



CITIPOWER

DISTRIBUTION

ANNUAL

PLANNING

REPORT

Disclaimer

The purpose of this document is to provide information about actual and forecast constraints on CitiPower'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 meeting the requirements of the (**DSPR**) Distribution System Planning Report required by the Victorian Electricity Distribution Code of Practice (VEDCoP).

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1 Overview

The Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that CitiPower proposes to undertake on its network. It covers information relating to 2022 as well as the forward planning period of 2023 to 2027.

CitiPower is a regulated Victorian electricity distribution business. It distributes electricity to around 348,000 homes and businesses in Melbourne's central business district (**CBD**) and inner suburbs. The network consists of 57,668 poles and over 4,171 kilometres of wires. Electricity is received via 108 sub transmission lines at 37 zone substations, where it is transformed from sub-transmission voltages to distribution voltages.

The report sets out the following information:

- forecasts, including import and export capacity, and associated maximum and minimum demand forecasts, at the zone substation, sub-transmission and primary distribution feeder level
- system limitations, which include limitations resulting from the forecast maximum demand breaching its import capacity, or from the forecast minimum demand breaching its export capacity, following an outage of an asset, or retirements and de-ratings of assets
- projects that have been, or will be, assessed under the regulatory investment test
- other high level summary information to provide context to CitiPower's planning processes and activities.

The DAPR provides a high-level description of the balance that CitiPower 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 Report and the Forecast Maximum and Minimum Demand 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 CitiPower 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.

¹ Transmission-distribution connection assets are discussed in the Transmission Connection Planning Report which is available on the CitiPower website at: <https://www.citipower.com.au/network-planning-and-projects/network-planning/>

The DAPR is aligned with the requirements of clauses 5.13.2(b) and (c) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.8 of the NER. In addition, the DAPR contains information consistent with the requirements of section 19.4 of the Victorian Electricity Distribution Code of Practice (VEDCoP), as published by the Essential Services Commission of Victoria.

1.1 Public consultation

CitiPower intends to hold a public forum to discuss this DAPR in early 2023. All interested stakeholders are welcome to attend, including interested parties on CitiPower's demand-side engagement register, and local councils.

CitiPower 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.

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

All written submissions or enquiries should be directed to:

- DMInterestedParties@CitiPower.com.au

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

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

2 Background

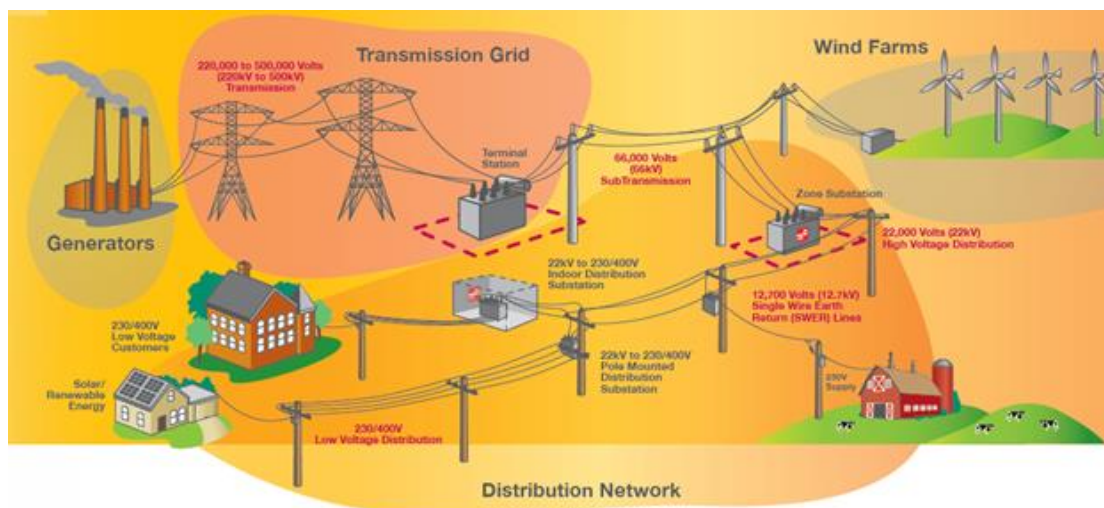
This chapter sets out background information on CitiPower Pty Ltd (**CitiPower**) and how it fits into the electricity supply chain.

2.1 Who we are

CitiPower is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. CitiPower 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 (**PV**) 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 CitiPower 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.

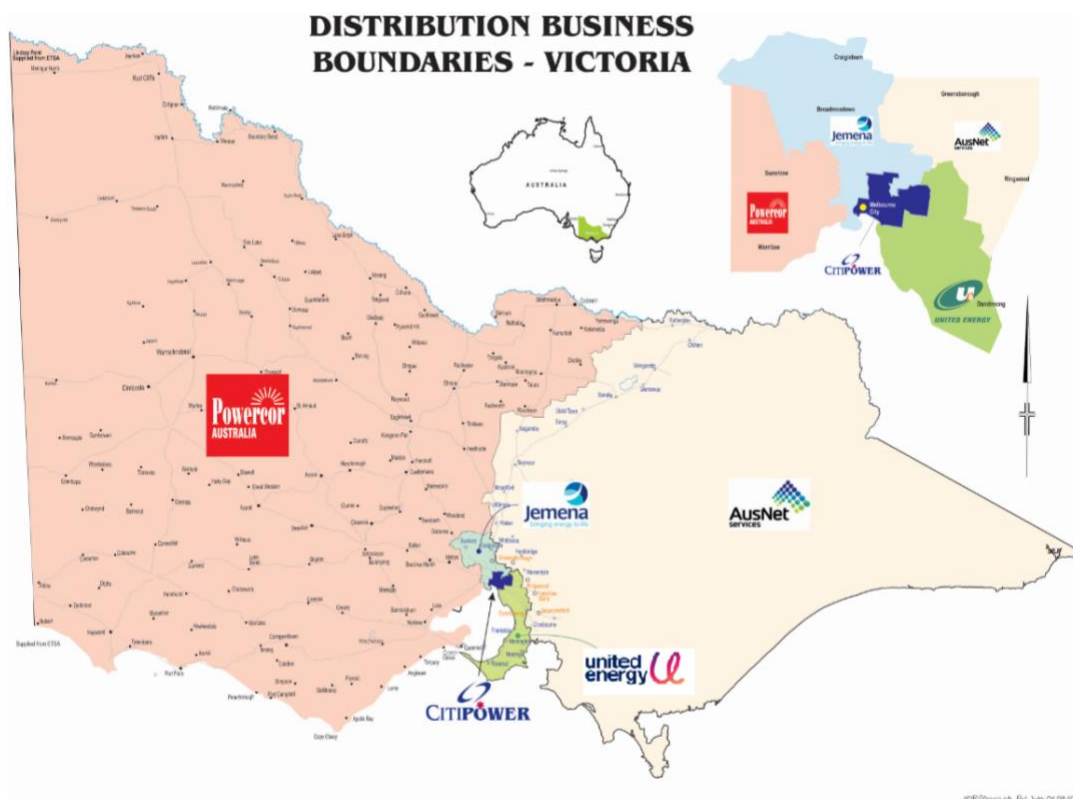
2.2 The five Victorian distributors

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

The CitiPower network provides electricity to customers in Melbourne's central business district (CBD) and inner suburbs, and supplies world-class cultural and sporting facilities such as Federation Square, the Melbourne Cricket Ground, the Victorian Arts Centre and Melbourne Park.

The coverage of CitiPower and other Victorian distributors is shown in the figure below.

Figure 2.2 CitiPower and other Victorian distribution areas

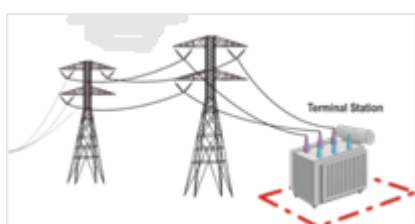


In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, CitiPower must plan augmentation and asset replacement of the network to match network

capacity to customer demand. The need for augmentation is largely driven by customer peak demand growth, local generation (PV) and geographic shifts of demand due to urban redevelopment.

2.3 Delivering electricity to customers

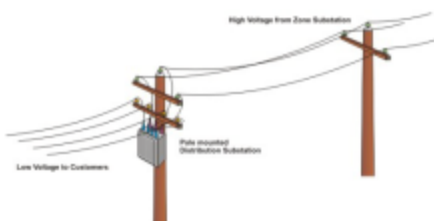
Power that is produced by large-scale generators is transmitted over the high voltage transmission network and is changed to a lower voltage before it can be used in the home or industry. This occurs in several stages, which are simplified below.



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 CitiPower network is supplied from the terminal stations.

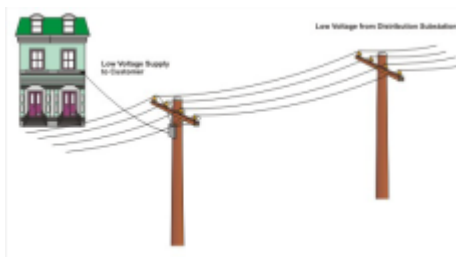


Second, CitiPower distributes the electricity on the **sub-transmission system** which is made up of large concrete or wooden power poles and powerlines, or sometimes underground powerlines. The sub-transmission system transports electricity to CitiPower's zone substations at 66kV or 22kV.



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

CitiPower delivers electricity to around 348,000 homes and businesses in a 157 square kilometre area, or around 2,217 customers per square kilometre.

The CitiPower electricity network comprises a sub-transmission network which consists of predominately overhead lines which operate at 66kV with some at 22kV and a distribution network that generally operates at a voltage of 11kV with some 6.6kV. The overall network consists of around 55 per cent overhead lines and 45 per cent underground cables.

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

The sub-transmission network nominally operates at 66kV or 22kV and is often configured in loops to maximise reliability. The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for 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 11kV, there are some notable exceptions. For example, although they are being progressively decommissioned, 6.6kV distribution systems can still be found in areas of:

- Port Melbourne
- CBD
- North Melbourne
- Brunswick
- Fitzroy.

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

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 or 400 volts. These voltages are derived from distribution substations which are located throughout the distribution network and typically range in size from 200kVA to 8000kVA. Both overhead and underground low voltage reticulation, including service arrangements, complete the final connections to the low voltage consumer's points of supply. CitiPower's customer base comprises of high rise domestic and commercial customers, some industrial customers through to small domestic customers.

At the end of 2021-22FY, the CitiPower network comprised approximately:

Table 2.1 CitiPower network statistics

Item	Number / km
Poles	57,668
Overhead lines	4,171
Underground cables	3,384
Sub-transmission lines	108
Zone substation transformers	90
Distribution feeders	718
Distribution transformers	4,995

Appendix A shows maps that indicate location of CitiPower's zone substation assets and the connected terminal stations on a geographic basis.

3 Factors Impacting the Network

This chapter sets out the factors that may have a material impact on the CitiPower 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 or increased take-up of distributed energy resources and associated exports into the network
- **fault levels:** the increasing amount of embedded generation being directly connected to the CitiPower network is increasing the overall fault levels on the network which is reaching its fault level capacity in certain areas
- **voltage levels:** the short distances between the customer and the voltage regulating equipment in the CitiPower network means that the voltage levels have generally not been a concern however recent increases in PV have created overvoltage issues
- **other system security requirements:** there will be greater resilience in the network as the Melbourne CBD security of supply upgrade plan continues to be implemented. This plan requires significant investment to achieve coverage of the whole CBD
- **quality of supply:** CitiPower may carry out system studies on a case-by-case basis as part of the new customer connection process
- **ageing and potentially unreliable assets:** CitiPower utilises a Health Index as a guide to determining the condition, and therefore risk of the assets. Many of the ageing assets that are in deteriorated condition in the CitiPower network exist within the 22kV sub-transmission network and its associated zone substations
- **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
- **customer equipment and embedded generators:** the equipment that sits behind the customer meter including solar panels and batteries (which may mask the real demand behind the meter) causing capacity constraints, televisions, pool pumps, electric vehicles, solar panels, wind turbines, batteries, etc.

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

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

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.

CitiPower 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
- voltage.

The following fault level limits are generally applied within CitiPower:

Table 3.1 Fault level limits

Voltage	Fault limit (kiloAmps, kA)
66kV	21.9 kA
22kV	13.1 kA for distribution lines
	26.2 kA for sub-transmission lines
11kV	18.4 kA
6.6kV	21.9 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 CitiPower network as the level of embedded generation being directly connected to the network increases. This is because of the increasing fault level contribution from local 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
- load
- capacitors in the network.

For CitiPower, the length of sub-transmission and distribution feeders in the network is relatively short compared with rural areas and this reduces the potential for customer voltage variations due to load however this situation is rapidly changing due to the impact of local solar generation which causes a sudden drop in voltage as the sun goes down and residential load increases.

CitiPower also installs additional voltage regulation equipment at zone substations where a bus-tie circuit breaker is opened as a result of fault level constraints.

3.4 System security

This section sets out other power system security requirements for the CitiPower network. In particular, it discusses the Melbourne CBD security of supply upgrade plan including:

- an outline of the capital and other works undertaken in 2022 to implement the plan
- an evaluation of whether the relevant security of supply objectives specified in the plan were achieved in 2022
- an outline of the capital and other works connected to the plan that is proposed to be carried out over the next 5 years.

The majority of works for the CBD upgrade plan was completed in 2016, and the new Waratah Place (**WP**) zone substation was commissioned in July 2020 with four new feeders. New works to complete coverage across the CBD are now required to be implemented.

3.4.1 2022 implementation of CBD security of supply upgrade plan

The Melbourne CBD security upgrade plan is an obligation under clause 19.5 of the VEDCoP. This obligation followed the publication of a Regulatory Test Final Report by CitiPower that economically justified the scope of works defined to upgrade the 66kV sub-transmission network in the Melbourne CBD to an 'N-1 Secure' standard.

All capital and other works carried out in 2021 as part of the plan have been completed. Refer to the 2021 DAPR for more information.

3.4.2 Future CBD upgrade works

Due to load growth in the southwest of Melbourne CBD, which is mainly supplied by zone substations Little Bourke (JA) and Little Queen (LQ), CitiPower is planning to rebuild the existing zone substation Tavistock Place (TP). Elements of the new zone substation are required as part of the Melbourne CBD security program which seeks to increase resilience into the 66 kV sub-transmission network given the critical nature of reliable electricity supply to the area. The new TP zone substation with new distribution feeders will provide sufficient transfer capacity at 11 kV to JA and LQ to meet the requirements of 'N-1 Secure'.

Table 3.2 below presents the project timeline for the CBD security of supply project.

Table 3.2 Future CBD upgrade works

Description of capital works	2025	2026	2027	2028	2029
<i>Distribution, Security Enhancement</i>					
Establish Tavistock Place (TP) zone substation at 66kV	X	X	X	X	X
Transfer load from Little Queen (LQ) zone substation to TP					X
Transfer load from Little Bourke (JA) to TP					X

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, CitiPower 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

CitiPower carries out routine maintenance on all its assets to reduce the probability of plant failure, and ensures they are fit for operation.

There are two key areas of ageing and potentially unreliable assets that are a priority for CitiPower:

- assets with a high Health Index
- assets in the 22kV sub-transmission network.

These are further discussed below.

3.6.1 Health Index

CitiPower 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
- 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.

CitiPower 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 an asset's Health Index exceeds 5.5 and intervention prioritised when an asset's 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. For the purposes of this DAPR, the Health Index of some assets has been provided where CitiPower has assessed the risk to be sufficient to require intervention in the next five years.

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
- environment

The risk to CitiPower is calculated by combining the probability of failure of the asset 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.

3.6.2 Replacement of 22kV sub-transmission network

The 22kV sub-transmission network contains many ageing assets that are in a deteriorated condition. These assets include transformers, underground sub transmission oil/paper cables and indoor switchgear within existing zone substations. CitiPower reviews the Health

Indexes of these assets as a factor to assist in determining whether or not to trigger intervention.

CitiPower is planning to continue replacing the 22kV sub-transmission network by upgrading zone substations to the 66kV sub-transmission network or transferring the zone substation load to an existing 66kV zone substation. We are also working with AusNet Services to align our works programs so that the removal of 220/22kV transmission assets are coordinated with our 22kV sub-transmission upgrades (see section 10.1). Operation of the sub-transmission network at the higher voltages also reduces the amount of distribution losses from the network. At the same time CitiPower intends to upgrade the associated 6.6kV distribution network to 11kV.

3.6.3 Replacement of 6.6kV high voltage feeder network

A number of the older zone substations have secondary voltages of 6.6kV, which is inconsistent with the current 11kV standard in the CitiPower network. These non-standard 6.6kV secondary voltages have many technical limitations when compared with the standard 11kV secondary voltage including a limited loading capability. Having 6.6kV distribution feeders limits system flexibility with regard to load transfers and with encroachment by the 11kV network has created islands within the 6.6kV network which are now not able to be backed up from the surrounding 11kV network.

Now that many plant items in these older zone substations are reaching their end of life, it is time to consider a planned upgrade to 11kV to eliminate the limitations the 6.6kV system imposes. This will renew these areas, enabling higher loads to be supported and providing backup possibilities from surrounding areas. This is especially important for a number of urban renewal projects occurring in these older areas of CitiPower.

3.7 Solar Enablement

Distributed Energy Resources (particularly solar PV) connected to the network are creating voltage variations, which 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 10 years.

In areas with a higher proportion of solar customers, solar PV exports are causing the localised network voltage to rise during daylight hours. 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 above the limits set by the VEDCoP (Code).

Solar PV exports also have the potential to create capacity constraint concerns on the LV network. This is due to the increasing solar PV penetration, increasing average solar PV system sizes (to a point where a customer's 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.

CitiPower's delivery of its 5-year 'Solar Enablement' program of works to limit these issues is progressing and includes:

- implementation of a Dynamic Voltage Management System (DVMS) planned with commissioning that has progressively occurred from June to November 2022 at the majority of CitiPower zone substations. This will enable increased solar hosting capacity by dynamically adjusting system voltages based on feedback from AMI meters installed at each customer premise
- completion of remedial interventions such as phase rebalancing, distribution transformer tapping, distribution transformer replacement and undertaking conductor works and replacements

The CitiPower solar network optimisation project was initiated and delivered in 2021, then continued through 2022. This involved network interventions across the CitiPower network. Further works involving high and low voltage interventions and system upgrade activities are planned for 2023, including:

- reviewing customer's inverter settings and compliance with contracts
- DVMS enhancements to continue to improve voltage compliance

3.8 Distribution System Operator (DSO) enhanced capability

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

- enabling DER export and increasing hosting capacity whilst addressing minimum demand and other system security obligations that may be placed on the distributor
- utilising batteries to manage constraints and value stacking arrangements with third parties to demonstrate multiple benefits
- enabling competition for non-network solutions through expanded platforms for sharing network constraints
- develop Dynamic Operating Envelope capability that is flexible to more dynamically manage the network and enable third party service offerings on the distribution network

Chapter 18.2 details the specific projects that CitiPower is delivering in terms of demand management and non-network solutions.

4 Network Planning Standards

This chapter sets out the process by which CitiPower identifies maximum and minimum demand-driven limitations in its network.

4.1 Approaches to planning standards

In general there are two different approaches to network planning.

Deterministic planning standards: this approach calls for zero interruptions to customer supply (or no curtailment of embedded generation) following any single outage of a network element, such as a transformer. 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 the cost of curtailing generation), 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 (or the amount of energy that would need to be forceably curtailed) 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 (or some generation needs to be curtailed) with a network element out of service (hence the N-1 criterion is not met), however;
- the actual energy 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 energy at risk under system normal conditions (known as the “N” condition). This is where all assets are operating but the demand breaches either the total import or export capacity. Contingency transfers may be used to mitigate energy at risk in the interim period until it is economically prudent for an augmentation to be completed.

4.2 Application of the probabilistic approach to planning

CitiPower 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 during periods of high import or export, 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 that expected cost.

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 limitation. Probabilistic network planning aims to ensure that an economic balance is struck between:

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

In other words, recognising that very extreme demand conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur at the same time. 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 the actual demand for the network and significant load shedding or generation curtailment could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

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

4.3 Application of the CBD Secure approach to planning in the Melbourne CBD

CitiPower adopts a modified probabilistic approach to planning its Central City zone substation and sub-transmission asset augmentations. This standard referred to as CBD Secure requires that for any loss of a sub transmission cable, no load is lost. Also it requires adequate transfers are available such that following a 30 minute interval to allow for transfers, a second sub transmission cable can fail without loss of load.

5 Forecasting Demand

This chapter sets out the methodology and assumptions for calculating historical 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” and available on the CitiPower website.²

5.1 Maximum and minimum demand forecasts

CitiPower has set out its forecasts for maximum and minimum demand for each existing zone substation and sub-transmission system in the Forecast Maximum and Minimum Demand Sheet.

5.2 Zone substation methodology

This subsection sets out the methodology and information used to calculate the demand forecasts and related information that is referred to in the Forecast Maximum and Minimum Demand Sheet, and System Limitation Reports.

5.2.1 Historical demand

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

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

The temperature correction for the maximum demand forecast seeks to ascertain the “50th percentile maximum demand”. The 50th percentile demand represents the maximum demand on the basis of a normal season (summer and winter). For summer, it relates to a maximum average 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

² <https://www.citipower.com.au/network-planning-and-projects/network-planning/>

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**).

The weather correction for the minimum demand forecasts presented in this DAPR seeks to ascertain the “50th percentile annual minimum demand”. The 50th percentile demand represents the minimum demand on the basis of a weather condition that would lead to a one-in-two year minimum demand, dictated primarily by the amount of cloud cover impacting solar PV output embedded within the distribution network.

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.

CitiPower 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 CitiPower service area. CitiPower has also taken into account information relating to DER installations by our customers. These bottom-up forecasts for demand have been reconciled with top-down independent econometric forecasts for CitiPower as a whole.

These forecasts are set out in the Forecast Maximum and Minimum Demand Sheet.

5.2.3 Definitions for zone substation forecast tables

The Forecast Maximum and Minimum Demand Sheet contains other statistics of relevance to each zone substation, including:

- **N import (or export) rating:** this provides the maximum capacity of the zone substation according to the equipment in place (for forward and reverse power flows respectively) up to its nameplate value;
- **Cyclic N-1 import (or export) rating:** this assumes that the net load follows a daily pattern and is calculated using net load curves appropriate to the season and assuming the outage of one transformer (for forward and reverse power flows respectively). This is also known as the “firm” rating;
- **Hours 95% of maximum (or minimum) demand:** based on at least the most recent 12 months of data, assesses the net load duration curve and the total hours during the year that the net load is greater than or equal to 95 per cent of maximum or minimum demand;

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

- **Station power factor at maximum (or minimum) demand:** based on the most recent maximum or minimum 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 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 demand 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 transfer capacity:** 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 and minimum demands for the sub-transmission lines.

5.3.1 Historical demand

The sub-transmission line historical N-1 maximum and minimum demands for different line configurations are determined using a powerflow 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 and minimum demand, by utilising historical actual demands and assessing:

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

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

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

The data is used to assess the maximum and minimum 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 demand is identical whether the zone substation is operating under N or N-1 (loss of a transformer). Therefore the N-1 cyclic import or export rating (as appropriate) is used to compare against the demand 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 import or export rating (as appropriate).

5.3.2 Forecast demand

Similar to the sub-transmission line historical maximum and minimum demands, bottom-up forecasts for maximum and minimum 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 and minimum demand forecasts at each zone substation are used in calculating the maximum and minimum 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 and minimum demands are diversified based on the historical diversity factors mentioned above.

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

5.3.3 Definitions for sub-transmission line forecast tables

The Forecast Maximum and Minimum Demand Sheet refers to other statistics of relevance to each sub-transmission line, including:

- **Line import (or export) rating:** this provides the maximum capacity of the sub-transmission line (for forward and reverse power flows respectively) as measured by its current and expressed in MVA
- **Hours 95% of maximum (or minimum) demand:** based on at least the most recent 12 months of data, assesses the net load duration curve and the total hours during the year that the net load is greater than or equal to 95 per cent of maximum or minimum demand
- **Power factor at maximum (or minimum) demand:** 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 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 demand 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 transfer capacity:** forecasts the available capacity of alternative sub-transmission lines that can carry electricity to the zone substation in emergency situations
- **Generation capacity:** calculates the total capacity of all embedded generation units that have been directly connected to the sub-transmission line at the date of this report

5.4 Transmission-distribution connection points methodology

This subsection sets out the methodology and information used to calculate the demand forecasts and related information that is referred to in the Forecast Maximum and Minimum Demand Sheet, Transmission Connection Planning Report and System Limitation Reports.

5.4.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual maximum and minimum demand values recorded at each terminal station.

As maximum and minimum demand in CitiPower is very temperature and weather dependent, the actual maximum and minimum demand values referred to in the Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report are normalised for the purpose of forecasting, in accordance with the relevant weather conditions experienced across any given period. The correction enables the underlying maximum and minimum demand growth year-by-year to be estimated, which is used in making future forecast and investment decisions.

5.4.2 Forecast demand

Historical demand values taking into account local generation inputs are trended forward, and adjusted for the changes in the zone substation growth rates of the zone substations connected to that terminal station. These bottom-up forecasts for demand are reviewed against AEMO's connection point forecasts.

These forecasts are set out in the Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report.

5.4.3 Definitions for zone substation forecast tables

The Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report contains other statistics of relevance to each terminal station, including:

- **N import (or export) rating:** this provides the maximum capacity of the terminal station according to the equipment in place (for forward and reverse power flows respectively) up to its nameplate value;
- **Cyclic N-1 import (or export) rating:** this assumes that the net load follows a daily pattern and is calculated using net load curves appropriate to the season and assuming the outage of one transformer (for forward and reverse power flows respectively). This is also known as the "firm" rating;

- **Hours 95% of maximum (or minimum) demand:** based on at least the most recent 12 months of data, assesses the net load duration curve and the total hours during the year that the net load is greater than or equal to 95 per cent of maximum or minimum demand;
- **Station power factor at maximum (or minimum) demand:** based on the most recent maximum or minimum demand achieved in a season at the terminal station, 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 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 demand 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 terminal station;
 - one: efficient loading of the terminal station;
- **Load transfer capacity:** forecasts the available capacity of adjacent terminal stations, sub-transmission lines and feeder connections to take load away from the terminal station in emergency situations; and
- **Generation capacity:** calculates the total capacity of all embedded generation units that have been connected to the terminal station at the date of this report. Summation of generation above and below 1MW is provided.

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

5.5 Primary distribution feeders

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

5.5.1 Forecast demand

Primary distribution feeder maximum and minimum 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 rates including known or predicted loads and embedded generators that are forecast for connection. Weather 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 CitiPower 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, probabilistic network planning aims to strike an economic balance between:

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

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

For zone substations, **energy at risk** is defined as, the amount of energy that would not be supplied to load during periods of maximum demand, or would need to be curtailed from embedded generators during periods of minimum demand, from a zone substation if a major outage⁴ of a transformer occurs at that station in that particular year, and no other mitigation action is taken.

This measure provides an indication of magnitude of loss of load (or forced curtailment of generation) 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 asset 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.

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.

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

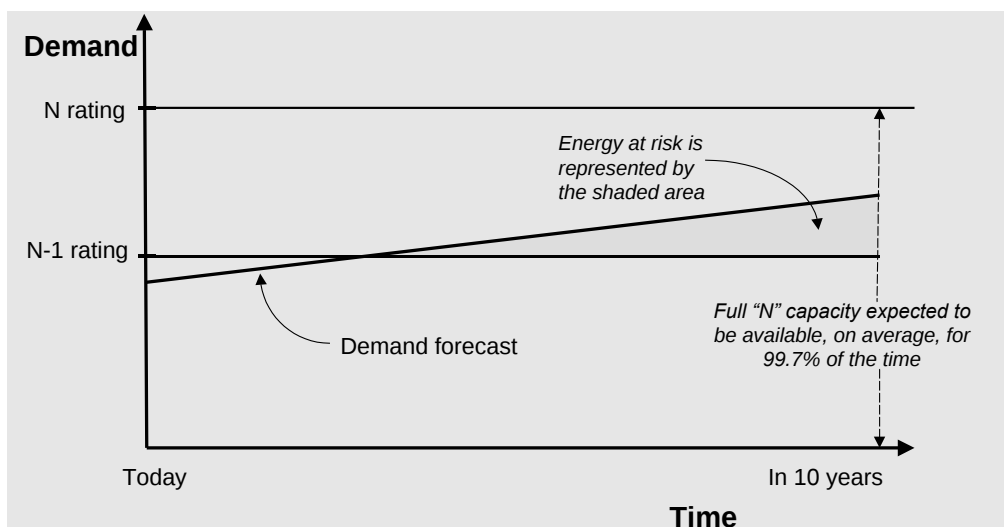
6.2 Interpreting “energy at risk”

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

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

The relationship between the N and N-1 cyclic ratings of a station and the energy at risk (assuming maximum demand conditions) is depicted in Figure 6.1 below.

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



Note that:

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

- 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 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**), CitiPower will undertake a detailed assessment process to determine whether or not to proceed with the augmentation.

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

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

A rule change in July 2018 made the Australian Energy Regulator (AER) responsible for determining the values different customers place on having a reliable electricity supply. The AER subsequently developed an updated methodology for deriving Value of Customer Reliability (**VCR**) values and published new VCRs in December 2019. The applicable CitiPower VCR values from this publication are as per Table 6.3 below.

Table 6.3 Values of customer reliability

Sector	VCR for 2022 (\$/kWh)
Residential	\$22.23
Commercial	\$46.18
Agricultural	\$39.28
Industrial (<10MVA)	\$66.17

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 data 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, CitiPower will proceed with the works.

CitiPower notes that there has been a reduction in the VCR estimates for the residential, commercial and agricultural sectors while a significant increase for the industrial sector compared to the results of the 2019 VCR study, which was published in AEMO's 2019 Application Guide.

From a planning perspective, it is appropriate for CitiPower 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 study⁵
- Oakley Greenwood's 2012 estimate of the New South Wales VCR⁶, of \$95 per kWh
- AER's latest Victorian VCR⁷ estimate of \$40.73 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.

6.4 Valuing generation curtailment

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

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change⁷. Under the Rule change, the AER is required to develop customer export curtailment values ("CECV"), which are an estimate of the detriment to customers and the market of export curtailment due to network limitations (in \$ per kWh of exports curtailed). CECVs are expected to play a similar

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

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

⁷ AER, Values of Customer Reliability, Final Report on VCR Values, December 2019.

⁷ AEMC, Rule Determination, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, 12 August 2021.

role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is expected that the CECVs will be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology. At the same time, the AER also published a DER Integration Expenditure Guidance Note⁸, which includes direction on how distribution network service providers should i) develop business cases for network investment integrating higher levels of customer DER and quantify DER values, ii) develop DER integration plans and investment proposals, and ii) quantify DER benefits in a cost-benefit analysis.

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

⁸ <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure-guidance-note/final-decision>

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:

- Import limitations:
 - forecasts for maximum demand to 2027
 - summer and winter cyclic N-1 import ratings for each zone substation
- Export limitations:
 - forecasts for minimum demand to 2027
 - cyclic N-1 export ratings for each zone substation

Where the zone substations are forecast to operate with maximum or minimum demands beyond 5 per cent of their firm summer or winter import or export rating during 2022 respectively, then this section assesses the energy at risk for those assets.

If the energy at risk assessment is material, then CitiPower sets out possible options to address the system limitations. CitiPower may employ the use of contingency transfers to mitigate the system limitations although this will not always address the entire energy at risk. At other times the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available 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 limitations at the same time. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

CitiPower 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

CitiPower proposes to augment the zone substations with import limitations listed in the table during the forward planning period.

Table 7.1 Proposed import-limited zone substation augmentations

Zone substation	Description	Direct cost estimate (\$ million)				
		2023	2024	2025	2026	2027
BK	Offload to WB and decommission	0.15	0.35	1.0	6.1	6.1
DA	WMTS 22kV retirement – Upgrade DA site to 66kV	1.0				
F	Offload to CW and decommission	0.15	0.35	5.9	5.9	
TP	Rebuild TP to 66/11kV (Including 66kV lines)	0.15	0.35	2.5	9.0	11.5

CitiPower proposes to augment the zone substations with export limitations listed in the following table during the forward planning period.

Table 7.2 Proposed export-limited zone substation augmentations

Zone substation	Description	Direct cost estimate (\$ million)				
		2023	2024	2025	2026	2027
Nil	-	-	-	-	-	-

Whilst there are currently no identified export limitations, it should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

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

- Reducing float voltages, or applying LDC settings at zone substations;
- Installing reactors at zone substations;
- Network reconfigurations and augmentations;
- Reviewing zone substation power transformer tap changer specification;
- Optimising existing capacitor bank switching settings at zone substations; and
- Non-network options.

In 2022 we introduced a Dynamic Voltage Management System to better manage export limitations associated with voltage. CitiPower will continue to monitor the declining minimum demand levels on some of our zone substations and explore the feasibility of specific options to alleviate forecast export limitations on a case-by-case basis.

The excel based detailed system limitation reports can be found at the link below by searching for zone substation system limitation report:

<https://spaces.hightail.com/space/UaPnYl6yeV>

CitiPower intends to undertake replacement-driven augmentation projects over the forecast period, including:

- conducting a program of works to enable decommissioning of the 22kV sub-transmission network served from West Melbourne terminal station (**WMTS**)
- offloading of Brunswick (**BK**) and Fitzroy (**F**) zone substations and conversion of their distribution areas from 6.6kV to 11kV
- constructing Tavistock Place (**TP**) zone substation to support partially offloading of Little Bourke (**JA**) and Little Queen (**LQ**) zone substations for CBD Security of supply

The replacement-driven augmentation projects are discussed in section 14.1. The options and analysis are explained below.

7.2 Zone substations with forecast system limitations

7.2.1 Collingwood (**B**) zone substation

The zone substation in Collingwood (**B**) is served by sub-transmission lines from the Richmond Terminal Station (**RTS**). It supplies the Collingwood, Abbotsford and North Richmond areas.

Currently, the B zone substation is comprised of two 20/27MVA transformers operating at 66/11kV. The maximum demand is forecast to be 36.0 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 29 MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2027, CitiPower estimates that there will be 13.1 MVA of load at risk and for 3661 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 B. 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 B zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of North Richmond (NR) and Collingwood (CW) up to a maximum transfer capacity of 6.1 MVA
- establish a third transformer at B for an estimated cost of \$6 million.

CitiPower's preferred option is to establish a third transformer at B. 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.

7.2.2 Bouverie/Queens (BQ) zone substation

The zone substation in Bouverie/Queens (**BQ**) is served by sub-transmission lines from the Brunswick Terminal Station (**BTS**). It supplies the Melbourne CBD, Carlton, North Melbourne, Parkville, Princes Hill areas.

Currently, the BQ zone substation is comprised of two 36/55MVA transformers operating at 66/11kV. The maximum demand is forecast to be 79.62 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 64.9 MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2026, CitiPower estimates there will be 21.4 MVA of load at risk and for 409 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 BQ. 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 BQ zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- transfer 10.8MVA load away to adjacent zone substations WA, VM and JA
- establish a 3rd 55MVA transformer at BQ zone substation at estimated cost of \$6 million in next regulatory reset period July 2026 – July 2031
- re-build LS zone substation and offload 16MVA from BQ to LS.

CitiPower's preferred option is to install a third transformer at BQ by 2026. 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 Fitzroy (F) zone substation

The zone substation in Fitzroy (**F**) is served by two sub-transmission lines from Brunswick terminal station 22kV (**BTS22**). This zone substation supplies areas of Fitzroy, which is a mixed-use area, with residential, commercial and a small number of industrial customers.

Currently, F zone substation is comprised of two 10/13MVA transformers operating at 22/6.6kV. The maximum demand is forecast to be 15.8 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 13.5 MVA.

CitiPower estimates that in 2026 there will be 3.8 MVA of load at risk and for 27 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 F. 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 F zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 6.6kV links to adjacent zone substations of Collingwood (**CW**) and Brunswick (**C**) up to a maximum transfer capacity of 4.6 MVA, the available transfer is limited as only one CW feeder operates at 6.6kV via an auto-transformer and zone substation C is to be offloaded and retired by end of 2025
- offload F to CW and convert the 6.6kV feeders to 11kV to enable more transfers for an estimated cost of \$13 million.

CitiPower's preferred option is to offload F and convert the 6.6kV feeders to 11kV by end of 2026 to meet the load growth in Fitzroy and Collingwood area as well as to reduce the load at risk for an N-1 event.

7.2.4 Deepdene (L) zone substation

The zone substation in Deepdene (**L**) is served by sub-transmission lines from the Templestowe Terminal Station (**TSTS**). It supplies the Balwyn, Canterbury and Kew areas.

Currently, the L zone substation is comprised of two 20/30MVA transformers operating at 66/11kV. The maximum demand is forecast to be 44.1 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 32.1 MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2026, CitiPower estimates that there will be 13.2 MVA of load at risk and for 76.5 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 L. 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 L zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Kew **(Q)**, Riversdale **(RD)** and Camberwell **(CL)** and West Doncaster **(WD)** up to a maximum transfer capacity of 9.6 MVA
- install a third transformer at L for an estimated cost of \$5 million.

CitiPower's preferred option is to establish a third transformer at L. 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.

7.2.5 Kew **(Q)** zone substation

The zone substation in Kew **(Q)** is served by sub-transmission lines from the Templestowe Terminal Station **(TSTS)**. It supplies the Kew area.

Currently, the Q zone substation is comprised of two 20/30MVA transformers operating at 66/11kV. The maximum demand is forecast to be 38.2 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 27.2MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2027, CitiPower estimates there will be 13.1 MVA of load at risk and for 201 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 Q. 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 Q zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of North Richmond **(NR)**, Deepdene **(L)** and Camberwell **(CL)** up to a maximum transfer capacity of 8.5 MVA
- establish a third transformer at Q for an estimated cost of \$5 million
- establish a third transformer at L and permanently transfer load away from Q to L at an estimated cost of \$5 million

CitiPower's preferred option is to install a third transformer at L and permanently transfer load away from Q to L. 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.

7.2.6 Richmond **(R)** zone substation

The zone substation in Richmond **(R)** is served by sub-transmission lines from the Richmond Terminal Station **(RTS)**. It supplies the Richmond, Cremorne, South Yarra and Toorak areas.

Currently, the R zone substation is comprised of three 10/14MVA transformers operating at 66/11kV. The maximum demand is forecast to be 31.8 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 30.1 MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2027, CitiPower estimates that there will be 11.2 MVA of load at risk and for 4369.5 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 R. 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 R zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Toorak **(TK)**, Balaclava **(BC)** and North Richmond **(NR)** up to a maximum transfer capacity of 7.5 MVA.

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.

7.2.7 Riversdale (RD) zone substation

The zone substation in Riversdale **(RD)** is served by sub-transmission lines from the Springvale Terminal Station **(SVTS)**. It supplies the Camberwell area.

Currently, the RD zone substation is comprised of two 20/30MVA transformers operating at 66/11kV. The maximum demand is forecast to be 37.8 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 24.9MVA.

CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.

For example in 2027, CitiPower estimates there will be 13.7 MVA of load at risk and for 140 hours it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at RD. 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 RD zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Burwood **(BW)**, Deepdene **(L)**, Gardiner **(K)** and Camberwell **(CL)** up to a maximum transfer capacity of 6.8 MVA
- establish a third transformer at RD at cost of \$5 million.

CitiPower's preferred option is to establish a third transformer at RD. 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 some of the risk in the interim period.

7.2.8 West Brunswick (WB) zone substation

The zone substation in West Brunswick (**WB**) is served by sub-transmission lines from the West Melbourne terminal station (**WMTS**). This station supplies the domestic, commercial and industrial areas of Brunswick West.

Currently, the WB zone substation is comprised of three 20/30MVA transformers operating at 66/6.6kV. The maximum demand is forecast to be 37.2 MVA in summer 2022/23 which will exceed the N-1 cyclic capacity of 34.2 MVA.

For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

CitiPower estimates that in 2026 there will be 7.1 MVA of load at risk and 7,414 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 WB. 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 WB zone substation, CitiPower considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Brunswick (BK) up to a maximum transfer capacity of 0.7 MVA
- augment WB ZSS and distribution feeders to 11kV system for an estimated cost of \$8 million.

CitiPower's preferred option is to augment WB ZSS and distribution feeders to 11kV system by the end of 2026. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.3 Proposed new zone substations

This section sets out CitiPower's plans for new zone substations. These substations are not taken into account in the forecasts that have been referred to in the Forecast Maximum and Minimum Demand Sheet or in the analysis in section 7.1 above which relates to existing substations.

In summary, CitiPower has committed to building the zone substation set out below in Table 7.2 during the forward planning period.

Table 7.2 Proposed new or redeveloped zone substations

Name	Location	Proposed commissioning date	Reason
Tavistock Place (TP)	Melbourne CBD	2029	Achieve CBD Security of Supply project objectives

Greater detail on the new zone substation is provided in subsections below.

In addition to the new zone substation noted in the table above, CitiPower is also in discussions with the State Government of Victoria and local councils relating to new developments and the demand for new electricity services in areas including:

- Fishermans Bend precinct: Places Victoria has released its updated strategic framework for the redevelopment of this area to provide homes for more than 80,000 residents and new workplaces for up to 60,000 people. This urban renewal will involve a variety of residential and commercial developments ranging from townhouses to high rise towers and small to large commercial spaces⁹. This may result in a requirement for an additional 30MVA of capacity
- Arden Macaulay: the City of Melbourne has identified the 147 hectare precinct in parts of Kensington and North Melbourne as an urban renewal area that will accommodate significantly more residents and employment growth over the next 30 years.

These loads are not yet included in the demand forecasts in the Forecast Maximum and Minimum Demand Sheet. These developments are likely to result in significant augmentation to the CitiPower network, including the possible construction of new zone substations.

7.3.1 Tavistock Place (TP) zone substation

CitiPower is planning to rebuild the existing zone substation at Tavistock Place (**TP**), located in the South West district of the Melbourne CBD. It will be upgraded from the existing 22/6.6kV to 66/11kV with higher capacity.

Elements of the new zone substation are required as part of the Melbourne CBD security program which seeks to increase resilience into the 66kV sub-transmission network given the critical nature of reliable electricity supply to the area. The CBD security work associated with TP involves providing extra capacity at 11kV to allow the offloading of LQ and JA zone substations, consistent with the CBD Security of Supply project objectives.

The TP zone substation will take load from the following adjacent zone substations:

⁹ Refer: <https://www.development.vic.gov.au/projects/fishermans-bend>

-
- Little Bourke **(JA)**: 14 MVA
 - Little Queen **(LQ)**: 24 MVA.

Other benefits of the new zone substation are to support load growth in Southbank and Docklands and defer major augmentations at the heavily loaded JA, LQ and Southbank (SB) zone substations. Without completing the works at TP, there will be a shortage of circuit breakers in the western CBD, which will prevent the connection of further large loads, such as high rise buildings.

Completing the works at TP will introduce additional circuit breakers into the western CBD and Docklands area. It is currently forecast that no spare circuit breakers will be available in any of the western CBD and Docklands zone substations by the end of 2023. Without circuit breakers it will no longer be possible to connect any new large loads such as high rise buildings.

The planned commissioning date for the TP zone substation was to be November 2023, with feeder offload works completed by end of 2024, at an estimated total cost of \$24.5 million (including the cost of the sub-transmission lines). During the covid lockdowns, CitiPower has observed a reduction in the peak demand of Melbourne CBD network due to shutdown of retail businesses and restricted access to offices. As a result, the risk of 'N-1 Secure' was lower than previously forecasted. Currently the TP rebuild project is being reviewed and the timing is yet to be confirmed.

Solutions are being prepared which meet the aims of the CBD Security of Supply project, which shall be assessed via the RIT-D process.

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:

- Import limitations:
 - forecasts for N-1 maximum demand to 2027
 - line import ratings for each subtransmission line
- Export limitations:
 - forecasts for N-1 minimum demand to 2027
 - line export ratings for each sub-transmission line

Where the sub-transmission line is forecast to operate with maximum or minimum demands beyond 5 per cent of their summer or winter import or export rating (respectively), under N-1 conditions during 2021, this chapter assesses the energy at risk for those assets. Solutions may also address zone substation limitations at the same time.

If the energy at risk assessment is material, then CitiPower sets out possible options to address the system limitations. CitiPower may employ the use of contingency transfers to mitigate the system limitations although this will not always address the entire energy at risk. At other times the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available 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. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. Non-network proponents are encouraged to discuss opportunities to provide alternatives to the network options presented in this chapter.

CitiPower 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, CitiPower proposes to augment the sub-transmission lines with import limitations listed in the table below to address system limitations during the forward planning period.

Table 8.1 Proposed import-limited sub-transmission line augmentations

Sub-transmission line	Description	Direct cost estimate (\$ million)				
		2025	2026	2027	2028	2029
FBTS-TP-SB*	Establish 2 new 66kV lines to rebuilt TP and reconfigure at sub-transmission exits at SB				7	
JA-TP-WP*	Cut into existing JA-WP cable and run in and out of rebuilt TP				3.5	

* NB solution for CBD Security of Supply is under review, considering most recent forecast data accounting for the effect of the COVID-19 pandemic on the CBD. At this stage the baseline solution for TP Zone Substation is retained whilst alternatives are developed.

CitiPower proposes to augment sub-transmission lines with export limitations listed in the table below during the forward planning period.

Table 8.2 Proposed export-limited sub-transmission line augmentations

Sub-transmission line	Description	Direct cost estimate (\$ million)				
		2023	2024	2025	2026	2027
Nil	-	-	-	-	-	-

Whilst there are currently no identified export limitations, it should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

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

- reducing float voltages, or applying LDC settings at terminal stations
- installing reactors at terminal stations
- network reconfigurations and augmentations
- reviewing terminal station power transformer tap changer specification
- optimising existing capacitor bank switching controls at terminal stations
- non-network options.

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

The excel based detailed system limitation reports for the subtransmission lines with forecast limitations can be found at the link below by searching for sub transmission system limitation report:

<https://spaces.hightail.com/space/UaPnYl6yeV>

The options and analysis is undertaken below.

8.2 Sub-transmission lines with forecast system limitations

CitiPower does not propose to augment any sub-transmission lines to address system limitations in the next 5 years.

8.2.1 BTS-F179 22 kV sub-transmission line

The BTS-F179 22 kV sub-transmission line supplies the Fitzroy (F) zone substation from Brunswick terminal station (BTS) at 22 kV.

For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

CitiPower estimates that in 2026 for the lines within this loop there will be:

- 5.1 MVA of load at risk, and for 379 hours it will be unable to supply all customers on the BTS-F179 line during an outage of the BTS-F189 line.

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

- Contingency plan to transfer load away from Fitzroy (F) via 6.6kV links to adjacent zone substation Collingwood (CW) up to a maximum transfer capacity of 1 MVA.
- As part of the asset retirement at Fitzroy (F) zone substation, CitiPower is proposing to rebuild Brunswick (C) zone substation and offload both Fitzroy (F) zone substation and Brunswick (BK) zone substation and convert the distribution network voltage from 6.6kV feeders to 11kV in year 2026 for an estimated cost of 67.9 million. It is

expected that the asset retirement work will mitigate the load at risk at Fitzroy (F) zone substation.

CitiPower's preferred option is to rebuild Brunswick (C) zone substation, offload F and convert the 6.6kV feeders to 11kV by end of 2026 to meet the load growth in Fitzroy and Collingwood area as well as to reduce the load at risk for an N-1 event.

8.2.2 BTS-F189 22 kV sub-transmission line

The BTS-F189 22 kV sub-transmission line supplies the Fitzroy (F) zone substation from Brunswick terminal station (BTS) at 22 kV.

For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

CitiPower estimates that in 2026 for the lines within this loop there will be:

- 3.9 MVA of load at risk, and for 32 hours it will be unable to supply all customers on the BTS-F189 line during an outage of the BTS-F179 line.

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

- Contingency plan to transfer load away from Fitzroy (F) via 6.6kV links to adjacent zone substation Collingwood (CW) up to a maximum transfer capacity of 1 MVA.
- As part of the asset retirement at Fitzroy (F) zone substation, CitiPower is proposing to rebuild Brunswick (C) zone substation and offload both Fitzroy (F) zone substation and Brunswick (BK) zone substation and convert the distribution network voltage from 6.6kV feeders to 11kV in year 2026 for an estimated cost of 67.9 million. It is expected that the asset retirement work will mitigate the load at risk at Fitzroy (F) zone substation.

CitiPower's preferred option is to rebuild Brunswick (C) zone substation and offload F and convert the 6.6kV feeders to 11kV by end of 2026 to meet the load growth in Fitzroy and Collingwood area as well as to reduce the load at risk for an N-1 event.

8.2.3 TSTS-L 66 kV sub-transmission line

The TSTS-L sub-transmission line supplies the Deepdene (L) zone substation from Templestowe terminal station (TSTS) at 66 kV.

For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

CitiPower estimates that in 2027 for the lines within this loop there will be:

- 16.8 MVA of load at risk, and for 7 hours it will be unable to supply all customers on the TSTS-L line during an outage of the TSTS-HB line.

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

- Contingency plan to transfer load away via 11kV links to adjacent zone substations of Camberwell (CL), North Richmond (NR) and Riversdale (RD) for up to a maximum transfer capacity of 8.4 MVA.

CitiPower's preferred option utilise the 11kV feeder ties to reduce the load at risk for an N-1 event on the TSTS-L-Q-HB sub-transmission loop.

8.2.4 WMTS-WB-NC 66 kV sub-transmission line

The WMTS-WB-NC 66 kV sub-transmission line supplies the West Melbourne (**WB**) and Northcote (**NC**) from West Melbourne Terminal Station (**WMTS**) at 66 kV.

For the historic and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

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

- 18.7 MVA of load at risk, and for 133 hours it won't be able to supply all customers on the WMTS-WB line during an outage of the WMTS-WB line.
- 20.4 MVA of load at risk, and for 167 hours it won't be able to supply all customers on the WMTS-NC line during an outage of the WMTS-NC line.

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

- Contingency plan to transfer load away via 6.6kV links from West Brunswick (WB) to Brunswick (BK) up to a maximum transfer capacity of 0.6 MVA, the available transfer is very limited as there is only one WB feeder operated at 6.6KV for the transfer.
- Augment part of the WMTS-WB and WMTS-NC sub-transmission line by replacing small conductors with larger conductors to increase thermal rating for an estimate cost of \$0.5 million.

CitiPower's preferred option is to augment part of the WMTS-WB and WMTS-NC sub-transmission line. However, as part of another project the WB and NC zone substations will be transferred from West Melbourne Terminal Station (**WMTS**) to Brunswick Terminal Station (**BTS**) in 2023 which will mitigate the load at risk over the five-year planning horizon for the sub-transmission line.

8.3 Proposed new sub-transmission lines

This section sets out CitiPower's plans for new sub-transmission lines. These lines are taken into account in the forecasts that have been set out in the Forecast Load Sheet and the analysis in section 8.2 above which relates to existing sub-transmission lines.

In summary, CitiPower has committed to building the sub-transmission lines set out below in table 8.2 during the forward planning period.

Table 8.2 Proposed new sub-transmission lines

Name	Location	Proposed commissioning date	Reason
JA-TP-WP*	TP cut in existing JA-WP cable	Nov 2028	CBD security requirements
FBTS-TP, TP-SB*	Fishermans Bend to CBD to South Melbourne	Nov 2028	CBD Load requirements while complying with CBD Security

* NB solution for CBD Security of Supply is under review, considering most recent forecast data accounting for the effect of the COVID-19 pandemic on the CBD. At this stage the baseline solution for TP Zone Substation is retained whilst alternatives are developed.

Each of these lines is described in more detail below.

8.3.1 JA-TP-WP

To meet the CBD security requirements, a second source of 66kV supply is to be established for the new TP zone substation. CitiPower plans to extend JA-WP cable to TP so as to enable supply from WMTS for TP at an estimated cost of \$3.5 million.

8.3.2 FBTS-TP, TP-SB

CitiPower plans to build a new zone substation at TP once the existing substation is demolished. It will be supplied at 66kV from FBTS and complete the loop via SB at an estimated cost of \$7 million.

9 Transmission-Distribution Connection Point Review

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

- Import limitations:
 - these are addressed in the Transmission Connection Planning Report
- Export limitations:
 - forecasts for minimum demand to 2027
 - cyclic N and N-1 export ratings for each terminal station

Where the terminal stations are forecast to operate with minimum demands beyond 5 per cent of their firm export rating during 2023, then this section assesses the energy at risk for those assets.

If the energy at risk assessment is material, then CitiPower sets out possible options to address the system limitations. CitiPower may employ the use of contingency transfers to mitigate the system limitations although this will not always address the entire energy at risk. At other times the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available 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. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

CitiPower notes that all other terminal stations 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 and sub-

transmission network to adjacent terminal stations. In these cases, all customers can be supplied following the failure or outage of an individual network element.

9.1 Terminal stations with forecast system limitations overview

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

Whilst there are currently no identified limitations from the forecast use of distribution services by embedded generating units at transmission-distribution connection points, it should be noted that the export ratings currently used for terminal stations are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the terminal station's thermal rating. Work is underway to quantify the impacts of system limitations on terminal station export ratings. Until that work is finalised, thermal ratings are applied.

10 Primary Distribution Feeder 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:

- Import limitations:
 - forecasts for maximum demand to 2024
 - summer and winter cyclic import ratings for each feeder
- Export limitations:
 - forecasts for minimum demand to 2024
 - cyclic export ratings for each feeder

Where the feeders are forecast to operate with maximum or minimum demands in breach of their import or export rating (respectively) 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 customer.

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

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

10.1 Primary distribution feeders with forecast system limitations overview

CitiPower proposes to augment the import-limited distribution feeders listed in Table 10.1 below in the next two years.

Table 10.1 – Proposed import-limited primary distribution feeders augmentations

Feeder	Description	Direct cost estimate (\$ million)	
		2023	2024
Nil	-	-	-

CitiPower proposes to augment the export-limited feeders listed in Table 10.2 below in the next two years.

Table 10.2 – Proposed export-limited primary distribution feeders augmentations

Feeder	Description	Direct cost estimate (\$ million)	
		2023	2024
Nil	-	-	-

The excel based detailed system limitation reports for the primary distribution feeders with forecast limitations can be found at the link below by searching for primary feeder system limitation report:

<https://spaces.hightail.com/space/UaPnYI6yeV>

10.2 Proposed new primary distribution feeders

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 2022-23.

Table 10.3 Future primary distribution feeder projects

BQ feeder augmentation	
------------------------	--

11 Joint Planning

This chapter 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.

CitiPower has not identified any new required projects from our joint planning activities with other DNSPs in 2022. 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.

11.1 West Melbourne terminal station 22kV sub-transmission

CitiPower and AusNet Services continue to jointly plan options for the replacement of the 220/22kV assets at West Melbourne terminal station (**WMTS**). During 2015 a study assessed the overall costs, including both distribution and transmission costs, depending on whether:

- Option 1: the assets are replaced on a like-for-like basis or
- Option 2: the WMTS 22 assets are not replaced and CitiPower transfers all load from the 22kV sub-transmission network to the 66kV network.

The joint analysis shows that the least cost alternative to replacing the 220/22kV assets at WMTS is to retire the WMTS 220/22kV and CitiPower 22kV sub-transmission assets, replace the minimum ageing CitiPower assets and transfer the majority of the 22/6.6kV load to the 66/11kV network.

Further details of the retirement and transfer works required are discussed below in section 14.1.16.

12 Changes to Analysis Since 2021

The following information details load forecasts and project timing changes that have occurred since the publication of the 2021 DAPR.

12.1 Constraints addressed or reduced due to projects completed

CitiPower has undertaken the following projects in 2022 to address constraints which were identified in the 2021 DAPR:

- (LS) zone substation has been permanently offloaded to (BQ)
- (C) zone substation has been permanently offloaded to (WB)
- A third 20/30 MVA transformer has been installed at (WB)

12.2 New constraints identified

Changes in load forecasts or other factors during 2022 have resulted in CitiPower undertaking risk assessments for the zone substations and sub-transmission loops which were not included in the 2021 DAPR:

- (BQ) zone substation forecast has increased resulting in load at risk
- WMTS-WB-NC sub-transmission line forecasts have increased resulting in load at risk

12.3 Other material changes

In addition to the matters identified above, material changes compared to the 2021 DAPR include:

- Nil

13 Asset Management

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

13.1 Asset Management Framework

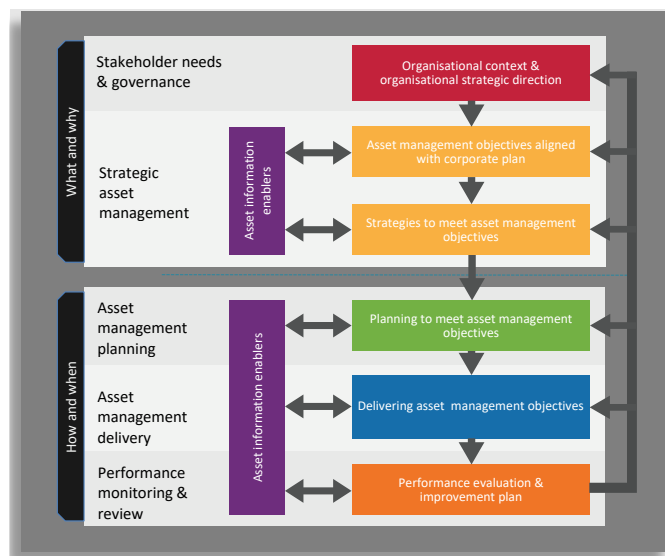
CitiPower are committed to the application of best practice asset management strategies to ensure the safe and reliable operation of our electrical network. CitiPower is continuing to develop and implement an asset management system that is aligned with the requirements of ISO 55001:2014, the international standard in asset management.

The Asset Management System (**AMS**) Framework is a high-level document that describes the asset management system that CitiPower applies to its network assets. The AMS Framework identifies CitiPower's asset management roles and accountabilities, and all significant steps and processes involved in the asset life cycle from the identification of need to creation, operation, maintenance and eventual disposal. Our AMS consists of five key levels:

- Level 1: Stakeholder needs and governance
- Level 2: Strategic Asset Management
- Level 3: Asset management planning
- Level 4: Asset management delivery
- Level 5: Performance monitoring and review

The structure and hierarchy of the AMS is illustrated in Figure 12.1.

Figure 13.1 Asset Management System Framework



Levels 1 and 2 describe 'What' asset management strategies and objectives are to be targeted and provide details regarding 'Why' these are required. Level 3 describes the approach taken to plan and budget for the delivery of the asset management activities, while level 4 describes 'how' and 'when' these activities are delivered to meet the strategies and objectives. Level 5 describes CitiPower's approach to performance monitoring and review of the asset management system.

The relationships between CitiPower's strategic asset management documentation are shown in figure 13.2. These strategic documents describe what asset management strategies and objectives are to be targeted and provide details regarding why these are required.

Figure 13.2 Strategy and planning document hierarchy



An overview of these documents is provided in the following sections.

13.1.1 Strategic Asset Management

CitiPower's asset management strategies and objectives are aligned to the asset management policy and to the needs of our stakeholders, including the direction articulated in our organisational strategic pillars and the asset management-related commitments made in our approved regulatory submission.

The strategic asset management level of CitiPower's AMS framework comprises the following key components:

- asset management objectives
- asset management policy
- Strategic Asset Management Plan (SAMP)
- asset management strategies
- asset class strategies

13.1.1.1. Asset Management Objectives

CitiPower's asset management objectives form the basis for evaluating the success of the asset management system in delivering against the organisational strategic pillars.

The asset management objectives for CitiPower are:

- manage and operate the network safely
- meet our network reliability performance targets
- manage our assets on a total life cycle basis at least cost
- adapt to our customer's future needs
- manage our compliance obligations
- empower and invest in our employees
- monitor opportunities and drive continuous improvement

The AMS Framework maps the asset management policy principles and asset management objectives to demonstrate the alignment to the organisational strategic pillars.

13.1.1.2. Asset Management Policy

CitiPower's Asset Management (**AM**) Policy drives all asset management activities in our organisation. The AM Policy is a high-level statement providing:

- Our overall approach to asset management;
- The principles to be followed, and direction for establishing asset management strategies and objectives; and
- Management expectations regarding asset management outcomes.

The AM Policy requires asset management activities to meet business objectives and benefit the current and future needs of all customers, stakeholders and employees.

13.1.1.3. Strategic Asset Management Plan

CitiPower's strategic asset management plan (**SAMP**) identifies our high-level strategies and objectives for asset management, and links these to CitiPower's 'five strategic pillars',

providing line of sight to the organisational strategy. The SAMP takes full account of our approaches to network risk and asset investment decision making, and provides long-term guidance for the development of the asset management strategies and class strategies.

13.1.1.4. Asset Management Strategies

Asset management strategies have been developed for eight subject areas to deliver CitiPower's SAMP objectives. The Asset Management Strategy subjects are not asset specific and apply across all asset classes. Individual subject strategies are developed by considering:

- CitiPower's organisational context and key asset management issues of a range of internal stakeholders
- the asset management requirements of a range of external stakeholders, including the AER, AEMO and CFA.

The asset management strategies provide guidance for development of asset operational plans and asset management plans, to prioritise and deliver the asset management objectives and strategies. Refer to appendix D for a detailed list of the asset management strategy subjects and purpose of each strategy.

13.1.1.5. Asset Class Strategies

CitiPower has identified sixteen asset class strategies (**ACS**) for which specific strategies and objectives have been developed, all of which are aligned to the SAMP. Each ACS is formed from analysis of the required performance in terms of reliability and quality of supply, risk profile, functionality, availability and safety. The ACSs provide guidance for development of asset operational plans and asset management plans, which drive inspection, maintenance, condition monitoring, maintenance policies and work instructions. Refer appendix D for a detailed list of ACS documents and corresponding asset coverage.

13.1.2 Asset Management Planning

CitiPower plans its asset management activities to maximise the value realised over the life of its assets. The asset management planning stream of CitiPower's AM Framework is undergoing further development, with key focusses on asset investment planning, asset maintenance requirements and optimising the asset lifecycle.

CitiPower has implemented a new value framework that will form the basis for quantitatively prioritising investments. The value framework is used to configure the Copperleaf C55 asset planning and investment tool to facilitate the quantitative prioritisation of investments going forward.

13.1.3 Asset management delivery

CitiPower's asset management delivery and governance is facilitated via existing standards, policy, procedures and processes that stipulate the requirements for our asset management delivery. Monitoring of compliance is achieved via regular internal audit processes and reporting. CitiPower's asset management committee provides specific oversight and governance to the Asset Management System.

13.1.4 Performance monitoring and review

CitiPower monitors the performance of both network assets and the asset management system as a whole. The components of CitiPower's performance monitoring and review level of the AM framework are outlined below:

- risk assessment and management
- business continuity planning
- change management
- asset performance and health monitoring
- asset management monitoring and continual improvement
- audit and assurance
- stakeholder engagement

Considerable capital investment has been made to configure the network to provide real-time asset performance data that is used to develop a range of high and lower level performance indicators, including those that are required to be reported under the terms of our distribution licence. Additionally, CitiPower conducts a range of internal and external reviews of the network and asset management system performance through internal audits, external audits and via regular management reviews. Where improvements to the AMS are required, these are consolidated into an AMS improvement plan.

13.1.5 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, chapters 3 and 14 of this DAPR cover the effect on the system of ageing and potentially unreliable assets.

13.1.6 Distribution Losses

Distribution losses refer to the energy used in transporting it across distribution networks. In 2019/20, 4.2 per cent of the total energy into the CitiPower network was made up of losses. This is essentially calculated as the difference between the energy that CitiPower procures and that which it supplies. These losses represent 88 per cent of CitiPower's total greenhouse gas emissions, as defined under the *National Greenhouse and Energy Report Act*.

CitiPower 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. CitiPower, as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchases.

13.1.7 Contact for further information

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

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

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

14 Asset Management Methodologies

The Asset Management Framework (AMF) describes the Asset Management System (AMS) that is applied to CitiPower's network assets, and requires the AMS to:

- support the asset life cycle
- recognise the value of assets in decision-making at each stage of the life cycle
- enable asset management decisions to be optimised based on quantified risk, asset performance and life cycle cost.¹⁰

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

CitiPower's preferred asset management methodologies⁹ applied to its network assets are as follows:

- Reliability-Centred Maintenance (RCM) — CitiPower applies a reliability and safety-based regime which is based on the principles of RCM methodology 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, etc. The approach has regard for the asset age, condition and operating environment
- Condition Based Risk Management (CBRM) — this methodology is applied to determine the condition of assets from routine inspection and maintenance, including the risk of the deterioration, of major items of plant and critical high volume asset replacements These are discussed in more detail in the sections below.

¹⁰ CitiPower and Powercor Australia Asset Management System Framework (March 2019) page 7

⁹ Where the application of RCM or CBRM methodologies are not practical, alternative asset management methodologies are applied e.g high volume or low criticality asset classes

14.1 Reliability Centred Maintenance (RCM)

CitiPower applies a reliability and safety based regime, based on RCM principles, regulatory obligations and risk assessment, 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.

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. Asset replacements for Poles assets are not determined by RCM alone, the RCM is an input into the CBRM model which provides a more granular quantification of risk and appropriate interventions.

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

Figure 14.1 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 occurred on the same or similar equipment; are prevented by existing maintenance 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 occurred, 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, regulations, 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
 - 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 periodically. 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.

As part of the Pole Management Improvement Program, a pole CBRM model is being established for implementation mid-2021 to enable a risk based asset management approach. This will result in proactive pole interventions on a risk justified basis when operationalised.

A.1. Location and timing of asset retirements

The location and the timing of the retirements of high volume asset types is 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.

14.2 Condition Based Risk Management (CBRM)

CBRM is a structured methodology that combines CitiPower's engineering experience, asset information, environmental factors, operating context to define current and future condition, performance and to quantify consequence and risk of asset failure for network assets.

The CBRM methodology that CitiPower uses has been developed by EA Technology and is integrated into CitiPower's asset and investment planning software¹¹.

CitiPower applies the CBRM methodology to the following asset classes:

- poles
- zone substation transformers and regulators
- zone substation and switching station switchboards
- zone substation and switching station circuit breakers
- protection relays
- low voltage circuit breakers
- ring main units.

Where applicable, new asset models are developed and implemented by CitiPower to quantify and manage asset risk through prioritised interventions. The following models are currently under development:

- high voltage distribution cables
- distribution regulators.

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

¹¹ Copperleaf Investment Planning and Management software

Table 13.1 Steps in the CBRM process

Step	Description
1	Define asset condition Health indices (HI) 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 investment 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
- 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, CitiPower updates the data in its CBRM models as part of its budget submission process. CitiPower 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, timing of the investment may change due to:

- risk reduction benefits of the project when compared to other projects
- alignment opportunities with augmentation projects for delivery synergies.

14.3 Other methodologies

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.

15 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.

15.1 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. It indicates how the current retirement date has changed from the date specified in the 2021 DAPR. A more detailed assessment, including a consideration of non-network alternatives will be carried out at the business case and RIT-D stage. Further changes to the planned retirements and de-ratings below may arise from this further assessment.

Table 15.1 Planned asset retirements and de-ratings

Location	Asset	Project	Retirement date	2021 DAPR
Albert Park (AP) Zone Substation	AP 11kV No1 Bus - J18/J22 Circuit Breaker	Replacement	2025	2025
Albert Park (AP) Zone Substation	AP 11kV No2 Bus - J18/J22 Circuit Breaker	Replacement	2024	2024
Albert Park (AP) Zone Substation	AP 11kV No3 Bus - J18/J22 Circuit Breaker	Replacement	2024	2024
Celestial Avenue (WA) Zone Substation	Transformer 1	Replacement	2024	2024
Celestial Avenue (WA) Zone Substation	Transformer 2	Replacement	2025	2026

Location	Asset	Project	Retirement date	2021 DAPR
Collingwood (B) Zone Substation	B 11kV Email J18 HV Switchboard	Replacement	2026	2024
Fishermans Bend (FB) Zone Substation	FB 11kV No1 Bus - J18/J22 Circuit Breaker	Replacement	2025	2025
Fishermans Bend (FB) Zone Substation	FB 11kV No2 Bus - J18/J22 Circuit Breaker	Replacement	2025	2025
Fishermans Bend (FB) Zone Substation	FB 11kV No3 Bus - J18/J22 Circuit Breaker	Replacement	2025	2025
North Richmond (NR) Zone Substation	Transformer 2	Replacement	2026	2026
Toorak (TK) Zone Substation	TK 11kV No1 Bus - J18/J22 Circuit Breaker	Replacement	2026	2026
Toorak (TK) Zone Substation	TK 11kV No2 Bus - J18/J22 Circuit Breaker	Replacement	2026	2026
North Richmond (NR) Zone Substation	Transformer 1	Replacement	2027	Not included
Little Bourke St (JA) Zone Substation	Transformer 1, 2 & 3 Cooling Towers	Replacement	2023	Not Included

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

The excel based detailed system limitation reports for asset replacements can be found at the link below by searching for asset replacement system limitation report:

<https://spaces.hightail.com/space/UaPnYI6yeV>

15.1.1 Albert Park **(AP)** Zone Substation 11kV No1, 2 & 3 Bus J18/J22 Circuit Breakers

The Albert Park **(AP)** zone substation is served by 66KV sub-transmission lines from the Fishermans Bend terminal station **(FBTS)** in a loop with Montague zone substations **(MG)**. The three 20/27 MVA 66/11kV transformers feed three 11kV bus sections consisting of a mix of Email J18/J22 oil filled circuit breakers and Reyrolle LMVP vacuum circuit breakers. This project is to replace existing Email J18/J22 oil filled circuit breakers from bus section 1, 2 and 3.

The 11KV bus sections consists of old non arc fault contained Email J18 and J22 oil filled circuit breakers installed at transformer incomers, bus section ties and feeder positions which have been in service for 59 years.

The current CBRM model has determined that the J18 and J22 circuit breakers indicate a health index of 5.5 and projected health index of 6.3 in next five years, and is nonetheless forecast to replace No.1 Bus in 2025 and No. 2 and No. 3 Bus in 2024 respectively.

Currently this switchgear is inspected and tested according to twelve yearly maintenance plans. An oil filled J18 or J22 circuit breaker failure will risk the reliability of the network due to the inadequate spare parts availability and the unavailability of internal and external skilled resources to repair these old assets safely.

CitiPower estimates that with the 11kV J18 & J22 Circuit Breakers at AP Zone Substation retired at the end of their lifetime in 2026 there will be 53.7 MVA of load at risk and for 8760 hours it will be unable to supply all customers.

To address the anticipated constraints at AP zone substation switchboard, CitiPower considers that the following options could be implemented to manage the risk:

- replace Email J18 & J22 circuit breakers at AP zone substation with SF6 or Vacuum type new circuit breakers for an estimated total cost of \$1.6 million
- Transfer load away to adjacent zone substations via 11kV links to adjacent zone substations of Montague **(MG)**, St Kilda **(SK)** and South Melbourne **(SO)** zone substations up to a maximum transfer capacity of 6.1 MVA.

Given recent offline testing of the switchboard shows the insulation is in good condition, CitiPower's preference is to replace the J18 & J22 circuit breakers within the existing switchboard.

15.1.2 Celestial Avenue (WA) Zone Substation Transformer 1

The Celestial Avenue **(WA)** zone substation is supplied at 66kV via sub transmission lines originating from Victoria Market (VM) zone substation and currently comprises of two 66/11kV 20/27 MVA transformers in service from 1963 and one 66/11kV 20/30 MVA transformer in service from 1973. WA zone substation supplies a portion of the central and eastern CBD in Melbourne.

CBRM analysis determined that the No.1 66/11kV 20/27 MVA transformer has a health index of 7.73 rising to 8.84 in next five years and is nonetheless forecast to be replaced in 2024. Excessive heating gases have been detected through routine oil sampling of the transformer. Investigations have determined that ineffective building ventilation to be the main contributing the gassing issue and accelerated aging of the asset. To manage risk until replacement the transformer is current energised only and not supply load to customers.

The risks associated with the current condition of the transformer can be efficiently mitigated by replacement in 2024. Retirement of the No.1 transformer would result in a significant shortfall of transformation capacity at WA zone substation. This would place the customers supplied at risk of extended outages during times of unplanned network contingencies.

With No1 transformer retired, CitiPower estimates that in 2025 there will be 8.4 MVA of load at risk and for 295 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 WA. Also it would not be possible to maintain the CBD security standard.

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

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Bouverie/Queensberry (**BQ**), and Victoria Market (**VM**) up to an estimated maximum transfer capacity of 12.2 MVA should a transformer fail in the interim
- replace the existing No1 transformer in 2024 with a new transformer of similar rating for an estimated cost of \$2.9 million.

CitiPower's preferred option is to replace the No.1 transformer in 2024. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast retirement date. For more details and data on the limitation please refer to the attached Systems Limitations Spreadsheet.

A demand side initiative to reduce the forecast maximum demand load by 8.4 MW at WA zone substation would defer the need for this capital investment by one year.

15.1.3 Celestial Avenue (WA) Zone Substation Transformer 2

The Celestial Avenue (**WA**) zone substation is supplied at 66kV via sub transmission lines originating from Victoria Market (VM) zone substation and currently comprises of two 66/11kV 20/27 MVA transformers in service from 1963 and one 66/11kV 20/30 MVA transformer in service from 1973. WA zone substation supplies a portion of the central and eastern CBD in Melbourne.

CBRM analysis determined that the No2 66/11kV 20/27 MVA transformer has a health index of 4.8 rising to 5.5 in the next 5 years and is nevertheless forecast to be replaced in 2025. To a lesser extent building ventilation issues have also impacted the service life of this asset and caused advanced ageing.

The associated risks with the transformer condition can be efficiently mitigated by replacement in 2025. Retirement of the No2 transformer would result in a significant shortfall of transformation capacity at WA zone substation. This would place the customers supplied at risk of extended outages during times of unplanned network contingencies.

With No2 transformer retired, CitiPower estimates that in 2026 there will be 8.5 MVA of load at risk and for 305 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 WA. Also it would not be possible to maintain the CBD security standard.

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

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Bouverie/Queensberry (**BQ**), and Victoria Market (**VM**) up to an estimated maximum transfer capacity of 12.2 MVA should a transformer fail in the interim
- replace the existing No2 transformer in 2025 with a new transformer of similar rating for an estimated cost of \$3.0 million.

CitiPower's preferred option is to replace the No2 transformer in 2025. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast

retirement date. For more details and data on the limitation please refer to the attached Systems Limitations Spreadsheet.

A demand side initiative to reduce the forecast maximum demand load by 8.5 MW at WA zone substation would defer the need for this capital investment by one year.

15.1.4 Collingwood (B) Zone Substation 11kV Email J18 HV Switchboard

The Collingwood (B) zone substation is served by two sub-transmission lines from the Richmond terminal station (RTS) in a loop with North Richmond (NR) and Collingwood (CW) zone substations. This zone substation supplies the Collingwood and Fitzroy areas.

Currently, B zone substation is comprised of two 20/27 MVA transformers operating at 66/11kV and connected to 66kV sub-transmission lines from CW and NR.

The insulation on the 11kV switchboard has been compromised due to a CB failure in 2016 and cannot be reconditioned. Whilst fit for service, these repairs are not a long term solution as evident from the intermittent low level PD (**partial discharge**) detected from the online monitoring system, and is nonetheless forecast to require replacement in 2024.

The B zone substation consists of 4 air insulated bus sections with twenty five J18 and J22 oil circuit breakers.

This switchgear has been in service since 1965 and the CBRM model has determined a health index of the Email CBs rising to 6.9 in the next five years. The average health index of the switchboard is rising to 6.2 with the maximum of 8.6 at Bus 4 in the next 5 years.

According to the zone substation switchgear asset class strategy, CitiPower plans to reduce the population of non-arc fault contained switchboard with oil filled old circuit breakers to significantly reduce the fire risks and network reliability risks should a catastrophic failure occurred of these oil filled circuit breakers.

This switchgear is currently inspected and tested according to twelve yearly maintenance plans. In addition, the online PD monitoring sensors has been installed on this switchboard for continuous monitoring. This ensures early detection of the potential failures and taking control measures in event of a failure prior to the complete replacement in 2026.

CitiPower estimates that with the 11kV switchboard retired at the end of its lifetime in 2026, the entire zone substation load of 42.8 MVA will be at risk and for 8760 hours in the year it will not be able to supply any customers from the zone substation.

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

- contingency plan to transfer load away via 11kV links to adjacent zone substations of Collingwood (CW) and North Richmond (NR) up to a maximum transfer capacity of 5.9 MVA should a circuit breaker fail in the interim
- replace 11kV switchboard at B in 2026 for an estimated cost of \$11.7 million.

CitiPower's preferred option is to replace the 11kV switchboard in 2026. The use of contingency load transfers 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 the preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 42.8 MW at B zone substation would defer the need for this capital investment by one year.

15.1.5 Fisherman's Bend (FB) Zone Substation 11kV No1, 2 & 3 Bus J18/J22 Circuit Breakers

The Fisherman's Bend (**FB**) zone substation is served by 66KV sub-transmission lines from the Fisherman's Bend terminal station (**FBTS**) in a loop with Westgate zone substation (**WG**). The three 20/30 MVA 66/11kV transformers feed three 11kV bus sections comprised of sixteen 11kV feeders supplying the Port Melbourne area.

The 11KV bus consists of old non arc fault contained Email J18 and J22 oil filled circuit breakers installed at transformer incomers, bus section ties and feeder positions in service from 1969. The current CBRM model has determined that these circuit breakers indicate a health index of 5.2 and projected health index of 6.1 in next five years, and is nonetheless forecast to require replacement in 2025.

Currently this switchgear is inspected and tested according to twelve yearly maintenance plans. A circuit breaker failure will risk the reliability of the network due to the inadequate spare parts availability and the unavailability of internal and external skilled resources to repair these old assets safely.

According to the zone substation switchgear asset class strategy, CitiPower plans to reduce the population of non arc fault contained oil filled old circuit breakers from the network to significantly reduce the associated safety and reliability risks in event of an oil filled circuit breaker failure.

CitiPower estimates that with all the 11kV J18 & J22 circuit breakers at FB zone substation retired at the end of their lifetime in 2025 the entire zone substation or 33.5 MVA of load will be at risk and for 8760 hours it will be unable to supply any customers.

To address the anticipated constraints at FB zone substation switchboards, CitiPower considers that the following options could be implemented to manage the risk:

- replace Email J18 & J22 circuit breakers at FB zone substation with SF6 or Vacuum type new circuit breakers for an estimated cost of \$1.7 million
- transfer load away via 11 kV links to adjacent zone substations up to a maximum capacity of 5.1 MVA if a circuit breaker fails in the interim.

Given recent offline testing of the switchboard shows the insulation is in good condition, CitiPower's preferences is to replace the J18 & J22 circuit breakers within the existing switchboard.

A demand side initiative to reduce the forecast maximum demand load by 33.5 MW at FB zone substation would defer the need for this capital investment by one year.

15.1.6 North Richmond (NR) Zone Substation Transformer 2

The North Richmond (**NR**) zone substation is served by two 66kV sub-transmission lines from Richmond terminal station (**RTS**) in a loop with Collingwood (**B**) zone substation. The substation currently comprises of two 66/11kV 23/28MVA transformers in service from 1958

and one 20/27 MVA transformer which was replaced in year 2000. The NR zone substation supplies the Richmond and North Richmond areas.

The transformer CBRM analysis determined that the No2 transformer has a high health index of 5.3 rising to 6.0 in the next five years. The No2 transformer replacement is expected to be completed by 2026.

With the No2 transformer retired, CitiPower estimates that in 2027 there will be 27.6 MVA of load at risk and for 1,453 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 NR.

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

- replace No2 transformer at NR with a new transformer of similar rating for an estimated cost of \$3.6 million
- Transfer load away via 11 kV links to adjacent Collingwood **(B)**, **(CL)** and Kew **(Q)** zone substations up to a maximum capacity of 3.1 MVA should the transformer fail in the interim.

CitiPower's preferred option is to replace the No2 transformer at NR in 2026. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date.

A demand side initiative to reduce the forecast maximum demand load by 27.6 MW at NR zone substation would defer the need for this capital investment by one year

15.1.7 Toorak (TK) Zone Substation 11kV No1 & 2 Bus J18/J22 Circuit Breakers

The Toorak **(TK)** zone substation is served by 66KV sub-transmission lines from the Richmond terminal station **(RTS)** in a loop with Balaclava zone substation **(BC)**. This is a three transformer zone substation with 20/30 MVA, 66/11kV transformers feed three 11kV bus sections consisting a mix of Email and Reyrolle oil filled circuit breakers. This project is to replace existing Email J18/ J22 oil filled circuit breakers from the No 1 and 2 buses.

The 11KV buses consist of old non arc fault contained Email J18 and J22 circuit breakers installed at bus ties, transformer incomers and feeder positions which have been in service for 51 years. The current CBRM model has determined that these circuit breakers indicate a health index of 4.3 and projected health index of 5.1 in next five years and is nonetheless forecast to require replacement in 2026.

Currently this switchgear is inspected and tested according to twelve yearly maintenance plans. A circuit breaker failure will risk the reliability of the network due to the inadequate spare parts availability and the unavailability of internal and external skilled resources to repair these old assets safely.

According to the zone substation switchgear asset class strategy, CitiPower plans to reduce the population of non arc fault contained oil filled old circuit breakers from the network to significantly reduce the associated safety and reliability risks in event of an oil filled circuit breaker failure.

CitiPower estimates that with the No 1 and No 2 bus 11kV J18 & J22 circuit breakers at TK Zone Substation retired at the end of their lifetime in 2026 there will be 56.3 MVA of load at risk and for 8760 hours it will be unable to supply all customers.

To address the anticipated constraints at TK zone substation switchboards, CitiPower considers that the following options could be implemented to manage the risk:

- replace bus 1 and 2 Email J18 & J22 circuit breakers at TK zone substation with SF6 or Vacuum type new circuit breakers for an estimated cost of \$1.2 million.
- Transfer load away to adjacent zone substations via 11kV links to Richmond (**R**), Balaclava (**BC**), Armadale (**AR**) zone substations up to a maximum transfer capacity of 26.2 MVA should a circuit breaker fail in the interim.

Given recent offline testing of the switchboard shows the insulation is in good condition, CitiPower's preference is to replace the J18 & J22 circuit breakers within the existing switchboard.

15.1.8 North Richmond (NR) Zone Substation Transformer 1

The North Richmond (NR) zone substation is served by two 66kV sub-transmission lines from Richmond terminal station (RTS) in a loop with Collingwood (B) zone substation. The substation currently comprises of two 66/11kV 23/28MVA transformers in service from 1958 and one 20/27 MVA transformer which was replaced in year 2000. The NR zone substation supplies the Richmond and North Richmond areas.

The transformer CBRM analysis determined that the No1 transformer has a health index of 6.2 rising to 7.0 in the next five years. The No1 transformer replacement activities are expected to be completed by 2027.

With the No1 transformer retired, CitiPower estimates that in 2027 there will be 27.6 MVA of load at risk and for 1,453 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 NR.

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

- replace No1 transformer at NR with a new transformer of similar rating for an estimated cost of \$3.6 million
- transfer load away via 11 kV links to adjacent Collingwood (B), (CL) and Kew (Q) zone substations up to a maximum capacity of 3.3 MVA should the transformer fail in the interim.

CitiPower's preferred option is to replace the No1 transformer at NR in 2027. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date.

A demand side initiative to reduce the forecast maximum demand load by 27.6 MW at NR zone substation would defer the need for this capital investment by one year.

15.1.9 Little Bourke St (JA) Zone Substation Transformer Cooling Towers

The Little Bourke St (JA) zone substation is served by 66kV sub-transmission lines from West Melbourne Terminal Station (WMTS), Waratah Place (WP), Little Queen (LQ) and Victoria Market (VM) zone substations. The JA zone substation comprises of three 66/11kV 55MVA transformers supplying the western Melbourne CBD district.

The cooling system for the three transformers, is an aged open loop water cooled system located on the substation roof top. These cooling towers are currently in a poor condition due to excessive corrosion of its structures and functional components. This condition is imposing a high reliability risk to all three transformers with frequent cooling system interruptions. This old cooling system replacement activities are expected to be completed in 2024.

In event of a complete cooling system failure, CitiPower estimates that in 2024 there will be 136.3 MVA of load at risk and for 8,760 hours in the year it will not be able to supply all customers from the zone substation.

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

- replace the three aged cooling towers with a new cooling system while maintaining transformer performance targets, for an estimated cost of \$1.2 million
- transfer load away to adjacent zone substations up to a maximum capacity of 68.3 MVA should the transformers tripped by cooling system failures in the interim.

CitiPower's preferred option is to replace old cooling towers at JA in 2024. The use of contingency load transfers will mitigate the risk should the asset fails ahead of its forecast replacement date.

15.1.10 West Melbourne terminal station (WMTS) 22kV sub-transmission network

The West Melbourne terminal station (**WMTS**) proposed works are detailed in section 10.1 above. It is comprised of two transformers that each has a capacity of 165MVA operating at 22kV and four transformers that each has a capacity of 150MVA operating at 66kV. The 22kV connection is used by CitiPower however the 66kV load is shared by CitiPower (79 per cent) and Jemena Electricity Networks (21 per cent).

AusNet Services are undertaking significant works to rebuild WMTS due to the condition and age of the plant and equipment. As part of these works, AusNet Services proposed to retire the 22kV switchgear given its deteriorated condition.

CitiPower's 22kV sub-transmission network is also aged and deteriorated, particularly the transformers and indoor switchgear within existing zone substations. Some of these zone substations also have a secondary voltage of 6.6kV that is inconsistent with the current standard of 11kV used in those areas. CitiPower's strategy is to progressively replace the 22kV sub-transmission network with the 66kV sub-transmission network and convert existing 6.6kV distribution feeders to 11kV.

To reduce the cost of rebuilding WMTS, AusNet Services will now retire the 22kV supply assets which include transformers and switchgear. This is consistent with CitiPower's strategy.

CitiPower's 22kV WMTS sub-transmission network included Bouverie St/Bouverie Queensberry (**BSBQ**), Spencer St (**J**), Laurens Street (**LS**) and Dock Area (**DA**) zone substations. As per the preferred strategy below, BSBQ was transferred to Bouverie/Queensberry (**BQ**) during 2017 and decommissioning completed at the end of 2017. J was transferred to Little Bourke St (**JA**) during 2020 and decommissioning completed at the end of 2020. As a consequence of offloading J, the adjacent Tavistock Place (**TP**) 22/6.6kV zone substation lost its 6.6kV ties. Rather than upgrading TP to 66/11kV in the short term, the TP feeders were transferred to the Little Bourke St (**JA**) and Victoria Market (**VM**) 66/11kV zone substations during 2020-2021 and decommissioning completed in 2021. Laurent (LS) zone substation is declared Out of Service and the LS feeders were transferred to Bouverie/Queensberry (BQ) in 2022.

The following table details the deterioration in health indexes of the transformers at the above zone substations which are high indicating an elevated risk of failure:

Table 14.2 CitiPower WMTS 22kV zone substation health indices

Zone substation	2022 Health Index		2027 Health Index (no augmentation)	
	Transformers	Switchgear	Transformers	Switchgear
Dock Area (DA)	0.5, 5.58, 5.78	3.7	0.5, 6.15, 6.49	4.4

In the absence of any alternative strategies, the scheduled 'like for like' replacements are outlined below:

- Dock Area (**DA**) zone substation also requires replacement of three transformers due to age and condition. The first transformer was replaced in 2022 and the remaining two transformers will be replaced by one larger transformer in 2023
- Laurens Street (**LS**) zone substation 'end of life' replacement of the 6.6kV switchgear is declared out of service with the feeders were transferred to Bouverie/Queensberry in 2022. The remaining work is to decommission the zone substation in 2023.

An alternative and preferred strategy is to retire the 22kV sub-transmission network earlier than scheduled, by offloading the Bouverie St/Bouverie Queensberry (**BSBQ**), Spencer St (**J**), and Laurens Street (**LS**) zone substations served by WMTS 22kV assets, and upgrade the Dock Area (**DA**) zone substation to 66kV with supply from WMTS 66kV, in collaboration with the AusNet Services rebuild of WMTS.

The Vic Rail (**VR**) customer substation will also need to be transferred to the WMTS 66kV point of supply.

The exact timing of these works is currently being co-ordinated with AusNet Services, and the table below provides the estimated timing and cost of the major components of this plan. DA No.1 transformer has been removed in 2021 and another in 2022, the remaining transformer is planned to be retired and removed in 2023.

As these works are driven by asset replacement needs, CitiPower considers these works to be non-demand driven augmentation.

Table 15.3 WMTS 22kV offload plan

Zone substation	Description	Direct cost estimate (\$ million)				
		2023	2024	2025	2026	2027
Laurens St (LS)	Permanently transfer the entire LS load to the BQ zone substation, by extending 11kV high voltage feeders from LS to BQ (approved in 2017)	0.8				
Dock Area (DA)	Upgrade DA and associated sub-transmission cables to 66kV	1.0				

CitiPower and AusNet Services have identified that the costs to offload the 22kV network are far lower than replacing the existing aged 22kV assets and rectifying the building issues necessary to maintain the WMTS 22kV and associated sub-transmission network.

15.1.11 Brunswick Area Strategy - Retirement of the 22kV sub transmission and 6.6kV distribution network

The second phase of the Brunswick Area Strategy is discussed in Section 7.1 above. It is proposed to rebuild Brunswick (C) zone substation and to transfer the entire Fitzroy (F) and Brunswick (BK) zone substation load to Brunswick (C) zone substation and convert the distribution network voltage from 6.6kV to 11kV.

Fitzroy (F) zone substation is supplied by three 22kV underground cables from Brunswick Terminal Station (BTS). These cables have experienced multiple faults in recent years and one is permanently out of service. F zone substation has three 22/6.6kV transformers rated at 10/13MVA. One of these transformers (F No 2 Transformer) has also been declared permanently out of service due to oil analysis indicating an internal thermal defect. The F No 3 Transformer is a sister unit that may also be susceptible to this condition, which was also observed on sister units at J zone substation before decommissioning. The 6.6kV switchgear at F zone substation has compound filled busbars that in the event of failure pose a significant safety hazard and are considered unrepairable. The 6.6kV circuit breakers are manually charged units that also require hand applied earths. The circuit breakers have experienced an increasing number of defects in recent years and their older design does not include modern safety features. Both the No 3 Transformer and the 6.6kV switchgear were manufactured in the 1940s. Finally, the majority of the protection relays are types targeted for replacement due to obsolescence and reliability issues. Overall the asset health is poor and requires intervention.

Brunswick (BK) zone substation is supplied by three 22kV overhead lines from Brunswick Terminal Station (BTS). BK zone substation has three 22/6.6kV transformers rated at 10/13MVA. Two of these transformers are sister units to those at F zone substation and have the potential for a similar thermal defect to emerge. The units are in unsatisfactory visual condition, with minor oil leaks. Site oil containment is satisfactory having concrete

bunds and a stormwater oil/water system. The 6.6kV switchgear is not suitable for upgrading to 11kV and limits the options for augmentation at the site. The site also has three 6.6/11kV auto transformers for supplying 11kV feeders. The auto transformers are in poor visual condition with moderate oil leaks. Oil containment requires improvement on the No 3 auto transformer to maintain compliance. Overall asset health is unsatisfactory and requires intervention.

Both F and BK zone substation have one newer (2011) transformer each which is a sister unit to the Richmond (R) zone substation No 3 Transformer. The other two transformers at Sub R are sister units to the 1940s units at F and BK and will also require replacement in the medium term. It would be advantageous to utilise the F and BK transformers at Sub R to provide a matched set of transformers at minimal cost once the F and BK zone substations are decommissioned.

15.2 Group of assets

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

15.2.1 Poles and towers

CitiPower 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 five years is expected to increase in line with changes to poles management policies. CitiPower 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 which forms an input into the CBRM model to inform the policy position. The inspection frequency is based on priority and economic optimisation to deliver the legislative obligations under the Electricity Safety Act 1998. 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, (i.e. pole reinforcement), it is necessary and prudent to replace the pole or tower.

15.2.2 Pole top structures

CitiPower intends to replace pole top structures in various locations across its network in each year of the forward planning period. Pole top structures includes the following assets, which are managed as set out below:

- 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 operate; 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.

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 expected to increase in line with changes to pole top management policies.

15.2.3 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
- oil switches use mineral oil 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.

CitiPower intends to replace most¹² switchgear assets in each year of the forward planning period in line with historical volumes for most assets. Line mounted Air-break switches are now replaced with gas switches in place of cyclic maintenance or defect repair activities which is above the historical replacement volumes. This change has been implemented to address key issues such as operational delivery inefficiencies and inability to maintain the assets due to equipment obsolescence.

15.2.4 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.

¹² All switchgear with the exception of line mounted Air-break switches

CitiPower 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 historical replacements due to safety issues associated with deteriorated insulation on twisted grey PVC (and the “dog-bone” terminations) and open wire systems. In addition to these, the continued use of AMI meter analytics to detect, assess and replace services where the neutral is suspect, to address safety issues.

15.2.5 Overhead conductor

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

Conductor replacements are based on two methodologies:

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

CitiPower plans to replace sections of overhead conductors each year over the forward planning period. The location and the timing of the conductor replacement will be determined based on condition assessments. The forecast number of sections of overhead conductor to be replaced in the coming 5 years is in line with historic replacements with an expected increase from 2024. 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 is expected in the near term.

In addition CitiPower plans to address insulation deficiencies around foreign objects such as sewer vents.

15.2.6 Underground sub-transmission 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 five 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.

Over the forward planning period CitiPower plans to replace underground cables in line with historical volumes.

15.2.7 Other underground assets

Other underground assets include the following:

- Cable-head termination, which is the termination of an underground cable. Over the forward planning period CitiPower plans to replace aged metal box type terminations in line with historical volumes.
- Distribution service pits are the point where the underground service connects to the customer premises, typically of concrete and plastic construction. Repairs and replacements are to be in line with historical volumes.
- CBD roadways pits are access points for HV distribution feeders and communication cables which are situated under roadways within the CitiPower CBD network. These assets are of concrete, steel brick construction. Over the forward planning period CitiPower plans to repair or replace large roadway pits due to an increase in identified structural defects from routine inspection activities. Repair and replacements are planned to be more than historical volumes.
- Low-voltage pillars are typically concrete or steel, where low voltage underground cables are terminated. CitiPower plans to replace or refurbish large type LV distribution pillars due to identified defects and condition in line with historical volumes.
- Services (underground), which are required to connect a customer supply point (underground pit) to the network, are replaced as a result of defect reports

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

15.2.8 Distribution plant

In the forward planning period, CitiPower plans to replace distribution plant assets in line with historical volumes. Distribution plant assets include a variety of assets listed below:

- HV Circuit breakers (22kV, 11kV and 6.6kV) 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 scheduled inspections and defect reporting. 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, replacement is managed by the following strategies.
 - **Unplanned** - on condition identified by scheduled inspection and defect reports.
 - **Planned** - through prioritised risk based replacement using the implemented CBRM model.
- 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.

- 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.

15.2.9 Zone substation switchyard equipment

In the forward planning period, CitiPower plans to replace station switchyard assets in line with historical volumes. Zone substation switchyard equipment assets include a variety of assets including those listed below:

- Surge arrestors, which are required to protect primary plant from voltage surges, are generally replaced after failure. They can also be replaced based on age and condition, or opportunistically where other asset replacements take place at the zone substation.
- 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. 11kV busses usually form part of modular switchgear and thus are included as part of switchgear replacement.
- Joints, terminations and connector assets are replaced on inspection, or as part of the replacement of the assets to which they are connected.
- 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.

15.2.10 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. CitiPower plans to replace protection and control room equipment and instruments each year over the forward planning period. This includes the following assets:

- Protection relays: are replaced based on age and/or economic assessment of risk.
 - CitiPower'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.
 - Relays will be replaced at the following zone substations over the forward planning period: Albert Park (**AP**), Armadale (**AR**), Collingwood (**B**), Balaclava (**BC**), , Collingwood (**CW**), Fishermen's Bend (**FB**), Deepdene (**L**), Little Queen (**LQ**), Montague (**MG**), Northcote (**NC**), Kew (**Q**), Riversdale (**RD**), South Melbourne (**SO**) and Westgate (**WG**).

- 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 CitiPower 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 CitiPower to maintain asset spares.

Aside from the proactive replacement of protection relays at zone substation locations, the timing and the location of the replacement of other assets are determined through routine inspection and detection of defects, or upon asset failure.

15.3 Planned asset de-ratings

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

15.4 Committed projects

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

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

15.5 Timing of proposed asset retirements / replacements and deratings

CitiPower is now also required to provide 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.

CitiPower has 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.

The table below summarises the change in timing of proposed major network retirements/replacements.

Table 15.4 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2021 DAPR	2022 DAPR
Celestial Avenue (WA) Zone Substation Transformer 2	2026	2025 ¹²
Collingwood (B) Zone Substation 11kV Email J18 HV Switchboard	2024	2026 ¹²
North Richmond (NR) Zone Substation Transformer 1	Not included	2027
Little Bourke St (JA) Zone Substation Transformer 1, 2 & 3 Cooling Towers	Not included	2023

¹² Project timing changes allows the business to address reliability and safety risks associated with JA water cooling system, defective CBD cable tunnels and the commencement of the LQ 11kV switchboard replacement

16 Regulatory Tests

This chapter sets out information about large network projects that CitiPower 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 CitiPower 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 that have been “committed” to by a distributor on or prior to 30 January 2018. These projects are also listed in this chapter, as well as published on our website.¹³ There is no material impact on connection charges and distribution use of system charges that have been estimated.

16.1 Current regulatory tests

There were no Regulatory Test projects underway or completed by CitiPower in 2022.

16.2 Future regulatory investment tests

Based on the information contained within sections 7, 8, and 14, CitiPower expects to commence reviewing options to address the identified system limitations. The table below sets out the possible timeframes for consideration of RIT-D under clause 5.17 of the NER relating to investments where the cost of the most expensive credible option is more than \$6 million.

¹³ <https://www.citipower.com.au/network-planning-and-projects/network-planning/>

Table 16.2 Future RIT-D projects

Project name	Proposed RIT-D start date	Comments
Brunswick Area Strategy – Retirement of the 22kV sub transmission and 6.6kV distribution network	June 2024	Rebuild Brunswick (C) zone substation and transfer of Fitzroy (F) and Brunswick (BK) zone substation load to Brunswick (C) zone substation and conversion to 11kV
Port Melbourne Area Strategy – Retirement of the 6.6kV network	June 2025	In accordance with the AER determination, this project is to be delivered post 2026. Transfer of Port Melbourne (PM) and Fishermans Bend (E) zone substations load to Westgate (WG) and conversion to 11kV
HV Switchboard Replacement B 11kV Email J18	June 2024	Replace the 11kV switchboard
Western CBD and Docklands security strategy	October 2023	Significant reduction in forecast CBD load growth due to COVID-19 pandemic requires re-assessment and development of strategic options to meet project aim.

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

16.3 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 16.3 Excluded RIT-D projects

Project name	Description	Scheduled completion date
Decommission of Laurens Street (LS) zone substation	Transfer of load to BQ zone substation and decommission of LS zone substation. The LS zone substation assets are aged and poor condition. We have committed to	Project underway expected completion

Project name	Description	Scheduled completion date
	decommissioning these 22kV sub-transmission assets rather than the more expensive option of replacing them. Required as part of the program to decommission the 22kV sub-transmission network from WMTS and replace with the 66kV network.	in Q2 2023

17 Network Performance

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

17.1 Reliability measures and standards

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

The key reliability of supply metrics to which CitiPower 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
- 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 CBD and urban feeder types.

The table below shows the reliability service targets set by the AER for CitiPower in its Distribution Determination in April 2021.¹⁴ CitiPower reported to the AER its 2021/22 Financial Year performance against those targets in the 2021/22 Financial Year Regulatory Information Notice (**RIN**), and these figures are included in the table.

¹⁴ AER, CitiPower - Distribution Determination 2021–2026, Final, April 2021.

Table 17.1 Reliability targets and performance

Feeder	Parameter	AER target (2021-26)	2021-2022 performance
CBD	SAIDI	8.855	9.312
	SAIFI	0.108	0.060
	MAIFI	0.0024	0.0.0368
Urban	SAIDI	28.173	20.849
	SAIFI	0.392	0.269
	MAIFI	0.1949	0.1595

In 2021/22 FY, CitiPower achieved its targets for CBD SAIFI and Urban SAIDI, SAIFI & MAIFI parameters.

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

17.1.1 Corrective reliability action undertaken or planned

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

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

- undertaking the various routine asset management programs, including:
 - inspection of nearly 15,000 poles and pole tops
 - testing of lines such as sub-transmission cables in the CBD
 - maintenance and replacement programs for overhead and underground lines, primary plant (and secondary systems
 - civil works to restore zone substation buildings, switchrooms and transformer enclosures at various zone substations.
- 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 6.6kV and 11kV switchgear in Zone substations including several continuous on line monitoring systems
 - vegetation management programs to improve line clearances
 - 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
 - dehydration of power transformer.
- use of innovative solutions such as auxiliary power generation or by-pass cables to maintain supply where practicable
 - conduct fault investigations of significant outages to understand the root cause, in order to prevent a re-occurrence
 - 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 2021/22 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.

17.2 Quality of supply measures and standards

The main quality of supply measures that CitiPower control are:

- voltage, including measuring customer voltage and network voltage using AMI data
- harmonics.

17.2.1 Voltage

Voltage requirements are governed by the VEDCoP and the NER. The NER requires that CitiPower adheres to the 61000.3 series of Australian and New Zealand Standards.

In addition, the VEDCoP requires that CitiPower must maintain nominal voltage levels at the point of supply to the customer's electrical installation in accordance with the Electricity Safety (General) Regulations 2019 or, if these regulations do not apply to the distributor, at one of the following standard nominal voltages:

- (a) 230V
- (b) 400V
- (c) 460V
- (d) 6.6kV
- (e) 11kV

(f) 22kV or

(g) 66kV.

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

Table 17.2: Permissible voltage variations¹⁵

STANDARD NOMINAL VOLTAGE VARIATIONS					
	Voltage Level in kV	Voltage Range for Time Periods			Impulse voltage
		Steady State	Less than 1 minute	Less than 10 seconds	
1	<1	AS 61000.3.100*	+ 13%	Phase to Earth +50%, -100%	6 kV peak
2**		+ 13% - 10%	- 10%	Phase to Phase +20%, -100%	
3	1 – 6.6	± 6% (± 10% Rural Areas)	± 10%	Phase to Earth +80%, -100%	60 kV peak
4	11			Phase to Phase +20%, -100%	95 kV peak
5	22				150 kV peak
6	66	± 10%	± 15%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	325 kV peak

CitiPower must use best endeavours to minimise the frequency of **voltage** variations allowed for periods of less than 1 minute (other than in respect of AS 61000.3.100 where the time period of less than one minute does not apply).

CitiPower is able to measure voltage variations at zone substations, as many have power quality meters installed. This enables CitiPower to address any systemic voltage issues. The table below provides the number of instances of voltage variations at CitiPower zone substations in the 2021-22 financial year, although many of these instances would have occurred from abnormalities or transients in the system.

¹⁵ Table 2 Clause 20.4.2 of the Victorian Electricity Distribution Code of Practice.

Table 17.3 Zone substation voltage variation in 2021-22 FY

Voltage variations	Number of occurrences
Steady state (zone substation)	155
One minute (zone substation)	1
10 seconds (zone substation) Min<0.7	458
10 seconds (zone substation) Min<0.8	78
10 seconds (zone substation) Min<0.9	547

CitiPower responds quickly to investigate and resolve voltage issues. The issues may be identified through the system monitoring undertaken by CitiPower 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 CitiPower 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, or
- installation of additional reactive power compensation, such as capacitor banks, to improve voltage performance.

CitiPower 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.

17.2.2 Customer voltage performance at low voltage

AS 61000.3.100 (as referenced in chapter 16.2.1) requires that the 99th percentile voltage must be less than 253V and the 1st percentile voltage must be above 216V. This is a deviation from the previous requirements that stipulated a hard limit of 216V and 253V. The VEDCoP stipulates the above mentioned voltage levels should be at the meter closest to and applicable to the point of supply as mentioned in clause 20.4.1 of VEDCoP. AS 61000.3.100 also recognises that for distribution companies like CitiPower, with hundreds of thousands of customers spread over a large geographic area, that achieving 100% compliance for all customers at all times is not economically or practically possible. Therefore a network is considered to be ‘functionally compliant’ if it can achieve voltage within each limit for 95% of sites.

Figures 17.1 and 17.2 below show CitiPower's performance for both 99th percentile voltage (V99%) and 1st percentile voltage (V1%) with respect to the 95% functional compliance target. Additionally, the average voltage data is provided in Figure 17.3 as required by VEDCoP.

Figure 17.1 Monthly V99% 253V customer compliance

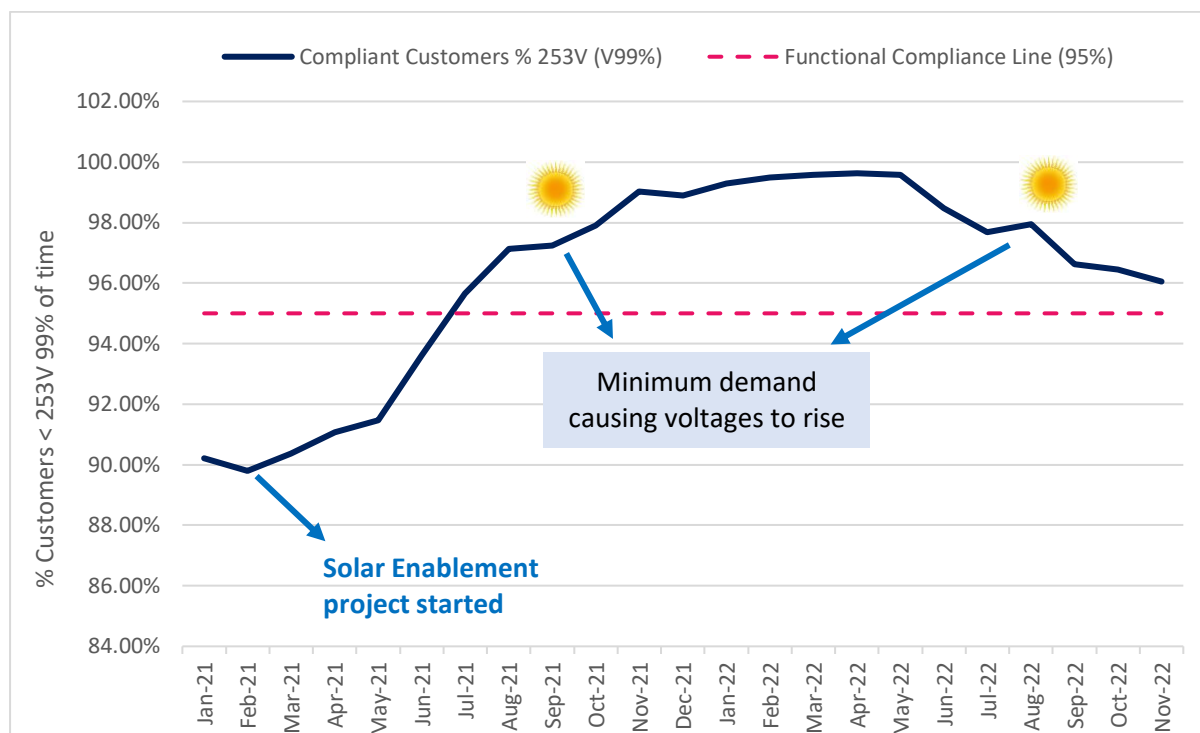


Figure 17.2 Monthly V1% 216V customer compliance

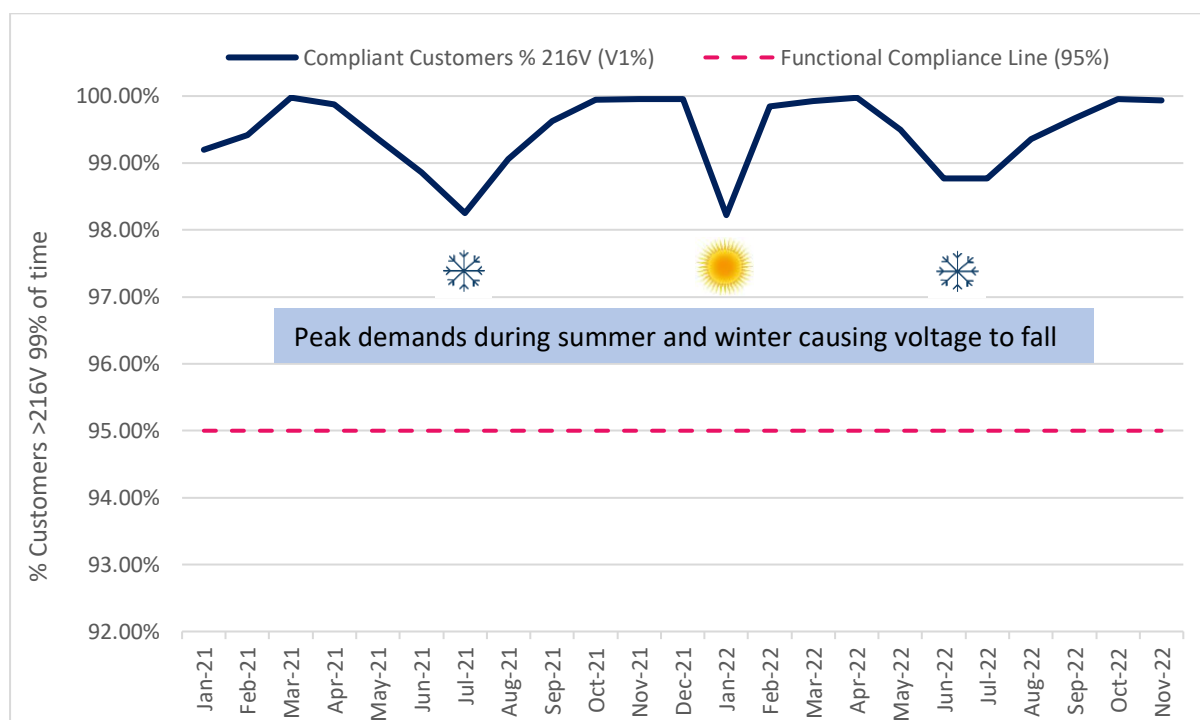
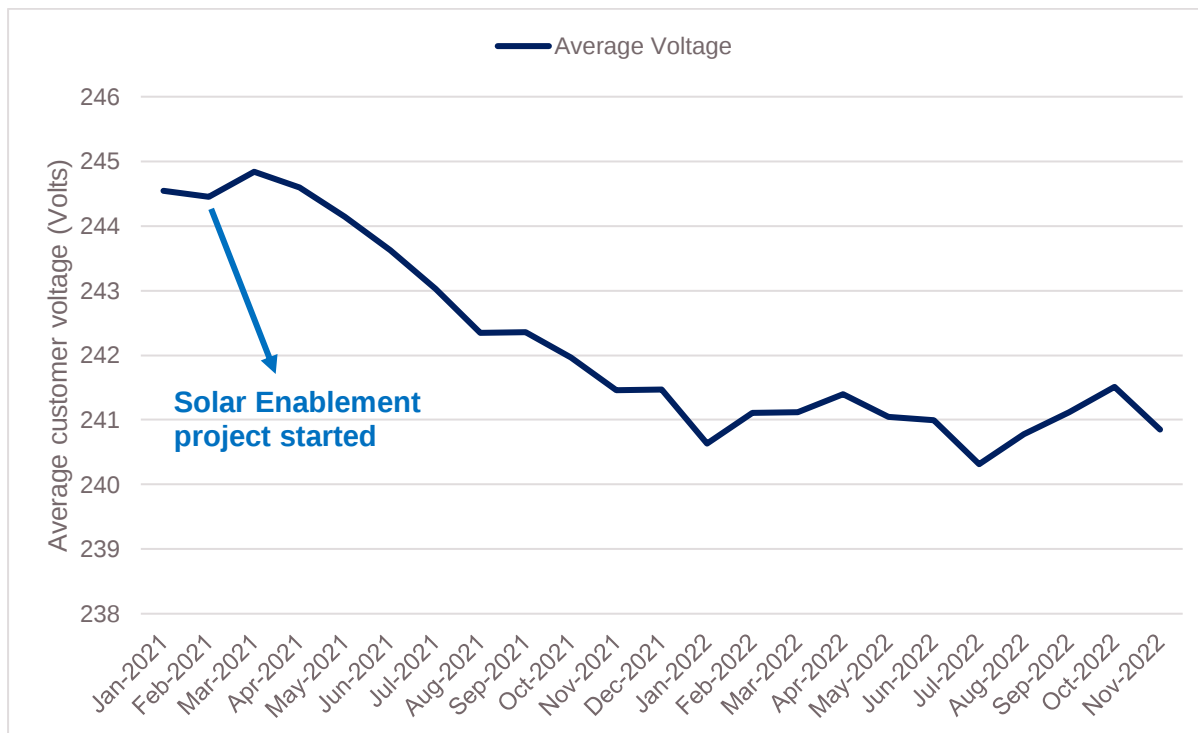


Figure 17.3 Monthly average voltage during 2021-22



As noted in Section 3.7, CitiPower is undertaking numerous steps to improve customer voltage and have significantly increased works in 2022 with CitiPower's 5-year Solar Enablement program. As a result, V99% performance has demonstrably improved year-on-year (i.e. comparison of June 2021 vs. June 2022). It should be noted there is seasonal and monthly variability to V99% performance and hence a year-on-year evaluation approach is taken to assess the impact of improvement works.

Moreover, the V1% performance of the CitiPower networks remains high with some seasonal variations as shown in Figure 17.2. As illustrated in Figure 17.3, the average voltage levels on the networks are continuing to decline over time towards the standard voltage (230V).

Additionally, Solar PV inverter compliance to AS 4777 is a key priority area for CitiPower to maintain voltage and improve Solar PV hosting capacity. On 1 October 2022, CitiPower introduced a new commissioning sheet process to embed inverter compliance within our export approval system. Advanced DVMS analytics trialled throughout the period have allowed us to detect and verify compliance rates. Initial results suggest inverter compliance has improved significantly throughout the period. This will be a continued focus going forward, as achieving near 100% installation compliance is crucial to maximising the amount of rooftop solar on the network while improving network wide functional voltage compliance.

Going forward, to improve and maintain voltage compliance CitiPower will:

- invest in new systems, including the completion of implementing the DVMS and optimising its settings to manage network voltages in real time based on feedback from our AMI meters to optimise customer volts;

- invest in the network, by continuing to identify works that improve customer voltage and deliver extra hosting capacity;
- complete the works as part of the solar enablement program discussed in section 3.7.

17.2.3 AMI voltage data

CitiPower is required to report AMI voltage information, as specified in Schedule 2 of the VEDCoP.

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

The voltage data to be published for each section is the aggregated 10-minute average voltage data, aggregated over 3 months periods (December-November), by time of day into 6 hour periods (from 4am to 4am). Under the requirements of the Clause 19.4.1(e) of the VEDCoP this planning report is required to include all of the information provided in Table 7 of the Code.

The CitiPower dataset provided is the average of all customers connected to the relevant feeder and regulator section. The averages are calculated by taking the average across all customers for each 10 minute block within each day of the year. Those 10 minute averages are then grouped into the season and time period and averaged for the report.

CitiPower's data is sorted by year and month and can be found by accessing the link shown below and searching for LV voltage reports:

<https://spaces.hightail.com/space/UaPnYI6yeV>

For avoidance of any doubt, blanks in the data reflect changes in the network that cause a feeder to be out of service for an entire quarter. These changes include but are not limited to:

- establishment of a new zone substation
- decommissioning of an existing zone substation
- long duration (3 months) transfers while the network is being re-arranged and then returned to normal state

17.2.4 Harmonics

Voltage harmonic requirements are governed by the VEDCoP and the NER. The NER essentially requires that CitiPower adheres to the 61000.3 series of Australian and New Zealand Standards.

CitiPower is required to ensure that the voltage harmonic levels at the point of common coupling (for example, the service pole nearest to a residential premises), with the levels specified in the following table from AS 61000.3.6.

Table 17.4 Voltage harmonic distortion limits

Odd harmonics non-multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %
5	6	3	5	2	2
7	5	9	1,5	4	1
11	3,5	15	0,4	6	0,5
13	3	21	0,3	8	0,5
$17 \leq h \leq 49$	$2,27 \cdot \frac{17}{h} - 0,27$	$21 < h \leq 45$	0,2	$10 \leq h \leq 50$	$0,25 \cdot \frac{10}{h} + 0,25$
NOTE The compatibility level for the total harmonic distortion is THD = 8 %.					

CitiPower responds quickly to investigate and resolve voltage issues. The issues may be identified through the power quality meters that CitiPower 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, CitiPower will investigate and resolve the issue. The solutions that CitiPower 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, or
- installation of harmonic filtering equipment to improve voltage harmonic performance.

CitiPower 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.

18 Embedded Generation and Demand Management

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

18.1 Embedded generation connections

The table below provides a quantitative summary of the connection enquiries under chapter 5 of the NER and applications to connect EG units received in 2022.

Table 18.1 Summary of embedded generation connections

Description	Quantity (>5 MW)
Connection enquiries under 5.3A.5	0
Applications to connect received under 5.3A.9	0
The average time taken to complete application to connect in days	N/A
Description	Quantity (>30 kW and <5 MW)
Connection enquiries under 5A.D.2	146
Applications to connect received under 5A.D.3	48

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

- available capacity of the sub-transmission network is limited due to the existing and committed large-scale generators
- fault levels in the Melbourne CBD and tight allocations where applicants have sought to connect in dense supply areas.

18.2 Non-network options and actions

CitiPower actively seeks opportunities to promote non-network alternatives for both general and project-specific purposes. Up to summer 2022/23, the following details some of CitiPower's activities:

- CitiPower monitors industry developments and engages with providers of demand management and smart network technologies
- Over the next year CitiPower is actively exploring opportunities in the industry of Electric Vehicles (EV) technology and use cases. The purpose will be to determine future network effects of large uptake of the technology by customers as well as a variety of other considerations.
- In 2021, CitiPower trialled a residential demand management program for customers to voluntarily reduce demand and be rewarded during peak periods on specific distribution substations in the network. 392 customers registered to the program, which represented an uptake rate of 7% from customer base of 5,706. CitiPower called 4 events and yielded a total energy reduction of 3.1 MWh. This program is complemented by 'Energy Partner' program initiated in 2020 which allows us to directly control participating customers' Air-conditioning load. CitiPower is open to collaborate with partners who can add value to the programs from customer experience perspective while delivering network benefit cost-effectively.
- CitiPower participated in a feasibility study, led by Powercor and in partnership with 12 community energy groups and local councils, United Energy, and supported by the Department of Environment, Land, Water and Planning (DELWP) through the Neighbourhood Battery Initiative (NBI) program. This study aimed to identify opportunities for neighbourhood batteries and develop supporting information to assist community groups who are looking to explore a neighbourhood battery project. The outcomes of the study included the proposal of a potential program of battery projects to DELWP, the 'Powerful Neighbours Report' a comprehensive guideline for future battery projects as well as a series of animations to improve community and customer understanding of neighbourhood batteries.
- Through the feasibility study it was also identified that there is an interest from community energy groups, local councils, research organisations and DELWP in having a greater understanding of their local distribution network. Investigation has commenced regarding how this information may be shared with these stakeholders, with a prototype network visualisation tool being trialled with NBI partners. This mapping tool would also be able to demonstrate the locations and scale of network opportunities which may be addressed by non-network solutions.

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

18.3 Battery Programs

CitiPower is supporting network owned and 3rd party owned community batteries, for example through partnership with the Yarra Energy Foundation's 110kW/285kWh community battery installed in June 2022 at a CitiPower site in Fitzroy North. CitiPower has actively collaborated with several partners through the Victorian Government's Neighbourhood Battery Initiative program, with funding for two additional batteries within the CitiPower network announced by the Victorian Government in October 2022. These batteries aim to support increased DER hosting capacity as well as provide opportunities for 3rd party investment into assets that support the networks as a non-network solution.

18.4 Demand side engagement strategy and register

CitiPower updated and published its Demand Side Engagement Strategy in July 2019. The strategy is designed to assist non-network providers in understanding CitiPower'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.citipower.com.au/network-planning-and-projects/network-planning/#demand_side_engagement_strategy

CitiPower has also established its Demand Side Engagement Interested Parties Register. The register was established in mid-2013. It currently allows interested parties to provide contact details and other relevant information, 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@CitiPower.com.au

In 2022, no formal submissions from non-network providers were received however there are a total of 162 registered entities.

19 Information Technology and Communication Systems

This chapter discusses the investments we have undertaken in 2022, or plan to undertake over the forward planning period 2023-2027, relating to information technology (IT) and communications systems.

19.1 Security Program

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

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

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

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

19.2 Currency

We routinely undertake system currency upgrades across our IT systems to reflect vendor software release life cycles and support agreements. These refresh cycles are necessary to ensure system performance and reliability are maintained, and that the functional and technical aspects of our systems remain current.

In 2022, we began the following upgrades:

- Customer information system (CIS/OV) upgrade – this included upgrading the surrounding components of our customer information system, for example, database, operating system, to ensure currency
- Distribution Management System (DMS) upgrade – this included upgrading our current DMS to improve resilience and currency
- Telephony refresh – this includes an upgrade of our existing system which is nearing its end of life to deliver a more resilient platform to avoid the risk of incidents to the system.

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

- Outage Management System (OMS) upgrade – this includes migrating the current OMS off PowerOn Restore to PowerOn Advantage, map the LV model for improved safety outcomes and LV data quality.
- Market system upgrade – uplift capability of market systems applications, which support market transitions and data to be provided to the market

19.3 Compliance

We are focused on ensuring that, as regulated businesses, our IT systems support all regulatory, statutory, market and legal requirements for operating in the National Electricity Market (NEM). These obligations are regularly amended by various government bodies and regulators to reflect the changing energy market. We ensure compliance through prudent investment in systems, data, processes, and analytics that provide the requisite functionality and reporting capability to efficiently comply with statutory and regulatory obligations.

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

1. preparedness and readiness for the installation of 5-minute enabled meters by 1 December 2022,
2. ensuring AMI meter fleet installed after 1 December 2018 are configured to collect and send data in 5-minute intervals by 1 December 2022. Key Phase 2 changes include:
 - Upgrading of all key metering applications to be five-minute settlement compliant
 - Ensure all required meters are collecting, storing, and processing data in five-minute intervals

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

This year we also updated our key market systems to:

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

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

19.4 Infrastructure

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

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

This included:

- Deployed additional storage and data backup infrastructure to accommodate growing data volumes. The additional storage was delivered via the deployment of a new storage array, which will accommodate our projected data volumes in a more cost-effective fashion is approximately one tenth the physical footprint of the current device.
- Deployed dedicated infrastructure for the Network Analytics Platform, which is designed to support a more efficient and safer network for our customers.
- Refreshed critical network infrastructure to ensure we were on a fully supported solution, have the capacity to accommodate increasing network traffic volumes and

ensure that our network devices are able to have security patches applied to protect against cyber attacks

- Upgraded server infrastructure to ensure that we are on a fully supported solution, have the capacity to accommodate increasing application demands and ensure that our servers are able to have security patches applied to protect against cyber attacks
- Upgraded our Netscaler load balancer solution to ensure that we are on a fully supported solution, and ensure that the solution is able to have security patches applied to protect against cyber attacks
- Completed the rollout of Office 365 to all users to enable more users to work remotely without requiring a Citrix or VPN SSL remote access solution
- Completed the rollout of a new Windows 10 image, including providing new laptop devices to many users. The new Windows 10 solution includes an "always on" VPN solution to seamlessly connect to simplify the remote working experience.

During the forward planning period for this DAPR, we will continue to upgrade our underlying infrastructure to support our IT environments to maintain capacity, performance, and availability to ensure business continuity capability. We will also continue our program of gradually migrating some of our existing on-premises IT infrastructure to the cloud.

We have also initiated a program to consolidate the United Energy IT infrastructure into the CitiPower and Powercor data centres to achieve efficiencies and cost savings for both organisations.

19.5 Customer Enablement

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

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

In 2022 we also completed the following key technology initiatives:

- We digitised the capturing of customer reported faults, tracking of progress and rectification of these. This improves the user experience as customers are kept informed of the progress and closure of their claim.
- We enabled customers to track the end-to-end project status of their augmentation project and/or no-go zone enquiries. This provided customers will more accurate and up to date information on the status of their project, allowing for more informed decisions to be made

- We enhanced and expanded our solar pre-approval tool, rapidly increasing speed at which customers can obtain pre-approval for solar exports. This provides customers increased certainty and accuracy relating to their request for solar export and other customer energy resources

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

19.6 Becoming a more digital network

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

In 2022 we continued to grow the use of our enhancement to the Distribution Management System to actively manage network constraints resulting from solar or wind generators connected to our high voltage network. This has allowed more generation to be included in the distribution network and speed the decarbonisation of our energy sources.

The implementation of a strategic network analytics capability in 2021 has allowed us to implement in 2022 an active and dynamic voltage management solution across CitiPower and Powercor's networks which allow greater uptake of rooftop solar whilst maintaining system security on high demand days.

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

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats. In 2022 we trialled making network performance information available to a selected set of trial external users using a visualisation tool that is used within the business.

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

- Development of Dynamic Operating Envelope (DOE) methodologies based on AMI and other sensor data to determine how best to implement DOEs and guide investment requirement for ubiquitous integration in the future
- Trial an implementation of DOEs for commercial customers and residential customers to improve overall solar hosting capacities

- Implement a first-generation operational forecasting capability along with a complete digital network model from Terminal Station (transmission connection) to the customer connection
- Expand the visualisation of network performance to more community groups and entities

19.7 Other communication system investments

To facilitate and maintain the protection, control, and supervision of the network, we continue investment in Supervisory Control and Data Acquisition (**SCADA**) and the requisite network communication media and control equipment needed to achieve this. This is used to monitor and control the distribution network assets, including zone substations, Customer distribution substations and feeders.

In 2022 we have completed works on the following: -

- Full Retirement of 38 aging narrowband 900MHz Point to Multipoint (P-MP) Radio systems, and replacement with new 450Mhz Ethernet radio links with improved reliability, robustness and with real time performance monitoring and reporting.
- Commenced selection of MPLS technology to ease capacity issues on some sections of CitiPower's optical fibre network
- Initiation of the replacement of 10 aging 400MHz P-MP and PtoP narrowband Radio systems with new 450Mhz Ethernet radio links with improved reliability, robustness and with real time performance monitoring and reporting.
- Retrofitting of aging "Conitel" (VF) over Supervisory cable based signalling network control equipment in key CitiPower Distribution Substations (DSS) with modern DNP3 over Ethernet carried on Optic Fibre.
- Commenced 3G device replacement with new 4G technology introducing ISO55001 Asset Management functionality with centralised and remote configuration management and real time performance monitoring and reporting.
- Work closely with other Victorian DNSPs to leverage and share respective fibre network facilities to expand the business fibre network deployment footprint cost effectively to retire selected radio network links and improve communications reliability.

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

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

- where the manufacturer no longer supports the equipment which can no longer be upgraded and

-
- there is a reduced pool of skilled workers able to maintain the system.

We continue to modernise systems that are dependent on communications systems such as remote communications devices presently using the Telstra 3G Cellular network, such as Automatic Circuit Reclosers (**ACRs**), SWER ACRs, Gas Switches, Regulators, Cap Balancing Units and remote controlled HV switches, to 4G and 5G. Also, Powercor / CitiPower will be investing in MPLS technology to increase capacity to meet the future network needs.

20 Advanced Metering Infrastructure Benefits

This section discusses our use of advanced metering infrastructure (**AMI**) technology and how information generated by AMI is being used to better support life support customers, guide network planning and demand side response initiatives, and support network reliability initiatives. AMI technology is also being leveraged in our digital network initiatives presented in section 18.6 above.

20.1 Life support customers

We are using our AMI technology to service and support our vulnerable customers more effectively, allowing us to keep our communities safe.

We are keeping our customers and communities safe through being alerted to life support customers off supply more quickly through our AMI meters across our network. Our systems alert us if the supply to an AMI meter associated with a life support customer fails enabling us to more quickly resolve supply to the customer. This is key to our response planning for customers off-supply and allows us to understand the criticality of the disruption.

Our AMI technology also assists us in rotating load in emergencies. By rotating load, we can share energy among our customers in times of emergency. As such, we can prioritise life-support customers in these cases to ensure their power remains on.

We plan to continue to leverage AMI data and services to develop further benefits for our customers, including life support customers, over the forward planning period. An example of an initiative we are proposing under our Digital Network program which is reliant on our AMI includes more accurate mapping of customers to supplying LV transformers to help keep more life support customers connected during emergency load shedding and provide more accurate communications to customers of planned outages.

20.2 Network planning and demand side response

AMI technology has been critical in allowing us to innovate in the way we operate the network and deliver effective customer service. Visibility of the low voltage (**LV**) network has improved customer outcomes by lowering prices through more efficient network management, improved network safety and reliability outcomes and improved responsiveness to customer needs.

Our AMI meters provide us with the ability to improve safety by identifying neutral faults at customer premises. Our systems alert us if the supply to an AMI meter has a neutral fault enabling us to more quickly resolve it. The system identifies unsafe situations as they develop, so corrective action can be initiated immediately. This is key for maintaining safety for our network and our customers.

Using Victorian AMI specification also allows us to manage voltages and prevent load shedding and blackouts on peak demand days.

Further the Victorian AMI is vital for enabling growth in distributed energy resources (**DER**) such as rooftop solar, batteries and electric vehicles. AMI provides us with the information to manage the network and accommodate the dynamic and less predictable energy flows that result from the increasing uptake of DER technologies by Victorians. We also use our AMI data for more accurate spatial demand forecasting, ensuring we optimise timing of network augmentation. Information from our AMI meters also assist us with detecting of customer with solar connections that are not registered as solar customers and/or are exporting more than they are contracted to export.

Our AMI technology is also an essential input into our Digital Network program which will enable more demand response initiatives through our proposed DER management system as well as enable us to accommodate more solar with the existing network capacity. We plan to continue to leverage AMI data and services to develop new benefits for customers over our DAPR forward planning period. The following are some examples of initiatives we are proposing under our Digital Network program which are reliant on our AMI:

- Promoting electric vehicle uptake – monitoring and optimising EV charging to understand and estimate the impact of increasing demand on the distribution network resulting from EV penetration
- Optimising load control of customer appliances – optimising existing hot water load control and enabling new load control programs (e.g. air conditioners and pool pumps), including through utilising excess solar in the middle of the day
- Enhancing cost reflective incentives – analysing AMI interval data to construct more effective demand management incentives and time-of-use tariffs to reduce peak demand. This would improve overall utilisation of the distribution network, resulting in lower prices
- Detecting electricity theft – identifying sites with bypass connections and reduction of theft, as well as identifying unregistered DER
- Proactively managing asset failures—resulting in fewer fire-starts and avoided replacement expenditure
- Avoiding overblown fuses—improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacement expenditure from blown fuses.

20.3 Network reliability

AMI information is being used to support our network reliability measures. We have shorter outages due to earlier identification of faults and more efficient restoration. This is because AMI meters give us almost instant notification of customers going off supply. We receive immediate notification of outages from the AMI meter which feeds into our outage management systems and automatically schedules and dispatches field crew to restore supply.

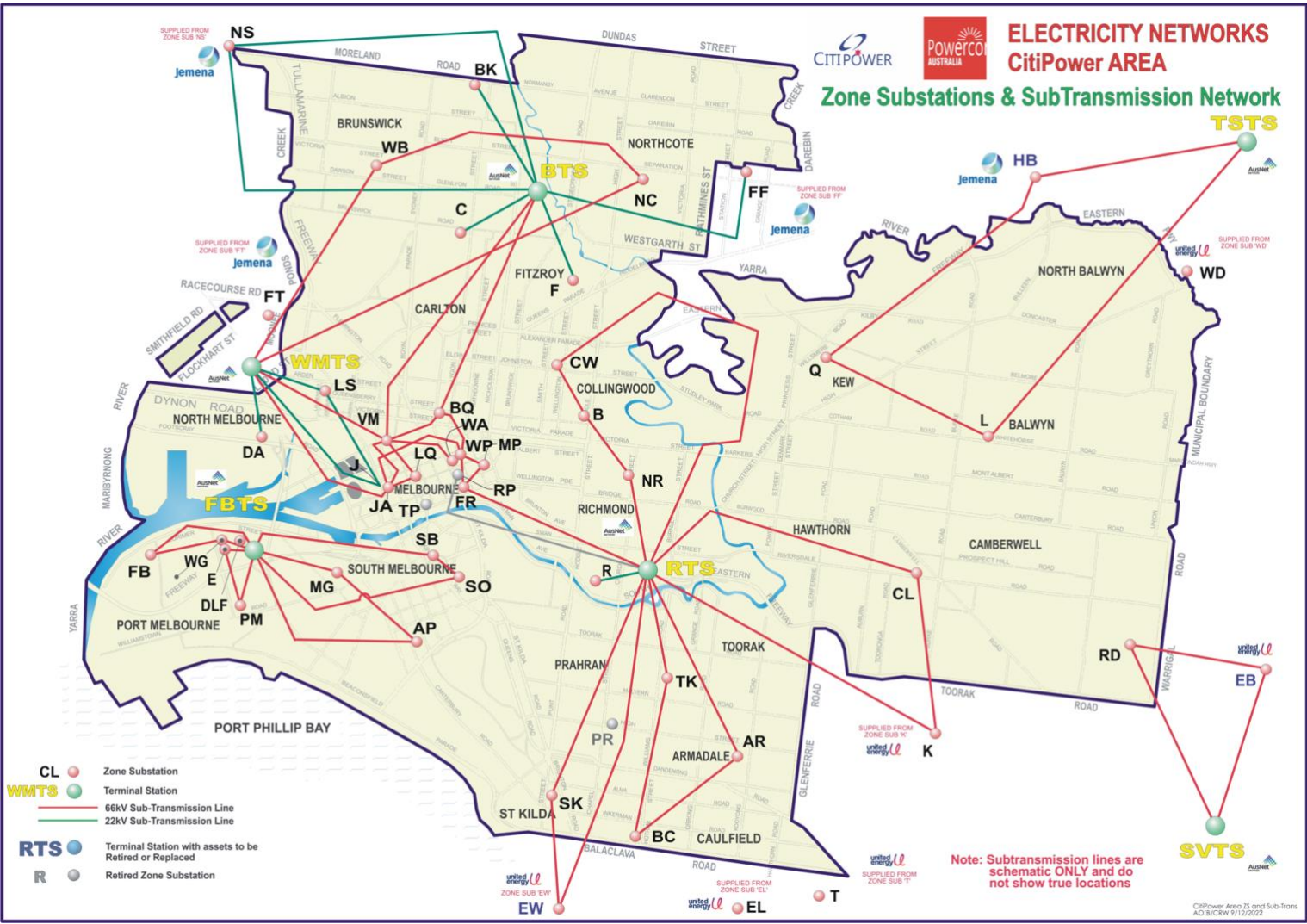
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. We have enhanced the AMI architecture to provide an engineering user interface for customer power quality information and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Our AMI technology also allows for supply capacity control enabling us to more effectively target load shedding to minimise supply impacts.

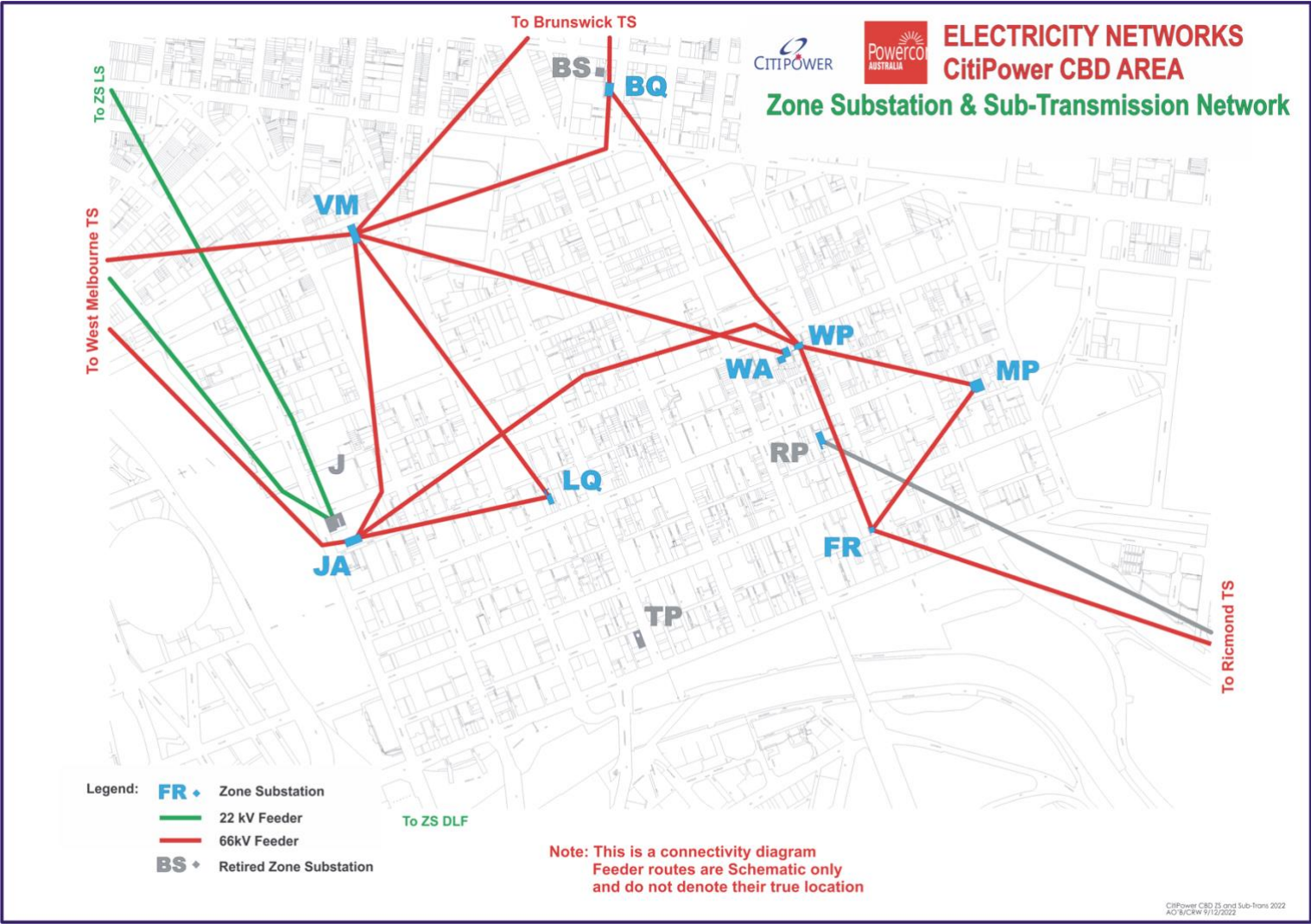
There is also improved quality of information and customer services during outages. We have developed an Interactive Voice Response service and SMS service which automatically advises customers of outages identified in a timely way through the last gasp AMI function. This has contributed to high levels of customer satisfaction with the service received. The quality of supply of information throughout the network is also enabling better network load profiling, identification of safety risks and voltage management.

Appendix A Maps

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

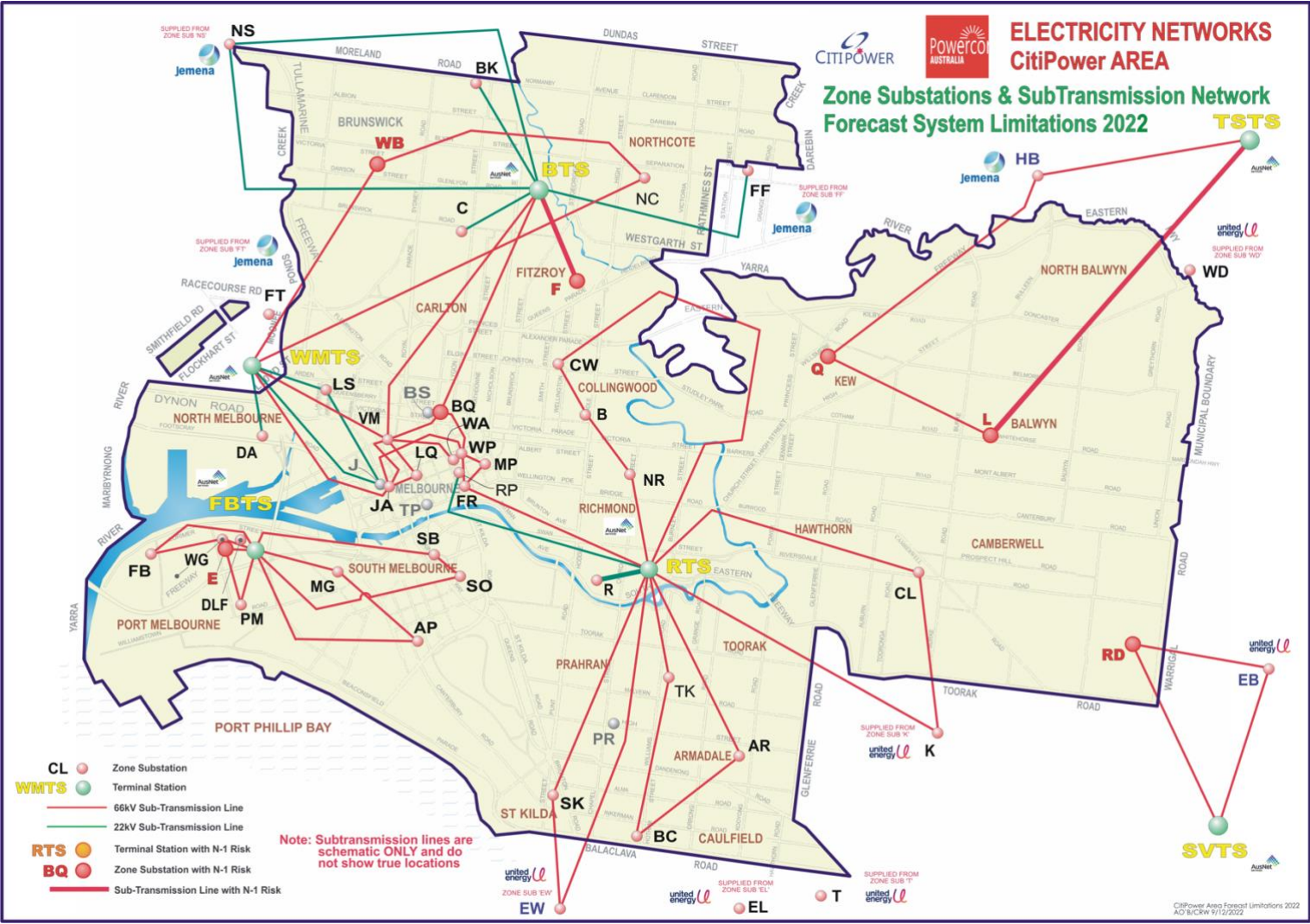


A.2. CBD area zone substations and sub-transmission lines

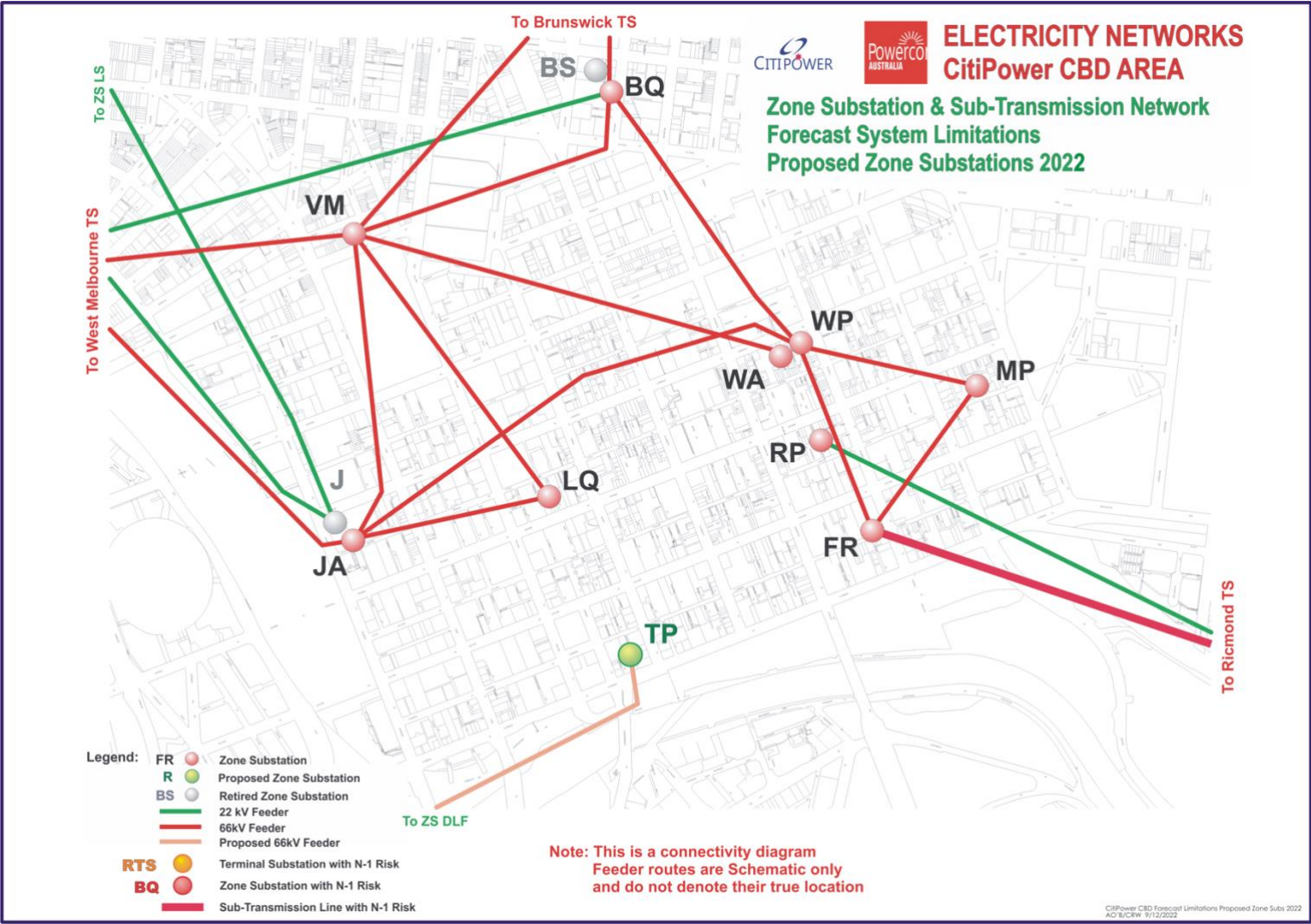


Appendix B Maps with system limitations and asset to be retired or replaced

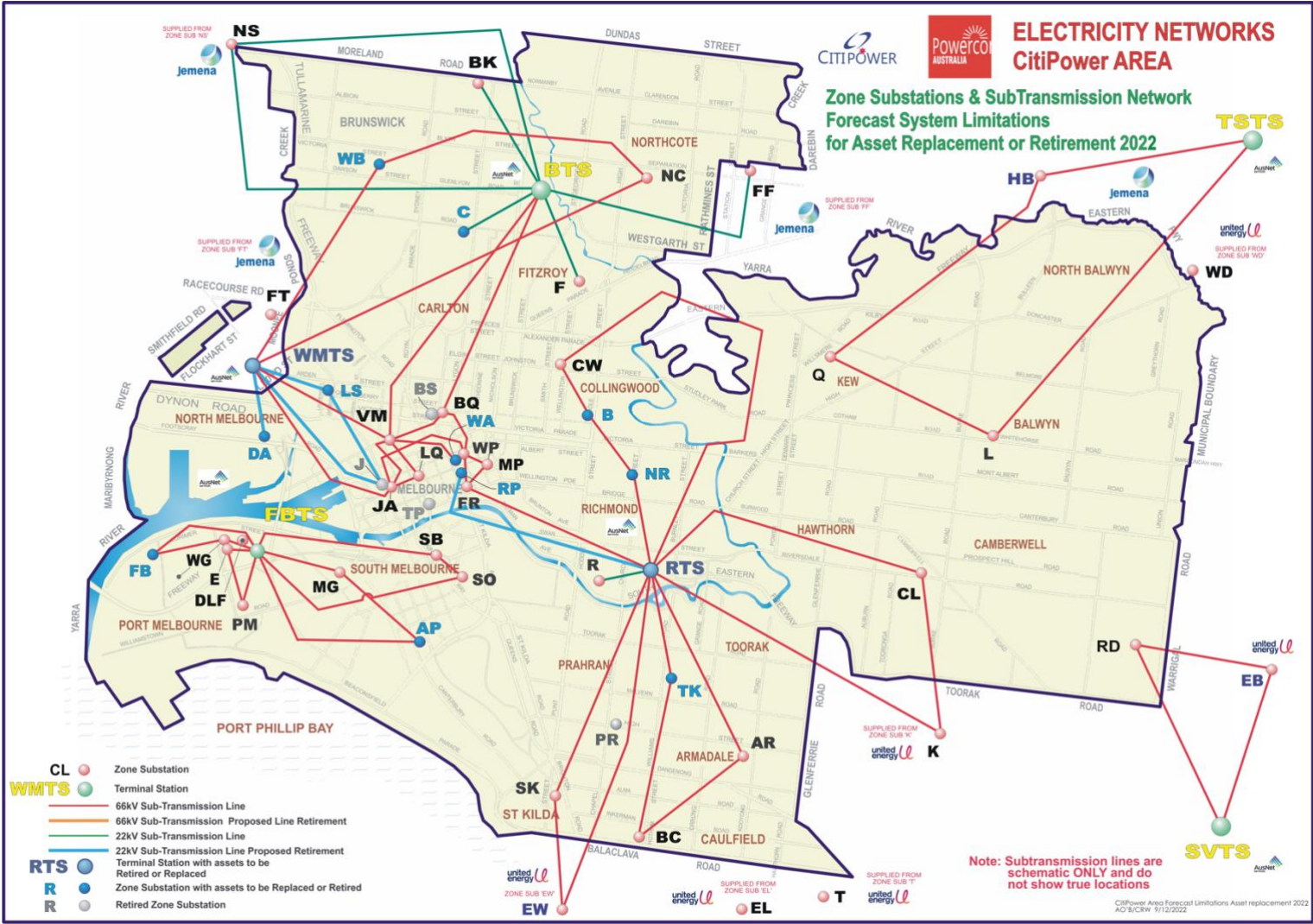
B.1. CitiPower area map with forecast system limitation



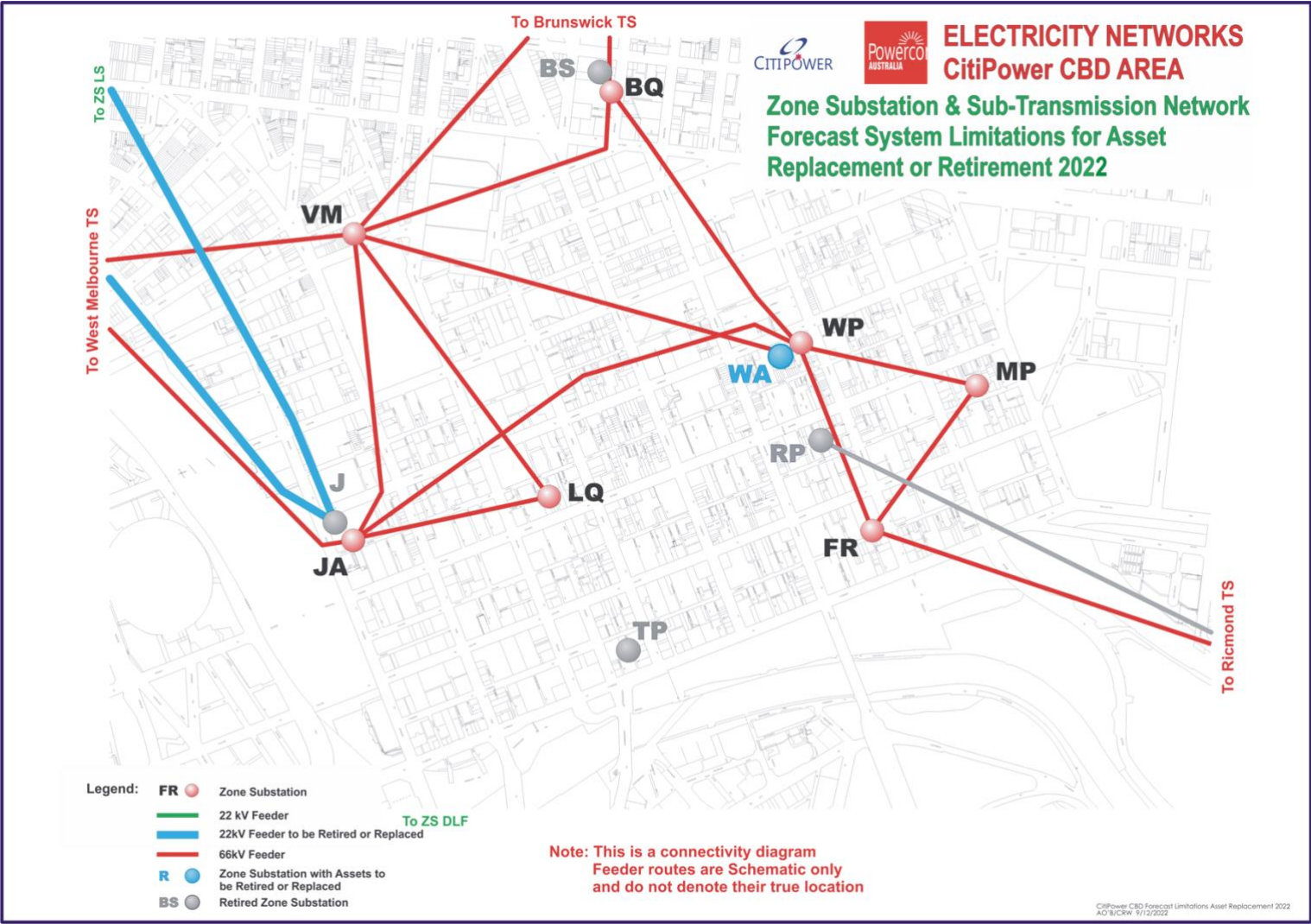
B.2. CBD area map with proposed zone substations



B.3. CitiPower area map with assets to be retired or replaced



B.4. CBD 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 CitiPower 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 (or the amount of generation that would need to be curtailed) 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 50 th percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.
Import rating	Import ratings define the network capability to transfer forward power flows (i.e., flows downstream towards customer loads) at that location.
Export rating	Export ratings define the network capability to transfer reverse power flows (flows from that location upstream towards the transmission point of connection).
Maximum demand	The highest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak load, as seen by the

	network.
Minimum demand	The lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units (as seen by the network, in aggregate) for the year. This is also referred to as the peak supply, as seen by the network.

C.2. Zone substation abbreviations

Abbreviation	CitiPower Zone Substation	Abbreviation	CitiPower Zone Substation
AP	Albert Park	MG	Montague
AR	Armada	MP	McIllwraith Place
B	Collingwood	NC	Northcote
BC	Balaclava	NR	North Richmond
BK	Brunswick	PM	Port Melbourne
BQ	Bouverie Queensberry	PR	Prahran
BS	Bouverie St	Q	Kew
C	Brunswick	R	Richmond
CL	Camberwell	RD	Riversdale
CW	Collingwood	RP	Russell Place
DA	Dock Area	SB	Southbank
DLF	Docklands	SK	St Kilda
E	Fishermans Bend	SO	South Melbourne
F	Fitzroy	TK	Toorak
FB	Fisherman's Bend	TP	Tavistock Place
FR	Flinders/Ramsden	VM	Victoria Market
J	Spencer Street	WA	Celestial Avenue
JA	Little Bourke Street	WB	West Brunswick
L	Deepondene	WG	Westgate
LQ	Little Queen	WP	Waratah Place
LS	Laurens Street		

C.3. Terminal station abbreviations

Abbreviation	Terminal Station (AusNet Services Asset)	Abbreviation	Terminal Station (AusNet Services Asset)
BTS	Brunswick	SVTS	Springvale
FBTS	Fisherman's Bend	TSTS	Templestowe
RTS	Richmond	WMTS	West Melbourne

Appendix D Asset Management Documents

CitiPower document references are:

Asset Management Policy: JEQA4UJ443MT-150-27559

Asset Management System Framework: JEQA4UJ443MT-150-27597

Strategic Asset Management Plan: JEQA4UJ443MT-150-27604

Asset Management Strategies subjects – the following table lists the asset management strategies that apply across all asset classes:

Asset management strategy subject	Purpose
Network Operations and Utilisation	Structured approaches to improvements to a range of operational functions which together improve operational performance of the network.
Asset Information and Systems	Asset data and information types, relationships between them and the systems used to manage asset data and information.
Network Performance	Performance improvement programs to meet network reliability and performance requirements over the regulatory period, and an increasingly complex generation and distribution landscape requiring sophisticated technical responses from CP/PAL
Bushfire Mitigation	Structured approaches to prevention of bushfires associated with the design, operation, construction and maintenance of network assets.
Vegetation and Line Clearance (<i>planned for future</i>)	Integration of vegetation and line clearance requirements into the asset management system to align with asset management objectives and ensure ongoing regulatory and statutory compliance.
Connections, Augmentation and Replacement	Improvement programs to manage the connections, augmentation and replacement processes to ensure the network remains capable of distributing a reliable supply of electricity to customers
Maintenance Management	The rationale behind various maintenance management initiatives, projects and plans that together ensure the right maintenance is delivered at the right time and in the right way.
Network Safety	Integration of network safety practices into the asset management system to ensure visibility of regulatory and statutory compliance obligations, and alignment with asset management objectives.
Future Grid	Technologies and smart networks (including batteries, solar and wind generation, decentralised generation, demand management, metering, demand management) and associated impacts on network design, dynamics, monitoring and corresponding changing skill requirements.
Environment and Sustainability (<i>planned for future</i>)	Integration of environment and sustainability requirements into the asset management system to ensure visibility of regulatory and statutory compliance obligations and alignment with asset management objectives.
Asset Management System Performance (<i>planned for future</i>)	Description of the strategies and objectives that CP/PAL use to measure asset management system performance, and ensure optimum asset management system effectiveness, efficiency and continued alignment with the SAMP objectives.
Asset Management System Resources (<i>planned for future</i>)	The assessment, selection, development, procurement or acquisition, deployment and application of human and non-human resources required to develop and implement the CP/PAL asset management system, and implement and monitor the asset management objectives.

Asset Class Strategies – the following table lists the asset class strategy subjects and the asset coverage of each strategy:

Asset class strategy subjects	Asset coverage
Poles and towers	Wood, concrete, and steel poles Steel lattice towers
Pole top structures	Pole top structures including crossarms and insulators HV fuses Surge arresters
Overhead conductors	Bare conductors (aluminium, copper, steel) High voltage aerial bundled cable Low voltage aerial bundled cable Covered conductor
Underground cables	Sub transmission, high voltage and low voltage cables Cable pits Cable pillars Auxiliary services Cascade LV lighting cables
Zone transformers	Zone substation transformers, regulators and autotransformers Transformer bushings Transformer tap changers Transformer water cooling systems
Distribution substation plant miscellaneous	Regulators Capacitors Capacitor balancing units
Public lighting	Luminaires PE cells Brackets
Zone substation plant miscellaneous	Capacitor banks Capacitor bank step switches Reactors Static VAR compensators Instrument transformers Surge diverters Steel work Fire walls Neutral earth resistors (NER) Rapid earth fault current limiter (REFCL) systems Direct current (DC) supply systems Station low voltage (LV) supply systems
Distribution transformers	Pole transformers Kiosk transformers Ground transformers Indoor transformers
SCADA and communications	Optic fibre cable Supervisory cable Digital microwave radio Cellular radio Voice over IP (VoIP) system RTUs
Zone switchgear	Circuit breakers Switchboards Outdoor busses Switches

Asset class strategy subjects	Asset coverage
Protection and control	6.6kV, 11kV, 22kV, 66kV and zone substation protection schemes and relays Line and feeder protection schemes Bus and station protection schemes Transformer protection schemes Cap bank protection schemes
Property and facilities	Zone substation buildings Zone substations leases Non kiosk ground or below ground distribution substations Communications buildings
Metering	AMI network communications AMI single phase direct connected meters AMI three phase direct connected meters AMI LV CT connected three phase meters. Low voltage metering current transformers Pole top high voltage metering VT & CT transformers (CP/PAL owned) Boundary metering HV & EHV Zone substation metering transformers (CP/PAL owned) Legacy type 5 MRIM Meters Legacy type 6 (basic) Meters Timber meter boards (includes CP/PAL owned fuse or facia mounted service protective device (SPD) holders and neutral links)
Distribution switchgear	Circuit breakers Automatic circuit re-closers (ACRs) Switches Ring main units (RMUs)
Service lines	Overhead low voltage service assets Service cable attachment fittings Service protection devices Junction boxes