetservices.com.au)

14.3.3 Grid-Connected Microgrids for Energy Resilience and Stand Alone Power Systems

Due to the bushfire in the 2019/2020 summer, AusNet Services investigated opportunities for Stand Alone Power Systems (SAPS) for resiliency and ongoing work continues to determine the feasibility of this as an option. A grid-connected network support solution at Mallacoota is currently in final implementation which will enable the township to remain on-supply in the event of it being electrically isolated in planned or unplanned outages. SAPS as either individual customer solutions or as Grid-Connected Microgrids will be a feature of future planning opportunities and assessed based on safety, reliability, resiliency and economics in line with any future regulatory changes which enable DNSPs to consider these options.

14.4 Plans for non-network solutions over the forward planning period

AusNet Service Services will engage with network support providers over the forward planning period in compliance with the RIT–D test for augmentations greater than $5M and at other times as required. AusNet Services has published on its public website a Demand Side Engagement Strategy and maintains a Demand Side Engagement Register.

For traditional network augmentation projects with an estimated capital expenditure less than $5 million, AusNet Services will continue to evaluate the suitability of non-network alternatives and publish Requests for Proposals to service providers as requirements are identified.

AusNet Service's Demand Side Engagement Strategy[27] facilitates co-operative engagement in network planning between DNSPs and proponents of non-network solutions. This document describes the processes by which AusNet Services will identify potential non-network, Demand Side Participation measures and engage with non-

[27] A copy of the Demand Side Engagement Strategy can be viewed at AusNet Services' website: http://www.ausnetservices.com.au/About+Us/Regulatory+Publications.html

network providers on a case-by-case basis to consider non-network options in its asset management strategy. Demand-side service providers are encouraged to contact AusNet Services where they believe they can deliver a valuable network support service.

AusNet Services will continue to:

- Maintain a web page where providers of non-network solutions can view AusNet Services' approach to Demand Side Participation.
- Encourage demand-side service providers to contact AusNet Services where they believe they can deliver a valuable network support service via a non-network solution. Providers are added to AusNet Services' Demand Side Engagement Register.
- Maintain the portfolio of commercial and industrial demand management customers for availability during the summer period. The portfolio is reviewed annually in response to changing network conditions and customer demand management performance data. The program will continue to enlist customers that are supplied by constrained feeders with 10% POE or 50% POE risk in the short (1-3 years) or supplied from zone substations that are forecast to carry energy at risk under an N-1 contingency.
- Engage commercial and industrial customers on demand-based tariffs, e.g., customers with an annual consumption greater than 160 MWh that are on tariffs with a critical peak demand (CPD) component. This CPD charge provides a significant pricing signal to customers to reduce the demand over five nominated critical peak demand days during the summer period (1 December to 31 March). The response to this incentive has improved and this is expected to continue.
- Utilise future Demand Management Innovation Allowance funding to build additional demand management capability, tools and techniques, focussing on residential customer demand management that may be deployed in urban growth corridors and remote communities.

14.5 Embedded generation enquiries and applications

AusNet Services supports customers wishing to connect embedded generators to our electricity distribution network. The information in Table 48 covers the connection of embedded generators that are required to or intend to register with the Australian Energy Market Operator (AEMO). These embedded generators typically have a capacity greater than AEMO's standing exemption from registration, which is currently 5 MW.

2019/20 Embedded Generation - 66 kV	North	East	Central	Total
(i) *Connection* enquiries received under clause 5.3A.5	4	7	3	14
(ii) *Applications to connect* received under clause 5.3A.9	2	1	0	3
(iii) The average time taken to complete *applications to connect* (months)	N/A*	N/A	N/A	N/A
2019/20 Embedded Generation - 22 kV	North	East	Central	Total
(i) Connection enquiries received under clause 5.3A.5	2	6	8	16
(ii) Applications to connect received under clause 5.3A.9	0	0	0	0
(iii) The average time taken to complete applications to connect (months)	N/A	N/A	N/A	N/A

Table 48: Information on establishing or modifying connection for embedded generation

**Applications are still active and therefore the time to complete is not currently available*

15 Information Technology and Communication Systems

This section presents an overview of AusNet Services' investments in information technology and communication systems, as required under schedule 5.8 (m) of the National Electricity Rules.

15.1 Expenditure in the current regulatory period

During the CY2016-2020 regulatory period and the six-month period before the forecast period from FY2022, AusNet Services focused on cost reduction and re-prioritisation of expenditure towards our business drivers.

Our ongoing and planned investments for this period are also aimed at readying AusNet Services to evolve in response to the expected business environment post FY2022; that is, a more uncertain and complex electricity environment with consumers' investment in technologies such as local solar PV generation and battery storage significantly impacting the business.

Sound information technology is critical to supporting AusNet Services' increased and increasing role in balancing residential generation and supply of electricity with residential demand. The modernised technological environment being established in CY2016 – 2020 intends to provide the basis to enable the business to deal with the uncertain future.

AusNet Services' key outcomes of this current period are to:

- Deliver core business outcomes for customers and realise the benefits of the foundational enterprise investments.
- Reduce capex (relative to CY2011-2015) and cap and control opex in alignment with our risk appetite.
- Optimise the Technology operating model and sourcing strategies, developing capabilities, and upgrading our assets to improve our maturity as a business enabler.
- Ensure the robustness and reliability of metering assets, systems, and data.

The planned Technology investments enable business strategies and have built on the foundational enterprise capabilities delivered in CY2011-15, focusing on customer service, customer safety, security of the distribution system, and technology that support the distribution network (assets, work, people, field mobility).

The following details some of the proposed programmes currently being implemented:

- Comply with metering regulatory requirements, including:
  - Life Support Customer Registration Changes
  - Unmetered Supply sites compliance
  - Joint Online Tracker website
  - DER National Register
  - 5-minute settlement (over both the current and upcoming FY2022-26 regulatory period):
- Develop low voltage network management capability to cater for increased Distributed Energy Resources (DER), including impact analysis modelling and the development of tactical tools to monitor and manage two-way energy flows across the distribution network to optimise network safety, resilience and reliability and ultimately enhance customer service delivery.
- Develop enhanced energy demand forecasting to understand and better manage the changes in energy demand due to Distributed Energy Resources, to increase network reliability in peak times, through the development of tactical models of DER take up and hosting capacity.
- Drawing on meter data to enhance capabilities and enable us to accurate identify the location of various types of faults that could cause safety issues to the public, damage to either AusNet Services or customer's assets or parts of the network.
- Manage and enhance customer interactions and experiences through the provision of easy to access and value-added information and services including enhancement of customer communications and notifications around maintenance and delivery of asset works, including:
  - Online customer service order tracking
  - Improvement in identification of customers impacted by outages to enable timely and accurate notification

  - Online connection cost calculation for electricity connections
  - Improvement in determination and communication of Estimate Time of Return and
  - Online tools to enhance solar connection process for customers.
- Enhance communications capabilities and field mobility to leverage network and asset management investments, improve service performance and reliability, and improve safety providing operational functions to the field. This includes expanding mobility tools to our field force to support a broader range of field tasks and activities, upgrading mobile devices and providing access to a broader range of applications and information.
- Develop data and analytics capabilities through information management to better manage risk and provide the information required for business decision making, including an enterprise management platform, automated asset risk modelling reporting, and advanced analytics.
- Continued investment in information security to ensure the safety of customer information and protect the electricity networks and business systems from cyber-attack.
- Enhanced employee capabilities making it easier to respond to customer queries through work collaboration and communication tools; and
- Lifecycle management of systems and platforms including rationalisation and consolidation to maintain the overall integrity and stability of the network, optimise investment, manage risk, and efficiently maintain services to our customers.

To mid-2019, key improvements in this period have included:

- Delivery of compliance programmes such as Power of Choice and Ring-Fencing, which has involved modifications to systems and processes to meet new regulatory requirements.
- Completed the AMI Remediation program, which commenced in 2014, and included the following technology components:
  - Refresh of metering network management system
  - Refresh of mesh network management system
  - Refresh of meter data management system
  - Refresh of key application infrastructure interfaces i.e., Enterprise Application Integration

  The maintenance of the described applications and supporting infrastructure was undertaken in alignment with asset management policies to ensure currency of systems and to ensure alignment to AusNet Services' risk appetite

- Delivered Life Support Compliance capability to ensure compliance to new regulatory obligations
- Refresh of customer communication channels (customer portal), which has enabled improved communication through the refresh of a web platform with mobile capabilities.
- Completed the Customer Delivery and Experience Program that has evaluated customer service-related pain points and implemented solutions to improve the customer experience. i.e., customer access to data, case management.
- Established an Information Management Platform, based on a business-use case approach, i.e., asset risk modelling.
- Application whitelisting (creating a list of applications that are in Ausnet Services' technology environment to protect it from potentially harmful applications), which has included:
  - Implementing measures to prevent targeted cyber intrusions through a software refresh, protecting supply, customer data, processes and core network business systems to mitigate and manage risk, underpinning the security and reliability of the network.
  - Centralising management of corporate applications, actively whitelisting authorised software.
  - Preventing the use of unauthorised software including profile-based malware.
- Regulatory information notice reporting, which has included:
  - Leveraging existing software to provide integrated regulatory reporting and compliance capabilities to support the effective production of annual regulatory reporting.
  - Providing AusNet Services with data quality information allowing data to be proactively updated.

- Refresh of storage, server and data centre, which has included:
  - Delivery of several end-of-life technology and capacity uplift refresh initiatives in the storage, server and data centre domains.
  - Maintenance of the currency of database platforms supporting several critical business systems.
  - Delivered TAM improvements leading to technology and capacity uplift and efficient information management, such as:
    - Enhanced security functionality.
    - Improvements to the employee experience.
    - Improved spatial capability.
  - Reduction of the risk of business disruption and outages due to obsolete (end of life / out of support) infrastructure and/or constrained capacity thereby enabling AusNet Services to continue to meet its service and regulatory obligations; and
- Completing a Digital Workplace program that provides a secure, efficient, and modern work environment to enable workforce collaboration, productivity, and communications at sustainable cost levels
- Enhance the enterprise issue and risk management tool to ensure appropriate management of enterprise risk.
- Delivered an enhanced asset inspection tool that captures enhanced asset information and integrates into key asset and work management platforms
- Completing an enhanced drawing capability that supports the management of engineering drawings to support design and management decisions
- Continuous improvements to Enterprise Asset Management (EAM) and Enterprise Resource Planning (ERP) which has delivered several business-initiated enhancements to improve the effectiveness of the EAM/ERP solution, including business systems and interfaces associated with network management.
- Delivered an enhanced employee performance, recruitment and management tool designed to attract and retain our workforce at a sustainable cost basis.

15.2 Priorities for the upcoming regulatory period

In the upcoming regulatory period (2022-2026), AusNet Services will seek to deliver on key strategic enablers with evolving customer expectations at the centre of these developments. Driving better outcomes for customers that are aligned to their expectations is the central focus of technology investments, which is balanced with value delivery through lower costs and effectively managed risk.

For the upcoming regulatory period, AusNet Services' proposed investments in technology are divided into thirteen programs of work, with each program grouped into one of the following work stream themes:

- Distributed Energy Resources (DER).
- Intelligent Operations.
- Cyber Security.
- Lifecycle.
- Metering.

The five work stream themes, and thirteen programs of work are summarised in the following sections.

15.2.1 Distributed Energy Resources (DER)

AusNet Services must integrate and manage DER efficiently during the next regulatory period to progress on the path to becoming a digitally optimised utility that can support increased customer choices in DER connection options. This work stream aims to balance the costs of integrating and managing solar PV, batteries, and other new and emerging customer technologies with the risk these challenges pose to network resilience, reliability and security.

Integration of DER

Across the electricity industry, energy networks are trying to identify the most efficient ways to manage new customer requirements in an uncertain environment, while also continuing to provide customers the more traditional network services they require. During the upcoming regulatory period AusNet Services will drive improvements in forecasting and modelling capability to forecast DER uptake more accurately and better understand the impact of DER on the network and existing customers. This will underpin more accurate monitoring and understanding of the constraints arising from network and DER operations. Ultimately, the business will be able to support efficient interaction and data exchange with third parties seeking to aggregate customers' DER and facilitate peer-to-peer trading.

Future Distribution Network Management

As the network continues to evolve, core technology platforms must support, orchestrate, and manage the growth in DER. There is also rising customer expectations for improved network performance, service delivery, reduced outages, quicker supply restoration, and smart control/integration and information systems, as well as the ability to proactively manage customer demand. This programme of work will ensure AusNet Services has the appropriate systems and controls in place to manage these new customer and network requirements.

Examples of this work include:

- AusNet Services is a partner in the Flexible Exports for Solar PV trial, which is an ARENA supported project led by SA Power Networks that will trial the connection of active solar PV inverters to operate within limits issued by the DNSP.

- Energy Demand and Generation Exchange, which is an ARENA supported project being led by AEMO that AusNet Services and Mondo is partnering in to enable aggregated DER to participate in a trial market and test different market arrangements. Part of the trial will also test the feasibility of local network services provided by DER.

Customer Information Services

This programme will enable AusNet Services to better track and understand evolving interactions with our customers as the network is increasingly used for two-way energy flow. Implementing an effective Customer Information Management solution will enable AusNet Services to provide appropriate advice to assist DER connected customers in maximising their generation, while ensuring the network is protected. Alternatively, it will allow for investment in a refreshed network if necessary. This will also ensure the business is well placed to meet regulatory rule changes, which increasingly require sophisticated data management capabilities.

15.2.2 Intelligent Operations

Many advanced sensors and smart meters create valuable sources of data that can be leveraged by the business to improve network reliability and efficiency while reducing customer bills. There is a need to continue enhancing the use of data to improve grid availability, security, and DER integration. This work stream aims to balance the risks to asset and network reliability with the cost of managing those risks through improved data and analytics, automation, visualisation, modelling, and risk management.

Information Management

AusNet Services will continue to extend the Information Management platform to develop the capability to analyse network performance, supported by advanced automation on near real time data. This will underpin better decision making, more efficient operations and an increasingly reliable network.

Outage Management

The business will integrate the various sources of asset, maintenance and interconnectivity data required to plan outages and augment the network. This programme will simplify outage management, providing field crews with automated reports and live data dashboards, while supporting network controllers with advanced automation and analytics.

Workforce Collaboration

As employees progress within the organisation they acquire knowledge, which is specialised to the company's operations, structure, and culture. This programme will make these unique insights more readily accessible regardless of workforce location or business area, creating productivity gains.

Corporate Enablement

AusNet Services runs multiple enterprise applications to support day-to-day operations. The enterprise application landscape and related integrations underpin the continuity of all operational processes. As such, AusNet Services must ensure these core functionalities are adaptable in an increasingly changing environment, while also being robust and reliable solutions for all employees. In alignment with the business shift to cloud (where prudent), core business functions such as human resources and payroll systems will move to the cloud, where the enterprise resource planning solution will commence the pre-work required for migrating to the desired future state platform, post-2025.

15.2.3 Cyber Security

This work stream aims to balance risks and costs of protecting the distribution network, and customer and business information and assets through improvements in cyber security capabilities.

Cyber Security

Investment in cyber security in the forecast period will ensure compliance to current and emerging regulations, including sufficient investment to comply with the regulatory obligations under AEMO's Australian Energy Sector Cyber Security Framework (AES-CSF). This will provide better protection of critical assets required to supply energy to customers, better protect critical customer and operations data, and support ongoing development and measurement of cyber security capabilities within the organisation.

15.2.4 Lifecycle

This work stream aims to efficiently manage the risks and costs of maintaining core systems by undertaking prudent lifecycle refreshes.

Technology Asset Management (TAM) - Applications

AusNet Services has approximately 200 systems that require periodic patching and enhancements, as aligned to the standard technology lifecycle. This ensures ongoing vendor support, patches and bug fixes, limits downtime and ultimately underpins reliability of critical operations across the business.

Technology Asset Management (TAM) - Infrastructure

Technology infrastructure comprises the hardware, software, network resources and services required to deliver information and technology to the business. This programme of work ensures the business has sufficient capacity, performance, and service levels to maintain the operation of technology systems whilst optimising data centre infrastructure to operate more efficiently.

Corporate Communications

Corporate communications at AusNet Services comprise technology networking devices (i.e., Wi-Fi, routers), internet services provision and gateways, as well as data centre interconnectivity, covering both systems and assets. As is conducted for critical systems above, this programme expenditure on capacity management and like-for-like lifecycle refreshes ensures the network performance requirements are met for both existing and future business growth.

Corporate Enablement

70% of corporate enablement costs are allocated to Lifecycle.

15.2.5 Metering

This work stream aims to balance the risks and costs of maintaining AusNet Services' metering systems, while meeting new regulatory compliance requirements.

Five-Minute and Global Settlement

Under the National Electricity Rules, there is a requirement to provide meter level consumption data to AEMO specific time intervals. Currently this interval is thirty-minutes. However, in the upcoming regulatory period this requirement will shift to five-minute intervals, creating the need to store and manage six times in the volume of meter data currently being managed. There is multiple critical meter data management and customer data bases and systems that require modification and refreshing to meet this new regulatory requirement. From 1 July 2021, all contestable type 1-4 meters must be capable of five-minute settlement of meter data. This is a significant and transformative variation from current systems and processes.

Metering Lifecycle

AusNet Services has technology systems that operate and coordinate metering functions with the rest of the distribution business.

In the upcoming regulatory period, these systems will require periodic refreshes and patching to ensure they remain supported and well maintained. Maintaining ongoing vendor support and patch and bug fixes will limit downtime, which underpins the reliability of critical operations across the business.

Additionally, there is new market compliance rules that will require capability extensions of systems to ensure compliance. These refreshes will achieve both the compliance and lifecycle activities to achieve lowest possible costs. Compliant metering solutions underpin AusNet Services' smart network capabilities, providing timely delivery of the necessary consumption, supply quality and exceedance data, which enables key functions in the monitoring of the electricity distribution network.

16 Regional Development Plan

A regional development plan consisting of maps of AusNet Services' network is provided on our corporate website, in accordance with the requirements of schedule 5.8 (n) of National Electricity Rules:

https://dapr.ausnetservices.com.au/

These maps are updated annually and/or following major project completions to provide the latest available information on current and emerging feeder, zone substation and sub-transmission network limitations.

Appendix A Glossary

Abbrev	Name	Abbrev	Name
AFI	Australian Forest Industries	MDI	Murrindindi Zone Substation
APM	Australian Paper Maryvale	MFA	Maffra Zone Substation
BDL	Bairnsdale Zone Substation	MJG	Merrijig Zone Substation
BDSS	Bairnsdale Switching Station	MOE	Moe Zone Substation
BGE	Belgrave Zone Substation	MPS	Morwell Power Station
BHWF	Bald Hills Wind Farm	MSD	Mansfield Zone Substation
BM8	Bombala feeders from NSW (BOM)	MWE	Morwell East Zone Substation
BN	Benalla Zone Substation	MWN	Morwell North Zone Substation
BRA	Boronia Zone Substation	MWL	Morwell Zone Substation
BOM	Bombala Zone Substation (Essential Energy)	MWTS	Morwell Terminal Station
BRT	Bright Zone Substation	MWW	Morwell West Substation
BWA	Barnawartha Zone Substation	MYT	Myrtleford Zone Substation
BWN	Berwick North Zone Substation	NH	North Heidelberg (Jemena)
BWR	Bayswater Zone Substation	NLA	Newmerella Zone Substation
CBTS	Cranbourne Terminal Station	NRN	Narre Warren Zone Substation
CF	Clover Flat Zone Substation	OFR	Officer Zone Substation
CLN	Clyde North Zone Substation	PHI	Phillip Island Zone Substation
CLPS	Clover Power Station	PHM	Pakenham Zone Substation
CNR	Cann River Zone Substation	RUBA	Rubicon 'A' Zone Substation
CPK	Chirnside Park Zone Substation	RWN	Ringwood North Zone Substation
CRE	Cranbourne Zone Substation	RWT	Ringwood Terminal Station 22 kV Yard
CYN	Croydon Zone Substation	RWTS	Ringwood Terminal Station
DN	Dandenong Zone Substation (UE)	SFS	Sassafras Zone Substation
DRN	Doreen Zone Substation	SLE	Sale Zone Substation
DSH	Dandenong South Zone Substation	SLF	Sugarloaf Reservoir Melbourne Water Substation
DVY	Dandenong Valley Zone Substation (UE)	SMG	South Morang Zone Substation
ELM	Eltham Zone Substation	SMR	Seymour Zone Substation
EPG	Epping Zone Substation	SMTS	South Morang Terminal Station
ERTS	East Rowville Terminal Station	ST	Somerton Zone Substation (Jemena)
FGY	Ferntree Gully Zone Substation	TGN	Traralgon Zone Substation
FTR	Foster Zone Substation	TRC	Tumut River Council - NSW (Essential Energy)
GNTS	Glenrowan Terminal Station	TSTS	Templestowe Terminal Station
HPK	Hampton Park Zone Substation	TT	Thomastown Zone Substation
HPS	Hume Power Station	TTS	Thomastown Terminal Station
KLK	Kinglake Zone Substation	TWF	Toora Wind Farm
KLO	Kalkallo Zone Substation	UWY	Upwey Zone Substation

KMS	Kilmore South Zone Substation	WGI	Wonthaggi Zone Substation
LDL	Lilydale Zone Substation	WGL	Warragul Zone Substation
LFD	ESSO Longford	WN	Wangaratta Zone Substation
LGA	Leongatha Zone Substation	WO	Wodonga Zone Substation
LLG	Lang Lang Zone Substation	WOTS	Wodonga Terminal Station
LSSS	Leongatha South Switching Station	WT	Watsonia Zone Substation
LYD	Lysterfield Zone Substation	WYK	Woori Yallock Zone Substation
LYS	Loy Yang South Zone Substation	YEA	Yea Substation
MBTS	Mt Beauty Terminal Station	YN	Yallourn North Open Cut Zone Substation
MBY	Mt Beauty Zone Substation	YPS	Yallourn Power Station
MDG	Mt Dandenong Zone Substation		

Appendix B Schedule 5.8 of the National Electricity Rules Version 102

Schedule 5.8 Distribution Annual Planning Report

Note:

The local definitions in clause 5.10.2 apply to this schedule.

For the purposes of clause 5.13.2(c), the following information must be included in a *Distribution Annual Planning Report*:

(a) information regarding the *Distribution Network Service Provider* and its *network*, including:

(1) a description of its *network*;

(2) a description of its operating environment;

(3) the number and types of its distribution assets;

(4) methodologies used in preparing the *Distribution Annual Planning Report*, including methodologies used to identify system limitations and any assumptions applied; and

(5) analysis and explanation of any aspects of forecasts and information provided in the *Distribution Annual Planning Report* that have changed significantly from previous forecasts and information provided in the preceding year;

(b) forecasts for the forward planning period, including at least:

(1) a description of the forecasting methodology used, sources of input information, and the assumptions applied;

(2) *load* forecasts:

(i) at the transmission-distribution connection points;

(ii) for sub-transmission lines; and

(iii) for zone substations,

including, where applicable, for each item specified above:

(iv) total capacity;

(v) firm delivery capacity for summer periods and winter periods;

(vi) *peak load* (summer or winter and an estimate of the number of hours per year that 95% of *peak load* is expected to be reached);

(vii) power factor at time of peak load;

(viii) load transfer capacities; and

(ix) generation capacity of known *embedded generating units*;

(3) forecasts of future transmission-distribution connection points (and any associated *connection assets*), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation:

(i) location;

(ii) future *loading level*; and

(iii) proposed commissioning time (estimate of month and year);

(4) forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service target performance incentive scheme; and

(5) a description of any factors that may have a material impact on its *network*, including factors affecting;

(i) fault levels;

(ii) *voltage* levels;

(iii) other *power system security* requirements;

(iv) the quality of *supply* to other *Network Users* (where relevant); and

(v) ageing and potentially unreliable assets;

(b1) for all *network* asset retirements, and for all *network* asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset:

(1) a description of the *network* asset, including location;

(2) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset;

(3) the date from which the *Distribution Network Service Provider* proposes that the *network* asset will be retired or de-rated; and

(4) if the date to retire or de-rate the *network* asset has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;

(b2) for the purposes of subparagraph (b1), where two or more *network* assets are:

(1) of the same type;

(2) to be retired or de-rated across more than one location;

(3) to be retired or de-rated in the same calendar year; and

(4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),

those assets can be reported together by setting out in the *Distribution Annual Planning Report*:

(5) a description of the *network* assets, including a summarised description of their locations;

(6) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* assets to be retired or de-rated, taking into account factors such as the condition of the *network* assets;

(7) the date from which the *Distribution Network Service Provider* proposes that the *network* assets will be retired or de-rated; and

(8) if the calendar year to retire or de-rate the *network* assets has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;

(c) information on system limitations for sub-transmission lines and zone substations, including at least:

(1) estimates of the location and timing (month(s) and year) of the system limitation;

(2) analysis of any potential for load transfer capacity between *supply* points that may decrease the impact of the system limitation or defer the requirement for investment;

(3) impact of the system limitation, if any, on the capacity at transmission-distribution connection points;

(4) a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and

(5) where an estimated reduction in forecast *load* would defer a forecast system limitation for a period of at least 12 months, include:

(i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1);

(ii) the relevant *connection points* at which the estimated reduction in forecast *load* may occur; and

(iii) the estimated reduction in forecast *load* in MW or improvements in *power factor* needed to defer the forecast system limitation;

(d) for any primary distribution feeders for which a *Distribution Network Service Provider* has prepared forecasts of *maximum demands* under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the *Distribution Network Service Provider* must set out:

(1) the location of the primary distribution feeder;

(2) the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);

(3) the types of potential solutions that may address the overload or forecast overload; and

(4) where an estimated reduction in forecast *load* would defer a forecast overload for a period of 12 months, include:

(i) estimate of the month and year in which the overload is forecast to occur;

(ii) a summary of the location of relevant *connection points* at which the estimated reduction in forecast *load* would defer the overload;

(iii) the estimated reduction in forecast *load* in MW needed to defer the forecast system limitation;

(e) a high-level summary of each RIT-D project for which the *regulatory investment test for distribution* has been completed in the preceding year or is in progress, including:

(1) if the *regulatory investment test for distribution* is in progress, the current stage in the process;

(2) a brief description of the identified need;

(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);

(4) if the *regulatory investment test for distribution* has been completed a brief description of the conclusion, including:

(i) the net economic benefit of each credible option;

(ii) the estimated capital cost of the preferred option; and

(iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and

(5) any impacts on *Network Users*, including any potential material impacts on *connection* charges and *distribution use of system charges* that have been estimated;

(f) for each identified system limitation which a *Distribution Network Service Provider* has determined will require a *regulatory investment test for distribution*, provide an estimate of the month and year when the test is expected to commence;

(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address

an urgent and unforeseen *network* issue as described in clause 5.17.3(a)(1), including:

(1) a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;

(2) a brief description of the alternative options considered by the *Distribution Network Service Provider* in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, *generation* options, demand side options, and options involving other *distribution or transmission networks*;

(h) the results of any joint planning undertaken with a *Transmission Network Service Provider* in the preceding year, including:

(1) a summary of the process and methodology used by the *Distribution Network Service Provider* and relevant *Transmission Network Service Providers* to undertake joint planning;

(2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and

(3) where additional information on the investments may be obtained;

(i) the results of any joint planning undertaken with other *Distribution Network Service Providers* in the preceding year, including:

(1) a summary of the process and methodology used by the *Distribution Network Service Providers* to undertake joint planning;

(2) a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and

(3) where additional information on the investments may be obtained;

(j) information on the performance of the *Distribution Network Service Provider's* network, including:

(1) a summary description of reliability measures and standards in *applicable regulatory instruments*;

(2) a summary description of the quality of *supply* standards that apply, including the relevant codes, standards and guidelines;

(3) a summary description of the performance of the *distribution network* against the measures and standards described under subparagraphs (1) and (2) for the preceding year;

(4) where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;

(5) a summary description of the *Distribution Network Service Provider's* processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and

(6) an outline of the information contained in the *Distribution Network Service Provider's* most recent submission to the *AER* under the *service target performance incentive scheme*;

(k) information on the *Distribution Network Service Provider's* asset management approach, including:

(1) a summary of any asset management strategy employed by the *Distribution Network Service Provider*;

(1A) an explanation of how the *Distribution Network Service Provider* takes into account the cost of *distribution losses* when developing and implementing its asset management and investment strategy;

(2) a summary of any issues that may impact on the system limitations identified in the *Distribution Annual Planning Report* that has been identified through carrying out asset management; and

(3) information about where further information on the asset management strategy and methodology adopted by the *Distribution Network Service Provider* may be obtained;

(l) information on the *Distribution Network Service Provider's* demand management activities, including:

(1) a qualitative summary of:

(i) non-network options that have been considered in the past year, including *generation* from *embedded generating units*;

(ii) key issues arising from *applications to connect embedded generating units* received in the past year;

(iii) actions taken to promote non-*network* proposals in the preceding year, including *generation* from *embedded generating units*; and

(iv) the *Distribution Network Service Provider's* plans for demand management and *generation* from *embedded generating units* over the forward planning period;

(2) a quantitative summary of:

(i) connection enquiries received under clause 5.3A.5;

(ii) applications to connect received under clause 5.3A.9; and

(iii) the average time taken to complete applications to connect;

(m) information on the *Distribution Network Service Provider's* investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of *network* assets in the forward planning period; and

(n) a regional development plan consisting of a map of the *Distribution Network Service Provider's* network as a whole, or maps by regions, in accordance with the *Distribution Network Service Provider's* planning methodology or as required under any *regulatory obligation or requirement*, identifying:

(1) sub-transmission lines, zone substations and transmission-distribution connection points; and

(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.

Appendix C Asset Management Strategy Reference

Document Scope	AMS Number	Description
High Level Summary	AMS 20-01	Electricity Distribution Network
High Level Summary	AMS 20-03	Network Contingency Plan
Process and System	AMS 20-12	Augmentation
Process and System	AMS 20-13	Enhanced Network Safety Strategy
Process and System	AMS 20-14	Infrastructure Security
Process and System	AMS 20-15	Quality of Supply
Process and System	AMS 20-16	Distribution Network Planning Standards and Guidelines
Process and System	AMS 20-17	Reliability Maintained
Process and System	AMS 20-23	Vegetation Management
Process and System	AMS 20-24	Sub-transmission line and Station Data for Planning Purposes
Process and System	AMS 20-30	Demand Forecasting Procedure
Process and System	AMS 20-35	Network Support Services
Plant Strategy	AMS 20-52	Conductor
Plant Strategy	AMS 20-53	Zone Substation Capacitor Banks
Plant Strategy	AMS 20-54	Circuit Breakers
Plant Strategy	AMS 20-55	Civil Infrastructure
Plant Strategy	AMS 20-56	Indoor Switchboards
Plant Strategy	AMS 20-57	Crossarms
Plant Strategy	AMS 20-58	Distribution Transformers
Plant Strategy	AMS 20-59	Electrical Earths
Plant Strategy	AMS 20-60	MV Switches and ACRs
Plant Strategy	AMS 20-61	MV Fuse Switch Disconnectors
Plant Strategy	AMS 20-62	HV Switches, Disconnectors and Earth Switches
Plant Strategy	AMS 20-63	Instrument Transformers
Plant Strategy	AMS 20-64	Sub Transmission Towers, Insulators and Ground Wires
Plant Strategy	AMS 20-65	Insulated Cable Systems
Plant Strategy	AMS 20-66	Insulators – High and Medium Voltage
Plant Strategy	AMS 20-67	Line Surge Arresters
Plant Strategy	AMS 20-68	Line Voltage Regulators
Plant Strategy	AMS 20-69	Pole-Top Capacitors
Plant Strategy	AMS 20-70	Poles
Plant Strategy	AMS 20-71	Power Transformers and Station Voltage Regulators

Plant Strategy	AMS 20-72	Protection and Control Systems
Plant Strategy	AMS 20-73	Public Lighting
Plant Strategy	AMS 20-76	Service Cables
Plant Strategy	AMS 20-77	Surge Arresters in Zone Substations
Plant Strategy	AMS 20-79	Neutral Earthing Devices
Plant Strategy	AMS 20-80	Auxiliary Power Supplies
Plant Strategy	AMS 20-81	Communication Systems
Plant Strategy	AMS 20-90	Zone Substation Transformer Contingency Plan

Appendix D Asset retirement and de rating asset groupings

Assets have been categorised to align with National Electricity Rules. Schedule 5.8 Clause (5) (b1) refers to individual asset reporting and Clause (5) (b2) refers to assets that can be reported together, referred to as Group Reporting in this Appendix.

<table>
<tr><th>Individual reporting</th><th>Group reporting</th></tr>
<tr><td>

Zone substation transformers
Circuit breakers 66kV
Switchboards
Capacitor banks
Circuit breakers 22kV in zone substation

</td><td>

Poles
Pole top structures

Cross-arms
Insulators
Surge arrestors
Pole top capacitors
Other (dampers, armour rods, spreaders, brackets etc.)

Switchgear

Automatic Circuit Reclosers
Gas switches
Isolators
Other

Overhead conductor LV, HV and ST
Underground cables
Other underground assets

Cable head terminations
Pits
LV Pillars

Distribution plant

Circuit breakers – other
Substation kiosk
Distribution transformers
Isolators
Services

</td></tr>
</table>

	- Ring Main Unit - Earthing cables - Regulators - Combo switches
	• Protection and control room equipment and instrumentation - Protection relay - Voltage Regulator Relay - VAR (Capacitor Bank) controllers - Batteries - AC and DC distribution equipment - Voltage/Current transformers
	• Communications and SCADA - Remote telemetry unit
	• Zone substation switchyard equipment - Surge arrestors - Busses - Terminations - Steel structures

Table 49: AusNet Services proposed Asset Grouping

Appendix E Retired or de-rated grouped assets

Appendix E outlines the methodologies and assumptions used for grouped assets listed in Appendix D of this report and should be read in conjunction with Section 5, Network Asset Retirement and De-ratings.

The complete asset management strategies are available upon request to the contacts outlined in Appendix F of this report.

E.1 Poles

The methodologies and assumptions for all sub-transmission and distribution pole replacements are described in Asset Management Strategy AMS 20-70.

This document outlines the methodologies such as Simple Sustainable, Age Based, Condition Based and Dependability Management strategies that are combined to develop AusNet Services' pole replacement strategy. Applying a condition-based replacement forecast over the next five years requires replacement or reinforcement of all very poor condition poles.

Table 50 summarises the expected pole replacements, including in-service failures, required over the five-year planning period.

	2021	2022	2023	2024	2025
Replaced Poles	3,274	3,293	3,516	3,002	2,646
Staked Poles	1,659	1,829	1,995	1,653	1,885
Total	4,933	5,122	5,511	4,655	4,531

Table 50 – Forecast for Pole Replacements and Staking

E.2 Cross-arms

The methodologies and assumptions for all sub-transmission and distribution pole top cross-arm replacements are described in Asset Management Strategy AMS 20-57. This document outlines methodologies such as Simple Sustainable, Age Based, Condition Based and Dependability Management strategies that are combined to develop AusNet Services cross arm replacement strategy.

The proposed cross-arm replacement volumes are forecast to decline from observed historical volumes to a sustainable replacement level, due to completion of the aerial inspection program.

Table 51 summarises the expected cross arm replacements, including in-service failures, to be replaced between 2021 and 2025.

	2021	2022	2023	2024	2025
Proposed Replacement Option	4,135	4,135	4,135	4,135	4,135

Table 51 – Forecast timber cross arm replacements

E.3 Insulators

The methodologies and assumptions for all HV and MV insulators are described in Asset Management Strategy AMS 20-66. This document outlines methodologies and strategies such as new assets, inspection, maintenance and replacement that are combined to develop AusNet Services' insulator replacement strategy. An average of 236 insulator replacements per annum are currently forecasts, and these are replaced when a pole or cross-arm is replaced.

E.4 Surge Arrestors

The methodologies and assumptions for all line surge arrestor replacement are described in Asset Management Strategy AMS 20-67. This document outlines methodologies such as failure mode effect criticality analysis and risk assessment strategies that are combined to develop AusNet Services surge arrestor replacement strategy.

Some installed surge arresters are not capable of operating with REFCLs. These surge arresters will be replaced as part of the REFCL implementation line hardening works. Surge arrester replacements are targeted in the highest bushfire risk areas as the REFCLs are being installed these areas.

	2021	2022	2023	2024	2025
Proposed Replacement Option	406	406	406	406	406

Table 52 – Forecast surge arrestor replacements

E.5 Pole Top Capacitors

The methodologies and assumptions for all pole top capacitor replacement are described in Asset Management Strategy AMS 20-69. This document outlines methodologies such as Inspection, Failure Mode, Effects and Criticality Analysis strategies that are combined to develop AusNet Services pole top capacitor replacement strategy. These methodologies and approaches suggest two pole top capacitor replacements per annum is required.

E.6 Conductors and associated Hardware

The methodologies and assumptions for all conductor and conductor hardware replacement are described in Asset Management Strategy AMS 20-52. This document outlines methodologies such as Failure Modes Effects Criticality Analysis and risk analysis strategies that are combined to develop AusNet Services conductor and conductor hardware replacement strategy.

It also identifies the number of assets that need to be replaced to manage bushfire ignition risk, conditional asset failures and mitigate reliability impacts.

Deteriorated steel conductor ties and fiberglass conductor spacers are replaced in conjunction with maintenance activities.

In addition to risk-based conductor replacement, 100km of SWER conductor will also be pro-actively replaced in Codified Areas between 2021 and 2026.

E.7 Gas Switches and Automatic Circuit Reclosers

The methodologies and assumptions for all Medium Voltage Switches and Automatic Circuit Reclosers (ACR) are described in Asset Management Strategy AMS 20-60. This document outlines methodologies such as Failure Mode Effects Criticality Analysis, Research and Development strategies that are combined to develop AusNet Services Automatic Circuit Reclosers replacement strategy.

	2021	2022	2023	2024	2025
Control boxes & ACRs	118	119	120	121	122
Manual gas switches	131	137	141	146	150
Air Break switches	19	20	21	22	22
Ground/indoor switches	2	2	2	2	2
Total	270	278	284	291	296

Table 53 – Forecast gas switch and ACR replacements

E.8 Isolators

The methodologies and assumptions for all Isolator replacements are described in Asset Management Strategy AMS 20-62. This document outlines methodologies such as Failure Mode Effects and Criticality Analysis, and Risk Assessment strategies that are combined to develop AusNet Services Isolator replacement strategy.

It also identifies the number of assets (i.e., disconnections and switches) that need to be replaced to manage bushfire ignition risk, conditional asset failures and mitigate reliability impacts. Most replacements will occur in conjunction with station rebuilds or circuit breaker replacements. Outside of these programs, isolators will also be replaced at 4 sites over period 2021-2026.

E.9 Underground Cables

The methodologies and assumptions for all Underground Cable replacements are described in Asset Management Strategy AMS 20-65. This document outlines methodologies such as failure mode effect and criticality analysis strategies that are combined to develop AusNet Services Underground Cable replacement strategy. These methodologies and approaches suggest the 625 cable segments in the highest risk category should all be tested within the FY22-26 regulatory period. It is expected that there will be up to 11km of necessary replacement and several joint repairs as an outcome of the testing program.

A key underground cable asset replacement project proposed within the forward planning period is Mount Hotham underground cable replacement project. This project proposes duplication of poor condition underground cables in the mountain area. The cables were installed by plough-in methods and have deteriorated at a significantly faster rate than cables installed in the traditional trench method. This cable replacement and duplication requires a significant investment and is subject to a RIT-D.

E.10 Distribution Transformers

The methodologies and assumptions for all Distribution Transformer replacements are described in Asset Management Strategy AMS 20-58. This document outlines methodologies such as Failure Mode Effect and Criticality Analysis strategies that are combined to develop AusNet Services Distribution Transformer replacement strategy. These methodologies and approaches utilise a combination of age-based replacement and condition-based replacement methods, proposing a replacement forecast of 125 units per annum.

E.11 Service Cables

The methodologies and assumptions for all service cable replacement are described in Asset Management Strategy AMS 20-76. This document outlines methodologies such as Failure Modes Effects and Critical Analysis strategies that are combined to develop AusNet Services service cable replacement strategy. These methodologies and approaches suggest a replacement model consisting of preventative replacements and corrective replacements.

	2021	2022	2023	2024	2025
Proposed Replacement Option	908	908	908	908	908

Table 54 – Forecast service cable replacements

E.12 Protection and Control Room Equipment and Instrumentation

The methodologies and assumptions for all protection and control room equipment and instrumentation replacement are detailed in Asset Management Strategy AMS 20-72, AMS 20-80 and AMS 20-63. These documents outline methodologies such as Service Age, Functionality Assessment, Asset Condition, Risk Assessment and Failure Modes Effects Criticality Analysis strategies that are combined to develop AusNet Services protection and control room equipment and instrumentation replacement strategy.

Protection and control room equipment and instrumentation includes protection relays, voltage regulator relays, VAR (capacitor bank) controllers, batteries, AC and DC distribution equipment and voltage/current transformers.

Methodologies and approaches described in AMS 20-72 suggest the replacement of:

- 940 protection relays over 10 years as part of the scope of station rebuilds. These replacements include 598 very poor condition (C5) electro-mechanical protection relays, 170 very poor condition (C5) electronic protection relays, 160 very poor condition (C5) IED (Intelligent Electronic Device) protection relays that do not meet bushfire mitigation requirements and 12 very poor condition (C5) micro-processor protection relays.

- Obsolete voltage regulating relays at 10 sites.

Methodologies and approaches described in AMS 20-80 suggest:

- Replace boards containing asbestos.
- Replace ageing auxiliary DC supply cables that are causing battery earth problems.
- Replace high risk DC and 5 AC auxiliary systems.

Methodologies and approaches described in AMS 20-63 suggest replacing approximately 21 current transformers and 31 voltage transformers over the 2020-25 period.

E.13 Communications and SCADA Remote Telemetry Units

The methodologies and assumptions for all remote telemetry unit (RTU) replacement are described in Asset Management Strategy AMS 20-72. This document outlines methodologies such as Service Age and Functionality Assessment strategies that are combined to develop AusNet Services RTU replacement strategy. An average replacement rate of three RTUs per year is currently forecast.

E.14 Surge Arresters in Zone Substations

The methodologies and assumptions for all Surge Arresters in Zone Substations replacement are described in Asset Management Strategy AMS 20-77. This document outlines methodologies such as Risk Assessment, Failure Mode Effects and Criticality Analysis strategies that are combined to develop AusNet Services Surge Arresters in Zone Substations replacement strategy.

These methodologies and approaches have identified surge arresters that need to be replaced in conjunction with Zone Substation rebuild projects.

A review of remaining poor and very poor condition assets (Condition 4 & 5) with associated risk also suggests the replacement of 81 units between 2021 and 2025.

Appendix F Contacts

Tom Langstaff

Manager, Distribution Network Planning

Network Strategy and Planning

AusNet Services

Tom.Langstaff@ausnetservices.com.au

(03) 9695 6859

Stuart Dick

Asset Management Strategy Manager

Network Strategy and Planning

AusNet Services

Stuart.Dick@ausnetservices.com.au

(03) 9679 4117

Justin Harding

Manager, Network Growth

Emerging Markets

AusNet Services

Justin.Harding@ausnetservices.com.au

(03) 9695 6532