DISTRIBUTION ANNUAL PLANNING REPORT

December 2018

Disclaimer

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

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This Distribution Annual Planning Report (**DAPR**) has been prepared in accordance with the National Electricity Rules (**NER**), in particular Schedule 5.8, as well as the Electricity Distribution Code.

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

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1 Overview

The Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that Powercor proposes to undertake on its network. It covers information relating to 2018 as well as the forward planning period of 2019 to 2023.

Powercor is a regulated Victorian electricity distribution business. It distributes electricity to more than 800,000 homes and businesses in central and western Victoria, as well as Melbourne's outer western suburbs. The network consists of over 570,000 poles and over 86,000 kilometres of wires.

The report sets out the following information:

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

The DAPR provides a high-level description of the balance that Powercor will take into account between capacity, demand and replacement of its assets at each zone substation and sub-transmission line over the forecast period. This document should be read in conjunction with the System Limitation Reports and the Forecast Load Sheet. Transmission-distribution connection assets are addressed in a separate report.[1]

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

The DAPR also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at zone substations, sub-transmission lines and primary distribution feeders where remedial action may be required. Providing this information to the market facilitates the efficient development of the network to best meet the needs of customers.

The DAPR is aligned with the requirements of clauses 5.13.2(b) and (c) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.8 of the NER. In addition, the DAPR contains information consistent with

[1] Transmission-distribution connection assets are discussed in the Transmission Connection Planning Report which is available on the Powercor website at http://www.powercor.com.au/Electricity_Networks/Powercor_Network/Powercor_-_Network_Planning/

the requirements of section 3.5 of the Electricity Distribution Code, as published by the Essential Services Commission of Victoria.

1.1 Public consultation

Powercor intends to hold a public forum to discuss this DAPR in early 2019. All interested stakeholders are welcome to attend, including interested parties on Powercor's demand-side engagement register, and local councils.

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

All written submissions or enquiries should be directed to:
DMInterestedParties@powercor.com.au

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

Powercor
Attention: Head of Network Planning and Development
Locked Bag 14090
Melbourne VIC 8001

2 Background

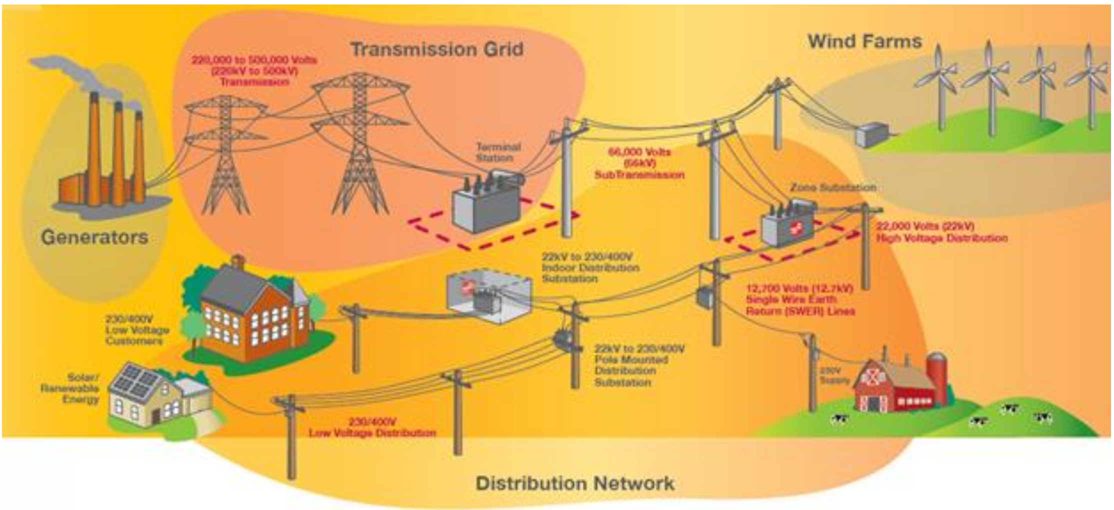
This chapter sets out background information on Powercor Australia Ltd (**Powercor**) and how it fits into the electricity supply chain.

2.1 Who we are

Powercor is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. Powercor own the poles and wires which supply electricity to homes and businesses.

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

Figure 2.1 The electricity supply chain



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

- **Generation**: generation companies produce electricity from sources such as coal, wind or sun, and then compete to sell it in the wholesale National Electricity Market (**NEM**). The market is overseen by the Australian Energy Market Operator (**AEMO**), through the co-ordination of the interconnected electricity systems of Victoria, New South Wales, South Australia, Queensland, Tasmania and the Australian Capital Territory. It is recognised that a growing amount of generation is occurring at lower voltages including individual household photovoltaic arrays.

- **Transmission**: the transmission network transports electricity from generators at high voltage to five Victorian distribution networks. Victoria's transmission network also connects with the grids of New South Wales, Tasmania and South Australia.

- **Distribution**: distributors such as Powercor convert electricity from the transmission network into lower voltages and deliver it to Victorian homes and businesses. The major focus of distribution companies is developing and maintaining their networks to ensure a reliable supply of electricity is delivered to customers to the required quality of supply standards.

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

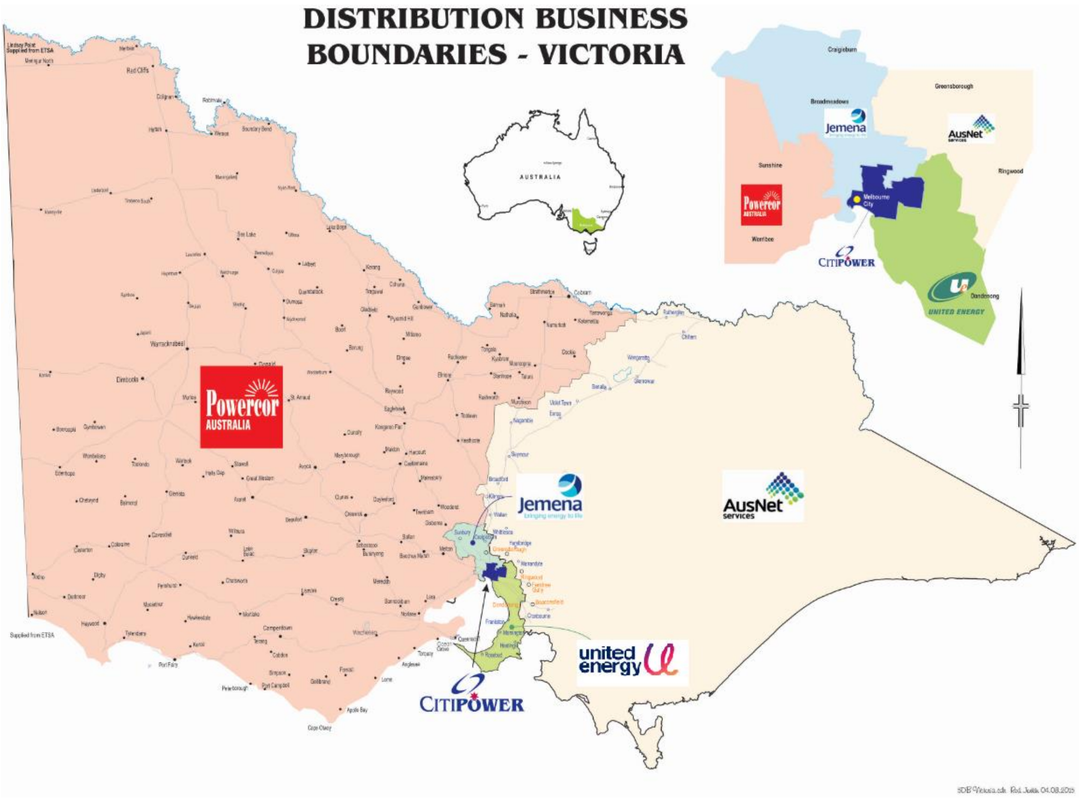
2.2 The five Victorian distributors

In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network. Powercor is one of those distribution businesses.

The Powercor network provides electricity to customers in central and western Victoria, as well as Melbourne's outer western suburbs. Powercor supplies major regional centres including Ballarat, Bendigo and Geelong, and provides electricity to some of Australia's most popular tourist destinations, such as the towns along the Great Ocean Road.

The coverage of Powercor, and its related entity CitiPower, is shown in the figure below.

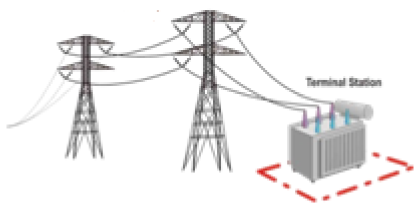
Figure 2.2 Powercor and CitiPower distribution areas



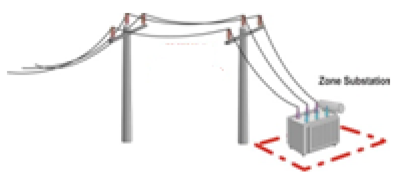
In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, Powercor must plan augmentation and asset replacement of the network to match network capacity to customer demand.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

2.3 Delivering electricity to customers

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

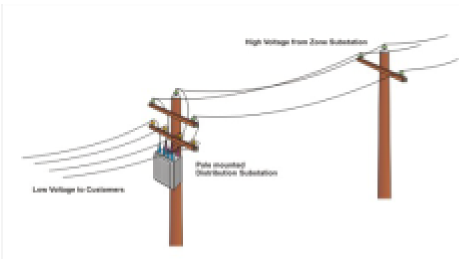


Firstly, the voltage of the electricity that is delivered to **terminal stations** is reduced by transformers. Typically in Victoria, most of the transmission lines operate at voltages of 500,000 volts (500 kilovolts or kV) or 220,000 volts (220kV). The transformer at the terminal station reduces the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



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

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



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

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

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

A growing amount of generation is occurring at lower voltages including individual customer level PV arrays.

2.4 Operating environment and asset statistics

Powercor delivers electricity to around 800,000 homes and businesses in a 145,651 square kilometre area, or around 5 customers per square kilometre.

Powercor’s customer base comprises of large industrial and commercial customers through to small domestic and rural consumers. There are also a number of high voltage customer supplies and interconnection points for embedded generation such as wind farms and solar farms.

Powercor’s electricity network comprises a sub-transmission network which consists of predominately overhead lines which operate at 66kV and a distribution network. The overall network consists of approximately 86 per cent overhead lines and 14 per cent underground cables that generally operate at 22kV. There is also some distribution network in Melbourne’s western suburbs operating at a voltage of 11kV.

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

The sub-transmission network nominally operates at 66kV and is generally configured in loops to maximise reliability, however some remote rural locations are supplied by radial 66kV lines.

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

The distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment to provide effective protection and control.

Whilst the majority of the high voltage distribution system nominally operates at 22kV, there are notable exceptions:

- in remote and sparsely settled rural areas there is a substantial volume of Single Wire Earth Return (**SWER**) lines which operates at a nominal voltage of 12.7kV;
- in the western suburbs of Melbourne, there are three smaller areas where the high voltage distribution system operates at a nominal voltage of 11kV;

- in the far north west of the state, there a small system supplied from the South Australian network. This system operates at 33kV; and
- in the far south west of the state, there a small SWER system supplied from the South Australian network. This system operates at 19kV.

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

Powercor takes two supplies from the South Australian network at 33kV to supply the small townships of Nelson in the far south-west and at 19kV at Lindsay Point in the far north-west of the state. The Nelson supply is converted to 22kV at the state border.

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 or 400 volts. These voltages are derived from “distribution substations” which are located throughout the distribution network and typically range in size from 5kVA to 2000kVA. Both overhead and underground low voltage reticulation, including service arrangements, complete the final connections to the low voltage consumer points of supply.

At the start of 2018, the Powercor network comprises approximately:

Table 2.1 Powercor network statistics

Item	Number / km
Poles	571,800
Overhead lines	75,709
Underground cables	12,178
Sub-transmission lines	125
Zone substation transformers	143
Distribution feeders	413
Distribution transformers	84,899

Appendix A provides maps which show the coverage of Powercor’s asset on a geographic basis.

3 Factors impacting network

This chapter sets out the factors that may have a material impact on the Powercor network:

- demand: changes in demand causing thermal capacity constraints, such as that caused from population growth resulting in new residential customers connecting to the network, new or changed business requirements for electricity;
- fault levels: the increasing amount of embedded generation being directly connected to the Powercor network is increasing the overall fault levels on the network which is reaching its fault level capacity in certain areas;
- voltage levels: the long distance between the customer and the voltage regulating equipment means that lower voltage levels are observed on the Powercor network and need to be carefully managed;
- other system security requirements: improvements in system security for single transformer zone substation, radial lines or zone substations with banked switching configuration will be considered when an increase in demand is forecast;
- quality of supply to other network users: Powercor may carry out system studies on a case-by-case basis as part of the new customer connection process;
- ageing and potentially unreliable assets: Powercor utilises a Health Index as a guide to determining the condition and therefore risk of the assets; and
- solar enablement: the rapid uptake of distributed energy resources are driving voltage variations and reverse flow capacity constraints.

These factors are discussed in more detail below.

3.1 Demand

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

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

Forecasting for demand is discussed later in this document.

3.2 Fault levels

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

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

Fault levels are determined according to a number of factors including:

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

The following fault level limits are generally applied within Powercor:

Table 3.1 Fault level limits

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

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

Fault level mitigation programs are becoming increasingly common on the Powercor network as the level of embedded generation being directly connected to the network increases. This is because of the increasing fault level contribution from generators which the network was not designed for when originally conceived.

3.3 Voltage levels

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

Electricity distributors are obligated to maintain customer voltages within specified thresholds, and these are further discussed in section 16.2. Similarly, manufacturers can only supply such appliances and equipment that operate within the Australian Standards. Supply voltage at levels outside these limits could affect the performance or cause damage to the equipment as well as industry processes.

Voltage levels are affected by a number of factors including:

- generation of electricity into the network;
- impedance of transmission and distribution network equipment;
- length of sub-transmission or distribution feeders;
- implementation of REFCLs;
- load; and
- capacitors in the network.

The long distance between the customer and the voltage regulating equipment e.g. transformers and regulators means that lower voltage levels are observed on the Powercor network and need to be carefully managed. Powercor is actively monitoring lines susceptible to voltage issues.

In addition, groups of solar photovoltaic generators are increasingly causing fluctuations in voltage levels in localised areas. Powercor is monitoring the voltages in these areas. Higher voltage levels caused by solar generation are a particular concern.

3.4 System security

For zone substations and sub-transmission lines, the Powercor network may contain:

- single transformer at a zone substation;
- radial sub-transmission lines; and
- banked configuration of the transformers.

The use of a single transformer or a radial sub-transmission line generally occurs in remote areas of the network, typically with low demand. Where increases in demand are expected at the zone substation or on the line, then Powercor will consider improving the security of supply by installing an additional transformer or line.

When major augmentation is planned at a zone substation, Powercor will consider improving the switching configuration such that supply can be maintained without any intermittent loss of supply in the event of a transformer outage. For example, this can be achieved by isolating the faulty transformer automatically. This configuration is referred to as full switching as opposed to banked.

3.5 Quality of supply to other network users

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

3.6 Ageing and potentially unreliable assets

There are many ageing assets within the Powercor network. Powercor carries out routine maintenance on all its assets to reduce the probability of plant failure, and ensure they are fit for operation.

Powercor uses the Condition Based Risk Management (**CBRM**) methodology to plan any required interventions to manage risks associated with the performance of major items of plant and equipment.

The model is an ageing algorithm that takes into account a range of inputs including:

- condition assessment data, such as transformer oil condition;
- environmental factors, such as whether the assets are located indoors or outdoors, or coastal areas; and
- operating factors, such as the load utilisation, frequency of use and load profiles that the asset is supplying.

These factors are combined to produce a Health Index for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The Health Index provides a means of comparing similar assets in terms of their calculated probability of failure.

Powercor will closely monitor assets with a Health Index in the range 5 to 7 to determine options for intervention, including replacement or retirement, in the context of energy at risk. Interventions are planned when asset health index exceeds 5.5 and intervention prioritised when asset health index exceeds 7.

A Health Index profile gives an immediate appreciation of the condition of all assets in a group and an understanding of the future condition of the assets.

As part of the CBRM process, a consequence of failure of the asset is also calculated. This assesses the consequence to customers due to loss of supply. The loss of a large amount of load (in MW) to a large industrial customer or to a large number of residential customers will indicate a high consequence of failure. This consequence of failure consists of four elements:

- network performance;

- safety;
- financial; and
- environment.

The risk to Powercor is calculated by combining the probability of failure and the consequence of failure of the asset. CBRM is used to calculate how the risk will change in future years and determine the optimum timing for any intervention.

For the purposes of this DAPR, the Health Index of some assets has been provided where Powercor has assessed the risk to be sufficient to require intervention in the next 5 years.

3.7 Solar enablement

Distributed Energy Resources (particularly solar PV) connected to the network are creating voltage variations and reverse flow is restricted by capacity issues. These are expected to significantly increase, in part due to penetration levels reaching a tipping point and a new Victorian Government policy subsidising solar PV for up to 650,000 households over the next 10 years.

In areas with a higher proportion of solar customers, solar PV exports are causing the localised network voltage to rise. This can affect the quality of electricity supply to all customers in the area, trip solar customers' solar PV systems (from export and in-home-use) and raise network voltages towards the limits set by the Electricity Distribution Code (Code).

Solar PV exports are also creating capacity constraint concerns on the LV network (not experienced on HV network to date). This is due to the increasing solar PV penetration, increasing average solar PV system sizes (to a point that households' export capacity can exceed their load requirements) and the relatively low diversity of exports when compared to load diversity, for which the network was traditionally designed to accommodate.

Powercor is adopting and exploring ways to limit these issues including:

- requiring changes to customers' inverter settings and the use of smart inverters;
- undertaking remedial works such as phase rebalancing, distribution transformer tapping, distribution transformer replacement, installing dynamic voltage controllers and undertaking conductor works and replacements;
- implementing advanced network management systems allowing for more dynamic control of network elements to support exported electricity; and
- limiting/constraining exports when network ratings are met.

3.8 REFCLs

This section sets out Powercor's plans to install Rapid Earth Fault Current Limiters (**REFCL**s) in the network. The purpose of installing REFCLs is to provide safety benefits to the community through reduced risk of electrical assets contributing to starting a fire.

A REFCL is a network protection device, normally installed at a zone substation that can reduce the risk of a fallen powerline or a powerline indirectly in contact with the earth causing a fire-start. It is capable of detecting when a powerline falls to the ground and almost instantaneously reduces the voltage to near-zero on the fallen line.

Customers that are directly connected to Powercor's 22kV high voltage (**HV**) network may need to take action in response to Powercor's REFCL deployment program

For Powercor, the installation of REFCLs also ensures compliance with the amendments to the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (Regulations) which were implemented in Victoria on 1 May 2016.

The Regulations require each polyphase electric line originating from 45 specified zone substations (22 of which are Powercor zone substations) to comply with performance standards specified in the Regulations. Schedule two of the Regulations assigns a number of 'points' to each of the specified zone substations. Powercor is required to ensure that:

- at 1 May 2019, the points set out in schedule two to the Regulations in relation to each zone substation upgraded, when totalled, are not less than 30;
- at 1 May 2021, the points set out in schedule two in relation to each zone substation upgraded, when totalled, are not less than 55; and
- from 1 May 2023, in the Powercor supply network, each polyphase electric line originating from every zone substation specified in schedule two has the required capacity.

3.8.1 Zone substations

In 2018, Powercor commissioned REFCLs at the following zone substations:

- Camperdown (**CDN**);
- Maryborough (**MRO**);
- Castlemaine (**CMN**);
- Winchelsea (**WIN**); and
- Eaglehawk (**EHK**).

On 20 August 2018, the Essential Services Commission of Victoria (**ESCV**) amended the Distribution Code which had the impact of transferring responsibility from distributors to HV customers for hardening of the HV customer assets to withstand the higher REFCL voltages or isolating the connection from the network when a REFCL operates. For all zone substations where REFCLs will be commissioned from 2019 onwards (with the exception of Colac (**CLC**) where Powercor retains responsibility), HV customers will need to take action to:

- ensure that their assets are compatible with the operation of a REFCL; and
- complete any required works prior to the commissioning of the relevant Powercor REFCL zone substation.

The table below sets out the proposed commissioning date for the planned installation of REFCLs over the next five years in the following substations.

Table 3.2 Commissioning year for REFCLs

Year	**2019**	**2020**	**2021**	**2022**
Zone substation	Colac (**CLC**) Charlton (**CTN**) Ararat (**ART**) Ballarat North (**BAN**)	Bendigo (**BGO**) Bendigo Terminal (**BETS**) Terang (**TRG**) Ballarat South (**BAS**)	Hamilton (**HTN**) Waurn Ponds (**WPD**)	Geelong (**GL**) Stawell (**STL**) Koriot (**KRT**) Corio (**CRO**) Merbein (**MBN**)

Note that Powercor has brought forward the planned REFCL commissioning dates for the Ararat (**ART**) and Terang (**TRG**) zone substations to 2019 and 2020 respectively, which will fall within the second tranche of the REFCL deployment program. Geelong (**GL**) zone substation has been deferred from tranche two to tranche three while options for the zone substation are further investigated.

3.8.2 Other impacted areas of the network

The installation of a REFCL at a zone substation can impact other parts of the Powercor distribution network. Generally, the REFCL would only impact the 22kV HV feeders directly connected to the REFCL zone substation. During contingent events, however, the open points on the network may change resulting in feeders connected to non-REFCL zone substations being served from a REFCL zone substation and thus experiencing the higher voltages associated with the operation of a REFCL.

New or existing HV customers connected to the feeders listed below, which may experience a REFCL condition during contingent events, are also required to take action to:

- ensure that their assets are compatible with the operation of a REFCL; and
- complete any required works prior to the commissioning of the relevant Powercor REFCL zone substation.

Table 3.3 Other impacted areas of the network

Year	2019	2020	2021	2022
Zone substation	• OYN005 (from CTN) • WPD014 (from CLC)	• HTN005, STL005, TRG002 (from ART) • BMH003 (from BAN) • COB021, HTN003 (from TRG)	• HYT011, KRT013 (from HTN) • DDL023, GCY014, GL021, GLE012, GLE013 (from WPD)	• GB014, GB031, GCY012, GCY014, GCY022 (from GL) • HSM001 (from STL) • WBL005, WBL006 (from KRT) • GB031, FNS011, FNS012, FNS013 (from CRO) • MDA022, MDA023, MDA024, MDA032, MDA033, MDA034 (from MBN)

Note that the Cobden 011, 012 feeders were hardened as part of Powercor's REFCL program for CDN. Any new HV customer assets connecting to this network will be required to be compatible with the operation of a REFCL.

4 Network planning standards

This chapter sets out the process by which Powercor identifies constraints in its network.

4.1 Approaches to planning standards

In general there are two different approaches to network planning.

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

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

- under a probabilistic approach, there are conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
- the actual load at risk may be very small when considering the probability of a forced outage of a particular element of the sub-transmission network.
- In addition, the probabilistic approach assesses load at risk under system normal conditions (known as the "N" condition). This is where all assets are operating but load exceeds the total capacity. Contingency transfers may be used to mitigate load at risk in the interim period until an augmentation is completed.

4.2 Application of the probabilistic approach to planning

Powercor adopts a probabilistic approach to planning its zone substation and sub-transmission asset augmentations.

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

- the expected cost that will be incurred if no action is taken to address an emerging constraint, and therefore
- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of energy at risk (which is discussed in section 6.1) is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

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

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

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

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

5 Forecasting demand

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

Please note that information relating to transmission-distribution connection points are provided in a separate report entitled the "Transmission Connection Planning Report" which is available on the Powercor website.[2]

5.1 Maximum demand forecasts

Powercor has set out its forecasts for maximum demand for each existing zone substation and sub-transmission system in the Forecast Load Sheet.

5.2 Zone substation methodology

This sub section sets out the methodology and information used to calculate the demand forecasts and related information that is referred to in the Forecast Load Sheet and System Limitation Reports.

5.2.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual load and demand values recorded across the distribution network.

As peak demand in Powercor is very temperature and weather dependent, the actual peak demand values referred to in the Forecast Load Sheet are normalised for the purpose of forecasting, in accordance with the relevant weather conditions experienced across any given summer loading period. The correction enables the underlying peak demand growth year-by-year to be estimated, which is used in making future forecast and investment decisions.

The temperature correction seeks to ascertain the "*50th percentile maximum demand*". The 50th percentile demand represents the peak demand on the basis of a normal season (summer and winter). For summer, it relates to a maximum average load temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50 per cent probability of being higher than the 50th percentile demand forecast.[3] The 50th percentile forecast can therefore be considered to be a forecast of the "most-likely" level of demand, bearing in mind that actual demand will vary depending on temperature and other factors. It is often referred to as 50 per cent probability of exceedance (**PoE**).

[2] http://www.powercor.com.au/Electricity_Networks/Powercor_Network/Powercor_-_Network_Planning/

[3] Consequently there is also a 50% probability that demand will not reach forecast.

5.2.2 Forecast demand

Historical demand values taking into account local generation inputs are trended forward and added to known and predicted loads that are to be connected to the network. This includes taking into account the number of customer connections and the calculated total output of known embedded generating units.

Powercor has taken into account information collected from across the business relating to the load requirements of our customers, and the timing of those loads. This includes population growth and economic factors as well as information on the estimated load requirements for planned, committed and developments under-construction across the Powercor service area. Powercor, however, has not yet assessed the impact of a significant increase in solar PV penetration following the Victorian Government’s recently announced Solar Homes Program (offering a rebate on solar PV systems to eligible homes). Powercor will look to support the program in its planning and management of the network.

These bottom-up forecasts for demand have been reconciled with top–down independent econometric forecasts for Powercor as a whole.

These forecasts are referred to in the Forecast Load Sheet.

5.2.3 Definitions for zone substation forecast tables

The Forecast Load Sheet refers to other statistics of relevance to each zone substation, including:

- **Nameplate rating**: this provides the maximum capacity of the zone substation according to the equipment in place;
- **Cyclic N-1 rating**: this assumes that the load follows a daily pattern and is calculated using load curves appropriate to the season and assuming the outage of one transformer. This is also known as the “firm” rating;
- **Hours load is ≥ 95% of maximum demand** (**MD**): based on at least the most recent 12 months of data, assesses the load duration curve and the total hours during the year that the load is greater than or equal to 95 per cent of maximum demand;
- **Station power factor at maximum demand (MD):** based on the most recent maximum demand achieved in a season at the zone substation, this is a measure of how effectively the current is being converted into output and is also a good indicator of the effect of the load current on the efficiency of the supply system. It is calculated as a ratio of real power and apparent power and is used to inform load forecasts. A power factor of:
  - less than one: indicates a lagging or leading current in the supply system which may need correction, such as by increasing or reducing capacitors at the zone substation;
  - one: efficient loading of the zone substation;

- **Load transfers**: forecasts the available capacity of adjacent zone substations and feeder connections to take load away from the zone substation in emergency situations; and
- **Generation capacity**: calculates the total capacity of all embedded generation units that have been connected to the zone substation at the date of this report. Summation of generation above and below 1MW is provided.

5.3 Sub-transmission line methodology

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

5.3.1 Historical demand

The sub-transmission line historical N-1 maximum demand loads for different line configurations are determined using a power flow analysis tool called Power System Simulator for Engineering (**PSS/E**).

The tool models the sub-transmission line from the terminal station to the zone substation to determine the theoretical N-1 maximum demand, by utilising historical actual loads and assessing:

- system impedances;
- transformer tapping ratios, which are used to regulate the transformer voltages;
- capacitor banks; and
- other technical factors relevant to the operation of the system.

The historical maximum demand data for the relevant zone substations is applied to the load flow analysis to enable calculation of the theoretical N-1 maximum demand of the sub-transmission line.

The zone substation forecast maximum demands are diversified to the expected zone substation loads at the time of the respective sub-transmission loop/ line maximum demand. Historical diversity factors are derived and applied.

The data is used to assess the maximum demand in the worst case “N-1” conditions. This is for a single contingency condition where there is the loss of an element in the power system, in particular the loss of another associated sub-transmission line. For a zone substation the load is identical whether the zone substation is operating under N or N-1 (loss of a transformer). Therefore the N-1 cyclic rating is used to compare against the load forecast. However for the loss of a sub-transmission line, other associated lines are loaded more heavily so it is appropriate to consider the N-1 condition for the forecast and compare to the line rating.

5.3.2 Forecast demand

Similar to the sub-transmission line historical maximum demand loads, bottom-up forecasts for maximum demand are predicted utilising a powerflow analysis tool, PSS/E for different line configurations.

The present sub-transmission system is modelled from the terminal stations to the zone substations, taking into account system impedances, transformer tapping ratios, voltage settings, capacitor banks and other relevant technical factors.

The reconciled maximum demand forecasts at each zone substation are used in calculating the maximum demand forecasts for the sub-transmission lines. As discussed in section 5.2 above, the bottom-up forecasts for demand at each zone substation have been reconciled with top–down independent econometric forecasts.

The zone substation forecast maximum demands are diversified based on the historical diversity factors mentioned above.

The data is used to forecast the maximum demand under “N-1” conditions. These forecasts are referred to in the Forecast Load Sheet.

5.3.3 Definitions for sub-transmission line forecast tables

The Forecast Load Sheet refers to other statistics of relevance to each sub-transmission line, including:

- **Line rating**: this provides the maximum capacity of the sub-transmission line as measured by its current and expressed in MVA;
- **Hours load is ≥ 95% of maximum demand** (**MD**): based on at least the most recent 12 months of data, assesses the load duration curve and the total hours during the year that the load is greater than or equal to 95 per cent of maximum demand;
- **Power factor at maximum demand (MD):** based on historical data**,** is a measure of how effectively the current is being converted into output and is also a good indicator of the effect of the load current on the efficiency of the supply system. It is calculated as a ratio of real power and apparent power and is used to inform load forecasts. A power factor of:
  - less than one: indicates a lagging or leading current in the supply system which may need correction, such as by increasing or reducing capacitors at the zone substation;
  - one: efficient loading of the zone substation.
- **Load transfers**: forecasts the available capacity of alternative sub-transmission lines that can carry electricity to the zone substation in emergency situations; and
- **Generation capacity**: calculates the total capacity of all embedded generation units that are greater than 1MW that have been directly connected to the sub-transmission line at the date of this report.

5.4 Primary distribution feeders

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

5.4.1 Forecast demand

Primary distribution feeder maximum demand forecasts are calculated using a similar methodology to our zone substation forecasts. The historical feeder demand values are trended forward using the underlying feeder growth rate including known or predicted loads that are forecast for connection.

Temperature correction and top down reconciliation occurs on the feeder and zone substation forecasts and is therefore inherent in the sub-transmission forecasts.

6 Approach to risk assessment

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

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

6.1 Energy at risk

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

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

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

For zone substations, **energy at risk** is defined as:

- the amount of energy that would not be supplied from a zone substation if a major outage[4] of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months and no other mitigation action is taken.

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

For sub-transmission lines, the same definition applies however, the mean duration of an outage due to a significant failure is 8 hours for overhead sub-transmission lines and 1 week for underground sub-transmission lines.

Estimates of energy at risk are based on the 50th percentile demand forecasts, which were discussed in sections 5.2 and 5.3.

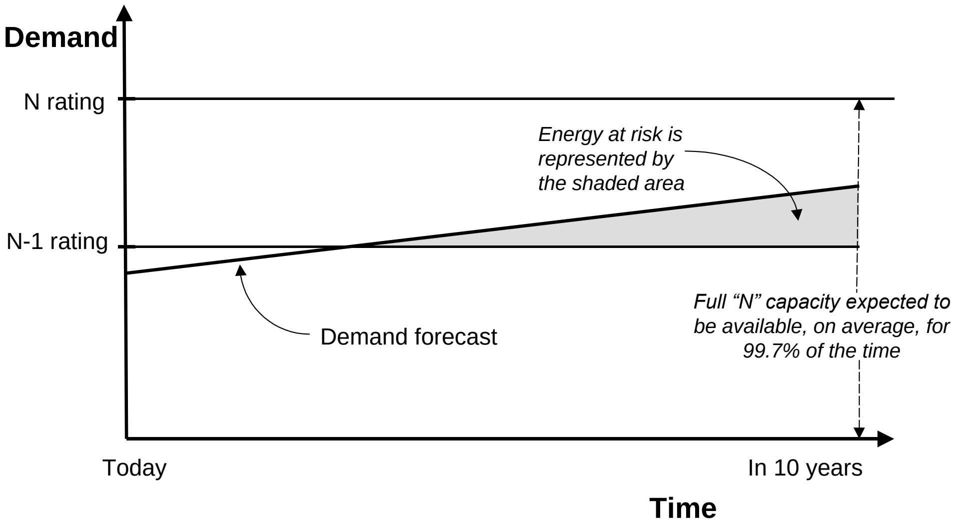
[4] The term 'Major Outage' refers to an outage that has a duration of 2.6 months, typically due to a significant failure within the transformer.

6.2 Interpreting "energy at risk"

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

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

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



Note that:

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

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

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

In estimating the expected cost of plant outages, this report considers the first order contingency condition ("N-1") only.

6.3 Load Index

To enhance the use of probabilistic planning, Powercor collaborated with EA Technology to develop a suitable band of Load Indices. These indices are intended to provide a 'top down' lead indication of risk and performance, and to verify in a tangible way the reasonableness of the 'bottom-up' investment plans.

The Load Index, which is a measure of asset utilisation, is generated from two factors:

- demand driver – measure of maximum demand relative to firm capacity; and
- duration driver – measure of hours or energy at risk.

The Load Indices developed cover a range of conditions, including several bands for increasing hours above firm capacity (N-1 rating) and the 2 top bands for situations where the load is approaching or even exceeding the N capacity. The bandings are intended to provide sufficient breadth and sufficient discrimination to both visualise/communicate the overall level of load, and to show the effects of modest load increases over the next few years. The bandings are shown in the table below.

Table 6.1 Load Index bands

Load Index	Condition	Load%		Hrs above Firm Capacity	
		>Minimum	≤ Maximum	>Minimum	≤ Maximum
1	N-1	0	90	N/A	N/A
2	N-1	90	100	N/A	N/A
3	N-1	100	110	N/A	N/A
4	N-1	110	…	N/A	100
5	N-1	110	…	N/A	250
6	N-1	110	…	N/A	500
7	N-1	110	…	N/A	750
8	N-1	110	…	750	7500
9	N	90	100	N/A	N/A
10	N	100		N/A	N/A

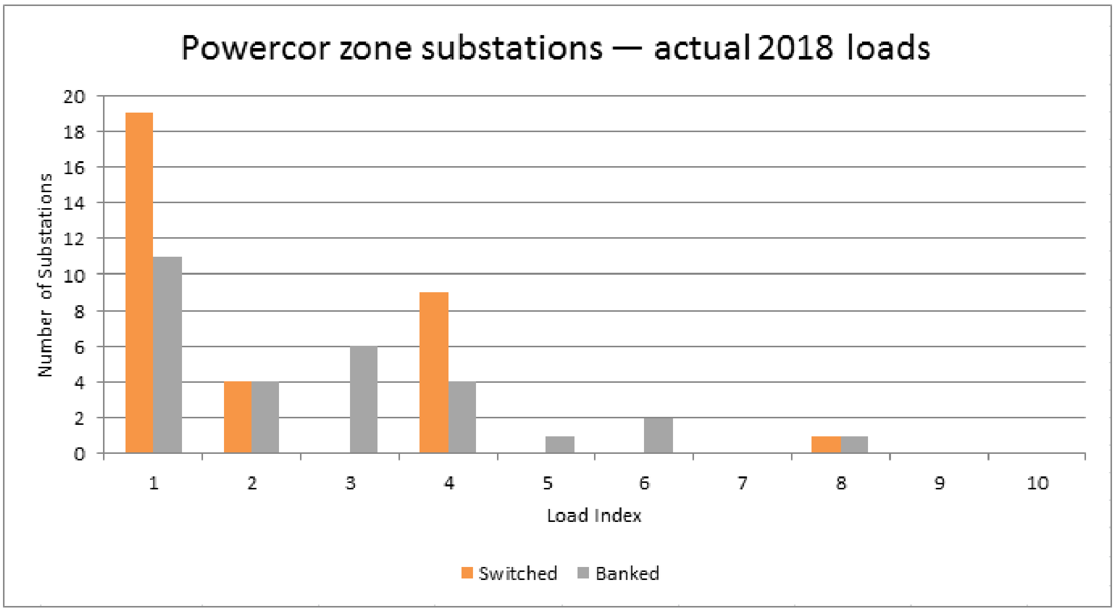
Powercor uses the Load Indices for zone substations and sub-transmission lines.

It is noted that for a single transformer substation or radial sub-transmission line, the firm capacity is taken as the transfer capacity. As the time over firm capacity is not supplied for this definition, where the maximum demand exceeds the transfer capacity it is assumed that the number of hours over firm capacity is >750, so the asset is classified as LI 8.

Powercor has separately identified the Load Index for zone substations where the switching configuration is banked or fully switched.

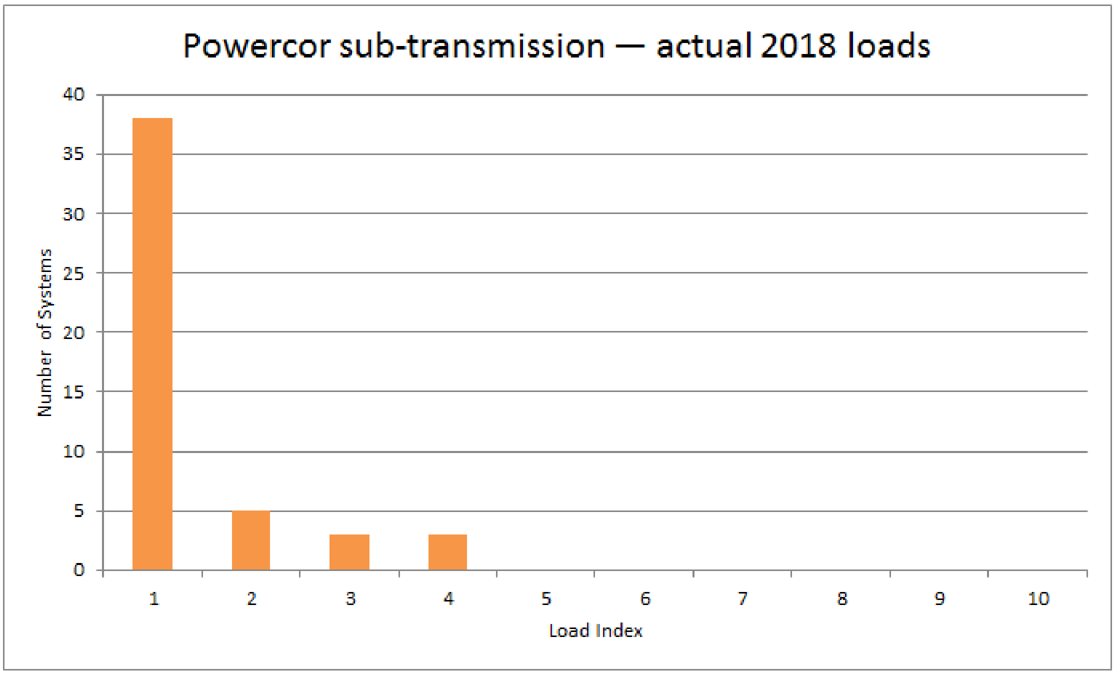
The 2018 actual Load Index profile for zone substations is shown below.

Figure 6.2 Load Index for zone substations



The 2018 forecast Load Index profile for sub-transmission systems (loops and radial lines) is shown below.

Figure 6.3 Load Index for sub-transmission systems



6.4 Valuing supply reliability from the customer's perspective

For large augmentation or replacement projects over $6 million that are subject to a Regulatory Investment Test for Distribution (**RIT-D**), Powercor will undertake a detailed assessment process to determine the most efficient solution.

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

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

Powercor relies upon surveys undertaken by the AEMO to establish the Value of Customer Reliability (**VCR**). AEMO published the following Victorian VCR values in its final report dated 28 November 2014 which have been escalated using the ratio of March 2014 to March 2017 CPI figures as per the AEMO Application Guide to the following amounts:

Table 6.2 Values of customer reliability

Sector	VCR for 2018 ($/kWh)
Residential	$26.45
Commercial	$47.77
Agricultural	$50.93
Industrial	$47.07

These values are multiplied by the relative weighting of each sector at the zone substation or for the sub-transmission line, and a composite single value of customer reliability is estimated.

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

Powercor notes that there has been a significant reduction in the VCR estimates for the commercial and agricultural sectors compared to the results of the 2007/08 VCR study, which was conducted on behalf of VENCorp (AEMO's predecessor) by CRA International. This has led to a reduction in AEMO's estimate of the composite VCR from $63 per kWh in 2013 to $42.20 per kWh in 2018.

From a planning perspective, it is appropriate for Powercor to have regard to the latest available VCR estimates. It is also important to recognise, however, that all methods for estimating VCR are prone to error and uncertainty, as illustrated by the wide differences between:

- AEMO's VCR estimate for 2013 of $63 per kWh, which was based on the 2007/08 VENCorp study[5];
- Oakley Greenwood's 2012 estimate of the New South Wales VCR[6], of $95 per kWh; and
- AEMO's latest Victorian VCR (escalated from 2014 to 2018) estimate of $42.20 per kWh.

The wide range of VCR estimates produced by these three studies is likely to reflect estimation errors and methodological differences between the studies, rather than changes in the actual value that customers place on reliability. Moreover, the magnitude of the reduction in the AEMO's VCR estimates since 2013 raises concerns that the investment decisions signalled by applying the current VCR estimate may fail to meet customers' reasonable expectations of supply reliability.

It should be noted that the Australian Energy Regulator (**AER**) plans to release an update to the VCR estimate by 31 December 2019.

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

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

7 Zone substations review

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

- forecasts for maximum demand to 2023; and
- summer and winter cyclic N-1 ratings for each zone substation.

Where the zone substations are forecast to operate with maximum demands greater than 5 per cent above their firm summer or winter rating during 2019, then this section assesses the energy at risk for those assets.

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

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

Powercor notes that all other zone substations that are not specifically mentioned below either have loadings below the relevant rating or the loading above the relevant rating is minimal and can be addressed using load transfer capability via the distribution network to adjacent zone substations. In these cases, all customers can be supplied following the failure or outage of an individual network element.

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

7.1 Zone substations with forecast system limitations overview

Using the analysis undertaken below in section 7.2, Powercor proposes to augment the zone substations listed in the table below to address system limitations during the forward planning period. Powercor will investigate combining augmentation and asset replacement projects where net economic benefits are feasible.

Table 7.1 Proposed zone substation augmentations

Zone substation	Description	Direct cost estimate ($ millions)				
		2019	**2020**	**2021**	**2022**	**2023**
WBE & LV	Construct new 22kV feeder ties and permanently transfer load to TNA	1.8				
DDL	Construct new 22kV feeder ties and permanently transfer load to GLE	1.0				
BMH	Install a new 25/33MVA transformer			0.2	2.0	5.0
TNA	Install a third transformer			0.4	2.6	
SA	Install new 22kV CB isolators			0.2		
TQY	New TQY zone substation				1.3	18.2
TRT	New TRT zone substation					0.5
Total		**2.8**	**0**	**0.8**	**5.9**	**23.7**

The options and analysis is undertaken in the sections below.

7.2 Zone substations with forecast system limitations

7.2.1 Altona (AL) zone substation

The Altona (**AL**) zone substation is served by sub-transmission lines from the Brooklyn Terminal Station (**BLTS**) and Altona Terminal Station (**ATS**). It supplies the areas of Altona and Altona North, including Kororoit Creek Road.

Currently, the AL zone substation is comprised of a single 20/30 MVA 66/11kV transformer supplying the 11kV buses. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimate for 2019 maximum demand is forecast to be 18.3 MVA in summer 2018/19; which is well within the existing transformer cyclic capacity of 34.2 MVA.

For an outage of the single transformer at AL, Powercor will utilise its 11kV automatic changeover system to the adjacent Altona Chemical (**AC**) zone substation that is comprised of two 66/11kV transformer units. This arrangement will automatically transfer all AL zone substation 11kV loads to AC zone substation in case of any transformer outage at AL, thus having no residual load at risk.

7.2.2 Ararat (ART) zone substation

The Ararat (**ART**) zone substation is served by sub-transmission lines predominately from the Ballarat terminal station (**BATS**). It supplies the Ararat area.

Currently, the ART zone substation is comprised of two 10 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 1.3 MVA of load at risk for 15 hours of the year where it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at ART. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the ART zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Stawell (**STL**), Maryborough (**MRO**), Hamilton (**HTN**) and Terang (**TRG**) up to a maximum transfer capacity of 5.0MVA;
- install high capacity fans to increase the transformer cyclic ratings for an estimated cost of $0.3 million. Fans will improve oil cooling by an increase in airflow through the radiators.

Powercor’s preferred option is to install high capacity fans at ART, however given that the probability weighted value of energy at risk is not sufficient to justify augmentation this project is not expected to occur during the forecast period. Although the expected demand will exceed the station’s N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.3 Bacchus Marsh (BMH) zone substation

The Bacchus Marsh (**BMH**) zone substation is served by two sub-transmission lines from the Brooklyn terminal station (**BLTS**) and Ballarat terminal station (**BATS**). This station supplies the areas of Bacchus Marsh, Ballan, Balliang and the surrounding areas.

Currently, the BMH zone substation is comprised of two 10/13.5 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 15.2 MVA of load at risk and for 783 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at BMH. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BMH zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Melton (**MLN**) and Ballarat North (**BAN**) up to a maximum transfer capacity of 3.2 MVA;
- install a new 25/33 MVA third transformer at BMH zone substation for an estimated cost of $7.3 million;

Powercor's preferred option is to install a new transformer in 2023. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

A demand side initiative to reduce the forecast maximum demand load by 2.2 MW across the zone substation would defer the need for this capital investment by one year.

7.2.4 Bendigo (BGO) zone substation

The Bendigo (**BGO**) zone substation is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies the City of Bendigo and the area to the east.

Currently, the BGO zone substation is comprised of two 20/27/33 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 14.5 MVA of load at risk and for 113 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at BGO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BGO zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Eaglehawk (**EHK**) and Bendigo terminal station 22kV (**BETS 22kV**) up to a maximum capacity of 13.9 MVA;
- establish a new 22kV feeder, offload to EHK zone substation, and reconductor 5.2km of associated sub-transmission line for an estimated total cost of $5.5 million;
- install a new 25/33 MVA third transformer at BGO zone substation for an estimated cost of $4.9 million;

Powercor's preferred option is to establish a new transformer at BGO over the longer term. However given that the probability weighted value of energy at risk is not sufficient to justify the augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.5 Charam (CHM) zone substation

The Charam (**CHM**) zone substation is served by a single radial sub-transmission line from the Horsham terminal station (**HOTS**). It supplies Edenhope and surrounding areas.

Currently, the CHM zone substation is comprised of one 25/33MVA transformer operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 2.2 MVA of load at risk and for 8760 hours it will not be able to supply all customers from the zone substation if there is a failure of the one transformer at CHM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the CHM substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent Horsham (**HSM**) zone substation up to a maximum transfer capacity of 1.1 MVA;
- contingency plan to transfer load away via temporary conversion of the HOTS-CHM 66kV sub-transmission to 22kV and links to adjacent HSM zone substation up to a maximum transfer capacity of 2MVA;
- install a new 25/33 MVA third transformer at CHM zone substation for an estimated cost of $6.0 million;

Powercor's preferred option for an outage of the single transformer per above, is to utilise contingency load transfers to mitigate the load at risk during the forecast period.

7.2.6 Cobram East (CME) zone substation

The Cobram East (**CME**) zone substation is served by a sub-transmission line from the Numurkah zone substation (**NKA**). It supplies the areas of Cobram and Yarrawonga, extending into surrounding areas.

Currently, the CME zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22 kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 3.3 MVA of load at risk and for 14 hours it would not be able to supply all customers from the zone substation if there is a failure of a transformer at CME. That is, it would not be able to supply all customers during high load periods following the loss of a 10/13.5 MVA transformer.

To address the anticipated system constraint at substation CME, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- install 2.0 MVA of portable emergency generation;
- augment capacity by replacing two 10/13.5 MVA transformers, each with a 25/33 MVA transformer, at an estimated cost of $7.0 million.

Powercor's preferred option is to augment capacity at CME by replacing two 10/13.5 MVA transformers, each with a 25/33 MVA transformer. However, given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N−1 cyclic rating, the use of portable emergency generation will mitigate the risk in the interim period.

7.2.7 Drysdale (DDL) zone substation

The Drysdale (**DDL**) zone substation is served by sub-transmission lines from Geelong terminal station (**GTS**). It supplies the Bellarine Peninsula and coastal towns of Queenscliff, Point Lonsdale, Ocean Grove and Barwon Heads.

Currently, the DDL zone substation is comprised of two 20/27/33 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 33 MVA of load at risk for 80 hours of the year it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at DDL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the DDL substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong East (**GLE**) up to a maximum transfer capacity of 4.4 MVA;
- utilise demand management to defer augmentation;
- permanently transfer load away from DDL to GLE by constructing a new feeder at GLE for an estimated cost of $1.0 million;
- install a new third 25/33 MVA transformer at DDL zone substation for an estimated cost of $6.0 million;

Powercor's preferred option is to permanently transfer load away from DDL to GLE by constructing a new feeder at GLE in 2019, followed by the installation of a new transformer over the longer term. There will be still load at risk following the transfer to GLE, however given that the forecast annual hours at risk is low, the transformer installation is not expected to occur during the forecast period. Demand management opportunities will be investigated prior to the new transformer project. Although the expected demand will exceed the station’s N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.8 Eaglehawk (EHK) zone substation

The Eaglehawk (**EHK**) zone substation is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies Eaglehawk, Bridgewater, Inglewood, the northern part of Bendigo and the surrounding areas north of Bendigo.

Currently, the EHK zone substation is comprised of two 20/27 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 19.8 MVA of load at risk and for 348 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at EHK. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at EHK zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Bendigo zone substation (**BGO**) and Bendigo terminal station 22kV (**BETS 22kV**) up to a maximum transfer capacity of 16.1 MVA;
- install a new 25/33 MVA third transformer at EHK zone substation for an estimated cost of $4.5 million;

Powercor’s preferred option is to establish a new transformer at EHK. However given that the probability weighted value of energy at risk is not sufficient to justify augmentation this project is not expected to occur during the forecast period. Although the expected demand will exceed the station’s N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.9 Geelong (GL) zone substation

The Geelong (**GL**) zone substation is served by sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the area of Geelong and extends into the surrounding north and western rural towns of Bannockburn, Lethbridge and Meredith.

Currently, the GL zone substation is comprised of two 20/40 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 21.8 MVA of load at risk for 122 hours of the year where it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at GL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the GL substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong B (**GB**), Geelong City (**GCY**), Waurn Ponds (**WPD**) and Corio (**CRO**) up to a maximum transfer capacity of 11.9 MVA.
- install a new 25/33 MVA third transformer at GL zone substation for an estimated cost of $6.0 million;

Powercor's preferred option is to install a new transformer. However given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.10 Geelong City (GCY) zone substation

The Geelong City (**GCY**) zone substation is served by two sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the area of Geelong central business district and surrounding east and southern suburban areas.

Currently, the GCY zone substation is comprised of two 20/27/33 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 17.3 MVA of load at risk for 153 hours of the year where it would be unable to supply all customers from the zone substation if there is a failure of one of the transformers at GCY. That is, it would be unable to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the GCY substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong (**GL**), Geelong East (**GLE**) and Waurn Ponds (**WPD**) up to a maximum transfer capacity of 15.9 MVA;
- install a new 25/33 MVA third transformer at GCY zone substation for an estimated cost of $6.0 million;

Powercor's preferred option is to install an additional 25/33MVA transformer at GCY. However given that the probability weighted value of energy at risk is not sufficient to justify the augmentation this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.11 Horsham (HSM) zone substation

The Horsham (**HSM**) zone substation is served from sub-transmission lines from Horsham terminal station (**HOTS**). It supplies the Horsham area.

Currently, the HSM zone substation is comprised of three 10/13.5MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 6.2 MVA of load at risk and for 34 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at HSM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint and replacement needs at HSM substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Charam (**CHM**), Stawell (**STL**) and Nhill (**NHL**) up to a maximum transfer capacity of 4.0 MVA;
- augment capacity by replacing two of the existing 10/13.5MVA transformers with 25/33MVA transformers at HSM at an estimated cost of $7 million in total or $3.5 million each.

Powercor's preferred option is to augment HSM by replacing the two 10/13.5 MVA transformers with larger 25/33 MVA units. However given that the probability weighted value of energy at risk is not sufficient to justify the augmentation this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.12 Laverton (LV) zone substation

The Laverton (**LV**) zone substation is served by two sub-transmission lines from the Altona West terminal station (**ATS**). It supplies the area of Laverton extending into surrounding areas of Altona Meadows, Tarneit, Hoppers Crossing and Point Cook.

Currently, the LV zone substation is comprised of two 25/33MVA transformers and one 20/33MVA transformer operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 48.8 MVA of load at risk and for 159 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at LV zone substation. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the LV zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Werribee (**WBE**) and Truganina (**TNA**) up to a maximum transfer capacity of 18.8MVA;
- augment the network by establishing new 22kV feeder ties to TNA zone substation for an estimated cost of $1.8 million.

Powercor's preferred option is to install 22kV feeder tie to TNA zone substation in 2019. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 5.8 MW would defer the need for this capital investment by one year.

7.2.13 Laverton North 11kV (LVN11) zone substation

The Laverton North (**LVN**) zone substation is served by two sub-transmission lines from the Altona West terminal station (**ATS**) and the Brooklyn terminal station (**BLTS**).

Currently, the LVN zone substation is comprised of three 33MVA 66/22kV (referred to as **LVN22** zone substation), as well as a single 20/30MVA 66/11kV transformer (referred to as **LVN11** zone substation) supplying an industrial customer at high voltage (11kV). There is no other 11kV customer connected through this transformer. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2022 maximum demand is forecast to be 12.7MVA in summer 2021/22; which is well within the existing transformer cyclic capacity of 32.5MVA.

For the loss of the single transformer, the customer's automatic changeover system will transfer the critical load to a back-up 22/11kV transformer connected to the 22kV LVN network, which is required as part of the customer connection agreement.

7.2.14 Maryborough (MRO) zone substation

The Maryborough (**MRO**) zone substation is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies Maryborough, Dunolly and the surrounding areas.

Currently, the MRO zone substation is comprised of two 10/13.5MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 4.3 MVA of load at risk and for 60 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at MRO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at MRO zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substation of Castlemaine (**CMN**) up to a maximum transfer capacity of 3.9 MVA;
- install a third 10/13.5 MVA transformer at MRO zone substation for an estimated cost of $4.5 million.

Powercor's preferred option is to establish a third transformer at MRO. However given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.15 Merbein (MBN) zone substation

The Merbein (**MBN**) zone substation is served from sub-transmission lines from Red Cliffs terminal station (**RCTS**). It supplies the city of Merbein and a small irrigation area.

Currently, the MBN zone substation is comprised of two 10/13 MVA transformers and one 25/33MVA transformer operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 8.4 MVA of load at risk and for 84 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at MBN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the MBN zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent Mildura zone substation (**MDA**) up to a maximum transfer capacity of 22.4 MVA;
- replace an existing 10/13MVA transformer with a new 25/33 MVA transformer at MBN zone substation for an estimated cost of $4.6 million;

Powercor's preferred option is to install a new 25/33 MVA transformer at MBN. However given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the load at risk in the interim period.

7.2.16 Mooroopna (MNA) zone substation

The Mooroopna (**MNA**) zone substation is served by a sub-transmission line from the Shepparton terminal station (**SHTS**) and a sub-transmission line from Shepparton zone substation (**STN**). It supplies the area of Mooroopna and Tatura, extending into surrounding areas.

Currently, the MNA zone substation is comprised of two 20/27/33 MVA transformers operating at 66/22 kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 9.2 MVA of load at risk and for 108 hours it would not be able to supply all customers from the zone substation if there is a failure of a transformer at MNA. That is, it would not be able to supply all customers during high load periods following the loss of a 20/27/33 MVA transformer.

To address the anticipated system constraint at MNA zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Shepparton (STN) up to a maximum transfer capacity of 7.3 MVA;
- install a new 25/33 MVA third transformer at MNA zone substation for an estimated cost of $3.0 million, however it is not possible to establish new feeders to the Tatura area where the load is expected to emerge;
- establish a new zone substation at Tatura (**TAT**) with two 25/33 MVA transformers and transfer load from MNA to TAT, at an estimated cost of $20 million.

Powercor's preferred option is to establish a new zone substation at Tatura (TAT) with two 25/33 MVA transformers over the longer term to cater for the possible increase in demand in the Tatura area. However given that the hours at risk are low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N−1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.17 St Albans (SA) zone substation

The zone substation in St Albans (**SA**) is served by sub-transmission lines from the Keilor terminal station (**KTS**). It supplies the domestic, commercial and industrial areas of St Albans and extending into surrounding urban areas of Sunshine North, Keilor Downs, Kings Park, Delahey, Burnside Heights, Taylors Hill and Caroline Springs.

Currently, the SA zone substation is comprised of two 20/30MVA and one 20/33MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 12.7 MVA of load at risk and for 88 hours it would not be able to supply all customers from the zone substation if there is a failure of a transformer at SA. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at SA zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Sunshine (**SU**), Sunshine East (**SSE**) and Truganina (**TNA**) up to a maximum transfer capacity of 12.2MVA;
- construct feeder ties for permanent load transfer to Sunshine East (**SSE**) zone substation at an estimated cost of $1 million.

Powercor’s preferred option is to construct additional feeder ties between SSE and SU, however given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station’s N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.18 Swan Hill (SHL) zone substation

The Swan Hill (**SHL**) zone substation is served by sub-transmission lines from the Kerang terminal station (**KGTS**). It supplies the area of Swan Hill extending into surrounding areas.

Currently, the SHL zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 1.8 MVA of load at risk and for 8 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at SHL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the SHL substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent Kerang terminal station (**KGTS 22kV**) up to a maximum transfer capacity of 0.8 MVA;
- install a new 25/33 MVA third transformer at SHL zone substation for an estimated cost of $4.3 million;

Powercor's preferred option is to augment capacity by installing an additional transformer at SHL over the longer term. However given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of load transfers will mitigate the risk in the interim period.

7.2.19 Terang (TRG) zone substation

The Terang (**TRG**) zone substation is served by two sub-transmission lines from Terang terminal station (**TGTS**). It supplies Terang and surrounding area.

Currently, the TRG zone substation is comprised of two 10/13.5MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 4.1 MVA of load at risk for 146 hours of the year where it would be unable to supply all customers from the zone substation if there is a failure of one of the transformers at TRG. That is, it would be unable to supply all customers during high load periods following the loss of a transformer.

Also at TRG, the health index of the No1 and No3 transformers is 7.12 and 9.17 respectively, which indicates an elevated risk of failure.

To address the anticipated system constraint and replacement needs at TRG zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Cobden (**COB**) and Camperdown (**CDN**) up to a maximum transfer capacity of 11.4 MVA;
- install a third 10/15MVA transformer at TRG for an estimated cost of $3 million;
- augment TRG by replacing both 13.5MVA transformers with larger 25/33MVA units at an estimated cost of $7.3 million.

Powercor's preferred option is to augment TRG by replacing the No3 10/13.5MVA transformer with a larger 25/33MVA unit at an estimated cost of $2.9 million in 2019, and the No1 transformer with a 25/33 MVA unit for an estimated cost of $3.8 million in 2023 as part of asset replacement work. The new No3 25/33MVA transformer will be installed prior to the retirement of the No3 10/13.5MVA transformer to cater for the load during the replacement. Please refer to sections 14.1.4 and 14.1.5 for further details on the TRG asset replacement strategy. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the Asset Replacement System Limitation Report for further information regarding the preferred network investment.

7.2.20 Truganina (TNA) zone substation

The Truganina (**TNA**) zone substation is served by sub-transmission lines from Deer Park terminal station (**DPTS**). It supplies the area of Caroline Springs, Tarneit, Truganina and Laverton North.

Currently, the TNA zone substation is comprised of two 25/33MVA transformers operating at 66/22 kV. For the forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2019 there will not be any load at risk however by 2022 Powercor expects there to be 13MVA of load at risk and for 595 hours for failure of one of the transformers at TNA.

To address the anticipated system constraint at the TNA zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to adjacent zone substations of Laverton (**LV**) Werribee (**WBE**), Laverton North (**LVN22**), Sunshine (**SU**) and St Albans (**SA**) zone substations up to a maximum transfer capacity of 52.2 MVA;
- augment capacity by installing a third 25/33MVA transformer at TNA for an estimated cost of $3.0 million.

Powercor's preferred option is to install a third transformer at TNA in 2022 to offload WBE and LV zone substations and eliminate the risk at TNA. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

This project is driven by the overall load at risk at TNA zone substation. Therefore a demand side initiative to reduce the forecast maximum demand by 12.4 MW would defer the need for this capital investment by one year.

7.2.21 Warrnambool (WBL) zone substation

The Warrnambool (**WBL**) zone substation is served by sub-transmission lines from the Terang terminal station (**TGTS**). It supplies the Warrnambool and surrounding areas.

Currently, the WBL zone substation is comprised of one 25/33 MVA transformer and two 10/13.5 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 18.2 MVA of load at risk for 342 hours of the year where it would not be able to supply all customers from the zone substation if there is a failure of the 25/33 MVA transformer at WBL. That is, it would not be able to supply all customers during high load periods following the loss of the 25/33 MVA transformer.

Also at WBL, the health index of the No2 transformer is 8.05 which indicates an elevated risk of failure.

To address the anticipated system constraint at substation WBL, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Koroit (**KRT**) up to a maximum transfer capacity of 12.3 MVA;
- augment capacity by replacing the existing No.2 10/13.5 MVA 66/22kV transformer at WBL with a larger 25/33MVA for an estimated cost of $6.32 million.

Powercor's preferred option is to augment the existing No2 66/22kV 10/13.5 MVA transformer at WBL with a larger 25/33 MVA unit in 2019 as part of asset replacement work. Please refer to sections 14.1.6 and 14.1.7 for further details on the WBL asset replacement strategy. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers to KRT will mitigate the risk in the interim period. Please refer to the Asset Replacement System Limitation Report for further information regarding the preferred network investment.

7.2.22 Waurn Ponds (WPD) zone substation

The Waurn Ponds (**WPD**) zone substation is served by two sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the areas of Waurn Ponds extending into the Surf Coast area.

Currently, the WPD zone substation is comprised of one 10/13.5 MVA transformer and two 25/33 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 40.5 MVA of load at risk for 213 hours of the year where it would not be able to supply all customers from the zone substation if there is a failure of one of the 25/33 MVA transformers at WPD. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the WPD zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong East (**GLE**), Geelong (**GL**) Geelong City (**GCY**) and Drysdale (**DDL**) up to a maximum transfer capacity of 9.5 MVA;
- establish a new zone substation at Torquay (**TQY**) to transfer approximately 35 MVA of load from WPD for an estimated cost of $19.5 million.

Powercor's preferred option is to establish a new zone substation at Torquay (**TQY**) and transfer 35MVA of load from WPD in 2023. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

7.2.23 Wemen (WMN) zone substation

The Wemen (**WMN**) zone substation is served by a sub-transmission line from the Wemen terminal station (**WETS**). It supplies the area of Wemen extending into surrounding areas.

Currently, the WMN zone substation is comprised of one 10/13.5 MVA transformer and one 25/33MVA transformer operating at 66/22 kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 there will be 18.2 MVA of load at risk and for 353 hours it will not be able to supply all customers from the zone substation if there is a failure of the 25/33 MVA transformer at WMN. That is, it would not be able to supply all customers during high load periods following the loss of the 25/33 MVA transformer.

To address the anticipated system constraint at substation WMN, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Robinvale (**RVL**) up to a maximum transfer capacity of 1.5 MVA;
- augment capacity by replacing the 10/13.5MVA transformer with a 25/33 MVA transformer at an estimated cost of $3.0 million.

Powercor's preferred option is to augment capacity at WMN by replacing the 10/13.5MVA transformer with a 25/33MVA transformer. However given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.24 Werribee (WBE) zone substation

The Werribee (**WBE**) zone substation is served by two sub-transmission lines from the Altona West terminal station (**ATS**). It supplies the area of Werribee extending into surrounding areas of Mt Cottrell, Wyndham Vale, Tarneit, Hoppers Crossing and Point Cook.

Currently, the WBE zone substation is comprised of two 20/33 MVA and one 25/33 MVA transformers operating at 66/22kV. For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2021 there will be 45.8 MVA of load at risk and for 146 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at WBE. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the WBE zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Laverton (**LV**) and Truganina (**TNA**) up to a maximum transfer capacity of 19.8 MVA in 2019;
- augment the network by establishing new 22kV feeder ties to TNA zone substation for an estimated cost of $1.8 million.

Powercor's preferred option is to install a new 22kV feeder to TNA in 2019. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

This project is driven by the load at risk at WBE zone substation. Therefore a demand side initiative to reduce the forecast maximum demand load by 6.8 MW would defer the need for this capital investment by one year.

7.3 Proposed new zone substations

The new Torquay zone substation (**TQY**) is planned to be commissioned in 2023. It is also proposed to commence options analysis and scope concept and design for the following new zone substations in 2020:

- Tarneit zone substation (**TRT**)

As part of the REFCL program, Bannockburn (**BNK**) zone substation and Torquay (**TQY**) zone substation are been considered as alternate options to Geelong (**GL**) and Waurn Ponds (**WPD**) respectively (subject to net cost benefit analysis).

8 Sub-transmission lines review

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

- forecasts for N-1 maximum demand to 2023; and
- line ratings for each sub-transmission line.

Where the sub-transmission line is forecast to operate with maximum demands greater than 5 per cent above their summer or winter rating under N-1 conditions during 2019, then this section assesses the energy at risk for those assets.

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

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

Powercor notes that all other sub-transmission lines that are not specifically mentioned below either have loadings below the relevant rating or the loading above the relevant rating is minimal and can be addressed using the load transfer capability. In these cases, all customers can be supplied following the failure or outage of an individual network element.

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

8.1 Sub-transmission lines with forecast system limitations overview

Using the analysis undertaken below in section 8.2, Powercor does not propose to augment any sub-transmission lines to address system limitations during the forward planning period.

The options and analysis is undertaken in the sections below.

8.2 Sub-transmission lines with forecast system limitations

8.2.1 ATS-WBE-HCP 66 kV sub-transmission loop

The ATS-WBE-HCP sub-transmission loop supplies the Werribee (**WBE**) zone substation and Hoppers Crossing (**HCP**) customer substation fed from Altona terminal station (**ATS**) at 66 kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2020 for the lines within this loop there will be:

- 15.8 MVA of load at risk and for 14 hours it will not be able to supply all customers from the ATS-HCP line if there is an outage of the ATS-WBE sub-transmission line;
- 15.9 MVA of load at risk and for 14 hours it will not be able to supply all customers from the ATS-WBE line if there is an outage of the ATS-HCP sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substations of Laverton (**LV**) and Truganina (**TNA**) up to a maximum transfer capacity of 19.8 MVA;
- augment capacity by installing a new feeder to TNA zone substation for an estimated cost of $1.3 million.

Powercor's preferred option is to install a new 22kV feeder to TNA in 2019, primarily driven by risk at WBE zone substation and is therefore listed in the WBE zone substation limitation report spreadsheet. Although the expected demand will exceed the sub-transmission loop's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report and zone substation review in section 7.2 for WBE for further information regarding the preferred network investment.

This project is driven by the overall load at risk at WBE. Therefore a demand side initiative to reduce the forecast maximum demand load by 6.8 MW would defer the need for this capital investment by one year.

8.2.2 BETS-CMN-MRO 66 kV sub-transmission loop

The BETS-CMN-MRO 66kV sub-transmission loop supplies the Castlemaine and Maryborough zone substations fed from Bendigo terminal station (**BETS**) at 66 kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 for the lines within this loop there will be:

- 1.4 MVA of load at risk and for 4 hours it will not be able to supply all customers from the CMN-MRO line if there is an outage of the BETS-CMN sub-transmission line;

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent terminal station Bendigo (**BETS 22kV**) up to a maximum transfer capacity of 0.8 MVA;
- increase the capacity of both of the sub-transmission lines by augmenting the line from CMN to MRO.

Powercor's preferred option is to utilise contingency transfers of load to BETS 22kV. These contingency measures will mitigate the risk for the forward planning period.

8.2.3 GTS-GB-GL-GCY 66 kV sub-transmission loop

The GTS-GB-GL-GCY 66kV sub-transmission loop supplies the Geelong City (**GCY**), Geelong B (**GB**) and Geelong (**GL**) zone substations fed from Geelong terminal station (**GTS**) at 66 kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2023 for the lines within this loop there will be:

- 27.1 MVA of load at risk and for 9 hours it will not be able to supply all customers from the GTS-GCY line if there is an outage of the GTS-GB sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Waurn Ponds (**WPD**), Corio (**CRO**), and Geelong East (**GLE**) up to a maximum transfer capacity of 15.9 MVA;
- augment part of the GTS-GCY sub-transmission line by replacing the small underground cable section with larger cable in order to increase thermal rating for an estimated cost of $0.5 million;

Powercor's preferred option to address the GTS-GCY line constraint is to replace a cable section on part of the line. However given that the forecast annual hours at risk is low this project is not expected to occur during the forecast period.

To protect the line from damage, Powercor has an automatic line protection scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of contingency load transfers will mitigate the risk in the interim period.

8.2.4 KGTS-GSF-SHL No1 & No2 66kV sub-transmission loop

The KGTS-GSF-SHL sub-transmission loop supplies the Gannawarra Solar Farm (**GSF**) and Swan Hill (**SHL**) zone substation from Kerang terminal station (**KGTS**) at 66kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet*.*

Powercor estimates that in 2023 for the lines within this loop there will be:

- 15.2 MVA of load at risk and for 140 hours it will not be able to supply all customers from the KGTS-SHL line if there is an outage of the KGTS-GSF or GSF-SHL sub-transmission lines due to voltage limitations.
- 3 MVA of load at risk and for 68 hours it will not be able to supply all customers from the KGTS-GSF line if there is an outage of the KGTS-SHL sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the Boundary Bend (**BBD)** and Ouyen (**OYN**) zone substations up to a maximum transfer capacity of 0.5 MVA;
- contingency plan to transfer load away via 22kV links to the Kerang terminal station (**KGTS 22kV**) up to a maximum transfer capacity of 0.3 MVA;
- an automatic line protection scheme to limit load to the line rating if an outage occurs for an estimated cost of $0.2 million;
- augment the sub-transmission lines by replacing the small conductors with larger conductors in order to increase the voltage limitation on the KGTS-SHL line at an estimated cost of $13 million.
- augment the KGTS-GSF sub-transmission line by replacing small sized conductors with large conductors in order to increase thermal rating at an estimated cost of $1.2 million.

Powercor’s preferred option is to replace the conductors on the KGTS-SHL and KGTS-GSF lines over the longer term, which would also address voltage and thermal rating constraints under N-1 conditions. However given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station’s N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

To protect the lines from damage, Powercor has installed an automatic line protection scheme.

8.2.5 TGTS-HTN-NRB 66 kV sub-transmission loop

The TGTS-HTN-NRB 66kV sub-transmission loop supplies the Hamilton (**HTN**) zone substation and Nareeb (**NRB**) switching station from Terang terminal station (**TGTS**) at 66 kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Load Sheet.

Powercor estimates that in 2020 for the lines within this loop there will be:

- 5.3 MVA of load at risk and for 33 hours it will exceed the voltage limit of the TGTS-NRB line if there is an outage of the TGTS-HTN sub-transmission line.

To address the anticipated system constraint within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Koroit (**KRT**) and Terang (**TRG**) up to a maximum transfer capacity 2.7 MVA;
- build a 66kV switching station halfway between TGTS and HTN. This changes the impedance for the loss of half an existing line, and therefore improves voltage response. The project cost is estimated at $5.5 million;
- establish an 80 km 66 kV line between Portland (**PLD**) and HTN to strengthen the system at HTN as well as PLD. However this option would cost in excess of $20 million and could not be economically justified, hence this option is not recommended;

Powercor's preferred option is to build a 66kV switching station halfway between TGTS and HTN over the longer term. To protect the lines from damage, Powercor has completed installing an automatic line protection scheme in 2018. Although the expected demand will exceed the voltage limit at HTN, for the worst case outage per above, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

8.3 Proposed new sub-transmission lines

This section sets out Powercor's plans for new sub-transmission lines. No new lines are forecast to be built in the forward planning period.

9 Primary distribution feeder reviews

This chapter reviews the primary distribution feeders where further investigation into the balance between capacity and demand over the next two years is warranted, taking into account the:

- forecasts for maximum demand to 2020; and
- summer and winter cyclic ratings for each feeder.

Where the feeders are forecast to operate with maximum demands at their firm summer or winter rating over the next two years, then this section assesses the energy at risk for those assets.

This review considers the primary section of a feeder, or what is commonly known as the backbone of the feeder exiting the zone substation to the first point of load for a low-voltage feeder or customer.

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

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

Finally, distribution feeders that are proposed to be commissioned during the next two years are also discussed.

9.1 Primary distribution feeders with forecast system limitations overview

Using the analysis undertaken below in section 9.2, Powercor proposes to augment the feeders listed in the table below to address system limitations in the next two years.

Table 9.1 – Proposed primary distribution feeder augmentations

Feeder	Description	Direct cost estimate ($ million)	
		2019	2020
MNA24	Thermally uprate feeder exit	0.12	
TOTAL		**0.12**	

9.2 Primary distribution feeders with forecast system limitations

9.2.1 MNA024 feeder

The Mooroopna (**MNA**) zone substation is served by two sub-transmission lines from the Shepparton Terminal Station (**SHTS**). It supplies the domestic and commercial areas of Mooroopna. Currently, the MNA zone substation is comprised of two 25/33MVA transformers operating at 66/22kV.

MNA024 feeder is one of six 22kV feeders supplying the area surrounding MNA zone substation. The limitation in MNA024 feeder is due to medium size of the overhead line exit conductors that during high load times are overloaded. For the historic and forecast asset ratings and forecast feeder maximum demand, please refer to the System Limitation Report.

Powercor estimates that on MNA024 feeder, in 2020, there will be 1.2 MVA of unserved load above the thermal rating for 21 hours during system normal conditions. That is, it would not be able to supply all customers during high load periods.

To address the anticipated system constraint on MNA024 feeder, Powercor considers that the following network solutions could be implemented to manage the unserved load:

- contingency plan to transfer load away via 22kV links to adjacent STN feeders of up to 2 MVA;
- thermally uprate the overhead feeder exit at an estimated cost of $0.12 million.

Powercor's preferred option is to thermally uprate the feeder exit in 2019. This project resolves the MNA024 feeder constraint. Although the expected demand will exceed the feeder ratings, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitation Report for further information regarding the preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 1 MW on MNA024 feeder would defer the need for this capital investment by one year.

9.3 Proposed new primary distribution feeders

As per section 7.2.12 and 7.2.24, Powercor proposes to establish a new 22kV feeder tie to TNA in 2019 to address the constraints at Laverton (**LV**) and Werribee (**WBE**) zone substations. The following primary distribution feeder projects are currently sitting outside of the primary feeder forecast period. It is however proposed to commence scope investigation and option analysis in 2019-20.

Table 9.2 Future primary distribution feeder projects

BAS031 new 22kV Ring Road feeder	BAS033 New 22kV Ring Road feeder
BET010 22kV Feeder exit upgrade	BGO023 Feeder extension
BLT015 Re-commission	BMH007 New 22kV feeder
DDL031 New 22kV feeder	EHK011 New 22kV feeder
EHK023 66kV line section, stage 1	FNS032 22kV feeder extension to Avalon
FNS032 Feeder extension	GL013 New 22kV feeder to Bannockburn
KGT004 Feeder backbone augmentation	MBN023 Feeder exit upgrade
MBN023 Feeder exit upgrade	MLN031 New 22kV feeder to Rockbank
MLN034 New 22kV feeder to Rockbank	SA011 Feeder exit upgrade
SA003 Feeder exit upgrade	SSE013 Feeder tie
SU014 Feeder extension to Orica site	STN Two new 22kV feeders
TNA Two new 22kV feeders	WBE 22kV feeder to Point Cook
WPD New 22kV feeder to Grovedale	

10 Joint Planning

This section sets out the joint planning with DNSPs and TNSPs in relation to zone substations and sub-transmission lines. Joint planning in relation to terminal stations in isolation is discussed in the Transmission Connection Planning Report.

Powercor has not identified any new projects from our joint planning activities with other DNSPs in 2018. Our joint planning activities have included sharing load forecast information and load flow analysis between Victorian distributors relating to the sub-transmission system. Where a constraint is identified on our network that may impact another distributor, then project specific joint planning meetings are held to determine the most efficient and effective investment strategy to address the system constraint.

11 Changes to analysis since 2017

The following information details load forecasts and project timing changes that have occurred since the publication of the 2017 DAPR.

11.1 Constraints addressed or reduced due to projects completed

Powercor has undertaken the following projects in 2018 to address constraints identified in the 2017 DAPR:

- Line protection scheme installed to protect the KGTS-SHL and KGTS-GSF lines from overload;
- Line protection scheme installed to protect the TGTS-HTN and TGTS-NRB lines from overload;
- A new third 66/22kV 25/33 MVA transformer has been installed at MLN addressing its load at risk;
- A new line between WETS and RVL has been installed addressing the load at risk on the WETS-RVL line.

11.2 New constraints identified

Changes in load forecasts or other factors during 2018 have resulted in Powercor undertaking risk assessments for the following zone substations or sub-transmission lines, which were not included in the 2017 DAPR:

- Merbein (**MBN**): load forecasts have increased, resulting in load and hours at risk above threshold limits;
- BETS-CMN-MRO loop: load forecasts have decreased on the Bendigo terminal station (**BETS**) to Castlemaine (**CMN**) to Maryborough (**MRO**) sub-transmission line loop resulting in load and hours at risk below threshold limits.

11.3 Other material changes

In addition to the matters identified above, material changes compared to the 2017 DAPR include:

- Ballarat South (**BAS**): load forecasts have decreased, resulting in no hours at risk;
- Stawell (**STL**): load forecasts have decreased, resulting in no hours at risk;
- Mildura (**MDA**): load forecasts have decreased, resulting in no hours at risk;
- Sunshine (**SU**): load forecasts have decreased, resulting in no hours at risk;
- Cohuna (**CHA**): load forecasts have decreased, resulting in no hours at risk;
- Cobden (**COB**): load forecasts have decreased, resulting in no hours at risk;
- BATS-BAN loop: load forecasts have decreased on the Ballarat terminal station (**BATS**) to Ballarat North (**BAN**) sub-transmission line loop, resulting in no hours at risk;

- BLTS-BMH: load forecasts have decreased, resulting in no hours at risk.

12 Asset Management

This section provides information on the Powercor asset management approach including the strategy employed, impacts on system limitations and where further details can be obtained.

12.1 Asset Management Framework

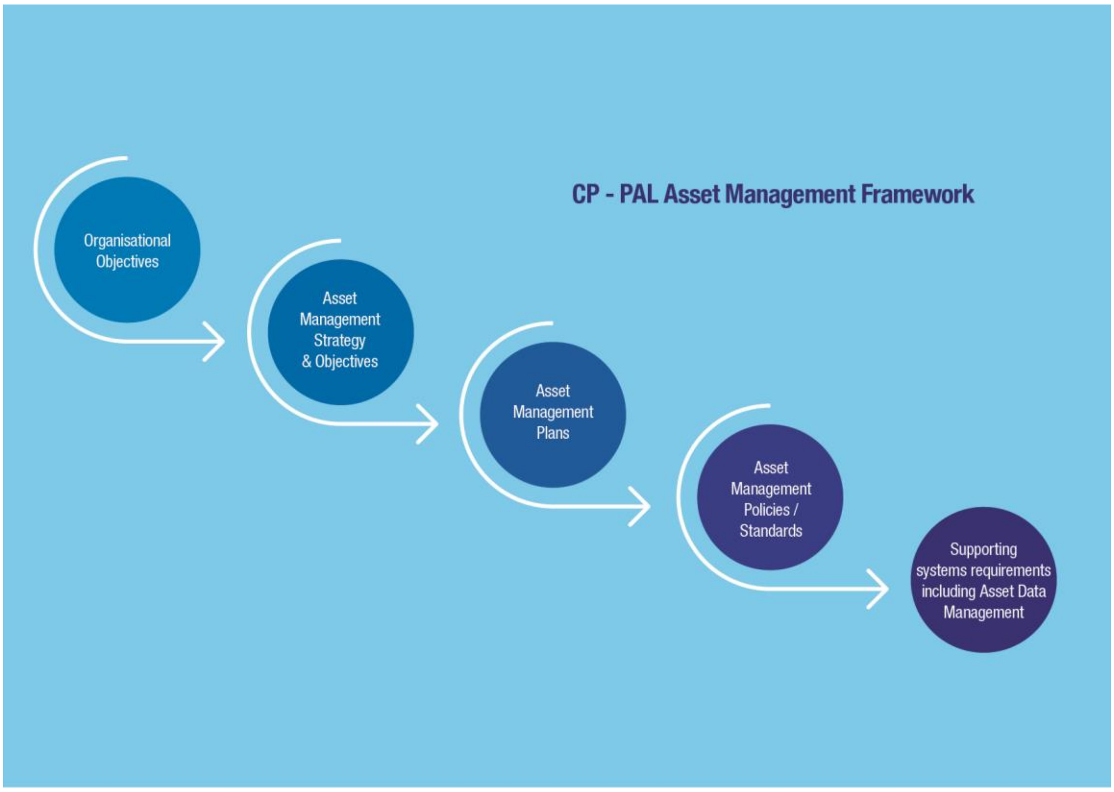
Powercor is committed to the application of best practice asset management strategies to ensure the safe and reliable operation of our electrical network.

Our asset management framework aligns with the principles of PAS 55, which is the British Standards Institution's publicly available specification for the optimised management of physical assets. It is currently being reviewed and updated to align with the requirements of ISO 55001 the international standard in asset management.

The Asset Management Framework is a high level document that describes the asset management system that is applied to Powercor's network assets. The Asset Management Framework encompasses the full range of the asset life cycle activities from identification of need, to creation, operation, maintenance and eventual disposal of network assets.

The structure and hierarchy of the Asset Management Framework is illustrated in Figure 12.1.

Figure 12.1 Asset Management Framework



12.1.1 Asset Management Strategy and Objectives

The Powercor Asset Management strategy requires that all physical assets installed on the electricity distribution network are maintained, refurbished or replaced in accordance with documented Network Asset Management Plans.

The Asset Management objectives for Powercor are:

Reliability, Availability & Maintainability

- Meet or exceed agreed regulatory and business targets;
- Optimise utilisation and performance of physical assets.

Regulatory Compliance

- Ensure that all relevant regulatory obligations are met;
- Ensure all significant network related safety issues are effectively managed to achieve an acceptable risk profile;
- Provide flexibility to encourage innovation, continuous improvement and the effective use of resources.

Network Safety

- Meet bushfire mitigation regulatory obligations, plans and strategies;
- Eliminate public and employee safety incidences as far as practical.

Financial

- Optimise whole of life costs for owning, operating and managing assets;
- Optimise capital expenditure;
- Optimise operational and maintenance expenditure.

Health, Safety & Environment

- Zero LTIs;
- Increase reuse and recycling;
- Dispose of assets in a safe and environmentally responsible manner;
- Minimise impact on the environment.

Risk Management

- Maintain an acceptable corporate risk profile and have active management plans for all significant risks identified.

Work Force Development

- Ensure asset management resources and skills meet future challenges.

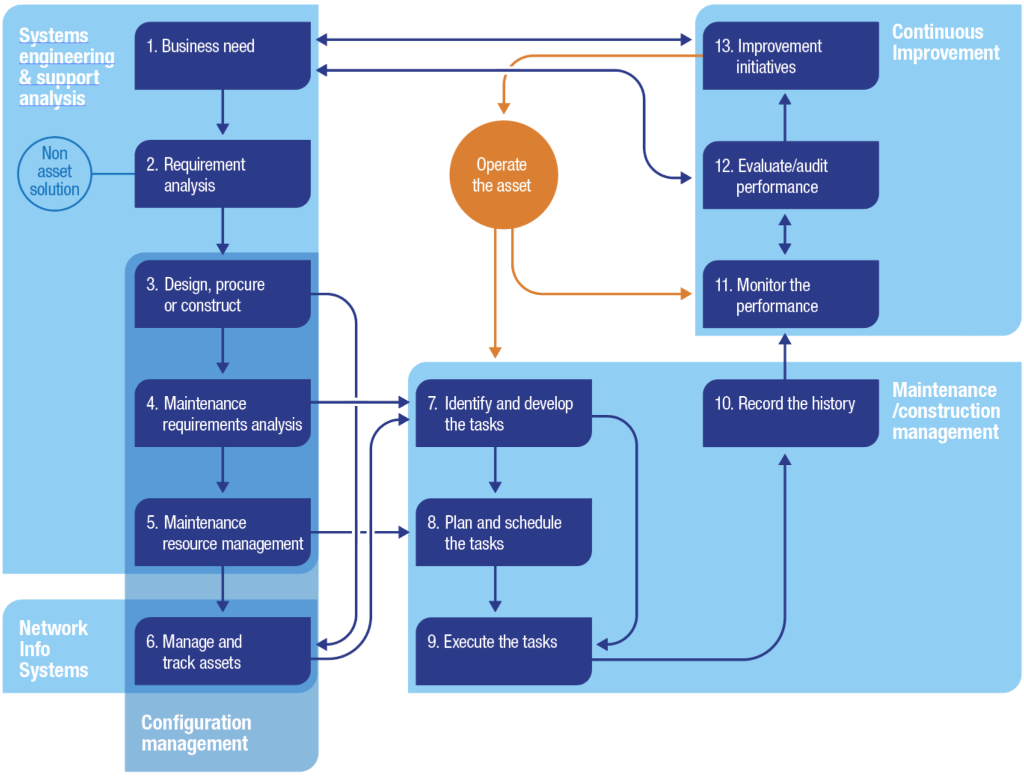
12.1.2 Asset Management System Process

To complement our Asset Management Strategy and Objectives, we utilise an asset management system process, as shown in Figure 12.2. The objective of this system process is to identify all significant steps and processes involved in the total management of assets throughout their life cycle, the typical roles in each and the roles and accountabilities of Powercor.

Our Asset Management System process consists of five key areas:

- systems engineering & support analysis;
- configuration management;
- network Information systems;
- maintenance / construction management; and
- continuous improvement.

Figure 12.2 Asset Management System Process



12.1.3 Network Management Plans

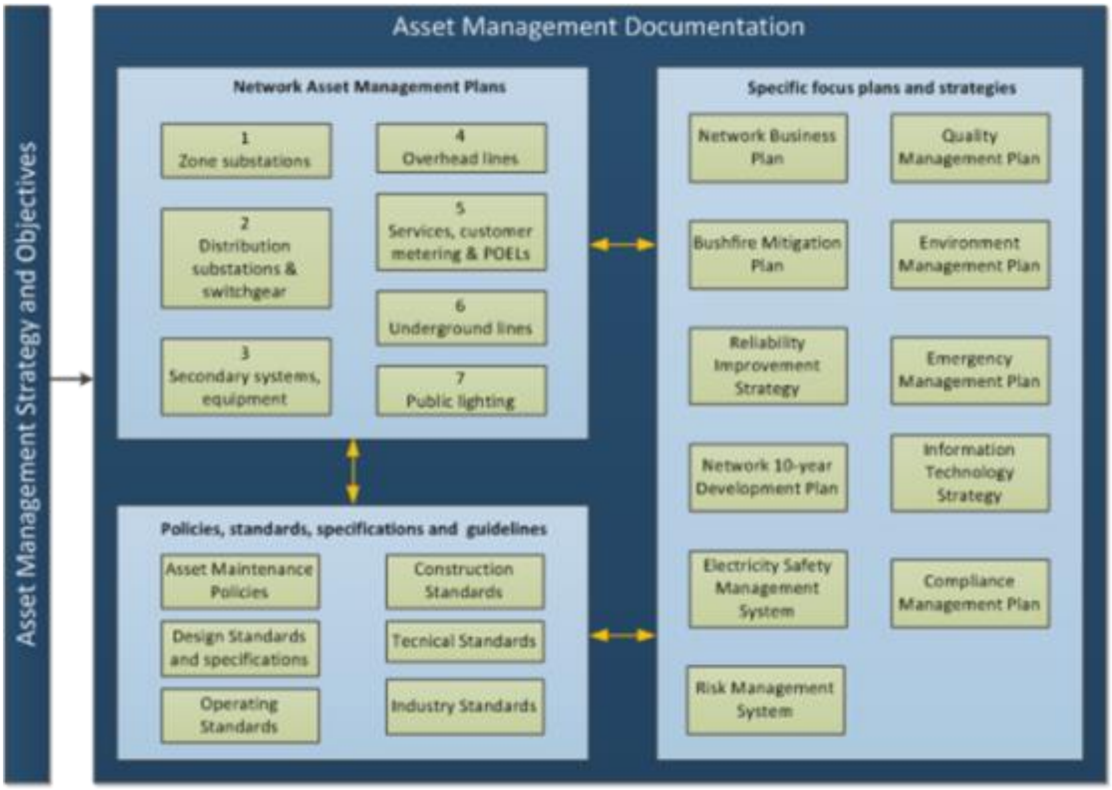
There are many documents that underpin Powercor's Asset Management Framework. The main documents for ongoing asset management are described collectively as Network Management Plans, comprising the following:

- Asset Management Plans by asset type and major asset group;
- Supporting systems, strategies and plans for management of network assets;

- Standards, specifications, guidelines and policies for specific tasks or activities.

The diagram below shows how these documents are related.

Figure 12.3 Network Management Plans



12.1.4 Asset Management Plans

Asset Management Plans (**AMP**) document the management strategies and plans for each of the major asset groups. Each AMP is formed from analysis of the required performance in terms of reliability and quality of supply, risk profile, functionality, availability and safety. The AMPs drive maintenance and inspection plans, condition monitoring, maintenance policies and work instructions. Refer to appendix D for a detailed list of asset management plans in use by Powercor.

12.1.5 Specific Focus Plans and Strategies

Specific focus plans and strategies outline Powercor's approach to management of activity that is relevant to or common across many network asset groups and include the following:

- Operational policies that relate to specific asset management objectives linked to corporate objectives;
- Strategies required for a group of assets or a specific local geographic area where the general asset management plans may not be adequate;
- Strategies that impact on the asset management plans (e.g. bushfire mitigation strategy plan);

- Supplementary or supporting strategies or plans.

12.1.6 Policies, Standards and Guidelines

Network asset maintenance policies, technical standards and specifications are supporting documents which provide more specific information on how assets are managed or maintained.

12.1.7 Impact of Asset Management on System Limitations

Electrical plant and conductor ratings may be affected by asset management activities in that a condition assessment could result in a higher or lower operating temperature. This could improve ratings to defer augmentation costs or lower ratings which will tend to bring forward expenditure whilst maximising system reliability, safety and security of supply. In addition, sections 3 and 14 cover the effect on the system of ageing and potentially unreliable assets.

12.1.8 Distribution Losses

Distribution losses refer to the energy used in transporting it across distribution networks. In 2017/18, 5.73 per cent of the total energy into the Powercor network was made up of losses. This is essentially calculated as the difference between the energy that Powercor procures and that which it supplies. These losses represent 90.4 per cent of Powercor's total greenhouse gas emissions, as defined under the *National Greenhouse and Energy Report Act*.

Powercor has a process to identify, justify and implement augmentation plans to address network constraints. Whilst loss reduction alone is not the main contributing factor in the decision of the preferred option, it is seen as the deciding factor if all other factors are equal. Powercor, as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchases.

12.1.9 Contact for further information

Further information on Powercor's asset management strategy and methodology can be obtained from contacting Powercor Customer Service:

- General Enquiries 13 22 06
- Website www.powercor.com.au

Detailed enquiries may be forwarded to the appropriate representatives within Powercor.

13 Asset management methodologies

The Asset Management Framework describes the asset management system that is applied to Powercor's network assets and requires that all assets are either maintained, refurbished or replaced in accordance with the asset management plans.[7]

Powercor's assets are subject to relevant condition assessment methods through planned inspection and monitoring programs. These programs have been developed taking into account regulatory obligations, industry knowledge as well as proven and established asset management methodologies.

Powercor applies the following asset management methodologies to its network assets:

- reliability and safety based regime — this methodology is based on the principles of Reliability-Centred Maintenance (**RCM**) together with regulatory obligations and risk assessment that are built into the asset management procedures. It is applied to routine replacement expenditure for high- volume assets such as poles, pole top-equipment, cross-arms, insulators, batteries etc. The approach has regard for the asset age, condition and operating environment; and
- Condition Based Risk Management (**CBRM**) — this methodology is applied to assess the condition of assets, including the risk of the deterioration, of major items of plant, which involve significant expenditure. This includes assets such as zone substation transformers and switchgear.

These are discussed in more detail in the sections below.

13.1 'Poles and wires'

The reliability and safety based regime, based on RCM principles, regulatory obligations and risk assessment, is applied to high-volume assets such as poles, cross-arms, conductors etc.

The RCM process is used to determine what must be done to ensure that our physical network assets continue to operate at their intended performance levels at the most efficient cost. It is an internationally recognised and widely used methodology used to determine the most appropriate maintenance strategy for a particular class of asset at efficient cost.

For each asset type, the RCM process identifies possible ways in which a defect may occur in an asset, and the root cause of that defect. For each different type of defect, the possible impact on the safety, operations and other equipment in the network is assessed and a maintenance strategy is determined.

[7] Powercor, *Asset Management Framework*, 2015.

When implementing the RCM methodology for the inspection of assets, the risks associated with asset failures have been considered together with the inspection and repair costs to determine the most efficient inspection frequency and timeframe for repair of identified defects. Where a defect is identified, the maintenance strategy to address that defect is implemented. This may involve either asset replacement or maintenance measures to prolong the asset's life, such as pole staking.

The RCM process can be summarised by a series of steps, as follows.

Figure 13.1 Steps in the RCM process to develop a maintenance strategy

1. Select functions and performance standard of asset	• ensure the asset continues to do what its users want it to do • consider primary functions and secondary functions of asset
2. Identify function failures	• identify the ways in which the asset may fail to fulfil its functions
3. What causes each functional failure	• identify all of the events which are reasonably likely to cause each failed state • includes failures which have occured on the same or similar equipment; are prevented by existing maintainence procedures; and those which possibly may occur
4. What happens when failure occurs	• list all failure effects that describe what happens when a failure mode occurs, including supporting evidence • e.g. what is the evidence that a failure has occured, how does it pose a threat to safety or the environment
5. How does the failure matter	• consequences of failure of a hidden function, where failure will not become evident to operators under normal circumstances • consequence of failure of an evident function in terms of the impact on safety, environment, operational and non-operational matters
6. How to prevent or predict each failure	• identify the most appropriate maintenance strategy for each failure mode, which is also technically and economically feasible • where it is not possible to identify a pro-active task, select default actions such as proof testing, re-design or run to failure
7. Regularly review process	• once maintenance recommendations are put into practice, these are routinely reviewed and renewed as additional information is found

RCM analysis is undertaken by taking into account the equipment manufacturer's recommendations, the physical and electrical environment in which the asset is installed, fault and performance data, test data, condition data, duty cycles as well as many years of field-based experience.

The combination of general maintenance requirements and the specific requirements based on the environments in which the assets operate, may result in varying maintenance and condition monitoring regimes for the same type of asset. Tests and inspections are undertaken using tools such as thermal imagery, visual inspections, and invasive pole testing to assess asset condition.

The following example demonstrates how we apply RCM methodology in the case of wood poles, in practice:

1. Data collection — population demographics are determined so that the volume, age, strength, location and timber species is known. Each of these parameters are analysed to determine how they impact on the performance of poles and may require differing maintenance strategies. Performance data is gathered to determine defect rates, population condition, failure rates and root causes of failures.
2. RCM analysis team — a team of subject matter experts are assembled comprising employees and industry representatives (wood pole suppliers, other authorities, research bodies) to undertake the analysis;
3. Failure mode analysis — all the known and potential failure modes are identified. This generally includes identification of the following:
   - function of the asset;
   - failure types;
   - potential impacts of failure; and
   - potential causes of failure.
4. Maintenance policy developed — appropriate maintenance policies are determined for each failure mode to meet the required performance. This performance is generally expressed as an availability rate for the asset. The maintenance strategies include inspection frequencies, pole treatment frequencies (fungal decay), pole reinstatement, redesign, pole replacement and termite treatment.
5. Systems updated — the policy development/RCM process determines the frequency of inspections based on risk and economics. SAP (our corporate asset management system) then applies the policy rules to the poles to ensure that inspections take place with the right frequency based on that prioritisation. Prioritised inspections are automatically generated and notifications are created to undertake any required maintenance actions triggered during the inspection process.
6. Monitoring — performance of maintenance strategies are monitored such as defect and failure rates to ensure effective implementation and verification of expected outcomes. A further review may be undertaken should performance not meet expectation.

Maintenance and associated condition monitoring policies are reviewed every five years. When new assets are introduced into the network, existing maintenance and condition monitoring plans are reviewed to ensure coverage of the change or new plans are created as appropriate.

Maintenance plans, policies, tasks and work instructions are captured and managed in the SAP Maintenance Management system. The RCM rules are configured in SAP, which automatically generates time based work orders for inspection and maintenance planning.

13.1.1 Location and timing of asset retirements

The location and the timing of the retirements of the ‘poles and wires’ types of assets are not available at the start of any planning year. The location of the asset is determined only once an inspection is carried out and if a defect is detected. The severity of the inspected defect will determine the maximum time that can lapse before action is taken.

13.2 Transformers and switchgear

CBRM is a structured process that combines asset information, engineering knowledge and practical experience to define future condition, performance and risk for network assets.

Powercor applies the CBRM methodology to certain plant-based asset classes, namely transformers and circuit breakers. The CBRM methodology that Powercor uses has been developed by EA Technology.

The methodology draws upon Powercor’s knowledge and experience relating to degradation, failure, condition assessment, performance and influence of environment, duty, operational policy and specification of network assets. It is used to define current and future condition and performance of the assets.

The CBRM process can be summarised by a series of sequential steps, which is set out below.

Table 13.1 Steps in the CBRM process

Step	Description
1	**Define asset condition** Health indices are derived for individual assets within different asset groups. Health indices are described on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.
2	**Link current condition to performance** Health indices are calibrated against relative probability of failure (**PoF**). The HI/PoF relationship for an asset group is determined by matching the HI profile with the relevant observed failure rates.
3	**Estimate future condition and performance** Knowledge of degradation processes is used to trend health indices over time. This ageing rate for an individual asset is dependent on its initial HI and operating conditions. Future failure rates can then be calculated from aged HI profiles and the previously defined HI/PoF relationship.
4	**Evaluation of potential interventions in terms of PoF and failure rates** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future HI profiles and failure rates reviewed accordingly.
5	**Define and weight consequences of failure (CoF)** A consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial, environmental, etc. The consequence categories are weighted to relate them to a common unit.
6	**Build risk model** For an individual asset, its probability and consequence of failure are combined to calculate risk. The total risk associated with an asset group is then obtained by summing the risk of the individual assets.
7	**Evaluate potential interventions in terms of risk** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk profile associated with different strategies.
8	**Review and refine information and process** Building and managing a risk based process driven by asset specific information is not a one-off process. The initial application will deliver results based on available information and crucially, identify opportunities for ongoing improvement that can be used to build an improved asset information framework.

In terms of the steps in the process:

- steps 1 to 4 essentially relate to condition and performance and provide a systematic process to identify and predict end-of-life. Future expenditure plans can then be linked to probability of failure and failure rates;
- steps 5 to 7 deal with consequence of failure and asset criticality that are combined with PoF values to enable definition and quantification of risk; and
- step 8 is a recognition that building and operating a risk-based process using asset specific information is not a one-off exercise.

Each year, Powercor updates the data in its CBRM model, which is contained in a MS Excel spreadsheet. Powercor reviews the outputs of the CBRM and identifies the projects that deliver the greatest risk reduction. The latter projects are determined by calculating the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced, and then assessing the various options to deliver the risk reduction.

While the CBRM methodology identifies a proposed year for the replacement of an asset, the project is then reviewed in conjunction with other augmentation and development plans in order to identify opportunities for synergies, such that the replacement schedule can coincide with other major works. The project is then captured within a future works plan.

13.3 Other items of plant and equipment

Condition-based monitoring and risk-based economic assessment is not possible or cost-effective for all types of plant and equipment. Some plant and equipment rely upon inspection cycles, similar to poles and wires, while others rely on age as the best estimate of condition. Some assets that do not directly impact the performance of the network, and for which the cost of implementing a condition-based or a risk-based approach outweighs the benefit, are run to failure. Other assets, such as surge arrestors, are designed to only be used once and are replaced upon use.

Details of retirement and replacement methodologies for these assets are set out in the relevant asset management plans, and explained in the next chapter.

14 Retirements and de-ratings

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

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

The System Limitation Report details those asset retirements and de-ratings that result in a system limitation.

Where more than one asset of the same type is to be retired or de-rated in the same calendar year, and the capital cost to replace each asset is less than $200,000, then the assets are reported together below.

14.1 Individual assets

A summary of the individual assets that are planned to be retired in the forecast planning period is provided in the table below. A more detailed and accurate assessment including the assessment of non-network alternatives will be carried out at the business case or RIT-D stage.

Table 14.1 Planned asset retirements and de-ratings

Location	Asset	Project	Retirement date
Cobram East (CME) zone substation	Feeder 14 ACR	Replacement	2019
Cobram East (CME) zone substation	Feeder 21 ACR	Replacement	2019
Robinvale (RVL) zone substation	Transformer No1	Replacement	2021
Terang (TRG) zone substation	Transformer No1	Replacement	2023
Terang (TRG) zone substation	Transformer No3	Replacement	2019
Warrnambool (WBL) zone substation	Transformer No2	Replacement	2019

Warrnambool (WBL) zone substation	Transformer No3	Replacement	2022
Corio (CRO) zone substation	66kV circuit breaker 'A'	Replacement	2019

For the forward planning period, there are no committed investments worth $2 million or more to address urgent and unforeseen network issues.

14.1.1 Cobram East (CME) zone substation CME014 22kV feeder ACR

The Cobram East (**CME**) zone substation is served by a single radial sub-transmission line from the Numurkah zone substation (**NKA**). This station supplies the Cobram East area. Currently, the CME zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22 kV.

CME014 feeder is one of five 22kV feeders that supply the surrounding area to CME zone substation and in particular, it is a long rural feeder that supplies farms along the Murray River east of Cobram East and including Yarrawonga. For the historic and forecast asset ratings and forecast feeder maximum demand, please refer to the System Limitation Report.

CBRM analysis determined that the CME014 22kV Feeder ACR has a health index of 3.75 rising to 4.5 in 2023 and requires replacement in 2019. Retirement of this ACR would result in an inability to supply the load presently supplied by the feeder.

With the CME021 feeder ACR retired, Powercor estimates that in 2020 there will be 7.6 MVA of unserved load and for 8760 hours in the year it will not be able to supply all customers on the feeder.

To address the anticipated system constraint at CME zone substation, Powercor considers that the following network solutions could be implemented to manage the unserved load:

- contingency plan to transfer load away via 22 kV links to the adjacent CME016 up to a maximum transfer capacity of 1.5 MVA, and install 1.5 MVA of portable emergency generation;
- replace CME014 22kV feeder ACR at CME with a standard Powercor 22kV circuit breakers (VOX) for an estimated cost of $0.28 million.

Powercor's preferred option is to replace CME014 22kV feeder ACR at CME in 2019. The use of contingency load transfers and emergency generation will mitigate the risk should the asset fail ahead of its forecast replacement date. Please refer to the System Limitation Report for further information regarding details of the limitation and preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 7.2 MW on CME014 feeder would defer the need for this capital investment by one year.

14.1.2 Cobram East (CME) zone substation CME021 22kV feeder ACR

The Cobram East (**CME**) zone substation is served by a single radial sub-transmission line from the Numurkah zone substation (**NKA**). This station supplies the Cobram East area. Currently, the CME zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22 kV.

CME021 feeder is one of five 22kV feeders that supply the surrounding area to CME zone substation and in particular, it supplies a large portion of the town of Cobram East. For the historic and forecast asset ratings and forecast feeder maximum demand, please refer to the System Limitation Sheet.

CBRM analysis determined that the CME021 22kV Feeder ACR has a health index of 3.75 rising to 4.5 in 2023 and requires replacement in 2019. Retirement of this ACR would result in an inability to supply the load presently supplied by the feeder.

With the CME021 feeder ACR retired, Powercor estimates that in 2020 there will be 6.9 MVA of unserved load and for 8760 hours in the year it will not be able to supply all customers on the feeder.

To address the anticipated system constraint at CME zone substation, Powercor considers that the following network solutions could be implemented to manage the unserved load:

- contingency plan to transfer load away via 22 kV links to the adjacent CME014 up to a maximum transfer capacity of 2.5 MVA, and install 1.5 MVA of portable emergency generation;
- replace CME021 22kV feeder ACR at CME with a standard Powercor 22kV circuit breaker (VOX) for an estimated cost of $0.28 million.

Powercor’s preferred option is to replace CME021 22kV feeder ACR at CME in 2019. The use of contingency load transfers and emergency generation will mitigate the risk should the asset fail ahead of its forecast replacement date. Please refer to the System Limitation Report for further information regarding details of the limitation and preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 6.6 MW on CME021 feeder would defer the need for this capital investment by one year.

14.1.3 Robinvale (RVL) zone substation transformer No. 1

The zone substation in Robinvale (**RVL**) is served by a sub-transmission line from Red Cliffs terminal station (**RCTS**) and consists of three 5/6.5 MVA transformers. It supplies the area of Robinvale extending into surrounding areas.

CBRM analysis determined that the No1 transformer has a health index of 6.05 rising to 6.84 in 2023 and is forecast to require replacement in 2021. Retirement of this transformer would require the remaining station load would need to be carried by the two remaining transformers and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No1 transformer retired, Powercor estimates that in 2021 there will be be 10.2 MVA of load at risk and for 1082 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of one of the two remaining transformers at RVL.

To address the anticipated system constraint at RVL zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to install mobile generation at 22kV to RVL feeders;
- Replace No1 Transformer at RVL for an estimated cost of $3.8 million.

Powercor’s preferred option is to replace the No1 Transformer at RVL in 2021. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 3 MW at RVL zone substation would defer the need for this capital investment by one year.

14.1.4 Terang (TRG) zone substation transformer No. 1

The Terang (**TRG**) zone substation is served by two sub-transmission lines from the Warrnambool Zone Substation (**WBL**) and two from Terang Terminal Station (**TGTS**) and is comprised of two 10/13.5MVA transformers operating at 66/22kV. This zone substation supplies the Terang and surrounding areas.

CBRM analysis determined that the No.1 transformer has a health index of 7.12 rising to 8.06 in 2023 and is forecast to require replacement in 2023. Retirement of this transformer would require the remaining station load to be carried by the single remaining transformer and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No1 transformer retired in 2023 and assuming that the No3 transformer has been replaced in 2019 (refer to section 14.1.7), Powercor estimates that in 2024 there will be 20.1 MVA of load at risk and for 8760 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of the single remaining transformer at TRG.

To address the anticipated system constraint at TRG zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Cobden (**COB**) and Camperdown (**CDN**) up to a maximum transfer capacity of 7.2 MVA;
- augment TRG by replacing the No1 10/13.5MVA transformer with a larger 25/33 MVA unit at an estimated cost of $3.8 million.

Powercor's preferred option is to replace the No1 Transformer at TRG in 2023. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 20 MW at TRG zone substation would defer the need for this capital investment by one year.

14.1.5 Terang (TRG) zone substation transformer No.3

The Terang (**TRG**) zone substation is served by two sub-transmission lines from the Warrnambool Zone Substation (**WBL**) and two from Terang Terminal Station (**TGTS**) and is comprised of two 10/13.5MVA transformers operating at 66/22kV. This zone substation supplies the Terang and surrounding areas.

CBRM analysis determined that the No.3 transformer has a health index of 9.17 rising to 10.53 in 2023 and is forecast to require replacement in 2019. Retirement of this transformer would require the remaining station load would need to be carried by the single remaining transformer and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No3 transformer retired, Powercor estimates that in 2020 there will be 20.5 MVA of unserved load above the system normal rating for 134 hours in the year that will be unable to be supplied from the substation. Also in 2020 there will be 1.3 MVA of load at risk and for 8760 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of one of the two remaining transformers at TRG.

To address the anticipated system constraint at TRG zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Cobden (**COB**) and Camperdown (**CDN**) up to a maximum transfer capacity of 7.2 MVA;

- augment TRG by replacing the No3 10/13.5MVA transformer with a larger 25/33 MVA unit at an estimated cost of $2.9 million.

Powercor's preferred option is to replace the No3 Transformer at TRG in 2019. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 20 MW at TRG zone substation would defer the need for this capital investment by one year.

14.1.6 Warrnambool (WBL) zone substation transformer No. 2

The zone substation Warrnambool (**WBL**) is served by two sub-transmission lines from the Terang Zone Substation (**TRG**) and one from Koroit (**KRT**) zone substation and is comprised of one 25/33 MVA transformer and two 10/13.5 MVA transformers operating at 66/22kV. This zone substation supplies the Warrnambool and surrounding areas.

CBRM analysis determined that the No.2 Transformer has a health index of 7.91 rising to 9.02 in 2023 and is forecast to require replacement in 2019. Retirement of this transformer would require the remaining station load to be carried by the two remaining transformers and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No2 transformer retired, Powercor estimates that in 2020 there will be 34.5 MVA of load at risk and for 4309 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of one of the two remaining transformers at WBL.

To address the anticipated system constraint at WBL zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Koroit (KRT) up to a maximum transfer capacity of 12.3 MVA;
- augment capacity by replacing the existing No2 66/22kV 10/13.5 MVA transformer at WBL with a larger 25/33 MVA unit for an estimated cost of $6.3 million.

Powercor's preferred option is to replace the No2 Transformer at WBL in 2019. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 26 MW at WBL zone substation would defer the need for this capital investment by one year.

14.1.7 Warrnambool (WBL) zone substation transformer No. 3

The zone substation Warrnambool (**WBL**) is served by two sub-transmission lines from the Terang Zone Substation (**TRG**) and one from Koroit (**KRT**) zone substation and is comprised of one 25/33 MVA transformer and two 10/13.5 MVA transformers operating at 66/22kV. This zone substation supplies the Warrnambool and surrounding areas.

CBRM analysis determined that the No.2 Transformer has a health index of 6.43 rising to 7.26 in 2023 and is forecast to require replacement in 2022. Retirement of this transformer would require the remaining station load to be carried by the two remaining transformers and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No3 transformer retired, Powercor estimates that in 2023 there will be 37.9 MVA of load at risk and for 8383 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of one of the two remaining transformers at WBL.

To address the anticipated system constraint at WBL zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Koroit (KRT) up to a maximum transfer capacity of 12.3 MVA;
- augment capacity by replacing the existing No3 66/22kV 10/13.5 MVA transformer at WBL with a larger 25/33 MVA unit for an estimated cost of $3.8 million.

Powercor's preferred option is to replace the No3 Transformer at WBL in 2022. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 26 MW at WBL zone substation would defer the need for this capital investment by one year.

14.1.8 Corio (CRO) zone substation 66kV circuit breaker "A" replacement

The zone substation Corio (**CRO**) is served by sub-transmission lines from the Geelong Terminal Station (**GTS**) and customer zone substation Ford Norlane (FDN) and is comprised of two 20/27 MVA transformers operating at 66/22kV. This zone substation supplies Corio and surrounding areas.

CBRM analysis determined that the CB"A" has a health index of 5.61 rising to 7.05 in 2023 and is forecast to require replacement in 2019. Retirement of this circuit breaker would require a protection rearrangement and require the station load to be carried by the remaining transformer for line faults placing customers at risk of extended outages during times of unplanned network contingencies.

To address the anticipated system constraint at CRO zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- Retain switching ability by replacing the existing CRO CB"A" at CRO for an estimated cost of $0.6 million.

Powercor' s preferred option is to replace the CB"A" 2019. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 25 MW at CRO zone substation would defer the need for this capital investment by one year.

14.2 Groups of Assets

This section discusses planned retirements and replacements for groups of assets.

14.2.1 Poles and towers

Powercor intends to replace poles and towers in various locations across the network in each year of the forward planning period. The number of poles and towers replaced each year is determined by condition assessments undertaken on each pole/tower inspected. The forecast number of poles/towers to be replaced in the coming 5 years is generally in line with historic replacements with the addition of a new program to address double staked poles. Powercor has a range of poles in its network, including hardwood, steel and concrete, supporting different voltages of conductor. All towers on the network are steel lattice structures.

Poles and towers are assessed using the RCM methodology. The inspection frequency is based on priority and economic optimisation. This methodology was discussed in the previous chapter. Where the pole or tower is inspected and found to be defective, and a routine maintenance option is not viable to remedy the defect, it is necessary and prudent to replace the pole or tower.

14.2.2 Pole top structures

Pole top structures includes the following assets:

- Wood or steel cross arms are inspected at the same time as the pole using the RCM methodology discussed in the previous section.
- Insulators are generally made of porcelain, are inspected at the same time as the pole using the RCM methodology discussed in the previous section;
- Surge arrestors are attached to the pole and provide an alternate current path for the electricity to ground in the event of a lightning strike. These are generally replaced after they fail; otherwise they are replaced based upon age.

- Other pole top structure equipment include: fuses, dampers, armour rods, spreaders, brackets, etc. These are all inspected at the same time as the pole.
- Fuses in high bushfire risk areas are also being replaced by fault tamers as part of a program.

Powercor intends to replace pole top structures in various locations across its network in each year of the forward planning period. The number of pole top structures replaced each year is determined by condition assessments undertaken on each pole top structure inspected. The forecast number of pole top structures to be replaced in the coming 5 years is in line with the historic replacements.

14.2.3 Switchgear

Switchgear can be classified as overhead or ground-mounted. Switchgear includes the following assets:

- Automatic circuit reclosers (**ACR**) - interrupt fault current and automatically restore supply after a dead time in the event of a transient fault.
- Air-break switches (**ABS**) - use air as an insulating medium to interrupt load current.
- Gas switches - use SF6 gas as an insulating medium to interrupt load current;
- Isolators - use air as an insulating medium to interrupt load current.

Switchgear assets are replaced based on condition, which is monitored through routine maintenance and inspection. When a defect is found and it cannot be rectified through maintenance, a refurbishment or replacement of the asset is prudent.

The replacement need and timing are prioritised through risk and economic assessments. The location and the timing of the asset retirement is only determined when a defect is identified. Powercor intends to replace switchgear assets in each year of the forward planning period which are expected to be in line with historical volumes.

14.2.4 Overhead services

Overhead services, which are required to connect a customer supply point to the network are inspected at the same time as the pole and pole top structures using the same RCM methodology discussed in the previous sections.

Powercor intends to replace overhead services in various locations across its network in each year of the forward planning period. The number of overhead services replaced each year is determined by condition assessments undertaken on each overhead service inspected. The forecast number of overhead services to be replaced in the coming 5 years is expected to increase above the historic replacements due to deteriorated insulation associated with dogbone terminations and also during 2019 a special project aided by AMI meter analysis will be undertaken to detect, assess and replace services where the neutral is suspect as part of a targeted program to address a safety issue.

14.2.5 Overhead conductor

Overhead conductors are an integral part of the distribution system. Overhead conductors may be bare or covered and are made of aluminium, copper and galvanised steel.

Conductor replacements are been based on two methodologies:

- through inspection, asset failures or defect reports; and
- proactively through risk-assessment using health indices.

Powercor plans to replace sections of overhead conductors each year over the forward planning period. The location and timing of conductor replacement will be determined based on condition assessments and risk. The forecast number of sections of overhead conductor to be replaced in the coming 5 years is in line with historic replacements. As data and modelling improves, a better understanding of the location and timing of the conductor replacement at the planning stage of the proactive replacement programme may be available in the future.

14.2.6 Underground cable

Underground sub-transmission cables are performance monitored and condition assessed by a scheduled cyclic testing program. Cables found by the test program to be in unacceptable condition are generally repaired as the issue is normally location specific or the result of damage by third parties. Sections of cable may be replaced from time to time on an unplanned basis as a response to identified defects or damage. No sub-transmission cables are planned for replacement due to condition in the next 5 year period.

HV and LV Underground cables are performance monitored and condition assessed when the cable is exposed for augmentation works or defect repairs. Cables identified in unacceptable condition are prioritised for replacement using an economic assessment of risk associated with the identified defect.

Powercor’s planned volumes for underground cable replacements over the forward planning period are in line with historic volumes.

14.2.7 Other underground assets

Other underground assets include the following:

- Cable-head terminations, which are the termination of an underground cable.
- Pits which are the point where the underground service connects to the customer premises, typically concrete or steel.
- Low-voltage pillars are typically concrete or steel, where low voltage underground cables are terminated.

- Services (underground), which are required to connect a customer supply point (underground pit) to the network, are replaced based on condition when inspected or through defect reports.

Underground assets replacements are prioritised using an assessment of risk associated with the identified defect. The timing of replacement is determined by the risk assessment.

14.2.8 Distribution plant

Powercor plans to replace distribution plant assets each year in the forward planning period. Distribution plant assets include a variety of assets listed below:

- HV Circuit breakers (22kV and 11kV) which are required to interrupt load or fault current are replaced based on the CBRM results, as explained in the previous chapter.
- Distribution substation transformers include indoor, kiosk, ground mounted (compound) or pole mounted types. Transformers are replaced based on condition, as identified through schedule inspections and defect reporting. Replacement prioritisation is determined by conducting risk and economic assessments. Some older kiosk transformers with integral oil RMU's are also being replaced due to safety concerns.
- Pole top capacitors are attached to the network to improve power factor, usually on longer lines. These are replaced based on condition when inspected or through defect reports. Replacement prioritisation is determined by conducting risk and economic assessments.
- Ring Main Units, which are banked switching units that enable switching between three or more underground cables, are replaced based on condition identified by scheduled inspection and defect reports, and then prioritised through risk and economic assessment.
- Earthing cables, which are required as one measure to prevent de-energised assets from becoming energised in the event of insulation breakdown or contact with live assets, are replaced following an inspection and/or condition monitoring.
- Regulators, which adjust voltage levels according to measured network dynamics, are replaced based on condition, with a dedicated program to remove obsolete regulators i.e. regulators that are no longer supported by the manufacturer support and no longer have spares available.
- Combination switches, which are a high voltage switch and fuse combined, are replaced based on age with prioritisation of replacement determined by economic and risk assessment, given that neither the condition nor performance can readily be measured.

The location and the timing of the replacement of distribution plant assets are determined at the time of inspection and detection of defect, or upon failure of the asset.

14.2.9 Zone substation switchyard equipment

Powercor plans to replace zone substation switchyard equipment each year in the forward planning period. Zone substation switchyard equipment assets include a variety of assets listed below:

- Surge arrestors, which are required to protect primary plant from voltage surges, are generally replaced after they fail. They can also be replaced based on age and condition, or opportunistically where other asset replacements take place at the zone substation.
    - As part of our REFCL installation programme, we are planning to replace surge arrestors at Bendigo terminal station (**BETS**), Charlton (**CTN**), Bendigo (**BGO**), Ballarat South (**BAS**), Ballarat North (**BAN**), Geelong (**GL**) Corio (**CRO**), Koroit (**KRT**), Stawell (**STL**), Waurn Ponds (**WPD**), Hamilton (**HTN**), Ararat (**ART**), Merbein (**MBN**) and Terang (**TRG**) before the end of 2023.
- Busses, which allow multiple connections to a single source of supply, are usually replaced as part of the associated zone substation equipment being replaced, e.g. 22kV busses usually form part of modular switchboards and thus will be included as part of switchboard replacements.
- Joints, terminations and connector assets are replaced on inspection, or as part of the replacement of the assets they are connected to.
- Steel structures, which are required to hold energised assets in place, are replaced based on inspection and observed condition.

The location and the timing of the replacement of zone substation assets are determined at the time of inspection or upon identification of defects.

14.2.10 Protection and control room equipment and instrumentation

Protection and control systems are designed to detect the presence of power system faults and/or other abnormal operating conditions and to automatically isolate the faulted network by the opening of appropriate high voltage circuit breakers. Powercor plans to replace protection and control room equipment and instruments each year over the forward planning period. Volumes are expected to be similar to historic volumes. This includes the following assets:

- Protection relays are replaced based on age and/or economic assessment of risk.
    - Powercor's relay replacement program focusses on electro-mechanical and electronic protection relays. The risk profile of these types of relays is forecast to significantly increase as the technology is approaching end of life.
    - The relays will be replaced at the following zone substations over the forward planning period: CHA, MRO, RVL, NHL, OYN, WBE, AL, AC, ART, BMH, BAS, CRO, FNS, COB, CME, EHK, ECA, GL, HTH, HSM, KRT, LV, LVN, MNA, NKA, PLD, STN, SA, STL, WND.

  - As the need to replace the assets will be reassessed on a risk based approach closer to the replacement period, the date of replacement is unknown at time of writing.
- Capacitor Bank controllers (or VAR controllers), are usually run-to-failure and as such it is prudent for Powercor to maintain asset spares.
- Battery banks are replaced based on the results of condition tests.
- Voltage/Current transformers: are usually run-to-failure and as such it is prudent for Powercor to maintain asset spares.

Aside from the proactive replacement of protection relays where the location of the zone substation is known in advance, the timing and the location of the replacement of other assets are determined upon inspection and detection of defects, or upon asset failure.

14.3 Planned asset de-ratings

Powercor has no planned asset deratings in the forward planning period.

14.4 Committed projects

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

Powercor does not have any committed projects to address urgent and unforeseen network issues.

14.5 Timing of proposed asset retirements / replacements and deratings

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

Powercor have made improvements to the risk assessment quantification. These changes primarily involve a refinement of the estimated failure probability for transformers, taking into account failures and replacements, and the inclusion of analysis at a substation level, considering common-cause failure risk for substations with identical assets. As a result, some asset retirements have been deferred, and other future retirements have been brought forward.

Table 14.2 below summarises the change in timing of proposed major network retirements/replacements.

Table 14.2 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2018 DAPR	2017 DAPR
Terang (**TRG**) zone substation Transformer No1	2023	2020
Warrnambool (**WBL**) zone substation Transformer No3	2022	Not included
Corio (**CRO**) zone substation 66kV circuit breaker ‘A’	2019	Not included

The Colac (CLC) and Horsham (HSM) transformer replacements and Ouyen (OYN) 66kV circuit breaker replacements have been deferred as a result of re-prioritisation of asset replacements based on the most recent asset and substation risk analysis.

15 Regulatory tests

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

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

Large network investments are assessed using the RIT-D process. The RIT-D relates to investments where the cost of the most expensive credible option is more than $5 million. The RIT-D has historically been used for large augmentation projects, and was extended to include replacement projects from 18 September 2017.

Transitional arrangements apply for the introduction of the RIT-D for replacement projects where the following projects are excluded:

- replacement projects that have been “committed” to by a distributor on or prior to 30 January 2018; and
- the second tranche of Rapid Earth Fault Current Limiters (**REFCL**s), in so far as they relate to replacement.

The excluded projects are listed in this chapter, as well as published on our website.[8] There is no material impact on connection charges and distribution use of system charges that have been estimated.

15.1 Current regulatory tests

There was a regulatory test commenced by Powercor in 2018 for the REFCL Tranche 3 program.

Powercor has published a determination under clause 5.17.4(c) of the National Electricity Rules that there will not be a non-network option that is a potential credible option, or that forms a significant part of a credible option. The identified need is to comply with the Victorian Government’s requirement that REFCLs will be installed to meet the performance standard specified in the Regulations.

The RIT-D is for installation of REFCL’s at the following zone substations for Tranche three by 1 May 2023 as shown in table 15.1 below.

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8 https://www.powercor.com.au/about-us/electricity-networks/network-planning/network-limitations/

Table 15.1 Current RIT-D projects

Project name	Description	Scheduled completion date
Installation of REFCLs at Hamilton (**HTN**) zone substation	Refurbishment and replacement works at the zone substation and on 22kV high voltage network to allow the operation of a REFCL.	1 May 2023
Installation of REFCLs at Koroit (**KRT**) zone substation		1 May 2023
Installation of REFCLs at Corio (**CRO**) zone substation		1 May 2023
Installation of REFCLs at Waurn Ponds (**WPD**) zone substation		1 May 2023
Installation of REFCLs at Merbein (**MBN**) zone substation		1 May 2023
Installation of REFCLs at Stawell (**STL**) zone substation		1 May 2023
Installation of REFCLs at Geelong (**GL**) zone substation		1 May 2023

There were no credible non-network options found to address the identified need, which is to comply with the Regulations. Also Powercor has not identified any other network options that would comply with the regulations.

15.2 Future regulatory investment tests

The following projects are planned for future Regulatory Tests in the period 2019 through to 2023.

Table 15.2 Future RIT-D projects

Project name	Description	Scheduled completion date
Bacchus Marsh zone substation	*Install the third transformer	1 May 2021
Torquay zone substation	Establish new Torquay zone substation and offload WPD	1 May 2020
Bannockburn zone substation	Establish new Bannockburn zone substation as a REFCL cost optimisation	1 May 2021
Tarneit zone substation	Establish new Tarneit zone substation and offload WBE, LV and TNA	1 May 2022

*Note the BMH 10/13 MVA number one transformer is due for replacement outside the DAPR forecast period, we are considering a joint augmentation for the third transformer project in 2023 (subject to economic benefit analysis).

15.3 Excluded projects

The table below provides a list of the excluded projects from the RIT-D under the transitional arrangements relating to the extension of the RIT-D to replacement projects.

Table 15.3 Excluded RIT-D projects

Project name	Description	Scheduled completion date
Installation of REFCLs at Ballarat North (**BAN**) zone substation	Refurbishment and replacement works at the zone substation and on 22kV high voltage network to allow the operation of a REFCL. Clause 11.99.6 of the NER exempts replacement projects from the RIT-D relating to the Powercor program to install REFCLs.	1 May 2021
Installation of REFCLs at Ballarat South (**BAS**) zone substation		1 May 2021
Installation of REFCLs at Bendigo Terminal Station (**BETS**)		1 May 2021
Installation of REFCLs at Bendigo (**BGO**) zone		1 May 2021

substation		
Installation of REFCLs at Charlton (**CTN**) zone substation)		1 May 2021
Installation of REFCLs at Ararat (**ART**) zone substation		1 May 2021
Installation of REFCLs at Terang (**TRG**) zone substation		1 May 2021

16 Network Performance

This section sets out Powercor's performance against its targets for reliability and quality of supply, and its plans to improve performance over the forward planning period.

16.1 Reliability measures and performance

Powercor is subject to a range of reliability measures and standards.

The key reliability of supply metrics to which Powercor is incentivised under the Service Target Performance Incentive Scheme (**STPIS**) are:

- System average interruption duration index (**SAIDI**): Unplanned SAIDI calculates the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. It does not include momentary interruptions that are one minute or less;
- System average interruption frequency index (**SAIFI**): Unplanned SAIFI calculates the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. It does not include momentary interruptions that are one minute or less. SAIFI is expressed per 0.001 interruptions; and
- Momentary average interruption frequency index (**MAIFI**): calculates the total number of momentary interruptions divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate).

The reliability of supply parameters are segmented into urban, rural short and rural feeder types.

The table below shows the reliability service targets set by the AER for Powercor in its Distribution Determination in May 2016.[9] Powercor reported to the AER its 2017 performance against those targets in the 2017 calendar year in its Regulatory Information Notice (**RIN**), and these figures are included in the table. In addition, Powercor has also forecast its outturn performance for the 2018 calendar year, based on actual performance for the period from 1 January 2017 to 31 August 2018, and then projected forward taking into account seasonal factors.

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[9] AER, Powercor Australia Limited, Distribution determination 2016–2020, Final, May 2016.

Table 16.1 Reliability targets and performance

Feeder	Parameter	AER target (2016-20)	2017 performance	2018 forecast performance (at 31 August 2018)
Urban	SAIDI	83.111	56.14	70.019
	SAIFI	1.047	0.713	0.848
	MAIFI	1.184	1.186	1.236
Rural Short	SAIDI	113.191	99.395	110.062
	SAIFI	1.357	1.156	1.229
	MAIFI	2.998	2.162	2.752
Rural Long	SAIDI	273.091	167.961	306.431
	SAIFI	2.369	1.666	2.537
	MAIFI	5.401	4.381	4.930

In 2017, Powercor achieved its targets for all parameters except unplanned MAIFI for Urban lines.

In 2018, Powercor is forecast to achieve its targets for all parameters except the unplanned MAIFI for Urban lines, SAIDI, SAIFI and MAIFI for Rural Long lines

Actual network performance is also often influenced by external events such as storms, heat, flood, or third party damage which may be outside of Powercor's control. The influence of these factors on network performance can also vary significantly from one year to the next.

16.1.1 Corrective reliability action undertaken or planned

Actual network reliability performance is the result of many factors and reflects the outcomes of numerous programs and practices right across the network. To achieve long term and sustainable reliability improvements, Powercor continues to refine and target existing asset management programs as well as reliability specific works.

The processes and actions which Powercor undertakes to sustain reliability include:

- undertaking the various routine asset management programs, including:
  - inspection of nearly 180,000 poles and pole tops;
  - maintenance and replacement programs for overhead and underground lines, primary plant (for example, Powercor replaced a number of circuit breakers, 66kV transformer bushings and current transformers) and secondary systems (such as replacement of ageing protection relays at zone substations);

    - Implementation of enhanced monitoring and replacement program of capacitive voltage transformers in zone subs to provide improved safety and reliability.
- deployment of portable auxiliary cooling fans at several substations to assist in cooling heavily loaded transformers;
- targeted installation of smart technologies to improve network monitoring, control and restoration of supply including intelligent circuit reclosers, gas switches and line fault indicators at strategic locations;
- targeted reduction of the exposure to faults on the distribution network by using:
    - thermography programs to detect over-heated connections;
    - Partial Discharge detection program for indoor 22kV switchgear in Zone subs. including several continuous on line monitoring systems
    - vegetation management programs to improve line clearances;
    - targeted lines for bark inspections such as in the Otways and Macedon ranges;
    - animal and bird mitigation measures to reduce the risk of 'flash-overs';
    - targeted insulator washing and pole-top fire mitigation to reduce the risk of pole fires; and
    - dehydration of power transformer.
- use of innovative solutions such as auxiliary power generation or by-pass cables to maintain supply where practicable;
- trialling of new technologies such as fuse savers to assess and evaluate any improvement in the reliability outcomes
- conduct fault investigations of significant outages and plant failures to understand the root cause, in order to prevent re-occurrences;
- undertake asset failure trend analysis and outage cause analysis to identify any emerging asset management issues and to mitigate those through enhancing the related asset management plans, maintenance policies or technical standards.

Evaluation of the 2018 reliability improvement initiatives should be considered in the context of the longer term goals stipulated above and the volatility caused by uncontrollable events such as severe storms and the effect of third party events.

16.2 Quality of supply measures and standards

The main quality of supply measures that Powercor control are:

- voltage; and
- harmonics.

16.2.1 Voltage

Voltage requirements are governed by the Electricity Distribution Code and the NER.

The NER essentially requires that Powercor adheres to the 61000.3 series of Australian and New Zealand Standards.

In addition, the Electricity Distribution Code requires that Powercor must maintain nominal voltage levels at the point of supply to the customer's electrical installation in accordance with the Electricity Safety (Network Assets) Regulations 1999 or, if these regulations do not apply to the distributor, at one of the following standard nominal voltages:

a) 230V;
b) 400V;
c) 460V;
d) 6.6kV;
e) 11kV;
f) 22kV; or
g) 66kV.

The Electricity Safety (Network Assets) Regulations 1999 were revoked on 8 December 2009 by regulation 104 (Schedule 1) of the Electricity Safety (Installations) Regulations 2009. Therefore the standard nominal voltages specified in the Code apply.

Variations from the standard nominal voltages listed above are permitted to occur in accordance with the following table with the exception of REFCL areas:

Table 16.2 Permissible voltage variations

<table>
<tr><th colspan="5">Standard nominal voltage variations</th></tr>
<tr><th rowspan="2">Voltage Level in kV</th><th colspan="3">Voltage Range for Time Periods</th><th rowspan="2">Impulse Voltage</th></tr>
<tr><th>Steady State</th><th>Less than 1 minute</th><th>Less than 10 seconds</th></tr>
<tr><td>< 1.0</td><td>+10%
-6%</td><td>+14%
-10%</td><td>Phase to Earth +50% -100%
Phase to Phase +20% -100%</td><td>6kV peak</td></tr>
<tr><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>60kV peak</td></tr>
<tr><td>11</td><td>95kV peak</td></tr>
<tr><td>22</td><td>150kV peak</td></tr>
<tr><td>66</td><td>±10%</td><td>±15%</td><td>Phase to Earth +50% -100%
Phase to Phase +20% -100%</td><td>325kV peak</td></tr>
</table>

* In REFCL areas while the REFCL is in operation, the 22kV phase to earth voltages may equal the phase to phase voltage for periods greater than 1 minute.

As required by the Electricity Distribution Code, Powercor uses best endeavours to minimise the frequency of voltage variations listed above for periods of less than one minute.

Powercor is able to measure voltage variations at zone substations, as many have power quality meters installed. This enables Powercor to address any systemic voltage issues. The table below provides a forecast of the number of instances of voltage variations at Powercor zone substations in the 2018 calendar year, based on actual instances to the end of September 2018, although many of these instances would have occurred from abnormalities or transients in the system.

Table 16.3 Forecast zone substation voltage variations in 2018

Voltage variations	Forecast number of occurrences
Steady state (zone substation)	1249
One minute (zone substation)	86
10 seconds (zone substation) Min<0.7	602
10 seconds (zone substation) Min<0.8	273
10 seconds (zone substation) Min<0.9	1332

Powercor responds quickly to investigate and resolve voltage issues. The issues may be identified through the system monitoring undertaken by Powercor or as a result of customer complaints. The Supply Quality team may subsequently carry out projects to address concerns relating to voltages.

The solutions that Powercor may adopt include:

- installation of voltage regulators which will bring voltage levels at customer connection points within the applicable requirement;
- the upgrade of existing distribution transformers, or the installation of new distribution transformers, to increase the ability of the network to meet customers' demand for electricity and improve voltage performance;
- replacing small sized conductors with large conductors in order to improve the voltage performance; and
- installation of additional reactive power compensation, such as capacitor banks, to improve voltage performance.

Powercor may also identify issues with voltage following applications from potential "disturbing load" customers, such as an embedded generator or a large industrial customer, to connect to the network. System studies are carried out on a case-by-case basis to identify voltage or harmonic constraints relating to proposals, with recommendations for corrective action provided to the party seeking to connect.

16.2.2 Harmonics

Voltage harmonic requirements are governed by the Electricity Distribution Code and the NER.

The NER essentially requires that Powercor adheres to the 61000.3 series of Australian and New Zealand Standards.

In addition, Powercor is required under the Electricity Distribution Code to ensure that the voltage harmonic levels at the point of common coupling (for example, the service pole nearest to a residential premise), with the levels specified in the following table:

Table 16.4 Voltage harmonic distortion limits

Voltage at point of common coupling	Total harmonic distortion	Individual voltage harmonics	
		Odd	Even
< 1kV	5%	4%	2%
> 1kV and ≤ 66kV	3%	2%	1%

Powercor responds quickly to investigate and resolve voltage issues. The issues may be identified through the power quality meters that Powercor has installed to monitor the quality of supply or as a result of customer complaints. The Supply Quality team may subsequently carry out projects to address concerns relating to voltages.

Where the voltage harmonics are measured to be consistently outside of the required levels, Powercor will investigate and resolve the issue. The solutions that Powercor may adopt include:

- alter the switching sequencing of the network equipment to reduce the voltage harmonic distortions;
- replacing small sized conductors with large conductors in order to improve the voltage harmonic performances ; and
- installation of harmonic filtering equipment to improve voltage harmonic performance.

Powercor may also identify issues with harmonics following applications from potential “disturbing load” customers, such as an embedded generator or a large industrial customer, to connect to the network. System studies are carried out on a case-by-case basis to identify voltage or harmonic constraints relating to proposals, with recommendations for corrective action provided to the party seeking to connect.

17 Embedded generation and demand management

This section sets out information on embedded generation as well as demand management activities during 2018 and over the forward planning period.

17.1 Embedded generation connections

The table below provides a quantitative summary of the connection enquires under chapter 5 of the NER and applications to connect EG units received in 2018.

Table 17.1 Summary of embedded generation connections

Description	Quantity (> 5MW)
Connection enquires under 5.3A.5	85
Applications to connect received under 5.3A.9	14
The average time taken to complete application to connect	30

Key issues to connect embedded generators to Powercor's network include:

- fault levels;
- thermal capacity;
- voltage fluctuations under various contingency scenarios;
- harmonics and flicker issues for large-scale generator as a result of limitations of power quality allocations at terminal stations and consequential allocations to wind and solar farms leading to tight design criteria.

17.2 Non-network options and actions

Powercor actively seeks opportunities to promote non-network alternatives for both general and project-specific purposes. For 2018, the following details some of Powercor activities:

- Powercor has communicated with providers of demand management and embedded generation services to explore potential non-network options;
- Powercor is presently involved with the development of a number of embedded generation projects at various stages. Powercor has recently commissioned 234.4 MW of embedded generation over three installations and there are 98 projects totalling 1715 MW in development;
- Powercor monitors industry developments and engages with providers of demand management and smart network technologies;
- For the summer of 2018/19, Powercor can bid into the Reliability and Emergency Reserve Trader Market (**RERT**) using their Smart Meter Voltage Management

(**SMVM**) scheme when called upon by AEMO. SMVM is an improvement upon the current method of lowering the voltage set points at the zone substation, which in turn lowers the amount of Power (MW) supplied to the network and reduces demand on peak days; and

- In the second half of 2018 Powercor has initiated the 'Energy Partner' project to reduce demand caused by Air-conditioning load during peak periods on specific feeders in the Bellarine Peninsula. Powercor hopes to engage and educate the local community on Demand Response in addition to better understanding market drivers.

Over the forward planning period, Powercor intends to continue to consider demand side options via its Demand Side Engagement Strategy.

17.3 Demand side engagement strategy and register

Powercor updated the published Demand Side Engagement Strategy in July 2016. The strategy is designed to assist non-network providers in understanding Powercor's framework and processes for assessing demand management options. It also details the consultation process with non-network providers. Further information regarding the strategy and processes is available from:

https://www.powercor.com.au/our-services/demand-management/

https://www.powercor.com.au/media/3013/demand-side-engagement-strategy-v20_final.pdf

Powercor have also published their Demand Side Engagement Interested Parties Register. The register was established in mid-2013. It currently allows interested parties to provide contact details and email address data, but will be enhanced in the near future to become an online form portal. To register as a Demand Management Interested Party, please email the following:

- DMInterestedParties@powercor.com.au

In 2018, no formal submissions from non-network providers were received.

18 Information Technology and communication systems

This section discusses the investments we have undertaken in 2018, or plan to undertake over the forward planning period 2019-2023, relating to information technology (**IT**) and communications systems.

18.1 Security Program

Our IT security program continues to refine and update our response to the ever-changing risk landscape that is unique to digitalised utility networks. Our ongoing program of works introduces increasingly sophisticated processes and systems that align with our commitment to proactively identify security threats and reduce information security vulnerabilities.

In 2018 we built on work in 2017 in developing a security program of work as well as introducing a number of changes identified as essential by the Australian Signals Directorate (**ASD**) and similar frameworks. These changes address targeted cyber intrusions (e.g. executed by advanced persistent threats such as foreign intelligence services), ransomware and external adversaries with destructive intent, malicious insiders, business email compromise and industrial control systems.

During the forward planning period we will continue to invest in protecting our network and customer information from increasingly sophisticated and persistent cyber threats. We will continue to co-ordinate security initiatives in line with industry standards such as National Energy Reliability Corporation Critical Infrastructure Protection (**NERC CIP**) and ASD recommendations to introduce additional protection to our systems. A key part of the program is to provide effective security between our Operational Technology and IT systems and enhancing security monitoring.

Furthermore, we will undertake IT security initiatives, through our best practice program, focusing on the capabilities of identify, detect, monitor, protect and govern. This program seeks to maintain our current capability and proactively look forward to new and emerging threat protection.

18.2 Currency

We routinely undertake system currency upgrades across the IT landscape in line with vendor software release life cycles and support agreements. These refresh cycles are necessary to ensure system performance and reliability are maintained and that the functional and technical aspects of our systems remain up-to-date.

In 2018 we completed a number of activities including to:

- enhance the Fault Detection Isolation and Restoration system (FDIR), to ensure network faults remain visible and actionable in real time, allowing us to reduce and averter outages;

- establish an Electricity Distribution Network Access Register (EDNAR), to ensure outage systems and customer outage notifications are unified and operate seamlessly;
- implement statutory changes to SAP HR Payroll data (annual obligation);
- establish a Data Platform to manage critical Network Testing and Inspection Results;
- update the Market Systems suite to meet ‘Power of Choice’ obligations.

During the forward planning period, we will continue to maintain the currency of our systems so that we can continue to provide fully supported systems that underpin the operation of our network and core business activities, including Billing, the Enterprise Service Bus, Meter Data, People Management, Reporting & Analytics Data, Workforce Mobility, Finance and Planned Notifications functionality. Other key systems due for life cycle replacement include commencing an upgrade to the SAP system that was originally installed in 1996.

18.3 Compliance

We are focused on ensuring that, as regulated businesses, our IT systems support all regulatory, statutory, market and legal requirements for operating in the National Electricity Market (**NEM**). This is achieved via investment in systems, data, processes and analytics to provide the functionality and reporting capability to efficiently comply with statutory and regulatory obligations.

In 2018, we re-configured the meter data management system and associated market transaction suite. This was done to facilitate the ‘Power of Choice’ program mandated by the Australian Energy Market Commission (**AEMC**) through changes to the National Electricity Rules (**rules**). The Power of Choice program seeks to provide consumers with more opportunities to make informed choices about electricity products and services.

Other initiatives involve making changes to system and data controls to ensure customer, employee and asset data is hosted in Australia and ensuring systems and processes comply with strengthened obligations for life support customers. Changes to ensure compliance with AMI estimated data and change request objection requirements were also undertaken.

Enterprise Management enhancements were also implemented to support compliance and regulatory obligations for Finance, Payroll and Regulation reporting.

We are also implementing 5 minute settlement, under which the settlement period for the electricity spot price is altered from 30 minutes to 5 minutes. The first stage was met with the provisioning of advanced interval meters capable of recoding 5 minute data from December 2018.

To continue to comply with statutory and regulatory obligations during the forward planning period, we will continue to implement 5 minute settlement. Under this project we will equip our systems to manage significant increases in data. The scope of this project includes enhancing storage to handle significantly more data, changes to system architecture (e.g. Market Transaction System (**MTS**), Enterprise Edition (**IEE**), CIS/OV, Utility IQ (UIQ), Salesforce, SAP) as well as business and operational processes (e.g. billing, contract centres, reporting, network, AMI Operations and network analytics).

Compliance will also be maintained through automation of changes to Distribution Loss Factor (**DLF**) and Transmission Node Identity (**TNI**) values for all connection points on our systems.

Compliance obligations will also be met through enhancements to our Vegetation Management system and strengthening of our Technology Security systems.

18.4 Infrastructure

We have an ever-growing need to store and recall data and information and to support applications, processes and functions within our IT systems.

To support this, IT infrastructure must be refreshed to meet technical currency requirements and pro-actively manage maintenance of the IT infrastructure to meet service level requirements.

In 2018, we undertook technical refreshes, server hardening, firmware updates, capacity uplifts and upgrading of firewalls and IT environments in accordance with our IT infrastructure life cycles.

We are also implementing a strategy to move some key and supporting applications to the cloud. This will provide us with greater ability to scale our IT capabilities and reduce reliance on infrastructure in future.

During the forward planning period, we will focus on upgrading our underlying infrastructure that supports the IT environments to ensure ongoing capacity, performance and availability to ensure continuity of service and a comprehensive business continuity capability.

18.5 Customer Enablement

The customer engagement stream incorporates our response to ongoing changes and demands from our customers for greater access and greater choice in electricity services.

In 2018, we delivered:

- changes mandated as part of the Metering Contestability initiative
- improvements to data management, data quality resulting in better compliance;
- the ability for greater volumes of customer transfers between retailers;

- demand response initiatives that help to keep the grid stable in peak usage periods;
- improvements/efficiencies to our connections process(s);
- improvements to our online customer experience and making it easier to find information;
- provision of more consistent and accurate outage information to customers.

In the forward planning we will continue to proactively respond to anticipated industry and regulatory changes, including those that are designed to encourage greater demand side participation, a more flexible network to enable customers to export solar, as well as allowing customer's greater access to their data

We will continue to perform the necessary upgrades to our billing system, to provide continued assurance of accurate and timely billing for our customers. Improvements to our corporate website will also ensure our customers can find the information they need, when they need it.

18.6 Other communication system investments

To facilitate and maintain the protection and control of the network, we have continued to invest in Supervisory Control and Data Acquisition (**SCADA**) and associated network communication and control equipment. This is used to monitor and control the distribution network assets, including zone substations and feeders.

In 2018, we have continued to invest in SCADA, in particular:

- working to reduce dependency on copper supervisory cables with the upgrade of street light control to AMI Network control and transitioning control and protection on selected services;
- modernising the communications network and transitioning protection and SCADA services from mostly aerial copper supervisory cables to optical fibre and private IP/Ethernet network infrastructure;
- initiating replacement programs for aged remote telemetry units (**RTU**s) and associated Local/ Metropolitan Area Networks (**LAN**/ **MAN**) assets in zone substations to continue reliable monitoring of primary and second equipment;
- expanded and selectively modernised digital radio sites to support control and protection schemes for new renewable energy sites;
- selectively trialled an 4G Upgrade program for ACR Pole Top Controller to improve wireless communications reliability supporting Fault Detection, Isolation and Restoration (FDIR) schemes.

Over the forward planning period, our investment in SCADA will continue to increase, consistent with the growth and complexity of the network. Our SCADA expenditure will continue to modernise the communications network and ensuring adequate capability and capacity by installing larger systems.

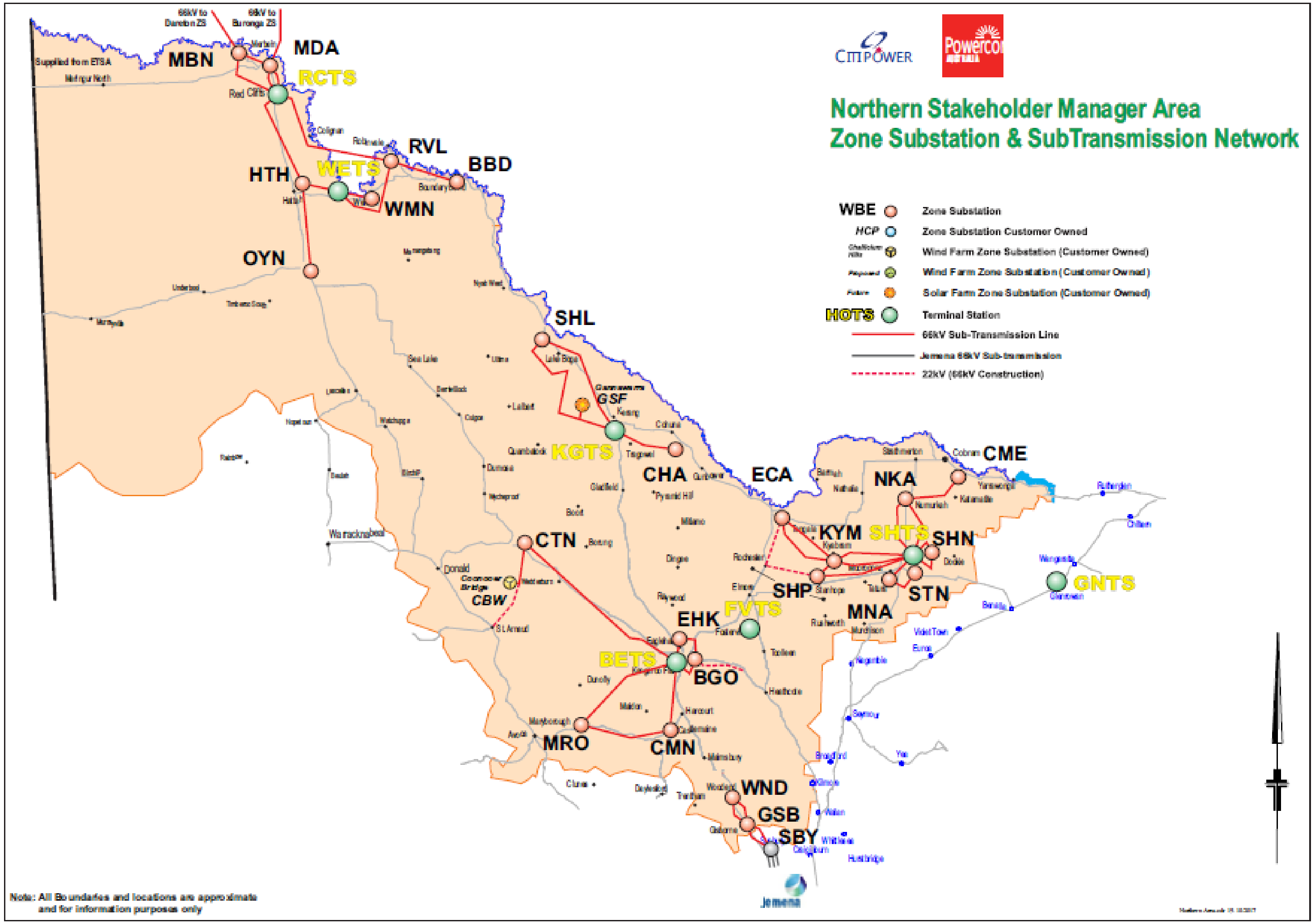
In addition, we will continue to replace old communications systems with newer up-to-date systems. In some cases, this will be to address technical obsolescence where the manufacturer no longer supports the equipment, which we are no longer able to upgrade and there is a reduced pool of skilled workers able to maintain the system.

We will also modernise systems that rely on communications systems. For example, as Telstra is intending to switch off its 3G network, we will upgrade remote communications devices using the 3G network, such as Automatic Circuit Reclosers (**ACR**s) and switches, to 4G and 5G.

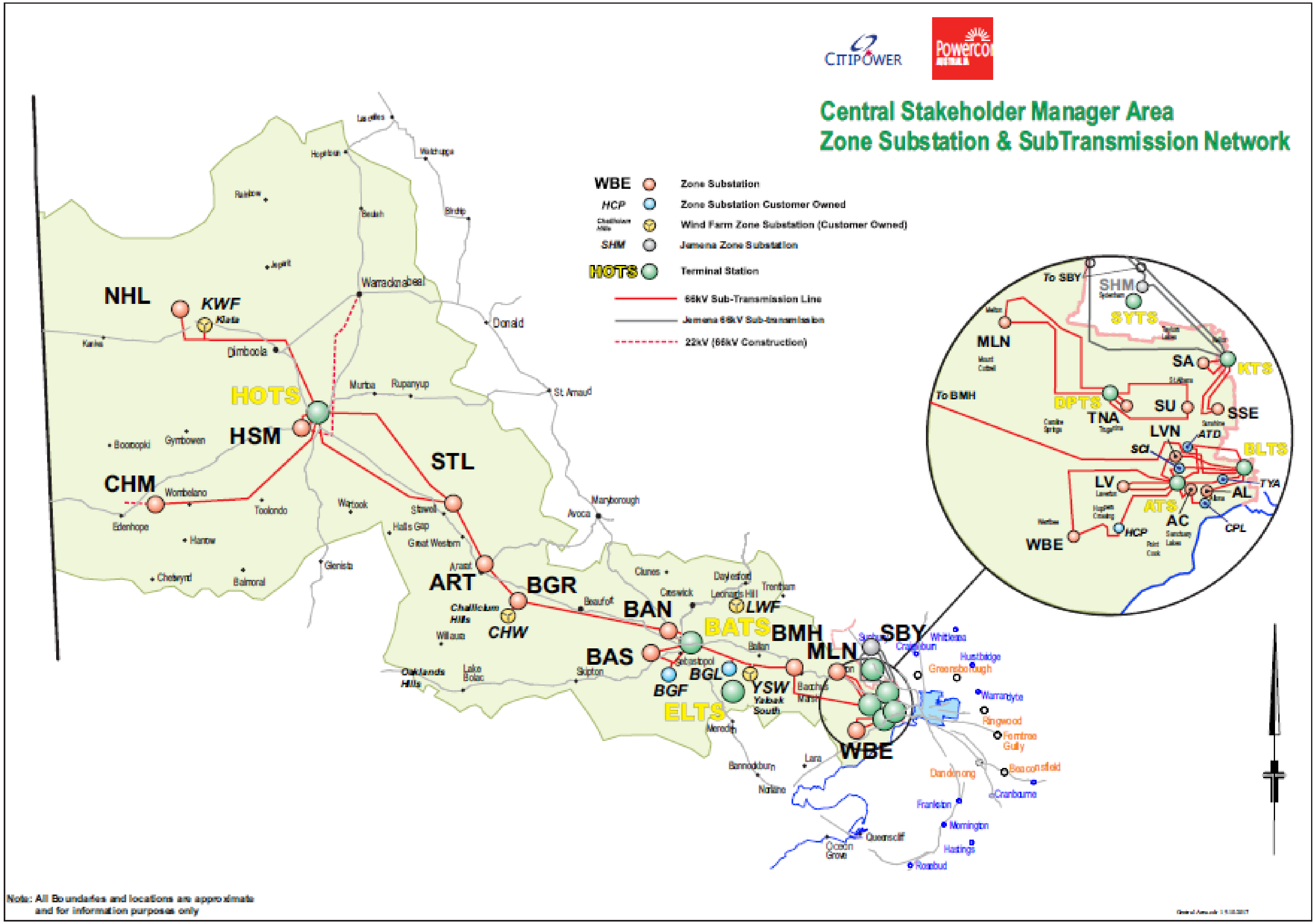
Furthermore, we will utilise new technologies, where appropriate and if it aligns with our strategy, such as the Internet of Things (**IoT**), and continue to leverage existing capabilities and AMI smart meter functionality.

Appendix A Maps

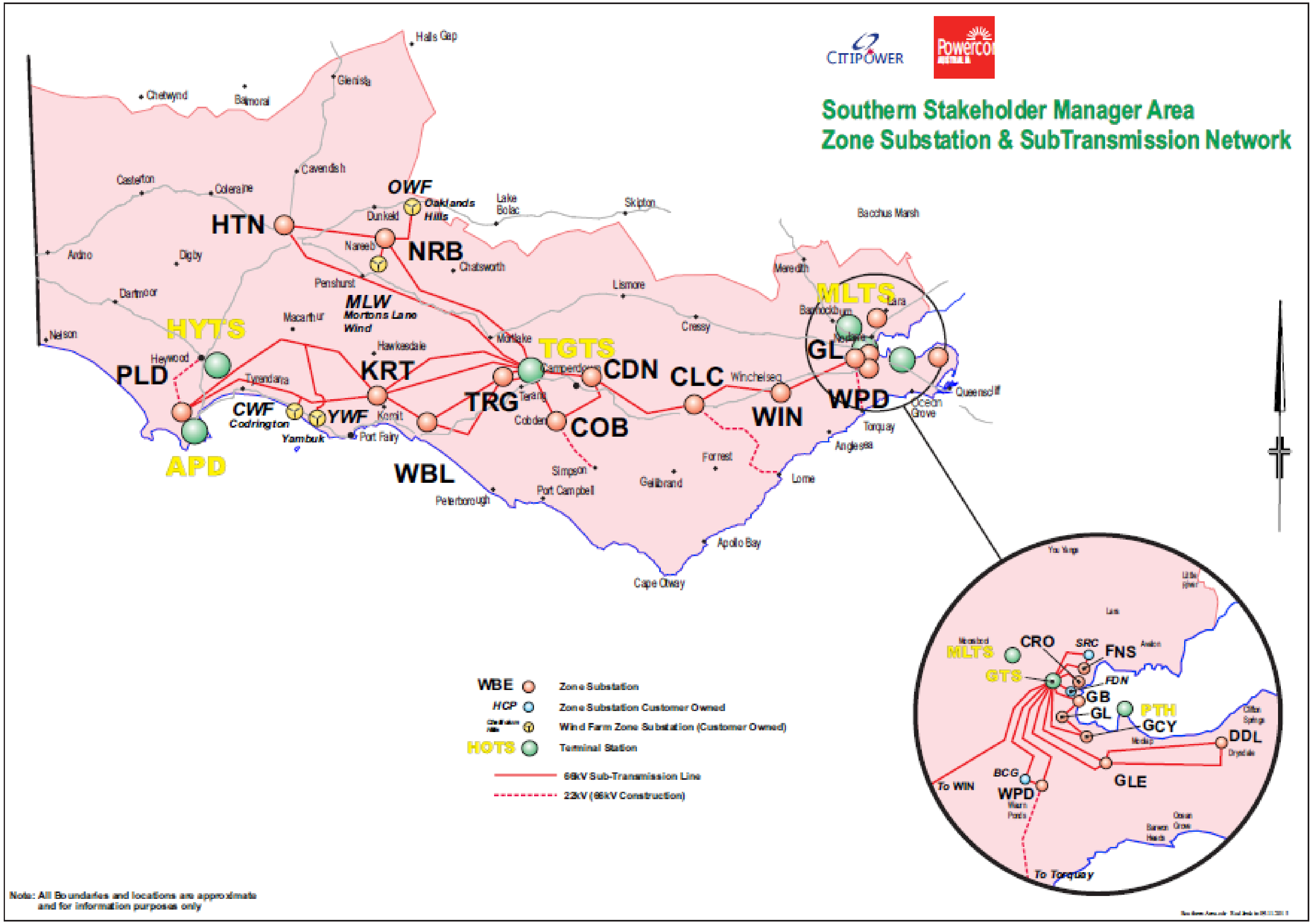
A.1. Northern area zone substations and sub-transmission lines



A.2. Central area zone substations and sub-transmission lines

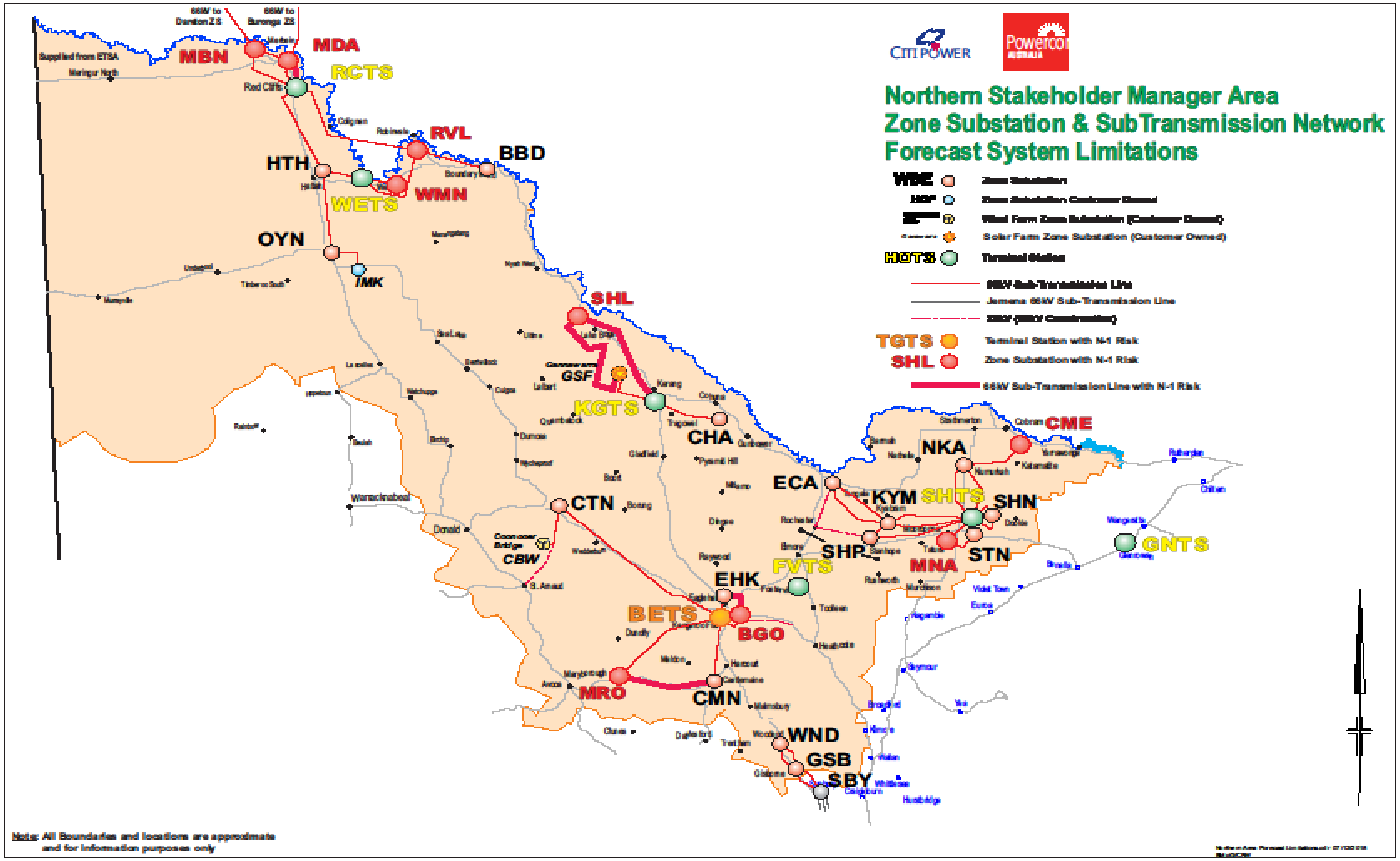


A.3. Southern area zone substations and sub-transmission lines

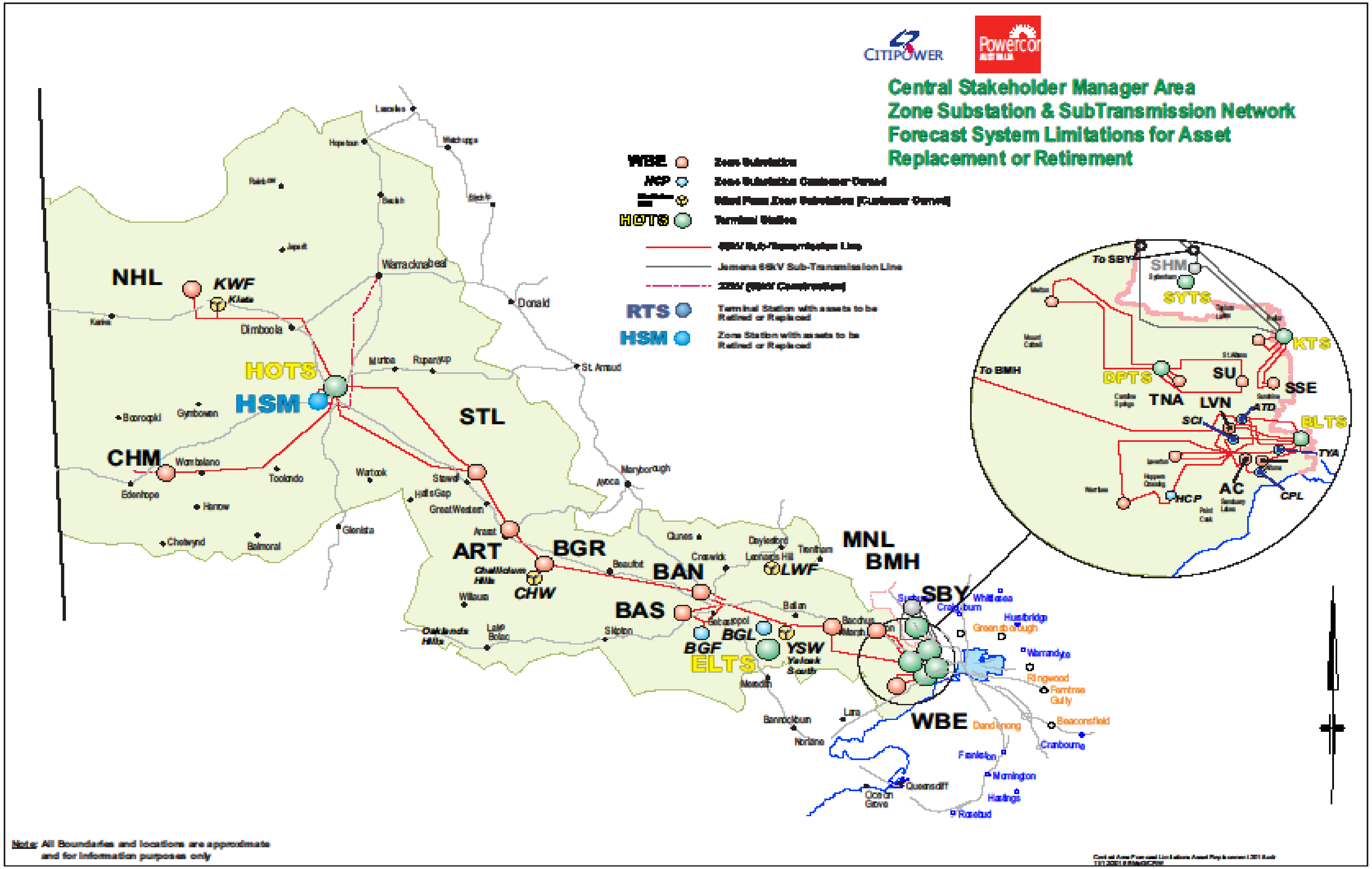


Appendix B Maps with forecast system limitations and assets to be retired or replaced

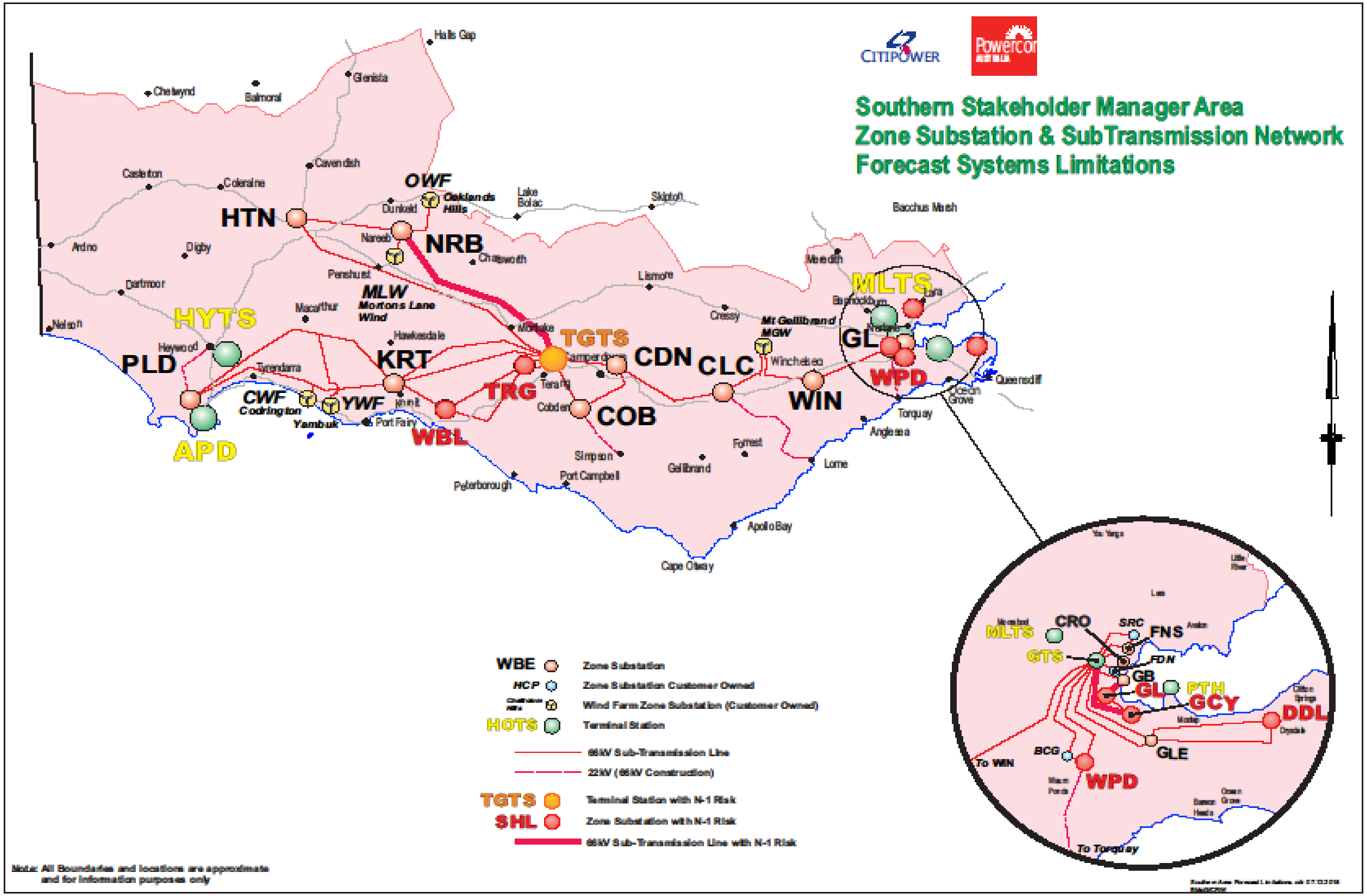
B.1. Northern area map with forecast system limitations



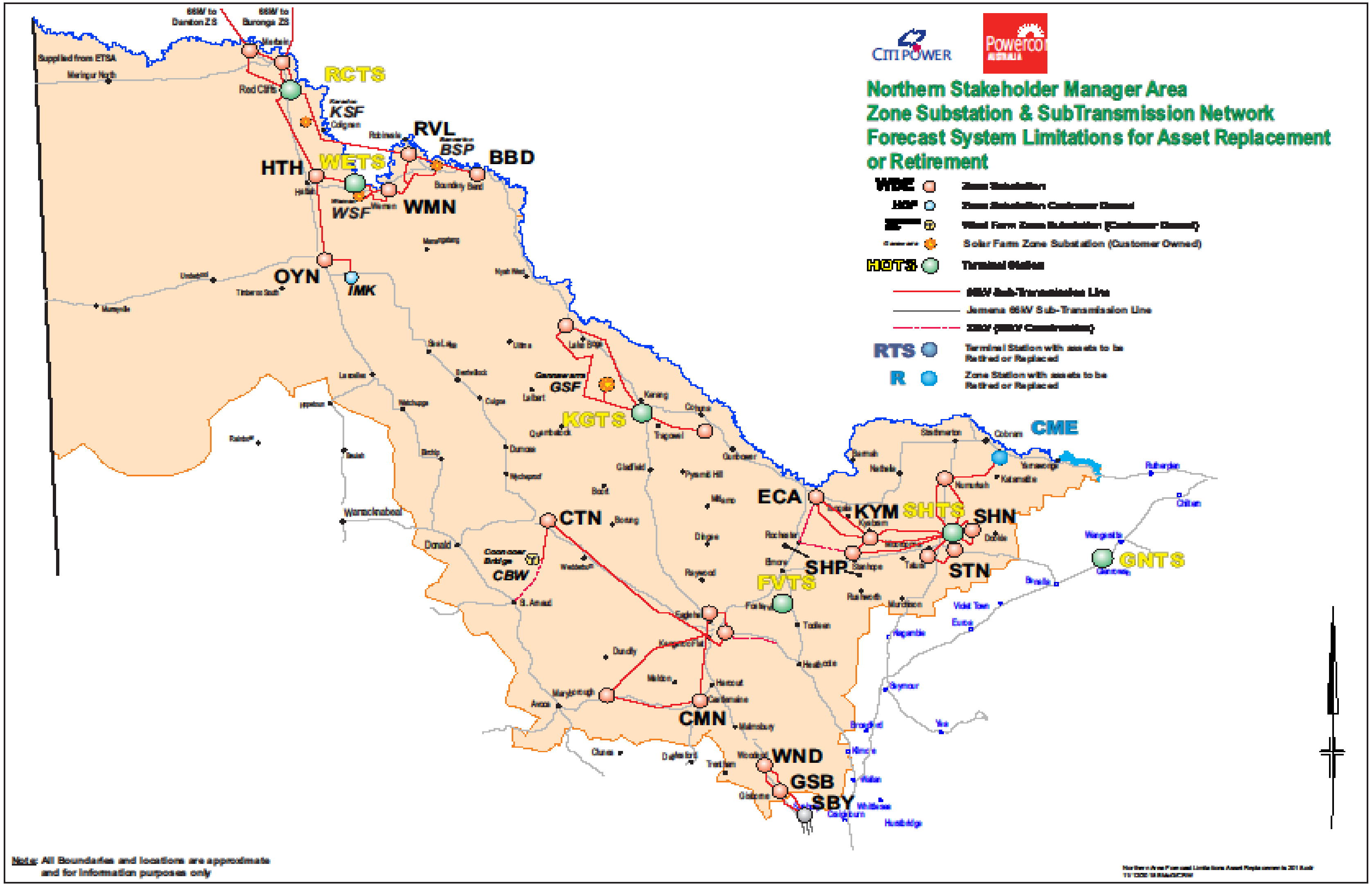
B.2. Central area map with forecast system limitations



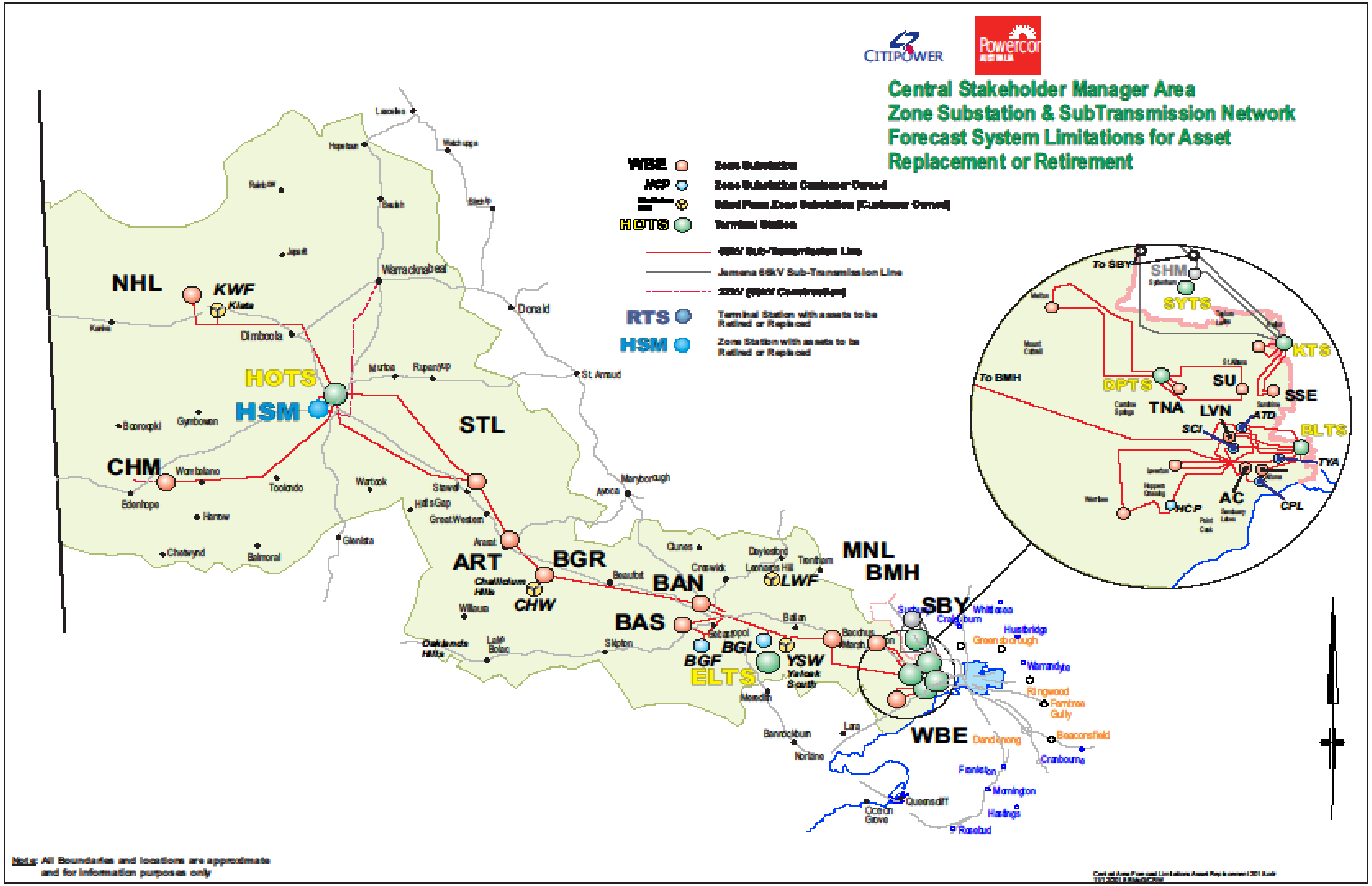
B.3. Southern area map with forecast system limitations



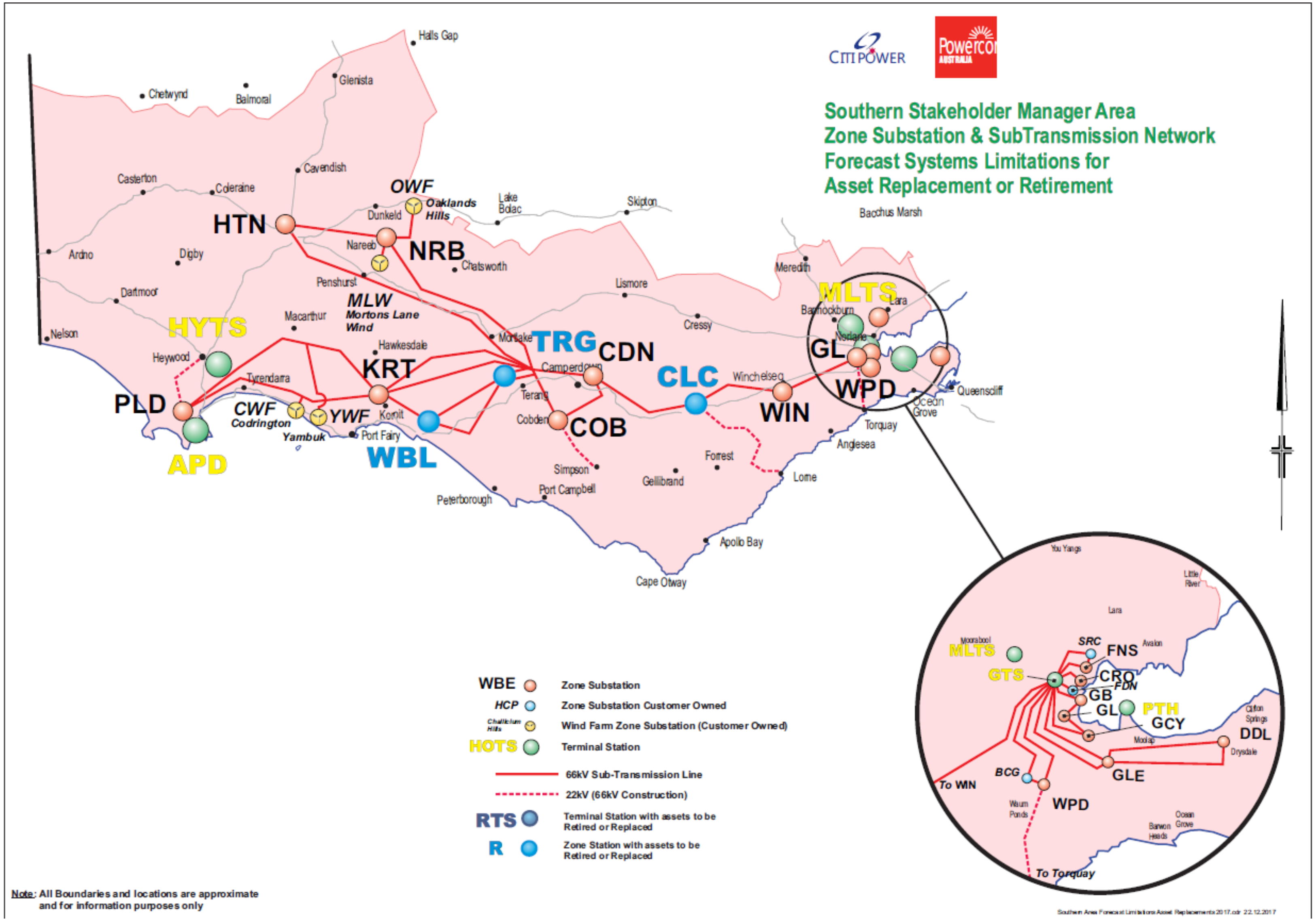
B.4. Northern area map with assets to be retired or replaced



B.5. Central area map with assets to be retired or replaced



B.6. Southern area map with assets to be retired or replaced



Appendix C Glossary and abbreviations

C.1. Glossary

Common Term	Description
kV	kilo Volt
Amps	Ampere
MW	Mega Watt
MWh	Mega Watt hour
MVA	mega volt ampere
Firm Rating	The cyclic station output capability with an outage of one transformer. Also known as the N-1 Cyclic Rating.
N Cyclic Rating	The station output capacity with all transformers in service. Cyclic ratings assume that the load follows a daily pattern and are calculated using load curves appropriate to the season. Cyclic ratings also take into consideration the thermal inertia of the plant.
N-1 Cyclic Rating	The cyclic station output capability with an outage of one transformer.
Capacity of Line (Amps)	The line current rating which takes into consideration the type of line, conductor materials, allowable insulation temperature, effect of adjacent lines, allowable temperature rise and ambient conditions. It should be noted that Powercor operates many types of underground cables in its sub-transmission system. The different types of underground cables have varying operating parameters that in turn define their ratings.
MVA above either WCR or SCR	The amount of demand forecast to exceed the Winter Cyclic Rating or the Summer Cyclic Rating.
% Above Capacity	The percentage by which the forecast maximum demand exceeds the N-1 cyclic rating.
Energy at risk	The amount of energy that would not be supplied if a major outage of a transformer or sub-transmission line occurs at the station or sub-transmission loop in that particular year, and no other mitigation action is taken.
Annual hours per year at risk	The number of hours in a year during which the 50th percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.

C.2. Zone substation abbreviations

Abbreviation	Powercor Zone Substation	Abbreviation	Powercor Zone Substation
AC	Altona Chemicals	**KRT**	Koroit
AL	Altona	**KYM**	Kyabram
ART	Ararat	**LV**	Laverton
BAN	Ballarat North	**LVN**	Laverton North
BAS	Ballarat South	**MBN**	Merbein
BBD	Boundary Bend	**MDA**	Mildura
BGO	Bendigo	**MLN**	Melton
BMH	Bacchus Marsh	**MNA**	Mooroopna
CDN	Camperdown	**MRO**	Maryborough
CHA	Cohuna	**NHL**	Nhill
CHM	Charam	**NKA**	Numurkah
CLC	Colac	**OYN**	Ouyen
CME	Cobram East	**PLD**	Portland
CMN	Castlemaine	**RVL**	Robinvale
COB	Cobden	**SA**	St Albans
CRO	Corio	**SHL**	Swan Hill
CTN	Charlton	**SHN**	Shepparton North
DDL	Drysdale	**SHP**	Stanhope
DLF	Docklands	**SSE**	Sunshine East
ECA	Echuca	**STL**	Stawell
EHK	Eaglehawk	**STN**	Shepparton
FNS	Ford North Shore	**SU**	Sunshine
GB	Geelong B	**TRG**	Terang
GCY	Geelong City	**WBE**	Werribee
GL	Geelong	**WBL**	Warrnambool
GLE	Geelong East	**WIN**	Winchelsea
GSB	Gisborne	**WMN**	Wemen
HSM	Horsham	**WND**	Woodend
HTN	Hamilton	**WPD**	Waurn Ponds

C.3. Terminal station abbreviations:

Abbreviation	terminal station (AusNet Services Asset)	Abbreviation	terminal station (AusNet Services Asset)
ATS	Altona	**HOTS**	Horsham
BATS	Ballarat	**KGTS**	Kerang
BETS	Bendigo	**KTS**	Keilor
BLTS	Brooklyn	**RCTS**	Red Cliffs
DPTS	Deer Park (TransGrid)	**SHTS**	Shepparton
FBTS	Fishermans Bend	**TGTS**	Terang
GTS	Geelong	**WETS**	Wemen

Appendix D Asset Management documents

Powercor document references are:

Asset management framework: CP-AMF-0001

Asset Management Plans - the following table lists the AMPs relating to key network assets:

Major Asset Group	Asset Management Plan	AMP No
Zone Substations	Zone Substation Transformers & Regulators	CP-AMP-04 PAL-AMP-04
	HV Circuit Breakers (66,22 & 11 kV)	CP-AMP-05 PAL-AMP-05
	Indoor HV switchgear	CP-AMP-06
	Zone Substation – Instrument transformers	PAL-AMP-19
	Surge Arresters	PAL-AMP-15
	Zone Substation – Cooling Systems	CP-AMP-10
	Zone Substation Building & Property	CP-AMP-30 PAL-AMP-51
Distribution Substations & Switchgear	Distribution Substations	CP-AMP-09 PAL-AMP-41
	Distribution Voltage Regulators	PAL-AMP-13
	Automatic Circuit Recloses	PAL-AMP-30
	Distribution HV Switches (Outdoor, Load Breaking)	PAL-AMP-40
Secondary, protection & Earthing Systems	Protection Equipment (Relays)	CP-AMP-11 PAL-AMP-11
	Earthing Systems	CP-AMP-30 PAL-AMP-50
Overhead Lines	Pole Top Structures	CP-AMP-03 PAL-AMP-03
	Poles	CP-AMP-02 PAL-AMP-02
	Overhead conductors – Sub transmission, HV & LV, excluding LV Services	CP-AMP-07 PAL-AMP-07
	Fault Indicators – Overhead Lines	PAL-AMP-18
	High Voltage Fuses	CP-AMP-12 PAL-AMP-12
Underground Lines	Underground Cables	CP-AMP-01 PAL-AMP-01
	Pits and Pillars	CP-AMP-33